153 FERC ¶ 61,051
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Southwest Power Pool, Inc. — Docket Nos. ER14-2850-001, ER14-2851-001

ORDER ON REHEARING AND CLARIFICATION

(Issued October 15, 2015)

1. On November 10, 2014, the Commission conditionally accepted in part, rejected in part, and established hearing and settlement judge procedures with regard to Southwest Power Pool, Inc.'s (SPP) proposed revisions to its Open Access Transmission Tariff (Tariff), Bylaws, and Membership Agreement (collectively, Governing Documents). SPP's proposed revisions were to facilitate the decision of the U.S. Department of Energy, 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),[1] to integrate into SPP.[2] As discussed below, we deny the requests for rehearing and grant in part and deny in part the requests for clarification of the Commission's November 2014 Order.

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[1] The Integrated System Parties together jointly own and operate a significant portion of the bulk electric transmission system in the Upper Great Plains region of the United States.

[2] *Sw. Power Pool, Inc.*, 149 FERC ¶ 61,113, at P 2 (2014) (November 2014 Order).

I. **Background**

A. **Procedural History**

2. On September 11, 2014, pursuant to section 205 of the Federal Power Act (FPA),[3] SPP submitted a number of changes to its Governing Documents to allow the Integrated System Parties to join SPP as transmission owning members, place their respective transmission facilities under the functional control of SPP, and begin taking transmission service under the SPP Tariff. First, SPP proposed a Federal Service Exemption that would permanently exempt Western-UGP from congestion and marginal losses settlements for transmission usage over the facilities in SPP's new pricing zone, Zone 19, to deliver the output from Western-UGP's federal power resources to meet its Statutory Load Obligations.[4] The Federal Service Exemption also exempts Western-UGP from the Schedule 11 regional postage stamp rate,[5] for transmission service it takes to deliver the output from its federal power resources to meet its Statutory Load Obligations.

3. Second, with regard to transitioning the Integrated System Parties into SPP's regional transmission planning process, SPP proposed modifying the definition of "Base Plan Upgrade" in Schedule 11 of its Tariff. The modification reflected the intention of SPP and the Integrated System Parties to set the proposed integration date of October 1, 2015 as a bright line date delineating when regional cost sharing would begin between SPP and the Integrated System Parties for base plan upgrades.[6]

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[3] 16 U.S.C. § 824d (2012).

[4] SPP proposed 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.

[5] The Schedule 11 regional postage stamp rate funds expansion of the SPP transmission system. SPP September 11, 2014 Transmittal at 3, 11, 30.

[6] *Id*. at 20.

4. Third, SPP proposed a co-supply arrangement to enable load-serving entities to maintain their current practice of providing supplemental power supplies to Western-UGP's preference power customers using network service. Under this proposal, Western-UGP will 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 will also take network service, designating the remainder of the load at the same point of delivery as their network load.[7] SPP also proposed revisions to Schedule 12 of the Tariff, which is the schedule SPP uses to recover the FERC assessment from transmission customers, as well as modifications to its generator interconnection procedures.

5. Finally, SPP proposed limited revisions to its Bylaws and Membership Agreement to facilitate integration of the Integrated System Parties into SPP. According to SPP, integration of Western-UGP, Basin Electric, and Heartland into its 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.[8]

6. In the November 2014 Order, the Commission summarily decided a number of issues, including the following: the Federal Service Exemption, co-supply arrangement, base plan upgrades, the FERC assessment, generator interconnection procedures, and the Bylaws and Membership Agreement. With respect to all other issues, the Commission found that SPP's proposed revisions to the Governing Documents had not been shown to be just and reasonable and set them for hearing and settlement judge procedures.[9] In addition, the Commission found that concerns regarding pancaked transmission rates were outside the scope of the proceeding, and that concerns regarding the facilities of Corn Belt Power Cooperative (Corn Belt) and Central Power Electric Cooperative (Central Power) were premature because those facilities had not yet been transferred to SPP. Thus, the issues of pancaked rates and the Corn Belt/Central Power facilities were not included in the ongoing hearing and settlement judge procedures.[10]

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

[8] *Id*. at 2.

[9] November 2014 Order, 149 FERC ¶ 61,113 at P 17.

[10] *Id*. P 113.

B. Description of Integrated System Parties and Integrated System

7. The U.S. Department of Energy's 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 U.S. Department of the Interior's Bureau of Reclamation and the U.S. Army Corps of Engineers.[11] 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 it markets federally generated hydroelectric power in the Pick-Sloan Missouri-Basin Program-Eastern Division of Western.[12] Western-UGP has entered into long-term firm electric service contracts for widespread distribution of federal hydroelectric generation to project use and preference customers.[13]

8. 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. Basin Electric was organized by its members to be an "all supplemental requirements" power supplier, and its purpose is to provide power and energy to its members in excess of preference power provided to them through Western-UGP's allocations.[14]

9. 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.

10. The Integrated System is the backbone of the bulk electric transmission system across seven states in the Upper Great Plains region consisting of approximately

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[11] SPP September 11, 2014 Transmittal at 4.

[12] *Id*. at 5.

[13] *Id*. 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)).

[14] *Id*. at 6.

9,500 miles of transmission lines rated 115 kV through 345 kV. Spanning the Eastern and Western Interconnections of the U.S. electric grid, the Integrated System includes the combined transmission facilities of Western-UGP, Basin Electric and Heartland.[15] It also includes, through facility credits, facilities owned by Northwestern Energy and Missouri River Energy Services. According to SPP, 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.[16]

II. Requests for Clarification and/or Rehearing

11. On December 10, 2014, timely requests for rehearing and/or clarification of the November 2014 Order were filed by SPP, Midcontinent Independent System Operator, Inc. (MISO), Otter Tail Power Company (Otter Tail), and the State Corporation Commission of the State of Kansas (Kansas Commission). Answers to the requests for rehearing and/or clarification were filed by Montana-Dakota Utilities Co. (Montana-Dakota Utilities), Western-UGP, SPP, and Basin Electric.

III. Discussion

A. Procedural Issues

12. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d)(1) (2015), prohibits answers to a request for rehearing. Therefore, we reject the answers to the requests for rehearing submitted by Montana-Dakota Utilities, Western-UGP, SPP, and Basin Electric.

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[15] 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 Integrated Marketplace. *Id*. at 7.

[16] *Id*.

B. Substantive Issues

1. Federal Service Exemption

a. November 2014 Order

13. In the November 2014 Order, the Commission accepted SPP's proposal to establish a Federal Service Exemption for the delivery of Western-UGP's resources to its Statutory Load Obligations.[17] The Commission explained that Congress provided a statutory framework in section 1232 of the Energy Policy Act of 2005 (EPAct 2005) for federal power authorities, such as Western-UGP, to place their transmission systems under the functional control of an RTO, but within and subject to specific limitations.[18] Moreover, in the November 2014 Order, the Commission recognized that Western-UGP had 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 that Western-UGP did not have authority to meet its customers' load growth. For these reasons, the Commission concluded that Western-UGP's Statutory Load Obligations will not grow.[19]

14. The Commission also found that under SPP's proposal, the integration of Western-UGP's resources into SPP would bring benefits to all parties involved. 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.[20]

b. Requests for Rehearing

15. The Kansas Commission requests rehearing of the Commission's unconditional acceptance of SPP's proposal to establish a Federal Service Exemption for the delivery of

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[17] The Federal Service Exemption does not apply to other transactions by Western-UGP and the other Integrated System Parties under the Tariff and, therefore, does not apply to purchases or sales into the SPP Integrated Marketplace. November 2014 Order, 149 FERC ¶ 61,113 at P 18 (citing SPP September 11, 2014 Transmittal at 14, 31).

[18] *Id*. PP 48, 49 (citing section 1232(b)-(d) of EPAct 2005).

[19] *Id*. P 50.

[20] *Id*. P 53.

