Southwest Power Pool
REGIONAL STATE COMMITTEE
Skirvin Hotel, Oklahoma City, OK
January 29, 2018
• MINUTES •

ADMINISTRATIVE ITEMS

The following members participated:

- Shari Feist Albrecht, Kansas Corporation Commission (KCC)
- Kristie Fiegen, South Dakota Public Utilities Commission (SDPUC)
- Randy Christmann, North Dakota Public Service Commission (NDPSC)
- Dennis Grennan, Nebraska Power Review Board (NPRB)
- Geri Huser, Iowa Utilities Board (IUB)
- Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)
- Dana Murphy, Oklahoma Corporation Commission (OCC)
- Kim O’Guinn, Arkansas Public Service Commission (APSC)
- Scott Rupp, Missouri Public Service Commission (MoPSC)
- DeAnn T. Walker, Public Utility Commission of Texas (PUCT)

President Shari Feist Albrecht called the Regional State Committee (RSC) meeting to order at 1:06 p.m. with roll call, and a quorum was declared. President Albrecht welcomed Commissioner Scott Rupp from the Missouri Public Service Commission and Mr. Lane Sisung from the Louisiana Public Service Commission. Lane will be the Cost Allocation Working Group representative. Commissioner Foster Campbell will represent the commission on the RSC. President Albrecht requested introductions of those in attendance. There were 125 people in attendance, either in person or via the phone (Attendance & Proxies – Attachment 1).

The first item of business was the approval of the 10/30/17 meeting minutes (RSC Minutes 10/30/17 – Attachment 2).

Commissioner DeAnn Walker moved to approve the minutes with corrections; Commissioner Geri Huser seconded. The motion was approved unanimously.

Ms. Kandi Hughes (SPP staff) reviewed the RSC action items (RSC Action Items – Attachment 3).

UPDATES

RSC Fourth Quarter Financial Report
Mr. Paul Suskie (SPP staff) provided the financial report for the fourth quarter (RSC 2017 Q4 Financials – Attachment 4). He noted that the RSC was under budget for the fourth quarter with the exception of the audit.

Federal Energy Regulatory Commission (FERC) Report
Mr. Patrick Clarey (FERC staff) provided the FERC report. Mr. Clarey reported that FERC was now operating with five commissioners after the swearing in of Chairman Kevin McIntyre. The full commission held open meetings in December and January.
At the December meeting, Chair McIntyre announced FERC will examine the Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, adopted in 1999, as part of a pledge he made during his Senate confirmation to take a fresh look at all aspects of the agency’s work. The next steps will be announced in the near future.

On January 8th, FERC terminated the proceeding it initiated in Docket No. RM18-1-000 to consider the Department of Energy’s September 29 proposal on grid reliability and resilience pricing. In addition, the Commission initiated a new proceeding, Docket No. AD18-7-000, to holistically examine the resilience of the bulk power system.

In Docket No. AD18-7, the Commission directs operators of the regional wholesale power markets to provide information as to whether FERC and the markets need to take additional action on resilience of the bulk power system. The goals of the proceeding are to: (1) develop a common understanding among the Commission, industry and others of what resilience of the bulk power system means and requires; (2) understand how each regional transmission organization and independent system operator assesses resilience in its geographic footprint; and (3) use this information to evaluate whether additional Commission action regarding resilience is appropriate.

Each regional market operator must submit the required information within 60 days of issuance of the order. FERC also invited other interested entities to respond to the market operators’ comments.

SPP Report
Mr. Nick Brown (SPP staff) provided the SPP update. He began his report by discussing the plan for putting together comments to FERC on the resilience docket. SPP has until March 9 to respond to 39 questions posed by FERC. SPP staff will work with the Strategic Planning Committee (SPC) to pull the information together in response to the questions. This is a very broad topic. Paul Suskie has the questions posed by FERC. If you are interested in reviewing the questions and the information please contact Paul. The goal is to distribute a draft of the SPP response to the SPC by February 20. SPP will then host an SPC webinar on February 23. Resiliency has been looked at in the past as a subcategory of reliability. It is now taking a lead in the consideration of reliability.

Mr. Brown also provided an update on Mountain West Transmission Group efforts over the last nine months. There have been a number of forums and meetings involving members, the RSC and state staff. There have been a number of topics discussed and reduced. A smaller negotiating team was formed which consists of SPP Board Chair Jim Eckelberger, SPP Board Vice Chair Larry Altenbaumer, Mr. Mike Wise (Golden Spread Electric Cooperative), Mr. Kelly Harrison (Westar), and Nick Brown and Mr. Carl Monroe (SPP staff).

Commissioner Geri Huser moved to have the RSC direct the Cost Allocation Working Group (CAWG) to start performing the duties listed on page 13, Section 8.2, of the New Member Process document dated October 24, 2016; Commissioner DeAnn Walker seconded the motion. The motion was approved unanimously.

BUSINESS MEETING
Auditor Costs for Audit and Taxes for 2017 and Auditor Engagement Letter (Voting Item)
Mr. Suskie (SPP staff) discussed the engagement letter from Thomas and Thomas (Thomas and Thomas Letter – Attachment 5) to conduct the audit and prepare the taxes for 2017 for the RSC.

Commissioner Patrick Lyons made a motion to engage Thomas and Thomas again to complete the audit and taxes for the RSC; Commissioner Geri Huser seconded the motion. The motion was approved unanimously.

Mr. Suskie provided an update on the revised RSC travel policy (RSC Travel Policy – Attachment 6), which has not been updated since 2007.

Commissioner Geri Huser made a motion to accept the revised RSC travel policy; Commissioner Dennis Grennan seconded the motion. The motion was approved unanimously.
Cost Allocation Working Group Report and Voting Items

CAWG Report
Ms. Christine Aarnes (KCC staff and CAWG Chair) provided the CAWG report (CAWG Report – Attachment 7). Ms. Aarnes reported on the meetings that have taken place since October and future meeting dates. She provided an update of the various projects and voting items of the CAWG. There were no revision requests (RR) approved on the CAWG consent agenda. The expected future issues are cost allocation for projects in wind-rich areas, competitive project minimum threshold (FERC Docket No. ER17-2523-000), and continued developments with the Mountain West Transmission Group.

Safe Harbor Criteria “Lessons Learned” Update (Voting Item)
Mr. Adam McKinnie (MoPSC staff) provided a report on the safe harbor criteria (Lessons Learned: Aggregate Study Safe Harbor Waiver Criteria Review – Attachment 8). The purpose of this report was to provide a list of CAWG-approved lessons learned from the Aggregate Study Safe Harbor Waiver Criteria work and to request a vote from the RSC to adopt the lessons learned. The safe harbor is applied if the applicable aggregate study waiver criteria are met. A utility may apply for a waiver if the transmission service request (TSR) does not meet the applicable safe harbor criteria or for an increase in the safe harbor amount. The CAWG will continue to work with SPP staff to determine how many waiver requests have been submitted, and continue to ask for feedback from stakeholders. The CAWG asked the RSC to endorse the lessons learned on the safe harbor criteria.

Commissioner Patrick Lyons made a motion for the RSC to endorse the safe harbor criteria lessons learned as drafted; Commissioner Randy Christmann seconded the motion. The motion was approved unanimously.

RR251 – Supply Adequacy Update (Voting Item)
Supply Adequacy Working Group Chair Mr. Brad Hans provided a report on RR 251 Supply Adequacy (RR251 Presentation and Recommendation Report – Attachment 9). Mr. Hans noted that FERC rejected SPP’s RR187 filing without prejudice and provided guidance on three issues: 1) SPP’s proposal failed to include a requirement that all power purchases agreements be backed by verifiable capacity to meet SPP’s resource adequacy requirement (RAR) and failed to include provisions to allow SPP to review the agreements to verify that they are backed by capacity, 2) SPP’s proposed treatment of firm power purchases and sales in the determination of net peak demand was unduly discriminatory, and 3) SPP did not support as just and reasonable its proposal to post publicly a list of all load responsible entities (LREs) that have not met their RAR. There were changes reflected in RR251 to address these issues, and SPP re-engaged the stakeholder process to address only the FERC-identified issues.

Commissioner Dennis Grennan made a motion for the RSC to approve RR251 as addressing the FERC-identified issues outlined in their rejection without prejudice in FERC Docket No. ER17-1098, while maintaining the originally-approved Capacity Margin Task Force (CMTF); Commissioner Kim O’Guinn seconded the motion. The motion was approved unanimously.

Cost Allocation in Wind-Rich Areas (Voting Item)
Mr. Al Tamimi (Sunflower) provided a presentation on cost allocation in wind-rich areas (Cost Allocation in Wind-Rich Areas – Attachment 10). He provided an overview of the problem as he sees it and provided a case history and analysis. He also provided possible solutions to the problem.

Commissioner Patrick Lyons made a motion to adopt the action item in which the RSC directed the CAWG to work with SPP staff and stakeholders on a proposed scope of work identifying interrelated issues as it relates to issues of cost allocation and report at the April 2018 meeting; Commissioner DeAnn Walker seconded the motion. The motion was approved unanimously.

REPORTS/PRESENTATIONS

Integrated Transmission Planning (ITP) Update
Mr. Lanny Nickell (SPP staff) proved the ITP Update (Integrated Transmission Planning Update – Attachment 11). The three areas covered in the update is the 2018 Integrated Transmission Planning Near-Term
assessments (ITPNT) update, the 2019 ITP update, and the 2018 SPP Transmission Expansion Plan (STEP).
The 2019 ITP scope is an assessment to develop a regional transmission plan that provides reliable and
economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to
the end-use customer. The 2018 STEP includes ITP, high priority, balanced portfolio, interregional, transmission
service, generation interconnection, and sponsored upgrades.

Integrated Marketplace Update
Mr. Bruce Rew (SPP staff) provided the Integrated Marketplace Operational update (Integrated Marketplace
Operational Update – Attachment 12). A new winter peak was set on December 19. The low temperatures in
the last week of December and early January did drive high system demand with higher gas prices and
increased generation outages. There are currently 211 market participants with 141 financial only and 70 asset
owning. The real-time balancing market has successfully solved 99.92% of all intervals. SPP set a new
historical maximum wind output of 15,690 MW in December.

Regional Allocation Review Task Force (RARTF) Update
Commissioner Dennis Grennan provided an RARTF update (RARTF Presentation – Attachment 13).
Commissioner Grennan was appointed chair of the RARTF on January 1. During its last meeting, the group
focused on the SPP/AECI seams remedy project, the regional cost allocation review (RCAR) frequency filing at
FERC, and RCAR III options.

The SPP/AECI seams projects are the Brookline Reactor and Morgan Transformer projects. The Brookline
Reactor project is being evaluated in the 2018 ITPNT, and if it is approved in the planning process then no
further FERC filing will be necessary. SPP staff visited with FERC regarding the Morgan Transformer project
and believes another filing at FERC is appropriate.

Staff has provided four options to the RARTF for consideration with RCAR III. Staff was directed to provide
more analysis at the January 15 meeting. Staff will provide results of a limited proof concept using the market
to provide adjusted production cost savings and is comfortable that this process is feasible. At the next
meeting there will be a strawman proposal to review the fourth option discussing hybrid operational/planning
based to include cost and schedule, stakeholder group involvement, and RCAR II lessons learned.

Seams Projects Update
Mr. Suskie provided the seams projects update (SPP-AECI Joint Projects – Attachment 14). SPP and AECI
agreed on two joint projects out of the 2016 SPP-AECI Joint and Coordinated System Plan (JCSP). SPP made
filings at FERC for the two projects. FERC issued an order rejecting SPP’s proposal for region-wide/load-ratio
share funding for SPP’s portion of the costs for the two joint projects. The order did not preclude SPP from
making additional filings to the Commission to support region-wide funding or propose a new cost allocation
methodology for the two joint projects. SPP staff is continuing to review the Commission’s order and is
determining the best path forward for the two joint projects with AECI. Staff is also continuing to work on the
best path forward for non-order 1000 joint projects.

Ms. Kandi Hughes reviewed the action items from the RSC education session and the RSC meeting.

Commissioner DeAnn Walker made a motion that if a special meeting is called at the April RSC meeting
that there be an action item on the agenda for the RSC to go into a closed session, to the extent that the
motion requires it, for deliberation on the topic of Mountain West; Commissioner Patrick Lyons
seconded the motion. The motion was approved unanimously.
Regional State Committee  
January 29, 2018

**SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS**

2018:
April 23, 2018 - Kansas City, MO  
July 30, 2018 - Omaha, NE  
October 29, 2018 - Little Rock, AR

With no further business, the meeting adjourned at 5:16 p.m.

Respectfully Submitted,

Paul Suskie
1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Commissioners’ Roll Call and Declaration of a Quorum
   b. Meeting Attendees Roll Call
   c. Adoption of Minutes from October 30, 2017
   d. Review of Ongoing Action Items

3. UPDATES
   a. RSC Fourth Quarter 2017 Financial Report
   b. SPP
   c. FERC

4. BUSINESS MEETING
   a. Auditor Cost for Audit and Taxes for 2017 and Engagement Letter [Voting Item]
   b. RSC Travel Policy [Voting Item]

5. COST ALLOCATION WORKING GROUP REPORT
   a. CAWG Report..............................Christine Aarnes
      This report will update the RSC on the activities of the Cost Allocation Working Group.
      i. Safe Harbor Criteria “Lessons Learned” Update..............................Adam McKinnie
         [Voting Item]
         This report will update the RSC on the Safe Harbor Criteria “Lessons Learned”.
      ii. RR251 - Supply Adequacy Update .............................................Brad Hans
          [Voting Item]
          This report will update the RSC on RR251 - Supply Adequacy Update
      iii. Cost Allocation in Wind Rich Areas...........................................Al Tamimi
           [Voting Item]
           This report will update the RSC on Cost Allocation in Wind Rich Areas.

6. REPORTS/PRESENTATIONS
   a. Integrated Transmission Planning (ITP) Update..............................Lanny Nickell
      This report will update the RSC on the 2018 and 2019 ITP study activities.
   b. Integrated Marketplace Update.....................................................Bruce Rew
      This report will update the RSC on the Integrated Marketplace.
   c. RARTF Update..........................................................Dennis Grennan
      This report update the RSC on the activities of the Regional Allocation Review Task Force.
   d. Seams Projects Update............................................................Paul Suskie
      This report update the RSC on Seams projects.

7. OTHER RSC MATTERS

8. NEW ACTION ITEMS
8. SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS

a. RSC Meetings:
   April 23, 2018 – Kansas City, MO
   July 30, 2018 – Omaha, NE
   October 29, 2018 – Little Rock, AR
   January 28, 2019 – Austin, TX
   April 29, 2019 – Tulsa, OK
   July 29, 2019 – Denver, CO
   October 29, 2019 – Little Rock, AR

9. ADJOURN

* NOTE: ADDITIONAL INFORMATIONAL MATERIAL ATTACHED

Attached to the RSC’s meeting agenda and background material is additional material that is either for informational or reporting purposes.
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REGIONAL STATE COMMITTEE
Skirvin Hotel, Oklahoma City, OK
January 29, 2018

• ATTENDANCE LIST •

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<td>Greg Rislov</td>
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<td>Robert Pick</td>
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<td>Brian Rounds</td>
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<td>Justin Hiton</td>
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<td>Jeff Krottek</td>
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<td>John Stevens</td>
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<td>Steve Drew</td>
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<td>Aaron Bell</td>
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<td>Heather Starnes</td>
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</table>
ADMINISTRATIVE ITEMS:

The following members participated:

- Steve Stoll, Missouri Public Service Commission (MoPSC)
- Shari Feist Albrecht, Kansas Corporation Commission (KCC)
- Kristie Fiegen, South Dakota Public Utilities Commission (SDPUC)
- Randy Christmann, North Dakota Public Service Commission (NDPSC)
- Dennis Grennan, Nebraska Power Review Board (NPRB)
- Geri Huser, Iowa Utilities Board (IUB)
- Heidi Pitts for Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)
- Dana Murphy, Oklahoma Corporation Commission (OCC)
- Kim O’Guinn, Arkansas Public Service Commission (APSC)
- DeAnn T. Walker, Public Utility Commission of Texas (PUCT)

President Steve Stoll called the Regional State Committee (RSC) meeting to order at 1:06 p.m. with roll call, and a quorum was declared. President Stoll welcomed the new commissioner, DeAnn T. Walker, Public Utility Commission of Texas, to her first meeting and education session. He welcomed commissioners Cynthia Hall from New Mexico and Scott Rupp from Missouri. President Stoll requested introductions of those in attendance. There were 116 people in attendance, either in person or via the phone (Attendance & Proxies – Attachment 1).

The first item of business was the approval of the 7/24/17 meeting minutes (RSC Minutes 7/24/17 – Attachment 2).

Commissioner Kristie Fiegen moved to approve the minutes with corrections; Commissioner Shari Feist Albrecht seconded. The motion was approved unanimously.

Ms. Kandi Hughes reviewed the RSC Action Items (RSC Action Items – Attachment 3).

UPDATES

RSC Third Quarter Financial Report
Mr. Paul Suskie (SPP staff) provided the financial report for the third quarter (RSC 2017 Q2 Financials – Attachment 4). He noted that the RSC was under budget for the third quarter.

SPP Report
Mr. Nick Brown discussed the Sunday dinner with the RSC commissioners and the Board of Directors. This is a time for the Board and RSC commissioners to get to know each other better. Based on the dialogue and feedback, and due to the turnover that occurs regularly on the RSC, SPP staff is committed to preparing an orientation package for new RSC members. The staff will seek input from each of the commissioners on the
content in preparation for the commissioners’ successors. This will be an action item for SPP staff. During the dinner, the integration of the Mountain West Transmission Group (MWTG) into the SPP membership was discussed. SPP has been actively involved in the negotiations for quite some time. There is a State Commission forum and most of the commissioners are engaged. The participation of the states is very much appreciated. Various aspects of the negotiated items with the MWTG will be assigned to various stakeholder organizational groups.

President Stoll agreed that a new member orientation packet would be a good idea. The industry is constantly changing and it is good to have a review.

**Federal Energy Regulatory Commission Report (FERC)**

Mr. Patrick Clarey provided the FERC report. Mr. Clarey provided an update about the FERC nominees. Last month the U.S. Senate Committee on Energy and Natural Resources held a hearing and voted in favor of the nominations of Kevin McIntyre and Richard Glick. They are awaiting a vote from the full senate. After the confirmations, Kevin McIntyre will become the FERC Chairman.

Since establishing a quorum, the Commission has acted on over 250 filings. FERC held open meetings in September and October. At the open meeting in October, FERC staff and the Regional Transmission Organizations (RTOs) updated the Commission on winter readiness. Both staff and the RTOs indicated that the markets are prepared for the upcoming winter with adequate capacity and the forecast of warmer than average temperatures. Mr. Clarey thanked SPP and Mr. Bruce Rew for their help and participation.

Last month the U.S. Department of Energy (DOE) sent a Notice of Proposed Rulemaking pursuant to section 403 of the Department of Energy Organization Act (DOE Act) to the Commission for final action. The proposed rule involves “Grid Resiliency rules” to ensure that certain eligible resources recover their full allocated costs. The proposed rule was noticed by the Commission on October 2, with comments due by October 23 and reply comments due by November 7. As of last week there have been over 550 comments filed in Docket No. RM18-1-000.

**BUSINESS MEETING**

**RSC Budget for 2018**

Mr. Paul Suskie presented the RSC proposed budget for 2018 (2018 Proposed RSC Budget– Attachment 5). Travel was increased in the 2017 budget, and that increase was carried over into the 2018 budget. Commissioner Albrecht recommends increasing the consultant budget line item from $50,000 to $150,000 in the event the course of the engagement as the RSC and MWTG integration would necessitate consultant expertise with targeted issues as yet unknown.

Commissioner Shari Feist Albrecht made a motion to increase the Principal Consultant fee from $50,000 to $150,000; Commissioner Geri Huser seconded the motion. The motion was approved unanimously.

**Commissioner Shari Feist Albrecht made a motion to approve the Amended 2018 Proposed Budget; Commissioner Geri Huser seconded the motion. The motion was approved unanimously.**

**Election of RSC Officers**

President Stoll provided the 2018 slate of officers: Shari Feist Albrecht, President; Kristie Fiegen, Vice President; and Dennis Grennan, Secretary/Treasurer. The titles for the RSC officers will be updated on the SPP website.

Commissioner Dana Murphy made a motion to approve the slate of officers nominated for 2018; Commissioner Geri Huser seconded the motion. The motion was approved unanimously.

