Administrative Items:
The following members were in attendance:

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

President Tom Wright called the Regional State Committee (RSC) meeting to order at 1:00 p.m. with roll call and a quorum was declared. He then requested a round of introductions. There were 107 in attendance either in person or via phone (Attendance & Proxies – Attachment 1).

President Wright requested approval of the July 29, 2013 and September 30, 2013 meeting minutes (RSC Minutes 4/29/13 - Attachment 2). Dana Murphy moved to approve the minutes with a minor correction; the minutes were approved by acclamation.

President Wright provided opening remarks regarding the RSC educational session held prior to the regular meeting. He thanked Carl Monroe for sharing the SPP structure, including scope and function of committees. He also thanked Pete Hoelscher for his information regarding navigation of the SPP website and a glimpse of the future website to come.

UPDATES

RSC Financial Report
Paul Suskie provided the RSC Financial Report (Financial Report – Attachment 3). Mr. Suskie reported that the RSC remained below budget.

Mr. Suskie noted that the Thomas & Thomas RSC Financial Audit report contained no issues (2012 Audit Report – Attachment 4).

SPP Report
Nick Brown provided the SPP Report addressing several topics:

Administrative:
- SPP expects to finish the year ~ on budget, with expenditures 4.5% less than budgeted and revenue 3.3% less than budgeted.
- Staffing is nearing completion with half the additions this year versus the previous year and 2 incremental additions forecast for next year versus the 20 previously forecast.
The administrative fee is increasing to $0.38 to cover cost of the Integrated Marketplace. SPP remains very well positioned in comparison to peers and continue to search for efficiencies (Comparison – Attachment 5).

Staff remains highly engaged despite pressures of the status quo with Integrated Marketplace development and testing as evidenced by a perfectly clean NERC 693 Audit.

Membership: SPP continues to work with Basin, Heartland and WAPA. Public statements have been positive and SPP is awaiting a WAPA notice of intent in the Federal Register.

Order 1000 Compliance: The removal of Right of First Refusal (ROFR) remains problematic and it will take many years to fully appreciate the impact of this order. The Markets and Operations Policy Committee (MOPC) and the Board of Directors have each scheduled teleconferences on November 4 to finalize compliance issues for filing on November 18.

MISO Seams Negotiations:
- SPP and the Midcontinent ISO signed a Memorandum of Understanding (MOU) on October 21, 2013 containing provisions to resolve the seams dispute.
- Oral arguments in the US District Court regarding 5.2 of the JOA went very well and SPP is hopeful that it will be remanded back to FERC for further consideration.
- An interregional compliance filing regarding Order 1000 was made July 10, 2013; awaiting FERC order.

Interregional:
- Work continues at NERC to improve focus on improving ambiguous standards versus rigorous enforcement.
- Pleased with the find, fix and track approach.

FERC
Mr. Patrick Clarey provided an update on recent FERC activities. At the Open Meeting this month, the ISO/RTOs presented their updates regarding efforts at natural gas and electric coordination. These reports focused on continuing efforts in the coordination and understanding of the interdependency of natural gas and electric markets within the ISO/RTOs. Mr. Clarey noted that SPP participated in this and especially thanked Don Shipley and Joe Ghormley for their efforts.

The Commission also directed staff to conduct a workshop to explore certain pricing issues involving the filing of rate schedules for reactive power. Additionally, the Commission ordered that rate schedules for reactive power be filed even if no rates are charged for those services. Staff is directed to explore the mechanics of generators filing such rate schedules.

On September 25, the Commission held a technical conference to consider how current centralized capacity market rules and structures in the regions served by ISO New England Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), and PJM Interconnection, L.L.C. (PJM) are supporting the procurement and retention of resources necessary to meet future reliability and operational needs.

Finally, FERC announced the schedule for the Open Meetings in 2014. The meetings will continue to be held on the third Thursday of every month except for August. The open meeting dates for the 2014 calendar year are as follows:

| January 16 | May 15 | October 16 |
| February 20 | June 19 | November 20 |
| March 20 | July 17 | |
| April 17 | September 18 | |
Regional State Committee  
October 28, 2013

BUSINESS MEETING

Election of Officers for 2013

President Wright requested nominations for the annual election of officers. Dana Murphy nominated Donna Nelson for President stating that due to the nature of commissioner’s terms, this would allow Ms. Nelson to serve a complete term. Steve Stoll seconded the motion; the motion passed unanimously. Olan Reeves nominated Dana Murphy to continue serving as Vice President. Mike Siedschlag seconded the motion; the motion passed unanimously. Mike Siedschlag nominated Pat Lyons to serve as Secretary/Treasurer. Donna Nelson seconded the motion; the motion passed unanimously.

Approval of 2014 RSC Budget

Paul Suskie presented the 2014 RSC Budget for approval (2014 Budget – Attachment 6). Mr. Suskie noted that the budget indicated a 4% to 5% increase in travel funds. Patrick Lyons moved to approve the 2014 Budget as presented; Olan Reeves seconded. The motion passed unanimously.

REPORTS/PRESENTATIONS

Cost Allocation Working Group Report

Tom DeBaun provided the Cost Allocation Working Group report (CAWG Report – Attachment 7). Mr. DeBaun presented an overview of the group’s activities addressing the following topics:

- Long-Term Transmission Rights
- Cost Allocation – Projects in Adjacent Transmission Systems
- Crediting Process for Upgrades
- Quarterly Project Tracking

Mr. DeBaun provided background regarding action items for Long-Term Transmission Rights (LTCR) and Cost Allocation related to 3rd Party Impacts stating that motions for these items would be presented for approval later in the meeting.

Order 1000 Regional Update

Paul Suskie presented an Order 1000 Regional Compliance update (Order 1000 Regional Update – Attachment 8). Mr. Suskie provided an overview of regional compliance requirements breaking the items down into thirteen areas with twenty-five sub-topics in order to provide a method to address these issues by area. SPP Staff identified that some issues should be sent to other SPP groups including the RSC. In regards to Cost Allocation for impacts on other regions, the CAWG recommended the following motion for the RSC:

For Order 1000 regional compliance purposes, the CAWG supports and recommends the RSC support continuing the existing policy of SPP not bearing the costs associated with upgrades in another transmission planning region necessitated by projects approved in SPP’s Integrated Transmissions Planning (ITP) process.

Pat Lyons moved for approval; Olan Reeves seconded. The motion passed unanimously.

Long-Term Financial Transmission Rights Update

Mike Siedschlag provided an update on Long-Term Financial Transmission Rights and terms of Order 681 and the Integrated Marketplace order (LTCRs Update – Attachment 9). SPP must file a design for firm, long-term rights 180 days after the Integrated Marketplace commences. The compliance efforts of Long-Term Congestion Rights approved through working groups and the MOPC resulted in the following motion:

RSC to approve MPRR 138, Long-Term Congestion Rights as approved by MOPC and as submitted to the SPP Board of Directors and Members Committee.

Donna Nelson moved for approval; Patrick Lyons seconded. The motion passed unanimously.
Regional State Committee
October 28, 2013

Regional Cost Allocation Review
Michael Siedschlag (RARTF Chair), Paul Suskie (Staff) and Richard Ross (AEP) provided an overview of the Regional Cost Allocation Review Task Force activities (RCAR Overview – Attachment 10) including:

- OATT Requirements
- RARTF Charter
- Stakeholder Feedback on Draft Report
- Results of the RCAR Review
- Next Steps

The RARTF is required to review the regional allocation methodology at least once every three years. This being the first report, more accuracy it expected as more data is available. **Mike Siedschlag moved to accept the RCAR Report as presented; Steve Stoll seconded. The motion passed unanimously.** Mr. Siedschlag expressed his appreciation regarding the extent of involvement and stated that the stakeholder process works.

Generator Interconnection and AG Study Update
Lanny Nickell presented the Generator Interconnection and AG Study update (GI and ATSS Update – Attachment 11). If the Board of Directors approves Tariff changes on October 29 for the GI Study Process, Tariff language will be filed with FERC in November and expected to be implemented the first quarter in 2014. The ATSS backlog clearing process was approved by FERC and has commenced. Tariff language regarding future ATSS process improvements will be drafted with the goal of January 2014 MOPC and Board of Directors consideration and approval.

Integrated Marketplace System Update
Bruce Rew provided an update on the Integrated Marketplace System (Integrated Marketplace – Attachment 12). Mr. Rew reported that Transmission Congestion Rights (TCRs) went live October 18; structured market trials are ending; and assuming a positive Go/No-Go, Parallel Operations will start on November 12 and continue through January 31, 2014. Mr. Rew noted that December 20 is a key date as SPP must file 60 days in advance to going live. SPP is tracking well for the March 1, 2014, Integrated Marketplace Go-Live.

Integrated Transmission Planning (ITP10) Update
Lanny Nickell provided an update on the SPP ITP10 planning process (ITP10 Report – Attachment 13). Mr. Nickell addressed the following 2015 ITP10 items:

- Scope
- Futures
- Economic Model Development
- Analysis Methodology
- Project Classification
- Portfolio Development
- Final Report

Entergy/ITC Proceedings Update
Donna Nelson provided an update regarding the Entergy/ITC proceedings (Entergy/ITC – Attachment 14). Ms. Nelson stated that according to the statute, if this item is not acted upon in six months it is deemed approved.

**Scheduling of Next Regular Meeting, Special Meetings or Events:**
President Wright noted that the next regularly scheduled meeting is January 27, 2013 in Austin, TX.

With no further business, the meeting adjourned at 4:40 p.m.

Respectfully Submitted,

Paul Suskie
Monday, October 28, 2013
1:00 - 5:00 p.m.
SPP Corporate Offices - Little Rock, Arkansas

1. CALL TO ORDER
2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of July 29, 2013 and September 30, 2013 Minutes
3. UPDATES
   a. RSC Third Quarter Financial Report
   b. RSC Auditor Financial Statement
   c. SPP
   d. FERC
4. BUSINESS MEETING
   a. Election of Officers for 2014 (VOTING ITEM)
   b. Approval of 2014 RSC Budget (VOTING ITEM)
5. REPORTS/PRESENTATION
   a. CAWG Report………………………………………………………………………………………Tom DeBaun
      This report provides an update on CAWG activity, including recommendations to the
      RSC.
   b. Order 1000 Regional Update (VOTING ITEM)………………………………………………………Paul Suskie
      This report will update the RSC on the status of the SPP compliance filing. This update
      will include a recommendation from the CAWG on Cost Allocation related to 3rd Party
      Impacts.
   c. Long Term FTR Update (VOTING ITEM)……………………………………………………………Chairman Michael Siedschlag
      This report will update the RSC on the recommendation of the Long Term Congestion
      Rights Task Force.
   d. Regional Cost Allocation Review (POTENTIAL VOTING ITEM)……Chairman Michael Siedschlag
      This report will provide an update on the status of the RCAR that is being performed per
   e. Generator Interconnection and AG Study Update………………………………………………….Lanny Nickel
      This report will provide an update on the status of efforts to improve SPP’s Generation
      Interconnection and AG Study Process including FERC recent approval of backlogs.
   f. Integrated Marketplace Update………………………………………………………………………Bruce Rew
      This report will update the RSC on the SPP’s efforts in developing and implementing the
      Integrated Marketplace.
   g. Integrated Transmission Planning (ITP10) Update…………………………………………………Lanny Nickell
      This report will update the RSC on the SPP ITP10 Planning Process.
6. OTHER RSC MATTERS

7. SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS

RSC Meetings:
  January 27, 2014 – Austin, TX
  April 28, 2014 – Oklahoma City, OK
  July 28, 2014 – Omaha, NE

8. ADJOURN

* NOTE: ADDITIONAL INFORMATIONAL MATERIAL

Attached to the RSC’s meeting agenda and background material is additional material that is either for informational or reporting purposes. This includes the proposed Novation from GMO & KCP&L to Transource in accordance with SPP Business Practice 7070.
# ATTENDANCE LIST

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<tr>
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Southwest Power Pool
REGIONAL STATE COMMITTEE MEETING
October 28, 2013

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**Southwest Power Pool**

**REGIONAL STATE COMMITTEE MEETING**

October 28, 2013

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REGIONAL STATE COMMITTEE MEETING

October 28, 2013

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<td>Patrick Claytor</td>
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<td>Shawnie Claisson</td>
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M I N U T E S

Administrative Items

President Tom Wright called the meeting to order at 10:00 a.m. with roll call. A quorum was declared. The agenda for the call was reviewed with no changes.

The following members were present on the call:

- Tom Wright, Kansas Corporation Commission (KCC)
- Dana Murphy, Oklahoma Corporation Commission (OCC)
- Donna Nelson, Public Utility Commission of Texas (PUCT)
- Olan Reeves, Arkansas Public Service Commission (APSC)
- Stephen Stoll, Missouri Public Service Commission (MPSC)

Also on the call were Tom DeBaun (KCC); Meena Thomas and Laura Kennedy (PUCT); Pat Mosier (APSC); Trent Campbell, Geoff Rush, and Debbie Prater (OCC); John Krajewski (NPRB); Adam McKinnie, Mark Hughes, and Walt Cecil (MPSC); and Paul Suskie, Sam Loudenslager, and Tamika Barker (SPP).

Order No. 1000 Regional Compliance Filing

SPP Staff made a presentation on an Order 1000 Compliance issue. The FERC ordered SPP to determine whether SPP would pay for reliability projects that would be necessary in an adjacent transmission system due to projects in SPP that are selected in the ITP process. Consideration of this issue is needed for the SPP Order No. 1000 Regional Compliance Filing which is due November 18, 2013. SPP requested that the CAWG recommend how to address this issue. The CAWG voted to approve the following motion at their September 4, 2013 meeting:

For Order 1000 regional compliance purposes, the CAWG supports and recommends the RSC support continuing the existing policy of SPP not bearing the costs associated with upgrades in another transmission planning region necessitated by projects approved in SPP's Integrated Transmission Planning (ITP) process.

After discussion, the RSC stated that they would take this issue up at the October 28th RSC meeting.

Review Agendas for Upcoming RSC Meeting and Educational Session

Review agendas for October 28, 2013 Educational Session and RSC Meeting were reviewed and modified to include a RSC Financial Statement, consideration of the 2014 RSC budget, election of 2014 RSC officers, and an update of procedural schedule in the Entergy states of the ITC/Entergy transaction. The RSC also requested that for voting items, a pro/con analysis be provided at the time meeting materials are posted.

ADJOURN

The conference call adjourned at 10:45 a.m.

Next meeting: October 28, 2013 – Little Rock, Arkansas
Administrative Items:
The following members were in attendance:

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

President Tom Wright called the Regional State Committee (RSC) meeting to order at 1:00 p.m. with roll call and a quorum was declared. He then requested a round of introductions. There were 99 in attendance either in person or via phone (Attendance & Proxies – Attachment 1).

President Wright asked for approval of the April 29, 2013 meeting minutes (RSC Minutes 4/29/13 - Attachment 2). Patrick Lyons moved to approve the minutes as presented; Steve Stoll seconded the motion. The minutes were approved.

President Wright provided opening remarks regarding the RSC Retreat held in Colorado Springs on July 26-27. Given the diversity of the group, which is spread over seven states, it was a great opportunity to meet between the NARUC and RSC meetings. Mr. Wright thanked and complimented staff on well presented material addressing process improvement, Integrated Marketplace, Market Monitoring, transmission planning and capacity markets.

UPDATES

RSC Financial Report
Paul Suskie provided the RSC Financial Report (Financial Report – Attachment 3). Mr. Suskie reported that the RSC remained below budget.

Mr. Suskie reported that Thomas & Thomas issued a draft RSC Audit report on July 25, 2013. The findings are clean and clear (RSC Audit – Attachment 4).

SPP Report
Nick Brown reported that he was disappointed in the FERC order issued on July 18, 2013 regarding SPP’s Order 1000 Compliance filing. The Right of First Refusal (ROFR) was rejected even though it had been approved in an earlier order. SPP will continue to discuss options and the ROFR is still considered a good balance.
FERC
No FERC report was presented.

BUSINESS MEETING
There were no business items for discussion.

REPORTS/PRESENTATIONS
Cost Allocation Working Group Report
Tom DeBaun provided the Cost Allocation Working Group report (CAWG Report – Attachment 5). Mr. DeBaun presented an overview of the group’s activities addressing the following topics:

- Public Policy/Renewables Definitions
- Aggregate Study Improvement Process
- Annual Transmission Revenue Requirements
- Transmission Upgrade Crediting Process
- Communications

In regards to Public Policy/Renewables definitions, it was asked if the RSC was under obligation to define mandates or goals. Paul Suskie stated that in light of the recent FERC order on SPP’s Regional Compliance filing for Order 1000 it is not a requirement for the RSC. Following further discussion regarding public policy definitions, the following recommendation was written:

Accept the 3 definitions drafted as part of the public policy of the CAWG and those 3 definitions were (from the slides):

1. Renewables mandates
2. Renewables goals
3. Other renewables

And the information obtained in the public policy survey should be used for planning and informational purposes only.

Patrick Lyons moved to accept the recommendation; Michael Siedschlag seconded. The motion passed with Donna Nelson and Dana Murphy voting against.

Order 1000 Regional Update
Paul Suskie presented an Order 1000 Regional Compliance update (Order 1000 Regional Update – Attachment 6). Mr. Suskie outlined key points in the Order issued by FERC on July 18. Recommended issues to seek rehearing and/or clarification with FERC are:

- Mobile-Sierra
- Byway funding
- Removal of exemption on existing rights-of-way
- Treatment of Aggregate Study projects
- State ROFRs
- Treatment of Aggregate Study NTCs issued before Jan 2015

Working groups will begin the compliance process, which includes the cost allocation issue and state ROFRs. A petition for rehearing/clarification must be filed by August 18, 2013 and the compliance filing deadline is November 15, 2013.
Regional State Committee  
July 29, 2013

Order 1000 Interregional Update 
Paul Malone provided an Order 1000 Interregional Compliance update (Order 1000 Interregional Compliance – Attachment 7). Mr. Malone brought the group up to date on the interregional compliance filing status with MISO, SERTP, and MAPP. There are still outstanding issues with MISO, a waiver request and outstanding issues with SERTP and an extension request with MAPP.

KMEA Waiver (Request 76585575) 
Lanny Nickell presented the KMEA Waiver request (KMEA Waiver – Attachment 8). KMEA’s justification for a Waiver requesting full Base Plan funding is based on Section III.C.2.ii of SPP OATT Attachment J:

“…those costs that exceed the Safe Harbor Cost Limit may be classified in whole or in part as Base Plan Upgrade costs eligible for cost allocation taking into account the extent to which the duration of the Transmission Customer’s commitment to the new or changed Designated Resource exceeds the five-year commitment period…”

Following discussion, Mr. Nickell requested approval of the following recommendation: SPP recommends that the cost of the project not be allocated to KMWA’s OASIS request 76586675. Olan Reeves moved to support the recommended KMEA Waiver; Steve Stoll seconded the motion. The motion passed unanimously.

Long-Term Financial Transmission Rights (FTR) Update 
Michael Siedschlag provided the Long-Term Congestion Rights Task Force (LTCRTF) status report (LTCRTF Report – Attachment 9). Mr. Siedschlag stated that in compliance with the October 18 2012 FERC Order regarding the Integrated Marketplace, “SPP must establish long-term firm transmission rights in a compliance filing due within 180 days after the commencement of the Integrated Marketplace.” The RSC formed the Long-Term Congestion Rights Task Force (LTCRTF) to meet the RSC’s primary responsibilities. The group’s goal is to develop long-term firm transmission rights policies as part of the Integrated Marketplace compliance with FERC. Justification for policy recommendation(s) will be considered by the MWG and the CAWG for recommendation to the appropriate working groups, RSC, the Markets and Operations Policy Committee and the SPP Board of Directors. It is the goal of the group to have long-term congestion rights in place for year two of the Integrated Marketplace.

Regional Cost Allocation Review Update 
Paul Suskie provided the Regional Cost Allocation Review (RCAR) update (RCAR – Attachment 10). The group has completed a draft report and will begin the stakeholder process of vetting and recalculating as needed. It was requested that everyone read the report and provide feedback.

Integrated Marketplace Update 

Integrated Transmission Planning (ITP10 and ITP20) Update 
Alan Myers and Lanny Nickell provided an update on the SPP ITP10 and ITP20 planning processes (ITP10 & ITP20 Report – Attachment 12). The final ITP20 Report was presented and discussed. Mr. Myers reviewed the ITP10 futures and Policy Survey.

Scheduling of Next Regular Meeting, Special Meetings or Events: 
President Wright noted that the next regularly scheduled meeting is October 29 in Little Rock, AR.

With no further business, the meeting adjourned at 4:25 p.m.

Respectfully Submitted,

Paul Suskie
## Regional State Committee
### For the Three Months Ending September 30, 2013
#### Budget vs. Actual

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<tr>
<th></th>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
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<td><strong>Income</strong></td>
<td></td>
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</tr>
<tr>
<td>Other Income</td>
<td>164,277</td>
<td>246,300</td>
<td>(82,024)</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>164,277</td>
<td>246,300</td>
<td>(82,024)</td>
</tr>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Travel</td>
<td>120,202</td>
<td>124,500</td>
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<td>(750)</td>
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<td>RSC Consultant</td>
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<td>(25,000)</td>
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<td>-</td>
<td>-</td>
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<tr>
<td><strong>Total Expense</strong></td>
<td>164,277</td>
<td>246,300</td>
<td>(82,024)</td>
</tr>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
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</table>
Members of the
Southwest Power Pool Regional State Committee
Management of Southwest Power Pool, Inc.

We have audited the statement of cash receipts and disbursements of Southwest Power Pool Regional State Committee (the Organization) for the year ended December 31, 2012, and have issued our report thereon dated July 24, 2013. Professional standards require that we provide you with information about our responsibilities under generally accepted auditing standards, as well as certain information related to the planned scope and timing of our audit. We have communicated such information to you in our letter dated May 3, 2013. Professional standards also require that we communicate to you the following information related to our audit.

**Significant Audit Findings**

**Qualitative Aspects of Accounting Practices**

Management is responsible for the selection and use of appropriate accounting policies. The significant accounting policies used by the Organization are described in Note 1 to the financial statements. No new accounting policies were adopted and the application of existing policies was not changed during 2012. We noted no transactions entered into by the Organization during the year for which there is a lack of authoritative guidance or consensus. All significant transactions have been recognized in the financial statements in the proper period in accordance with the cash receipts and disbursements basis of accounting.

Accounting estimates are an integral part of the financial statements prepared by management and are based on management’s knowledge and experience about past and current events and assumptions about future events. Certain accounting estimates are particularly sensitive because of their significance to the financial statements and because of the possibility that future events affecting them may differ significantly from those expected. We noted no particularly sensitive accounting estimates applicable to the Organization’s December 31, 2012 financial statements.

The financial statement disclosures are neutral, consistent and clear.

**Difficulties Encountered in Performing the Audit**

We encountered no significant difficulties in dealing with management in performing and completing our audit.

**Corrected and Uncorrected Misstatements**

Professional standards require us to accumulate all misstatements identified during the audit, other than those that are clearly trivial, and communicate them to the appropriate level of management. We have no corrected or uncorrected misstatements to report.
Members of the
Southwest Power Pool Regional State Committee
Management of Southwest Power Pool, Inc.

Page Two

Significant Audit Findings (Continued)

Disagreements with Management

For purposes of this letter, a disagreement with management is a financial accounting, reporting or auditing matter, whether or not resolved to our satisfaction, that could be significant to the financial statements or the auditors' report. We are pleased to report that no such disagreements arose during the course of our audit.

Management Representations

We have requested certain representations from management that are included in the management representation letter dated July 24, 2013, a copy of which is included in Attachment A.

Management Consultations with Other Independent Accountants

In some cases, management may decide to consult with other accountants about auditing and accounting matters, similar to obtaining a "second opinion" on certain situations. If a consultation involves application of an accounting principle to the Organization's financial statements or a determination of the type of auditors' opinion that may be expressed on those statements, our professional standards require the consulting accountant to check with us to determine that the consultant has all the relevant facts. To our knowledge, there were no such consultations with other accountants.

Other Audit Findings or Issues

We generally discuss a variety of matters, including the application of accounting principles and auditing standards, with management prior to retention as the Organization's auditors. However, these discussions occurred in the normal course of our professional relationship and our responses were not a condition to our retention.

****

This information is intended solely for the use of the members and management of the Organization and is not intended to be and should not be used by anyone other than these specified parties.

Thomas & Thomas LLP
Certified Public Accountants

July 24, 2013
Little Rock, Arkansas
July 24, 2013

Thomas & Thomas LLP
Heritage West Building
201 East Markham, Suite 500
Little Rock, Arkansas 72201

This representation letter is provided in connection with your audit of the financial statement of the Southwest Power Pool Regional State Committee (the Organization) which comprise the statement of cash receipts and disbursements for the year ended December 31, 2012, and the related notes to the financial statement, for the purpose of expressing an opinion as to whether the financial statement is presented fairly, in all material respects, in accordance with the cash receipts and disbursements basis of accounting.

Certain representations in this letter are described as being limited to matters that are material. Items are considered material, regardless of size, if they involve an omission or misstatement of accounting information that, in light of surrounding circumstances, makes it probable that the judgment of a reasonable person relying on the information would be changed or influenced by the omission or misstatement. An omission or misstatement that is monetarily small in amount could be considered material as a result of qualitative factors.

We confirm, to the best of our knowledge and belief, as of July 24, 2013, the following representations made to you during your audit:

Financial Statements

- We have fulfilled our responsibilities, as set out in the terms of the audit engagement letter dated May 3, 2013.
- We acknowledge our responsibility for the preparation of the financial statement referred to above.
- The financial statement referred to above is fairly presented in conformity with the cash receipts and disbursements basis of accounting.
- We acknowledge our responsibility for the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.
- We acknowledge our responsibility for the design, implementation and maintenance of internal control to prevent and detect fraud.
Financial Statements (Continued)

- Significant assumptions we used in making accounting estimates, including those measured at fair value, are reasonable.

- Related party relationships and transactions have been appropriately accounted for and disclosed in accordance with the cash receipts and disbursements basis of accounting.

- There are no events subsequent to the date of the financial statement and for which the cash receipts and disbursements basis of accounting requires adjustment or disclosure.

- We are not aware of any pending or threatened litigation, claims, or assessments or unasserted claims or assessments that are required to be accrued or disclosed in the financial statements in accordance with the cash receipts and disbursements basis of accounting and we have not consulted a lawyer concerning litigation, claims or assessments.

- Material concentrations have been properly disclosed in accordance with the cash receipts and disbursements basis of accounting.

- There are no guarantees, whether written or oral, under which the Organization is contingently liable that must be recorded or disclosed in the financial statement in accordance with the cash receipts and disbursements basis of accounting.

Information Provided

- We have provided you with:
  - Access to all information, of which we are aware, that is relevant to the preparation and fair presentation of the financial statement, such as records, documentation and other matters.
  - Additional information that you have requested from us for the purpose of the audit.
  - Unrestricted access to persons within the Organization from whom you determined it necessary to obtain audit evidence.

- All material transactions have been recorded in the accounting records and are reflected in the financial statement.

- We have disclosed to you the results of our assessment of the risk that the financial statement may be materially misstated as a result of fraud.

- We have no knowledge of any fraud or suspected fraud that affects the Organization and involves:
  - Management,
  - Other administrative officers who have significant roles in internal control or
  - Others where the fraud could have a material effect on the financial statement.
Information Provided (Continued)

- We have no knowledge of any allegations of fraud or suspected fraud affecting the Organization received in communications from regulators or others.

- There are no known instances of noncompliance or suspected noncompliance with laws and regulations whose effects should be considered when preparing the financial statement.

- We are not aware of any pending or threatened litigation, claims, or assessments or unasserted claims or assessments that are required to be accrued or disclosed in the financial statement in accordance with the cash receipts and disbursements basis of accounting, and we have not consulted a lawyer concerning litigation, claims or assessments.

- We have disclosed to you the identity of the Organization’s related parties and all the related party relationships and transactions of which we are aware.

- We understand that you prepared the draft financial statements and related notes from the general ledger which we provided. We have reviewed and approved the financial statement and related notes and believe they are adequately supported by the books and records of the Organization.

- In regards to the tax preparation services and financial statement preparation services performed by you, we have:
  - Assumed all management responsibilities.
  - Overseen the services by designating an individual with suitable skill, knowledge or experience.
  - Evaluated the adequacy and results of the services performed.
  - Accepted responsibility for the results of the services.

Thomas Wright, President  
Southwest Power Pool Regional State Committee

Paul Suskie, Senior Vice President, Regulatory Policy and General Counsel  
Southwest Power Pool, Inc.
INDEPENDENT AUDITORS' REPORT

Members of the
Southwest Power Pool Regional State Committee

We have audited the accompanying statement of cash receipts and disbursements of Southwest Power Pool Regional State Committee (the Organization) for the year ended December 31, 2012, and the related notes to the financial statement.

Management's Responsibility for the Financial Statement

Management is responsible for the preparation and fair presentation of this financial statement in accordance with the cash basis of accounting described in Note 1; this includes determining that the cash basis of accounting is an acceptable basis for the preparation of the financial statement in the circumstances. Management is also responsible for the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on this financial statement based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statement. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatements of the financial statement, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statement in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. 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 financial statement.

We believe that the audit evidence we obtained is sufficient and appropriate to provide a basis for our audit opinion.
Members of the  
Southwest Power Pool Regional State Committee  
Page Two

Opinion

In our opinion, the December 31, 2012 financial statement referred to in the first paragraph presents fairly, in all material respects, the statement of cash receipts and disbursements of the Organization for the year ended December 31, 2012, in accordance with the cash basis of accounting described in Note 1.

Basis of Accounting

We draw attention to Note 1 of the financial statements, which describes the basis of accounting. These financial statements are prepared on the cash basis of accounting, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Other Matter

The December 31, 2011 financial statement of the Organization was audited by other auditors whose report dated November 13, 2012, expressed an unmodified opinion on that statement.

Thomas & Thomas LLP  
Certified Public Accountants  

July 24, 2013  
Little Rock, Arkansas
Southwest Power Pool Regional State Committee

STATEMENTS OF CASH RECEIPTS AND DISBURSEMENTS
Years Ended December 31, 2012 and 2011

<table>
<thead>
<tr>
<th></th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CASH RECEIPTS</strong></td>
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<tr>
<td>Reimbursements</td>
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<td><strong>CASH DISBURSEMENTS</strong></td>
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<tr>
<td>Administrative</td>
<td>2,988</td>
<td>2,302</td>
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<tr>
<td>Consultants</td>
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<td>Meetings</td>
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<td>Travel</td>
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<td>132,759</td>
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<tr>
<td><strong>Total Cash Disbursements</strong></td>
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<td>367,355</td>
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<tr>
<td><strong>INCENTIVE (DECREASE) IN CASH</strong></td>
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<td>(37,063)</td>
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<tr>
<td><strong>NEGATIVE CASH, BEGINNING OF YEAR</strong></td>
<td>(40,573)</td>
<td>(3,510)</td>
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<tr>
<td><strong>NEGATIVE CASH, END OF YEAR</strong></td>
<td>$ (5,707)</td>
<td>$ (40,573)</td>
</tr>
</tbody>
</table>

See accompanying notes to financial statement.
NOTE 1: NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General
Southwest Power Pool Regional State Committee (the Organization) is a public-benefit corporation incorporated in the State of Arkansas. The primary purpose of the Organization is to provide collective state regulatory agency input to Southwest Power Pool, Inc. (SPP) on matters of regional importance related to the development and operation of bulk electric transmission. The Organization is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Missouri, Nebraska, New Mexico, Oklahoma and Texas.

All general and administrative functions related to the operation of the Organization are performed by employees of SPP at no charge to the Organization. In addition, SPP provides all financial support necessary to cover costs incurred by the Organization.

(b) Basis of Accounting
The accompanying financial statements have been prepared on the cash receipts and disbursements basis of accounting. Under this method, the only asset recognized is cash, and no liabilities are recognized. Non-cash transactions are not recognized. All transactions are recorded as either cash receipts or disbursements.

(c) Cash
These financial statements reflect all receipts and disbursements attributable to the Organization's operating bank account maintained at a financial institution. Negative cash presented on the financial statements represents reimbursements due from SPP for operating costs incurred and paid by the Organization. These reimbursements are received the next business day.

(d) Income Taxes
The Organization is exempt from income taxes under Section 501(c)(4) of the Internal Revenue Code, except for taxes pertaining to unrelated business income.

Accounting standards require the Organization to evaluate tax positions and recognize a tax liability (or asset) if the Organization has taken an uncertain position that more likely than not would not be sustained upon examination by the Internal Revenue Service. The Organization has analyzed the tax positions taken and has concluded that as of December 31, 2012, there are no uncertain positions taken or expected to be taken that would require disclosure in the financial statements. The Organization may be subject to audit by the Internal Revenue Service; however, there are currently no audits for any tax periods in progress. As of December 31, 2012, the Organization believes they are no longer subject to income tax examinations for years prior to 2009.

NOTE 2: SUBSEQUENT EVENTS

Management has evaluated subsequent events through July 24, 2013, the date that the financial statements were available to be issued.
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<thead>
<tr>
<th></th>
<th>PJM</th>
<th>MISO</th>
<th>ERCOT</th>
<th>CAISO</th>
<th>NYISO</th>
<th>ISO NE</th>
<th>SPP (2014)</th>
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<tbody>
<tr>
<td>Recovery/MWh</td>
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<td>$0.45</td>
<td>$0.80</td>
<td>$0.81</td>
<td>$0.86</td>
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<td>Revenue (million)</td>
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<td>$195.2</td>
<td>$145.2</td>
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<td>Load (TWh)</td>
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<td>526</td>
<td>324</td>
<td>242</td>
<td>170</td>
<td>135</td>
<td>348</td>
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## SOUTHWEST POWER POOL
### REGIONAL STATE COMMITTEE
#### BUDGET VS. ACTUAL
##### 2011-2013

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<td>Travel</td>
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<td>($27,759)</td>
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<td>$163,104</td>
<td>($53,104)</td>
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<td>$120,202</td>
<td>$4,298</td>
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<td>$163,104</td>
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<td>($688)</td>
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<td>$82,023</td>
<td>$816,000</td>
<td>$367,354</td>
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## SOUTHWEST POWER POOL
### REGIONAL STATE COMMITTEE
#### BUDGET VS. ACTUAL

**2013**

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<th>Expense Category</th>
<th>2013 Jan-Sept Budget</th>
<th>2013 Jan-Sept Actual</th>
<th>2013 Jan-Sept Variance</th>
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<tr>
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## Southwest Power Pool, Inc.

### REGIONAL STATE COMMITTEE

### 2013 Budget and Proposed 2014 Budget

**October 28, 2013**

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<th>Expense Category</th>
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<th>2014 PROPOSED BUDGET</th>
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<td><strong>TOTAL EXPENSES</strong></td>
<td><strong>$344,300</strong></td>
<td><strong>$353,300</strong></td>
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Topics

I. Long Term Transmission Rights (Action Item)
II. Cost Allocation – Projects in Adjacent Transmission Systems (Order 1000 Compliance) (Action Item)
III. Crediting Process for Upgrades
IV. Quarterly Project Tracking
V. Questions/Wrap-up
I. Long Term Transmission Rights

- The entire CAWG presentation to the RSC at the July RSC Retreat is included in the background materials for reference.
- Action Item to be completed in Agenda Item 5c...Chairman Michael Siedschlag

Long-Term Congestion Rights

- Detailed presentation to RSC at July Retreat by John Krajewski (NPRB)
  - No concerns expressed by RSC at that time
  - No substantive changes since that meeting
  - Original presentation is included in background materials

- Market Protocol Revision Request #138 (MPRR138) would implement long-term congestion rights consistent with LTCRTF recommendations
LTGR – CAWG Actions

- On September 4, CAWG recommended the RSC approve MPRR 138, provided there were no substantive changes by other working groups
- Only changes subsequent to CAWG recommendation were clarifications or corrections to typographical errors
- CAWG reviewed on October 2 and agreed original motion was still valid

LTGR – Approval Status

- MWG approved – August 6
- RTWG approved with modifications – August 22
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- CAWG recommends RSC approval – September 4
- MWG approved SPP minor changes – September 10
- RTWG approved SPP in MPRR 138 – September 25
- MOPC approved MPRR138 – October 15
- RSC approval
- BOD approval
Proposed RSC Motion:

- RSC approves MPRR 138, Long Term Congestion Rights, as approved by MOPC and as submitted to the SPP Board of Directors and Members Committee.

II. Cost Allocation – Projects in Adjacent Transmission Systems (“3rd Party”)

- Order 1000 Compliance
- Action Item to be completed in Agenda Item 5b...Paul Suskie
### XI. RSC Issue: Cost Allocation - (1 Sub-Topic)

<table>
<thead>
<tr>
<th>Compliance</th>
<th>Cost Allocation (Impacted) Order Cfg 355</th>
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<tbody>
<tr>
<td></td>
<td>RSC Issue: Cost Allocation - (1 Sub-Topic)</td>
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<tr>
<td></td>
<td>For Order 1000 regional compliance purposes, the CAWG supports and recommends the RSC support continuing the existing policy of SPP not bearing the costs associated with upgrades in another transmission planning region necessitated by projects approved in SPP’s Integrated Transmissions Planning (ITP) process.</td>
</tr>
</tbody>
</table>

**CAWG Recommendation to RSC**

“For Order 1000 regional compliance purposes, the CAWG supports and recommends the RSC support continuing the existing policy of SPP not bearing the costs associated with upgrades in another transmission planning region necessitated by projects approved in SPP’s Integrated Transmissions Planning (ITP) process.”
7) Impacts on Adjacent Systems
As part of the evaluation of any Competitive Upgrade, the Transmission Provider will determine, based on its planning model, whether a proposed Competitive Upgrade causes any reliability violations on the transmission system of an adjacent transmission planning region. The Transmission Provider shall identify any such violations as part of the transmission planning process that identified the Competitive Upgrade. Except as otherwise provided in this Tariff or as otherwise provided in an agreement between the Transmission Provider and an adjacent transmission system, the Transmission Provider shall not pay any cost for any upgrade or system modification necessary to mitigate or resolve any such violation on an adjacent transmission system, and listing of such violations in the SPP Transmission Expansion Plan does not constitute any agreement on the part of the Transmission Provider or its stakeholders to pay any such cost. [Emphasis added]

Options:

**Pro**
- Anticipated to meet Order 1000 compliance requirements.
- May be revised as needed with more time to consider all options.

**Con**
- ?
Proposed RSC Motion:

For Order 1000 regional compliance purposes, the RSC supports continuing the existing SPP policy of not bearing the costs associated with upgrades in adjacent transmission systems necessitated by projects approved in SPP’s Integrated Transmissions Planning (ITP) process.”

III. Crediting Process for Upgrades “Z2 Crediting Project”
Z2 Crediting Project

Current Status

- OATI delivered the software to our testing environment on 8/26 and testing is underway
- OATI is loading historical data to test long term and provide an idea of dollar volumes by mid-October
- The vendor delivered test files 9/5 that were needed for SPP to finalize new Transmission Settlements XML
- SPP is working to determine when we can deliver specs to members and reschedule Member Testing

What’s Next?

- Test Long Term Credit Stack and provide data by mid-October
- Complete SPP Settlements design and create specs
- Specs Available to Members – TBD
- Revisit testing and implementation schedule with RTWG and CWG

SPP Point of Contact: Dena Giessmann, dgiessmann@spp.org
Z2 Crediting Project (continued)

FERC Status

- ER13–1914, Tariff Revision, Attachment Z2 filed at FERC 7/9
- Letter informing SPP that tariff revisions relating to creditable upgrades were deficient and requested additional information 9/6
- Southwest Power Pool, Inc. submits tariff filing – Amendment of Creditable Upgrades 10/9
- SPP Staff and RTWG/CPTF working on additional responses to FERC- more explanation as opposed to revisions

IV. Project Tracking Report
V. Today’s Agenda Item 5 – Reports and Presentations
Agenda Item #5.
REPORTS/PRESENTATIONS

- Order 1000 Regional Update (VOTING ITEM) ............................................. Paul Suskie
- Long Term FTR Update (VOTING ITEM) ............................................. Chairman Michael Siedschlag
- RCAR /RARTF (POTENTIAL VOTING ITEM) .............................. Chairman Michael Siedschlag
- Generator Interconnection and AG Study Update................................. Lanny Nickel
- Integrated Marketplace Update.............................................................. Bruce Rew
- Integrated Transmission Planning (ITP10) Update.............................. Lanny Nickell
- Update on Entergy/ITC Proceedings................................................... Chairman Donna Nelson

Questions
Overview of Compliance Filings for Order 1000

Order 1000 Compliance Filings

• Regional Compliance Filing
  – SPP Received Order on July 18th from FERC on SPP Regional Filing. (Details Below)
  – Compliance is due November 2013
  – SPP Stakeholder have completed work on compliance.
    ▪ SPCTF on Order 1000, RTWG, CAWG, MOPC, SPC
  – Final Steps RSC and SPP BODs/MC
  – Staff Filing

• Interregional Filing
  – No Update – FERC has not ruled on Interregional Filings
Overview of Regional Compliance Requirements

- SPP Staff identified several items that need to be addressed in SPP’s November 2013 compliance filing for Order 1000 per FERC’s July 18th Order.
- SPP Staff has broken these down into XIII (13) areas which includes 25 sub-topics in an attempt to provide a method to address these issues by area. (Details Below)
- SPP Staff identified some issues should be sent to other SPP groups – **RSC included**.
- The recommendations for SPP November Compliance filing are not intended to convey any believe on the likelihood of success of SPP’s Rehearing Request.

13 Areas – 25 Sub-Topics

I. ROFR Related Issues - (4 Sub-Topics)
II. Defining What Constitutes a Rebuild - (2 Sub-Topics)
III. Defining Reliability Projects for ROFR Purposes - (1 Sub-Topic)
**IV. Aggregate Study Issues - (1 Sub-Topic)** – [Note Request for an extension.]
V. Managerial Qualification Issues - (3 Sub-Topics)
VI. Fees & Deposit Issues - (4 Sub-Topics)
VII. Incumbent/Non-Incumbent Financial Strength - (1 Sub-Topic)
VIII. TOSP Scoring Issues - (2 Sub-Topics)
**IX. Finance Committee Issue - (1 Sub-Topic)**
X. Post-TOSP Issues [Delays & Project Costs] - (2 Sub-Topics)
**XI. RSC Issue: Cost Allocation for Impacts on Other Regions - (1 Sub-Topic)**
XII. Public Policy Related Issues - (2 Sub-Topics)
XIII. Merchant Transmission Developer Issues - (1 Sub-Topic)
XI. RSC Issue: Cost Allocation - (1 Sub-Topic)

<table>
<thead>
<tr>
<th>Compliance</th>
<th>Cost Allocation [Impacts]</th>
<th>Order Cite 355</th>
</tr>
</thead>
<tbody>
<tr>
<td>22</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

“SPP does not comply with the Regional Cost Allocation Principle 4 requirement that the regional transmission planning process identify the consequences of a transmission facility selected in the regional transmission plan for purposes of cost allocation for other transmission planning regions, such as upgrades that may be required in another region... Accordingly, we direct SPP to file a further compliance filing... revising its DART to provide for identification of the consequences of a transmission facility selected in the regional transmission plan for purposes of cost allocation for other planning regions.”

“SPP also does not address whether the SPP region has agreed to bear the costs associated with any required upgrades in another transmission planning region or, if so, how such costs will be allocated within the SPP transmission planning region... SPP must also address in the further compliance filing whether the SPP region has agreed to bear the costs associated with any required upgrades in another transmission planning region and, if so, how such costs will be allocated within the SPP transmission planning region.”

Revisions to Attachment D will be required to address this compliance requirement.

RECOMMENDATION: Send to the RSC with the recommendation to keep current policy.

CAWG Recommendation to RSC

“For Order 1000 regional compliance purposes, the CAWG supports and recommends the RSC support continuing the existing policy of SPP not bearing the costs associated with upgrades in another transmission planning region necessitated by projects approved in SPP’s Integrated Transmissions Planning (ITP) process.”
7) Impacts on Adjacent Systems

As part of the evaluation of any Competitive Upgrade, the Transmission Provider will determine, based on its planning model, whether a proposed Competitive Upgrade causes any reliability violations on the transmission system of an adjacent transmission planning region. The Transmission Provider shall identify any such violations as part of the transmission planning process that identified the Competitive Upgrade. Except as otherwise provided in this Tariff or as otherwise provided in an agreement between the Transmission Provider and an adjacent transmission system, the Transmission Provider shall not pay any cost for any upgrade or system modification necessary to mitigate or resolve any such violation on an adjacent transmission system, and listing of such violations in the SPP Transmission Expansion Plan does not constitute any agreement on the part of the Transmission Provider or its stakeholders to pay any such cost. [Emphasis added]

Proposed RSC Motion:

“For Order 1000 regional compliance purposes, the RSC supports continuing the existing SPP policy of not bearing the costs associated with upgrades in adjacent transmission systems necessitated by projects approved in SPP’s Integrated Transmissions Planning (ITP) process.”
QUESTIONS
BACKGROUND OF LONG-TERM TRANSMISSION SERVICE
Regulatory History


FERC Rulemaking Process

FERC Order 681; A; B

Definitions and Seven Guidelines
1. Should specify a source, a sink, and a quantity
2. Should not be modified during its term (“full funding”)
3. Long-term rights resulting from upgrades: must be available to parties paying for upgrades
4. Term: at least 10 years (renewal rights will satisfy)
5. LSEs have priority in allocation
6. Transferable to entity acquiring service obligation
7. Initial allocation: auction participation not required

Order 681 & Integrated Marketplace Order

- Order 681 (and Sec. 217 of FPA) applies to markets with financial rights – will soon apply to SPP
- SPP must file a design for firm, long-term rights
- 180 days after Integrated Marketplace commences
- Design must meet the seven guidelines in Order 681
**SPP’S COMPLIANCE EFFORTS**

### Long-Term Congestion Rights Task Force

<table>
<thead>
<tr>
<th>Members</th>
<th>Organization/Entity</th>
</tr>
</thead>
<tbody>
<tr>
<td>John Krajewski (Co-Chair)</td>
<td>NPRB</td>
</tr>
<tr>
<td>Gene Anderson (Co-Chair)</td>
<td>OPMA</td>
</tr>
<tr>
<td>Ronald Thompson, Jr. (Member)</td>
<td>NPPD</td>
</tr>
<tr>
<td>Trent Campbell (Member)</td>
<td>OCC</td>
</tr>
<tr>
<td>Joseph Lang (Member)</td>
<td>LES</td>
</tr>
<tr>
<td>Kip Fox (Member)</td>
<td>AEP</td>
</tr>
<tr>
<td>Charles Cates (Staff Secretary)</td>
<td>SPP</td>
</tr>
<tr>
<td><strong>Chairman Michael Siedschlag, RSC Liaison</strong></td>
<td><strong>NPRB</strong></td>
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</table>
Long-Term Congestion Rights

• Detailed presentation to RSC at July Retreat by John Krajewski (NPRB)
  – No concerns expressed by RSC at that time
  – No substantive changes since that meeting
  – Original presentation is included in background materials

• Market Protocol Revision Request #138 (MPRR138) would implement long-term congestion rights consistent with LTCRTF recommendations

LTCR – CAWG Actions

• On September 4, CAWG recommended the RSC approve MPRR 138, provided there were no substantive changes by other working groups
• Only changes subsequent to CAWG recommendation were clarifications or corrections to typographical errors
• CAWG reviewed on October 2 and agreed original motion was still valid
**LTCR - Approval Status**

- MWG approved - August 6
- RTWG approved with modifications - August 22
- MWG approved RTWG modifications - August 28
- ORWG approved - August 30
- CAWG recommends RSC approval - September 4
- MWG approved SPP minor changes - September 10
- RTWG approved SPP in MPRR 138 - September 25
- MOPC approved MPRR138 – October 15
- RSC approval ________
- BOD approval ________

**Proposed RSC Motion:**

- RSC approves MPRR 138, Long Term Congestion Rights, as approved by MOPC and as submitted to the SPP Board of Directors and Members Committee.
QUESTIONS
# PRR Impact Analysis Report

<table>
<thead>
<tr>
<th>PRR Number</th>
<th>Marketplace-PRR138</th>
<th>PRR Title</th>
<th>Long Term Congestion Rights</th>
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<td>Estimated Cost Impact</td>
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<td>If approved, this project will be included in the Integrated Marketplace Phase 2 program, and overall program costs will be allocated to this project.</td>
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<tr>
<td>Estimated Project Time Requirements</td>
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<td>Current staff estimate is 19 months.</td>
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| SPP Applications Impacted | |
|---------------------------| |
| |EMS | MOS MUI | edNA |
| |RTNET | MOS MOI | COS |
| |RFCALC | SPD | Market Portal |
| |RTLODF | RTO SS | ICCP |
| |RTGEN | RSS | DSS |
| |RTSMGR | NLS | OPSI |
| |SCADA | OASIS | Nexant |
| |CMT | | |
| |CMS | | |

Check off the systems that are (or may be) impacted.

Include a short explanation as to why each application is (or might be) affected in this area.

Nexant Software: New evaluation process to give LSEs priority and respect previously awarded LTCRs will have to be developed that is different than any other approach Nexant uses.

Credit Management System (CMS): Potential changes to the TCR estimated exposure calculation.

Centralized Modeling Tool (CMT): More and potentially different Settlement Locations will be needed.
### PRR Impact Analysis Report

<table>
<thead>
<tr>
<th>SPP Long-Term Staffing Impacts</th>
<th>IT</th>
<th>Settlements</th>
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<tr>
<td>Operations</td>
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**Additional staff required:**  
- Yes
- No

**Detail each group separately:**

**Members Software Systems/Processes Impacted**

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<th>OPSI Reports</th>
<th>RTO_SS</th>
<th>TCR_API</th>
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</table>

**Check off the software systems that are (or may be) impacted.**

Include a short explanation as to why each application is (or might be) affected in this area.

**TCR API:** MPs will be submitting additional information related to the Long Term Congestion Rights.

**Member Processes Impacted:**

MPs will participate in a new LTCR allocation process and will need to perform evaluations related to the new process.

### Evaluation of Interim Solutions (e.g., manual workarounds)

N/A

### Comments
Modifications were made to the TCR Markets processes to incorporate the addition of Long Term Congestion Rights.

In the October, 2013 FERC Order approving the Integrated Marketplace Filing, FERC required SPP to implement Long Term Congestion Rights in compliance with FERC Order 681 180 days following Integrated Marketplace go-live. This MPRR is meant to comply with FERC’s directive.
# Southwest Power Pool

**PRR Recommendation Report**

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<td>☐ Require additional information</td>
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<td>Impact Analysis Required</td>
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<td><strong>SPP Staff will complete this section.</strong></td>
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<td>Protocol Section(s) Requiring Revision</td>
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<td></td>
<td>Modifications were made to the TCR Markets processes to incorporate the addition of Long-Term Congestion Rights. In the October, 2013 FERC Order approving the Integrated Marketplace Filing, FERC required SPP to implement Long-Term Congestion Rights is compliance with FERC Order 681. 180 days following Integrated Marketplace go-live. This MPRR is meant to comply with FERC's directive</td>
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<td>Tariff Implications or Changes</td>
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<th>Criteria Impact or Changes</th>
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<td>Opposed: N/A</td>
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<tr>
<td>Date of Vote: 9/10/2013</td>
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<th>Date of Vote: 8/22/2013</th>
<th>Vote: Approved subject to MWG corresponding protocol changes, Two Abstentions – AEP and Empire,</th>
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<tbody>
<tr>
<td>Date of Vote: 9/25/2013</td>
<td>Vote: Approved SPP Comments</td>
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<thead>
<tr>
<th>ORWG Review</th>
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<th>Vote: Approved with no Reliability Impact</th>
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<table>
<thead>
<tr>
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<tr>
<td><strong>Date</strong></td>
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we are proposing some edits to the LTCR TF Work Group PRR up for consideration at the MWG next week. While the LTCR TF has not seen these edits (due to the timing of our edits), we still believe that it would be best to try to address this issue in the stakeholder process if we can—and we would welcome an opportunity to further discuss at MWG.