Western-UGP's federal resources to its statutory load obligations.[21] The Kansas Commission argues that its expert testimony regarding the net benefits of the incorporation of the Integrated System Parties contradicts the conclusions on which the November 2014 Order relies. Accordingly, the Kansas Commission contends that the Commission should grant rehearing and establish hearing procedures to determine what net benefits, if any, will exist upon the integration of the Integrated System Parties.[22]

16. Specifically, the Kansas Commission asserts that when the Commission accepted SPP's Federal Service Exemption that included economic concessions imposed by SPP on its participants, transmission customers and, ultimately, its retail customers, the Commission relied upon the testimony of SPP witness Carl Monroe and a benefits study that SPP never made public. The Kansas Commission asserts that the Commission gave undue weight to SPP's expert testimony over the testimony of the Kansas Commission's witness, John Bell, without examining the actual economic studies underlying the claims of benefits and without conducting an evidentiary hearing.[23] According to the Kansas Commission, the November 2014 Order mischaracterizes and rejects its witness' analysis that the benefits claimed by SPP ignore the costs of the concessions that SPP extended to the Integrated System Parties to join SPP and, thereafter, imposed upon SPP's pre-integration members. Because the Commission did not address the deficiencies in SPP's claims of "net benefits," the Kansas Commission contends that the November 2014 Order lacks any substantial evidentiary support and reasoned decision-making.[24]

17. The Kansas Commission asserts that when the Commission considered the proposal of Entergy Operating Companies (Entergy) to join MISO, the Commission analyzed the MISO-Entergy integration proposal in light of cost causation principles.[25] In contrast, the Kansas Commission argues that the Commission did not evaluate whether or how the SPP proposal complies with or implements cost causation principles. The Kansas Commission asserts that the Commission instead relied upon the SPP study, without considering the Kansas Commission's equally credible testimony that controverts

[21] Kansas Commission Rehearing Request at 1.

[22] *Id*. at 2-7.

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

[24] *Id*. at 5-9.

[25] *Id*. at 11-12 (citing *Midwest Indep. Transmission Sys. Operator, Inc.* 139 FERC ¶ 61,056, at P 182 (MISO-Entergy Integration Order), *order on reh'g*, 141 FERC ¶ 61,128 (2012) (MISO-Entergy Integration Rehearing Order)).

the conclusions of the SPP study.[26] According to the Kansas Commission, its expert testimony concluded that "when the true cost of this transaction to current SPP members is revealed, the transaction metrics fall terribly negative, from a positive $219 million . . . to a very negative ($140) million . . . ."[27] The Kansas Commission asserts that the Commission failed to address the numerous genuine issues of material fact, ignored or dismissed the undisputed record evidence and incorrectly concluded that the Kansas Commission had neglected to "consider the benefits that the rest of the SPP membership will receive from the Integrated System Parties' legacy systems."[28]

18. The Kansas Commission asserts that where a non-jurisdictional public power entity proposes to join an RTO, the Commission's precedent is to conduct a case-by-case analysis of the proposal.[29] The Kansas Commission asserts that in the November 2014 Order, the Commission failed to address the substantial contentions of parties opposing SPP's claims of the benefits of the Federal Service Exemption.[30] The Kansas Commission contends that the Commission instead relied upon EPAct 2005 section 1232 as the rationale for foregoing any material examination of the impact of SPP's proposal, rather than requiring additional review of SPP's proposed transitional arrangements. Moreover, the Kansas Commission argues that the Commission abdicated its responsibility to ensure that the rates resulting from the proposal are just and reasonable to all affected interests. The Kansas Commission asserts that the Commission ignored the testimony of the Kansas Commission's expert witness that the Federal Service Exemption would result in Western-UGP receiving unreasonably large economic benefits. The Kansas Commission estimated that the benefit to Western-UGP from the Federal Service Exemption resulted in an annual "free rider" subsidy amounting to between $15 million and $24 million.[31]

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[26] *Id*. at 7, 12-13.

[27] *Id*. at 13 (citing Bell Testimony at 4-5).

[28] *Id*. at 14 (citing November 2014 Order, 149 FERC ¶ 61,113 at P 75).

[29] *Id*. at 19 (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 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001)).

[30] *Id*. at 20 (citing *La. PSC v. FERC*, 184 F.3d 892, 895 (D.C. Cir. 1999); *Cajun Elec. Pwr. Coop v. FERC*, 28 F.3d 173, 178-179 (D.C. Cir. 1994)).

[31] *Id*. at 21.

c. **Commission Determination**

19. We deny the Kansas Commission's request for rehearing. The Commission's acceptance of the Federal Service Exemption was based on its policy of promoting membership in RTOs[32] and the authority granted by Congress under section 1232 of EPAct 2005 that provided a statutory framework to encourage the transfer of control of transmission facilities to and participation by a federal power marketing authority in an RTO.[33] Further, the Commission's acceptance of the Federal Service Exemption was based upon the Commission's determination that the Federal Service Exemption is consistent with Western-UGP's interpretation of its statutory authorities and limitations, and that it is narrowly drawn to apply only to the delivery of resources from Western-UGP to its statutory load customers to maintain its statutory responsibilities. Consistent with these considerations and the evidentiary record in this proceeding, the Commission found that the Federal Service Exemption is a central component of the integration of Western-UGP with SPP.[34]

20. We are not persuaded by the Kansas Commission's argument that the Commission ignored the testimony of the Kansas Commission's expert witness challenging SPP's claims of the benefits of its proposal, and erred by not setting the Federal Service Exemption for hearing. Contrary to the assertions of the Kansas Commission, a protested proceeding, even with competing testimony, need not necessarily be set for hearing and settlement judge procedures.[35] Rather, the Commission enjoys "wide discretion in determining the probative weight to be given the opinion testimony of expert witnesses, and may substitute its own expert opinion."[36] Here, the Commission decided the issue of

[32] November 2014 Order, 149 FERC ¶ 61,113 at PP 48-50.

[33] 42 U.S.C. § 16431.

[34] November 2014 Order, 149 FERC ¶ 61,113 at PP 48, 50.

[35] *Blumenthal v. FERC*, 613 F.3d 1142, 1145 (D.C. Cir. 2010) (finding that even where there are disputed factual issues, the Commission does not need to conduct an evidentiary hearing if it can adequately resolve the issues on a written record); *Southern California Edison Co.*, 109 FERC ¶ 61,086, at P 38 (2004) (finding that "[t]he Commission may properly deny an evidentiary hearing if the issues, even disputed issues, may be adequately resolved on the written record, at least where there are no issues of motive, intent, or credibility").

[36] *Williston Basin Interstate Pipeline Co.*, 68 FERC ¶ 61,357, at 62,432 (1994) (citing *Market Street Ry. Co. v. Railroad Comm'n of the State of Cal.*, 324 U.S. 548 (1945)).

the Federal Service Exemption based on the entirety of the written record. In addition, the Commission took into account its statutory authority and the policy directives of section 1232 of EPAct 2005, and concluded that there was sufficient evidence in the record to adequately resolve the issues raised in this proceeding and make a determination on the merits of SPP's proposal. Accordingly, the Commission's determinations on the merits of the Federal Service Exemption obviated any need for an evidentiary hearing on the Federal Service Exemption.[37]

21. In granting the Federal Service Exemption, the Commission relied in part on SPP's representation that stakeholders are expected to receive over $334 million in total net benefits as a result of the Integrated System Parties integration into SPP. In reaching this determination, the Commission considered the expert testimony and the summary of the benefits study provided by SPP.[38] Although the Kansas Commission submitted an economic analysis of the proposal, the Kansas Commission used SPP's analysis as a baseline and only added costs for exemptions from Schedule 11.[39] The Kansas Commission did not include any additional benefits of the integration (e.g., benefits to existing SPP members throughout the RTO from the use of the Integrated System Parties' system). In the November 2014 Order, the Commission found that the economic study submitted by SPP provided a more balanced analysis and demonstrated that the proposed integration would provide substantial benefits to all parties.[40] Among the benefits identified by SPP are the creation of increased efficiency and reliability for the newly-combined RTO, which are expected to increase the ability of SPP to commit and dispatch

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[37] *Sw. Power Pool, Inc.*, 137 FERC ¶ 61,075, at P 84 (2011) (Highway/Byway Rehearing Order) (citing *Blumenthal v. FERC*, 613 F.3d 1142 at 1145(finding that even where there are disputed factual issues, the Commission does not need to conduct an evidentiary hearing if it can adequately resolve the issues on a written record)); *see also*, *Ark. Elec. Energy Consumers v. FERC*, 290 F.3d 362, 369-70 (D.C. Cir. 2002); *Moreau v. FERC*, 982 F.2d 556, 568 (D.C Cir. 1993)).

