New Member Cost Allocation Review Process

Prepared by:
COST ALLOCATION WORKING GROUP

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1. HISTORY AND BACKGROUND

In 2004, the Southwest Power Pool (SPP) was approved as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC). Since that time, there have been two occasions where SPP experienced a significant expansion of its footprint. Cost allocation for transmission facilities was one issue that was addressed in negotiations between the new members and SPP.

When SPP became an RTO, the Regional State Committee (RSC) was formed and given policy oversight responsibilities for four significant areas. One of these areas was transmission cost allocation. The RSC, working primarily through the Cost Allocation Working Group (CAWG), exercises authority in two specific areas related to transmission cost allocation:

a. whether and to what extent participant funding will be used for transmission enhancements
b. whether license plate or postage stamp rates will be used for the regional access charge

Prior to 2010, facilities were funded under a variety of methodologies, ranging from "MW-Mile" allocation to the "Balanced Portfolio".[1] In April 2010, the RSC approved the current "Highway/Byway" methodology for new transmission facilities.[2] Under this methodology, any costs for facilities included in the "Base Plan" after June 19, 2010 would be allocated as follows:

1. Less than or equal to 100 kV facilities: 100% on a zonal basis
2. Greater than 100 kV and less than 300 kV facilities: 2/3 to the zone in which the facilities are located, 1/3 on a regional basis
3. Greater than or equal to 300 kV: 100% on regional basis

The Integrated System (IS) joined SPP on October 1, 2015. Much of the negotiation involving IS and SPP occurred in 2013 between SPP Staff and IS representatives. During those negotiations, the SPP Staff and IS agreed to propose to the Membership and the RSC a method to include them under the Highway/Byway funding methodology. The intent of the tariff changes was to establish October 1, 2015 as the effective date of cost sharing applicable to SPP members and the IS. The net effect of this change was that the IS zones did not fund SPP facilities with a need date prior to October 1, 2015. Similarly, SPP entities would not fund IS facilities with a need date prior to October 1, 2015.

The other key tariff revision, the Federal Service Exemption (FSE) among other considerations, provided as part of the IS integration, was that the Western Area Power Administration (Western) is not required to pay for regional funding for Federal deliveries to its loads using the IS facilities pursuant to statutory obligations.

During the review of proposed membership of the IS in SPP, several items became clear:

[1] The Balanced Portfolio methodology involved calculation of benefit/cost ratios and transfer payments to deficient zones.

[2] The Highway/Byway methodology was approved by FERC on June 17, 2010.

1. While the issues under the authority of the RSC are clear, there was not a consensus that certain issues such as the establishment of the effective date for cost sharing of facilities were in fact cost allocation issues.
2. There were no guidelines for what standards should be applied in reviewing issues that were under the RSC's authority under Section 7.2 of the SPP Bylaws. The lack of standards made it difficult to determine what information was necessary to review the reasonableness of the changes impacting issues under the RSC's authority.
3. The schedule for the RSC to complete its review was not defined.

As a result of the issues listed above, the RSC and CAWG were unable to reach a consensus on what actions should be taken in spite of a number of unresolved questions, particularly related to the effective date of cost sharing and the appropriateness of the one portion of the FSE. The one motion taken to endorse the new membership proposal at the CAWG failed for lack of a second. The CAWG ultimately voted to take no position on the proposed IS integration. The RSC did not make a motion regarding the membership, though three individual states sent a joint letter on June 6, 2014 to the SPP Board of Members and Members Committee expressing concerns about various aspects of the proposal and the need for further analysis regarding the terms and impacts of the proposed IS membership on existing members and ratepayers within the then-current SPP footprint. The three states requested that the SPP Board of Directors and Members Committee delay their decision to no sooner than the regular July 2014 Board meeting. The state of Kansas intervened in the FERC proceeding opposing the change in the effective date of cost sharing, the FSE, along with other issues. The state of Texas also intervened in the FERC proceeding and submitted comments to state that it did not support the proposed revisions to SPP's governing documents due to concerns regarding the cost-benefit analysis and the FSE, among other issues.

The RSC discussed the communication and process issues related to new member review over the course of several meetings in early 2015. In April 2015, the RSC directed the CAWG to develop a cost allocation review process that could be used in future discussions involving new members. The CAWG drafted a scope of the issues that would be included in the review process and a schedule for completion. That scope (included as Attachment A) was approved by the RSC at the July 27, 2015 meeting.

This document is designed to provide a process for the RSC and CAWG to follow in the future when a potential new member is being considered, particularly when that new member is asking for significant changes to the SPP Open Access Transmission Tariff (OATT) or Membership Agreement that would impact the RSC approved regional cost allocation. This process is intended to work as a separate, parallel process with the communication and work group processes delineated in the New Member Task Force report that was approved by the RSC at the July 27, 2015 meeting and subsequently approved by the SPP Board of Directors (see Attachment B). It is anticipated that information will be shared between SPP Staff, the RSC and CAWG to ensure timely completion of the review process contemplated in this document. Sharing of information would be subject to the resolution of any issues pertaining to confidentiality.

2. PURPOSE / GOAL STATEMENT

The purpose of this document is to provide the RSC and CAWG a process to follow when considering cost allocation issues related to potential new transmission-owning member additions to the SPP. This review process is particularly important when the new member is requesting modifications to SPP's governing documents (OATT, Bylaws, Membership Agreement) that go beyond pro forma changes and would impact the authority of the RSC pursuant to Section 7.2 of the SPP Bylaws.

2.1 GOAL STATEMENT

The goals of the New Member Cost Allocation Review Process (Review Process) is to evaluate the impact of new transmission owning members on stakeholders (including retail ratepayers) in the existing SPP footprint and assess the benefits that would accrue to existing stakeholders. The impact assessment is intended to take into account economic and non-economic impacts. In addition, this process is intended to assist the RSC in developing a position regarding cost allocation issues for new members as well as an action plan, consistent with the RSC's authority under Section 7.2 of the SPP Bylaws.

The RSC positions developed as a result of this document regarding the areas under its authority pursuant to Section 7.2 of the SPP Bylaws may be used by the RSC to determine whether to intervene in FERC proceedings or file a cost allocation methodology which may be in conflict with the methodology filed by SPP staff.

3. OVERVIEW OF PROCESS

The Review Process will consist of several steps, which will be completed over a prescribed time period as outlined in Section 8.1. The process generally includes the following steps:

1. Collect information about proposed new member (Section 4).
2. Review previous cost allocation and integration approaches (Section 5).
3. Complete analyses (Section 6).
4. Discuss other considerations (Section 7).
5. Prepare recommendation for RSC action.

4. NEW MEMBER CHARACTERISTICS

SPP Staff shall provide all available information to the RSC and CAWG about the new member as set forth in the SPP Stakeholder Communication Process[3], for purposes of completing the Review Process. Certain information may be confidential or unavailable. In addition, the information provided pursuant to this section may be Critical Energy Infrastructure Information (CEII) and as such would need to be afforded the appropriate protections. The information to be collected by SPP and provided to the RSC/CAWG is as follows:

[3] https://www.spp.org/spp-documents-filings/?id=19994

4.1 TRANSMISSION FACILITIES AND PLANNING INFORMATION

Related to transmission facilities owned by the potential new member:

1. Line miles of transmission owned, separated by voltage class
2. List of existing interconnection points to SPP
3. List of interconnection points to neighboring RTO regions
4. List of utilities in non-RTO regions that new member is interconnected with, along with interconnection points
5. Transmission planning studies used to determine if existing facilities are adequate to meet SPP Planning Criteria and applicable NERC TPL standards (steady state, dynamics and short circuit) in effect when the evaluation is being prepared
6. Current cost recovery mechanism for transmission service (i.e., Stand-alone FERC-jurisdictional Open Access Transmission Tariff, joint tariff with other transmission owners, membership in Regional Transmission Organization, non-jurisdictional transmission tariff)

4.2 GENERATION AND LOAD INFORMATION

Related to the potential new member:

1. Actual summer and winter peak demand (including capacity sales) for most recently completed calendar year. (Note: May be provided for alternate 12-month time period based on information availability.)
2. Comparison of peak demand to capacity resources by month for most recent year, including calculation of reserve margin.
3. Projected peak demand for 10-year period, beginning in current year.
4. Comparison of projected peak demand to resources for subsequent 10-year period.
5. For planned resources, identify location and status of transmission planning to integrate resources into transmission system.
6. Resource mix, including fuel type.

