Monday, January 30, 2012
1:00 - 5:00 p.m.
Intercontinental Room - Capital Ballroom
Austin, Texas

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of October 24, 2012 Minutes

3. UPDATES
   a. RSC Financial Report
   b. SPP
   c. FERC

4. BUSINESS MEETING
   a. Approval of RARTF Report (Action Item) ........................................................... Michael Siedschlag
   b. Approval of Patricia Salman as 2011 Auditor & Preparation (Action Item)........ Pat Mosier

5. REPORTS/PRESENTATION
   a. CAWG Report........................................................................................... Dr. Mike Proctor/Pat Mosier
   b. Order 1000
      - SPCTF on Order 1000 .................................................................................... Ricky Bittle
      - RSC Seams Cost Allocation Consultant (Brattle) Report .................... Johannes Pfeifenberger
   c. ITP10/ITPNT............................................................................................................. Lanny Nickell
   d. Integrated Marketplace Update ................................................................. Bruce Rew
   e. EPA Rules Update .............................................................................................. Michael Desselle
   f. ATRR Update ....................................................................................................... Paul Suskie

6. SCHEDULING OF NEXT REGULAR MEETING, SPECIAL MEETINGS OR EVENTS
   a. RSC Meetings:
      April 23, 2012 – Oklahoma City, OK          July 30, 2012 – Kansas City, MO
      October 29, 2012 – Little Rock, AR
Southwest Power Pool
REGIONAL STATE COMMITTEE
Eldorado Hotel & Spa, Santa Fe, NM
October 24, 2011

• M I N U T E S •

Administrative Items:
The following members were in attendance:

- Jeff Davis, Missouri Public Service Commission (MOPSC)
- 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)
- Thomas Wright, Kansas Corporation Commission (KCC)

President Jeff Davis called the meeting to order at 1:05 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 – Attachment 1).

President Davis asked for adoption of the July 25 and August 19, 2011 meeting minutes (RSC Minutes 7/25/11 & 8/19/11 - Attachment 2). Patrick Lyons moved to approve the minutes as presented; Tom Wright seconded the motion. The minutes were unanimously approved.

Updates

RSC Financial Report
Paul Suskie provided the RSC Financial Report (Financial Report and Audit – Attachment 3). Mr. Suskie reported that the group remained under budget.

Mr. Suskie reported that the RSC 2010 Audit report showed no issues and requested a motion to accept. Patrick Lyons moved to accept the 2010 Audit; Tom Wright seconded the motion. The motion passed unanimously.

SPP Report
Nick Brown provided the SPP report. Last month the Environmental Protection Agency (EPA) issued new rules that would greatly impact reliability. SPP has written two letters to the EPA and copied the RSC as well as US Congressional delegations. PJM, MISO, ERCOT, SPP and NYISO have distributed a list of proposed rules to offer a “Reliability Safety Valve”. This proposal has been posted on the various ISO/RTO websites. Mr. Brown asked that this document be read and feedback provided. He stressed that SPP needs continued help from the state commissions.

Mr. Brown thanked those who attended the morning educational session regarding SPP 101 and promised follow-up.

FERC
Mr. Patrick Clarey provided an update on recent FERC activities:
September:
FERC issued an order on MISO’s request to waive cost allocation associated with MVP projects for a period of time to the Entergy region once Entergy joins. FERC found that the requested waiver of certain sections of the MISO Tariff was an inappropriate vehicle for implementing the transition period that MISO seeks for Entergy. FERC made no findings here as to the nature or the duration of any transition arrangements that may be appropriate to integrate Entergy into MISO.

FERC began a series of informational conferences to aid stakeholders in the Order No. 1000 compliance process. These meetings included meetings with the Strategic Planning Committee (SPC) and Entergy Regional State Committee (ERSC).

October
FERC denied requests for rehearing of a June 17, 2010 order that accepted proposed revisions to SPP’s tariff to implement the Highway/Byway Methodology for allocating the costs of certain transmission facilities.

FERC also affirmed MISO’s MVP cost allocation proposal but required periodic reviews at least every three years of the costs and benefits of the cumulative effects of all approved MVP projects and post the analyses on MISO’s website.

Business Meeting
Election
President Davis called for a motion for the election of officers. Patrick Lyons moved to elect the following slate of officers effective January 1, 2012:

- President – Olan Reeves
- Vice President – Tom Wright
- Secretary/Treasurer – Dana Murphy

Donna Nelson seconded the motion. The motion passed unanimously.

Adoption of RSC 2012 Budget
Paul Suskie reported that it is procedure to present the proposed budget and projected budgets two years out (RSC 2012 Budget – Attachment 4). The proposed budget does not include the seams consultant, Brattle Group. Mr. Suskie asked for a motion to approve. Patrick Lyons moved to adopt the 2012 Budget as submitted; Dana Murphy seconded the motion. The motion passed unanimously.

Cost Allocation Working Group (CAWG) Report
Mike Proctor provided an update on CAWG activities (CAWG Report – Attachment 5). Dr. Proctor provided information regarding waiver requests for new designated resources from the Nebraska Public Power District (NPPD) and Omaha Public Power District (OPPD) and two transformers (Thistle and Hitchland) from the Priority Projects. The CAWG recommended that these four waivers be approved as recommended by the SPP Staff.

Other issues before the CAWG are: cost allocation for what the Area Generation Interconnection Task Force called a Hub and Spoke System and period of transfers for the Balanced Portfolio.

Waiver Requests
Katherine Prewitt provided information regarding NPPD’s and OPPD’s Aggregate Study Waiver requests and SPP Staff’s recommendations (Waivers – Attachment 6):

The recommendation of SPP staff is to approve the increase of the Safe Harbor Cost Limit to $8,100,000 based on the length of the NPPD’s power purchase contract term.
The recommendation of SPP staff is to approve the increase of the Safe Harbor Cost Limit to $12,150,000 based on the length of the OPPD’s power purchase contract term.

Ms. Prewitt then provided information regarding the Hitchland and Thistle transformer waiver requests.

**Staff recommends for the SPP Board to approve Mid-Kansas’s classification waiver request to use the 345 kV higher voltage level of the Thistle (Medicine Lodge) 345/138 kV transformer for cost allocation purposes.**

**Staff recommends the SPP Board to approve SPS’s classification waiver request to use the 345 kV higher voltage level of the Hitchland 345/230 kV transformer circuit 2 for cost allocation purposes.**

During discussion, it was decided that the Regional Allocation Review Task Force (RARTF) should review these and other waivers in the future.

**Olan Reeves moved to approve the NPPD and OPPD waiver requests; Tom Wright seconded the motion. The motion passed with Mike Siedschlag in abstention.**

**Tom Wright moved to take no action regarding the transformer waiver requests; Donna Nelson seconded the motion. The motion passed with Patrick Lyons and Mike Siedschlag opposed.**

President Davis introduced special guests from FERC: Commissioner John Norris; Mike Bardee, General Counsel; and Jeff Dennis, FERC staff. Also introduced were: Michael Ming, Oklahoma Secretary of Energy and Jay Albert, Oklahoma Deputy Secretary of Energy. Commissioner Norris complimented the group on its great work with the Highway-Byway model and looks forward to future engagement regarding the Integrated Marketplace.

**RSC Seams Cost Allocation Consultant (Brattle) Report**
Johannes Pfeifenberger provided an update on the RSC seams and cost allocation efforts (Brattle Report – Attachment 7). Mr. Pfeifenberger encouraged everyone to review Appendices A & B. Sam Loudenslager reported that to date there has been great participation on the Seams Cost Allocation Task Force (SCATF).

**RARTF Update**
Michael Siedschlag reviewed activities of the Regional Allocation Review Task Force (RARTF Update – Attachment 8). Mr. Siedschlag recognized members of the task force stating that the group has received great member support. In September the group received presentations from three different groups and incorporated proposals into the Whitepaper. An RARTF meeting is scheduled in Dallas on November 21 and 22. At that time, sample data will be available to run through methodology projected from ITP10. It is expected that the draft Whitepaper will be completed and ready to present at the January meetings. All are encouraged to participate in the RARTF discussions.

**Report on RSC Motions**
Terri Gallup and Jake Langthorn provided an update on the RSC Motions (RSC Motions – Attachment 9). Ms. Gallup reviewed the Project Cost Working Group (PCWG) Whitepaper; Mr. Langthorn addressed the Study Estimate Design Guide. It was pointed out that the Standardized Cost Estimate Reporting Template (SCERT) will be a future tool used for all estimates and quarterly reporting. President Davis commended them on a job well done.

**FERC Order 1000 & SPP’s Compliance Plan**
Paul Suskie provided a high level overview of FERC Order 1000 compliance filing deadlines and requirements (Order 1000 – Attachment 10).
Regional State Committee
October 24, 2011

Update of Balance Portfolio and Priority Projects
Katherine Prewitt provided an update on the Balance Portfolio and Priority Projects (BP & PP Update – Attachment 11).

ITP20
Katherine Prewitt presented an ITP20 overview (ITP20 – Attachment 12). It was requested that the Economic Studies Working Group (ESWG) send a list of current assumptions on natural gas, carbon, etc.

ATRR
Paul Suskie provided the current Annual Transmission Revenue Requirements (ATTRs) per SPP OATT, Attachment H, as of October 14, 2011 (ATTRs – Attachment 13). President Davis requested that the group be updated on ATRRs in January.

President Davis recognized Jeff Cloud of the Oklahoma Corporation Commission for his service in the RSC from 2007 – 2011. Mr. Cloud held the offices of Secretary/Treasurer and Vice President serving with distinction.

President Davis expressed his appreciation to Nick Brown and Jim Eckelberger for their help and patience during his tenure. This is President Davis’s last meeting as President of the RSC.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President Davis noted that the next regularly scheduled meeting is on January 30 in Austin, Texas.

With no further business, the meeting adjourned at 5:00 p.m.

Respectfully Submitted,

Paul Suskie
# Regional State Committee
## For the Twelve Months Ending December 31, 2011
### Budget vs. Actual

<table>
<thead>
<tr>
<th></th>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Income</td>
<td>367,231</td>
<td>816,000</td>
<td>(448,769)</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>367,231</td>
<td>816,000</td>
<td>(448,769)</td>
</tr>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Travel</td>
<td>132,636</td>
<td>105,000</td>
<td>27,636</td>
</tr>
<tr>
<td>Meetings</td>
<td>18,389</td>
<td>28,000</td>
<td>(9,611)</td>
</tr>
<tr>
<td>Audit</td>
<td>2,302</td>
<td>2,000</td>
<td>302</td>
</tr>
<tr>
<td>Administrative Costs</td>
<td>-</td>
<td>1,000</td>
<td>(1,000)</td>
</tr>
<tr>
<td>RSC Consultant</td>
<td>72,795</td>
<td>100,000</td>
<td>(27,205)</td>
</tr>
<tr>
<td>Technical Conference</td>
<td>-</td>
<td>30,000</td>
<td>(30,000)</td>
</tr>
<tr>
<td>Seams Cost Allocation</td>
<td>141,109</td>
<td>550,000</td>
<td>(408,891)</td>
</tr>
<tr>
<td><strong>Total Expense</strong></td>
<td>367,231</td>
<td>816,000</td>
<td>(448,769)</td>
</tr>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
SPP RARTF: Final Report

RSC Presentation

Paul Suskie, SPP Staff
psuskie@spp.org

Michael Siedschlag, RARTF Chair
michael.siedschlag@hdrinc.com
RARTF Overview: Attachment J, Section III.D Requirements & RARTF Charter
OATT REQUIREMENTS
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.
RARTF CHARTER
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>Role</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>
</tr>
<tr>
<td>Commissioner</td>
<td>Olan Reeves</td>
<td>Arkansas Public Service Commission</td>
</tr>
<tr>
<td></td>
<td>Bary Warren</td>
<td>Empire District Electric</td>
</tr>
<tr>
<td></td>
<td>Philip Crissup</td>
<td>Oklahoma Gas &amp; Electric</td>
</tr>
<tr>
<td></td>
<td>Harry Skilton</td>
<td>SPP Board of Director</td>
</tr>
</tbody>
</table>
(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.
RARTF’s Deliverables

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.
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
Overview of RARTF Report

Unanimously adopted 1/3/2012
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.
Sect. 3.1 - 10 Principles of the RARTF

(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

Because the Regional Cost Allocation Review is for projects that will be built under SPP’s Highway/Byway cost allocation methodology, the RARTF recommends 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 recommends 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 proposes 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 would issue two evaluation reports to assess the impacts of the Highway/Byway cost allocation methodology.
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.” *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 32 (2011).

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.
3.3 Weighting Given to Projects without NTCs.

When conducting the Regional Cost Allocation Review described in Section 3.2(2) above, the RARTF recommends that projects with ATPs with an in-service of 10 years or less, but without NTCs, be considered in the Review. However, in considering these projects, the RARTF recommends a reduced weighting of the valuation of the costs and benefits at seventy-five percent (75%) of the total value. The RARTF makes this 0.75 weighting recommendation due to the less certain nature of these projects as well as their costs and benefits.
3.4 Baseline for the RCA Review

- Because the Regional Cost Allocation Review is for projects that will be built under SPP’s Highway/Byway cost allocation methodology, the RARTF recommends 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 baseline used in the first Regional Cost Allocation Review should be the same baseline used in all future reviews.
3.5 Calculation of Benefits to Cost Ratios.

- The RARTF recommends using a methodology in which each assessment report 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 Use of a 40-Year Project Evaluation.

- To remain consistent with SPP’s OATT, the RARTF recommends using a 40-year assessment to evaluate all transmission projects in the Regional Cost Allocation Review. Pursuant to SPP’s OATT, the last 20 years of benefits should have a terminal value.
3.7 Recommendation on the Calculation of Costs.

- When conducting the Regional Cost Allocation Review the RARTF recommends using the most up to date ATRR for each zone.
3.8 Benefits to be Calculated.

- When conducting the Regional Cost Allocation Review, the RARTF recommends using the list of benefits in this section to assess the benefit to cost ratio. Additionally, 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.
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*
3.8 Benefits to be Calculated.

• Summary of RARTF’s recommendation on ESWG’s work.

• The RARTF recommends that the MOPC make the development of these metrics a priority for the ESWG since, absent a methodology for valuing the each of the benefits, the Regional Cost Allocation Review may not provide a complete reasonableness assessment.

• The ESWG was presented with the RARTF Report on January 12, 2012 to understand the task at hand.
3.9 Assumptions to be Used.

- The RARTF recommends that the assumptions used in the Regional Cost Allocation Review should be vetted through SPP’s open and transparent stakeholder process.
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.”
4.2 Zones Above Threshold but Below 1.0 B/C.

- Pursuant to the RARTF Charter, the RARTF recommends that a threshold be established to determine when it is warranted that SPP staff study possible remedies as stated in Section 4.1.

- Additionally, 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 benefit to cost ratio, should be used and considered as a part of SPP’s transmission planning process in the future.
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:

<table>
<thead>
<tr>
<th>Remedy</th>
<th>Entity with Authority/Duty to Implement</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Acceleration of planned upgrades;</td>
<td>SPP BOD</td>
</tr>
<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>
</tr>
<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>
</tbody>
</table>
### 6.1 Proposed RCA Review Timeline

<table>
<thead>
<tr>
<th>Ref.</th>
<th>Action</th>
<th>1Q11</th>
<th>2Q11</th>
<th>3Q11</th>
<th>4Q11</th>
<th>1Q12</th>
<th>2Q12</th>
<th>3Q12</th>
<th>4Q12</th>
<th>1Q13</th>
<th>2Q13</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Establishment of RARTF</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>RARTF Develops Methodologies</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Stakeholder’s Endorsement of RARTF Methodologies</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>ESWG Determines Benefits Calculation Methodologies</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Staff Prepares &amp; Implements Regional Cost Allocation Review</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Stakeholder Vetting of Regional Cost Allocation Review</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
7.1 4 Recommendations Going Forward

(1) First, the Regional Cost Allocation Review should not be conducted until the ESWG completes its work in defining how the benefits described in Section 3.8 are calculated.

(2) Second, the RARTF recommends that the SPP Board of Directors approve the RARTF Report, and SPP stakeholders develop and revise Business Practices, the ITP Manual, and, as necessary the OATT, to effectively implement the Regional Cost Allocation Review process and potential remediation actions as contained in this Report. Once the Regional Cost Allocation Review process and potential remedies are a part of SPP’s Business Practices or ITP Manual any subsequent changes to the procedures detailing this process must be reviewed by the MOPC and RSC and approved by the Board. The RARTF finds that many of the issues addressed in the RARTF Report may serve as valuable and useful additions to SPP’s Business Practices, the ITP Manual, as well as the language of the OTT, for existing transmission planning processes and future Regional Cost Allocation Reviews.
7.1 4 Recommendations Going Forward

(3) Third, as required by SPP’s OATT, the Regional Cost Allocation Review must be conducted at least every three years. Because this three year requirement can be synchronized with SPP’s three year ITP planning cycle, the RARTF recommends that the Regional Cost Allocation Review be conducted simultaneous with SPP’s three-year planning cycle.

(4) Fourth, the 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.
Next Steps for Approval of Methodology

- Meeting with Stakeholders
  - ESWG Meeting – January 12, 2012
  - MOPC Meeting – January 17-18, 2011 (Need Approval)
  - RSC Meeting – January 30, 2011 (Need Approval)
  - RSC BOD – January 31, 2011 (Asking Approval)
Next Steps for ESWG & Tasks

  - ESWG develops methods to capture the benefits of transmission projects recommended by the RARTF
  - The ESWG begins process in January 2012 ending in October 2012
- The RARTF recommends that the Regional Cost Allocation Review should not be finalized until the ESWG develops the methodology for valuing the benefits that will be used in the Review.
Request of the MOPC

- Approve the Report of the RARTF
QUESTIONS???
Regional Allocation Review Task Force Report

Executive Summary

This Report contains the recommendations of the Regional Allocation Review Task Force (RARTF) as to how Southwest Power Pool (SPP) should review the Highway/Byway transmission cost allocation methodology per Attachment J, Section III.D of SPP’s Open Access Transmission Tariff (OATT). The RARTF recommends that this review be called the “Regional Cost Allocation Review”.

The RARTF makes a number of recommendations as to how SPP should conduct the Regional Cost Allocation Review. This includes a recommendation of applying ten principles, used by the RARTF, as a guide to conducting the review. These principles include: simplicity; acknowledgment of the “roughly commensurate” legal standard; equity over time; the use of the best quantifiable information available; consistency; transparency; stakeholder input; the use of real dollars values; and the inclusion in the review of Board approved transmission plans with more weight being given to nearer term projects. Applying these principles the RARTF recommends that:

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

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

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

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

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

- Through the work of the Economic Studies Working Group (ESWG) certain benefits be measured in the review. These benefits include: adjusted production costs; positive impact on capacity required for losses; improvements in reliability; remedy benefits in future reviews; reduction of emission rates and values; reduced operating reserves benefits; improvements to import/export limits; and public policy benefits.
Additionally, the Report contains a recommendation regarding the establishment of a Benefit to Cost (B/C) threshold. The recommended B/C threshold would be the basis for SPP staff and stakeholders to evaluate remedies for any zone falling below the threshold. Specifically, the Report recommends:

- That a threshold be set at a B/C ratio of 0.8. With this benchmark, if the review shows that any zones fall below this threshold; SPP Staff will study and report on potential remedies for these zones.