Commissioner Murphy thanked President Stoll for his hard work and dedication during the 2017 term. President Stoll thanked the commissioners for their commitment to the RSC and SPP. He has enjoyed working with everyone.
RSC Bylaws Revisions
Commissioner Albrecht reported on the revisions to the RSC Bylaws (Bylaws Changes Matrix – Attachment 6, RSC Bylaws Redline – Attachment 7). President Stoll thanked Commissioner Albrecht for her hard work and diligence on updating the RSC Bylaws.

Commissioner Shari Feist Albrecht made a motion to approve the amended language to Article I, Section 3 of the RSC Bylaws; Commissioner Kristie Fiegen seconded the motion. The motion was approved unanimously.

Commissioner Shari Feist Albrecht made a motion to approve the amended language to Article IV, Section 10 of the RSC Bylaws; Commissioner Dennis Grennan seconded the motion. The motion was approved unanimously.

Commissioner Shari Feist Albrecht made a motion to approve the amended language to Article VIII of the RSC Bylaws; Commissioner Geri Huser seconded the motion. The motion was approved unanimously.

Commissioner Shari Feist Albrecht made a motion to approve the technical edits made in the RSC Bylaws; Commissioner Dana Murphy seconded the motion. The motion was approved unanimously.

Commissioner Shari Feist Albrecht made a motion to approve the amended language to Article VII, Section 3 and Article XI regarding the Nominating Committee; Commissioner Randy Christmann seconded the motion. New Mexico Public Regulation Commission abstained. The motion was approved.

During the discussion to Article VII, Section 4, Executive Committee, the following additional changes were suggested: changing the first “shall” to “may” in subsection (a) and striking “the immediate past-President of the RSC Board” from the listing of RSC officers who would participate on the Executive Committee. General consensus among the RSC commissioners was to drop the language from the amended bylaws and adding Section 4. The language for adding an executive committee will remain in the redline version of the bylaws and attached to the minutes for this meeting.

Commissioner Shari Feist Albrecht made a motion to add the Executive Committee language to the existing RSC Bylaws with the additional deletion and substitution; Commissioner Geri Huser seconded the motion. No votes: Kristie Fiegen, South Dakota Public Utilities Commission, Steve Stoll, Missouri Public Service Commission, Kim O’Guinn, Arkansas Public Service Commission, Dennis Grennan, Nebraska Power Review Board, Heidi Pitts for Patrick Lyons, New Mexico Public Regulation Commission and DeAnn Walker, Public Utility Commission of Texas. The motion did not pass with the required two-thirds vote of a quorum.

Cost Allocation Working Group (CAWG) Report and Voting Items
CAWG Report
Mr. Adam McKinnie (MoPSC) provided the CAWG report (CAWG Report – Attachment 8). Mr. McKinnie reviewed the meeting information from the CAWG meetings since the July RSC meeting. Ms. Meena Thomas (PUCT) provided an update on the 2019 Integrated Transmission Planning (ITP) futures development. The study will consider the near and long-term needs of transmission planning. The main driver of the study is the generation assumptions, particularly wind and solar. This study is of importance to the RSC because the projects that are approved will automatically be highway/byway projects. Prior studies have underestimated wind production. The Economic Studies Working Group (ESWG) approved two futures, reference case and emerging technologies.

The CAWG approved its first consent agenda item in October. It was revision request (RR) 244 containing the Z2 Task Force recommendations.

Future issues to be discussed in CAWG are projects related to wind generation, the MWTG, and non-Order 1000
interregional projects. Mr. McKinnie asked the RSC to let the CAWG know if there are any topics and/or issues the RSC would like the CAWG to add to its agenda for future meetings. The CAWG completed its initial derated facilities review with respect to cost allocation, passing a motion at its October meeting recommending that the RSC take no action on the matter.

Commissioner Kristie Fiegen made a motion to adopt the CAWG recommendation to take no action; Commissioner Shari Feist Albrecht seconded the motion. The motion was approved unanimously.

Commissioner Stoll thanked Mr. McKinnie for serving as the CAWG chair for the past year.

REPORTS/PRESENTATIONS

Integrated Marketplace and Operations Update
Mr. Bruce Rew (SPP staff) provided an update on the Integrated Marketplace (Integrated Marketplace Update – Attachment 9). There are currently 197 market participants, 130 of those are financial only and 67 are asset owning. One financial only entity has dropped since the last quarter. The SPP Balancing Authority (BA) has successfully maintained NERC control performance standards. The day-ahead market has been delayed once from posting in the last 12 months and the real-time balancing market has successfully solved 99.87% of all intervals. To date, there has been a total of 16,680 MW of installed and operation wind capacity. SPP averaged just over 12,000 MW of wind for an entire day this past quarter.

Seams Update
Mr. Carl Monroe (SPP staff) provided the seams update (Seams Update – Attachment 10). SPP and AECI agreed on two joint projects out of the 2016 SPP-Associated Electric Cooperative, Inc. (AECI) Joint and Coordinated System Plan (JCSP). SPP made filings at FERC for the two projects. Comments were received in support and in protest of the filing. FERC issued an order rejecting SPP’s filing. The order does not preclude SPP from making additional filings to the Commission to support region-wide funding or propose a new cost allocation for the two joint projects. SPP will continue to review and evaluate the Commission’s order and coordinate next steps with AECI and City Utilities of Springfield. A future goal is to try to develop another cost allocation proposal specific to these two projects and make a recommendation to SPP Markets and Operations Policy Committee (MOPC), Board of Directors, and RSC in January 2018, and make another filing at the Commission.

The joint study between SPP and MISO resulted in one interregional project being recommended by SPP and MISO to continue to the regional review process. The project was to loop one Split Rock to Lawrence 115 kV circuit into Sioux Falls. MISO is not recommending the I-18 interregional project for further consideration. MISO recommends maintaining the status quo and operating the Lawrence-Sioux Falls kV line in the open state.

Mountain West Update
Mr. Carl Monroe (SPP staff) provided an update on the MWTG. SPP has entered the stakeholder review phase in its efforts with the MWTG, and will begin working with the stakeholders and the RSC to review the policies and proposals that the MWTG is requesting related to governance to provide the MWTG the ability to join SPP. A page on the SPP website has been dedicated to the MWTG effort. The current schedule is to come back in April 2018 to finalize the proposals and reach an agreement between the members and the MWTG parties.

Generator Interconnection Improvement Task Force (GIITF) Update
Mr. Al Tamimi (Sunflower) provided the update on the GIITF (GIITF Update Presentation – Attachment 11). The purpose of the GIITF is to evaluate the existing SPP generator interconnection procedures, including internal SPP transmission processes, and recommend changes. The GIITF requests that the MOPC take the following actions: publish study models and eliminate the standalone analysis, and appoint a stakeholder group with appropriate background and expertise to re-evaluate the purpose, scope and study requirements of Network Resource Interconnection Service (NRIS) with the goal of aligning it more closely with SPP’s current and future market structure. The task force would also like the MOPC to approve the concept of the three-stage study process and direct that a full and complete proposal be provided to the MOPC. The GIITF is also asking the MOPC to approve an amended charter extending the scope of the GIITF to address the remaining charter tasks and address the identified additional proposals. The benefits of the three-stage GI study process are that it is
streamlined, simplified, and less confusing. It is also easier for SPP to administer, and for customers to understand and navigate. Mr. Tamimi reviewed all of the recommendations the GIITF placed before the MOPC, and the results of that review.

Z2 Update
Mr. Charles Locke (SPP staff) provided a Z2 Crediting Resettlement Update (Z2 Crediting Resettlement Update Presentation – Attachment 12). Attachment Z2 to the SPP Open Access Transmission Tariff ("Tariff") provides a process to compensate those Upgrade Sponsors who pay for upgrades that are subsequently used by transmission customers. The credit amounts occurred as early as 2008. The complexity of system implementation delayed the invoicing until 2016. FERC approved a waiver of the Tariff to permit settlement of the 2008-2016 charges and credits under Attachment Z2. In the initial and revised settlement, a number of updates and corrections to the input data were identified. A resettlement has been prepared for both the historical period and the month subsequent to the historical period. For those affected by the payment plan, the historical period amounts owed and received will be adjusted for the remaining installments. Individual company results were posted on October 13, 2017. The payment plan will continue on the original schedule but with revised amounts. Net amounts, the differences between revised settlement and original settlement, and the next installment of the payment plan are to be invoiced on November 3, 2017.

Regional Allocation Review Task Force (RARTF) Update
President Steve Stoll (MoPSC) provided the update on the RARTF (RARTF Update Presentation – Attachment 13). The RARTF is preparing for the third Regional Cost Allocation Review (RCAR). On October 6, FERC issued an order rejecting the proposed Morgan Transformer and Brookline Reactor transmission projects identified pursuant to the joint planning process contained in the Commission-approved Joint Operating Agreement (JOA) between SPP and AECI. The first two RCARs were conducted once every three years. The timeline was changed to conducting an RCAR once every six years. The transmission provider and/or the RSC may initiate such a review at any time. President Stoll reviewed the RCAR III options being considered. SPP staff will provide additional information on creating the operational model process and initial metrics results for evaluation.

Commissioner Dennis Grennan has agreed to serve as chair of the RARTF after Commissioner Stoll steps down.

SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS:

2018:
January 29, 2018 - Oklahoma City, OK
April 23, 2018 - Kansas City, MO
July 30, 2018 - Omaha, NE
October 29, 2018 - Little Rock, AR

With no further business, the meeting adjourned at 4:20 p.m.

Respectfully Submitted,

Paul Suskie
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<tr>
<th>No.</th>
<th>Action Item</th>
<th>Date Originated</th>
<th>Status</th>
<th>Comments</th>
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<tbody>
<tr>
<td>19</td>
<td>Circulation of RSC Agendas</td>
<td>4/25/2016</td>
<td>Ongoing</td>
<td>SPP to circulate draft agendas to RSC members and CAWG earlier for comment</td>
</tr>
<tr>
<td>27</td>
<td>Consolidate all previously approved RSC policies into one document.</td>
<td>7/24/2017</td>
<td>Ongoing</td>
<td>SPP Staff working to consolidate said policies and will include as a part of the orientation package referenced in Action Item No. 35.</td>
</tr>
<tr>
<td>33</td>
<td>RSC Website Page Revisions</td>
<td>10/30/2017</td>
<td>Ongoing</td>
<td>Contact Communications to update officers’ titles on website. Add secretary/treasurer to the website, as well. (Update: the SPP website is moving in-house and will be updated as soon as practically possible.)</td>
</tr>
<tr>
<td>35</td>
<td>RSC Orientation Package</td>
<td>10/30/2017</td>
<td>Ongoing</td>
<td>SPP Staff to put together an orientation package for current and future RSC Commissioners.</td>
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<tr>
<td>1</td>
<td>EPA 111(d) : (1) Lanny Nickell to provide scope document on compliance analysis and an update on when SPP reliability analysis will be completed (2) Commissioner Reeves to provide update on possibility of studies to be performed by BPC and GPI, what services those entities are providing</td>
<td>8/25/2014</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting</td>
</tr>
<tr>
<td>2</td>
<td>RARTF: Update on RARTF and New Metrics</td>
<td>8/25/2014</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting</td>
</tr>
<tr>
<td>3</td>
<td>Seams Project Task Force: CAWG will consider the issue at next meeting and bring back to RSC for discussion</td>
<td>8/25/2014</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting; On 10/27/14 Meeting as a voting item</td>
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<td>4</td>
<td>SPC Task Force on New Members: RSC should email Commissioner Murphy with any concerns or topics. Update to be provided at next RSC meeting</td>
<td>8/25/14</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting</td>
</tr>
<tr>
<td>5</td>
<td>Consideration of RSC Bylaws changes related to membership eligibility</td>
<td>Ongoing</td>
<td>Completed</td>
<td>Discussed at December 1, 2014 meeting, January 2015 Educational Session and March 9, 2015 Meeting. The bylaws draft modifications were discussed at the RSC retreat and meeting on July 27, 2015. Bylaws changes were considered at the September 21, 2015 meetings but were not approved. January 25, 2016 – RSC Goal for 2016 to consider adopting the clean-up of the Bylaws discussed in 2015. Prior to the January 30, 2017 RSC meeting, the current draft of the bylaws was distributed to the RSC. Phone call late August/early September on a Friday (Kandi to work with SS to get it scheduled) to finalize bylaws changes nominating committee; technical clean-up language, Executive Committee inclusion. July 2017 RSC meeting. Plan to vote in October. Send call information/agenda.</td>
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<td>7</td>
<td>SPC Task Force on New Members – Discuss 3 RSC Action Items</td>
<td>9/29/2014</td>
<td>Completed</td>
<td>Discussed at October 27, 2014 Meeting and December 1, 2014 Meeting. On January 2015 Educational Session for discussion and January 2015 Meeting Agenda as a voting item. Feedback was provided to SPC TF on NM on items 1 and 2 on January 26, 2015 and subsequent to the March 9, 2015 RSC teleconference. The RSC will continue to discuss item 3 on cost allocation and has delegated this item to the CAWG (Action Item 12). On July 27, 2015, the RSC approved a scoping document developed by CAWG. The SPC TF on New Members finalized its report, which was approved by the SPC in July 2015. The RSC approved the New Member Process document with the addition of catch-al language permitting the RSC to invoke the new member process for matters within the RSC’s responsibility.</td>
</tr>
<tr>
<td>9</td>
<td>Goals and Objectives for 2015 RSC Year</td>
<td>12/1/2014</td>
<td>Completed</td>
<td>Discussed at December 1, 2014 meeting and draft goals were reviewed on January 26, 2015, March 9, 2015, April 27, 2015 and September 21, 2015.</td>
</tr>
<tr>
<td>11</td>
<td>Educational Session on SPP &quot;Building Blocks&quot;</td>
<td>1/25/2015</td>
<td>Removed</td>
<td>Educational Session on the SPP “Building Blocks” – possible topic for July retreat. Unclear what this was intended to cover. Removed when list of retreat topics was updated.</td>
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<td>12</td>
<td>RSC Role in Cost Allocation for New Member Integrations</td>
<td>4/27/2015</td>
<td>Completed</td>
<td>In January 2015, the RSC tasked the CAWG with looking at what role the RSC should have in regards to Cost Allocation methodology for new members joining SPP. The RSC tasked the CAWG to develop a scoping document on how to apply cost allocation for new members joining SPP. The Scope Document developed by CAWG was approved by the RSC on July 27, 2015. At its October 2016 meeting, the RSC approved the process document developed by the CAWG.</td>
</tr>
<tr>
<td>13</td>
<td>Aggregate Study Waiver Criteria</td>
<td>4/27/2015</td>
<td>Completed</td>
<td>The RSC determined it should review the eligibility requirements set out in Section III.B.1 (specifically the 20% threshold), and whether the requirements are applicable today in light of the changes to the transmission system since the requirements were approved. The RSC tasked the CAWG to evaluate the eligibility requirements for a waiver request to see if the requirements are still applicable to the transmission system as it operates now. CAWG presented a draft scoping document to the RSC on July 27, 2015. A recommendation by the CAWG to retain the study waiver criteria was approved by the RSC on January 30, 2017.</td>
</tr>
<tr>
<td>14</td>
<td>Capacity Margin Task Force Update</td>
<td>4/27/2015</td>
<td>Completed</td>
<td>After a presentation at the April 2015 RSC meeting, and discussion of the Capacity Margin Task Force, the RSC tasked the CAWG to evaluate how load is forecasted for the purpose of determining the reserve margin. CAWG reported back to the RSC at their July 2015 meeting. Voted and approved at April 2016 meeting.</td>
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<tr>
<td>15</td>
<td>RSC Goals for 2016</td>
<td>1/25/2016</td>
<td>Completed</td>
<td>RSC discussed goals for 2016 at the January 2016 Educational Session. Any additional goals should be submitted to Erin Cullum for distribution in advance of the April 2016 RSC meeting.</td>
</tr>
<tr>
<td>16</td>
<td>Engagement Term of RSC Auditor</td>
<td>1/25/2016</td>
<td>Completed</td>
<td>Determine the initial arrangement with the RSC auditor and the number of years for reengagement. Erin Cullum will review the agreement and inform the RSC.</td>
</tr>
<tr>
<td>17</td>
<td>Educational Session Topic Request – Role of RSC in SPP FERC Filings</td>
<td>1/25/2016</td>
<td>Completed</td>
<td>Request for SPP Staff to provide educational update on the FERC filings process and the role of the RSC.</td>
</tr>
<tr>
<td>18</td>
<td>Talking Points on CPP</td>
<td>1/25/2016</td>
<td>Completed</td>
<td>Request for SPP’s talking points on the CPP. Erin Cullum will distribute the link to posted comments.</td>
</tr>
<tr>
<td>20</td>
<td>Z2 Crediting Overview</td>
<td>4/25/2016</td>
<td>Completed</td>
<td>SPP to provide higher level overview of Z2 key points, significance, and state specific information (if possible). This will be provided in advance of the next RSC Meeting.</td>
</tr>
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<tr>
<td>21</td>
<td>Form Commissioner Forum for Mountain West proposal.</td>
<td>01/30/2017</td>
<td>Completed</td>
<td>Phone call scheduled for February 10, 2017 to discuss further.</td>
</tr>
<tr>
<td>22</td>
<td>Establish a Nominating Committee per the RSC Bylaws</td>
<td>01/30/2017</td>
<td>Completed</td>
<td>Established for providing a slate of officers for RSC. Commissioner Albrecht to draft sample bylaw language in establishing a Nominating Committee for review at July RSC Meeting</td>
</tr>
<tr>
<td>23</td>
<td>Aggregate Study Waiver Criteria Review</td>
<td>01/30/2017</td>
<td>Completed</td>
<td>Annual CAWG review for limited time period (i.e. not in perpetuity). CAWG to present recommendation(s) to the RSC in July 2017 on how the RSC should proceed in reviewing the Aggregate Study Criteria.</td>
</tr>
<tr>
<td>24</td>
<td>RSC Retreat Information</td>
<td>04/17/2017</td>
<td>Completed</td>
<td>Paul Suskie to send RSC Retreat information to Commissioners.</td>
</tr>
<tr>
<td>25</td>
<td>Send new member integration process documents to RSC members.</td>
<td>07/24/2017</td>
<td>Completed</td>
<td>Emailed on July 24, 2017</td>
</tr>
<tr>
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<tr>
<td>26</td>
<td>Paul Suskie to send SPP bylaws to Commissioner Huser.</td>
<td>07/24/2017</td>
<td>Completed</td>
<td>Provided July 24, 2017</td>
</tr>
<tr>
<td>28</td>
<td>RSC Bylaw Revisions</td>
<td>07/24/2017</td>
<td>Completed</td>
<td>Schedule phone call late August/early September to finalize bylaws changes nominating committee, technical clean-up language, and Executive Committee inclusion. Plan to vote in October. Send call information/agenda.</td>
</tr>
<tr>
<td>29</td>
<td>Annual Review of Safe Harbor Criteria</td>
<td>07/24/2017</td>
<td>Completed</td>
<td>CAWG will bring a proposal to the RSC for the limited annual review of the Safe Harbor Criteria CAWG and will synchronize the limited review with SPP’s annual filing with FERC.</td>
</tr>
<tr>
<td>30</td>
<td>October Education Session topic(s)</td>
<td>07/24/2017</td>
<td>Completed</td>
<td>Kandi Hughes will send request to RSC soliciting potential educational session topics for October.</td>
</tr>
<tr>
<td>31</td>
<td>FERC Contact Information</td>
<td>10/30/2017</td>
<td>Completed</td>
<td>Sam Loudenslager to send Patrick Clarey's contact information to RSC members.</td>
</tr>
<tr>
<td>No.</td>
<td>Action Item</td>
<td>Date Originated</td>
<td>Status</td>
<td>Comments</td>
</tr>
<tr>
<td>-----</td>
<td>-----------------------------------------------------------------------------</td>
<td>----------------</td>
<td>----------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>32</td>
<td>January 2018 Education Session Topic(s)</td>
<td>10/30/2017</td>
<td>Completed</td>
<td>Kandi Hughes will send request to RSC soliciting potential educational session topics for January 2018. One topic suggested is the Mountain West Transmission Group.</td>
</tr>
<tr>
<td>34</td>
<td>State Commissioner Forum for Mountain West proposal.</td>
<td>10/30/2017</td>
<td>Completed</td>
<td>RSC Member to review online documents pertaining to Mountain West. Commissioner Fiegen will send a Doodle Poll to schedule a State Commissioner Forum to be held during the last week of November.</td>
</tr>
</tbody>
</table>
### Regional State Committee
For the Twelve Months Ending December 31, 2017
Budget vs. Actual

<table>
<thead>
<tr>
<th></th>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Income</td>
<td>256,237</td>
<td>321,700</td>
<td>(65,463)</td>
</tr>
<tr>
<td>Total Income</td>
<td>256,237</td>
<td>321,700</td>
<td>(65,463)</td>
</tr>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Travel/Meeting</td>
<td>253,637</td>
<td>268,400</td>
<td>(14,763)</td>
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<tr>
<td>Audit</td>
<td>2,600</td>
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<tr>
<td>Administrative Costs</td>
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<td>(1,000)</td>
<td></td>
</tr>
<tr>
<td>RSC Consultant</td>
<td>-</td>
<td>50,000</td>
<td>(50,000)</td>
</tr>
<tr>
<td>Technical Conference</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Total Expense</td>
<td>256,237</td>
<td>321,700</td>
<td>(65,463)</td>
</tr>
<tr>
<td><strong>Net Income</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
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</table>
Southwest Power Pool Regional State Committee  
Shari Feist Albrecht, President and Management  
201 Worthen Drive  
Little Rock, Arkansas 72223

We are pleased to confirm our understanding of the services we are to provide for **Southwest Power Pool Regional State Committee** (the Organization) for the year ended December 31, 2017.

