144 FERC ¶ 61,224
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 Nos. ER12-1179-003
ER12-1179-004
ER12-1179-005
ER13-1173-000

ORDER ON COMPLIANCE FILING AND PROPOSED TARIFF REVISIONS

(Issued September 20, 2013)

1. In an order dated October 18, 2012, the Commission 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] On February 15, 2013, SPP submitted a filing to comply with directives set forth by the Commission in the October Order.[2] In a second filing, dated March 25, 2013,[3] SPP submitted its Readiness Plan and Reversion Plan, in compliance with the Commission's requirement in the October Order. In a third filing, dated March 28, 2013,[4] SPP submitted additional Tariff revisions to modify its Integrated Marketplace pursuant to section 205 of the Federal Power Act (FPA).[5]

2. In an order dated March 21, 2013, the Commission addressed requests for rehearing and clarification of the October Order.[6] In a fourth filing, dated April 19, 2013,[7] SPP submitted an additional Tariff revision to comply with the Rehearing Order. Here, the Commission addresses the February 2013 Compliance Filing, Readiness and Reversion Plans Filing, the March 2013 Filing, and the April 2013 Compliance Filing.

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[1] *Southwest Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012) (October Order), *order on reh'g and clarification*, 142 FERC ¶ 61,205 (2013) (Rehearing Order).

[2] SPP's February 15, 2013 Submission of Tariff Revisions to Implement SPP Integrated Marketplace in Docket No. ER12-1179-003 (February 2013 Compliance Filing). *See* Appendix A for E-Tariff designations.

[3] SPP's March 25, 2013 Informational Filing of Integrated Marketplace Readiness Metrics and Reversion Plan in Docket No. ER12-1179-004 (Readiness and Reversion Plans Filing).

[4] SPP's March 28, 2013 Submission of Tariff Revisions to Implement SPP Integrated Marketplace in Docket No. ER13-1173-000 (March 2013 Filing). *See* Appendix A for E-Tariff designations.

[5] 16 U.S.C. § 824d (2006).

[6] Rehearing Order, 142 FERC ¶ 61,205 (2013).

[7] SPP's April 19, 2013 Submission of a Compliance Filing in Docket No. ER12-1179-005 (April 2013 Compliance Filing). *See* Appendix A for E-Tariff designations.

As discussed below, the Commission conditionally accepts in part and rejects in part SPP's proposed Tariff revisions.

Background

History

3. 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]

4. In the October Order, the Commission conditionally accepted for filing, subject to further modifications and compliance, 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 a Readiness Certification ahead of market-start-up. The Commission conditioned its acceptance of SPP's proposed Tariff revisions on SPP filing these plans. The Commission also required SPP to file an informational report 15 months after market start-up to evaluate the effectiveness of the Integrated Marketplace based upon the first full 12 months of the operations of the Integrated Marketplace.

5. 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) a real-time balancing market; (4) price-based co-optimized energy and operating reserve procurement; (5) a 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

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[8] SPP's May 15, 2012 Amendatory Filing of Tariff Revisions to Implement SPP Integrated Marketplace (May 2012 Amendment).

[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.

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 Monitoring unit (Market Monitor).

February 2013 Compliance Filing

6. In the October Order, the Commission directed SPP to submit a compliance filing within 90 days to include certain Tariff revisions to and explanations of its Integrated Marketplace proposal. On November 16, 2012, SPP filed a Motion for an Extension of Time requesting a 30-day extension of the compliance deadline to allow it to develop the required Tariff revisions through its stakeholder process.[10] On November 28, 2012, the Commission issued a notice granting SPP's requested extension of time to make the compliance filing due February 15, 2013.[11]

7. On February 15, 2013, SPP submitted the February 2013 Compliance Filing to comply with the Commission's directives in the October Order. The February 2013 Compliance Filing provides a number of revisions to and explanations of the following market design components: (1) day-ahead must-offer requirement; (2) demand response; (3) variable energy resources (VERs); (4) uninstructed resource deviation (URD); (5) manual commitments; (6) make whole payments; (7) revenue neutrality uplift; (8) marginal losses; (9) price formation during shortage conditions; (10) operating reserves; (11) Reserve Zones; (12) congestion management; (13) ARR allocation processes; (14) TCR auctions; (15) bilateral settlement schedules; (16) seams issues; (17) reserve sharing; (18) pseudo-tie arrangements; (19) parameters of mitigation and withholding; (20) mitigated offer development; (21) conduct and impact thresholds; (22) physical withholding and unavailability of facilities; (23) monitoring and mitigation of virtual bids and offers; (24) general monitoring; (25) credit policy; and (26) confidentiality provisions.

8. SPP requests an effective date of March 1, 2014 for the Tariff revisions submitted in its February 2013 Compliance Filing. SPP also requests a waiver of the Commission's

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[10] November 16, 2012 SPP Motion for an Extension of Time, Shortened Comment Period, and Expedited Consideration in Docket Nos. ER12-1179-000 and ER12-1179-001.

[11] November 28, 2012 Notice of Extension of Time in Docket Nos. ER12-1179-000 and ER12-1179-001.

notice requirement in section 35.3 of the Commission's regulations, 18 C.F.R. § 35.3 (2012), to allow SPP to submit these Tariff revisions to the Commission more than 120 days prior to the requested effective date. In addition, SPP requests that the Commission issue an order on this compliance filing by April 16, 2013.

Readiness and Reversion Plans Filing

9. On March 25, 2013, SPP submitted its Readiness and Reversion Plans Filing as an informational filing to comply with the Commission's directives in the October Order. SPP states that the Readiness Plan addresses its efforts to develop and satisfy appropriate readiness metrics, its plan for performing readiness testing for Integrated Marketplace systems, and its plan to achieve final readiness certification 60 days prior to market launch. SPP's Readiness Plan contains 39 metrics to measure, monitor and report on SPP's readiness to start the Integrated Marketplace.[12]

10. According to SPP, the Reversion Plan is intended to mitigate the impacts of unplanned or unexpected operational issues during launch of the Integrated Marketplace and maintain reliability during these events. SPP explains that its Reversion Plan will address system operations in the event of a severe operations failure, including a detailed explanation of how it intends to switch over to alternative systems that can analyze and monitor, among other things, Area Control Error and contingency reserve. SPP adds that the Reversion Plan includes a "reversion window" for implementation, which is less than or equal to 30 operating days following the launch of the Integrated Marketplace. SPP notes that it will, at a minimum, maintain the Reversion Plan for ten operating days after market launch and that it can extend the Reversion Plan up to 60 days, as warranted. SPP states that if the Reversion Plan is implemented, the market will revert back to the Energy Imbalance Service (EIS) Market and current Balancing Authorities resuming their balancing functions.[13] Finally, SPP states that it intends to file its readiness certification no later than 60 days prior to the implementation of the Integrated Marketplace.[14]

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[12] SPP Readiness and Reversion Plans Filing at 3-4.

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

[14] *Id*. at 4.

March 2013 Filing

11. On March 28, 2013, SPP submitted revisions to its Tariff to modify, clarify, and supplement existing provisions of its Integrated Marketplace, pursuant to section 205 of the FPA. Specifically, the March 2013 Filing provides revisions to Tariff language in the following sections: (1) VERs; (2) manual commitment of resources for reliability; (3) demand response and non-conforming load; (4) calculation of market prices during system failure; (5) start-up and no-load offer floors; (6) Market Hub creation; (7) Market Participant Service Agreement; and (8) various corrections and clarifications to the Tariff.

12. SPP requests an effective date of March 1, 2014 for the revisions proposed in this filing. SPP also requests a waiver of the Commission's notice requirement in section 35.3 of the Commission's regulations, 18 C.F.R. § 35.3, to allow SPP to submit these Tariff revisions to the Commission more than 120 days prior to the requested effective date.

April 2013 Compliance Filing

13. On April 19, 2013, SPP submitted a compliance filing to revise section 4.4 of Attachment AG in the Tariff to include language required by the Commission in the Rehearing Order.

Notice and Pleadings

14. Notice of the February 2013 Compliance Filing was published in the *Federal Register*, 78 Fed. Reg. 1,334 (2013), with interventions and protests due on or before March 8, 2013. Notice of the Readiness and Reversion Plans Filing was published in the *Federal Register*, 78 Fed. Reg. 20,907 (2013), with interventions and protests due on or before April 15, 2013. Notice of the March 2013 Filing was published in the *Federal Register,* 78 Fed. Reg. 20,910 (2013), with interventions and protests due on or before April 18, 2013. Notice of the April 2013 Compliance Filing was published in the *Federal Register*, 78 Fed. Reg. 25,260 (2013), with interventions and protests due on or before April 19, 2013.

15. Comments and/or protests to the February 2013 Compliance Filing were filed by: E.ON Climate & Renewables North America LLC (ECRNA), BP Wind Energy North America Inc. (BP Wind Energy), Nebraska Public Power District (NPPD), and TDU

Intervenors.[15] Westar Energy, Inc. (Westar) filed a late protest. SPP filed an answer to the comments and protests. TDU Intervenors filed a reply to SPP's answer.

16. The following parties filed motions to intervene in the March 2013 Filing: NextEra Energy Resources, LLC, American Electric Power Service Corporation, TDU Intervenors, ECRNA, and Lincoln Electric System.

17. On May 10, 2013, Omaha Public Power District (OPPD) filed a protest and motion for appointment of a settlement judge to address grandfathered agreement (GFA) issues raised by the April 2013 Compliance Filing.[16] On June 6, 2013, the Commission issued an order establishing settlement judge procedures to address the unresolved issues regarding the integration of OPPD's GFAs into the Integrated Marketplace. On June 24, 2013, Midwest Energy filed a motion to intervene out of time.

Discussion

Procedural Issues

18. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2013), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to the proceedings in which they were filed. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2013), the Commission will grant Midwest Energy's late-filed motion to intervene given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

19. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2013), prohibits an answer to a protest unless otherwise ordered by the

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[15] The TDU Intervenors include the City of Independence, Missouri, Kansas Power Pool, Missouri Joint Municipal Electric Utility Commission, and West Texas Municipal Power Agency.

[16] OPPD's protest and motion concerning the treatment of grandfathered agreements (GFA) were addressed by the Commission in a June 6, 2013 Order Establishing Settlement Judge Procedures. *See Southwest Power Pool, Inc.*, 143 FERC ¶ 61,219 (2013) (GFA Order).

decisional authority. We will accept the filed answers and replies because they have provided information that assisted us in our decision-making process.

<u>Substantive Issues</u>

20. In this order, we accept in part and reject in part the February 2013 Compliance Filing, and we find that SPP's proposed revisions that are not protested and are not specifically discussed herein are just and reasonable and accepted for filing. We further find that SPP has complied with the Commission's directives in the Rehearing Order and accept the April 2013 Compliance Filing. Finally, as discussed herein, we accept in part and reject in part the March 2013 Filing, and the Readiness and Reversion Plan to be effective March 1, 2014, as requested.

21. While we are cognizant of the proposed implementation date of the Integrated Marketplace, we note that SPP's initial filing lacked sufficient detail and support in many areas. As a result, the October Order had over 100 compliance requirements. Many of these directives required SPP to substantially revise or to provide additional support for its original proposal. In the February 2013 Compliance Filing, SPP addresses many but not all of these compliance requirements, and in some instances fails to fully support its proposed revisions.[17] In addition, SPP proposes revisions to the Integrated Marketplace proposal that were not required by the October Order, several of which SPP has not fully supported on this record. Further, SPP states in the February 2013 Compliance Filing, that it would submit additional Tariff revisions reflecting further market design refinements not required by the October Order on or before March 15, 2013. On March 28, 2013, SPP filed the March 2013 Filing that, in some cases, significantly modified the February 2013 Compliance Filing proposal. It was thus not possible for the Commission to process SPP's compliance filing by SPP's April 16, 2013 requested action date.

22. To the extent that SPP can fully satisfy the compliance requirements associated with this order and file in less than 60 days, it may do so in order to expedite Commission action on the remaining compliance directives associated with the Integrated Marketplace. However, as SPP complies with the requirements in this order, SPP must provide adequate support for each compliance requirement to allow stakeholders and the Commission to respond in a timely fashion once the compliance filing has been submitted for review.

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[17] *See* Appendix B for a list of compliance Directives included in this order.

Day-Ahead Market and Real-Time Balancing Market

Must Offer Requirement

Load Forecasting Error

October Order

23. In the October Order, the Commission conditionally accepted SPP's proposed day-ahead must-offer requirement, subject to compliance.[18] The Commission directed SPP to revise its Tariff to create a process by which SPP or its Market Monitor will: (1) verify that market participants have not exceeded a pre-determined acceptable load forecasting error; and (2) establish non-compliance penalties if market participants' estimates exceed the acceptable range of load forecasting error.[19] The Commission stated that this verification process should compare a load-serving market participant's actual operating daily peak load to that market participant's peak load estimate. In developing this process, the Commission indicated that SPP would need to propose and justify an acceptable range of forecasting error. As an example, the Commission stated that SPP could communicate this range as a certain deviation, expressed as a percentage, above or below the actual operating daily peak load value that SPP deems acceptable.[20]

February 2013 Compliance Filing

24. SPP proposes adding section 2.11.1.B(1) to Attachment AE, Integrated Marketplace, specifying that market participants who have offered and/or self-committed

[18] October Order, 141 FERC ¶ 61,048 at PP 50-57. In its initial Integrated Marketplace filing, SPP proposed a day-ahead must-offer requirement obligating market participants to offer sufficient resources into the day-ahead market to cover their load plus operating reserve obligations, to the extent their resources are available. SPP also proposed that, for the day-ahead must-offer requirement, a market participant's load would be equal to that market participant's expected daily peak load for the operating day, as estimated by the market participant. SPP February 29, 2012 Filing in Docket No. ER12-1179-000; SPP Tariff, Attachment AE, section 2.11.1.

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

[20] *Id.* P 54 & n.61.

100 percent of their net resource capacity, as determined in a new section 2.11.1.A(4) of Attachment AE,[21] will be deemed compliant with the day-ahead must-offer requirement. SPP also proposes adding section 2.11.1.B(2) to Attachment AE, specifying that market participants who have offered and/or self-committed less than 100 percent of their net resource capacity and less than 90 percent of their maximum hourly reported load for the operating day shall be deemed resource deficient and may be subject to sanctions, as provided in section 3.9 of Attachment AF. In addition, SPP proposes adding language at the beginning of section 2.11.1.B that states that the Market Monitor will monitor offered resources, self-committed resources, firm power purchases, firm power sales, and reported load for the operating day as part of its obligations for monitoring the day-ahead market.

25. SPP also modifies section 2.11.1.A(1) of Attachment AE to substitute the phrase "maximum hourly Reported Load for the Operating Day" for the phrase "expected daily peak load for the Operating Day as estimated by the market participant." SPP also proposes adding section 2.11.1.A(3) to Attachment AE, specifying that a market participant may satisfy the day-ahead must-offer requirement only by offering resources with a commitment status indicating either that the market participant is self-committing the resource, or that the resource may be committed by the transmission provider, as specified in sections 4.1(10)(a) and 4.1(10)(b) of Attachment AE.

26. SPP submits testimony from Dr. John Hyatt explaining that, although in the October Order the Commission suggested that the verification process for a market participant's compliance with the day-ahead must-offer requirement should compare a load-serving market participant's actual operating daily peak load to that market participant's peak load estimate,[22] SPP's market design does not require market participants to submit day-ahead peak load estimates. According to Dr. Hyatt, there is no need for this requirement because SPP has developed an alternative mechanism to comply with the October Order. Specifically, Dr. Hyatt explains that the Market Monitor will monitor all offered resources in the day-ahead market (accounting for all firm power

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[21] SPP proposes that net resource capacity include offered capacity by resources less operating reserve obligations, and firm purchases less firm sales. SPP's proposed net resource capacity provisions are further discussed in section 2.11.1.A(4) of Attachment AE *infra* P 49-50 as they relate to deliverability compliance requirements.

[22] February 2013 Compliance Filing, Exh. No. SPP-11 at 3 (citing October Order, 141 FERC ¶ 61,048 at P 54 & n.61).

purchases and firm power sales) and compare the amounts of such offers from each market participant to the market participant's actual maximum hourly reported load for the operating day. Dr. Hyatt states that if the market participant fails to offer sufficient resources in the day-ahead market to cover its load and operating reserve obligations for the operating day, SPP will deem the market participant to be resource-deficient. According to Dr. Hyatt, SPP proposes an exception to this standard and will deem that the market participant has satisfied its day-ahead must-offer obligation when it has offered 100 percent of its net resource capacity or has offered net resource capacity to cover at least 90 percent of its maximum hourly reported load for the operating day.[23]

27. Dr. Hyatt explains that under this proposal, it is incumbent upon market participants to ensure that their offered resources align as accurately as possible with their next-day peak load obligation, because the Market Monitor will be comparing actual day-ahead offers to actual operating day load values. Dr. Hyatt asserts that using offered resources as the metric against which actual reported load is compared provides a more objective standard for monitoring market participants' compliance with SPP's must-offer requirements.[24]

28. SPP submits testimony from Mr. Richard Dillon explaining that its ten percent forecasting error is based on an internal performance review of its Mid-Term Load Forecasting model, which is currently used to forecast loads for each of SPP's internal balancing authorities. Mr. Dillon explains that 99 percent of the time, SPP's Mid-Term Load Forecasting model is within ten percent of the actual next-day balancing authorities' actual loads. Therefore, Mr. Dillon asserts that a ten percent forecasting error is a reasonable standard to apply, at least for initial market operations. Mr. Dillon states that once the Integrated Marketplace commences, experience may indicate the need for future adjustments to this forecasting error.[25]

29. Additionally, SPP proposes adding section 3.9 to Attachment AF, Market Power Mitigation Plan, to set forth the sanctions for non-compliance with the day-ahead must-offer requirement. Proposed section 3.9.A states that a market participant is noncompliant with the day-ahead must-offer requirement when: (1) the market

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

[24] *Id.* at 5.

[25] February 2013 Compliance Filing, Exh. No. SPP-10 at 19.

participant is resource deficient, within the meaning of section 2.11.1.B(1) of Attachment AE; (2) as a consequence of the resource deficiency impacts on locational marginal prices (LMP), market clearing prices, and/or make whole payments, the Market Monitor determines that the market impact test thresholds (specified in section 3.7 of Attachment AF) have been exceeded; and (3) the Market Monitor determines that the total production costs of the market would be reduced if the market participant had offered the resource. Section 3.9.B states that if a market participant is found to be non-compliant, SPP will assess a penalty for each MW of withheld capacity in excess of the ten percent forecasting error. Section 3.9.B further specifies that the penalty amount shall be equal to the day-ahead market LMP associated with the withheld capacity.

30. Dr. Hyatt states that SPP proposes to assess a penalty equal to the day-ahead LMP per MW of capacity not delivered beyond the ten percent forecasting error. Dr. Hyatt explains that by setting the penalty equal to the day-ahead LMP, SPP has put in place a hierarchy based on the value of the energy withheld. Dr. Hyatt states that a high LMP corresponding to an unavailable resource indicates a loss in market efficiency and higher production costs. Thus, Dr. Hyatt explains, market participants with unavailable resources that have a high LMP are subject to a higher penalty than market participants with unavailable resources that have a low LMP. Additionally, Dr. Hyatt notes that this penalty is similar to the penalty applicable to physically withheld generation described in Module D of the Midcontinent Independent System Operator, Inc. (MISO)[26] Tariff.[27]

31. Additionally, Dr. Hyatt explains that the proposed penalty will not be applied in all circumstances where a market participant has exceeded the ten percent forecasting error. According to Dr. Hyatt, when a market participant is resource deficient,[28] the Market Monitor will determine whether the impacts on LMPs, market clearing prices for operating reserve, and/or make whole payments exceed the market impact test threshold

[26] Effective April 26, 2013, MISO changed its name from "Midwest Independent Transmission System Operator, Inc.," to "Midcontinent Independent System Operator, Inc."

[27] February 2013 Compliance Filing, Exh. No. SPP-11 at 5-6.

[28] Dr. Hyatt indicates that SPP considers a market participant resource deficient when the market participant offers into the day-ahead market less than 90 percent of its maximum hourly reported load for the operating day and less than 100 percent of its net resource capacity. *Id.* at 6.

established by SPP. Dr. Hyatt elaborates that the Market Monitor will also determine whether the total production costs of the market would be reduced if the market participant had offered the resource. Dr. Hyatt states that if both conditions are met, SPP will impose the penalty on the market participant.[29]

Comments

32. TDU Intervenors assert that there are inconsistencies in SPP's proposed section 2.11.1 of Attachment AE that need to be corrected. Specifically, TDU Intervenors point out that the introductory sentence of section 2.11.1[30] is inconsistent with newly proposed section 2.11.1.B(1) of Attachment AE, which appears to limit a market participant's day-ahead must-offer obligation to offering or self-committing 100 percent of its net resource capacity.[31]

33. TDU Intervenors also argue that, although the proposed ten percent forecasting error may be an acceptable range for large utilities, many of which are internal balancing authorities within the SPP region, this proposal may have a disproportionate impact on small load-serving entities. TDU Intervenors assert that because large utilities serve thousands of MWs of load, they would be immune to penalties for failing to offer their resources, even if they are hundreds of MWs short. TDU Intervenors argue that large utilities failing to offer their resources could have a significant impact on prices in the day-ahead market. In contrast, TDU Intervenors contend that even though the absence of small load-serving entity resources is likely to have little effect on the robustness of the day-ahead market given their size, a percentage-based forecasting error is problematic because smaller systems often have proportionately lower load factors and larger load swings. According to TDU Intervenors, some small load-serving entities have their entire load in a relatively compressed geographic area, and that unexpected weather changes may have more significant impact on these entities' load forecasts compared to

[29] *Id*.

[30] The introductory sentence of section 2.11.1 of Attachment AE states that "Each market participant must offer sufficient resources to the Day-Ahead Market to cover its load plus [o]perating [r]eserve obligation to the extent its resources are available." SPP Tariff, Attachment AE, section 2.11.1.

[31] TDU Intervenors at 7.

large utilities that can cushion load swings due to their geographic diversity.[32] Accordingly, TDU Intervenors urge the Commission to direct SPP to revise its acceptable load forecasting error to include both a percentage deviation and a minimum absolute error (e.g., the greater of ten percent or 20 MW).[33]

Answer

34. SPP asserts that it has complied with the Commission's directive and has fully demonstrated that its ten percent figure is based on its historical load forecasting experience. SPP argues that TDU Intervenors do not provide empirical support for their claim that smaller load-serving entities will be disproportionately affected. Further, SPP questions the prediction of a disproportionate impact on smaller entities, arguing that the probability of greater forecasting error would presumably increase with larger and more disparate loads.[34]

35. SPP asserts that the implications for the market of an erroneous load forecast are the same regardless of the size of the load being served by the market participant. SPP states that the essential purpose of the day-ahead must-offer requirement is to ensure that sufficient resources are available to cover the load of a load-serving entity. Thus, SPP

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

[33] TDU Intervenors point out that the Commission has previously adopted error bandwidths comprising both a percentage deviation and a minimum absolute deviation. For example, TDU Intervenors note that in Order No. 888-A, the Commission found that a 1.5 percent deviation band for energy imbalance service should be supplemented by a minimum deviation of 2 MW per hour to address concerns raised by small utilities that may exceed the bandwidth without exceeding the minimum. *Id.* at 9-10 (citing *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, at 30,232-30,233, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002)).

[34] SPP Answer at 11-12.

argues, it is not relevant whether the load shortfall of a smaller load-serving entity is, in MWs, less than that of a larger load-serving entity. SPP asserts that there is nothing discriminatory or inequitable in applying a fixed tolerance percentage equally to all market participants under the day-ahead must-offer requirement. Moreover, SPP argues that introducing a MW minimum into the verification process would generate disputes about where to set the minimum.[35]

Reply

36. TDU Intervenors argue that SPP's proposed ten percent forecasting tolerance should be adjusted to have an absolute value as well as a percentage because it is more difficult for small load serving entities to forecast load. TDU Intervenors assert that the Commission accepted similar arguments in Order No. 888-A. Finally, TDU Intervenors assert that it is SPP's burden to demonstrate that its proposed forecasting tolerance is just and reasonable.[36]

Commission Determination

37. We find that SPP's revisions to section 2.11.1 of Attachment AE partially comply with the directives set forth in the October Order. Specifically, we agree with TDU Intervenors that there are inconsistencies between the terminology used in the introduction of section 2.11.1.A of Attachment AE (referring to "sufficient resources") and new language proposed elsewhere in this section (referring to "net resource capacity"). For example, SPP includes the definition of net resource capacity within section 2.11.1.A(4), yet there is no explanation within section 2.11.1.A of how net resource capacity relates to the day-ahead must-offer requirement in section 2.11.1.A.

38. We also find that proposed section 2.11.1 of Attachment AE, as drafted, appears to articulate two different versions of the day-ahead must-offer requirement. In the first version, outlined in section 2.11.1.A of Attachment AE, each market participant must offer sufficient resources into the day-ahead market to cover its maximum hourly reported load plus operating reserve obligations for the operating day, to the extent that its resources are available. We note that this version of the day-ahead must-offer requirement is for the most part consistent with the one conditionally accepted by the

[35] *Id.* at 11-12 & n.29.

[36] TDU Intervenors' Reply at 12.

Commission in the October Order.[37] However, there appears to be a second day-ahead must-offer requirement, described in section 2.11.1.B(1) of Attachment AE, which provides that market participants who have offered and/or self-committed 100 percent of their net resource capacity are compliant with the day-ahead must-offer requirement. We believe SPP intends the language in section 2.11.1.B(1) as part of its screening process to verify compliance with the day-ahead must-offer requirement. However, the relationship between this screening process (which employs the term "net resource capacity") and the day-ahead must-offer requirement (as articulated at the beginning of section 2.11.1.A) is ambiguous from the proposed Tariff language.

39. Accordingly, we direct SPP to submit a compliance filing within 60 days of the date of this order that clarifies section 2.11.1 of Attachment AE and clearly delineates (1) what the screening process for verification of the day-ahead must-offer requirement entails, and (2) how the Market Monitor will conduct this screening process, particularly the Market Monitor's responsibility in regard to verification and the values the Market Monitor is comparing when making its determination.[38] Additionally, we direct SPP to make conforming changes to section 3.9 of Attachment AF to be consistent with section 2.11.1 of Attachment AE. Finally, we accept SPP's proposed section 2.11.1A(3) because it provides clarification to the Tariff that is consistent with related compliance directives in the October Order.

40. We find that a ten percent load forecasting error is reasonable for market start-up. In the EIS Market, SPP uses the Mid-Term Load Forecasting model for forecasting loads for each of SPP's internal balancing authorities, and according to Mr. Dillon, this model provides a high level of accuracy. Therefore, we conclude that it is reasonable to continue applying the Mid-Term Load Forecasting model for the start of the Integrated Marketplace. However, in response to TDU Intervenors' concerns that there is no fixed

[37] With the exception that the term "maximum hourly Reported Load for the Operating Day" is substituted for "expected daily peak load for the Operating Day as estimated by the market participant."

[38] From the testimony, it appears that SPP intends for the Market Monitor to identify instances where a market participant is resource deficient by comparing the market participant's offered resource capacity against actual reported load. Section 2.11.1.B does not include this requirement. Moreover, section 2.11.1.B does not specify that the Market Monitor will compare the net resource capacity value against a market participant's maximum hourly reported load for the operating day.

minimum deviation, we will require SPP to re-evaluate this issue in its informational report due 15 months after commencement of the Integrated Marketplace.[39]

41. We conditionally accept SPP's proposal in section 3.9 of Attachment AF relating to penalties associated with the day-ahead must-offer requirement. We find that SPP has demonstrated that the penalty provisions proposed in section 3.9.B and 3.9.C are just and reasonable. However, we find that SPP has not justified the two situations (described in section 3.9A) that would limit the instances in which the Market Monitor would assess penalties under section 3.9.[40] Specifically, SPP has not demonstrated why the Market Monitor would need to conduct a market impact test in this instance, nor has SPP explained the need for assessing the impact on total production costs. Accordingly, it is not clear whether an appropriate incentive exists for market participants to offer enough resources to cover load plus operating reserve obligations in the day-ahead market. Moreover, the compliance directive in the October Order stated that if market participants exceed the acceptable range of load forecasting error, then SPP should assess a penalty. The Commission did not direct SPP to evaluate actual market impacts as a condition for assessing this penalty. Accordingly, we direct SPP to remove sections 3.9.A(2) and 3.9.A(3) from Attachment AF in a compliance filing due 60 days after the issuance of this order.[41]

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[39] Specifically, we require SPP to discuss: whether its ten percent forecasting error has had a disproportionate impact on smaller load-serving entities; whether expressing the acceptable forecasting error as a percentage deviation and as a minimum MW absolute error is warranted based on market observations; and, if so, a possible MW value for this minimum absolute error.

[40] Section 3.9.A of Attachment AF states that a market participant is noncompliant with the day-ahead must-offer requirement when: (1) the market participant is resource deficient, within the meaning of section 2.11.1.B(1) of Attachment AE; (2) as a consequence of the resource deficiency impacts on LMPs, market clearing prices, and/or make whole payments, the Market Monitor determines that the market impact test thresholds (specified in section 3.7 of Attachment AF) have been exceeded; and (3) the Market Monitor determines that the total production costs of the market would be reduced if the market participant had offered the resource.

[41] In reviewing revision 14.0a of the Market Protocols for the Integrated Marketplace (last updated May 10, 2013), we note an error in section 8.2.7.1. This section, which specifies the penalty calculation for non-compliance with the day-ahead

(continued…)

42. Finally, we note that in the October Order the Commission required SPP to monitor the effect that the limited day-ahead must-offer requirement has on market operations, and to report its observations in an informational report due 15 months after commencement of the Integrated Marketplace.[42] As part of this informational filing, we direct SPP to consider and report on whether the penalty provisions in section 3.9 of Attachment AF have ensured that sufficient resources are available to cover the load and operating reserve obligations of load-serving entities, as well as the extent to which the Market Monitor has had to assess penalties under section 3.9 during the first year of market operations. This information will help the Commission and stakeholders assess the impact of the limited day-ahead must-offer requirement, and associated monitoring and penalty provisions, on market operations.

Deliverability

October Order

43. In the October Order, in the context of monitoring for manipulative behavior, the Commission required SPP to clarify how it will ensure that offered resources are deliverable to the load they were offered to cover, and to modify its Tariff, if necessary, to reflect verification of deliverability. As an example, the Commission suggested that SPP could specify in its Tariff that each load-serving market participant must ensure deliverability to its own load.[43]

February 2013 Compliance Filing

44. SPP proposes that a market participant who has offered and/or self-committed 100 percent of its net resource capacity is deemed to have complied with the day-ahead must-offer requirement. In a new section 2.11.1.A(4) of Attachment AE, SPP proposes that a market participant's net resource capacity shall include: (i) offered capacity less operating reserve obligations; and (ii) firm power purchases less firm power sales.

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must-offer requirement, references sections 8.2.6.1(1) through 8.2.6.1(3) of the Market Protocols, which contain provisions for physical withholding. This reference appears to be incorrect and should refer to section 8.2.7.

[42] October Order, 141 FERC ¶ 61,048 at P 50.

[43] *Id.* P 55 & n.62.

Section 2.11.1.A(4)(ii) further states that firm purchases and firm power sales shall include:

> sales and purchases that are deliverable with transmission service comparable to Firm Point-To-Point Transmission Service or Firm Network Integration Transmission Service and the capacity and energy is supplied under standards of reliability and availability equivalent to supply of native load customers with the supplier assuming the obligation to provide both capacity and energy.[44]

Comment

45. TDU Intervenors argue that SPP's native-load equivalence requirement unnecessarily excludes some capacity from the day-ahead must-offer requirement. TDU Intervenors explain that a load-serving entity with a unit-specific purchase would be under no obligation to serve on a basis equivalent to native load, which is unusual in a unit-specific contract. TDU Intervenors argue that, even if that power were deliverable to load and even if the load-serving entity used that power to meet its service obligations, the load-serving entity would not be required to offer that power. Further, TDU Intervenors assert that if the owner of the unit were not a load-serving entity, then the unit's capacity would not be subject to the day-ahead must-offer requirement. TDU Intervenors contend that SPP's proposal could create the potential for a significant amount of physical capacity to be exempt from the day-ahead must-offer requirement. Finally, TDU Intervenors argue that the native load equivalence requirement is unnecessary to demonstrate deliverability, because this is addressed already by SPP's firm transmission service requirement.[45]

46. TDU Intervenors note that the types of power purchases having a native-load equivalence level of firmness are generally system power sales, which are backed by the seller's reserve capacity. According to TDU Intervenors, these types of power purchases appear to be the only types of power purchases included in a load-serving entity's net

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[44] February 2013 Compliance Filing at 5. SPP states that market participants offering designated resources into the day-ahead market have already demonstrated deliverability-to-load because SPP verifies deliverability as part of granting firm network integration transmission service associated with those resources.

[45] TDU Intervenors at 4-5.

resource capacity; therefore, these would be subject to the day-ahead must-offer requirement. However, TDU Intervenors allege that SPP indicated that system-purchase Power Purchase Agreements are not eligible to be offered into the day-ahead market. TDU Intervenors cite SPP's May 15, 2012 initial Integrated Marketplace proposal in which SPP explains that, "[o]nly Energy deliveries associated with bilateral contracts that are Resource-specific with contract terms that allow the buyer to offer its share of the Resource(s) into the market may be offered into the market as a Resource, provided that such Resources are registered as Jointly-Owned Unit(s)."[46] According to TDU Intervenors, in all other situations, a Power Purchase Agreement must be handled through a Bilateral Settlement Schedule or by having the seller register the load served under the Power Purchase Agreement as its own load. Thus, TDU Intervenors assert that although certain power purchases may qualify as net resource capacity, the buyer would not be permitted to offer the purchase into the day-ahead market, but the buyer could be subject to penalties for failing to offer.[47]

Answer

47. SPP responds that the native-load equivalence criterion is the same requirement specified under section 2.1.2 of the SPP Criteria[48] to qualify a power purchase as firm power for meeting a load-serving entity's obligations under SPP Criteria 2. SPP asserts that TDU Intervenors' concern that the must-offer requirement will improperly exclude certain power purchases from eligibility is based on a misunderstanding of the SPP Tariff. SPP explains that the ability to offer a resource into the market and to utilize firm power purchases to meet SPP's must-offer requirement is dependent on who registers the resource. According to SPP, if the owner/seller agrees to let the buyer register the resource in the market, the buyer can offer the generation into the market. SPP states that

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[46] *Id.* at 6 (citing SPP May 15, 2012 Answer in Docket No. ER12-1179-000 at 40).

[47] *Id.* at 5-7.

[48] As explained in the SPP Criteria: "In some instances, the [North American Electric Reliability Corporation (NERC)] documents are not in sufficient detail to meet specific needs of SPP. Additional necessary details have been adopted by SPP as Criteria. This Criteria is considered as the policies, standards or principles of conduct by which the coordinated planning and operation of the interconnected electric system is achieved." Southwest Power Pool, Inc., SPP Criteria, foreword (revised January 30, 2012).

in this scenario, the resource being offered is not considered by SPP as a power purchase, but rather is a resource registered by a market participant. By contrast, SPP explains that if the owner/seller retains registration responsibility for the resource, only the seller can offer the resource into the market. SPP states that it allows an exception for resources registered as joint operating units, in which case all owners can register their portion and offer each portion according to the Tariff rules. SPP asserts that, under its must-offer rules, in cases where the resource is not registered by the market participant, such market participant will be credited for a firm Power Purchase Agreement only if it meets the deliverability/native load standards of the Tariff. SPP states that the seller will have its must-offer obligation increased, and the buyer will have its must-offer obligation reduced, by the amount of the firm power purchase.[49]

Reply

48. TDU Intervenors assert that SPP has not justified excluding firm purchases without native-load equivalence from the day-ahead must-offer obligation. TDU Intervenors note that the SPP Criteria document serves a different purpose than the market rules in the Tariff.[50] Specifically, TDU Intervenors state that, to the best of their knowledge, the SPP Criteria have only been filed with the Commission as an exhibit to the Southwestern Power Administration Agreement between SPP and the United States of America. TDU Intervenors further note that it does not appear that SPP seeks Commission approval for changes to the SPP Criteria. TDU Intervenors argue that referencing language from SPP Criteria 2 does not demonstrate the justness and reasonableness of excluding firm power purchases without native-load equivalence from the day-ahead must-offer requirement.[51] Additionally, TDU Intervenors assert that SPP's answer does not adequately address their concerns about the buyer not being permitted to offer the purchase into the day-ahead market, but at the same time being subject to penalties for failing to offer. According to TDU Intervenors, SPP merely explains that if an owner/seller allows the buyer to register the resource in the market, the buyer can offer the generation without treating it as a power purchase. TDU Intervenors argue that this

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[49] SPP Answer at 9-10.

[50] TDU Intervenors' Reply at n.14.

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

does not resolve situations where the owner/seller retains the right to register a resource on its own.[52]

Commission Determination

49. We find that SPP's net resource capacity provisions, proposed in section 2.11.1.A(4)(ii) in Attachment AE, partially comply with the Commission's directive that SPP clarify how it will ensure that offered resources are deliverable to the load they were offered to cover. We agree with TDU Intervenors that, as drafted, section 2.11.1 of Attachment AE leaves ambiguous how SPP will account for firm purchases that do not have native load equivalency,[53] particularly in situations where, in a power purchase arrangement, the owner/seller retains the right to register a resource.

50. Additionally, as discussed below, the Commission requires SPP to allow the seller, with the agreement of the buyer, to register the buyer's load if the seller agrees to assume responsibility for the requirements of the load.[54] We note that SPP states that it would not object to allowing load transfers and/or bilateral contracts to count toward must-offer obligations, as long as the seller agrees to assume responsibility for the buyer's load that is transferred or served under the bilateral agreement.[55] Accordingly, we direct SPP to revise its Tariff in section 2.11.1 of Attachment AE to allowed load transfers and/or bilateral contracts to count toward must-offer obligations. We will also require SPP to further explain the relationship between the day-ahead must-offer requirement and these load transfers and/or bilateral contracts and to propose clarifying edits to the Tariff, as needed. Accordingly, we direct SPP, in its compliance filing due 60 days after the issuance of this order, to clarify the net resource capacity definition in section 2.11.1of Attachment AE to account for the full range of firm purchases subject to the day-ahead must-offer obligation.

[52] *Id.* at 11.

[53] For example, a contract for firm power from a single generator (a unit power sale) is generally acceptable as a designated network resource for the purposes of meeting a resource adequacy requirement but would not meet a native load equivalency standard in the same way a system power sale would.

[54] *See infra* P 227.

[55] SPP Answer at 16-17.

Demand Response Resources

Aggregation of Demand Response Resources

October Order and Order No. 719 Compliance Orders

51. In the October Order, the Commission required SPP to clarify whether the Tariff provisions allowing for the aggregation of retail customers into a demand response resource also apply to wholesale customers.[56]

February 2013 Compliance Filing

52. SPP provides testimony from Mr. Dillon stating that the aggregation procedures in the Tariff apply to both retail demand response customers and wholesale demand response customers.[57]

Comments

53. NPPD asserts that SPP's aggregation procedures, by their own terms, are expressly limited to retail customers. NPPD explains that it currently has a demand response program applicable to retail customers and load serving entities that are wholesale customers of NPPD. NPPD seeks clarification that wholesale customers will be permitted to participate in SPP's proposed demand response program.[58]

Answer

54. SPP states that its proposed Tariff provisions for the aggregation of demand response resources only address the aggregation of retail customers because these provisions were adopted to comply with Order No. 719.[59] However, SPP asserts that, in

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[56] October Order, 141 FERC ¶ 61,048 at P 84.

[57] February 2013 Filing, Exh. No. SPP-10 at 3.

[58] NPPD at 3.

[59] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), *order denying reh'g*. Order No. 719-B, 129 FERC ¶ 61,252 (2009).

practice, it accepts the aggregation of wholesale customers as well as retail customers, provided that the market participant follows all applicable Integrated Marketplace rules and practices. SPP also requires the market participant to register its demand response resources in accordance with the procedures set forth in the Tariff.[60]

Commission Determination

55. In the October Order, we directed SPP to clarify whether the Tariff provisions allowing for the aggregation of retail customers into a demand response resource also apply to wholesale customers. We find that SPP has complied with this directive by explaining that its practice is to accept the aggregation of wholesale customers into a larger demand response resource. However, we find that the Tariff does not specifically provide for the aggregation of wholesale customers. We direct SPP to revise its Tariff to provide that wholesale customers may be aggregated into a larger demand response resource, in a compliance filing due 60 days after the issuance of this order. Including this provision in the Tariff will allow market participants to know that this option is available to them and will reduce any ambiguity regarding customer eligibility for demand response aggregation. Additionally, SPP should include in its Tariff any associated aggregation requirements.

Retail Customer Aggregation Requirements

October Order and Order No. 719 Compliance Orders

56. In an Order No. 719 compliance order, the Commission found that SPP had not provided sufficient justification to demonstrate that its "electrically equivalent point" aggregation requirement, which limited the ARC behind a single price node, was just and reasonable.[61] The Commission expressed concern that this requirement could unnecessarily restrict the ability of Aggregators of Retail Customers (ARC) to effectively and efficiently aggregate demand response for participation in the SPP marketplace. The

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[60] SPP Answer at 29.

[61] *Southwest Power Pool, Inc.*, 141 FERC ¶ 61,047 (2012) (2012 SPP 719 Compliance Order), *order on compliance*, 144 FERC ¶ 61,032 (2013) (2013 SPP 719 Compliance Order). SPP included this single electrically equivalent point requirement in its ARC aggregation requirements for both its EIS Market and the Integrated Marketplace.