- A list of recommended mitigation remedies for SPP staff to study and report for any zone below the 0.8 threshold. The recommended list of remedies in preferential order includes, but is not limited to: (1) acceleration of planned upgrades; (2) issuance of new upgrades; (3) applying highway funding to one or more byway projects; (4) applying highway funding to one or more seams projects; (5) zonal transfers (similar to balanced portfolio transfers) to offset costs or a lack of benefits to a zone; (6) exemptions for cost associated with the next set of projects; and (7) changes to cost allocation percentage.

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

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.”

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 RSC President Jeff Davis and MOPC Chairman Bill Dowling jointly selected the members of the RARTF. The 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 Commision</td>
</tr>
<tr>
<td>Bary Warren</td>
<td>Empire District Electric</td>
</tr>
<tr>
<td>Philip Crissup</td>
<td>Oklahoma Gas &amp; Electric</td>
</tr>
<tr>
<td>Harry Skilton</td>
<td>SPP Board of Director</td>
</tr>
</tbody>
</table>

Pursuant to the mandate in the RARTF Charter, the RARTF prepared this White Paper which includes its recommendation as to how to define the “analytical methods” to be used in the Regional Cost Allocation Review.

SECTION 1: OVERVIEW

1.1 Overview of SPP Tariff Requirements

Attachment J, Section III.D to the SPP OATT establishes a four-step process for the Regional Cost Allocation Review. These steps are:

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.
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 NTC 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.  

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 contains 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 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 contains a list of key deliverables for the RARTF which states:  

The RARTF scope of work and key deliverables include the following:  

---  
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.
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 7th 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 7th 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 cited the 7th Circuit's roughly commensurate standard in approving SPP's Highway/Byway cost allocation methodology, Midwest Independent Transmission System Operator’s (MISO) multi-value project (“MVP”), and California Independent Transmission System Operator’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, as well as FERC’s Orders on Rehearing for SPP’s Highway/Byway cost allocation methodology and on MISO’s MVP cost allocation methodology. Specifically, as quoted by FERC in its October 20, 2011 Order on Rehearing in, the 7th Circuit stated that the

---

8 576 F.3d 470 (7th Cir. 2009).
9 *Southwest Power Pool, Inc.,* 137 FERC ¶ 61,075 (2011).
11 *Southwest Power Pool, Inc.,* 137 FERC ¶ 61,075 (2011).
legal standard is that “an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities.”

The RARTF notes a couple of important aspects of the orders from the 7th 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 Benefit/Cost (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.”

Additionally, the RARTF notes that the ICC case and the precedent on which the 7th Circuit relied in its decision did articulate certain principles that a cost allocation method must satisfy. These include:

- A cost allocation mechanism may tracks 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 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 articulable 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.

The RARTF considered the research of 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 Section 4 below.

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.\(^{14}\)

The difficulties of implementing cost allocation methods for transmission projects are evident. Because of the many challenges associated with regional transmission cost allocation and its accompanying critics, it is critical that SPP’s Regional Cost Allocation Review be based upon reasonable, sound, and defensible methods.

**SECTION 2: SPP STAFF RESEARCH**

2.1 SPP Staff Research

In preparing for the work of the RARTF, SPP staff gathered information that would be helpful to SPP stakeholders in developing analytical methods to review both the cost and the benefits of SPP transmission projects. SPP staff researched how transmission costs are allocated in different regions of the United States and the various ways that benefits are calculated for transmission projects. A summary of SPP staff’s research is provided below. The research helps to illustrate the difficulty of allocating cost of transmission projects and the number of methods available for use in measuring the benefits of transmission projects. The RARTF believes that this information can help SPP stakeholders to develop sound analytical methods to determine the impacts of SPP’s Highway/Byway cost allocation methodology that are reasonable, sound, and defensible.

2.2 Transmission Cost Allocation Methods in the United States and SPP

The difficulties of transmission cost allocation are demonstrated by the wide variety of methods used in the various regions of the United States. This difficulty is further demonstrated by the inability of most regions to adopt transmission cost allocation methodologies for regional overlay projects. This is effectively illustrated in Figure 1, below, which presents a summary of the various transmission cost allocation methods in the United States, as prepared by the Brattle Group.

---

\(^{14}\) *Transmission Planning Processes Under Order No. 890, Notice of Request for Comments at 5, Docket No. AD09-8-000 (Oct. 8, 2009).*
### Summary of Current Cost Allocation Methodologies

<table>
<thead>
<tr>
<th>RTO/Region</th>
<th>General Tariff Methodology</th>
<th>Reliability</th>
<th>“Economic” Projects</th>
<th>Renewables</th>
<th>Regional/Overlay Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAISO</td>
<td>PS 100% ≥2200kV; otherwise LP or M</td>
<td>✓</td>
<td>✓</td>
<td>✓ GI and location-constrained resource tariff (Tehachapi)</td>
<td>✓ Not specifically discussed, but 100% PS of all network facilities</td>
</tr>
<tr>
<td>ERCOT</td>
<td>PS or M</td>
<td>✓</td>
<td>✓</td>
<td>✓ CREZ (100% PS)</td>
<td>✓ Not specifically discussed, but 100% PS of all network facilities</td>
</tr>
<tr>
<td>SPP</td>
<td>Before 6/19/10: 33% PS +67% LP w/ Beneficiary Analysis After 6/19/10: 100% PS ≥3000kV; 33% PS +67% LP &gt;100kV to &lt;3000kV; 100% LP ≤100kV</td>
<td>✓</td>
<td>✓</td>
<td>✓ GI; Highway/Byway PS treatment</td>
<td>✓ Highway/Byway PS treatment</td>
</tr>
<tr>
<td>Southeast</td>
<td>LP (utility specific tariffs)</td>
<td>✓</td>
<td>n/a</td>
<td>n/a (GI only)</td>
<td>n/a</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>PS 100% ≥115kV; otherwise LP or M</td>
<td>✓</td>
<td>too narrowly defined</td>
<td>n/a (GI only)</td>
<td>n/a</td>
</tr>
<tr>
<td>PJM</td>
<td>PS sharing 100% ≥500kV; otherwise LP allocation (beneficiary pays) or M</td>
<td>✓</td>
<td>too narrowly defined</td>
<td>n/a (GI only)</td>
<td>n/a</td>
</tr>
<tr>
<td>MISO</td>
<td>PS sharing 20% ≥345kV; rest LP allocation (beneficiary pays) or M; MVP approach</td>
<td>✓</td>
<td>too narrowly defined</td>
<td>Multi Value Project (“MVP”) PS treatment</td>
<td>MVP PS treatment</td>
</tr>
<tr>
<td>PJM-MISO</td>
<td>Sharing of reliability project based on net flows/beneficiaries</td>
<td>✓</td>
<td>too narrowly defined</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>NYISO</td>
<td>LP allocation (based on beneficiary pays) or M</td>
<td>✓</td>
<td>too narrowly defined</td>
<td>n/a (GI only)</td>
<td>n/a</td>
</tr>
<tr>
<td>WECC (non-CA)</td>
<td>LP; often with cost allocation based on co-ownership</td>
<td>✓</td>
<td>✓ (differs across WECC subregions)</td>
<td>✓ GI (e.g., BPA open season); under discussion in WREZ</td>
<td>n/a – under discussion in WREZ</td>
</tr>
</tbody>
</table>

---

**Figure 1. Cost Allocation Methodologies of Regions of the United States**¹⁵

As has been done in the various regions of the United States, SPP has developed a variety of cost allocation methodologies. Since SPP’s recognition as an RTO and the establishment of the RSC,¹⁶ the SPP Region has developed and implemented differing transmission cost allocations in an evolutionary manner through the RSC. These methods are summarized below in Figure 2.

---


¹⁶ Through SPP’s governance structure, the SPP RSC has been delegated authority to establish cost allocations that the SPP Board of Directors must file at FERC as a Section 205 filing of under the Federal Power Act.
Figure 2. SPP Cost Allocation Methods

The most recent method established by the RSC and approved by FERC is the Highway/Byway cost allocation methodology. The Highway/Byway method 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 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 (T Cs). New upgrades under 100 kV are allocated 100% to the T Cs of the host zone.

![Highway Byway Cost Allocation Overview](image)

**Figure 3. Highway/Byway Cost Allocation Overview**

The ATRRs assigned to the zones are collected from their respective T Cs using the previous year’s 12 month Coincident Peak LRS.

Cost allocation of new construction is the focus of Attachment J to the SPP OATT. The recovery of the ATRR is through Schedule 11 of the OATT and booked by each zone in Attachment H of the OATT.

2.3 Methods of Measuring Transmission Upgrade Benefits

Just as SPP staff’s research found that many different transmission cost allocation methods are used in the United States, staff’s research has found that a number of methods can be used to determine the amount of benefits transmission projects provide to society.

Based upon this research, the RARTF recommends that the benefits to be assessed for the Regional Cost Allocation Review should not be limited to a single methodology. Instead, the RARTF recommends that in order to study a broader scope of benefits in the region, multiple methodologies should be used. Staff believes that a very narrow focus on only one benefit type over a very narrow timeframe does not provide a large enough sample size to reasonably determine the impact of SPP’s Highway/Byway cost allocation methodology. Additionally, because different benefits are valued differently by various people and segments of society, the RARTF believes that in order to provide for a reasonable, fair, and acceptable review of the Highway/Byway, numerous methods should be used in this review as opposed to a single narrowly-focused method. The RARTF’s recommendations are outlined in this Report.

As illustrated below in Figure 4, a number of benefits can be gained from transmission projects.
Figure 4. Benefits of a Robust Transmission System

SPP staff’s research has found that a number of benefits exist that can be measured under a benefit to cost analysis. Although the RARTF does not recommend using all of these benefits for the Regional Cost Allocation Review, they are included below for educational purposes.

**Adjusted Production Cost**

Adjusted Production Cost (APC) has quickly become the “standard” that utilities are employing to measure the benefit of transmission expansion. APC is a measure of the impact on production cost savings by Locational Marginal Price (LMP), taking into account purchases and sales of energy between areas of the transmission grid. APC is determined using a production cost modeling tool that accounts for 8,760 hourly commitment and dispatch profiles for one simulation year. Nodal analysis from the production cost model is aggregated on a zonal basis.

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 the SPP footprint.

References to an APC-based B/C (Adjusted Production Cost-based Benefit-to-Cost ratio) refer to the reduction in APC due to a project divided by the cost of that project.

**Meeting State and Utility Goals and Standards**

This metric links a transmission project to meeting the goals and standards set forth by the utilities and states that are in a study analysis. Simply put – does a transmission project or
portfolio positively contribute to the success of an entity in meeting its stated goals or standards. Traditionally, utilities have looked at standards or goals for renewable energy, but this metric could be extended to plans such as Demand Side Management, Energy Efficiency and SMART grid initiatives.

**Improvements in Reliability (value of improving the ability to keep the lights on)**

This metric has three distinct components:

- **Value of delaying or eliminating the need for previously approved reliability projects:** This component monetizes (quantifies) the reliability benefit as the avoided cost (or additional cost) in dollars of delaying, canceling, or accelerating previously approved reliability projects.
- **Value of improved Available Transfer Capacities (ATCs) of the SPP grid:** This component provides a non-monetized (qualitative) assessment of the added flexibility for the potential redirection of power flows within SPP made possible by ATC increases. The challenge in defining this metric is the development of a meaningful weighting structure of ATC defined for multiple combinations of points of receipt and points of delivery.
- **Value of providing a backstop to a catastrophic event:** This component provides a qualitative assessment of improved grid reliability and its ability to withstand the impact of catastrophic events. This component requires the assessment of catastrophic events and the determination of their probability.

**Enable Efficient Location of New Generation Capacity**

This metric is a quantitative measure of the ability of a transmission project or portfolio to provide for efficient location of new generation capacity. For wind resources, SPP measured distance from the transmission hubs to high wind resource zones. SPP has not yet determined a methodology to use for conventional generation.

**Reduced Losses**

Transmission expansion has an impact on total system losses. This metric serves as a first step in calculating Positive Impact on Capacity required for losses, described below, and gives a quantitative measure for evaluating the relationship between a reduction in losses and the monetary and physical savings from reduced capacity and capital costs.

**Increased Effective Capacity Factor**

This metric is a measure of the value of adding transmission to reduce congestion on curtailed resources. The capacity factor may change due to a reduction in congestion.
**Ability to Reduce Cost of Capacity**

This metric captures the value from reducing the cost of capacity. This metric is an opportunity to capture value which is not currently being captured. SPP does not currently utilize this metric, and it will require additional tools to calculate which are not currently being used by SPP.

**Positive Impact on Capacity Required for Losses**

This metric captures a value for the generation capacity that may no longer be required due to a reduction in losses. Due to a lower amount of losses on the system, there is a lower need for generation capacity to support system loses, improving capacity margins.

**Levelization of Locational Marginal Price (LMP)**

This metric provides a qualitative indicator of the impact an alternate transmission topology could make on regional generation owners’ ability to compete on equal grounds. In the absence of congestion and losses on the system, any generator has the potential to serve any load, and there will be a single system price in each hour. A transmission system with no constraints and low losses makes the electricity market more competitive, as it provides an equal opportunity to all generators with similar costs to compete for loads.

In such transmission systems, the market for new entry will also be more competitive. An increase in congestion and losses places generators at certain locations at a disadvantage relative to other similar-cost generators, making the market less competitive. This metric measures the levelization of LMPs for each transmission topology using the standard deviation of LMPs across locations for the SPP footprint. All else being equal, a decrease in the value of this metric indicates an improvement in the competitiveness of the SPP market.

**Improved Access to Economical Resources Participating in SPP Markets**

This metric provides a qualitative measure of competitiveness across the SPP footprint. It analyzes a generating unit’s ability to compete within its own technology type. Capacity-weighted LMPs are calculated for generating plants of different technology types on an hourly basis, and then averaged across 25% of the largest hourly standard deviations.

**Change in Operating Reserves**

This metric provides a measure for the impact on operating reserves due to transmission expansion. Calculation of this metric requires a capacity expansion model which SPP does not currently license. This metric could provide an opportunity to capture value from reducing operating reserves.

**Transmission Loading Relief (TLR) Reduction - Enabling Market Solutions**

This metric has been utilized in the past to determine the impact on TLR Reduction for transmission expansion plans; however, with the implementation of the Integrated Marketplace
(SPP’s Day Ahead market) in SPP, the need for TLR calls between SPP Balancing Authorities will be eliminated. Congestion will be managed by economic security constrained unit commitment and dispatch.

**Improvements to Import/Export Limits**

This metric quantifies the change in ATC that corresponds to an alternative topology in the Cost-Effective Plan. Three categories of ATC changes are of interest and addressed by this metric:

- **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.

**Improved Economic Market Dynamics Not Measured in the Security Constrained Economic Dispatch Model**

This metric quantifies the impacts on market dynamics that are not captured in a traditional production cost tool. This metric has not been calculated by SPP; however, it should be evaluated for use in future assessments as there is the potential to calculate value not currently being captured by other metrics.

**Improved Economic Market Dynamics Measured in the Nodal Security Constrained Economic Dispatch Model**

This metric measures the impacts on market dynamics as seen in production cost analysis. However, because this metric requires calculating the generation loading distribution factor for every hour, SPP has not yet been able to calculate this metric. Future assessments should evaluate this metric to capture additional value.

**Reduction in Market Price Volatility**

This metric measures the reduction of market price volatility for transmission expansion projects. This metric requires using a stochastic model which SPP does not currently have the ability to process. Future assessments should reevaluate this metric to determine a calculation method which could be used to capture reductions in market price volatility.

**Reduction of Emission Rates and Values**

If an alternative topology results in a lower fossil fuel burn (or less coal-intensive generation), then SO$_2$, NO$_X$, CO$_2$, and Hg emissions would be lower with the alternative topology in place. APC captured the cost savings associated with reduced SO$_2$, NO$_X$, and CO$_2$ emissions because the allowance prices for these pollutants were inputs to the production cost model simulations.
However, since mercury is not a pollutant subject to an allowance price, changes in coal generation and the corresponding changes in mercury emissions are not currently captured.

This metric addresses that analytical deficiency and quantifies the changes in mercury emissions. This metric also quantifies the changes in SO2, NOX, and CO2 emissions so that they may be represented as stand-alone values, separate from APC.

**Transmission Corridor Utilization**

Transmission expansion plans that effectively utilize existing right-of-way (ROW) and have topology that largely avoids environmentally sensitive areas are preferable to those that do not, all else being equal.

The metric is comprised of two sub-metrics. The first sub-metric measures the proportion of transmission expansion plan costs that do not effectively utilize existing ROW. The second sub-metric measures the proportion of transmission expansion plan costs that traverse environmentally sensitive areas.

**Ability to Reduce Cycling of Base Load Units**

This metric evaluates the benefit derived from reducing cycling of large base load generating plants. For purposes of this metric, a cycle occurs each time a unit’s output crosses or reaches the average output, then recedes below this average minus a tolerance during any start-up to shut-down period. A transmission project that reduces the total number of cycles for a base load unit would reduce maintenance costs and prolong the unit’s life span.

If SPP had data on the relationship between the number of cycles and operations and maintenance cost, or had a dollar value associated with excessive versus normal or ideal cycling, this metric could be monetized to determine a value to generators from reduced cycling.

**Generation Resource Diversity**

Transmission topology that results in a more diverse generation capacity expansion plan would add benefit because the power system could respond more flexibly to relative fuel price changes.

This is a semi-quantitative metric based on generation mix (energy basis) from the production cost model simulation. For a given future, this metric is a comparison of the generation mixes (energy basis) from the cost-effective topology and an alternative topology. Both the annual generation mix and the fuel-on-the-margin mix are considered. Of particular interest is whether gas-fired generation approaches or exceeds a specific percentage of the generation mix, because the level and volatility of gas prices is typically relatively high compared to the level and volatility of coal and nuclear fuel prices. Excessive dependence on gas-fired generation, to the detriment of a more balanced dispatch of gas, oil, coal, and nuclear energy, exposes ratepayers to greater fuel price risk.
**Ability to Serve Unexpected New Load**

This metric measures the ability of an alternative transmission topology to serve new load at levels that are different from those considered in APC. The metric tests two types of load changes: an overall incremental load in proportion to load forecast used in the development of each future and load shifts between major load centers.

**Part of overall EHV Overlay Plan**

This metric serves as an indicator to determine how a project fits in with the overall EHV Overlay Plan. If a project keeps appearing across multiple studies, it is a strong candidate for future development. This metric applies value for projects that fit in well with the overall goals of EHV expansion for a region.

**SECTION 3: RECOMMENDED REVIEW METHODOLOGY**

3.1 **RARTF Recommended Principles for the Regional Cost Allocation Review**

Based upon research, stakeholder input and extensive discussion, the RARTF recommends that the Regional Cost Allocation Review be conducted utilizing the following principles:

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

Because the Regional Cost Allocation Review is for projects that will be built under SPP’s Highway/Byway cost allocation methodology, the RARTF recommends that certain projects and plans which are approved by the Board of Directors be evaluated. However, due to the less certain nature of some projects, the RARTF recommends 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 proposes 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 would issue two evaluation reports to assess the impacts of the Highway/Byway cost allocation methodology. The two evaluations would include an assessment of:

1. **NTCs:** All SPP projects that have been issued an NTC since June 2010;\(^{17}\) and

2. **NTCs and Projects within 10 years:** All SPP projects that have been issued an NTC\(^ {18}\) 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.

---

\(^{17}\) 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.” *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 32 (2011).

