THE HISTORY OF THE REGIONAL STATE COMMITTEE

FOR THE SOUTHWEST POWER POOL, INC.

SPP Southwest Power Pool

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2023

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SECTION I: EXECUTIVE SUMMARY

Since the Federal Energy Regulatory Commission (FERC) designated Southwest Power Pool, Inc. (SPP) as a Regional Transmission Organization (RTO) in 2004,[1] the Regional State Committee (RSC) has served a unique and special role in influencing all aspects of SPP. Following FERC's guidance, SPP Bylaws[2] confer on the RSC certain authorities and responsibilities within the governance of SPP.

The membership of the RSC is comprised of one designated commissioner or board member from one state regulatory utility commission or board from each state within the SPP Region where SPP provides services as a regional transmission organization.[3]

Pursuant to Section 7.2 of the SPP Bylaws, the RSC is granted the following specific authorities within the governance of SPP:

1. Cost allocation
2. Financial transmission rights (also known specifically in SPP as transmission congestion rights, or TCRs)
3. Planning for remote resources
4. Regional resource adequacy

Along with these specific authorities, the SPP Bylaws generally grant the RSC the power to join and participate in many of SPP's working groups, task forces and committees. By working in these groups, the RSC may offer input on any issue SPP faces. The RSC has been an active participant in the Synergistic Planning Project Team, Rate Impact Task Force, Regional Allocation Review Task Force, Strategic Planning Committee Task Force on New Member Process, Interregional Cost Allocation Task Force, and Holistic Integrated Tariff Team (HITT).

Outside the general and specific authorities granted them by the SPP Bylaws, the RSC has taken a leadership role on numerous issues that faced SPP through its history. The formation of SPP's markets and addressing cost overruns of transmission projects are examples of initiatives in SPP that were either instigated or lead by the RSC.

This document's intent is to inform readers of the important role and function the RSC has served and will continue to serve in SPP. Compared to authorities granted state regulators

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[1] *Sw. Power Pool, Inc.*, 106 FERC ¶ 61,110 (2004) ("2004 Order"). (A Regional Transmission Organization is an independent electric power transmission system operator that coordinates, controls, and monitors a multistate electric grid).

[2] Southwest Power Pool, Inc., Bylaws, First Revised Volume No. 4.

[3] *Id.* at Section 7.2. The RSC approved the modification to the membership of the RSC at its quarterly meeting on April 25, 2022.

in other RTOs and Independent System Operators (ISO), the RSC has a unique and special place in SPP.

SECTION II: FORMATION OF THE RSC

On February 10, 2004, after three prior attempts by SPP, FERC issued an order conditionally granting SPP recognition as an RTO.[4] In the 2004 Order, FERC also approved the establishment of the RSC. FERC found that:

> *[the RSC] should have the primary responsibility for determining regional proposals and the transition process in the following areas: (1) whether and to what extent participant funding would be used for transmission enhancements; (2) whether license plate or postage-stamp rates will be used for the regional access charge; (3) [financial transmission rights (FTR)] allocation where a locational price methodology is used; and (4) the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights.*[5]

FERC also found that:

> *[t]he RSC should also determine the approach for resource adequacy across the entire region. In addition, with respect to transmission planning, the RSC should determine whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process.*[6]

Lastly, FERC found that:

> *[i]f the RSC reaches a decision on the methodology that would be used, SPP would file this methodology pursuant to Section 205 of the [Federal Power Act (FPA)]. SPP can also file its own proposal pursuant to Section 205.*[7]

On October 1, 2004, after several parties filed petitions for rehearing of the 2004 Order, FERC issued an order clarifying the purpose of approving the RSC. FERC stated the RSC was not created to "usurp state authority, but rather, to facilitate state consensus on certain regional issues and partnership between [FERC] and state commissions."[8] On April 26, 2004, the RSC adopted the proposed Southwest Power Pool Regional State Committee

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[4] *See* 2004 Order..

[5] *Id.* at P 219.

[6] *Id.* at P 220.

[7] *Id.* at P 219.

[8] *Sw. Power Pool, Inc.*, 109 FERC ¶ 61,010, at P 90 (2004).

Bylaws (SPP RSC Bylaws), by unanimous vote by the RSC. The RSC was also incorporated with the State of Arkansas on April 7, 2004.

The SPP RSC Bylaws, as approved by the RSC, states in the Purpose and Membership section:

> *The SPP RSC shall provide collective state regulatory agency input and participation in the Southwest Power Pool, Inc. (SPP) and SPP's Board of Directors, committees, working groups and task forces, including any independent transmission system operator (ISO) or regional transmission organization (RTO) formed by the SPP. Such input and participation shall include but not be limited to: whether and to what extent participant funding will be used for transmission enhancements; whether license plate or postage-stamp rates will be used for the regional access charge; determination of Financial Transmission Rights (FTR) allocations where a locational price methodology is used; determination of the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights; determination of the approach for resource adequacy across the entire region; determination of whether transmission upgrades for remote resources will be included in the regional transmission planning process; and determination of the role of transmission owners in proposing transmission upgrades in the regional planning process.*
>
> *Membership: Open to all government entities that: "Regulate the retail electricity or distribution rates of transmission owning members or transmission dependent utility members of SPP; or "Are the primary regulatory agency responsible for siting electric transmission facilities in states where there are transmission owning members of SPP or independent transmission companies that own or operate transmission facilities associated with the SPP.*

Following FERC's 2004 Order, SPP Bylaws, Section 7.2, the SPP granted the following authorities to RSC:

> *An RSC, to be comprised of one designated commissioner from each state regulatory commission having jurisdiction over an SPP Member, shall be established to provide both direction and input on all matters pertinent to the participation of the Members in SPP. This direction and input shall be provided within the context of SPP's organizational group meetings as well as Board of Directors meetings. The SPP Staff will assist the RSC in its collective Responsibilities and requests by providing information and analysis. SPP will fund the costs of the RSC pursuant to an annual budget developed by the RSC and submitted to SPP as part of its budgeting process, which budget must ultimately be approved by the Board of Directors. The RSC has primary responsibility for determining regional*

> *proposals and the transition process in the following areas: whether and to what extent participant funding will be used for transmission enhancements; whether license plate or postage-stamp rates will be used for the regional access charge; FTR allocation, where a locational price methodology is used; and the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights. The RSC will also determine the approach for resource adequacy across the entire region. In addition, with respect to transmission planning, the RSC will determine whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process. As the RSC reaches decisions on the methodology that will be used to address any of these issues, SPP will file this methodology pursuant to Section 205 of the Federal Power Act. However, nothing in this section prohibits SPP from filing its own related proposal(s) pursuant to Section 205 of the Federal Power Act.*

In 2004, the SPP RSC Bylaws also established the Cost Allocation Working Group (CAWG). This working group consists of one staff member from each state regulatory commission represented in the RSC.[9] The CAWG is tasked with assisting the RSC in addressing the matters for which the RSC has primary responsibility as defined in Section 7.2 of the SPP Bylaws and with assisting the RSC in addressing other issues as requested.

[9] Regional State Committee Bylaws, Article VI.

SECTION III: RSC AUTHORITIES

The RSC was the first organization of state regulators from multiple states to be expressly granted authorities in a FERC jurisdictional RTO or ISO. Detailed below is a description of each of the RSC's important authorities and a summary of how the RSC exercised them throughout its history.

A. COST ALLOCATION

As an RTO, SPP's central role is to maintain the reliability of the North American bulk power grid. SPP's success in this regard depends on a robust transmission infrastructure capable of transporting electricity from where it is generated to where it is most needed. The cost of implementing this infrastructure is of interest to all of SPP's members and stakeholders, especially those regulatory commissions throughout SPP's footprint who oversee how these costs affect retail and end-use customers' rates. How the costs of transmission infrastructure enhancements are allocated across SPP is an important authority granted to the RSC.

Cost allocation is arguably the RSC's most important authority in SPP's governance. The RSC exercises this authority in two specific areas: (1) whether and to what extent participation funding will be used for transmission enhancements; and (2) whether license plate or postage-stamp rates will be used for the regional access charge. Throughout its history, the RSC's most frequently exercised authority has been that of cost allocation. Below is the historical development of cost allocation methodologies approved by the RSC.

I. THE ORIGINAL REGIONAL COST ALLOCATION (BASE PLAN FUNDING)

After FERC approved SPP as an RTO in 2004,[10] SPP became responsible for planning and expansion of transmission in its region. The RSC's first exercise of its cost allocation authority was approval of SPP's base-plan funding on October 26, 2004. Base-plan funding was developed from a CAWG proposal which specified how to allocate base plan funded projects in SPP. The SPP Board of Directors also approved base-plan funding on January 25, 2005, after which SPP filed the proposed cost allocation with FERC, who approved it on April 22, 2005.[11]

Base-plan funding proposed changes to SPP's Open Access Transmission Tariff (OATT, or tariff).[12] As amended by the base-plan funding proposal, the tariff would place new transmission expansion projects into one of four categories: (1) SPP base plan facilities; (2) economic upgrades; (3) generation interconnection facilities; and (4) facilities required to respond to transmission requests. Base-plan funding defined base plan facilities as "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 those upgrades required for new or changed Designated Resources to the extent allowed for in Attachment J to this Tariff."[13] Economic upgrades are defined as "[e]lective upgrades, identified in the SPP Transmission Expansion Plan, which have potential economic benefits to the SPP Region, but are not required for reliability reasons."[14] Lastly, requested upgrades are defined as "[t]ransmission upgrades, requested by a Transmission Customer or other entity, which do not meet the definition of any other category of Network Upgrades."[15]

Base-plan funding cost allocation was based on a dollar-threshold amount. If the cost of a base-plan upgrade was less than or equal to $100,000, the associated annual transmission revenue requirement was allocated to the zone in which the upgrade was located. If the upgrade's cost was greater than $100,000, one-third of its revenue requirement was allocated to the region on a postage-stamp basis, and the remaining two-thirds would be allocated locally to whatever zone the project was being built based on each zone's share of the incremental MW-mile benefits as computed in Section 4 of Attachment Z of the OATT. Economic upgrades, if constructed, would be allocated in accordance with agreements reached with project sponsors. Generation interconnection facilities and facilities required to respond to transmission requests would be allocated consistent with

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[10] *Sw. Power Pool, Inc.*, 109 FERC ¶ 61,009 (2004); *order on reh'g*, 110 FERC ¶ 61,137 (2005).

[11] *Sw. Power Pool, Inc.*, 111 FERC ¶ 61,118 ("Base Plan Funding Order"), *order on reh'g*, 112 FERC ¶ 61,319 (2005).

[12] Southwest Power Pool, Inc., Open Access Transmission Tariff.

[13] Base Plan Funding Order at n. 7.

[14] *Id.* at n. 8.

[15] *Id.* at n. 9.

provisions of the OATT, although the base plan cost allocation provided a waiver mechanism for network upgrades associated with certain designated network resources to be treated the same as base-plan facilities.

II. BALANCED PORTFOLIO AND ECONOMIC UPGRADES

The RSC's next exercise of its cost allocation authority was focused on cost allocation for economic upgrades. SPP's transition from primarily reliability-focused transmission expansion to a portfolio of projects that were focused on economic upgrades marked a significant advancement toward construction of a modern transmission system enabling reliability and reduced energy cost for consumers. On January 28, 2008, the RSC approved a cost-allocation methodology known as the Balanced Portfolio: a portfolio of transmission upgrades with a collective benefit-to-cost ratio of greater than a 1.0 by virtue of a balancing process.

For the two years prior to the RSC approving the Balanced Portfolio, the CAWG worked with SPP and its stakeholders to develop a cost-allocation procedure for economic upgrades. The CAWG prepared a concept paper outlining a "balanced portfolio" approach for economic upgrades including a regional postage-stamp rate design for recovery of their costs. The RSC unanimously adopted the paper, and SPP's Regional Tariff Working Group subsequently developed tariff language to implement the cost-allocation approach and rate design. On July 29, 2008, the SPP Board of Directors approved the proposed tariff revisions with the unanimous support of the Members Committee.

SPP filed with FERC a request for approval of the RSC's Balanced Portfolio of economic upgrades. On October 16, 2008, in Docket No. ER08-1419, FERC accepted SPP's request to approve the RSC's establishment of a process to evaluate a portfolio of economic upgrades to be included in SPP's Transmission Expansion Plan rather than evaluate the benefits of individual upgrades.[16]

Specifically, the RSC's Balanced Portfolio enabled SPP to evaluate a portfolio's costs and benefits to determine whether it is "cost beneficial" and "balanced" for identified upgrades. A portfolio is "cost beneficial" when the sum of the net present value of the benefits of the upgrades equals or exceeds the net present value of the costs of the upgrades over the same ten-year period and assuming that all the upgrades are available at the same time during the ten-year period. A portfolio is "balanced" when in each zone the sum of the net present value of the benefits equals or exceeds the net present value of the costs over the same ten-year period. In short, a portfolio is "balanced" when the upgrades are determined to be "cost beneficial" for each SPP zone simultaneously.

Under the RSC's Balanced Portfolio methodology, once SPP's Board of Directors approves a balanced portfolio, 100 percent of its revenue requirement (including revenue requirements for economic upgrades and those associated with reliability upgrades included to achieve balance) will be recovered through SPP's postage-stamp based region-wide charge. The region-wide postage-stamp charge was to be assessed to all

[16] *Sw. Power Pool, Inc.*, 125 FERC ¶ 61,054 (2008), *order on reh'g*, 127 FERC ¶ 61,271 (2009).

load, including resident load and transmission customers taking point-to-point transmission service under the SPP tariff.

Pursuant to the Balanced Portfolio methodology, a portfolio is "balanced" when the adjusted production cost benefits calculated for each zone are simultaneously equal to or greater than the costs allocated to each zone based on a ten-year planning horizon. To ensure that that there was a balance between projected construction costs and the actual construction costs of the projects are included in rates, the methodology allows for incremental transfers and reallocation of revenue requirements from deficient zones (meaning those zones that are not receiving as least as much net present value in benefits compared to net present value cost, by reducing the disadvantaged zone(s)'s costs). Although this balancing does not result in exact equality in benefits among zones, it still ensures that all zones benefit from the balanced portfolio and that no zone is harmed or received little or no benefit.

This reallocation of revenue requirements is triggered when at least 10 percent of an approved balanced portfolio's projects' associated costs have been included in rates. On the trigger date, 20 percent of the reallocated revenue requirements are transferred to the balanced portfolio region-wide annual transmission revenue requirement total. On the anniversary of the trigger date in the subsequent four years, an additional 20 percent of the reallocated revenue requirement is transferred to the total balanced portfolio region-wide annual transmission revenue requirement total. After the fifth annual transfer, the balanced portfolio is trued up based on actual construction costs for the upgrades measured against benefits estimated at the time the upgrades were approved. Over the next five years, the final amount of reallocated revenue requirements is determined. The ten-year analysis reviews the annual reallocation amount in the remaining years six through ten and increases annual reallocation to an adequate level to offset, on a present value basis, the lesser amount of the reallocated revenue requirements for years one through five such that the present value of the total amount of the reallocated annual revenue requirements is consistent with the balanced portfolio.

On August 2, 2012 — and amended on September 26, 2012 — SPP submitted tariff revisions to FERC to update revenue requirements and associated rates to implement the initial reallocation of revenue requirements of the first of SPP's board-approved balanced portfolios. On November 20, 2012, FERC accepted the proposed revisions effective October 1, 2012, for the initial reallocation of 20 percent of the estimated costs, and October 1 of each year for all subsequent annual reallocations for years two (2013) through five (2016).[17]

On September 29, 2017, in Docket No. ER17-2583, SPP submitted an informational filing to notify FERC of the implementation of the final reallocation and true-up of reallocated revenue requirement in accordance with the balanced portfolio process. SPP noted it would implement the final reallocation and true-up of allocated revenue requirement for

[17] *Sw. Power Pool, Inc.*, 141 FERC ¶ 61,149 (2012).

years six (2017) through ten (2021) on October 1 of each year commencing in 2017. After year 2021, when the portfolio would be deemed "balanced", the reallocation of revenue requirements would be complete. In a letter order on December 13, 2017, FERC accepted SPP's notice of the implementation of the final reallocation and true-up of reallocated revenue requirements of the balanced portfolio.[18]

There has been only one balanced portfolio approved through the transmission upgrade process.

[18] *Sw. Power Pool, Inc.*, Letter Order, Docket No. ER17-2583-000 (Dec. 13, 2017).

III. HIGHWAY/BYWAY

In December 2008, the SPP Board of Directors formed the Synergistic Planning Project Team (SPPT) to holistically assess SPP's transmission planning processes and cost allocation methodologies. The SPPT consisted of representatives of the RSC; representatives from SPP's membership; an officer of SPP; an independent, non-SPP stakeholder; and an outside facilitator.

In April 2009, the board approved the SPPT's recommendations, including development of a new transmission planning process, and asked the RSC to evaluate a highway/byway-type cost allocation methodology in which both reliability and economic projects could be evaluated and cost could be allocated in a common process.

On April 23, 2009, the SPPT issued a report with recommendations to revise SPP's cost allocation and transmission planning processes. They recommended adopting the Highway/Byway methodology and the Integrated Transmission Planning (ITP) Process[19] and identifying and recommending a list of extra high voltage (EHV) "priority projects"[20] to be approved by the Board of Directors within six months. The RSC and CAWG met frequently from April through October 2009 to develop a cost allocation methodology according to the SPPT's recommendations. On October 26, 2009, the RSC approved the CAWG's recommended cost allocation methodology (which formed the basis for SPP's Highway/Byway methodology) with only Nebraska voting no.

VOLTAGE	REGIONAL	ZONAL
300 kV and above	100%	0%
Above 100 kV and below 300 kV	33%	67%
100 kV and below	0%	100%

Table 1: Cost allocation of transmission facilities according to the Highway/Byway methodology

The Highway/Byway methodology proposed to allocate costs of future transmission facilities based on their voltage level, with the cost of EHV facilities (operating at or above 300kV) allocated 100 percent to the regional rate; the cost of mid-tier facilities (operating above 100 kV and below 300 kV) allocated on a one-third-regional/two-thirds-zonal basis;

[19] *See infra* Section (3)(A) for more on ITP.

[20] Priority Projects were defined as projects at that time that continued to show up in multiple system evaluations as needed to relieve congestion in existing flowgates (i.e. boundaries between two parts of a transmission system that has a defined limit of power that can flow across it) and to tie the eastern and western sections of the region together.

and the cost of low voltage facilities (operating at or below 100 kV) allocated entirely to the zone. By allocating costs in this manner the Highway/Byway methodology provides a tariff mechanism that appropriately allocates the costs of projects developed in a comprehensive regional planning process and ensures a correlation between the costs and benefits of the enhancements.

