UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southwest Power Pool, Inc.	)	Docket No. ER12-1179-000

MOTION FOR LEAVE TO ANSWER AND ANSWER OF SOUTHWEST POWER POOL, INC. TO PLEADINGS CONCERNING PROPOSED INTEGRATED MARKETPLACE

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.213, Southwest Power Pool, Inc. ("SPP") moves to answer,[1] and answers the various pleadings filed in response to SPP's May 15, 2012 Answer[2] and SPP's May 15, 2012 Amendatory Filing[3] in this proceeding.[4] In support, SPP states as follows:

---

1 SPP seeks leave to submit this answer to assist the Commission's decision-making process and clarify the issues. The Commission regularly allows answers for such purposes. *See, e.g., Sw. Power Pool, Inc.*, 135 FERC ¶ 61,223, at P 27 (2011) (accepting answers that aided the Commission's decision-making); *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042, at P 28 (2010) (same), *reh'g denied*, 136 FERC ¶ 61,050 (2011); *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252, at P 19 (2010) (same); *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,018, at P 15 (2009) (same); *Sw. Power Pool, Inc.*, 126 FERC ¶ 61,153, at P 18 (2009) (same).

2 Answer of Southwest Power Pool, Inc., Docket No. ER12-1179-000 (May 15, 2012) ("May 15 Answer").

3 Amendatory Filing of Tariff Revisions to Implement SPP Integrated Marketplace, Docket No. ER12-1179-001, (May 15, 2012) ("May 15 Amendatory Filing").

4 SPP limits this response to new arguments and proposals not previously covered in SPP's May 15 Answer and not otherwise addressed in SPP's Integrated Marketplace, or any other issues currently pending before the Commission in non-Integrated Marketplace related dockets, is not intended, and should not be construed, as SPP's concession with respect to any such requested modification or other points of issue.

I. BACKGROUND

Detailed background concerning the development of SPP's Integrated Marketplace proposal was provided in the Integrated Marketplace Filing and supporting testimony.[5] There, SPP explained that the Integrated Marketplace Filing represented the culmination of an extensive, multi-year process involving the entire SPP stakeholder community (including the SPP Regional State Committee ("RSC")),[6] and incorporated many key design elements that had been approved for and operating in other regional markets. SPP noted that cost efficiencies attributable to the Integrated Marketplace were projected to result in annual net benefits of between $45 million and $100 million.[7]

In response to SPP's Integrated Marketplace filing, numerous parties filed comments raising issues or concerns with certain proposed market design features. Prominent in these comments were questions regarding SPP's proposed market mitigation procedures, must-offer requirements, treatment of Grandfathered Agreements ("GFAs") and planned development of long-term firm transmission rights.

On May 15, 2012, SPP filed an Answer to these comments. SPP's May 15 Answer defended the proposed Integrated Marketplace design and, where appropriate, clarified design features that were either misunderstood or mischaracterized in the parties' comments.

---

5 Submission of Tariff Revisions to Implement SPP Integrated Marketplace of Southwest Power Pool, Inc., Docket No. ER12-1179-000 (Feb. 29, 2012) ("Integrated Marketplace Filing").

6 *Id.*, Transmittal Letter at 2 and Exhibit No. SPP-1 at 7-8.

7 *Id.*, Transmittal Letter at 2 and Exhibit No. SPP-1 at 7-8.

Also on May 15, 2012, SPP filed an Amendatory Filing to the Integrated Marketplace Filing. In the May 15 Amendatory Filing SPP proposed, *inter alia*, revised market mitigation procedures; revised rules governing Contingency Reserve retesting; new tariff provisions to ensure compensation for locally-committed generation; clarifications addressing the implementation of Manual Dispatch Instructions and the calculation of Real Time Balancing Market ("RTBM") payments to Resources responding to Manual Dispatch Instructions; creation of a new Resource type – "External Dynamic Resource," or "EDRs" – that will allow External Resources that are not pseudo–tied to participate in the Integrated Marketplace; modifications to the registration requirements for Jointly-Owned Units; creation of two additional exemptions from Uninstructed Resource Deviation ("URD") charges; and various revisions affecting the modeling of excess generation and the protocols to be followed in response to excess generation conditions.

Over the past few weeks, several parties filed answers to SPP's May 15 Answer and/or comments regarding SPP's May 15 Amendatory Filing. In many cases, these pleadings served simply to rehash arguments on issues already fully joined. However, certain parties have advanced new objections to elements of SPP's market design, including elements reflected in SPP's May 15 Amendatory Filing. To ensure a full and accurate record, this answer responds to these new objections, corrects factual errors, and provides clarifications relevant to issues not previously addressed by SPP.