\(^{18}\) 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.
3.3 RARTF Recognition of Weighting Given to Projects without NTCs.

When conducting the Regional Cost Allocation Review described in Section 3.2(2) above, the RARTF recommends that projects with ATPs with an in-service of 10 years or less, but without NTCs, be considered in the Review. However, in considering these projects, the RARTF recommends a reduced weighting of the valuation of the costs and benefits at seventy-five percent (75%) of the total value. The RARTF makes 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 Regional Cost Allocation Review is for projects that will be built under SPP’s Highway/Byway cost allocation methodology, the RARTF recommends 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 baseline used in the first Regional Cost Allocation Review should be the same baseline used in all future reviews.

3.5 RARTF Recommended Calculation of Benefits to Cost Ratios.

The RARTF recommends using a methodology in which each assessment report 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.

To remain consistent with SPP’s OATT, the RARTF recommends using a 40-year assessment to evaluate all transmission projects in the Regional Cost Allocation Review. Pursuant to SPP’s OATT, the last 20 years of benefits should have a terminal value.

3.7 RARTF Recommendation on the Calculation of Costs.

When conducting the Regional Cost Allocation Review the RARTF recommends using the most up to date ATRR for each zone.

3.8 RARTF Recommendation on Benefits to be Calculated.

The RARTF recommends that the set of benefit categories listed below in this section be used in the Regional Cost Allocation Review process. It is further recommended that before the Regional Cost Allocation Review is conducted, the development of specific metrics that quantify 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 amount but in other terms (MW, MWh, Tons, etc.), 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 most conservative or lowest number in any range provided by the ESWG will be used in the Regional Cost Allocation Review. For those metrics that the ESWG does not endorse monetizing, the ESWG will not provide a monetized value for use in the Regional Cost Allocation Review 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 Regional Cost Allocation Review, the RARTF recommends using the list of benefits in this section to assess the benefit to cost ratio. Additionally, 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 recommends be used in the Regional Cost Allocation Review are:

- **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.\(^{19}\)

• **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. This metric is still under evaluation by the ESWG and will continue to be developed throughout early 2012.\(^{20}\)

3.9 **RARTF Recommendation on Assumptions to be Used.**

The RARTF recommends that the assumptions used in the Regional Cost Allocation Review should be vetted through SPP’s open and transparent stakeholder process.

**SECTION 4: REPORT THRESHOLDS**

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.\(^{21}\) 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

---

\(^{19}\) 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.

\(^{20}\) The RARTF notes that although it is SPP’s current practice is to plan for public policy objectives, under FERC Order 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.

\(^{21}\) 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.
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 finds 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 recommends that a threshold be established to determine when it is warranted that SPP staff study possible remedies as stated in Section 4.1.

Additionally, 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 benefit to cost 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 Regional Cost Allocation Review are below the threshold in Section 4.1, the RARTF recommends that the SPP staff should evaluate, and recommend possible mitigation remedies for the zone. In Figure 5, there is a list of mitigation remedies that the RARTF recommends SPP staff 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, listed in order of preference, that SPP staff could evaluate include, but are not limited to:

22 The Tulsa Reactor from Priority Projects is estimated to be the only project in service by June 2012.
23 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).
<table>
<thead>
<tr>
<th>Remedy</th>
<th>Entity with Authority/Duty to Implement</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Acceleration of planned upgrades;</td>
<td>SPP BOD</td>
</tr>
<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>
</tr>
<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>
</tbody>
</table>

Figure 5. Potential remedies.

SECTION 6: TIMELINE

6.1 Proposed Regional Cost Allocation Review Timeline

The RARTF recommends the Action Plan, identified in Figure 6 below, be followed to conduct the Regional Cost Allocation Review. The ESWG’s determination of the metric and values of all benefits to be studied as stated in Sections 3.9 and 7.1 is critical to the timeline.

Figure 6. RARTF Proposed Action Plan
SECTION 7: ADDITIONAL RECOMMENDATIONS/CONSIDERATIONS

7.1 Recommendations Going Forward

The RARTF makes four additional recommendations:

First, the Regional Cost Allocation Review should not be conducted until the ESWG completes its work in defining how the benefits described in Section 3.8 are calculated. As stated in Figure 6, the RARTF recommends that the ESWG define the benefits by the end of the third quarter of 2012. This will allow for Regional Cost Allocation Review to be conducted pursuant the methods recommended by the RARTF.

Second, the RARTF recommends that the SPP Board of Directors approve the RARTF Report, and SPP stakeholders develop and revise Business Practices, the ITP Manual, and, as necessary the OATT, to effectively implement the Regional Cost Allocation Review process and potential remediation actions as contained in this Report. Once the Regional Cost Allocation Review process and potential remedies are a part of SPP’s Business Practices or ITP Manual any subsequent changes to the procedures detailing this process must be reviewed by the MOPC and RSC and approved by the Board. The RARTF finds that many of the issues addressed in the RARTF Report may serve as valuable and useful additions to SPP’s Business Practices, the ITP Manual, as well as the language of the OTT, for existing transmission planning processes and future Regional Cost Allocation Reviews.

Third, as required by SPP’s OATT, the Regional Cost Allocation Review must be conducted at least every three years. Because this three year requirement can be synchronized with SPP’s three year ITP planning cycle, the RARTF recommends that that the Regional Cost Allocation Review be conducted simultaneous with SPP’s three-year planning cycle. This coordination can assist SPP and its stakeholders in evaluating past and conducting future three-year planning cycles.

Fourth, the 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.
RSC Auditor Background Information

Since its inception in 2004, the Regional State Committee (RSC), pursuant to its by-laws, has engaged an auditor to provide an independent audit of its cash receipts and expenditures and to file the relevant income tax returns. Also since its inception, because the books and records of the RSC reside in Little Rock, Arkansas, it has been the responsibility of the Arkansas Commissioner member of the RSC to seek out an auditor to perform these functions. For its first filings with the IRS and performance of its first audit, the Arkansas Commissioner member of the RSC engaged Patricia Salman of Cabot, Arkansas. As an associate of the CPA firm engaged by the Arkansas Commission to audit the MARC conference held in Little Rock, Ms. Salman was familiar with the regulatory commission, and was, and has continued to be, approved by the RSC for engagement to audit its books and file its tax returns. Ms. Salman was also engaged to audit the books and records of the Entergy-Regional State Committee (ERSC) and to file those returns, beginning for the year 2010, the first year of financial activity for the ERSC.

The SPP Regional State Committee agrees to retain Patricia Salman & Associates to conduct the annual examination of the financial accounts of the Regional State Committee for 2010 as required by Section 9, Audits of the Regional State Committee Bylaws.
BALANCE PORTFOLIO
HISTORY AND
IMPLEMENTATION

RSC Meeting Jan 30, 2012; Mike Proctor
At its January 2008 meeting the RSC adopted the first cost allocation for economic upgrades that became known as the **Balanced Portfolio** (BP).

- The purpose of the BP was to allocate the costs of 345 kV upgrades that would provide economic benefits as measured by Adjusted Production Cost and Energy Loss Savings.

- The BP cost allocation recovered revenue requirements from the entire footprint using a region-wide (postage stamp) rate.

- The concept was to design a portfolio of upgrades that would provide greater benefits than costs to each zone within the SPP footprint.
Balancing the Portfolio of Upgrades

- If a 345 kV upgrade produced greater economic benefits than costs to the entire region, then it was a potential candidate for the BP.
  - Candidate upgrades were to be put together in various portfolios and evaluated with respect to: 1) overall net benefits; and 2) their balance of benefits throughout the SPP region.
    - Balance was defined as each zone having a $B/C \geq 1$; i.e., a “no losers” test.
    - Lower voltage upgrades could be added to achieve balance.
    - If a balance could not be achieved in the upgrades, then any zone with negative net benefits would be made whole through a transfer mechanism.
BP Implementation

- After almost a year of reviewing potential upgrades and portfolios, it was not possible to balance the portfolio of economic upgrades.
- 8 of 16 zones had positive net benefits (B/C > 1)
- 4 of the 8 zones with negative net benefits (B/C < 1) actually experienced negative benefits (B/C < 0).

<table>
<thead>
<tr>
<th>#</th>
<th>Zone</th>
<th>Portfolio Benefits</th>
<th>Portfolio Costs</th>
<th>Net Benefits Before Transfers</th>
<th>B/C Before Transfers</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>AEPW</td>
<td>$224,210</td>
<td>$199,394</td>
<td>$24,816</td>
<td>1.1</td>
</tr>
<tr>
<td>2</td>
<td>EMDE</td>
<td>$-2,465</td>
<td>$23,376</td>
<td>$-25,841</td>
<td>-0.1</td>
</tr>
<tr>
<td>3</td>
<td>GMO</td>
<td>$-9,457</td>
<td>$35,906</td>
<td>$-45,363</td>
<td>-0.3</td>
</tr>
<tr>
<td>4</td>
<td>GRDA</td>
<td>$6,214</td>
<td>$17,352</td>
<td>$-11,138</td>
<td>0.4</td>
</tr>
<tr>
<td>5</td>
<td>KCPL</td>
<td>$60,832</td>
<td>$68,532</td>
<td>$-7,700</td>
<td>0.9</td>
</tr>
<tr>
<td>6</td>
<td>LES</td>
<td>$-22,149</td>
<td>$17,030</td>
<td>$-39,179</td>
<td>-1.3</td>
</tr>
<tr>
<td>7</td>
<td>MIDW</td>
<td>$92,734</td>
<td>$6,382</td>
<td>$86,352</td>
<td>14.5</td>
</tr>
<tr>
<td>8</td>
<td>MKEC</td>
<td>$85,555</td>
<td>$9,945</td>
<td>$75,610</td>
<td>8.6</td>
</tr>
<tr>
<td>9</td>
<td>NPPD</td>
<td>$39,839</td>
<td>$71,125</td>
<td>$-31,286</td>
<td>0.6</td>
</tr>
<tr>
<td>10</td>
<td>OKGE</td>
<td>$192,965</td>
<td>$125,771</td>
<td>$67,195</td>
<td>1.5</td>
</tr>
<tr>
<td>11</td>
<td>OPPD</td>
<td>$16,376</td>
<td>$55,134</td>
<td>$-38,759</td>
<td>0.3</td>
</tr>
<tr>
<td>12</td>
<td>SPRM</td>
<td>$-0,697</td>
<td>$13,748</td>
<td>$-14,445</td>
<td>-0.1</td>
</tr>
<tr>
<td>13</td>
<td>SUNC</td>
<td>$27,059</td>
<td>$9,475</td>
<td>$17,584</td>
<td>2.9</td>
</tr>
<tr>
<td>14</td>
<td>SWPS</td>
<td>$406,581</td>
<td>$102,414</td>
<td>$304,167</td>
<td>4.0</td>
</tr>
<tr>
<td>15</td>
<td>WEFA</td>
<td>$57,802</td>
<td>$28,047</td>
<td>$29,755</td>
<td>2.1</td>
</tr>
<tr>
<td>16</td>
<td>WRI</td>
<td>$102,979</td>
<td>$102,483</td>
<td>$0,496</td>
<td>1.0</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>$1,278,378</td>
<td>$886,113</td>
<td>$392,265</td>
<td>1.44</td>
</tr>
</tbody>
</table>
Transfer Mechanism

- The transfer mechanism would transfer costs from the zonal rate of those having less benefits than allocated costs ("deficient zones") and place those costs in a region-wide rate.
  - Deficient zones would go from paying 100% of zonal cost to paying their load ratio share of those costs.
  - Non-deficient zones would go from paying 0% of those same costs to paying their load ratio share.

- The transfer amount was a level required to move the deficient zones to where their benefits plus cost savings from the transfers were just equal to the costs allocated to them for the costs of the BP projects.
## Expected Transfers

### Attachment H Transfer Adjustments - Portfolio 3E

**PV$ Over 10 Years of Levelized Costs and Benefits**

<table>
<thead>
<tr>
<th>#</th>
<th>Zone</th>
<th>Portfolio Benefits</th>
<th>Portfolio Costs</th>
<th>Transfer Allocation</th>
<th>Transfer Out</th>
<th>Net Benefits</th>
<th>B/C</th>
<th>B/C Before Transfers</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>AEPW</td>
<td>$224,209,603</td>
<td>$199,393,967</td>
<td>$154,656,573</td>
<td>-$129,840,937</td>
<td>$0.0</td>
<td>1.00</td>
<td>1.12</td>
</tr>
<tr>
<td>2</td>
<td>EMDE</td>
<td>-$2,465,029</td>
<td>$23,375,642</td>
<td>$18,130,923</td>
<td>-$43,971,594</td>
<td>$0.0</td>
<td>1.00</td>
<td>-0.11</td>
</tr>
<tr>
<td>6</td>
<td>GMO</td>
<td>-$9,456,847</td>
<td>$35,905,963</td>
<td>$27,849,856</td>
<td>-$73,212,666</td>
<td>$0.0</td>
<td>1.00</td>
<td>-0.26</td>
</tr>
<tr>
<td>3</td>
<td>GRDA</td>
<td>$6,213,812</td>
<td>$17,351,655</td>
<td>$13,458,519</td>
<td>-$24,596,362</td>
<td>$0.0</td>
<td>1.00</td>
<td>0.36</td>
</tr>
<tr>
<td>4</td>
<td>KCPL</td>
<td>$60,832,344</td>
<td>$68,531,962</td>
<td>$53,155,663</td>
<td>-$60,855,280</td>
<td>$0.0</td>
<td>1.00</td>
<td>0.89</td>
</tr>
<tr>
<td>16</td>
<td>LES</td>
<td>-$22,148,746</td>
<td>$17,030,090</td>
<td>$13,209,102</td>
<td>-$52,387,938</td>
<td>$0.0</td>
<td>1.00</td>
<td>-1.30</td>
</tr>
<tr>
<td>5</td>
<td>MIDW</td>
<td>$92,734,341</td>
<td>$6,381,996</td>
<td>$4,950,088</td>
<td>$0</td>
<td>$81,402,257.2</td>
<td>8.18</td>
<td>14.53</td>
</tr>
<tr>
<td>7</td>
<td>MKEC</td>
<td>$85,555,021</td>
<td>$9,945,022</td>
<td>$7,713,689</td>
<td>$0</td>
<td>$67,896,310.0</td>
<td>4.84</td>
<td>8.60</td>
</tr>
<tr>
<td>14</td>
<td>NPPD</td>
<td>$39,838,842</td>
<td>$71,125,064</td>
<td>$55,166,958</td>
<td>-$86,453,179</td>
<td>$0.0</td>
<td>1.00</td>
<td>0.56</td>
</tr>
<tr>
<td>8</td>
<td>OKGE</td>
<td>$192,965,105</td>
<td>$125,770,557</td>
<td>$97,551,815</td>
<td>-$30,357,266</td>
<td>$0.0</td>
<td>1.00</td>
<td>1.53</td>
</tr>
<tr>
<td>15</td>
<td>OPPD</td>
<td>$16,375,576</td>
<td>$55,134,272</td>
<td>$42,763,970</td>
<td>-$81,522,666</td>
<td>$0.0</td>
<td>1.00</td>
<td>0.30</td>
</tr>
<tr>
<td>9</td>
<td>SPRM</td>
<td>-$696,808</td>
<td>$13,747,982</td>
<td>$10,663,390</td>
<td>-$25,108,180</td>
<td>$0.0</td>
<td>1.00</td>
<td>-0.05</td>
</tr>
<tr>
<td>10</td>
<td>SUNC</td>
<td>$27,058,940</td>
<td>$9,475,369</td>
<td>$7,349,410</td>
<td>$0</td>
<td>$10,234,161.2</td>
<td>1.61</td>
<td>2.86</td>
</tr>
<tr>
<td>11</td>
<td>SWPS</td>
<td>$406,581,435</td>
<td>$102,414,209</td>
<td>$79,435,857</td>
<td>$0</td>
<td>$224,731,369.8</td>
<td>2.24</td>
<td>3.97</td>
</tr>
<tr>
<td>12</td>
<td>WEFA</td>
<td>$57,801,538</td>
<td>$28,046,911</td>
<td>$21,754,115</td>
<td>$0</td>
<td>$8,000,512.4</td>
<td>1.16</td>
<td>2.06</td>
</tr>
<tr>
<td>13</td>
<td>WRI</td>
<td>$102,978,953</td>
<td>$102,482,810</td>
<td>$79,489,066</td>
<td>-$78,992,922</td>
<td>$0.0</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>Total PV</td>
<td>$1,278,378,081</td>
<td>$886,113,470</td>
<td>$687,298,992</td>
<td>-$687,298,992</td>
<td>$392,264,611</td>
<td>1.44</td>
<td>1.44</td>
<td></td>
</tr>
</tbody>
</table>
Current Status of BP Upgrades and Transfer Implementation
## Updated Cost Assumptions

Most Up-To-Date E&C Cost Estimates for Balanced Portfolio

- Levelized Fixed Charge Rates Provided by TOs
- Both Costs and ARRs to be Trued Up