On June 17, 2010, FERC approved the Highway/Byway methodology in Docket No. ER10-1069,[21] ruling "the proposed Highway/Byway methodology is an important step in facilitating investment in new transmission facilities to integrate the eastern and western portions of the SPP grid, reduce congestion, efficiently integrate new resources, and accommodate new or growing loads."[22]

[21] *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010).
[22] *Id.* at P 4.

IV. SAFE HARBOR LIMITS

When SPP proposed its original base-plan funding cost allocation methodology, a safe harbor provision was added to the plan. The provision relates to costs of facilities needed for network upgrades associated with designating a generation resource.[23] Specifically, a designated resource is eligible for base-plan funding if among other things, its costs are less than or equal to $180,000 per MW. The safe harbor limit establishes the maximum allowable cost of network upgrades associated with designating a generating resource that is eligible for base plan funding. After numerous arguments that the safe harbor limit was too low, FERC approved the $180,000 per MW threshold as an initial amount in Docket No. ER05-652 (original cost allocation).[24] FERC directed SPP to assess average costs of all network upgrades as part of its biennial planning process and work with stakeholders and the RSC to evaluate the effectiveness and accuracy of the $180,000 per MW threshold.[25] FERC directed SPP to file a report each year to include: (1) average costs of new network upgrades and the effectiveness of the safe harbor threshold; (2) a regional cost allocation review (now done separately every three years); and (3) SPP's disposition of requests for waiver of base-plan criteria.[26] Since 2006, SPP has complied with this yearly filing requirement.

Although SPP has made a yearly compliance filing with FERC relating to the safe-harbor provision, the safe-harbor cost limit has never been changed since FERC approved SPP's original cost allocation in 2005. On April 17, 2017, the RSC directed CAWG to review the $180,000 safe harbor cost limit to determine if it was still appropriate. On July 24, 2017, the RSC approved CAWG's recommendation not to modify the $180,000 safe harbor cost limit. They also approved CAWG's recommendation for the RSC to direct CAWG to conduct a limited review of the three base-plan funding eligibility criteria and the $180,000 per safe-harbor limit on an annual basis with a more in-depth review at least once every five years. The RSC directed CAWG to synchronize the limited review with SPP's annual filing with FERC.

In 2019, CAWG conducted a limited review of the three base-plan funding eligibly criteria and the $180,000 safe-harbor limit. At the July 29, 2019 RSC quarterly meeting, after CAWG had conducted a limited review three times the RSC unanimously recommended that the next review of the base-plan funding eligibly criteria and the $180,000 safe-harbor limit will be a full review to be completed in 2022.

On January 30, 2023, The RSC unanimously approved keeping three base-plan funding eligibiliyy criteria and the $180,000 safe-harbor limit for 2023 and directed SPP Staff and

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[23] Safe Harbor is not applicable to other transmission upgrades approved through the transmission expansion plan.

[24] *See* Base Plan Funding Order at P 51.

[25] *Id.*

[26] *Id.*

CAWG to assess the impacts of various Supply Adequacy Working Group initiatives on the three base-plan funding eligibility criteria and the $180,000 safe-harbor limit.

V. WIND COST ALLOCATION

After the formation of the SPP RTO, several states in SPP's footprint adopted renewable portfolio standards (RPS) with various requirements. These state policies along with federal tax policies led the RSC to consider unique issues related to wind resources and wind cost allocation. These issues and related proposals were initially discussed by the CAWG on October 24, 2007 and were reviewed by the RSC at four separate meetings. On June 16, 2008, the RSC unanimously approved a wind cost allocation proposal.

On June 18, 2009, in Docket No. ER09-1039, FERC conditionally accepted SPP's filing for the proposed wind cost allocation.[27] Under the SPP OATT, before the new wind cost allocation methodology was developed, the costs of network upgrades associated with designating a generation resource were eligible for base-plan funding if, among other things, the costs were less than or equal to the safe-harbor limit. The safe-harbor limit established the maximum allowable cost of network upgrades associated with designating a generating resource that were eligible for base-plan funding (currently 33 percent postage-stamp to region and 67 percent on a megawatt-mile basis to SPP pricing zone or zones that were affected by the network upgrade based on power flow analysis). Costs that exceeded safe harbor limit or were not otherwise eligible for base plan funding were directly assigned to the customer. Because the fuel source for wind resources is intermittent, SPP had generally assigned wind resources a net dependable capacity of 10 percent of their nameplate capacity to calculate the safe-harbor limit for network upgrade costs associated with wind resources. Therefore, the level of network upgrade costs associated with wind resources that were eligible pursuant to the safe-harbor limit for base-plan funding were significantly less than that for other types of generating resources.

Generally, network upgrades associated with designating a wind resource were constructed in a zone where the wind resource is located (host zone). Thus, the host zone was allocated a majority of the network upgrade costs on a MW-mile basis. This outcome was reasonable when the wind resource was serving load within the same zone because the zone that required the network upgrades received the benefit of the upgrades and bore the costs accordingly. However, SPP's cost allocation methodology at the time often resulted in the host zone and other non-point-of-delivery zones for wind resources being allocated a disproportionate share of the costs of such transmission when the load being served was outside the resource's host zone because SPP's MW-mile methodology took into account the location of the network upgrades and not the zone that benefited from the network upgrades.

[27] *Sw. Power Pool, Inc.*, 127 FERC ¶ 61,283 (2009).

SPP's FERC-approved wind cost allocation allows customer's requested capacity (i.e. up to 100 percent of nameplate capacity) to be used to calculate a safe harbor limit for network upgrade costs associated with designating a wind resource instead of having to use the only the net dependable capacity (i.e., 10 percent of nameplate capacity). By more wind resources qualifying for the safe-harbor limit, the transmission customers associated with new wind resources would be directly assigned a much smaller portion of the network upgrade costs.[28] Also, the FERC-approved wind cost allocation allows for the cost of network upgrades needed for a wind resource to serve load in another zone. Therefore, if the cost for the network upgrades associated for a wind resource serving load in another zone and the project otherwise meets the eligibility requirements for base-plan funding, the cost for the network upgrades shall be allocated as follows:

- 67 percent of the costs will be allocated to the entire SPP region on a postage-stamp basis
- 33 percent of the costs will be directly assigned to the transmission customer.[29]

Part of SPP's FERC-approved proposal limited base-plan funding eligibility for network upgrades from a wind resource if the sum of a customer's newly requested transmission capacity designated for wind and its existing transmission capacity designated for wind exceeds 20 percent of the customer's projected system peak responsibility in the first year the customer plans to take service from the wind resource.[30]

[28] *Id.*
[29] *Id.*
[30] *Id.*

VI. COST ALLOCATION OF WIND RICH AREAS

In January 2018, the RSC directed the CAWG to assess cost allocation in wind rich areas. The CAWG developed a scope of work that was approved by the RSC in April 2018. The CAWG completed a Wind Rich Cost Allocation Report, which was a summary of the work that the CAWG completed during the investigation into cost allocation of wind rich areas and the actions recommended for approval by the RSC. As detailed in the Wind Rich Cost Allocation Report, the CAWG reviewed several analyses and presentations prepared by SPP staff, stakeholders, and CAWG members between May 2018 and January 2019. In February 2019, the CAWG adopted the following motion: "The Cost Allocation Working Group has determined that the current cost allocation methodology and/or rate recovery mechanism in zones with a high proportion of generation relative to zonal load is not reflective of cost causation principles."

In coordination with recommendations by the HITT, the CAWG approved three recommendations to the RSC. These recommendations are as follows:

1. Decouple Schedule 9 and Schedule 11 transmission pricing zones, allowing for potentially larger Schedule 11 pricing zones (HITT recommendation)

2. Evaluate byway facility cost allocation review process (HITT recommendation)

3. Complete a future study of a generator injection rate (stand-alone recommendation)

At a special meeting on August 5, 2019, the RSC approved the Wind Rich Cost Allocation Report, completing the task assigned by the RSC in January 2018, and directed the CAWG to work on implementing the following recommendations: Decouple Schedule 9 and Schedule 11 transmission pricing zones, allowing for potentially larger Schedule 11 pricing zones, evaluate byway facility cost allocation review process, and complete a future study of a generator injection rate.

VII. ORDER 1000 COST ALLOCATION

FERC issued Order No. 1000 (Order 1000) on July 21, 2011, directing public utility transmission providers like SPP, in consultation with their stakeholders, to implement a series of reforms to existing transmission planning and cost allocation processes to ensure the rates, terms and conditions of service provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential.[31] Order 1000 directed public utility transmission providers to:

1. Participate in a regional transmission planning process that produces a regional transmission plan
2. Modify their OATTs to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in both local and regional transmission planning processes
3. Eliminate provisions in FERC-jurisdictional tariffs and agreements that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation
4. Coordinate, through their regional transmission planning processes, with each of their neighboring transmission planning regions within their interconnection to implement interregional transmission coordination procedures
5. Adopt in their OATTs a method or set of methods for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation and interregional transmission facilities

On April 23, 2012, to comply with Order 1000's requirement for interregional cost allocation, the RSC voted to form the Interregional Cost Allocation Task Force (ICATF), which was a joint task force comprised of three RSC members, three SPP members, and one SPP board member. The ICATF was charged to look at proposals for interregional cost allocation pursuant to Order 1000, and they decided that interregional Order 1000 projects should be allocated through Highway/Byway cost allocation or through highway allocation only (regional/postage-stamp basis). The ICATF's preference was for highway cost allocation only.

On October 29, 2012, CAWG presented the group's approved principles and guidelines to use in discussion with SPP's seams neighbors and developing projects with SPP's seams neighbors. CAWG recommended that any Order 1000 interregional projects with SPP's seams neighbors that are selected pursuant to interregional planning process be 100 percent regionally allocated. All the CAWG members except for those from New Mexico and Texas supported the recommendation. The RSC approved CAWG's recommendation

[31] *Transmission Planning and Cost Allocation by Transmission Owning and Operation Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011).

to allocate selected Order 1000 interregional planning projects on a 100 percent regional basis. RSC members from Texas and New Mexico voted against the recommendation.

SPP filed its compliance filings pursuant to Order 1000 in Docket No. ER13-1939.[32] SPP in its filing proposed to use highway cost allocation of 100 percent of the regional cost allocation for any interregional projects approved by the SPP Board of Directors. FERC approved SPP's filing for highway regional cost allocation on March 19, 2015; 150 FERC ¶ 61,210 (First Order); August, 2015, 152 FERC ¶ 61,172 (Second Order); and February 2, 2016, 154 FERC ¶ 61,075 (Third Order). FERC found SPP had demonstrated that an Order 1000 interregional transmission facility of 100 kV or above provides sufficient regional benefits to support a highway regional cost allocation.

As of today, no Order 1000 interregional projects have been built in SPP's footprint.

[32] *See* Compliance Filing of Southwest Power Pool, Inc., Docket No. ER13-1939-000 (July 10, 2013); Order No. 1000 Interregional Compliance Filing for the SPP-SERTP Seam of Southwest Power Pool, Inc., Docket No. ER13-1939-001 (May 18, 2015); Order No. 1000 Interregional Compliance Filing for the SPP-SERTP Process of Southwest Power Pool, Inc., Docket No. ER13-1939-002 (Sept. 30, 2015).

VIII. NON-ORDER 1000 COST ALLOCATION

SPP identified through its Seems Steering Committee the need to develop procedures to plan and cost share interregional projects that do not fit within the Interregional Order 1000 process. Specifically, these projects include

1. Projects developed with neighboring Transmission Owners that are not RTOs, such as Associated Electric Cooperative, Inc. (AECI), Entergy Services, Inc., and Ameren Missouri
2. Byway projects 100-300 kV

Because it is possible that Order 1000 interregional cost allocation does not apply to all potential interregional upgrades, the RSC unanimously approved on October 27, 2014, a methodology to allocate non-Order 1000 projects on a regional basis. This proposal was approved by SPP's board on December 9, 2014.

SPP filed a proposal with FERC to provide a project category and cost allocation methodology for transmission facilities identified and approved through one of SPP's set of transmission planning processes or pursuant to coordinated transmission planning between SPP and external entities that are not neighboring planning regions as defined by FERC Order 1000. The proposal stated it would identify potential transmission projects that fall outside of the Order 1000 interregional planning process or may not be eligible for cost allocation under SPP's Order 1000 interregional processes. In addition, the proposal stated the process proposed was intended to be utilized only to evaluate projects that do not qualify for Order 1000 treatment.

Under this proposal, SPP would assign costs to parties engaged in a shared cost seams project. A joint study process was proposed to be used if there was no predefined joint study process between SPP and the seams partner. Based on the results of the joint study, the RSC would make a recommendation to the board to approve cost allocation for seams project under the principles of SPP's Highway/Byway cost allocation methodology. Under the filed proposal, the board may approve such cost allocation as part of its approval of the proposed seams project if all of the following criteria are met:

1. The proposed seams project has a nominal operating voltage rating of between 100 kV and 300 kV
2. A single zone is expected to receive 60% or more of the proposed seams project's calculated benefits to the SPP region
3. A benefit to cost ratio greater than or equal to 1.0 for the zone referenced in (2) above, with the costs calculated in accordance with Section III.A.2 of Attachment J of the Tariff with X equaling 33%

FERC denied the proposal, finding that:[33]

1. SPP had not demonstrated that its proposed tariff revisions were narrowly crafted so as to differentiate seams transmission projects from projects that would qualify under SPP's Order 1000 processes
2. SPP's planning process for seams transmission projects lacked clarity and did not adequately explain how a seams transmission project would progress from project identification to approval for construction
3. SPP had not outlined how a seams transmission project identified through various planning processes, both those under Order 1000 and not, ultimately becomes part of the Order 1000 transmission owner selection process

Although FERC denied the proposal, it noted that the rejection of SPP's proposal in the instant filing did not preclude SPP from making a filing with FERC on a project-by-project basis for non-Order 1000 facilities. Future filings may relate to seams concerns with an associated cost allocation and justifying specific cost allocation for that specific type of non-Order 1000 projects.

[33] *Sw. Power Pool, Inc.*, 153 FERC ¶ 61,249 (2015).

IX. AECI PROJECTS COST ALLOCATION

After FERC rejected the RSC's non-Order 1000 cost allocation but noted SPP could ask FERC for project-by-project approval, the RSC approved unanimously on April 17, 2017 the joint SPP/AECI Morgan transformer project (already approved by the board in the 2017 Integrated Transmission Plan) and cost allocation. The Morgan transformer project would be constructed in AECI's service territory, not within SPP's.

Specifically, as approved by the RSC, SPP made a FERC filing stating that, pursuant to the SPP-AECI Joint Operating Agreement, SPP and AECI would develop procedures for evaluating on a case-by-case basis the relative contribution of their systems to the constraint and the relative benefits derived by the resolution of the constraint. SPP and AECI would then memorialize the allocation of costs for each transmission project in a cost-and-usage agreement. The agreement specified SPP agreed to pay $12.25M of the Morgan transformer project's estimated costs (89.1 percent), and AECI agreed to bear the remaining $1.5M (10.9 percent). SPP's obligation for its portion of the Morgan transformer project's costs was to be determined using the project's final installed costs multiplied by a 16 percent levelized carrying charge annually over the physical service life of the facilities. The 16 percent levelized carrying charge included all final costs of construction and ongoing operating and maintenance expenses. This calculation determined the annual transmission revenue requirement that would be billed to SPP's transmission customers monthly. With regard to the Brookline reactor project, SPP agreed to pay $4.85M of the project's costs (97 percent), and AECI agreed to pay the remaining $150,000 (3 percent).[34] Interestingly, neither of these two projects were located in SPP's footprint; both of the projects were located exclusively within AECI.

The request filed with FERC proposed that the two projects' costs would be allocated on a load-ratio-share basis by inserting the projects' revenue requirements into the annual transmission revenue requirement of its Highway/Byway regional cost allocation method.

On October 6, 2017, FERC denied SPP's proposed request for approval of the Morgan transformer and Brookline reactor projects.[35] FERC found SPP had not provided specific information on the benefits the Morgan project would provide SPP.[36] FERC found SPP had not demonstrated that the benefits accrue throughout the entire SPP footprint, and that SPP did not provide an economic analysis for the Brookline project.[37] FERC was not persuaded by SPP's argument that allocating its share of the costs of the Morgan project on a region-wide, load-ratio-share basis was appropriate, because the facilities are not

[34] This project was subsequently evaluated in the SPP Integrated Transmission Planning process.
[35] *Sw. Power Pool, Inc.*, 161 FERC ¶ 61,026 (2017).
[36] *Id.* at P 40.
[37] *Id.*

located on the SPP system, and therefore there was no host zone to which SPP may assign the costs on a zonal basis.[38]

On August 17, 2018, in Docket Nos. ER18-2243-000 and ER18-2245-000, SPP resubmitted filings to FERC to construct the Morgan Transformer Project and to allocate the costs of SPP's negotiated share of the project within SPP. The filings addressed the deficiencies outlined by FERC in its denial of SPP's original request to approve this project. On October 10, 2018, FERC issued a letter order accepting SPP's filings, with the effective date of October 15, 2018.[39]

X. ATTACHMENT Z (Z2)

In the docket in which FERC approved SPP's original cost allocation, Docket No. ER05-109, SPP included an aggregate transmission service study (ATSS) process in a new Attachment Z to the tariff.[40] The new process for revenue credits allowed pursuant to Attachment Z provided that transmission customers paying for a directly assigned network upgrade will receive credits for a portion of any new transmission service customers that use the facility that was directly assigned network upgrade costs. Specifically, credits were determined based upon the subsequent incremental use of the network upgrade. However, SPP and its stakeholders determined that the process in Attachment Z lacked the specificity necessary to properly calculate revenue credits.

Beginning in September 2005, the CAWG began reviewing SPP's ATSS and revenue crediting procedures in the tariff. The CAWG developed numerous recommendations, which were adopted by the RSC in January 2007. The Regional Tariff Working Group (RTWG), Markets and Operations Policy Committee (MOPC) and SPP board developed and reviewed the tariff modifications to effectuate these recommendations. The board approved the tariff modifications in December 2007, and FERC approved the tariff revisions on August 28, 2008, with an effective date of May 27, 2008.[41]

With FERC's approval, Attachment Z was split into attachments Z1 and Z2. The ATSS process was defined in Attachment Z1 and the revenue crediting process in Attachment Z2. The 2008 revisions include:

- Clarified the criteria for crediting purposes to provide that revenue credits be based on transmission service that could not be provided but for the existence of the creditable upgrade
- Expanded revenue crediting procedures to sponsored upgrades and included provisions that had been approved to provide transmission revenue crediting for generator interconnection upgrades

[38] *Id.* at P 42.
[39] *Sw. Power Pool, Inc.*, Letter Order, Docket Nos. ER18-2243-000 and ER18-2245-000 (October 10, 2018).
[40] *Sw. Power Pool, Inc.*, 111 FERC ¶ 61,118 (2005).
[41] Sw. Power Pool, Inc., Letter Order, Docket Nos. ER08-746-001 and ER08-746-002 (August 28, 2008).