[38] November 2014 Order, 149 FERC ¶ 61,113 at PP 50, 52-53.

[39] Specifically, the Kansas Commission included a pre-2015 Schedule 11 exemption for all of the Integrated System Parties and a post-2015 Schedule 11 Federal Service Exemption for Western-UGP. Kansas Commission October 9, 2014 Protest, Testimony of John Bell at 4-5. As the Commission noted in the November 2014 Order, the Kansas Commission's estimate of costs and benefits was thus largely attributable to the inclusion of costs for the recovery of legacy base plan upgrades that SPP did not include in its estimate. November 2014 Order, 149 FERC ¶ 61,113 at n.81.

[40] *Id.* P 53.

all generation affecting the west to east flows and the north to south flows on the western edge of SPP. Moreover, according to SPP, these benefits are expected to increase the availability of lower-priced energy throughout the region through reduced curtailment of generation.[41] Thus, the Commission concluded that the economic analysis provided by SPP was sufficient for the Commission to make a determination on the merits,[42] and to support the Commission's acceptance of this proposal.

2. Base Plan Upgrades

a. November 2014 Order

22. In the November 2014 Order, the Commission accepted SPP's proposal for regional charges for base plan upgrades collected under Schedule 11 of the SPP Tariff.[43] Under SPP's proposal, the planned integration date of October 1, 2015 served as the bright line date delineating when regional cost sharing would begin between SPP and the Integrated System Parties. The Integrated System Parties' existing systems, as well as any planned transmission facilities with a need-by date prior to October 1, 2015, would continue to be funded by the Integrated System Parties. Similarly, SPP's legacy system and base plan upgrades with a need-by date prior to October 1, 2015 would continue to be funded by the current SPP membership. Transmission projects in both the SPP and Integrated System Parties' footprints with a need-by date on or after October 1, 2015 would 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 SPP Tariff. In addition, the Commission accepted SPP's proposal to modify the definition of "Base Plan Upgrade" in the Tariff to reflect this bright line date and to provide that facilities identified in a new Schedule 2 to Attachment J in the Tariff will be deemed base plan upgrades.[44]

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[41] November 2014 Order, 149 FERC ¶ 61,113 at n.83 (citing Ex. No. SPP-12).

[42] *Southern California Edison Co*., 109 FERC ¶ 61,086 at P 38 (finding that "[t]he Commission may properly deny an evidentiary hearing if the issues, even disputed issues, may be adequately resolved on the written record, at least where there are no issues of motive, intent, or credibility") (citing *Texaco Inc. v. FERC*, 148 F.3d 1091, 1100 (D.C. Cir. 1998)).

[43] November 2014 Order, 149 FERC ¶ 61,113 at PP 72-77.

[44] According to Schedule 2 of Attachment J, Basin Electric will own all facilities listed in Schedule 2 of Attachment J.

b. Requests for Rehearing

23. MISO, Otter Tail, and the Kansas Commission seek rehearing of the Commission's acceptance of SPP's base plan upgrade and regional cost sharing proposal. MISO and Otter Tail argue that permitting SPP to classify certain Basin Electric projects as base plan upgrades, thereby granting them regional cost sharing, violates the Commission's cost causation precedent, is unduly discriminatory, and is not supported by substantial evidence. Moreover, MISO asserts that the courts require "all approved rates [to] reflect to some degree the costs actually caused by the customer who must pay them,"[45] and that the courts evaluate the Commission's compliance with this principle by "comparing the costs assessed against a party to the burdens imposed or other benefits drawn by that party."[46] MISO requests that the Commission hold an evidentiary hearing to determine material issues of disputed fact regarding the classification of Basin Electric projects as base plan upgrades.[47] Otter Tail argues that the Commission should reject the proposal to classify the Basin Electric projects as base plan upgrades unless or until proper study and determinations are made in compliance with SPP's Tariff and Commission policy.[48] The Kansas Commission focuses its request for rehearing on SPP's proposal regarding legacy projects and raises many of the same evidentiary and legal arguments that MISO and Otter Tail raise in support of their requests for rehearing.

24. MISO contends that recent Commission precedent regarding the MISO and Entergy integration highlights the appropriate treatment of "legacy" facilities for cost allocation purposes following an integration.[49] According to MISO, in order to prevent unfair subsidization of the costs of projects required to make Entergy's transmission infrastructure comparable to that of MISO's historical footprint, MISO and its transmission owners proposed a five-year transition period with two separate planning areas: one for MISO's historical footprint and one for Entergy's footprint. According to

[45] MISO Rehearing Request at 10 (citing *KN Energy v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

[46] *Id*. (citing *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009)).

[47] *Id*. (citing *Cajun Elec. Power Coop., Inc. v. FERC*, 28 F.3d 173, 177, 307 (D.C. Cir. 1994)).

[48] Otter Tail Rehearing Request at 11.

[49] MISO Rehearing Request at 11 (citing MISO-Entergy Integration Order, 139 FERC ¶ 61,056, *order on reh'g*, MISO-Entergy Integration Rehearing Order, 141 FERC ¶ 61,128).

MISO, for the duration of this transition period, upgrades proposed solely within one of these planning areas would be allocated only to that area.[50] MISO contends that while the November 2014 Order acknowledges that it would be inappropriate to require cost-sharing for legacy transmission systems, the Commission uncritically adopted SPP's proposed "need-by" date to define such legacy facilities. According to MISO, the Commission's adoption of this date is not supported by substantial evidence and appears to have been negotiated by the parties.[51] MISO contends that SPP's statements and arguments made throughout the proceeding confirm that there is no principled difference between the Basin Electric Schedule 2 projects and other legacy projects.

25. MISO argues that if the Integrated System Parties needed the Basin Electric Schedule 2 projects regardless of their decision to join SPP, then those projects should be considered legacy projects. MISO asserts that the Commission's Schedule 2 analysis is inadequate in light of extensive evidence presented by MISO. Such evidence includes regulatory application filings and orders from state regulatory commissions that, MISO contends, demonstrate that the costs of the Schedule 2 projects were approved by Basin Electric independent of whether the Integrated System Parties would join an RTO. MISO further asserts that evidence it submitted indicates that the Schedule 2 projects were intended to benefit primarily Basin Electric's own system rather than serve any regional needs.[52]

26. MISO argues that the November 2014 Order fails to acknowledge and respond meaningfully to these findings in its analysis.[53] MISO and Otter Tail contend that, at a minimum, it is clear that the Basin Electric Schedule 2 projects were well advanced in the planning process even before the Integrated System Parties decided to join SPP.

[50] *Id*. at 12 (citing MISO-Entergy Integration Rehearing Order, 141 FERC ¶ 61,128 at P 6).

[51] *Id*. (citing SPP September 11, 2014 Ex. No. SPP-8 at 7).

[52] Among other evidence, MISO points to a 2011 North Dakota Public Service Commission transmission siting order noting that Basin Electric members needed one of the Basin Electric projects to provide access to base load generation to serve increasing load in their service areas, as well as to address grid reliability issues in northwestern North Dakota and eastern Montana largely caused by development within the Bakken oil field. *Id.* at 13-14 (citing North Dakota Public Service Commission Siting Order, Finding of Fact at P 4).

[53] *Id.* at 14 (citing *PSEG Energy Res. & Trade LLC v. FERC*, 665 F.3d 203, 209 (D.C. Cir. 2011)).

According to MISO, the Commission previously approved tariff filings to exclude such proposed, but well-advanced, projects from regional cost allocation, and the Court of Appeals for the District of Columbia Circuit sustained the Commission's decision to exclude certain previously planned, but not yet constructed, projects from MISO's regional cost allocation for reliability projects.[54] MISO states that the court found that it is not unreasonable to exclude such projects from regional cost allocation, even if they have regional benefits, simply due to their advanced planning stage.

