Monday, April 28, 2014
1:00 - 5:00 p.m.
Skirvin Hilton - Oklahoma City, OK

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of January 27, 2014 Minutes

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

4. BUSINESS MEETING
   a. RSC Bylaws Amendment [Voting Item].............................Commissioner Dana Murphy

5. REPORTS/PRESENTATIONS
   a. CAWG Report..............................................................................Meena Thomas
      This report provides an update on CAWG activity.
   b. New Marketplace PRR 171 (LTCR Clarifications) [Voting Item].........John Krajewski / Meena Thomas
      This report will provide information on a design enhancement preserving the original intent of the
      MPRR 138 design and ensuring that the holder of a LTCR receives their LTCR at zero cost and
      allows the associated TCRs to be resold in the Annual TCR Auction.  This will include CAWG’s
      recommendation.
   c. RCAR Lessons Learned [Voting Item]............................................Michael Siedschlag
      This report will provide information on the RCAR Lessons Learned Report for the RSC’s
      consideration.  The RARTF is seeking the RSC to Approve/Endorse this Report.
   d. Proposed Changes to SPP Wind Accreditation ..............................Mitch Williams
      This report will provide information regarding a recommendation to modify the accreditation for
      wind which will have an impact on the SPP Methodology to determine planning capacity. This will
      include an update on the CAWG’s work on this issue.
   e. Capacity Margin Presentation......................................................Carl Monroe
      This report will provide information regarding improvements that Staff will propose to RSC and
      CAWG in Fall 2014 to the Capacity Margin Criteria
   f. Update on Integrated System (WAPA/Basin/Heartland).................Carl Monroe
      This report will provide an update on the process of consideration of the announced intent of the
      Integrated System entities becoming members of SPP.
   g. Update on Seams Related Dockets at FERC.................................Carl Monroe
      This report will provide an update on the pending matters at FERC related to the MISO Seam.
   h. Order 1000 Update ........................................................................Paul Suskie
This report will provide an update on SPP’s Order 1000 filings, SPP’s implementation of Order 1000 and a report regarding the creation, role and compensation of the Industry Expert Pool required for Order 1000.

i. **Integrated Marketplace Update**
   Bruce Rew
   This report will update the RSC on the implementation of SPP’s Integrated Marketplace on March 1, 2014.

j. **High Priority Increment Load Study**
   Lanny Nickell
   This report will update the RSC on the MOPC Action on HPILS and next steps.

k. **SPP Strategic Plan**
   Michael Desselle
   This report will update the RSC on the Strategic Plan and seek input on further development.

l. **Report to FERC on 2013-14 Winter**
   Bruce Rew / Chairman Donna Nelson
   This report will update the RSC on the presentations provided to FERC by Bruce Rew and Chairman Donna Nelson on April 1, 2014 at the FERC Technical Conference on the 2013-14 severe winter weather and its impact on grid operations.

6. **OTHER RSC MATTERS**

7. **SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS**
   
   **RSC Meetings:**
   
   - July 28, 2014 – Omaha, NE
   - October 27, 2014 – Little Rock, AR

8. **ADJOURN**

*NOTE: ADDITIONAL INFORMATIONAL MATERIAL ATTACHED*

Attached to the RSC’s meeting agenda and background material is additional material that is either for informational or reporting purposes. **This includes the proposed Novation from ITC to MKEC and proposed Assignment from AEP to OK Transco.**
Southwest Power Pool
REGIONAL STATE COMMITTEE
Omni Hotel, Austin, TX
January 27, 2014

• M I N U T E S •

Administrative Items:
The following members were in attendance:

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

President Donna Nelson called the Regional State Committee (RSC) meeting to order at 1:00 p.m. with roll call and a quorum was declared. She then requested a round of introductions. There were 114 in attendance either in person or via phone (Attendance & Proxies – Attachment 1).

President Nelson requested approval of the October 28, 2013 and January 13, 2014 meeting minutes (RSC Minutes 10/28/13 and 1/13/14 - Attachment 2). Olan Reeves moved to approve the October 28, 2013 minutes; Steve Stoll seconded. The motion passed unanimously. Patrick Lyons noted that he attempted to call into the January 13 teleconference meeting but was unable to connect. Michael Siedschlag moved to approve the January 13 minutes; Patrick Lyons seconded. The minutes passed unanimously.

President Nelson stated that the group held an educational session prior to the regular meeting, which covered the High Priority Incremental Load Study (HPILS), an introduction to seams and the Integrated System (WAPA, Basin and Heartland).

UPDATES
RSC Financial Report
Paul Suskie provided the RSC Financial Report (Financial Report – Attachment 3). Mr. Suskie reported that the RSC remains under budget. He noted that $100,000 had been budgeted for an RSC consultant with just over $30,000 expended.

SPP Report
Mr. Nick Brown provided the SPP report. Mr. Brown stated that SPP is poised and ready for the Integrated Marketplace Go-Live on March 1, 2014. SPP’s is the first market to be on schedule and on budget. This is all due to the support of the regulatory community, SPP Staff and stakeholders and the level of honesty achieved.

FERC
Mr. Patrick Clarey provided an update on recent FERC activities. In December, FERC directed staff to participate in the PJM and MISO regional transmission operators’ (RTOs’) meetings to address seams issues. The order acknowledges the time and effort of the RTOs and their stakeholders, and states that
staff’s participation in future meetings will help FERC monitor the RTOs’ progress on the market initiatives. The order also establishes a new proceeding to reflect the broader scope of issues identified in the June and September filings.

FERC and the Idaho Public Utilities Commission (Idaho PUC) signed a Memorandum of Agreement under which they will dismiss their court claims related to interpretation and enforcement of the Public Utility Regulatory Policies Act (PURPA).

In January, FERC proposed to adopt a new reliability standard intended to mitigate the impacts of geomagnetic disturbances (GMDs) that can have potentially severe, widespread effects on reliable operation of the nation’s Bulk-Power System. The proposal takes the first step in implementing a May 2013 final rule in which FERC directed the North American Electric Reliability Corporation (NERC) to develop new mandatory reliability standards to address GMD vulnerabilities, and it directed NERC to develop new standards in two stages. This Notice of Proposed Rulemaking (NOPR) pertains to a standard offered by NERC to address implementation of operating plans and operating procedures or processes to mitigate the effects of GMD.

The 4th Circuit Court of Appeals upheld a FERC Order granting certain transmission rate incentives for 11 transmission projects to a Virginia utility.

**BUSINESS MEETING**

Paul Suskie stated that the RSC Bylaws require an annual audit (Auditor Engagement Letter – Attachment 4). Mr. Suskie asked for approval of auditor cost for the audit and taxes for 2013 to be prepared by Thomas & Thomas in the amount of $2,300. Patrick Lyons moved for approval; Olan Reeves seconded the motion. The motion passed unanimously.

**REPORTS/PRESENTATIONS**

Cost Allocation Working Group Report

Meena Thomas provided the Cost Allocation Working Group report (CAWG Report – Attachment 5). Ms. Thomas presented an overview of the group’s activities addressing the following topics:

- Cost Recovery related to Third-Party Impacts in New Aggregate Transmission Service Study (ATSS) process
- High Priority Incremental Load Study
- Seams Projects
- CAWG Input regarding SPP Strategic Plan
- CAWG 2014 Issues List

Order 1000 Regional Update

Paul Suskie presented an Order 1000 Regional Compliance update (Order 1000 Regional Update – Attachment 6). Mr. Suskie provided background regarding compliance for regional planning and interregional planning for cost allocation. Both compliance issues are awaiting FERC rulings.

Cost Allocation for Non-Order 1000 Seams Projects

Paul Malone provided an update on cost allocation for seams projects (Cost Allocation for Seams Projects – Attachment 7). RSC began to consider seams issues in 2010 and the Cost Allocation Working Group (CAWG) was directed to begin work on cost allocation of seams projects. The Seams Steering Committee (SSC) completed a white paper, “Cost Allocation Principles for Seams Transmission Expansion Projects”, in January 2011. The RSC then issued a request for proposal (RFP) to Brattle Group to develop recommendations on cost allocation for seams projects. The principles and guidelines recommended in the Brattle Report were adopted by the RSC to be used in negotiations with SPP neighbors. Mr. Malone presented SPP’s criteria for Order 1000 Interregional Projects and the Order 1000 Interregional filing. He presented seams projects examples and stated that the group did not need approval but more a sense of support that they should continue on the same path moving forward. The RSC agreed with the direction but
requested additional information including type of funding, more metrics, cost/benefits, etc. President Nelson suggested that this might be added to an educational session. Mr. Malone stated that this issue will be revisited in April with a request for approval.

**Integrated Marketplace Update**

Bruce Rew provided an update on the Integrated Marketplace (Integrated Marketplace – Attachment 8). Mr. Rew reported that the Parallel Operations had been completed and that the Integrated Deployment Testing was going well. The Change Working Group (CWG) approved Go-Live as well as SPP Staff. The Go-Live Team will vote on January 31, 2014. SPP is poised to be the first to implement a market on time and on budget.

**Integrated Transmission Planning Near Term (ITPNT), ITP10 and SPP Transmission Expansion Plan (STEP) Update**

Lanny Nickell provided an update on ITPNT, the ITP10 planning process and the SPP Transmission Expansion Plan (STEP) (ITPNT, ITP10 and STEP Reports – Attachment 9). Mr. Nickell reviewed the ITPNT stating that it was near completion. He provided an ITPNT summary including milestones, the project portfolio, and investments. Mr. Nickell provided the 2015 ITP10 Scope and schedule. Paul Suskie reviewed the 2014 ITPNT Rate Impacts to the average residential ratepayers in SPP.

President Nelson took a moment to recognize Tom Wright and Michael Siedschlag for their significant service to the RSC and RSC task forces over the last several years. Resolutions were read and presented to each (Resolutions – Attachment 10). This is the last RSC meeting for both gentlemen.

**High Priority Increment Load Study**

Lanny Nickell presented a report on the High Priority Increment Load Study (HPILS – Attachment 11). Mr. Nickell reviewed details of the HPILS and status of tasks. SPP Staff will work with stakeholders to refine and revise cost estimates for the HPILS projects, as well as determine necessary lead times. David Hudson (SPS) provided information regarding expected retail load growth in SE New Mexico. Following discussion, it was decided that the RSC would like additional information regarding HPILS projects as well as a recommendation at the April meeting. The RSC requested an earlier draft of the HPILS Report if possible.

**Update on Integrated System (WAPA/Basin/Heartland)**

Carl Monroe reviewed the Integrated System integration into SPP (IS Integration – Attachment 12). He provided an overview of the IS members, WAPA’s public process and the timeline/next steps for the integration into SPP. Mr. Monroe introduced and welcomed Bob Harris (WAPA) and Mike Risan (Basin).

**Update on Integration of Entergy into MISO**

Carl Monroe provided an update on the integration of Entergy into MISO (Entergy Integration – Attachment 13). Mr. Monroe highlighted three significant events:

1. Dec. 3, 2013 - D.C. Court of Appeals Vacates FERC Orders interpreting Section 5.2 of the SPP-MISO JOA.

In late January 2014, a mandate is expected from the D.C. Circuit to FERC. SPP will work with SPP Members to vigorously oppose MISO’s intentional use of SPP Transmission Owners’ System without reservation and without compensation to SPP’s customers. SPP believes the unauthorized and free use of the transmission system paid for by SPP ratepayers is “unjust and unreasonable.”

**SPP Strategic Plan**

Michael Desselle provided an update on the SPP Strategic Plan (SPP Strategic Plan – Attachment 14). Mr. Desselle listed the three foundational strategies as:

- Build a Robust Transmission system
- Develop Efficient Market Processes
Create Member Value

It is time to review and renew the SPP Strategic Plan. SPP is seeking input from working groups by March/April as well as input from stakeholders and the Board of Directors.

**Scheduling of Next Regular Meeting, Special Meetings or Events:**

President Nelson noted the next RSC meeting will be in Oklahoma City on April 28, 2014 and will mark the Tenth Anniversary of the RSC. Past members of the RSC will be invited to the Monday night dinner.

Prior to adjourning, Michael Siedschlag introduced Steve Lichter as his replacement as Chair of the Nebraska Power Review Board.

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

Respectfully Submitted,

Paul Suskie
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RSC Bylaws – Proposed Amendment

Commissioner
Dana Murphy
April 28, 2014

Southwest Power Pool

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

ARTICLE XI - OPEN MEETINGS

The Annual Meeting and all meetings of the SPP RSC Board of Directors and subordinate committees and work-groups shall be open meetings, except that discussion of commercially sensitive, legal, and personnel issues and educational sessions/retreats may be conducted in closed session.
Southwest Power Pool
REGIONAL STATE COMMITTEE
BYLAWS

April 27, 2009
ARTICLE I

1. NAME: The organization shall be known as the Southwest Power Pool Regional State Committee ("SPP RSC"). The principal office of the SPP RSC shall be at such location, within the United States, as the SPP RSC Board of Directors shall from time to time establish. The SPP RSC may also maintain such branch offices and places of business as the SPP RSC Board of Directors may deem necessary or appropriate in the conduct of its business.

2. PURPOSE: The SPP RSC shall provide collective state regulatory agency input and participation in the Southwest Power Pool, Inc. ("SPP") and SPP’s Board of Directors, committees, working groups and task forces, including any independent transmission system operator ("ISO") or regional transmission organization ("RTO") formed by the SPP. Such input and participation shall include but not be limited to: whether and to what extent participant funding will be used for transmission enhancements; whether license plate or postage stamp rates will be used for the regional access charge; determination of Financial Transmission Rights ("FTR") allocations where a locational price methodology is used; determination of the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers’ existing firm rights; determination of the approach for resource adequacy across the entire region; determination of whether transmission upgrades for remote resources will be included in the regional transmission planning process; and determination of the role of transmission owners in proposing transmission upgrades in the regional planning process.

3. Nothing in the formation or operation of the SPP RSC as a FERC recognized regional state committee is in any way intended to diminish existing state regulatory jurisdiction and authority. Each state regulatory agency expressly reserves the right to exercise all lawful means available to protect its existing jurisdiction and authority.

ARTICLE II – MEMBERSHIP

1. MEMBERSHIP: Membership shall be open to all official governmental entities that:

   (a) Regulate the retail electricity or distribution rates or approve retail service areas of transmission-owning members or transmission-dependent utility members of the SPP; or

   (b) Are the primary regulatory agency responsible for siting electric transmission facilities in states where there are transmission-owning members of the SPP or independent transmission companies that own or operate transmission facilities associated with the SPP.

2. ASSOCIATE MEMBERSHIP: Associate membership shall be open to all official governmental agencies that:

   (a) Are involved with energy planning, and or environmental issues that relate to electric transmission; or
(b) Are involved with consumer advocacy issues that relate to electric transmission; or

(c) To all other entities that are approved by the SPP RSC Board of Directors for associate member status.

**ARTICLE III – ANNUAL MEETING**

The Annual Meeting of the SPP RSC (Annual Meeting) shall be held each year in conjunction with the fall meeting of the SPP Board of Directors, and/or at such time and place as may be determined by the SPP RSC Board of Directors. Notice of the time, place, and purpose of the meeting, shall be provided by mail or electronic means to each Member and Associate Member of the SPP RSC not less than fifteen (15) calendar days prior to the meeting, except that the agenda may be amended up to three (3) calendar days prior to the meeting in accordance with Article XI. At the Annual Meeting, all member regulatory agencies may have a seat and voice. The business of the Annual Meeting will be conducted by vote of the SPP RSC Board of Directors as provided for in these Bylaws.

**ARTICLE IV – BOARD OF DIRECTORS**

1. **POWERS, RESPONSIBILITIES AND ACCOUNTABILITIES:** The corporate business and affairs of the SPP RSC shall be managed by the SPP RSC Board of Directors, except as may be otherwise provided for in these Bylaws and/or the articles of incorporation (Articles of Incorporation) adopted by the SPP RSC Board of Directors.

2. **COMPOSITION:** Each member regulatory agency, as defined in Article II.1 of these Bylaws, may designate one Commissioner to serve on the SPP RSC Board of Directors. In the case of member state regulatory agencies organized without commissioners, an official of similar level may be designated. When any such person ceases to be the duly authorized representative of that Member, he or she shall be replaced on the SPP RSC Board of Directors by another representative from his or her state regulatory agency. A member state regulatory agency may replace its Director by notifying the Secretary of the SPP RSC by mail, facsimile transmission and/or electronic mail at least one business day in advance of any meeting of the SPP RSC Board of Directors.

3. **RESPONSIBILITIES:** The SPP RSC Board of Directors shall elect the officers of the SPP RSC and determine the general policies and direction of the SPP RSC. The SPP RSC Board of Directors may amend the Articles of Incorporation and Bylaws, take all other action requiring membership vote, and conduct other business as delineated in Article IX.

4. **REGULAR MEETINGS:** Regular meetings of the SPP RSC Board of Directors shall be held at such time and place as may be determined by the SPP RSC Board of Directors, except that the SPP RSC Board of Directors shall meet no less than one time each calendar year, in addition to the Annual Meeting. Notice of the time, place and purpose of the meeting(s) shall be provided by mail, facsimile
transmission and/or electronic means to each Member and Associate Member of the SPP RSC not less than seven (7) calendar days prior to the meeting, except that the agenda may be amended up to three (3) calendar days prior to the meeting in accordance with Article XI. Public notice shall also be given at the same time that it is given to each Member and Associate Member of the SPP RSC in accordance with Article XI.

5. SPECIAL MEETINGS: The President may call a special meeting(s) of the SPP RSC Board of Directors. Notice of the time, place and purpose of the meeting(s) shall be provided by mail, facsimile transmission and/or electronic means to each Member and Associate Member of the SPP RSC not less than three (3) calendar days prior to the meeting(s).

6. QUORUM: If a Director from each of a majority of the member state regulatory authorities is present (either in person, by authorized telephonic or electronic means, or by designated proxy), a quorum exists for the transaction of business at any meeting of the SPP RSC Board of Directors, but if less than such majority is present at a meeting, a majority of the members that are present may adjourn the meeting without further notice. The SPP RSC Directors present at a properly noticed meeting may continue to transact business until adjournment, notwithstanding the withdrawal of enough members to leave less than a quorum. A member state regulatory agency may allow a proxy from the same agency to participate as a substitute for its designated SPP RSC Director at a meeting(s) of the SPP RSC Board of Directors by notifying the Secretary of the SPP RSC as provided for in these Bylaws.

7. PROXY: A request of a member state regulatory agency for recognition by the SPP RSC Board of Directors of a proxy to participate in a meeting of the SPP RSC Board of Directors must be received by the Secretary of the SPP RSC at least one business day in advance of the meeting at which the proxy is to be exercised. Where prior written notice is not possible, the designating Director shall submit written confirmation of this proxy no later than ten (10) calendar days after the applicable Board meeting takes place. The person who is identified as exercising the proxy cannot be the person submitting the request for recognition of the proxy. Notices of proxies must be sent by mail, facsimile transmission and/or electronic mail to the Secretary of the SPP RSC and identify the date of the meeting of the SPP RSC Board of Directors for which the proxy is authorized and identify by name, and position at the member state regulatory agency, the person who is authorized to exercise the proxy. The Secretary of the SPP RSC must receive a new request for recognition of a proxy for each meeting of the SPP RSC Board of Directors at which the proxy will be sought to be recognized. The SPP RSC Board of Directors will not recognize, for more than one meeting at a time, a proxy request by a member state regulatory agency. The request for recognition of a proxy must not identify more than one person as being authorized to exercise the proxy.

8. VOTING PROCEDURES: Each SPP RSC Director present (either in person, by authorized telephonic or electronic means, or by representation of the member state regulatory agency by a properly designated proxy) shall be entitled to one equally weighted vote. However, if a state has more than one state regulatory agency that
is a Member of the SPP RSC, voting rights shall be divided equally among the SPP RSC Directors from that state present and voting (equating to one total vote per state). Elections shall be by ballot in contested elections and may be by voice or other means in uncontested elections. A plurality of votes cast shall elect. Changes in the Bylaws shall require a vote consistent with Article XII of this document. All other matters shall be determined by a majority of the SPP RSC Directors present and voting, unless otherwise provided by the laws of the state where the SPP RSC is incorporated or these Bylaws.

9. ELECTRONIC VOTING: The President has the option and authority to conduct an electronic vote on non-policy, administrative matters, such as approval of minutes or appointment of the annual SPP RSC auditor, or on policy matters that have been discussed during a prior RSC meeting.

10. POSITIONS ON POLICY ISSUES: The SPP RSC Board of Directors will give direction to formation of issue statements, which will then be referred to member state regulatory agencies. A position approved by a majority of the SPP RSC Board of Directors may be issued as the SPP RSC’s position with identification of the participating and non-participating member state regulatory agencies. Individual member state regulatory agencies retain all rights to object to, support, or otherwise comment on, issue statements of the SPP RSC, including the attachment of a minority report or dissenting opinion, provided it is submitted in a timely manner. The SPP RSC Board of Directors may authorize intervention in proceedings before federal regulatory agencies and in related judicial proceedings to express the SPP RSC’s positions, and may retain legal counsel to represent the SPP RSC in such proceedings. Consistent with Article I, § 3 above, each individual state regulatory agency shall also retain all rights to intervene in and/or comment on such federal regulatory agency proceedings and/or related judicial proceedings.

ARTICLE V - OFFICERS

1. NUMBER AND TITLE: The officers of the SPP RSC shall be the President, Vice-President, Secretary, and Treasurer.

2. ELECTION, TERM, VACANCIES: The President, Vice-president, Secretary, and Treasurer shall be elected by the SPP RSC Board of Directors for a term of one year, or until their successors are elected. Officers shall be elected at the Annual Meeting to take office on the first day of January following the Annual Meeting at which elections are held. The SPP RSC Board of Directors may fill a vacancy among the officers other than the President to serve until the next scheduled election. In the case of a permanent vacancy in the office of the President, the Vice-President will succeed until the next scheduled election. The terms of the officers elected in 2004 shall be deemed partial terms. In the event of a vacancy or temporary inability to serve, the duties of the Secretary or Treasurer may be fulfilled by a designee of the SPP RSC Board of Directors.

3. GEOGRAPHIC BALANCE: The officers elected shall be SPP RSC Directors from different states.
4. DUTIES: The duties of the officers shall be as follows:

(a) The PRESIDENT shall be the principal officer of the SPP RSC and shall preside at the Annual Meeting and all meetings of the SPP RSC Board of Directors, shall be responsible for seeing that the lines of direction given by the SPP RSC Board of Directors are carried into effect — including the representation and presentation of all SPP RSC majority positions and minority reports and dissenting opinions of the member state regulatory authorities, and shall have such other powers and perform such other duties as may be assigned by the SPP RSC Board of Directors; including but not limited to: serving as the SPP RSC’s non-voting representative at the meetings of the SPP’s Board of Directors, performing or delegating presentations/speeches on behalf of the SPP RSC, designating member state regulatory agency staff members proposed by the state regulatory agency to carry out daily functions and operations of the SPP RSC, assigning member state regulatory agency staff members proposed by the state regulatory agency to committees and work-groups created by the SPP RSC and requesting technical support from SPP as necessary. The President (or other officer serving as the RSC representative at meetings of the SPP Board of Directors) shall also be responsible for requesting recusal of a Director where a conflict of interest may arise and for clearly stating on all matters whether he/she is representing the position of the SPP RSC or solely his/her member state regulatory agency.

(b) In the temporary absence or disability of the President, the VICE-PRESIDENT shall preside at meetings of the SPP RSC Board of Directors and have such other powers and perform such other duties as performed by the President. The Vice-President shall also serve as the SPP RSC’s non-voting representative at the meetings of the SPP’s Board of Directors. He or she shall have such other powers and perform such other duties as performed by the President or as may be assigned by the SPP RSC Board of Directors.

(c) The SECRETARY shall be responsible for keeping a roll of the Members and seeing that notices of all meetings of the SPP RSC Board of Directors are issued and shall see that minutes of such meetings are kept. The Secretary shall be responsible for the custody of corporate books, records and files, shall exercise the powers and perform such other duties usually incident to the office of Secretary, and shall exercise such other powers and perform such other duties as may be assigned by the President or the SPP RSC Board of Directors.

(d) The TREASURER shall be responsible for monitoring the receipt and custody of all monies of the SPP RSC and for monitoring the disbursement thereof as authorized, for assuring that accurate accounts of monies received and disbursed are kept, for execution of contracts or other instruments authorized by the SPP RSC Board of Directors, and for overseeing the preparation and issuance of financial statements and reports. The Treasurer shall give a report of the SPP RSC’s finances at the Annual Meeting. The Treasurer shall be an ex officio member of the finance committee, if such a committee shall be established by the SPP RSC Board of Directors, shall exercise the powers and perform such other duties usually incident to the office of Treasurer, and shall
perform such other duties as may be assigned by the President or SPP RSC Board of Directors.

5. REMOVAL: An officer of the SPP RSC may be removed with or without cause by written vote of two-thirds of the total membership of the SPP RSC Board of Directors.

ARTICLE VI – MEMBER STATE REGULATORY AGENCY STAFF MEMBER PARTICIPATION

Member state regulatory agency staff members shall participate at the discretion of their respective member state regulatory agency, including but not limited to: attendance at SPP RSC and SPP Board of Directors meetings in support of or in lieu of member state regulatory agency commissioners, attendance and active participation in assigned SPP committees, working groups and task forces (including providing summaries of meetings and reporting to the SPP RSC members and associate members), active representation of the majority positions and minority reports or dissenting opinions of the SPP RSC member state regulatory authorities, and attending and actively participating in assigned SPP RSC committees and work-groups created by the SPP RSC Board of Directors (including providing summaries of meetings and reporting to the SPP RSC members and associate members). Member state regulatory agency staff members must clearly indicate whether they are representing the SPP RSC or solely their member state regulatory agency.

ARTICLE VII - COMMITTEES

1. ESTABLISHED: The SPP RSC Board of Directors may establish SPP RSC committees and work-groups as it deems necessary and provide for their governance.

2. COMPOSITION AND APPOINTMENT: The President shall appoint members of the SPP RSC committees. Unless otherwise provided by the SPP RSC Board of Directors, a committee may elect its chair. Members and Associate Members may participate in the work of committees and work-groups that relate to matters within their jurisdiction.

ARTICLE VIII – MEMBERS AND ASSOCIATE MEMBERS NOT BOUND

No vote of, or resolution passed by, the SPP RSC Board of Directors has any binding effect upon any member state regulatory agency, or any associate member, in the exercise of that entity’s powers.

ARTICLE IX - FISCAL RESPONSIBILITIES OF THE SPP RSC BOARD OF DIRECTORS

1. FISCAL YEAR: The SPP RSC Board of Directors shall establish the fiscal year of the SPP RSC.
2. **FUNDING:** Any funds shall be accepted or collected only as authorized by the SPP RSC Board of Directors.

