Monday, January 26, 2015
1:00 - 5:00 p.m.
Doubletree Dallas
Dallas, TX

1. CALL TO ORDER
2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of Minutes from October 27, 2014 and December 1, 2014
3. UPDATES
   a. RSC Fourth Quarter Financial Report
   b. SPP
   c. FERC
4. BUSINESS MEETING
   a. Auditor Cost for Audit and Taxes for 2014 and Engagement Letter [Voting Item]
5. CAWG REPORT AND VOTING ITEMS
   a. CAWG Report…………………………………………………………………………………………..Jason Chaplin
      This report provides an update on CAWG activity.
   b. Strategic Planning Committee Task Force on New Members
      ……………………………………………………………………………………………………..Dana Murphy and Kristine Schmidt
      This voting item will include the consideration of the RSC’s Action Items from the SPC.
   c. Cost Allocation for Non-Order 1000 Seams Projects………………………………………..Dennis Reed
      This voting item will include an update on the RTWG action following the December 2014 RSC
      and Board of Directors Meetings and consideration of endorsement of TRR 144.
   d. Congestion Rights in Integrated Marketplace…………………………………………………..John Krajewski
      i. Long Term Congestion Rights (MPRR 227)
      ii. Transitional ARR Process (MPRR 221)
      These two voting items are related to the award of congestion rights under the Integrated
      Marketplace. Background information and the CAWG recommendation on these MPRRs will be
      provided.
6. REPORTS/PRESENTATIONS
   a. Integrated Transmission Planning (ITP) Near Term and ITP10 Update and SPP Transmission
      Expansion Plan (STEP)………………………………………………………………………….Lanny Nickell
      This report will provide an update on the ITP Near Term, ITP10-Year and STEP, as well as an
      update on the ITP waiver filing with FERC.
   b. Seams Update…………………………………………………………………………………………..Carl Monroe
      This report will provide an update on the pending matters at FERC related to the MISO Seam, as
      well as an update on the completed SPP-AECI Join Coordinated System Plan Study.
   c. Regional Allocation Review Task Force…………………………………………………………..Richard Ross
This voting item will provide an update on the activities of the RARTF.

d. Integrated Marketplace Update........................................................................................................Bruce Rew
   This report will update the RSC on the Integrated Marketplace.

e. EPA Rule 111(d) Update..................................................................................................................Lanny Nickell
   This report will update the RSC on SPP’s anticipated next steps related to proposed Rule 111(d).

7. OTHER RSC MATTERS

8. ACTION ITEMS

9. SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS
   RSC Meetings:
   March 9, 2015 – Conference Call
   April 27, 2015 – Tulsa, OK
   July 27, 2015 – Kansas City, MO
   October 26, 2015 – Little Rock, AR

10. 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.
Southwest Power Pool

REGIONAL STATE COMMITTEE
Southwest Power Pool Corporate Office
October 27, 2014
• MINUTES •

ADMINISTRATIVE ITEMS:
The following members were in attendance:

Dana Murphy, Oklahoma Corporation Commission (OCC)
Donna Nelson, Public Utility Commission of Texas (PUCT)
Olan Reeves, Arkansas Public Service Commission (APSC)
Stephen Lichter, Nebraska Power Review Board (NPRB)
Steve Stoll, Missouri Public Service Commission (MOPSC)
Shari Feist Albrecht, Kansas Corporation Commission (KCC)
Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)

President Donna Nelson called the Regional State Committee (RSC) meeting to order at 1:12 p.m. with roll call and a quorum was declared. She then requested introductions of those in attendance. There were 127 in attendance, either in person or via the phone (Attendance & Proxies – Attachment 1).

President Nelson requested approval of the following July 28, 2014, August 25, 2014, and September 29, 2014 meeting minutes (RSC Minutes 7/28/14, 8/25/14, 9/29/14 – Attachment 2). Commissioner Steve Lichter moved to approve the three sets of minutes; Commissioner Patrick Lyons seconded. The motion passed unanimously.

UPDATES

RSC Third Quarter Financial Report
Mr. Paul Suskie provided the financial report (RSC 2014 Q3 Financials – Attachment 3). He noted that everything is below budget except travel.

SPP Report
Mr. Nick Brown, Southwest Power Pool, Inc. (SPP), welcomed everyone. Mr. Brown discussed the work that is already going into 75th anniversary book for SPP. He commented on the hard work and the high level of engagement of the RSC and all the things they have done and continue to do. He noted that the RSC is also dealing with an even bigger challenge and that is of 111(d) from the Environmental Protection Agency (EPA). Mr. Brown said that he has been encouraged for SPP to support our states and our members and be in compliance with whatever the final 111(d) regulations are. Mr. Brown reiterated that SPP is very committed to helping our members.

FERC
Mr. Patrick Clarey, Federal Energy Regulatory Commission (FERC) staff, provided an update on recent FERC activities. Mr. Clarey began his report by introducing Ms. Janel Burdick from Commissioner Bay’s office. She is Commissioner Bay’s advisor for SPP, the Western Interconnection, natural gas matters and reliability matters. He noted that Commissioner Bay will succeed Chairman LaFluer as Chair in 2015.
In August FERC approved a settlement agreement between FERC’s Office of Enforcement and the North American Electric Reliability Corporation (NERC) and Imperial Irrigation District that includes a $12 million civil penalty and a number of compliance requirements. The agreement resolved FERC Enforcement staff’s and NERC’s investigation into Imperial’s involvement in the 2011 Southwest blackout in Southern California.

In September the President nominated Arkansas Chair Colette Honorable to fill the unexpired term of former Commissioner John Norris.

Mr. Clarey also stated that FERC accepted in part SPP’s Order 1000 compliance filing. The order granted rehearing to allow SPP to recognize state and local laws and regulations during early stages of the competitive solicitation process. The order also granted rehearing to find that SPP’s Aggregate Study process is not part of SPP’s Order 1000 regional transmission planning process. The Commission determined that the Aggregate Study process is a mechanism for evaluating a discrete group of individual transmission service requests, rather than addressing broader regional needs.

BUSINESS MEETING

Election of RSC Officers for 2015
President Nelson said the first office to be voted on is that of President. She went on to nominate the Commissioner Dana Murphy for RSC President. Commissioner Lyons seconded the motion. President Nelson said that Commissioner Murphy has worked hard on the RSC, has played a leadership role, and has been very helpful. The motion passed.

Commissioner Murphy nominated Commissioner Patrick Lyons for the position of Vice President. Commissioner Lichter seconded the motion. The motion passed.

Commissioner Murphy nominated Commissioner Steve Stoll for the position of Secretary/Treasurer. Commissioner Lyons seconded the motion. The motion passed.

Commissioner Murphy commented on what a great job President Nelson and her staff have done this past year.

Approval of 2015 RSC Budget
President Nelson asked if there was any discussion prior to approving the 2015 RSC budget. Commissioner Lyons proposed two amendments to the budget (RSC Budget Revision Motion 2015 – Attachment 4):

The Technical Conference line item has been in the budget since 2011 and was not utilized in 2012, 2013, or 2014. The item should be removed and zeroed out of the 2015 budget. The Principal Consultant line item is budgeted at $100,000 but only $20,500 has been spent. That should be reduced to $50,000. That takes the budget to a total of $263,300. And it reflects that the RSC is concerned with reducing costs also.

Commissioner Lyons then made a motion to reduce the Principal Consultant Expenses for 2015 from $100,000 to $50,000 and eliminate the expense of $50,000 for the Technical Conference from the 2015 RSC Budget entirely, and approve the 2015 RSC Budget as amended at $263,000. Commissioner Stoll seconded the motion. The motion passed.

REPORTS/PRESENTATIONS

CAWG Report
Cost Allocation Working Group (CAWG) Chair Meena Thomas provided the CAWG report (CAWG Report – Attachment 5). She covered four topics:

1. Cost Allocation for Non-Order 1000 Seams Projects
   a. Seams Steering Committee (SSC) has developed a policy paper regarding seams projects that fall outside the scope of the Order 1000 interregional planning process or that do not meet the Order 1000 criteria.
2. Aggregate Study Waiver Process  
   a. Business Practices Working Group (BPWG) has endorsed changes in the waiver request process. 
   b. The changes are outlined in Business Practice Revision – 051 (BPR-051). The BPR and the tariff revisions needed to implement have yet to be considered by Markets & Operations Policy Committee (MOPC) and the SPP Board. 

3. SPP Regional Order 1000 Process  
   a. Competitive bidding on certain transmission projects in the regional Order 1000 process is expected to take place in 2015. 
   b. An RFP will be issued for each Competitive Upgrade approved by the SPP Board in January 2015. 
   c. Certain issues related to the execution of Order 1000 in states and the RFP/bid approval process are expected to be presented for CAWG consideration. 

4. Potential Issues for Future RSC Consideration  
   a. CAWG members continue to monitor pertinent Working Group/Task Force activity in anticipation of future RSC actions. 
   b. Of relevance are four major issues that will likely come up for RSC consideration within the next year:  
      i. RCAR II Analysis and Results  
      ii. Capacity Margin Requirements  
      iii. Impact of EPA Rule 111(d)  
      iv. State Issues related to Implementation of SPP Regional Order 1000 Process 

Update on Seams Project Policy Paper  
Mr. Paul Malone, Chairman of the SSC, provided the report on the Seams Policy Paper (Seams Project Policy Paper – Attachment 6). Mr. Malone provided some background and updates on the paper.  
- There are still some gaps that remain having to deal with  
  o Projects not meeting Order 1000 criteria (voltage, project type)  
  o Projects with neighboring TOs instead of regions  
  o Seams Projects Task Force (SPTF) chartered by SSC in March 2014  
  o Chartered to develop criteria for seams projects  
    ▪ Project requirements  
    ▪ Planning and approval process  
    ▪ Stakeholder process  
    ▪ Regional cost allocation  
- Approvals and Reviews  
  o SPTF completed draft development in August  
  o CAWG and SSC approval in September  
  o Multiple review at the RSC 

Mr. Malone also reviewed the seams project criteria, cost sharing, regional cost allocation proposal, and stakeholder input. 

Cost Allocation for Non-Order 1000 Seams Projects  
Ms. Meena Thomas provided the report on cost allocation for non-order 1000 seams projects (Cost Allocation for Non-Order 1000 Seams Projects – Attachment 7). Included in this report is the CAWG recommendation to the RSC. The background of the recommendation and the arguments made in support and against Option 1 – which states the following: Assign costs of all Seams Projects to the regional rate (i.e. Highway) for cost allocation for Non-Order 1000 Seams Projects 100 kV and above  
- RSC approved 100% regional allocation of costs related to Order 1000 interregional projects  
- FERC has not issued its decision on the compliance filing  
- SSC identified gaps in the types of projects that can be approved and cost shared through the Interregional Order 1000 process
• SSC developed a policy paper delineating the project criteria
• The SSC and MOPC approved the policy paper by a majority vote

President Nelson made the following clarification that she would like the representations that were discussed today in RCAR be included in the Tariff language.

Commissioner Lichter made a motion to approve Highway funding for all Non-order 1000 Seams projects with a voltage of 100 kV and above provided that tariff language requires RSC review and input before a vote on such projects by the SPP Board if only one SPP zone is found to receive 100% of the SPP allocated benefits. Commissioner Olan Reeves seconded the motion. After a roll-call vote, the motion passed unanimously.

Strategic Planning Committee Task Force on New Members
Mr. Ricky Bittle, Chairman of the SPC, began the report on the Strategic Planning Committee Task Force on New Member Additions (Strategic Planning Committee TF on New Member Additions – Attachment 8). The task force met in October to finalize documents, recommendations, and SPC presentation. Mr. Bittle went over the following items that are under review by the RSC:

1. Can/should RSC, CAWG or State Commission staff attend the SPC meetings' Executive Sessions, and to possibly join the ad hoc Members Forum
   a. Need RSC feedback on preference to participate, and assurance that they can protect the confidential information that may be subject to FOIA and state open meeting laws, and assurance that the confidential information would not be used in other adjudicatory cases
2. When SPP Staff convenes the all-Member special meeting, SPP Staff convene an RSC/CAWG special meeting to follow so that Members and Commissioners/Staff can hear the issues of concern from each other
   a. Need RSC feedback on preference to have a second SPP Staff convened special meeting
3. The Task Force request more information from the RSC as to how it views its role regarding the Bright Line date

Commissioner Murphy thanked Mr. Bittle for all of his hard work on the SPC over the years. She also expressed appreciation to Ms. Kristine Schmidt for all of her hard work on the SPCTF on New Members along with John Bell from Kansas, and Jason Chaplin and Nicole King from Oklahoma, all of whom helped with the SPCTF New Member work.

EPA's Clean Power Plan – SPP Update
Mr. Lanny Nickell, SPP, provided an update on the EPA's Clean Power Plan (EPA’s Clean Power Plan – Attachment 9).

1. Recent Clean Power Plan Activities
   a. SPP completed its reliability assessment of the EPA's projected Electric Generating Unit (EGU) retirements
      i. Two types of assessments
         1. Transmission system impacts
         2. Reserve margin impacts
      ii. Both modeled projected EGU retirements within the SPP region and surrounding areas
         iii. Transmission system impact assessment performed in two parts
            1. Part 1: Assumed unused capacity from generators currently available in SPP’s models would be used to replace retired EGU’s
            2. Part 2: Relied upon both currently available generation and new generation added to replace retired EGU’s
   b. SPP met with FERC to share conclusions and recommendations, submitted its comments and recommendations to the EPA, SPP met with EPA staff
   c. A letter and assessment report have been posted on the SPP website
   d. SPP Reserve Margin Assessment
i. Used currently load forecasts supplied by SPP members
ii. SPP’s minimum required reserve margin is 13.6%
iii. By 2020, SPP’s anticipated reserve margin would be 4.7%, representing a capacity margin deficiency of approximately 4,600 MW
iv. By 2024, SPP’s anticipated reserve margin would be -4.0%, representing a capacity margin deficiency of approximately 10,100 MW
v. Out of 14 load serving members assessed, 9 would be deficient by 2020 and 10 by 2024

2. SPP’s recommendations to EPA
   a. Technical conferences jointly sponsored by FERC and EPA to discuss
      i. Reliability impacts
      ii. Impacts on regional markets
      iii. How to move forward to accomplish both reliability and environmental objectives
   b. Comprehensive nationwide analysis of reliability impacts before final rule issued
   c. Extension of schedule for compliance – at a minimum, interim goals extended at least five years
   d. Adoption of “reliability safety valve”

3. Next Steps for SPP
   a. Cost of Compliance Study
      i. Current scope includes comparison of regional approach and individual state approaches
      ii. Could be used to evaluate mass-based versus rate-based approaches
      iii. Could be used to inform states
      iv. Could be used to develop possible futures for inclusion in the next ITP-10

Commissioner Murphy suggested that the RSC consider writing a letter to send to the EPA and FERC that would address the proposed issues of concern to the RSC. From a high level standpoint of what the comments should contain, Commissioner Murphy talked about the reliability concerns because transmission impacts were not included in part of the models used by the EPA, that the energy efficiency assumptions might not be accurate because assumptions should not treat all of the states the same because each state is in different places, the time frame to build transmission or construct generation needs more consideration, problems that will have to be dealt with as far as cost and time, and the assumption that EPA made about 70% capacity factor that does not seem realistic. So Commission Murphy suggested that all of the state commissioners from the RSC sign off on a letter that would highlight the seriousness of looking at 111(d) from the state perspective. Commissioner Murphy made a motion that the RSC members send a letter to the EPA and FERC ahead of the December 1 comment deadline addressing our concerns on a statewide level about the proposed 111(d) rule. Commissioner Stoll seconded the motion, the motion passed.