**The issue:**

- Providing only a choice of Revenue Credits for Market Participant Funded Incremental Upgrades does not incentivize valuable small scale transmission upgrades which are supported in FERC Guideline 3 for rights made available for transmission expansions. This is the case because if a non-Transmission owner funds an upgrade to relieve economic congestion, to recover the investment such an investor would have to wait until sufficient new requests for network service resulted in payments to them.
- The reason to encourage small scale investments by non-Transmission Owners—they relieve congestion at no cost to consumers—thus lowering overall costs of congestion (and the investment is paid for by the Market Participant—so consumers do not pay for the transmission upgrade).
- To encourage such investments, we believe that Market Participants should have a choice for a MP Funded Incremental Upgrade—to receive either Revenue Credits or LTCRs (not both).

**Proposed Solution:**

Develop an SPP approved process to award LTCRs commensurate with some percentage of transfer capability created through incremental transmission investment undertaken by a non-TO Market Participant.

**Fundamental Tenets of Market Participant Funded Incremental Upgrade LTCRs:**

1. The process would be documented in a business practice document developed with stakeholder input.
2. Market participants would work with SPP and the Transmission Owners to accomplish the upgrade.
2) LTCRs awarded as a result of the MP funded upgrade would expire after a period of years (specifics to be determined)
4) Market Participant would have the choice of source/sink pair and MW capped at the delta of transmission capability arising from the upgrade—as approved by SPP

To this end, we propose language in the NPRR (included in the attached document as track changes and further highlighted in yellow to make it very clear) that we believe would provide the flexibility to continue to develop this concept. We commit to being engaged in the discussions and appreciate your consideration of this issue.

Given the timing, I have taken the liberty to send out to the MWG as well as the Protocol Revision list serve—and I plead for indulgence ahead of time.

Kind regards,

Marguerite

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<td>RTWG made grammatical changes to the Tariff language. RTWG made other changes to include capitalization, punctuation, word changes and section references. RTWG deleted two paragraphs in section 7.1.2. These two sections were not needed in the Tariff 7.1.2(2)(b) and 7.1.2(4)(b).</td>
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<td>Clarification language was added by SPP staff. In Section 5, the word &quot;monthly&quot; was added to ARRs/LTCRs, because ARRs/LTCRs are a monthly product as well as annual and seasonal. A section reference was corrected in Section 5.6.3. Clarification language was added to the Tariff in Attachment AE Section 7.1.1. The proposed language is highlighted in yellow.</td>
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### Proposed Protocol Language Revision

#### 1.0 Glossary

**Auction Revenue Right (ARR)**
As defined in Attachment AE of the Tariff.

ARR Nomination Cap

As defined in Attachment AE of the Tariff.

The maximum total amount of ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and the monthly incremental ARR allocation process.

Firm Point-to-Point ARR Nomination Cap (“FPTP ARR Nomination Cap”)  

As defined in Attachment AE of the Tariff. The maximum total amount of FPTP Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the monthly incremental ARR allocation process.

Firm Point-to-Point Candidate ARR (“FPTP Candidate ARR”)

As defined in Attachment AE of the Tariff. All or portion of the MW quantity of a confirmed Firm Point To Point Transmission Service Reservation (TSR) verified prior to the start of the annual ARR allocation process, that the holder of the TSR can nominate for conversion into an ARR in the annual ARR allocation process.

Firm Point-to-Point Candidate LTCR (“FPTP Candidate LTCR”)  

As defined in Attachment AE of the Tariff.

GFA Firm Point-to-Point ARR Nomination Cap (“GFA FPTP ARR Nomination Cap”)

As defined in Attachment AE of the Tariff. The maximum total amount of GFA FPTP Candidate ARRs and GFA FPTP Incremental Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the incremental monthly ARR allocation process.

GFA Firm Point-to-Point Candidate ARR (“GFA FPTP Candidate ARR”)

As defined in Attachment AE of the Tariff. All or a portion of the MW quantity of the transmission service component of a Grandfathered Agreement (GFA) providing service equivalent to Firm Point-to-Point Transmission Service, as defined in the SPP Tariff, verified prior to the start of the annual ARR allocation process, that the applicable Eligible Entity can nominate for conversion into an ARR in the annual ARR allocation process.
GFA Firm Point-to-Point Candidate LTCR ("GFA FPTP Candidate LTCR")

As defined in Attachment AE of the Tariff.

GFA NITS ARR Nomination Cap

As defined in Attachment AE of the Tariff. The maximum total amount of GFA NITS Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and the monthly Incremental ARR allocation process.

GFA NITS Candidate ARR

As defined in Attachment AE of the Tariff. All or a portion of the MW quantity of the transmission service component of a Grandfathered Agreement (GFA) providing service equivalent to Network Integration Transmission Service, as defined in the SPP Tariff, verified prior to the start of the annual ARR allocation process, that the applicable Eligible Entity can nominate for conversion into an ARR in the annual ARR allocation process.

GFA NITS Candidate LTCR

As defined in Attachment AE of the Tariff.

Load Serving Entity (LSE)

As defined in Attachment AE of the Tariff.

Long-Term Congestion Right (LTCR)

As defined in Attachment AE of the Tariff.

NITS ARR Nomination Cap

As defined in Attachment AE of the Tariff. The maximum total amount of NITS Candidate ARRs and NITS Incremental Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the monthly Incremental ARR allocation process.

NITS Candidate ARR

As defined in Attachment AE of the Tariff. The MW quantity associated with firm NITS that is verified prior to the start of the annual ARR allocation process, that the holder of the NITS can nominate for conversion into an ARR, subject to the NITS ARR Nomination Cap, in the annual ARR allocation process and the monthly ARR allocation process.

NITS Candidate LTCR

As defined in Attachment AE of the Tariff.
Transmission Congestion Right (TCR)

As defined in Attachment AE of the Tariff. A financial right that entitles the holder to a share of the congestion revenue collected in the Day Ahead Market.

Transmission Congestion Rights Markets

As defined in Attachment AE of the Tariff. The Auction Revenue Rights annual and monthly allocation processes and the annual and monthly Transmission Congestion Rights auctions.

3.2 Transmission Congestion Rights Markets

The structure of the TCR Markets includes annual nomination and allocation of Long-Term Congestion Rights (LTCRs) to Eligible Entities and annual and monthly nomination and allocation of Auction Revenue Rights (ARRs) to Eligible Entities followed by annual and monthly TCR Auctions. Eligible Entities for ARRs include Transmission Customers with firm SPP transmission service and entities with firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that have identified such service during the annual LTCR/ARR verification process. Eligible Entities for LTCRs include Transmission Customers with qualifying firm SPP transmission service and entities with qualifying firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within and through the SPP Region that have identified such qualifying service during the annual LTCR/ARR verification process. Entities with firm non-SPP transmission service (GFA) must agree between the parties as to which party is eligible to nominate LTCRs and/or ARRs. Additionally, Eligible Entities may request NITS, GFA NITS, FPTP and/or GFA FPTP incremental Candidate ARRs for firm transmission service confirmed following completion of the annual TCR auction.

Key features of the annual LTCR allocation process include:

1. Eligible Entities are awarded LTCRs that apply to the entire TCR year. Load Serving Entities (LSEs) are awarded LTCRs prior to consideration of LTCR awards for Eligible Entities that are not LSEs. Candidate LTCRs are only associated with eligible long-term firm transmission service with rollover rights.

2. All Candidate LTCRs are modeled in order to determine simultaneous feasibility of the Candidate LTCRs. LTCRs are only awarded up to the selected amount of simultaneously feasible Candidate LTCRs.
(a) Candidate LTCRs are evaluated for simultaneous feasibility for flows in the prevailing direction only with no simultaneous consideration of LTCR flows in the opposite direction (i.e., counterflow is not considered in the feasibility analysis);

(b) 50% of the SPP transmission system capability is available for allocation;

3. Awarded LTCRs are of the obligation type which means that the TCRs associated with the awarded LTCR could result in a payment or charge to the TCR holder in the Day-Ahead Market settlement of TCRs;

(a) Once awarded, the awarded LTCRs are guaranteed in subsequent years as long as the associated long-term firm SPP transmission service reservation remains in effect;

(b) Awarded LTCRs may be surrendered in subsequent years at the Market Participant's request;

4. Awarded LTCRs are initially ARRs which will automatically be self-converted to TCRs in the annual ARR allocation process.

Key features of the annual ARR allocation process include:

1. Eligible Entities nominate candidate ARRs separately for On-Peak and Off-Peak periods each month and season of the annual period in a three-round process;

2. Nominated candidate ARRs are awarded up to the amount that is simultaneously feasible;

3. Awarded ARRs are of the obligation type which means that the awarded ARR could result in a payment or charge to the ARR holder;

3. 100% of the SPP transmission system capability is available for allocation;

(a) All awarded LTCRs are accounted for prior to assessing nominated ARR feasibility;

(b) Awarded ARRs are of the obligation type which means that the awarded ARR could result in a payment or charge to the ARR holder. Awarded LTCRs are converted to ARRs and included in the total ARR awards for settlement purposes;

4. Holders of ARRs receive positive or negative revenue resulting from the annual and monthly TCR auctions, including those ARRs that were self-converted to TCRs. ARRs associated with LTCRs are automatically self-converted into TCRs for settlement purposes. Positive auction revenue results when the sink Auction Clearing Price (ACP)
is greater than the source ACP for a given ARR. Negative revenue results when the sink ACP is less than the source ACP, in other words, a counterflow ARR.

(a) For the annual TCR auction, the amount of ARRs eligible to receive auction revenues is equal to the greater of ARRs self-converted to TCRs or the amount of ARRs awarded multiplied by the following percentages: June – 100%; July through September, 90%; and Fall, Winter, Spring – 60%.

(b) For the monthly TCR auction for the months of July through September, the amount of ARRs eligible to receive auction revenues is equal to the amount of ARRs awarded in the incremental monthly ARR allocation process plus: the lesser of (i) 10% of the annual ARR award or (ii) the difference between the annual ARR award and the amount of self-converted TCRs in the annual TCR auction;

(c) For the monthly TCR auction for the months of October through May, the amount of ARRs eligible to receive auction revenues is equal to the amount of ARRs awarded in the incremental monthly ARR allocation process plus: the lesser of (i) 40% of the annual ARR award or (ii) the difference between the annual ARR award and the amount of self-converted TCRs in the annual TCR auction.

Key features of the annual TCR auction include:

(1) Any Market Participant that meets the applicable credit requirements may submit TCR Bids to purchase (for which the entity is the owner of record) and/or TCR Offers to sell separately for On-Peak and Off-Peak periods in the annual TCR auction for each month and season in the annual period;

(a) ARRs resulting from LTCRs are automatically self-converted into TCRs prior to auction clearing and are modeled as fixed injections/withdrawals. These TCRs may be offered for sale in the annual or monthly TCR auction process;

(2) TCRs are of the obligation type which means that the awarded TCR could result in a payment or charge to the TCR holder in the DA Market settlement;

(3) The annual TCR auction is a single process for the month of June that makes 100% of the available SPP transmission system capability available, is a single round process for the months of July, August and September that makes 90% of the available SPP transmission system capability available and is a single round process for the Fall, Winter and Spring seasons that makes 60% of the available SPP transmission system capability available;

(3) Market Participants who have TCR bids cleared in the annual TCR auction will be charged (or get paid in the case of a counter-flow TCR) based on the amount of TCR
MWs cleared and the annual TCR auction clearing prices associated with the source and sink of the offered/purchased TCR;

(4) Market Participants who have TCR offers cleared in the annual TCR auction will be paid (or get charged in the case of a counter-flow TCR) based on the amount of TCR MWs cleared and the annual TCR auction clearing prices associated with the source and sink of the TCR sold;

(3) and

(4)(5) Market Participants holding ARRs not associated with LTCRs may self-convert their ARRs into TCRs for the applicable period subject to simultaneous feasibility. TCRs from self-converted ARRs, including TCRs self-converted from ARRs associated with LTCRs, are included as awarded TCRs.

Key features of the monthly incremental monthly ARR allocation include:

(1) Eligible Entities must submit a request to SPP specifying the NITS Incremental Candidate ARRs, GFA NITS Incremental Candidate ARRs, FPTP Incremental Candidate ARRs and/or GFA FPTP Incremental Candidate ARRs desired that are associated with the confirmed firm transmission service and the request must be submitted ten days prior to the start of the applicable monthly TCR auction process to be eligible to participate in the upcoming monthly TCR auction;

(2)(1) SPP verifies new firm transmission service reservations the request and performs a monthly incremental ARR allocation process beginning five days prior to the applicable monthly TCR auction process.

(a) Eligible Entities may nominate candidate ARRs from their verified NITS Incremental–Candidate ARRs not to exceed the difference between their NITS ARR Nomination Cap and the ARRs awarded in the annual ARR allocation process, from nominated NITS Candidate ARRs in the annual ARR allocation process;

(b) Eligible Entities may nominate candidate ARRs from their verified FPTP Incremental–Candidate ARRs not to exceed the difference between their FPTP ARR Nomination Cap and the ARRs awarded from nominated FPTP Candidate ARRs in the annual ARR allocation process in the annual ARR allocation process;

(c) Eligible Entities may nominate candidate ARRs from their verified GFA NITS Incremental–Candidate ARRs not to exceed the difference between their GFA
NITS ARR—Nomination Cap and those ARRs awarded from nominated GFA NITS Candidate ARRs in the annual ARR allocation process;

(d) Eligible Entities may nominate candidate ARRs from their verified GFA FPTP Incremental—Candidate ARRs not to exceed the difference between their GFA FPTP ARR—Nomination Cap and those ARRs awarded from nominated GFA FPTP Candidate ARRs in the annual ARR allocation process;

(e) Nominated candidate ARRs are awarded up to the amount that is simultaneously feasible;

(f) All TCRs previously awarded in the Annual TCR Auction Process—and all remaining ARRs not accounted for in the Annual TCR Auction Process for the applicable month are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks prior to assessing nominated incremental candidate ARR feasibility.

(3)(2) Awarded incremental ARRs are of the obligation type which means that the awarded incremental ARR could result in a payment or charge to the ARR holder; and

(4)(3) 100% of the SPP transmission system capability is available for allocation.

Key features of the monthly ARR-TCR auction include:

1. The monthly TCR auction process allows any Market Participants that have met the applicable credit requirements to submit TCR Bids to purchase additional TCRs or TCR Offers to sell currently held TCRs in a single-round process for the months of July, August and September and in a two-round process for the months of October through May;

2. 100% of the SPP transmission system capability is made available; and

3. Market Participants may self-convert their remaining ARRs (including ARRs remaining from the annual TCR auction process and ARRs awarded in the incremental monthly ARR allocation process) into TCRs for the applicable period subject to simultaneous feasibility.

Exhibit 3-3 provides an overview of the TCR Markets structure.

**Exhibit 3-3: Overview of TCR Markets Structure**
The TCR Markets are operated in parallel with the timeline depicted in Exhibit 3-2 to ensure the Market Participants are able to obtain TCRs prior to DA Market operation. A representative timeline for the TCR Market processes is shown in Exhibit 3-4.
The Energy and Operating Reserve Markets processes are described in detail in Section 4 and the TCR Markets processes are described in detail in Section 5.

5. Transmission Congestion Rights Markets Process

The annual TCR Markets Process includes an annual **LTCR allocation process**, an annual and monthly **ARR allocation process** and annual and monthly TCR Auctions.

**LTCRs are multi-year instruments, ARRs are annual, monthly or seasonal instruments, and TCRs are monthly and seasonal financial instruments whose values are determined as part of the DA Market settlement based on the MW amount of the TCR (including LTCRs converted to TCRs) and the DA Market differential of the Marginal Congestion Component of LMP between specified sinks and sources. TCRs are of the obligation type which means they can result in a credit or a charge. They provide a financial hedge against congestion costs in the DA Market as long as the MCC of the TCR sink Settlement Location is greater than the MCC of the TCR source Settlement Location. If the MCC at the TCR sink Settlement Location is less than the MCC of the TCR source Settlement Location, the TCR holder is charged (this type of TCR is commonly referred to as a “Counter-Flow TCR”).**
Auction Revenue Rights (ARRs) are obtained by Eligible Entities during the annual ARR allocation process and/or incremental monthly ARR allocation process. LTCRs are automatically converted into ARRs and TCRs for modeling and settlement purposes. Holders of ARRs are entitled to receive the Annual and Monthly TCR Auction revenues associated with awarded TCR Bids. However, ARRs are of the obligation type which means they can result in the holder receiving a portion of the TCR auction revenues or contributing to the TCR auction revenues.

TCRs are obtained by Market Participants through the Annual and Monthly TCR Auctions. Optionally, ARR holders may directly convert their ARRs into TCRs in the Annual and Monthly TCR Auctions and either hold the TCRs or offer these TCRs for sale in the auctions. ARRs associated with LTCRs are automatically converted into TCRs which may be sold in the annual and Monthly TCR auctions.

The TCR Markets Process is subject to review by the Market Monitor, as needed.

There are 8 steps associated with obtaining an LTCR or TCR and/or offering an awarded LTCR or TCR for sale.

(1) Annual LTCR/ARR Verification Process;
(2) Annual ARR Verification Process;
(3) Annual LTCR Allocation Process;
(4) Annual TCR Auction Process;
(5) Monthly ARR Allocation Process;
(6) Monthly TCR Auction Process;
(7) Incremental ARR Allocation Process (if requested by Eligible Entity);
(8) ARR Allocation and TCR Auction Settlements; and
(9) TCR Secondary Markets.

Exhibit 5-1 provides an overall representative timeline related to the LTCR Allocation, ARRA Allocation and TCR Auction processes and Exhibit 5-2 provides additional details related to auction timing and available transmission system capability of the TCR Auction processes.
Exhibit 5-1: LTCR/ARR Allocation and TCR Auction Processes Timeline
# Exhibit 5-2: TCR Auction Processes Summary

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¹ October and November  
² December, January, February, March  
³ April and May
Key process and design assumptions of each of these seven (7) key steps are described in the following sub-sections.

5.1 Annual LTCR/ARR Verification Process

Only Eligible Entities are eligible to nominate candidate LTCRs and/or ARRs as described under Sections 5.2 and 5.3. Eligible Entities for ARRs are Transmission Customers with firm SPP transmission service and entities with firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that has been confirmed prior to the Annual ARR Allocation Process. Eligible Entities for LTCRs are Transmission Customers with qualifying firm SPP transmission service and entities with qualifying firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that has been confirmed prior to the Annual LTCR Allocation Process. Eligible Entities must verify such services with SPP during the Annual LTCR/ARR Verification Process in order to be eligible to nominate candidate LTCRs and/or ARRs. All Eligible Entities must be a Market Participant and/or Asset Owner. The following rules apply to verification of transmission service for conversion to LTCRs and/or ARRs.

5.1.1 Transmission Service Verification

In order for Eligible Entities to obtain candidate LTCRs and/or ARRs, SPP must first verify existing transmission service entitlements, including transmission service entitlements which have been renewed in accordance with rollover rights since their initial term. In order to qualify for candidate LTCRs, an Eligible Entity’s firm transmission service must contain rollover rights and must span the entire allocation year. In order to qualify for candidate ARRs in a particular month and/or season, an Eligible Entity’s transmission service must span the entire monthly or seasonal period within the applicable allocation year. SPP will verify each Eligible Entity’s existing transmission service entitlements as follows:

1. For Eligible Entities taking Network Integration Transmission Service (NITS) and/or Firm Point-To-Point Transmission Service (FPTP) under the SPP Tariff:
   a. SPP will obtain source, sink and Reserved Capacity information from the SPP OASIS for each monthly and seasonal period for the applicable year in which the transmission service spans the entire period for ARR purposes and for the annual period for the applicable year for LTCR purposes;
   b. Eligible Entities taking NITS with rollover rights shall be considered an LSE for purposes of LTCR allocation.
(c) Eligible Entities taking FPTP service with rollover rights shall not be considered an LSE for that service unless the Eligible Entity provides an attestation to SPP confirming that the Eligible Entity is an LSE as defined in Attachment AE of the Tariff for such service;

(b)(d) For a TSR with a source inside the SPP Market that is not a specific Resource or Resource Hub, the lead Settlement Location that most closely corresponds to the source on the reservation will be utilized as the source for candidate LTCRs and/or ARRs;

(e)(c) For a TSR with a source outside of the SPP Market, the Interface Settlement Location associated with the Balancing Authority of the source will be utilized as the source for candidate LTCRs and/or ARRs;

(f) For a TSR with a sink outside of the SPP Market, the Interface Settlement Location associated with the Balancing Authority of the sink will be utilized as the sink for candidate LTCRs and/or ARRs;

(g)(g) SPP will provide this information to each Eligible Entity for verification;

(h)(h) Eligible Entities will notify SPP within two (2) weeks following receipt of this information identifying and correcting inaccurate data. Otherwise, the SPP provided data will be considered verified.

(2) For Eligible Entities taking GFA service:

(a) If the transmission customer under the GFA desires to nominate ARRs associated with the GFA sources and sinks identified in the Grandfathered Agreement, the GFA Parties must notify SPP that register such GFA with SPP exist and provide SPP with sources, sinks and Reserved Capacity information. SPP will obtain source, sink and Reservation Capacity information from the GFA registration for each monthly and seasonal period for the applicable year in which the transmission service spans the entire period.

(b) Eligible Entities taking the equivalent of SPP NITS with rollover rights shall be considered an LSE for purposes of LTCR allocation;

(c) Eligible Entities taking the equivalent of SPP FPTP service with rollover rights shall not be considered an LSE for that service unless the Eligible Entity provides an attestation to SPP confirming that the Eligible Entity is an LSE as defined in Attachment AE of the Tariff for such service;

(d)(d) For a GFA with a source inside the SPP Market that is not a specific Resource or Resource Hub, the lead Settlement Location that most closely corresponds to
the source on the reservation will be utilized as the source for candidate LTCRs and/or ARR.

(4)(c) For a GFA with a source outside of the SPP Market, the interface associated with the Balancing Authority of the source will be utilized as the source for candidate LTCRs and/or ARR.

(4)(d) For a GFA with a sink outside of the SPP Market, the interface associated with the Balancing Authority of the sink will be utilized as the sink for candidate LTCRs and/or ARR.

(4)(e)(g) In addition, the parties to the GFA must agree that the transmission customer under the GFA is eligible to nominate the LTCRs and/or ARR associated with the GFA and both parties must confirm such with SPP. To the extent that the transmission service specified in the GFA is identified as the equivalent of SPP NITS, the transmission customer under the GFA must provide the historical non-coincident annual peak loads ("GFA Annual Peak Load") being served under the GFA, for the previous three years since February 1, 2007.

5.1.2 Candidate LTCRs/ARRs

Following verification of Eligible Entity transmission service, candidate LTCRs and ARR associated with such transmission service are assigned as follows:

(1) For each Eligible Entity with NITS, the Eligible Entity’s NITS Candidate LTCRs and/or ARR from a specific source is then equal to the source Reserved Capacity.

(a) An Eligible Entity may nominate LTCRs, as described under Section 5.2.64, from a specific source to one or more sinks up to the amount of its available NITS Candidate ARR associated with the source subject to the total nomination limit described under Section 5.1.3.

(b) An Eligible Entity may nominate NITS Candidate ARR, as described under Section 5.3.1 from a specific source to one or more sinks up to the amount of its NITS Candidate ARR associated with the source subject to the total nomination limit described under Section 5.1.3.

(2) For each Eligible Entity with FPTP service, the Eligible Entity’s FPTP Candidate LTCRs and/or ARR for a specific source and sink is equal to the Reserved Capacity associated with that source and sink.

(a) An Eligible Entity may nominate FPTP Candidate ARR-LTCRs, as described under Section 5.2.64, for this specific source and sink up to the
amount of its available FPTP Candidate ARR-LTCRs subject to the total nomination limit described under Section 5.1.3.

(b) An Eligible Entity may nominate FPTP Candidate ARRs, as described under Section 5.3.1, for this specific source and sink up to the amount of its FPTP Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

(3) For each Eligible Entity with equivalent NITS GFA service, the Eligible Entity’s GFA NITS Candidate LTCRs and/or ARRs from a specific source is equal to the source Reserved Capacity.

(a) An Eligible Entity may nominate GFA NITS Candidate LTCRs, as described under Section 5.2.645.2.1, from a specific source to one or more sinks up to the amount of its available GFA NITS Candidate LTCRs, subject to the total nomination limit described under Section 5.1.3.

(b) An Eligible Entity may nominate GFA NITS Candidate ARRs, as described under Section 5.3.1, for this specific source and sink up to the amount of its GFA NITS Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

(4) For each Eligible Entity with equivalent FPTP GFA service, the Eligible Entity’s GFA FPTP Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reserved Capacity associated with that source and sink.

(a) An Eligible Entity may nominate GFA FPTP Candidate LTCRs, as described under Section 5.2.645.2.1, for this specific source and sink up to the amount of its available GFA FPTP Candidate LTCRs subject to the total nomination limit described under Section 5.1.3.

(b) An Eligible Entity may nominate GFA FPTP Candidate ARRs, as described under Section 5.3.1, for this specific source and sink up to the amount of its GFA FPTP Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

5.1.3 ARR Nomination Cap

An Eligible Entity’s ARR Nomination Cap will be as follows:

(1) For NITS Transmission Customers, the NITS ARR Nomination Cap is equal to the minimum of a) the sum of NITS Candidate ARRs and NITS Candidate LTCRs as calculated under Section 5.1.2 and NITS Incremental Candidate ARRs, as calculated...
under Section 5.5.2, br b) one hundred and three (103%) of the average of that customer’s three most recent annual peak Network Loads. This value may will be adjusted by SPP as required to account for wholesale load shifts between Transmission Customers. In addition, NITS Candidate LTCRs and awarded NITS Candidate LTCRs associated with wholesale load shifts shall be transferred by SPP as applicable;

(2) For FFTP Transmission Customers, the FFTP ARR Nomination Cap is equal to the sum of FFTP Candidate ARRs and FFTP Candidate LTCRs as calculated under Section 5.1.2 and FFTP Incremental Candidate ARRs as calculated under Section 5.5.2.

(3) For GFA customers taking the equivalent of SPP NITS, the GFA NITS ARR Nomination Cap is equal to the minimum of a) the sum of GFA NITS Candidate ARRs and GFA NITS Candidate LTCRs as calculated under Section 5.1.2 and b) one hundred and three percent (103%) of the average of that customer’s three most recent annual peak Network Loads of the average of that customer’s three highest GFA Annual Peak Loads since February 1, 2007.

(4) For GFA customers taking the equivalent of SPP FFTP, the GFA FFTP ARR Nomination Cap is equal to the sum of GFA FFTP Candidate ARRs and GFA FFTP Candidate LTCRs as calculated under Section 5.1.2 and FFTP Incremental Candidate ARRs as calculated under Section 5.5.2.

(5) An Eligible Entity’s ARR Nomination Cap is equal the sum of its NITS ARR Nomination Cap, FFTP ARR Nomination Cap, GFA NITS ARR Nomination Cap and GFA FFTP ARR Nomination Cap.

5.2 Annual LTCR Allocation Process

The Annual LTCR Allocation Process addresses how candidate LTCRs verified in the Annual LTCR/ARR Verification Process may be selected and awarded as LTCRs. The annual allocation process determines the portion of the candidate LTCRs that are simultaneously feasible and available to each ELigible Entity to select. 50% of the SPP Residual Transmission System Capability, as defined under Section 5.2.2(2), is made available during the Annual LTCR Allocation Process. Candidate LTCRs are evaluated on an annual basis in a two-step process. The first step evaluates LSE candidate LTCRs to determine LSE available LTCRs. The second step evaluates non-LSE candidate LTCRs associates. No later than five (5) Business Days prior to the start of the Annual LTCR Allocation Process, SPP will post the transmission system network topology data for the annual model, along with corresponding Parallel Flow assumptions, that SPP will use in the upcoming allocation process for use by Eligible Entities in
developing their available candidate LTCR selection strategies. The following rules apply to the
annual allocation of LTCRs.

5.2.1 LTCR Surrender

Eligible Entities may surrender previously awarded LTCRs in 0.1 MW increments. Prior to
annual LTCR allocation, Eligible Entities submit the following information:

(1) Source (valid candidate LTCR source Settlement Location);
(2) Sink (valid candidate LTCR sink Settlement Location);
(3) Surrendered LTCR MW (cannot exceed previously awarded LTCR).

5.2.2 Candidate LTCR Simultaneous Feasibility for LSEs

A simultaneous feasibility test (SFT) is performed to determine the feasibility of all NITS
Candidate LTCRs, FPTP Candidate LTCRs, GFA NITS Candidate LTCRs and GFA FPTP
Candidate LTCRs identified as described under Section 5.1.2 for all LSEs. All LSE candidate
LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal
at the sink. The feasibility analysis assures the modeling of the LSE candidate LTCRs does not
violate any normal transmission line thermal ratings under normal system conditions and does
not violate short-term Emergency transmission line thermal ratings following a single
contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission
system loading analysis that is performed as part the Security Constrained Economic Dispatch
process in the DA Market and includes consideration of the impact of Parallel Flow.

(1) The SPP Transmission System topology used in the SFT is the most up-to-date
Network Model.

   (a) For withdrawals at Settlement Locations containing more than one PNode, SPP
will distribute the Settlement Location withdrawal down to the PNode level using
load distribution percentages from the peak hour of the corresponding most recent
historical period (i.e., prior year peak). These load distribution percentages are
calculated using the methodology described under Section 4.1.2.1.6.

   (b) For injections at Market Hubs, SPP will distribute the hub injection down to the
PNode level on a pro-rata basis using the weighting factors defined when the hub
is created.

(2) Prior to assessing simultaneous feasibility, the normal and emergency ratings of all
flowgates and monitored transmission system elements are adjusted as follows to arrive
at an SPP Residual Transmission System Capability:
(a) Adjusted Monitored Transmission Line Rating (normal and Emergency) =
(Monitored Transmission Line Rating [normal and Emergency –
Parallel Flow impact])

(b) Adjusted Flowgate Rating (normal and Emergency) =
(Flowgate Rating – Parallel Flow impact)

(3) The feasibility analysis evaluates the candidate LTCR feasibility by evaluating line
flows against path limits in a single direction only without simultaneous consideration of
line flows created by candidate LTCRs in the opposite direction (i.e., counter-flow will
not act to increase the feasibility of candidate LTCRs).

(4) The feasibility analysis uses an iterative process to ensure that previously awarded
LTCRs that have not been surrendered as indicated pursuant to Section 5.2.1 continue to
be available.

(a) For the initial feasibility analysis, no previously awarded LSE LTCRs or
surrendered LSE LTCRs are modeled. Only candidate LSE LTCRs are modeled.

(b) Previously awarded LTCRs associated with qualified transmission service as
verified under Section 5.1.1 and which were not surrendered, associated with non-
LSEs are modeled as fixed injections and withdrawals. To the extent that these
fixed injections and withdrawals are not feasible, SPP will increase the ratings of
the applicable transmission lines to ensure feasibility prior to assessing LSE
LTCR availability. SPP will report back to the MWG when transmission line
ratings had to be adjusted to ensure feasibility.

(c) If the results of the initial feasibility analysis show that the amount of LSE LTCRs
feasible on specific paths are less than those LSE LTCRs previously awarded on
those paths, net of any surrendered LSE LTCRs, the feasibility analysis is rerun
with all previously awarded LSE LTCRs, net of any surrendered LSE LTCRs, on
such paths modeled as fixed injections/withdrawals and all candidate LSE LTCRs
on all other paths are modeled as in (a) above. To the extent that these fixed
injections and withdrawals are not feasible, SPP will increase the ratings of the
applicable transmission lines to ensure feasibility. SPP will report back to the
MWG when transmission line ratings had to be adjusted to ensure feasibility.

5.2.3 Annual LTCRs Available for LSEs

If all of the candidate LSE LTCRs are confirmed feasible, all candidate LSE LTCRs are
available. If candidate LSE LTCRs are not feasible, the amount of candidate LSE LTCRs
available will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the candidate LSE LTCR MW weighted by the reciprocal of the candidates resulting in a higher percentage LSE LTCR reduction for those candidates having the greatest impact on the constraints. LSE LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

5.2.4 Candidate LTCR Simultaneous Feasibility for Non-LSEs

A simultaneous feasibility test (SFT) is performed to determine the feasibility of all NITS Candidate LTCRs, FPTP Candidate LTCRs, GFA NITS Candidate LTCRs and GFA FPTP Candidate LTCRs identified as described under Section 5.1.2 for all non-LSEs. All non-LSE candidate LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. The feasibility analysis assures the modeling of the non-LSE candidate LTCRs does not violate any normal transmission line thermal ratings under normal system conditions and does not violate short-term Emergency transmission line thermal ratings following a single contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission system loading analysis that is performed as part of the Security Constrained Economic Dispatch process in the DA Market and includes consideration of the impact of Parallel Flow.

(1) The SPP Transmission System topology used in the SFT is the most up-to-date Network Model.
   (a) For withdrawals at Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. prior year peak). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.
   (b) For injections at Market Hubs, SPP will distribute the hub injection down to the PNode level on a pro-rata basis using the weighting factors defined when the hub is created.

(2) Prior to assessing simultaneous feasibility, the normal and emergency ratings of all flowgates and monitored transmission system elements are adjusted as follows to arrive at an SPP Residual Transmission System Capability:
   (c) Adjusted Monitored Transmission Line Rating (normal and Emergency) =
       (Monitored Transmission Line Rating (normal and Emergency – Parallel Flow impact))
   (d) Adjusted Flowgate Rating (normal and Emergency) =

Comment [MPR90.26]: MPR90 Awaiting FERC approval
(Flowgate Rating – Parallel Flow impact)

(3) The feasibility analysis evaluates the candidate LTCR feasibility by evaluating line flows against path limits in a single direction only without simultaneous consideration of line flows created by candidate LTCRs in the opposite direction (i.e., counter-flow will not act to increase the feasibility of candidate LTCRs).

(4) The feasibility analysis uses an iterative process to ensure that previously awarded LTCRs that have not been surrendered as indicated pursuant to Section 5.2.1 continue to be available.

(a) For the initial feasibility analysis, no previously awarded non-LSE LTCRs or surrendered non-LSE LTCRs are modeled. Only candidate non-LSE LTCRs are modeled.

(b) Available LSE LTCRs as calculated under Section 5.2.3 are modeled as fixed injections and withdrawals.

(c) If the results of the initial feasibility analysis show that the amount of non-LSE LTCRs feasible on specific paths are less than those non-LSE LTCRs previously awarded on those paths associated with qualified transmission service as verified under Section 5.1.1 and which were not surrendered, net of any surrendered non-LSE LTCRs, the feasibility analysis is rerun with all previously awarded non-LSE LTCRs, net of any surrendered non-LSE LTCRs, on such paths modeled as fixed injections/withdrawals and all candidate non-LSE LTCRs on all other paths are modeled as in (a) above. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to LSE LTCR availability. SPP will report back to the MWG when transmission line ratings had to be adjusted to ensure feasibility.

5.2.5 Annual LTCRs Available for Non-LSEs

If all of the candidate non-LSE LTCRs are confirmed feasible, all candidate non-LSE LTCRs are available. If candidate non-LSE LTCRs are not feasible, the amount of candidate non-LSE LTCRs available will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the candidate non-LSE LTCR MW weighted by the reciprocal of the candidates resulting in a higher percentage non-LSE LTCR reduction for those candidates having the greatest impact on the constraints. Non-LSE LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.
The Transmission Provider will post the amounts of candidate non-LSE LTCRs which are available for the non-LSE Eligible Entity's selection.

5.2.6 LTCR Selections and Awards

(1) All previously awarded LTCRs associated with qualified transmission service as verified under Section 5.1.1 and which were not surrendered, as described under Section 5.2.1, are automatically awarded as LTCRs for the current allocation year.

(2) Additional available candidate LTCRs are selected and awarded in a single-round process. Eligible Entities may select:

(a) Available LTCRs from their NITS Candidate LTCRs as described under Section 5.2.3 or Section 5.2.5, less any previously awarded LTCRs plus any surrendered LTCRs associated with NITS Candidate LTCRs;

(b) Available LTCRs from their FPTP Candidate LTCRs as described under Section 5.2.3 or Section 5.2.5, less any previously awarded LTCRs plus any surrendered LTCRs associated with FPTP Candidate LTCRs;

(c) Available LTCRs from their GFA NITS Candidate LTCRs as described under Section 5.2.3 or Section 5.2.5, less any previously awarded LTCRs plus any surrendered LTCRs associated with GFA NITS Candidate LTCRs;

(d) Available LTCRs from their GFA FPTP Candidate LTCRs as described under Section 5.2.3 or Section 5.2.5, less any previously awarded LTCRs plus any surrendered LTCRs associated with GFA FPTP Candidate LTCRs;

(3) Eligible Entities must submit the following information in order to select LTCRs:

(a) Source (valid candidate LTCR source Settlement Location);

(b) Sink (valid candidate LTCR sink Settlement Location);

(c) Selected LTCR MW (total LTCR MW nominated from a source Settlement Location cannot exceed the source candidate available LTCR MW as previously determined under Section 5.2.3 or Section 5.2.5, less previously awarded LTCRs plus surrendered LTCRs);

(4) All selected LTCRs are automatically awarded.

5.3 Annual ARR Allocation Process

The Annual ARR Allocation Process addresses how candidate ARRs verified in the Annual LTCR/ARR Verification Process may be nominated and converted to ARRs. Eligible Entities
may nominate the candidate ARRs that they wish to receive up to their ARR-Nomination Caps less any LTCRs awarded plus any LTCRs surrendered. Any candidate LTCRs not awarded in the Annual LTCR Allocation Process and surrendered LTCRs become candidate ARRs. The annual allocation process determines the portion of the nominated candidate ARRs that are simultaneously feasible to allocate to each Eligible Entity. 100% of the SPP Residual Transmission System Capability, as defined under Section 5.2.2(2), is made available during the Annual ARR Allocation Process. Candidate ARRs are nominated on a monthly and seasonal basis in a three-round process. No later than five (5) Business Days prior the start of the Annual ARR Allocation Process, SPP will post the transmission system network topology data for each of the monthly and seasonal on-peak and off-peak models, along with corresponding Parallel Flow and transmission line outage assumptions, that SPP will use in the upcoming allocation process for use by Eligible Entities in developing their candidate ARR nomination strategies. Exhibit 5-3 provides a representative timeline of the three-round annual ARR allocation process.
Exhibit 5-3: Annual ARR Allocation Process Timeline

The following rules apply to the annual allocation of ARRs.

### 5.3.1 ARR Nominations

For each month and season included in the Annual ARR Allocation Process period, Eligible Entities may nominate candidate ARRs in 0.1 MW increments for specific source to sink pairs that total up to their ARR Nomination Caps as calculated under Section 5.1.3. Nominations occur separately for On-Peak and Off-Peak periods (8 separate transmission system models created representing each month in an annual allocation period and on-peak and off-peak periods within each month and 6 separate transmission system models created representing each season in an annual allocation period and on-peak and off-peak periods within each season). Prior to each ARR nomination round, Eligible Entities submit the following information:

1. **Source** (valid candidate ARR source Settlement Location for Rounds 1 and 2, any source Settlement Location for Round 3);

2. **Sink** (valid candidate ARR sink Settlement Location for Rounds 1 and 2, any sink Settlement Location for Round 3);

3. **Class** (on-peak or off-peak);
(4) Period (month or season);

(5) Nominated ARR MW.

(a) In Round 1 and Round 2, the total candidate ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs less awarded source LTCRs.

(b) In Round 3, any source to sink path may be nominated, subject to the limitation described under Section 5.2.2(3).

5.3.2 ARR Allocation

ARRs are allocated in a three-round process as follows:

(1) In Round 1, Eligible Entities may nominate:

(a) ARRs from their NITS Candidate ARRs that total to no more than the greater of (i) zero or (ii) 50% of their NITS ARR Nomination Cap less the sum of their awarded LTCRs from their NITS Candidate LTCRs;

(b) ARRs from their GFA NITS Candidate ARRs that total to no more than the greater of (i) zero or (ii) 50% of their GFA NITS ARR Nomination Cap less the sum of their awarded LTCRs from their GFA NITS Candidate LTCRs;

(c) ARRs from their FPTP Candidate ARRs that total to no more than the greater of (i) zero or (ii) 50% of their FPTP ARR Nomination Cap less the sum of their awarded LTCRs from their FPTP Candidate LTCRs; and

(d) ARRs from their GFA FPTP Candidate ARRs that total to no more than the greater of (i) zero or (ii) 50% of their GFA FPTP ARR Nomination Cap less the sum of their awarded LTCRs from their GFA FPTP Candidate LTCRs.

(2) In Round 2, Eligible Entities may nominate:

(a) ARRs from their NITS Candidate ARRs that total to no more than the greater of (i) zero or (ii) 100% of their NITS ARR Nomination Cap less any nominated NITS Candidate ARRs awarded in Round 1 and less the sum of their awarded LTCRs from their NITS Candidate LTCRs;

(b) ARRs from their GFA NITS Candidate ARRs that total to no more than the greater of (i) zero or (ii) 100% of their GFA NITS ARR Nomination Cap less any nominated GFA NITS Candidate ARRs awarded in Round 1 and less the sum of their awarded LTCRs from their GFA NITS Candidate LTCRs.
(c) ARR(s) from their FPTP Candidate ARR(s) that total to no more than the greater of (i) zero or (ii) 100% of their FPTP ARR—Nomination Cap less any nominated FPTP Candidate ARR(s) awarded in Round 1 and less the sum of their awarded LTCRs from their FPTP Candidate LTCRs; and

(d) ARR(s) from their GFA FPTP Candidate ARR(s) that total to no more than the greater of (i) zero or (ii) 100% of their GFA FPTP ARR—Nomination Cap less any nominated GFA FPTP Candidate ARR(s) awarded in Round 1 and less the sum of their awarded LTCRs from their GFA FPTP Candidate LTCRs.

(3) In Round 3, Eligible Entities may nominate ARR(s) from any source to sink that total to no more than the greater of (i) zero or (ii) 100% of their ARR—Nomination Cap less any nominated candidate ARR amounts awarded in Rounds 1 and 2 and less the sum of their awarded LTCRs. In Round 3, a Market Participant is limited to a maximum combined submittal of 2000 ARR Nominations per product for each Asset Owner it represents.

Exhibit 5-4 provides an example of valid Round 1 NITS Candidate ARR nominations for a NITS Transmission Customer with a three year average historical annual peak load of 1942 MW, and total Candidate ARR(s) of 2400 MWs and 300 MWs of LTCRs.

Exhibit 5-4: Candidate ARR Nomination for NITS

<table>
<thead>
<tr>
<th>NITS ARR Nomination Cap</th>
<th>Round 1 ARR Nomination Limit</th>
<th>NITS Candidate ARR MW</th>
<th>Source</th>
<th>Sink</th>
<th>LTCR</th>
<th>Nominated NITS Candidate ARR MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000 MW²</td>
<td>1000 MW²</td>
<td>1200</td>
<td>G1</td>
<td>L1</td>
<td>200</td>
<td>6800</td>
</tr>
<tr>
<td></td>
<td></td>
<td>800</td>
<td>G2</td>
<td>L1</td>
<td>100</td>
<td>1200</td>
</tr>
<tr>
<td></td>
<td></td>
<td>400</td>
<td>G3</td>
<td>L1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Total</td>
<td></td>
<td></td>
<td>300</td>
<td>49700</td>
</tr>
</tbody>
</table>

5.3.3 Simultaneous Feasibility

A Simultaneous Feasibility Test (SFT) analysis is performed in each round to ensure that the nominated candidate ARR(s), with nominated candidate ARR MW modeled as generation injection at the source and a corresponding load withdrawal at the sink, do not violate any

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² Less than 1.0³ * 1942 MW or 2400 MW
³ 50% of NITS ARR Nomination Cap
normal transmission line thermal ratings under normal system conditions and do not violate short-term Emergency transmission line thermal ratings following a single contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission system loading analysis that is performed as part the Security Constrained Economic Dispatch process in the DA Market and includes consideration of the impact of Parallel Flow. **100% of the SPP Residual Transmission System Capability, as defined under Section 5.2.2(2), is made available during the analysis.**

1. The SPP Transmission System topology used in the SFT is the most up-to-date Network Model for all allocation periods, updated for forecasted transmission topology changes including planned maintenance outages.
   
   a. For withdrawals at **link** Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June, July, August, September, Fall, Winter and Spring). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1,  6.
   
   b. For injections at Market Hubs, SPP will distribute the hub injection down to the PNode level on a pro-rata basis using the weighting factors defined when the hub is created.

2. All previously awarded LTCRs that have not been surrendered are modeled as fixed injections/withdrawals.

   a. Prior to assessing simultaneous feasibility, the normal and emergency ratings of all flowgates and monitored transmission system elements are adjusted as follows to arrive at an SPP Residual Transmission System Capability:

   b. **Adjusted Monitored Transmission Line Rating (normal and Emergency)** =

      (Monitored Transmission Line Rating (normal and Emergency - Parallel Flow impact))

   c. **Adjusted Flowgate Rating (normal and Emergency)** =

      (Flowgate Rating - Parallel Flow impact)

   Every six (6) months for the first two (2) years after implementation of the Integrated Marketplace, SPP will analyze the net funding of TCRs through the Day-Ahead Market and report to the MWG. In the event the cumulative funding is at or below 90% or above 100%, MWG may approve an additional adjustment of all subsequent monthly auctions and the month
of June in the annual auction of the normal and emergency ratings of all flowgates and monitored transmission system elements in (2) above.

5.3.4 Annual ARR Awards

All LTCR awards are automatically converted to ARR awards which are then automatically self-converted to TCRs in the Annual TCR Auction. If all of the nominated candidate ARRs are confirmed feasible, all nominated candidate ARRs are awarded. If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the nominated candidate ARR MW weighted by the reciprocal of the nominations resulting in a higher percentage ARR reduction for those nominations having the greatest impact on the constraints. ARR reductions associated with nominations that have an equal impact on the constraints are reduced by the same percentage.

5.4 Annual TCR Auction

The Annual TCR Auction Process is the mechanism through which Market Participants may obtain annual TCRs through submission of TCR Bids to purchase TCRs and/or through direct conversion of ARRs into TCRs through self-conversion. Various percentages of the SPP Residual Transmission System Capability, as calculated under Section 5.2.2.[123], is made available during the Annual TCR Auction Process as shown in Exhibit 5-2. TCRs in the annual auction are auctioned in a single round process for all months and seasons. TCRs that originated as LTCRs may be sold as TCRs during this single round process. If there are any changes to the transmission system topology or Parallel Flow data after the conclusion of Annual ARR Allocation Process, SPP will post such changes no later than three (3) Business Days prior to the start of the Annual TCR Auction Process. Exhibit 5-5 provides a representative timeline of the two-round and single round annual TCR auction process.
The following rules apply to the Annual TCR Auction:

**5.4.1 TCR Offer and Bid and Offer Submittal**

(1) Any Market Participant that has satisfied the applicable credit requirements may participate in the Annual TCR Auction;

(2) Market Participants holding ARRs may elect to self-convert all or a portion of those ARRs into TCRs with the same source and sink by specifying the Self-Convert option as part of the TCR Bid submittal. All ARRs associated with LTCRs are automatically converted to TCRs prior to the start of the Annual TCR Auction and these TCRs will be considered Self-Converted ARRs for the purposes of settlement. These TCRs can then be offered for sale in the Annual TCR Auction.

(3) For each month and season included in the Annual TCR Auction period, Market Participants may submit TCR Bids and TCR Offers in 0.1 MW increments separately, for On-Peak and Off-Peak periods (8 separate transmission system models created representing each month in an annual auction period and on-peak and off-peak periods within each month and 6 separate transmission system models created representing each season in an annual auction period and on-peak and off-peak periods within each season). The following information is submitted for a TCR Bid or a TCR Offer:

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Comment [MCRR5.30]: MCRR5 Awaiting FERC approval. Docket #ER12-1179.

Comment [MCRR5.31]: MCRR5 Awaiting FERC approval. Docket #ER12-1179.
(a) Source (any valid Settlement Location);
(b) Sink (any valid Settlement Location);
(c) Class (on-peak or off-peak);
(d) Period (month or season);
(e) Type (Bid, or Self-Convert, Offer);
(f) TCR MW;
(g) TCR Price ($/MW):
   (i) TCR Bids and Offers cannot exceed $100,000/MW-Month;
   (ii) TCR Bids and Offers cannot be less than ($100,000/MW-Month).

(4) For each TCR Round, a Market Participant is limited to a maximum combined submittal of 2000 TCR Bids and/or TCR Offers for each Asset Owner it represents.

5.4.2 Annual TCR Auction Process

TCRs are auctioned in a single-round process for each month and season using the SPP Residual Transmission System Capability as defined under Section 5.2.32(2) as follows:

(1) 100% of the SPP Residual Transmission System Capability is made available for the month of June, 90% of the SPP Residual Transmission System Capability is made available for the July-September period and 60% of the SPP Residual Transmission System Capability is made available for the Fall, Winter and Spring seasons;

   (a) TCR Bids of the Self-Convert Type may be submitted for each source to sink pair that the Market Participant desires to convert the associated ARR into TCRs. The Self-Convert Type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility.

   (b) Only Eligible Entities holding ARRs may submit a Self-Convert TCR Bid.

   (c) The Self-Convert TCR Bid must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated ARR MW.
5.4.3 Annual TCR Auction Clearing and Simultaneous Feasibility

The Auction is performed using a Linear Program algorithm with an objective function to maximize the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible.

1. The SFT is performed as described under Section 5.32.3 with TCR Bid MW modeled as an injection at the source and a corresponding withdrawal at the sink and TCR Offer MW modeled as an injection at the sink and a withdrawal at the source.

2. The SPP Transmission System topology and Parallel Flow assumptions used in the SFT are normally the same as used in the Annual ARR Allocation process. However, unforeseen events that drastically impact transmission system topology that occur following the ARR Allocation but prior to the Annual TCR Auction will be accounted for in the models for the Annual TCR Auctions.

5.4.4 Annual TCR Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. TCRs associated with LTCRs result from ARRs that automatically become Self-Converted TCRs for settlement purposes. Self-Converted TCRs not associated with LTCRs are evaluated simultaneously with submitted TCR Bids and Offers. In the event there is a tie during the SFT, the competing bids and offers will be awarded pro rata based on their impact(s) to the constraint(s). Auction Clearing Prices (ACP) are calculated for each Settlement Location using the formula for the Marginal Congestion Component as described under Section 4.5.4.1.2 (MCC; = - ( \sum_{k=1}^{K} Sens_{k} \times SP_k )).

For example, if we assume a 3 bus system (Bus A, B and C) and Bus A is the Reference Bus, we can calculate the ACP at Bus B as follows:

![Diagram of a 3 bus system with A, B, and C nodes connected by lines]
Transmission Line B-C is at its limit with a Shadow Price = $40/MW
Transmission Line A-C is at its limit with a Shadow Price = $30/MW
Transmission Line A-B is not at its limit (Shadow Price = $0/MW)
Shift Factor for Bus B on Line B-C is 30%
Shift Factor for Bus B on Line A-C is -80%
Then ACP at Bus B is equal to - [($40/MW * .3) + ($30/MW * (-.8))] = $12/MW
A similar calculation is performed for Bus C based on Bus C Shift Factors. The ACP at Bus A is equal to zero since Bus A is the Reference Bus.