Commission also noted that most Regional Transmission Operators (RTO) and Independent System Operators (ISO) effectively manage localized congestion, while allowing ARCs to aggregate smaller retail customers into a demand response resource on a sub-regional basis, such as within a local balancing authority area, transmission zone, or load zone. The Commission required SPP to provide, in a filing in its ongoing Order No. 719 compliance proceeding, additional explanation regarding the electrically equivalent point aggregation requirement for both the EIS Market and Integrated Marketplace.[62]

57. In the October Order, the Commission conditionally accepted SPP's ARC proposal for the Integrated Marketplace, conditioned on the outcome of its ongoing Order No. 719 compliance proceeding. The Commission also directed SPP to address how the requirement in section 2.2(2) of proposed Attachment AE, which specifies that demand response load may only be associated with a single price node, may be affected by broadening ARC aggregation requirements to allow for aggregation at the sub-regional level. The Commission found that SPP had provided little explanation for its single price node limitation and required SPP to provide further clarification on its proposal. The Commission also required SPP to modify sections 2.2(2) and 2.2(3) of proposed Attachment AE, as well as related provisions in sections 4.1.2.1(1) and 4.1.2.1(2) of Attachment AE, if SPP believed ARC-specific modifications were necessary, based on the outcome of its ongoing Order No. 719 compliance proceeding.[63]

58. In the 2013 SPP 719 Compliance Order, the Commission found SPP's ARC aggregation requirements for its current EIS Market complies with Order No. 719 due to present EIS Market software limitations and the transition to the Integrated Marketplace. The Commission indicated that it would make a determination on whether SPP's ARC aggregation requirements for the Integrated Marketplace were compliant with Order No. 719 in SPP's ongoing Integrated Marketplace proceeding, given the new Tariff provision proposed in section 2.2(2) of Attachment AE in SPP's March 2013 Filing.[64]

[62] *Id.* PP 45-46.

[63] October Order, 141 FERC ¶ 61,048 at P 84.

[64] 2013 SPP 719 Compliance Order, 144 FERC ¶ 61,032 at P 22.

February 2013 Compliance Filing

59. SPP submits the testimony of Mr. Dillon, which states that in an LMP market, reliability and congestion are managed through the dispatch of appropriately-sited resources, as determined by the use of a Security Constrained Economic Dispatch model. Mr. Dillon explains that demand response customers, whether retail or wholesale, participate in LMP markets in direct competition with traditional resources. Mr. Dillon asserts that SPP's nodal construct for ARC aggregation purposes appropriately treats demand response resources the same as other resources in the Integrated Marketplace. Mr. Dillon states that by utilizing a nodal resource design, SPP hopes to avoid problems encountered in other regional markets, such as in the Electric Reliability Council of Texas (ERCOT) and the California Independent System Operator Corporation (CAISO), where the non-nodal management of congestion and reliability resulted in significant additional costs and manual interventions by the transmission provider.[65]

Comments

60. NPPD objects to limiting the aggregation of customers behind a single price node. NPPD also points out that SPP did not discuss how broadening ARC aggregation requirements could affect the SPP system. NPPD further states that SPP did not quantify the additional costs incurred by ERCOT and CAISO, nor did SPP provide a citation to support the alleged problems they experienced. According to NPPD, it has a long-standing demand response program that has historically recognized a load reduction of up to 600 MW in a given hour, which has delayed or avoided the need to build additional generation capacity. NPPD asserts this program would be negatively affected by SPP's aggregation requirements, and that SPP should not be allowed to force NPPD to roll back the aggregation of customers within the NPPD balancing area. NPPD requests that the Commission require SPP to allow aggregation across a balancing authority area and to quantify any additional costs incurred as a result of this broader aggregation zone. NPPD also requests that the Commission require periodic review of SPP's demand response

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[65] February 2013 Filing, Exh. No. SPP-10 at 3-4. Mr. Dillon indicates that ERCOT cited benefits such as improved price signals, improved dispatch efficiencies, and more representative assignment of congestion costs when moving from a zonal to a nodal market design.

program to provide information to determine whether broader aggregation produces net benefits to the public interest.[66]

Answer

61. SPP asserts that its aggregation requirements do not preclude participation of demand response resources or limit an ARC's ability to represent multiple demand response loads at different electrical points. According to SPP, these requirements only mandate that an ARC must register and offer load located at different electrical points as separate resources. SPP asserts that if NPPD chooses to have its demand response participate in SPP's wholesale demand response program, then NPPD should be able to bid its entire 600 MW load reduction into the Integrated Marketplace as one or more resources, depending on the load's electrical location.[67]

March 2013 Filing

62. SPP proposes revising section 2.2(2) of Attachment AE to state that non-conforming load and demand response load may be associated with an aggregated price node containing multiple electrically equivalent price nodes. SPP states that a single demand response resource or non-conforming load may, in reality, be served from more than one pricing point location. SPP also explains that operators may not be able to forecast loads on a price node basis; rather, they may only be able to forecast those loads in the aggregate. SPP asserts this revision is just and reasonable because it will enhance the ability of operators to forecast load.[68]

Commission Determination

63. We find that SPP's proposal in its March 2013 Filing, which provides that demand response load may be associated with an aggregated price node containing multiple electrically equivalent points, provides for broader and less restrictive aggregation when applied to ARCs. This aggregated price node concept, when applied to ARCs, is a

[66] NPPD at 2-6.

[67] SPP Answer at 30-31.

[68] March 2013 Filing at 8.

reasonably defined area and, thus, is compliant with Order No. 719.[69] Accordingly, we accept the proposed revision to section 2.2(2) of Attachment AE in SPP's March 2013 Filing. However, SPP does not reflect this modification in other sections of Attachment AE that contain demand response provisions and ARC aggregation requirements. Accordingly, to provide internal consistency in the Tariff, we direct SPP to revise section 2.8(2)(a) of Attachment AE to state that end-use customers may be aggregated into a single dispatchable or block demand response resource behind an aggregated price node containing multiple electrically equivalent points, in accordance with section 2.2(2) of Attachment AE, in a compliance filing due 60 days after the issuance of this order. We will also require SPP to revise sections 4.1.2.1(1) and 4.1.2.1(2) of Attachment AE, which contain demand response provisions, to reflect the aggregated price node option specified in section 2.2(2), and to make any additional related Tariff revisions, as necessary, in a compliance filing due 60 days after the issuance of this order. Finally, we direct SPP to assess whether additional revisions are necessary to section 2.2(3)[70] of Attachment AE to accommodate the revision made to section 2.2(2) in the March 2013 Filing.

64. To provide more information to the Commission and stakeholders, we direct SPP to include the number of registered aggregated demand response resources in the Integrated Marketplace, in its informational report due 15 months after commencement of the Integrated Marketplace. SPP should also report on its experience with any problems relating to the aggregated price node concept specified in section 2.2(2) of Attachment AE (for both demand response and non-conforming load).

Variable Energy Resources

October Order

65. In the October Order, the Commission conditionally accepted SPP's VER proposal, including provisions to define two types of VERs: (1) dispatchable VERs,

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[69] Order No. 719 provides that RTOs and ISOs may require that single aggregated bids be from a single area that is reasonably defined. Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 158.

[70] Section 2.2(3) of Attachment AE, as accepted, limits the aggregation of multiple meter data submittal locations behind the same physical and electrically equivalent injection point.

which are capable of being incrementally dispatched by SPP; and (2) non-dispatchable VERs, which are not capable of being incrementally dispatched by SPP. On compliance, the Commission required SPP to clarify whether dispatchable VERs may provide operating reserves and to submit any corresponding Tariff revisions. The Commission stated that, if SPP decided to not allow dispatchable VERs to provide operating reserves, it should justify this restriction.[71]

66. With regard to VER forecasts and data requirements, the Commission found that because SPP's output forecasts for dispatchable VERs may be used to calculate a dispatchable VER's maximum operating limit,[72] there could be rate implications. The Commission further found that meteorological data reporting should be limited to data that are necessary for SPP to produce the specific power production forecasts it intends to produce. Thus, the Commission required SPP to submit an explanation of (1) its methodology for determining SPP's output forecasts for dispatchable VERs, and (2) any meteorological data that are required from VERs and, if needed, corresponding Tariff revisions.[73]

67. The Commission conditionally accepted SPP's proposed maximum operating limit requirements for the real-time market. In particular, the Commission found it appropriate to substitute SPP's output forecast for a dispatchable VER's maximum operating limit in the real-time market when the VER (1) fails to provide that limit, (2) fails to update that limit close to real-time, or (3) submits a limit that exceeds the resource's physical operating limit. Accordingly, the Commission required SPP to submit Tariff revisions to

[71] October Order, 141 FERC ¶ 61,048 at P 116.

[72] In the RUC processes, SPP proposed to calculate a dispatchable VER's maximum operating limit as the lesser of the maximum operating limit submitted by the VER or SPP's output forecast for the VER. In the real-time market, SPP proposed that when SPP issues a dispatch instruction to increase output after issuing a dispatch instruction in the previous interval to reduce output, the dispatchable VER's maximum operating limit will be the lesser of SPP's output forecast for the VER or the sum of five times the VER's ramp rate and the dispatch instruction issued in the previous interval. *Id.* P 86.

[73] *Id.* P 115.

incorporate the instances in which SPP's output forecast would be substituted for the maximum operating limit submitted for a dispatchable VER.[74]

68. In the October Order, the Commission expressed concern regarding SPP's proposed VER registration requirements. Specifically, SPP proposed that: (1) wind-powered VERs with an interconnection agreement executed after May 21, 2011 must register as dispatchable VERs;[75] (2) VERs with fuel sources other than wind have the option to register as dispatchable VERs, if the VER is capable of being dispatched by SPP; and, (3) all other VERs (i.e., wind-powered VERs with an interconnection agreement executed on or before May 21, 2011) must register as non-dispatchable VERs.[76] Specifically, the Commission was concerned that these requirements could prevent wind-powered VERs with interconnection agreements executed on or before May 21, 2011 from registering as dispatchable VERs, even if they satisfy the applicable requirements. Therefore, the Commission required SPP to submit Tariff revisions to these registration requirements providing that wind-powered VERs with interconnection agreements executed on or prior to May 21, 2011 may register as dispatchable VERs, if they satisfy the applicable requirements.[77] The Commission also directed SPP to submit Tariff revisions providing that resources previously registered as dispatchable VERs may not later register as non-dispatchable VERs.[78]

69. In addition, the Commission directed SPP to submit revisions that fully explain its treatment of non-dispatchable VERs, including its curtailment procedures, and to indicate

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[74] *Id.* P 113.

[75] SPP maintained that this requirement is consistent with the Commission's directives in Docket No. ER11-3154-000. *Id.* P 85 & n.110 (citing Exh. No. SPP-3 at 36; *Southwest Power Pool, Inc.*, 135 FERC ¶ 61,148, at P 13 (2011) (accepting Tariff amendment to require that new wind resources be capable of reducing their output in 50 MW increments, effective May 21, 2011)).

[76] *Id.* P 85.

[77] *Id.* P 117.

[78] *Id.* P 118.

whether SPP will continue to apply the systematic[79] and automated processes that were conditionally accepted by the Commission in the September 20 Order. Thus, the Commission required SPP to submit an explanation of how non-dispatchable VERs will be treated in the Integrated Marketplace and, as needed, corresponding Tariff revisions.[80]

February 2013 Compliance Filing

70. SPP proposes revisions to section 2.10 of Attachment AE to clarify that dispatchable VERs may qualify to provide regulation-down reserve.[81] SPP states that VERs should not be permitted to provide other operating reserve products (i.e., so-called Up-products) because VERs' output is, by definition, variable and, therefore, VERs cannot ensure the production of more energy than the current output on demand.[82]

71. SPP proposes revisions to section 3.1.2 of Attachment AE to clarify that it will develop output forecasts for each wind-powered VER on an hourly basis, using a physical modeling technique that considers the relationships between the wind powered

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[79] By using the term "systematic," SPP meant that its market software tools will send instructions directing Non-Dispatchable Resources (i.e., resources in shut-down, start-up, or test mode; operating under exigent circumstances; or that are intermittent resources) to curtail output, rather than sending instructions that merely reflect the resource's actual output and that do not contemplate or instruct that the resources change

the amount of the output. *Id.* P 119 (citing *Southwest Power Pool, Inc.*, 140 FERC ¶ 61,225, at P 2 & n.2-n.3 (2012) (September 20 Order)).

[80] *Id.*

[81] Regulation-down is defined in Attachment AE of the SPP Tariff as, "an [o]perating [r]eserve product procured by the Transmission Provider from resources that reduce their energy output in response to a Regulation Deployment instruction from the Transmission Provider."

[82] February 2013 Compliance Filing at 10 (citing Exh. No. SPP-10 at 7). Regulation-up is defined in Attachment AE of the SPP Tariff as "An [o]perating [r]eserve product procured by the Transmission Provider from resources that increase their energy output in response to a Regulation Deployment instruction from the Transmission Provider."

VER and certain forecast data, as further described in SPP's Market Protocols. SPP explains that these forecast data include geographic data, meteorological data, wind turbine data, and other data that influence wind-powered VER production, as further described in SPP's Market Protocols.[83] SPP states that it has developed Tariff revisions to address further the meteorological data requirements for VERs, and that SPP will submit these Tariff revisions in its filing to comply with Order No. 764.[84]

72. According to SPP, its proposed revisions to section 4.1.2.4(2) provide that it will use its output forecast, rather than the maximum operating limit submitted by a wind-powered VER, in the RUC processes in the event that the limit is more than 30 minutes old, is not submitted, or exceeds the maximum physical rating of the registered resource.[85] SPP proposes to revise the VER registration requirements in section 2.2(10) of Attachment AE to give wind-powered VERs with interconnection agreements executed on or before May 21, 2011, the option to register as dispatchable VERs if they meet the applicable requirements. SPP also proposes to prohibit VERs that register as dispatchable VERs from later registering as non-dispatchable VERs.[86]

73. With regard to the treatment of non-dispatchable VERs, SPP proposes Tariff revisions to clarify that it will notify a non-dispatchable VER when a Manual Dispatch Instruction is issued to resolve an emergency condition or reliability issue, in lieu of using the systematic and automated curtailment procedures.[87]

March 2013 Filing

74. SPP proposes several VER-related revisions to its Tariff to reflect Tariff revisions filed in its March 1, 2013 filing in Docket No. ER12-2292-003 to comply with the September 20 Order and to provide certain clarifications. Among other things, SPP

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[83] February 2013 Compliance Filing at 9-10.

[84] *Id.* at n.50 (citing *Integration of Variable Energy Resources*, Order No. 764, 77 Fed. Reg. 41,481 (July 13, 2012), FERC Stats. & Regs. ¶ 31,331 (2012)).

[85] *Id.* at 9.

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

[87] *Id.* at 11.

proposes Tariff revisions to implement minor clarifications to the maximum operating limit requirements for dispatchable VERs in the Integrated Marketplace. SPP contends that the existing Tariff language describing the maximum operating limit requirements for dispatchable VERs in the RUC processes inadvertently indicates that these requirements would apply only to wind-powered dispatchable VERs. SPP proposes Tariff revisions to correct this error, so that these requirements apply uniformly to all dispatchable VERs.[88] SPP also proposes that, in dispatch intervals immediately following a dispatch interval in which SPP instructed a dispatchable VER to reduce output in the real-time market, the dispatchable VER's maximum operating limit will equal the lesser of the maximum operating limit submitted in the resource's offer or, if available, SPP's output forecast. As a result of this change, SPP will not use the sum of the dispatch instructions issued in the previous dispatch interval and five times the resource's ramp rate to determine these maximum operating limits, which was previously approved by the Commission.[89] In addition, with regard to the maximum operating limits for both dispatchable and non-dispatchable VERs, SPP proposes Tariff language specifying that, in the RUC processes, SPP will calculate a non-dispatchable VER's maximum operating limit as the lesser of the maximum operating limit submitted by the resource or SPP's output forecast only to the extent that SPP's output forecast is available.[90]

75. SPP proposes to revise a registration requirement for certain VERs to reflect the explanation and revisions included in a compliance filing submitted in response to an earlier order relating to VER integration in the EIS Market.[91] In particular, with regard to

[88] March 2013 Filing at 6-7.

[89] *Id.* (discussing SPP Tariff, Attachment AE, section 4.1.2.4(6)(a)-(c)).

[90] *Id.* at 7.

[91] March 2013 Filing at 5 (citing September 20 Order, 140 FERC ¶ 61,225 at P 47)). SPP states that, in the September 20 Order, the Commission conditionally accepted SPP's revisions to Attachment AE of the Tariff to permit the systematic curtailment of Non-Dispatchable Resources that were commercially operable on or after October 15, 2012, in the EIS Market during periods of congestion. According to SPP, the Commission required SPP to file a compliance filing to address, among other things, the applicability of the systematic curtailment provisions based on the date the Non-Dispatchable Resources became commercially operable and to explain how the provisions would work in the Integrated Marketplace. SPP filed Tariff revisions to

(continued…)

the registration requirement that would give wind-powered VERs that executed interconnection agreements on or before May 21, 2011 the option to register as either dispatchable or non-dispatchable VERs, SPP proposes that, if such VERs did not commence commercial operation until on or after October 15, 2012, they must register as dispatchable VERs in the Integrated Marketplace (i.e., they could not choose to instead register as non-dispatchable VERs). SPP contends that this modification reflects the treatment of these resources in the EIS Market, pursuant to the September 20 Order.[92]

Comments

76. ECRNA supports SPP's proposal to allow dispatchable VERs to provide regulation down. However, ECRNA argues that as SPP gains more experience with dispatchable VER participation in the Integrated Marketplace, data may demonstrate that under certain conditions dispatchable VERs are able to supply regulation up and/or contingency reserves. According to ECRNA, SPP may improve its ability to dispatch dispatchable VERs in the upward direction based on additional forecasting and availability information. Thus, ECRNA requests that the Commission direct SPP to submit an annual informational report that: (1) demonstrates, with data, whether dispatchable VERs can reliably offer regulation up and/or contingency reserves; and (2) either includes Tariff revisions to allow dispatchable VERs to provide additional products or explains why preventing dispatchable VERs from providing additional products is just and reasonable and not unduly discriminatory. ECRNA adds that SPP should present such data at stakeholder meetings prior to filing the informational report and include in the report information regarding any adverse positions taken by stakeholders.[93]

77. ECRNA further contends that SPP's proposed Tariff provisions in sections 2.15 and 3.1.2 do not provide a full and clear explanation of its methodology for determining output forecasts for dispatchable VERs or the meteorological data that are required from VERs. ECRNA maintains that SPP has not provided any explanation of its specific forecasting methodology or the types of data that a dispatchable VER may be required to provide in its Tariff, because it intends to provide these details in its Market Protocols.

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comply with these requirements in its March 1, 2013 filing in Docket No. ER12-2292-003 to comply with the September 20 Order.

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

[93] ECRNA at 1-2.

According to ECRNA, the Commission required SPP to provide these details in its Tariff because "forecasted values may be used for a dispatchable VER's maximum operating limit and, therefore, could have rate implications."[94]

Answer

78. In its answer, SPP argues that ECRNA inaccurately describes the Commission's compliance directives regarding SPP's methodology for producing output forecasts for dispatchable VERs. Further, SPP asserts that its proposed Tariff revisions specify that additional forecast and data requirement information will be provided in SPP's Market Protocols.[95] According to SPP, its Market Protocols describe its production of an hourly expected wind output forecast, total wind power forecast, and probabilistic production potential forecast for each wind-powered VER.[96] SPP argues that the October Order did not require the Tariff to reflect the level of specificity that ECRNA requests, and its forecasting methodology is an "implementation detail" that may be included in business practices manuals, consistent with Commission precedent.[97] SPP maintains that, taken together, its February 2013 Compliance Filing and Market Protocols are consistent with the Commission's directives.

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[94] *Id.* at 3-4 (citing October Order, 141 FERC ¶ 61,048 at P 115).

[95] SPP Answer at 33-34.

[96] *Id.* at 34 (citing Southwest Power Pool, Inc., *Market Protocols SPP Integrated Marketplace Revision 13.0a*, section 4.1.2.2 (Mar. 15, 2013), *available* at: http://www.spp.org/publications/Integrated%20Marketplace%20Protocols%2013.0a.pdf).

[97] *Id.* (citing, *e.g.*, *Cal. Indep. Sys. Operator Corp.*, 122 FERC ¶ 61,271, at P 16 (2008) (stating that "[t]he Commission's policy, as implemented through the rule of reason, is that only those practices that significantly affect rates, terms and conditions fall within the directive of . . . the FPA" and that "[i]t is appropriate for Business Practice Manuals to contain implementation details, such as instructions, guidelines, examples and charts, which guide internal operations and inform market participants" of how a utility conducts its operations under its Tariff)).

Commission Determination

79. We conditionally accept, subject to an additional compliance filing, the Tariff revisions included in SPP's February 2013 Compliance filing regarding the treatment of VERs. We also conditionally accept, subject to an additional compliance filing, the Tariff revisions proposed in SPP's March 2013 Filing, as discussed below.

80. We find SPP's proposal to allow dispatchable VERs to provide regulation-down reserve, but not other operating reserve products (i.e., Up-Products) to be just and reasonable. We note that this limitation reflects SPP's concern that VERs cannot ensure the production of more energy than their current output due to the variability of their energy source.[98] We agree with ECRNA, however, that SPP may find that dispatchable VERs are capable of satisfying the requirements to supply regulation-up and/or contingency reserves, as it gains more experience with dispatchable VER participation in the Integrated Marketplace. Thus, we will require SPP to include, as part of its informational filing due within 15 months of the launch of the Integrated Marketplace, an analysis of whether dispatchable VERs may reliably provide regulation-up and/or contingency reserves.

81. We find that SPP has failed to comply with the Commission's directive that it address both its methodology for determining its output forecasts for VERs and any meteorological data that will be required from dispatchable VERs.[99] In the October Order, the Commission found that meteorological data reporting should be limited to data that are necessary for SPP to produce the specific power production forecasts it intends to produce.[100] Thus, we find that SPP's explanation of its forecasting methodology and data requirements and minimal Tariff revisions are insufficient to allow the Commission to determine whether the data required from VERs are necessary to produce SPP's power production forecast. While the directives in the October Order applied to "VERs" and "dispatchable VERs,"[101] SPP discusses its forecasting methodology and data requirements only for wind-powered VERs. SPP also does not justify why its proposed forecasting methodologies and data requirements are appropriate

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[98] February 2013 Compliance Filing at 10 (citing Exh. No. SPP-10 at 7).

[99] October Order, 141 FERC ¶ 61,048 at P 115.

[100] *Id.*

[101] *Id.*

for all wind-powered VERs (e.g., both non-dispatchable and dispatchable VERs and both small and large VERs), including whether its data requirements are consistent with the capabilities of these resources or the terms of any applicable interconnection agreements.

82. Accordingly, we require SPP to submit, in the compliance filing due within 60 days of the date of this order, an explanation of its methodology for determining SPP's output forecasts for dispatchable VERs, its meteorological data requirements for VERs, and corresponding Tariff revisions. In addition, we note that the Commission recently conditionally accepted SPP's proposed revisions to its *pro forma* generator interconnection agreement, effective June 16, 2013, to comply with the requirements of Order No. 764.[102] In its compliance filing due within 60 days of the date of this order, SPP should explain why and how its data requirements for dispatchable VERs that execute Large Generator Interconnection Agreements (LGIA) on or after June 16, 2013, are consistent with the *pro forma* LGIA revisions that were conditionally accepted in that order.

83. We find that SPP's Tariff revisions proposed in its February 2013 Compliance Filing regarding the determination of maximum output limits do not satisfy the requirements set forth in the October Order. In particular, the Commission required that SPP substitute its output forecast for the maximum output limit submitted by a wind-powered VER in the event that the limit is not updated, is not submitted, or exceeds the resource's physical operating limit applied to the real-time market.[103] However, SPP's proposed Tariff revisions apply to the RUC processes, rather than the real-time market. We will require SPP to submit, in the compliance filing due within 60 days of the date of this order, Tariff revisions to use SPP's output forecast, rather than the maximum output limit submitted by a wind-powered VER, in the event that the limit is not updated, is not submitted, or exceeds the resource's physical operating limit in the real-time market and not in the RUC processes. In addition, we find that SPP's Tariff revisions proposed in its March 2013 Filing, which clarify the maximum operating limit requirements for dispatchable VERs, including to ensure that they apply to VERs that are not wind powered, are just and reasonable.

84. We find that SPP's Tariff revisions proposed in the February 2013 Compliance Filing regarding VER registration requirements are consistent with the October Order's

[102] *Southwest Power Pool, Inc.*, 143 FERC ¶ 61,285 (2013).

[103] October Order, 141 FERC ¶ 61,048 at P 113.

requirement that SPP permit wind-powered VERs with interconnection agreements executed on or prior to May 21, 2011 to register as dispatchable VERs, if they satisfy the applicable requirements (i.e., so that these resources may choose whether to initially register as dispatchable or non-dispatchable VERs).[104] We also find that the modifications to the registration requirement for certain VERs proposed in the March 2013 Filing are consistent with the Commission's September 20 Order regarding the treatment of VERs in SPP's EIS Market. In particular, SPP proposes in the March 2013 Filing that wind-powered VERs that executed interconnection agreements on or before May 21, 2011, but did not commence commercial operation until on or after October 15, 2012, must register as dispatchable VERs in the Integrated Marketplace (i.e., they cannot choose to instead register as non-dispatchable VERs). This modification is consistent with the Commission's conditional acceptance in the September 20 Order of SPP's proposal to permit the systematic curtailment of Non-Dispatchable Resource that were commercially operable on or after October 15, 2012, in the EIS Market during periods of congestion.[105]

85. With regard to the treatment of non-dispatchable VERs, SPP explains in its February 2013 Compliance Filing that its systematic and automated curtailment procedures approved in the September 20 Order for certain resources in the EIS Market will not apply to non-dispatchable VERs in the Integrated Marketplace. We find that this explanation is consistent with the Commission's acceptance, in an order issued concurrently, of SPP's proposal to exempt from its systematic and automated curtailment procedures Non-Dispatchable Resources, including intermittent resources, that executed interconnection agreements on or before May 21, 2011 and commenced commercial operation before October 15, 2012.[106] Accordingly, we will accept SPP's explanation, subject to the outcome of that proceeding. While SPP did not provide the necessary corresponding Tariff revisions in the February 2013 Compliance Filing,[107] we find that SPP's Tariff revisions proposed in the March 2013 Filing regarding VER registration requirements are sufficient to ensure that these curtailment procedures will not apply to

[104] *Id.* P 117.

[105] *See* September 20 Order, 140 FERC ¶ 61,225 at P 47.

[106] *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,223, at P 28 (2013).

[107] October Order, 141 FERC ¶ 61,048 at P 119.

non-dispatchable VERs, as described above. Therefore, we will not require SPP to submit further Tariff revisions.

Uninstructed Resource Deviation

October Order

86. In the October Order, the Commission conditionally accepted SPP's URD proposal subject to certain compliance requirements. The Commission found that SPP had not provided sufficient justification regarding the specifics of its proposed URD tolerance band, nor had SPP made a sufficient showing that the proposed tolerance band was reasonable with respect to the treatment of VERs. Accordingly, the Commission found that the proposed tolerance band was unsupported and directed SPP to submit a compliance filing to either justify and support its tolerance band, or propose a less restrictive version.[108]

February 2013 Compliance Filing

87. SPP proposes to retain its proposed operating tolerance band at plus or minus five percent of maximum capacity.[109] SPP provides testimony from Mr. Dillon stating that the SPP Integrated Marketplace will differ from the EIS Market (in which SPP employed a plus or minus ten percent operating tolerance band), because SPP proposes to procure regulation-up and regulation-down to meet Balancing Authority Area requirements. SPP states that this operating tolerance band will enable SPP to reduce the requirements for regulation-up and regulation-down resources and lower the costs for market participants, while maintaining its ability to reliably meet NERC control performance requirements.[110] SPP argues that the plus or minus five percent operating tolerance band results in tighter output band for a given resource, resulting in a reduction of regulation-up and regulation-down requirements that would be needed from what would have been required if the plus or minus ten percent operating tolerance band was adopted from the EIS Market. According to SPP, the reduction of regulation-up and regulation-down requirements

[108] *Id.* P 125.

[109] February 2013 Compliance Filing at 11.

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

translates into lower costs for market participants while maintaining SPP's ability to reliably meet NERC control performance requirements.[111]

88. SPP expresses concern that a plus or minus ten percent operating tolerance applied to each dispatch interval would create the potential for incurring procurement costs for regulation-up or regulation-down services, but it would not result in any actual regulation deployment when needed.[112] Mr. Dillon provides an example in his testimony of a 200 MW unit with a ramp rate of three MW per minute. Over the course of five minutes, the unit could potentially clear 15 MW of regulation reserve and then, when deployed, never move and still be within a plus or minus ten percent operating tolerance band of 20 MW. SPP asserts that applying a plus or minus five percent operating tolerance with a minimum of five and a maximum of 20 MW to each five minute dispatch interval is a reasonable solution to its concerns, explained above, while allowing resources a realistic bandwidth within which they can operate.[113]

89. In response to the Commission's suggestion that SPP use the less restrictive MISO tolerance band as a basis for its revised proposal, SPP states that its proposal already satisfies the less restrictive criterion.[114] SPP explains that the MISO tolerance band is calculated based upon eight percent of the dispatch instruction versus SPP's calculated tolerance band of five percent of maximum capacity. Therefore, depending upon where a resource is being dispatched, SPP states that its proposed operating tolerance can actually be greater (or less restrictive) than the MISO tolerance band. For example, Mr. Dillon explains in his testimony that under SPP's proposed operating tolerance, a 200 MW resource would have an operating tolerance of plus or minus ten MW under SPP's URD proposal. However, if that resource is issued a dispatch instruction of 100 MW, its operating tolerance band is actually ten percent of its dispatch instruction which would be a larger operating tolerance band than under MISO's eight percent URD proposal.[115] Mr. Dillon states that in analyzing the 2012 actual results, SPP determined that use of the

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[111] *Id.*, Exh. No. SPP-10 at 9.

[112] *Id.* at 12.

[113] *Id.*, Exh. No. SPP-10 at 9-10.

[114] *Id.* at 12.

[115] *Id.*, Exh. No. SPP-10 at 11.

eight percent of the dispatch instruction MISO tolerance band would have resulted in more URD events than under SPP's proposed five percent of maximum capacity tolerance band. Mr. Dillon notes that during stakeholder discussions regarding the proposed reduction from the ten percent tolerance band in the EIS Market to the proposed five percent tolerance band in the Integrated Marketplace, there were no objections raised by generation owners as to the operational feasibility of their resources being able to follow set point instructions at the lower tolerance band.[116]

90. SPP also states that the proposed operating tolerance is reasonable for the treatment of dispatchable VERs and non-dispatchable VERs, specifically wind-powered VERs. As Mr. Dillon notes, an efficient market design must provide incentives for VERs to respond to set point instructions to reduce output to address reliability issues. Mr. Dillon explains that when wind-powered VERs are operating in manual control status, i.e., their four second set point instructions will be an echo of actual output four seconds ago, it will be virtually impossible for a wind-powered VER to incur URD outside of its operating tolerance.[117] SPP adds that when VERs are instructed by SPP to respond to set point instructions to reduce their output to address a reliability issue, they are at risk of incurring URD if they do not follow SPP's instructions. Therefore, SPP asserts that the tolerance band provides a necessary market incentive for VERs to follow these instructions.

91. In addition, SPP states that the plus or minus five percent operating tolerance band is reasonable because the VER is being dispatched down and output variability caused by changes in wind speed should not change significantly enough to cause an output reduction in excess of the instructed reduction. SPP explains that while wind speed changes may also cause a VER to operate outside its operating tolerance band and incur URDs when it is instructed to increase output following the end of a reliability event, the market participant representing the VER may submit a request to SPP for a URD waiver if it experiences such conditions.[118]

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[116] *Id*.

[117] *Id*. at 10.

[118] *Id.* at 12.

Comments

92. BP Wind Energy argues that SPP provides no justification for its proposed 20 MW ceiling on the tolerance band. BP Wind Energy requests that the Commission direct SPP to provide this justification.[119]

Commission Determination

93. The Commission accepts SPP's justification and support for its proposed URD tolerance band of plus or minus five percent of maximum capacity, subject to additional compliance. We disagree with BP Wind Energy's argument that SPP needs to provide additional justification for the 20 MW ceiling. Although SPP does not directly address the 20 MW ceiling in its filing, the testimony SPP provided explains that SPP adopted the URD tolerance band in order to provide the appropriate incentive for VERs to follow set point instructions balanced against the procurement cost of regulation-up and regulation-down services for market startup. This incentive structure includes the need for a ceiling on the URD tolerance band, and we are not convinced that additional justification is necessary. However, we require SPP to include, in the informational filing due 15 months after market start-up, an analysis addressing whether the URD tolerance band continues to be appropriate based on actual operating experience.[120]

Manual Commitments

October Order

94. The Commission conditionally accepted SPP's proposal to allow local transmission operators to make commitments in emergency conditions on low voltage facilities and to require that these operators communicate their actions to SPP as soon as possible.[121] However, the Commission found that this proposal did not explain the process SPP would use to determine whether these manual commitments were made in a

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[119] BP Wind Energy at 7-8.

[120] We note that the Commission imposed on MISO a similar reporting requirement based on 12 months of its operating data. *See MISO*, 134 FERC ¶ 61,141 at P 81.

[121] October Order, 141 FERC ¶ 61,048 at P 184.

non-discriminatory manner. The Commission stated that, for a resource committed by a local transmission operator to receive make whole payments, the Commission expected the manual commitment decision to be reviewed by SPP to ensure it was done in a non-discriminatory manner.[122] The Commission directed SPP to include in its Tariff all necessary defined terms, as well as a description of the process SPP would use to determine that commitments made by local transmission operators in emergency situations were done in a non-discriminatory manner. The Commission also stated that the revisions should include criteria that will ensure that manual commitments are made consistently and in a non-discriminatory manner both by SPP and the local transmission operator.[123]

95. In the October Order, the Commission also agreed with Acciona that in those circumstances when manual commitment is necessary, the process should be as transparent as possible. Accordingly, the Commission directed SPP to amend the Tariff to state explicitly that it will declare the emergency condition as soon as possible, post it on the SPP Open Access Same-Time Information System (OASIS), and displace manual dispatch with a market solution as soon as possible, consistent with system safety and reliability.[124]

<u>February 2013 Compliance Filing</u>

96. SPP proposes a discrimination screen in a new section 6.1.2.1 of Attachment AE that, it asserts, will ensure that resources committed by a local transmission operator will only receive make whole payment compensation if SPP determines the commitment decision was made in a non-discriminatory manner.[125] Section 6.1.2.1(i) specifies that SPP will evaluate cost, ownership, resource operating parameters, availability of non-selected resources relative to the selected resource, and any prior instances where the local transmission operator committed resources. Section 6.1.2.1(ii) further specifies that when SPP determines that a local transmission operator selected a resource in a discriminatory manner, SPP will notify the local transmission operator of the best practice should the situation arise again. SPP states that it also revised section 6.1.2(4)(d)

[122] *Id.* P 185.

[123] *Id.* P 185 & n.260.

[124] *Id.* P 367.

[125] February 2013 Compliance Filing at 16.

of Attachment AE and added a new section 6.1.2(5) to Attachment AE to clarify the circumstances under which units committed by a local transmission operator would receive make whole payment compensation.[126]

97. Additionally, SPP proposes revisions to section 8.6.5(1) of Attachment AE, which contains RUC make whole payment provisions, to specify that resources committed by a local transmission operator are not eligible to receive a RUC make whole payment if SPP determines the resource was selected in a discriminatory manner by the local transmission operator.

98. Further, SPP revised section 6.2.4 of Attachment AE to state that SPP will post the emergency condition on OASIS as soon as possible if a Manual Dispatch Instruction is issued to resolve a problem and, consistent with system safety and reliability standards, SPP will seek to displace the Manual Dispatch Instruction with a market solution as soon as possible.

<u>March 2013 Filing</u>

99. SPP proposes revising section 4.5.2(4) of Attachment AE, which specifies procedures for conducting the Multi-Day Reliability Assessment analysis,[127] to provide that SPP may commit resources to address transmission system-related reliability problems. SPP asserts that this modification is necessary to remove potentially limiting language.[128]

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[126] *Id*. Sections 6.1.2(4)(d) and 6.1.2(5) of Attachment AE both reference the discrimination screen proposed by SPP in section 6.1.2.1 of Attachment AE.

[127] The Multi-Day Reliability Assessment identifies resources with long lead times that must be given commitment instructions prior to completion of the day-ahead RUC in order for these resources to be available during the operating day. As detailed in section 4.5.3 of Attachment AE, SPP communicates commitment instructions resulting from the Multi-Day Reliability Assessment to affected market participants. SPP-committed Multi-Day Reliability Assessment resources are eligible for day-ahead make whole payment guarantees.

[128] March 2013 Filing at 7. Previously, this section stated that SPP may also commit long lead time resources to address transmission system-related reliability problems using the procedures specified in section 4.5.2(3) of Attachment AE, except that the merit order list of available resources would be limited to specific resources in

(continued…)

100. SPP also proposes revising sections 5.2.2(3) and 6.1.2(3) of Attachment AE to modify provisions governing SPP's ability to decommit resources in the day-ahead and intra-day RUC processes. Currently, these sections provide that SPP may only manually commit resources and/or decommit self-committed resources to alleviate transmission system reliability issues. Section 6.1.2(3) also extends this authority to local transmission operators. SPP proposes revising these sections to permit SPP (and the local transmission operator in the intra-day RUC) to decommit any resource, including self-committed resources, to alleviate reliability issues identified in the day-ahead or intra-day RUC. SPP asserts that these modifications are just and reasonable because they clarify SPP's authority to commit or decommit resources to address reliability issues, which SPP claims is critical to the successful performance of its Reliability Coordinator functions.[129]

Comments

101. TDU Intervenors assert that SPP has not included criteria to ensure that manual commitments are made consistently and in a non-discriminatory manner by both SPP and the local transmission operator, as directed in the October Order.[130] Without these criteria, TDU Intervenors believe that SPP may take an expedient approach and accept the local transmission operator's decisions without proper evaluation. TDU Intervenors note that while section 6.1.2.1 of Attachment AE lists factors SPP will consider in its evaluation, this section provides no methodology or standards for assessing these factors. TDU Intervenors also assert that section 6.1.2.1 of Attachment AE assumes that all manual commitments issued by SPP, at the request of the local transmission operator to address a reliability issue, are made in a non-discriminatory manner. Moreover, TDU Intervenors argue that SPP has not proposed Tariff language describing how it would determine whether a unit commitment is needed for local reliability, as opposed to regional reliability. TDU Intervenors request that the Commission direct SPP to specify in the Tariff how it will make these determinations.[131]

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the needed geographic location.

[129] *Id.* at 8.

[130] TDU Intervenors at 11 (citing October Order, 141 FERC ¶ 61,048 at P 185, n.260).

[131] *Id.* at 11-13.

102. Additionally, TDU Intervenors argue that section 8.6.5(1) of Attachment AE, which provides that a commitment made by a local transmission operator in a discriminatory manner would not be eligible for make whole payments, could create harmful results, especially without any criteria for determining what constitutes discrimination. TDU Intervenors assert that if there are only a few resources that could resolve a local constraint, and all of them are limited in their available hours of operation under environmental permits or regulations, the language in section 8.6.5(1) could encourage a local transmission operator to commit a competitor's units and save the available run hours of its own units for periods when the LMP would more likely produce profits. TDU Intervenors assert that a transmission operator should not be allowed to manipulate LMPs through discriminatory unit commitments. Further, TDU Intervenors argue that the language in proposed section 8.6.5(1) would penalize the victim of discrimination by denying it a make whole payment while benefiting its competitors.[132]

Answer

103. SPP argues that Tariff language requiring SPP's own unit commitment decisions to be non-discriminatory is unnecessary because SPP is an independent RTO. According to SPP, as an RTO, it has no ability or incentive to discriminate and must administer its Tariff in a non-discriminatory manner. SPP also asserts that it conducts its own independent assessment when it manually commits a resource at the request of a local transmission operator.[133]

104. SPP argues that, contrary to TDU Intervenors' protests regarding the proposed discrimination screen in section 6.1.2.1 of Attachment AE, this screen was the result of a lengthy stakeholder process. SPP explains that during this process, it became apparent that no single factor or set of factors could be applied for the purpose of creating a "discrimination standard." SPP asserts that its proposed revisions reflect the reality that reliability-based commitment decisions must be evaluated on a case-by-case basis. Thus, SPP asserts that it must use its subjective and independent judgment as part of such evaluations. Further, SPP notes that any suspected exercise of market power is subject to

[132] *Id.* at 13-15.

[133] SPP Answer at 19.

examination by the Market Monitor and referral to the Commission's Office of Enforcement.[134]

105. SPP disputes TDU Intervenors' concerns regarding the potential for a local transmission operator to manipulate the manual commitment process by committing an unaffiliated generator during periods of low LMP in order to then benefit from committing affiliated generation during periods of high LMP. SPP argues that TDU Intervenors did not offer any explanation as to how an operator could reliably predict when to anticipate higher LMPs so that it could plan its commitment decisions accordingly. SPP contends that it is unclear whether the discrimination scenario presented by TDU Intervenors could even arise with a local reliability issue. Nonetheless, SPP asserts that it has proposed adequate monitoring and mitigation procedures to address known and reasonably expected instances of market manipulation or the exercise of market power.[135]

<u>Reply</u>

106. In their answer, TDU Intervenors respond that the Tariff gives a local transmission operator the motivation to commit its competitors' generation, even if it has alternatives that may be more economically or operationally effective in relieving a local constraint. TDU Intervenors argue that a Tariff provision allowing a local transmission operator to cause a competitor to incur costs (for which it would be denied reimbursement) is sufficient for a local transmission operator to engage in such behavior. TDU Intervenors assert that the penalty for discrimination must be aimed at the party engaged in the discrimination, not at the third party affected by the discrimination because the third party had no role in the decision-making. Thus, TDU Intervenors argue that the Tariff should prohibit make whole payment compensation to any local transmission operator who discriminates in favor of committing its own units, rather than prohibiting such payments to the third party.[136]

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

[135] *Id.* at 20-22.

[136] TDU Intervenors' Reply at 6-7.