<table>
<thead>
<tr>
<th>ZONE</th>
<th>DESCRIPTION</th>
<th>NTC ISSUE DATE</th>
<th>IN-SERVICE DATE</th>
<th>COST</th>
<th>Levelized FC%</th>
<th>Levelized FC$</th>
</tr>
</thead>
<tbody>
<tr>
<td>WFEC</td>
<td>Anadarko (Gracemont) Tap 138 kV</td>
<td>6/19/2009</td>
<td>12/31/2011</td>
<td>$200,000.00</td>
<td>15.10%</td>
<td>$30,200</td>
</tr>
<tr>
<td>OGE</td>
<td>GRACEMONT 345/138KV TRANSFORMER CKT 1</td>
<td>6/19/2009</td>
<td>12/31/2011</td>
<td>$15,000,000.00</td>
<td>15.10%</td>
<td>$2,265,000</td>
</tr>
<tr>
<td>KCPL</td>
<td>West Gardner 345 kV</td>
<td>6/19/2009</td>
<td>6/1/2012</td>
<td>$2,171,096.00</td>
<td>15.10%</td>
<td>$327,835</td>
</tr>
<tr>
<td>ITCGP</td>
<td>POST ROCK - SPEARVILLE 345KV CKT 1</td>
<td>6/19/2009</td>
<td>6/1/2012</td>
<td>$77,703,351.00</td>
<td>12.00%</td>
<td>$9,324,402</td>
</tr>
<tr>
<td>ITCGP</td>
<td>POST ROCK 345/230KV TRANSFORMER CKT 1</td>
<td>11/6/2009</td>
<td>6/1/2012</td>
<td>$3,994,000.00</td>
<td>12.00%</td>
<td>$479,280</td>
</tr>
<tr>
<td>GRDA</td>
<td>CLEVELAND - SOONER 345KV CKT 1 (GRDA)</td>
<td>6/19/2009</td>
<td>12/31/2012</td>
<td>$1,806,000.00</td>
<td>15.10%</td>
<td>$272,706</td>
</tr>
<tr>
<td>OGE</td>
<td>CLEVELAND - SOONER 345KV CKT 1 (OGE)</td>
<td>6/19/2009</td>
<td>12/31/2012</td>
<td>$69,000,000.00</td>
<td>15.10%</td>
<td>$10,419,000</td>
</tr>
<tr>
<td>NPPD</td>
<td>AXTELL - POST ROCK 345KV CKT 1 (NPPD)</td>
<td>6/19/2009</td>
<td>6/1/2013</td>
<td>$76,000,000.00</td>
<td>13.50%</td>
<td>$10,260,000</td>
</tr>
<tr>
<td>ITCGP</td>
<td>AXTELL - POST ROCK 345KV CKT 1 (ITC GP)</td>
<td>6/19/2009</td>
<td>6/1/2013</td>
<td>$93,302,649.00</td>
<td>12.00%</td>
<td>$11,196,318</td>
</tr>
<tr>
<td>OGE</td>
<td>MUSKOGEE - SEMINOLE 345KV CKT 1</td>
<td>6/19/2009</td>
<td>6/1/2013</td>
<td>$160,115,000.00</td>
<td>15.10%</td>
<td>$24,177,365</td>
</tr>
<tr>
<td>OGE</td>
<td>Stateline 345 kV - Woodward EHV 345kv</td>
<td>6/19/2009</td>
<td>5/19/2014</td>
<td>$127,032,500.00</td>
<td>15.10%</td>
<td>$19,181,908</td>
</tr>
<tr>
<td>OGE</td>
<td>WOODWARD DISTRICT EHV 345/138KV TRANSFORMER CKT 2</td>
<td>6/19/2009</td>
<td>5/19/2014</td>
<td>$19,327,500.00</td>
<td>15.10%</td>
<td>$2,918,453</td>
</tr>
<tr>
<td>SPS</td>
<td>TUCO INTERCHANGE 345 kV - Stateline 345 kV</td>
<td>6/19/2009</td>
<td>5/19/2014</td>
<td>$158,277,970</td>
<td>12.10%</td>
<td>$19,151,634</td>
</tr>
<tr>
<td>OGE</td>
<td>Stateline 345 kV</td>
<td>6/19/2009</td>
<td>5/19/2014</td>
<td>$14,880,000.00</td>
<td>15.10%</td>
<td>$2,246,880</td>
</tr>
<tr>
<td>KCPL</td>
<td>IATAN - NASHUA 345KV CKT 1</td>
<td>6/19/2009</td>
<td>6/1/2015</td>
<td>$49,824,000.00</td>
<td>15.10%</td>
<td>$7,523,424</td>
</tr>
<tr>
<td>KCPL</td>
<td>NASHUA 345/161KV TRANSFORMER CKT 1</td>
<td>6/19/2009</td>
<td>6/1/2015</td>
<td>$4,620,000.00</td>
<td>15.10%</td>
<td>$697,620</td>
</tr>
<tr>
<td>SPS</td>
<td>TUCO INTERCHANGE 345/230KV TRANSFORMER CKT 2</td>
<td>2/8/2010</td>
<td>11/30/2015</td>
<td>$14,900,907.00</td>
<td>12.10%</td>
<td>$1,803,010</td>
</tr>
</tbody>
</table>

**Base Case** $888,154,973.00 13.77% $122,275,035
Transfers Will Begin in 2012

- With BP upgrades and CWIP going into rate base, SPP expects the January 2012 updates to formula rates will produce in excess of 10% of the BP upgrade costs to be in rates.

  - This triggers a 5 year period over which the transfers are implemented at 20% of expected transfers being added each year.

  - If 100% of the BP upgrades go into rates before the fifth year, then in that year there will be a true up of costs with 100% of the transfers being implemented.

  - **Expected date of true up is 2016**
Transfers Based on Ten-Year Period

- **History:** At the time of the Balanced Portfolio, all SPP transmission planning was based on using a 10 year period – similar to ITP 10.
  - At that time assumption about out-year benefits were not yet specified.

- **Period over which transfers are calculated:**

  Attachment O: Section J IV.4.c.i

  Limit the amount to be transferred from the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual Transmission Revenue Requirement to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement to the **minimum amount that will balance the portfolio over the ten-year period analyzed.**
Tariff Interpretation – “amount”

- Interpretation 1: The total amount of the transfers are limited to what is calculated on a present value basis over the 10-year period analyzed.

- Interpretation 2: The total amount of the transfers are limited to what is calculated on a per-year basis over the 10-year period analyzed.
Interpretations Analyzed

- While there is no wording in the tariff as to whether the “amount” is a present value (Interpretation 1) or a per-year transfer (Interpretation 2), Interpretation 1 appears to be the most straight-forward interpretation of the tariff.

- If the wording intended a per-year amount rather than a total amount (pot of dollars), then there should have been wording as to the period of time over which the per-year transfers should go into place.
Further Analysis of Interpretation 2

- If the 10-year analysis was meant to calculate transfers per-year over the life of the assets (Interpretation 2), what would the benefit stream from years 12 through year 40 look like?

This stream of 40-year benefits would result in the same B/C ratio as in the 10-year analysis and would also result in the same per year transfers over a 40-year period instead of over a 10-year period.

40-yr PV of Benefits = $2,272 M
40-yr PV of Costs = $1,575 M
40-yr B/C = 1.44
Benefits would have to decrease at a rate of $6.7$ Million per year for the out years to have the same B/C as for the 10-year analysis.

This is an unrealistic assumption about out-year benefits from the Balanced Portfolio.

In order to have the same B/C over 40 years, the levelized benefits would have to be the same as for the 10-year analysis. This means that the out-year benefits MUST be less than the benefits estimated in year 11.
Recommendation to Meet SPP’s Immediate Need for 2012

- CAWG Recommends to the RSC that Balanced Portfolio Transfer Payments as determined by the tariff be implemented over a 10 year period.
  - This recommendation reflects interpretation 1 of the tariff, but even if interpretation 2 is accepted as correct, the per-year transfers would be the same.
  - This recommendation allows the SPP to go forward with 20% of the transfers that are likely to be required in 2012.
    - Expected SPP filing early in April.
Illustration of CAWG Recommendation

- To better understand the concept — assume the transfers from zonal to regional rates have a present value of $100.

- If the discount rate (cost of money) were zero, then the per year amount over 10 years would be $10 per year (\(\approx \frac{100}{10}\)).

- If the discount rate used is 8%, then the per year amount over 10 years is $13.80 per year (\(\approx \frac{100}{\sum \text{discount factors over 10 years}}\)).

- This produces an annual stream of transfers that has the same present value as the $100.
# Interest on Unpaid Balance

The additional $3.80 per year is the interest on the unpaid balance at 8% needed to make the present value of the payment stream equal to $100.

<table>
<thead>
<tr>
<th>Year</th>
<th>Discount Factor</th>
<th>Annual Transfers</th>
<th>Present Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.00000</td>
<td>$13.80</td>
<td>$13.80</td>
</tr>
<tr>
<td>2</td>
<td>0.92593</td>
<td>$13.80</td>
<td>$12.78</td>
</tr>
<tr>
<td>3</td>
<td>0.85734</td>
<td>$13.80</td>
<td>$11.83</td>
</tr>
<tr>
<td>4</td>
<td>0.79383</td>
<td>$13.80</td>
<td>$10.95</td>
</tr>
<tr>
<td>5</td>
<td>0.73503</td>
<td>$13.80</td>
<td>$10.14</td>
</tr>
<tr>
<td>6</td>
<td>0.68058</td>
<td>$13.80</td>
<td>$9.39</td>
</tr>
<tr>
<td>7</td>
<td>0.63017</td>
<td>$13.80</td>
<td>$8.70</td>
</tr>
<tr>
<td>8</td>
<td>0.58349</td>
<td>$13.80</td>
<td>$8.05</td>
</tr>
<tr>
<td>9</td>
<td>0.54027</td>
<td>$13.80</td>
<td>$7.46</td>
</tr>
<tr>
<td>10</td>
<td>0.50025</td>
<td>$13.80</td>
<td>$6.90</td>
</tr>
<tr>
<td>Total</td>
<td>7.24689</td>
<td></td>
<td>$100.00</td>
</tr>
</tbody>
</table>
If the present value of the transfers is $100, then 100% of the transfers per year for 10 years would be $13.80.

- 20% of $13.80 is $2.76 per year.

Actual amount of estimated transfers is $687.3 million with a per-year transfer of $94.8 million per year.

- 20% of $94.8 million is $18.96 million per year.

<table>
<thead>
<tr>
<th>Phase-In Transfers Over 5 Years @ 20%/year</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>$18,968,114</td>
<td>$37,936,229</td>
<td>$56,904,343</td>
<td>$75,872,457</td>
<td>$94,840,572</td>
<td></td>
</tr>
</tbody>
</table>
This section is meant to provide additional information on possible changes since the BP analysis and approval. Details for this information were presented at the January 2012 CAWG meeting. Cost have been updated (updates in previous slides) since this information was presented.
If the out-year benefits follow what is now recommended by the ESWG, what would the out-year benefits look like?

This stream of 40 year benefits would result in a higher B/C ratio than for the 10 year analysis (2.0 compared to 1.5) and would also result in much lower per year transfers over a 40 year period than over a 10 year period.
Question 2

- Would the present value of the transfers from the 40-year ESWG-type stream of benefits be higher or lower than the present value of the transfers from the 10-year analysis?

- Lower. The following table gives the results.

<table>
<thead>
<tr>
<th>Transfers $M</th>
<th>1/2 % Change in LFC Rate</th>
<th>Analysis Time Period</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>-0.50%</td>
<td>Base 0.50%</td>
</tr>
<tr>
<td></td>
<td>13.26%</td>
<td>13.76%</td>
</tr>
<tr>
<td>10 Year</td>
<td>$425</td>
<td>$490</td>
</tr>
<tr>
<td>40 Year</td>
<td>$437</td>
<td>$465</td>
</tr>
<tr>
<td>Difference</td>
<td>$12</td>
<td>-$25</td>
</tr>
</tbody>
</table>

Using the Levelized Fixed Charge Rates at the time of the BP, the PV of transfers for the 40 year ESWG type analysis results in a $25 Million drop in the present value of transfers.
Question 3

- Why is there a drop in transfers in going from a 10-year analysis to a 40-year ESWG-type analysis?

- Primary reason is there are two zones whose 10-year B/Cs are close to 1.
  - After initial transfers are made to the deficient zones, the costs to the two “border line” zones increase and their B/Cs fall below 1. Thus, additional transfers are required in 10-year analysis.
  - In 40-year analysis, increase in benefits to the two border line zones eliminates the need for additional transfers.
Question 4

☐ Are the transfers to the zones similar between the 10-year and 40-year, ESWG-type analysis?

☐ No.

☐ This is because in the 10-year analysis, a significant portion of the transfers out of the zonal rate are going to the two “border-line” zones (just over 25%).

☐ In the 40-year analysis, even though total transfers are decreased, transfers to those zones having a B/C<1 increase by 27.6%.
Question 5

- What is likely to happen to the annual revenue requirement associated with the B/C upgrades compared to currently estimated costs?

- The current annual revenue requirements costs assume an average levelized fixed charge rate of 13.76%.

  - My calculations show that with debt at 5% interest and equity with an ROE of 11%, assuming 50% debt and 50% equity, the levelized fixed charge rate will increase to just over 15%.
Question 6

- What are the implications of a higher levelized fixed charge rate for transfers?

- Transfers will increase from a PV of $490 M to $820 M as levelized fixed charge rate increases from 13.76% to 15% and benefits are held constant.

Attachment J: Section IV.A.2

Upon the completion and inclusion in rates under the Tariff of all of the upgrades that are part of the approved Balanced Portfolio and the determination of the actual cost of any third party impacts attributable to the Balanced Portfolio under Section IV.3.c of Attachment O, the final amount of costs to be reallocated from the Reallocated Revenue Requirements for the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement to balance the approved Balanced Portfolio shall be trued-up based on the applicable fixed charge rate and actual costs. The final reallocation shall be performed using the same benefits estimated at the time the Balanced Portfolio was approved.
Question 7

Does an increase in levelized fixed charge rate result in a similar increase in transfers for the 40-year ESWG-type analysis?

No – much smaller increase.

- Increasing the levelized fixed charge rate to 15% would increase transfers in the 40-year ESWG type analysis from $465 Million to $535 Million.
- Again, this is because additional transfers are not required for the “border-line” zones.
Question 8

- Have Benefits from the Balanced Portfolio decreased from the calculations made at the time of approval.

- Don’t Know
  - Using ITP 10 assumptions, the spread between natural gas and coal costs have decreased from the BP assumptions \( \Rightarrow \) decrease in benefits for BP.
  - HOWEVER: Changes in environmental regulations will decrease demand for coal and increase demand for natural gas, and will likely decrease coal prices and increase natural gas prices.
    - ESWG is working on these assumptions for ITP 20.
Any Additional Questions?
Overview of CAWG Meetings

- Since the October 2011 RSC meeting, the CAWG has had three recurring items on its agenda:
  1. **Area Generation Connection Task Force Hub & Spoke Design and associated cost allocation.**
     - Proposals for interconnection of a large number of generators to the 345 kV transmission system
  2. **Timing of transfers for the Balanced Portfolio**
     - Separate Report by Mike Proctor
  3. **Obstacles to Transmission Construction**
     - Separate Report by Pat Mosier
AGCTF: Hub & Spoke Update

- The AGCTF is considering two alternative designs for generation interconnection:
  - Hub Only
  - Hub & Spoke
- Presentations have been made to the CAWG on the potential cost savings for the Hub Only design.
  - The Hub only design appears to be complete, and Mike Proctor will be presenting specific materials on cost allocation at the February CAWG meeting.
- The AGCTF is meeting to complete the Hub & Spoke design.
  - When the design is completed, the cost savings will be presented to the CAWG for consideration as an alternative to the Hub Only design.
  - If the Hub & Spoke design is more cost-effective than the Hub Only design, the CAWG will develop a cost allocation for the Hub & Spoke design.

Current GI Cost Allocation

- The Hub is classified as a network upgrade related to generation interconnection.
  - Generator pays the up-front costs for all network upgrades along with any directly assigned costs (e.g., transformers and generation leads).
  - Generator is entitled to revenue credits from any additional use of network facilities for which it has paid up-front costs.
    - If a Transmission Customer (load) designates a generator as a network resource it receives firm transmission service for delivery of power from that generator.
    - A related portion of the cost of network upgrades incurred by that generator and used by the Transmission Customer would be included in the upgrade costs to the Transmission Customer, and the revenues collected by SPP for those costs would be credited to the generator.
AGCTV has asked the CAWG to consider including $13 Million per hub (12 hubs being considered) in a region-wide rate.

The CAWG has concerns about directly paying for a portion of the hub in a region-wide rate for two basic reasons:
- Not all generation connected will result in transmission service being taken by SPP load; and
- With varying renewable energy requirements, the transmission service taken by various loads is not likely to be reflected by the load ratio share allocation associated with the region-wide rate.

The CAWG is considering alternative cost allocations, one of which could include regional funding.
The RSC previously requested that it be provided with a list of obstacles to construction which could significantly increase the cost of construction. In response to that request, the CAWG issued a Request for Information (Request) which it distributed to the SPP Transmission Owners (TOs) over which the RSC member commissions have jurisdiction. The basis of the request was not to garner specific cost data related to projects but rather to have each TO provide a list of obstacles based both on its prior experience and which it anticipated may occur in the future. Significantly, the Request asked "that the TO list the types of obstacles it has encountered in the past which resulted in material cost increases ... (and) ... that the list include any obstacles which are expected to occur pursuant to current or prospective changes within the states in which the TO operates."

The responses to the CAWG’s Request for Information are provided on the following pages and are listed by TO. The obstacles identified by each TO are shown by general type with additional information provided in some instances. The CAWG hopes that this relatively comprehensive explanation of the obstacles faced by TOs provides the RSC the information it seeks and will be useful for future reference.

Additionally for the RSC’s information, the CAWG notes that the RSC’s request in this regard is also being pursued by the Project Cost Working Group (PCWG) and, to that end, the CAWG has provided the following information to the PCWG for use in its own ongoing compilation of data.
## AEP Response

<table>
<thead>
<tr>
<th>Obstacle Type</th>
<th>Obstacle Description of Obstacles Resulting in Increased Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Regulatory</strong></td>
<td>Regulatory Certificate of Convenience and Necessity (CCN) Process can result in change of planned transmission path</td>
</tr>
<tr>
<td></td>
<td>Unexpected Regulatory Issues due to state law changes during the construction period (over several years)</td>
</tr>
<tr>
<td></td>
<td>Unexpected landowner intervention and legal resolution</td>
</tr>
<tr>
<td></td>
<td>Regulatory process delays (i.e. Commission rulings on CCN's)</td>
</tr>
<tr>
<td></td>
<td>Injunctions for various cause (i.e. legal issues, city mandate, county approval)</td>
</tr>
<tr>
<td><strong>Environmental</strong></td>
<td>Environmentally protected species in transmission Right of Way</td>
</tr>
<tr>
<td></td>
<td>Discovery of significance during field work (i.e. mammoth skeleton, Indian burial ground)</td>
</tr>
<tr>
<td></td>
<td>Unanticipated environmental testing requirements imposed by state or national authority</td>
</tr>
<tr>
<td></td>
<td>Unanticipated environmental mitigation requirements imposed by state or national authority</td>
</tr>
<tr>
<td></td>
<td>Legal costs associated with regulatory or environmental permitting</td>
</tr>
<tr>
<td><strong>Project Related</strong></td>
<td>Unexpected cost increases in materials due to basic raw materials commodity index increases, (i.e. steel and aluminum).</td>
</tr>
<tr>
<td></td>
<td>Unexpected cost increases in materials due to other issues, (i.e. earthquake in Japan, fire at insulator plants)</td>
</tr>
<tr>
<td></td>
<td>Increase in estimated Contract Labor costs due to increased demand and reduced supply.</td>
</tr>
<tr>
<td></td>
<td>Increase in estimated Contract Labor costs due to field conditions encountered being worse than estimated, (i.e. more subsurface rock than anticipated, weather delays, etc.)</td>
</tr>
<tr>
<td></td>
<td>Increased competition for limited resources (i.e. contract skilled labor, rare/special components)</td>
</tr>
<tr>
<td></td>
<td>Weather related delays (i.e. tornado destroys portion of project, rain delays beyond planned amount)</td>
</tr>
</tbody>
</table>
### Transmission Construction Obstacles

**Provided by SPP Transmission Owners (TOs)**

<table>
<thead>
<tr>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transportation issues (i.e. late delivery of heavy transformer, overseas shipping of components)</td>
</tr>
<tr>
<td>Technical issues (i.e. change in design required during construction)</td>
</tr>
<tr>
<td>Foreign exchange rates for equipment manufactured in foreign countries artificially increasing material costs</td>
</tr>
<tr>
<td>Labor costs to construct planned facilities</td>
</tr>
<tr>
<td>Right-of-way (land) easement costs</td>
</tr>
</tbody>
</table>

While there are other influences, these make up the majority of the "root causes" for cost escalation. A good rule of thumb (and amazingly consistent) is that line costs are generally split 45% for Material, 45% for construction and ROW, and 10% for Engineering (including environmental permitting, regulatory, design, project management, etc.). With the labor and material being driven primarily by (constantly changing) national and international economic conditions and land pricing being subjective and highly volatile in some areas, its easy to see where the biggest exposure lies.

