142 FERC ¶ 61,205
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony Clark.

Southwest Power Pool, Inc. Docket No. ER12-1179-002

ORDER ON REHEARING AND CLARIFICATION

(Issued March 21, 2013)

1. In this order, the Commission addresses requests for clarification and/or rehearing of an order dated October 18, 2012 that conditionally accepted for filing, subject to further modifications, a proposal by Southwest Power Pool Inc. (SPP) to revise its Open Access Transmission Tariff (Tariff) to implement an Integrated Marketplace.[1] Here, the Commission grants in part and denies in part requests for clarification and/or rehearing of the October Order.

I. Background

2. On February 10, 2004, the Commission conditionally granted SPP's application for recognition as a regional transmission organization (RTO), subject to SPP making tariff, organizational and other changes prior to qualifying for RTO status.[2] On October 1, 2004, when acting on SPP's compliance filing, the Commission found that SPP's

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[1] *Southwest Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012) (October Order).

[2] *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 2, *order on reh'g*, 109 FERC ¶ 61,010 (2004).

proposal to become an RTO satisfied the requirements of Order No. 2000,[3] and thus the Commission granted SPP RTO status.[4]

3. In an order dated March 20, 2006, the Commission rejected, in part, and conditionally accepted and suspended, in part, SPP's filing to establish an Energy Imbalance Service (EIS) market and market monitoring and mitigation plan, subject to further Commission orders.[5]

4. On January 26, 2007, the Commission accepted SPP's certification that it was ready to start the EIS market on February 1, 2007.[6] In its certification filing, SPP stated that upon the successful implementation of the EIS market, the SPP Strategic Planning Committee determined that it was important to assess opportunities for future market development. Following that recommendation, SPP created the Cost Benefit Task Force, with representatives and members from the Regional State Committee, which SPP tasked with working with a third-party consultant to develop a cost-benefit analysis. SPP contracted with Ventyx to analyze the costs and benefits of four options for SPP future market design. Ventyx recommended in 2009 that SPP institute a market design combining a day-ahead market with unit commitment and a co-optimized energy and ancillary services markets as quickly as possible, because of the estimated net benefits that would average approximately $100 million per year.[7]

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[3] *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 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[4] *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 (2004), *order on reh'g*, 110 FERC ¶ 61,137 (2005).

[5] *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289, *order on reh'g*, 116 FERC ¶ 61,289 (2006).

[6] *Southwest Power Pool, Inc.*, 118 FERC ¶ 61,055, *reh'g denied*, 120 FERC ¶ 61,018 (2007).

[7] SPP notes that the study has been updated with an assumption of low gas prices and the estimated net benefit drops to $45 million per year. SPP's February 29, 2012 Submission of Tariff Revisions to Implement SPP Integrated Marketplace, Exh. No. SPP-1 at 8 (February 2012 Filing).

5. On February 29, 2012, SPP filed its proposal to implement the Integrated Marketplace. On May 15, 2012, SPP filed an amendment to revise its February 2012 Filing that included major changes to its market mitigation measures, and addressed certain clean-up items and inconsistencies that SPP identified after it submitted the February 2012 Filing.[8]

6. In the October Order, the Commission conditionally accepted for filing, subject to further modifications and compliance filings, SPP's proposal to revise its Tariff to implement the Integrated Marketplace, effective March 1, 2014, as requested. The Commission noted SPP's intention to submit its Readiness and Reversion Plans, and to submit a Readiness Certification ahead of market-start-up. The Commission conditioned its acceptance of SPP's proposed Tariff revisions upon SPP filing these plans. Finally, the Commission required SPP to file an informational report 15 months after market start-up to evaluate the effectiveness of the Integrated Marketplace.

7. As conditionally accepted in the October Order, the Integrated Marketplace includes the following major market-design components: (1) day-ahead energy and operating reserve market; (2) day-ahead and intra-day Reliability Unit Commitment (RUC) processes; (3) real-time balancing market; (4) price-based co-optimized energy and operating reserve procurement; (5) market-based congestion management process including a market for transmission congestion rights (TCRs) and allocation of auction revenue rights (ARRs);[9] (6) consolidation of 16 Balancing Authority Areas in the SPP footprint into a single Balancing Authority Area operated by SPP; (7) multi-day reliability assessment performed prior to the day-ahead market to manage the commitment of long-start resources; and (8) market monitoring and mitigation with an internal market monitor (Market Monitor).

II. <u>Requests for Rehearing and/or Clarification</u>

8. Requests for rehearing and/or clarification of the October Order were filed by: SPP; Golden Spread Electric Cooperative, Inc. (Golden Spread); Westar Energy, Inc.

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[8] SPP's May 15, 2012 Amendatory Filing of Tariff Revisions to Implement SPP Integrated Marketplace (May 2012 Amendment). The February 2012 Filing, as amended by the May 2012 Amendment, will be referred to herein as the SPP Proposal.

[9] The term "congestion management" refers to a process that recognizes the physical limitations of the existing transmission grid and, based on those limitations, adjusts the production of various generation and demand resources.

(Westar); TDU Intervenors;[10] and Nebraska Public Power District (NPPD). The requests for rehearing and/or clarification address a number of issues, including specifically the following: (1) limited day-ahead must-offer obligation; (2) make whole payments; (3) marginal losses; (4) timing of compliance with Order No. 755; (5) market-based congestion management; (6) grandfathered agreements (GFAs); (7) seams and reserve sharing; (8) implementation of market-to market protocols with the Midwest Independent Transmission System Operator, Inc. (MISO); and (9) market power mitigation. We describe and address the issues raised in the requests for rehearing and/or clarification in greater detail below.

9. Answers to requests for rehearing and/or clarification and/or answers to answers were filed by: Electric Power Supply Association; SPP; SPP Transmission Owners; Lincoln Electric System; and MISO.

III. Discussion

A. Procedural Issues

10. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d)(1) (2012), prohibits an answer to a request for rehearing. Therefore, we will reject the answers from Electric Power Supply Association, SPP, SPP Transmission Owners, Lincoln Electric System, and MISO.

B. Day-Ahead and Real-Time Balancing Market

1. Must-Offer Requirement

a. Day-Ahead Must-Offer Requirement

i. October Order

11. In the October Order, the Commission conditionally accepted SPP's limited day-ahead must-offer requirement,[11] subject to compliance requirements. The Commission

[10] TDU Intervenors include the following four transmission-dependent utilities located in SPP: City of Independence, Missouri; Kansas Power Pool; Missouri Joint Municipal Electric Utility Commission; and West Texas Municipal Power Agency.

[11] The limited day-ahead must-offer requirement obligates each load-serving market participant to offer sufficient resources to cover its expected daily peak load for the operating day (as estimated by the market participant) plus operating reserve

(continued…)

rejected requests to expand the day-ahead must-offer requirement to all resources. In doing so, the Commission found that it had not required and, in some cases, had rejected a day-ahead must-offer requirement in other RTOs and Independent System Operators (ISOs) absent a capacity payment. The Commission further noted that SPP had not proposed an enhanced resource adequacy construct as part of its Integrated Marketplace proposal.[12] The Commission also found that virtual trading in the Integrated Marketplace would aid in driving price convergence between the day-ahead and real-time markets.[13] Additionally, the Commission required SPP to develop a process to ensure market participants offer sufficient resources to cover their load.[14] The Commission also required SPP to revise its Tariff to specify that SPP's Market Monitor would monitor for various manipulative practices, including those relating to physical withholding.[15] The Commission also required SPP to file an informational report 15 months after the commencement of the Integrated Marketplace, including a non-public description of any potential manipulative practices observed in the day-ahead market, among other reporting requirements.[16]

ii. <u>Request for Rehearing and Clarification</u>

12. TDU Intervenors contend that the Commission erred by accepting SPP's limited day-ahead must-offer requirement without giving substantive consideration to concerns that this requirement will result in "an unduly thin" day-ahead market and unjust and unreasonable day-ahead prices.[17] TDU Intervenors further argue that the Commission erred in requiring SPP's compliance filings to address only concerns regarding the impact

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obligations (as estimated by SPP), to the extent that the market participant has available resources.

[12] October Order, 141 FERC ¶ 61,048 at PP 51-52 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,280, at P 96 (2003)).

[13] *Id.* P 53.

[14] *Id.* P 54.

[15] *Id.* P 55.

[16] *Id.* P 56.

[17] TDU Intervenors' Request for Rehearing and Clarification at 2.

of the limited day-ahead must-offer requirement on real-time prices and price convergence.[18]

13. TDU Intervenors argue that the Commission's determination on the limited day-ahead must-offer proposal omits any consideration of the issues regarding the direct effects of SPP's proposal on prices in the day-ahead market, focusing almost exclusively on its potential consequences for the real-time market and price convergence. TDU Intervenors argue that this omission is significant because SPP has not provided, and the Commission has not required, a market power study for the new day-ahead energy market. Absent such a study, TDU Intervenors assert that the risk remains high that Market Participants will attempt to exercise market power in the day-ahead market. TDU Intervenors remain concerned that there has been no meaningful demonstration that the day-ahead market, without a more comprehensive must-offer requirement, i.e., one that requires market participants to offer all available capacity into the day-ahead market, will be sufficiently competitive to produce just and reasonable locational marginal prices (LMP). On rehearing, TDU Intervenors contend that the Commission must "expressly tackle" this issue and act to ensure just and reasonable day-ahead market prices. At a minimum, TDU Intervenors request that the Commission expand SPP's obligation to monitor for manipulative behavior to include monitoring for artificially high prices in the day-ahead market.[19]

14. TDU Intervenors assert that the Commission's reliance on the existence of virtual trading to drive price convergence between the day-ahead and real-time markets is misplaced, as it ignores the possibility that the prices in both markets could converge on an unreasonably high price. TDU Intervenors explain that the Commission's directive that SPP discuss in its 15-month report the effects of the must-offer requirement on the extent of price divergence between its day-ahead and real-time markets is insufficient. Accordingly, TDU Intervenors request that the Commission require SPP to explain how the limitations on the day-ahead must-offer requirement contribute to distortion of both day-ahead and real-time prices in its 15-month report.[20]

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[18] *Id.*

[19] *Id.* at 5.

