VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C.  20426

Re:  Southwest Power Pool, Inc., Docket No. ER17-____-000

Tariff Revisions to Implement Resource Adequacy Requirement

Dear Secretary Bose:


I.  EXECUTIVE SUMMARY

Since the Commission’s approval of SPP as a Regional Transmission Organization (“RTO”)² SPP’s transmission footprint has expanded from 17 original Transmission Owners³ under the Tariff to the current 51 Transmission Owners that have joined SPP and placed its transmission facilities under SPP’s functional control. SPP’s Transmission Owner Members represent a diverse group of Commission jurisdictional Public Utilities, and non-jurisdictional public power entities,

¹ Southwest Power Pool, Inc., FERC Electric Tariff, Sixth Revised Volume No. 1 (“Tariff”). References in this filing to “Tariff” refer to the version of SPP’s Tariff currently in effect. “Proposed Tariff” refers to a version reflecting the revisions proposed in this filing.


³ Capitalized terms not otherwise defined herein, shall have the definitions provided in the Tariff.
cooperatives and municipalities. SPP offers a variety of services to its Members and customers, including the provision of transmission service through the Commission-approved Tariff, regional and interregional transmission planning, Reliability Coordination, regional reliability oversight and support, and the implementation of the day-ahead and real-time energy markets. As part of the development of the SPP markets, SPP also assumed the role as the Balancing Authority for the entire SPP footprint. These services, and SPP’s robust stakeholder process, have provided open access to the transmission systems of SPP Members that is both transparent and driven by good utility practice.

On October 1, 2015, SPP integrated the transmission facilities of the Western Area Power Administration—Upper Great Plains region (“Western-UGP”), Basin Electric Power Cooperative (“Basin Electric”) and Heartland Consumers Power District (“Heartland”) (the “Integrated System”) into the RTO. The Integrated System represented a substantial expansion of the SPP footprint, including an additional fourteen (14) entities that joined SPP and became Transmission Owners as a result of the Integrated System’s decision to join SPP. The increased load that came into the SPP footprint instigated discussions amongst SPP staff and stakeholders regarding the overall reliability of the region and the need for resource adequacy within the SPP Balancing Authority Area. SPP stakeholders and SPP staff determined the need to implement an enforceable resource adequacy requirement for entities serving load within the region. Over a roughly two and a half period, SPP staff and stakeholders engaged in extensive discussions and negotiations, working mainly through various SPP stakeholder working groups, to develop the process which is contained in the Tariff revisions being proposed in this instant filing.

The RAR, as proposed in this filing, which includes the supporting Prepared Direct Testimony of Lanny D. Nickell and other related materials, will set the requirement that entities serving load in the SPP Balancing Authority Area shall maintain sufficient capacity and planning reserve margins to serve its load. The Tariff revisions proposed in this filing shall establish a reserve margin, provide data and reporting requirements whereby SPP may administer the annual RAR process, allow enforcement of the RAR against deficient entities through the assessment of payments, and a revenue distribution mechanism to disburse revenues to entities that have capacity in excess of its requirements. The RAR will be an annual process commencing on July 1 of each calendar year.

SPP intends to implement the RAR by June 1, 2017 for the upcoming Summer Season (the time period of June 1 through September 30); however, SPP intends the

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2 Prepared Direct Testimony of Lanny D. Nickell, Vice President, Engineering, Southwest Power Pool, Inc., on Behalf of Southwest Power Pool, Inc. (“Nickell Test.”) (attached to this filing as Exhibit No. SPP-1).
assessment of penalties for lack of compliance to not be effective until the 2018 RAR cycle. Therefore, SPP is requesting an effective date of July 1, 2017 for those specific assurance provisions outlined herein. Granting a phased-in approach will allow for a transparent and non-discriminatory approach to compliance. First, a June 1, 2017 effective date will allow SPP to implement the RAR for the 2017 Summer Season, which is supported by SPP’s Members. Second, a July 1, 2017 effective date for the assurance provisions will provide the opportunity for entities that will be potentially subject to the assurance provisions to have a complete annual cycle to satisfy the RAR. Commission approval of the RAR starting June 1, 2017 will permit SPP to implement resource adequacy for 2017, which supports SPP’s reliability interests. Granting the assurance provisions to become effective July 1, 2017 will allow entities that will be subject to the enforcement provisions the opportunity to engage in a full RAR process prior to being subject to financial risk. SPP believes this approach to be just, reasonable and in the public interest.

II. BACKGROUND

A. SPP

SPP is a Commission-approved RTO. SPP is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP has 94 Members, including 16 investor-owned utilities, 14 municipal systems, 20 generation and transmission cooperatives, 8 state agencies, 13 independent power producers, 12 power marketers, 10 independent transmission companies, and 1 federal agency. As an RTO, SPP administers open access Transmission Service over approximately 60,000 miles of transmission lines covering portions of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming, across the facilities of SPP’s Transmission Owners, and administers the Integrated Marketplace, a centralized day ahead and real-time energy and operating reserve market with locational marginal pricing (“LMP”) and market-based congestion management.

See supra n. 2.


B. THE NEED FOR RESOURCE ADEQUACY IN THE SPP REGION

With the implementation of the Integrated Marketplace, SPP became the Balancing Authority for the entire SPP region. Prior to the Integrated Marketplace, the SPP region consisted of several Balancing Authorities that corresponded, for the most part, with SPP’s Transmission Owner Members. As part of the transition to the Integrated Marketplace, SPP assumed the Balancing Authority function in its entirety for purposes of compliance with the North American Electric Reliability Corporation, Inc.’s (“NERC”) mandatory reliability standards that are enforceable under the Commission’s authority granted in the FPA. NERC has identified the necessity of reserve margin as part of its 2016 Long-Term Reliability Assessment (“2016 LTRA”).

All Resource and load assets operating in the Integrated Marketplace are included in the SPP Balancing Authority Area. Load assets within the SPP Balancing Authority Area are represented by both SPP Members and non-members. For reliability reasons, SPP desires an effective mechanism to ensure adequate resources are being planned for the entire load served by the SPP Balancing Authority. A major element of maintaining reliability for the SPP footprint is an enforceable requirement that each entity serving load in the SPP Balancing Authority has sufficient capacity and planned reserves to serve its load. SPP’s current mechanisms provided in the SPP Planning Criteria are inadequate to provide assurance that resource and planning reserve capacity will be available as needed to reliably serve load within the SPP footprint.

For one, existing assurance options under the SPP Planning Criteria are not applicable to non-members; nor is mitigation for non-members required under any mandatory reliability standard or regulation. Second, potential revocation of SPP membership is the only current assurance option to ensure SPP Member compliance with the SPP Planning Criteria, which SPP believes is an extreme recourse which SPP has never sought since its inception as an RTO. As a result, SPP’s capacity margin requirements contained in the SPP Planning Criteria are not generally applicable to all load in the SPP Balancing Authority Area. SPP’s history is full of initiatives that provide value and financial benefits to its Members, customers, and the general public. From its first offerings of open access transmission service back in the late

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8 *See* 2016 LTRA at Introduction (“NERC’s primary objective with the *LTRA* is to assess resource and transmission adequacy across the NERC footprint, and to assess emerging issues that have an impact on BPS reliability over the next ten years”). The 2016 LTRA is posted at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf.
1990s to the establishment of the RTO in 2005, and beyond with the implementation of the Integrated Marketplace in 2014, SPP has continually sought to implement valuable benefits to its ever growing footprint. One necessary interest is ensuring and promoting reliability over the transmission facilities and market operations within its boundaries. The establishment of a RAR as developed by SPP staff and stakeholders is an important vehicle to increase the SPP’s ability to reliably serve its load obligations and provide planned reserves that promote reliability.

C. SPP STAKEHOLDER PROCESS

SPP staff and SPP stakeholders held multiple meetings and extensive discussions representing significant travel, resources and time spent to develop SPP’s RAR. SPP’s stakeholders have been discussing a resource adequacy requirement for the SPP region since 2014. SPP’s Strategic Planning Committee identified resource adequacy as a priority for the SPP 2014 Strategic Plan; and the Markets and Operations Policy Committee (“MOPC”) tasked SPP staff with the review of the current capacity margin contained in the SPP Planning Criteria and development of a recommendation for the group. During that same period of time, SPP was preparing to assimilate new SPP Transmission Owners, Western-UGP, Basin Electric, and Heartland (known as the “Integrated System”), that expected to join SPP and transfer the functional control of their transmission facilities to SPP effective October 1, 2015. These two tasks (i.e., the review of resource adequacy within SPP and joining of the Integrated Systems) required SPP to review its current SPP Planning and Operating Criteria (together, the “SPP Criteria”) to determine whether the current SPP Criteria’s requirements for capacity margins (that had been in place since 1998) were sufficient given the significant expansion of the SPP footprint resulting from the Integrated System.

SPP staff recommended that a new task force, to be known as the Capacity Margin Task Force (“CMTF”), be organized and populated with a diverse set of subject matter experts from the SPP region to review the issue and provide a recommendation to the whole SPP membership pool. The MOPC approved the recommendation and the task force was created in July 2014. Starting in August

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9 See Exhibit No. SPP-2 at 15.
10 The MOPC consists of a representative officer or employee from each SPP Member and reports to the SPP Board of Directors. Its responsibilities include recommending modifications to the Tariff. See Southwest Power Pool, Inc., Bylaws, First Revised Volume No. 4 (“Bylaws”) at Section 6.1.
2014 and over the course of a roughly year and a half period, the CMTF developed three policy white papers, and subsequent modifications or clarifications, pertaining to resource adequacy that were approved by the MOPC and SPP Board of Directors. These stakeholder approved policy white papers are the foundation of the Tariff revisions being proposed in this filing. All three policy papers are included as exhibits to this filing. The CMTF was subsequently disbanded and stakeholder ownership of resource adequacy has been transferred to a new SPP working group, the Supply Adequacy Working Group (“SAWG”) which will be ongoing vehicle for stakeholder oversight of resource adequacy in the SPP region.

After approval of the resource adequacy policies, the task of Tariff drafting was given to the SPP Regional Tariff Working Group (“RTWG”) for development. The RTWG instructed its task force, the Process Improvement Tariff Task Force (“PITTF”), to prepare draft Tariff language for review by the group. The PITTF prepared draft Tariff language which was debated by the RTWG and other interested participants in the RTWG over many months. The discussions were extensive and the RTWG’s development was open and transparent, allowing all interested parties, both members and non-members of the RTWG, to raise their concerns or support for the initiative. The resulting Tariff language was approved by the RTWG on December 15, 2016 with no opposition and eight abstentions. Other SPP working groups also were given the opportunity to review and approve/endorse the Tariff language. The Market Working Group (“MWG”) reviewed and approved the language on December 13, 2016 with no opposition and one abstention. The Transmission Working Group (“TWG”) initially failed to pass the language citing concerns with the study process contained in the proposal; however, SPP addressed those concerns and the Tariff

12 The white papers are attached to this filing as Exhibit Nos. SPP-3 through SPP-5.

13 The RTWG is responsible for development, recommendation, overall implementation, and oversight of SPP’s Tariff. The RTWG also advises SPP staff on regulatory and implementation issues not specifically covered by the Tariff or issues where there may be conflicts or differing interpretations of the Tariff.


15 See MWG Meeting Minutes dated December 13, 2016 at Agenda item 4 posted at: https://www.spp.org/documents/46269/mwg%20minutes%20&%20attachments%2020161213.pdf.

16 See TWG Meeting Minutes dated December 14, 2016 at Agenda Item 3 posted at: https://www.spp.org/documents/47496/twg%20minutes%20&%20attachments%2020161214.pdf.
language was approved unanimously by the TWG during its January 6, 2017 meeting.\textsuperscript{17}

The draft Tariff language, as approved by the RTWG, was presented to the SAWG on December 20, 2016 and passed with three abstentions and no negative votes.\textsuperscript{18} The MOPC reviewed the Tariff language at its January meeting. At the meeting, SPP presented a comprehensive presentation to SPP members that explained the RAR and provided examples of how SPP would administer the process. The MOPC presentation is also included as an exhibit to this filing to provide additional materials for the Commission to consider.\textsuperscript{19} After extensive discussion in this public meeting the proposal was passed by the MOPC with one opposition and ten abstentions.\textsuperscript{20} At the joint SPP Board of Directors/Member’s Committee meetings held on January 31, 2017, the measure passed with one abstention and one in opposition.\textsuperscript{21} The SPP Board of Directors voted in favor of the resolution and approved SPP’s filing of the proposed Tariff language.\textsuperscript{22}

D. STATE-FEDERAL JURISDICTIONAL MATTERS

SPP has reviewed pertinent Commission precedent regarding jurisdictional authority over the resource adequacy and planning reserve margin issues. As stated in the Commission’s various orders on other public utility resource adequacy proposals, SPP understands and agrees with the Commission that the question of jurisdiction over resource adequacy is a complex matter that represents “the confluence of state-

\textsuperscript{17} See TWG Meeting Minutes dated January 6, 2017 at Agenda Item 2 posted at: https://www.spp.org/documents/47499/twg%20minutes%20&%20attachments%2020170106.pdf.

\textsuperscript{18} See SAWG Meeting Minutes No. 6 at Agenda Item 2 posted at: https://www.spp.org/documents/47401/sawg%20meeting%20minutes%20december%202016.pdf.

\textsuperscript{19} See Exhibit No. SPP-6.

\textsuperscript{20} See MOPC Meeting Minutes dated January 17-18, 2017 at Agenda item 8 posted at: https://www.spp.org/documents/47410/mopc%20minutes%20and%20attachments%2020170117-18%20revised.pdf.

\textsuperscript{21} See Board of Directors/Members Committee Meeting Minutes No. 172 at Agenda item 4 posted at: https://www.spp.org/documents/47489/bod-me%20minutes%2020170131.pdf (“January 31 Meeting Minutes”).

\textsuperscript{22} Id. The January 31 Meeting Minutes reflect that the Tariff revisions request to implement the RAR proffered by SPP (RR 187) also contains a revision to Attachment J of the Tariff. Although, part of the formal revisions request, the issue addressed in Attachment J is not related to the implementation of the RAR; and therefore, SPP will include that proposed Tariff revision in a separate filing.
federal jurisdiction and the effect of resource adequacy on Commission-jurisdictional prices and, importantly, on the ability of the operator of the interstate transmission grid to ensure reliable service.”23 The Commission has stated that it generally accepts the role for state regulatory authorities in resource adequacy requirements,24 but reinforced “the FPA confers upon the Commission the responsibility for ensuring that transmission and wholesale power sales, rates and charges, including any rule, regulation, practice or contract affecting them, are just and reasonable and not unduly discriminatory.”25 While the Commission does not exercise jurisdictional authority to set resource adequacy requirements or fix planning reserve margins,26 the Commission has authority to review resource adequacy under Sections 201, 205, and 206 of the FPA to ensure reliable transmission service.27

SPP also recognizes the interests of state authority over resource adequacy requirements. Section 7.1 of the Commission-approved SPP Bylaws provides that “[n]othing in the formation or operation of SPP as a FERC recognized regional transmission organization is in any way intended to diminish existing state regulatory jurisdiction and authority.”28 In addition, the SPP Bylaws grants certain responsibility for resource adequacy to the Regional State Committee (“RSC”)29 providing that “[t]he RSC will also determine the approach for resource adequacy

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25 Id. at P 54.
27 See MISO Resource Adequacy Order at P 52. See also id. at P 56 (citing New York State Reliability Council, 122 FERC ¶ 61,153 at P 33 (2008)). (“[t]he Commission has an independent obligation under sections 201, 205, and 206 of the FPA to consider whether [resource adequacy] practices affecting jurisdictional transactions result in rates, terms, or conditions that are unjust, unreasonable, or unduly discriminatory”). See also California Independent System Operator Corporation, 116 FERC ¶ 61,274, at P 1112 (2006).
28 See Bylaws at Section 7.1.
29 The RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission. The SPP RSC is comprised of retail regulatory commissioners from agencies in Arkansas, Iowa, Kansas, Missouri, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota and Texas.
across the entire region.” In turn, as the RSC reaches decisions on methodologies for resource adequacy, SPP will make the requisite filings at the Commission.

To that end, SPP brought its proposal on multiple occasions to the SPP working groups involved with state outreach and state-regulatory oversight of SPP’s members: the Cost Allocation Working Group (“CAWG”) and the RSC. Both the CAWG and RSC reviewed the white papers and the RSC approved SPP’s resource adequacy policies contained in the three white papers in April 2016. SPP also reviewed the proposed Tariff revisions with the CAWG at its January 2017 meeting. The CAWG endorsed the proposed Tariff revisions with no votes in opposition and one abstention and recommended that the RSC approve the Tariff revisions as “implementing previously approved regional resource adequacy policies of the [Regional State Committee].” On January 30, 2017, the RSC voted to approve the CAWG’s recommendation.

III. OVERVIEW OF REVISIONS TO TARIFF AND JUSTIFICATION

With this filing, SPP proposes to revise its Tariff to include a new Attachment AA in the Tariff, which will establish terms and conditions whereby SPP may establish the RAR, a requirement that its Load Responsible Entities (“LREs”) (new term defined as Asset Owners serving load in the Integrated Marketplace) have sufficient capacity to serve its peak load and maintain sufficient capacity to satisfy a planning reserve margin (“Planning Reserve Margin” or “PRM”) which is a percentage of its forecasted peak demand that must be maintained as planning reserves. The intent of the Tariff filing is to implement a RAR that is universally enforceable against all entities that serve load through SPP’s Integrated Marketplace.

Attachment AA of the Tariff contains the mandatory requirements for the LREs, Market Participants and Generator Owners (new term) that are participants in

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30 See Bylaws at Section 7.2
31 Id.
32 The CAWG reports directly to the Regional State Committee and is responsible for reviewing, approving and endorsing projects and topics that are of particular interest to state regulators and commissioners.
33 See RSC Minutes dated April 25, 2016 at pages 2-3 posted at: https://www.spp.org/documents/39003/rsc%20minutes%2020160425.pdf.
34 See CAWG Minutes dated January 5, 2017 at Agenda Item 5 posted at: https://www.spp.org/documents/47345/cawg%20minutes%20and%20attachments%2020170105.pdf.
the RAR process. The provisions of Attachment AA and revisions to Attachment AE of the Tariff contain the terms and conditions whereby SPP, as the Transmission Provider, shall administer the RAR process. The proposed Tariff revisions are structured in a manner to ensure that entities serving load in the SPP Balancing Authority Area have sufficient and reliable capacity and planned reserves to meet the RAR and provide an enforceable requirement that reasonably determines deficiency liabilities and distributes revenues in a fair and equitable manner. To that end, SPP provides this overview of the proposed Tariff revisions:

A. Attachment AA

1. Determination of Resource Adequacy Requirement

Attachment AA sets for the process for the determination of the RAR for the LREs. The RAR is equal to the LRE’s Net Peak Demand plus the PRM multiplied by the Net Peak Demand (which results in a MW value that must be held in reserves).

a. Net Peak Demand

The calculation of the Net Peak Demand identifies the load requirements of the LRE that will be subject to Attachment AA. “Net Peak Demand,” as defined in new Attachment AA, will be the determination of the LRE’s forecasted highest demand for energy, including transmission losses for energy measure over a one clock hour period (“Peak Demand”) plus the amount of Megawatts (“MW”) subject to a firm power sales contract in effect during the determination of the Peak Demand but less the following types of variables: a) projected impacts of demand response programs and behind-the-meter generation that are controllable and dispatchable but not registered in the Integrated Marketplace, and b) the amount of MW subject to a firm power purchase contract in effect during the determination of the Peak Demand. In a nutshell, and as explained in Mr. Nickell’s testimony, Net Peak Demand includes the LRE’s highest demand plus any capacity deliveries to third parties pursuant to contract but less any capacity purchases and load served by resources that are located behind the wholesale meter or reduced as part of a demand response program.36

Firm capacity (i.e., capacity supported by firm transmission service) may not be double counted by two LREs. In other words, firm capacity is only available to be utilized by one LRE to satisfy the RAR. In a similar vein, an LRE that contracts to deliver firm capacity to another entity may not utilize that firm capacity for satisfaction of its own RAR. Further, Attachment AA is not intended to satisfy an LRE’s compliance for resource adequacy external to SPP. Under SPP’s proposal, an LRE must maintain distinct resources to serve its internal SPP load and external load.

36 Nickell Test. at 14-15.
Finally, an entity that uses an Export Interchange Transaction, per the Integrated Marketplace, and where such Export Interchange Transaction is supported by a firm power contract (contract for capacity and includes set planning reserves) must include the off-system load in its formulation of Net Peak Demand.

b. Planning Reserve Margin

The RAR includes a capacity element that is maintained as planned reserves. The calculation of the planned reserves component equals the LRE’s Net Peak Demand” multiplied by the PRM value. SPP proposes to establish an initial PRM of twelve percent (12%). In addition, if an LRE utilizes the firm capacity that is seventy-five percent (75%) hydro-based generation, then the PRM will be 9.89%. Simply put, the planned reserves component of the RAR equals an LRE’s Net Peak Demand times 12% (or 9.89%). This calculation results in an additional amount of MW of capacity that the LRE will be required to maintain in addition to the capacity required to serve its Net Peak Demand.

In coordination with LREs on a biennial basis, SPP will determine an appropriate PRM for the SPP Balancing Authority Area based upon a probabilistic analysis using a Loss of Load Expectation (“LOLE”) study. Any changes to the Commission approved PRM shall require a filing to revise Attachment AA. SPP determined the initial PRM through a LOLE study, which was reviewed by a third party consulting group. Based on the results of the LOLE study and the third party review, the stakeholders settled on 12% as a reasonable reserve margin to safeguard reliability in the SPP footprint. Both reports are included as exhibits to this filing.

c. Application of the RAR

The RAR is for the period from June 1 through September 30 of each calendar year (“Summer Season”) and failure to comply with the RAR for the Summer Season shall result in a financial obligation in the form of a Deficiency Payment. Attachment AA provides an additional obligation to satisfy its Net Peak Demand and PRM requirements for the winter season (“Winter Season Obligation”); however, SPP does not request to put a liability component on compliance for this duration. Because most SPP LREs experience highest demand during the Summer Season, financial liability is tied to the Summer Season. The satisfaction of the Winter Season

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37 Nickell Test. at 15.
38 Id. at 15-16.
39 The LOLE Study is attached to this filing as Exhibit No. SPP-7.
Obligation is a proposed Tariff requirement and is structured so that the SPP Balancing Authority Area has reasonable assurance that the load obligations of its LREs are maintained throughout the year, and specifically for the two seasons where demand is historically the highest.

2. **Roles and Responsibilities**

As stated above, Attachment AA proposes two newly defined entities that will have rights and obligations under the proposed RAR process. In addition, two current Tariff entities, the Market Participant and Transmission Provider, also have roles and responsibilities in the process.

**Transmission Provider**: Like all services SPP administers under the Tariff, SPP oversees and facilitates the RAR process and is responsible for the duties outlined in Attachment AA. General duties include, identifying all LREs in the SPP Balancing Authority Area, receiving required data and performing calculations necessary to determine each individual LRE’s RAR, determining the deliverability of the Generator Owner’s Resources, administering the RAR annual process, determining deficient LREs, calculating deficiency payments, assessing deficiency payments against applicable Market Participants, and distributing revenues.

**Load Responsible Entity**: The LRE is an Asset Owner represented in the Integrated Marketplace with registered physical assets that is either load or Export Interchange Transactions that are supported by firm transmission service. Being the Asset Owner of the load, the LRE is the entity responsible to ensure it has secured sufficient resources to meet the RAR for the Summer Season and Winter Season Obligation. The LRE also provides the information to SPP via the Workbook in accordance with the timeline to allow SPP to qualify the LRE’s compliance with the RAR. Under SPP’s proposal, LREs that have capacity in excess of the capacity required to satisfy its RAR shall have a right to its portion of any deficiency revenues that SPP may collect in accordance with the terms of Attachment AA.

**Market Participant**: As proposed, the Market Participant is the entity with which SPP has the contractual tie via the Market Participant Agreement found in Attachment AH of the Tariff. As identified in both Attachment AE of the Tariff and the Market Participant Agreement, the Market Participant also has the direct relationship with the Asset Owner. The Market Participant identifies the Asset Owner which it represents in market transactions through an appendix to the Market Participant Agreement. The Asset Owner is identified by the Market Participant, generally, as either load or resources. At its sole discretion, a Market Participant may aggregate the RAR of

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41 The Market Participant Agreement found in Attachment AH of the Tariff is attached to this filing as Exhibit No. SPP-9.
multiple LREs which it represents; however, aggregation shall result in the Market Participant becoming the LRE for purposes of reporting and other tasks which are assigned to the LRE.

Because the Market Participant is the entity that has the direct contractual relationship with SPP, the Market Participant is in the best position to ensure, both on a performance and financial level, that the LRE fulfills its obligations to meet the RAR. As a result, SPP proposes that the Market Participant shall be the entity that is assessed deficiency payments for its LRE(s) that do not comply with the RAR. Similarly, the Market Participant receives applicable deficiency revenues on behalf of its LREs and is responsible to distribute. As explained in the testimony of Mr. Nickell, built into the process is an option for the Market Participant to assign its duties, obligations, and responsibilities for an LRE to another Market Participant, which will be evidenced to SPP. Although SPP shall take no direct role in the bilateral agreement between the assignor and assignee Market Participants, the process requires that the assignment be constructed to allow SPP to rely on the assignment; and the process provides protections for both SPP and the parties involved with the assignment to minimize disputes.

**Generator Owner:** A Generator Owner is an Asset Owner that owns a Resource participating in the Integrated Marketplace. Responsibilities include the provision of data to SPP necessary to allow identification of deliverable capacity to the footprint. A Generator Owner that has excess capacity to provide for use by the SPP Balancing Authority may also become eligible to receive part of the disbursement of deficiency revenues in accordance with the terms of Attachment AA. A Generator Owner may be an entity that is also an LRE if identified in the Market Participant Agreement as the Asset Owner for load or is an affiliate under the same parent company of the LRE; however, the responsibilities between each role are separate and distinct and SPP will recognize the designations and distinct functions.

### 3. Deliverability and Qualification of Resources

Under Attachment AA, SPP shall perform an annual Deliverability Study to evaluate the Resources of Generator Owners to determine the amount of MWs that the Resource may deliver to the SPP Balancing Authority Area without affecting reliability or requiring additional transmission upgrades to be constructed. “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 to serve load have a certain level of measurable capability to deliver capacity to the SPP Balancing Authority Area that is free of contractual encumbrances and will not impact reliability. SPP will provide the results of the annual Deliverability Study to each Generator Owner on an individualized basis so that the proprietary interests of each individual Generator Owner are protected. The results of the Deliverability Study will determine how much of the available capacity
of a Resource is available to satisfy the PRM. Generator Owners and LREs are then free to contract for such capacity to meet the PRM portion of the RAR.

Because the Deliverability Study determines deliverable capacity without affecting reliability or need for transmission construction, coupled with the fact the capacity required to satisfy the PRM are planned reserves only, and not used to serve Net Peak Demand, SPP proposes to allow LREs to contract for capacity based on the Deliverability Study results on a short-term basis without having to acquire firm transmission service. Entities may rely on the results of the Deliverability for up to two years from publication; however, contracts for capacity based on the Deliverability Study will be on a short-term basis to satisfy the planned reserve requirement for the Summer Season or Winter Season Obligation, but not both. Notwithstanding this proposal, firm transmission will continue to be required to serve Net Peak Demand (i.e., load) or if the LRE desires to participate in the Integrated Marketplace’s congestion hedging process and seek the opportunity to nominate candidate Auction Revenue Rights or receive Long-Term Transmission Rights.

4. Reporting Requirements

In order to comply with the RAR, LREs must demonstrate that they have sufficient capacity to meet its Net Internal Demand plus the required MW to be held as planned reserves. Generator Owners must also provide information pertaining to its Resources for use by SPP to determine the Resource’s deliverability and total uncommitted MW’s available for purchase by LREs to satisfy the PRM. Both of these entities provide the necessary data to SPP through the “Workbook”, which is an excel spreadsheet provided by SPP and which requires the entity to fill in the pertinent information. SPP utilizes the Workbook to qualify the LRE’s compliance with the RAR for the upcoming Summer Season. SPP is also proposing Tariff language that provides a timeline to identify to the dates by which the Workbook must be submitted, opportunities to appropriately update the Workbook, and other necessary milestones in the annual process. The timeline also contains other dates by which SPP shall begin studies, post study reports, calculate and assess deficiency payments, or take other defined actions pertaining to the RAR. The proposed process and timeline is open and transparent, and ensures that all impacted entities understand the specific requirements which apply to them individually.

5. RAR Assurance

With this filing, SPP proposes to include assurance provisions to incentivize compliance by requiring a fee in the form of a Deficiency Payment from Market Participants who represents LREs that fail to comply with the RAR for the Summer Season. The amount of the deficiency payment is based on the Cost of New Entry
(“CONE”) for new natural gas peaking generation facilities to be constructed in the SPP region utilizing the factors listed in Attachment AA. SPP proposes an initial CONE of $85.61 per kilowatt year. Justification for the proposed CONE, and the discussion of the study methodology SPP utilized to determine the value is contained in the Planning Reserve Assurance Policy white paper and the testimony of Mr. Nickell. The Deficiency Payment shall be calculated by SPP utilizing the following formula:

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\text{Deficiency Payment} = \text{LRE Deficient Capacity (stated in MWs)} \times \text{CONE} \times \text{CONE FACTOR}
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Where the CONE FACTOR shall be:
(a) 125% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 8%; or
(b) 150% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 3%, but less than the PRM plus 8%; or
(c) 200% when the SPP Balancing Authority Area Planning Reserve is less than the PRM plus 3%.

As proposed, revenues from Deficiency Payments collected by SPP shall be distributed to Market Participant(s) for its LRE(s) that have excess capacity above the amount needed to satisfy its RAR or Generator Owners with available capacity to meet the PRM in accordance with the process outlined in Attachment AA. Revenues are distributed based on the status of the total excess LRE capacity compared to the total deficiencies. If the total excess capacity is greater than or equal to the total amount of deficiencies, then the LREs will receive a portion of the revenues based on its percentage of total excess capacity available. If the LREs’ total excess capacity is less than the total amount of deficiency, then the LREs with excess capacity shall receive an amount of revenues consistent with the percentage of its excess, and any remaining revenues will be distributed to Generator Owners that have excess capacity that is uncommitted. Exhibit No. SPP-6 contains hypothetical examples to show how the revenue distribution may work. These examples are illustrative only and do not represent any actual financial obligation or benefit.

The distribution mechanism was developed to address the equity issues that will arise if contingencies occur in the future that require the SPP Balancing

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42 See also Exhibit No. SPP-5 at 3.0(D).
43 Id. at 3.0(E)
44 Nickell Test. at 33-35.
45 See Exhibit No. SPP-6 at pages 46-50.
Authority Area to call upon planned reserves to fulfill load obligations. In other words, if an LRE is short on capacity and the SPP Balancing Authority Area relies on the excess capacity of other parties in SPP to provide adequate regional reliability, then those parties that have the excess capacity should receive compensation through the assurance mechanism. SPP’s proposed assessment of deficiency payments is intended to incent LREs to comply with the RAR. Likewise, the distribution mechanism incentivizes LREs by addressing potential equity issues by rewarding those LREs that maintain capacity in excess of its needs and will be required to fill gaps during capacity shortages or periods of unusually high demand, and also provides potential revenues to Generator Owners that have available capacity to fill those gaps when the excess capacity of LREs is not able to bridge those deficiency gaps.

B. Attachment AE

Attachment AE contains the terms and conditions of the Integrated Marketplace. Section 2.2(6) of Attachment AE currently requires all loads and all Resources (excluding Behind the Meter Generation less than 10 MW) to register in the market.\(^{46}\) Registration occurs by executing SPP’s pro forma Market Participant Agreement, which is Attachment AH of the Tariff.\(^{47}\) During the development of the reserve margin policies referenced herein and corresponding Tariff revisions, it became apparent that situations may arise when load served by the SPP Balancing Authority may not be represented by a Market Participant, or a Market Participant may terminate a relationship with an Asset Owner that has load registered in the Integrated Marketplace. As part of the Tariff revision process, SPP developed language to be included in Section 2.2(6) of Attachment AE that remedies this potential issue.

Section 2.2(6) of Attachment AE currently contains a term that allows SPP to file an unexecuted service agreement for a Resource that fails or refuses to register its Resource.\(^{48}\) However, as explained above, both load and Resources are required to register in the market. It is reasonable to conclude that because the registration requirement applies to both load and Resources, that the terms and conditions

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\(^{46}\) Tariff at Attachment AE, Section 2.2(6).

\(^{47}\) Attachment AH is included as Exhibit No. SPP-9.

\(^{48}\) Tariff at Attachment AE, Section 2.2(6) (“Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner”).
whereby SPP remedies an Asset Owner’s refusal or failure to execute a service agreement should also be stated explicitly and clearly in Section 2.2(6). To that end, and to remedy the potential issue that arises when an Asset Owner that would otherwise be considered an LRE does not have a Market Participant representing it in the market, SPP proposes to add clarifying language to Section 2.2(6) of Attachment AE that applies to load and mirrors the Commission-approved language applicable to Resources. The clarifying language reads:

“Failure or refusal to register a load will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that load with the Commission under the name of the load Asset Owner.”

Commission acceptance of this language will allow SPP to register a load that fails or refuses to register in the market by filing an unexecuted service agreement with the Commission for resolution. This language will protect SPP by ensuring that all identified LREs are attached to a Market Participant and are required to maintain the RAR. Commission approval will also benefit the administration of the Integrated Marketplace by including language that reasonably should be part of the registration process.

C. Justification

The justification for the proposed Tariff revisions is contained in the Testimony of Mr. Nickell and the other exhibits accompanying this transmittal letter. The foundation issue, and underlying reason, for the entire proposal is SPP’s interest in and obligation to ensure reliability in its footprint and ensure sufficient capacity, plus planned reserves, are maintained to meet the SPP Balancing Authority’s load requirements. SPP’s proposal has been thoroughly vetted and approved by the SPP stakeholder process. While SPP recognizes that stakeholder approval does not by itself cause a filing to be just and reasonable, SPP requests that the Commission extend appropriate deference to the wishes of SPP’s stakeholders, who have spent significant time and resources developing this proposal, consistent with Commission precedent.

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49 Proposed Tariff at Attachment AE, Section 2.2(6).
In addition, SPP’s proposal complies with the requirements of Section 205 of the FPA, and SPP has provided precedent supporting the Commission’s jurisdictional authority to accept SPP’s proposal for inclusion in the Tariff.\(^{51}\) Although the SPP region is made up of a diverse collection of individual Transmission Owners and Market Participants that serve the loads within the SPP Balancing Authority Area, all of these entities are participants in a regionally operated system, and as such it is appropriate for the Commission to consider resource adequacy in determining whether SPP’s terms and rates for open access transmission service and the Integrated Marketplace’s operations are just, reasonable, and not unduly discriminatory.\(^{52}\) SPP believes the Tariff revisions proposed herein that implements the RAR is just and reasonable, not unduly discriminatory or preferential, and is in the public interest to secure SPP’s reliability needs in the present and future.

SPP has developed an appropriate assurance mechanism that will apply to all loads served in the SPP Balancing Authority Area and should incent proper planning to ensure timely compliance with the RAR. SPP’s proposal to include the RAR as a Tariff obligation will allow SPP to implement the capacity and planned reserve requirements for the entire footprint that are enforceable against all Asset Owners with load assets and the Market Participants that represent them. In addition, including the RAR in the Tariff provides transparency and non-discriminatory treatment to all Market Participants, and the load serving entities they represent, under the Tariff. Ultimately, the proposed Tariff revisions will promote improved non-discriminatory treatment to all Market Participants, and the load serving entities they represent, under the Tariff. Ultimately, the proposed Tariff revisions will promote improved

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\(^{52}\) See MISO Resource Adequacy Order at P 55 (“[w]e find that, in situations where one party’s resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory”).
reliability in the SPP Balancing Authority Area. For these reasons, SPP respectfully requests the Commission accept the RAR proposal as a means to achieve these results.

IV. IMPLEMENTATION AND REQUESTED EFFECTIVE DATES

As stated previously, SPP prefers to implement the RAR by June 1, 2017 for the upcoming Summer Season (the time period of June 1 through September 30); however, SPP intends the enforcement provisions and, most specifically, the assessment of penalties for lack of compliance, to not be effective until the 2018 RAR cycle. Therefore, SPP is requesting an effective date of July 1, 2017 for those specific assurance provisions outlined herein. SPP requests the following effective dates for the proposed revisions:

(1) June 1, 2017 for the following proposed Tariff revisions that set the RAR for the 2017 Summer Season, and allow SPP to administer the process:

- Attachment AA, Section 1.0 Overview
- Attachment AA, Section 2.0 Definitions
- Attachment AA, Section 3.0 Roles and Responsibilities
- Attachment AA, Section 4.0 Planning Reserve Margin
- Attachment AA, Section 5.0 Summer Season Resource Adequacy Requirement
- Attachment AA, Section 6.0 Winter Season Obligation
- Attachment AA, Section 7.0 Short-Term Transactions
- Attachment AA, Section 8.0 Resource Adequacy Timeline
- Attachment AA, Section 9.0 Deliverability Study
- Attachment AA, Section 10.0 Workbook
- Attachment AA, Section 11.0 Post-Season Analysis
- Attachment AE, Section 2.2

(2) July 1, 2017 for the proposed Tariff revisions that contain the assurance provisions, including, but not limited to terms, of enforcement and financial liability, that will be fully implemented for the 2018 annual RAR process:
V. ADDITIONAL INFORMATION

A. Documents Submitted with this Filing:

In addition to this transmittal letter, the following documents are included with this filing:

Clean and Redline Tariff revisions under the Sixth Revised Volume No. 1

The following Exhibits:

- SPP-1 Prepared Direct Testimony of Lanny D. Nickell
- SPP-2 SPP 2014 Strategic Plan
- SPP-3 Deliverability Study White Paper
- SPP-4 Load Responsible Entity White Paper
- SPP-5 Planning Reserve Assurance Policy White Paper
- SPP-6 MOPC Presentation
- SPP-7 LOLE Study
- SPP-8 Astrapè Report
- SPP-9 Attachment AH Market Participant Agreement

B. Service:

SPP has electronically served a copy of this filing on all its Members, Transmission Customers, and Market Participants. A complete copy of this filing will be posted on the SPP web site, www.spp.org, and is also being served on all affected state commissions.

See 18 C.F.R. § 35.3 at (a) (1).
C. **Requisite Agreement:**

These revisions to the Tariff do not require any contracts or agreements, other than as described herein.

D. **Part 35.13 Cost of Service Support**

To the extent necessary, SPP requests waiver of any provisions of section 35.13 of the Commission’s regulations that may be deemed to require cost support in the form of cost-of-service statements for the enclosed revisions. SPP notes that the enclosed revisions propose to assess a fee for non-compliance with the RAR; however, there is not a corresponding cost-of-service statement that can be generated because there is no revenue requirement for transmission service for which to base a rate. SPP has provided hypothetical examples in the exhibits to this filing how fees are calculated.

E. **Communications**

Correspondence and communications with respect to this filing should be sent to, and SPP requests the Secretary to include on the official service list, the following:

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VI. CONCLUSION

For all of the foregoing reasons, SPP respectfully requests that the Commission accept the revisions to the Tariff proposed herein as just and reasonable, and with the effective dates as discussed above.

Respectfully submitted,

/s/ Matthew Harward
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Attorney for
Southwest Power Pool, Inc.
Exhibit No. SPP-1
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

SOUTHWEST POWER POOL, INC.  Docket No. ER17-___-000

PREPARED DIRECT TESTIMONY

OF

LANNY D. NICKELL
VICE PRESIDENT, ENGINEERING
SOUTHWEST POWER POOL, INC.

ON BEHALF OF SOUTHWEST POWER POOL, INC.

MARCH 3, 2017
I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lanny D. Nickell. My business address is 201 Worthen Drive, Little Rock, AR 72223.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Southwest Power Pool, Inc. (“SPP”) as Vice President, Engineering.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am directly responsible for providing strategic and tactical leadership to SPP’s Engineering Department necessary to ensure successful completion of goals and essential functions assigned to that group, including the development of transmission expansion
plans that ensure reliable and efficient usage of a regional transmission grid covering all or parts of fourteen states. I also oversee the coordination, tracking, and monitoring of approved transmission expansion projects, the performance of technical studies necessary to process requests for interconnection of generation resources and requests for long-term transmission service, and the provision of engineering support as necessary for members, customers, and regulators.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor’s Degree in Electrical Engineering from the University of Tulsa. Prior to being named Vice President, Engineering, I served as SPP’s Vice President, Operations and, before that, in various management and engineering roles within the Operations Department. Prior to joining SPP in 1997, I served in various engineering roles with the Public Service Company of Oklahoma and Central and South West Services. I have served on numerous SPP and North American Electric Reliability Corporation (“NERC”) committees working to develop and implement both regional and national transmission operations, planning, and market development policies.

II. OVERVIEW

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am submitting this testimony to: (1) provide an overview of SPP’s proposal to implement a Resource Adequacy Requirement (“RAR”) for the SPP Balancing Authority Area; (2) describe the background and stakeholder process SPP has undertaken to
develop the RAR proposal; and (3) explain the benefits that Commission acceptance of the Tariff revisions being proposed will bring to the SPP footprint, and specifically, the SPP Balancing Authority Area.

Q. PLEASE IDENTIFY THE PORTIONS OF THE SPP TARIFF THAT SPP PROPOSES TO AMEND.

A. First and foremost, SPP is requesting to add an additional attachment to the SPP Open Access Transmission Tariff (“Tariff”). As proposed, new Attachment AA will contain the terms and conditions whereby SPP will establish and enforce the RAR to be assigned to load serving entities represented by a Market Participant in the SPP Integrated Marketplace. Additionally, SPP proposes a revision to Attachment AE (Integrated Marketplace) needed in order to assign the RAR to load serving entities that are not represented by a Market Participant in the SPP Integrated Marketplace but are under the purview of the SPP Balancing Authority Area.

Q. WHAT IS THE INTEGRATED MARKETPLACE?

A. As authorized by the Federal Energy Regulatory Commission (“Commission”), SPP launched its Integrated Marketplace on March 1, 2014, including (among other things) Day-Ahead and Real-Time Energy and Operating Reserve Markets with locational marginal pricing and a market-based congestion management process based on allocations of Auction Revenue Rights (“ARR”) and auctions of Transmission

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2 All capitalized terms not defined herein shall have the definitions provided by the Tariff.
Congestion Rights ("TCR"). To implement the Integrated Marketplace, SPP assumed Balancing Authority responsibilities for the SPP footprint.