### Empire District

<table>
<thead>
<tr>
<th>Obstacle Type(a)</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td>Siting Legislative Changes</td>
<td>Empire hasn’t been a big builder of new EHV transmission over the last few years. However we have constructed a few 161kV lines. Our obstacles that we have faced or work around to avoid increased costs where possible are:</td>
</tr>
<tr>
<td>Change of Eminent Domain Laws. Such change of law actions, such as experienced in Missouri, can cause significant delays in obtaining approvals and resolving condemnation proceedings.</td>
<td></td>
</tr>
<tr>
<td>Siting/Land Use</td>
<td>Siting/routing through and around Indian land and national forests is a barrier that adds time and money to the process.</td>
</tr>
<tr>
<td>In addition, EDE concurs with the obstacles previously identified by the other utilities.</td>
<td></td>
</tr>
</tbody>
</table>

(a) Type Provided by CAWG for Consistence
## Transmission Construction Obstacles
### Provided by SPP Transmission Owners (TOs)

<table>
<thead>
<tr>
<th>Obstacle Type</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td>Environmental</td>
<td><strong>Migratory Bird Treaty Act</strong></td>
</tr>
<tr>
<td></td>
<td><strong>Impacts:</strong> Agencies such as the USFWS and KDWP require that design of the line and marking occur to minimize avian collisions and electrocution, particularly in areas where more likely to occur such as identified flyways, wetlands, and open water. They also require that we track and mitigate avian mortality by marking lines or adding diverters as needed to correct problem areas.</td>
</tr>
<tr>
<td></td>
<td><strong>Threatened or Endangered Species, Actual and Potential</strong></td>
</tr>
<tr>
<td></td>
<td><strong>Impacts:</strong> Anytime a project will affect potential habitats of threatened or endangered species, which include areas such as streams, wetlands, open water, riparian areas, native woodlands, or native prairies, or other potential suitable habitats; the project area must be reviewed for impacts to threatened or endangered species. Via consultation with KDWP, the USFWS, and with early site investigations, potential impacts can sometimes be determined early in the planning phase, or are determined during the design phase and changes are made minimize or avoid impacts. If sufficient minimization of impacts cannot be made, a Permit may be required from the KDWP with potential for mitigation for the impacts such as habitat recreation/mitigation or date restrictions. If impacts are anticipated by the USFWS, a Formal Section 7 Analysis of impacts to the species via a Biological Assessment and Biological Opinion must be made. In some instances, the species may not be listed at the time the line is planned, but is a species of concern (i.e. Prairie Chicken), thus impacts must be avoided due to concerns voiced by various agencies and stakeholders. Increased costs would be associated with additional route planning, meeting attendance, coordinating with various stakeholders, biological assessments, changes in design and construction practices, and at times mitigation required by the KDWP Permit.</td>
</tr>
<tr>
<td></td>
<td><strong>Wetlands / Streams / Open Water</strong></td>
</tr>
<tr>
<td></td>
<td><strong>Impacts:</strong> US Army Corps of Engineers 404 permit: Activities that temporarily or permanently disturb less than ½ acre of wetlands can obtain coverage under a Nationwide Permit (NWP). The NWP that typically applies is NWP 12 for Utility Line Activities. This permit covers activities that include access roads, temporary staging areas, and trenching and backfilling activities. NWP impacts over 0.1 acre require submittal of a Pre-Construction Notification (PCN). Other PCN thresholds may apply depending on the nature of impacts and regional conditions. Impacts over 0.5 acres would require an Individual Permit. USACE strongly recommends siting facilities to avoid wetland impacts greater than 0.1 acres, possibly requiring extended line distances</td>
</tr>
</tbody>
</table>
Environmental Wetlands / Streams / Open Water
Impacts: (cont)

The project team spends a large amount of time avoiding wetlands along all transmission line routes. If required, a USACE 404 wetland permit takes a great deal of time and effort to obtain. Additional costs are associated with investigating wetland maps, delineating wetland boundaries in the field, meeting with design to collaborate design changes to reduce or eliminate impacts, and meetings with agencies to determine permit parameters and needs.

Environmental Floodplains
Impacts:

Floodplain Fill Permit / Stream Obstruction Permit: An evaluation of potential impacts to floodplains, streams, and their drainage areas is required to determine whether these permits are applicable. Consultation with the Kansas Department of Agriculture Chief Engineer is recommended to determine the applicability to the Project. Avoidance of impacts to or special construction practices for installation across a flood plain created additional construction costs. In addition, local floodplain fill permits are required by many counties if fill in the floodplain occurs.

Siting Historical / Archeological / Cultural Sites
Impacts:

Consultation with the Kansas Historic Preservation Office is required to determine the potential for the Project to impact sites listed on or eligible for listing on the National Register of Historic Places (NRHP). SHPO requires that historic properties be identified and that the SHPO is notified of any project that may adversely affect any such historic property. Avoidance of historic properties can lead to additional costs. Archeological site must also be reviewed for when a federally associated permit (CoE 404 Permit) or federal funds are involved. Unidentified and unknown archeological sites can also be discovered during construction which can require reroutes or structure relocations.

Siting Soil / Ground Conditions
Impacts:

Varying soil conditions or soil conditions outside of those expected during preliminary design may require foundation / pole designs of greater costs.

Siting Aerospace Areas
Impacts:

Structures over 200 feet tall or within close proximity to airports or heliports must have a determination of No Hazard from the FAA. The FAA also conducts a review of the potential impacts to military radar as part of its aviation hazard review. Any hazard determination would require a route variance to the project. More recently local officials (counties) received the authority to and have implemented their own, more extensive added regulation to protect their airspace. Thus must receive their review of proposed lines near airports.
## Transmission Construction Obstacles
Provided by SPP Transmission Owners (TOs)

<table>
<thead>
<tr>
<th>Siting</th>
<th>Permitting</th>
</tr>
</thead>
</table>
|                 | **Impacts:** 
|                 | Challenges presented by an ever increasing number of local, county, state,  |
|                 | and federal permitting requirements and possible reroutes to address       |
|                 | permits.                                                                   |

<table>
<thead>
<tr>
<th>Siting</th>
<th><strong>Substation Conditional Use Permit (CUP)</strong></th>
</tr>
</thead>
</table>
|                 | **Impacts:** 
|                 | Many localities require a CUP for substation construction or expansion.    |
|                 | Substation location requirements due to the CUP process may require        |
|                 | transmission line routing to be modified, increasing costs. Substation     |
|                 | land acquired via condemnation may only result in an easement, not clear   |
|                 | title. Typically when we must acquire a site via condemnation the         |
|                 | relationship between the utility and the landowner is not optimal and     |
|                 | the chances of the landowner being willing to agree to a CUP application   |
|                 | is slim.                                                                   |

<table>
<thead>
<tr>
<th>Siting</th>
<th><strong>Existing infrastructure</strong></th>
</tr>
</thead>
</table>
|                 | **Impacts:** 
|                 | Existing infrastructure on private easement that was intended to be on    |
|                 | road ROW may require additional costs for relocating existing infrastructure|
|                 | or rerouting the new line.                                                |

<table>
<thead>
<tr>
<th>Regulatory</th>
<th><strong>Landowner Alternates</strong></th>
</tr>
</thead>
</table>
|                 | **Impacts:** 
|                 | Landowner submitted alternate routes, while possibly reducing costs,      |
|                 | ultimately add to reroute expenses. Proper notification for routes not    |
|                 | studied prior to landowner proposals usually results in affecting         |
|                 | landowners not involved in open houses, those feeling slighted due to     |
|                 | late notification, and with additional costs associated with landowner    |
|                 | meetings and responding to letters and information requests from other    |
|                 | stakeholders.                                                             |

<table>
<thead>
<tr>
<th>Construction</th>
<th><strong>Underground</strong></th>
</tr>
</thead>
</table>
|                 | **Impacts:** 
|                 | Underground locates from foreign utilities marked in the wrong location or |
|                 | not marked at all requires redesign and relocation of poles.               |

<table>
<thead>
<tr>
<th>Construction</th>
<th><strong>Electric Infrastructure</strong></th>
</tr>
</thead>
</table>
|                 | **Impacts:** 
|                 | Ability to obtain outages (i.e. crossing foreign electric utilities, tying |
|                 | other electric utilities lines into new substations)                      |

<table>
<thead>
<tr>
<th>Construction</th>
<th><strong>Electric Infrastructure</strong></th>
</tr>
</thead>
</table>
|                 | **Impacts:** 
|                 | Assigning re-dispatch costs of generation to projects, or other utilities, |
|                 | due to an outage required on a transmission line                           |

<table>
<thead>
<tr>
<th>Construction</th>
<th><strong>Electric Infrastructure</strong></th>
</tr>
</thead>
</table>
|                 | **Impacts:** 
|                 | Congestion within the ROW relating to other utilities.                     |
The responses of other parties, are broadly indicative of those faced by Midwest as well; (Midwest) tried to raise some issues that ... (were not) covered in other responses or felt needed to be re-emphasized.

<table>
<thead>
<tr>
<th>Obstacle Type</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Siting / Permitting</strong></td>
<td>Difficulty in obtaining easements –</td>
</tr>
<tr>
<td></td>
<td>Landowners are increasingly unwilling to grant easements for transmission lines, or expect excessively large payments for such easements.</td>
</tr>
<tr>
<td></td>
<td>This is exacerbated by the payments now being made by wind developers; such developers are offering easement payments well above the value of the property, and in some cases are now offering perpetual payments rather than the traditional one-time payments.</td>
</tr>
<tr>
<td></td>
<td>Wind developers usually have most, if not all, their easements obtained before they start talking to a utility</td>
</tr>
<tr>
<td></td>
<td>Permit requirements –</td>
</tr>
<tr>
<td></td>
<td>Local units of government are more often requiring at least a conditional use permit for substation construction. Trying to orchestrate this permit with easement negotiations becomes a circular process, with the landowner holding up one process while they try to sweeten the deal in the other process.</td>
</tr>
<tr>
<td></td>
<td>The myriad of permits required where any wildlife, wetlands, or flood plain issues may be involved is incredibly complicated, introduces long delays, and increases the final cost of construction through the extensive studies and the resulting changes in line routing.</td>
</tr>
<tr>
<td></td>
<td>The uncertainty has come mostly through the uncertainty associated with the time lag between the investment and the recovery. Formula transmission rates were implemented and approved, with the objective of reducing the lag time, but changes in regulatory staffs have lead to unpredictable review periods for annual updates, and changes in interpretation of previously approved protocols.</td>
</tr>
<tr>
<td><strong>Regulatory Uncertainty</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Cooperation with Other Utilities</strong></td>
<td>Cooperation with other electric utilities has traditionally been quite good. The same is not entirely true for gas pipeline companies, and is absolutely not true for railroads where crossings are involved. Railroads in particular try to hold electric utilities hostage when new crossing permits are requested.</td>
</tr>
<tr>
<td></td>
<td>Rural water districts often do not participate in the One-Call program, so locating existing water lines in advance of construction is often difficult and time consuming. Moreover, their mapping is sometimes lacking, making it difficult for them to tell us where existing lines are located, even if we suspect they have something in close proximity to a planned transmission line route.</td>
</tr>
</tbody>
</table>
### Environmental Challenges:

<table>
<thead>
<tr>
<th>Obstacle Type</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td>State-listed Threatened and Endangered Wildlife Species (4)</td>
<td>Included FYI, however these species are located in NE Oklahoma and generally not in OG&amp;E service area. They live in water so addressed by Corps of Engineers permitting.</td>
</tr>
<tr>
<td></td>
<td>· Long-nosed darter (fish)</td>
</tr>
<tr>
<td></td>
<td>· Neosho mucket (mussel)</td>
</tr>
<tr>
<td></td>
<td>· Oklahoma Cave Crayfish</td>
</tr>
<tr>
<td></td>
<td>· Black-sided darter (fish)</td>
</tr>
<tr>
<td>Federal-listed Threatened and Endangered Wildlife Species (16)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Gray bat</td>
</tr>
<tr>
<td></td>
<td>· Indiana bat</td>
</tr>
<tr>
<td></td>
<td>· Ozark big-eared bat</td>
</tr>
<tr>
<td></td>
<td>· Whooping crane</td>
</tr>
<tr>
<td></td>
<td>· Piping Plover</td>
</tr>
<tr>
<td></td>
<td>· Interior Least Tern</td>
</tr>
<tr>
<td></td>
<td>· Red-cockaded Woodpecker</td>
</tr>
<tr>
<td></td>
<td>· Black-capped Vireo</td>
</tr>
<tr>
<td></td>
<td>· Arkansas River Shiner</td>
</tr>
<tr>
<td></td>
<td>· Ozark Cavefish</td>
</tr>
<tr>
<td></td>
<td>· Neosho Madtom (fish)</td>
</tr>
<tr>
<td></td>
<td>· Leopard darter (fish)</td>
</tr>
<tr>
<td></td>
<td>· American Burying Beetle</td>
</tr>
<tr>
<td></td>
<td>· Ouachita Rock Pocketbook (mussel)</td>
</tr>
<tr>
<td></td>
<td>· Winged mapleleaf (mussel)</td>
</tr>
<tr>
<td></td>
<td>· Scaleshell (mussel)</td>
</tr>
<tr>
<td>(Species more likely to impact transmission are highlighted)</td>
<td></td>
</tr>
<tr>
<td>Candidate species of concern (candidate for federal listing with high priority listing number):</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Lesser Prairie Chicken</td>
</tr>
</tbody>
</table>
Other:

- American Bald Eagle – Bald and Golden Eagle Protection Act
- Migratory Bird Treaty Act (all migratory birds)
- Wetlands, floodplains – Waters of the US
- State/Federal Wildlife Management Areas (WMAs)
- National Historic Preservation Act (sites or objects with historical/cultural significance)

(If) we conduct archaeological surveys at desktop level on all projects, will route around or span certain types of findings depending on area of impact; for Sunnyside-Hugo we conducted field surveys in negotiation with the Choctaw Nation.

(A) (g)roup (is) putting together data base for locations and species led by USFWS/ODWC, with other stakeholder environmental agencies (The Nature Conservancy, Oklahoma Biological Survey, Natural Resource Conservation Service, etc.) and interested industry groups (OIPA, Chesapeake, KAMO (sp?), Clean Lines and OG&E have attended some of the meetings) are currently developing a transmission planning tool that is intended for use in planning. Estimated date of draft report is February 2012 which will be followed by publication of a mapping tool. Date of tool availability is estimated late 2012.

Federal Lands:

- Arkansas Riverbed
- Deep Fork Wildlife Refuge
- Black Kettle National Grasslands

Tribal Lands of the:

- Cherokee (United Keetoowah Band)
- Chickasaw
- Choctaw
- Seminole
- Creek (Muscogee)
- Otoe-Missouria
- Pawnee
- Osage
- Chillico
### Southwestern Public Service Company (SPS) (Exel Energy)

<table>
<thead>
<tr>
<th>Obstacle Type&lt;sup&gt;a&lt;/sup&gt;</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Construction</strong></td>
<td>At the request of CAWG, Southwestern Public Service Company (SPS) put together the following list of obstacles which have been encountered during construction of transmission in the past and which may be expected to occur in the future. These obstacles may or have resulted in rerouting of proposed lines or other changes which may result in significant increases in the cost of planned lines.</td>
</tr>
<tr>
<td></td>
<td>SPP issues a Notice to Construct (NTC) for a new transmission line into and out of specific substations. In one instance, one of the substations was located in a congested area, thus limiting the ability to terminate the new transmission line. To accommodate the expansion for the new transmission line either a new site must be located for the substation or in some instances it may be necessary to purchase and remove a structure to accommodate the expansion of the substation. Both of these options result in increased cost to the project and can add length to the transmission line which would also increase the cost of the project.</td>
</tr>
<tr>
<td><strong>Park And Wildlife Lands</strong></td>
<td>An obstacle that can add a considerable amount of time and money to a transmission line project is crossing or going around land owned by Texas Parks and Wildlife (TPWD), such as Caprock Canyons State Park (approximately 15,313 acres) and Trailway (approximately 64 miles long). Due to the size of the park and trailway, routing a transmission line around the park would add significant miles to a transmission line, thereby increasing the cost considerably. Not only are the costs higher to secure the land, but also the TPWD approval process for granting of the easement must go through the TPWD Board of Directors and their Chapter 26 process.</td>
</tr>
<tr>
<td><strong>Siting</strong></td>
<td>The approval and construction of Competitive Renewable Energy Zone (CREZ) lines in SPS’s service area has made it increasingly difficult to work with landowners. Historically, SPS has worked with and accommodated landowners as much as possible both prior to filing CCN applications and after approval. We have heard from multiple landowners about bad experiences they have had dealing with other utilities crossing their land with CREZ lines. Many of these landowners have intervened in our recent dockets as the result of their experiences with the CREZ lines.</td>
</tr>
</tbody>
</table>
Environmental
Federal and State listed plant and animal species can also play a significant role in proposed new lines. If a field survey reveals habitat that must be avoided with the proposed line this can add time, cost, and length to the line. For example, the Lesser Prairie Chicken and the Dunes Sagebrush Lizard will likely become more of an obstacle if they go on the threatened and endangered list in 2012 as anticipated. The habitat covers large areas of the Texas Panhandle, Permian Basin, and much of eastern New Mexico. The necessary studies, permitting, and monitoring will add both time and expense to potential transmission lines crossing through their habitat. Building new lines in southeastern New Mexico requiring a Bureau of Land Management (BLM) permit will become even more challenging once these two species go on the list. Any new lines will require extensive coordination prior to approval and construction from the U. S. Fish and Wildlife Service (USFWS), the BLM, and in some cases New Mexico State Lands Office.

Archeological
Archeological site locations on BLM lands are not commonly known prior to surveys being conducted. Once a site is found on BLM lands a planned line crossing through a site must be relocated or mitigated prior to a ROW Grant (permit) being issued. The surveys, mitigation and/or relocation of the proposed line add time and cost to the project.