3. **DEPOSITORIES:** All funds of the SPP RSC shall be deposited to the credit of the SPP RSC in fully insured accounts.

4. **DELEGATED AUTHORITY:** For routine payment of meeting and travel expenses incurred by SPP RSC Members and their designees, including designated State Commission Staff members, the SPP RTO may act as agent for the RSC and make payment of such expenses in accordance with the RSC’s then-current Expense Reimbursement Policy. Such expenses shall be paid from the RSC’s approved budget. For items of non-routine and more financially significant nature, such as an RSC-commissioned cost-benefit study or a large conference or event, the RSC Board of Directors may provide approval to the appropriate person within the SPP RTO to pay for such expenses, acting as agent for the RSC.

5. **BONDING:** All persons having access to or major responsibility for the handling of monies and securities of the SPP RSC shall be bonded as provided by resolution of the SPP RSC Board of Directors.

6. **INDEMNIFICATION AND INSURANCE:** Indemnification and Directors and Officers insurance shall be provided by resolution of the SPP RSC Board of Directors in accordance with the Articles of Incorporation and the laws of the state where the SPP RSC is incorporated.

7. **BUDGET:** The annual budget of estimated income and expenditures shall be prepared for the fiscal year and approved by the SPP RSC Board of Directors in conjunction with the Annual Meeting. No expenses shall be incurred in excess of approved budget levels without prior approval of the SPP RSC Board of Directors.

8. **CONTRACTS AND DEBTS:** Contracts may be entered into or debts incurred only as directed by resolution of the SPP RSC Board of Directors.

9. **AUDITS:** A certified public accountant or other independent public accountant shall be retained by the SPP RSC Board of Directors to make an annual examination of the financial accounts of the SPP RSC. A report of this examination shall be submitted to the SPP RSC Board of Directors and made available to the general membership of the SPP RSC and the public.

10. **LEGAL COUNSEL:** Independent legal counsel may, if deemed necessary and appropriate, be retained by the SPP RSC Board of Directors to: (a) insure compliance with federal and state requirements; (b) review and advise on any and all legal instruments the SPP RSC Board of Directors executes, such as leases, contracts, property purchases, or sales; (c) for interventions before federal regulatory agencies and related judicial proceedings; or (d) for any other matters as determined necessary by the SPP RSC Board of Directors – including those matters that are deemed to be administrative in nature.
11. PROPERTY: Title to all property shall be held in the name of the SPP RSC, unless otherwise approved by the SPP RSC Board of Directors; or otherwise required by law.

12. INVESTMENT: The Treasurer shall invest the funds of the SPP RSC in accordance with the direction of the SPP RSC Board of Directors or any committee of the SPP RSC Board of Directors appointed for such purpose.

ARTICLE X - PARLIAMENTARY AUTHORITY

All meetings shall be conducted in a manner that will allow the fullest possible participation by all members. In the event of a dispute, Robert’s Rules of Order, newly revised, shall be the parliamentary authority governing the meetings of the SPP RSC Board of Directors and all committees, subject to the laws of the state where the SPP RSC is incorporated, the Articles of Incorporation, these Bylaws, and any special rules of order adopted by the SPP RSC.

ARTICLE XI - OPEN MEETINGS

The Annual Meeting and all meetings of the SPP RSC Board of Directors and subordinate committees and work-groups shall be open meetings, except that discussion of commercially sensitive, legal, and personnel issues and educational sessions/retreats may be conducted in closed session. For the purposes of these Bylaws, open meeting means:

(a) Notice of the time, place, and purpose of the meeting, as provided in Articles III and IV, shall be made available to the public, through printed or electronic means, provided however, that the agenda for any annual, regular, or special meeting may be amended up to three (3) calendar days prior to the meeting date, as long as the amendment does not involve a change to the Bylaws or otherwise affect the substantive rights of Members.

(b) Minutes of the SPP RSC Board of Directors and subordinate committee meetings shall be made available to the public, through printed or electronic means, as soon as practical.

(c) The public may attend all open meetings of the SPP RSC.

(d) The SPP RSC Board of Directors may provide for participation by telephone or electronic means.

ARTICLE XII- AMENDMENTS

Except as otherwise stated herein, these Bylaws may be amended by a two-thirds vote of a quorum at the Annual Meeting and any regular meeting of the SPP RSC Board of Directors, provided that the proposed amendment(s) must have been included in the notice of the meeting in which such changes were to be considered.
Exceptions to two-thirds voting requirement: Any amendment(s) to Article I, § 3; Article IV, § 9 or Article VIII shall require the unanimous vote of the entire Board of Directors.

**ARTICLE XIII- EXECUTIVE DIRECTOR**

1. **EMPLOYMENT:** The SPP RSC Board of Directors may select an Executive Director. Where an Executive Director is hired, the SPP RSC Board of Directors shall determine the terms and conditions of the employment of the Executive Director. Thereafter, the Executive Director’s employment may be terminated by a majority of all serving SPP RSC Directors.

2. **RESPONSIBILITIES:** If deemed necessary and appropriate, where an Executive Director is hired, the Executive Director shall be the chief executive of the SPP RSC under the supervision and day-to-day policy guidance of the President of the SPP RSC Board of Directors. The Executive Director shall be responsible for providing advice and assistance to the SPP RSC Board of Directors, the President and other officers, and any subordinate committees and work-groups; and shall be responsible for administering the operations of the SPP RSC. The Executive Director shall have such other powers and perform such other duties as may be provided by the SPP RSC Board of Directors. The Executive Director shall be an ex officio non-voting member of the SPP RSC Board of Directors.
Report to the Regional State Committee
April 28, 2014

COST ALLOCATION WORKING GROUP (CAWG)

Meena Thomas
CAWG Chairman
CAWG REPORT TO RSC

TOPICS

I. MPRR 171- Long Term Congestion Rights (LTCR) Clarifications (Separate Recommendation)

II. Criteria Revisions for Wind and Solar Accreditation (Separate Report)

III. List of IS Integration Topics for CAWG Consideration

IV. Potential Issues for Future RSC Consideration
I. MPRR 171 – LTCR Clarifications

- In October 2013, the RSC approved MPRR 138 which implemented the long-term congestion rights (LTCR) design recommended by the Long Term Congestion Rights Task Force (Task Force).

- Subsequently, SPP staff identified two issues, namely, potential uplift charges from the Auction Revenue Rights (ARR) market and the absence of an explicit cap on number of awarded LTCRs.
I. MPRR 171 - LTCR Clarifications

- MPRR 171 addresses these two issues to ensure that the original MPRR (MPRR 138) is consistent with the intent of the Task Force and the relevant FERC Order.

- CAWG recommendation on MPRR 171 will be presented following the presentation on MPRR 171.
II. Criteria Revisions – Wind and Solar Accreditation

- The Generation Working Group (GWG) has proposed changes to SPP Criteria 12.
- SPP Criteria 12.1.5.3.g. outlines the methodology for the calculation of net capability for wind and solar facilities on a facility – specific basis.
- The criteria was first developed in 2004 and the proposed revision is the first change in ten years.
II. Criteria Revisions – Wind and Solar Accreditation

- CAWG considered the impact of the proposed criteria revision on resource adequacy and cost allocation for any potential upgrades.

- CAWG’s report will be presented following the presentation on the proposed changes to SPP wind accreditation.
III. IS Integration

- At the April 4, 2014 RSC Workshop on IS Integration, CAWG was directed to consider and report its recommendations on cost allocation issues pertaining to the potential IS integration.

- CAWG plans to consider the following issues:
  - Cost allocation for SPP and IS Upgrades placed in service before October 1, 2015
  - Cost allocation for SPP and IS Upgrades placed in service after October 1, 2015
III. IS Integration

- Possible application of Schedules 7, 8, 9 and 11 charges to IS entities
- Application of Federal Service Exemption to IS entities
- Western-UGP Federal Service Exemption and application of Schedule 11 Charges
- Western-UGP Federal Service Exemption and application of FERC assessment charge
- Exemptions from withdrawal (exit) obligations
- Exemptions from liability for penalties
IV. Potential Issues for Future RSC Consideration

- CAWG members continue to monitor pertinent Working Group/Task Force Activity in anticipation of future RSC actions.

- Of relevance are three major issues that will likely come up for RSC consideration this year:
IV. Potential Issues for Future RSC Consideration

1. Benefits Metrics Review for RCAR II Analysis:
   - Allocation of Benefits to Individual Zones.
   - Calculation of Multiple Benefits (Reliability, Public Policy, and Economic) for a Transmission Project.
IV. Potential Issues for Future RSC Consideration

2. Non-Order 1000 Seams Projects:
   - Development of Criteria by the Seams Project Task Force
   - Cost Allocation

3. Capacity Margin Requirements
CAWG Report to RSC

Questions?

Submitted by: Meena Thomas
CAWG Chairman
April 28, 2014
SPP Long-Term Congestion Rights Task Force Principles, FERC Guidelines, and Design

April 28, 2014

John Krajewski
Task Force Co-Chair
Outline

- Background
- Current Status
- MPRR 171
- CAWG Motion
Overview of Long-Term Congestion Rights
Background

• Long-Term Congestion Rights provide a tool for entities to hedge congestion risk over long-term period (five years and greater)

• Required by FERC under Order 681

• Congestion rights allocation is an area of RSC oversight explicitly identified in the SPP Bylaws

• SPP formed Long-Term Congestion Rights Task Force (LTCRTF) to develop policy to comply with Order 681
  – Included two MWG members, two CAWG members, one ESWG and TWG member, and RSC non-voting liason
Background

• MPRR 138 was approved by RSC, Board of Directors and Members Committee in October 2013

• Staff has been working on tariff filing for FERC
  – Pre-filing meeting with FERC staff in February
  – Implementation in software and other systems

• In developing tariff language and internal systems, identified potential issues in MPRR 138 that were inconsistent with intent of LTCRTF and with FERC Order 681
Current Status and MPRR 171
Current Status

• Staff held “pre-filing meeting” with FERC staff in February

• In developing internal systems, identified two potential issues

• Staff issued MPRR 171 to resolve identified issues with MPRR 138
Submitted by SPP on March 12, 2014

In developing internal systems, identified two potential issues

– Potential uplift from converting to the Long-Term Congestion Right first into an Auction Revenue Right (ARR)

– While there is an implied cap on long-term rights, there is not explicit language establishing a cap on long-term rights
Issue One: Potential Uplift

• Original design converted the LTCR first to an ARR
  – The ARR would be automatically self-converted into a 8,760 hour transmission congestion right (TCR)
  – It would be subject to uplift from revenue shortfalls from TCR auction

• SPP staff felt this would violate Guideline 7 which requires that long-term rights be allocated and not subject to an auction
Issue One: Potential Uplift

Solution: Convert LTCR directly into a TCR

- Bypasses TCR auction, avoiding uplift
- TCRs would be modeled as fixed injections and withdrawals in ARR Annual Allocation
- Allows associated TCRs to be resold in the annual TCR auction
Issue Two: No Explicit Cap on LTCRs

• Original design limited the amount of LTCRs that would be allocated through design features
  – No counter-flows included
  – System modeled at 50% capability

• Although there were design features that would limit LTCRs, there was no explicit cap as there is in ARR section
Issue Two: No Explicit Cap on LTCRs

- Solution: Explicit cap on number of awarded LTCRs
  - NITS: LTCRs cannot exceed the cap on NITS Candidate ARRs
  - FPTP: LTCRs cannot exceed the cap on FPTP Candidate ARRs

- Consistent with original intent of Task Force
CAWG RECOMMENDATION TO RSC

MPRR 171- LTCR Clarifications

Approval Status

- MPRR submitted by SPP Staff: March 12
- MWG approved: March 18
- RTWG approved with modifications: March 26
- CAWG recommends RSC approval: April 2
- ORWG approved with no reliability impacts: April 3
- MOPC approved: April 15
- RSC approval: ________
- Board approval: __________
CAWG RECOMMENDATION TO RSC

MPRR 171- LTCR Clarifications

At its April 2\textsuperscript{nd} meeting, CAWG unanimously approved the following motion:

CAWG recommends the RSC approve MPRR 171, LTCR Clarifications, presented in the background materials for the April 2, 2014 CAWG meeting, as approved by the Market Working Group on March 18, 2014 and Regional Tariff Working Group on March 26, 2014. This recommendation is conditioned on there being no substantive changes by other working groups or committees prior to the SPP Regional State Committee meeting on April 28, 2014.

CAWG reviewed the motion on April 17 and agreed the original motion was still valid.
CAWG RECOMMENDATION TO RSC

MPRR 171- LTCR Clarifications

Proposed RSC Motion:

RSC approves MPRR 171, LTCR Clarifications, as approved by MOPC and as submitted to the SPP Board of Directors and Members Committee.
Questions?

Submitted by: Meena Thomas
CAWG Chairman
April 28, 2014
# PRR Recommendation Report

<table>
<thead>
<tr>
<th>PRR No.</th>
<th>171</th>
<th>PRR Title</th>
<th>LTCR Clarifications</th>
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## Timeline

- [x] Normal
- [ ] Expedited
- [ ] Urgent Action

Provide explanation if Expedited and/or Urgent Action is selected:

## Recommendation Action

- [x] Approve
- [ ] Reject
- [ ] Require additional information
- [ ] Defer
- [ ] Refer

## Rating-Ranking

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<tr>
<td></td>
<td>1 – FERC Compliance</td>
<td>[x] Yes – If yes, estimated cost:</td>
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<td></td>
<td>2 – Defect</td>
<td>[ ] No</td>
</tr>
<tr>
<td></td>
<td>3 – Member Request</td>
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<td></td>
<td>4 – Other</td>
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## Impact Analysis Required

- [ ] Yes – If yes, estimated cost:
- [x] No

SPP Staff will complete this section.

## Protocol Section(s) Requiring Revision

### Section No.:
3.2; 5; 5.1.1; 5.1.2; 5.2.6; 5.3.3; 5.3.4; 5.4.1; 5.4.4; 5.5.2; 5.5.3; 5.6.3;

### Title:
Transmission Congestion Rights Markets; Transmission Congestion Rights Markets Process; Transmission Service Verification; Candidate LTCRs/ARRs; LTCR Selections and Awards; Simultaneous Feasibility; Annual ARR Awards; TCR Bid and Offer Submittal; Annual TCR Awards; Monthly ARR Nominations; Simultaneous Feasibility; Monthly TCR Auction Clearing and Simultaneous Feasibility;

### Protocol Version:
19.1

## Type of Revision

- [ ] Correction/Clean-Up
- [ ] Clarification
- [x] Design Enhancement
- [x] Design Change

## Revision Description

These changes preserve the original intent of the MPRR 138 design by directly converting awarded LTCRs into TCRs prior to the ARR Annual Allocation. These TCRs are then directly modeled as fixed injections and withdrawals as an input into both the Annual ARR Allocation and Annual TCR Auction. This change ensures that LTCRs holder receive their LTCRs at zero cost and allows the associated TCRs to be resold in the Annual TCR Auction.

Changes are also included that clarify that total LTCR selection is limited to a maximum amount.

## Tariff Implications or Changes

- [x] Yes – Section No: *(Include a summary of impact and/or specific changes)*

Attachment AE Section 1.1 Definitions; 7.0 Transmission Congestion Rights Markets; 7.1.1 Transmission Service Verification; 7.1.2 Candidate Long-Term Congestion Rights/Auction Revenue Rights; 7.1.3 Auction Revenue Right Nomination Cap; 7.2 Annual Long-Term Congestion Right Allocation; 7.2.4 LTCR Selection and Awards; 7.3.3 Annual Auction Revenue Right Awards; 7.4 Annual Transmission Congestion Right Auction; 7.4.3 Annual Transmission Congestion Right Auction Clearing and Simultaneous Feasibility; 7.6.3 Monthly Auction Revenue Right Nominations;
<table>
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<tr>
<td>MWG Review PRR Recommendation</td>
<td><strong>Date of Vote:</strong> 3/18/2014  <strong>Vote:</strong> Unanimously Approved  <strong>Opposed:</strong> N/A  <strong>Abstained:</strong> N/A</td>
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<tr>
<td>RTWG Review</td>
<td><strong>Date of Vote:</strong> 3/26/2014  <strong>Vote:</strong> Approved with modifications  <strong>Abstained:</strong> NPPD</td>
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<td>ORWG Review</td>
<td><strong>Date of Vote:</strong> 4/3/2014  <strong>Vote:</strong> Approved with no Reliability impact</td>
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<td>CAWG Review</td>
<td><strong>Date of Vote:</strong> 4/2/2014  <strong>Vote:</strong> Approved</td>
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<td>Board Review</td>
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**Date** 3/12/2014

**Sponsor**

<table>
<thead>
<tr>
<th>Name</th>
<th>Debbie James</th>
</tr>
</thead>
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<tr>
<td>E-mail Address</td>
<td><a href="mailto:djames@spp.org">djames@spp.org</a></td>
</tr>
<tr>
<td>Company</td>
<td>Southwest Power Pool</td>
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<tr>
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</table>

**Comments Received**

| Comment Author | Micha Bailey on behalf of MWG |
| Date | 3/18/2014 |
| Comment Description | Language was added to Section 5.3.3(2). This new language helps clarify what happens to TCRs associated with LTCRs that have not been surrendered. Language was added to Section 5.5.2 for Monthly ARR Nominations. This new language clarifies how the nomination process is currently working now. |
| Comment Status | The MPRR was approved as modified in these comments. The approved language is reflected in this recommendation report. |

| Comment Author | Brenda Fricano on behalf of RWTG |
| Date | 3/26/2014 |
| Comment Description | Section 5 Transmission Congestion Rights Markets Process of the Protocols had some language left in it that allowed an ARR associated with LTCR to be converted into TCRs and then sold in the same auction. The ARR process cannot support a buy and a sell in the same auction. This language was removed. |
3.2 Transmission Congestion Rights Markets

The structure of the TCR Markets includes allocation of Long-Term Congestion Rights (LTCRs) to Eligible Entities and annual and monthly nomination and allocation of Auction Revenue Rights (ARRs) to Eligible Entities followed by annual and monthly TCR Auctions. Eligible Entities for ARRs include Transmission Customers with firm SPP transmission service and entities with firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that have identified such service during the annual LTCR verification process. Eligible Entities for LTCRs include Transmission Customers with qualifying firm SPP transmission service and entities with qualifying firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within and through the SPP Region that have identified such qualifying service during the annual LTCR/ARR verification process.

Entities with firm non-SPP transmission service (GFA) must agree between the parties as to which party is eligible to nominate LTCRs and/or ARRs. Additionally, Eligible Entities may request NITS, GFA NITS, FPTP and/or GFA FPTP Candidate ARRs for firm transmission service confirmed following completion of the annual TCR auction.

Key features of the annual LTCR allocation process include:

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

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

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

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

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

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

(4) Awarded LTCRs are initially ARRs which will automatically be self-directly converted to TCRs prior to the annual ARR allocation for the current allocation year, in the annual ARR allocation process. [MPRR138.6]

Key features of the annual ARR allocation process include:

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

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

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

a. All awarded LTCRs are directly converted to TCRs and are accounted for prior to assessing nominated ARR feasibility;

b. Awarded ARRs are of the obligation type which means that the awarded ARR could result in a payment or charge to the ARR holder. Awarded LTCRs are converted to ARRs and included in the total ARR awards for settlement purposes. [MPRR138.7]

(4) Holders of ARRs receive positive or negative revenue resulting from the annual and monthly TCR auctions, including those ARRs that were self-converted to TCRs. ARRs associated with LTCRs are automatically self-converted into TCRs for settlement purposes. [MPRR138.8] Positive auction revenue results when the sink Auction Clearing Price (ACP) is greater than the source ACP for a given ARR. Negative revenue results when the sink ACP is less than the source ACP, in other words, a counterflow ARR.
(a) For the annual TCR auction, the amount of ARRs eligible to receive auction revenues is equal to the greater of ARRs self-converted to TCRs or the amount of ARRs awarded multiplied by the following percentages: June – 100%; July through September, 90%; and Fall, Winter, Spring – 60%.

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

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

Key features of the annual TCR auction include:

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

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

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

3. The annual TCR auction is a single round process for the month of June that makes 100% of the available SPP transmission system capability available, is a single round process for the months of July, August and September that makes 90% of the available SPP transmission system capability available and is a single round process for the Fall, Winter and Spring seasons that makes 60% of the available SPP transmission system capability available;
(4) Market Participants who have TCR bids cleared in the annual TCR auction will be charged (or get paid in the case of a counter-flow TCR) based on the amount of TCR MWs cleared and the annual TCR auction clearing prices associated with the source and sink of the purchased TCR.

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

(6) Market Participants holding ARRs associated with LTCRs may self-convert their ARRs into TCRs for the applicable period subject to simultaneous feasibility. TCRs from self-converted ARRs, including TCRs self-converted from ARRs associated with LTCRs, are included as awarded TCRs.

Key features of the monthly ARR allocation include:

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

   a. Eligible Entities may nominate candidate ARRs from their verified NITS. Candidate ARRs not to exceed the difference between their NITS ARR Nomination Cap and those ARRs awarded in the annual ARR allocation process.

   b. Eligible Entities may nominate candidate ARRs from their verified FPTP. Candidate ARRs not to exceed the difference between their FPTP Nomination Cap and those ARRs awarded in the annual ARR allocation process.

   c. Eligible Entities may nominate candidate ARRs from their verified GFA NITS. Candidate ARRs not to exceed the difference between their GFA NITS Nomination Cap and those ARRs awarded in the annual ARR allocation process.

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

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

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

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

Key features of the monthly TCR auction include:

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

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

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

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

5. Transmission Congestion Rights Markets Process

The annual TCR Markets Process includes an annual LTCR allocation process, an annual and monthly ARR allocation process and annual and monthly TCR Auctions. LTCRs are multi-year instruments, ARRs are annual, monthly or seasonal instruments, and TCRs are monthly and seasonal financial instruments whose values are determined as part of the DA Market settlement based on the MW amount of the TCR (including LTCRs converted to TCRs) and the DA Market differential of the Marginal Congestion Component of LMP between specified sinks and sources. TCRs are of the obligation type which means they can result in a credit or a charge. They provide a financial hedge against congestion costs in the DA Market as long as the MCC of the TCR sink Settlement Location is greater than the MCC of the TCR source Settlement Location. If the MCC at the TCR sink Settlement Location is less than the MCC of the TCR source Settlement Location, the TCR holder is...
charged (this type of TCR is commonly referred to as a “Counter-Flow TCR”). **Awarded LTCRs are directly converted into TCRs prior to the annual ARR allocation for the current allocation year.**

Auction Revenue Rights (ARRs) are obtained by Eligible Entities during the annual ARR allocation process and/or monthly ARR allocation process. **LTCRs are automatically converted into ARRs and TCRs for modeling and settlement purposes.** Holders of ARRs are entitled to receive the Annual and Monthly TCR Auction revenues associated with awarded TCR Bids. However, ARRs are of the obligation type which means they can result in the holder receiving a portion of the TCR auction revenues or contributing to the TCR auction revenues. **ARRs associated with LTCRs are automatically converted into TCRs which may be sold in the annual and Monthly TCR auctions.**

TCRs are obtained by Market Participants through the annual LTCR allocation and the Annual and Monthly TCR Auctions. Optionally, ARR holders may convert their ARRs into TCRs in the Annual and Monthly TCR Auctions and either hold the TCRs or offer these TCRs for sale in the auctions.

The TCR Markets Process is subject to review by the Market Monitor, consistent with Attachment AG of the SPP OATT.

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

1. Annual LTCR/ARR Verification Process;
2. Annual LTCR Allocation Process;
3. Annual ARR Allocation Process;
4. Annual TCR Auction Process;
5. Monthly ARR Allocation Process;
6. Monthly TCR Auction Process;
7. ARR Allocation and TCR Auction Settlements; and
8. TCR Secondary Markets.

Exhibit 5-1 provides an overall representative timeline related to the LTCR Allocation, ARR Allocation and TCR Auction processes and Exhibit 5-2 provides additional details related to auction timing and available transmission system capability of the TCR Auction processes.
Exhibit 5-1: LTCR/MPRR138.38 ARR Allocation and MPRR138.39 TCR Auction Processes Timeline

- **4/5 - 4/23**
  - Annual ARR Allocation
- **5/3 - 5/23**
  - Annual TCR Auction
- **6/1 - 9/30**
  - Annual ARR Awards and TCR Auction Awards by Month On-Peak and Off-Peak
- **10/1 - 5/31**
  - Annual ARR Awards and TCR Auction Awards by Season On-Peak and Off-Peak
- **12/15 - 5/31**
  - ARR Allocation / TCR Auctions
- **2/14 - 3/15**
  - MP Verification of Transmission Entitlements
- **5/25 - 6/5**
  - Incremental ARR Allocation and Awards. Repeats Each Month as Needed
- **6/8 - 6/18**
  - Monthly TCR Auction for July Repeats for Each Month
- **7/1 - 5/31**
  - Monthly TCR Auction Awards Month to Month On-Peak and Off-Peak
## Exhibit 5-2: TCR Auction Processes Summary

<table>
<thead>
<tr>
<th>Auction Month</th>
<th>Auction Type</th>
<th>TCR Award Periods</th>
<th>TCR Products</th>
<th>Auction Rounds</th>
<th>Total Auctions</th>
</tr>
</thead>
<tbody>
<tr>
<td>May (System Capability %)</td>
<td>Annual</td>
<td>Jun (100)</td>
<td>Oct (100)</td>
<td>On-Peak/Off-Peak</td>
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<tr>
<td></td>
<td></td>
<td>Jul (90)</td>
<td>Nov (100)</td>
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<td>Aug (90)</td>
<td>Dec (100)</td>
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<td>Sep (90)</td>
<td>Jan (100)</td>
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<tr>
<td></td>
<td></td>
<td>Fall (60)</td>
<td>Feb (100)</td>
<td>On-Peak/Off-Peak</td>
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<tr>
<td></td>
<td></td>
<td>Winter (60)</td>
<td>Mar (100)</td>
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<td></td>
<td>Spring (60)</td>
<td>Apr (100)</td>
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<td></td>
<td></td>
<td></td>
<td>May (100)</td>
<td>On-Peak/Off-Peak</td>
<td>2</td>
</tr>
</tbody>
</table>

1 October and November
2 December, January, February, March
3 April and May
Key process and design assumptions of each of these eight (8) key steps are described in the following sub-sections.