Integrated Transmission Planning Update
Mr. Lanny Nickell provided the update on Integrated Transmission Planning (2015 ITP10 Overview – Attachment 10). Mr. Nickell began his report by discussing the assumptions and processes.

1. A recap of the 2015 ITP10 Futures
   a. Future 1: Business as usual

Future 2: Decreased Base Load Capacity
   i. Up to 20% capacity reduction of conventional generation and hydro
   ii. Most coal units under 200 MW retired

2. Statistics
   a. Reliability Needs – 489 unique facilities
   b. Economic Needs – 25 per future
   c. Policy Needs – No policy needs
   d. Projects Evaluated – 1374

3. 2017 ITP10 Scope & Timeline
   a. SPP Board has directed another ten-year assessment be performed following completion of the 2015 ITP10
      i. EPA Clean Power Plan section 111(d) impacts, nationwide 30% of CO₂ by 2030
      ii. Integration of the IS facilities
   b. Final 111(d) rule expected June 2015
4. Next Steps
   a. ITP20 Waiver
      i. Forgo the ITP20 for the next ITP Planning Cycle
   b. 24-month ITP10 Study
      i. Begin scoping ITP10 in January 2015
      ii. Begin ITP10 model development in July-October 2015
         1. Subject to EPA adhering to the CPP schedule

Capacity Margin Task Force
Mr. Tom Hesterman, Chairman of the CMTF, provided an update on the Capacity Margin Task Force (Capacity Margin Task Force – Attachment 11). He began by informing the Commissioners the CMTF was formed in July of 2014 by the MOPC to look at capacity margin issues. He reviewed the membership list and pointed out that there are some CAWG members and Commissioner Lyons has a seat on the task force. The reason they have been incorporated into the task force is because capacity adequacy is part of the RSC’s responsibilities and in their bylaws. Mr. Hesterman also reviewed the policy topics:
- Reserve Margin entity application and assumptions
- Assumptions about Reserve Margin calculation and requirements
- Accreditation policies
- Fuel supply and transportation firmness policies
- Deliverability policies
- Environmental policies
- State law policies
- Penalty policies
- Timing of implementation of policy changes
- Working Group ownership of Reserve Margin

Update on Seams Related Dockets at FERC
Mr. David Kelley, SPP, reported on the Seams Related Dockets at FERC, (Seams Related Dockets at FERC – Attachment 12).
   1. Background
      a. MISO filed request for declaratory order on interpretation of Section 5.2 of SPP-MISO JOA to effectuate integration of Entergy - FERC granted MISO’s request
      b. SPP appealed FERC’s decision to the DC Circuit - D.C. Circuit vacated and remanded FERC’s decision in January 2014
      c. SPP began billing MISO for usage
      d. SPP made filing at FERC for Service Agreement under Section 205
      e. MISO filed Section 206 compliant
   2. Settlement Proceedings - March 2014 FERC accepted SPP’s service agreement effective in January 2014
   3. FERC Technical Conference
      a. Conference held at FERC offices in September, topics covered:
         i. Interface bus pricing, Deferral of day-ahead FFE exchange/settlement, Addition of M2M flowgates.

Integrated Marketplace
Mr. Bruce Rew, SPP, provided the Integrated Marketplace update (Integrated Marketplace Update – Attachment 13). Currently there are 131 market participants with 87 financial only and 44 asset owning. The SPP Balancing Authority has successfully maintained NERC control performance standards and system availability has exceeded expectations. There are lower prices in real time because of market participant behavior and virtual participation.
Regional State Committee
October 27, 2014

**ACTION ITEMS:**
Consideration of RSC Bylaws changes will be discussed at the next meeting.
Consideration of the 3 RSC Action items requested by the SPC New Member Task Force will be discussed at the next meeting.

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

President Nelson noted that there will be a net conference prior to the meeting in January meeting. The SPP staff will follow-up with the Commissioners to find a convenient time.

- January 26, 2015  Dallas, TX
- April 27, 2015  Tulsa, OK
- July 27, 2015  Kansas City, MO
- October 26, 2015  Little Rock, AR

With no further business, the meeting adjourned at 4:00 p.m.

Respectfully Submitted,

Paul Suskie
Southwest Power Pool

REGIONAL STATE COMMITTEE

Net Conference

December 1, 2014

• MINUTES •

ADMINISTRATIVE ITEMS:
The following members were in attendance:

- Dana Murphy, Oklahoma Corporation Commission (OCC)
- Donna Nelson, Public Utility Commission of Texas (PUCT)
- Olan Reeves, Arkansas Public Service Commission (APSC)
- Stephen Lichter, Nebraska Power Review Board (NPRB)
- Steve Stoll, Missouri Public Service Commission (MOPSC)
- Shari Feist Albrecht, Kansas Corporation Commission (KCC)
- Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)

Vice President Dana Murphy called the Regional State Committee (RSC) meeting to order at 2:00 p.m. with roll call and a quorum was declared. She then requested introductions of those in attendance. There were 35 in attendance (Attendance & Proxies – Attachment 1).

REPORTS/PRESENTATIONS

CAWG Report
Ms. Meena Thomas did not have a presentation but provided a quick report. There are two issues the Cost Allocation Working Group (CAWG) is working on and both of these will be discussed in more detail later in this meeting.

- Non-Order 1000 Seams Update
- Long Term Congestion Rights Update

The last issue the CAWG is working on is the regulatory issues involved in the competitive bidding process for Non-Order 1000. This issue will be taken up again once commission staff has had the chance to discuss this with their individual staffs.

Non-Order 1000 Seams Projects Update
Mr. Dennis Reed provided a report on the cost allocation for Seams projects, (Cost Allocation for Seams Transmission Projects – Attachment 2). Mr. Reed reported that this will provide everyone insight into what the Regional Tariff Working Group (RTWG) is doing. The RSC Motion on Cost Allocation was unanimously approved at the October meeting. At the Board meeting the following day there was more discussion around the test of 100% of benefits to a single zone. Mr. Jim Eckelberger asked the RTWG to take the discussion and put it into tariff language. The Board approved the Seams Steering Committee (SSC) Whitepaper as presented. The RTWG took the following actions to develop Tariff language for both options. Draft Tariff language is still under review, however, in reviewing the discussion at the BOD and the RSC motion it appears that the only significant difference is what can trigger a change in the cost allocation of a Seams Transmission Project. References to the RCAR remedies will be done as part of the overall RCAR TRR currently being worked on.
• Draft Language
  o Default cost allocation: Regional
  o Create a test to review cost allocation
  o Requires SPP to calculate Zonal Benefits for all proposed Seams Transmission Projects for voltages between 100kV and 300kV
  o Working on two options:
    ▪ Option 1: If any single Zone receives “significantly all” of the SPP allocated benefits
    ▪ Option 2 follows RSC motion: 100% of benefits to a single zone
  o Results of the study to be reviewed by MOPC and RSC
  o The Board may change the cost allocation to “by-way”

• Remaining questions:
  o Did the RSC mean to have the same review of Zonal Benefits for Seams Transmission Projects > 300kV
    ▪ RSC motion did not specify although the general discussion seemed to be that these projects should always receive Regional cost allocation
  o Can the RSC support the BOD version of “Substantially All” rather than 100%

Commissioner Albrecht made a motion to adopt Option 2 language from Dennis Reed’s presentation to read a single zone is expected to receive 60% or greater of the calculated benefits. Commissioner Nelson seconded the motion. There was a roll call vote. The vote was unanimous.

Long Term Congestion Rights Update
Mr. John Krajewski provided an update on long term congestion rights (Long Term Congestion Rights – Attachment 3). SPP filed Long-Term Congestion Rights proposal on July 2014. FERC accepted most of the changes. There were seven areas the long-term congestion rights filing had to meet, four of those there were no concerns. There were three issues on which FERC required a compliance filing:
  • Issue One: Providing Long-Term Congestion Rights for entities who sponsor transmission system upgrades
    o SPP Position was that a long-term transmission right would be necessary and that the Attachment Z2 Crediting process was adequate
    o Protest by Boston Energy disagreed
    o FERC ruled in favor of Boston Energy and required SPP to make compliance filing to provide long-term congestion rights for entities that sponsor transmission upgrades
    o Issue of Concern:
      ▪ FERC Order required SPP to address how crediting would interact with the provision of LTCRs and ensure the approach is just and reasonable and consistent with Order 681
      ▪ MWG is generally in agreement that it should be an either/or decision
  • Issue Two: Allow entities to nominate the long-term congestion rights they want before preparing simultaneous feasibility
    o TDU Interveners protested the approach of doing simultaneous feasibility of all long-term rights and letting parties know which reservations were eligible for long-term rights
    o FERC partially agreed and is requiring SPP to include a nomination process before the simultaneous feasibility analysis
  • Issue Three: Assurance of inclusion of LTCRs in long-term planning processes to assure they are feasible.
    o TDU Interveners contended the approach fails to require SPP to plan system to ensure continued feasibility
    o SPP disagreed and started the integrated transmission planning process adequately safeguards continued feasibility
    o FERC agreed with TDU Interveners and is requiring SPP to demonstrate the existing planning process provides for the continued feasibility of LTCRs
Compliance filing was originally due on November 28, SPP requested an extension and it was granted. CAWG, RTWG, and Market Working Group (MWG) each have a role in developing the changes and RSC and the Board/Members Committee will have to approve.
Regional State Committee
December 1, 2014

SPC Task Force on New Members
Ms. Dana Murphy provided an update the SPC Task Force on New Members, (SPC Task Force on New Member Additions – Attachment 4). Ms. Murphy discussed bringing up the New Member information at the RSC educational session in January, the RSC members agreed.

RSC Bylaws Membership Provisions
Ms. Dana Murphy spoke to this topic (RSC Bylaws Membership Provisions – Attachment 5). At the RSC education session in January Ms. Murphy would like to discuss the RSC bylaws and possible revisions.

OTHER RSC MATTERS:
Ms. Dana Murphy asked everyone to think about adjustments or changes they would like to see in the future. Ms. Murphy said she would like to see Actions Items with the minutes. Everyone can think about any changes between now and the next meeting, Ms. Murphy will welcome emails or calls.

SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS:

- January 26, 2015 Dallas, TX
- April 27, 2015 Tulsa, OK
- July 27, 2015 Kansas City, MO
- October 26, 2015 Little Rock, AR

With no further business, the meeting adjourned at 3:16 p.m.

Respectfully Submitted,

Paul Suskie
### Regional State Committee
For the Twelve Months Ending December 31, 2014
Budget vs. Actual

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<td>243,189</td>
<td>327,600</td>
<td>(84,411)</td>
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<td><strong>Total Income</strong></td>
<td>243,189</td>
<td>327,600</td>
<td>(84,411)</td>
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<td>Technical Conference</td>
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<td><strong>Total Expense</strong></td>
<td>243,189</td>
<td>327,600</td>
<td>(84,411)</td>
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<tr>
<td><strong>Net Income (Loss)</strong></td>
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Southwest Power Pool Regional State Committee  
Dana Murphy, President  
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, 2014.  

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, 2014, and the related notes to the financial statement.  

We will also prepare the Organization's annual federal information return (IRS Form 990) for the period ended December 31, 2014.  

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 to issue a report as a result of 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 made by management, as well as evaluating the overall presentation of the statement of cash receipts
Southwest Power Pool Regional State Committee
Dana Murphy, President
Page Two

Audit Services (Continued)

Audit Procedures (Continued)

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 are 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 establishing and maintaining internal controls, including monitoring ongoing activities; for the selection and application of accounting principles; and for the 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)

Responsibilities of Management (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, except as described in the audit services section of this letter. 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.
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.
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 any fees through the date of our withdrawal.

Nonattest Services

As part of this engagement, we will assist in drafting the financial statement and notes based on the general ledger and other information provided to us during the audit. 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 by designating 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.
Southwest Power Pool Regional State Committee  
Dana Murphy, President  
Page Six

Administration, Fees and Other

We understand that your employees 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 expect to begin our audit on approximately June 15, 2015 and issue our report no later than July 24, 2015.

Our fee for these services for the year ended December 31, 2014, is estimated to be $2,325. 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 9, 2015  
Little Rock, Arkansas

RESPONSE:

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

__________________________  __________________________
Signature                        Date
Report to the Regional State Committee
January 26, 2015

Cost Allocation Working Group (CAWG)

Jason Chaplin
Oklahoma Corporation Commission
Topics:

- Cost Allocation for Non-Order 1000 Seams Projects
- Congestion Rights in Integrated Marketplace
- Capacity Margin Task Force Update
- Aggregate Study Waiver Process
Cost Allocation for Non-Order 1000 Seams Projects

- October 27, 2014 RSC Meeting: Unanimous RSC Vote (100%)
- December 1, 2014 RSC Teleconference: Unanimous Vote (60%)
- December 9, 2014 BOD/MC Vote: Approved Brightline Option 2 (60%); SPP Staff tasked to study how 60% brightline might work in the future
- RSC Agenda Item 5(c)
Congestion Rights in IM

- MPRR 227 – Long Term Congestion Rights
  - CAWG recommends the RSC approve MPRR 227 as approved by the RTWG; conditioned on there being no substantive changes by other working groups or committees prior to January RSC Meeting

- MPRR 221 – Transitional ARR Process
  - CAWG recommends the RSC approve MPRR 221 as approved by MOPC on January 13, 2015

- Agenda Item 5(d)
LOLE Study
Load Responsible Entity (LRE)
Fuel Supply and Transportation Firmness
Fuel Assurance related to FERC Order
Possible Deliverability Study
Enforcement of Capacity Margin
MOPC approved Business Practice Revision (BPR) – 051 and the associated Tariff Revision Request 146 at its January 2015 meeting.

