149 FERC ¶ 61,113
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Southwest Power Pool, Inc. Docket Nos. ER14-2850-000

ER14-2851-000

ORDER CONDITIONALLY ACCEPTING IN PART, REJECTING IN PART, ACCEPTING AND SUSPENDING FILINGS IN PART, ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES AND CONSOLIDATING PROCEEDINGS AND DIRECTING COMPLIANCE FILING

(Issued November 10, 2014)

1. On September 11, 2014, pursuant to section 205 of the Federal Power Act (FPA),[1] Southwest Power Pool, Inc. (SPP) submitted proposed revisions to its Open Access Transmission Tariff (Tariff), Bylaws, and Membership Agreement (collectively, Governing Documents). SPP proposes the revisions to the Governing Documents to facilitate the decision of the Western Area Power Administration – Upper Great Plains Region (Western-UGP), Basin Electric Power Cooperative (Basin Electric), and Heartland Consumers Power District (Heartland) (collectively, Integrated System Parties), to join SPP as transmission owning members, to place their respective transmission facilities under the functional control of SPP, and to begin taking transmission service under the SPP Tariff.[2] The Integrated System Parties together

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[1] 16 U.S.C. § 824d (2012).

[2] SPP filed the Tariff revisions and supporting testimony on the proposed integration in Docket No. ER14-2850-000. SPP filed the revisions to the Bylaws and

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jointly own and operate a significant portion of the bulk electric transmission system in the Upper Great Plains region of the United States.

2. SPP requests that the proposed Tariff revisions become effective October 1, 2015, and that the proposed revisions to the Bylaws and Membership Agreement become effective November 10, 2014. SPP requests waiver of the Commission's prior notice requirement to allow these Tariff revisions to be effective on the dates requested.[3] In this order, we conditionally accept in part, reject in part, and accept and suspend in part for a nominal period, to become effective as requested, subject to refund SPP's proposed revisions to the Governing Documents, and establish hearing and settlement judge procedures. Additionally, this order consolidates Docket Nos. ER14-2850-000 and ER14-2851-000 for purposes of hearing and settlement judge procedures.

I. <u>Background</u>

3. SPP states that its filings to integrate Western-UGP, Basin Electric, and Heartland into the regional transmission organization (RTO) results in substantial expansion of the SPP footprint that will: (1) provide significant benefits to SPP members and customers; (2) provide the Integrated System Parties' customers access to organized markets; and (3) increase efficiency and reliability for the newly combined portion of the bulk electric system. SPP argues that integration of the Integrated System Parties into SPP is supported by the Commission's policy to support public power participation in RTOs, and that integration of Western-UGP into SPP furthers the congressional preferences expressed in section 1232 of the Energy Policy Act of 2005 (EPAct 2005), which allows federal entities to place transmission facilities under a Commission-jurisdictional open access tariff.[4]

Membership Agreement in Docket No. ER14-2851-000. SPP states that although the overall filing has been divided into two parts to accommodate the eTariff system, the Commission should treat the submission as a single filing. All references to the "Transmittal" are to the transmittal letter submitted by SPP in Docket No. ER14-2850-000.

[3] Transmittal at 2.

[4] *Id*. (citing 42 U.S.C. § 16431(b)).

A. Description of Integrated System Parties and Integrated System

4. The United States Department of Energy, Western Area Power Administration (Western) is a federal power marketing agency that markets federal power and owns and operates transmission facilities through 15 western and central states, encompassing a geographic area of 1.3 million square miles. Western's primary mission is to market federal power and transmission resources constructed with Congressional authorization. The federal generation marketed by Western is generated by power plants that were constructed by federal generating agencies, principally the Department of the Interior's Bureau of Reclamation and the U.S. Army Corps of Engineers.[5] Western comprises four regions, one of which is the Upper Great Plains Region, or Western-UGP. Western-UGP owns an extensive system of high-voltage transmission facilities and markets federally generated hydroelectric power in the Pick-Sloan Missouri-Basin Program-Eastern Division of Western.[6] Western-UGP has entered into long-term firm electric service contracts for widespread distribution of federal hydroelectric generation to project use and preference customers.[7]

5. The Basin Electric membership serves 2.8 million customers in territories covering approximately 540,000 square miles using nearly 2,100 miles of transmission lines and 70 switch yards. Basin Electric was organized by its members to be an "all supplemental requirements" power supplier to provide power and energy to its members in excess of preference power provided to them through Western-UGP's allocations.

6. Heartland is a public corporation and political subdivision of the State of South Dakota. Heartland provides wholesale power to 28 municipalities in eastern South Dakota, southwest Minnesota and northwest Iowa, to six South Dakota state agencies, and to one electric cooperative in South Dakota.

7. The Integrated System is the backbone of the bulk electric transmission system across seven states in the Upper Great Plains region consisting of approximately 9,500 miles of transmission lines rated 115 kV through 345 kV. Spanning the Eastern

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[5] *Id*. at 4.

[6] *Id*. at 5.

[7] SPP states that Western-UGP is required to give "preference in power sales" to public agencies, cooperatives, municipalities, and other non-profit entities. *Id.* at 15 (citing 43 U.S.C. § 485h(c)(1)(B)).

and Western Interconnections of the U.S. electric grid, the Integrated System includes the combined transmission facilities of Western-UGP, Basin Electric and Heartland.[8] It also includes, through facility credits, facilities owned by Northwestern Energy and Missouri River Energy Services. SPP notes that the collaborative development of the Integrated System has resulted in transmission facilities that are highly integrated, and in some instances jointly owned, among the Integrated System Parties and with other transmission owners in the region.

B. SPP's Filing

8. SPP proposes a number of changes to its Governing Documents to allow the Integrated System Parties to sign the SPP Membership Agreement. First, SPP proposes a Federal Service Exemption that would permanently exempt Western-UGP from congestion and marginal losses settlements for transmission usage over the facilities in its new pricing zone, Zone 19, to deliver the output from its federal power resources to meet its Statutory Load Obligations. The Federal Service Exemption would also exempt Western-UGP from the Schedule 11 regional postage stamp rate,[9] for transmission service it takes to deliver the output from its federal power resources to meet its Statutory Load Obligations.[10] Second, with regard to transitioning Integrated System Parties into SPP's regional transmission planning process, SPP proposes modifying the definition of "Base Plan Upgrade" in Schedule 11 of its Tariff to specify that the Integrated System

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[8] The facilities of the Integrated System Parties located in both the Western and Eastern Interconnections will be transferred to the functional control of SPP; however, only the facilities in the Eastern Interconnection will be within the SPP footprint. *Id*. at 7.

[9] The Schedule 11 regional postage stamp rate funds expansion of the SPP transmission system. *Id*. at 3, 11, 30.

[10] SPP proposes to define Statutory Load Obligations in section 1-S of the Tariff, as follows:

> Western-UGP's power marketing function obligations under federal law to deliver power and energy from the output of the federal hydroelectric projects operated by the Department of the Army and the Bureau of Reclamation to loads which include project use loads, preference power customer loads in Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota located in a marketing area defined pursuant to a power marketing plan, and other loads required to be served under federal law.

Parties and SPP will commence regional cost sharing for projects with a "need-by" date on or after October 1, 2015.[11] Third, SPP proposes a Co-Supply Arrangement to enable load-serving entities to maintain their current practice of providing supplemental power supplies to Western-UGP's preference customers using network service. Under this proposal, Western-UGP would take network service, designating network load at points of delivery for its preference power customers up to their preference power allotment; Basin Electric or Heartland would also take network service, designating the remainder of the load at the same point of delivery as their network load.[12] Finally, SPP proposes limited revisions to its Bylaws and Membership Agreement to facilitate integration of the Integrated System Parties into SPP.

II. <u>Notice and Responsive Pleadings</u>

9. Notice of SPP's filings in Docket Nos. ER14-2850-000 and ER14-2851-000 was published in the *Federal Register*, 79 Fed. Reg. 56,353, with interventions and protests due on or before October 2, 2014. On September 16, 2014, the State Corporation Commission of the State of Kansas (Kansas Commission) filed a motion for an extension of time for parties to submit comments. On September 26, 2014, the Commission granted the extension of time to and including October 9, 2014.

10. Montana Public Service Commission and Minnesota Public Utilities Commission (Minnesota Commission) filed notices of intervention in both dockets. Motions to intervene in both dockets were filed by: American Electric Power Service Corporation on behalf of Public Service Company of Oklahoma and Southwestern Electric Power Company; Arkansas Electric Cooperative Corporation; Exelon Corporation; Flat Ridge 2 Wind Energy, LLC; Geronimo Wind Energy, LLC; Golden Spread Electric Cooperative, Inc.; Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company; Midcontinent ISO Transmission Owners;[13] NorthWestern Corporation;

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[11] Transmittal at 20.

[12] *Id*. at 3, 18-19.

[13] The Midcontinent ISO Transmission Owners for this filing consist of: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois, American Transmission Company LLC, Arkansas Electric Cooperative Corporation, Big Rivers Electric Corporation, Central Minnesota Municipal Power Agency, City Water, Light & Power (Springfield, IL), Cleco Power LLC, Dairyland

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Occidental Permian Ltd.; Omaha Public Power District; Rolling Thunder I Power Partners, LLC; South Central Municipal Cooperative Network, LLC; Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC; TDU Intervenors; Westar Energy, Inc.; Western Farmers Electric Cooperative (Western Farmers); and Xcel Energy Services, Inc.. Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company (collectively, Southern Companies) filed a motion to intervene out-of-time in Docket No. ER14-2850-000. DC Energy, LLC (DC Energy) filed a motion to intervene out-of-time in both dockets. Arkansas Public Service Commission (Arkansas Commission) filed a notice of intervention in Docket No. ER14-2850-000 and motions to intervene out-of-time in both dockets.

11. Motions to intervene and comments were filed by: Basin Electric; Central Montana Electric Power Cooperative, Inc.; Central Power Electric Cooperative, Inc. (Central Power); Corn Belt Power Cooperative; East River Electric Power Cooperative; Inc.; Goldenwest Electric Cooperative, Inc.; Heartland; Hill County Electric Cooperative, Inc.; ITC Great Plains, LLC (ITC Great Plains); Marias River Electric Cooperative; McKenzie Electric Cooperative, Inc.; Minnesota Valley Electric Cooperative; Montana-Dakota Utilities Co., A Division of MDU Resources Group, Inc., (Montana-Dakota); Municipal Energy Agency of Nebraska (MEAN); Northwest Iowa Power Cooperative; NorVal Electric Cooperative, Inc.; Otter Tail Power Company (Otter Tail); Powder River Energy Corporation; Rushmore Electric Power Cooperative; Tri-State Generation and Transmission Association, Inc.; United States Department of Energy, Western Area

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Power Cooperative, Duke Energy Business Services, LLC for Duke Energy Indiana, Inc., East Texas Electric Cooperative, Inc., Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc., Entergy Texas, Inc., Great River Energy, Hoosier Energy Rural Electric Cooperative, Inc., Indiana Municipal Power Agency, Indianapolis Power & Light Company, Michigan Public Power Agency, MidAmerican Energy Company, Minnesota Power (and its subsidiary Superior Water, L&P), Montana-Dakota Utilities Co., Northern Indiana Public Service Company, Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc., Northwestern Wisconsin Electric Company, Otter Tail Power Company, Prairie Power Inc., South Mississippi Electric Power Association, Southern Illinois Power Cooperative, Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana), Southern Minnesota Municipal Power Agency, Wabash Valley Power Association, Inc., and Wolverine Power Supply Cooperative, Inc.

Power Administration (Western); Upper Missouri Power Cooperative; and Wright-Hennepin Cooperative Electric Association. The Public Utility Commission of Texas (Texas Commission), the North Dakota Public Service Commission (North Dakota Commission), and the South Dakota Public Utilities Commission (South Dakota Commission) filed notices of intervention and comments.

12. Midcontinent Independent System Operator, Inc. (MISO), Montana Consumer Counsel, and Nebraska Public Power District (NPPD) filed motions to intervene and protests.[14] Missouri River Energy Services (Missouri River) filed a motion to intervene, provisional request for a technical conference, and protest. Kansas Commission filed a motion to intervene and to consolidate proceedings and a protest. Entergy Services, Inc., on behalf of Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc. (collectively, Entergy) filed a motion to file a limited protest out of time and a limited protest. Minnesota Commission filed a motion to file comments out of time and comments. The Organization of MISO States (MISO States) filed a motion to intervene out of time and comments.

13. Texas Commission and Kansas Commission request consolidation of Docket Nos. ER14-2850-000 and ER14-2851-000.[15]

14. SPP, Basin Electric, Heartland, Western, Kansas Commission, Missouri River, Montana-Dakota, MEAN, Otter Tail, Western Farmers, and NPPD filed answers in response to the comments and protests.

III. Discussion

A. Procedural Issues

15. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2014), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2014), the Commission will grant the late-filed motions to intervene of

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[14] On October 3, 2014, NPPD filed an errata to its motion to intervene and protest to correct the caption on its motion to intervene and protest filed on October 2, 2014.

[15] Texas Commission Comments at 1, 6.

Arkansas Commission, DC Energy, Entergy, MISO States, and Southern Companies given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

16. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2014), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We are not persuaded to accept the answers submitted by SPP, Basin Electric, Heartland, Western, Kansas Commission, Missouri River, Montana-Dakota, MEAN, Otter Tail, Western Farmers, and NPPD, and we therefore reject them.

B. Substantive Issues

17. Our preliminary analysis indicates that SPP's proposed revisions to the Governing Documents have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. SPP's proposed revisions to its Governing Documents raise issues of material fact that cannot be resolved based on the record before us and that are more appropriately addressed in hearing and settlement judge procedures. Therefore, with the exception of the issues summarily decided below, which include the Federal Service Exemption, the Co-Supply Arrangement, Base Plan Upgrades, the FERC Assessment, Generator Interconnection Procedures, and SPP's proposed revisions to its Bylaws and Membership Agreement, we are setting these matters for hearing and settlement judge procedures.

C. Revisions to Tariff

1. Federal Service Exemption

18. SPP proposes to establish a Federal Service Exemption that would apply only to Western-UGP's Statutory Load Obligations. Specifically, the Federal Service Exemption would apply to the transmission of federal power to serve Western-UGP's statutory preference customers. SPP states that the Federal Service Exemption would not apply to other transactions by Western-UGP and the other Integrated System Parties under the Tariff.[16]

19. SPP explains that the effect of the Federal Service Exemption is to carve out Western-UGP's long-term contract deliveries from the Integrated Marketplace charges

[16] Transmittal at 14. Thus, the Federal Service Exemption would not apply to purchases or sales into the SPP Integrated Marketplace. *Id*. at 31.

for congestion and marginal losses. In addition, the Federal Service Exemption provides that Western-UGP shall be exempt from the Tariff's Schedule 11 Region-wide Charge associated with Western-UGP's delivery of federal power resources[17] to Western-UGP's Statutory Load Obligations internal to the Integrated System Parties' zone, and/or external to SPP.[18] In addition, any load served by Western-UGP from resources in the Western Interconnection using transmission facilities from the Integrated System Parties' zone would not be subject to the Tariff's Schedule 11 Region-wide Charge to the extent the load is served only by resources in the Western Interconnection. SPP also asserts that the Federal Service Exemption will apply to a bilateral agreement between Western-UGP and Southwestern Power Administration, which also is a Federal Marketing Administration.[19]

20. According to SPP, section 1232 of EPAct 2005 authorizes a power marketing agency to join an RTO. SPP states that sections 1232(b) and (c) authorize a power marketing agency to enter into a contract with an RTO as long as the contract is consistent with the existing contracts of that power market agency and with statutory authorities, obligations, and limitations. SPP asserts that section 1232(d) prohibits Commission jurisdiction over the power marketing agency's generation, transmission, energy, and power sales activities.[20] Accordingly, SPP explains that the proposed Federal Service Exemption for Western-UGP complies with the requirement in section 1232 for Western-UGP to ensure consistency with existing contracts and with the statutory authorities, obligations, and limitations of the federal utility.