Commission Determination

107. We find that the February 2013 Compliance Filing does not comply with the Commission's directives in the October Order regarding several matters. Thus, we conditionally accept the proposed revisions subject to SPP making a compliance filing within 60 days to revise the manual commitment process as discussed below. In addition, we conditionally accept SPP's proposed section 205 revisions submitted in its March 2013 Filing regarding manual commitments, subject to a compliance filing that is due within 60 days of the date of this order, which reflects the revisions discussed below.

February 2013 Compliance Filing

108. In the October Order, the Commission accepted SPP's proposal to allow local transmission operators to make manual commitments on facilities not modeled by SPP, but only for emergency conditions. The Commission did not direct SPP to expand the circumstances in which local transmission operators would be allowed to make manual commitments directly. However, SPP proposes in its February 2013 Compliance Filing Tariff revisions that would permit local transmission operators to make manual commitments to resolve any reliability issues, which includes but is not limited to a reliability issues affecting the transmission system. Specifically, we note that in the proposed revisions to Attachment AE, sections 6.1.2(5) (Intra-Day Reliability Unit Commitment Execution) and 6.2.4(4) (Out-of-Merit Energy Dispatch), local transmission operators can make a manual commitment directly to resolve an issue other than a Local Reliability Issue. Also, in section 6.1.2(4) of Attachment AE, SPP proposes to change the circumstances in which a local transmission operator might make manual commitments from "emergency conditions" to a "Local Reliability Issue" which, as defined, is not limited to emergencies. We find that these proposed revisions to the manual commitment provisions are a significant departure from the Tariff provisions the Commission accepted in the October Order, because they expand the scope of circumstances in which local transmission operators can directly make manual commitments. Furthermore, in addition to the fact that the Commission did not require these revisions in the October Order, we find that SPP's proposed expansion of authority to local transmission operators is contrary to Commission precedent that holds the transmission provider – and not the local transmission operator – is the entity responsible for the reliability of the transmission system.[137] For these reasons, we direct SPP in a

[137] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 31,090 (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.*

(continued…)

compliance filing due 60 days after the issuance of this order to remove all proposed Tariff provisions that (1) allow a local transmission operator to directly commit resources in situations outside of emergency situations, and (2) allow a local transmission operator to directly commit resources that affect the facilities modeled by SPP, including the transmission system. Because local transmission operators may directly commit resources during "emergencies," which is not a defined term in the Tariff, we further require SPP to submit in a compliance filing due 60 days after the issuance of this order Tariff revisions that limit manual commitments made by local transmission operators to "Emergency Conditions," as defined in the Tariff. [138]

109. We find that SPP has not fully complied with the Commission's directives in the October Order that it submit a description of the process it will use to determine that manual commitments are made in a non-discriminatory manner. While SPP has included criteria/factors it will consider,[139] we agree with TDU Intervenors that SPP has not included a description of the process it will use to assess whether a manual commitment by a local transmission operator is discriminatory. Additionally, we find that for this review process to have the intended effect of detecting existing discriminatory behavior and discouraging future discriminatory behavior, the manual commitment process must also be clearly explained in the Tariff to provide transparency. This will enable market participants to know when and why manual commitments are to be made and how local transmission operators and SPP will decide which resources to commit manually.

110. We note that in an analogous situation, the Commission directed MISO, the local transmission operator, and the generator at issue to develop operating guides for frequently occurring manual commitments so that all such manual commitments would

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FERC, 272 F.3d 607 (D.C. Cir. 2001) ("We conclude . . . that the RTO is also required to be the NERC security coordinator for its region. The role of a security coordinator is to ensure reliability in real-time operations of the power system.").

[138] "Emergency Condition" is defined in the Tariff as "A condition or situation determined by the Transmission Provider that is imminently likely to cause a material adverse effect on the security of or damage to the Transmission System." SPP Tariff, Section 1.1.

[139] These factors include: cost; ownership; resource operating parameters; availability of non-selected resources relative to the selected resources; and any prior instances where the local transmission operator committed resources.

be transparent.[140] We find that similar transparency is appropriate in the instant case. Thus, we direct SPP to revise its Tariff to require SPP, the local transmission operator, and the owner of the generator to establish operating guides to address known and recurring reliability issues that are associated with manual commitments. Additionally, to provide transparency into the manual commitment process, SPP should explain the bases for its manual commitments, when the commitments will be made, and how SPP will determine which units to commit.[141]

111. Further, we find that SPP has not fully complied with the Commission's directives in the October Order that it revise its Tariff to make its proposed criteria applicable not only to local transmission operators, but also to SPP in order to ensure that manual commitments are made consistently and not in a discriminatory manner. We note that an "RTO needs to be independent in both reality and perception."[142] Accordingly, we find that SPP should be subject to the same process as local transmission operators to ensure that any manual commitments it makes are not discriminatory. Thus, in a compliance filing due 60 days from the date of this order, we require SPP to submit Tariff revisions that: (1) apply identical factors to SPP for assessing whether manual commitments made by SPP are discriminatory, as are applied to local transmission operators; and (2) clarify that the Market Monitor will review the manual commitments made by both SPP and the local transmission operators.

112. As noted by TDU Intervenors, the factors used in the discrimination provisions in section 6.1.2.1 of Attachment AE fail to explicitly address situations in which a local transmission operator commits an unaffiliated generator during periods of low LMP in order to reserve its own generation for periods of high LMP. Subject to the condition that SPP provides additional transparency in its Tariff detailing the manual commitment process, we find that SPP's proposed factors are just and reasonable, because SPP will consider, among other things, availability of non-selected resources relative to the selected resources. However, we agree with TDU Intervenors that denying compensation

[140] *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 FERC ¶ 61,171 (2012) (MISO VLR Order).

[141] *See id.* P 54 (discussing the MISO definition of Voltage and Local Reliability Issue).

[142] *See* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,061.

to unaffiliated generators would harm those generators that were merely following the instructions of the local transmission operators. Thus, we find that compensation should only be denied to generators affiliated with local transmission operators in cases where SPP and/or the Market Monitor determine that the commitment made by the local transmission operator was done in a discriminatory fashion.

113. Further, we find that SPP's proposal that requires it to notify the local transmission operator of the best practice when SPP suspects that a local transmission operator's commitment of generation may be discriminatory is not adequate to address the underlying discrimination. Instead, notice of an alleged discriminatory action must be provided to the Commission so that it can determine whether additional action is necessary. Thus, in a compliance filing due 60 days after the issuance of this order, we direct SPP to revise its Tariff to provide that the Commission's Office of Enforcement or successor organization is to be notified of any suspected discrimination.[143]

114. Finally, as explained above, we are requiring SPP to limit manual commitments made by local transmission operators to Emergency Conditions, as defined in the Tariff, on facilities not modeled by SPP. With this revision limiting the circumstances in which local transmission operators are permitted to make direct manual commitments, it is our expectation that these types of circumstances should occur infrequently. Therefore, at this time we are not persuaded by TDU Intervenors, given the modifications required above, that local transmission operators will be able to manipulate LMPs.

March 2013 Filing

115. We conditionally accept SPP's proposed section 205 revisions submitted in its March 2013 Filing regarding manual commitments made by SPP, subject to a compliance filing. We find these revisions, which remove potential limitations to SPP's ability to commit or decommit resources to alleviate transmission system related reliability issues,

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[143] We note that this compliance requirement is consistent with the Order No. 719 directive that Market Monitoring units report suspected market violations to the Commission's Office of Enforcement. While this is a Market Monitoring unit requirement, we find that SPP reporting on potentially discriminatory practices in this instance is consistent with Order No. 719, because SPP is in the position of reviewing commitments made by the local transmission operator. Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 354.

to be just and reasonable, subject to a compliance revision. However, SPP's proposed revision to section 6.1.2(3) includes the same expansion of authority for local transmission operators that we rejected. Accordingly, we condition our acceptance of SPP's March 2013 Filing on SPP submitting a compliance filing to remove "or local transmission operator" from section 6.1.2(3) of Attachment AE.

Make Whole Payments

Eligibility

October Order

116. In the October Order the Commission required SPP to modify its make whole payment provisions to clarify in sections 8.5.9 and 8.6.5 of Attachment AE that only SPP-committed resources are eligible to receive make whole payments.[144]

February 2013 Compliance Filing

117. SPP proposes revising section 8.5.9 of Attachment AE to specify that asset owners of resources either committed by SPP with a day-ahead market offer commitment status that is specified in sections 4.1(10)(b) and 4.1(10)(c) of Attachment AE,[145] or that are committed as part of the Multi-Day Reliability Assessment, are eligible to receive day-ahead make whole payments. Additionally, SPP proposes revising section 8.6.5 of Attachment AE to specify that asset owners of resources committed by SPP, with a real-time offer commitment status specified in sections 4.1(10)(b) and 4.1(10)(c) or are committed by a local transmission operator that SPP determines were selected in a non-discriminatory manner, as pursuant to section 6.1.2.1 of Attachment AE,[146] are eligible to receive RUC make whole payments.

[144] October Order, 141 FERC ¶ 61,048 at P 144.

[145] Section 4.1(10) of Attachment AE specifies four possible commitment statuses: (a) self-committed; (b) available for commitment by SPP; (c) available for commitment by SPP only to alleviate an anticipated emergency condition or local reliability issue; and (d) unavailable.

[146] As discussed above, SPP proposes a new section 6.1.2.1 of Attachment AE that provides details on how SPP will verify that the process used by a local transmission

(continued…)

Commission Determination

118. We find that the revisions to section 8.5.9 of Attachment AE provide sufficient clarification that only resources committed by SPP in the day-ahead market will receive make whole payments. However, we will require modifications to language in section 8.6.5 of Attachment AE concerning resources committed by a local transmission operator. In the Rehearing Order, we stated that resources committed by a local transmission operator to address local reliability issues are deemed "SPP-committed" for purposes of receiving make whole payments.[147] When a local transmission operator commits a resource (in a manner consistent with our discussion *supra* PP 108-112), that resource is eligible for a RUC make whole payment only when it is committed to address an emergency-related reliability issue on facilities not monitored by SPP. This limitation is not explicitly stated in SPP's proposed revisions to section 8.6.5 of Attachment AE. Thus, to avoid any ambiguity and to provide consistency within the Tariff, we require SPP to limit RUC make whole payment eligibility in cases where a resource is committed by a local transmission operator (in a manner consistent with our discussion *supra* PP 108-114) to cases where the local transmission operator commits the resource to address an emergency-related reliability issue on facilities not monitored by SPP. We direct SPP to make this revision to section 8.6.5 of Attachment AE in a compliance filing due 60 days after the issuance of this order.

119. Additionally, we note that in section 8.6.5 of Attachment AE, SPP proposes to add the following language regarding RUC make whole payments: "Recovery of such compensation shall be collected in accordance with section 8.6.7 of Attachment AE."[148] We accept this language because it further clarifies the Tariff, consistent with the compliance directive in the October Order.

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operator to determine which resource to select when responding to a local reliability issue was not discriminatory.

[147] Rehearing Order, 142 FERC ¶ 61,205 at P 27.

[148] Section 8.6.7 of Attachment AE contains the RUC make whole payment cost allocation methodology.

Regional v. Local Allocation

October Order

120. In the October Order, the Commission conditionally accepted SPP's proposal to provide payments to resources on low voltage facilities that respond to emergency-related local reliability conditions, subject to several modifications. The Commission directed SPP to revise its make whole payment procedures to: (1) allocate these costs locally, rather than regionally; (2) explain which local entities will be allocated a share of the costs to address local reliability issues; and (3) explain how SPP will determine the amount of the costs. The Commission also directed SPP to include in its Tariff an outline of the study process it will use to determine which local parties will be assessed make whole payment costs. Finally, the Commission noted that SPP's proposal lacked definitions for Tariff terms and, therefore, it directed SPP to provide in a compliance filing definitions for the term "Local Reliability Issue" and all other necessary defined terms.[149]

February 2013 Compliance Filing

121. SPP asserts that it revised section 6.1.2(4)(d) of Attachment AE and proposes a new section 6.1.2(5) to Attachment AE to clarify the circumstances under which units committed by a local transmission operator will receive make whole payment compensation.[150] Section 6.1.2(4)(d) specifies that if SPP determines that a local transmission operator's instructions to a resource were issued in a non-discriminatory manner to resolve a local reliability issue, that resource will receive make whole payment compensation, and the costs of such compensation will be allocated on a local basis. However, new section 6.1.2(5) specifies that in the event a local transmission operator issues instructions to a resource to resolve an issue that is not a local reliability issue, the costs of the resource's make whole payment compensation will be allocated regionally.[151]

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

[150] February 2013 Compliance Filing at 16.

[151] The local transmission operator's instructions to a resource must have been done in a non-discriminatory manner. *See* SPP Tariff Attachment AE, sections 6.1.2(5) and 6.1.2.

122. SPP also proposes modifications throughout its RUC make whole payment cost allocation methodology, described in section 8.6.7 of Attachment AE, including provisions that specify when such costs will be allocated either locally or regionally.[152] In the introductory language of section 8.6.7, SPP proposes that a local RUC make whole payment charge will be determined for each Settlement Area affected by a local reliability issue. SPP states that it will calculate each asset owner's share of the RUC make whole payment on a pro rata basis.

123. Finally, SPP proposes, in section 1.1 (Definitions L) of Attachment AE, to define a "Local Reliability Issue" as "A reliability condition within the SPP Balancing Authority Area that does not impact Transmission System reliability."

Comments

124. TDU Intervenors argue that the definition of Settlement Area, which is the basis for allocating make whole payment costs, is supposed to equate to the now-existing SPP Balancing Authority Areas. However, TDU Intervenors assert that the Tariff definition is vague and needs to be clarified.[153] TDU Intervenors also argue that SPP should edit section 8.6.7 of Attachment AE to clarify that make whole payments are made to resources committed to address a local reliability issue. Finally, TDU Intervenors assert that SPP should delete the phrase "will be determined" the first of the three times that it appears in this Tariff provision, as it is unnecessary.[154]

125. Westar asserts that make whole payment costs to cover payments due to Out-Of-Merit Energy (OOME) procured to relieve local issues should be allocated locally. Westar reasons that because the Commission has directed SPP to allocate on a local basis make whole payment costs relating to local issues, the Commission should direct SPP to

[152] SPP Tariff Attachment AE, sections 8.6.7 (A) & (B).

[153] TDU Intervenors at 15-16 (citing Section 1.1 (Definitions S) of Attachment AE that defines a Settlement Area as "A geographic area within the SPP Balancing Authority Area for which transmission interval metering can account for the net area load within the geographic area.").

[154] *Id.* at 15 & n.15.

revise its OOME make whole payment provisions to specify that costs relating to local issues also should be allocated locally.[155]

126. Additionally, Westar asserts that the definition of "Local Reliability Issue" is too narrow to encompass the make whole payment costs identified by the Commission. According to Westar, SPP's proposed definition only includes resource commitments on the distribution system, but excludes resource commitments on the 34.5 kV through 69 kV sub-transmission system. Although resources on the sub-transmission system have local market impacts, they receive regional cost allocation; therefore, the definition needs to be revised to include these costs. Westar also argues that the definition of "Local Reliability Issue," which is used in Tariff provisions for mitigation without a binding constraint, is so narrowly defined that it excludes resources that the Market Monitor may need for analyzing the mitigation of local power issues or for properly allocating costs. Moreover, Westar asserts that the definition of "Local Reliability Issue" should be more transparent.[156] Finally, Westar suggests that the Tariff should be revised to allow SPP to study facilities below 100 kV to determine if a local resource has a predominant purpose to support reliability constraints, voltage, or stability on the SPP regional reliability system so as to be eligible for regional allocation. Accordingly, Westar requests that the Commission direct SPP to make these modifications to the definition.[157]

<u>Answer</u>

127. SPP asserts that the question of whether make whole payments costs are allocated locally or regionally depends on whether a resource is committed to address a local reliability issue. Thus, SPP asserts that the Tariff clearly specifies that (1) make whole payment costs associated with unit commitments to address system-wide reliability issues will be allocated regionally, and (2) make whole payment costs associated with unit commitments to address local reliability issues will be allocated locally.[158]

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[155] Westar at 4.

[156] *Id*. at 3. Westar requests that the definition of "Local Reliability Issue" include "facilities less than 100 kV."

[157] *Id.* at 2-3.

[158] SPP Answer at 20.

128. SPP also argues that the Commission did not require a 100 kV bright line test to delineate when costs would be allocated locally or regionally. SPP contends that such a bright line test would be inappropriate because there are sub-100 kV transmission facilities that affect the SPP Transmission System and, thus, could cause a reliability issue that impacts the broader region. SPP argues that Westar has not explained how local cost allocation connected to such an issue would be just and reasonable.[159]

Commission Determination

129. We conditionally accept SPP's proposed local cost allocation for make whole payments related to local reliability issues, subject to SPP submitting modifications to its proposal in a compliance filing due 60 days after the issuance of this order. We find that the term "Settlement Area" is not clearly defined in the Tariff and, therefore, we direct SPP to provide a clear definition of "Settlement Area." Additionally, we direct SPP to make a number of revisions to its make whole payment provisions to ensure the proper allocation of such costs. Specifically, in the third sentence of section 8.6.7 of Attachment AE, we direct SPP to remove the phrase "will be determined" the first time it appears in the sentence. Additionally, in section 8.6.7(A)(1), we direct SPP to move the phrase "to address a Local Reliability Issue" after the phrase "excluding make whole payments made to Resources committed" in order to clarify that all commitments to address local reliability issues are excluded from the system-wide RUC make whole payment distribution.

130. Further, SPP currently includes only RUC make whole payments (described in section 8.6.5 of Attachment AE) in the system-wide make whole payment distribution amount, but SPP includes both RUC make whole payments and the OOME payment amount (described in section 8.6.6 of Attachment AE) in the RUC local make whole payment amount. We direct SPP to explain why it assumes that all OOME payment amounts pertain to Local Reliability Issues and could not possibly pertain to reliability issues affecting the Transmission System. If OOME payment amounts could pertain to reliability issues affecting the Transmission System, we direct SPP to revise the Tariff so that local OOME payment amounts are included in local allocations and regional OOME payment amounts are included in regional allocations.

[159] *Id.* at 20 & n.43.

131. We agree with Westar that the definition of "Local Reliability Issue"[160] needs to be revised to explain the basis for commitments to address "Local Reliability Issues."[161]

132. Accordingly, we direct SPP to provide more specific information in the Tariff regarding what constitutes a "Local Reliability Issue" and on what basis SPP will make its commitment decisions to address Local Reliability Issues. These clarifications to the definition of "Local Reliability Issue" will provide market participants with insight into SPP's commitment decisions and allow greater transparency into the costs being allocated. Additionally, because the Commission did not require a bright line test for "Local Reliability Issue" in the October Order, we will not require one here.

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[160] The Tariff defines "Local Reliability Issue" as "[a] reliability condition within the SPP Balancing Authority Area that does not impact Transmission System reliability."

[161] For example, MISO's definition of "Voltage and Local Reliability Commitment" provides more specificity by stating that MISO will make manual commitments to address local reliability requirements, operational considerations and generation and transmission outages. The MISO definition of Voltage and Local Reliability Commitment states as follows:

> A Transmission Provider issued Resource commitment in addition to, or in lieu of, commitments resulting from the Security Constrained Unit Commitment in the Day-Ahead energy and Operating Reserve Market or any Reliability Assessment Commitment, in order to mitigate issues with Transmission System voltage or other local reliability concerns. These Resource commitment requirements are established prior to or during an Operating Day and are based on projected local reliability requirements, operational considerations, and generation and transmission outages. [Voltage and Local Reliability] commitments will be based on Operating Guides for recurring voltage and local reliability requirements, but an Operating Guide is not required prior to a resource commitment being designated as a voltage and local reliability commitment. Resource commitments to relieve a potential or actual [Interconnection Reliability Operating Limit] violation will not be designated in this category. MISO VLR Order, 140 FERC ¶ 61,171 at P 54.

133. We will require SPP to make a compliance filing within 60 days of the date of this order to address the compliance requirements discussed above.

Allocation of RUC Make Whole Payment Costs to Virtual Energy Bids

October Order

134. In the October Order, the Commission accepted SPP's proposal to allocate RUC make whole payment costs to virtual energy offers, but it did not accept SPP's proposal to allocate RUC make whole payment costs to virtual energy bids. The Commission directed SPP either to provide a more complete justification for allocating these costs to virtual energy bids or to modify its RUC make whole payment cost allocation methodology so as to limit cost allocation to virtual energy offers.[162]

February 2013 Compliance Filing

135. SPP provides three reasons in support of its original proposal to include virtual energy bids, in addition to virtual energy offers, as part of the allocation of RUC make whole payment costs. First, SPP asserts that, due to the settlement location deviation calculation,[163] the inclusion of virtual energy bids in the RUC make whole payment cost allocation methodology allows virtual energy bids to net against either real-time load and/or real-time export transactions. SPP asserts that this provides market flexibility in the day-ahead market. Second, according to SPP, cleared virtual energy bids may create excess commitments in the day-ahead market that will depress real-time LMPs. Therefore, SPP asserts, to the extent that RUC commitments are required to address a reliability issue, the depressed real-time LMPs will result in increased RUC make whole payments to any RUC-committed resources. Thus, SPP reasons that virtual energy bids should be included in the RUC make whole payment cost allocation. Finally, SPP states that including virtual energy bid deviations in the RUC make whole payment cost allocation methodology is consistent with how physical load is treated when actual real-time load is less than the amount cleared in the day-ahead market. SPP asserts that a deviation is included when real-time load is less than that cleared in the day-ahead

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[162] October Order, 141 FERC ¶ 61,048 at P 153.

[163] *See* SPP Tariff, Attachment AE, section 8.6.7(2)(a).

market. SPP explains that this occurs because under-consumption tends to depress real-time LMPs, which increases any make whole payments to RUC-committed resources.[164]

Commission Determination

136. We are not persuaded by SPP's arguments in support of its proposal to assess RUC make whole payment costs to both virtual energy offers and virtual energy bids and, therefore, we reject this proposal. On compliance, SPP retains its original proposal to allocate RUC make whole payment costs to virtual energy bids as well as offers. In support of its proposal, SPP asserts that the inclusion of virtual energy bids in the RUC make whole payment cost allocation methodology allows virtual energy bids to net against either real-time load and/or real-time export transactions. SPP claims that this adds flexibility in the day-ahead market. We find that SPP is unclear what it means by increased flexibility in the day-ahead market, and it does not explain why this increased flexibility necessitates the allocation of RUC make whole payment costs to virtual energy bids.

137. We find SPP's assertion that cleared virtual energy bids may create excess commitments in the day-ahead market, thereby depressing real-time prices and increasing RUC make whole payments, is speculative and lacking in factual support. Specifically, SPP bases its claim on assumptions regarding how its Integrated Marketplace will function in the future, but SPP does not provide evidence from any existing markets to support its claims. Moreover, SPP does not take into account that excess commitments in the day-ahead market may decrease the number of unit commitments made in the RUC process, which lowers RUC make whole payments, as the Commission explained in the October Order.[165] Finally, SPP argues that including virtual energy bid deviations in the RUC make whole payment cost allocation methodology is consistent with how physical load is treated when actual real-time load is less than the amount cleared in the day-ahead market. However, SPP does not explain why it is appropriate to treat virtual energy bids the same as physical load in this context, because there is no virtual energy equivalent to physical load in real-time. Thus, we are not persuaded that SPP should allocate RUC make whole payment costs to virtual energy bids at commencement of the Integrated Marketplace. Accordingly, we will require SPP to remove virtual energy bids from its

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[164] February 2013 Compliance Filing at 14.

[165] October Order, 141 FERC ¶ 61,048 at P 153.

RUC make whole payment cost allocation methodology in a compliance filing due 60 days after the issuance of this order.

138. We note that our findings here are without prejudice to a future section 205 filing in which SPP may propose allocating RUC make whole payment costs to virtual energy bids, based on its experience in the Integrated Marketplace.

Revisions to RUC Make Whole Payment Cost Allocation Methodology

March 2013 Filing

139. SPP proposes revisions to sections 8.6.7A(2)(b)(iii), 8.6.7A(2)(c)(iii), and 8.6.7A(2)(f) of Attachment AE, which contain provisions for the allocation of RUC make whole payment costs, and to correct some errors. These proposed revisions also provide clarification in the Tariff regarding values used in the calculation of the RUC make whole payment distribution volume relating to dispatch instructions.[166]

140. SPP also proposes revisions to section 8.6.7A(2)(f) to state that, for resources not cleared in the day-ahead market that self-commit following the close of the day-ahead market, the actual resource output should be incorporated in the calculation of the RUC make whole payment distribution volume.[167] However, the resource output should be included in the RUC calculation only if the resource received a dispatch instruction *less than or equal to* the real-time applicable *minimum* limit for at least one dispatch interval in the hour.[168]

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[166] March 2013 Filing at 12.

[167] Previously, this language referred to the resource receiving a dispatch instruction *equal to* the real-time applicable *maximum* limit for a dispatch interval in the hour.

[168] In its protest to the February 2013 Filing, BP Wind Energy observed that SPP had agreed in its May 15, 2012 Answer in the initial Integrated Marketplace proceeding that a reference to a resource's maximum operating limit in section 8.6.7A(2)(f) of Attachment AE should refer to the resource's minimum operating limit. SPP responded in its April 19, 2013 Answer that it had made this correction as part of its March 2013 Filing. BP Wind Energy at 6-7, SPP Answer at 22-23.

Commission Determination

141. We will accept the proposed revisions to sections 8.6.7A(2)(b)(iii), 8.6.7A(2)(c)(iii), and 8.6.7A(2)(f) of Attachment AE, because they address the full scope of dispatch instructions applicable to the scenarios described in these sections. We will also accept the revision to section 8.6.7A(2)(f) that corrects a typographical error.

Other Make Whole Payment Issues

October Order

142. In the October Order, the Commission required SPP to provide justification for all of its proposed URD exemptions in section 6.4.1.1, subject to compliance. The Commission found it reasonable to exempt resources from URD charges because they are following a specific instruction from SPP to maintain system reliability. The Commission also found it reasonable not to include a blanket exemption for VERs. However, the Commission found the exemption for resources, in section 6.4.1.1(7) of Attachment AE, to be overly broad. Thus, the Commission required SPP on compliance to modify section 6.4.1.1(7) to clarify the events or circumstances that qualify a resource for exemption and to provide justification for such exemptions. The Commission also required SPP to delineate the types of events or circumstances that are beyond a market participants control regarding wind-powered VERs.[169]

February 2013 Compliance Filing

143. SPP proposes to extend a URD exemption in *force majeure* circumstances as defined in section 6.4.1.1(7) of Attachment AE and, in the case of VERs, to high wind or other extreme weather conditions that materially and directly affect the VERs' ability to provide energy.[170] In addition, in his testimony, Mr. Dillon supports four of the exemptions: (1) contingency reserve deployment, (2) dispatch during emergency conditions, (3) dispatch for Violation Relaxation Limit,[171] and (4) following a Manual

[169] October Order, 141 FERC ¶ 61,048 at P 170.

[170] February 2013 Compliance Filing at 15.

[171] When the security-constrained economic dispatch, reflecting all the constraints on the system, does not result in a solution or does not result in a solution that is feasible at a Shadow Price, SPP applies the Violation Relaxation Limit with the lowest value on a

(continued…)

Dispatch Instruction, by explaining that these exemptions are all situations where the market participant is following instructions from SPP to maintain system reliability and the reasonableness of the exemptions are self-explanatory. Mr. Dillon explains that a fifth proposed exemption would apply when a resource trip or de-rate is already accounted for in the RUC make whole payment cost allocation. Because provisions in section 8.6.7(2)(c) for a de-rate, and sections 8.6.7(2)(d) and (g) for a resource trip, already assess make whole payments for these events, Mr. Dillon states that a URD exemption is required to avoid double charging the resource. Mr. Dillon also explains that SPP proposes to exempt market participants from URD-related charges involving inaccurate Supervisory Control and Data Acquisition, which constitutes a market system failure. He notes that such events should not result in the imposition of costs on market participants. Finally, Mr. Dillon explains that under the Common Bus[172] treatment a group of resources registered at a Common Bus are allowed to have URD calculated based on the total output at the Common Bus. For this reason, Mr. Dillon states that individual resources that are part of the Common Bus and the Common Bus URD and within the Common Bus operating tolerance should be exempted from URD related charges.[173]

March 2013 Filing

144. SPP proposes, in sections 4.1.2.4(2)(a) and 4.1.2.5(5)(a) of Attachment AE, that dispatchable and non-dispatchable VERs for which SPP is calculating an output forecast

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temporary basis. We note that SPP defines Shadow Price as "[a] price for a commodity that measures the marginal value of the commodity." Tariff section 1.1 Definitions S. A higher Violation Relaxation Limit value indicates the relative priority for enforcing the constraint type. For example, the Violation Relaxation Limit value assigned to a ramp rate limit exceeds that assigned to a flowgate limit indicating that the flowgate constraint should be relaxed before the ramp rate constraint. The Violation Relaxation Limit values are identified in Addendum 1 to Attachment AE and sections 8.3.2 and 8.3.3 describe the process for applying Violation Relaxation Limits.

[172] Common Bus is defined in the SPP Tariff, Attachment AE as a single bus to which two or more resources owned by the same Asset Owner are connected in an electrically equivalent manner where such resources may be treated as interchangeable for certain compliance monitoring purposes.

[173] February 2013 Compliance Filing, Exh. No. SPP-10 at 12-13.

are not eligible to receive RUC make whole payments. SPP states that, in the RUC process, VERs for which SPP is providing a forecast are assumed to be on-line and operating at the SPP forecasted level. Therefore, SPP contends, such resources are not eligible for a make whole payment because their status is equivalent to a self-committed resource; that is, for those resources that SPP has forecasted output, SPP assumes that the VER is generating and not in need of a make whole payment for commitment in the RUC. SPP clarifies that this limitation does not apply to day-ahead make whole payments, for which VERs remain eligible.[174]

Comments

145. While ECNRA explains that it does not support the narrow five percent (URD) operating tolerance band as appropriate for VERs, it agrees with SPP that it is necessary to include the proposed language in section 6.4.1.1(7). ECNRA asserts that this provision should be modified as follows to ensure that there is no misunderstanding in terms of its applicability: "extremely high wind or other extreme weather-related conditions materially and directly impacting a [VER's] ability to provide or reduce energy."[175]

Commission Determination

146. We find that SPP has complied with the Commission's directive that it (1) further explain and justify all of the proposed URD exemptions, and (2) clarify or justify the events or circumstances that qualify for the section 6.4.1.1(7) URD exemption from a *force majeure* event or, in the case of a VER, if the URD results from extremely high wind or other extreme weather-related conditions materially and directly affecting a VER's ability to provide energy. Specifically, we find that SPP's proposal to extend a URD exemption in *force majeure* circumstances as defined in Section 6.4.1.1(7) of Attachment AE and, in the case of VERs, to high wind or other extreme weather conditions that materially and directly affect the VER's ability to provide energy is just and reasonable. However, the Commission requires further clarification of URD exemption 6.4.1.1(7) as applicable to VERs in the case of a physical limitation, such as a wind spike, which prevents the VER from reducing output. Specifically, to eliminate confusion in this specific instance, we require SPP, in a compliance filing due 60 days

[174] March 2013 Filing at 7.

[175] ECNRA at 3.

from the date of this order, to add the words “or reduce output of” in between “provide” and “energy” in section 6.4.1.1(7). We find that this modification should alleviate any potential misunderstanding as to how this exemption applies.

147. With regard to proposed sections 4.1.2.4(2)(a) and 4.1.2.5(5)(a) of Attachment AE in the March 2013 Filing, which specify that dispatchable and non-dispatchable VERs for which SPP is calculating an output forecast are not eligible to receive RUC make whole payments, we find that SPP has not sufficiently demonstrated the justness and reasonableness of these provisions. Specifically, we find that SPP has failed to support its proposal that these resources be ineligible to recover their variable costs if, for example, SPP issues a curtailment instruction to the resource (i.e., SPP has not demonstrated why a VER should be ineligible to recover any revenues that it may otherwise have received had it not been curtailed). Accordingly, we direct SPP to provide additional justification in a compliance filing due 60 days from the date of this order.

Out-of-Merit Energy

October Order

148. In the October Order, the Commission conditionally accepted SPP’s OOME proposal, subject to SPP submitting a compliance filing to cap the OOME payments at the amount of the actual under-recovery. The Commission explained that such a cap is consistent with the Commission’s determinations regarding SPP’s OOME dispatch compensation in its EIS Market.[176] Moreover, the Commission stated that a cap on OOME payments is necessary because otherwise, SPP’s proposal could over-compensate generators that are subject to OOME instructions that require an increase in the generator’s production. The Commission directed SPP to calculate the difference in price consistent with the calculation the Commission accepted in the prior SPP OOME Order.[177] In the October Order, the Commission noted that SPP proposed to multiply the difference between the market price and the offer curve at the OOME set point instruction by the difference in the OOME set point instruction and the economic

[176] October Order, 141 FERC ¶ 61,048 at P 188 (citing *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,068 (2011) (SPP OOME Order)).

[177] *Id.* P 189.

operating point.[178] Because the energy offer curve may be the same as the LMP over a range of MW output, the Commission found that SPP may experience in the Integrated Marketplace the same over-recovery problems that existed in the SPP OOME Order. Thus, in the October Order the Commission found that without such a cap on the total OOME payments equal to the total under-recovery, resources may over-recover the costs of meeting OOME set point instructions.[179]

February 2013 Compliance Filing

149. SPP explains that it proposes to revise the calculation of the "Real-Time Out-of-Merit Amount" to create a cap on compensation to an asset owner.[180] SPP asserts that the cap will limit compensation to the amount necessary to address any under-recovery resulting from a resource's response to a manual dispatch instruction. SPP explains that this cap on compensation is similar to the language that the Commission accepted in the EIS Market.[181]

Commission Determination

150. We conditionally accept SPP's proposed revisions to section 8.6.6 of Attachment AE concerning the OOME payment amount. While SPP's modifications attempt to limit the generator's recovery to the amount of the under-recovery, we find that the revisions do not completely cap the compensation at the amount of the under-recovery. Therefore, we direct SPP to revise section 8.6.6(1) of Attachment AE, which governs OOME manual dispatch instructions to generators that are instructed to increase production but that result in an under-recovery. Specifically, we direct SPP to move the phrase "multiplied by the OOME MW" in the first sentence to the end of that sentence. Without this edit, SPP's proposed language would require SPP to compare the generator's cost on the energy offer curve to the product of the market price multiplied by a MW output

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[178] The Tariff describes economic operating point as the output at which the energy offer curve is equal to the LMP. *See* SPP Tariff, Attachment AE, section 8.6.5(4)(d).

[179] October Order, 141 FERC ¶ 61,048 at P 190.

[180] SPP Tariff, Attachment AE, section 8.6.6.

[181] February 2013 Compliance Filing at 17.

amount. By moving the phrase “multiplied by the OOME MW” to the end of the sentence, SPP is comparing the generator’s cost to the market price and then multiplying the difference by the OOME MW amount. SPP should include this revision in the compliance filing due 60 days after the issuance of this order.

151. Additionally, we direct SPP to refine the definition of “economic operating point” in section 8.6.6(1) of Attachment AE.[182] Currently, the economic operating point is described as the MW output where the cost on the resource’s current dispatch interval energy offer curve is equal to the real-time LMP for that resource. This definition could apply to several MW output levels if the cost on the energy offer curve is the same as the LMP price over a range of MW output levels. For purposes of calculating the cap on compensation for under recovery in section 8.6.6(1) of Attachment AE, the difference in the energy offer curve and LMP should be multiplied by the difference between the (1) lesser of the actual resource output or the resource’s OOME manual dispatch instruction MW, and (2) the MW output at which the energy offer curve first exceeds the LMP. SPP should include this modification in the compliance filing due 60 days after the issuance of this order.

Marginal Losses

October Order

152. In the October Order, the Commission found SPP’s proposal to adopt the marginal loss method for calculating losses to be just and reasonable. However, the Commission found that SPP’s proposal for refunding the marginal loss surpluses had not been shown to be just and reasonable. Specifically, the Commission acknowledged that the marginal loss methodology over-collects losses,[183] but it found that SPP’s proposal for refunding the over-collection appeared to be impermissible because it would refund surplus losses directly to individual market participants in proportion to their contribution to the

[182] Section 8.6.6(1) of Attachment AE refers to the description of economic operating point contained in Section 8.6.5(4)(d) of Attachment AE.

[183] October Order, 141 FERC ¶ 61,048 at P 211; *see also Atlantic City Elec. Co. v. PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,132, *order on reh’g*, 117 FERC ¶ 61,169 (2006) (The Commission found that the use of the marginal loss method results in over recovery of the ISO’s expenditures because marginal losses increase as the number of MWs of power moved on the grid increases.).

surplus.[184] The Commission explained that it is inappropriate for SPP to provide refunds directly to market participants, because it diminishes the price signal provided by marginal loss pricing.[185] Accordingly, the Commission directed SPP either to provide additional information and justification as to how its proposal would not result in a direct reimbursement to customers or to submit a different proposal for refunding the marginal loss surplus. As further guidance, the Commission offered the mechanism used in MISO as an example of a marginal loss refund mechanism that was found to be just and reasonable.[186]

February 2013 Compliance Filing

153. SPP proposes to retain its original refund method, and it provides expert testimony from Mr. Dillon in support of its arguments that its refund method does not result in a direct refund. Mr. Dillon's analysis consists of two tables. The first table compares data for SPP's marginal loss method with the average loss method, and the second table compares settlement data under both methods. SPP also provides the formulas used to calculate the over-collection under both approaches. According to SPP, its analysis demonstrates that SPP's proposal is not a direct refund. SPP adds that its proposed marginal loss refund method does not affect resource price signals because its over-collection is only refunded to loads and, as a result, load located remotely from its generation is held accountable for additional losses to serve its load.[187]

Comments

154. NPPD asserts that the Commission should reject SPP's proposed refund method because it is so complicated that there is no way of knowing whether it will achieve its stated objective. NPPD also requests that the Commission direct SPP to adopt the refund mechanism approved by the Commission for MISO.[188] Further, NPPD repeats its request

[184] October Order, 141 FERC ¶ 61,048 at P 211.

[185] *Id*. (citing *Northeast Util. Serv. Co.*, 109 FERC ¶ 61,204, at P 21 (2004)).

[186] *Id.* P 212.

[187] February 2013 Compliance Filing, Ex. No. SPP-10 at 15-17.

[188] NPPD at 8 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at PP 90-94, *order on reh'g*, 109 FERC ¶ 61,157 (2004)).

that the Commission require SPP to implement a transitional refund period. NPPD argues that such a transition mechanism will protect market participants from incurring excessive losses while providing time to experience actual operation of SPP's marginal loss calculation.

Answer

155. SPP asserts that in the October Order and Rehearing Order the Commission considered and denied NPPD's requests for a transitional refund mechanism.[189] Thus, SPP claims that the Commission has ruled finally on NPPD's request for a transitional mechanism for marginal loss refunds, and should reject NPPD's protest here.

Commission Determination

156. We find that SPP has not demonstrated that its proposed marginal loss refund method will avoid making direct refunds to consumers. Therefore, we conclude that SPP has not shown its proposal to be just and reasonable. SPP does not demonstrate how its proposed method would avoid providing a direct refund, that is, refunding excess loss revenues to customers in direct proportion to the amount of losses they paid.[190] As we explained in *Northeast Utilities Services Co.*:

> Refunding of excess loss revenues can be done in many ways, but it should not be done in a manner that undermines the LMP [locational marginal price] calculation. Refunding excess loss revenues to the participants who incurred the losses would undermine the usefulness of including marginal losses in the LMP calculation. This is because, if excess LMP revenues are to be refunded to those who paid the marginal losses, then these purchasers would no longer be paying the marginal cost for energy, which is the basis of LMP. If that were to occur, the price signal incentives to investors and load that the Commission

[189] SPP Answer at 32 (citing October Order, 141 FERC ¶ 61,048 at P 213; Rehearing Order, 142 FERC ¶ 61,205 at PP 34-35).

[190] SPP's proposed method results in market participants receiving a direct refund of approximately 80 percent of the amount of losses they would have paid under an average loss method.

wishes to see from LMP would be undermined. The net result would be system-wide pricing for losses.[191]

157. Further, we dispute SPP's claim that because it proposes to refund the over-collection to load, resource price signals will not be dampened and generators will retain an incentive to locate near load. Rather, we find that SPP's proposed refund method would result in load customers paying and generators receiving prices that do not reflect the marginal cost of energy. If prices do not reflect the marginal cost of energy, generators will not have an incentive to locate near load. Accordingly, we find that SPP has not distinguished its proposal from a direct refund and reject SPP's proposed refund method.

158. In the October Order, the Commission explained that the marginal loss refund method used in MISO "does not suffer from the same direct refund concerns" that formed the basis for the Commission not accepting SPP's proposal. MISO's refund methodology first calculates each Balancing Authority Area's share of the surplus and then allocates the Balancing Area's share of the surplus to load within the Balancing Authority area on a load ratio share basis.[192] Thus, in MISO the distribution of the surplus is not tied to the amount of losses originally paid by an individual customer and, therefore, achieves the goal of refunding surplus marginal losses without distorting the appropriate price signals. In a compliance filing to be submitted within 60 days of the issuance of this order, we direct SPP to submit an alternative proposal for refunding marginal loss surpluses.

159. We will not address NPPD's request for a transitional refund mechanism because we previously determined that a transitional refund period for SPP was not warranted. Moreover, NPPD has not shown that it would be adversely affected by the lack of a transitional refund mechanism.[193]

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[191] *Northeast Util. Serv. Co.*, 105 FERC ¶ 61,122 at P 20 (2003).

[192] October Order, 141 FERC ¶ 61,048 at P 211 & n.295 (citing *Midwest Indep. Sys. Operator, Inc.*, 131 FERC ¶ 61,185 (2010)).

[193] October Order, 141 FERC ¶ 61,048 at P 213; Rehearing Order, 142 FERC ¶ 61,205 at PP 33-36.