5.1.1 Transmission Service Verification

In order for Eligible Entities to obtain candidate LTCRs and/or ARRs, SPP must first verify existing transmission service entitlements, including transmission service entitlements which have been renewed in accordance with rollover rights since their initial term. In order to qualify for candidate LTCRs, an Eligible Entity’s firm transmission service must contain rollover rights and must span the entire allocation year. In order to qualify for candidate ARRs in a particular month and/or season, an Eligible Entity’s transmission service must span the entire monthly or seasonal period within the applicable allocation year. For Transmission Service with rollover rights whose deadline for providing notice of rollover occurs after the annual LTCR/ARR verification but before June 1, the Transmission Provider shall assume that the rollover will occur and shall consider the Transmission Service entitlement to span the entire allocation year, provided, however, that, if rollover rights for such Transmission Service are not exercised by the applicable deadline, any ARRs, TCRs, or LTCRs associated with such Transmission Service shall revert to the Transmission Provider effective on the date such Transmission Service terminates. SPP will verify each Eligible Entity's existing transmission service entitlements as follows:

(1) For Eligible Entities taking Network Integration Transmission Service (NITS) and/or Firm Point-To-Point Transmission Service (FPTP) under the SPP Tariff:
   (a) SPP will obtain source, sink and Reserved Capacity information from the SPP OASIS for each monthly and seasonal period for the applicable year in which the transmission service spans the entire period for ARR purposes and for the annual period for the applicable year for LTCR purposes, or would if or when rolled over;
   (b) Eligible Entities taking NITS with rollover rights shall be considered an LSE for purposes of LTCR allocation;
   (c) Eligible Entities taking FPTP service with rollover rights shall not be considered an LSE for that service unless the Eligible Entity provides an attestation to SPP confirming that the Eligible Entity is an LSE as defined in Attachment AE of the Tariff for such service;
   (d) For a TSR with a source inside the SPP Market that is not a specific Resource or Resource Hub, the load Settlement Location that most closely corresponds to the source on the reservation will be utilized as the source for candidate LTCRs
and/or [MPRR138.47]ARRs. Eligible Entities may create Resource specific TSRs that represent their current TSRs using the process described under Section 5.1.1.1;

(e) For a TSR with a source outside of the SPP Market, the Interface Settlement Location [MPRR138.48] associated with the Balancing Authority of the source will be utilized as the source for candidate LTCRs and/or ARRs [MPRR138.49];

(f) For a TSR with a sink outside of the SPP Market, the Interface Settlement Location associated with the Balancing Authority of the sink will be utilized as the source for candidate LTCRs and/or ARRs [MPRR138.50];

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

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

(2) For Eligible Entities taking GFA service without Carve Out treatment:

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

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

(c) Eligible Entities taking the equivalent of SPP FPTP service with rollover rights shall not be considered an LSE for that service unless the Eligible Entity provides an attestation to SPP confirming that the Eligible Entity is an LSE as defined in Attachment AE of the Tariff for such service [MPRR138.51];

(d) For a GFA with a source inside the SPP Market that is not a specific Resource or Resource Hub, the load Settlement Location that most closely corresponds to the source on the reservation will be utilized as the source for candidate LTCRs and/or ARRs [MPRR138.52];

(e) For a GFA with a source outside of the SPP Market, the interface associated with the Balancing Authority of the source will be utilized as the source for candidate LTCRs and/or ARRs [MPRR138.53].
(f) For a GFA with a sink outside of the SPP Market, the interface associated with the Balancing Authority of the sink will be utilized as the sink for candidate LTCRs and/or ARRs;

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

(3) For entities that have been granted GFA Carve Out treatment:

(a) GFAs with GFA Carve Out treatment are not eligible for candidate ARRs;

(b) The parties to the GFA must register the GFA with SPP, identify the GFA Responsible Entity, and provide source, sink and reserved capacity information. SPP will obtain source, sink and reserved capacity information from the GFA registration for each monthly and seasonal period for the applicable year in which the transmission service spans the entire period;

(c) To the extent that the transmission service specified in the GFA Carve Out is identified as the equivalent of SPP NITS, the transmission customer under the GFA must provide the historical non-coincident annual peak loads (“GFA Annual Peak Load”) being served under the GFA for the previous three years.

5.1.2 Candidate LTCRs/ARRs

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

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

a. An Eligible Entity may select NITS Candidate LTCRs, as described under Section 5.2.6, from a specific source to one or more sinks up to the amount of its available NITS Candidate LTCRs associated with the source such that the total of such selections does not exceed the lesser of the sum of NITS Candidate LTCRs or the limit described under Section 5.1.3(1)(b) for that Eligible Entity.

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

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

   a. An Eligible Entity may select FPTP Candidate LTCRs, as described under Section 5.2.6, for this specific source and sink up to the amount of its available FPTP Candidate LTCRs such that the total of such selections does not exceed the total FPTP Candidate LTCRs available for that Eligible Entity.

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

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

   a. An Eligible Entity may select GFA NITS Candidate LTCRs, as described under Section 5.2.6, from a specific source to one or more sinks up to the amount of its available GFA NITS Candidate LTCRs such that the total of such selections does not exceed the lesser of the sum of GFA NITS Candidate LTCRs or the limit described under Section 5.1.3.(b) for that Eligible Entity.

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

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

   a. An Eligible Entity may select GFA FPTP Candidate LTCRs, as described under Section 5.2.6, for this specific source and sink up to the amount of its available GFA FPTP Candidate LTCRs such that the
b. An Eligible Entity may nominate GFA FPTP Candidate ARRs, as described under Section 5.3.1, for this specific source and sink up to the amount of its GFA FPTP Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

5.2.6 LTCR Selections and Awards

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

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

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

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

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

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

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

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

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

(c) Selected LTCR MW (total LTCR MW nominated from a source Settlement Location cannot exceed the source candidate available LTCR MW as previously determined under Section 5.2.3 or Section 5.2.5, less previously awarded LTCRs plus surrendered LTCRs);
(4) All selected LTCRs are automatically awarded, and these awarded LTCRs and those awarded as described under (1) above are directly converted to TCRs prior to the Annual ARR Allocation Process for the current allocation year.

5.3.3 Simultaneous Feasibility

A simultaneous feasibility test (SFT) is performed in each round to ensure that the nominated candidate ARRs, with nominated candidate ARR MW modeled as generation injection at the source and a corresponding load withdrawal at the sink, do not violate any normal transmission line thermal ratings under normal system conditions and do not violate short-term Emergency transmission line thermal ratings following a single contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission system loading analysis that is performed as part the Security Constrained Economic Dispatch process in the DA Market and includes consideration of the impact of Parallel Flow. 100% of the SPP Residual Transmission System Capability, as defined under Section 5.2.2(2), is made available during the analysis.

(1) The SPP Transmission System topology used in the SFT is the most up-to-date Network Model for all allocation periods, updated for planned maintenance outages.

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

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

(c) For GFA Carve Outs that will be nominated, an injection at the source and a corresponding withdrawal at the sink will be included in the Annual ARR Allocation Process and will be subject to SFT. The capacity used in the allocation will be the maximum allowable nomination as defined in section 5.2.2.

(2) All previously awarded TCRs associated with LTCRs that have not been surrendered are modeled as fixed injections/withdrawals. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility. SPP will report back to the MWG when and which
transmission line ratings had to be adjusted, and the magnitude of each adjustment, to ensure feasibility.

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

5.3.4 Annual ARR Awards

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

5.4.1 TCR Bid and Offer

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

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

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

(a) Source (any valid Settlement Location);
(b) Sink (any valid Settlement Location);
(c) Class (on-peak or off-peak);
(d) Period (month or season);
(e) Type (Bid, Self-Convert, Offer);
(f) TCR MW;
(g) TCR Price ($/MW);

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

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

(5) Market Participants may not submit offers to buy TCRs between Settlement Locations that are collocated and electrically equivalent.

5.4.4 Annual TCR Awards

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

For example, if we assume a 3 bus system (Bus A, B and C) and Bus A is the Reference Bus, we can calculate the ACP at Bus B as follows:
Transmission Line B-C is at its limit with a Shadow Price = $40/MW
Transmission Line A-C is at its limit with a Shadow Price = $30/MW
Transmission Line A-B is not at its limit (Shadow Price = $0/MW)
Shift Factor for Bus B on Line B-C is 30%
Shift Factor for Bus B on Line A-C is -80%

Then ACP at Bus B is equal to - \[($40/MW \times .3) + ($30/MW \times (-.8))\] = $12/MW

A similar calculation is performed for Bus C based on Bus C Shift Factors. The ACP at Bus A is equal to zero since Bus A is the Reference Bus.

5.5.2 Monthly ARR Nominations

Five (5) days prior to the start of each applicable Monthly TCR Auction Process, Eligible Entities may nominate in a single round process (i) NITS Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between (1) their NITS Nomination Cap and (2) the sum of (a) awarded ARRs associated with NITS Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with NITS Candidate LTCRs awarded in the Annual ARR Allocation processes [MPRR138.100]; (ii) FPTP Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between (1) their FPTP Nomination Cap and (2) the sum of (a) awarded ARRs associated with FPTP Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with FPTP Candidate LTCRs awarded in the Annual ARR Allocation processes; (iii) GFA NITS Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between (1) their GFA NITS Nomination Cap and (2) the sum of (a) awarded ARRs associated with GFA NITS Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with GFA NITS Candidate LTCRs awarded in the Annual ARR Allocation processes; and/or (iv) GFA FPTP Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between (1) their GFA FPTP Nomination Cap and (2) the sum of (a) awarded ARRs associated with GFA FPTP Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with GFA FPTP Candidate LTCRs awarded in the Annual ARR Allocation processes.
increments along specific source to sink paths that total to no more than the difference between (1) their GFA FPTP Nomination Cap and (2) the sum of (a) awarded ARRs associated with GFA FPTP Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with GFA FPTP Candidate LTCRs awarded in the Annual ARR Allocation processes. Nominations occur separately for On-Peak and Off-Peak periods. Eligible Entities submit the following information:

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

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

5.5.3 Simultaneous Feasibility

The SFT to assess feasibility of nominated monthly candidate ARRs is performed as described under Section 5.3.3 with the following adjustments:

1. The SPP Transmission System model used in the SFT will be the same model to be used in the upcoming Monthly TCR Auction Process which will include the most up-to-date Network Model, including planned maintenance outages, and updated Parallel Flow assumptions;
   
   (a) For withdrawals at sink Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June for the month of July). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

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

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

4. All TCRs previously awarded in the Annual TCR Auction Process directly converted TCRs from associated with LTCRs that were awarded.
all remaining ARRs not accounted for in the Annual TCR Auction Process (as defined under Section [5.4], and for the applicable month are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to assessing monthly ARR feasibility. SPP will report back to the MWG on a quarterly basis regarding the number of times that transmission line ratings had to be adjusted to ensure feasibility.

5.6.3 Monthly TCR Auction Clearing and Simultaneous Feasibility

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

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

2. The SFT is performed as described under Section 5.5.3 except that LTCRs awarded in the Annual LTCR Allocation process are not modeled as fixed injections/withdrawals since they have already been awarded as self-converted TCRs. TCR Bid MWs are modeled as an injection at the source and a corresponding withdrawal at the sink. TCR Offers associated with the sale of existing TCRs are modeled as injections at the sink and withdrawals at the source. Residual SPP Transmission System Capability includes the most up to date Parallel Flow assumptions.
   a. For Round 1, all TCRs awarded in the Annual TCR Auction for the month are modeled as fixed injections and withdrawals. To the extent that the fixed injections and withdrawals representing TCRs awarded in the Annual TCR Auction are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to the Round 1 auction. SPP will
report back to the MWG on a quarterly basis regarding the number of times that
that transmission line ratings had to be adjusted to ensure feasibility;

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

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**Proposed Tariff Language Revision**

**Attachment AE**

### 1.1 Definitions A

#### Auction Revenue Right (“ARR”)

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

#### Transmission Congestion Rights Markets

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

There are eight (8) key processes associated with LTCRs, ARRs and TCRs:

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

Table 7-1 in Section 7.3.2 of this Attachment AE provides additional details related to auction timing and Transmission System capability available for the TCR auctions.

(b) Except as otherwise provided in this Section 7.0.b (ii), an entity taking firm transmission service under a GFA Carve Out will not be eligible to participate in the TCR Markets for the MW capacity associated with the GFA Carve Out.

(i) The MW capacity associated with each GFA Carve Out shall be included in the Transmission Provider’s ARR allocation and TCR auction processes in a manner that reflects the transmission service pursuant to the GFA Carve Out, provided, however, that (Aa) candidate ARRs associated with the GFA Carve Out service shall not be nominated for a product period if, based upon the twelve preceding months for which congestion data is available, such ARR, had it been converted to a TCR, would have resulted in a net charge to the holder of the TCR over that product period, and (Bb) until twelve months of Integrated Marketplace data are available, the Transmission Provider shall use relevant data from both the EIS Market and the Integrated Marketplace to estimate whether the result would have been a net charge to the TCR holder.

(ii) On an annual basis, the GFA Responsible Entity may elect, in writing, to cancel the GFA Carve Out treatment and will be eligible to participate in the TCR Markets pursuant to Section 7.0 of Attachment AE. The conversion of GFA Carve Out to the TCR Market is irrevocable.

7.1.1 Transmission Service Verification
In order for Eligible Entities to obtain candidate LTCRs and/or ARRs, the Transmission Provider must first verify existing transmission service entitlements, including transmission service entitlements that have been renewed in accordance with rollover rights since their initial term. An Eligible Entity’s Transmission Service must span the entire monthly or seasonal period for which ARRs are allocated to qualify for candidate ARRs in a particular month or season. **An Eligible Entity’s transmission service must span the entire annual period for which LTCRs are allocated and must have rollover rights to qualify for candidate LTCRs.** For Transmission Service with rollover rights whose deadline for providing notice of rollover occurs after the annual LTCR/ARR verification but before June 1, the Transmission Provider shall assume that the rollover will occur and shall consider the Transmission Service entitlement to span the entire allocation year, *provided, however, that, if rollover rights for such Transmission Service are not exercised by the applicable deadline, any ARRs, TCRs, or LTCRs associated with such Transmission Service shall revert to the Transmission Provider effective on the date such Transmission Service terminates.* The Transmission Provider will verify Eligible Entity existing Transmission Service entitlements as follows:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

7.1.2 Candidate Long-Term Congestion Rights/Auction Revenue Rights

Following verification of an Eligible Entity transmission service, candidate LTCRs and/or ARRs associated with such transmission service are assigned as follows:

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

(a) An Eligible Entity may select Network Integration Transmission Service Candidate LTCRs, as described in Section 7.2.4 of this Attachment AE from a specific source to one or more sinks up to the amount of its available Network Integration Transmission Service Candidate LTCRs
associated with the source such that the total of such selections does not exceed the lesser of: i) the sum of Network Integration Transmission Service Candidate LTCRs or ii) the limit described under Section 7.1.3(1)(b) for that Eligible Entity.

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

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

(a) An Eligible Entity may select Firm Point-To-Point Candidate LTCRs, as described in Section 7.2 of this Attachment AE, for this specific source and sink up to the amount of its available Firm Point-To-Point Candidate LTCRs such that the total of such selections does not exceed the total Firm Point-To-Point Candidate LTCRs available for that Eligible Entity.

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

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

(a) An Eligible Entity may select Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs, as described in Section 7.2 of this Attachment AE, from a specific source to one or more
sinks up to the amount of its available Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs such that the total of such selections does not exceed the lesser of: i) the sum of Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs or ii) the limit described under Section 7.1.3(3)(b) for that Eligible Entity.

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

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

(a) An Eligible Entity may select Grandfathered Agreement Firm Point-To-Point Candidate LTCRs, as described in Section 7.2 of this Attachment AE, for this specific source and sink up to the amount of its available Grandfathered Agreement Firm Point-To-Point Candidate LTCRs such that the total of such selections does not exceed the total Grandfathered Agreement Firm Point-To-Point Candidate LTCRs available for that Eligible Entity.

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

7.1.3 Auction Revenue Right Nomination Cap
An Eligible Entity’s ARR Nomination Cap will be as follows:

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

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

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

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

7.2 Annual Long-Term Congestion Right Allocation

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

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

7.2.4 LTCR Selection and Awards

(1) All previously awarded LTCRs are automatically awarded as LTCRs for the current allocation year; provided that such LTCRs meet the criteria specified in Section 7.1.1 of this Attachment AE; or were not surrendered as described under Section 7.2.1 of this Attachment AE.

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

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

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

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

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

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

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

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

(4) All selected LTCRs selected in accordance with Section 7.2.4(3) are automatically awarded; and

(5) All awarded LTCRs are directly converted to TCRs prior to the annual ARR allocation for the current allocation year.

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

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

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

### 7.4 Annual Transmission Congestion Right Auction

Market Participants may obtain TCRs by purchasing them in the annual TCR auction or through conversion of ARRs into TCRs. LTCRs awarded as ARRs as described under Section 7.3.3 are automatically converted to TCRs which the holder may offer for sale in the auction. The percentages of the Transmission System capability made available during the annual TCR auction are listed in Table 7-1 in Section 7.4.2 of this Attachment AE. TCRs in the annual auction are auctioned in a
single round process for all months and seasons. If there are any changes to the transmission system topology or Parallel Flow data after the conclusion of Annual ARR Allocation Process, the Transmission Provider will post such changes no later than three (3) Business Days prior to the start of the Annual TCR Auction Process.

7.4.3 Annual Transmission Congestion Right Auction Clearing and Simultaneous Feasibility

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

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

1. TCR submittals of both the self-convert type and Bid type are modeled as a generation injection at the source and a corresponding load withdrawal at the sink.
2. TCR submittals of the Offer type are modeled as a generation injection at the sink and a corresponding load withdrawal at the source; and
3. Directly converted TCRs from ARRs associated with LTCRs are automatically converted into awarded TCRs, are modeled as fixed injections and withdrawals, and such TCRs are treated as self-converted TCRs for settlement purposes.

7.6.3 Monthly Auction Revenue Right Nominations

Five (5) days prior to the start of the monthly TCR auction, Eligible Entities may nominate in a single round:

(i) Network Integration Transmission Service Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between (1) their Network Integration Transmission Service
ARR Nomination Cap and (2) the sum of (a) awarded ARRs associated with Network Integration Transmission Service Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with **Network Integration Transmission Service Candidate LTCRs** awarded in the annual ARR-allocation processes;

(ii) Firm Point-To-Point Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between (1) their Firm Point-To-Point ARR Nomination Cap and (2) the sum of (a) awarded ARRs associated with Firm Point-To-Point Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with **Firm Point-To-Point Candidate LTCRs** awarded in the annual ARR-allocation processes;

(iii) Grandfathered Agreement Network Integration Transmission Service Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between (1) their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap and (2) the sum of (a) awarded ARRs associated with Grandfathered Agreement Network Integration Transmission Service Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with **Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs** awarded in the annual ARR-allocation processes; and

(iv) Grandfathered Agreement Firm Point-To-Point Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between (1) their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap and (2) the sum of (a) awarded ARRs associated with Grandfathered Agreement Firm Point-To-Point Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with **Grandfathered Agreement Firm Point-To-Point Candidate LTCRs** awarded in the annual ARR-allocation processes.

Nominations occur separately for On-Peak and Off-Peak periods. Eligible Entities submit the following information:
(i+) Source: valid candidate ARR source Settlement Location;

(2ii) Sink: valid candidate ARR sink Settlement Location;

(3iii) Class: On-Peak or Off-Peak; and

(4iv) ARR MW:

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

Proposed Criteria Language Revision

N/A
RARTF - RCAR
Lessons Learned

RSC Update
April 29, 2014

Michael Siedschlag
Work of the RARTF – Meeting Dates

**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

**RCAR Guidance Meetings**

- May 31, 2013 – Conference Call Meeting
- September 12, 2013 – 2nd Review and Stakeholder Comments
- October 8, 2013 – Meeting
  - Lessons Learned Review
- February 3, 2013 - RARTF Reviewed Stakeholder Comments
- March 3, 2014 RARTF – Held Meeting to review
- March 31, 2014 RARTF – Conference Call Meeting to finalize
SECTION I: INTRODUCTION
Objective

• With the approval of the RARTF Report in January 2012 and the RCAR Final Report in October 2013 the RARTF provided for a process to evaluate “lessons learned” from the first RCAR Report and to finalize suggested improvement to be implemented in subsequent RCAR processes.

• The RARTF has been working to finalize these suggestions since November 2013 utilizing stakeholder and staff input. The results of this work is included in the RARTF RCAR Lessons Learned Report.
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### Section 1.2 – Stakeholder Comments and Suggestions

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10 Lessons Learned contained in the Draft Report

Recommendation 1: Incorporating Lessons Learned in RARTF

Recommendation 2: Improvement of Benefits

Recommendation 3: Benefits used in RCAR II Assessment

Recommendation 4: Improvements to and Vetting of Models

Recommendation 5: Synchronizing ITP10 and RCAR II

Recommendation 6: Review of NTCs and Projects w/in 10 Years

Recommendation 7: Improvements and Vetting of PTP Revenue

Recommendation 8: B/C Threshold

Recommendation 9: Stakeholder Guidance during the RCAR II

Recommendation 10: Amendment to SPP Tariff
RCAR LESSONS LEARNED
RECOMMENDATIONS
Recommendations

• Recommendation #1
  – The recommendations contained in this Lessons Learned Report should be incorporated and used by SPP staff when conducting the RCAR II assessment of the SPP Highway/Byway.
Recommendations

• Recommendation #2
  – That the Economic Studies Working Group (ESWG) continues to review the benefits contained in the Metrics Task Force (MTF) Report that were approved through the SPP stakeholder process in 2012. This review should be established to provide SPP stakeholders the opportunity to offer wide-ranging improvements to the benefits contained in the MTF Report. Any changes or improvements to the benefits shall be presented to the ESWG, RARTF, MOPC, and RSC for recommendation to the BOD for approval by the July 2014 meeting cycle.
Recommendations

• **Recommendation #3**
  
  – That the ESWG continue to review the benefits contained in the MTF Report that were approved through the SPP stakeholder process in 2012. This review should provide SPP stakeholders the opportunity to suggest which benefits should be included in future RCAR reports. Any changes or improvements to the benefits shall be presented to the ESWG, RARTF, MOPC, and RSC for recommendation to the BOD for approval by the July 2014 meeting cycle.
Recommendations

• Recommendation #4
  – That SPP staff continue to work with the SPP Transmission Working Group (TWG) and ESWG to improve models used for RCAR II. This effort should provide SPP stakeholders the opportunity to offer or suggest improvements to models used in future RCAR reports. Any changes or improvements to the models should be vetted by the TWG and ESWG as appropriate. These changes or improvements should also be in alignment with the ten guiding principles contained in the RARTF Report.
Recommendations

• Recommendation #5
  – That SPP staff utilize, to the maximum extent possible, models used in the Integrated Transmission Plan 10-year planning horizon assessment (ITP10) for RCAR II. Conducting the ITP10 and RCAR II processes in parallel should allow leveraging of models and promote consistency and efficiency in the model vetting process. This measure could reduce cost and help to eliminate redundancy of efforts between SPP staff and stakeholders.
Recommendations

• Recommendation #6
  – That SPP staff evaluate remedies for zones below the threshold in the Notification to Construct (NTC)-only review for RCAR II.
Recommendations

• Recommendation #7

– That SPP staff continue to work with SPP stakeholders to find ways to improve upon calculating Point to Point (PTP) revenue credits for RCAR II. This effort should provide SPP stakeholders the opportunity to suggest improvements to PTP revenue credits calculations for use in future RCAR reports that most closely align with SPP’s OATT. Additionally, by updating how PTP revenue credits are projected with up-to-date information, SPP staff will be using “the most up[-]to[-]date and best available information,” consistent with Principle 3 contained in the RARTF Report. Any changes or improvements to the PTP projection methodology should be vetted by the RARTF and RTWG as it was handled during the RCAR I Report in an open and transparent manner that will enable the participation of SPP stakeholders.
Recommendations

• **Recommendation #8**
  - That the RARTF and SPP stakeholder-approved 0.8 benefit to cost ratio threshold continue to be the basis to determine when it is warranted for members to request and for SPP staff to subsequently study possible remedies as stated in Section 4.1 of the RARTF Report. Additionally, the RARTF recommends that if RCAR II shows that a zone is above the 0.8 threshold, but below a 1.0 benefit to cost ratio, that this analysis should be used and considered as a part of SPP’s transmission planning process in the future.
Recommendations

• Recommendation #9
  – That SPP staff continue to update and brief the RARTF throughout the RCAR II analysis and seek guidance from the RARTF when input from SPP stakeholders is necessary for SPP staff to complete RCAR II.
Recommendations

- **Recommendation #10**
  - That SPP make a filing with the Federal Energy Regulatory Commission (FERC) to amend Attachment J, Section III.D.2 to read as follows:

  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 approved for construction with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region.
Conclusion

• RARTF and Staff request RSC endorse the RCAR I Lessons Learned Report for implementation with RCAR II.
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QUESTIONS???
Criteria Changes
Wind Accreditation by Generation
Working Group

RSC 4/28/2014

Mitchell Williams - WFEC
GWG Chair
CRR-012 Wind and Solar Capacity Accreditation

• GWG developed a Capacity Accreditation method in 2004 using a statistical method that measures wind performance during peak hours:
  – Uses top 10% load hours during the peak month, and
  – An 85% confidence that wind would be producing at or above a certain output

• Since that time the GWG has reviewed the performance of this criteria and now proposes changes:
  – Peak Load hours: from 10% to 3%
  – Confidence: from 85% to 60%
How does SPP compare to other RTOs/ISO/Markets?

<table>
<thead>
<tr>
<th>ISO</th>
<th>Method</th>
<th>Value</th>
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</thead>
<tbody>
<tr>
<td>SPP</td>
<td>Peak/Statistical</td>
<td>0 to 4%</td>
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<tr>
<td>NYISO</td>
<td>Peak</td>
<td>10%</td>
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<tr>
<td>MISO</td>
<td>ELCC</td>
<td>12-13 %</td>
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<tr>
<td>ERCOT</td>
<td>ELCC</td>
<td>8.7%</td>
</tr>
<tr>
<td>PJM</td>
<td>Peak</td>
<td>13%</td>
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</table>
Methods Considered:

– **ELCC = Effective Load Carrying Capability:**
  - Uses Loss of Load Expectation studies to determine what level of wind must be added to get the same effect as a dispatchable generator. This method is data intensive and requires many dispatch model runs for each wind project.