BPR – 051 addresses the waiver process for two types of waiver requests for base plan funding.
Questions?

Submitted by:
Jason Chaplin
CAWG Chairman
January 26, 2015
Strategic Planning Committee Task Force on New Member Additions

**Jan. 25, 2015 RSC Education Session**
Update

• Oct. 2014 – Interim Report with Final Recommendations from SPP SPCTFN to RSC and SPP Board

• Recommendations:
  – SPP Staff – reflect SPCTFN recommendations in work processes (presented to SPC 01/15/15)
  – RSC – take up the three recommendations for discussion at the Jan. RSC meeting

• April 2015 – Final Report to RSC and SPP Board
Under Review by the RSC

1. Can/should RSC, CAWG or State Commission staff attend the SPC meetings’ Executive Sessions, and to possibly join the ad hoc Members Forum
   • Need RSC feedback on preference to participate, and assurance that they can protect the confidential information that may be subject to FOIA and state open meeting laws

2. When SPP Staff convenes the all-Member special meeting, SPP Staff convene an RSC/CAWG special meeting to follow so that Members and Commissioners/Staff can hear the issues of concern from each other
   • Need RSC feedback on preference to have a second SPP Staff convened special meeting as proposed

3. The Task Force discussed the issues of cost allocation as to the RSC’s involvement and as to a “Bright Line” date with regard to such cost allocation. The Task Force requests more information from the RSC as to how it views its role in cost allocation regarding the “Bright Line” date
BACKGROUND MATERIALS
Strategic Planning Committee Task Force on New Members

• Task Force was formed to develop recommended prospective communications and work group processes to be followed during the various stages of engaging new transmission owning and load serving members

  – This prospective process would only apply to new members whose request for membership requires modifications to the SPP Membership Agreement, SPP OATT (beyond the typical *pro forma* changes), and SPP Governing Documents
SPC TF on New Members

- Stages engaging prospective new members:
  1. Initial Discussions
  2. Due Diligence and Membership Agreement Discussions
  3. SPP OATT and Governing Document changes
  4. FERC Approvals
  5. Integration

- The Task Force discussed and plans to make recommendations for improvements to the process for communications and working group coordination for Stages 1-3 only
Process for New Members

**Stage 1: Initial Discussions**

- Informal communications between prospective new members and SPP Staff
- SPP Staff updates the Strategic Planning Committee (SPC) of on-going interest while preserving confidentiality as needed
- Triggering event – prospective new member formally notifies SPP of their desire to join SPP, but their membership requires changes to the Membership Agreement, SPP OATT, and Governing Documents, beyond the *pro forma* changes to add new members
  - Discussions may be proprietary/confidential due to the new member’s needs, or due to negotiations between RTOs
  - SPP Staff notifies SPC, and forms a Members Forum to assist in guiding the negotiations
Process for New Members

• **Stage 1: Initial Discussions** – *Recommendations for Process Improvements:*
  
  A. SPP Staff identify on SPC agendas there is to be a discussion on new members that could require an Executive Session
  
  B. Representatives(s) from RSC and CAWG attend the SPC meetings, and to possibly join the ad hoc Members Forum*
  
  C. SPP Members attend the SPC meetings and can join the ad hoc Members Forum as space allows
  
  D. SPP Staff review and modify its work processes to reflect the final approved changes from the Task Force

*Subject to RSC determination on preference to participate, and assurance that they can protect the confidential information that may be subject to FOIA and state open meeting laws.*
Process for New Members

• **Stage 2: Due Diligence and Membership Agreement Discussions**
  - SPP Staff is solely responsible for the direct negotiations with the prospective new member(s) consulting with SPC and Members Forum
  - Due to many of these discussions being highly confidential, SPP Staff regularly updates the Strategic Planning Committee (SPC) of discussions and negotiations in Executive Sessions
  - SPP Staff updates the SPP Board, Members Committee, RSC and MOPC periodically as discussions progress; oftentimes, in executive session or closed meetings
  - SPP Staff conducts a cost/benefit study to assess the impact of adding the new member(s)
  - Triggering event – at a certain point, the negotiations and discussions become public to all SPP Stakeholders (e.g., through press releases)
    • SPP Staff convenes a special all-Member meeting to walk through the various discussions, changes to documents, the SPP cost/benefit studies conducted to date, and any legal analyses conducted
Process for New Members

- **Stage 2: Due Diligence and Membership Agreement Discussions** –

  **Recommendations for Process Improvements:**

  A. SPP Staff identify on SPC agendas the discussion on new members that could require an Executive Session

  B. SPP Staff formally brings the decision of a more extensive production cost/benefit analysis or third party analysis to the SPC, and have this decision clearly noted on the SPC agenda and that the item could be discussed in Executive Session

  C. When SPP Staff convenes the all-Member special meeting, SPP Staff convene an RSC/CAWG special meeting to follow so that Members and Commissioners/Staff can hear the issues of concern from each other*

  D. Any time a prospective new member identifies a legal matter they intend to seek a legal review, SPP Staff should conduct a similar legal analysis

  E. SPP Staff review and modify its work processes to reflect the final approved changes from the Task Force

  F. SPP Legal Staff should develop a process document describing the general legal analyses that could be requested and provide guidance on how SPP Legal Staff would pursue and disseminate the information

*Subject to RSC determination on preference to participate, and assurance that they can protect the confidential information that may be subject to FOIA and state open meeting laws.
Process for New Members

- **Stage 3: SPP OATT and Governing Document Changes**

  - SPP Staff is solely responsible for the direct negotiations with the prospective new member(s), while the SPC and Members Forum continue to give guidance to SPP Staff.

  - Matters of concern are highly unique to the entity(ies) joining and thus, all negotiations are on a case-by-case basis.

  - SPP Staff will continue to update the SPC, SPP Board, Members Committee, RSC and MOPC.
Process for New Members

- **Stage 3: SPP OATT and Governing Document Changes** – 
  *Recommendations for Process Improvements:*

  A. SPP Staff ensure working group and committee agendas state potential changes to the SPP OATT and Governing Documents are being discussed as part of new member negotiations.

  B. SPP Staff carve out specific times/meetings to solely discuss potential new members and address the concerns and questions of the RSC Members and their Commission Staff.
Under Review by the RSC

1. Can/should RSC, CAWG or State Commission staff attend the SPC meetings’ Executive Sessions, and to possibly join the ad hoc Members Forum
   • Need RSC feedback on preference to participate, and assurance that they can protect the confidential information that may be subject to FOIA and state open meeting laws

2. When SPP Staff convenes the all-Member special meeting, SPP Staff convene an RSC/CAWG special meeting to follow so that Members and Commissioners/Staff can hear the issues of concern from each other
   • Need RSC feedback on preference to have a second SPP Staff convened special meeting as proposed

3. The Task Force discussed the issues of cost allocation as to the RSC’s involvement and as to a “Bright Line” date with regard to such cost allocation. The Task Force requests more information from the RSC as to how it views its role in cost allocation regarding the “Bright Line” date
Process for New Members, Membership Conversion, and New Contract Services

Process Participants

1. SPP Staff- including any outside services needed
2. Strategic Planning Committee (SPC)
3. Membership Forum (MF) - Ad hoc group of interested members

Process

1) Stage 1 – Initial Discussion
   a) SPP Staff regularly reports to SPC on discussions with parties interested in information about Membership or Contract Services

2) Stage 2 – Confidential Discussions
   a) Stage 2 is initiated when prospective new members request that with their membership, they require modifications to the SPP Open Access Transmission Tariff (OATT) (beyond pro forma changes for typical new members) or Governing Documents.¹
      i) SPP Staff will inform Chair of the SPC and requests the SPC Chair determine if it warrants a special SPC meeting or can be handled at next regular SPC meeting. SPC will determine if it warrants forming a MF to assist the SPP Staff in discussions or changes in pro forma membership. The MF will be formed to represent the diversity of SPP members including type of member and geography. Members on the seam with any prospective member(s) will be preferred. Also participation on the MF will require that information and discussions in the MR meetings will be held confidentially within the MF.
      ii) At each SPC meeting, SPP Staff will provide updates on all pending requests and work with potential new members or contract arrangements. SPP Staff will also update the SPC on any MF activities. This may require executive sessions for discussion of confidential information or negotiation strategies. The SPC agenda will clearly indicate when these discussions will occur, including if in an SPC executive session. Only stakeholders that can maintain confidential treatment of the information to be shared will be allowed to attend the executive sessions.
      iii) SPC will request SPP Staff to perform or have performed any analyses required or requested based on the desires of the prospective new members, the MF, or the SPC, including a transmission reliability study or optional production cost study.
      iv) SPC will request SPP Staff to perform or have performed any legal memorandum that may be needed.
      v) Proposed changes to the Governing Documents will be discussed at the Corporate Governance Committee meetings and may require an executive session.

¹ SPP Bylaws and Membership Agreement
3) Stage 3 – Public Discussions
   a) Stage 3 is initiated when the prospective new member either makes public their decision to join SPP or when SPP determines that the open stakeholder process should be engaged.
   i) SPP Staff will schedule a public meeting to present all the information about discussions with the prospective new members including any requested modifications to the SPP OATT (beyond pro forma changes for typical new members) or the Governing Documents. This public meeting would include discussions and questions from all attendees including members, stakeholders, and other interested participants. This may include review of any analyses that have been performed under the guidance of the SPC.
   ii) SPP Staff will schedule another meeting following the above public meeting to discuss the same information with the RSC and Cost Allocation Working Group (CAWG), if they are unable to attend the above public meeting.
   iii) Any additional information or legal memorandum requested will be performed by SPP Staff if approved by SPC or BOD.
   iv) SPP Staff will provide additional information and status updates as requested to the MOPC, BOD, and RSC.

4) Stage 4 – Stakeholder Process for Approval of Changes to SPP OATT, Governing Documents, or RSC Bylaws.
   a) Stage 4 is initiated when changes are developed for approval to the SPP OATT, Governing Documents, or RSC Bylaws
   i) If changes are to the SPP OATT,
      (1) Changes will be reviewed and approved by the appropriate SPP Working Group based on the area of changes within the SPP OATT;
      (2) All changes to the SPP OATT require review by the Regional Tariff Working Group (RTWG); and
      (3) Changes approved by the appropriate Working Groups will follow the standard process of presentation and approval by MOPC and then recommended to the BOD.
   ii) If changes are to the SPP Governing Documents,
      (1) Changes will be reviewed and approved by the Corporate Governance Committee; and
      (2) Changes approved by the CGC will be recommended to the BOD for approval.
   iii) If changes are to the RSC Bylaws,
      (1) Changes that may suggested will be addressed by the RSC.

5) SPP Staff will inform the SPP membership of all new members, membership conversions, and new contract services.
COST ALLOCATION FOR SEAMS TRANSMISSION PROJECTS

RSC Meeting
January 26, 2015
Seams Transmission Projects

- The Whitepaper written by the SSC was approved by the MOPC and BOD in October.
- RSC modified its October motion on Dec. 1 to set the possibility of changing the cost allocation if a Zone gets at least 60% of the benefits.
- BOD affirmed the motion after much discussion:
  - Directed Staff to study the issue and see if 60% is reasonable.
- The SSC also wanted to be sure the Zone getting the “byway” costs was not harmed:
  - Target is to be sure the Benefit/Cost ratio for the Zone where the project is built does not drop below 1.0.
Cost Allocation Example 1

- Assume:
  - Regional B/C=1.0
  - 138 kV facility
- No Zone exceeds 60% or more of the Benefits
- Result: Regional Cost Allocation

<table>
<thead>
<tr>
<th>Zone</th>
<th>LRS</th>
<th>SPP Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>20%</td>
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<tr>
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<td>20%</td>
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</table>
Cost Allocation Example 2

- Assume:
  - Regional B/C=1.0
  - 138 kV facility
- Zone 1 receives 70% of the Benefits
- Result: MOPC and/or RSC may recommend By-way Cost Allocation if B/C ratio for Zone 1≥ 1.0

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<thead>
<tr>
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<th>SPP Benefits</th>
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</thead>
<tbody>
<tr>
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<td>15%</td>
</tr>
<tr>
<td>3-17</td>
<td>70%</td>
<td>15%</td>
</tr>
</tbody>
</table>
Unintended Consequences

- Assume:
  - Regional B/C=1.0
  - 138 kV facility
- Flip the Benefits so that Zone 2 receives 70% of the Benefits
- Result: Zone 2 exceeds the 60% benefit test
- HOWEVER, Zone 1 would receive
  - 67% + 20%* 33% = 73.6% of the costs
  - B/C ratio = 15% / 73.6% < 1.0
- Reason why results must be reviewed on a case-by-case basis

<table>
<thead>
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<th>LRS</th>
<th>SPP Benefits</th>
</tr>
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<tbody>
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<td>2</td>
<td>10%</td>
<td>70%</td>
</tr>
<tr>
<td>3-17</td>
<td>70%</td>
<td>15%</td>
</tr>
</tbody>
</table>
Question:

- RTWG interpreted the comments from the SSC to add an addition criteria that the B/C ratio for the Zone that built the project has to be > 1.0
- Ensures the customers in the Zone where the STP is built are not harmed
- Is the RSC comfortable with the idea of the second test requirement?
Tariff Logic Flow

- Identify Seams Transmission Projects (STP)
  - Joint Studies (JOA)
  - ITP
  - High Priority Studies
  - Balanced Portfolio

- Define Assumptions and Benefits to be used
  - Done w/Seams Partner if Joint Study or JOA
  - Follow criteria for ITP, HPS or BP

- Report on study
  - Input Assumptions
  - Reliability Impacts
  - Benefits assigned to each Seam Partner
    - Zonal Benefits if Project > 100 kV & < 300 kV
  - Cost allocation between Seam Partners
  - Recommendation

- STP Criteria
  - Operating voltage > 100 kV
  - Cost > $5 million
  - Needed <= 10 years
  - Seams Partner
  - Benefits to SPP > 5%

- Review
  - MOPC
  - RSC
  - Either or both may recommend Cost allocation change to BOD
  - BOD makes final decision
Approvals

- TRR144 was approved by the RTWG at its December meeting

- TRR144 was approved by the MOPC in January

- Review by the RSC

- Comments from the RSC will be presented to the BOD meeting
Seams Project Evaluation for Illustrative Purposes