- Clarified the credits for upgrade sponsors of sponsored upgrades

Although the 2008 revisions provided clarification on some points, the changes did not simplify the process, which continued to evolve substantially in complexity. The complexity resulted from numerous elements, such as:

- The necessity of guidelines to rank subsequent transmission service credit obligations; assessment of multi-directional impacts on transmission facilities
- Calculation of impacts on both upgrades that have capacity limits and those that do not
- Determination of methodologies for calculating credit payment obligations for both network integration and point-to-point transmission service and for multiple upgrade types
- Distribution of credits from reservations of variable length to compensate upgrade sponsors with variable payment obligations
- Integration of long-term and short-term transmission service study procedures with the transmission service settlements system; and specification of partial credit funding through the region-wide and zonal charges under Schedule 11 of the SPP OATT

Due to this complexity, SPP and its stakeholders concluded a more detailed process and calculation methodology needed to be developed so that SPP could effectively implement the revenue crediting process. In April 2009, the RTWG created the Crediting Process Task Force (CPTF) to work with SPP and its stakeholders to develop and recommend specific processes and methods to be used to calculate revenue credits pursuant to Attachment Z2. The CPTF worked from April 2009 through June 2011 to create a whitepaper on certain aspects of the crediting process. In July 2011, the MOPC voted for SPP to move forward with implementing the revenue crediting process as described in the CPTF whitepaper. In its January 2012 meeting, the MOPC supported SPP moving forward immediately with software development.

The CPTF and RTWG continued to review the revenue crediting process and developed tariff changes to further clarify the determination of credit payment obligations and distribution of revenue credits. In April 2013, the board approved additional tariff changes to further clarify the process. SPP filed the changes in Docket No. ER13-1914. On December 6, 2013, FERC accepted the changes after a compliance filing with an effective date of September 8, 2013.[42]

In the 2013 revisions, SPP added definitions to the tariff for the revenue crediting process, modified Attachment H to account for revenue credits explicitly, modified Attachment L to incorporate revenue distribution procedures associated with revenue credits, and modified

[42] *Sw. Power Pool, Inc.*, 145 FERC ¶ 61,198 (2013).

Attachment Z2 to clarify the description of a creditable upgrade and specify when a sponsored upgrade becomes a creditable upgrade.

In July 2019, the SPP Board of Directors approved a recommendation from the HITT regarding the elimination of Z2 revenue credits with an implementation date of February 1, 2020. During the October 28, 2019 RSC meeting, SPP Staff provided a report to the RSC on the proposed elimination of Z2 revenue credits. The RSC unanimously approved the HITT recommendation to eliminate Z2 revenue credits with an implementation date of February 1, 2020.

On November 22, 2019, SPP filed with FERC proposed edits to the tariff to eliminate transmission revenue credits under Attachment Z2 of the Tariff as approved by the RSC. On January 31, 2020, the Commission rejected SPP's proposed Tariff revisions, without prejudice.[43] On April 29, 2020, SPP refiled proposed edits to the tariff to eliminate transmission credits, with changes suggested in the Commission's order rejecting the previous filing. On June 30, 2020, the Commission accepted SPP's filing to eliminate Z2 revenue credits.[44]

XI. GENERATOR RETIREMENT

In 2020, SPP developed a Generator Retirement Process to assess system reliability impacts caused by a generator retiring in the SPP footprint. The RSC was responsible for developing the cost allocation methodology for any Network Upgrades that are identified as needed in the Generator Retirement Process. On July 27, 2020, the RSC unanimously approved the proposal that any Network Upgrade that is identified as needed because of the retirement of a generating resource is considered Base Plan Upgrades and should be cost allocated pursuant to Attachment J, Section III.A of the Tariff.

On October 14, 2020, SPP submitted FERC the proposed process for SPP to evaluate the short-term and long-term impacts of retiring generation on the SPP transmission system, which includes the cost allocation approved by the RSC. On December 21, 2020, the Commission approved SPP's proposed Generator Retirement Process.[45]

XII. JOINT TARGETED INTERCONNECTION QUEUE

The Joint Targeted Interconnection Queue (JTIQ) effort was conceived by and Midcontinent Independent System Operator ("MISO") in mid-2020 to address certain transmission system needs along the SPP-MISO seam contributing to delays in processing regional generator interconnection queues. The two RTOs worked together to analyze

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43 *Sw. Power Pool, Inc.*, 170 FERC ¶ 61,070 (2020).
44 *Sw. Power Pool, Inc.*, 171 FERC ¶ 61,272 (2020).
45 *Sw. Power Pool, Inc.*, Letter Order, ER21-102-000 (2020).

issues, identify system needs and complete the technical study work by late 2021. The final study report was published in March 2022[46] and included the following portfolio of projects:

JTIQ Portfolio	Location by RTO	Cost ($M)
Bison – Hankinson – Big Stone South 345 kV	MISO	476
Brookings Co – Lakefield 345 kV	MISO	331
Raun – S3452 345 kV	MISO - SPP	144.4
Auburn – Hoyt 345 kV	SPP	90.5
Sibley 345 Bus Reconfiguration	SPP	18.8
Total Cost of Portfolio of Projects	**MISO - SPP**	**1,060.7**

SPP and MISO estimate the costs of the JTIQ portfolio of projects to be $1 Billion.

On January 30, 2023, the RSC approved the following motions related to the JTIQ portfolio:

1. Approve the cost-sharing of this JTIQ portfolio's capital costs between generators and load to be 90% to generators and 10% to load;
2. Approve the cost-sharing of the 10% load portion of the JTIQ portfolio Annual Transmission Revenue Requirement (ATRR) between SPP and MISO loads to be based upon Adjusted Production Cost benefits in accordance with the Joint Operating Agreement between MISO and SPP (JOA);
3. Approve that SPP loads' allocable share of 10% of the JTIQ portfolio ATRR for this portfolio and the portfolio for the next study of the southern part of the SPP/MISO seam be allocated on a region-wide load-ratio share basis consistent with previous RSC policies;
4. Recommend that the RSC directs SPP Staff to ensure JTIQ is implemented in a manner that would reasonably maximize the likelihood of receiving U.S. Department of Energy (DOE) funding as a method of improving the benefit/cost ratio for all load within the SPP region; and
5. Approve that each building transmission owner recover the non-capital component of cost (i.e. O&M, A&G, etc.) associated with construction costs allocable to GI customers through the building transmission owner's formula rate template in the building transmission owner's respective region.

B. FINANCIAL TRANSMISSION RIGHTS

A key component to protecting transmission rights in an electric energy market is a Financial Transmission Right (FTR). An FTR is a contract that gives market participants an offset, or hedge, against transmission congestion costs in the day-ahead market. They

[46] https://www.spp.org/Documents/66725/JTIQ%20Report.pdf

protect the holder from costs arising from transmission congestion over a specific path on the grid. Since the actual cost of congestion is uncertain and is unknown until the day-ahead market clears, an FTR allows the holder to pay ahead for transmission congestion costs, guaranteeing the price paid for the transmission congestion component of locational marginal prices[47].[48] In SPP's day-ahead market, the FTR holder can receive revenues if the clearing prices in the day ahead are higher than the cost of the FTR, or can result in a charge to that FTR holder if the FTR price is higher than the clearing prices in the day ahead. FTRs are allocated to load-serving entities, transmission owners or firm transmission right holders in SPP. The RSC was delegated the authority, under Section 7.2 of the SPP Bylaws, to decide how FTRs are treated within SPP's footprint.

On January 25, 2010, because of the RSC's authority relating to FTRs, the RSC directed the CAWG to provide recommendations on the proposed day-ahead market's (later to become a part of the SPP Integrated Marketplace) transmission congestion rights[49] (TCRs) process. The RSC directed CAWG to assess whether non-asset owning parties should be able to participate in the proposed TCR market process.

On October 25, 2010, the RSC approved the following CAWG recommendation:

Recommendation 1: In the future consideration of long-term firm transmission rights (LTFTRs),

a) the Market Working Group (MWG) should revisit whether the first stage of the allocation of annual auction revenue rights[50] (ARRs) should be restricted to base-load generation with capacity factors greater than 50 percent and long-term firm point-to-point transmission (PTP) with loading factors greater than 50 percent and
b) The MWG should make recommendations on LTFTRs in time to implement LTFTRs one year after the start of the day-ahead markets.

Recommendation 2: Infeasible ARRs for base-load resources

[47] Locational Marginal Pricing is used as a pricing mechanism by RTOs/ISOs for energy transactions throughout each RTO/ISO's footprint.
[48] Francisoco Flores-Espino, Tian Tian, Ilya Chernyakhovskiy, Megan Mercer, and Mackay Miller. Competitive Electricity Market is Regulation in the United States: A Primer, National Renewable Energy Laboratory, p. 15 (2016).
[49] Transmission Congestion Right is a financial instrument that entitles the holder to receive compensation for or requires the holder to pay certain congestion related transmission charges when the transmission system is congested. A TCR value is based on transmission congestion charges calculated in the Day-Ahead Market.
[50] Auction Revenue Right is a financial instrument that entitles an Asset Owner to share the revenues generated in the annual or monthly TCR Auctions.

a) SPP should review results of the allocations from the first annual ARR auction prior to the implementation of LTFTRs. When the MWG takes up the LTFTR issue, it should evaluate the issue of TCRs not able to get ARRs for base-load requirements.

Recommendation 3: Participation in TCR auctions by non-transmission customers

a) Assuming sufficient financial protections (as determined by the SPP credit standards and approved by the RSC) are put in place for non-transmission customers to participate in TCR auctions, the RSC should approve participation by any entity that meets the required financial protections.

Recommendation 4: Managing the risk of default

a) The buyer's payments for its purchase of an infeasible TCR should not be paid by SPP to the seller until the seller makes good on its commitment to pay the congestion costs. If the seller defaults on its obligation to pay, the buyer's payment to SPP should be refunded.

In 2013, SPP formed the Long-Term Congestion Rights Task Force devoted to the consideration and design of its long-term congestion rights (LTCR) process.[51] The membership of the task force was specifically designed to reflect the diversity of SPP's members and was composed of two members of the CAWG, two members of the MWG, one member of the Transmission Working Group and one member from the Economic Studies Working Group. The task force included a commissioner liaison from the RSC. The task force's duties included developing and recommending changes to SPP's business practices, protocols and tariff as needed to meet requirements for LTCRs consistent with the SPP OATT and the design of the Integrated Marketplace; and providing SPP with the perspectives and input of the members and transmission customers.

Recommendations from this task force were presented to the RSC, and the RSC approved the recommendations on April 28, 2014. On July 31, 2014, SPP filed with FERC the RSC recommendations to provide for LTCRs. SPP believed these recommendations complied with following guidelines from FERC Order No. 681.[52]

> Guideline 1: The right should be point-to-point and should specify a source, a sink and a quantity.

[51] Long-term congestion rights are any congestion rights that are for a term of longer that one year.
[52] FERC Order No. 681 required transmission organizations that are public utilities with organized electricity markets to make available long-term firm transmission rights that satisfy certain guidelines adopted by the Commission in this Final Rule. SPP's Integrated Marketplace was approved by FERC as an "organized electricity market." *Sw. Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012), *order on reh'g and clarification*, 142 FERC ¶ 61,205 (2013), *appeal dismissed sub nom. Neb. Pub. Power Dist. v. FERC*, No. 13-1181, 2014 U.S. App. LEXIS 10064 (D.C. Cir. Apr. 15, 2014).

Guideline 2: Once allocated, the right's financial coverage should not be modified during its term.

Guideline 3: Rights made feasible by upgrades should be available to parties funding such upgrades.

Guideline 4: The long-term firm transmission right reflects a 10-year term of renewal rights.

Guideline 5: Load-serving entities should have priority in allocation of rights based on existing capacity.

Guideline 6: Rights held by a load-serving entity to support a service obligation should be assignable to another entity that acquires said service obligation.

Guideline 7: The initial allocation of the rights should not require a load-serving entity to submit bids in an auction.

On July 31, 2014, SPP submitted its Order No. 681 compliance filing to implement long-term financial transmission rights that are to be referred to as LTCRs in the context of the Integrated Marketplace.[53] On October 28, 2014, FERC found that SPP's filing did not completely comply with the guidelines of FERC Order No. 681, and required SPP to file compliance filings to comply with FERC Order No. 681.[54] Specifically, the FERC found that guideline three and guideline five failed to comply with Order No. 681.[55] FERC denied SPP's request for rehearing, but in the same order accepted SPP's compliance filing revising its LTCR guidelines consistent with the October 2014 order and FERC Order No. 681,[56] subject to a further compliance filing.

[53] Submission of Tariff Revisions in Compliance with Order 681 of Southwest Power Pool, Inc., Docket No. ER14-2553-000 (July 31, 2014).
[54] *Sw. Power Pool, Inc.*, 149 FERC ¶ 61,076 (2014) ("October 2014 Order").
[55] *Id.*
[56] *Sw. Power Pool, Inc.*, 152 FERC ¶ 61,034 (2015).

C. PLANNING FOR REMOTE RESOURCES

An area of concern at the time of the RSC formation was how planning would be conducted for remote resources, such as wind, and whether transmission upgrades for remote resources would be included in the regional transmission planning process. Because of this concern and how these remote resources' costs and benefits would impact the end-use ratepayers within each state, the RSC was granted the authority in SPP Bylaws, Section 7.2, on how SPP should plan for remote resources in the regional transmission planning process.

I. INTEGRATED TRANSMISSION PLAN (ITP)

In January 2009, the SPP Board of Directors established the SPPT, which included two members of the RSC. The purpose of the SPPT was to recommend improvements to SPP's regional transmission planning process and cost allocation methodology. Based on its findings, the SPPT issued a report and recommendation for reforming SPP's transmission planning and cost allocation processes.

The SPPT recommended adopting an integrated planning process (now referred to as the ITP), establishing a highway/byway cost allocation methodology for the SPP region and identifying and recommending a list of extra high voltage (EHV) priority projects to be approved by SPP within six months.

On April 28, 2009, the RSC endorsed the SPPT report and its recommendations. The first recommendation was for the reliability assessment, the balanced portfolio and the EHV studies to be replaced with an integrated planning process. The second recommendation was for SPP to be more proactive in transmission expansion and for SPP to commit to a forward-looking transmission system. The third recommendation was for the generation interconnection and aggregate study process studies to be less burdensome. The fourth recommendation was for there to be a reduction in the number of cost allocation methods.

On May 17, 2010, SPP filed in Docket No. ER10-1269-000 to revise the SPP OATT to incorporate the ITP to determine near-term and long-term transmission needs. SPP described the ITP as a planning process that includes 20-year, 10-year and near-term assessments. For the long-term planning horizons, the ITP focuses on high-voltage facility solutions: 300 kV and above for 20-year assessments and 100-300 kV for 10-year assessments. The near-term assessment's primary purpose was to meet reliability needs and compliance with North American Electric Reliability Corporation (NERC) standards. Under SPP's proposal, the 20-year and 10-year assessments would be initiated every three years, while the near-term assessment would be performed annually. On July 15, 2010,

FERC issued an order conditionally accepting SPP's ITP, subject to a compliance filing.[57] On August 16, 2010, SPP submitted its compliance filing in Docket No. ER10-2244-000. On February 2, 2011, FERC issued an order accepting SPP's compliance filing.[58]

On April 17, 2017, the RSC moved to support revisions to the ITP planning process. SPP made a filing with FERC proposing to move from a three-year transmission planning cycle to an annual planning cycle, combining its near-term and 10-year assessments into a single annual ITP assessment and modifying the timing of its 20-year assessment to once every five years instead of every three years. FERC accepted SPP's filing and found that the revisions to the ITP process were just and reasonable.[59]

[57] *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010).
[58] *Sw. Power Pool, Inc.*, Letter Order. Docket No. ER10-2244-000 (Feb 2, 2011).
[59] *Sw. Power Pool, Inc.*, 161 FERC ¶ 61,261 (2017).

II. HUB AND SPOKE

With the significant increases in the number of wind generators interconnecting into the SPP transmission system, SPP stakeholders, over the years, have debated various engineering solutions. Each of these engineering solutions created issues of cost allocation.

One of these proposals to address the wind cost allocation issues was the hub and spoke system. The "hub" is a generation hub defined as the interconnection substation designated by the transmission provider for interconnecting generation in a given area. The "spoke" is a generation collector spoke defined as the transmission line that ultimately connects multiple generators to the hub. A spoke collector station is defined as the substation built on the spoke to accommodate the interconnection of a generating facility to the transmission system. This proposal requires generators to interconnect at the hub. This would minimize the number of interconnections on the same line. The ITP process would identify the hubs. The proponents of this proposal argued that having multiple generators interconnect at a hub would result in reduced costs associated with a reduced number of reactors and breakers.

On April 4, 2012, the CAWG recommended that the RSC accept a policy such that no generation interconnection costs associated with the hub and spoke be included in the regional transmission rates, but these costs be assigned to generators requesting to interconnect to SPP's system. CAWG had considered several questions relating to the cost allocation of the hub and spoke system such as: should a portion of the hub and spoke system be included under SPP's OATT?; should interconnection charges be used for the hub and spoke system with temporary funding of costs through SPP's OATT?; and should the hub and spoke system costs just be assigned to the generators interconnection? In the end, CAWG recommended interconnection costs be borne by the generators requesting to interconnect because this solution more appropriately reflected cost causation and beneficiary pays ratemaking principles.

On April 23, 2012, an outside consultant for the RSC presented to the RSC the background and information regarding the hub and spoke cost allocation between load and generation. He also presented CAWG's recommendation. RSC unanimously voted to accept the policy that no generation interconnection costs associated with a hub and spoke system be included in the regional transmission rates and instead be assigned to generators requesting to be interconnected. This policy was not filed with FERC because there was no change in the SPP OATT.

D. RESOURCE ADEQUACY

In the United States regulatory structure, state commissions or state regulatory agencies have traditionally regulated the amount of capacity utilities planned for and the amount of capacity that needed to be constructed. As a result, the issue of resource adequacy for the SPP region was delegated to the RSC per section 7.2 of the SPP Bylaws.

In July 2014, the Capacity Margin Task Force (CMTF) was created to look at SPP's capacity margin requirements and methodology based on stakeholder and staff input. The CMTF looked at determining the resource adequacy required in SPP and how to calculate capacity/reserve margins. Members of the CMTF included two CAWG members and a member of the RSC.