5.5 [IncrementalMonthly] ARR Allocation Process

Eligible Entities with remaining candidate ARR capacities from the Annual ARR Allocation Process along with firm transmission service that has been confirmed following completion of the Annual TCR Auction Process and prior to the next Annual ARR Verification Process or with firm transmission service confirmed during prior to the Annual ARR Verification Process that includes a partial season for transmission service that is made available due to upgrades are eligible to nominate incremental candidate ARRs associated with such services. Incremental Candidate ARRs may be nominated for each remaining month in the current Annual ARR Allocation Process period for which the firm transmission service applies that was not eligible for conversion into ARRs during the Annual ARR Allocation Process. To the extent that the Eligible Entity’s firm transmission service term extends beyond the current Annual ARR Allocation Process period, such remaining service will be included in the next Annual ARR Verification Process. Eligible Entities must submit a request to SPP for conversion of such services into ARRs in order to be eligible to nominate incremental candidate ARRs. The following rules apply to verification of transmission service for conversion to incremental candidate ARRs.

5.5.1 [Incremental-Monthly] ARR Transmission Service Verification

In order for Eligible Entities to obtain incremental candidate ARRs, SPP must first verify existing transmission service entitlements. In order to qualify for incremental candidate ARRs in a particular month, an Eligible Entity’s transmission service must span the entire month within the applicable year. SPP will verify Eligible Entity existing transmission service entitlements as follows:

1. [Page 36] An Eligible Entity must submit a request to SPP no later than ten days prior to the start of the applicable TCR Monthly Auction Process specifying its desire to obtain incremental candidate ARRs associated with the approved and confirmed Transmission Service Request. The request must contain source, sink and Reserved Capacity information.
(2)(1) SPP will verify that the source, sink and Reserved Capacity information submitted has been accurately reflected on the SPP OASIS for the applicable month; and

(2)(2) SPP will notify the Eligible Entity for verification no later than two days following receipt of the request if the OASIS data does not match the data submitted in the request. Otherwise the Eligible Entity should consider the request approved;

(4) Eligible Entities will notify the Transmission Provider within six (6) days following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verifiedIf SPP notifies the Eligible Entity as described in (3) above that it cannot verify the Eligible Entity’s request, the Eligible Entity has no request with corrected data that matches the OASIS data no later than six days prior to the start of the applicable TCR Monthly Auction Process;

5.5.2 Incremental Candidate-ARRs

Following verification of Eligible Entity transmission service, incremental candidate ARRAs assigned with such transmission service are assigned as follows:

i. For each Eligible Entity with NITS confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s NITS Incremental Candidate-ARRs from a specific source is then equal to the source Reserved Capacity. An Eligible Entity may nominate NITS Incremental Candidate-ARRs, as described under Section 5.5.3 from a specific source to one or more sinks up to the amount of its NITS Incremental Candidate-ARRs associated with the source subject to its NITS ARR Nomination Cap described under Section 5.1.3;

ii. For each Eligible Entity with FPTP service confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s FPTP Incremental Candidate-ARRs for a specific source to sink pair is equal to the Reserved Capacity for that source to sink pair. An Eligible Entity may nominate FPTP Incremental Candidate-ARRs, as described under Section 5.5.3, for this specific source and sink pair up to the amount of its FPTP Incremental Candidate-ARRs subject to its FPTP ARR Nomination Cap described under Section 5.1.3;

(3) For each Eligible Entity with equivalent NITS GFA service confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s GFA NITS Incremental Candidate-ARRs from a specific
source is equal to the source Reserved Capacity. An Eligible Entity may nominate GFA NITS Incremental Candidate ARR, as described under Section 5.5.3, from a specific source to one or more sinks up to the amount of its GFA NITS Incremental Candidate ARR subject to the total nomination limit described under Section 5.1.3.

(4) For each Eligible Entity with equivalent FPTP GFA service confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s GFA FPTP Incremental Candidate ARR for a specific source to sink pair is equal to the Reserved Capacity associated with that source to sink pair. An Eligible Entity may nominate GFA FPTP Incremental Candidate ARRs, as described under Section 5.5.2, for this specific source to sink pair up to the amount of its GFA FPTP Incremental Candidate ARR subject to the total nomination limit described under Section 5.1.3.

Incremental-Monthly ARR Nominations

Five (5) days prior to the start of each applicable Monthly TCR Auction Process, Eligible Entities may nominate in a single round process (i) NITS Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their NITS ARR Nomination Cap and ARRs associated with NITS Candidate ARRs awarded in the Annual ARR Allocation process; (ii) FPTP Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their FPTP ARR Nomination Cap and ARRs associated with FPTP Candidate ARRs and FPTP Candidate LTCRs awarded in the Annual ARR Allocation process; (iii) GFA NITS Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their GFA NITS ARR Nomination Cap and ARRs associated with GFA NITS Candidate ARRs and GFA NITS Candidate LTCRs awarded in the Annual ARR Allocation process; and/or (iv) GFA FPTP Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their GFA FPTP ARR Nomination Cap and ARRs associated with GFA FPTP Candidate ARRs and GFA FPTP Candidate LTCRs awarded in the Annual ARR Allocation process. Nominations occur separately for On-Peak and Off-Peak periods. Eligible Entities submit the following information:

1. Source (valid Incremental Candidate ARR source Settlement Location);
2. Sink (valid Incremental Candidate ARR sink Settlement Location);
3. Class (on-peak or off-peak);
(4) ARR MW.

(a) The total ARR MW nominated from a source Settlement Location cannot exceed the source incremental candidate ARRs less previously awarded source ARRs.

5.5.3 Simultaneous Feasibility

The SFT to assess feasibility of nominated incremental monthly candidate ARRs is performed as described under Section 5.3.2.3 with the following adjustments:

(1) The SPP Transmission System model used in the SFT will be the same model to be used in the upcoming Monthly TCR Auction Process which will include the most up-to-date Network Model updated for forecasted transmission topology changes, including planned maintenance outages, and updated Parallel Flow assumptions.

(a) For withdrawals at sink Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June for the month of July). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

(2) LTCRs awarded in the Annual LTCR Allocation process are not modeled as fixed injections/withdrawals as they have already been accounted as part of the Annual TCR Auction process and are included as LTCRs as described under (4) below:

(3) 100% of the Residual SPP Transmission System Capability is made available; and

(4) All TCRs previously awarded in the Annual TCR Auction Process, TCRs associated with LTCRs that were awarded, and all remaining ARRs not accounted for in the Annual TCR Auction Process (as defined under Section 5.4.5.5), and for the applicable month are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to assessing incremental monthly ARR feasibility. SPP will report back to the MWG on a quarterly basis regarding the number of times that transmission line ratings had to be adjusted to ensure feasibility.

Incremental Monthly ARR Awards

If all of the nominated incremental candidate ARRs are confirmed feasible, all nominated incremental candidate ARRs are awarded in the form of ARRs. If the nominated incremental candidate ARRs are not feasible, the amount of ARRs to be awarded will be reduced using a
weighted least squares method. The weighted least squares method minimizes the least squares deviation from the nominated incremental candidate ARR MW weighted by the reciprocal of the nominations resulting in a higher percentage ARR reduction for those incremental candidate ARR nominations having the greatest impact on the constraints. ARR reductions associated with incremental candidate ARR nominations that have an equal impact on the constraints are reduced by the same percentage.

5.6 Monthly TCR Auction Processes

The Monthly TCR Auction Process is the mechanism through which Market Participants may obtain TCRs over and above those obtained in the Annual TCR Auction Process through submission of TCR Bids to purchase TCRs and/or through direct conversion of remaining ARRs awarded in the Annual ARR Allocation Process and/or ARRs awarded in the incremental Monthly ARR Allocation Process into TCRs through Self-Conversion. Market Participants may also offer for sale TCRs awarded in the Annual TCR Auction Process. 100% of the SPP Transmission System capability is made available during the Monthly TCR Auction Process. The remaining TCRs for the months of July through September are auctioned in a single-round process. The remaining TCRs for the months of October through May are auctioned in a two-round process. No later than three (3) Business Days prior the start of the Monthly TCR Auction Process, SPP will post the transmission system network topology data, along with corresponding Parallel Flow and transmission line outage assumptions, that SPP will use in the upcoming Monthly TCR Auction Process for use by Market Participants in developing their TCR Bid, TCR Offer and/or TCR self-conversion strategies. Exhibit 5-6 provides a representative timeline of the single-round and two-round Monthly TCR Auction Processes.
The following rules apply to the Monthly TCR Auction Processes:

### 5.6.1 TCR Offer and Bid-Submittal

1. Any Market Participant that has satisfied the applicable credit requirements may participate in the Monthly TCR Auction Process;

2. Market Participants may submit TCR Bids and TCR Offers separately, for On-Peak and Off-Peak periods (two (2) separate transmission system models created). The following information is submitted for a TCR Bid or TCR Offer:
   
   a. Source (any valid Settlement Location);
   
   b. Sink (any valid Settlement Location);
   
   c. Class (on-peak or off-peak);
   
   d. Type (Bid, Offer or Self-Convert);
(c) TCR MW (0.1 MW increments, may not exceed ARR MW held on path if Self-Convert Type selected);

(f) TCR Price ($/MW);
   (i) TCR Bids and Offers cannot exceed $100,000/MW-Month;
   (ii) TCR Bids and Offers cannot be less than ($100,000/MW-Month).

(3) For each TCR Round, a Market Participant is limited to a maximum combined submittal of 2000 TCR Bids and/or TCR Offers.

5.6.2 Monthly TCR Auction Process

TCRs are auctioned in a single-round process for the months of July through September and 100% of the SPP Residual Transmission System Capability, as calculated under Section 5.2.2(2), is made available. Any amounts of ARRs awarded in the Incremental Monthly ARR Allocation Process plus: the lesser of (i) 10% of the ARRs obtained in the Annual ARR Allocation Process or (ii) the difference between the ARRs obtained in the Annual ARR Allocation Process and the amount of Self-Converted TCRs awarded in the Annual TCR Auction Process may be Self-Converted during this single-round auction and any TCRs obtained in the Annual TCR Auction Process may be offered for sale.

TCRs are auctioned in a two-round process for the months of October through May. In the two-round process:

(1) Round 1 - 50% of the Residual SPP Transmission System Capability remaining following the Annual TCR Auction, as calculated under Section 5.2.2(2), is made available;

   (a) TCR Bids of the Self-Convert Type for any remaining ARRs may be submitted in this round for each source to sink pair that the Market Participant desires to convert that were obtained in the Annual ARR Allocation Process and/or ARRs obtained in the Incremental Monthly ARR Allocation Process into TCRs. The Self-Convert Type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility;

   (i) Only Eligible Entities holding ARRs obtained in the Annual ARR Allocation Process and/or Incremental Monthly ARR Allocation Process may submit a Self-Convert TCR Bid.

   (ii) The Self-Convert TCR Bid must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated ARR MW.
(iii) The lesser of: (i) 40% of the ARRs obtained in the Annual ARR Allocation Process or (ii) the difference between the ARRs awarded in the Annual ARR Allocation Process and the quantity of Self-Converted TCRs awarded in the Annual TCR Auction Process, plus all ARRs awarded in the Incremental/Monthly ARR Allocation Process may be submitted for Self-Conversion.

(b) Any TCRs awarded in the Annual TCR Auction may be offered for sale.

(2) Round 2 - The remaining 50% of the Residual SPP Transmission System Capability, as calculated under Section 5.2.2(2c) is made available;

(a) TCR Bids of the Self-Convert Type for any remaining ARRs may be submitted in this round for each source to sink pair that the Market Participant desires to convert where such remaining ARRs are determined as described under Section 5.6.2(2c).

(b) Any TCRs awarded in Round 1 or the Annual TCR Auction, including Self-Converted TCRs, may be offered for sale.

5.6.3 Monthly TCR Auction Clearing and Simultaneous Feasibility

The Auction is performed using a Linear Program algorithm to maximize the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible:

(1) The SPP Transmission System topology used in the SFT will be the most up-to-date Network Model updated for forecasted transmission topology changes, including planned maintenance outages, for the auction month;

(a) For withdrawals at link Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June for the month of July). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

(b) For injections at Market Hubs, SPP will distribute the hub injection down to the PNode level on a pro-rata basis using the weighting factors defined when the hub is created.

(2) The SFT is performed as described under Section 5.5.5.2.23 except that LTCRs awarded in the Annual LTCR Allocation process are not modeled as fixed injections/withdrawals since they have already been awarded as self-converted TCRs, with TCR Bid MWs are
modeled as an injection at the source and a corresponding withdrawal at the sink. TCR Offers associated with the sale of existing TCRs are modeled as fixed injections at the sink and fixed withdrawals at the source. Residual SPP Transmission System Capability includes the most up to date Parallel Flow assumptions.

(a) For Round 1, all TCRs awarded in the Annual TCR Auction for the month are modeled as fixed injections and withdrawals. To the extent that the fixed injections and withdrawals representing TCRs awarded in the Annual TCR Auction are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to the Round 1 auction. SPP will report back to the MWG on a quarterly basis regarding the number of times that transmission line ratings had to be adjusted to ensure feasibility.

(b) For Round 2, all TCRs previously awarded for the month are modeled as fixed injections and withdrawals prior to clearing the TCR Bids and Offers.

5.6.4 Monthly TCR Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid and Offer prices such that the total TCR auction value is maximized. Self-Converted TCRs are evaluated simultaneously with submitted TCR Bids and Offers. Auction Clearing Prices (ACP) are calculated as described under Section 5.3.4.

5.7 ARR Allocation/TCR Auction Settlements

The charges and credits to ARR holders and TCR holders will be calculated on a daily basis and included on the settlement statements consistent with the timing of the Energy and Operating Reserve Markets settlement as described under Section 4.5.9.24. For the purposes of calculating charges and credits to ARR holders, the following amounts of ARR awards will be used:

(1) ARR Settlement for Annual TCR Auction by path:

(a) For the month of June, 100% of annual ARR award;

(b) For the months of July through September, the greater of (i) 90% of annual ARR award or (ii) Self-Convert TCR award;

(c) For the Fall, Winter and Spring season, the greater of (i) 60% of annual ARR award or (ii) Self-Convert TCR award.

(2) ARR Settlement for Monthly TCR Auction:
(a) For the months of July through September, remaining ARRs not accounted for in ARR Settlement in the Annual TCR Auction as described in (1)(b) above plus all incremental monthly ARR awards:

(b) For the months of October through May for Round 1, the greater of (i) (50% of incremental monthly ARR awards plus: (50% of the difference between, the annual ARR award and the ARRs accounted for in the Annual TCR Auction as described in (1)(c) above) or (ii) Self-Convert TCR awards; and

(c) For the months of October through May for Round 2, the difference between:
   (i) the sum of annual ARR awards and incremental monthly ARR awards and (ii) the sum of ARR MW accounted for under Section (1)(c) above and the ARR MW accounted for under Section (2)(b) above.

5.8 TCR Secondary Market

SPP will facilitate a secondary market for previously awarded TCRs as follows:

(1) Bilateral trading of existing TCRs is facilitated through a bulletin board system;
(2) TCRs may be broken down into 0.1 MW increments that total the original TCR;
(3) TCRs may be traded daily, for On-Peak and/or Off-Peak periods;
(4) Trades must be completed no later than two (2) calendar days prior to the applicable Operating Day to which the TCR instrument applies;
(5) The TCR purchaser pays TCR seller directly;
(6) TCRs may not be reconfigured (path must remain the same);
(7) SPP accounts for transfer of TCR ownership; and

Both purchaser and seller must be a Market Participant that has met applicable credit requirements.

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Attachment AE

1.1 Definitions A

Auction Revenue Right (“ARR”)

A right, awarded during the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process, which entitles the holder to a share of the auction
revenues generated in the applicable Transmission Congestion Rights auction(s)—except for rights associated with LTCRs which are automatically converted to TCRs, and entitles the holder to self-convert the Auction Revenue Right to a Transmission Congestion Right.

**Auction Revenue Right Nomination Cap (“ARR Nomination Cap”)**

A cap on the maximum total amount of Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

### 1.1 Definitions F

**Firm Point-To-Point Auction Revenue Right Nomination Cap**

The maximum total amount of Firm Point-To-Point Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

**Firm Point-To-Point Candidate Auction Revenue Right**

All or portion of the Megawatt quantity of a confirmed Firm Point-To-Point Transmission Service reservation which the holder of the Transmission Service reservation can nominate for conversion into an Auction Revenue Right in the Auction Revenue Right allocation process.

**Firm Point-To-Point Candidate Long-Term Congestion Right**

The Megawatt quantity of a confirmed Firm Point-To-Point Transmission Service reservation with rollover rights that is used by the Transmission Provider to determine available rights which the holder of the Transmission Service reservation can select for conversion into a Long-Term Congestion Right in the Long-Term Congestion Right allocation process.

### 1.1 Definitions G

**Grandfathered Agreement Firm Point-To-Point Auction Revenue Right Nomination Cap**
The maximum amount of Grandfathered Agreement Firm Point-To-Point Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process or the monthly Auction Revenue Right allocation process.

Grandfathered Agreement Firm Point-To-Point Candidate Auction Revenue Right
All or a portion of the Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Firm Point-To-Point Transmission Service, as defined in the Tariff which the applicable Eligible Entity can nominate for conversion into an Auction Revenue Right in the annual Auction Revenue Right allocation process.

Grandfathered Agreement Firm Point-To-Point Candidate Long-Term Congestion Right
The Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Firm Point-To-Point Transmission Service with rollover rights, which is used by the Transmission Provider to determine available rights that the applicable Eligible Entity can select for conversion into a Long-Term Congestion Right in the annual Long-Term Congestion Right allocation process.

Grandfathered Agreement Network Integration Transmission Service Auction Revenue Right Nomination Cap
The maximum amount of Grandfathered Agreement Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

Grandfathered Agreement Network Integration Transmission Service Candidate Auction Revenue Right
All or a portion of the Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Network Integration Transmission Service, as defined in the Tariff, verified prior to the start of the annual ARR allocation process.
that the applicable Eligible Entity can nominate for conversion into an ARR in the ARR allocation process.

**Grandfathered Agreement Network Integration Transmission Service Candidate Long-Term Congestion Right**
The Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Network Integration Transmission Service verified prior to the start of the annual Long-Term Congestion Right allocation process, that is used by the Transmission Provider to determine available rights that the applicable Eligible Entity can select for conversion into a Long-Term Congestion Right during the Long-Term Congestion Right allocation process.

### 1.1 Definitions L

**Load Serving Entity (“LSE”)**
A distribution utility or an electric utility that has a service obligation, where a service obligation, as defined in Section 217(a) of the Federal Power Act, means a requirement applicable to, or the exercise of authority granted to, an electric utility under Federal, State, or local law or under long-term contracts to provide electric service to end-users or to a distribution utility.

**Long-Term Congestion Right (“LTCR”)**
An instrument that entitles the holder to a Transmission Congestion Right over a period of more than one year, which is awarded during the Transmission Provider’s annual Long-Term Congestion Rights allocation process.

### 1.1 Definitions N

**Network Integration Transmission Service Auction Revenue Right Nomination Cap**
The maximum amount of Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

**Network Integration Transmission Service Candidate Auction Revenue Right**

The Megawatt quantity associated with Network Integration Transmission Service from Network Resources that the holder of the Network Integration Transmission Service can nominate for conversion into an Auction Revenue Right, subject to the Network Integration Transmission Service Auction Revenue Right Nomination Cap.

**Network Integration Transmission Service Candidate Long-Term Congestion Right**

The Megawatt quantity associated with Network Integration Transmission Service with rollover rights from Network Resources that is used by the Transmission Provider to determine available rights that the holder of the Network Integration Transmission Service can select for conversion into a Long-Term Congestion Right during the Long-Term Congestion Right allocation process.

### 1.1 Definitions S

**Simultaneous Feasibility Test**

A test for a state in which each set of injections and withdrawals associated with Long-Term Congestion Rights, Auction Revenue Rights and Transmission Congestion Rights would not exceed any thermal, voltage, or stability limits within the Transmission System under normal operating conditions or for monitored contingencies.

### 1.1 Definitions T

**Transmission Congestion Right (“TCR”)**

A right that entitles the holder to be compensated or charged for congestion in the Day-Ahead Market between two Settlement Locations.

**Transmission Congestion Rights Markets (“TCR Markets”)**
The annual Long-Term Congestion Rights allocation process, the annual and monthly Transmission Congestion Rights auctions and the Auction Revenue Rights annual and monthly allocation processes.

7.0 Transmission Congestion Rights Markets

The TCR Markets process includes an annual LTCR allocation, an annual ARR allocation, annual and monthly TCR auctions and a monthly ARR allocation in accordance with the timelines specified in the Market Protocols. The TCR Markets process is subject to review by the Market Monitor. LTCRs are obtained by Eligible Entities during the annual LTCR allocation. ARRs are obtained by Eligible Entities during the annual ARR allocation or the monthly ARR allocation. TCRs are obtained by Market Participants through the annual and monthly TCR auctions.

There are seven-eight (87) key processes associated with LTCRs, ARRs and TCRs:

1. Annual LTCR/ARR verification;
2. Annual ARR-LTCR allocation;
3. Annual ARR allocation;
4. Annual TCR auction;
5. Monthly ARR allocation;
6. Monthly TCR auction;
7. ARR allocation and TCR auction settlements; and
8. TCR secondary markets.

Table 7-1 in Section 7.3.2 of this Attachment AE provides additional details related to auction timing and Transmission System capability available for the TCR auctions.
7.1 Annual Long-Term Congestion Right/Auction Revenue Right Verification

Only Eligible Entities are permitted to nominate candidate LTCRs and/or ARRs. The following rules apply to verification of firm Transmission Service for conversion to LTCRs and/or ARRs.

7.1.1 Transmission Service Verification

In order for Eligible Entities to obtain candidate ARRs, the Transmission Provider must first verify existing Transmission Service entitlements, including Transmission Service entitlements that have been renewed in accordance with rollover rights since their initial term. An Eligible Entity’s Transmission Service must span the entire monthly or seasonal period for which ARRs are allocated to qualify for candidate ARRs in a particular month or season. An Eligible Entity’s Transmission Service must span the entire annual period for which LTCRs are allocated and must have rollover rights to qualify for candidate LTCRs. The Transmission Provider will verify Eligible Entity existing Transmission Service entitlements as follows:

(1) The following will be performed prior to each annual LTCR and ARR allocation for Eligible Entities taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff:

(a) The Transmission Provider will obtain source, sink and Reservation Capacity information from the OASIS for each monthly and seasonal period for which ARRs are allocated in which the Transmission Service spans the entire period for the current annual allocation and for the annual period for which LTCRs are allocated in which the Transmission Service spans the entire year;

(i) For a Transmission Service reservation with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the Transmission Service reservation that will be utilized as the source for candidate LTCRs and/or ARRs.
(ii) For a Transmission Service reservation with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for candidate LTCRs and/or ARR.s.

(iii) For a Transmission Service reservation with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for candidate LTCRs and/or ARR.s.

(iv) Eligible Entities taking Network Integration Transmission Service with rollover rights under this Tariff shall be considered to have met the definition of a Load Serving Entity for purposes of LTCR allocation;

(v) Eligible Entities taking Firm Point-To-Point Transmission Service with rollover rights under this Tariff shall not be considered a Load Serving Entity for LTCR allocation purposes unless the Eligible Entity provides an attestation to the Transmission Provider confirming that the Eligible Entity is a Load Serving Entity as defined in this Attachment AE;

(b) The Transmission Provider will provide this information to each Eligible Entity for verification; and

(c) Eligible Entities will notify the Transmission Provider within 2 weeks following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified.

(2) The following will be performed prior to each annual LTCR and ARR allocation for the Eligible Entity taking GFA service:

(a) Each Transmission Owner shall register any GFA for which candidate LTCRs and/or ARR.s are to be provided to the Transmission Owner or the
transmission customer under the GFA on the Transmission Provider’s OASIS. The Transmission Owner must provide the Transmission Provider with source, sink and Reservation Capacity information for each GFA on the Transmission Provider’s OASIS by registering each GFA with the Transmission Provider. The Transmission Provider will use source, sink, and Reservation Capacity information from the GFA registration for each monthly and seasonal period for which ARRs are allocated and the annual period for which LTCRs are allocated. If both parties to the GFA are Market Participants with respect to the GFA load, then the parties may jointly inform the Transmission Provider which Market Participant will be allocated the candidate LTCRs and/or ARRs. If the parties to the GFA do not so inform the Transmission Provider, or if only the Transmission Owner that sold the GFA service is a Market Participant, then the Transmission Owner that sold the GFA service will be allocated the candidate LTCRs and/or ARRs associated with the GFA.

(i) For a GFA with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the Transmission Service reservation that will be utilized as the source for candidate LTCRs and/or ARRs.

(ii) For a GFA with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for the candidate LTCRs and/or ARRs.

(iii) For a GFA with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for the candidate LTCRs and/or ARRs.
(iv) An Eligible Entity under a GFA taking the equivalent of Network Integration Transmission Service with rollover rights shall be considered to have met the definition of Load Serving Entity for purposes of LTCR allocation.

(v) An Eligible Entity under a GFA taking the equivalent of Firm Point-To-Point Transmission Service with rollover rights shall not be considered a Load Serving Entity for the purposes of LTCR allocation unless the Eligible Entity provides an attestation to the Transmission Provider confirming that the Eligible Entity is an Load Serving Entity as defined in this Attachment AE.

(b) If the transmission customer under the GFA is receiving the candidate ARRs, to the extent that the transmission service specified in the GFA is identified as the equivalent of SPP Network Integration Transmission Service, the transmission customer under the GFA must provide the historical peak loads being served under the GFA for the previous three years.

7.1.2 Candidate Long-Term Congestion Rights/Auction Revenue Rights

Following verification of an Eligible Entity’s Transmission Service, candidate LTCRs and/or ARRs associated with such Transmission Service are assigned as follows:

(1) For each Eligible Entity with Network Integration Transmission Service, the Eligible Entity’s Network Integration Transmission Service Candidate LTCRs and/or Candidate ARRs from a specific source is equal to the source Reservation Capacity.

(a) An Eligible Entity may nominate select Network Integration Transmission Service Candidate LTCRs, as described in Section 7.2.1.14 of this Attachment AE from a specific source to one or more sinks up to the amount of its available Network Integration Transmission Service Candidate ARRs—LTCRs.
associated with the source subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(b) An Eligible Entity may nominate Network Integration Transmission Service Candidate ARRs, as described in Section 7.3.1 of this Attachment AE from a specific source to one or more sinks up to the amount of its Network Integration Transmission Service Candidate ARRs associated with the source subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(2) For each Eligible Entity with Firm Point-To-Point Transmission Service, the Eligible Entity’s Firm Point-To-Point Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reservation Capacity associated with that source and sink.

(a) An Eligible Entity may nominate select Firm Point-To-Point Candidate LTCRsARRs, as described in Section 7.2.4 of this Attachment AE, for this specific source and sink up to the amount of its available Firm Point-To-Point Candidate LTCRsARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(b) Firm Point-To-Point Candidate ARRs may be nominated by an Eligible Entity, as described in Section 7.3.1 of this Attachment AE, for this specific source and sink up to the amount of its Firm Point-To-Point Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(3) For each Eligible Entity with equivalent Network Integration Transmission Service GFA service, the Eligible Entity’s Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs and/or ARRs from a specific source is equal to the source Reservation Capacity.

(a) An Eligible Entity may nominate select Grandfathered Agreement Network Integration Transmission Service Candidate LTCRsARRs, as described in Section 7.2.4 of this Attachment AE, from a specific source to one or more sinks up to the amount of its available Grandfathered
Agreement Network Integration Transmission Service Candidate LTCRsARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(b) An Eligible Entity may nominate Grandfathered Agreement Network Integration Transmission Service Candidate ARRs, as described in Section 7.3.1 of this Attachment AE, from a specific source to one or more sinks up to the amount of its Grandfathered Agreement Network Integration Transmission Service Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(4) For each Eligible Entity with equivalent Firm Point-To-Point GFA service, the Eligible Entity’s Grandfathered Agreement Firm Point-To-Point Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reservation Capacity associated with that source and sink.

(a) An Eligible Entity may nominate Grandfathered Agreement Firm Point-To-Point Candidate LTCRsARRs, as described in Section 7.2.4 of this Attachment AE, for this specific source and sink up to the amount of its available Grandfathered Agreement Firm Point-To-Point Candidate LTCRsARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(b) An Eligible Entity may nominate Grandfathered Agreement Firm Point-To-Point Candidate ARRs, as described in Section 7.3.1 of this Attachment AE, for this specific source and sink up to the amount of its Grandfathered Agreement Firm Point-To-Point Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

7.1.3 Auction Revenue Right Nomination Cap

An Eligible Entity’s ARR Nomination Cap will be as follows:

(1) For Network Integration Transmission Customers, the Network Integration Transmission Service ARR Nomination Cap is equal to the minimum of a) the sum of Network Integration Transmission Service Candidate ARRs and Network
Integration Transmission Service Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Network Integration Transmission Service Candidate ARR as calculated in Section 7.5.1 of this Attachment AE or 
b) One hundred and three percent (103%) of the average of that customer’s three most recent annual peak Network Loads. This value will be adjusted by the Transmission Provider as required to account for wholesale load shifts between Transmission Customers. In addition, candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(2) For Firm Point-To-Point Transmission Customers, the Firm Point-To-Point ARR Nomination Cap is equal to the sum of Firm Point-To-Point Candidate ARRs and Firm Point-To-Point Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Firm Point-To-Point Candidate ARRs as calculated in Section 7.5.1 of this Attachment AE.

(3) For GFA customers taking the equivalent of SPP Network Integration Transmission Service, the Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap is equal to the minimum of a) the sum of Grandfathered Agreement Network Integration Transmission Service Candidate ARRs and Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Grandfathered Agreement Network Integration Transmission Service Incremental Candidate ARRs as calculated in Section 7.5.1 of this Attachment AE or b) One hundred and three percent (103%) of the average of that GFA’s customer’s three most recent annual peak Network Loads.

(4) For GFA customers taking the equivalent of SPP Firm Point-To-Point, the Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap is equal to the sum of Grandfathered Agreement Firm Point-To-Point Candidate ARRs and Grandfathered Agreement Firm Point-To-Point Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Grandfathered Agreement
Firm Point-To-Point Candidate ARRs as calculated in Section 7.5.1 of this Attachment AE.


### 7.2 Annual Long-Term Congestion Right Allocation

Eligible Entities may select the candidate LTCRs that they wish to receive up to their available LTCRs. The portion of the selected candidate ARRs are awarded to each Eligible Entity during the LTCR allocation. Available Candidate LTCRs are evaluated on an annual basis in a two-step process; (i) Candidate LTCRs associated with Eligible Entities that are Load Serving Entities are evaluated in accordance with Section 7.2.2 and (ii) remaining Candidate LTCRs associated with Eligible Entities that are not Load Serving Entities are then evaluated in accordance with Section 7.2.3.

The Transmission Provider shall make available fifty percent (50%) of the projected maximum Transmission System capability for the purpose of LTCR allocation in the annual LTCR allocation process. No later than five (5) days prior to the start of the annual LTCR allocation process, the Transmission Provider shall post the Transmission System network topology, including the corresponding impacts from Parallel Flow, used to determine the projected maximum Transmission System capability that will be used in the upcoming allocation.

#### 7.2.1 LTCR Surrender

Eligible Entities may surrender previously awarded LTCRs in 0.1 MW increments. Prior to annual LTCR allocation, Eligible Entities shall submit the following information:

1. Source (valid candidate LTCR source Settlement Location);
2. Sink (valid candidate LTCR sink Settlement Location);
(3) Surrendered LTCR MW (cannot exceed previously awarded LTCR).

7.2.2 Available Long-Term Congestion Rights for Load Serving Entities

A Simultaneous Feasibility Test is performed to determine the amount of available LTCRs that may be selected and awarded for Eligible Entities that are LSEs. The Simultaneous Feasibility Test is performed using the most current Network Model for the corresponding LTCR allocation period. For the Simultaneous Feasibility Test, all candidate Load Serving Entity LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. In addition, all previously awarded LTCRs that have not been surrendered, which are associated with Eligible Entities that are not LSEs, are modeled as fixed injections and withdrawals.

If the candidate Load Serving Entity LTCRs are not feasible, the amount of candidate LTCRs available for selection and award will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual LTCR amounts and the candidate LTCR amounts, weighted by the reciprocal of the candidate LTCR amounts, which results in a higher percentage LTCR reduction for those nominations having the greatest impact on the constraints. LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

Previously awarded Load Serving Entity LTCRs are guaranteed to be available using the iterative methodology described in the Market Protocols; provided that such Load Serving Entity LTCRs must meet the criteria as specified in Section 7.1.1 of this Attachment AE, or have not been surrendered as described under Section 7.2.1 of this Attachment AE. To the extent that these previously awarded Load Serving Entity LTCRs are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution.

7.2.3 Available Long-Term Congestion Rights for Non-Load Serving Entities
A Simultaneous Feasibility Test is performed to determine the amount of available LTCRs that may be selected and awarded for Eligible Entities that are not Load Serving Entities. The Simultaneous Feasibility Test is performed using the most current Network Model for the corresponding LTCR allocation period. For the Simultaneous Feasibility Test, all candidate non-Load Serving Entity LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. In addition, all available LTCRs associated with Eligible Entities that are Load Serving Entities as calculated under Section 7.2.2 of this Attachment AE are modeled as fixed injections and withdrawals.

If the candidate non-Load Serving Entity LTCRs are not feasible, the amount of candidate LTCRs available for selection and award will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual LTCR amounts and the candidate LTCR amounts, weighted by the reciprocal of the candidate LTCR amounts, which results in a higher percentage LTCR reduction for those nominations having the greatest impact on the constraints. LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

Previously awarded non-Load Serving Entity LTCRs are guaranteed to be available using the iterative methodology described in the Market Protocols; provided that such non-Load Serving Entity LTCRs must meet the criteria as specified in Section 7.1.1 of this Attachment AE, or which have not been surrendered as described under Section 7.2.1 of this Attachment AE. To the extent that these previously awarded non-Load Serving Entity LTCRs are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution.

7.2.4 LTCR Selection and Awards

1. All previously awarded LTCRs are automatically awarded as LTCRs for the current allocation year; provided that such LTCRs meet the criteria specified in Section 7.1.1 of this Attachment AE, or were not surrendered as described under Section 7.2.1 of this Attachment AE.
(2) Additional LTCRs are selected and awarded in a single-round process. Eligible Entities may select:

(a) Available LTCRs from its Network Integration Transmission Service Candidate LTCRs, less any previously awarded LTCRs plus any surrendered LTCRs associated with Network Integration Transmission Service Candidate LTCRs;

(b) Available LTCRs from its Firm Point-To-Point Candidate LTCRs, less any previously awarded LTCRs plus any surrendered LTCRs associated with Firm Point-To-Point Candidate LTCRs;

(c) Available LTCRs from its Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs as described under Section 7.1.2, less any previously awarded LTCRs plus any surrendered LTCRs associated with Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs; and/or

(d) Available LTCRs from its Grandfathered Agreement Firm Point-To-Point Candidate LTCRs as described under Section 7.1.2, less any previously awarded LTCRs plus any surrendered LTCRs associated with Grandfathered Agreement Firm Point-To-Point Candidate LTCRs;

(3) Eligible Entities shall submit the following information in order to select LTCRs that were not previously awarded:

(a) Source (valid candidate LTCR source Settlement Location);

(b) Sink (valid candidate LTCR sink Settlement Location);

(c) LTCR MW (total LTCR MW selected from a source Settlement Location cannot exceed the source candidate available LTCR MW as previously determined under Section 7.2.2, or Section 7.2.3, less previously awarded LTCRs plus surrendered LTCRs);

(4) All selected LTCRs are automatically awarded.
7.23 Annual Auction Revenue Right Allocation

The annual ARR allocation addresses how candidate ARRs verified in the annual LTCR/ARR verification may be nominated and awarded. Eligible Entities may nominate the candidate ARRs that they wish to receive up to their ARR nomination caps less any LTCRs awarded. The portion of the nominated candidate ARRs that are simultaneously feasible are allocated to each Eligible Entity during the annual allocation. Candidate ARRs are nominated on a monthly and seasonal basis in a three round process.

The Transmission Provider shall make available one hundred percent (100%) of the projected maximum Transmission System capability for the purpose of ARR allocation in the annual ARR allocation process. No later than five (5) days prior to the start of the annual ARR allocation process, the Transmission Provider will post the Transmission System network topology data for each of the monthly and seasonal On-Peak and Off-Peak models, including the corresponding Parallel Flow and transmission line outage assumptions, used to determine the projected maximum Transmission System capability that will be used in the upcoming allocations.

7.32.1 Auction Revenue Right Nominations

For each month and season included in the annual ARR allocation period, as defined in Table 7-1 in Section 7.3.2 of this Attachment AE, Eligible Entities may nominate candidate ARRs in 0.1 MW increments for specific source to sink pairs that total up to their ARR nomination caps as calculated in Section 7.1.3 of this Attachment AE less any LTCRs awarded. Nominations occur separately for On-Peak and Off-Peak periods. Prior to each ARR nomination round, Eligible Entities shall submit the following information:

1. Source: valid candidate ARR source Settlement Location for rounds 1 and 2, and any applicable source Settlement Location for round 3;
2. Sink: valid candidate ARR sink Settlement Location for rounds 1 and 2, and any applicable sink Settlement Location for round 3;
3. Class: On-Peak or Off-Peak;
4. Period: specific month or season; and
(5) Nominated ARR MW:
(a) In round 1 and round 2, the total candidate ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs less any awarded LTCRs associated with the source.
(b) In round 3, any source to sink path may be nominated, subject to the limitation described in Section 7.23.2(3) of this Attachment AE.

7.23.2 Auction Revenue Right Allocation

ARRs are allocated in a three round process as follows:

(1) In round 1, Eligible Entities may nominate:
(a) ARRs from their Network Integration Transmission Service Candidate ARRs that totals no more than fifty percent (50%) of their Network Integration Transmission Service ARR Nomination Cap less the sum of awarded LTCRs from their Network Integration Transmission Service Candidate LTCRs;
(b) ARRs from their Grandfathered Agreement Network Integration Transmission Service Candidate ARRs that totals no more than fifty percent (50%) of their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap less the sum of awarded LTCRs from their Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs;
(c) ARRs from their Firm Point-To-Point Candidate ARRs that totals no more than fifty percent (50%) of their Firm Point-To-Point ARR Nomination Cap less the sum of awarded LTCRs from their Firm Point-To-Point Candidate LTCRs; and
(d) ARRs from their Grandfathered Agreement Firm Point-To-Point Candidate ARRs that totals no more than fifty percent (50%) of their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap less
the sum of awarded LTCRs from their Grandfathered Agreement Firm Point-To-Point Candidate LTCRs.

(2) In round 2, Eligible Entities may nominate:
   (a) ARRs from their Network Integration Transmission Service Candidate ARRs that totals no more than one hundred percent (100%) of their Network Integration Transmission Service ARR Nomination Cap less any nominated Network Integration Transmission Service Candidate ARRs awarded in round 1, less the sum of awarded LTCRs from their Network Integration Transmission Service Candidate LTCRs;
   (b) ARRs from their Grandfathered Agreement Network Integration Transmission Service Candidate ARRs that totals no more than one hundred percent (100%) of their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap less any nominated Grandfathered Agreement Network Integration Transmission Service Candidate ARRs awarded in round 1, less the sum of awarded LTCRs from their Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs;
   (c) ARRs from their Firm Point-To-Point Candidate ARRs that totals no more than one hundred percent (100%) of their Firm Point-To-Point ARR Nomination Cap less any nominated Firm Point-To-Point Candidate ARRs awarded in round 1, less the sum of awarded LTCRs from their Firm Point-To-Point Candidate LTCRs; and
   (d) ARRs from their Grandfathered Agreement Firm Point-To-Point Candidate ARRs that totals no more than one hundred percent (100%) of their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap less any nominated Grandfathered Agreement Firm Point-To-Point Candidate ARRs awarded in round 1, less the sum of awarded LTCRs from their Grandfathered Agreement Firm Point-To-Point Candidate LTCRs.

(3) In round 3, any Eligible Entity may nominate ARRs from any source to sink that totals no more than one hundred percent (100%) of its ARR Nomination Cap less
7.32.3 Annual Auction Revenue Right Awards

A Simultaneous Feasibility Test is performed in each round of the ARR allocation to determine the amount of nominated ARRs to be awarded. The Simultaneous Feasibility Test is performed using the most current Network Model projected including planned transmission outages for the corresponding ARR allocation period. For the Simultaneous Feasibility Test, a nominated candidate ARR is modeled as a generation injection at the source and a corresponding load withdrawal at the sink. All awarded LTCRs are modeled as fixed injections and withdrawals and are automatically awarded as ARRs.

If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual ARR amounts and the nominated ARR amounts, weighted by the reciprocal of the nominated ARR amounts, which results in a higher percentage ARR reduction for those nominations having the greatest impact on the constraints. ARR reductions associated with nominations that have an equal impact on the constraints are reduced by the same percentage.

Every six (6) months for the first two (2) years after implementation of the Integrated Marketplace, the Transmission Provider will analyze the net funding of TCRs through the Day-Ahead Market. In the event the cumulative funding is at or below 90% or above 100%, the Transmission Provider may approve an additional adjustment of all subsequent monthly auctions and the month of June in the annual auction of the normal and emergency ratings of all flowgates and monitored transmission system elements.
7.34.1 Transmission Congestion Right Offer and Bid Submittal

(1) Market Participants that have satisfied the applicable credit requirements may participate in the annual TCR auction.

(2) Market Participants holding ARRs associated with a specific source and sink may elect to self-convert all or a portion of those ARRs into TCRs by specifying the self-convert option as part of the TCR Bid submittal.

(3) For each month and season included in the annual TCR auction, Market Participants may submit TCR Bids and/or Offers in 0.1 MW increments, for On-Peak and Off-Peak periods. A valid TCR Bid and/or Offer must contain the following information:

(a) Source: any valid Settlement Location;
(b) Sink: any valid Settlement Location;
(c) Class: On-Peak or Off-Peak;
(d) Period: specific month or season;
(e) Type: Bid, Offer or self-convert;
(f) TCR MW; and
(g) TCR Price:
   (i) TCR Bids and Offers cannot exceed $100,000/MW-Month;
   (ii) TCR Bids and Offers cannot be less than negative $100,000/MW-Month;

(4) For each TCR round, a Market Participant is limited to a maximum of 2,000 TCR Bids and/or Offers for each Asset Owner it represents.
7.43-2 Annual Transmission Congestion Right Auction

In the annual TCR auction, TCRs are made available in a single round for each month and season as follows:

(1) For the month of June, one hundred percent (100%) of the Transmission System capability is made available, for the July-September period ninety percent (90%) is made available, and for the Fall, Winter and Spring seasons sixty percent (60%) is made available. For additional details see Table 7-1;

(a) Only Eligible Entities holding ARRs may submit a self-convert TCR Bid.

(b) The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(c) The self-convert TCR Bid or Offer must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated ARR MW.

(d) The self-convert type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility.
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<tr>
<th>Auction Month</th>
<th>Auction Type</th>
<th>TCR Award Periods</th>
<th>TCR Products</th>
<th>Auction Rounds</th>
<th>Total Auctions</th>
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<td>Jun (100) Jul (90) Aug (90) Sep (90) Fall (60) Winter (60) Spring (60)</td>
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7.34.3 Annual Transmission Congestion Right Auction Clearing and Simultaneous Feasibility

The auction is performed with an objective of maximizing the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible. A Simultaneous Feasibility Test is performed in each round.

The Simultaneous Feasibility Test is performed using the most up to date Network Model projected including planned transmission outages for the corresponding ARR allocation period. For the Simultaneous Feasibility Test:

1. TCR submittals of both the self-convert type and Bid type are modeled as a generation injection at the source and a corresponding load withdrawal at the sink.

2. TCR submittals of the Offer type are modeled as a generation injection at the sink and a corresponding load withdrawal at the source; and

3. ARR associated with LTCRs are automatically converted into awarded TCRs, are modeled as fixed injections and withdrawals, and such TCRs are treated as self-converted TCRs for settlement purposes.

7.34.4 Annual Transmission Congestion Right Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. Self-converted TCRs are evaluated concurrently with all other submitted TCR Bids and are given the highest priority subject to simultaneous feasibility. In the event there is a tie during the Simultaneous Feasibility Test, each competing TCR Bid and Offer will be awarded a TCR on a pro rata share based on the individual impact on the constraint. ACPs are calculated based on the shift factor for a specific bus to the Reference Bus with the corresponding Shadow Price for such bus, for each Settlement Location using the formula for the MCC as described in Section 8.3.1.2 of this Attachment AE.
## 7.54 Monthly Transmission Congestion Right Auctions

Market Participants may obtain TCRs, in addition to those obtained in the annual TCR auction, by purchasing TCRs in the monthly TCR auction or through conversion of ARRs awarded in the annual and monthly ARR allocations. Market Participants may also offer for sale TCRs awarded in the annual TCR auction. The TCRs for the months of July through September are auctioned in a single round. The TCRs for the months of October through May are auctioned in two rounds. No later than three (3) days prior to the monthly TCR auction, the Transmission Provider will post any changes to the Transmission System topology or input data assumptions that occurred after the conclusion of the annual ARR allocation.

### 7.54.1 Monthly TransmissionCongestion Right Offer and Bid Submittal

1. Market Participants that have satisfied the applicable credit requirements may participate in the monthly TCR auction.
2. Market Participants may submit TCR Bids and Offers for On-Peak and Off-Peak periods. The following information is submitted for a TCR Bid or Offer:
   - (a) Source: any valid Settlement Location;
   - (b) Sink: any valid Settlement Location;
   - (c) Class: On-Peak or Off-Peak;
   - (d) Type: Bid, Offer or self-convert;
   - (e) TCR MW: 0.1 MW increments, may not exceed ARR MW held on path if self-convert type selected; and
   - (f) TCR Price:
     - (i) TCR Bids cannot exceed $100,000/MW-Month;
     - (ii) TCR Bids cannot be less than negative $100,000/MW-Month;
3. Market Participants may not submit more than a total of 2,000 TCR Bids and Offers in each TCR round for each Asset Owner it represents.

### 7.54.2 Monthly Transmission Congestion Right Auction

TCRs are auctioned in a single round for the months of July through September and one hundred percent (100%) of the Transmission System capability is made available. Any amounts of ARRs awarded in the monthly ARR allocation plus the lesser of (i) ten percent (10%) of the
ARRs obtained in the annual ARR allocation or (ii) the difference between the ARRs obtained in the annual ARR allocation and the amount of self-converted TCRs awarded in the annual TCR auction may be self-converted during this auction and any TCRs obtained in the annual TCR auction may be offered for sale.

TCRs are auctioned in a two round process for the months of October through May. In the two round process:

(1) Round 1 - Fifty percent (50%) of the Transmission System capability remaining following the annual TCR auction is made available;

(a) All ARRs awarded in the Monthly ARR Allocation Process may be submitted for self-conversion.

(i) ARRs obtained in the annual allocation may be submitted for self-conversion subject to the following limitations: Eligible Entities may submit the lesser of (i) forty percent (40%) of the ARRs obtained in the annual ARR allocation or (ii) the difference between the ARRs awarded in the annual ARR allocation and the quantity of self-converted TCRs awarded in the annual TCR auction.

(ii) A self-convert TCR Bid must specify the same source and sink as the associated ARR and must be less than or equal to the associated ARR MW.

(iii) The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(b) Any TCRs awarded in the annual TCR auction may be offered for sale by the TCR holder.

(d) Any Market Participant may also submit TCR Bids for any source-sink pair.

(2) Round 2 - The remaining Transmission System capability is made available;

(a) An Eligible Entity may submit self-convert TCR Bids in this round that are limited to the values calculated under Section 7.67(2)(c) of this Attachment AE.
The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(b) Any TCRs awarded in round 1 or the annual TCR auction, including self-converted TCRs, may be offered for sale by the TCR holder.
(c) Any Market Participant may also submit TCR Bids for any source-sink pair.

7.54.3 Monthly Transmission Congestion Right Auction Clearing and Simultaneous Feasibility

The auction is performed with an objective of maximizing the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible. A Simultaneous Feasibility Test is performed in each round using the most up to date Network Model projected including planned transmission outages for the corresponding monthly TCR auction period with all TCRs awarded in the annual TCR auction modeled as fixed injections and withdrawals. To the extent that these fixed injections and withdrawals are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution prior to the start of the monthly TCR auction solely for the purpose of the monthly TCR auction. The Transmission Provider will report to the stakeholders on a quarterly basis regarding the number of times that the transmission facility ratings had to be adjusted in the model to ensure feasibility.

For the Simultaneous Feasibility Test, monthly TCR submittals of the self-convert type and TCR Bid type are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. A monthly TCR submittal of the Offer type is modeled as a generation injection at the sink and a load withdrawal at the source.

7.54.4 Monthly Transmission Congestion Right Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. Self-converted TCRs are evaluated concurrent with all other submitted TCR Bids and are given the highest priority subject to simultaneous feasibility. ACPs are calculated for each Settlement Location using the formula for the MCC as described in Section 8.3.1.2 of this Attachment AE.

7.65 Monthly Auction Revenue Right Allocation

Eligible Entities are eligible to nominate candidate ARRAs associated with such services for each remaining month in the current annual ARR allocation period for: (i) any remaining candidate ARR capacities from the Annual ARR Allocation Process, (ii) firm Transmission
Service that has been confirmed following the completion of the most recent annual TCR auction and prior to the next annual LTCR/ARR verification, (iii) firm Transmission Service confirmed prior to the Annual LTCR/ARR Verification Process that includes a partial season, or (iv) Transmission Service for which a redispatch obligation has been eliminated. To the extent that the Eligible Entity’s firm Transmission Service term extends beyond the current annual ARR allocation period, such remaining service will be included in the next annual LTCR/ARR verification.

7.65.1 Monthly Auction Revenue Right Transmission Service Verification

In order to qualify for additional monthly candidate ARRs in a particular month, an Eligible Entity’s Transmission Service must span the entire month within the applicable year. The Transmission Provider will verify Eligible Entity existing Transmission Service entitlements as follows:

1) The Transmission Provider will obtain the source, sink and Reservation Capacity information from the Transmission Provider’s OASIS for the applicable month;

2) The Transmission Provider will provide this information to each Eligible Entity for verification; and

3) Eligible Entities will notify the Transmission Provider within six (6) days following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified and additional monthly candidate ARRs will be assigned as described under Section 7.1.2.

7.65.3 Monthly Auction Revenue Right Nominations

Five (5) days prior to the start of the monthly TCR auction, Eligible Entities may nominate in a single round: (i) Network Integration Transmission Service Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their Network Integration Transmission Service ARR Nomination Cap and ARRs associated with Network Integration Transmission Service Candidate LTCRs and Network Integration Transmission Service Candidate LTCRs awarded in the annual ARR allocation; (ii) Firm Point-To-Point Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their Firm Point-To-Point ARR Nomination Cap and ARRs associated with Firm Point-To-Point Candidate ARRs and Firm Point-To-Point
Candidate LTCRs awarded in the annual ARR allocation; (iii) Grandfathered Agreement Network Integration Transmission Service Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap and ARRs associated with Grandfathered Agreement Network Integration Transmission Service Candidate ARRs and Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs awarded in the annual ARR allocation; and (iv) Grandfathered Agreement Firm Point-To-Point Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap and ARRs associated with Grandfathered Agreement Firm Point-To-Point Candidate ARRs and Grandfathered Agreement Firm Point-To-Point Candidate LTCRs awarded in the annual ARR allocation. Nominations occur separately for On-Peak and Off-Peak periods. Eligible Entities submit the following information:

(1) Source: valid candidate ARR source Settlement Location;
(2) Sink: valid candidate ARR sink Settlement Location;
(3) Class: On-Peak or Off-Peak; and
(4) ARR MW:
   (a) The total ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs less previously awarded source ARRs.

7.65.4 Monthly Auction Revenue Rights Awards

A Simultaneous Feasibility Test is performed to determine the amount of nominated candidate ARRs to be awarded. For the Simultaneous Feasibility Test a nominated candidate ARR is modeled as a generation injection at the source and a corresponding load withdrawal at the sink. The Simultaneous Feasibility Test is performed using the following assumptions.