- All projects evaluated are 100 – 300 kV
  - As seams projects, the costs are assumed to be 100% Highway allocated in these examples

- In these examples:
  - SPP bears 100% of the project costs
  - Only 1 year of benefits and costs are evaluated, rather than the 40 years of benefits and costs that are typically evaluated in planning studies.
Messick 500/230 kV Transformer (Reliability)

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<th>Mitigation of Transmission Outage Costs</th>
<th>2024 Benefits (in 2015 $million)</th>
<th>Total Benefits</th>
<th>% of Total Benefits</th>
<th>2024 Costs (in 2015 $million)</th>
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<tr>
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<tr>
<td>GMO</td>
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<tr>
<td>GRDA</td>
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<tr>
<td>KCPL</td>
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<td>($0.01)</td>
<td>$0.00</td>
<td>$0.00</td>
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<tr>
<td>LES</td>
<td>($0.02)</td>
<td>$0.00</td>
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<td>MkEC</td>
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<td>$0.00</td>
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<td>-0.6%</td>
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<tr>
<td>NPPD</td>
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<tr>
<td>OKGE</td>
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</tr>
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<td>OPPD</td>
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<tr>
<td>IS</td>
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<td><strong>$0.01</strong></td>
<td><strong>$0.06</strong></td>
<td><strong>$8.82</strong></td>
<td><strong>$8.99</strong></td>
<td><strong>100.0%</strong></td>
</tr>
</tbody>
</table>
New Collins – Bolivar Burns – Huben 161 kV (Reliability)
Clinton – Truman – N Warsaw 161 kV Rebuild (Reliability)
Sioux City – Twin Church – Hoskins 230 kV (Reliability)
Morgan – Stockton – Collins 161 kV Rebuild
(Economic)

<table>
<thead>
<tr>
<th></th>
<th>2024 Benefits (in 2015 $million)</th>
<th>2024 Costs (in 2015 $million)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>APC Savings</td>
<td>Mitigation of Transmission Outage Costs</td>
</tr>
<tr>
<td>AEPW</td>
<td>$0.23</td>
<td>$0.06</td>
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<tr>
<td>CUS</td>
<td>($1.11)</td>
<td>$0.00</td>
</tr>
<tr>
<td>EDE</td>
<td>$0.55</td>
<td>$0.01</td>
</tr>
<tr>
<td>GMO</td>
<td>$0.11</td>
<td>$0.01</td>
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<tr>
<td>GRDA</td>
<td>$0.28</td>
<td>$0.01</td>
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<tr>
<td>KCPL</td>
<td>$2.82</td>
<td>$0.02</td>
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<tr>
<td>LES</td>
<td>($0.04)</td>
<td>$0.01</td>
</tr>
<tr>
<td>MIDW</td>
<td>($0.07)</td>
<td>$0.00</td>
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<tr>
<td>MKEC</td>
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<td>$0.00</td>
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<td>NPPD</td>
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<tr>
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<tr>
<td>OPPD</td>
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<tr>
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<tr>
<td>WRI</td>
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<td>$0.03</td>
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<tr>
<td>IS</td>
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<td>$0.03</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$2.59</td>
<td>$0.29</td>
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</table>
Questions?
Background on ARR/TCR Allocation

- Under SPP Bylaws, the Regional State Committee has primary responsibility in four key areas
- Two areas are directly related to Auction Revenue Rights (ARR) and Transmission Congestion Rights (TCR)
  - (c) Financial Transmission Rights (FTR) allocation, where a locational price methodology is used
  - (d) the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers’ existing firm rights
RSC Oversight of ARR/TCR Allocation

• In October 2010, RSC endorsed the current market design, including ARR/TCR allocation methods
  – ARR allocation was based on firm transmission reservations, with limitations based on load and system modeling to avoid risk of over-subscription / uplift
  – Agreed with MWG recommendation permitting non-transmission customers to participate in TCR auctions

• In October 2013, RSC endorsed the design of Long-Term Congestion Rights developed by the Long-Term Congestion Rights Task Force
Action Items / CAWG Recommendation

- MPRR 227: Long Term Congestion Rights
- MPRR 221: Transitional ARR Allocation Process
MPRR 227 Update

Long-Term Congestion Rights
FERC Order

- SPP filed to implement Long-Term Congestion Rights proposal on July 31, 2014
- Filing would implement changes that were approved by Regional State Committee, Board of Directors, and Members Committee in October 2013
- FERC accepted most of the proposed changes
- Required a compliance filing to address three issues
Changes to LTCR Methodology

• Issue One: Providing Long-Term Congestion Rights for entities who sponsor transmission system upgrades
  – Entity can choose to take either Attachment Z2 credits or new product, Incremental Long-Term Congestion Rights (ILTCR)
  – If they choose ILTCR,
    ▪ Sponsoring entity will tell SPP staff to evaluate up to three paths for LTCR feasibility;
    ▪ Staff will then provide amount of LTCRs available on each path
    ▪ Entity then can choose the one path they want
  – Minimum term of 10 years, maximum term of 20 years
Changes to LTCR Methodology

• Issue One: Providing Long-Term Congestion Rights for entities who sponsor transmission system upgrades
  – Upgrade must be completed before the verification process begins if they choose LTCRs
  – LTCRs still subject to Load-Serving Entity priority
  – Provisions related to surrender of LTCRs would apply
  – An upgrade already identified in any SPP planning process would not be eligible for the granting of ILTCRs
  – Minimum cost threshold of $5 million
Changes to LTCR Methodology

• Issue Two: Allow entities to nominate the Long-Term Congestion Rights they want before preparing simultaneous feasibility
  – With changes in MPRR 227, entities would nominate those LTCRs they want to be included in the simultaneous feasibility analysis
  – This occurs during the verification process and before the simultaneous feasibility analysis is completed
  – No other changes necessary to comply with this issue
Changes to LTCR Methodology

• Issue Three: Assurance of inclusion of LTCRs in long-term planning processes to assure they are feasible
  – SPP is planning further explanation of how LTCRs are included in planning processes in the compliance filing
  – No further tariff revisions proposed at this point
  – There may be a business practice that further clarifies that SPP will ensure continued feasibility of granted LTCRs
Approvals to Date

- MWG: December 16
- RTWG: December 29 (minor wording change)
- TWG: December 29 (minor wording change)
- MOPC: January 13-14
  - Accepted minor wording changes from RTWG and TWG
CAWG Motion / Recommendation

- CAWG recommends the RSC approve MPRR 227, Long-Term Congestion Rights, presented in the background materials for the January 6, 2015, CAWG meeting, as approved by the Regional Tariff Working Group on December 29, 2014. This recommendation is conditioned on there being no substantive changes by other working groups or committees prior to the SPP Regional State Committee meeting on January 26, 2015
MPRR 221 Update

Transitional ARR Allocation Process

January 6, 2015

John Krajewski
Nebraska Power Review Board
MPRR 221 Overview

- MPRR 221 is intended to address the allocation of ARRs to parties who join in the middle of the TCR year
  - Current schedule is based on June through May calendar
  - ARR activity begins in early February with start of LTCR allocation process
MPRR 221 Overview

- With Integrated System membership slated for October 1, 2015, there would be an eight month lag before they would be eligible for annual or seasonal ARRs under normal calendar.

- For new members, only access to congestion rights would be to receive ARRs through monthly process or purchase TCRs in monthly auction:
  - Competing with other eligible customers
  - May not be able to procure same rights as would be available in annual process.
MPRR 221 Overview

• MPRR provides opportunity for transmission owners and new transmission service customers who join in conjunction with members to access ARRs through a transitional allocation

• A transitional allocation process will only occur if the requested allocations include at least the Winter (December through March) plus Spring (April and May)
MPRR 221 and Past RSC Action

- There are no changes to any past policies established by the RSC with regard to ARR/TCR eligibility
- No changes to the existing Long-Term Congestion Rights and ARR allocation processes after the transitional process
  - New customers would go through the same allocation process as existing customers for LTCRs and ARRs during next annual process
CAWG Motion / Recommendation

CAWG moves as follows:

1. The CAWG finds MPRR 221, Transitional Auction Revenue Rights Allocation Process, to be consistent with past policy decisions by the RSC related to the award of Auction Revenue Rights and Transmission Congestion Rights

2. The CAWG recommends the RSC approve MPRR 221 as approved by the Market and Operations Policy Committee
2015 ITP Update

January 26, 2015
Regional State Committee

Lanny Nickell
2015 ITP10
2015 ITP10 Futures

• Future 1: Business as Usual
  – Assumes no major changes to generation or load modeling assumptions
  – Assumes no major changes to policies currently in place

• Future 2: Decreased Base Load Capacity
  – Up to 20% capacity reduction of conventional generation and hydro
  – Most coal units under 200 MW retired

• Primary driver for recommended portfolio was Future 1
2015 ITP10 Consolidated Portfolio

Total Cost: $273.2M
Reliability*: $209.6M
Economic*: $69.7M
EHV Cost: $87.2M
Reliability*: $71.1M
Economic*: $22.2M
Total Mileage: 260 mi
Reliability: 166 miles
Economic: 94 miles
EHV Mileage: 14 mi
Reliability: 0 miles
Economic: 14 miles

Economic Portfolio Stats
1-year totals:
Cost: $11.9M
APC Benefit: $37.8M
B/C**: 3.2

*One project and one upgrade are both reliability and economic
**B/C includes or
# 2015 ITP10 Rate Impact Projections

<table>
<thead>
<tr>
<th>Zone</th>
<th>One-Year ATTR Costs</th>
<th>One-Year Benefit</th>
<th>Rate Impact - Cost</th>
<th>Rate Impact - Benefit</th>
<th>Net Impact: Cost Less Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>American Electric Power</td>
<td>$8,895,937</td>
<td>$221,218</td>
<td>$0.17</td>
<td>$0.00</td>
<td>$0.16</td>
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<td>City Utilities of Springfield</td>
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<td>$0.04</td>
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<td>Grand River Dam Authority</td>
<td>$283,545</td>
<td>($661,023)</td>
<td>$0.05</td>
<td>($0.11)</td>
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<td>Greater Missouri Operations</td>
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<td>$0.07</td>
<td>($0.01)</td>
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<td>Kansas City Power &amp; Light</td>
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<td>Lincoln Electric System</td>
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<td>($0.01)</td>
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<td>$0.87</td>
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<td>Midwest Energy, Inc.</td>
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<td>$0.02</td>
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<td>Omaha Public Power District</td>
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<td>Upper Missouri Zone</td>
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<td>Western Farmers</td>
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<td><strong>47,225,386</strong></td>
<td><strong>$0.11</strong></td>
<td><strong>$0.16</strong></td>
<td><strong>($0.05)</strong></td>
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</tbody>
</table>

Rate impacts calculated on the full Consolidated Portfolio. Data represents 1-year APC benefit in 2024.
2015 ITPNT Background

- ITPNT is a near-term reliability assessment performed annually
- Reliability needs, generally in the form of transmission overloads or voltage limit violations, are determined in accordance with NERC, SPP, and local requirements
- Solutions are classified and cost allocated as follows:

<table>
<thead>
<tr>
<th>Reliability Need Driver</th>
<th>Transmission Solution</th>
<th>Cost Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>NERC Reliability Standards or SPP Criteria</td>
<td>Regional Reliability Upgrade</td>
<td>Highway-Byway</td>
</tr>
<tr>
<td>Local Planning Criteria</td>
<td>Zonal Reliability Upgrade</td>
<td>Zonal</td>
</tr>
</tbody>
</table>
2015 ITPNT Generation Mix Scenario 0

[Bar chart showing generation mix for various energy sources including CT Gas, CT Oil, CT Other, Combined Cycle (Existing), Combined Cycle (Planned), Conventional Hydro, Diesel, Internal Combustion, Nuclear (Existing), Pumped Storage Hydro, ST Coal, ST Gas, ST Other, Solar, Wind. The chart uses different colors for different scenarios: 15LO, 15SP0, 16SP0, 20LO, 20SP0.}
2015 ITPNT Generation Mix Scenario 5

[Bar chart showing the generation mix for various energy sources in 2015 with labels for CT Gas, CT Oil, CT Other, Combined Cycle (Existing), Combined Cycle (Planned), Conventional Hydro, Diesel, Internal Combustion, Nuclear (Existing), Pumped Storage Hydro, ST Coal, ST Gas, ST Other, Solar, Wind. The chart includes data for 15L5, 15SP5, 16SP5, 20L5, 20SP5 scenarios.]
2015 ITPNT Portfolio

- 2015-2020 timeframe
- 272 unique potential issues mitigated
- 42 projects/68 upgrades
- $248.2M study cost
- 8 common projects between 2015 ITP10 and ITPNT
  - 7 of 8 accelerated from ITP10 into ITPNT
2015 ITPNT Voltage Needs and All Solutions
(January 2015)

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2015 ITPNT
Thermal Needs and All Solutions
(January 2015)

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2015 ITPNT Upgrades by Need Date and Dollars

2015 ITPNT Upgrades
Need Year and Total Dollars

Number of Upgrades

2015 39 $133.8
2016 8 $61.4
2017 3 $13.0
2018 5 $17.7
2019 8 $9.1
2020 5 $13.1

Dollars (M)

Upgrades by Need Year
Total Dollars

0 5 10 15 20 25 30 35 40 45

0 20 40 60 80 100 120 140 160

## 2015 ITPNT Portfolio Breakdown by State

<table>
<thead>
<tr>
<th>State</th>
<th>New NTC</th>
<th>Modified NTC</th>
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</thead>
<tbody>
<tr>
<td>Kansas</td>
<td>$37.3M</td>
<td>$0</td>
</tr>
<tr>
<td>Louisiana</td>
<td>$4.0M</td>
<td>$0</td>
</tr>
<tr>
<td>Missouri</td>
<td>$5.8M</td>
<td>$0</td>
</tr>
<tr>
<td>Nebraska</td>
<td>$11.2M</td>
<td>$35.1M</td>
</tr>
<tr>
<td>New Mexico</td>
<td>$86.3M</td>
<td>$0</td>
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<tr>
<td>Oklahoma</td>
<td>$39.0M</td>
<td>$0</td>
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<tr>
<td>Texas</td>
<td>$29.5M</td>
<td>$0</td>
</tr>
<tr>
<td>Subtotals</td>
<td>$213.1M</td>
<td>$35.1M</td>
</tr>
</tbody>
</table>
2015 ITP Total Dollars

2015 ITP10
$225.7M*

2015 ITPNT
$207.6M

Total Impact: $473.9M

*ITP10 is shown in 2014 dollars. Amount in 2015 dollars = $231.4M + $41.6M = $273M
Approvals and Next Steps