Great Plains Energy

<table>
<thead>
<tr>
<th>Obstacle Type</th>
<th>Obstacle</th>
<th>Obstacle Type</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td>Environmental</td>
<td>Impact on Lesser Prairie Chicken habitat(s)</td>
<td>Environmental</td>
<td>Migration corridors for Whooping Cranes and other migratory birds</td>
</tr>
<tr>
<td>Environmental</td>
<td>Avoidance of environmentally protected or sensitive areas, especially related to state-listed species</td>
<td>Environmental</td>
<td>Avoidance of State designated areas of no development like the Flint Hills</td>
</tr>
<tr>
<td>Governmental</td>
<td>Local governments enactment of zoning ordinances which impact construction of transmission lines and substations, sometimes in conflict with state statutes</td>
<td>Siting</td>
<td>Landowner opposition over localized interests, such as prospective wind farm development, oil and gas interests, and hunting interests</td>
</tr>
</tbody>
</table>

(a) Type Provided by CAWG for Consistence
## Transmission Construction Obstacles
Provided by SPP Transmission Owners (TOs)

### Kansas City Power & Light and
KCP&L Greater Missouri Operations

<table>
<thead>
<tr>
<th>Obstacle Type</th>
<th>Obstacle</th>
<th>Cost/Delay</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inflation</td>
<td>Cost pressures on material, engineering and construction labor are expected to continue. Cost/Delay = Medium/Major</td>
<td></td>
</tr>
<tr>
<td>Internal Resources</td>
<td>The scope of these projects probably will exceed steady state internal resources. Cost/Delay = Minor/Major</td>
<td></td>
</tr>
<tr>
<td>External Coordination</td>
<td>Coordination with multiple external agencies entails added labor time and requirements to provide information to the agencies. Cost/Delay = Minor/Medium</td>
<td></td>
</tr>
<tr>
<td>Line Routing</td>
<td>Need a well-defined routing process with full public involvement and full support of interested parties and regulatory authorities. The current process includes significant potential for lawsuits to be filed in opposition. Cost/Delay = Major/Major</td>
<td></td>
</tr>
<tr>
<td>Permitting</td>
<td>Must make preliminary contacts with all permitting agencies and note known issues/conflicts. Cost/Delay = Major/Major</td>
<td></td>
</tr>
<tr>
<td>Easement Acquisition</td>
<td>Missouri law requires formal written notice of condemnation (60 and 30 days) and proof of good faith negotiations. Cost/Delay = Medium/Major</td>
<td></td>
</tr>
<tr>
<td>Material Issues</td>
<td>Fluctuating lead times exceeding normal lead time as domestic suppliers reach their capacity. Cost/Delay = Medium/Major</td>
<td></td>
</tr>
<tr>
<td>Labor Issues</td>
<td>Limited resources for both design and construction activities. Cost/Delay = Medium/Major</td>
<td></td>
</tr>
<tr>
<td>Weather</td>
<td>Obvious impact of ability to access the job site for both preliminary survey and actual construction work. Cost/Delay = Major/Major</td>
<td></td>
</tr>
<tr>
<td>Operational Restrictions</td>
<td>Restricted access for initial survey/design work as well as limited outage time availability for the construction. Cost/Delay = Major/Major</td>
<td></td>
</tr>
<tr>
<td>Changing System Configuration</td>
<td>New system loads, generation sources, and power flows may impact the overall project requirements. Cost/Delay = Major/Major</td>
<td></td>
</tr>
</tbody>
</table>
## Transmission Construction Obstacles
Provided by SPP Transmission Owners (TOs)

<table>
<thead>
<tr>
<th>Obstacle Type&lt;sup&gt;(a)&lt;/sup&gt;</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Siting</strong></td>
<td>The SPP CAWG recently sent a letter to all Transmission Owners (TOs) seeking information on obstacles to building transmission projects. Oklahoma Municipal Power Authority (OMPA) owns transmission or has been involved with generation projects that have encountered issues related to transmission. Shown below are three (3) projects where OMPA has encountered delays. Joint use of public rights-of-ways - encountered significant reluctance by another utility (an area coop) in overbuilding its distribution lines with new transmission facilities in Jackson County, specifically the city of Altus.</td>
</tr>
<tr>
<td><strong>Archeological</strong></td>
<td>Indian settlement - had to stop construction of a power plant and associated transmission lines on the site due to finding signs of previous Indian activity at plant construction site south side of South Canadian River just east of Interstate 44 in McClain County</td>
</tr>
<tr>
<td><strong>Environmental / Court Challenges</strong></td>
<td>COE 404 Permit Injunctions – new coal plant in southwest Arkansas has had repeated delays on plant construction and transmission line river crossing due to court challenges of this permit. AEP oversees construction activity for the plant and may report this same issue in their TO survey response to (the Oklahoma Commerce Commission) ... or to ... the Arkansas Public Service Commission.</td>
</tr>
</tbody>
</table>

<sup>(a)</sup> Type Provided by CAWG for Consistence

<table>
<thead>
<tr>
<th>Obstacle Type</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Environmental</strong></td>
<td>GRDA would group common obstacles into three major categories as follows: Wetlands, proximity to wetlands, SWPPP Protected and endangered species, habitat and potential habitat, species surveys Historical and archeological sites</td>
</tr>
<tr>
<td><strong>Permitting</strong></td>
<td>Federal, state and local permitting and approval processes Street, highway and railroad crossings</td>
</tr>
<tr>
<td><strong>Rights of Way</strong></td>
<td>NIMBY attitudes / Condemnation processes / Urban v. rural construction</td>
</tr>
</tbody>
</table>
## Western Farmers Electric Cooperative (WFEC)

<table>
<thead>
<tr>
<th>Obstacle Type&lt;sup&gt;(a)&lt;/sup&gt;</th>
<th>Obstacle</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Siting Construction</strong></td>
<td>For Western Farmers Electric Cooperative, the largest obstacles causing reroutes and const increases are:</td>
</tr>
<tr>
<td></td>
<td>Right-of-way acquisition</td>
</tr>
<tr>
<td></td>
<td>Completion Deadlines.</td>
</tr>
<tr>
<td></td>
<td>Once WFEC has identified right of Way tracts that will require condemnation, WFEC may be required to re-route around those tracts. Cost increases are due to additional line length and more expensive turn structures required for the reroute.</td>
</tr>
<tr>
<td><strong>Environmental</strong></td>
<td>Increasing environmental requirements (endangered species, wetlands, RUS environmental approval process).</td>
</tr>
<tr>
<td><strong>Archeological / Tribal Lands</strong></td>
<td>Tribal lands and requirements, and location.</td>
</tr>
</tbody>
</table>

<sup>(a) Type Provided by CAWG for Consistence</sup>

## Omaha Public Power District

### Obstacle Type

<table>
<thead>
<tr>
<th>Obstacle Type</th>
<th>Obstacle (Provides Listing of Species Recognized)&lt;sup&gt;(1)&lt;/sup&gt;</th>
</tr>
</thead>
</table>

### Summary of Animals listings

**Animal species listed in this state and that occur in this state (8 species)**

<table>
<thead>
<tr>
<th>Species</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beetle, American burying (&lt;i&gt;Nicrophorus americanus&lt;/i&gt;)</td>
</tr>
<tr>
<td>Crane, whooping except where EXPN (&lt;i&gt;Grus americana&lt;/i&gt;)</td>
</tr>
<tr>
<td>Plover, piping except Great Lakes watershed (&lt;i&gt;Charadrius melodus&lt;/i&gt;)</td>
</tr>
<tr>
<td>Shiner, Topeka (&lt;i&gt;Notropis topeka (=tristis)&lt;/i&gt;)</td>
</tr>
<tr>
<td>Sturgeon, pallid (&lt;i&gt;Scaphirhynchus albus&lt;/i&gt;)</td>
</tr>
<tr>
<td>Tern, least interior pop. (&lt;i&gt;Sterna antillarum&lt;/i&gt;)</td>
</tr>
<tr>
<td>Tiger beetle, Salt Creek (&lt;i&gt;Cicindela nevadica lincolniana&lt;/i&gt;)</td>
</tr>
<tr>
<td>Wolf, gray Lower 48 States, except MN, MT, ID, portions of eastern OR, eastern WA, north-central UT, and where EXPN. Mexico. (&lt;i&gt;Canis lupus&lt;/i&gt;)</td>
</tr>
</tbody>
</table>
Animal species listed in this state that do not occur in this state (2 species)

Species
Higgins eye (pearlymussel) (*Lampsilis higginsii*)
Mapleleaf, winged Entire; except where listed as experimental populations (*Quadrula fragosa*)

Animal listed species occurring in this state that are not listed in this state (3 species)

Species
Curlew, Eskimo (*Numenius borealis*)
Ferret, black-footed entire population, except where EXPN (*Mustela nigripes*)
Mussel, scaleshell (*Leptodea leptodon*)

Summary of Plant listings

Plant species listed in this state and that occur in this state (4 species)

Species
Butterfly plant, Colorado (*Gaura neomexicana var. coloradensis*)
Ladies'-tresses, Ute (*Spiranthes diluvialis*)
Orchid, western prairie fringed (*Platanthera praeclara*)
Penstemon, blowout (*Penstemon haydenii*)

Plant species listed in this state that do not occur in this state (1 species)

Species
Orchid, eastern prairie fringed (*Platanthera leucophaea*)
Areas of Order 1000 Requirements

2 Areas:

(1) Regional Requirements – SPP only

(2) Interregional – Seams Partners
<table>
<thead>
<tr>
<th>No.</th>
<th>RTO Regional Requirements</th>
<th>Current Status of SPP Compliance</th>
<th>Leads on Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td>1(a)</td>
<td>Participate in a regional transmission planning process that produces a regional transmission plan and complies with the Order No. 890 transmission planning principles. ([\S 6, 146])</td>
<td>SPP Complies with requirement.</td>
<td>N/A</td>
</tr>
<tr>
<td>1(b)</td>
<td>Amend OATT to explicitly provide for the consideration of transmission needs driven by Public Policy Requirements in both local and regional transmission planning processes. ([\S 203, 222])</td>
<td>Section III.6.k &amp; n of Attachment O to the SPP OATT considers Public Policy</td>
<td>SPP Legal/Regulatory, Strategic Planning Committee, &amp; RTWG: Consider drafting amendments to Attachment O that more directly addressing Public Policy requirements in Order 1000.</td>
</tr>
<tr>
<td>1(c)</td>
<td>Regional Planning must evaluate alternative transmission planning processes.</td>
<td>SPP Complies with requirement.</td>
<td>N/A</td>
</tr>
<tr>
<td>1(d)</td>
<td>Regional Planning must consider proposed non-transmission alternatives on a comparable basis. ([\S 148])</td>
<td>SPP Complies with requirement.</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Right of First Refusal**

2. Remove from FERC-jurisdictional tariffs and agreements any right of first refusal for an incumbent transmission provider to construct transmission facilities identified in the regional transmission plan for cost allocation. \([\S 313]\) | SPP’s OATT has ROFR language. | Strategic Planning Committee, Corporate Governance: Review and consider amendments to SPP Membership Agreement & OATT that directly address “ROFR.” |

**Cost Allocation**

3. Include in its OATT a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for cost allocation. \([\S 482]\) | SPP Complies with requirement. | N/A |

<table>
<thead>
<tr>
<th>No.</th>
<th>Interregional Requirements</th>
<th>Current Status of SPP Compliance</th>
<th>Leads on Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Engage in interregional coordination with each neighboring transmission planning region within the same interconnection to identify and jointly evaluate interregional transmission facilities that may more efficiently or cost-effectively address the individual needs of each respective local and regional transmission planning processes. ([\S 345, 393, 415])</td>
<td>Although SPP has Seams Agreements with neighboring regions, Order 1000 places additional requirements on interregional planning</td>
<td>SPP Engineering &amp; SPP Seams Steering Committee: Review Seams Agreements/Joint Operating Agreements. Develop procedures to comply with the interregional coordination requirements set forth in Order No. 1000 and to develop the same language to be included in each public utility transmission provider’s OATT that describes the procedures that a particular pair of transmission planning regions will use to engage in interregional coordination. OATT must still provide enough description so that stakeholders can follow how interregional transmission coordination will be conducted, and the OATT must contain links to the actual agreements</td>
</tr>
</tbody>
</table>

**Interregional Cost Allocation**

2. Develop, working through its transmission planning region, a method or set of methods for allocating the costs of new interregional transmission facilities that two (or more) neighboring transmission planning regions determine resolve the individual needs of each region more efficiently and cost-effectively. \([\S 578]\) | SPP has no methods for allocating costs for interregional transmission facilities with neighboring regions | SPP Regulatory, SPP Seams Steering Committee & SPP Regional State Committee: SPP’s RSC has already engaged the Brattle Group to look at Seams Cost Allocation. |
Update on RSC Seams Cost Allocation Effort

Presented to:
SPP RSC

Presented by:
Johannes Pfeifenberger

January 30, 2012

Presentation Content

Recap
Progress Update and Next Steps
Proposed Seams Cost Allocation Framework
Case Study
Recap: Overview

At our previous presentation at the October RSC meeting, we:

♦ Reviewed **seams and cost allocation frameworks and principles in other markets**

♦ Discussed **barriers to seams cost allocation** based on our review of seams cost allocation experiences in SPP and elsewhere

♦ Presented **interregional planning and cost allocation framework** for a flexible and robust approach to seams cost allocation, which needs to be an integral part of the interregional planning process

♦ Identified and discussed **seven necessary (and one optional) building blocks** that should be incorporated into seams planning and cost allocation agreements

♦ Noted that **building on SPP’s existing Joint Operating Agreements ("JOAs") with AECI and MISO** may be the most efficient way to incorporate and further develop the building blocks

Recap: Barriers to Seams Cost Allocation

♦ Uncertainty as to how or when neighboring regions will evaluate and consider seams projects as part of their regular planning processes;

♦ Limited availability of sufficiently detailed and current data to the neighboring system (e.g., fully updated interregional power flow cases);

♦ Limited time and staff to evaluate and consider seams projects, given high work load of region-internal planning efforts;

♦ Lack of sufficiently detailed, actionable cost allocation principles and guidelines;

♦ Different project types, evaluation processes, and benefits/metrics used in neighboring regions;

♦ Individual seams projects may offer very different types of benefits to each of the neighboring regions and transmission owners;

♦ Difficulty of developing single interregional evaluation frameworks that do not yield least-common denominator outcomes;

♦ Uncertainty about who owns which portions of the project and gets rights commensurate to share of project costs;

♦ Gap between top-down (ITP) and bottom-up (TSR & GI) transmission planning studies
Recap: The Seven Building Blocks

1. Regular interregional planning meetings
2. Regular exchange of planning data
3. Process to propose and analyze seams projects
4. Evaluation criteria and benefit metrics
5. Seams cost allocation principles and guidelines
6. Payment mechanisms
7. Integration with internal planning and cost allocation

Optional building block – may be added over time

Recap

Progress Update and Next Steps

Proposed Seams Cost Allocation Framework

Case Study
Progress Since Last Meeting and Next Steps

Since the October RSC meeting, we worked with SPP staff, Seams Steering Committee, and stakeholders to:

♦ Get buy-in on detailed outline of *Brattle* report
♦ Develop illustrative “straw man” language to integrate the seven building blocks into generic SPP JOAs
♦ Start applying (conceptually) the framework to candidate seams projects

Moving forward, we will incorporate feedback and prepare the final report

♦ January and February - Receive feedback from stakeholders on integration of building blocks. If necessary conduct interviews with individual stakeholders
♦ March – Draft report to Cost Allocation Working Group
♦ April – Final report to RSC

Draft Outline of *Brattle* Report

I. Executive Summary
II. Background
III. Efforts at Interregional Cost Allocation and Seams Issues Outside SPP
IV. Barriers to Seams Cost Allocation
V. Review of SPP RSC Draft Cost Allocation Principles for Seams Transmission Expansion Projects
VI. Framework for Interregional Planning and Cost Allocation
VII. Qualification, Proposal, and Analysis of Seams Projects
VIII. Benefits and Metrics for Seams Projects
IX. Seams Cost Allocation Principles and Guidelines
X. Payment Mechanisms to Implement Seams Cost Allocation
XI. Optional Pre-Specified Formulaic Cost Allocation
XII. Case Studies: Illustrative Application of Framework to Candidate Seams Projects
XIII. Conclusions/Recommendations/Further Work

Appendices
Appendix A: Seams and Cost Allocation Methodologies in Other Power Markets
Appendix B: SPP RSC Draft Cost Allocation Principles for Seams Transmission Expansion Projects (SPP Draft Whitepaper)
Appendix C: Possible Additions to Interregional Planning and Cost Allocation Provisions in Existing JOAs
Appendix D: Summary of Candidate Seams Projects
Leverage and Expand Existing JOAs

With some modifications, clarifications, and expansion, existing JOAs can serve as a foundation for building blocks 1, 2, and 7 of an interregional planning and cost allocation agreement between SPP and its seams entities.

<table>
<thead>
<tr>
<th>Existing</th>
<th>To add</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Regular interregional planning meetings</td>
<td>Retail regulator involvement, perhaps via IPSAC</td>
</tr>
<tr>
<td>2. Regular exchange of planning data</td>
<td>Jointly develop and validate load flow and other planning models for combined footprint</td>
</tr>
<tr>
<td>7. Integration with internal planning and cost allocation</td>
<td>Include public policy requirements; validate consistency in modeling assumptions; specify how seams projects can be proposed; consider synergies with transmission service and generation interconnection requests</td>
</tr>
</tbody>
</table>
Missing or Unspecified Building Blocks

Building blocks 3, 4, 5, and 6, are either missing or largely unspecified in the current JOAs. They are also most closely related to seams cost allocation.

<table>
<thead>
<tr>
<th>Building Block</th>
<th>Existing</th>
<th>To add</th>
</tr>
</thead>
<tbody>
<tr>
<td>3. Process to propose and analyze seams projects</td>
<td>Focused on projects that are identified in Joint &amp; Coordinated System Plan</td>
<td>Add seams qualification criteria and more flexible process with commitment to jointly analyze</td>
</tr>
<tr>
<td>4. Evaluation criteria and benefit metrics</td>
<td>Broad reliability and economic considerations</td>
<td>Add new section on internally-used criteria and benefit metrics at minimum, plus seams-specific</td>
</tr>
<tr>
<td>5. Seams cost allocation principles and guidelines</td>
<td>Case-by-case review</td>
<td>Add new section</td>
</tr>
<tr>
<td>6. Payment mechanisms</td>
<td>Does not exist</td>
<td>Add new section</td>
</tr>
<tr>
<td>OPTIONAL: Pre-specified formulaic evaluation and cost allocation methodology</td>
<td>Does not exist</td>
<td>Possibly add new section if parties can agree to formulaic methodology</td>
</tr>
</tbody>
</table>

Building Block #3
Process to Propose and Analyze Seams Projects

- As long as the proposed seams project addresses both seams entities’ transmission needs and offers benefits to both, the project could be:
  - A single line or several lines that are logically grouped together
  - Crossing seam or (unlike Order 1000) be wholly within one entity’s footprint

- No threshold such as voltage class, total cost, or total benefits
  - Some “small” projects may offer substantial benefits

- Projects can be proposed unilaterally and must include:
  - A detailed description of the project
  - A qualitative discussion of the project’s purpose and benefits to both neighbors (which could differ on either side of the seam)
  - Preliminary analyses (e.g., power flow studies) of the project’s benefits to both entities … documenting results, assumptions, and data consistent with the planning methods and metrics of each entity as specified in the agreement
  - A proposed preliminary cost allocation consistent with specified cost allocation principles and benefits identified in screening analyses

- Seams entities can agree to jointly propose any seams project(s)
- Seams entities commit to jointly analyze any proposed project(s)
Building Block #4
Evaluation Criteria and Benefit Metrics

Interregional cost allocation (e.g., as would be specified in the JOA) should be based on a set of guiding principles such as:

♦ Recognition that seams projects may offer combinations of different types of benefits and entirely different sets of benefits may accrue to each entity;
♦ Benefits and metrics used for the evaluation of seams projects by each entity will include all benefits and metrics considered in each entity’s internal (local and regional) transmission planning process;
♦ Each entity shall have the option, but not the obligation, to consider some or all of the benefits and metrics used by the other entity;
♦ Seams projects can offer unique benefits beyond those currently considered in either entity’s internal transmission planning process;
♦ Additional benefits can be developed and documented as more experience is gained;
♦ Seams projects may serve to avoid or delay the cost of (1) transmission projects in existing regional and local transmission plans; (2) transmission upgrades that may be needed in the future to meet local or regional needs; and (3) transmission upgrades needed to satisfy GI and TSRs.

Building Block #4
Benefit Metrics: SPP

Evaluation criteria and benefit metrics applied to seams projects should include, at minimum, internally-considered criteria and metrics. Some of SPP’s defined benefits and metrics include:

<table>
<thead>
<tr>
<th>SPP Internally Used Benefits</th>
<th>Quantitative / Qualitative Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted production cost savings</td>
<td>Monetized through PROMOD simulations</td>
</tr>
<tr>
<td>Ability to replace or delay previously approved projects</td>
<td>Monetized as the avoided cost of previously approved projects</td>
</tr>
<tr>
<td>Energy value of reduced transmission losses</td>
<td>Monetized based on quantification through power flow simulations</td>
</tr>
<tr>
<td>Capacity value of reduced transmission losses</td>
<td>Monetized as avoided capacity</td>
</tr>
<tr>
<td>Value of improved ATC</td>
<td>Quantified as incremental capacity (MW)</td>
</tr>
<tr>
<td>Additional robustness metrics</td>
<td>As specified</td>
</tr>
</tbody>
</table>
Building Block #4
Benefit Metrics: Non-RTO Neighbor Example

For non-RTO regions, evaluation criteria and benefits metrics may be less formulaic or clearly stated. We provide as an illustrative example below, benefits and metrics based on our interpretation of Western Area Power Administration’s 2011 Strategic Plan.