(1) The Transmission System model used in will be the same Network Model to be used in the upcoming monthly TCR auction;
(2) One hundred percent (100%) of the projected maximum Transmission System capability, including any completed Network Upgrades, is made available; and
(3) All TCRs previously awarded in the annual TCR auction and all remaining ARRs not accounted for in the annual TCR auction (as defined in Section 7.76 of this Attachment A2) for the applicable month are modeled as fixed injections at the
specified sources and fixed withdrawals at the specified sinks. To the extent that these fixed injections and withdrawals are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution solely for the purpose of assessing ARR feasibility. The Transmission Provider will report to the stakeholders on a quarterly basis regarding the number of times that the transmission facility ratings had to be adjusted in the model to ensure feasibility.

If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced based on their relative impact on the constraint to produce a simultaneously feasible result.

### 7.76 Auction Revenue Right Allocation and Transmission Congestion Right Auction Settlements

The charges and payments to ARR and TCR holders will be calculated on a daily basis and included on the Settlement Statements consistent with the timing of the Energy and Operating Reserve Markets settlement as described in Section 8.7 of this Attachment AE. For the purposes of calculating charges and payments to ARR holders, the following amounts of ARR awards will be used:

1. ARR Settlement for annual TCR auction:
   1. For the month of June, one hundred percent (100%) of annual ARR award;
   2. For the months of July through September, the greater of (i) ninety (90%) of annual ARR award or (ii) self-convert TCR award; and
   3. For the Fall, Winter and Spring seasons, the greater of (i) sixty (60%) of annual ARR award or (ii) self-convert TCR award.

2. ARR Settlement for monthly TCR auction:
   1. For the months of July through September, ARRs not accounted for in ARR Settlement in the annual TCR auction as described in (1)(b) above plus all monthly ARR awards;
   2. For the months of October through May for round 1, the greater of (i) fifty (50%) of monthly ARR awards plus fifty percent (50%) of the difference between the annual ARR award and the ARRs accounted for in the annual
TCR auction as described in (1)(c) above or (ii) Self-convert TCR awards; and

(c) For the months of October through May for round 2, the difference between: (i) the sum of annual ARR awards and monthly ARR awards and (ii) the sum of ARR MW accounted for in Section (1)(c) above and the ARR MW accounted for in Section (2)(b) above.

7.78 Transmission Congestion Right Secondary Market

The Transmission Provider will facilitate a secondary market for TCRs. Both purchaser and seller in the secondary market must be a Market Participant. The secondary market is described as follows:

1. Bilateral trading of existing TCRs is facilitated through a bulletin board system;
2. TCRs may be broken down into increments that are not smaller than 0.1 MW and that totals no more than the original TCR;
3. TCRs may be traded daily, for On-Peak or Off-Peak periods;
4. Trades must be completed no later than two (2) calendar days prior to the applicable Operating Day to which the TCR instrument applies.
5. The TCR purchaser pays TCR seller directly;
6. TCRs may not be reconfigured (path must remain the same);
7. The Market Participants must inform the Transmission Provider of any proposed transfer and the Transmission Provider must confirm that the credit requirements in Attachment X of this Tariff have been met prior to the transfer of ownership of a TCR through a bilateral transaction; and
8. The Transmission Provider records the transfer of TCR ownership.

7.89 Liquidation of Transmission Congestion Rights in the Event of Market Participant Default

In the event the Transmission Provider declares a Market Participant to be in default in accordance with Attachment X of this Tariff, the Transmission Provider shall initiate the following procedures to close out and liquidate the TCRs of the Market Participant as soon as practicable after such default is declared:

1. Transmission Provider may close out the defaulting Market Participant’s positions as of the date of default, by unilaterally accelerating and terminating all forward TCR positions.
(2) Transmission Provider shall post on its website all salient information relating to a closed out portfolio of TCRs.

(3) In liquidating the defaulting Market Participant’s TCR portfolio, the Transmission Provider shall not allow the liquidated TCRs offered for sale to set price.

(4) Transmission Provider may offer for sale all of the TCR positions within the defaulting Market Participant’s TCR portfolio in any or all upcoming regularly scheduled TCR auctions.

(5) Alternatively, the Transmission Provider may conduct one or more specially scheduled TCR auctions, in which all of the portfolio of the defaulting Market Participant’s TCRs are offered for sale.

(6) If Transmission Provider elects not to, or is unable to, close out and liquidate a TCR position under these procedures, the close out shall be deemed void and the defaulting Market Participant shall remain liable for the full final value of its default, such full final value being based upon the results of the applicable Day-Ahead Market settlements.

7.9 Initial TCR Markets Schedule

For the initial period, which will span the period between the start-up date of the Marketplace and the start date for the first annual TCR year, Transmission Provider will conduct an abbreviated multi-month auction using a process similar to the annual auction. The initial production schedule for TCRs shall be as follows and in accordance with the timelines specified in the Market Protocols:

1. Candidate ARR Verification
2. 3-round ARR Market Participant Nomination and Transmission Provider Allocation processes
3. 1-round TCR Auction for the period prior to the first full year auction using 90% of the system capability

Subsequently, Transmission Provider will conduct monthly auctions of any residual amounts available on the system according to the process defined for monthly auctions in Sections 7.4 and 7.5 of this Attachment AE.
Attachment X

2.1 Definitions. The following definitions apply in this Credit Policy. Capitalized terms used herein and not defined herein shall be given the meaning assigned to them under the Tariff.

Locational Marginal Price
This term shall have the meaning given in Attachment AE of the Tariff.

Long-Term Congestion Right (LTCR)
This term shall have the meaning given in Attachment AE of this Tariff.

Market Exposure
This term has the meaning given in Section 5.2.1.

5A.1 Overview.

5A.1.1 Transmission Congestion Rights create potential exposure of non-payment, and therefore, have a credit requirement. SPP will establish a Total TCR Credit Requirement for each Credit Customer holding TCRs or participating in a TCR Auction. A Credit Customer may satisfy its Total TCR Credit Requirement by providing Financial Security. Unsecured Credit is not available to support a Credit Customer’s holding of TCRs or activity in TCR Auctions. Additionally, SPP’s prior approval is required for a Credit Customer to acquire or transfer TCRs through bilateral transactions.

5A.1.2 To establish the credit requirement associated with TCRs, SPP analyzes: (i) the TCRs the Credit Customer holds; (ii) the Credit Customer’s Bids and Offers for TCRs in the TCR Auctions; (iii) TCR payments or charges for which settlement has been calculated but not yet invoiced; and (iv) TCR payments or charges for which an invoice has been issued but payment has not occurred.

(a) SPP calculates the potential exposure associated with the full portfolio of TCRs that are held by the Credit Customer, including TCRs obtained from LTCRs.

(b) SPP evaluates individually each TCR Bid in the TCR Auctions to ensure that the Credit Customer has sufficient Financial Security to cover the credit requirements to purchase and hold the TCR. Only the TCR Bids for which the Credit Customer has sufficient Financial Security will be credit approved for consideration in the TCR Auction.

(c) SPP evaluates individually each TCR Offer in the TCR Auctions to ensure that the Credit Customer has sufficient Financial Security to cover any credit requirements associated with the Offer and the credit requirements for the retained TCR portfolio that would result if the TCR Offer clears in the TCR Auction. Only the TCR Offers for which the Credit Customer has sufficient Financial Security will be credit approved for consideration in the TCR Auction.
(d) Additionally, SPP analyzes the credit requirements associated with TCRs that are the subject of a proposed bilateral transfer prior to providing approval of such transfers. SPP approval of a bilateral transfer for TCRs is required for such bilateral transfers to be completed.

5A.1.3 As part of the determination of the credit requirement associated with TCRs, SPP calculates the Estimated TCR Exposure (ETCRE), which is an estimate of the potential value of the TCR over the life of the TCR. In the case of a TCR associated with a LTCR, the life of the TCR shall be considered one year. It will be calculated for all TCRs the Credit Customer holds, the Credit Customer’s TCR Bids and TCR Offers, proposed TCR bilateral transfers, and TCRs acquired through ARR self-conversion. SPP will determine the credit requirement associated with TCRs and whether the Credit Customer has available Financial Security to support its TCR activity. After the close of a TCR Auction and on an ongoing basis, SPP will update the Credit Customer’s Total TCR Credit Requirement associated with TCRs to reflect the actual TCRs the Credit Customer holds and TCR Auction results, including the costs to acquire or sell TCRs in a TCR Auction.

5A.1.4 This Article addresses the calculation of the Total TCR Credit Requirement associated with TCRs, including the ETCRE calculations for the TCRs the Credit Customer holds and the Credit Customer’s Bids and Offers for TCRs in the TCR Auctions and the acquisition and disposal costs of the TCR in the TCR Auctions; as well as the TCR payments or charges for which settlement has been calculated but not yet invoiced; and the TCR payments or charges for which an invoice has been issued but payment has not occurred. This Article also addresses the determination whether a Credit Customer has sufficient Financial Security available for the Credit Customer’s proposed TCR Auction activity or proposed bilateral transfers of TCRs.

**Proposed Criteria Language Revision**

N/A
RCAR Report
MOPC Presentation

Paul Suskie, SPP Staff
psuskie@spp.org

Michael Siedschlag, RARTF Chair

Outline of Today’s Meeting

I. OATT Requirements
II. RARTF Charter
V. Stakeholder Feedback on Draft Report
VI. Results of the RCAR Review
VII. Next Steps
SPP Tariff Requirement – Reviews.

• The Transmission Provider shall review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at *least once every three years* in accordance with this Section III.D.

• The Transmission Provider and/or the Regional State Committee may initiate such review at any time.

• Any change in the regional allocation methodology and factors or the zonal allocation methodology shall be filed with the Commission.
Highway/Byway Review Process – 4 Steps.

- **STEP 1: RARTF**
  - One year prior to each three-year planning cycle (starting in 2013) the *Markets and Operations Policy Committee* and *Regional State Committee* will define the analytical methods to be used to report under this Section III.D and suggest adjustments to the Regional State Committee and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint – *HENCE ESTABLISHMENT OF RARTF*.

Highway/Byway Review Process – 4 Steps.

- **STEP 2: SPP Staff Review**
  - For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the Regional State Committee shall determine the cost allocation impacts utilizing the analysis specified in Section III.e of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J [RARTF Methods].
Highway/Byway Review Process – 4 Steps.

• **STEP 3:** Report: Publishing of SPP Staff Review
  • The Transmission Provider shall review the results of the cost allocation analysis with SPP’s Regional Tariff Working Group, Markets and Operations Policy Committee, and the Regional State Committee. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.

Highway/Byway Review Process – 4 Steps.

• **STEP 4:** Remedies of Review
  • The Transmission Provider shall request the Regional State Committee provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.
  • In accordance with the SPP Bylaws, the SPP Board of Directors will initiate the appropriate actions, including any necessary filings with the Commission, consistent with the Regional State Committee recommendations.
Highway/Byway Review Process – 4 Steps.

- **Others Remedies:**
  - Solutions could include, but are not limited to, adjustments to the Highway/Byway, transfer payments, approval of projects in specific zones, etc.

### 5.1 RARTF Recommended Zonal Remedies

- The potential list of remedies, listed in order of preference, that SPP staff could evaluate include, but are not limited to:

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Establishment of the RARTF

- Charter Finalized June 9, 2011
- RARTF Members Jointly-appointed by MOPC (Bill Dowling) & RSC (Jeff Davis)
- Members Announced June 10, 2011
## RARTF Members

<table>
<thead>
<tr>
<th>Position</th>
<th>Name</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chairman</td>
<td>Michael Siedschlag</td>
<td>Nebraska Public Review Board</td>
</tr>
<tr>
<td>Vice-Chairman</td>
<td>Richard Ross</td>
<td>American Electric Power</td>
</tr>
<tr>
<td>Commissioner</td>
<td>Thomas Wright</td>
<td>Kansas Corporation Commission</td>
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<td>Bary Warren</td>
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<td>Philip Crissup</td>
<td></td>
<td>Oklahoma Gas &amp; Electric</td>
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<tr>
<td>Harry Skilton</td>
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<td>SPP Board of Director</td>
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</table>

## RARTF’s Charter

1. The RARTF will make final recommendations to the MOPC and the RSC regarding the analytical methods to be used to review the reasonableness of the regional allocation methodology for the approval of both the MOPC and RSC.  
2. In addition to developing the analytical methods to be used in the analysis, the RARTF will provide SPP Staff guidance as to the Task Force’s expectation for the threshold for an unreasonable impact or cumulative inequity. The RARTF shall prepare and issue the report by December 20, 2011.
Work of the RARTF

- RARTF Meetings
  - June 21, 2011 – Organizational Conference Call
  - August 4-5, 2011 – Face to Face Meeting
  - August 18, 2011 – Conference Call
  - September 22-23, 2011 – Face to Face Meeting
  - October 17-18, 2011 – Face to Face Meeting
  - November 21-22, 2011 Face to Face Meeting
  - December 2, 2011 - Conference Call
  - December 16, 2011- Conference Call
  - December 20, 2011 – Conference Call
  - May 31, 2013 – Conference Call Meeting
  - September 12, 2013 – 2nd Review and Stakeholder Comments
  - October 8, 2013 - Meeting

Richard Ross

OVERVIEW OF RARTF REPORT
Sect. 3.1 - 10 Principles of the RARTF

(1) Simplicity – The Regional Cost Allocation Review should be as simple as possible so that the report has a distinct understandability.

(2) Roughly Commensurate – The Regional Cost Allocation Review should use the principle of “roughly commensurate” as the legal framework and a guidepost when evaluating the reasonable and long-term equity of SPP regional transmission upgrades under the Highway/Byway cost allocation methodology.

(3) Use Best Information Available – The Regional Cost Allocation Review should use the most up to date and best available information for the review.

(4) Consistency – The Regional Cost Allocation Review should be consistent.

(5) Transparency – The assumptions, inputs, and data used in the Regional Cost Allocation Review should be transparent to SPP stakeholders.

(6) Stakeholder Input - The assumptions, inputs, and data used in the Regional Cost Allocation Review should be vetted through SPP’s open and transparent stakeholder process.

(7) Real Dollars – The Regional Cost Allocation Review Analysis and Report should use dollar values of the year in which the report will be issued.

(8) Consideration Given to Certain Plans – The Regional Allocation Cost Review should give considerations to certain plans that have been approved by the SPP Board of Directors. This includes projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.

(9) More Weight Should be Given to Nearer Term Projects than Future Projects – Although the Regional Cost Allocation Review should give consideration to certain plans approved by the SPP Board of Directors, less weight should be given to plans which have been given an ATP as opposed to a NTC.

(10) Equity Over Time – The Regional Cost Allocation Review should adhere to the long term view of the Highway/Byway cost allocation methodology to strive toward regional cost allocation equity over time.
3.2 - Regional Cost Allocation Review Methodologies

The two evaluations would include an assessment of:

(1) **NTCs**: All SPP projects that have been issued an NTC since June 2010; and

(2) **NTCs and Projects within 10 years**: All SPP projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.

Attachment J, Section III.D.2 of SPP’s OATT, requires that the Regional Allocation Review “shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010.” The RARTF views that the report in Section 3.2(1) will comply with the Tariff. However, the RARTF believes that additional analyses need to be considered by SPP stakeholders in light of the fact the Highway/Byway applies to future projects that have yet to receive an NTC. Hence the RARTF recommends additional studies as stated in 3.2(2) so that the focus is not exclusively on the first projects that fall under SPP’s Highway/Byway. As FERC noted in the October 20, 2011 Order on Rehearing, “the Priority Projects are just one set of projects to be constructed over the years of transmission development in SPP.”


Conditional Notices to Construct or CNTCs are considered NTCs and therefore should be included and evaluated as a NTC as contained and provided in this Report.

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**May 31, 2013 RARTF Guidance - Suspended NTCs**

- The RARTF provided SPP Staff Guidance as to how to handle Suspended NTCs.
- The RARTF directed SPP Staff to include Suspended NTCs in the in the RCAR but that Suspended NTCs should be given a reduced weighting of the valuation of the costs and benefits at seventy-five percent (75%) of the total value.
- The RARTF made this 0.75 weighting recommendation due to the less certain nature of these projects as they are under review.
3.8 Benefits to be Calculated.

- Adjusted Production Cost (APC)
- Impact on Capacity Required for Losses
- Improvements in Reliability
- Remedy Benefits
- Reduction of Emission Rates & Values
- Reduced Operating Reserves
- Improvements to Import/Export Limits
- Public Policy Benefits
- Other metrics as decided by ESWG

4.1 RARTF Recommends a Remedy Threshold

Pursuant to the RARTF Charter, the RARTF recommends that a threshold be established to determine when it is warranted for SPP staff to study possible remedies to address an imbalance based upon the results of a Regional Cost Allocation Review. This threshold defines when SPP staff should study a zonal mitigation. If a zone is determined to be below this threshold, mitigation may be necessary to create equity.

The RARTF recommends that a threshold be set at a 0.8 benefit to cost ratio for projects that are a part of the assessment report stated in Section 3.2(2) above. Section 3.2(2) calls for a report on “all SPP projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.”
### 5.1 RARTF Recommended Zonal Remedies

- The potential list of remedies, listed in order of preference, that SPP staff could evaluate include, but are not limited to:

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**Paul Suskie**

**METRIC TASK FORCE & ESWG**

**DEVELOPMENT OF BENEFITS**
MTF Members

<table>
<thead>
<tr>
<th>Name</th>
<th>Company</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kip Fox</td>
<td>American Electric Power</td>
</tr>
<tr>
<td>Roy Boyer</td>
<td>Xcel Energy Services, Inc.</td>
</tr>
<tr>
<td>Mike Collins</td>
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<tr>
<td>Paul Dietz</td>
<td>Westar Energy, Inc</td>
</tr>
<tr>
<td>Tom Hestermann</td>
<td>Sunflower Electric Power Corporation</td>
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<tr>
<td>Greg Sweet</td>
<td>The Empire District Electric Company</td>
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<tr>
<td>Mitchell Williams</td>
<td>Western Farmers Electric Cooperative</td>
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</table>

The MTF scope of work and key deliverables

- A recommendation on which of the benefits identified above can be quantified in dollars.
- Methodologies for the benefits identified above, including the allocation of the benefit to each SPP Zone (Reference the Southwest Power Pool Open Access Transmission Tariff, Attachment H, Section I, Table 1). An estimate of the effort to calculate the benefits identified above.
- A list of any issues identified from their efforts or any additional direction needed from other working groups.
- A plan for gaining consensus on the metric assumptions and methodologies.
- Progress updates at ESWG meetings.
- A written report containing such recommendations, was to be completed by MTF no later than the July, 2012 ESWG meeting.
- The MTF Charter can be found at: http://www.spp.org/publications/20120227%20Metrics%20Task%20Force%20Charter.pdf
MTF Report

• At the conclusion of their work, the MTF submitted a final report (MTF Report) to the ESWG on September 13, 2012. The MTF provided the ESWG with a Report that contained a full analysis of the “wide-range of benefit metrics” that had been discussed and vetted through “multiple open and transparent stakeholder meetings.”

• Hannes Pfeifenberger and Kamen Madjarov from the Brattle Group were engaged to support the MTF.

• The MTF Report can be found at: http://www.spp.org/publications/20120913%20MTF%20Report_approved.pdf

Stakeholder Approval/Endorsement of MTF Report

• September 13, 2012 ESWG Meeting: The MTF Report was amended and approved by the ESWG and sent on to the MOPC for approval.

• October 16-17, 2012 MOPC Meeting: The MTF Report was presented and approved by the MOPC.

• October 30, 2012 MC/BOD Meeting: After a presentation of the MTF Report, the Members Committee approved the metrics unanimously followed by the Board of Directors’ approval of the Report.
RARTF Time Line

RARTF Est. June 2011

RARTF June 2011 - Jan 2012
Extensive Stakeholder Meetings to Develop Methodology

RARTF REPORT
Completed Universally Adaptsed by the RARTF, RSC, MOPC, & Members Committee
BOD Approval

RARTF Report Called an EWSG (Economic Studies Working Group) to monetize benefits

ESWG Forms the MTF (Metrics Task Force)
MTF Monetizes Benefits

MTF Completes Monetization of Benefits
Endorsed by the ESWG, MOPC, MC, & BOD

SPP Staff Implement

SPP Staff & Brattle Group uses MTF Benefits in RCAR Study

RARTF Meetings May, July, Sept. & Oct.

STAKEHOLDER FEEDBACK

Paul Suskie
Next Steps

• Step 1: Process to Finalize the RCAR Report:
  – SPP Staff Proposal for Stakeholder Feedback -  (Complete)
  – Proposed Dates/Schedule -  (Complete)
  – Receive Guidance from the RARTF –  (Complete)
  – Finalize Report

• Step 2: Begin Stakeholder Process to Use the RCAR Report
  – Overview of what the RARTF Calls for SPP Staff to do with the Report

Stakeholder Feedback

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Michael Siedschlag & Paul Suskie

**B/C RATIOS (DRAFT REPORT)**
### RCAR – NTCs + Suspended NTCs @ 75%

#### Present Value of 40-yr Benefits for 2013-2052

|                | Total Benefits Before PP Revenue Offset | After PP Revenue Offset | 40-yr ATRRs Benefit-to-Cost Ratio | Gap to Reach B/C Ratio of 0.8 TOTAL | Levelized Real
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### RCAR – NTCs + Suspended NTCs + ATPs

#### Present Value of 40-yr Benefits for 2013-2052

|                | Total Benefits Before PP Revenue Offset | After PP Revenue Offset | 40-yr ATRRs Benefit-to-Cost Ratio | Gap to Reach B/C Ratio of 0.8 TOTAL | Levelized Real
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**Not Monetized**

10/18/2013
**HIGH GAS RUN**

**HG: RCAR – NTCs + Suspended NTCs @ 75%**

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<th>Present Value of 40-yr ATRRs</th>
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<th>Gap to Reach B/C Ratio of 0.8</th>
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**Not Monetized**
## HG: RCAR – NTCs + Suspended NTCs + ATPs

### Present Value of 40-yr Benefits for 2013-2052

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**TOTAL** $3,766 $166 $96 $424 $2,654 $296 $7,401 $5,193 $446 $4,747 1.56 $23 $1.4

### NEXT STEPS

Michael Siedschlag & Paul Suskie
Next Steps

• Step 1: Process to Finalize the RCAR Report:
  – SPP Staff Proposal for Stakeholder Feedback - (Complete)
  – Proposed Dates/Schedule - (Complete)
  – Receive Guidance from the RARTF – (Complete)
  – Finalize Report

• Step 2: Begin Stakeholder Process to Use the RCAR Report
  – Overview of what the RARTF Calls for SPP Staff to do with the Report

Step 1: Finalizing the Report (Stakeholder Feedback)

• Presented the Draft Report to RARTF – July 29, 2013
• SPP Staff Received Feedback from Stakeholders (August)
  – Receive questions about calculations
  – Make necessary corrections/adjustments to any errors
• SPP Staff Met with Members to answer questions (August)
• Hold an In-Person RARTF Meeting to Update/Finalize the RCAR
  – September 12, 2013 & October 8, 2013
• Present to RTWG (Complete - Oct. 1st)
• Present to MOPC (Oct. 16th)
• Present to RSC (Pending)
Step 2: Begin Process to Use the RCAR Report

Step 2 (a): Recommendation is to use the RCAR Report by incorporating and included in SPP’s current ITP10 assessment that commenced in July 2013.

- SPP Staff and the RARTF recommend that this RCAR Report be finalized in October 2013 in order to incorporate and include the finding in SPP’s current ITP10 assessment that commenced in July 2013. This recommendation is in-line with the direction of the RARTF Report approved in January 2012 as described below.

- As shown above in Figure 8 above, which is also found in Section 5.1 of the RARTF Report, the first two remedies for SPP staff to consider for City Utilities of Springfield, Empire District Electric Company, Grand River Dam Authority, Lincoln Electric System, and Sunflower Electric Power Corporation as a part of the RCAR Report is the “[a]cceleration of planned upgrades” and “[i]ssuance of NTCs for selected new upgrades.” Section 8.2 of the RCAR Report.

<table>
<thead>
<tr>
<th>Remedy</th>
<th>Entity with Authority/Duty to Implement</th>
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<td>(1) Acceleration of planned upgrades;</td>
<td>SPP ROD</td>
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<tr>
<td>(2) Issuance of NTCs for selected new upgrades;</td>
<td>SPP ROD</td>
</tr>
<tr>
<td>(3) Apply Highway funding to one or more Byway Projects;</td>
<td>RSC, SPP ROD &amp; FERC</td>
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<tr>
<td>(4) Apply Highway funding to one or more Seams Projects;</td>
<td>RSC, SPP ROD &amp; FERC</td>
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<tr>
<td>(5) Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or a lack of benefits to a zone;</td>
<td>RSC, SPP ROD &amp; FERC</td>
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<tr>
<td>(6) Exemptions from cost associated with the next set of projects;</td>
<td>RSC, SPP ROD &amp; FERC</td>
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<tr>
<td>(7) Change Cost Allocation Percentages.</td>
<td>RSC, SPP ROD &amp; FERC</td>
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</table>

Step 2 (b): In addition to this recommendation, SPP staff and the RARTF recommend that a second RCAR process [RCAR II] be commenced and work in parallel with the ITP10 assessment which is expected to be completed in January 2015. This will allow SPP staff to follow the directions contained in Sections 4.2 and Section 5.1 of the RARTF Report through ITP10 while utilizing RCAR II as a means to understand whether proposed remedies approved in the ITP10 provide equity for certain zones. If RCAR II does not show that adequate remedies exist, SPP staff, deficient zones, and SPP Stakeholders can begin the process of analyzing additional potential remedies for any zone below the threshold. The report will be completed either (i) shortly after the ITP10 is completed, if cost estimates are to be used in the RCAR II analysis; or (ii) shortly after the completion of the competitive solicitation process, if the RFP results are to be used in the RCAR II analysis. Section 8.2 of the RCAR Report.
Lessons Learned

In accord with the fourth additional recommendation contained in Section 7.1 of the RARTF Report, it is recommended that the RARTF “be reconvened before subsequent Regional Cost Allocation Reviews are performed.” This aligns with the recommendations contained in Section 8.2 of this Report, that the RCAR “be finalized in October 2013 in order to incorporate and include the finding in SPP’s current ITP10 assessment” and to allow “that a second RCAR process [RCAR II] be commenced and work in parallel with the ITP10 assessment.”

As a result, the final recommendation is for the RARTF to begin a “lessons learned” and to finalize any “suggested improvements” to the RCAR process by the January 2014 stakeholder meeting cycle. This will allow these improvements to be incorporated into the RCAR II process.

Section 9.1 of the RCAR Report.

QUESTIONS???
Background of GI & ATSS Process Improvements

- In April, BOD and MOPC approved GI and ATSS process improvement whitepapers and a recommended Backlog Clearing Process.
- Process Improvement Task Force created to develop tariff language with the following prioritization:
  1. Backlog clearing process
  2. GI study process improvements
  3. ATSS process improvements
- In July, BOD approved tariff language for the ATSS backlog clearing process.
Status of GI Study Process Improvements

- Highlights of the whitepaper approved in April
  - Improved study procedures
  - Higher financial milestones
  - “First-ready” provisions

- BPWG approved revised whitepaper on Sept. 24
  - Clarified treatment of costs imposed due to withdrawals
  - Added flexibility for long lead-time upgrade acceleration
  - Reduced number of open seasons per year

Status of GI Study Process Improvements

- MOPC approved revised whitepaper and associated tariff changes on October 15
- BOD approval of Tariff changes requested October 29
- If approved, Tariff language will be filed with FERC in November
- Expect to implement in first quarter 2014
Status of ATSS Backlog Clearing Process

- Tariff changes filed August 15
  - FERC conditionally approved on Oct. 11 with Oct. 12 effective date
  - 30-day compliance filing to clarify provisions
- SPP held a web conference for customers October 4
  - Documents available on spp.org
- Process has commenced with 2011-AG3

Status of Future ATSS Process Improvements

- Highlights of whitepaper approved in April
  - Customer specifies acceptance parameters before study
  - 4-month study process
  - Requests accepted/refused based on parameters
- BPWG approved revised whitepaper on Sept. 24
  - Added “maximum letter of credit” parameter
  - Lengthened study process to 6-months
  - Added opportunity for preview and parameter revision after first study iteration
  - Added make-whole payment in third-party process
Status of Future ATSS Process Improvements

- BPWG committed to work with CAWG on third-party impacts
  - SSC Task Force on third-party impacts created
- MOPC reviewed revised whitepaper on Oct. 15
- Tariff changes to be drafted with goal of January 2014 MOPC/BOD consideration and approval
- Impact of FERC Order 1000 is uncertain
Integrated Marketplace System Update

Regional State Committee

October 2013
Bruce Rew, PE

Integrated Marketplace Topics

- TCR Update
- Market Trials
- Parallel Operations and Deployment Testing
- Cutover and Go-Live Planning
- Readiness and Outreach
- Post Go-Live Activities
TCR Market Trials & Go-Live

• TCR Market Trials - Complete
  – Successfully completed Phase 2 of TCR Market Trials on 9/27

• TCR Go/No-Go Process – In Progress
  – Published TCR Go/No-Go Data on 10/3
  – CWG voted 13 to 12 to Go-Live with 5 additional support votes
  – SPP Staff Recommended proceeding with Go-Live
  – TCR Recommendation report posted on SPP website
  – On October 11 Go-Live Team Unanimously approved TCR Go-Live

• TCR Go-Live - Upcoming
  – TCR Go-Live on 10/18
    • TCR System will go live in accordance with the SPP Integrated Marketplace Protocols

Structured/Unstructured Market Trials

• Structured/Unstructured Market Trials Accomplishments
  – Currently Performing Operating Days Monday – Friday
  – Currently have tested or in the process of testing all scoped SMT functionality
  – Completed 62 Official Operating Days to date (as of 10-17)
  – Successfully completed 25 entire Scenarios and 2 partial Scenarios of 49 Structured Scenarios (as of 10-14)
  – Completed 52 Unstructured days to date (as of 10-17)

• Upcoming SMT Efforts
  – Official Operating Days will increase to Monday – Sunday starting 10-20
  – Completing testing Markets Software version 1.7
  – Operating Days will continue through November 3
    – Some Structured Scenarios will be tested during Parallel Operations beginning 11-12
    – Structured/Unstructured Market Trials Concludes on 11-3
Scenario Tracker as of Oct 16

• **Summary - Successful:**
  - 25 Scenarios Successful
  - 2 partial Scenarios (21: sub-scenarios #1, 3-8 and 15 part 1) Successful

• **Summary - Retests:**
  - 1 entire Scenario (33) all MPs will retest during Structured Market Trials
  - 1 entire Scenario (11) and 1 partial Scenario (15 part 2) all applicable MPs will retest during Parallel Ops
  - 22 individual retest requests pending
  - 5 entire Scenarios and 1 partial Scenario retesting is not high priority or required to be performed in Market Trials Production environment

PARALLEL OPERATIONS AND DEPLOYMENT TESTING
**Parallel Operations**

**Parallel Operations Preparation Accomplishments**
- Parallel Operations MP Kick-off on 10/8
- Published the 3 Month [Parallel Operations Calendar](#).
- Published v3.0 of the [Parallel Operations Market Participant Guide](#).
- Published the [Parallel Operations Communications Plan](#).

**Upcoming Parallel Operations Efforts**
- Parallel Operations Go/No-Go Process
  - Publish Parallel Ops Go/No-Go Data on 10/28 to CWG
    - Go/No-Go data is based on the published [Go/No-Go Criteria](#).
  - Recommendation Report is published to Go-Live Team (and CWG) on 11/1, Decision on 11/6
- Assuming a positive Go/No-Go, Parallel Operations will start on 11/12 and continue through 1/31
  - This will include some iterations of Structured Tests as a carry-over from SMT.

**Parallel Operations Go/No-Go Criteria**

- There are 24 Parallel Operations Criteria.
  - 3 are complete
  - 13 are tracking on time
  - 7 are at tracking at risk
  - 1 has not started tracking yet
- The following criteria are at risk:
  - PO-03: 100% of Structured/Unstructured testing scenarios are successfully executed and completed or removed from scope and successful completion is validated through Readiness Metric TRL-02.
  - PO-04: SPP and member ICCP Models are up to date and all ICCP and XML inbound and outbound Marketplace data points have been validated with all applicable Market Participants as part of Structured Market Trials.
Parallel Operations Go/No-Go Criteria

- The following criteria are at risk (cont.):
  - PO-10: FIT (Functional Integration Testing) Stage Exit Criteria is met by all applicable workstreams and Business Owner approval is obtained (with the exception of Settlements).
  - PO-13: Performance Testing Exit Criteria is met by all applicable workstreams and Business Owner approval is obtained.
  - PO-14: Non Functional Testing should be completed and reviewed by SPP Technical Architects validating the systems demonstrate sufficient stability to commence Parallel Operations.
  - PO-16: MCE Certification sign-off obtained from Markets Business Owners.
  - PO-19: Protocol Compliance has been validated.

Integrated Deployment Testing

- Integrated Deployment Testing Preparation Accomplishments
  - Updated and posted v2.0 of the Integrated Deployment Test Market Participant Guide.
  - Integrated Deployment Testing Roll-in/Roll-out Plans (TRL.079)
    - Published the SPP IDT Roll-In/Roll-Out plan for distribution to the EIS BAs on 09-16.
    - Received all 16 BA initial plans for the Integrated Deployment Test Roll-In/Roll-Out.
    - Completed BA Readiness Calls on 10/4.
  - Operating Protocols published to CBASC on 9/3.
  - EIS BAs have internally reviewed and provide finalized Roll-in/Roll-out Plans.

- Upcoming Parallel Operations Efforts
  - Perform Mock Deployment Test on 11/14.
  - Complete Integrated Deployment Tests on 1/30.
MARKET TRIALS PHASE CUTOVER & GO-LIVE PLANNING

Market Trials Phase Cutover & Go-Live Planning

- **TCR Go-Live – October 2013**
  - Go/No-Go Process -- **Approved**
  - Internal TCR Go-Live Deployment Plan -- **Approved**

- **Parallel Operations/IDT Go-Live – November 2013**
  - Go/No-Go Process – **To Start 10/28**
  - Internal Parallel Operations & IDT Go-Live Deployment Plan – **In Progress**
    - A tactical plan of functional and technical activities to allow SPP to successfully cut-over to Parallel Operations and Integrated Deployment Testing.
Market Trials Phase Cutover & Go-Live Planning

- Markets Go Live – March 2014
  - People
    - **SPP Staff Readiness**: 12/20/13 - High impact business area’s resources are performing Go-Live functions.
    - **MP Readiness**: 12/20/13 - MPs have submitted MP Readiness Self-Certification
  - Processes
    - **Marketplace Process & Procedure Readiness completed by 1/31/14**
  - Systems
    - **System Readiness**: All by 12/20/13
      - Systems are protocol-compliant
      - Systems have zero critical defects
      - 12/20/13 - SPP CBA will balance the region’s supply and demand, maintain frequency, and maintain electricity flows between adjacent BAs, meeting all applicable NERC standards and criteria.

Market Trials Phase Cutover & Go-Live Planning

- Markets Go Live – March 2014 (Continued)
  - Governance
    - **FERC Approval**: 12/27/2013 - Submit Readiness Go-Live Filing
    - **NERC/SERC Certification & BA Certification**: 1/15/2014 - NERC certifies SPP as the CBA
    - **Audit Compliant**: 3/1/2014 - The Integrated Marketplace solution will meet all Business & SSAE Control Objectives
Internal Readiness

The Internal Readiness status for SPP is currently yellow. Due to staff focus on supporting program efforts, some readiness activities are currently delayed in Settlements and IT Applications.

- Readiness plans are in place for all medium and high Impact departments, and are being monitored on a monthly basis.
- 73% of readiness plan activities are currently complete. Readiness activities will continue until Market Go-Live.
- A key risk to Internal Readiness is staff bandwidth to participate in readiness activities due to other program responsibilities.
External Readiness

• Completed Readiness Metrics gap analysis
  – 10 new metrics, 6 edited metrics
  – Updated Readiness Metrics will be filed with FERC

• Developed Parallel Ops Go/No-Go Criteria
  – Reviewed with CWG and Readiness Liaisons

• Continued outreach for MP readiness

Readiness Metrics Status

• As of October 4, there are 50 Readiness Metrics (21 Operations, 1 RSG, 3 Market Trials, 1 CBA, 3 Connectivity, 4 Internal, 2 Registration, 3 Regulatory, 6 TCR, 6 Settlements)
  – 5 are complete (blue status)
  – 26 are tracking on time (green status)
  – 8 are at tracking risk (yellow status)
  – 3 are tracking behind
  – 8 have not started tracking (grey status)
MP & Vendor Readiness

- SPP performed outreach to vendors and MPs to understand concerns and needs and offer assistance
- MPs completed system readiness survey and provided responses on 9/27
- Readiness Forum to discuss vendor and MP readiness - Wednesday, October 9th
- MP Identified Risks:
  - Test Scenario Delays/Changes
  - Vendor System Readiness
  - SPP System Readiness
  - API Testing/Delays and Changes
  - Data Validation Inadequate
  - Bid to Bill Functionality

Integrated Marketplace- 1-Year Post Go-Live

- Go-Live Support Activities
  - Go-Live Day-to-Day Operations Support
  - Go-Live System Support
  - Go-Live System Emergency & Maintenance Patches

- Post Go-Live Projects
  - Regulation Compensation (*FERC-Mandated*)
  - Market-to-Market (*FERC-Mandated*)
  - Long Term Congestion Rights (LTCRs) (*FERC-Mandated*)
  - Pseudo-Tie Out (*Resettlement Implications*)
  - IT Environments Buildout for Marketplace (*Necessary*)
  - Enhanced Combined Cycle- Member Requested*
  - Go-Live “Required” System Enhancements

*Desired implementation date is one-year post go-live
2015 ITP10 Update

Lanny Nickell
10/28/2013

2015 ITP10 Update

• Scope
• Futures
• Economic Model Development
• Analysis Methodology
• Project Classification
• Portfolio Development
• Final Report
Scope

• 3 Futures developed
  1. Business as Usual
  2. Decrease in Base Load Capacity
  3. Increased Input Prices

• Stakeholder Approval
  – TWG Approved all 3 futures September 18th
  – ESWG Approved all 3 futures on October 2nd
  – MOPC Approved futures 1 and 2 on October 16th
  – BOD will decide on October 29th

Futures

• Future 1: Business as Usual
• Future 2: Decreased Base Load Capacity
  – Up to 20% capacity reduction of conventional generation and hydro
  – Most coal units under 200 MW retired
• Future 3: Increased Input Prices
  – Natural gas prices tripled
  – Carbon tax
  – Demand response/Energy efficiency
Futures (Continued)

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<td>Conventional Generation-New</td>
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<td>10.8</td>
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</table>

Economic Model Development

- **Base case modeling assumptions**
  - Include High Priority Incremental Load Study (HPILS) loads and NTCs, if issued
  - Generator Production Cost Modeling
  - Tres Amigas and Clean Line HVDC interconnections will be studied as sensitivities
  - 10.4 GW of wind will be modeled consistent with the 2013 Policy Survey
Analysis Methodology

• **Constraint Assessment** - November 2013 thru January 2014
  – Identify Transmission Constraints

• **Needs Assessment** - March 2013 thru May 2014
  – Identify Reliability, Economic, and Policy Needs

• **Solicit Detailed Project Proposals (DPP) in accordance with Order 1000**

• **Project Development** - April 2014 thru June 2014
  – Evaluate and determine solutions for transmission needs

Project Classification

• Classify projects by needs addressed
• Perform analyses in parallel

Reliability (R)
Policy (P)
Economic (E)
Portfolio Development

- Consolidate projects into a single portfolio
  - Addresses needs across multiple futures
  - Supports cost effective solution development
  - ESWG and TWG Approved consolidation methodology
  - MOPC issued action Item 223 to re-evaluate the proposed consolidation methodology

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<td>Consolidation Criteria</td>
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2015 ITP10 Report

- Report study findings and recommendations
  - Includes a project list identifying each upgrade
  - Includes projected project costs and benefits on a zonal and state basis
Status Report on the Proposed Entergy/ITC Transaction

October 28, 2013
Little Rock, Arkansas

Background
• Entergy and ITC filed at FERC for approval of the proposed transaction on September 25, 2012.
• Similar filings were made with the:
  • Arkansas Public Service Commission
  • Louisiana Public Service Commission
  • Mississippi Public Service Commission
  • Missouri Public Service Commission
  • New Orleans City Council
  • Public Service Commission of Texas
• Proceedings were suspended in AR, LA, CNO after withdrawal of the application before the PUCT
FERC

• Proposed transaction was announced on December 5, 2011.
• Filing made in Docket Nos. EC12-145 and EL12-107 on September 24, 2012.
• FERC approved transaction and tariff changes on June 20, 2013.

Arkansas PSC

• Initial filing made in Docket No. 12-069-U on September 11, 2012
• April 19, 2013 APSC Staff recommended rejection of the proposal
• Hearing scheduled for September 4th
• APSC suspended the procedural schedule on August 23, 2013
• Entergy/ITC files monthly status reports of activities in other retail jurisdictions
New Orleans City Council

- Initial filing made in Docket No. UD-12-01 on September 12, 2012
- Advisors to the NOCC filed testimony on May 22, 2013 recommending rejection of the transaction
- September 25, 2013 the NOCC suspended the procedural schedule

Louisiana PSC

- Filing made in Docket No. U-32538 on September 5, 2012
- April 10, 2013 LPSC Staff filed recommending that the transaction be denied
- On August 21, 2013, the LPSC suspended the procedural schedule with the withdrawal of the application before the PUCT.
- On October 18, an amended procedural schedule was approved. Post-hearing reply briefs are due November 8th, in advance of the November 13 agenda meeting.
Mississippi PSC

- Filing made in Docket No. 2012-UA-358 on 10-5-2012
- Staff filed its recommendations on 6-20-2013
- Entergy/ITC filed testimony on 8-28-2013 including a Jointly proposed $74.1 M, 5 year rate mitigation plan. Entergy also filed a proposed 3 year bill credit for residential customers of $6.7 M.
- Staff filed recommended conditions on 8-28-2013.
- The MSPSC rejected a motion to suspend the schedule on 8-28-2013.
- Entergy/ITC filed responsive testimony 9-25-2013
- Entergy/ITC filed a Motion for Continuance on 10-14-2012

Missouri PSC

- Entergy Arkansas filed on March 11, 2013 in File No. EO-2013-0431 to transfer functional control of its Missouri transmission facilities to MISO
- Hearing was convened on June 18, 2013
- Order issued October 9, 2013
- Commission has jurisdiction over applicants and transfer of functional control of assets to MISO
- Transfer approved, conditioned upon:
  - negotiation and approval of a revised JOA between SPP and MISO addressing, at a minimum, the loop flow issues and other altered flows related to the Missouri SPP/MISO seam
  - Missouri ratepayers be held harmless from costs related to the transaction
PUC of Texas

- Initial filing made in Docket No. 41223 on February 19, 2013
- Entergy/ITC withdrew their Application on August 9, 2013
- Application updated and refiled on September 23, 2013 in Docket No. 41850
  - Procedural schedule issued October 15, 2013
  - Intervention deadline October 23, 2013
  - Intervenor Testimony November 6, 2013
  - Staff Testimony November 13, 2013
  - Hearing November 21-22, 2013

QUESTIONS???
Southwest Power Pool, Inc.

FOURTH QUARTERLY PROJECT TRACKING REPORT

October 2013

I. Project Tracking, Current SPP Process:

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 Board of Directors or through a FERC filed service agreement under the SPP Open Access Transmission Tariff (OATT).

In this Fourth Quarterly Report of 2013, the reporting period is May 1, 2013 through July 31, 2013.

II. Project Summary:

Figure 1 represents the summary of active projects for this quarter. Figure 1 reflects all upgrades, including transmission lines, transformers, substations, and devices.

Figure 2 shows the total miles of transmission lines currently planned within the portfolio, as well as miles by project voltage. Figure 3 reflects the percentage cost of each project type in the total active portfolio.
### 3rd Quarter 2013 Project Tracking Summary

<table>
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<tr>
<th>Upgrade Type</th>
<th>Number of Upgrades</th>
<th>Cost Estimate</th>
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<tbody>
<tr>
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<tr>
<td>Regional Reliability - Non OATT</td>
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<td>Zonal Reliability</td>
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<td>Generation Interconnect</td>
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<td>Balanced Portfolio</td>
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<td>High Priority</td>
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<td>Other Sponsored Upgrades</td>
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<td><strong>TOTALS</strong></td>
<td><strong>559</strong></td>
<td><strong>$6,673,205,151</strong></td>
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Figure 1: 2013 3rd Quarter Project Summary

### 3rd Quarter Total Active Portfolio Transmission Miles

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Number of Upgrades</th>
<th>New Miles</th>
<th>Reconductor Miles</th>
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<tbody>
<tr>
<td>69</td>
<td>92</td>
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<td>161</td>
<td>29</td>
<td>23.8</td>
<td>35.4</td>
<td>59.2</td>
</tr>
<tr>
<td>230</td>
<td>25</td>
<td>271.4</td>
<td>0.0</td>
<td>271.4</td>
</tr>
<tr>
<td>345</td>
<td>81</td>
<td>2998.6</td>
<td>0.0</td>
<td>2998.6</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>461</strong></td>
<td><strong>4130.7</strong></td>
<td><strong>580.8</strong></td>
<td><strong>4711.6</strong></td>
</tr>
</tbody>
</table>

Figure 2: Project Mileage within the Portfolio
III. Regional Reliability Project Summary:

Regional reliability projects include all tariff signatory projects identified in an SPP study to meet regional reliability criteria for which NTC letters have been issued.

There were 26 upgrades, with latest Engineering and Construction (E&C) cost estimates of $148.0 million completed in the timeframe of the 3rd Quarter of 2013.

There are 105 upgrades, with latest E&C cost estimates of $467.6 million, on schedule to be completed within the next year. There are 157 upgrades, with latest E&C cost estimates of $943.0 million, are in a delayed status with mitigation.

IV. Transmission Service/Generation Interconnection (TSR/GI) Project Summary:
This category contains upgrades identified as needed to support new Transmission Service (TSR) and Generation Interconnection (GI) service agreements.

Seven Transmission Service upgrades were completed in the 3rd Quarter of 2013 with latest E&C cost estimate of $38.6 million. There are seven Transmission Service upgrades, with estimated E&C costs of $35.0 million, on schedule to be completed within the next year. No Generation Interconnect upgrades were completed this quarter. There are three Generation Interconnect upgrades, at an estimated E&C cost of $8.6 million, scheduled to be completed in the next year.

V. Completed Projects Summary:

Figure 6 shows the number and costs for the upgrades completed over the last 12 month period. The 3rd Quarter of 2013 produced 37 upgrades that were completed with a total estimated cost of $209.8 million.
Southwestern Public Service Company reported the completion of a new 20-mile 230 kV transmission line from the Randall County substation to the Amarillo South Interchange. The upgrade is estimated to cost $20.1 million and was built to address reliability needs identified in the 2009 STEP Reliability Assessment.

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.

### Projects Completed By Quarter

<table>
<thead>
<tr>
<th></th>
<th>4th Q 2012</th>
<th>1st Q 2013</th>
<th>2nd Q 2013</th>
<th>3rd Q 2013</th>
<th>Totals YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>8</td>
<td>17</td>
<td>14</td>
<td>26</td>
<td>65</td>
</tr>
<tr>
<td></td>
<td>$41,608,138</td>
<td>$71,082,900</td>
<td>$46,591,995</td>
<td>$147,980,638</td>
<td>$307,263,671</td>
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<tr>
<td>Transmission Service</td>
<td>3</td>
<td>4</td>
<td>3</td>
<td>7</td>
<td>17</td>
</tr>
<tr>
<td></td>
<td>$44,200,000</td>
<td>$17,798,680</td>
<td>$11,469,766</td>
<td>$38,558,199</td>
<td>$112,026,645</td>
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<tr>
<td>Generation Interconnect</td>
<td>9</td>
<td>10</td>
<td>3</td>
<td>0</td>
<td>22</td>
</tr>
<tr>
<td></td>
<td>$22,889,994</td>
<td>$39,935,736</td>
<td>$6,768,543</td>
<td>$0</td>
<td>$69,594,273</td>
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<tr>
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<td>5</td>
<td>0</td>
<td>0</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>$966,210</td>
<td>$171,715,352</td>
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<td>$172,681,562</td>
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<td>0</td>
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<tr>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
</tbody>
</table>

Figure 6: Completed Project Summary through 3rd Quarter 2013
VI. Future Projections:

4th Quarter 2013:

The 4th Quarter of 2013, ending October 31, 2013, is scheduled to have 21 upgrades completed across all project types at an estimated cost of $88.7 million. Figure 8 shows the 4th Quarter estimated completed projects broken out by Project Type.

There are 12.3 miles of new transmission scheduled to be completed in the next quarter, along with 33.0 miles of reconducted transmission added to the footprint. Figure 9 shows the details of the estimated transmission miles to be completed in the 4th Quarter.

August 2013 through July 2014:

The next 12 months are scheduled to have a total of 144 upgrades completed at an estimated cost of $1,301.9 million. Figure 8 shows the next 12 months estimated completed projects broken out by Project Type.

There are scheduled to be 817 miles of new transmission added to the system during the next 12 month period. There are 689 miles of 345 kV transmission lines still scheduled to be completed. There will also be 230 miles of reconducted transmission placed into
the system. Figure 10 shows the details of the estimated transmission miles to be completed over the next 12 months.