27. Additionally, MISO argues that there is no rational basis to support the Commission's conclusions regarding the findings in the SPP Transmission Working Group study regarding the Basin Electric projects. MISO contends that the Transmission Working Group study did not look at regional benefits or regional needs for the Integrated System expansions; rather, it looked only at whether the Integrated System itself needed those expansions.[55] Moreover, both MISO and Otter Tail assert that the Basin Electric projects were not evaluated pursuant to the SPP Transmission Expansion Plan.[56] According to MISO, even if the SPP region receives an incidental benefit from the Basin Electric projects, because it did not follow the SPP Transmission Expansion Plan process, SPP failed to consider alternatives that could provide the rest of its footprint (i.e., load outside of North Dakota) with a less expensive alternative to the Basin Electric projects. MISO contends that by implying that the Transmission Working Group study was a regional study, SPP misled the Commission into a faulty "bootstrap" analysis: "[b]ecause the new member's system needs reliability upgrades in service after its facilities become RTO facilities, the upgrades must be regional."[57] Thus, MISO asserts that the Commission misapprehended the Transmission Working Group study and incorrectly concluded that the Basin Electric Schedule 2 projects met regional reliability needs. MISO contends that because the Commission included the Basin Electric Schedule 2 projects in regional cost allocation, the determinations in the November 2014 Order are arbitrary and capricious.[58]

[54] *Id*. at 15 (citing *Pub. Serv. Comm'n of Wis. v. FERC*, 545 F.3d 1058, 1065-66 (D.C. Cir. 2008)).

[55] *Id*. at 15.

[56] *Id*.; Otter Tail Rehearing Request at 10.

[57] MISO Rehearing Request at 16 (citing *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983)).

[58] *Id*.

28. MISO and Otter Tail assert that SPP's proposed regional cost allocation for the Basin Electric projects is inconsistent with SPP's cost allocation methodology and provides an unjustified exception from Tariff procedures.[59] Moreover, MISO argues that under the SPP Tariff, evaluation in the SPP Transmission Expansion Plan process is a key threshold condition for a transmission upgrade to qualify as a base plan upgrade and be deemed eligible for regional cost allocation. MISO states that the SPP Tariff defines "Base Plan Upgrade" in relevant part as "upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure reliability of the [SPP] Transmission System."[60] MISO and Otter Tail point out that, as the November 2014 Order acknowledged, the Basin Electric Schedule 2 projects were not included in or constructed pursuant to the SPP Transmission Expansion Plan, nor were they vetted under the SPP Transmission Expansion Plan process. Further, MISO notes that neither the November 2014 Order nor SPP's filing point to any provision in SPP's transmission planning processes that would permit *ad hoc* studies to replace SPP's normal procedures, in order to facilitate the admission of new transmission-owning members.[61] Accordingly, MISO and Otter Tail assert that the Basin Electric Schedule 2 projects are "legacy" projects that were planned and approved well before Western-UGP officially announced its decision to join SPP.[62]

29. MISO states that the November 2014 Order suggests that the Commission's acceptance of the proposed Basin Electric Schedule 2 projects as base plan upgrades is consistent with the Commission's prior decision involving the integration of certain Nebraska public power utilities into SPP.[63] MISO contends that the Nebraska precedent is inapposite. MISO points out that, in the Nebraska case, no parties objected to the proposal, which the Commission accepted by delegated letter order. Thus, MISO argues that the proceeding was never subject to judicial review.[64] By contrast, in the instant proceeding, MISO emphasizes that several parties objected to SPP's proposed

[59] *Id*. at 17; Otter Tail Rehearing Request at 10.

[60] MISO Rehearing Request at 17 (citing SPP Tariff, section 1.1, definitions—B).

[61] *Id*. at 17-18.

[62] *Id*. at 17; Otter Tail Rehearing Request at 10-11.

[63] MISO Rehearing Request at 18 (citing November 2014 Order, 149 FERC ¶ 61,113 at P 73).

[64] *Id*. (citing *Sw. Power Pool, Inc.*, Docket No. ER09-254-000 (Jan. 27, 2009) (delegated letter order)).

classification of the Basin Electric Schedule 2 projects as base plan upgrades, and these objections warrant further review of the proposal. Additionally, MISO contends that the Nebraska case is of limited precedential value because it preceded SPP's adoption of the Highway/Byway cost allocation methodology,[65] which sets forth criteria governing what constitutes base plan upgrades in the SPP region.[66]

30. MISO also asserts that the November 2014 Order fails to address MISO's "notification to construct" arguments, which MISO argues apply even if the Basin Electric Schedule 2 projects are deemed base plan upgrades.[67] MISO notes that section III.A.2 of Attachment J of the SPP Tariff provides that base plan upgrades that received a "notification to construct" from SPP prior to the effective date of the Highway/Byway methodology would not be eligible for 100 percent regional cost allocation, including facilities rated at 300 kV and higher voltages. Thus, MISO argues that even if Basin Electric's listed Schedule 2 345 kV projects are "deemed" to be base plan upgrades, they should still not be included in 100 percent regional cost allocation to the extent they obtained an equivalent of SPP's "notification to construct" prior to the October 1, 2015 integration date.[68] MISO contends that the November 2014 Order makes no finding with respect to the applicability of this provision.

31. The Kansas Commission requests rehearing of the Commission's determination that the Integrated System Parties have no cost responsibility for the legacy SPP-approved and regionally-funded transmission projects having a "need-by" date before October 1, 2015. According to the Kansas Commission, Commission precedent requires that a utility should bear cost responsibility for projects that were planned or authorized prior to the new member joining the RTO, in part, because "the new member may

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[65] Under the Highway/Byway methodology, SPP allocates the costs of transmission facilities on a voltage threshold basis. For facilities at 300 kV or above, SPP allocates costs on a regional, postage stamp basis. For facilities between 100 kV and 300 kV, SPP allocates 33 percent of costs on a regional basis and 67 percent of costs to the zone in which the facilities are located. For facilities at or below 100 kV, SPP allocates costs on a zonal basis. *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010) (Highway/Byway Order), *reh'g denied*, 137 FERC ¶ 61,075 (2011) (Highway/Byway Rehearing Order).

[66] MISO Rehearing Request at 18.

[67] *Id*. (citing MISO Protest at 14-15).

[68] *Id*. MISO notes that the SPP Tariff defines the term "notification to construct" within the context of the SPP Transmission Expansion Plan process. *Id*. n.54.

nevertheless use and benefit from the new facilities in the future."[69] The Kansas Commission also asserts that the Commission erred in the November 2014 Order because it did not consider that the costs current SPP members will bear from the Integrated System integration are grossly disproportionate to the benefits that the Integrated System Parties will receive from such cost sharing. Finally, the Kansas Commission protests the Commission's failure to establish hearing procedures regarding the study upon which SPP relied to support its assertions.[70]

32. The Kansas Commission asserts that the Commission attempted to justify its acceptance of the Integrated System proposal with the statement that "[t]here is no clear one-size fits-all just and reasonable approach for such an integration," and that "the proposal must respect both the principle of cost causation and the practical realities of a transition."[71] The Kansas Commission asserts that the Commission relies on SPP's 2008 integration of the Nebraska entities and the MISO-Entergy integration as examples of acceptable approaches for RTOs to manage transmission cost allocation during transitions to expanded RTO footprints. However, the Kansas Commission argues that neither example provides any justification for the Commission's endorsement of SPP's "slaughter of 'the principle of cost causation' on the altar of the 'practical realities' of inducing the [Integrated Systems] Parties to join the SPP."[72] Specifically, the Kansas Commission argues that when the Nebraska entities joined SPP, they immediately began paying their load ratio share of the existing $7 million of regionally-funded projects.[73] In contrast, the Kansas Commission contends that the November 2014 Order accepted SPP's proposal to excuse the Integrated System Parties from paying any part of the $500 million revenue requirement for the regional cost sharing pools for SPP's regionally-funded projects. The Kansas Commission also argues that the analogy to the Nebraska integration fails because it purports to treat SPP transmission customers in 2014 in the same manner as SPP transmission customers in 2008, despite vastly different

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[69] Kansas Commission Rehearing Request at 7 (quoting *American Transmission Service, Inc.*, 140 FERC ¶ 61,266, at P 26 (2012) and citing *FirstEnergy Service Co. v. FERC*, 758 F.3d 346, 354-356 (D.C. Cir. 2014)).

[70] *Id*. at 8.

[71] *Id*. at 10 (quoting November 2014 Order, 149 FERC ¶ 61,113 at P 72).