– **Peak/Statistical Methods:**
  - Definition of Peak hours or Super Peak hours
  - Uses Mean or Average or Confidence Factor.
  - Members did an analysis of the ELCC method in comparison to the statistical method of top 3% of load hours and 50% Confidence Factor with comparable results.
Data Review – Peak Hours

- Too much risk in a single hour.
- 10% load hours is also a lot of data - GWG was motivated to simplify the process.
- We looked at:
  - Top 10 hours
  - 3% (22 hours) All GWG members supported 3%
  - 5% (37 hours)
  - 10% (74 hours)
- Top 3% of load hours leads to a more accurate representation of what occurs statistically during the peak hours. Top 10% and 60% Confidence Factor (CI) and Top 10% and 85% CI did not result in data accuracy based on historical analysis.
## Wind Generation During Peak Hour

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak</th>
<th>Time</th>
<th>MWs</th>
<th>% Nameplate</th>
<th>Avg Wind Nameplate</th>
<th>Hourly Pk Avg. MW</th>
<th>% of Wind towards Peak Load</th>
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</thead>
<tbody>
<tr>
<td>2010</td>
<td>8/12/2010</td>
<td>15:00</td>
<td>747</td>
<td>22.0%</td>
<td>3,402</td>
<td>45,405</td>
<td>1.65%</td>
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<tr>
<td>2011</td>
<td>8/2/2011</td>
<td>15:00</td>
<td>686</td>
<td>16.1%</td>
<td>4,285</td>
<td>47,622</td>
<td>1.44%</td>
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<td>8/1/2012</td>
<td>15:00</td>
<td>383</td>
<td>5.2%</td>
<td>7,442</td>
<td>45,402</td>
<td>0.84%</td>
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<tr>
<td>2013</td>
<td>8/30/2013</td>
<td>16:00</td>
<td>406</td>
<td>5.0%</td>
<td>8,121</td>
<td>45,457</td>
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<tr>
<td>Avg</td>
<td></td>
<td></td>
<td></td>
<td>12.03%</td>
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</table>
Data Review – Confidence Factor

• Proposed Confidence Factor: The Generation Working Group was split 3 to 3 over two Confidence Factors:
  – 50% represents the median output of a wind project during the super peak hours and
  – 65% loosely approximates 1 Sigma of standard deviation.
  – After much negotiations the group settled on 60% Confidence.

• 85% confidence Factor that would lead to 0MWs of Solar capacity accreditation.
Wind Capacity for the Top 3% Load Hours

Hourly net power output value that can be expected from the facility N% of the time or greater
<table>
<thead>
<tr>
<th>Wind Project</th>
<th>10% Ld/85%CF Old Criteria</th>
<th>3%/60% Proposed</th>
<th>10%/75% Empire</th>
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</thead>
<tbody>
<tr>
<td>A</td>
<td>0%</td>
<td>2.4%</td>
<td></td>
</tr>
<tr>
<td>B</td>
<td>2.1</td>
<td>4.9</td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>2.2</td>
<td>12.2</td>
<td></td>
</tr>
<tr>
<td>D</td>
<td>1</td>
<td>9.3</td>
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<tr>
<td>E</td>
<td>0</td>
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<td>G</td>
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<td>2.2</td>
<td></td>
</tr>
<tr>
<td>H</td>
<td>2.1</td>
<td>7.8</td>
<td></td>
</tr>
<tr>
<td>I</td>
<td>0.2</td>
<td>7.4</td>
<td></td>
</tr>
<tr>
<td>J</td>
<td>1.4%</td>
<td>13.1</td>
<td></td>
</tr>
<tr>
<td>K</td>
<td>3.4</td>
<td>11.9</td>
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<td>L</td>
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<td>16.2</td>
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<tr>
<td>M</td>
<td>2</td>
<td>22.8</td>
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</tr>
<tr>
<td>N</td>
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<tr>
<td>O</td>
<td>0.3</td>
<td>9.1</td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>2%</td>
<td>8.6</td>
<td></td>
</tr>
<tr>
<td>Q</td>
<td>1.4%</td>
<td>7.1</td>
<td></td>
</tr>
<tr>
<td>Average</td>
<td>1.4%</td>
<td>10.0%</td>
<td>4.1%</td>
</tr>
</tbody>
</table>

- 554MW assigned out of SPP
- Much less is assigned to loads
- capacity = 6% (Probably errors in Reporting - overstating wind capacity.)
Summary

• Modify Criteria 12 to better represent Wind and Solar Accreditation:
  ▪ Reduce data requirement from 10% load hours to 3%.
  ▪ Reduce Confidence Factor from 85% to 60%.
  ▪ Allow 5% Capacity for a new project instead of 3% for up to 3 years.

  – MOPC – Approved with 73% vote – Also forming task force to address Planning Reserve Margin and other topics.
  – CAWG – No action; Requests a report on wind capacity in 3 years, and define a generators authority to select a lower accreditation value.
  – TWG – Approved CRR
  – ORWG – Took no action; Prepared comments concerning reliability and review of SPP planning reserve Margin
Proposed Changes to SPP Wind Accreditation

Background

- The Generation Working Group (GWG) has proposed changes to the section in Criteria 12 which delineates the methodology used to measure the performance of wind and solar facilities on a facility-specific basis.

- The GWG Chair presented the proposed changes to Criteria 12 to CAWG at its March 21st and April 2nd meetings.
Proposed Changes to SPP Wind Accreditation

Impact on Areas of Responsibilities under RSC authority

- The RSC bylaws do not require approval of the proposed changes in SPP criteria.

- However, the resulting change in wind accreditation may have impacts on resource adequacy, transmission planning and related cost allocation for potential upgrades caused by the wind accreditation.
Proposed Changes to SPP Wind Accreditation
Impact on Resource Adequacy

- Load serving members in SPP are required to maintain a minimum capacity margin of 12% under SPP criteria 2.1.9.
- SPP Criteria 2.1.7 defines Capacity Margin as the amount by which a Load Serving Member's System Capacity exceeds its System Peak Responsibility.
- The increase in wind accreditation as a result of the criteria change would allow Load Serving Members to rely more on wind to meet their capacity margin requirements.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation Impact on Resource Adequacy

- However, over time, the accreditation change could drive the decisions regarding the installation of other generation facilities and possibly reduce the peaking capacity in the system.

- On a system wide basis, over time, the change could impact reliability and may necessitate an evaluation of whether the capacity margin of 12% is sufficient to support a reliable system.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

Impact on Resource Adequacy

- Integrated Resource Plans (IRP): The increase in accredited capacity could delay the construction of new generation because load serving entities can rely on the increase in accredited wind capacity to meet their capacity needs and requirements in their IRPs.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation Impact on Transmission Planning:

- The change in wind accreditation could have implications for cost allocation if the increase in accredited wind capacity caused transmission upgrades to be built or reduced the need for transmission upgrades.
- It is CAWG’s understanding that the increase in wind accreditation is not expected to have an impact on transmission planning in general.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

Action by Other Working Groups and Committees

- Transmission Working Group approved the proposed criteria change.
- Operations Reliability Working Group expressed concern about the potential impact of the change on system reliability and commented on the need for SPP to monitor the actual wind output at peak hours and review SPP’s overall capacity accreditation philosophy.
- MOPC approved the proposed criteria change by a majority vote.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

CAWG Consideration

- The proposed criteria revision is the first change since the criteria was developed ten years ago.
- Wind generation has increased significantly in the SPP footprint over the last ten years.
- The criteria revision would increase the wind accreditation capacity on an average from 1.4% to 10%, based on a study of seventeen wind projects.
- The average accredited wind capacity of 10% falls within the range of values for accredited wind capacity adopted in other RTOs/ISOs.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

CAWG Consideration

After considering the methodology outlined in the criteria revision and the results based on the study of seventeen wind projects, CAWG reached the following conclusions during its April 17th meeting:

1) SPP should evaluate the current SPP capacity margin to ensure that it is adequate to meet the needs for a reliable system.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

CAWG Consideration

2) SPP should inform RSC and CAWG, on an ongoing basis, if the increase in accredited wind capacity, as a result of the criteria change, is partly or wholly responsible for causing any changes in the need for transmission upgrades in the SPP footprint.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

CAWG Consideration

3) RSC and CAWG should be presented with the GWG annual report regarding the performance of wind and solar facilities. The report should include a yearly comparison of wind and solar output during peak periods. This would allow the criteria to be reevaluated, if necessary, based on information on actual wind and solar output at peak periods.
Questions?

Submitted by: Meena Thomas
CAWG Chairman
April 28, 2014
Capacity Margin Discussion

RSC
April 28, 2014
Capacity Margin background

• Capacity Margin
  – The amount of capacity available for planned and emergency use
  – \( \text{Capacity Margin} = \frac{\text{Net Total Capacity} - \text{Net Total Load}}{\text{Net Total Capacity}} \)

• System Reliability
  – The intent of Capacity Margin requirement is to ensure sufficient capacity is planned and available to meet forecasted demand
Capacity Margin requirement

• SPP Criteria
  – Section 2 defines Capacity Margin
  – Section 2.1.1 states - “A Load Serving Member shall mean any SPP Member assuming legal obligation to provide firm electric service to a customer or group of customers within SPP.”
  – Section 4.3.5 states Load Serving Member requirement of 12% for conventional generation and 9% for hydro-based utilities
Summary of questions

- Should Capacity Margin requirement apply to all load serving entities operating within the electrical boundaries of the SPP Balancing Authority?
- Which SPP Working Group should own the Capacity Margin process?
- Should we use Coincident Peak loads to calculate each entity's Capacity Margin?
- Should fuel supply and transportation firmness be documented?
- Can anything other than firm transmission be used to demonstrate deliverability?
- Do plants need to be available more than a certain percentage of the year?
- How do we factor in environmental limits?
- Penalties for non-compliance?
- Any issues with IRP state laws?
Proposed Plan of Attack

• SPP Staff to survey Members for additional questions about Capacity Margin. Then survey for Member answers to all submitted questions.

• SPP Staff propose in July MOPC and RSC meetings schedule of activities for review of Capacity Margin requirement language and applicability

• SPP Staff propose Working Group assignment to Chair to start work before July

• SPP Staff sponsor workshop on Resource Adequacy

• SPP Staff revise and provide to WG the draft for review to bring to MOPC and RSC in January
Update on Integration of WAPA, Basin, Heartland (RSC Meeting)

April 28, 2014
AGENDA

I. Overview On-going SPP Stakeholder Processes
   a. Corporate Governance Committee (CGC)
   b. Regional Tariff Working Group (RTWG)
AREAS FOR SPP STAKEHOLDER PROCESS
CGC Responsibilities

• The SPP CGC is responsible for overall governance structure of SPP. When necessary the CGC makes recommended changes to SPP governance structure. This responsibility is stated in the CGC Organizational Group Scope Statement dated October 29, 2013.

– Purpose

  ▪ The Corporate Governance Committee is responsible for the overall governance structure, including nominations, for the company in accordance with its scope as approved by the Board of Directors.

– Scope of Activities

  ▪ The Corporate Governance Committee is responsible for the overall governance structure, including nominations, for the company in accordance with its scope as approved by the Board of Directors.

  ▪ * * * * *

  ▪ 1) Review annually the structure of the Organizational Groups, and together with the Organizational Group Chairs, the charters of each Organizational Group, and recommend changes to the Board of Directors, as appropriate;
### SPP CGC Process for Integrating Western, Basin, & Heartland

| Meeting Schedule | Feb 27, 2014  
Little Rock, AR | Mar 31, 2014  
Dallas, TX | Apr 11, 2014  
Dallas, TX | May 1, 2014  
Conf Call |

### Next Steps

| Next Steps for CGC Recommendations | MOPC – May 29-June 2, 2014?  
Conference Call? | BOD/MC - June 9-10, 2014  
Little Rock, AR |

### Areas of Changes to SPP Governance under consideration

| SPP Membership Agreement | (1) Add “Federal Law” to pertinent sections;  
(2) Add references to “Federal Power Marketing Agencies” (FPMA) in pertinent sections;  
(3) Addition of definitions to correspond with new definitions in OATT (e.g. Upper Missouri Zone);  
(4) Add references to FERC's relationship with FMPA in ratemaking context;  
(5) Add language about withdrawal and related obligations;  
(6) Add language about assigning Membership Agreement;  
(7) Party Specific Issues; and  
(8) Penalty Recovery |

| SPP Bylaws | (1) Add FPMA seats to the Members Committee and the CGC,*  
(2) Added pertinent language about FPMA withdrawing as Members (Federal Law Matters) |
RTWG Responsibilities

• PURPOSE

  – The Regional Tariff Working Group (RTWG) is responsible for development, recommendation, overall implementation and oversight of SPP’s open access regional transmission service tariff (Tariff). The RTWG will further advise the SPP Staff on regulatory or implementation issues not specifically covered by the Tariff or issues where there may be conflict or differing interpretations of the Tariff. The RTWG provides policy input to the Market Operations Policy Committee (MOPC) and Board of Directors (BOD) and its committees, if requested.
### SPP RTWG Process for Integrating Western, Basin, & Heartland

<table>
<thead>
<tr>
<th>Meeting Schedule</th>
<th>March 26-27, 2014 Dallas, TX</th>
<th>April 23, 2014 Dallas, TX</th>
<th>May 22, 2014 Dallas, TX</th>
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</thead>
</table>

### Next Steps

|-------------------------------|---------------------------------------------|----------------------------------------|

### Areas of Changes to SPP OATT under consideration

OATT Changes

1. Creation of New Pricing Zone, called the Upper Missouri Zone or "Zone 19," to cover the region in which the IS Owners and facilities are located;
2. Defined "Federal Service Exemption" for WAPA/Western not being subject to certain charges for deliveries of federal power over the UMZ for purposes of fulfilling Western's statutory obligations and related changes to Schedule 11;
3. Regional Cost Allocation, How to integrate, Based on Need by date;
4. Western is excluded from FERC Assessment costs in Schedule 12; and
5. "Federal law" is added to pertinent references to state law obligations.
Western-UGP Federal Service Exemption

- Federal Statutes govern the functions and limitations of Western-UGP
  - Other Federal law as applicable, and specifically Western-UGP’s ability to join an RTO consistent with section 1232 of the Energy Policy Act of 2005
  - Western has advised that consistent with its statutory obligations it cannot agree to: (1) involuntary cost allocation for third-party transmission facilities, which includes SPP’s cost allocation share under its tariff and (2) Western’s rates are subject to a different standard of review pursuant to the delegation of authority from the Department of Energy to FERC.

- Joining SPP is based on the fixed nature of the generation resources committed to the preference customers of Western-UGP as well as the sufficiency of existing transmission Western-UGP built to meet its requirements.

- Any Western-UGP power marketing activity beyond federal resources to federal load will be subject to full SPP transmission service charges.
## Application of Rate Schedules and FSE

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</table>

*WAPA exemption from Schedule 11 (regional portion) only for FSE to serve Federal load with Federal resources and from all activities for Schedule 12
Federal Service Exemption

• Includes treatment for the Congestion and Marginal Losses.

• Only applicable from the Federal Dams to the Federal Preference Customer Loads

• Any other purchases or sales would not be exempt

• Treated like other “carved-out” Grandfathered Transmission Service

• Monitored to insure that Western has sufficient transmission facilities
Regional Cost Allocation Integration

• Based on previous integration of Nebraska and the offer from the SPC to Entergy.
• Based on SPP determined Need By Date for each facility of SPP and the IS
• No regional cost sharing for facilities “Need By” Date before Integration
• Full regional cost sharing for facilities “Need By” Date after Integration
• Analysis provided on impact based on current NTCs
Why are only Basin Projects Considered?

- **Western – UGP**
  - No new resources
  - No new “load” obligations
  - Transmission in place is only transmission charges allowed for preference customers

- **Heartland**
  - No new transmission needed in near future

- **Basin**
  - All transmission expansion needed for and constructed by Basin
RSC Next Steps

- RSC Meeting on May 27th in Dallas, TX
Seams Update for RSC

Carl Monroe
April 28, 2014

Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future
SPP-MISO JOA Section 5.2

- Remand of FERC’s 5.2 ruling by the DC Circuit Court of Appeals (EL11-34-002)

- SPP continuing to bill MISO monthly for the use of SPP’s system. First bills were per the SPP tariff, current bills are per the FERC approved service agreement – subject to refund.

- SPP filed a 206 Complaint (EL14-21) and a 205 Unexecuted Service Agreement (ER14-1175)

- MISO filed a 206 Complaint (EL14-30) asking FERC to order SPP to stop billing MISO.
SPP’s Section 5.2 Filings

• Complaint (EL14-21)
  – Asking that if FERC finds that the JOA permits use of SPP’s system without compensation such a provision is “unjust, unreasonable, and unduly discriminatory” in light of Entergy’s integration into MISO with the minimal 1000 MW Partial Contract Path

• Unexecuted Service Agreement (ER14-1175)
  – Charging MISO for usage of the SPP system above 1000 MW

• MISO’s neighbors filed in agreement with SPP
  – WAPA, Basin, AECI, TVA, and Southern
FERC’s March 28 Order

• Denied MISO TO’s motion to dismiss
• Accepted SPP’s service agreement for filing
  – Suspended for a nominal period to be effective January 29, 2014
• Accepted MISO’s complaint for filing
  – Refund effective date February 18, 2014
• Consolidating all of the dockets relating to Section 5.2
• Set for hearing but held in abeyance for settlement judge procedures
Recent Filing MISO

- **April 11\(^{th}\)**
  - MISO Filed at FERC to reduce their dispatch to the 1000MW Limit
  - MISO also filed a rehearing request

- **April 17\(^{th}\)**
  - MISO submitted a 205 Filing to recover cost owed to SPP, subject to refund, under the FERC accepted service agreement
Current Transmission Charges for MISO Usage

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<td><strong>December</strong></td>
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<td><strong>Jan 1-28</strong></td>
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Order 1000 Filings Update

April 28, 2014

Paul Suskie
Senior Vice President, Regulatory Policy and General Counsel
Order 1000 Filings

A. Regional Compliance Requirements

B. Interregional Compliance Requirements
Order 1000 – Regional Planning and Cost Allocation

• **November 13, 2012** – SPP filed tariff revisions to comply with Order No. 1000’s regional planning and cost allocation requirements
  – SPP requested an effective date of March 30 of the year following FERC’s issuance of an order

• **July 18, 2013** - FERC issued order accepting SPP’s Filing further Compliance Requirements

• **November 15, 2013** – SPP submitted compliance filing
  – Filing included the RSC’s policy on not funding 3rd Party impacts
• MISO – July Filing
  – SPP & MISO have significant differences.  *Awaiting FERC Ruling*

• Midcontinent Area Planning Pool (MAPP) – June Filing
  – SPP filed request for extension of time to comply til 120 days after FERC issues an order in response to a request for waiver from the regional requirements of Order 1000 filed by NorthWestern Corporation (MAPP member).
    
  – *July 2013: FERC granted SPP’s request*

• Southeastern Regional Transmission Planning region
  – July 2013: SPP requested a limited waiver because SPP’s only interconnection with SERTP is through Associated Electric Cooperative, Inc., a non-FERC jurisdictional utility, with no obligation to comply with Order 1000.  *Waiting on FERC order*
FERC Order 1000
Independent
Expert Pool/Panel
RSC
April 28, 2014

Paul Suskie
psuskie@spp.org

Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future
• Order 1000 Process Review
• Industry Expert Pool and Panel Defined
• Industry Expert Process
• IEP Compensation Discussion
• Affiliation Definition
• Stakeholder Input and Guidance
Order 1000 Process

Transmission Owner Designation Process
Attachment Y

Qualified RFP Participants
Application and Qualification

Transmission Owner Selection Process

Attachment O

Requests for Proposal
Competitive Bidding

Industry Expert Pool / Panel
Application / Selection
Scoring and Eval - RFP

Notification to Construct
Attachment Y
Industry Expert Terms Defined

- **Industry Expert Pool**: A group of industry experts recommended to the SPP BOD by the Oversight Committee.

- **Industry Expert Panel**: A 3-5 person group of industry experts selected from the pool by the Oversight Committee who are engaged to review and evaluate proposals submitted in response to the Transmission Owner Selection RFP. The SPP BOD may approve the use of multiple industry expert panels.
Industry Expert Pool Process

- Industry Expert Pool
  - Applications
  - Recommendations
  - Selection
Industry Expert Pool Process

- Industry Expert applicants must complete an application and submit it to SPP. The Industry Expert candidate shall have documented expertise on file with the SPP in one or more of the following areas:
  1. Electric transmission engineering design
  2. Electric transmission project management and construction
  3. Electric transmission operations
  4. Electric transmission rate design and analysis
  5. Electric transmission finance.

- The proposed application period for Industry Expert candidates for 2015 will be June 1 – September 1, 2014.
Industry Expert Pool Process

- SPP Staff plans to solicit industry expert candidates through:
  1. Press releases in trade publications
  2. Direct contact
  3. SPP website

- SPP Staff will provide initial review of candidate application and disclosure documents and bring to the Oversight Committee for review
  - Candidate affiliations with any SPP stakeholder or QRP will be flagged and addressed with the Oversight Committee

- Industry expert pool must be recommended to the SPP BOD by the Oversight Committee in a meeting prior to the approval of Competitive Upgrades
Applications to be a part of the Industry Expert Pool will be evaluated by SPP then reviewed with the Oversight Committee at the September meeting.

The Oversight Committee will present the recommended candidate pool to the Board of Directors at the October meeting.
Industry Expert Panel Process

- Selection
- Scoring and Evaluation
- Recommendation
Industry Expert Panel
Industry Expert Panel

1. Board of Directors Report
   • Respondent names will be excluded on this version of the report

2. Public Report
   • Respondent names and Confidential Information will be excluded from this version of the report
Timeline

Projects Approved / RFPs Issued

Select and Secure IE Panel

Panel Reviews and Makes Decision

Final Report submitted for BOD Action

January – February

IEP Panel Begins plus 60/90 days

Final Decision
Industry Expert Compensation Proposal

• **Goals**
  – Attract and maintain pool of experts for suitable for Order 1000 requirements
  – Ensure pool is available when needed; tariff requires
  – Compensate pool and panel members fairly
  – Standardize compensation for all members

• **Options Considered**
  – Retainer Fee
  – Monthly Retainer
  – Hourly Rate
  – Retainer Fee + Monthly Retainer + Hourly Rate
Two Part Proposal

1. IE Pool – Compensated for being in Pool
   - After Oversight Committee recommendation and BOD approval
   - One year consulting agreement (renewable)
   - Retainer Fee (payable after IEP training)
   - Monthly retainer for remainder of year

2. IE Panel – Compensated for Actual Work
   - Panel selected by Oversight Committee from pool
   - Hourly rate for actual work performed
   - Offset initial hours from monthly retainer (10 hours)
## Cost Example

### IE Pool Members

<table>
<thead>
<tr>
<th>Retainer Fee</th>
<th>Monthly Retainer</th>
<th>Total Retainer Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>$5,000</td>
<td>$1,250</td>
<td>$400,000</td>
</tr>
</tbody>
</table>

**Total Est Spend**: $100,000, $300,000

**Annual cost of IE Pool**: $400,000

### IE Panel Members

<table>
<thead>
<tr>
<th>Hourly Rate</th>
<th>Average Hours per Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>$200</td>
<td>25</td>
</tr>
</tbody>
</table>

**Total Est Spend**: $25,000

**Per Panel cost per Project (before hourly offset)**: $25,000

### Per Panel Cost per Project

<table>
<thead>
<tr>
<th>Est of Projects</th>
<th>Project</th>
<th>Est Project Costs</th>
<th>Hourly Offset Amount</th>
<th>Total Retainer Cost</th>
<th>Est Total Costs</th>
<th>Cost per Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$25,000</td>
<td>$25,000</td>
<td>$10,000</td>
<td>$400,000</td>
<td>$415,000</td>
<td>$415,000</td>
</tr>
<tr>
<td>5</td>
<td>$25,000</td>
<td>$125,000</td>
<td>$10,000</td>
<td>$400,000</td>
<td>$515,000</td>
<td>$103,000</td>
</tr>
<tr>
<td>10</td>
<td>$25,000</td>
<td>$250,000</td>
<td>$10,000</td>
<td>$400,000</td>
<td>$640,000</td>
<td>$64,000</td>
</tr>
<tr>
<td>25</td>
<td>$25,000</td>
<td>$625,000</td>
<td>$10,000</td>
<td>$400,000</td>
<td>$1,015,000</td>
<td>$40,600</td>
</tr>
<tr>
<td>40</td>
<td>$25,000</td>
<td>$1,000,000</td>
<td>$10,000</td>
<td>$400,000</td>
<td>$1,390,000</td>
<td>$34,750</td>
</tr>
</tbody>
</table>

Assumes using one IE Panel for all projects; Offset amount would increase if more than one panel is approved for use.
IEP AFFILIATION DEFINITION
Affiliations

• Discussed by the Oversight Committee in March 2014
  – “the existence of a relationship or situation whereby an Expert has past, present, or currently planned interests that either directly or indirectly (through a client, contractual, financial, organizational or other relationship) may relate to a QRP or SPP stakeholder.”
Stakeholder Input and Guidance

- Staff would like input on the following items:
  - Industry Expert Compensation?
  - Industry Expert Application?

- Please provide input by May 10
  - Ben Bright - bbright@spp.org
Integrated Marketplace Update

April 28, 2014

Bruce Rew, PE

BRew@spp.org  501.614.3214

Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future
• SPP’s Culture delivers as planned on March 1!!

• Big thanks to for everyone’s hard work to make it a success

• First month has been a great success
  – Systems meeting design targets for solution times
  – High Market Participant engagement
  – Settlements systems working with very few disputes
  – Cold weather and new wind peak experienced
1.4 Congestion by Flowgate

<table>
<thead>
<tr>
<th>Flowgate Name</th>
<th>Region</th>
<th>Flowgate Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>OSGCANBUSDEA</td>
<td>Texas Panhandle</td>
<td>Osage Switch-Canyon East (115) flio Bushland-Deaf Smith (230)</td>
</tr>
<tr>
<td>SHAXFRELKXFR</td>
<td>Texas Panhandle</td>
<td>Shamrock Xfmr (115/69) flio Elk City Xfmr (230/138)</td>
</tr>
<tr>
<td>SHAXFRTUOCOKU</td>
<td>Texas Panhandle</td>
<td>Shamrock Xfmr (115/69) flio Tuco-Oklahoma (345)</td>
</tr>
<tr>
<td>IATSTRSTJHAW*</td>
<td>Kansas City - Omaha Corridor</td>
<td>Iatan-Stranger Creek (345) flio St. Joe-Hawthorn (345)</td>
</tr>
<tr>
<td>NEORIVNEOBLC</td>
<td>SE Kansas</td>
<td>Neosho-Riverton (161) flio Neosho-Blackberry (345)</td>
</tr>
<tr>
<td>STR87STJHAW*</td>
<td>Kansas City - Omaha Corridor</td>
<td>Stranger Creek-87th Street (345) flio St. Joe-Hawthorn (345)</td>
</tr>
<tr>
<td>PENMUN87TCRA</td>
<td>Kansas City - Omaha Corridor</td>
<td>Pentagon-Mund (115) flio 87th Street-Craig (345)</td>
</tr>
<tr>
<td>EASXFREASSTJ</td>
<td>Kansas City - Omaha Corridor</td>
<td>Eastowne Xfmr (345/161) flio Eastowne-St. Joe (345)</td>
</tr>
<tr>
<td>ELKXFRTUOCOKU</td>
<td>Texas Panhandle</td>
<td>Elk City Xfmr (230/138) [CSWS] flio Tuco-Oklahoma (345)</td>
</tr>
<tr>
<td>IATSTRIATEAT</td>
<td>Kansas City - Omaha Corridor</td>
<td>Iatan-Stranger Creek (345) flio Iatan-Eastowne (345)</td>
</tr>
</tbody>
</table>

* RCF with MISO
Unit Commitment Improvement

1.9 Capacity Overage

Average RT Daily Capacity Overage:

*Overage = Economic Max - Load - NSI - (RegUp+SPIN+SUPP)
Day-Ahead and Real-Time Prices
HPILS Presentation to RSC

Lanny Nickell
April 28, 2014

Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future
What is HPILS?