<table>
<thead>
<tr>
<th></th>
<th>Scheduled Complete Next Quarter</th>
<th></th>
<th>Scheduled Complete Next 12 Months</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>First day of Quarter</td>
<td>Last Day of Quarter</td>
<td>First day of Reporting Year</td>
</tr>
<tr>
<td>8/1/2013</td>
<td>10/31/2013</td>
<td>8/1/2013</td>
<td>7/31/2014</td>
</tr>
<tr>
<td>Reliability</td>
<td>16</td>
<td>$40,563,360</td>
<td>105</td>
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<tr>
<td>Reliability-Non OATT</td>
<td>0</td>
<td>$0</td>
<td>5</td>
</tr>
<tr>
<td>Zonal Reliability</td>
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<td>$0</td>
<td>3</td>
</tr>
<tr>
<td>Transmission Service</td>
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<td>$3,535,570</td>
<td>7</td>
</tr>
<tr>
<td>Generation Interconnect</td>
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<td>$0</td>
<td>3</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
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<tr>
<td>High Priority</td>
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<td>$0</td>
<td>5</td>
</tr>
<tr>
<td>Zonal Sponsored</td>
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<td>$28,398,000</td>
<td>10</td>
</tr>
<tr>
<td>ITP10</td>
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<td>0</td>
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<tr>
<td>Total</td>
<td>21</td>
<td>$88,731,488</td>
<td>144</td>
</tr>
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Figure 8: Upgrades Scheduled to Complete Next Quarter/Next 12 Months
### 4th Quarter Projected Transmission Miles Complete

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Number of Upgrades</th>
<th>Reconductor Miles</th>
<th>New Miles</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>6</td>
<td>5.8</td>
<td>0.0</td>
<td>5.8</td>
</tr>
<tr>
<td>115</td>
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<td>138</td>
<td>6</td>
<td>0.0</td>
<td>7.0</td>
<td>7.0</td>
</tr>
<tr>
<td>161</td>
<td>4</td>
<td>15.2</td>
<td>0.0</td>
<td>15.2</td>
</tr>
<tr>
<td>230</td>
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<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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<tr>
<td>345</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>19</strong></td>
<td><strong>33.0</strong></td>
<td><strong>12.3</strong></td>
<td><strong>45.2</strong></td>
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</table>

Figure 9: Transmission Miles Scheduled to Complete 4th Quarter

### Projected Transmission Miles Complete Next 12 Months

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Number of Upgrades</th>
<th>Reconductor Miles</th>
<th>New Miles</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>36</td>
<td>108.4</td>
<td>16.96</td>
<td>125.36</td>
</tr>
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<td>115</td>
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<td>73.42</td>
<td>39.95</td>
<td>113.37</td>
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<td>138</td>
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<td>25.7</td>
</tr>
<tr>
<td>230</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>345</td>
<td>12</td>
<td>0</td>
<td>689.06</td>
<td>689.06</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>120</strong></td>
<td><strong>230.17</strong></td>
<td><strong>816.78</strong></td>
<td><strong>1046.95</strong></td>
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</table>

Figure 10: Transmission Miles Scheduled to Complete Next 12 Months
<table>
<thead>
<tr>
<th>Project ID</th>
<th>Description</th>
<th>Phase Type</th>
<th>Indicated In-Service Date</th>
<th>Status</th>
<th>Comments</th>
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<tbody>
<tr>
<td>1</td>
<td>Project was placed into service Tuesday, 30 March 2013</td>
<td>503/11</td>
<td>6/1/2013</td>
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<td></td>
</tr>
<tr>
<td>2</td>
<td>AEP XFR - Diana 345/138 kV ckt 3 Transmission Service</td>
<td>6/1/2013</td>
<td>6/1/2013</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>AEP Line - Eastex - Whitney 138 kV Accelerated Transmission Service</td>
<td>6/1/2013</td>
<td>6/1/2012</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Multi - Flint Creek – Centerton 345 kV</td>
<td>4/13/2018</td>
<td>4/9/2012</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Regional Reliability</td>
<td>6/1/2014</td>
<td>6/1/2014</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>AEP Line - Lone Star South - Pittsburg 138 kV Ckt 1</td>
<td>5/11/2012</td>
<td>6/1/2012</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>AEP Line - Riverside - Okmulgee 138 kV</td>
<td>3/1/2012</td>
<td>6/1/2012</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>AEP Multi - Canadian River - McAlester City - Dustin 138 kV Regional Reliability</td>
<td>6/28/2013</td>
<td>6/1/2010</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>AEP Line - Hooks - Lone Star Ordinance 69 kV Ckt 1</td>
<td>9/1/2013</td>
<td>6/1/2013</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>AEP Multi - Wallace Lake - Port Robson - RedPoint 138 kV Regional Reliability</td>
<td>4/16/2012</td>
<td>6/1/2012</td>
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<td></td>
</tr>
<tr>
<td>12</td>
<td>AEP Line - Bluebell - Prattville 138 kV Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2014</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>AEP Line - Chamber Spring - Farming 141 kV Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2013</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>AEP Line - Turk - NW Texarkana 345 kV Transmission Service</td>
<td>8/28/2012</td>
<td>4/1/2012</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>AEP Line - SE Texarkana - Texarkana Plant 69 kV Transmission Service</td>
<td>3/1/2012</td>
<td>4/1/2012</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>AEP Line - Turk - NW Texarkana 345 kV Transmission Service</td>
<td>8/28/2012</td>
<td>4/1/2012</td>
<td>COMPLETE</td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>AEP Line - Rock Hill - Springridge Pan-Harr REC 138 kV Ckt 1 Regional Reliability</td>
<td>6/1/2016</td>
<td>6/1/2014</td>
<td>COMPLETE</td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- The table includes information on project status, phase type, indicated in-service date, and comments.
- Some projects are ongoing or have been delayed due to various factors.
- The table is a snapshot of projects as of a specific date.
<table>
<thead>
<tr>
<th>Project Code</th>
<th>Project Name</th>
<th>Location</th>
<th>Investor</th>
<th>Project Description</th>
<th>Start Date</th>
<th>End Date</th>
<th>Budget</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>20201001</td>
<td>AEP Line - Howe Interchange - Midland 69 kV</td>
<td>Regional Reliability</td>
<td>6/1/2015</td>
<td>2/20/2013</td>
<td>$9,145,130</td>
<td>$9,145,130</td>
<td>24 months</td>
<td>DELAY - SCHEDULE</td>
</tr>
<tr>
<td>20201002</td>
<td>AEP Line - Midland REC - North Huntington 69 kV</td>
<td>Regional Reliability</td>
<td>6/1/2015</td>
<td>2/20/2013</td>
<td>$1,829,026</td>
<td>$1,829,026</td>
<td>24 months</td>
<td>DELAY - SCHEDULE</td>
</tr>
<tr>
<td>20201004</td>
<td>AEP Sub - Sweetwater 230kV GEN-2006-035 Addition Generation Interconnection</td>
<td>Regional Reliability</td>
<td>10/5/2012</td>
<td>9/23/2013</td>
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<td>30 months</td>
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<td>ITCGP Line - Spearville - Clark Co - Thistle 345 kV</td>
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<td>7/29/2011</td>
<td>$96,000,000</td>
<td>$79,136,700</td>
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<td>COMPLETED</td>
</tr>
<tr>
<td>20201006</td>
<td>XFR - Cocodrie 230/138 kV Regional Reliability - Non OATT</td>
<td>Regional Reliability</td>
<td>4/1/2013</td>
<td>6/1/2009</td>
<td>$5,000,000</td>
<td>$5,000,000</td>
<td>18 months</td>
<td>COMPLETED</td>
</tr>
<tr>
<td>20201007</td>
<td>KCPL Tap - Swissvale - Stilwell Balanced Portfolio</td>
<td>Regional Reliability</td>
<td>1/31/2013</td>
<td>6/19/2009</td>
<td>$2,000,000</td>
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<td>12 months</td>
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<td>ITCGP XFR - Hugo 345/138 kV Transmission Service</td>
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<td>24 months</td>
<td>DELAY - SCHEDULE</td>
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<tr>
<td>20201009</td>
<td>GRDA Device - Sallisaw 69 kV Capacitor</td>
<td>Regional Reliability</td>
<td>6/1/2011</td>
<td>1/27/2009</td>
<td>$374,000</td>
<td>$374,000</td>
<td>12 months</td>
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<tr>
<td>20201010</td>
<td>GRDA XFR - Sallisaw 161/69 kV Auto #2 Regional Reliability</td>
<td>Regional Reliability</td>
<td>7/15/2012</td>
<td>6/1/2008</td>
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<td>GMO Multi - Iatan - Nashua 345 kV Balanced Portfolio</td>
<td>Regional Reliability</td>
<td>6/1/2015</td>
<td>4/17/2012</td>
<td>$48,438,919</td>
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<td>12 months</td>
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<td>20201012</td>
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<td>Regional Reliability</td>
<td>6/1/2017</td>
<td>7/23/2010</td>
<td>$114,500,000</td>
<td>$152,640,000</td>
<td>72 months</td>
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</tr>
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<td>GMO Multi - Nebraska City - Maryville - Sibley 345 kV (GMO) High Priority</td>
<td>Regional Reliability</td>
<td>6/1/2017</td>
<td>7/23/2010</td>
<td>$174,500,000</td>
<td>$231,600,000</td>
<td>72 months</td>
<td>COMPLETED</td>
</tr>
<tr>
<td>20201014</td>
<td>GMO Multi - Loma Vista - Montrose 161 kV - Tap into K.C. South Regional Reliability</td>
<td>Regional Reliability</td>
<td>1/14/2013</td>
<td>6/1/2009</td>
<td>$2,369,625</td>
<td>$3,527,710</td>
<td>18 months</td>
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</tr>
<tr>
<td>20201015</td>
<td>EDE Device - Quapaw Cap 69 kV Regional Reliability</td>
<td>Regional Reliability</td>
<td>12/1/2012</td>
<td>6/1/2018</td>
<td>$50,152,303</td>
<td>$50,152,303</td>
<td>24 months</td>
<td>ON SCHEDULE &lt; 4</td>
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<td>20201016</td>
<td>KCPL Sub - Waldron Sub Zonal - Sponsored</td>
<td>Zonal Reliability</td>
<td>6/1/2016</td>
<td>2018</td>
<td>$1,632,300</td>
<td>$1,632,300</td>
<td>18 months</td>
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<tr>
<td>20201017</td>
<td>GRDA Sub - Crescent 69 kV Sub</td>
<td>Zonal Reliability</td>
<td>6/1/2013</td>
<td>1/27/2009</td>
<td>$1,500,000</td>
<td>$1,500,000</td>
<td>12 months</td>
<td>ON SCHEDULE &lt; 4</td>
</tr>
<tr>
<td>20201018</td>
<td>GMO Multi - Missouri River POE</td>
<td>Zonal Reliability</td>
<td>6/1/2015</td>
<td>4/17/2012</td>
<td>$2,369,625</td>
<td>$3,527,710</td>
<td>18 months</td>
<td>COMPLETED</td>
</tr>
<tr>
<td>20201019</td>
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<td>Regional Reliability</td>
<td>6/1/2017</td>
<td>7/23/2010</td>
<td>$114,500,000</td>
<td>$152,640,000</td>
<td>72 months</td>
<td>COMPLETED</td>
</tr>
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<td>20201020</td>
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<td>6/1/2017</td>
<td>7/23/2010</td>
<td>$174,500,000</td>
<td>$231,600,000</td>
<td>72 months</td>
<td>COMPLETED</td>
</tr>
</tbody>
</table>

Note: The status of each project is marked as either COMPLETED or ON SCHEDULE < 4. Projects marked as ON SCHEDULE < 4 may be experiencing delays and are being reevaluated.
<table>
<thead>
<tr>
<th>Project Description</th>
<th>Start Date</th>
<th>End Date</th>
<th>Actual Cost</th>
<th>Total Cost</th>
<th>Status</th>
<th>Notes</th>
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</thead>
<tbody>
<tr>
<td>KCPL Line - Olathe - Switzer 161 kV Zonal - Sponsored</td>
<td>11/14/2012</td>
<td>6/1/2013</td>
<td>$796,000</td>
<td>$796,000</td>
<td>COMPLETE</td>
<td>Delay - Mitigation</td>
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<tr>
<td>LES Line - 17th &amp; Holdrege - 30th &amp; A 115 kV Ckt 1 Zonal - Sponsored</td>
<td>9/13/2013</td>
<td>6/1/2013</td>
<td>$190,000</td>
<td>$190,000</td>
<td>COMPLETE</td>
<td>Delay - Mitigation</td>
</tr>
<tr>
<td>MKEC Line - Pratt - St. John 115 kV rebuild Regional Reliability</td>
<td>6/15/2014</td>
<td>6/1/2013</td>
<td>$6,480,000</td>
<td>$6,382,777</td>
<td>COMPLETE</td>
<td>Delay - Mitigation</td>
</tr>
<tr>
<td>MIDW MULTI - RICE - CIRCLE 230KV CONVERSION Generation Interconnection</td>
<td>10/1/2012</td>
<td></td>
<td>$2,473,404</td>
<td></td>
<td>COMPLETE</td>
<td>24 months</td>
</tr>
<tr>
<td>LES Line - SW 7 &amp; Bennet - 40th &amp; Rokeby 115 kV Ckt 1 Zonal - Sponsored</td>
<td>5/31/2015</td>
<td></td>
<td>$7,675,000</td>
<td></td>
<td>COMPLETE</td>
<td>Project complete and in-service. Final costs to be submitted through annual rate template update.</td>
</tr>
<tr>
<td>MKEC Line - Harper - Milan Tap 138 kV Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2012</td>
<td></td>
<td>$5,914,221</td>
<td>COMPLETE</td>
<td>12 months</td>
</tr>
<tr>
<td>MIDW Sub - Wheatland 115 kV Generation Interconnection</td>
<td>12/31/2012</td>
<td></td>
<td>$88,126</td>
<td>$80,326</td>
<td>$80,326</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>MKEC Multi - Ellsworth - Bushton - Rice 115 kV Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2012</td>
<td></td>
<td>$2,669,385</td>
<td>COMPLETE</td>
<td>24 months</td>
</tr>
<tr>
<td>MKEC XFR - Spearville 345/115kV CKT 1 Generation Interconnection</td>
<td>11/8/2014</td>
<td></td>
<td></td>
<td></td>
<td>COMPLETE</td>
<td>24 months</td>
</tr>
<tr>
<td>MKEC XFR - Medicine Lodge 138/115 kV Transmission Service</td>
<td>2/1/2013</td>
<td>1/1/2010</td>
<td>$5,625,000</td>
<td></td>
<td>COMPLETE</td>
<td>36 months</td>
</tr>
<tr>
<td>MIDW Multi - Ellsworth - Bushton - Rice 115 kV Regional Reliability</td>
<td>9/28/2012</td>
<td>6/1/2012</td>
<td></td>
<td>$2,669,385</td>
<td>COMPLETE</td>
<td>24 months</td>
</tr>
<tr>
<td>LES XFR - 56th &amp; K 115/12kV Zonal - Sponsored</td>
<td>5/31/2015</td>
<td></td>
<td></td>
<td></td>
<td>COMPLETE</td>
<td>Project is complete and in-service. Costs to be submitted through annual rate template update.</td>
</tr>
<tr>
<td>MKEC Line - Medicine Lodge - Pratt 115 kV Transmission Service</td>
<td>1/31/2013</td>
<td>6/1/2011</td>
<td></td>
<td></td>
<td>COMPLETE</td>
<td>36 months</td>
</tr>
<tr>
<td>MIDW Line - Hays Plant - South Hays 115 kV Ckt 1 Rebuild Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2013</td>
<td>$4,734,006</td>
<td>$8,832,219</td>
<td>COMPLETE</td>
<td>30 months</td>
</tr>
<tr>
<td>MIDW Line - Pheasant Run - Seguin 115 kV Ckt 1 Regional Reliability</td>
<td>6/1/2014</td>
<td>6/1/2014</td>
<td>$10,794,325</td>
<td>$11,128,231</td>
<td>COMPLETE</td>
<td>36 months</td>
</tr>
<tr>
<td>MIDW Line - MIDW Heizer - Mullergren 115kV Regional Reliability</td>
<td>12/31/2012</td>
<td>6/1/2011</td>
<td>$400,000</td>
<td>$590,000</td>
<td>COMPLETE</td>
<td>12 months</td>
</tr>
<tr>
<td>MKEC Line - Clifton - Greenleaf 115 kV Transmission Service</td>
<td>1/31/2013</td>
<td>6/1/2011</td>
<td></td>
<td>$3,600,000</td>
<td>COMPLETE</td>
<td>36 months</td>
</tr>
<tr>
<td>NPPD Line - Albion - Genoa 115 kV Regional Reliability</td>
<td>6/1/2014</td>
<td>6/1/2014</td>
<td>$1,240,000</td>
<td>$1,240,000</td>
<td>COMPLETE</td>
<td>Delay - Mitigation</td>
</tr>
<tr>
<td>NPPD Device - Kearney 115 kV Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td></td>
<td>$1,000,000</td>
<td>COMPLETE</td>
<td>12 months</td>
</tr>
<tr>
<td>NPPD Line - Loup City - North Loup 115 kV Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td></td>
<td>$1,000,000</td>
<td>COMPLETE</td>
<td>12 months</td>
</tr>
<tr>
<td>Project ID</td>
<td>UID</td>
<td>Description</td>
<td>Cost</td>
<td>Date of Completion</td>
<td>Status</td>
<td>Notes</td>
</tr>
<tr>
<td>-----------</td>
<td>-----</td>
<td>------------------------------</td>
<td>---------------------</td>
<td>--------------------</td>
<td>--------------</td>
<td>-------</td>
</tr>
<tr>
<td>2001</td>
<td>10927</td>
<td>Substation - Zachary Substation</td>
<td>~ $8,275,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2002</td>
<td>10928</td>
<td>Substation - Scottsbluff Substation</td>
<td>~ $6,642,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2003</td>
<td>10929</td>
<td>Substation - Diller Substation</td>
<td>~ $6,200,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2004</td>
<td>10930</td>
<td>Substation - North Platte Substation</td>
<td>~ $6,000,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2005</td>
<td>10931</td>
<td>Substation - Pacific Substation</td>
<td>~ $5,800,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>10932</td>
<td>Substation - Swanson Substation</td>
<td>~ $5,500,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td>10933</td>
<td>Substation - Harvard Substation</td>
<td>~ $5,200,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>10934</td>
<td>Substation - Elkhorn Substation</td>
<td>~ $5,000,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>10935</td>
<td>Substation - Imperial Substation</td>
<td>~ $4,800,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>10936</td>
<td>Substation - North Platte Substation</td>
<td>~ $4,600,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>10937</td>
<td>Substation - South Platte Substation</td>
<td>~ $4,400,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>10938</td>
<td>Substation - North Platte Substation</td>
<td>~ $4,200,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>10939</td>
<td>Substation - South Platte Substation</td>
<td>~ $4,000,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>10940</td>
<td>Substation - North Platte Substation</td>
<td>~ $3,800,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>10941</td>
<td>Substation - South Platte Substation</td>
<td>~ $3,600,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>10942</td>
<td>Substation - North Platte Substation</td>
<td>~ $3,400,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>10943</td>
<td>Substation - South Platte Substation</td>
<td>~ $3,200,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>10944</td>
<td>Substation - North Platte Substation</td>
<td>~ $3,000,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td>10945</td>
<td>Substation - South Platte Substation</td>
<td>~ $2,800,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>10946</td>
<td>Substation - North Platte Substation</td>
<td>~ $2,600,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2021</td>
<td>10947</td>
<td>Substation - South Platte Substation</td>
<td>~ $2,400,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td>10948</td>
<td>Substation - North Platte Substation</td>
<td>~ $2,200,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td>10949</td>
<td>Substation - South Platte Substation</td>
<td>~ $2,000,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2024</td>
<td>10950</td>
<td>Substation - North Platte Substation</td>
<td>~ $1,800,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td>10951</td>
<td>Substation - South Platte Substation</td>
<td>~ $1,600,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2026</td>
<td>10952</td>
<td>Substation - North Platte Substation</td>
<td>~ $1,400,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2027</td>
<td>10953</td>
<td>Substation - South Platte Substation</td>
<td>~ $1,200,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2028</td>
<td>10954</td>
<td>Substation - North Platte Substation</td>
<td>~ $1,000,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2029</td>
<td>10955</td>
<td>Substation - South Platte Substation</td>
<td>~ $800,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td>10956</td>
<td>Substation - North Platte Substation</td>
<td>~ $600,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2031</td>
<td>10957</td>
<td>Substation - South Platte Substation</td>
<td>~ $400,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2032</td>
<td>10958</td>
<td>Substation - North Platte Substation</td>
<td>~ $200,000</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>2033</td>
<td>10959</td>
<td>Substation - South Platte Substation</td>
<td>~ $0</td>
<td>12/1/2020</td>
<td>Complete</td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- "COMPLETE" indicates that the project has been completed and all work has been signed off.
- "ON SCHEDULE" indicates that the project is on schedule as per the approved schedule.
- "DELAY - MITIGATION*" indicates that the project has been delayed due to external factors and mitigation measures have been implemented.
- "BUILDING" indicates that the project is currently under construction.
- "PROJECT CANCELED" indicates that the project has been canceled.

**Construction Update:**

- The construction update includes the current status of each project, including the completion date and any delays.
- The update also includes information on any adjustments to the initial cost estimates and the reasons behind them.
- The update highlights any changes in the project scope or design due to unforeseen circumstances.

**Cost Analysis:**

- The cost analysis includes a detailed breakdown of costs incurred, including labor, materials, and equipment.
- The analysis also includes the impact of inflation and other economic factors on the project costs.

**Risk Management:**

- The risk management plan outlines the strategies put in place to mitigate potential risks and challenges.
- The plan includes a risk assessment matrix that categorizes risks based on their likelihood and impact.

**Conclusion:**

- The conclusion summarizes the key lessons learned from the project and highlights areas for improvement.
- The conclusion also includes recommendations for future projects to ensure better performance and outcomes.
200198

858

11131

OGE

Multi - Cushing Area 138 kV

Regional Reliability

6/1/2014

6/1/2014

11/20/2012

ON SCHEDULE < 4

$15,000,000

$15,000,000

200198

858

11132

OGE

Multi - Cushing Area 138 kV

Regional Reliability

6/1/2014

6/1/2014

11/20/2012

ON SCHEDULE < 4

200198

858

11133

OGE

Multi - Cushing Area 138 kV

Regional Reliability

3/1/2013

3/1/2013

11/20/2012

COMPLETE

200198

858

11134

OGE

Multi - Cushing Area 138 kV

Regional Reliability

3/1/2013

3/1/2013

11/20/2012

COMPLETE

200198

858

50594

OGE

Multi - Cushing Area 138 kV

Regional Reliability

3/1/2013

3/1/2013

11/20/2012

COMPLETE

20081

892

11182

OGE

Sub - Canadian River Substation

Regional Reliability

6/30/2013

897

11191

OGE

Multi - 36 & Meridian - WRAirport - Pennsylvania 138 kV Ckt 1

Zonal - Sponsored

6/1/2012

897

11192

OGE

Multi - 36 & Meridian - WRAirport - Pennsylvania 138 kV Ckt 1

910

11207

OGE

Line - Bryant - Memorial 138 kV

928

11228

OGE

Line - Cushing - Pumping Station 32 138 kV

20100

941

11244

OGE

20100
20121
20121
200204
20110

941
942
942
1017
1021

11245
11246
11247
11339
11343

20128

1095

20137
200174
20017
20017

20110

6/1/2010

2/8/2010

$5,500,000

$9,453,000

30 months

COMPLETE

COMPLETE
$510,000

Zonal - Sponsored

6/1/2012

Transmission Service

6/1/2019

Zonal - Sponsored

5/31/2013

Line - Hitchland - Woodward 345 kV dbl Ckt (OGE)

High Priority

6/30/2014

6/30/2010

OGE
OGE
OGE
OGE
OGE

Line - Hitchland - Woodward 345 kV dbl Ckt (OGE)
Line - Thistle - Woodward 345 kV dbl Ckt (OGE)
Line - Thistle - Woodward 345 kV dbl Ckt (OGE)
Line - Classen - Southwest 5 Tap 138 kV
Line - Arcadia - Redbud 345 kV Ckt 3

High Priority
High Priority
High Priority
Regional Reliability
Transmission Service

6/30/2014
12/31/2014
12/31/2014
2/15/2014
6/1/2019

$97,427,500

$145,040,000

6/1/2013
6/1/2019

6/30/2010
11/22/2010
11/22/2010
2/20/2013
8/25/2010

$161,204
$19,000,000

$161,204
$18,000,000

11439

OGE

Line - OGE Alva - WFEC Alva 69 kV Ckt 1

Regional Reliability

11/20/2012

6/1/2011

2/14/2011

$112,500

$396,793

1134
30092
30160

11496
50098
50168

OGE
OGE
OGE

XFR - Northwest 345/138 kV Ckt 3
Device - Kolache 69 kV Capacitor
XFR - Ft Smith 500/161 kV Ckt 3

Transmission Service
Regional Reliability
Transmission Service

6/1/2017
10/31/2013
6/1/2017

6/1/2017
6/1/2012
6/1/2017

5/27/2011
4/9/2012
1/16/2009

$15,000,000
$523,888
$11,000,000

$15,000,000
$523,888
$14,000,000

30161

50169

OGE

Multi - Hugo - Sunnyside 345 kV (OGE)

Transmission Service

4/1/2012

4/1/2012

1/16/2009

$75,000,000

$871,604
COMPLETE

6/1/2019

8/25/2010

$250,000

$225,000

12 months

$6,700,000

$363,184

40 months

ON SCHEDULE < 4

40 months
40 months
40 months
12 months
36 months

ON SCHEDULE < 4
ON SCHEDULE < 4
ON SCHEDULE < 4
DELAY - MITIGATION
ON SCHEDULE > 4

6 months

COMPLETE

40 months
12 months
36 months

ON SCHEDULE < 4
DELAY - MITIGATION*
ON SCHEDULE < 4

42 months

COMPLETE

24 months

COMPLETE

$157,000,000
20017

30161

50171

OGE

Multi - Hugo - Sunnyside 345 kV (OGE)

Transmission Service

4/1/2012

4/1/2012

1/16/2009

$6,750,000

20017

30164

50172

OGE

Line - VBI - VBI North 69 kV

Transmission Service

6/1/2017

6/1/2017

1/16/2009

$100,000

$100,000

9 months

ON SCHEDULE < 4

200174

30302

50346

OGE

XFR - Paoli 138/69 kV

Regional Reliability

3/22/2013

6/1/2012

4/9/2012

$2,020,094

$2,090,660

12 months

COMPLETE

20128

30305

50347

OGE

Device - Little River Lake 69 kV

Regional Reliability

10/1/2012

12/1/2011

2/14/2011

$352,350

$352,350

22 months

COMPLETE

200174

30357

50408

OGE

Device - Lula 69 kV

Regional Reliability

12/31/2013

6/1/2012

4/9/2012

$377,797

$561,667

12 months

DELAY - MITIGATION

200185

30361

50419

OGE

Multi - Elk City - Gracemont 345 kV

ITP10

3/1/2018

3/1/2018

4/9/2012

$75,486,000

$75,486,000

60 months

ON SCHEDULE > 4

200223

30364

50420

OGE

Multi - Woodward District EHV - Tatonga - Matthewson - Cimarron 345
kV

ITP10

3/1/2021

3/1/2021

5/23/2013

$71,876,622

$59,522,400

72 months

ON SCHEDULE > 4

200223

30364

50421

OGE

Multi - Woodward District EHV - Tatonga - Matthewson - Cimarron 345
kV

ITP10

3/1/2021

3/1/2021

5/23/2013

$82,139,900

$65,785,650

72 months

ON SCHEDULE > 4

200223

30364

50456

OGE

Multi - Woodward District EHV - Tatonga - Matthewson - Cimarron 345
kV

ITP10

3/1/2021

3/1/2021

5/23/2013

$32,780,617

$32,936,400

72 months

ON SCHEDULE > 4

200223

30364

50458

OGE

Multi - Woodward District EHV - Tatonga - Matthewson - Cimarron 345
kV

ITP10

3/1/2021

3/1/2021

5/23/2013

$20,169,602

$19,967,850

72 months

ON SCHEDULE > 4

30381

50646

OGE

SUB - SHIDLER 138KV OG&E Osage Sub work

Generation Interconnection

1/15/2014

30433

50529

OGE

Line - Arcadia - Redbud 345 kV

Regional Reliability

11/17/2013

200204

$530,068

$399,300
6/1/2013

2/20/2013

$1,010,523

$1,010,523

12 months

DELAY - MITIGATION

30441

50536

OGE

Device - Gracemont 345 kV

Regional Reliability

4/1/2015

4/1/2015

2/20/2013

$3,500,452

$3,500,452

12 months

RE-EVALUATION

200204

30442

50537

OGE

Device - Hunter 345 kV

Regional Reliability

4/1/2016

4/1/2016

2/20/2013

$3,500,452

$3,500,452

24 months

RE-EVALUATION

30445

50540

OGE

Device - Tatonga 345 kV

200194

30481

50577

OGE

200199

30486

50586

OGE

200199

30486

50587

OGE

200199

30486

50588

OGE

200199

30486

50589

OGE

200199

30486

50590

OGE

200199

30486

50592

OGE

30542

50674

OGE

Line - El Reno - Service PL El Reno 69 kV CKT 1
Multi - Renfrow 345/138 kV substation and Renfrow - Grant
line
Multi - Renfrow 345/138 kV substation and Renfrow - Grant
line
Multi - Renfrow 345/138 kV substation and Renfrow - Grant
line
Multi - Renfrow 345/138 kV substation and Renfrow - Grant
line
Multi - Renfrow 345/138 kV substation and Renfrow - Grant
line
Multi - Renfrow 345/138 kV substation and Renfrow - Grant
line
Sub - Hunter 345kV

Regional Reliability

5/30/2014

4/1/2013

2/20/2013

$3,500,452

$3,500,452

24 months

RE-EVALUATION

Transmission Service

6/1/2017

6/1/2017

11/20/2012

$10,000

$10,000

14 months

ON SCHEDULE < 4

Regional Reliability

3/15/2014

3/1/2013

12/20/2012

$3,079,700

$3,079,700

DELAY - MITIGATION

Regional Reliability

3/15/2014

3/1/2013

12/20/2012

$11,659,600

$11,659,600

DELAY - MITIGATION

Regional Reliability

3/15/2014

3/1/2013

12/20/2012

$4,998,388

$4,998,388

DELAY - MITIGATION

Regional Reliability

5/1/2014

3/1/2013

12/20/2012

$1,173,170

$1,173,170

DELAY - MITIGATION

Regional Reliability

10/1/2014

3/1/2013

12/20/2012

$7,081,847

$4,540,425

DELAY - MITIGATION

Regional Reliability

9/1/2014

3/1/2013

12/20/2012

$571,210

$587,690

DELAY - MITIGATION

Generation Interconnection

9/26/2012

$8,226,915

COMPLETE

30545

50678

OGE

Sub - Deer Creek - Sinclair 69kV Ckt 1

Generation Interconnection

10/1/2012

$2,079,212

COMPLETE

30549

50682

OGE

Sub - Cimarron 345kV GEN-2010-040 Addition

Generation Interconnection

12/31/2012

$6,946,798

COMPLETE

30550

50683

OGE

Sub - Minco 345kV GEN-2011-010 Addition

Generation Interconnection

8/30/2012

$2,554,395

COMPLETE

138 kV
138 kV
138 kV
138 kV
138 kV
138 kV

Customer driven in-service date delayed New in-service date - Costs do not include
distribution assets - Portion of cost to be
reimbursed to OG&E
Construction labor estimates provided by
bidding contractors were less than
expected.
Project milage increased

Project has been completed and facilities
have been energized. Waiting on final
costs. In-service delay due to material
delivery

Full BPF
Project has been completed and facilities
have been energized. Waiting on final
costs.
Project has been completed and facilities
have been energized. Waiting on final
costs. Full BPF. Total cost of project
reflected on UID 50169.
Full BPF - Reviewing metering CT - May be
able to increase rating to 600 amps
Project is complete and facilities have been
energized. Waiting on final costs.
Contractor construction costs came in 50%
of original estimated cost.
Project is complete and final costs have
been submitted.
Long lead materials have delayed the start
of construction until after the summer.
OG&E will construct the east half of the ~93
miles of 345kv line and complete the
substation work at Gracemont Substation
which will include a reactor. Delayed and
waiting on resolution with AEP & SPP.
Transmission line to utilize previously
obtained Right of Way along the existing
Woodward EHV to Tatonga (1st circuit) line.
This estimate does include terminating the
existing Tatonga or Mathewson substations.
Those costs are included in the Mathewson
Substation network upgrade PID 30364 &
UID 50458.
This estimate does include terminating the
existing Cimarron or Mathewson
substations. Those costs are included in
the Mathewson Substation network upgrade
PID 30364 & UID 50458.
Mathewson substation is new 345 kV
substation at the intersection point of the
existing 345 kV Cimarron - Woodring and
the 345 kV Northwest - Tatonga lines that
will be built as part of the Campbell Creek
wind farm project. Mathewson substation
will start with (1) 345kV line to Campbell
Creek wind farm, (1) 345kV line to Cimarron
and (1) 345kV line to Woodring.

ON SCHEDULE < 4

200204

200204

Transmission costs were escalated due the
location of the substation site selected by
AEP. The substation site required
extensive excavation and dirt work which
resulted in a substation cost increase from
the estimate. OG&E construction is
complete and waiting on AEP to complete
their portion of the substation.
Transmission assets associated with project
- Costs are still being compiled. Project
required special transmission design and
structures.
Transmission assets associated with project
- Costs are still being compiled

ON SCHEDULE > 4
COMPLETE

$165,000,000

Original costs included distribution capital
assets. New cost does not. Also 69 kV
GOAB switch replaced by a 138 kV GOAB
switch on another project. Total cost of
project including distribution assets is
$18,400,000
Original costs included distribution capital
assets. New cost does not. Also 69 kV
GOAB switch replaced by a 138 kV GOAB
switch on another project. Total cost of
project including distribution assets is
$18,400,000
Original costs included distribution capital
assets. New cost does not. Also 69 kV
GOAB switch replaced by a 138 kV GOAB
switch on another project. Total cost of
project including distribution assets is
$18,400,000
Original costs included distribution capital
assets. New cost does not. Also 69 kV
GOAB switch replaced by a 138 kV GOAB
switch on another project. Total cost of
project including distribution assets is
$18,400,000

The project was delayed due to long lead
times for material including the required
345kV breakers. Expected delivery for the
345kV breakers is September 2013.
OG&E believes the reactor is not required
to mitigate high voltage. The 50 MVAR of
reactors located on the Gracemont bus tie
transformer tertiary winding provide
mitigation for high bus voltages at
Gracemont. See OG&E's official response
to the NTC. SPP is re-evaluating project.
OG&E believes the reactor is not required
to mitigate high voltage. The 50 MVAR of
reactors located at the new Hunter
substation, on the tertiary winding of the
bus tie transformer, provide mitigation for
high bus voltages. See OG&E's official
response to the NTC. SPP re-evaluating
need.

OG&E believes the reactor is not required
to mitigate high voltage. An existing special
protection scheme will disconnect Tatonga,
Crossroads Wind Farm and the 345kV
Tatonga to Woodward EHV line for the loss
of the 345kV Northwest to Tatonga line.
Addtionally the 50 MVAR of tertiary reactors
located on the 2nd bus tie transformer at
Woodward EHV and the 230 MVAR of line
reactors that will be located at Woodward
EHV provide mitigation for high volatages.
See OG&E's official response to the NTC.
SPP re-evaluating need for project.

Customer paid for entire project.
Customer paid for entire project. Total cost
of project = $0.00
Customer paid for project. Total Cost =
$0.00
Customer to paid for entire project. Total
cost = $0.00


<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Description</th>
<th>Start Date</th>
<th>End Date</th>
<th>Budget</th>
<th>Status Notes</th>
</tr>
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<tbody>
<tr>
<td>200207-150</td>
<td>OPPD Line - Arcadia - OMPA Edmond Garber 138 kV Ckt 1 Transmission Service</td>
<td></td>
<td>6/1/2012</td>
<td>6/1/2010</td>
<td>$30,000</td>
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<tr>
<td>200207-200</td>
<td>OPPD Line - 915 Tap South in Ckt 623 - Sub 915 T2 69 kV Ckt 1 Regional Reliability</td>
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<td>6/1/2015</td>
<td>6/1/2015</td>
<td>$260,590</td>
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<td>200207-250</td>
<td>PW Line - Thistle - Wichita 345 kV dbl Ckt High Priority</td>
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<td>12/31/2014</td>
<td>7/29/2011</td>
<td>$65,000,000</td>
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<tr>
<td>200207-300</td>
<td>OPPD Line - Ben Wheeler - Barton's Chapel (Rayburn) 138 kV Ckt 1 Regional Reliability - Non OATT</td>
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<td>6/1/2014</td>
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<td>$4,218,750</td>
<td>18 months</td>
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<tr>
<td>200207-350</td>
<td>SEPC Line - Holcomb - Fletcher 115 kV Ckt 1 Regional Reliability</td>
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<td>12/31/2013</td>
<td>6/1/2013</td>
<td>$4,000,000</td>
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<tr>
<td>200207-400</td>
<td>OPPD Line - Sub 1221 - Sub 1255 161 kV Zonal - Sponsored</td>
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<td>11/10/2012</td>
<td>11/10/2012</td>
<td>$675,523</td>
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<tr>
<td>200207-450</td>
<td>SEPC Sub - Spearville 345kV GEN-2005-012 Addition Generation Interconnection</td>
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<td>6/1/2012</td>
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<tr>
<td>200207-500</td>
<td>SPS XFR - Tuco 115/69 kV Transformer Ckt 3 Regional Reliability</td>
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<td>6/1/2014</td>
<td>6/1/2012</td>
<td>$2,917,852</td>
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<td>200207-550</td>
<td>OPPD Sub - Sub 1366 161 kV Regional Reliability</td>
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<td>5/20/2013</td>
<td>6/1/2013</td>
<td>$11,067,000</td>
<td>36 months</td>
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<tr>
<td>200207-650</td>
<td>SPS Multi:  Dallam - Channing - Tascosa -Potter Regional Reliability</td>
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<td>5/29/2012</td>
<td>6/1/2009</td>
<td>$9,590,276</td>
<td>30 months</td>
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<td>200207-700</td>
<td>SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV Regional Reliability</td>
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<td>3/19/2013</td>
<td>6/1/2011</td>
<td>$1,417,703</td>
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<td>200207-750</td>
<td>SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV Regional Reliability</td>
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<td>4/9/2013</td>
<td>6/1/2009</td>
<td>$20,137,782</td>
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<td>200207-800</td>
<td>SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV Regional Reliability</td>
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<td>6/8/2012</td>
<td>6/1/2010</td>
<td>$36,991,437</td>
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<td>200207-900</td>
<td>SEPC Line - Holcomb - Plymell 115 kV Regional Reliability</td>
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<td>6/1/2012</td>
<td>6/1/2008</td>
<td>$1,980,000</td>
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<tr>
<td>200207-950</td>
<td>SPS XFR - Tuco 115/69 kV Transformer Ckt 3 Regional Reliability</td>
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<td>6/1/2014</td>
<td>6/1/2012</td>
<td>$2,917,852</td>
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<tr>
<td>Project ID</td>
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<td>Description</td>
<td>Owner</td>
<td>Interconnection</td>
<td>Type</td>
<td>Status</td>
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<tr>
<td>20031</td>
<td>TX</td>
<td>Multi - Tuco - Woodward 345 kV (SPS)</td>
<td>Bal Int Portfolio</td>
<td>6/15/2015</td>
<td>6/1/2010</td>
<td>2/8/2010</td>
</tr>
</tbody>
</table>

**Note:**
- Project costs are subject to change due to construction delays, materials, and labor costs. Updated cost estimates are available upon request.
- All projects are on schedule unless otherwise noted.
- Mitigation plans are in place for potential delays.
- Updated ISD: current cost estimate remains unchanged. TRM 8/16/13.
<table>
<thead>
<tr>
<th>Project Code</th>
<th>Work Type</th>
<th>Description</th>
<th>Start Date</th>
<th>End Date</th>
<th>Status</th>
<th>Mileage</th>
<th>Cost (in USD)</th>
<th>Comments</th>
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</thead>
<tbody>
<tr>
<td>20084 795 11053</td>
<td>SPS Multi - Pleasant Hill - Potter</td>
<td>230 kV Ckt 1 Regional Reliability</td>
<td>12/30/2014</td>
<td>6/1/2011</td>
<td>2/8/2010</td>
<td>$13,500,000</td>
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<tr>
<td>20084 795 11052</td>
<td>SPS Multi - Pleasant Hill - Potter</td>
<td>230 kV Ckt 1 Regional Reliability</td>
<td>12/30/2014</td>
<td>6/1/2011</td>
<td>2/8/2010</td>
<td>$11,250,000</td>
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<tr>
<td>20130 792 11046</td>
<td>SPS Line - Cunningham - Buckey Tap</td>
<td>115 kV reconductor Regional Reliability</td>
<td></td>
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</tbody>
</table>

The table above lists various projects with their details such as the work type, description, start and end dates, and costs. The comments section includes additional information about the project status and any relevant details.
<table>
<thead>
<tr>
<th>Project ID</th>
<th>CIP</th>
<th>Description</th>
<th>Facility</th>
<th>Voltage</th>
<th>Project Name</th>
<th>Start Date</th>
<th>End Date</th>
<th>Estimated Cost</th>
<th>Actual Cost</th>
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<tbody>
<tr>
<td>200166</td>
<td>1031</td>
<td>SPS Line - Hereford - Northeast Hereford</td>
<td>115 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>12/30/2013</td>
<td>6/1/2012</td>
<td>$2,362,500</td>
<td>$4,139,406</td>
<td>18 months</td>
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<tr>
<td>200214</td>
<td>1031</td>
<td>SPS XFR - Crosby Co. 115/69 kV Transformers Ckt 1 and Ckt 2</td>
<td>Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2013</td>
<td>$2,357,062</td>
<td>$2,378,798</td>
<td>24 months</td>
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<td>200193</td>
<td>1000</td>
<td>SPS Line - Jones Station Bus#2 - Lubbock South Interchange</td>
<td>230 kV Ckt</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2016</td>
<td>$295,313</td>
<td>$242,156</td>
<td>18 months</td>
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<tr>
<td>200184</td>
<td>1140</td>
<td>SPS Multi - Tuco - Stanton 345 kV ITP10</td>
<td>Regional Reliability</td>
<td>6/1/2018</td>
<td>6/1/2018</td>
<td>$6,158,183</td>
<td>$6,158,183</td>
<td>36 months</td>
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<td>200214</td>
<td>11380</td>
<td>SPS Line - Wolford-Yuma 115 kV Ckt 1 Wave Trap</td>
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<td>6/1/2017</td>
<td>6/1/2014</td>
<td>$10,946,449</td>
<td>$10,946,449</td>
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<tr>
<td>200214</td>
<td>11346</td>
<td>SPS XFR - Swisher 230/115 kV Transformer Ckt 1 Upgrade</td>
<td>Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2013</td>
<td>$5,953,500</td>
<td>$3,965,030</td>
<td>24 months</td>
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<tr>
<td>200214</td>
<td>11314</td>
<td>SPS Line - Allen Sub - Lubbock South Interchange 115 kV Ckt 1</td>
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<td>6/1/2018</td>
<td>6/1/2018</td>
<td>$2,429,760</td>
<td>$2,429,760</td>
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<tr>
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<td>SPS Line - Hereford - Northeast Hereford</td>
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<td>12/30/2013</td>
<td>6/1/2012</td>
<td>$2,362,500</td>
<td>$4,139,406</td>
<td>18 months</td>
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<tr>
<td>200214</td>
<td>11318</td>
<td>SPS Multi - Randall County Interchange - Palo Duro Sub 115 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2016</td>
<td>$2,429,760</td>
<td>$2,429,760</td>
<td>COMPLETE</td>
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</tbody>
</table>

**Notes:**
- Estimated costs include:
  - Escalation:
    - Study Estimate (escalation costs are included in Contingency costs: $235,780; Escalation: $226,700, Q1-2013)
- Actual costs include:
  - Escalation costs are included in Contingency costs: $26,559; Escalation: $242,156, 18 months
  - On Schedule:
    - <4 months
  - Delay - Mitigation:
    - 6 months
  - NTC Suspension:
    - Re-Evaluation
  - TRM 8/16/13.
  - TRM - 5/20/13.
<table>
<thead>
<tr>
<th>Project Number</th>
<th>Project Description</th>
<th>Location</th>
<th>Project Details</th>
<th>Estimated Costs</th>
<th>Funding Source</th>
<th>Status</th>
<th>Notes</th>
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<tbody>
<tr>
<td>200166 1190 17606</td>
<td>Multi-Phase - Station 500 kV</td>
<td>(PSG)</td>
<td>6/1/2016</td>
<td>$23,582,899</td>
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<td>30 months</td>
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<td>Reference</td>
<td>Project Type</td>
<td>Description</td>
<td>Proposed Date</td>
<td>AS/psi Date</td>
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<tr>
<td>200214 30467 50561</td>
<td>50561 SPS XFR - Potash Junction 115/69 kV Ckt 2</td>
<td>Regional Reliability</td>
<td>12/31/2014</td>
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<td>200214 30452 50547</td>
<td>SPS Line - Oxy Permian - Sanger Switching Station 115 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>12/31/2016</td>
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<tr>
<td>200214 30451 50546</td>
<td>SPS Line - Atoka - Eagle Creek 115 kV Ckt 1</td>
<td>Regional Reliability</td>
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<tr>
<td>200214 30429 50522</td>
<td>SPS Line - Crosby - Floyd 115 kV Ckt 1</td>
<td>Regional Reliability</td>
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<tr>
<td>200214 30428 50521</td>
<td>SPS Device - Red Bluff 115 kV Capacitor</td>
<td>Regional Reliability</td>
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<td>200214 30424 50517</td>
<td>SPS Line - Ochiltree - Tri-County Cole 115 kV Ckt 1</td>
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<tr>
<td>200190 30414 50507</td>
<td>SPS Device - Howard 115 kV Capacitors</td>
<td>Regional Reliability</td>
<td>6/1/2014</td>
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<tr>
<td>200190 30410 50503</td>
<td>SPS Line - Bowers - Canadian 69 kV Rebuild</td>
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<td>18 months</td>
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<tr>
<td>200184 30376 50452</td>
<td>SPS Multi - Tuco - Amoco - Hobbs 345 kV ITP10</td>
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<td>1/1/2020</td>
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<tr>
<td>200184 30376 50451</td>
<td>SPS Multi - Tuco - Amoco - Hobbs 345 kV ITP10</td>
<td>Regional Reliability</td>
<td>1/1/2020</td>
<td>1/1/2020</td>
<td>72 months</td>
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<tr>
<td>30468 50676</td>
<td>SPS Line(s) - Harrington - Nichols 230kV DBL CKT Generation Interconnection</td>
<td>Regional Reliability</td>
<td>12/1/2012</td>
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<td>9/11/2013</td>
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<tr>
<td>200214 30468 50562</td>
<td>SPS Line(s) - Harrington - Nichols 230kV DBL CKT Generation Interconnection</td>
<td>Regional Reliability</td>
<td>12/1/2012</td>
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<td></td>
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</tbody>
</table>

**Notes:**
- **36 months** indicates 36-month time frames for the projects.
- **COMPLETE** signifies that the project has been completed.
- **NTC SUSPENSION** and **DELAY - MITIGATION** indicate suspended or delayed projects.
- **Contingency costs:** $279,658; Escalation: $182,610 Q2-2013 No changes.
- **Project remains unchanged.** TRM 8/15/13.

**Additional Information:**
- **Mitigation:**
  - TRM 5/14/13. Q4-2013 All remains unchanged. TRM 5/14/13.
  - TRM 5/14/13. Q4-2013 All remains unchanged. TRM 5/14/13.
  - TRM 5/14/13. Q4-2013 All remains unchanged. TRM 5/14/13.
  - TRM 5/14/13. Q4-2013 All remains unchanged. TRM 5/14/13.
  - TRM 5/14/13. Q4-2013 All remains unchanged. TRM 5/14/13.
  - TRM 5/14/13. Q4-2013 All remains unchanged. TRM 5/14/13.
  - TRM 5/14/13. Q4-2013 All remains unchanged. TRM 5/14/13.
<table>
<thead>
<tr>
<th>Project Code</th>
<th>Description</th>
<th>Region</th>
<th>Start Date</th>
<th>End Date</th>
<th>Estimated Cost</th>
<th>Actual Cost</th>
<th>Duration</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013017</td>
<td>Multi - Zudlow - South Parham - Market</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td>$3,098,955</td>
<td>$6,496,050</td>
<td>20 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
<tr>
<td>2013018</td>
<td>Multi - Zudlow - South Parham - Market</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td>$6,315,700</td>
<td>$6,315,700</td>
<td>24 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
<tr>
<td>2013019</td>
<td>Multi - Zudlow - South Parham - Market</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td>$7,990,750</td>
<td>$7,990,750</td>
<td>24 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
<tr>
<td>2013020</td>
<td>Multi - Zudlow - South Parham - Market</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td>$6,286,350</td>
<td>$6,286,350</td>
<td>20 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
<tr>
<td>2013021</td>
<td>Multi - Zudlow - South Parham - Market</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td>$2,573,553</td>
<td>$2,573,553</td>
<td>12 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
<tr>
<td>2013022</td>
<td>Multi - Zudlow - South Parham - Market</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td>$17,928,848</td>
<td>$17,928,848</td>
<td>60 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
<tr>
<td>2013023</td>
<td>Multi - Zudlow - South Parham - Market</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td>$3,005,283</td>
<td>$3,005,283</td>
<td>24 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
<tr>
<td>2013024</td>
<td>Multi - Zudlow - South Parham - Market</td>
<td>Regional Reliability</td>
<td>6/1/2012</td>
<td>6/1/2012</td>
<td>$230,000</td>
<td>$230,000</td>
<td>12 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
<tr>
<td>2013026</td>
<td>SPS Sub - Potter County 345kV GEN-2008-051 Addition Generation Interconnection</td>
<td></td>
<td>5/1/2012</td>
<td>5/1/2012</td>
<td>$3,005,283</td>
<td>$3,005,283</td>
<td>24 months</td>
<td>TRM 8/16/13. Q3-2013 Project In-Service as of 8/16/13.</td>
</tr>
</tbody>
</table>
| 2013027 | SPS Sub - Lopez 115 kV | Regional Reliability | 2/20/2013 | 2/20/2013 | $250,000 | $250,000 | 6 months | TRM 5/22/2013. Q4-2013 This portion of the project was in progress in the 2nd quarter and is now 80 – 85% complete. Construction is complete and energization is 4/3/14. Mitigation has been completed. 
| 2013028 | SPS Sub - Lopez 115 kV | Regional Reliability | 2/20/2013 | 2/20/2013 | $3,000,000 | $3,000,000 | 24 months | TRM 5/22/2013. Q4-2013 This portion of the project was in progress in the 2nd quarter and is now 80 – 85% complete. Construction is complete and energization is 4/3/14. Mitigation has been completed. 
| 2013029 | SPS Sub - Lopez 115 kV | Regional Reliability | 2/20/2013 | 2/20/2013 | $5,136,476 | $5,136,476 | 24 months | NTC - COMMITMENT WINDOW COMPLETE 
<p>| 2013030 | SPS Sub - Lopez 115 kV | Regional Reliability | 2/20/2013 | 2/20/2013 | $7,316,677 | $7,316,677 | 24 months | NTC - COMMITMENT WINDOW COMPLETE |</p>
<table>
<thead>
<tr>
<th>Project ID</th>
<th>Description</th>
<th>Details</th>
<th>Cost Summary</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>WR 5031706</td>
<td>Multi- Trail - 138 kV</td>
<td>138 kV</td>
<td>$2,614,395</td>
<td>DELAY - MITIGATION</td>
</tr>
<tr>
<td>WR 5031706</td>
<td>Line - El Paso - Farber 138 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>6/1/2014</td>
<td>2/20/2013</td>
</tr>
<tr>
<td>WR 5031706</td>
<td>XFR - Auburn Road 230/115 kV Transformer Ckt 1</td>
<td>Regional Reliability</td>
<td>6/1/2014</td>
<td>2/20/2013 (\pm 24) months</td>
</tr>
<tr>
<td>WR 5031706</td>
<td>XFR - Rose Hill 345/138 kV Ckt 3</td>
<td>Transmission Service</td>
<td>10/1/2013</td>
<td>3/31/2010</td>
</tr>
<tr>
<td>WR 5031706</td>
<td>Multi - Trail - 138 kV</td>
<td>138 kV</td>
<td>$2,614,395</td>
<td>DELAY - MITIGATION</td>
</tr>
<tr>
<td>WR 5031706</td>
<td>Multi - Trail - 138 kV</td>
<td>138 kV</td>
<td>$2,614,395</td>
<td>DELAY - MITIGATION</td>
</tr>
<tr>
<td>WR 5031706</td>
<td>Multi - Trail - 138 kV</td>
<td>138 kV</td>
<td>$2,614,395</td>
<td>DELAY - MITIGATION</td>
</tr>
<tr>
<td>WR 5031706</td>
<td>Multi - Trail - 138 kV</td>
<td>138 kV</td>
<td>$2,614,395</td>
<td>DELAY - MITIGATION</td>
</tr>
</tbody>
</table>

**Note:** The table above provides a summary of various projects and their associated costs and timelines. The cost estimates vary widely, with some projects requiring significant investments, particularly in the construction of new substations and transmission lines. The projects are categorized based on their purpose, with some focusing on regional reliability enhancements, while others are aimed at improving specific segments of the electrical grid. The timeline for each project varies, with some expected to be completed within 12 months, whereas others may require up to 30 months or longer to complete. The notes column indicates potential delays or mitigation measures in place to address any anticipated issues.
<table>
<thead>
<tr>
<th>Project Number</th>
<th>Date</th>
<th>Description</th>
<th>Duration</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>200228 30527 50534 WR Multi - Geary County 345/115 kV and Geary - Chapman 115 kV Regional Reliability</td>
<td>6/1/2017 - 6/1/2019</td>
<td>$27,938,225</td>
<td>36 months</td>
<td>NTC - COMMITMENT 09/10/13</td>
</tr>
<tr>
<td>200228 30527 50506 WR Multi - Geary County 345/115 kV and Geary - Chapman 115 kV Regional Reliability</td>
<td>6/1/2015 - 9/10/2013</td>
<td>$15,376,365</td>
<td>24 months</td>
<td>NTC - COMMITMENT 09/10/13</td>
</tr>
<tr>
<td>200212 30581 50541 WR E - 138-5/115 kV Chp 2 Regional Reliability</td>
<td>12/1/2015 - 6/1/2015</td>
<td>$7,122,480</td>
<td>18 months</td>
<td>NTC - COMMITMENT 09/10/13</td>
</tr>
<tr>
<td>200228 30582 50512 WR Multi - Viola 345/138kV Transformer and 138 kV Lines to Clearwater and Gill Regional Reliability</td>
<td>6/1/2016 - 6/1/2018</td>
<td>$14,331,670</td>
<td>36 months</td>
<td>NTC - COMMITMENT 09/10/13</td>
</tr>
<tr>
<td>200228 30583 50513 WR Multi - Viola 345/138kV Transformer and 138 kV Lines to Clearwater and Gill Regional Reliability</td>
<td>6/1/2016 - 6/1/2018</td>
<td>$5,007,657</td>
<td>36 months</td>
<td>NTC - COMMITMENT 09/10/13</td>
</tr>
<tr>
<td>200228 30584 50514 WR Multi - Viola 345/138kV Transformer and 138 kV Lines to Clearwater and Gill Regional Reliability</td>
<td>6/1/2016 - 6/1/2018</td>
<td>$40,525,225</td>
<td>36 months</td>
<td>NTC - COMMITMENT 09/10/13</td>
</tr>
<tr>
<td>200228 30584 50515 WR Multi - Viola 345/138kV Transformer and 138 kV Lines to Clearwater and Gill Regional Reliability</td>
<td>6/1/2016 - 6/1/2018</td>
<td>$22,234,744</td>
<td>36 months</td>
<td>NTC - COMMITMENT 09/10/13</td>
</tr>
<tr>
<td>200212 30587 50538 WR Device - Potwin 69 kV Capacitor Zonal Reliability</td>
<td>6/1/2014 - 6/1/2013</td>
<td>$724,896</td>
<td>18 months</td>
<td>COMPLETE 09/10/13</td>
</tr>
<tr>
<td>200212 30546 50529 WR Sub - Viola 345kV Generation Interconnection 6/1/2012</td>
<td>6/1/2012</td>
<td>$9,567,558</td>
<td>COMPLETE 09/10/13</td>
<td></td>
</tr>
<tr>
<td>200212 30546 50539 WR Sub - Viola 345kV GEN-2010-005 Addition Generation Interconnection 10/1/2012</td>
<td>10/1/2012</td>
<td>$26,000</td>
<td>COMPLETE 09/10/13</td>
<td></td>
</tr>
</tbody>
</table>
October 4, 2013

Mr. Dan Jones  
Lead Regulatory Engineer  
Southwest Power Pool, Inc.  
201 Worthen Drive  
Little Rock, AR 72223

Dear Mr. Jones,

**Subject: Transource Missouri, LLC Due Diligence Review**  
This letter presents the results of the due diligence review of Transource Missouri, LLC (“Transource”) conducted by Donald J. Morrow of Quanta Technology, LLC (“Quanta Technology”). The purpose of the due diligence review was to provide insights to Southwest Power Pool, Inc. (“SPP”) in evaluating the ability of Transource to assume the responsibility for the development and operation of the 345 kV line from Sibley to Maryville to Nebraska City and the 345 kV line from Iatan to Nashua (collectively, the “Projects”).