SPP’s filings to implement the Integrated Marketplace were submitted in several dockets including (among others) Docket Nos. ER12-1179, ER13-1173, ER13-2078, and ER14-416. Operation of the Integrated Marketplace is governed largely by Attachment AE of the Tariff, with implementation details included in the SPP Integrated Marketplace Market Protocols. Participation in the Integrated Marketplace by a Market Participant is subject to the Market Participant executing SPP standardized Market Participant Service Agreement, which is provided in Attachment AH of the Tariff. Attachment AH requires the Market Participant to identify the Asset Owners it represents for Integrated Marketplace transactions.

**Q. WHAT IS THE CONSOLIDATED BALANCING AUTHORITY?**

**A.** With the implementation of the Integrated Marketplace, SPP became the Balancing Authority for the SPP region. Prior to the Integrated Marketplace, the SPP region consisted of several Balancing Authority Areas that, for the most part, were operated by SPP’s Transmission Owner Members. As part of the transition to the Integrated Marketplace, SPP and sixteen (16) former Balancing Authorities entered into Attachment AN of the Tariff, which is the standardized agreement that delineates the division of responsibilities, rights and obligations between SPP and the former Balancing Authorities whose areas were consolidated. All Resource and load assets operating in the IntegratedTariff at Attachment AE, Section 1.1 Definitions A. An Asset Owner is “[a]n owner of any combination of: (1) registered physical assets (Resource, load, Import Interchange Transaction, Export Interchange Transaction, Through Interchange Transaction), (2) Transmission Congestion Rights, (3) Virtual Energy Offers, (4) Virtual Energy Bids, or (5) Bilateral Settlement Schedules.”
Marketplace are included in the SPP Balancing Authority Area. Most load assets within the SPP Balancing Authority Area are represented by SPP Members; however, some load assets are represented by non-member Market Participants. In addition, some transmission facilities included in the SPP Balancing Authority have not been placed under the functional control of SPP, although loads connected to such non-SPP transmission facilities are served by the Integrated Marketplace and SPP performs the role of Balancing Authority for those loads. For reliability reasons, SPP needs an effective mechanism to ensure adequate resources are being planned for the entire load served by the SPP Balancing Authority, including a percentage of the total RAR held as a reserve margin.

**Q.** PLEASE EXPLAIN THE PLANNING RESERVE MARGIN.

**A.** A reserve margin is the total amount of existing or prospective resource capacity in excess of demand. The division of this excess by the demand provides a percentage of reserve margin. Maintaining an adequate reserve margin provides assurance of reliable service to load in situations where demand is unusually high and/or some portion of resource capacity is unavailable. Planning Reserve Margin (“PRM”) is the term used by a majority of North American Regional Transmission Organizations (“RTO”) and Independent System Operators (“ISO”) to describe the reserve margin amount used for planning purposes, and SPP has adopted that vernacular for this proposal.

**Q.** DOES SPP HAVE A CURRENT MECHANISM TO REQUIRE A RESERVE MARGIN?
A. Yes, however, SPP has limited ability to enforce its current mechanism in a manner that can provide the type of assurance and reliability needed by the SPP Balancing Authority. As I will describe in more detail below, SPP’s enforcement ability is limited because not all load in its Balancing Authority Area has an obligation to plan capacity and because the currently available enforcement mechanism against the load that is under a capacity obligation is extreme.

The SPP Membership Agreement\(^4\) requires SPP Members to adhere to SPP Criteria. Section 4 of SPP’s Planning Criteria requires SPP’s load-serving Members to secure sufficient capacity to serve their peak load, and maintain a capacity margin that is twelve percent of the capacity needed to serve their peak load.\(^5\) There is load in SPP that is served by non-member Market Participants to which the SPP Planning Criteria do not apply, and therefore, the current capacity margin requirements are not applicable to these load-serving entities.

The capacity margin requirement provided in the SPP Planning Criteria is only applicable to SPP Members that are load-serving Members. In other words, the obligation to comply with SPP’s capacity margin requirement are only enforceable against SPP Members. The only remedy available to SPP under the Membership Agreement against SPP Members that do not comply with the SPP Planning Criteria is termination of membership, which must be approved by the SPP Board of Directors in accordance with the SPP Bylaws.\(^6\)

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\(^4\) See Southwest Power Pool, Inc., Membership Agreement, First Revised Volume No. 3 at Section 3.8(b).

\(^5\) SPP’s current twelve percent capacity margin requirement is equivalent to a reserve margin of 13.6 percent.

\(^6\) Southwest Power Pool, Inc., Bylaws, First Revised Volume No. 4.
This remedy is unnecessarily extreme and not one which SPP is likely to want to pursue in this instance.

Q. **IN YOUR OPINION, IS THE CURRENT METHODOLOGY DESCRIBED ABOVE INSUFFICIENT TO ADDRESS SPP’S RELIABILITY INTEREST?**

A. It is my opinion that relying solely on the current SPP Planning Criteria does not provide SPP with the assurance it will have sufficient resources at its disposal to reliably serve the total load under its responsibility as the Balancing Authority. With this proposal, SPP is requesting to include new requirements in the Tariff for all entities with load served by the SPP Balancing Authority to have sufficient capacity to meet their peak load obligations plus a planning reserve margin. As will be described in more detail herein, this issue is of vital importance to the SPP Stakeholders, who have broadly supported this initiative.

Q. **WHY IS SPP PROPOSING TO MOVE FROM THE SPP PLANNING CRITERIA’S CAPACITY MARGIN TERMINOLOGY TO A RESERVE MARGIN TERMINOLOGY?**

A. The capacity margin and reserve margin terms are focused on the same issue (i.e., the difference between an entity’s resource capacity and load obligation). However, the difference between the terms stems from the denominator used in the percentage calculation. Demand or peak load obligation is used as the denominator for calculating the percentage of reserve margin whereas capacity margin utilizes capacity as the denominator. Within the electric industry, reserve margin terminology is commonly used to determine the amount of excess capacity necessary to be maintained for reliability
reasons. As stated above, “Planning Reserve Margin” is the term used by a majority of
North American RTOs/ISOs to describe the reserve margin amount used for planning
purposes, and SPP has adopted that vernacular and formulaic process for this proposal.

Q. WHY DOES SPP PROPOSE TO PLACE ITS RESOURCE ADEQUACY
REQUIREMENTS IN ITS TARIFF?

A. As stated above, SPP’s capacity margin requirements contained in the SPP Planning
Criteria are not generally applicable to all load in the SPP Balancing Authority Area.
SPP’s proposal to include the RAR as a Tariff obligation is intended to allow SPP to
implement the capacity and PRM requirements for the entire footprint that are
enforceable against all Asset Owners with load assets and the Market Participants that
represent them. In addition, including the RAR in the Tariff provides transparency and
non-discriminatory treatment to all Market Participants, and the load serving entities they
represent, under the Tariff. Ultimately, the proposed Tariff revisions will promote
improved reliability in the SPP Balancing Authority Area.

Q. PLEASE SUMMARIZE SPP’S PROPOSAL.

A. SPP is proposing to revise its Tariff to include a new Attachment AA, which will
establish terms and conditions whereby SPP may establish the RAR, a requirement that
its load serving entities (i.e., Asset Owners) have sufficient capacity to serve their peak
loads, while also maintaining sufficient capacity to satisfy a minimum planning reserve
margin (“Planning Reserve Margin” or “PRM”). Attachment AA will contain the terms
and conditions for setting the RAR and the required PRM. SPP proposes the creation of a
new defined term for Asset Owners serving load in the Integrated Marketplace called the
Load Responsible Entity (identified as the “LRE” in Attachment AA). The LRE will be responsible to maintain the RAR and is described in more detail in Section V of this testimony. SPP also proposes that the Market Participant that represents the LRE is the party ultimately responsible to ensure that the RAR under Attachment AA is met. The Market Participant’s role is also explained in detail in Section V of this testimony.

In addition, Attachment AA will also contain reporting requirements, roles and responsibilities, and assurance provisions to assess a fee against non-compliant entities, including respective provisions to govern SPP’s collection and eventual distribution of revenues associated with deficiency penalty revenues. Further, Attachment AA includes the provision of two types of studies SPP will perform in order to a) set and establish the required PRM and b) determine the deliverability of generation Resources registered in the Integrated Marketplace. Finally, SPP is proposing a modification to Attachment AE of the Tariff, to facilitate the enforcement of the RAR as applied to entities serving their load through SPP’s Integrated Marketplace that are not represented by a Market Participant.

III. STAKEHOLDER PROCESS

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS SPP USED TO IDENTIFY NEEDED IMPROVEMENTS TO SPP’S RESOURCE ADEQUACY CONSTRUCT.

In April 2014, the Markets and Operations Policy Committee (“MOPC”) began discussing the need to improve SPP’s resource adequacy construct and the need to perform an evaluation of whether SPP’s current capacity margin requirement could be
reduced given that it was implemented in 1998 and has not been changed. Several factors contributed to the MOPC’s interest in evaluating a reduced capacity margin requirement and other resource adequacy policy improvements. These factors included the 2014 implementation of the Integrated Marketplace and the SPP Balancing Authority, SPP’s successful planning and construction of significant transmission expansion, and the proposed integration into SPP of new Members Western Area Power Administration-Upper Great Plains Region, Basin Electric Power Cooperative, Heartland Consumers Power District (known as the “Integrated System”) by October 1, 2015. As a result of the MOPC’s expressed interest, SPP staff recommended the establishment of a new task force, the Capacity Margin Task Force (“CMTF”) to be populated with a diverse set of stakeholders with technical expertise related to resource adequacy issues. At its July 2014 meetings, the MOPC approved the CMTF’s creation and the staff proposed charter. In addition to the actions of the MOPC, the SPP Strategic Planning Committee (“SPC”) reported to the SPP Board of Directors at its July 2014 meetings that it had identified Capacity Margin Improvements as a Priority A initiative to assure reliability, stating “[r]esource adequacy will become an increasingly important component of SPP’s responsibility as the Balancing Authority. Having…the ability to enforce adequacy through [capacity margin requirements] are tools to accomplish this.”

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8 Id. at Agenda item 21.

9 See Board of Directors/Members Committee Meeting materials dated July 29, 2014 at page 257 posted at: https://www.spp.org/documents/22889/bod-
The CMTF held its first meeting on August 26, 2014, and after a year and half period of stakeholder deliberation, developed three policy white papers proposing improvements of SPP’s resource adequacy construct. The three white papers developed by the CMTF covered three issues that have become the foundations for SPP’s proposal today: Deliverability Study white paper, Load Responsible Entity for Planning Reserve Margin Obligation white paper, and Planning Reserve Assurance Policy white paper. All three white papers along with a proposal to reduce SPP’s reserve margin from 13.6% to 12.0% were presented to the MOPC\textsuperscript{10} and SPP Board of Directors\textsuperscript{11} for approval. In addition, the Regional State Committee ("RSC")\textsuperscript{12} approved the policies developed by the CMTF and contained in the white papers on April 25, 2016.\textsuperscript{13} Subsequent to approval by these governing stakeholder groups, the Regional Tariff Working Group ("RTWG") was tasked to develop Tariff language to implement the policies of the three white papers into the Tariff. All three white papers are included as Exhibit Nos. SPP-3 through SPP-5 to SPP’s filing.

\textsuperscript{10} The MOPC approved the package of white papers at its April 2016 meetings. See MOPC Minutes dated April 12-13, 2016 at Summary of Action Items Taken #11 at 1. See also id. at Agenda Item 10. \url{https://www.spp.org/documents/37791/mopc%20minutes%20and%20attachments%2020160412-13.pdf}

\textsuperscript{11} See Board of Directors/Members Committee Meeting Minutes No. 168 at Agenda item 4 posted at: \url{https://www.spp.org/documents/37863/bod_mc%20minutes%2020160426_full.pdf}

\textsuperscript{12} The RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission. The RSC is comprised of retail regulatory commissioners from agencies in Arkansas, Iowa, Kansas, Missouri, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, and Texas.

\textsuperscript{13} See RSC Minutes dated April 25, 2016 at pages 2-3 posted at: \url{https://www.spp.org/documents/39003/rsc%20minutes%2020160425.pdf}
The CMTF was disbanded after approval of the white papers, and stakeholder ownership of the resource adequacy construct was transferred to a new working group: the Supply Adequacy Working Group (“SAWG”) which assisted the RTWG during the Tariff-drafting process with any necessary clarifications. Prospectively, the SAWG will have stakeholder oversight of the Tariff language being proposed today. All in all, the work to develop SPP’s proposal entailed substantial stakeholder and staff hours from the performance of myriad loss-of-load-expectation (“LOLE”) studies and development of the white papers to drafting Tariff modifications, which included engagement of the following working groups or task forces: CMTF, SAWG, Process Improvement Tariff Task Force, RTWG, Operating Reliability Working Group (“ORWG”), Generation Working Group (“GWG”), Transmission Working Group, and Cost Allocation Working Group.

The proposed changes to the Tariff were presented to the MOPC on January 17-18, 2017 and were approved with one “no” vote and ten abstentions. On January 30, 2017, the RSC reviewed and endorsed the approved the Tariff language as consistent with the policies it previously approved. The SPP Board of Directors approved the Tariff

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15 See RSC Minutes dated January 30, 2017 at page 3 posted at: https://www.spp.org/documents/48631/rsc%20minutes%2020170130.pdf.
language on January 31, 2017, and authorized SPP to file the proposal with the Commission.\(^\text{16}\)

Q. **AS PART OF THE STAKEHOLDER PROCESS, DID SPP PERFORM ANY STUDIES?**

A. Yes, the details of the studies performed by SPP to support its proposal are explained in more detail in Section IV of this testimony.

IV. **THE RESOURCE ADEQUACY REQUIREMENT**

Q. **PLEASE EXPLAIN SPP’S PROPOSAL FOR THE RESOURCE ADEQUACY REQUIREMENT.**

A. SPP proposes to include an RAR in the Tariff which will obligate the applicable LRE (i.e., Asset Owner with load or transactions subject to the requirement) to maintain sufficient capacity to satisfy its peak load obligation plus the PRM. The RAR is equal to the LRE’s “Net Peak Demand” plus the “Net Peak Demand” multiplied by the PRM. The RAR is intended by SPP to be enforceable from June 1 through September 30 of each calendar year (“Summer Season”). Thus, the LRE is obligated to maintain sufficient capacity to satisfy its requirement for the Summer Season. An entity’s failure to comply with the RAR will subject it to the assurance provisions and a financial penalty, which is explained in better detail below.

Q. **WHY IS SPP PROPOSING THE RESOURCE ADEQUACY REQUIREMENT TO BE ENFORCEABLE DURING THE SUMMER SEASON?**

\(^\text{16}\) See Board of Directors/Members Committee Meeting Minutes No. 172 at Agenda item 4 posted at: https://www.spp.org/documents/47489/bod-mc%20minutes%2020170131.pdf.
A. The Summer Season is the period in which SPP and the majority of load-serving entities in SPP experience highest demands for electricity, and therefore, is the timeframe where the need for availability of resources to serve load is most critical. Notwithstanding this requirement, SPP and the stakeholders recognize that a small minority of load-serving entities may experience a peak during the winter season. Although not attaching a payment-based enforcement mechanism for the winter season, Attachment AA contains a provision that requires all LREs to also meet their winter season peak obligations, which runs from December 1 through the following year’s March 31 (“Winter Season”) and is equal to the Net Peak Demand for the winter season plus the correlating PRM. In this manner, the Tariff will require the LRE to maintain sufficient capacity to meet its winter obligations. Although there is no financial liability attached to the Winter Season obligation, the SPP stakeholders vetted this issue thoroughly and this solution was determined by consensus as appropriate to meet SPP’s reliability needs.

Q. EXPLAIN THE DEFINITION OF NET PEAK DEMAND.

A. As stated above, each part of the RAR is determined for each LRE based on its “Net Peak Demand” for the Summer Season. “Net Peak Demand,” as defined in new Attachment AA will be the determination of the LRE’s forecasted highest demand for energy, including transmission losses, during a one clock-hour period (“Peak Demand”) plus the amount of capacity subject to a firm power sales contract in effect during the determination of the Peak Demand less the following: a) projected impacts of demand response programs and behind-the-meter generation that are controllable and dispatchable but not registered in the Integrated Marketplace, and b) the amount of
capacity subject to a firm power purchase contract in effect during the determination of the Peak Demand.

To understand how Net Peak Demand is to be calculated for the RAR, two concepts need to be explained in more detail: the addition of capacity subject to a firm power sales contract and the subtraction of capacity subject to firm power purchase contracts referenced above. Under SPP’s proposal, sales of firm power to others is included in the determination of Net Peak Demand because the seller is obligated by contract to provide firm power (i.e., capacity and reserve margin requirements supported by firm transmission service) to a purchaser. Similarly, a purchaser of firm power is entitled to receive the firm power by contract from the third-party seller, and therefore, such receipt will have the effect of reducing the Net Peak Demand that the LRE must self-provide or procure through other contracts.

Q. WHAT PLANNING RESERVE MARGIN REQUIREMENT DOES SPP PROPOSE FOR THE SPP BALANCING AUTHORITY AREA?

A. SPP proposes that the initial PRM for the SPP Balancing Authority be set at 12% of the capacity needed by each individual LRE to serve its load. In other words, an LRE’s RAR will include the obligation to plan adequate capacity to satisfy its Net Peak Demand (see explanation of Net Peak Demand in previous section) and have additional planning reserves no less than 12% of its Net Peak Demand. If the LRE’s firm capacity utilized to serve its load is comprised of at least seventy-five percent (75%) hydro-based generation, then SPP proposes to set the PRM for such entities at 9.89%. This allowance for hydro-
based capacity is contained in SPP’s current criteria and is being included here to apply to the applicable LREs.

Q. HOW DOES SPP DETERMINE THE APPROPRIATE PLANNING RESERVE MARGIN REQUIREMENT FOR THE SPP BALANCING AUTHORITY AREA?

A. SPP determines the appropriate PRM for its area through a probabilistic Loss of Load Expectation ("LOLE") Study, which analyzes the ability of SPP to reliably serve the SPP Balancing Authority Area’s forecasted peak demand. As proposed, SPP will perform future PRM assessments using the LOLE Study, at least on a biennial basis, or more often as warranted (to be determined by SPP). The LOLE Study will be performed in a transparent manner and SPP shall develop the inputs and assumptions that are to be used for the LOLE Study, with input from stakeholders. A PRM for the SPP Balancing Authority Area is considered appropriate when the LOLE Study performed to evaluate that amount of planning reserves adequately demonstrates that the expectation for loss of load for the applicable planning year does not exceed one (1) day in ten (10) years, or 0.1 day per year. The LOLE Study will be performed by SPP 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 threshold of loss of load for 0.1 day per year is not exceeded. SPP shall post the final results of the LOLE Study on its website so that all interested entities may review the results in a publicly available format.

Q. DID SPP PERFORM A LOLE STUDY TO SET THE PLANNING RESERVE MARGIN REQUIREMENT BEING PROPOSED FOR ATTACHMENT AA?
A. Yes. The CMTF directed staff to evaluate SPP’s capacity margin requirement through a series of analyses referred to as the “Limbo Study.” The CMTF reviewed and approved the scope of the Limbo Study. Assumptions were established considering historical data and were modeled using SPP’s LOLE simulation software. The years 2016, 2017, and 2020 were included in the probabilistic LOLE analyses. Applying the assumptions contained in the approved scope, the study showed that a 1-day-in-10-years LOLE criteria could be maintained at reserve margins of 7.53% and above for 2016 and 2020, while a 1-day-in-10-years LOLE criteria could be maintained at reserve margins of 8.70% and above for 2017. The LOLE for the above margins decreases from 2017 to 2020 due to planned transmission expansion combined with additional future generation expected to be placed in constrained areas. After review of the initial results of the Limbo Study, additional assumption sensitivities were recommended for analysis by the CMTF and other SPP working groups (ORWG and GWG). These additional sensitivities were performed to test the impact on LOLE of applying more extreme assumptions, compared to those originally established for the Limbo Study. Applying these more extreme assumptions as a combined sensitivity showed that an LOLE of less than 1 day in 10 years could be maintained at 12.0% reserve margin for all years.\footnote{See MOPC Minutes dated April 12-13, 2016 at pages 689-706 posted at: \url{https://www.spp.org/documents/37791/mopc%20minutes%20and%20attachments%2020160412-13.pdf.}}

SPP staff contracted Astrapè Consulting (“Astrapè”) to analyze the assumptions and results of the Limbo Study. Astrapè suggested modifications to assumptions involving wind variability, load variability and uncertainty, and non-firm support from external regions. In consideration of their suggested assumption modifications combined with SPP’s LOLE results, Astrapè suggested a reserve margin of 11.25% would meet SPP’s 1
day in 10 years criteria. Astrapè’s analysis was qualitative in nature and did not include any additional quantitative simulations. Astrapè’s analysis is included as Exhibit No. SPP-8 to SPP’s filing. Based on the results of both the Limbo Study and Astrapè’s analysis, the CMTF recommended that the MOPC approved a reserve margin requirement of 12%. The proposed reserve margin requirement of 12% was approved by the MOPC on April 12-13, 2016\textsuperscript{18} and was subsequently presented to and approved by the RSC and SPP Board of Directors on April 25-26, 2016.

Q. WHAT IS THE PROCESS PROPOSED FOR SPP TO CHANGE THE PLANNING RESERVE MARGIN REQUIREMENT FOR THE SPP BALANCING AUTHORITY AREA?

A. As proposed, SPP is requesting that the PRM be stated in the Tariff. A change to a Commission-accepted PRM shall not be made absent a filing with the Commission requesting a change to the PRM with a corresponding Tariff revision to state the value in Attachment AA. SPP believes that requiring changes to the PRM to be filed for Commission acceptance shall provide the needed transparency to ensure the margin is set at an appropriate level and is enforced in a non-discriminatory manner.

Q. WHAT IS SPP’S PURPOSE IN IMPLEMENTING A RESOURCE ADEQUACY ASSURANCE MECHANISM FOR ITS LOAD SERVING ENTITIES?

A. SPP’s current mechanisms are inadequate to provide assurance that resource and planning reserve capacity will be available as needed to reliably serve load within the SPP footprint.Existing assurance options under the SPP Planning Criteria are not

\textsuperscript{18} See id. at Agenda Item 10.
applicable to non-members; nor is mitigation for non-members required under any mandatory reliability standard or regulation. Even with potential revocation of the Membership Agreement as an extreme recourse for SPP Members, SPP does not currently have an adequate mechanism to assure that its Members maintain required levels of resource adequacy. An appropriate assurance mechanism should apply to all loads served in the SPP Balancing Authority Area and should incent proper planning to ensure timely compliance with the RAR. In addition, a well-designed assurance methodology should reward good behavior while addressing bad behavior. For example, if an LRE is capacity deficient and the SPP Balancing Authority Area relies on the excess capacity of other parties in SPP to provide adequate regional reliability, then those parties that have excess capacity should receive compensation through the assurance mechanism.\textsuperscript{19} SPP’s existing assurance mechanisms are either unlikely to be exercised or would be exercised in a way that would not incent the desired behavior and would not adequately compensate parties with capacity in excess of their RAR in SPP.

Q. HOW WILL IMPLEMENTATION OF THE PROPOSED RESOURCE ADEQUACY REQUIREMENT BENEFIT THE SPP BALANCING AUTHORITY AREA?

A. The requirement for each entity serving load in the SPP Balancing Authority to plan sufficient capacity and reserves to serve its projected load is critical to ensure reliability can be maintained within the SPP footprint. Indeed, NERC has identified the necessity of

\textsuperscript{19} The proposed revenue distribution mechanism was developed to address the equity issues that will arise if contingencies occur in the future that require the SPP Balancing Authority Area to call upon planned reserves to fulfill load obligations.
adequate planning reserves as part of its 2016 Long-Term Reliability Assessment (“2016 LTRA”). Simply put, implementing an RAR under the terms proposed in SPP’s filing will provide the means for SPP to assure regional reliability interests are met in a manner that is efficient, practical, and equitable.

V. OVERVIEW OF ROLES AND RESPONSIBILITIES

Q. PLEASE BRIEFLY DESCRIBE THE ROLES AND RESPONSIBILITIES ASSIGNED TO THE ENTITIES SUBJECT TO ATTACHMENT AA.

A. SPP’s proposal identifies the LRE, Market Participant, Generator Owner, and SPP (as the Transmission Provider) as entities which will have certain roles and responsibilities under proposed Attachment AA. SPP, as the Transmission Provider, will be the entity responsible to administer the provisions of the Tariff as outlined in Attachment AA and its responsibilities are described throughout this testimony.

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20 See 2016 LTRA at Introduction (“NERC’s primary objective with the LTRA is to assess resource and transmission adequacy across the NERC footprint, and to assess emerging issues that have an impact on BPS reliability over the next ten years. NERC assesses this reliability by comparing projected reserve margins to Reference Margin Levels established by the assessment area or to a default Reference Margin Level. Reserve margins are typically developed using probabilistic methods that calculate the [LOLE] that could occur less than or equal to one time in ten years based on daily peak information. Whereas these analyses typically evaluate resource adequacy in order to meet a peak day requirement. NERC recognizes that a changing resource mix with a significant portion of it being energy-limited, changes in off-peak demand, single points of disruption, and other factors can have an effect on resource adequacy. As a result, NERC is incorporating more probabilistic approaches into this assessment and other ongoing analyses that provide further insights into how to best establish adequate reserve margins amidst a BPS undergoing unprecedented changes”). The 2016 LTRA is posted at: [http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf](http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf).
Load Responsible Entity:

As stated throughout this testimony, SPP desires an enforceable mechanism to foster reliability by ensuring sufficient resource capacity is maintained to meet the entire load serving obligations of the SPP Balancing Authority. To that end, SPP proposes an RAR be assigned to appropriate entities with responsibility for load served in the Integrated Marketplace. To effectuate the establishment of this RAR for all load served by the SPP Balancing Authority in the Integrated Marketplace, SPP proposes to create a new entity type, heretofore, the referenced LRE. The LRE is an Asset Owner represented in the Integrated Marketplace with registered physical assets that is either load or a certain subset of Export Interchange Transactions as provided in Attachment AA. Being the Asset Owner of the load, the LRE is the entity responsible to ensure it has secured sufficient resources to meet the RAR. A majority of these entities already have statutory and regulatory obligations, imposed by a state or other governing body, to serve the electrical demand of its end-use customers.\(^{21}\) As these entities participate in the Integrated Marketplace, tying the concept of the LRE to the Asset Owner with load or the specific type of External Interchange Transactions (as defined in Attachment AA) was a reasonable and efficient means of identifying the proper entity to satisfy the RAR.

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\(^{21}\) SPP did not adopt the term “load serving entity” for use in Attachment AA because SPP understands that NERC and the industry may have differing definitions, although the purpose of serving end-use customers is consistent. SPP believes it is appropriate to have a specific defined terminology for use in the Tariff to represent the entity that will be subject to the procurement requirements proposed in Attachment AA, and “Load Responsible Entity” is the term that was chosen by consensus of the SPP stakeholders. Similarly, the term “Asset Owner” applies to many different types of physical assets under the Integrated Marketplace, and because Attachment AA is only applicable to a subset of defined Asset Owners, a unique term was preferred to identify the entity subject to the RAR.
Market Participant:

As proposed, the Market Participant is the entity under the Tariff with which SPP has a contractual tie via the Market Participant Agreement. The Market Participant Agreement is SPP’s standardized service agreement (found Attachment AH of the Tariff) that is executed by eligible entities wishing to transact in the Integrated Marketplace. As identified in both Attachment AE of the Tariff and the Market Participant Agreement, the Market Participant also has the direct relationship with the Asset Owner. The Market Participant identifies the Asset Owner which it represents in market transactions through an appendix to the Market Participant Agreement. The Asset Owner is identified by the Market Participant, generally, as either owning load or resources. Because the Market Participant is the entity that has the direct contractual relationship with SPP, the Market Participant is in the best position to ensure, both on a performance and financial level, that the LRE fulfills its obligations to meet the RAR, and all other terms and obligations, including but not limited to, the provision of necessary data to SPP, contained in Attachment AA of the Tariff.

Generator Owner:

A Generator Owner is defined in Attachment AA as “[t]he Asset Owner of a Resource.” SPP proposes to utilize the ownership of a Resource, as defined in Attachment AE of the Tariff, as the determining factor for whether the owner of a generating resource may participate in the process described in Attachment AA. Because the RAR is tied to the

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22 The Market Participant Agreement is attached as Exhibit No. SPP-9 to SPP’s filing.
23 See Tariff at Attachment AE, Section 1.1 Definitions R. “An asset that injects energy into the transmission grid or reduces the withdrawal of energy from the transmission grid including a Demand Response Resource, a Variable Energy Resource, a Dispatchable Resource, External Resource, External Dynamic Resource and a Quick-Start Resource.”
Net Peak Demand of the LREs serviced by the Integrated Marketplace, it is reasonable to conclude that those Resources registered in the Integrated Marketplace are the appropriate facilities capable of providing capacity to meet the RAR. Further, in its proposed Deliverability Study, described in more detail later in this testimony, SPP will evaluate capacity deliverable to the SPP footprint from Resources in the Integrated Marketplace. Generator Owners have limited responsibilities under Attachment AA. Responsibilities include the provision of data to SPP necessary to allow identification of deliverable Resource capacity to the footprint. A Generator Owner that has excess capacity to provide for use by the SPP Balancing Authority may also become eligible to receive part of the disbursement of deficiency revenues, as described in more detail below. A Generator Owner may be an entity that is also an LRE; however, the responsibilities between each are separate and distinct and SPP will appropriately recognize the designations and distinct functions.

**Q. WHY IS SPP PROPOSING TO ENFORCE THE RESOURCE ADEQUACY REQUIREMENT AGAINST THE MARKET PARTICIPANT?**

**A.** SPP and the stakeholders recognized that, absent an existing contractual obligation, the enforceability of the RAR and collectability of deficiency payments from non-compliant entities would present legal and practical challenges. Use of existing Tariff provisions and the Market Participants’ current responsibilities to represent load being served in the SPP footprint were identified as the most reasonable means to create a methodology that was enforceable under the Commission’s jurisdiction and by rule of law. First, SPP does not have a direct contractual relationship with the Asset Owners participating in the
Integrated Marketplace. Asset Owners are not required to sign a Market Participant Agreement, and indeed, many Market Participants represent Asset Owners under principles of agency without any separate affiliation.

Second, SPP has the contractual relationship with the Market Participant through the Market Participant Agreement. Although the LRE is the entity that has the obligation to meet the RAR, it is the Market Participant only who has the relationship with both SPP and the LRE. SPP believes it can best enforce the RAR against the Market Participant, who in turn is the only entity that can ensure the LRE’s compliance with the RAR.

The unique relationship between the LRE and the Market Participant was a determining factor in the consensus reached by SPP stakeholders. Because of this relationship between the Asset Owner and Market Participant, and because SPP has a current contractual relationship only with the Market Participant, the Market Participant is the only entity against which SPP may enforce the provisions of Attachment AA. The Market Participant is also the only entity which SPP may also assess a deficiency payment through the contractual tie of the Market Participant Agreement in conjunction with the Attachment AA of the Tariff. When reviewing the importance of legal enforceability of any potential Tariff requirement, the placement of ultimate responsibility for compliance with Attachment AA on the Market Participant was by consensus the preferred approach and the most reasonable method to implement a legally enforceable RAR.

Q. PLEASE EXPLAIN SPP’S PROPOSAL TO ALLOW A MARKET PARTICIPANT TO ASSIGN ITS OBLIGATIONS UNDER ATTACHMENT AA.
A. As proposed, SPP is providing a mechanism whereby a Market Participant may assign its duties and obligations for the LRE to another Market Participant. This option is available to those Market Participants that bilaterally agree to transfer the obligations, and SPP requires that the agreement be memorialized in a legally enforceable document to be provided as evidence before SPP will accept the assignment. The rules around valid assignment are provided in Attachment AA in a transparent manner. SPP will not be a party to such assignments, and the proposed Tariff provisions insulate SPP from disputes between Market Participants and LREs. Additionally, the proposed Tariff language contains limitations of liability for SPP that are consistent with the Tariff’s provisions related to transmission service and Integrated Marketplace transactions. A valid assignment does not affect any rights or obligations the Market Participants may have under the other sections of the Tariff, and Attachment AA is a stand-alone obligation that does not impact other rights or obligations for other services that the Market Participant may take from SPP. The proposal to allow assignments is an accommodation that was debated and negotiated by the stakeholders, is just and reasonable, and is not inconsistent with other assignment provisions of the Tariff.

Q. DOES SPP PROPOSE TO REVISE THE MARKET PARTICIPANT AGREEMENT?

A. SPP does not propose revisions to SPP’s pro forma Market Participant Agreement. The pro forma Market Participant Agreement already provides the necessary information to identify a Market Participant’s LRE(s) and SPP is concerned that unnecessary revisions to a pro forma service agreement will cause confusion and result in SPP being required to
seek out and re-execute hundreds of current Market Participant Agreements on file with the Commission. The information to determine the LRE is already included in Attachment AH. Such information is sufficient to allow SPP and its customers to determine any obligations under Attachment AA. SPP has attached Attachment AH, and Appendix 1 to Attachment AH, as Exhibit No. SPP-9 to its filing.

Attachment AH requires the Market Participant to identify its Asset Owners that are a Load Serving Entity in Appendix 1 to Attachment AH. The block table identified as “Asset Owner and TC Information” in Appendix 1 contains a place to identify whether the Asset Owner is a Load Serving Entity. By checking “yes,” the Market Participant is representing that its Asset Owner has load assets that are being supplied through the Integrated Marketplace. By utilizing this information, SPP is able to determine which Asset Owners are LREs, and which Market Participant represents such LREs.

Because Attachment AH already contains the needed information to allow SPP to identify both the LRE with load in the market, and the respective Market Participant that represents such load, SPP believes that no change to the *pro forma* service agreement is needed in order to effectuate Attachment AA; and given the costs in both staffing resources, time and expense of re-executing current Market Participant Agreements, SPP believes its proposal before the Commission is just and reasonable.

**Q. PLEASE EXPLAIN HOW SPP WILL ENSURE IT HAS SUFFICIENT INFORMATION TO ADMINISTER ATTACHMENT AA.**

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[^24]: See Tariff at Attachment AH, Appendix 1 (also attached as Exhibit No. SPP-9 to SPP’s filing).
A. SPP has developed a process and methodology provided in Attachment AA that is transparent and will provide SPP with the information necessary to perform its obligations. The majority of information to be provided by LREs and Generator Owners will be contained in a workbook-style set of electronic spreadsheets (“Workbook”) that will be filled out and returned by the dates specified in Attachment AA’s timeline. SPP has built public postings and reporting requirements that allow stakeholders to participate in the process and public discussions will be facilitated through the stakeholder process. In addition, all deadlines for information provision and obligations that must be met by the different participating entities is provided by Attachment AA. The timelines were developed to allow the relationship between an LRE and a Market Participant to be determined and set in a manner that assures that SPP will be able to rely on the parties for the upcoming Summer Season. In this manner, SPP assures accountability that is non-discriminatory and transparent for itself and the SPP customers that have rights and obligations under the Tariff.

VI. DELIVERABILITY OF RESOURCES AND THE “DELIVERABILITY STUDY”

Q. PLEASE EXPLAIN SPP’S USE OF THE TERM “DELIVERABILITY”.

A. “Deliverability,” as the term is used in Attachment AA, is the concept that generation resources registered to provide energy to the SPP Integrated Marketplace have a certain level of measurable capability to deliver capacity to the SPP Balancing Authority Area. In essence, the proposed term “Deliverability” describes the Resource’s ability to provide its available capacity to the entire SPP footprint which may be made available for
contractual use by an LRE to satisfy its PRM portion of the RAR without requiring firm transmission service.

Q. WHAT IS THE DELIVERABILITY STUDY?

A. As proposed, SPP shall perform an annual Deliverability Study. The Deliverability Study will evaluate the deliverability to the SPP Balancing Authority Area of each Resource registered in the Integrated Marketplace. It does not evaluate whether such Resources are deliverable to specific delivery points or SPP Zones. The Deliverability Study will result in a determination of each Resource’s capacity that is deliverable to the SPP Balancing Authority Area. SPP will utilize its current transmission planning models to perform the Deliverability Study. SPP will begin the Deliverability Study with the initial assumption that any Resource currently dispatched in the planning model is deliverable to the SPP Balancing Authority Area for the dispatched output. This assumption results from the expectation that SPP’s planning process will recommend transmission upgrades necessary to reliably facilitate planned dispatch of modeled Resources. SPP will then study each Resource to determine if any additional capacity from that Resource can be delivered to the SPP Balancing Authority Area without creating new constraints. A Resource’s total capacity deemed deliverable equals the Resource’s initial modeled dispatch plus any additional capacity found to be deliverable. For multiple generating units at one site, the total deliverable capacity for the site is the sum of deliverable capacities of all such generating units. SPP requests that the Commission accept Tariff language that limits validity of the results of the Deliverability Study to the upcoming Summer Season and the subsequent Summer Season. SPP will perform this study
annually, and therefore, allowing the results to be valid for the next two years will give both the LRE and the Generator Owners a reasonable window to utilize the results for contracting purposes.

Q. PLEASE EXPLAIN HOW LOAD RESPONSIBLE ENTITIES MAY UTILIZE CONTRACTS BASED ON THE DELIVERABILITY STUDY.

A. As proposed, the Generator Owners may utilize the results of the Deliverability Study to enter into contracts with LREs for available capacity deemed to be deliverable. An LRE may rely on this capacity to satisfy the PRM portion of its RAR without being required to arrange for firm transmission service to support delivery of the capacity. SPP’s proposal allows an LRE to rely on available transmission capacity, as demonstrated through performance of the Deliverability Study, to meet its PRM portion of its RAR, at least in short near-term timeframes, without sacrificing reliability. Although SPP’s existing processes may be used to obtain firm transmission service, this process is intended to provide an additional mechanism for demonstrating reliable access to transmission capacity needed to support the near-term capacity needs an LRE might have to meet its PRM. To be clear, firm transmission service will continue to be required to demonstrate delivery of capacity needed to supply an LRE’s peak demand.

Q. WHY ARE PURCHASES BY THE LOAD RESPONSIBLE ENTITY OF CAPACITY TO SATISFY THE PLANNING RESERVE MARGIN BASED ON DELIVERABILITY STUDY RESULTS NOT REQUIRED TO SECURE FIRM TRANSMISSION SERVICE?
A. The underlying philosophy for not requiring firm transmission service for purchases to satisfy the PRM based on the results of the Deliverability Study is based on the reasoning that the amount of resource capacity that can be delivered in SPP without impacting reliability can be pre-determined on a system-wide basis using latest planning models. The PRM is an element of future planning of resources and represents a forecasted excess of the amount of capacity needed to reliably meet load. Since the PRM is a requirement related to future planning purposes, and where the reserve’s use is contingent on a speculative future event, SPP believes it is just and reasonable to forego the requirement for firm transmission service to facilitate delivery of reserve margin capacity. SPP believes the exception for firm transmission service should be narrowly limited to capacity shown by the Deliverability Study to be deliverable on a short-term basis without impacting reliability. Notwithstanding this proposal, SPP would make clear that firm transmission service will continue to be necessary to acquire congestion rights (i.e., TCRs and Long-Term Congestion Rights) under Attachment AE of the Tariff, and therefore capacity purchases based on the Deliverability Study will not be eligible for participation in SPP’s ARR and TCR markets. In addition, as explained in more detail below, the Deliverability Study may not be used to secure capacity purchases to serve an LRE’s Net Peak Demand, which require firm transmission service.

Q. MAY THE LOAD RESPONSIBLE ENTITY UTILIZE PURCHASES BASED ON THE DELIVERABILITY STUDY TO SERVE ITS LOAD?

A. No. Firm transmission service needed to deliver power from generation to load is currently and will continue to be required by SPP in order for that generating capacity to
count toward meeting an LRE’s Net Peak Demand. Confirmed firm transmission service, whether network or point-to-point service, will continue to be required, consistent with the existing SPP Criteria and the Tariff, in order for an LRE to demonstrate firm transmission service necessary to count generating capacity toward serving load.

Q. EXPLAIN HOW SALES OF SHORT-TERM CAPACITY AND SHORT-TERM FIRM POWER CONTRACTS ARE TREATED IN THE PROCESS.

A. Because the end purpose of SPP’s proposal is to maintain reliability and ensure sufficient generation capacity resources are available to serve load in the SPP Balancing Authority Area, any firm capacity utilized by an LRE should not be available to be included as firm capacity used by another LRE. The proposed Tariff limitations reflect this approach. With regards to short-term sales for either capacity or firm power (transactions supported by firm transmission service), SPP proposes, consistent with current SPP Criteria, that an LRE may utilize short-term sales to serve its Net Peak Demand not to exceed twenty-five percent (25%) of the Net Peak Demand. The LRE may utilize such short-term sales under this provision for either the Summer Season or Winter Season, but not both. In addition, such short-term sale contracts must be for a minimum of four consecutive months starting either June 1 or December 1, depending on which season the LRE intends to utilize such contracts to serve its load. As stated, the twenty-five percent (25%) threshold is a carry-over from the SPP Criteria, and SPP stakeholders desire to maintain such limitation based on historical practices designed to promote use of reliable long-term contracts to support load obligations.
VII. RESOURCE ADEQUACY ASSURANCE

Q. PLEASE EXPLAIN SPP’S PROPOSAL TO ENSURE COMPLIANCE WITH THE RESOURCE ADEQUACY REQUIREMENT.

A. Pursuant to the policy paper developed by SPP and stakeholders, the RSC, and approved by the SPP Board of Directors, the proposal to ensure compliance with the RAR, and the accompanying PRM obligation, is designed on the following basic principles:

1. Assurance should be timely and proactive, preferably by determining an LRE’s potential lack of compliance in advance and allowing the deficient LRE to take corrective action, if available.

2. Assurance should consist of a payment by a deficient LRE to those parties with excess capacity in SPP that were ultimately relied upon to make up any shortfall.

3. The amount of the payment should economically incent a deficient LRE to address its PRM capacity deficiency.

4. The receipt of the payment should be allocated to the appropriate parties in a manner reflecting the impact of the LRE’s [PRM] deficiency.  

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25 See Exhibit No. SPP-5, Planning Reserve Assurance Policy Whitepaper at 1.0. The white paper refers to the term “[Planning Reserve Margin] deficiency” to include the entire capacity deficiency of the LRE, which includes both capacity required to meet the LRE’s peak load as well as the capacity required to meet the LRE’s PRM above peak load. In order to reduce potential confusion as to what “Planning Reserve Margin” means, SPP has proposed that the term RAR be used to reflect the intent of the policy, and that PRM will only equal the 12 % or 9.89% reserve margin required above capacity needed to serve load.
To effectuate these guidelines to ensure compliance, SPP and the stakeholders developed Tariff language in Attachment AA that distributes deficiency payments by non-compliant LREs to other LREs in the region that are long on capacity. A non-compliant LRE has the ability under the proposal to remedy any deficiencies well ahead of the Summer Season.