• 2015 ITP10
  – MOPC approved – 1/13/15

• 2015 ITPNT
  – MOPC approved with modification – 1/13/15
    ▪ Walkemeyer – North Liberal 21 mile 115kV line was removed from the ITPNT plan

• 2015 ITP10 plan and 2015 ITPNT plan as modified, will be recommended to SPP Board of Directors for approval – 1/27/15
2015 SPP Transmission Expansion Plan (STEP)

Lanny Nickell
January 26, 2015 RSC
STEP Components

SPP Transmission Expansion Plan

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

Board Approval Required
Board Endorsement Required
2015 STEP by Project Type - $5.7B

- ITP (56%) $3,234M
- High Priority (36%) $2,047M
- Balanced Portfolio (1%) $65M
- TSS (5%) $283M
- GI (2%) $105M
% of Total 2015 STEP Cost by Facility Type

- New Line: 59%
- Rebuild/Re-Conductor: 18.8%
- Transformer: 10.0%
- Substation: 7.7%
- Voltage Conversion: 2.6%
- Capacitive/Reactive Devices: 1.9%
- Raise Line/Line Work: 0.02%
Changes of Significance from Previous STEP

- $1.7 B in STEP projects completed in 2014
- $1.2 B in new NTCs issued in 2014
  - $244 M for 2014 ITPNT
  - $573 M for HPILS
- $68.3 M in withdrawn NTCs in 2014
STEP Projects Completed in 2014

- $848 M in High Priority projects completed in 2014
- $308 M in Balanced Portfolio projects completed in 2014
- $491 M in ITP projects completed in 2014
2015 STEP Project Costs by Year

- **$M**: $200M, $400M, $600M, $800M, $1000M, $1200M, $1400M, $1600M, $1800M

Bar chart showing costs over time, with categories for non-NTC and NTC projects.
Seams Update

Carl Monroe, SPP

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

• MISO filed a motion for expedited consideration of MISO’s rehearing request on November 7, 2014
  – SPP responded on November 17, 2014 opposing MISO’s motion and stated SPP’s preference to continue the ongoing settlement process

• Settlement conferences
  – 5 held in 2014
  – Next conference scheduled for January 29, 2015
Transmission Charges for MISO Usage

<table>
<thead>
<tr>
<th>Period</th>
<th>Tariff Charges</th>
<th>Service Agreement Charges</th>
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<tbody>
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<td>12/13-1/14</td>
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<tr>
<td>Qtr 1, 2014</td>
<td>$6,661,798</td>
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<td>Qtr 2, 2014</td>
<td>$10,740,652</td>
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<tr>
<td>Qtr 3, 2014</td>
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<td></td>
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<tr>
<td>Qtr 4, 2014</td>
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<td></td>
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<tr>
<td>Service Agreement Total</td>
<td></td>
<td>$41,009,128</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>$49,638,129</td>
</tr>
</tbody>
</table>

Charges | Penalties | Losses | Accrued Interest
---------|-----------|--------|-------------------
Other Relevant Activity

- July 16, 2014 MISO filed to exceed the 1000 MW contract path limit when it is economical to do so by utilizing a hurdle rate of $9.57

- On compliance filing on January 12, 2015 MISO filed to update the hurdle and increase it to $42
SPP-AECI JOINT COORDINATED SYSTEM PLAN STUDY
SPP-AECI JCSP Study

Objective

• Evaluate the reliability and robustness of the SPP and AECI transmission systems and identify whether mutually beneficial joint projects exist

Assessments

• Reliability assessment consistent with the ITPNT

• Low Hydro Scenario
  – Based on historical operational data hydro units were dispatched at 50% of the amount in the base case
Stakeholder Involvement

• Four Interregional Planning Stakeholder Advisory Committee Meetings
  – Joint stakeholder group which includes SPP stakeholders and AECI stakeholders

• Study updates were also provided to various other SPP working groups
  – SSC, TWG, ESWG, Planning Summit
Solution Development

• Staff Approach
  – Focused on potential joint projects that are mutually beneficial

• Staff Evaluation
  – Evaluated stakeholder provided solutions
  – Evaluated SPP and AECI staff proposed solutions
  – Evaluated projects submitted in 2015 ITP10 and 2015 ITPN10 in the JCSP model
  – Projects submitted by AECI also evaluated in the ITP10
Solutions Evaluation

• Created a list of the top mutually beneficial projects
  – Reviewed with IPSAC
• Compared for cost-effectiveness and feasibility versus SPP’s regional solutions
• Considered SPP and AECI stakeholder input
• No joint solutions were agreed upon
  – SPP ACCC needs mitigated by projects identified in the 2015 ITPNT
Drivers for lack of joint projects

- Lower load growth has reduced potential opportunities along the seam
- Interregional solutions evaluated were not cost effective
- Model corrections
- Invalid contingencies
Moving Forward

• Next SPP-AECI JCSP in 2016
• Continue to coordinate potential seams projects opportunities in off years
  – AECI Long Range Plan in 2015
• Consider adding incentive points for project submissions
• Review lessons learned in 2014 SPP-AECI JCSP with the SSC
RARTF Status
Report to the RSC
January 26, 2015

Southwest Power Pool
Helping our members work together to keep the lights on... today and in the future
Topics Discussed at Dec 15th and Jan 19th Meetings

(1) Schedule of Regional Cost Allocation Review (RCAR) II

(2) Updates on
   i. Status of 2015 ITP10 and NT
   ii. Tariff Changes – Inclusion of Remedies in the tariff
   iii. RCAR I Lessons Learned
   iv. Point to Point Revenue Credits

(3) Review RITF Scope and Responsibilities

(4) Next Steps
UPDATES
Schedule for RCAR II

• At September and December meetings of the RARTF, the RARTF discussed the timing of the RCAR II schedule.

• After receiving input from SPP staff and a request from the ESWG to provide the ESWG more time to review models the RARTF:

• RARTF adopted a motion *unanimously* to extend the RCAR II Final Report approval to July 2015 in order to accommodate members request for more time.

  – The RARTF requests that preliminary remedy recommendations be provided no later than May 2015.
Updates On Other Issues

- SPP Staff provided:
  - an overview of the 2015 ITP10 and NT
  - Point to Point Revenue Credits
    - TRR143 was approved by MOPC and will be considered by the Board on January 27th
  - The Lessons Learned from RCAR I
    - The SPP Staff reviewed the status of the 10 lessons learned
  - Tariff Changes to Include Remedies from the RARTF Report in the Tariff
    - TRR131 was approved by MOPC and will be considered by the Board on January 27th
REVIEW OF RITF SCOPE AND RESPONSIBILITIES
Review of RITF Scope & Responsibilities

- SPP Staff an overview of the background to the RITF
- Noted that the RITF took the peak year and then broke down the costs for that year by zone to residential and small commercial customers
- Discussed what needs to be decided for a rate impact analysis
  - What projects to include?
  - What is the appropriate peak year?
  - What benefits should be included?
Next

- The RARTF will meet again on February 27th at the AEP Offices in Dallas beginning at 9 am
SPP Integrated Marketplace Update

• New Peaks
  – Winter Load peak of 36,995 MW on 1/8/2015
  – Wind Generation peak of 7,800 MW on 12/23/2014

• Summary of first nine months

• Marketplace Statistical Information

• Integrated Marketplace Benefits Analysis
Marketplace as of January 1, 2015

• 138 Market Participants
  – 93 financial only and 45 asset owning
    ▪ Some entities as multiple Market Participants
    ▪ EIS Market had 50 Market Participants

• SPP BA has successfully maintained NERC control performance standards

• System availability has exceeded expectations
  – Day-Ahead Market has only been delayed from posting twice
    ▪ Early June (due to a modeling issue)
    ▪ Mid October (due to an importer timeout which effected MPs ability to submit offers)
  – Real-Time Balancing Market has successfully solved 99.885% of all intervals
Unit Commitment Improvement

Average RT Daily Capacity Overage*

*Overage= Economic Max - Load - NSI - (RegUp+SPIN+SUPP)
Unit Commitment Improvement

RT Daily Capacity Overage*

*Overage=Economic Max - Load - NSI - (RegUp+SPIN+SUPP)
Graph on Dispatch by Fuel Type

Real-Time

Generation (GWh)

- Oct 13
- Nov 13
- Dec 13
- Jan 14
- Feb 14
- Mar 14
- Apr 14
- May 14
- Jun 14
- Jul 14
- Aug 14
- Sep 14
- Oct 14
- Nov 14
- Dec 14

- Other
- Gas-SC
- Gas-CC
- Coal
- Hydro
- Renewable
- Wind
- Nuclear
Graph on Fuel on the Margin in RT

% Intervals on Margin


- Other
- Gas
- Coal
- Wind

113 of 175
Graph on Real-Time versus DA pricing
DA vs RT: Percent Contribution to LMP Difference

% Contribution of LMP Difference

<table>
<thead>
<tr>
<th>Month</th>
<th>MCC</th>
<th>MLC</th>
<th>MEC</th>
</tr>
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<tbody>
<tr>
<td>1-Mar</td>
<td>75</td>
<td></td>
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</tr>
<tr>
<td>1-Apr</td>
<td>97</td>
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<td>1-Aug</td>
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<td>1-Sep</td>
<td></td>
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</tr>
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<td>1-Oct</td>
<td></td>
<td>31</td>
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</tr>
<tr>
<td>1-Nov</td>
<td></td>
<td></td>
<td>97</td>
</tr>
<tr>
<td>1-Dec</td>
<td></td>
<td></td>
<td>72</td>
</tr>
</tbody>
</table>

MCC: Marginal Congestion Cost
MLC: Marginal Loss Cost
MEC: Marginal Energy Cost
Integrated Marketplace Benefits Analysis

• SPP performed a preliminary analysis to determine quantifiable benefits since the Integrated Marketplace implementation March 1st, 2014

• The analysis was for 6 months, April – September

• Analysis compared Integrated Marketplace Energy + No Load versus individual 16 former Balancing Authorities (BAs) Energy + No Load
  - Assumes the 16 BAs did not have a Market in place and dispatch to their obligation
Capacity Requirements

- Each Control Zone must be able to serve Load Forecast + NSI
- SPP OR Obligations are distributed to Control Zones on Load Ratio Share
  - Only online obligations are considered (no Supp requirement)
  - No attempt at establishing reserve zones – Control Zone requirement only
- Headroom is based on Historical Average for that Month/Hour
- DVER, NDVER, and CROW Outaged resources are considered non-dispatchable
  - Study dispatch echoes real-time Resource MW
Study Highlights

• Historical headroom was applied for all zones

• **Total benefit to serve load in Integrated Marketplace was $179,416,951 for those six months**
  – Extrapolated to annual: $358,833,902

• An average 3,338 MW capacity increase in no market situation
## Study Projected Annual Savings

<table>
<thead>
<tr>
<th>Calculation</th>
<th>Financial Impact (millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Study Estimated Savings</td>
<td>$360</td>
</tr>
<tr>
<td>EIS Historical Savings</td>
<td>($170)</td>
</tr>
<tr>
<td>Integrated Marketplace Annual Cost</td>
<td>(                        ($50)</td>
</tr>
<tr>
<td>Net Integrated Marketplace Savings</td>
<td>$140</td>
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</table>
Helping our members work together to keep the lights on... today and in the future
<table>
<thead>
<tr>
<th>No.</th>
<th>Action Item</th>
<th>Date Originated</th>
<th>Status</th>
<th>Comments</th>
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<tr>
<td>5</td>
<td>Consideration of RSC Bylaws changes related to membership eligibility</td>
<td>Ongoing</td>
<td>Action needed before IS Parties join SPP (expected join date is October 1, 2015)</td>
<td>Discussed at December 1, 2014 meeting. On agenda for January 2015 Educational Session. Action is needed by July 2015 meeting.</td>
</tr>
<tr>
<td>8</td>
<td>Cost Allocation for Non-Order 1000 Seams Projects</td>
<td>October 27, 2014</td>
<td>Tariff Language In Process</td>
<td>RSC vote taken in December 2015 approving 60% threshold. On agenda for January 2015 meeting as a voting item</td>
</tr>
<tr>
<td>9</td>
<td>Goals and Objectives for 2015 RSC Year</td>
<td>December 1, 2014</td>
<td>Ongoing</td>
<td>Discussed at December 1, 2014 meeting. On agenda for January 2015 Educational Session or RSC lunch.</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>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>
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<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>
</tr>
<tr>
<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>8/25/2014</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting</td>
</tr>
</tbody>
</table>
Organizational Roster

The following members represent the Capacity Margin Task Force:

Thomas Hestermann, Mid-Kansas Electric Co., LLC  
Jason Atwood, Northeast Texas Electric Cooperative  
Zac Hager, Oklahoma Gas and Electric Company  
Jon Iverson, Omaha Public Power District  
Patrick Lyons, New Mexico PRC  
Noman Williams, South Central MCN, LLC.  
John Varnell, Tenaska Power Services Co.  
Lloyd Linke, Western Area Power Administration  
Bryan Taggart, Westar Energy  
Ed Johnson, Xcel Energy  
Jon Sunneberg, Nebraska Public Power District  
Jim Jacoby, American Electric Power  
Aaron Ramsdell, Basin Electric  
Marguerite Wagner, ITC Holdings Corp.  
Walt Cecil, Missouri Public Service Commission  
Jason Chaplin, Oklahoma Corporation Commission  
Randy Hughes, Kansas City  
Randy Root, Grand River Dam Authority  
Michael Wise, Golden Spread Electric Cooperative, Inc.  
Bill Bojorquez, Hunt Transmission Services, LLC  
Pat McCool, Kansas City Power & Light Company  
Clinton Bruhn, Lincoln Electric System  
Bradley Hans, Municipal Energy Agency of Nebraska  
Bill Dowling, Midwest Energy, Inc.  
John Grotzinger, Missouri Joint Municipal EUC  
Lanny Nickell, Southwest Power Pool

The CMTF has held five meetings since the October 2014 MOPC meeting. The focus of discussion has been policy topics related to the capacity margin construct. The CMTF is working to follow the timelines set forth in the CMTF work plan for establishing capacity margin construct criteria.

Baseline capacity margin LOLE assumptions were approved October 30, 2014. The 2014 baseline capacity margin LOLE study has been performed and the report is posted on SPP.org. The sensitivity capacity margin LOLE studies will be performed in 2015 and will be used to study the effects of changes to study assumptions in order to determine the data inputs and parameter settings that provide the most accurate and informative results. The CMTF plans to finalize capacity margin LOLE sensitivity assumptions by February 2015.