II. ANSWER

A. Challenges and Requested Modifications to SPP's Treatment of GFAs Are Unsupported and Should Be Rejected.

1. Contrary to MRES/Heartland's Contentions, Service Associated with GFA # 496 Is Subject to Centralized Scheduling.

Missouri River Energy Services, jointly with Heartland Consumers Power District ("MRES/Heartland"), filed an answer to SPP's May 15 Answer challenging SPP's contention that all firm reservations, including reservations under GFAs, are subject to centralized scheduling.[8] MRES/Heartland argue that SPP GFA #496, which transmits power from the Laramie River Station ("Laramie") under a service agreement by and between Basin Electric Power Cooperative and Nebraska Public Power District ("NPPD") is not subject to centralized scheduling inasmuch as power from Laramie is not scheduled with or committed to SPP in any way.[9] According to MRES/Heartland, SPP's refusal to carve-out GFAs from the design of the Integrated Marketplace based on the assumed centralized scheduling of *all* GFAs is "factually erroneous" and undercuts SPP's claim that the Integrated Marketplace simply preserves the status quo with respect to GFAs.[10]

Following filing of MRES/Heartland's Answer, SPP investigated the facts concerning GFA # 496 and confirmed that GFA # 496 is associated with two reservations

---

8 Motion for Leave to Answer and Answer of Missouri River Energy Services and Heartland Consumers Power District, Docket No. ER12-1179-000 (May 30, 2012) ("MRES/Heartland Answer").

9 MRES/Heartland explain that they are participants in the joint venture that developed the Laramie station. *Id.* at 2-3.

10 *Id.* at 4.

out of the same generator (Laramie). The first reservation, for 190 MW from the Laramie to LES, was converted to network service in April 2009 under SPP OASIS No. 1588681. Since that time, this network reservation, like all network service, has been subject to centralized scheduling.

The second reservation associated with GFA # 496 covers a transmission service that does not flow through, into, or out of the SPP region. Instead, this reservation – for 272 MWs from Laramie to MRES – is designated only on NPPD's OASIS, not on SPP's OASIS, and sources and sinks entirely within the WAPA Balancing Authority. Because this reservation is not associated with an SPP Settlement Location or SPP transmission service, it is not tagged by SPP and is not a GFA transmission service eligible for TCR and ARR allocation under SPP's Integrated Marketplace.

2. OPPD's Partial Path Service Is Properly Excluded from ARR/TCR Eligibility.

Omaha Public Power District ("OPPD") also filed an answer to SPP's May 15 Answer.[11] OPPD, which joined SPP as a transmission-owning member in 2009, argues that service under certain of OPPD's pre-existing transmission agreements will be denied ARRs and TCRs, contrary to SPP's claim that the proposed Integrated Marketplace design ensures equal and non-discriminatory treatment to all firm transmission service. OPPD challenges as unreasonable the ARR/TCR eligibility criteria established by SPP, including, specifically, the requirement that grandfathered service be "across a full firm

[11] Motion for Leave to Answer and Answer of Omaha Public Power District, Docket No. ER12-1179-000 (May 25, 2011) ("OPPD Answer").

path or be combined with supplemental GFAs (or SPP transmission service) that collectively represent a full firm path."[12]

Under the relevant agreements, OPPD is entitled to transmission to points that were originally SPP "border points," but became internal to SPP after OPPD joined SPP.[13] As next discussed, because these transmission arrangements involve only partial paths, they are properly excluded from TCR/ARR eligibility within the design of the Integrated Marketplace.

Specifically, with respect to transmission service to internal SPP points, OPPD is not entitled to schedule on its partial path *unless* there is a corresponding downstream reservation submitted with the upstream (partial path) reservation. With no entitlement to schedule power to these former border but now internal SPP points, SPP cannot properly consider these points as valid Settlement Locations for purposes of allocating TCRs and ARRs. To the contrary, these partial path reservations are more akin to conditional firm transmission reservations and are clearly distinct from the rights arising under conventional firm transmission service agreements, including pre-Order No. 888 GFAs and/or OATT point-to-point or network service agreements. The congestion protection intended through the awarding of TCRs and ARRs is neither necessary nor appropriate,

---

12 The TCR/ARR eligibility criteria were set forth in materials circulated by SPP to all TCR Market Participants on May 21, 2012. *See id.* at Attachment 1.

13 *See id.* at 3. Additionally, OPPD holds firm transmission to current SPP border points of Associated Electric Cooperative, Inc. ("AECI") and MidAmerican Energy Company ("MidAmerican"). SPP deems the transmission arrangements involving firm service to the AECI and MidAmerican border points as TCR/ARR qualified, and has so notified OPPD.

given that these arrangements do not represent firm service rights across the *full* path from source to sink.