We will audit the financial statement of the Organization, which is comprised of the statement of cash receipts and disbursements for the year ended December 31, 2017, and the related notes to the financial statement (the financial statement).

We will also prepare the Organization’s annual federal information return (IRS Form 990) for the period ended December 31, 2017.

**Audit Services**

**Audit Objective**

The objective of our audit is the expression of an opinion about whether the statement of cash receipts and disbursements is fairly presented, in all material respects, in conformity with the cash basis of accounting. Our audit will be conducted in accordance with auditing standards generally accepted in the United States of America and will include tests of the accounting records and other procedures we consider necessary to enable us to express such an opinion. We will issue a written report upon completion of our audit of the Organization’s statement of cash receipts and disbursements. Our report will be addressed to the Members of the Organization. We cannot provide assurance that an unmodified opinion will be expressed. Circumstances may arise in which it is necessary for us to modify our opinion or add an emphasis-of-matter or other-matter paragraph. If our opinion is other than unmodified, we will discuss the reasons with you in advance. If, for any reason, we are unable to complete the audit or are unable to form or have not formed an opinion, we may decline to express an opinion or withdraw from this engagement.

**Audit Procedures**

Our procedures will include tests of documentary evidence supporting the transactions recorded in each cash account and may also include direct confirmation of receipts and cash balances with related parties and financial institutions. We may also request written representations from the Organization’s attorneys as part of the engagement. At the conclusion of our audit, we will require certain written representations from management and those involved in accounting and recordkeeping for the Organization about the statement of cash receipts and disbursements and related matters.

An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statement of cash receipts and disbursements; therefore, our audit will involve judgment about the number of transactions to be examined and the areas to be tested. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates.
Audit Services (Continued)

Audit Procedures (Continued)

made by management, as well as evaluating the overall presentation of the statement of cash receipts and disbursements. We will plan and perform the audit to obtain reasonable assurance about whether the statement of cash receipts and disbursements is free of material misstatement, whether from errors, fraudulent financial reporting, misappropriation of assets or violations of laws or governmental regulations that are attributable to the Organization or to acts by management or employees acting on behalf of the Organization.

Because of the inherent limitations of an audit, combined with the inherent limitations of internal control, and because we will not perform a detailed examination of all transactions, there is a risk that material misstatements may exist and not be detected by us, even though the audit is properly planned and performed in accordance with auditing standards generally accepted in the United States of America. In addition, an audit is not designed to detect immaterial misstatements or violations of laws or governmental regulations that do not have a direct and material effect on the statement of cash receipts and disbursements. Our responsibility as auditors is limited to the period covered by our audit and does not extend to any later periods for which we are not engaged as auditors.

Our audit will include obtaining an understanding of the Organization and its environment, including internal control, sufficient to assess the risks of material misstatement of the statement of cash receipts and disbursements and to design the nature, timing and extent of further audit procedures. An audit is not designed to provide assurance on internal control or to identify deficiencies in internal control. However, during the audit, we will communicate to you internal control related matters that are required to be communicated under professional standards.

Management Responsibilities

The Organization is responsible for designing, implementing and maintaining internal controls, including monitoring ongoing activities; for the selection and application of accounting principles; and for the preparation and fair presentation of the statement of cash receipts and disbursements in conformity with the cash basis of accounting. Additionally, management is responsible for including all informative disclosures that are appropriate for the cash basis of accounting. The Organization is also responsible for making all financial records and related information available to us and for the accuracy and completeness of that information. The Organization is also responsible for providing us with access to all information that is relevant to the preparation and fair presentation of the statement of cash receipts and disbursements, additional information that we may request for the purpose of the audit and unrestricted access to persons from whom we determine it necessary to obtain audit evidence.

The Organization's responsibilities include adjusting the statement of cash receipts and disbursements to correct material misstatements and confirming to us in the management representation letter that the effects of any uncorrected misstatements aggregated by us during the current engagement and pertaining to the latest period presented are immaterial, both individually and in the aggregate, to the statement of cash receipts and disbursements taken as a whole.
Audit Services (Continued)

Management Responsibilities (Continued)

The Organization is responsible for the design and implementation of programs and controls to prevent and detect fraud, and informing us about all known or suspected fraud affecting the Organization involving management, employees who have significant roles in internal control and others where the fraud could have a material effect on the statement of cash receipts and disbursements. The Organization's responsibilities include informing us of any knowledge of any allegations of fraud or suspected fraud affecting the Organization received in communications from employees, former employees, regulators or others. In addition, the Organization is responsible for identifying and ensuring the Organization complies with applicable laws and regulations.

Tax Services

The terms of our tax engagement with the Organization will be designed to perform the following services:

1. Prepare Form 990, Return of Organization Exempt from Income Tax, with supporting schedules.
2. Prepare any tax adjusting entries we find necessary in connection with preparation of these returns.
3. Electronically file the Organization's return or other filings as required or requested, upon authorization by a representative of the Organization.

The Organization is responsible for the safeguarding of assets, the proper recording of transactions in the books of accounts, the substantial accuracy of the financial records, and the full and accurate disclosure of all relevant facts affecting the return to us. The Organization has the final responsibility for the return and should review the return carefully before the return is filed.

We may provide communications requesting specific information related to the completion of the Organization's return. Providing this information will assist us in making sure the Organization is well served for a reasonable fee. The Organization represents that the information supplied to us is accurate and complete and that all relevant facts affecting the return have been disclosed to us. We will not verify the information provided to us. We may ask for additional clarification of some information.

If, during our work, we discover information that affects prior-year returns, we will make the Organization aware of the facts. However, we cannot be responsible for identifying all items that may affect prior-year returns. If management becomes aware of such information during the year, management should contact us to discuss the best resolution of the issue.

Our work in connection with the preparation of the Organization's return does not include any procedures designed to discover defalcations or other irregularities, should any exist. The return will be prepared solely from information provided to us without verification by us.
Southwest Power Pool Regional State Committee  
Shari Feist Albrecht, President and Management  
Page Four

**Tax Services (Continued)**

In accordance with federal law, in no case will we disclose the Organization’s return information to any location outside the United States, to another return preparer outside of our firm for purposes of a second opinion, or to any other third party for any purpose other than to prepare the Organization’s return without first receiving your consent. Execution of this engagement letter serves as consent to allow us to use the Organization’s return information to send management or members of the Southwest Power Pool Regional State Committee our firm newsletter and any other communication sent to some or all of the firm’s clients.

Any advice or information regarding the tax treatment of certain items delivered orally or in the body of an email will be based upon limited tax research and a limited discussion of the underlying facts. Additional research or a more complete review of the facts may affect our analysis and conclusions. Because of these limitations and the related risks, we do not recommend that the Organization proceed with any transaction solely on the basis of any oral or email communication.

The law provides various penalties that may be imposed upon taxpayers. It is understood that tax advice, if any, communicated as a result of our services, is not intended to be used, and cannot be used, for the purpose of avoiding such penalties or for the purpose of promoting, marketing or recommending to another party any transaction or matter contained therein, unless specifically communicated in writing to the contrary. We may provide additional information on the amount or circumstances of these penalties, if requested.

The Internal Revenue Code and regulations impose preparation and disclosure standards with non-compliance penalties on both the preparer of a tax return and on the taxpayer. To avoid exposure to these penalties, it may be necessary in some cases to make certain disclosures to management and/or in the tax returns concerning positions taken on the returns that do not meet these standards. Accordingly, we will advise management if we identify such a situation, and we will discuss those tax positions that may increase the risk of exposure to penalties and any recommended disclosures with management before completing the preparation of the return. If we conclude that we are obligated to disclose a position and management refuses to permit the disclosure, we reserve the right to withdraw from the engagement. Likewise, if we disagree about the obligation to disclose a position, management has a right to choose another professional to prepare the Organization’s return. In either event, management agrees to compensate us for our services to the date of withdrawal. Our engagement will terminate upon our withdrawal.

The IRS permits the Organization to authorize us to discuss, on a limited basis, aspects of the Organization’s returns for one year after the return’s due date. Consent to such a discussion is evidenced by checking a box on the return. Unless we are otherwise instructed, we will check that box authorizing the IRS to discuss the Organization’s return with us.

It is our policy to keep records related to this engagement for six years. However, we do not keep any of the Organization’s original records and will return those upon completion of the engagement. When records are returned, it is the Organization’s responsibility to retain and protect the records for possible future use, including potential examination by governmental or regulatory agencies. By signing this engagement letter, management acknowledges and agrees that upon the expiration of the six year period, we are free to destroy our records related to this engagement.
Southwest Power Pool Regional State Committee
Shari Feist Albrecht, President and Management
Page Five

**Tax Services (Continued)**

Certain communications involving tax advice are privileged and not subject to disclosure to the IRS or other governmental authorities. By disclosing the contents of those communications to anyone, or by turning over information about those communications to the government, you, your employees or agents may be waiving this privilege. To protect this right to privileged communication, please consult with us or the Organization’s attorney prior to disclosing any information about our tax advice. Should it be decided that it is appropriate for us to disclose any potentially privileged communication, we must receive written, advance authority to make that disclosure.

Should we receive any request for the disclosure of privileged information from any third party, including a subpoena or IRS summons, we will notify management. In the event we are directed not to make the disclosure, the Organization agrees to hold us harmless from any expenses incurred in defending the privilege.

The Organization's return may be selected for review by the IRS or other governmental authorities. In the event of an audit, the Organization may be requested to produce documents, records or other evidence to substantiate the disclosures or amounts reported on the return. Any proposed adjustments by the examining agent are subject to certain rights of appeal. In the event of a tax examination, we will be available, upon request, to represent the Organization. However, such additional services are not included in the fees for the preparation of the return and will be billed separately at our standard billing rates.

We have the right to withdraw from this engagement, at our discretion, if management does not provide us with any information we request in a timely manner, does not cooperate with our reasonable requests, or misrepresents any facts. Our withdrawal will release us from any obligation to complete the Organization’s return and will constitute completion of our engagement. Management agrees to compensate us for our fees through the date of our withdrawal.

**Nonattest Services**

As part of this engagement, we will prepare the financial statement of the Organization in conformity with the cash basis of accounting based on the information provided by you. These services are in addition to those procedures required to complete an audit in accordance with generally accepted auditing standards and are referred to as “nonattest services.” Preparation of the Organization’s Form 990 is also considered a nonattest service.

Management agrees to assume all management responsibilities for tax services and any other nonattest services we provide; oversee the services bydesignating a senior management-level individual with suitable skill, knowledge or experience; evaluate the adequacy and results of the services; and accept responsibility for them.

We may perform other nonattest services not specifically listed above as part of this engagement, provided they do not impair our independence.
Administration, Fees and Other

We understand that employees of Southwest Power Pool, Inc. will prepare all cash and other confirmations we request and will locate any documents selected by us for testing.

Sherry Chesser is the engagement partner and is responsible for supervising the engagement and signing the report or authorizing another individual to sign it. We will begin our audit and issue our report no later than the date agreed upon with management.

Our fee for these services for the year ended December 31, 2017, is estimated to be $2,700. The fee estimate is based on anticipated cooperation from the Organization and others involved in accounting and recordkeeping for the Organization and the assumption that unexpected circumstances will not be encountered during the audit. If significant additional time is necessary, we will discuss it with you and arrive at a new fee estimate before we incur the additional costs. Our invoices for these fees will be rendered as work progresses and are payable on presentation.

We appreciate the opportunity to be of service to the Organization and believe this letter accurately summarizes the significant terms of our engagement.

Very truly yours,

Thomas & Thomas LLP
Certified Public Accountants

January 11, 2018
Little Rock, Arkansas

RESPONSE:

This letter correctly sets forth the understanding of Southwest Power Pool Regional State Committee.

________________________  _______________________
Shari Feist Albrecht, President  Date
Southwest Power Pool Regional State Committee

________________________  _______________________
Paul Suskie, Executive Vice President  Date
Regulatory Policy and General Counsel
Southwest Power Pool, Inc.
RSC Travel Policy Update

January 2018 RSC Meeting
RSC Travel Policy

• The current posted RSC Travel Policy was last updated in 2007

• The RSC auditor mentioned that the policy seemed outdated and may need to be reviewed

• The current policy includes references to:
  • RSC Associate Members (removed from RSC Bylaws in 2017)
  • Price guidelines for travel (airfare, hotels, meals, car rental, etc.) based in 2007
  • Cost guidelines for meetings (meeting rooms, meals, snacks, etc.) based in 2007
RSC Travel Policy

• Staff proposed an updated policy to the CAWG in December 2017 that included:
  • Removal of the RSC Associate Member references
  • Removal of the Price Guidelines for Travel
    • “Members are expected to use their best judgment while traveling.”
  • Removal of Cost Guideline for Meetings
    • SPP Corporate Services handles meetings based on their guidelines
    • RSC has not scheduled meetings on their own

• CAWG voted on this proposed policy in January 2018; it passed unanimously.

• CAWG Recommendation:

  “The CAWG recommends the RSC approve the updated RSC Travel Policy.”
Travel Policy

The Southwest Power Pool Regional State Committee (“RSC”) will reimburse RSC members (and/or their delegated representatives) and RSC associate members [BB1] (hereinafter severally and jointly referred to as “Member(s)”) for all fair and reasonable expenditures incurred by Members when conducting RSC business. It is intended that Members should neither lose nor gain money as a result of reimbursement.

1. Travel expenses must be submitted on the RSC expense reimbursement form within 60 days after the conclusion of the travel. Receipts are required for all expenses.

2. The RSC expense reimbursement form must be signed by Member seeking reimbursement and in the case of an assigned delegate, by the individual state Commissioner assigned to the RSC.

3. While traveling and away from home, Members are expected to use good judgment when incurring expenses for lodging, meals, transportation, etc. RSC will reimburse business related mileage at the rate approved by the IRS. Reimbursement will be for mileage claimed due to travel to business location and return.

4. Members are responsible for making their own arrangements for transportation, lodging and car rentals. All accommodations should be purchased as far in advance as possible to obtain available discount fares/rates. All air travel is to be booked at the lowest accommodating fare.

5. Lodging reservations should be made at mid-priced establishments, when available. If a Member is attending a meeting or function being held at a specific facility or where a room block has been negotiated, then reservations may be made at that facility.

6. The RSC will not accommodate advances for travel expenses; the RSC will only reimburse expenses after the fact with supporting documentation and approval as specified in this policy.

7. If a spouse or family member accompanies a Member on a business trip for non-business reasons, the family member’s travel expenses are not reimbursable.
Travel Guidelines

These numbers are provided as guidelines and are based on historical averages. Members are expected to use their best judgment while traveling.

Price Guidelines:
1. Airfare – $500 roundtrip within the SPP footprint
2. Hotel – $130/night
3. Meals – $45/day
4. Car Rental – $70/day
5. Parking – $10/day
6. Tips & Gratuities – 15% tip for meals, 10% tip for cab fare, $1 per bag for baggage handling
Expense Reimbursement Policy

This policy is intended to identify reasonable, necessary and customary business expenses, which are eligible for reimbursement. Southwest Power Pool Regional State Committee ("RSC") participants eligible for reimbursement include RSC members (and their delegates assigned to specific task forces and working groups) \textit{and RSC associate members} (hereinafter severally and jointly referred to as “Member(s)’’)

**Business Mileage** – Members will be reimbursed for all mileage incurred while using a personal vehicle for business. The Member will be reimbursed at the standard IRS mileage rate.

**Personal Auto Use on Company Business** – If a Member requests use of a personal vehicle in lieu of air travel, reimbursement will be made at the approved reimbursement rate for the most direct mileage to and from the business destination unless round trip air travel is less expensive. When this occurs, the round trip air travel cost will be reimbursed instead.

Mileage will be reimbursed at the then current IRS mileage rate. This expense is to be turned in on an expense account (within 30 days) with the number of miles and the purpose of the trip.

**Rental Cars, Taxis, Bus Fares, tolls, etc.** – Reimbursement will be made for transportation while on RSC business, including transportation to and from airports and transportation to and from local businesses. Members are expected to use cost effective methods. The standard rental automobile will be a mid-size sedan.

**RSC Meals** – Members will be reimbursed for meals under the following circumstances:

- When out of town on business, the reasonable costs of the Member’s meals will be reimbursed.
- Business meals will be reimbursed when business is discussed and the Member documents the business purpose and who attended.

**Lodging** – Members will be reimbursed for lodging expenses incurred while on RSC business.

**Meetings** – The following are guidelines for a meeting the RSC might incur:

1. Lunch – plan for $25/person
2. Continental Breakfast – plan for $10/person
3. Afternoon Break - plan for $150/total
4. Beverages – plan for $12/person
5. Meeting Room (<20 people) – $250/day
6. Meeting Room (>20 people) – $650/day
7. Supplies (<20 people) - $350/day
8. Supplies (>20 people) - $700/day
9. A/V Equipment
10. Conference Phones
11. Internet Access
12. Teleconference: 25 ports/2 hr. meeting

Receipts are required on all expenses.

Reimbursement will be approved per this policy. Periodically, reimbursements will be reviewed by the RSC officers for compliance with this policy.
CAWG Report to the RSC
January 29, 2018

Christine Aarnes
KCC
Goal of Presentation:

• Discuss CAWG activities since last RSC meeting
  ➢ November 14, 2017 – WebEx/Teleconference
  ➢ December 5, 2017 – AEP Offices, Dallas, TX
  ➢ January 12, 2018 – AEP Offices, Dallas, TX
• Discuss CAWG recommendations on RSC voting items
• List any Revision Requests reviewed by CAWG under a CAWG consent agenda
• Discuss ongoing and expected future CAWG issues
November 14 WebEx/Teleconference:

• Project Tracking

• Morgan Transformer and Brookline Reactor Projects

• Supply Adequacy

• Mountain West Transmission Group
December 5, AEP Offices, Dallas, TX:

- RSC Travel Policy
- Morgan Transformer and Brookline Reactor Projects
- Generation Interconnection Improvement Task Force
- Cost Allocation in Wind Rich Areas
- Safe Harbor Lessons Learned
- Supply Adequacy Update (RR 251)
- NITS Redispatch Compliance Filing Update (RR 257)
January 12, AEP Offices, Dallas, TX:

- Competitive Project Minimum Threshold (ER17-2523-000)
- CAWG Effectiveness Survey
- RSC Travel Policy (Voting Item – CAWG unanimously approved)
- Morgan Transformer and Brookline Reactor Projects
- Cost Allocation in Wind Rich Areas
- Safe Harbor Lessons Learned (Voting Item – CAWG approved via e-mail vote on January 16)
- RR 251 Supply Adequacy (Voting Item – CAWG unanimously approved)
- RR 255 Adding Triggers to Stop Annual Escalation of Baseline Estimates
- Mountain West Transmission Group
RSC Travel Policy

- Current travel policy was developed in 2007.
- Policy contained outdated expense estimates and needed to be updated.
- New travel policy eliminates expense estimates and cleans up language.

CAWG Motion: The CAWG recommends the RSC approve the updated RSC Travel Policy.
Safe Harbor Criteria “Lessons Learned”

- Evaluation of the lessons learned from CAWG’s review of the Aggregate Study Safe Harbor Waiver Criteria

- Adam McKinnie will present to the RSC.

- CAWG approved the revised lessons learned via an e-mail vote on January 16th.

- CAWG Motion: The CAWG recommends the RSC endorse the Safe Harbor Criteria “Lessons Learned” as drafted.
RR 251 Supply Adequacy

- RR 187 (Planning Reserve Margin) was approved by the MOPC, the RSC, and the BOD at their respective January 2017 meetings and Tariff revisions were filed on March 3, 2017.

- A FERC Order rejecting the filing without prejudice was issued on August 29, 2017.