4.3 MODIFICATION TO SPP GOVERNING DOCUMENTS

SPP Staff shall provide, as developed in the SPP stakeholder process (see Attachment B), in clean and redline format, all proposed changes to the following documents related to the new member that impact areas under the authority of the RSC pursuant to Section 7.2 of the SPP Bylaws:

1. Open Access Transmission Tariff
2. Membership Agreement
3. SPP Bylaws
4. Regional State Committee Bylaws

5. SPP Criteria

SPP Staff shall provide a summary of those changes that go beyond "*pro forma*" changes and provide information related to any changes that affect cost allocation and other areas under the authority of the RSC pursuant to Section 7.2 of the SPP Bylaws. SPP Staff shall identify and provide the purpose for any changes that impact areas under the authority of the RSC pursuant to Section 7.2 of the SPP Bylaws beyond *pro forma* changes. The RSC and CAWG can review and ensure that the proposed changes are consistent with the Goals listed in Section 2.1.

For purposes of this document, a "*pro forma*" change to a governing document (Tariff, Bylaws, Membership Agreement, and Service Agreement) is defined as, but not limited to, one of the following examples:

1. Addition of new member to list of signatories.
2. Addition of new members taking service under the *pro forma* Tariff. Examples include Attachment H (addition of a new member's stated rate or Formula Rate Template to Revenue Requirements calculations) or Attachment M (a new member's Transmission loss factors).
3. Effective date of integration for new member, unless establishment of the effective date results in other substantial revisions to the Tariff.
4. Creation of a new zone for a new member, or adding a new member to existing zone, provided no other cost allocation changes are being proposed.

5. <u>PREVIOUS COST ALLOCATION AND INTEGRATION APPROACHES</u>

The purpose of this section is to provide the RSC and CAWG examples of how new member integration has occurred in the past within SPP as well as in other RTOs. These examples are intended to provide a "range" of reasonable cost allocation approaches that have been used previously and approved by FERC so the RSC and CAWG can determine if the new member integration is being treated in a fashion similar to previous situations. However, approaches that differ from an approach previously used will be evaluated on their own merits to determine if they are just and reasonable. If a new member is offered terms that differ substantially from those that have been offered in previous new member integration cases, then the RSC and CAWG may want to complete further investigation into the reasonableness of the proposed changes.

Because of the volume of information and the potential for additional data in the future, this information is included as a separate Appendix 4.

6. <u>CRITERIA FOR COST ALLOCATION REVIEW</u>

6.1 RATE STANDARD

The SPP OATT is governed by FERC and is required to meet the "just and reasonable" rate standard. As such, any tariff changes related to the addition of a new member must meet this rate standard.

6.2 IMPACT TO EXISTING MEMBERS

In the past, SPP evaluated the impact on existing members using two primary metrics: ATRR and SPP Schedule 1-A (Administration Charge). The costs for these two components were evaluated to determine if there would be a cost or savings. In the case of the IS integration, each existing transmission zone had a net benefit when ATRR and Administration Charge were considered.

The CAWG will evaluate the effect of new members on the existing SPP region. Any proposed integration that results in a benefit/cost ratio to the existing SPP customer base of less than 1.0 may warrant further consideration by the RSC.

6.3 EVALUATION METHODOLOGY

6.3.1 ADMINISTRATION CHARGE

SPP will calculate the projected change in the Administration Charge (Schedule 1-A) with the new member integration. The revised Schedule 1-A costs will take into account projected load changes as well as projected incremental costs, if any, associated with serving new members. The change in Administration Charge shall be tabulated for the existing SPP footprint and for each existing transmission zone.

6.3.2 TRANSMISSION COSTS

SPP will calculate the existing (without new members) and projected ATRR for each transmission zone and for the existing SPP footprint as a whole. The calculations will take into account already-issued Notices to Construct (NTCs) for the existing footprint and facilities planned by the potential new member(s) that are expected to receive base plan funding.

6.3.3 PRODUCTION COSTS

For purposes of new member integration benefit/cost analysis, adjusted production cost benefits may be considered in certain circumstances. In general, production cost analysis will not be included unless one of the following conditions is expected:

1. The new member has significantly different generation profile than the existing footprint.
2. Integration of the new member is expected to result in significant changes in locational marginal prices or congestion in the existing SPP footprint.

6.3.4 OVERALL BENEFIT / COST EVALUATION

The following parameters shall be used to determine the benefit/cost ratio of the new member on existing members:

1. The economic parameters most-recently approved for use by the Economic Studies Working Group shall be used. These parameters may be associated with a recently completed study or a study that is in process.
2. A 40-year study horizon shall be used.
3. Only costs and benefits associated with the Administration Charge (Schedule 1-A) and ATRR shall be considered, unless CAWG determines that it is appropriate to model adjusted production costs.
4. Other benefits, such as reserve sharing costs, market related benefits or transmission planning synergies, may be considered on a case by case basis.

The net benefits/costs shall be calculated for SPP as a whole and for each existing transmission zone if possible. Benefits and costs related to the Administration Charge, ATRR, production (if applicable and if possible), and other benefits as determined will be provided by SPP Staff if available as specified in the SPP Stakeholder Communication Process (Attachment B).

6.3.5 NON-ECONOMIC / QUALITATIVE BENEFITS

If there are other non-economic or qualitative benefits that would accrue to existing SPP stakeholders, SPP staff will identify those benefits and provide information to the RSC regarding those benefits. Non-economic or qualitative benefits may be taken into account in the evaluation, but will not be considered as an offset against costs to existing stakeholders. In situations where economic benefits to existing stakeholders associated with a new member are minimal, non-economic or qualitative benefits may be considered by the RSC in developing a position regarding cost allocation issues associated with the new member.

6.4 EFFECTIVE DATE FOR HIGHWAY/BYWAY COST-SHARING

Among the considerations that may inform the analyses on the reasonableness of the cost sharing are the following:

1. Should the effective date of cost sharing be tied to the need date for SPP projects and the projects of a new member? The various approaches to cost sharing may include but are not limited to the following:

    a. *Need Date Approach*:

i. Upgrades in the existing SPP system and those in the new member system that have a need date prior to a certain date (e.g. integration date) are not subject to cost sharing;
ii. Upgrades in the existing SPP system and those in the new member system that have a need date after a certain date (e.g. integration date) are subject to cost sharing. The analysis may consider whether the only evaluation required for projects of a new member is a need-by date analysis or whether such projects must be evaluated in an SPP regional planning process or a high priority planning process before they can be subject to cost sharing.

b. *Combination of Need Date and Regional Cost Allocation Review (RCAR) Approach*: In addition to the need date approach, the benefits derived by the new member from the use of SPP highway/byway facilities in place before the cost sharing date and, if applicable and possible, the benefits derived by SPP from the use of existing upgrades of the new members would be evaluated in a future RCAR study.

c. *Delay and/or Transition Period for Cost Sharing Approach*: Factors that may be considered are:

i. a need for a pre-determined transition period after the integration date during which cost sharing for existing upgrades or new projects does not occur or occurs to a limited extent;
ii. the cost sharing for <u>existing upgrades whether approved by the SPP board or the relevant board of a new member, as applicable,</u> is phased in over a period of time according to a pre-determined methodology and the cost sharing for <u>projects with a need date after the effective date of integration</u> is applied only to transmission projects that have been evaluated and studied in an SPP regional planning process (e.g. ITP process or a high priority study as delineated in SPP tariffs).

d. *Cost Sharing for All Applicable Projects Regardless of Need Date and Effective Date of Membership*: There is no distinction made between projects based on need date for projects with respect to cost sharing.

i. Cost Sharing for Existing Upgrades: A new member and SPP will share in the unrecovered costs of each other's existing upgrades (100 kV and above). The analysis may limit the scope of the upgrades to which such cost sharing may apply to the extent there are any complexities involved in implementing this approach.
ii. Cost Sharing for New Upgrades: The costs of projects 100 kV and above that are approved for construction by the SPP Board or by the relevant board of a new member, as applicable, will be shared by SPP and the new member. The analysis may consider whether the only

evaluation required for projects approved by the relevant board of a new member is a need-by date analysis or whether such projects must be evaluated in an SPP regional planning process or a high priority planning process before they can be subject to cost sharing.