21. Further, SPP explains that Western-UGP interprets its statutory requirements within the RTO structure to require an exemption from market charges related to

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[17] Federal power resources include power and energy generated at reservoir projects under the control of the U.S. Department of the Army or the Bureau of Reclamation located within the marketing area of Western-UGP. SPP Tariff, section 39.3(f).

[18] Approximately 25 percent of the total Integrated System load and much of the Western-UGP Statutory Load Obligation is located outside of the Integrated System footprint and external to SPP. Ex. No. SPP-10 at 15-16; Ex. No. SPP-5 at 8.

[19] Ex. No. SPP-7 at 5-6.

[20] Transmittal at 15.

congestion and marginal losses, as well as the exemption from the Tariff's Schedule 11 Region-Wide costs for delivery of federal-power-Western-UGP resources to its Statutory Load Obligations.[21] SPP explains that although section 1232 does not provide direction regarding the specific rate issues addressed in its filing, the statutory requirements that any agreement to transfer functional control and use of facilities must ensure "consistency with existing contracts"[22] and "consistency with the statutory authorities, obligations, and limitations of the Federal utility"[23] support the need for the proposed Federal Service Exemption.

22. According to SPP, Western-UGP asserts that it is required pursuant to section 9(c) of The Reclamation Project Act of 1939 to give "preference in power sales" to public agencies, cooperatives, municipalities and other non-profit entities, including but not limited to, organizations financed in whole or in part by loans made under the Rural Electrification Act of 1936.[24] SPP explains that Western-UGP is required by statute to sell such power at the "lowest possible rates to consumers consistent with sound business principles" and to "encourage widespread use."[25] SPP states that construction of transmission lines to support such preference power is only authorized to the extent such construction is necessary to make the power generated at the federal projects available for sale. Because Western-UGP has constructed sufficient transmission facilities or purchased transmission capacity within Western-UGP to enable it to enter into long-term contractual commitments for the delivery of its federal finite generation to its statutory load customers, and because "Western-UGP has no authority to meet its customers' load growth," its Statutory Load Obligations will not grow.[26] Therefore, SPP explains that Western-UGP has concluded that it will not need to increase its regional transmission capacity because it has no authority to meet its customers' load growth to assist in

[21] *Id*. (citing Ex. No. SPP-7 at 4).

[22] *Id*. (quoting 42 U.S.C. § 16431(c)(1)(B)).

[23] *Id*. (quoting 16 U.S.C. § 825s).

[24] *Id*. (quoting 43 U.S.C. § 485h(c)(1)(B)).

[25] *Id*. (quoting 16 U.S.C. § 825s).

[26] Ex. No. SPP-7 at 13-14.

meeting future delivery needs and, hence, Western-UGP lacks statutory authority to subject itself to additional charges for these purposes.[27]

23. SPP states that section 1232(e) exempts power sales activities of a power marketing agency from the Commission's jurisdiction, and that Western-UGP has interpreted "power sales activities" to include all delivery of energy from Western-UGP to its customers. SPP explains that the Federal Service Exemption recognizes Western-UGP's duty to comply with its federal requirements, statutory obligations and related contractual terms that are not subject to Commission oversight. According to SPP, the Federal Service Exemption is narrowly constructed to apply only to Western-UGP's delivery of federal resources to its Statutory Load Obligations over the Zone 19 transmission facilities. SPP explains that the total energy that can be transmitted under the Federal Service Exemption is finite and static, and the proposed Federal Service Exemption is similar to how SPP structures deliveries for its carved-out grandfathered agreements (GFAs). SPP asserts that the Commission cannot abrogate certain contracts,[28] and that the Commission has approved similar treatment for contracts that are not subject to Commission jurisdiction.[29] SPP asserts that participation by Western-UGP within the Integrated Marketplace, other than for the delivery of federal resources to its Statutory Load Obligations, will be subject to the same terms and conditions that apply to other Members, Transmission Customers, and Market Participants under the Tariff.

24. SPP proposes to add new section 39.3(e) to its Tariff to describe the application of the Federal Service Exemption. Specifically, SPP explains that the transactions subject to the Federal Service Exemption would not pay the Region-wide Charge in Schedule 11 of the Tariff associated with Western-UGP's Statutory Load Obligations internal to the Zone 19 or external to SPP.[30] However, SPP notes that Western-UGP would continue to

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[27] Transmittal at 16 (citing Ex. No. SPP-7 at 13-14).

[28] *Id*. at 17.

[29] *Id*. (citing *Southwest Power Pool, Inc.*, 141 FERC ¶ 61,048, at P 309 (2012), *order on reh'g and clarification*, 142 FERC ¶ 61,205 (2013); *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,255 (2013); *Midwest Indep. Transmission System Operator, Inc.*, 108 FERC ¶ 61,236, at P 150 (2004)).

[30] *Id*. at 25.

pay the zonal charge in Schedule 11.[31] SPP states that any load served by Western-UGP in the Western Interconnection using transmission facilities in Zone 19 will not be subject to the Schedule 11 Region-wide Charge to the extent the load is served only by resources in the Western Interconnection.

25. SPP also proposes revisions to section 39.3(e) that would exclude Western-UGP from paying for marginal losses for use of the Integrated System for deliveries of federal power resources to meet Statutory Load Obligations. Western-UGP would also be excluded from receiving any redistribution of the over-collection of marginal loss revenue. Instead, SPP explains that Western-UGP would be responsible for providing real power losses based on an average loss factor included in Attachment M of the Tariff.[32] SPP further proposes that Western-UGP would not pay congestion costs determined as part of the Integrated Marketplace to serve the Statutory Load Obligations, and it would be excluded from obtaining the Auction Revenue Rights and Transmission Congestion Rights that are available for transmission usage to serve this load.[33]

26. With respect to the exemption of marginal losses and congestion costs, SPP asserts that because section 1232(e) of EPAct 2005 exempts power sales activities[34] of the power marketing agency from the Commission's jurisdiction, the Federal Service Exemption is similar to the unique exemption from marginal losses and congestion costs for certain parties with GFAs in SPP's Integrated Marketplace.[35] SPP states that it will remove the marginal losses and congestion costs from the settlement statement of Western-UGP for

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[31] Ex. No. SPP-7 at 14.

[32] Transmittal at 25-26; Ex. No. SPP-4 at 8. The proposed delivery loss factor for Zone 19 is 4.00 percent.

[33] Ex. No. SPP-3 at 13.

[34] SPP states that Western has interpreted "power sale activities" to include all delivery of energy from Western-UGP to its customers. Transmittal at 16.

[35] *Id*. (citing *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,254, at PP 18, 23 (2013) (conditionally approving settlement filed by SPP to implement a "carve-out" for certain GFAs from the SPP Integrated Marketplace); *see also Southwest Power Pool, Inc.*, 144 FERC ¶ 61,255, at PP 1, 19 (2013) (conditionally accepting revisions to the SPP Tariff to implement a GFA carve out subject to additional Tariff revisions)).

the schedules submitted under the Federal Service Exemption[36] and uplift those costs to the rest of the region, as it does for carved-out GFAs.[37] SPP explains that it will attempt to reduce the uplift attributable to the Federal Service Exemption similar to how it reduces the uplift attributable to carved-out GFAs. SPP states it will use the over-collected refund from the marginal loss surplus to offset the marginal loss costs uplifted to the region. Additionally, SPP states that the capacity associated with the Federal Service Exemption will be included in SPP's Auction Revenue Rights allocation and transmission congestion right auction processes, and the resulting auction revenue rights and transmission congestion rights will be held by SPP. According to SPP, the associated revenues will be used to offset the congestion costs uplifted to the region.[38]

27. SPP also explains that Western-UGP's hydropower resources are static; i.e., they are limited in the load to which they market capacity, because Western-UGP hydroelectric facilities are a finite resource, and Western-UGP has no authority or obligation to meet future load growth. According to Western-UGP, the last hydropower dam project finished and marketed by Western-UGP was in the 1960s.[39] Moreover, the load to which Western-UGP must market its power is fixed, because Western-UGP has no authority or obligation to use its 2,675 MW of installed hydropower capacity or to acquire additional resources to meet future load growth.[40] Load covered by the Federal Service Exemption will be about 3 percent of total load within the SPP footprint; whereas all of the GFAs combined comprise about 3.2 percent of the total load within the SPP footprint.[41] Moreover, Western-UGP notes that the percentage of the load receiving the Federal Service Exemption will decrease over time because the load not subject to the

[36] SPP states that Western-UGP may also need to submit an E-Tag for the transaction in the day-ahead market and the removal of such charges is limited to the maximum MW capacity permissible under the Federal Service Exemption.

[37] Ex. No. SPP-4 at 9.

[38] Transmittal at 39.

[39] Ex. No. SPP-7 at 6.

[40] *Id.*

[41] *Id.* at 8.

Federal Service Exemption increases as the load within the SPP footprint grows, while the load subject to the Federal Service Exemption is fixed.[42]

28. SPP states that it performed a study on the economic benefits over 10 years of the Integrated System Parties joining SPP and presented that study to stakeholders. SPP states that stakeholders were expected to receive over $334 million in total net benefits ($219 million of total net benefits on a net present value basis). SPP states that the total net benefits reflect benefits due to a reduction in the administration fee, reserve sharing benefits and benefits attributable to the Integrated Marketplace as well as costs pertaining to the Schedule 11 revenue allocations for point-to-point transactions. In addition to these quantifiable benefits, SPP states that there will be qualitative benefits. For example, SPP states that the incorporation of the Integrated System Parties should benefit grid reliability and congestion management through the ability to commit and dispatch generation that impacts the flows through and out of Nebraska. SPP states that those flows currently impact generation curtailment on the western side of the SPP region. Thus, this ability to commit and dispatch all generation will increase the availability of lower-priced energy throughout the region through reduced curtailment of generation. Additionally, SPP states that any excess hydro generation of Western-UGP, beyond what is needed to meet the needs of its Statutory Load Obligations, will result in access to lower-cost hydro resources for SPP members.

a. <u>Comments and Protests</u>

29. Western asserts that the changes incorporated in the Governing Documents are necessary to satisfy the requirements of EPAct 2005 section 1232(c), which provides for, among other items, that membership must be consistent with existing contracts, as well as statutory authorities, obligations and limitations of the federal power marketing agency. Western states that those changes include provisions for federal specific seats on the Members and Corporate Governance Committees, monitoring and oversight, withdrawal, as well as limitations on assessments of civil monetary penalties against federal power marketing agencies. Western argues that the Federal Service Exemption is needed to satisfy the section 1232(c) requirements of consistency with existing contracts and authorities, as well as the section 1232(d) requirement which precludes conferring

[42] *Id.*

jurisdiction or authority on the Commission over electric generation assets, electric capacity, or energy of a power marketing agency.[43]

30. Western contends that its Statutory Load Obligations require that under its marketing function, pursuant to federal law, Western must deliver power and energy from the output of federal hydroelectric projects to project use loads and preference customers. Western explains that its transmission system was built primarily to enable those deliveries. Western states that it has no authority or obligation to meet its customers' load growth and that the load to which Western markets the federal resources is "basically fixed."[44] Because Western's existing transmission facilities are sufficient to meet its load, and because of its lack of load growth responsibility, Western-UGP asserts that the Federal Service Exemption embodies the concepts that Western is exempt from SPP Region-wide Schedule 11 charges for its federal resource to federal load deliveries across Zone 19, which is essentially the current Integrated System footprint in the Eastern Interconnection.

31. Western argues that the Federal Service Exemption exempts Western's long-term contractual delivery of its Western federal power to its Statutory Load Obligations from the SPP Integrated Marketplace charges for congestion and marginal losses, similar to the manner in which SPP dealt with its carved-out GFAs.[45]

32. Western states that capacity in its transmission facilities provided to SPP under the proposed Membership Agreement is solely for use of Available Transfer Capability in excess of the capability Western requires for the delivery of long-term firm capacity and energy to its Statutory Load Obligations. Western contends that this is necessary so that Western can meet its "widespread use" statutory requirement.[46] According to Western, its existing marketing plan provides that once every ten years, through a public process,

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[43] Western notes that its authorities are defined under the Department of Energy Organization Act; the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent laws, particularly section 9(c) of the Reclamation Project Act of 1939 and section 5 of the Flood Control Act of 1944. Western Comments at 6.

[44] *Id*. at 6.

[45] *Id*. at 7.

[46] Western is required by statute to "encourage widespread use." Transmittal at 15 (citing 16 U.S.C. § 825s).

any eligible new preference customers may request a hydropower allocation. Western explains that as a result of the public process, Western could withdraw a certain amount of allocations from existing customers, and reallocate them to those new preference customers granted an allocation. Thus, Western contends that reserving the Available Transfer Capability Western currently has within the Integrated System for this purpose is necessary for Western to meet statutory requirements and its existing obligations, as is required under EPAct 2005.[47]

33. Heartland, Tri-State, ITC Great Plains, Rushmore, Central Montana, Powder River, Basin Electric, and Corn Belt filed comments in support of the proposal as filed. Several of these commenters assert that the proposal is narrowly tailored, consistent with the Commission policy of supporting public power participation in RTOs, and they note that SPP identified approximately $334 million in net benefits to its existing members.[48] Similarly, in addition to noting economic benefits stemming from the integration of the Integrated System parties into SPP, ITC Great Plains points to the reliability benefits.[49] Heartland further explains that because the Integrated System Parties jointly developed, own, and operate the Integrated System, transferring functional control over the Integrated System to SPP necessitates that they all be integrated into SPP simultaneously.[50]

34. Basin Electric supports the Federal Service Exemption, noting that SPP and its members have agreed that Western-UGP should not be responsible for costs associated with congestion, losses, or the expansion of the system for the delivery of federal power to Western-UGP's preference customers.[51] It further notes that Western-UGP's transmission system was built to serve Western-UGP's statutory load obligations using

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[47] *Id*. at 8.

[48] Heartland Comments at 10, 11; Tri-State Comments at 3-5; Rushmore Comments at 2-4; Central Montana Comments at 3, 4; Powder River Comments at 2, 3 Basin Electric Comments at 6, 7; Corn Belt Comments at 3, 4.

[49] ITC Great Plains Comments at 6.

[50] Heartland Comments at 11.

[51] Basin Electric Comments at 9.

federal power and is sufficient for doing so without upgrades or expansion.[52] Basin Electric also explains that because the Integrated System straddles the Eastern and Western Interconnections, the Federal Service Exemption also provides that SPP shall not assess load served by Western-UGP in the Western Interconnection for the Region-wide Charge associated with transmission facilities in the Eastern Interconnection, to the extent that load located in the Western Interconnection is served only by resources in the Western Interconnection.[53]

35. In contrast, other commenters, including Kansas Commission, Texas Commission, Montana Consumer Counsel and NPPD, raise concerns with SPP's proposal. Kansas Commission protests that under SPP's proposal, SPP members will unreasonably subsidize the expansion of the SPP region to include the Integrated System Parties under Tariff provisions that are unduly discriminatory.[54] Kansas Commission asserts that the SPP Regional State Committee, of which it is a member, was not included in the SPP stakeholder approval process for the proposal.[55] Moreover, Kansas Commission asserts that the filing raises numerous significant issues of material fact that SPP does not adequately address. Therefore, Kansas Commission concludes that SPP has not provided Kansas Commission with sufficient information to enable it to analyze relevant aspects of the proposal.[56]

36. Kansas Commission argues that SPP did not conduct or provide an independent study conducted of the costs to SPP members of its proposal but, instead, SPP relied upon the results of a study conducted by The Brattle Group for the Integrated System Parties. According to Kansas Commission, SPP's CEO announced in March 2013 that SPP was developing a Federal Service Exemption to encourage Western-UGP to join SPP, which was many months before any studies were conducted and before SPP stakeholders had an

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[52] *Id.*

[53] *Id.*

[54] Kansas Commission Protest at 3 (citing *City of Frankfort v. FERC*, 679 F.2d 699, 704 (7th Cir. 1982)).