[20] *Id.* at 6.

iii. **Commission Determination**

15. We clarify that the Commission's directive in the October Order requiring that the SPP Market Monitor report on any potential manipulative practices observed in the day-ahead market includes monitoring for and reporting of excessive day-ahead prices. However, to remove any ambiguity regarding the Commission's expectations, we will require that SPP, in a compliance filing due 30 days after the issuance of this order, revise section 4.4 of Attachment AG in its Tariff to state that "Such actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices *(including actions resulting in excessive day-ahead clearing prices)*, market conditions, or market rules for electric energy or electric products are prohibited."[21]

16. We will not require SPP to discuss how limitations on the day-ahead must-offer requirement contribute to distortion of both day-ahead and real-time prices. If SPP's Market Monitor observes real or potential price distortion during the first year of market operations, we expect SPP's Market Monitor to discuss these observations in the 15-month informational report, including potential reasons for the observed distortions. In regard to TDU Intervenors' concerns regarding the exercise of market power and its impact on day-ahead prices, we reiterate that any seller wishing to make market-based rate sales of energy within the SPP market must provide in its application for market based rate authority a study demonstrating that it does not possess market power. Additionally, we note that SPP is continuing to refine a comprehensive mitigation proposal for the Integrated Marketplace.[22]

b. **Deliverability**

i. **October Order**

17. The October Order required SPP to clarify on compliance how it will ensure that offered resources are deliverable to the load they were offered to cover. The Commission further required SPP to modify its Tariff, if necessary, to reflect verification of deliverability.[23]

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[21] New language appears in italics.

[22] *See* October Order, 141 FERC ¶ 61,048 at P 386.

[23] *Id.* P 55.

ii. Request for Clarification

18. TDU Intervenors request that the Commission clarify that the requirement to demonstrate deliverability applies only in the context of a market participant's offer of resources other than designated resources. TDU Intervenors note that SPP studies all designated resource requests to ensure that they can be delivered to load. Thus, TDU Intervenors argue that there is no reasonable basis for shifting to customers an obligation to demonstrate deliverability of designated resources.[24]

iii. Commission Determination

19. We deny TDU Intervenors' request for clarification regarding the demonstration of deliverability as being beyond the scope of the instant proceeding. Unless and until a compliance filing is before us that raises the issue of whether SPP will shift to customers a deliverability obligation for designated resources, TDU Intervenors' concerns are speculative. TDU Intervenors may raise the issue of the deliverability of designated resources in response to SPP's compliance filing, as appropriate, and the Commission will address any such concerns within the context of that proceeding.[25]

c. Informational Report

i. October Order

20. The October Order required SPP and its Market Monitor to file with the Commission an assessment of Integrated Marketplace performance after the first year of market operations, with special attention given to various components of the marketplace, such as the limited day-ahead must-offer requirement. Specifically, the Commission required SPP and its Market Monitor to file an informational report with the Commission 15 months following commencement of the Integrated Marketplace to reflect a full 12 months of data. The Commission stated that this 15-month report was for informational purposes only and would not be formally noticed or acted upon by the Commission.[26]

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[24] TDU Intervenors' Request for Rehearing and Clarification at 8.

[25] SPP submitted a compliance filing on February 15, 2013 in Docket No. ER12-1179-003.

[26] October Order, 141 FERC ¶ 61,048 at P 50, n.58.

ii. Request for Rehearing

21. TDU Intervenors argue that the Commission is statutorily obligated to ensure that the Integrated Marketplace produces just and reasonable rates. Thus, they allege that the Commission's statement that it will not act on the report is tantamount to abdicating this statutory responsibility. TDU Intervenors request that the Commission remain open to further action, based on information provided in the 15-month report. TDU Intervenors also request that the Commission invite comments on the 15-month report from Market Participants and other interested parties to satisfy due process requirements and to develop a complete record.[27]

iii. Commission Determination

22. We deny TDU Intervenors' request that the Commission formally notice and act upon the 15-month informational report. The Commission uses informational reporting as a compliance tool to monitor the effectiveness of proposals after their implementation and to provide publicly available information to interested stakeholders.[28] While the Commission will not formally act on the 15-month report itself, we clarify that the Commission may take action, if deemed necessary, under section 206 of the Federal Power Act (FPA)[29] if the Commission observes or suspects that manipulative behavior or inadequacies in market rules and/or market design may be contributing to unjust and unreasonable rates and undue discrimination. Additionally, although the 15-month report will not be formally noticed, market participants and other interested stakeholders may use the report to inform SPP stakeholder processes and/or to file a complaint with the Commission under section 206 of the FPA.

2. Make Whole Payments

a. October Order

23. In the October Order, the Commission found that it was inappropriate to assess day-ahead make whole payment costs to resource offers, import interchange transaction

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[27] TDU Intervenors' Request for Rehearing and Clarification at 6-7.

[28] *See, e.g., Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,218, at PP 35, 36, 45 (2009); *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172, at PP 240, 257 (2008); *see also Southwest Power Pool, Inc.*, 128 FERC ¶ 61,114, at PP 130-131 (2009).

[29] 16 U.S.C. § 824e (2006).

bids, and virtual energy offers (i.e., supply-increasing transactions), and it required SPP to remove these transactions from its day-ahead make whole payment charge provisions.[30] The Commission also required SPP to modify its make whole payment provisions to specify that only SPP-committed resources are eligible to receive make whole payments.[31] Finally, the Commission conditionally accepted SPP's proposal to provide make whole payments to resources on low voltage facilities that respond to local reliability issues, specifying that these payments should be allocated locally rather than regionally.[32]

b. Request for Rehearing and Clarification

24. TDU Intervenors argue that, although supply-increasing transactions may make it less likely that SPP will have to commit additional resources in the day-ahead market, these resources may also reduce day-ahead market prices. TDU Intervenors contend that these lower prices make it more likely that resources committed by SPP in the day-ahead market do not recover their costs through market revenues, resulting in the incurrence of a make whole payment. TDU Intervenors also point out that supply-increasing transactions are allocated RUC make whole payment costs. TDU Intervenors further note that in the October Order, the Commission found it reasonable to allocate RUC make whole payment costs to import interchange transactions because these transactions could reduce real-time market revenues.[33] TDU Intervenors also assert that day-ahead commitments are more likely to result in significant make whole payments than resource commitments made in the RUC process, because not all resources are available for commitment in the day-ahead market. TDU Intervenors request that the Commission reverse this ruling and follow cost causation principles by allocating day-ahead make whole payment costs to supply-increasing transactions.[34]

25. Additionally, TDU Intervenors note that local resources committed to address local reliability issues may initially be committed by transmission operators rather than by SPP itself. For purposes of clarification, TDU Intervenors request that the

[30] October Order, 141 FERC ¶ 61,048 at PP 145, 152.

[31] *Id.* P 144.

[32] *Id.* PP 184-185.

[33] TDU Intervenors' Request for Rehearing and Clarification at 9 (citing October Order, 141 FERC ¶ 61,048 at P 171).

[34] *Id.* at 10.

Commission clarify that such local resources will be deemed "SPP-committed" for purposes of being eligible for make whole payments.[35]

c. Commission Determination

26. We deny TDU Intervenors' request to allocate day-ahead make whole payment costs to supply-increasing transactions. We disagree with TDU Intervenors' characterization of the day-ahead context as it relates to the allocation of day-ahead make whole payment costs. Supply-increasing transactions do not increase the commitment costs incurred in the day-ahead market and, therefore, these transactions should not be allocated such costs. Day-ahead resource offers include start-up, no-load, and energy offer costs, and SPP commits resources in the day-ahead market using a solution that minimizes these costs to meet cleared bids. Thus, supply-increasing transactions receive day-ahead make whole payments because they represent part of the minimized costs to serve cleared bids; they should not in turn have to pay for their own compensation as TDU Intervenors' request. TDU Intervenors also fail to demonstrate that any price impacts warrant the allocation of day-ahead commitment costs to supply-increasing transactions. Further, in the RUC and real-time context, the reasons for incurring make whole payments costs are more numerous than the day-ahead period and include, for example, deviations from scheduled day-ahead generation, thus making it appropriate to allocate RUC make whole payment costs to supply-increasing transactions. Additionally, TDU Intervenors do not support their claim that day-ahead commitments are more likely to result in significant make whole payments than resource commitments in the RUC process, nor do they adequately explain why resources offered and cleared in the day-ahead market should pay for such costs. Moreover, we find this assertion speculative. Finally, we note that other RTOs and ISOs exclude supply-increasing transactions from day-ahead make whole payment cost allocation methodologies. For example, MISO excludes supply-increasing transactions from paying day-ahead Revenue Sufficiency Guarantee charges, which are similar to SPP's day-ahead make whole payment charges.[36] For these reasons, we deny TDU Intervenors' request.

27. With respect to the treatment of low-voltage facilities, we grant TDU Intervenors' request and clarify that local resources committed to address reliability issues will be deemed "SPP-committed" for purposes of being eligible for make whole payments. During emergency conditions, some low-voltage resources may be committed by local

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[35] *Id.*

[36] Midwest Independent Transmission System Operator, Inc., FERC FPA Electric Tariff, 39.3.1A, Day-Ahead Revenue Sufficiency Guarantee Charges, 0.5.0.

transmission operators. In this circumstance, the local transmission operator is required to inform SPP of the commitment. As explained in the October Order, the Commission required SPP to review commitments made by local transmission operators after the emergency commences to ensure that the commitments are made in a non-discriminatory manner.[37] Because such commitments will be reviewed by SPP, it is reasonable to deem such commitments as "SPP-committed" for the purposes of being eligible for make whole payments.

3. Marginal Losses

a. October Order

28. In the October Order, the Commission found that SPP's proposal to use the marginal loss method in calculating losses was a just and reasonable approach.[38] However, the Commission found that SPP's refund methodology appeared to impermissibly refund surplus losses to individual Market Participants in proportion to their contribution to the surplus.[39] Therefore, the Commission directed SPP to submit a compliance filing either explaining why its refund proposal was not a direct reimbursement or proposing an alternative methodology.

29. In the October Order, the Commission also denied NPPD's request for a transitional refund period to mitigate the initial impact of using marginal losses. The Commission found that NPPD had not shown that a transitional refund period was necessary. Specifically, the Commission found that although NPPD based its request upon the Commission's approval in MISO of a transitional refund period, the Commission concurred with SPP's analysis that distinguished specific factors in the MISO market from the SPP market.[40] In the MISO TEMT II Order, the Commission

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[37] October Order, 141 FERC ¶ 61,048 at P 185.