B. Objections to SPP's Proposed Market Mitigation Procedures Lack Merit and Should Be Rejected.

Two parties – TDU Intervenors and Golden Spread Electric Cooperative, Inc. ("Golden Spread") – filed comments in opposition to SPP's revised market mitigation procedures, as reflected in SPP's May 15, 2012 Amendatory Filing. Ironically, these parties advance diametrically opposing views on the reasonableness of SPP's mitigation plan: TDU Intervenors seek more stringent mitigation protocols; Golden Spread complains that SPP has gone too far in terms of market power presumptions and price mitigation.[14]

As might be inferred from the comments of TDU Intervenors and Golden Spread, the perceived reasonableness of any mitigation proposal is very much in the eye of the beholder. The fact that parties representing different market segments find fault with some element of SPP's mitigation plan is hardly surprising; that such parties assert contrary and mutually exclusive objections serves to validate the reasonableness of SPP's proposal.

In any event, the Commission should reject requests for modification of SPP's mitigation plan. Dr. Hyatt fully explained and defended SPP's mitigation procedures, as revised in the May 15 Amendatory Filing. These procedures necessarily reflect the subjective expert judgment of SPP's Independent Market Monitoring ("IMM") unit.

[14] Beyond suggesting that SPP's mitigation plan may over-mitigate and adversely impact new, high-cost, generation, Golden Spread offers no specific recommendations.

They represent the IMM's best assessment of the measures required for market start-up, recognizing that market mitigation is a dynamic responsibility, subject to continuous re-evaluation as experience and circumstances dictate.

Several issues raised by TDU Intervenors warrant a brief response. First, SPP agrees with TDU Intervenors that final approval of the Integrated Marketplace design is necessarily subject to the development of the Mitigated Offer Development Guidelines. These guidelines are currently being formulated and vetted by SPP's IMM, in collaboration with SPP's stakeholders, and will include well defined methods for updating and revising. All interested parties will be afforded an opportunity to review and comment on the guidelines, which are expected to be completed and presented to SPP's Markets and Operating Policy Committee ("MOPC") in January 2013. SPP therefore requests that the Commission conditionally approve the proposed market design, including SPP's market mitigation plan, subject to the adoption of final Mitigated Offer Development Guidelines prior to market start-up.

SPP disagrees with TDU Intervenors that the Mitigated Offer Development Guidelines must be filed as part of SPP's OATT. As currently contemplated, SPP will memorialize these guidelines in SPP's Attachment G Market Protocols. No guideline will be adopted without thorough stakeholder vetting and consensus stakeholder approval. Relegating the guidelines to non-tariff Market Protocols is consistent with the approach followed in PJM and will facilitate more timely adjustments in the event the

IMM, either on its own, or in response to a stakeholder initiative, determines that that the guidelines require modification.[15]

It bears emphasizing that the guidelines will serve only to establish inputs to mitigated offer prices. These prices are then adjusted to set offer thresholds. Offers exceeding the adjusted thresholds are then further subject to a market impact test before determining whether mitigation applies. Thus, while there is admittedly a connection between the offer guidelines/inputs and market prices, such connection is not so direct that, under Commission precedent, tariff incorporation is required.[16]

Additionally, TDU Intervenors advocate for a lower mitigated offer threshold, citing PJM's 110% threshold and MISO's $26 threshold that is in effect in one of MISO's designated Narrow Constrained Areas ("NCAs"). TDU Intervenors give short-shrift to the significantly *higher* thresholds in use in ISO-NE and in other MISO NCAs, claiming that comparisons to these other RTOs are "inapt."

---

15 In PJM, the components of offer price caps are generally described in PJM's Schedule 2, but the detailed discussion and computation of costs is contained in PJM's Cost Development Task Force Manual. *See PJM Interconnection, L.L.C.*, 133 FERC ¶ 61,081, at P 5 (2010).

16 *See Entergy Services, Inc.,* 137 FERC ¶ 61,199, at PP 216, 217 & n.230 (2011) (rejecting arguments that implementation details relating to Entergy's Available Flowgate Capacity process must be removed from business practices to tariff provisions, finding that appropriate lines must be drawn for practical and administrative reasons and that only rules, standards and practices that directly and "*significantly* affect transmission service" must be incorporated in utility tariffs); *see also supra* note 15. Should TDU Intervenors determine that the Mitigated Offer Development Guidelines, as ultimately adopted in SPP's Market Protocols, are not operating to produce reasonable offer thresholds, TDU Intervenors may raise their concerns in the stakeholder process and/or seek Commission action pursuant to a section 206 complaint.

However, on closer inspection, it is the TDU Intervenors, *not SPP*, that present a skewed picture of prevailing mitigation thresholds within operating markets. MISO's $26 threshold – the only MISO threshold cited by TDU Intervenors – is the only threshold at *any* NCA that is currently below $50; in fact, the next lowest is $64. And, as previously noted, MISO's mitigation procedures for non-NCAs set offer thresholds at the lower of 300% or $100, far above the thresholds proposed by SPP.