[55] *Id*. at 5.

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

opportunity to understand the costs and benefits of such a decision.[57] Moreover, Kansas Commission contends that SPP did not conduct a rate impact analysis, as required by the SPP Tariff.[58]

37. Kansas Commission explains that its own analysis of the actual costs versus the benefits to existing SPP members concludes that SPP members will subsidize the Integrated System Parties by more than $213 million over the next 10 years.[59] Kansas Commission argues that unless existing SPP members receive similar economic benefits from the Integrated System Parties joining SPP, then the proposal would establish an unjust and unreasonable precedent by permitting an entity to join an RTO based upon documented subsidization by other RTO members.[60] Kansas Commission also argues that although SPP expects that the addition of the Integrated System Parties will reduce the rate per MWH of SPP's administrative costs, these administrative fee savings are not comparable to the economic benefits that the Integrated System Parties will receive under the proposed Tariff revisions. This results in what Kansas Commission describes as a "sweetheart deal" between SPP and the Integrated System Parties.[61]

38. Kansas Commission argues that SPP's proposed Federal Service Exemption is not supported by any Commission precedent, including those situations where the Commission has approved tariff modifications to permit public power entities to become SPP members.[62] Moreover, the Commission in Order No. 2000 stated that it would analyze proposals to include non-jurisdictional public power entities into an RTO on a case-by-case basis in recognition of the unique difficulties such entities face in RTO

[57] *Id*. at 9.

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

[59] *Id*. at 12.

[60] *Id*. at 30.

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

[62] *Id*. at 22-23 (citing *Southwest Power Pool, Inc*., 125 FERC ¶ 61,239 (2008)).

participation.[63] However, Kansas Commission asserts that SPP has failed to justify the proposed exemption in the Federal Service Exemption from the costs of congestion and marginal loss charges. Similarly, the Kansas Commission protests exempting Western-UGP from SPP regional charges.

39. Texas Commission asserts that SPP has not provided sufficient information to determine the effect, from a cost/benefit stand point, the Integrated System Parties' membership would have on the ratepayers in SPP's footprint in Texas. Texas Commission argues that the cost/benefit analysis provided by SPP to the Regional State Committee was merely the table that is set forth in the testimony of SPP witness Mr. Monroe,[64] Executive Vice President and Chief Operating Officer of SPP,[65] and that it was not supported by any public studies or reports that could be duplicated or otherwise confirmed by SPP members or state commissions. Texas Commission states that SPP appeared to rely on a Brattle Group study commissioned by the Integrated System Parties for a bulk of the claimed benefits to support its recommendation to proceed with the membership proposal. Texas Commission asserts that the Brattle Study was not made public nor was the information supporting SPP's internal cost/benefit analysis provided to the Regional State Committee in a timely manner. Consequently, Texas Commission states that the analysis and inputs could not be reviewed by SPP members or the state commissions within SPP's footprint before the proposal was approved by the SPP Board of Directors. Thus, Texas Commission remains concerned with the level of due diligence exercised by SPP in performing an independent analysis of the study and with the lack of disclosure of relevant studies demonstrating the claimed member benefits of the proposed Integrated System membership.[66]

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[63] *Id*. at 24 (citing *Southwest Power Pool, Inc*., 147 FERC ¶ 61,003 (2014) (citing *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 v. FERC,* 272 F.3d 607 (D.C. Cir. 2001)).

[64] Texas Commission Comments at 3-4 (citing Ex. No. SPP-3 at 10).

[65] Mr. Monroe's duties include the implementation and management of a regional operation center, the administration of SPP's Tariff, oversight of engineering information technology and interregional affairs, development, analysis and operation of all markets, and oversight of staff support for all SPP technical organizational groups.

[66] Texas Commission Comments at 4.

40. Texas Commission argues that the October 1, 2015 effective date creates an unnecessarily compressed timeframe for consideration of membership in the Integrated System in SPP.[67] Texas Commission asserts that SPP has not provided sufficient evidence to support its claim that the proposal to facilitate the membership of the Integrated System is supported by all stakeholders or that the proposal is in the public interest. Texas Commission requests that the Commission order SPP to revise the Tariff language so that the membership of the Integrated System does not result in inequitable impacts to existing members of SPP and ratepayers within the SPP footprint, including Texas. Should the Commission approve the proposed filings, Texas Commission recommends that the Commission note that the process used for integrating the Integrated System and the changes to SPP's Governing Documents are specific to these facts and should not be viewed as precedential for future membership proposals.[68]

41. Texas Commission explains that all other SPP members, including the remaining Integrated System entities, will have to pay for the share of the costs for regionally-funded upgrades in the SPP footprint that otherwise would have been allocated to Western-UGP's load in the absence of the Federal Service Exemption. Furthermore, Texas Commission notes that high voltage upgrades to transmission facilities used for the delivery of Western-UGP's generation to its Statutory Load Obligations may be required as a result of the SPP planning process for the benefit of SPP members. Texas Commission states that under the Federal Service Exemption, Western-UGP would be exempted from region-wide Schedule 11 charges for these upgrades under the federal service exemption although Western-UGP's statutory obligation load customers would benefit from these upgrades.[69]

42. Given the numerous concerns over the effectiveness of the protections contained in the MISO-SPP JOA, and the continuing nature of disputes over its substance, Montana Consumer Counsel does not believe it can appropriately protect Montana ratepayers from harm resulting from SPP's proposal. As a result, Montana Consumer Counsel requests that the Commission require SPP and the Integrated System Parties to examine and address how the Integrated System Parties' decision to join SPP will affect the utilities

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[67] *Id*.

[68] *Id*. at 6.

[69] *Id*. at 5.

that serve Montana retail electric customers at the wholesale and transmission rate level.[70]

43. NPPD generally supports the inclusion of the Western-UGP, Basin Electric, and Heartland as new transmission owner-members of SPP under the terms and conditions set forth in SPP's filings.[71] However, NPPD protests the exclusion of preference customers located in SPP's existing zones from the Federal Service Exemption provided to preference customers in the new Zone 19. NPPD points out that, unless the Federal Service Exemption is extended to preference customers in all SPP zones, it will result in giving Western-UGP's preference customer load exemptions from costs that apply to other preference customers. For example, as proposed, the Federal Service Exemption excludes the costs of certain transmission upgrades under Schedule 11, congestion charges, marginal losses, and the FERC administrative fee under Schedule 12 for the preference power load. Because preference customers located in SPP's existing zones, including NPPD's Zone 17, are not eligible for these exemptions, NPPD argues that the Federal Service Exemption is unduly discriminatory. NPPD contends that it is aware of no statutory or equitable basis for excluding preference customers located in SPP's existing zones from the benefits and flexibility that SPP proposes to provide to preference customers located in the new Zone 19, and at points external to SPP. According to NPPD, the preference customers in SPP's existing zones, including many preference customers (municipalities, cooperatives and water districts) served by NPPD in Zone 17, are similarly situated in every relevant respect to the preference customers located in the new Zone 19.[72]

44. In addition, NPPD contends that SPP is proposing to charge similarly situated preference customers unduly discriminatory rates. According to NPPD, the rates and charges for deliveries of preference power to points located in the new Zone 19, and to points external to SPP will be very different from the rates and charges applicable to deliveries of preference power in Zone 17. NPPD states that administrative charges under Schedule 12, the Region-wide charge under Schedule 11, and congestion charges and marginal losses under Schedule AE will be assessed against all Statutory Load Obligations located in NPPD's Zone 17, but they will not be assessed to the preference

[70] Montana Consumer Counsel Protest at 5, 6.

[71] NPPD Protest at 1.

[72] *Id.* at 7.

power loads located in the new Zone 19, or to Western-UGP's off-system Statutory Load Obligations. NPPD contends that the total value of these exemptions is not insignificant.[73]

45. NPPD asserts that the fact that the ultimate delivery of federal power to preference customers located in Zone 17 is from facilities owned by NPPD, rather than exclusively from transmission facilities owned by Western-UGP, is not a distinguishing factor. According to NPPD, the ultimate delivery of federal power to some of Western-UGP's Statutory Load Obligations in Zone 19 will be made through facilities owned by Basin Electric and Heartland; and use of such "third party" transmission facilities is not distinguishable from the use of NPPD facilities to deliver preference power in Zone 17. NPPD contends that, even assuming some deliveries in Zone 19 will be made exclusively from facilities owned by Western-UGP, all deliveries are made under the same SPP Tariff. [74]

46. NPPD challenges SPP's argument for Western-UGP's exclusion from certain Schedule 11 charges on the ground that Western-UGP has no need for any increased transmission capacity funded under Schedule 11. NPPD argues that the exemption from Schedule 11 charges also applies to direct and indirect deliveries of preference power to Western-UGP's Statutory Load Obligations in NPPD's Zone 17. NPPD states that Western-UGP's Statutory Load Obligations in NPPD Zone 17 consist of direct purchases of preference power from Western-UGP by preference customers located in Zone 17, and purchases of preference power from Western-UGP by NPPD on behalf of wholesale preference customers served by NPPD.[75] According to NPPD, the same capacity constructed by Western-UGP to serve Zone 19 was also constructed to deliver preference power to the edge of NPPD's system in Zone 17. NPPD states that it has also constructed transmission capacity from its interconnection with Western-UGP to serve Western-UGP's Statutory Load Obligations in Nebraska on a long-term firm basis, and such obligations are fixed to the same extent as Western-UGP's Statutory Load Obligation in Zone 19.[76]

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[73] *Id*. at 9.

[74] *Id*. at 10.

[75] *Id*. (citing Ex. No. NPPD-1 at 2).

[76] *Id*. at 11.

47. Further, NPPD argues that there is also no basis for excluding preference customer load in Zone 17 from the exemption from congestion charges and marginal losses. NPPD agrees with SPP that exemption of the deliveries of preference power in the new Zone 19 from SPP congestion charges and marginal losses is closely analogous to similar exemptions approved by the Commission for certain GFAs; however, NPPD notes that the existing exemption from congestion charges and marginal losses for certain GFAs in Zone 17 does not include deliveries of Western's Statutory Load Obligation.[77] NPPD asserts that there is no basis for distinguishing the need to exempt deliveries of preference power in Zone 19 from congestion charges and marginal losses from the need to provide the same exemption to deliveries of preference power in Zone 17, and that both situations represent deliveries to Western-UGP's Statutory Load Obligations. NPPD asserts that Western-UGP's interpretation of its federal statutory obligations applies with equal force to deliveries of preference power to Zone 17.

b. <u>Commission Determination</u>

48. A central component of SPP's proposal, a component that Western-UGP believes is necessary for Western-UGP joining SPP's RTO, is the Federal Service Exemption. In light of section 1232 of EPAct 2005, in which Congress provided a statutory framework for federal power authorities, such as Western-UGP, to place their transmission systems under the functional control of an RTO, we accept SPP's proposal to establish a Federal Service Exemption for the delivery of Western-UGP's resources to its Statutory Load Obligations.

49. Specifically, section 1232(b) provides that "[t]he appropriate Federal regulatory authority may enter into a contract, agreement, or other arrangement transferring control and use of all or part of the transmission system of a Federal utility to a Transmission Organization."[78] Section 1232(c) sets forth requirements for contracts for the transfer of control and use of a federal power marketing administration's transmission system to a transmission organization, and requires that such an agreement include:

> (1) performance standards for operation and use of the transmission system to ensure recovery of all the costs and expenses of the federal utility related to the transmission facilities that are the subject of the contract, agreement, or other

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[77] *Id*. (citing Ex. No. NPPD-1 at 3).

[78] 42 U.S.C. § 16431.

arrangement, consistency with existing contracts and third-party financing arrangements, and consistency with the statutory authorities, obligations, and limitations of the federal utility;

(2) provisions for monitoring and oversight by the federal utility of the transmission organization's terms and conditions of the contract; and

(3) a provision that allows the federal utility to withdraw from the transmission organization and terminate the contract.

Section 1232(d) further states that participation by a federal power marketing administration in a transmission organization will not confer upon the Commission jurisdiction over the electric generation assets, electric capacity, or energy that is authorized by law to market, or over the power sales activities of that administration.

50. In light of section 1232 of EPAct 2005, authorizing federal power marketing administration participation in RTOs and ISOs, but within and subject to express limitations, we will accept Western-UGP's requested exemption for the delivery of its resources to its Statutory Load Obligations. The Federal Service Exemption, we note, is narrowly limited to apply only to the delivery of electric energy from Western-UGP resources to its statutory load customers to maintain Western's statutory responsibilities or obligations. Moreover, because Western-UGP has constructed sufficient transmission facilities or purchased transmission capacity within Western-UGP to enable it to enter into long-term contractual commitments for the delivery of its federal finite generation to its statutory load customers, and because Western-UGP has no authority to meet its customers' load growth, its Statutory Load Obligations will not grow.[79]

51. Further, we will reject NPPD's request that the Federal Service Exemption be extended to Western-UGP's Statutory Load Obligations outside Zone 19 to points internal to SPP. The Zone 19 transmission system is a highly integrated and jointly planned transmission system of Western-UGP, Basin Electric, and Heartland that was built to facilitate the delivery of power from federal hydro resources, across the Zone 19 transmission system, to preference power customers within that system and to neighboring systems such as NPPD's system. Western-UGP has no load growth responsibilities to serve its preference power customers, and the Zone 19 transmission system is sufficient to deliver power to serve Western-UGP's obligations within Zone 19 and to the edge of Zone 19 for Western-UGP obligations outside of Zone 19.

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[79] *See* Western Comments at 6.

Western-UGP has not built transmission facilities outside of Zone 19 to deliver federal power to preference power customers located at points outside of Zone 19. Such preference power customers at points internal to SPP outside of Zone 19 already pay a third party for transmission service for deliveries from the Zone 19 border to the point of delivery within SPP. Such transmission service from the Zone 19 border would be subject to the same charges it is currently subject to (i.e., marginal losses, congestion costs and region-wide Schedule 11 charges). Moreover, NPPD is not similarly situated to Western-UGP because it is not a federal power marketing administration. Accordingly, NPPD does not qualify for the Federal Service Exemption because entities such as NPPD and its customers, and the transmission service used to transmit power preference power from the Zone 19 border, are not covered by section 1232 of EPAct 2005.

52. We disagree with Kansas Commission's assertions that SPP did not conduct its own analysis of the costs and benefits of integrating the Integrated System Parties into SPP, and that SPP relied only on the results of The Brattle Group study commissioned by the Integrated System Parties. As shown in SPP's testimony, SPP conducted its own analysis of the costs and benefits to current SPP members from the Integrated System Parties' integration into SPP, using information from The Brattle Group only for one of the five components of its analysis (the Integrated Marketplace) and only after reviewing the inputs and assumptions for reasonableness.[80] Likewise, we disagree with commenters, including Kansas Commission and Texas Commission, that SPP did not provide adequate opportunity for SPP stakeholders to consider the membership of the Integrated System Parties.[81] Rather, we find that the record indicates that SPP presented and discussed Western-UGP's recommendation to pursue membership in SPP at a number of meetings of the Regional State Committee and with stakeholders throughout 2014.[82]

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[80] *See, e.g.*, Ex. No. SPP-3 at 9-11.