[38] *Id.* P 210 (citing *Midwest Indep. Sys. Operator, Inc.*, 102 FERC ¶ 61,196, at P 53 (2003); *Cal. Indep. Sys. Operator Corp*., 116 FERC ¶ 61,274 at PP 90-95; *Atlantic City Electric Co. v. PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,169 (2006)).

[39] October Order, 141 FERC ¶ 61,048 at P 211 (citing *Northeast Util. Serv. Co.*, 109 FERC ¶ 61,204, at P 21 (2004)(finding that a direct reimbursement to customers of the amount of over-collection is inappropriate as it diminishes the price signal provided by marginal loss pricing)).

[40] October Order, 141 FERC ¶ 61,048 at PP 207, 213.

recognized that MISO did "not have prior experience operating as a single power pool and ha[d] only a short period of experience operating under a single reliability framework."[41] Further, the Commission concluded that MISO and its customers lacked experience with LMP.[42] In contrast, the Commission determined in the October Order that the circumstances present in MISO that justified the need for a transitional refund period in that case are not present in SPP. Moreover, the Commission determined that in order to find that a transitional refund period for SPP was warranted based upon the MISO precedent, NPPD would have to explain why it would be adversely affected by the lack of a transitional refund period. The Commission concluded that NPPD had not made this showing.[43]

b. <u>Request for Rehearing</u>

30. NPPD argues that the Commission acted arbitrarily and capriciously in finding that a transitional refund mechanism was not necessary, and in finding that NPPD had not shown that it would be adversely affected by the lack of a transitional refund period.[44] NPPD contends that, in the MISO TEMT II Order, the Commission required the development of a mechanism to return marginal loss surplus revenues to customers in a way that is equitable and that does not distort the marginal price signal.[45] NPPD asserts that the MISO TEMT II Order recognized a transitional mechanism that allowed for marginal loss calculations, but suspended marginal loss charges above average or historical loss charges for a period of five years.[46] NPPD asserts that the Commission explained that the transitional refund mechanism was necessary so as to "give market participants more time to adjust to the LMP approach for setting prices and to develop confidence in market processes…."[47] Accordingly, NPPD argues that the Commission erred in failing to require a transitional refund mechanism.

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[41] *Id*. P 208 (quoting Midwest Indep. Transmission Operator, Inc., 108 FERC ¶ 61,163, at P 73) (2004) (MISO TEMT II Order).

[42] *Id.*

[43] *Id*. P 213 and n.297 (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at P 68).

[44] NPPD Request for Rehearing at 9.

[45] *Id.* (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at P 66).

[46] *Id.* at 9-10 (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at P 66).

[47] *Id.* at 10 (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at P 73).

31. Moreover, NPPD asserts that, contrary to the findings in the October Order, NPPD explained the harm that it would experience from the Commission's failure to approve a transitional refund mechanism as implemented in MISO. Specifically, NPPD argued there was a risk that the Market Participants would not receive the refunds of the over-collections of transmission losses, and that because SPP's proposed methodology was too complicated and unclear, SPP might not refund the over-collection of transmission losses to Market Participants in proportion to their contributions to the marginal loss surplus.[48] Finally, NPPD asserts that it covers a large geographic area with lengthy transmission lines from its network resources to its load centers. For this reason, NPPD asserts that it will be the type of entity that experiences a significant over-assessment of marginal losses, especially compared to the current average loss method.[49]

32. NPPD also seeks clarification that parties will not be foreclosed from raising the need for a transitional refund mechanism in connection with SPP's compliance filing that proposes a new surplus refund mechanism for its marginal loss methodology.[50]

c. <u>Commission Determination</u>

33. We deny NPPD's request for rehearing and clarification. We disagree with NPPD that the Commission acted arbitrarily and capriciously in finding that a transitional refund mechanism was not necessary, and that NPPD had not shown that it would be adversely affected by the lack of a transitional refund period. In the October Order the Commission stated:

> While NPPD describes the unique circumstances that warranted a transition period in the MISO proceeding, SPP has demonstrated that the circumstances present in MISO are not present in SPP. For the Commission to find that a transition for SPP is warranted, based upon the MISO precedent, NPPD would have to explain why it would be adversely affected by the lack of a transitional refund period. NPPD has not made that showing here.[51]

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[48] NPPD further notes the observations of SPP's Market Monitor that the refund calculation may be unnecessarily complex, and that the magnitude of these over-collections could be significant, making it crucial to determine how this money is distributed. NPPD Request for Rehearing at 10 (citing NPPD Protest at 28).

[49] *Id.* at 11.

[50] *Id.* at 10.

[51] October Order, 141 FERC ¶ 61,048 at P 213.

Thus, contrary to NPPD's assertion, the Commission did consider the MISO proceeding and found that SPP had demonstrated that the circumstances present in MISO that warranted a transitional refund period are not present in SPP.

34. Further, we deny rehearing of the Commission's finding that NPPD had not made a showing that it would be adversely affected by the lack of a transitional refund mechanism. NPPD simply asserted that absent experience with the calculation of actual incremental losses and related refunds, there is no way of knowing whether the refund mechanism will produce a more equitable distribution of the refund to each individual asset owner.[52] NPPD's assertion was on its face speculative and did not demonstrate that it would be adversely affected by the lack of a transitional refund period. On rehearing, NPPD has not demonstrated that the Commission erred in making these findings. Accordingly, we deny NPPD's request for rehearing.

35. Moreover, we deny NPPD's request for clarification that parties will not be foreclosed from raising the need for a transitional refund mechanism in connection with SPP's compliance filing containing a new marginal loss surplus refund methodology. Our determination on whether a transition period is necessary was based on our finding that the circumstances in SPP are different from those in MISO; it was not based on the nature of the refund mechanism. Thus, because we already determined that a transition period is not necessary for SPP, we deny NPPD's request for clarification.

36. Finally, in response to NPPD's concerns about the effectiveness of a refund mechanism for marginal losses, we note that the Commission found in the October Order that SPP had not shown its proposed refund mechanism to be just and reasonable. Accordingly, the Commission directed SPP to submit a compliance filing with supplemental information supporting its refund proposal, or to propose an alternative for refunding these surpluses. Therefore, to the extent that NPPD has concerns regarding whether NPPD's refund proposal will result in equitable distribution of refunds, NPPD will have the opportunity to review and comment on SPP's compliance filing.

4. Operating Reserves

a. October Order

37. In the October Order, the Commission directed SPP to file with the Commission no later than June 30, 2013 a proposal to comply with the requirements of Order

[52] *Id*. P 206.

No. 755.[53] The Commission selected this date to ensure that SPP would be able to implement new market rules by its anticipated March 2014 market launch date.[54]

b. Request for Rehearing and/or Clarification

38. SPP seeks rehearing on this issue, stating that, while it could file a proposal to comply with Order No. 755 by June 30, 2013, SPP seeks to implement the changes one year after market start-up. Specifically, SPP submits that it has been working diligently to develop the necessary Tariff changes required by Order No. 755 and that it anticipates completing the stakeholder process and submitting the required Tariff revisions by the ordered compliance deadline of June 30, 2013. However, SPP asserts that implementing these changes prior to or at the time of market start-up will result in substantial disruption to on-going system production efforts necessary for market start-up. SPP estimates that it requires over 1200 hours of work to design and develop the necessary software changes, perform testing, and complete the configuration necessary to integrate changes required by Order No. 755. SPP asserts that such a disruption could cause a one year delay in implementing the Integrated Marketplace, which could result in a loss of $100 million in market benefits.[55]

39. SPP also explains that, at present, few Market Participants will have capabilities to take advantage of the provisions of Order No. 755, and it notes that other Independent System Operators (ISOs) and RTOs were allowed to start their Day 2 market operations without complying with Order No. 755.[56]

c. Commission Determination

40. We grant SPP's request for rehearing. In Order No. 755, the Commission revised its regulations to remedy undue discrimination in the procurement of frequency regulation in the organized wholesale electric markets. Specifically, the Commission found that existing compensation methods for regulation service in RTO and ISO markets failed to acknowledge the inherently greater amount of frequency regulation service

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[53] *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012).

[54] October Order, 141 FERC ¶ 61,048 at P 222.

[55] SPP Request for Rehearing and Clarification at 9.

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

being provided by faster-ramping resources. The Commission stated that it expects lower costs for consumers will result from the implementation of Order No. 755 because less total capacity must be procured and because the capacity that is procured will be from lower-cost resources entering the market. The Commission further stated that the displacement of existing resources may result in those resources being able to more efficiently operate in the energy markets, submitting lower offers to supply energy, and thereby lowering costs to consumers in that market. In the long-run, efficient price signals will also incent the efficient mix of resources to enter the market, thereby leading to lower long-run costs to consumers. The Commission directed RTOs and ISOs to revise their tariffs to implement the requirements of the Final Rule. Requiring that frequency regulation resources are compensated based on the actual service provided continues to be important to ensuring that providers of frequency regulation receive just and reasonable and not unduly discriminatory or preferential rates. Accordingly, we will continue to require SPP to submit by June 30, 2013 its proposed Tariff sheets for compliance with Order No. 755, as SPP stated that it was preparing to do. However, we are persuaded that by granting SPP's request to delay its implementation of the Order No. 755 requirements until up to one year following market start-up, SPP will be able to design its software for implementing its Order No. 755 requirements based upon its actual experience operating its new market. The additional time will allow SPP to design necessary software changes, perform unit testing on those changes, provide the necessary documentation and integrate those changes with any other software required for the functioning of the new market. We conclude that granting SPP's request for additional implementation time is reasonable under these circumstances. Accordingly, SPP is required to file Tariff revisions to comply with the requirements of Order No. 755 no later than June 30, 2013, which are to be implemented no later than one year following market start-up.

C. Market-Based Congestion Management

1. Long-Term TCRs and Incremental ARRs

a. October Order

41. In the October Order, the Commission conditionally accepted, subject to modification and clarification, SPP's market-based congestion management proposal, which establishes TCRs[57] and ARRs[58] to assist Market Participants in managing the costs

[57] TCRs entitle the holder to a stream of revenues or charges based upon the difference between the hourly day-ahead market Marginal Congestion Component of locational marginal prices at the source settlement location and the hourly day-ahead market Marginal Congestion Component of LMPs at the sink settlement location

(continued…)

of congestion.[59] The Commission found that the proposal was similar to other RTO congestion management constructs previously accepted by the Commission.[60]

42. In the October Order, the Commission found that SPP's proposal for hedging the costs of congestion provided firm transmission customers with an adequate congestion cost hedge for the first year. Specifically, the Commission found it to be a reasonable interim mechanism until SPP files, and the Commission accepts, SPP's Order No. 681 compliance filing.[61] The Commission rejected SPP's proposal to submit its Order No. 681 long-term firm transmission rights compliance filing before the start of the second year of market operations; instead, the Commission directed SPP to submit its Order No. 681 compliance filing within 180 days after market start-up. The Commission stated that in Order No. 681 it found that such compliance filings could be reasonably made within a 180 day timeframe.[62] The Commission reasoned that filing a long-term firm transmission rights proposal 180 days after market start-up will enable the Commission to review the filing prior to the second year of market operations.