**Q. EXPLAIN THE DEFICIENCY PAYMENT.**

**A.** As proposed, a LRE that does not satisfy the RAR prior to the start of the Summer Season shall subject its Market Participant to a deficiency payment. SPP shall determine the deficiency payment on an individual LRE basis which shall be assessed against the applicable Market Participant.

**Q. HOW DOES SPP DETERMINE THE AMOUNT OF THE DEFICIENCY PAYMENT TO ASSESS A DEFICIENT LOAD RESPONSIBLE ENTITY?**

**A.** The amount of the deficiency payment is based on the Cost of New Entry (“CONE”) for new natural gas peaking generation facilities to be constructed in the SPP region utilizing the factors listed in Attachment AA. The CONE value reflects appropriate costs and shall not include the anticipated net revenue from the sale of capacity, Energy or Ancillary Services (as defined in Attachment AE of the Tariff). The deficiency payment is determined by multiplying the amount of the LRE’s deficient capacity by the CONE value and then multiplied by a “CONE FACTOR.” The CONE FACTOR is determined using a sliding scale based on principles established in Attachment AA, and varies based on the amount of surplus capacity existing in the SPP region. The proposed deficiency
payment calculation is a reasonable means of incenting the LRE to procure sufficient 
resources to comply with the RAR.

Q.  PLEASE EXPLAIN THE PURPOSES OF THE COST OF NEW ENTRY 
CALCULATION THAT SPP WILL PERFORM.

A.  The CONE multiplier of the assurance mechanism discussed above provides increasing 
incentives to maintain required capacity that correlate with the potential for reduced 
reliability in the SPP Balancing Authority Area. The CONE multiplier mechanism also 
reflects the increased reliability value of capacity as PRMs diminish in the SPP region. 
The total deficiency payment made by an LRE for the annual Summer Season shall cover 
the annual capital and fixed operating costs as defined in the assurance mechanism.

Q.  WHAT CONE VALUE IS SPP REQUESTING?

A.  SPP proposes an initial CONE value of $85.61 per kilowatt year. The proposed CONE 
value was determined by SPP utilizing the most recent EIA report on Updated Capital 
Cost Estimates for Utility Scale Electricity Generation Plans based on natural gas peaking 
technology\(^{26}\) in 2013 dollars, which were inflation adjusted (1.72%) using data from the 
Bureau of Labor Statistics in order to convert EIA cost-data to 2015 dollars.\(^{27}\) SPP also 
utilized a set of assumptions as approved by the CMTF. The initial CONE value being 
proposed in this filing is contained in the Planning Reserve Assurance Policy white

\(^{26}\) See Exhibit No. SPP-5, Planning Reserve Assurance Policy whitepaper at 3.0(D).

\(^{27}\) Id. at 3.0(E).
As proposed, the CONE value is subject to Commission approval, will be reviewed annually by SPP, and any change to the value shall be filed for Commission approval.

Q. **EXPLAIN HOW DEFICIENCY PAYMENT REVENUES ARE DISTRIBUTED.**

A. The total revenues collected by SPP shall be distributed to those LREs and Generator Owners that have available capacity. Revenue distribution to these entities will reward LREs that will have the necessary resources to backfill the requirements of deficient LREs should a contingency arise. Similarly, Generator Owners that have deliverable capacity, and that choose to participate in the deliverability study, are eligible for potential revenue payments which may incentivize such Generator Owners to make capacity available to the process. Such Generator Owners may also be called upon to backfill reliability needs during contingencies when LREs are unable to fill the gaps. Hypothetical examples of how the deficiency payments are calculated and distributed are contained in the Planning Reserve Assurance Policy white paper and presentation given to the MOPC that are attached to SPP’s filing.

Q. **HOW WILL SPP PROTECT ITSELF FROM DISPUTES INVOLVING A LOAD RESPONSIBLE ENTITY AND THE MARKET PARTICIPANT?**

A. Attachment AA contains a limitation of liability that insulates SPP from disputes between Market Participants and LREs with regards to revenue distribution. Market Participants have the responsibility under Attachment AA to distribute revenues to their LREs.

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28 *Id.*
29 *Id.* at 3.0(F).
30 See Exhibit No. SPP-6 at pages 46-51.
proposed, SPP shall not be liable to an LRE for revenues collected and distributed pursuant to Attachment AA or for damages arising out of any act by the Market Participant. SPP’s performance is subject to the requirement contained in the Tariff that limits SPP liability except for cases of gross negligence or willful misconduct. SPP believes these provisions are consistent with the limitations of liability that SPP enjoys for other services it performs. In addition, all disputes shall be subject to the dispute resolution procedures of the Tariff which grants any entity the same process Transmission Customers utilize to resolve issues with SPP.

VIII. CONCLUSION

Q. DO YOU BELIEVE THE TARIFF REVISIONS PROPOSED BY SPP ARE JUST AND REASONABLE AND WHY?

A. Yes, I believe the Tariff revisions proposed in this filing are just and reasonable and are needed to meet SPP’s expressed reliability interests. The proposal has been thoroughly vetted by the stakeholder process. The resource adequacy rules, requirements, and accountability for non-compliance are all provided by Attachment AA in a transparent manner. The assurance methodology is one that penalizes those entities that do not satisfy the RAR, and rewards those with excess capacity that will need to make up all shortfalls in a contingency situation. Given all the interests of stakeholders, the proposal is a just and reasonable means to accomplish the intended purpose of ensuring sufficient capacity is secured and planned reserves are in place to meet the load obligations of the SPP Balancing Authority Area in the present and future.
Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.
AFFIDAVIT

STATE OF ARKANSAS    
COUNTY OF PULASKI    

I, Lanny D. Nickell, being duly sworn according to law, state under oath that the matters set forth in my Prepared Direct Testimony in this docket are true and correct to the best of my knowledge, information and belief.

Lanny D. Nickell

Subscribed and sworn to before me, a Notary Public, on this 3rd day of March, 2017.

Notary Public

My Commission Expires: 04.01.2018
Exhibit No. SPP-2
2014 SPP Strategic Plan

Developed by the

Southwest Power Pool, Inc.

Strategic Planning Committee

July 2014
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Purpose

The 2014 Strategic Plan establishes a strategic direction for SPP, positioning SPP to fulfill its Mission Statement over the next decade and beyond. The Plan recognizes that the future is uncertain and that depending upon circumstances, responses must be conditioned upon cooperation, industry knowledge, technology, and the interdependence of neighboring regions as well as other fuel resources for generation. This plan introduces a fourth foundational strategy, Reliability Assurance, as its bedrock. With Reliability Assurance as its basis, the plan revises the 2010’s three foundational strategies which are anchored in the Mission Statement and the five components of SPP’s Value Proposition to its members. The strategic initiatives related to each of the four interdependent Foundational strategies will position SPP for the future while balancing operational priorities and financial considerations.

Strategic Planning Process

With input from the members, the Market and Operations Policy Committee and its Working Groups, the Regional State Committee and Board members, the 2014 Strategic Plan was developed by first establishing a baseline for where SPP is today.

The Strategic Planning Committee then reviewed alternative visions of how the industry may change over the next decade. SPP has revised its strategic planning process to also include active engagement of the Board of Directors as a group. This enhanced approach recognizes that SPP and the strategy set by the Board covers not just the goals and activities of Staff, but also the activities of the stakeholders that are integral to the Plan’s success and effectiveness.

In the course of this process, some themes emerged that guided the development of this next strategic plan. The themes led to the development of four foundational strategies. The themes can be summarized as follows: Plans, Seams, Fuels, and Costs. Additional one-word themes embodied within the four noted in the previous sentence include: affordability, risk, security, exports, and funding.

The major focus is that SPP has and must remain focused on its core mission of reliable planning and operation of the grid. Ensuring that SPP’s capacity margins are adequate and that the grid is resilient is key. Keeping the lights on, today and in the future, also involves the continued reliable operation of our electricity marketplace and open access.

The next theme to emerge is that the Integrated Transmission planning process envisioned five years ago has delivered tangible results and should be re-evaluated and adjusted to accommodate the introduction of day-ahead and real-time markets, as well as other substantive events and changes. Another theme to emerge is that of optimization (both natural gas and transmission).

The portfolio of generating capacity in the region is undergoing a shift with the introduction of EPA Rules limiting coal production as well as the introduction of renewable energy resources (wind and solar) into the fleet. Accordingly, natural gas is becoming increasingly important as a fuel source, dictating an ever increasing need for reliability situational awareness of this emerging fuel source. Enhancing the transmission on the borders of SPP’s region is an increasingly important interdependency that is ripe for improvement.
Lastly, all of these fundamentals elements of our mission have economic implications for consumers and end-use customers. SPP must be mindful of a continued focus on affordability and communicating the value that the Organization provides. The four SPP foundational strategies and the Strategic Initiatives were developed to leverage SPP’s capabilities and operational processes to enhance member value; maintain an economical optimized transmission system; and to optimize interdependent systems, all while maintaining reliability assurance.

**Strategic Planning Committee members:**

- **Ricky Bittle, Committee Chair, VP, Arkansas Electric Cooperative Corporation**
- **Jim Eckelberger, Chairman, SPP Board of Directors**
- **Harry Skilton, Vice Chair, SPP Board of Directors**
- **Phyllis Bernard, SPP Board of Directors**
- **Les Evans, Sr. VP & COO, Kansas Electric Power Cooperatives, Inc.**
- **Robert Janssen, President, Dogwood Energy**
- **Venita McCellon-Allen, President and COO, AEP, Southwestern Electric Power Company**
- **Jake Langthorn, Director, Transmission Policy, Oklahoma Gas and Electric Company**
- **Jon Hansen, VP, Omaha Public Power District**
- **Michael Wise, VP, Transmission & Operations, Golden Spread Electric Cooperative**
- **William Grant, Manager, Transmission Control, Xcel Energy**
- **Michael Desselle, Staff Secretary, VP, Process Integrity, SPP**
OUR MISSION

Helping our members work together to keep the lights on ... today and in the future.

VALUE PROPOSITION

SPP’s five Value Propositions are the principles that have driven its history and frame its future. These principles are very familiar to SPP members, and they distinguish this organization from other regional organizations.

RELATIONSHIP-BASED

SPP dates to 1941 when 11 utilities across seven states pooled their generation resources to serve a critical defense plant in central Arkansas. After the war, the organization continued to exist. It grew to a peak membership of 78 entities without any legal recognition, until it incorporated in December of 1993. Until 1998, the membership agreement consisted of a single paragraph obligating members to abide by the organization’s bylaws. As in the past, relationships, rather than contracts, continue to keep this diverse organization together.

MEMBER-DRIVEN

SPP’s organizational structure of broad-based committees, working groups, and ad hoc task forces is the true source of SPP’s success. More than 360 people are involved in efforts driven by these groups. These groups’ rosters match the organization’s diverse membership, requiring participants from across the footprint and recognizing the various member types and sizes. These principles promote member ownership in the organization’s products, reduce interventions in regulatory proceedings, and continue to keep SPP’s staff size the smallest in the industry.

INDEPENDENCE THROUGH DIVERSITY

Since its inception, SPP’s membership has been one of the most diverse of any regional organization in the industry. With membership comprised of investor-owned utilities, independent power producers and independent transmission companies, municipal systems, generation and transmission cooperatives, state authorities, wholesale generators, and power marketers, any and all opinions are heard loudly and clearly in organizational group meetings.

As a member-driven organization, meaningful stakeholder involvement drives SPP’s efforts and effectively balances diverse opinions. Since 2004, this independence has been further enhanced with governance residing in an independent Board of Directors. When SPP was recognized as a Regional Transmission Organization, the SPP Regional State Committee was formed giving not only customers, but state regulators a formal voice in SPP’s decisions as well.
RELIABILITY & ECONOMIC/EQUITY ISSUES INSEPARABLE

In 1968, SPP took on the responsibility of serving as a regional reliability council under what became the North American Electric Reliability Corporation. The Federal Energy Regulatory Commission approved SPP as a Regional Transmission Organization in 2004 and a Regional Entity in 2007. As a Regional Transmission Organization, SPP provides transmission planning, tariff administration, reliability coordination, and wholesale market services to our members in an efficient and cost-effective manner. As a Regional Entity, SPP enforces reliability standards for our members and other users, owners, and operators of the bulk electric system in the SPP region. SPP members have long maintained that electric reliability issues cannot be debated in the absence of economic/equity issues.

History has shown that attempts to separate reliability and economic/equity issues result in the same people meeting in different venues with confusion over which organization should attempt to resolve problems. A single organization providing both Regional Transmission Organization and Regional Entity services results in greater cost-effectiveness and organizational efficiency for SPP’s members.

EVOLUTION, NOT REVOLUTION

SPP’s original purpose was to pool power to support the war effort. In the decades since then, SPP’s mission and our members’ needs have changed. Reliability remains SPP’s preeminent focus; however, a deliberate evolutionary process has guided the growth in services delivered by the organization, resulting in a carefully staged continuous improvement.
SOUTHWEST POWER POOL — JUNE 2014

SPP administers reliability coordination, wholesale markets and transmission services for the benefit of all electric utility operations in the region SPP serves, using members’ transmission systems. As a Regional Transmission Organization, SPP is mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and a competitive wholesale electricity marketplace. Regional Transmission Organizations are like “air-traffic controllers” of the electric power grid. They do not own the power grid, but independently operate the grid minute-by-minute to ensure reliable delivery of power to end users. SPP also serves as a Regional Entity of the North American Electric Reliability Corporation.

MEMBERSHIP

SPP’s 76 diverse members serve over 15 million customers across nine states.

- Investor Owned: 14
- Cooperatives: 13
- Marketers: 12
- Municipal: 11
- IPPs/Wholesale Gen: 11
- ITCs: 10
- State Agencies: 5

GENERATING CAPACITY BY FUEL MIX

Current SPP Generating Capacity by Fuel Mix

- Gas/Oil: 42%
- Coal: 34%
- Dual Fuel: 4%
- Hydro: 5%
- Wind: 10%
- Nuclear: 3%
- Other: 2%

370,000 square miles
48,930 miles of transmission lines
4,103 substations
627 generating plants
2013 Peak Load: 46,362
Generating Capacity: 77,366 megawatts

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**Primary Services Provided to Members and Customers**

**Reliability Coordination:** SPP monitors power flow throughout our footprint, takes action to manage congestion, and in emergency situations coordinates regional response.

**Tariff Administration:** SPP provides “one-stop shopping” for use of the region’s transmission lines and independently administers an Open Access Transmission Tariff with consistent rates and terms. SPP processes more than 10,422 transmission service requests per month; 2013 transmission service transactions totaled $1.29 billion.

**Compliance:** SPP has functionally separated its compliance model in order to continue to provide value to its members in an efficient and cost effective manner. The SPP Regional Entity as a delegated representative of the North American Electric Reliability Corporation enforces compliance with federal and regional reliability standards for users, owners, and operators of the region’s bulk power grid. Separately, the SPP Regional Transmission Organization has undertaken measures to promote reliability excellence to the entire SPP footprint through reliability forums, advice, and other guidance to SPP members and Registered Entities. The Organization also supports an internal culture of compliance through ethics and compliance awareness training.

**Transmission Expansion:** SPP’s planning processes seek to identify system limitations, develop transmission upgrade plans, and track project progress to ensure timely completion of system improvements.

**Market Operations:** The Integrated Marketplace launched in 2014 and replaced the existing Energy Imbalance Service market. It includes a 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. It is expected to yield its more than 115 participants up to $100 million in annual net savings by allowing load serving participants to use the least expensive available energy in the SPP footprint regardless of ownership while maintaining the reliability of the transmission system. It also allows generation owning participants another avenue to sell their energy.

**Regional Scheduling:** SPP ensures the amount of power sent is matched with power received.

**Facilitation:** The foundation of SPP’s independent stakeholder process is collaboration. SPP Staff facilitates and fosters collaboration by helping our members work together by actively organizing meetings, developing straw proposals, and administering organizational decision making processes. The SPP staff facilitates organizational continuous improvement and efficiency efforts as well as the accomplishment of strategic goals.

**Training:** SPP offers continuing education for operations personnel at SPP and throughout the region. SPP’s 2013 training program awarded 25,336 hours of continuing education to more than 900 operators from 27 member organizations.
Our Vision of the Future

Our vision for 2020 and beyond drives our strategies for this Strategic Plan covering the next five years. As the vision materializes over the coming years, the strategies and initiatives will evolve.

Our SPP 2020 crystal ball reveals the energy industry is still in a period of dynamic transformation. There are many factors at work which may significantly alter the structure of the industry and will drive the future requirements for transmission capacity. The pace at which “game-changer” technologies develop and are adopted has the potential to accelerate changes to the current environment. Change in public policy relative to carbon emissions, U.S. energy independence, and economic recovery may change the economics and mix of generation capacity and use. We considered several of the evolving factors affecting demand, resources, and transmission requirements of SPP and its members in the development of our Strategic Initiatives. The Plan envisions change; change we cannot define today. To continue to promote reliability excellence and meet the needs of our members in the footprint, the Plan is intentionally flexible providing for the investment in assets that allow both the market and regulation to serve the end users across the footprint in the most effective manner.

Demand Growth

It is forecasted that the demand for electricity in the United States will grow at an average rate of 1.23 percent annually for the next decade, with growth for the SPP region averaging 0.89 percent annually*. This forecast, however, is subject to a number of factors. SPP has also experienced pockets of significant increases in demand (northern Oklahoma, southwestern Kansas, Texas, and New Mexico) caused by the recent and sudden growth of oil and natural gas drilling and transportation industries. Significant increases or decreases in any of these factors could cause the aggregate demand to either increase or decrease substantially. We fully expect that the economic cycles and the energy market pricing fluctuations will produce wide swings in overall demand from year to year.

SPP’s planning processes have identified a number of transmission projects needed for reliability purposes, and it is expected that those projects will be completed as scheduled or mitigation plans will be developed. The most significant transmission challenges facing portions of the SPP footprint are related to an increase in oil and gas drilling. New oil and gas drilling facilities are built faster than they can be captured in SPP’s planning processes and models. Additionally, pipeline expansions are proposed for the region that will increase the need for electric transmission facilities to serve the pumping stations.
Continued annual growth in Energy Efficiency and conservation and DR programs is expected through 2023; however, the overall impact of these programs is relatively small. DR programs in the SPP RE footprint are voluntary and are primarily targeted for summer peak load reduction use. For the most part, SPP RE members include their own DR and Energy Efficiency programs as reductions in their load forecasts. The utilization of DR resources is not vital to meeting the energy and capacity obligations of the SPP Region.

*(NERC 2013 Long-Term Reliability Assessment 2014-2023)*

**ENERGY GENERATION RESOURCES**

One of the key strategic issues facing SPP and its members is the evolution from our current power generation mix to the generating capacity mix in 2020 and beyond. There are many competing factors that will impact the economics, availability, viability, and acceptability of various solutions. SPP needs to stay informed about continuing developments and engineer maximum flexibility and adaptability into its future plans. SPP also continues to have an influx of variable generation resources, leading to operational challenges. However, SPP is enhancing planning processes to better capture the impacts of the oil and gas projects and variable generation. Given the Region’s generation capacity, transmission infrastructure, and enhancements being made to processes and models, SPP is expected to be able to meet any challenges — including environmental regulations—that may arise during the next decade.

**Renewable Resources** — SPP has access to some of the best wind and solar resources in the United States. This and a combination of public policy, decreasing cost, hedging value, environmental concerns, and the possible long-term depletion of fossil fuels are forces driving the increased usage of renewable resources. New construction of renewable power generation facilities will require the expansion of transmission capacities and the development of new tools and capabilities, such as enhanced forecasting and the need for backup generation requires balancing capabilities to reliably integrate renewables into the existing transmission system, particularly in the case of intermittently available resources. SPP’s increase in installed variable generation, which is composed almost entirely of wind generation, will continue to cause operational challenges. These challenges arise because local area transmission congestion can occur as transmission projects are constructed and interconnected prior to completion of the planned transmission upgrades. In addition, SPP’s reliability-focused studies are based on deterministic criteria and do not necessarily capture wind-generation outlet constraints given limited power-flow models and current assumptions about reduced wind output. The SPP RTO Consolidated BA will provide balancing benefits for the widespread installed wind generation. Impending unit retirements are not expected to impact reliability outside of the local area. SPP RE has sufficient capacity and is expected to continue to be sufficient despite resource retirements.

**Energy Storage** — The continued evolution of energy storage technologies or reutilization techniques is expected to complement the growth of renewable generation by enhancing its reliability and improving its cost effectiveness.

**Carbon Policy** — Future federal legislative initiatives restricting carbon emissions and its attendant pricing policy, will most likely impact the economics of coal, and perhaps natural gas,
as a base load energy generating resource. Additionally, environmental regulations promulgated will have cumulative impacts on the economics of coal as a generating resource. SPP’s Operational Planning group performs bi-annual system planning studies in order to capture potential reliability impacts of retirements and retrofits. Analysis results that reveal reliability concerns are then passed to the SPP RTO long-term planning group. This study process consists of the creation of weekly snapshots — through the next four years — that take into account load forecasts, known transmission, and known generation outages. Local issues are reported to the SPP Transmission Operators involved. Since SPP has sufficient capacity, the impacts of long-term maintenance outages are expected to be more economic in nature.

**Solar** – Solar energy panels may experience significant improvements in efficiency and effectiveness due to exponential improvements in nanotechnology that will advance the commercial viability of solar power. Initially, this would result in the emergence of large solar fields and, over time, could spark a significant growth in distributed generation.

**Nuclear Power** – There could be a major shift in the increased support for expansion of nuclear power generation. It is possible that smaller, distributed nuclear plants could become more viable in the future.

**Fuel Cells** – Fuel cells, powered by natural gas or biomass have the potential to be new efficient sources of energy. They also have the potential to be effective distributed generation sources.

**Shale and Tight Sandstone Gas** – Technology breakthroughs in shale and Tight Sandstone gas production are allowing producers to tap huge resources that were previously uneconomic. Shale gas could have an important role as the industry moves to lower CO2 fuels, renewable energy sources. Gas produces lower CO2 emissions than coal and oil, but it still is a carbon emitting fossil fuel.

**Coal Gasification** – The prospect exists for continued advancement of coal gasification technology that will prolong the usage of coal as a viable alternative from an economic and a carbon-emission perspective.

**Water Availability** – Drought in portions of the SPP footprint is not uncommon and may affect power generation as decreasing water levels will contribute to the risk of generation availability.

**Strategic Expansion of SPP Membership** – Expansion of the SPP footprint may serve to offset some of the negative impacts of environmental policies by increasing the diversity of generating resources in the region. Geographic additions represent outstanding future opportunities but the challenge will be to maintain the value/equity relationships into the future.

**TRANSMISSION**

The electric transmission grid must evolve as generation capacity grows and the generation mix changes. The transmission system must be engineered for reliable and efficient operations, meeting both current and anticipated needs. SPP’s planning processes have identified a number of transmission projects needed for reliability purposes, and it is expected that those projects will be completed as scheduled or mitigation plans will be developed. The most significant transmission challenges facing portions of the SPP footprint are related to an increase in oil and
gas drilling and environmental policies restricting carbon emissions. New oil and gas drilling facilities are built faster than they can be captured in SPP’s planning processes and models. The cumulative effect of environmental regulations on generating capacity may significantly shift the planning for future transmission facilities. Factors impacting the operation and build-out of the future transmission system include at least the following:

**Expansion of Renewable Resources** – Many of the sources of green, renewable energy will be located in areas not now connected to the existing grid or the capacities will need to be greatly expanded. The development of these generation resources will spur development of the transmission system, tools, and operating structures, to help reliably integrate significant amounts of renewable resources.

**Interregional Planning Coordination** – The introduction of renewables, clean coal, revamped nuclear and distributed generating resources into the mix of traditional generating resources will require greater interregional perspective, planning, cooperation, and coordination.

**Market Development** – To extend and expand the benefits of utilizing the most efficient, effective, and reliable resources across the region for electric energy products, in the midst of a changing marketplace, the future will require more robust market capabilities. To fully optimize Independent System Operator/Regional Transmission Organization markets, regional grid operators will need to develop better mechanisms to extend benefits across the seams between market areas.

**Smart Grid** – Advanced technologies will be available in the future to both support robust grid operations and to help end-use customers make more informed decisions about their energy use and even providing energy to the grid.

**Land Acquisition Restrictions** – Land acquisition and “right of way” issues will likely continue to become more complex and time-consuming. This may be a limiting factor in the ability to adjust the transmission system in a dynamic manner as dictated by the rapidly changing generation and regulatory landscape.

**Reliability Standards** – Reliability standards are likely to grow in complexity and will require the ability to deal with multiple simultaneous contingencies. Zero tolerance and immediate remediation will become the expected norm.
SPP’S FOUR FOUNDATIONAL STRATEGIES

The Strategic Planning Committee identified four foundational strategies to create the capabilities and operational processes needed to fulfill SPP’s Mission and maintain or improve its Value Propositions in the face of a rapidly changing environment. These four strategies are interdependent with Reliability Assurance as the basis and the enhancement of member value and affordability as the discipline to drive all SPP strategies.

The foundational strategies are long-term, fundamental components of the SPP business model. This plan focuses on four broad Strategies to be continued, initiated, and/or completed over the next 10 years. The identified Initiatives become the tactical implementation of our strategies. These Initiatives are longer-term and strategic in nature but are likely to change over time as the baseline for SPP operations changes and as future changes require new initiatives to improve value and competitiveness. The key is planning ahead in order to flexibly adapt to a rapidly changing environment. We will be ready to take full advantage of future opportunities and respond to future constraints, to advantage of the end users in our footprint.

The strategic initiatives are also prioritized by categories A, B or C. Category A represents initiatives that are budgeted for which resources are committed and unbudgeted resources may be committed to achieve. Category B represents budgeted initiatives for which resources are committed to achieve within budget limits. Finally, Category C represents budgeted initiatives for which resources are committed to achieve, but may be taken from to achieve Priority A or B initiatives.

FOUNDATIONAL STRATEGIES

- Optimize Interdependent Systems
- Enrich Member Value and Affordability
- Reliability Assurance
- Maintain an Economical, Optimized Transmission System
**RELIABILITY ASSURANCE**

Reliability is the bedrock of SPP’s business. During the planning horizon, SPP may begin to experience a shift toward greater reliance on variable energy resources while during the same time consumers may begin shifting to less predictable load patterns from the use of their own intermittent technologies, like distributed generation, price-responsive demand, and energy efficiency.

In order to continue to meet high levels of reliability, protocols need to be developed to ensure capacity margins are maintained and enforced. Understanding and integrating emerging categories of distributed energy resources technologies will shift how SPP plans and operates the system. Understanding the reliability implications of environmental policies and rules is increasingly important. SPP should take the evolutionary step to be in the position to opine from a reliability perspective such impacts and to understand the market implications associated with member resource plans. SPP is also investigating centralizing the data gathering from several Phase Monitoring Units (PMU) systems within the footprint to enhance reliability analysis and situational awareness.

At this time, SPP and its members are in the early stages of investigating appropriate smart grid programs. The ongoing evaluation of cyber and physical threats require SPP to continually reassess and upgrade defenses and risk management capabilities. SPP should continue to prevent such threats and improve its resilience and recovery.

**MAINTAIN AN ECONOMICAL, OPTIMIZED TRANSMISSION SYSTEM**

The 2010 SPP Plan focused on the build out of a “robust” transmission system which was described as one containing an optimal mix of “highways” (300 kV+) and byways (below 300 kV) and minimizes future transmission constraints without over-investing in transmission capacity. A robust system creates immense new value for SPP members and end users in the SPP region.

In 2012, SPP members completed 111 transmission projects totaling more than $1 billion. The SPP Board has authorized Notices to Construct roughly $8 billion of transmission grid upgrades. This represents the culmination of efforts begun seven years ago to get transmission built in SPP’s footprint.

Additionally, in 2010, the Integrated Transmission Planning Process was just beginning and since its inception, 2 ITP-20 studies, 3 ITP-NT studies, 1 ITP-10 study and 1 ITP Special study (HPILS) have been performed. Subsequently, the FERC issued its Order 1000,
which fundamentally changes SPP’s planning process by introducing competition to build the transmission facilities resulting from SPP’s studies.

SPP and its members have also been reforming the Aggregate Planning and other transmission service processes. With all these changes, including the introduction of the Integrated marketplace, the strategy is to check our planning processes and consider holistically adjusting them.

Additionally, with the continued changes in the generation portfolio within the SPP footprint and North America, consideration should be given to export pricing mechanisms. Because of SPP’s geographic location in the Eastern Interconnection and ties with the Western Interconnection and ERCOT, SPP is uniquely situated to play a key role in the strategic processes necessary to identify critical corridors via rightsizing key lines during rebuilds, reconfiguring grid topology, and potential converting select lines from AC to DC operation to manage congestion and improve overall grid efficiency across North America.

**Enhance and Optimize Interdependent Systems**

SPP implemented its Integrated Marketplace (Marketplace) on March 1, 2014. This centralized unit commitment across 16 former BA Areas that have consolidated operations into a single BA — known as the SPP RTO BA. The Marketplace is a five-minute, security-constrained economic dispatch in order to provide Real-time balancing activities, while also providing centralized commitment of resources through the end of the operating horizon.

Additional enhancements (including member-driven as well as FERC-directed) are also being made. With the evolving resource mix and climate change, increased coordination between natural gas and power industry with regard to data and information sharing can improve SPP’s situational awareness to deal with extreme load conditions and the risk pipeline curtailment potential. This can also facilitate more economically efficient centralized dispatch.

If the Members are required to move toward more utilization of natural gas as a generation fuel, it will be necessary to coordinate with the natural gas industry to facilitate additional gas transmission pipelines and developing the operating flexibility that will allow the generators to follow load.

Additional value can be derived by optimizing transmission on the boundary seams of the region. This will be a comprehensive effort to focus on inter-regional agreements to plan, allocate cost, optimize usage and provide for fair compensation for the use of transmission across boundaries.
ENHANCE MEMBER VALUE AND AFFORDABILITY

SPP continually strives to improve the value it delivers to its members. In addition to the Strategic Initiatives noted above, SPP will create and continually improve work processes to ensure they are efficient and effective.

SPP recognizes the importance of prioritization of strategic initiatives. SPP will continue to work with its members through the Markets and Operation Policy Committee to share the costs and benefits of member-facing project initiatives and quarterly provide visibility of the entire portfolio.

SPP will further develop processes and a communication strategy to demonstrate to members, regulators, and customers the general inter-zonal equity of costs and benefits for strategic initiatives.
FOUNDATIONAL STRATEGIES AND RELATED STRATEGIC INITIATIVES DESCRIPTIONS

RELIABILITY ASSURANCE

We all depend on a reliable electric grid to power our homes and businesses. Reliability is the bedrock of SPP’s mission of helping our members work together to keep the lights on — today and in the future. National concerns and initiatives are changing the traditional paradigm. The nation is seeking to be more energy independent, economically prosperous, and environmentally conscious. These initiatives are enabled by a robust transmission infrastructure and the understanding of a regional resource plan. Resource adequacy is a fundamental component necessary to determine that future peak demands can be accommodated on a reliable basis. SPP will continue to anticipate and respond rapidly to changes that are directed toward understanding and ensuring resource adequacy with enforceable capacity margins, resource planning, and integration of variable energy resources and grid resilience.

CAPACITY MARGIN REFINEMENT (PRIORITY A)

Resource adequacy will become an increasingly important component of SPP’s responsibility as the Balancing Authority. Having a situational awareness as well as the ability to enforce adequacy through capacity margin requirements and other mechanisms are tools to accomplish this. The MOPC has already begun an effort to assess this important issue and completion of that effort is a high priority.

REGIONAL RESOURCE NEED AND VALUE ASSESSMENT (PRIORITY B)

SPP’s active coordination and understanding of its members’ resource plans will provide state and regional insight. This is not the typical Integrated Resource planning, but coordination through a formulaic approach that will provide SPP the necessary overview of resource adequacy and other reliability concerns. This coordination would occur with the members and the Regional State Committee to provide assessments. These assessments are needed to also better inform the transmission planning process because major changes in the generation fleet in SPP’s footprint will have major changes to the transmission that is planned and constructed in SPP.

RELIABILITY ASSESSMENTS OF ENVIRONMENTAL RULES (PRIORITY A)

The EPA has issued Rules that will impact the generation fleet in North America and the impact of these Rules on the SPP region have consequences that need to be understood from a reliability perspective. The state-by-state and regional remedies to comply with the EPA’s Rules will also impact the security constrained economic dispatch that SPP performs on behalf of its members. Understanding the regional resource needs will provide the necessary insight for SPP to accommodate these changes. The fuel mix needed to run the fleet of generation in SPP’s footprint needs to be understood by SPP in order to reliably operate the system in the most
effective manner. As policy changes are mandated dependency on single fuel sources creates a reliability risk that requires better situational awareness from an operation standpoint. SPP needs to assess the separate and cumulative regional reliability and market impacts associated with EPA’s Rules. Completion of this effort is a high priority.

**INTEGRATION OF VARIABLE ENERGY RESOURCES (PRIORITY C)**

With growth of variable energy resources (e.g., wind and solar) in SPP and its greater responsibility as the Consolidated balancing authority comes the challenge of maintaining system frequency using these units within their standard limits. Operators will face more challenges in real-time to integrate these variable energy resources and will need tools and process to manage the balance between supply and demand in cost effective and reliable ways. Understanding and integrating distributed energy technology and resources also represents a shift in how SPP will plan and operate the grid. Lastly, new transmission technologies like synchrophasers and advanced line switching may impact the way the grid is managed. Having the ability to take advantage of such technology, where cost-effective, will be needed.

**GRID RESILIENCY – CYBER AND PHYSICAL (PRIORITY B)**

Cyber threats continue to be a risk for the industry requiring constant vigilance, risk assessment and rapid ability to be able to recover from such instances. Ongoing standardization and new security initiatives are only a part of what SPP needs to be engaged in in order to prevent such incidences. SPP also needs to work with its members and others to develop the tools, skills, and processes to be able to rapidly recover from cyber and physical incidences. New standardization efforts have also been focused on physical protection for critical infrastructure that place ISOs/RTOs in the position of independent certification on behalf of their members.

**RELIABILITY EXCELLENCE (B)**

SPP is committed to promoting excellence in reliability for the organization, its members, and its registered entities. Working together with the SPP Regional Entity, an independent and functionally separate division within SPP, SPP will continue to promote and work to improve bulk power system (BPS) reliability. The SPP Regional Entity oversees regional reliability standard development; monitors and enforces registered entities’ compliance with reliability standards; and assesses and evaluates BPS reliability. SPP will accomplish these goals through reliability forums, lessons learned, advice, and other guidance intended to train, educate, and assist. SPP further promotes reliability excellence by providing leadership in national forums that are focusing on improving the language and focus of national reliability standards. The goal of reliability excellence is the continuous achievement of zero-defect compliance to NERC and regional reliability standards in the most cost-effective manner possible. The SPP RE has identified two particular areas of focus to highlight in the plan: Relay Misoperations Improvement and Event Analysis.

**RELAY MISOPERATIONS IMPROVEMENT (PRIORITY B)**

NERC has identified protection-system misoperations as one of the greatest risks to Bulk Electric System reliability. The SPP RE and RTO have been tracking misoperations in the SPP footprint for several years. The data indicates that communication failures are a leading cause
of regional misoperations; this characteristic is not unique to the SPP footprint. SPP’s technical organizational groups should continue their misoperations research and analysis to increase the success rate of regional operations. This is an ongoing effort.

**Event Analysis (Priority B)**

In 2010, NERC formalized an Event Analysis process that classifies system events in categories from 1 (least severe) to 5 (most severe). Analysis of system events, regardless of their severity, leads to improved operations through the discovery of lessons learned and trends that can be shared continent-wide. Analyzing even minor events will generally lead to corrective actions that could prevent other, more serious events from escalating. SPP established the regional Event Analysis Working Group in 2011 to foster the analysis of events in the footprint. SPP RE works with impacted entities and NERC following events to determine categorization and root causes, and to develop lessons learned as appropriate. The SPP RE and RTO encourage a proactive review of all system events to continue to improve BES reliability. This is an ongoing effort.

**Maintain an Economical, Optimized Transmission System**

In the 2010 Strategic Plan, SPP has just begun the implementation of its Integrated Transmission Plan. Evolution of the process has occurred and this Plan addresses the opportunity to evaluate where the process stands and make enhancements to the process to accommodate policy changes directed by the FERC and other events like the implementation of the Integrated Marketplace. Lastly, the abundance of Variable Energy Resources in SPP’s footprint presents a strategic opportunity for SPP and its Members.

**Integrated Transmission Planning Check and Adjust (Priority B)**

The continued growth of SPP’s transmission system and markets as well as the challenges and opportunities presented by changing federal and state energy and environmental regulations, growing NERC compliance requirements, and the potential for efficiencies in SPP’s generation interconnection process, aggregate transmission service study process, demand the adoption and implementation of more progressive, forward-thinking, regional planning processes. Planning engineers should continue to assess the metrics used to evaluate proposed projects; continue to evaluate planning the transmission system beyond the traditional planning criteria of first contingency (“N-1”); anticipate the transmission asset life-cycle curve impacts; take into consideration the changes resulting from the implementation of the transmission congestion rights market as part of the Marketplace; implement and improve technical skills necessary to develop transmission project costs; incorporate the Aggregate Generation (AG) and Generator Interconnect (GI) queue components holistically into the process; and begin utilizing the data collected by operators to better plan the transmission system to meet operational contingencies.

While SPP facilitates the future development of a robust electric transmission infrastructure that will enable the maximum use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint, it should continue to develop and enhance policies, tools, and practices to optimize the use of the existing transmission system. This will involve
SPP and its stakeholders taking a fresh look in a consolidated, coordinated manner at how the existing system is managed, maintained, and could be improved, with a particular emphasis on any progress that could be made toward making additional transmission service available to SPP’s customers on the existing system without unduly compromising system reliability.

**Cost Controls on Competitive Transmission (Priority A)**

SPP in response to FERC’s Order 1000 has created a competitive solicitation process to award Notices to Construct to entities that have been qualified to build and maintain transmission facilities. The process contemplates an independent review of proposals submitted in response to Requests for Proposals. Cost is just one factor that must be considered. Bids estimates are required to be submitted not to exceed plus or minus 20 percent; however, controls will need to be developed to ensure that facilities awarded to be built will not exceed the bandwidth of accepted costs.

**Flexibility to Address Policy Initiatives (Priority B)**

The Integrated Transmission Planning Process needs to be able to anticipate and be able to respond to policy initiatives promulgated at the Federal, State, and local levels. As just one example, the cumulative effect of environmental regulations on generating capacity may significantly shift the planning for future transmission facilities. Other policy driven changes such as increases in distributed generation and the expansion of renewable portfolio standards can impact transmission. Non-policy driven initiatives can also impact the way transmission is planned. The planning process needs to flexible enough to react expeditiously to observations and signposts that been anticipated as potential scenarios.

**Value Pricing: Import/Export Strategy; and, Cost Allocation (Priority B)**

SPP’s Highway/Byway cost allocation process was not intended to fairly recover the cost of transmission built and used solely to export renewable resources to markets outside of SPP. The abundance of variable energy resources in portions of SPP’s footprint represents a strategic opportunity for SPP and its members to capitalize on the ability to export this resource for profit. Further, there could be policy driven circumstances that would necessitate the importation of energy from other markets or regions into the Southwest Power Pool that the current cost allocation methodology was not intended to facilitate. Stakeholders should develop proposals to develop, build, and allocate costs and benefits of transmission necessary to accomplish this strategic initiative.

**Fair and Equitable Cost/Benefit Allocation Policies (Priority A)**

It is the goal of SPP and its members for the development of a regional transmission system to provide a balance of cost and benefits among members. In order to accomplish this goal, a Task Force effort has been underway for three years now to “review the reasonableness” of the regional and zonal allocation methodology associated with the impacts of the Base Plan Upgrades with NTCs issued after June 19, 2010 to each pricing zone within the SPP Region.” The Task Force is evaluating allocation of transmission costs that could leave some member’s benefits below a reasonable threshold thereby creating an inequitable impact. The Task Force working with the Regional State Committee is to determine possible long-term solutions that
may include, but are not limited to, adjustments to the Highway/Byway, transfer payments, approval of projects in specific zones, or other options. Completion of this effort is a high priority.

**ENHANCE AND OPTIMIZE INTERDEPENDENT SYSTEMS**

This plan recognizes as both a threat and an opportunity the interdependency of its mission with other organizations and industries; specifically, transmission on the seams of SPP’s region and the natural gas industry.

**TRANSMISSION (SEAMS) (PRIORITY A)**

As SPP develops and produces regional plans it is identifying transmission projects that could provide opportunities to realize benefits across SPP’s regional boundaries. SPP must work to foster cooperative and joint transmission projects with its neighboring systems to support broader inter-regional planning. Progressive development will prevent inter-regional optimization from being the next limiting factor to SPP’s progress. SPP, working with the Seams Steering Committee, will work to improve Seams Agreements to not only improve operational coordination, but also address inter-regional planning and transmission cost allocation. The objective is to identify specific projects across seams and work with neighbors on how to plan and build with equitable cost allocation and recovery methods. SPP must embark on a comprehensive effort to enhance its transmission processes that would identify and develop projects that can be built on the seams of the region. This would include working with regulators and state governments to educate that it is most economic for the region to build transmission, not just for today but for the longer term. This comprehensive effort would include; how to plan, estimate, and allocate costs; use, compensate, and interregionally optimize such facilities. Completion of this effort is a high priority.

**OPTIMIZE MARKET EFFICIENCIES ALONG SEAMS (PRIORITY A)**

The Integrated Marketplace launched in 2014 and replaced the existing Energy Imbalance Service market. It includes a Day-Ahead Market with Transmission Congestion Rights, a Reliability Unit Commitment process, a Real-Time Balancing Market. Now that the Marketplace is functioning, completion and finalization of market-to-market provisions amongst our neighbors is paramount. SPP needs to begin to think about how utilize the existing and committed transmission to take advantage of generating resources on both sides of the seams.