[81] In any event, Kansas Commission's estimate of cost and benefit is largely attributable to the inclusion of costs for the recovery of legacy base plan upgrades that SPP did not include in its estimate, discussed at P 37, and as discussed below, we find SPP's proposed treatment of base plan upgrades just and reasonable separate and apart from the Federal Service Exemption.

[82] Ex. No. SPP-3 at 6-8.

53. Moreover, SPP states that stakeholders are expected to receive over $334 million in total net benefits as a result of the Integrated Parties integration into SPP. In light of section 1232 of EPAct 2005, authorizing federal power marketing administration participation in RTOs and ISOs, we find that SPP's proposal to integrate Western-UGP into SPP's RTO represents a significant expansion of the SPP footprint that SPP explains will bring benefits to all parties involved. We further find that the Integrated System Parties' consumers will gain access to organized markets and all RTO members will benefit from the creation of increased efficiency and reliability for the newly combined RTO. SPP explains that it will have increased ability to commit and dispatch all generation affecting the west to east flows and the north to south flows on the western edge of SPP which is expected to increase the availability of lower-price energy throughout the region through reduced curtailment of generation.[83]

2. Co-Supply Arrangement

54. SPP proposes a Co-Supply Arrangement to enable load-serving entities in Zone 19 to maintain their current practice of providing supplemental power supplies to Western-UGP's preference customers utilizing network service.[84] Under the existing arrangement, SPP explains that Western-UGP supplies power to its preference customers using a fixed allocation of federal power, and the co-supplier provides the remainder of the customer's power requirements. However, SPP states that its Tariff currently requires a network customer to designate 100 percent of its load at a delivery point.[85] In light of this Tariff requirement, SPP asserts that its proposed revisions are necessary to enable the Co-Supply Arrangement to continue once the Integrated System Parties join SPP and begin taking transmission service from SPP. Under SPP's proposal, Western-UGP would take network service, designating network load at points of delivery for its preference power customers up to their preference power allotment; Basin Electric or Heartland would also take network service, designating the remainder of the load at the same point of delivery as their network load.[86] Basin Electric explains that it would be extremely

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[83] Ex. No. SPP-3 at 12.

[84] Ex. No. SPP-9 at 3-5.

[85] Transmittal at 18 (citing SPP Tariff at Definitions N- Network Load which states "[A] Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery").

[86] Transmittal at 18-19.

difficult for the Integrated System Parties to join SPP without the Co-Supply Arrangement because it would be unable to continue using network service to deliver power to its customers.[87]

55. SPP requests approval of the Tariff revisions to permit the Co-Supply Arrangement because the revisions will allow the Integrated System Parties to join SPP and place their transmission facilities under the Tariff. Moreover, SPP argues that the Tariff revisions to permit the Co-Supply Arrangement are consistent with Commission precedent. According to SPP, in *Duke Power Co.*, the Commission permitted preference customers of the Southeast Power Administration (SEPA) to designate less than their entire load at a discrete point as network load because the entire load would be served on a network basis where the "the portion of the preference customers' loads met by their SEPA allocation would be served under [an open access transmission tariff]."[88]

a. <u>Comments and Protests</u>

56. NPPD protests SPP's proposal to limit access to the Co-Supply Arrangement to co-suppliers of preference customers located in the new Zone 19 and to points external to the SPP system. NPPD argues that there is no basis for excluding deliveries to preference customer loads in existing SPP zones from the Co-Supply Arrangement. According to NPPD, the circumstances related to deliveries of preference power to points located in NPPD's Zone 17 are identical to those described by Western-UGP in Zone 19, as well as to points outside of Zone 19 on the MISO system.[89] NPPD also argues that Commission precedent supports the use of a co-supplier provision to address the unique circumstances surrounding the delivery of federal allocations of preference power to preference customers,[90] and it asserts that there is no basis for excluding application of such precedent to NPPD Zone 17 and other existing SPP zones. Thus, NPPD requests that the

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[87] Ex. No. SPP-9 at 4.

[88] Transmittal at 19 (citing *Duke Power Co.*, 81 FERC ¶ 61,010 at 61,047, *order deny reh'g*, 81 FERC ¶ 61,312 (1997) (*Duke Power*)).

[89] NPPD Protest at 13 (citing Ex. No. NPPD-1 at 2).

[90] *Id*. (citing *Duke Power*, 81 FERC ¶ 61,010).

Commission extend the Co-Supply Arrangement to all preference customers located in SPP's existing zones.[91]

57. Missouri River contends that the proposed Co-Supply Arrangement is unclear when there is more than one co-supplier to a Western-UGP delivery point.[92] Missouri River asserts that under a Co-Supply Arrangement a co-supplier's network load for purposes of Network Integration Transmission Service will be the total load at each delivery point less Western-UGP's Statutory Load Obligations. Missouri River argues that this arrangement does not account for third-party suppliers.[93] As a result, Missouri River explains that it may be required to purchase Network Integration Transmission Service for its customers' load serviced by a third-party supplier.

58. Entergy states that SPP does not offer MISO a similar arrangement on comparable terms and conditions.[94] According to Entergy, the Co-Supply Arrangement allows Basin Electric and Heartland to designate and undesignate loads on a daily basis to minimize their transmission charges.[95] By contrast, Entergy argues, SPP calculates daily billing determinants for MISO based on peak one-minute flow for the day in both directions. Entergy urges the Commission to direct SPP to offer the same Co-Supply Arrangement to MISO.[96]

b. Commission Determination

59. We find SPP's proposed Co-Supply Arrangement is just and reasonable. SPP's Co-Supply Arrangement is consistent with Commission precedent in *Duke Power*,[97]

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[91] *Id*.

[92] Missouri River Protest at 13.

[93] *Id*. at 14-15. Missouri River states that its customers can cap the amount of power they receive from Missouri River and purchase power from a third-party supplier for their remaining requirements.

[94] Entergy Protest at 6.

[95] *Id*.

[96] *Id*.

[97] *Duke Power*, 81 FERC ¶ 61,010.

where the Commission found that it would be permissible and not inconsistent with its open access rules, for multiple parties to each designate a portion of the same discrete load at a point of delivery for network transmission service so that preference customers' entire loads can be met using network service under an open access transmission tariff.[98] Specifically, the Commission stated:

> The parties are correct that the Commission's Order Nos. 888 and 888-A do not permit a network customer to take a combination of both network and point-to-point transmission service to serve the same discrete load.[99] However, the fact that the portion of the preference customers' loads met by their SEPA allocation would be served under Duke's open access transmission tariff, while the remainder of the load continues to be met by bundled service, would not alter the network nature of the service. The entire load would be served on a network basis, but payment would be made to Duke by SEPA for the SEPA preference customers' allocation, and by the preference customers for the remainder of their loads. Thus, the preference customers' entire loads can be met using network service under Duke's open access transmission tariff.

60. With respect to NPPD's concerns about the availability of the Co-Supply Arrangement to co-suppliers of preference customers located in NPPD's Zone 17, we find that NPPD has not demonstrated that it is or will be similarly situated to Basin and Heartland as a co-supplier of preference power customers whereby Western-UGP has taken responsibility for transmission service to deliver its supply across the SPP transmission system to the customer's point of delivery. Moreover, such preference power customers in NPPD's Zone 17 have been supplied in SPP since 2008 without a Co-Supply Arrangement. NPPD has not explained how Western-UGP's joining SPP creates the problem NPPD alleges. However, we expect that SPP will offer these types of Co-Supply Arrangements, including Co-Supply Arrangements with multiple co-suppliers, on a non-discriminatory basis to other similarly situated customers located in Zone 19 or SPP's existing zones, if requested. In the event of a dispute, such transmission customers may request SPP to file unexecuted service agreements with the Commission pursuant to the terms of the Tariff, or seek other available relief under the FPA. However, we deny Entergy's request to require SPP to extend the Co-Supply

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[98] *Id.*

[99] *Id.*

Arrangement to MISO's transmission service on SPP's system. Specifically, we find that Entergy has not demonstrated MISO's service over SPP's system, which is used to integrate Entergy with the rest of MISO, is similar to the use of network service by co-suppliers to serve the same load at a discrete point of delivery, as allowed by the SPP Tariff.

3. **Base Plan Upgrades**

61. With regard to regional charges for base plan upgrades collected under Schedule 11 of the SPP Tariff that are not subject to the Federal Service Exemption,[100] SPP proposes a bright line date of October 1, 2015, the planned integration date, as delineating when regional cost sharing will begin between SPP and the Integrated System Parties. SPP states that the Integrated System Parties' existing systems, as well as any planned transmission facilities with a need-by date prior to October 1, 2015, will continue to be funded by the Integrated System Parties. Similarly, SPP explains that its legacy system, and base plan upgrades with a need-by date prior to October 1, 2015, will continue to be funded by the current SPP membership. SPP indicates that transmission projects in both the SPP and Integrated System Parties' footprints with a need-by date on or after October 1, 2015 will be designated as base plan upgrades under the SPP Tariff, with regional cost recovery accomplished through the region-wide charges under Schedule 11 of the Tariff.[101]

62. To accomplish this transition, SPP proposes revisions to the definition of "Base Plan Upgrade" in the Tariff to specify that Zone 19 (i.e., the zone applicable to the Integrated System Parties) will not be allocated costs for base plan upgrades in Zones 1-18 (i.e., the zones comprising the rest of the SPP region) with a need-by date prior to October 1, 2015; conversely, transmission upgrades in Zone 19 with a need-by date prior to October 1, 2015 will not qualify as base plan upgrades under the Tariff. SPP also proposes specifying within the definition of "Base Plan Upgrade" that the facilities

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[100] SPP clarifies that Western-UGP will pay regional Schedule 11 charges for any power deliveries to loads that are not Statutory Load Obligations and for any deliveries of power from resources other than its own hydropower sources. SPP states that the Federal Service Exemption does not apply to Basin Electric or Heartland or any entity imbedded within Zone 19, nor does it apply to Western-UGP's marketing activities in the Integrated Marketplace. Transmittal at 31.

[101] *Id.*

identified in Schedule 2 of Attachment J are deemed base plan upgrades under the Tariff. SPP proposes a new Schedule 2 to Attachment J listing the Integrated System projects with a need-by date on or after the planned integration date.[102]

63. In the testimony of Mr. Monroe submitted with its filing, SPP states that it conducted a Transmission Working Group study to confirm, in part, the October 1, 2015 need-by date of the transmission projects identified in Schedule 2 of Attachment J and assess whether these projects met needs identified in SPP's regional planning studies.[103] Mr. Monroe explains that the Transmission Working Group study used a planning horizon consistent with the 2013 Integrated Transmission Planning Near-Term study. According to Mr. Monroe, the Transmission Working Group study confirmed that the Basin Electric projects met regional reliability needs and that the proposed integration date met timing requirements for these needs in the study models. Mr. Monroe asserts that this evaluation is consistent with SPP's current Integrated Transmission Planning Near-Term study.[104] Additionally, Mr. Monroe notes that the Integrated System Parties will be subject to SPP's Regional Cost Allocation Review process, which SPP conducts to determine whether regional cost sharing results in benefits being commensurate with costs to the SPP membership. Mr. Monroe indicates that the Regional Allocation Review Task Force will incorporate the Integrated System Parties into this review process and propose remedies if it identifies inequities in cost recovery.[105] Overall, Mr. Monroe asserts that SPP's proposal is consistent with how SPP members transitioned to regional cost sharing under the SPP Highway/Byway methodology[106] and is a just and reasonable

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[102] The facilities listed in Schedule 2 of Attachment J will be owned by Basin Electric, are located in Zone 19, range in voltages from 230 kV to 345 kV, and have need-by dates after the date of integration.

[103] Mr. Monroe represents that SPP also conducted the Transmission Working Group study to confirm that the Integrated System Parties' existing transmission systems met North American Electric Reliability Corporation (NERC) and SPP Criteria standards. Ex. No. SPP-3 at 17.

[104] *Id*.

[105] *Id.* at 18.

[106] The Commission accepted SPP's Highway/Byway cost allocation methodology on June 17, 2010. *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010).

approach for transitioning the Integrated System Parties into SPP's regional cost sharing process.[107]

a. **Comments and Protests**

64. MISO states that, through Schedule 2 in Attachment J, SPP has created a special list of Basin Electric transmission facilities that are eligible for regional cost recovery, regardless of qualifications. MISO contends that the designation of these projects as base plan upgrades overrides the well-established qualification that base plan upgrades be evaluated as part of the SPP Transmission Expansion Plan process. MISO asserts that SPP has not evaluated the Basin Electric projects as part of this regional process and has not adequately demonstrated the region-wide benefits provided by the projects. MISO notes that these facilities, estimated to cost $343 million, include massive upgrades to Basin Electric's transmission system to accommodate an increase in demand driven by oil and gas production in the Bakken Shale formation. MISO argues that because SPP was unable to fit these projects within the current cost allocation framework it redefines the term "Base Plan Upgrades" by simply declaring the listed projects base plan upgrades. According to MISO, this designation avoids the established qualification that base plan upgrades must be evaluated as part of the SPP Transmission Expansion Plan process to ensure the reliability of the SPP transmission system. According to MISO, no such SPP Transmission Expansion Plan evaluation has taken place and these projects have not been demonstrated to have region-wide benefits. MISO further argues that publicly available information indicates that Basin Electric planned and committed to constructing these projects based on meeting the growing demand on the Basin Electric transmission system prior to the Integrated System Parties electing to join SPP, and in any event, prior to the proposed October 1, 2015 effective date.[108] Given these facts, MISO argues that the Basin Electric projects should not be eligible for regional cost sharing under SPP's Highway/Byway methodology and should be considered legacy projects, further alleging that SPP's cost allocation proposal violates the Commission's cost causation principles.[109]

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[107] Ex No. SPP-3 at 16, 18.

[108] MISO Protest at 2.

[109] *Id*. at 2-3, 11, 13.

65. According to MISO, Basin Electric's Attachment J projects are not consistent with the Commission's cost causation principles and would not be eligible for regional cost sharing under SPP's existing Highway/Byway cost allocation methodology as it stands now.[110] MISO contends that the essence of the SPP proposal is to create an exception to its cost allocation policy, which will operate primarily for Basin Electric's (and its load's) benefit and at the expense of the rest of the SPP footprint.[111] MISO further argues that replacing the objective marker of a "notification to construct" in the current Attachment J with a subjective "need-by date," results in Basin Electric's otherwise ineligible projects becoming eligible base plan upgrades. MISO states that this would be the result under SPP's proposal, despite the fact that Basin Electric projects were not vetted under the SPP Transmission Expansion Plan process and despite the fact that Basin Electric had a functional equivalent of a "notification to construct" well before the November 1, 2013 RTO election date and, in any event, prior to the proposed October 1, 2015 integration date.[112]

66. MISO argues that Basin Electric's projects listed in Schedule 2, Attachment J do not qualify under the terms of Attachment J, as revised by the Highway-Byway orders. As a threshold matter, MISO contends that the listed projects do not qualify as base plan upgrades.[113] The SPP Tariff defines the term, as "upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the [SPP] Transmission System."[114] According to MISO, Basin Electric's listed upgrades are neither included in nor constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the regional SPP transmission system, and there is no indication that these projects have been vetted under the SPP Transmission Expansion Plan process as set forth in Attachment O of the Tariff. To the contrary, MISO argues, the projects were planned and approved well before Western-UGP officially announced its election to join SPP. Thus, MISO contends that the proposed facilities are

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[110] *Id*. at 3, 11.

[111] *Id*. at 3.

[112] *Id*. at 11.

[113] *Id*. at 13.