Load Responsible Entity (LRE) is a new term that the CMTF developed in order to establish an entity responsible for the capacity margin obligation. The current entity in the SPP Criteria, Load Serving Member (LSM), does not cover all SPP load. The LRE will cover all SPP load under the SPP Balancing Authority area and any load connected to SPP transmission. The LRE definition was approved by the CMTF on December 10, 2014. The CMTF is currently working on application of the LRE in various processes within SPP and applicable SPP Tariff language.

Accreditation of generation and demand side resources is an ongoing topic of discussion with the CMTF. Accreditation methodologies vary throughout the SPP region and vary by season, making this a longstanding policy topic. The CMTF is currently working to establish guidelines for accreditation of resources in the capacity margin deterministic calculations as well as the probabilistic LOLE analysis.
A fuel supply and transportation firmness straw man recommendation was brought to the CMTF by SPP staff and the CMTF asked for more information before deciding on language that specified guidelines for on-site fuel supply and securing firm fuel transportation. The CMTF is also addressing fuel assurance concerns as related to the FERC order in which each RTO/ISO was directed to file a report on the status of its efforts to address market and system performance associated with fuel assurance issues.

The CMTF has discussed the possibility of SPP performing a deliverability study that will allow LREs the option to secure capacity above their load total, as non-firm transmission, in order to meet their capacity margin obligation as long as the load and resource are within the same designated zone. This concept is being discussed internally within SPP and will be brought back to the CMTF once the details have been clarified.

Enforcement of capacity margin is a new topic that the CMTF has integrated into the other policy discussions. The CMTF plans to determine what type of penalty could be given for non-compliance with the obligation to carry the SPP designated capacity margin.

**Upcoming Meetings**
February 25, 2015 - CMTF meeting, AEP Offices, Dallas, Texas 8:30 am – 3:00 pm
March 25, 2015 - CMTF meeting, AEP Offices, Dallas, Texas 8:30 am – 3:00 pm

Respectfully submitted,

Lanny Nickell
CMTF Secretary
Bi-Annual Report – Summer 2014

12/5/2014

Generation Working Group
## Revision History

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<thead>
<tr>
<th>Date or Version Number</th>
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<th>Change Description</th>
<th>Comments</th>
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<td>12/8/2014</td>
<td>GWG</td>
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<td>Includes comments from GWG meeting on 12/5/2014</td>
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</table>


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Background

Purpose
The Generation Working Group (GWG) maintains, coordinates, and implements Criteria related to generation in Southwest Power Pool (SPP). One task of the GWG is to monitor and establish criteria for the rating of generating units within SPP and report results to the Markets and Operations Policy Committee (MOPC). During the course of the GWG activities over the last few years, there has been a need to perform analysis on an ad-hoc basis using operational data to support changes to the SPP Criteria. The following report aims to support the GWG’s Charter responsibilities by analyzing operational data on a bi-annual basis in order to promote a high standard of rating criteria for generating unit.

Scope and Methodology
The following report will focus on the historical performance of wind generation, the commitment statistics from the Integrated Marketplace, and generation outage data.

Historical Performance of Wind Generation
In order to evaluate the performance of wind generation, SPP staff:
1. Identified the top 3% peak load hours and the peak load hour for each legacy Balancing Authority (BA) during the summer months of 2012, 2013, and 2014. Due to limited data access and availability, staff chose to limit the sample to the most recent three years.
2. Obtained the wind output data for the months that the peak hour occurred for each legacy BA. SPP doesn’t record the load amounts for each individual entity that serves load within the SPP footprint. The historical load amounts for each legacy BA are readily available and represent the different geographic regions of SPP’s footprint.
   - In SPP’s operational models, individual resources registered in SPP’s Marketplace are associated to one of the legacy BA areas. This relationship could be based on the ownership of the individual resource share for joint owned facilities or the physical location on the transmission system. In order to streamline the analysis process, only wind resources with three years of operational data were evaluated. This results in an incomplete set of legacy BA areas.
   - The same analysis was also performed on the complete SPP Consolidated Balancing Authority footprint.
3. Displayed the wind amounts as a percentage of the aggregate sum of the nameplate maximums in relation to the confidence factor.
4. Identified the wind amounts during the top 3% peak load hours of each year.
5. Compiled the results from each area into a single table.

Commitment Statistics from the Integrated Marketplace
This section aims to examine the amount of capacity, regardless of generation type being offered and awarded in the market. The data is derived from the commitment plan at the time of the latest Intra-day RUC study for each hourly interval. SPP staff:
1. Charted the amount of capacity that was committed for the projected peak hour of each day and the amount of capacity that was available.
2. Identified the amount of capacity that failed to start for each hour and displayed the results with an overlay of the projected peak load for that day.

**Generation Outage Data from CROW**

For the purpose of this report, SPP focused on the amount of capacity that was submitted to SPP’s CROW system as a Forced or Emergency priority outage during the summer months. There is a chart that includes all generator outages and two others that focus solely on coal and natural gas.

It should be clarified the wind production values used in this report already take into consideration:

1) forced outages and failed to start; 2) curtailments due to both reliability and economic reason; and 3) weather related events.

**SPP Load Statistics**

In order to determine if the top three percent of load hours are an accurate representation of the super peak hours, SPP staff examined the SPP aggregate load duration curves for each month. The top three percent is threshold is noted on each graph. In addition to the load duration curves, SPP also determined the average generation amounts by fuel type during the top three percent of load hours for the peak summer month.

**Executive Summary**

The accompanying charts and graphs take into account all of the wind resources within the SPP footprint that had operational data for the peak months of 2012, 2013, and 2014. The resource sample is comprised of resources having both firm and non-firm transmission rights. The output data for the resources includes failed starts, forced outages, impacts from severe weather conditions, and curtailments for both reliability and economic reasons. The data reported for the “SPP” labeled charts would be considered the coincident peak for the legacy BAs included in the Consolidated Balancing Authority (CBA). The data reported at the Legacy BA level takes into account the peak for that BA and the resources within its footprint. These charts and data represent 12 of the 16 Legacy BAs. The remaining 4 BAs did not have wind resources with operational data in SPP’s archives for the three year period nor physically located in their BA. The wind resource accreditation values are based on the peak load and wind resource output levels for the Legacy BA aggregation.

The approved language in the SPP Criteria allows for a new wind or solar resource to either use proxy data from another resource that is located within 50 miles, data developed through an engineering study, a flat 5% of installed nameplate for wind resource, or a flat 10% of installed nameplate for solar resource. The flat average wind resource output level during the annual peak hour for the Legacy BAs was 22.1% of installed nameplate capacity. The range of wind output during the annual peak hour included a minimum of 0.5% and a maximum of 83.7% over the 3 year sample period. The corresponding wind accreditation based on the current approved methodology is 17.9%. The flat average wind resource output level during the annual peak hour for the SPP CBA was 20.4% of installed nameplate with a minimum of 4.9% and a maximum of 49.5% over the 3 year sample period.
The Criteria presently requires the rating for wind resources to correspond to the peak hours of the Load Serving Member. If the wind resources were to correspond to the peak hours of the CBA, then the corresponding wind accreditation based on the current approved methodology is 16.4% hence confirming the current 5% used in the SPP Criteria is a conservative number. The GWG considers these results to highlight the need for a methodology that includes multiple years while also expanding the sample data beyond the single peak hour. At this time, the GWG recommends no changes to the approved SPP Criteria 12.1.5.3.g which covers the approved methodology for establishing net capability for wind and solar facilities.
# Results

## Historical Performance of Wind Generation

All wind generation outputs are represented as a percentage of the aggregate nameplate amount for the given area.

<table>
<thead>
<tr>
<th>Area</th>
<th>Wind Output at Annual Peak Hour (2012-2014)</th>
<th>Wind Output at 60% Confidence Factor for the Top 3% Load Hours (2012-2014)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Average (Yearly peak hour)</td>
<td>Min (Yearly peak hour)</td>
</tr>
<tr>
<td>Legacy BA 1</td>
<td>8.1%</td>
<td>0.5%</td>
</tr>
<tr>
<td>Legacy BA 2</td>
<td>12.9%</td>
<td>4.5%</td>
</tr>
<tr>
<td>Legacy BA 3</td>
<td>37.3%</td>
<td>9.9%</td>
</tr>
<tr>
<td>Legacy BA 4</td>
<td>13.4%</td>
<td>1.0%</td>
</tr>
<tr>
<td>Legacy BA 5</td>
<td>28.0%</td>
<td>15.3%</td>
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<td>Legacy BA 6</td>
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<td>5.0%</td>
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<td>Legacy BA 7</td>
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<td>Legacy BA 8</td>
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<td>Legacy BA 9</td>
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<td>Legacy BA 11</td>
<td>25.0%</td>
<td>4.5%</td>
</tr>
<tr>
<td>Legacy BA 12</td>
<td>30.7%</td>
<td>1.4%</td>
</tr>
<tr>
<td><strong>Area Totals</strong></td>
<td><strong>22.1%</strong></td>
<td><strong>0.5%</strong></td>
</tr>
<tr>
<td><strong>SPP CBA</strong></td>
<td><strong>20.4%</strong></td>
<td><strong>4.9%</strong></td>
</tr>
</tbody>
</table>

Note: This data represents the output at a 60% confidence factor during the top 3% of load hours.
Wind Generation During Top 3% of Load Hours for SPP

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>8/1/12 15:00</td>
<td>6.8%</td>
</tr>
<tr>
<td>2013</td>
<td>8/30/13 15:00</td>
<td>4.9%</td>
</tr>
<tr>
<td>2014</td>
<td>8/21/14 16:00</td>
<td>49.5%</td>
</tr>
</tbody>
</table>

Wind Generation During Top 3% of Load Hours for Legacy BA #1

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>8/2/12 16:00</td>
<td>0.5%</td>
</tr>
<tr>
<td>2013</td>
<td>8/6/13 16:00</td>
<td>10.6%</td>
</tr>
<tr>
<td>2014</td>
<td>8/7/14 16:00</td>
<td>13.3%</td>
</tr>
</tbody>
</table>
## Wind Output At Peak Hour

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>7/25/12 8:00</td>
<td>20.2%</td>
</tr>
<tr>
<td>2013</td>
<td>7/19/13 9:00</td>
<td>14.1%</td>
</tr>
<tr>
<td>2014</td>
<td>8/3/14 18:00</td>
<td>4.5%</td>
</tr>
</tbody>
</table>

### Wind Generation During Top 3% of Load Hours for Legacy BA #2

- **Year**: 2012
- **Peak Hour**: 7/25/12 8:00
- **Percent of Aggregate Nameplate**: 20.2%

### Wind Generation During Top 3% of Load Hours for Legacy BA #3

- **Year**: 2012
- **Peak Hour**: 6/27/12 16:00
- **Percent of Aggregate Nameplate**: 40.0%
### Wind Generation During Top 3% of Load Hours for Legacy BA #4

**Wind Output At Peak Hour**

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>8/1/12 15:00</td>
<td>1.0%</td>
</tr>
<tr>
<td>2013</td>
<td>6/27/13 17:00</td>
<td>24.9%</td>
</tr>
<tr>
<td>2014</td>
<td>8/25/14 17:00</td>
<td>14.2%</td>
</tr>
</tbody>
</table>

### Wind Generation During Top 3% of Load Hours for Legacy BA #5

**Wind Output At Peak Hour**

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>8/2/12 16:00</td>
<td>22.7%</td>
</tr>
<tr>
<td>2013</td>
<td>8/6/13 16:00</td>
<td>46.1%</td>
</tr>
<tr>
<td>2014</td>
<td>8/25/14 16:00</td>
<td>15.3%</td>
</tr>
</tbody>
</table>
## Wind Generation During Top 3% of Load Hours for Legacy BA #6

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>8/1/12 16:00</td>
<td>5.0%</td>
</tr>
<tr>
<td>2013</td>
<td>6/27/13 16:00</td>
<td>23.7%</td>
</tr>
<tr>
<td>2014</td>
<td>8/25/14 16:00</td>
<td>16.5%</td>
</tr>
</tbody>
</table>

## Wind Generation During Top 3% of Load Hours for Legacy BA #7

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>7/25/12 15:00</td>
<td>33.0%</td>
</tr>
<tr>
<td>2013</td>
<td>7/9/13 16:00</td>
<td>9.9%</td>
</tr>
<tr>
<td>2014</td>
<td>7/22/14 16:00</td>
<td>3.7%</td>
</tr>
</tbody>
</table>
### Wind Generation During Top 3% of Load Hours for Legacy BA #10

#### Wind Output At Peak Hour

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>7/25/12 17:00</td>
<td>59.3%</td>
</tr>
<tr>
<td>2013</td>
<td>8/30/13 15:00</td>
<td>2.5%</td>
</tr>
<tr>
<td>2014</td>
<td>7/22/14 17:00</td>
<td>2.9%</td>
</tr>
</tbody>
</table>

### Wind Generation During Top 3% of Load Hours for Legacy BA #11

#### Wind Output At Peak Hour

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>7/25/12 16:00</td>
<td>30.4%</td>
</tr>
<tr>
<td>2013</td>
<td>8/30/13 16:00</td>
<td>4.5%</td>
</tr>
<tr>
<td>2014</td>
<td>8/25/14 16:00</td>
<td>40.1%</td>
</tr>
</tbody>
</table>
Wind Output At Peak Hour

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Hour</th>
<th>Percent of Aggregate Nameplate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>7/25/12 14:00</td>
<td>6.9%</td>
</tr>
<tr>
<td>2013</td>
<td>9/9/13 14:00</td>
<td>83.7%</td>
</tr>
<tr>
<td>2014</td>
<td>8/25/14 14:00</td>
<td>1.4%</td>
</tr>
</tbody>
</table>
Commitment Statistics from the Integrated Marketplace

**Daily Committed Capacity at Peak Hour**

- Daily Forecasted Peak
- Committed Capacity at Peak Hour
- Available Capacity at Peak Hour

**Failed to Start Capacity**

- FAILED_TO_START_CAP
- Load
Generation Outage Data from CROW

Forced/Emergency Outage Capacity - All Fuels

Forced/Emergency Outage Capacity - Coal
SPP Load Statistics

Note: This slide depicts the top 3% of the winter load hours as it relates to the winter load duration curve.

Note: This slide depicts how the top 3% of the spring months load hours relate to the spring load duration curve.
Note: This slide depicts how the top 3% of the summer load hours relate to the summer load duration curve. One will note that beyond the top 3% of the summer hours the load duration curve is a fairly straight line trending down, while the top 3% top of the load hours curve the exponential portion of the curve.