<table>
<thead>
<tr>
<th>Illustrative Internally-Used Benefits</th>
<th>Quantitative / Qualitative Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avoid reliability violations</td>
<td>Quantified as number/duration of violations and monetized as avoided cost of regional/local upgrade</td>
</tr>
<tr>
<td>Reduce frequency and cost of supply interruptions during low-hydro years</td>
<td>Quantified as number/duration of likely events and monetized as cost of interruptions or replacement power</td>
</tr>
<tr>
<td>Reduce dispatch of high-cost generation needed to serve load in presence of internal transmission congestion or import constraints</td>
<td>Monetized as reduced generation and emission costs</td>
</tr>
<tr>
<td>Avoid cost of local transmission upgrades needed to support load growth</td>
<td>Monetized as avoided cost of regional/local upgrade</td>
</tr>
<tr>
<td>Reduced transmission losses</td>
<td>Monetized as energy and on-peak capacity savings</td>
</tr>
<tr>
<td>Increase ATC (and off-system sales)</td>
<td>Monetized as incremental off-system sales profits and/or transmission rights</td>
</tr>
</tbody>
</table>

Building Block #4
Benefit Metrics: Additional Benefits of Seams Projects

In addition to internally-considered benefits and metrics, there are benefits and metrics that are unique to seams projects.

- We propose that the seams entities consider including at minimum the seams-specific metrics listed below in the evaluation process

<table>
<thead>
<tr>
<th>Seams-Specific Benefits</th>
<th>Quantitative / Qualitative Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental wheeling through and out revenues</td>
<td>Estimates of additional wheeling volumes may be derived from transmission service requests and PROMOD modeling</td>
</tr>
<tr>
<td>Benefits from increased reserve sharing capability</td>
<td>Quantified as a reduction in MW of reserve capacity</td>
</tr>
</tbody>
</table>

- Additional benefits and metrics can be considered on a project-specific basis upon mutual agreement of the seams entities
Building Block #5
Seams Cost Allocation Principles and Guidelines

The agreement would specify the "general cost allocation principles" that will be applied to seams projects, such as:

- Cost allocated should be at least roughly commensurate with total benefits to each entity; neither seams entity shall be allocated cost without receiving benefits
- Cost allocation methodologies and identification of benefits and beneficiaries must be transparent
- Different cost allocation methods may be applied to different types or different portions of transmission facilities (e.g., transmission needs driven by reliability, economic, or public policy requirements)
- The seams entities will quantify and, if possible, monetize benefits; but they will also recognize non-monetized and non-quantified benefits in assessing overall reasonableness of proposed cost allocations
- Monetized reliability, load serving, or public policy benefits will be at least equal to the avoided cost of achieving the same benefit through local or regional upgrades
- If benefit-to-cost ratios are utilized, the minimum ratio should not exceed 1.25
- The share of benefits to each seams entity should be sufficient to support the seams projects' approval through each entity's internal planning process

Building Block #5
Seams Cost Allocation Principles and Guidelines

The agreement would also pre-specify flexible cost allocation mechanisms. For example, it may specify that cost allocation to each entity should be based on one or a combination of:

- The share of seams projects' total benefits received by each entity as a proportion of the sum of the entities' total benefits received (consistent with specified principles and metrics)
- If shares are reasonably proxies for received benefits or roughly proportionate to benefits received, cost allocation can also be based on:
  - The share of seams projects' physical location in each Party's footprint (e.g., shares of circuit miles)
  - The share of each entity's relative contribution to the need for a project (e.g., power flows that contribute to a reliability-driven upgrade)
  - The share of each entity's projected or allocated usage of the seams projects' transmission capability (e.g., shares of increased flow-gate capacity)

Provision of transmission rights:
- To the extent feasible and practical, an entity sharing the cost of seams projects should receive a physical or financial right for a commensurate share of the projects' capability (e.g., a share of increased ATC or flow-gate capacity).
Building Block #6
Payment Mechanisms

Once a reasonable cost allocation has been determined, the cost allocation shall be implemented consistent with following principles:

♦ To the extent feasible, cost allocation shall be implemented through either
  • Physical ownership of individual segments of a project by the seams entities or their transmission owners such that the cost of each owned portion is consistent with the determined cost allocation; or
  • Co-ownership of the project (or individual segments) where the project (or segment) cannot be divided into fully-owned segments or if a proposed project (or segment) is entirely within the service territory of one of the seams entities

♦ Where ownership allocation is not feasible, cost allocation should be implemented through payments (from one entity to the other) that correspond to the obtained physical or financial rights to the projects’ transmission capability

♦ Each entity will recover allocated costs consistent with cost recovery of local and regional projects within its footprint

Optional Building Block
Pre-specified Formulaic Options

As more experience with the cost allocation of seams projects is gained, the seams entities may pre-specify cost allocation options.

♦ These pre-specified formulaic cost allocations would be based on (i) specific metrics for the evaluation of the seams project and (ii) a pre-specified cost allocation methodology that formulaically relies on these benefits and metrics.
  • Entities that already use similar pre-specified metrics (e.g., use of APC in SPP and MISO) would be more likely to adopt this approach
  • Examples: PJM-MISO interregional evaluation and cost allocation process for reliability and economic projects
  • A less formulaic option (e.g., in an agreement between SPP and AECI) might include a cost allocation in proportion to each entity’s avoided costs of implementing their own alternative solutions to the identified reliability problems

♦ Different formulas can be applied to specific project types (e.g., reliability, economic, public policy, multi-value)

Projects that do not fit the pre-specified options would be considered under the general cost allocation principles
Case Study

Acadiana Load Pocket (ALP) Project

The Acadiana Load Pocket (ALP) Project, sponsored by Cleco, EGSL, and LUS presents a useful ex post case study for the recommended cost allocation framework.

♦ The ALP is an area in south central Louisiana, which encompasses customers of Cleco Power (Cleco), Lafayette Utilities System (LUS), Entergy Gulf States Louisiana (EGSL), Louisiana Generating (LaGen), and Louisiana Energy and Power Authority (LEPA)

♦ In September 2008, SPP, as the Independent Coordinator of Transmission (ICT), facilitated an agreement to implement a $200 million upgrade funded by the following utilities in recognition of various benefits:
  • $120 million funded by Cleco for reliability but mostly economic benefits (avoid running one of its oldest and most expensive generators)
  • $60 million funded by Entergy for reliability benefits (reduce TLRs, which included firm curtailments) and generator interconnection benefits
  • $20 million funded by LUS for mostly reliability and some economic benefits (reliability concerns triggered reliance on more costly generators during summer peak)
Case Study
ALP Project – Benefits of Project

The ALP Project was developed to address the following concerns and capture corresponding benefits:

♦ **Increase in TLR procedures and their severity** – Loss of Cleco or LUS’s lines resulted in TLR procedures on EGSL’s system for both firm and non-firm curtailments for imported energy, requiring Cleco and LUS to keep must-run generators.

♦ **Over-reliance on inefficient units** – Cleco’s and LUS’s and must-run generators were expensive to dispatch. Cleco’s unit was also the single largest generation contingency in ALP and provided both load-serving capability and voltage support, which may complicate any scheduled maintenance and cause reliability concerns if the unit was to be offline for an extended period of time.

  • If a solution such as the ALP Project was implemented, fuel savings to Cleco were estimated to be **$144.2 million between 2010 and 2016** and **$905.6 million between 2010 and 2039**. LUS was also estimated to realize economic benefits, such as fuel cost savings and increased generation flexibility.

Case Study
ALP Project – Benefits of Project (cont’d)

♦ **Disconnects between planning model assumptions and operation:**
  • Long-term models did not account for short-term (real-time) economic dispatch resulting in heavier transmission usage than the system could easily handle
  • Natural gas price increases caused economic dispatch to favor imports and stress the transmission system further.

♦ **Lack of operational flexibility** – Increased reliance on imports means that it is more difficult to obtain scheduled outages on the transmission system to perform routine maintenance.

♦ **Accommodating additional transmission service** – Entergy’s newly purchased 580 MW Acadia combined cycle power plant would need ALP and additional upgrades to avoid significant redispatch.

The ALP project offered both reliability and economic benefits, but these types of benefits accrued differently to each sponsor. Agreement was reached that each sponsor captured a pro-rata share of the reliability benefits, but Cleco capture slightly more of the overall economic benefits.
Case Study
ALP Project – Applicable Benefits Principles

The ALP Project embodies many of the benefits principles we laid out:

♦ Recognition that seams projects may offer combinations of different types of benefits and entirely different sets of benefits may accrue to each entity;

♦ Benefits and metrics used for the evaluation of seams projects by each entity will include all benefits and metrics considered in each entity's internal (local and regional) transmission planning process;

♦ Each entity shall have the option, but not the obligation, to consider some or all of the benefits and metrics used by the other entity;

◊ Seams projects can offer unique benefits beyond those currently considered in either entity's internal transmission planning process;

◊ Additional benefits can be documented as more experience is gained;

♦ Seams projects may serve to avoid or delay the cost of (1) transmission projects in existing regional and local transmission plans; (2) transmission upgrades that may be needed in the future to meet local or regional needs; and (3) transmission upgrades needed to satisfy GI and TSRs.

Case Study
ALP Project – Cost Allocation

The ALP Project, as originally proposed, first determined reliability and an economic components of total costs, then allocated these reliability and economic portions to participants through ownership shares:

<table>
<thead>
<tr>
<th>Component Benefit</th>
<th>Total Est. Cost ($ million)</th>
<th>Cost Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability Benefits</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Relieves EGSL TLR procedures (allows for increased economic import)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Accommodates load growth and improves load serving capability for all</td>
<td>$71.9</td>
<td>Allocated roughly based on load ratio share and then matched with component ownership</td>
</tr>
<tr>
<td>Economic Benefits</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Allows removal of must-run designation for Cleco and LUS units</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Economic benefits largely to Cleco (est. fuel cost savings of $906 million 2010-2039)</td>
<td>$128.1</td>
<td>Allocated largely to Cleco and then matched with component ownership</td>
</tr>
<tr>
<td>• Additional generation dispatch flexibility and potential fuel cost savings for LUS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Allow interconnection and dispatch of new generation for EGSL</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>$200.0</td>
<td></td>
</tr>
</tbody>
</table>
Case Study
ALP Project – Applicable Cost Allocation Principles

ALP also embodies most of the proposed cost allocation principles:

♦ Cost allocated should be at least roughly commensurate with total benefits to each entity; neither seams entity shall be allocated cost without receiving benefits

♦ Cost allocation methodologies and identification of benefits and beneficiaries must be transparent

♦ Different cost allocation methods may be applied to different types or different portions of transmission facilities (e.g., transmission needs driven by reliability, economic, or public policy requirements)

♦ The seams entities will quantify and, if possible, monetize benefits; but they will also recognize non-monetized and non-quantified benefits in assessing overall reasonableness of proposed cost allocations

♦ Monetized reliability, load serving, or public policy benefits will be at least equal to the avoided cost of achieving the same benefit through local or regional upgrades

♦ If benefit-to-cost ratios are, the minimum ratio used should not exceed 1.25

♦ The share of benefits to each seams entity should be sufficient to support the seams projects’ approval through each entity’s internal planning process

Case Study
ALP Project – Applicable Payment Mechanism

The ALP Project also used ownership of project components to implement cost allocation

♦ To the extent feasible, cost allocation shall be implemented through either:

  • Physical ownership of individual segments of a project by the seams entities or their transmission owners such that the cost of each owned portion is consistent with the determined cost allocation; or

  • Co-ownership of the project (or individual segments) where the project (or segment) cannot be divided into fully-owned segments or if a proposed project (or segment) is entirely within the service territory of one of the seams entities

♦ Where ownership allocation is not feasible, cost allocation should be implemented through payments (from one entity to the other) that correspond to the obtained physical or financial rights to the projects’ transmission capability

♦ Each entity will recover allocated costs consistent with cost recovery of local and regional projects within its footprint
SPP Transmission Expansion Plan
-2012 ITPNT
-2012 ITP10
-2012 STEP

January 30 & 31, 2012
Lanny Nickell

Topics

- SPP Transmission Expansion Planning Process
- CNTCs, NTCs, and ATPs
- 2012 ITPNT Summary
- 2012 ITP10 Summary
- 2012 STEP Summary
- Rate Impacts
SPP TRANSMISSION EXPANSION PLANNING PROCESS

SPP Transmission Expansion Planning

- Attachment O governs SPP transmission expansion planning process
- Results of SPP transmission planning process contained in the SPP Transmission Expansion Plan (STEP)
- STEP must be presented to Board at least annually
- Updates may be made between the annual approvals
STEP Components

SPP Transmission Expansion Plan

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

Board Approval Required
Board Endorsement Required

ITP Efforts

Integrated Transmission Planning

- Annual
- Near Term
- Triennial
- 20-Year
- 10-Year
CNTCs, NTCs, AND ATPs

NTC, CNTC, & ATP

- **NTC**
  - approval to build
  - financial expenditure in next 4 years

- **CNTC**
  - approved concept
  - Projects > 100 kV and > $20 million, ±20% estimate
  - business practice to be developed

- **ATP**
  - approved by BOD
  - no NTC
  - business practice under development
PCTF Cost Estimation Recommendations

- SPCTF on RSC motion (PCTF White Paper) was approved by the SPP BOD in July 2011.
- PCWG is in the process of drafting Business Practices to implement the PCTF’s White Paper. The process is not finalized.
- Request SPP BOD approve the issuance of NTCs contingent upon changes to SPP’s Business Practices that incorporate the Project Cost Task Force (PCTF) project cost estimation recommendations.

2012 ITPNT SUMMARY
2012 ITPNT Plan Summary

- $251 million new and modified NTCs
  - CNTCs specified for 4 upgrades
    - Projects that are >100 kV and >$20M
    - Include estimate completion date
  - 1 upgrade classified as ATP
- $190 million withdrawn NTCs
2012 ITP10 SUMMARY

2012 ITP10

- Two futures
  - Future 1: Business as Usual
  - Future 2: EPA Rules with Additional Wind
- Projects that synergistically provide value by optimizing
  - Reliability concerns
  - Provide economic benefits
  - Fulfill policy requirements
Valuing Cleaner Air

The reduction in CO₂ emissions for Future 1 was equivalent to that of 83,000 SUVs

Annual emissions of 1,000 SUVs =
Offering Lasting Savings

The portfolio provided $834 million of net savings over their expected 40-year life.

Preparing for Reliable Operation

More than 61 potential reliability issues were mitigated by the projects.

Zero voltage or transient stability concerns were identified related to the portfolio.
Achieving Renewable Targets & Goals

The portfolio enabled the achievement of renewable goals and targets in every state in the SPP RTO.

Incorporating from ITP20

500 miles of proposed new transmission in the ITP10 portfolio (4 projects) coincided with the approved 2010 ITP20 plan.
2012 ITP10 by the Numbers

- 83,000 SUVs worth of annual CO₂ emissions avoided
- $834 million in net savings over forty years*
- > 61 potential reliability issues mitigated
- Zero negative impacts to stability.
- Every states’ renewable goals or targets achieved
- 500 miles of the 2010 ITP20 plan included

*34¢ average savings across the region for each 1000 kWh/month of customer consumption over 40 years

2012 STEP SUMMARY
2012 STEP Components

- Proposed ITP upgrades
  - ITP10
  - ITPNT
- ITP 20 and previous reliability projects
- Generation Interconnection upgrades
- Transmission Service upgrades
- Previously endorsed Sponsored and approved Balanced Portfolio and High Priority upgrades

2012 STEP

Cost by Project Type
$7.1 billion total
($4.1 billion NTCs)
**NTC Issuance**

**Cost of NTC Upgrades by Year**

- **Historical**
- **Projected**

- **$1400M**
- **$1600M**

**Rate Impacts** – Paul Suskie
Rate Impact Task Force – January 2011

- RSC formed a RITF to study transmission cost impacts on customers on a monthly basis.
- Considered ALL Projects & Used conservative benefits.
- Looked at the highest cost year – (2017).
- RITF Members:
  - Barry Smitherman, PUCT - (Chairman)
  - Michael Siedschlag, NPRB - (Member)
  - Thomas Wright, KCC - (Member)
  - Larry Altenbaumer, SPP BOD - (Member)
  - Ricky Bittle, Ark Electric Coops - (Member)
  - Mike Palmer, Empire District Electric - (Member)
  - Les Dillahunty - (Staff Secretary)

ITP10/NT - Rate Impact using RITF Method

- Utilizes the Rate Impact Task Force’s methodology developed for the RSC as presented in January, 2011.
  - [http://www.spp.org/publications/RITF%20Output%20for%20RSC%20Jan%202011%20REV%204.ppt](http://www.spp.org/publications/RITF%20Output%20for%20RSC%20Jan%202011%20REV%204.ppt)
- Overview uses the Peak Year of 2023 for ITP10 plus ITPNT
- Calculations were performed by allocating ATRR in peak year using Member supplied zonal data for actual average retail residential ratepayers in each SPP Pricing Zone (retail and residential transmission allocation %, etc.)
- COSTS Only are shown - no offsetting benefits are shown
- SPP RTO weighted average was computed with zonal load ratio shares
Summary: ITP10 and ITP Near Term Upgrades

1. Reliability Upgrades from ITP10 and ITPNT - *required* for compliance
   - $0.50/mo weighted average in SPP
   - 67% of total "cost only" rate impact, rounded

2. Public Policy Upgrades - *required* to meet projected renewable energy standards
   - $0.08/mo weighted average in SPP
   - 10% of total "cost only" rate impact

3. Economic Upgrades generating economic benefits
   - $0.17/mo weighted average in SPP
   - 23% of total "cost only" rate impact

4. Total "COST ONLY" Rate Impact – *COST NOT OFFSET BY BENEFITS*
   - $0.74/mo weighted average in SPP
   - Discounted at 8% to 2012 $ from Peak Rate Impact Year 2023

Rate Impact of ITP 10 and ITP Near Term by Component for SPP

<table>
<thead>
<tr>
<th>Component</th>
<th>ITP10 Reliability</th>
<th>ITP10 Economic</th>
<th>ITP10 Policy</th>
<th>Total Rate Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPP Regional Weighted Average</td>
<td>$0.50</td>
<td>$0.08</td>
<td>$0.17</td>
<td>$0.74</td>
</tr>
<tr>
<td>% of Total Rate Impact</td>
<td>66.8%</td>
<td>10.2%</td>
<td>23.0%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
Zonal Rate Impact of ITP10 and ITP Near Term

Zonal Rate Impacts of ITP10 and ITP NT, Cost Only, Peak ATRR Year of 2023 in $20Y2, 8% Discount Rate Increase in Average Monthly Residential Electric Bill in $/Mo