On April 25, 2016, SPP staff presented the RSC with a report from the CMTF. The report outlined that SPP's current criteria obligated load-serving members to meet SPP's reserve margin requirement, but not all load served in SPP is served by a SPP member. The proposal from the CMTF was that all parties serving load in the SPP balancing authority should be included in the obligation to meet SPP's planning reserve margin requirement. CMTF developed policies to identify who is responsible for resource adequacy, what the resource adequacy requirement is and how and when the resource adequacy requirement can and should be met. On April 25, 2016, the RSC unanimously approved the policies developed by the CMTF, which were previously approved by CAWG.

On January 30, 2017, the RSC approved a recommendation from CAWG to approve revision request 187, which implemented policies from the CMTF previously approved by the RSC. The recommendation approved by the RSC was that there should be changes to the SPP OATT to implement a resource adequacy requirement (RAR) for the SPP footprint. The planning criteria at that time required a capacity requirement that did not apply to the entire load in SPP's footprint. This RAR would require that entities serving load in SPP's balancing authority area[60] maintain sufficient capacity and planning reserves to serve their load. The SPP Board of Directors approved this recommendation on January 31, 2017.

SPP filed in Docket No. ER17-1098-000 the proposed revisions to the SPP OATT to implement the RAR. On August 29, 2017, FERC denied the proposed revisions finding that "SPP has not demonstrated that its proposed treatment of power purchases and sales is just and reasonable, and not unduly discriminatory or preferential because (1) SPP's proposal fails to include a requirement that all power purchase agreements are backed by verifiable capacity to meet SPP's RAR and fails to include provisions to allow SPP to review the agreements to verify that they are backed by capacity, and (2) SPP's proposed

[60] As the balancing authority, SPP is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within its balancing authority area, and supporting interconnection frequency in real time.

treatment of firm power purchases and sales in the determination of net peak demand is unduly discriminatory."[61]

On March 30, 2018, in Docket No. ER18-1268-000, SPP filed new revisions to the SPP OATT to implement a set of resource adequacy policies for the SPP balancing authority area. SPP amended its filing on June 8, 2018. On August 15, 2018, FERC accepted the tariff changes and stated that this current filing addressed the deficiencies found in docket ER17-1098. [62]

I. DISTRIBUTED ENGERY RESOURCE POLICY WHITEPAPER

As more generators near retirement and SPP's historical planning reserve margin begins to subside to a margin closer to planning reserve margin ("PRM") levels that have been studied (e.g. Non-Coincident Peak PRM of 12%), it becomes critical for the SPP Planning Coordinator and Balancing Authority to clearly track and ensure the availability of demand response programs and behind the meter generation for purposes of meeting the Resource Adequacy Requirement and Winter Season Obligation. As described in Attachment AA of the tariff, the forecasted Peak Demand of a Load Responsible Entity can be reduced by the impacts of demand response programs or behind-the-meter generation that are either registered or not registered resources in the SPP Integrated Marketplace and do not have SPP firm transmission service.

The purpose for drafting the DER policy whitepaper ("DER Whitepaper") was to further define the requirements for demand response programs and behind-the-meter generation, and address if each is treated strictly as a modifier for an LRE's load or as capacity. Resources identified under this policy do not meet the requirements for Firm Capacity or Deliverable Capacity as defined in Attachment AA of the tariff.

The RSC, having primary authority over resource adequacy in the SPP region, was asked by SPP Staff to review and endorse the requirements of the DER Whitepaper. The CAWG unanimously approved the endorsement of the DER Whitepaper on April 5, 2019. On April 29, 2019, the RSC unanimously endorsed the requirements of the DER Whitepaper.

On July 31, 2020, SPP submitted to FERC revisions to Attachment AA of the tariff to further define the requirements applicable to demand response programs and behind-the-meter generation for resource adequacy purposes. On September 23, 2020, FERC accepted SPP's proposed tariff revisions.[63]

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[61] *Sw. Power Pool, Inc.*, 160 FERC ¶ 61,033, at P 40 (2017).
[62] *Sw. Power Pool, Inc.*, 164 FERC ¶ 61,092 (2018).
[63] *Sw. Power Pool, Inc.*, Letter Order, ER20-2578-000 (Sept. 23, 2020).

II. SOLAR AND WIND ELCC ACCREDITATION WHITEPAPER

Since 2004, when FERC originally accepted SPP request to be an RTO, SPP has used the same methodology for criteria to evaluate the capacity of all generation resources in the SPP balancing authority area. Over the last 15 years, wind penetration in the SPP region has increased substantially. The original criteria accredits the capacity of renewable generating resources, such as wind and solar, without any direct consideration of the existing total penetration of that resources energy output in the SPP region. As the penetration of wind and solar generation increases in the SPP footprint, there may be reliability impacts that are not taken into account using the original capacity accreditation methodology, which results in over valuing the capacity accreditation of these resources.

The purpose of SPP drafting the Solar and Wind ELCC Accreditation Whitepaper was to propose a methodology for estimating and allocating the available effective load carrying capability (ELCC) from wind and solar generating facilities as capacity in the SPP balancing authority area. Because of wind and solar generation intermittency, the capacity value or ELCC of wind and solar powered resources are lower than their nameplate values and will decrease as their penetration increases across the SPP balancing authority area.

The RSC, having primary authority over resource adequacy in the SPP region, was asked by SPP Staff to review and endorse the requirements of the Solar and Wind ELCC Accreditation Whitepaper. The CAWG unanimously approved the endorsement of the Solar and Wind ELCC Whitepaper on November 5, 2019. On January 27, 2020, the RSC unanimously endorsed the requirements of the Solar and Wind ELCC Accreditation Whitepaper.

III. ENERGY STORAGE ELCC ACCREDITATION WHITEPAPER

The purpose of SPP drafting the Energy Storage ELCC Accreditation Whitepaper was to propose a methodology for accrediting and allocating the effective load carrying capability from registered battery generating facilities as capacity in the SPP Balancing Authority Area.

The RSC, having primary authority over resource adequacy in the SPP region, was asked by SPP Staff to review and endorse the requirements of the Energy Storage ELLC Accreditation Whitepaper. The CAWG unanimously, with one abstention, approved the endorsement of the Solar and Wind ELCC Whitepaper on December 10, 2020. On January 25, 2021, the RSC unanimously endorsed the requirements of the Energy Storage ELCC Accreditation Whitepaper.

IV. HYBRID STORAGE ACCREDITATION WHITEPAPER

The purpose of SPP drafting the Hybrid Storage Accreditation Whitepaper was to propose

a methodology for accrediting hybrid facilities as capacity in the SPP Balancing Authority Area. For purposes of the whitepaper a hybrid facility is a combination of two or more resources behind the same point of interconnection where at least one resource is battery storage.

On December 9, 2021, the CAWG endorsed the Hybrid Storage Accreditation Whitepaper as it implements the RSC's ELCC accreditation policy.

V. PERFORMANCE BASED ACCREDITATION

Since the approval of Attachment AA, SPP's generator testing capability practices outlined in the SPP Planning Criteria are the foundation of accrediting conventional generation in SPP. The SPP Planning Criteria requires, at a minimum, these resources be tested once every five years to establish a net generating capability. The capability test result is then used as the accredited capacity of the resource in SPP Resource Adequacy as outlined in Attachment AA. Utilizing the net generating capability of the resource acknowledges the resource's maximum output but does not consider the resource's performance or contribution to reliability in comparison to the other resources in the SPP footprint. A change to the existing accreditation practices that considers performance or availability would more accurately quantify each resource's contribution to reliability in the SPP BA and incentivize increased resource performance during the peak seasons.

In recognition of need to change how conventional resources are accredited in SPP, SPP's Supply Adequacy Working Group made recommendations for a performance based accreditation method for conventional resources in the SPP Balancing Authority (BA) footprint as outlined in the Performance Based Accreditation Recommendations for Conventional Resources policy paper. On July 25, 2022, the RSC unanimously approved the performance based accreditation methodologies described in the "Performance Based Accreditation Recommendations for Conventional Resources" policy paper with full implementation by the 2027 summer season.

VI. 2022 CHANGE IN PLANNING RESERVE MARGIN

Section 4.0 of Attachment AA specifies the Planning Reserve Margin ("PRM") will be set in the SPP Planning Criteria. In determining the PRM, SPP is required to perform a probabilistic Loss of Load Expectation ("LOLE") Study biennially to determine the PRM. The LOLE Study analyzes the ability of the SPP to reliably serve the SPP Balancing Authority Area's forecasted Peak Demand. SPP is required to study the PRM such that the LOLE for the applicable planning year does not exceed one (1) day in ten (10) years, or 0.1 day per year. The Tariff requires that, at a minimum, the PRM shall be determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure the LOLE does not exceed 0.1 day per year.

On June 29, 2022, SPP issued the 2021 LOLE Study Report.[64] The 2021 LOLE study results show that the current 12% PRM requirement would not satisfy the one day in ten year LOLE metric for the 2023 Summer Season and should be considered to be increased. SPP staff, based on the LOLE study, recommended the increase of the PRM from 12% to 15% for the 2023 Summer Season. In recognition of the RSC authority over resource adequacy in the SPP footprint, the RSC approved the increase the SPP Balancing Authority's PRM from 12% to 15% effective for the 2023 summer season on July 25, 2022.

On October 24, 2022, the RSC unanimously approved the revision request that included the increased PRM of 15% in the SPP Planning Criteria, which implemented the RSC's July 2022 approved increase of the PRM.

VII. DELIVERABLE CAPACITY WINTER SEASON

Section 6.0 of Attachment AA of the Tariff sets forth the Winter Season Obligation. Specifically, Section 6.1 specifies that each Load Responsible Entity ("LRE") shall maintain sufficient capacity equal to the LRE's Winter Season Net Peak Demand plus its Winter Season Net Peak Demand multiplied by the PRM.[65] Section 6.2 specifies the Firm Capacity utilized by an LRE may not be included in the Firm Capacity utilized by another LRE; and that Firm Capacity that is contracted to other entities shall not be available to the LRE that is transferring the Firm Capacity.[66] Further, Section 6.3 specifies if an LRE serves load both internal and external to the SPP Balancing Authority Area, compliance with the obligation in Section 6.0 of Attachment AA is not intended to affect an LRE's obligation to maintain distinct and separate amounts of Resources to cover its applicable planning reserve obligation for its load located external to the SPP Balancing Authority Area; and Load and Resources that are pseudo-tied into the SPP Balancing Authority Area shall be considered internal for purposes of complying with Section 6.0 of Attachment AA.[67]

SPP performs an annual deliverability study to evaluate the Resources of Generator Owners to determine the amount of capacity that the Resource may deliver to the SPP Balancing Authority Area without affecting reliability or requiring additional transmission upgrades.[68] The results of the deliverability study provide to each Generator Owner, on an individualized basis, an indication of how much of the available capacity of a resource is available to satisfy the PRM. Entities may rely on the results of the deliverability study for the upcoming summer

[64] The 2021 LOLE Study Report can be found at the following website: https://www.spp.org/documents/67465/2021%20spp%20lole%20study%20report.pdf.
[65] Tariff at Attachment AA, Section 6.1.
[66] Tariff at Attachment AA, Section 6.2.
[67] Tariff at Attachment AA, Section 6.3.
[68] The term "deliverability," as the term is used in Attachment AA, is the concept that all generation resources that are registered to provide energy to the SPP Integrated Marketplace have a level of measurable capability to deliver capacity to the SPP Balancing Authority Area and will not impact reliability.

season and the subsequent summer season, and firm transmission service is not a requirement to support the use of Deliverable Capacity to meet an entity's PRM.

Currently, LREs can use Deliverable Capacity to meet only the PRM portion of the Summer Season Resource Adequacy Requirement that is specified in Section 5.0 of Attachment AA of the Tariff. The current definition of Deliverable Capacity is "[t]he accredited capacity of a Resource that is determined to be deliverable in an annual Deliverability Study for a Summer Season."[69] Changing patterns in electrical usage that are being seen across the country are also being seen in SPP. These pattern changes are resulting with more SPP LREs seeing increased loads in the Winter Season while some LREs that were previously summer peaking are now becoming winter peaking. These patterns are expected to continue and winter loads in SPP are expected to continue growing. With these changes, SPP staff and stakeholders determined that the same methods available to LREs to meet their Summer Season Resource Adequacy Requirement should be available to meet the Winter Season Obligation. Allowing Deliverable Capacity to be used for the Winter Season Obligation will better allow LREs to meet their Winter Season Obligation going forward by providing additional optionality and will allow for a more accurate representation of capacity available on a per Resource basis throughout the year.

On October 24, 2022, the RSC unanimously approved the inclusion of Deliverable Capacity for the Winter Season Obligation in Attachment AA. SPP filed this proposed revisions to Attachment AA with FERC, and FERC approved the revisions on February 10, 2023.[70]

VIII. MITIGATION MEASURES RELATED TO PRM INCREASE

In July of 2022, the RSC and the SPP Board approved the increase in the PRM from 12% to 15%. SPP recognized that some LREs may have difficulty in acquiring capacity needed to meet that increase in the PRM and associated Resource Adequacy Requirement prior to the 2023 Summer Season; and therefore, SPP proposed mitigation measures to help these LREs.

First, SPP staff proposed an process to allow LREs to be exempt from the Deficiency Payment obligation in Attachment AA if they satisfied specific criteria. Specifically, SPP's proposal stated that for an LRE to qualify for the exemption from the Deficiency Payment, the LRE must satisfy the following, objective criteria: (1) demonstration of adequate capacity to meet the current year's Resource Adequacy Requirement based upon the PRM in effect during the prior two years; (2) no capacity available for the LRE to purchase in order to cure its PRM deficiency as determined through the Resource Adequacy Capacity Bulletin Board ("Capacity Bulletin Board"); (3) the LRE has contracted for capacity of sufficient size that would allow the LRE to meet the current year's Resource Adequacy Requirement from a resource owner/developer, but that capacity is not available to meet the current year or subsequent

[69] Tariff at Attachment AA, Section 2.0.
[70] *Sw. Power Pool, Inc.*, Letter Order, ER22-634-000 (Feb 10, 2023).

year's Resource Adequacy Requirement or the LRE has sufficient capacity in a pending request for Interim Interconnection Service, or Surplus Interconnection Service, or Replacement Interconnection Service that is of sufficient size that would allow the LRE to meet the current year's Resource Adequacy Requirement; and (4) the LRE has done all it can do to defer any planned Resource retirements.

On October 24, 2022, the RSC approved SPP's process for exemption from the Deficiency Payment to be included in Attachment AA. SPP filed the exemption process with FERC in Docket No. ER23-636, and that docket is currently pending.

As another mitigation measure, SPP also proposed an alternative, less punitive, Deficiency Payment that would be applicable for two (2) years after the approval of a PRM increase by the RSC and the SPP Board. This alternative Deficiency Payment would be based on a sufficiency valuation curve. On January 30, 2023, the RSC approved the proposed alternative Deficiency Payment methodology.

SECTION IV: RSC STAKEHOLDER GROUPS

Section 7.2 of the SPP Bylaws states that the RSC "shall be established to provide both direction and input on all matters pertinent to the participation of the Members in SPP". Since the RSC was established, its members have played key roles in numerous SPP working groups, task forces and committees. This input into SPP's stakeholder groups has enabled the RSC to present issues of concern unrelated to its expressed authorities. These collaborative forums have enabled the SPP Board of Directors, members, and RSC to work cooperatively in developing policies that have broad stakeholder support. Below is a summary of the many leadership roles RSC members have held in SPP organizational groups.

A. SYNERGISTIC PLANNING PROJECT TEAM (SPPT)

When the SPP Board of Directors established the SPPT in 2009, the team included two RSC members. The SPPT's purpose was to recommend broad improvements to SPP's regional transmission planning process and cost allocation methodology. On, April 23, 2009, the SPPT issued a final report for reforming SPP's transmission planning and cost allocation processes. On April 27, 2009, the RSC endorsed the SPPT's report, which was subsequently approved by the SPP Members Committee and SPP Board of Directors. The report recommended:

1. SPP should adopt new planning principles to establish its new vision for an Integrated Planning Process (IPP).
2. SPP should implement the IPP, as described in this report, to facilitate the creation of a robust, flexible, and cost-effective transmission network in the SPP footprint.
3. The SPP Board of Directors and the Members Committee should develop a plan to monitor the approved IPP facilities to ensure construction.
4. The RSC should establish a "highway-byway" cost allocation methodology for the SPP region.
5. SPP staff and jurisdictional utilities should work with their respective state commissions to establish the appropriate method for rate recovery of regionally allocated transmission costs.
6. As an interim measure, SPP should evaluate and recommend to the RSC a list of Priority Projects within six months for approval by the SPP Board of Directors. In parallel with this task, the RSC should select either an existing cost allocation methodology or the new "highway-byway" cost allocation methodology for approved Priority Projects.

7. The SPP Board of Directors should set timelines, as set forth in this Report, for implementing these recommendations and assign a group to shepherd this effort through the SPP stakeholder process.

B. RATE IMPACT TASK FORCE (RITF)

On April 26, 2010, the RSC established the RITF to study the costs and benefits of transmission upgrades on customer rates moving forward. The intent was to take a holistic look at all projects to understand how costs affect all ratepayers. The task force included RSC members, one person from the SPP Board of Directors, and one person from the Strategic Planning Committee. The RITF was eventually merged with the Regional Allocation Review Task Force.

C. REGIONAL ALLOCATION REVIEW TASK FORCE (RARTF)

In 2010, FERC accepted SPP's Highway/Byway cost allocation methodology,[71] which amended the base plan funding methodology, and the ITP regional transmission planning process. Both the Highway/Byway and ITP processes modified the unintended consequences review process, which was renamed the "regional cost allocation review" (RCAR) process. In general, the RCAR process: required review of the Highway/Byway methodology and allocation factors at least every three years; authorized the RSC to recommend adjustments to cost allocations if a review showed an imbalanced cost allocation to one or more zones; required the MOPC and RSC to define the analytical methods to be used during review; and, beginning in 2015, enabled member companies that think they have been allocated an imbalanced portion of costs to seek relief from the MOPC.

On April 25, 2011, to implement the RCAR process, the RSC established the RARTF, which was responsible for defining "the analytical methods to be used" to "review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology."[72] The RARTF was charged with creating an analytical method that would be designed to "determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region."[73] After establishing the proposed analytical methods to review the reasonableness of the regional and zonal allocation methodology, the RARTF was to prepare and present a report to the MOPC and RSC for approval. The RARTF initially consisted of seven members, and three were to be from the RSC.