43. In the October Order, the Commission conditionally accepted SPP's incremental ARR proposal, subject to a compliance filing. The Commission stated that SPP's proposed incremental ARR allocation process did not explain the reason for the incremental capacity becoming available after the annual TCR auction. The Commission found that, to the extent the new capacity on the system is available as a result of network

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associated with the TCR. TCRs are obtained in the TCR auction, either through purchase or self-conversion of ARRs, or through secondary sales of TCRs.

[58] An ARR can result in a credit or charge to the holder, based upon the TCR auction clearing price on the particular ARR path. SPP states that eligible entities may either self-convert awarded ARRs into TCRs, or hold the ARR to receive a share of the revenue SPP collects from auction purchasers of TCRs.

[59] *See* October Order, 141 FERC ¶ 61,048 at PP 237-239.

[60] *Id*. P 237 (citing *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,276 (2003); MISO TEMT II Order, 108 FERC ¶ 61,163, *order on reh'g*, 109 FERC ¶ 61,157 (2004) (MISO TEMT II Rehearing Order)).

[61] *Id.* P 245.

[62] *Id.* (citing *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, FERC Stats. & Regs. ¶ 31,226, at P 490, *reh'g denied*, Order No. 681-A, 117 FERC ¶ 61,201 (2006)).

additions built in response to a transmission service request, SPP's proposal would be one way to allocate the ARRs for this incremental capacity to the new transmission service request.[63]

44. The Commission found that to the extent incremental ARRs represent existing capacity on the transmission system, including capacity expected to be added during the year (e.g., the addition of regionally-allocated transmission facilities), SPP should modify its proposal to allow a load-serving entity to acquire incremental ARRs for this existing transmission capacity. The Commission specified that this would be up to the load-serving entity's nomination cap, along with Market Participants with newly acquired reservations.[64]

45. Finally, the Commission directed SPP to clarify how the ARR allocation process works when network upgrades are made to the transmission system, and in particular when the network upgrade is not the result of a transmission service request.[65]

b. Request for Rehearing and Clarification

46. TDU Intervenors request rehearing or clarification regarding the long-term TCR and incremental ARR components of SPP's congestion management construct. Regarding long-term TCRs, TDU Intervenors argue that the Commission erred by not ensuring sufficient time for action on SPP's long-term transmission rights compliance filing. Specifically, TDU Intervenors argue that SPP should be required to make its Order No. 681 compliance filing at market start-up, rather than 180 days thereafter. TDU Intervenors assert that, because the approval and implementation process for long-term TCRs is time-consuming, these long-term rights may not be available until after the start of the second operating year of the Integrated Marketplace.[66] TDU Intervenors contend that Congress intended that long-term TCRs be available as soon as possible, and they note that the Commission required the California Independent System Operator Corporation (CAISO) to file its long-term TCR proposal at least nine months before its market commenced. Further, TDU Intervenors submit that the Commission should not be concerned with whether SPP can implement such provisions in the first year; rather,

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[63] October Order, 141 FERC ¶ 61,048 at P 276.

[64] *Id.* P 277.

[65] *Id.* P 281.

[66] TDU Intervenors' Request for Rehearing and Clarification at 11-13.

the Commission should be concerned with whether customers can live without long-term congestion management provisions for the first year.

47. TDU Intervenors assert that if SPP is allowed to postpone providing long-term TCRs until after market start-up, the Commission should require SPP to file its long-term TCR proposal one year prior to the start of the second annual ARR allocation process. TDU Intervenors explain that this will ensure sufficient time for the Commission and other interested parties to resolve the issues that are likely to arise in review of SPP's long-term rights proposal, and it will give SPP sufficient time to get the necessary software and other mechanisms in place for the second annual allocation/auction process prior to commencement of the second market year.[67]

48. Regarding incremental ARRs, TDU Intervenors request that the Commission clarify that incremental ARRs are to be allocated to those customers whose transmission service requests result in new network capacity, but only for those customers who bear the full costs of the new facilities. TDU Intervenors argue that if the costs of the network additions are rolled in, as is the case with most facility additions and upgrades in SPP, then the additional capacity should be treated like existing capacity, and transmission customers who have not received all their nominated ARRs in earlier allocations should be eligible for incremental ARRs resulting from such upgrades.[68]

c. Commission Determination

49. We deny TDU Intervenors' request that SPP be required to file and implement its Order No. 681 long-term transmission rights compliance program in a shorter timeframe than established in the October Order. In establishing a just and reasonable timeframe for requiring SPP to comply with Order No. 681, the Commission carefully balanced Congress' intention that implementation of long-term firm transmission rights occur as soon as possible against the potential harm, i.e., a delay in market-start-up, that could occur by requiring immediate compliance.[69]

50. In determining that requiring Order No. 681 compliance within 180 days of market start-up was just and reasonable, the Commission found that during the first year

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

[68] *Id*. at 14.

[69] With its request for rehearing, SPP submitted an affidavit of Bruce Rew, who stated that for every month of delay of the Integrated Marketplace, the SPP region loses $8.3 million in benefits. Rew Affidavit at ¶ 3.

of market operation, SPP will provide transmission customers with a hedging mechanism for congestion costs.[70] Based upon its determination that transmission customers will be protected and that rates would be just and reasonable during the first year, the Commission allowed SPP to file its long-term TCR proposal 180 days after market start-up because of this hedging mechanism. Accordingly, we find that TDU Intervenors have not demonstrated that SPP's proposal to provide transmission customers with a hedging mechanism for congestion cost in year one with a long-term hedging mechanism beginning in year two is unjust and unreasonable, nor have they demonstrated that delaying compliance for 180 days post market start-up is unjust and unreasonable.[71]

51. In selecting 180 days post market-start as a just and reasonable timeframe for SPP to submit it Order No. 681 compliance filing, the Commission noted that, when Order No. 681 went into effect, entities were given 180 days to comply.[72] The Commission further reasoned that the 180-day timeframe would enable the Commission to review the filing prior to the second year of market operation.[73]

52. We do not agree with TDU Intervenors that SPP's Order No. 681 compliance filing should be made one year before the second ARR year. This would require SPP to make its Order No. 681 compliance filing approximately 90 days after market start-up, which is approximately 90 days earlier than the timeframe established in the October Order. As stated above, TDU Intervenors have not shown that the Commission's 180-day timeframe is unjust and unreasonable. Moreover, we find that the timeline established in the October Order provides sufficient time for SPP to comply with Order No. 681 and have the long-term transmission rights mechanism in effect for year two and beyond to ensure that just and reasonable rates are in effect.

53. TDU Intervenors point to the fact that CAISO was required to make its filing nine months ahead of market launch. The Commission's finding that nine months was appropriate for CAISO was based on CAISO's unique circumstances. CAISO's market

[70] October Order, 141 FERC ¶ 61,048 at P 245.

[71] The Commission notes that other markets have been allowed to launch while some market components were still being developed beyond the conceptual level that was pre-approved by the Commission. *See Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 (2006), *order on reh'g*, 119 FERC ¶ 61,076, *order on reh'g and denying motion to reopen record*, 120 FERC ¶ 61,271 (2007).

[72] Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 490.

[73] October Order, 141 FERC ¶ 61,048 at P 245.

included a number of market design elements that were being finalized prior to market launch. SPP's circumstances are distinguishable from CAISO's, as the Commission has found that SPP's transmission customers are provided with a just and reasonable mechanism for hedging congestion cost in year one. Accordingly, allowing SPP to file its Order No. 681 compliance 180 days following market start-up will allow sufficient time to have a long-term transmission rights mechanism in effect by year two.

54. Finally, the Commission grants TDU Intervenors' request for clarification with respect to how incremental ARRs are to be allocated to those customers whose transmission service requests result in network additions. Accordingly, if the costs of a network addition are rolled-in, then the additional capacity should be treated in the same manner as existing capacity, and all transmission customers who have not received all their nominated ARRs should be eligible for incremental ARRs resulting from such upgrades.

2. Congestion Transition Mechanism

a. October Order

55. In the October Order, the Commission conditionally accepted SPP's market-based congestion management proposal, subject to modification.[74] The Commission found that SPP's proposal was similar to the market-based congestion management constructs successfully implemented by other RTOs,[75] pointing out that it utilizes the Marginal Congestion Component of the day-ahead LMP. The Commission further held that SPP's proposal takes into account the system's expected usage. The Commission elaborated that under SPP's proposal, using a security-constrained power flow model, firm transmission rights are allocated in a simultaneously feasible manner, allowing for congestion cost hedging based upon the historical rights of firm transmission customers.[76]

56. The Commission denied NPPD's request for an expanded congestion cost hedge transition mechanism. While noting that in some cases the Commission has allowed RTOs/ISOs additional time to adjust to new markets, the Commission agreed with SPP's Answer that its proposal was distinguishable from the cases that NPPD cited. Specifically, the Commission noted that NPPD conceded that it is not a MISO-type load

[74] *Id.* PP 237-239.

[75] *Id.* P 237.