SPP had originally issued a Notification to Construct (“NTC”) to Kansas City Power and Light – GMO (“KCPL”) for both of the Projects. KCPL now proposes to transfer the responsibility to own, develop, operate and maintain the Projects to Transource. Before granting such a Novation, SPP requested that a due diligence review of the candidate organization be performed by a qualified subject matter expert in the area of transmission development, operations and maintenance.

**Due Diligence Process**  
Quanta Technology followed the process specified in Work Order 2 under the Master Services Agreement made as of August 31, 2012, between Quanta Technology and SPP. The process followed was similar to that used in 2009 for ITC Great Plains and in 2010 for Prairie Wind, but was updated to reflect recent changes to the SPP business practices. These changes defined the technical, financial and managerial qualifications necessary for transmission developers to receive a novation from a Designated Transmission Owner (“DTO”) for a project that has been issued a NTC by SPP. A description of the updated procedure is included as Attachment A to this report.

**Document Review**  
The due diligence review started with a data request for Transource. The data request list is provided as Attachment B to this report.
Transource provided 31 documents in response to the data request. These documents were reviewed by Quanta Technology to evaluate Transource qualifications. Table 1 lists the documents provided by Transource.

**Table 1: Data Request Response by Transource**

<table>
<thead>
<tr>
<th>Document No.</th>
<th>Date Received</th>
<th>Document Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>9/13/2013</td>
<td>Transource Missouri Report &amp; Order</td>
</tr>
<tr>
<td>2</td>
<td>9/13/2013</td>
<td>TMO Compliance Filing ER12-2554</td>
</tr>
<tr>
<td>3</td>
<td>9/13/2013</td>
<td>Order on Transmission Rate Incentives and Formula Rate Proposal</td>
</tr>
<tr>
<td>4</td>
<td>9/13/2013</td>
<td>TMO Letter Order Accepting Compliance Filing ER12-2554</td>
</tr>
<tr>
<td>5</td>
<td>9/13/2013</td>
<td>TMO Letter Order Accepting Settlement ER12-2554</td>
</tr>
<tr>
<td>6</td>
<td>9/13/2013</td>
<td>Application for Authorization for Disposition and Consolidation of Jurisdictional Facilities</td>
</tr>
<tr>
<td>7</td>
<td>9/13/2013</td>
<td>TMO Settlement ER12-2554</td>
</tr>
<tr>
<td>8</td>
<td>9/18/2013</td>
<td>Iatan Nashua 345 kV NTC</td>
</tr>
<tr>
<td>9</td>
<td>9/18/2013</td>
<td>NTC 200097_Kansasa City Power &amp; Light Greater Missouri Operations Company</td>
</tr>
<tr>
<td>10</td>
<td>9/18/2013</td>
<td>Transource Background Presentation</td>
</tr>
<tr>
<td>11</td>
<td>9/18/2013</td>
<td>Transource Energy Formation</td>
</tr>
<tr>
<td>12</td>
<td>9/18/2013</td>
<td>Transource Energy Written Consent</td>
</tr>
<tr>
<td>13</td>
<td>9/18/2013</td>
<td>Transource Missouri Formation</td>
</tr>
<tr>
<td>14</td>
<td>9/18/2013</td>
<td>Transource Missouri Intercompany Support Agreement</td>
</tr>
<tr>
<td>15</td>
<td>9/18/2013</td>
<td>Transource Missouri qualification in MO</td>
</tr>
<tr>
<td>16</td>
<td>9/18/2013</td>
<td>Transource AEPSC SA</td>
</tr>
<tr>
<td>17</td>
<td>9/18/2013</td>
<td>Transource KCPL SA</td>
</tr>
</tbody>
</table>
The documents provided by Transource show that -

- Transource is a Delaware corporation and is registered as a foreign corporation in the state of Missouri (Document Nos. 10, 11, 12, 13 and 15).
- KCPL has been approved to transfer the plant and operating rights to Transource for the Projects and Transource has been issued a Certificate of Convenience and Necessity for the Projects by the State of Missouri (Document No. 1).
- Transource has a FERC approved tariff and has reached a settlement agreement with the Missouri Commission (Document Nos. 2, 3, and 7).
- Transource will secure services through Transource Energy, LLC which has agreements in place with both KCPL and American Electric Power (“AEP”) to develop, operate and
maintain the Project. The services provided to Transource include business support, tax compliance, risk management, siting/land acquisition, regulatory support, procurement, engineering/design (including environmental), construction, operations, maintenance, and web hosting (Document Nos. 12, 14, 16 and 17).

- KCPL’s safety program will be used during construction, operation and maintenance of the Projects. Detailed information was provided which included KCPL’s safety policy, safety records, and safety program - both internal and external (Document Nos. 25, 27, 28, 29, 30, and 31).
- The Iatan to Sibley 345 kV line will be single circuit, steel H-frame construction with a “heavy” NESC loading zone assumption and a design capacity of 4100A @ 200°C (Document No. 21).
- The Sibley to Nebraska City 345 kV line will be single circuit, steel H-frame construction with a “heavy” NESC loading zone assumption and a design capacity of 4178A @ 200°C (Document No. 26).

Financial Review
Quanta Technology used the information provided by Transource to assess the cost impact to SPP’s members. Please note that Quanta Technology’s expertise is in engineering, operations, maintenance and management of transmission and distribution organizations. We are not an accounting firm and we do not represent ourselves as financing experts. Therefore, for this aspect of the review, our focus was on the methodology used to assess the cost impact to SPP’s members, the data inputs utilized in the analysis, the factors leading into the FERC authorized return on equity (ROE) and the estimated expenses related to the operations and maintenance of the Projects. Quanta Technology is not qualified and did not render an opinion on the appropriateness of tax benefits claimed by Transource, consistency of Transource’s financial accounting practices with GAAP or the cost of short-term and long-term debt used by Transource in the analysis.

The analysis reviewed by Quanta Technology for this review was titled “Financial Analysis for Novation of Iatan-Nashua Sibley NE City to Transource Missouri w CWIP” (Document No. 32).

FERC has authorized a base Return on Equity (“ROE”) of 9.8% for Transource. FERC has also granted certain incentives to Transource. For both Projects, FERC granted a 50 point basis adder for RTO membership and CWIP in rate base treatment. For the Sibley to Nebraska City project, FERC has approved an additional 100 point basis adder for size, scope, benefits and risks of the Project. Therefore, Transource will have an ROE of 10.3% for Iatan to Nashua and 11.3% for Sibley to Nebraska City. The financial analysis provided by Transource assumed that KCPL would have received the same incentives but on a higher base ROE.

FERC put a limit on the capital structure for Transource. FERC set an equity cap of 55% of the Capital Structure. This compares with 50% for KCPL.

For long term debt, Transource assumed its cost of debt would be 5.25% and the cost of debt for KCPL would be 5.77%.
Table 2 compares the financial assumptions between Transource and KCPL\(^1\).

<table>
<thead>
<tr>
<th>Item</th>
<th>Transource</th>
<th>KCPL (assumed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base ROE</td>
<td>9.8%</td>
<td>10.6% (actual)</td>
</tr>
<tr>
<td>RTO Membership</td>
<td>50 basis points</td>
<td>50 basis points</td>
</tr>
<tr>
<td>Size, Scope, Benefits, Risks</td>
<td>100 basis points (Sibley only)</td>
<td>100 basis points (Sibley only)</td>
</tr>
<tr>
<td>CWIP in Rate Base?</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Capital Structure</td>
<td>55% Equity</td>
<td>50% Equity</td>
</tr>
<tr>
<td>Long Term Interest Rate</td>
<td>5.25%</td>
<td>5.77%</td>
</tr>
</tbody>
</table>

Quanta Technology reviewed the information provided by Transource and noted that the O&M costs for Iatan were 6.7% higher for Transource than those assumed for KCPL and those for Sibley were 3% higher for Transource than those assumed for KCPL. For both KCPL and Transource, the assumptions provided show that O&M costs make up less than .2% of the annual revenue requirement for the Projects combined (.19% for Transource and .18% for KCPL).

Transource indicated that the O&M costs include KCPL performance of line inspections, vegetation management, switching, substation O&M, relay maintenance, and control center monitoring.

For this analysis, we assume the difference in O&M costs between Transource and KCPL is that the AEP A&G is not included in the annual revenue requirement in case of KCPL.

Quanta Technology notes that losses were not included in the O&M cost estimate. For this analysis, we assume that losses will be recovered through Attachment M of the SPP Tariff.

**Cost to Customers**

Quanta Technology used the information provided by Transource to evaluate the impact on the cost to SPP members for the Projects. Quanta Technology spot checked formulas used in the spreadsheet and found no errors in our sampling.

The data provided by Transource shows that the annual cost to SPP customers is expected to be less than if KCPL retained the Projects. The main reason for this decrease is that the ROE and the long-term debt are lower for Transource than for KCPL. These savings are lessened somewhat by the lower debt-to-equity ratio for Transource and its slightly higher O&M charges. In its analysis, Transource calculated a total savings of about $18.3M over a 40 year period. However, this was calculated as a sum of year-of-occurrence savings.

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\(^1\) Per discussions with Transource, these same financial assumptions were filed as testimony by Transource in the Missouri Commission docket investigating approval for transfer of the Projects.
Quanta Technology and SPP did an adjusted calculation that discounted the year-of-occurrence savings by the standard 8% SPP discount rate (the average of its members). If the costs were discounted back to 2013, we noted that the discounted savings total is $5.8M for SPP’s members.

The calculation in Transource’s spreadsheet did include the impacts of CWIP in rate base. The calculation provided showed the Annual Transmission Revenue Requirement (ATRR) starting at the date the Projects go into service (2015 for Iatan and 2017 for Sibley) as well as the impacts of development costs incurred before the Projects are placed in-service.

**Transource Interview**

An interview of the Transource executive team was conducted via conference call on September 24, 2013. SPP sat in on the call as an observer. Table 3 lists the participants in the call.

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
<th>Title</th>
</tr>
</thead>
<tbody>
<tr>
<td>Donald Morrow</td>
<td>Quanta Technology</td>
<td>Partner &amp; SVP Corporate Strategy</td>
</tr>
<tr>
<td>Dan Jones</td>
<td>SPP</td>
<td>Lead Regulatory Engineer</td>
</tr>
<tr>
<td>Todd Fridley</td>
<td>Transource Missouri &amp; Transource Energy</td>
<td>VP Transource Missouri</td>
</tr>
<tr>
<td>Julie Shull</td>
<td>KCPL</td>
<td>Director Transmission Construction</td>
</tr>
<tr>
<td>Antonio Smyth</td>
<td>Transource Missouri &amp; Transource Energy</td>
<td>President</td>
</tr>
<tr>
<td>Mike Higgins</td>
<td>AEP</td>
<td>Managing Director of Transmission</td>
</tr>
<tr>
<td>Raja Sundararajan</td>
<td>Transource Missouri &amp; Transource Energy</td>
<td>VP Finance</td>
</tr>
</tbody>
</table>

Following is a summary of the discussions during the interview. A copy of Quanta Technology’s notes from the conference call is provided as Attachment C to this report.

**Financing and Cost to Customers**

During the interview, Transource stated that long term interest rate used in the analysis was based upon discussions with financial institutions for financing the Projects. The KCPL long term interest rate was the historical marginal cost of long-term debt.

Transource indicated that they have not locked the long term debt yet since the Projects have yet to be novated to them. They also noted that Transource does not have a credit rating yet for the same reason. However, with respect to the marginal cost of long-term debt, they expect that Transource’s cost of debt will always be lower than that for KCPL since the financial community views a pure transmission play investment as lower risk than a blended portfolio in a vertically integrated utility.

Transource stated that it may be possible that the financial climate could change and their assumptions may be imperfect. However, because of the view of risk by the financial
community, Transource indicated that the spread in the cost of debt should still be lower for Transource and the spread should not be impacted by any financial climate change.

With respect to the FERC rates, Transource stated that they strongly believe that KCPL would have received the same incentives as Transource. They noted that since KCPL had intended to novate the Projects to Transource, KCPL did not put together a FERC rate filing for the Projects.

**Staffing Levels**
Transource indicated that Transource will have no employees. Instead, Transource will contract all services from KCPL and from AEP through Transource Energy, LLC.

**Engineering**
Transource indicated that it will contract all engineering services primarily from KCPL and secondarily from AEP. They expect that KCPL will provide the engineering services related to the Projects’ design through the provision of engineering services using a qualified engineering firm. It was noted that Transource expects KCPL to use their existing contracts with engineering firms, which would be the same firms that KCPL would use if they retained the Projects.

**Permitting**
Transource indicated that it will contract all permitting services from KCPL with backup services provided by AEP.

**ROW Acquisition**
Transource indicated that it will contract all ROW acquisition services from KCPL. It was noted that KCPL has already begun the ROW acquisition process for the Iatan to Nashua line.

**Procurement**
Transource indicated that it will contract procurement services primarily from AEP with KCPL as a backup. Since AEP has preferred vendor contracts, the capital costs are expected to be less than if KCPL developed the Projects. It was noted, though, that these cost savings have not been factored into the capital estimates provided for this due diligence review.

**Project Management**
Transource indicated that it will contract all project management services from KCPL.

**Construction**
Transource indicated that it will contract all construction services from KCPL. They expect that KCPL will sub contract construction work to their construction contractors. It was noted that use of the established KCPL safety practices and procedures would be required for any of the contractors to be used by KCPL to construct the Projects.

**Commissioning**
Transource indicated that it will contract all commission services from KCPL.
Technology Content
Transource indicated that no special technology (e.g., composite core conductor) or construction techniques will be used to develop the Projects. The KCPL transmission line design standards will be used as the basis of their design.

Operations
Transource indicated that its intent is to have KCPL operate and maintain the facilities through the services agreement. They noted that the KCPL' control center operates 24 hours per day and that the Projects would be monitored and controlled by the KCPL EMS. The losses for the projects will be included in the KCPL Balancing Authority (“BA”) area. Transource noted that KCPL’s storm response plan will be applicable to the Projects and that AEP may also provide assistance during storms and offer stores services and spare parts to keep the Projects in service.

Because KCPL is anticipated to be the contract operator of the Projects, it is Transource’s intent that the obligation to satisfy applicable NERC requirements would be passed through to KCPL. Transource noted, however, that because the Projects have not yet been developed the terms of this arrangement have not yet been negotiated.

Maintenance
Transource indicated that it anticipates contracting with KCPL for maintenance services and may use AEP as a backup. Similar to the approach discussed in the operations section above, it is Transource’s intent that the obligation to satisfy NERC requirements applicable to maintenance would be passed through to KCPL.

Findings
Due Diligence Findings with Respect to Financing Assumptions
It is the opinion of Quanta Technology that the FERC basis point incentives that were granted to Transource would have been granted to KCPL.

- In forming this opinion, Quanta Technology notes that KCPL is a member of SPP and would likely have received the 50 basis point incentive for membership in an RTO.

- In forming this opinion, Quanta Technology notes FERC granted the 100 basis point incentive for Sibley on the risks associated with the project and not based upon the attributes of the developer. Therefore, since the project dynamics would not change if KCPL built the project, it is reasonable to assume that the 100 basis point adder would have been granted to KCPL as well.

Quanta Technology is not able to render an opinion on whether or not KCPL would have also been granted the CWIP in Rate Base incentive.

- In making this statement, we note that FERC had granted KCPL CWIP in rate base treatment for projects in Kansas.
However, we also note that Missouri only grants CWIP in rate base treatment on an exception basis. In the case of Transource, the Missouri commission was willing to agree to this incentive in the settlement agreement.

To render an opinion that KCPL would or would not have reached a settlement with the Missouri commission on CWIP in rate base would require a detailed regulatory assessment that factors in many other issues in play between KCPL and the Missouri commission. Such an assessment is outside the scope of this project.

It is the opinion of Quanta Technology that the capital cost of the Project would be essentially the same for Transource as for KCPL.

In forming this opinion, Quanta Technology notes that Transource will be contracting all necessary development services from KCPL, supplemented by AEP. Therefore, while there may be differences in difficult-to-quantify administrative costs, there should be no material difference in the final capital cost of the Project.

In forming this opinion, Quanta Technology also notes that the buying power of AEP will be used when possible to lower the cost of the Projects. Having this option introduces the possibility that the capital costs of the Projects could actually be lower than if KCPL retained ownership.

It is the opinion of Quanta Technology that the difference in O&M between Transource operating and maintaining the facility and KCPL operating and maintaining the facility will not result in a material difference in ATRR.

In forming this opinion, Quanta Technology notes that the percentage of O&M in the annual revenues is less than .2% for both Transource and KCPL.

In forming this opinion, Quanta Technology notes that losses have not been included in the O&M cost estimate. However, Quanta Technology does not expect a material difference would exist between Transource and KCPL owning and operating the Project with respect to the cost of losses since that the actual amount of energy lost would be the same and the lines will be included in the KCPL BA area.

Due Diligence Finding with Respect to Cost to SPP Customers

Is the opinion of Quanta Technology that Transource’s calculation showing that the cost to SPP Customers is lower for Transource than for KCPL is reasonable.

In forming this opinion, Quanta Technology notes that the ROE and the cost of debt are lower for Transource than for KCPL.

In forming this opinion, Quanta Technology agrees that the risk profile for a pure transmission play investment is different than the risk profile for a vertically integrated entity that includes generation and distribution investments.
In forming this opinion, Quanta Technology notes that treatment of CWIP in rate base in was properly accounted for in the financial analysis provided by Transource. We note that this analysis assumed both had the same FERC incentives.

**Due Diligence Finding with Respect to Project Development, Operations and Maintenance**

It is the opinion of Quanta Technology that the approach chosen by Transource to develop, operate and maintain the Project is equivalent or superior to KCPL developing, operating and maintaining the Project.

- In forming this opinion, Quanta Technology notes that Transource has chosen to outsource all design, construction, ROW acquisitions, environmental controls operations and maintenance to KCPL, the organization which received the original NTC from SPP for the Projects. Transource also intends to use a similar set of services from AEP as a backup to those offered by KCPL.

- In forming this opinion, Quanta Technology notes that Transource has chosen to outsource procurement from AEP and to use procurement services from KCPL as a supplement. This arrangement should allow Transource to maximize its leverage with vendors and service providers to achieve the lowest overall cost for the Projects.

- In forming this opinion, Quanta Technology reviewed the safety material provided by Transource in the data request. This material included safety requirements for KCPL staff and for contractors used on the system. It included the safety record for contractors currently utilized by KCPL. The safety material showed that contractors must maintain an acceptable safety record for their contracts to be renewed by KCPL. The contractor safety program addresses safety culture, attitude toward safety rules, accountability, pre-job planning, project communications, safety training expectations and safety audits.

- In forming this opinion, Quanta Technology has reviewed the contracts between Transource and KCPL and between Transource and AEP to engage their services. These services are discussed above and are sufficient to cover all aspects of the development, operation and maintenance of the Project.

- In rendering this opinion, Quanta Technology notes that services will be provided by KCPL and AEP. Both KCPL and AEP are established utilities in the SPP region, are members of SPP in good standing, and have a history of successful transmission project development, operation and maintenance. In addition, Quanta Technology notes that KCPL originally received the NTC from SPP for the Projects and, therefore, had been deemed qualified to develop, operate and maintain the Projects by SPP.

- In forming this opinion Quanta Technology expects that Transource, if it has not already, will be required to register with SPP as a Transmission Owner and Transmission
Operator and will, therefore, be compelled to abide by applicable NERC and SPP Reliability Standards.

Because of the various complications and external factors that enter into the successful development of transmission projects (e.g., legal challenges to regulatory approval, difficulty in securing easements, supply chain issues, etc.), this opinion constitutes neither a warrantee nor a guarantee on the part of Quanta Technology that Transource will actually develop, successfully operate and/or adequately maintain the Projects. Rather, this opinion is rendered based upon demonstration at the time of this review that Transource has engaged qualified partners for the provision of all necessary services throughout the life of the Projects.

**SME Qualifications**
The resume for Donald J. Morrow is provided as Attachment D to this report.

If there are any questions or comments on this report summarizing the findings from the due diligence review of the ability of Transource to develop, operate and maintain the Projects, please contact me at 919-334-3023.

Respectfully Submitted,

[Signature]

Donald J. Morrow
Partner & SVP Corporate Strategy
Quanta Technology, LLC.

Attachments
Introduction
Note: This document was revised to reflect additional requirements to be included in the qualification review that were identified in SPP’s Business Practices, updated on August 7, 2013.

This document provides guidance to SPP when considering approval of a Novation Agreement. A Novation Agreement applies when a Designated Transmission Owner (original “DTO”) has been issued a Notification to Construct (“NTC”) for a transmission facility, but the party wishes to transfer the responsibility to build and/or own this facility to another party (“Candidate”). Before approval of the Novation Agreement, SPP should qualify the candidate organization as being capable of adequately performing the transferred responsibility for the facility. The qualification process of a Candidate described herein is consistent with the most recent versions of the SPP Membership Agreement, Attachment O of the SPP OATT and SPP’s Business Practices.

For the qualification process, SPP should consider three phases in the life of a project. The phases are:

1. **Financing Phase** (Test ability to raise sufficient funds from qualified parties to finance the construction project and compare the cost of customers for the Candidate with estimated cost of customers for the original DTO.)
2. **Development Phase** (Test ability to execute engineering, permitting, environmental strategies, real-estate acquisition, procurement, project management, construction, and commissioning of the project.)
3. **Operational Phase** (Test ability to provide on-going operation and maintenance of the project.)

**Suggested Criteria**
The following tables provide guidance in judging the qualifications of Candidate in key areas related to the three phases in the life of the project.

In general, for item 1 below the legal right for an organization to incorporate and engage in commercial activities is a necessary condition to determine if a Candidate may be qualified. Also, the ability to raise financing should be tested and verified.

In general, for items 2 and 3 below a Candidate has three options. Perform the duties internally, contract with outside parties to execute, or some combination of the two. A Candidate should be able to describe how it plans to proceed with the project using one of these options.
## Item 1 – Financing and Rate Analysis Phase:

<table>
<thead>
<tr>
<th>Item</th>
<th>Tests</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Organizational Viability</strong></td>
<td>✓ Articles of Incorporation exist and have been registered</td>
</tr>
<tr>
<td></td>
<td>✓ Certificate of Public Convenience granted for applicable states</td>
</tr>
<tr>
<td></td>
<td>✓ Favorable regulatory rulings related to transmission construction</td>
</tr>
<tr>
<td></td>
<td>authorization and/or operation if necessary</td>
</tr>
<tr>
<td><strong>Capital Financing</strong></td>
<td>✓ FERC 203 Filing has been made</td>
</tr>
<tr>
<td></td>
<td>✓ FERC 205 Filing has been made</td>
</tr>
<tr>
<td></td>
<td>✓ Evidence of previous bond issuances</td>
</tr>
<tr>
<td></td>
<td>✓ Capital budgeting and cash flow forecasting processes exist</td>
</tr>
<tr>
<td></td>
<td>✓ Credit rating of BBB or better</td>
</tr>
<tr>
<td><strong>Cost to Customers</strong></td>
<td>✓ Perform a NPCC and a CWIP analysis (As indicated by SPP, this</td>
</tr>
<tr>
<td></td>
<td>factor does significantly affect the rate impact analysis over the</td>
</tr>
<tr>
<td></td>
<td>life of a transmission project. During the performance of this</td>
</tr>
<tr>
<td></td>
<td>analysis, Consultant will work closely with SPP staff to assess</td>
</tr>
<tr>
<td></td>
<td>this aspect of the review.)</td>
</tr>
<tr>
<td></td>
<td>✓ Compare total cost of Project for Candidate vs original DTO</td>
</tr>
<tr>
<td></td>
<td>✓ Compare financing costs for Candidate vs original DTO</td>
</tr>
<tr>
<td></td>
<td>✓ Compare FERC incentives</td>
</tr>
<tr>
<td></td>
<td>✓ Compare lifetime costs to customers</td>
</tr>
</tbody>
</table>
### Item 2 – Development Phase:

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficiency of staff (note 3) to cover breadth of detailed engineering required</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Professional Engineering License for supervisory engineer</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Existence of engineering standards</td>
<td></td>
</tr>
<tr>
<td>Permitting</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Environmental and regulatory expertise on staff at state &amp; federal level</td>
<td></td>
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<tr>
<td></td>
<td>✓ Demonstrated understanding of overall application process and its impact on critical path for the project</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Attorney’s on staff with relevant experience with CPCN or equivalent state regulatory filings</td>
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</tr>
<tr>
<td></td>
<td>✓ (Local relations? – Discuss with David and/or Les)</td>
<td></td>
</tr>
<tr>
<td>Environmental</td>
<td>✓ Environmental Permits identified and applied for</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Environmental Plan for project developed</td>
<td></td>
</tr>
</tbody>
</table>
## ATTACHMENT A

### SPP Qualification Process for Novation Agreements

April 1, 2009  
Revised September 16, 2013

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
</tr>
</thead>
</table>
| **ROW Acquisition** | ✓ Relevant previous experience (notes 1 & 2)  
✓ Easements for ROW (transferrable from initial party?)  
✓ On-going process for dealing with land owners  
✓ Attorney’s with expertise in drafting & filing easements & condemnation  
✓ Certified real estate agents on staff  
✓ Public ROW franchises | ✓ Contracts in place with qualified firms  
✓ Easements transferred from previous initial party |
| **Procurement** | ✓ Relevant previous experience (notes 1 & 2)  
✓ Demonstrated understanding of key equipment providers, procurement timeline, and impacts on critical path  
✓ Procurement systems in place (HW, SW, PO forms, etc.)  
✓ Sufficiency of staff (note 3)  
✓ Contracts with critical vendors in place | ✓ EPC contract(s) in place with qualified firms  
✓ Contracts in place with qualified firms |
| **Project Management** | ✓ Relevant previous experience (notes 1 & 2)  
✓ Systems in place to track tasks on the project, resources, progress, expenses, cost forecasts, cash flows, and critical path  
✓ Sufficiency of staff (note 3) | ✓ Some level of monitoring should be performed internal to Candidate Organization  
✓ Embedded in construction contracts  
✓ Project management contracts in place with qualified firms |
## ATTACHMENT A

### SPP Qualification Process for Novation Agreements

April 1, 2009

Revised September 16, 2013

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Construction</strong></td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficiency of staff (notes 3 &amp; 4)</td>
<td>✓ Project update processes</td>
</tr>
<tr>
<td></td>
<td>✓ Ownership of equipment such as cranes, bucket trucks, trenchers, helicopters, or contracts for their lease</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of safety program</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Crew training program</td>
<td></td>
</tr>
<tr>
<td><strong>Commissioning</strong></td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Process in place for internal sign off and designating equipment in-service and “used &amp; useful”</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficiency of staff (notes 3 &amp; 4)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Pre-existing testing procedures</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Established criteria for judging acceptance</td>
<td></td>
</tr>
<tr>
<td><strong>Technology Content</strong></td>
<td>✓ Consistent with NTC issued by SPP</td>
<td>✓ n/a</td>
</tr>
<tr>
<td></td>
<td>✓ Type of construction (material, loading, etc.) compared with Original DTO</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Estimated life of plant</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Losses</td>
<td></td>
</tr>
</tbody>
</table>
**Item 3 – Operations Phase:**

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)&lt;br&gt; ✓ Sufficient staff (notes 3 &amp; 4)&lt;br&gt; ✓ 24 hour control center operation&lt;br&gt; ✓ 24 hour field coverage with qualified field staff (note 5)&lt;br&gt; ✓ SCADA system with key points monitored (breaker status &amp; line flows)&lt;br&gt; ✓ Established storm/outage response plan&lt;br&gt; ✓ Articulated safety program with clearly defined tagging and clearance procedures covering both internal personal and contractors&lt;br&gt; ✓ Safety record exists &amp; comparison to industry&lt;br&gt; ✓ Presence of a NERC and SPP standards compliance process&lt;br&gt; ✓ Compliance history</td>
<td>✓ Contracts in place with qualified firms&lt;br&gt; ✓ Regular reporting of activities provided&lt;br&gt; ✓ Outage Response times tracked</td>
</tr>
</tbody>
</table>
## SPP Qualification Process for Novation Agreements

**April 1, 2009**  
**Revised September 16, 2013**

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintenance</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficient staff (notes 3 &amp; 4)</td>
<td>✓ Regular reporting of activities provided</td>
</tr>
<tr>
<td></td>
<td>✓ Qualified field staff (note 5)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Ownership of equipment such as cranes, bucket trucks, trenchers, helicopters, or contracts in place for their lease</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of safety program</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ On-going training program for crews</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Written maintenance program</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Able to articulate testing criteria for items monitored</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of a NERC and SPP standards compliance process</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Compliance history</td>
<td></td>
</tr>
</tbody>
</table>

### Table Notes:
1. “Relevant experience” means experience designing, constructing, operating and maintaining similar voltage transmission facilities. As an example, an IPP would not have relevant experience if its previous assets were only generation facilities.
2. “Experience” means having performed relevant work either at the Candidate or at previous organizations.
3. “Sufficiency” means both having staff with the breadth of experience to cover all aspects of the work and enough staff to adequately perform the work.
4. Construction for EHV transmission is rarely performed internally in the US.
5. “Qualified field staff” means labor that has received appropriate, regular, and on-going safety and skills training necessary to execute the work required. Typically, field staff should progress through an apprentice oriented job progression.
Suggested Qualification Process:
The suggested qualification process for Candidates before approval of a Novation Agreement is based upon the establishment of a “Reasonable Professional” standard. The tables above provide guidance in the issues and suggest tests to use to determine if a Candidate satisfies this Reasonable Professional standard. The assessment of the Candidate should be conducted by a subject matter expert(s) in the area of transmission development, operations and maintenance.

1. Review formation documents of Candidate (focus is on item 1)
   a. Articles of incorporation
   b. State authorizations of Convenience and Authority
   c. FERC Filings – 203, 205, and 206

2. Conduct an interview with an officer of Candidate to cover the following items (focus is on items 2 & 3):
   a. Discussion of Candidate’s plans for addressing the issues in the table
   b. Describe staffing levels, plans and capability for internal groups performing either all or a portion of the tasks
   c. Describe the safety program and manual for the organization, with a special emphasis on field safety
   d. Identify key contracts in place to cover any of the above items, including provider of outside services
   e. Identify major external partners
      i. Attorneys
      ii. Detail Engineering
      iii. ROW acquisition
      iv. Equipment procurement
      v. Project Management
      vi. Construction Management
      vii. Construction Contractors
      viii. Environmental
   f. Discuss procurement methods and expectations
   g. Describe real-estate acquisition process
   h. Describe understanding of project timeline & critical path
   i. Describe equipment owned and leased by Candidate
   j. Describe NERC & RRO compliance history and corporate compliance program and/or process
   k. Describe the metrics used to track project development, operations and maintenance
   l. Describe training programs in place at the organization
3. Contract reviews (focus is on items 2 & 3):
   a. Contract(s) exists
   b. Contract(s) cover appropriate time periods for the facility in question
   c. Contract(s) covers key areas identified in the tables above that are not covered internal to the Candidate Organization
   d. Contract(s) includes reporting and feedback to provide a measure of control over external partner
   e. Contract(s) include NERC & RRO standards compliance expectations (applicable to O&M phase)
   f. Contract(s) include response time requirements and/or expectations for outages (applicable to O&M phase)
   g. Contract(s) contain appropriate incentives to ensure personal safety and Bulk Electric System reliability
Attachment B
Data Request List sent 9/12/2013

Data Request No.

1. Articles of incorporation
2. State authorizations to act as utility and which establish eligibility to own and operate transmission
3. FERC Filings – 203, 205, & 206
4. Tariff filing
5. Plans for or contracts to provide the following
   - Engineering services
   - Permitting/ROW Acquisition services
   - Material Procurement
   - Project/Construction Management services
   - Construction services
   - Commissioning services
   - System Operation services
   - Field operation/response services
   - Maintenance services
6. Most recent “Standardized Cost Estimate Reporting Template” (SCERT) identified in BP 7060, Section 9. Per that BP, there should be one submitted by KCPL before the NCT was issued. There may be an updated one after the NCT was issued.
7. Description of Safety Program – internal and for contractors
8. Safety record of Transource or the company that will provide field operation & maintenance services
9. Design Characteristics of the line (wood, steel, tower type, conductor type, insulators, etc.)
10. Estimated total owning cost
11. Estimated losses on the facility
12. Estimate of useful life of the facility
13. Financial Information (this may be available in a spreadsheet you have provided to FERC, State of Kansas and/or SPP)
   - NPCC cost estimate
   - WACOC
   - Authorized ROR
   - Long term debt interest rate
   - Short term interest rate
   - Equity Ratio
   - Estimate of annual operating costs – field & control center
   - Estimate of annual maintenance costs
14. NTC Letters
Background
This document presents a summary of Quanta Technology’s notes during the interview session of Transource Energy and Transource Missouri conducted during the due diligence review for the Novation of the Iatan to Nashua 345 kV Line (SPP Project ID: 703) and a portion (approximately 140 miles) of the Nebraska City to Maryville to Sibley 345 kV Line (SPP Project ID: 938). This interview was conducted via conference call on September 24, 2013 between 2pm and 5pm EDT.

Participants
The following table shows the participants in the Q&A:

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
<th>Title</th>
</tr>
</thead>
<tbody>
<tr>
<td>Donald Morrow</td>
<td>Quanta Technology</td>
<td>Partner &amp; SVP Corporate Strategy</td>
</tr>
<tr>
<td>Dan Jones</td>
<td>SPP</td>
<td>Lead Regulatory Engineer</td>
</tr>
<tr>
<td>Todd Fridley</td>
<td>Transource Missouri &amp; Transource Energy</td>
<td>VP Transource Missouri</td>
</tr>
<tr>
<td>Julie Shull</td>
<td>KCPL</td>
<td>Director Transmission Construction</td>
</tr>
<tr>
<td>Antonio Smyth</td>
<td>Transource Missouri &amp; Transmource Energy</td>
<td>President</td>
</tr>
<tr>
<td>Mike Higgins</td>
<td>AEP</td>
<td>Managing Director of Transmission</td>
</tr>
<tr>
<td>Raja Sundararajan</td>
<td>Transource Missouri &amp; Transource Energy</td>
<td>VP Finance</td>
</tr>
</tbody>
</table>
**Interview Notes**

Item 1 – Financing and Rate Analysis Phase:

<table>
<thead>
<tr>
<th>Item</th>
<th>Tests</th>
<th>Notes from Q&amp;A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Organizational Viability</td>
<td>✓ Articles of Incorporation exist and have been registered</td>
<td>✓ Delaware certificate</td>
</tr>
<tr>
<td></td>
<td>✓ Certificate of Public Convenience granted for applicable states</td>
<td>✓ Settlement accepts Iatan to Nashua and CPCN for a utility operation in Missouri</td>
</tr>
<tr>
<td></td>
<td>✓ Favorable regulatory rulings related to transmission construction authorization and/or operation if necessary</td>
<td>✓ A few items of a reporting nature, routing and siting of the line is a key issue – outreach has been done – putting a filing together and targeting end of the month – not trying to further qualify</td>
</tr>
<tr>
<td>Capital Financing</td>
<td>✓ FERC 203 Filing has been made</td>
<td>✓ The basis for the interest rate for Transource was based upon bank indications</td>
</tr>
<tr>
<td></td>
<td>✓ FERC 205 Filing has been made</td>
<td>✓ In testimony did a savings case assuming Transource Missouri</td>
</tr>
<tr>
<td></td>
<td>✓ Evidence of previous bond issuances</td>
<td>✓ Backed by investment</td>
</tr>
<tr>
<td></td>
<td>✓ Capital budgeting and cash flow forecasting processes exist</td>
<td>✓ Have not locked the 5.25% - put a construction facility in place – will take out in form of long term debt.</td>
</tr>
<tr>
<td></td>
<td>✓ Credit rating of BBB or better</td>
<td>✓ 5.77% for KCPL historical integrated debt – estimated marginal cost of long-term debt.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>✓ Difference would be financing only that project – no other risks are incorporated into estimated Transource rate.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>✓ No credit rating yet. There is a cost to get it done, so will do it later once the novation occurs.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>✓ Electric Transmission Texas – offered</td>
</tr>
<tr>
<td>Item</td>
<td>Tests</td>
<td>Notes from Q&amp;A</td>
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<tr>
<td>----------------------</td>
<td>----------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Cost to Customers</td>
<td>✓ Perform a NPCC and a CWIP analysis (As indicated by SPP, this factor does significantly affect the rate impact analysis over the life of a transmission project. During the performance of this analysis, Consultant will work closely with SPP staff to assess this aspect of the review.) ✓ Compare total cost of Project for Candidate vs original DTO ✓ Compare financing costs for Candidate vs original DTO ✓ Compare FERC incentives ✓ Compare lifetime costs to customers</td>
<td>✓ Assumed the incentives for the projects would be the same in both cases. ✓ SPP had done some previous analysis – very small change ✓ Formula rate for KCP&amp;L 10.6 base, RTO adder of 50 basis points. Assumed 100 basis adder for Sibley for risk of development would also be approved. ✓ Transource Missouri does not believe that the financial assumptions have changed since the filing. It was noted that the spread is the key issue and that should not be affected by financial climate changes.</td>
</tr>
<tr>
<td>Item</td>
<td>Internal Tests</td>
<td>External Tests</td>
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<tr>
<td>--------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Engineering</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td>Permitting</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td></td>
</tr>
<tr>
<td>Environmental</td>
<td>✓ Environmental Permits identified and applied for</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Environmental Plan for project developed</td>
<td></td>
</tr>
<tr>
<td>Item</td>
<td>Internal Tests</td>
<td>External Tests</td>
</tr>
<tr>
<td>----------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| ROW Acquisition      | ✓ Relevant previous experience (notes 1 & 2)  
✓ Easements for ROW (transferrable from initial party?)  
✓ On-going process for dealing with land owners  
✓ Attorney’s with expertise in drafting & filing easements & condemnation  
✓ Certified real estate agents on staff  
✓ Public ROW franchises | ✓ Contracts in place with qualified firms  
✓ Easements transferred from previous initial party | ✓ Outsourced. Securing the easement for Transource Missouri. |
| Procurement          | ✓ Relevant previous experience (notes 1 & 2)  
✓ Demonstrated understanding of key equipment providers, procurement timeline, and impacts on critical path  
✓ Procurement systems in place (HW, SW, PO forms, etc.)  
✓ Sufficiency of staff (note 3)  
✓ Contracts with critical vendors in place | ✓ EPC contract(s) in place with qualified firms  
✓ Contracts in place with qualified firms | ✓ Outsourced from AEP with KCPL as a backup.  
✓ Potential procurement savings would be factored into the final capital costs. |
| Project Management   | ✓ Relevant previous experience (notes 1 & 2)  
✓ Systems in place to track tasks on the project, resources, progress, expenses, cost forecasts, cash flows, and critical path  
✓ Sufficiency of staff (note 3) | ✓ Some level of monitoring should be performed internal to Candidate Organization  
✓ Embedded in construction contracts  
✓ Project management contracts in place with qualified firms | ✓ Outsourced to KCPL. |
<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
<th>Notes from Q&amp;A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction</td>
<td>Relevant previous experience (notes 1 &amp; 2)</td>
<td>Contracts in place with qualified firms</td>
<td>Outsourced to KCPL.</td>
</tr>
<tr>
<td></td>
<td>Sufficiency of staff (notes 3 &amp; 4)</td>
<td>Project update processes</td>
<td>KCPL safety practices and procedure would be in effect for the contractor</td>
</tr>
<tr>
<td></td>
<td>Ownership of equipment such as cranes, bucket trucks, trenchers, helicopters,</td>
<td></td>
<td>relationships.</td>
</tr>
<tr>
<td></td>
<td>or contracts for their lease</td>
<td></td>
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<tr>
<td></td>
<td>Presence of safety program</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Crew training program</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commissioning</td>
<td>Relevant previous experience (notes 1 &amp; 2)</td>
<td>Process in place for internal sign off and designing equipment in-service and</td>
<td>Contracted out to KCPL.</td>
</tr>
<tr>
<td></td>
<td>Sufficiency of staff (notes 3 &amp; 4)</td>
<td>“used &amp; useful”</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Pre-existing testing procedures</td>
<td>Contracts in place with qualified firms</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Established criteria for judging acceptance</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Technology Content</td>
<td>Consistent with NTC issued by SPP</td>
<td>n/a</td>
<td>no special conductor or construction techniques.</td>
</tr>
<tr>
<td></td>
<td>Type of construction (material, loading, etc.) compared with Original DTO</td>
<td></td>
<td>Combined set of organizations allows for the best of both organizations –</td>
</tr>
<tr>
<td></td>
<td>Estimated life of plant</td>
<td></td>
<td>therefore it’s been helpful vs KCPL-GMO only – especially cost.</td>
</tr>
<tr>
<td></td>
<td>Losses</td>
<td></td>
<td>KCPL design standard will be used.</td>
</tr>
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</tbody>
</table>
### Item 3 – Operations Phase:

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<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
<th>Notes from Q&amp;A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place</td>
<td>✓ Intent is to have KCPL operate &amp; maintain the facilities through the services agreement.</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficient staff (notes 3 &amp; 4)</td>
<td>with qualified firms</td>
<td>✓ KCPL control center 24 hour operating.</td>
</tr>
<tr>
<td></td>
<td>✓ 24 hour control center operation</td>
<td>✓ Regular reporting of activities provided</td>
<td>✓ EMS, metered output to KCPL control center</td>
</tr>
<tr>
<td></td>
<td>✓ 24 hour field coverage with qualified field staff (note 5)</td>
<td>✓ Outage Response times tracked</td>
<td>✓ In KCPL balancing authority</td>
</tr>
<tr>
<td></td>
<td>✓ SCADA system with key points monitored (breaker status &amp; line flows)</td>
<td></td>
<td>✓ NERC liabilities and requirements would be set up through KCPL – intent is to set that up.</td>
</tr>
<tr>
<td></td>
<td>✓ Established storm/outage response plan</td>
<td></td>
<td>✓ Transource is the ultimate owner of the line and ultimate legal owner of the line. So Transource has the obligation, but pass it on through the services agreement. This will be yet to come.</td>
</tr>
<tr>
<td></td>
<td>✓ Articulated safety program with clearly defined tagging and clearance procedures covering both internal personal and contractors</td>
<td></td>
<td>✓ KCPL’s storm response plan will govern the facilities – AEP may also provide assistance and will offer up stores &amp; spares as needed.</td>
</tr>
<tr>
<td></td>
<td>✓ Safety record exists &amp; comparison to industry</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of a NERC and SPP standards compliance process</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Compliance history</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Item</td>
<td>Internal Tests</td>
<td>External Tests</td>
<td>Notes from Q&amp;A</td>
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<td>----------------------------------------------------</td>
</tr>
<tr>
<td>Maintenance</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
<td>✓ KCPL would be contracted – with AEP assistance.</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficient staff (notes 3 &amp; 4)</td>
<td>✓ Regular reporting of activities provided</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Qualified field staff (note 5)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Ownership of equipment such as cranes, bucket trucks, trenchers,</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>helicopters, or contracts in place for their lease</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of safety program</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ On-going training program for crews</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>✓ Written maintenance program</td>
<td></td>
<td></td>
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<td></td>
<td>✓ Able to articulate testing criteria for items monitored</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of a NERC and SPP standards compliance process</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Compliance history</td>
<td></td>
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</tbody>
</table>

Table Notes:

1. “Relevant experience” means experience designing, constructing, operating and maintaining similar voltage transmission facilities. As an example, an IPP would not have relevant experience if its previous assets were only generation facilities.
2. “Experience” means having performed relevant work either at the Candidate or at previous organizations.
3. “Sufficiency” means both having staff with the breadth of experience to cover all aspects of the work and enough staff to adequately perform the work.
4. Construction for EHV transmission is rarely performed internally in the US.
5. “Qualified field staff” means labor that has received appropriate, regular, and on-going safety and skills training necessary to execute the work required. Typically, field staff should progress through an apprentice oriented job progression.
Additional Notes

1. Review formation documents of Candidate (focus is on item 1)
   a. Articles of incorporation
   b. State authorizations of Convenience and Authority
   c. FERC Filings – 203, 205, and 206

2. Conduct an interview with an officer of Candidate to cover the following items (focus is on items 2 & 3):
   a. Discussion of Candidate’s plans for addressing the issues in the table
   b. Describe staffing levels, plans and capability for internal groups performing either all or a portion of the tasks – The intent is loaned staff from the owners. There will be no direct employees in either Transource Missouri or Transource Energy.
   c. Describe the safety program and manual for the organization, with a special emphasis on field safety -
   d. Identify key contracts in place to cover any of the above items, including provider of outside services
   e. Identify major external partners – Transource does not have it’s own contracts for support, all support is through KCPL and AEP.
      i. Attorneys
      ii. Detail Engineering
      iii. ROW acquisition
      iv. Equipment procurement
      v. Project Management
      vi. Construction Management
      vii. Construction Contractors
      viii. Environmental
   f. Discuss procurement methods and expectations
   g. Describe real-estate acquisition process
   h. Describe understanding of project timeline & critical path – On course for both projects w/in budget and in service 2015 for Iatan to Nashua, Sibley in 2017.
      i. Describe equipment owned and leased by Candidate
   j. Describe NERC & RRO compliance history and corporate compliance program and/or process
   k. Describe the metrics used to track project development, operations and maintenance – None, all through the contracts.
   l. Describe training programs in place at the organization

3. Contract reviews (focus is on items 2 & 3):
   a. Contract(s) exists
b. Contract(s) cover appropriate time periods for the facility in question

c. Contract(s) covers key areas identified in the tables above that are not covered internal to the Candidate Organization

d. Contract(s) includes reporting and feedback to provide a measure of control over external partner

e. Contract(s) include NERC & RRO standards compliance expectations (applicable to O&M phase)

f. Contract(s) include response time requirements and/or expectations for outages (applicable to O&M phase)

g. Contract(s) contain appropriate incentives to ensure personal safety and Bulk Electric System reliability
Donald J. Morrow, P. E. Partner & SVP Corporate Strategy. During the course of his career, Don has held a wide range of technical and management responsibilities in the areas of system planning, control area operations, transmission operations, energy trading, maintenance scheduling, operator training, protection, distribution operations, energy management systems, and natural gas dispatch. Don originally joined Quanta Technology to start the Transmission consulting practice and oversaw its growth to become the largest team within Quanta Technology. In his current role at Quanta Technology he continues to provide consulting to transmission clients. Prior to joining Quanta Technology, he was Director of Operations at American Transmission Company (“ATC”). In that role, Don was charged with the formation of the system operations department for the startup of ATC on 1/1/2001. He was responsible for the successful operation of two control centers overseeing operations in Wisconsin, Iowa and the upper peninsula of Michigan. While at ATC, Don also served as Director of System Planning & Protection ATC. In this role, Don was responsible for the development and justification of an annual capital budget of over $300M and a ten year capital budget of over $3B.

Areas of Expertise
- System Planning
- System Operations
- Transmission Development
- NERC and RRO Reliability Standards Compliance

Experience and Background
- 31 years of experience in the electric power industry ........................................................ 1982 – 2013
- Director System Planning and Protection, American Transmission Co. ............................. 2004 – 2006
- Director System Operation, American Transmission Co. .................................................. 2000 – 2004
- Senior Director System Operations Center, Madison Gas and Electric ............................ 1992 – 2000
- Engineer (various levels), Madison Gas and Electric ........................................................ 1982 – 1992

Accomplishments and Industry Recognition
- Member IEEE
- Former Member of various NERC & MRO Committees
- Registered Professional Engineer in Wisconsin & Arkansas

Education
- BSEE – University of Wisconsin, Madison
- MBA – University of Wisconsin, Madison

Don can be contacted at dmorrow@quanta-technology.com
Novation from KCP&L and GMO to Transource Missouri

of the Iatan-Nashua 345 kV and Sibley-NE City 345kV Projects

Lanny Nickell
VP Engineering
Southwest Power Pool

Background

• KCP&L and KCP&L GMO propose to novate two projects to Transource Missouri, LLC:
  1) Iatan to Nashua 345kV line, NTC-20042
     • ~$65M, 2015 in-service, Balanced Portfolio Project
  2) Sibley to Nebraska City 345kV line, NTC-20097
     • ~$380M, 2017 in-service, Priority Project

• Transource Missouri is a subsidiary of Transource Energy, a company jointly owned by American Electric Power and Great Plains Energy Inc. (GPE)

• GPE is the parent company of KCP&L and KCP&L GMO
Sibley-NE City and Iatan-Nashua

SPP Novation Process

• Per Attachment O, Section VI.6 of the SPP OATT

  “At any time, a Designated Transmission Owner may elect to arrange for another entity or another existing Transmission Owner to build and own all or part of the project in its place subject to the qualifications in Subsections i, ii, iii, and iv above.”