• **High Priority Incremental Load Study**
• Out-of-cycle study governed by high priority study requirements in Attachment O of the SPP Tariff
• Directed by Board in April 2013
• Study scope developed and approved by HPILSTF, TWG, ESWG, and MOPC
• HPILSTF oversaw technical aspects of HPILS under reliability guidance of TWG and economic guidance of ESWG
Need for HPILS

- Needed to address expected incremental loads that had not previously been studied and was not in progress of being studied in integrated fashion

- Better option than using Attachment AQ process to studying incremental loads*
  - AQ studies are performed serially for each requested delivery point addition and provide incremental solutions that could ultimately result in a more costly system than if the additions were studied in aggregate
  - HPILS provides quicker and more holistic assessment to yield more cost effective solutions

*Note: needed Network Upgrades identified by SPP in both high priority studies and AQ studies are eligible for base plan funding
HPILS Scope

• Included restudy of 3 NTC-Cs suspended by Board in April 2013
  – Tuco – New Deal 345 kV
  – Tuco – Amoco – Hobbs 345 kV
  – Grassland – Wolfforth 230 kV

• Study to be conducted using 2015, 2018, and 2023 summer peak models
  – Included 50/50 and 90/10 load forecast probabilities

• Prescribed steady-state reliability analyses and economic assessments

• Expected that HPILS results would be utilized in 2015 ITP10 and ITPNT
HPILS ASSUMPTIONS - LOAD CHANGES
2023 Summer Total Load Change by Area

<table>
<thead>
<tr>
<th>Area</th>
<th>50-50</th>
<th>90-10</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECI</td>
<td>198</td>
<td>330</td>
</tr>
<tr>
<td>CLEC</td>
<td>0.3</td>
<td>502</td>
</tr>
<tr>
<td>AEPW</td>
<td>843</td>
<td>520</td>
</tr>
<tr>
<td>OKGE</td>
<td>393</td>
<td>524</td>
</tr>
<tr>
<td>WFEC</td>
<td>219</td>
<td>525</td>
</tr>
<tr>
<td>SPS</td>
<td>1246</td>
<td>526</td>
</tr>
<tr>
<td>MIDW</td>
<td>1079</td>
<td>531</td>
</tr>
<tr>
<td>SUNC</td>
<td>1027</td>
<td>534</td>
</tr>
<tr>
<td>WERE</td>
<td>105</td>
<td>536</td>
</tr>
<tr>
<td>KCPL</td>
<td>188</td>
<td>541</td>
</tr>
<tr>
<td>NPPD</td>
<td>657</td>
<td>640</td>
</tr>
<tr>
<td>OPPD</td>
<td>552</td>
<td>645</td>
</tr>
<tr>
<td></td>
<td>238</td>
<td></td>
</tr>
</tbody>
</table>
2013 High Priority Incremental Load Study:
90/10 Load Change

(January 2014)
- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- 500 kV

Value (MW)
- High: 220
- Low: 10

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ALL SPP TRANSMISSION EXPANSION PLANS ARE SUBJECT TO CHANGE.
HPILS ASSUMPTIONS - INCREMENTAL GENERATION
HPILS RESULTS
HPILS Highlights

- Report identifies projects needed to connect and to reliably serve incremental load
- Both Base Plan Upgrades and Direct Assigned Upgrades were identified
- Analyses identified portfolio of projects to cost effectively address reliability needs through 2023.
- Report recommends NTCs for upgrades needed within 3 years or for which financial commitment is required prior to when a commitment could be made for projects recommended out of the 2015 ITP assessments.
HPILS Recommendation

- Study recommends:
  - NTCs for $573M of new Base Plan Upgrades (Highway/Byway funded)
  - NTCs for approximately $85M of projects that are not Highway/Byway funded
  - Withdraw suspended NTC-Cs for Tuco – New Deal and Grassland – Wolfforth projects saving $114M
  - Replace the existing $258M Tuco-Amoco-Hobbs suspended NTC-C with Tuco-Yoakum-Hobbs as a better performing solution saving at least $20M
## HPILS Impact on STEP

<table>
<thead>
<tr>
<th>Project Category</th>
<th>Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>New NTC Base Plan Funded Projects</td>
<td>$573 M</td>
</tr>
<tr>
<td>Withdrawal of Suspended NTC-C for Tuco - New Deal</td>
<td>($57 M)</td>
</tr>
<tr>
<td>Withdrawal of Suspended NTC-C for Grassland – Wolfforth</td>
<td>($57 M)</td>
</tr>
<tr>
<td>Unsuspend NTC-C for Tuco-Amoco-Hobbs and Modify to Tuco-Yoakum-Hobbs ($238M-$258M)</td>
<td>($20 M)</td>
</tr>
<tr>
<td>HPILS Impact on STEP</td>
<td>$439 M</td>
</tr>
</tbody>
</table>
HPILS Projects Recieving NTCs/NTC-Cs
(April 2014)
<table>
<thead>
<tr>
<th>% Overload</th>
<th>2015</th>
<th>2018</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;100-105</td>
<td>21</td>
<td>37</td>
<td>162</td>
</tr>
<tr>
<td>&gt;105-110</td>
<td>12</td>
<td>18</td>
<td>141</td>
</tr>
<tr>
<td>&gt;110-120</td>
<td>14</td>
<td>49</td>
<td>245</td>
</tr>
<tr>
<td>&gt;120</td>
<td>10</td>
<td>23</td>
<td>125</td>
</tr>
<tr>
<td><strong>Subtotals</strong></td>
<td><strong>57</strong></td>
<td><strong>127</strong></td>
<td><strong>673</strong></td>
</tr>
</tbody>
</table>

*Some potential violations may have appeared in multiple years*
### Potential Voltage Limit Violations*

<table>
<thead>
<tr>
<th>Per Unit Voltage</th>
<th>2015</th>
<th>2018</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1.05</td>
<td>10</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>&gt;.9</td>
<td>4</td>
<td>23</td>
<td>36</td>
</tr>
<tr>
<td>&gt;.88-.9</td>
<td>48</td>
<td>33</td>
<td>161</td>
</tr>
<tr>
<td>.85-.88</td>
<td>47</td>
<td>29</td>
<td>98</td>
</tr>
<tr>
<td>&lt;.85</td>
<td>105</td>
<td>123</td>
<td>130</td>
</tr>
<tr>
<td><strong>Subtotals</strong></td>
<td><strong>214</strong></td>
<td><strong>209</strong></td>
<td><strong>428</strong></td>
</tr>
</tbody>
</table>

*Some potential violations may have appeared in multiple years*
# 2023 50/50 Incremental Reliability Portfolio APC Delta

## SPP Footprint Summary

**Adjusted Production Cost Delta (2023$, Millions) (Negative Values = Benefits, Positive Values = Costs)**

<table>
<thead>
<tr>
<th>Description</th>
<th>TAH</th>
<th>YH</th>
<th>TYH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case Comparison to Incremental Reliability Portfolio without West TX/NM Alternatives</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SPP TS Customers Benefits</td>
<td>$ (152.0)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SPP Other Benefits (SWPA)</td>
<td></td>
<td>$ 0.4</td>
<td></td>
</tr>
<tr>
<td>TOTAL (TS Customers + Other)</td>
<td>$ (151.6)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base Case Comparison to Reliability Portfolio with West TX/NM Alternatives</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SPP TS Customers Benefits</td>
<td>$ (163.6)</td>
<td>$ (137.5)</td>
<td>$ (167.6)</td>
</tr>
<tr>
<td>SPP Other Benefits (SWPA)</td>
<td>$ (0.3)</td>
<td>$ (0.1)</td>
<td>$ (0.3)</td>
</tr>
<tr>
<td>TOTAL (TS Customers + Other)</td>
<td>$ (164.0)</td>
<td>$ (137.5)</td>
<td>$ (167.9)</td>
</tr>
</tbody>
</table>

## Regional SPP TSC APC Delta Breakdown (2023$, Millions)

<table>
<thead>
<tr>
<th>Region</th>
<th>TAH</th>
<th>YH</th>
<th>TYH</th>
</tr>
</thead>
<tbody>
<tr>
<td>AR</td>
<td>$ (0.2)</td>
<td>$ 1.0</td>
<td>$ 0.1</td>
</tr>
<tr>
<td>KS</td>
<td>$ (9.4)</td>
<td>$ (9.6)</td>
<td>$ (9.1)</td>
</tr>
<tr>
<td>LA</td>
<td>$ -</td>
<td>$ (0.2)</td>
<td>$ -</td>
</tr>
<tr>
<td>MO</td>
<td>$ (2.1)</td>
<td>$ (2.4)</td>
<td>$ (1.6)</td>
</tr>
<tr>
<td>NE</td>
<td>$ 2.7</td>
<td>$ 0.7</td>
<td>$ 1.3</td>
</tr>
<tr>
<td>NM</td>
<td>$ (38.0)</td>
<td>$ (24.5)</td>
<td>$ (40.2)</td>
</tr>
<tr>
<td>OK</td>
<td>$ (0.8)</td>
<td>$ (5.6)</td>
<td>$ (2.3)</td>
</tr>
<tr>
<td>TX</td>
<td>$ (113.1)</td>
<td>$ (100.5)</td>
<td>$ (113.6)</td>
</tr>
</tbody>
</table>

1 Exclude SPP IPP entities
EVOLUTION OF TEXAS/NEW MEXICO SOLUTIONS
(I.E., CONSIDERATION OF ALTERNATIVES THAT RESULTED IN COST EFFECTIVE PLAN)
ATRR AND COST IMPACTS
ATRR Allocations from Incremental HPILS Upgrades

HPILS Cost Allocation Forecast by Zone 2015-2024
April 1, 2014

[Bar graph showing HPILS incremental ATRR by year ($ Millions/yr) for various entities from 2015 to 2024.]
Projected HPILS Incremental Rate Impacts

2014 HPILS Rate Impacts by Zone in 2019
1000 kWh per Month Retail Residential Consumer
April 1, 2014

Peak Year Rate Impact (2019$/month)

- AEP  
- CUS  
- EDE  
- GMO  
- GRDA  
- KCPL  
- LES  
- MIDW  
- MKEC  
- NPPD  
- OGE  
- OPPD  
- SEPC  
- SPS  
- WFEC  
- WR  
- SPP Wt Ave

- $0.51  
- $0.28  
- $0.25  
- $0.29  
- $0.02  
- $0.30  
- $0.29  
- $0.78  
- $11.58  
- $0.35  
- $0.44  
- $0.34  
- $0.17  
- $1.44  
- $0.58  
- $0.37  
- $0.70
Risks

- If HPILS projects are not approved by Board
  - Incremental load cannot be quickly served thus delaying benefits
  - Reliability risks are incurred if load is connected without transmission solutions
- If HPILS projects are approved by Board
  - Unnecessary transmission costs may be incurred if load does not materialize
Our Vision of the Future
Three Foundational Strategies

- Build a Robust Transmission System
- Develop Efficient Market Processes
- Create Member Value
Three Foundational Strategies

BUILD A
ROBUST
TRANSMISSION
SYSTEM
Initiatives

- Impact Assessments/Project Prioritization/PMO best practices
- Enhanced Combined Cycle
- Renewable Energy Credit Market
- Demand Response integration (check and adjust)
- Enhanced Outage Coordination
- Align Transmission Service process with Market
- Gas/Electric Coordination
- Improve Wind Integration
- IS Integration
CREATE MEMBER VALUE

Initiatives
• Reliability Excellence
• SPP Grid-level preparedness/CIP support
• Benchmarking and measurement
• Ratepayer value
• Strategic membership expansion
SPP Winter 2013-2014 Operations and Market Performance Agenda

• Regional Gas/Electric Coordination
• Winter 2013/2014 Preparations
• Operations Under EIS Market Operations
  – Cold Weather event January 6-8
  – Cold Weather event February 4-6
• Integrated Marketplace Operations
  – Implemented March 1
  – Cold Weather event March 1-3
• Lessons Learned from Winter events
Coordination Activities

• Gas Electric Coordination Task Force (GECTF)
  – SPP created the Gas Electric Coordination Task Force in 3rd quarter of 2012
  – The group meets monthly to discuss:
    ▪ Support and respond to gas and electric coordination issues impacting SPP
    ▪ Operational updates
    ▪ Training and planning activity updates
• SPP Operations preparation has included:
  – SPP conducted training at SPP led by Gas Industry experts, to address
    ▪ Gas-scheduling practices
    ▪ Timing of the gas industry scheduling day compared to electric industry scheduling day
    ▪ Specific pipeline and transmission line configurations in the SPP region
  – Increased awareness of gas pipeline regional impacts
• Participation in national gas/electric coordination group
Winter 2013/2014 Preparations

• Fall 2013 Preparation for Winter 2013/2014
  • SPP Operations personnel visited primary Gas Industry Operation facilities in the SPP Region. As a result of the visits, SPP initiated the development and implementation of the SPP Winter Preparedness Plan, including:
    • Joint calls with Gas and Electric Operations
    • Developed/implemented communication protocol
    • Exchanged operational information such as system maps, data points, etc...
    • Used approximately 4 times during 2013/2014 winter months
Winter 2013/2014 Preparations

- The SPP Winter Preparedness Plan improved gas and electric coordination in the SPP region significantly.
- SPP intends to expand to other gas industry operation entities prior to Winter 2015.
- Prepared for March 1\textsuperscript{st} Integrated Marketplace startup changes.
  - 16 Balancing Authorities responsible for Unit Commitment through February 2014.
  - SPP Consolidated Balancing Authority commenced on March 1 with Regional Unit Commitment performed by RTO.
EIS Market Operations Prior to March 1

- SPP single Reliability Coordinator with Regional Tariff
- Regional Reserve Sharing Group
- Real-Time Energy Imbalance Market only with 5 minute dispatch
- Region had 16 Balancing Authorities
  - Maintained compliance with NERC standards
  - Responsible for all day-ahead and real-time unit commitments
• SPP market set all time winter peak load during this event

• SPP Preparation
  – SPP canvassed each BA/GOP requesting information related to ability to carry sufficient capacity to meet BA obligations
  – Reviewed reserve levels; no changes made
  – Planned outages were canceled

• Transmission
  – No issue with interchange schedules
  – No reported issues with substation equipment performance
Impacts related to the Extreme Cold Weather event:

• Three of sixteen Balancing Authorities in the SPP region experienced freeze issues; two had major generator unit trips, one resulting in an EEA-2 for 3½ hours

• Fuel issues
  – Gas supply was restricted to pre-arranged nominations
  – Coal and minor ancillary support systems for six SPP generators resulted in derates or temporary forced outages

• SPP maintained required reserves with EEA activity for impacted BAs

• SPP worked with neighboring systems on coordination
• Experienced the second highest winter peak load level on February 5 and very high natural gas prices

• SPP Preparation
  – Correspondence with member GOPs related to awareness and preparation
  – Communication with gas pipeline companies regarding restrictions and potential mechanical service issues

• Transmission
  – No major forced transmission outages during the event
  – No issue with interchange schedules
  – No reported issues with substation equipment performance
• Integrated Marketplace started as planned on March 1
• Includes full Day-2 market systems
• Sixteen Balancing Authorities were consolidated into one simultaneously with the market startup
  – Centralized dispatch with real-time generation dispatch
  – Single reliability unit commitment
  – Overall SPP Integrated Marketplace systems performed well
• Experienced third highest all-time winter peak loading on March 3

• SPP Actions with Integrated Marketplace launch
  – Additional staff and resources were on-site and available to address concerns in preparation for the weather and in real time
  – Heightened awareness based on compliance with additional NERC Standards
  – Multiple studies/cases and preparations were made to confirm results of new processes
  – Limited testing of unit commitment process during market trials
  – Experience was rapidly gained during first three days of the market
SPP Winter Peak Loads
• **SPP Preparation**
  – SPP ran a conservative operation; long on capacity intending to compensate for unusually high outages, no-starts, gas restrictions, and transmission issues
  – Correspondence with member GOPs related to awareness and preparation
  – Communication with gas pipeline companies regarding restrictions and potential mechanical service issues

• **Transmission**
  – No major forced transmission outages during the event
  – No issue with interchange schedules
  – No reported issues with substation equipment performance
Cold event of March 1 – 3, 2014 (cont’d)

Actions/Information for the Extreme Cold Weather event:

• Generation outages or inability to start units were more transparent based on the Consolidated BA

• Fuel issues
  – Gas supplies were more constrained than previous events based on lower temperatures forcing SPP resources set to depend on coal supplies, and gas needs to start oil burners
  – Wind forecasting was challenging providing greater uncertainty

• Planned outages introducing unnecessary BES risk were delayed and SPP maintained required generation reserves

• SPP had good communications with neighboring systems
Preliminary Lessons Learned/Post-Event Analysis

• SPP continues to review load forecasting processes
  – Increasing accuracy
  – Reviewing additional weather vendors adding to our data inputs

• Good coordination with neighboring systems; increased the limit on an interface in coordination with an adjacent BA to assist with their obligations

• Continued discussions in the Gas Electric Coordination Task Force; follow up conference call scheduled with major gas supplier in SPP’s region to discuss lessons learned
Preliminary Lessons Learned/Post-Event Analysis (cont’d)

- Oil-Fueled gas generators presenting challenges as natural gas needed to start was limited
- Some intermittent (wind) resources included as part of generation mix, which were unavailable due to low wind speeds and low temperatures
- Cold weather with Integrated Marketplace operating was valuable for gaining experience and quick learning
Novation of NTC 200162—Thistle Metering

Information Provided by Mid-Kansas pursuant to SPP Business Practice 7070

April 1, 2014

3.1.1

The SPP Board shall approve Novations conditioned only on the four specific criteria already identified in the SPP Tariff. Those criteria are:

a. The Entity’s having obtained all state regulatory authority necessary to construct, own and operate transmission facilities within the state(s) where the project is located.

   See attached file “2007 Adoption Notice KCC Docket No. 06-MKEE-524-ACQ”

b. The Entity’s meeting the creditworthiness requirements of the Transmission Provider

   See attached files “14-MKEE-253-DRC Order Affirming Mid-Kansas’ Election to Deregulate” and “SPP Letters of Credit” current letters of credit pledged to the Southwest Power Pool. Mid-Kansas Electric Company, LLC (Mid-Kansas) filed its deregulation notice with the Kansas Corporation Commission and the Commission entered its order affirming January 7, 2014. This order allows Mid-Kansas members to set generation rates without KCC jurisdiction, regulation, supervision and control.

   Mid-Kansas is a Transmission Owner and customer that participates in the integrated marketplace as a single consolidated market participant with Sunflower Electric Power Corporation. Currently, the single market participant (representing both Mid-Kansas and Sunflower) has secured credit of $7 million and unsecured credit of $1.5 million, which demonstrates the entity’s ability to meet the creditworthy requirements of this section.

c. The Entity’s having signed, or capability and willingness to sign, the SPP Membership Agreement as a Transmission Owner upon the selection of its proposal to construct and own the project

   See attached file “Mid-Kansas Membership Agreement with SPP (2007)”

d. The Entity’s meeting such other technical, financial and managerial qualifications as are specified in the Transmission Provider’s business practices

   “Mid-Kansas has the necessary capability to construct, operate and manage transmission assets in the state of Kansas. As a certified Transmission Owning member of the Southwest Power Pool, Mid-Kansas has provided transmission services and maintenance to its transmission assets since 2007. Mid-Kansas continues to demonstrate
capability to construct, operate, maintain and manage transmission assets by being the Designated Transmission Owner for 10 separate NTCs representing multiple component transmission projects since 2008.”

Noman Williams
Vice President Transmission Policy
Mid-Kansas Electric Company, LLC

3.1.2

a. The identification of the project proposed to be novated

The Thistle Substation Metering equipment for the Project pursuant to SPP-NTC-200162 (the original NTC was issued by SPP to Mid-Kansas for the Project (SPP-NTC-20102) and then novated to ITC in the 2011 Novation Agreement to ITCGP. SPP subsequently issued SPP-NTC-200162 for the Project). Specifically, ITC is requesting to novate the equipment at Thistle Substation associated with the metering of the four interconnections to Prairie Wind, the owner of the four transmission lines. The metering equipment includes twelve (12) current transformers, twelve (12) potential transformers, two metering panels, RTU (remote terminal unit) and telecommunications equipment required to provide real-time data located inside ITC’s control building, and associated equipment such as strands, cable wire and telecommunications equipment (collectively, the “Metering Equipment”). The estimated project capital cost is $1.45 million.

b. The identification of the Transmission Owner making the novation

ITC Great Plains, LLC

c. The identification of the entity receiving the novation

Mid-Kansas Electric Company, LLC

d. The identification and status of pertinent matters before FERC or state commissions related to the project including the novation (this shall include the status of any certification proceeding, approvals, etc.)

All applications before the Federal Energy Regulatory Commission and the Kansas Corporation Commission have been granted. ITC and Mid-Kansas entered into a Stipulation and Agreement and a Second Stipulation and Agreement filed with and approved by the Kansas Corporation Commission in Docket Nos. 08-ITCE-936-COC, 08-ITC-937-COC, 08-ITCE-938-COC and 08-PWTE-1022-COC. Likewise, ITC Great Plains has been granted approval of a siting application under Docket No. 11-ITCE-644-MIS and issued a certificate for the instant project under Docket No. 12-ITCE-222-COC.
<table>
<thead>
<tr>
<th></th>
<th>ITC Great Plains</th>
<th>Mid-Kansas Electric Company</th>
</tr>
</thead>
<tbody>
<tr>
<td>i. Actual or Projected debt/equity ratios:</td>
<td>40/60</td>
<td>90/10</td>
</tr>
<tr>
<td>ii. Actual or Projected cost of capital:</td>
<td>7.97%</td>
<td>7.52%</td>
</tr>
<tr>
<td>iii. Actual or Projected return on equity or applicable measure:</td>
<td>12.16%</td>
<td>Applicable Measure: MKEC is allowed recovery based upon a 1.53 MFI</td>
</tr>
<tr>
<td>iv. Actual or Proposed type and amount of construction financing costs, i.e. Interest Rate, AFUDC or CWIP:</td>
<td>CWIP in rate base. Assuming costs are incurred 6 month before project is placed in service, the estimated CWIP in rate base cost is $75,000.</td>
<td>AFUDC: Assuming costs are incurred for 6 months before project is in service, the estimated cost is $60,000</td>
</tr>
</tbody>
</table>
v. S&P and Moody’s credit rating: | S&P: A- Corporate | Moody’s: Baa1 |
|vi. Estimated Net Plant Carrying Charge (NPCC) or ATRR for the life of the project after it is placed in-service: | The estimated ATRR impact assuming all V-Plan plant has been in-service for 13 months is $170,000. | The estimated ATRR impact assuming all plant has been in-service for 13 months is $150,000 |

vii. An explanation describing the difference in ATRR:  
*The difference in the ATRR is primarily a function of the variation of the two formula rate constructs and the inputs to the formula rates, including G&A, O&M, and ROE.*  

f. A comparative analysis as to whether novation changes the ROE, weighted cost of capital, and overall costs for the project, whether any performance guarantees between the parties exists and whether any consideration between the parties is included in the ATRR  
*No material changes.*  
g. Whether the Novating Party will own, operate and maintain the facility; and Detail on what process was used in selecting the potential DTO  
*Mid-Kansas will own, operate and maintain the identified metering equipment. Mid-Kansas was selected as the potential DTO because the location of the assets resides within the service territory of their retail members.*
Mid-Kansas Membership Agreement

with SPP (2007)
IN WITNESS WHEREOF, Member and SPP have caused their duly authorized representatives to execute this Agreement on their respective behalves.

**MEMBER:**

Mid-Kansas Electric Company, LLC

Name of Member

Transmission Owner

Type of Entity (Transmission Owner or Non-Transmission Owner)

L. Earl Watkins, Jr.

Name of Authorized Representative

President and CEO

Title of Authorized Representative

Signature of Authorized Representative

March 19, 2007

Date of Execution

**SOUTHWEST POWER POOL, INC.:**

Nick Brown

Name of Authorized Representative

President & CEO

Title of Authorized Representative

Signature of Authorized Representative

3-25-2007

Date of Execution

Issued by: L. Patrick Bourne, Manager
Transmission and Regulatory Policy

Issued on: August 2, 2004


Effective: May 1, 2004
14-MKEE-253-DRC Order Affirming
Mid-Kansas’ Election to Deregulate
THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Before Commissioners:  Mark Sievers, Chairman
                        Thomas E. Wright
                        Shari Feist Albrecht

In the Matter of the Election of Mid-Kansas Electric Company, LLC to Deregulate Pursuant to K.S.A. 66-104d(c)(4).

Docket No. 14-MKEE-253-DRC

ORDER AFFIRMING MID-KANSAS ELECTRIC COMPANY, LLC’S ELECTION TO DEREGULATE

This matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration and determination. Having reviewed the pleadings and record, the Commission finds and concludes as follows:

1. On November 22, 2013, Mid-Kansas Electric Company, LLC (Mid-Kansas) filed its Deregulation Notice with the Commission that the Members of Mid-Kansas have approved by the affirmative vote of not less than a majority of the Members to exempt Mid-Kansas from the jurisdiction, regulation, supervision, and control of the Commission pursuant to K.S.A. 66-104d.1

2. On November 27, 2013, Mid-Kansas filed its Certification of Election Results (Certification).2 In the Certification, Mid-Kansas’s Secretary stated that the Board of Directors resolved to hold a Special Meeting concerning the issue of deregulation on August 16, 2013, the Members were given notice of the Special Meeting on August 19, 2013, and the Special Meeting was held on September 20, 2013.3 At the Special Meeting, the Members considered the proposition to exempt Mid-Kansas from the jurisdiction, regulation, supervision, and control

---

2 Certification of Election Results, (November 27, 2013).
3 Id.
of the Commission.\textsuperscript{4} Also, the Members have received the ballots pertaining to the question of whether or not Mid-Kansas should exempt itself from the Commission’s regulations, rules, and procedures.\textsuperscript{5} Since receiving the ballots, the Members by an affirmative vote of not less than a majority approved the proposition for deregulation.\textsuperscript{6}

3. K.S.A. 66-104d(b) permits an electric cooperative that would otherwise be under the Commission’s jurisdiction to elect to be exempt from the jurisdiction, regulation, supervision, and control of the Commission, provided that the directives contained in subsection (c) of K.S.A. 66-104d are followed.\textsuperscript{7} Subsection (c) requires the board of trustees to call a meeting\textsuperscript{8} which shall be held not less than 21 nor more than 45 days after notice of the meeting is given.\textsuperscript{9} If the majority of the members voting do indeed vote for deregulation, then the cooperative shall notify the Commission of the election in writing within 10 days.\textsuperscript{10} K.S.A. 66-104d(f) enumerates circumstances under which an electric cooperative, notwithstanding its election to deregulate, remains subject to the continuing jurisdiction of the Commission.\textsuperscript{11} A deregulated cooperative may also be subject to Commission jurisdiction under K.S.A. 66-104d(g) and (j).\textsuperscript{12}

4. The Commission finds that notice of the Special Meeting was properly given to the Members, the Special Meeting was held within 21 days and 45 days after the notice, a majority of the Members voted for deregulation, and Mid-Kansas provided notice of the

\textsuperscript{4} Id.
\textsuperscript{5} Id.
\textsuperscript{6} Id.
\textsuperscript{7} K.S.A. 66-104d(b).
\textsuperscript{8} K.S.A. 66-104d(c)(1).
\textsuperscript{9} K.S.A. 66-104d(c)(2).
\textsuperscript{10} K.S.A. 66-104d(c)(4).
\textsuperscript{11} K.S.A. 66-104d(f).
\textsuperscript{12} K.S.A. 66-104d(g) and (j).
election to the Commission within 10 days of the vote. Thus, the Commission affirms Mid-Kansas's Deregulation Notice.