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

[73] *See Sw. Power Pool, Inc.*, Docket No. ER09-254-000 (Jan. 27, 2009) (delegated letter order).

transmission revenue requirements. The Kansas Commission asserts that this is undue discrimination in favor of the Integrated System Parties.[74]

33. The Kansas Commission argues that the November 2014 Order dismissed, without reasoned analysis, its testimony challenging SPP's proposed use of the October 1, 2015 integration date as the starting date for cost-sharing of the SPP legacy projects. According to the Kansas Commission, in the November 2014 Order, the Commission stated that the Kansas Commission's evidence "neglect[ed] to consider the benefits that the rest of the SPP membership will receive from the Integrated System Parties' legacy system." The Kansas Commission argues that, even if it did accept SPP's claimed "benefits" for the sake of argument, the economic impact of the proposal would have a negative impact of over $140 million over ten years.[75] The Kansas Commission asserts that even though it properly raised these genuine issues of material fact, the Commission incorrectly concluded that the benefits of the legacy systems were relevant. Moreover, the Kansas Commission asserts that each member's legacy system is included in the Tariff and that these costs are paid for only by that zone's customers.[76] In contrast, the Kansas Commission contends that the SPP regionally-funded projects, which are those projects constructed by SPP between 2005 and the present, are included in the SPP Tariff at Attachment H. The Kansas Commission argues that the Integrated System Parties should pay for their legacy projects, just like every other zone, and that the Integrated System Parties should share the cost responsibility for SPP regionally-funded projects. The Kansas Commission argues that the Commission erred in not requiring the Integrated System Parties to pay their fair share of the regionally-funded projects, even though they will be entitled to use these facilities in perpetuity.[77]

34. Finally, the Kansas Commission asserts that the Commission erred by relying, in part, upon SPP's Regional Cost Allocation Review process to correct inconsistencies in regional cost sharing. The Kansas Commission contends that this is an informal procedure that is not in the SPP Tariff and was not part of this proceeding. Further, the Kansas Commission argues that there is nothing in the SPP Tariff that would permit the

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[74] Kansas Commission Rehearing Request at 12.

[75] *Id*. at 15.

[76] *Id*. at 16.

[77] *Id.* at 17.

Regional Cost Allocation Review process to supersede express Tariff provisions exempting the Integrated System Parties from bearing regionally-allocated costs.[78]

c. Commission Determination

35. We deny MISO and Otter Tail's requests for rehearing with regard to the appropriate treatment of Basin Electric's Schedule 2 projects. First, the underlying statutory authority and Commission policies that formed the basis for the Commission's acceptance of the Federal Service Exemption also support its acceptance of SPP's base plan upgrade proposal. Second, with respect to base plan upgrades, we find that SPP crafted a reasonable transition proposal for integrating the current SPP and Integrated System transmission systems.

36. In the November 2014 Order, the Commission explained that section 1232 of EPAct 2005 provides a statutory framework for federal power authorities, such as Western-UGP, to place their transmission systems under the functional control of an RTO.[79] The Integrated System transmission system, described by the parties as the backbone of the bulk electric system in the Upper Great Plains region of the United States, includes the combined transmission facilities of Western-UGP, Basin Electric, and Heartland. These facilities were jointly planned, expanded, and operated by the Integrated System Parties to serve their transmission customers[80] and, accordingly, they evolved over a period of many years to function as an interdependent system. The transmission facilities of the Integrated System also have been operated by Western-UGP on behalf of Basin Electric and Heartland.[81] Thus, given the integrated nature and joint planning of the Integrated System, we find that it was reasonable for SPP to treat the Basin Electric Schedule 2 projects as a necessary part of the proposal to integrate Western-UGP into its RTO. For these reasons, we do not view the Basin Electric Schedule 2 projects in isolation; rather, we consider these projects as part of the comprehensive proposal to integrate the Western-UGP system into an RTO.

37. In addition, with respect to base plan upgrades, we find that SPP has crafted a reasonable transition proposal for integrating the current SPP and Integrated System transmission systems. We find that SPP's proposal creates a reciprocal and balanced

[78] *Id*. at 18.

[79] November 2014 Order, 149 FERC ¶ 61,113 at P 48.

[80] SPP September 11, 2014 Transmittal at 7.

[81] Basin Electric October 9, 2014 Comments at 6.

approach, in that both the current SPP membership and the Integrated System Parties will be allocated costs for transmission projects approved through pre-integration transmission planning processes that did not take into account the regional needs over the post-integration, expanded SPP footprint. We emphasize that both the Basin Electric Schedule 2 projects and the SPP projects planned through a pre-integration planning process with post-integration in-service dates will function as part of the expanded, post-integration SPP transmission system, over which transmission service is provided on a regional, single-system basis at a single rate under the SPP Tariff. As such, both the Integrated System Parties and the current SPP membership will gain access to, and receive benefits from, these planned transmission facilities.

38. Under SPP's current rate design, the costs of high voltage facilities such as the Basin Electric Schedule 2 projects are allocated regionally, a rate design SPP proposed—and the Commission approved—in the Highway/Byway proceeding. As part of its support in the Highway/Byway proceeding, SPP conducted a Transmission Distribution Analysis that assessed the responsiveness of different facilities to power transfers among SPP zones, an analysis that incorporated study of SPP's existing transmission system, including facilities pre-dating SPP's regional transmission planning process. The results of the study demonstrated that high voltage facilities were far more responsive to inter-zonal flows than lower voltage facilities.[82] Here, we expect the Basin Electric Schedule 2 projects to function in a similar fashion within the post-integration SPP transmission system and to provide benefits beyond the Integrated System zone. With respect to MISO's argument that the SPP Transmission Working Group study did not support the Commission's acceptance of SPP's base plan upgrade proposal, we also note that, through the Transmission Working Group study, SPP confirmed that the Basin Electric Schedule 2 projects met reliability needs of the Integrated System after the planned integration date, and that these projects, as well as the Integrated System transmission system, met North American Electric Reliability Corporation (NERC) and SPP Criteria standards.[83] Based on these study findings, we find that it was reasonable for SPP to conclude that the Basin Electric Schedule 2 projects were necessary to operate a reliably sound transmission system after the integration date. Accordingly, we find that SPP

[82] Highway/Byway Order, 131 FERC ¶ 61,252 at P 23.

[83] SPP September 11, 2014 Transmittal, Ex. No. SPP-3 at 9 ("SPP conducted a reliability analysis to assess the IS System for potential NERC Transmission Planning ("TPL") 3 violations and for adherence to the SPP Criteria. SPP, following its internal process requested mitigations, as needed, for the potential issues identified and then confirmed that the mitigations provided by the IS Parties addressed the potential issues identified in the reliability analysis.").

designed a just and reasonable transition proposal for transmission facilities necessary to operate a functioning transmission system and providing regional transmission services after the integration date. Moreover, this proposal is consistent with SPP's current rate design affording a single, regional rate for services provided over facilities that provide regional benefits.

39. Additionally, with respect to MISO's argument that the five-year transition proposal for the MISO-Entergy integration is a model to inform the SPP-Integrated System integration proposal, we find that substantive differences exist between these two integrations. For example, in the MISO-Entergy integration, commenters expressed concerns regarding deficiencies in Entergy's transmission infrastructure, including stakeholder complaints alleging that the Independent Coordinator of Transmission for the Entergy system allowed inadequate transmission infrastructure development due to conflicting interpretations of reliability standards.[84] The parties to the MISO-Entergy integration developed the transition proposal, in part, to prevent unfair subsidization of the costs of projects required to make Entergy's transmission infrastructure comparable to MISO's footprint.[85] In contrast, no parties in this proceeding have alleged deficiencies in the current—and planned—Integrated System transmission infrastructure, and in fact SPP confirmed, through the Transmission Working Group study, that the Integrated System infrastructure met NERC and SPP reliability standards. Accordingly, the MISO-Entergy integration approach was tailored to the specific circumstances surrounding that integration, which is consistent with the Commission's view in the November 2014 Order that there is no "one-size fits-all" integration approach.[86] For this reason we also reject MISO's argument that the SPP-Integrated System integration proposal should be rejected because the proposal did not follow the SPP Transmission Expansion Plan or adequately mirror the Highway/Byway transition proposal, specifically that the Basin Electric Schedule 2 projects should not receive 100 percent regional cost allocation because they

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[84] MISO-Entergy Integration Order, 139 FERC ¶ 61,056 at P 3.