<table>
<thead>
<tr>
<th>ZONE</th>
<th>ITP10 Reliability</th>
<th>ITP Non-TP Reliability</th>
<th>ITP10 Economic</th>
<th>ITP10 Policy</th>
<th>Total Rate Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>$0.39</td>
<td>$0.25</td>
<td>$0.05</td>
<td>$0.09</td>
<td>$0.79</td>
</tr>
<tr>
<td>CUS</td>
<td>$0.19</td>
<td>$0.24</td>
<td>$0.00</td>
<td>$0.04</td>
<td>$0.27</td>
</tr>
<tr>
<td>EDE</td>
<td>$0.22</td>
<td>$0.05</td>
<td>$0.00</td>
<td>$0.05</td>
<td>$0.33</td>
</tr>
<tr>
<td>ORDA</td>
<td>$0.02</td>
<td>$0.01</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.03</td>
</tr>
<tr>
<td>KCPL</td>
<td>$0.20</td>
<td>$0.06</td>
<td>$0.02</td>
<td>$0.06</td>
<td>$0.40</td>
</tr>
<tr>
<td>LES</td>
<td>$0.32</td>
<td>$0.16</td>
<td>$0.10</td>
<td>$0.04</td>
<td>$0.43</td>
</tr>
<tr>
<td>MIDW</td>
<td>$0.17</td>
<td>$0.30</td>
<td>$0.00</td>
<td>$0.04</td>
<td>$0.57</td>
</tr>
<tr>
<td>GMO</td>
<td>$0.30</td>
<td>$0.06</td>
<td>$0.07</td>
<td>$0.04</td>
<td>$0.44</td>
</tr>
<tr>
<td>MKTC</td>
<td>$0.24</td>
<td>$0.55</td>
<td>$0.00</td>
<td>$0.06</td>
<td>$0.55</td>
</tr>
<tr>
<td>MPH</td>
<td>$0.26</td>
<td>$0.06</td>
<td>$0.00</td>
<td>$0.06</td>
<td>$0.43</td>
</tr>
<tr>
<td>OSE</td>
<td>$0.24</td>
<td>$0.06</td>
<td>$0.02</td>
<td>$0.06</td>
<td>$0.38</td>
</tr>
<tr>
<td>OPPO</td>
<td>$0.22</td>
<td>$0.05</td>
<td>$0.01</td>
<td>$0.05</td>
<td>$0.34</td>
</tr>
<tr>
<td>SEPC</td>
<td>$0.13</td>
<td>$0.03</td>
<td>$0.00</td>
<td>$0.03</td>
<td>$0.16</td>
</tr>
<tr>
<td>SPB</td>
<td>$0.46</td>
<td>$0.52</td>
<td>$0.11</td>
<td>$0.11</td>
<td>$0.41</td>
</tr>
<tr>
<td>WFEC</td>
<td>$0.20</td>
<td>$0.04</td>
<td>$0.07</td>
<td>$0.09</td>
<td>$0.66</td>
</tr>
<tr>
<td>WM</td>
<td>$0.25</td>
<td>$0.20</td>
<td>$0.09</td>
<td>$0.09</td>
<td>$0.74</td>
</tr>
</tbody>
</table>

Rate Impact SPP Weighted Average: $0.31, $0.10, $0.17, $0.08, $0.74

Questions
Integrated Marketplace Review

SPP Regional State Committee
January 30, 2012

Bruce Rew, PE
Vice President, Operations

Why Integrated Marketplace?

• Net benefits ~ $45-100 million/year
• Reduce total energy costs through centralized unit commitment while maintaining reliable operations
• Day-Ahead Market allows additional price assurance capability prior to real-time
• Includes new markets for Operating Reserve to support implementation of Consolidated Balancing Authority (CBA) and facilitate reserve sharing
The Marketplace’s Processes

DA Market Offers (Energy and Operating Reserve), Bids, Operating Reserve Requirements

RTBM Offers, Load Forecast, Operating Reserve Requirements

RTBM Offers, Load Forecast, Operating Reserve Requirements

Dispatch Instruction, cleared Operating Reserve (MW) (5 minute)

Reliability Unit Commitment (RUC)

Day-Ahead Market (DA Market)

Real-Time Balancing Market (RTBM)

Reliability Unit Commitment (RUC)

DA Market & Net RTBM Settlements

RTBM Commitment

EMS

TCR Markets

Resource and Load Meter Data

Program Structure (Design)

Marketplace Leadership Team

Chair - Sam Ellis (5)*

Bruce Row, Program Sponsor

SPP Officers

Program Manager

Integrated Marketplace PMO

Decision Task Force

Philip Miller

Cody Parker

Gary Cote

Jim Davis

Market Architects

Richard Dillon

Wayne Camp

Jodi Woods

Elizabeth Kwiatkowski

Regulatory & Compliance

Heather Starnes

Beth Miller

Market Systems

Markets (5)

Market Operations (3)

CBA (3)

TCC (2)

Settlements (3)

Registration (2)

Credit & Risk Mgmt (2)

Reqs Mgmt & Testing (4)

EMS (3)

Technology

Technical Architecture (7)

Integration Services (7)

IT Infrastructure (7)

Business Intelligence (7)

Performance Testing (7)

Legacy Applications (5)

Renal (7)

Breakfast, Training

Communications

John Woods

Lesliz Reider

Stakeholder

Communications (6)

Readiness & Metrics (6)

Participant Training (6)

Operations Training (6)

Internal Training (6)

Market Trials (4)

Regulator & Compliance

Heather Starnes

Beth Miller

Market Trials (4)

* (numbers) denote MLT escalation points

Stakeholder

Communications (6)

Readiness & Metrics (6)

Participant Training (6)

Operations Training (6)

Internal Training (6)

Market Trials (4)
## 2012 Program Milestones

<table>
<thead>
<tr>
<th>2012 Milestones</th>
<th>Baseline End Date</th>
<th>Tracking End Date</th>
<th>Actual End Date</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vendor API Specs Released to Market Participants</td>
<td>1 Jan 2012</td>
<td>31 Mar 2012</td>
<td></td>
<td>Released Jan to Mar 2012</td>
</tr>
<tr>
<td>Initial SPP Membership Agreement and CBA Filing Submitted</td>
<td>29 Feb 2012</td>
<td>29 Feb 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Complete First TCR Mock Auction Runs with Members</td>
<td>13 Apr 2012</td>
<td>13 Apr 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Publish Readiness Metrics Dashboard</td>
<td>13 Apr 2012</td>
<td>13 Apr 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>TCR FAT Complete</td>
<td>16 Apr 2012</td>
<td>16 Apr 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Conditional FERC Order on Initial Tariff/Credit Policy Implementation Filing</td>
<td>29 Jun 2012</td>
<td>29 Jun 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Markets DDNs Complete</td>
<td>23 Jul 2012</td>
<td>23 Jul 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Complete Second TCR Mock Auction Runs with Members</td>
<td>31 Aug 2012</td>
<td>31 Aug 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Markets FAT Complete</td>
<td>16 Nov 2012</td>
<td>16 Nov 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Final FERC Approval Order Received for Initial Tariff/Credit Implementation</td>
<td>31 Dec 2012</td>
<td>31 Dec 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Final FERC Approval Order Received for Membership Agreement and CBA</td>
<td>31 Dec 2012</td>
<td>31 Dec 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Build/FAT End</td>
<td>31 Dec 2012</td>
<td>31 Dec 2012</td>
<td></td>
<td>Green</td>
</tr>
</tbody>
</table>

## Upcoming Program Activities

- Draft internal Release & Integration Strategy (Q1 2012)
- Deliver initial release of API specifications via Programmatic Interface Review Group (Q4 2011 through Q1 2012)
- Finalize Readiness Metrics & Checklists
- Finalize Marketplace Communication Plan
- Demonstrate basic Day Ahead study functionality (Q1 2012)
- Validate Marketplace resource plans against integration build and test efforts
## 2012 Market Participant Milestones

<table>
<thead>
<tr>
<th>2012 Milestones</th>
<th>Baseline End Date</th>
<th>Tracking End Date</th>
<th>Actual End Date</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vendor API Specs Released to Market Participants</td>
<td>1 Jan 2012</td>
<td>31 Mar 2012</td>
<td></td>
<td>Released Jan to Mar 2012</td>
</tr>
<tr>
<td>Start First TCR Mock Auction Runs with Members</td>
<td>16 Jan 2012</td>
<td>16 Jan 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>CMT Provides Blank Registration to Market Participants</td>
<td>1 Feb 2012</td>
<td>1 Feb 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Publish Draft Readiness Metrics for Liaison Review</td>
<td>29 Feb 2012</td>
<td>29 Feb 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Publish Draft Readiness Checklist for Liaison Review</td>
<td>29 Feb 2012</td>
<td>29 Feb 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Start Second TCR Mock Auction Runs with Members</td>
<td>2 Apr 2012</td>
<td>2 Apr 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Distribute Pre-Filled Registration Packet to Market Participants</td>
<td>2 Apr 2012</td>
<td>2 Apr 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Complete First TCR Mock Auction Runs with Members</td>
<td>13 Apr 2012</td>
<td>13 Apr 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Publish Readiness Metrics Dashboard</td>
<td>13 Apr 2012</td>
<td>13 Apr 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>MPs Return Completed Registration Packets</td>
<td>1 Jun 2012</td>
<td>1 Jun 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Complete Second TCR Mock Auction Runs with Members</td>
<td>31 Aug 2012</td>
<td>31 Aug 2012</td>
<td></td>
<td>Green</td>
</tr>
<tr>
<td>Final FERC Approval Order Received for Membership Agreement and CBA</td>
<td>31 Dec 2012</td>
<td>31 Dec 2012</td>
<td></td>
<td>Green</td>
</tr>
</tbody>
</table>

## “When”: Market Participant Milestones

- **May 2, 2014**: Participants define market software/market staffing/roadmap and track
- **April 2, 2014**: Participants ready to begin TCR mock auctions
- **May 16, 2014**: Participants make appropriate regulatory filings
- **January 1, 2015**: Participants commence registration data submission to participants in Marketplace
- **May 15, 2013**: Participants ready for system integration with SPP
Southwest Power Pool
10 Year Annual Transmission Revenue Requirement Forecast

4th Quarter, 2011

Presented to the RTWG
January 26, 2012

&

RSC
January 30, 2012

Southwest Power Pool
ATRR Forecast Purpose and General Notes

Estimate the amount of annual cost recovery required for the SPP Rate Zone’s Transmission Plant In-Service by year – the Annual Transmission Revenue Requirement (ATRR).

1. Inputs:
   - Upgrade Investment Estimate in US Dollars
   - Upgrade In-Service Date
   - Transmission Owner’s and their Net Plant Carrying Charge Rate - %
   - Cost Allocation Methodology per SPP Tariff (OATT):
     - Traditional Base Plan Funding – NTC issued before 6/19/10
     - Highway Byway Base Plan Funding – NTC issued after 6/19/10

2. Assumptions:
   - Six Month shift was included to account for upgrades going into service through-out a typical year
   - 2.5% Straight-Line Depreciation
Original Base Plan Funding Method

- Upgrades with NTC issued before 6/19/10
  - ATRR before Cost Allocation = Upgrade Investment (Total $) * Transmission Owner’s Net Plant Carrying Charge (%/YR)
  - Cost Allocation of ATRR

<table>
<thead>
<tr>
<th>Regional</th>
<th>Zonal</th>
</tr>
</thead>
<tbody>
<tr>
<td>33% * Load Ratio Share</td>
<td>67% * Zone Specific Mega Watt Mile %</td>
</tr>
</tbody>
</table>
## Current SPP Cost Allocation Method

### Highway Byway Cost Allocation

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Regional</th>
<th>Zonal</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 kV and Above</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>100 kV – 299 kV</td>
<td>33%</td>
<td>67%</td>
</tr>
<tr>
<td>Below 100 kV</td>
<td>0%</td>
<td>100%</td>
</tr>
</tbody>
</table>

**Cost Allocation for Upgrades with NTCs issued after 6/19/10**
### SPP Transmission Owning Zones

#### Current Net Plant Carry Charges & Load Ratio Shares

<table>
<thead>
<tr>
<th>Zone</th>
<th>Zone Description</th>
<th>NPCC</th>
<th>LRS</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>American Electric Power</td>
<td>16.959%</td>
<td>23.030%</td>
</tr>
<tr>
<td>CUS</td>
<td>City Utilities of Springfield</td>
<td>15.670%</td>
<td>1.580%</td>
</tr>
<tr>
<td>EDE</td>
<td>Empire District Energy Company</td>
<td>18.300%</td>
<td>2.730%</td>
</tr>
<tr>
<td>GMO</td>
<td>KCPL&amp;L Greater Missouri Operations Company</td>
<td>18.944%</td>
<td>4.360%</td>
</tr>
<tr>
<td>GRDA</td>
<td>Grand River Dam Authority</td>
<td>19.040%</td>
<td>2.040%</td>
</tr>
<tr>
<td>KCPL</td>
<td>Kansas City Power &amp; Light</td>
<td>18.985%</td>
<td>8.270%</td>
</tr>
<tr>
<td>LES</td>
<td>Lincoln Electric System</td>
<td>11.599%</td>
<td>1.940%</td>
</tr>
<tr>
<td>MIDW</td>
<td>Midwest Energy</td>
<td>14.480%</td>
<td>0.690%</td>
</tr>
<tr>
<td>MKEC</td>
<td>Mid-Kansas Electric Company</td>
<td>9.120%</td>
<td>1.280%</td>
</tr>
<tr>
<td>NPPD</td>
<td>Nebraska Public Power District</td>
<td>12.297%</td>
<td>6.860%</td>
</tr>
<tr>
<td>OGE</td>
<td>Oklahoma Gas and Electric</td>
<td>17.322%</td>
<td>14.150%</td>
</tr>
<tr>
<td>OPPD</td>
<td>Omaha Public Power District</td>
<td>14.333%</td>
<td>5.060%</td>
</tr>
<tr>
<td>SEPC</td>
<td>Sunflower Electric Power Corporation</td>
<td>15.680%</td>
<td>1.050%</td>
</tr>
<tr>
<td>SPS</td>
<td>Southwestern Public Service Company</td>
<td>17.343%</td>
<td>11.590%</td>
</tr>
<tr>
<td>WFEC</td>
<td>Western Farmers Electric Cooperative</td>
<td>18.240%</td>
<td>3.370%</td>
</tr>
<tr>
<td>WR</td>
<td>Westar Energy</td>
<td>16.280%</td>
<td>12.000%</td>
</tr>
</tbody>
</table>

Estimates as of January 14, 2011, subject to changes and updates, input is sought and appreciated.
### SPP Current OATT Att. H, Table 1, Column 3 as of January 16, 2012

<table>
<thead>
<tr>
<th>Zone</th>
<th>Zone</th>
<th>Zonal ATRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>American Electric Power –West (Total)</td>
<td>$152,220,454</td>
</tr>
<tr>
<td>CUS</td>
<td>City Utilities of Springfield, Missouri</td>
<td>$8,651,509</td>
</tr>
<tr>
<td>EDE</td>
<td>Empire District Electric Company</td>
<td>$14,075,000</td>
</tr>
<tr>
<td>GRDA</td>
<td>Grand River Dam Authority (Est.)</td>
<td>$21,196,230</td>
</tr>
<tr>
<td>KCPL</td>
<td>Kansas City Power &amp; Light Company</td>
<td>$30,440,539</td>
</tr>
<tr>
<td>OGE</td>
<td>Oklahoma Gas &amp; Electric (Total)</td>
<td>$82,534,685</td>
</tr>
<tr>
<td>MIDW</td>
<td>Midwest Energy, Inc.</td>
<td>$8,819,682</td>
</tr>
<tr>
<td>GMO</td>
<td>KCP&amp;L Greater Missouri Operations Company</td>
<td>$36,405,920</td>
</tr>
<tr>
<td>SPS</td>
<td>Southwestern Public Service</td>
<td>$112,447,746</td>
</tr>
<tr>
<td>SEPC</td>
<td>Sunflower Electric Corporation</td>
<td>$14,484,045</td>
</tr>
<tr>
<td>WFEC</td>
<td>Western Farmers Electric Cooperative</td>
<td>$20,719,639</td>
</tr>
<tr>
<td>WR</td>
<td>Westar Energy, Inc. (Kansas Gas &amp; Electric and Westar Energy) (Total)</td>
<td>$148,462,476</td>
</tr>
<tr>
<td>MKEC</td>
<td>Mid-Kansas Electric Company (Total)</td>
<td>$16,897,799</td>
</tr>
<tr>
<td>LES</td>
<td>Lincoln Electric System</td>
<td>$21,433,977</td>
</tr>
<tr>
<td>NPPD</td>
<td>Nebraska Public Power District</td>
<td>$55,001,484</td>
</tr>
<tr>
<td>OPPD</td>
<td>Omaha Public Power District</td>
<td>$40,944,590</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td><strong>$784,735,775</strong></td>
</tr>
</tbody>
</table>

Nicknamed, "Legacy Tariff Rate"
ATRR Sources

• Legacy ATRR, Attachment H, Table 1, Col. 3
• Upgrades receiving NTCs before June, 2010
  – Original Base Plan Funding
• Balanced Portfolio with Zonal Transfers
• Upgrades receiving NTCs after June, 2010
  – Highway Byway Base Plan Funding
  – Zonal/Sponsored Upgrades
• ITP Near Term Upgrades
  – Scheduled for BoD Review, January 2012
Upgrade Summary with ITP Near Term

<table>
<thead>
<tr>
<th>Upgrade Group</th>
<th>Cost All'n Method</th>
<th># of Upgrades</th>
<th>Total Investment ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Traditionally Base Plan Funded</td>
<td>Current Base Plan Funding: 2/3 Zonal MW-Mi + 1/3 Regional LRS</td>
<td>380</td>
<td>$1,177</td>
</tr>
<tr>
<td>Highway Byway</td>
<td>Highway/Byway</td>
<td>107</td>
<td>$418</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>100% LRS with Zonal Transfers</td>
<td>17</td>
<td>$888</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>Highway/Byway</td>
<td>23</td>
<td>$1,424</td>
</tr>
<tr>
<td>2012 ITPNT</td>
<td>Highway/Byway</td>
<td>49</td>
<td>$251</td>
</tr>
<tr>
<td>Zonal</td>
<td>100% Zonal</td>
<td>363</td>
<td>$1,481</td>
</tr>
<tr>
<td>Totals</td>
<td>Various</td>
<td>939</td>
<td>$5,639</td>
</tr>
</tbody>
</table>

First Upgrade In-Service: year 2006
Last Upgrade Include in-Service: year 2021
ITP10 Upgrades ($1.5B) not included
ITP20 Upgrades not included

*As of Jan 14, 2012 these amounts are subject to change (Board Action, NTC additions, withdrawals, Est. Updates, etc.)
Upgrade Summary

*As of Jan 14, 2012 these amounts are subject to change (Board Action, NTC additions, withdrawals, est. updates, etc.)
10 Year Results by Year by Zone
Current Transmission Owning Zones, with Deprecation, Balancing Transfers, and available CWIP

*As of Jan 14, 2012 these estimates subject to change (SPP Board of Directors action, NTC add’n, w’drawals, Cost Est. Updates, etc.)
Contacts

Dan Jones, PE  
SPP Regulatory  
501-688-1717  
djones@spp.org

John Snyder  
SPP Engineering  
501-688-2501  
jsnyder@spp.org

Next Forecast: June, 2012

With attached Workbook:

“SPP 10 Year ATRR Forecast Jan 19 2012 REV 1 for POSTING to RTWG.xls”