Finally, SPP is compelled to correct an erroneous example presented by the TDU Intervenors. In the context of discussing SPP's proposed energy offer thresholds and, specifically, the higher threshold applicable in highly congested areas (i.e., greater of 125% of $50 above the mitigated energy offer curve), TDU Intervenors allege that, "[a]ssuming a resource's mitigated energy offer is based on the short-run marginal cost (consisting of fuel plus variable O&M) of $40 per MWh, SPP's proposed mitigation threshold would be $90/MWh, more than three times higher than applies in MISO's most constrained NCA."[17]

In fact, while the $90 threshold attributed to SPP is correct, the "three times higher" claim is not. The corresponding mitigation thresholds in MISO's three NCAs are $66 (i.e., $40 + $26) in North WUMS, $104 ($40 + $64) in SE Minnesota, and $136 ($40 + $96) in WUMS. Thus, using TDU Intervenors' hypothetical, two of MISO's NCAs thresholds are actually *higher* than SPP's.

SPP's proposed mitigation procedures are the product of extensive deliberation by and between SPP's IMM and stakeholder groups. They are modeled after mitigation plans adopted in approved regional markets and, for most elements, reflect middle ground

---

[17] TDU Intervenors Protest at 10.

positions relative to these other RTOs.[18] The Commission should therefore reject protests to SPP's proposed mitigation procedures and approve such procedures as just and reasonable.

C. The Integrated Marketplace Filing Sufficiently Addresses Firm Transmission Rights in the First Year of Market Operation.

In their reply, the TDU Intervenors ascribe to SPP a "view that [SPP] is not required to even submit to this Commission proposed provisions for long-term ARRs until its Integrated Marketplace begins operations in 2014."[19] This statement does not accurately reflect SPP's position. To the contrary, SPP recognizes that it must submit a further filing to demonstrate compliance with Order No. 681,[20] as SPP acknowledged in its answer,[21] and SPP plans to implement an Order No. 681-compliant long-term firm transmission rights construct by the second year of Integrated Marketplace operations, at the latest. Despite TDU Intervenors' suggestion, SPP has adequately addressed the issue of firm transmission rights for the first year of Integrated Marketplace operations, and has

---

[18] For example, the $25 historical standard deviation of SPP's system marginal price compares to PJM's $0 impact threshold and a $26 to $100 threshold range in MISO. Similarly, the Commission should reject TDU Intervenors' suggestion that SPP's mitigation plan is deficient for failing to propose any mitigation measures in SPP-wide markets in the absence of a binding local constraint. *See* TDU Intervenors Protest at 13-15. The fact is that most other regional markets have not adopted market-wide mitigation procedures and SPP's market consultant, Potomac Economics did not recommend market-wide mitigation in SPP.

[19] *Id.* at 4.

[20] *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,226, *order on clarification*, Order No. 681-A, 117 FERC ¶ 61,201 (2006), *order on reh'g*, Order No. 681-B, 126 FERC ¶ 61,254 (2009)

[21] May 15 Answer at 18-19.

every intention of demonstrating that it has adopted a long-term firm transmission rights mechanism as soon as practicable, but by no later than at the beginning of the second year of market operations.

In its answer, SPP expressly indicated that it would supplement its Integrated Marketplace through further development of long-term firm transmission rights, but that such a proposal would need to be developed through the SPP stakeholder process, including consideration by the SPP RSC.[22] To ensure that the Commission could consider the overall design of the SPP Integrated Marketplace without delay, SPP submitted its Integrated Marketplace filing, including its ARR and TCR proposals, and clarified that its proposed ARR and TCR mechanisms will provide LSEs sufficient opportunity to secure firm financial transmission rights during the first year of Integrated Marketplace operations (with such rights being available in subsequent years using the same annual verification and nomination processes if necessary).[23] Through its explanation, SPP did not intend to suggest that it would not further refine the ARR and TCR mechanisms to adopt a long-term firm transmission rights product, nor suggest that such a product would not be available "until the Day 2 markets have been in operation for several years" as TDU Intervenors state.[24] Rather, SPP's proposed ARRs and TCRs will serve as an appropriate transition mechanism while the stakeholder process remains ongoing.

[22] *Id.* at 18-21.

[23] *Id.* at 19.

[24] TDU Intervenors Protest at 4.

As SPP demonstrated in its answer, it is necessary for SPP to develop the long-term firm transmission rights mechanism through its stakeholder process, including consideration by the RSC.[25] Not only is such an approach consistent with SPP's Bylaws,[26] but it also enables SPP and its stakeholders to develop a long-term firm transmission rights proposal that accounts for differences in regional market design and addresses regional needs, in accordance with Order No. 681.[27] As requested in the May 15 Answer, the Commission should accept the Integrated Marketplace as just and reasonable and permit SPP to continue its progress on implementing the Integrated Marketplace, while allowing the stakeholder process to continue to develop refinements to address long-term firm transmission rights.

D. The Dispatchable Variable Energy Resource Provisions of the Integrated Marketplace are Reasonable and Should Be Approved.

E.ON Climate & Renewables North America LLC ("ECRNA") raises three issues related to SPP's proposal to integrate Dispatchable Variable Energy Resources ("DVER") into the Integrated Marketplace. Specifically, ECRNA: (i) requests additional details about SPP's use of persistence forecasting for energy offers, energy updates, and

25 May 15 Answer at 20-21.

26 *See* May 15 Answer at 20-21 (citing Southwest Power Pool, Inc., Bylaws, First Revised Volume No. 4 §§ 7.2(c)-(d)).

27 *See, e.g.*, Order No. 681 at PP 100-107 (discussing the Commission's decision to allow RTOs and their stakeholders flexibility to develop long-term firm transmission rights proposals that recognize regional differences in market design); *see also id*. at P 84 (summarizing the Commission's proposal that RTOs "develop specific long-term firm transmission right designs through [their] usual stakeholder process that would fit the prevailing regional market design.").

Unscheduled Resource Deviation ("URD") charges[28]; (ii) contends SPP has not supported the use of SPP's own forecasting to determine a DVER's maximum operating limits;[29] and (iii) argues that SPP's limitation on a DVER's submitted ramp rates based on the maximum capability of the Resource is not justified.[30]

The issues raised by ECRNA do not go to the justness and reasonableness of SPP's Integrated Marketplace filing. Rather, ECRNA's comments suggest potential future enhancements to SPP's DVER proposal that are more appropriately matters for consideration in SPP's stakeholder process. Only through stakeholder vetting can any such enhancements be evaluated to ensure that they are reasonable and feasible for all DVERs, not just ECRNA.

Additionally, ECRNA suggests that SPP's DVER proposal lacks clarity in certain respects. ECRNA raises several specific implementation questions regarding SPP's proposed accommodation of DVERs in the Integrated Marketplace. SPP offers a brief response to ECRNA's comments to help clarify and further the discussion on the operation of DVERs in the Integrated Marketplace.[31]

---

28 *See* Motion for Leave to Answer and Answer of E.ON Climate & Renewables North America LLC, Docket No. ER12-1179-000, at 2-4 (May 30, 2012) ("ECRNA Answer").

29 *Id*. at 4-5.

30 *Id*. at 6-7.

31 SPP notes that the Commission issued its Final Rule on integration of variable energy resources just as SPP was finalizing this answer. *See Integration of Variable Energy Resources,* Order No. 764, 139 FERC ¶ 61,246 (2012). To the extent the Final Rule requires additional tariff revisions to the provisions for DVERs, SPP will include them in a future filing.

1. The Use of Persistence Forecasting in the Integrated Marketplace is Supported.

ECRNA objects to the use of persistence forecasting and would prefer that SPP allow DVERs to submit their forecasted maximum limits and updates on a five-minute rolling basis ten minutes prior to each five-minute interval in real-time.[32] SPP's Integrated Marketplace filing, as well as SPP's prior answer in this proceeding, fully explained why the use of persistence forecasting is more accurate and reliable than the short-term interval forecasting advocated by ECRNA.[33] Indeed, ECRNA now states it does not *per se* oppose the use of persistence forecasting as long as certain questions that bear on the compensation and URD charges for DVERs are answered and understood.[34] Accordingly, SPP responds to each of ECRNA's questions below.

- *Does SPP intend to use persistence forecasting as a means to update a DVER's energy offers for settlement purposes? If so, how will SPP (or the DVER) do so? If so, how frequently will it do so, i.e., some time interval prior to each five-minute interval?*

<u>SPP Response</u>: No. SPP will utilize persistence forecasting on DVERs during times where congestion is not active during the five-minute interval. DVERs in this case will output as they do today. SPP will take that output and assume the same output in ten-minutes in time. This will account for the output so that the RTBM solution may meet the Short-Term Load Forecast value, plus net scheduled interchange.

Market Participants control their offers. For DVERs, the RTBM will utilize the Market Participant's offers in order to determine if the Resource may be economically and reliably dispatched down due to a congestion event. If the

---

32 *See* ECRNA Answer at 2.

33 *See* May 15 Answer at 40-42.

34 *See* ECRNA Answer at 4.

pricing at that Resource node is below the offer curve at the point of the Resource output, the RTBM will dispatch down according to the Market Participant's submitted ramp-rate down. Every five minutes, the RTBM will determine what the optimal dispatch shall be for the DVER given the Market Participant's submitted offer curve. Once the congestion event is reduced such that the RTBM releases the DVER to a pre-congestion state, the RTBM will utilize the SPP generated wind Resource forecast for 10 minutes out in time and ramp the Resource up to that pre-congested state. The forecast will be a non-curtailed forecast (what the Resource would have done, had SPP not dispatched the Resource down out-of-economic order, due to congestion). Once completely released, the RTBM will resume persistence forecasting.

- *Does this mean that a DVER will have no ability to update its energy offers close to real-time because SPP will do it instead based on its persistence forecast? If so, why is that not unduly discriminatory when all other dispatchable Resources have the option to update their energy offers so as to maximize compensation and minimize URD charges? If so, what are the implications if SPP's persistence forecast is wrong and differs from DVER's forecast?*

SPP Response: A DVER may update its offer curve as any other Market Participant. This practice is consistent with procedures in use in other real-time energy markets, as well as SPP's current EIS Market. All physical asset-owning Market Participants may change their status and offers up to 30 minutes prior to the top of the hour and may modify non-price related operating parameters anytime within the hour to reflect physical limitations.

There should not be implications if the DVER forecast happens to be more accurate for a five-minute interval, as it will not be used in the RTBM solution due to the concerns mentioned above. Please note that the SPP RTO forecast will only be used during the release from a congestion event. All other intervals will utilize persistence forecasting. Persistence forecasting is an accurate solution for short-term wind forecasting and is widely used in other markets.

- *What is the procedure to make a DVER whole from foregone sales that may occur from an SPP-imposed persistence forecast that is lower than a DVER is capable of operating at, and actually could have operated at, in real-time?*

SPP Response: Settlement is on the metering of the Resource, not the dispatch instruction. SPP's persistence forecast is used for pricing of the solution. In contrast, using a Market Participant's injected forecast to control the pricing of the interval would invite gaming and introduce inconsistencies with DVERs using different forecasting methodologies.

- *What is the impact on the URD charge assessed to a DVER from any SPP-imposed persistence forecast? How will SPP make the necessary adjustment that a DVER would have made on a rolling basis to avoid or minimize URD charges? How does SPP's persistence forecasting work with and impact the Operating Tolerances SPP's proposes for URD charges?*

SPP Response: A DVER has the flexibility to limit both Ramp-Rate Up and Ramp-Rate Down parameters. DVERs may also adjust their offer curves and turn around ramp rate factors. These adjustments give flexibility for the DVER to minimize URD charges, such that they may meet any dispatch instruction SPP RTBM may send to the Market Participant.

In accordance with the Market Protocols, URD is calculated with a tolerance band that averages 4-second output against 4-second stepped set points. This band is sufficient for any and all registered Resources deployed in the RTBM. In the case of a DVER where its maximum limit is set by persistence forecasting, the 4-second set-point instruction will echo the previous 4-second actual output, virtually eliminating any risk of any URD.

In SPP's view, the foregoing answers further demonstrate that the use of persistence forecasting is just and reasonable and no further action by the Commission is necessary.

2. SPP Clarifies the "Lesser of" Calculation for a DVER's Maximum Operating Limit.

ECRNA argues that SPP has not supported its position to use its own output forecasts for calculating a DVER's maximum operating limits in lieu of forecasts submitted by the DVER.[35] In this regard, ECRNA contends this represents a wholesale change from SPP's as-filed position that the maximum operation limit of a DVER would be calculated as the "lesser of" SPP's forecast for the Resource or the submitted maximum operation limit.[36] Even so, ECRNA's preference would be for the DVER to establish its own maximum operating limit and for SPP to use its forecasts only for discrete circumstances.[37]

ECRNA's comments indicate there is some confusion about the "lesser of" calculation for a DVER's maximum operating limit. To clarify, SPP has not changed its position on the Resource Offer procedures for DVERs established in the Integrated Marketplace filing. Pursuant to proposed Section 4.1.2.4 of Attachment AE, the "lesser of" calculation is used in only two situations. First, SPP calculates the maximum operating limit for a wind-powered DVER for use in the Day-Ahead Market, the Day-Ahead Reliability Unit Commitment ("RUC"), and the Intra-Day RUC by taking the lesser of the maximum operating limit submitted by a Market Participant in its Resource Offer or SPP's output forecast for the Resource.[38] Second, SPP uses the lesser of

---

[35] *See* ECRNA Answer at 4.

[36] *Id*.

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

[38] *See* Integrated Marketplace Filing, Proposed Tariff at Attachment AE § 4.1.2.4(2).

calculation for a DVER's maximum operating limit during the ramping up of the Resource that has previously been dispatched down for congestion and is being economically released, based on the Market Clearing Engine parameters (including the Market Participant's submitted offer curve) in the RTBM solution.[39] In all other periods, a DVER can establish its own maximum operating limit and include it in its Resource Offer.

Accordingly, ECRNA's concern about a DVER not being able to establish its own maximum operating limit is misplaced. As clarified here and in the response above, SPP's output forecasting may be used to assign a DVER's maximum operating limit only in limited circumstances. Otherwise, a DVER can set its maximum operating limit in its submitted Resource Offer.

3. SPP's Ramp Rate Limitation on DVERs is Justified.

ECRNA contends that SPP has not made the necessary showing that imposing gradual ramp rates on a wind-powered DVER is just and reasonable.[40] Instead, ECRNA argues that wind-powered DVERs should be allowed to rapidly ramp up or down consistent with their unique features and operating capabilities.[41]

ECRNA's objection to the gradual ramp rates for DVERs is misleading because ECRNA fails to recognize the limited nature of these restrictions. The proposed limitation on ramping for DVERs is only imposed during intervals where a DVER is being released from a previously curtailed value. For all other periods, the DVER may

---

39 *See id*. at § 4.1.2.4(6).

40 *See* ECRNA Answer at 6.

41 *See id*. at 7.

operate to the full extent its output allows (e.g., ramp up to as much as 100% or ramp down by as much as 100% within the next five-minute interval). In this regard, a DVER has the flexibility in its offer curve, ramp rate submission, and turn around ramp rate factor to establish a ramp rate speed over the output profile of the Resource that appropriately reflects the unique rapid ramping capabilities of that Resource.

However, in the specific circumstances where a DVER is coming out of congestion, the use of gradual ramping rates is required. As SPP explained in its previous answer, imposing limits to a DVER's ramp rate in these situations lessens the possibility of price spikes and reduces the need to call on spinning reserves.[42]

An example helps illustrate this point. A DVER is curtailed due to congestion. Subsequently, the congestion is solved systematically (not physically) in the market solution. If upon release from the congestion the DVER immediately ramps up to its previous output (or higher) in the next five-minute interval, then the market solution will once again violate the transmission constraint. This will occur continuously unless SPP is allowed to ease the ramp-up of the DVER over several five-minute intervals. As proposed, the gradual ramp rates mitigate this result by using a hybrid of the DVER's offer curve and ramp parameters, the output at the time, and the value of what the Resource would have been in the ten minutes in time had the Resource not been previously curtailed.

In addition, SPP's gradual ramp rates were specifically designed to reflect the unique nature of DVERs. A DVER Resource is "variable" by nature. So, its ramping capability is not necessarily assured. Therefore, if a DVER forecasts that it can ramp up

---

42 *See* May 15 Answer at 42.

to 100% of its capabilities, but then is unable to fully respond when called upon, the RTBM solution will be compromised because it assumed a DVER output that does not exist. This results in a shortage that will cause prices to rise for other Market Participants.

In conclusion, SPP's proposed restrictions on ramp rates for wind-powered DVERs are necessary and justified for the reliability and operational reasons discussed above. Accordingly, the Commission should deny ECRNA's request to remove these ramp rates and allow a DVER to ramp up or down to the fullest extent of its capabilities after being curtailed.

E. Contrary to Westar's Objection, Regional Allocation of Costs Associated with Locally-Committed Generation Is Reasonable.

In its May 15 Amendatory Filing, SPP proposed Tariff revisions to adopt a mechanism to compensate Resources that are committed, de-committed, or dispatched out-of-economic merit by a local transmission operator to address an emergency condition on facilities not monitored by SPP.[43] In such situations, the Resource would be compensated as if SPP had issued the commitment, de-commitment, or dispatch instruction.[44]

In its comments in response to the May 15 Amendatory Filing, Westar Energy, Inc. ("Westar") argues that the costs associated with compensating Resources that respond to instructions from a local transmission operator to address emergency conditions should not be allocated on a regional basis "because these local Resource

---

[43] *See* May 15 Amendatory Filing, Transmittal Letter at 8-9.

[44] *See id.*

commitments involve either sub-transmission issues or issues localized to a specific Settlement Area."[45] Contrary to Westar's assertion, however, allocation of such costs on a regional basis is appropriate. Emergency conditions, including those conditions that arise on elements not monitored by SPP, affect deliverability of other Resources that may not be located in the specific Settlement Area where the emergency condition arises. Prompt and appropriate response to emergency conditions, whether they are called by SPP or by a local transmission operator, help to ensure the reliability of the entire transmission system, which benefits all users of the transmission system by ensuring that Resources are able to deliver their output to load. Accordingly, regional allocation of the costs of compensating a Resource for its response, whether it is responding to an SPP-issued instruction or a local transmission operator-issued instruction, is just and reasonable.

F. Certain Clarifications Requested By TDU Intervenors Are Appropriate and Consistent with SPP's Intentions.

1. SPP Clarifies that Resources Cannot be Aggregated Into a Single Settlement Location.

The TDU Intervenors assert that SPP's proposed tariff is not explicit on a Market Participant's ability to aggregate Resources into a single Settlement Location.[46] In TDU Intervenors' view, under the proposed Integrated Marketplace, a Market Participant's loads can be aggregated into a single Settlement Location, but Resources must be settled at their individual physical locations rather than aggregated into a single Settlement

[45] Comments of Westar Energy, Inc., Docket No. ER12-1179-000, at 2 (June 6, 2012).

[46] *See* TDU Intervenors Protest at 28 (noting that this design feature is consistent with SPP's current EIS Market design).

Location.[47] However, because SPP's proposed tariff does not include specific language on this element of its market design, the TDU Intervenors ask the Commission to direct SPP to add express tariff language to make this clear.

SPP confirms that it intends to restrict the aggregation of Resources into a single Settlement Location in the Integrated Marketplace in the same manner that the aggregation of Resources is limited in SPP's EIS Market. Although the option exists for multiple generating units at a single facility to be combined and registered as a single Resource, Market Participants cannot aggregate multiple Resources into a single Resource Settlement Location. In other words, a single Resource must be registered and settled at a single Resource Price Node location. To the extent the Commission believes that more explicit tariff language is needed to clarify and confirm this market design feature, SPP will provide such language in a future compliance filing.

2. SPP Clarifies that Market Participants Cannot Net Load and Resources When Determining the Allocation of Make-Whole Payment Costs.

The TDU Intervenors contend that the lack of any expressed limitations on aggregating Resources raises a concern that Market Participants could net their loads and Resources at a Settlement Location to minimize their load-share responsibility for make-whole payment costs incurred in the Day-Ahead Market. TDU Intervenors claim that absent clarification the potential exists for unjustified (and unintended) cost shifts.[48] Accordingly, the TDU Intervenors ask the Commission to direct SPP to clarify its netting

---

47 *Id.*

48 *See id.* at 28-29.

proposal for purposes of determining the allocation of Day-Ahead make-whole payment costs.

SPP provides the following clarification. In the Integrated Marketplace, Settlement Locations for load and Resources are unique and, as such, physical load and generation cannot be settled at a single Settlement Location. Further, allocation of make-whole payments in the Day-Ahead Market is performed at the Settlement Location level and, as such, a Market Participant could not net its load and Resources at a Settlement Location for the reasons described above. However, netting between physical load and cleared Virtual Offers or Bids or between generation and cleared Virtual Offers or Bids may occur at a Settlement Location. In this regard, SPP's proposal is entirely consistent with the Commission's restrictions against widespread netting across an entire system.[49] Accordingly, the TDU's concern that Market Participants may be able to use netting to escape their cost responsibility for Day-Ahead make-whole payments in the Integrated Marketplace is misplaced.

3. The Use of Pseudo-Tie Arrangements for Load is Being Addressed Through the Stakeholder Process.

The TDU Intervenors raise a concern about how the Missouri Joint Municipal Electric Utility Commission's ("MJMEUC") existing service arrangements with SPP will be accommodated in the Integrated Marketplace.[50] Currently, MJMEUC uses pseudo-tie arrangements for the loads and almost all of the Resources from the Missouri Public

---

49 *See Ameren Servs. Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,121, P 112 (2009), *pet. for review filed sub nom., Edison Mission Energy, Inc. v. FERC*, Nos. 09-1006, *et al.* (D.C. Cir. Jan. 8, 2009).

50 *See* TDU Intervenors Protest at 29.

Energy Pool #1 ("MoPEP") to serve certain of its members. While the proposed Integrated Marketplace provides for the pseudo-tie arrangements for Resources into SPP Balancing Authority, it does not address similar arrangements for load. Accordingly, the TDU Intervenors seek confirmation that MJMEUC's existing arrangements can be accommodated in the Integrated Marketplace design.[51]

The TDU Intervenors are correct. The Integrated Marketplace tariff currently provides only for pseudo-tie arrangements for Resources, not load, into the SPP Balancing Authority. That being said, SPP is committed to accommodating load external to the SPP Balancing Authority within the design of the Integrated Marketplace. To this point, SPP advises the Commission that the development of pseudo-tie arrangement rules for load is currently being discussed by SPP's Market Working Group and SPP expects that appropriate tariff revisions will be developed through this stakeholder process.

Moreover, as recognized by the TDU Intervenors, SPP would like to keep MoPEP's load and Resources in SPP and has committed to work with MJMEUC to achieve that goal. However, SPP believes that the ongoing discussions related to accommodating MJMEUC's existing operations should not prevent the Commission from ruling on the justness and reasonableness of the current Integrated Marketplace proposal.

---

51 *Id.*

III. CONCLUSION

For the reasons set forth above, SPP requests that the Commission reject the protests submitted in this proceeding and approve the Integrated Marketplace to commence on March 1, 2014.

Respectfully submitted,

/s/ Barry S Spector

Barry S. Spector
Jeffrey G. DiSciullo
Matthew J. Binette
WRIGHT & TALISMAN, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005-3802
Telephone: (202) 393-1200
Fax: (202) 393-1240
spector@wrightlaw.com
disciullo@wrightlaw.com
binette@wrightlaw.com

Attorneys for
Southwest Power Pool, Inc.

June 26, 2012

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 26th day of June, 2012.

/s/ Matthew J. Binette
Matthew J. Binette

Attorney for
Southwest Power Pool, Inc.

Document Content(s)