[114] *Id*. (citing SPP Tariff, section 1.B).

quintessential "legacy" projects.[115] MISO argues that the fact that SPP and the Integrated System Parties agreed to designate some mutually convenient future date, which is past the Integrated System Parties integration, as a "need by date" cannot substitute for the rigorous vetting of the SPP Transmission Expansion Plan process.

67. MISO argues that the Transmission Working Group study conducted by SPP cannot replace the SPP Transmission Expansion Plan process. MISO notes that SPP's filing offers no further explanation as to how SPP applied the criteria and requirements of the SPP Transmission Expansion Plan process to arrive at the designation of Basin Electric's projects as base plan upgrades. Further, MISO asserts that the October 1, 2015 "need-by" date appears to be the result of negotiation rather than regional analysis. MISO argues that while a negotiated rate may be acceptable in some cases, it is unacceptable when parties not privy to the negotiation must bear the costs of private decisions, especially when not authorized under the RTO's tariff.[116]

68. MISO disagrees with SPP's claim that its proposed integration is consistent with the transition to its Highway/Byway procedures. According to MISO, when SPP's base plan funding Tariff provisions first became effective on May 5, 2005,[117] they included a predecessor Attachment J that provided some regional cost sharing for base plan upgrades, which were subject to a regional transmission planning process. MISO explains that the 2010 Highway/Byway proposal substantially revised these base plan upgrade provisions, although SPP still required that transmission projects be evaluated through its regional transmission planning process (i.e., through the SPP Transmission Expansion Plan). MISO emphasizes that, during the transition to the Highway/Byway methodology, base plan upgrades that received a "notification to construct" from SPP prior to the effective date of the new methodology would not be eligible for 100 percent regional cost recovery, including facilities rated at 300 kV and higher.[118] MISO contends that if the current integration is consistent with the Highway/Byway transition, then Basin

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[115] *Id*. (citing *Illinois Commerce Commission v. FERC*, Case No. 13-1764 (June 25, 2014); *Illinois Commerce Commission v. FERC*, 576 F.3d 470 (7th Cir. 2009)).

[116] *Id.* at 14.

[117] *Id.* (citing *Southwest Power Pool, Inc.*, 111 FERC ¶ 61,118, *order on reh'g*, 112 FERC ¶ 61,319 (2005) (accepting SPP's base plan funding Tariff revisions)).

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

Electric's listed 345 kV projects should not receive 100 percent regional cost recovery because they obtained an equivalent of SPP's "notification to construct" prior to the October 1, 2015 integration date. MISO states that it is this date, rather than a self-selected "need-by date," that is consistent with the Highway/Byway transition.[119] MISO also notes that SPP's proposed integration is contrary to the five-year transition period, incorporating two separate planning areas, which the Commission accepted for the integration of Entergy into MISO.[120]

69. MISO concludes that making SPP customers subsidize Basin Electric's listed projects, which were planned and approved before the proposed integration and were designed primarily to benefit Basin Electric's customers and loads, unreasonably departs from SPP's current cost allocation methodology. Moreover, MISO argues that SPP's proposal departs from the Commission's well-established cost-causation principles by creating a serious mismatch between the costs and benefits of these projects to the rest of the SPP region. MISO asserts that the Commission should reject these proposed provisions in Schedule 2 of Attachment J that permit regional cost recovery for certain Basin Electric projects, as unjust, unreasonable, unduly discriminatory and preferential.[121]

70. Finally, MISO notes that, while in the past it would have been indifferent as to how SPP allocated transmission costs within SPP, there is an ongoing dispute between SPP and MISO in which SPP alleges that MISO is unlawfully using its transmission facilities without compensation, an allegation that MISO vigorously disputes.[122] To the extent that the Commission decides to accept SPP's proposed cost allocation for Basin

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[119] *Id.* at 15.

[120] *Id.* at 16 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,056, *order on reh'g*, 141 FERC ¶ 61,128 (2012)).

[121] *Id.* at 3.

[122] In addition to ongoing Joint Operating Agreement disputes, SPP submitted an unexecuted transmission service agreement to make MISO an SPP transmission customer in Docket No. ER14-1174-000. The Commission accepted this service agreement but found that it had not been shown to be just and reasonable and set it for hearing and settlement judge procedures, which are ongoing. *See Southwest Power Pool, Inc.*, 146 FERC ¶ 61,231 (2014).

Electric's listed projects, MISO requests a confirmation that any such acceptance will not prejudice the issue of whether MISO should be held responsible for any Schedule 11 charges arising from the ongoing dispute.[123] MISO States support MISO's request that the Commission confirm that its acceptance of SPP proposed integration terms in this proceeding will not prejudice the decision as to whether MISO should be subject to Schedule 11 costs from SPP. MISO States otherwise take no position at this time on the merits of the Integrated System Parties' integration into SPP.[124]

71. Kansas Commission asserts that the Integrated System Parties should be responsible for a proportionate share of costs for all base plan upgrades in the SPP region in service before and after October 1, 2015 because they will benefit from SPP membership and services provided by SPP. Kansas Commission contends that, as an RTO, SPP should be considered a "sum of the parts" and not parsed out as individual pieces when pursuing new membership. Kansas Commission argues that SPP's proposed treatment of the Integrated System Parties will result in an unjust and unreasonable financial burden on Kansas ratepayers, when Kansas state utilities recover these costs from their customers.[125] Kansas Commission further argues that exempting Western-UGP from a proportionate share of the costs associated with existing facilities would be contrary to court precedent that a new RTO member must pay a proportionate share for existing RTO transmission facilities.[126] According to Kansas Commission, normally, any RTO member would be responsible for transmission facility costs under the provisions of a filed rate system. In addition, Kansas Commission asserts that the Order No. 1000 transmission planning process makes SPP's transmission plans binding upon all members of an RTO that are identified as beneficiaries by the RTO. According to Kansas Commission, in *Avista Corporation*,[127] the Commission found that if a non-jurisdictional entity elects to join an RTO and is a beneficiary of services provided by specific

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[123] *Id.* at 4.

[124] MISO States Comments at 3.

[125] Kansas Commission Protest at 18.

[126] *Id*. at 17 (citing *FirstEnergy Serv. Co. v. FERC*, Case No. 12-1461 (D.C. Cir. July 18, 2014), *Illinois Commerce Comm'n v. FERC*, 721 F.3d 764 (7th Cir. 2013)).

[127] Kansas Commission Protest at 20 (citing *Avista Corp.*, 148 FERC ¶ 61,212 (2014)).

transmission facilities, then the new member is required to bear the costs of those benefits.[128]

b. **Commission Determination**

72. We accept SPP's base plan upgrade and regional cost sharing proposal and find it to be just, reasonable, and not unduly discriminatory, as discussed below. We appreciate the challenges that come with the integration of different regions with their own transmission planning processes and legacy transmission systems. There is no clear one-size-fits all just and reasonable approach for such an integration. Rather, in order to find a proposal to be just and reasonable, the proposal must respect both the principle of cost causation and the practical realities of a transition.

73. The Commission has accepted a range of approaches from RTOs.[129] The 2008 proposal that created three new SPP transmission pricing zones composed of the NPPD, Omaha Public Power District, and Lincoln Electric System (Nebraska Entities) transmission systems is similar to the proposal here. In that proposal, SPP amended the definition of base plan upgrades in its Tariff and created a bright line delineating the date upon which upgrades on the Nebraska system would be eligible for base plan upgrade designation. SPP also proposed some exceptions to this bright line date, specifically to include as base plan upgrades network upgrades determined to be needed for reliability purposes.

74. SPP has shown that its base plan upgrade and regional cost sharing proposal is just and reasonable. The Transmission Working Group study conducted by SPP to evaluate the integration of the Integrated System Parties' transmission systems was substantively similar to and generally consistent with the 2013 Integrated Transmission Planning Near-Term study that SPP conducted as part of its regional transmission planning process.[130] We note that the Transmission Working Group study confirmed that the Basin Electric projects met regional reliability needs and that the proposed integration date met timing

[128] *Id.* (citing *Avista Corp.*, 148 FERC ¶ 61,212 at P 226).

[129] *See, e.g.*, *Southwest Power Pool, Inc.*, Docket No. ER09-254-000 (January 27, 2009) (unpublished letter order); *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,056, *order on reh'g*, 141 FERC ¶ 61,128 (2012); *FirstEnergy Serv. Co. v. FERC*, Case No. 12-1461 (D.C. Cir. July 18, 2014).

[130] *See* Ex. No. SPP-3 at 17.

requirements for these needs in the study models, and is consistent with its current Integrated Transmission Planning Near-Term study.[131] In the Transmission Working Group study, SPP determined that the Basin Electric projects identified in Schedule 2 of Attachment J were needed to meet reliability objectives in the SPP region. We note that no party has alleged defects in the planning for the Basin Electric projects or that these projects do not meet the reliability standards required of other transmission upgrades to the SPP system. We further note that these facilities are high voltage facilities that SPP has demonstrated will provide benefits on a larger scale than the local zone.[132] Accordingly, we find it reasonable for these Basin Electric projects to be considered base plan upgrades and eligible for regional cost sharing under the SPP Tariff. We also find that the October 1, 2015 bright line date is consistent with SPP's regional transmission planning objectives. Further, we note that SPP has a process in place—the Regional Cost Allocation Review process—that will serve as a *post hoc* check on whether inequities exist under SPP's Highway/Byway cost allocation methodology and that the Basin Electric projects listed in Schedule 2 of Attachment J will be subject to this review process.[133] If the regional cost allocation review process analysis determines that the costs of these Basin Electric projects are not roughly commensurate with the benefits provided to the SPP region, there are remedies available to correct such inconsistencies in regional cost sharing.

75. We decline to require cost-sharing for the SPP and Integrated System Parties legacy transmission systems (i.e., transmission assets with a need-by date prior to the October 1, 2015 integration date), as requested by Kansas Commission. Specifically, although Kansas Commission asserts that the Integrated System Parties will gain benefits from use of the SPP legacy system and should therefore contribute to its costs, we find that Kansas Commission neglects to consider the benefits that the rest of the SPP membership will receive from the Integrated System Parties' legacy systems. For example, SPP expects the integration to benefit the SPP membership through increased grid reliability and congestion management available through the ability to commit and

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[131] *Id*.

[132] *See Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252, at PP 23-26 (2010) (describing studies SPP conducted, as well as other supporting evidence, to demonstrate the regional benefits provided by Extra High Voltage transmission facilities in the SPP region).

[133] Ex. No. SPP-3 at 18.

dispatch generation affecting transmission flows through and out of Nebraska, flows that, in the past, have contributed to generation curtailments in the western SPP region.[134] Further, Kansas Commission has not shown that the proposed integration date is unjust and unreasonable as a milestone to distinguish transmission cost recovery between the legacy systems and the newly integrated SPP system.

76. Additionally, both current SPP members and the Integrated System Parties will be allocated costs for transmission projects not planned in the conventional planning processes that existed in the two regions prior to the integration date. The result will be the reciprocal; current SPP members will share in the costs of Integrated System Parties' transmission projects planned through a non-SPP planning process with a need-by date of October 1, 2015 or later, and Integrated System Parties except for the Federal Service Exemption, will share in the cost of transmission projects with a need-by date of October 1, 2015 or later that were planned through the SPP regional transmission planning process.

77. Finally, per the requests of MISO and MISO States, we confirm that our acceptance of this proposal does not prejudge the outcome of the ongoing hearing and settlement judge procedures in Docket No. ER14-1174-000, specifically the issue of whether MISO should be held responsible for any Schedule 11 charges under the SPP Tariff.

4. FERC Assessment

78. SPP proposes to revise section 2 of Schedule 12 of the Tariff, which is the schedule SPP uses to recover the FERC Assessment from transmission customers, to include language to specify that SPP will not assess Schedule 12 charges to transmission service provided to Western-UGP for its Statutory Load Obligations. SPP explains that because 18 C.F.R. § 382.201(a) provides that the calculation of the FERC Assessment does not include the cost of regulating the federal power marketing agencies, it is not appropriate to allocate to Western-UGP a portion of the FERC Assessment. Specifically, the new language states, in part:

79. Pursuant to 18 C.F.R. § 382.201(a), the calculation of the FERC Assessment does not include the cost of regulating the Federal Power Marketing Agencies. Therefore,

[134] *See id*. at 12.

charges under this Schedule 12 shall not be assessed with respect to transmission service provided to Western-UGP for its Statutory Load Obligations.

a. <u>Comments and Protests</u>

80. NPPD argues that the FERC Assessment exemption in SPP's proposal should be extended to transactions involving Western-UGP's preference power sales to customers in all of SPP's existing zones.[135] NPPD notes that SPP justifies the exemption asserting that because Western-UGP is subject to separate charges related to FERC review of rates of federal power marketing agencies, it should not be required to pay schedule 12 charges related to the costs of FERC regulation of SPP. NPPD argues that SPP's rationale applies to Western-UGP's Statutory Load Obligations located in NPPD's Zone 17.[136]

81. NPPD contends that the ultimate delivery of federal power to some of Western-UGP's Statutory Load Obligations in Zone 19 will be made through facilities owned by Basin Electric and Heartland. Thus, NPPD states that even if some of the deliveries in Zone 19 will be made exclusively from facilities owned by Western-UGP, all deliveries are made under the same SPP Tariff. Accordingly, NPPD states that the exemption from Schedule 12 should apply to Western-UGP's Statutory Load Obligations in Nebraska.[137]

b. <u>Commission Determination</u>

82. We reject SPP's proposal to revise Schedule 12 of its Tariff to specify that SPP will not assess Schedule 12 charges to transmission service provided to Western-UGP for its Statutory Load Obligations. The FERC Assessment charged under 18 C.F.R. § 382.201(a) includes the costs of the Commission's regulatory electric program, excluding the cost of regulating the federal power marketing agencies; those charges are assessed to public utilities based on the amount of transmission service provided.[138] The

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[135] NPPD Protest at 9.

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

[137] *Id.* at 10.

[138] Ex. No. SPP-7 at 27-31 (citing 18 C.F.R. § 382.201(a), which states, in part: "*(a) Determination of costs to be assessed to public utilities.* The adjusted costs of administration of the electric regulatory program, excluding the costs of regulating the Power Marketing Agencies, will be assessed to public utilities that provide transmission service…").

cost of regulating federal power marketing agencies is assessed under 18 C.F.R § 382.201(d); those charges are based on the amount of power sales by the federal power marketing agencies.[139] Under Schedule 12 of its Tariff, SPP recovers the cost of the FERC charges assessed under § 382.201(a) for SPP transmission service. Because Western-UGP will be taking transmission service over SPP's system, Western-UGP's transmission service should be reflected in the total amount of transmission service provided by SPP and subject to the FERC Assessment under 18 C.F.R. § 382.201(a). We recognize, however, because all the transmission service provided to Western-UGP under the Tariff is reflected in 18 C.F.R. § 382.201(a), when Western-UGP is billed directly by FERC for power sales under 18 C.F.R. § 382.201(d), it is possible that a double assessment of FERC costs may occur for these transactions.[140] To avoid such a result, Western-UGP could seek waiver of 18 C.F.R. § 382.201(d), instead of 18 C.F.R § 382.201(a), for any Western-UGP transactions over SPP's system.

5. Seams Issues

a. Comments and Protests

83. Missouri River requests a technical conference based on its concern that the integration of the Integrated System Parties into SPP will cause several operational and cost concerns for Missouri River.[141] According to Missouri River, the integration will require it to re-examine the amount of Network Integration Transmission Service it purchases from SPP and re-evaluate how its long-term generation resources will be used

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[139] 18 C.F.R. § 382.201(d) states in part:

> (d) *Determination of annual charges to be assessed to power marketing agencies.* The adjusted costs of administration of the electric regulatory program as it applies to Power Marketing Agencies will be assessed against each power marketing agency based on the proportion of the megawatt-hours of sales of each power marketing agency in the immediately preceding reporting year…

[140] There could be a charge to Western-UGP on Western-UGP's power sales and a charge to SPP for transmission of the same power sales.