Price Formation During Shortage Conditions

October Order

160. In the October Order, the Commission conditionally accepted SPP's proposed use of demand curves to reflect the value of energy during shortage conditions, subject to a compliance filing. While the Commission found that a demand curve for operating reserves is a reasonable way to institute shortage pricing, it found that SPP failed to fully address each of the six criteria outlined in Order No. 719.[194] Further, the Commission noted that SPP's explanation relied entirely on existing rules and market conditions and did not demonstrate how its proposed new demand curves for operating reserves, which will go into effect in the event of a shortage, are just and reasonable vis-à-vis the six criteria.[195] Thus, on compliance the Commission directed SPP to address the six criteria from Order No. 719, individually, as they apply to SPP's proposal.

161. In addition, the Commission found that SPP had not fully addressed how LMPs will be formed in the event of a shortage of necessary capacity to meet energy needs. The Commission stated that while Mr. Dillon described the effects of a shortage event on LMP, the Tariff sheets proposed by SPP fail to reflect this description. Specifically, the Commission pointed out that proposed section 6.2.2.1(b) states "[i]f there is a shortage of available capacity to meet energy requirements . . . LMPs [for energy] will be set . . . as specified in section 8.3.4.2 of this Attachment AE;" however, section 8.3.4.2 makes

[194] In Order No. 719, the Commission outlined six criteria it would consider in reviewing whether the factual record compiled by the RTO or ISO meets the requirements of the rule. The six criteria of any shortage pricing mechanism are that it: (1) improve reliability by reducing demand and increasing supply during periods of operating reserve shortages; (2) make it more worthwhile for customers to invest in demand response technologies; (3) encourage existing generation and demand resources to continue to be relied upon during an operating reserve shortage; (4) encourage entry of new generation and demand resources; (5) ensure that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage; and (6) ensure market power is mitigated and gaming behavior is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behavior to competitive levels. Order No. 719, FERC Stats. & Regs. ¶ 31,281 at PP 246-47.

[195] October Order, 141 FERC ¶ 61,048 at P 217.

reference only to how a shortage condition will affect market-clearing prices for operating reserves, regulation-up, and regulation-down.[196] Therefore, the Commission required SPP to describe the effects of a shortage event on LMP for energy.

162. Finally, the Commission found that while Mr. Dillon described shortage conditions as resulting in the energy LMPs and operating reserve, regulation-up, and regulation-down market clearing prices increasing by the values specified in the Tariff, SPP had not included these descriptions in the proposed Tariff sheets. The Commission stated that the proposed Tariff revisions imply that market clearing prices will be increased to the specified levels. The Commission found that these two methods of calculating scarcity pricing will result in different prices, but also will result in different incentives for market participants. Specifically, the Commission stated that to add to the existing LMP or market clearing price a fixed amount, the scarcity price can create incentives for resources not to follow dispatch instructions. Thus, the Commission directed that in a compliance filing SPP must clarify this issue and submit new Tariff sheets that describe how both LMPs and market clearing prices will be determined during shortage conditions.[197]

February 2013 Compliance Filing

163. SPP proposes new language in section 8.3.1 of Attachment AE to reflect how LMP is affected by shortage conditions. In addition, SPP provides revised Tariff language regarding pricing of operating reserves during shortages. These new Tariff provisions at proposed section 8.3.4.2 indicate that, during a shortage, Shadow Prices and, thus, market clearing prices will be capped in both the Day-Ahead and Real-Time Balancing Market according to certain parameters. This price cap would apply to the market clearing price of operating reserve, regulation-up, and regulation-down.

164. SPP also provides a response to each of the six criteria. SPP asserts that it complies with the first (improving reliability), third (encouraging existing resources to remain), and fourth (encouraging new entry) criteria, because its pricing methods for shortages, using demand curves to determine prices for operating reserves and energy, will encourage participation by supply resources thereby increasing reliability.

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[196] *Id.* P 218.

[197] *Id.* P 219.

According to SPP, such price signals will also encourage the entry of new resources. Finally, SPP notes that its demand curves are like those accepted in MISO.[198]

165. SPP asserts that it complies with second criterion (the shortage pricing methodology provides incentives for market participants to invest in demand response resources), because its methodology will provide sufficient incentive for investors in demand response to enter the market. SPP further contends that such entry will be driven by the desire to avoid high wholesale prices.[199]

166. SPP argues that it satisfies the fifth criterion (ensuring that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage) by providing comparable treatment of all supply resources. SPP explains that a demand response resource selling energy and operating reserve into the wholesale energy market will be paid the same price as generators contemporaneously selling energy and operating reserve into that market, including those times when operating reserves are in short supply. Moreover, SPP argues that both will have equal influence in setting LMPs and market clearing prices.[200]

167. Finally, SPP contends that it satisfies the sixth criterion (ensuring that market power is mitigated and gaming behavior is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behavior to competitive levels). SPP asserts that its market power mitigation provisions, including price suppression by demand response, are sufficient to mitigate market power. SPP further argues that it has robust market power mitigation provisions that include price-sensitive demand bidding, and enhanced demand response resource participation guidelines.[201]

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[198] February 2013 Compliance Filing at 19-20.

[199] *Id.* at 20.

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

[201] *Id*. at 21.

Commission Determination

168. As discussed below, we find that SPP has partially complied with the Commission's directives in the October Order relating to price formation during shortage conditions. We find that SPP's revisions to the definition of Scarcity Pricing, and to sections 8.3(4) and 8.3.1 to reflect LMP calculation during shortage conditions, comply with the Commission's directives in the October Order that SPP describe how LMPs and market clearing prices will be determined during shortage conditions.

169. Regarding the operation of demand curves for operating reserves during shortages in Tariff section 8.3.4.2, we find that SPP has not complied with our directive that it reconcile certain inconsistencies between the proposed Tariff language and the testimony provided by Mr. Dillon. In the October Order, the Commission found that the concept of using demand curves for operating reserve was just and reasonable. Under that methodology, when a shortage occurs, prices rise automatically to the preordained (higher) levels. On compliance, SPP describes its scarcity pricing provisions as "progressively rais[ing] market Energy and [o]perating [r]eserve prices as available Operating Reserves are depleted and fall below the minimum requirements."[202] However, we find that SPP's proposed corresponding Tariff language in section 8.3.4.2 does not necessarily result in progressively increasing LMP and market clearing prices, as shortage conditions worsen. Specifically, these Tariff provisions do not describe a "demand curve" at all; rather, they describe a price cap. We further note that under these proposed revisions, when the system is in normal operating conditions and not short of any product, prices will clear at the LMP and market clearing prices based on the appropriate Shadow Prices. During a shortage, the same process occurs, only with a new price cap.[203] When a system goes from normal operating conditions to a shortage, it is not appropriate to allow the market to clear at the Shadow Price. Allowing this price signal to be sent implies that all is normal. Instead, during a shortage—a period, by definition, when prices are not high enough to induce entry of sufficient resources—prices should rise above those at which resources have offered to supply. Accordingly, we find that SPP's new proposal fails to comply with our directive in the October Order and, therefore, we direct SPP to submit a compliance filing within 60 days of the date of

[202] *Id.* at 19.

[203] By contrast, during normal operating conditions there is no price cap, only offer caps.

this order, which revises SPP's methodology for calculating prices during shortage events, as discussed above.

170. We conditionally accept SPP's explanation of how its proposal satisfies each of the six criteria from Order No. 719. Specifically, we find that SPP fully explains its shortage pricing provisions and how they will send price signals that encourage existing and new resources to remain in and enter the market, respectively. We agree that these price signals will encourage load to invest in demand response and energy efficiency measures that will aid in avoiding such shortages and price increases. We further note that SPP is continuing to work to comply with Commission requirements for more stringent market power mitigation and monitoring. SPP has also proposed Tariff provisions governing the participation of demand response resources and price-sensitive bidding by demand resources that will help to mitigate any exercise of market power. We note that this is only a proposal for a new market, and that SPP has no experience on which to base its explanation or data to support its assertions. Because of SPP's understandable lack of market experience and to ensure compliance, we require SPP to revisit this issue in its informational report due 15 months after commencement of the Integrated Marketplace. Specifically, we require SPP to report on and discuss any shortage conditions and resulting prices that have occurred, overall demand response participation, and to provide analysis of how its shortage pricing provisions have impacted the entry and exit of demand response and other supply resources.

Operating Reserves

October Order

171. In the October Order, the Commission found that SPP's definitions of regulation-up, regulation-down, spinning reserve, and supplemental reserve may be more restrictive than intended, thereby eliminating certain resources from providing these services by definition rather than through qualification, and in contradiction of other sections of the proposed Tariff. Therefore, the Commission directed SPP to change these definitions so that they no longer inadvertently eliminated all qualified resources from providing regulation-up, regulation-down, spinning reserve, and supplemental reserve.[204] In

[204] October Order, 141 FERC ¶ 61,048 at P 224.

addition, the Commission required SPP to add qualification standards for providing operating reserves, which were contained in section 4.1, to section 2.10.3 as well.[205]

February 2013 Compliance Filing

172. SPP proposes changes to a number of definitions in its Tariff in order to comply with the Commission's directives in the October Order. First, SPP proposes to revise the definition of "Resource" to add that a resource can include, but is not limited to, the following: demand response resources; variable energy resources; dispatchable resources; external resources; external dynamic resources; and quick-start resources. Second, in an effort to make it clear that any qualified resource can provide the product in question, SPP proposes revising the definitions of regulation-up, regulation-down, spinning reserve, and supplemental reserve in Attachment AE to clarify that these products are offered by "qualified" resources. SPP also proposes to add to section 2.10.3 of Attachment AE the appropriate language from section 4.1 describing the qualification standards for providing operating reserves.[206]

Commission Determination

173. We find that SPP's proposed revisions to the definitions of Resource, spinning reserve, and supplemental reserve comply with the directives in the October Order, as they no longer eliminate some resources from providing these services by definition. However, we find that SPP's proposed revisions to the definitions of regulation-down and regulation-up fail to comply with the directives in the October Order. For these two definitions, we find that SPP's references to reducing their energy output (for regulation-down) and increasing their energy output (for regulation-up), may have the effect of precluding certain qualified resources from providing these services. For example, we note that demand response resources do not reduce or increase energy output when they provide these services. Therefore, we direct SPP to submit a compliance filing within 60 days of the date of this order that revises these definitions, such that they do not preclude otherwise-qualified resources from providing regulation-down and regulation-up service. Finally, we find that SPP has complied with the Commission's directive in the October Order that it add the qualification standards for providing operating reserves to proposed section 2.10.3 of Attachment AE.

[205] *Id.* P 223.

[206] February 2013 Compliance Filing at 22-23.

Market-Based Congestion Management

Overall Congestion Management Proposal

October Order

174. In the October Order, the Commission conditionally accepted SPP's market-based congestion management proposal subject to SPP making a compliance filing. The Commission directed SPP to include the following Tariff provisions in its compliance filing: (1) a process for awarding ARRs for contracts that provide for the rollover of transmission agreements;[207] (2) a provision identifying how pseudo-tied resources and load will be treated with regard to ARR allocation; (3) a provision stating that the TCR auction is subject to review by the Market Monitor and mitigation, as needed; and (4) a process for handling two or more winning bids in case there is a tie. Additionally, the Commission directed SPP to submit Tariff provisions explaining the process for awarding ARRs and TCRs between the start-up date of the market (i.e., March 1, 2014) and the start date for the annual TCR year (i.e., June 1, 2014) in its compliance filing.[208]

February 2013 Compliance Filing

175. SPP states that to ensure that ARRs will be awarded for transmission service that has been renewed, it has added language to section 7.1.1 of Attachment AE to clarify that ARR eligibility includes agreements that have been renewed in accordance with rollover rights since their initial term. SPP includes pseudo-tied load and resources in the definition of settlement location to describe how pseudo-tied resources and load will be treated for purposes of settling TCRs. Additionally, SPP states that the TCR market process is subject to review by the Market Monitor, and that TCRs will be awarded on a pro rata basis based on the impacts of the constraint when there are multiple winning bids in case there is a tie. SPP also states that for the period of time between the start of the

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[207] In the October Order, the Commission noted that the MISO Tariff assumes the rollover will occur during the annual auction and allocates ARRs for the agreement for the entire year unless notified otherwise prior to the auction that the rollover will not occur. If MISO is notified after the auction that the agreement will not be rolled over, then MISO takes the ARRs back for the period after the contract terminations. October Order, 141 FERC ¶ 61,048 at P 239 & n.353.

[208] *Id.* P 239.

market (i.e., March 1, 2014) and the beginning of the first annual TCR auction, SPP will conduct an abbreviated multi-month auction using a similar process to the annual auction, along with subsequent monthly auctions of any residual amounts of capacity available on the system.[209]

Comments

176. TDU Intervenors assert that in the October Order, the Commission required SPP to specify a process for awarding ARRs for contracts that provide for the rollover of transmission agreements; however, on compliance SPP only accounts for rollover rights that have been exercised. TDU Intervenors note that if a transmission customer with service that expires during the annual ARR allocation process the customer will not be entitled to ARRs for the period March 15 to June 1.[210] Thus, TDU Intervenors argue that SPP's proposal is contrary to what the Commission approved in MISO, and it deprives transmission customers of ARRs for any portion of the allocation process for which it actually continues to have transmission rights.[211] TDU Intervenors assert that while the Commission directed SPP to make the TCR auction subject to review by the Market Monitor and mitigation, as needed;[212] on compliance SPP addresses only Market Monitoring and does not include any market mitigation provisions in Attachment AF.[213]

Answer

177. SPP asserts that there is no risk of a market participant losing out on ARRs for an existing reservation that is subject to rollover, because all rollovers under the Tariff must be exercised with one year's notice. Therefore, SPP states that it will know in advance of the relevant ARR auction year whether a customer has exercised its rollover rights. SPP notes that injecting the retrospective cancelation procedure in SPP's simultaneous

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[209] February 2013 Compliance Filing at 23.

[210] TDU Intervenors at 17 (citing February 2013 Compliance Filing at 24 & n.105).

[211] *Id*.

[212] *Id.* (citing October Order, 141 FERC ¶ 61,048 at P 239).

[213] *Id.*

feasibility market design would prevent SPP from awarding ARRs to other participants and would increase underfunding possibilities attributable to awarded ARRs that are subsequently canceled. Thus, they state that no further clarification or revision is required.[214]

Reply

178. TDU Intervenors argue that SPP needs to comply with the Commission's requirement to award ARRs for contracts that provide for the rollover of transmission agreements. TDU Intervenors assert that for each operating year beginning June 1, the first stage of the ARR allocation process involves verification of the market participants' transmission entitlements which occurs between February 14 and March 15. According to TDU Intervenors, the annual ARR allocation, which occurs between April 5 and April 23, and it follows the verification process, which ends on March 15. TDU Intervenors assert that given these timeframes, a transmission customer with a transmission reservation that ended after the verification process (i.e., after March 15) and before the beginning of the operating year (i.e., before June 1) would either need to give its rollover notice more than a full year in advance or lose out on having an annual ARR allocation that covers its full existing transmission reservation period.[215]

Commission Determination

179. We find that SPP has only partially complied with the Commission's directive to submit Tariff provisions describing the process for awarding ARRs for contracts that provide for the rollover of transmission agreements. Under SPP's proposal, market participants with reservations subject to rollover occurring between March 15 and June 1 will either have to provide notice of rollover more than one year in advance or potentially lose their ARR eligibility. In addition, SPP assumes that in the absence of express notice, the rollover will not occur. However, customers who do not provide notice more than one year in advance during the period between March 15 and June 1 would be required to compete for ARRs in the monthly ARR process with other firm transmission customers. These customers might not receive ARRs after the rollover in the same quantity they would if SPP assumed during the annual ARR allocation that the rollover would occur. We are concerned that this process may result in uncertainty for firm transmission

[214] SPP Answer at 4-5.

[215] TDU Intervenors' Reply at 3-4.

customers with contracts containing rollover provisions. Thus, we find that SPP has failed to demonstrate that its proposed process for awarding ARRs for reservations subject to rollover is just and reasonable. Accordingly, we require SPP to submit a compliance filing 60 days after the date of this order to revise the Tariff so that transmission customers with rights to roll over their agreement will be able to obtain ARRs in the Annual Allocation Process without requiring them to give more than one year notice.

180. We find that SPP has complied with the Commission's directive to address the ARR allocation/TCR auction process for the period from March 1, 2014 through May 31, 2014. Additionally, SPP identified how pseudo-tied resources and load will be treated with regard to ARR allocation. Specifically, SPP sufficiently explains how pseudo-tied load and resources will be treated for purposes of settling TCRs, including how it will address TCRs if there are two or more winning bids.

181. We find that SPP has not complied with the Commission's requirement to include a provision stating that the TCR auction is "subject to review by the Market Monitor and mitigation, as needed."[216] While SPP made the TCR auction subject to a Market Monitor, it did not make it subject to mitigation, as needed. Accordingly, we direct SPP to submit a compliance filing within 60 days of the date of this order that provides that TCR auctions will also be subject to mitigation, as needed. We note that this could be addressed by adding "subject to review by the Market Monitor consistent with Attachment AG" to report any market manipulation concerns with the TCR Auction to the Commission.

ARR Allocation Processes

October Order

182. In the October Order, the Commission conditionally accepted SPP's proposed ARR allocation processes including its incremental ARR proposal,[217] subject to additional compliance filings. In particular, the Commission found that SPP had not demonstrated that its proposed method for approximating a network integration

[216] October Order, 141 FERC ¶ 61,048 at P 239.

[217] As initially proposed, Incremental ARRs are ARRs that become available after the annual ARR allocation.

transmission service customer's load is just and reasonable. The Commission stated that SPP's proposal for calculating the ARR nomination cap using the highest three annual peaks since February 1, 2007 did not account for all the relevant circumstances surrounding the current system.[218] Thus, the Commission found that SPP should file a revised proposal that would reflect system realities more accurately and directed SPP to adopt 103 percent of the previous three years average annual peak network loads.[219] The Commission also directed SPP to clarify its Tariff to state explicitly that in calculating peak load for purposes of determining ARR eligibility, it will adjust for load transfers among load-serving entities, as it committed to do in its answer.[220]

183. In addition, the Commission expressed concern that providing ARRs up to the nomination cap determined in part on the annual peak methodology for customers with significant swings in load could allow these firm transmission customers to receive more ARRs than required to provide a financial hedge of congestion costs, thereby leaving other market participants with fewer ARRs. Thus, the Commission required SPP either to support its use of an average peak methodology in the ARR allocation nomination cap for the firm transmission customers with significant swings in load, or to propose refinements to account for these significant monthly and seasonal differences.[221]

184. The Commission found that SPP's proposal for the incremental ARR allocation process did not include an explanation of the incremental capacity that will become available after the annual TCR auction. The Commission directed SPP to clarify the Tariff to explain the ARR allocation process 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.[222] The Commission stated that to the extent incremental ARRs represent existing capacity on the transmission system, including capacity expected to be added during the year, SPP must modify its proposal to allow a load-serving entity to acquire incremental ARRs for transmission capacity that comes

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[218] October Order, 141 FERC ¶ 61,048 at P 263.

[219] *Id.* P 264.

[220] *Id.* P 266.

[221] *Id.* P 265.

[222] *Id.* P 281.

available after the annual TCR auction to acquire incremental ARRs for this existing transmission capacity up to its nomination cap along with market participants with newly acquired reservations.[223]

185. Additionally, the Commission found that SPP's proposal for ARR allocation to firm point-to-point transmission customers with re-dispatch obligations did not accurately reflect the nature of this service, as it could be interpreted as denying all ARRs even when the service is not subject to re-dispatch.[224] The Commission found that when the service was not subject to re-dispatch, it was firm; thus, the Commission held that SPP should allow ARR allocation when the re-dispatch obligation is not required. Accordingly, the Commission directed SPP to modify section 13.5 of its Tariff to make clear that such firm point-to-point transmission customers with re-dispatch obligations will obtain ARR allocations except for those times of the year and for only those amounts of service that are subject to the re-dispatch obligation.[225]

186. The Commission also directed SPP to clarify its Tariff provisions with respect to the congestion management process. Specifically, the Commission required SPP to clarify the process for reducing the number of nominated ARRs when they are not simultaneously feasible, to clarify the ARR award process, to include the discussion in the Market Protocols in the Tariff, and to clarify the role the Shadow Price plays in the annual TCR awards in section 7.3.4 of Attachment AE.[226] Finally, the Commission directed SPP to explain whether it will reconfigure ARRs during annual and monthly TCR auctions to maximize value, and whether it intends to impose counter-flow ARRs. If SPP does include this feature, the Commission stated that it should clarify the Tariff to explain the process.[227]

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[223] *Id.* P 277.

[224] *Id.* P 254.

[225] *Id.* P 268.

[226] *Id.* P 269 & n.404.

[227] *Id.* P 271.

February 2013 Compliance Filing

187. SPP proposes using 103 percent of the previous three years average annual peak network loads for the annual peak methodology in the ARR allocation process.[228] In support of its annual peak methodology for the ARR allocation process for all seasons or months of the year, SPP explains that this methodology provides non-discriminatory access to the grid along the transmission paths that market participants have reserved and for which they have paid. SPP explains that this methodology is similar to the methodology approved for MISO and is, therefore, consistent with Commission precedent. SPP asserts that its methodology offers market participants the needed optionality to provide for a reasonable congestion hedge commensurate with their payment and use of the transmission grid. SPP also clarifies its Tariff explicitly to provide that it will adjust for load transfers among load-serving entities when calculating peak load for purposes of determining ARR eligibility.[229]

188. SPP revises section 13.5 to provide a candidate ARR to a firm point-to-point customer subject to re-dispatch at 100 percent for those times of the year that do not require re-dispatch. SPP states that for times of the year where re-dispatch is required to grant the service, candidate ARRs will be granted for only the amount of service that can be granted without re-dispatch, which could be equal to zero MW.[230]

189. SPP proposes to change its incremental ARR process to a monthly ARR process that would take place prior to the monthly TCR auction. SPP asserts that the monthly ARR allocation process allows eligible entities to nominate ARRs for: (1) any remaining ARR capacities from the annual ARR allocation process; (2) firm transmission service that was confirmed following the completion of the most recent annual TCR auction and prior to the next annual ARR verification; (3) firm transmission service confirmed prior to the annual ARR verification process that includes a partial season; or (4) transmission service for which a re-dispatch obligation has been eliminated. SPP asserts that this

[228] February 2013 Compliance Filing at 25.

[229] *Id.*

[230] *Id.* at 26.

modification will also allow customers with re-dispatch obligations to be eligible for ARRs if the re-dispatch condition is removed during the year due to capacity additions.[231]

190. SPP makes additional clarifications to comply with the directives set forth in the October Order. SPP incorporates language from the Market Protocols into the Tariff to clarify the ARR allocation process.[232] SPP also revises section 7.3.4 of Attachment AE to clarify how the Shadow Price is utilized in the calculation of the auction clearing price.[233] In addition, SPP clarifies that (1) the ARRs allocated in the annual and monthly allocation processes are final and will not be reconfigured to maximize value, and (2) it does not intend to impose counter-flow ARRs.[234] Finally, SPP submits proposed language in section 7.1.1(2) of Attachment AE that requires each GFA to be registered with the Transmission Provider.

Comments

191. BP Wind Energy expresses concern over SPP's proposal to grant ARRs only in the "amount of service that can be granted without re-dispatch, which could be equal to zero MW."[235] BP Wind Energy states that when SPP grants transmission service subject to re-dispatch pending the construction of upgrades, SPP does not distinguish between periods preceding the construction of network upgrades when re-dispatch may or may not be required, nor does it consider seasonal or system conditions. Thus, BP Wind Energy explains that SPP's granting of transmission service subject to re-dispatch puts the customer on notice that, when certain contingencies arise and re-dispatch is required, the customer is required to execute re-dispatch agreements and pay the associated re-dispatch costs. According to BP Wind Energy, for all re-dispatch-based services granted to date, the ARR award will be zero if SPP grants ARRs only in the amount of service that can be

[231] *Id.* at 28. SPP states that a sponsor of a transmission upgrade will be eligible for an ARR allocation if it obtains a transmission service reservation, because ARRs are allocated to transmission service customers.

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

[233] *Id.* at 27.

[234] *Id.*

[235] BP Wind Energy at 3-4 (quoting February 2013 Compliance Filing at 26).

granted without re-dispatch. BP Wind Energy asserts that it is SPP's practice when granting service to identify the maximum exposure that the customer will face, not its range of potential actual re-dispatch events. BP Wind Energy argues that this grant of zero ARRs will be true even if, under actual conditions, the contingencies never arise and re-dispatch is never required.[236]

192. BP Wind Energy also asserts that the current SPP transmission service evaluation process is not granular enough to identify adequately when re-dispatch is needed; instead, it only shows with certainty when dispatch is not needed. Moreover, BP Wind Energy contends the study process does not apply a period criterion, i.e., if the winter peak cases identify no overloads and a summer peak case does, SPP will only grant service subject to re-dispatch, with re-dispatch applying until such time as no case shows an overload occurring. BP Wind Energy is concerned that acceptance of the proposal would nullify the Commission's intent to distinguish between periods when re-dispatch is required and periods when it is not. Accordingly, BP Wind Energy argues that the Commission should direct SPP not to base ARR eligibility on the analyses it uses when granting transmission service to determine the customer's maximum exposure to re-dispatch; rather, ARRs should be provided for any period when re-dispatch is not required.[237]

193. BP Wind Energy contends that SPP should be required to adopt a clear and transparent methodology that defines the criteria for identifying the period(s) when re-dispatch applies and when it does not. For example, BP Wind Energy points out that SPP has proposed a monthly allocation of ARRs in the summer; however, the current transmission service study process at best identifies when re-dispatch is needed on a seasonal basis (e.g., the summer peak), and it does not evaluate every relevant period (e.g., each summer month individually). Further, BP Wind Energy argues that SPP should ensure that the ARR allocation for transmission customers that are subject to re-dispatch is communicated in advance so that those customers can determine whether to use the ARRs to hedge congestion.[238]

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[236] *Id.* at 4.

[237] *Id.* at 5.

[238] *Id.* at 6.

Answer

194. SPP responds that the Commission found it reasonable to differentiate between point-to-point transmission service subject to re-dispatch and transmission service with no re-dispatch obligation for purpose of determining ARR eligibility. SPP asserts that the Commission did not require SPP to modify how it determines when re-dispatch is necessary or make any changes to SPP's current study process for transmission service requests. SPP asserts that determining ARR eligibility is an inherently forward-looking process that was designed to conform to SPP's current transmission study process.[239] SPP explains that if ATC is insufficient to meet the request, it offers the customer the option of using interim re-dispatch, when necessary, to provide transmission service pending the completion of necessary system upgrades.[240]

195. SPP states that its transmission study process looks at certain peak seasons (i.e., summer and winter,) and that the re-dispatch obligation arises only in these seasons for which the studies have identified overloads. SPP asserts that the customer would be eligible for its full allotment of candidate ARRs in all periods except during the peak season in which with the overload has been identified.[241]

Commission Determination

196. We conditionally accept both SPP's proposed use of 103 percent of the average of the three previous annual peaks in the ARR nomination cap, and SPP's support for that methodology for network customers with significant swings in load, subject to SPP submitting certain clarifying revisions to the nomination cap, as described below. We find that, as modified below, the use of 103 percent of the average of the three previous annual peaks in the ARR nomination cap will adequately account for significant swings in load. Thus, we direct SPP to file a compliance filing within 60 days from the date of the order to modify section 7.1.3(1) to state, in part, that the:

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[239] SPP explains that real-time operations may be different from the conditions identified in the study process, but it would be impossible for SPP to determine, at the time that ARR eligibility is determined, whether the conditions that the study process determines may lead to overloads in a particular season will actually occur.

[240] SPP Answer at 6-7.

[241] *Id*. at 7.

> ARR Nomination Cap for a particular month or season is equal to the ~~minimum~~lesser of a) the sum Network Integration Transmission Service Candidate ARRs for that particular month or season as calculated in Section 7.1.2 of this Attachment AE and any additional Network Integration Transmission Service Candidate ARRs for that particular month or season as calculated in Section 7.5.1 of this Attachment AE or b) One hundred and three percent (103%) of the average of that customer's three most recent annual peak Network Loads.

Also, because GFAs will be providing service equivalent to network integration transmission service and will be subject to equivalent swings in load, the revisions we are directing for the calculation of the ARR nomination cap in section 7.1.3(1) also should apply to the ARR nomination caps for GFAs. Therefore, we direct SPP to revise section 7.1.3(3) to conform to the revised Tariff provisions we direct herein for section 7.1.3(1).

197. SPP proposes new Tariff language to implement its requirements for entities seeking to obtain ARRs in the ARR allocation process. Included in these new provisions are requirements that SPP obtain the source, sink, and reservation capacity information from SPP's OASIS for each reservation, including reservations for GFAs that seek ARRs.[242] SPP discussed these ARR reservation requirements in its earlier GFA status reports regarding its negotiations to resolve outstanding GFA issues.[243] In these status reports and subsequent GFA-related motions, SPP raised concerns about awarding ARRs and TCRs to GFA parties that SPP asserts do not have sinks to valid settlement locations. Thereafter, upon a request from OPPD, the Commission set this and related GFA issues for settlement judge proceedings.[244] We accept SPP's proposed revisions regarding reservation requirements in order to provide consistency within the Tariff. Our finding here is not intended to prejudge the outcome of the issues pending in the GFA settlement proceeding.

[242] SPP Tariff, Attachment AE, section 7.5.1.

[243] *See* SPP Status Reports dated January 16, 2013 and March 15, 2013.

[244] *See* GFA Order, 143 FERC ¶ 61,219; *see also Order of Chief Judge Granting Motion to Expand Settlement Proceedings*, 143 FERC ¶ 63,016 (2013).

198. Also, we conditionally accept, subject to a compliance filing, SPP's proposed ARR allocation process for point-to-point customers subject to re-dispatch. For the purpose of identifying these customers, SPP proposes to use its transmission study process, which determines potential overload conditions for both the summer and the winter peak periods for several years into the future. Based upon this information, SPP will determine which customers subject to re-dispatch will receive a reduction in ARR allocations, corresponding to the amount of the re-dispatch needed to address the overload conditions. Although BP Wind Energy challenges SPP's use of the transmission study process because it is not as granular as the ARR summer peak allocation process, SPP's proposal is sufficiently granular to identify the peak periods over the next several years when customers subject to re-dispatch could expect potential overloads on the SPP system that might affect the amount of their ARR allocations. Accordingly, we deny BP Wind Energy's request that we require SPP to change its study process. Moreover, we disagree with BP Wind Energy's assertion that it will not receive any ARRs until such time as the transmission studies no longer identify overloads. SPP's Tariff provides that transmission customers having firm point-to-point transmission service with a redispatch obligation will be eligible to nominate candidate ARRs associated with that service for those times of year and for the amounts of service not subject to a re-dispatch obligation. However, we find that SPP has not explained how it will allocate on-peak and off-peak ARRs. Thus, we direct SPP to explain in a compliance filing due 60 days following the date of this order, whether point-to-point transmission customers subject to re-dispatch during a peak period (e.g., summer) should be entitled to off-peak ARRs during the peak period with the overloads.

199. Finally, we do not agree with BP Wind Energy's suggestion that ARRs should be given except for those times when re-dispatch actually occurs. BP Wind Energy has not shown that SPP's proposal is unjust and unreasonable. In addition, we find that this requirement could be difficult for SPP to implement, because it will not know in advance when re-dispatch will occur. Moreover, we note that customers with re-dispatch obligations are provided service when the transfer capability is not otherwise available. Therefore, we conclude that requiring SPP to provide ARRs during the whole year, and separately charging for re-dispatch service is not reasonable. Finally, we find that because ARRs are based on transfer capability, providing ARRs to the extent BP Wind Energy requests could cause an underfunding problem with ARRs. For these reasons, we will not require SPP to allocate ARRs to customers with re-dispatch obligations for their entire reservation amount except for those times re-dispatch actually occurs.

200. In addition, we find that SPP has complied with the October Order by adding language from the Market Protocols to the Tariff and explicitly stating that it will account for load transfers between load-serving entities. In addition, SPP has revised

section 7.3.4 of Attachment AE to clarify how the Shadow Price is utilized in the calculation of the auction clearing price. SPP has further clarified that the ARRs allocated in the annual and monthly allocation processes are final and will not be reconfigured to maximize value. Finally, we find that SPP has clarified that it does not intend to impose counter-flow ARRs.

TCR Auctions

October Order

201. In the October Order, the Commission found that SPP had not explained whether its use of "bid" refers to both "Bid" and "Offer" as the term applies to the 2,000 TCR bid limit.[245] The Commission directed SPP on compliance to define each term clearly, and to clarify whether the 2,000 bid limit applies to Bids, Offers and/or self-conversions.[246] In addition, the Commission directed SPP to support its proposed percentages used in making transmission capability available during the annual TCR auction.[247]

February 2013 Compliance Filing

202. SPP revises the terms "Bids" and "Offers" in Attachment AE to clarify that both terms apply to the TCR Auction process and that both count toward the 2,000 TCR bid limit for each round of the monthly TCR auction. SPP further revises its Tariff to remove the reference to self-conversion with respect to the TCR bid limit in the TCR Auction. Finally, in other sections of Attachment AE, SPP removes "direct" from before the word "conversion" to distinguish it from "self-conversion."[248]

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[245] October Order, 141 FERC ¶ 61,048 at P 291.

[246] The Commission also noted that SPP uses the term "self-conversion" in many places in Attachment AE but it also uses the term "direct conversion" (e.g., section 7.3). To the extent these terms were intended to refer to the same concept, the Commission directed SPP to use a common defined term. *Id.* P 291 & n.435.

[247] *Id.* P 292.

[248] February 2013 Compliance Filing at 30.

203. SPP explains that the percentage reductions in available transmission for the annual TCR auction product periods mitigate the risk of over selling TCRs, which would negatively affect TCR values. SPP adds that there is a need to balance the value of a reasonable amount of TCRs upfront and the value in the ability of a TCR holder to adjust to changes in transmission topology and other factors that transpire closer to real-time, such as weather, transmission and generation outages, and loop flows. With respect to the specific amounts for the percentage reductions chosen, SPP states that it considered both its operational experience and the closeness in time of the annual model used in the annual auction and the offered months in the TCR auction. SPP explains that it proposed withholding ten percent of available transmission capability for annual TCR auction for the critical months of July through September, when information is at its highest confidence, due to its closer proximity to the annual model. SPP also proposes withholding 40 percent of available transmission capability in the annual TCR auction for the rest of year, because the information is more speculative during these later months. Thus, SPP asserts that it is providing a reasonable amount of available transmission that can be auctioned in the annual TCR auction, and it is making the rest available to be auctioned when the value is closer to its worth with better information and a better model of the transmission topology.[249]

Comments

204. According to TDU Intervenors, SPP has failed to explain its use of 90 percent of transmission capability during the summer period and 60 percent for the remaining seasons in the annual TCR auction, as directed. Therefore, TDU Intervenors request that the Commission require SPP to support its proposal, or revise or eliminate the capacity holdbacks.[250]

Commission Determination

205. We find that SPP has complied with the directives set forth in the October Order to revise the terms "Bid" and "Offer," and that SPP has supported its proposed percentages for making transmission capability available during the annual TCR auction. Specifically, we find that SPP has revised the terminology, as required, to clarify the TCR auction process. We further find that SPP has demonstrated that its proposal to hold

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[249] *Id*.

[250] TDU Intervenors at 17.

back transmission capability during the annual TCR auction, when information is less reliable, and then releasing the remaining transmission capability during the monthly auctions, when information is more reliable and more accurately reflects the system, is just and reasonable. Thus, we will not require SPP to provide additional support for its proposal or to revise it to eliminate the capacity holdbacks.

Integration Issues

Bilateral Settlement Schedules

October Order

206. In the October Order, the Commission conditionally accepted SPP's proposed treatment of bilateral agreements. The Commission expressed concern that the parties to existing bilateral agreements have already negotiated the terms and rates of their agreements, so that a seller may have limited incentive to agree to a Bilateral Settlement Schedule absent additional consideration.[251] Thus, the Commission encouraged parties to existing bilateral agreements to resolve any dispute as to how the existing bilateral agreement will be reflected in the market. If the parties cannot agree, the Commission required SPP to adopt a transition mechanism for any unsettled existing bilateral agreements to reduce the risk to buyers. The Commission found that this mechanism should provide a default method of addressing settlement of bilateral agreements entered into prior to the start of the Integrated Marketplace.[252]

207. The Commission further determined that SPP's proposed Tariff revisions to implement Bilateral Settlement Schedules are unclear in several respects. First, because the Bilateral Settlement Schedule pertaining to future bilateral system power sale agreements may involve careful negotiations, the Commission required SPP to provide an example of how a Bilateral Settlement Schedule can be used to settle a bilateral system power sale agreement.[253] Second, the Commission required SPP to clarify the Tariff to

[251] A "Bilateral Settlement Schedule" is an arrangement between two market participants for the transfer of Energy or operating reserve obligations to financially integrate bilateral agreements into the Integrated Marketplace construct.

[252] October Order, 141 FERC ¶ 61,048 at P 326.

[253] *Id.* P 270.

reflect SPP's answers on the alternatives to the Bilateral Settlement Schedule process (e.g., the seller registering the buyer's load) for addressing bilateral agreements in the Integrated Marketplace. Third, the Commission found that the termination provisions for a Bilateral Settlement Schedule were unclear in several respects. Among other things, the Commission noted that under section 8.2 of Attachment AE of the proposed Tariff, SPP may terminate a Bilateral Settlement Schedule for "settlement disputes," but in its answer SPP stated that it can only terminate the "auto-approve" feature, not the Bilateral Settlement Schedule itself. Accordingly, the Commission directed SPP to revise its Tariff to include a default transition mechanism to address settlement of existing bilateral transactions, to incorporate the clarifications made in its answers on Bilateral Settlement Schedule, and to clarify the disputed termination provisions in section 8.2.[254]

February 2013 Compliance Filing

208. SPP proposes a transitional mechanism only for bilateral agreements entered into prior to the October Order. SPP points out that as of the date of the October Order, SPP and market participants were on notice that a transition mechanism would be required for and applied to existing contractual arrangements that would remain in effect under the Integrated Marketplace.[255]

209. According to SPP, the new Tariff provisions specify the default procedures that will apply where the buyer and seller cannot agree to the terms of a Bilateral Settlement Schedule. SPP explains that under the transitional mechanism, the buyer may register and confirm a Bilateral Settlement Schedule corresponding to the terms of the pre-existing bilateral contract, subject to review and verification by SPP. Under this mechanism, SPP states that only the buyer may terminate the Bilateral Settlement Schedule associated with an existing bilateral agreement.[256] Finally, SPP provides an example of a Bilateral Settlement Schedule in Addendum 2 to Attachment AE of the Tariff.

[254] *Id.* P 327.

[255] February 2013 Compliance Filing at 32.

[256] *Id*.

Comments

210. TDU Intervenors contend that SPP's proposed application of the transition mechanism to bilateral agreements entered into prior to issuance date of the October Order is contrary to the Commission's directive that it apply to all bilateral contracts dated prior to March 2014. TDU Intervenors challenge as illogical SPP's assertion that the issuance date of the October Order is appropriate because after that date SPP and market participants were on notice that a transition mechanism would apply. According to TDU Intervenors, parties do not have certainty as to how the Bilateral Settlement Schedules rules will be applied going forward, so it is not logical to apply the mechanism only for bilateral agreements that predate the October Order.[257] Moreover, TDU Intervenors argue that while SPP has included an example of a Bilateral Settlement Schedule in its compliance filing, the example is unclear and does not explain the proposed Bilateral Settlement Schedule Tariff provisions, which have also not yet been finally approved. Thus, TDU Intervenors request that the Commission direct SPP to provide a more "readable and helpful example" of a Bilateral Settlement Schedule.[258]

211. TDU Intervenors assert that the default transition mechanism provisions in section 8.2.1(4) incorrectly refer to "section 7.1.1(1)(a)(i) or 7.1.1(2)(a)(i)," when they should instead refer to section 7.1.1(1)(a).[259] TDU Intervenors assert that this change would properly correlate the Bilateral Settlement Schedule settlement location with the proper settlement location associated with each bilateral contract, whether it is for a single resource, multiple resources, or one or more off-system resources.

212. TDU Intervenors state that SPP has included language in section 8.2.1 of Attachment AE that allows a buyer under an existing bilateral contract to control the creation and operation of a Bilateral Settlement Schedule if it cannot get the seller to agree on the terms. However, TDU Intervenors contend that this new provision conflicts with section 8.2, which includes a blanket requirement of mutual consent of buyer and seller to establish a Bilateral Settlement Schedule and allows the seller or SPP to

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[257] TDU Intervenors at 19-20.

[258] *Id.* at 18.

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

terminate the Bilateral Settlement Schedule. Thus, TDU Intervenors assert that SPP should be required to modify section 8.2 to be consistent with section 8.2.1.[260]

213. TDU Intervenors further argue that SPP has not supported its retention of the ability to terminate a Bilateral Settlement Schedule if either the buyer or the seller is in default. TDU Intervenors explain that a buyer could lose its Bilateral Settlement Schedule and with it the value of its bilateral purchase if the seller has failed to pay its transmission bill. TDU Intervenors assert that a buyer should not be penalized for the seller's failure to meet its obligations to SPP.[261]

214. TDU Intervenors state that in section 2.2(11) of the Tariff SPP improperly restricts the option that allows a seller to register as its own load asset the portion of the buyer's load that is served by the seller. According to TDU Intervenors, SPP is limiting the option to only where the firm power sale includes both capacity and energy and is supported by firm transmission service, and where "the capacity and energy is supplied under standards of reliability and availability equivalent to supply of native load customers."[262] TDU Intervenors argue that SPP has not supported limiting the application of the provision to contracts that provide for native-load firmness, and assert that this limitation should not be included.[263]

215. TDU Intervenors state that section 2.2(11) appears to apply to both existing and new bilateral agreements. According to TDU Intervenors, it is likely that in many existing contracts, the seller obligated itself to supply firm system capacity and energy but refused to include a provision putting the buyer on the same footing as the seller's native load. In such cases, TDU Intervenors state that even if the buyer and seller both wish to have the seller include in its load assets the amount of service it is providing to the buyer, they would not be able to do so without amending the bilateral agreement to include an express native-load-equivalence provision. However, TDU Intervenors note that some sellers may be unable to agree to this because they lack a native load of their

[260] *Id.* at 21.