[85] MISO Rehearing Request at 11-12.

[86] November 2014 Order, 149 FERC ¶ 61,113 at P 72. In the November 2014 Order, the Commission also pointed to the SPP-Nebraska entities integration as another example of a just and reasonable integration proposal with similarities to the proposal in this proceeding. *Id.* P 73. However, the November 2014 Order did not find that these similarities alone render the SPP-Integrated System proposal just and reasonable. As set forth in the November 2014 Order, the Commission considered a number of factors in its determination to accept SPP's base plan upgrade and regional cost sharing proposal. *See id*. PP 72-76.

obtained an equivalent of SPP's "notification to construct" prior to the October 1, 2015 integration date.[87] Rather, we find that a proposal transitioning to a new cost allocation methodology within a region need not serve as the only just and reasonable approach for the transition of new members and transmission owners into that region.[88] Further, we continue to believe that SPP's base plan upgrade and regional cost sharing proposal, including the parties' agreement to the October 1, 2015 bright line date, is a just and reasonable approach.

40. MISO also takes issue with the Commission's acceptance of the proposed "need-by" date, particularly its use as a bright-line date for cost allocation purposes, and it suggests that the "self-selected" date is a result of negotiations between the parties.[89] MISO does not explain why such a negotiated date was inappropriate. We find no fault with the manner in which the integration date was chosen. On the contrary, we expect parties to a large-scale integration to negotiate the details of that integration, which includes the actual date of the integration and its use as a milestone for transitioning to procedures and cost allocations under a post-integration Tariff. Although cost allocation for the Basin Electric Schedule 2 projects may have been a factor in determining the integration date, other factors also influenced the timing of the integration, including SPP's need for time to conduct studies, discuss and vet the integration in the stakeholder process, seek board and management approvals, seek necessary regulatory approvals, and prepare additional filings.[90] Further, the Commission expects that a new entrant proposal will be the result of a collaborative effort. For example, the Commission recognized that the MISO-Entergy integration proposal represented a negotiated solution consistent with

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[87] MISO Rehearing Request at 17-18.

[88] *Compare* MISO-Entergy Integration Order, 139 FERC ¶ 61,056 (accepting MISO's proposed tariff revisions to establish a transition for the integration of Entergy and its operating companies into MISO as transmission-owning members over a five-year transition period) *with Midwest Indep. Transmission Sys. Operator Inc. and Dairyland Power Coop.*, 131 FERC ¶ 61,187, *order on compliance*, 132 FERC ¶ 61,174, at P 9 (2010) (accepting MISO's proposal to not subject Dairyland Power Cooperative's planned or proposed projects to regional cost allocation and recovery provisions in MISO's tariff).

[89] MISO Rehearing Request at 12.

[90] *See* SPP September 11, 2014 Transmittal, Ex. No. SPP-3 at 4, 17.

previous Commission orders addressing RTO entry.[91] Finally, we reject MISO's assertion that the treatment of the Basin Electric Schedule 2 projects conflicts with the SPP Tariff definition of "Base Plan Upgrade." In this instance, SPP submitted a section 205 filing to amend the definition of "Base Plan Upgrade" to accommodate the SPP-Integrated System integration proposal, which the Commission accepted in the November 2014 Order. We note that amending the definition of "Base Plan Upgrades" in the SPP Tariff is not unprecedented, as this definition has evolved to accommodate key points of transition in the SPP region, as illustrated within the definition itself.[92] For these reasons,

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[91] MISO-Entergy Integration Order, 139 FERC ¶ 61,056 at P 68 (citing *American Transmission Sys., Inc.*, 129 FERC ¶ 61,249, at P 114 (2009) ("We find that given the voluntary nature of RTOs, such a collaborative effort is the most appropriate manner of resolving such cost issues.")).

[92] Section 1.1, Definitions—B, of SPP's Tariff currently defines "Base Plan Upgrade" as the following:

> Those upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System. Base Plan Upgrades shall also include: (i) those Service Upgrades required for new or changed Designated Resources to the extent allowed for in Attachment J to this Tariff, (ii) ITP Upgrades that are approved for construction by the SPP Board of Directors, and (iii) high priority upgrades, excluding Balanced Portfolios, that are approved for construction by the SPP Board of Directors. For Zones 1 through 15, all such upgrades shall specifically exclude planned Transmission System facilities identified in the SPP Transmission Expansion Plan that are: (i) placed in service during the 2005 calendar year or (ii) required to be in service to meet the SPP Criteria and the NERC Reliability Standards for the summer of 2005. For Zones 16, 17, and 18, all such upgrades shall specifically exclude planned Transmission System facilities in those zones identified in the SPP Transmission Expansion Plan Report (2009 – 2018) that are required to be in service to meet the SPP Criteria and the NERC Reliability Standards for the summer of 2008 or which are in operation prior to January 1, 2009, except for those upgrades that are in service prior to January 1, 2009 and are components of Phase 1 of the NPPD 345kV Norfolk to Lincoln (ETR) project or OPPD Sub 1255/3455 Transformer project. Network Upgrades that are components of Phase 1 of the NPPD 345kV Norfolk to Lincoln (ETR) project or OPPD Sub 1255/3455 Transformer project that are in service prior to January 1, 2009 will be

(continued…)

we find that treatment of the Basin Electric Schedule 2 projects does not conflict with SPP Tariff definition of "Base Plan Upgrade," and that as the treatment of base plan upgrades is just and reasonable and necessary for the integration of Western-UGP into an RTO, consistent with the framework established under section 1232 of EPAct 2005.[93]

41. We deny the Kansas Commission's request for rehearing regarding the Integrated System Parties' cost responsibility for SPP regionally-funded legacy facilities. We find that SPP and the Integrated System Parties have crafted a practical, reciprocal cost allocation approach for facilities in service before the integration date that is consistent with Commission precedent. Under this approach, costs for such legacy facilities in the Integrated System region will be allocated to the Integrated System Parties; likewise, costs for legacy facilities in the pre-integration SPP region will be allocated to the pre-integration SPP membership. Essentially, this is a license-plate rate concept, wherein the Integrated System region is treated as one zone and the pre-integration SPP region is treated as another for the purposes of cost allocation for existing facilities within each sub-region. The Commission has found that such license-plate cost allocation methods for existing facilities are just and reasonable because they reflect prior investment decisions and the fact that existing facilities were built principally to support load within the sub-region.[94] With regard to the concerns that the Integrated System Parties' use of the SPP legacy system will be subsidized, we find that the Kansas Commission continues to overlook the fact that the current SPP membership will gain access to and receive reciprocal use of the Integrated System Parties' legacy system and, in this manner, no subsidy exists.

42. Finally, the Kansas Commission takes issue with the Commission relying, in part, upon SPP's Regional Cost Allocation Review process to correct inconsistencies in regional cost sharing. We clarify that the Commission made these statements in reference to SPP's current Tariff procedures specifying review of the Highway/Byway methodology, and the Commission expected SPP to include the Basin Electric Schedule 2

> Base Plan Upgrades, however, the Zonal component of the costs shall be 100 [percent] allocated to the respective host zone.

[93] 42 U.S.C. § 16431.

[94] *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063, at P 3 (2007), *order on reh'g*, Opinion No. 494-A, 122 FERC ¶ 61,082 (2008), *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 473-74 (7th Cir. 2009) (recognizing that the "sunk" costs of existing facilities are expected to be paid for by the customers for which the facilities originally were built and remanding with respect to new facilities).

projects—like any other base plan upgrade—in future reviews of whether inequities exist in SPP's cost allocation methodology, consistent with its Tariff, which may inform future changes to cost allocations.[95]

3. Seams Issues

a. November 2014 Order

43. In the November 2014 Order, the Commission found that parties' arguments about seams issues resulting from the decision of the Integrated System Parties to integrate into SPP raised genuine issues of material fact that could not be resolved based on the record. Therefore, the Commission set seams issues for hearing and settlement judge procedures.[96] However, the Commission found that the issue of the perpetuation of pancaked transmission rates between the Integrated System and MISO, and between SPP and MISO, to be beyond the scope of this proceeding. The Commission also declined to include in hearing and settlement judge procedures the issue raised by Otter Tail and Municipal Energy Agency of Nebraska concerning the facilities of Corn Belt and Central Power, because Corn Belt and Central Power had not yet transferred their facilities to SPP.[97]

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[95] SPP's Regional Cost Allocation Review process, described in section III.D of Attachment J in the SPP Tariff, originated from an "unintended consequences" review process included in SPP's 2005 base plan funding cost allocation proposal. SPP modified this process in the Highway/Byway and Integrated Transmission Plan proceedings. In general, the Regional Cost Allocation Review process requires review of the Highway/Byway methodology and allocation factors at least every three years, authorizes the SPP Regional State Committee to recommend any adjustments to cost allocations if a review shows an imbalanced cost allocation to one or more zones, and enables member companies (beginning in 2015) that believe they have been allocated an imbalanced portion of costs to seek relief from the SPP Markets and Operations Policy Committee. *See Sw. Power Pool, Inc.*, 111 FERC ¶ 61,118, *order on reh'g*, 112 FERC ¶ 61,319 (2005); Highway/Byway Order, 131 FERC ¶ 61,252; Highway/Byway Rehearing Order, 137 FERC ¶ 61,075; *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010).