[141] Missouri River Protest at 13-14.

to serve its load located in MISO and SPP.[142] Missouri River also states that it is unclear how it will need to schedule deliveries to accommodate multiple market participants for a single Integrated System Party delivery point.[143]

84. Moreover, Missouri River states that the integration will increase the cost of Network Integration Transmission Service in what will become Zone 19 because of the elimination of Western-UGP's Nebraska load of approximately 450-600 MW and the possible elimination of other Western-UGP, Basin Electric and Heartland load from the Zone 19 rate denominator as compared to the existing Integrated System Parties' rate.[144] Missouri River estimates that its transmission costs will increase by $10-12 million (approximately 80 to 100 percent) a year for the same amount of SPP Network Integration Transmission Service as it purchases from the Integrated System Parties currently.[145]

85. According to Missouri River, because Western-UGP will terminate its Network Integration Transmission Service arrangement effective on the date of the Integrated System Parties' integration, Missouri River will need to obtain Network Integration Transmission Service from SPP to replace that service.[146] Given the October 2015 integration date, Missouri River states that it needs to request Network Integration Transmission Service from SPP by February 1, 2015; however, SPP will not file the annual transmission revenue requirement for Zone 19 with the Commission until April 1, 2015.[147] Thus, Missouri River does not know how much SPP Network Integration Transmission Service to purchase and does not want to be locked in to paying an unknown rate for transmission service for an extended period of time for loads that it may want to serve through alternative means.[148] This dilemma is exacerbated by the fact that

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[142] *Id*. at 10.

[143] *Id*.

[144] *Id*. at 15.

[145] *Id*.

[146] *Id*. at 7.

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

[148] *Id*. at 16.

Missouri River does not know how much SPP Network Integration Transmission Service it needs to meet the MISO capacity requirements.

86. During the SPP Integrated Marketplace proceeding, Missouri River states that the parties agreed that a 1977 Transmission Service Agreement between NPPD and Basin Electric, acting as an agent for the Missouri Basin Power Project, would be treated as a grandfathered agreement (GFA) that is exempt from SPP charges.[149] While the power transmitted under the 1977 Transmission Service Agreement is currently only "looped" through SPP, after the integration, the transmission service and delivery obligations under the agreement becomes internalized into SPP. Consequently, in order to comply with section 217 of the Federal Power Act in a context that accommodates the integration of Western-UGP into SPP, Missouri River requests GFA No. 496 be re-designated from exempt to carved-out status. Missouri River states that GFA No. 496 meets the criteria used to determine carve-out eligibility. Moreover, Missouri River asserts that carve-out status for GFA No. 496 would be consistent with a Commission-approved settlement establishing the GFA carve-out.[150]

87. Missouri River states that the integration will perpetuate pancaked rates for Missouri River and its members. According to Missouri River, it will need to take Network Integration Transmission Service from both SPP and MISO to transmit power from Missouri River resources located in Zone 19 to Missouri River load in MISO. Missouri River notes that the Commission consolidated two proceedings relating to RTO pancaking as a result of the integration of transmission assets within MISO and established hearing proceedings in addition to section 206 investigations into the

[149] *Id*. at 11-12. The contract is listed as GFA No. 496 on Attachment W to the SPP Tariff. Under the terms of the contract, the power is transmitted from the Laramie River Station (Laramie) in eastern Wyoming, outside of SPP, to the interconnection with Western-UGP, also outside of SPP. However, as part of this arrangement the Missouri Basin Power Project provided a contribution in aid of construction of approximately $56 million to NPPD to construct the "NPPD Bulk Transmission System" which transmits up to 575 MW of energy from Laramie to NPPD's interconnection with Western-UGP at a substation in Grand Island Nebraska. Having undertaken the up-front costs of building the "NPPD Bulk Transmission System," Basin Electric (and by extension Missouri River and Heartland) pay a rate based upon the annual operating and maintenance expenses to NPPD for operation of the NPPD Bulk Transmission System.

[150] *Id*. at 13.

transmission rates charged.[151] Missouri River argues that the Commission should re-examine transmission rate pancaking between RTOs to eliminate inter-RTO seams issues.[152] Specifically, Missouri River requests the Commission condition approval of SPP's filing on revisions that eliminate pancaked transmission rates and reduce other RTO tariff seams for Missouri River and its members.

88. Missouri River also requests that the Commission allow it to use the maximum SPP Network Integration Transmission Service load for purposes of meeting its MISO's must offer requirement if Missouri River retains MISO load as part of its SPP Network Integration Transmission Service. Missouri River notes that for a resource external to MISO, the MISO must-offer requirement in the forward reliability assessment commitment is met by making itself available for declared emergencies pursuant to North American Electric Reliability Standard EOP-002.[153] Missouri River states that, according to SPP, section 30.4 of the SPP tariff limits the output of a Missouri River Network Integration Transmission Service resource in SPP to the Missouri River' SPP Network Integration Transmission Service load in MISO. Thus, the resource would be unavailable to respond to a MISO emergency operating procedure and unable to meet the full MISO must-offer requirement associated with the Missouri River Network Integration Transmission Service load in MISO.

89. For this reason, Missouri River requests that the Commission order SPP to allow Missouri River network load under SPP Network Integration Transmission Service be based on Missouri River's must-offer requirement at those times when MISO calls an emergency. Alternatively, Missouri River asserts that SPP should give it the option to determine if Missouri River load served in MISO and designated as SPP Network Integration Transmission Service load, should be considered part of the SPP capacity and reserve sharing pool and thus not be required to meet the must-offer requirement of MISO.[154]

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[151] *Id*. at 18 (citing *Southwest Power Pool, Inc.*, 146 FERC ¶ 61,231 (2014); *ITC Holdings Corp.*, 146 FERC ¶ 61,111 (2014)).

[152] *Id*. at 19.

[153] *Id*. at 18-19 (citing MISO Resource Adequacy Business Practice Manual, BPM-011-r14 at section 4.2.4.9, (Sept. 1, 2014)).

[154] *Id*. at 21.

90. Montana-Dakota explains that the historical cooperation between Montana-Dakota and Western-UGP/Basin Electric is reflected in two long-term agreements: (1) a Transmission Service Agreement with Western; and (2) an Interconnection and Common Use Agreement between Basin Electric and Montana-Dakota (together, Agreements). Montana-Dakota states that these Agreements have facilitated the joint development of transmission and allowed Montana-Dakota, Western-UGP and Basin Electric to use each other's transmission systems to serve their respective loads. Montana-Dakota asserts that these Agreements have also served to hold Western-UGP and Basin Electric harmless from Montana-Dakota's "first-mover" decision to join MISO in 2001, ensuring that Western-UGP and Basin Electric would not be subject to MISO charges for transmission service. According to Montana-Dakota, Western-UGP and Basin Electric informed it that, upon the expiration of the Transmission Service Agreement with Western in December 2015, Montana-Dakota will be required to make new transmission service arrangements to serve approximately one-third to one-half of its customer load in western North Dakota and eastern Montana, because this load does not have direct ties to MISO. Similarly, Montana-Dakota notes that Western-UGP and Basin Electric will not be able to serve their entire load without taking similar service from Montana-Dakota under MISO's Tariff.[155]

91. Montana-Dakota states that it is now faced with the possibility that it will be required to take Network Integration Transmission Service from both SPP and MISO to serve up to 50 percent of its load, subjecting its customers to rate-pancaking. Montana-Dakota adds that Basin Electric and Western-UGP face similar challenges with the expiration of the Transmission Service Agreement with Western. Montana-Dakota asserts that Basin Electric and Western-UGP account for approximately 40 percent of the energy flows on Montana-Dakota's transmission facilities and will need to obtain new transmission service from Montana-Dakota through the MISO Tariff.[156]

92. Montana-Dakota asserts that Western-UGP and Basin Electric's use of Montana-Dakota's transmission system should be appropriately accounted for either through credits for Network Customer-owned transmission facilities pursuant to section 30.9 of SPP's Tariff or some similar crediting mechanism. Such credits would offset charges imposed on Montana-Dakota for SPP transmission service as well as offsetting MISO charges that Western-UGP and Basin Electric would otherwise incur for use of Montana-

[155] Montana-Dakota Comments at 6.

[156] *Id*. at 7.

Dakota facilities.[157] Montana-Dakota informed SPP that it would only seek section 30.9 credits for integrated transmission facilities that (1) meet the definition of transmission under the SPP Tariff, Attachment AI, Definition of Transmission; and (2) are integrated with the Integrated System and serve both Montana-Dakota and Western-UGP/Basin Electric load (i.e., transmission facilities that only serve Montana-Dakota customers would not be included). Montana-Dakota asserts that the eligibility of such facilities should not be controversial, as they are already recognized as transmission facilities in MISO and included in Montana-Dakota's MISO Attachment O formula rates.[158]

93. Montana-Dakota notes that its proposal would not affect any other MISO or SPP customers. Specifically, Montana-Dakota states that section 30.9 credits would offset transmission charges only in the proposed Western-UGP/Basin Electric Integrated System pricing zone, Zone 19. In addition, Montana-Dakota explains that no other customer in MISO is affected by such an arrangement, because Montana-Dakota's revenue requirement in its MISO pricing zone is recovered solely from its customers/load. According to Montana-Dakota, any credits received from SPP would be credited against Montana-Dakota's revenue requirement, thereby, reducing the amount paid by its customers for MISO and SPP transmission service.[159]

94. Montana-Dakota asserts that it has been suggested that if Montana-Dakota is credited for the use of its facilities, such facilities should be treated as SPP transmission facilities subject to SPP's operational and functional control. Montana-Dakota reiterates that it is not seeking to establish a joint pricing zone with Western-UGP/Basin Electric. Rather, it is seeking financial transmission facility credits to offset its SPP transmission service charges for the use of certain Montana-Dakota-owned facilities by Western-UGP and Basin Electric to serve Montana-Dakota's customer loads within the proposed Western-UGP/Basin Electric Integrated System pricing zone, Zone 19. Montana-Dakota states that it is currently a MISO transmission owning member, and as such it cannot be compelled to join SPP, in whole or in part, simply to receive Network Customer facility credits.[160]

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[157] *Id*.

[158] *Id*. at 8, 9.

[159] *Id*. at 11.

[160] *Id*. at 11, 12.

95. Montana-Dakota further asserts that it should not be compelled to split its transmission system between SPP and MISO, have two reliability coordinators and be responsible for two sets of regionally beneficial projects simply to receive compensation for the use of its facilities in SPP. Accordingly, Montana-Dakota requests that the Commission confirm that, as a Network Customer of SPP, Montana-Dakota will be eligible to receive section 30.9 credits.[161]

96. According to Montana Consumer Counsel, it is likely that utilities who serve Montana retail electricity customers could be required to pay for transmission service from both SPP and MISO, leading to the potential for higher transmission costs. Montana Consumer Counsel explains that the possibility of seams issues being created by the migration of various entities from MISO to SPP is not addressed in any of the documents filed in these dockets. Thus, Montana Consumer Counsel requests that the Commission require the SPP either to address potential seams issues, or include hold harmless provisions in its proposed Tariff modifications to ensure that Montana retail electric customers are not penalized as a result of the Integrated System Parties' integration into SPP.[162] Montana Consumer Counsel argues that the Commission has recognized that seams issues "impede efficient transmission system usage" between RTOs, and it has identified Joint Operating Agreements as an appropriate vehicle to address seams issues in the past. In this regard, Montana Consumer Counsel points out that the MISO-SPP Joint Operating Agreement is currently under negotiation in multiple Commission proceedings.[163]

97. MEAN notes that while preference power customers would enjoy partial protection from congestion charges – for the transmission leg that is within Zone 19– they would be exposed to congestion charges on the second leg of the transmission path, from Zone 19 border to their loads. According to MEAN, to demarcate the point at which congestion charges will start to apply, SPP proposes a new defined term in Attachment AE: the "FSE Transfer Point" which is a new settlement location on the border of Zone 19 and the other zones. MEAN asserts that this new settlement location would appear to be useful in structuring arrangements (e.g. bilateral settlement schedules) for continued deliveries of preference power to MEAN's members once the Integrated

[161] *Id*. at 12.

[162] Montana Consumer Counsel Protest at 3, 4.

[163] *Id*. at 4, 5.

System becomes part of SPP. Moreover, MEAN explains that the "FSE Transfer Point" could be used as the "source" for auction revenue rights and transmission congestion rights to hedge congestion on the second transmission leg for deliveries of the preference power (i.e., from Zone 19 border to the load).[164]

98. MEAN asserts that in order to form a proper baseline for the determination of congestion costs associated with deliveries of the Western-UGP preference power, the source settlement location must represent only Western-UGP's resources. Thus, MEAN infers that the resources whose costs will be aggregated at the locational marginal price at the Federal Service Exemption Transfer Point will consist of only Western-UGP's fleet of hydroelectric generation. Otherwise, MEAN states that it would seem that there would be no need to establish a new settlement location distinct from the existing settlement location that establishes the locational marginal price at the interface between SPP and the Integrated System. MEAN asserts that the locational marginal price at the existing settlement location aggregates not only the Western-UGP hydroelectric resources but many other generators located within the Integrated System. For this reason, MEAN supports the creation of a new source settlement location that aggregates only the Western-UGP generation.[165]

99. MEAN also argues that SPP must treat the new FSE Transfer Point as electrically equivalent to the existing Western-UGP Area Upper East settlement location so that existing holders of auction revenue rights/transmission congestion rights can use them on the transmission path for their preference power entitlements. According to MEAN, a new settlement location will not provide an effective solution if market participants can use that settlement location for congestion hedging only by making new transmission service requests and/or starting over with the process for obtaining auction revenue rights/transmission congestion rights.[166]

100. MEAN asserts that it must be able to make sensible market arrangements in MISO for delivery of Western-UGP preference power to its members. MEAN explains that the point of delivery under Western-UGP's contracts with the MISO-area preference customers is at the MISO interface, not the FSE Transfer Point settlement location. Thus,

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[164] MEAN Comments at 4.

[165] *Id*. at 5.

[166] *Id*.

MEAN asserts that it needs to be able either to designate a settlement location at the MISO interface, with a locational marginal price based only on Western-UGP's hydro generation, or make equivalent arrangements for settling the preference energy with SPP at the MISO border. In either case, MEAN must be able to identify, maintain or obtain appropriate MISO auction revenue rights and financial transmission rights on the MISO system, and it should not have to experience an increase in its energy or transmission costs on the SPP system related to deliveries of the preference energy to MISO. Thus, MEAN asserts that the Commission should direct SPP to provide MEAN with suitable tools to continue to serve its members located in MISO that have Western-UGP preference entitlements without additional costs or risks resulting from the Integrated System Parties integration into SPP.[167]

101. MEAN states that it is the full-requirements supplier for the city of Rockford, Iowa (Rockford), which is situated within the Integrated System footprint, but it is not directly connected to the high-voltage facilities comprising the Integrated System. It is connected to 69 kV transmission facilities owned by Corn Belt, which is a member of Basin Electric. According to MEAN, these Corn Belt 69 kV facilities are directly interconnected with the MISO transmission system and MEAN uses these facilities to deliver energy to Rockford from resources located in MISO. MEAN asserts that it is not necessary to utilize the Integrated System facilities or Corn Belt's 161 kV facilities in order for MEAN to complete the transmission path. Thus, MEAN has no reservations on these facilities for this purpose.[168]

102. MEAN asserts that, according to an item on page 2 of Corn Belt's October 2014 newsletter regarding Basin Electric's decision to place its transmission facilities under the SPP Tariff, Corn Belt "is evaluating how much of its transmission system should also be incorporated into SPP. Corn Belt Power's 161 kV system will likely be put into SPP, while the extent of its 69 kV system to be included is still under consideration." MEAN states that if Corn Belt elects not to place its 69 kV facilities under the SPP Tariff (or at least not the 69 kV facilities connecting Rockford to the MISO system), MEAN should be able to continue serving Rockford in the manner it does today, without any need for SPP transmission service, and the Rockford load should be considered to interconnect with MISO via Corn Belt's transmission for Integrated Marketplace energy settlement

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[167] *Id*. at 6.