[261] *Id.* at 22.

[262] *Id.* at 23 (citing section 2.2(11)).

[263] *Id.* at 24.

own or because they are prohibited by their state regulatory commissions from placing wholesale sales on equal footing with their native load.[264]

216. TDU Intervenors state that they do not understand the reason for SPP's proposed native load-equivalence requirement, or even who it is supposed to protect, particularly given that this is not a resource adequacy provision. TDU Intervenors explain that section 2.2(11) ensures that the buyer is not charged by SPP for the energy that the buyer has already committed to purchase from the seller under the bilateral contract. TDU Intervenors argue that if the seller considers its obligations under a bilateral sale agreement sufficiently firm to take on market responsibility for that portion of the buyer's load, SPP should permit them to do so.[265]

Answer

217. SPP states that it chose to limit the applicability of the default procedure to contracts entered into prior to the date of the October Order. SPP explains that the default transition mechanism places a burden on SPP because SPP must review the disputed agreement, arrange a meeting between the contracting parties, and verify that any submitted Bilateral Settlement Schedule conforms to the terms of the existing agreement. SPP argues that because contracting parties knew that if they entered into a bilateral agreement after the issuance of the October Order, they would need to reach agreement on the terms of a Bilateral Settlement Schedule, it is unnecessary for them to have known the precise terms of the default transition mechanism. Thus, SPP asserts that the Commission's rationale of requiring a default transitional mechanism to address the treatment of "existing bilateral agreements" does not apply to any agreements entered into after the issuance date of the October Order.[266]

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[264] *Id.*

[265] *Id.* at 25-26.

[266] SPP agrees with TDU Intervenors that section 8.2.1(4) was intended to apply to situations involving power purchase agreements out of a multiple units but would not apply in the context of other bilateral contracts (e.g., purchase of a single resource with its own settlement location). SPP agrees to revise section 8.2.1(4), as requested by TDU Intervenors, if ordered to do so by the Commission. SPP Answer at 17.

218. Moreover, SPP argues that no change is required to section 8.2 concerning Bilateral Settlement Schedule defaults. SPP explains that when a party to a Bilateral Settlement Schedule defaults on a payment to SPP for an obligation arising under the Bilateral Settlement Schedule, SPP must be able to protect itself and other market participants from financial exposure by terminating the Bilateral Settlement Schedule. SPP states that it cannot be forced to honor the Bilateral Settlement Schedule while the parties to the Bilateral Settlement Schedule exchange claims and counterclaims over their respective rights, obligations, and liabilities.[267]

219. According to SPP, it incorporated section 2.11(1)(A)(4)(ii) into its Tariff to apply the same deliverability criteria used for the must-offer obligation (i.e., firm transmission service where capacity and energy are provided under the standards of reliability and availability equivalent of native load) to the administration of bilateral transactions. SPP states that if ordered to do so by the Commission, it would not object to allowing load transfers and or bilateral contracts to count toward the must-offer obligations, as long as the seller agrees to assume responsibility for the buyer's load that is transferred or served under the bilateral agreement.[268]

Reply

220. TDU Intervenors state that SPP's suggestion that it could terminate the Bilateral Settlement Schedule only if there is a default of a party's obligations to SPP under the Bilateral Settlement Schedule is not reflected in the Tariff language. TDU Intervenors maintain that the Tariff language provides that if one party is in default of any obligation to SPP under the Tariff, SPP could terminate the Bilateral Settlement Schedule. TDU Intervenors object to this provision because the obligations under a Bilateral Settlement Schedule run to the other parties to the Bilateral Settlement Schedule, not to SPP.[269]

Commission Determination

221. We conditionally accept SPP's compliance filing as it pertains to Bilateral Settlement Schedules, subject to a compliance filing due 60 days from the date of this

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[267] *Id.* at 15.

[268] *Id.* at 16-17.

[269] TDU Intervenors' Reply at 5.

order. Specifically, we find that SPP's proposal to apply its transitional mechanism only to bilateral agreements entered into prior to the October Order does not comply with the Commission's directive that the transition mechanism would apply to all unsettled bilateral agreements entered into prior to the "start of the Integrated Marketplace."[270] If SPP believed that the transition mechanism should apply to all unsettled bilateral agreements entered into prior to the issuance date of the October Order, rather than prior to the "start of the Integrated Marketplace," SPP should have raised this issue on rehearing, and not on compliance. We further note that the Commission has held that requests to alter a compliance filing in a manner that differs from the underlying order requiring the compliance filing constitute a collateral attack on the underlying order.[271]

222. Moreover, we are not persuaded by SPP's assertion that the issuance date of the October Order is appropriate, because after that date SPP and market participants were on notice that a transition mechanism would apply. We note that the Bilateral Settlement Schedule provisions of the Tariff still have not been fully approved by the Commission. In addition, the example of a Bilateral Settlement Schedule, which was required to facilitate transparency in the Bilateral Settlement Schedule process, was not available until the February 2013 Compliance Filing, and it requires further clarification, as explained below. Thus, even after the October Order, we find that provisions governing Bilateral Settlement Schedules may lack sufficient clarity for market participants to negotiate their terms and to reflect such terms in new agreements. For these reasons, we require SPP to submit a compliance filing within 60 days of the date of this order that revises the transition mechanism to apply to all unsettled bilateral agreements entered into prior to the start of the Integrated Marketplace.

223. Additionally, we find that a further clarification is necessary to section 8.2, Bilateral Settlement Schedules. While the default mechanism in section 8.2.1 of Attachment AE appropriately allows a buyer to confirm a Bilateral Settlement Schedule, section 8.2 still requires both buyer and seller to confirm all Bilateral Settlement Schedules. Thus, we direct SPP to modify section 8.2 of Attachment AE of the Tariff to reflect that both a buyer and a seller must confirm a Bilateral Settlement Schedule except for a Bilateral Settlement Schedule associated with an existing bilateral agreement under section 8.2.1. This would avoid placing the buyer at a disadvantage when the seller does

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[270] October Order, 141 FERC ¶ 61,048 at P 326.

[271] *See, e.g., ISO New England*, 132 FERC ¶ 61,098, at P 12 (2010); *Cal. Indep. Sys. Operator Inc.*, 119 FERC ¶ 61,240, at P 13 (2007).

not have an incentive to enter into a Bilateral Settlement Schedule without additional consideration from the buyer. Accordingly, we direct SPP to make a compliance filing within 60 days of the date of this order to modify section 8.2 to be consistent with the default mechanism in section 8.2.1 as requested by TDU Intervenors.

224. We conditionally accept SPP's example of a Bilateral Settlement Schedule, subject to an additional compliance filing. In the October Order, the Commission required the example of a Bilateral Settlement Schedule to "facilitate transparency and ultimately reduce the likelihood of future disputes;"[272] however, we find that SPP's proposal lacks sufficient clarity to comply fully with the Commission's directive. In the first paragraph of Addendum 2 to Attachment AE, under "Settlement Results with Bilateral Settlement Schedules," SPP assumes that both parties agree to a sale with a maximum sales amount of 20 MWh, which SPP states is ten percent of market participant A's resource capacity.[273] SPP has not explained how it derived the ten percent amount and the assumptions underlying the numerical example do not show any resource capacity for market participant A. Additionally, in paragraph two, SPP provides an example, which assumes three 5 MW TCRs "from" its load "to" the resources.[274] We find that this language conflicts with the language in the "Settlement Results with Bilateral Settlement Schedule" section that states that the TCRs are "from" the resources "to" the load. Accordingly, we direct SPP to make a compliance filing within 60 days of the date of this order that revises Addendum 2 to explain how SPP derived its proposed numbers, and to reconcile the inconsistency in the tariff sections addressing the source and sink for TCRs.

225. We find that SPP has not complied with the directive set forth in the October Order to clarify the disputed termination provisions. SPP has not provided a sufficient explanation for why it would terminate the Bilateral Settlement Schedule, rather than allow parties to cure the default as provided for in SPP's credit policy in Attachment X of the Tariff. For these reasons, we find that SPP has failed to demonstrate that its termination provisions are just and reasonable and not unduly discriminatory. Accordingly, we direct SPP to submit a compliance filing within 60 days of the date of this order that removes the Tariff language in section 8.2 of Attachment AE, which

[272] October Order, 141 FERC ¶ 61,048 at P 270.

[273] SPP Tariff, Attachment AE, Addendum 2.

[274] *Id.*

allows SPP to terminate the Bilateral Settlement Schedule if a party is in default; that is, the Tariff's generally applicable default terms and conditions in Attachment X should apply. This requirement is without prejudice to SPP filing in a separate section 205 filing a proposal, with support, to explicitly address market participants who default on their bilateral settlement schedule obligations.

226. We note that in its answer, SPP has agreed to make a ministerial change to its Tariff. Specifically, SPP agrees to revise section 8.2.1(4), so that it no longer refers to an incorrect sub-section. Therefore, we direct SPP to make a compliance filing within 60 days of the date of this order that revises section 8.2.1(4) of its Tariff to no longer reference an incorrect sub-section.

227. We find that with further modification SPP's proposed section 2.2(11), which sets forth the deliverability requirements for a transfer of load under a bilateral contract, is just and reasonable.[275] It appears that, in crafting these provisions, SPP has given consideration to both the firmness of transmission service as well as the firmness of supply to ensure deliverability to load. These provisions concerning a transfer of load to the seller essentially make the seller the load-serving entity for that load, thereby, necessitating the requirement of "native load equivalency." However, we find that the TDU Intervenors have raised a valid concern. Even in those contracts which may not explicitly mention a native load equivalency of firmness, the seller may consider its obligations under the bilateral sale agreement as sufficiently firm to take on market responsibility for that portion of the buyer's load. We agree with TDU Intervenors that under this scenario, SPP should permit the seller to do so. In SPP's answer, SPP states that sellers may register the buyer's load if they agree to be responsible for the requirements of the load, even if the contract does not specify a native load equivalency. Accordingly, consistent with SPP's answer, we direct SPP to revise the Tariff in section 2.2(11) of Attachment AE within 60 days of the date of this order to allow load transfers if the seller agrees to assume responsibility for the buyer's load that is transferred.[276]

[275] Section 2.2(11) requires a market participant selling power under a bilateral transaction or registering another market participant's load as its own load asset to ensure the deliverability of the seller's power by having firm transmission and providing both capacity and energy with firmness that is equivalent to native load.

[276] The draft order addresses whether such load transfers and/or bilateral transactions can count towards the must-offer requirement in the must-offer section of the

(continued…)

General Seams Issues

October Order

228. In the October Order, the Commission found that parties that choose not to participate in the Integrated Marketplace must be assured that they will not be subject to the rules and practices of the Integrated Marketplace, and the Commission directed SPP to clarify its Tariff accordingly.[277] Similarly, the Commission found that SPP members with non-participating embedded loads must be assured that they are not responsible for Integrated Marketplace costs or requirements attributable to the operation of generation and transmission used to serve these loads.[278] Thus, the Commission directed SPP to revise its Tariff to clarify that SPP members with non-participating embedded loads are not responsible for Integrated Marketplace costs or requirements attributable to the operation of generation and transmission used to serve these loads.

February 2013 Compliance Filing

229. SPP states that it has revised section 2.1 of Attachment AE to state that "[e]xcept as may otherwise be provided in this Tariff with respect to Reserve Sharing Group member, entities that are external to the Integrated Marketplace footprint and that do not take services under the Tariff are not subject to the rules and practices of the Integrated Marketplace."[279] SPP asserts that it also further clarifies section 6.3.3 of Attachment AE to state that Reserve Sharing Group members are not subject to the rules and practices of the Integrated Marketplace, except for those specified in Attachment AK and in section 8.6.17 and 8.6.18 of Attachment AE.[280] According to SPP, these revisions clarify the applicability of the Integrated Marketplace rules to entities that choose not to participate in the Integrated Marketplace, but are in any of the other SPP footprints.

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draft order. *See supra* P 50.

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

[278] *Id*.

[279] February 2013 Compliance Filing at 32; SPP Tariff, Attachment AE, section 2.1.

[280] February 2013 Compliance Filing at 32-33.

230. Regarding the embedded load directive, SPP states that it has modified the registration procedures in section 2.2 of Attachment AE to require non-participating embedded load and/or generation either to register such load/generation in the Integrated Marketplace, or to transfer the load/generation to an external Balancing Authority.[281] According to SPP, the requirement to register and/or transfer-out all non-participating embedded load/generation ensures that none of the associated costs will be re-assigned to other SPP members.

Comments

231. NPPD disagrees that SPP can force non-participating embedded load and generation either to register such load/generation in the Integrated Marketplace or to transfer the load/generation to an external Balancing Authority. NPPD seeks clarification that it will not be treated as the default party responsible for the costs related to such non-participating load even if the Commission approves SPP's proposal. According to NPPD, such clarification can be achieved by the Commission directing SPP to include in its Tariff the following statement from the October Order: "SPP members with non-participating loads must be assured that they are not responsible for Integrated Marketplace costs or requirements attributable to the operation of generation and transmission used to serve these loads."[282]

Answer

232. SPP challenges NPPD's assertion that SPP failed to comply with the Commission's directive regarding non-participating embedded load. SPP contends that the Commission's directive was due to concern that in situations where an SPP member has within the SPP footprint a load that does not wish to participate in the SPP markets, the SPP member should not be assessed any market-related charges associated with that embedded load.[283] SPP notes that while it has not adopted the exact wording of the October Order as NPPD requests, the October Order contained no such requirement.

[281] *Id.* at 33; SPP Tariff, Attachment AE, section 2.2 (2).

[282] NPPD at 7 (citing October Order, 141 FERC ¶ 61,048 at P 333).

[283] SPP Answer at 35 (citing October Order, 141 FERC ¶ 61,048 at P 333 (stating that such members "must be assured that they are not responsible for Integrated Marketplace costs or requirements attributable" to these loads)).

Instead, SPP reiterates that by requiring registration and/or transfer-out of all non-participating embedded load/generation, revised section 2.2 ensures that none of the associated costs will be re-assigned to other SPP members. Therefore, SPP asserts that it addressed the Commission's compliance requirement in the October Order. SPP elaborates that the proposed Tariff revisions would ensure that, as a host utility to a non-participating embedded load, NPPD would not be responsible for market-related costs associated with that load, because the load will be required either to register in the Integrated Marketplace in its own capacity, thereby undertaking the obligation for all market-related charges, or to transfer to another balancing authority (by way of pseudo-tie or some similar mechanism).[284]

Commission Determination

233. We find that SPP has complied with the Commission's directive to revise its Tariff to ensure that non-participating parties will not be subject to the rules and practices of the Integrated Marketplace. Specifically, SPP has revised Attachment AE to provide that entities that are external to the Integrated Marketplace footprint and that do not take services under the Tariff are not subject to the rules and practices of the Integrated Marketplace, except as may otherwise be provided in SPP's Tariff with respect to Reserve Sharing Group members.[285]

234. Similarly, we find that SPP's proposed revisions to section 2.2(2) of Attachment AE comply with the Commission's directive regarding embedded load. Rather than revising the Tariff language to state that SPP members with non-participating loads will be assured that they are not responsible for Integrated Marketplace costs or requirements attributable to such loads/generation, SPP's Tariff revisions in section 2.2 establish the mechanisms by which SPP members with non-participating loads will be assured that they are not responsible for Integrated Marketplace costs or requirements attributable to

[284] SPP Answer at 36.

[285] *See, e.g.*, SPP Tariff, Attachment AE, sections 2.1 and 6.3.3. We note this language is consistent with the Commission's clarification in the rehearing order of the October Order that SPP may propose Tariff provisions requiring a party external to SPP that chooses to engage in transactions in the Integrated Marketplace, such as participation in reserve sharing arrangements with SPP, to comply with Integrated Marketplace rules and practices, if applicable to those transactions. *See* Rehearing Order, 142 FERC ¶ 61,205 at P 78.

the operation of generation and transmission used to serve these loads. SPP will require the load either to register in the Integrated Marketplace in its own capacity, thereby undertaking the obligation for all market-related charges, or to transfer to another balancing authority (by way of pseudo-tie or some similar mechanism). We agree with SPP that its proposal assures that in situations where an SPP member has within its footprint a load that does not wish to participate in the SPP markets, the SPP member should not be assessed any market-related charges associated with that embedded load. Thus, SPP's proposal complies with the October Order.

235. NPPD does not provide any evidence that SPP's proposed requirements are unjust and unreasonable, nor does NPPD provide any alternative solutions by which SPP members with non-participating loads would be assured that they are not responsible for Integrated Marketplace costs or requirements attributable to such loads/generation. Furthermore, SPP's Answer addresses NPPD's clarification request that the proposed Tariff revisions will ensure that, as a host utility to a non-participating embedded load, NPPD, or other similarly situated party, would not be responsible for market-related costs associated with that load, as a result of the Integrated Marketplace filing.[286] Accordingly, we find that SPP's proposed revisions are just and reasonable and accept them without further revision.

Pseudo-Tie Arrangements

October Order

236. In the October Order, the Commission conditionally accepted SPP's proposed revisions to Attachment AO to incorporate pseudo-ties as just and reasonable. The Commission indicated that the *pro forma* Agreement in Attachment AO should be used as a starting point for negotiations, because arrangements to integrate external resources (e.g., through pseudo-tie arrangements) may require provisions unique to that resource.[287]

237. The Commission also noted that SPP explained its proposal for a new arrangement called an External Dynamic Resource designed to integrate external resources, and SPP submitted rules for these resources to participate in the market in the Market Protocols. However, SPP did not propose conforming revisions to its Tariff. Thus, the Commission

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[286] SPP Answer at 36.

[287] October Order, 141 FERC ¶ 61,048 at P 349.

required SPP to submit revised tariff sheets and conforming language in a compliance filing to incorporate External Dynamic Resources into the appropriate sections of the SPP Tariff.[288]

February 2013 Compliance Filing

238. SPP submitted revisions to Attachment AE of the Tariff, which include: (1) a definition of External Dynamic resource; (2) detailed rules for the registration of External Dynamic resources; and (3) the requirements for submitting resource offers for this type of resource.[289]

Commission Determination

239. We conditionally accept SPP's proposed Tariff revisions regarding External Dynamic Resources subject to an additional compliance filing. While we find that SPP's definition of External Dynamic Resource and its proposed requirements for submitting resource offers for External Dynamic Resources are just and reasonable; we find that SPP has not fully incorporated External Dynamic Resources into its Tariff, as directed by the October Order. Specifically, SPP has not provided sufficient detail for the registration of External Dynamic Resources to explain how it determines which Reserve Zone to assign a registered External Dynamic Resource. Thus, within 60 days of the date of this order we require SPP to submit a compliance filing to modify section 2.14.5 of its Tariff to sufficiently explain its process for determining which Reserve Zone to assign a registered External Dynamic Resource during the registration process.

Market Mitigation and Monitoring

240. SPP will be implementing mitigation for economic withholding under Attachment AF of its tariff. If a market participant's offer[290] exceeds its mitigated offer levels (reference levels) by more than a specified amount and has more than a specified

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[288] *Id*. P 350.

[289] February 2013 Compliance Filing at 34.

[290] Mitigation of offers occurs for energy offers, operating reserve offers, start-up and no-load offers, and other resource offer parameters such as time-based offers and offer parameters that are neither time-nor dollar-based.

impact upon market prices, then the Market Participant's offer will be mitigated back to its mitigated offer. The specified conduct and impact test thresholds vary depending on market conditions. In particular, more stringent thresholds are applied under the revised proposal in (1) Frequently Constrained Areas where there is a pivotal supplier and where there are binding transmission constraints or binding reserve zones for an expected 500 hours per year or more, and (2) where the resource is manually committed by the Transmission Provider or selected for commitment by a local transmission operator under certain conditions. Under SPP's proposal, the mitigated offer levels from which the thresholds are based, and to which mitigation occurs, will be developed by the market participant and verified by SPP's Market Monitor for accuracy. Under Attachment AF, SPP also mitigates for Virtual Energy Bids and Offers for excessive divergence by restricting the participation of such resources at certain settlement locations for a period of time.

241. SPP also proposes that the Market Monitor monitor for physical withholding, unavailability of facilities, and uneconomic production under Attachment AG of its Tariff. Physical withholding or unavailability of facilities may involve such actions as declaring that a resource has been derated, forced out of service or otherwise made unavailable (in whole or in part) for reasons that are untrue or that cannot be verified, operating at less than dispatch instructions, refusing to provide offers or schedules when it otherwise would have been economic to do so, or similarly restricting transmission facilities. Attachment AG provides thresholds for screening of physical withholding of resource capacity and for transmission. The Market Monitor is to notify the Commission when it identifies these behaviors.

Parameters for Mitigation of Economic Withholding

October Order

242. In the October Order, the Commission conditionally accepted SPP's proposal for mitigation of economic withholding, but required a compliance filing that clarified and/or explained several proposed Tariff provisions. Specifically, the Commission noted an apparent contradiction between sections 3.2 and 3.2.2 of Attachment AF as those provisions relate to binding transmission constraints. The Commission required SPP to either rewrite section 3.2 to explicitly allow for the possibility of mitigation without a binding transmission constraint when there is a local reliability issue, or to put the mitigation associated with such local reliability constraints into a separate section of

Attachment AF. It also required SPP to define "local reliability issue" in the Tariff as it relates to mitigation.[291]

243. The Commission raised several additional concerns about the language in section 3.2.2. It noted that it was unclear under what conditions mitigation would occur for resources not committed by SPP to deal with local reliability issues. The Commission also found that section 3.2.2 appears to set differing mitigation standards for operating reserve offers as compared to energy, start-up, and no-load offers. Accordingly, the Commission required SPP to modify section 3.2.2 to establish that mitigation will occur for non-Frequently Constrained Areas, in the absence of a local reliability issue, only when there is a binding constraint or a binding Reserve Zone, *and* the additional conditions relating to the Resource-to-Load Distribution Factors apply.[292] It also required SPP to establish clearly that mitigation of operating reserves Offers will occur under the same general conditions discussed in section 3.2.2 of Attachment AF for other resources,[293] and to provide in the last paragraph of proposed section 3.2.2 that settlement is based on "LMP or market clearing price as applicable."[294]

244. The October Order required SPP to remove references to the terms "Caps," "Offer Caps" and "Offer Capped Resources" in Attachment AF (and as needed elsewhere in its Tariff), as these terms did not accurately portray the mitigation that SPP was proposing. The order directed SPP to use language consistently used in other RTOs and to use the terms "conduct threshold(s)" and "reference levels" or "default (with specification of type of service) offer(s)." In addition, because the conduct thresholds were unit-specific (as opposed to market-wide as they were in SPP's February filing), the Commission required SPP to remove the language from section 3.2.2 that provided for the electronic posting of "Energy Offer Caps," as such posting could reveal confidential information.[295]

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[291] October Order, 141 FERC ¶ 61,048 at P 405.

[292] *Id.* P 406.

[293] We make a similar requirement below for time-based offer parameters and offer parameters that are neither time nor dollar based.

[294] October Order, 141 FERC ¶ 61,048 at P 407.

[295] *Id.* P 408.

245. The Commission found that SPP had not defined Resource-to-Load Distribution Factor in the Tariff, nor had it explained why five percent is the appropriate Resource-to-Load Distribution Factor cut-off for mitigation in its markets. Without such an explanation, the Commission could not determine if the appropriate resources' offers were being considered for mitigation. Thus, the Commission required SPP to explain its choice of cut-off value.[296] The Commission further directed SPP to address how often the Resource-to-Load-Distribution Factors used to determine the applicability of mitigation would be re-computed.[297]

246. In the October Order, the Commission found a discrepancy in previous section 3.3 of the Attachment AF, as that provision related to time-based offer parameters and resource offer parameters expressed in units other than time or dollars. The Commission noted that the proposed section simply stated that the mitigation measures in this section would apply to such resources only in the presence of local market power as described in section 3.1.1 of Attachment AF. Section 3.1.1, however, did not exist. As a result, time-based offer parameters and resource offer parameters could have been subject to mitigation for economic withholding (perhaps because of the missing section), even if they did not involve the exercise of market power. The Commission directed SPP to explain the reason for such differences in mitigation or to revise its Tariff so that mitigation for these parameters is treated in a manner consistent with other offer parameters, including its Resource-to-Load Distribution factor requirement. The Commission further required SPP to remove references to non-existent section 3.1.1 of Attachment AF.[298]

247. Finally, the Commission required SPP to modify the title of section 3 of Attachment AF, to read "Mitigation Measures for Economic Withholding—Market Power in Energy and [o]perating [r]eserves."[299]

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[296] *Id.* P 409.

[297] *Id.*

[298] *Id.* P 410.

[299] *Id.* P 416.

February 2013 Compliance Filing

248. SPP proposes to delete sections 3.1 and 3.2 of Attachment AF in their entirety and has replaced them with four new sections. Section 3.1 sets forth a "local market power Test," while the other sections (3.2 through 3.4) address the mitigation of energy offer curves, start-up and no-load offers, and operating reserve offers.

249. In section 3.1, SPP proposes that a resource satisfying at least one of the following conditions will be found to have local market power (a necessary condition for mitigation under sections 3.2, 3.3, and 3.4): (1) the resource is located in a Frequently Constrained Area, as defined in section 3.1.1, and one or more of the transmission constraints that define the Frequently Constrained Areas is binding; (2) the resource has a Resource-to-Load-Distribution factor less than or equal to negative five percent relative to the binding transmission constraint; (3) the resource is located in a binding Reserve Zone; or (4) the resource is manually committed by the transmission provider or selected for commitment by a local transmission operator as described in Attachment AE, sections 5.2.2.(3), 6.1.2(3), and 6.1.2(4).[300]

250. In section 3.2A and 3.2B, SPP proposes energy offer curve conduct thresholds, which establish the conditions under which mitigation can occur. In particular, section 3.2A provides a separate conduct test thresholds for energy of increases above the mitigated offer level of: (1) ten percent for resources with local market power associated with a manual commitment by the transmission provider or selected for commitment by the local transmission operator;[301] (2) 17.5 percent for resources located in a Frequently Constrained Areas and not subject to mitigation as a resource with local market power associated with a commitment by the local transmission provider; or (3) 25 percent for all other resources.

251. In section 3.2B, SPP proposes to apply mitigation measures by replacing the energy offer curve with the mitigated energy offer curve if: (1) the resource's energy

[300] In SPP Tariff Attachment AE, section 5.2.2(3) addresses manual commitments in the reliability unit commitment, 6.1.2(3) addresses manual commitments to address local reliability commitments in the intra-day reliability unit commitment execution, and section 6.2.4 addresses out-of-merit energy dispatch. Other portions of section 3.1 address designation of Frequently Constrained Areas as discussed below.

[301] As established in SPP Tariff Attachment AF, section 3.1(4).

offer curve exceeds the mitigated energy offer curve by the applicable conduct threshold; (2) the resource has local market power as determined in section 3.1; and (3) the resource either fails the market impact test (as described in section 3.7) or has local market power due to a manual commitment by SPP or a local transmission operator as described in section 3.1(4). SPP retains its earlier proposal that an energy offer below $25 will not be subject to mitigation. Section 3.3 of Attachment AF contains similar conditions for the mitigation of start-up and no-load offers.

252. In section 3.4, SPP proposes that the transmission provider will mitigate operating reserve offers by replacing the operating reserve offer with the applicable mitigated operating reserve offer if: (1) the resource's operating reserve offer exceeds the applicable mitigated operating reserve offer by the conduct threshold; (2) the resource has local market power as determined in section 3.1; and (3) the resource either fails the market impact test or has local market power as described in 3.1(4).[302]

253. SPP files testimony from Dr. Hyatt to support its proposal. Dr. Hyatt states that SPP deleted the language providing for an offer cap for resources of a market participant on the same side of a constraint as other resources of that market participant that are subject to the offer cap based upon having sufficiently large Resource-to-Load Distribution Factors. He states that SPP will incorporate a pivotal supplier test as a part of the study identifying Frequently Constrained Areas, and that this test will identify this same set of resources that will be subject to mitigation. Dr. Hyatt further states that SPP removed all other references to offer caps in the proposed Tariff language.[303] SPP uses the term "mitigated offer" in its Tariff to designate default offers. In his testimony, Dr. Hyatt uses the term "reference level" to mean only those default offers that are determined (in other RTOs and ISOs) from LMPs or previously accepted offers.[304] He also states that SPP removed the language on electronic posting requirements, as required by the October Order.

[302] SPP also added conduct and impact thresholds for operating reserve offers, as discussed in the section on Conduct and Impact Thresholds for Economic Withholding.

[303] February 2013 Compliance Filing, Exh. No. SPP-11 at 7.

[304] This use is not consistent with the language used in other RTOs and ISOs in which reference levels can refer to default offers developed using resource-specific costs. Accordingly, when we use the term "reference level" in this order, we use the term in its broad sense, not the narrow one used by SPP.

254. As for the negative five percent cut-off value for the Resource-to-Load Distribution factor, Dr. Hyatt testifies that SPP chose that value because it is consistent with the cut-off value used by the NERC to manage interregional congestion. He states that in accordance with those procedures, SPP's reliability coordinator, when determining which energy schedules to curtail to manage a congested flowgate, uses NERC's Interchange Distribution Calculator, a calculation which considers all generators with a Generator-to-Load distribution factor greater than five percent. Dr. Hyatt notes that the purpose of using a five percent cut-off value in the SPP Reliability Coordinator's curtailment procedures is to identify resources that have a significant impact on a transmission constraint. Dr. Hyatt maintains that by curtailing these resources, the SPP Reliability Coordinator obtains the required megawatt relief while minimizing the megawatts that are subject to the financial impacts of curtailment. He asserts that the cut-off essentially serves the same purpose in the application of mitigation—that is, to identify resources that have a significant impact upon a transmission constraint, and that the cutoff is then used in conjunction with the conduct and impact tests to determine if mitigation is warranted.[305]

255. Dr. Hyatt explains that the Resource-to-Load Distribution Factors will be determined by the market clearing engine at the time the solution is computed, and thus will be based on current system conditions. He notes that a representative set of Resource-to-Load Distribution factors will be posted on SPP's website at least annually.[306] SPP proposes to use the same definition for "Local Reliability Issue" that it is proposing with respect to make whole payments.[307] That definition provides that a Local Reliability Issue is a reliability condition within the SPP Balancing Authority Area that does not affect Transmission System reliability.

256. As for the issue related to resource offer parameters expressed in units other than dollars, SPP proposes in section 3.6 of Attachment AF (previously section 3.3) to tie mitigation for such offers to the local market power test, as set forth in the new section 3.1 of Attachment AF. That change, according to SPP, ensures that the mitigation of these resources is the same as other resources. In addition, SPP adds a conduct

[305] February 2013 Compliance Filing, Exh. No. SPP-11 at 7-8.

[306] *Id.* at 9.

[307] February 2013 Filing at 35.

threshold for minimum economic capacity operating limit in situations where there is a manual commitment of resources.

257. Finally, SPP also modifies the title of Attachment AF section 3 as required by the October Order.

Commission Determination

258. We accept SPP's proposed sections 3.1 through 3.4 and find them to be in compliance with the October Order, subject to the revisions discussed below. These revised sections help to ensure that various resources will be treated in a consistent manner and will be subject to the same local market power test. SPP's proposed definition of local market power ensures that the local market power test is applied in the same manner to time-based and other non-price parameters as it is to other offer parameters. Accordingly, we find SPP to be in compliance with the requirement to treat mitigation for economic withholding of time-based and other non-dollar based parameters as it does other offer parameters with respect to the conditions for mitigation.

259. However, we find that section 3.1 (i.e., the local market power test) must be modified to ensure clarity and comply with the October Order. In the October Order, the Commission required SPP to ensure that "mitigation will occur, in the absence of a local reliability issue, only when there is a binding constraint or a binding Reserve Zone, *and* the additional conditions relating to the Resource-to-Load Distribution Factors apply."[308] In section 3.1(1), SPP fails to include binding Reserve Zones as part of its examination of local market power in Frequently Constrained Areas.[309] Accordingly, we require SPP to

[308] October Order, 141 FERC ¶ 61,048 at P 406 (emphasis in original). The Commission, however, left open the possibility that the Resource-to-Load Distribution Factor cut-off need not be applied to Frequently Constrained Areas. *Id*. at 411.

[309] Section 3.1(1) establishes that there is market power when the resource is located within a Frequently Constrained Area and one or more transmission constraints that defines the Frequently Constrained Area is binding. Section 3.1(3) provides that the resource is located in a binding Reserve Zone. From this formulation, it appears that the determination of local market power necessary for mitigation of a Frequently Constrained Area would not include the existence of a binding Reserve Zone, despite the definition of a Frequently Constrained Area in section 3.1.1 as an electrical area defined by one or more binding transmission constraints or binding Reserve Zone constraints (that meets additional criteria).

submit a compliance filing due 60 days after the issuance of this order modifying section 3.1 of Attachment AF so that local market power is found when at least one of the following conditions are met: (1) the resource is located in a Frequently Constrained Area, as defined in Section 3.1.1, and one or more of the transmission constraints that define the Frequently Constrained Areas is binding or the Reserve Zone that defines the area is binding; (2) the resource is not in a Frequently Constrained Area and (a) has a Resource-to-Load-Distribution factor less than or equal to negative five percent relative to a binding transmission constraint, or (b) is in a binding Reserve Zone; (3) the resource is manually committed by the Resource Provider or selected for commitment by a local transmission operator in the Day-Ahead or Intra-day RUC processes.

260. As for the other compliance requirements, we find that SPP's overall revisions to section 3 clarify the issue related to the non-existent section 3.1.1 in the previous version of Attachment AF. The revisions also provide for mitigation of offers associated with local reliability commitments that are not tied to the existence of a binding transmission constraint. SPP also complies with the Commission's directives in the October Order by ensuring that there is mitigation for operating reserve offers. SPP further complies with the requirement to modify the title of section 3 to reflect that mitigation applies to operating reserves.

261. SPP generally complies with the requirement to remove all references to offer caps within section 3, as well as the requirement to not electronically post energy offer caps. We note, however, that the term "caps" still appears in section 3.7 of Attachment AF in the following phrase: "After an initial market solution is computed with no mitigation measures caps in place...." We require SPP to remove the word "caps" from this phrase as part of its compliance filing due 60 days after the issuance of this order.

262. Finally, we find SPP to be in compliance with the requirement to: (1) define the Resource-to-Load Distribution Factor; (2) explain the use of a negative five percent cutoff value (with respect to non-Frequently Constrained Areas); and (3) address how often the Resource-to-Load-Distribution Factors will be re-computed. We also accept SPP's explanation of its use of the negative five percent cut-off value, as well as its explanation of how often the Resource-to-Load Distribution Factors will be re-evaluated. However, we will require SPP to modify the definition of a Local Reliability Issue as required in paragraphs 131-132 of this order in its compliance filing due 60 days after the issuance of this order.

Frequently Constrained Area Mitigation of Economic Withholding

October Order

263. In the October Order, the Commission directed SPP to address the need for more stringent mitigation for electrical areas defined by one or more transmission constraints that were expected to be binding for a significant number of hours in the year, within which one or more suppliers were pivotal. The Commission noted that different conduct and impact thresholds, with tighter thresholds for Frequently Constrained Areas could also be necessary. The Commission further required SPP to apply more stringent mitigation in frequently constrained regions on the SPP system with a pivotal supplier where a constraint was binding, in a manner similar to MISO's Narrow Constrained Area type mitigation. Finally, the Commission required SPP to justify the number of hours of expected binding constraint and any Resource-to-Load Distribution factor it chose for a designation of an area as a Frequently Constrained Area.[310]

264. The Commission stated that once it approves initial Frequently Constrained Areas (Narrow Constrained Area-type areas) on SPP's system, SPP could subsequently remove the Frequently Constrained Area designation if the Market Monitor determined that the binding transmission constraint or binding Reserve Zone constraints that define the zone were expected to be binding less than the requisite number of hours in the calendar year. The Commission directed SPP to provide in its Tariff that it would seek Commission approval before designation of any additional Frequently Constrained Areas for the purpose of mitigation, and for any change or removal of such designations for reasons other than an expectation that there would be insufficient hours of constraint for them to be so designated.[311]

February 2013 Compliance Filing

265. SPP proposes new mitigation provisions for Frequently Constrained Areas. In section 3.1.1 of Attachment AF, SPP defines a Frequently Constrained Area as an electrical area identified by the Market Monitor that is defined by one or more binding

[310] *Id.* PP 411-412. The Commission found that it might be appropriate to reduce or eliminate the Resource-to-Load Distribution Factor cut-off to ensure that appropriate mitigation can occur for the resources in these areas.

[311] *Id.* P 412.

constraints or binding Reserve Zone constraints that are expected to be binding for a least 500 hours during a given 12 month period and within which one or more suppliers is pivotal. Section 3.1.1 of Attachment AF provides that all Frequently Constrained Areas shall be listed in Addendum 1 of Attachment AF, and that any new or modifications to existing Frequently Constrained Areas must be filed with the Commission. Section 3.1.1.2 of Attachment AF provides that the Market Monitor will define and recommend the Frequently Constrained Areas to the SPP Board of Directors prior to the start of the Integrated Marketplace.

266. Dr. Hyatt testifies that 500 hours of constraint is appropriate in specifying a Frequently Constrained Area. He asserts that the principal concern with Frequently Constrained Areas is that congestion is predictable and market participants will be able to use that predictability to raise prices above short-run marginal cost. He states that given that substantial excessive profits can be extracted from the market in just a few hours, the Market Monitor finds that a reasonable range for the threshold for a Frequently Constrained Area falls within the bounds of one or two hours per day. He notes that the annual 500-hour threshold falls within this range and that MISO uses a 500-hour threshold to identify its Narrow Constrained Areas.[312]

267. In section 3.1.1.3, SPP proposes that the Market Monitor shall reevaluate Frequently Constrained Areas at least annually or more frequently if the Market Monitor deems necessary to determine if the designation is still appropriate. Under this proposal, the transmission provider may propose that an area be designated or undesignated as a Frequently Constrained Area if the transmission provider believes that the conditions have changed with respect to the binding transmission constraint or binding Reserve Zone constraints that define the Frequently Constrained Area. As proposed, section 3.1.1.3 states that the Market Monitor shall evaluate any proposed change and seek comments from the market participants before it recommends designation, modification, or removal of an area as a Frequently Constrained Area. Section 3.1.1.3 proposes that, subject to any applicable confidentiality requirements, the Market Monitor will provide any interested market participants with a description of its supporting analysis to allow comment on the proposed designation changes. Finally, section 3.1.1.3 states that the Market Monitor will recommend any changes to the Frequently Constrained Areas to the SPP Board of Directors for approval.

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[312] February 2013 Compliance Filing, Exh. No. SPP-11 at 12-13.

268. Dr. Hyatt testifies that the pivotal supplier analysis will identify market participants that are pivotal to a Frequently Constrained Area, as well as a list of resources that are located in the Frequently Constrained Area. He states that the list of resources will remain static until a subsequent evaluation of the Frequently Constrained Area is performed.[313] In section 3.1.1.1 of Attachment AF, SPP defines a supplier to be "pivotal when the energy output or provision of operating reserves by any of its [r]esources must be increased or decreased to resolve the binding transmission constraint or binding Reserve Zone constraint during some or all hours." SPP proposes that such determination will be made using transmission load flow cases or Real Time Balancing Market cases reflecting a variety of market conditions. Section 3.1.1.1 further proposes that "the load flow or market cases will be used to estimate: (i) the generation shift factors for all relevant resources outside the SPP Balancing Authority Area relative to each potentially constrained flowgate; (ii) the capability of all resources to meet the requirements of each binding Reserve Zone constraint; (iii) the base loadings of resources; (iv) the base allocation of operating reserves on resources; and (v) the base flows on each flowgate."

269. Dr. Hyatt testifies that SPP deleted the portion of section 3.2 of Attachment AF which provided for mitigation (an offer cap under the May 2012 proposal) for resources of a market participant on the same side of a constraint as other resources of that market participant that were subject to the offer cap based on the Resource-to-Load Distribution Factors. Dr. Hyatt states that SPP will now incorporate a pivotal supplier test as a part of the study identifying Frequently Constrained Areas, and argues that this should identify the same set of resources which the deleted provision was designed to identify.[314]

270. In section 3.2(A)(1) of Attachment AF, SPP proposes a conduct threshold of 17.5 percent increase over mitigated offer levels for energy offers of resources located in a Frequently Constrained Areas that are not manually committed by the transmission provider or selected for commitment by a local transmission operator.[315] SPP proposes

[313] *Id.* at 13.

[314] *Id.* at 7.

[315] Resources that are manually committed by the transmission provider or selected for commitment by a local transmission operator as described in Attachment AE, sections 5.2.2(3), 6.1.2(3), and 6.1.2.(4), are subject to a tighter conduct threshold of a ten percent increase above the mitigated energy offer curve.

the same conduct thresholds for start-up, no-load, operating reserve, and non-price offers in Frequently Constrained Areas and non-Frequently Constrained Areas.[316]

Commission Determination

271. As discussed below, we conditionally accept SPP's definitions of Frequently Constrained Areas and pivotal supplier, the manner for identification and modification of Frequently Constrained Areas, and the proposed conduct and impact tests, subject to the compliance requirements below.[317]

272. With regard to SPP's use of a 500-hour threshold in section 3.1.1, we find that SPP and the Market Monitor have provided sufficient justification to use this threshold. It is the same threshold used by MISO for its Narrow Constrained Areas and is consistent with our direction in the October Order.[318] However, we require SPP to modify the last sentence in section 3.1.1 to clarify that any designation or change in designation for Frequently Constrained Areas is subject to *prior* approval by the Commission.[319] As part of its compliance filing, SPP must modify that last sentence of section 3.1.1 so that it

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[316] This order discusses the justifications for these thresholds in the Conduct and Impact Thresholds for Economic Withholding section of the order.