[76] *Id.*

pocket,[77] and that NPPD did not explain why a five year transition period was necessary when, according to NPPD, the Nebraska City-Sibley Priority Project will address its congestion concerns in three years. Thus, the Commission held that SPP's proposal was just and reasonable without a transition period like the one approved for MISO. Finally, the Commission found that, given the directives set forth in the October Order to strengthen SPP's mitigation plan, and considering the burden that would be imposed on other customers to pay for an expanded congestion cost hedge transition period for NPPD, such a transition period had not been shown to be just and reasonable.

b. Request for Rehearing and Clarification

57. NPPD contends that the Commission erred in denying its request for an expanded congestion cost hedge transition mechanism to hold Market Participants harmless from extreme congestion arising from the start-up of a new market structure. Specifically, NPPD argues that the Commission's denial of NPPD's request for an expanded congestion cost hedge transition mechanism is arbitrary and capricious. Moreover, NPPD argues that the Commission's denial is not consistent with prior rulings affording an expanded congestion cost hedge to entities that face significant congestion, congestion charges, and are in heavily congested areas.[78]

58. NPPD takes issue with the Commission's statement that "NPPD conceded that it is not a MISO-type load pocket."[79] According to NPPD, the fact that it may not be a MISO-type load pocket is irrelevant, as it is located in a highly congested interface between SPP and MISO. NPPD explains that its experience with the SPP EIS market has shown that the market clearing prices can be highly negative for its generators located on the constraint side of the flowgate that can address this congestion. NPPD asserts that there is no assurance that the available ARRs and TCRs will be sufficient to cover NPPD's firm transmission rights.[80]

59. NPPD contends that, in the MISO TEMT II Order, the Commission did not limit the purpose and need for a congestion cost transition mechanism to load pockets.

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[77] *Id.* P 238 (citing NPPD Protest at 22).

[78] NPPD Rehearing Request at 4 (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at PP 90-94).

[79] *Id.*

[80] *Id.*

According to NPPD, in the MISO TEMT II Order, the Commission found that such a congestion cost transition mechanism was also necessary:

> to guarantee market participants that are highly dependent on existing firm transmission service and that are potentially subject to high congestion charges that they will receive sufficient [firm transmission rights] or an equivalent financial hedge to hold them harmless with respect to changes in the market design.[81]

NPPD contends that the Commission did not recognize that the MISO TEMT II Order acknowledged the broader impacts of congestion cost exposure beyond constrained load pockets. NPPD elaborates that it did so by approving a separate transitional firm transmission rights mechanism for Market Participants with existing firm service that were not located in load pockets, but nonetheless faced congestion costs.[82] Finally, NPPD asserts that the Commission did not distinguish other cases cited by NPPD in which the Commission has approved transition mechanisms to protect against congestion.[83]

60. According to NPPD, assuming the planned Nebraska City-Sibley Project comes on line in 2017, which is three years after startup of the Integrated Marketplace, there is no assurance that such facilities will resolve the congestion in the area between NPPD and SPP's interface with MISO. NPPD also argues that the Commission's finding that such facilities would resolve the severe congestion in its area ignored precedent requiring that Market Participants within congestion areas be provided "with an avenue to participation in regional markets during the period of time needed to address the infrastructure issues that contribute to high congestion costs in those areas."[84]

61. NPPD asserts that there is no basis to conclude that any market-to-market coordination process will resolve NPPD's congestion concerns. NPPD explains that during certain periods there are hundreds of megawatts of unaccounted for flows between MISO and SPP on NPPD-owned flowgates located on the MISO/SPP seam. NPPD states

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[81] *Id.* at 6.

[82] *Id.*

[83] *Id.* at 7-8 (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at P 90; *New England Power Pool and ISO New England, Inc.*,101 FERC ¶ 61,344, at P 36 (2002) (*ISO-NE*); *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,223, at P 45 (2004) (*PJM*)).

[84] *Id.* at 5 (citing MISO TEMT II Rehearing Order, 109 FERC ¶ 61,157 at P 113).

that, in large part, these flows are attributable to methodological differences between how MISO calculates its market flows as compared to SPP. Thus, NPPD contends that there is no basis for assuming that the market-to-market coordination directed by the Commission will resolve these methodological differences and related unaccounted for flows. For this reason, NPPD asks that, at a minimum, the Commission make clear on rehearing that NPPD will have the opportunity, upon review of the Joint Operating Agreement to be filed in June of 2013, to address the extent to which the Joint Operating Agreement resolves congestion along the MISO and Eastern Nebraska border. NPPD argues that should the Commission find that the congestion issue has not been resolved, it must then implement a mechanism to hedge congestion.[85]

c. Commission Determination

62. We deny rehearing of NPPD's request for an expanded congestion cost hedge as a transitional mechanism. In the October Order, the Commission found that, in light of the Commission's directives and considering the burden that would be imposed on other customers to pay for an expanded congestion cost hedge transition period for NPPD, such a transition period had not been shown to be just and reasonable.[86] The Commission required modifications to the allocation of ARRs that will make available additional ARRs to firm transmission customers with historic rights to the transmission system,[87] and required market-to-market coordination, including the execution of a joint operating agreement, to address congestion along the seam between SPP and MISO.

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[85] *Id.* at 6.

[86] October Order, 141 FERC ¶ 61,048 at P 238.

[87] In the October Order, the Commission required SPP to modify the allocation of ARRs to better approximate the network integration transmission service customer's load, to reflect system realities more accurately, and to either support the use of the annual peak methodology for allocating ARRs or propose refinements to account for significant monthly and seasonal differences. *Id.* PP 263-265. Additionally, the Commission required SPP to allow existing firm transmission customers to obtain incremental ARRs for new capacity made available after the annual TCR auction, unless that capacity was solely in response to a transmission service request and paid by the requesting transmission customer. The Commission stated that allowing existing transmission customers to obtain incremental ARRs would recognize historic rights to the transmission system.

63. NPPD has not shown that the Commission erred in finding that SPP's Proposal was just and reasonable without a congestion transition mechanism. The Commission further finds that NPPD has also not shown that refinements it directed to the ARR allocations and the market-to-market coordination will not address the unaccounted-for flows.

64. While NPPD is correct that the implementation of a transition hedge is not without precedent, it has not demonstrated that it is similarly situated to entities that have previously been granted such a mechanism. Specifically, NPPD has not shown that the SPP Proposal, as modified by the October Order, will cause NPPD to incur a significant amount of un-hedged congestion when serving its native load. In instances where transition mechanisms have been approved, the intent of the transition mechanisms was to facilitate serving native load at rates reflecting hedged congestion. NPPD has not shown that it is in the similar position of serving native load at rates reflecting un-hedged congestion. To the extent that NPPD is seeking a transition mechanism to facilitate the sales of excess power at rates with hedged congestion, we would be concerned that NPPD's request could lead to inefficiencies by giving improper price signals for generators.

65. We find that the instant case is not analogous to the facts presented in the MISO TEMT II Order. In that order, the Commission accepted a proposal to provide a congestion hedge to facilitate the importation of power into a load pocket so that entities could serve their native load at rates with hedged congestion. The Commission also extended a separate MISO proposal to provide congestion relief to entities to serve their native load that is not located in load pockets, from three years to five years when the load met certain MISO requirements.[88] NPPD has not demonstrated that the expanded cost hedge is necessary to serve its native load as was the case in MISO.

66. We further find that NPPD's reliance on *PJM* and *ISO-NE* is misplaced. In these cases, like the MISO TEMT proceeding, entities demonstrated that the transition mechanisms were necessary to serve their native load.[89]

67. For these reasons, we find that a congestion cost hedge as a transition mechanism has not been shown to be necessary to provide service to NPPD's native load at just and reasonable rates. Accordingly, we deny NPPD's request for rehearing. However, we note that if it does experience a significant amount of un-hedged congestion to serve

[88] MISO TEMT II Order, 108 FERC ¶ 61,163 at PP 187-189.

[89] *ISO-NE*, 101 FERC ¶ 61,344 at P 36; *PJM*, 107 FERC ¶ 61,223 at PP 45-48.

native load after the start-up of the Integrated Marketplace, NPPD may file at that time to seek relief from the Commission.

D. Integration

1. Grandfathered Agreements

a. October Order

68. In the October Order, the Commission conditionally accepted SPP's proposal to integrate GFAs into the Integrated Marketplace, with the condition that SPP was to negotiate with protestors the resolution of any outstanding GFA whose integration into the Integrated Marketplace has not been resolved. The Commission explained that, in contrast to the EIS market where GFAs are allowed to schedule in the real-time market, all GFAs in the Integrated Marketplace will be required to be scheduled in the day-ahead market to hedge congestion costs. The Commission acknowledged that the parties to GFAs may not be able to fully hedge congestion costs. Further, a GFA not integrated into the Integrated Marketplace will be exposed to marginal loss pricing, which may differ from the loss pricing provisions of the GFA, thereby exposing the GFA to additional costs for losses.[90] The Commission also explained that, if SPP's negotiations with any protesting parties concerning the unresolved GFAs are not successful, a carve-out of a GFA could be consistent with Commission precedent.[91]

b. Request for Clarification

69. Westar requests clarification regarding the allocation of costs associated with any GFAs that are carved-out of the Integrated Marketplace. Westar asserts that these costs should not be allocated to the market based on load-ratio share. Instead, Westar argues that these costs should be allocated locally to the transmission area where a given GFA transaction takes place. Westar also asserts that under SPP's Tariff, revenue neutrality uplift[92] is the only mechanism available to allocate unrecovered costs, but that this

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[90] October Order, 141 FERC ¶ 61,048 at P 311.

[91] *Id*. PP 314-316 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236 (2004), *order on reh'g*, 111 FERC ¶ 61,042, *order on reh'g*, 112 FERC ¶ 61,311 (2005), *aff'd sub nom. Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007)).

[92] Westar Request for Clarification at 3 (citing SPP OATT, Attachment AE, section 5.6).

mechanism will result in an allocation on the basis of load-ratio share to the entire market. Westar contends that because GFAs benefit the transmission area where the transaction takes place, consistent with the Commission's cost-causation principles, these costs should be allocated to the local transmission area where the GFA transaction takes place. Finally, Westar asserts that the Commission should require SPP to adopt a new allocation mechanism for recovering the costs of a GFA carve-out that allocates the costs to the local transmission area.[93]

c. Commission Determination

70. We deny Westar's request for clarification. In the October Order, the Commission directed SPP to negotiate the integration of any outstanding GFAs. The Commission also required SPP to update the Commission 90 days after the issuance of the October Order about the status of these negotiations and, at that time, SPP was to identify any remaining GFAs that have not been integrated into the Integrated Marketplace.[94] Further, the Commission directed SPP to commence a stakeholder process after SPP files the report, to finalize the carve-out proposal for any GFA that merits a carve-out.[95] Westar seeks a Commission determination regarding an allocation of costs that has not been established and cannot be assessed unless and until a GFA carve-out is filed with the Commission. Only then may the Commission consider the basis for allocating such costs within the context of that proceeding. Therefore, we deny Westar's request for clarification as beyond the scope of the instant proceeding.