[168] *Id*. at 7.

purposes. In this case, there would be no need for MEAN to hedge congestion in the Integrated Marketplace for service to the Rockford load.[169]

103. Otter Tail explains that it is a Local Balancing Authority located on the western seam of MISO, with 21 direct interconnections to the Western-UGP balancing authority.[170] Otter Tail states that it has contacted Western-UGP, Central Power , Basin Electric, and SPP to discuss potential seams issues; however, it has not been able to confirm whether SPP and Basin Electric have considered or identified a solution for the reliability and market-to-market seams issues associated with the proposed integration of the Integrated System Parties into SPP. Otter Tail explains that it cannot confirm whether Central Power intends to put part or all of its transmission facilities under the SPP Tariff. Due to this uncertainty, Otter Tail contends that it is unable to evaluate fully the ramifications of Basin Electric's integration into SPP and the potential unintended consequences to Otter Tail and its native load customers as a result of the Integrated Transmission System between Otter Tail and Central Power.[171] Otter Tail asserts that SPP's proposal fails to provide information sufficient to satisfy a section 205 analysis including how SPP will address Otter Tail load served by the Integrated Transmission System.[172]

104. Otter Tail states that unlike most balancing authorities, the Integrated Transmission System comprises both facilities owned and operated by Otter Tail and facilities owned by Central Power, but operated by Otter Tail on behalf of Central Power. As the balancing authority and transmission operator, Otter Tail is responsible for maintaining system reliability within the Integrated Transmission System. Otter Tail asserts that the result of Central Power joining SPP could be possibly conflicting directives from two different Reliability Coordinators for the same Integrated Transmission System facilities. Otter Tail argues that the Commission should not approve any proposal from SPP without clarification as to how transmission system reliability will be maintained on this non-contiguous seam.[173]

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

[170] Otter Tail Comments at 5.

[171] *Id*. at 7.

[172] *Id*.

[173] *Id*. at 8.

105. According to Otter Tail, with the integration of Basin Electric into SPP, Otter Tail and Central Power will have Points of Receipt on the joint transmission system connected to two different markets administered by two separate RTOs. Otter Tail believes that the integrated nature of its interconnections with the Western-UGP balancing authority and the extensive Integrated Transmission System jointly owned by Otter Tail and Central Power makes Otter Tail's situation unique as compared to other market-to-market seams with SPP. Otter Tail is concerned that, absent an express provision in the SPP OATT, Otter Tail's native load customers may be subjected to: (1) potential transmission charges that are not commensurate with benefits received; (2) impermissible rate-pancaking of MISO and SPP transmission charges; and (3) potentially costly price differentials between the MISO and SPP markets resulting in unjust and discriminatory prices.[174]

106. Otter Tail asserts that under SPP's proposal, it is unclear whether Otter Tail load, served via the Integrated Transmission System, taking MISO Network Integration Transmission Service, but physically located within the SPP footprint, would be subject to SPP's Highway/Byway cost allocation procedures. However, if Basin Electric's integration into SPP results in Otter Tail being assessed costs associated with upgrades in the SPP region, Otter Tail expresses concern that its customers—customers not within the SPP region—could be assessed charges to subsidize these projects. Otter Tail argues that because its load is served by MISO, not SPP, this would be both unjust and contrary to well-established cost-causation precedent, which requires that "all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[175]

107. According to Otter Tail, SPP's proposal does not indicate whether Otter Tail load on jointly owned facilities falling within the newly expanded SPP footprint would be subject to SPP transmission charges. However, Otter Tail asserts that because its energy is scheduled through MISO and incurs MISO transmission charges, allowing SPP to charge for transmission service on facilities within the Integrated Transmission System would subject Otter Tail native load customers to the type of rate-pancaking the Commission's policies respecting RTOs were intended to eliminate. To avoid this unacceptable outcome, Otter Tail believes that its customers served by facilities within the Integrated System must be exempted from any SPP transmission service charges or

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[174] *Id*. at 9.

[175] *Id*. at 10 (citing *Illinois Commerce Commission v. FERC*, 576 F.3d at 477).

regional cost allocation programs following integration of the Integrated System Parties.[176]

108. Otter Tail states that Western-UGP manages two balancing authorities: Western-UGP Area Upper West and Western-UGP Area Upper East. Because Western-UGP Area Upper East is not currently part of a locational marginal pricing market, Otter Tail asserts that there is no price differential between the price of power injected into the Western-UGP Area Upper East balancing authority and the price of power where it is withdrawn at the Otter Tail substations.[177] Otter Tail contends that if Western-UGP becomes part of SPP's energy market, there are two potential wholesale market issues that could result in negative financial impacts to Otter Tail and its native load customers taking transmission service through MISO. Otter Tail asserts that the first issue is the potential price differential between MISO's SPP interface and SPP's MISO interface. Currently, Otter Tail explains that it is not exposed to any market price differentials because it schedules the power to serve its load within the Western-UGP balancing authority in the MISO day-ahead market. Absent an express provision in SPP's Tariff providing otherwise, once Western-UGP becomes part of the SPP market, Otter Tail is concerned that it may be required to schedule (and may be charged for) both an export at MISO's SPP interface and a corresponding import of energy at SPP's MISO interface for the same Otter Tail load in the Western-UGP balancing authority. This would expose Otter Tail and its customers to price differentials between the two markets.[178]

109. Otter Tail states that its second pricing concern arising from Western-UGP's proposed integration into the SPP energy market is the potential price differential between SPP's MISO interface and the commercial pricing nodes where Otter Tail serves its load within the Western-UGP balancing authority. Under current conditions, Otter Tail explains that it is not exposed to any price differentials between these two points. According to Otter Tail, under SPP's proposal Otter Tail could potentially be required to import (and pay for) energy at SPP's MISO interface and withdraw (and be charged for) power at the commercial nodes where Otter Tail serves its native load within the Western-UGP balancing authority. Otter Tail contends that this will potentially expose

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[176] *Id*. at 11.

[177] *Id*. at 12.

[178] *Id*.

Otter Tail's customers to costly price differentials between these different points on the Western-UGP system within the SPP market.[179]

110. South Dakota Commission also supports Otter Tail's request for protections for Otter Tail customers from the assessment of charges under SPP's Tariff. South Dakota Commission requests that the Commission condition approval of SPP's proposed Tariff revisions on inclusion of provisions to ensure the proposed integration will allow Otter Tail to continue to serve its native load customers within the Western-UGP balancing authority without any new charges or exposure to discriminatory SPP pricing.[180]

111. North Dakota Commission supports Otter Tail's request for clarification that Otter Tail will not be assessed any charges for load that is served by facilities on the integrated transmission system between Central Power and Otter Tail.[181]

b. Commission Determination

112. Missouri River, Montana-Dakota, Montana Consumer Counsel, MEAN, Otter Tail, North Dakota Commission, and South Dakota Commission raise concerns about seams issues resulting from the decision of the Integrated System Parties to integrate into SPP. In particular, we recognize that many utilities in this area have facilities that are highly integrated with each other as a result of joint planning and ownership of transmission, and that these arrangements may need to be reflected in their service arrangements with SPP, such as, e.g., through transmission facilities credits under section 30.9 of the Tariff, and may present other seams issues. We find that these parties raise genuine issues of material fact that cannot be resolved based on the record before us and are more appropriately addressed through hearing and settlement judge procedures. Thus, we will set these issues for hearing and settlement procedures so that parties will have the opportunity to resolve them in a mutually beneficial manner.

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[179] *Id*. at 13. Otter Tail states that this issue arose when MISO was beginning its Energy Markets in 2005, and that the Commission approved an uncontested settlement that agreed that Central Power should not bear MISO costs due to Otter Tail's Transmission Owner and Market Participant status within MISO.

[180] South Dakota Commission Comments at 3.

[181] North Dakota Commission Comments at 3.

113. With respect to concerns by multiple parties about the perpetuation of pancaked transmission rates between the IS System and MISO, and more generally between SPP and MISO, we find that this issue is beyond the scope of this proceeding. We will also not include in the hearing and settlement judge procedures the issues raised by Otter Tail and MEAN concerning the facilities of Corn Belt or Central Power because Corn Belt and Central Power have not yet transferred their facilities to SPP. Otter Tail and MEAN may raise this issue if and when Corn Belt and Central Power transfer their facilities to SPP.

6. Generator Interconnection Procedures

114. SPP proposes several modifications to its generator interconnection procedures, in Attachment V of its Tariff, to recognize Western-UGP's status as a federal entity and to accommodate interconnection requests where Western-UGP is the transmission owner. SPP also proposes to add two new *pro forma* agreements to the appendices of Attachment V. The first, Appendix 13, is a *pro forma* Generator Interconnection Agreement (GIA) for use when Western-UGA is a transmission owner (Western-UGP GIA), based on the current SPP *pro forma* GIA contained in Appendix 6 of Attachment V. The second, Appendix 14, is a *pro forma* interim GIA for use when Western-UGA is a transmission owner (Western-UGP Interim GIA), based on the current SPP *pro forma* interim GIA contained in Appendix 8 of Attachment V. According to SPP, these standardized GIAs will avoid the need to file non-conforming GIAs with the Commission each time Western-UGA is a party to a GIA as a transmission owner.[182]

115. SPP proposes numerous revisions throughout Attachment V to reference and describe an environmental review process,[183] conducted by Western-UGP in the event an interconnection request results in an interconnection or modification to, the transmission facilities of Western-UGP.[184] SPP describes this environmental review process in a new section 8.6.1 of Attachment V. Western-UGP and the interconnection customer will enter into an environmental review agreement authorizing Western-UGP to conduct, at

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[182] SPP Transmittal at 38.

[183] The aim of this review is to study the potential environmental impact of a proposed interconnection to Western-UGP's facilities, pursuant to the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 *et seq.* (1969).

[184] *See* Ex. No. SPP-6 at 4.

the interconnection customer's expense, an environmental study, the costs of which will be estimated in the agreement.[185] The interconnection customer must execute and return the agreement to Western-UGP within 30 calendar days, along with funds to cover the estimated costs of the study. Proposed section 8.6.1 expressly prohibits a cure period, and failure to execute the agreement or provide sufficient funds in time will result in the withdrawal of the interconnection request.[186] If the costs incurred for the study are less than estimated, Western-UGP will refund the difference, without interest, to the interconnection customer. Proposed section 8.6.1.1(a) requires that Western-UGP use reasonable efforts to complete an environmental review and issue a draft study report to the interconnection customer within 18 months, or the actual time required to complete the necessary level of environmental review. Additionally, proposed section 8.6.1.1(b) specifies that Western-UGP shall notify the interconnection customer as to the status of the environmental review, at the interconnection customer's request or when Western-UGP anticipates it will not meet the estimated time frame for completing the review.

116. SPP also proposes revisions to section 11.1 of Attachment V to specify that, until the required NEPA decisional document is issued, no construction activities associated with Western-UGP's transmission facilities shall commence. This requirement may affect the commercial operation date of the generating facility, according to SPP.[187] Appendix A of the proposed Western-UGP GIA and Interim GIA contain placeholders

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[185] Proposed section 8.6.1 of Attachment V specifies that, unless previously requested, Western-UGP will tender an environmental review agreement to the interconnection customer within 15 days of SPP providing the definitive interconnection system impact study report to the interconnection customer. Proposed section 3.3.5 of Attachment V clarifies that the interconnection customer may request that the environmental review process commence any time after SPP accepts an interconnection request.

[186] Proposed section 8.6.1 of Attachment V also specifies that, if at any time the interconnection customer fails to comply with the terms of the environmental review agreement prior to issuance of the final NEPA decisional document, Western-UGP will notify SPP, who may deem the interconnection request withdrawn.

[187] This language is reiterated in revisions to section 11.A.3.1 of Attachment V, regarding interim GIAs and section 14.2.4 of Attachment V, regarding the SPP interconnection fast track process. This language, in part, is also proposed within Appendix A of the proposed Western-UGP GIA and Interim GIA.

for environmental requirements specified in the NEPA decisional document resulting from the environmental review process.[188]

117. In his testimony, Mr. Sanders explains that the proposed environmental review process is similar to procedures in Western's Open Access Transmission Tariff previously approved by the Commission.[189] Mr. Sanders notes that there is some potential, although low in likelihood, that the environmental review process could affect interconnection requests seeking to interconnect to another transmission owner's facilities, provided an interconnection facilities study identifies needed upgrades on Western-UGP's system due to the interconnection; such a finding would require an environmental review. However, Mr. Sanders explains that environmental review would still be required under SPP's existing Tariff when Western-UGP assumes the role of an affected system transmission owner.[190]

118. Mr. Sanders explains that, pursuant to the Antideficiency Act, as a federal agency, Western-UGP cannot make or authorize expenditures or obligations exceeding amounts made available in specific appropriations and funds. In the absence of appropriated funds, and pursuant to federal law including the Federal Contributed Funds Act, Mr. Sanders states that Western-UGP must require advance deposit of funds when it is required to perform work for third parties.[191] Accordingly, SPP proposes revisions throughout Attachment V to require advance payment of funds when Western-UGP is a transmission owner. These include modifications to section 9 of Attachment V, involving the engineering and procurement agreement, as well as advance payment provisions throughout the proposed Western-UGP GIA and Interim GIA.[192]

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[188] In testimony, Stephen Sanders states that Western-UGP intends to post additional details, such as study time frames and estimated costs for various levels of environmental review, under the business practice postings on the SPP Open Access Same Time Information System, as well as templates for the environmental review agreement. Ex. No. SPP-6 at 9.

[189] *Id.* (citing *Western Area Power Administration*, 133 FERC ¶ 61,193 (2010)).

[190] *Id.* at 18.

[191] Ex. No. SPP-6 at 5.

[192] *See* Proposed Attachment V, Appendices 13 and 14, Article 11.8. Article 5.5 (Equipment Procurement), Article 5.6 (Construction Commencement), and Article 11.7

(continued...)

119. With regard to liability provisions in the Western-UGP GIA and Interim GIA, Mr. Sanders explains that Western-UGP cannot indemnify SPP or the interconnection customer because of the Antideficiency Act. According to Mr. Sanders, any liability on Western-UGP's part would be determined pursuant to the Federal Tort Claims Act.[193] Accordingly, SPP proposes revisions to Article 18.1 in the proposed Western-UGP GIA and Interim GIA to specify that the transmission owner's liability is limited to and determined in accordance with the Federal Tort Claims Act. SPP also proposes removing all language from Article 5.3 (Liquidated Damages) in the Western-UGP GIA and Interim GIA, leaving the article reserved for future use.