2. Should the impact of the integration date on SPP stakeholders (including the existing retail rate-payers in the SPP footprint) or the new member as it relates to cost sharing be considered?

   The analysis may consider if, with respect to cost sharing, the date on which a new member seeks to integrate into the SPP system adversely impacts SPP stakeholders or the new member. As an example, SPP or the new member may approve projects as a result of federal regulations and policy directives (e.g. Clean Power Plan). These projects may entail significant investment and have need dates prior to the effective date of integration of the new member into SPP. If establishment of an effective date for cost-sharing results in disproportionate benefits to either the new member or the existing SPP stakeholders, a change in cost allocation methodology may be warranted. Under certain cost sharing approaches (e.g. need date approach), described above, the new member and SPP will not be responsible for cost sharing for such SPP or new member projects.

6.5 FACILITIES AND ENTITIES TO WHICH COST-SHARING APPLIES

The analysis should consider the following aspects of facilities to which cost sharing may apply:

1. Voltage of transmission lines
2. Classification of upgrades, if applicable: Reliability, Economic, and Public Policy

6.6 OTHER CONSIDERATIONS

There may be other relevant considerations in an analysis regarding cost sharing.

6.6.1 MINIMIZING ADMINISTRATIVE BURDEN ON SPP

One of the goals of a cost sharing approach adopted in the context of new member integration should be to maintain consistency/uniformity in tariff rates and minimize the administrative burden on SPP, its members, and the new member to the extent possible without compromising on the goals outlined in section 2.1 of this document. For example, there should be an effort to avoid creating new schedules that reflect different region wide rates for new members.

6.6.2 CONSIDERATION OF SPECIAL CIRCUMSTANCES

To the extent there are special circumstances that need to be considered in the evaluation of cost sharing for new members such as exemptions for certain new members (e.g. exemption due to federal statutory requirements or grandfathered agreements), SPP Staff shall provide information on the following in a manner consistent with the SPP Stakeholder Communication Process:

1. Scope of the exemption
2. Legal analysis demonstrating that such exemption is warranted, if applicable
3. Technical evidence demonstrating that the new member seeking exemption will not benefit from upgrades in the SPP system after integration
4. Documents supporting the basis for such exemption, if applicable

6.6.3 USE OF THIRD-PARTY VS. SPP ANALYSES

Each prospective new transmission-owning member may have unique characteristics associated with its transmission system. SPP Staff shall provide the following information in a manner consistent with Proposed SPP Stakeholder Communication Process:

1. A benefit/cost analysis to determine the impact the addition of the prospective transmission –owning member’s system would have on existing SPP members.
2. A more extensive production benefit/cost analysis conducted by SPP Staff or by a third party under SPP direction, if requested by the SPC or the RSC.
3. To the extent SPP relies on benefit/cost analysis or a study performed by the new member, detailed information of such studies to permit review of such studies (to the extent it is available and not protected by confidentiality provisions).

7. <u>FACTORS WHICH MAY RESULT IN DEVIATION FROM APPROVED COST ALLOCATION CRITERIA</u>

This is not an exhaustive list of circumstances that may warrant a deviation from following these criteria or strictly adhering to this process. Any and all requests for deviation shall follow Section 6 – Criteria for Cost Allocation Review in addition to the considerations or factors noted in this section.

7.1 REMOTE SYSTEM WITHOUT AC INTERCONNECTION

Should a new member request joining SPP without having any direct AC interconnection to the SPP system, several factors will need to be considered. First and foremost is what transmission path, or paths, is available for connection to the SPP system should energy be dispatched to or from the new member system. This may prove difficult to determine and independently verify as the pathways are outside of the SPP footprint and management. It shall be the responsibility of the new member to identify these pathways and determine what costs are associated with delivering energy to and from the SPP system to the requesting member's system, including any congestion and their associated costs which may arise from moving energy across non-SPP systems. Second, the new member shall provide a benefit/cost analysis for each and every identified pathway and a methodology for mitigation and independent verification should a non-SPP system owner determine that energy moved across pathways was not identified by SPP or the new member. Lastly, once the pathways for interconnection are identified, the new member shall propose what form of agreement be in place to effectuate efficient and cost effective transmission of energy over non-SPP member systems including proposed time frames for such agreements, and proposed exit payment provisions should these agreements not be renewed.

Should the new member request that their system remain as a stand-alone system, the preferred methodology for cost allocation for the new member will be that all transmission cost for the new member's system be directly assigned to that new member. Any request for an alternate cost allocation methodology under this scenario shall be accompanied by a benefit/cost analysis.

7.2 SYSTEM WITH LIMITED INTERCONNECTION CAPABILITY

Should a new member request to join SPP having only limited interconnection to the SPP system, the following factors will need to be considered. For pathways on the new member's system with limited interconnection capability the new member shall clearly identify the nature of those limitations including both qualitative and quantitative analysis of the limitations noting any time based limitations. Additionally, the new member shall identify what alternate transmission path or paths are available for connection to the SPP system should energy be dispatched to or from the requesting member and the interconnection limitations force energy to travel along alternate paths on non-SPP systems. It shall be the responsibility of the new member to identify these pathways and determine what costs are associated with delivering energy to and from the SPP system to the requesting member's system, including any congestion and their associated costs which may arise from moving energy across non-SPP systems. The new member shall provide a benefit/cost analysis for each and every identified pathway and a methodology for mitigation and independent verification should a non-SPP system owner determine that energy moved across pathways was not identified by SPP or the new member. Again, this may prove difficult to determine and independently verify as the pathways may lie outside of the SPP footprint and management. It shall be the responsibility of the new member to identify these pathways and determine what costs are associated with delivering energy to and from the SPP system to the requesting member's system, including any congestion which may arise from moving across non-SPP systems.

7.3 SYSTEM EMBEDDED IN EXISTING SPP MEMBER

There are a number of entities that are not members of SPP embedded within existing transmission owners. It is possible at some point in the future they may seek membership in SPP, either as a transmission owner or as a transmission user. One example of this type of entity would be a municipal system with transmission interconnections to a single transmission system. Another example would be a cooperative system that is a member of a cooperative that is already an SPP member that is seeking its own separate membership.

To the extent these entities do not seek changes beyond pro forma changes to SPP's governing documents, the necessary review under this document would be unnecessary. If the embedded entity is seeking changes to cost allocation methodology, effective date of cost-sharing for new facilities, or any other changes to SPP's governing documents, the provisions of this document would apply.

There have been instances where a new member is requesting to have its loads and transmission facilities included in the zone of an existing transmission zone. SPP Staff reviews such requests in a manner consistent with the tariff and the requirement that rates meet the just and reasonable standard established by FERC. If no other changes to cost allocation are being requested by the new member, the CAWG will not complete a review of the new member using this document.

7.4 SYSTEM WITH REQUIREMENTS TO SERVE UNDER FEDERAL LAW OR PRE-EXISTING CONTRACTS

There may be situations where a new member has a statutory prohibition from participating in the existing cost allocation methodology. This occurred in the case of the IS membership through the application of the FSE. Exempting future members from SPP's transmission allocation methodology will be reviewed on a case-by-case basis by the CAWG. The CAWG will consider the following factors in determining the acceptability of any potential exemptions or deviations from cost allocation methodology in a manner consistent with the SPP Stakeholder Communication Process:

1. Legal review of the requested cost allocation approach
2. Benefit/cost review of requested cost allocation approach
3. Impact on existing members and proposed members
4. Precedent established for future membership applications

8. <u>REVIEW PROCEDURES</u>

The following review procedures shall be followed to ensure timely review of cost allocation issues related to potential new transmission-owning member additions to the Southwest Power Pool.

8.1 SCHEDULE

The following schedule shall be followed after the SPC's new member forum discusses the proposed new member. All dates referenced are relative to the date when all necessary information is provided by SPP staff:

- 30 days: CAWG shall meet to discuss information and analyses.
- 60 days: CAWG shall provide a report to the RSC, including the CAWG's recommended course of action.

Next scheduled RSC meeting following receipt of the CAWG report: RSC shall discuss the report findings and vote on action to be taken. Note: If the proposed integration has shorter timeframe, a special RSC meeting may be necessary.