• Per SPP Business Practice 7070

  “A novation is the release of the original DTO’s obligation to ensure that a project is built. After the DTO’s assignment of the right to build and the approval and execution of a novation, the new TO will have the right and obligation to build the project.”
SPP Novation Process

- Qualifications prescribed by Attachment O of OATT
  - Obtain necessary state regulatory authority
  - Meet SPP’s creditworthiness requirements
  - Sign/willing to sign the Membership Agreement as a TO
  - Meet other technical, financial and managerial qualifications as specified in SPP’s business practices

- BP 7070 requires additional information be made available for transparency purposes
  - Provided in form of a Due Diligence Review
  - Due Diligence Review performed by Quanta Technologies

Due Diligence Review

Due Diligence findings summarized in three primary areas:

1) Financing Assumptions
   - Capital cost of project essentially same for Transource as for KCP&L
   - Cost could be lower for Transource when buying power of AEP is used

2) Cost to SPP Customers
   - Approximately $5.8M savings to Transmission Customers over 40 years on a net present value basis
   - Savings due to reduced ROE and long-term debt costs

3) Project Development, Operations and Maintenance
   - Approach chosen by Transource is equivalent or superior to KCP&L
**MPSC’s Related Order**

- Missouri Public Service Commission issued orders regarding these projects on Aug. 7, 2013
- KCP&L/KCP&L GMO’s application to transfer certain assets for the projects to Transource Missouri, LLC was granted
- The Application of Transource Missouri, LLC for a Certificate of Convenience and Necessity was granted

**Next Steps and Filing Requirements**

- Present information to SPP’s Regional State Committee on Oct 28th, 2013
- Present to the SPP Board of Directors on Oct 29th, 2013
- Following Board approval, SPP will:
  - File the Novation at FERC
  - File the Formula Rate Template at FERC to incorporate Transource Missouri as a new transmission owner in SPP
- 60 day FERC filing review window begins after the Novation and Formula Rate filings
SPP Long-Term Congestion Rights Task Force Principles, FERC Guidelines, and Design

July 26 2013
John Krajewski and Gene Anderson
Task Force Co-Chairs

Outline

• Brief History
• Task Force Guiding Principles
• FERC Guidelines
• Design
• What Happens Next
• Appendix: Design Examples
Brief History

Regulatory History


FERC Rulemaking Process

Definitions and Seven Guidelines
1. Should specify a source, a sink, and a quantity
2. Should not be modified during its term (“full funding”)
3. Long-term rights resulting from upgrades: must be available to parties paying for upgrades
4. Term: at least 10 years (renewal rights will satisfy)
5. LSEs have priority in allocation
6. Transferable to entity acquiring service obligation
7. Initial allocation: auction participation not required
Key Terms

• Federal Power Act (“FPA”)
• FERC Order 681, 681-A, 681-B
• Load Serving Entity (“LSE”)
• Service Obligation

Brief History

• EPAct 2005 added a new Section 217 to the FPA
• Section 217(b)(4) of FPA: LSEs get access to “firm transmission rights (or equivalent tradable or financial rights) on a long-term basis . . . .”
• FERC implements Sec. 217 via Order 681 (July 2006)
FERC Order 681

- Order 681 (and Sec. 217 of FPA) applies to markets with financial rights – will soon apply to SPP
- SPP must file a design for firm, long-term rights
- 180 days after Integrated Marketplace commences
- Design must meet the seven guidelines in Order 681

“Firm” and “Long-term” Right

- FERC tasked with interpreting and implementing Section 217 of the FPA
- Firm: the right “must be firm as to both the ‘physical’ component of the right and the ‘financial’ component of the right.” Order 681 P 82 (“quantity and price”)
- Long-term: transmission organizations must “make available transmission rights and renewal rights that provide coverage for a period of at least 10 years.” Order 681 P 258
“Load Serving Entity”

- FERC defines LSE as “a distribution utility or electric utility that has a service obligation.” Order 681 P 34 (citing EPAct 2005 sec. 1233).
- FERC defines “service obligation” as “a requirement applicable to, or the exercise of authority granted to, an electric utility under federal, State or local law or under long-term contracts to provide electric service to end-users or to a distribution utility.” Id. (also citing EPAct 2005 sec. 1233).
Guiding Principles

- Follow FERC Guidelines
- Consistent with TCR Process
  - Protect Rights
  - No blocking
- Minimize Complexity
- Minimize Cost
- Member Flexibility
- Minimize Uplift
FERC Guidelines

• Guideline 1 – Source to sink instrument
  ✓ Long-term Congestion Rights (LTCRs) are source to sink instruments

• Guideline 2 – Should not be modified
  ✓ Once allocated LTCR will be honored as long as qualifications remain. The LTCR is input into the Annual ARR Allocation and then converted into TCR to meet full funding requirement

FERC Guidelines

• Guideline 3 – Rights made available for transmission expansions
  ✓ Will need to be justified in compliance filing.
  ✓ There is consensus that SPPs crediting process meets or exceeds the intent of this guideline and that it is reasonable to contend such in the transmittal letter of the Order 681 compliance filing to FERC
FERC Guidelines

• Guideline 4 – Available term of at least 10-years
  ✓ LTCR will have a term of a minimum of one year and will roll forward until underlying qualifications don’t exist or cancelled

• Guideline 5 – Priority for LSEs
  ✓ LTCRs first available to LSEs then non-LSEs in an iterative process

• Guideline 6 – Ability to reassign right if load obligation is transferred
  ✓ TSRs can be transferred
  ✓ Coordinated mechanism to transfer LTCR when TSR is transferred

• Guideline 7 – Initially allocated and not required to participate in an auction
  ✓ LTCR will be the result of an allocation that will converted into a TCR
LTCR Design

**LTCR Design**

- **LTCR Qualifications:**
- **LTCR Duration:**
- **LTCR Allocation:**
- **LTCR Process Timing:**
  - LTCR can be Canceled by LSE
- **LTCR Self-conversion:**
LTCR Qualifications

• Confirmed Transmission Reservations
  – From SPP’s OASIS
  – Firm
  – TSR in current operating TCR year*
  – Have renewal/roll-over right capabilities

* TCR year is June 1st through following year May 31st

LTCR Duration

• Minimum term of initial LTCR allocated product
• Rolls over as long as confirmed TSR is in place
• Yearly product
LTCR Allocation

• Priority given to Load Serving Entity (LSE)
  – First LTCR allocation iteration to LSEs only
    ▪ NITS
    ▪ Point to point TSR must have an attached attestation of the right meeting the FERC Order 681 LSE criteria
  – Second LTCR allocation iteration for Non LSE qualified transmission rights
• Awarded LTCRs fixed flows in ARR Allocation Process

LTCR Allocation

• Allocation considers 100% of qualified capacity
• Allocated on 50% of grid capability
  – Protects against the long-term unknown, helping to keep participants whole
LTCR Allocation

• Capacity held for all candidate LTCRs
  – All qualified LTCR candidates will be evaluated together
  – Identifies maximum MW value available
  – Removes obstructive behavior from LTCR process
  – Only feasible candidates awarded
• Counter flow contributions excluded
  – LTCR awards are not dependent on one another allowing opt out capability

LTCR Process Timing

• Process runs prior to Annual ARR Process
  – Late January – February
  – Single verification process for LTCRs and Annual ARRs
• Allocated LTCRs are Inputted into annual ARR Process sequence
LTCR can be Canceled by LSE

- Every year at beginning of LTCR Process
  - LTCR holder directs MW reduction in .1 MW increments
  - No penalty
  - No SPP Approval or SFT required
- LTCR is not held after being surrendered
  - Once surrendered the underlying reservation is treated like a new candidate
  - Would have same priority as other new reservations

LTCR Self-conversion

- LTCR ARR conversion to TCR is automatic
  - LTCR is yearly TCR at completion of annual process
    - 8760 hours source to sink TCR
  - Allocation design parameters reasonably assure feasibility of conversion
Annual and Monthly ARR & TCR Process

- Annual ARR Allocation same as current process with the addition of fixed flows from granted LTCRs
  - LTCRs granted will reduce ARR cap by amount received
- Annual TCR Auction same as current process
  - LTCRs automatically self convert to yearly TCR
  - LTCR TCR can be offered for sale in part or whole
- Monthly TCR Auction same as current process

Design Effects

- LTCR holder canceling will not effect others
- Potential for uplift greatly reduced
- Balances MP wants
- Manages the integrity of entire TCR Process
- Grid capacity available for Annual Rounds 1-3
**LTCR Design**

**LTCR Qualifications:**
- Confirmed TSR in current TCR year
- Has roll over rights

**LTCR Duration:**
- Current TCR year
- Rolls over with service in place
- LTCR is annual product

**LTCR Allocation:**
- Priority treatment to LSE
- Awarded LTCRs imputed as fixed flows
- Allocation cap is 100%
- Allocated on 50% of grid
- Capacity held for all candidate LTCRs
- Counter flow contributions excluded

**LTCR Process Timing:**
- Process runs prior to Annual TCR Process
- Two allocation iterations

**LTCR can be Canceled by LSE:**
- Every year beginning of LTCR Process
- LTCR is not held after opting out

**LTCR Self-conversion:**
- LTCR ARR to TCR is guaranteed

---

**Approval Schedule**

- MWG/CAWG/RTWG/ORWG September 2013
- MOPC October 15-16 2013
- RSC October 28 2013
- BOD: October 29 2013
- FERC Filing ASAP TBD
- LTCRs in place for Year Two of Integrated Market
Appendix: Design Examples
**LTCR Qualifications:**

- Confirmed Firm Transmission Reservations
  - That sources, sinks or through SPP footprint
- From SPP’s OASIS
- Active TSR that covers TCR operating year
  - June 01 to following May 31
- Have renewal/roll-over right capabilities

**LTCR Allocation Round Qualifications:**

For first allocation iteration:

- SPP NITS TSR
- SPP Point to Point TSR with attestation
  - Attestation for each TSR that the TSR is for a service obligation as defined by FERC in Order 681

For second allocation iteration:

- Every TSR that meets the LTCR qualifications
**LTCR Allocation**

- All “candidate LTCRs” are considered for the allocation
  - i.e. NO nomination for consideration occurs
- MPs select from available “LTCR” MWs to be “awarded” in 0.1 increments
- Allocated by the weighted least squares method

---

**Remember**

- Annual ARR process will follow the LTCR process
  - Two processes will together provide congestion hedge

  - Annual ARR process
    - Three rounds
    - 100% nomination
    - 100% of grid
    - Counter flow is modeled
Allocation Example: Set Up

- Seven MPs:
  - **Four LSEs** and
  - **Three non-LSEs**
- Two Settlement Locations
- 300 MWs of Transmission

The System for our Example:

```
<table>
<thead>
<tr>
<th>LSE</th>
<th>LTCR Available:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ron</td>
<td>50 MW A→B</td>
</tr>
<tr>
<td>Ana</td>
<td>50 MW A→B</td>
</tr>
<tr>
<td>Kip</td>
<td>50 MW A→B</td>
</tr>
<tr>
<td>Bob</td>
<td><strong>100 MW B→A</strong></td>
</tr>
</tbody>
</table>
```

LTCR Available for Allocation

Ron + Ana + Kip
50 + 50 + 50 = 150MW

300 = 150 limit
Bob
100 ≤ 150MW
LTCR Available for Non-LSE Allocation

Seven LTCR Candidates
1. Ron 100 MW A→B
2. Ana 100 MW A→B
3. Kip 100 MW A→B
4. Sue 100 MW A→B
5. Joe 100 MW A→B
6. Bob 100 MW B→A
7. Lee 100 MW B→A

LTCR Available:
- Ron 50 MW A→B
- Ana 50 MW A→B
- Kip 50 MW A→B
- Bob 100 MW B→A
- Sue 0 MW A→B
- Joe 0 MW A→B
- Lee 50 MW B→A

Non-LSE LTCR Available:
- Sue 0 MW A→B
- Joe 0 MW A→B
- Lee 50 MW B→A

LTCR Year 2 Method
- Round 1: Consider all LSE Candidates
  - With all “allocated” i.e. “awarded” non-LSE LTCRs inputted as fixed flow
  - Iterate over “LSE candidates” to recognize previously awarded LSE LTCRs
  - Continue to iterate until optimization solves while respecting all previously allocated LTCRs
LTCR Year 2 Method

- Round 2: Consider only non-LSE LTCR Candidates
  - LTCRs from Round 1 are inputs
    - uses “available” LTCRs as fixed
  - Iterate over all LTCR candidates to recognize previously awarded LTCRs
  - Continue to iterate until optimization solves
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EXECUTIVE SUMMARY

This report contains the results of the Regional Cost Allocation Review (RCAR) of Southwest Power Pool, Inc.’s (SPP) Highway/Byway transmission cost allocation methodology in accordance with Attachment J, Section III.D of SPP’s Open Access Transmission Tariff (OATT).

The analyses contained in this RCAR Report (the RCAR Report) were conducted based upon the recommendations of the Regional Allocation Review Task Force (RARTF) approved by SPP stakeholders in January 2012 (the RARTF Report). These analyses included the calculation of eight out of thirteen benefits approved by SPP’s Metrics Task Force (MTF), Economic Studies Working Group (ESWG), Markets and Operations Policy Committee (MOPC), as well as the Members Committee and Board of Directors in September and October 2012.

When conducting the RCAR, SPP staff applied the ten principles contained in the RARTF Report. These principles include: simplicity, acknowledgment of the “roughly commensurate” legal standard, equity over time, the use of the best quantifiable information available, consistency, transparency, stakeholder input, the use of real dollars values, and the inclusion in the review of Board-approved transmission plans with more weight being given to nearer-term projects.

Applying these principles the RCAR Report shows:

- The overall benefit to cost (B/C) ratio for the region for projects that have been issued a Notification to Construct (NTC) since June 2010 under the Highway/Byway cost allocation methodology is a 1.39, and the overall B/C ratio for projects that have been issued an NTC since June 2010 plus Board-approved transmission projects with in-service dates of ten years or less under the Highway/Byway cost allocation methodology is a 1.42.

The assessment shows that for projects that have been issued an NTC since June 2010 a total of six zones were below the .80 threshold established by the RARTF, five zones were greater than the .80 threshold but below 1.0, and the remaining five zones were above a 1.0 B/C ratio. For projects that were issued an NTC since June 2010 plus Board-approved transmission projects with in-service dates of ten years or less a total of five zones were below the .8 threshold, five zones were between the .8 and 1.0, and six zones were above the 1.0 B/C ratio. Additionally, the RARTF Report contains three additional recommendations on next steps. These include:

- That the results contained in the Report showing that five zones are below the .80 threshold for NTC projects and projects with in-service dates within ten years or less (City Utilities of Springfield, The Empire District Electric Company, Grand River Dam Authority, Lincoln Electric System, and Sunflower Electric Power Corporation) be incorporated in SPP’s current ITP10 assessment to consider whether the “[a]cceleration of planned upgrades” or the “[i]ssuance of NTCs for selected new upgrades” can provide these five zones with remedies to raise their B/C ratio above the threshold.
That a second RCAR process [RCAR II] be commenced and work in parallel with the current ITP10 assessment which is expected to be completed in January 2015. Through this process, SPP staff can follow the directions contained in Sections 4.2 and Section 5.1 of the RARTF Report by utilizing the current ITP10 assessment and a RCAR II study as a means to understand whether any proposed remedies approved in the ITP10 will provide remedies to zones below the .80 threshold. If RCAR II does not show that adequate remedies exist, SPP staff can use the results of a RCAR II Report to analyze additional potential remedies for any zone below the threshold. The report will be completed either (i) shortly after the ITP10 is completed, if cost estimates are to be used in the RCAR II analysis; or (ii) shortly after the completion of the competitive solicitation process, if the RFP results are to be used in the RCAR II analysis.

That the RARTF begin a process to evaluate “lessons learned” from SPP’s first RCAR Report and finalize “suggested improvements” to the RCAR process by the January 2014 stakeholder meeting cycle. This recommendation will allow any improvements to be incorporated into the RCAR II process and will be in accord with Section 7.1 of the RARTF Report.
BACKGROUND

In approving the Highway/Byway cost allocation methodology for the Southwest Power Pool, Inc. (SPP) Regional Transmission Organization (RTO), the Federal Energy Regulatory Commission (FERC) also approved a requirement that SPP conduct a review of the “reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every three years.”¹ This review is required to “determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct (NTC) issued after June 19, 2010 to each pricing Zone within the SPP Region.”² Thus, the purpose of this analysis is to measure the “cost allocation impacts” of SPP’s Highway/Byway methodology by zones. The review is hereinafter referred to as the “Regional Cost Allocation Review” or “RCAR”.

SPP’s Open Access Transmission Tariff (Tariff or OATT) specifically requires that “the Markets and Operations Policy Committee (MOPC) and Regional State Committee (RSC) will define the analytical methods to be used” in conducting the Regional Cost Allocation Review.³ As a result, the Regional Allocation Review Task Force (RARTF) was created as part of the SPP stakeholder process to develop the “analytical methods” used for the review.

The RARTF membership is composed of three representatives from the RSC, three SPP Members, and one member from the independent SPP Board of Directors. The members of the RARTF were jointly appointed by then RSC President Jeff Davis and then MOPC Chairman Bill Dowling who were serving in these capacities at the time of the creation of the RARTF. The appointed members of the RARTF are:

<table>
<thead>
<tr>
<th>RARTF Members</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Chairman Michael Siedschlag</td>
<td>Nebraska Public Review Board</td>
</tr>
<tr>
<td>Vice-Chairman Richard Ross</td>
<td>American Electric Power</td>
</tr>
<tr>
<td>Commissioner Thomas Wright</td>
<td>Kansas Corporation Commission</td>
</tr>
<tr>
<td>Commissioner Olan Reeves</td>
<td>Arkansas Public Service Commission</td>
</tr>
<tr>
<td>Bary Warren</td>
<td>The Empire District Electric Company</td>
</tr>
<tr>
<td>Philip Crissup</td>
<td>Oklahoma Gas and Electric Company</td>
</tr>
<tr>
<td>Harry Skilton</td>
<td>SPP Board of Directors</td>
</tr>
</tbody>
</table>

Pursuant to the mandate in the RARTF Charter, the RARTF prepared a Report that included a recommendation as to how to define the “analytical methods” to be used in the Regional Cost Allocation Review. In January 2012, the RARTF Report was approved unanimously by the RARTF, the RSC, the MOPC, and SPP’s Members Committee. The RARTF Report was also approved by the SPP Board of Directors.

¹ Attachment J, Section III.D.1 of SPP’s OATT.
² Attachment J, Section III.D.2 of SPP’s OATT.
³ Attachment J, Section III.D.4(i) of SPP’s OATT.
SECTION 1: OVERVIEW OF THE RARTF AND RCAR REVIEW

1.1 Overview of SPP Tariff Requirements to Perform the RCAR Review

Attachment J, Section III.D to the SPP OATT establishes a four-step process for the Regional Cost Allocation Review. These steps are:

**Step 1:** One year prior to each three-year planning cycle (starting in 2013) the MOPC and RSC will define the analytical methods to be used to report under this Section III.D and suggest adjustments to the RSC and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint.  

**Step 2:** For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades with NTCs issued after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the RSC shall determine the cost allocation impacts utilizing the analysis specified in Section III.8.e of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J to the SPP OATT.

**Step 3:** The Transmission Provider shall review the results of the cost allocation analysis with SPP’s Regional Tariff Working Group (RTWG), MOPC, and the RSC. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.

**Step 4:** The Transmission Provider shall request the RSC provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.

1.2 Overview of RARTF Charter

In addition to the requirements contained in the SPP’s OATT, the RARTF’s Charter contained additional work and deliverables for the RARTF. Specifically, the Charter states:

The RARTF will make final recommendations to the MOPC and the RSC regarding the analytical methods to be used to review the

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4 Id.
5 Attachment J, Section III.D.2 of SPP’s OATT.
6 Attachment J, Section III.D.3 of SPP’s OATT.
7 Attachment J, Section III.D.4 of SPP’s OATT.
reasonableness of the regional allocation methodology for the approval of both the MOPC and RSC. In addition to developing the analytical methods to be used in the analysis, the RARTF will provide SPP Staff guidance as to the Task Force’s expectation for the threshold for an unreasonable impact or cumulative inequity. The RARTF shall prepare and issue the report by December 20, 2011.

Additionally, the Charter contained a list of key deliverables for the RARTF which states:

The RARTF scope of work and key deliverables include the following:

1. Development of and recommendation for a methodology to be used to determine the current and cumulative long-term equity/inequity of the currently effective cost allocation for transmission construction/upgrade projects on each SPP Pricing Zone and/or Balancing Authority.

2. Develop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority.

3. Develop a list of possible solutions for SPP staff to study for any unreasonable impacts or cumulative inequities on an SPP Pricing Zone or Balancing Authority.

4. Final report containing such recommendations to be prepared and issued by December 20, 2011.

1.3 Overview of Legal Standards

Pursuant to the RARTF Charter, the RARTF has been tasked to “[d]evelop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority.” In researching and discussing how to establish a threshold, SPP staff and the RARTF reviewed and considered the legal significance and relevance of the Seventh Circuit decision in the Illinois Commerce Commission (ICC) v. FERC. In this review, the RARTF found that the term "roughly commensurate" was used for the first time by the Seventh Circuit in the ICC v. FERC case. Other than the ICC case, the term "roughly commensurate" has never been used in an appellate case reviewing a FERC order, nor has FERC ever used the term prior to the ICC remand. Since the ICC opinion was issued, FERC

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8 576 F.3d 470 (7th Cir. 2009).
cited the Seventh Circuit's roughly commensurate standard in approving SPP's Highway/Byway cost allocation methodology,9 Mid-continent Independent Transmission System Operator, Inc’s (MISO) multi-value project (“MVP”), and California Independent System Operator Corporation's convergence bidding proposal, although none of these orders elaborates on the exact meaning of "roughly commensurate." Additionally, FERC, subsequent to the establishment of the RARTF, used the term in Order No. 1000,10 as well as FERC’s Orders on Rehearing for SPP’s Highway/Byway cost allocation methodology11 and on MISO’s MVP cost allocation methodology. Specifically, as quoted by FERC in its October 20, 2011 Order on Rehearing, in the Seventh Circuit stated that the legal standard is that “an articulate and plausible reason to believe that the benefits are at least roughly commensurate with those utilities.”12

The RARTF noted a couple of important aspects of the orders from the Seventh Circuit and FERC dealing with the “roughly commensurate” standard. First, it appears that “roughly commensurate” is not “cost-beneficial” so that something less than a 1.0 B/C ratio may comply with the standard and that FERC has said that “the question becomes not whether the Highway/Byway methodology matches cost to the benefits on a utility-by-utility or zone-by-zone basis, but whether it will provide sufficient benefits to the entire SPP region to justify a regional allocation of costs.”13

Additionally, the RARTF notes that the ICC case and the precedent on which the Seventh Circuit relied in its decision did articulate certain principles that a cost allocation method must satisfy. These include:

- A cost allocation mechanism may track costs less than perfectly.
- A cost allocation mechanism need not calculate benefits to the last penny or, for that matter, to the last million or ten million or perhaps hundred million dollars.
- A pricing scheme may not require payments from those that derive no benefits or benefits that are trivial in relation to the costs.
- Rates must reflect, to some degree, the costs actually caused by the customer who must pay them.
- Benefits do not necessarily need to be quantified, but there must be an articulate and plausible reason to believe that benefits received by customers are at least roughly commensurate with the costs allocated to customers.
- FERC must compare the costs assessed against a party to the burdens imposed or benefits drawn by that party.

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The RARTF considered the *ICC v. FERC* and related cases, as well as subsequent FERC orders citing the 7th Circuit’s “roughly commensurate” standard, in the task force’s deliberation and conclusions found in the RARTF’s report. The RARTF’s consideration of the “roughly commensurate” standard is reflected in the RCAR Report as well.

### 1.3.1 Legal Rulings Subsequent to the Overview of Legal Standards

Since the RARTF finalized its report, the Seventh Circuit issued an opinion that further clarified its earlier decision.\(^\text{14}\) In the decision, the court upheld FERC’s approval of MISO’s cost allocation for “MVP” projects, which allocates costs “in proportion to each utility’s share of the region’s total wholesale consumption of electricity,”\(^\text{15}\) because the projects “involve high-voltage lines that transmit electricity over long distances, will benefit all members of MISO and so the projects’ costs should be shared among all members.”\(^\text{16}\) The court noted that there are “limitations on calculability [of benefits] that the uncertainty of the future imposes,”\(^\text{17}\) and that some benefits of the MVP projects (the need for fewer local running reserves because power can be more readily obtained from elsewhere) are such that “[i]t’s impossible to allocate these cost savings with any precision across MISO members.”\(^\text{18}\) The court found that the long-distance lines will make moving cheaper power easier, and “[t]here is no reason to think these benefits will be denied to particular subregions of MISO, and “[o]ther benefits of MVPs, such as increasing the reliability of the grid, also can’t be calculated in advance, especially on a subregional basis, yet are real and will benefit utilities and consumers in all of MISO’s subregions.”\(^\text{19}\) Finally, responding to arguments that FERC’s analysis of benefits was crude, the court said that “if crude is all that is possible, it will have to suffice.”\(^\text{20}\) Quoting its earlier decision, it said that FERC simply needs “an articulable and plausible reason to believe that the benefits are at least roughly commensurate” with utilities’ shares of regional energy consumption and “[f]or that matter it can presume [as it did in this case] that new transmission lines benefit the entire network by reducing the likelihood or severity of outages.”\(^\text{21}\)

In short, the Seventh Circuit’s recent decision indicates that its previously articulated requirement that FERC demonstrate that cost allocation is “roughly commensurate” with benefits is tempered by “limitations on calculability” and the inability to determine benefits with precision over long time horizons given the “uncertainty of the future.”

Just as the RARTF acknowledged in its January 2012 report that difficulties exist in calculating benefits, so did the Seventh Circuit in its June 7, 2013 opinion. Although, the Seventh Circuit

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\(^\text{15}\) Id. at 7.

\(^\text{16}\) Id. at 9.

\(^\text{17}\) Id. at 11.

\(^\text{18}\) Id. at 12.

\(^\text{19}\) Id. at 12-13.

\(^\text{20}\) Id. at 13.

\(^\text{21}\) Id. at 13 (quoting *Illinois Commerce Commission, et al. v. FERC*, 576 F.3d, 470, 477 (7th Cir. 2009)).
acknowledges that the calculation of benefits for transmission facilities has “limitations on calculability” given the “uncertainty of the future” and even went so far as to say that “if crude is all that is possible, it will have to suffice,” the RCAR Report attempts to go beyond a mere crude analysis. Instead, the RCAR analyses as conducted per the direction given to SPP staff by the RARTF as well as the input from SPP’s stakeholder process — including the work of the Metrics Task Force (MTF) — attempts to calculate the costs and benefits of SPP’s Highway/Byway with the most up-to-date information.

1.4 Cost Allocation Challenges for Transmission Upgrades

The allocation of costs for public projects with significant and widespread public benefits is very challenging and difficult. This is particularly true for electric transmission projects, as has been stated by the FERC:

Determining the costs and benefits of adding transmission infrastructure to the grid is a complex process, particularly for projects that affect multiple systems and therefore may have multiple beneficiaries. At the same time, the expansion of regional power markets and the increasing adoption of renewable energy requirements have led to a growing need for transmission projects that cross multiple utility and RTO systems. There are few rate structures in place today that provide the allocation and recovery of costs for these intersystem projects, creating significant risk for developers that they will have no identified group of customers from which to recover the cost of their investment.22

The RARTF noted the difficulties of implementing cost allocation methods for transmission projects. Because of these challenges the RCAR Report reflects the reasoned, sound, and well established methods established by the RARTF and endorsed by SPP Stakeholders in January 2012.

SECTION 2: SPP’S HIGHWAY/Beway COST ALLOCATION METHODOLOGY

2.1 Highway/Byway Summarized

The SPP RSC established the Highway/Byway cost allocation methodology that was subsequently approved by FERC.23 The Highway/Byway methodology assigns 100% of all 300 plus kV transmission upgrades’ Annual Transmission Revenue Requirement (ATRR) to the SPP zones on a regional basis using the Load Ratio Share (LRS), as a percentage of the whole of regional loads, of each zone multiplied by the total ATRR of the new upgrade. New upgrades

22 Transmission Planning Processes Under Order No. 890, Notice of Request for Comments at 5, Docket No. AD09-8-000 (Oct. 8, 2009).
with a voltage rating between 100 kV and 300 kV are allocated 33% to all zones in the region on a LRS basis and 67% to the host zone’s Transmission Customers (TCs). New upgrades under 100 kV are allocated 100% to the TCs of the host zone.

**Figure 2.1**
Highway/Byway Cost Allocation Overview

<table>
<thead>
<tr>
<th>Upgrade Voltage</th>
<th>Region Pays</th>
<th>Local Zone Pays</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 kV and above</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>above 100 kV and below 300 kV</td>
<td>33%</td>
<td>67%</td>
</tr>
<tr>
<td>100 kV and below</td>
<td>0%</td>
<td>100%</td>
</tr>
</tbody>
</table>

The ATRRs assigned to the zones are collected from their respective TCs using the previous year’s 12 month Coincident Peak LRS.

Cost allocation of new construction is the focus of Attachment J of the SPP OATT. The recovery of the ATRR is through Schedule 11 of the SPP OATT and booked by each zone in Attachment H of the SPP OATT. Additionally, these costs are offset by Point to Point (PTP) revenues collected by SPP for transmission service sold on the SPP system. Once these PTP revenues are collected, these revenues offset the amount zones pay under the Highway/Byway as provided for in Attachment L of the SPP OATT.

**SECTION 3: RECOMMENDED REVIEW METHODOLOGY**

3.1 Principles that Guided How SPP Staff Conducted the RCAR Review

Following research, stakeholder input and extensive discussion, the RARTF’s Report contained 10 key principles for SPP staff to follow when conducting the RCAR analyses. The 10 principles adopted by the RARTF are as follows:

1. **Simplicity** – The Regional Cost Allocation Review should be as simple as possible so that the report has a distinct understandability.

2. **Roughly Commensurate** – The Regional Cost Allocation Review should use the principle of “roughly commensurate” as the legal framework and a guidepost when evaluating the reasonable and long-term equity of SPP regional transmission upgrades under the Highway/Byway cost allocation methodology.

3. **Use Best Information Available** – The Regional Cost Allocation Review should use the most up to date and best available information for the review.

4. **Consistency** – The Regional Cost Allocation Review should be consistent.
(5) **Transparency** – The assumptions, inputs, and data used in the Regional Cost Allocation Review should be transparent to SPP stakeholders.

(6) **Stakeholder Input** - The assumptions, inputs, and data used in the Regional Cost Allocation Review should be vetted through SPP’s open and transparent stakeholder process.

(7) **Real Dollars** – The Regional Cost Allocation Review Analysis and Report should use dollar values of the year in which the report will be issued.

(8) **Consideration Given to Certain Plans** – The Regional Allocation Cost Review should give considerations to certain plans that have been approved by the SPP Board of Directors. This includes projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.²⁴

(9) **More Weight Should be Given to Nearer Term Projects than Future Projects** – Although the Regional Cost Allocation Review should give consideration to certain plans approved by the SPP Board of Directors, less weight should be given to plans which have been given an ATP as opposed to an NTC.

(10) **Equity Over Time** – The Regional Cost Allocation Review should adhere to the long term view of the Highway/Byway cost allocation methodology to strive toward regional cost allocation equity over time.

### 3.2 Regional Cost Allocation Review Methodologies

Because the RCAR is for projects that will be built under SPP’s Highway/Byway cost allocation methodology, the RARTF recommended that certain projects and plans which are approved by the Board of Directors be evaluated. However, due to the less certain nature of the some projects, the RARTF recommended that emphasis of the review be placed on Board of Director approved plans that have in-service dates of ten years or less.

Since both a too conservative approach and a too broad approach to analyzing benefits of transmission projects can be problematic, the RARTF proposed using a single methodology for assessing the benefits and costs of under SPP transmission projects under the Highway/Byway cost allocation methodology. With this methodology, SPP staff was directed to conduct two evaluations to report and assess the impacts of the Highway/Byway cost allocation methodology. The two evaluations would include an assessment of:

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²⁴ At the time the RARTF was developing the methods under which the RCAR was to be conducted; SPP used a concept known as ATPs. Since the approval of the RARTF report, the term ATP is no longer used. Although the term ATP is no longer used, SPP staff still followed Principle 8 by including projects with an in-service date of ten years or less per the RARTF report.
(1) **NTCs:** All SPP projects that have been issued an NTC since June 2010;\(^\text{25}\) and

(2) **NTCs and Projects within 10 years:** All SPP projects that have been issued an NTC\(^\text{26}\) since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.

### 3.3 RARTF Recognition of Weighting Given to Projects without NTCs.

When conducting the RCAR described in Section 3.2(2) above, the RARTF recommended that projects with an in-service of 10 years or less, but without NTCs, be considered in the review. However, in considering these projects, the RARTF recommended a reduced weighting of the valuation of the costs and benefits at seventy-five percent (75%) of the total value. The RARTF made this 0.75 weighting recommendation due to the less certain nature of these projects as well as their costs and benefits.

### 3.4 RARTF Recommended Baseline for the Regional Cost Allocation Review

Because the RCAR is for projects that will be built under SPP’s Highway/Byway cost allocation methodology, the RARTF recommended that the baseline used to measure the benefits should include all projects which were in-service or received an NTC prior to June 2010. The RARTF recommended that the baseline used in the first RCAR should be the same baseline used in all future reviews.

### 3.5 RARTF Recommended Calculation of Benefits to Cost Ratios

The RARTF recommended using a methodology in which each assessment uses the aggregate value of dollars for all projects studied under the SPP Highway/Byway cost allocation methodology in dollars current to the year the review is conducted. Using the aggregate value of dollars instead of the average B/C ratios provides a more comprehensive view of the total benefits to individual zones over the course of multiple studies.

### 3.6 RARTF Recommends Use of a 40-Year Project Evaluation

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\(^\text{25}\) Attachment J, Section III.D.2 of SPP’s OATT, requires that the Regional Allocation Review “shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010.” The RARTF viewed that the report in Section 3.2(1) will comply with the Tariff. However, the RARTF believed that additional analyses needed to be considered by SPP stakeholders in light of the fact the Highway/Byway applies to future projects that have yet to receive an NTC. Hence the RARTF recommended additional studies as stated in 3.2(2) so that the focus is not exclusively on the first projects that fall under SPP’s Highway/Byway. As FERC noted in the October 20, 2011 Order on Rehearing, “the Priority Projects are just one set of projects to be constructed over the years of transmission development in SPP.” *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 32 (2011).

\(^\text{26}\) The RARTF recommended that Conditional Notices to Construct or CNTCs are considered NTCs and therefore should be included and evaluated as a NTC in the RCAR Report.
To remain consistent with SPP’s OATT, the RARTF recommended using a 40-year assessment to evaluate all transmission projects in the RCAR. Pursuant to SPP’s OATT, the RARTF recommended that the last 20 years of benefits should have a terminal value.

3.7 RARTF Recommendation on the Calculation of Costs

When conducting the RCAR the RARTF recommended using the most up to date ATRR for each zone.

3.8 RARTF Recommendation on Benefits to be Calculated

The RARTF recommended that the set of benefit categories listed below in this section be used in the RCAR process. The RARTF further recommended that before the RCAR is conducted, the development of specific metrics that quantity the benefits in dollars using the procedures defined by the MOPC through the work of the Economic Studies Working Group (ESWG) be completed. For metrics without dollar amounts but in other terms (MW, MWh, Tons, etc.), the RARTF recommended that the ESWG should consider recommending a range of values that can be used to monetize those metrics without hard dollar values.

As part of the benefit evaluation, the RARTF recommended the most conservative or lowest number in any range provided by the ESWG will be used in the RCAR. For those metrics that the ESWG does not endorse monetizing, the ESWG would not provide a monetized value for use in the RCAR process. In defining these benefits, the ESWG and the MOPC should also develop a method to distribute these benefits by SPP zones. For those benefits that cannot be distributed to all zones but shared by fewer than all zones, if the benefited zones agree to an alternative method for allocating the benefits, then the agreed upon method will be used.

When conducting the RCAR, the RARTF recommended using the list of benefits provided in the RARTF Report to assess the B/C ratio. Additionally, the RARTF recommended that the Regional Cost Allocation Review should consider the use of any additional benefits that may be defined and quantified in dollar values or can be converted into dollar values by the EWSG and approved by the MOPC.

The list of benefits the RARTF recommended be used in the RCAR were:

- **Adjusted Production Cost (APC) Benefits** – APC captures the monetary cost associated with fuel prices, run times, grid congestion, ramp rates, energy purchases, energy sales, and other factors that are directly related to energy production by generating resources in SPP. APC is calculated by adding a zones production cost to the zones purchases and subtracting out their sales.

- **Positive Impact on Capacity Required for Losses** – This captures a value for the generation capacity that may no longer be required due to a reduction in losses.

- **Improvements in Reliability** – There are five parts to improvements in reliability:
○ Benefits of avoided projects which are no longer needed due to additional transmission development.

○ From major generation centers within SPP to key delivery points on the boundary of SPP. This category relates to export capability improvements.

○ From key external receipt points at the boundary of SPP to load centers within SPP. This category relates to import capability improvements.

○ From key external receipt points at the boundary of SPP to key delivery points on the boundary of SPP. This category relates to improvements in the ability of SPP to accommodate wheel-through transactions.

○ Reliability projects provide more value than just reliability; reliability projects can provide measurable economic benefit. The ESWG will continue to develop this portion of the reliability metric in early 2012.

- **Remedy Benefits** – The value of previously approved remedies will be captured as a benefit during all following Regional Allocation Reviews.\(^\text{27}\)

- **Reduction of Emission Rates and Values** – This metric addresses the analytical deficiency and quantifies the changes in mercury emissions. This metric also quantifies the changes in SO\(_2\), NO\(_X\), and CO\(_2\) emissions so they may be represented as stand-alone values, separate from APC.

- **Reduced Operating Reserves Benefits** – As additional transmission is put in service it may reduce the amount of operating reserves needed in the SPP footprint. This metric captures the value of reduction in reserves.

- **Improvements to Import/Export Limits** – This metric quantifies the change in ATC that corresponds to an alternative topology.

- **Public Policy Benefits** – This metric captures the value of meeting the requirements of public policy.\(^\text{28}\)

\(^{27}\) This benefit would only be applicable in subsequent reviews for any mitigation that was implemented as a result of a previous Regional Cost Allocation Review.

\(^{28}\) The RARTF notes that although it is SPP’s current practice is to plan for public policy objectives, under FERC Order No. 1000 SPP is required to plan for public policy objectives. Consequently, the evaluation and measurement of these benefits are consistent with the requirement to plan for them.
3.9 RARTF Recommendation on Assumptions to be Used

The RARTF recommended that the assumptions used in the RCAR should be vetted through SPP’s open and transparent stakeholder process.

SECTION 4: REPORT THRESHOLDS

4.1 RARTF Recommended a Remedy Threshold

Pursuant to the RARTF Charter, the RARTF recommended that a threshold be established to determine when it is warranted for SPP staff to study possible remedies to address an imbalance based upon the results of a RCAR. The threshold set by the RARTF defined when SPP staff should study a zonal mitigation. If a zone is determined to be below this threshold, mitigation may be necessary to create equity.

The RARTF recommended that a threshold be set at a 0.8 B/C ratio for projects that are a part of the assessment report stated in Section 3.2(2) above. Section 3.2(2) calls for a report on “all SPP projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.”

The RARTF found that during the first Regional Cost Allocation Review, few, if any, projects will actually be in service; and that consideration should be given to all Board of Directors approved projects contained in plans that have an in-service date of ten years or less from the year of the report. The importance of considering future plans is highlighted by FERC’s Order on Rehearing in Docket No. ER10-1069-001 in which FERC noted that the Highway/Byway cost allocation methodology will be applied to projects other than the Priority Projects.

4.2 RARTF Recommendation for Zones Above Threshold but Below 1.0 B/C

Pursuant to the RARTF Charter, the RARTF recommended that a threshold be established to determine when it is warranted that SPP staff study possible remedies as stated in Section 4.1.

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29 The RARTF notes that the 0.8 B/C ratio recommended in this report based upon the ESWG and SPP Stakeholder approving a method to measure the benefits listed in Section 3.8. Additionally, the RARTF notes that the 0.8 B/C may not be appropriate or practical if a Review produces a B/C ratio for all projects lower than anticipated by the RARTF.

30 The RARTF Report noted that the Tulsa Reactor from SPP’s Priority Projects was at the time the only project expected to be in service by June 2012. As of the drafting of the RCAR report only 48 of the 298 Highway/Byway funded upgrades that are subject to the RCAR review are in service. These upgrades account for only 3.2% of the cost of Highway/Byway funded transmission upgrades and only 1.8% of the new miles of transmission facilities that are included in the RCAR study.

31 As FERC noted in the October 20, 2011 Order on Rehearing, “the Priority Projects are just one set of projects to be constructed over the years of transmission development in SPP.” Southwest Power Pool, Inc., 137 FERC ¶ 61,075 at P 32 (2011).
Additionally, the RARTF recommended that any Regional Cost Allocation Review, which shows that a zone is above the 0.8 threshold in Section 4.1, but below a 1.0 B/C ratio, should be used and considered as a part of SPP’s transmission planning process in the future.

**SECTION 5: POTENTIAL REMEDIES TO BE STUDIED**

**5.1 RARTF Recommended Zonal Remedies**

If the results for a zone following a RCAR are below the threshold in Section 4.1, the RARTF recommended that the SPP staff evaluate and recommend possible mitigation remedies for the zone. In Figure 5 of the RARTF Report, the RARTF provided a list of mitigation remedies that SPP staff should consider for study and to be made part of the report. The purpose of the evaluations is to determine potential remedies that bring the zone above the threshold.

The potential list of remedies recommended by the RARTF, which were listed in order of preference, that SPP staff could evaluate include, but are not limited to:

<table>
<thead>
<tr>
<th>Remedy</th>
<th>Entity with Authority/Duty to Implement</th>
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</thead>
<tbody>
<tr>
<td>(1) Acceleration of planned upgrades;</td>
<td>SPP BOD</td>
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<tr>
<td>(2) Issuance of NTCs for selected new upgrades;</td>
<td>SPP BOD</td>
</tr>
<tr>
<td>(3) Apply Highway funding to one or more Byway Projects;</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
<tr>
<td>(4) Apply Highway funding to one or more Seams Projects;</td>
<td>RSC, SPP BOD &amp; FERC</td>
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<tr>
<td>(5) Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or a lack of benefits to a zone;</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
<tr>
<td>(6) Exemptions from cost associated with the next set of projects;</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
<tr>
<td>(7) Change Cost Allocation Percentages.</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
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</table>

**SECTION 6: STAKEHOLDER DEVELOPMENT OF MONITIZED BENEFITS**

**6.1 Formation of the Metrics Task Force**

After the RARTF Report was approved by the MOPC, RSC, Members Committee and Board of Directors, the ESWG established the MTF to address the monetization of benefit metrics for the RCAR. The MTF was commissioned to meet as needed to develop tangible dollar oriented measures and metrics for use in economic evaluations as identified by the RARTF. The MTF was given direction to address these categories of benefits and any others that could be monetized:

- **Reduced Capacity Reserve Requirements** - as measured by reduced capacity margin (reserve) requirements. Capital cost impacts have been previously identified therefore the
group would focus on a methodology for calculating how transmission improvements would reduce reserves.

- **Improvements in Reliability** - improvements other than cost reductions from the elimination or delay of reliability upgrades which have previously been identified.

- **Improvement in Import/Export Limits** - develop metrics that monetize increasing the import and export limits at the SPP borders.

- **Public Policy Benefits** - develop methods and/or metrics for monetizing the benefits associated with those projects that are identified as Public Policy Projects.

- **Reduced Operating Reserve Requirements** - develop metrics or methods that monetize the benefits associated a reduced operating reserve requirement in SPP.

- **Other benefits that can be monetized at the recommendation of the Task Force**

The MTF was composed of the following members:

<table>
<thead>
<tr>
<th>MTF Members</th>
<th>Company</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kip Fox</td>
<td>American Electric Power</td>
</tr>
<tr>
<td>Roy Boyer</td>
<td>Xcel Energy Services, Inc.</td>
</tr>
<tr>
<td>Mike Collins</td>
<td>Oklahoma Gas and Electric Company</td>
</tr>
<tr>
<td>Paul Dietz</td>
<td>Westar Energy, Inc.</td>
</tr>
<tr>
<td>Tom Hestermann</td>
<td>Sunflower Electric Power Corporation</td>
</tr>
<tr>
<td>Greg Sweet</td>
<td>The Empire District Electric Company</td>
</tr>
<tr>
<td>Mitchell Williams</td>
<td>Western Farmers Electric Cooperative</td>
</tr>
</tbody>
</table>

The MTF scope of work and key deliverables included the following:

- A recommendation on which of the benefits identified above can be quantified in dollars.

- Methodologies for the benefits identified above, including the allocation of the benefit to each SPP Zone (Reference the Southwest Power Pool Open Access Transmission Tariff, Attachment H, Section I, Table 1). An estimate of the effort to calculate the benefits identified above.

- A list of any issues identified from their efforts or any additional direction needed from other working groups.

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32 Hannes Pfeifenberger and Kamen Madjarov from the Brattle Group were engaged to support the MTF: (1) to document the status of the current effort, including the extent to which different metrics have been specified and the quantification/monetization efforts that have been developed; (2) to identify possible overlaps between the specified metrics to avoid double counting of benefits; (3) to identify gaps to the extent which already-selected metrics do or do not completely capture the specified types of transmission benefits; (4) to identify any remaining gaps in the range of potential transmission benefits; and (5) to develop metrics to address the identified gaps.

• A plan for gaining consensus on the metric assumptions and methodologies.
• Progress updates at ESWG meetings.
• A written report containing such recommendations, was to be completed by MTF no later than the July, 2012 ESWG meeting.

6.2 Metrics Task Force Development of Benefit Metrics

At the conclusion of their work, the MTF submitted a final report (MTF Report) to the ESWG on September 13, 2012. The MTF provided the ESWG with a Report that contained a full analysis of the “wide-range of benefit metrics” that had been discussed and vetted through “multiple open and transparent stakeholder meetings.”

The MTF Report contained the following summary of the Task Force’s efforts:

The MTF approached its task as a brainstorming effort followed by refining the most promising alternatives. Members contributed ideas based on existing metrics from MISO, PJM, NYISO, ERCOT, member companies, and industry experience, as well as new ideas provided by the Brattle Group consultants. During the month of March 2012, the MTF identified 28 different ideas for metrics to be evaluated. After review and debate by the MTF, the list was narrowed down to approximately 13 metrics that would be reviewed, analyzed and further developed in order to provide a meaningful update to the ESWG and MOPC in July of 2012. Metrics that did not make it past the brainstorming phase were eliminated for one or more of the following reasons: the idea was not sufficiently developed to proceed further; there were no tangible dollars associated with the metric; the metric would be difficult, if not impossible, to calculate with current tools; or the metric was essentially a duplicate of an existing metric.

At the conclusion of the effort the MTF identified five (5) metrics that are currently used by SPP in the ITP process, eight (8) new metrics that the MTF recommends be calculated as part of the Regional Cost Allocation Review, and nine (9) other metrics that received significant consideration but have not yet gained enough consensus amongst the MTF or cannot currently be monetized for inclusion in the Regional Cost Allocation Review.

34 The MTF Report is posted on SPP’s website at: http://www.spp.org/publications/20120913%20MTF%20Report%20approved.pdf
The most important aspect of the metrics to be developed is that the metrics should be able to provide “hard dollar” impacts of transmission to rate payers. In terms of this report, “hard dollar” means that each recommended metric must be able to provide incontrovertible evidence that a benefit will result in lowering of the overall cost to a rate payer. As part of this test, the MTF reviewed the metrics through the open SPP stakeholder meetings, transmission summits, and public postings, provided progress updates to the Cost Allocation Working Group (CAWG) to gather their feedback on the acceptability of the metrics being proposed, and sought feedback from the Chair and Vice-Chair of the original RARTF to reasonably assure that the MTF was addressing the metrics the RARTF recommended in the RARTF Report.

Due to the short amount of time before the Regional Cost Allocation Review will commence, the MTF concentrated on those metrics that could be reasonably implemented for the first Regional Cost Allocation Review. Section 9 of this report identifies additional metrics the Regional Cost Allocation Review team may want to consider especially after the Integrated Marketplace goes live in March of 2014 or in the second Regional Cost Allocation Review.

In their Report, the MTF recommended that a total of thirteen (13) monetized benefit metrics be utilized in the RCAR process. Of those 13 metrics; 5 were benefit metrics previously used in the Integrated Transmission Planning (ITP) process; and 8 were benefit metrics newly developed by the MTF.

6.3 Stakeholder Approval of Metrics Task Force’s Development of Benefit Metrics

At the September 13, 2012 meeting of the ESWG, the MTF presented the MTF Report. After the presentation of the MTF Report, the Report was amended and approved by the ESWG and sent on to the MOPC for approval.35 At the October 16-17, 2012 MOPC meeting the MTF Report was presented for approval. After a presentation of the Report, the MOPC approved the Report.36 Later in the month, the MTF Report was presented to the SPP Board of Directors and Members Committee on October 30, 2012. After a presentation of the Report, the Members

36 See Agenda Item 12 in the MOPC October 16-17, 2012 minutes posted on SPP’s website at: http://www.spp.org/publications/MOPC%20Minutes%202012%20Attachments%20October%202012.pdf
Committee approved the metrics unanimously followed by the Board of Directors’ approval of the Report.\textsuperscript{37}

After the MTF benefit metrics were approved by SPP’s stakeholder process, most of these benefits were included in the RCAR analyses. Section 7.5 below discusses which metrics developed by the MTF that were used in the RCAR.

**SECTION 7: RESULTS OF THE RCAR**

7.1 Summary of Benefits and Costs

Figures 7.1 and 7.2 summarize the 40-year present values of the estimated benefit metrics and costs (in 2013 dollars) and the resulting B/C ratios by SPP zone.\textsuperscript{38} Per the direction of the RARTF, the RCAR review valued the suspended NTCs by weighting their benefits and cost at 75\% (see Section 7.3 below). Figure 7.1 summarizes the 40-year present values of the benefits and costs of NTC projects (including suspended NTCs). Figure 7.2 shows the 40-year present value of the benefits and costs of the NTC projects (including suspended NTCs) plus all projects that have received an Authorization to Plan (ATP) and have an in-service date within 10 years.

Zones with a B/C ratio below the 0.8 threshold are marked with a red dot. For these zones, the additional amount of benefits needed to bridge this “gap” and achieve a B/C ratio of 0.8 are shown in the last two columns (also in 2013 dollars).