**IT IS, THEREFORE, BY THE COMMISSION ORDERED THAT:**

A. The Commission affirms Mid-Kansas is exempt from the jurisdiction, regulation, supervision, and control of the Commission, subject to the Commission's continuing jurisdiction under K.S.A. 66-104d(f) and any Commission jurisdiction which may arise under K.S.A. 66-104d(g) and (j).

B. The parties have fifteen days, plus three days if service of this order is by mail, from the date this Order was served in which to petition the Commission for reconsideration.\(^{13}\)

C. The Commission retains jurisdiction over the subject matter and parties for the purpose of entering such further orders as it deems necessary.

**BY THE COMMISSION IT IS SO ORDERED.**

Sievers, Chairman; Wright, Commissioner; Albrecht, Commissioner.

**Dated:** JAN 07 2014

\[\text{ORDER MAILED JAN 08 2014}\]

Kim Christiansen
Executive Director

MLS

\(^{13}\) K.S.A. 66-118b; K.S.A. 2013 Supp. 77-529(a)(1).
IN RE: DOCKET NO. 14-MKEE-253-DRC

DATE JAN 07 2014

PLEASE FORWARD THE ATTACHED DOCUMENT (S) ISSUED IN THE ABOVE-REFERENCED DOCKET TO THE FOLLOWING:

<table>
<thead>
<tr>
<th>NAME AND ADDRESS</th>
<th>NO. CERT. COPIES</th>
<th>NO. PLAIN COPIES</th>
</tr>
</thead>
<tbody>
<tr>
<td>RAY BERGMEIER, LITIGATION COUNSEL KANSAS CORPORATION COMMISSION 1500 SW ARROWHEAD RD TOPEKA, KS 66604-4027 <em><strong>Hand Delivered</strong></em></td>
<td></td>
<td></td>
</tr>
<tr>
<td>STUART S. LOWRY, PRESIDENT AND CEO MID-KANSAS ELECTRIC COMPANY, LLC 301 W 13TH ST PO BOX 980 HAYS, KS 67601</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

ORDER MAILED JAN 08 2014

The Docket Room hereby certified that on this day of __________, 20__, it caused a true and correct copy of the attached ORDER to be deposited in the United States Mail, postage prepaid, and addressed to the above persons.
SPP Letters of Credit
Irrevocable Standby Letter of Credit No. KS053-R-5101-003
Issued: July 1, 2010
Expires at our counter (unless evergreen): June 30, 2011

Ladies and Gentlemen:

We do hereby issue this Irrevocable Non-Transferable Standby Letter of Credit No. KS053-R-5101-003 by order of, for the account of and on behalf of Sunflower Electric Power Corporation ("Account Party") and in favor of Southwest Power Pool ("Beneficiary" or "SPP") ("Letter of Credit").

This Letter of Credit is irrevocable and is issued, presentable and payable and we guaranty to the drawers, endorsers and bona fide holders of this Letter of Credit that drafts under and in compliance with the terms of this Letter of Credit will be honored on presentation and surrender of certain documents pursuant to the terms of this Letter of Credit.

This Letter of Credit is available in one or more drafts and may be drawn hereunder for the account of Beneficiary up to an aggregate amount not exceeding $3,200,000.00 (United States Dollars Three Million Two Hundred Thousand and 00/100).

This Letter of Credit is drawn against by presentation to us at our office located at the following address:

National Rural Utilities Cooperative Finance Corporation
2201 Cooperative Way
Herndon, VA 20171

of a drawing certificate: (i) signed by an officer or authorized agent of the Beneficiary; (ii) dated the date of presentation; and (iii) containing one (1) of the following statements:

1. "The undersigned hereby certifies to National Rural Utilities Cooperative Finance Corporation ("Issuer"), with reference to its Irrevocable Non-Transferable Standby Letter of Credit No. KS053-R-5101-003, dated July 1, 2010, issued on behalf of Sunflower Electric Power Corporation ("Account Party") and in favor of Southwest Power Pool, Inc. ("Beneficiary") that said Account Party has failed to make a payment in accordance with the terms and provisions of one or more of the following, as applicable: SPP's Tariff; as may be amended and supplemented from time to time, together with all replacements and substitutes (the "Tariff"), any and all agreements entered into by Account Party under, pursuant to, or in connection with the Tariff and any and all agreements to which Account Party and SPP are parties, as such agreements may be amended and supplemented from...
time to time, whether now or hereafter executed, and any replacements or substitutions thereof, (collectively, the “Agreements”). The Beneficiary hereby draws upon the Letter of Credit in an amount equal to $______________ (United States Dollars ______________ and 00/100)”; or

2. “As of the close of business on _________________, 20__ (fill in date which is less than eighty-seven (87) days before the expiration date of the Letter of Credit), Account Party has failed to renew, replace or amend the Letter of Credit in a manner acceptable to Beneficiary”; or

3. “As of the close of business on _________________, 20__ (fill in date which is more than three (3) Business Days after the Beneficiary has requested that Account Party replace the Letter of Credit because the Issuer’s corporate debt is rated less than “A-” by S&P, “A3” by Moody’s, “A-” by Duff & Phelps, or “A-” by Fitch), Account Party has failed to replace the Letter of Credit in a manner acceptable to Beneficiary.”

Beneficiary shall have the right, in the event of a draw pursuant to subparagraph (2) or (3) of the immediately preceding paragraph, to draw down the entire face value of the Letter of Credit.

If presentation of any drawing certificate is made on a business day and such presentations made on or before 10:00 a.m. Eastern Time, Issuer shall satisfy such drawing request on the same business day. If the drawing certificate is received after 10:00 a.m. Eastern Time, Issuer will satisfy such drawing request on the next business day.

It is a condition of this Letter of Credit that it will be automatically extended without amendment for one year from the expiration date hereof, or any future expiration date, unless 90 days prior to any expiration date we notify you by registered mail that we elect not to consider this Letter of Credit renewed for any such period.

This Letter of Credit may be terminated upon Beneficiary’s receipt of full payment from the Account Party and Issuer’s receipt of a written release from the Beneficiary releasing the Issuer from its obligations under this Letter of Credit.

Disbursements under the Letter of Credit shall be in accordance with the following terms and conditions:

1. The amount, which may be drawn by the Beneficiary under this Letter of Credit, shall be automatically reduced by the amount of any drawings hereunder.

2. All commissions and charges will be borne by the Account Party.

3. This Letter of Credit may not be transferred or assigned by the Issuer.
4. This Letter of Credit is irrevocable.

5. This Letter of Credit may not be amended, changed or modified without the express written consent of the Beneficiary and the Issuer.

6. No Beneficiary shall be deemed to have waived any rights under this Letter of Credit, unless a Beneficiary or an authorized agent of a Beneficiary shall have signed a written waiver. No such waiver, unless expressly so stated therein, shall be effective as to any transaction that occurs subsequent to the date of the waiver, nor as to any continuance of a breach after the waiver.

7. This Letter of Credit shall be governed by the International Standby Practices Publication No. 590 of the International Chamber of Commerce, including any amendments, modifications or revisions thereof (the “ISP”), except to the extent that terms thereof are inconsistent with the provisions of the ISP, in which case the terms of the Letter of Credit shall govern. This Letter of Credit shall be governed by the internal laws of the state of New York to the extent that the terms of the ISP are not applicable; provided that, in the event of any conflict between the ISP and such New York laws, the ISP shall control.

National Rural Utilities Cooperative Finance Corporation

By: Nazir Kostom
Assistant Secretary-Treasurer
FIRST AMENDMENT TO IRREVOCABLE STANDBY LETTER OF CREDIT

Issuer: NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION
Beneficiary: SOUTHWEST POWER POOL
Account Party: SUNFLOWER ELECTRIC POWER CORPORATION
Letter Of Credit: No. KS053-R-5101-003 issued as of July 1, 2010
Original Principal Amount: Three Million Two Hundred Thousand and 00/100 Dollars (US$3,200,000.00)

In consideration of the mutual promises made hereunder and other valuable consideration, the receipt and sufficiency of which is hereby acknowledged the Beneficiary and Issuer have agreed to amend the Letter of Credit as set forth herein:

1. The third full paragraph on the first page of the Letter of Credit is hereby deleted and shall hereafter state as follows:

   This Letter of Credit is available in one or more drafts and may be drawn hereunder for the account of Beneficiary up to an aggregate amount not exceeding $2,000,000.00 (United States Dollars Two Million and 00/100).

2. The Issuer and Beneficiary agree that the Letter of Credit has been extended according to its terms and the current expiration date is June 30, 2013, which date may be further extended according to the terms and at the times set forth in the Letter of Credit.

3. Except as amended herein, the terms and conditions of Letter of Credit remain in full force and effect.

4. This Amendment has been duly authorized, executed and delivered by Issuer and Beneficiary, and the Letter of Credit, as amended hereby, constitutes the legal, valid and binding obligation of each party enforceable in accordance with its terms.

IN WITNESS WHEREOF, duly authorized representatives of the parties have hereunto set their hands as of the Effective Date set forth below.

ISSUER:

By: Katrice Simpson, Assistant Secretary-Treasurer

Beneficiary:

By: [Signature]

Title: [Name]

Effective Date: July 1, 2012

CFC LTROE
KS053-R-5102 (VAUGHAF)
170540-2
As of the Effective Date set forth above, the Account Party hereby requests that this FIRST AMENDMENT TO IRREVOCABLE STANDBY LETTER OF CREDIT be executed by the Issuer and Beneficiary, and agrees to be bound by the terms hereof.

ACCOUNT PARTY:

By: [Signature]

Title: CFO
2007 Adoption Notice

KCC Docket No. 06-MKEE-524-ACQ
In the Matter of the Joint Application of Aquila, Inc., d/b/a Aquila Networks - WPK ("WPK") and Mid-Kansas Electric Company, LLC ("MKEC"), Joint Applicants, for an Order Approving the Transfer to MKEC of WPK's Certificates of Convenience and Franchises with Respect to All of WPK's Kansas Electric Business, Including Its Generation, Transmission and Local Distribution Facilities Located in the State of Kansas, and for Other Related Relief.

Thomas K. Hestermann, Mgr. Reg. Relations
SEP Corporation
dba Sunflower Electric Power Corporation
301 West 13th
P.O. Box 1020
Hays KS  67601

Dear Mr. Hestermann:

Enclosed herewith is one copy of the above-captioned filing, which was approved by this Commission on March 29, 2007.

Sincerely,

Donald A. Low
Director

GDD:ram

Enc.
ADOPTION NOTICE

Effective April 1, 2007, Mid-Kansas Electric Company, LLC ("MKEC") will acquire all of the Aquila, Inc. d/b/a Aquila Networks - WPK ("WPK") generation, transmission, and local distribution facilities located in Kansas and WPK will also transfer its certificate of convenience and franchises to MKEC pursuant to the Commission's Order Adopting Stipulation and Agreement in Docket No. 06-MKEE-524-ACQ dated February 23, 2007.

Pursuant to the Stipulation and Agreement as adopted by the Commission, Mid-Kansas Electric Company, LLC hereby adopts, ratifies and makes its own in every respect, as if the same had been originally filed by it, all tariffs, schedules, and rules and regulations of Aquila, Inc. d/b/a Aquila Networks - WPK filed with and approved by the Commission before March 31, 2007.
April 3, 2014

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

Dear Mr. Jones,

Subject: AEP Oklahoma Transmission Company Due Diligence Review

This letter presents the results of the due diligence review of AEP Oklahoma Transmission Company, Inc. (“OK Transco”) conducted by Donald J. Morrow of Quanta Technology, LLC (“Quanta Technology”).

The purpose of the due diligence review was to provide insights to Southwest Power Pool, Inc. (“SPP”) in evaluating the ability of OK Transco to be assigned Project ID 30346 which is part of SPP’s Notification to Construct (“NTC”) SPP-NTC-200167. Project ID 30346 is also referred to as Network Upgrade ID 50438 which is an upgrade of the Cornville 138 kV bus to breaker-and-a-half configuration in preparation for the 138 kV line conversion to Lindsay Water (Flood) Substation for regional reliability. The assignment includes the line re-terminations required for the existing OK Transco Lindsay Water Flood to Cornville 138 kV transmission line at the Cornville Substation. SPP had originally issued the NTC to American Electric Power (“AEP”) on April 9, 2012.

This review was performed to satisfy the requirements established by SPP’s Business Practice 7070 regarding assignment of NTCs to an affiliate.

**Due Diligence Process**

Quanta Technology followed the process specified in Work Order 3 under the Master Services Agreement dated August 31, 2012, between Quanta Technology and SPP. Since the due diligence review process for assignments is the same as that for novations, Quanta Technology followed the process used for the Transource Missouri, LLC due diligence review completed in October 2014. A description of the process is included as Attachment A.

**Document Review**

SPP provided 9 documents to Quanta Technology at the start of the review. We also submitted two data requests to OK Transco. OK Transco provided 19 documents in response. The data requests are shown in Attachment B.
Table 1 lists the documents reviewed. Documents 1 through 9 were provided by SPP, documents 10 through 28 were provided by OK Transco.

**Table 1: Documents Reviewed**

<table>
<thead>
<tr>
<th>Document No.</th>
<th>Date Received</th>
<th>Document Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>3/11/2014</td>
<td>SPP-NTC-200167 dated April 9, 2012 Attachment 1</td>
</tr>
<tr>
<td>3</td>
<td>3/11/2014</td>
<td>FERC Docket No. ER10-355-000 Attachment 3</td>
</tr>
<tr>
<td>7</td>
<td>3/11/2014</td>
<td>Attachment 8 to Assignment request showing signatures of AEP and SPP management</td>
</tr>
<tr>
<td>8</td>
<td>3/11/2014</td>
<td>Worksheet F - Oklahoma Transmission Company - Calculation of &quot;projected&quot; ARR for SPP Base Plan Upgrade Projects dated 2/28/14 Attachment 9</td>
</tr>
<tr>
<td>10</td>
<td>3/25/2014</td>
<td>Request for SPP Board of Directors approval of Assignment of a transmission Project pursuant to SPP OATT Attachment O and BP 7070</td>
</tr>
<tr>
<td>12</td>
<td>3/25/2014</td>
<td>In the Matter of the Application of AEP Oklahoma Transmission Company, Inc. For a Certificate of Authority Permitting it to Issue Secured Notes, Senior Unsecured Notes and/or Unsecured Promissory Notes in a Principal Amount of $200,000,000</td>
</tr>
<tr>
<td>14</td>
<td>3/25/2014</td>
<td>Attachment 9.xlsx providing calculation and comparison of ATRR</td>
</tr>
<tr>
<td>16</td>
<td>3/25/2014</td>
<td>Request for SPP Board of Directors approval of Assignment of a transmission Project pursuant to SPP OATT Attachment O and BP 7070</td>
</tr>
<tr>
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<tr>
<td>------------</td>
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</tr>
<tr>
<td>3/25/2014</td>
<td>Attachment 11.xlsx – The current SCERT for the Cornville Substation voltage upgrade &amp; ROW.</td>
<td></td>
</tr>
<tr>
<td>3/25/2014</td>
<td>AEP Supplemental Safety Terms &amp; Conditions</td>
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<tr>
<td>3/25/2014</td>
<td>Example Safety Directive</td>
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<td>Historical Safety Statistics</td>
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<td>3/26/2014</td>
<td>AEP Operational Structure</td>
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<tr>
<td>3/28/2014</td>
<td>ATRR Quanta Data Request #2 Response.xls</td>
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<tr>
<td>3/29/2014</td>
<td>ATRR Quanta Data Request #2 Response_revised version.xls</td>
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**Observations from Document Review**

The documents provided by OK Transco show that -

- OK Transco is legally incorporated in the State of Oklahoma (Document No. 5)
- OK Transco has an approved FERC Section 205 filing (Document Nos. 3 and 4)
- OK Transco has been authorized by Oklahoma Corporation Commission to issue debt up to $200M (Document No. 12)
- OK Transco started operations in 2010 and has invested approximately $242M in transmission assets within SPP since that time (Document No. 16).
- OK Transco utilizes the same AEP Service Company employees that PSO and the other AEP Operating Companies to plan, design, construction, operate and maintain its facilities. (Document No. 16)
- OK Transco has adopted AEP’s safety program which will be used for constructing, operating and maintaining the project. (Document Nos. 19, 20, 21, 22, 23, 24 and 25).
- The 138kV line upgrade will use single circuit, steel structures with 1272 ACSR and designed with a “heavy” NESC loading zone assumption (Document No. 17).
- The Cornville 138kV breaker-and-a-half scheme will be built on property adjacent to the Cornville substation (Document No. 18).
Financial Review

Note: Quanta Technology is a technology consulting firm whose expertise is in engineering, operations, maintenance and management of electric transmission and distribution facilities. We do not represent ourselves as experts in accounting, finance or tax law. Therefore, this review should not be construed as an opinion on the appropriateness of any tax benefits claimed, consistency of OK Transco’s accounting practices with GAAP or the appropriateness of the cost of short-term and long-term debt used by OK Transco in the analysis. We have limited our review to the calculation of ATRR and have focused on the formulas used in the calculation, the completeness of the data inputs, consistency of that data with publicly available records (e.g., FERC authorized ROE), and the differences between the organization receiving the NTC and the organization receiving the assignment of the NTC.

Quanta Technology’s financial review focused primarily on the spreadsheet titled “ATRR Quanta Data Request #2 Response_revised version.xls” (Document No. 28).

FERC has authorized a base Return on Equity (“ROE”) of 10.7% for OK Transco, which is the same as the AEP Operating Companies, including Public Service of Oklahoma (“PSO”). FERC has also granted a 50 point basis adder for RTO membership, again applicable to both OK Transco and PSO. The total ROE is, therefore, the same ROE of 11.2%.

Due to differences in the cost of long-term debt, the Weighted Average Cost of Capital of OK Transco is 7.98% vs 8.35% for PSO.

Table 2 compares the financial assumptions between OK Transco and PSO.

<table>
<thead>
<tr>
<th>Item</th>
<th>OK Transco</th>
<th>PSO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base ROE</td>
<td>10.7%</td>
<td>10.7%</td>
</tr>
<tr>
<td>RTO Membership</td>
<td>50 basis points</td>
<td>50 basis points</td>
</tr>
<tr>
<td>WACC</td>
<td>7.98%</td>
<td>8.35%</td>
</tr>
<tr>
<td>AFUDC or CWIP in Rate Base</td>
<td>AFUDC</td>
<td>AFUDC</td>
</tr>
</tbody>
</table>

OK Transco indicated that the O&M cost estimate, A&G cost estimate and tax estimates are the same as if PSO retained the NTC. They also indicated that OK Transco will use AFUDC treatment and indicated that AFUDC would have been used by PSO if it had retained the NTC.

Quanta Technology noted that losses were not included in the O&M cost estimate.

Cost to Customers
Quanta Technology used the information provided by OK Transco to evaluate the impact on the cost to SPP members for the Projects. Quanta Technology spot checked formulas used in the
spreadsheet and found one error of minor impact in the original spreadsheet provided in response to data request #2. This finding was discussed with OK Transmission and a revision was provided by OK Transco with a correction.

The data provided by OK Transco shows that the annual cost to SPP customers is expected to be less than if PSO retained the Projects. The sole reason for this decrease is that WACC is lower for OK Transco than for PSO.

To calculate the cost (savings) to SPP customers, Quanta Technology looked at the difference in the annual cost and calculated a sum of year-of-occurrence total savings of $830,127 over a 40 year period.

Quanta Technology also discounted the year-of-occurrence savings by the standard 8% SPP discount rate (i.e., the average discount rate used by SPP’s members). If the costs were discounted back to 2014, we calculated the discounted savings as $347,053 for SPP’s members.

**OK Transco Interview**
An interview of the OK Transco executive team was conducted via conference call on March 28, 2014. SPP participated in the call as an observer. Table 3 lists the participants.

**Table 3: Conference Call Participants**

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
<th>Title</th>
</tr>
</thead>
<tbody>
<tr>
<td>Donald Morrow</td>
<td>Quanta Technology</td>
<td>Partner &amp; SVP Corporate Strategy</td>
</tr>
<tr>
<td>Dan Jones</td>
<td>SPP</td>
<td>Lead Regulatory Engineer</td>
</tr>
<tr>
<td>Terri Gallup</td>
<td>AEP Transmission Company &amp; part of AEP Service Company</td>
<td>Manager of Transmission Asset Strategy</td>
</tr>
<tr>
<td>Adam Hickman</td>
<td>AEP Service Company</td>
<td>Business Development</td>
</tr>
<tr>
<td>Nancy Roby</td>
<td>AEP Transmission Company &amp; AEP Service Company</td>
<td>Business Development</td>
</tr>
<tr>
<td>Raja Sundararajan</td>
<td>AEP Service Company &amp; AEP Transmission Company</td>
<td>VP Asset Strategy</td>
</tr>
</tbody>
</table>

A summary of the interview follows. A copy of Quanta Technology’s notes from the interview is provided as Attachment C.

**Financing and Cost to Customers**
OK Transco indicated that was no FERC 203 filing required since they did not take over existing assets. Ok Transco just develops new assets so only a FERC 205 filing was made.

OK Transco indicated that interest rates were lower than for PSO since the risk profile is more easily understood by debt issuers than the risk profile is for vertically integrated utilities which have exposure to weather variations in revenue.
OK Transco indicated that approval by the Corporation Commission of Oklahoma to issue secured notes was the key authorization needed to own transmission assets in the state.

OK Transco verified that AFUDC treatment would be used by OK Transco.

**Staffing Levels**
OK Transco indicated that the exact same staff would be used to construct, operate and maintain the assets as if PSO developed the projects. These employees are AEP staff working either for the AEP Service Company or for PSO.

**Engineering**
OK Transco verified that the same engineering staff would be used.

**Permitting**
OK Transco verified that the same permitting staff and contractors would be used.

**ROW Acquisition**
OK Transco verified that the same ROW staff and contractors would be used.

**Procurement**
OK Transco verified that the same procurement staff would be used.

**Project Management**
OK Transco verified that the same project management staff and contractors would be used.

**Construction**
OK Transco verified that the same construction contractors would be used.

**Commissioning**
OK Transco verified that the same commissioning staff and contractors would be used.

**Technology Content**
OK Transco indicated that the project design will not be impacted by the assignment.

**Operations**
OK Transco verified that the same operations staff and contractors would be used.

**Maintenance**
OK Transco verified that the same maintenance staff and contractors would be used.
Findings

**Due Diligence Findings with Respect to Financing Assumptions**

It is the opinion of Quanta Technology that the O&M and A&G costs are the same for OK Transco as for PSO.

- In forming this opinion, Quanta Technology notes that same staff from the AEP Service Company and the AEP Operating Companies will be used to plan, design, construct, operating and maintain the projects.

It is the opinion of Quanta Technology that the capital costs of the projects are not impacted by the assignment.

- In forming this opinion, Quanta Technology notes that that same staff from the AEP Service Company and the AEP Operating Companies will be used to plan, design, construct, operating and maintain the projects. In addition, the same procurement contracts and outside contractors will be used.

It is the opinion of Quanta Technology that it is reasonable to assume the tax costs would be the same for OK Transco as for PSO

- In forming this opinion, Quanta Technology notes that the capital cost should be the same for OK Transco as for PSO.
- We also note that the same tax laws would apply.

It is the opinion of Quanta Technology that the WACC for OK Transco would be less than for PSO.

- In forming this opinion, Quanta Technology notes that the authorized ROE is the same for OK Transco as for PSO. We also note that cost of debt is less for OK Transco than for PSO.

**Due Diligence Finding with Respect to Cost to SPP Customers**

Is the opinion of Quanta Technology that OK Transco’s calculation of ATRR’s is valid. This calculation shows that the cost to SPP Customers is lower after assignment of the projects.

- In forming this opinion, Quanta Technology calculated the sum of year-of-occurrence total savings as $830,129 over a 40 year period. We also calculated the discounted savings as $347,053 for SPP’s members.

**Due Diligence Finding with Respect to Project Development, Operations and Maintenance**

It is the opinion of Quanta Technology that the approach chosen by OK Transco to develop, operate and maintain the projects is equivalent to that which would be used by PSO.

- In forming this opinion, Quanta Technology notes that that same staff from the AEP Service Company and the AEP Operating Companies will be used to plan, design, construct, operating and maintain the projects. In addition, the same procurement contracts and outside contractors will also be used.
In forming this opinion, Quanta Technology notes that OK Transco uses the same AEP safety policies, practices, and procedures as PSO.

**Note:** Because of the various complications and external factors that enter into the successful development of transmission projects (e.g., legal challenges to regulatory approval, difficulty in securing easements, supply chain issues, etc.), this opinion constitutes neither a warrantee nor a guarantee on the part of Quanta Technology that OK Transco will actually develop, successfully operate and/or adequately maintain the Projects. Rather, these opinions are rendered based upon demonstration at the time of this review that OK Transco has taken an approach that is equivalent to that which would be used by PSO.

**SME Qualifications**

The resume for Donald J. Morrow is provided as Attachment D to this report.

If there are any questions or comments on this report summarizing the findings from the due diligence review of OK Transco, please contact me at 919-334-3023.

Respectfully Submitted,

Donald J. Morrow, P. E.
Partner & SVP Corporate Strategy
Quanta Technology, LLC.

Attachments
Introduction
Note: This document was revised to reflect additional requirements to be included in the qualification review that were identified in SPP’s Business Practices, updated on August 7, 2013.