[96] November 2014 Order, 149 FERC ¶ 61,113 at P 112.

[97] *Id*. P 113.

b. Requests for Clarification or Rehearing

44. Otter Tail seeks clarification or, in the alternative, rehearing of the Commission's November 2014 Order regarding rate pancaking issues. Otter Tail also seeks clarification of whether its concerns that are not exclusive to Central Power's decision about joining SPP and are related to the integration of Integrated System Parties may be subject to hearing and settlement judge procedures.[98] SPP seeks clarification of whether the Commission included section 30.9 of the SPP Tariff in the hearing and settlement judge procedures

45. Otter Tail asserts that its customers may be exposed to overlapping and duplicative rates as a result of integration of the Integrated System Parties into SPP. According to Otter Tail, to the extent that the duplicative transmission rates issue involves a prohibited "rate pancaking," the Commission should clarify this is an issue of just and reasonable rates resulting from the proposed Integrated System Parties' integration, and that it should be addressed through further procedures.[99] Otter Tail argues that this issue arises directly from and falls squarely within the scope of the issues set for hearing, but that clarification is necessary to avoid the risk of parties arguing that the November 2014 Order precluded Otter Tail's customers from seeking relief on this issue.[100]

46. Otter Tail asserts that although the Commission has an obligation under the Administrative Procedures Act (APA) to explain its determinations,[101] the Commission failed to do so in its summary determination that the issues relating to rate pancaking are beyond the scope of this proceeding. Otter Tail asserts that the integration of the Integrated System Parties into SPP, which will change the current RTO boundaries, will introduce the risk of duplicative transmission rates. Otter Tail contends that the Commission must provide a reasoned basis for determining that these issues are beyond the scope of this proceeding in order to satisfy its statutory obligations under the APA.[102]

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[98] Otter Tail Rehearing Request at 1, 7, 11.

[99] *Id*. at 7.

[100] *Id*.

[101] *Id.* at 12 (citing 5 U.S.C. § 557(c)(3)).

[102] *Id.*

47. Otter Tail further asserts that Commission precedent requires the elimination of rate pancaking within RTOs[103] and within the merged systems of neighboring utilities.[104] Otter Tail contends that in the November 2014 Order, the Commission dismissed the fact that the integration of the Integrated System Parties will directly cause rate pancaking within an RTO by potentially layering MISO and SPP rates and requiring customers to pay twice for the same transmission service over the same transmission lines. Otter Tail argues that if the Commission examines the facts raised by Otter Tail and the unique characteristics of the integrated transmission system, it will find that the potential for impermissible rate pancaking exists. According to Otter Tail, in the November 2014 Order the Commission failed to consider this issue in sufficient detail.[105]

48. Otter Tail explains that its native load customers, who are currently taking Network Integrated Transmission Service under the MISO tariff, risk being required to pay both MISO and SPP for service, even though they are within the local balancing authority of Otter Tail (a MISO member) and are Otter Tail's native load customers. According to Otter Tail, this duplication of rates does not currently exist, but it is expected to occur as a direct result of the integration of the Integrated System Parties into SPP. Otter Tail asserts that the Commission cannot simply depart from its precedent regarding the impermissibility of such intra-regional rate pancaking without providing a reasoned explanation. Otter Tail argues that the Commission should grant rehearing and set the issue of rate pancaking with respect to Otter Tail's customers in the Western-UGP balancing authority for hearing and settlement judge procedures.[106]

49. Otter Tail also argues that the Commission should clarify that Otter Tail's concerns that are not exclusive to Central Power membership are not excluded from the hearing and settlement judge procedures.[107] Otter Tail states that the November 2014

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[103] *Id.* at 12-13 (citing *Cal. Indep. System Oper. Corp.*, 147 FERC ¶ 61,231, at P 155 (2014) (citing Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,174-75 ("As a matter of policy, the Commission generally has not required the elimination of inter-RTO rate pancaking, but has required the elimination of intra-RTO rate pancaking."))).

[104] *Id.* (citing *UtiliCorp United Inc. and St. Joseph Light & Power Co.*, 92 FERC ¶ 61,067, at 61,235 (2000) (*UtiliCorp*)).

[105] *Id.* at 13.

[106] *Id.* at 14.

[107] *Id*. at 5.

Order excluded from hearing those issues associated with Central Power joining SPP because Central Power has not proposed to join SPP at this time. However, Otter Tail contends many of the issues it raises concern changes in the seam when Basin Electric and Western-UGP join SPP, because Otter Tail's native load customers in the Western-UGP balancing authority area may be subject to transmission charges from both MISO and SPP for the same service over a common set of transmission lines.[108] Otter Tail explains that in several instances these concerns are not eliminated because Central Power is not joining SPP at this time.[109] Moreover, Otter Tail also explains that once its load within the Western-UGP balancing authority becomes subject to SPP energy market pricing, these native load customers may be subjected to a potential price differential between the energy markets of MISO and SPP. Otter Tail argues that these customers are part of the integrated transmission system of Otter Tail and Central Power. Thus, Otter Tail seeks clarification that these concerns may be subject to hearing and settlement procedures, even if they have some connection to Central Power facilities, as long as they arise as a result of the Integrated System Parties joining SPP.[110]

50. SPP seeks clarification that the aspects of rate pancaking that were set for hearing do not include section 30.9 of the SPP Tariff. SPP asserts that the Commission should clarify that the provisions of section 30.9 are outside the scope of issues in this proceeding because: (i) SPP did not propose any changes to section 30.9; and (ii) no non-Integrated System Party (e.g., Montana-Dakota Utilities) has applied for transmission service or facilities credits under the SPP Tariff. In the alternative, SPP seeks rehearing that the Commission erred by including transmission facilities credits under section 30.9 in the hearing and settlement judge procedures.[111]

c. **Commission Determination**

51. We deny Otter Tail's requests for rehearing as to rate pancaking but grant in part clarification regarding the seams issues. Also, we deny SPP's request for clarification or rehearing of the Commission's determination regarding transmission facilities service credits of section 30.9 of the SPP Tariff.

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[108] *Id*.

[109] *Id*. at 6.

[110] *Id*.

[111] SPP Rehearing Request at 14-16.

52. Otter Tail seeks rehearing of the Commission's determination regarding rate-pancaking that is expected to occur after the Integrated System Parties' system integrates with SPP. Otter Tail is concerned that it will pay both SPP and MISO transmission rates because Otter Tail's native load will use the transmission systems of both MISO and SPP. We reaffirm our determination in the November 2014 Order that the perpetuation of pancaked transmission rates between the Integrated System and MISO, and more generally between SPP and MISO, is beyond the scope of this proceeding. In any event, with respect to Otter Tail's concern that it will pay both SPP and MISO transmission rates because Otter Tail's native load will use the transmission systems of both MISO and SPP, these separate "inter-RTO" transmission charges are consistent with Commission precedent, which allows RTOs to collect transmission charges from a load-serving entity for every transmission system that the load-serving entity uses.[112]

53. However, to the extent that Otter Tail has facilities that are highly integrated with facilities in the expanded SPP transmission system as a result of joint planning and ownership, and is concerned that the integration of the Integrated System Parties into SPP will introduce duplicative or pancaked rates that did not previously exist for use of such jointly planned and owned facilities, we clarify that Otter Tail may address in the hearing and settlement judge procedures whether any provision is needed in its service agreement with SPP to mitigate such impacts in order to ensure just and reasonable rates.[113]

54. Finally, we grant Otter Tail's request for clarification concerning other seams issues that may occur regardless of whether Central Power joins SPP (e.g., "the potential

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[112] Commission policy does not require the elimination of inter-RTO pancaked transmission rates where customers take service on more than one RTO system. *Cal. Indep. Sys. Operator Corp*., 147 FERC ¶ 61,231, at P 155 (2014) (citing Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,174-75 ("As a matter of policy, the Commission generally has not required the elimination of inter-RTO rate pancaking, but has required the elimination of intra-RTO rate pancaking.")). Otter Tail relies upon *UtiliCorp* for the proposition that the Commission requires elimination of rate pancaking within the merged systems of neighboring utilities. However, *UtiliCorp* is not controlling here, as no merger is at issue in this proceeding.