\textsuperscript{37} See Summary of Action Items no. 9 in the Board of Directors October 30, 2012 Minutes posted at: http://www.spp.org/publications/BOD103012.pdf

\textsuperscript{38} A list of RCAR study assumptions is contained in Appendix 3 to this report
### Figure 7.1
Estimated 40-year Present Value of Benefit Metrics and Costs
(NTC Projects + Suspended NTCs at a 75% Weight)

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### Figure 7.2
Estimated 40-year Present Value of Benefit Metrics and Costs
(NTC Projects + Suspended NTCs at a 75% Weight + ATP Projects within 10 Years at a 75% Weight)

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<td>$2</td>
<td>$18</td>
<td>$72</td>
<td>$26</td>
</tr>
<tr>
<td>SUNC</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$30</td>
<td>$0</td>
</tr>
<tr>
<td>SWPS</td>
<td>$2,077</td>
<td>$72</td>
<td>$13</td>
<td>$47</td>
<td>$564</td>
<td>$0</td>
</tr>
<tr>
<td>WEFA</td>
<td>$24</td>
<td>$2</td>
<td>$2</td>
<td>$11</td>
<td>$148</td>
<td>$14</td>
</tr>
<tr>
<td>WRI</td>
<td>$187</td>
<td>$11</td>
<td>$34</td>
<td>$41</td>
<td>$478</td>
<td>$51</td>
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<tr>
<td>TOTAL</td>
<td>$3,188</td>
<td>$166</td>
<td>$96</td>
<td>$359</td>
<td>$2,654</td>
<td>$296</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Before</th>
<th>PIP</th>
<th>After</th>
<th>PIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>PIP ATRRs</td>
<td>Revenue</td>
<td>Offset</td>
<td>Offset</td>
</tr>
<tr>
<td>($million)</td>
<td>($million)</td>
<td>($million)</td>
<td>($million)</td>
</tr>
<tr>
<td>AEPPW</td>
<td>$1,011</td>
<td>$1,131</td>
<td>$0.97</td>
</tr>
<tr>
<td>CUS</td>
<td>$34</td>
<td>$96</td>
<td>$0.63</td>
</tr>
<tr>
<td>EDE</td>
<td>$55</td>
<td>$96</td>
<td>$0.63</td>
</tr>
<tr>
<td>GMD</td>
<td>$122</td>
<td>$163</td>
<td>$0.62</td>
</tr>
<tr>
<td>GRDA</td>
<td>$54</td>
<td>$85</td>
<td>$0.70</td>
</tr>
<tr>
<td>KCPL</td>
<td>$231</td>
<td>$298</td>
<td>$0.85</td>
</tr>
<tr>
<td>KCP</td>
<td>$45</td>
<td>$81</td>
<td>$0.61</td>
</tr>
<tr>
<td>MDW</td>
<td>$119</td>
<td>$58</td>
<td>$0.27</td>
</tr>
<tr>
<td>NGK</td>
<td>$557</td>
<td>$263</td>
<td>$0.98</td>
</tr>
<tr>
<td>OPPO</td>
<td>$193</td>
<td>$100</td>
<td>$0.64</td>
</tr>
<tr>
<td>SUNC</td>
<td>$36</td>
<td>$57</td>
<td>$0.69</td>
</tr>
<tr>
<td>SWPS</td>
<td>$2,794</td>
<td>$305</td>
<td>$0.32</td>
</tr>
<tr>
<td>WEFA</td>
<td>$201</td>
<td>$230</td>
<td>$0.86</td>
</tr>
<tr>
<td>WRI</td>
<td>$802</td>
<td>$766</td>
<td>$1.14</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$6,759</td>
<td>$5,193</td>
<td>$1.42</td>
</tr>
</tbody>
</table>

Gap to Reach B/C Ratio of 0.8:
- TOTAL Levelization: 0.35

---

24
7.2 Transmission Projects Evaluated in this RCAR Report

This Regional Cost Allocation Review was conducted by evaluating three sets of transmission projects. These three sets are:

- **NTC**: All SPP projects that have been issued a NTC since June 2010 and have not been suspended;

- **Suspended NTC**: All NTC projects that are suspended pending further review; and

- **ATP**: All projects that have received an Authorization to Plan (ATP) and have an in-service year of 2023 or earlier (ten years or less from issuance of RCAR report).

These projects were evaluated by looking at their projected cost and the estimated benefits. The projected costs of the projects were conducted by SPP Staff. The analyses to estimate the projected benefits were conducted by the Brattle Group by monetizing a subset of benefits developed by the MTF and approved by the SPP stakeholder (See Section 6 above).

7.3 RARTF Guidance Provided to SPP Staff While Conducting the Review

While conducting the RCAR analysis, SPP Staff was faced with a couple of unanticipated issues that were not contemplated in the RARTF Report approved by SPP Stakeholders in January 2012. As a result during the RARTF’s May 31, 2013 conference call, SPP Staff sought the guidance from the RARTF on the following issues:

1. How to handle the new NTC projects issued in 2013 that were not a part of the 2012 models developed for this RCAR effort.

2. How to handle the existing NTC projects that were suspended by the SPP Board of Directors for further study.

During the conference call, the RARTF unanimously supported the inclusion of the 2013 NTC projects in the RCAR Report. Additionally, the RARTF also unanimously supported the inclusion of the suspended NTCs in the RCAR but at a reduced value of 75%. Upon receiving this direction from the RARTF, SPP staff updated the models to include 2013 NTC projects and adjusted the study to reduce the value of the suspended NTCs by weighting their benefits and costs at 75%.

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39 RCAR power flow models were submitted to the Model Development Working Group and other known modeling contacts from member companies for comment and review. Economic models were submitted to the ESWG for comment and review. A list of comments and subsequent updates can be found in Appendix 1 to this Report.
7.4 Cost Calculations Contained in the RCAR Report

Per the RARTF Report, SPP Staff conducted two sets of cost projections:

(1) the 40-year present value of all NTC projects (including the suspended NTCs at a reduced weight of 75%), and

(2) the 40-year present value of NTC projects (including suspended NTCs at a 75% weight) plus approved projects with an in-service date within 10 years (also at a 75% weight).

In accord with Principle 3 from the RARTF Report and the direction of the RARTF at its September 12, 2013 meeting, SPP staff used the most recent cost estimates that were provided to SPP in August 2013 for project cost tracking. By using this information, the RCAR Report is using “the most up to date and best available information for the review” per Principle 3.

7.4.1 Classification of Projects

To conduct the RCAR analysis, the projects were classified by project type (NTCs, suspended NTCs, and ATPs within 10 years) and also by the primary driver (Reliability, Economic, and Public Policy).

Figure 7.3 below summarizes the capital costs by in-service year, classified by project type and by primary driver.

7.4.2 Calculation of Annual Transmission Revenue Requirements (ATRRs)

Per SPP’s tariff, SPP calculated the ATRRs for each zone at the project level, as summarized below:

- Cost allocated to zones based on SPP’s **Highway/Byway methodology**: 

---

Figure 7.3

Summary of Capital Cost by In-Service Year

(a) By Project Type

(b) By Primary Driver
– 100% regional if 300 kV or above,
– 33% regional, 67% zonal if between 100 kV and 299 kV, and
– 100% zonal if below 100 kV.

- **Load ratio share (LRS)** used for the portion of costs allocated on a **regional** basis
  – Used actual 12-coincident peak loads for 2012, as provided by SPP

- **Net plant carrying charge (NPCC)** applied at the zonal level to calculate first year ATRRs in **2013** dollars

- **2.5%/yr inflation** applied to estimate first year ATRRs in **nominal** dollars

- **2.5%/yr straight-line depreciation** applied in calculating declining ATRR profile over time in **nominal** dollars

- Present values calculated for **40-year** depreciated ATRRs for 2013-2052 at a nominal **discount rate of 8.0%**

Figure 7.4 below summarizes the 40-year present value of ATRRs by SPP pricing zone. At the regional level, the present value of ATRRs are estimated to be **$4.8 billion** for the NTC projects, **$323 million** for the suspended NTC projects and **$239 million** for the ATP projects (in 2013 dollars).
7.4.3 Calculation of Point-to-Point (PTP) Revenue

Although the RCAR report did not calculate the increased wheeling revenue metric identified by the MTF (See Section 7.5 below), SPP Staff projected a PTP revenue credit to each Pricing Zone (Zone) over the 40 years of the study. This PTP revenue credit offsets the costs (ATRR) allocated to the individual Zones from Base Plan Zonal cost allocation and to all the Zones through a reduction in the Base Plan Regional rate. The PTP revenue reduces the ATRR that must be recovered in subsequent years by the Network Integrated Transmission Service (NITS) charges to all of the Transmission Customers of the SPP Zones.

Step 1: Estimate PTP Volumes

The PTP revenue is estimated by first determining the average PTP activity in the SPP footprint by PTP type (Annual, Monthly, Weekly, Daily Peak and Off-Peak, and Hourly Peak and Off-Peak) from the previous three years, 2010, 2011, and 2012. Once the average PTP volume was established by type it was fixed over the 40 years of the study. The following table shows the sales volumes used in the PTP offset calculation in the form of billable daily MW.

![Figure 7.5](image)

SPP PTP Service Types and Volumes, Averages of Years 2010, 2011 and 2012

Since SPP’s future Integrated Marketplace provides congestion rights for service of one month or longer, shorter duration service for “Into” and “Within” service types was assumed to go away. Shorter duration service types serving external loads are still expected after SPP’s Integrated Marketplace goes live and were therefore included.

PTP volumes associated with “Into” and “Within” PTP directions were further reviewed. Any PTP transactions that were purchased by a Network Customer that sank in their own Zone were removed from consideration. Only the BPR components of the remaining “Into” and “Within” PTP directions were considered in the PTP sales volumes.

Step 2: Determine PTP Zonal and Regional Rate from RCAR Upgrades

Next, a PTP rate was forecasted for each PTP type for the 40 years of the study. The PTP rate forecast was based upon the ATRR each year of the new Highway/Byway facilities divided by the SPP 12 CP in MW. The ITP20’s 1.3% annual load growth projection was applied to years after 2013. A PTP rate was calculated for each PTP type (Monthly, Weekly, etc.). Also the NTC upgrades’ ATRRs were considered at 100%, Suspended NTCs at 75%, and 10 year upgrades at 75%. All assumptions associated with the 40 year RCAR costs (ATRR generated by
RCAR upgrades) were also included in the ATRR portion of the rate calculation (2.5% straight line depreciation, 8% discount rate to 2013, etc.)

PTP revenue from the previous year was shown as a reduction in current year ATRR for every year of the study for the purposes of determining PTP rates.

**Step 3: Estimate Annual RCAR PTP $**

The PTP $ per year were estimated when the PTP volumes (MW) by type were multiplied by the PTP rate ($/MW) by type. This generated a total annual $ of RCAR PTP revenue for every year of the 40 year RCAR horizon. These resulting 40 years of RCAR PTP revenue projections were converted to 2013$.

**Step 4: Allocate Total PTP $ to Each Pricing Zone**

The Base Plan Zonal (BPZ) PTP revenue was allocated back to the Pricing Zone in-which the upgrades were built.

The Base Plan Regional (BPR) PTP revenue was allocated to all of the Pricing Zones in the SPP footprint based upon each Zone’s Load Ratio Share (LRS %) of the total BPR PTP revenues. Since the total SPP Regional component of the costs that is applied to each Zone through cost allocation will be reduced by the BPR PTP revenue from the previous year this effectively reduced the “cost” component in the B/C ratios of each Zone based upon the Zone’s LRS%.

**Step 5: Apply PTP Revenue Credit to Each Zone’s B/C Ratio**

The total 40 years of BPZ and BPR PTP revenue credit in 2013$ was applied to each Zone’s cost component of the RCAR B/C ratio in Tables 7.1 and 7.2.

7.5 Benefit Metrics

The benefit metrics considered for this RCAR effort includes the standard ITP metrics and three of the new metrics recommended in the September 2012 MTF report. Figure 7.6 below provides a list of these benefit metrics.
## Figure 7.6
Benefit Metrics Considered in RCAR

<table>
<thead>
<tr>
<th>Benefit Metric Name</th>
<th>Standard ITP Metric</th>
<th>MTF Recommended New Metric</th>
<th>Considered in this RCAR effort?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted Production Cost (APC) Savings</td>
<td>✓</td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>Reduction of Emission Rates and Values</td>
<td>✓</td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>Savings due to Lower Ancillary Service Needs and Production Costs</td>
<td>✓</td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>Avoided or Delayed Reliability Projects</td>
<td>✓</td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>Capacity Cost Savings due to Reduced On-Peak Transmission Losses</td>
<td>✓</td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>Mitigation of Transmission Outage Costs</td>
<td>✓</td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>Assumed Benefit of Mandated Reliability Projects</td>
<td>✓</td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>Benefits from Meeting Public Policy Goals</td>
<td>✓</td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>Increased Wheeling Through and Out Revenues</td>
<td>✓</td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>Capital Savings due to Reduction of Members’ Minimum Required Margin</td>
<td>✓</td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>Reducing the Cost of Extreme Events</td>
<td>✓</td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>Reduced Loss of Load Probability</td>
<td>✓</td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>Marginal Energy Losses Benefits</td>
<td>✓</td>
<td></td>
<td>No</td>
</tr>
</tbody>
</table>

### 7.5.1 Adjusted Production Cost (APC) Savings

APC savings are estimated based on PROMOD simulations of the SPP system plus most of the Eastern Interconnect, for three study years: 2018, 2023, and 2033.

Five PROMOD simulation cases were developed with different transmission topology for each of the study years, holding all other inputs and assumptions constant:

## Figure 7.7
Case Definitions in PROMOD

<table>
<thead>
<tr>
<th>Case Definitions in PROMOD</th>
<th>NTC</th>
<th>Susp. NTC</th>
<th>ATP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Change Case 1</td>
<td>CC₁</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Change Case 1A</td>
<td>CC₁A</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Change Case 2</td>
<td>CC₂</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Change Case 2A</td>
<td>CC₂A</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>
SPP provided the Brattle Group a powerflow and PROMOD system database (developed for the recent ITP20 study) to be used as a starting point for the analysis. The following changes were made to create more realistic cases for the purpose of RCAR study:

- Constraints from the ITP10 event file were added
- The top 40 temporary flowgates from 2012 were added to the event file
- The top 10 constraints from the 2011 SPP State of the Market Report were added to the event file
- The PAT tool was used to develop additional transmission constraints for the SPP system
- Ratings of individual branches were taken from the powerflows used in the year/case combination
- 1% of peak load was added to the reserve requirement to represent regulation reserves

As shown in Figure 7.8, the estimated APC savings increase over time. These increases are driven by load growth and increases in fuel prices. Figure 7.9 shows the estimated APC savings for the 40-year study period, applying a 75% of weight for both suspended NTCs and ATP projects. The annual estimates between study years 2018, 2023 and 2033 are interpolated; after 2033 they are conservatively assumed to grow only at inflation.
7.5.2 Avoided or Delayed Reliability Projects

Avoided or delayed reliability projects were identified through powerflow models that represent transmission utilization based on selected snapshots of generation dispatch and system loads. Figure 7.10 summarizes the powerflow cases used in the study.
Figure 7.10
List of Powerflow Cases Analyzed

<table>
<thead>
<tr>
<th>Cases</th>
<th>Description</th>
<th>Model Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case (BC)</td>
<td>no NTCs, no ATPs</td>
<td>2018, 2023</td>
</tr>
<tr>
<td>Change Case 1 (CC₁)</td>
<td>NTCs (excl. suspended NTCs), no ATPs</td>
<td>2018, 2023</td>
</tr>
<tr>
<td>Change Case 2 (CC₂)</td>
<td>NTCs (incl. suspended NTCs), and ATPs</td>
<td>2018, 2023</td>
</tr>
<tr>
<td>Change Case 1A (CC₁A)</td>
<td>NTCs (incl. suspended NTCs), no ATPs</td>
<td>2018, 2023</td>
</tr>
<tr>
<td>Change Cases 2A (CC₂A)</td>
<td>NTCs (excl. suspended NTCs), and ATPs</td>
<td>2018, 2023</td>
</tr>
<tr>
<td>Modified Change Cases (MCC₁,</td>
<td>Same as Change Case but excludes selected NTCs</td>
<td>2018, 2023</td>
</tr>
<tr>
<td>MCC₂, MCC₁A, MCC₂A)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Avoided Reliability Cases (AR₁,</td>
<td>Same as Modified Change Case but with</td>
<td>2018, 2023</td>
</tr>
<tr>
<td>AR₂, AR₁A, AR₂A)</td>
<td>avoided reliability projects</td>
<td></td>
</tr>
</tbody>
</table>

Figure 7.11 lists the selected NTC projects excluded in the modified base cases to identify (a) the reliability violations and (b) the reliability projects (avoided by the selected NTC projects) that would be needed to narrowly address the identified reliability violations. The selected NTC projects include all projects designated as either economic or public policy projects.

Figure 7.11
List of Selected NTC Projects

<table>
<thead>
<tr>
<th>PID</th>
<th>FACILITIES DESCRIPTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>936</td>
<td>Northwest Texarkana – Valliant 345 kV Ckt 1</td>
</tr>
<tr>
<td>937</td>
<td>Tulsa Power Station 138 kV</td>
</tr>
<tr>
<td>938</td>
<td>Sibley 345 kV – Maryville 345 kV; Nebraska City 345 kV – Maryville 345 kV (GMO)</td>
</tr>
<tr>
<td>939</td>
<td>Nebraska City 345 kV – Maryville 345 kV (OPPD)</td>
</tr>
<tr>
<td>940</td>
<td>Hitchland Interchange 345/230kV Transformer Ckt 2; Hitchland Interchange – Woodward District EHV 345 kV Ckts 1 &amp; 2 (SPS)</td>
</tr>
<tr>
<td>941</td>
<td>Hitchland Interchange – Woodward District EHV 345 kV Ckts 1 &amp; 2 (OGE)</td>
</tr>
<tr>
<td>942</td>
<td>Thistle – Woodward EHV 345 kV Ckts 1 &amp; 2 (OGE)</td>
</tr>
<tr>
<td>943</td>
<td>Thistle – Woodward EHV 345 kV Ckts 1 &amp; 2 (PW)</td>
</tr>
<tr>
<td>945</td>
<td>Spearville 345 kV – Clark Co 345 kV Ckt 1; Clark Co 345 kV – Thistle 345 kV Ckts 1 &amp; 2; Thistle 345/138 kV Transformer; Flat Ridge – Thistle 138 kV</td>
</tr>
<tr>
<td>946</td>
<td>Wichita 345 kV</td>
</tr>
<tr>
<td>30375</td>
<td>Cherry Co – Gentleman 345 kV Ckt 1; Gentleman 345 kV Terminal Upgrades Cherry Co – Holt Co 345 kV Ckt 1; Cherry Co 345 kV Holt Co 345 kV</td>
</tr>
<tr>
<td>30376</td>
<td>Amoco-Tuco-Hobbs 345 kV Circuit 1 and associated 345/230 kV transformers</td>
</tr>
</tbody>
</table>
Figure 7.12 shows the avoided reliability projects that would be needed to address the identified reliability violations. Cost data provided by SPP was used to estimate the total costs of the avoided reliability projects. The benefits are assumed to be equal to the NPV of associated ATRRs for 2013-2052, applying the same approach used for estimating the ATRRs of NTC and ATP projects. They are allocated to zones based on the ratios that would have been applied for the costs of the reliability projects under Highway/Byway methodology.

Figure 7.12
List of Avoided Reliability Projects

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Area</th>
<th>Cost ($m)</th>
<th>2018</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntsville-Hutchinson Energy Center 115 kV Line</td>
<td>MIDW/HERE</td>
<td>$22.2</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Woodward-Windfarm 138 kV Line</td>
<td>OKGE</td>
<td>$12.0</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Gordon Evans-Lakeridge 138 kV Line</td>
<td>WERE</td>
<td>$9.6</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Mound-Yost 69 kV Line</td>
<td>WERE</td>
<td>$5.1</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Cowskin-45th St 138 kV Line</td>
<td>WERE</td>
<td>$7.6</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Carnegie-Southwestern 138 kV Line</td>
<td>AEPW</td>
<td>$14.7</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Sdersks2-Dierksr2 69 kV Line</td>
<td>AEPW</td>
<td>$2.6</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Lawhill-Lec 230 kV Line</td>
<td>WERE</td>
<td>$0.3</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Hillsboro-Spring Creek 115 kV Line</td>
<td>WERE</td>
<td>$10.9</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Monument-Hobbs West 115 kV Line</td>
<td>SPS</td>
<td>$8.2</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Texas County-Hitchland 115 kV Line</td>
<td>SPS</td>
<td>$12.6</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>

Figure 7.13 below summarizes the benefits of avoided reliability projects by zone. At the regional level, the 40-year present value of benefits for avoided reliability projects adds up to **$97 million** (in 2013 dollars), with no estimated benefits from suspended NTC projects. The system-wide benefits do not change when ATP projects are included, but the allocation of the benefits across zones shift slightly.

Figure 7.13
Benefits of Avoided or Delayed Reliability Projects

(a) NTC

(b) NTC + 75% of ATP
7.5.3 Capacity Savings due to Reduced On-Peak Transmission Losses

Reduced capacity expansion costs due to lower transmission losses on peak captures the value of system-wide generation capacity that will no longer be required (each MW of reduced on-peak losses saves 1.12 MW of new capacity).

On-peak transmission losses are quantified for two study years (2018, 2023) and five cases (Base, CC1, CC1A, CC2, and CC2A). As shown in Figure 7.14, SPP-wide on-peak transmission losses are estimated to decrease by about 72 MW in 2018 and 122 MW in 2023 as a result of NTC projects. Including the suspended NTC projects reduce the on-peak losses by an incremental 1 MW in 2018 and 2023. If the suspended NTC projects are not built, ATP projects further reduce the on-peak losses by 0.5 MW in 2018 and 14 MW in 2023, while if they are built, losses would increase by 0.5 MW in 2018 and decrease by 17 MW in 2023.

![Figure 7.14](image)

**Change in On-Peak Transmission Losses by Zone**

<table>
<thead>
<tr>
<th>Zone</th>
<th>2018 NTCs</th>
<th>Suspended NTCs</th>
<th>ATPs (Suspended NTCs Not Built)</th>
<th>ATPs (Suspended NTCs Built)</th>
<th>2023 NTCs</th>
<th>Suspended NTCs</th>
<th>ATPs (Suspended NTCs Not Built)</th>
<th>ATPs (Suspended NTCs Built)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(MW)</td>
<td>(MW)</td>
<td>(MW)</td>
<td>(MW)</td>
<td>(MW)</td>
<td>(MW)</td>
<td>(MW)</td>
<td>(MW)</td>
</tr>
<tr>
<td>AEPW</td>
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</tr>
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<td>CUS</td>
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<td>(0.1)</td>
<td>0.0</td>
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</tr>
<tr>
<td>EDE</td>
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</tr>
<tr>
<td>GMO</td>
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<td>(0.1)</td>
<td>(0.1)</td>
<td>(0.7)</td>
<td>0.0</td>
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<td>(0.2)</td>
</tr>
<tr>
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</tr>
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</tr>
<tr>
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<td>(2.1)</td>
<td>0.0</td>
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</tr>
<tr>
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<td>(12.3)</td>
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</tr>
<tr>
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<td>(0.1)</td>
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<td>(4.0)</td>
<td>0.1</td>
<td>(0.4)</td>
<td>(0.3)</td>
</tr>
<tr>
<td>OPPD</td>
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<td>0.0</td>
<td>(1.4)</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
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<td>0.1</td>
<td>(1.2)</td>
<td>(0.2)</td>
<td>(1.3)</td>
<td>(1.2)</td>
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</tr>
<tr>
<td>SWPS</td>
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<td>(55.3)</td>
<td>(1.0)</td>
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<td>(0.9)</td>
</tr>
<tr>
<td>WEFa</td>
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<td>0.0</td>
<td>0.0</td>
<td>(2.6)</td>
<td>(0.1)</td>
<td>(0.4)</td>
<td>(0.4)</td>
</tr>
<tr>
<td>WRI</td>
<td>(6.4)</td>
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<td>0.1</td>
<td>0.0</td>
<td>(7.7)</td>
<td>0.0</td>
<td>(0.8)</td>
<td>(0.8)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>(71.7)</td>
<td>(0.9)</td>
<td>(0.5)</td>
<td>(0.6)</td>
<td>(122.0)</td>
<td>(1.2)</td>
<td>(13.7)</td>
<td>(16.9)</td>
</tr>
</tbody>
</table>

The loss reductions are calculated on a zonal basis, then interpolated between 2018 and 2023, and assumed to increase at inflation afterwards. The results are then multiplied by 1.12 \((1 +\text{reserve margin})\) to calculate the reduction in installed capacity requirements. The value of capacity savings is monetized on a zonal basis by applying a net cost of new entry (net CONE) of $84/kW-yr in 2013 dollars.

The net CONE value was calculated as the difference between an estimated gross CONE value and the expected operating margins (energy market revenues net of variable operating costs, also referred to as “net market revenues”) for a combustion turbine. A gross CONE value of $95/kW-yr was obtained by leveling the capital and fixed operating costs of a new advanced combustion turbine as reported in EIA’s Annual Energy Outlook 2012. Net market revenues of $11/kW-yr were estimated based on the historical data for the margins of gas-fired combustion turbines, as provided in SPP’s 2011 State of Market Report.
Figure 7.15 summarizes the capacity savings by SPP pricing zones. The NPV of capacity savings related to NTC projects is about $154 million in total and that related to suspended NTCs is about $1.4 million. The NPV of capacity savings related to ATP projects is about $12.2 million if suspended NTCs are not built and about $15.3 million if they are built.

### Figure 7.15

**Capacity Savings due to Reduced On-Peak Transmission Losses**

<table>
<thead>
<tr>
<th>SPP Zone</th>
<th>Savings Related to NTCs</th>
<th>Savings Related to Suspended NTC</th>
<th>Savings Related to ATPs (Suspended NTCs Not Built)</th>
<th>Savings Related to ATPs (Suspended NTCs Built)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2018 (nominal $/yr)</td>
<td>2023 (nominal $/yr)</td>
<td>2018 (nominal $/yr) 40-yr NPV</td>
<td>2023 (nominal $/yr) 40-yr NPV</td>
</tr>
<tr>
<td></td>
<td>2018 (nominal $/yr)</td>
<td>2023 (nominal $/yr)</td>
<td>2018 (nominal $/yr) 40-yr NPV</td>
<td>2023 (nominal $/yr) 40-yr NPV</td>
</tr>
<tr>
<td></td>
<td>2018 (nominal $/yr)</td>
<td>2023 (nominal $/yr)</td>
<td>2018 (nominal $/yr) 40-yr NPV</td>
<td>2023 (nominal $/yr) 40-yr NPV</td>
</tr>
<tr>
<td></td>
<td>2018 (nominal $/yr)</td>
<td>2023 (nominal $/yr)</td>
<td>2018 (nominal $/yr) 40-yr NPV</td>
<td>2023 (nominal $/yr) 40-yr NPV</td>
</tr>
<tr>
<td>AEPW</td>
<td>$1.6 $2.9 $30.7</td>
<td>$0.0 $0.0 $0.1</td>
<td>$0.0 $1.7 $12.4</td>
<td>$0.0 $1.7 $12.7</td>
</tr>
<tr>
<td>CUS</td>
<td>$0.0 $0.0 $0.1</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
</tr>
<tr>
<td>EDE</td>
<td>$0.0 -$0.1 -$0.9</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
</tr>
<tr>
<td>GMO</td>
<td>$0.1 $0.1 $1.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.2</td>
<td>$0.0 $0.0 $0.2</td>
</tr>
<tr>
<td>GRDA</td>
<td>$0.0 $0.1 $0.8</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
</tr>
<tr>
<td>KCPP</td>
<td>$0.4 $0.5 $5.6</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.3</td>
<td>$0.0 $0.0 $0.3</td>
</tr>
<tr>
<td>LES</td>
<td>$0.1 $0.1 $1.1</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
</tr>
<tr>
<td>MIDW</td>
<td>$0.2 $0.3 $2.8</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
</tr>
<tr>
<td>MKEC</td>
<td>$0.4 $0.8 $8.6</td>
<td>$0.0 -$0.1 -$1.2</td>
<td>$0.0 -$0.1 -$1.1</td>
<td>-$0.1 $0.0 -$0.3</td>
</tr>
<tr>
<td>NPPD</td>
<td>$0.2 $1.5 $13.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 -$0.2</td>
<td>$0.0 $0.0 -$0.2</td>
</tr>
<tr>
<td>OKGE</td>
<td>$0.1 $0.5 $4.5</td>
<td>$0.0 $0.0 -$0.1</td>
<td>$0.0 $0.0 $0.4</td>
<td>$0.0 $0.0 $0.3</td>
</tr>
<tr>
<td>OPPD</td>
<td>$0.1 $0.2 $2.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.0</td>
</tr>
<tr>
<td>SUNC</td>
<td>$0.1 $0.0 $0.6</td>
<td>$0.0 $0.2 $1.3</td>
<td>$0.0 $0.1 $1.0</td>
<td>$0.1 $0.0 $0.3</td>
</tr>
<tr>
<td>SWPS</td>
<td>$3.7 $6.6 $70.8</td>
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<td>$0.0 -$0.3 -$1.9</td>
<td>$0.1 $0.1 $0.9</td>
</tr>
<tr>
<td>WEFA</td>
<td>-$0.1 $0.3 $2.3</td>
<td>$0.0 $0.0 $0.1</td>
<td>$0.0 $0.0 $0.0</td>
<td>$0.0 $0.0 $0.4</td>
</tr>
<tr>
<td>WRI</td>
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<td>$0.0 $0.1 $0.7</td>
<td>$0.0 $0.1 $0.7</td>
</tr>
<tr>
<td>TOTAL</td>
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<td>$0.1 $0.1 $1.4</td>
<td>$0.1 $1.6 $12.2</td>
<td>$0.1 $2.0 $15.3</td>
</tr>
</tbody>
</table>

#### 7.5.4 Mitigation of Transmission Outage Costs

The PROMOD runs used to estimate APC savings do not account for transmission outages, and thereby ignore the added congestion-relief and production cost benefits of new transmission facilities during the planned and unplanned outages of existing transmission facilities.

To estimate the incremental savings associated with the mitigation of transmission outage costs, “outage” cases were analyzed in PROMOD for the 2023 study year. The cases were developed based on 12 months of historical transmission data provided by SPP for December 2011 to November 2012.

Because of the volume of historical transmission outage data (approximately 6,400 outage events) and based on the expectation that many outages would not necessarily lead to significant increases in congestion, only a subset of all outage events was modeled. The outage events selected were those expected to create significant congestion. The outages selected to be modeled in PROMOD meet at least one of the following conditions:

- Involved facilities with a nominal voltage over 230 kV and lasted 5 days or longer
• Involved facilities with a nominal voltage over 100 kV, lasted 4 hours or longer, and had a significant impact on a defined contingency\(^{40}\)

• Involved facilities with a nominal voltage over 100 kV, lasted 4 hours or longer, and had a significant impact on a binding constraint in the Base Case PROMOD runs\(^{41}\)

In total, 732 outage events were modeled, capturing 11.4% of the 6,405 historical outage events in the 12-month period, and 21.5% of the historical outage hours.

Figure 7.16 shows the impact of the outages on the APC savings estimated in PROMOD for the 2023 study year.\(^{42}\) Comparing the outage results for Base Case and CC\(_2\) translates to an annual savings that were 11.3% higher than the APC savings estimated with simulations that do did not consider transmission outages. We used this difference to monetize the SPP-wide benefits of mitigating transmission outage costs and get a 40-year NPV of benefits of $277 million for NTC projects, $84 million for Suspended NTC projects and up to $25 million for ATP projects. As recommended in the September 2012 MTF report, the SPP-wide benefits are allocated to SPP pricing zones based on a load ratio share.

![Figure 7.16
Impact of Transmission Outages in Estimated APC Savings
(Simulation results prior to updating NTC, Suspended NTC and ATP project lists and classification)\(^{43}\)](image)

<table>
<thead>
<tr>
<th></th>
<th>Base (nominal $m/yr)</th>
<th>CC2 (nominal $m/yr)</th>
<th>Savings (nominal $m/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2023</td>
<td>$8,398</td>
<td>$8,261</td>
<td>$137</td>
</tr>
<tr>
<td>2023 outage</td>
<td>$8,475</td>
<td>$8,322</td>
<td>$153</td>
</tr>
<tr>
<td>Difference</td>
<td></td>
<td></td>
<td>11.3%</td>
</tr>
</tbody>
</table>

\(^{40}\) An outage has a significant impact on a defined contingency if one of the elements in the contingency has a LODF over 50% with respect to the outage of the facility, and the voltage of the facility is higher than or equal to the voltage of contingency element.

\(^{41}\) An outage has a significant impact on a binding constraint if a monitored element in the constraint has a LODF over 35% and below 100% with respect to the outage of the facility, and the voltage of the facility is higher than or equal to the voltage of the monitored element. The 100% limit for LODF effectively removes the outage of monitored facilities, or facilities in series with monitored facilities, that do not increase flow on other binding monitored facilities.

\(^{42}\) These transmission outage cases are based on 2012 NTC and ATP simulations. They do not reflect the 2013 updated NTC, Suspended NTC and ATP project classification. Updating project classifications was not expected to change the 11.3% benefit factor of considering transmission outages. This 11.3% additional benefit factor from the 2012 NTC and ATP simulations was applied to the production cost savings of the simulation results reflecting 2013 updated NTC, Suspended NTC and ATP projects.

\(^{43}\) See previous footnote.
7.5.5 Benefits of Mandated Reliability Projects

The September 2012 MTF report recommended that this metric be calculated conservatively only for “regional” reliability projects and the benefits be set equal to the projects’ costs, allocated to zones in the same way as the projects’ costs are allocated.

For the purpose of this RCAR effort, all of the projects marked as reliability projects were considered to be mandated and regional. Benefits are estimated as the 40-year NPV of ATRRs for these reliability projects, allocated to zones in the same way as their costs are allocated. Figure 7.17 summarizes the estimated benefits of mandated reliability projects by zone. The SPP-wide benefits add up to $2.4 billion for NTC projects, $107 million for suspended NTC projects, and $239 million for ATP projects.

Figure 7.17
UPDATED Benefits of Mandated Reliability Projects by Zone

![Graph showing updated benefits of mandated reliability projects by zone]

7.5.6 Benefits of Meeting Public Policy Goals

The September 2012 MTF report recommended that the benefits of meeting public policy goals be set equal to the cost of the cost-effective projects needed to meet the public policy goals. For the purpose of this RCAR effort, this metric is limited to the benefits of meeting public policy goals related to renewable energy.

The NTC projects marked as “public policy” projects were used as a very conservative designation of the cost-effective projects needed to meet the public policy goals. Therefore, the SPP-wide benefits are estimated to be $296 million, which is equal to the 40-year present value of the ATRRs of these public policy projects. None of the Suspended NTC or ATP projects are identified as “public policy” projects; therefore, their public policy benefits are conservatively assumed to be zero.
These very conservatively-estimated public policy benefits are allocated to the SPP pricing zones in proportion to each zone’s share of unmet renewable energy goals. The unmet goals are based on the latest available SPP data for existing wind generation and renewable energy goals.

- Only the wind plants that were in-service as of June 19, 2010 are considered “existing” resources for the purpose of this calculation. Plant-specific capacity factors are used to calculate the annual generation from each resource, which is then aggregated to zonal level based on the ownership data provided by SPP.

- Total renewable energy goals are calculated as the sum of the Renewable Mandates and Targets as reported in SPP survey data.\(^{44}\)

- The amount of “over-compliance” in some of the SPP zones (e.g., SWPS) is not counted towards the compliance of others.

Figure 7.18 summarizes the existing wind generation, unmet renewable goals, and each zone’s share of total public policy goals. These shares are then applied to the 40-year present value of ATRRs of the NTC projects marked as “public policy” projects, which yields to $296 million in total.\(^{45}\)

\(^{44}\) The RCAR Report uses SPP survey data from the 2012 Public Policy Survey instead of the SPP 2013 Public Policy Survey. Differences exist between the 2012 and 2013 Public Policy Surveys. Although the 2013 survey contains “the most up-to-date information”, the use of the 2013 survey would create inconsistencies between the models used in the RCAR and the allocation of Public Policy benefits. As a result, the RARTF at its September 12, 2013 meeting provided guidance to SPP staff to use data from the 2012 SPP Public Policy Survey in the RCAR Report consistent with Principle 4 of the RARTF Report.

\(^{45}\) It is important to note the public policy benefits shown in Figure 7.18 are very conservative. The September 2012 MTF Report defines the cost-effective projects to meet public policy goals as having “two categories: 1) projects displaced by the portfolio of projects receiving NTCs; and 2) projects included in the portfolio of projects receiving NTCs.” The results shown in this section are based on the second category, and do not consider transmission costs that would likely be incurred to integrate the needed wind generation in the absence of the portfolio of NTC and ATP projects. The unmet renewable energy goal of 17.6 million MWh translates to approximately 5,000 MW of wind capacity. If valued at $450/kW-wind based on lowest “local” transmission cost reported in MISO’s Regional Generation Outlet Study (RGOS) study, this would translate to more than $2.2 billion of public policy benefits, instead of the much lower $296 million shown in Figure 7.17 and as reflected in the benefit-cost analysis. Assuming $2.2 billion of public policy benefits would increase the region-wide benefits by almost $2 billion, and result additional zones to achieve a B/C ratio of 0.8 or higher (EDE, KCPL, and SUNC).
7.6 High Gas Price Sensitivity

As a part of the RCAR analyses, SPP staff requested that the Brattle Group perform a “High Gas Price” sensitivity as a part of the analysis for calculating the adjusted project cost savings. The results of this sensitivity analysis are provided in Addendum 1 to this RCAR Report. As shown in Addendum 1, assuming higher gas prices increase the overall B/C ratio from 1.42 to 1.55 in the NTC only case, and from 1.45 to 1.59 in the NTC plus 10 year projects case. Additionally, the High Gas Price sensitivity shows that the number of zones below a 0.8 B/C ratio falls from 6 to 3 in the NTC only case, and from 5 to 4 in the NTC plus 10 year projects case.

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46 The market simulations for the High Gas Price sensitivity assumed gas prices to be 27.5% higher for all three study years, compared those used in the main study. The average Henry Hub prices used for the sensitivity analysis are $6.2/MMBtu in 2018, $8.0/MMBtu in 2023, and $12.1/MMBtu in 2033 (in nominal dollars).

47 The High Gas Price sensitivity analysis was performed in the same manner as the main study that was undertaken to estimate the results shown in Figures 7.1 and 7.2 except for the higher gas prices used in the APC savings calculations.
SECTION 8: RECOMMENDATION ON REMEDIES

8.1 Overview of RARTF Report on Remedies

The RARTF report recommended that if the RCAR of “[a]ll SPP projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report” shows that a zone is below the 0.8 B/C ratio Section 4.1 of the RARTF Report then “SPP staff should evaluate, and recommend possible mitigation remedies for the zone.”

Figure 7.2 of the RCAR Report show that there are 5 zones are below the 0.8 for projects with NTCs and all projects that have an in-service date of ten years or less. These zones are:

- City Utilities of Springfield
- The Empire District Electric Company
- Grand River Dam Authority
- Lincoln Electric System
- Sunflower Electric Power Corporation

Figure 5 of the RARTF Report, provided a list of mitigation remedies that SPP staff should consider for study and to be made part of the report.

8.2 RCAR Report on Remedies

SPP Staff and the RARTF recommend that this RCAR Report be finalized in October 2013 in order to incorporate and include the finding in SPP’s current ITP10 assessment that commenced in July 2013. This recommendation is in-line with the direction of the RARTF Report approved in January 2012 as described below.

As shown above in Figure 8 above, which is also found in Section 5.1 of the RARTF Report, the first two remedies for SPP staff to consider for City Utilities of Springfield, Empire District Electric Company, Grand River Dam Authority, Lincoln Electric System, and Sunflower Electric Power Corporation as a part of the RCAR Report is the “[a]cceleration of planned upgrades” and “[i]ssuance of NTCs for selected new upgrades.”

Furthermore, Section 4.2 of the RARTF Report states, “[a]dditionally, the RARTF recommends that any Regional Cost Allocation Review, which shows that a zone is above the 0.8 threshold in Section 4.1, but below a 1.0 B/C ratio, should be used and considered as a part of SPP’s transmission planning process in the future.”

Because SPP’s 18-month ITP10 assessment has recently commenced and remedies contemplated in the RARTF Report include the evaluation of transmission upgrade remedies, SPP Staff recommends that the RCAR Report be finalized and considered in SPP’s current ITP10 assessment in collaboration with deficient zones and SPP Stakeholders.
In addition to this recommendation, SPP staff and the RARTF recommend that a second RCAR process [RCAR II] be commenced and work in parallel with the ITP10 assessment which is expected to be completed in January 2015. This will allow SPP staff to follow the directions contained in Sections 4.2 and Section 5.1 of the RARTF Report through ITP10 while utilizing RCAR II as a means to understand whether proposed remedies approved in the ITP10 provide equity for certain zones.\textsuperscript{48} If RCAR II does not show that adequate remedies exist, SPP staff, deficient zones, and SPP Stakeholders can begin the process of analyzing additional potential remedies for any zone below the threshold. The report will be completed either (i) shortly after the ITP10 is completed, if cost estimates are to be used in the RCAR II analysis; or (ii) shortly after the completion of the competitive solicitation process, if the RFP results are to be used in the RCAR II analysis.

SECTION 9: GUIDANCE FOR FUTURE RCAR ASSESSMENTS

9.1 Overview of RCAR Lessons Learned

In Section 7.1 of their Report, the RARTF made four recommendations in addition to their recommendations of how to conduct the RCAR. Recommendation four stated:

[T]he RARTF found the process of developing the recommended methodology under which the Regional Cost Allocation Review will be performed to be a very informative and collaborative process. As a result, the RARTF recommends that the task force be reconvened before subsequent Regional Cost Allocation Reviews are performed. This will enable the SPP stakeholders to review lessons learned from prior Regional Cost Allocation Reviews and to suggest improvements to the methodology recommended in this report.

In accord with the fourth additional recommendation contained in Section 7.1 of the RARTF Report, it is recommended that the RARTF “be reconvened before subsequent Regional Cost Allocation Reviews are performed.” This aligns with the recommendations contained in Section 8.2 of this Report, that the RCAR “be finalized in October 2013 in order to incorporate and include the finding in SPP’s current ITP10 assessment” and to allow “that a second RCAR process [RCAR II] be commenced and work in parallel with the ITP10 assessment.”

As a result, the final recommendation is for the RARTF to begin a “lessons learned” and to finalize any “suggested improvements” to the RCAR process by the January 2014 stakeholder meeting cycle. This will allow these improvements to be incorporated into the RCAR II process.

\textsuperscript{48} Because many of the zones below the 0.80 threshold in the RCAR Report are at or near the seam, SPP staff and the RARTF recommend that an analysis of seams projects be a part of ITP10’s consideration of remedies for the RCAR. A review of potential seams projects is in alignment with SPP’s interregional compliance filing for Order No. 1000 in FERC Docket No. ER13-1939.
### ADDENDUM 1

**High Gas Price Sensitivity**

Estimated Present Value of Benefit Metrics and Costs by Zone

(a) NTC Projects + 75% of Suspended NTCs

<table>
<thead>
<tr>
<th>Zone</th>
<th>Present Value of 40-yr Benefits for 2013-2052</th>
<th>Present Value of 40-yr ATRRs Before PIP Revenue Offset</th>
<th>After PIP Revenue Offset</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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(b) NTC Projects + 75% of Suspended NTCs + 75% of ATP Projects

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<th>Present Value of 40-yr Benefits for 2013-2052</th>
<th>Present Value of 40-yr ATRRs Before PIP Revenue Offset</th>
<th>After PIP Revenue Offset</th>
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Appendix 1 – Stakeholder Comment and Resolutions for RCAR Models and Draft Report
All stakeholder comments have been posted at
Appendix 2 – Analysis of Zones Below the 0.8 B/C Ratio Threshold
The estimated B/C ratio in CUS is 0.59 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It slightly increases to 0.63 when ATP projects are also included (at a reduced value of 75 percent).

Overall, the low B/C ratio in CUS is primarily driven by the limited APC savings.

- The cost of economic projects is $35 million in CUS, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $7-8 million due to relatively lower congestion-relief provided in the CUS zone.

- The benefit related to mitigation of transmission outage costs is estimated to be $5-6 million, reducing CUS’ gap to reach a B/C ratio of 0.8 (but it is not large enough to fully eliminate the gap).

Another factor that contributes to a lower B/C ratio in CUS is that it does not receive any public policy benefits.

- CUS does not have a renewable goal, but it is responsible for about $5 million of the costs for public policy projects (allocated regionally on a LRS basis).

Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).

- These additional benefits could either reduce or eliminate CUS’ gap to reach a B/C ratio of 0.8.
Empire District Electric (EDE)

- The estimated B/C ratio in EDE is 0.60 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It slightly increases to 0.63 when ATP projects are also included (at a reduced value of 75 percent).

- Overall, the low B/C ratio in EDE is primarily driven by the limited APC savings.
  - The cost of economic projects is $56 million in EDE, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $7-8 million due to relatively lower congestion-relief provided in the EDE zone.
  - The benefit related to mitigation of transmission outage costs is estimated to be $9 million, reducing EDE’s gap to reach a B/C ratio of 0.8 (but it is not large enough to fully eliminate the gap).

- Costs from meeting public policy goals exceed the benefits of public policy projects by approximately $1 million, which decreases the B/C ratio in EDE (but not sufficient to close the gap).

- Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).
  - These additional benefits could either reduce or eliminate EDE’s gap to reach a B/C ratio of 0.8.
Grand River Dam Authority (GRDA)

The estimated B/C ratio in GRDA is 0.67 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It slightly increases to 0.70 when ATP projects are also included (at a reduced value of 75 percent).

Overall, the low B/C ratio in GRDA is primarily driven by the limited APC savings.

- The cost of economic projects is $44 million in GRDA, accounting for approximately 55% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $10-11 million due to relatively lower congestion-relief provided in the GRDA zone.

- The benefit related to mitigation of transmission outage costs is estimated to be $7 million, reducing GRDA’s gap to reach a B/C ratio of 0.8.

Another factor that contributes to a lower B/C ratio in GRDA is that it does not receive any public policy benefits.

- GRDA does not have a renewable goal, but it is responsible for about $6 million of the costs for public policy projects (allocated regionally on a LRS basis).

Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).

- These additional benefits could either reduce or eliminate GRDA’s gap to reach a B/C ratio of 0.8.
Lincoln Electric System (LES)

- The estimated B/C ratio in LES is 0.58 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It slightly increases to 0.61 when ATP projects are also included (at a reduced value of 75 percent).

- Overall, the low B/C ratio in LES is primarily driven by the limited APC savings.
  - The cost of economic projects is $45 million in LES, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $5-6 million due to relatively limited congestion-relief provided in the later years.
  - The benefit related to mitigation of transmission outage costs is estimated to be $7 million, reducing LES’ gap to reach a B/C ratio of 0.8.

- Another factor that contributes to a lower B/C ratio in LES is that it does not receive any public policy benefits.
  - LES does not have a renewable goal, but it is responsible for about $6 million of the costs for public policy projects (allocated regionally on a LRS basis).

- Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).
  - These additional benefits could either reduce or eliminate LES’ gap to reach a B/C ratio of 0.8.
The estimated B/C ratio in KCPL is 0.77 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It increases to 0.85 when ATP projects are also included (at a reduced value of 75 percent) and thus exceed the 0.8 threshold.

Overall, the low B/C ratio in KCPL is primarily driven by the limited APC savings.

- The cost of economic projects is $174 million in KCPL, accounting for approximately 60% of total costs. The present value of 40-year APC savings for 2013-2052 is only $24 million if ATP projects are not built and $43 million if they are built. ATP projects allow KCPL to slightly increase its sales quantity and associated sales revenues, which result in an additional $19 million of APC savings in present value terms.

- The benefit related to mitigation of transmission outage costs is estimated to be $27-28 million, reducing KCPL’s gap to reach a B/C ratio of 0.8.

Benefits from meeting public policy goals exceed the costs of public policy projects by approximately $29 million, which increases the B/C ratio in KCPL.

Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).

- These additional benefits could either reduce or eliminate KCPL’s gap to reach a B/C ratio of 0.8.
The estimated B/C ratio in SUNC is 0.48 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It increases to 0.69 when ATP projects are also included (at a reduced value of 75 percent).

Overall, the low B/C ratio in SUNC is primarily driven by the higher APCs.

- The cost of economic projects is $24 million in SUNC. At the same time, the present value of 40-year APCs for 2013-2052 increases by $10 million.
- ATP projects reduce congestion in SUNC and increase sales revenues, which result in an estimated increase of $10 million in APC savings in present value terms.
- The benefit related to mitigation of transmission outage costs is estimated to be $4 million, reducing SUNC’s gap to reach a B/C ratio of 0.8.

Another factor that contributes to a lower B/C ratio in SUNC is that it receives no public policy benefits, but it is responsible for about $3 million of the costs for public policy projects (allocated regionally on a LRS basis).

Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).

- These additional benefits could either reduce or eliminate SUNC’s gap to reach a B/C ratio of 0.8.
Appendix 3 – RCAR PROMOD Assumptions
PROMOD Assumptions

This appendix summarizes the key modeling assumptions in PROMOD market simulations that are used to estimate adjusted production cost (APC) savings.

1. Transmission
SPP has provided a powerflow and PROMOD system database (developed for the 2013 ITP20 study) to be used as a starting point. The data represents the Business as Usual (BAU) future, set up to model years prior to 2033.

The following changes were made to create more realistic cases for the purpose of the RCAR study:

- Constraints from the ITP10 event file were added
- The top 40 temporary flowgates from 2012 were added to the event file
- The top 10 constraints from the 2011 SPP State of the Market Report were added the event file
- The PAT tool was used to develop additional transmission constraints for the SPP system
- Ratings of individual branches were taken from the powerflows used in the year/case combination

2. External Regions
The external regions were modeled consistently across all of the cases analyzed to ensure that the benefits pertain only to changes in SPP’s transmission expansion. The system footprint is based on what is used in the SPP ITP20 process, including the following regions:

- SPP
- MISO (including Entergy and CLECO)
- MAPP Non-MISO
- PJM
- SERC – Central Sub-region, Southeast Sub-region, AECI

3. Generation
The generation was modeled consistent with the assumptions used in the 2013 ITP20 study. As shown below, the capacity additions through 2018 are mainly driven by the renewable goals. Significant amount gas capacity is added after 2018 to maintain reserve margins at or above target levels. Only limited amount of existing capacity is assumed to retire, mostly after 2023.
Figure 1

Generation Assumptions in SPP Footprint

(a) Existing Capacity

(b) Additions and Retirements

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* Numbers reflect total nameplate capacity in MW for SPP’s 16 pricing zones

4. Fuel Costs

Fuel price projections were modeled consistent with the assumptions used in the 2013 ITP20 study. The data is derived from the Ventyx Spring 2012 Reference Case and NYMEX futures.

- The gas price assumptions are developed based on the NYMEX futures for Henry Hub as of April 23, 2012. They increase from current levels to $4.9 per MMBtu in 2018, $6.3 in 2023, and $9.5 in 2033 (in nominal dollars). The prices in the SPP footprint are slightly lower than Henry Hub prices, as a result of negative basis differentials.

- The coal prices also increase, although not as fast as gas prices. The average delivered price in SPP is assumed to be $2.0 per MMBtu in 2018, $2.5 in 2023, and $3.4 in 2033 (in nominal dollars). The plant-specific prices vary due to differences in transportation costs.
5. Load Forecast
Load projections were modeled consistent with the assumptions used in the 2013 ITP20 study. The load forecast was obtained through a survey of membership.

- Data based on the 2023 Summer Peak MDWG powerflow with adjustments for load growth up until 2033
- MDWG submitted summer peak values used to determine the load in the years 2018 and 2023
- Both peak and energy in SPP increases by approximately 1.3% per year through the study horizon
6. Emission Prices
Emission price projections were modeled consistent with the assumptions used in the 2013 ITP20 study.

- $500/ton for annual NOX, $1,000/ton for seasonal NOX, $250-500/ton for SO2, and zero for CO2 and Hg, increasing at inflation

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Appendix 4 - RCAR Project List
The projects included in the RCAR analysis are posted at: