UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

ANSWER OF
SOUTHWEST POWER POOL, INC.

Pursuant to Rule 213 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.213, Southwest Power Pool, Inc. ("SPP") files this answer[1] to the comments and protests submitted in this proceeding.[2]

I. BACKGROUND

On February 29, 2012, SPP submitted to the Commission proposed revisions to its Open Access Transmission Tariff ("Tariff") to implement the SPP Integrated Marketplace in March 2014.[3] As proposed, the Integrated Marketplace includes Day-Ahead and Real-Time Energy and Operating Reserve Markets and Transmission Congestion Rights ("TCR") markets aimed at maximizing the cost-effective utilization of

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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 SPP's silence in this answer on any issue or argument addressed in any comment or protest should not be construed as SPP's agreement with any such issue or argument.

3 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").

Energy Resources and the regional transmission system, resulting in estimated annual net benefits of between $45 million and $100 million.[4] As explained in the Integrated Marketplace Filing, design elements of the Integrated Marketplace are modeled on those successfully operating in other Regional Transmission Organization ("RTO") markets, modified as necessary to address regional differences and SPP stakeholder needs.[5] The Integrated Marketplace Filing was the culmination of a multi-year, extensive process involving the entire SPP stakeholder community, including the SPP Regional State Committee ("RSC").[6] As is evidenced by the numerous comments submitted in this proceeding, the SPP Integrated Marketplace is widely supported by diverse stakeholder interests.[7] Nonetheless, given the complexity and range of issues associated with

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4 Integrated Marketplace Filing, Transmittal Letter at 2 and Exhibit No. SPP-1 at 7-8.

5 *Id.*, Transmittal Letter at 2 and Exhibit No. SPP-1 at 13.

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

7 *See, e.g.*, Motion to Intervene and Comments of the American Wind Energy Association, Docket No. ER12-1179-000, at 2 (Apr. 6, 2012) ("AWEA Comments") ("AWEA strongly supports SPP's efforts to consolidate its balancing areas and develop an integrated market. Integrated markets and the grid operating features that typically accompany them have proven to be highly beneficial for wind energy development and integration."); Comments of Calpine Corporation, Docket No. ER12-1179-000, at 3-4 (Apr. 6, 2012) ("Calpine Comments") ("[I]mplementation of the Integrated Marketplace will improve competition and benefit Market Participants and consumers in the SPP footprint. In particular, Calpine supports SPP's decision to implement transparent day-ahead, TCR and ancillary services markets, and to consolidate the sixteen currently separate Balancing Authorities . . . which will lead to substantially greater market efficiencies."); Comments of E.ON Climate & Renewables North America LLC, Docket No. ER12-1179-000, at 1 (Apr. 6, 2012) ("E.ON Comments") ("The features of the Integrated Marketplace are comprehensive and generally should result in increased economic and operational efficiencies for all market participants in the SPP region."); Motion to Intervene and Comments of East Texas Electric Cooperative, Inc., Northeast Texas Electric Cooperative, Inc. and

(continued. . .)

designing a "Day 2" market, various questions and challenges were raised in response to the Integrated Marketplace Filing. This answer addresses those questions and challenges.[8]

II. ANSWER

The Integrated Marketplace Filing represents SPP's first foray into Day 2 markets that involve a Day-Ahead Market and financial transmission rights represented by Auction Revenue Rights ("ARR") and TCRs. For the first time, Balancing Authority Area functions will be consolidated under SPP's control, and Operating Reserve procurement will be centralized and co-optimized with Energy procurement to deploy the most cost-effective mix of Resources to meet Energy and Operating Reserve needs.

While elements of SPP's Integrated Marketplace are based on design features and lessons learned in other markets, the Commission typically has not imposed a one-size-fits-all design on RTO energy and ancillary services markets and should not do so here. The fact that SPP did not adopt a particular design element that may exist in another

(. . . continued)

Tex-La Electric Cooperative of Texas ("East Texas Cooperatives"), Docket No. ER12-1179-000, at 4-5 (Mar. 30, 2012) ("East Texas Cooperatives' Comments") ("SPP's Integrated Marketplace represents a significant step forward for all customers within the SPP region."); Motion to Intervene and Protest of Xcel Energy Services, Inc., Docket No. ER12-1179-000, at 2 (Apr. 6, 2012) ("Xcel Protest") ("XES . . . support[s] SPP's filing for an Integrated Marketplace and believe[s] that it is the next step to a more efficient, fully functional market.").

8 In the Integrated Marketplace Filing, SPP indicated that certain components of the market design were undergoing additional stakeholder consideration and that SPP contemplated making an additional supplemental filing in May 2012, along with other additional filings to address various Commission orders affecting the Integrated Marketplace. Within the next day or two, SPP will submit a supplemental filing in this docket, which will address some of the concerns expressed in various comments and protests.

market does not make the Integrated Marketplace unjust and unreasonable. Similarly, the Commission cannot properly reject the Integrated Marketplace Filing or direct SPP to adopt certain design features that other RTOs may have added following commencement of their markets. While SPP and its stakeholders are free to continue to consider market refinements leading up to and after the launch of the Integrated Marketplace, imposing additional burdens on SPP to implement market design elements that are desired by certain commenters but are not essential to the functioning of the Integrated Marketplace will create impediments to market system development and likely result in delays in the launch of the Integrated Marketplace beyond March 1, 2014. SPP therefore requests that the Commission reject protests and comments that demand market features that are not necessary to the implementation of the Integrated Marketplace.[9] SPP should be authorized to commence market operations, with consideration given to future enhancements and refinements based on experience gained after market start-up.

As discussed in more detail below, several of the issues raised by the parties commenting on SPP's Integrated Marketplace Filing will be addressed in a supplemental amendatory filing that SPP anticipates submitting to the Commission on or about May 15, 2012. SPP believes that the revisions and clarifications reflected in the supplemental filing will render moot certain concerns regarding, for example, adequacy of market mitigation measures, treatment of external Resources, and treatment of regulation

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9 The Commission also should reject protests and comments that seek to raise issues that are beyond the scope of this proceeding. *See, e.g.,* Motion to Intervene and Comments of the American Public Power Association, Docket No. ER12-1179-000, at 2, 5-8 (Mar. 30, 2012) ("APPA Comments") (objecting to RTO centralized capacity markets).

Resources in both the Reliability Unit Commitment ("RUC") and Real-Time Balancing Market ("RTBM") processes.

Beyond the issues that will be addressed in the supplemental filing are issues raised by certain parties who misconstrue aspects of the Integrated Marketplace and/or misinterpret Commission precedent. Because SPP demonstrates that the changes sought by these parties are based on faulty factual and legal premises, the Commission should reject their arguments and requested modifications. Finally, several parties seek clarification of certain Integrated Marketplace design features. To the extent these clarifications identify ambiguities warranting a response, SPP provides appropriate clarifications below.

A. SPP Fully Addressed All Market Power and Market Mitigation Issues in the Design of the Integrated Marketplace

TDU Intervenors[10] and American Public Power Association ("APPA") raise questions regarding the adequacy of the market analysis conducted in support of the Integrated Marketplace. TDU Intervenors further argue that various elements of SPP's mitigation plan are either insufficient to curb potential market abuse or have not been fully explained and supported. Arkansas Electric Cooperative Corp. and Golden Spread Electric Cooperative, Inc. ("AECC/GSEC") complain that the offer cap, as originally proposed in the February 29 filing, is too low, fails to consider the Locational Marginal Price ("LMP") that occurs during periods of congestion, and fails to account for the relationship of LMPs to the variable cost of a generator.

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

SPP reiterates, at the outset, that it will be amending the February 29 filing to propose, among other things, revised mitigation procedures, including a new approach for calculating offer caps. These revised measures directly address many of the issues raised by TDU Intervenors, APPA, and AECC/GSEC. Dr. John Hyatt, Supervisor of SPP's Market Monitoring Unit, will offer supplemental testimony to support these revised mitigation procedures. The residue of these protests – *i.e.*, largely allegations that SPP should have conducted a market power study for *both* Energy and Operating Reserve and that only through an examination of both markets can proper mitigation measures be developed – is addressed below.

1. No Justification Exists for Requiring a New Energy Market Power Study

a. SPP's Energy Imbalance Service Market Was Approved on the Basis of a Comprehensive Energy Market Power Study

In designing its Energy Imbalance Service ("EIS") Market, SPP conducted a comprehensive market power study and Pivotal Supplier Analysis. These studies, which the Commission considered in its evaluation of SPP's EIS Market proposal, showed SPP's Energy markets to be competitive except in times of transmission congestion. Based on the findings of these studies, SPP proposed mitigation measures that the Commission approved, including the establishment of market screens to determine when economic withholding is occurring in the EIS Market and when offer caps should be imposed to mitigate market power.

In preparing the mitigation plan for the Integrated Marketplace, the same threshold assumption used in the EIS Market mitigation plan was applied: i.e., that the Energy market is competitive except in times when local market power exists. As with the EIS Market, the presence of local market power is assumed only where competition is stifled due to transmission congestion or local reliability issues. Leveraging off of the EIS Market was entirely appropriate and justified inasmuch as the experience gained through five years of EIS Market operations confirms that the EIS Market has functioned as anticipated and in a workably competitive manner.[11]

Nonetheless, TDU Intervenors claim that the planned implementation of a Day-Ahead Market requires the development of a new Energy market power study. This claim improperly assumes that the Day-Ahead Market and RTBM markets constitute two different products. In fact, the Day-Ahead Market is simply a forward market for Energy and the RTBM is the spot market for Energy. Both markets depend on the same Resources and the same transmission facilities. Both generate LMPs through the operation of a security constrained economic dispatch ("SCED") model. The Day-Ahead Energy Market, with the exception of virtual bids and offers, is merely a subset of the real-time market.

TDU Intervenors further claim that there are material design differences between the EIS Market and the Integrated Marketplace. In TDU Intervenors' view, the "residual" nature of the EIS Market – where load-serving entities ("LSEs") could limit exposure by relying less on EIS Market and more on their own resources – offers fewer

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11 In its Annual State of the Market Report, the Market Monitoring Unit concluded that SPP's Energy market has performed in a competitive manner for each of the five years of operation. Boston Pacific, as the external Independent Market Monitor and later as the external advisor prepared the State of the Market Report for 2007 and 2008. The 2009 Report was a joint effort by Boston Pacific and the SPP Market Monitoring Unit. The SPP Market Monitoring Unit prepared the 2010 and 2011 reports.

opportunities for market power abuses versus the Integrated Marketplace.[12] TDU Intervenors also argue that the absence of an all-Resource must-offer requirement in the Day-Ahead Market, combined with wide swings between units dispatched in the Day-Ahead and units committed through RUC, present more opportunities for Resource information to be available to suppliers, increasing the potential for economic withholding.[13]

TDU Intervenors' arguments are not supported by the facts. In the first place, the residual nature of the EIS Market, and how it compares or contrasts to the residual nature of the Integrated Marketplace, is beside the point. LSEs that have historically relied on bilateral agreements in the EIS Market can continue to do so in the Integrated Marketplace, and LSEs that have historically utilized their own Resources to meet load requirements can continue to do so following implementation of the Integrated Marketplace. The establishment of a Day 2 market does not compel LSEs to change the manner by which these entities utilize market options. Moreover, it is simply not the case that LSEs are exposed to greater risk in the Integrated Marketplace. Except in limited circumstances, LSEs offering sufficient generation to cover their loads in the Day-Ahead Market will not see LMPs for Energy at their Settlement Locations in excess of prices realized by their own generation fleet. The only exception would be in circumstances where transmission constraints separate the load from generation. However, the award of TCRs is designed precisely for the purpose of mitigating this type of exposure.

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12 Motion to Intervene and Protest of TDU Intervenors, Docket No. ER12-1179-000, at 41-42 (Apr. 6, 2012) ("TDU Intervenors' Protest").

13 TDU Intervenors' Protest at 44-45.

In fact, LSEs' real-time exposure is reduced in the Integrated Marketplace relative to the EIS Market. In the Integrated Marketplace, the LSE's risk is limited to the difference between their Day-Ahead awards and metered consumption. By contrast, in the EIS Market, the LSE is exposed to real-time price variability when a bilateral schedule is curtailed, in addition to differences between scheduled and metered consumption. With the possible exception of severe constraints causing large, unexpected congestion differences (where, for example, the TCRs may not be fully funded due to the unanticipated size of the congestion), congestion in real-time will be covered by a LSE's Day-Ahead Market TCRs in the Integrated Marketplace.

b. TDU Intervenors' Reliance on Other Regional Markets Is Misplaced

TDU Intervenors further argue that in approving other regional markets, the Commission has required more comprehensive market power analyses and/or imposed mitigation measures that go beyond those proposed in SPP's Integrated Marketplace. A careful examination of the examples cited by TDU Intervenors provides no justification for either a new market power study for SPP's Energy markets or changes to SPP's mitigation procedures.

Contrary to the inferences invited by TDU Intervenors,[14] the Midwest Independent Transmission System Operator, Inc. ("MISO") was not required to submit a market power study to support its proposed market design and, in fact, did not do so. Rather, MISO supported its market design with an analysis justifying MISO's proposed designations of constrained areas, which served as the initial screen for whether a

[14] *See* TDU Intervenors' Protest at 40.

generator would be subject to conduct and impact tests for possible mitigation. The Commission specifically *rejected* a request that MISO be required to develop a comprehensive market power study, and that ruling was squarely affirmed by the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court").[15] Moreover, when MISO proposed to include ancillary services as part of an expanded Day 2 market, the market power study presented with that proposal only addressed the ancillary services market and did not include a new or updated market power study for energy.

The development of SPP's Integrated Marketplace design and mitigation plan followed a path similar to MISO. In certain respects, however, SPP's market analyses were more comprehensive than the analyses presented by MISO. SPP's market-based Operating Reserve procurement is specifically supported by a market power study and, as noted, SPP's Energy market was previously examined for market power issues as part of the approval process for SPP's EIS Market, where the Commission evaluated and relied upon SPP's market power study.[16] Moreover, like MISO's market monitoring and mitigation plan, Attachment AF of the SPP Tariff includes Mitigation Measures, or screens, that provide for mitigation of the exercise of horizontal and vertical market power in certain specified circumstances. The Tariff revisions to be included in SPP's

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15 *See Midwest Indep. Trans. Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 283, *order on reh'g,* 109 FERC ¶ 61,157, at PP 235, 241-44 (2004), *review denied sub nom. Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 258-62 (D.C. Cir. 2007).

16 *See Sw. Power Pool, Inc.*, 116 FERC ¶ 61,289, at P 33 (summarizing the Commission's findings regarding SPP's workably competitive imbalance market based on the SPP external monitor's Herfindahl-Hirschman Index ("HHI") and Pivotal Supplier Analyses.).

supplemental filing will provide additional mitigation enhancements by requiring the submission of cost-based mitigated offers for all products and the application of mitigated offer prices whenever a resource exceeds the applicable threshold and fails the Market Impact Test.

2. *Other Challenges to Proposed Mitigation Measures Lack Merit*

Regarding TDU Intervenors' claim that SPP's proposed offer-cap trigger is inadequate, SPP notes that it currently uses, and plans to continue to use, a 5% shift-factor cut-off to make a local market power determination when there is transmission congestion. The same methodology is approved and in use in MISO for the Broad Constrained Areas,[17] wherein MISO employs a cut-off threshold comparable to SPP's 5%.

Similarly without merit is TDU Intervenors' argument that SPP's market plan is deficient for failing to include market mitigation measures applicable to SPP-wide regulation or reserve markets. SPP followed the independent recommendations of Potomac Economics ("PE") in this regard, who found footprint-wide mitigation to be unnecessary. And PE's conclusions are well supported. On an annual basis, for regulation up, regulation down, and contingency reserve, PE identified a single, region-wide, pivotal supplier for only 87, 96, and 35 hours, respectively. Not only do these totals amount to less than 1% of the annual hours for each product but, as PE noted, the pivotal supplier cannot know with certainty when these pivotal hours will occur, thereby minimizing any opportunity or incentive to attempt to exert market power.

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17 *See Midwest Indep. Sys. Operator, Inc.* 108 FERC ¶ 61,163, at P 274.

Additionally, as PE found, co-optimization of Energy and Operating Reserve increases the substitutability of these products and reduces market power. In the case that Regulation-Down is scarce on a system-wide basis, the RTO has the ability to de-commit resources. Thus, the extent to which a Market Participant can potentially abuse market power in Regulation-Down is bounded by the cost to de-commit a resource.

TDU Intervenors also challenge the Market Impact Test proposed by SPP. As proposed, an impact test threshold will be used to determine when the mitigated solution will be used for dispatch, commitment, and settlement purposes. The impact test threshold applies to the difference between a mitigated market solution and an unmitigated market solution for both LMP and make whole payments ("MWP"). Initially, this threshold will be set at $5/MWH and will increase by $10/MWH at every six-month milestone following market start-up, until the threshold hits $25/MWH. However, the SPP's Market Monitoring Unit may freeze the threshold for any successive six month period based on a determination that market behavior does not warrant an increase.

The proposed Market Impact Test should be approved as filed. The price thresholds are based on a historical analysis of the system marginal price for the EIS Market. The $25/MWH value represents the standard deviation for the system marginal price over the last three years. On the basis of this data, SPP's Market Monitoring Unit reasonably concluded that price changes up to $25/MWH are consistent with the operation of competitive forces in the SPP electricity market and not indicative of market power abuse.

Additionally, TDU Intervenors seek clarification regarding the meaning of "local reliability issue" in the context of SPP's proposed mitigation procedures.[18] TDU Intervenors argue that the concept of a "local reliability issue" was not clearly defined in SPP's proposed mitigation procedures.

To aid in the understanding of this term, consider a Resource that normally would not be committed economically but is required to be on-line to address a low voltage issue. Typically, these types of voltage-related issues cannot be directly modeled in the market clearing engines through the use of thermal transmission line constraints. Therefore, on occasion, the system operator will instruct a Resource to go to a certain level of output and maintain this level for several hours at a time in order to address the local, voltage-related reliability issue. This is an example of what SPP means by a "local reliability issue." While it is unlikely that this Resource would have market power if it were not regularly committed (but is instead dispatched specifically to address a voltage-related issue), SPP's mitigation rules allow the Market Monitoring Unit to respond in the event that the presence of market power is detected. Theoretically, market power concerns could arise if the Resource is regularly committed and/or dispatched to address a recurring voltage issue — thus giving the Resource the opportunity to systemically increase its offer price (i.e., if it knows that it is always going to be committed). It is therefore reasonable for SPP to propose mitigation in instances where such local reliability issues present themselves.

Finally, TDU Intervenors argue that more stringent mitigation measures should apply to MWPs where generators must be committed for reliability. In TDU Intervenors'

[18] TDU Intervenors' Protest at 2, 68-69.

view, generators committed to address voltage or local reliability problems could extract unreasonably high MWPs. As explained above, mitigation measures are in place to detect recurring local reliability problems that are susceptible to remedy only by certain Resources. Thus, TDU Intervenors' concerns are unwarranted.

B. Challenges to SPP's Proposed Treatment of Grandfathered Agreements Are Unsupported and Should Be Rejected

In designing the Integrated Marketplace, SPP and its stakeholders sought to accommodate existing contractual arrangements to the extent possible, rather than requiring that the parties abrogate or modify them. To that end, SPP proposed to treat Grandfathered Agreements ("GFAs") comparable to other firm reservations by extending to all firm transmission service – regardless of whether it is conventional Tariff service or service subject to a GFA – the same right to receive ARRs. Market Participants with GFAs possess the right to convert the ARR associated with their transmission service to a TCR in the same manner as other Market Participants.[19]

Several parties protest SPP's proposed treatment of GFAs, arguing that SPP's failure to carve-out GFAs is unlawful and contrary to Commission and court precedent.[20] Other parties argue that the Commission lacks authority to approve any arrangement that

19 The parties to the GFA may designate which party is to receive the ARRs, and the ARRs and TCRs for GFAs are treated identically to all other ARRs and TCRs. Integrated Marketplace Filing, Exhibit No. SPP-3 at 49. Absent agreement between the parties to the GFA, the Transmission Owner that is a party to the GFA will receive the allocation of ARRs by default. *See* Integrated Marketplace Filing, Proposed Tariff at Attachment AE § 7.1.1(2) and Exhibit No. SPP-3 at 49. GFAs related to transactions through, into, or out-of the SPP Balancing Authority Area will continue their current scheduling practices.

20 *See* Protest of Basin Electric Power Cooperative, Docket No. ER12-1179-000, at 3-6 (Apr. 6, 2012).

would subject GFAs between "non-jurisdictional entities" to congestion and loss charges.[21] These protests are all grounded on the same premise – i.e., that SPP's proposed accommodation of GFAs in the Integrated Marketplace effects an "abrogation" of these agreements by altering the bargain struck between the GFA parties.

The Commission should reject these arguments and approve SPP's proposed handling of GFAs. As Mr. Dillon explained, treating GFAs comparable to other firm transmission service is entirely consistent with and preserves the manner by which these agreements are currently treated under existing scheduling protocols.[22] More to the point, the individual GFAs are unchanged by virtue of SPP's proposal; nothing in SPP's proposed accommodation of GFAs purports to effect any modification to any term or condition of these existing agreements. As with every firm service arrangement currently in place (both GFAs and non-GFAs), implementation of the financial and settlement rules of the Integrated Marketplace will be between SPP and the Transmission Customer under the SPP Tariff (which, in the case of GFAs, is the Transmission Owner that is a party to the GFA), similar to the way in which all firm transmission service (both GFA transmission and non-GFA transmission) has been administered under SPP's EIS Market.

It is true that in other markets GFAs have been subject to various carve-out arrangements. In MISO, for example, the Commission approved MISO's proposed carve-out of 127 GFAs, despite the objection of certain Transmission Owning members

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21 Protest of Missouri River Energy Services and Heartland Consumers Power District, Docket No. ER12-1179-000, at 8-9, 12-14 (Apr. 6, 2012); Motion to Intervene, Comments, and Protest of Nebraska Public Power District ("NPPD"), Docket No. ER12-1179-000, at 16-20 (Mar. 30, 2012) ("NPPD Protest").

22 *See* Integrated Marketplace Filing, Exhibit No. SPP-3 at 50.

who argued that requiring GFA parties to abide by the terms of the MISO Tariff would not abrogate or modify the GFAs.[23] On review of the Commission's orders, the D.C. Circuit Court considered the abrogation-of-contract argument, ultimately upholding the Commission's rulings. However, the Court's findings focused on a particular element of the MISO GFAs – i.e., how they had historically been scheduled – and the implications of subjecting the GFA load to the new scheduling protocols of MISO's Day 2 market. In the Court's words:

> [C]entralized scheduling in the Day-Ahead market is utterly foreign to the GFAs . . . [and] out of sync with FERC's post-1990 efforts to spur the development of competitive bulk power markets. . . . [A] number of the GFAs do not spell out the quantity of electricity to be purchased or the precise time when the buyer will take delivery; those details have often been worked out . . . between the GFA parties. . . .
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> . . . [T]he scheduling problem justified FERC's conclusion that subjecting GFA parties to the Tariff terms . . . would result in 'significant changes . . . affecting the bargain between the parties to the individual GFAs.'[24]

In contrast to MISO, centralized scheduling is currently used within the SPP footprint for *all* reservations, including GFAs, and has been for many years. Those scheduling procedures are neither new nor "foreign" to the GFA load within SPP, but have been in use since the start-up of SPP's EIS Market. Significantly, none of the parties protesting SPP's GFA treatment alleges centralized scheduling as the basis for their contract abrogation claims.

Additionally, the Integrated Marketplace provides the GFA parties with the financial instruments necessary effectively to carve-out their GFAs, at least on a financial

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23 *See Wis. Pub. Power, Inc.*, 493 F.3d at 270.

24 *Id*. at 272-73.

basis, without having to impose any special scheduling rules. This can be accomplished through a combined use of allocated ARRs converted to TCRs and Bilateral Settlement Schedules.

In any event, nothing in SPP's proposed market design mandates GFAs into the Integrated Marketplace. When Transmission Owners joined SPP, they brought with them their own load obligations and all of the load obligations under their GFAs. SPP has historically treated, and proposes to continue to treat, GFA load as effectively the load of the Transmission Owner. All that is proposed in the design of the Integrated Marketplace is that ARRs will be allocated to the Transmission Owner for its GFA load and corresponding charges will be assessed to the Transmission Owner for any congestion attributable to that load. How the rights and obligations may fall out between the GFA parties, *under the GFA*, is a matter to be resolved by the parties to the GFA – i.e., the Transmission Owner and the customer.

SPP fully supported its non-discriminatory treatment of GFAs and demonstrated that treating GFA transmission comparable to other firm transmission avoids the likely revenue shortfalls to other TCR holders that a carve-out – with its reduced allocations and funding – would produce.[25] Such ripple-effect consequences preclude any finding that protestors' carve-out recommendations can be found to be just and reasonable.[26]

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[25] *See* Integrated Marketplace Filing, Exhibit No. SPP-3 at 50.

[26] Similarly infirm is NPPD argument that the proposed GFA treatment is inconsistent with the terms of the NPPD-specific Membership Agreement. The dispositive response is that SPP is not requiring GFA service to be converted to service under the Tariff. Any GFA can remain effective through the conclusion of its term. SPP's proposal merely provides the ARR/TCR mechanism as a replacement to the current scheduling mechanism, to provide the hedge against congestion costs for load being served under the GFA.

Like every other critical element of market design, SPP's proposed treatment of GFA transmission was developed through SPP's stakeholder process and ultimately voted out with consensus support. Any changes to this feature of the Integrated Marketplace would have significant ramifications to the level and availability of TCRs. Carve-outs of selective loads invite contentious cost allocation and congestion management issues that undermine the overall integrity of the market design.

Consequently, should the Commission determine that SPP's proposed treatment of GFAs cannot be approved as filed, a referral back to the SPP stakeholder process is necessary. If the Commission deems a limited GFA carve-out appropriate, SPP's stakeholders, particularly the RSC, given its vested role in all matters affecting financial transmission rights and cost allocation,[27] need to re-engage to consider how such carve-out will be structured and to address the resultant allocation and funding issues.

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

Certain parties[28] observe that the Integrated Marketplace Filing does not expressly address the requirements set forth in Order No. 681[29] that "organized electricity markets" provide long-term firm transmission rights to LSEs that meet seven guidelines set forth in Order No. 681. While SPP acknowledges that, upon implementation, the Integrated

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27 *See infra* note 34 and accompanying text.

28 *See* East Texas Electric Cooperatives' Comments at 4-5; TDU Intervenors' Protest at 9-13; NPPD Protest at 29-30.

29 *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).

Marketplace will qualify as an "organized electricity market" subject to the requirements of Order No. 681,[30] the Integrated Marketplace as proposed provides for firm transmission rights, which SPP will supplement through the further development of long-term firm transmission rights.

While SPP's current Integrated Marketplace design may not currently address ARRs and TCRs for periods longer than one year in accordance with Order No. 681, SPP's proposed ARR construct provides protection for LSEs to secure firm financial transmission rights during the first year of Integrated Marketplace operations and then in the years following using the same annual verification and nomination processes. Specifically, as discussed in the Integrated Marketplace Filing, Transmission Customers and Market Participants with firm transmission service are permitted to nominate candidate ARRs along specific transmission paths consistent with their firm transmission service. Network Integration Transmission Service ("NITS") customers and GFA customers taking the equivalent of NITS may nominate candidate ARRs up to a cap that is equal to 103% of the average of the customer's three highest annual peak Network Loads since February 1, 2007,[31] and Point-To-Point and firm GFA customers taking the equivalent of Point-To-Point service may nominate ARRs based on the customer's

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30 Order No. 681 defines "organized electricity market" as "an auction-based day-ahead and real-time wholesale market where a single entity receives offers to sell and bids to buy electric energy and/or ancillary services from multiple sellers and buyers and determines which sales and purchases are completed and at what prices, based on formal rules contained in Commission-approved tariffs, and where the prices are used by a transmission organization for establishing transmission usage charges." Order No. 681 at P 30.

31 Integrated Marketplace Filing, Transmittal Letter at 14-15 and Proposed Tariff at Attachment AE §§ 7.1.3(1) & (3).

Reservation Capacity associated with the specific source and sink of the Point-To-Point or GFA service.[32] Based upon the ARR nominations, SPP will allocate the portion of the nominated ARRs that is simultaneously feasible given SPP's transmission system, which can then be converted to TCRs or held as an ARR to receive a share of the revenue SPP collects from auction purchasers of TCRs.[33] In this manner, LSEs are entitled to nominate ARRs for their existing long-term firm transmission arrangements during the first and subsequent years of the Integrated Marketplace, until such time as SPP supplements this process with a long-term transmission rights mechanism consistent with the requirements of Order No. 681.

SPP's compliance with Order No. 681 requires involvement of the SPP stakeholders and, in particular, the SPP RSC. In its orders approving SPP's application to be an RTO, the Commission required that certain responsibilities be delegated under the SPP Bylaws to the SPP RSC, including, among other items, "[financial transmission rights] allocation, where a locational price methodology is used[,] and . . . the transition mechanism to be used to assure that existing firm customers receive [financial transmission rights] equivalent to the customers' existing firm rights."[34] Given the relationship between financial transmission rights and the long-term firm transmission

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32 *Id.*, Transmittal Letter at 14-15 and Proposed Tariff at Attachment AE §§ 7.1.2(2) & (4), 7.1.3(2) & (4).

33 *Id.*, Transmittal Letter at 14-15.

34 *Sw. Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 219, *order on reh'g*, 109 FERC ¶ 61,010 (2004); *see also* Southwest Power Pool, Inc., Bylaws, First Revised Volume No. 4 §§ 7.2(c)-(d).

rights requirements of Order No. 681,[35] it is necessary and appropriate for the RSC to be involved in the development of SPP's mechanism to comply with Order No. 681. The RSC and several SPP stakeholder groups have discussed the obligation to provide long-term firm transmission rights and continue to evaluate the approaches adopted in other RTOs. SPP will submit additional Tariff revisions in response to Order No. 681 upon completion of a stakeholder process, and SPP requests that the Commission allow SPP to develop a mechanism to provide long-term firm transmission rights through the appropriate stakeholder groups.

In the meantime, the Commission should accept the Integrated Marketplace Filing as submitted, find that SPP's proposed ARR methodology provides LSEs a sufficient financial hedge for the first and subsequent years of market operations, and permit SPP to address any additional requirements regarding long-term transmission rights through the stakeholder process.

D. Criticisms of SPP's Day-Ahead Must-Offer Requirement Ignore Commission Precedent

In the Integrated Marketplace Filing, SPP proposed implementing certain "must-offer" requirements for Resources in the Day-Ahead Market, Day-Ahead RUC, and RTBM. Specifically, in the Day-Ahead Market, each Market Participant is required to

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[35] *See* Order No. 681 at P 30 ("We make this modification to clarify the application of this Final Rule and ensure that the definition captures the transmission organizations with organized electricity markets using LMP and FTRs to which Congress directed the Commission to apply this Final Rule. . . . those electricity markets do not offer financial transmission instruments supported by existing capacity with terms longer than one year, and thus entities are not able to obtain a 'firm' transmission right on a long-term basis in those markets as section 217(b)(4) of the FPA directs. As a result, they are appropriately the focus of this Final Rule.").

offer sufficient Resources to cover its expected load plus Operating Reserve obligation for the next day (to the extent that its Resources are available); in the Day-Ahead RUC and RTBM, the must-offer requirement applies to all Resources to the extent that they are available.[36] Despite the arguments of certain intervenors, the Day-Ahead Market, RUC, and RTBM must-offer requirements are consistent with Commission precedent,[37] and arguments to the contrary are unavailing and should be rejected.

None of the intervenors cites a single Commission order requiring an RTO to impose a must-offer obligation on all resources in a day-ahead market.[38] In fact, contrary to the suggestions of the intervenors, Commission precedent heavily disfavors broad must-offer requirements in RTO day-ahead markets, absent some form of resource adequacy construct or other form of capacity payment.[39] Intervenor requests that SPP modify its must offer requirement misinterpret or ignore Commission precedent limiting the applicability of must-offer requirements in RTO day-ahead markets.

The Commission has explained that generators should have the option of selling their capacity on a bilateral basis or offering their capacity into a day-ahead energy or

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36 Integrated Marketplace Filing, Transmittal Letter, at 21-22 and Exhibit No. SPP-3 at 15-17.

37 *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.,* 102 FERC ¶ 61,280, at P 96 ("[W]e believe that it is reasonable to require generators to bid available generation into the Real-Time Market.").

38 *See* Calpine Comments at 3-6 (citing no Commission precedent mandating a day-ahead must-offer requirement); Motion for Leave to Intervene and Protest of the Electric Power Supply Association, Docket No. ER12-1179-000, at 4-7 (Apr. 6, 2012) ("EPSA Protest") (same); TDU Intervenors' Protest at 33-36 (same); Xcel Protest at 6-8 (same).

39 *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,280, at P 96 (2003).

ancillary services market,[40] and has characterized a day-ahead must-offer obligation as essentially a "call option" on a generator's capacity,[41] which precludes a generator from engaging in bilateral sales of its capacity.[42] As a result, the Commission generally only allows an RTO to impose a must-offer obligation in its day-ahead market if the obligation is coupled with a resource adequacy construct, which effectively compensates generators for foregoing their ability to choose to make bilateral sales.[43]

For example, in considering a market mitigation proposal by MISO to impose withholding penalties on generators in its day-ahead market, the Commission found that "absent a [MISO] imposed Resource Adequacy requirement or state obligation, generators should not be required to bid into the Day-Ahead market,"[44] because imposing such penalties in the day-ahead market "constitutes a must offer obligation without a corresponding payment for capacity resources."[45] The Commission contrasted MISO's proposal with the ISO New England, Inc. ("ISO-NE") and New York Independent System Operator, Inc. ("NYISO") markets, which imposed physical withholding requirements only on "ICAP resources" (i.e., designated installed capacity resources) in

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40 *See Cal. Indep. Sys. Operator Corp.*, 107 FERC ¶ 61,274, at P 26 (2004).

41 *See Cal. Indep. Sys. Operator Corp.*, 105 FERC ¶ 61,140, at P 229 (2003).

42 *See Cal. Indep. Sys. Operator Corp.*, 107 FERC ¶ 61,274, at P 26.

43 *See id.*, 107 FERC ¶ 61,274, at P 26. The compensation must be true compensation for capacity. Payments only for a generator's start-up and no-load costs are not capacity payments because they do not compensate the generator for fixed costs. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,147, at P 26.

44 *Midwest Indep. Transmission Sys. Operator, Inc.,* 102 FERC ¶ 61,280, at P 96.

45 *Id*.

the day-ahead markets.[46] The Commission subsequently accepted a MISO proposal to impose a limited must-offer requirement in its day-ahead market; however, the Commission accepted it only as a temporary measure and expressed concerns regarding the lack of a corresponding capacity payment,[47] and only later approved a permanent must-offer requirement in conjunction with MISO's long-term resource adequacy proposal.[48] While the Commission did accept MISO proposals to implement limited must-offer requirements in its day-ahead market, the Commission did not order MISO to do so, nor did the Commission find that MISO's day-ahead market would be unjust and unreasonable without one.

The Commission took a similar approach in ruling against a California Independent System Operator Corp. ("CAISO") proposal to implement a must-offer requirement in its day-ahead market, stating that CAISO's "proposal to extend the must-offer obligation to the forward markets, *coupled with . . . [the] lack of a corresponding obligation on LSEs to acquire*, in advance, adequate resources to serve their needs, does not strike an appropriate balance between obligations of suppliers and obligations of LSEs."[49] In a subsequent CAISO market design order, the Commission noted that in the

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[46] *Id.*

[47] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at PP 409-411.

[48] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,283, at P 201, *order on reh'g*, 125 FERC ¶ 61,062 (2008) (noting that other RTOs with resource adequacy programs and capacity payments have similar day-ahead must-offer requirements). The Commission noted that the must-offer requirement applies only to resources designated as "Capacity Resources" under MISO's resource adequacy mechanism. *Id.* at P 208.

[49] *Cal. Indep. Sys. Operator Corp.*, 105 FERC ¶ 61,140, at P 227 (emphasis added).

Northeast markets, there is typically a must-offer obligation in the RTO day-ahead markets, but that it is coupled with the supply of a resource adequacy product.[50] In again rejecting CAISO's proposed day-ahead must-offer requirement, the Commission said, "[u]ntil the resource adequacy requirement is implemented, it is inappropriate to place a mandatory day-ahead obligation onto generators without a corresponding capacity payment."[51]

Intervenors provide no basis for the Commission to ignore its precedent by requiring SPP to implement a must-offer requirement in the SPP Day-Ahead Market absent a resource adequacy proposal or capacity payment mechanism. Despite TDU Intervenors' characterization of the Day-Ahead Market must-offer requirement as "striking,"[52] the Day-Ahead Market must-offer requirement is tailored to ensure that sufficient Resources are available to serve load while being limited to Market Participants with state-imposed load-serving obligations, consistent with Commission precedent.[53] Suggestions that the requirement should be expanded to other Market Participants including merchant generators,[54] or that LSEs should be required to offer all of their resources,[55] are unavailing and contrary to Commission policy.

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50 *Cal. Indep. Sys. Operator Corp.*, 108 FERC ¶ 61,254, at P 10 (2004).

51 *Id.*

52 TDU Intervenors' Protest at 33.

53 Integrated Marketplace Filing, Transmittal Letter at 22. The Commission previously has accepted a day-ahead must-offer requirement applicable to retail-regulated load-serving entities. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at PP 409-411.

54 EPSA Protest at 5 (noting that load-serving market participants are subject to "a must-offer requirement that differs from other market participants."); TDU Intervenors' Protest at 33 ("[M]erchant generators are under no must-offer
(continued. . .)

Likewise, the fact that SPP's Day-Ahead Market must offer requirement is different than other RTOs is no basis for rejecting it, as some intervenors suggest.[56] First, the Commission repeatedly has recognized the need for and accepted regional differences in various RTO market designs.[57] SPP's Day-Ahead Market must-offer requirement was the product of extensive stakeholder discussions and was designed to satisfy the needs of the market without being overbroad in violation of Commission precedent. Moreover, without a corresponding long-term resource adequacy construct or capacity payment

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obligation"); Xcel Protest at 6-7 (criticizing the SPP proposal because it does not include Market Participants that do not serve load).

55 *See, e.g.*, Calpine Comments at 5 (criticizing SPP's must offer requirement that permits LSEs to choose which resources to offer in the Day-Ahead Market; TDU Intervenors' Protest at 34, 44 (suggesting that other RTOs impose a must offer requirement on all resources in their day-ahead markets.

56 Calpine Comments at 5-6 (asserting that the Commission should direct SPP to establish a day-ahead must offer requirement similar to those implemented in other RTOs); EPSA Protest at 6 ("SPP's must-offer requirement should be the same as that in other proven markets unless it can offer substantial support for a different approach."); TDU Intervenors' Protest at 34 (characterizing the day-ahead must-offer requirement as "a significant departure from the design of other RTO Day 2 markets"); Xcel Protest at 6 (contrasting SPP's must-offer requirement with those of other RTOs).

57 *See, e.g.*, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, III FERC Stats. & Regs., Regs. Preambles ¶ 31,324, at P 75 (2011) (declining to mandate standardized market rules, instead allowing RTOs "flexibility to design market rules that accommodate their markets"), *order denying reh'g*, Order No. 755-A, 138 FERC ¶ 61,123 (2012); *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, III FERC Stats. & Regs., Regs. Preambles ¶ 31,281, at PP 59, 86, 160 (2008) (declining to mandate that RTOs develop standardized procedures for demand response), *as amended,* 126 FERC ¶ 61,261, *order on reh'g,* Order No. 719-A, III FERC Stats. & Regs., Regs. Preambles ¶ 31,292, *reh'g denied,* Order No. 719-B, 129 FERC ¶ 61,252 (2009); *Duquesne Light Co.*, 122 FERC ¶ 61,039, at P 132 ("The Commission has permitted RTOs to adopt different just and reasonable
(continued. . .)

mechanism, SPP's adoption of a must-offer requirement similar to other RTOs would contravene Commission precedent, as discussed above.

Additional concerns expressed by intervenors provide no basis for the Commission to modify SPP's proposed must-offer requirement. For instance, TDU Intervenors' assertion that all other RTOs require all available Resources to offer in the Day-Ahead Market[58] is incorrect. As demonstrated above, RTO day-ahead must-offer requirements are limited to Resources that receive a capacity payment or are designated in a resource adequacy program. Moreover, intervenor concerns that basing the Day-Ahead Market must-offer requirement on the LSE's expected load provides opportunities for LSEs to underestimate their load to escape the must-offer requirement[59] are unavailing, because market incentives exist for LSEs to use accurate estimates of expected load in calculating the Resource capacity to be offered into the Day-Ahead Market. For example, LSEs that underestimate their load and do not clear sufficient load in the Day-Ahead Market that is close to their actual consumption in real-time will be subject to RUC MWP charges, potentially higher real-time LMPs, and congestion costs to serve their remaining load in real-time. Accordingly, the Commission should reject requests to modify the day-ahead must-offer requirement.

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approaches based on the circumstances of their systems."), *order on reh'g*, 124 FERC ¶ 61,219 (2008).

[58] TDU Intervenors' Protest at 34, 44.

[59] Calpine Comments at 5-6; EPSA Protest at 7; TDU Intervenors' Protest at 33-34; Xcel Protest at 7.

E. Intervenors Misinterpret SPP's Statements Regarding Reserve Sharing

In the Integrated Marketplace Filing, SPP proposed to retain the ability to enter into arrangements with entities external to the SPP Balancing Authority Area to share Contingency Reserve.[60] SPP indicated that, "[w]ith the creation of the new SPP Balancing Authority, existing reserve sharing arrangements will be eliminated."[61] Certain intervenors take issue with this statement,[62] arguing that the "availability of reserve sharing" will be "curtailed"[63] and that while "the Integrated Marketplace Tariff 'allows' SPP to enter into reserve sharing [contracts] . . . that SPP *is not required to do so*."[64]

Despite intervenor suggestions to the contrary,[65] SPP has no intention of terminating its *voluntary*[66] participation in reserve sharing arrangements with entities

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60 Integrated Marketplace Filing, Transmittal Letter at 46 and Exhibit No. SPP-1 at 20.

61 *Id.*, Transmittal Letter at 46.

62 APPA Comments at 5; Motion to Intervene, Protest, Motion for Partial Rejection and Alternative Motion for Suspension and Hearing by the Lafayette Utilities System, et al., Docket No. ER12-1179-000, at 6-12, Docket No. ER12-1179-000 (Mar. 30, 2012) ("L-M Municipals Protest"); Motion to Intervene, Protest and Statement of Position by the Louisiana Energy and Power Authority, Docket No. ER12-1179-000, at 3-4 (Apr. 3, 2012).

63 L-M Municipals Protest at 6-7.

64 *Id.* at 7-8.

65 *See, e.g. id.* at 8 (characterizing SPP's proposal on reserve sharing as a "bait and switch"); *id.* at 10 (suggesting that "SPP is simply using its new market proposal as a pretext for shedding a long-standing arrangement.").

66 Participation in a reserve sharing group is voluntary, and, despite their concern that SPP will be under no obligation to continue its reserve sharing arrangements in the Integrated Marketplace, L-M Municipals cite no Commission precedent (continued. . .)

external to the SPP Balancing Authority Area with whom SPP currently has a reserve sharing agreement, once the Integrated Marketplace commences. In fact, proposed Attachment AE contains several provisions governing SPP's participation in reserve sharing arrangements.[67] In stating that existing reserve sharing arrangements will be eliminated, SPP intended to convey that, because the sixteen current Balancing Authorities within the SPP Region will be consolidated into a single SPP Balancing Authority, existing arrangements involving the current individual Balancing Authorities will no longer be necessary (i.e., because the Balancing Authorities will cease to exist).[68] However, to the extent that SPP currently engages in reserve sharing with an external Balancing Authority, it intends to continue that reserve sharing in the Integrated Marketplace. Because SPP is not currently a Balancing Authority, revisions to existing

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mandating SPP's continued participation in any reserve sharing arrangement. *See*, *e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,241, at P 277 ("[W]e are not mandating the use of reserve sharing groups."), *order on reh'g*, Order No. 890-A, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009); *see also* Order No. 890-A at P 91 ("[T]he Commission did not mandate the use of reserve sharing groups.").

67 *See, e.g.*, Integrated Marketplace Filing, Proposed Tariff at Attachment AE §§ 6.3.3 ("Reserve Sharing Group Scheduling Procedures"), 8.6.17 ("Real-Time Reserve Sharing Group Amount"), and 8.6.18 ("Real-Time Reserve Sharing Group Distribution Amount").

68 *See id.*, Transmittal Letter at 46 ("The *current* Balancing Authorities in the SPP footprint participate in a Reserve Sharing Group. . . . With the *creation* of the new SPP Balancing Authority Area, the *existing* reserve sharing arrangements will be eliminated.") (emphasis added).

agreements will be necessary, and SPP intends to explore modification of the current agreements with the parties to those agreements.

F. The Proposed Integrated Marketplace Registration Moratorium Will Not Preclude Resources from Coming On-Line

In the Integrated Marketplace Filing, SPP requested Commission authorization to adopt a one-year moratorium on registration of new Market Participants in the Integrated Marketplace, beginning six months prior to the start of the market and ending six months after the market commences.[69] SPP explained that the moratorium is necessary to permit SPP to validate market models and complete market trials, and to ensure that the market is operating as designed once initiated.[70]

In response to the proposed moratorium, AWEA acknowledges the need for the moratorium but asserts that "any moratorium must be sufficiently flexible to not prevent new resources, such as wind energy generators from coming on-line during this period."[71] As SPP stated in the Integrated Marketplace Filing, the proposed moratorium would apply only to the registration of new Market Participants; existing Market Participants would be permitted to modify their market registrations as necessary.[72] The moratorium would not limit the ability for new Resources to come on-line during the period, provided that the Market Participant registered the new Resources with SPP prior to the start of the moratorium, even with an effective date during the market trials. Once registered, a

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[69] *Id.*, Transmittal Letter at 65-66.

[70] *Id.*

[71] AWEA Comments at 11.

[72] Integrated Marketplace Filing, Transmittal Letter at 65-66.

Market Participant can modify its Resources as necessary, including bringing a new, pre-registered Resource on-line during the moratorium period.

G. SPP's Proposed ARR Methodology is Just and Reasonable

Certain parties take issue with several aspects of SPP's proposed provisions governing the nomination and allocation process for ARRs; however, none provides a basis for the Commission to reject SPP's ARR proposals.

1. SPP's Proposed Treatment of Firm Transmission Service Subject to Redispatch is Appropriate

In the Integrated Marketplace Filing, SPP proposed that "Firm Point-To-Point Transmission Service that is requested and that requires this redispatch shall be ineligible for the portion of the Auction Revenue Right ("ARR") allocation associated with such redispatch until the transmission facility additions have been made and redispatch is no longer required."[73] Intervenor comments critical of this limitation[74] are misplaced.

Pursuant to Order Nos. 888[75] and 890, SPP offers the redispatch option when the existing transmission system has insufficient capability to grant requested transmission

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73 *Id.*, Proposed Tariff § 13.5.

74 AWEA Comments at 4-6; Motion to Intervene and Protest of BP Wind Energy North America Inc., Docket No. ER12-1179-000, at 4-8 (Apr. 6, 2012) ("BP Wind Energy Protest"); Motion for Leave to Intervene and Protest of TradeWind Energy, LLC, Docket No. ER12-1179-000, at 4-12 (Apr. 5, 2012) ("TradeWind Energy Protest").

75 *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, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission*
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service over the requested path, but an SPP study has determined that the request can be accommodated by redispatching resources. As part of the study process, SPP determines whether there is sufficient available transfer capability ("ATC") to accommodate the requested service without any network upgrades. If there is sufficient ATC available, the service is granted and no interim redispatch is required to grant the service. If only a portion of the requested service can be granted without any network upgrades, SPP will inform the customer how much of the request can be granted without any network upgrades and whether service can be granted using interim redispatch. The customer may then choose whether to take the lesser amount and be eligible for ARRs, or whether to take the service subject to redispatch. Given the nature of redispatch service, it is appropriate that Firm Point-To-Point Transmission Service that is subject to a redispatch condition not share in the allocation of ARR. Redispatch service, by definition, is not provided using the "path" that has been requested by the Transmission Customer. To the contrary, the pre-existence of transmission service commitments to other customers renders that path unavailable for the customer receiving service subject to the redispatch condition.

Allocation of ARRs is based on the existing transmission system's capability and is subject to simultaneous feasibility. Firm Point-To-Point Transmission Service customers and Network Integration Transmission Service customers are eligible to nominate candidate ARRs reflective of their Point-To-Point path or their peak Network Load, and SPP determines the amount of nominated ARRs that are simultaneously

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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).

feasible. Allowing Firm Point-To-Point customers whose service is subject to redispatch also to nominate candidate ARRs over the same requested path would result in a deliberate over-allocation of ARRs, because more service is being provided over that path (due to redispatch) than is actually physically feasible.[76]

Moreover, given that transmission service subject to redispatch is provided through redispatch of generation Resources and thus occurs over paths other than the requested path, it would be infeasible if not impossible to identify an ARR that accurately reflects the path over which the service is being provided. Attempting to identify an alternate path over which to provide ARRs could result in reducing ARR availability for customers that are entitled to take service over and thus nominate candidate ARRs over the alternate path.

Finally, SPP notes that the redispatch option is available as an alternative to increase the available capability of the transmission system pending completion of network upgrades to accommodate a transmission service request. As Section 13.5 notes, once network upgrades are completed, the redispatch condition, and thus the limitation on ARR eligibility, will terminate. Thus, for long-term Firm Point-To-Point customers relying on interim redispatch for a portion of their confirmed service, the limitations on ARR eligibility could be temporary.

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[76] In fact, AWEA acknowledges that the limitation on ARR eligibility for Firm Point-To-Point Transmission Service subject to redispatch is appropriate to prevent overallocation of ARRs. *See* AWEA Comments at 5 (noting that concerns regarding overallocation is a "plausible" reason for limiting ARR eligibility for service subject to a redispatch limitation).

2. *Criticisms of SPP's Proposed ARR Nomination Provisions for NITS Service Are Inapposite*

Certain parties take issue[77] with SPP's proposal to permit Network Integration Transmission Service customers to nominate candidate ARRs for the reservation capacity for each source up to a total nomination cap of 103% of the average of the customer's three highest annual peak Network Loads since February 1, 2007. As discussed in SPP's Integrated Marketplace Filing, the nomination eligibility for NITS customers was designed to account for current system usage and load growth.[78] SPP's stakeholders considered using other periods to determine ARR nomination eligibility (i.e. most recent three years),[79] but opted to select a period that coincides with the launch of the SPP EIS Market as being a sufficient representative historical period, giving seven years of historical peak data prior to Integrated Marketplace start up on March 1, 2014. Including annual peaks back to 2007 in the calculation of the average annual peak for ARR eligibility will account for short-term load reductions that some NITS customers may have experienced during the financial crisis and economic downturn of 2008 and lingering recession. While some NITS customers may have experienced load reductions or load shifts,[80] the proposed cap ensures that future ARR nomination eligibility accounts for future load growth. Additionally, in calculating peak load for purposes of determining ARR eligibility, SPP will adjust for load transfers among LSEs.

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77 *Id.* at 6-8; BP Wind Energy Protest at 8-10.

78 Integrated Marketplace Filing, Transmittal Letter at 15.

79 BP Wind Energy Protest at 9-10.

80 *See* AWEA Comments at 7-8.

3. *Other Requested Modifications to the ARR Methodology Should Be Rejected*

In the Integrated Marketplace Filing, SPP proposed a monthly ARR allocation process to allocate incremental ARRs for transmission service confirmed following completion of the annual ARR allocation process.[81] TDU Intervenors request that eligibility for incremental ARRs be expanded to any entity that unsuccessfully sought ARRs during the annual process.[82] However, the purpose of the incremental ARR process is to provide an opportunity for customers that were not able to participate in the annual ARR allocation process (because their transmission service had not yet been confirmed) the same opportunity to nominate candidate ARRs as customers that were eligible to participate in the annual ARR process, not to provide customers that were unsuccessful in the annual process a “second bite at the apple” to obtain additional ARRs. Because ARR allocations are subject to simultaneous feasibility, broadening the eligibility to nominate incremental ARRs could enable entities that participated in the annual ARR allocation process to crowd out entities seeking ARRs for the first time through the incremental ARR process. Allowing additional participation in the incremental ARR process also would add complexity to the process, requiring SPP to initiate the incremental process an entire month earlier than under the current construct.

It should also be noted that TDU Intervenors do not identify any Commission precedent requiring SPP to adopt their request, nor do they cite any other RTO market that permits unsuccessful entities an additional opportunity to secure ARRs. It is SPP’s

81 Integrated Marketplace Filing, Transmittal Letter at 16 and Proposed Tariff at Attachment AE §7.5.

82 TDU Intervenors’ Protest at 13-14.

understanding that in other RTO markets, entities seeking additional hedges must purchase TCR-equivalent products in the auctions to supplement the ARRs that they obtained in the ARR process. TDU Intervenors' request to broaden eligibility for incremental ARRs should therefore be rejected.

Likewise, DC Energy's request that the Commission mandate that SPP incorporate multi-period auctions is unsupported and should be rejected.[83] DC Energy provides no argument or suggestion that SPP's auction process as proposed is unjust or unreasonable, but instead requests that SPP "take one further step as has been done in other ISO markets."[84] As an initial matter, as discussed above, Commission policy does not require SPP's market design to be identical to other markets. Additionally, it should be noted that none of the markets DC Energy identifies as currently having or contemplating multi-period auctions had such a process in place when the market commenced.[85] SPP's Integrated Marketplace ARR and TCR processes were designed to address the needs of Market Participants and conditions on the SPP system,[86] and stakeholders considered and declined to support a multi-period auction process in the

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83 Motion to Intervene, Limited Protest, and Comments of DC Energy, LLC, Docket No. ER12-1179-000, at 19-21 (Apr. 6, 2012) ("DC Energy Protest").

84 DC Energy Protest at 19.

85 According to DC Energy's Protest, only PJM currently has a multi-period auction, and has only had one since 2006. The other markets DC Energy identifies either have not yet implemented multi-period auctions (i.e., ISO-NE "plans" to implement a multi-period construct in January 2013 and MISO plans to do so by the end of 2013) or have not yet even decided whether to implement one (i.e., ERCOT and NYISO). DC Energy Protest at 19 n.14.

86 *See* Integrated Marketplace Filing, Transmittal Letter at 16-20 and Exhibit No. SPP-3 at 44-45.

Integrated Marketplace. That DC Energy may prefer this feature of other markets does not render SPP's proposal unjust and unreasonable.

H. The Integrated Marketplace Accommodates Bilateral Transactions

TDU Intervenors express concern that the design of the Integrated Marketplace may not readily accommodate existing bilateral power purchase and power sale agreements.[87] Among other things, TDU Intervenors question whether, and to what extent, purchases of power are considered Resources that can be (or must be) offered into the market by the purchaser as separate Resources that are independent of the generating units supporting the sales (which are offered into the Integrated Marketplace by the seller under the bilateral agreement).[88]

The scenario posited by TDU Intervenors appears to contemplate that the seller would have total control over the Resource, with the buyer simply paying the seller the contract rate for serving all or a portion of the buyer's load. In this situation, only the seller can offer the Resource into the market, and the buyer and seller, through execution of a Bilateral Settlement Schedule, can effectuate a transfer of the buyer's load obligation in the market to the seller. This ensures that the buyer is ultimately credited for the Energy purchase. Alternatively, the seller can simply register all or a portion of the buyer's load as its own load asset. Under either scenario, there are no duplicative offers and no duplicative charges.

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87 TDU Intervenors' Protest at 22-29.

88 *Id*. at 22-24.

TDU Intervenors further complain that the challenges are even greater when a buyer makes "system purchases" from the seller's fleet of Resources.[89] According to TDU Intervenors, a buyer in this situation would have volumetric scheduling rights (i.e., the ability to decide whether to purchase power, and in what quantities), but no control over the seller's choices of which units to dispatch to provide the scheduled power. Again, however, the design of SPP's Bilateral Settlement Schedules addresses this concern: such schedules can be submitted up to four days after the operating day in which the Bilateral Settlement Schedule takes effect for use in the initial settlement and up to 44 days following the operating day in which the Bilateral Settlement Schedule takes effect so that these types of hourly Energy deliveries can be matched and properly accounted for.

While generally supporting the use of Bilateral Settlement Schedules to facilitate the use of bilateral transactions, TDU Intervenors complain that there are no assurances that a purchaser under a bilateral agreement can avail itself of this option because the seller's agreement to the terms of the Bilateral Settlement Schedule is required. TDU Intervenors fear the prospect of "foot-dragging" by the seller, and/or the insistence on unreasonable terms which could, in TDU Intervenors' view, erode the purchaser's original bargain. TDU Intervenors suggest that SPP's Tariff be revised to include a requirement ensuring that a purchaser under a bilateral contract can obtain a Bilateral Settlement Schedule "on reasonable terms and conditions," even where the seller refuses to agree. TDU Intervenors also construe SPP's proposed Tariff as vesting SPP with a right to terminate the Bilateral Settlement Schedule without buyer's consent and suggests

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[89] *Id.* at 23.

that if such interpretation is accurate, explicit conditions be set forth in the Tariff defining and limiting such termination authority.

To the extent that TDU Intervenors seek revisions to SPP's Tariff that would compel a seller's agreement to a Bilateral Settlement Schedule, SPP is at a loss to understand how such a Tariff provision would operate or be enforced. The theoretical dispute suggested by TDU Intervenors would involve the parties to the bilateral contract, and SPP cannot act as arbiter of the parties' rights and obligations that may arise under that bilateral agreement.

With respect to the asserted right of SPP to terminate the Bilateral Settlement Schedule, TDU Intervenors' interpretation is incorrect. The Protocols allow for both the buyer and seller to set up an "auto-approve" feature (which both buyer and seller need to agree to), and once this option is activated, the Bilateral Settlement Schedule is approved when submitted by either party. Only if a dispute arises between the parties over submittals, where the auto-approve option has been selected, can SPP rescind this option and only for the purpose of requiring both the buyer and seller to confirm the Bilateral Settlement Schedule.

TDU Intervenors raise several peripheral issues concerning the use of bilateral agreements in the Integrated Marketplace. These issues can be addressed through simple clarifications. As to TDU Intervenors' question regarding a buyer's ability to "preserve the value" of its full requirement contracts, SPP confirms that the "simple and fair solution" suggested by TDU Intervenors – *viz.*, that the seller register as the Asset Owner for the buyer's load – is an option available under the registration rules for the Integrated Marketplace.

Similarly, TDU Intervenors question whether, in cases where the buyer is the Market Participant with load responsibility, it may offer as a Resource the Energy quantities that it has the right to receive under a bilateral agreement, at a Settlement Location that corresponds to the delivery point in the bilateral agreement, thereby essentially buying back the Energy at the buyer's load Settlement Location. SPP confirms that TDU Intervenors may not offer these Energy quantities into the market as a Resource, but can effectuate these types of arrangements through the combined utilization of a Market Hub and a Bilateral Settlement Schedule. Only 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).

I. The Variable Energy Resource Provisions of the Integrated Marketplace Are Appropriate

In the Integrated Marketplace Filing, SPP proposed a series of provisions to facilitate the integration of Variable Energy Resources ("VER") into the Integrated Marketplace.[90] Given the large quantity of VERs expected to be registered by the start of the market and the vast potential for additional VER development in the SPP Region, the Integrated Marketplace provisions aim at striking an appropriate balance between facilitating VER participation and ensuring continued operational reliability in the market.

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[90] *See, e.g.*, Integrated Marketplace Filing, Transmittal Letter at 42-43 and Proposed Tariff at Attachment AE §§ 4.1.2.4 and 4.1.2.5.

Several intervenors take issue with various provisions governing the use of VER output forecasting. First, intervenors oppose SPP's use of its own forecasting in lieu of forecasts submitted by the VER.[91] As an initial matter, SPP will be performing VER output forecasting regardless of whether VERs are able to submit their own. Requiring SPP to rely on a VER's own forecasting would be duplicative and burdensome, as SPP would need to develop additional systems to analyze and utilize VER-submitted forecasts and compare them to SPP's own forecasts. Also, the fact that VER-submitted forecasting is an option adopted in other RTO markets does not mean SPP's reliance on its own forecasting is unjust and unreasonable. The benefit of relying on SPP's forecasting is that it eliminates any opportunities for gaming in the submission of Resource output forecasts, which would have a direct impact on pricing because the market clearing engines would dispatch based on these forecasts. An additional benefit is the improved consistency of Resource output forecasting across the SPP market because a single forecasting methodology will be used (rather than multiple methodologies adopted by multiple VERs).

Additionally, E.ON's request that SPP allow VERs to submit their forecasts and updates on a five-minute rolling basis ten minutes prior to the Dispatch Interval[92] is unnecessary and will not improve market efficiency. Through experience and analysis, SPP has determined that persistence forecasting is more accurate and reliable than any short-term interval forecasting.

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91 AWEA Comments at 8-9; BP Wind Energy Protest at 1, 10-12; E.ON Comments at 3-5.

92 E.ON Comments at 3-5.

Intervenor criticisms of SPP's ramp rate limitations are likewise inapposite. SPP's proposed VER ramp limitations in the Integrated Marketplace were designed to reflect the unique nature of VERs.[93] While VERs may have the potential of ramping quickly in response to dispatch, given their inherently variable nature, such ramping is not assured; otherwise, the Resource would not be considered "variable." If a VER fails to respond fully to a Dispatch Instruction due to the variable nature of the Resource, the RTBM solution will assume VER output that does not exist, leading to a shortage that will drive up prices for other Market Participants. Limiting ramping of VERs to allow for gradual reload of a VER over several five-minute dispatch intervals after it has responded to a Dispatch Instruction will lessen the possibility of price spikes and reduce the need to call on spinning reserves, which are intended to maintain operational reliability rather than operate for the convenience of VERs.

Finally, several parties point out that Section 8.6.7(f) of Attachment AE contains an apparent error regarding the allocation of RUC MWP costs to Resources that self-commit after the close of the Day-Ahead Market and then receive a Dispatch Instruction to their *maximum* operating limit.[94] SPP agrees that this section is intended to allocate RUC MWP costs to Resources that self-commit and then are dispatched to their *minimum* operating limit. SPP has revised Section 8.6.7(f) and will submit the revision in its soon-to-be-filed supplemental filing.

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[93] Integrated Marketplace Filing, Transmittal Letter at 42 and Exhibit No. SPP-3 at 37-38.

[94] AWEA Comments at 10; BP Wind Energy Protest at 14.

J. Western Area Power Administration's Proposed Tariff Revisions Should Be Vetted Through Conventional SPP Stakeholder Processes

Western Area Power Administration, Upper Great Plains Region ("Western") requests that the Commission order SPP to adopt Tariff revisions that would facilitate the participation of Western in the Integrated Marketplace. Western offers specific Tariff language designed to permit Western to purchase and sell power and transmission services within the Integrated Marketplace, while ensuring Western's ability "to comply with its obligations under Federal law." Western submits that adoption of the proposed Tariff language, which Western claims has been approved in other regional market tariffs, will improve the scope and operation of the Integrated Marketplace.[95]

As a general proposition, SPP supports broad participation in the Integrated Marketplace. To that end, SPP is committed to working with Western, and any other interested Market Participant, to facilitate access to all products and services available in the Integrated Marketplace. However, the Tariff revisions proposed by Western potentially implicate the contracting terms and conditions of other Market Participants that transact directly or indirectly with Western through the Integrated Marketplace.[96] More broadly, the Tariff revisions offered by Western introduce possible implementation issues by cross-referencing U.S. Department of Energy regulations, rate schedules and

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[95] Importantly, Western does not allege that the as-filed Tariff changes proposed by SPP are unjust or unreasonable without the Western modifications. Motion to Intervene and Comments of the United States Department of Energy, Western Area Power Administration, Docket No. ER12-1179-000, at 4 (Mar. 28, 2012) ("Western Comments").

[96] *See, e.g.,* Western Comments, Proposed Tariff Revisions, Exhibit WPA-1, at Article XA.3, "Contractor Agreement," which requires all counter-parties to contracts with Western to abide by specified employment and labor provisions.

"federal participation provisions" that would take precedence over otherwise applicable terms of the SPP Tariff.[97] One provision proposed by Western could be interpreted as requiring arbitration for any disputes related to Western's Integrated Marketplace participation, posing a potential conflict with the dispute resolution and remedy provisions of SPP's Tariff and Attachment AE.[98]

To ensure careful consideration to all potentially affected interests, the planned accommodation of Western as a participant in the Integrated Marketplace – including the development of appropriate Tariff revisions – should be referred to SPP's stakeholder process. As discussed in detail in the testimony of Carl Monroe, all design elements of the Integrated Marketplace were subject to a multi-year stakeholder process and related Tariff revisions were developed by and vetted through SPP's working group and task force organizations, with final review and refinement by SPP's Regional Tariff Working Group and Markets and Operations Policy Committee before presentation to and approval by the SPP Board of Directors.[99] The point is that by subjecting all Tariff revisions to stakeholder review, the interests of all affected parties are accounted for,

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97 *See* Western Comments, Proposed Tariff Revisions, Exhibit WPA-1, at Article XA.1, "Subject to Acts of Congress."

98 *Compare* Western Comments, Proposed Tariff Revisions, Exhibit WPA-1, at Article XA.1 *with* SPP Tariff § 12 (Dispute Resolution Procedures) and Integrated Marketplace Filing, Proposed Tariff at Attachment AE §§ 10.3 (Invoice Disputes) and 11.1.3 (Injunctive Relief and Specific Performance).

99 Integrated Marketplace Filing, Exhibit No. SPP-1 at 8-10.

thereby facilitating the development of appropriate and properly tailored Tariff language.[100]

In short, it is both premature and outside the normal course of business for the Commission to uncritically adopt Western's proposed Tariff changes without the benefit of review by SPP's stakeholders.[101] SPP therefore requests that the Commission refer the issues raised in Western's comments, including the proposed Tariff insert appended to Western's filing, to SPP's stakeholder process. SPP commits to provide the Commission with updates on developments concerning this matter.

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100 Western indicates that language comparable to what is proposed for inclusion in SPP's Tariff has been incorporated in the regional tariff of at least one other RTO, i.e., MISO. However, it appears that this language was approved prior to MISO's launch of its day-ahead and real-time markets. In connection with referral to SPP's stakeholder process, SPP commits to investigate how MISO's market transactions are structured given the contracting and dispute resolution provisions included in Western's proposed tariff.

101 On numerous occasions the Commission has recognized the benefits of stakeholder review in the development of revisions to SPP's Tariff and the appropriateness of according deference to provisions approved through the stakeholder process. *See, e.g., Sw. Power Pool, Inc.*, 127 FERC ¶ 61,283, at P 33 (2009) (noting that the Commission "accord[s] an appropriate degree of deference to RTO stakeholder processes"). Similar findings have been made in considering tariff revisions of other RTOs. *See, e.g., New Eng. Power Pool*, 105 FERC ¶ 61,300, at P 34 (2003) (Commission approval of transmission cost allocation proposal based upon an extensive and thorough stakeholder process); *Policy Statement Regarding Regional Transmission Groups*, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 30,976, at 30,872 (1993) (the Commission will afford an appropriate degree of deference to the stakeholder approval process). The Commission's deference to RTO stakeholder processes has been upheld by the courts. *See Pub. Serv. Comm'n of Wis. v. FERC*, 545 F.3d 1058, 1062-63 (D.C. Cir. 2008) (noting that the Commission often gives weight to RTO proposals that reflect the position of the majority of the RTO's stakeholders) (quoting *Am. Elec. Power Serv. Corp. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,083, at P 172 (2008)).

K. DC Energy's Challenges to the Integrated Marketplace Design Should Be Rejected

1. SPP's Proposed RUC MWP Allocation Methodology is Reasonable and Should Be Approved

DC Energy challenges SPP's proposed RUC MWP cost allocation methodology. That methodology is based on the sum of the absolute value of real-time deviations from cleared Day-Ahead Market positions and, as in other markets, does not attempt to allocate deviation charges based on actual or assumed reasons why a Resource may have been committed in the RUC process. DC Energy argues that, as proposed, SPP's RUC MWP allocation approach fails to embrace long-standing cost causation principles. The focus of DC Energy's protest appears to be on virtual trades, and the appropriateness of subjecting virtual transactions to MWP costs.

The Commission has recognized in other RTO proceedings that deviation or "uplift" charges are properly applied to virtual transactions.[102] This is because, when a virtual sale or purchase is cleared in a day-ahead market and generation or load does not materialize in real-time, costs are incurred by the market operator to reconcile the differences (imbalances or deviations).[103] The operator may, for example, incur costs associated with requesting Resources in real-time to start-up, ramp-down, ramp-up, or extend run times on schedules that deviate from the schedules or levels cleared in the

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102 *See, e.g., PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,244, at PP 2, 37 (2008); *Midwest Indep. Sys. Operator, Inc.,* 115 FERC ¶ 61,108, at PP 48-49, *order on reh'g*, 117 FERC ¶ 61,113 (2006).

103 *See DC Energy, LLC, DC Energy Mid-Atlantic, LLC v. PJM Interconnection, L.L.C.,* 138 FERC ¶ 61,165, at P 64 (2012).

Day-Ahead Market.[104] Thus, there is ample support for assessing virtual transactions RUC MWP charges.

The Commission has also recognized the inherent difficulty in matching deviation costs affecting the entire market to individual Market Participants or classes of Market Participants. For these reasons, the Commission has not insisted on granular cost allocation methodologies when approving, for example, procedures governing PJM Interconnection, L.L.C.'s ("PJM") allocation of balancing operating reserve ("BOR") costs.[105] In that case, the Commission took note of the inherent difficulty of attempting to model the financial impacts and allocation of BOR deviation charges, due to the volatile nature and real-time operational basis of Operating Reserve.[106]

Nonetheless, DC Energy insists that more precise matching should be ordered in the Integrated Marketplace for purposes of allocating RUC MWP costs. According to DC Energy, MWPs associated with a Resource that was committed due to the need for incremental Energy or constraint management should be allocated to those entities that caused the shortfall in the unit commitment process. DC Energy cites certain events (e.g., generator trips, voltage support and/or local reliability issues, interface de-rates, unexpected loop flows) that can trigger MWPs and argues that such events cannot be associated with virtual transactions. On this basis, DC Energy maintains that virtual transactions should not be allocated any MWP costs associated with such events.

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104 *Id.*

105 *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,244.

106 *Id.* at P 3.

The Commission should reject DC Energy's suggested MWP allocation changes. As noted, the Commission has largely considered and rejected similar arguments in other regional markets. Simply put, the Commission's "cost causation" precedent does not support DC Energy's claims and, in fact, cuts against them. Moreover, the RUC MWP cost allocation proposal that was adopted in the Integrated Marketplace design was the product of extensive stakeholder discussion and ultimately approved with broad stakeholder support. None of the issues or arguments now being advanced by DC Energy were presented during the stakeholder vetting process.

The notion that RUC MWP costs should be allocated to recognize specific Resource commitment decisions is not only contrary to precedent but impractical. Deviations are caused by a variety of reasons, including: increases in real-time load and export transactions above Day-Ahead Market cleared amounts; reductions in real-time load below Day-Ahead Market cleared amounts; virtual bids cleared in the Day-Ahead Market that must be replaced with real-time physical unit commitment; virtual load cleared in the Day-Ahead Market that does not materialize in real-time; and generators cleared in the Day-Ahead Market that increase or decrease their minimum or maximum output operating limit above/below Day-Ahead Market limits, to name but a few examples that are all included as deviations in the proposed SPP RUC MWP cost allocation. The granular cost-causation construct suggested by DC Energy is simply not realistic.

2. *Other Design Features Protested by DC Energy Are Reasonable and Should be Approved*

a. Exemptions from RUC MWP Costs Based on Existing Uninstructed Resource Deviation Exemption Is Reasonable

DC Energy takes issue with other design features associated with RUC MWP costs. For example, DC Energy argues that SPP's proposed exemption of certain Resources from RUC MWP costs – based on a pre-existing exemption from Uninstructed Resource Deviation ("URD") charges – is unsupported and should be eliminated. SPP disagrees. In the Integrated Marketplace design, there are no explicit charges for URDs other than what is embedded in the RUC MWP charges. If the Integrated Marketplace design had included an explicit charge for URDs and the Resource had been exempt from such charges, then the exemption would logically and necessarily continue with no charge applied.

b. SPP's Proposed Allocation of RUC MWP Costs to Real-Time Import Interchange Transactions Is Reasonable

DC Energy also protests SPP's proposal to allocate RUC MWP costs to real-time Import Interchange Transactions, claiming that such transactions increase the amount of available generation and therefore should not be assessed costs that are based on the commitment of other Resources. However, DC Energy ignores the fact that these are fixed transactions that are not dispatchable. As such, they operate to depress real-time LMP which, in turn, depresses revenues received by RUC-committed units. The upshot is that RUC MWP costs are potentially increased as a direct result of these transactions and should therefore be allocated to them.

c. SPP's Proposed Bid Limit and Bid Limit Definition Are Reasonable as Filed

The Commission should also reject DC Energy's request to limit the types, or increase the number, of permissible bids per Market Participant. The 2,000 bid limit proposed by SPP was imposed due to concerns over model performance and the desire to minimize potential logistical challenges that could delay market start-up. SPP is amenable to re-visiting the bid limit if operational experience indicates no performance problems during testing and market trials. However, SPP does not agree with DC Energy's related suggestion that only bids – not bids and *offers* – be counted for bid limit purposes. Both are evaluated simultaneously and thus impact model performance the same way. Accordingly, offers should continue to be counted toward the bid limit.

d. SPP's Proposed Allocation of Revenue Neutrality Uplift Is Reasonable

DC Energy opposes SPP's proposed allocation of Revenue Neutrality Uplift ("RNU"), arguing that a more equitable solution is required due to perceived differences between cleared virtual offers and metered generation. Specifically, DC Energy argues that it is unfair for a Market Participant with both metered generation and cleared virtual offers to be allocated only a portion of the RNU (based on the lesser of metered generation of cleared virtual offers), when a Market Participant with only metered generation or only cleared virtual offers will be allocated RNU on the basis of the metered generation or the cleared virtual offers.

SPP submits that there is no inequity in its RNU allocation proposal. Allocating RNU on the "lesser of" basis accounts for the fact that the Market Participant with the virtual offer actually showed up in real-time with physical generation. This approach therefore avoids unfairly charging the Market Participant for both physical generation and virtual offers.

e. SPP's Day-Ahead MWP Allocation Proposal Should Not be Modified to Incorporate Netting of Virtuals

DC Energy argues that the absence of netting provisions in SPP's Day-Ahead Market MWP cost allocation proposal is unreasonable and should be revised. DC Energy rationalizes that a Market Participant should be able to net volumes of virtual bids across Settlement Locations so as to avoid an allocation of MWP costs because "unit commitment processes evaluate capacity requirements for the market from a much broader perspective than a single Settlement Location and [] evaluate capacity requirements based on net impact of all bids collectively."[107]

SPP's Day-Ahead Market MWP allocation proposal is reasonable and should be approved. As previously noted, the Commission has confirmed that virtual transactions impact the market and should be subject to uplift charges similar to physical transactions. Inclusion of virtual bids is comparable to the inclusion of physical load (exports and demand bids) in the Day-Ahead Market MWP allocation. Netting virtual bids and offers on a system-wide basis, as suggested by DC Energy, would logically require netting of physical load and physical generation on a system-wide basis. The result would be that SPP would lack any basis to allocate Day-Ahead Market MWP costs, because all transactions would effectively net out to zero.

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107 DC Energy Protest at 18.

L. Contrary to MISO's Suggestion, SPP's Joint Operating Agreement with Western Will Have Little Impact on Implementation of the Integrated Marketplace

In late-filed comments, MISO raises a single question regarding how the joint operating agreement between SPP and Western recently filed in Docket No. ER12-1586 ("SPP-Western JOA") will affect the implementation of the Integrated Marketplace. Apparently, MISO intends to challenge the voluntarily-entered SPP-Western JOA, to which MISO is not a party, in the docket in which it was filed.[108] Here, MISO questions the SPP-Western JOA's impact on both SPP's TCR market[109] and SPP's ability to coordinate with other neighboring systems.[110] MISO also wonders who will be responsible for obtaining and paying for transmission service required for flows in excess of allowable flow limits under the SPP-Western JOA.[111]

The SPP-Western JOA will have little impact on SPP's implementation of its Integrated Marketplace. SPP will calculate parallel path flow impacts when addressing TCRs so as to account for the contract path rights of Western. Contract path obligations will be modeled as injections and withdrawals (i.e., actual power flows) that will impact flowgates and thus the commitment of congestion rights. The SPP-Western JOA also will not affect SPP's Resource commitment and dispatch related to the coordinated flowgates that SPP and MISO currently monitor and observe under their joint operating

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108 Motion to Intervene Out of Time and Comments of the Midwest Independent Transmission System Operator, Inc., Docket No. ER12-1179-000, at 6 n.10 (May 2, 2012) ("MISO Late Comments").

109 *Id.* at 5-6.

110 *Id*. at 5.

111 *Id*. at 6

agreement. There simply will be a difference in the translation of the Western contract path amounts into flowgate responsibilities; these amounts will be shared with MISO, allowing MISO to be fully and transparently informed. As MISO notes, the "MISO/SPP JOA currently in place" already is designed to "reliably and equitably manage this seam with existing tariff provisions in both RTOs, as well as SPP's proposed Integrated Marketplace."[112] As to obtaining transmission service for any excess flows, under the SPP-Western JOA, the party that creates the excess flows will be responsible for obtaining, and paying for, any necessary transmission service. However, as a general matter, the SPP-Western JOA contemplates that the parties will operate their respective systems within their physical capabilities, so as not to place unauthorized flows on other systems, and, therefore, so as not to require the use of, and payment for, service on other transmission systems.

M. NPPD's Request to Be Held Harmless from Congestion and Marginal Loss Charges Should Be Rejected

NPPD's request that the Commission direct SPP to develop special hold harmless provisions for the NPPD Zone[113] lacks merit and should be rejected. NPPD cites certain Commission precedent from other RTOs, none of which provides a basis for SPP to exempt NPPD from the same congestion and loss charge mechanisms to which all Market Participants are subject in the Integrated Marketplace.

As an initial matter, NPPD's requests to be held harmless from congestion charges and to be refunded for the difference between marginal loss charges and average

112 *Id.* at 2.

113 NPPD Protest at 21-25, 27-29.

losses would undermine the price signals that LMP is designed to achieve. Including a marginal congestion component in LMP appropriately reflects the cost of congestion to identify where transmission or generation investment would be most appropriate. Moreover, as the Commission has stated, a marginal loss method sends more accurate price signals and lowers the overall production cost of electricity as compared to an average loss method.[114] Holding NPPD financially harmless from these costs would remove the financial incentives that underlie the Integrated Marketplace.

NPPD's reliance on precedent in MISO, ISO-NE, and PJM for its request to be held harmless from congestion charges[115] is misplaced. In MISO, the Commission approved a limited congestion cost protection mechanism for persistently congested areas with respect to "[o]nly FTRs from external sources,"[116] due to the significant potential that MISO's FTR allocation design could result in significant oversubscription on the most congested lines.[117] Contrary to the MISO situation, however, "NPPD is not located in a load pocket as in the *MISO* case," as NPPD acknowledges.[118] The PJM precedent on which NPPD relies[119] is similarly inapposite, because the Commission's concern in PJM

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114 *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 90-95 (2006).

115 NPPD Protest at 21-25.

116 *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 92. The Commission defined "external sources" as generation resources located outside of the area (either within MISO or external to MISO). *Id.* at P 82.

117 *Id.* at P 90.

118 NPPD Protest at 22 (emphasis in original).

119 *Id.* at 23-24 (citing *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,223, at PP 45, 48 (2004)).

was establishing a transitional FTR mechanism for a new transmission zone integrating into PJM.[120] NPPD is not transitioning into an existing SPP ARR/TCR market, but instead is similarly situated to all other Market Participants in SPP.

Finally, the Commission did not mandate that ISO-NE develop a mechanism for mitigating the impact of congestion on LMP for certain customers. While expressing that it was "sympathetic to the concerns of" certain customers regarding the effects of LMP in certain constrained areas, the Commission declined to require that ISO-NE delay implementation of its LMP proposal pending resolution of identified transmission constraints.[121] Instead, the Commission suggested that ISO-NE consider adopting measures to moderate the financial impact of LMP "without blunting LMP price signals," such as "building a defined set of transmission upgrades into Southwest Connecticut, *identified at the start of the implementation of LMP*, and [assigning] a portion of the upgrade costs to other New England customers."[122] As NPPD acknowledges, SPP already has identified a transmission upgrade, the Nebraska City-Sibley Priority Project, which is designed to address the very congestion about which NPPD complains,[123] the costs of which will be shared among other SPP customers through the SPP Highway/Byway cost allocation methodology. Consistent with the ISO-NE precedent,

[120] *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,223, at P 6 ("PJM's filing in this docket is designed to establish the initial yearly allocation of FTRs applicable to the customers in the newly integrated ComEd.").

[121] *New Eng. Power Pool and ISO New Eng., Inc.*, 101 FERC ¶ 61,344 at PP 35-36 (2002).

[122] *Id.* at P 36 (emphasis added).

[123] NPPD Protest at 24.

the Commission should find that SPP has adequately addressed NPPD's congestion concerns, and reject its request for a hold harmless mechanism.

Likewise, NPPD's argument that SPP should implement a transitional mechanism to refund load-serving entities the difference between the marginal loss charges and average losses, based on MISO precedent,[124] is inapposite. In MISO, the Commission expressly adopted certain transition procedures, including a transitional refund mechanism for the difference between marginal and average losses, given MISO's "unique features, such as the fact that this ISO does not have prior experience operating as a single power pool and has only a short period of experience operating under a single reliability framework,"[125] and MISO's and its customers' lack of experience with LMP pricing.[126] The Commission also cautioned that "such a refund measure could dampen the incentive to make efficient purchases in the spot market," and therefore directed MISO to adopt additional rules to encourage efficient activity in the spot market.[127] In contrast, SPP and its customers already have experience with locational pricing and a centralized real-time Energy market, experience that did not exist in MISO when the Commission approved certain short-term transitional features such as the losses refund methodology. Because the "unique features" that existed in MISO do not exist in SPP, the refund mechanism sought by NPPD is unnecessary and should be rejected.

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[124] *Id.* at 27-29 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 73).

[125] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 3.

[126] *Id.* at P 72.

[127] *Id.* at P 76.

N. The Integrated Marketplace Registration Provisions Are Based on EIS Market Provisions and Are Reasonable

NPPD takes issue with certain Market Participant registration requirements in the Integrated Marketplace, specifically Section 2.2(2) of Attachment AE,[128] which NPPD argues may cause NPPD to be responsible for load that does not take service from SPP or NPPD.[129] Contrary to NPPD's concerns, however, the registration requirements and expectations for the Integrated Marketplace are not materially different than under the current EIS Market. Section 1.2.2 of the current Attachment AE requires Market Participants to register all Resources and loads, including loads associated with GFAs.[130] The Integrated Marketplace Filing modified the registration requirements only to reflect certain definitional changes in the Integrated Marketplace for two categories of load – i.e., Non-Conforming Load[131] and Demand Response Load.[132] Absent information to the

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128 Section 2.2(2) of Attachment AE as proposed in the Integrated Marketplace Filing requires that "Market Participants must register all Resources and load, including applicable load associated with [GFAs], Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols." Integrated Marketplace Filing, Proposed Tariff at Attachment AE § 2.2(2).

129 *See* NPPD Protest at 20 (citing Integrated Marketplace Filing, Proposed Tariff at Attachment AE § 2.2(2)).

130 *See* SPP Tariff at Attachment AE § 1.2.2.

131 Non-Conforming Load is defined as "[l]oad that is process driven that does not follow a predictable pattern." *See* Integrated Marketplace Filing, Proposed Tariff at Attachment AE at § 1.1, Definitions N.

132 Demand Response Load is defined as "[a] registered measurable load that is capable of being reduced at the instruction of the Transmission Provider and subsequently may be increased at the instruction of the Transmission Provider." *See* Integrated Marketplace Filing, Proposed Tariff at Attachment AE at § 1.1, Definitions D.

contrary, SPP will assume that NPPD will be responsible in the Integrated Marketplace for the same loads for which it is currently registered in the EIS Market.

III. CONCLUSION

For the reasons set forth above and in the Integrated Marketplace Filing, SPP requests that the Commission reject the protests submitted in this proceeding, find that the Tariff revisions implementing the Integrated Marketplace are just and reasonable, and approve the Integrated Marketplace to commence on March 1, 2014.

Respectfully submitted,

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May 15, 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 15th day of May, 2012.

/s/ Matthew J. Binette
Matthew J. Binette

Attorney for
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