On January 30, 2012, RARTF presented its report to the RSC and board, and both groups approved the report. The report stated the following:

> *"This Report contains the recommendations of the Regional Allocation Review Task Force (RARTF) as to how Southwest Power Pool (SPP) should review the Highway/Byway transmission cost allocation methodology per Attachment J, Section III.D of SPP's Open Access Transmission Tariff (OATT). The RARTF recommends that this review be called the "Regional Cost Allocation Review" [RCAR].*
>
> *The RARTF makes a number of recommendations as to how SPP should conduct the Regional Cost Allocation Review. This includes a recommendation of applying ten principles, used by the RARTF, as a guide to conducting the review. These principles include: simplicity;*

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[71] *See supra* Section (1)(C).
[72] SPP OATT at Attachment J, Section III. D. 1.
[73] *Id.* at Section III. D. 2.

acknowledgment of the "roughly commensurate" legal standard; equity over time; the use of the best quantifiable information available; consistency; transparency; stakeholder input; the use of real dollars values; and the inclusion in the review of Board approved transmission plans with more weight being given to nearer term projects. Applying these principles the RARTF recommends that:

- *The review contains two evaluations; (1) as required by SPP's OATT, the evaluation of the benefits and costs of all SPP Board approved transmission projects for which a Notification to Construct (NTC) has been issued since June 2010 and (2) the evaluation of the benefits and costs of all SPP Board approved transmission projects for which a NTC has been issued since June 2010 plus Board approved transmission projects that have received an Authorization to Plan (ATP) with in-service dates of ten years or less. The RARTF recommends a 0.75 weighting for ATP projects due to the less certain nature of these projects as well as their costs and benefits.*

- *The review be integrated with the 10 Year ITP Plan schedule and be undertaken after its completion.*

- *The review use the aggregate value of dollars for all projects studied under the SPP Highway/Byway cost allocation methodology in dollars current to the year the review is conducted.*

- *To remain consistent with SPP's OATT, the review use a 40-year horizon to evaluate all transmission projects in the review.*

- *The information used in the review be the most up to date and that all assumptions be vetted through SPP's stakeholder process.*

- *Through the work of the Economic Studies Working Group (ESWG) certain benefits be measured in the review. These benefits include: adjusted production costs; positive impact on capacity required for losses; improvements in reliability; remedy benefits in future reviews; reduction of emission rates and values; reduced operating reserves benefits; improvements to import/export limits; and public policy benefits.*

Additionally, the Report contains a recommendation regarding the establishment of a Benefit to Cost (B/C) threshold. The recommended B/C threshold would be the basis for SPP staff and stakeholders to evaluate remedies for any zone falling below the threshold. Specifically, the Report recommends:

- *That a threshold be set at a B/C ratio of 0.8. With this benchmark, if the review shows that any zones fall below this threshold; SPP Staff will study and report on potential remedies for these zones.*
- *A list of recommended mitigation remedies for SPP staff to study and report for any zone below the 0.8 threshold. The recommended list of remedies in preferential order includes, but is not limited to: (1) acceleration of planned upgrades; (2) issuance of new upgrades; (3) applying highway funding to one or more byway projects; (4) applying highway funding to one or more seams projects; (5) zonal transfers (similar to balanced portfolio transfers) to offset costs or a lack of benefits to a zone; (6) exemptions for cost associated with the next set of projects; and (7) changes to cost allocation percentage.*

Finally, the Report contains a recommended timeline and action plan with four additional recommendations for implementation of the Regional Cost Allocation Review process.

SPP completed the first RCAR analysis in 2013 and the second RCAR analysis in 2016. After the second RCAR analysis, SPP and its stakeholders determined the frequency of the RCAR analysis should be modified from at least once every three years to at least once every six years. On August 2, 2017, SPP filed with FERC to request permission to change the frequency of the RCAR.

On September 29, 2017, FERC approved SPP's proposal to perform an RCAR analysis at least once every six years instead of at least once every three years.[74] FERC noted that, while SPP's proposal reduces the frequency of the mandatory RCAR analysis to at least once every six years, it does not prevent SPP from conducting an RCAR analysis more frequently. Specifically, Attachment J, Section III.D.1 of the SPP OATT provides that SPP or the RSC may initiate an RCAR analysis at any time. In addition, Attachment J, Section III.D.4(ii) of the SPP OATT provides that "any member company that feels that it has an imbalanced cost allocation may request relief through the [MOPC]." FERC agreed that SPP did not propose to eliminate or change these provisions, allowing for additional RCAR analyses to be conducted or for a member to request relief.

On October 28, 2019, the RSC received a report relating to the RCAR II Lessons Learned Report. The RSC unanimously approved the RCAR II Lessons Learned Report to be used for the RCAR III. Included within RCAR II Lessons Learned Report was a recommendation to change the SPP Tariff to provide flexibility to future RCAR studies. Specifically, this recommended Tariff change would modify the requirement for *all* Base Plan Upgrades approved for construction be studied in the RCAR and instead only require consideration

[74] *Sw. Power Pool, Inc.*, 160 FERC ¶ 61,138 (2017).

of certain projects, as determined by both the MOPC and the RSC. The rationale for this change was that future RCARs will be conducted on a higher percentage of projects that will actually be in-service, whereas RCAR I and RCAR II analyzed only the small number of projects that were in-service.[75] The RCAR II Lessons Learned Report stated that a future RCAR may not need to study all approved upgrades because actual data for Highway/Byway projects in-service may be a better measure for future RCARs. This modification to SPP Tariff would allow RARTF to recommend that the MOPC and the RSC review the benefits of only certain projects. On November 3, 2021, SPP filed with FERC modifications to the Tariff to make clear that future RCAR studies are not required to study all Highway/Byway projects in-service, and instead, may study a subset of Highway/Byway Projects. On April 5, 2022, FERC approved these proposed modifications.[76]

On July 25, 2022, the RSC unanimously approved the RARTF's recommendation to direct staff to finalize the RCAR III Report based solely on actual operational results in October 2022, instead of RCAR III studying Highway/Byway projects using prospective estimates of the benefits.

On January 30, 2023, the RSC approved the RCAR III Final Report as drafted and that the RCAR III study had been completed as required by the SPP Tariff and under the methodology approved by the RARTF, MOPC, and RSC.

[75] RCAR I: 3.2% of the cost of the upgrades and approximately 1.8% of new miles of transmission studied were in-service. RCAR II: 41.5% of the cost of the upgrades and approximately 50% of the miles of transmission studied were in-service.

[76] *Sw. Power Pool, Inc.,* Letter Order, ER22-331-000 (April 5, 2022).

D. SPC TASK FORCE ON NEW MEMBER PROCESS (SPCTFNM)

When the Integrated System transmission system[77] was being proposed to be added to SPP in 2014, stakeholders raised concerns about communications around new member integration. The SPP Board of Directors charged the Strategic Planning Committee (SPC) with developing improved communications and processes for adding new members to SPP. At their July 17, 2014 meeting, the SPC created the SPCTFNM. The task force was charged with developing communication and work group processes for engaging prospective transmission-owning and load serving members. On July 27, 2015, the RSC approved the process delineated in the SPCTFNM report; the report was subsequently approved by the board.

On October 24, 2016, the RSC approved the New Member Cost Allocation Review Process. This document provided processes for the RSC and CAWG to follow when a potential new member is being considered, particularly when that new member is asking for significant changes to the SPP OATT or Membership Agreement that would impact the RSC's approved regional cost allocation methodologies. This process is intended to work as a separate, parallel process with the communication and work group processes delineated in the SPCTFNM's 2015 report. Information will be shared among SPP staff, RSC, and CAWG to ensure timely completion of the review process. Information sharing is subject to the resolution of any confidential issues.

In January of 2017, the Mountain West Transmission Group (Mountain West), an informal collaboration of electricity service providers working to develop strategies to adapt to changes in the electric industry, announced that they would commence discussions with SPP to explore membership in the RTO and its wholesale electricity market. On September 22, 2017, Mountain West announced their intent to pursue RTO membership with SPP. After Mountain West made the announcement that it would seek to join the SPP RTO, the RSC and CAWG began its New Member Cost Allocation Review Process. This review process continued until Xcel Energy-Colorado announced that it would not pursue SPP membership on April 20, 2018. On October 3, 2018, Black Hills Energy provided formal notice to the Colorado Public Utilities Commission that the company would not pursue membership in Southwest Power Pool at that time. On October 30, 2018, the Western Area Power Administration announced it decided to defer further plans on exploring SPP membership for portions of its units not currently in SPP while continuing to evaluate opportunities to optimize the use of generation and transmission resources.

[77] The Integrated System is the backbone of the high-voltage transmission grid in the Upper Great Plains region of eastern Montana, North Dakota and South Dakota. This jointly developed transmission system evolved from the 1962 Joint Transmission System agreement of the Bureau of Reclamation (now the Western Area Power Administration) with Basin Electric Power Cooperative and 103 cooperative and municipal preference customers in this region.

E. Interregional Cost Allocation Task Force (ICATF)

On April 23, 2012, the RSC formed the Interregional Cost Allocation Task Force to develop cost allocation principles relating to Order 1000 interregional projects. This task force included three RSC members, three SPP members and one SPP Board of Director member. The ICATF proposed the following principles:

- Allocated costs should be at least roughly commensurate with total benefits to each entity; neither seams entity shall be allocated costs without receiving benefits (Order 1000);
- Cost allocation methodologies and identification of benefits must be transparent (Order 1000);
- Different cost allocation methods may be applied to different types or different portions of transmission facilities (e.g., transmission needed for different reasons) (Order 1000);
- Seams entities will quantify and, if possible, monetize benefits:
    - Non-monetized and non-quantified benefits may also be recognized in assessing overall reasonableness of proposed interregional cost allocations;
- Monetized reliability, load serving or public policy benefits will be at least equal to the avoided cost of achieving the same benefit through local or regional upgrades;
- If minimum benefit-to-cost thresholds are utilized, they should not exceed 1.25 (Order 1000);
- The share of benefits to each seams entity should be sufficient to support the interregional projects' approval through each entity's internal planning process;
- The costs of an interregional project allocated to each seams entity will be recovered by use of the existing internal cost allocation process of each entity (Order 1000).

The ICATF recommended that interregional projects' cost allocation should be either through Highway/Byway or, preferably, solely Highway. The RSC adopted the ICATF's principles on July 30, 2012.

This task force was retired after its principles were approved.

F. HOLISTIC INTEGRATED TARIFF TEAM (HITT)

In March 2018, the Board of Directors formed the HITT to consider the many issues challenging the SPP region. The HITT includes two RSC members. After gathering information and considering ideas, the HITT issued a report containing high-level recommendations to provide solutions for the SPP region. Specifically, the HITT was tasked to explore and assess the following areas:

- SPP's transmission planning and study processes, including but not limited to: Generation Interconnections (GI); the GI queue; Aggregate Studies; Energy Resource Interconnection Service and Network Resource Interconnection Service; capacity requirements, including more attributes than energy; and related FERC planning requirements;
- Transmission cost allocation issues, including but not limited to: Highway/Byway, directly assigned costs, Attachment Z2 credits, cost allocation impacts on transmission pricing zones with large wind resources and state-by-state supply resource mix requirements and goals;
- Integrated Marketplace impacts related to a changing resource mix, access to lower cost generation, potential changes in production tax credits, approach of using market-based compensation for varying attributes of different types of generators, etc.;
- Disconnects or potential synergies between transmission planning and real-time reliability and economic operations; and
- Additional areas and issues as appropriate and reasonably related to its scope of work.

On July 30, 2019, the HITT provided its final recommendations to the Board of Directors ("HITT Recommendations"). As stated in the HITT Recommendations, the goals of HITT was to ensure reliability for a changing generation mix and new technologies, enhance the Integrated Marketplace to reliably deliver low-cost energy to customers, and to align transmission planning and cost allocation with SPP's market and Consolidated Balancing Authority. There were twenty-one recommendations from HITT in four categories: reliability, marketplace, transmission planning and cost allocation, and strategic. Twelve of those recommendations were termed as actions, and nine were termed as evaluations/studies. The Board of Directors approved the HITT Recommendations.

During the August 5, 2019 special meeting, the RSC directed CAWG to work on implementing the following HITT Recommendations:

1. Decouple Schedule 9 and Schedule 11 transmission pricing zones, allowing for potentially larger Schedule 11 pricing zones;
2. Evaluate byway cost allocation review process; and
3. Complete a future study of a generator injection rate.

I. BYWAY FACILITY COST ALLOCATION REVIEW PROCESS

During 2019-2020, the CAWG developed the "Byway Facility Cost Allocation Review Process White Paper" ("Byway Cost Allocation Whitepaper"). The Byway Cost Allocation Whitepaper recommended:

1) The establishment of a narrow byway facility cost allocation review process through which future revenue requirements for specific qualifying facilities, with voltage levels between 100kV and 300kV, can be fully allocated on a region-wide basis.

2) Projects eligible for the narrow byway facility cost allocation review process should include new and existing Schedule 11 facilities; and

3) The review process criteria will be based on the utilization or anticipated utilization of the transmission facility, which is further detailed in Section IV of this White Paper.

CAWG presented the Byway Cost Allocation Whitepaper to the RSC on July 27, 2020, and the RSC approved the Whitepaper at that time. The recommendations were subsequently used to develop revisions to the Tariff. These revisions to implement the recommendations of the Byway Cost Allocation Whitepaper were reviewed and approved by the RSC on October 26, 2020 and by Board of Directors on October 27, 2020.

On April 14, 2021, SPP submitted to FERC revisions to the tariff to implement the recommendations of the Byway Cost Allocation Whitepaper.[78] On June 11, 2021, FERC rejected SPP's proposed revisions without prejudice.[79] Although the Commission stated that it recognized and encouraged SPP's efforts to proactively address transmission cost allocation issues associated with the increasing amount of renewable generation in the SPP region, it ultimately found that SPP had not demonstrated that its proposal would result in rates that are just and reasonable and not unduly discriminatory or preferential, and therefore rejected it.

Specifically, FERC stated that the proposal granted the SPP Board of Directors too much discretion in allocation of the costs of Byway Facilities without clear standards of how those decisions would be made. FERC stated that the proposed process lacked transparency because the proposed tariff provisions did not indicate that SPP would document and provide an explanation about how SPP, the relevant committees, and the SPP Board of Directors would evaluate the information provided by applicants and reach their conclusions about whether to approve (or recommend approving) a request.

To address FERC concerns outlined in the rejection, the CAWG developed a more detailed

[78] *Sw. Power Pool, Inc.*, Submission of Tariff Revisions to Add the Waiver of Base Plan Allocation Methodology in Section III.E of Attachment J, ER21-1676-000 (Sept. 23, 2020).
[79] *Sw. Power Pool, Inc.*, 175 FERC ¶ 61,198 (2021).

Byway Facility Cost Allocation process that gave clear standards of how the SPP Board of Directors would grant or deny any application. The new process also detailed how relevant stakeholders participate in the approval or denial of an application. On January 24, 2022, the RSC approved the newly developed Byway Facility Cost Allocation process as implementing the previously approved Byway Facility Cost Allocation Review Process White Paper, this time with additional criteria and processes developed by the CAWG to address FERC-identified issues.

On May 10, 2022, SPP filed Byway Facility Cost Allocation Process with FERC in Docket No. ER22-1846-000. On October 28, 2022, FERC accept the proposed Byway Facility Cost Allocation Process.[80]

II. EVALUATION OF COST ALLOCATION FOR ENERGY STORAGE AS A TRANSMISSION ASSET.

HITT recommendation C4 was assigned to the CAWG and RSC, as the primary working group, to evaluate the cost allocation for an electric storage resource (ESR) as a transmission asset. As directed by the RSC, the CAWG developed The Evaluation of Cost Allocation for Energy Storage as a Transmission Asset White Paper. The Evaluation of Cost Allocation for Energy Storage as a Transmission Asset White Paper recommended the following:

- Cost allocation should be determined by the planning process by which the energy storage as a transmission only asset (SATOA) project is identified. For the purposes of base plan funding, cost allocation for SATOAs should be based upon the location and voltage level associated with the transmission issue being resolved.

- The Energy Storage Resource Steering Committee (ESRSC) and Transmission Working Group (TWG) are better suited to decide whether a mobile ESR solution would/should be considered as a SATOA, and if so, what location and voltage level transmission issue such mobile ESR should be considered as resolving.

- The Safe Harbor threshold of $180,000 per MW should be the same for a SATOA as it is for any other wire solution.

- To the extent a SATOA can establish it meets the requirements for ILTCRS, SATOAs should be allowed to apply and receive ILTCRs in the same manner as any wires solution.

- Cost recovery for a SATOA under transmission rates be limited to the cost of the maximum capacity needed to address the transmission issue and pro-

[80] *Sw. Power Pool, Inc.,* 181 FERC ¶ 61,076 (Oct. 28, 2022).

rated on that basis if a SATOA of higher capacity is proposed. Any excess capacity beyond the required capacity will be required to go through the full GI process if the SATOA seeks to offer the excess capacity in the market.

- Any revenues collected from the SATOA's market activities directed under SPP's functional control shall be credited through transmission rates in a manner consistent with the treatment of costs associated with the project category in transmission rates. The costs resulting from a SATOA's market activities directed under SPP's functional control shall be collected through transmission rates in a manner consistent with the treatment of costs associated with the transmission project type. The SATOA owner will need a registered market participant to receive energy net costs, but only in a price taking role in which bids and offers are not submitted. The ESRSC, working with the Market Working Group (MWG) and SPP settlements are best suited to implement the necessary business practices.

- There should be included Specific FERC/Uniform System of Accounts (USOA) accounting guidance on which FERC accounts are to be used for purposes of cost recovery.

On July 26, 2021, the CAWG presented the Evaluation of Cost Allocation for Energy Storage as a Transmission Asset White Paper to the RSC. The RSC unanimously approved the white paper, which addresses the Board of Directors approved HITT recommendation for CAWG and RSC to evaluate cost allocation for energy storage resources used as a transmission asset. The RSC further directed CAWG, with assistance from SPP Staff, to coordinate with other working groups to implement the cost allocation methods outlined in the Evaluation of Cost Allocation for Energy Storage as a Transmission Asset White Paper.

On January 24, 2022, the RSC unanimously approved the proposed tariff language under the RSC's authority (SATOA Definition, Schedule 11, Attachment H, Attachment J, and Attachment AI) in Revision Request 476 as implementing the cost allocation policies of the HITT C4 white paper, "Evaluation of Cost Allocation for Energy Storage as a Transmission Asset".

On July 12, 2022, SPP filed the proposed Tariff revisions related to Storage as a Transmission Only Asset in Docket No. ER22-2344. This docket is still pending before FERC.