- In that Order, FERC guidance was given on three key issues: (1) SPP’s proposal fails to include a requirement that all power purchase agreements are backed by verifiable capacity to meet SPP’s Resource Adequacy Requirement (RAR) and fails to include provisions to allow SPP to review the agreements to verify that they are backed by capacity; (2) SPP’s proposed treatment of firm power purchases and sales in the determination of net peak demand is unduly discriminatory; and (3) SPP has not supported as just and reasonable its proposal to post publicly a list of all Load Responsible Entities (LREs) that have not met their RAR.

- RR 251 addresses the key issues identified by FERC.

- SAWG Chair, Brad Hans, will present RR 251 to the RSC.

- **CAWG Motion:** The CAWG recommends that the RSC approve RR 251 as addressing the FERC identified issues outlined in their rejection without prejudice in FERC Docket No. ER17-1098, while maintaining the originally approved CMTF policies.
Cost Allocation in Wind Rich Areas

• Large percentage of wind projects are built in small SPP load zones with stagnant load growth.

• Two-thirds of the costs of projects are assigned to the local zone.

• Is the current cost allocation method properly allocating costs to those who benefit from the transmission build out?

• Al Tamimi will present to the RSC.

• **CAWG Motion:** The CAWG recommends the RSC direct CAWG to work with SPP Staff to further investigate the cost allocation in wind rich areas issue.
Revision Requests Approved Through the CAWG Consent Agenda

- None
Expected Future Issues:

- Cost allocation for projects in wind rich areas

- FERC, in Docket No. ER17-2256, issued an order rejecting the cost allocation for the Morgan and Brookline projects from the SPP-AECI interregional study.
  - The RSC had previously approved the 100% highway funding for regional recovery of the cost of non Order 1000 interregional projects.

- Competitive Project Minimum Threshold (ER17-2523-000)

- Mountain West Transmission Group
Upcoming CAWG Meetings:

- February 13, 2018 - WebEx/Teleconference
- March 6, 2018 - AEP Offices, Dallas, TX
- April 3, 2018 - AEP Offices, Dallas, TX
Lessons Learned: Aggregate Study
Safe Harbor Waiver Criteria Review

Adam McKinnie
RSC Meeting
January 29, 2018
Purpose

• Give a list of CAWG approved “Lessons Learned” from our Aggregate Study Safe Harbor Waiver Criteria work
• Request a vote from the RSC to adopt the “Lessons Learned”
Refresher – Aggregate Study Safe Harbor Criteria

• The “Safe Harbor” is applied if the applicable Aggregate Study waiver criteria are met:
  – If the TSR is granted, the utility will not have over 20% of their designated resources from wind (only applies to a TSR related to designating wind as a Designated Resource*) [<20% wind]
  – 5 year minimum term of commitment for the TSR
  – If the TSR is granted, the utility will not have Designated Resources greater than 125% of their forecasted load [<125% of load]

• A utility may apply for a waiver if the TSR does not meet the applicable “Safe Harbor” criteria or for an increase in the “Safe Harbor” amount.

• *A Designated Resource is used to meet the capacity margin requirement of a Load Serving Entity
General Lessons Learned

• For all three criteria, continue work with SPP staff to determine how many waiver requests have been submitted
• Continue to ask for feedback from stakeholders.
125% of Load Criterion Lessons

• Request information from stakeholders and/or work with SPP staff to verify whether the criteria adversely affects smaller transmission customers
• Consider a business practice or other report/statement that memorializes the reasons this criteria might be waived around the idea of some stakeholder comments that were received on possibly revising or revisiting this metric in light of stakeholder work on capacity, including changes to wind and solar capacity accreditation.
20% Wind Criterion Lessons

• It is difficult to pick a number between 20% and 100% and provide a rationale for that number.
• To the extent the wind limit is increased to a number other than 100%, there may be a need to ensure that entities that have already exceeded the 20% wind limit are not disadvantaged (e.g. if the limit is increased from 20% to 30%, an option to consider would be to apply the percentage increase (10%) to all entities regardless of whether they are at or exceed the 20% limit).
  – For example, if a hypothetical utility was at 25% wind when the 20% wind criterion was raised to 30% (a 10% increase), that hypothetical utility could have a limit of 35%, a 10% increase over their current wind amount
• If parties raise concerns such as operational cost shifts that have to be addressed by other stakeholder groups (e.g. MWG), CAWG may need to work with those groups to ensure that the concerns are addressed within a reasonable period of time.
• Should the limit apply to solar, hydro, or other renewable resources?
• Work with SPP staff and stakeholders to verify whether the original concerns that justified the 20% wind limit still exist.
• See if there are additional reasons utilities may be designating wind as a Network Resource, which may cause more utilities to reach the 20% wind criterion.
$180k/MW Safe Harbor amount Lesson

• Work with SPP staff and stakeholders to come up with a reasonable methodology to update the $180,000 Safe Harbor amount.
Recommended RSC motion

• The CAWG recommends the RSC endorse the Safe Harbor Criteria “Lessons Learned” as drafted.
RR 251

Implementation of Resource Adequacy Policies

Brad Hans

Chairman – Supply Adequacy Working Group
Background

- Filing (RR 187) was made on March 3, 2017 requesting effective dates of June 1, 2017 and July 1, 2017 to implement stakeholder approved resource adequacy package
- FERC rejected the filing without prejudice on August 29, 2017 and provided guidance on three key issues
- SPP reengaged the stakeholder process to address the FERC identified issues while maintaining the foundational policies
  - RR 251 was approved by the SAWG on December 21, 2017
  - RR 251 was approved by the RTWG on January 3, 2018 with five abstentions (AECC, City of Independence, KMEA, MJMEUC, Westar)
  - CAWG reviewed on January 12, 2018 and recommended that the RSC approve RR 251
  - RR 251 was approved by the MOPC on January 16, 2018 with one no vote (KMEA) and ten abstentions (Flat Ridge 2, Westar KGE, Prairie Wind, Westar Energy, LES, South Central MCN, Empire Dist., MJMEUC, Enel Green, BPU)
Three Issues Identified by FERC

1. SPP’s proposal fails to include a requirement that all power purchase agreements are backed by verifiable capacity to meet SPP’s RAR and fails to include provisions to allow SPP to review the agreements to verify that they are backed by capacity.

2. SPP’s proposed treatment of firm power purchases and sales in the determination of net peak demand is unduly discriminatory.

3. SPP has not supported as just and reasonable its proposal to post publicly a list of all LREs that have not met their RAR.
Changes to Address Issues 1 & 2

- New Section 7.0 (Qualification of Deliverable Capacity, Firm Capacity, and Firm Power)

- (7.1, 7.2, and 7.4) Internal resources must:
  - Register the Resource in the Integrated Marketplace (Deliverable Capacity)
  - Register the Resource in the Integrated Marketplace or declare the Designated Resource on the Network Integration Transmission Service Agreement (Firm Capacity and Firm Power)
  - Submit the current Operational Test results
  - Submit the current Capability Test results
  - Demonstrate that there is firm transmission service from the internal capacity to the LRE’s load

- (7.3 and 7.5) External resources must:
  - Demonstrate ownership or contractual rights
  - Submit the current operational test results per the requirements of the Balancing Authority where the resource is located
  - Demonstrate that there is firm transmission service from the external capacity to the LRE’s load
  - Demonstrate that the capacity includes planning reserves (Firm Power)
  - Attest that any external capacity being identified is not otherwise being used as capacity in any other Balancing Authority or in another resource adequacy construct
Changes to Address Issues 1 & 2

• New Section 8.0 (Qualification and Verification of Power Purchase Agreements)

• (8.1) Required to provide a copy of the PPA

• (8.2) When a PPA qualifies as Firm Power and the purchaser and seller are both LREs
  • Purchaser deducts the contract amount from its Net Peak Demand
  • Seller adds the amount to its Net Peak Demand and becomes responsible for the Resource Adequacy Requirement

• (8.3) When a PPA qualifies as Firm Power and the seller is not an LRE
  • Purchaser cannot deduct the contract amount from its Net Peak Demand
  • Purchaser reflects the contract amount plus the purchaser’s PRM multiplied by the contract amount as Firm Capacity
  • Firm transmission service is only required for the contract amount
Changes to Address Issues 1 & 2

• (8.4) When a PPA qualifies as Firm Power and the purchaser is not an LRE
  • Seller cannot include the purchased contract amount in its Net Peak Demand
  • Seller reflects the contract amount plus the seller’s PRM multiplied by the contract amount as Firm Capacity
  • Firm transmission service is only required for the contract amount

• (8.5) Grandparent PPAs (prior to July 1, 2018) will be continued to be defined and qualified as Firm Power
Changes to Address Issue 3

• (9.0) Removes the April report requirement

• “(7) No later than 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.”
Additional Tariff Changes

- (2.0) Firm Capacity definition – removed Deliverable Capacity
  - Associated changes throughout

- (2.0) Net Peak Demand definition

- (4.0) Planning Reserve Margin moved to the SPP Planning Criteria
  - Details of how the Planning Reserve Margin will be determined remain in the Tariff

- (7.0) Language added to the SPP Planning Criteria for satisfying Operational and Capability test results for newly installed generation and generation that was out of service during the entire preceding peak season

- (7.6 and 8.7) Added confidentiality provisions

- (8.6) Clarifying language to short-term capacity provisions
Recommendation

- The CAWG recommends that the RSC approve RR 251 as addressing the FERC identified issues outlined in their rejection without prejudice in FERC Docket No. ER17-1098, while maintaining the originally approved CMTF policies.
Action Items for 2018

- **Distributed Energy Resources**
  - Demand Response/Behind the Meter Generation/Battery Storage/Variable Resources
  - Policy Development with consideration for accreditation, market registration, reliability and other factors

- **Effective Load Carrying Capability Accreditation Methodology**
  - Consideration of methodology for accrediting variable resources
  - Mountain West consideration
  - Utilization of variable resources for capacity

- **SERVM zonal representation**
  - Preparation for 2019 LOLE Study
  - Study as zones or one balancing area

- **Non-Coincident vs Coincident Peak Methodology for Resource Adequacy**
  - Continue discussion
  - Address cost/benefit analysis
Action Items for 2018

- Resource Adequacy Policy
  - Implementation into Tariff
  - Workbook integration and verifications

- Criteria Updates
  - Generator Testing and accreditation
  - Fuel Supply

- Mountain West Integration

- Other Action Items
  - Winter Reserve Margin
  - Post Season Analysis for Resource Adequacy
  - LOLE Studies
  - Deliverability Studies
  - Standardization of Load Forecasting Methodology
Revision Request Recommendation Report

RR #: 251
Date: 10/12/2017

RR Title: Implementation of Resource Adequacy Policies

SUBMITTER INFORMATION

Name: Charles Hendrix
Company: Southwest Power Pool
Email: chendrix@spp.org
Phone: 501.614.3546

EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION

On August 29, 2017 FERC issued an order rejecting the SPP Resource Adequacy filing without prejudice. SPP reengaged the stakeholder process to address the FERC identified issues while maintaining the originally approved policies. This revision request implements the approved resource adequacy package.

SAWG recommends that the MOPC approve RR 251 as submitted.

OBJECTIVE OF REVISION

Objectives of Revision Request:
The capacity margin has remained unchanged since 1998. Since that time, SPP has had significant transmission expansion, as well as expanding the footprint and operational responsibilities. SPP became the Balancing Authority in 2014, thus creating the need to revisit existing SPP criteria regarding capacity margin. The current mechanisms to ensure timely, reliable assurance of requirements in SPP are inadequate. SPP’s existing assurance mechanisms are either unlikely to be exercised or would be exercised in a way that would not encourage proper behavior and would not adequately compensate parties with excess capacity.

Tasked by the MOPC to review resource adequacy in SPP, the Capacity Margin Task Force created 4 whitepapers:

- Load Responsible Entity
- Planning Reserve Margin Requirement
- Planning Reserve Assurance Policy
- Deliverability Study

These policies identify who is responsible for resource adequacy, what the resource adequacy requirement is, and how and when the resource adequacy requirement can be and should be met. These four policy papers were approved by MOPC, RSC, and the Board in April 2016.

RR 187 (Planning Reserve Margin) was approved by the MOPC and the BOD at their January 2017 meetings and Tariff revisions were filed on March 3, 2017. Numerous comments and protests were received and SPP answered on April 18, 2017. FERC issued a deficiency letter on May 31, 2017 and SPP answered on June 30, 2017. A FERC order rejecting the filing without prejudice was received on August 29, 2017. In that order, FERC guidance was given on three key issues: (1) SPP’s proposal fails to include a requirement that all power purchase agreements are backed by verifiable capacity to meet SPP’s RAR and fails to include provisions to allow SPP to review the agreements to verify that they are backed by capacity; (2) SPP’s proposed treatment of firm power purchases and sales in the determination of net peak demand is unduly discriminatory; and (3) SPP has not supported as just and reasonable its proposal to post publicly a list of all LREs that have not met their RAR.

This revision request implements the approved resource adequacy package. It also addresses the three issues identified by FERC while continuing to maintain the foundational policy that has already been approved. Additionally, it moves the Planning Reserve Margin percentage to the SPP Planning Criteria and keeps the study process for determining the Planning Reserve Margin in the Tariff.

SPP STAFF ASSESSMENT

SPP supports RR 251.
**IMPACT**

Will the revision result in system changes  ☒ No  ☐ Yes

Summarize changes:

Will the revision result in process changes?  ☒ No  ☐ Yes

Summarize changes:

Is an Impact Assessment required?  ☒ No  ☐ Yes

If no, explain:

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Primary Working Group Score/Priority:

<table>
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<td>☐ Market Protocols</td>
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**WORKING GROUP REVIEWS AND RECOMMENDATIONS**
List Primary and any Secondary/Impacted WG Recommendations as appropriate

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Reason for Opposition:
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<th>Secondary Working Group: RTWG</th>
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**Reasons for Opposition:**

**KMEA:** KMEA feels that B-T-M generation should have option to be included as Firm Capacity instead of being a Load Modifier, regardless of NITS or Registration Status. Load Modifiers allows LSE to cover less reserves, since Load Modifiers adjust Peak load. KMEA believes that all should carry reserves for entirety of Actual Load. New material in Attachment AA, Section 7 defines Firm Capacity in a different manner than KMEA has interpreted for the past 10 years.

**RSC**

**Reasons for Opposition:**

**BOD/Members Committee**

**Reasons for Opposition:**

**COMMENTS**

**Comment Author:** Woody Lally, Jim Jacoby

**Date Comments Submitted:** 10/31/2017

**Description of Comments:** The existing Criteria includes "capacity" in the definition of Firm Power and there is no reason to lessen this requirement because of the FERC rejection. This term should not be removed since capacity is critical to the supply of Firm Power as compared to the supply of "financially firm" power. As we learned from our discussion with SWPA, just because the term "capacity" does not appear in older agreements does not mean that capacity is not being committed to support the
transaction. In addition, the sellers of Firm Power will need to verify the specific resources that supply the capacity just as is required for any other purchase agreement. See the added requirements in the Article 8.

An important concept for adjusting Net Peak Demand for Firm Power is that the contract amount is used to make the adjustment. This concept was lost with the revised definition. The requirement to provide a copy of the contract and verify the agreement should apply equally to a "Firm Power" agreement.

**Status:** Addressed.

**Comment Author:** Various

**Date Comments Submitted:** 10/26-31/2017

**Description of Comments:** SPP staff did receive comments from stakeholders outside of the revision request process. Through the stakeholder process all of the comments received were addressed and discussed, excluding the comments that were outside the scope of addressing the FERC identified issues. The comments that fell outside of the scope of this effort have been captured and will be addressed through the stakeholder process in the future.

**Status:** Addressed comments that met the scope of this effort.

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<th>PROPOSED REVISION(S) TO SPP DOCUMENTS</th>
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<td>SPP Tariff (OATT)</td>
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### 10 Force Majeure and Indemnification

#### 10.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider, the Transmission Owner(s), nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.
ATTACHMENT AA
Resource Adequacy
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 14.2 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.

**Firm Capacity**
The accredited capacity of commercially operable generating units, or portions of generating units, adjusted to reflect purchases and sales of capacity with another party, and that is deliverable with firm transmission service to the LRE’s load.

**Firm Power**
Power purchases and sales deliverable with firm transmission service to serve the LRE’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 with registered load in the Integrated Marketplace.

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) adjusted to reflect the contract amount of Firm Power with another entity as specified in Section 8.2 of this Attachment AA.

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 31st 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 9.3(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 14.0 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.

(1)(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 set in the SPP Planning Criteria. 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 14.2 of this Attachment AA.

5.2 The Deliverable Capacity or Firm Capacity utilized by an LRE to meet the Resource Adequacy Requirement may not be included in the Deliverable Capacity or Firm Capacity utilized by another LRE to meet the Resource Adequacy Requirement. Deliverable Capacity or Firm Capacity that is contracted to other entities shall not be available to the LRE that is transferring the Deliverable Capacity or 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.
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.
Qualification of Deliverable Capacity, Firm Capacity, and Firm Power

7.1 As part of the annual Workbook submission, an LRE or Generator Owner with Deliverable Capacity from resources internal to the SPP Balancing Authority Area shall qualify such capacity by: (a) registering the Resource in the Integrated Marketplace; (b) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; and (c) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria.

7.2 As part of the annual Workbook submission, an LRE or Generator Owner with Firm Capacity from a resource(s) internal to the SPP Balancing Authority Area shall qualify such capacity by: (a) demonstrating the resource(s) is (i) registered in the Integrated Marketplace or (ii) listed as a Designated Resource in the Network Integration Transmission Service Agreement; (b) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; (c) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria; and (d) demonstrating that there is firm transmission service from the internal resource(s) to the LRE’s load.

7.3 As part of the annual Workbook submission, an LRE or Generator Owner with Firm Capacity from a resource(s) external to the SPP Balancing Authority Area shall qualify such capacity by: (a) demonstrating ownership or contractual rights; (b) submitting, or causing to be submitted, to the Transmission Provider the current operational test results per the requirements of the Balancing Authority where the resource(s) is located; (c) demonstrating that there is firm transmission service from the external resource(s) to the LRE’s load; and (d) attesting that any external capacity being identified is not otherwise being used as capacity in any other Balancing Authority Area or in another resource adequacy construct.
7.4 As part of the annual Workbook submission, an LRE with Firm Power from a resource(s) internal to the SPP Balancing Authority Area shall qualify those purchases or sales by: (a) demonstrating the resource(s) is (i) registered in the Integrated Marketplace or (ii) listed as a Designated Resource in the Network Integration Transmission Service Agreement; (b) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; (c) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria; and (d) demonstrating that there is firm transmission service from the internal resource(s) to the LRE’s load.

7.5 As part of the annual Workbook submission, an LRE with Firm Power from a resource(s) external to the SPP Balancing Authority Area shall qualify those purchases or sales by: (a) demonstrating ownership or contractual rights; (b) submitting, or causing to be submitted, to the Transmission Provider the current operational test results per the requirements of the Balancing Authority where the resource(s) is located; (c) demonstrating that there is firm transmission service from the external resource(s) to the LRE’s load; (d) demonstrating that the capacity includes planning reserves; and (e) attesting that any external capacity being identified is not otherwise being used as capacity in any other Balancing Authority Area or in another resource adequacy construct.

7.6 The Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information received pursuant to Section 7 of this Attachment AA when such information is so designated as “confidential” and if such designation is reasonable, except to the extent required by this Tariff, by regulatory or judicial order, by law or statute.
8.0 **Qualification and Verification of Power Purchase Agreements**

8.1 An LRE or Generator Owner shall provide the Transmission Provider a copy of the power purchase agreement(s) to enable the Transmission Provider to verify the Deliverable Capacity, Firm Capacity, or Firm Power and to confirm compliance with this Attachment AA. On a prospective basis, the LRE or Generator Owner shall only submit a copy of a new or modified agreement(s).

1. Any redacted versions of a power purchase agreement submitted by an LRE or Generator Owner shall contain sufficient information to allow the Transmission Provider to verify compliance with the Resource Adequacy Requirement.

2. An LRE or Generator Owner with a power purchase agreement that does not identify the specific resource(s) shall identify each resource that is available or partially available through an attestation supporting the power purchase agreement.

8.2 When the purchaser and seller are both LREs, a power purchase agreement that qualifies as Firm Power shall result in a Net Peak Demand adjustment of the obligation for capacity and planning reserves from the purchaser to the seller. The purchaser shall deduct the purchased contract amount from its Net Peak Demand and the seller shall add the amount to its Net Peak Demand. The responsibility to maintain the Resource Adequacy Requirement and the Winter Season obligation shall transfer from the purchaser to the seller.

8.3 When the seller is not an LRE, a power purchase agreement that qualifies as Firm Power shall not result in a Net Peak Demand adjustment and the purchaser will remain responsible for the Resource Adequacy Requirement and Winter Season obligation for load served by the agreement. The purchaser shall not deduct the purchased contract amount from its Net Peak Demand; however, the purchaser may reflect as Firm Capacity the contract amount of the agreement plus the purchaser’s PRM multiplied by the contract amount. Firm transmission service is only required for the contract amount.

8.4 When the purchaser is not an LRE, a power purchase agreement qualifies as Firm Power shall result in a Firm Capacity transaction for load served by the agreement. The seller, who is an LRE,
shall not include the purchased contract amount in its Net Peak Demand; however, the seller shall reflect as Firm Capacity the contract amount of the agreement plus the seller’s PRM multiplied by the contract amount. Firm transmission service is only required for the contract amount.

8.5 A power purchase agreement executed prior to July 1, 2018 will continue to be defined and qualified as Firm Power if it does not include provisions permitting the seller to interrupt deliveries thereunder for reasons other than Force Majeure (as defined in Section 10.1 of this Tariff) or uncured defaults. All other power purchase agreements must specifically meet the definition of Firm Power.

8.6 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;

2. The amount of short-term Firm Capacity, Deliverable Capacity, or short-term Firm Power purchased in aggregate shall not exceed 25% of an LRE’s applicable Net Peak Demand; and

3. If the seller under a short-term Firm Power agreement is not an LRE, then the purchaser under the short-term Firm Power agreement will remain responsible for any Resource Adequacy Requirement or Winter Season obligation for load served under the short-term Firm Power agreement.

8.7 The Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information received pursuant to Section 8 of this Attachment AA when such information is so designated as “confidential” and if such designation is reasonable, except to the extent required by this Tariff, by regulatory or judicial order, by law or statute.
9.0 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) No later than 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) 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.

(9) By May 15th of each year, an LRE must demonstrate it has cured any deficiency in compliance with the Resource Adequacy Requirement.

(10) 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.

(11) 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 14.2 and 14.3, respectively, of this Attachment AA.
10.0 Deliverability Study

10.1 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.

10.2 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.

10.3 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.

10.4 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.

10.5 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.

10.6 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.
11.0 Workbook

11.1 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.

11.2 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 Deliverable Capacity;

(4) Purchases and sales for Firm Capacity;

(5) Purchases and sales for Firm Power; and

(6) Uncommitted Deliverable Capacity available to meet the PRM.

11.3 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.
12.0 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.
13.0 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.
14.0 Resource Adequacy Assurance

14.1 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 the sum of Deliverable Capacity and Firm Capacity, or zero if the sum of Deliverable Capacity and Firm Capacity is greater than or equal to the Resource Adequacy Requirement.

(3) LRE Excess Capacity
Deliverable Capacity and Firm Capacity less Resource Adequacy Requirement, or zero if the Deliverable Capacity and Firm Capacity is less than or equal to the Resource Adequacy Requirement.

(4) SPP Balancing Authority Area Planning Reserve
[(The sum of all LREs’ Deliverable Capacity and 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.

14.2 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 Deliverable Capacity and Firm Capacity to zero and utilize the previous year’s Summer Season Peak Demand.

14.3 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 14.2 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.

14.4 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) \[
\text{LRE revenue} = \left( \frac{\text{individual LRE Excess Capacity}}{\text{sum of LRE Deficient Capacity}} \right) \times \text{sum of the Deficiency Payment(s)} \]

(b) Any remaining revenues not allocated pursuant to Section 14.4(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:

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

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 = 
\[
\frac{\text{individual Generator Owner Excess Capacity}}{\text{sum of LRE Deficient Capacity}} \times \text{sum of Deficiency Payment(s)}
\]; and

(b) All remaining revenue not allocated in Section 14.4(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:

\[
\text{LRE revenue} = 
\frac{\text{sum of LRE Deficient Capacity – sum of all LRE Excess Capacity – sum of all Generator Owner Excess Capacity}}{\text{sum of LRE Deficient Capacity}} \times \frac{\text{individual LRE Summer Season Net Peak Demand}}{\text{sum of LRE Summer Season Net Peak Demand(s) that have met the Resource Adequacy Requirement}} \times \text{sum of Deficiency Payment(s)}
\]

(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 14.4 of this Attachment AA to its eligible LREs.

### 14.5 Dispute Resolution

All disputes under this Attachment AA shall be subject to the dispute resolution procedures contained in Section 12 of this Tariff.
4. **Planning Reserve Margin**

The Planning Reserve Margin (“PRM”) shall be twelve percent (12%). If a Load Responsible Entity’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%).

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 in accordance with Attachment AA of the SPP OATT.

4.1 **Definitions**

4.1.1 **Load Responsible Entity**

As defined in Attachment AA of the SPP OATT.

4.1.2 **Firm Capacity**

As defined in Attachment AA of the SPP OATT.

4.1.3 **Peak Demand**

As defined in Attachment AA of the SPP OATT.

A Load Serving Member’s System Capacity shall be equal to the capability of its generating facilities, including its ownership share of jointly owned units, demonstrated under procedures set forth in SPP Rating of Generating Equipment Criteria, adjusted to reflect the purchase from and/or sale to any other party of generating capacity or SPP defined Operating Reserve, under any appropriate agreement. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load.
Capacity purchases shall only be considered if Firm Transmission Service is in place to the Load Serving Member for delivery of power from such capacity.

Unless reported separately, generating facilities owned by others within the Load Serving Member’s system that are obligated to furnish firm power to customers within the Load Serving Member’s system shall also be reported. Absent any bilateral contractual arrangements with the host Control Area, the host Control Area will not be required to be responsible for capacity and/or reserve requirements. The reporting of generating facilities owned by others does not constitute an obligation on the Load Serving Member's part to furnish reserves or back up power for that generation.

4.1.4——Net Load

The term Net Load for any Load Serving Member shall mean, for any clock hour:

a) Net generation by the Load Serving Member's facilities; plus b) Net receipts into the Load Serving Member's system; minus c) Net deliveries out of such Load Serving Member's system

Unless reported separately, the Net Load of other non-Load Serving Members located within the Load Serving Member's system shall also be reported. Absent any bilateral contractual arrangements, the reporting of these loads does not constitute an obligation on the Load Serving Member's part to furnish reserves, back up power, or incur financial obligations from SPP for that load.

4.1.5——Capacity Year

Capacity Year shall mean a period of twelve consecutive months beginning on October 1 of each calendar year. Any period less than a Capacity Year shall be designated as Short Term.

4.1.6——System Peak Responsibility

System Peak Responsibility of a Load Serving Member for any Capacity Year shall mean the Load Serving Member's greatest Net Load during that Capacity Year plus:

a) The contract amount of Firm Power sold to others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the sale of a specified amount of Firm Power; and minus

b) The contract amount of Firm Power purchased from others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the purchase of a specified amount of Firm Power.
In each case, the contract amount governs regardless of the amount actually delivered at the time of a Load Serving Member's greatest Net Load.

4.1.7 Capacity Margin

Capacity Margin shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Peak Responsibility.

4.1.8 Percent Capacity Margin

Percent Capacity Margin shall be defined by the formula:

\[
\text{Percent Capacity Margin} = \left(\frac{\text{Capacity Margin}}{\text{System Capacity}}\right) \times 100
\]

4.1.9 Minimum Required Capacity Margin

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.

4.1.10 System Capacity Margin Responsibility

A Load Serving Member’s System Capacity Responsibility for any Capacity Year shall mean the sum of that Load Serving Member's System Peak Responsibility and its Minimum Required Capacity Margin.

4.1.11 Capacity Balance

Capacity Balance shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Capacity Responsibility.

4.1.12 Firm Transmission Service

Firm Transmission Service is that service defined in any applicable transmission service provider tariff.

4.2 Capacity Responsibility

a) Each Capacity Year, each Load Serving Member shall possess System Capacity at least equal to its System Capacity Responsibility.
b) Prior to the establishment of its System Peak Responsibility for each Capacity Year, each Load Serving Member shall provide System Capacity by one or more of the following means:

i) Establishing a unit rating consistent with SPP generating equipment rating Criteria, prior to establishing its System Peak Responsibility;

ii) Reducing its System Peak Responsibility by purchase of Firm Power from any Member or non-Member by separate agreement;

iii) Separate written agreement with another Member or a non-Member for purchase of a specified amount of capacity; and/or

iv) Reducing its Net Load.

c) A Load Serving Member may purchase Short Term capacity to provide a part of its System Capacity or Short Term Firm Power to reduce its System Peak Responsibility subject to each of the following restrictions:

i) Such Short Term period shall not be less than four consecutive months, and shall include the day the Load Serving Member establishes its System Peak Responsibility. Such period shall begin during May 1 to June 1 or November 1 to December 1;

ii) The amount of Short Term capacity or Short Term Firm Power purchased shall not exceed 25% of the Load Serving Member's System Peak Responsibility; and

iii) The Load Serving Member shall purchase such Short Term Capacity or Short Term Firm Power prior to the start of the Short Term period.

d) A Load Serving Member may sell Short Term Capacity or Short Term Firm Power from resources comprising its Capacity Balance, provided that it’s System Capacity Responsibility is met.

4.3 Records

Each Load Serving Member, upon request, shall provide accurate and detailed records of information related to this Criteria to the SPP Staff. Except for System Peak Responsibility, all other information shall be provided prior to establishing System Peak Responsibility for a Capacity Year and shall include: validation of System Capacity per SPP Rating of Generating Equipment Criteria, Capacity purchase and sale contracts, Firm Power purchase and sale contracts, and firm transmission service agreements. The SPP Staff shall verify information supplied by each Load Serving Member. Calculations shall be based on the highest peak load of each of the Load Serving Members during the
Capacity Year. All capacity and demand values will be rounded to the nearest whole MW for purposes of this Criteria. All data submitted to SPP related to this Criteria shall be considered confidential by the SPP Staff and shall not be released in any form except by force of law.

4.4 — Generation Planning

4.4.1 — Design Futures

a) In order to maintain a balanced design of the electric system, excessive concentration of generating capacity in one unit, at one location, or in one area shall be avoided.

b) Auxiliary power sources shall be provided in each major generating station to provide for the safe shutdown of all the units in the event of loss of external power.

c) In each major load area of SPP, a unit capable of black start shall be provided having the capability of restarting the other units in the area.

d) Boiler controls and other essential automation of major generating units shall be designed to withstand voltage dips caused by system short circuits.

4.4.2 — Fuel Supply

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel shall be provided. Due to the dependence of hydroelectric plants on seasonal water flows, this factor shall be taken into consideration when calculating capacity for capacity margin requirements.

6.3.5 — Capacity Benefit Margin (CBM)

CBM on a Flowgate basis is the amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. 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 requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10%—11% capacity margin. SPP does not utilize CBM for calculations of ATC for some or all of the following reasons:
(1) the existing level of internal capacity reserve margin of each member is adequate
(2) historical reliability indicators of transmission strength of the SPP area
(3) Open Access transmission usage environment allows greater purchasing options

Since SPP does not utilize CBM for any flowgate within the SPP footprint, the CBM value used in any calculations will be zero.

7.1 Accredited Net Generating Capacity

This Section shall be used to determine the annual and seasonal accredited net generating capacity of generators in calculating the capacity/reserve margin. Procedures are herein for establishing a system of records so that changes in capacity during the life of the equipment can be recognized. These procedures define the framework under which the net generating capacity are to be established while recognizing the necessity of exercising judgment in their determination. The terms defined and the net generating capacity established pursuant to these procedures shall be used for SPP purposes, including determining capacity reserve margins for capacity planning and preparation of reports of other information for industry organizations, news media, and governmental agencies. These net generating capacity are not intended to restrict daily operating practices associated with SPP operating reserve sharing, for which more dynamic ratings may be necessary. Each member shall test its generating equipment in accordance with the procedures contained herein. On the basis of these tests summer and winter net capability ratings for each generating unit and station on the member's electric system shall be established. This net capability is the maximum capacity a unit can sustain over a specified period modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries. The summer net capability of each unit may be used as the winter net capability without further testing, at the option of the member. As a minimum, each member shall conduct tests on all its generators that are designated as a part of the resource for supplying a member’s peak load and minimum capacity/reserve margin requirement of this Criteria. The seasonal net capabilities shall be furnished to SPP for all existing generating units and upon installation of new generating units and shall be revised at other times when necessary.

For newly installed generating units, design output may be used for the first peak operating season to allow sufficient time for Operational and Capability test. For generating units out of service during the entire preceding peak season, the Operational test and the effective Capability test results may be used to satisfy the Operational and Capability test requirement for the upcoming peak operating season. Members shall annually report the seasonal net generating unit capability in conjunction with the Department of Energy 411 Report data gathering effort.
7.1.5.2 Seasonality

(1) The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, February, and March. The adjustments required to develop seasonal net capabilities are intended to include seasonal variations in ambient temperature, condenser cooling water temperature and availability, fuel changes, quality and availability, steam heating loads, reservoir levels, scheduled reservoir discharge, and wind speed.

(2) The total seasonal net capability rating shall be that available regularly to satisfy the daily load patterns of the member and shall be available for a minimum of four continuous hours taking into account possible fuel curtailments and thermal limits.

(3) The seasonal net capability of each generating unit shall be based upon a set of conditions, referred to as the "Net generating capacity Conditions" for that unit. This set of conditions is determined by the geographical location of the unit, and is composed of three or four factors, depending upon the type of unit. The three factors which can affect most generating units are: Ambient dry-bulb temperature, Ambient wet-bulb temperature and Barometric pressure. Condensing steam turbines which obtain condenser cooling water from a lake, river, or comparable source have a fourth factor: Condenser cooling water source temperature.

(4) The Rating dry-bulb and wet-bulb temperatures shall be obtained from weather data provided in the most recently published American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Fundamentals Handbook, Chapter 27 Climatic Design Information. The handbook is published every four years; 1997, 2001, etc., and is based on 15 years of historical weather data where available. If the generating station is within 30 miles of the nearest weather station reported in the Handbook, then these temperatures will be those for the nearest station. For all other stations, rating temperatures shall be determined by interpolating between weather stations using plant latitude and longitude. The steps to be used for interpolating weather data and correcting for elevation are presented in SPP Criteria Appendix PL-1.

(5) If experience for a given unit suggests otherwise, members may optionally use their own site specific temperature data if accurate hourly data is available to allow calculation of the temperature levels as defined in the Criteria. Site specific data shall contain both dry-bulb and wet-bulb temperatures.

(6) Temperatures for summer rating of equipment should be taken from Handbook Table 1B: Cooling and Dehumidification Design Conditions - Cooling DB/MWB for 0.4% DB (dry-
bulb) and MWB (mean wet-bulb) (Column 2a and 2b, respectively). According to the 2001 Handbook Page 27.2, "The 0.4% annual value is about the same as the 1.0% summer design temperature in the 1993 ASHRAE Handbook." In older Handbooks, the dry-bulb temperature for summer rating of equipment shall be taken as that which is equaled or exceeded 1% of the total hours during the months of June through September for the plant's geographical location. The wet-bulb temperature for the summer rating shall be the "mean coincident wet-bulb" temperature corresponding to the above dry-bulb temperature.

(7) The temperature for winter rating of equipment should be taken from Handbook Table 1A: Heating and Wind Design Conditions-United States - Heating Dry Bulb 99% (Column 2b). According to the 2001 Handbook Page 27.3, "Annual 99.6% and 99.0% design conditions represent a slightly colder condition than the previous cold season design temperatures, although there is considerable variability in this relationship from location to location." In older Handbooks, the minimum dry-bulb temperature for winter testing and net generating capacity shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through February (per Handbook definition) for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded.

(8) Standard barometric pressure for a plant site shall be determined for each plant elevation from the equation provided in Appendix PL-1.

(9) For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the month concurrent with the Load Serving Member's peak load of the year, averaged over the past ten years.

(10) Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

7.1.5.3 Net Generating Capacity Adjustments

(1) The rated net capability of a unit may be above or below the actual tested net generation as a result of adjustments for Net generating capacity Conditions, with the exception of units with winter season net generating capacity greater than their summer net generating capacity. For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No net generating capacity adjustment for ambient conditions shall be made.
(2) Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

(3) Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

(4) The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.

(5) The seasonal net capability established for hydro electric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.

(6) The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.

(7) The recommended methodology to evaluate the net planning capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member’s desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:

(a) Assemble all available hourly net power output (MWH) data measured at the system interconnection point.

(b) Select the hourly net power output values occurring during the top 3% of load hours for the SPP Load Serving Entity for each month of each year for the evaluation period.

(c) Select the hourly net power output value that can be expected from the facility
60% of the time or greater. For example, for a 5 year period with the 110 hourly net power output values ranked from highest to lowest, the capacity of the facility will be the MW value in the 65th data point.

(d) A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the Load Serving Entity’s peak load month of the season of interest (e.g., 22 hours for a typical 30 day month and 110 hours for a 5 year period).

(e) Facilities in commercial operation 3 years or less:
   (i) The data must include the most recent 3 years.
   (ii) Values may be calculated from wind or solar data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Supply Adequacy Working Group approval. Solar data correlated with a reference measuring device beyond two hundred miles is subject to Generation Supply Adequacy Working Group approval. For calculated values, at least one year must be based on site specific data.
   (iii) If the Load Serving Entity chooses not to perform the net capability calculations as described above during the first 3 years of commercial operation, the Load Serving Entity may submit 5% for wind facilities and 10% for solar facilities of the site facility’s nameplate rating.

(f) Facilities in commercial operation 4 years and greater:
   (i) The data must include all available data up to the most recent 10 years of commercial operation.
   (ii) Only metered hourly net power output (MWH) data may be used.
   (iii) After three years of commercial operations, if the Load Serving Entity does not perform or provide the net capability calculations to SPP as described above, then the net capability for the resource will be 0 MW.

(g) The net capability calculation shall be updated at least once every three years.

7.1.6 4.4.2 Fuel Supply

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel shall be
provided. Due to the dependence of hydroelectric plants on seasonal water flows, this factor shall be taken into consideration when calculating capacity for reserve margin requirements.

<table>
<thead>
<tr>
<th>Table Title</th>
<th>N/A</th>
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</thead>
<tbody>
<tr>
<td>Market Protocols</td>
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<tr>
<td>SPP Business Practices</td>
<td></td>
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<tr>
<td>Integrated Planning Model (ITP Manual)</td>
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<tr>
<td>Revision Request Process</td>
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<tr>
<td>Minimum Transmission Design Standards for Competitive Upgrades (MTDS)</td>
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</tr>
<tr>
<td>Reliability Coordinator and Balancing Authority Data Specifications (RDS)</td>
<td></td>
</tr>
<tr>
<td>SPP Communications Protocols</td>
<td></td>
</tr>
</tbody>
</table>
Cost Allocation - Wind Rich Areas
(2011 – Now)

January 29, 2018
Al Tamimi, Ph.D., P.E.
VP, Transmission Planning & Policy
Sunflower Electric Power Corporation
Overview

• There has been a Paradigm Shift on why SPP builds Transmission
  o When HWBW was created, Transmission projects were primarily based on changes in load or changes in Designated Resources
  o What is driving transmission build today?
    ▪ load is mostly stagnant and DR's are taken care of by the Aggregate Study process
    ▪ Renewable generation is built Geographically far from load centers, i.e. Wind where the wind blows, Solar where the sun shines

• Large percentage of wind projects in SPP are built in small load zones
  o Causes wind power to be exported out of the local zones for many hours of the year as connected wind has exceeded the local load in the Zone
  o Additional Wind benefits the whole SPP Market, but not necessarily the local zones
    ▪ More transmission upgrades may need to be built, most of which are Byway Projects
  o 2/3 of the costs of Byway projects will probably be assigned to the local Zone which is not receiving the benefits of reduced energy costs
  o Continued development of Wind/Solar may drive additional upgrades in the ITP process
  o The GI and/or Aggregate study does not protect the local Zone the situation
    ▪ All direct assigned upgrade costs are eligible for Z2 credits, over 90% of Z2 credits are uplifted through HWBW
Overview (cont.)

• Highway/byway cost allocation is **not working well** under the new Paradigm
  o HWBW based on voltage level and geography
  o Load growth: works well since transmission would be built close to load
  o No load growth in host zones: does not work as well, local upgrades may be built for other reasons
  o Costs are not being assigned to those getting the benefits
    ▪ Lower energy costs to the Market as a whole, but not necessarily to the local Zone
    ▪ Building new transmission that releases trapped generation will probably **not lower** energy costs to the local Zone.
  • Generally there is an increase in energy cost plus the increase in Zonal Transmission rates
    ▪ Congestion and congestion relief impact on host entities
• RCAR is not finding the problem
  o The current analysis is only focused on “Historic Benefit/Costs”
  o Need to look at how new facilities are being used and why it is being built.
    ▪ The use of the transmission facilities changes under different markets
      • BA
      • Energy Imbalance Service Market (EIS)
      • Integrated Market (IM)
Questions Needing Answered

• Why are we building transmission today with minimal load growth?

• Is the current cost allocation method properly allocating cost to those who benefit from the transmission build out?
Paradigm Shift: Is the Current Byway Voltage Cost Allocation in SPP Reflective of the System Use Today?

2009
- Historically Transmission Built to connect generators to Load & Changes in Load
- SPP Examined Cost Allocation
- Ran Tests for FERC Filing
- Developed Highway/Byway Cost Allocation

Mar-14
- Integrated Marketplace started
- Economic Upgrades became more important
- IPPs can send power into the Market w/o Firm Transmission (ERIS)

11-17
- <2000 MW load growth, >13,000 MW of wind additions*, 3600 MW of generation retirements**
- More Projects Constructed on the “Byway” Than the “Highway” ***
  - 5x as many Byway projects than Highway projects through based on RCAR II project list
    - About 2,000 miles of 345 kV
    - With minimal load growth, 1,600 miles of Byway projects

Future
- Has the “Highway” been built out enough that most of the future upgrades are “Byway” projects?
- Are “Byway” projects the new Economic Upgrade?
- If So, Should the Cost Allocation Method be modified?

*** SPP Quarterly Project Status Update
The Current Situation

• SPP Peak Load in 2016 = 51,200 MW

• 5 yr. demand growth of 1,100 MW in SPP (approx. 2% total or 0.4%/yr.)

• 6GW of solar in the queue

• Analysts predict 8.2 GW of wind build (43 GW in queue)
Case History & Analysis: Sunflower Electric

- Sunflower is in a “Wind Rich Area”
- Sunflower zone exported wind power to other SPP members 61.89% of the time in 2016
- Transmission facility costs are high
  - Sunflower zone has small load compared to facilities needed for new generation installed.
- Impacts to Customers is large
  - For the same cost, projects in Zones with small loads cost more per customer than larger load zones

Note: The use of “Sunflower in this presentation refers to the combined Sunflower (SECI) and Mid-Kansas (MKEC) Zones unless otherwise noted
COMPARISON OF COST / MW OF LOAD FOR $1.0 M OF BYWAY PROJECT FOR EA. ZONE

Impact on SECI VS Selected Zones

<table>
<thead>
<tr>
<th>Utility</th>
<th>Impact</th>
<th>Cost / MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>1</td>
<td>9.5</td>
</tr>
<tr>
<td>KCPL</td>
<td>1</td>
<td>3.4</td>
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<tr>
<td>OGE</td>
<td>1</td>
<td>6.0</td>
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<tr>
<td>WR</td>
<td>1</td>
<td>4.7</td>
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<tr>
<td>SPS</td>
<td>1</td>
<td>5.2</td>
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## 2011 – 2018 Transmission Byway Cost / MW Load

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<tr>
<th>Zone</th>
<th>2016 12CP</th>
<th>LRS (w/o IS)</th>
<th>67% of Byway Costs Allocated to The Zone for Projects built between 2011-2018</th>
<th>% of B/W Project Per Entity</th>
<th>Byway Projects $/MW Load</th>
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<tr>
<td>AEP</td>
<td>8,174</td>
<td>22.75%</td>
<td>199,892,054</td>
<td>15.82%</td>
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<tr>
<td>EDE</td>
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<td>0.00%</td>
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<td>GMO</td>
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<td>4.15%</td>
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<td>SPRM</td>
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<td>WFEC</td>
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<tr>
<td>WR</td>
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<td>11.25%</td>
<td>205,438,245</td>
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<td>$50,809</td>
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- **Ranked 10th**
- **4th Largest Total Cost**
- **Largest Cost/MW**
Transmission Build Vs. Generation Build

Upgrades in the Sunflower Zone – RCAR II Project List
With 2,471 MW of Wind

<table>
<thead>
<tr>
<th>Cost Allocation</th>
<th>Number of Projects</th>
<th>Cost</th>
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<tbody>
<tr>
<td>BW</td>
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<td>$185,638,996</td>
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<tr>
<td>HW</td>
<td>10</td>
<td>$328,463,780</td>
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</tbody>
</table>
What Has Been Happening in the Sunflower Zone?

Schedule 11 ATRR vs MW Wind Installed vs Combined Sunflower/MKEC Load

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What Has Been Happening in the Sunflower Zone?
## Wind Generation in The Sunflower Zone

### Wind Generation for 2016

<table>
<thead>
<tr>
<th>Month</th>
<th>Wind Generation (MW)</th>
<th>Load (MW)</th>
<th>Penetration</th>
</tr>
</thead>
<tbody>
<tr>
<td>January - March</td>
<td>667</td>
<td>605</td>
<td>110.25%</td>
</tr>
<tr>
<td>April - May</td>
<td>613</td>
<td>586</td>
<td>104.61%</td>
</tr>
<tr>
<td>June - August</td>
<td>499</td>
<td>804</td>
<td>62.06%</td>
</tr>
<tr>
<td>September - December</td>
<td>621</td>
<td>627</td>
<td>99.04%</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td><strong>600</strong></td>
<td><strong>655.5</strong></td>
<td><strong>93.99%</strong></td>
</tr>
</tbody>
</table>

Max Penetration on Hourly Basis 253%
Projected Wind Generation for 2019

Approximately 50% more Wind connected in 2019 vs 2016 (1,233 MW IA Pending & Facility Study)

<table>
<thead>
<tr>
<th></th>
<th>Expected Average for 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2019</strong></td>
<td>Wind in MW</td>
</tr>
<tr>
<td>January - March</td>
<td>1019</td>
</tr>
<tr>
<td>April - May</td>
<td>936</td>
</tr>
<tr>
<td>June - August</td>
<td>762</td>
</tr>
<tr>
<td>September - December</td>
<td>948</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td>916.8</td>
</tr>
</tbody>
</table>
$114M of new Byway investment to enable SPP wind penetration of 45%, 60%
Transfer Impacts on Highway vs. Byway Summer Peak

- 756 Unique Transfers Modeled (each transfer is 1,000 MW between two zones across all SPP footprint)
- Each transfer will flow on the Highway and Byway transmission facilities in each zone.
- Example: AEP Zone: 22.8% of all the flows impacted Highway Facilities, 14.2% of the Flows impacted the Byway
Average Flow on the Byway vs Total Flows in Zone
Summer Peak

Average 46.29%
All SPP Weighted Average Based on LRS 44.42%
Wind exporting entities average 58.37% utilization of byway projects

Wind Exp. Entities: MIDW, WFEC, SECI
Case History & Analysis: Sunflower Electric

- Benefit/Cost Ratio is dependent on energy prices
  - Currently lower energy prices due to trapped generation
  - Recent SPP studies show that long term, those benefits are projected to be relatively small
  - Energy Benefits are only one ITP study away from being half as big.
    - i.e. The Potter-Tolk 345 kV line
RCAR Analysis is not capturing the issues

- Largest Benefits are the APC and Assumed Reliability Benefits
- APC Savings from Congestion keeping the energy costs low in the MKEC and SEPC Zones
- Elimination of Congestion: Good for the Region, but will reduce the APC saving for Zones like Sunflower
- Transmission Projects are mostly caused to solve issues from the many Windfarms in the Sunflower Zone
- All reliability projects are assumed to have B/C ratio of 1, can give a false indication of “Benefits” from Reliability Projects
What is in the Tariff?

• Tariff has a limited “Wind protection” rule in the HWBW cost allocation
  o Only applies to upgrades from the Aggregate Study Process (i.e. Designated Resources)
  o Upgrades in Zones where the Load is NOT located
    ▪ 2/3 of upgrade costs Regionally allocated
    ▪ 1/3 of upgrade cost is direct assigned to Customer
  o Does not cover any other renewable resources (i.e. Solar)

• Generation Interconnections
  o All costs are direct assigned to the GI customer
  o Does not cover all the upgrades required to deliver power to the Market

• All Customers with Direct Assigned Costs are eligible for Z2 credits
  o Over 90% of Z2 credits are uplifted to general rates
    ▪ Any Z2 credits for Byway Projects do NOT receive the Wind Protection

• ITP Upgrades
  o All costs are HWBW allocated
  o No protection if transmission upgrades are indicated due to additional Generation
What is The Solution?

• Four Possible solutions:

• Option 1: Do Nothing
  o Pros: Easy to do
  o Cons:
    ▪ Inflicts cost on Zones in SPP that are not seeing the Benefits from the Construction
    ▪ Having Zones that will fail the RCAR review in the future as the RCAR looks backward not forward on transmission investments

• Option 2: Modify the Current HMBW – Expand the Wind Protections

• Option 3: Modify the Percent Allocations of the Byway Projects

• Option 4: Combination of Options 2 and 3
Option 2: Add More Generation Protections

• All costs related to a transmission upgrade which was paid, all or in part, by an entity (Sponsored Upgrade) is eligible for Z2 credits
  o Over 90% of the Z2 Credits that are collected for payment are uplifted to Transmission Rates using HWBW which means that all costs related to a Byway voltage project can be reasonably assumed to eventually be cost allocated to the host Zone.

• Any Z2 credits for Sponsored Project related to a Generation Interconnection be Regionally Allocated
  o Only for Generation that is not a DR for the local load.
  o Cost allocated for Byway Upgrades related to local DR – Normal HWBW

• Economic Upgrades related to releasing “trapped generation” into the SPP Market be 100% Regionally Allocated

• Pros:
  o Very targeted change
  o Protects the Zonal Customers from costs of upgrades that do not benefit them
  o Allocates Costs to the Customers that get the benefits, i.e. the entire SPP Market
    ▪ Assumes these upgrades are required to deliver the cheaper energy from the IPPs to Load outside the host Zone

• Cons:
  o Does increase the regional costs paid by all load
  o Need to be able to define which upgrades qualify for the Regional cost allocation
Option 3: Changing the Percentage Byway Cost Allocation

Conclusions

• Use of the Byway System is greater than ever
• Model flows indicate that the Byway is supporting more regional flows
• A change in the regional vs Zonal costs is needed
• Recommend a change from 33% Regional, 67% Zonal to a new allocation based upon an updated flow analysis (example: 50% Regional, 50% Zonal as indicated by the Sunflower Analysis)

• Pros:
  o Allocates costs to those customers getting benefits
  o Reflects today’s reality related to what is driving the building of byway facilities
  o Minimal Tariff changes to Implement

• Cons:
  o Additional model runs by SPP Staff to confirm the analysis
  o Does shift some costs from a Zone to the Region
Option 4: Combine Option 2 and 3 (Preferred)

- Makes sense to provide the additional protections to those Zones that are receiving a disproportionate number of generation interconnections under Option 2
  - The current Tariff has several significant “holes” that can inappropriately over allocate costs to a Zone
  - Properly allocated the cost of any Z2 credit payments to those customers benefiting from the upgrade

- Make the change in percentage allocation as supported in Option 3 to reflect the current reality of how the byway facilities are being used
Conclusions

• Sunflower believes that Option 4 is the correct strategy
  o Change the Tariff to stop the inadvertent allocation of costs of upgrades to the host Zonal customers
  o Sunflower is proposing to change the cost allocation to match or be close to the usage of the HWBW transmission system.
  o Future projects should be changed to reflect a new zonal allocation

• Sunflower supports wind and solar development projects and only wants to be sure all SPP Customers are paying the proper costs for transmission upgrades being built.

Questions?
Included Topics

• 2018 Integrated Transmission Planning – Near-Term Assessment (ITPNT) Update
• 2019 Integrated Transmission Planning (ITP) Update
• 2018 SPP Transmission Expansion Plan (STEP)
2018 ITPNT Update
2018 ITPNT Timeline

2017
- May
- Jul
- Sep
- Nov
- 2018
- Mar
- May
- Jul

2018
- TWG Final Approval
- Jul 17
- MOPC Approval
- Jul 31
- SPP Board Approval
- Jul 31

Today

Needs Assessment
DPP Window
Solutions Development & Evaluation
Upgrade Determination/Study Cost Estimates - Round 1
Draft Portfolio Development
Upgrade Determination/Study Cost Estimates - Round 2
Finalize Portfolio
ATRR/Staging
Final Report with recommendations
SPP ITPNT Load Trends

<table>
<thead>
<tr>
<th>Year</th>
<th>Year-1</th>
<th>Year-2</th>
<th>Year-5</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015 ITPNT</td>
<td>55,017</td>
<td>55,837</td>
<td>58,561</td>
</tr>
<tr>
<td>2016 ITPNT</td>
<td>54,225</td>
<td>54,744</td>
<td>56,795</td>
</tr>
<tr>
<td>2017 ITPNT</td>
<td>53,683</td>
<td>54,052</td>
<td>55,169</td>
</tr>
<tr>
<td>2018 ITPNT</td>
<td>52,832</td>
<td>53,401</td>
<td>54,646</td>
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</tbody>
</table>
2017 ITPNT Posted Needs vs 2018 ITPNT Preliminary Needs

<table>
<thead>
<tr>
<th></th>
<th>2018 ITPNT</th>
<th>2017 ITPNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal</td>
<td>67</td>
<td>137</td>
</tr>
<tr>
<td>Voltage</td>
<td>99</td>
<td>591</td>
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</table>
2019 ITP Update
2019 ITP Scope

• The objective of the 2019 ITP Assessment is to develop a regional transmission plan that provides reliable and economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to the end-use customer
  • The 2019 ITP Scope contains assumptions to be utilized in the 2019 ITP Assessment that are not standardized in the ITP Manual

• The 2019 Scope was approved by ESWG and TWG on January 4
• MOPC approved January 16
• Board approval requested January 30
## 2019 ITP Futures

- **Future 1: Reference Case**
- **Future 2: Emerging Technologies**

<table>
<thead>
<tr>
<th>Key Assumptions</th>
<th>Drivers</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Year 2</td>
</tr>
<tr>
<td>Energy Demand Growth Rates</td>
<td>As submitted in load forecast</td>
</tr>
<tr>
<td>Fossil Fuel Retirements</td>
<td>Age-based 60+, subject to stakeholder input</td>
</tr>
<tr>
<td>Distributed Generation (Solar)</td>
<td>As submitted in load forecast</td>
</tr>
</tbody>
</table>

### Total Renewable Capacity

<table>
<thead>
<tr>
<th></th>
<th>Solar (GW)</th>
<th>Wind (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>~0.25+</td>
<td>~18+</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>26</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>29</td>
</tr>
<tr>
<td></td>
<td>7</td>
<td>32</td>
</tr>
</tbody>
</table>
2019 ITP Timeline

- **2017**
  - Jul: Scope Development
  - Nov: Load Forecast and Generation Review
  - Mar: Renewable/Conventional Resource Plans
  - Jul: Siting Plan and GOFs (Generator Outlet Facilities)
  - Nov: Powerflow Model Development
  - Mar: Short Circuit Model Development
  - Jul: Economic Model Development and Benchmarking
  - Model Updates after Jul '18 MOPC/SPP Board

- **2018**
  - Nov: Constraint Assessment
  - Needs Assessment
  - DPP Response Window
  - Solution Evaluation and Portfolio Development

- **2019**
  - Study Cost Estimates #1
  - Study Cost Estimates #2
  - MOPC Oct 16
  - SPP Board Oct 29
  - Summit
  - Project Staging
  - Benefit Metrics Calculations
  - Stability Analysis
  - Sensitivity Analysis
  - Review draft report with recommended solutions
  - Final report with recommended solutions
2018 STEP
STEP Components

SPP Transmission Expansion Plan

- ITP Upgrades
- High Priority Upgrades
- Balanced Portfolio Upgrades
- Interregional Upgrades
- Transmission Service Upgrades
- Generation Interconnection Upgrades
- Sponsored Upgrades

Board Approval Required
Board Endorsement Required
Projects Completed in 2017

• 36 upgrades - $246 M
  – 19 Integrated Transmission Planning - $163.9 M
  – 3 Transmission Service - $26.6 M
  – 13 Generator Interconnection - $43.4 M
  – 1 High Priority - $11.7 M
New or Modified NTCs Issued in 2017

• 71 projects - $263.2 M
  – $0.11 M for Generator Interconnection
  – $28.7 M for High Priority
  – $140.9 M for Transmission Service
  – $93.5 M for Integrated Transmission Planning
2018 STEP NTC Cost by Project Type – $2.6 B

- GI: $0.23M
- High Priority: $443M
- TSS: $289M
- ITP: $1,863M
Integrated Marketplace Operational Update

Bruce Rew, PE
Vice President, Operations
SPP Integrated Marketplace Update

• Marketplace Highlights Over Last 12 Months
• Marketplace Statistical Information
• Marketplace Wind Highlights and Records
• Enhancements implemented and under development
Q4 Marketplace Operational Highlights

- New Winter Peak set on December 19 with a peak of 40,322 MW.
- No significant winter ice/snow storms, but very low temperatures in the last week of December (and first two weeks of January) did drive high system demand, higher gas prices, and increased generation outages. New winter peaks set in January.
- Total of 17,530 MW of installed and operational wind capacity to date.
  - As of January 9th, there is approximately 75 MW of wind registered, but not yet operational.
- New wind generation peak (15,690 MW) and wind penetration (56.25%) peaks in the first half of December.
- 21 of 92 days in October – December (23% of days) had average wind power output over 10 GW.
Marketplace Over Last 12 Months

• **211 Market Participants**
  • 141 financial only and 70 asset owning

• **SPP BA has successfully maintained NERC control performance standards (BAAL & CPS)**

• **High System availability**
  • Day-Ahead Market results have posted late four times in the last 12 months
    • 3 due to oracle upgrade; one due to difficult solution
  • Real-Time Balancing Market has successfully solved 99.92% of all intervals
Dispatch by Fuel Type

Real-Time

Generation (TWh)

- Oct 16
- Nov 16
- Dec 16
- Jan 17
- Feb 17
- Mar 17
- Apr 17
- May 17
- Jun 17
- Jul 17
- Aug 17
- Sep 17
- Oct 17
- Nov 17
- Dec 17

- Other
- Gas, simple cycle
- Gas, combined cycle
- Coal
- Hydro
- Renewable
- Wind
- Nuclear
Fuel on the Margin in RT
Real-Time versus DA pricing
Wind Peaks in December

- SPP set a new historical maximum wind output of 15,690 MW on 12/15/2017 at 20:51
  - Previous wind max output was 14,150 MW on 12/4/2017 @ 21:55
- SPP Load at time of 12/15 peak was 30,956 MW
- Generation Mix at Peak:

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Generation</th>
<th>Penetration Per Fuel Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>15,690 MW</td>
<td>50.69%</td>
</tr>
<tr>
<td>Coal</td>
<td>9,847 MW</td>
<td>31.81%</td>
</tr>
<tr>
<td>Gas</td>
<td>3,689 MW</td>
<td>11.92%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2,045 MW</td>
<td>6.61%</td>
</tr>
<tr>
<td>Hydro</td>
<td>970 MW</td>
<td>3.13%</td>
</tr>
<tr>
<td>Other</td>
<td>49 MW</td>
<td>0.16%</td>
</tr>
</tbody>
</table>
## Wind Output: October - December 2017

<table>
<thead>
<tr>
<th></th>
<th>@ Max Wind Output</th>
<th>@ Min Wind Output</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MW Wind</strong></td>
<td>15,690 MW</td>
<td>638 MW</td>
</tr>
<tr>
<td><strong>Time</strong></td>
<td>12/15 @ 22:00</td>
<td>12/2 @11:15</td>
</tr>
<tr>
<td><strong>SPP Load</strong></td>
<td>30,956 MW</td>
<td>26,470 MW</td>
</tr>
<tr>
<td><strong>Appx Gen Mix</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>26%</td>
<td>63%</td>
</tr>
<tr>
<td>Wind</td>
<td>49%</td>
<td>2%</td>
</tr>
<tr>
<td>Nat. Gas</td>
<td>11%</td>
<td>22%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>6%</td>
<td>8%</td>
</tr>
<tr>
<td>Hydro</td>
<td>3%</td>
<td>5%</td>
</tr>
</tbody>
</table>
## Wind Penetration: October - December 2017

<table>
<thead>
<tr>
<th></th>
<th>Max Penetration</th>
<th>Min Penetration</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Wind Penetration</strong></td>
<td>56.25% of load</td>
<td>2.4% of load</td>
</tr>
<tr>
<td><strong>Time</strong></td>
<td>12/4 @05:20</td>
<td>12/2 @11:15</td>
</tr>
<tr>
<td><strong>SPP Load</strong></td>
<td>23,591 MW</td>
<td>26,470 MW</td>
</tr>
<tr>
<td><strong>Wind Output</strong></td>
<td>13,270 MW</td>
<td>638 MW</td>
</tr>
<tr>
<td><strong>Appx Gen Mix</strong></td>
<td></td>
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<tr>
<td>Coal</td>
<td>27%</td>
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<td>Wind</td>
<td>51%</td>
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<tr>
<td>Nat. Gas</td>
<td>11%</td>
<td>22%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>8%</td>
<td>8%</td>
</tr>
<tr>
<td>Hydro</td>
<td>2%</td>
<td>5%</td>
</tr>
</tbody>
</table>
October - December 2017

![Graph showing daily averages of wind output MW and wind penetration percentages from October 1, 2017 to December 31, 2017.](image-url)
Min and Max Percent of Generation Mix Per Fuel Type – Q4 2017

- **Coal**: Min = 24.5%, Max = 66.9%
- **Wind**: Min = 2.4%, Max = 52.9%
- **Natural Gas**: Min = 7.3%, Max = 37.1%
- **Nuclear**: Min = 5.2%, Max = 9.8%
- **Hydro**: Min = 1.1%, Max = 6.3%
Min and Max Percent of Generation Mix Per Fuel Type - 2017

- **Coal**: Percent values range from 20.1% to 70.3%.
- **Wind**: Percent values range from 0.5% to 52.9%.
- **Natural Gas**: Percent values range from 6.0% to 44.8%.
- **Nuclear**: Percent values range from 0.0% to 10.0%.
- **Hydro**: Percent values range from 3.6% to 4.1%.

Fuel Type:
- Coal
- Wind
- Natural Gas
- Nuclear
- Hydro
Integrated Marketplace Enhancements

Recently Implemented:

• RR242 – Regulation Deployment Priority Change

On The Way:

• RR243 – Mitigated Energy Offer for Regulation Deployment Adjustment Settlements
  • Estimated Implementation Q2 2018

• Other MP and SPP requested enhancements

Future:

• RR229 - Order No. 831 Compliance (Offer Caps)

• Quick Start Real-Time Commitment design enhancements
RARTF Update

January 2018 RSC Meeting

Dennis Grennan, RARTF Chair
RARTF Update
RARTF Update - Membership

• Dennis Grennan (NPRB) appointed Chair of RARTF on January 1, 2018
  • Steve Stoll term on the Missouri PSC ended December 13, 2017

• Phil Crissup (OG&E) resigned his RARTF seat effective December 31, 2017

• RARTF Charter states:
  “The RSC and SPP Members representatives shall be appointed by the
  RSC President and MOPC Chairman and shall represent diverse
  members.”

• Next Steps:
  • RSC President Shari Albrecht and MOPC Chair Paul Malone will
    appoint one RSC member and one MOPC member to the RARTF.
RARTF UPdate

• The RARTF has met twice since the October RSC Meeting:
  • December 8, 2017 Conference Call Webex
  • January 15, 2018 - Dallas Texas

• Major Topics of Discussion:
  • SPP/AECI Seams Remedy Project
  • RCAR Frequency Filing at FERC
  • RCAR III Options
RARTF Update – SPP/AECI Seams Projects

• Brookline Reactor Project
  • Addition of a 50 MVAR Reactor at City Utilities Brookline 345 kV substation
  • Wholly on SPP’s Transmission System
  • $5M Cost Estimate
  • SPP Responsible for $4.85M (97%)

• This project is being evaluated in the 2018 ITP Near Term; July 2018
  • If approved in the planning process; no further FERC filing is necessary.
RARTF Update – SPP/AECI Seams Projects

• Morgan Transformer Project
  • Addition of a new 400 MVA 345/161 kV Transformer at AECI’s Morgan substation and an uprate of the 161 kV line between Morgan and Brookline
  • Wholly on AECI’s Transmission System
  • $13.75M Cost Estimate
    • SPP Responsible for $12.25M (89%)

• Staff visited with FERC January 10, 2018 regarding this project
  • Staff believes another filing at FERC to establish cost allocation for this project is warranted.
  • Staff will provide additional justification
  • Staff determining timing on the next filing

• RARTF Motion: The RARTF supports SPP refiling the Morgan Transformer seams project with FERC seeking approval. The RARTF notes the benefits the Morgan Transformer would have for improving RCAR benefits for the region.
D. Review of Base Plan Allocation Methodology

1. The Transmission Provider shall review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every six three years in accordance with this Section III.D. The Transmission Provider and/or the Regional State Committee may initiate such review at any time. Any change in the regional allocation methodology and factors or the zonal allocation methodology shall be filed with the Commission.
RARTF Update – RCAR Frequency

- 2/17/17 – RARTF voted unanimously to recommend the RCAR analysis move to a six year cycle.
- 3/23/17 – RTWG tabled vote on RR-223 pending RSC and MOPC policy decision
- 4/4/17 – CAWG reviewed and took no action on RR-223
- 4/11/17 – MOPC approved policy and language for RR-223
- 4/17/17 – RSC approved policy for RR-223
- 4/18/17 – RTWG approved tariff language for RR-223
- 4/25/17 – BOD approved RR-223
- 8/02/17 – Tariff Language filed at FERC (ER17-2229)
  - Comment period ended 8/23/2017
  - One protest: Sunflower/Mid-Kansas
- 9/29/17 – FERC Order Accepting Tariff Revisions
- 10/30/17 – Request for Rehearing – Sunflower/MKEC
- 11/29/17 – FERC issued “Tolling Order” on Request for Rehearing
RARTF Update – RCAR III Options

• Staff has provided 4 options to the RARTF for consideration:
  1. Planning Based (Status Quo)
  2. Operations Based
  3. Operations Based (Historical Only)
  4. Hybrid (Operations/Planning Based)

• Staff was directed to provide more analysis in the January 15 meeting
  • Staff provided results of a “limited proof of concept” using the market engine to provide Adjusted Production Cost savings
  • Staff comfortable that this process is feasible

• Next Steps – April 4, 2018 Conference Call
  • Strawman Proposal: Option 4 Hybrid (Operations/Planning Based) to include:
    • Cost and Schedule
    • Stakeholder Group involvement
    • Inclusion of RCAR II Lessons Learned
SPP-AECI Joint Projects
Morgan Transformer Project

- Addition of a new 400 MVA 345/161 kV Transformer at AECI’s Morgan substation and an uprate of the 161 kV line between Morgan and Brookline
  - Located in southwest Missouri
  - Wholly on AECI’s transmission system
  - $13.75M Cost Estimate
Brookline Reactor Project

- Addition of a 50 MVAR Reactor at City Utilities Brookline 345 kV substation
  - Located in southwest Missouri
  - Wholly on SPP’s transmission system
  - $5.0M Study-level Cost Estimate
Approvals

• **SPP Board of Directors**
  - Approved the Morgan Transformer Project as a part of the 2017 SPP ITP10 Portfolio
  - Approved Regional Cost Allocation of the Morgan Transformer Project
  - Approved the Brookline Reactor Project out of the Regional Review of the SPP-AECI JCSP

• **Regional State Committee**
  - Approved Regional Cost Allocation of the Morgan Transformer Project

• **AECI Board of Directors**
  - Met on May 24th, 2017 to approve AECI’s participation in both the Morgan Transformer and Brookline Reactor Projects
2016 SPP-AECI Joint Projects

- SPP and AECI agreed to two joint projects out of the 2016 SPP-AECI Joint and Coordinated System Plan (JCSP)

- **Morgan Transformer Project**
  - Addition of a new 400 MVA 345/161 kV Transformer at AECI’s Morgan substation and an uprate of the 161 kV line between Morgan and Brookline
  - Wholly on AECI’s Transmission System
  - $13.75M Cost Estimate
    - SPP Responsible for $12.25M (89%)

- **Brookline Reactor Project**
  - Addition of a 50 MVAR Reactor at City Utilities Brookline 345 kV substation
  - Wholly on SPP’s Transmission System
  - $5M Cost Estimate
    - SPP Responsible for $4.85M (97%)
FERC Filings for Joint Projects with AECI

- SPP made filings at FERC for the two projects on August 7, 2017
  - Approval of SPP-AECI Joint Projects
  - Cost Sharing between SPP and AECI
  - SPP Regional Cost Allocation of both projects
  - Other Issues Related to the Treatment of the Projects
  - Docket Numbers ER17-2256 & ER17-2257

- Comments received in support of the filing
  - City Utilities, AECI, Missouri PSC, Southwestern Power Administration & South Central MCN

- Comments received in protest of the filing
  - Xcel & Westar
Summary of FERC’s Order

• FERC issued an order rejecting SPP’s filing on October 6, 2017

• The Commission rejected SPP’s proposal for region-wide / load-ratio share funding for SPP’s portion of the costs for the two joint projects
  • “SPP has not shown that the proposed cost allocation for these specific non-Order No. 1000 projects, and the allocation of SPP’s share of the costs of these projects on a region-wide, load-ratio share basis, is roughly commensurate with the projects’ benefits…”

• The order did not preclude SPP from making additional filings to the Commission to support region-wide funding or propose a new cost allocation for the two joint projects
  • “Our rejection of SPP’s proposal in these dockets does not preclude SPP from making a filing with the Commission demonstrating that the Morgan Transformer Project and Brookline Reactor Project provide regional benefits or proposing an alternative allocation of its share of the costs of these transmission projects that is roughly commensurate with the benefits”
Next Steps

• SPP staff is continuing to review the Commission’s order and determining the best path forward for the two joint projects with AECI

• SPP staff is continuing to work on the best path forward for Non Order 1000 Joint Projects
Next Steps – Brookline Reactor

- Being Studied in current ITP
- Estimated Decision July 2018
- If approved: Highway Funding
- Per SPP’s Tariff no FERC Filing
Next Steps – Morgan Transformer Project

- SPP’s tariff has no method to cost allocate this project
- Requires a FERC filings
- SPP Stakeholder’s (RSC supports Highway Funding
- Seeking FERC Advice
FIRST QUARTERLY
PROJECT TRACKING
REPORT 2018

January 2018
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EXECUTIVE SUMMARY

SPP actively monitors and supports the progress of transmission expansion projects, emphasizing the importance of maintaining accountability for areas such as regional grid reliability standards, firm transmission commitments, and Tariff cost recovery.

SPP staff solicits quarterly feedback from the project owners to determine the progress of each approved transmission project. This quarterly report charts the progress of all SPP Transmission Expansion Plan (STEP) projects approved by the SPP Board of Directors (Board) or through a FERC filed service agreement under the SPP Open Access Transmission Tariff (OATT).

The reporting period is August 1, 2017 through October 31, 2017. Table 1 provides a summary of all projects in the current Project Tracking Portfolio (PTP), which includes all Network Upgrades in which construction activities are ongoing, or construction has completed but not all the close-out requirements have been fulfilled in accordance with Section 13 of Business Practice 7060. The PTP includes all active Network Upgrades including transmission lines, transformers, substations, and devices.

Table 1 below summarizes the PTP for this quarter. Figures 1 reflects the percentage cost of each upgrade type in the PTP. Figure 2 shows the percentage cost of each project status in the PTP.

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>No. of Upgrades</th>
<th>Estimated Cost</th>
<th>Miles of New</th>
<th>Miles of Rebuild</th>
<th>Miles of Voltage Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic</td>
<td>23</td>
<td>$74,829,382</td>
<td>1.9</td>
<td>0.0</td>
<td>28.8</td>
</tr>
<tr>
<td>High Priority</td>
<td>61</td>
<td>$1,114,960,503</td>
<td>757.7</td>
<td>5.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>351</td>
<td>$3,214,044,137</td>
<td>1598.4</td>
<td>423.6</td>
<td>457.1</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>18</td>
<td>$100,495,428</td>
<td>12.9</td>
<td>15.3</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>8</td>
<td>$138,128,100</td>
<td>28.0</td>
<td>26.9</td>
<td>0.0</td>
</tr>
<tr>
<td>NTC Projects Subtotal</td>
<td>461</td>
<td>$4,642,457,550</td>
<td>2399.0</td>
<td>470.9</td>
<td>485.9</td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>84</td>
<td>$256,476,756</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>1</td>
<td>$7,107,090</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>TO - Sponsored</td>
<td>3</td>
<td>$16,719,000</td>
<td>10.7</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Non-NTC Projects Subtotal</td>
<td>88</td>
<td>$280,302,846</td>
<td>10.7</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Total</td>
<td>549</td>
<td>$4,922,760,396</td>
<td>2409.7</td>
<td>470.9</td>
<td>485.9</td>
</tr>
</tbody>
</table>

Table 1: Q1 2018 Portfolio Summary
Figure 1: Percentage of Project Type on Cost Basis

Figure 2: Percentage of Project Status on Cost Basis
In adherence to the OATT and Business Practice 7060, SPP issues Notifications to Construct (NTCs) to Designated Transmission Owners (DTOs) to begin work on Network Upgrades that have been approved or endorsed by the SPP Board to meet the construction needs of the STEP, OATT, or Regional Transmission Organization (RTO).

Figure 3 reflects project status within each source study, and Table 2 provides the supporting data. Figure 4 shows the amount of estimated cost by in-service year for all Network Upgrades that have been issued an NTC or Notifications to Construct with Conditions (NTC-C). **Note: Figures 3 and 4, and Table 2 provide data for all projects for which SPP has issued an NTC or NTC-C, regardless of completion date, and therefore include data from Network Upgrades no longer included in PTP.**
<table>
<thead>
<tr>
<th>Source Study</th>
<th>Complete</th>
<th>Delayed</th>
<th>Suspended</th>
<th>On Schedule</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006 STEP</td>
<td>$202,493,500</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$202,493,500</td>
</tr>
<tr>
<td>2007 STEP</td>
<td>$498,368,218</td>
<td>$393,563</td>
<td>$0</td>
<td>$0</td>
<td>$498,761,781</td>
</tr>
<tr>
<td>2008 STEP</td>
<td>$415,126,157</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$415,126,157</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>$834,720,484</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$834,720,484</td>
</tr>
<tr>
<td>2009 STEP</td>
<td>$533,469,214</td>
<td>$1,441,050</td>
<td>$0</td>
<td>$0</td>
<td>$534,910,264</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>$1,348,761,003</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$1,348,761,003</td>
</tr>
<tr>
<td>2010 STEP</td>
<td>$109,968,782</td>
<td>$4,041,273</td>
<td>$0</td>
<td>$0</td>
<td>$114,010,055</td>
</tr>
<tr>
<td>2012 ITPNT</td>
<td>$182,110,561</td>
<td>$4,294,271</td>
<td>$0</td>
<td>$0</td>
<td>$186,404,832</td>
</tr>
<tr>
<td>2012 ITP10</td>
<td>$105,901,240</td>
<td>$342,148,981</td>
<td>$0</td>
<td>$295,933,246</td>
<td>$743,983,467</td>
</tr>
<tr>
<td>2013 ITPNT</td>
<td>$333,999,035</td>
<td>$130,387,317</td>
<td>$0</td>
<td>$33,289,587</td>
<td>$497,675,939</td>
</tr>
<tr>
<td>2014 ITPNT</td>
<td>$257,913,185</td>
<td>$271,353,382</td>
<td>$0</td>
<td>$53,073,689</td>
<td>$582,340,256</td>
</tr>
<tr>
<td>HPILS</td>
<td>$214,658,160</td>
<td>$157,726,337</td>
<td>$0</td>
<td>$285,465,421</td>
<td>$657,849,918</td>
</tr>
<tr>
<td>2015 ITPNT</td>
<td>$88,084,589</td>
<td>$119,077,120</td>
<td>$0</td>
<td>$7,342,119</td>
<td>$214,503,828</td>
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<td>2015 ITP10</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$50,553,697</td>
</tr>
<tr>
<td>IS Integration Study</td>
<td>$223,284,902</td>
<td>$38,000,000</td>
<td>$0</td>
<td>$111,000,000</td>
<td>$372,284,902</td>
</tr>
<tr>
<td>2016 ITPNT</td>
<td>$79,924,328</td>
<td>$428,831,040</td>
<td>$0</td>
<td>$14,675,075</td>
<td>$523,430,443</td>
</tr>
<tr>
<td>2017 ITP10</td>
<td>$0</td>
<td>$13,975,764</td>
<td>$0</td>
<td>$0</td>
<td>$13,975,764</td>
</tr>
<tr>
<td>2017 ITPNT</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$17,077,427</td>
<td>$17,077,427</td>
</tr>
<tr>
<td>Ag Studies</td>
<td>$715,580,900</td>
<td>$100,245,986</td>
<td>$0</td>
<td>$86,871,775</td>
<td>$901,698,661</td>
</tr>
<tr>
<td>DPA Studies</td>
<td>$180,276,593</td>
<td>$15,339,894</td>
<td>$0</td>
<td>$7,282,123</td>
<td>$202,898,610</td>
</tr>
<tr>
<td>GI Studies</td>
<td>$629,412,971</td>
<td>$10,273,744</td>
<td>$0</td>
<td>$177,706,865</td>
<td>$817,393,580</td>
</tr>
<tr>
<td>Total</td>
<td>$6,954,053,822</td>
<td>$1,637,529,722</td>
<td>$0</td>
<td>$1,139,271,022</td>
<td>$9,730,854,566</td>
</tr>
</tbody>
</table>

Table 2: Project Status by NTC Source Study

Figure 4: Estimated Cost for NTC Project per In-Service Year
**NTC ISSUANCE**

Three new NTCs were issued in the reporting period totaling an estimated $31.2 million.

One new NTCs were issued as a result of the Board’s approval of the 2017 Integrated Transmission Planning Near-Term Assessment (ITPNT). Total estimated cost of upgrades described in that NTCs are $21.8 million.

One new NTC was issued as a result of Aggregate Study 2016-AG2-AFS-2. Total estimated costs for upgrades resulting from this NTC are $9.2 million.

One NTC was issued resulting from Generation Interconnection study GEN-2015-016. Total estimated cost of the Network Upgrades are $110 thousand.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>Owner</th>
<th>NTC Issue Date</th>
<th>Upgrade Type</th>
<th>Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of New Upgrades</th>
<th>Estimated Cost of Previously Approved Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200462</td>
<td>CPEC</td>
<td>8/2/2017</td>
<td>Regional Reliability</td>
<td>2017 ITPNT</td>
<td>2</td>
<td>$21,780,000</td>
<td></td>
</tr>
<tr>
<td>200463</td>
<td>WR</td>
<td>8/16/2017</td>
<td>Generation Interconnection</td>
<td>GEN-2015-016</td>
<td>1</td>
<td>$110,000</td>
<td></td>
</tr>
<tr>
<td>200466</td>
<td>WR</td>
<td>9/21/2017</td>
<td>Regional Reliability</td>
<td>2016-AG2-AFS-2</td>
<td>4</td>
<td>$9,260,540</td>
<td></td>
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<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Total</td>
<td>$9,370,540</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$21,780,000</td>
</tr>
</tbody>
</table>

**Table 3: NTC Issuance Summary**

**NTC WITHDRAW**

One NTC was withdrawn for one Network Upgrade during the reporting period, totaling an estimated $145.8 thousand. The NTC for this upgrade was issued out of Aggregate Study 2015-AG1-AFS-6 and is no longer needed.

Table 4 lists the NTC Withdraw activity during the reporting period. NTC ID values in **bold** font indicate NTC-Cs.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>Owner</th>
<th>NTC Withdraw Date</th>
<th>Upgrade Type</th>
<th>Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of Withdrawn Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200464</td>
<td>WR</td>
<td>9/21/2017</td>
<td>Transmission Service</td>
<td>SPP-2015-AG1-AFS-6</td>
<td>1</td>
<td>$145,773</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Total</td>
</tr>
</tbody>
</table>

**Table 4: NTC Withdraw Summary**
**COMPLETED PROJECTS**
Six Network Upgrades with NTCs were verified as completed during the reporting period, totaling an estimated $39.4 million.

Table 5 lists the Network Upgrades reported and confirmed as completed during the reporting period. Table 6 summarizes the completed projects over the previous year, including Network Upgrades not yet confirmed as completed. Figure 5 reflects the completed projects by upgrade type on a cost basis for the current year and the following year based on current projected in-service dates. Tables 7 and 8 summarize all Network Upgrades that include construction of transmission lines, both for the current year and the following year. **Note: Previous quarter’s updated results are listed as the Transmission Owners may make adjustments to final costs and status of projects completed during the year.**

<table>
<thead>
<tr>
<th>UID</th>
<th>Network Upgrade Name</th>
<th>Owner</th>
<th>NTC Source Study</th>
<th>Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>50608</td>
<td>Bobcat Canyon 345/115 kV Transformer Ckt 1</td>
<td>NPPD</td>
<td>2014 ITPNT</td>
<td>$5,928,480</td>
</tr>
<tr>
<td>50609</td>
<td>Bobcat Canyon - Scottsbluff 115 kV Ckt 1</td>
<td>NPPD</td>
<td>2014 ITPNT</td>
<td>$23,700,242</td>
</tr>
<tr>
<td>50616</td>
<td>Bobcat Canyon 345 kV Terminal Upgrades</td>
<td>NPPD</td>
<td>2014 ITPNT</td>
<td>$4,072,936</td>
</tr>
<tr>
<td>51474</td>
<td>Minco 345kV Substation GEN-2014-056 Addition (TOIF)</td>
<td>OGE</td>
<td>GI Studies</td>
<td>$5,000</td>
</tr>
<tr>
<td>51509</td>
<td>Berthold - Southwest Minot 115 kV Ckt 1 Reconductor</td>
<td>BEPC</td>
<td>2016 ITPNT</td>
<td>$2,876,720</td>
</tr>
<tr>
<td>71925</td>
<td>Tap Coyote-Medford Tap 138kV - GEN-2015-015 Addition (NU)</td>
<td>OGE</td>
<td>GI Studies</td>
<td>$2,840,000</td>
</tr>
</tbody>
</table>

**Table 5: Completed Network Upgrades as of Q4 2017**

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Q1 2017</th>
<th>Q2 2017</th>
<th>Q3 2017</th>
<th>Q4 2017</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
<td>9</td>
<td>16</td>
<td>13</td>
<td>11</td>
<td>49</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>$98,767,760</td>
<td>$112,710,788</td>
<td>$42,899,461</td>
<td>$157,568,378</td>
<td>$411,946,387</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>$0</td>
<td>$228,364</td>
<td>$0</td>
<td>$0</td>
<td>$228,364</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>High Priority</td>
<td>8</td>
<td>0</td>
<td>5</td>
<td>0</td>
<td>13</td>
</tr>
<tr>
<td>High Priority</td>
<td>$523,778,049</td>
<td>$0</td>
<td>$36,074,471</td>
<td>$0</td>
<td>$559,852,520</td>
</tr>
<tr>
<td>Economic</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td>Economic</td>
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<td>$0</td>
<td>$0</td>
<td>$0</td>
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<tr>
<td>Zonal Reliability</td>
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<td>0</td>
<td>0</td>
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<tr>
<td>Zonal Reliability</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>11</td>
<td>8</td>
<td>11</td>
<td>14</td>
<td>44</td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>$28,039,697</td>
<td>$14,242,460</td>
<td>$38,872,518</td>
<td>$39,126,045</td>
<td>$120,280,720</td>
</tr>
</tbody>
</table>

**Table 6: Completed Project Summary as of Q4 2017**
Southwest Power Pool, Inc.

**Figure 5: Completed Upgrades by Type per Quarter**

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>New</th>
<th>Rebuild/Reconductor</th>
<th>Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>6</td>
<td>7.9</td>
<td>30.4</td>
<td>69.0</td>
<td>$47,667,540</td>
</tr>
<tr>
<td>115</td>
<td>12</td>
<td>67.8</td>
<td>42.6</td>
<td>0.0</td>
<td>$91,410,897</td>
</tr>
<tr>
<td>138</td>
<td>3</td>
<td>27.5</td>
<td>16.5</td>
<td>138.0</td>
<td>$33,750,509</td>
</tr>
<tr>
<td>161</td>
<td>1</td>
<td>0.0</td>
<td>11.1</td>
<td>0.0</td>
<td>$12,705,537</td>
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<td>230</td>
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<td>32.0</td>
<td>0.0</td>
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<td>$44,100,000</td>
</tr>
<tr>
<td>345</td>
<td>6</td>
<td>377.7</td>
<td>0.0</td>
<td>0.0</td>
<td>$633,456,253</td>
</tr>
<tr>
<td>Total</td>
<td>30</td>
<td>512.9</td>
<td>100.7</td>
<td>207.0</td>
<td>$863,090,736</td>
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</table>

**Table 7: Line Upgrade Summary for Previous 12 Months**

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>New</th>
<th>Rebuild/Reconductor</th>
<th>Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>9</td>
<td>3.9</td>
<td>40.0</td>
<td>69.0</td>
<td>$64,345,742</td>
</tr>
<tr>
<td>115</td>
<td>20</td>
<td>149.7</td>
<td>29.9</td>
<td>13.0</td>
<td>$151,493,161</td>
</tr>
<tr>
<td>138</td>
<td>11</td>
<td>110.0</td>
<td>2.4</td>
<td>0.0</td>
<td>$102,067,394</td>
</tr>
<tr>
<td>161</td>
<td>1</td>
<td>17.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$29,069,150</td>
</tr>
<tr>
<td>230</td>
<td>2</td>
<td>18.8</td>
<td>0.0</td>
<td>0.0</td>
<td>$31,270,623</td>
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<td>345</td>
<td>12</td>
<td>329.5</td>
<td>0.0</td>
<td>28.8</td>
<td>$408,278,114</td>
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<tr>
<td>Total</td>
<td>55</td>
<td>628.9</td>
<td>72.3</td>
<td>110.8</td>
<td>$786,524,183</td>
</tr>
</tbody>
</table>

**Table 8: Line Upgrade Projections for Next 12 Months**
**PROJECT STATUS SUMMARY**

SPP assigns a project status to all Network Upgrades based on the projected in-service dates provided by the DTOs relative to the Need Date determined for the project. Project status definitions are provided below:

- **Complete**: Construction complete and in-service
- **Closed Out**: Construction complete and in-service; all close-out requirements fulfilled
- **On Schedule < 4**: On Schedule within 4-year horizon
- **On Schedule > 4**: On Schedule beyond 4-year horizon
- **Delayed**: Projected In-Service Date beyond Need Date; interim mitigation provided or project may change but time permits the implementation of project
- **Within NTC Commitment Window**: NTC/NTC-C issued, still within the 90-day written commitment to construct window and no commitment received
- **Within NTC-C Project Estimate Window**: Within the NTC-C Project Estimate (CPE) window
- **Within RFP Response Window**: RFP issued for the project
- **Re-evaluation**: Project active; pending re-evaluation
- **Suspended**: Project suspended; pending re-evaluation

Figure 6 reflects a summary of project status by upgrade type on a cost basis.
OUT-OF-BANDWIDTH PROJECTS

In adherence to the Business Practice 7060, SPP reports projects that have updated cost values that exceed their established baseline values based upon a ±20% bandwidth. Variances are determined by total project cost.

Seven projects with a cost estimate greater than $5 million were identified as having exceeded the ±20% bandwidth requirement during the reporting period.

Table 9 provides summary information and Table 10 lists cost detail for out-of-bandwidth projects for Q4 2017.

<table>
<thead>
<tr>
<th>PID</th>
<th>Project Name</th>
<th>Owner</th>
<th>NTC Source Study</th>
<th>Upgrade Type</th>
<th>In-Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>30596</td>
<td>Multi - Broken Bow Wind - Ord 115 kV Ckt 1</td>
<td>NPPD</td>
<td>2014 ITPNT</td>
<td>Regional Reliability</td>
<td>6/1/2018</td>
</tr>
<tr>
<td>30637</td>
<td>Multi - Hobbs - Kiowa 345 kV Ckt 1</td>
<td>SPS</td>
<td>HPILS</td>
<td>High Priority</td>
<td>4/30/2018</td>
</tr>
<tr>
<td>30817</td>
<td>Line - Canyon West - Dawn - Panda - Deaf Smith 115 kV Ckt 1 Rebuild</td>
<td>SPS</td>
<td>2016 ITPNT</td>
<td>Regional Reliability</td>
<td>12/15/2018</td>
</tr>
<tr>
<td>1001</td>
<td>Line - Randall - South Georgia and Osage Station 115 kV Line Re-termination</td>
<td>SPS</td>
<td>Ag Studies</td>
<td>Regional Reliability</td>
<td>4/19/2017</td>
</tr>
<tr>
<td>30694</td>
<td>Multi - Ponderosa - Ponderosa Tap 115 kV</td>
<td>SPS</td>
<td>HPILS</td>
<td>High Priority</td>
<td>6/1/2017</td>
</tr>
<tr>
<td>30988</td>
<td>Sub - Eddy Co. 230 kV Bus Tie</td>
<td>SPS</td>
<td>Ag Studies</td>
<td>Transmission Service</td>
<td>11/30/2019</td>
</tr>
</tbody>
</table>

Table 9: Out-of-Bandwidth Project Summary

<table>
<thead>
<tr>
<th>PID</th>
<th>Baseline Cost Estimate</th>
<th>Baseline Cost Estimate Year</th>
<th>Baseline Cost Estimate with Escalation</th>
<th>Latest Estimate or Final Cost</th>
<th>Variance</th>
<th>Variance %</th>
</tr>
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<tbody>
<tr>
<td>30596</td>
<td>$34,593,371</td>
<td>2014</td>
<td>$37,253,277</td>
<td>$(8,718,604)</td>
<td>-23.40%</td>
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</tr>
<tr>
<td>30637</td>
<td>$71,058,482</td>
<td>2014</td>
<td>$76,522,213</td>
<td>$(17,755,172)</td>
<td>-23.20%</td>
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</tr>
<tr>
<td>30817</td>
<td>$19,159,617</td>
<td>2016</td>
<td>$19,638,607</td>
<td>$(6,851,373)</td>
<td>-34.89%</td>
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<tr>
<td>1001</td>
<td>$10,316,217</td>
<td>2016</td>
<td>$10,574,122</td>
<td>$2,605,086</td>
<td>24.64%</td>
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</tr>
<tr>
<td>30694</td>
<td>$13,201,633</td>
<td>2014</td>
<td>$14,216,715</td>
<td>$(3,994,351)</td>
<td>-28.10%</td>
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<tr>
<td>30988</td>
<td>$10,425,309</td>
<td>2016</td>
<td>$10,685,942</td>
<td>$5,243,079</td>
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<tr>
<td>31127</td>
<td>$3,872,285</td>
<td>2017</td>
<td>$5,400,044</td>
<td>$1,527,759</td>
<td>39.45%</td>
<td></td>
</tr>
</tbody>
</table>

Table 10: Out-of-Bandwidth Project Cost Detail
Table 11 and Figures 7 and 8 provide insight into the responsiveness of DTOs constructing Network Upgrades within SPP in the Quarterly Project Tracking Report for Q3 2017. **Note:** Network Upgrades with statuses of “Suspended”, “Re-evaluation”, “Within NTC Commitment Window”, “Within NTC-C Project Estimate Window”, and “Within RFP Response Window” were excluded from this analysis.

<table>
<thead>
<tr>
<th>Project Owner</th>
<th>Number of Upgrades</th>
<th>Number of Upgrades Reviewed</th>
<th>Reviewed %</th>
<th>In-Service Date Changes</th>
<th>ISD Change %</th>
<th>Cost Changes</th>
<th>Cost Change %</th>
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<tr>
<td>AEP</td>
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<td>61</td>
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<td>2</td>
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<td>2%</td>
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<tr>
<td>BEPC</td>
<td>24</td>
<td>8</td>
<td>33%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
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<tr>
<td>GMO</td>
<td>2</td>
<td>2</td>
<td>100%</td>
<td>1</td>
<td>50%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>GRDA</td>
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<td>10%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>ITCGP</td>
<td>7</td>
<td>2</td>
<td>29%</td>
<td>2</td>
<td>29%</td>
<td>2</td>
<td>29%</td>
</tr>
<tr>
<td>KCPL</td>
<td>8</td>
<td>8</td>
<td>100%</td>
<td>1</td>
<td>13%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>LES</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>MIDW</td>
<td>11</td>
<td>11</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>3</td>
<td>27%</td>
</tr>
<tr>
<td>MKEC</td>
<td>7</td>
<td>7</td>
<td>100%</td>
<td>1</td>
<td>14%</td>
<td>7</td>
<td>100%</td>
</tr>
<tr>
<td>NPPD</td>
<td>38</td>
<td>20</td>
<td>53%</td>
<td>3</td>
<td>8%</td>
<td>3</td>
<td>8%</td>
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<tr>
<td>OGE</td>
<td>47</td>
<td>5</td>
<td>11%</td>
<td>4</td>
<td>9%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>OPPD</td>
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<td>14</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>SPS</td>
<td>185</td>
<td>183</td>
<td>99%</td>
<td>35</td>
<td>19%</td>
<td>49</td>
<td>26%</td>
</tr>
<tr>
<td>TSMO</td>
<td>7</td>
<td>7</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>1</td>
<td>14%</td>
</tr>
<tr>
<td>WFEC</td>
<td>29</td>
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<tr>
<td>WR</td>
<td>38</td>
<td>37</td>
<td>97%</td>
<td>4</td>
<td>11%</td>
<td>6</td>
<td>16%</td>
</tr>
<tr>
<td>Total</td>
<td>501</td>
<td>379</td>
<td>76%</td>
<td>55</td>
<td>11%</td>
<td>87</td>
<td>17%</td>
</tr>
</tbody>
</table>

Table 11: Responsiveness Summary by Project Owner
Figure 7: In-Service Date Changes by Project Owner

Figure 8: Cost Changes by Project Owner
APPENDIX 1

{See accompanying list of active Applicable Projects}
<table>
<thead>
<tr>
<th>NTC_ID</th>
<th>State(s)</th>
<th>Project Name</th>
<th>Converter Center</th>
<th>Voltage</th>
<th>Project Status</th>
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<tbody>
<tr>
<td>200379</td>
<td>OK</td>
<td>Terminal Upgrades</td>
<td>Arkansas City - Paris</td>
<td>69 kV</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>200167</td>
<td>TX</td>
<td>Line - Diana - Perdue</td>
<td>Diana - Perdue</td>
<td>138 kV</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>200208</td>
<td>OK</td>
<td>Multi - Payne Switching Station - OU</td>
<td>Payne Switching Station</td>
<td>138 kV</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>20126</td>
<td>KS</td>
<td>XFR - Colby</td>
<td>Colby 115/34.5 kV Transformer Ckt 4</td>
<td>115/69 kV</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>20110</td>
<td>OK</td>
<td>Line - Arcadia - Redbud</td>
<td>Arcadia - Redbud 345 kV Ckt 3</td>
<td>345 kV</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>20132</td>
<td>OK</td>
<td>Line - Alva - Freedom</td>
<td>Alva - Freedom 69 kV Ckt 1</td>
<td>69 kV</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>200167</td>
<td>TX</td>
<td>Line - Diana - Perdue</td>
<td>Diana - Perdue 138 kV Ckt 1</td>
<td>138 kV</td>
<td>COMPLETE</td>
</tr>
</tbody>
</table>

**Conversion Centre St. - Hereford NE 115 kV Ckt 1 Regional Reliability 3/30/2018 6/1/2014 2/19/2014 2014 ITPNT $9,247,136 2014 $9,958,154 $10,699,546 $10,699,546**

**Complete 138**

**115 9 COMPLETE 115**

**230/115 COMPLETE**

**115 4 COMPLETE**


**< 4 COMPLETE**

**< COMPLETE**
<table>
<thead>
<tr>
<th>PID</th>
<th>CNT</th>
<th>State</th>
<th>Project Name</th>
<th>Project Description</th>
<th>Type</th>
<th>Start Date (Year)</th>
<th>Estimated Start Date (Year)</th>
<th>Estimated End Date (Year)</th>
<th>End Date (Year)</th>
<th>Cost Est (Year)</th>
<th>Cost Est (Year)</th>
<th>Cost Est (Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>200221 30367 50429</td>
<td>ON</td>
<td>KS</td>
<td></td>
<td>Conversion Project</td>
<td>Rebuild/Reconstructor</td>
<td>345 kV Elm Creek - Summit Ckt 1</td>
<td>Regional Reliability</td>
<td>12/31/2016</td>
<td>3/1/2018</td>
<td>3/21/2013</td>
<td>2012 ITP10</td>
<td>$66,202,442</td>
</tr>
<tr>
<td>200212 30369 10425</td>
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<td>KS</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>XFR - Moundridge 138/115 kV Transformer Ckt 2</td>
<td>Regional Reliability</td>
<td>4/7/2015</td>
<td>6/1/2013</td>
<td>2/20/2013</td>
<td>2013 ITPNT</td>
<td>$19,770,066</td>
</tr>
<tr>
<td>200214 30424 50517</td>
<td>ON</td>
<td>TX/OK</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Line - Ochiltree - Tri-County Cole 115 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>11/20/2015</td>
<td>6/1/2013</td>
<td>2/20/2013</td>
<td>2013 ITPNT</td>
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</tr>
<tr>
<td>200241 30438 50533</td>
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<td>OK</td>
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<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Line - Kerr - 412 Sub 161 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>6/1/2017</td>
<td>6/1/2017</td>
<td>2/19/2014</td>
<td>2014 ITPNT</td>
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<tr>
<td>200214 30451 50546</td>
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<td>NM</td>
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<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Line - Atoka - Eagle Creek 115 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>12/31/2018</td>
<td>6/1/2015</td>
<td>2/20/2013</td>
<td>2013 ITPNT</td>
<td>$20,808,304</td>
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<tr>
<td>200229 30469 50565</td>
<td>ON</td>
<td>NM</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Multi - Kilgore Switch - South Portales - Market St. - Portales 115 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>2/7/2018</td>
<td>6/1/2018</td>
<td>9/10/2013</td>
<td>2013 ITPNT</td>
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</tr>
<tr>
<td>200216 30474 50570</td>
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<td>AR</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Line - Midland - Midland REC 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>5/15/2015</td>
<td>6/1/2013</td>
<td>2/20/2013</td>
<td>2013 ITPNT</td>
<td>$5,653,353</td>
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<tr>
<td>200228 30484 50584</td>
<td>ON</td>
<td>KS</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Multi - Viola 345/138kV Transformer and 138 kV Lines to Clearwater and Gill Ckt 1</td>
<td>Regional Reliability</td>
<td>12/31/2018</td>
<td>6/1/2018</td>
<td>9/10/2013</td>
<td>2013 ITPNT</td>
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<tr>
<td>200400 30496 50608</td>
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<td>NE</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Multi - Bobcat Canyon 345/115 kV and Bobcat Canyon - Scottsbluff 115 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>10/26/2017</td>
<td>6/1/2014</td>
<td>8/17/2016</td>
<td>2014 ITPNT</td>
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<tr>
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<td>Project</td>
<td>Terminal Upgrade</td>
<td>Multi -  Bobcat Canyon 345/115 kV and Bobcat Canyon - Scottsbluff 115 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>10/26/2017</td>
<td>6/1/2014</td>
<td>8/17/2016</td>
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</tr>
<tr>
<td>200420 30513 50640</td>
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<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>XFR - Potash Junction 230/115 kV Transformer Upgrade</td>
<td>Regional Reliability</td>
<td>3/15/2022</td>
<td>6/1/2021</td>
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<td>200246 30574 50719</td>
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<td>TX</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Line - Sandy Corner 138 kV Sandy Corner 138 kV Cap Bank</td>
<td>Regional Reliability</td>
<td>6/1/2017</td>
<td>6/1/2017</td>
<td>2/19/2014</td>
<td>2014 ITPNT</td>
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<td>6/1/2017</td>
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<tr>
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<td>ON</td>
<td>TX</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Line - Daingerfield - Jenkins Rec 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>11/9/2017</td>
<td>6/1/2019</td>
<td>2/19/2014</td>
<td>2014 ITPNT</td>
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</tr>
<tr>
<td>200246 30574 50719</td>
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<td>TX</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Line - Daingerfield - Jenkins Rec 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>11/9/2017</td>
<td>6/1/2019</td>
<td>2/19/2014</td>
<td>2014 ITPNT</td>
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<td>TX</td>
<td></td>
<td>Project</td>
<td>Rebuild/Reconstructor</td>
<td>Line - Daingerfield - Jenkins Rec 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>11/9/2017</td>
<td>6/1/2019</td>
<td>2/19/2014</td>
<td>2014 ITPNT</td>
<td>$2,819,806</td>
</tr>
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<td>Project Type</td>
<td>Start Date</td>
<td>End Date</td>
<td>Stat(s)</td>
<td>Conversion</td>
<td>Outage</td>
<td>Delay</td>
<td>Close Date</td>
</tr>
<tr>
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<td>--------------</td>
<td>-------</td>
<td>--------------</td>
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<td>30</td>
<td>200311</td>
<td>30622</td>
<td>50807</td>
<td>OGE OK</td>
<td>6/1/2018</td>
<td>6/1/2018</td>
<td>12/2/2014</td>
<td>HPILS</td>
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<td></td>
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<tr>
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<td>30</td>
<td>200362</td>
<td>30732</td>
<td>51394</td>
<td>MKEC KS</td>
<td>6/1/2018</td>
<td>6/1/2015</td>
<td>12/21/2015</td>
<td>HPILS</td>
<td></td>
<td></td>
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| UID       | Owner  | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Baseline (as of month) | Baseline (as of month) | Mitigation | Status   | Initial | Date       | Action | Owner     | Cost        | Project Name                                                                 | Base...