2. Seams and Reserve Sharing

a. October Order

71. In the October Order, the Commission found that SPP's proposed Tariff language did not clearly articulate that the rules and practices of the Integrated Marketplace will not extend beyond the geographic boundary of the SPP market footprint to include external members of SPP.[96] Thus, the Commission directed SPP to revise its Tariff to

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[93] *Id*. at 5.

[94] We note that on January 16, 2013 SPP filed its status report regarding GFA negotiations.

[95] October Order, 141 FERC ¶ 61,048 at P 317.

[96] *Id.* P 333. SPP currently has five footprints: a Regional Entity footprint, a Reserve Sharing Group footprint, a Reliability Coordinator Area footprint, a Regional

(continued…)

specify that entities that are in any of the other SPP footprints but that choose not to participate in the Integrated Marketplace will not be subject to the Integrated Marketplace's rules and practices.[97]

72. The Commission accepted SPP's proposal to consolidate its 16 individual Balancing Authority Areas into a single Balancing Authority Area operated by SPP.[98] Accordingly, the Commission accepted SPP's proposed revisions to its existing reserve sharing arrangements, because such arrangements were made between the individual Balancing Authority Areas, which will no longer exist under the Integrated Marketplace.[99] The Commission noted that SPP's proposal did not terminate voluntary participation in reserve sharing arrangements with entities that are external to the SPP Balancing Authority Area and with whom SPP currently has reserve sharing agreements, once the Integrated Marketplace commences. The Commission further noted that SPP may enter into or modify existing reserve sharing agreements with external Balancing Authority Areas.[100]

b. Request for Rehearing and Clarification

73. SPP agrees that its members that are external to the Integrated Marketplace footprint and that do not take services under the Integrated Marketplace Tariff are not subject to the rules and practices of the Integrated Marketplace. However, SPP requests clarification of the Commission's directive that SPP revise its Tariff to specify that entities that are in any of the other footprints but that choose not to participate in the Integrated Marketplace will not be subject to the Integrated Marketplace's rules and practices.[101] According to SPP, this directive could be read as precluding SPP from

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Transmission Organization/Tariff footprint and an EIS market footprint. The entities participating in the various footprints are different. *See id.* n.498.

[97] *Id.*

[98] The Commission conditioned its acceptance on a requirement that SPP complete Balancing Authority Area negotiations, file the Balancing Authority Area agreement, and become certified as the Balancing Authority Area by NERC. *See id.* P 374.

[99] *Id.* P 342.

[100] *Id.*

[101] SPP Request for Rehearing and Clarification at 18-19 (citing October Order, 141 FERC ¶ 61,048 at P 333).

proposing Tariff provisions to require parties external to SPP that engage in transactions in the Integrated Marketplace to comply with the Integrated Marketplace rules and practices.

74. Similarly, SPP asserts that to the extent that entities physically located outside of the SPP Integrated Marketplace footprint choose to participate in reserve sharing arrangements with SPP, such entities may be engaging in transactions (specifically, the procurement of Contingency Reserve) within the Integrated Marketplace. Therefore, SPP contends that applying the Integrated Marketplace rules and practices to such transactions may be appropriate. For these reasons, SPP requests that the Commission clarify that the October Order did not intend to preclude SPP from applying the Integrated Marketplace rules and practices to transactions that are entered into within the Integrated Marketplace by entities that are physically located outside of – and that are not otherwise engaging in transactions – in the Integrated Marketplace.[102]

75. Additionally, SPP notes that the Integrated Marketplace filing did not address the extent to which the rules and practices would apply to certain services, such as reserve sharing, that SPP may provide to entities external to the SPP region. Rather, SPP contends that it indicated that the details regarding participation in reserve sharing would be addressed subsequently though agreements with other balancing authorities. According to SPP, it should be free to propose whatever rates, terms, and conditions that it believes are necessary to provide the service, subject to Commission approval. Therefore, SPP requests that the Commission clarify that, in the October Order, the Commission did not intend to prejudge the terms and conditions that would apply to the reserve sharing arrangements that SPP negotiates with external parties within the Reserve Sharing Group footprint. Moreover, SPP seeks clarification that, by listing the Reserve Sharing Group footprint in the list of current SPP footprints, the Commission did not intend to prohibit SPP from applying certain Integrated Marketplace rules and practices to Reserve Sharing Group members if appropriate.[103]

76. Furthermore, SPP contends that it must be afforded a mechanism to recover costs associated with external entities that participate in transactions under the Integrated Marketplace Tariff, consistent with the Commission's cost causation principle.[104] Thus,

[102] *Id.* at 20.

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

[104] *Id*. at 20 (citing *K N Energy, Inc.*, 968 F.2d 1295, 1300-001 (D.C. Cir. 1992) ("rates should be based on the costs of providing service to the utility's customers plus a just and fair return on equity…. Properly designed rates should produce revenues from

(continued…)

SPP seeks clarification that the Commission did not intend to prejudge whether SPP can recover Integrated Marketplace costs from external entities taking service from SPP.[105]

77. SPP states that to the extent that the Commission declines to grant the requested clarification, SPP seeks rehearing of the Commission's directive to revise its Tariff to specify that entities that are in any of the other SPP footprints will not be subject to the Integrated Marketplace's rules and practices.[106]

c. Commission Determination

78. In the October Order, the Commission directed SPP to revise its Tariff to specify that entities that are in any of the other SPP footprints but that choose not to participate in the Integrated Marketplace will not be subject to the Integrated Marketplace's rules and practices.[107] In response to SPP's requests, we provide the following clarifications. First, we clarify that our directive does not preclude SPP from proposing Tariff provisions requiring a party external to SPP that chooses to engage in transactions in the Integrated Marketplace to comply with Integrated Marketplace rules and practices, if applicable to those transactions, even if the external party is not otherwise transacting in the Integrated Marketplace. This includes transactions in the Integrated Marketplace resulting from such party's participation in reserve sharing arrangements with SPP. Similarly, in the October Order, the Commission did not intend to prejudge whether SPP can recover Integrated Marketplace costs from external entities taking service from SPP.

3. Network Resource Interconnection Service

a. October Order

79. In the October Order, the Commission denied Acciona's request that the Commission require that existing generators, who were previously prevented from requesting and obtaining SPP footprint-wide Network Resource Interconnection Service

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each class of customers which match, as closely as practicable, the costs to serve each class or individual customer")).

[105] *Id*.

[106] *Id.* at 20-21.

[107] October Order, 141 FERC ¶ 61,048 at P 333.

(NRIS), due to the disaggregated existence of SPP's various balancing areas,[108] be restudied and receive footprint-wide NRIS on an as-available basis, before new requests for NRIS are processed.[109] The Commission stated that footprint-wide NRIS will be a new service not previously available under the SPP Tariff. Thus, the Commission found it reasonable to require that all SPP customers submit a new request for NRIS.[110]

b. Request for Clarification

80. TDU Intervenors are concerned that the statement that "all SPP customers" is inadvertently broad and could be misconstrued. TDU Intervenors believe that the Commission intended to refer to a much narrower class of customers than all SPP customers; TDU Intervenors assert that the Commission intended to refer only to those generators that wish to apply for SPP-wide NRIS.[111] Thus, TDU Intervenors request clarification of the Commission's intention regarding requests for NRIS.

c. Commission Determination

81. We clarify that, in the October Order, the Commission did not intend that "all SPP customers" would need to apply for NRIS; rather, the Commission's statement was in reference to generators seeking SPP-wide NRIS.

4. Market-To-Market Coordination

a. October Order

82. In the October Order, the Commission required SPP to negotiate with MISO to develop a market-to-market coordination process for managing congestion across the seam between MISO and SPP and to file the Joint Operating Agreement by June 30, 2013.[112] The Commission stated that such "market-to-market mechanisms have been

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[108] These generators could choose either NRIS service for the control area where the generating facility is located or take Energy Resource Interconnection Service.

[109] October Order, 141 FERC ¶ 61,048 at P 376.

[110] *Id*.

[111] TDU Intervenors' Request for Rehearing and Clarification at 15.

[112] October Order, 141 FERC ¶ 61,048 at P 364.

shown to economically relieve congestion and align border prices successfully."[113] The Commission further noted a directive by the Commission in a 2004 order that SPP implement a market-to-market mechanism in its Joint Operating Agreement with MISO prior to commencement of a Day 2 Market.[114] Finally, the Commission stated that if the parties use the market-to-market mechanism in the Joint Operating Agreement between MISO and PJM Interconnection, LLC (PJM) as a template, SPP should be able to meet the June 30, 2013 deadline. The Commission found that this should be "sufficient time to ensure that all issues are addressed prior to the commencement of SPP's markets."[115]

b. Request for Rehearing and Clarification

83. SPP argues that the Commission should clarify or grant rehearing to the extent that implementation of market-to-market procedures is a pre-condition to market start-up. SPP contends that the need for market-to-market protocols has not been demonstrated. SPP notes that PJM and NYISO operated Day 2 markets for years with no market-to-market procedures, and that SPP has operated its EIS market since 2007 (i.e., after the issuance of the 2004 Joint Operating Agreement Order) without such procedures. SPP explains that when it filed the EIS Market Tariff, it informed the Commission that neither MISO nor SPP perceived any need for further refinements to their seam.[116] Additionally, SPP contends that a 2008 analysis of the potential flowgates that could be candidates for SPP-MISO market-to-market coordination found only limited opportunities for enhanced congestion management across the seam despite both RTOs operating a market. Further, SPP asserts that its seam with MISO will not change with the implementation of its Day 2

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[113] *Id.* (quoting *New York Indep. Sys. Operator*, 133 FERC ¶ 61,276, at P 32 (2010)).

[114] *Id.* (citing *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,008, at P 34 (2004) (2004 Joint Operating Agreement Order) "SPP and [MISO] must execute a Phase 2 [Joint Operating Agreement], and SPP must file it, in sufficient time to ensure that all issues are addressed prior to commencement of SPP's markets.")

[115] October Order, 141 FERC ¶ 61,048 at P 364 (citing 2004 Joint Operating Agreement Order, 109 FERC ¶ 61,008 at P 34).

[116] SPP states that, at the time it was developed, the Joint Operating Agreement only required the parties to consider market-to-market enhancements. According to SPP, the parties evaluated such enhancements but considered them unnecessary. SPP Request for Rehearing and Clarification at 12.

market.[117] Thus, SPP argues that requiring the market-to-market protocols to be in place as a pre-condition to market start-up is inconsistent with prior Commission rulings and should not be a pre-condition to its Integrated Marketplace.