8.2 REPORT OF FINDINGS TO RSC

The CAWG shall provide a report to the RSC that includes, but is not limited to, the following information:

1. Proposed New Member Information
   a. Transmission Facilities and Planning Information (Section 4.1)
   b. Generation and Load Information (Section 4.2)
   c. Proposed Modifications to SPP Governing Documents (Section 4.3)

2. Cost Allocation Review
   a. Rate Standard (Section 6.1)
   b. Impact to Existing Members (Section 6.2)
   c. Evaluation of Costs and Benefit/Cost Analysis (Section 6.3)
   d. Effective Date for Cost-Sharing (Section 6.4)
   e. Facilities and Entities to Which Cost-Sharing Applies (Section 6.5)
   f. Other Considerations (Section 6.6)

3. Recommendation to RSC, including Action Plan

8.3 ACTION PLAN

The report shall include a recommended course of action that may include, but is not limited to:

1. Endorsement of the proposed member(s);
2. No action taken; or
3. Oppose the integration of the proposed new member(s) through FERC proceedings. Opposition may or may not include filing of a cost allocation methodology pursuant to Section 205 of the Federal Power Act that differs from the methodology filed by SPP.

<u>ATTACHMENT A: NEW MEMBER REVIEW PROCESS SCOPE</u>

Approved by RSC, July 27, 2015

New Member Cost Allocation Review Process Scope Document

1. Identify new member characteristics
    a. Transmission Facilities
    b. Generation and Load Characteristics
    c. Proposed modifications beyond pro forma changes to the Tariff and other governing documents

2. Identify cost allocation and integration approaches used in other similar situations
    a. Existing SPP integration – Nebraska and Integrated System
    b. Other RTO member additions
    c. Non RTO member additions

3. Develop criteria used to analyze the application of existing cost allocation methodologies for future new members
    a. Rate standard
        i. Public interest
        ii. Just and reasonable
    b. Impact to existing members and new members
    c. Evaluation methodology
        i. Administrative costs
        ii. Production costs
        iii. Transmission costs
        iv. Appropriate benefit / cost measurements
        v. Ensure coordination with SPP
    d. Appropriate effective date for cost-sharing
    e. Appropriate facilities and entities to which cost-sharing to be applied
    f. Practical considerations for implementing cost-sharing

4. Identify other factors that may warrant deviation from established cost allocation criteria
    a. Remote system without direct AC interconnections
    b. System with limited interconnection capability to SPP region
    c. Systems embedded within SPP member transmission system

5. Draft procedures for CAWG/RSC use in future reviews
    a. Schedule for completion
    b. Reporting findings
    c. Action plan

6. Other considerations
    a. Need for uniformity in tariff language relating to cost-sharing
    b. Minimizing administrative burden on SPP
    c. Phasing in or delaying of cost allocation for new members
    d. Consideration of special circumstances (ex. Federal Service Exemption)
    e. Ensure that a Goal Statement is included in the final draft of the scope document

f. Use of third-party technical and/or economic analysis in addition to SPP internal technical and/or economic analysis

7. Other Issues of Interest to the RSC

Schedule for Completion

1. Approval of scope for July 2015 RSC meeting
2. Review scope items 1, 2, and 3 – October 2015
3. RSC approval of CAWG review procedures – January 2016

ATTACHMENT B: SPP TASK FORCE ON NEW MEMBERS SPP STAKEHOLDER COMMUNICATIONS PROCESS

Approved by SPP Board of Directors, July 2015.

SPP Task Force on New Members

Proposed SPP Stakeholder Communication Process

*** * Final Report * ***

Introduction

Given communication concerns raised during the Integrated Systems addition to the Southwest Power Pool (SPP) in 2013/2014, the SPP Board charged the Strategic Planning Committee to develop improved and enhanced communications and processes for new member additions to SPP. At the July 17, 2014 SPP Strategic Planning Committee (SPC) meeting, the SPC Task Force on New Members (SPCTFNM) was formed and charged with developing recommended prospective communication and work group processes that would be followed during the various stages of engaging prospective transmission-owning and load serving members. The outcome of this Final Report and Communication Process only applies to prospective transmission-owning members who request membership contingent upon modifications beyond minor pro forma changes to typical new members to the SPP Open Access Transmission Tariff (OATT), Governing Documents, or Regional State Committee (RSC) Bylaws.[4]

The SPCTFNM had several meetings over the course of fall of 2014 and reviewed the existing SPP Staff process document for adding prospective transmission-owning members and discussed improvements in the SPP Staff process as well as documenting a recommended Communication Process for future transmission-owning member additions. The SPCTFNM was guided by the overarching need to allow flexibility to deal with unique features of the prospective transmission-owning member throughout the process, while balancing appropriate transparency for member participation while allowing for confidential discussions/negotiations. Noteworthy is that the SPP staff remains solely responsible for the direct negotiations with the prospective member with input from the stakeholders on both policy and specific changes to the governing documents.

When evaluating the overall process of adding new transmission-owning members, the prospective member goes through the following five stages:

1. Initial Discussions
2. Due Diligence and Membership Agreement Discussions
3. SPP OATT and Governing Document Changes
4. FERC Approvals
5. Integration

[4] The applicability of the process contained herein is further defined in Chart 1, Applicability of New Member Process, contained on Page 6.

Each of these stages will be discussed further in this Final Report and the recommended Communication Process improvements are noted for each of the stages. The focus of the SPCTFNM efforts was on Stages 1, 2 and 3 as those are the stages where most communications and discussions are confidential and proprietary to the SPP region and where the communication concerns were concentrated.

Regarding the effective date for regional cost sharing associated with the integration of the new member, the SPCTFNM brought the issue to the RSC to determine how the issue should be addressed. The SPCTFNM recommends that while the issue is a significant concern when adding a new transmission-owning member to the SPP region, the issue is outside the scope of this task force which was tasked with improving the communication process.

This document is the final product of the SPCTFNM and recommends the Strategic Planning Committee (SPC) approve the recommendations for process improvements. SPP Staff has also made a series of changes and clarifications in the Staff work process document, which is included in this report as ATTACHMENT A.

Key Definitions

Stakeholders – Stakeholders include existing transmission-owning members, transmission-using members, and RSC members and their staffs.

Prospective transmission-owning member – A potential SPP member who is seeking to bring its transmission system into the SPP region. Due to its request for membership, the prospective member requires modifications to the SPP OATT (beyond minor pro forma changes for typical new members), Governing Documents, or RSC Bylaws.

Members Forum – A group of interested SPP members, including SPP members who are electrically adjacent to the prospective transmission-owning member, who will give guidance to SPP Staff. A prerequisite to joining the Members Forum is an executed SPP Members Agreement and confidentiality agreement.

State Commission Forum – A group of interested RSC Commissioners or Commission Staff who will give guidance to SPP Staff. A prerequisite to joining the State Commission Forum is an executed confidentiality agreement.

Governing Documents – Includes the SPP Bylaws and SPP Membership Agreement.

First Triggering Event – Typically when the potential new transmission-owning member formally requests SPP to begin negotiations to change the SPP OATT, Governing Documents, or RSC Bylaws to allow for its membership into SPP.

Second Triggering Event – This occurs when SPP Staff and the prospective transmission-owning member determine that the discussions and the potential new member information need to become public to all SPP Stakeholders.

Communication Process

Stage 1: Initial Discussions

Periodically, prospective transmission-owning members approach SPP, typically in confidence, indicating they would like to discuss membership. SPP Staff will periodically report to the SPP SPC the general discussions and these discussions may remain "general" for months and years. SPP Staff does not take any formal action until the First Triggering Event occurs, which is typically when the prospective new transmission-owning member formally requests SPP to begin negotiations to change the SPP OATT, Governing Documents, or RSC Bylaws to allow for its membership into SPP.

Once this First Triggering Event occurs, SPP Staff formally notifies the SPC. If the potential new member requests confidentiality of the negotiations, or if the new member is also negotiating with another Regional Transmission Organization (RTO), the negotiations are considered proprietary, and updates to the SPC are conducted in Executive Session with proper notification given, by ensuring the meeting agendas note an Executive Session is expected and the topic is New Members. In the Executive Session, the phones may be closed out; however, all SPP Members and RSC Commissioners or Commissioner Staff present at the meeting shall be permitted to remain in the Executive Session.[5]

Once this First Triggering Event occurs, SPP Staff also shall establish a Members Forum and State Commission Forum to give guidance and assist SPP Staff on due diligence. The Members Forum is typically open to SPP members who are located electrically adjacent to the potential new transmission-owning member(s) and while no existing Member requesting to join the Members Forum is turned down, the Members Forum size needs to be managed so that SPP Staff can be agile and efficient in their work.