G. STRATEGIC AND CREATIVE RE-ENGINEERING OF INTEGRATED PLANNING TEAM (SCRIPT)

In 2020, the Board of Directors approved the creation of the SCRIPT. SCRIPT is responsible for strategically developing broad changes to SPP's transmission planning processes to better meet customer needs while resolving growing stakeholder concerns about the

amount, nature and funding of continued transmission investment amid rapid industry changes.

- Appropriate consolidation, modification, or elimination of SPP's transmission planning and study processes, in order to:
    - Develop more optimal solutions that meet a broader set of customer needs
    - Synergize analysis so that beneficiaries and cost-causers can be identified in a holistic, uniform fashion
    - Improve planning efficiency, effectiveness and timeliness o Reduce the number of model sets needed
    - Reduce reliance on customer-requested, queue-driven studies
- Improved responsiveness, efficiency and cost certainty of studies needed to provide customer-requested service
- Reduced dependence on queue-driven studies, with consideration given to development of proactive processes that identify and make transparent underutilized transmission capacity
- Utilization of processes and information needed to ensure decisions being made about future investment in transmission infrastructure are made with a high degree of confidence and quality
- Optimization of the existing and planned transmission network to most cost effectively meet future needs while providing maximum value to the region
- Facilitation of generation transfers in a way that will provide future net benefits to the SPP region
- Improved cost sharing among users of the transmission system that appropriately recognizes causers and beneficiaries of transmission investment decisions

The SCRIPT consist of 11 members from the Strategic Planning Committee and Members Committee, the chair of the Markets and Operations Policy Committee, and will have representation from two members of the RSC and the Board of Directors, with SPP COO serving as Staff Secretary.

H. ORDER 2222 TASK FORCE

On October 6, 2020,[81] FERC issued Order No. 2222 to remove barriers to the participation of distributed energy resource ("DER") aggregations in the capacity, energy, and ancillary service markets operated by Regional Transmission Organizations and Independent System Operators. SPP created the Order 2222 Task Force to develop policy and accompanying changes to SPP's governing documents to enable the participation of DERs in SPP's market by providing a means for these resources to, in the aggregate, satisfy

[81] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (2020).

minimum size and performance requirements that they may not meet on a stand-alone basis as required by FERC Order No. 2222.

The 2222 Task Force consists of various members from the Strategic Planning Committee, the Market and Operations Policy Committee and related working groups, the Members Committee, and two members from the Regional State Committee.

In January 2022, MOPC approved RR468, Order 2222 Compliance. SPP will file RR468 with FERC in April 2022.

I. FEBRUARY 2021 WINTER WEATHER EVENT

As an RTO tasked with ensuring the reliable delivery of electricity to a 14-state region, SPP experienced the most operationally challenging week in its 80-year history during February 14-20, 2021. Many locations across the entire SPP service territory, from North Dakota to the Texas panhandle, experienced record-low temperatures for days on end. As consumers' use of electricity and natural gas increased in response to the cold, power producers simultaneously faced fuel-supply issues and equipment malfunctions, transmission system equipment approached unsafe operating limits, and the overall reliability of the bulk electric system was severely tested.

Despite the challenges of managing record wintertime electricity use, generation unavailability, fuel-supply issues, transmission congestion and historically high energy costs, SPP kept the lights on across its region throughout the winter storm, with two short exceptions. SPP directed its transmission operators (TOP) to curtail electricity use by temporarily interrupting their customers' electric service twice: once to lessen regional energy consumption by about 1.5% for 50 minutes February 15 and again to lessen it by about 6.5% for a little more than three hours February 16. Underscoring the historic significance of the February 2021 winter weather event, these marked the first times in the organization's history that SPP has called for region-wide curtailments.

In response to the 2021 February Weather Event, the RSC established the Cost Allocation Working Group Ad Hoc Task Force (CAHTF) to review the impact the weather event had on electricity service through SPP's footprint. Three members of the CAWG made up the CAHTF, which was charged with gaining a broad but thorough understanding of the factors that resulted in SPP's unprecedented declaration of emergencies that curtailed the delivery of electricity at certain times. They were also charged with developing recommendations appropriately related to the RSC's authority (and to other stakeholder working groups) that would reasonably mitigate any emergencies from future extreme weather events. In the development of its recommendations, the CAHTF took into consideration the value of any incremental improvement in service reliability in relation to the potential impact on utility ratepayers.

Of the areas over which the RSC has authority, the CAHTF has identified resource adequacy and unscheduled outages of generators in the SPP footprint as the central elements that

adversely affected electricity service during the extreme weather event of February 2021. A variety of factors identified by the CAHTF can be associated with resource adequacy. They include capacity accreditation, fuel supply, fuel diversity, and improved weatherization. The CAHTF also identified other concerns and opportunities such as demand-side resources, behind-the-meter generation, and enhanced import/export ability. While these factors appear to be within the purview of the RSC's authority working as part of the RTO's general responsibility to ensure the reliability of the system, any measure that addresses resource adequacy should be carefully weighed against the jurisdiction and authority of each State Public Utility Commission (PUC) over resource planning, fuel diversity and generator siting. This extreme weather event should not be used as a pretext for SPP to engage in any measures that may interfere with the authority of State PUCs. Instead, SPP should be encouraged to address issues that provide the most short-term net benefits to resource adequacy in similar extreme weather circumstances.

On June 14, 2021, the RSC unanimously approved the CAHTF Winter Weather Ad Hoc Report.

SECTION V: LEADERSHIP IN INITIATIVES

In addition to the RSC's authority over specific SPP policies, the RSC has taken on numerous other leadership roles. Below is a summary of these leadership roles and examples of the RSC instigating or leading important SPP initiatives.

A. SUPPORT OF MARKETS

1. Energy Imbalance Service (EIS):[82] In 2004-2005, the RSC approved the EIS market cost benefit analysis. This effort was led by a CAWG member.
2. Integrated Marketplace:[83] On April 27, 2009, the RSC endorsed the cost benefit analysis for the Integrated Marketplace and recommended that SPP move forward with the initiative.

[82] The EIS was a real-time balance market.

[83] The Integrated Market is day-ahead market with transmission congestion rights, a reliability unit commitment process, a real-time balancing market replacing the EIS market, and the incorporation of price-based operating reserve procurement.

B. ISSUES WITH PROJECT COST ESTIMATIONS

On October 25, 2010, after some approved transmission projects overran their projected costs, the RSC approved the following motions to address cost overruns:

> MOTION 1: RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded;
>
> MOTION 2: RSC recommends that SPP review the Novation Process and report to the RSC by April 2011;
>
> MOTION 3: RSC recommends that SPP consider establishing design & construction standards for transmission projects at 200 kV & above that are regionally funded;
>
> MOTION 4: SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed;
>
> MOTION 5: Move that the CAWG study various methods on how costs that exceed some standard can be addressed with different cost allocation mechanisms and recommend strategies to the RSC.

On July 25, 2011, after the CAWG completed a study of these motions, the RSC approved the following:

- Transmission projects proposed for assignment or novation should receive RSC approval prior to approval by the SPP Board of Directors;
- Assignment or novated projects not receiving RSC approval should not receive highway/byway (base plan) cost allocation treatment for all costs in excess of the designated transmission owner (DTO) estimate;
- Assignment as well as Novation evaluations should be consistent with the incumbent transmission owner (TO) or DTO and specifically include estimated costs and Annual Transmission Revenue Requirement (ATRR) impacts; and
- CAWG is directed to work with SPP staff and stakeholders to develop recommendations for the January RSC meeting on: a) detailed cost comparison estimate inputs and analysis for novations and assignments; b) competitive selection processes and any necessary tariff changes when a DTO cannot perform its obligations.

At the January 30, 2012 RSC meeting, the CAWG presented various obstacles that transmission owners were incurring which resulted in reasonable cost overruns.

C. RSC/OMS SEAM LIAISON COMMITTEE

Organization of MISO States (OMS) and RSC Commissioners have recognized there are issues preventing efficient economic transmission planning, market and operations, and resource integration along the SPP-MISO seam. A liaison committee was formed by the boards of the OMS and the RSC to facilitate identification of issues and potential solutions to enhance the benefits to customers from better-coordinated seams policies.

On October 29, 2018, the RSC unanimously approved RSC/OMS Seam Liaison Committee's ("SLC") Goals Statement and Guiding Principles. The stated goals of the SLC are to identify potential improvements in the following areas: (1) increase benefits to ratepayers in both markets by improving market-based transactions and operations across the seam; (2)ensure equal consideration of beneficial regional and inter-regional projects in transmission planning; (3) support the timely interconnection of new resources that includes consideration of the interconnection queue in both RTOs; and (4) improve inter-RTO relations through state-led cooperation.

The Guiding Principles approved by the RSC, relating to the SLC, are the following:

- No one is right or wrong where viewpoints do not align. We strive to understand the drivers behind our differences. It is not personal.
- Working from a common set of facts is critical. Be willing to challenge others thoughtfully and professionally so that all points of view are understood.
- The best outcome for customers is the best outcome. Customers in all portions of an RTO footprint should benefit from RTO membership. Internal viewpoints from states on both sides of the seam are crucial as it represents balancing of customer interests.
- Everyone is open to change if better solutions are identified, even if they aren't perfect.
- Alleviating transmission constraints can provide benefits under the right circumstances. There can be significant benefits from alleviating transmission constraints.
- Commissioners are the primary participants in these efforts with support from staff.

On October 15, 2018, the SLC issued a whitepaper request of MISO and SPP. The request stated that MISO's and SPP's whitepaper should cite examples, including historical events, and identify procedural and regulatory differences that may be barriers to efficient operations between MISO and SPP. Additionally, the whitepaper should discuss opportunities for improvement in all areas – planning, markets & operations, and resource integration. The SLC requested SPP and MISO to identify tariffs, joint operating agreements, coordination procedures, or other existing documents or processes that provide guidance for how MISO and SPP operate on the seam, and indicate the extent to which each constitutes a barrier to seams efficiency. On November 2, 2018, SPP and MISO presented the Seams Whitepaper to the SLC.

On December 11, 2018, the SLC issued a request to any interested stakeholders to provide their reaction to the SPP and MISO's Seam Whitepaper. The list of the responses from interested stakeholders can be found on the SLC's reference document page on SPP's website.

On March 4, 2019, the SLC asked a list of follow-up questions to MISO and SPP. On April 8, 2019, both MISO and SPP responded to the SLC's follow-up questions.

The SLC asked the SPP Market Monitor and the MISO Market Monitor to review the stakeholder feedback on the impacts of Rate Pancaking, Market-to-Market Coordination, Joint Dispatch, Unreserved Use Charges, and Rate Pancaking. Each of the market monitors presented the findings at the April 2020 and June 2020 SLC meetings.

In the latter half of 2020, the SLC and OMS worked together to prioritize the following issues: Market-to-Market; Rate Pancaking; Interregional Planning; Targeted Market Efficient Projects; Generator Interconnection and Coordinated Transaction Scheduling and Interface Pricing Improvements.

Goal of SLC in 2021 is to combine the recommendations with their rankings in a final document that has been approved by RSC and OMS.

D. ADVANCE NOTICE OF PROPOSED RULEMAKING

On July 15, 2021, FERC issued an Advance Notice of Proposed Rulemaking (ANOPR)[84] to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection (GI) processes and, if so, which changes are necessary to ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained. The Commission requested comments on several wide-ranging areas: regional transmission planning, regional cost allocation, GI funding, GI queueing processes, and consumer protection.

On October 8, 2021, the RSC unanimously approved RSC Comments in response to the ANOPR.

84 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (2021).

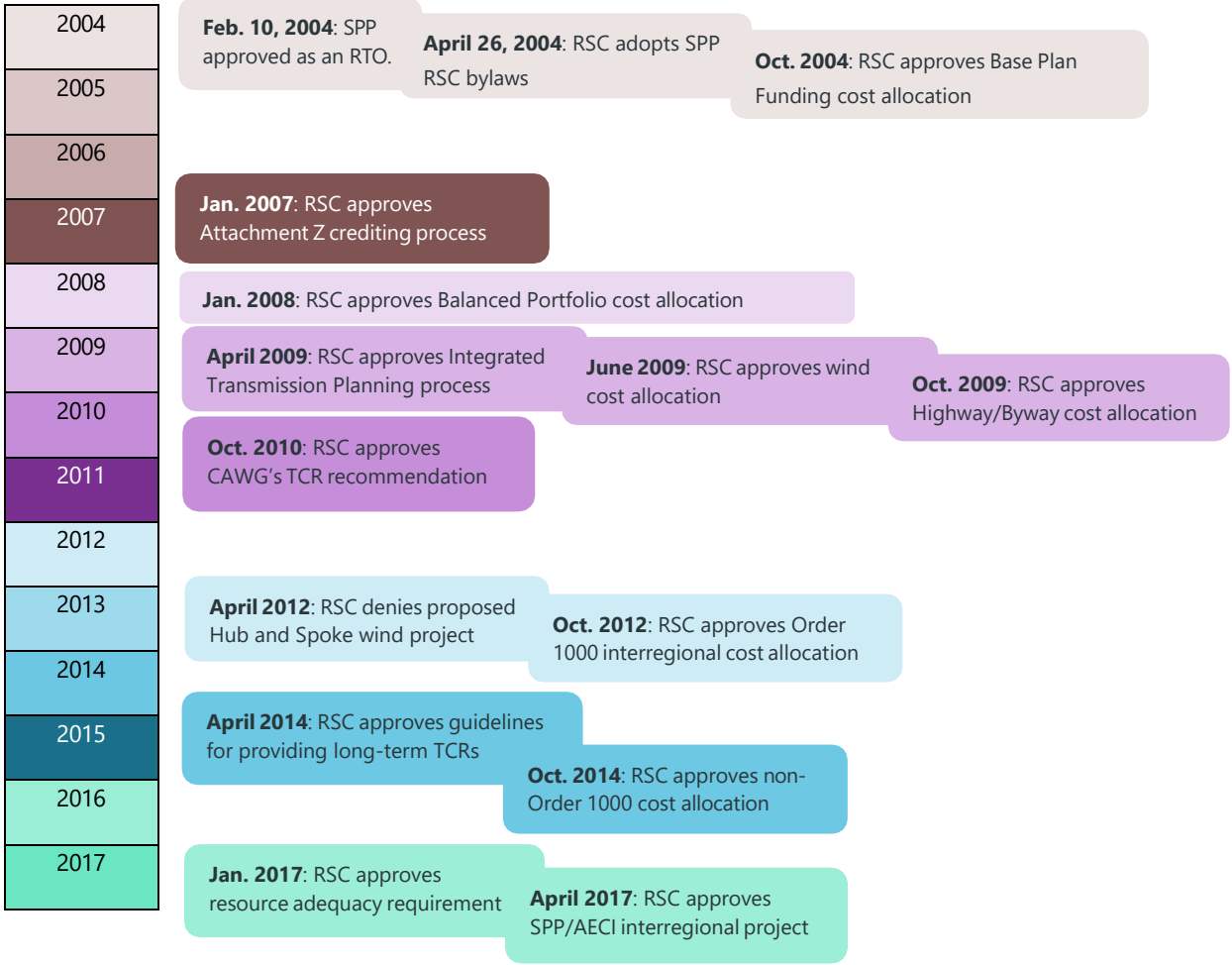
E. IMPROVED RESOURCE AVAILABILITY TASK FORCE (IRATF)

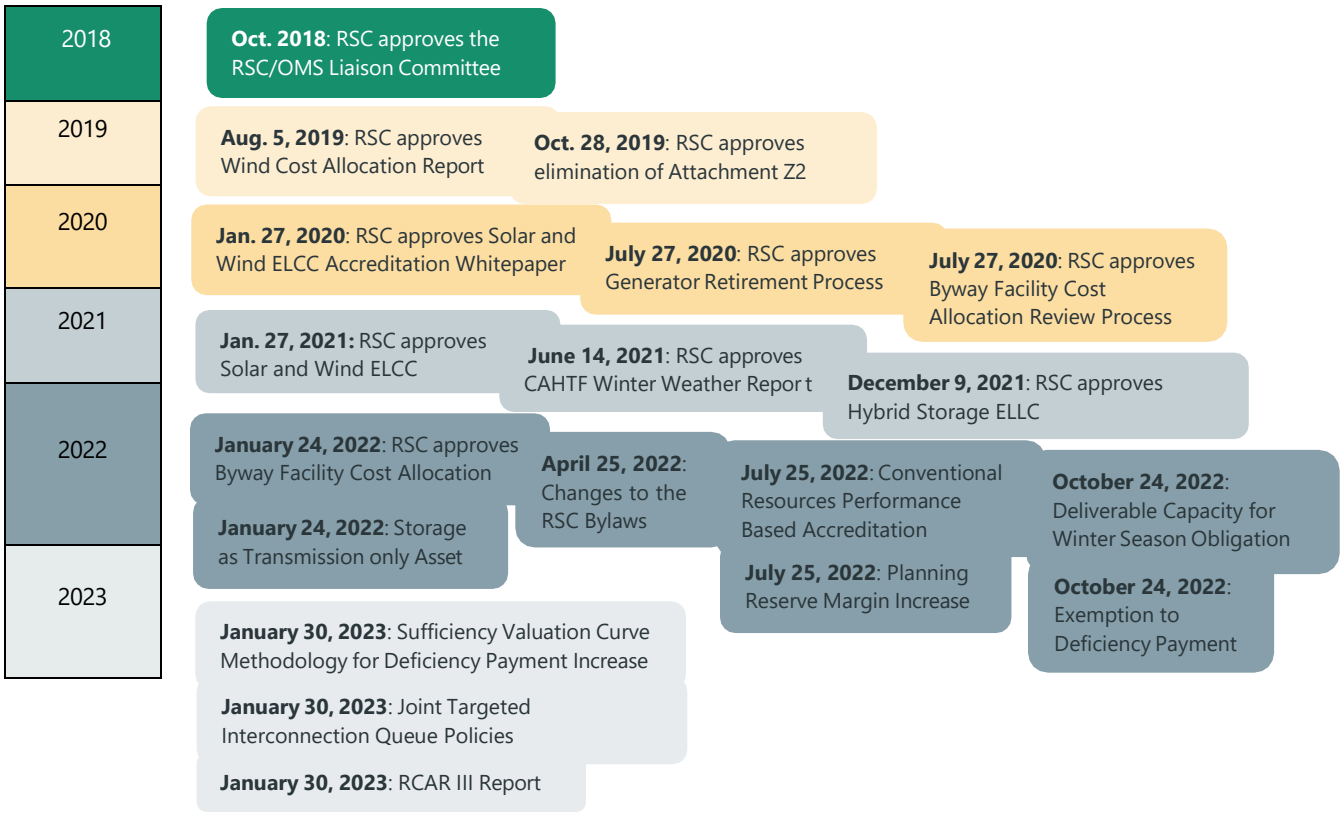
On August 9, 2021, the was created to take primary responsibility for addressing Tier 1 recommendations related to fuel assurance and resource planning and availability identified in the Comprehensive Review of SPPs Response to the February 2021 Winter Storm report as approved by the SPP Board of Directors on July 26, 2021.