120. SPP proposes other modifications that it asserts are necessitated by Western-UGP's federal status. SPP proposes removing all language from Article 5.17 (Taxes) in the Western-UGP GIA and Interim GIA, leaving the article reserved for future use. Mr. Sanders explains that Western-UGP, as a general rule, does not pay taxes as a federal entity.[194] Article 18.3 in the proposed Western-UGP GIA and Interim GIA specifies that the transmission owner is self-insured, in accordance with its status as a federal agency. SPP also proposes additional provisions regarding environmental releases, testing of metering equipment, limitations on assignment, and limitations on the terms of the Western-UGP GIA and Interim GIA, as well as other minor modifications.[195]

121. Finally, SPP proposes a new section 2.6 in Attachment V that specifies that, in the event that Western-UGP is the transmission owner under any of the provisions or agreements contained in SPP's interconnection procedures, section 39.3 of the Tariff (which describes the Federal Service Exemption) shall be incorporated as part of the

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(Provision of Security) in the proposed Western-UGP GIA and Interim GIA reference advance payment provisions in Article 11.8.

[193] Ex. No. SPP-6 at 5, 6.

[194] Ex. No. SPP-6 at 6.

[195] *See* Proposed Attachment V, Appendices 13 and 14, Articles 2.2, 7.4, 19, and 23.

interconnection procedures.[196] SPP also proposes additional, minor modifications within Attachment V.[197]

a. Comments and Protests

122. Western supports the Tariff revisions to Attachment V. Western notes the federal statutory requirements necessitating various provisions and points to similar, Commission-approved provisions contained in Western's Open Access Transmission Tariff.[198]

b. Commission Determination

123. We conditionally accept SPP's proposed revisions to the generator interconnection procedures in Attachment V of its Tariff, subject to a compliance filing due 30 days after the issuance of this order, as discussed below.

124. We find that SPP has demonstrated its proposed generator interconnection procedure provisions to be just and reasonable. While the environmental review procedures described in section 8.6.1 and elsewhere in Attachment V will increase the time required to process an interconnection request, this process is necessitated by federal statutes[199] and is limited to cases where upgrades are required on Western-UGP's

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[196] SPP also incorporates by reference section 39.3 of the Tariff within Article 30.4 of the proposed Western-UGP GIA and Interim GIA.

[197] *See* Proposed Attachment V §§ 2.1.3, 5.2, 12.4, and Appendix 9. SPP also proposes revisions to several appendices within Attachment V to remove the transmission owner as a signatory to various agreements, e.g., the definitive interconnection system impact study agreement (*see* Proposed Attachment V, Appendices 3, 3A, 4, 4A, and 5). SPP notes that these revisions are not directly related to the Integrated System Parties' integration. However, SPP states that it performs these studies, making the transmission owner's signature unnecessary. SPP Transmittal at 37, n.102.

[198] Western Comments at 10.

[199] In addition to NEPA, these statutes include the National Historic Preservation Act (16 U.S.C. § 470 *et seq.* (1966)), the Endangered Species Act (16 U.S.C. § 1531 *et seq.* (1973)), and the Archeological Resources Protection Act (16 U.S.C. §§ 470aa-470mm (1979)), as well as regulations and Executive Orders implementing these statutes.

transmission system. Additionally, if an interconnection customer seeks to lessen the time required to conduct an environmental review, it may request that Western-UGP commence such study as soon as SPP accepts its interconnection request, pursuant to section 3.3.5 of Attachment V. While the Commission typically permits cure periods for various agreements within the interconnection study process,[200] we will accept the prohibition of a cure period associated with the environmental review agreement in section 8.6.1 of Attachment V, in order to avoid further delay in the study process.[201] We also accept revisions associated with Western-UGP's federal status throughout Attachment V, including advance payment and liability provisions, as federal statute necessitates these changes.

125. We conditionally accept the proposed Western-UGP GIA and Western-UGP Interim GIA, contained within new Appendices 13 and 14 of Attachment V. We agree that providing these standardized agreements within the Tariff will reduce the need for SPP to file non-conforming GIAs and interim GIAs with the Commission. Additionally, interconnection customers will be on full notice of special requirements and limitations necessitated by Western-UGP's status as a federal entity. However, we will require additional compliance. First, there appears to be an incorrect reference to the Federal Tort Claims Act within Article 18.1 in both the Western-UGP GIA and Interim GIA.[202] We will require SPP to correct this reference in a compliance filing due 30 days after the issuance of this order. Additionally, Article 11.8.3 in the Western-UGP GIA and Interim GIA specifies that, if an advance payment exceeds actual costs, the transmission provider will provide a refund without interest. Similarly, section 8.6.1 of Attachment V specifies that if the costs incurred for an environmental review study are less than the estimated costs, Western-UGP will refund the difference, without interest, to the interconnection customer. We will require SPP, in a compliance filing due 30 days after the issuance of this order, either to: (1) confirm that the lack of interest payment is due to federal limitations associated with the Antideficiency Act and modify Article 12.4 in the

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[200] *See, e.g., Southwest Power Pool, Inc.*, 128 FERC ¶ 61,114, at P 44 (2009).

[201] Within the SPP generator interconnection study process, a definitive interconnection system impact study and facilities study—excluding cure periods, potential restudies, and time to tender and execute agreements—generally require roughly seven months to complete. Thus, the 18-month environmental review analysis adds a substantial amount of time to processing an interconnection request.

[202] Specifically, Article 18.1 references 28 U.S.C. § 1346(c) rather than 1346(b).

Western-UGP GIA and Interim GIA to specify that Western-UGP will not pay interest on funds associated with billing disputes; or (2) revise Article 11.8.3 in the Western-UGP GIA and Interim GIA, as well as section 8.6.1 of Attachment V, to provide for accrued interest, consistent with Article 12.4 in the Western-UGP GIA and Interim GIA.

126. Finally, our acceptance of SPP's modifications to its generator interconnection procedures is conditioned on SPP providing more information on the merger of Western-UGP's interconnection study queue with SPP's interconnection queue in a compliance filing due 30 days after issuance of this order, as discussed in more detail below.[203]

7. Study Queue Transition

127. SPP does not address in its Tariff filing the issue of transitioning the transmission and interconnection study queues.

a. Comments

128. In its comments, MEAN raises questions about the process to merge the SPP and Integrated System Parties' existing transmission service study queues, as well as how SPP will handle studying new transmission service requests over the combined, integrated system. According to MEAN, the elimination of the seam between SPP and the Integrated System Parties will affect at least one contract with Heartland involving the purchase of capacity and associated energy from a wind generating facility located in the Integrated System region. MEAN states that it may choose to designate this generating facility as a designated network resource, requiring study through SPP's aggregate transmission service study process. MEAN is skeptical that SPP could complete an aggregate study involving its request before October 1, 2015. MEAN requests that the Commission require SPP to specify when it will commence accepting and processing long-term transmission service requests, as well as require SPP to begin this process as soon as possible to avoid potential service delays.[204]

b. Commission Determination

129. We will require SPP to provide more information on the merger of the Integrated System Parties and SPP long-term transmission service study and generator

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[203] *See infra* P 130.

[204] MEAN Comments at 9-10.

interconnection study queues in a compliance filing due 30 days after the issuance of this order. We agree with MEAN that customers need more information about these transition processes to reduce uncertainty and aid in making business decisions in light of the integration. We will require SPP, for both its aggregate transmission service study and generator interconnection study queues, to provide in its compliance filing: (1) information detailing the transition process for both study queues; (2) a timeline for the transitions, including estimated dates for completion of various studies; and (3) Tariff revisions to implement the transition processes, as needed.[205]

D. Revisions to Members Committee and Corporate Governance Committee

1. SPP Filing

130. SPP filed proposed revisions to the Bylaws to add a seat to the Members Committee for a federal power marketing agency representative and an additional seat for a cooperative representative,[206] and to add a seat to the Corporate Governance Committee for a federal power marketing agency.

2. Commission Determination

131. We find the proposed revisions to the composition of the Members Committee and the Corporate Governance Committee to be just and reasonable and we accept them.

E. Withdrawal Obligations

1. SPP Filing

132. SPP proposes revisions to the withdrawal obligations in the Bylaws and Membership Agreement. SPP also provided, as exhibits but not as formal parts of the Membership Agreement, signed amendments between SPP and each of the Integrated

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[205] *See, e.g.*, SPP Tariff, Attachment V section 5.

[206] These revisions also add to the Members Committee an additional seat for an investor-owned utility representative and a seat for an independent transmission company representative. SPP explains that these proposed revisions are based on the growth in SPP membership of investor-owned utilities and independent transmission companies. *See* Ex. No. SPP-3 at 28-29.

System Parties.[207] Proposed section 8.7.5 of the Bylaws, proposed section 4.2.2(b)(v) of the Membership Agreement[208] and section A1.9 of the Western-UGP Amendment provide that upon Western-UGP withdrawing from SPP membership, Western-UGP will not be subject to the notice and financial obligations in section 8.7 of the Bylaws if (1) the Commission finds that SPP has not adhered to all the Federal Power Marketing Agency Amendments[209] or (2) SPP files and the Commission approves changes to the Federal Power Marketing Agency Amendments and the changes cause Western-UGP to be non-compliant with its statutory requirements. In addition, proposed revisions to section 4.2 of the Membership Agreement provide that a federal power marketing agency will not be required to make a withdrawal deposit and will only pay SPP's costs for the withdrawal after they are incurred and invoiced. SPP explains that these proposed revisions are needed in order for Western-UGP to be held harmless if SPP makes changes to the agreement and these changes cause Western-UGP to be non-compliant with its statutory obligations.[210]

133. The Basin Electric Amendment and the Heartland Amendment, among other things, set forth their withdrawal obligations. Specifically these Amendments cover what

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[207] *See* Ex. No. SPP-14 (Western-UGP Amendment); Ex. No. SPP-15 (Basin Electric Amendment); and Ex. No. SPP-16 (Heartland Amendment).

[208] Proposed section 4.2.2(b)(v) of the Membership Agreement applies to all three of the Integrated System Parties ("[a]ny Member with Transmission Facilities located in the Upper Missouri Zone [Zone 19]"). The withdrawal obligations and procedures applicable to Basin Electric and Heartland are set out in the Basin Electric Amendment and Heartland Amendment.

[209] The term "Federal Power Marketing Agency Amendments" is defined in proposed section 1.0 of the Bylaws as "[t]he amendments and revisions to the SPP Bylaws, the SPP Membership Agreement, and Section 39.3 of the OATT that are required by a Federal Power Marketing Agency for membership in SPP at the time of the Federal Power Marketing Agency's initial membership or as they may be revised in the future by mutual agreement between the [f]ederal [p]ower [m]arketing [a]gency and SPP."

[210] Transmittal at 42.

happens: (1) if Western-UGP withdraws from SPP membership;[211] (2) if the Commission finds that SPP has not adhered to all of the Federal Power Marketing Agency Amendments or all of the Basin Electric Amendment and Heartland Amendment; or (3) if SPP files and the Commission approves changes to the Basin Electric Amendment or Heartland Amendment without Basin Electric's or Heartland's consent, and such changes materially adversely affect Basin Electric or Heartland.[212]

134. SPP explains that the withdrawal provisions are necessary due to the integrated nature of the facilities owned by Basin Electric, Heartland, and Western-UGP, to address what should happen if Western-UGP withdraws and then Basin Electric and Heartland withdraw too.[213] SPP notes, however, that because Basin Electric and Heartland are not federal entities, they would be subject to the financial withdrawal obligations to which SPP members other than federal power marketing agencies are subject.[214]

2. <u>Protest</u>

135. Kansas Commission argues that proposed section A1.10 of the Western-UGP Amendment to the Membership Agreement, exempting Western-UGP from withdrawal obligations under certain circumstances, should not be approved, due to an absence of evidence that it will result in just and reasonable rates.[215]

3. <u>Commission Determination</u>

136. We accept the proposed revisions to the Bylaws and Membership Agreement governing the withdrawal obligations of the Integrated System Parties. Specifically, we

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[211] In addition, if Western-UGP withdraws, then Basin Electric's or Heartland's withdrawal will have the same effective date as Western-UGP's withdrawal; and upon withdrawal, Basin Electric or Heartland will be subject to the financial obligations set out in section 4.3 of the Membership Agreement.

[212] Under this circumstance Basin Electric or Heartland will withdraw and work with SPP to facilitate the withdrawal.

[213] Transmittal at 47.

[214] *Id*.

[215] Kansas Commission Protest at 27-28.

find that the withdrawal provisions exempting Western-UGP from certain withdrawal obligations reflect Western-UGP's status as a federal power marketing agency, with obligations under federal law and regulations that require Western-UGP to withdraw without penalty if a change by SPP causes Western-UGP to become out of compliance with its obligations. Likewise, we find that the proposed provisions governing the withdrawal obligations of Basin Electric and Heartland reflect that their membership in SPP is dependent on Western-UGP's membership. In addition, the withdrawal obligations for the Integrated System Parties are similar to provisions the Commission accepted to facilitate the integration of the Nebraska Entities into SPP.[216] Therefore, we find that the proposed withdrawal obligation provisions are just and reasonable.

137. However, we note that SPP filed the Western-UGP Amendment, the Basin Electric Amendment, and the Heartland Amendment as exhibits to the SPP Transmittal and not as tariff amendments to the Membership Agreement. These Amendments must be on file with the Commission as part of the Membership Agreement.[217] Therefore, we direct SPP to submit a compliance filing, within 30 days of the date of this order, incorporating the Western-UGP Amendment, the Basin Electric Amendment, and the Heartland Amendment as part of the Membership Agreement.

F. Hearing and Settlement Judge Procedures

138. With the exception of the issues discussed above, our preliminary analysis indicates that SPP's proposed revisions to its Governing Documents have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. With the exception of the issues discussed above, SPP's proposed revisions raise issues of material fact that cannot be resolved based on the record before us and that are more appropriately addressed in hearing and settlement judge procedures. Therefore, with the exception of the matters addressed summarily above, we will set these matters for a trial-type evidentiary hearing. Accordingly, we conditionally accept in part and suspend for a nominal period, to become effective as

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[216] *See Southwest Power Pool*, *Inc*., 125 FERC ¶ 61,239 (2008).

[217] In the Nebraska Entities' proceeding, Docket No. ER08-1601-000, which preceded eTariff, SPP submitted each Nebraska Entity's amendment to the Membership Agreement as SPP Tariff sheets, with designations.

requested,[218] subject to refund, and reject in part, SPP's proposed revisions to the Governing Documents. Given the common issues of fact and law in SPP's proposed Tariff revisions in Docket Nos. ER14-2850-000 and its proposed revisions to the Bylaws and Membership Agreement in Docket No. ER14-2851-000, we will consolidate these two proceedings for purposes of settlement, hearing, and decision.

139. While we are setting these matters for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[219] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[220] The settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

The Commission orders:

(A) SPP's proposed revisions to the Governing Documents are hereby conditionally accepted in part and rejected in part, and accepted and suspended for a nominal period, to become effective November 10, 2014 and October 1, 2015, as requested, subject to refund, as discussed in the body of this order.

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[218] SPP requests waiver of the Commission's prior notice requirement because the effective date proposed for the Tariff revisions is more than 120 days after the submission of its filing. Transmittal at 49 (citing 18 C.F.R. § 35.3(a)(1) (2014)). We grant waiver of the prior notice requirement for good cause shown.

[219] 18 C.F.R. § 385.603 (2014).

[220] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges available for settlement proceedings and a summary of their background and experience (http://www.ferc.gov/legal/adr/avail-judge.asp).

(B) SPP is hereby directed to submit a compliance filing within 30 days of the issuance of this order, as discussed in the body of this order.

(C) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure, and the regulations under the Federal Power Act (18 C.F.R. Part I), a public hearing shall be held concerning Puget's tariff revisions. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (D) and (E) below.

(D) Pursuant to Rule 603 of the Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2014), the Chief Administrative Law Judge is directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

(E) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and with the Chief Judge on the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(F) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such a conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Rules of Practice and Procedure.

(G) Docket Nos. ER14-2850-000 and ER14-2851-000 are hereby consolidated for purposes of settlement, hearing, and decision.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.