All SPP members, as well as RSC and commission staff, may attend the SPC Executive Session discussions on New Members. For these Executive Sessions, an executed confidentiality agreement will be required for all participants.

Stage 2: Due Diligence and Membership Agreement Discussions

During this stage, SPP Staff is solely responsible for the negotiations with the prospective new transmission-owning member. The SPP SPC, State Commission Forum and Members Forum can provide input to SPP Staff as well as receive regular updates on progress or issues of concern. These discussions, and updates from the due diligence work SPP Staff conducts, are typically highly confidential and proprietary. Also during this stage, SPP Staff provides regular updates to the SPC and as the updates require, in Executive Session. The Executive Session will be noticed on the agenda. As appropriate, SPP Staff will provide updates to the appropriate working groups and committees, including the SPP Board, Members Committee, RSC, and Markets and Operations Policy Committee (MOPC).

During this stage, a Second Triggering Event occurs that makes the discussions and the potential new member's identity public to all SPP Stakeholders. Once this Second

[5] Subject to assurances from Commissioners and Commission staff regarding protection of confidential information that may be subject to Freedom of Information Act and state open meeting laws.

Triggering Event occurs, SPP Staff convenes a special all-member meeting to discuss all the proposed document changes and analyses conducted to date.

Each prospective new transmission-owning member generally has unique characteristics associated with its transmission system. In all cases, SPP Staff conducts a cost/benefit analysis to determine the impact the addition of the prospective transmission-owning member's system would have on existing SPP members. The potential new transmission-owning member may conduct a cost/benefit study of its own that could include a production cost analysis.

The SPC shall make a determination of whether to have a more extensive production cost/benefit analysis conducted, either by SPP Staff or by a third party under SPP direction. When posting the SPC agenda, SPP Staff will ensure the agenda states there is a new member discussion item and that it may be discussed in Executive Session. The decisions to conduct such a cost/benefit study will be evaluated on a case-by-case basis.

<u>Stage 3: SPP OATT and Governing Document Changes</u>

During this stage, SPP Staff is solely responsible for the direct negotiations with the prospective new member, and the SPP SPC, State Commission Forum and Members Forum provide input to SPP Staff as well as receive regular updates on progress or issues of concern. During this stage, SPP Staff provides regular updates to the SPC and as the updates require, in Executive Session. As appropriate, SPP Staff will provide updates to the appropriate working groups and committees, including the SPP Board and Members Committee, RSC, and MOPC.

At this stage, SPP Staff convenes a special all-Member meeting to discuss the proposed OATT and Governing Document Changes and any analyses conducted to date. Throughout this stage, as appropriate, SPP Staff shall provide updates to the appropriate Working Groups and Committees, including the SPP Board and Members Committee, the RSC, the Cost Allocation Working Group, and MOPC.

When SPP Staff convenes the special all-Member meeting SPP Staff shall include the RSC Commissioners and Commission staff. The RSC may request SPP Staff to hold a special meeting of the RSC to review the proposed changes; however, this would not preclude the RSC Commissioners or Commission Staff from attending the all-Member special meeting to review and discuss the potential document changes and new members.

Finally, if the SPP OATT and Governing Documents are amended and presented for stakeholder approval, the following groups' roles are defined.

> MOPC: Prior to going to the Members Committee and Board for a vote, any changes to the SPP OATT will be presented to MOPC for all members to discuss and vote on changes.

SPC: Prior to going to the Members Committee and Board for a vote, all negotiating strategies, guidance, and deliberations for prospective new members will be reviewed by the SPC, either in an open meeting or Executive Session for review and approval.

Corporate Governance Committee (CGC): Prior to going to the Members Committee and Board for a vote, any changes to the Governing Documents will be reviewed and approved by the CGC.

RSC: SPP Staff will provide regular updates to the RSC on new transmission owning member deliberations and negotiations. Any matters for which the RSC has delegated authority will be presented to the RSC for discussion and approvals, in accordance with the RSC and SPP Governing Documents, prior to SPP Board action.

Legal Analysis

Depending on the unique characteristics of the potential new member, or the request of the potential new member for OATT and Governing Document changes, a legal analysis may be required. The prospective new member shall be responsible for any legal analysis it needs. SPP will be responsible for any legal analysis SPP determines it needs. Any time the potential new member indicates that it has identified a matter for which it is seeking a legal analysis, an analysis may be requested of SPP's General Counsel. This request should be made in writing.

Additionally, on a case-by-case basis, Stakeholders, as defined in this document, may request an SPP legal analysis on issues related to the prospective new member. This request should be made of the General Counsel in writing. Nothing in this recommendation precludes any SPP Member, the RSC, or State Commission from pursuing its own legal analysis on any legal matter associated with the prospective new member.

The SPP General Counsel has a process for conducting general legal analyses in response to such requests. This process documents how that legal analyses would be pursued and disseminated during the non-public and public stages of the process of adding new members. Such legal analysis would be released subject to the resolution of attorney-client privilege issues and professional responsibility obligations.

CHART 1

Applicability of New Member Processes

Below are examples of situations of when the New Member Process Document will and will not apply to prospective new members integrations into SPP.

New Member Process Document Applies	**New Member Process Document Does Not Apply**
The prospective New Member is requesting changes to the SPP tariff including Schedule 11, Schedule 12, Attachment J, Attachment AE, or other rate schedule.	The prospective New Member is only requesting pro forma changes to the SPP tariff.
The prospective New Member is requesting significant changes to the pro forma SPP Membership Agreement.	The prospective New Member is only requesting minor changes to their membership agreement or changes to the membership agreement already approved by FERC for other members of the same zone.
The prospective New Member is requesting significant changes to the SPP Bylaws.	The prospective New Member has no requested changes to the SPP Bylaws.
The prospective New Member is requesting significant changes to the RSC Bylaws or to the delegated authorities of the RSC, as stated in the SPP Bylaws.	The prospective new member is not a prospective transmission-owning member.
Any other instances not specifically listed herein where the SPC or Board of Directors determine that the changes are significant enough that the New Member Process Document should apply.	The prospective new member will not be classified as a TO member within the SPP Membership Agreement.
Any other instances not specifically listed herein that are within the responsibilities of the RSC, where the RSC finds that the changes are significant enough that the New Member Process Document should apply.	

APPENDIX 1: DESCRIPTION OF NEBRASKA MEMBERS

- Omaha Public Power District (OPPD) - OPPD has been operating since 1946 and is a publicly owned, business-managed electric utility governed by an elected board of eight directors. OPPD is headquartered in Omaha, Neb.; with other locations in a 13-county, 5,000-square-mile service area. OPPD serves a population of approximately 799,000 people, more than any other electric utility in the state and ranks as the 12th-largest public power utility in the U.S. in number of customers served. OPPD serves 47 towns at retail and five at wholesale. The majority of OPPD's power comes from three baseload power plants: North Omaha Station and Nebraska City Station, both coal-fired plants, and Fort Calhoun Station, a nuclear power plant. OPPD has generating capability of 3,232 MW and a system peak load of 2,291 MW.

- Lincoln Electric System (LES) - Feb. 1, 1966, Lincoln Electric System was formed and a single utility began providing electric energy in and around Lincoln, Neb. In November 1970, Lincoln voters approved formation of a semi-autonomous administrative board of local citizens to oversee operations of the nonprofit, customer-owned utility. Today, LES services approximately 200 square miles within Lancaster County in Nebraska, comprising the cities of Lincoln, Prairie Home, Waverly, Walton, Cheney, and Emerald. The primary goal of their approximately 500 employees is to provide an adequate and reliable electric supply at the lowest possible cost to its more than 116,000 residential customers and 15,000 commercial and industrial customers.