84. SPP contends that no stakeholder requested market-to-market protocols during the market design meetings, and that to incorporate them now as a condition of market start-up could delay the market. According to SPP, it may take one year to put the additional systems in place to implement the market-to-market protocols. SPP asserts that each month of market delay causes $8.3 million in lost benefits, while the market-to-market protocols should produce benefits of only $10 million per year. Moreover, SPP adds that until the negotiations with MISO are complete, neither SPP nor MISO will know the extent of the system changes necessary to implement any negotiated coordination process.[118] SPP also contends that its seam with MISO is different from the seam between MISO and PJM, and that its negotiations with MISO should not be constrained by the MISO-PJM Joint Operating Agreement. If the Commission imposes any condition, SPP requests that the deadline for implementation of the market-to-market protocols be changed to one year after market start-up.[119]

c. <u>Commission Determination</u>

85. We deny SPP's request for rehearing that a need for market-to-market coordination has not been demonstrated. In addition, we reiterate our finding in the October Order that SPP is required to negotiate a revised Joint Operating Agreement with MISO that includes a market-to-market mechanism, and that SPP must file it with the

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[117] SPP states that no operational change is being made to SPP's real-time market, which has operated adjacent to MISO's real-time market for years. SPP asserts that the real-time flowgates will continue to be managed successfully, because the amount and frequency of congestion will not change as a result of the Integrated Marketplace. *Id.* at 13.

[118] SPP contends that, even if SPP and MISO file an amended Joint Operating Agreement by June 30, 2013, additional time is needed to account for the issuance of a Commission order and SPP's submission of vendor orders, which will further compress a tight schedule for implementing the new market. In an affidavit filed with SPP's Request for Rehearing and Clarification, SPP explains the magnitude of the on-going efforts of SPP staff, consultants, and vendors to implement the Integrated Marketplace, even without undertaking the market-to-market obligation. *Id.* at 15-16.

[119] *Id.* at 18.

Commission by June 30, 2013.[120] However, we clarify that SPP is not required to implement its market-to-market mechanism until one year following market start-up.

86. In the 2004 Joint Operating Agreement Order, the Commission required SPP to have a seams agreement with MISO on file as a prerequisite for RTO status. The Commission's mandate that SPP execute and file a seams agreement with MISO was based upon the need that the agreement be executed and contain certain provisions. However, the Commission did not require SPP to address coordination of the MISO Day 2 market-to-SPP Day 2 market at that time.[121] The Commission further explained that if and when SPP chooses to operate Day 2 markets (following a cost-benefit analysis), SPP and MISO must execute a Phase 2 Joint Operating Agreement that governs coordination between SPP's Day 2 market and MISO's Day 2 market.[122] Additionally, the Commission stated that SPP must file the Phase 2 Joint Operating Agreement in sufficient time to ensure that all issues are addressed prior to commencement of SPP's (Day 2) markets.[123] We reiterate that "market-to-market mechanisms have been shown to economically relieve congestion and align border prices successfully."[124] Finally, SPP has even conceded that some potential value may result from reexamining and refining seams management processes.[125]

87. While SPP points to PJM and NYISO, which operated for some time without market-to-market protocols, we note that such protocols are now in place in both markets. Specifically, the Commission directed MISO, NYISO, and PJM to develop initiatives, including market-to-market coordination, to address issues associated with loop flow

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[120] October Order, 141 FERC ¶ 61,048 at P 364.

[121] Joint Operating Agreement Order, 109 FERC ¶ 61,008 at P 29.

[122] In the 2004 Joint Operating Agreement Order, the Commission noted that the SPP Joint Operating Agreement referred to three market phases, i.e., non-market-to-non-market as Phase 0, market-to-non-market as Phase 1, and market-to-market as Phase 2 and the PJM Joint Operating Agreement referred to the same phases as Phase 1, 2 and 3, respectively. *Id.* n.14.

[123] *Id.* P 34.

[124] *Id.* (quoting *New York Indep. Sys. Operator, Inc.*, 133 FERC ¶ 61,276, at P 32 (2010)).

[125] SPP Request for Rehearing and Clarification at 14.

around Lake Erie (Lake Erie Loop Flow).[126] With respect to PJM and NYISO, the Commission required market-to-market coordination to resolve a specific problem. In the instant case, SPP/MISO seams coordination has a lengthy history, and concerns about congestion and coordination along the SPP/MISO seam have been expressly raised by NPPD and MISO. In light of these facts, it would be unreasonable for the Commission to wait for an issue between SPP and MISO to arise prior to requiring that these parties work together to start addressing congestion management across the seams. For these reasons, we deny SPP's request for rehearing and find that a need for market-to-market coordination has been amply demonstrated.

88. However, the Commission recognizes that MISO and SPP's EIS market have operated side-by-side and that there is no reason that the parties cannot continue to do so for one-year following the launch of the Integrated Marketplace, especially if the Joint Operating Agreement has been negotiated and there is transparency into both the seams congestion concerns and how the market-to-market mechanism will function once implemented. Accordingly, the Commission finds that, as required in the October Order, SPP must negotiate a revised Joint Operating Agreement with MISO that includes a market-to-market mechanism and file it with the Commission by June 30, 2013.[127] We further clarify that SPP is not required to implement its market-to-market mechanism until one year following market start-up.

E. <u>Mitigation</u>

1. <u>October Order</u>

89. In the October Order, the Commission conditionally accepted, subject to a series of additional revisions, explanations, and reports, SPP's revised proposal establishing a conduct and impact style of market power mitigation in the Integrated Marketplace. Specifically, the Commission accepted SPP's May 2012 Amendment to change the offer cap style mitigation SPP proposed in February 2012[128] to a conduct and impact style of

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[126] *New York Indep. Sys. Operator, Inc.*, 133 FERC ¶ 61,276 at PP 28, 32. In fact, the Commission encouraged the parties to base their market-to-market coordination process on the existing Joint Operating Agreement between MISO and PJM so that the market-to-market mechanism could be developed as soon as possible to address Lake Erie Loop Flow. *Id.* P 32.

[127] October Order, 141 FERC ¶ 61,048 at P 364.

[128] SPP's initially proposed market mitigation plan, submitted as part of its February 2012 Filing, included an offer cap mitigation structure. Under that initial proposal, a generator in a transmission constrained area would have been mitigated to an

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mitigation.[129] The Commission accepted SPP's revised proposal in which mitigation will be applied when a generator's[130] offer (for energy, operating reserve, start-up or no-load) in a transmission constrained area is in excess of a "cost-based" reference level by a specified amount (the conduct test). For this mitigation to occur, the generation unit also must have a sufficient Resource-to-Load Distribution Factor,[131] and its offer must raise

offer cap of (1) the cost and annual revenue requirement of a hypothetical new combustion turbine divided by the annual hours of congestion plus (2) the variable costs of such a turbine.

[129] Under the conduct and impact style of market power mitigation, individual market participant offers are compared to a conduct threshold, which is usually established to be a specified percentage or dollar value above the market participant's individual reference level (which is meant to measure the marginal cost of that reference level). The conduct threshold is designed to address uncertainties associated with the marginal cost level. If the offer exceeds that conduct threshold, the impact of the offer upon the market clearing prices and upon uplift payments is examined. If the impact exceeds a set impact threshold, then mitigation occurs to the market participant's individual reference level. Under the conduct and impact approach to mitigation, there may be additional conditions for mitigation such as the existence of a constraint. SPP incorrectly continued to refer to its revised mitigation plan, submitted on May 15, 2012, as offer-cap mitigation, even though its revised plan uses conduct and impact style of mitigation. In the October Order the Commission required SPP to remove the language relating to offer caps, and to refer to conduct thresholds, default offers, and reference levels, as appropriate. October Order, 141 FERC ¶ 61,048 at P 408.

[130] The Commission, in the October Order, required SPP to explain whether it intends to mitigate demand response, and if so, it directed SPP to explain how it will determine if a demand response resource is exercising market power. Further, if SPP intends to mitigate demand response offers, the Commission required SPP to discuss the reference levels and conduct and impact thresholds under which SPP would do so. *Id*. P 415.

[131] SPP defines the Resource-to-Load Distribution Factor as the simulated impact of incremental power output from a specific Resource (source) on the loading of a specific flowgate based on delivery to a representation of the locational weighting of all loads within all Settlement Locations (sink). North American Energy Standards Board (NAESB) defines Generation-to-Load Distribution Factor as the sum of a Generation Shift Factor and a Load Shift Factor. NAESB defines a Generation Shift Factor as a factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose upon an identified transmission

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locational market clearing prices for the energy or operating reserve product by more than a specified level or must increase make whole payments beyond a specified threshold (the impact test). The Commission also conditionally accepted SPP's proposal for additional mitigation where there is a local reliability issue but no transmission constraint. Such reliability-area mitigation has no Resource-to-Load Distribution Factor requirement.

90. Under the proposal accepted by the Commission, costs used in the determination of the reference level would be specific to the individual generator, rather than based on the costs of the hypothetical new combustion turbine unit. When the conditions for mitigation are met, mitigation will replace the generator's offer with the generation unit's own reference level for the component(s) of the offer being mitigated.[132] The Commission required SPP to base the generation unit reference levels on the generation unit's short-run marginal costs, to place details for the development of mitigated offers in its tariff,[133] and to justify its proposed conduct and impact thresholds.[134] The Commission also required SPP to establish more stringent mitigation in electrical areas defined by one or more transmission constraints that are expected to be binding for a significant number of hours in the year, within which one or more suppliers is pivotal, to establish associated conduct and impact thresholds. Further, the Commission directed SPP to justify the number of hours of expected binding constraint and any Resource-to-

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facility or monitored flowgate. Load Shift Factor is a factor to be applied to a load's expected change in demand on such a facility or flowgate.

[132] SPP did not sufficiently define the costs that could be included in the reference level, and in the October Order the Commission required it to do so. October Order, 141 FERC ¶ 61,048 at P 420.

[133] *Id.*

[134] The Commission noted that SPP's proposed conduct and impact thresholds for its proposed Broad Constrained Area-type mitigation are lower than those of other ISOs and RTOs, and that these lower thresholds may be appropriate given daily development of mitigated offers by market participants. However, the Commission required SPP to provide for mitigated offer development by the Market Monitor if SPP cannot show how it will monitor mitigated offers of market participants to ensure that they apply accurately the formula for mitigated offers and associated definitions of costs. The Commission stated its concern that, in that circumstance, SPP's thresholds may lead to over-mitigation. *Id*. P 444.