This document provides guidance to SPP when considering approval of a Novation Agreement. A Novation Agreement applies when a Designated Transmission Owner (original “DTO”) has been issued a Notification to Construct (“NTC”) for a transmission facility, but the party wishes to transfer the responsibility to build and/or own this facility to another party (“Candidate”). Before approval of the Novation Agreement, SPP should qualify the candidate organization as being capable of adequately performing the transferred responsibility for the facility. The qualification process of a Candidate described herein is consistent with the most recent versions of the SPP Membership Agreement, Attachment O of the SPP OATT and SPP’s Business Practices.

For the qualification process, SPP should consider three phases in the life of a project. The phases are:

1. Financing Phase (Test ability to raise sufficient funds from qualified parties to finance the construction project and compare the cost of customers for the Candidate with estimated cost of customers for the original DTO.)
2. Development Phase (Test ability to execute engineering, permitting, environmental strategies, real-estate acquisition, procurement, project management, construction, and commissioning of the project.)
3. Operational Phase (Test ability to provide on-going operation and maintenance of the project.)

Suggested Criteria
The following tables provide guidance in judging the qualifications of Candidate in key areas related to the three phases in the life of the project.

In general, for item 1 below the legal right for an organization to incorporate and engage in commercial activities is a necessary condition to determine if a Candidate may be qualified. Also, the ability to raise financing should be tested and verified.

In general, for items 2 and 3 below a Candidate has three options. Perform the duties internally, contract with outside parties to execute, or some combination of the two. A Candidate should be able to describe how it plans to proceed with the project using one of these options.
## Item 1 – Financing and Rate Analysis Phase:

<table>
<thead>
<tr>
<th>Item</th>
<th>Tests</th>
</tr>
</thead>
</table>
| **Organizational Viability** | ✓ Articles of Incorporation exist and have been registered  
✓ Certificate of Public Convenience granted for applicable states  
✓ Favorable regulatory rulings related to transmission construction authorization and/or operation if necessary |
| **Capital Financing**   | ✓ FERC 203 Filing has been made  
✓ FERC 205 Filing has been made  
✓ Evidence of previous bond issuances  
✓ Capital budgeting and cash flow forecasting processes exist  
✓ Credit rating of BBB or better |
| **Cost to Customers**   | ✓ Perform a NPCC and a CWIP analysis (As indicated by SPP, this factor does significantly affect the rate impact analysis over the life of a transmission project. During the performance of this analysis, Consultant will work closely with SPP staff to assess this aspect of the review.)  
✓ Compare total cost of Project for Candidate vs original DTO  
✓ Compare financing costs for Candidate vs original DTO  
✓ Compare FERC incentives  
✓ Compare lifetime costs to customers |
## Item 2 – Development Phase:

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Engineering</strong></td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficiency of staff (note 3) to cover breadth of detailed engineering required</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Professional Engineering License for supervisory engineer</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Existence of engineering standards</td>
<td></td>
</tr>
<tr>
<td><strong>Permitting</strong></td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Environmental and regulatory expertise on staff at state &amp; federal level</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Demonstrated understanding of overall application process and its impact on critical path for the project</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Attorney’s on staff with relevant experience with CPCN or equivalent state regulatory filings</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ (Local relations? – Discuss with David and/or Les)</td>
<td></td>
</tr>
<tr>
<td><strong>Environmental</strong></td>
<td>✓ Environmental Permits identified and applied for</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Environmental Plan for project developed</td>
<td></td>
</tr>
<tr>
<td><strong>ROW Acquisition</strong></td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Easements for ROW (transferrable from initial party?)</td>
<td>✓ Easements transferred from previous initial party</td>
</tr>
<tr>
<td></td>
<td>✓ On-going process for dealing with land owners</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Attorney’s with expertise in drafting &amp; filing easements &amp; condemnation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Certified real estate agents on staff</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Public ROW franchises</td>
<td></td>
</tr>
<tr>
<td>Item</td>
<td>Internal Tests</td>
<td>External Tests</td>
</tr>
<tr>
<td>----------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Procurement</strong></td>
<td>✅ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✅ EPC contract(s) in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✅ Demonstrated understanding of key equipment providers, procurement timeline, and impacts on critical path</td>
<td>✅ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✅ Procurement systems in place (HW, SW, PO forms, etc.)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✅ Sufficiency of staff (note 3)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✅ Contracts with critical vendors in place</td>
<td></td>
</tr>
<tr>
<td><strong>Project Management</strong></td>
<td>✅ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✅ Some level of monitoring should be performed internal to Candidate Organization</td>
</tr>
<tr>
<td></td>
<td>✅ Systems in place to track tasks on the project, resources, progress, expenses, cost forecasts, cash flows, and critical path</td>
<td>✅ Embedded in construction contracts</td>
</tr>
<tr>
<td></td>
<td>✅ Sufficiency of staff (note 3)</td>
<td>✅ Project management contracts in place with qualified firms</td>
</tr>
<tr>
<td><strong>Construction</strong></td>
<td>✅ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✅ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✅ Sufficiency of staff (notes 3 &amp; 4)</td>
<td>✅ Project update processes</td>
</tr>
<tr>
<td></td>
<td>✅ Ownership of equipment such as cranes, bucket trucks, trenchers, helicopters, or contracts for their lease</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✅ Presence of safety program</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✅ Crew training program</td>
<td></td>
</tr>
<tr>
<td><strong>Commissioning</strong></td>
<td>✅ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✅ Process in place for internal sign off and designating equipment in-service and “used &amp; useful”</td>
</tr>
<tr>
<td></td>
<td>✅ Sufficiency of staff (notes 3 &amp; 4)</td>
<td>✅ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✅ Pre-existing testing procedures</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✅ Established criteria for judging acceptance</td>
<td></td>
</tr>
<tr>
<td><strong>Technology Content</strong></td>
<td>✅ Consistent with NTC issued by SPP</td>
<td>✅ n/a</td>
</tr>
<tr>
<td></td>
<td>✅ Type of construction (material, loading, etc.) compared with Original DTO</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✅ Estimated life of plant</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✅ Losses</td>
<td></td>
</tr>
</tbody>
</table>

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### Item 3 – Operations Phase:

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficient staff (notes 3 &amp; 4)</td>
<td>✓ Regular reporting of activities provided</td>
</tr>
<tr>
<td></td>
<td>✓ 24 hour control center operation</td>
<td>✓ Outage Response times tracked</td>
</tr>
<tr>
<td></td>
<td>✓ 24 hour field coverage with qualified field staff (note 5)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ SCADA system with key points monitored (breaker status &amp; line flows)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Established storm/outage response plan</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Articulated safety program with clearly defined tagging and clearance procedures covering both internal personal and contractors</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Safety record exists &amp; comparison to industry</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of a NERC and SPP standards compliance process</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Compliance history</td>
<td></td>
</tr>
<tr>
<td>Maintenance</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficient staff (notes 3 &amp; 4)</td>
<td>✓ Regular reporting of activities provided</td>
</tr>
<tr>
<td></td>
<td>✓ Qualified field staff (note 5)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Ownership of equipment such as cranes, bucket trucks, trenchers, helicopters, or contracts in place for their lease</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of safety program</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ On-going training program for crews</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Written maintenance program</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Able to articulate testing criteria for items monitored</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of a NERC and SPP standards compliance process</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Compliance history</td>
<td></td>
</tr>
</tbody>
</table>
Table Notes:
1. “Relevant experience” means experience designing, constructing, operating and maintaining similar voltage transmission facilities. As an example, an IPP would not have relevant experience if its previous assets were only generation facilities.
2. “Experience” means having performed relevant work either at the Candidate or at previous organizations.
3. “Sufficiency” means both having staff with the breadth of experience to cover all aspects of the work and enough staff to adequately perform the work.
4. Construction for EHV transmission is rarely performed internally in the US.
5. “Qualified field staff” means labor that has received appropriate, regular, and on-going safety and skills training necessary to execute the work required. Typically, field staff should progress through an apprentice oriented job progression.

Suggested Qualification Process:
The suggested qualification process for Candidates before approval of a Novation Agreement is based upon the establishment of a “Reasonable Professional” standard. The tables above provide guidance in the issues and suggest tests to use to determine if a Candidate satisfies this Reasonable Professional standard. The assessment of the Candidate should be conducted by a subject matter expert(s) in the area of transmission development, operations and maintenance.

1. Review formation documents of Candidate (focus is on item 1)
   a. Articles of incorporation
   b. State authorizations of Convenience and Authority
   c. FERC Filings – 203, 205, and 206

2. Conduct an interview with an officer of Candidate to cover the following items (focus is on items 2 & 3):
   a. Discussion of Candidate’s plans for addressing the issues in the table
   b. Describe staffing levels, plans and capability for internal groups performing either all or a portion of the tasks
   c. Describe the safety program and manual for the organization, with a special emphasis on field safety
   d. Identify key contracts in place to cover any of the above items, including provider of outside services
   e. Identify major external partners
      i. Attorneys
      ii. Detail Engineering
      iii. ROW acquisition
      iv. Equipment procurement
      v. Project Management
      vi. Construction Management
      vii. Construction Contractors
      viii. Environmental

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f. Discuss procurement methods and expectations

g. Describe real-estate acquisition process

h. Describe understanding of project timeline & critical path

i. Describe equipment owned and leased by Candidate

j. Describe NERC & RRO compliance history and corporate compliance program and/or process

k. Describe the metrics used to track project development, operations and maintenance

l. Describe training programs in place at the organization

3. Contract reviews (focus is on items 2 & 3):

   a. Contract(s) exists

   b. Contract(s) cover appropriate time periods for the facility in question

   c. Contract(s) covers key areas identified in the tables above that are not covered internal to the Candidate Organization

   d. Contract(s) includes reporting and feedback to provide a measure of control over external partner

   e. Contract(s) include NERC & RRO standards compliance expectations (applicable to O&M phase)

   f. Contract(s) include response time requirements and/or expectations for outages (applicable to O&M phase)

   g. Contract(s) contain appropriate incentives to ensure personal safety and Bulk Electric System reliability
Clear identification of the projects being assigned from Public Service of Oklahoma to AEP Oklahoma Transmission Company.

Letter from AEP (or Public Service of Oklahoma) requesting SPP’s approval for the assignment of those projects.

Some formal document that clearly shows that AEP Oklahoma Transmission Company is a wholly owned subsidiary of AEP Transmission Company L.L.C.

Some form of documentation that establishes the FERC authorized rate of return for AEP’s OPCOs in the SPP footprint. An unlocked spreadsheet used to create Worksheet F – OKLAHOMA TRANSMISSION COMPANY – Calculation of “Projected” ARR for SPP Base Plan Upgrade Projects. I’m looking for the spreadsheet used as the basis to create Attachment 9.

SPP had provided me with a series of documents that were labelled Attachment 1, Attachment 2, Attachment 3, Attachment 4, Attachment 5, Attachment 6, Attachment 8, Attachment 9, and Attachment 10
   a. However, the document that these were attached to was not provided. Please provide the main document.
   b. Attachment 7 was missing. Please provide Attachment 7.

Plans for or contracts to provide the following
   a. Engineering services
   b. Permitting/ROW Acquisition services
   c. Material Procurement
   d. Project/Construction Management services
   e. Construction services
   f. Commissioning services
   g. System Operation services
   h. Field operation/response services
   i. Maintenance services

Most recent “Standardized Cost Estimate Reporting Template” (SCERT) identified in BP 7060, Section 9. Per that BP, there should be one submitted by Public Service of Oklahoma before the NCT was issued. There may be an updated one after the NCT was issued.

Description of Safety Program – internal and for contractors

Safety record of AEP Oklahoma Transmission Company or the company that will provide field operation & maintenance services

Design Characteristics of the facilities (wood, steel, tower type, conductor type, insulators, etc.)

Estimated total owing cost

Estimated losses on the facilities

Estimate of useful life of the facilities

Please provide an updated spreadsheet for the ATRR and NPCC comparisons that show ROR, cost of debt, O&M, A&G and Tax values for both AEP OK Transmission Company and Public Service of Oklahoma. The updated spreadsheet should show the equations used to calculate the ARR values for the 40 year (or 50 year) life of the asset.
Background
This document presents a summary of Quanta Technology’s notes during the interview session of AEP Oklahoma Transmission Company conducted during the due diligence review for the Assignment of Project ID: 30346 which is part of SPP-NTC-200167. Project ID 30346 is Network Upgrade ID 50438 to upgrade the Cornville 138 kV bus to breaker-and-a-half configuration in preparation for the 138 kV line conversion to Lindsay Water (Flood) Substation for regional reliability. This includes the line re-terminations required for the existing OK Transco Lindsay Water Flood to Cornville 138 kV transmission line at the Cornville Substation. This interview was conducted via conference call on March 26, 2014 between 11:30 am and 1:30 pm EDT.

Participants
The following table shows the participants in the Q&A:

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
<th>Title</th>
</tr>
</thead>
<tbody>
<tr>
<td>Donald Morrow</td>
<td>Quanta Technology</td>
<td>Partner &amp; SVP Corporate Strategy</td>
</tr>
<tr>
<td>Dan Jones</td>
<td>SPP</td>
<td>Lead Regulatory Engineer</td>
</tr>
<tr>
<td>Terri Gallup</td>
<td>AEP Transmission Company &amp; part of AEP Service Company</td>
<td>Manager of Transmission Asset Strategy</td>
</tr>
<tr>
<td>Adam Hickman</td>
<td>AEP Service Company</td>
<td>Business Development</td>
</tr>
<tr>
<td>Nancy Roby</td>
<td>AEP Transmission Company &amp; AEP Service Company</td>
<td>Business Development</td>
</tr>
<tr>
<td>Raja Sundararajan</td>
<td>AEP Service Company &amp; AEP Transmission Company</td>
<td>VP Asset Strategy</td>
</tr>
</tbody>
</table>

For this interview, the AEP employees are speaking on behalf of AEP Transmission Company, the parent company of AEP Oklahoma Transmission Company.
## Interview Notes

### Item 1 – Financing and Rate Analysis Phase:

<table>
<thead>
<tr>
<th>Item</th>
<th>Tests</th>
<th>Notes from Q&amp;A</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Organizational Viability</strong></td>
<td>✓ Articles of Incorporation exist and have been registered</td>
<td>✓ Oklahoma Company</td>
</tr>
<tr>
<td></td>
<td>✓ Certificate of Public Convenience granted for applicable states</td>
<td>✓ Been in business since 2009</td>
</tr>
<tr>
<td></td>
<td>✓ Favorable regulatory rulings related to transmission construction</td>
<td>✓ Over $242M in assets</td>
</tr>
<tr>
<td></td>
<td>authorization and/or operation if necessary</td>
<td>✓ Approval from OCC to issue debt instruments</td>
</tr>
<tr>
<td><strong>Capital Financing</strong></td>
<td>✓ FERC 203 Filing has been made</td>
<td>✓ Yes, a 205 has been filed</td>
</tr>
<tr>
<td></td>
<td>✓ FERC 205 Filing has been made</td>
<td>✓ No 203 is required since only new assets are being developed.</td>
</tr>
<tr>
<td></td>
<td>✓ Evidence of previous bond issuances</td>
<td>✓ All AEP transcos are wholly owned under AEP transmission company LLC</td>
</tr>
<tr>
<td></td>
<td>✓ Capital budgeting and cash flow forecasting processes exist</td>
<td>✓ AEP Transco llc is the financing company and raises funds for all transcos and passes the costs of rates through</td>
</tr>
<tr>
<td></td>
<td>✓ Credit rating of BBB or better</td>
<td>✓ OCC has authorized AEP OK to issue debt to AEP Transco</td>
</tr>
<tr>
<td></td>
<td></td>
<td>✓ OCC is the key since don’t need to be a utility.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>✓ Not publicly rated were issued into private market.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>✓ Most recent issuance is that transmission-only business risk profile is more</td>
</tr>
<tr>
<td></td>
<td></td>
<td>identifiable to debt issuers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>✓ At some point</td>
</tr>
</tbody>
</table>
## Cost to Customers

- Perform a NPCC and a CWIP analysis (As indicated by SPP, this factor does significantly affect the rate impact analysis over the life of a transmission project. During the performance of this analysis, Consultant will work closely with SPP staff to assess this aspect of the review.)
- Compare total cost of Project for Candidate vs original DTO
- Compare financing costs for Candidate vs original DTO
- Compare FERC incentives
- Compare lifetime costs to customers

### Notes from Q&A

- Input data provided in memo to SPP
- O&M and Tax are the same in both cases
- Both companies do file for their OATT. Did a mid-year 2013, then added this investment
- Existing ATRR, then calculated the
- Will use AFUDC
**Item 2 – Development Phase:**

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
<th>Notes from Q&amp;A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
<td>✓ They will use the same resources as PSO</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficiency of staff (note 3) to cover breadth of detailed engineering required</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Professional Engineering License for supervisory engineer</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Existence of engineering standards</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permitting</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
<td>✓ Same resources as PSO</td>
</tr>
<tr>
<td></td>
<td>✓ Environmental and regulatory expertise on staff at state &amp; federal level</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Demonstrated understanding of overall application process and its impact on critical path for the project</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Attorney’s on staff with relevant experience with CPCN or equivalent state regulatory filings</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ (Local relations? – Discuss with David and/or Les)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Environmental</td>
<td>✓ Environmental Permits identified and applied for</td>
<td>✓ Contracts in place with qualified firms</td>
<td>✓ Same resources as PSO</td>
</tr>
<tr>
<td></td>
<td>✓ Environmental Plan for project developed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Item</td>
<td>Internal Tests</td>
<td>External Tests</td>
<td>Notes from Q&amp;A</td>
</tr>
<tr>
<td>---------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>-------------------------------------</td>
</tr>
<tr>
<td>ROW Acquisition</td>
<td>☑ Relevant previous experience (notes 1 &amp; 2)</td>
<td>☑ Contracts in place with qualified firms</td>
<td>☑ Same resources as PSO.</td>
</tr>
<tr>
<td></td>
<td>☑ Easements for ROW (transferrable from initial party?)</td>
<td>☑ Easements transferred from previous initial party</td>
<td></td>
</tr>
<tr>
<td></td>
<td>☑ On-going process for dealing with land owners</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>☑ Attorney’s with expertise in drafting &amp; filing easements &amp; condemnation</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>☑ Certified real estate agents on staff</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>☑ Public ROW franchises</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Procurement</td>
<td>☑ Relevant previous experience (notes 1 &amp; 2)</td>
<td>☑ EPC contract(s) in place with qualified firms</td>
<td>☑ Same resources as PSO.</td>
</tr>
<tr>
<td></td>
<td>☑ Demonstrated understanding of key equipment providers, procurement timeline,</td>
<td>☑ Contracts in place with qualified firms</td>
<td></td>
</tr>
<tr>
<td></td>
<td>and impacts on critical path</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>☑ Procurement systems in place (HW, SW, PO forms, etc.)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>☑ Sufficiency of staff (note 3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>☑ Contracts with critical vendors in place</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Management</td>
<td>☑ Relevant previous experience (notes 1 &amp; 2)</td>
<td>☑ Some level of monitoring should be performed internal to Candidate Organization</td>
<td>☑ Same resources, but it was noted that project management may be outsourced.</td>
</tr>
<tr>
<td></td>
<td>☑ Systems in place to track tasks on the project, resources, progress, expenses,</td>
<td>☑ Embedded in construction contracts</td>
<td></td>
</tr>
<tr>
<td></td>
<td>cost forecasts, cash flows, and critical path</td>
<td>☑ Project management contracts in place with qualified firms</td>
<td></td>
</tr>
<tr>
<td></td>
<td>☑ Sufficiency of staff (note 3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Item</td>
<td>Internal Tests</td>
<td>External Tests</td>
<td>Notes from Q&amp;A</td>
</tr>
<tr>
<td>--------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>----------------------------------------------------------</td>
</tr>
<tr>
<td>Construction</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Contracts in place with qualified firms</td>
<td>✓ The same contractors would be used.</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficiency of staff (notes 3 &amp; 4)</td>
<td>✓ Project update processes</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Ownership of equipment such as cranes, bucket trucks, trenchers, helicopters, or contracts for their lease</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Presence of safety program</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Crew training program</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commissioning</td>
<td>✓ Relevant previous experience (notes 1 &amp; 2)</td>
<td>✓ Process in place for internal sign off and designating equipment in-service and “used &amp; useful”</td>
<td>✓ Same resources as PSO.</td>
</tr>
<tr>
<td></td>
<td>✓ Sufficiency of staff (notes 3 &amp; 4)</td>
<td>✓ Contracts in place with qualified firms</td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Pre-existing testing procedures</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Established criteria for judging acceptance</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Technology Content</td>
<td>✓ Consistent with NTC issued by SPP</td>
<td>✓ n/a</td>
<td>✓ Technology content will not change due to assignment.</td>
</tr>
<tr>
<td></td>
<td>✓ Type of construction (material, loading, etc.) compared with Original DTO</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Estimated life of plant</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>✓ Losses</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
## Item 3 – Operations Phase:

<table>
<thead>
<tr>
<th>Item</th>
<th>Internal Tests</th>
<th>External Tests</th>
<th>Notes from Q&amp;A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>• Relevant previous experience (notes 1 &amp; 2)</td>
<td>• Contracts in place with qualified firms</td>
<td>• Same resources as PSO.</td>
</tr>
<tr>
<td></td>
<td>• Sufficient staff (notes 3 &amp; 4)</td>
<td>• Regular reporting of activities provided</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• 24 hour control center operation</td>
<td>• Outage Response times tracked</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• 24 hour field coverage with qualified field staff (note 5)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• SCADA system with key points monitored (breaker status &amp; line flows)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Established storm/outage response plan</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Articulated safety program with clearly defined tagging and clearance procedures covering both internal personal and contractors</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Safety record exists &amp; comparison to industry</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Presence of a NERC and SPP standards compliance process</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Compliance history</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
## Table Notes:

1. “Relevant experience” means experience designing, constructing, operating and maintaining similar voltage transmission facilities. As an example, an IPP would not have relevant experience if its previous assets were only generation facilities.
2. “Experience” means having performed relevant work either at the Candidate or at previous organizations.
3. “Sufficiency” means both having staff with the breadth of experience to cover all aspects of the work and enough staff to adequately perform the work.
4. Construction for EHV transmission is rarely performed internally in the US.
5. “Qualified field staff” means labor that has received appropriate, regular, and on-going safety and skills training necessary to execute the work required. Typically, field staff should progress through an apprentice oriented job progression.
Additional Notes

1. Review formation documents of Candidate (focus is on item 1)
   a. Articles of incorporation
   b. State authorizations of Convenience and Authority
   c. FERC Filings – 203, 205, and 206

2. Conduct an interview with an officer of Candidate to cover the following items (focus is on items 2 & 3):
   a. Discussion of Candidate’s plans for addressing the issues in the table
   b. Describe staffing levels, plans and capability for internal groups performing either all or a portion of the tasks - No difference are anticipated in the staffing levels between AEP OK vs PSO
   c. Describe the safety program and manual for the organization, with a special emphasis on field safety -
   d. Identify key contracts in place to cover any of the above items, including provider of outside services
   e. Identify major external partners – All external partners are through the service company, therefore they are the exact same.
      i. Attorneys
      ii. Detail Engineering
      iii. ROW acquisition
      iv. Equipment procurement
      v. Project Management
      vi. Construction Management
      vii. Construction Contractors
      viii. Environmental
   f. Discuss procurement methods and expectations
   g. Describe real-estate acquisition process
   h. Describe understanding of project timeline & critical path – No changes.
   i. Describe equipment owned and leased by Candidate
   j. Describe NERC & RRO compliance history and corporate compliance program and/or process
   k. Describe the metrics used to track project development, operations and maintenance – Managed through AEP Service Company
   l. Describe training programs in place at the organization

3. Contract reviews (focus is on items 2 & 3):
   a. Contract(s) exists
   b. Contract(s) cover appropriate time periods for the facility in question
c. Contract(s) covers key areas identified in the tables above that are not covered internal to the Candidate Organization
d. Contract(s) includes reporting and feedback to provide a measure of control over external partner
e. Contract(s) include NERC & RRO standards compliance expectations (applicable to O&M phase)
f. Contract(s) include response time requirements and/or expectations for outages (applicable to O&M phase)
g. Contract(s) contain appropriate incentives to ensure personal safety and Bulk Electric System reliability
Donald J. Morrow, P. E.  Partner & SVP Corporate Strategy. During the course of his career, Don has held a wide range of technical and management responsibilities in the areas of system planning, control area operations, transmission operations, energy trading, maintenance scheduling, operator training, protection, distribution operations, energy management systems, and natural gas dispatch. Don originally joined Quanta Technology to start the Transmission consulting practice and oversaw its growth to become the largest team within Quanta Technology. In his current role at Quanta Technology he continues to provide consulting to transmission clients. Prior to joining Quanta Technology, he was Director of Operations at American Transmission Company (“ATC”). In that role, Don was charged with the formation of the system operations department for the startup of ATC on 1/1/2001. He was responsible for the successful operation of two control centers overseeing operations in Wisconsin, Iowa and the upper peninsula of Michigan. While at ATC, Don also served as Director of System Planning & Protection ATC. In this role, Don was responsible for the development and justification of an annual capital budget of over $300M and a ten year capital budget of over $3B.

Areas of Expertise
- System Planning
- System Operations
- Transmission Development
- NERC and RRO Reliability Standards Compliance

Experience and Background
- 31 years of experience in the electric power industry ........................................................ 1982 – 2013
- Director System Planning and Protection, American Transmission Co. ....................... 2004 – 2006
- Director System Operation, American Transmission Co. ............................................. 2000 – 2004
- Senior Director System Operations Center, Madison Gas and Electric ....................... 1992 – 2000
- Engineer (various levels), Madison Gas and Electric ..................................................... 1982 – 1992

Accomplishments and Industry Recognition
- Member IEEE
- Former Member of various NERC & MRO Committees
- Registered Professional Engineer in Wisconsin & Arkansas

Education
- BSEE – University of Wisconsin, Madison
- MBA – University of Wisconsin, Madison

Don can be contacted at dmorrow@quanta-technology.com
Novation and Assignment

CORNVILLE: Assignment of sub equip
Background- Novation

• In 2011, MKEC novated NTC 20102, Project 945 to ITC
  • 345 kV double circuit line from Spearville – Clark County – Thistle – Wichita
  • Novation Agreement approved by FERC in Docket No. ER11-3451 in June 2011
• July 2011 SPP issued NTC 200162 to ITC
Novation

• ITC proposes to novate the metering equipment at the new 345 kV Thistle Substation to MKEC

• Metering Equipment shall include: current transformers and potential transformers located on the interconnections to Prairie Wind, the owner of the transmission lines, inside the ITC-owned Thistle Substation and associated metering equipment located inside the control center
SPP Novation Process

• Per Attachment O of the SPP OATT
  “At any time, a Designated Transmission Owner may elect to arrange for another entity or another existing Transmission Owner to build and own all or part of the project in its place subject to the qualifications in Subsections i, ii, iii, and iv above.”