The IRATF is chaired by one member of the RSC and includes five members or representatives of the CAWG.

SECTION VI: APPENDICES

APPENDIX A: RSC TIMELINE




2018
2019
2020
2021
2022
2023
Oct. 2018: RSC approves the RSC/OMS Liaison Committee
Aug. 5, 2019: RSC approves Wind Cost Allocation Report
Oct. 28, 2019: RSC approves elimination of Attachment Z2
Jan. 27, 2020: RSC approves Solar and Wind ELCC Accreditation Whitepaper
July 27, 2020: RSC approves Generator Retirement Process
July 27, 2020: RSC approves Byway Facility Cost Allocation Review Process
Jan. 27, 2021: RSC approves Solar and Wind ELCC
June 14, 2021: RSC approves CAHTF Winter Weather Report
December 9, 2021: RSC approves Hybrid Storage ELLC
January 24, 2022: RSC approves Byway Facility Cost Allocation
April 25, 2022: Changes to the RSC Bylaws
July 25, 2022: Conventional Resources Performance Based Accreditation
October 24, 2022: Deliverable Capacity for Winter Season Obligation
January 24, 2022: Storage as Transmission only Asset
July 25, 2022: Planning Reserve Margin Increase
October 24, 2022: Exemption to Deficiency Payment
January 30, 2023: Sufficiency Valuation Curve Methodology for Deficiency Payment Increase
January 30, 2023: Joint Targeted Interconnection Queue Policies
January 30, 2023: RCAR III Report

APPENDIX B: A HISTORY OF RSC MEMBERS

Arkansas Public Service Commission

1. Sandra Hochstetter Byrd: 2004-07
2. Paul Suskie: 2007, 2008-10
3. Colette Honorable: 2008
4. Olan Reeves: 2011-2014
5. Lamar Davis: 2015-2016
6. Kim O'Guinn: 2016-2020
7. Ted Thomas: 2021-2022
8. Justin Tate: 2022-Present

Iowa Utilities Board

1. Libby Jacobs: 2015-2017
2. Geri Huser: 2017-Present (Current Vice-President of the RSC)

Kansas Corporation Commission

1. Brian Moline: 2004-07
2. Mike Moffet: 2007-10
3. Thomas Wright: 2010-2014
4. Shari Feist Albrecht: 2014-2020
5. Andrew J. French: 2020-Present (Current President of the RSC)

Louisiana Public Service Commission

1. Foster Campbell: 2018-2019
2. Mike Francis: 2020-Present

Missouri Public Service Commission

1. Steve Gaw: 2004-07
2. Jeff Davis: 2007-12
3. Kevin Gunn: 2012-2013
4. Steve Stoll: 2013-2017
5. Scott Rupp: 2018-Present

Nebraska Power Review Board

1. Mike Siedschlag: 2009-2014
2. Steve Lichter: 2014-2016
3. Dennis Grennan: 2016-2021
4. Chuck Hutchison: 2022-Present

New Mexico Public Regulation Commission

1. David King: 2004-11
2. Patrick Lyons: 2011-2018
3. Jeff Byrd: 2019-2022
4. TBD

North Dakota Public Service Commission

1. Brian Kalk: 2015-2017
2. Randel Christmann: 2017-Present

Oklahoma Corporation Commission

1. Denise Bode: 2004-07
2. Jeff Cloud: 2007-11
3. Dana Murphy: 2011-2022
4. Todd Hiett: 2022-Present

Public Utility Commission of Texas

1. Julie Parsley: 2004-08
2. Barry Smitherman: 2008-11
3. Donna Nelson: 2011-2017
4. Brandy Marty Marquez: 2017
5. DeAnn T. Walker: 2017-2021
6. Will McAdams: 2022-Present

South Dakota Public Utilities Commission

1. Kristie Fiegen: 2015-Present

APPENDIX C: SPP RSC BYLAWS

Southwest Power Pool
REGIONAL STATE COMMITTEE
BYLAWS

Revised: November 1, 2022

ARTICLE I

1. NAME: The organization shall be known as the Southwest Power Pool Regional State Committee ("SPP RSC"). The principal office of the SPP RSC shall be at such location, within the United States, as the SPP RSC Board of Directors ("RSC Board") shall from time to time establish. The SPP RSC may also maintain such branch offices and places of business as the RSC Board may deem necessary or appropriate in the conduct of its business.

2. PURPOSE: The SPP RSC shall provide collective state regulatory agency input and participation in the Southwest Power Pool, Inc. ("SPP") and SPP's Board of Directors, committees, working groups and task forces, including any independent transmission system operator ("ISO") or regional transmission organization ("RTO") formed by the SPP. As specified in the SPP Bylaws, §7.2, such input and participation shall include but not be limited to: whether and to what extent participant funding will be used for transmission enhancements; whether license plate or postage stamp rates will be used for the regional access charge; determination of Financial Transmission Rights ("FTR") allocations where a locational price methodology is used; determination of the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights; determination of the approach for resource adequacy across the entire region; determination of whether transmission upgrades for remote resources will be included in the regional transmission planning process; and determination of the role of transmission owners in proposing transmission upgrades in the regional planning process.

3. Nothing in the formation or operation of the SPP RSC as a FERC-recognized regional state committee is in any way intended to diminish existing state regulatory jurisdiction and authority. Each Member state regulatory agency expressly reserves the right to exercise all lawful means available to protect its existing jurisdiction and authority.

ARTICLE II – MEMBERSHIP

MEMBERSHIP: As specified in the SPP Bylaws, §7.2, effective 11/01/2022, membership shall be open to one designated representative from one regulatory utility commission or board from each state where SPP operates as an RTO.

For purposes of RSC membership, membership is open to one member from one state regulatory commission or board of a state in which:

1. SPP has functional control of transmission facilities in the state and
2. The state has load served by SPP's RTO electricity markets.

ARTICLE III – ANNUAL MEETING

The Annual Meeting of the SPP RSC ("Annual Meeting") shall be held each year in conjunction with the fall meeting of the SPP Board of Directors, and/or at such time and place as may be determined by the RSC Board. Notice of the time, place, and purpose of the meeting, shall be provided by mail or electronic means to each Member of the SPP RSC not less than fifteen (15) calendar days prior to the meeting, except that the agenda may be amended up to three (3) calendar days prior to the meeting in accordance with Article XI. At the Annual Meeting, each Member state regulatory agency may have a seat and voice. The business of the Annual Meeting will be conducted by vote of the RSC Board as provided for in these Bylaws.

ARTICLE IV – BOARD OF DIRECTORS

1. POWERS, RESPONSIBILITIES AND ACCOUNTABILITIES: The corporatebusiness and affairs of the SPP RSC shall be managed by the RSC Board, except as may be otherwise provided for in these Bylaws and/or the SPP RSC Articles of Incorporation.

2. COMPOSITION: Each Member state regulatory agency, as defined in Article II.1 of these Bylaws, may designate one Commissioner to serve on the RSC Board. In the case of Member state regulatory agencies organized without commissioners, an official of similar level may be designated. When any such person ceases to be the duly authorized representative of that Member, he or she shall be replaced on the RSC Board by another representative from his or her state regulatory agency. A Member state regulatory agency may replace its Director by notifying the Secretary of the RSC Board by mail, facsimile transmission and/or electronic mail at least one business day in advance of any meeting of the RSC Board.

3. RESPONSIBILITIES: The RSC Board shall elect the Officers of the SPP RSC and determine the general policies and direction of the SPP RSC. The RSC Board may amend the Articles of Incorporation and Bylaws, take all other action requiring membership vote, and conduct other business as delineated in Article IX.

4. REGULAR MEETINGS: Regular meetings of the RSC Board shall be held at such time and place as may be determined by the RSC Board, except that the RSC Board shall meet no less than one time each calendar year, in addition to the Annual Meeting. Notice of the time, place and purpose of the meeting(s) shall be provided by mail, facsimile transmission and/or electronic means to each Member of the SPP RSC not less than seven (7) calendar days prior to the meeting, except that the agenda may be amended up to three (3) calendar days prior to the meeting in accordance with Article XI. Public notice shall also be given at the same time that it is given to each Member of the SPP RSC in accordance with Article XI.

5. SPECIAL MEETINGS: The President may call a special meeting(s) of the RSC Board. Notice of the time, place and purpose of the meeting(s) shall be provided by

mail, facsimile transmission and/or electronic means to each Member of the SPP RSC not less than three (3) calendar days prior to the meeting(s).

6. QUORUM: If a Director from each of a majority of the Member state regulatory agencies is present (either in person, by authorized telephonic or electronic means, or by designated proxy), a quorum exists for the transaction of business at any meeting of the RSC Board, but if less than such majority is present at a meeting, a majority of the Directors that are present may adjourn the meeting without further notice. The SPP RSC Directors present at a properly noticed meeting may continue to transact business until adjournment, notwithstanding the withdrawal of enough Directors to leave less than a quorum. A Member state regulatory agency may allow a proxy from the same agency to participate as a substitute for its designated SPP RSC Director at a meeting(s) of the RSC Board by notifying the Secretary of the RSC Board as provided for in these Bylaws.

7. PROXY: A request of a Member state regulatory agency for recognition by the RSC Board of a proxy to participate in a meeting of the RSC Board must be received by the Secretary of the RSC Board at least one business day in advance of the meeting at which the proxy is to be exercised. Where prior written notice is not possible, the designating Director shall submit written confirmation of this proxy no later than ten (10) calendar days after the applicable RSC Board meeting takes place. The person who is identified as exercising the proxy cannot be the person submitting the request for recognition of the proxy. Notices of proxies must be sent by mail, facsimile transmission and/or electronic mail to the Secretary of the RSC Board and identify the date of the meeting of the RSC Board for which the proxy is authorized and identify by name, and position at the Member state regulatory agency, the person who is authorized to exercise the proxy. The Secretary of the RSC Board must receive a new request for recognition of a proxy for each meeting of the RSC Board at which the proxy will be sought to be recognized. The RSC Board will not recognize, for more than one meeting at a time, a proxy request by a Member state regulatory agency. The request for recognition of a proxy must not identify more than one person as being authorized to exercise the proxy.

8. VOTING PROCEDURES: Each Director present (either in person, by authorized telephonic or electronic means, or by representation of the Member state regulatory agency by a properly designated proxy) shall be entitled to one equally weighted vote. However, if a state has more than one state regulatory agency that is a member of the RSC Board, voting rights shall be divided equally among the Directors from that state present and voting (equating to one total vote per state). All votes of the RSC Board shall be recorded by the Secretary and shall become part of the official record of the RSC Board.

(a) ELECTIONS: Elections for Officers of the RSC Board shall be by ballot in contested elections and may be by voice or other means in uncontested elections. A plurality of votes cast shall elect.

(b) BYLAWS: Changes in the Bylaws shall require a vote consistent with Article XII of this document.

(c) BUSINESS MATTERS: All other business matters, including administrative and procedural matters, shall be determined by a majority of the Directors present and voting, unless otherwise provided by the laws of Arkansas or these Bylaws.

9. ELECTRONIC VOTING: The President has the option and authority to conduct an electronic mail vote on non-policy, administrative and procedural matters, such as approval of minutes or appointment of the annual SPP RSC auditor, or on policy matters that have been presented, moved, seconded, and discussed during a prior open RSC Board meeting.

10. POSITIONS ON POLICY ISSUES: The RSC Board will give direction to formation of issue statements, which will then be referred to Member state regulatory agencies. A position approved by a majority of the RSC Board may be issued as the SPP RSC's position with identification of the participating and non-participating Member state regulatory agencies. Individual Member state regulatory agencies retain all rights to object to, support, or otherwise comment on, issue statements of the SPP RSC, including the attachment of a minority report or dissenting opinion, provided it is submitted in a timely manner. The RSC Board may authorize intervention in proceedings before federal regulatory agencies and in related judicial proceedings to express the SPP RSC's positions, and may retain legal counsel to represent the SPP RSC in such proceedings. Consistent with Article I, § 3 above, each individual Member state regulatory agency shall also retain all rights to intervene, protest, and/or comment on such federal regulatory agency proceedings and/or related judicial proceedings.

ARTICLE V – OFFICERS

1. NUMBER AND TITLE: The Officers of the RSC Board shall be the President, Vice-President, Secretary, and Treasurer.

2. ELECTION, TERM, VACANCIES: The President, Vice-President, Secretary, and Treasurer shall be elected by the RSC Board for a term of one year, or until their successors are elected. Officers shall be elected at the Annual Meeting to take office on the first day of January following the Annual Meeting at which elections are held. The RSC Board may fill a vacancy among the Officers other than the President to serve until the next scheduled election. In the case of a permanent vacancy in the office of the President, the Vice-President will succeed until the next scheduled election.

3. GEOGRAPHIC BALANCE: The Officers elected shall be SPP RSC Directors from different states.

4. DUTIES: The duties of the Officers shall be asfollows:

(a) The PRESIDENT shall be the principal Officer of the SPP RSC and shall preside at the Annual Meeting and all meetings of the RSC Board. The President shall be responsible for seeing that the lines of direction given by the RSC Board are carried into effect – including the representation and presentation of all SPP RSC majority positions and minority reports and dissenting opinions of the Member state regulatory agencies. The President shall have such other powers and perform such other duties as may be assigned by the RSC Board, including but not limited to: serving as the SPP RSC's non-voting representative at the meetings of the SPP's Board of Directors; performing or delegating presentations/speeches on behalf of the SPP RSC; designating Member state regulatory agency staff members proposed by the state regulatory agency to carry out daily functions and operations of the SPP RSC; assigning Member state regulatory agency staff members proposed by the state regulatory agency to committees and work-groups created by the SPP RSC; and requesting technical support from SPP staff as necessary. The President (or other Officer serving as the RSC representative at meetings of the SPP Board of Directors) shall also be responsible for requesting recusal of a Director where a conflict of interest may arise and for clearly stating on all matters whether he/she is representing the position of the SPP RSC or solely his/her Member state regulatory agency.

(b) The VICE-PRESIDENT, in the temporary absence or disability of the President, shall preside at meetings of the RSC Board and have such other powers and perform such other duties as performed by the President. The Vice-President shall also serve as the SPP RSC's non-voting representative at the meetings of the SPP's Board of Directors. He or she shall have such other powers and perform such other duties as performed by the President or as may be assigned by the RSC Board.

(c) The SECRETARY shall be responsible for keeping a roll of the Members and seeing that notices of all meetings of the RSC Board are issued and shall see that minutes of such meetings are kept. The Secretary shall be responsible for the custody of corporate books, records and files, shall exercise the powers and perform such other duties usually incident to the office of Secretary, and shall exercise such other powers and perform such other duties as may be assigned by the President or the RSC Board.

(d) The TREASURER shall be responsible for monitoring the receipt and custody of all monies of the SPP RSC and for monitoring the disbursement thereof as authorized, for ensuring that accurate accounts of monies received and disbursed are kept, for execution of contracts or other instruments authorized by the RSC Board, and for overseeing the preparation and issuance of financial statements and reports. The Treasurer shall give a report of the SPP RSC's finances at the Annual Meeting. The Treasurer shall be an ex officio member of the finance committee, if such a committee shall be established by the RSC Board, shall exercise the powers and perform such other duties usually incident to the office of Treasurer, and shall perform such other duties as may be assigned by the President or RSCBoard.

5. REMOVAL: An Officer of the RSC Board may be removed with or without cause by written vote of two-thirds of the total membership of the SPP RSC Board.

ARTICLE VI – MEMBER STATE REGULATORY AGENCY STAFF MEMBER PARTICIPATION

Member state regulatory agency staff members may participate at the discretion of their respective Member state regulatory agencies, including but not limited to: attendance at RSC Board and SPP Board of Directors meetings in support of or in lieu of Member state regulatory agency commissioners; attendance and active participation in assigned SPP committees, working groups and task forces (including providing summaries of meetings and reporting to the SPP RSC Members); active representation of the majority positions and minority reports or dissenting opinions of the SPP RSC Member state regulatory agencies; and attending and actively participating in assigned RSC Board committees and work-groups created by the RSC Board (including providing summaries of meetings and reporting to the SPP RSC Members). Member state regulatory agency staff members must clearly indicate whether they are representing the RSC Board or solely their Member state regulatory agency.

ARTICLE VII – COMMITTEES

1. ESTABLISHED: The RSC Board may establish RSC Board committees and work-groups as it deems necessary and provide for their governance.

2. COMPOSITION AND APPOINTMENT: Unless otherwise provided in these Bylaws, the President shall appoint members of the RSC Board committees. Unless otherwise provided by the RSC Board, a committee may elect its chair. Members may participate in the work of committees and work-groups that relate to matters within their jurisdiction.

3. NOMINATING COMMITTEE:

(a) COMPOSITION: The Nominating Committee shall consist of three Directors of the RSC Board.

(b) METHOD OF ELECTION, TERM, VACANCIES: Members of the Nominating Committee shall be elected by the RSC Board annually each July. Terms of office shall begin at the close of the July meeting at which elections are held and shall expire at the close of the following Annual Meeting. The President shall have the power to fill vacancies in the NominatingCommittee.

(c) RESPONSIBILITIES: At the Annual Meeting, the Nominating Committee shall present to the RSC Board a single slate of nominations for Officers of the RSC Board. Any Director may make additional nominations from the floor at the Annual Meeting.

ARTICLE VIII – MEMBERS NOT BOUND

No vote of, or resolution passed by, the RSC Board has any binding effect upon any Member state regulatory agency in the exercise of that entity's powers.

ARTICLE IX - FISCAL RESPONSIBILITIES OF THE RSC BOARD

1. FISCAL YEAR: The RSC Board shall establish the fiscal year of the SPP RSC.

2. FUNDING: Any funds shall be accepted or collected only as authorized by the RSC Board.

3. DEPOSITORIES: All funds of the SPP RSC shall be deposited to the credit of the SPP RSC in fully insured accounts.

4. DELEGATED AUTHORITY: For routine payment of meeting and travel expenses incurred by SPP RSC Members and their designees, including Member state regulatory agency staff members, the SPP RTO may act as agent for the RSC Board and make payment of such expenses in accordance with the RSC Board's then-current Expense Reimbursement Policy. Such expenses shall be paid from the RSC Board's approved budget. For items of non-routine and more financially significant nature, such as an RSC-commissioned cost-benefit study or a large conference or event, the RSC Board may provide approval to the appropriate person within the SPP RTO to pay for such expenses, acting as agent for the RSC Board.