[317] We note that this accepted Tariff language includes no Resource-to-Load Distribution Factor cutoff requirement for mitigation in Frequently Constrained Areas. Dr. Hyatt's testimony states that the cutoff has been retained in the proposal for Frequently Constrained Areas. The approach in the Tariff is consistent with the approach used in MISO's Narrow Constrained Areas, and addresses the circumstance that resources in a Frequently Constrained Area that cannot affect the constraint, may still be able to exercise market power by engaging in economic withholding in that area because they are aware that the constraint is frequently binding. According, we are not requiring any Resource-to-Load Distribution Factor cutoff requirement for mitigation in Frequently Constrained Areas.

[318] October Order, 141 FERC ¶ 61,048 at P 411.

[319] *Id*. P 412 ("We direct SPP to provide in its Tariff that it will seek Commission approval *before* designation of any additional frequently constrained areas for the purpose of mitigation, and for any change or removal of such designation. . ..") (emphasis added).

reads: "Any new or modifications to existing Frequently Constrained Areas are subject to prior Commission approval."

273. We accept SPP's proposed definition of pivotal supplier subject to a compliance filing. In section 3.1.1.1, SPP proposes that "[a] supplier is pivotal when the energy output or provision of operating reserves by any of its resources must be increased or decreased to resolve the binding transmission constraint." This definition, however, ignores that market participants may attempt to exercise market power by using several or all of the resources under its control in a concerted action. To clarify that a pivotal supplier may arise under that situation, SPP must modify section 3.1.1.1 in its compliance filing due 60 days after the issuance of this order to provide that a supplier is pivotal in relation to the energy output or provision of operating reserves by "any or some of its resources jointly" rather than by "any of its resources." Further, we will require SPP to address whether and how a demand response resource can be determined to be a pivotal supplier under section 3.1.1.1 given that it is unclear how each of the conditions therein applies to demand response resources. We will require SPP to address the applicability of each of the provisions under 3.1.1.1 to demand response resources as potential pivotal suppliers.

274. As for SPP's proposed conduct and impact tests, we accept those tests subject to a minor modification in section 3.2(A)(2). That section mistakenly refers to section 3.2(1) which does not exist. In a compliance filing due 60 days from the date of this order, SPP must revise that section so that it refers to section 3.2(A)(1).

275. We also accept SPP's proposed language in section 3.1.1.3 as it relates to any changes to Frequently Constrained Area Designations. However, we note that, while SPP proposes that its Board approve any change to such designation, such approval does not alleviate the Market Monitor's independent obligation to notify the Commission of any market design flaws interfering with appropriate price signals or when it believes a Frequently Constrained Area should be designated or un-designated.[320]

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[320] As established in Order No. 719, the Market Monitoring Unit functions include evaluating existing and proposed market rules, tariff provisions, and market design elements, and recommending proposed rule and tariff changes not only to the RTO or ISO, but also to the Commission's Office of Energy Market Regulation Staff, and to other interested entities such as state commissions and market participants, with the caveat that the Market Monitor should limit distribution of its identifications and recommendations to the RTO or ISO and to the Commission staff in the event it believes

(continued…)

276. Finally, we note that SPP's revised Attachment AF does not include a provision previously found in its proposal in section 3.2.2, which provided for mitigation of other resources represented by the market participant that were on the importing (i.e. load) side of the constraint within the SPP system.[321] In Dr. Hyatt's testimony, he states that this requirement was being replaced by a pivotal supplier "test"[322] as a part of the study identifying Frequently Constrained Areas. However, it is unclear how SPP's requirement that there be a pivotal supplier for an electrical area to qualify as a Frequently Constrained Area identifies the same affiliated resources for mitigation as the deleted provision in section 3.2.2. In particular, the application of the previous section 3.2.2 was not limited to Frequently Constrained Areas, and accordingly would have applied to all areas where there is mitigation including when there is mitigation within non-Frequently Constrained Areas and areas with local reliability issues. Further, a group of affiliated suppliers may exist within a Frequently Constrained Area and be subject to the more stringent mitigation associated with those areas without them qualifying as a pivotal supplier either individually or jointly. We will require SPP, in its compliance filing due 60 days after the issuance of this order, to provide examples that show how mitigation of affiliated resources would occur given the pivotal supplier designation and given the language in section 3.2.2 that SPP proposes to remove. These examples should show how the mitigation would occur with and without the provision for mitigation of other resources represented by the market participant that were on the importing (i.e. load) side of the constraint within the SPP system. SPP must include examples which show mitigation of an affiliated resource in Frequently Constrained

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broader dissemination could lead to exploitation. The Commission also established in that order that the Market Monitor should advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule or tariff changes. Further Order No. 719 found that where market design flaws interfere with appropriate price signals, these flaws should be brought to the attention of concerned entities. Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 354, PP 357-358.

[321] Mitigation of an affiliate's offer may be necessary because the affiliated resource on the load side of the constraint can benefit from the higher prices associated with its affiliate's actions or can in some manner make the constraint worse, thereby increasing the impact.

[322] SPP's pivotal supplier "test" in section 3.1.1.1 is simply the definition of a pivotal supplier that is to be used within section 3.1.1 to determine Frequently Constrained Areas within which more stringent conduct and impact tests are applied.

Areas, non-Frequently Constrained Areas and in areas with commitments for reliability reasons, and show instances when the affiliated resources have and have not failed the conduct and impact tests.

Mitigated Offer Development

October Order

277. In the October Order, the Commission found that SPP's mitigated offers development proposal lacked sufficient information on the development of mitigated offers. Accordingly, the Commission required SPP to include the details for development of mitigated offers for energy, each type of operating reserve, start-up and no-load in its Tariff, along with clear definitions and explanations for the formula terms. While SPP stated that offers would be mitigated to incremental costs, the Commission found that SPP must be more specific and establish that offers were to be mitigated to the short-run marginal costs of the generating unit. Further, the Commission directed SPP to define the costs to be measured in the short-run marginal costs. The Commission also found that in order for SPP to include opportunity cost in mitigated offers, the method for determining opportunity cost need to be specified in the Tariff.[323]

February 2013 Compliance Filing

278. SPP proposes language in section 3.2(C) of Attachment AF that provides that the mitigated Energy Offer Curve shall be the resource's short-run marginal cost of producing energy as determined by the unit's heat rate, its fuel costs and the costs related to fuel usage, such as transportation and emissions costs ("total fuel related costs"), and its variable operations and maintenance (VOM) costs, as detailed in the Market Protocols. Section 3.2(C) provides that opportunity cost may be reflected in the total fuel related costs and/or the VOM when there are: (1) externally imposed environmental run-hour restrictions; (2) physical equipment limitations on the number of starts or run-hours; or (3) fuel supply limitations. This section defines opportunity cost for energy to be an estimate of the energy and operating reserves revenues net of short run marginal costs for the marginal forgone run-time during the period of limitation as detailed in the Market Protocols. It provides that the market participant shall submit heat rates and the methods for determining fuel costs, fuel related costs including emissions costs, opportunity costs,

[323] October Order, 141 FERC ¶ 61,048 at P 420.

and VOM to the Market Monitor, and that the information will be sufficient for replication of the mitigated energy offer curve.

279. SPP addresses mitigation measures for start-up offer and no-load offers in section 3.3 of Attachment AF. Section 3.3(C) addresses mitigated offer development for start-up offers. In that section, SPP proposes that the mitigated start-up offer shall represent the cost per start as determined to be the sum of: (1) start fuel usage and the costs related to that fuel usage; (2) cost of electricity for station to start; (3) maintenance costs attributed to starts; and (4) additional labor costs, if required above normal station staffing levels. It also addresses the mitigated start-up offer for demand response resources as discussed below.

280. In section 3.3(D), SPP addresses mitigated no-load offers. It proposes that the mitigated no-load offer shall be the hourly fixed cost required to create a monotonically increasing mitigated energy offer curve.[324] The section establishes that the mitigated no-load offer shall be calculated according to either of the No-Load Fuel Approach or the No-Load Cost Approach. Under the No-Load Fuel Approach, the mitigated offer is equal to the no-load fuel multiplied by the total fuel related cost. Under the No-Load Cost Approach, the mitigated no-load offer is equal to the Heat Input at Min(imum) Econ(omic) Capacity multiplied by the Total Fuel Related Cost plus the VOM minus the product of the incremental cost up to minimum economic capacity times the minimum economic capacity.[325]

281. In section 3.4, SPP proposes various mitigation provisions related to operating reserve offers. Section 3.4(C) provides that the mitigated spinning reserve offer shall not exceed the sum of any increased fuel related costs necessary for the resource to be prepared for deployment of spinning reserves and any cost increase from heat rate degradation due to operating at a lower output level. It also provides that the mitigated supplemental reserve offer shall not exceed any fuel related costs and labor costs necessary for the resource to be prepared for deployment of supplemental reserve, and any cost increase from heat rate degradations due to operating at a lower output level.

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[324] A monotonically increasing energy offer curve would provide for increased offer prices as quantities increase.

[325] Min(imum) Econ(omic) Capacity, while used in this section, does not appear to be a defined tariff term. It appears that SPP means to refer to Minimum Economic Capacity Operating Limit which is defined in the Tariff.

Section 3.4(D) provides that the mitigated regulation-up offer shall not exceed the sum of the cost increase due to: (1) unit specific heat degradation due to operating at a lower output level; (2) the heat rate increase during non-steady state operation; (3) uncompensated increase in costs attributable to moving between a lower economic and a higher regulating minimum operating limit and operating at the higher regulating minimum operating limit; (4) increase in VOM due to non-steady-state operation; and (5) uncompensated costs attributable to moving from a higher economic to a lower economic regulating maximum operating limit and operating at the lower regulating maximum operating limit.

282. SPP proposes to include further details associated with the development of the exact costs in the formulas for mitigated offers in its Market Protocols. Those costs may include fuel costs, fuel related costs including emissions costs, opportunity costs and the VOM.[326]

Comments

283. TDU Intervenors are not opposed to the inclusion of opportunity costs in mitigated offers per se. However, they argue that SPP's proposed Tariff fails to explain and limit with proper specificity the resources for which opportunity costs may be included in developing mitigated offers. TDU Intervenors maintain that getting the mitigated offers, including permissible opportunity costs, right is essential to the effectiveness of SPP's market power mitigation proposal, which is critical to ensuring just and reasonable rates.[327]

284. As an example, TDU Intervenors point to the Commission's recent rejection of PJM Interconnection L.L.C's (PJM) proposed recovery for opportunity costs associated with an "Out of Management Control fuel supply limitation."[328] They note that the Commission limited opportunity costs for physical equipment limitations to circumstances "that can be documented by an original equipment manufacturer recommendation or bulletin, or a documented restriction imposed on the generating unit

[326] SPP Tariff, Attachment AF, sections 3.2C(3), 3.3E, and 3.4E.

[327] TDU Intervenors at 27.

[328] *Id.* at 30-31 (citing *PJM Interconnection, L.L.C*, 134 FERC ¶ 61,192, at P 32 (2011)).

by the insurance carrier."[329] TDU Intervenors assert that the same restrictions should apply with respect to SPP's proposed methodology for determining opportunity cost recovery in mitigated offers.

285. TDU Intervenors also seek clarification regarding the application of section 3.2(C), which states that for energy offers, "Opportunity cost shall be an estimate of the Energy and [o]perating [r]eserve Markets revenues net of short run marginal costs for the marginal foregone [*sic*] run time during the period of limitation as detailed in the Market Protocols." They argue that this section could be read to provide for the recovery of opportunity costs that reflect the market power premiums that mitigation is designed to protect against—i.e., revenues forgone during the period of mitigation. TDU Intervenors argue that to the extent the provision authorizes recovery of the market revenues that could be garnered during the period where the market participant could exercise market power, the opportunity cost could result in rates that are unjust and unreasonable. TDU Intervenors request that the section be modified to read: "During the period of limitation, opportunity cost shall be an estimate of the Energy and operating reserve Market revenues net of short run marginal costs for the marginal forgone run time. . .." They state that this modification is necessary for it to be clear that opportunity costs reflect revenues that the resource could have appropriately recovered if it were to run during a period other than the mitigation period.[330]

286. TDU Intervenors further claim that there is "a fundamental defect" in SPP's methodology for determining opportunity costs.[331] They maintain that nothing in the proposed language prevents a market participant from seeking to recover marginal forgone revenues that reflect non-competitive market conditions. They believe the proposed language is broad enough to allow a market participant to seek recovery of excessive market revenues in the form of opportunity costs for a time period when there are transmission constraints and the market participant possesses market power, or to seek recovery of revenues that are associated only with peak clock hour(s) of the year

[329] *Id.*

[330] *Id.* at 28.

[331] *Id*.

notwithstanding that the resource may be able to operate for many additional hours in the year. They emphasize that opportunity costs must be "legitimate and verifiable."[332]

287. TDU Intervenors note that while SPP's mitigation approach departs from MISO's use of reference levels based on LMPs and offers, the restrictions used by MISO in the development of reference levels are instructive on the boundaries that SPP needs to use. TDU Intervenors argue that MISO's mitigation methodology expressly restricts resource recovery to competitive market conditions, or in the absence of adequate data, lowest-priced time periods.[333] TDU Invervenors state that the Tariff must be revised to ensure that opportunity costs fairly reflect the inter-temporal revenues associated with the unit's actual operational restrictions.[334]

Answer

288. In its answer, SPP offers to add an additional point of consideration in the calculation of a resource's opportunity costs. Citing to the PJM case cited by TDU Intervenors, SPP states that it will, upon concurrence by the Commission, revise the Tariff to include a *force majeure* requirement for the calculation of opportunity costs.[335]

289. SPP also challenges that TDU Intervenors' claim that the definition of opportunity costs is unclear. SPP maintains that section 3.2(C) sets forth a clear standard for what

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[332] *Id.* at 28 & n.28 (citing to *Mont. Consumer Counsel v. FERC*, 659 F.3d 910, 918-19 (9th Cir. 2011)).

[333] TDU Intervenors point to the MISO Tariff stating that, for example, a generator's "reference levels" used for mitigation are to be determined first as the lower of the mean or median of a unit's accepted offers in competitive periods during the previous 90 days during similar hours or load levels, adjusted for changes in fuel prices. If that data is not sufficient, the mitigated offer price in MISO will be based on the mean of the price at the unit's location during the lowest 25 percent of hours that the unit was dispatched (or scheduled for operating reserves) during the previous 90 days, adjusted for changes in fuel prices).

[334] TDU Intervenors at 29-30.

[335] SPP Answer at 26-27 (citing *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,192).

constitutes an opportunity cost for mitigated offers. SPP further notes that additional details related to the development and validation of these costs will be included in the Market Protocols.[336]

290. SPP believes TDU Intervenors' protest is based, in part, on what it says is an incorrect understanding of revised section 3.2(C) of Attachment AF. It states that TDU Intervenors mistakenly assume the "period of limitation" referenced in the new definition refers to the mitigation time period. SPP maintains that the phrase "period of limitation" actually refers to the timeframe when resources are subject to run-time restrictions, not to mitigation. It argues that, thus, the revised definition of "opportunity cost" provided in the February 2013 Compliance Filing therefore captures revenues that could have been received during periods when run-time restrictions are in effect and is not associated with the period of mitigation.[337]

291. SPP also challenges the assertion that defined opportunity costs could reflect non-competitive market conditions and/or market power premiums. On the contrary, SPP notes that with its mitigation measures, prices used in determination of opportunity costs should always be at or near competitive levels. SPP also emphasizes the challenge of tying opportunity costs directly to competitive market prices since opportunity costs are based on forward-looking prices. SPP further asserts that market participants (i.e., the ones who will calculate mitigated offers) do not have access to the data required to determine during which periods the market is competitive.[338]

292. Finally, SPP agrees with TDU Intervenors that opportunity costs should reflect the "inter-temporal revenues" from a resource's actual operational restrictions. SPP states that this qualification is currently being developed and included as part of the Market Protocols.[339]

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[336] *Id.* at 24.

[337] *Id.* at 24-25.

[338] *Id.* at 25-26.

[339] *Id.* at 26.

Reply

293. TDU Intervenors claim that SPP has failed to adequately address their concerns and is making circular arguments by saying that its mitigation measures will ensure that prices will remain at competitive levels.[340]

294. TDU Intervenors also request that the Commission reject SPP's proposal to include a force majeure event in its opportunity costs calculation. They assert that, given that force majeure events are by definition not predictable, it makes no sense for SPP to include such events in that calculation. They also note, contrary to SPP's reliance on the PJM case, that the Commission found PJM's proposal to be "unclear and unsupported."[341] Finally, TDU Intervenors point out that the Commission stated that a force majeure disruption of a gas supply "would not necessarily lead to a future limitation on run hours."[342]

Commission Determination

295. We appreciate SPP's efforts to provide more details related to the development of mitigated offers under the Tariff. However, we still find that certain aspects of the mitigated offer proposals, especially surrounding the calculation for opportunity costs, are not fully supported and/or lack sufficient details to be accepted. Accordingly, we will conditionally accept them and require an additional compliance filing as discussed below.

296. In particular, SPP has not sufficiently specified the physical equipment limitations on starts and stops, nor the fuel supply limitations associated with the determination of opportunity costs. As previously emphasized by the Commission, opportunity costs must be included in mitigated offers and such costs must be "legitimate and verifiable."[343]

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[340] TDU Intervenors' Reply at 7.

[341] *Id.* at 8-9 (citing *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,192 at P 32 & n.25).

[342] *Id*.

[343] *PJM Interconnection, L.L.C.*, 127 FERC ¶ 61,188, at P 7 (2009). *See also Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,285, at P 229 (2004) ("'legitimate risks and opportunity costs' include inter-temporal opportunity costs caused by run-time restrictions, operational risks such as the risks of unit failure (including costs

(continued…)

SPP's proposal fails to meet that standard and, thus, we require SPP clearly specify these limitations in its compliance filing due 60 days after the issuance of this order.

297. With respect to the physical equipment limitations on starts and stops, we agree with TDU Intervenors that SPP has not specified how it will verify the limitations submitted by a market participant. In PJM, for example, the Commission previously addressed concerns raised by PJM's Market Monitor about the use of a market participant's self-generated engineering analysis to verify physical equipment limitations, which could be subject to bias.[344] Accordingly, the Commission accepted PJM's proposal to rely solely on the analysis prepared by original equipment manufacturers and insurance carriers.[345]

298. Here, SPP's proposal does not explain how the Market Monitor will verify equipment limitations, but rather leaves it up to the market participant in section 3.3(E) to submit documentation "adequate to permit the Market Monitor to verify submitted offers." This standard does not sufficiently address how equipment limitations will be verified consistent with the concerns that the Commission addressed in the PJM case. Nor does section 3.3(E) state that it requires NERC-verifiable data, and/or other data that can be independently verified and that is subject to penalty. We will require SPP, in its compliance filing due 60 days after the issuance of this order, to explain how the Market Monitor will verify such limitations as part of the Market Monitor's review of the offer and to make any necessary Tariff revisions to implement this process.

299. SPP also has not fully addressed the issue raised by TDU Intervenors regarding the possibility that market participants may seek to recover excessive market revenues in the form of opportunity costs for only the peak clock hours of the year. We find that it would not be appropriate for mitigated offers to include opportunity costs associated with revenues from only the expected highest priced hours in the market when the resource is not constrained to only a few such peak hours. In addition, we believe that the opportunity cost for a resource may change as the going-forward limitations upon a resource changes (for example, a resource would likely have different opportunity costs

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of repairs and costs of foregone sales during the repair period), short-term fluctuations in fuel prices or availability, and possibly, other factors.").

[344] *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,192 at PP 27-28.

[345] *Id*.

when it has 200 hours remaining in which it can operate versus two hours remaining). We will require SPP to develop Tariff language to address this issue in a manner that addresses opportunity costs that vary associated with these factors, and submit a compliance filing due 60 days after the issuance of this order.

300. It also is unclear how market participants will specify an estimate of the energy and operating reserves revenues net of short-run marginal costs for the marginal forgone run-time during the period of limitation as detailed in the Market Protocols. SPP has not specified (in its Tariff or otherwise) how those projected market prices will be developed, nor does it provide any method to ensure that different market participants will use the same prices when they calculate possible foregone sales during the same time period and location. Indeed, Dr. Hyatt acknowledges that, under the proposal, the market participants are the parties that calculate the mitigated offers in the Integrated Marketplace, and that they do not have access to the data required to determine during which periods the market is competitive. SPP also has not established how market participants will estimate future prices nor provided a formula for that estimation. Accordingly, we require SPP, in its compliance filing due 60 days after the issuance of this order, to explain how market participants will estimate such forgone future market prices and how they will determine associated opportunity costs.

301. We do not agree with the concerns raised by TDU Intervenors regarding SPP's proposal to allow opportunity costs reflecting non-competitive periods. In potential time periods when there are transmission constraints and the market participant may possesses market power, prices (and thus the associated opportunity costs for the resource) should reflect the market mitigation that will occur during these periods. However, we do not believe it is appropriate to include within opportunity costs forgone revenues associated with sales during prices during which there may be administrative pricing, such as during the implementation of shortage pricing.

302. Moreover, we require SPP, in its compliance filing due 60 days after the issuance of this order, to modify the language in section 3.2(C) of Attachment AF (stating "Opportunity cost shall be an estimate of the Energy and [o]perating [r]eserve Markets revenues net of short run marginal costs for the marginal forgone run time during the period of limitation as detailed in the Market Protocols"). As noted by TDU Intervenors, the "during the period of limitation" is unclear and may create unnecessary confusion. According, we require SPP on compliance to file language that instead refers to revenues forgone during the timeframe when resources experience the run-time restrictions.

303. We will not order SPP to include a *force majeure* requirement (nor accept its proposed addition of such a requirement). The Commission rejected a similar provision in PJM because PJM failed to demonstrate how events out of resources' control would

necessarily result in a limited number of run hours.[346] SPP's proposal for a *force majeure* provision similarly lacks sufficient justification.

304. Finally, we require SPP to clarify the use of certain formula terms in its Tariff. As noted above, several formula terms use abbreviated terms and it is unclear whether those terms are defined in the Tariff (e.g., Min. Econ. Capacity in section 3.3(D)). Accordingly, SPP must propose revisions to ensure that formula terms are tied to defined Tariff terms. It must provide these changes in its compliance filing due 60 days after the issuance of this order.

Mitigated Offer Development by Market Participant

October Order

305. In the October Order, the Commission raised concerns about SPP's proposal allowing market participants to submit their own mitigated offers, rather than having them created by a disinterested, experienced party (e.g., the Market Monitor or SPP itself). The Commission stated that mitigated offer submission by the market participant would provide opportunities for either inadvertent miscalculation or intentional padding of the offers. The Commission noted that SPP did not discuss review of offers, beyond intra-day changes to offers, nor did it discuss the timeliness with which its Market Monitor will conduct any review. The Commission conditionally accepted SPP's proposal for determination of mitigated offers, subject to SPP explaining how it will provide for monitoring mitigated offers of market participants to ensure that the market participants apply the formula and definitions of costs correctly. The Commission found that if SPP was unable to demonstrate adequate monitoring for submission of appropriate mitigated offers, it must revise its proposal to have mitigated offers developed by SPP or the Market Monitor.[347]

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[346] *Id.* P 32.

[347] October Order, 141 FERC ¶ 61,048 at P 422 & n.597 (finding that while it is the RTO/ISO that conducts prospective mitigation, the Commission provided in Order No. 719 that the Market Monitor may provide inputs to that process. The determination of the amount and other parameters of an offer constitute an input to the mitigation process and, thus, may be delegated to the Market Monitor).

February 2013 Compliance Filing

306. SPP continues to propose in sections 3.2, 3.3, and 3.4 of Attachment AF that market participants will submit mitigated energy, start-up, no-load, and operating reserve offers on a daily basis. Those mitigated offers will be developed in accordance with guidelines set forth in the Market Protocols.

307. Section 3.2 (energy offers) provides that further details associated with the development and validation of costs, including opportunity costs, will be included in the Market Protocols. SPP proposes language in section 3.2(C)(3) providing formulas for the mitigated energy offer and establishing that the market participant is to submit heat rates and the "methods for determining fuel costs including emissions costs, opportunity costs, and VOM" to the Market Monitor. This section establishes that further details associated with the development and validation of these costs is included in the Market Protocols. Section 3.2(D) provides that intra-day changes to the mitigated energy offer curve must follow the mitigated offer development guidelines in the Market Protocols and will be validated by the Market Monitor.

308. Proposed section 3.3(E) of Attachment AF provides that the market participant submits documentation of the method for calculating mitigated start-up and mitigated no-load offers, which is adequate to permit the Market Monitor to verify submitted offers. It establishes that further details associated with the development of these costs are included in the Market Protocols.

309. Dr. Hyatt explains the Market Monitor will monitor mitigated offers by reviewing every mitigated offer submitted by a market participant and comparing that to its own analysis. Accordingly, the Market Monitor will collect operational cost data from market participants through a web application provided on SPP's website. He testifies that costs will be validated against submitted figures for similar units and publically available historical figures (e.g., EIA form 923). Dr. Hyatt maintains that the data collected is sufficient for the Market Monitor to apply the formulas in the Tariff to compute shadow mitigated offers. He states that concerns with the accuracy of mitigated offers submitted by a market participant will be discussed with that market participant and reported to the Commission.[348]

[348] February 2013 Compliance Filing, Exh. No. SPP-11 at 23.

310. Dr. Hyatt also discusses why SPP decided not to base mitigated offers on accepted offers or market prices during similar periods. He notes that the SPP stakeholders and the Market Monitor did review two approaches—one based on offer histories similar to the process used by the MISO and a "Mitigated Offer" approach with development of mitigated offers by the market participant, which SPP ultimately adopted.[349] He asserts that the two methods require different conduct thresholds because the level of uncertainty associated with the approach based on offer histories is considerably greater.[350]

311. Dr. Hyatt believes weighted-average prices do not reflect, and are generally higher than necessary to recover, short-run marginal costs, and that tying mitigation to such prices potentially results in mitigated offers that exceed the short-run marginal costs and to a market participant avoiding mitigation by submitting a mitigated offer tied to LMP rather than to its short-run marginal costs. He states that this would be exacerbated in a situation involving falling costs or rising LMPs. Dr. Hyatt maintains that economic theory suggests that the LMP under competitive market conditions is an upper-bound on the short-run marginal cost of capacity that has cleared in the market, and that a reference level based on the LMP would nearly always exceed short-run marginal costs. Dr. Hyatt states that given what he says is the lack of an economic basis for a price-based mitigated offer and SPP members' lack of interest in further complicating the mitigation process, the Market Monitor does not currently recommend implementing this strategy.[351]

312. Dr. Hyatt maintains that incorporating both the offer history and Mitigated Offer approaches by giving resources the choice of methodology is problematic because of the difference in the conduct thresholds. Dr. Hyatt states that an optimal implementation would require that the conduct threshold applied to a resource's offer be dependent upon the mitigation methodology chosen for the resource. He avers that further complicating matters is that the market clearing engine would have two different sources for the estimates of short-run marginal costs. In particular, Dr. Hyatt explains that for resources using the approach based on offer histories, the Market Monitor would provide the data, but with the Mitigated Offer approach, the data would be submitted by the market

[349] Dr. Hyatt distinguishes between "reference level" and "mitigated offer." We do not concur with his use of the term "reference level" which the industry uses to include cost-based default offers.

[350] February 2013 Compliance Filing, Exh. No. SPP-11 at 24.

[351] *Id.* at 25-27.

participant. He argues that more stringent validation procedures will be necessary with the Mitigated Offer approach because the market participants are computing and submitting the offers. Finally, Dr. Hyatt maintains that SPP and the Market Monitor believe the proposed approach is reasonable given: (1) the Market Monitor considers both methods to be valid and does not prefer one over the other; (2) SPP has incorporated validation procedures that require the Market Monitor to shadow the mitigated offer submissions; (3) the implementation that offers a choice of the two options is considerably more complex; and (4) SPP stakeholders prefer the mitigated offer methodology after examining both options.[352]

March 2013 Filing

313. SPP proposes to modify its additional mitigation measures for resource offer parameters in section 3.6 of Attachment AF. This proposed section states that the mitigation measures in this section apply to all resource offer parameters expressed in units other than dollars and only will apply in the presence of local market power, as defined in the Tariff. In relevant part, SPP submits that when there is local market power and when the resource fails conduct and impact thresholds, the Market Monitor will inform the transmission provider of any potential issue. In proposed section 3.6, SPP establishes that if the transmission provider, in consultation with the Market Monitor, concludes that the market participant has demonstrated the validity of the submitted resource offer parameter, no further action will be taken. SPP provides that if this is not the case, the transmission provider will replace the changed resource offer parameter with the corresponding reference level.[353]

314. Section 3.6 further states (with the proposed additions in blackline) that "Mitigation measures will remain in place until such time that the [m]arket [p]articipant demonstrates the validity of the [r]esource [o]ffer parameter or the [m]arket [p]articipant <u>notifies the [m]arket [m]onitor that</u>~~changes~~ the [r]esource [o]ffer parameter <u>has been changed </u>to a value that is within the tolerance band as described above." SPP provides that in the event that the market participant submits a dispute, the mitigation measure will remain in place until the resolution of the dispute. SPP explains that the language was ambiguous with respect to the manner in which the Market Monitor would become aware of the change in the offer parameter. SPP asserts that these edits are intended to clarify

[352] *Id.* at 24-25.

[353] *See* March 2013 Filing at 12.

that the mitigation measure will remain in effect until the market participant has demonstrated its validity or until it has informed the SPP Market Monitor that the resource offer parameter has been changed to an acceptable value.[354]

Comments

315. TDU Intervenors question whether the Market Monitor has adequate authority to revise the mitigated offer curves submitted by market participants, especially where SPP's formulas (such as its provision for the inclusion of opportunity costs) leave "opportunities for either inadvertent or intentional padding of the [mitigated] offers."[355]

316. TDU Intervenors maintain that SPP's revised proposal limits the role of the Market Monitor to reviewing the underlying data and validating that the market participant has applied the formulas correctly. They note that the proposed Tariff does not say what should happen if a dispute arises over the proper application of the "not-well-specified formulas." Thus, TDU Intervenors argue that if SPP is permitted to allow market participants to calculate mitigation offers (including opportunity costs) in the first instance, the Commission should direct SPP to revise its Tariff to provide that, in the case of a dispute, the Market Monitor's interpretation will prevail, subject to dispute resolution.[356]

Answer

317. SPP argues that its Tariff revisions comply with the October Order. It states that, as proposed, section 3.5 of Attachment AF requires that the market participant provide the operational cost data necessary to calculate its mitigated offer. SPP states that the Market Monitor will validate this cost data against publicly available historical data and then compare this data and the formulas in the Tariff to compute Shadow Prices.[357]

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[354] *Id.*

[355] TDU Intervenors at 31 (citing October Order, 141 FERC ¶ 61,048 at P 422).

[356] *Id.* at 31-32.

[357] SPP Answer at 28.

318. SPP further argues that it has revised its Tariff to require referral to the Commission whenever a concern arises over the calculation or validity of a mitigated offer. Pointing to the October Order, SPP states that the Commission instructed that the Market Monitor should be able to intercede and substitute its own mitigated offer, in lieu of the market participant's order, only if adequate monitoring procedures for the Market Monitor were not in place. Moreover, to the extent that a dispute arises, SPP asserts that its current mitigated offer development guidelines provide that the previously approved mitigated offer is used until the dispute is resolved.[358]

319. Section 1.6 of the current (May 2013) version of Appendix G of the Market Protocols for the Integrated Market provides that a market participant who seeks to obtain an exemption, exception or change to any time frame, process, methodology, calculation or policy set forth in the guidelines, or approval of any mitigated offer that is not specifically permitted by these guidelines shall submit a request to the SPP Market Monitor for consideration and determination. It provides that the SPP Market Monitor shall approve or disapprove such a request based on the following criteria: the cost components included in all mitigated offers shall include the short run marginal cost of generation, the formulas used to calculate mitigated offers and the components of cost included in mitigated offers do not deviate from those specified in the SPP tariff, and data validation provided by the market participant are sufficient for the Market Monitor to verify mitigated offers on an ongoing basis. After receiving such a request, the Market Monitor has 15 days to act, or the request is automatically approved. In the event that the market participant disagrees with the SPP Market Monitor's decision and submits a dispute following procedures in section 12 of the SPP tariff, the previously approved time frame, process, methodology, calculation, or policy shall remain in place until the resolution of the dispute.

<u>Reply</u>

320. TDU Intervenors respond that they continue to believe that the Market Monitor needs the authority to revise proposed offer curves subject to dispute resolution. They state that, at a minimum, the Tariff needs to reflect that SPP will use the previously approved offer while dispute resolution is ongoing.[359]

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[358] *Id.*

[359] TDU Intervenors' Reply at 10.

Commission Determination

321. We find that SPP has not explained how certain costs that are to be used in the development of mitigated offers, including fuel costs, fuel-related costs (e.g., emissions costs), opportunity costs, VOM, and start-up and no-load costs, will be consistently developed by market participants. Rather, the current proposal appears to grant market participants with significant discretion in how to calculate such costs, including allowing them to use various unspecified "methods" for calculation of such costs, as proposed in sections 3.2(C)(3) and 3.3(E) of Attachment AF. Such an approach does not provide the consistency necessary for SPP's market. Accordingly, we conditionally accept SPP's proposal and will require SPP to propose specific Tariff language in its compliance filing due 60 days after the issuance of this order, that will ensure consistency in the calculation (but not necessarily the level) of these costs across all market participants. Where there are common factors or measures that are applied in multiple mitigated offers (such as projected prices of forgone sales used in the determination of opportunity costs), these must be applied consistently. Further, we will require SPP to provide how mitigated offers will address frequently changing input costs, such as fuel costs, so that input costs are up to date in the mitigated offers.[360]

322. We are also concerned that SPP's proposed treatment of the development of mitigated offers by market participants does not appropriately address how mitigation will occur when the mitigated offers submitted by the market participant and those calculated by the Market Monitor differ. Specifically, we find that the Tariff's requirement for reporting the inconsistency to the Commission does not ensure that market participants apply the formulas and definitions of costs correctly, and that appropriate mitigation is applied, as required in the October Order. We require SPP to provide in its Tariff, consistent with its Market Protocols, that if a market participant submits a dispute over its mitigated offer, the previously approved mitigated offer is used until the dispute is resolved.[361] We find that the 15-day timeline in which the Market Monitor must resolve disputes associated with the mitigated offer level that SPP proposes in its Market Protocols to be reasonable. However, we also find that SPP must propose

[360] For example, MISO adjusts its calculation of reference levels for fuel prices on a daily basis. See MISO Tariff section 64.1.4 and MISO Market Monitoring and Mitigation BPM at 6-42. CAISO's Tariff section 39.7.1.1.1 similarly provides for daily calculation of the fuel price index.

language for the Commission to review that establishes any additional measures that will occur if and when the dispute is resolved in the market participant's favor such as what will occur with respect to market settlements that have occurred while the disputed mitigated offers were in effect, and that SPP must explain its proposed approach. We will require SPP to make these modifications to the Tariff language in its compliance filing due 60 days after the issuance of this order.

323. We conditionally accept the change to section 3.6 of Attachment AF, as SPP proposes in its March 2013 Filing. However, SPP must file a compliance filing due 60 days after the issuance of this order specifying that the Market Monitor will verify that the resource offer has been modified to an acceptable level, such that the amended sentence reads: "Mitigation measures will remain in place until such time that the Market Participant demonstrates the validity of the Resource Offer parameter or the Market Participant notifies the Market Monitor that the Resource Offer parameter has been changed to a value that is within the tolerance band as described above, <u>and the Market Monitor has verified that this change has occurred</u>."

<u>Variable Energy Resources</u>

<u>October Order</u>

324. The Commission directed SPP to address how its Market Monitoring and mitigation procedures would apply to VERs, including "information on economic withholding, physical withholding, unavailability of facilities and uneconomic production."[362] The Commission also required SPP to address issues raised by ECNRA, including whether SPP's physical withholding threshold applied to dispatchable VERs; how the Market Monitor would monitor energy offers of VERs, given the unique characteristics of VERs and their use of forecasts; how monitoring would be applied if SPP used its own forecast rather than the offer information submitted by a VER; and how all facets of SPP's Market Monitoring and mitigation measures would, or would not, apply to VERs.[363]

[362] October Order, 141 FERC ¶ 61,048 at PP 414, 454, 464.

[363] *Id.* PP 395, 414.

February 2013 Compliance Filing

325. SPP submits testimony from Dr. Hyatt stating that the procedures for market power mitigation and monitoring apply to VERs in the same way that they apply to other resources. He maintains that, "[a]s base load capacity, they are less likely to cause a price impact, and are thus unlikely to trigger Energy Offer Curve mitigation."[364] He also states that "physical withholding and uneconomic production are both of potential concern for VERs."[365]

Commission Determination

326. We find that SPP has not sufficiently explained how its monitoring and mitigation procedures apply to VERs. While SPP states that it will monitor and mitigate VERs in the same way that it monitors and mitigates other resources, it fails to explain whether these monitoring and mitigation measures for economic withholding, physical withholding, unavailability of facilities and/or uneconomic production are appropriate for VERs, given their unique characteristics and risks of exercising market power. For example, SPP has not demonstrated that all types of VERs (e.g., dispatchable and non-dispatchable VERs) present a risk of economic withholding sufficient to justify applying SPP's monitoring and mitigation procedures to VER energy offer curves during all five-minute dispatch intervals. SPP also fails to address whether all types of VERs warrant identical monitoring and mitigation measures during all five-minute dispatch intervals in the real-time market (e.g., when SPP applies persistence forecasting for dispatchable VERs). Further, SPP has not demonstrated how various generic Tariff provisions will apply to VERs. For example, SPP has not addressed how its Market Monitor would monitor the maximum output limits and other forecasting information submitted by VERs in the real-time market and RUC processes to ensure that the relevant resources are not engaging in physical withholding or unavailability of facilities. In addition, SPP has not addressed all of the issues previously raised by E.ON, including: how the Market Monitor will monitor energy offers of VERs, given the unique characteristics of VERs and their use of forecasts; how monitoring and mitigation will apply if SPP uses its own forecast rather than the offer information submitted by a VER; and how all facets of the Market Monitor's monitoring and mitigation approach will, or

[364] February 2013 Compliance Filing, Exh. No. SPP-11 at 20.

[365] *Id.*

will not, apply to VERs.[366] Accordingly, we will require SPP to address these issues in its compliance filing due 60 days after the issuance of this order. SPP should demonstrate whether its monitoring and mitigation measures for economic withholding, physical withholding, unavailability of facilities and/or uneconomic production are appropriate for dispatchable and/or non-dispatchable VERs and under which circumstances; address how these measures would be applied; and file any tariff revisions necessary to provide these clarifications.

Mitigation of Demand Response

October Order

327. In the October Order, the Commission questioned whether SPP intended to apply mitigation measures to demand response resources, even though SPP had not identified why it had concerns about those resources' potential exercise of market power, and had not analyzed demand response resources in its market power study. The Commission further found that SPP had not explained how its proposed conduct and impact tests would apply to demand response resources, how the tests would be effective in determining whether a demand response resource is exercising market power, or the proposed methods for calculating offer reference levels.[367] Therefore, the Commission required SPP to "explain whether it intends to mitigate demand response, and if so, how it will determine if a demand response resource is exercising market power."[368] Finally, the Commission stated that "if SPP intends to mitigate demand response offers, it must discuss the reference levels and conduct and impact thresholds under which it would do so."[369]

February 2013 Compliance Filing

328. SPP submits testimony from Dr. Hyatt stating that SPP intends to apply its mitigation measures to demand response resources in the same manner as it applies those

[366] October Order, 141 FERC ¶ 61,048 at PP 395, 414.

[367] October Order, 141 FERC ¶ 61,048 at P 415.

[368] *Id*.

[369] *Id*.

measures to other resources. He maintains that a market participant owning or controlling more than one demand response resource, or a combination of demand response resources and other resources, may find itself in a position where it could exercise local market power, similar to any other entity with multiple resources. Dr. Hyatt states that even in the absence of jointly controlled physical resources, a demand response resource that can alter prices away from competitive levels may benefit by virtual or Transmission Congestion Rights positions held in the market.[370]

329. Dr. Hyatt addresses monitoring of demand response resources, stating that presently there are about 1400 MW of co-generation capacity and behind-the-meter generation registered as generation in SPP's EIS Market. He states that at least one of these co-generation facilities is controlled by a market participant that controls other generating resources, which could benefit from the withholding of capacity from the co-generation plant. According to Dr. Hyatt, on occasion, some of these resources trigger the Market Monitor's market power screens, but that none to date has been deemed to have exercised market power.[371]

330. Dr. Hyatt testifies that demand response resource offers will be subject to the conduct and impact test mitigation process for economic withholding, described in the revised Attachment AF section 3. According to Dr. Hyatt, this process is the same as that applied to other resources. Dr. Hyatt states that reference levels for demand response resources will reflect the short-run marginal cost of load reduction, which it states varies with the characteristics of the resource. He maintains that demand response resources utilizing behind-the-meter generation will use the same guidelines as other generating resources. He maintains that demand response resources reducing load will base their mitigated offers on quantifiable incremental costs. Dr. Hyatt argues that the reference levels for demand response resources are reasonable because they will be resource-specific and generally determined on a case-by-case basis. He testifies that the thresholds do not vary by resource type for any resource. He further asserts that, in the case of demand response resources, all those known by SPP at this time utilize behind-the-meter generation, which SPP is treating the same as any other resource.[372]

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[370] February 2013 Compliance Filing, Exh. No. SPP-11 at 20.

[371] *Id.* at 21.

[372] *Id.* at 22.

331. To accomplish these changes, SPP proposes several Tariff revisions. In Attachment AE, SPP defines a resource to be "an asset that injects energy into the transmission grid or reduces the withdrawal of energy from the transmission grid including a Demand Response Resource, a Variable Energy Resource, a Dispatchable Resource, External Dynamic Resource and a Quick-Start Resource."[373] This revision ensures that demand response resources are included in mitigation.