**OPTIMIZE NATURAL GAS PIPELINE SYSTEM SEAMS (PRIORITY A)**

SPP has actively worked toward improving its coordination with natural gas interstate and intrastate pipelines within its footprint since the formation of the Gas Electric Coordination Task Force (GECTF) in early 2013. During its first year, the task force focused on building relationships between SPP’s and pipelines’ operations staff, developing SPP’s understanding of the pipeline connections with power plants in SPP, and responding to FERC’s inquiries regarding SPP’s gas and electric coordination activities. Following the adverse weather conditions of the 2013-2014 winter and FERC’s issuance of various Notice of Proposed Rulemakings (NOPR’s) and Orders, the task force has focused on gas and electric scheduling “harmonization” activities
and coordinating with other working groups to develop appropriate SPP protocol and tariff changes to reduce the “seams” scheduling and operating barriers to increased reliability and availability of gas-fired generating units within the SPP system during adverse winter weather conditions. As a result of SPP’s successful outreach to the pipelines, representatives of several such pipelines routinely participate in the GECTF’s meetings and contribute to the task force’s discussions.

Increased coordination between natural gas fuel pipelines and the power industry in operations and short and medium term planning, with regard to data, information and scheduling, can improve SPP’s situational awareness and fuel supply reliability of gas-fired plants in the SPP footprint. In operations, improved coordination can enhance real-time operational decision- making regarding gas curtailments during abnormal load and weather conditions, improve real-time economic dispatch decisions, and increase fuel supply reliability by committing natural gas-fired generating units multiple days in advance of adverse winter weather conditions, when pipelines are most constrained. SPP should continue to improve coordination and information sharing with the natural gas pipelines in its footprint for the purpose of reducing barriers to increased reliability, which may include entering into comprehensive agreements with pipeline providers and member companies to provide real-time supply visibility to SPP operations.

A FERC NOPR and an accompanying order appear likely to require changes in the timing of the start of the natural gas “day” and the corresponding daily and intraday nominations cycles. A companion FERC order also requires RTO’s, such as SPP, to either change their Day Ahead and intraday generation commitment timing to be consistent with changes to the gas day timing, or to explain why such changes are not needed. During the next few years, SPP and its members will need to be prepared to either defend the current timing of SPP’s Integrated Marketplace Day Ahead and Reliability Unit Commitments, or expend the time, effort, and funds to change the timing of such generation commitments to more appropriately match changes that FERC may order in the timing of the natural gas nomination cycles.

**OPTIMIZE DATA SEAMS (PRIORITY C)**

SPP systems and processes rely on a multitude and numerous exchanges of data internal to SPP, with our members and customers, as well as with external parties. These data exchanges were designed to meet the requirements of the systems and processes as they evolved to the present. These data seams might be either limiting the efficiency of SPP, or its members and customers, or even need to be changed or enhanced to more effectively and efficiently meet the present functions of SPP as well as to prepare SPP and its members for the future challenges in the electric industry. This effort would need to be coordinated with any system or process change in SPP as well as the strategic effort to improve the seams between SPP and other electric industry participants and with other seams mentioned in this foundational strategy.

**INTEGRATED MARKETPLACE ENHANCEMENTS (PRIORITY B)**

SPP has underway a project effort to deliver essential incremental capabilities to the Integrated Marketplace for delivery during 2015. Project Pinnacle is comprised of seven projects that were either FERC-mandated or member-driven and were Board-approved for completion, including: Pseudo Tie-Out, Long-Term Congestion Rights (LTCR), Regulation Compensation (RegComp), Market to Market (M2M), Enhanced Combined Cycle (ECC), Phase II Environment Build-Out (EBO) and Live Track. Staff will continue to work with members to facilitate timely completion of these strategic market enhancements.
ENHANCE MEMBER VALUE AND AFFORDABILITY

COMMUNICATION STRATEGY ON VALUE/AFFORDABILITY (PRIORITY A)

SPP’s members are facing rising natural gas prices, increases in utility capital expenditure to upgrade the grid, increases in utility capital expenditures to comply with environmental regulations and liabilities associated with pension obligations. All these costs contribute to higher retail rates while (as noted earlier) demand is expected to stay relatively flat. SPP’s organizational costs, as well as the cost of new transmission, are additional costs that our members must incur and pass on to end-use consumers. The values associated with these costs are not well communicated. SPP needs to develop a comprehensive communication plan that articulates the value of its services provided to members. A component of this communication strategy should translate the value of SPP down to the typical end-user of an SPP member or load serving entity. Completion of this effort is a high priority.

FAIR AND EQUITABLE COST/BENEFIT ALLOCATION POLICIES (PRIORITY A)

As noted above, some member entities have been allocated transmission costs that leave them below a certain benefit threshold thereby creating, for them, an inequitable impact. A Task Force and Regional State Committee effort to determine possible solutions that may include, but are not limited to, adjustments to the Highway/Byway, transfer payments, approval of projects in specific zones, or other options is underway. Completion of this effort is a high priority.

PROJECT MANAGEMENT OFFICE BEST PRACTICES AND RIGOR (PRIORITY B)

All major SPP projects include cost/benefit studies as part of the investment justification process. SPP will perform impact assessments for major projects before authorizing them and then will employ PMO best practices to ensure costs are not exceeded and benefits are maintained. These best practices also ensure that project efforts are prioritized appropriately. Working with the membership and translating the value of project efforts as part of the communication plan described above.

SPP will continue its benchmarking and measurement processes for major investment projects. This will provide feedback on the assumptions made in the cost/benefit justifications by evaluating the actual experience compared to the projected benefits, the cost/benefit estimating process can be improved. Further, it will provide a baseline for evaluation of transmission upgrades, inter-zonal equity, and unintended consequences.

A key component of SPP’s ability to continue to create member value is the ability to continually improve the effectiveness and efficiency of all administrative, coordination, planning, and operational processes. Healthy organizations periodically review their processes and procedures to ensure that they are most effectively achieving their original business intent. This initiative targets both lowering operating costs and building more efficacious operating methods through objective review of SPP processes and procedures. SPP has adopted the LEAN process to help facilitate a corporate-wide effort. LEAN is a set of principles and tools used to create and deliver the most value from the customer’s perspective while consuming the fewest resources and fully utilizing the skills and knowledge of those who perform the work routinely. Staff will ensure continued penetration and expansion of this effort.
ENHANCED MARKET ANALYTICS (PRIORITY B)

Now that the Marketplace has been successfully launched, SPP is updating and enhancing its analytics of the market. Utilizing this data and information will assist in telling the story of the value SPP provides to the Membership.

STRATEGIC MEMBERSHIP EXPANSION AND IMPROVED STAKEHOLDER PROCESSES (PRIORITY A)

Another way to create member value is to expand SPP’s membership base to better leverage the aggregate economies of scale and minimize seams issues. As opportunities arise SPP will continue to strategically pursue expansion of its membership and geographic footprint to further leverage its capabilities and lower costs. SPP senior staff will follow a structured and transparent process under which the impact of adding prospective new members will be disclosed to existing stakeholders prior to agreements being finalized, as well as a transition process so that issues are identified and dealt with in working groups in which members will participate. Each new member integration will be unique, making it difficult to develop a standard integration process; however, SPP will develop an integration framework designed to minimize adverse impacts to existing members.

COMMUNICATION AND EDUCATION (PRIORITY C)

There are a large number of rapidly changing industry developments that could dramatically transform the future operating environment for SPP and its members. These developments are likely to be in the form of breakthrough technologies or major legislative initiatives coming from a wide range of sources. SPP and its members must stay informed of new developments to have as much lead time as possible to position for emerging issues.

SPP will continue its efforts to communicate with and educate various audiences about SPP’s initiatives and external issues potentially impacting the organization. In concert with the Regional State Committee and in conjunction with its members, SPP will visit the region’s federal/state regulatory and legislative constituencies to discuss issues of joint concern. Other audiences with which SPP needs to stay appropriately engaged include: members and stakeholders, the general public, other industry organizations, and the media.
Exhibit No. SPP-3
Deliverability Study

March 2016

SPP Staff
## Revision History

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<td>Version 0.0 February, 2015</td>
<td>Michael Odom</td>
<td>Initial Draft</td>
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<tr>
<td>Version 3.0 June, 2015</td>
<td>SPP Staff</td>
<td>Proposed new study concept</td>
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<tr>
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<td>SPP Staff</td>
<td>Modified study assumptions</td>
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<td>Version 6.0 August, 2015</td>
<td>SPP Staff</td>
<td>Provided options for reporting deliverability results</td>
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<td>SPP Staff</td>
<td>Updated language per Stakeholder feedback</td>
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Background and Introduction

Firm transmission service needed to deliver power from generation to load is currently required by SPP in order for that generating capacity to count toward meeting a load’s Planning Reserve Margin (PRM)\(^1\) requirement. Confirmed firm transmission service, whether for network or point-to-point service, will continue to be required, consistent with the existing SPP Criteria, in order for a Load Responsible Entity (LRE) to demonstrate firm transmission service necessary to count generating capacity toward serving load. Firm transmission service will continue to be necessary to acquire Auction Revenue Rights (ARRs). SPP is now developing an option to rely upon a pre-established determination of deliverability to allow the LRE to meet its PRM requirements in excess of its peak load, including losses, without requiring firm transmission service.

The approach described below will allow a LRE to rely on available transmission capacity, as demonstrated through performance of a deliverability study, for its PRM requirements, at least in short near-term timeframes, without sacrificing reliability. Although SPP’s existing processes may be used to obtain firm transmission service, this process is intended to provide an additional mechanism for demonstrating reliable access to transmission capacity needed to support the near-term needs an LRE might have to meet its PRM requirements consistent with the schedule of the Planning Reserve Assurance Policy.

\(^1\) SPP Criteria currently specifies a Capacity Margin of 12%, which equates to a 13.6% Planning Reserve Margin. Since it is expected that the Capacity Margin Task Force (CMTF) will recommend a terminology shift from the term “Capacity Margin” to “Planning Reserve Margin”, this paper reflects that shift. Throughout this document, the Planning Reserve Margin shall mean the difference in Total Capacity and Net Internal Demand, divided by Net Internal Demand.
Deliverability Study

Study Purpose
PRM is required to ensure resources are readily available in the situation of unexpected loss of generation or unexpected significant increase of demand. Annually, each LRE in SPP must report capacity committed to supply its load and PRM obligations. Under the existing SPP Criteria, firm transmission service is required for the delivery of capacity, including reserves, to meet each LRE’s peak load obligation. In the future, it is being proposed that the deliverability of capacity resources needed to meet only the required PRM, not the load itself, could be assured through either the acquisition of appropriate firm transmission service or by obtaining from generating facilities with capacity that is deemed to be deliverable to the load through the performance of a deliverability study. It is proposed that the deliverability study should take the form of analyzing all SPP Balancing Authority (BA) modeled generation to determine if the associated capacity is deliverable to the BA and not to specific load points, model areas, or zones.

Study Models
SPP staff and members develop planning models representing specific system conditions as part of the ITPNT process. SPP members request generator capability data from the appropriate Generation Owners (GO) for the resources in their modeling area and reflect the capability ratings in the planning models. Based on these specific system conditions, the models demonstrate expected transmission system flows under an SPP BA security constrained economic dispatch similar to the Integrated Marketplace dispatch. Transmission projects are developed through the ITPNT process to address thermal and voltage needs in each model. These planning models will be the base models for the deliverability analysis.

Analysis
The current-year summer ITPNT Consolidated Balancing Authority (CBA) planning model will be used to evaluate deliverability of each plant in the BA. The initial assumption is that any resource generating in the model is automatically deliverable to the SPP BA for the dispatched output since the model dispatches around constraints and sets the CBA dispatch amounts. Each modeled plant that was not committed or dispatched at its maximum output is then evaluated individually to determine that plant’s total deliverability. Each plant’s deliverability amount is the amount of MWs that is deliverable to the SPP BA from the studied plant. Of that deliverable amount, committed capacity, as determined by the GO, would be subtracted to determine the capacity that could be made available for purchase for PRM obligation (see Figure 1 below for an example).

A plant’s maximum output is the summation of the maximum output of all units at the same site. Each plant is studied to capture the maximum possible MW injection at the point of interconnection as opposed to an individual unit analysis that might only identify the MW deliverability of a plant’s largest unit. A transfer level equal to the difference between the facility/plant max capacity and the amount dispatched in the model is determined for each plant. The transfer will be analyzed as a generation to load transfer sinking into SPP BA so as the individual plant generation is increased, the SPP BA load uniformly increases. A First Contingency Incremental Transfer Capability (FCITC) analysis of each transfer will be performed to determine the deliverability of the resources. If the FCITC is equal to the transfer amount then the resource is fully deliverable to the SPP BA. SPP facilities 100 kV and above will be included in the FCITC analysis. Limits associated with invalid contingencies and Transmission Operating Guides (TOGs) will be excluded as constraints. A three percent transfer distribution factor threshold will be used to analyze constraints impacted by the transfer.
### Deliverability Study Result Examples:

Plant 2 is offline in the BA powerflow model and has a max capacity of 200 MW. An FCITC analysis showed that Plant 2 could deliver 200 MW without breaching a transmission constraint. Therefore, Plant 2 is 100% deliverable (200 MW) to the SPP BA region, and the GO and a LRE could contract capacity up to 100% (200 MW) of the Plant 2 maximum capacity (200 MW) amount.

Plant 5 is offline in the BA powerflow model and has a max capacity of 1348 MW. An FCITC analysis showed that Plant 5 could deliver 997.5 MW until breaching a transmission constraint. Therefore, Plant 5 is 74% deliverable (997.5 MW) to the SPP BA region, and the GO and a LRE could contract capacity up to 74% (997.5 MW) of the Plant 5 maximum capacity (1,348 MW) amount.

### Applicability

The SPP BA Deliverability amount allows an entity to use the SPP BA deliverability amount to contract capacity. This is an Integrated Marketplace simulated approach so that as load increases across the SPP BA, individual plant generation increases accordingly to serve the incremental BA load. This approach allows for load to be served with the pool of SPP resources based on an economic dispatch regardless of long-term firm transmission service amounts. Long-term firm transmission service allows an entity to have a hedge against congestion that could occur during real-time operations and has no impact on which resources are dispatched to serve load.

A LRE may enter into a capacity contract to meet all or part of its PRM shortfall with any resource(s) within the SPP BA, if the resource has deliverable capacity that is not already committed. In other words, deliverable capacity, in excess of the committed capacity, from a resource is available to be contracted to a LRE.

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Table 1: Example of Deliverability Study Results

<table>
<thead>
<tr>
<th>Plant</th>
<th>Max Cap MW</th>
<th>CBA Model Dispatch MW</th>
<th>Study Transfer MW</th>
<th>FCITC</th>
<th>Deliverability % of Plant PMAX to SPP BA</th>
<th>MW Deliverability of Plant PMAX to SPP BA</th>
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<tr>
<td>Plant 1</td>
<td>128</td>
<td>119.7</td>
<td>8.3</td>
<td>8.3</td>
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<td>128</td>
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<td>Plant 2</td>
<td>200</td>
<td>0</td>
<td>200</td>
<td>200</td>
<td>100%</td>
<td>200</td>
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<td>Plant 3</td>
<td>140</td>
<td>138.6</td>
<td>1.4</td>
<td>1.4</td>
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<td>140</td>
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<td>100</td>
<td>40</td>
<td>60</td>
<td>50</td>
<td>90%</td>
<td>90</td>
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<tr>
<td>Plant 5</td>
<td>1348</td>
<td>0</td>
<td>1348</td>
<td>997.5</td>
<td>74%</td>
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Jointly Owned Units (JOUs)

Deliverability study results for each GO will consist of the total plant deliverability percentage and MW amounts without generator ownership percentage breakdown. The MW deliverability amount based on percentage of generator ownership will be determined by the GO(s).

Each GO’s MW deliverability amount can be determined by multiplying the plant MW deliverability amount by the GO’s percentage of ownership.

Example from Table 1:

Plant 5 is a JOU with 25% ownership by GO 1 and 75% ownership by GO 2. Plant 5 has a deliverability amount of 74% to the SPP BA.

PMAX for Plant 5 is 1348 MW and 74 % of 1348 is 997.5 MW.

GO 1 would have 0.25 * 997.5 MW which equates to 249.3 MW deliverable to SPP BA.

GO 2 would have 0.75 * 997.5 MW which equates to 748.1 MW deliverable to SPP BA.
Figure 2: Regional map indicating the dispatch boundary for deliverability analysis
Deliverability Process Timeline

Deliverability Process Overview

- SPP Board of Directors approves Notice To Construct (NTCs)
- ITPNT CBA planning model finalized
- Deliverability study performed for current year + 1 and current year + 2
- Internal review of Deliverability study results
- Deliverability study results provided to Generator Owners
- GOs determine available capacity and contract with LREs short on capacity for PRM obligation
- LREs report Resource Adequacy Workbook capacity and load amounts to SPP
- SPP performs pre-season deterministic PRM calculation on LRE data for Planning Reserve Assurance
- LREs report Resource Adequacy Workbook cured capacity and load amounts to SPP
- SPP performs final deterministic PRM calculation on LRE data for Planning Reserve Assurance
- SPP submits final PRM values through EIA-411 submittal to NERC
The findings of the Deliverability study results for each plant will be provided to each appropriate GO in the last quarter of the current year. Based upon these results, each GO can work with applicable LREs to develop a plan for acquiring the necessary capacity for PRM requirements. The results of each annual study will extend for two consecutive summer periods. Each LRE may obtain a capacity contract based on the latest results for the upcoming summer season. The Planning Reserve Assurance Policy process is intended to ensure that each LRE enters the peak season with its PRM intact and ready to meet peak load conditions. Prior to the start of the summer season, each LRE will report, through the Resource Adequacy Workbook, their total capacity, including capacity contract amounts and demand values for validation by SPP staff.
Exhibit No. SPP-4
Load Responsible Entity for Planning Reserve Margin Obligation

February 16, 2016

SPP Staff
## Revision History

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<td>Version 0.0 (November 1, 2014)</td>
<td>Michael Odom</td>
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<tr>
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<td>Michael Odom</td>
<td>Added draft Attachment AS language and Appendix 1 to Attachment AS</td>
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<td>Michael Odom</td>
<td>Added language for RM Validation and LOLE study</td>
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<tr>
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<td>Michael Odom</td>
<td>Removed language deemed unnecessary by the CMTF</td>
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<td>Version 1.14</td>
<td>Michael Odom</td>
<td>Updated LRE definition and modified language to reflect new definition</td>
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<tr>
<td>Version 1.15</td>
<td>Jim Jacoby</td>
<td>Updated LRE definition and modified language to reflect proposal to use Market Participant.</td>
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<tr>
<td>Version 1.16</td>
<td>Michael Odom</td>
<td>Restructured LRE responsibilities based upon AEP updates</td>
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**Background and Introduction**

Reserve Margin is the amount of Deliverable or Prospective Resources minus the Net Internal Demand. The division of this difference by the Net Internal Demand provides a percentage of reserve margin, which is used interchangeably with the term reserve margin. A system possessing a reserve margin has generation capacity in excess of maximum net internal demand. Reserve margin will reduce the risk of not serving all net internal demand in situations where that demand is unusually high in combination with some portion of the generation (capacity) being unavailable. Maintaining an adequate reserve margin will decrease this risk to an acceptably low probability. Capacity margin is the same value, the difference between an entity’s resources and demand. The difference between reserve margin and capacity margin stems from the denominator used in the reserve or capacity margin percentage calculations. Reserve margin has a net internal demand denominator and capacity margin has a resource denominator. Within the electrical industry, a percentage of reserve margin is what is commonly used to determine the amount of reserve margin necessary to be maintained for reliability reasons. Planning Reserve Margin (PRM) is the term used by a majority of North American RTOs/ISOs to describe the reserve margin amount used for planning purposes.

Currently SPP Criteria section 2 specifies that a capacity margin obligation shall be maintained by a Load Serving Member. Load Serving Member, as defined by the SPP Criteria, does not cover all load in the SPP Balancing Authority Area footprint. Capacity margin or reserve margin should be calculated as a percentage above all load within a region’s boundary of reliability responsibility in order to provide adequate reliability when needed.

On March 1, 2014, SPP implemented the Integrated Marketplace and became the consolidated Balancing Authority for its region. SPP has been working with the Integrated System and SPP members to develop tariff language and agreements that will expand SPP’s footprint to integrate WAPA, Basin Electric Cooperative and Heartland by October 2015. The implementation of the Integrated Marketplace and the integration of the Integrated System have raised a need to address SPP’s PRM requirements in order to ensure continued reliability.

The SPP Balancing Authority area covers Integrated Marketplace resources and load. The SPP BA covers loads represented by both members and non-members of SPP. In addition, some facilities served by the BA are not facilities that have been placed under the functional control of SPP. For reliability reasons, SPP needs a mechanism to ensure the entire load served by the SPP BA is covered by sufficient capacity. Since the SPP Criteria outlines capacity margin requirements that only apply to SPP Load Serving Members, and does not apply to entities that simply have facilities or load registered in the market or non-registered load connected to the Transmission System, but no membership agreement with SPP, SPP has created the concept of a Load Responsible Entity. This entity will have the obligation to provide planning reserves through its Market Participant (MP). The Market Participant has an agreement directly with SPP and will be responsible for ensuring compliance with the reserve margin requirements established in the SPP Tariff and Criteria. The intent of this whitepaper is not to create contractual relationships directly between SPP and the LRE.
Load Responsible Entity

Load Responsible Entity ("LRE") definition:

A Load Responsible Entity shall mean any Asset Owner participating in the Integrated Marketplace with registered physical assets that are either load or firm Export Interchange Transactions. Asset Owners with load pseudo-tied out of the SPP Balancing Authority will not be considered a Load Responsible Entity.

SPP Tariff Definitions


Market Participant: An entity that generates, transmits, distributes, purchases, or sells electricity or provides Ancillary Services with respect to such services (or contracts to perform any of the foregoing activities) within, into, out of, or through the Transmission System. Market Participant expressly includes:

(a) Transmission Owner(s) and any of their Affiliates including Transmission Owners providing transmission service to: (i) bundled retail load for which such Transmission Owners are taking neither Network Integration Transmission Service nor Firm Point-To-Point Transmission Service under this Tariff; and (ii) load being served under Grandfathered Agreements for which such Transmission Owners are taking neither Network Integration Transmission Service nor Firm Point-To-Point Transmission Service under this Tariff, (b) Transmission Customers, (c) Network Customers, (d) Generation Interconnection Customers, (e) any Eligible Customer offering Resources for sale into the Energy and Operating Reserve Markets that executes the Service Agreement specified in Attachment AH, or on whose behalf an unexecuted Service Agreement has been filed at the Commission, (f) any retail customer or eligible person that is not precluded under the laws or regulations of the relevant electric retail regulatory authority including state-approved retail tariff(s) from participating directly in wholesale demand response programs in the Energy and Operating Reserve Markets and that is technically qualified to offer Demand Response Load (as defined in Attachment AE of this Tariff) into the Energy and Operating Reserve Markets or an aggregator of such retail customers that offers qualified Demand Response Load into the Energy and Operating Reserve Markets under Section 2.8 of Attachment AE, and (g) an entity that executes the Service Agreement specified in Attachment AH and registers the assets of one or more Asset Owners.
Summary of LRE, MP, and SPP responsibilities:

LRE Identification
An MP may represent and aggregate the PRM and reporting obligations of one or more LREs.

*SPP*
SPP, in coordination with applicable Market Participants, must identify the Load Responsible Entity(ies).

Reserve Margin

*SPP*
SPP will validate the LRE reserve margin compliance through discrete calculations based upon LRE submitted data.

SPP will compile LRE reserve margin calculations and provide a report of the findings to the LREs and SPP Stakeholders before and after the summer peak period.
**MP**

The Market Participant has the legal relationship with SPP and will ensure that all LREs, represented by the Market Participant, meet the PRM obligations and provides the required data to SPP so that SPP can independently verify compliance. If an LRE refuses to either 1) become a Market Participant or 2) procure a third party Market Participant to represent them, SPP will file an unexecuted Market Participant Agreement with FERC.

**LRE**

The LRE will ensure the obligation for PRM requirements is met pursuant to requirements to be established in the SPP Tariff. Pseudo tied loads that are subject to the PRM obligations of another Balancing Authority shall not be subject to LRE requirements.

**Demand Data Reporting**

**SPP**

SPP will validate that the demand values submitted for PRM requirements against the previous year(s) forecasts.

**MP**

The Market Participant will ensure that the LRE provides the necessary demand value data needed to calculate planning reserves to SPP.

**LRE**

The LRE will ensure that demand values reported for the planning reserve calculation are accurately reflective of the LRE’s system peak responsibility pursuant to requirements to be established in the SPP Tariff.

**Capacity Data Reporting**

**SPP**

SPP will validate that the resource MW values used for PRM requirements are accredited properly per the latest unit testing results conducted in accordance with the SPP Criteria (or SPP Tariff if the procedures are replicated there).

**MP**

The Market Participant will ensure that the LRE provides the necessary resource MW value data needed to calculate planning reserves to SPP.
**LRE**

The LRE will ensure that resources used to meet the PRM requirement are properly accredited and tested per the SPP Criteria. The Criteria testing procedures could be replicated in the Tariff in order to have a self-contained set of requirements.

**Planning Reserve Assurance**

**LRE**

A Planning Reserve Assurance policy will establish guidelines and actions for the LRE to abide by in order to ensure that PRM requirements are met. Circumstances in which the Planning Reserve Assurance policy is applicable:

- LRE fails to submit to SPP the data necessary for planning reserve calculation
- LRE fails to meet PRM obligation as specified by the Tariff

**Obligation and Performance**

**LRE – MP – SPP**

The LRE, through its Market Participant, submits necessary planning reserve data directly to SPP. The LRE maintains PRM and the MP maintains the performance obligation. SPP performs data validation and planning reserve calculation.
Resource Adequacy Workbook sent to LRE’s
1/18

Resource Adequacy Workbook due from LRE’s
2/15

Pre-Season Reserve Margin validation completed by SPP staff
3/18

Begin working with each LRE to reconcile Reserve Margin calculations
3/25

Final Reserve Margin validation released
4/15

Deadline for submitting deficiency contracts to SPP
5/15

Issue Assurance Policy charges to LRE’s that are deficient
6/15

Draft Reserve Margin LRE comparison report released
11/18

Final LRE Reserve Margin outlook report released
12/9

Post Season validation started
10/1

Post Season validation completed
10/21

1/15

Resource Adequacy Workbook Educational Session with LRE’s

11/30/2016

Annual CONE Payment Calculation
Exhibit No. SPP-5
Planning Reserve Assurance Policy

March 2016

Capacity Margin Task Force
## Revision History

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<th>Author</th>
<th>Change Description</th>
<th>Comments</th>
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<td>Rob Janssen/Chris Haley</td>
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<td>Added CONE Payment language</td>
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<td>Updated Language</td>
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Future Planning Reserve Margin Assurance ............................................................................................ 4

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  2.0 Proposed Guidelines ........................................................................................................................... 4
  3.0 Planning Reserve Margin (PRM) Deficiency Payment Guidelines ................................................... 5
  4.0 Planning Reserve Margin (PRM) Timeline ......................................................................................... 8
Current mechanisms to ensure timely, reliable assurance of Planning Reserve Margin (PRM) requirements in SPP are inadequate. Currently identified mechanisms are:

- NERC reliability standard penalty provisions in SPP’s Attachment AP\(^1\)
- Potential revocation of membership under the SPP Membership Agreement

Both of these existing, identified assurance options are either too extreme or occur too late to assure that required levels of PRM are maintained. An appropriate assurance mechanism should incent proper planning to ensure timely compliance with PRM requirements and should result in compensation to the parties potentially impacted by non-compliant parties. That is, if a Load Responsible Entity (LRE) is short on capacity and the region relies on the excess capacity of other parties in SPP to provide adequate regional reliability, then those parties should be the ones receiving compensation through the assurance mechanism. SPP’s existing assurance mechanisms are either unlikely to be exercised or would be exercised in a way that would not encourage proper behavior proactively and would not adequately compensate parties with capacity in excess of the PRM requirements in SPP.

\(^1\) See SPP OATT Attachment AP
1.0 Assurance Principles

A. Any new future PRM assurance mechanism should be designed based on the following principles:

   I. Assurance should be timely and proactive, preferably by determining a Load Responsible Entity’s (LRE’s) potential lack of compliance in advance and allowing such LRE to potentially take corrective action, if available.

   II. Assurance should consist of a payment by a deficient LRE to those parties with excess capacity in SPP.

   III. The amount of the payment should economically incent LREs to address their PRM capacity deficiency.

   IV. The receipt of the payment should be allocated to the appropriate parties in a manner reflecting the impact of the LRE’s PRM deficiency.

The term “PRM deficiency” includes the entire capacity deficiency of an LRE with regard to its failure to meet SPP’s PRM requirement, which includes both capacity required to meet an LRE’s peak load as well as the capacity required to meet an LRE’s PRM requirement above peak load.

2.0 Proposed Guidelines

A. Consistent with these principles, the Capacity Margin Task Force (CMTF) recommends that the following principles be adopted regarding the assurance of PRM in the SPP region:

   I. An effective assurance mechanism in the SPP region would utilize payments to provide compensation from LREs who are short on capacity to those in the SPP region who are long on capacity. This mechanism may only be used to pay LREs and other capacity resource owners in the SPP region.

   II. The status of each LRE’s compliance would be established in advance of the summer peak season(s), which is June 1st through September 30th, by SPP Staff based on load forecast and accredited capacity data provided by each LRE and Staff’s independent review of such data to ensure accuracy and compliance with SPP’s PRM calculation requirements.

   III. Prior to the start of the summer peak season(s), each LRE that is short on capacity has the option to make appropriate arrangements, including entering into a bilateral contract for capacity or demand response from any Generation Owner or demand response provider, including another LRE, that is long on capacity in the SPP region. Any such arrangements will need to meet the terms of applicable SPP Criteria and/or SPP OATT provisions for PRM requirements existing at the time such arrangements are relied upon to satisfy an LRE’s PRM.
B. Finally, if an LRE’s reserve margin is not compliant with the relevant SPP Criteria and/or SPP OATT provisions prior to the start of the summer peak season(s) then that LRE shall make a PRM deficiency payment in accordance with Section 3.0 F.

3.0 Planning Reserve Margin (PRM) Deficiency Payment Guidelines

A. The amount of the PRM deficiency payment shall be based on the Cost of New Entry (CONE) for new generation in SPP. The CONE figures for each year shall be developed and published by SPP as part of the compliance assurance process and shall be based on publicly available information, such as that from the Energy Information Administration (EIA) for the SPP region. The sliding scale shall be:

1. When the region-wide PRM is equal to the SPP PRM requirement plus 8% or greater, then the CONE would be based on 125% of the estimated annual capital and fixed operating costs of a new natural gas-fired peaking facility.

2. When the region-wide PRM is equal to the SPP PRM requirement plus 3% or greater, but less than the PRM requirement plus 8%, then the CONE would be based on 150% of the estimated annual capital and fixed operating costs of a new natural gas-fired peaking facility.

3. When the region-wide PRM is less than the SPP PRM requirement plus 3%, then the CONE would be based on 200% of the estimated annual capital and fixed operating costs of a new natural gas-fired peaking facility.

B. The CONE multiplier of the assurance mechanism discussed above provides increasing incentives consistent with the potential for reduced reliability in the SPP region. The CONE multiplier mechanism also reflects the increased reliability value of capacity as PRMs diminish in the SPP region.

C. The total PRM deficiency payment made by an LRE for the annual summer peak season(s) shall cover the annual capital and fixed operating costs as defined in the assurance mechanism.

D. Referencing the most recent EIA report on Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants, SPP will annually determine the appropriate CONE value based on an appropriate natural gas peaking technology. The CONE value most appropriately only reflects costs and shall not include the anticipated net revenue from the sale of capacity, Energy or Ancillary Services.

2 Refer to the SPP Criteria and/or OATT for the latest Planning Reserve Margin requirement
3 The CT unit cost used is the Frame 7FA 05 which is labeled Advanced CT in the U.S. Energy Information Administration’s Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants
E. The results shown in Table 1 were derived by SPP based, in part, upon data supplied by the EIA in year 2013 dollars, which were inflation-adjusted (1.72%) using data from the Bureau of Labor Statistics in order to convert EIA cost data from 2013 dollars into 2015 dollars. In order to produce the annualized CONE value for the LREs from these cost numbers, SPP assumed: a 50/50 debt to equity ratio; a 20-year project life and loan term; a 5.25 percent debt interest rate; an 11 percent after tax internal rate of return on equity; a 38.9 percent combined effective federal and state tax rate; and a calculated weighted average cost of capital based on a combination of debt and equity financing (8.1%). SPP along with stakeholders will continue to examine these factors annually in order to determine if any modifications are needed. These factors and assumptions are comparable to those used by other RTOs in the development of CONE estimates4.

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Table 1
Combustion Turbine Plant, 2015 Results

F. The LREs who are found to be deficient in meeting their PRM requirement as determined by this assurance policy are subject to the deficiency payment requirement based on the applicable CONE. The LRE is responsible to make a deficiency payment for the PRM deficiency, including any deficiency in meeting peak load in addition to meeting SPP’s PRM requirement. The deficiency payment shall be made to SPP, and SPP shall initially distribute such payment to all the LREs who have surplus reserves above the SPP PRM requirement. The allocation of the payment to each of these LREs shall be based on the LRE’s contribution on a MW share to the total SPP Region’s MW above the PRM requirement. Therefore, in combination, all the LREs who have PRMs in excess of the SPP PRM requirement will receive 100% of the deficiency payment. The capacity being provided to the LRE that is deficient must be subtracted from the surplus reserves of each LRE that is long. This process will ensure this block of MW’s will no longer be available for capacity contracts to other LRE’s during the peak season.

4 The assumptions made in the CONE calculation are consistent with the EIS Market Offer Cap calculation that was FERC approved and are similar to MISO’s methodology.
G. In the event that the total PRM deficiency in the SPP region is greater than the total capacity
LREs have in surplus of their PRMs, allocation of deficiency payment shall occur using the
following steps. 1) Payment for the portion of PRM deficiency equal to surplus capacity will
be allocated to all LREs who have surplus reserves as described above. 2) Remaining
deficiency payment will be allocated to generator owners who have SPP accredited resources
with excess capacity not already committed, for the portion of PRM deficiency payment that
did not get allocated in step 1. This allocation will be based on the non-LRE capacity
resources’ contribution to the total of all such excess, uncommitted non-LRE capacity in
SPP. 3) As a final backstop, if there is still unallocated deficiency payment after steps 1 and 2 above, then it will be distributed to originally non-deficient SPP LREs based on their SPP load-ratio share.

H. SPP shall create a voluntary process for non-LRE capacity resources in the SPP Balancing Authority, as referenced above, to participate in the Planning Reserve Assurance Policy consistent with the LRE’s timeline for submitting the Resource Adequacy Workbook (RAW) data request to SPP.

4.0 Planning Reserve Margin (PRM) Timeline

A. For clarity, after the determination of peak season PRM compliance (prior to the start of the applicable peak season for an LRE), a LRE’s intermittent failure to maintain the availability of its resources, including demand response and purchased capacity, shall not indicate that it is non-compliant with the PRM assurance process. PRM is intended to provide for planned reliable operations of the SPP system and the ability to satisfy LRE’s load under reasonably anticipated circumstances. It should be expected that at certain times, any LRE may need to use the resources comprising its PRM for operational purposes, resulting in available resources less than the LRE’s peak load plus its PRM requirement.

B. This PRM assurance policy is intended to ensure that each LRE enters the peak season with its PRM intact and ready to meet peak load conditions. This shall be the determining factor of whether compliance with this policy is met for the peak season after the determination of compliance has been made. During the peak season, it is expected that each LRE will at all times maintain the availability of its owned or contracted resources to meet its daily load and operating reserves obligations, per the SPP criteria, at a minimum. However, compliance with any such operating reserve requirement shall be monitored and assessed by SPP Staff and the appropriate SPP working group (the ORWG) separately from this PRM assurance policy.

C. The intent of this PRM assurance policy is that each LRE will provide SPP it’s RAW by February 15th of each year with a plan to meet its PRM requirement. If the LRE workbook is complete and shows that the LRE has adequate planning reserves, the LRE will be considered to have met its PRM requirement. If the LRE does not have adequate reserves in place, it will have an opportunity to bilaterally contract for additional capacity in the timeframe between February 15th and May 15th. So long as the LRE solves its deficient PRM by May 15th, it will be considered to have met its PRM requirement. If the LRE fails to obtain additional capacity or submit its data to SPP by May 15th, it will be considered deficient and, as such, will make a deficiency payment.

Additionally, below are some details on the data submission, calculation errors, and timeline requirements:

a. The RAW submissions by LREs on February 15th will be used to qualify the LREs’ PRM requirement for the upcoming summer peak season. Absent any calculation errors or otherwise misstated information, any LRE that has adequate reserves in this submission is considered to have met its PRM requirements.
b. The February 15th submission may include any resources, new or existing, provided they are expected to be available during June 15th – September 15th. The LRE can count on these resources for compliance with the PRM assurance policy. If after February 15th, the planned availability of a resource change such that it is not available during June 15th – September 15th, it will still be considered as available in the determination of that LRE’s PRM.

c. Resources that are expected by February 15th to be unavailable during part or all of the period from June 15th – September 15th will not count as capacity for purposes of meeting the LRE’s PRM requirement.

d. Any LRE that is short of its PRM requirement in the February 15th submission will have until May 15th to correct the deficiency with bilateral contracts. This provides 90 days for LREs to bilaterally contract for additional capacity and obtain transmission service or rely on SPP’s transmission deliverability determination to arrange capacity needed to meet its PRM. Should the LRE also need capacity to cover part of its load obligation, FIRM transmission is required and the LRE will have 90 days to arrange for that transmission.

e. Any LRE that fails to supply a RAW to SPP will be considered to be deficient of its PRM requirement. If the LRE does not submit the required data by May 15th, SPP will consider them in violation and subject to the assurance policy for the entirety of their PRM requirement, which includes all capacity required to meet the LREs peak load.

D. Post-season analysis should be conducted to compare the actual results versus each LREs planning forecast. Further PRM assurance activities would not be based on the post-season analysis, although SPP may refer cases of potential violations of the PRM assurance rules to the Markets and Operations Policy Committee (MOPC) for further investigation and action, if necessary. Post-season analysis would be used to evaluate LRE’s planning forecast consistency and develop further improvements for the PRM assurance process.
Exhibit No. SPP-6
HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.
Resource Adequacy Education Session
Outline

• Background

• Attachment AA
  • Definitions
  • Roles and Responsibilities
  • Planning Reserve Margin
  • Summer Season Resource Adequacy Requirement
  • Winter Season Obligation
  • Short-Term Transactions
  • Resource Adequacy Timeline
  • Deliverability Study
  • Workbook
  • Post-Season Analysis
  • Cost of New Entry & Resource Adequacy Assurance

• Next Steps
Background
Drivers for New Policy

- Significant transmission expansion in place
- Expanding footprint and operational changes
- SPP became the Balancing Authority in March 2014
- Issues raised with existing SPP Criteria language
- Capacity margin requirement unchanged since 1998
Balance Goals

Balance between Reliability and Economics
Recommended Policies

These policies were developed by a broad stakeholder group that included regulators and were approved by SPP’s MOPC, Board, and the RSC in April 2016.
Recap of Approved Policies

Load Responsible Entity

- Entities with load-serving obligations in the SPP Balancing Authority will be responsible for complying with SPP’s resource adequacy requirement
- LRE is an asset owner in the Integrated Marketplace for load or firm Export Interchange Transactions
- Market Participant is responsible to ensure the LRE’s compliance

Reserve Margin Requirement

- Will utilize Reserve Margin terminology rather than Capacity Margin
- Set SPP’s Planning Reserve Margin at 12% while maintaining current hydro-based exception at 9.89%
Recap of Approved Policies

Planning Reserve Assurance Policy

- Created mechanism that utilizes payments to provide compensation to LREs in SPP that have excess capacity from LREs who have not met the requirement and are capacity deficient
- Payment based on the potential for reduced reliability in SPP

Deliverability Study

- Gave LREs an option to use “deliverable” capacity on short-term basis for meeting the PRM, in lieu of requiring firm transmission service
- Firm transmission service still required for load and can also be used to meet the PRM if an LRE wants to maintain Auction Revenue Rights
Revision Request 187

• MOPC and the BOD directed the Regional Tariff Working Group (RTWG) to implement the policy package based on the approved whitepapers

• Based on policy direction given to the RTWG from the Capacity Margin Task Force and the Supply Adequacy Working Group, parts of Section 4.0 of the Planning Criteria were also incorporated

• Resulting RR 187 contains changes to:
  • Tariff
    • Attachment J (Recovery of Costs Associated With New Facilities)
    • Attachment AA (Resource Adequacy)—new
    • Attachment AE (Integrated Marketplace)
  • Planning Criteria
    • Section 4 (Capacity Margin)—removed
    • Section 6.3.5 (Capacity Benefit Margin)
    • Section 7.1 (Accredited Net Generating Capacity)—moved Section 4.4.2 (Fuel Supply) to Section 7.1.6
  • Market Protocols Section 6.2 (Registration of Load)
Definitions

(Attachment AA Section 2.0)
Definition Highlights

• **Firm Power**: Power sales and purchases deliverable with firm transmission service where the seller assumes the obligation to serve the purchaser’s load with capacity, energy, and planning reserves that must be continuously available in a manner comparable to power delivered to native load customers.

• **Net Peak Demand**: The forecasted Peak Demand less the a) projected impacts of demand response programs and behind-the-meter generation that are controllable and dispatchable and not registered as a Resource and b) **contract amount of Firm Power purchased under agreements in effect as of the time of the forecasted Peak Demand**, plus the contract amount of Firm Power sold to others in effect as of the time of the forecasted Peak Demand.

• **Peak Demand**: The highest demand including transmission losses for energy measured over a one clock hour period.

• **Summer Season**: June 1st through September 30th of each year.

• **Winter Season**: December 1st through March 31st of each year.
Roles and Responsibilities

(Attachment AA Section 3.0)

+ Denotes addition to the approved policy package
Load Responsible Entity

- **Load Responsible Entity (LRE):** An Asset Owner represented in the Integrated Marketplace with a registered physical asset that is either a) load or b) an Export Interchange Transaction as specified in Section 5.4 of Attachment AA.

- Any entity that utilizes an Export Interchange Transaction that is supported by a Firm Power contract will be considered an LRE and must include that load in its Summer Season Net Peak Demand to meet the Resource Adequacy Requirement.
Market Participant & Load Responsible Entity

• An LRE must be represented by a Market Participant (MP)
  • If an LRE refuses to either (a) become an MP or (b) engage a third party MP to represent it, SPP will file an unexecuted Market Participant Agreement with the Federal Energy Regulatory Commission (FERC)

• An MP that represents an LRE is responsible to ensure the LRE’s compliance with the Resource Adequacy Requirement

• The relationship between an MP and its LRE, as established in the submission of the Workbook on February 15th, is considered fixed for the upcoming Summer Season for enforcement of the Resource Adequacy Requirement
  • Only for purposes of compliance with Attachment AA
Market Participant & Load Responsible Entity

- The MP is responsible to ensure its LRE provides the necessary data to allow SPP to verify the LRE’s compliance with the Resource Adequacy Requirement

- An LRE will submit all data to SPP either directly or through the LRE’s MP

- An MP may aggregate the forecasted Peak Demand of multiple LREs whose load assets are served by a common set of Designated Resources or a Firm Power transaction between the LREs
  
  - In this case, the MP will be considered the LRE for the aggregated demand and, for purposes of compliance with this Attachment AA, the MP’s forecasted Peak Demand will be used to calculate a single Resource Adequacy Requirement for the aggregated load
Peak Demand Aggregation Example

Same Market Participant using Non-Coincident Peak Demand versus Coincident Peak Demand when aggregating load

- Non-coincident load is 1,000 MW
- Resource Adequacy Requirement is 1,120 MW

- Coincident load is 950 MW
- Resource Adequacy Requirement is 1,064 MW

Resource Adequacy Requirement difference is 56 MW
Generator Owner & Load Responsible Entity

- An entity may be an LRE, a Generator Owner, or both, but SPP will recognize the rights, roles, and responsibilities as separate and distinct functions under Attachment AA.

- An LRE that is also a Generator Owner will be considered an LRE for Workbook reporting purposes, and all excess capacity of the Generator Owner will be considered LRE Excess Capacity for purposes of allocating the Deficiency Payment.
Procedures for Assignment of MP Obligations

• For purposes of compliance with Attachment AA, an MP may assign its duties, obligations and responsibilities for an LRE to another MP

• A negotiated assignment must be in writing and bilaterally executed by both MPs
  • Copies of the assignment must be provided to SPP prior to February 15th
  • SPP will accept the transfer of the LRE, and enforce the provisions of Attachment AA against the assigned MP
  • If the assignment does not occur prior to February 15th, SPP will not accept the assignment for the upcoming Summer Season

• Either party may provide SPP with written notice of the assignment’s termination
  • The notice must contain written acknowledgement by both parties that the assignment has been terminated
  • If the assignment is terminated, the duties, obligations, and responsibilities of the MP for the transferred LRE under Attachment AA will revert back to the original MP, unless a replacement assignment that meets the requirements is provided to SPP
Planning Reserve Margin

(Attachment AA Section 4.0)
Planning Reserve Margin

- A Loss of Load Expectation (LOLE) Study will be performed by SPP biennially to assess the Planning Reserve Margin (PRM)
  - Analyzes the ability to reliably serve the SPP Balancing Authority Area’s forecasted Peak Demand
  - Inputs and assumptions used for the LOLE Study will be developed by SPP with input from the stakeholders

- Based on the initial LOLE Study, the PRM is 12%
  - If an LRE’s Firm Capacity is comprised of at least 75% hydro-based generation, then the PRM is 9.89%

- A change to the PRM will not be made absent a filing with FERC
Summer Season Resource Adequacy Requirement

(Attachment AA Section 5.0)
Resource Adequacy Requirement

- The Resource Adequacy Requirement (RAR) requires an LRE to maintain enough capacity to meet its PRM in addition to its Summer Season Net Peak Demand.

- The LRE is responsible to meet the RAR for the Summer Season.
  - Capacity shortfall will result in a Deficiency Payment.

- Load and Resources that are pseudo-tied in will be considered internal to the SPP Balancing Authority Area for purposes of determining the RAR.

- An LRE with load both internal and external to the SPP Balancing Authority Area is required to maintain distinct and separate amounts of Resources to cover applicable planning reserve obligations.
Winter Season Obligation

(Attachment AA Section 6.0)

+ Denotes addition to the approved policy package
Winter Season Obligation

- The Winter Season Obligation requires an LRE to maintain enough capacity to meet its PRM in addition to its Winter Season Net Peak Demand

- The LRE is responsible to meet the Winter Season Obligation for the Winter Season
  - Capacity shortfall will not result in a Deficiency Payment

- Load and Resources that are pseudo-tied in will be considered internal to the SPP Balancing Authority Area for purposes of complying with the Winter Season Obligation

- An LRE with load both internal and external to the SPP Balancing Authority Area is required to maintain distinct and separate amounts of Resources to cover applicable planning reserve obligations
Short-Term Transactions

(Attachment AA Section 7.0)

+ Denotes addition to the approved policy package
Short-Term Transactions

- An LRE may arrange for:
  - Short-term capacity to provide a part of its Firm Capacity or
  - Short-term Firm Power to reduce a portion of either its Summer Season Net Peak Demand or Winter Season Net Peak Demand

- Must be available for a minimum of four consecutive months, starting either June 1st or December 1st

- The amount shall not exceed 25% of an LRE’s applicable Net Peak Demand
Resource Adequacy Timeline

(Attachment AA Section 8.0)
Timeline Highlights

- **July 1st**: Commencement of the annual process
- **October 1st**: Deliverability Study results & Workbooks
- **April 1st**: Initial Report
- **May 15th**: Final Report
- **June 15th**: Calculate and assess Deficiency Payments
- **June 30th**: Final Report
- **February 15th**: Workbook submission deadline
  *Notice to those who have not submitted a Workbook
- **May 15th**: Deadline to update any purchases and sales that occurred after the initial submission and to cure any deficiencies
Deliverability Study

(Attachment AA Section 9.0)
Process Flow

Annual Deliverability Study performed

SPP verifies LRE compliance with Resource Adequacy Requirement

Deliverability Study results provided to Generator Owners (GOs)

LREs report capacity and load amounts to SPP

GOs determine available capacity and contract with LREs
Deliverability Study

• Annual study to evaluate the deliverability of each Resource registered in the Integrated Marketplace
  - Based on SPP Balancing Authority Area load

• Firm transmission service must exist to support delivery of capacity to an LRE’s load

• Utilizes the current summer Security Constrained Economic Dispatch Balancing Authority transmission planning model

• Initial assumption that any Resource dispatched is automatically deliverable to the SPP Balancing Authority Area for the dispatched output

• Increases load across the SPP Balancing Authority Area, where individual plant generation increases accordingly to serve the SPP Balancing Authority Area load
Deliverability Study

• Results determine the Deliverable Capacity of each Resource to the SPP Balancing Authority Area

• Results allow entities to purchase Deliverable Capacity through a bilateral contract in order to meet the PRM portion of the RAR

• LREs may use firm transmission service or Deliverable Capacity to meet the PRM portion of the RAR
  • Deliverable Capacity contracts based on the Deliverability Study results may only be for the Summer Season
  • Each LRE may obtain a Deliverable Capacity contract based on the latest results for no longer than two Summer Seasons
Deliverability Study Example

PLANT “A” 500 MW
100% deliverable to SPP BAA
500 MW

SPP Balancing Authority Area Load

PLANT “B” 500 MW
50% deliverable to SPP BAA
250 MW
Capacity Deliverability and Availability Example

Capacity Deliverability and Availability

Capacity (MW)

<table>
<thead>
<tr>
<th>Plant</th>
<th>Nameplate MW (SPP Determination)</th>
<th>Deliverable MW (SPP Determination)</th>
<th>Committed MW (GO Determination)</th>
<th>Available MW (GO Determination)</th>
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<td>Plant 2</td>
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<td>Plant 4</td>
<td>100</td>
<td>90</td>
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<td>70</td>
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Workbook

(Attachment AA Section 10.0)
Workbook

- Used to qualify an LRE’s compliance with the RAR for the upcoming Summer Season for purposes of Attachment AA

- A Workbook may include any Resources expected to be available during June 15th through September 15th
  - After February 15th, if the Resource becomes unavailable, the Resource will still be considered as available for purposes of meeting the RAR

- Resources initially identified as unavailable during part or all of the period from June 15th through September 15th but subsequently become available will count as capacity for purposes of meeting the RAR if the LRE updates its Workbook by May 15th

- A Generator Owner that does not submit a Workbook containing the amount of generation capacity available from the Deliverability Study will not be entitled to receive any revenue distributions collected from Deficiency Payments
Post-Season Analysis

(Attachment AA Section 11.0)
Post-Season Analysis

• SPP will conduct a post-Summer Season analysis to compare the LRE’s actual Summer Season Net Peak Demand versus the LRE’s planning forecast

• Used to evaluate, at a minimum, LRE’s planning forecast consistency and develop further improvements for the resource adequacy process

• Supply Adequacy Working Group will refer cases of potential discrepancies to the Markets and Operations Policy Committee for further investigation and action
Cost of New Entry and Resource Adequacy Assurance

(Attachment AA Sections 12.0 & 13.0)
Variables

- **Generator Owner Excess Capacity**: The available Deliverable Capacity above the committed capacity of Generator Owner Resource(s) as reflected in its completed Workbook.

- **LRE Deficient Capacity**: Resource Adequacy Requirement less LRE Firm Capacity, or zero if the LRE’s Firm Capacity is greater than or equal to the RAR.

- **LRE Excess Capacity**: LRE Firm Capacity less Resource Adequacy Requirement, or zero if the LRE’s Firm Capacity is less than or equal to the RAR.

- **SPP Balancing Authority Area Planning Reserve**: \( \frac{\text{(The sum of all LREs’ Firm Capacity less the sum of all LREs’ Summer Season Net Peak Demand) plus the sum of all Generator Owner Excess Capacity}}{\text{the sum of all LREs’ Summer Season Net Peak Demand}} \)
Cost of New Entry

• The Cost of New Entry (CONE) will be based on publicly available information relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility

• SPP will annually review the CONE on or before November 1st and file any changes with FERC
  • SPP will post on the SPP website the FERC-approved CONE for the next Summer Season within 10 days of approval
Deficiency Payment

- Deficiency Payment =

  \[ \text{LRE Deficient Capacity} \times \text{CONE} \times \text{CONE FACTOR} \]

- Where the CONE FACTOR shall be:

  - **125%**
    - When the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 8%

  - **150%**
    - When the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 3%, but less than the PRM plus 8%

  - **200%**
    - When the SPP Balancing Authority Area Planning Reserve is less than the PRM plus 3%
Deficiency Payment

- An LRE that resolves its capacity deficiency by May 15th will be considered compliant for the purpose of meeting the RAR

- An LRE that fails to obtain sufficient capacity to meet the RAR by May 15th will be considered deficient for the upcoming Summer Season
  - The responsible MP will be subject to the Deficiency Payment

- An MP, or its LRE, that does not submit a Workbook by May 15th will be considered deficient for the upcoming Summer Season
  - The responsible MP will be subject to the Deficiency Payment for the entire RAR
  - To calculate the LRE Deficient Capacity, SPP will set the LRE’s Firm Capacity to zero and utilize the LRE’s previous year’s Summer Season Peak Demand
Billing Procedure

• SPP will calculate Deficiency Payments to be assessed

• On or before June 30th, SPP will submit an invoice to the MP for the Deficiency Payment

• The invoice must be paid by the MP within 7 days of receipt

• In the event of a dispute, the MP must pay the amount in dispute, and SPP will deposit into an escrow account the portion of the invoice in dispute, pending resolution of such dispute
In the event that the sum of all LRE Excess Capacity is greater than or equal to the sum of LRE Deficient Capacity then:

\[
\text{LRE revenue} = \left( \frac{\text{individual LRE Excess Capacity}}{\sum \text{LRE Excess Capacity}} \right) \times \sum \text{Deficiency Payment(s)}
\]

<table>
<thead>
<tr>
<th>LRE ID</th>
<th>Net Peak Demand (MW)</th>
<th>Firm Capacity</th>
<th>Net Peak Demand + Net Peak Demand * PRM (MW)</th>
<th>LRE Excess Capacity (MW)</th>
<th>Deficient Planning Reserve (MW)</th>
<th>Deficiency Payment Amount</th>
<th>Deficiency Payment Allocation (LRE)</th>
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Total 348 $6,741,788 6,741,788 0
Revenue Distribution

- (13.4(2)(a)) In the event that the sum of all LRE Excess Capacity is less than the sum of LRE Deficient Capacity, then the allocation of revenues shall be distributed according to the following steps:

\[
LRE\ revenue = \left( \frac{\text{individual LRE Excess Capacity}}{\sum \text{LRE Excess Capacity}} \right) \times \sum \text{Deficiency Payment(s)}
\]

<table>
<thead>
<tr>
<th>LRE ID</th>
<th>Net Peak Demand (MW)</th>
<th>Firm Capacity</th>
<th>Net Peak Demand + Net Peak Demand * PRM (MW)</th>
<th>LRE Excess Capacity (MW)</th>
<th>Deficient Planning Reserve (MW)</th>
<th>Deficiency Payment Amount</th>
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<td>$11,236,313</td>
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Revenue Distribution

- (13.4(2)(b)(i)) In the event that the sum of all LRE Excess Capacity and all Generation Owner Excess Capacity is greater than or equal to the sum of Deficient Planning Reserve(s) then:

\[
GO\, revenue = \left( \frac{\sum LRE\, Deficient\, Capacity - \sum LRE\, Excess\, Capacity}{\sum LRE\, Deficient\, Capacity} \right) \times \frac{\text{individual GO Excess Capacity}}{\sum GO\, Excess\, Capacity} \times \sum \text{Deficiency Payment(s)}
\]

<table>
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Revenue Distribution

- (13.4(2)(b)(ii)(a)) In the event that the sum of all LRE Excess Capacity and all Generation Owner Excess Capacity is less than the sum of Deficient Planning Reserve(s) then:

\[
GO \ revenue = \left( \frac{\text{individual GO Excess Capacity}}{\sum \text{LRE Deficient Capacity}} \right) \times \sum \text{Deficiency Payment(s)}
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<table>
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<td>60</td>
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Revenue Distribution

• (13.4(2)(b)(ii)(b)) All remaining revenue not allocated in Section 13.4(2)(b)(ii)(a) will be allocated to each LRE that has met its RAR on a load ratio share based on Summer Season Net Peak Demand:

\[
LRE\ revenue = \left( \frac{\left( \sum LRE\ Deficient\ Capacity - \sum LRE\ Excess\ Capacity - \sum GO\ Excess\ Capacity \right)}{\sum LRE\ Deficient\ Capacity} \right) \times \left( \frac{\text{individual}\ LRE\ Net\ Peak\ Demand}{\sum\ LRE\ Net\ Peak\ Demand\ (s)\ that\ have\ met\ the\ RAR} \right) \times \sum\ Deficiency\ Payment(s)
\]

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<th>Firm Capacity</th>
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Next Steps

- Seeking approval of RR 187 from MOPC, Regional State Committee, and the Board of Directors at their respective January meetings
  - Approved at the working group level by the RTWG, SAWG, MWG, TWG, and CAWG

- FERC filing—Q1 2017
  - Request a June 1, 2017 effective date for Attachment AA, excluding Sections 12.0 and 13.0 (applicable Summer Season 2017)
  - Request a July 1, 2017 effective date for Attachment AA Sections 12.0 and 13.0 (applicable Summer Season 2018)

- Summer Season 2017
  - PRM is 12%
  - Attachment AA Sections 12.0 and 13.0 not applicable

- Summer Season 2018
  - Timeline starts July 1, 2017
  - All of Attachment AA is applicable
Exhibit No. SPP-7
SPP Reserve Margin

Loss of Load Expectation Report

SPP Engineering
## Revision History

<table>
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<tr>
<th>Date or Version Number</th>
<th>Author</th>
<th>Change Description</th>
<th>Comments</th>
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<tr>
<td>9/24/2015</td>
<td>SPP Staff</td>
<td>Initial Release</td>
<td></td>
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<tr>
<td>10/7/2015</td>
<td>SPP Staff</td>
<td>Inserted description in Wind Modeling section, Appendix B, and comparison to previous studies</td>
<td>CMTF suggested edits</td>
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<tr>
<td>10/15/2015</td>
<td>SPP Staff</td>
<td>Inserted map of wind resources locations, Language updated in Introduction section, study improvements section, and clarification of forced outage and load uncertainty inputs</td>
<td>CMTF suggested edits</td>
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<tr>
<td>11/24/2015</td>
<td>SPP Staff</td>
<td>Inserted 2020 LOLE assumptions and results.</td>
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<td>Inserted example of standard error calculation</td>
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1. Introduction

1.1 Background

The Capacity Margin Task Force (CMTF) under the direction of Markets and Operations Policy Committee (MOPC) was assigned the responsibility for updating the SPP Reserve Margin requirements and methodology based on SPP Stakeholder and Staff input. A recommendation of updated requirements and methodology improvements, which includes proposing an adjusted reserve margin requirement, will be presented to MOPC.

Currently SPP Criteria section 2.1.9 states, “Each Load Serving Member’s Minimum Required Capacity Margin shall be twelve percent. If a Load Serving Member’s System Capacity for a Capacity Year is comprised of at least seventy-five percent hydro-based generation, then such Load Serving Member’s Minimum Required Capacity Margin for that Capacity Year shall be nine percent”.

1.2 Objective

The standard Loss of Load Expectation (LOLE) study investigates the expected number of days per year for which available generating capacity is insufficient to serve forecasted demand. LOLE is also sometimes referred to as loss of load probability (LOLP), where LOLP is the proportion (probability) of days per year, hours per year, or events per season which occurs in the LOLE analysis. The timeframe for this analysis is typically a near term horizon of one to five years. The typical industry standard metric is the loss of load probability of one day in ten years or 0.1 day/year.

The SPP LOLE study provides an assessment of whether existing and planned capacity is adequate to serve the planning forecasted load by determining the reserve margin requirement adequate to maintain an LOLE of one day in ten years. The proposed adjusted reserve margin requirement, based on the results of the probabilistic study, will be provided to SPP stakeholders for review and presented to MOPC. The study results reflect the assumptions and methodology approved by the CMTF in the 2015 Reserve Margin LOLE scope.
2. Data Description and Analysis

The production-cost modeling tool used for the reserve margin LOLE analysis was GridView™ which requires various detailed data inputs. The information below lists the data used to build and simulate each model.

2.1. Area Overview

The SPP Balancing Authority (BA) footprint includes all or parts of Arkansas, Kansas, Louisiana, Missouri, New Mexico, Nebraska, Oklahoma, and Texas. Based on member input Iowa, Minnesota, Montana, North Dakota, and South Dakota were included due to integration of Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumer Power District, Northwestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative. For simplicity these entities are represented as WAPA in the list below. The areas defined in the LOLE study include the following:

- **AEPW**
- **EMDE**
- **GRDA**
- **INDN**
- **KACY (BPU)**
- **KCPL (KCPL, GMO)**
- **LES**
- **NPPD**
- **OKGE**
- **OPPD**
- **SPS**
- **SUNC (SEPC)**
- **SPRM**
- **WAPA**
- **WERE**
- **WFEC**

1. **AEPW**
2. **American Electric Power West**
3. **Empire District Electric Company**
4. **Grand River Dam Authority**
5. **Independence Power & Light Department**
6. **Board of Public Utilities, Kansas City, Kansas**
7. **Kansas City Power & Light Company**
8. **Lincoln Electric System**
9. **Nebraska Public Power District**
10. **Oklahoma Gas and Electric Company**
11. **Omaha Public Power District**
12. **Southwestern Public Service Company**
13. **Sunflower Electric Cooperative**
14. **Southwestern Power Administration**
15. **Western Area Power Administration**
16. **Westar Energy, Incorporated**
17. **Western Farmers Electric Cooperative**

---

1. **FERC 714 Hourly Load data for AECC is reported through AEPW, OKGE, and SWPA and combined with these entities for simulation purposes.**
2. **FERC 714 Hourly Load data for OMPA is reported through AEPW and OKGE and combined with AEPW and OKGE for simulation purposes.**
3. **FERC 714 Hourly Load data for SPRM is reported in SWPA through 2010. 2011 SPRM Hourly Load data was added to SWPA numbers to create the forecasted hourly load shape for simulation purposes.**
4. **WAPA contains eastern interconnect portions of Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumers Power District, NorthWestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative.**
5. **FERC 714 Hourly Load data for MIDW is reported through WERE and combined with WERE for simulation purposes.**
2.2. **Base Models and Topology**

System Topology was captured from the 2016 Integrated Transmission Planning Near-Term (ITPNT) scenario 0 summer peak models for the 2016, 2017, and 2020 study years. Transmission additions, corrections, and resource retirements included in the ITPNT models were created with SPP member input and modeled in GridView™ for the LOLE analysis.

2.3. **Hourly Load Shapes and Forecasted Peak Demand**

The non-coincident annual peak loads of each SPP area sourced from the 2015 member submitted Energy Information Administration (EIA)-411⁶ forms were used for each entity in the LOLE models. Historical hourly load data from 2007 to 2011 was used to produce an 8,760 hourly load shape for each modeled area. This historical data was obtained by either member data submittals or Federal Energy Regulatory Commission (FERC) 714 filings. The data was then modified by normalizing each hour to the maximum load value for each year, shifting each year to match the correct day of the week, averaging the years together, and multiplying the normalized values by the projected peak load. Analyzing a minimum of five years of historical load data provided a typical range of load patterns for the study. Approximately 98% of reported peak demand included losses.

2.4. **Traditional Dispatchable Capacity and Generation**

The generation data included in the models consist of the following: Capacity Resource Capability information from EIA-411 data, Equivalent Forced Outage Rate – demand (EFORd), Outage Duration, and Fuel Price information from current PROMOD data and maintenance schedule information from historical planned outages submitted through the SPP Control Room Operations Window (CROW) database.

2.4.1. **Ratings**

The maximum capacity ratings were submitted in the 2015 EIA-411 data and are based on SPP member’s summer seasonal capability testing. The capability testing procedure and requirements are described in SPP Criteria section 12.1.1⁷.

---

⁶ The EIA-411 data for the area labeled WAPA was submitted by Mid-Continent Area Power Pool (MAPP) on behalf of the WAPA area entities. MAPP provided SPP with the most recent EIA-411 version of each entity.

2.4.2. Forced outage modeling

Forced outage modeling within GridView™ consists of using the EFORd values calculated by Ventyx from the Energy Velocity database. The Capacity Margin Task Force discussed using NERC GADs data for the forced outage rate, but without having a better working knowledge of GADs felt it was best to continue using the Ventyx data.

The number of unit outages per hour was determined by comparing GridView™ simulation outages to real time historical outages sourced from SPP CROW database. The number of resource outages correlates to the amount of generation on outage (MW) for each hour in the SPP footprint which was compared to the outage shape created by GridView™. The value for hourly resource outages was set to a maximum of 24 units per hour and five new outages to be available for outage. Figure 1 shows the comparison of max outages for each hour from GridView™ to the averages historical outages per hour for the past three years within the summer timeframe. The historical outages sourced from CROW include all forced and planned outages in Figure 1 but do not include partially de-rated capacity.

Historically, planned outages have been recorded in the summer timeframe. Since GridView™ does not allow planned outages for this timeframe, the historical summer planned outages had to be considered as forced outages. The setting of N-24 was selected due to the amount of simulated outaged generation closely representing the averaged historical outage values. For the 2020 study, the maximum number of outages per hour was increased to N-30 due to generation changes from 2017 to 2020.

---

8 Maintenance schedules for Integrated System (Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumers Power District, NorthWestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative) were obtained through member submitted data.

9 The only resources considered for outage comparison were ones with an “out-of-service” status. The capability to de-rate capacity is currently not modeled in GridView™.
2.4.3. Planned Outage Modeling

Planned outages for thermal units, provided by SPP Members, were modeled using the scheduled maintenance function in GridView™ by switching the status of each unit to “off-line” for a specified period of time based on start time, end time, and duration. Once the outage duration elapsed, the unit was placed back online in the model. The maintenance start date and outage duration were sourced from the CROW database which SPP members use to plan maintenance outages. For generators that did not have a designated outage planned, previous planned outages were modeled from previous LOLE studies in comparison with planned historical outages submitted in CROW. If historical planned outages sourced from CROW were inconsistent with previous LOLE study maintenance schedules, then the averaged historical CROW outage durations and timeframes from 2012 to 2014 were modeled for simulation.

2.4.4. Behind-the-meter generation

Behind-the-meter generation is generally netted and modeled with customer load. If the behind-the-meter generation was not netted, then it was modeled as a resource.

2.5. Wind Resources

The LOLE model included wind resources currently installed, under construction, or that have a signed interconnection agreement within the SPP CBA footprint. The total wind

---

10 Crow maintenance schedules for 2012 to 2014 were the years used for comparison purposes against modeled maintenance schedules for the LOLE study.
nameplate capacity in the LOLE models is 12,992 MW for 2016, 13,254 MW for 2017, and 13,554 for 2020.

Hourly wind generation shapes were derived from normalized and averaged historical shapes from 2007 to 2011, which were obtained through member data submittals or National Renewable Energy Laboratory (NREL). An hourly normalized value was calculated dividing each hourly output value by the wind shape peak for each year. The hourly wind shapes were then shifted to align the same day of the week for all five years. Each normalized value was averaged to create one wind shape for each resource. The nameplate value of the resource was then multiplied by the hourly normalized and averaged values to reflect the dispatch of the wind resources. The location of wind resources within the SPP region are geographically diversified as shown in Figure 2.

![Figure 2: Wind resources within the SPP footprint](image)

The capacity value dispatched during model simulation was based on an 8760 wind shape and the peak hourly output value was applied to each area’s load adjustment calculation. The
peak hourly output used in the calculating the load adjustment’s was 947 MW in 2016, 965 MW in 2017, and 988 MW in 2020. Table 1 reflects the non-coincident peak values for total wind accounted for during simulation, the 2015 EAI-411 accredited capacity for wind, and the amount not accounted for in simulation when compared to the wind accreditation values. The adjusted committed capacity and adjusted reserve margin percentages reflect the additional accredited wind capacity added to the studied total committed capacity as shown in Table 8 and Table 1011.

<table>
<thead>
<tr>
<th>Category</th>
<th>2016 (MW)</th>
<th>2017 (MW)</th>
<th>2020 (MW)</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind nameplate Capacity</td>
<td>12,992</td>
<td>13,254</td>
<td>13,554</td>
<td></td>
</tr>
<tr>
<td>Testing Wind Capacity</td>
<td>947</td>
<td>965</td>
<td>988</td>
<td>[A]</td>
</tr>
<tr>
<td>EIA-411 Accredited Wind Capacity</td>
<td>1,137</td>
<td>1,217</td>
<td>1,237</td>
<td>[B]</td>
</tr>
<tr>
<td>Additional accredited Wind Not Accounted in Simulation</td>
<td>190</td>
<td>252</td>
<td>249</td>
<td>[C] = [B – A]</td>
</tr>
</tbody>
</table>

Table 1: Wind accreditation compared to studied wind values

The example in Figure 3 shows an hourly dispatch shape of a 200 Megawatt (MW) nameplate wind resource located in northern Kansas for the month of August incorporated in the LOLE model. The blue line indicates the wind shape from NREL for one year and the red line indicates the wind shape for five years for the same wind resource.

![Image](August Wind Shape Example)

Figure 3: A 200 MW nameplate resource shape compared to one year shape

The example in Figure 4 shows four historical hourly wind output values for five years and the normalized, averaged hourly wind shape value as a comparison to the historical values.

11 The reserve margin was adjusted for the additional accreditation of wind not used in the simulations.
2.6. **Monitored Constraints and Elements**

All internal and crossing interfaces along with SPP flowgates for the LOLE study years were implemented using the 2015 SPP Operation’s OASIS Book of Flowgates. Interfaces are key groups of transmission lines that are observed as one group between external regions or internal Legacy Balancing Authorities (LBA).

The monitored elements were kept to a minimal amount in order to reduce run-time. The number for each element within both studies is listed in Table 2.

<table>
<thead>
<tr>
<th>Element</th>
<th>2016 Study</th>
<th>2017 Study</th>
<th>2020 Study</th>
</tr>
</thead>
<tbody>
<tr>
<td>Monitored Contingencies</td>
<td>214</td>
<td>214</td>
<td>214</td>
</tr>
<tr>
<td>Monitored Branches either crossing or internal to SPP (230 kV and above)</td>
<td>530</td>
<td>546</td>
<td>564</td>
</tr>
<tr>
<td>Monitored Interfaces within SPP&lt;sup&gt;12&lt;/sup&gt;</td>
<td>8</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Branches included in Interfaces within SPP</td>
<td>41</td>
<td>43</td>
<td>46</td>
</tr>
<tr>
<td>Monitored Interfaces connecting SPP to any external region&lt;sup&gt;13&lt;/sup&gt;</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Branches included in Interfaces connecting SPP to any external region</td>
<td>366</td>
<td>366</td>
<td>366</td>
</tr>
</tbody>
</table>

<sup>12</sup> The internal interface list includes the SPS to SPP ties for limitation purposes pertaining to generation outage factors as well as other monitored interfaces concerning voltage stability limits when specific generation is not available.

<sup>13</sup> The external regions included in the crossing interface list consist of Midcontinent Independent System Operator (MISO), Associated Electric Cooperative Incorporated (AECI), and Western Electricity Coordinating Council (WECC).
2.7. **DC Ties**

Direct current (DC) ties were modeled as hourly generators at the point of interconnection to SPP. The amount for each DC tie was derived by using the same method outlined for Interregional transactions. The Modeling Development Working Group (MDWG) submittal workbook contains transaction amounts for the firm capacity amount and the firm transmission reservation amounts across each DC tie. These values were verified against the SPP OASIS database and the DC tie limitations used in the Integrated Transmission Planning ten year (ITP10) study model. Table 3 shows the amount applied to each DC tie within the LOLE model. The net value was determined by subtracting the export planning capacity amount from the import firm transmission reservation amount.

![Table 3: DC tie transactional amounts used in the LOLE analysis](image)

<table>
<thead>
<tr>
<th>DC Tie</th>
<th>2016, 2017, and 2020 LOLE Studies (MW)(^{14})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blackwater</td>
<td>0</td>
</tr>
<tr>
<td>Eddy</td>
<td>0</td>
</tr>
<tr>
<td>ERCOT East</td>
<td>-550</td>
</tr>
<tr>
<td>ERCOT North</td>
<td>220</td>
</tr>
<tr>
<td>Lamar</td>
<td>208</td>
</tr>
<tr>
<td>Miles City</td>
<td>140</td>
</tr>
<tr>
<td>Rapid City</td>
<td>0</td>
</tr>
<tr>
<td>Sidney</td>
<td>90</td>
</tr>
<tr>
<td>Stegall</td>
<td>0</td>
</tr>
<tr>
<td><strong>Net Amount</strong></td>
<td><strong>108</strong></td>
</tr>
</tbody>
</table>

2.8. **Interregional Transactions**

All interregional capacity sales and purchases were firm transactions obtained through the SPP ITPNT Scenario 0 model series and verified against the 2015 EIA-411 submissions. The net transaction amount was calculated by subtracting the export planning capacity amount from the import firm transmission reservation amount for each area. Once the transaction amounts were obtained, they were modeled as generators external to the SPP footprint with no forced outage rates applied to the generators. If the net amount was negative (exporting from SPP), a negative generator with a set hourly dispatch for the net amount was assigned to the external area’s swing bus, obtained through PSS®E data, and committed to the internal area within the SPP footprint. In the example shown below, if an area within SPP, Area A, is planning on a net transaction

\(^{14}\) DC Tie transactions were the same values for all study years.
amount to an external area, Area B, for 50 MW then a negative generator would be placed in Area B and committed to Area A for each hour of the year at -50 MW (Figure 5).

If the net amount was positive (importing to SPP), a thermal generator was modeled on the external area’s swing bus and committed to the area within the SPP footprint planning for the capacity. The minimum capacity was set to zero MW and the max capacity was set to the net transaction value. If the planning capacity amount for the summer season was less than the firm transmission reservation of the transaction, then it was given an additional capacity amount for dispatch purposes. For example, if there is a capacity contract for 50 MW from an external area outside the SPP footprint committed to an area within SPP but there is a 100 MW firm transmission reservation amount for the transaction then both values will be honored. A price curve will be established for the generator with the minimum capacity set to zero, the next capacity step set to 50 MW, and the max capacity set to 100 MW. However, the pricing will be double for the max capacity amount, 100 MW, when compared to the second capacity amount, 50 MW (Figure 6), to dispatch internal capacity within the SPP footprint prior to relying upon external resources for capacity needs.

The net transaction amounts from external regions incorporated in the LOLE analysis are given in Table 4.
### 2.9. Demand Response

SPP has controllable-capacity demand in the form of interruptible (curtailable) demand. In areas that reported controllable-capacity demand, equivalent thermal units were added to the model with assumed high fuel costs so those units would be dispatched last to reflect demand-response operating scenarios to prevent loss of load events.

### 2.10. Load Forecast Uncertainty

#### 2.10.1. Method

GridView™ allows for two options in dealing with load uncertainty: 1) user defined uncertainty pattern, and 2) probability distribution. For this study, a user-defined uncertainty pattern and a probability distribution were both used to add uncertainty to the load values. A different load uncertainty was created for each area within SPP.

#### 2.10.2. Uncertainty Component

A load model was used to define the peak-load multipliers used to modify forecasted loads. The daily peak was selected and regressed against historical peak temperatures from 2007-2011. Crystal Ball Pro® was used to analyze the probability distributions of temperatures observed at key weather stations throughout the SPP footprint. The load model increased load as the winter temperatures decreased and as the shoulder and summer temperatures increased. A forecast was then created for both study years. Based on the derived forecasts, multipliers were calculated and populated in a user defined uncertainty pattern. The multipliers were then normalized to where the highest multiplier was 3.95\% higher than the base multiplier. All other multipliers between the base and the highest multiplier were given load increases from 0\% to 3.95\% based upon a linear regression in relation to the proportional increase of each multiplier. The user-defined uncertainty pattern allows users to provide seven monthly load patterns. Each area has a different value for each month multiplied by seven probabilities (a total of 84 values). GridView™ randomly selects the load pattern at the beginning of the simulation hour, and applies it for that trial. The random load uncertainty allows for unexpected increases of load added to the adjusted peak

<table>
<thead>
<tr>
<th>Region</th>
<th>2016 Net External Transactions (MW)</th>
<th>2017 Net External Transactions (MW)</th>
<th>2020 Net External Transactions (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPP</td>
<td>1,785</td>
<td>1,793</td>
<td>1,360</td>
</tr>
</tbody>
</table>

Table 4: Net Interregional transaction value modeled in the LOLE analysis
demand for each area to analyze the criteria of one day in ten years at the testing reserve margin.

2.10.3. Incorporating the Probability

The randomly selected load multipliers were determined from a uniform distribution and selecting one of seven possible multipliers. The probability of occurrence for load multipliers decreased as the multiplier for load increased (e.g., Set 1 is 50% likely, Set 2 is 19% likely, Set 7 is 0.6% likely). No multipliers decreased the load values in this study for reliability considerations of load increases. Multiplier Set 1 was the base case multiplier, and effectively multiplies all loads by 1. Sets 2–7 were intended to proportionally increase loads up to extreme peaks within SPP. Figure 7 is an example of one area’s load incremental matrix and Figure 8 shows the occurring probability of each load increase pattern.

<table>
<thead>
<tr>
<th>Area Name</th>
<th>Pattern</th>
<th>M1</th>
<th>M2</th>
<th>M3</th>
<th>M4</th>
<th>M5</th>
<th>M6</th>
<th>M7</th>
<th>M8</th>
<th>M9</th>
<th>M10</th>
<th>M11</th>
<th>M12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area 1</td>
<td>P1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Area 1</td>
<td>P2</td>
<td>1.0112</td>
<td>1.0123</td>
<td>1.0137</td>
<td>1.0134</td>
<td>1.0132</td>
<td>1.0066</td>
<td>1.0060</td>
<td>1.0121</td>
<td>1.0134</td>
<td>1.0140</td>
<td>1.0126</td>
<td></td>
</tr>
<tr>
<td>Area 1</td>
<td>P3</td>
<td>1.0154</td>
<td>1.0173</td>
<td>1.0228</td>
<td>1.0228</td>
<td>1.0222</td>
<td>1.0123</td>
<td>1.0112</td>
<td>1.0112</td>
<td>1.0206</td>
<td>1.0225</td>
<td>1.0236</td>
<td>1.0178</td>
</tr>
<tr>
<td>Area 1</td>
<td>P4</td>
<td>1.0203</td>
<td>1.0225</td>
<td>1.0288</td>
<td>1.0288</td>
<td>1.0283</td>
<td>1.0217</td>
<td>1.0211</td>
<td>1.0208</td>
<td>1.0289</td>
<td>1.0233</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Area 1</td>
<td>P5</td>
<td>1.0225</td>
<td>1.0250</td>
<td>1.0340</td>
<td>1.0343</td>
<td>1.0335</td>
<td>1.0261</td>
<td>1.0252</td>
<td>1.0252</td>
<td>1.0321</td>
<td>1.0337</td>
<td>1.0354</td>
<td>1.0261</td>
</tr>
<tr>
<td>Area 1</td>
<td>P6</td>
<td>1.0230</td>
<td>1.0255</td>
<td>1.0376</td>
<td>1.0381</td>
<td>1.0376</td>
<td>1.0285</td>
<td>1.0274</td>
<td>1.0274</td>
<td>1.0357</td>
<td>1.0379</td>
<td>1.0395</td>
<td>1.0269</td>
</tr>
<tr>
<td>Area 1</td>
<td>P7</td>
<td>1.0230</td>
<td>1.0255</td>
<td>1.0376</td>
<td>1.0381</td>
<td>1.0376</td>
<td>1.0285</td>
<td>1.0274</td>
<td>1.0274</td>
<td>1.0357</td>
<td>1.0379</td>
<td>1.0395</td>
<td>1.0269</td>
</tr>
</tbody>
</table>

Figure 7: A load probability matrix example for one area

<table>
<thead>
<tr>
<th>Load Multiplier Pattern</th>
<th>Percentage Chance of selection for simulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>P1</td>
<td>50%</td>
</tr>
<tr>
<td>P2</td>
<td>19.15%</td>
</tr>
<tr>
<td>P3</td>
<td>14.99%</td>
</tr>
<tr>
<td>P4</td>
<td>9.18%</td>
</tr>
<tr>
<td>P5</td>
<td>4.41%</td>
</tr>
<tr>
<td>P6</td>
<td>1.65%</td>
</tr>
<tr>
<td>P7</td>
<td>0.62%</td>
</tr>
</tbody>
</table>

Figure 8: The occurrence probability for each multiplier

2.10.4. Consideration for variability of uncertainty

The load-uncertainty probability took into consideration stochastic temperature within the different areas, in addition to recognizing the structural affects that holidays, weekends, quarters, and previous hour’s load have on load expectations. Other sources of uncertainty reasonably independent of temperature were considered to be sufficiently small in magnitude and not necessary at this time to model independently. A random error term was created to...
incorporate variability that could occur from uncertainty types such as economic industrial/commercial health and dew point.
## 3. Study Assumptions

### 3.1. LOLE Study Comparisons

Table 5 demonstrates the comparison of LOLE studies from 2012 to 2015 and shows the assumption improvements compared to the previous study. The impact of the modifications reflects improvements due to defects in software and study simulation based on historical analysis.

<table>
<thead>
<tr>
<th>Study Inputs</th>
<th>2012 LOLE Study Assumptions</th>
<th>2015 LOLE Study Assumptions</th>
<th>Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator Outages</td>
<td>Maximum of 5 (N-5) forced outages per hour</td>
<td>Maximum of 24 (N-24) forced outages per hour</td>
<td>Increasing the amount of resources forced out per hour demonstrated a more realistic approach when compared to historical outage MWs</td>
</tr>
<tr>
<td>Transformer Ratings</td>
<td>Ratings Not Updated</td>
<td>Ratings Updated</td>
<td>A software bug which inaccurately imported transformer ratings from PSSe was corrected</td>
</tr>
<tr>
<td>Transformer Impedances</td>
<td>Impedances Not Updated</td>
<td>Impedances Updated</td>
<td>A software bug which inaccurately imported transformer impedances from PSSe</td>
</tr>
<tr>
<td>Generator Dispatch</td>
<td>Area by Area</td>
<td>Regional Dispatch</td>
<td>Regional dispatch allowed generation to serve load throughout the SPP footprint with respect to transmission limitations</td>
</tr>
<tr>
<td>Load Forecast Uncertainty (LFU)</td>
<td>Range of 0% to 25% (^{15}), All areas set to different maximum LFU</td>
<td>Range of 0% to 3.95%, All areas set to same maximum LFU</td>
<td>The change in load forecast uncertainty represents a realistic load increment for uncertainty based on historical load forecast deviation</td>
</tr>
<tr>
<td>Load Shedding Penalty</td>
<td>$800 per MW-hour</td>
<td>$2000 per MW-hour</td>
<td>Increasing the load shedding penalty allowed economic generation to be dispatched in place of shedding load</td>
</tr>
<tr>
<td>LOLE Metric</td>
<td>Events/per year</td>
<td>Days/per year</td>
<td>Software update which reflects the standard of days per year rather than events per year</td>
</tr>
<tr>
<td>Facility Rating</td>
<td>Rate B</td>
<td>Rate A</td>
<td>Rate A limits the flow on the transmission system more than Rate B, which is more conservative</td>
</tr>
<tr>
<td>Transactions</td>
<td>Area to Area modeled</td>
<td>Area to Area not modeled</td>
<td>Removing the area to area transactions allowed for a CBA dispatch constrained by transmission limits</td>
</tr>
<tr>
<td>Wind Modeling</td>
<td>Modeled single year 2005 wind shape (^{16})</td>
<td>2007 to 2011 averaged wind shape</td>
<td>Averaging the wind shapes decreases the volatility</td>
</tr>
</tbody>
</table>

Table 5: LOLE comparisons between the 2012 and 2015 studies

\(^{15}\) The 25% maximum load uncertainty was applied to two areas. The other areas ranged anywhere from 5% to 20%.

\(^{16}\) The accredited wind used in the 2012 study was 1,192 MW for 2014 and 1,290 MW for 2016.
Key assumptions and methodologies outlined in the SPP LOLE study were compared to surrounding Regional Transmission Organizations (RTOs), which are shown in Table 6.

<table>
<thead>
<tr>
<th>Item</th>
<th>SPP</th>
<th>MISO</th>
<th>ERCOT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Software</td>
<td>GridView™</td>
<td>GE MARS</td>
<td>SERVM</td>
</tr>
<tr>
<td>Method</td>
<td>Monte Carlo</td>
<td>Monte Carlo</td>
<td>Monte Carlo</td>
</tr>
<tr>
<td>Trials</td>
<td>3,000</td>
<td>2,000</td>
<td>11,000</td>
</tr>
<tr>
<td>Run time</td>
<td>72 hours</td>
<td>3 hours</td>
<td>35 hours</td>
</tr>
<tr>
<td>Load Forecast Uncertainty</td>
<td>0% to +3.95%,</td>
<td>-5% to +5%,</td>
<td>-5% to +4.2%,</td>
</tr>
<tr>
<td></td>
<td>7 step only</td>
<td>7 step normalized</td>
<td>normal distribution,</td>
</tr>
<tr>
<td></td>
<td>positive normal</td>
<td>distribution,</td>
<td>55 load scenarios</td>
</tr>
<tr>
<td></td>
<td>distribution,</td>
<td>20 years</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1.5 years</td>
<td>historical</td>
<td></td>
</tr>
<tr>
<td></td>
<td>historical market</td>
<td>data (5 minute intervals)</td>
<td></td>
</tr>
<tr>
<td>Uncertainties considered</td>
<td>weather, forecast</td>
<td>weather, economic</td>
<td>weather, economic, forecast</td>
</tr>
<tr>
<td>Peak Demand</td>
<td>Non-Coincident</td>
<td>Coincident</td>
<td>Coincident</td>
</tr>
<tr>
<td>Wind Modeling</td>
<td>Resource</td>
<td>Load Modifier</td>
<td>Resource</td>
</tr>
<tr>
<td>Wind shapes</td>
<td>Hourly shape</td>
<td>Modeled as capacity credit value</td>
<td>Hourly for 11 years matching load shape</td>
</tr>
<tr>
<td>Transmission modeling</td>
<td>DC load flow</td>
<td>None</td>
<td>Transportation/pipeline</td>
</tr>
<tr>
<td>Monitored transmission</td>
<td>Flowgates,</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>interfaces, and</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>230 kV+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity de-rates for thermal generation</td>
<td>None</td>
<td>Monthly</td>
<td>Temperature based</td>
</tr>
<tr>
<td>Forgo Operating Reserves</td>
<td>Fully</td>
<td>Not Considered</td>
<td>Partially</td>
</tr>
</tbody>
</table>

Table 6: Assumption and methodology comparisons of other RTOs to SPP

3.2. Simulation Period

Each simulation period (years 2016, 2017, and 2020) included all hours from January 1\textsuperscript{st} to December 31\textsuperscript{st}. The LOLE calculation considers all hours of the year for the probability of loss of load.

3.3. Summer Season

The defined summer timeframe was June 1\textsuperscript{st} through September 30\textsuperscript{th}. This timeframe was established from the assumption there were no maintenance outages in the summer timeframe and it aligned with the summer planning season.
3.4. **Branch and Load Penalties**

The load shed penalty was set to $2000/MWh and the branch overload penalty was $6000/MWh. With the branch overload penalty higher than the load shed penalty, the software sheds load before violating any transmission limits rated at 230 kV and above.

3.5. **Modeled Generation**

Only existing and future planned reported generation were used as inputs for the analysis from the 2016 ITPNT scenario 0 summer peak models for the 2016, 2017, and 2020 study years. Future planned generation had to be under construction or have a signed generation interconnection agreement to be included in the analysis.

3.6. **Capacity Configuration**

The capacity configuration by fuel type and category for the LOLE studies are shown below in Table 7.

<table>
<thead>
<tr>
<th>Total Committed Capacity Fuel Type</th>
<th>2016 Study (MW)</th>
<th>2017 Study (MW)</th>
<th>2020 Study (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Response-Available</td>
<td>706</td>
<td>828</td>
<td>973</td>
</tr>
<tr>
<td>Coal Capacity</td>
<td>26,428</td>
<td>25,657</td>
<td>25,507</td>
</tr>
<tr>
<td>Gas Capacity</td>
<td>30,345</td>
<td>31,330</td>
<td>31,121</td>
</tr>
<tr>
<td>Hydro and Pumped Storage Capacity</td>
<td>5,226</td>
<td>5,226</td>
<td>5,226</td>
</tr>
<tr>
<td>Nuclear Capacity</td>
<td>2,565</td>
<td>2,565</td>
<td>2,565</td>
</tr>
<tr>
<td>Wind Capacity</td>
<td>947</td>
<td>965</td>
<td>988</td>
</tr>
<tr>
<td>Solar Capacity</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Petroleum Capacity</td>
<td>2,293</td>
<td>2,193</td>
<td>2,243</td>
</tr>
<tr>
<td>Other Capacity&lt;sup&gt;17&lt;/sup&gt;</td>
<td>134</td>
<td>134</td>
<td>134</td>
</tr>
<tr>
<td>Sales</td>
<td>1,387</td>
<td>1,387</td>
<td>896</td>
</tr>
<tr>
<td>Purchases</td>
<td>3,284</td>
<td>3,292</td>
<td>2,256</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>70,465</td>
<td>70,808</td>
<td>70,161</td>
</tr>
</tbody>
</table>

<sup>17</sup> The resources listed as other include behind the meter generators with an unidentified fuel type, 31 MW, or biomass, 103 MW.
3.7. **Load Uncertainty**

A forecasted load model was used to define the peak-load multipliers for forecasted loads. Based on historical load shapes sourced from SPP operational data, multipliers were calculated and populated in a user defined uncertainty pattern as previously described in Section 2.10. The multipliers were normalized to where the highest multiplier was 3.95% higher than the base multiplier, which was 0% load increase. All other multipliers between the base and the highest multiplier were given load increases from 0% to 3.95% based upon the proportional increase of each multiplier derived from a linear regression load forecast matrix.

3.8. **Operating Reserves**

SPP operating reserves were assumed to be available during simulation to avoid load shed.

3.9. **Transmission Monitoring**

The LOLE study monitored SPP transmission rated 230 kV or above and all SPP flowgates sourced from the 2015 SPP Book of Flowgates.

Transmission below 230 kV was not monitored due to the time constraint associated with the computational time. With the current assumption of monitoring 230kV and above through 3,000 trials, the simulation time period was 72 hours. Monitoring the entire transmission system could result in an excessive runtime for the analysis that would take weeks to perform.

3.10. **Area Demand Adjustment**

Demand was manually calculated and adjusted on an area basis to ensure all areas were being tested at the studied reserve margin by comparing each area’s peak demand with their associated planning capacity amount. The load adjustments were applied to scalable load points within the SPP footprint that were derived from the ITPNT model and applied to the LOLE study. Table 8 shows the total calculated capacity used for the 2016, 2017, and 2020 simulation years.

<table>
<thead>
<tr>
<th>Category (NCP)</th>
<th>2016 (MW)</th>
<th>2017 (MW)</th>
<th>2020 (MW)</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Intraregional Transactions</td>
<td>-80</td>
<td>-121</td>
<td>73</td>
<td>([A])</td>
</tr>
<tr>
<td>Thermal Generation Max Capacity</td>
<td>66,995</td>
<td>67,238</td>
<td>67,067</td>
<td>([B])</td>
</tr>
<tr>
<td>Studied Wind Generation</td>
<td>947</td>
<td>965</td>
<td>988</td>
<td>([C])</td>
</tr>
<tr>
<td>Net DC Tie Transactions</td>
<td>112</td>
<td>112</td>
<td>112</td>
<td>([D])</td>
</tr>
<tr>
<td>Net Interregional Transactions</td>
<td>1,785</td>
<td>1,793</td>
<td>1,248</td>
<td>([E])</td>
</tr>
<tr>
<td>Demand Response</td>
<td>706</td>
<td>821</td>
<td>973</td>
<td>([F])</td>
</tr>
<tr>
<td>Installed Committed Capacity</td>
<td>70,465</td>
<td>70,808</td>
<td>70,161</td>
<td>(G = [A + B + C + D + E + F])</td>
</tr>
<tr>
<td>Studied Reserve Margin</td>
<td>9.89%</td>
<td>9.89%</td>
<td>9.89%</td>
<td>([X])</td>
</tr>
<tr>
<td>Desired Total Demand</td>
<td>64,123</td>
<td>64,435</td>
<td>63,846</td>
<td>(H = [G / (1+X)])</td>
</tr>
</tbody>
</table>

**Table 8:** Total NCP committed capacity and applied testing demand values at 9.89% reserve margin
The total installed committed capacity calculation for each area included:

1. SPP Intraregional transactions
   a. Not modeled for simulation, but included in the studied reserve margin calculation
2. Net capability of thermal, hydro, pump storage, and other fuel types
   a. Modeled as resources for simulation
3. Wind and solar generation at the time of the area’s peak load
   a. Modeled as resources for simulation
4. SPP Interregional and DC tie transactions
   a. Modeled as resources for simulation
   b. Net amount is determined by subtracting the planning export amount by the full firm import reservation amount for each area.
5. Total demand response
   a. Modeled as high cost resources for simulation

The total committed capacity values and studied non-coincident peak demand for each studied reserve margin are shown in Table 9, Table 10, and Table 11 for the 2016, 2017, and 2020 study years, respectively. The adjusted committed capacity and the adjusted reserve margin include the additional wind accredited amount\(^\text{18}\) that was not included for simulation as described in section 2.5. Figure 9 indicates the demand adjustment boundaries for each area outlined in each assessment.

<table>
<thead>
<tr>
<th>Studied Reserve Margin (%)</th>
<th>Adjusted Reserve Margin (%)</th>
<th>Total Committed Capacity (MW)</th>
<th>Adjusted Committed Capacity (MW)</th>
<th>Studied Non-Coincident Peak Demand (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.53</td>
<td>7.82</td>
<td>70,465</td>
<td>70,655</td>
<td>65,530</td>
</tr>
<tr>
<td>8.70</td>
<td>9.00</td>
<td>70,465</td>
<td>70,655</td>
<td>64,825</td>
</tr>
<tr>
<td>9.89</td>
<td>10.19</td>
<td>70,465</td>
<td>70,655</td>
<td>64,123</td>
</tr>
<tr>
<td>11.11</td>
<td>11.41</td>
<td>70,465</td>
<td>70,655</td>
<td>63,419</td>
</tr>
</tbody>
</table>

Table 9: The 2016 SPP adjusted peak demand values associated with the studied reserve margins

---

\(^{18}\) The EIA-411 accredited capacity was added to the peak hourly output value and applied to each area’s load adjustment calculation.

\(^{19}\) The EIA-411 non-coincident peak demand for 2016 was 53,913 MW, 55,085 MW for 2017, and 56,413 for 2020.
<table>
<thead>
<tr>
<th>Studied Reserve Margin (%)</th>
<th>Adjusted Reserve Margin (%)</th>
<th>Total Committed Capacity (MW)</th>
<th>Adjusted Committed Capacity (MW)</th>
<th>Studied Non-Coincident Peak Demand (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.53</td>
<td>7.91</td>
<td>70,808</td>
<td>71,036</td>
<td>65,850</td>
</tr>
<tr>
<td>8.70</td>
<td>9.09</td>
<td>70,808</td>
<td>71,036</td>
<td>65,141</td>
</tr>
<tr>
<td>9.89</td>
<td>10.29</td>
<td>70,808</td>
<td>71,036</td>
<td>64,435</td>
</tr>
<tr>
<td>11.11</td>
<td>11.51</td>
<td>70,808</td>
<td>71,036</td>
<td>63,728</td>
</tr>
</tbody>
</table>

Table 10: The 2017 SPP adjusted peak demand values associated with the studied reserve margins

<table>
<thead>
<tr>
<th>Studied Reserve Margin (%)</th>
<th>Adjusted Reserve Margin (%)</th>
<th>Total Committed Capacity (MW)</th>
<th>Adjusted Committed Capacity (MW)</th>
<th>Studied Non-Coincident Peak Demand (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.53</td>
<td>7.91</td>
<td>70,161</td>
<td>70,410</td>
<td>65,248</td>
</tr>
<tr>
<td>8.70</td>
<td>9.08</td>
<td>70,161</td>
<td>70,410</td>
<td>64,545</td>
</tr>
<tr>
<td>9.89</td>
<td>10.28</td>
<td>70,161</td>
<td>70,410</td>
<td>63,846</td>
</tr>
<tr>
<td>11.11</td>
<td>11.50</td>
<td>70,161</td>
<td>70,410</td>
<td>63,145</td>
</tr>
</tbody>
</table>

Table 11: The 2020 SPP adjusted peak demand values associated with the studied reserve margins
Figure 9: Geographical load adjustment boundaries within SPP
3.11. Regional Dispatch

Generation was dispatched using a Security Constrained Economic Dispatch (SCED) algorithm based upon the SPP Consolidated Balancing Authority boundary.

3.12. Interregional Transactions

Region to region firm transactions, including DC ties, were modeled as thermal resources representing the full capacity of the transaction based upon firm transmission service sourced from the MDWG Submittal workbook verified with the SPP OASIS database. The net transaction amount was achieved by subtracting the firm export planning amount from the firm import capacity amount for the transmission reservations.

3.13. Operating procedures

SPP operating guides structured around resources or demand were incorporated into the study due to possible impact on the loss of load probability.
4. Model Simulation

4.1. Market Analysis Approach

The GridView™ software solves each hour using a Security Constrained Economic Dispatch (SCED) algorithm which is similar to the SPP Integrated Market. The setting in GridView™ for committing resources was set to a “Commit All” status for all generation within the SPP footprint. This setting was based on the assumption in which all capacity in the SPP footprint was available for dispatch if not on maintenance outage, forced outage, retired, or unavailable firm service capacity committed to serving an external area outside the SPP footprint. The analysis was performed simulating a regional dispatch as the software solves for the least cost generation to serve all load within the SPP region. (A detailed software description is given in Appendix A: Software Model Description.)

4.2. Monte-Carlo algorithm

SPP conducted the GridView™ Monte Carlo Simulation at 3,000 or more trials, in which each trial accounts for variations in random forced outages and load forecast uncertainty. Each trial represented a single 8760-hour simulation. GridView™ calculates a standard error to determine whether more simulation trials are needed. The standard error recommended to reach a considerable probability convergence to prevent excessive time for trial simulation is 10% or less.

The standard error calculation is a measure of the statistical accuracy or variability of an estimate which is equal to the standard deviation of the distribution of sample means while taking into consideration the amount of trials in the data set. The equation and the respective variables for the standard error relating to the variation of the sampling set for LOLE used in GridView™ is shown in the following example.

<table>
<thead>
<tr>
<th>Standard Deviation</th>
<th>σ</th>
<th>0.2645</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of yearly trials in the data set</td>
<td>N</td>
<td>150</td>
</tr>
<tr>
<td>Average or Mean of the data set</td>
<td>( \bar{X} )</td>
<td>0.06 days per year</td>
</tr>
<tr>
<td>GridView™ Standard Error Formula</td>
<td>( [\sigma/\sqrt{N}]/\bar{X} )</td>
<td>0.360</td>
</tr>
</tbody>
</table>

Number of LOLE days (summation of the days within the simulations) = 9 days
LOLE days/year (\( \bar{X} \)) = 9/150 = 0.06 days/year = 0.60 days per 10 years
Standard Error of the LOLE results = \( [\sigma/\sqrt{N}]/\bar{X} = [0.2645/\sqrt{150}]/0.06 = 0.360 \)

\(^{20}\) 1 simulation has 2 days LOLE, 7 simulations has 1 day LOLE, 142 simulations has 0 days LOLE
4.3. **Regional Security Constrained Economic Dispatch**

The map in Figure 10 shows the dispatching boundaries of the SPP footprint for the LOLE analysis. The GridView™ software dispatches generation on an hour by hour basis by balancing load and generation taking into account localized constraints, generation outages, and increased load forecast uncertainty for the entire SPP region\(^\text{21}\). 

![Figure 10: Regional map indicating the dispatch boundary for the LOLE analysis](image)

\(^{21}\) The area labeled “WAPA” only included the eastern interconnect portions of WAPA for simulations purposes, i.e. all facilities east of the DC ties.
5. Results

5.1. Study Results

The Loss of Load Expectation (LOLE) calculation considers all hours of the year for any occurrence of loss of load. Per the SPP Criteria, generation reliability assessments examine the regional ability to maintain a LOLE standard of one day in 10 years (0.1 day/year).

Through the EIA-411 process, capacity margin percentages were submitted for each modeled area based upon certain capacity, net firm transactions, available demand-side management, and projected peak demand values. All EIA-411 submissions exhibited a reserve margin above 13.6% for the years studied in the LOLE analysis. The non-coincident peak demand values were then adjusted for each area based upon their respective expected planning capacity. An increase in peak demand resulted in a lower capacity margin and was assigned per area for the trial simulations to reflect the desired studied margin for each area across the SPP region. Based upon the submitted EIA-411 planning values for load, energy, generation, and the assumptions established for the analysis, the GridView™ software was able to calculate a loss of load expectation amount for the studied reserve margin values. The values in Figure 11 reflect the simulation results for all study years (2016, 2017, and 2020).

Table 12, Table 13, and Table 11 show the results depicted in for each studied reserve margin the studied years as well as the correlating capacity margin percentages. The reason for studying the selected reserve margins is due to the conversion of reserve margin to capacity margin percentages where the capacity margin percentages are whole numbers.
<table>
<thead>
<tr>
<th>Capacity Margin (%)</th>
<th>Studied Reserve Margin (%)</th>
<th>Adjusted Reserve Margin (%)</th>
<th>LOLE (Days/10 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.0</td>
<td>7.53</td>
<td>7.82</td>
<td>0.920</td>
</tr>
<tr>
<td>8.0</td>
<td>8.70</td>
<td>9.00</td>
<td>0.458</td>
</tr>
<tr>
<td>9.0</td>
<td>9.89</td>
<td>10.19</td>
<td>0.267</td>
</tr>
<tr>
<td>10.0</td>
<td>11.11</td>
<td>11.41</td>
<td>0.184</td>
</tr>
</tbody>
</table>

Table 12: 2016 LOLE results

<table>
<thead>
<tr>
<th>Capacity Margin (%)</th>
<th>Studied Reserve Margin (%)</th>
<th>Adjusted Reserve Margin (%)</th>
<th>LOLE (Days/10 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.0</td>
<td>7.53</td>
<td>7.91</td>
<td>1.727</td>
</tr>
<tr>
<td>8.0</td>
<td>8.70</td>
<td>9.09</td>
<td>0.454</td>
</tr>
<tr>
<td>9.0</td>
<td>9.89</td>
<td>10.29</td>
<td>0.189</td>
</tr>
<tr>
<td>10.0</td>
<td>11.11</td>
<td>11.51</td>
<td>0.153</td>
</tr>
</tbody>
</table>

Table 13: 2017 LOLE results

<table>
<thead>
<tr>
<th>Capacity Margin (%)</th>
<th>Studied Reserve Margin (%)</th>
<th>Adjusted Reserve Margin (%)</th>
<th>LOLE (Days/10 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.0</td>
<td>7.53</td>
<td>7.91</td>
<td>0.453</td>
</tr>
<tr>
<td>8.0</td>
<td>8.70</td>
<td>9.08</td>
<td>0.367</td>
</tr>
<tr>
<td>9.0</td>
<td>9.89</td>
<td>10.28</td>
<td>0.145</td>
</tr>
<tr>
<td>10.0</td>
<td>11.11</td>
<td>11.50</td>
<td>0.011</td>
</tr>
</tbody>
</table>

Table 14: 2020 LOLE results

---

22 Multiple iterations were performed for each testing reserve margin which ranged from 3,000 trials to 7,000. All simulations met the standard error threshold of 0.10 or less.
6. Conclusion

6.1. **2016 Reserve Margin LOLE Study**

With the inclusion of the latest 2016 Integrated Transmission Planning Near-Term model for the SPP region, along with the installation of new capacity, firm imports from external regions, and the previously stated study assumptions, the GridView™ results determined that the SPP region can maintain the LOLE criteria of one day in ten years for the following adjusted reserve margin percentages: 7.82%, 9.00%, 10.19%, and 11.41%. These adjusted reserve margin values are below the current SPP reserve margin requirement of 13.6%.

6.2. **2017 Reserve Margin LOLE Study**

With the inclusion of the latest 2017 Integrated Transmission Planning Near-Term model for the SPP region, along with the installation of new capacity, firm imports from external regions, and the previously stated study assumptions, the GridView™ results determined that the SPP region can maintain the LOLE criteria of one day in ten years for the following tested reserve margin percentages: 9.09%, 10.29%, and 11.51%. These adjusted reserve margin values are below the current SPP reserve margin requirement of 13.6%.

6.3. **2020 Reserve Margin LOLE Study**

With the inclusion of the latest 2017 Integrated Transmission Planning Near-Term model for the SPP region, along with the installation of new capacity, firm imports from external regions, and the previously stated study assumptions, the GridView™ results determined that the SPP region can maintain the LOLE criteria of one day in ten years for the following tested reserve margin percentages: 7.91%, 9.08%, 10.28%, and 11.50%. These adjusted reserve margin values are below the current SPP reserve margin requirement of 13.6%.
7. Future Study Improvements

7.1. De-rates and market bid file data for resources

The current LOLE study does not include any de-rate options for resources. The options applied to the LOLE study only incorporate “off-line” status for random forced outages, a generation minimum capacity value, and a generation maximum value. This information can be applied in correlation with the economic pricing curves specific for every generator within the analysis. Gathering market type data for the study will improve simulation metrics.

7.2. Wind variability

There was no wind variability incorporated in the LOLE analysis. Any type of unknown temperature or wind patterns is an uncertainty that can be applied in future studies.

7.3. Topology branch outages

The branches which are out of service in the LOLE study are ones submitted through the ITPNT process but GridView™ has the capability to incorporate additional transmission outages for the simulation as one of the uncertainty factors. Historical transmission outages will have to be analyzed in depth to develop a probability matrix for voltage ratings on transmission equipment within SPP.

7.4. Forced outage rates for Interregional transactions

Region to region transactions, including DC ties, are modeled as generation in the LOLE analysis and do not include forced outage rates. The fuel type source of capacity for external transactions will have to be analyzed to determine an applicable forced outage rate applied to each transaction.

7.5. Demand response modeling of energy availability

Demand response reported through the EIA-411 process was modeled as generation with high costs associated with each generator. For future analysis, the incorporation of time constrained or energy constrained programs could be incorporated to the analysis if the LOLE software considers variation with various demand response programs throughout the SPP region.
7.6. **Seasonal incorporation**

The LOLE study includes resource ratings and topology ratings and infrastructure applied to the summer season. It is possible to run additional assessments that address the off-peak seasons or winter season with other ratings. The current LOLE software for SPP only has the capability to study one season per assessment which limits the variability of other seasons to be included in the same trial simulation.

7.7. **Hydro availability limitations**

The specific limitation of other hydro resources can be researched and incorporated to a more granular modeling approach than what is currently assumed for hydro resources.

7.8. **Load forecasting methodology**

The methodology of load forecasting in determining the load multiplier matrix for each area can be improved to incorporate load type classifications, the economic status of the region, additional weather measurements, the occurrence of energy efficiency or demand response programs, or the use of the frequency of irrigation usage within the SPP footprint.

7.9. **Forced Outage Rates for resources**

Ventyx data was incorporated into the LOLE study for all thermal and hydro resources. However, further analysis and research can be performed to validate Ventyx outage rate data compared to historical performance of resources from the North American Electric Reliability Corporation (NERC) Generating Availability Data Systems (GADS).
Appendix A: Software Model Description

A.1 Computational Approach

GridView™ 9.1.12 was used to perform the LOLE study analysis. GridView™ is a software application developed by ABB© Inc. to simulate the economic dispatch of an electric power system while monitoring key transmission elements for each hour. GridView™ can be used to study the operational and planning issues facing regulated utilities, as well as competitive electric markets. The key advantage of using the GridView™ application is having the ability to model a detailed transmission system in the study region, not just a transportation model (Figure 1412). The transmission model allows for realistic power delivery based on actual modeled limits on transmission lines imported from powerflow models. Some other features available in this program include contingency constraints, nomograms, and emergency imports. A sequential Monte-Carlo simulation was used to perform the analysis of the SPP reserve margin study.

![Figure 12: Detailed model diagram of GridView™ software](image)

A.2 Algorithm Usage

Monte Carlo simulation is a method for iteratively evaluating a deterministic model using sets of random numbers as inputs. The goal is to determine how random variation or uncertainty affects the reliability of the system that is being modeled. Monte Carlo simulation is categorized as a sampling
method because the inputs are randomly generated from probability distributions to simulate the process of sampling from an actual population. Within GridViewTM, Monte Carlo simulation allows detailed modeling of the pre-contingency conditions and outages of generation and/or transmission equipment and/or changes in demand, fuel prices, and/or wind generation. GridViewTM can also model the correlation between area load demands and fuel prices. It uses probability distributions for equipment outages during a sequential mode of simulations hour by hour, and typically for a year. The selection of studied conditions is by random sampling. In order to obtain accurate risk indices, multiple simulations will have to be performed (2,400 or more simulations/year study). In general, the simulations provide the loss of load reliability indices. A linear model is applied to the generation dispatch calculation for every hour in each trial in order to compute the amount of load shed in order to eliminate transmission overload problems. The engineer performing the analysis will choose a distribution for the inputs that most closely matches data the planning area already has, or best represents the planning area’s current state of knowledge.

### A.3 Tiered Simulation

The Reserve Margin LOLE study was modeled in a tiered approach that became more and more constraining as the study advanced. This was akin to multiple scenarios for SPP and allowed the footprint to be analyzed under more and more constricting parameters. The first simulation type was a transmission model both internal and external to the SPP CBA footprint. No limits were attached to the transmission model, and any amount of power necessary could flow to solve the case. The next simulation type incorporated important flowgates and interfaces within SPP and between SPP and its first-tier areas were added to the model. With these, flow was monitored on these lines and kept within the appropriate transmission line ratings. The final tier was to monitor and enforce ratings on all 230kV and above transmission lines within SPP and its first-tier areas. The 230kV distinction was chosen based on simulation time. With 230kV and above being monitored, simulation time was approximately 72 hours for the 2400 trial simulation.

### A.4 External area modeling

GridViewTM allows external areas to be modeled in the same fashion as internal areas. The key difference between the two is that external load and generation is ignored. External transmission, however, is considered for calculating flow on lines.
# Appendix B: LOLE Study Scope

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Introduction

SPP Criteria 4.3.5 states “SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria (2.0) requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities.”

The reserve margin Loss of Load Expectation (LOLE) study investigates the expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand. The LOLE is usually measured in days/year or hours/year. When given in days/year, it represents a comparison between daily peak and installed capacity values. This analysis is performed biennially based upon the typical industry standard metric which is the loss of load probability of one day in ten years or 0.1 day/year.
Overview

The reserve margin LOLE study is an iterative process, which starts with scope definition, analysis, modeling updates and evaluation of results. Once the scope is finalized, input data is collected based on the requirements listed in the scope. The data is then modeled in GridView™ along with the assumptions for the analysis. This analysis will be performed on individual legacy Balancing Authorities in the SPP footprint while incorporating a Consolidated Balancing Authority (CBA) dispatch. Modeling updates are then made if the analysis determines a change is needed. Final results are then compiled into a report and presented to the SPP Capacity Margin Task Force (CMTF). Once the report is reviewed, any additional sensitivity studies may be performed to analyze recommendations set forth by the CMTF.
Objective

**Reserve Margin LOLE Study**

The reserve margin LOLE study is a biennial assessment to determine the lowest reserve margin that can be attained while maintaining an LOLE of 1 day in 10 years.
Process Steps

Step 1: Create scope
Step 2: Collect input data
Step 3: Model data using GridView™ software
Step 4: Run simulation
Step 5: Evaluate results
Step 6: If necessary, make additional model updates and rerun the simulation
Step 7: Compile results into a report
Step 8: Present to Stakeholders for approval
GridView™ is the modeling tool used for the reserve margin LOLE study. Production-cost models such as GridView™ require many different and detailed data inputs. The information below details the data used to build and simulate the models for the reserve margin LOLE study.

Areas

The SPP Consolidated Balancing Authority (CBA) footprint includes all or parts of Arkansas, Kansas, Louisiana, Missouri, New Mexico, Nebraska, Oklahoma, Texas, Iowa, Minnesota, Montana, North Dakota, and South Dakota. The Legacy Balancing Authorities defined in the study include the following:

- AEPW²³,²⁴ American Electric Power West
- EMDE Empire District Electric Company
- GRDA Grand River Dam Authority
- INDN Independence Power & Light Department
- KACY (BPU) Board of Public Utilities, Kansas City, Kansas
- KCPL Kansas City Power & Light Company
- LES Lincoln Electric System
- GMO (MPS) Greater Missouri Operations Company
- NPPD Nebraska Public Power District
- OKGE Oklahoma Gas and Electric Company
- OPPD Omaha Public Power District
- SPS Southwestern Public Service Company
- SUNC (SEPC) Sunflower Electric Cooperative
- SWPA²⁵ Southwestern Power Administration
- WAPA²⁶ Western Area Power Administration
- WERE²⁷ Westar Energy, Incorporated
- WFEC Western Farmers Electric Cooperative

Base Models and Topology

System topology is captured from the 2016 Integrated Transmission Planning Near-Term (ITPNT) scenario 0 summer models for the 2016 and 2017 study years²⁸. Transmission additions

²³ FERC 714 Hourly Load data for AECC is reported through AEPW, OKGE, and SWPA.
²⁴ FERC 714 Hourly Load data for OMPA is reported through AEPW, OKGE, and WFEC.
²⁵ FERC 714 Hourly Load data for SPRM is reported in SWPA through 2010. 2011 SPRM Hourly Load data was added to SWPA numbers to create the forecasted hourly load shape.
²⁶ WAPA contains eastern interconnect portions of Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumers Power District, NorthWestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative.
²⁷ FERC 714 Hourly Load data for MIDW is modeled with WERE.
and retirements are captured in the ITPNT models built with SPP member input from the ITPNT process. Differences between the current LOLE study model and the recommended LOLE study model include: New transmission topology, including the 2015 ITPNT NTCs, and generation and load updates, which allows for a more current and accurate model to be analyzed. New transmission topology should allow for more power to transfer to the areas within SPP that could have been capacity deficient in previous LOLE models.

**Hourly Load Shapes and Peak Loads**

The study models will incorporate the non-coincident annual peak loads of each SPP LBA sourced from member submitted data through the EIA-411 assessment. Historical hourly load data from 2007 to 2011 will be used to produce an 8,760 hourly load shape for each modeled LBA. The historical data is obtained by member data submittals or FERC 714 filings.

**Traditional Dispatchable Capacity and Generation Modeling**

Generation data is obtained from current PROMOD data, EIA-411, or additional member submitted data.

**Conventional Ratings**

The maximum capacity ratings for conventional resources will be based on 2015 EIA-411 data, as developed by the SPP member’s capability testing. The capability testing procedure and requirements are described in SPP Criteria section 12.1.1.

**Forced outage modeling**

Forced outage modeling within GridView™ will consist of using the Equivalent Forced Outage Rate – demand (EFORD) values calculated from the Energy Velocity using data from the NERC Generating Availability Data Systems (GADS) and supplemented by Ventyx Advisors staff based on generator age.

Simulation parameters for random forced outages in GridView™ are to be compared to hourly historical forced outages from January 2012 to December 2014. The maximum number of outages per hour (N-24) and number of new outages per hour (N-5) parameters will be established through analysis of the historical outages.

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28 2016 and 2017 summer models are part of the current 2016 ITPNT model build. A 2018 current model would require additional work and more time for the model building process. For future LOLE studies, it should be determined the model years used for the LOLE study.

29 The EIA-411 data for the area labeled WAPA was submitted by Mid-Continent Area Power Pool (MAPP) on behalf of the WAPA area entities. MAPP provided SPP with 2014 EIA-411 data for each entity.

30 Future hourly load data cannot be obtained from the FERC 714 data due to SPP reporting 714 data on a CBA footprint.

31 PROMOD data supplies fuel pricing data and heat rates.

Planned outage modeling

Planned outages for thermal units, provided by members, are modeled using the scheduled maintenance function in GridView™ by switching the status of each unit to “off-line” for a specified period of time based on start time, end time, and duration. Once the outage duration has elapsed, the unit is placed back online in the model. The maintenance start date and outage duration are sourced from Control Room Operations Window (CROW) software SPP members use to plan maintenance outages. If generators do not have a designated outage planned, previous planned outage times are modeled from previous LOLE studies.

Behind-the-meter generation

Behind-the-meter generation can be used as load modifier and netted from the peak demand load. If the behind-the-meter generation is not netted, then it is modeled as generation.

Wind Modeling

The model includes wind resources currently installed, under construction, or that have a signed interconnection agreement within the SPP CBA footprint with an hourly wind generation shape assigned to each resource. Hourly wind generation is based upon averaged historical shapes from 2007 to 2011, which are obtained through member data submittals or NREL (National Renewable Energy Laboratory). The nameplate capacity is multiplied to the max normalized value of the wind shape.

Constraints and Monitored Elements

Internal and crossing interfaces and flowgates for years 2016 and 2017 are to be implemented using the 2015 SPP Operation’s OASIS flowgate list. Interfaces are key groups of transmission lines that are observed as one group between CBA regions or internal LBAs.

The simulation penalty of violating any constraint is $6,000/MWh while the load shedding penalty is $2000/MWh. Therefore, the system tends to shed load before violating any transmission constraint. Not only are specific constraints monitored, specific groups of ties between regions and every branch 230 kV and above within the SPP region are monitored as well.

DC Tie Modeling

DC ties are modeled as hourly generators at the point of interconnection to SPP. They are set at the total capacity firm reservation amount based upon transmission service rights. The generators are set at a low cost to simulate the capacity as readily available.

33 Maintenance schedules for Integrated System (Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumers Power District, NorthWestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative) were obtained through member submitted data.
Capacity Sales and Purchases

All capacity sales and purchases are firm transactions. The transactions used for both study years are obtained through the SPP ITPNT Scenario 0 model series and verified against the EIA-411 submissions.

Demand Response Modeling

In areas that reported controllable-capacity demand through the EIA-411 process, equivalent thermal units were added to the model with high fuel costs assumed, so those units would be dispatched last to reflect demand-response operating scenarios.

Modeling Load Forecast Uncertainty

Method

GridView™ allows for two options in dealing with load uncertainty: 1) User defined uncertainty pattern, and 2) probability distribution. For this study, a user-defined uncertainty pattern and a probability distribution are both used to add uncertainty to the load values. A different load uncertainty distribution pattern was created for each LBA and normalized to a maximum load uncertainty increase of 3.95%.

Uncertainty Components

A load model is used to define the peak-load multipliers used to modify forecasted loads. The daily peak was selected and regressed against historical peak temperatures from 2007-2011. Crystal Ball Pro was used to analyze the probability distributions of temperatures observed at key weather stations throughout the SPP footprint. The load model increased load as the winter temperatures decreased and as the shoulder and summer temperatures increased. A forecast was then created for both study years. Based on the forecasts, multipliers were calculated and were populated in a user defined uncertainty pattern. The multipliers were then normalized to where the highest multiplier was 3.95% higher than the base multiplier. All other multipliers between the base and the highest multiplier were given load increases from 0% to 3.95% based upon a linear regression in relation to the proportional increase of each multiplier. The user-defined uncertainty pattern allows users to provide seven monthly load patterns. Each area has a different value for each month multiplied by seven probabilities (a total of 84 values). GridView™ randomly selects the load pattern at the beginning of the simulation hour, and applies it for that trial. The random load uncertainty allows for unexpected increases of load added to the adjusted testing reserve margin.

Adjusting Demand to meet testing reserve margin

The forecasted load shall be adjusted for each LBA in GridView™ by calculating the new non-coincident peak demand to meet the testing reserve margin. Each area shall be set to the testing reserve margin based upon the committed installed capacity of each area. Only scalable loads will be subject to incremental load increases.
Assumptions

1) Each simulation period will be from January 1 to December 31.

2) GridView™ defined summer timeframe:
   a. June – September

3) Load shed penalty is $2000/MWh, Branch overload penalty is $6000/MWh.

4) Only Existing, Certain and Future, Planned reported generation are used as inputs from the LTRA.
   a. Future, planned generation must be under construction or have a signed GIA to be included.

5) A Load Uncertainty range from 0% to 3.95% will be applied to the calculated load probability distribution for each area.

6) SPP Operating reserves will be available to avoid load shed.

7) Transmission limits being honored include:
   a. Monitored branches that are 230 kV and above
   b. SPP Flowgates limits established using the SPP book of flowgates.

8) Load is adjusted on an area basis to ensure all areas are being tested at the testing reserve margin. Scalable loads are to be the only loads adjusted in the study.

9) Number of unit outages will be determined by comparing GridView™ simulation outages to real time historical outages.

10) Area to area transactions are included in the installed capacity values used for area load adjustments.

11) Generation is dispatched using a Security Constrained Economic Dispatch (SCED) algorithm based upon the SPP boundary

12) Region to region firm transactions will be modeled as the full capacity of the transaction based upon firm transmission service.

13) Operating procedures that could impact the loss of load will be incorporated into the study.
Simulation and Study Process

SPP will conduct the GridView™ Monte Carlo Simulation at 3000 trials (or as needed to reach a 90 percent or greater convergence), in which a determined maximum amount of resources in SPP may be forced out of service at the same hour of study. The trials account for variations in forced outages, wind output, and load uncertainty variability. Each trial represents a single 8760-hour simulation.
The results of the LOLE analysis and Limbo study analysis will be communicated to respective members so that any adjustments to assumptions can be evaluated for additional scenarios. Once the final metric results are calculated, they will be compiled and presented to the SPP CMTF for review.
Exhibit No. SPP-8
Review of SPP Reserve Margin Loss of Load Expectation Report

12/17/2015

Prepared for

Southwest Power Pool
Background

The purpose of this report is to provide a review of SPP's most recent 2015 Reserve Margin LOLE Report. Loss of Load Expectation (LOLE) modeling is performed by major RTO's, ISO's, Reliability Councils, and individual utilities to understand the risk of shedding firm load due to capacity shortages in any hour of the year. Within the U.S., the most common LOLE metric is the one day in 10 year standard which states load will not be shed more than one day in 10 years\(^1\). Reserve margins are generally set to maintain this level of reliability.

There are several key drivers to any LOLE analysis and specifically SPP's analysis. The following are discussed in detail as part of this review. For each driver, Astrapé also shared its preferred modeling approach.

1. Load Uncertainty
2. Conventional Generator Outages
3. Wind Modeling
4. Hydro Modeling
5. Demand Response Modeling
6. Neighbor Assistance Modeling
7. Transmission Modeling
8. Operating Reserves

The report concludes with estimated impacts to the reserve margin if SPP chose to adopt Astrapé's recommended input and approach changes. These are simply estimates based on Astrapé's modeling intuition and are not supported by real simulations.

SPP Reliability Criteria

The LOLE of one day in ten years or 0.1 days/year is the accepted standard across the industry. Historically, some regions or utilities interpreted this standard as being 24 hours of firm load shed over a 10 year period or 2.4 hours per year. However, the generally accepted interpretation is that if load is shed for 1 hour or 10 hours in a day, then it is considered one day of lost load. Some models only count days of lost load if the event occurs during the peak hour of the day, but this still means that a single

\(^1\) The standard will be referred to as 1 day in 10 years or .1 days per year.
hour of lost load in a 10 year period can be equal to meeting the standard. SPP confirmed that GridView assumes a day of lost load has occurred if load is shed in any hour of a day.

Currently SPP Criteria section 2.1.9 states, “Each Load Serving Member’s Minimum Required Capacity Margin shall be twelve percent. If a Load Serving Member’s System Capacity for a Capacity Year is comprised of at least seventy-five percent hydro-based generation, then such Load Serving Member’s Minimum Required Capacity Margin for that Capacity Year shall be nine percent”.

Astrapé requested additional information surrounding the nine percent capacity margin for hydro based members but it seems this is simply a guideline carried over from previous studies. While hydro generators likely have lower forced outages, hydro resources also have flow requirements and potential droughts that may derate the unit during peak conditions. This is discussed in more detail in the hydro portion of the report.

**Load Uncertainty**

Load uncertainty is one of the largest drivers in any resource adequacy study. Typically, load uncertainty can be divided into two types of uncertainty: (1) Weather Uncertainty and (2) Economic Growth Uncertainty. Weather uncertainty represents how much weather can vary from normal. The weather component of load uncertainty is primarily driven by temperature variation. As an example², the average annual peak temperature in Lincoln, Nebraska is 102° F. As shown in the chart below, the annual peak temperature can vary substantially. The highest temperature seen in the past 30 years is 107° F.

![Figure 1. Lincoln, Nebraska Temperature Data](image)

² Lincoln Nebraska is only used to illustrate annual weather variance patterns. We do not imply that Lincoln is the only or even primary driver of SPP weather-related load variance.
Regression analysis on 2011 weekday afternoon summer loads demonstrate a relationship between temperature and load at high temperatures of approximately 850 MW/°F.

Figure 2. Temperature/Load Relationship

There is significant variation around the loads at a given temperature because SPP load is not simply a function of Lincoln Nebraska temperatures and because of other factors. However, this does illustrate that a very hot year with peak annual temperature of 107°F would be expected to have a peak load 4,250 MW\(^4\) higher than a year with average peak temperatures. This represents a deviation of approximately 8% from expected peak load. Since there were four years with peak temperatures at 107°F or above in the last 30 years, there is a greater than 10% chance of having weather-related load variation of this magnitude.

The assessment of load variation performed by SPP identified distributions for each load-serving member area that were roughly in line with the magnitude of variation shown above. The average of the summer multipliers across all areas and their associated probability are shown in the following table.\(^5\)

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\(^3\) Load data is from SPP Historical loads excluding LEPA, LAFA, and CLECO from 2007-2011

\(^4\) 5°F * 850 MW/°F = 4,250 MW

\(^5\) Table reflects a simple average of the multipliers provided by SPP for all 16 areas within SPP.
Table 1. Load Multipliers

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However, these multipliers were not directly input into Gridview. Rather, they were normalized such that the annual max multiplier of each area was 1.0395. The 3.95% max value is derived from the average of all historical day-ahead forecast values in which load was under-forecast. For the summer period, this reduced multipliers for the highest uncertainty tier to 2-3%. This has the effect of substantially reducing the effect of weather variation on peak loads. For day-ahead forecasts of load, the projected weather conditions for the subsequent day are embedded in the forecast. If a day is projected to be 5 degrees hotter than the average hottest day of the year, the forecaster will take that into account into his load forecast. This is why the difference between the actual load and the day-ahead forecast load is rarely greater than a few percentage points. While total peak load variation to be considered for resource adequacy evaluations can exceed 8% because of longer-range uncertainty, day-ahead forecasts for large systems rarely under-estimate load by more than 2-3% during peak conditions. The most significant component of load uncertainty used in resource adequacy electric system simulations should be the weather related uncertainty which is the magnitude that extreme weather can cause peak loads to deviate from normal weather year peak loads. The approach that SPP has taken to develop multiplier tables (prior to normalization: see Table 1) captures an expected range of this load uncertainty. However, the normalization process removes much of the appropriate uncertainty.

Historical day-ahead forecast information typically does not need to be taken into account in resource adequacy simulations since, during extreme weather conditions, all available resources will be committed. The only reason to consider day ahead forecast error in resource adequacy simulations is if planners believe that some resource adequacy events are driven by poor commitment decisions. In our experience, it is rare that large and slow-responding base-load resources are in reserve shutdown status during extreme weather conditions due to day ahead load forecast error. If day ahead load forecast error is considered, it should be accounted for separately from weather-related peak load variance. In SERVM simulations, the day ahead commitment is made using a load forecast that mimics the amount of historical day-ahead forecast error, but the loads reflect the full range of possible weather conditions seen over the past 30 or more years. Since the approach that SPP employs results in an inappropriate overlap between these two components of load uncertainty it is our opinion that the scaling should be removed.
The magnitude of the difference in multipliers between capped and uncapped distributions in the highest uncertainty tranche is between 4-6%. Since the probabilities of the high uncertainty tranche are small, the impact on the planning reserve margin is not 1:1. Given the probability weighting of the variation, this would likely translate to an increase in the reserve margin requirement of 2-4%.

Another component of considering load variation is the load shape. The approach employed to develop load shapes in the SPP resource adequacy evaluation consisted of averaging 5 years of normalized hourly load shapes. While the average shape attempts to capture a range of possible load shapes, it may miss the effects of individual weather years. Figure 3 compares the normalized load duration curves for the top 100 load hours for SPP from 2007 - 2011 to the average shape.

Figure 3. Load Shape Comparisons

The issue with using an average shape is the asymmetry of reliability. Hours with load above the average negatively impact reliability worse than hours with load below the average improve reliability. Therefore the averaging approach could result in targeting a reserve margin that is too low to achieve the level of reliability desired.

These points emphasize the importance of considering a significant number of load shapes in performing reliability analysis. Most of Astrapé's clients performing resource adequacy assessments include 30 or more load shapes. The required number to achieve statistical significance would depend on analysis of historical weather patterns and could vary from 20 to 30 years.

SERVM simulations take into account not only weather-related load uncertainty, but also economic growth-related load uncertainty. Load forecast multipliers for economic load growth uncertainty and their probabilities are typically included in Astrapé resource adequacy analysis. Each historical load shape is scaled by each load forecast multiplier and given the corresponding probability of occurrence. For example if there were 35 load shapes in the model each given equal probability of occurrence and 5 load forecast error multipliers (as shown in the left side of Figure 4), then SERVM would develop 175
hourly load scenarios (35 load shapes x 5 load forecast error multipliers). In this illustration using the figure below, the probability of one of the load shapes occurring with the +4% load forecast error is simply $1/35 \times 7.9\%$ probability $= .23\%$. It is expected that the economic growth uncertainty increases as the forward period increases. The right side of Figure 4 shows how that error may increase based on the forward period.

Figure 4. Economic Growth Uncertainty

Astrapé develops economic growth multipliers based on the economic uncertainty in the underlying forecast. Some entities have already developed values within their load forecasting and resource adequacy planning processes based on analysis of historical weather normalized load vs. historical load forecasts. If data isn't available, one method Astrapé has used is to analyze the difference between Congressional Budget Office (CBO) GDP forecasts multiple years ahead and actual GDP data. This data can then be fit to a normal distribution to develop multipliers and probabilities as shown in the previous figure. Because electric load grows at a slower rate than GDP, Astrapé has typically applied a 30%-40% multiplier to the raw CBO forecast error distribution.

In the short term of 1-2 years, the economic component of load uncertainty is relatively small; typically less than 1-2%, but this amount could be reflected in the resource adequacy analysis and in the planning reserve margin target.

Another component of load uncertainty that should be considered when using an average shape approach is that of load diversity. Load diversity measures the deviation from annual peak for one area when a different area or aggregation of areas is at their respective peak. Modeling load diversity recognizes that part of the means to meeting reliability standards is benefiting from differences in the timing of peaks. However, creating an average shape will tend to mute load diversity. The average
diversity in SPP based on the difference in the coincident and non-coincident SPP peak loads using the average approach was 1%\textsuperscript{6}. However, historical analysis shows approximately 3% average diversity\textsuperscript{7}. Therefore the approach of using average shapes can potentially result in an under-estimate of the value of diversity. If the full historical diversity were included in the simulations by using annual shapes instead of an average shape, the planning reserve margin could be adjusted down by approximately 2%.

Conventional Generator Outages

SPP used Ventyx class average EFORd data for its study and allowed for GridView to take as many as 24 generators offline in a given hour which is an input setting in the model. The input was developed through some calibration of model results and actual results. EFORd is the correct input assumption for the GridView setup, but Astrapé recommends the EFORd data actually represent the SPP fleet and not a class average of units across the U.S.

Figure 5 from the SPP report shows the max forced outages from Gridview versus the average over the last 3 years from actual history. After looking further into the data, both the red line and the gray line include planned outages. In 2012, many of the outages across the summer were defined as planned which greatly increased this average curve. The figure is further confusing because SPP has compared the max system capacity offline across all 3,000 trials (gray line) to an average from actual history. It seems a better comparison would be the average outages from Gridview versus the average forced outages from actual data.

\textsuperscript{6} The 5-year averaged load information provided to Astrape demonstrated a non-coincident sum of peaks excluding WAPA of 57,785 MW compared to a coincident peak of 57,200 MW resulting in 1% diversity. Including WAPA, the non-coincident sum of peaks is 63,258 MW compared to a coincident peak including WAPA of 62,106 MW resulting in 1.85% diversity. The values described here are from simulations at a 11.11% reserve margin meaning the loads are scaled from the expected peaks for 2016 or 2017. However, the diversity values are maintained since all hours are scaled uniformly.

\textsuperscript{7} The average diversity from 2009-2011 excluding WAPA was 3%. The average diversity from 2009-2011 including WAPA was 4%.
Astrapé went back to the raw actual data and only pulled forced outages from June - September. This data was compared to the Gridview output. Since Gridview includes both forced and planned outages, only July and August were pulled for the comparison since planned outages are not possible in those months in the model. Based on this comparison, Gridview is showing similar numbers as history but may be slightly overstating forced outages by ~400 MW (4,340 MW – 3,912 MW) or 0.6% reserve margin. However, the actual outages do not include partial outages so if partial outages were included, the values could potentially be closer. Astrapé recommends SPP investigate why the planned outages were so high in 2012 and ensure that some of those outages weren’t categorized incorrectly.

Table 2. Actual vs. GridView Comparison

<table>
<thead>
<tr>
<th></th>
<th>Average Forced MW</th>
<th>Average Forced + Planned MW</th>
<th>Gridview Average Forced MW</th>
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<tbody>
<tr>
<td>2012</td>
<td>4,216</td>
<td>12,909</td>
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<td>2013</td>
<td>3,479</td>
<td>5,170</td>
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<tr>
<td>2014</td>
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</tr>
<tr>
<td>All</td>
<td>3,912</td>
<td>8,026</td>
<td>4,340</td>
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</table>

Figure 6 shows the actual forced outages as a percentage of time for annual and summer periods. The maximum forced outages in the summer over the last 3 years was 7,579 MW with an average of 3,912 MW (3,912 MW/70,000 MW = 5.65% of the fleet in a forced outage state). The max hourly output in Gridview for forced outages over the summer is 9,686 MW. Again, the modeled versus the actual history is comparable.
Astrapé’s approach using SERVM is to calibrate modeling results to these actual cumulative outage curves to ensure the modeling represents reality. Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate on demand (EFORd) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. The events are entered using the following variables:

**Full Outage Modeling**
- Time-to-Repair Hours
- Time-to-Fail Hours

**Partial Outage Modeling**
- Partial Outage Time-to-Repair Hours
- Partial Outage Derate Percentage
- Partial Outage Time-to-Fail Hours

**Maintenance Outages**
- Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage.
- Time-to-Repair Hours
SERVM uses this percentage along with the time-to-repair distributions and schedules the maintenance outages during off peak periods

**Planned Outages**
- Entered in as a % or with actual dates

---

8 If desired, SERVM can be simulated with all units as Must Run and EFORd can be modeled with time to fail and time to repair values.
As an example, assume that from 2011 – 2015, a generator had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because typically there is an improvement in EFOR across the summer, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling incorporating multiple states is important to capture the tails of the distribution that a simple convolution method or a Monte Carlo approach that only captures full outages would not capture.

**Wind Modeling**

SPP modeled its wind resources based on five years of hourly historical data from 2007 to 2011. The shapes were normalized by year and then averaged across the five years to develop profiles. By averaging five years of data, the lowest wind hours seen in history are never modeled and the volatility during high load hours is smoothed resulting in overstated reliability of the wind portfolio. Astrapé analyzed the top 10% of load hours based on FERC 714 data of each of the 5 years and plotted the actual versus normalized profiles. During high load hours, the modeled wind fleet is almost always contributing at least 10% of its capacity while the actual data shows the wind is much lower than 10% a significant amount of the time (see Figure 7). In fact, if we take the difference when the actual is lower than the normalized, we get an average delta of 8% with a max difference of 24%. Assuming 13,000 MW of wind, this normalized approach is estimated to overstate reliability by approximately 1,040 MW (8% * 13,000 MW) or approximately 1.75% reserve margin.
Similar to load, Astrapé recommends modeling multiple weather years of wind shapes to be simulated with the appropriate load shapes. This type of approach ensures a reasonable representation of wind during peak conditions.

**Hydro Modeling**

Hydro resources are modeled as conventional generation with a given EFORd. While this may be sufficient, some analysis should be performed on hydro output during peak load hours to understand if there are drought conditions or river flow constraints that could keep the hydro fleet from reaching its full nameplate capacity. Astrapé recommends retrieving hourly hydro output and load for at least 10 years. Given the fact that the hydro fleet is 5,225 MW, Astrapé believes this analysis during peak conditions is important and will only put upward pressure on the reserve margin compared to what is currently modeled. Without hourly hydro data available, it is difficult to estimate this impact.

Similar to load, Astrape's approach is to model monthly hydro energies for every weather year. This ensures that when load from 2007 is simulated, the appropriate hydro dispatch and potential drought is also captured. The SERVM model allows users to separate the hydro resources into run of river, minimum flow blocks, peak shaving, and emergency blocks. By modeling based on analysis of historical data, the model is able to dispatch the hydro resources in a manner that better represents historical operation especially during peak periods.
Demand Response Modeling

SPP modeled its controllable demand response as equivalent thermal units with no EFORD. Depending on the actual contract constraints of these resources, there is potential that reliability was overstated. As demand response increases and these constraints become tighter, LOLE can be impacted significantly. However, given the 706 MW of demand response that is being modeled in the simulations, this likely has little to no impact on the SPP LOLE Study.

Astrapé’s approach to modeling demand response is more detailed. If available, Astrapé models the contract limits of the resources. These include hours per year, hours per day, hours per month, etc. In areas with a high penetration of demand response, this modeling becomes more critical.

Neighbor Assistance Modeling

Besides contracted capacity which was included in the reserve margin calculation, no tie benefits or non-firm assistance from external areas were considered in the study.

Astrapé’s modeling approach is to model areas one tie away from the study area in a pipe and bubble representation assuming target reserve margin levels. SERVM commits and dispatches resources in each area (internal and external areas) and allows areas to share energy based on economics and subject to transmission limits. By modeling multiple weather years for the study area and areas one tie away, an accurate picture of both weather diversity along with generator outage diversity is captured. If SPP modeled areas one tie away, it is likely that SPP could import several reserve margin percentages points.

Transmission Modeling

SPP incorporates DC power flow and models generator and load at the bus level in its resource adequacy studies. Astrapé recommends SPP perform the study without the transmission being monitored to better understand its impact on LOLE and ultimately the planning reserve margin. While Astrapé’s intuition doesn’t believe transmission is the most significant driver, the results of this sensitivity would provide validation.

In Astrapé’s experience, SPP is one of the few if not the only entity that is incorporating DC power flow in its hourly resource adequacy modeling. ERCOT, PJM, MISO, ISO-NE, NY-ISO, Southern Company, Duke Energy and others all assume a pipe and bubble representation for its resource adequacy analysis. Most of these entities divide their respective region into smaller zones with transmission limits between zones. A deliverability analysis can then be performed on these individual zones to prove that all capacity within the zone is deliverable to all loads.
Astrapé has included functionality within SERVM to create RAW files for use in PSS/E during its simulations. In this process, SERVM generates multiple generation dispatch snapshots and contingency lists to be analyzed in full A/C power flow models.

**Operating Reserves**

Based on the report, operating reserves are allowed to go to zero before shedding firm load.

Astrapé’s approach is to model operating reserves which consist of regulation, spinning, and non-spinning reserves. SERVM allows the user to set the minimum threshold for operating reserves. This varies across studies but is dependent on input from operations. Most of Astrapé’s studies include 1%-3% of operating reserves that will be maintained before shedding firm load.

**GridView Results**

Astrapé reviewed the results and found the LOLE at the 7.53% reserve margin to be non-intuitive. LOLE was significantly higher in 2017 than in 2016 at the same level of reserves. Given the resource mix, load shapes, and load uncertainty didn't change drastically between studies, the difference in LOLE doesn't seem intuitive especially since the LOLE values are similar for the other reserve margin levels.

Figure 8. LOLE Results from SPP Study
In general, Astrapé is not aware of another entity that uses GridView for its resource adequacy modeling. As discussed previously, most entities have separated transmission planning from resource adequacy planning due to the unique requirements of transmission adequacy. Astrapé cannot comment on the model itself as it has no experience using the tool, but it does seem that the model is limited in a number of key areas with respect to reliability modeling: (1) Only allows one load shape with the ability to incorporate probability distributions (2) Similar to Load shape, only allows one wind shape with the ability to incorporate probability distributions (3) Requires a maximum generator offline input rather than allowing traditional Monte Carlo analysis to determine the maximum number of generators offline in a given hour (4) Energy limited resources such as DR/hydro/pump storage modeling have limited flexibility and are often times modeled as thermal resources (5) Modeling neighbor assistance adds significant complexity compared to a pipe and bubble resource adequacy tool.

Astrapé recognizes the value in combining transmission and resource adequacy tools but tools designed to perform both tasks typically have shortcomings in key areas. Recognizing the importance of transmission adequacy modeling, Astrapé recommends an approach which uses generation adequacy tools to identify important reliability scenarios that are then simulated in transmission adequacy tools which are capable of performing AC power flow analysis to assess transmission adequacy.

**Estimated Impact on Reserve Margin of Recommended Changes**

Astrapé estimates the following impact to the SPP 1 in 10 level reserve margin results if the recommended changes are performed. Astrapé started with the current results which show a LOLE of 0.1 days per year at approximately a 7.5% reserve margin.

- **Load Uncertainty:** 4% increase (Approximately 2-4 % increase due to additional weather-related uncertainty and 1-2% for economic load forecast error)
- **Load Diversity:** 2% decrease
- **Wind Modeling:** 1.75% increase (Range of 1 %-2.5% increase if actual shapes were utilized)
- **Operating Reserves:** 2% increase (Range of 1% - 3% if some minimum level of operating reserves were maintained)
- **Neighbor Assistance:** 2% decrease (1%-3% decrease if neighbors one tier away were modeled and assumed to provide 600 to 1,800 MW during peak conditions)
- **Generator Outages:** No impact estimated since forced outages were slightly higher than the actual data and the actual data excluded partial outages.
- **Hydro and Demand Response:** The constraints of these resources are not currently modeled and would only put upward pressure on reserve margin. However, given the demand response penetration in SPP, it is expected that only hydro would have any impact. Astrapé would need to perform additional analysis on historical hourly dispatch to better understand if this impact is significant.

**Final Reserve Margin Estimate:** \( = 7.5\% + 4\% - 2\% + 1.75\% + 2\% - 2\% = 11.25\% \).
Exhibit No. SPP-9
ATTACHMENT AH
MARKET PARTICIPANT SERVICE AGREEMENT
FORM OF SERVICE AGREEMENT FOR MARKET PARTICIPANTS IN THE INTEGRATED MARKETPLACE

1. This Service Agreement dated as of _______________ is entered into by and between ________________ (Transmission Provider) and ________________ (Customer).

2. The Customer has submitted an application for participation in the Integrated Marketplace and desires to register as a Market Participant in accordance with the market application and asset registration procedures specified in the Market Protocols and has provided the information specified in Appendix 1 to this Service Agreement.

3. The Customer represents and warrants that it has met all applicable requirements set forth in the Transmission Provider's Tariff and has complied with all applicable procedures under the Tariff.

4. The Transmission Provider agrees to provide and the Customer agrees to take and pay for, or to supply to the Transmission Provider, any or all of the products defined in the Integrated Marketplace in accordance with the provisions of the Transmission Provider's Tariff and to satisfy all obligations under the terms and conditions of the Transmission Provider's Tariff, as may be amended from time-to-time, filed with the Commission.

5. The Transmission Provider and the Customer agree that this Service Agreement shall be subject to, and shall incorporate by reference, all of the terms and conditions of the Transmission Provider's Tariff.

6. It is understood that, in accordance with the Transmission Provider's Tariff, the Transmission Provider may amend the terms and conditions of this Service Agreement by notifying the Customer in writing and making the appropriate filing with the Commission.

7. The Customer represents and warrants that:
   
   (a) At any time it has registered one or more Resources that the Customer intends to offer for sale into the Energy and Operating Reserve Markets in accordance with procedures specified in the Market Protocols, the participation of its Resource(s) in the Energy and Operating Reserve Markets is not precluded under the laws or regulations of the relevant electric retail regulatory authority, including state-approved retail tariff(s), and it either (a) has on file with the Commission for each
of such Resources market-based rate authority and/or other Commission-approved basis for setting prices in the Energy and Operating Reserve Markets, or (b) is exempt from the requirement to have rates for services on file with the Commission;

(b) This Service Agreement, or any Transaction entered into pursuant to the Service Agreement, as applicable, has been duly authorized;

(c) This Service Agreement is the legal, valid, and binding obligation of the Customer enforceable in accordance with its terms, except as it may be rendered unenforceable by reason of bankruptcy or other similar laws affecting creditors' rights, or general principles of equity.

8. The Customer warrants and covenants that, during the term of the Service Agreement, the Customer shall be in compliance with all federal, state, and local laws, rules, and regulations related to the Customer's performance under the agreement.

9. Service under this Service Agreement shall commence on the later of the date of execution of the Service Agreement, or such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate in accordance with Section 12 below.

10. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below:

    Transmission Provider: ________________________________

    Customer: ____________________________________________

11. Cancellation Rights:
    If the Commission or any regulatory agency having authority over this Service Agreement determines that any part of this Service Agreement must be changed, the Transmission Provider shall offer to the Customer within fifteen (15) days of such determination an amended Service Agreement reflecting such changes. In the event that the Customer does not execute such an amendment within thirty (30) days, or longer if
the Parties mutually agree to an extension, after the Commission's action, this Service Agreement and the amended Service Agreement shall be void.

12. Termination:
   (a) The Customer may terminate service under this Service Agreement no earlier than ninety (90) days after providing the Transmission Provider with written notice of the Customer's intention to terminate. The Customer's provision of notice to terminate service under this Service Agreement shall not relieve the Customer of its obligation to pay any rates, charges, or fees due under this Service Agreement, and which are owed as of the date of termination.

   (b) The Transmission Provider may terminate service under this Service Agreement if the Customer is in default, such default condition as defined under Section 8.1 of the SPP Credit Policy, in accordance with the procedures specified under Section 7.4 of the Transmission Provider’s Tariff or Section 10.5 of Attachment AE to the Transmission Provider’s Tariff, as applicable.

13. The Customer hereby appoints the Transmission Provider as its agent for the limited purpose of effectively transacting on the Customer's behalf in accordance with the terms and conditions of the Transmission Provider's Tariff. The Customer agrees to pay all amounts due and chargeable to the Customer and the Transmission Provider agrees to pay all amounts creditable to the Customer in accordance with the terms of the Transmission Provider's Tariff.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

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<th>Transmission Provider:</th>
<th>Customer:</th>
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<td>Dated:</td>
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<td>Title:</td>
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Effective Date: 3/1/2014 - Page 4
### Appendix 1 to Attachment AH

#### MARKET PARTICIPANT INFORMATION:

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<th>Requested Change Type¹</th>
<th>Market Participant Name²</th>
<th>Market Participant Acronym³ (4 characters)</th>
<th>Registered in EIR?⁴ (yes/no)</th>
<th>Credit Customer Name⁵</th>
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#### ASSET OWNER AND TC INFORMATION:

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<th>Requested Change Type¹</th>
<th>Asset Owner Name⁶</th>
<th>Asset Owner Acronym⁷ (4 characters)</th>
<th>Registered in EIR?⁸ (yes/no)</th>
<th>Resource Owner⁹ (yes/no)</th>
<th>Load Serving Entity¹⁰ (yes/no)</th>
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#### TRANSMISSION CUSTOMER TO ASSET OWNER RELATIONSHIPS:

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<th>Asset Owner Acronym⁷ (4 characters)</th>
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#### METER AGENT INFORMATION:

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Effective Date: 3/1/2014 - Page 5
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**CONTACT INFORMATION:**

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<th>Phone Number (nnn) nnn-nnnn</th>
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**PROPOSED EFFECTIVE DATE**:<sup>16</sup> _______________________________
1 **Requested Change Type** – Indication of the type of change for each record. For adding an entity or relationship this will be Add. To terminate an entity or relationship from the Integrated Marketplace, enter Terminate. For requesting a modification or name change of an entity, enter Modify. When requesting a name change to an entity, enter the existing name followed by a forward slash “/” and then the new name.

2 **Market Participant Name** - Full name of the Market Participant.

3 **Market Participant Acronym** - The NAESB Electric Industry Registry (“EIR”) acronym that will be used for the Market Participant. If the entity is not registered in the EIR, the acronym should conform to the EIR format of no more than four (4) alpha numeric characters. Any acronym for an entity that is not registered in EIR must also be unique from any abbreviation that is registered in EIR by another party.

4 **Registered in EIR** – Enter “yes” if the entity is registered at EIR.

5 **Credit Customer Name** - The name of the entity that will be providing secured and unsecured credit for the Market Participant's activities in the Integrated Marketplace in accordance with Attachment X of this Tariff.

6 **Asset Owner Name** - The name of the Asset Owner that is represented by the Market Participant.

7 **Asset Owner Acronym** - The Asset Owner acronym abbreviation that will be used for this Asset Owner will be the same as the acronym in the EIR if the entity is registered in the EIR. If the entity is not registered in the EIR, the abbreviated name should conform to the EIR format of no more than four (4) alpha numeric characters. Any abbreviation for an entity not registered in the EIR must also be unique from any abbreviation that is registered in the EIR by another party.

8 **Registered in EIR?** - This field is used to identify if the entity is registered at EIR. For Asset Owners not registered at EIR, the Transmission Provider will validate the acronym used is not registered at EIR by another party currently. To ensure uniqueness against EIR
in the future, the Transmission Provider will also append “_X” to the Asset Owner Acronym supplied for those that are not registered.

9 **Resource Owner** - This is a Yes or No answer indicating whether or not the Asset Owner is a Resource owner and will be registering Resources to participate in the Energy and Operating Reserves Market.

10 **Load Serving Entity** - This is a Yes or No answer indicating whether or not the Asset Owner is a Load Serving Entity and will be registering Load Assets to be supplied in the Energy and Operating Reserves Market.

11 **Transmission Customer (TC) Acronym** – The acronym of the Transmission Customer that is associated with the given Asset Owner, if applicable. This includes Transmission Customers that may have the same Registered Acronym as the Asset Owner.

12 **Meter Agent Name** - Any Market Participant with load and/or Resources will either be a Meter Agent or have a relationship with at least one Meter Agent (MA). Identify the Meter Agent(s) registered with the Transmission Provider that will be responsible for the acquisition of end-use meter data, aggregation of meter data, application of data to Settlement Intervals, and transfer of meter data to the Transmission Provider on behalf of this Market Participant. This entity can be a traditional utility entity or other competitive entity. Show the Meter Agent as the Entity’s name as it is registered on the Meter Agent Agreement form in Attachment AM of the SPP Tariff.

13 **Meter Agent Acronym** - The applicable abbreviation that will be used for this Meter Agent which agrees with EIR if the Entity is registered in the EIR. If the entity is not registered in the EIR, the abbreviated name should conform to the EIR format of no more than four (4) alpha numeric characters. Any abbreviation for an entity not registered in EIR must be unique from any abbreviation that is registered in TSIN by another party.
14 **Registered in EIR** - This field is used to identify if the entity is registered at EIR. For Meter Agents not registered at EIR, the Transmission Provider will validate the acronym used is not registered at EIR by another party currently. To ensure uniqueness against EIR in the future, the Transmission Provider will also append “_X” to the MA Acronym supplied for those that are not registered.

15 **Contact Type** - Specific points of contact for each Market Participant for questions regarding the Network and Commercial Models as well as a Primary Market Operations contact for the Market Participant.

   **Type A** - Primary Market Operations and Commercial Model Point of Contact - required
   **Type B** - EMS and ICCP contacts - required for MPs with physical assets.
   **Type C** - Secondary Market Operations Contacts - optional.

16 **Proposed Effective Date**: The date on which the Market Participant would like these changes to be effective in the Transmission Provider’s models and systems.
I. COMMON SERVICE PROVISIONS

1 Definitions
   A - Definitions
   B - Definitions
   C - Definitions
   D - Definitions
   E - Definitions
   F - Definitions
   G - Definitions
   H - Definitions
   I - Definitions
   J - Definitions
   K - Definitions
   L - Definitions
   M - Definitions
   N - Definitions
   O - Definitions
   P - Definitions
   Q - Definitions
   R - Definitions
   S - Definitions
   T - Definitions
   U - Definitions
   V - Definitions
   W - Definitions
   XYZ - Definitions

2 Initial Allocation and Renewal Procedures
   2.1 Initial Allocation of Available Transfer Capability
   2.2 Reservation Priority For Existing Firm Service Customers

3 Ancillary Services

4 Open Access Same-Time Information System (OASIS)

5 Local Furnishing Bonds
   5.1 Transmission Owners That Own Facilities Financed by Local Furnishing Bonds or that are Tax Exempt Entities
   5.2 Alternative Procedures for Requesting Transmission Service

6 Reciprocity

7 Billing and Payment
   7.1 Billing Procedure
   7.2 Interest on Unpaid Balances
   7.3 Financial Security Held By SPP
   7.4 Customer Default

8 Accounting for Use of the Tariff
   8.1 Study Costs and Revenues

9 Regulatory Filings

10 Force Majeure and Indemnification
   10.1 Force Majeure
10.2 Liability
10.3 Indemnification
10.4 Further Limitation of Liability
10.5 Transmission Provider Recovery

11 Creditworthiness

12 Dispute Resolution Procedures
12.1 Internal Dispute Resolution Procedures
12.2 External Arbitration Procedures
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1.0 Overview

Maintaining appropriate planning reserves ensures that the Transmission Provider will have sufficient capacity to serve the SPP Balancing Authority Area’s peak demand. This Attachment AA requires a Load Responsible Entity to maintain capacity required to meet its load and planning reserve obligations. Additionally, this Attachment AA provides the obligations and responsibilities of the Transmission Provider, Market Participants, Load Responsible Entities, and Generator Owners with regard to load and planning reserves.
2.0 Definitions

Terms defined herein shall only be applicable to this Attachment AA.

Asset Owner
As defined in Attachment AE of this Tariff.

Deficiency Payment
A payment by a Market Participant when one or more of its LREs has not met the Resource Adequacy Requirement as calculated in accordance with Section 13.2 of this Attachment AA.

 Deliverable Capacity
The accredited capacity of a Resource that is determined to be deliverable in an annual Deliverability Study for a Summer Season.

Export Interchange Transaction
As defined in Attachment AE of this Tariff.

Firm Capacity
The projected accredited capacity of an LRE’s commercially operable generating units, or portions of generating units, adjusted to reflect purchases and sales of accredited capacity with another party, and that is supported by firm transmission service to the LRE’s load, or is Deliverable Capacity to meet the PRM portion of the Resource Adequacy Requirement.

Firm Power
Power sales and purchases deliverable with firm transmission service where the seller assumes the obligation to serve the purchaser’s load with capacity, energy, and planning reserves that must be continuously available in a manner comparable to power delivered to native load customers.

Generator Owner
The Asset Owner of a Resource.

**Jointly Owned Unit**  
As defined in Attachment AE of this Tariff.

**Load Responsible Entity (“LRE”)**  
An Asset Owner represented in the Integrated Marketplace with a registered physical asset that is either a) load or b) an Export Interchange Transaction as specified in Section 5.4 of this Attachment AA.

**Market Participant**  
As defined in Attachment AE of this Tariff.

**Net Peak Demand**  
The forecasted Peak Demand less the a) projected impacts of demand response programs and behind-the-meter generation that are controllable and dispatchable and not registered as a Resource and b) contract amount of Firm Power purchased under agreements in effect as of the time of the forecasted Peak Demand, plus the contract amount of Firm Power sold to others in effect as of the time of the forecasted Peak Demand.

**Peak Demand**  
The highest demand including transmission losses for energy measured over a one clock hour period.

**Resource**  
As defined in Attachment AE of this Tariff.

**Summer Season**  
June 1st through September 30th of each year.

**Winter Season**
December 1st through March 31th of each year.

**Workbook**

An electronic spreadsheet provided by the Transmission Provider which is used by an LRE or Generator Owner to submit information to the Transmission Provider for the purposes of administering this Attachment AA.
3.0 Roles and Responsibilities

3.1 Generator Owner and Load Responsible Entity

Except as provided in Section 3.1(1) of this Attachment AA, the roles and responsibilities of the LRE and Generator Owner are separate and distinct from the other under this Attachment AA. An entity may be an LRE, a Generator Owner, or both. For an entity that is both an LRE and Generator Owner, the Transmission Provider shall recognize the rights, roles, and responsibilities as separate and distinct functions.

(1) An LRE that is also a Generator Owner shall access its Workbook pursuant to the provisions of Section 8.3(b) of this Attachment AA but shall be considered an LRE for Workbook reporting purposes, and all excess capacity of the Generator Owner shall be considered LRE Excess Capacity for purposes of Resource Adequacy Assurance as described in Section 13.0 of this Attachment AA.

3.2 Market Participant and Load Responsible Entity

(1) An LRE may be a Market Participant or can engage a third party Market Participant to represent it. If an LRE refuses to either (a) become a Market Participant or (b) engage a third party Market Participant to represent it, the Transmission Provider shall file an unexecuted Market Participant Agreement with the Commission pursuant to Section 2.2(6) of Attachment AE of this Tariff.

(2) A Market Participant that represents an LRE under Attachment AH of this Tariff is the entity responsible under this Attachment AA to ensure the LRE’s compliance with the Resource Adequacy Requirement.

(3) The relationship between a Market Participant and its LRE, as established in the submission of the Workbook on February 15th, will be considered fixed for the upcoming Summer Season for enforcement of the Resource Adequacy Requirement.

(4) The Market Participant is responsible to ensure its LRE(s) provides the necessary data to allow the Transmission Provider to verify its LRE(s)’ compliance with the Resource Adequacy Requirement.
(5) An LRE shall submit all necessary data to the Transmission Provider either directly or through the LRE’s Market Participant.

(6) A Market Participant may aggregate the forecasted Peak Demand of multiple LREs whose load assets are served by a common set of Designated Resources or a Firm Power transaction between the LREs. In such case, the Market Participant shall be considered the LRE for the aggregated demand and, for purposes of compliance with this Attachment AA, the Market Participant’s forecasted Peak Demand shall be used to calculate a single Resource Adequacy Requirement for the aggregated load assets.

(7) The Market Participant is responsible for any Deficiency Payment(s) incurred by the LRE(s) it represents.

3.3 Procedures for Assignment of Market Participant Obligations

(1) A Market Participant may assign its duties, obligations and responsibilities for an LRE under this Attachment AA, but only to another Market Participant. A non-Market Participant must become a Market Participant prior to accepting an assignment.

(2) Assignor Market Participant shall be responsible to negotiate and contract with another Market Participant for the assignment of its duties, obligations, and responsibilities with respect to the LRE. A valid assignment must be in writing, bilaterally executed by both parties, and the assignee Market Participant shall affirmatively accept the duties, obligations, and responsibilities of the assignor Market Participant under this Attachment AA.

(3) Assignor Market Participant shall provide copies of the assignment to the Transmission Provider prior to February 15th of each calendar year. In the event the demonstration of such assignment does not occur prior to February 15th of each calendar year, the Transmission Provider shall not be required to accept the assignment for the upcoming Summer Season.

(4) A valid assignment by the assignor Market Participant under this Attachment AA does not affect the assignor Market Participant’s status as a Market Participant or other rights and obligations it may have under other provisions of this Tariff.
Except as otherwise provided in Sections 3.3(6), 3.3(7), and 3.3(8) of this Attachment AA, upon demonstration of a valid assignment, Transmission Provider will accept the transfer of the LRE to the assignee Market Participant, and enforce the provisions of Attachment AA against the assignee Market Participant, without recourse against the assignor Market Participant.

Either party may serve the Transmission Provider with written notice of the assignment’s termination. The Transmission Provider will recognize the assignment’s termination if the notice contains a written acknowledgement by both parties that the assignment has been terminated. Upon termination of the assignment, the duties, obligations, and responsibilities of the Market Participant for the transferred LRE under Attachment AA of the Tariff shall immediately revert back to assignor Market Participant, unless a replacement assignment that meets the requirements of this section is provided to the Transmission Provider.

Nothing in the Transmission Provider’s acceptance of the assignment shall be construed to create or give rise to any liability on the part of the Transmission Provider and the parties to the assignment expressly waive any claims that may arise in their favor against the Transmission Provider, except as specifically may be provided in the Tariff. The Transmission Provider shall be held harmless by the by parties for any breach of the assignment or dispute between the parties with regards to the assignment, and such dispute shall not delay or cancel the financial responsibilities of the assignee Market Participant under this Attachment AA. Any dispute between the Transmission Provider and either party may be subject to the dispute resolution provisions of Section 12 of the Tariff.

The Transmission Provider shall not be responsible for the actions of any party, or have any affirmative duties assigned to the Transmission Provider under the assignment. The Transmission Provider’s recognition of the assignment shall not be construed as Transmission Provider’s acceptance of the provisions of the assignment that may conflict with the Tariff or the Transmission Provider’s administration of the Tariff, and specifically, the application of this Attachment AA against the assignee Market Participant, or upon termination of the assignment, the assignor Market Participant. In the event there exists a conflict
between a term of the assignment and this Tariff, the provisions of this Tariff shall control.
4.0 Planning Reserve Margin

The Planning Reserve Margin (“PRM”) shall be twelve percent (12%). If an LRE’s Firm Capacity is comprised of at least seventy-five percent (75%) hydro-based generation, then such PRM shall be nine point eight nine percent (9.89%). A change to the PRM shall not be made absent a filing with the Commission.

Determination of the PRM will be supported by a probabilistic Loss of Load Expectation (“LOLE”) Study, which will analyze the ability of the Transmission Provider to reliably serve the SPP Balancing Authority Area’s forecasted Peak Demand. The LOLE Study will be performed by the Transmission Provider on a biennial basis, or more often as determined by the Transmission Provider. The Transmission Provider, with input from the stakeholders, shall develop the inputs and assumptions to be used for the LOLE Study. The Transmission Provider will 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. 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. The Transmission Provider shall post the final results of the LOLE Study.
5.0 **Summer Season Resource Adequacy Requirement**

5.1 The Resource Adequacy Requirement is equal to the LRE’s Summer Season Net Peak Demand plus its Summer Season Net Peak Demand multiplied by the PRM.  
(1) The LRE is responsible to meet the Resource Adequacy Requirement for the Summer Season and failure to comply shall result in a Deficiency Payment as calculated in accordance with Section 13.2 of this Attachment AA.

5.2 The Firm Capacity utilized by an LRE to meet the Resource Adequacy Requirement may not be included in the Firm Capacity utilized by another LRE to meet the Resource Adequacy Requirement. Firm Capacity that is contracted to other entities shall not be available to the LRE that is transferring the Firm Capacity for compliance with the Resource Adequacy Requirement.

5.3 If an LRE serves load both internal and external to the SPP Balancing Authority Area, compliance with the Resource Adequacy Requirement contained in this 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. Load and Resources that are pseudo-tied into the SPP Balancing Authority Area shall be considered internal for purposes of determining the Resource Adequacy Requirement.

5.4 Any entity that utilizes an Export Interchange Transaction that is supported by a Firm Power contract shall be considered an LRE and must include that off-system load in its Summer Season Net Peak Demand to meet the Resource Adequacy Requirement. Any entity that utilizes an Export Interchange Transaction that is not supported by a Firm Power contract shall not be considered an LRE solely for the use of that transaction and shall not be required to include that off-system load in its Summer Season Net Peak Demand to meet the Resource Adequacy Requirement.
6.0 Winter Season Obligation

6.1 For the Winter Season, each 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.

6.2 The Firm Capacity utilized by an LRE may not be included in the Firm Capacity utilized by another LRE. Firm Capacity that is contracted to other entities shall not be available to the LRE that is transferring the Firm Capacity.

6.3 If an LRE serves load both internal and external to the SPP Balancing Authority Area, compliance with the obligation in Section 6.0 of this 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. 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 this Attachment AA.
7.0 Short-Term Transactions

An LRE may arrange for short-term capacity to provide a part of its Firm Capacity or short-term Firm Power to reduce a portion of either its Summer Season Net Peak Demand or Winter Season Net Peak Demand, but not both, subject to the following provisions:

(1) Such short-term capacity or short-term Firm Power shall be available for a minimum of four consecutive months, starting either June 1st or December 1st; and

(2) The amount of short-term capacity or short-term Firm Power shall not exceed 25% of an LRE’s applicable Net Peak Demand.
8.0 Resource Adequacy Timeline

The Resource Adequacy Requirement process is performed annually beginning on July 1st of each year. For any prescribed date that falls on a weekend or holiday, the date of performance shall be the next business day.

(1) On July 1st of each year the Transmission Provider shall post the following on the SPP website and distribute via email distribution list:
   (a) Notification of the commencement of the process; and
   (b) A timeline indicating when the Market Participant, LRE, and Generator Owner are required to meet their respective obligations.

(2) By October 1st of each year the Transmission Provider will perform the Deliverability Study.

(3) On October 1st of each year the Transmission Provider shall post and provide notice via email distribution list:
   (a) The following on the SPP website:
      (i) The unpopulated Workbook;
      (ii) Instructions for completing the Workbook; and
      (iii) The deadline to submit the Workbook.
   (b) The following on a secure website:
      (i) A Workbook populated with the results of the Deliverability Study for each individual Generator Owner.

(4) The Transmission Provider shall not modify the unpopulated Workbook after December 31st of each year. Any modification to the unpopulated Workbook by the Transmission Provider after the initial October 1st posting shall be posted on the SPP website and distributed via email distribution list.

(5) By February 15th of each year, each Market Participant and participating Generator Owner will ensure the Transmission Provider is provided with a Workbook.

(6) No later than five (5) calendar days after February 15th, the Transmission Provider shall provide notice to all Market Participants, LREs, and Generator Owners that have not submitted a Workbook by the deadline. Such notice shall
include the communication that the Market Participant may be subject to a Deficiency Payment if such deficiency is not cured. A Market Participant, LRE, or Generator Owner that receives such notice shall have ten (10) calendar days to submit its Workbook. Failure to provide a Workbook within the ten (10) calendar days after notification shall result in the Transmission Provider disclosing a listing of the entities that have not submitted a Workbook to the Supply Adequacy Working Group, which will provide a report to the Markets and Operations Policy Committee.

(7) Prior to April 1st of each year, the Transmission Provider will review the information in the Workbook to determine whether each LRE meets the Resource Adequacy Requirement. The Transmission Provider will notify the Market Participant and the LRE if the LRE has not met the Resource Adequacy Requirement.

(8) No later than April 1st of each year, an initial report on the status of all LREs shall be posted on the SPP website by the Transmission Provider.

(9) By May 15th of each year, an LRE or Generator Owner shall update its Workbook to reflect purchases and sales that occurred after the initial submission.

(10) By May 15th of each year, an LRE must demonstrate it has cured any deficiency in compliance with the Resource Adequacy Requirement.

(11) No later than June 15th of each year, the Transmission Provider shall post its final report on the status of each LRE’s compliance with the Resource Adequacy Requirement for the upcoming Summer Season and whether the respective Market Participant is subject to the Deficiency Payment.

(12) On or before June 30th of each year, and after the posting of the final report, the Transmission Provider shall calculate and assess the Deficiency Payment in accordance with the provisions contained in Sections 13.2 and 13.3, respectively, of this Attachment AA.
9.0 Deliverability Study

9.1 The Transmission Provider shall perform an annual Deliverability Study. The Deliverability Study will evaluate the deliverability to the SPP Balancing Authority Area of each Resource registered in the Integrated Marketplace and not whether such Resources are deliverable to specific delivery points or SPP Zones. The Deliverability Study will result in a determination of each Resource’s capacity that is deliverable to the SPP Balancing Authority Area. The results of the Deliverability Study shall be valid for the upcoming Summer Season and the subsequent Summer Season.

9.2 The Transmission Provider will utilize its current transmission planning models to perform the Deliverability Study. The Transmission Provider will begin the Deliverability Study with the initial assumption that any Resource generating in the planning model is automatically deliverable to the SPP Balancing Authority Area for the dispatched output. A Resource’s total capacity equals the generating unit’s maximum output of MWs. For multiple generating units at one site, the total capacity for the site is the sum of maximum MWs of all generating units. A transfer level equal to the difference between the Resource’s maximum MW capacity and the amount dispatched in the planning model is determined for each Resource. A First Contingency Incremental Transfer Capability (“FCITC”) analysis of each transfer will be performed to determine the deliverability of the Resource. Transmission Facilities 100 kV and above will be included in the FCITC analysis. A three percent (3%) transfer distribution factor threshold will be used to analyze constraints impacted by the transfer.

9.3 The Deliverability Study results for each Generator Owner’s Resource shall consist of the total Resource’s deliverability of MW amounts. Each Generator Owner of a Jointly Owned Unit will coordinate to determine the MW deliverability amounts for its share of a Jointly Owned Unit.
9.4 The amount of Deliverable Capacity of any Resource available for purchase to meet the PRM portion of the Resource Adequacy Requirement shall equal the lesser of: a) the Resource’s accredited capacity less the MW amount of capacity that has been committed to meet i) Firm Capacity and ii) a sale to another entity; or b) the amount of a Resource’s total deliverable MWs less the MW amount of capacity that has been committed to meet i) Firm Capacity and ii) a sale to another entity, as determined from the Generator Owner’s Workbook.

9.5 A Generator Owner that does not submit a Workbook that contains the amount of generation capacity available through the Deliverability Study shall be deemed to have no Deliverable Capacity and shall not be entitled to receive any revenue distributions collected from Deficiency Payments.

9.6 A power purchase agreement to satisfy the PRM portion of the Resource Adequacy Requirement based on the most recent Deliverability Study may only rely on the results of such study for no longer than the upcoming Summer Season and the subsequent Summer Season.