- Nebraska Public Power District (NPPD) - NPPD is Nebraska’s largest electric utility, with a chartered territory including all or parts of 86 of Nebraska’s 93 counties. NPPD was formed on Jan. 1, 1970, when Consumers Public Power District, Platte Valley Public Power and Irrigation District (PVPPID) and Nebraska Public Power System merged to become NPPD. Merger properties also included assets formerly operated by Loup River Public Power District. NPPD is a public corporation and political subdivision of the state of Nebraska. The utility is governed by an 11-member Board of Directors, who are popularly elected from NPPD’s chartered territory. NPPD’s revenue is mainly derived from wholesale power supply agreements with 50 towns and 25 rural public power districts and rural cooperatives that rely totally or partially on NPPD’s electrical system. NPPD also serves about 80 communities at the retail level. Over 5,200 miles of transmission lines make up the NPPD electrical grid system, which delivers power to about 600,000 Nebraskans.

APPENDIX 2: DESCRIPTION OF IS MEMBERS

- Basin Electric Power Cooperative - Basin Electric Power Cooperative (Basin Electric) is one of the largest electric generation and transmission (G&T) cooperatives in the United States. Basin is a not-for-profit generation and transmission cooperative incorporated in 1961 to provide supplemental power to a consortium of rural electric cooperatives. Basin has a diverse energy portfolio consisting of coal, gas, oil, nuclear, distributed, and renewable energy, including wind power. Basin is consumer owned by 137-member cooperative systems whose members' service territories comprise 540,000 square miles in nine states. By end of year 2013 Basin Electric will operate 4,824 megawatts (MW) of wholesale electric generating capacity and have 5,289.2 MW of capacity within its generation portfolio. Basin owns 2,165 miles and maintains 2,250 miles of high-voltage transmission, and owns and maintains equipment in 70 switchyards and 149 telecommunication sites and serves 2.8 million electric consumers.

- Heartland Consumers Power District - Heartland is a non-profit public power district headquartered in Madison, South Dakota. Heartland is a public corporation and political subdivision of the State of South Dakota, formed in 1969 under South Dakota's Consumers Power District statutes – Title 49, Chapters 35-40 – which is similar in structure to Nebraska public power entities. Heartland is a wholesale power supplier to 29 municipal systems in SD, MN and IA, five South Dakota state institutions and one cooperative – mostly supplemental to Western. These 35 customers represent load of 140 MW. Heartland is a minority owner of the Integrated System and most of their assets are jointly owned with other public entities.

- Western Area Power Administration (Western): Upper Great Plains (UGP) Region - The Upper Great Plains Region is one of four regions of the Western Area Power Administration. Western UGP has 378,000 square miles of service area including 118 substations and 7,920 miles of transmission lines which are federally owned. UGP sells power in Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota to wholesale customers such as towns; rural electric cooperatives; public utility and irrigation districts; Federal, state, and military agencies; Native American tribes; investor-owned utilities; power marketers; U.S. Bureau of Reclamation; and U.S. Army Corps of Engineers customers. UGP sells more than 9 billion kilowatt-hours of firm power generated from eight dams and power plants of the Pick-Sloan Missouri Basin Program-Eastern Division. This power is enough to serve more than 3 million households.

APPENDIX 3: DESCRIPTION OF ENTERGY

Entergy Corporation is an integrated energy company engaged primarily in electric power production and retail distribution operations. Entergy owns and operates power plants with approximately 30,000 megawatts of electric generating capacity, including nearly 10,000 megawatts of nuclear power, making it one of the nation's leading nuclear generators. Entergy delivers electricity to 2.8 million utility customers in Arkansas, Louisiana, Mississippi and Texas. Entergy operates a system composed of approximately 15,500 miles of interconnected transmission lines at voltages of 69 kilovolt and above and approximately 1,500 substations across a 114,000 square mile area.

ENTERGY/MISO INTEGRATION
Transition Period Cost Allocation – Non-MVPs

Type and Location of Project	Approved Before Transition Period		Approved and/or Identified[1] During Transition Period		Approved After Transition Period Ends
	Treatment During Transition Period	Treatment After Transition Period	Treatment During Transition Period	Treatment After Transition Period	
Non-MVP projects terminating First Planning Area	Allocated solely to First Planning Area	Allocated solely to First Planning Area	Allocated solely to First Planning Area	Allocated solely to First Planning Area	Allocated as applicable to both Planning Areas
Non-MVP projects terminating in Second Planning Area	Subject to South Planning Area pre-transition Tariff(s)	Allocated solely to Second Planning Area	Allocated solely to Second Planning Area[1]	Allocated solely to Second Planning Area[1]	Allocated as applicable to both Planning Areas
Non-MVP projects terminating in both Planning Areas	Not Applicable	Not Applicable	Allocated as applicable to both Planning Areas	Allocated as applicable to both Planning Areas	Allocated as applicable to both Planning Areas

Non-MVPs = Baseline Reliability Projects, Generator Interconnection Projects, and Market Efficiency Projects

[1] Includes projects identified, but not yet approved, with in-service date no more than 5 years after end of transition period.

In MISO's tariff, the Midwest Planning Area is referred to as the First Planning Area and the South Planning Area is referred to as the Second Planning Area.

Source: Attachment FF-6, Section IV

ENTERGY/MISO INTEGRATION
Transition Period Cost Allocation –MVPs

Location of MVP Project	Treatment During Transition Period of Projects Approved		Treatment After Transition Period of Projects Approved		
			MVP Cost/Benefit Test Not Met	MVP Cost/Benefit Test Met	
	Before Transition Period	During Transition Period	Before and During Transition Period	Before and During Transition Period	After Transition Period
MVP terminating in First Planning Area	Allocated within First Planning Area	Allocated within First Planning Area	Allocated within First Planning Area	Begin 8 year phase-in of cost allocation to SPA	Allocated as applicable to both Planning Areas
MVP terminating in Second Planning Area	Not Applicable	Allocated within Second Planning Area	Allocated within Second Planning Area	Begin 8 year phase-in of cost allocation to FPA	Allocated as applicable to both Planning Areas
MVP terminating in both planning areas	Not Applicable	Allocated as applicable to both Planning Areas	Allocated as applicable to both Planning Areas	Allocated as applicable to both Planning Areas	Allocated as applicable to both Planning Areas

MVP = Multi-Value Projects FPA = First Planning Area or MISO Midwest SPA = Second Planning Area or MISO South
In MISO's tariff, the Midwest Planning Area is referred to as the First Planning Area and the South Planning Area is referred to as the Second Planning Area.

Source: Attachment FF-6, Section IV

APPENDIX 4: PREVIOUS COST ALLOCATION AND INTEGRATION APPROACHES

4.1.1 NEBRASKA INTEGRATION

The members of the Nebraska Integration consist of: Omaha Public Power District (OPPD), Lincoln Electric System (LES), and Nebraska Public Power District (NPPD). A summary of each entity can be found in Appendix 1.

4.1.1.1 EVALUATION PROCESS

There was no formal, documented process SPP used for the Nebraska integration. After the Nebraska integration there was a request from SPP members to document the integration process which the Strategic Planning Committee (SPC) developed. The SPC further refined the integration process in July 2015 with the approval of SPC Task Force on New Members SPP Stakeholder Communication Process.

4.1.1.2 TRANSMISSION SYSTEM STUDY

A transmission system study was performed in 2008. The purpose of the transmission system study was to perform an evaluation of the Nebraska transmission system to ensure its transmission facilities met SPP criteria and NERC standards as interpreted by SPP.

4.1.1.3 COST ALLOCATION

The Nebraska entities joined SPP in 2009. The Nebraska entities paid all regional cost sharing for regional facilities to date, as well as in the future, and SPP members cost shared in one project NPPD was constructing. The Annual Transmission Revenue Requirement (ATRR) Nebraska cost shared in was around $7 million and the SPP members cost shared 33% of phase one (1) of NPPD's 345kV ETR project. The regional cost allocation methodology at this time was base plan funding that was approved in 2005 and allocated funding 33% regionally and 67% zonal based on a MW-Mile calculation.

4.1.2 INTEGRATED SYSTEM INTEGRATION

The IS consists of three (3) members: Basin Electric Power Cooperative, Heartland Consumers Power District, and Western Area Power Administration (Western) Upper Great Plains (UGP) Region. A summary of each entity can be found in the Appendix 2.