332. In addition, SPP proposes Tariff changes in Attachment AF that directly address mitigation of demand response resources. SPP proposes revisions to section 3.2(C) to provide that for demand response resources utilizing behind-the-meter generation, the mitigated Energy Offer Curve shall be developed in the same manner (as described in the mitigated offer section of this order) as any other generating resource. For demand response resources utilizing load reduction, the mitigated energy offer curve will reflect the quantifiable opportunity costs associated with the reduction, net of related offsetting increases in usage. SPP proposes revisions to section 3.3(C) to provide that for demand response resources, the mitigated start-up offer shall be the cost to shut down or curtail load for a given period, which varies with the number of deployments rather than the amount of response, and/or the start cost of behind-the-meter generation utilizing the mitigated start-up offer calculation applicable to other generation.[374] SPP proposes revisions to section 3.3(D) to provide that the mitigated no-load offer for demand response resources utilizing behind-the-meter generation shall adhere to the same definition as a generating resource.[375] It further provides that for demand response resources utilizing load reduction, the mitigated no-load offer shall not exceed the quantifiable ongoing hourly costs associated with load reduction.

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[373] SPP Tariff, Attachment AE, section 1.1 Definitions R.

[374] Proposed SPP Tariff section 3.3C provides that the mitigated start-up offer shall represent the cost per start as determined from start fuel usage and the costs related to that fuel usage, cost of electricity from station use to start, maintenance costs attributable to starts, and additional labor costs, if required above normal staffing levels.

[375] Proposed SPP Tariff section 3.3D provides that the mitigated no-load offer shall be the hourly fixed costs required to create a monotonically increasing mitigated energy offer curve, and that it shall be calculated under either a no-load fuel approach or a no-load cost approach.

333. In section 3.4(C) of Attachment AF, SPP proposes that for demand response resources utilizing load reduction to offer into the market, the mitigated spinning reserve offer shall not exceed the quantifiable costs necessary for a resource to be prepared to shut-down or curtail load. Section 3.4(C) further provides that for demand response resources utilizing behind-the-meter generation, the mitigated spinning reserve offer shall adhere to the same definition as for generating resources. SPP, however, does not propose language relating to demand response resources in sections addressing regulating reserves.

334. Dr. Hyatt also affirms that demand response resources will be monitored for physical withholding, consistent with provisions set forth in section 4.6.4 of Attachment AG. He asserts that the Market Monitor will evaluate any circumstances where a demand response resource is not available or does not follow SPP's dispatch instruction when it otherwise would be economic to do so in a competitive market. This determination will be made according to the screens for physical withholding (addressed below in more detail in the section of this order Physical Withholding and Unavailability of Facilities) described in Attachment AG sections 4.6.4.1 and 4.6.4.2. Dr. Hyatt states that if the demand response resource is deemed to have abused market power through physical withholding, the Market Monitor will inform the Commission's Office of Enforcement.[376]

Commission Determination

335. We conditionally accept SPP's proposal for monitoring and mitigating demand response resources, subject to further clarification and Tariff revisions. In its February 2013 Compliance Filing, SPP expresses the concern that demand response resources in the Integrated Marketplace will have the potential to exercise market power. As support, Dr. Hyatt testifies that a Market Participant owning or controlling more than one demand response resource, or a combination of demand response resources and other resources, may find itself in a position where it could exercise local market power, similar to any other entity with multiple resources.[377] Therefore, SPP proposes to subject demand response resource offers to the same conduct and impact test mitigation process for economic withholding as other resources in SPP's Integrated Marketplace. Demand

[376] February 2013 Compliance Filing, Exh. No. SPP-11 at 21-22.

[377] February 2013 Compliance Filing, Exh. No. SPP-11 at 20.

response resources will also be subject to monitoring for physical withholding, as established in Attachment AG.

336. SPP proposes to determine the reference levels for demand response resources on a resource-specific, case-by-case basis. For demand response resources utilizing load reduction, SPP proposes that the mitigated energy offer curve of such a resource shall be based on the resource's short run marginal costs, which will include the opportunity costs associated with the reduction.[378] Dr. Hyatt states that demand response resources reducing load will base their mitigated offers on quantifiable incremental costs, which may include opportunity costs related to losses in production. For demand response resources utilizing behind-the-meter generation,[379] SPP proposes that the mitigated energy offer curve shall be developed in the same manner as a generating resource. As proposed, behind-the-meter generators will also be able to submit opportunity costs based on energy and operating reserve market revenues. In addition, behind-the-meter generators can reflect opportunity costs in total fuel related costs and/or variable operations and maintenance costs, under certain circumstances. SPP also proposes mitigation measures for start-up, no-load, and operating reserve offers of demand response resources.

337. We find that SPP's proposed Tariff revisions, in concert with Dr. Hyatt's explanation, provide greater clarity regarding how SPP intends to mitigate the exercise of local market power by a demand response resource and how it will determine if a demand response resource is exercising market power, as required by the October Order. SPP recognizes, and we agree, that legitimate and verifiable opportunity costs associated with providing demand response, including for instance forgone profits from modifying primary production operations, will legitimately be reflected in an energy market offer from demand response resources. SPP also appropriately acknowledges that Mitigated Energy Offer Curves will need to be established on a resource-specific basis, which

[378] Attachment AF, section 3.2C.

[379] SPP defines Behind-The-Meter Generation as a generation unit that is connected on the load side of a load Meter Settlement Location and is used by the load Market Participant that is the registered owner for the Meter Settlement Location to serve all or part of its capacity, Energy or Ancillary Services needs. Attachment AF 1.1. The Commission understands from this definition that behind-the-meter generation supporting a demand response resource is distinguishable from behind-the-meter generation that is registered by a Market Participant as a generator.

recognizes the variability in the type of resources that can provide demand response (i.e., hospitals, retail and commercial businesses, industrial facilities, households, *etc*.) and the methodology that the resource uses to provide the reduction in load on the system.

338. We also find it appropriate that the Market Monitor will monitor energy offers and evaluate a resource's operating costs and operational parameters on a case-by-case basis. Our understanding, from testimony provided in SPP's filing and from SPP's proposed Tariff provisions, is that SPP's Market Monitor will consult with each demand response resource when developing and adjusting the appropriate reference levels for a mitigated energy offer curve. We find such consultation to be appropriate in order to fully account for the unique characteristics, operating parameters, and costs of a demand response resource.

339. However, while a resource-specific evaluation appropriately recognizes the inherent variability among demand response resources, SPP must provide consistent treatment between demand response resources when considering generally applicable parameters. Our concern here is similar to the concerns we have with respect to opportunity costs for all resources, as delineated in the section of this order focusing on Mitigated Offer Development by a Market Participant. We find that SPP must develop a consistent plan for dealing with those operating parameters that are generally applicable to all demand response resources.[380] For example, SPP should consider whether opportunity costs for limited starts should be tied to prices in other hours such as average or peak hours, and if the latter, to which peak hours. Accordingly, SPP must submit a compliance filing within 60 days of the date of this order explaining its treatment of generally applicable operating parameters for demand response resources.

340. We also find that SPP has not sufficiently addressed how physical withholding standards should be applied to demand response, and how it can be determined that the resource is simply using its capacity rather than physically withholding from the market. It is not clear what a derating or forcing out of service means in the context of a demand response resource. Nor is it clear how operation of a demand response resource in an uneconomic manner or declaring that its capability to provide energy is reduced would apply. We also find it unclear how changes in offer parameters such as ramp rates or

[380] As the Commission stated in Order No. 719, limits on duration, frequency, and the amount of service in a demand response resource's bid are comparable to the limits generators may specify on price, quantity, startup and no-load costs. *See* Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 81.

economic and emergency limits; or in operating parameters such as a resource's availability for dispatch, maximum duration for the dispatch, maximum amount of energy per day or week that a resource could produce, and limitations related to the primary operation of the facility should be analyzed for demand response resources. Therefore, we require SPP to submit a compliance filing, within 60 days of the date of this order, clarifying and providing tariff revisions, as necessary, to account for how the Market Monitor will apply physical withholding standards to demand response.

Conduct and Impact Thresholds

October Order

341. In the October Order, the Commission found that SPP failed to provide sufficient justification for its conduct and impact thresholds, "especially given that SPP did not provide sufficient information regarding how it will determine mitigated offers, sufficient monitoring for the creation of such offers, and because it did not sufficiently address mitigation needs for more Frequently Constrained Areas."[381]

342. Specifically, the Commission found that SPP's proposed thresholds for Broad Constrained Area-type mitigation were lower than those of other RTOs. In particular, the Commission noted that the thresholds were substantially lower for each of the offer types, except time-based and other non-dollar-based parameters. While the Commission noted that such lower thresholds could be appropriate in SPP given daily development of mitigated offers by market participants, it required SPP to provide for mitigated offer development by the Market Monitor if SPP could not show how it would monitor mitigated offers of market participants to ensure that they applied the formula for mitigated offers and associated definitions of costs accurately. In that circumstance, the Commission found that the thresholds proposed by SPP could lead to over-mitigation. Accordingly, the Commission directed SPP to justify its conduct and impact thresholds for prices and make whole payments for energy, operating reserve, start-up, and no-load offer parameters.[382]

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[381] October Order, 141 FERC ¶ 61,048 at P 441.

[382] *Id.* P 444.

343. The Commission also directed SPP to revise its thresholds for conduct and impact associated with voltage and local reliability commitment events.[383] The Commission found that more stringent economic withholding thresholds were necessary to prevent market participants with resources that were committed due to voltage and local reliability events from exercising market power by submitting bid levels or bidding parameters substantially different from their reference levels. Also, the Commission required SPP to address if tighter thresholds were needed to identify uneconomic production in cases where a generation resource was committed to address a local reliability event.[384] The Commission further required SPP to modify section 3.4 of Attachment AF such that the impact test addresses the price impact on energy or operating reserves.

344. The Commission also noted a difference in the way that the Market Monitor consults with the market participant related to offer parameters that were time-based and expressed in units other than time or dollars. The Commission found that this could potentially forestall the mitigation of valid offers that failed the conduct and impact tests, but that SPP did not have a similar procedure for other offer parameters. In cases where an offer exceeds the conduct and impact levels, the Commission required that the Market Monitor shall, as soon as practicable and if warranted in light of the information available to the Market Monitor, contact the market participant to request an explanation. The Commission noted that a market participant could provide that explanation before submitting an offer if it anticipates exceeding the levels. The Commission stated that the Market Monitor need not mitigate a market participant when the explanation provided does not indicate anti-competitive behavior. However, the Commission required SPP to include in Attachment AF a requirement that the Market Monitor would record instances where, after market participants notified the Market Monitor with an explanation of the

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[383] *Id.* P 445 (referencing *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 FERC ¶ 61,171, at PP 116, 118 (2012)). MISO proposed a conduct threshold tied to the increase in total production costs due to an increase in the market participant submitted offer from the applicable reference level for the generation resource, and to uneconomic production levels. Its impact threshold to determine a substantial effect upon day-ahead or real-time revenue sufficiency guarantee credits paid to resources with voltage and local reliability commitments is $0 per MW per hour. MISO Tariff section 64.1.2.

[384] October Order, 141 FERC ¶ 61,048 at P 445.

offer prior to submitting an offer that would fail the conduct test, the offer subsequently failed the conduct and impact screens but, due to consultation, the Market Monitor determined that mitigation would not be appropriate. The Commission required SPP to include in Attachment AF language that provided that SPP's Market Monitor would report on such instances to the Commission's Office of Enforcement every three months during the first year of Integrated Market operations, and yearly thereafter.[385]

February 2013 Compliance Filing

345. SPP proposes removing language which would have, if approved, established a less stringent conduct threshold for energy offers where resources are subject to mitigation for 2,000 hours per year or more. It proposes new, tighter conduct thresholds for resources that are: (1) manually committed by the transmission provider or selected for commitment for reliability issues by a local transmission provider in the Day-Ahead Reliability Unit Commitment or the Intra-day Reliability Unit Commitment; or (2) located in Frequently Constrained Areas.

346. For resources with local market power due to manual commitments by the transmission provider or local operator, SPP proposes to tighten the conduct thresholds for energy, start-up, no-load and operating reserve offers to ten percent above the mitigated energy offer curve.[386] Dr. Hyatt testifies that a ten percent conduct threshold will be applied to all resources that are manually committed to address a voltage and local reliability need. He elaborates that the ten percent conduct threshold will apply to all dollar-based offers including energy, start-up, no-load, regulation-up, regulation-down, spinning reserves, and supplemental reserves. Dr. Hyatt maintains that the threshold level is based on industry standards. According to Dr. Hyatt, because the manual commitments are not subject to the automated Market Impact Test that is embedded in the market clearing engine, the mitigation decisions [are] based on the results of the conduct test. Dr. Hyatt asserts that this methodology is essentially the same as applying a zero dollar impact threshold to these resources. He argues that if a resource committed to address a voltage or local reliability issue fails the conduct test at the ten percent threshold level, the offer in question will be replaced by the appropriate mitigated

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[385] *Id.* P 447.

[386] SPP Tariff, Attachment AF, sections 3.2A(1), 3.3A, and 3.4 A.

offer for the market dispatch as well as for make whole payments calculations—i.e., the impact test is zero.[387]

347. SPP proposes to modify its Tariff to provide that for resources located in Frequently Constrained Areas, which are not manually committed by SPP or the local operator as discussed above, the conduct threshold for energy offers is a 17.5 percent increase above the mitigated energy offer curve.[388] It proposes a conduct threshold of a 25 percent increases above the mitigated start-up, no-load, or operating reserve offers for such resources.[389] SPP provides that for all other resources, the conduct test for mitigation of energy offer curves is a 25 percent increase above the energy offer curve.[390]

348. In proposing the tighter conduct thresholds for Frequently Constrained Areas, Dr. Hyatt argues that a more aggressive mitigation plan for energy offers is appropriate in these areas. He states that there is less concern with the cost of intervening and additional weight is given to more recent observations of volatility in Henry Hub Daily Natural Gas Prices by month in Exhibit No. SPP-12. Dr. Hyatt supports the 17.5 percent threshold for energy, stating that the volatility has not exceeded 20 percent since November 2011, and that in the most recent 12-month period, nine of the observations are below 15 percent with the remaining observations clustered just below 20 percent. He believes that the appropriate conduct threshold for energy should fall between 15 percent and 20 percent, which is consistent with the 17.5 percent threshold that SPP is proposing.[391]

349. Dr. Hyatt asserts that the rationale for not imposing tighter thresholds for operating reserve offers in Frequently Constrained Areas than in other areas is based on the co-optimization of the energy and operating reserves markets, He maintains that is very unlikely that an economic withholding strategy based exclusively on inflated

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[387] February 2013 Compliance Filing, Exh. No. SPP-11 at 16.

[388] SPP Tariff, Attachment AF, section 3.2.

[389] *Id.*, sections 3.3A (2) and 3.4A (2).

[390] *Id.* section 3.2A (2). Note that this section contains an incorrect reference to section 3.2(1) rather than 3.2A (1), which we have required a correction for above.

[391] February 2013 Compliance Filing, Exh. No. SPP-11 at 14.

operating reserve offers would be successful. According to Dr. Hyatt, the tighter thresholds on the energy offer curve should be sufficient to address withholding. Dr. Hyatt notes the MISO conduct threshold applicable to start-up offers for Narrow Constrained Areas is 50 percent and the threshold for other areas is 100 percent, and that SPP is proposing a 25 percent conduct threshold for areas start-up and no-load offers of resources in Frequently Constrained Areas and non-Frequently Constrained Areas. He maintains that by lowering the energy offer curve conduct threshold to 17.5 percent, SPP removed some of the buffer allowed for the cost of over-mitigation and additional risk not reflected in the fuel price volatility numbers. He argues that because of their “higher operational risks”, start-up and no-load offers should not be subject to the same cost buffer reduction as energy offers. He states that accordingly, SPP has determined that it is appropriate to retain the conduct threshold for start-up and no-load offers at 25 percent. Dr. Hyatt asserts that if operational experience indicates that tighter thresholds should be applied to these offers, SPP is prepared to re-examine and adjust them in the future.[392]

350. Dr. Hyatt asserts that a 25 percent conduct threshold (for these resources start-up and no-load offers, as well all offer parameters for resources in non-Frequently Constrained Areas without manual commitments) is reasonable because it is based upon the volatility of natural gas fuel costs. He states that the principle uncertainty associated with generation cost is fuel cost volatility, and that natural gas has the most price volatility. According to Dr. Hyatt, because natural gas is generally the marginal fuel in constrained areas, tying the conduct threshold to the price volatility of natural gas provides a metric for assessing the expected variation in prices. He testifies that the monthly average daily volatility for the Henry Hub gas trading hub over the last six years varies from a low of six percent to a high of 51 percent in November of 2009. He points to 66 of the 72 observations being below 25 percent with the 12 most recent observations varying between ten percent and 19 percent. Dr. Hyatt believes that given these volatility factors, it is reasonable to expect an offer to include an adder related to fuel price risk. He notes that there are additional risks such as an unexpected weather event that affects the performance of a generator. He also maintains that attention must be paid to the cost of intervening in the market via mitigation, and states that an aggressive mitigation plan increases the likelihood of over-mitigation in an instance where an otherwise valid offer exceeds the conduct threshold and mitigation is applied. Dr. Hyatt observes that over-mitigation not only results in an inefficient solution with artificially low prices, but that it also weakens the integrity of the market and confidence of the market participants. He

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

maintains that given the observations of fuel price volatility and the concerns over the cost of intervening, a 25 percent conduct threshold is appropriate.[393]

351. Dr. Hyatt asserts that it is reasonable to apply the same conduct threshold to start-up, no-load, and operating reserve offers as to energy offers. He states that as the new provisions on mitigated offers make clear, fuel cost is a significant component of start-up cost, no-load cost and the cost of holding operating reserve capacity. He argues that thus a percentage conduct threshold identical to the energy offer conduct threshold is reasonable for each of these offers.[394]

352. In section 3.7 of Attachment AF, SPP modifies its proposal to provide for an impact test related to market clearing prices, rather than just upon LMPs and make whole payments. Accordingly, this section now provides for an impact test of threshold of $5 upon the LMP, $5 upon the market clearing price, or a $5 increase in make whole payments. Section 3.7 provides that the impact thresholds will be increased to $10/MWH unless the Market Monitor finds market behavior that warrants keeping the threshold constant for the next six months. The Tariff provides that the periodic increases will continue until each of the thresholds (LMP, market clearing price, and make whole payments) are $25/MWh. Dr. Hyatt addresses the reasonableness of the impact test threshold explaining that the goal of an impact test is to differentiate between price increases caused by legitimate supply shortages and price increases caused by economic withholding. He observes that a price increase caused by a legitimate supply shortage in a constrained area is the result of a movement up the local supply curve which is comprised of competitive offers by the generators in the constrained areas. According to Dr. Hyatt, working from the premise that the SPP EIS Market generally exhibits competitive pricing, the standard deviation of the system marginal price is indicative of legitimate increase. He maintains that the system marginal cost is analogous to the marginal energy cost, and that it does not reflect the cost of congestion.[395] SPP proposes an impact threshold for resources that are manually committed by the transmission provider or selected for commitment by the local transmission operator of zero.

[393] *Id.* at 9-10.

[394] *Id.* at 10.

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

353. Dr. Hyatt states that the same impact test is used in looking at the effects upon LMP, market clearing price, and the make-whole payment comparison. He testifies that generally the revenue component of a make whole payment is heavily weighted by revenue from energy sales as compared to revenue from sales of operating reserve capacity. According to Dr. Hyatt, the driving factor in determining make whole payments is the LMP and it is reasonable to use the same impact threshold for both the LMP and make-whole payment comparisons. He argues that given that the market clearing price will always be less than or equal to the LMP, the impact threshold for market clearing price comparisons should be less than or equal to the impact threshold for LMP comparisons. Dr. Hyatt maintains that SPP satisfies this by choosing to use the same threshold for both comparisons. He states that SPP is reluctant to set the market clearing price threshold less than the LMP threshold because the eventual impact threshold of $25/MWh is a tight threshold as compared to the impact thresholds in place at MISO, ISO New England, Inc, (ISO New England) and New York Independent System Operator (New York ISO). Dr. Hyatt states that the lowest market clearing price test threshold in place at MISO is $26, which applies in one of MISO's Narrow Constrained Areas.[396]

354. Dr. Hyatt testifies that the impact test thresholds are low compared to other RTOs that employ conduct and impact mitigation. At market start, these thresholds will be $5/MWH for all each of locational marginal prices, market clearing prices (for operating reserves) and make whole payment impacts. Dr. Hyatt states that prior to raising the impact thresholds the Market Monitor must also study the impact of higher thresholds. He states that at the time of such a study, the Market Monitor will consider separately the effects of raising the impact thresholds in non-Frequently Constrained Areas and in Frequently Constrained Areas.[397]

355. SPP proposes a new section 3.8 of Attachment AF that addresses mitigation exceptions. Section 3.8A provides that the Market Monitor will, as soon as practicable and if warranted by the information available to the Market Monitor, contact a market

[396] *Id.* at 11-12. We note that Potomac Economics' Informational Filing of February 21, 2013 relating to Narrow Constrained Areas states that the Narrow Constrained Area thresholds for energy were $100, $33.10, and $23.17 for the Wisconsin Upper Michigan System (WUMS), North WUMS, and Southeast Minnesota Narrow Constrained Areas respectively.

[397] *Id*. at 15.

participant to request an explanation of its actions in cases when an impact threshold in section 3.7 of Attachment AF is exceeded and the market participant's offer exceeds the mitigated offer by more than the relevant conduct threshold.

356. SPP proposes new language in section 3.8B of Attachment AF that provides if a market participant anticipates submitting an offer that will exceed the mitigated offer by more than the relevant threshold amount, it may contact the Market Monitor to provide an explanation of the changes in its offer. Section 3.8B proposes that if the market participant's explanation indicates to the Market Monitor that the questioned behavior is consistent with competitive behavior; in such instances, SPP will not conduct mitigation with respect to that offer unless and until circumstances appear to warrant it, and SPP or the Market Monitor so notifies the market participant. The proposed language provides that the Market Monitor will record such instances and will report on such instances to the Commission's Office of Enforcement every three months during the first year of Integrated Market operations, and yearly thereafter. SPP submits that to the extent that the report contains sensitive data, the Market Monitor should include such data in a non-public portion (or version) of the report.

Commission Determination

357. We find SPP has complied with the October Order by providing sufficient explanation regarding its proposed conduct and impact thresholds. We continue to find that SPP's proposed conduct and impact thresholds are more stringent for potentially mitigated conduct than those adopted in other RTOs and ISOs, except for the proposed conduct threshold associated with reliability events which is comparable to that adopted in some other RTOs and ISOs.[398] With mitigated offer submission by market participants (appropriately executed as discussed above), fairly tight thresholds may be appropriate. Further, the Commission has at times required or approved tighter thresholds at market start because the initial months of a market's start-up may warrant a more cautious approach to mitigation.[399] Accordingly, we accept SPP's proposed Tariff changes to

[398] For example, New York ISO has a similar conduct threshold when resources are committed for reliability purposes of the greater of ten percent or $10/MWh.

[399] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172, at PP 122-123 (2008) (requiring a tighter conduct threshold for economic withholding); *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,013, at P 104 (2005) (approving a lower energy bid cap for day one of MRTU implementation, with a two year transition to a higher bid cap).

implement the conduct and impact thresholds. In order to assess the effectiveness and appropriateness of the conduct and impact thresholds, we require SPP to report on them as a part of the informational report due 15 months following commencement of the Integrated Marketplace.[400] In particular, SPP must address whether the conduct and impact thresholds for the various products and under the various circumstances (i.e. non-Frequently Constrained Areas, Frequently Constrained Areas, and where there are manual commitments as described in section 3.1(4)) appropriately identify conduct that needs to be mitigated.

358. We find that, by replacing the language related to energy offer curve conduct thresholds, SPP has removed language which appeared to provide for the conduct threshold being tied to the group of energy offers from all resources. We find that this revision clarifies the Tariff as required by the Commission in the October Order and will accept it.

359. We also find that SPP has provided for more stringent mitigation in Frequently Constrained Areas and areas associated with voltage and local reliability events, as required by the Commission. As discussed above, we require SPP to address in the report due 15 months after the commencement of the Integrated Marketplace whether the conduct and impact levels associated with these areas appropriately identify conduct that should be mitigated.

360. We find that SPP has appropriately modified Attachment AF of its Tariff to provide for the impact threshold measuring impacts on operating reserve prices, in addition to impacts on and make whole payments and we therefore accept these changes.

361. We find that SPP, in adding section 3.8 of Attachment AF, has allowed for explanations (and exceptions to mitigation) when the market participant has exceeded the conduct and impact levels for economic withholding, as required by the Commission. However, with respect to 3.8(B), SPP has not limited the reports to the Commission (of circumstances where the higher than conduct-threshold offer is explained pre-offer, and is not mitigated) to instances when both the conduct and impact test for economic

[400] The Commission ordered that SPP must also discuss any need for mitigation when there is no binding constraint. Further, the report must detail any evidence of the exercise of market power by market participants in the first year of operations that is not addressed by SPP's market mitigation. October Order, 141 FERC ¶ 61,048 at P 413.

withholding were failed.[401] Accordingly, we will conditionally accept this Tariff addition and require SPP, in its compliance filing due 60 days after the issuance of this order, to limit the reporting of non-mitigation after a pre-offer consultation occurs under section 3.8(B), to instances when the resulting offer violates both the conduct and impact threshold.

Uneconomic Production

October Order

362. The Commission required SPP to address if tighter conduct and impact thresholds are needed to identify uneconomic production to address situations where a generation resource is committed to address a local reliability event.[402]

363. The Commission also required SPP explain why it "has not established a cut-off value for mitigation that will capture uneconomic production on the other side of a constraint (by focusing on a cut-off value of an *absolute value* of the Resource-to-Load Distribution factor rather than just the Resource-to-Load Distribution factor)."[403]

February 13 Compliance Filing

364. In response to the Commission's concerns regarding the need for tighter thresholds to identify uneconomic production associated with generator commitment for a local reliability event, SPP proposes a conduct threshold of a 25 percent increase in the Minimum Economic Capacity Operating Limit for resources that are manually committed in section 3.6 of Attachment AF. SPP proposes that the mitigation measures in section 3.6 would apply to all resource offer parameters expressed in units other than dollars, and will apply only in the presence of local market power, as described in section 3.1 of Attachment AF.

[401] *Id.* P 447.

[402] *Id.* P 445 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 FERC ¶ 61,171, at P 117 (2012)).

[403] October Order, 141 FERC ¶ 61,048 at P 409 (emphasis in original).

365. As proposed, there are three thresholds that may determine uneconomic production including: (1) an increase of three hours in a time-based offer parameter, or an increase of six hours total for multiple time-based offer parameters; (2) a 100 percent increase for resource offer parameters that are minimum values, or a 50 percent decrease for resource offer parameters that are maximum values; and (3) the newly proposed standard of a 25 percent increase in the Minimum Economic Capacity Operating Limit for resources that are manually committed. Section 3.6 provides that, in the case that a resource offer fails one of the thresholds, and the impact exceeds the impact tests for mitigation established in the Tariff, the Market Monitor will discuss the parameter changes with the market participant for an explanation of those changes, and then the Market Monitor will inform SPP of any potential issue. If SPP, in consultation with the Market Monitor, concludes that the market participant has demonstrated the validity of the offer parameter, no further action will be taken. If not, SPP will replace the resource offer parameter with the corresponding reference level, and the mitigation measure will remain in effect until the market participant demonstrates the validity of the resource offer parameter or the market participant changes to a value within the tolerance band.

366. Dr. Hyatt states that tighter conduct thresholds are warranted for identifying uneconomic production caused by an increase in the Minimum Economic Capacity Operating Limit for resources committed to address local reliability events. He maintains that these resources will likely be eligible for make whole payments and as such can earn a return on every MW produced; and that therefore there is significant concern that market forces will not be sufficient to deter over-production. Dr. Hyatt concedes that SPP does not apply automatic mitigation to address uneconomic production, but argues that there are procedures in place to address the mitigation of operational parameters. He states that SPP and the Market Monitor propose to apply this lower conduct threshold to the minimum economic capacity operating limit of resources that have been manually committed by the transmission provider to address voltage or local reliability issues. According to Dr. Hyatt, this revision lowers the conduct threshold from a 100 percent increase to a 25 percent increase (with respect to the corresponding reference level) for resources manually committed to address a voltage issue or local reliability event. Dr. Hyatt maintains that the 100 percent threshold is based on thresholds in place at other RTOs, noting that MISO uses the 100 percent threshold. He highlights that MISO recently amended its tariff to address this same issue and states that the choice of the

25 percent threshold is based on the threshold in the FERC approved amendment to the MISO tariff.[404]

367. Dr. Hyatt also addresses why SPP has not established a cut-off value for mitigation that would capture uneconomic production on the other side of a constraint. He states that such a test would have looked at the absolute value of the Resource-to-Load Distribution factor, rather than only at negative Resource-to-Load Distribution factors. By screening for positive Resource-to-Load Distribution factors, the automatic mitigation measures would also have screened for uneconomic production. Dr. Hyatt establishes that the Market Monitor will monitor for uneconomic production in lieu of automated mitigation measures being applied by the market clearing engine. He argues that by not specifying a cut-off value, the SPP Tariff retains the flexibility for the Market Monitor to examine uneconomic production on a broader range of resources.[405]

Commission Determination

368. We find that SPP's proposed section 3.6, as well its proposed plan to mitigate for uneconomic production at the proposed 25 percent conduct threshold for Minimum Economic Capacity Operating Limit when resources are manually committed comply with the Commission's directive in the October Order and we will conditionally accept it. This standard is consistent with the standard used by MISO for its hourly economic minimum offer parameter.[406]

369. However, without an automatic screen with a positive Resource-to-Load Distribution cut-off for uneconomic production on the other side of a constraint, SPP's proposal to examine uneconomic production on a broader range of resources may not sufficiently flag such resources. In particular, a positive Resource-to-Load Distribution cut-off could have been used to help determine what resources on the other side of a constraint could be engaging in uneconomic production to cause or exacerbate a constraint for the potential benefit of affiliated resources within the constrained area. However, it would not be unreasonable to use a broader examination for uneconomic production as SPP advocates, instead of a screen using a positive Resource-to-Load

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[404] February 2013 Compliance Filing, Exh. No. SPP-11 at 16-17.

[405] *Id.* at 8.

[406] *See* MISO ASM Tariff, Module D section 64.1.3.a.i.(b).

Distribution Factor cutoff. Therefore, to ensure an appropriate screening occurs, we will require SPP to provide, as the Commission found appropriate for MISO,[407] that the screen for uneconomic production will include not only the existing criteria in section 3.6, but we also require SPP to insert language in section 4.6.1 of Attachment AG providing that it will monitor for uneconomic production being accomplished (1) via the energy offer where the incremental energy offer price for the resource is less than 50 percent of the applicable reference level and (2) via time-based or other resource offer parameters (non-time and non-dollar based), including in situations when the resource has a positive Resource-to-Load Distribution Factor. Further, to ensure that uneconomic production is fully reported under the sections addressing uneconomic production such as section 4.6.1, we will require SPP to clarify that the language (which addresses economic withholding) in Attachment AF section 3.2B which reads "An Energy Offer below $25/MWh will not be subject to mitigation measures" by adding the clause "for economic withholding" such that it reads "An Energy Offer below $25/MWh will not be subject to mitigation measures for economic withholding." We require SPP to make these modifications to the Tariff language in its compliance filing due 60 days after the issuance of this order. We note, however, that application of the standards in section 3.6 of Attachment AF and 4.6.1 of Attachment AG is meant to help clarify what SPP should be looking for in terms of uneconomic production. This does not alleviate SPP's notification and referral obligations to the Office of Enforcement that exist even when the suspected behavior does not fall explicitly within the categories or descriptions mentioned above.[408]

[407] *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 FERC ¶ 61,171, at P 90 (2012).

[408] SPP's Market Monitor has an obligation to refer to the Office of Enforcement all instances as to which it has reason to believe that a market violation has occurred. 18 C.F.R. §35.28 (g)(3)(iv)(A) (2013). It also has an obligation to notify the Office of Enforcement of instances in which behavior by a market participant or the ISO itself might require investigation, including, but not limited to, suspected market violations. 18 C.F.R. §35.28 (g)(3)(ii)(C). A market participant's conduct may appear to constitute a market violation, or otherwise require investigation, whether it falls within or outside of the scope of the screen. If the Market Monitor suspects that this is the case, it must report the behavior to the Office of Enforcement in accordance with the Commission's applicable regulations.

Physical Withholding and Unavailability of Facilities

October Order

370. In the October Order, the Commission found that SPP must further define physical withholding and unavailability of facilities to include withholding a part of a transmission or generation facility.[409] We note that this partial withholding could be accomplished in a number of ways including changes in physical offer parameters which reduce resource availability including, but not limited to, changing ramp rates, emergency and economic minimums and maximums, start-up times, minimum run times, and minimum down times. Also, the Commission also required SPP to define physical withholding within Attachment AG, as the term pertains to withholding of an electric facility or generation resource. The Commission directed SPP to revise its definition of physical withholding and unavailability of facilities to provide that it may include a market participant: (1) declaring that an electric facility has been derated, forced out of service or otherwise been made unavailable for technical reasons that are untrue or that cannot be verified; (2) refusing to provide offers or schedules for an electric facility when it is required to offer into the market when it would otherwise have been in the economic interest to do so without market power; (3) operating a generation resource in real-time to produce an output level that is less than dispatch targets; (4) derating a transmission facility or interface for technical reasons that are not true or verifiable; (5) operating a transmission facility in a manner that is not economic and that causes a binding transmission constraint or binding Reserve Zone constraint or local reliability issue; and (6) declaring that the capability of resources to provide energy or operating reserves is reduced for reasons that are not true or verifiable. The Commission stated that SPP must provide that market participants would not be deemed to be physically withholding under this definition if they are following the directions of the SPP Balancing Authority or applicable reliability standards or if they were selling into another market at a higher price.[410]

371. The Commission required SPP to establish initial screening thresholds similar to those established in MISO, New York ISO, and ISO-NE for which the Market Monitor would identify physical withholding in Attachment AG of its Tariff.[411] The Commission

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[409] October Order, 141 FERC ¶ 61,048 at P 450.

[410] *Id.*

[411] *Id.* P 452.

also directed SPP to include in Attachment AG a requirement that the Market Monitor record instances where market participants failed SPP's defined physical withholding screen, and to notify the Commission's Office of Enforcement, or successor organization, of such behavior.[412]

February 2013 Compliance Filing

372. SPP revises section 4.6.4 of Attachment AG to provide further definition of physical withholding and unavailability of facilities. These revisions are nearly identical to the language required by the October Order. However, in section 4.6.4(b), SPP changes the language from "refusing to provide offers or schedules for an electric facility <u>when it is required to offer into the market</u> when it would otherwise have been in the economic interest to do so without market power" to "refusing to provide offers or schedules for a resource when it would otherwise have been in the economic interest to do so without market power."

373. In addition, SPP revises section 4.6.4 to make clear that market participants will not be deemed to be physically withholding if: (1) they are following the directions of the SPP Balancing Authority, Reliability Coordinator, or applicable reliability standards; or (2) they are selling into another market at a higher price.

374. SPP also proposes thresholds for identifying physical withholding of resource capacity in section 4.6.4.1 of Attachment AG. It addresses physical withholding in Frequently Constrained Areas in section 4.6.4.1.1 to Attachment AF. In particular, it proposes that a market participant is deemed to be physically withholding capacity in a Frequently Constrained Area if all of the following conditions exist: (1) one or more transmission constraints or Reserve Zone constraints that define the Frequently Constrained Area are binding; (2) the market participant controls or owns a resource in the Frequently Constrained Area that satisfies one of several of the specific conditions associated with physical withholding[413]; and (3) the Market Monitor determines that the

[412] *Id.* P 453.

[413] In particular, the conditions are: (1) declaring that an electric facility has been derated, forced out of service or otherwise been made unavailable for technical reasons that are untrue or that cannot be verified; (2) refusing to provide offers or schedules for an electric facility when it is required to offer into the market when it would otherwise have been in the economic interest to do so without market power; (3) operating a generation resource in real-time to produce an output level that is less than dispatch

(continued…)

withheld capacity has impacts on prices or make whole payments that exceed the market impact test thresholds in Attachment AF.

375. In section 4.6.4.1.2, SPP proposes thresholds for physical withholding in an area not designated as a Frequently Constrained Area. In particular, it proposes that a market participant is deemed to be physically withholding capacity in such an area if all of the following are true: (1) the Market Monitor determines that the withheld capacity has impacts on prices or make whole payments that exceed the market impact thresholds in Attachment AF, section 3.7; (2) one or more transmission constraints are binding or a Reserve Zone is binding; (3) the market participant owns or controls one or more resources that has local market power as defined Attachment AF, section 3.1 (thereby including a Resource-to-Load Distribution Factor cut-off to be met in non- Frequently Constrained Areas); (4) the resource(s) identified in this section either (a) satisfies one of several of the conditions associated with physical withholding and the total withheld capacity exceeds the lower of 5 percent of the total capacity owned or controlled by the market participant or 200 MW, or (b) where the real-time output of each such resource is less than the resource's operating tolerance defined in Attachment AE section 6.4.1 and the resource is not exempt from uninstructed resource deviation under Attachment AE section 6.4.1.1. The conditions associated with economic withholding are the same as those SPP proposes for Frequently Constrained Areas except that, in the case of non-Frequently Constrained Areas, SPP does not propose the standard of operating a generation resource in real-time to produce an output level that is less than dispatch targets.

376. SPP also adds section 4.6.4.2 to Attachment AG to provide for thresholds for screening of potential physical withholding of transmission facilities. This section provides that a transmission facility fails the physical withholding screen if all of the following conditions are met: (1) one or more transmission constraints are binding, a Reserve Zone is binding, or a local reliability issue is active; (2) the facility is derated for reasons that are not true or verifiable or the facility is found to be operated in an uneconomic manner causing the transmission constraint or Reserve Zone to be binding, or giving rise to a local reliability issue; (3) one or more resources owned or controlled by a market participant that is affiliated with the transmission owner satisfies the local market power test as specified in Attachment AF section 3.1; and (4) the Market

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targets; and (4) declaring that the capability of resources to provide energy or operating reserves is reduced for reasons that are not true or verifiable.

Monitor determines that the operation of the transmission facility as identified per sections 4.6.4(d) or 4.6.4(e) of Attachment AG has an impact on prices that exceeds the market impact test thresholds of Attachment AF section 3.7.

377. In section 4.6.4.3, SPP provides that the Market Monitor will record instances where market participants have failed the screens in sections 4.6.4.1 and 4.6.4.2 of Attachment AG and notify the Commission's Office of Enforcement, or successor organization, of such behavior. It provides that in the event the Market Monitor determines there is credible evidence of a market violation, the Market Monitor shall make a referral to the Commission as described in Attachment AG section 4.3.

Commission Determination

378. We find that SPP has complied with the October Order's requirement to generally provide a more specific definition of physical withholding and unavailability of facilities within Attachment AG. The revised section 4.6.4 of Attachment AG has specific list that complies with the Commission guidance in the October Order and we accept that language in this order.[414] As noted earlier in this order, we will require SPP to explain the application of the various physical withholding provisions to demand response resources. We also find that SPP complied with the requirement to make clear that market participants will not be deemed to be physically withholding if they are following the directions of the SPP Balancing Authority, Reliability Coordinator, or applicable reliability standards or they are selling into another market at a higher price.

379. With respect to the Commission's requirement that SPP provide thresholds for the identification of physical withholding in Attachment AG, SPP proposes separate thresholds for resource capacity and transmission facilities. However, SPP's proposal applies additional conditions to when a possible physical withholding determination will be made, which are not found in the standards for other ISOs and RTOs[415] and which generally relate to the standards for economic withholding in SPP. In particular, in these thresholds, SPP establishes that the impact test must be met, and for non-Frequently Constrained Areas, that the conditions for determination of local market power are met

[414] While SPP's language was slightly different in one subsection, as noted above in P 365, that difference does not affect our determination in this proceeding.

[415] *See* MISO ASM Tariff Module D, section 64.1.1, NYISO Attachment H, section 23.2.1.1.1.1, and ISO-NE Market Rule I Appendix A III.A.4.2.

including the requirement of meeting the Resource-to-Load Distribution cut-off.[416] We find that the language SPP has inserted to provide for the determination of physical withholding is overly limiting in that it requires the impact test to be met, and the Resource-to-Load Distribution factor cut-off to be met. Given that SPP has only a limited day-ahead must-offer obligation, it is very important that monitoring for physical withholding capture all such potential withholding, and we require SPP to remove these conditions from the determination of physical withholding that is reported to the Commission in its compliance filing due 60 days after the issuance of this order.

380. Further, SPP has not explained its proposal under section 4.6.4.2 that limits the Market Monitor's reporting of physical withholding of transmission facilities to circumstances where: (1) one or more transmission constraints are binding, a Reserve Zone is binding, or a local reliability issue is active; (2) one or more resources owned or controlled by a market participant that is affiliated with the transmission owner satisfies the local market power test; and (3) the Market Monitor determines that the operation of the transmission facility in question has an impact on prices or on make whole payments that exceeds the market impact test thresholds. Because SPP has not demonstrated these provisions to be just and reasonable, we require SPP to remove these specific conditions from the reporting of potential physical withholding by transmission facilities. We also require SPP, in its compliance filing due 60 days after the issuance of this order, to add to the determination of physical withholding of transmission facilities in section 4.6.4.2 of Attachment AG that the Market Monitor will also identify a pattern of scheduling outages resulting in increased market costs compared to an alternative and lower cost impact outage schedule. Monitoring such behavior may help to identify additional attempts to exercise market power by physical withholding of transmission facilities.