[113] In the November 2014 Order, the Commission stated "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." November 2014 Order, 149 FERC ¶ 61,113 at P 112.

price differential between the energy markets of MISO and SPP").[114] In the November 2014 Order, the Commission included those seams issues in the hearing and settlement judge procedures to the extent they are not related to the transfer of facilities of Corn Belt and Central Power to SPP.[115]

55. We deny SPP's request that the Commission clarify that the aspects of rate pancaking that were set for hearing do not include section 30.9 of the SPP Tariff. Moreover, we deny SPP's request for rehearing of this issue. As noted above, in the November 2014 Order, the Commission specifically recognized that many utilities in the area have facilities that are highly integrated with each other, that these arrangements may need to be reflected in their service agreements, and that their service agreements may need to reflect transmission facilities credits under section 30.9.[116] Section 30.9 of the SPP Tariff provides that a Network Integration Transmission Service customer such as Otter Tail, or other entities that own eligible facilities, may receive transmission credits against the customer's SPP transmission service charge. Therefore, although the issue of rate pancaking was excluded from hearing and settlement judge procedures in the November 2014 Order, the Commission noted that parties could raise the issue of transmission facilities credits under section 30.9 as a way to receive recognition of the integrated facilities that they contribute after the integration of the Integrated System Parties.[117] Thus, the Commission did not exclude transmission facilities credits under section 30.9 from the hearing and settlement judge procedures, because the Commission recognized that these credits might offer a potential solution to concerns that their highly integrated facilities were not properly reflected in the service agreements. We conclude that SPP has not demonstrated on rehearing that the issue of transmission facilities credits under section 30.9 should be excluded from the hearing and settlement judge procedures. Therefore, we affirm the Commission's determination to include section 30.9 in the issues set for hearing and settlement.

[114] Otter Tail Request for Rehearing at 5.

[115] November 2014 Order, 149 FERC ¶ 61,113 at PP 112-113 (recognizing 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).

[116] *Id*. P 112.

[117] *Id*.

4. Other Issues

a. Requests for Clarification or Rehearing

56. SPP seeks expedited consideration of its request for clarification or rehearing to provide certainty as to the scope of the issues in the settlement procedures.[118] SPP also seeks clarification, or in the alternative rehearing, of whether the Commission intended to include issues regarding the Governing Documents, hold harmless issues, or potential seams issues in the hearing and settlement judge procedures. Specifically, SPP seeks clarification that the only issues set for hearing and settlement are those seams concerns raising genuine issues of material fact raised by protestors and commenters specifically identified in PP 83-111 of the November 2014 Order, which do not include any issues regarding the Governing Documents, hold harmless issues, or seams mitigation issues.

57. In addition, SPP seeks clarification, or in the alternative, rehearing of the Commission's potential inclusion of the request that SPP be required to hold retail electric customers harmless from the Integrated System Parties' integration into SPP, or provide seams mitigation measures for such customers in the issues set for hearing and settlement.

58. Finally, SPP requests clarification that the Commission's acceptance of the changes to the SPP Bylaws, which included adding seats to the Members Committee, included approval of two additional seats for investor-owned utilities, consistent with the SPP filing. In the alternative, SPP seeks rehearing of this issue.[119]

b. Commission Determination

59. We clarify that, in the November 2014 Order, the Commission set all issues not summarily decided in the November 2014 Order for hearing and settlement judge procedures. Specifically, in the November 2014 Order the Commission summarily decided the following issues: the Federal Service Exemption, co-supply arrangement, base plan upgrades, the FERC assessment, generator interconnection procedures, and the Bylaws and Membership Agreement. The Commission found that SPP's proposed revisions to the Governing Documents, except for those issues that were summarily decided, as identified above, had not been shown to be just and reasonable and set them for hearing and settlement judge procedures.[120] The Commission did not set for hearing

[118] SPP Rehearing Request at 5 & n.17.

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

[120] November 2014 Order, 149 FERC ¶ 61,113 at P 17.

and settlement judge procedures those issues concerning the facilities of Corn Belt and Central Power because those facilities had not been transferred to SPP.[121] The Commission also did not set for hearing or settlement judge procedures those issues involving pancaked transmission rates between RTOs, or rate pancaking that involves the facilities of Corn Belt and Central Power. However, the Commission did include in the hearing and settlement judge procedures the issue of transmission facilities credits under section 30.9 of the SPP Tariff as a remedy to reduce a party's SPP transmission charge after the integration of the Integrated System Parties.[122]

60. We deny SPP's request that the Commission clarify that the only issues set for hearing and settlement are those seams concerns raising genuine issues of material fact raised by protestors and commenters specifically identified in PP 83-111 of the November 2014 Order. SPP seeks clarification that the Commission did not set for hearing and settlement judge procedures, "any issues regarding the Governing Documents, hold harmless issues, or seams mitigation issues[.]"[123] Rather, we clarify that, as discussed above, the Commission included those seams issues in the hearing and settlement judge procedures to the extent the issues are not related to rate pancaking or to the transfer of the facilities of Corn Belt or Central Power to SPP.[124]

61. With respect to SPP's request that the Commission clarify that it did not include in the issues set for hearing and settlement the request that SPP be required to hold retail electric customers harmless from the Integrated System Parties' integration into SPP or provide seams mitigation measures for such customers, we clarify that this issue is included in the issues set for hearing and settlement. Although SPP "seeks rehearing of the Commission's error including in the scope of issues set for settlement and hearing the Montana Consumer Counsel's request that SPP be required to include Tariff modifications holding Montana retail electric customers harmless from the Integrated System Parties' membership SPP,"[125] setting this issue for hearing and settlement was not

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[121] *Id*. P 113.

[122] *Id*. P 112.

[123] SPP Rehearing Request at 5.

[124] In the November 2014 Order, the Commission stated that seams issues resulting from the decision of the Integrated System Parties to integrate into SPP raise issues of material fact that are included in the settlement and hearing procedures. November 2014 Order, 149 FERC ¶ 61,113 at P 112.

[125] SPP Rehearing Request at n.41.

in error. In the November 2014 Order, the Commission discussed seams issues raised by Montana Consumer Counsel, as well as the arguments regarding hold harmless provisions, and specifically included the issue involving hold harmless provisions among the seams issues set for hearing.[126] Although SPP argues that this issue should be addressed in the MISO-SPP Joint Operating Agreement proceeding, it provides no support for the notion that seams issues or the need for a hold harmless provision do not raise issues of material fact. Further, including the option of hold harmless provisions in the hearing and settlement judge proceedings allows the parties to discuss such provisions as a remedy to the seams issues raised in this proceeding.

62. Finally, with respect to SPP's request that the Commission clarify that its acceptance of the changes to the SPP Bylaws included approval of two additional seats to the Members Committee for investor-owned utilities, we clarify that, consistent with SPP's filing, the Commission's acceptance of the changes to the SPP Bylaws included approval of two additional seats for investor-owned utilities.[127]

<u>The Commission orders</u>:

(A) The requests for rehearing are hereby denied, as discussed in the body of this order.

(B) The requests for clarification are hereby granted in part and denied in part, as discussed in the body of this order.

By the Commission. Commissioner Honorable is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

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[126] November 2014 Order, 149 FERC ¶ 61,113 at PP 96, 112.

[127] *Id*. P 131, n.206.