1) Deliverable Capacity purchases by an LRE to satisfy the PRM portion of the Resource Adequacy Requirement will not require firm transmission service to support the capacity. Deliverable Capacity purchases shall not entitle a Market Participant to receive Auction Revenue Rights under Attachment AE of the Tariff.

2) Deliverable Capacity purchases shall not be utilized to serve any portion of the LRE’s Summer Season Net Peak Demand. If the LRE’s power purchase agreement to satisfy the PRM portion of the Resource Adequacy Requirement also includes capacity needed to serve any portion of its Summer Season Net Peak Demand, the LRE must secure firm transmission service for such capacity to serve any portion of its Summer Season Net Peak Demand.
10.0 Workbook

10.1 The Generator Owner’s Workbook will contain, but is not limited to, the following information:

(1) Capacity sales to another entity; and
(2) Uncommitted Deliverable Capacity available to meet the PRM.

10.2 The LRE’s Workbook will contain, but is not limited to, the following information:

(1) The LRE’s Summer Season Net Peak Demand;
(2) Firm Capacity owned by the LRE;
(3) Purchases and sales for Firm Capacity;
(4) Purchases and sales for Firm Power; and
(5) Uncommitted Deliverable Capacity available to meet the PRM.

10.3 The LRE’s Workbook shall be subject to the following provisions:

(1) A Workbook will be used to qualify the LRE’s compliance with the Resource Adequacy Requirement for the upcoming Summer Season. Absent a calculation error or otherwise incorrect information, an LRE that demonstrates compliance with the requirements of Section 5.0 of this Attachment AA is considered to have met its Resource Adequacy Requirement, subject to any subsequently reported sales. An LRE shall update its Workbook by May 15th to correct calculation errors or incorrect information.

(2) A Workbook may include any Resources, provided the Resource’s capacity is expected to be available during June 15th through September 15th. After February 15th, if the expected availability of a Resource changes to unavailable during June 15th through September 15th, the
Resource will be considered as available for purposes of meeting the Resource Adequacy Requirement.

(3) Resources contained in the Workbook that are identified by February 15th to be unavailable during part or all of the period from June 15th through September 15th will not count as capacity for purposes of meeting the LRE’s compliance with the Resource Adequacy Requirement. Should a Resource that is initially identified to be unavailable during part or all of the period from June 15th through September 15th but subsequently becomes available and the LRE updates its Workbook by May 15th, such Resource will count as capacity for purposes of meeting the Resource Adequacy Requirement.
11.0 Post-Season Analysis

The Transmission Provider shall conduct a post-Summer Season analysis to compare the LRE’s actual Summer Season Net Peak Demand versus the LRE’s planning forecast. The analysis would be used to evaluate, at a minimum, LRE’s planning forecast consistency and develop further improvements for the resource adequacy process. The Transmission Provider will take the results to the Supply Adequacy Working Group for review who may refer cases of potential discrepancies to the Markets and Operations Policy Committee for further investigation and action, if necessary.
12.0 Cost of New Entry

The Cost of New Entry ("CONE") value shall be 85.61 $/kw-yr. The CONE value shall be reviewed on or before November 1st of each year by the Transmission Provider and any changes shall be filed with the Commission. The Transmission Provider shall post the Commission-approved CONE for the next Summer Season on the SPP website within ten (10) calendar days of Commission approval.

The Transmission Provider’s calculation of the CONE for the SPP Balancing Authority Area shall be based on publicly available information (e.g., information provided by the Energy Information Administration) relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The Transmission Provider shall consider factors, including, but not limited to: (1) physical factors (such as, the type of generating resource that could reasonably be constructed to provide Firm Capacity in the SPP Balancing Authority Area, costs associated with locating the Resource within the SPP Balancing Authority Area); (2) financial factors (such as, the hypothetical debt/equity ratio for the Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE value, the Transmission Provider shall not consider the anticipated net revenue from the sale of capacity, energy or Ancillary Services.
13.0 Resource Adequacy Assurance

13.1 Variables

The variables used in the calculations are as follows:

(1) **Generator Owner Excess Capacity**

The available Deliverable Capacity above the committed capacity of Generator Owner Resource(s) as reflected in its completed Workbook.

(2) **LRE Deficient Capacity**

Resource Adequacy Requirement less LRE Firm Capacity, or zero if the LRE’s Firm Capacity is greater than or equal to the Resource Adequacy Requirement.

(3) **LRE Excess Capacity**

LRE Firm Capacity less Resource Adequacy Requirement, or zero if the LRE’s Firm Capacity is less than or equal to the Resource Adequacy Requirement.

(4) **SPP Balancing Authority Area Planning Reserve**

\[ \text{(The sum of all LREs’ Firm Capacity less the sum of all LREs’ Summer Season Net Peak Demand) plus the sum of all Generator Owner Excess Capacity]} \text{ divided by the sum of all LREs’ Summer Season Net Peak Demand.} \]

13.2 Deficiency Payment

(1) Deficiency Payment =

\[ \text{LRE Deficient Capacity} \times \text{CONE} \times \text{CONE FACTOR} \]

Where the CONE FACTOR shall be:
(a) 125% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 8%; or

(b) 150% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 3%, but less than the PRM plus 8%; or

(c) 200% when the SPP Balancing Authority Area Planning Reserve is less than the PRM plus 3%.

(2) An LRE that resolves its capacity deficiency for the purpose of meeting the Resource Adequacy Requirement by May 15th of the applicable year will be considered compliant.

(3) An LRE that fails to obtain sufficient capacity to meet the Resource Adequacy Requirement by May 15th of the applicable year, or fails to correct its Workbook by May 15th of the applicable year, will be considered deficient for the upcoming Summer Season. The responsible Market Participant shall be subject to the Deficiency Payment and such payment shall not relieve the LRE’s obligation to comply with the Resource Adequacy Requirement.

(4) A Market Participant, or its LRE, that does not submit the Workbook to the Transmission Provider by May 15th of the applicable year will be considered one hundred percent (100%) deficient and in violation of the Resource Adequacy Requirement for the upcoming Summer Season and shall subject the responsible Market Participant to the Deficiency Payment for the entire Resource Adequacy Requirement. To calculate the LRE Deficient Capacity, the Transmission Provider shall set the LRE’s Firm Capacity to zero and utilize the LRE’s previous year’s Summer Season Peak Demand.

13.3 Billing Procedure
On an annual basis, the Transmission Provider shall calculate the Deficiency Payment amounts to be assessed against a Market Participant pursuant to Section 13.2 of this Attachment AA. On or before June 30th of the applicable calendar year, the Transmission Provider shall submit an invoice to the Market Participant as a charge for the Deficiency Payment amount. The invoice shall be paid by the Market Participant within seven (7) calendar days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider. In the event of a dispute between the Transmission Provider and the Market Participant related to the calculation and assessment of a Deficiency Payment, the Market Participant shall pay the amount in dispute, and the Transmission Provider shall deposit into an escrow account the portion of the invoice in dispute, pending resolution of such dispute.

13.4 Revenue Distribution

Revenues from Deficiency Payments collected by the Transmission Provider shall be distributed to Market Participant(s) for its LRE(s) with LRE Excess Capacity or Generator Owner(s) with Generator Owner Excess Capacity on a pro rata basis according to the following:

(1) In the event that the sum of all LRE Excess Capacity is greater than or equal to the sum of LRE Deficient Capacity then:

\[
\text{LRE revenue} = \left( \frac{\text{individual LRE Excess Capacity}}{\text{sum of all LRE Excess Capacity}} \right) \times \text{sum of the Deficiency Payment(s)}
\]

(2) In the event that the sum of all LRE Excess Capacity is less than the sum of LRE Deficient Capacity, then the allocation of revenues shall be distributed according to the following steps:

(a) \[
\text{LRE revenue} =
\]
[(individual LRE Excess Capacity / sum of LRE Deficient Capacity) * sum of the Deficiency Payment(s)]; and

(b) Any remaining revenues not allocated pursuant to Section 13.4(2)(a) of this Attachment AA will be allocated to Generator Owner(s) in accordance with each Generator Owner’s submitted completed Workbook in the following manner:

(i) In the event that the sum of all LRE Excess Capacity and all Generation Owner Excess Capacity is greater than or equal to the sum of Deficient Planning Reserve(s) then:

Generator Owner revenue =

$$\left(\frac{\text{sum of LRE Deficient Capacity} - \text{sum of all LRE Excess Capacity}}{\text{sum of LRE Deficient Capacity}}\right) \times \left(\frac{\text{individual Generator Owner Excess Capacity}}{\text{sum of all Generator Owner Excess Capacity}}\right) \times \text{sum of Deficiency Payment(s)};$$
or

(ii) In the event that the sum of all LRE Excess Capacity and all Generator Owner Excess Capacity is less than the sum of Deficient Planning Reserve(s) then:

(a) Generator Owner revenue =

$$\left(\frac{\text{individual Generator Owner Excess Capacity}}{\text{sum of LRE Deficient Capacity}}\right) \times \text{sum of Deficiency Payment(s)};$$

and

(b) All remaining revenue not allocated in Section 13.4(2)(b)(ii)(a) of this Attachment AA will be allocated to each LRE that has met its Resource Adequacy Requirement on a load ratio share based on Summer Season Net Peak Demand:

LRE revenue =
[(sum of LRE Deficient Capacity – sum of all LRE Excess Capacity – sum of all Generator Owner Excess Capacity) / sum of LRE Deficient Capacity] * (individual LRE Summer Season Net Peak Demand / sum of LRE Summer Season Net Peak Demand(s) that have met the Resource Adequacy Requirement) * sum of Deficiency Payment(s)

(3) The Transmission Provider shall not be liable to an LRE for any revenues collected and distributed pursuant to this Attachment AA, or for damages arising out of or relating to any act or omission, performance, or failure to perform of a Market Participant with respect to such revenues or distribution thereof. It is the responsibility of each Market Participant to distribute such revenues that it receives pursuant to Section 13.4 of this Attachment AA to its eligible LREs.

13.5 Dispute Resolution

All disputes under this Attachment AA shall be subject to the dispute resolution procedures contained in Section 12 of this Tariff.
2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements (“GFAs”), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.
(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant’s share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant’s share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares. In order to qualify for this option, each Market Participant must register its share and certify that it is greater than or equal to the minimum physical capacity operating limit of the physical Jointly Owned Unit.

The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit; and
- Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant’s share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Once committed, each share is dispatched independently. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.
The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state; and
- Participant share percentage by Market Participant.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts (“MWs”), must register. Failure or refusal to register a load will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that load with the Commission under the name of the load Asset Owner. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the
Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8.1 of this Attachment, an aggregator of retail customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).
An aggregator of retail or wholesale customers offering Demand Response Load of one or more end-use retail customers or wholesale customers as a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment, as required.

All Variable Energy Resources must register as a Dispatchable Variable Energy Resource except for (1) a wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation before October 15, 2012 or (2) a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility or (3) a non-wind powered Variable Energy Resource registered on or prior to January 1, 2017 and with an interconnection agreement executed on or prior to January 1, 2017. Variable Energy Resources included in (1) and (3) above may register as Dispatchable Variable Energy Resources if they are capable of being incrementally dispatched by the Transmission Provider. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider and will be subject to the Dispatchable Variable Energy Resource market rules including Uninstructed Resource Deviation charges. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer’s load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation to serve the buyer’s load with both capacity and energy. For the purposes of Section 2.11.1 of this Attachment AE, such registration of the buyer’s load by the seller shall be accounted for by including such load in the seller’s Reported Load and not
including such load in the buyer’s Reported Load, as described under Section 2.11.1(A)(1) of this Attachment AE, and such associated bilateral contracts shall not be included in either the buyer’s or seller’s net resource capacity described under Section 2.11.1(A)(4) of this Attachment AE.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;
(b) Load Settlement Location;
(c) The maximum MW capacity contracted under the GFA Carve Out;
(d) The identification of the GFA in Attachment W; and
(e) Any other information reasonably required by the Transmission Provider.

(14) Market Participants with assets interconnected to the Transmission System that are not participating in the Energy and Operating Reserve Markets must pseudo-tie the Resource or load out of the SPP Balancing Authority Area in accordance with Attachment AO. Such assets shall continue to be registered in the Integrated Marketplace for the purposes of accounting for congestion and loss charges between the Resource Price Node and the applicable External Interface Settlement Location as described under Sections 8.6.23 and 8.6.24 of this Attachment AE.

(a) To the extent that the SPP Balancing Authority or associated external Balancing Authority can no longer maintain the Resource pseudo-tie for reliability reasons, the Market Participant representing the pseudo-tied Resource must immediately reduce the output of the pseudo-tied resource to the available pseudo-tie capability after receiving notification from the affected Balancing Authority of the reduced capability. A Market Participant shall not generate any energy in excess of the available
pseudo-tie capability after receiving such notification and shall not be compensated in the Energy and Operating Reserve Markets settlement for any energy generated in excess of the available pseudo-tie capability.

(15) Western-UGP shall provide to the Transmission Provider the information necessary to administer the FSE. The required information shall include the following:
   (a) Resource Settlement Locations;
   (b) Load Settlement Locations;
   (c) The maximum MW capacity contracted under the FSE;
   (d) The identification of the FSE Statutory Load Obligations as described in the SPP-Western-UGP NITSA; and
   (e) Any other information reasonably required by the Transmission Provider.

(16) The Transmission Provider shall establish FSE Transfer Points consistent with the FSE transmission service power flow impacts.
Southwest Power Pool, Inc.
Open Access Transmission Tariff
Sixth Revised Volume No. 1
Superseding
Fifth Revised Volume No. 1
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1.0 Overview

Maintaining appropriate planning reserves ensures that the Transmission Provider will have sufficient capacity to serve the SPP Balancing Authority Area’s peak demand. This Attachment AA requires a Load Responsible Entity to maintain capacity required to meet its load and planning reserve obligations. Additionally, this Attachment AA provides the obligations and responsibilities of the Transmission Provider, Market Participants, Load Responsible Entities, and Generator Owners with regard to load and planning reserves.
2.0 Definitions

Terms defined herein shall only be applicable to this Attachment AA.

**Asset Owner**
As defined in Attachment AE of this Tariff.

**Deficiency Payment**
A payment by a Market Participant when one or more of its LREs has not met the Resource Adequacy Requirement as calculated in accordance with Section 13.2 of this Attachment AA.

**Deliverable Capacity**
The accredited capacity of a Resource that is determined to be deliverable in an annual Deliverability Study for a Summer Season.

**Export Interchange Transaction**
As defined in Attachment AE of this Tariff.

**Firm Capacity**
The projected accredited capacity of an LRE’s commercially operable generating units, or portions of generating units, adjusted to reflect purchases and sales of accredited capacity with another party, and that is supported by firm transmission service to the LRE’s load, or is Deliverable Capacity to meet the PRM portion of the Resource Adequacy Requirement.

**Firm Power**
Power sales and purchases deliverable with firm transmission service where the seller assumes the obligation to serve the purchaser’s load with capacity, energy, and planning reserves that must be continuously available in a manner comparable to power delivered to native load customers.

**Generator Owner**
The Asset Owner of a Resource.

**Jointly Owned Unit**
As defined in Attachment AE of this Tariff.

**Load Responsible Entity (“LRE”)**
An Asset Owner represented in the Integrated Marketplace with a registered physical asset that is either a) load or b) an Export Interchange Transaction as specified in Section 5.4 of this Attachment AA.

**Market Participant**
As defined in Attachment AE of this Tariff.

**Net Peak Demand**
The forecasted Peak Demand less the a) projected impacts of demand response programs and behind-the-meter generation that are controllable and dispatchable and not registered as a Resource and b) contract amount of Firm Power purchased under agreements in effect as of the time of the forecasted Peak Demand, plus the contract amount of Firm Power sold to others in effect as of the time of the forecasted Peak Demand.

**Peak Demand**
The highest demand including transmission losses for energy measured over a one clock hour period.

**Resource**
As defined in Attachment AE of this Tariff.

**Summer Season**
June 1st through September 30th of each year.

**Winter Season**
December 1st through March 31th of each year.

Workbook
An electronic spreadsheet provided by the Transmission Provider which is used by an LRE or Generator Owner to submit information to the Transmission Provider for the purposes of administering this Attachment AA.
3.0 Roles and Responsibilities

3.1 Generator Owner and Load Responsible Entity

Except as provided in Section 3.1(1) of this Attachment AA, the roles and responsibilities of the LRE and Generator Owner are separate and distinct from the other under this Attachment AA. An entity may be an LRE, a Generator Owner, or both. For an entity that is both an LRE and Generator Owner, the Transmission Provider shall recognize the rights, roles, and responsibilities as separate and distinct functions.

(1) An LRE that is also a Generator Owner shall access its Workbook pursuant to the provisions of Section 8.3(b) of this Attachment AA but shall be considered an LRE for Workbook reporting purposes, and all excess capacity of the Generator Owner shall be considered LRE Excess Capacity for purposes of Resource Adequacy Assurance as described in Section 13.0 of this Attachment AA.

3.2 Market Participant and Load Responsible Entity

(1) An LRE may be a Market Participant or can engage a third party Market Participant to represent it. If an LRE refuses to either (a) become a Market Participant or (b) engage a third party Market Participant to represent it, the Transmission Provider shall file an unexecuted Market Participant Agreement with the Commission pursuant to Section 2.2(6) of Attachment AE of this Tariff.

(2) A Market Participant that represents an LRE under Attachment AH of this Tariff is the entity responsible under this Attachment AA to ensure the LRE’s compliance with the Resource Adequacy Requirement.

(3) The relationship between a Market Participant and its LRE, as established in the submission of the Workbook on February 15th, will be considered fixed for the upcoming Summer Season for enforcement of the Resource Adequacy Requirement.

(4) The Market Participant is responsible to ensure its LRE(s) provides the necessary data to allow the Transmission Provider to verify its LRE(s)’ compliance with the Resource Adequacy Requirement.
(5) An LRE shall submit all necessary data to the Transmission Provider either directly or through the LRE’s Market Participant.

(6) A Market Participant may aggregate the forecasted Peak Demand of multiple LREs whose load assets are served by a common set of Designated Resources or a Firm Power transaction between the LREs. In such case, the Market Participant shall be considered the LRE for the aggregated demand and, for purposes of compliance with this Attachment AA, the Market Participant’s forecasted Peak Demand shall be used to calculate a single Resource Adequacy Requirement for the aggregated load assets.

(7) The Market Participant is responsible for any Deficiency Payment(s) incurred by the LRE(s) it represents.

### 3.3 Procedures for Assignment of Market Participant Obligations

(1) A Market Participant may assign its duties, obligations and responsibilities for an LRE under this Attachment AA, but only to another Market Participant. A non-Market Participant must become a Market Participant prior to accepting an assignment.

(2) Assignor Market Participant shall be responsible to negotiate and contract with another Market Participant for the assignment of its duties, obligations, and responsibilities with respect to the LRE. A valid assignment must be in writing, bilaterally executed by both parties, and the assignee Market Participant shall affirmatively accept the duties, obligations, and responsibilities of the assignor Market Participant under this Attachment AA.

(3) Assignor Market Participant shall provide copies of the assignment to the Transmission Provider prior to February 15th of each calendar year. In the event the demonstration of such assignment does not occur prior to February 15th of each calendar year, the Transmission Provider shall not be required to accept the assignment for the upcoming Summer Season.

(4) A valid assignment by the assignor Market Participant under this Attachment AA does not affect the assignor Market Participant’s status as a Market Participant or other rights and obligations it may have under other provisions of this Tariff.
(5) Except as otherwise provided in Sections 3.3(6), 3.3(7), and 3.3(8) of this Attachment AA, upon demonstration of a valid assignment, Transmission Provider will accept the transfer of the LRE to the assignee Market Participant, and enforce the provisions of Attachment AA against the assignee Market Participant, without recourse against the assignor Market Participant.

(6) Either party may serve the Transmission Provider with written notice of the assignment’s termination. The Transmission Provider will recognize the assignment’s termination if the notice contains a written acknowledgement by both parties that the assignment has been terminated. Upon termination of the assignment, the duties, obligations, and responsibilities of the Market Participant for the transferred LRE under Attachment AA of the Tariff shall immediately revert back to assignor Market Participant, unless a replacement assignment that meets the requirements of this section is provided to the Transmission Provider.

(7) Nothing in the Transmission Provider’s acceptance of the assignment shall be construed to create or give rise to any liability on the part of the Transmission Provider and the parties to the assignment expressly waive any claims that may arise in their favor against the Transmission Provider, except as specifically may be provided in the Tariff. The Transmission Provider shall be held harmless by the by parties for any breach of the assignment or dispute between the parties with regards to the assignment, and such dispute shall not delay or cancel the financial responsibilities of the assignee Market Participant under this Attachment AA. Any dispute between the Transmission Provider and either party may be subject to the dispute resolution provisions of Section 12 of the Tariff.

(8) The Transmission Provider shall not be responsible for the actions of any party, or have any affirmative duties assigned to the Transmission Provider under the assignment. The Transmission Provider’s recognition of the assignment shall not be construed as Transmission Provider’s acceptance of the provisions of the assignment that may conflict with the Tariff or the Transmission Provider’s administration of the Tariff, and specifically, the application of this Attachment AA against the assignee Market Participant, or upon termination of the assignment, the assignor Market Participant. In the event there exists a conflict
between a term of the assignment and this Tariff, the provisions of this Tariff shall control.
4.0 Planning Reserve Margin

The Planning Reserve Margin (“PRM”) shall be twelve percent (12%). If an LRE’s Firm Capacity is comprised of at least seventy-five percent (75%) hydro-based generation, then such PRM shall be nine point eight nine percent (9.89%). A change to the PRM shall not be made absent a filing with the Commission.

Determination of the PRM will be supported by a probabilistic Loss of Load Expectation (“LOLE”) Study, which will analyze the ability of the Transmission Provider to reliably serve the SPP Balancing Authority Area’s forecasted Peak Demand. The LOLE Study will be performed by the Transmission Provider on a biennial basis, or more often as determined by the Transmission Provider. The Transmission Provider, with input from the stakeholders, shall develop the inputs and assumptions to be used for the LOLE Study. The Transmission Provider will 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. 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. The Transmission Provider shall post the final results of the LOLE Study.
5.0  Summer Season Resource Adequacy Requirement

5.1  The Resource Adequacy Requirement is equal to the LRE’s Summer Season Net Peak Demand plus its Summer Season Net Peak Demand multiplied by the PRM.

(1) The LRE is responsible to meet the Resource Adequacy Requirement for the Summer Season and failure to comply shall result in a Deficiency Payment as calculated in accordance with Section 13.2 of this Attachment AA.

5.2  The Firm Capacity utilized by an LRE to meet the Resource Adequacy Requirement may not be included in the Firm Capacity utilized by another LRE to meet the Resource Adequacy Requirement. Firm Capacity that is contracted to other entities shall not be available to the LRE that is transferring the Firm Capacity for compliance with the Resource Adequacy Requirement.

5.3  If an LRE serves load both internal and external to the SPP Balancing Authority Area, compliance with the Resource Adequacy Requirement contained in this 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. Load and Resources that are pseudo-tied into the SPP Balancing Authority Area shall be considered internal for purposes of determining the Resource Adequacy Requirement.

5.4  Any entity that utilizes an Export Interchange Transaction that is supported by a Firm Power contract shall be considered an LRE and must include that off-system load in its Summer Season Net Peak Demand to meet the Resource Adequacy Requirement. Any entity that utilizes an Export Interchange Transaction that is not supported by a Firm Power contract shall not be considered an LRE solely for the use of that transaction and shall not be required to include that off-system load in its Summer Season Net Peak Demand to meet the Resource Adequacy Requirement.
6.0 Winter Season Obligation

6.1 For the Winter Season, each 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.

6.2 The Firm Capacity utilized by an LRE may not be included in the Firm Capacity utilized by another LRE. Firm Capacity that is contracted to other entities shall not be available to the LRE that is transferring the Firm Capacity.

6.3 If an LRE serves load both internal and external to the SPP Balancing Authority Area, compliance with the obligation in Section 6.0 of this 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. 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 this Attachment AA.
7.0 Short-Term Transactions

An LRE may arrange for short-term capacity to provide a part of its Firm Capacity or short-term Firm Power to reduce a portion of either its Summer Season Net Peak Demand or Winter Season Net Peak Demand, but not both, subject to the following provisions:

(1) Such short-term capacity or short-term Firm Power shall be available for a minimum of four consecutive months, starting either June 1st or December 1st; and

(2) The amount of short-term capacity or short-term Firm Power shall not exceed 25% of an LRE’s applicable Net Peak Demand.
8.0 Resource Adequacy Timeline

The Resource Adequacy Requirement process is performed annually beginning on July 1st of each year. For any prescribed date that falls on a weekend or holiday, the date of performance shall be the next business day.

(1) On July 1st of each year the Transmission Provider shall post the following on the SPP website and distribute via email distribution list:
   (a) Notification of the commencement of the process; and
   (b) A timeline indicating when the Market Participant, LRE, and Generator Owner are required to meet their respective obligations.

(2) By October 1st of each year the Transmission Provider will perform the Deliverability Study.

(3) On October 1st of each year the Transmission Provider shall post and provide notice via email distribution list:
   (a) The following on the SPP website:
      (i) The unpopulated Workbook;
      (ii) Instructions for completing the Workbook; and
      (iii) The deadline to submit the Workbook.
   (b) The following on a secure website:
      (i) A Workbook populated with the results of the Deliverability Study for each individual Generator Owner.

(4) The Transmission Provider shall not modify the unpopulated Workbook after December 31st of each year. Any modification to the unpopulated Workbook by the Transmission Provider after the initial October 1st posting shall be posted on the SPP website and distributed via email distribution list.

(5) By February 15th of each year, each Market Participant and participating Generator Owner will ensure the Transmission Provider is provided with a Workbook.

(6) No later than five (5) calendar days after February 15th, the Transmission Provider shall provide notice to all Market Participants, LREs, and Generator Owners that have not submitted a Workbook by the deadline. Such notice shall
include the communication that the Market Participant may be subject to a Deficiency Payment if such deficiency is not cured. A Market Participant, LRE, or Generator Owner that receives such notice shall have ten (10) calendar days to submit its Workbook. Failure to provide a Workbook within the ten (10) calendar days after notification shall result in the Transmission Provider disclosing a listing of the entities that have not submitted a Workbook to the Supply Adequacy Working Group, which will provide a report to the Markets and Operations Policy Committee.

(7) Prior to April 1st of each year, the Transmission Provider will review the information in the Workbook to determine whether each LRE meets the Resource Adequacy Requirement. The Transmission Provider will notify the Market Participant and the LRE if the LRE has not met the Resource Adequacy Requirement.

(8) No later than April 1st of each year, an initial report on the status of all LREs shall be posted on the SPP website by the Transmission Provider.

(9) By May 15th of each year, an LRE or Generator Owner shall update its Workbook to reflect purchases and sales that occurred after the initial submission.

(10) By May 15th of each year, an LRE must demonstrate it has cured any deficiency in compliance with the Resource Adequacy Requirement.

(11) No later than June 15th of each year, the Transmission Provider shall post its final report on the status of each LRE’s compliance with the Resource Adequacy Requirement for the upcoming Summer Season and whether the respective Market Participant is subject to the Deficiency Payment.

(12) On or before June 30th of each year, and after the posting of the final report, the Transmission Provider shall calculate and assess the Deficiency Payment in accordance with the provisions contained in Sections 13.2 and 13.3, respectively, of this Attachment AA.
9.0 Deliverability Study

9.1 The Transmission Provider shall perform an annual Deliverability Study. The Deliverability Study will evaluate the deliverability to the SPP Balancing Authority Area of each Resource registered in the Integrated Marketplace and not whether such Resources are deliverable to specific delivery points or SPP Zones. The Deliverability Study will result in a determination of each Resource’s capacity that is deliverable to the SPP Balancing Authority Area. The results of the Deliverability Study shall be valid for the upcoming Summer Season and the subsequent Summer Season.

9.2 The Transmission Provider will utilize its current transmission planning models to perform the Deliverability Study. The Transmission Provider will begin the Deliverability Study with the initial assumption that any Resource generating in the planning model is automatically deliverable to the SPP Balancing Authority Area for the dispatched output. A Resource’s total capacity equals the generating unit’s maximum output of MWs. For multiple generating units at one site, the total capacity for the site is the sum of maximum MWs of all generating units. A transfer level equal to the difference between the Resource’s maximum MW capacity and the amount dispatched in the planning model is determined for each Resource. A First Contingency Incremental Transfer Capability (“FCITC”) analysis of each transfer will be performed to determine the deliverability of the Resource. Transmission Facilities 100 kV and above will be included in the FCITC analysis. A three percent (3%) transfer distribution factor threshold will be used to analyze constraints impacted by the transfer.

9.3 The Deliverability Study results for each Generator Owner’s Resource shall consist of the total Resource’s deliverability of MW amounts. Each Generator Owner of a Jointly Owned Unit will coordinate to determine the MW deliverability amounts for its share of a Jointly Owned Unit.
9.4 The amount of Deliverable Capacity of any Resource available for purchase to meet the PRM portion of the Resource Adequacy Requirement shall equal the lesser of: a) the Resource’s accredited capacity less the MW amount of capacity that has been committed to meet i) Firm Capacity and ii) a sale to another entity; or b) the amount of a Resource’s total deliverable MWs less the MW amount of capacity that has been committed to meet i) Firm Capacity and ii) a sale to another entity, as determined from the Generator Owner’s Workbook.

9.5 A Generator Owner that does not submit a Workbook that contains the amount of generation capacity available through the Deliverability Study shall be deemed to have no Deliverable Capacity and shall not be entitled to receive any revenue distributions collected from Deficiency Payments.

9.6 A power purchase agreement to satisfy the PRM portion of the Resource Adequacy Requirement based on the most recent Deliverability Study may only rely on the results of such study for no longer than the upcoming Summer Season and the subsequent Summer Season.

(1) Deliverable Capacity purchases by an LRE to satisfy the PRM portion of the Resource Adequacy Requirement will not require firm transmission service to support the capacity. Deliverable Capacity purchases shall not entitle a Market Participant to receive Auction Revenue Rights under Attachment AE of the Tariff.

(2) Deliverable Capacity purchases shall not be utilized to serve any portion of the LRE’s Summer Season Net Peak Demand. If the LRE’s power purchase agreement to satisfy the PRM portion of the Resource Adequacy Requirement also includes capacity needed to serve any portion of its Summer Season Net Peak Demand, the LRE must secure firm transmission service for such capacity to serve any portion of its Summer Season Net Peak Demand.
10.0 Workbook

10.1 The Generator Owner’s Workbook will contain, but is not limited to, the following information:

(1) Capacity sales to another entity; and
(2) Uncommitted Deliverable Capacity available to meet the PRM.

10.2 The LRE’s Workbook will contain, but is not limited to, the following information:

(1) The LRE’s Summer Season Net Peak Demand;
(2) Firm Capacity owned by the LRE;
(3) Purchases and sales for Firm Capacity;
(4) Purchases and sales for Firm Power; and
(5) Uncommitted Deliverable Capacity available to meet the PRM.

10.3 The LRE’s Workbook shall be subject to the following provisions:

(1) A Workbook will be used to qualify the LRE’s compliance with the Resource Adequacy Requirement for the upcoming Summer Season. Absent a calculation error or otherwise incorrect information, an LRE that demonstrates compliance with the requirements of Section 5.0 of this Attachment AA is considered to have met its Resource Adequacy Requirement, subject to any subsequently reported sales. An LRE shall update its Workbook by May 15th to correct calculation errors or incorrect information.

(2) A Workbook may include any Resources, provided the Resource’s capacity is expected to be available during June 15th through September 15th. After February 15th, if the expected availability of a Resource changes to unavailable during June 15th through September 15th, the
Resource will be considered as available for purposes of meeting the Resource Adequacy Requirement.

(3) Resources contained in the Workbook that are identified by February 15th to be unavailable during part or all of the period from June 15th through September 15th will not count as capacity for purposes of meeting the LRE’s compliance with the Resource Adequacy Requirement. Should a Resource that is initially identified to be unavailable during part or all of the period from June 15th through September 15th but subsequently becomes available and the LRE updates its Workbook by May 15th, such Resource will count as capacity for purposes of meeting the Resource Adequacy Requirement.
11.0 Post-Season Analysis

The Transmission Provider shall conduct a post-Summer Season analysis to compare the LRE’s actual Summer Season Net Peak Demand versus the LRE’s planning forecast. The analysis would be used to evaluate, at a minimum, LRE’s planning forecast consistency and develop further improvements for the resource adequacy process. The Transmission Provider will take the results to the Supply Adequacy Working Group for review who may refer cases of potential discrepancies to the Markets and Operations Policy Committee for further investigation and action, if necessary.
12.0 Cost of New Entry

The Cost of New Entry ("CONE") value shall be 85.61 $/kw-yr. The CONE value shall be reviewed on or before November 1st of each year by the Transmission Provider and any changes shall be filed with the Commission. The Transmission Provider shall post the Commission-approved CONE for the next Summer Season on the SPP website within ten (10) calendar days of Commission approval.

The Transmission Provider’s calculation of the CONE for the SPP Balancing Authority Area shall be based on publicly available information (e.g., information provided by the Energy Information Administration) relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The Transmission Provider shall consider factors, including, but not limited to: (1) physical factors (such as, the type of generating resource that could reasonably be constructed to provide Firm Capacity in the SPP Balancing Authority Area, costs associated with locating the Resource within the SPP Balancing Authority Area); (2) financial factors (such as, the hypothetical debt/equity ratio for the Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE value, the Transmission Provider shall not consider the anticipated net revenue from the sale of capacity, energy or Ancillary Services.
13.0 Resource Adequacy Assurance

13.1 Variables

The variables used in the calculations are as follows:

(1) Generator Owner Excess Capacity

The available Deliverable Capacity above the committed capacity of Generator Owner Resource(s) as reflected in its completed Workbook.

(2) LRE Deficient Capacity

Resource Adequacy Requirement less LRE Firm Capacity, or zero if the LRE’s Firm Capacity is greater than or equal to the Resource Adequacy Requirement.

(3) LRE Excess Capacity

LRE Firm Capacity less Resource Adequacy Requirement, or zero if the LRE’s Firm Capacity is less than or equal to the Resource Adequacy Requirement.

(4) SPP Balancing Authority Area Planning Reserve

[(The sum of all LREs’ Firm Capacity less the sum of all LREs’ Summer Season Net Peak Demand) plus the sum of all Generator Owner Excess Capacity] divided by the sum of all LREs’ Summer Season Net Peak Demand.

13.2 Deficiency Payment

(1) Deficiency Payment =

LRE Deficient Capacity * CONE * CONE FACTOR

Where the CONE FACTOR shall be:
(a) 125% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 8%; or

(b) 150% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 3%, but less than the PRM plus 8%; or

(c) 200% when the SPP Balancing Authority Area Planning Reserve is less than the PRM plus 3%.

(2) An LRE that resolves its capacity deficiency for the purpose of meeting the Resource Adequacy Requirement by May 15th of the applicable year will be considered compliant.

(3) An LRE that fails to obtain sufficient capacity to meet the Resource Adequacy Requirement by May 15th of the applicable year, or fails to correct its Workbook by May 15th of the applicable year, will be considered deficient for the upcoming Summer Season. The responsible Market Participant shall be subject to the Deficiency Payment and such payment shall not relieve the LRE’s obligation to comply with the Resource Adequacy Requirement.

(4) A Market Participant, or its LRE, that does not submit the Workbook to the Transmission Provider by May 15th of the applicable year will be considered one hundred percent (100%) deficient and in violation of the Resource Adequacy Requirement for the upcoming Summer Season and shall subject the responsible Market Participant to the Deficiency Payment for the entire Resource Adequacy Requirement. To calculate the LRE Deficient Capacity, the Transmission Provider shall set the LRE’s Firm Capacity to zero and utilize the LRE’s previous year’s Summer Season Peak Demand.

13.3 Billing Procedure
On an annual basis, the Transmission Provider shall calculate the Deficiency Payment amounts to be assessed against a Market Participant pursuant to Section 13.2 of this Attachment AA. On or before June 30th of the applicable calendar year, the Transmission Provider shall submit an invoice to the Market Participant as a charge for the Deficiency Payment amount. The invoice shall be paid by the Market Participant within seven (7) calendar days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider. In the event of a dispute between the Transmission Provider and the Market Participant related to the calculation and assessment of a Deficiency Payment, the Market Participant shall pay the amount in dispute, and the Transmission Provider shall deposit into an escrow account the portion of the invoice in dispute, pending resolution of such dispute.

**13.4 Revenue Distribution**

Revenues from Deficiency Payments collected by the Transmission Provider shall be distributed to Market Participant(s) for its LRE(s) with LRE Excess Capacity or Generator Owner(s) with Generator Owner Excess Capacity on a pro rata basis according to the following:

1. In the event that the sum of all LRE Excess Capacity is greater than or equal to the sum of LRE Deficient Capacity then:

   \[
   \text{LRE revenue} = \frac{\text{individual LRE Excess Capacity}}{\text{sum of all LRE Excess Capacity}} \times \text{sum of the Deficiency Payment(s)}
   \]

2. In the event that the sum of all LRE Excess Capacity is less than the sum of LRE Deficient Capacity, then the allocation of revenues shall be distributed according to the following steps:

   (a) \[\text{LRE revenue} = \]
[(individual LRE Excess Capacity / sum of LRE Deficient Capacity) * sum of the Deficiency Payment(s)]; and

(b) Any remaining revenues not allocated pursuant to Section 13.4(2)(a) of this Attachment AA will be allocated to Generator Owner(s) in accordance with each Generator Owner’s submitted completed Workbook in the following manner:

(i) In the event that the sum of all LRE Excess Capacity and all Generation Owner Excess Capacity is greater than or equal to the sum of Deficient Planning Reserve(s) then:

Generator Owner revenue =

\[
\text{[(sum of LRE Deficient Capacity - sum of all LRE Excess Capacity) / sum of LRE Deficient Capacity]} \times \text{individual Generator Owner Excess Capacity / sum of all Generator Owner Excess Capacity) * sum of Deficiency Payment(s)];}\]

or

(ii) In the event that the sum of all LRE Excess Capacity and all Generation Owner Excess Capacity is less than the sum of Deficient Planning Reserve(s) then:

(a) Generator Owner revenue =

\[
\text{[(individual Generator Owner Excess Capacity / sum of LRE Deficient Capacity) * sum of Deficiency Payment(s)]}; \text{ and}
\]

(b) All remaining revenue not allocated in Section 13.4(2)(b)(ii)(a) of this Attachment AA will be allocated to each LRE that has met its Resource Adequacy Requirement on a load ratio share based on Summer Season Net Peak Demand:

LRE revenue =
[(sum of LRE Deficient Capacity – sum of all LRE Excess Capacity – sum of all Generator Owner Excess Capacity) / sum of LRE Deficient Capacity] * (individual LRE Summer Season Net Peak Demand / sum of LRE Summer Season Net Peak Demand(s) that have met the Resource Adequacy Requirement) * sum of Deficiency Payment(s)

(3) The Transmission Provider shall not be liable to an LRE for any revenues collected and distributed pursuant to this Attachment AA, or for damages arising out of or relating to any act or omission, performance, or failure to perform of a Market Participant with respect to such revenues or distribution thereof. It is the responsibility of each Market Participant to distribute such revenues that it receives pursuant to Section 13.4 of this Attachment AA to its eligible LREs.

13.5 Dispute Resolution

All disputes under this Attachment AA shall be subject to the dispute resolution procedures contained in Section 12 of this Tariff.
2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements (“GFAs”), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.
In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant’s share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant’s share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares. In order to qualify for this option, each Market Participant must register its share and certify that it is greater than or equal to the minimum physical capacity operating limit of the physical Jointly Owned Unit.

The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit; and
- Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant’s share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Once committed, each share is dispatched independently. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.
The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state; and
- Participant share percentage by Market Participant.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts (“MWs”), must register. Failure or refusal to register a load will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that load with the Commission under the name of the load Asset Owner. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the
Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8.1 of this Attachment, an aggregator of retail customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).
An aggregator of retail or wholesale customers offering Demand Response Load of one or more end-use retail customers or wholesale customers as a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment, as required.

All Variable Energy Resources must register as a Dispatchable Variable Energy Resource except for (1) a wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation before October 15, 2012 or (2) a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility or (3) a non-wind powered Variable Energy Resource registered on or prior to January 1, 2017 and with an interconnection agreement executed on or prior to January 1, 2017. Variable Energy Resources included in (1) and (3) above may register as Dispatchable Variable Energy Resources if they are capable of being incrementally dispatched by the Transmission Provider. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider and will be subject to the Dispatchable Variable Energy Resource market rules including Uninstructed Resource Deviation charges. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer’s load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation to serve the buyer’s load with both capacity and energy. For the purposes of Section 2.11.1 of this Attachment AE, such registration of the buyer’s load by the seller shall be accounted for by including such load in the seller’s Reported Load and not
including such load in the buyer’s Reported Load, as described under Section 2.11.1(A)(1) of this Attachment AE, and such associated bilateral contracts shall not be included in either the buyer’s or seller’s net resource capacity described under Section 2.11.1(A)(4) of this Attachment AE.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;
(b) Load Settlement Location;
(c) The maximum MW capacity contracted under the GFA Carve Out;
(d) The identification of the GFA in Attachment W; and
(e) Any other information reasonably required by the Transmission Provider.

(14) Market Participants with assets interconnected to the Transmission System that are not participating in the Energy and Operating Reserve Markets must pseudo-tie the Resource or load out of the SPP Balancing Authority Area in accordance with Attachment AO. Such assets shall continue to be registered in the Integrated Marketplace for the purposes of accounting for congestion and loss charges between the Resource Price Node and the applicable External Interface Settlement Location as described under Sections 8.6.23 and 8.6.24 of this Attachment AE.

(a) To the extent that the SPP Balancing Authority or associated external Balancing Authority can no longer maintain the Resource pseudo-tie for reliability reasons, the Market Participant representing the pseudo-tied Resource must immediately reduce the output of the pseudo-tied resource to the available pseudo-tie capability after receiving notification from the affected Balancing Authority of the reduced capability. A Market Participant shall not generate any energy in excess of the available
pseudo-tie capability after receiving such notification and shall not be compensated in the Energy and Operating Reserve Markets settlement for any energy generated in excess of the available pseudo-tie capability.

(15) Western-UGP shall provide to the Transmission Provider the information necessary to administer the FSE. The required information shall include the following:
(a) Resource Settlement Locations;
(b) Load Settlement Locations;
(c) The maximum MW capacity contracted under the FSE;
(d) The identification of the FSE Statutory Load Obligations as described in the SPP-Western-UGP NITSA; and
(e) Any other information reasonably required by the Transmission Provider.

(16) The Transmission Provider shall establish FSE Transfer Points consistent with the FSE transmission service power flow impacts.