Load Distribution factor it chooses to use for such Narrow Constrained Area type mitigation.[135]

91. The Commission dismissed concerns raised by Golden Spread concerning the recovery of its fixed costs in frequently constrained areas that often might be subject to mitigation. The Commission explained that the proposed mitigation is designed to address the exercise of market power and to ensure that market prices clear at competitive levels. The Commission found that SPP's proposal to mitigate resources based on marginal cost is appropriate to ensure competitive market results, and disagreed with Golden Spread that such a mitigation approach will inappropriately affect the ability of resources to recover fixed costs.[136]

2. <u>Request for Rehearing</u>

92. Golden Spread requests rehearing of the Commission's finding that mitigation of resources based on marginal cost is appropriate, and that mitigation will not inappropriately affect the ability of resources to recover fixed costs.[137] Moreover, Golden Spread requests that the Commission grant rehearing to make clear that, when SPP submits its final proposed market power mitigation plan for Commission approval, the Commission will require that SPP justify all aspects of its plan, including the basis upon which it determines that a generator has the ability to exercise market power and the proper mitigation that should be applied to each generator.[138]

93. In its request for rehearing, Golden Spread reiterates concern over what it describes as SPP's use of hours of congestion to develop the maximum possible offer of a constrained generator, and Golden Spread's associated fear that, as a result, peaking units in the SPP market would be subject to mitigation in hours when they did not in fact have

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[135] *Id*. P 411.

[136] *Id*. P 446.

[137] Golden Spread's comments vary between comparisons to the generation unit's variable cost (total expenditure on variable inputs during the time period which would potentially include start-up and no load costs and additional costs of each additional unit) and the unit's marginal cost (addition to total costs for the last unit of output). The Commission in the October Order determined that reference levels must be based upon short-run marginal cost. Accordingly, we will address Golden Spread's comments in relation to the marginal cost of the generation unit.

[138] Golden Spread Request for Rehearing at 6.

the ability to exercise market power, and thus would be unable to recover their costs.[139] Golden Spread also argues that the Commission incorrectly concluded that SPP's approach will not affect the ability of a resource to recover fixed costs. Golden Spread contends that the Commission's conclusion is correct only in those circumstances where an owner of a resource is able to recover its fixed costs independent of the operation of the Integrated Marketplace.[140] Further, Golden Spread argues that it is extremely unlikely that an entity will have market power when its variable costs are, in fact, above the market clearing price.[141] It asserts that a fundamental concern with the SPP approach is that it does not look at marginal cost, as reflected at the resource node of the generator. Specifically, Golden Spread asserts that section 10.2.3 of the SPP Protocols provides that the (current) Resource Node locational market clearing price is set at the offer price to meet the next MW in a security constrained economic dispatch of a resource. According to Golden Spread, SPP incorrectly uses the hours of constraint for an area as a measure of market power, without regard to local market clearing prices or generator costs. Golden Spread argues that it is irrational to base mitigation on the assumption that every resource in a constrained area is deemed to be capable of exercising market power during every hour of constraint, even when the variable cost of the resource is higher than the actual Resource Node locational price during the hours of constraint.[142]

94. In addition, Golden Spread argues that it is problematic to base mitigation on individual units' variable costs, without direct consideration of the units' fixed costs. It argues that SPP's proposed mitigation will be applied to all generators based on hours of

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[139] *Id*. at 1-2 (citing Golden Spread and Arkansas Electric Cooperative Corporation April 23, 2012 Answer at 8-9 addressing SPP's then-proposed offer-cap style mitigation. Golden Spread and Arkansas Electric Cooperative Corporation stated that they had been adding generation in an area of the SPP system that experiences significant congestion, where reliability can be maintained only by constructing generation or building transmission to import capacity. They noted that the proposed offer caps would apply whenever there is transmission congestion, and that there is no consideration given to the locational price that actually occurs or the relationship of those prices to the variable cost of the generator).

[140] Golden Spread states that its costs will be covered by its members, but it asserts that it has a responsibility to its members to minimize costs by making sales of excess capacity and energy from those resources at a positive margin. *Id*. at 3.

[141] *Id*.

[142] *Id*. at 3-4.

congestion in the area where they are located, rather than on whether the variable costs of a generator are actually less than the prevailing locational prices. Golden Spread provides the example of one of its simple cycle Mustang Station peaking units, which has a variable cost typically well above the market clearing price. Golden Spread states that a unit cannot exercise market power during an hour when its variable costs exceed the market clearing price. Accordingly, Golden Spread argues that a generator that cannot exercise market power should not be denied the opportunity to charge rates that will contribute to the recovery of its fixed costs, where it its compensation is limited due to constraints (for example with transmission) that limit the delivery of lower cost power from elsewhere in SPP.[143]

95. Golden Spread further argues that SPP's approach to mitigation provides the wrong signals to generation investment. Golden Spread asserts that because the adder permitted for recovery of fixed costs is based on variable costs, units with higher variable costs, such as old depreciated steam units, will receive more revenue. It maintains that such an approach could disproportionately benefit the owners of older, less efficient generation. According to Golden Spread, SPP's approach to mitigation will not encourage the type of investment that is needed in SPP.[144]

3. Commission Determination

96. We deny rehearing. SPP's market power mitigation plan, as conditionally accepted by the Commission, will not mitigate a generator because it is in a congested (i.e., constrained) area, independent of the relationship between its costs and the locational price. Under the SPP proposal as conditionally accepted in the October Order, mitigation will occur only when there are constraints, and the generator crosses additional

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[143] *Id*. at 5. In its June 6 comments in response to the May 2012 Amendment, Golden Spread stated that the changes to the market power mitigation proposal did not address its core concern that the existence of a transmission constraint does not automatically vest every generator in the market area with market power. According to Golden Spread, it had added all of its new dispatchable generation in areas SPP showed as congested between 3,000 and 4,000 hours per year, yet the variable cost of 50 percent of this new generation is greater than the market clearing price during most of these periods of congestion. Golden Spread asserted that the SPP's revised approach to mitigation might actually exacerbate an "already difficult situation for market participants who construct new, high capital cost generation." Golden Spread June 6, 2012 Comments at 3.

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

conduct and impact thresholds and has a sufficiently significant Resource-to-Load Distribution factor.[145] SPP's conduct test is structured to prevent mitigation below the unit's marginal costs, because it allows offers that exceed (by a specific percentage) the marginal costs specified in the reference level.[146] Further, mitigation of a generation unit's offer would only occur under an hour of constraint if the offer meets all of the other conditions for mitigation during the hour. When the generator is mitigated, it will be mitigated to its reference level, which is based on its own marginal cost levels. Moreover, to the extent that Golden Spread's concerns may relate to the number of hours of mitigation being used as a divisor for a fixed cost term in the formula to determine the reference level for mitigation, under the revised mitigation proposal conditionally accepted by the Commission, this is not the case.

97. Further, the fact that market clearing prices are the "offer price to meet the next MW in a security constrained economic dispatch"[147] does not foreclose a resource from recovering its marginal costs. It simply means that the market is pricing based on the next offer in the supply stack, and that the marginal cost to the market is that next offer.[148] A high marginal cost resource may not be selected to run in many hours, because it is not economic for energy or operating reserves. Under these circumstances, cost recovery from the product (energy or one of the operating reserves products) is limited by the offer and not by mitigation. If the generator is at the margin and would be needed to meet the next increment of demand for the product, that generator's offer will set the market clearing price for that product. Its offer will be mitigated only if the conditions for mitigation are met, as explained above.

[145] The Resource-to-Load Distribution factor and the requirement for a constraint are not relevant to mitigation for the reliability events.

[146] In the October Order, the Commission required SPP to provide a justification for the levels it proposed for the conduct and impact test thresholds. October Order, 141 FERC ¶ 61,048 at P 444. The level of fixed costs that may be recovered may depend upon the levels of the thresholds, to the extent that offers fall under those thresholds but above marginal costs.

[147] Golden Spread Request for Rehearing at 4 (citing section 10.2.3 of the SPP Protocols).

[148] Under certain circumstances, the marginal cost to the market may differ from this offer, such as when other generation commitments must be changed on the margin, affecting the marginal cost to the market, and thus the market clearing price.

98. We continue to find that it is appropriate to base mitigated offers on short run marginal costs when the specified conditions for mitigation are met. In the October Order, the Commission required SPP to clarify its Tariff to establish that mitigation of a generation unit's offer can occur only when there is a congested transmission element or a local reliability issue, a binding constraint or reserve zone, and when the additional conditions relating to the Resource-to-Load Distribution factors apply. Under the SPP proposal as conditionally accepted by the Commission, a congested transmission element or local reliability issue is necessary, but the presence of either factor or both factors alone is not sufficient for mitigation of a particular generator's offer. Further, mitigation is designed to prevent the exercise of market power, not to guarantee fixed cost recovery of units with high marginal costs. Market power can arise associated with transmission constraints, especially where the generation unit can affect the constraint (when it has a sufficient Resource-to-Load Distribution Factor in the case of a transmission constraint). Therefore, conduct and impact style mitigation that mitigates to marginal costs is appropriate to prevent the exercise of market power under these circumstances. In cases where the generation offer exceeds marginal costs but not the conduct test, exceeds the conduct test but not the impact test, or in some other cases when the generator provides an infra-marginal offer (i.e., when it is not the last unit selected in the supply stack), the generator will be able to recover additional fixed costs. Further, while the generator may be unable to recover fixed costs in one market, such as energy, it may be able to recover some or all of those costs in other markets, such as the operating reserve markets. In cases where there are shortages of operating reserves, scarcity pricing may allow a generator to recover additional fixed costs.

99. We note that the conduct and impact approach to mitigation has been adopted in several other RTOs and ISOs, including MISO, NYISO, and ISO New England. We do not agree with Golden Spread's argument that SPP's mitigation proposal has the potential for sending the wrong signals to generation investment with units with higher variable costs, such as old depreciated steam units, receiving more revenue. We find that Golden Spread's argument ignores the reality that units with high marginal costs will be selected less often in the market due to those higher costs. Thus, units with high marginal costs will be unlikely to recover more of their fixed costs across time than other generators.

<u>The Commission orders</u>:

(A) The requests for rehearing and/or clarification of the October Order are granted in part and denied in part, as discussed in the body of this order.

(B) SPP is directed to make a compliance filing, as described in the body of this order, within 30 days of the date of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.