5. BONDING: All persons having access to or major responsibility for the handling of monies and securities of the SPP RSC shall be bonded as provided by resolution of the RSC Board.

6. INDEMNIFICATION AND INSURANCE: Indemnification and Directors andOfficers insurance shall be provided by resolution of the RSC Board in accordance with the Articles of Incorporation and the laws of Arkansas.

7. BUDGET: The annual budget of estimated income and expenditures shall be prepared for the fiscal year and approved by the RSC Board in conjunction with the Annual Meeting. No expenses shall be incurred in excess of approved budget levels without prior approval of the RSC Board.

8. CONTRACTS AND DEBTS: Contracts may be entered into or debts incurred only as directed by resolution of the RSC Board.

9. AUDITS: A certified public accountant or other independent public accountant shall be retained by the RSC Board to make an annual examination of the financial accounts of the SPP RSC. A report of this examination shall be submitted to the RSC Board and made available to the general membership of the SPP RSC and the public.

10. LEGAL COUNSEL: Independent legal counsel may, if deemed necessary and appropriate, be retained by the RSC Board to: (a) ensure compliance with federal and state requirements; (b) review and advise on any and all legal instruments the RSC Board executes, such as leases, contracts, property purchases, or sales; (c) intervene, protest, and/or comment on federal regulatory proceedings and/or related judicial proceedings; or (d) for any other matters as determined necessary by the RSC Board – including those matters that are deemed to be administrative in nature.

11. PROPERTY: Title to all property shall be held in the name of the SPP RSC, unless otherwise approved by the RSC Board or as otherwise required by law.

12. INVESTMENT: The Treasurer shall invest the funds of the SPP RSC in accordance with the direction of the RSC Board or any committee of the RSC Board appointed for such purpose.

ARTICLE X - PARLIAMENTARY AUTHORITY

All meetings shall be conducted in a manner that will allow the fullest possible participation by all members. In the event of a dispute, Robert's Rules of Order, newly revised, shall be the parliamentary authority governing the meetings of the RSC Board and all committees, subject to the laws of Arkansas, the Articles of Incorporation, these Bylaws, and any special rules of order adopted by the RSC Board.

ARTICLE XI - OPEN MEETINGS

The Annual Meeting and all meetings of the RSC Board and subordinate committees and work-groups shall be open meetings, except that discussion of commercially sensitive, legal, and personnel issues, (including meetings of the Nominating Committee), educational sessions/retreats, and the state commission forum (established in the new member process document as adopted by the SPP Board of Directors on July 28, 2015) may be conducted in closed session. For the purposes of these Bylaws, open meeting means:

(a) Notice of the time, place, and purpose of the meeting, as provided in Articles III and IV, shall be made available to the public, through printed or electronic means, provided however, that the agenda for any annual, regular, or special meeting may be amended up to three (3) calendar days prior to the meeting date, as long as the amendment does not involve a change to the Bylaws or otherwise affect the substantive rights of Members.

(b) Minutes of the RSC Board and subordinate committee meetings shall be made available to the public, through printed or electronic means, as soon as practical.

(c) Official governmental agencies that are involved with energy planning and/or environmental issues or are involved with consumer advocacy, as well as the public, may attend all open meetings of the SPP RSC.

(d) The RSC Board may provide for participation by telephone or electronic means.

ARTICLE XII- AMENDMENTS

Except as otherwise stated herein, these Bylaws may be amended by a two-thirds vote of a quorum at the Annual Meeting and any regular meeting of the RSC Board, provided that the proposed amendment(s) have been included in the notice of the meeting in which such changes were to be considered.

Exceptions to two-thirds voting requirement: Any amendment(s) to Article I, § 3; Article IV, § 10 or Article VIII shall require the unanimous vote of the entire RSC Board.

ARTICLE XIII- EXECUTIVE DIRECTOR

1. EMPLOYMENT: The RSC Board may select an Executive Director. When an Executive Director is hired, the RSC Board shall determine the terms and conditions of the employment of the Executive Director. Thereafter, the Executive Director's employment may be terminated by a majority vote of the RSCBoard.

2. RESPONSIBILITIES: If deemed necessary and appropriate, when an Executive Director is hired, the Executive Director shall be the chief executive of the SPP RSC under the supervision and day-to-day policy guidance of the President of the RSC Board. The Executive Director shall be responsible for providing advice and assistance to the RSC Board, the President and other Officers, and any subordinate committees and work-groups; and shall be responsible for administering the operations of the SPP RSC. The Executive Director shall have such other powers and perform such other duties as may be provided by the RSC Board. The Executive Director shall be an ex officio non-voting member of the RSC Board.

APPENDIX D: SPP BYLAWS 7.2

Excerpted from the SPP Governing Documents Tariff generated August 8, 2017

A Regional State Committee (RSC), to be comprised of one designated commissioner or board member from one state regulatory utility commission or board from each state within the SPP Region where SPP provides services as a regional transmission organization, shall be established to provide both direction and input on all matters pertinent to the participation of the Members in SPP. This direction and input shall be provided within the context of SPP's organizational group meetings as well as Board of Directors meetings. The SPP Staff will assist the RSC in its collective responsibilities and requests by providing information and analysis. SPP will fund the costs of the RSC pursuant to an annual budget developed by the RSC and submitted to SPP as part of its budgeting process, which budget must ultimately be approved by the Board of Directors.

The RSC has primary responsibility for determining regional proposals and the transition process in the following areas:

(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;

(c) FTR allocation, where a locational price methodology is used; and

(d) the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights.

The RSC will also determine the approach for resource adequacy across the entire region. In addition, with respect to transmission planning, the RSC will determine whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process.

As the RSC reaches decisions on the methodology that will be used to address any of these issues, SPP will file this methodology pursuant to Section 205 of the Federal Power Act. However, nothing in this section prohibits SPP from filing its own related proposal(s) pursuant to Section 205 of the Federal Power Act.

APPENDIX E: POLICIES APPROVED BY THE RSC

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
SPP RSC Bylaws: Outlined the authorities granted to the RSC.	Other	April 26, 2004	N/A
Base-Plan Funding / Original Cost Allocation: The Original Cost Allocation approved by the RSC after SPP received RTO status.	Cost Allocation	October 26, 2004	N/A
Balanced Portfolio Cost Allocation: Establishment of a process to evaluate a group, or a portfolio, of economic upgrades to be included in SPP's Transmission Expansion Plan.	Cost Allocation	January 28, 2008	N/A
Attachment Z2 Revenue Crediting Process: Assignment of credits to transmission service customers, who were directly assigned network upgrade costs for a portion of new transmission service, from customers that use the facility that was directly assigned network upgrade costs.	Cost Allocation	January 29, 2007	N/A
Wind Cost Allocation: The change in cost allocation for network upgrades associated with designating a wind generation resource.	Cost Allocation	October 24, 2007	N/A

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Integrated Transmission Plan (ITP): ITP was a change to the transmission planning process to determine near term and long-term transmission needs. ITP was a planning process that includes 20-Year, 10-Year, and Near-Term Assessments.	Planning for Remote Resources	April 27, 2009	N/A
Synergistic Planning Project Team (SPPT) Report: The report recommended several reforms for SPP's transmission planning and cost allocation processes. This report lead to the ITP and to the Highway/Byway cost allocation.	SPP Stakeholder Groups	April 27, 2009	N/A
Integrated Marketplace Cost-Benefit Analysis: Enforcement of the Cost Benefit Analysis for the future Integrated Marketplace cost benefit analysis and recommended that SPP move forward.	Leadership Initiatives	April 27, 2009	N/A
Highway/Byway Cost Allocation: Cost allocation that allocated costs to the zone and to the entire footprint based on the voltage level of the transmission facility.	Cost Allocation	October 26, 2009	N/A
Established the Rate Impact Task Force: Task Force looked at the cost and benefits of transmission upgrades on customer rates.	SPP Stakeholder Groups	April 26, 2010	N/A

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Established the Regional Allocation Rate Task Force: Task Force responsible for reviewing the unintended consequences review process, which was named the regional cost allocation review (RCAR) process.	SPP Stakeholder Groups	April 25, 2011	N/A
Cost Overrun and Novation Policy: Policy to review cost overruns for approved transmission projects.	Leadership Initiatives	January 30, 2012	N/A
Denial of Hub and Spoke Cost Allocation: The "Hub" was a generation hub defined as the interconnection substation designated by the transmission provider for interconnecting generation in a given area. The "Spoke" was a generation collector spoke defined as the transmission line that ultimately connects multiple generators to the Hub	Planning for Remote Resources	April 23, 2012	N/A
Established Interregional Cost Allocation Task Force: The Interregional Cost Allocation Task Force was responsible for developing cost allocation principles relating to Order No. 1000 interregional projects.	SPP Stakeholder Groups	April 23, 2012	N/A

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Order 1000 Cost Allocation: Order 1000 required SPP to implement a method or set of methods for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation and interregional transmission facilities.	Cost Allocation	October 29, 2012	N/A
Transmission Congestion Rights (TCR) Process: The policy how these financial transmission rights are allocated throughout SPP.	Financial Transmission Rights	April 28, 2014	N/A
Long Term Financial Transmission Rights (LTFTR) Process: The design of the LTFTR process.	Financial Transmission Rights	April 28, 2014	N/A
Approved policies developed by Strategic Planning Committee Task Forces on New Member Process: This task force was tasked with developing improved and enhanced communications and processes for new member additions to SPP.	SPP Stakeholder Groups	July 27, 2015	N/A
Non-Order 1000 Cost Allocation: The allocation of costs for interregional transmission plans that fall outside the Order 1000 Cost Allocation procedures.	Cost Allocation	October 27, 2014	N/A

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Capacity Margin Task Force (CMTF) Resource Adequacy Recommendations: The proposal from the CMTF was that all parties serving load in the SPP Balancing Authority should be included in the obligation to meet SPP's Planning Reserve Margin (PRM) requirement. CMTF developed policies to identify who is responsible for resource adequacy, what the resource adequacy requirement is, and how and when the resource adequacy requirement can and should be met.	Resource Adequacy	April 25, 2016	N/A
New Member Cost Allocation Process: Approved a document 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 in to the SPP OATT.	SPP Stakeholder Groups	October 24, 2016	N/A
Resource Adequacy Requirement: Approved the recommendations for changes to the SPP OATT to implement a Resource Adequacy Requirement ("RAR") for the SPP footprint.	Resource Adequacy	January 30, 2017	187
AECI Joint Projects: Joint transmission projects between AECI and SPP. The facilities are located within AECI's territory.	Cost Allocation	April 17, 2017	N/A

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Revisions to the ITP: Changes to the ITP planning process to move from a three-year transmission planning cycle to an annual planning cycle, combining its Near Term and 10-year Assessments into a single annual ITP Assessment and modifying the timing of its 20-year Assessment to once every five years instead of every three years.	Planning for Remote Resources	April 17, 2017	N/A
RSC/OMS Seams Liaison Committee: OMS and RSC Commissioners have recognized there are issues preventing efficient economic transmission planning, market and operations, and resource integration along the SPP-MISO seam. A liaison committee was formed by the boards of the OMS and the SPP RSC to facilitate identification of issues and potential solutions to enhance the benefits to customers from better coordinated seams policies.	Leadership Initiatives	October 29, 2018	N/A
Distributed Energy Resources Policy Whitepaper: RSC unanimously endorsed the requirements of the DER Whitepaper.	Resource Adequacy	April 25, 2019	N/A

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Wind Cost Allocation Report: RSC approved the Wind Rich Cost Allocation Report and to directed the CAWG to work on implementing the following recommendations: Decouple Schedule 9 and Schedule 11 transmission pricing zones, allowing for potentially larger Schedule 11 pricing zones, evaluate byway facility cost allocation review process, and complete a future study of a generator injection rate.	Cost Allocation	August 5, 2019	N/A
HITT: RSC directed CAWG to work in implementing the following HITT Recommendations: (1) Decouple Schedule 9 and Schedule 11 transmission pricing zones, allowing for potentially larger Schedule 11 pricing zones; (2) Evaluate byway cost allocation review process; and (3) Complete a future study of a generator injection rate.	SPP Stakeholder Groups	August 5, 2019	N/A
Attachment Z2 Elimination: The RSC unanimously approved the HITT recommendation to eliminate Z2 revenue credits	Cost Allocation	October 28, 2019	N/A
Solar and Wind ELCC Accreditation Whitepaper: The RSC approved the methodology for prioritizing and allocating the available effective load carrying capability (ELCC) from wind and solar generating facilities that qualify as capacity in the SPP balancing authority area.	Resource Adequacy	January 27, 2020	N/A

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Generator Retirement Process: The RSC approved the cost allocation methodology for the Generator Retirement Process.	Cost Allocation	July 27, 2020	373
Byway Facility Cost Allocation Review Process: The RSC approved a process by which entities may request that the costs certain transmission facilities that are currently allocated 67% to the local zone and 33% to the entire SPP regions be reallocated on a prospective basis.	Cost Allocation	July 27, 2020/January 24, 2022	422/483
ELCC Storage Whitepaper: The RSC approved the methodology for accrediting and allocating the available effective load carrying capability (ELCC) from battery generating facilities that qualify as capacity in the SPP balancing authority area.	Resource Adequacy	January 25, 2021	462
ELCC Hybrid Whitepaper: The RSC approved the methodology for accrediting and allocating the available effective load carrying capability (ELCC) from battery generating facilities that qualify as capacity in the SPP balancing authority area.	Resource Adequacy	January 25, 2021	N/A

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Cost Allocation of Energy Storage as a Transmission Asset: The RSC approved the whitepaper to evaluate cost allocation for energy storage resources used as a transmission asset.	Cost Allocation	January 24, 2022	RR476
Performance Based Accreditation: The RSC approved the conventional resources in the SPP Balancing Authority (BA) footprint as outlined in the Performance Based Accreditation Recommendations for Conventional Resources policy paper.	Resource Adequacy	July 25, 2022	N/A
Change in Planning Reserve Margin ("PRM"): The RSC approved the increase in the PRM from 12% to 15%.	Resource Adequacy	July 25, 2022	N/A
Deliverable Capacity Winter Season: The RSC approved changes to Attachment AA to allow deliverable capacity to be used for the Winter Season Obligation.	Resource Adequacy	October 24, 2022	RR549
Mitigation to the PRM Increase: In response to the increase in the PRM in 2022, the RSC approved two mitigation methodologies to help Load Responsible Entities who may be short because of the increase in the PRM.	Resource Adequacy	October 24, 2022	RR515/ RR536q

POLICY	TYPE	DATE APPROVED	REVISION REQUEST #
Joint Targeted Interconnection Queue ("JTIQ"): The RSC Approved policies related to the JTIQ.	Cost Allocation	January 30, 2023	N/A

APPENDIX F: GLOSSARY

Annual Transmission Revenue Requirement (ATRR): The amount of revenue the Company must recover annually to recover costs associated with its transmission system.

Auction Revenue Rights (ARRs): A financial right, awarded during the Annual ARR Allocation Process that entitles the holder to a share of the auction revenues generated in the applicable Transmission Congestion Rights (TCR) Auction(s) and/or entitles the holder to self-covert the ARRs into TCRs.

Balancing Authority (BA): The responsible entity that maintains load interchange-generation balance within a Balancing Authority Area. Also known as Control Area or Settlement Area.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority.

Capacity: Amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station or system is rated by the manufacturer.

Congestion: Situation where the desired amount of electricity is unable to flow due to physical limitations (line, bus, storm damages) or regulated limitations, such as Contingency Reserves. Congestion impairs the ability to use least-cost electricity to meet demand, and a price difference between source and sink.

Congestion Hedging: A strategy used to reduce the risk of adverse price movements in an asset due to transmission overcrowding.

Day-ahead market: The financially binding market for Energy and Operating Reserve that is conducted on the day prior to the Operating Day.

Designated Resource: Any designated generation resource owned, purchased, or leased by a Transmission Customer (TC) to serve load in the SPP region. Designated resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the TC's load on a non-interruptible basis.

Federal Energy Regulatory Commission (FERC): Quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates and gas pipeline certification.

Financial Transmission Rights (FTR): a contract that gives market participants and offset or hedge against transmission congestion cost in the day–ahead market.

Integrated Marketplace: A day-ahead market with transmission congestion rights, a reliability unit commitment process, a real-time balancing market and an operating reserve market, all operated from a central balancing authority.

License Plate Rates: The practice by which all transmission owners within a specific zone in SPP are allocated costs of new transmission enhancements.

North American Reliability Corporation (NERC): A non-profit organization whose mission is to ensure that the Bulk Electric System in North America is reliable, adequate and secure.

Open Access Transmission Tariff (OATT): A regulatory mandate to allow others to use a utility's transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee.

Operating Reserve: Resource capacity held in reserve for resource contingencies and NERC controlled performance compliance, which includes the following products: Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve.

Postage Stamp Rates: The practice by which all transmission owners within an RTO or ISO pay equally for the costs of new transmission enhancements.

Regional Transmission Organization (RTO): An organization that FERC has deemed to meet certain criteria, including independence and scope. Regional Transmission Organizations are mandated by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity.

Reserve Margin: Amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.

Resource: An asset which injects energy into the transmission grid or which reduces the withdrawal of energy from the transmission grid and may be discretely directed by the Regional Transmission Organization/Independent System Operator. These resources include generation and controllable load.

Revision Request (RR): A request to make additions, edits, deletions, revisions, or clarifications to the SPP Business Practices, SPP Criteria, SPP Market Protocols, and SPP Open Access Transmission Tariff including any attachments and exhibits to these documents, except for Appendix F of the Market Protocols.

Safe Harbor Limit: a designated resource is eligible for base plan funding, if, among other things, the costs are less than or equal to $180,000 per MW.

Tariff: Establishes services to be provided and rights and obligations of the parties pursuant to those services. It specifies rates, terms, and conditions under which Transmission Customers and Market Participants participate in the Integrated Marketplace.

Transmission Congestion Rights (TCRs): A financial instrument that entitles the holder to receive compensation for or requires the holder to pay certain congestion related transmission charges when the transmission system is congested. A TCR value is based on transmission congestion charges calculated in the day-ahead energy market.

Transmission Operator: A NERC functional entity that ensures the real-time operating reliability of the transmission assets within a Transmission Operator area.

Transmission Owner (TO): A NERC functional entity that owns and maintains transmission facilities.

Transmission Provider: A NERC functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Zone: The geographic area of the facilities of an SPP Transmission Owner (TO) or a specific combination of the TO as specified in the SPP Regional Tariff.