Note: This slide depicts how the top 3% of the fall months load hours relate to the summer/fall load duration curve.
NOTE: This chart displays the actual MW output amounts during the top 3% of load hours during 2014 for the SPP CBA.
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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 grid regional reliability standards, firm transmission commitments and tariff cost recovery.

Each quarter SPP staff solicits 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 either directly by the SPP Board of Directors (BOD) or through a FERC filed service agreement under the SPP Open Access Transmission Tariff (OATT).

The reporting period for this report is August 1, 2014 through October 31, 2014. Table 1 provides a summary of all projects in the current Project Tracking Portfolio (PTP), which includes all Network Upgrades that have been completed since January 1, 2013. 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>Regional Reliability</td>
<td>336</td>
<td>$2,320,645,970</td>
<td>1099.8</td>
<td>446.4</td>
<td>365.9</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>37</td>
<td>$193,142,694</td>
<td>31.5</td>
<td>141.2</td>
<td>0.0</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>11</td>
<td>$557,353,388</td>
<td>457.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>High Priority</td>
<td>105</td>
<td>$2,213,970,661</td>
<td>1746.4</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>ITP10</td>
<td>17</td>
<td>$773,176,433</td>
<td>515.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>9</td>
<td>$108,568,750</td>
<td>34.7</td>
<td>28.5</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>NTC Projects Subtotal</strong></td>
<td>515</td>
<td><strong>$6,166,857,896</strong></td>
<td><strong>3884.4</strong></td>
<td><strong>616.1</strong></td>
<td><strong>365.9</strong></td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>40</td>
<td>$193,605,444</td>
<td>44.0</td>
<td>11.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>11</td>
<td>$131,567,090</td>
<td>108.0</td>
<td>11.8</td>
<td>0.0</td>
</tr>
<tr>
<td>TO - Sponsored</td>
<td>29</td>
<td>$156,671,145</td>
<td>17.3</td>
<td>2.1</td>
<td>77.1</td>
</tr>
<tr>
<td><strong>NTC Projects Subtotal</strong></td>
<td>80</td>
<td><strong>$481,843,679</strong></td>
<td><strong>169.3</strong></td>
<td><strong>25.0</strong></td>
<td><strong>77.1</strong></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>595</td>
<td><strong>$6,648,701,574</strong></td>
<td><strong>4053.6</strong></td>
<td><strong>641.1</strong></td>
<td><strong>443.0</strong></td>
</tr>
</tbody>
</table>

*Table 1: Q1 2015 Portfolio Summary*
**Figure 1: Percentage of Project Type on Cost Basis**

- 36% Regional Reliability
- 12% Transmission Service
- 36% Balanced Portfolio
- 35% High Priority
- 3% ITP10
- 9% Zonal Reliability
- 3% Generation Interconnection

**Figure 2: Percentage of Project Status on Cost Basis**

- 35% Complete
- 21% On Schedule < 4
- 9% On Schedule > 4
- 31% Delay - Mitigation
- 4% NTC Suspension
- 0.4% Re-evaluation
In adherence to the OATT and Business Practice 7060, SPP issues Notifications to Construct (NTCs) to Designated Transmission Owners (DTOs) to commence the construction of Network Upgrades that have been approved or endorsed by the SPP Board of Directors (BOD) intended 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 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>$229,644,927</td>
<td>$912,000</td>
<td></td>
<td></td>
<td>$230,556,927</td>
</tr>
<tr>
<td>2007 STEP</td>
<td>$407,060,905</td>
<td>$144,309,000</td>
<td></td>
<td></td>
<td>$551,369,905</td>
</tr>
<tr>
<td>2008 STEP</td>
<td>$416,968,342</td>
<td>$3,317,000</td>
<td></td>
<td></td>
<td>$420,285,342</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>$756,878,564</td>
<td></td>
<td></td>
<td>$65,342,069</td>
<td>$822,220,633</td>
</tr>
<tr>
<td>2009 STEP</td>
<td>$455,854,869</td>
<td>$109,949,713</td>
<td></td>
<td></td>
<td>$565,804,582</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>$830,840,899</td>
<td>$127,995,000</td>
<td></td>
<td>$430,401,450</td>
<td>$1,389,237,349</td>
</tr>
<tr>
<td>2010 STEP</td>
<td>$103,763,619</td>
<td>$24,288,655</td>
<td>$10,316,217</td>
<td>$21,157,136</td>
<td>$159,525,627</td>
</tr>
<tr>
<td>2012 ITPNT</td>
<td>$98,244,181</td>
<td>$97,902,407</td>
<td>$6,300,000</td>
<td>$1,143,670</td>
<td>$203,590,258</td>
</tr>
<tr>
<td>2012 ITP10</td>
<td></td>
<td></td>
<td></td>
<td>$773,176,433</td>
<td>$773,176,433</td>
</tr>
<tr>
<td>2013 ITPNT</td>
<td>$53,091,177</td>
<td>$334,854,297</td>
<td></td>
<td>$155,352,341</td>
<td>$543,297,814</td>
</tr>
<tr>
<td>2014 ITPNT</td>
<td>$4,063,262</td>
<td>$303,493,943</td>
<td></td>
<td>$384,010,651</td>
<td>$691,567,856</td>
</tr>
<tr>
<td>HPILS</td>
<td>$26,952,690</td>
<td>$190,319,058</td>
<td></td>
<td>$608,422,459</td>
<td>$825,694,207</td>
</tr>
<tr>
<td>Ag Studies</td>
<td>$704,007,396</td>
<td>$98,756,989</td>
<td></td>
<td>$76,748,505</td>
<td>$879,512,890</td>
</tr>
<tr>
<td>DPA Studies</td>
<td>$69,939,283</td>
<td>$114,275,330</td>
<td></td>
<td>$5,085,427</td>
<td>$189,300,040</td>
</tr>
<tr>
<td>GI Studies</td>
<td>$335,943,924</td>
<td>$65,782,555</td>
<td>$8,033,890</td>
<td>$55,684,824</td>
<td>$465,445,193</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$4,493,254,037</strong></td>
<td><strong>$1,616,155,947</strong></td>
<td><strong>$24,650,107</strong></td>
<td><strong>$2,576,524,964</strong></td>
<td><strong>$8,710,585,055</strong></td>
</tr>
</tbody>
</table>

Table 2: Project Status by NTC Source Study

![Figure 4: Estimated Cost for NTC Projects per In-Service Year](image-url)
NTC Issuance

Five (5) NTCs were issued since the last quarterly report for new and previously approved projects with a total cost estimate of the included Network Upgrades totaling $581 million.

One (1) NTC was issued to American Electric Power (AEP) as a result of the completion of the Delivery Point Addition study, DPA-2013-September-351. The total estimated cost of the Network Upgrade described in this NTC is $4.7 million.

Four (4) of the NTCs were issued as a result of Transmission Owners submitting updated cost estimates in response to Notifications to Construct with Conditions (NTC-Cs). The NTC-Cs were issued as a result of the High Priority Incremental Load Study (HPILS) approved by the BOD in April. For these projects, all cost estimates were found to meet the conditional requirements of the NTC-C, and therefore were issued NTCs without the NTC-C conditions. The total estimated cost of the Network Upgrades described in these NTCs is $576.3 million.

Table 3 summarizes the NTC activity from October 1, 2014 through January 5, 2015. NTC ID values in **bold** font indicate NTC-Cs.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>Transmission 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>200306</td>
<td>AEP</td>
<td>11/24/2014</td>
<td>Regional Reliability</td>
<td>DPA Study</td>
<td>1</td>
<td>$4,715,419</td>
<td></td>
</tr>
<tr>
<td>200308</td>
<td>MKEC</td>
<td>11/24/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>1</td>
<td>$134,366</td>
<td></td>
</tr>
<tr>
<td>200310</td>
<td>SPS</td>
<td>12/3/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>27</td>
<td>$520,950,426</td>
<td></td>
</tr>
<tr>
<td>200311</td>
<td>OGE</td>
<td>12/2/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>4</td>
<td>$43,585,671</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>Total</strong></td>
<td><strong>34</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>$4,715,419</strong></td>
<td><strong>$576,322,570</strong></td>
</tr>
</tbody>
</table>

*Table 3: Q1 2015 NTC Issuance Summary*
**NTC Withdraw**

Five (5) NTCs were withdrawn since the last quarterly report. All five NTCs included projects from the HPILS that were either no longer needed due to decreased load projections, or the NTC was requested to be withdrawn by the DTO.

Table 4 lists the NTC Withdraw activity from October 1, 2014 through January 5, 2015. NTC ID values in **bold** font indicate NTC-Cs.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>Transmission Owner</th>
<th>NTC Issue 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>200301</td>
<td>ITCGP</td>
<td>11/14/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>1</td>
<td>Included in NTC 200304</td>
</tr>
<tr>
<td>200302</td>
<td>ITCGP</td>
<td>11/14/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>1</td>
<td>Included in NTC 200303</td>
</tr>
<tr>
<td>200303</td>
<td>MKEC</td>
<td>11/14/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>4</td>
<td>$60,883,925</td>
</tr>
<tr>
<td>200304</td>
<td>MKEC</td>
<td>11/14/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>3</td>
<td>$26,586,397</td>
</tr>
<tr>
<td>200312</td>
<td>ITCGP</td>
<td>1/5/2015</td>
<td>High Priority</td>
<td>HPILS</td>
<td>2</td>
<td>$9,484,914</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>Total</strong> 11</td>
<td><strong>$96,955,236</strong></td>
</tr>
</tbody>
</table>

*Table 4: Q1 2015 NTC Withdraw Summary*

**Completed Projects**

Eight (8) Network Upgrades with NTCs and five (5) Generation Interconnection Network Upgrades were completed during the reporting period, totaling an estimated $244 million.

SPS completed its portion of the 327-mile 345 kV line from Tuco to Woodward District EHV in the northern panhandle of Texas on September 25th. OGE previously reported the completion of their portion of the line in western Oklahoma on May 19th. The total estimated cost of the project is $320.4 million.

Table 5 lists the Network Upgrades completed during the reporting period. Table 6 summarizes the completed projects over the previous year. 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>10792</td>
<td>COTTONWOOD CREEK - CRESENT 138KV CKT 1</td>
<td>OGE</td>
<td>2008 STEP</td>
<td>$8,100,000</td>
</tr>
<tr>
<td>10936</td>
<td>Tuco Interchange - Stateline 345 kV</td>
<td>SPS</td>
<td>Balanced Portfolio</td>
<td>$192,875,814</td>
</tr>
<tr>
<td>50045</td>
<td>ESQUANDALE 69KV</td>
<td>WFEC</td>
<td>2008 STEP</td>
<td>$243,000</td>
</tr>
<tr>
<td>50459</td>
<td>Pawnee 138 kV</td>
<td>GRDA</td>
<td>GI Studies</td>
<td>$2,500,000</td>
</tr>
<tr>
<td>50460</td>
<td>FAIRFAX - PAWNEE 138KV CKT 1</td>
<td>GRDA</td>
<td>GI Studies</td>
<td>$11,900,000</td>
</tr>
<tr>
<td>50588</td>
<td>Grant County Substation</td>
<td>OGE</td>
<td>DPA Studies</td>
<td>$4,998,388</td>
</tr>
<tr>
<td>50590</td>
<td>Renfrow - Grant County 138 kV line</td>
<td>OGE</td>
<td>DPA Studies</td>
<td>$4,540,425</td>
</tr>
<tr>
<td>50592</td>
<td>Koch Substation Voltage Conversion</td>
<td>OGE</td>
<td>DPA Studies</td>
<td>$587,690</td>
</tr>
<tr>
<td>50634</td>
<td>Hays Plant - Vine Street 115kV Ckt 1 Terminal Upgrade</td>
<td>MIDW</td>
<td>Ag Studies</td>
<td>$15,720</td>
</tr>
<tr>
<td>50810</td>
<td>Jenson - Jenson Tap 138 kV Ckt 1 Terminal Upgrades</td>
<td>OGE</td>
<td>HPILS</td>
<td>$0</td>
</tr>
<tr>
<td>51024</td>
<td>Tatonga 345kV Substation GEN-2007-044 Addition</td>
<td>OGE</td>
<td>GI Studies</td>
<td>$1,973,375</td>
</tr>
<tr>
<td>51025</td>
<td>Hitchland 115kV Interchange GEN-2007-046 Addition</td>
<td>SPS</td>
<td>GI Studies</td>
<td>$513,231</td>
</tr>
<tr>
<td>51038</td>
<td>Beaver County 345kV Substation</td>
<td>OGE</td>
<td>GI Studies</td>
<td>$15,744,936</td>
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<tr>
<td></td>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>$243,992,580</strong></td>
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</table>

*Table 5: Q1 2015 Completed Network Upgrades*
<table>
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<tr>
<th>Upgrade Type</th>
<th>Q1 2014</th>
<th>Q2 2014</th>
<th>Q3 2014</th>
<th>Q4 2014</th>
<th>Total</th>
</tr>
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<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>20</td>
<td>23</td>
<td>28</td>
<td>6</td>
<td><strong>77</strong></td>
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<tr>
<td></td>
<td><strong>$83,901,536</strong></td>
<td><strong>$148,631,021</strong></td>
<td><strong>$149,339,227</strong></td>
<td><strong>$18,485,224</strong></td>
<td><strong>$400,357,008</strong></td>
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<td>Transmission Service</td>
<td>2</td>
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<td>0</td>
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<td></td>
<td><strong>$4,781,255</strong></td>
<td><strong>$0</strong></td>
<td><strong>$23,399,683</strong></td>
<td><strong>$0</strong></td>
<td><strong>$28,180,938</strong></td>
</tr>
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<td>Balanced Portfolio</td>
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<td>0</td>
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<tr>
<td></td>
<td><strong>$165,000,000</strong></td>
<td><strong>$0</strong></td>
<td><strong>$127,550,762</strong></td>
<td><strong>$192,875,814</strong></td>
<td><strong>$485,426,576</strong></td>
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<td>2</td>
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<td>1</td>
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<td></td>
<td><strong>$538,071</strong></td>
<td><strong>$4,212,722</strong></td>
<td><strong>$356,230,003</strong></td>
<td><strong>$0</strong></td>
<td><strong>$360,980,796</strong></td>
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<td>ITP10</td>
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<td><strong>$0</strong></td>
<td><strong>$0</strong></td>
<td><strong>$0</strong></td>
<td><strong>$0</strong></td>
<td><strong>$0</strong></td>
</tr>
<tr>
<td>Zonal Reliability</td>
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<td>0</td>
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<tr>
<td></td>
<td><strong>$0</strong></td>
<td><strong>$0</strong></td>
<td><strong>$0</strong></td>
<td><strong>$0</strong></td>
<td><strong>$0</strong></td>
</tr>
<tr>
<td>Generation Interconnection</td>
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<td>1</td>
<td>1</td>
<td>5</td>
<td><strong>13</strong></td>
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<tr>
<td></td>
<td><strong>$22,462,011</strong></td>
<td><strong>$399,000</strong></td>
<td><strong>$399,300</strong></td>
<td><strong>$32,631,542</strong></td>
<td><strong>$55,891,853</strong></td>
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</table>