4.1.2.1 EVALUATION PROCESS

The following steps describe the evaluation process:

1. SPP Staff and the Transmission Working Group (TWG) evaluation of IS system.

2. SPP's staff evaluation of cost and benefits of the IS joining SPP was shared with Stakeholders.
3. Evaluation of cost/benefits included transmission expansion, SPP administrative fee, transmission service revenue, reserve sharing, and market impacts.
4. Tariff revisions were approved by the Regional Tariff Working Group (RTWG), Markets and Operations Policy Committee (MOPC), SPP Board of Directors and Members Committee (BOD/MC).
5. Membership Agreement/Bylaw Changes were approved by Corporate Governance Committee (CGC), the SPP BOD/MC
6. RSC Discussion - Potential for new RSC membership.
7. BOD/MC approved Changes filed with and approved by FERC.

SPP used the member integration process approved by the SPC to assist SPP Staff with the process of working with the IS to explore membership in SPP. This is the same process used with prospective members since the Nebraska entities joined SPP. This evaluation process involves the SPC appointing a sub-group to assist SPP Staff with regular reports to the SPC. This process was also used during negotiations with Entergy on prospective membership. The SPC chair appointed a sub-group in September, 2012 to assist SPP Staff based on the interest expressed by the IS. SPP Staff reviewed progress with the SPC in all meetings including three meetings (May 1, 2013, October 17, 2013 and January 16, 2014) that were in executive session. State regulatory staff were included in the executive sessions held as part of the May 1, 2013 and October 17, 2013 meetings. In these meetings SPP Staff received comments and adjustments to the proposals in negotiations with the IS entities. SPP Staff validated with SPC the proposals provided to the IS parties in the negotiations. The SPC further refined the integration process in July 2015 with the approval of SPC Task Force on New Members SPP Stakeholder Communication Process. (See attachment

As part of the discussions at the SPC, SPP Staff provided two analyses needed for SPP members:

- Cost/Benefit Analysis for SPP from IS joining SPP
- Transmission Analysis to ensure that IS transmission facilities met SPP standards (SPP Criteria and SPP interpretation of NERC Standards) (See below at 5.1.2.2)

4.1.2.2 TRANSMISSION SYSTEM STUDY

The purpose of the transmission system study was to perform an evaluation of the IS transmission system in the event a decision was made to join the SPP RTO. There were two main objectives of the System Study:

- Evaluate the IS transmission system to determine whether it met SPP's Planning Criteria and NERC TPL Standards
- Identify the SPP "need-by" dates of the transmission projects provided by the IS in relation to the assumed October 2015 integration date

4.1.2.3 COST ALLOCATION

During the negotiation process an assumed integration date was set for October 1, 2015, based on estimated time needed for IS parties to obtain approval and also complete integration activities to integrate into SPP. Costs for any upgrades to the IS system needed before the integration date are paid for by the IS members only, while costs for any upgrades to the SPP system needed before the integration date are paid for by SPP members only. Costs for any upgrades to the IS system and/or the SPP system needed after the integration date are cost shared according to SPP Highway/Byway methodology.

The one exception to this cost allocation methodology relates to a portion of the FSE, which only applies to Western-UGP. The FSE is set forth in Section 39.3(e) of the SPP OATT and includes modifications to Schedule 11 and Attachment AE.

The FSE applies to the transmission of Federal Power from Western-UGP resources to meet Western-UGP's Statutory Load Obligations under the Tariff. Western-UGP is exempt from the Schedule 11 Region-wide Charge for delivery of its Federal Power from Western-UGP resources to its Statutory Load Obligations internal to the Upper Missouri Zone (UMZ) or delivery across the UMZ to obligations external to the UMZ or external to SPP. Western-UGP will pay regional Schedule 11 charges for any deliveries of power to loads other than its Statutory Load obligations internal to the UMZ and for any deliveries of power from resources other than its own hydropower resources. Western-UGP is responsible for its share of Schedule 11 Zonal charges. The FSE will not apply to Basin Electric or Heartland or any other entity embedded within Zone 19 nor will it apply to Western-UGP's marketing activities in the Integrated Marketplace to either purchase or sell energy.

Additionally, any load served by Western-UGP in the Western Interconnection utilizing transmission facilities in the UMZ will not be subject the Schedule 11 Region-wide Charge to the extent the load is served only by resources in the Western Interconnection.

An additional part of the FSE is that Western-UGP is also exempt from congestion and marginal loss charges for deliveries of Federal Power from Western-UGP resources across the UMZ to its Statutory Load Obligations. Western-UGP is responsible for providing SPP with energy losses in accordance with Attachment M of the Tariff.

4.2 ENTERGY MEMBERSHIP PROPOSAL

In 2010, SPP proposed membership to the Entergy Corporation. A summary describing this entity can be found in Appendix 3.

4.2.1 EVALUATION PROCESS

SPP used the member integration process approved by the SPC to assist SPP Staff with the process of working with Entergy to explore membership in SPP. This is the same process used with prospective members since Nebraska entities joined SPP. This process involves the SPC appointing a sub-group to assist Staff with regular reports to the SPC. The proposal SPP offered the IS was the same proposal offered to Entergy.

4.2.2 TRANSMISSION SYSTEM STUDY

A transmission system study was performed on the Entergy system. The purpose of the transmission system study was to perform an evaluation of the Entergy transmission system to ensure their transmission facilities met SPP Criteria standards and NERC TPL standards.

4.2.3 PROPOSED COST ALLOCATION

The cost allocation proposal SPP offered Entergy was the same proposal that was subsequently offered to the IS. This involved an integration date where Entergy and SPP would use Highway/Byway cost allocation methodology after Entergy's facilities came under the SPP Tariff. Any upgrades needed to the Entergy System prior to the integration date would be paid for by Entergy and any upgrades needed to the SPP System prior to the integration date would be paid for by SPP members. Entergy decided to join the Midcontinent Independent System Operator (MISO) in April 2011, ending negotiations with SPP.

4.3 OTHER RTO REGIONS

4.3.1 ENTERGY / MISO INTEGRATION

The expansion of MISO's market operations to a new South Region in December 2013 introduced customers in that region to benefits that Midwest Region customers enjoy which include greater reliability, lower costs, and improved oversight. To ensure the benefits accruing to one region are not adversely affected by transmission expansion and upgrade costs in another, MISO developed a transition plan for extending transmission planning and cost allocation practices to its South Region in a just and reasonable manner. The FERC approved on April 19, 2012 MISO's proposal for a five-year transition period, beginning when the first Entergy Operating Company joins the MISO Market.[6]

The cost allocation rules that apply to network upgrades approved before, during, and after the five-year transition period are described in Attachment FF-6 of MISO's Tariffs.[7] Tables summarizing the cost allocation methodology during and after the five-year transition period can be found in Appendix 3.

In general, projects approved prior to the transition period will be subject to the tariff under which they were approved and will not be eligible for cost sharing between the Midwest and South regions. Similarly, the costs of projects approved during the transition period that are located wholly in one region will remain in the region and will not be subject to cost sharing between the two regions. To the extent the projects approved during the transition period terminate in both regions, the associated costs will be allocated to both regions during and after the five-year transition period, in accordance with the cost allocation rules under Attachment FF of MISO's tariffs. The only exception to this cost allocation approach is the treatment of costs of Multi-Value Projects under certain circumstances. Multi-Value Projects (MVP) address energy policy laws and/or provide widespread benefits across MISO footprint and encompass all voltages. Under MISO tariffs, these upgrades are generally subject to 100% regional funding.

During the five-year transition period, MISO will attempt to develop a portfolio of MVPs approved before or during the transition period for the combined Midwest and South Regions (Combined MVP Portfolio) that satisfies a cost benefit test, such that: 1) each zone in the Midwest Region does not experience a degradation in the net benefits estimated for MVPs approved prior to the five-year transition period; and 2) each zone in the South Region will receive a net benefit from the Combined MVP Portfolio. If MISO identifies a Combined MVP Portfolio that satisfies the cost-benefit test by the end of the five-year transition period, then the cost of MVPs approved by MISO before or during the five-year transition period that terminate exclusively in either region will be shared across both regions. Such regional cost allocation will be phased in over eight years at gradually increasing annual percentages of 12.5 percent.

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[6] *Midwest Independent Transmission System Operator, Inc.*, 139 FERC ¶61,056 (2012). FERC subsequently issued Orders on Rehearing and Compliance on November 15, 2012 and July 11, 2013, *Midwest Independent Transmission System Operator, Inc.*, 141 FERC ¶61,128 (2012) and *Midwest Independent Transmission System Operator, Inc.*, 144 FERC ¶61,020 (2013).

[7] MISO, FERC Electric Tariff, ATTACHMENT FF-6, Transmission Expansion Planning and Cost Allocation for Second Planning Area's Transition; https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/One%20Pager%20-%20Cost%20Allocation%20Transition.pdf; https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RECBTF/2016/20160216/20160216%20RECBTF%20Item%2003%20Transition%20Period%20MVP%20Flowchart.pdf

In the event that the Combined MVP Portfolio does not satisfy the cost-benefit test, but the MVPs approved during the transition period that terminate exclusively in either region satisfy the existing benefit criteria of Attachment FF in the MISO tariffs, the associated costs would be shared across the regions pursuant to Attachment FF. On the other hand, if MVPs approved during the transition period that terminate exclusively in either region cannot satisfy the cost-benefit test or the conditions for cost sharing across the regions in Attachment FF, the costs of such MVPs will be allocated solely to the region in which the MVP upgrade terminated. Lastly, if the Combined MVP portfolio does not satisfy the cost-benefit test, the costs of MVPs approved before the transition period (and included in the Combined MVP Portfolio) that, by their nature, terminate only within the Midwest Region, would not be shared across both regions after the five-year transition period.

The costs of network upgrades approved after the end of the five-year transition period will be allocated across the combined regions pursuant to Attachment FF of the MISO tariffs.

4.3.2 PJM INTEGRATIONS

4.3.2.1 ATSI INTEGRATION

On December 17, 2009, FERC approved a regional transmission organization (RTO) realignment request submitted by American Transmission Systems, Inc. (ATSI) to withdraw from MISO and join PJM.[8] The reasons cited by ATSI in support of its proposed realignment request were the elimination of operational efficiencies and reduction in congestion.

As part of its RTO realignment request, ATSI requested a waiver of PJM's annual allocation of regional transmission expansion plan costs, under Schedule 12 of PJM's tariffs, for transmission expansion projects approved by PJM prior to ATSI's integration into PJM.[9] In the event the waiver request was denied, ATSI's parent entity, FirstEnergy Services Company (First Energy), sought a finding that allocation of costs to ATSI for legacy projects in PJM is unjust, unreasonable, and unduly discriminatory.[10] Due to the differing cost methodologies in MISO and PJM, First Energy asserted that the ATSI would be required to pay twice in conjunction with its planned realignment because it would have to pay under both allocations, for projects planned and approved in separate

[8] *American Transmission System, Inc.*, 129 FERC ¶61,249 (2009) (ATSI Realignment Order). FERC subsequently issued an order on September 20, 2012 to address remaining requests for rehearing and clarification, *American Transmission System, Inc.*, 140 FERC ¶61,226 (2012) (ATSI Rehearing Order).

[9] *ATSI Realignment Order* at paragraph 2.

[10] *Id.* at paragraph 3.

RTOs over the same period.[11] MISO allocates its costs on the basis of a one-time allocation at the time specific projects are approved while PJM reallocates costs annually to each transmission owner based on its share of PJM's total load that is within PJM as of the date of the allocation. FERC rejected ATSI's waiver request and dismissed First Energy's complaint.[12]

With respect to cost allocation, FERC required ATSI to honor its financial obligations to MISO for costs associated with transmission facility additions incurred under MISO tariffs prior to withdrawal from MISO[13] although FERC determined that ATSI was not responsible for the costs of the Multi-Value Projects (MVPs) approved by the MISO Board prior to its withdrawal.[14] In addition, ATSI is required to pay the system-wide costs in PJM under Schedule 12 of PJM's tariff, which would include system-wide costs for legacy projects approved by PJM prior to ATSI's integration into PJM on June 1, 2011. FERC recognized that the cost allocation methodologies for the two RTOs were different and that both methodologies had been accepted by FERC as just and reasonable and not unduly discriminatory.

Furthermore, FERC concluded as a basis for its decision that "cost causation also includes the allocation of "costs to serve" that party including those facilities that benefit the party. Even if a new member was not using the system when a particular project was planned or authorized, the new member may nevertheless use and benefit from the new facility in the future."[15] FERC also noted that "ATSI and the PJM transmission owners are free to negotiate the terms of ATSI's entrance into PJM to the extent that ATSI brings benefits to the existing PJM transmission grid" and that " given the voluntary nature of RTOs, such a collaborative effort is the most appropriate manner of resolving such cost issues."[16] On July 18, 2014, the D.C. Circuit Court of Appeals upheld FERC's decision on the cost allocation issue.[17]

4.3.2.2 DUKE ENERGY INTEGRATION

On October 21, 2010, in response to a regional transmission request (RTO) realignment request from Duke Energy Ohio and Duke Energy Kentucky, FERC authorized the two companies to withdraw from the MISO RTO and join the PJM RTO, effective January 1, 2012.[18] Duke

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[11] *Id.* at paragraph 21.
[12] *Id.* at paragraph 7.
[13] *Id.* at paragraph 51.
[14] *Midwest Independent Transmission System Operator, Inc.*, 153 FERC ¶61,101 (2015) at paragraphs 69-78.
[15] *ATSI Rehearing Order* at paragraph 26.
[16] *ATSI Realignment Order* at paragraph 114; *ATSI Rehearing Order* at paragraph 23.
[17] *FirstEnergy Service Co. v. F.E.R.C.*, 758 F.3d 346 (2014).
[18] *Duke Energy Ohio, Inc., et al.*, 133 FERC ¶ 61,058 (2010).

Ohio and Duke Kentucky are wholly owned subsidiaries of Duke Energy Corporation and are principally engaged in providing integrated retail and wholesale electric utility service in Ohio and Kentucky, respectively.

With respect to cost allocation, Duke Energy Ohio and Duke Energy Kentucky were required to honor their financial obligations to MISO, including the transmission cost allocations for projects approved by the MISO Board of Directors prior to the Duke Companies' integration into PJM. However, as in the case of ATSI, the Duke Companies were not responsible for the costs of the Multi-Value Projects (MVPs) approved by the MISO Board prior to their withdrawal from MISO.[19] As far as cost allocation for PJM projects are concerned, Duke Companies are subject to Schedule 12 of the PJM tariffs which allocates costs to the Duke Companies for the projects approved in PJM regardless of whether the projects were approved prior to the companies' integration into PJM (legacy projects) or are approved after their integration into PJM.[20]

[19] *Midwest Independent Transmission System Operator, Inc.*, 153 FERC ¶61,101 (2015) at paragraphs 69-78.

[20] *Duke Energy Ohio, Inc., et al.*, 139 FERC ¶ 61,068 (2012); *Duke Energy Ohio, Inc., et al.*, 151 FERC ¶ 61,029 (2015)

SPP New Member Cost Allocation Review Process Document

and Appendix Acronyms List

AC	Alternating Current
ATSI	American Transmission Systems, Inc.
ATRR	Annual Transmission Revenue Requirement
Board	Southwest Power Pool Board of Directors
CAWG	Cost Allocation Working Group
CEII	Critical Energy Infrastructure Information
ETR	Entergy Corporation
FERC	Federal Energy Regulatory Commission
FPA	First Planning Area or MISO Midwest
FSE	Federal Service Exemption
Highway/Byway	A FERC approved cost allocation methodology
IS	Integrated System, which includes the transmission systems owned by Western Area Power Administration – Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District.
kV	kilovolt (1,000 volts)
MISO	Mid-Continent Independent System Operator, Inc.
MVP	Multi-Value Projects
NERC TPL	North American Electric Reliability Corporation Transmission Planning Standards
NTC	Notice To Construct
OATT	Open Access Transmission Tariff
PJM	Pennsylvania, New Jersey, Maryland Interconnection
RCAR	Regional Cost Allocation Review

SPP New Member Cost Allocation Review Process Document

and Appendix Acronyms List

RSC	Regional State Committee
RTO	Regional Transmission Organization
SPA	Second Planning Area or MISO South
SPC	Strategic Planning Committee
SPP	Southwest Power Pool
TO	Transmission Owner
TPL Standards	Transmission Planning Standards
Western	Western Area Power Administration