Monitoring and Mitigation of Virtual Bids and Offers

October Order

381. In the October Order, the Commission conditionally accepted SPP's proposal with respect to monitoring and mitigation of virtual bids and offers. However, the Commission found that it was not clear what SPP meant by its proposal to mitigate

[416] The impact test requirements are included in sections 4.6.4.1.1(c), 4.6.4.1.2(d) and 4.6.4.2(2). The requirement to meet the Resource-to-Load Distribution cut-off is contained due to the reference in 4.6.4.1.2(b) which references Attachment AF, section 3.1.

virtual offers and bids by a market participant at similar settlement locations, when it determines that there is excessive divergence between day-ahead and real-time balancing market LMPs caused by that market participant under section 4.6.3 of Attachment AG. The proposal had provided that the mitigation measures will restrict the market participants that caused the divergence from submitting any virtual energy bids or virtual energy offers at the settlement location or similar settlement locations where the market participant's virtual energy bids or virtual energy offers caused the excessive divergence. The Commission required SPP to insert the term "electrically" before "similar" in the phrase "similar Settlement Locations" in section 4.0 of Attachment AF, and to define the term "electrically similar" therein.[417]

February 2013 Compliance Filing

382. SPP proposes to modify section 4 of Attachment AF, to modify "similar Settlement Locations" with "electrically", and to define an electrically similar settlement location for purposes of this section as any settlement location that fails the divergence test under section 4.6.3 of Attachment AG.[418] Section 4.6.3 of Attachment AG provides the formulaic method by which the hourly LMP divergence is determined.

Commission Determination

383. We find SPP to be in compliance with the direction to modify the term similar, with "electrically" and we will accept it. However, we find that SPP's proposed definition of "electrically similar as any settlement location that fails the divergence test" under section 4.6.3 of Attachment AG to be unresponsive to the Commission's requirement that SPP define the term "electrically similar" for the purposes of section 4 of Attachment AF. Instead, this "definition" would, at best, appear to refer to any and all points at which there is a sufficient divergence for mitigation under the section to be mitigated along with other points that have such a sufficient divergence. Accordingly, we require SPP to further explain this provision, and to propose modification to section 4

[417] October Order, 141 FERC ¶ 61,048 at P 458.

[418] Section 4.6.3 of Attachment AG provides for the Market Monitor to compute the hourly LMP deviation between the day-ahead market and the Real-Time Balancing Market on a rolling four week rolling average. If the absolute value of the four week rolling average is greater than ten percent then the divergence is considered to be excessive and further analysis is required.

of Attachment AF that would implement its intention in its compliance filing due 60 days after the issuance of this order.

General Monitoring

October Order

384. In the October Order, the Commission noted that SPP had provided a substantial list of market data and information that the Market Monitor will monitor, acknowledging that this is not an inclusive list, the Commission required SPP to expand its monitoring focus. Specifically, the Commission found that the list of market data and information to be monitored should also include logs of Transmission Service requests and Generator Interconnection requests, along with the disposition of the request and the explanation of any refused requests. The Commission stated that the list also needs to include generation and transmission facility outage data beyond the line status and outage data they currently provide for.[419]

385. The Commission required SPP's Market Monitor to explain how its Market Monitoring procedures will apply to VERs. The Commission further stated that this explanation must include information regarding how monitoring for economic withholding, physical withholding, unavailability of facilities and uneconomic production will occur for VERs.[420]

386. The Commission required SPP's Market Monitor to monitor demand response resource participation in SPP's markets in a manner comparable to generation resources, and to notify the Office of Enforcement of any behavior by a demand response resource that the Market Monitor has reason to believe may constitute a Market Violation. In addition, the Commission required the Market Monitor as part of its Annual State of the Market Report, to assess and report on uplift charges associated with the make whole payments given to the demand response resources, and to assess and report on the market effects of demand response resources in SPP's markets, including any market benefits and perceived risks of exercising market power.[421]

[419] October Order, 141 FERC ¶ 61,048 at P 463.

[420] *Id.* P 464.

[421] *Id.* P 465.

387. The Commission stated that SPP provides in section 4.5 of Attachment AG that it will monitor for "potential transmission market power activities" and that it will refer any instances of "potential transmission market power" directly to the Commission. The Commission found that SPP's wording should be amended, such that SPP's Market Monitor should focus on and report instances of the suspected *exercise* of market power to the Commission, not the mere existence of market power. Accordingly, the Commission required SPP to clarify in section 4.5 of Attachment AG that the Market Monitor is to monitor for the *exercise* of market power and that it will bring to the attention of the Commission's Office of Enforcement any potential instances of *the exercise of* market power that it believes may require attention, and that the Market Monitor will refer any instances of the exercise of market power that may be part of a suspected market violation, such as manipulation.[422]

388. Further, the Commission required SPP to revise section 4.6 of Attachment AF to modify the language to provide that mitigation measures for certain of those behaviors are provided in Attachment AF. The Commission also required SPP to provide that nothing in section 4.6 limits the Market Monitor's obligation to refer other suspected market violations, even where the suspected behavior does not fall explicitly within these categories or descriptions.[423]

389. The Commission noted that Attachment AF sections 3.2.3(3), 3.2.4(3), and 3.2.5(3) refer to section 3.5 of Attachment AF (while referencing the impact test), when those sections should refer to section 3.4 of Attachment AF. The Commission required SPP to correct these errors.[424]

390. Finally, the Commission required SPP to fix the Table of Contents to Attachments AF and AG such that they match the titles to the corresponding sections of those Attachments.[425]

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[422] *Id.* P 466.

[423] *Id.* P 467.

[424] *Id*. P 468.

[425] *Id.* P 469.

Commission Determination

391. We find that SPP appropriately expands its market monitoring scope in section 4.2 of Attachment AG, as required by the Commission. We accept SPP's proposal to revise section 4.5 of Attachment AG to require the Market Monitor to report the suspected *exercise* of market power. We also require SPP in its compliance filing due 60 days after the issuance of this order to clarify the first sentence of section 4.5 of Attachment AG to read: "The [M]arket [M]onitor shall monitor Markets and Services for the exercise of transmission market power by…."

392. In addition, within section 4.5 of Attachment AG, SPP has provided for referral of any perceived market design flaws and recommended tariff language changes to the Commission's Office of Enforcement rather than to the Office of Energy Market Regulation. Referrals of market design flaws and associated tariff language change requests should be directed to the Commission's Office of Energy Market Regulation, as established in Order No. 719.[426] Accordingly, we require SPP, in its compliance filing due 60 days after the issuance of this order, to modify section 4.5 of Attachment AG to remove language associated with referrals of perceived market design flaws to the Office of Enforcement (while retaining the language on referral of instances of suspected market power exercise).[427]

393. We find that that language SPP has inserted in section 4.6 of Attachment AG providing that nothing in section 4.6 limits the Market Monitor's obligation to refer other suspected market violations, even where the suspected behavior does not fall explicitly

[426] *See* Order No. 719, FERC Stats. & Regs. ¶ 31,281 at PP 357, 354. *See also* 18 C.F.R. § 35.28(g)(3)(v)(C). Referrals of perceived market design flaws and requests for associated Tariff language changes by the Market Monitor to the Office of Energy Market Regulation are already included in accepted Tariff Language in section 1.3 of Attachment AG. Under section 1.3, SPP has provided for evaluation of existing and proposed market rules, Tariff provisions, and market design elements and recommendations of proposed rules and Tariff changes to the Transmission Provider, the Office Energy Market Regulation and other interested entities. We note that copies of the referral to the Office of Energy Market Regulation also are to be provided to the Director of the Office of Enforcement and to the General Counsel. 18 C.F.R. § 35.28(g)(3)(v)(C).

within these categories or description, meets the Commission's required change relating to section 4.6 of Attachment AG and will accept it.

394. We also find that SPP has complied with the requirement to modify its Tariff to include appropriate references to the Market Impact test in what were sections 3.2.3(3), 3.2.4(3), and 3.2.5(3) of Attachment AF. Finally, we find that SPP has updated the Table of Contents in compliance with the directives in the October Order and we accept these changes.

Miscellaneous Compliance Issues

Confidentiality Provisions

October Order

395. In the October Order, the Commission conditionally accepted SPP's proposed revisions to its confidentiality provisions subject to further revisions. Specifically, the Commission directed that in section 9.0 of Attachment AE, SPP must clearly state that it will provide data on all bids and offers rather than only cleared bids and offers.[428] The Commission also directed SPP to explain why it should not release such data by settlement location.

February 2013 Compliance Filing

396. SPP's filing revises section 9.0 of Attachment AE to state that SPP will release "data on all" day-ahead offers and bids.[429] SPP explains that the bid and offer data will not be released by settlement location because doing so could reveal the identity of the market participant submitting the bid and offer data. SPP asserts that this would be contrary to the Commission's finding in Order No. 719 that masking of identities for bid

[428] October Order, 141 FERC ¶ 61,048 at P 484.

[429] SPP Tariff, Attachment AE, section 9.0.

and offer data is appropriate.[430] Thus, SPP also clarifies in section 9.0 that bid and offer data released by SPP will not "be provided by [s]ettlement [l]ocation."[431]

Commission Determination

397. We find that SPP has complied with the Commission's directives in the October Order regarding its confidentiality provisions. SPP's revised Tariff provisions make clear that SPP will release data on all day-ahead bids and offers, rather than only cleared bids and offers. In addition, we find SPP's reasoning for not releasing such data by settlement location to be just and reasonable and accept the associated Tariff revisions clarifying as such.

Readiness and Reversion Plans

October Order Compliance Directive

398. In the October Order, the Commission conditionally accepted SPP's proposed Integrated Marketplace filing subject to, among other things, SPP filing its proposed Readiness Plan and Reversion Plan by March 2013.[432] In addition, the Commission required SPP to include in the Readiness Plan the Market Monitor's implementation plan to explain the timeline to ensure appropriate operations, staff, and resources are in place for the Market Monitor by the Integrated Marketplace's effective date.[433]

Readiness and Reversion Plans Filing

399. SPP submits its independently developed readiness metrics related to commercial operations (Readiness Plan) and Reversion Plan. SPP requests that the Commission

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[430] February 2013 Compliance Filing at 46-47 (citing Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 423).

[431] *Id.*, SPP Tariff, Attachment AE, section 9.0.

[432] This requirement was consistent with SPP's representations in the February 2012 Filing that it would make the Readiness Plan and Reversion Plan filing by March 2013. October Order, 141 FERC ¶ 61,048 at P 499.

[433] *Id.* P 462.

accept this filing for informational purposes and advises the Commission that further refinements, if any, to the readiness metrics, and other aspects of the Readiness Plan,[434] and the Reversion Plan[435] will be forthcoming.

Commission Determination

400. As discussed below, the Commission conditionally accepts SPP's Readiness Plan and Reversion Plan, subject to additional filings. We find that SPP's Readiness Plan provides information regarding SPP's plans to: develop appropriate readiness metrics, perform readiness testing for Integrated Marketplace systems, and achieve final readiness certification 60 days prior to market launch. In particular, SPP's Readiness Plan contains 39 metrics to measure, monitor, and report on SPP's readiness to start the Integrated Marketplace.[436] However, SPP's Readiness Plan fails to address the Market Monitor implementation plan and the timeline required by the October Order. Therefore, we require SPP to provide its Market Monitor implementation plan to ensure that the Market Monitor has access to sufficient market data, resources, and personnel to carry out its functions in the Integrated Market. We also require SPP to include in the compliance filing a timeline that ensures that appropriate operations, staff, and resources are in place for the Market Monitor by the Integrated Marketplace's proposed effective date. Thus, we require SPP to submit within 60 days of the date of this order, a compliance filing to address the Market Monitor implementation plan and the timeline.

401. Additionally, we note that when MISO submitted a similar Readiness and Reversion Plan ahead of the launch of its energy markets, the Commission required it to file reports detailing its progress toward market launch every 60 days with the Commission.[437] The Commission also required MISO to file a certification of readiness

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[434] SPP Readiness and Reversion Filing at 4.

[435] *Id.* at 5.

[436] SPP further commits to file with the Commission any further refinements to the metrics, and other aspects of the Readiness Plan, as they are developed.

[437] *Midwest Indep. Transmission Sys. Operator, Inc.* 108 FERC ¶ 61,163, at P 45 (2004), *reh'g denied*, 116 FERC ¶ 61,130 (2006).

prior to market launch.[438] Finally, the Commission required MISO to explain how the transition of functional responsibilities will not affect reliability.[439]

402. In order to help facilitate launch of the Integrated Marketplace, we find that similar requirements would benefit SPP and its stakeholders. Thus, we direct SPP to document its progress toward launch of the Integrated Marketplace by filing informational reports with the Commission every 60 days from the date of this order. SPP must also file a certification of readiness 60 days prior to market launch, as it has committed to do. We further direct SPP to explain how the transition of functional responsibilities will not adversely affect reliability, in a compliance filing due 60 days after the date of this order. Finally, our acceptance is subject to the outcome of the proceeding in which SPP proposed consolidation of the Balancing Authority Areas in a filing that was submitted on June 25, 2013.

403. We also conditionally accept SPP's proposed Reversion Plan subject to a compliance filing. We note that SPP's Reversion Plan is similar to the reversion plan filed by MISO when it launched its energy markets, and we find that it will facilitate the transfer from Integrated Marketplace operations back to pre-Integrated Marketplace operations in the event of any problems with the new market.[440] While SPP includes the same timeframes as required of MISO, SPP's Reversion Plan does not state that should SPP revert back to the EIS market, the window for invoking the plan will start anew upon the restart of the Integrated Marketplace.[441] Accordingly, we direct SPP to revise its Reversion Plan to clarify that the window for invoking its plan will start again upon the restart of the Integrated Marketplace, in a compliance filing due 60 days from the date of this order.

404. Finally, we note that the October Order was silent as to whether SPP should submit its Readiness Plan and Reversion Plan as a compliance or informational filing. SPP filed its Readiness Plan and Reversion Plan as an informational filing. Following

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[438] *Id.* P 55.

[439] *Id.* P 54.

[440] *Id*. P 58.

[441] The Commission required in MISO that the window would start again upon the restart of the MISO Day 2 operations. *Id.*

receipt, the Commission noticed the filing in the Federal Register and provided a comment period as would have been provided if the filing had been made as a compliance filing.

Miscellaneous Issues

Market Hubs

March 2013 Filing

405. In its March 2013 Filing, SPP proposes revising section 3.1.1 of Attachment AE to specify that the SPP Markets and Operations Policy Committee will consider the establishment or modification of a proposed Market Hub and shall obtain approval of such Market Hub in accordance with the procedures specified in the Market Protocols.[442] SPP states that it has established detailed procedures in its Market Protocols to guide the establishment of Market Hubs.[443] SPP also proposes decreasing the posting time for announcing the establishment of or modification to a Market Hub from six months to 45 days prior to the proposed effective date. Additionally, SPP proposes revising section 3.1.1 to remove language permitting the deletion of an established Market Hub.

Commission Determination

406. We find that SPP has not demonstrated that its revisions to section 3.1.1 of Attachment AE are just and reasonable. Specifically, SPP has not supported its proposal to remove oversight authority from the SPP Board of Directors for the establishment, modification, or deletion of a Market Hub, nor has it supported including these procedures in its Market Protocols, rather than in its Tariff. Additionally, SPP has not

[442] Previously, section 3.1.1 of Attachment AE provided that the Markets and Operations Policy Committee would provide its own recommendation regarding the establishment, modification, or deletion of a Market Hub to the SPP Board of Directors for review and approval.

[443] March 2013 Filing at 10. We note that SPP appears to include these Market Hub procedures in section 4.5.2.3 of its Market Protocols for the Integrated Marketplace. *See* Southwest Power Pool, Inc., Market Protocols SPP Integrated Marketplace, Revision 14.0a (May 10, 2013).

demonstrated that its proposals to eliminate the ability to delete an established Market Hub and reduce, by nearly 75 percent, the notice time for posting the establishment or modification of a Market Hub are just and reasonable. For these reasons, we reject without prejudice SPP's proposed revisions to section 3.1.1 of Attachment AE.

Attachment AH – Market Participant Service Agreement

March 2013 Filing

407. SPP proposes changes to its Market Participant Service Agreement, set forth in Attachment AH of the Tariff. SPP states that, currently, it requires prospective market participants to complete a spreadsheet as part of their market registration packets to provide market participant, asset, and metering information necessary for processing of the registration. SPP proposes adding a new Appendix 1 to Attachment AH, which specifies the information required from market participants upon execution of the Market Participant Service Agreement. SPP also proposes modifying section 2 of Attachment AH to require the prospective market participant to provide the Appendix 1 data. SPP asserts that these revisions are just and reasonable, because they clarify the data and information requirements for registering in the Integrated Marketplace for prospective market participants.[444]

Commission Determination

408. We accept SPP's proposed revisions to the pro forma Market Participant Service Agreement in Attachment AH of the SPP Tariff, effective March 1, 2014, as requested. We find SPP's revisions to be just and reasonable, as they clarify for prospective market participants the data and information requirements for registering in the SPP Integrated Marketplace.

Other Filings

409. We note that SPP has submitted compliance filings for the consolidation of Balancing Authority Areas, a Phase 2 market-to-market mechanism for managing congestion, and a filing in compliance with Order No. 755 on operating reserves.[445]

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[444] March 2013 Filing at 11.

[445] SPP Order No. 755 Compliance Filing in Docket No. ER13-1748-000.

Additionally, SPP has filed tariff revisions to carve out certain grandfathered agreements.[446] These filings are pending Commission action in separate proceedings and will be addressed in subsequent Commission orders.[447]

410. Prior to market launch, SPP is required to make additional compliance filings to complete Commission review of the Integrated Marketplace. Within 60 days of the date of this order, the Commission will require SPP to make a compliance filing addressing issues as specified in the order, including making revisions to Tariff language and providing additional support for elements of its proposal. SPP must also file its readiness certification at least 60 days prior to market start-up. Finally, the Commission requires SPP submit informational filings every 60 days to inform the Commission on the status of SPP's market readiness.

411. In addition, as directed in the October Order and discussed herein, SPP is required to make an informational filing 15 months following market launch. This filing is designed to assess how certain market design elements are functioning once market operations have commenced.

412. Moreover, Sellers in SPP that are authorized to sell energy at market-based rates are authorized to also sell ancillary services at market-based rates in the Integrated Marketplace, effective as of the start of the Integrated Marketplace, upon inclusion in their market-based rate tariffs[448] of the following standard ancillary services provision:[449]

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[446] GFA Order, 143 FERC ¶ 61,219.

[447] October Order, 141 FERC ¶ 61,048 at P 506.

[448] Sellers registered in the E FERC FPA Electric Tariff Program (Traditional Cost of Service and Market Based Rates) should use Type of Filing Code 80 – Compliance Filing. Sellers registered in the M FERC FPA Electric Program (Market Based Rate) should use Type of Filing Code 70. *See Implementation Guide for Electronic Filing of Parts 35, 154, 284, 300, and 341 Tariff Filings* (August 12, 2013) for the definitions of Type of Filing Code, *available at http://www.ferc.gov/docs-filing/etariff/implementation-guide.pdf*.

[449] In Appendix C to Order No. 697, the Commission adopted standard ancillary services provisions for PJM, NYISO, ISO-NE, and CAISO. The Commission stated that it would post these provisions on its website and update them as appropriate. The

(continued…)

> Southwest Power Pool: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self-supplying ancillary services to SPP.

413. Those who wish to sell these ancillary services in the Integrated Marketplace must file to include the above provision in their market-based rate tariffs no later than 60 days prior to the date on which they wish to begin selling these ancillary services.

414. Finally, we note that SPP has not submitted (and justified) its day-ahead Virtual Energy Transaction Fee, described in proposed section 8.5.17 of Attachment AE, in a section 205 filing. In the October Order, the Commission found that while it was reasonable for SPP to assess an administrative fee on virtual transactions, the Commission could not determine the justness and reasonableness of the actual fee without seeing the rate and cost causation support justifying the rate.[450]

The Commission orders:

(A) The proposed revisions to SPP's Tariff to comply with Commission orders and modify the Integrated Marketplace are conditionally accepted, in part, and rejected, in part, subject to the conditions described in the body of this order.

(B) Waiver of section 35.3 of the Commission's regulations is granted to allow the proposed Tariff revisions to become effective March 1, 2014, as requested.

Commission similarly adopted a standard ancillary services provision for MISO. *See Midwest Independent Transmission System Operator, Inc.*, 123 FERC ¶ 61,297, at P 46 (2008).

[450] October Order, 141 FERC ¶ 61,048 at P 133.

(C) SPP is required to make compliance and informational filings as described in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

Southwest Power Pool, Inc.

FERC FPA Electric Tariff

Open Access Transmission Tariff, Sixth Revised Volume No. 1

Docket No. ER12-1179-003

Definitions M, 1 Definitions M, 2.1.0

Definitions R, 1 Definitions R, 2.1.0

Section 13.5, 13.5 Transmission Customer Obligations for Facilities ..., 1.1.0

Attachment AE (MPL), Attachment AE Integrated Marketplace, 0.1.0

Att. AE (MPL) 1.1 A, Attachment AE (MPL) Section 1.1 A, 0.1.0

Att. AE (MPL) 1.1 B, Attachment AE (MPL) Section 1.1 B, 0.1.0

Att. AE (MPL) 1.1 C, Attachment AE (MPL) Section 1.1 C, 0.2.0

Att. AE (MPL) 1.1 D, Attachment AE (MPL) Section 1.1 D, 0.2.0

Att. AE (MPL) 1.1 E, Attachment AE (MPL) Section 1.1 E, 0.1.0

Att. AE (MPL) 1.1 F, Attachment AE (MPL) Section 1.1 F, 0.1.0

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Attachment AF, Attachment AF Market Power Mitigation Plan, 1.1.0

Attachment AF Section 2, Attachment AF Section 2, 1.1.0

Attachment AF Section 3, Attachment AF Section 3, 4.2.0

Attachment AF Section 4, Attachment AF Section 4, 1.1.0

Att. AF Add. 1, Attachment AF Addendum 1 - Frequently Constrained Areas, 0.0.0

Attachment AG, Attachment AG Market Monitoring Plan, 3.1.0

Attachment AG Section 4, Attachment AG Section 4, 2.1.0

Attachment AK, Attachment AK Treatment of Reserve Sharing Charges and ..., 1.0.0

Docket No. ER12-1179-005

Attachment AG Section 4, Attachment AG Section 4, 2.3.0

Docket No. ER13-1173-000

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Attachment AF Section 3, Attachment AF Section 3, 5.0.0

Attachment AH, Attachment AH Market Participant Service Agreement, 2.0.0

Attachment AH Appendix 1, Attachment AH Appendix 1, 0.0.0

Appendix B[451]

The items below outline the compliance directives established in the order.

Day-Ahead Market and Real-Time Balancing Market

1. Must-Offer Requirement

- Clarify section 2.11.1 of Attachment AE by clearly delineating (1) what the screening process for verification of the day-ahead must-offer requirement entails, and (2) how the Market Monitor will conduct this screening process, particularly the Market Monitor's responsibility in regard to verification and the values the Market Monitor is comparing when making its determination. (P 39)

- Make conforming changes to section 3.9 of Attachment AF to be consistent with section 2.11.1 of Attachment AE. (P 39)

- Discuss whether the ten percent forecasting error has had a disproportionate impact on smaller load-serving entities; whether expressing the acceptable forecasting error as a percentage deviation and as a minimum MW absolute error is warranted based on market observations; and, if so, a possible MW value for this minimum absolute error. (P 40, n.38) **15 month informational filing**

- Remove sections 3.9.A(2) and 3.9.A(3) from Attachment AF. (P 41)

- Consider and report on whether the penalty provisions in section 3.9 of Attachment AF have ensured that sufficient resources are available to cover the load and operating reserve obligations of load-serving entities, as well as the extent to which the Market Monitor has had to assess penalties under section

[451] We note that Appendix B sets forth the comprehensive list of compliance directives included in the order. To the extent that there is inconsistency with respect to the order text and the language in Appendix A regarding the individual directives, the order text shall govern.

3.9 during the first year of market operations. (P 42) **15 month informational filing**

- Revise section 2.11.1 of Attachment AE to allow load transfers and/or bilateral contracts to count toward must-offer obligations; further explain the relationship between the day-ahead must-offer requirement and these load transfers and/or bilateral contracts and propose clarifying edits to the Tariff, as needed; and, overall, clarify the net resource capacity definition in section 2.11.1of Attachment AE to account for the full range of firm purchases subject to the day-ahead must-offer obligation. (P 50)

2. <u>Demand Response Resources</u>

- Revise the Tariff to provide that wholesale customers may be aggregated into a larger demand response resource and include in the Tariff any associated aggregation requirements. (P 55)

- Revise section 2.8(2)(a) of Attachment AE to state that end-use customers may be aggregated into a single dispatchable or block demand response resource behind an aggregated price node containing multiple electrically equivalent points, in accordance with section 2.2(2) of Attachment AE. (P 63)

- Revise sections 4.1.2.1(1) and 4.1.2.1(2) of Attachment AE to reflect the aggregated price node option specified in section 2.2(2) of Attachment AE, and make any additional related Tariff revisions, as necessary. (P 63)

- Assess whether additional revisions are necessary to section 2.2(3) of Attachment AE to accommodate the revision made to section 2.2(2) in the March 2013 Filing. (P 63)

- Include the number of registered aggregated demand response resources in the Integrated Marketplace. (P 64) **15 month informational filing**

- Report on experiences with any problems relating to the aggregated price node concept specified in section 2.2(2) of Attachment AE (for both demand response and non-conforming load). (P 64) **15 month informational filing**

3. <u>Variable Energy Resources</u>

- Include an analysis of whether dispatchable VERs may reliably provide regulation-up and/or contingency reserves. (P 80) **15 month informational filing**

- Explain SPP's methodology for determining its output forecasts for dispatchable VERs, its meteorological data requirements for VERs, and corresponding Tariff revisions. (P 82)

- Explain why and how SPP's data requirements for dispatchable VERs that execute LGIAs on or after June 16, 2013, are consistent with the *pro forma* LGIA revisions that were conditionally accepted in the Commission's order conditionally accepting SPP's proposed revisions to comply with the requirements of Order No. 764. (P 82)

- Revise the SPP Tariff to use SPP's output forecast, rather than the maximum output limit submitted by a wind-powered VER, in the event that the limit is not updated, is not submitted, or exceeds the resource's physical operating limit in the real-time market and not in the RUC processes. (P 83)

4. <u>Uninstructed Resource Deviation</u>

- Include in an informational filing an analysis addressing whether the URD tolerance band continues to be appropriate based on actual operating experience. (P 93) **15 month informational filing**

5. <u>Manual Commitments</u>

- Remove all Tariff provisions that (1) allow a local transmission operator to directly commit resources in situations outside of emergency conditions, and (2) allow a local transmission operator to directly commit resources that affect the facilities modeled by SPP, including the transmission system. (P 108)

- Limit manual commitments made by local transmission operators to "Emergency Conditions," as defined in the Tariff. (P 108)

- Include a transparent description of the manual commitment process explaining when and why manual commitments are to be made and how local transmission operators and SPP will decide which resources to commit manually. (PP 109-110)

- Require the creation of operating guides to address known and recurring reliability issues that are associated with manual commitments. (P 110)

- Apply the local transmission operator discrimination criteria to SPP and clarify that the Market Monitor will review the manual commitments made by both SPP and the local transmission operator. (P 111)

- Clarify the denial of compensation for non-discriminatory behavior applies only resources affiliated with local transmission operators. (P 112)

- Require that notice of an alleged discriminatory action be provided to the Commission. (P 113)

- Remove "or local transmission operator" from section 6.1.2(3) of Attachment AE, proposed in the March 2013 Filing. (P 115)

6. <u>Make Whole Payments</u>

- Provide a clear definition of the term "Settlement Area." (P 129)

- Remove the phrase "will be determined" the first time it appears in the third sentence of section 8.6.7. (P 129)

- Move the phrase "to address a Local Reliability Issue" later in the sentence. (P 129)

- Explain why SPP assumes that all OOME payment amounts pertain to Local Reliability Issues and could not pertain to reliability issues affecting the transmission system. If such amounts could pertain to reliability issues affecting the transmission system, revise the OOME cost allocation. (P 130)

- Revise the definition of "Local Reliability Issue" to explain the basis for commitments to address such issues. (PP 131-132)

- Remove virtual energy bids from the RUC make whole payment cost allocation methodology. (P 137)

- Add the words "or reduce output of" in between "provide" and "energy" in section 6.4.1.1(7) of Attachment AE. (P 146)

- Provide additional justification for the provisions in sections 4.1.2.4(2)(a) and 4.1.2.5(5)(a) of Attachment AE in the March 2013 Filing, which specify that dispatchable and non-dispatchable VERs for which SPP is calculating an output forecast are not eligible to receive RUC make whole payments, particularly why these resources should be ineligible to recover their variable costs if, for example, SPP issues a curtailment instruction to the resource (*i.e.*, explain why a VER should be ineligible to recover any revenues that it may otherwise have received had it not been curtailed). (P 147)

- Revise section 8.6.6(1) to properly cap the compensation. (P 150)

- Refine the "economic operating point" in section 8.6.6(1). (P 151)

7. Marginal Losses

- Submit an alternative proposal for refunding marginal loss surpluses. (P 158)

8. Price Formation During Shortage Conditions

- Revise SPP's methodology for calculating prices during shortage events. (P 169)

- Report on and discuss any shortage conditions and resulting prices that have occurred, overall demand response participation, and provide an analysis of how its shortage pricing provisions have impacted the entry and exit of demand response and other supply resources. (P 170) **15 month informational filing**

9. Operating Reserves

- Revise the definitions of Regulation-up and Regulation-down, such that they do not preclude otherwise-qualified resources from providing regulation-down and regulation-up service. (P 173)

Market-Based Congestion Management

1. Overall Congestion Management Proposal

    - Allow transmission customers with rights to roll over their agreement to obtain ARRs in the Annual Allocation Process without requiring them to give more than one year notice. (P 179)

    - Require the TCR Auction to be subject to mitigation. (P 181)

2. ARR Allocation Processes

    - Modify section 7.1.3(1) to include Commission-provided revisions. (P 196)

    - Explain how SPP will allocate on-peak and off-peak ARRs for customers with redispatch obligations. (P 198)

3. TCR Auction

    - N/A

Integration Issues

1. Bilateral Settlement Schedules

    - Revise the transition mechanism to apply to all unsettled bilateral agreements entered into prior to the start of the Integrated Marketplace. (P 222)

    - Modify section 8.2 of Attachment AE to reflect that both a buyer and a sell must confirm a Bilateral Settlement Schedule except for a Bilateral Settlement Schedule associated with an existing bilateral agreement under section 8.2.1, as requested by TDU Intervenors. (P 223)

    - Revise Addendum 2 to explain how SPP derived its proposed numbers, and to reconcile the inconsistency in the tariff sections addressing the source and sink for TCRs. (P 224)

    - Remove the tariff language in section 8.2 of Attachment AE, which allows SPP to terminate the Bilateral Settlement Schedule if a party is in default. (P 225)

- Make the ministerial changes SPP has agreed to make. (P 226)

- Revise section 2.2(11) of Attachment AE to allow load transfers if the seller agrees to assume responsibility for the buyer's load that is transferred. (P 227)

2. General Seams

- N/A

3. Pseudo-Tie Arrangements

- Modify section 2.14.5 of the Tariff to sufficiently explain the process for determining which Reserve Zone to assign a registered External Dynamic Resource during the registration process. (P 239)

Market Mitigation and Monitoring

1. Parameters for Mitigation of Economic Withholding

- Modify section 3.1 of Attachment AF so that local market power is found when at least one of the following conditions are met: (1) the resource is located in a Frequently Constrained Area, as defined in section 3.1.1, and one or more of the transmission constraints that define the Frequently Constrained Areas is binding or the Reserve Zone that defines the area is binding; (2) the resource is not in a Frequently Constrained Area and (a) has a Resource-to-Load-Distribution factor less than or equal to negative five percent relative to a binding transmission constraint, or (b) is in a binding Reserve Zone; (3) the resource is manually committed by the Resource Provider or selected for commitment by a local transmission operator in the Day-Ahead or Intra-day RUC processes. (P 259)

- Remove the word "caps" from the phrase "After an initial market solution is computed with no mitigation measures caps in place...." in section 3.7 of Attachment AF. (P 261)

- Modify the definition of definition of a Local Reliability Issue as required in paragraphs 131-132 of this order. (P 262)

2. Frequently Constrained Area Mitigation of Economic Withholding

- Modify the last sentence in section 3.1.1 to clarify that any designation or change in designation for Frequently Constrained Areas is subject to prior approval by the Commission. SPP must modify that last sentence of section 3.1.1 so that it reads: "Any new or modifications to existing Frequently Constrained Areas are subject to prior Commission approval." (P 272)

- Modify section 3.1.1.1 of Attachment AF to provide that a supplier is pivotal in relation to the energy output or provision of operating reserves by "any or some of its resources jointly" rather than by "any of its resources." Also, address whether and how a demand response resource can be determined to be a pivotal supplier under section 3.1.1.1 given that it is unclear how each of the conditions therein applies to demand response resources. Address the applicability of each of the provisions under 3.1.1.1 to demand response resources as potential pivotal suppliers. (P 273)

- Revise the cite in section 3.2(A)(2) of Attachment AF, which mistakenly refers to section 3.2(1) so that it appropriately refers to section 3.2(A)(1). (P 274)

- Provide examples that show how mitigation of affiliated resources would occur given the pivotal supplier designation and given the language in section 3.2.2 of Attachment AF that SPP proposes to remove relating to mitigation of other resources represented by the market participant that were on the importing (i.e. load) side of the constraint within the SPP system. These examples should show how the mitigation would occur with and without the provision for mitigation of other resources represented by the market participant that were on the importing (i.e. load) side of the constraint within the SPP system. SPP must include examples which show mitigation of an affiliated resource in Frequently Constrained Areas, non-Frequently Constrained Areas and in areas with commitments for reliability reasons, and show instances when the affiliated resources have and have not failed the conduct and impact tests. (P 276)

3. Mitigated Offer Development

- Clearly specify the physical equipment limitations on starts and stops and fuel supply limitations associated with determination of opportunity costs to be included in mitigated offers such that the costs are legitimate and verifiable.
- (P 296)

- Explain how the Market Monitor will verify equipment limitations under section 3.3(E) of Attachment AF as part of the Market Monitor's review of the offer and to make any necessary Tariff revisions to implement this process. (P 298)

- Address the issue of opportunity cost associated with peak hours and changing opportunity costs as the going forward limitations upon a resource change. Develop tariff language to address this issue in a manner that addresses opportunity costs that vary associated with these factors. (P 299)

- Explain how market participants will estimate forgone future market prices and how they will determine associated opportunity costs. (P 300)

- Modify the language in section 3.2(C) of Attachment AF (stating "Opportunity cost shall be an estimate of the Energy and [o]perating [r]eserve Markets revenues net of short run marginal costs for the marginal forgone run time during the period of limitation as detailed in the Market Protocols"). File language that instead refers to revenues forgone during the timeframe when resources experience the run-time restrictions. (P 302)

- Clarify the use of certain formula terms in its Tariff. Several formula terms use abbreviated terms and it is unclear whether those terms are defined in the Tariff (e.g., Min. Econ. Capacity in section 3.3(D)). Accordingly, SPP must propose revisions to ensure that formula terms are tied to defined Tariff terms. (P 304)

4. <u>Mitigated Offer Development by Market Participant</u>

- Propose specific Tariff language that will ensure consistency across all market participants in the calculation (but not necessarily the level) of certain costs that are to be used in the development of mitigated offers, including fuel costs, fuel-related costs (e.g., emissions costs), opportunity costs, VOM, and start-up and no-load costs. Where there are common factors or measures that are applied in multiple mitigated offers (such as projected prices of forgone sales used in the determination of opportunity costs), these must be applied consistently. Also provide how mitigated offers will address frequently changing input costs, such as fuel costs, so that input costs are up to date in the mitigated offers. (P 321)

- Provide in the Tariff, that if a market participant submits a dispute over its mitigated offer, the previously approved mitigated offer is used until the dispute is resolved. Propose language for the Commission to review that establishes any additional measures that will occur if and when the dispute is resolved in the market participant's favor such as what will occur with respect to market settlements that have occurred while the disputed mitigated offers were in effect, and to explain the proposed approach. (P 322)

- Amend section 3.6 of Attachment AF such that it reads "Mitigation measures will remain in place until such time that the Market Participant demonstrates the validity of the Resource Offer parameter or the Market Participant notifies the Market Monitor that the Resource Offer parameter has been changed to a value that is within the tolerance band as described above, and the Market Monitor has verified that this change has occurred." (P 323)

5. <u>Variable Energy Resources</u>

- Address how SPP's monitoring and mitigation procedures apply to VERs including: (1) whether monitoring and mitigation measures for economic withholding, physical withholding, unavailability of facilities and/or uneconomic production are appropriate for VERs, given their unique characteristics and risks of exercising market power; (2) whether all types of VERs warrant identical monitoring and mitigation measures; and (3) whether identical monitoring and mitigation measures will apply during all five-minute dispatch intervals in the real-time market; to the extent that SPP's monitoring and mitigation measures should apply to VERs, how various generic Tariff provisions will apply to VERs; all of the issues previously raised by E.ON. (P 326)

- Demonstrate whether SPP's monitoring and mitigation measures for economic withholding, physical withholding, unavailability of facilities and/or uneconomic production are appropriate for dispatchable and/or non-dispatchable VERs and under which circumstances, address how these measures would be applied, and file any tariff revisions necessary to provide these clarifications. (P 326)

6. <u>Mitigation of Demand Response</u>

- Explain its treatment of generally applicable operating parameters for demand response resources. SPP must develop a consistent plan for dealing with those operating parameters that are generally applicable to all demand response resources. (P 339)

- Clarify and provide tariff revisions, as necessary to account for how the Market Monitor will apply physical withholding standards to demand response addressing the issues specified in this paragraph.(P 340)

7. Conduct and Impact Thresholds

- Report on the effectiveness of the conduct and impact thresholds, we require SPP to report on them as a part of the informational report due 15 months following commencement of the Integrated Marketplace. In particular, SPP must address whether the conduct and impact thresholds for the various products and under the various circumstances (i.e. non-Frequently Constrained Areas, Frequently Constrained Areas, and where there are manual commitments as described in section 3.1(4)) appropriately identify conduct that needs to be mitigated. (P 357, P 359) **15 month informational filing**

- Limit the reporting of non-mitigation after a pre-offer consultation occurs under section 3.8(B) of Attachment AF, to instances when the resulting offer violates both the conduct and impact threshold. (P 361)

8. Uneconomic Production

- Insert language in section 4.6.1 of Attachment AG providing that it will monitor for uneconomic production being accomplished (1) via the energy offer where the incremental energy offer price for the resource is less than 50 percent of the applicable reference level and (2) via time-based or other resource offer parameters (non-time and non-dollar based), including in situations when the resource has a positive Resource-to-Load Distribution Factor. Further clarify that the language (which addresses economic withholding) in Attachment AF section 3.2B which reads "An Energy Offer below $25/MWh will not be subject to mitigation measures" by adding the clause "for economic withholding" such that it reads "An Energy Offer below $25/MWh will not be subject to mitigation measures for economic withholding." (P 369)

9. Physical Withholding and Unavailability of Facilities

- As noted earlier in the order, explain the application of the various physical withholding provisions to demand response resources. (P 378)

- Remove the following conditions upon physical withholding that is to be reported to the Commission under Attachment AG: that the impact test must be met, and for non-Frequently Constrained Areas, that the Resource-to-Load Distribution cut-off be met. The impact test requirements are included in sections 4.6.4.1.1(c), 4.6.4.1.2(d) and 4.6.4.2(2). The requirement to meet the Resource-to-Load Distribution cut-off is contained due to the reference in 4.6.4.1.2(b) which references Attachment AF, section 3.1. (P 379)

- Remove from section 4.6.4.2 of Attachment AG the following conditions limiting to reporting of physical withholding to circumstances where: (1) one or more transmission constraints are binding, a Reserve Zone is binding, or a local reliability issue is active; (2) one or more resources owned or controlled by a market participant that is affiliated with the transmission owner satisfies the local market power test; and (3) the Market Monitor determines that the operation of the transmission facility in question has an impact on prices or on make whole payments that exceeds the market impact test thresholds. (P 380)

- Add to the determination of physical withholding of transmission facilities in section 4.6.4.2 of Attachment AG that the Market Monitor will also identify (as potential physical withholding) a pattern of scheduling outages resulting in increased market costs compared to an alternative and lower cost impact outage schedule. (P 380)

10. Monitoring and Mitigation of Virtual Bids and Offers

- Further explain the term "electrically similar", and to propose modification to section 4 of Attachment AF that would implement its intention. (P 383)

11. General Monitoring

- Clarify the first sentence of section 4.5 of Attachment AG to read: "The [M]arket [M]onitor shall monitor Markets and Services for the exercise of transmission market power by…." (P 391)

- Modify section 4.5 of Attachment AG to remove language associated with referrals of perceived market design flaws to the Office of Enforcement (while retaining the language on referral of instances of suspected market power exercise). (P 392)

- **Please Note:** There are requirements above for the Market Monitor in the must-offer section and market-based congestion management section. There is a requirement below for the Market Monitor implementation plan and timeline for implementation.

Miscellaneous Compliance Issues

1. Confidentiality Provisions

   - N/A

2. Readiness and Reversion Plans

   - Provide the Market Monitor implementation plan and a timeline for implementation. (P 400)

   - Informational reports filed every 60 days on the progress toward the launch of the Integrated Marketplace. (P 402)

   - File the readiness certification. (P 402)

   - Explain how the transition of functional responsibilities will not adversely affect reliability. (P 402)

   - Revise the Reversion Plan to clarify that the window for invoking its plan will start again upon the restart of the Integrated Marketplace. (P 403)

Miscellaneous Issues

1. Market Hubs

   - N/A

2. Attachment AH – Market Participant Service Agreement

   - N/A

3. Future Filings

- Those who wish to sell these ancillary services in the Integrated Marketplace must file to include Commission-provided language in their market-based rate tariffs no later than 60 days prior to the date on which they wish to begin selling these ancillary services. (P 412)