*Table 6: Completed Project Summary through 4th Quarter 2014*
Table 7: Line Upgrade Summary for Previous 12 Months

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>Miles of New</th>
<th>Miles of Rebuild/Reconductor</th>
<th>Miles of Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>13</td>
<td>14.0</td>
<td>86.3</td>
<td>0.0</td>
<td>$69,405,109</td>
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<tr>
<td>115</td>
<td>13</td>
<td>81.0</td>
<td>61.2</td>
<td>15.7</td>
<td>$112,847,131</td>
</tr>
<tr>
<td>138</td>
<td>15</td>
<td>30.5</td>
<td>11.2</td>
<td>113.3</td>
<td>$66,225,691</td>
</tr>
<tr>
<td>161</td>
<td>7</td>
<td>10.5</td>
<td>31.1</td>
<td>0.0</td>
<td>$31,406,743</td>
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<tr>
<td>230</td>
<td>1</td>
<td>0.1</td>
<td>0.0</td>
<td>0.0</td>
<td>$3,792,408</td>
</tr>
<tr>
<td>345</td>
<td>11</td>
<td>844.1</td>
<td>0.0</td>
<td>0.0</td>
<td>$859,380,260</td>
</tr>
<tr>
<td>Total</td>
<td>60</td>
<td>980.1</td>
<td>189.7</td>
<td>129.0</td>
<td>$1,143,057,342</td>
</tr>
<tr>
<td>Voltage Class</td>
<td>Number of Upgrades</td>
<td>Miles of New</td>
<td>Miles of Rebuild/Reconductor</td>
<td>Miles of Voltage Conversion</td>
<td>Estimated Cost</td>
</tr>
<tr>
<td>--------------</td>
<td>--------------------</td>
<td>--------------</td>
<td>-------------------------------</td>
<td>-----------------------------</td>
<td>------------------</td>
</tr>
<tr>
<td>69</td>
<td>18</td>
<td>34.9</td>
<td>46.1</td>
<td>0.0</td>
<td>$88,656,916</td>
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<tr>
<td>115</td>
<td>13</td>
<td>126.7</td>
<td>4.1</td>
<td>3.0</td>
<td>$121,100,451</td>
</tr>
<tr>
<td>138</td>
<td>24</td>
<td>66.1</td>
<td>56.5</td>
<td>88.1</td>
<td>$145,989,743</td>
</tr>
<tr>
<td>161</td>
<td>1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$4,636,045</td>
</tr>
<tr>
<td>230</td>
<td>5</td>
<td>61.0</td>
<td>0.0</td>
<td>122.0</td>
<td>$64,253,240</td>
</tr>
<tr>
<td>345</td>
<td>12</td>
<td>556.7</td>
<td>0.0</td>
<td>0.0</td>
<td>$616,477,342</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>73</strong></td>
<td><strong>845.32</strong></td>
<td><strong>106.62</strong></td>
<td><strong>213.07</strong></td>
<td><strong>$1,041,113,737</strong></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
- **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
- **Re-evaluation**: NTC/NTC-C active; pending re-evaluation
- **NTC Suspension**: NTC/NTC-C suspended; pending re-evaluation

Figure 6 reflects a summary of project status by upgrade type on a cost basis.

![Figure 6: Project Status Summary on a Cost Basis](image-url)
Balanced Portfolio

Approved in April 2009, the Balanced Portfolio was an initiative to develop a group of economic transmission upgrades that benefit the entire SPP region, and to allocate those project costs regionally. The projects that were issued NTCs as a result of the study include a diverse group of projects, estimated to add approximately 717 miles of new 345 kV transmission line to the SPP system.

The total cost estimate for the projects making up the Balanced Portfolio increased by less than one percent from the previous quarter during the 4th quarter 2014 update cycle to a total of $822.2 million.

Figure 8 below depicts a historical view of the total estimated cost of the Balanced Portfolio. Table 9 provides a project summary of the projects making up the Balanced Portfolio.

![Figure 7: Balanced Portfolio Cost Estimate Trend](image-url)
Table 9: Balanced Portfolio Summary

Only one project from the Balanced Portfolio remains under construction, the 30-mile 345 kV line from Iatan to Nashua in northwest Missouri being constructed by Transource Missouri. The project is on schedule to be completed by June 1st of 2015.

Table 10 provides a construction status update for the Balanced Portfolio project not yet completed.
Priority Projects

In April 2010 the SPP Board of Directors and Members Committee approved for construction a group of "priority" high voltage electric transmission projects estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years. The projects issued NTCs as a result of the study are estimated to add 258 miles of new single circuit 345 kV transmission line and 422 miles of double circuit 345 kV transmission to the SPP region.

In October 2010 the SPP Board of Directors approved an overall cost increase for the Priority Projects due to line rerouting and addition costs for reactive compensation. The total cost estimate for the Priority Projects after the variances were approved was $1.42 billion.

The total cost estimate for the projects making up the Priority Projects decreased by 0.5% from the previous quarter during the 4th quarter 2014 update cycle to a total of $1.39 billion.

Figure 9 below depicts a historical view of the total estimated cost of the Priority Projects. Table 11 provides a project summary of the projects making up the Priority Projects.

Figure 8: Priority Projects Cost Estimate Trend
Southwest Power Pool, Inc.

Prairie Wind Transmission (PW) and Oklahoma Gas and Electric Co. (OGE) notified SPP that the new 109-mile double circuit 345 kV line from the Woodward District EHV substation in northwestern Oklahoma to the Thistle substation located in south central Kansas was energized on November 4th. OGE constructed 79 miles of the new double circuited line from Woodward District EHV up to the Oklahoma/Kansas border, while PW built the 30-mile portion of the line located in Kansas. The project is estimated to cost $187.3 million, and was originally not expected to be complete until late December.

ITC Great Plains, LLC (ITCGP) announced the completion of the 113.5-mile double circuit 345 kV line from the Spearville to Ironwood to Clark Co. to Thistle in the southwest quadrant of Kansas on December 17th. Originally designated to Mid-Kansas Electric Company, the project was novated to ITCGP shortly after the Priority Projects report was approved. Estimated to cost $309 million, the project completed two weeks prior to the expected in-service date.

Table 12 lists construction status updates for the Priority Projects not yet completed.

Table 11: Priority Projects Summary

<table>
<thead>
<tr>
<th>Project ID(s)</th>
<th>Project Owner(s)</th>
<th>Project</th>
<th>Est. Line Length</th>
<th>BOD Approved Estimates (10/2010)</th>
<th>Q4 2014 Cost Estimates</th>
<th>Q1 2015 Cost Estimates</th>
<th>Var. %</th>
</tr>
</thead>
<tbody>
<tr>
<td>937</td>
<td>AEP</td>
<td>Tulsa Power Station 138 kV Reactor</td>
<td>N/A</td>
<td>$842,847</td>
<td>$960,895</td>
<td>$960,895</td>
<td>0.0%</td>
</tr>
<tr>
<td>940/941</td>
<td>SPS/OGE</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt</td>
<td>120.0</td>
<td>$221,572,283</td>
<td>$228,331,670</td>
<td>$229,203,065</td>
<td>0.4%</td>
</tr>
<tr>
<td>942/943</td>
<td>PW/OGE</td>
<td>Thistle – Woodward District 345 kV Dbl Ckt</td>
<td>109.4</td>
<td>$201,940,759</td>
<td>$189,640,000</td>
<td>$187,260,000</td>
<td>-1.3%</td>
</tr>
<tr>
<td>945</td>
<td>ITCGP</td>
<td>Spearville – Ironwood – Clark Co. – Thistle 345 kV Dbl Ckt</td>
<td>113.5</td>
<td>$293,235,000</td>
<td>$304,793,640</td>
<td>$309,000,001</td>
<td>1.4%</td>
</tr>
<tr>
<td>946</td>
<td>PW/WR</td>
<td>Thistle – Wichita 345 kV Dbl Ckt</td>
<td>77.5</td>
<td>$163,488,000</td>
<td>$136,555,302</td>
<td>$127,026,938</td>
<td>-7.0%</td>
</tr>
<tr>
<td>936</td>
<td>AEP</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>76.3</td>
<td>$131,451,250</td>
<td>$127,995,000</td>
<td>$127,995,000</td>
<td>0.0%</td>
</tr>
<tr>
<td>938/939</td>
<td>OPPD/TSMO</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV</td>
<td>181.2</td>
<td>$403,740,000</td>
<td>$407,791,450</td>
<td>$407,791,450</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>677.9</strong></td>
<td><strong>$1,416,270,139</strong></td>
<td><strong>$1,396,067,957</strong></td>
<td><strong>$1,389,237,349</strong></td>
<td><strong>-0.5%</strong></td>
</tr>
</tbody>
</table>

Q1 2015 Project Tracking Report
<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Projected In-Service Date</th>
<th>Engineering</th>
<th>Siting and Routing</th>
<th>Environmental Studies</th>
<th>Permits</th>
<th>Material Procurement</th>
<th>Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td>936</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>10/1/2015</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
</tr>
<tr>
<td>938</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (TSMO)</td>
<td>6/1/2017</td>
<td>IP</td>
<td>IP</td>
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<td>IP</td>
<td>IP</td>
<td>NS</td>
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<td>939</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (OPPD)</td>
<td>6/1/2017</td>
<td>IP</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>NS</td>
</tr>
</tbody>
</table>

Table 12: Priority Projects Construction Status
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.

One project with a cost estimate greater than $5 million was identified as having exceeded the ±20% bandwidth requirement during the reporting period. The identified project was placed into service on July 15, 2014.

Table 13 provides summary information and Table 14 lists the cost detail for the out-of-bandwidth project for Q4 2014.

<table>
<thead>
<tr>
<th>PID</th>
<th>Project Name</th>
<th>Owner</th>
<th>NTC Source</th>
<th>Upgrade Type</th>
<th>In-Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>30426</td>
<td>Line - Pheasant Run - Seguin 115 kV Ckt 1</td>
<td>MIDW</td>
<td>2013 ITPNT</td>
<td>Regional Reliability</td>
<td>7/25/2014</td>
</tr>
</tbody>
</table>

Table 13: 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>
</thead>
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<tr>
<td>30426</td>
<td>$11,128,231</td>
<td>2013</td>
<td>$11,406,437</td>
<td>$7,811,905</td>
<td>($3,594,532)</td>
<td>-31.5%</td>
</tr>
</tbody>
</table>

Table 14: Out-of-Bandwidth Project Cost Detail
Table 15 and Figures 10 and 11 provide insight into the responsiveness of DTOs constructing Network Upgrades within SPP in the Quarterly Project Tracking Report for Q4 2014. **Note:** Network Upgrades with statuses of “Within NTC Commitment Window” and “Within NTC-C Project Estimate 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>Number of ISD Changes</th>
<th>ISD Change %</th>
<th>Number of Cost Changes</th>
<th>Cost Change %</th>
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<td>AEP</td>
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<td>71</td>
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<td>1</td>
<td>1.4%</td>
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<tr>
<td>CUS</td>
<td>3</td>
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<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>GMO</td>
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<td>0</td>
<td>0.0%</td>
</tr>
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<td>15.4%</td>
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<td>46.2%</td>
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<td>0.0%</td>
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<td>10.0%</td>
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<td>36%</td>
<td>9</td>
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<td>6</td>
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<tr>
<td>NPPD</td>
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<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>OGE</td>
<td>73</td>
<td>25</td>
<td>34%</td>
<td>8</td>
<td>11.0%</td>
<td>4</td>
<td>5.5%</td>
</tr>
<tr>
<td>OPPD</td>
<td>14</td>
<td>14</td>
<td>100%</td>
<td>1</td>
<td>7.1%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>PW</td>
<td>4</td>
<td>4</td>
<td>100%</td>
<td>2</td>
<td>50.0%</td>
<td>4</td>
<td>100.0%</td>
</tr>
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<td>SEPC</td>
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<td>0%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
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<td>SPS</td>
<td>162</td>
<td>162</td>
<td>100%</td>
<td>17</td>
<td>10.5%</td>
<td>34</td>
<td>21.0%</td>
</tr>
<tr>
<td>TSMO</td>
<td>5</td>
<td>5</td>
<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>5</td>
<td>100.0%</td>
</tr>
<tr>
<td>WFEC</td>
<td>60</td>
<td>60</td>
<td>100%</td>
<td>2</td>
<td>3.3%</td>
<td>6</td>
<td>10.0%</td>
</tr>
<tr>
<td>WR</td>
<td>61</td>
<td>10</td>
<td>16%</td>
<td>2</td>
<td>3.3%</td>
<td>7</td>
<td>11.5%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>579</strong></td>
<td><strong>393</strong></td>
<td><strong>68%</strong></td>
<td><strong>46</strong></td>
<td><strong>7.9%</strong></td>
<td><strong>78</strong></td>
<td><strong>13.5%</strong></td>
</tr>
</tbody>
</table>

*Table 15: Responsiveness Summary by Project Owner*
Figure 9: In-Service Date Changes by Project Owner

Figure 10: Cost Changes by Project Owner
Appendix I

See accompanying list of Network Upgrades
<table>
<thead>
<tr>
<th>Project Name</th>
<th>Project Owner</th>
<th>Indicated In-Service</th>
<th>Letter of Notification</th>
<th>NTC Source Study</th>
<th>Baseline Cost</th>
<th>Current Cost</th>
<th>Estimate</th>
<th>Project Status</th>
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Note: The table above provides a summary of various projects with their respective codes, descriptions, regional affiliations, status, and financial details.
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<td>$5,750,000</td>
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<td>NPPD Line - Twin Church - Dixon County 230kV Ckt 1 Twin Church - Dixon County 230kV Line Upgrade Generation Interconnection</td>
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<td>OGE Sub - Matthewson 345kV GEN-2011-007 Addition Advanced Construction of Matthewson 345kV Substation for Limited Operation of GEN-2011-007 Generation Interconnection</td>
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