• Per SPP Business Practice 7070
  “A novation is the release of the original DTO’s obligation to ensure that a project is built. After the DTO’s assignment of the right to build and the approval and execution of a novation, the new TO will have the right and obligation to build the project.”
SPP Novation Process

- Qualifications prescribed by Attachment O of OATT
  - Obtain necessary state regulatory authority
  - Meet SPP’s creditworthiness requirements
  - Sign the SPP Membership Agreement as a TO
  - Meet other technical, financial and managerial qualifications as specified in SPP’s business practices.
SPP Novation Process

- BP 7070 requires additional information be made available for transparency purposes
- Information provided by MKEC is included in background materials
Novation- Information Provided for Transparency

Summarized in three primary areas:

1) Financing Assumptions
   ▪ No material changes

2) Cost to SPP Customers
   ▪ Approximately $190K savings to Transmission Customers over 40 years in current-year dollars (2.5% straight line depreciation, 8% discount rate)

3) Project Development, Operations and Maintenance
   ▪ Mid-Kansas will own, operate and maintain the identified metering equipment. Mid-Kansas was selected as the potential DTO because the location of the assets resides within the service territory of their retail members.
Background- Assignment

• April 2012- SPP issued NTC 200167 to AEP
  – Project ID 30346: Sub – Cornville 138 kV
Assignment

• AEP proposes to assign Project ID 30346 from NTC 200167 to its affiliate AEP Oklahoma Transmission Company (“AEP OTC”)
  – AEP OTC is a wholly-owned subsidiary of AEP Transmission Company, LLC, which is a wholly-owned subsidiary of AEP
SPP Assignment Process

• Per SPP Business Practice 7070-
  – An “assignment” is the transfer of a DTO’s legal right to build a project pursuant to a NTC issued by SPP. Although the DTO has transferred its legal right to build a project pursuant to an assignment, the original DTO is still under a legal obligation to ensure that the project is built.
SPP Assignment Process

• **Qualifications prescribed by BP 7070**
  - Obtain necessary state regulatory authority
  - Meet SPP’s creditworthiness requirements
  - Sign the SPP Membership Agreement as a TO
  - Meet other technical, financial and managerial qualifications as specified in SPP’s business practices.

• **BP 7070 requires additional information be made available for transparency purposes**
  - Provided in form of a Due Diligence Review since AEP OTC has not yet had a project assigned to them in SPP
  - Due Diligence Review performed by Quanta Technologies
Assignment- Due Diligence Review

Due Diligence findings summarized in three primary areas:

1) Financing Assumptions
   - Capital cost of project essentially same for AEP OTC as for AEP

2) Cost to SPP Customers
   - Approximately $864,236 savings to Transmission Customers over 40 years in current-year dollars
   - Savings due to lower long-term debt costs

3) Project Development, Operations and Maintenance
   - Will use same staff to construct, operate and maintain the assets as if AEP developed the projects
Novation and Assignment

- April 3- Motion that the Novation and Assignment had been reviewed and satisfied the needs of Business Practice 7070 was approved by TWG
- April 16- Novation and Assignment were Approved by MOPC
- Information provided to Regional State Committee in April 28th Meeting Materials
Next Steps and Filing Requirements

• Present to the SPP Board of Directors on April 29th

• With Board approval, SPP will file the Novation Agreement at FERC

• No filing is required for the Assignment
Second Quarterly Project Tracking Report 2014

April 2014
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Executive Summary

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

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

The reporting period for this report is November 1, 2013 through January 31, 2014. Table 1 provides a summary of all projects in the current Project Tracking Portfolio (PTP), which includes all Network Upgrades that have been completed since January 1, 2013. The PTP includes all active Network Upgrades including transmission lines, transformers, substations, and devices.

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

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>No. of Upgrades</th>
<th>Estimated Cost</th>
<th>Miles of New</th>
<th>Miles of Rebuild</th>
<th>Miles of Voltage Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
<td>329</td>
<td>$2,339,705,823</td>
<td>1040.8</td>
<td>401.5</td>
<td>365.9</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>33</td>
<td>$149,456,185</td>
<td>5.0</td>
<td>137.7</td>
<td>0.0</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>11</td>
<td>$560,597,951</td>
<td>457.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>High Priority</td>
<td>24</td>
<td>$1,394,974,546</td>
<td>1109.4</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>ITP10</td>
<td>25</td>
<td>$1,139,238,495</td>
<td>775.7</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>9</td>
<td>$108,582,827</td>
<td>34.7</td>
<td>28.5</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>NTC Projects Subtotal</strong></td>
<td><strong>431</strong></td>
<td><strong>$5,692,555,827</strong></td>
<td><strong>3422.6</strong></td>
<td><strong>567.6</strong></td>
<td><strong>365.9</strong></td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>25</td>
<td>$107,031,706</td>
<td>40.5</td>
<td>11.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>10</td>
<td>$31,567,090</td>
<td>33.6</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal - Sponsored</td>
<td>28</td>
<td>$128,925,341</td>
<td>22.8</td>
<td>5.1</td>
<td>77.1</td>
</tr>
<tr>
<td><strong>Non-NTC Projects Subtotal</strong></td>
<td><strong>63</strong></td>
<td><strong>$267,524,137</strong></td>
<td><strong>96.9</strong></td>
<td><strong>16.2</strong></td>
<td><strong>77.1</strong></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>494</strong></td>
<td><strong>$5,960,079,964</strong></td>
<td><strong>3519.5</strong></td>
<td><strong>583.8</strong></td>
<td><strong>443.0</strong></td>
</tr>
</tbody>
</table>

*Table 1: Q2 2014 Portfolio Summary*
Figure 1: Percentage of Project Type on Cost Basis

- Regional Reliability: 40%
- Transmission Service: 3%
- Balanced Portfolio: 24%
- High Priority: 2%
- ITP10: 2%
- Zonal Reliability: 3%
- Generation Interconnection: 10%

Figure 2: Percentage of Project Status on Cost Basis

- Complete: 11%
- On Schedule < 4: 1%
- On Schedule > 4: 1%
- Delay - Mitigation: 7%
- NTC Suspension: 15%
- NTC - Commitment Window: 17%
- Re-evaluation: 17%
In adherence to the OATT and Business Practice 7060, SPP issues Notifications to Construct (NTCs) to Designated Transmission Owners (DTOs) to commence the construction of Network Upgrades that have been approved or endorsed by the SPP Board of Directors (BOD) intended to meet the construction needs of the STEP, OATT, or Regional Transmission Organization (RTO).

Figure 3 reflects project status within each source study, and Table 2 provides the supporting data. Figure 4 shows the amount of estimated cost by in-service year for all Network Upgrades that have been issued an NTC or NTC-C. **Note: Figures 3 and 4 and Table 2 provide data for all projects for which SPP has issued an NTC or NTC-C, regardless of completion date, and therefore include data from Network Upgrades no longer included in PTP.**
### Table 2: Project Status by NTC Source Study

<table>
<thead>
<tr>
<th>Source Study</th>
<th>Complete</th>
<th>Delayed</th>
<th>Suspended</th>
<th>On Schedule</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006 STEP</td>
<td>$202,202,401</td>
<td>$912,000</td>
<td></td>
<td></td>
<td>$203,114,401</td>
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<tr>
<td>2007 STEP</td>
<td>$355,126,919</td>
<td>$43,309,000</td>
<td>$160,151,000</td>
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<td>$558,586,919</td>
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<tr>
<td>2008 STEP</td>
<td>$395,835,478</td>
<td>$18,564,204</td>
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<td>$2,393,000</td>
<td>$416,792,682</td>
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<tr>
<td>Balanced Portfolio</td>
<td>$457,343,667</td>
<td>$367,735,027</td>
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<td></td>
<td>$825,078,694</td>
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<td>2009 STEP</td>
<td>$412,517,261</td>
<td>$155,698,616</td>
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<td></td>
<td>$568,215,877</td>
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<tr>
<td>Priority Projects</td>
<td>$960,895</td>
<td>$13,649,558</td>
<td>$1,381,324,988</td>
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<td>$1,395,935,441</td>
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<td>2010 STEP</td>
<td>$66,095,848</td>
<td>$72,653,953</td>
<td>$28,778,517</td>
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<td>$167,528,318</td>
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<tr>
<td>2012 ITPNT</td>
<td>$25,994,023</td>
<td>$117,342,398</td>
<td></td>
<td>$60,091,423</td>
<td>$203,427,844</td>
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<tr>
<td>2012 ITP10</td>
<td></td>
<td></td>
<td>$371,648,177</td>
<td>$767,590,318</td>
<td>$1,139,238,495</td>
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<td>2013 ITPNT</td>
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<td>$360,617,532</td>
<td>$17,810,955</td>
<td>$177,625,516</td>
<td>$570,761,197</td>
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<tr>
<td>2014 ITPNT</td>
<td></td>
<td></td>
<td></td>
<td>$458,695,447</td>
<td>$720,393,294</td>
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<tr>
<td>Ag Studies</td>
<td>$670,577,844</td>
<td>$424,272,222</td>
<td>$63,879,049</td>
<td></td>
<td>$776,884,115</td>
</tr>
<tr>
<td>DPA Studies</td>
<td>$32,022,401</td>
<td>$140,463,146</td>
<td>$19,713,490</td>
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<td>$192,199,037</td>
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<tr>
<td>GI Studies</td>
<td>$128,815,590</td>
<td>$30,481,506</td>
<td></td>
<td>$56,414,885</td>
<td>$215,711,981</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$2,762,199,520</strong></td>
<td><strong>$1,257,816,983</strong></td>
<td><strong>$389,459,132</strong></td>
<td><strong>$3,544,392,660</strong></td>
<td><strong>$7,953,868,294</strong></td>
</tr>
</tbody>
</table>

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

Nineteen (19) NTCs were issued since the last quarterly report for new and previously approved projects with a total cost estimate of the included Network Upgrades totaling $1.17 billion.

NTC No. 200239 was issued to ITC Great Plains as a modification to the existing project to construct a double-circuit 345 kV line from Spearville to Clark Co. to Thistle. The modification, approved by the BOD on December 10, 2013, re-routes the line adjacent to the Ironwood substation located approximately 2 miles to the east of Spearville. Circuit 1 of the double-circuit from Clark Co. will terminate at Ironwood.

Two of the NTCs were issued as a result of Transmission Owners submitting updated cost estimates in response to Notifications to Construct with Conditions (NTC-Cs). The NTC-Cs were issued to American Electric Power (AEP) and OGE for the project Chisolm (formerly Elk City) – Gracemont 345 kV Ckt 1. The cost estimates submitted by both parties for the shared project were found to meet the conditional requirements of the NTC-Cs, and therefore were issued NTCs without the NTC-C conditions.

Sixteen (16) NTCs were issued in February, six (6) of which were NTC-Cs, as a result of the 2014 ITP Near-Term Assessment approved by the BOD on January 28, 2014. The total estimated cost of the new Network Upgrades from the NTCs is $496.0 million.

Table 3 summarizes the NTC activity from December 1, 2013 through February 28, 2014. NTC ID values in **bold** font indicate NTC-Cs.
Completed Projects

Twenty-two (22) Network Upgrades with NTCs were completed during the reporting period, totaling an estimated $265.6 million. Oklahoma Gas and Electric (OGE) reported the completion of the construction of a 100-mile 345 kV line from Muskogee to Seminole. OGE was issued an NTC for the Network Upgrade as a part of the Balanced Portfolio. The reported cost estimate for the Upgrade is $170 million.

Table 4 lists the Network Upgrades completed during the reporting period. Table 5 summarizes the completed projects over the previous year. Figure 5 reflects the completed projects by upgrade type on a cost basis for the current year and the following year based on current projected in-service dates. Tables 6 and 7 summarize all Network Upgrades that include construction of transmission lines, both for the current year and the following year. Note: Previous quarter’s updated results are listed as the Transmission Owners may make adjustments to final costs and status of projects completed during the year.

Table 3: Q2 2014 NTC Issuance Summary

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>DTO</th>
<th>NTC Issue Date</th>
<th>Upgrade Type</th>
<th>Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of New Upgrades</th>
<th>Estimated Cost of Previously Approved Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200240</td>
<td>OGE</td>
<td>12/20/2013</td>
<td>ITP10</td>
<td>2012 ITP10</td>
<td>1</td>
<td>N/A</td>
<td>$43,853,500</td>
</tr>
<tr>
<td>200239</td>
<td>ITCGP</td>
<td>12/31/2013</td>
<td>High Priority</td>
<td>Priority Projects</td>
<td>5</td>
<td>N/A</td>
<td>$300,000,001</td>
</tr>
<tr>
<td>200255</td>
<td>AEP</td>
<td>2/6/2014</td>
<td>ITP10</td>
<td>2012 ITP10</td>
<td>3</td>
<td>N/A</td>
<td>$119,098,857</td>
</tr>
<tr>
<td>200241</td>
<td>GRDA</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>2</td>
<td>$322,200</td>
<td>N/A</td>
</tr>
<tr>
<td>200242</td>
<td>WR</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>14</td>
<td>$80,988,511</td>
<td>$64,658,982</td>
</tr>
<tr>
<td>200244</td>
<td>WR</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>2</td>
<td>$105,346,721</td>
<td>N/A</td>
</tr>
<tr>
<td>200245</td>
<td>WFEC</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>3</td>
<td>$8,904,000</td>
<td>N/A</td>
</tr>
<tr>
<td>200246</td>
<td>AEP</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>7</td>
<td>$42,626,890</td>
<td>$8,174,689</td>
</tr>
<tr>
<td>200247</td>
<td>OGE</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>1</td>
<td>$740,254</td>
<td>N/A</td>
</tr>
<tr>
<td>200248</td>
<td>SEPC</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>2</td>
<td>$7,603,530</td>
<td>N/A</td>
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<tr>
<td>200250</td>
<td>GMO</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>2</td>
<td>$3,778,700</td>
<td>N/A</td>
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<tr>
<td>200251</td>
<td>AEP</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>1</td>
<td>$24,880,495</td>
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</tr>
<tr>
<td>200252</td>
<td>OGE</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>4</td>
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<tr>
<td>200253</td>
<td>NPPD</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>7</td>
<td>$30,000</td>
<td>$133,697,720</td>
</tr>
<tr>
<td>200254</td>
<td>NPPD</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>2</td>
<td>$32,573,600</td>
<td>NA</td>
</tr>
<tr>
<td>200256</td>
<td>SPS</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>10</td>
<td>$34,889,575</td>
<td>$3,496,698</td>
</tr>
<tr>
<td>200257</td>
<td>SPS</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>9</td>
<td>$95,438,662</td>
<td>N/A</td>
</tr>
<tr>
<td>200258</td>
<td>OPPD</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>5</td>
<td>$9,420,606</td>
<td>N/A</td>
</tr>
<tr>
<td>200259</td>
<td>OPPD</td>
<td>2/19/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>3</td>
<td>$35,091,946</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Total 83 $496,030,660 $672,980,447

Table 3: Q2 2014 NTC Issuance Summary
<table>
<thead>
<tr>
<th>UID</th>
<th>Network Upgrade Name</th>
<th>Owner</th>
<th>NTC Source Study</th>
<th>Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>10575</td>
<td>Osbourne - Osbourne Tap 161 kV Ckt 1</td>
<td>AEP</td>
<td>2008 STEP</td>
<td>$2,000,000</td>
</tr>
<tr>
<td>10843</td>
<td>KILGORE - VBI 69KV Ckt 1 #2</td>
<td>OGE</td>
<td>2008 STEP</td>
<td>$33,267</td>
</tr>
<tr>
<td>10795</td>
<td>DOVER - TWIN LAKES 138KV Ckt 1</td>
<td>WFEC</td>
<td>2008 STEP</td>
<td>$5,315,700</td>
</tr>
<tr>
<td>10794</td>
<td>DOVER - DOVER SW 138KV Ckt 1</td>
<td>WFEC</td>
<td>2008 STEP</td>
<td>$5,765,600</td>
</tr>
<tr>
<td>10829</td>
<td>CHAVES COUNTY INTERCHANGE - ROSWELL INTERCHANGE 115KV Ckt 1</td>
<td>SPS</td>
<td>2008 STEP</td>
<td>$8,610,000</td>
</tr>
<tr>
<td>10930</td>
<td>MUSKOGEE - SEMINOLE 345KV Ckt 1</td>
<td>OGE</td>
<td>Balanced Portfolio</td>
<td>$170,000,000</td>
</tr>
<tr>
<td>10603</td>
<td>GILL ENERGY CENTER EAST - INTERSTATE 138KV Ckt 1</td>
<td>WR</td>
<td>2009 STEP</td>
<td>$123,581</td>
</tr>
<tr>
<td>11040</td>
<td>NEWHART 230 230/115KV TRANSFORMER Ckt 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$13,796,842</td>
</tr>
<tr>
<td>11043</td>
<td>CASTRO COUNTY INTERCHANGE - NEWHART 115KV Ckt 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$18,501,085</td>
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<tr>
<td>11044</td>
<td>HART INDUSTRIAL - NEWHART 115KV Ckt 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$2,568,905</td>
</tr>
<tr>
<td>11117</td>
<td>Nash - Wakita 69 kV Ckt 1</td>
<td>WFEC</td>
<td>2010 STEP</td>
<td>$6,705,000</td>
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<tr>
<td>50093</td>
<td>Bushland Interchange Cap Banks 230 kV</td>
<td>SPS</td>
<td>2012 ITPNT</td>
<td>$1,865,510</td>
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<tr>
<td>50098</td>
<td>Kolache Cap Bank 69 kV</td>
<td>OGE</td>
<td>2012 ITPNT</td>
<td>$737,743</td>
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<tr>
<td>10698</td>
<td>Maid - Pryor Foundry South 69 kV Ckt 1</td>
<td>GRDA</td>
<td>2012 ITPNT</td>
<td>$1,374,534</td>
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<tr>
<td>50529</td>
<td>Arcadia 345 kV Terminal Upgrades</td>
<td>OGE</td>
<td>2013 ITPNT</td>
<td>$983,369</td>
</tr>
<tr>
<td>10385</td>
<td>KANSAS TAP - WEST SILOAM SPRINGS 161KV Ckt 1</td>
<td>GRDA</td>
<td>Ag Study</td>
<td>$4,780,359</td>
</tr>
<tr>
<td>10386</td>
<td>SILOAM CITY - WEST SILOAM SPRINGS 161KV Ckt 1</td>
<td>GRDA</td>
<td>Ag Study</td>
<td>$2,002,021</td>
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<tr>
<td>11201</td>
<td>FLATRDG3 - MEDICINE LODGE 138KV Ckt 1</td>
<td>MKEC</td>
<td>Ag Study</td>
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<td>10487</td>
<td>Creswell - Oak 69 kV Ckt 1</td>
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<td>Ag Study</td>
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<td>11195</td>
<td>FLETCHER - HOLCOMB 115KV Ckt 1 #2</td>
<td>SEPC</td>
<td>Ag Study</td>
<td>$4,091,866</td>
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</table>

**Total**: $265,597,456

*Table 4: Q1 2014 Completed Network Upgrades*
<table>
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<tr>
<th>Upgrade Type</th>
<th>Q2 2013</th>
<th>Q3 2013</th>
<th>Q4 2013</th>
<th>Q1 2014</th>
<th>Total</th>
</tr>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>14</td>
<td>27</td>
<td>13</td>
<td>17</td>
<td>71</td>
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<tr>
<td></td>
<td>$50,151,481</td>
<td>$142,951,509</td>
<td>$32,009,659</td>
<td>$79,255,382</td>
<td>$304,368,031</td>
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<tr>
<td>Transmission Service</td>
<td>3</td>
<td>7</td>
<td>2</td>
<td>2</td>
<td>14</td>
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<tr>
<td></td>
<td>$11,342,901</td>
<td>$34,931,121</td>
<td>$4,235,570</td>
<td>$4,932,312</td>
<td>$55,441,904</td>
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<td>Balanced Portfolio</td>
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<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
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<td>$0</td>
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<td>$0</td>
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<td>$170,000,000</td>
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<tr>
<td>High Priority</td>
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<td>0</td>
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<tr>
<td></td>
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<td>ITP10</td>
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<td>$0</td>
</tr>
<tr>
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<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td>Generation Interconnection</td>
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<td>2</td>
<td>6</td>
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<tr>
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<td>$8,725,553</td>
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<td>$0</td>
<td>$11,409,762</td>
<td>$20,135,315</td>
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</tbody>
</table>

*Table 5: Completed Project Summary through 1st Quarter 2014*
### Table 6: Line Upgrade Summary for Previous 12 Months

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>Miles of New</th>
<th>Miles of Rebuild/Reconductor</th>
<th>Miles of Voltage Conversion</th>
<th>Estimated Cost</th>
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</thead>
<tbody>
<tr>
<td>69</td>
<td>9</td>
<td>3.0</td>
<td>34.7</td>
<td>0.0</td>
<td>$29,535,113</td>
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<tr>
<td>115</td>
<td>15</td>
<td>36.3</td>
<td>43.0</td>
<td>35.0</td>
<td>$92,189,347</td>
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<tr>
<td>138</td>
<td>16</td>
<td>13.5</td>
<td>53.4</td>
<td>66.0</td>
<td>$93,110,240</td>
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<tr>
<td>161</td>
<td>9</td>
<td>7.2</td>
<td>15.1</td>
<td>5.6</td>
<td>$36,206,732</td>
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<tr>
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<td>2</td>
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<td>0.0</td>
<td>$40,215,864</td>
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<tr>
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<td>1</td>
<td>100.0</td>
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<td>0.0</td>
<td>$170,000,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>52</strong></td>
<td><strong>214.97</strong></td>
<td><strong>146.13</strong></td>
<td><strong>106.61</strong></td>
<td><strong>$461,257,296</strong></td>
</tr>
</tbody>
</table>

*Figure 5: Completed Projects by Upgrade Type*
<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>Miles of New</th>
<th>Miles of Rebuild/Reconductor</th>
<th>Miles of Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
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<tbody>
<tr>
<td>69</td>
<td>13</td>
<td>14.0</td>
<td>72.8</td>
<td>0.0</td>
<td>$58,280,425</td>
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<tr>
<td>115</td>
<td>12</td>
<td>151.7</td>
<td>50.1</td>
<td>3.0</td>
<td>$165,639,328</td>
</tr>
<tr>
<td>138</td>
<td>26</td>
<td>62.7</td>
<td>27.1</td>
<td>134.9</td>
<td>$127,537,285</td>
</tr>
<tr>
<td>161</td>
<td>3</td>
<td>9.0</td>
<td>6.3</td>
<td>0.0</td>
<td>$16,388,592</td>
</tr>
<tr>
<td>230</td>
<td>4</td>
<td>61.1</td>
<td>0.0</td>
<td>0.0</td>
<td>$59,504,717</td>
</tr>
<tr>
<td>345</td>
<td>19</td>
<td>1162.2</td>
<td>0.0</td>
<td>0.0</td>
<td>$1,166,156,199</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>77</strong></td>
<td><strong>1460.62</strong></td>
<td><strong>156.18</strong></td>
<td><strong>137.85</strong></td>
<td><strong>$1,593,506,546</strong></td>
</tr>
</tbody>
</table>

*Table 7: Line Upgrade Projections for Next 12 Months*
Project Status Summary

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

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

Figure 6 reflects a summary of project status by upgrade type on a cost basis. **Note: Figure 6 includes data for Network Upgrades in the PTP only.**
Approved in April 2009, the Balanced Portfolio was an initiative to develop a group of economic transmission upgrades that benefit the entire SPP region, and to allocate those project costs regionally. The projects that were issued NTCs as a result of the study include a diverse group of projects, estimated to add approximately 717 miles of new 345 kV transmission line to the SPP system.

The total cost estimate for the projects making up the Balanced Portfolio increased by 0.7% from the previous quarter during the 1st quarter 2014 update cycle to a total of $825.1 million. OGE reported the completion of the 100-mile 345 kV line from Seminole to Muskogee in east central Oklahoma placed into service on December 31st, 2013.

Figure 7 below depicts a historical view of the total estimated cost of the Balanced Portfolio. Table 8 provides a project summary of the projects making up the Balanced Portfolio. Table 9 lists construction status updates for the Balanced Portfolio projects not yet completed.
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>705/709</td>
<td>WFEC/OGE</td>
<td>Gracemont Substation 345 kV</td>
<td>N/A</td>
<td>$8,000,000</td>
<td>$14,921,070</td>
<td>$14,921,070</td>
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</tr>
<tr>
<td>707/708</td>
<td>ITCGP/NPPD</td>
<td>Spearville - Post Rock - Axtell 345 kV</td>
<td>223.0</td>
<td>$236,557,015</td>
<td>$203,559,673</td>
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<tr>
<td>698/699</td>
<td>OGE/GRDA</td>
<td>Sooner - Cleveland 345 kV</td>
<td>36.0</td>
<td>$33,530,000</td>
<td>$49,718,139</td>
<td>$49,718,139</td>
<td>0.00%</td>
</tr>
<tr>
<td>702</td>
<td>KCPL</td>
<td>Swissvale - Stilwell Tap 345 kV</td>
<td>N/A</td>
<td>$2,000,000</td>
<td>$1,922,840</td>
<td>$2,910,227</td>
<td>51.35%</td>
</tr>
<tr>
<td>700</td>
<td>OGE</td>
<td>Seminole - Muskogee 345 kV</td>
<td>100.0</td>
<td>$129,000,000</td>
<td>$170,000,000</td>
<td>$170,000,000</td>
<td>0.00%</td>
</tr>
<tr>
<td>701/704</td>
<td>SPS/OGE</td>
<td>Tuco - Woodward 345 kV</td>
<td>327.0</td>
<td>$227,727,750</td>
<td>$313,570,903</td>
<td>$318,627,516</td>
<td>1.61%</td>
</tr>
<tr>
<td>703</td>
<td>KCPL/GMO</td>
<td>Iatan – Nashua 345 kV</td>
<td>31.0</td>
<td>$54,444,000</td>
<td>$65,364,014</td>
<td>$65,364,014</td>
<td>0.00%</td>
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<tr>
<td><strong>Total</strong></td>
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<td></td>
<td><strong>717.0</strong></td>
<td><strong>$691,258,515</strong></td>
<td><strong>$819,056,639</strong></td>
<td><strong>$825,100,639</strong></td>
<td><strong>0.74%</strong></td>
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**Table 8: Balanced Portfolio Summary**

<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Projected In-Service Date</th>
<th>Engineering</th>
<th>Siting and Routing</th>
<th>Environmental Studies</th>
<th>Permits</th>
<th>Material Procurement</th>
<th>Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td>701</td>
<td>Tuco – Woodward 345 kV (OGE)</td>
<td>5/19/14</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
</tr>
<tr>
<td>704</td>
<td>Tuco – Woodward 345 kV (SPS)</td>
<td>9/30/14</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
</tr>
<tr>
<td>703</td>
<td>Iatan – Nashua 345 kV</td>
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<td>IP</td>
<td>IP</td>
<td>N/A</td>
<td>N/A</td>
<td>IP</td>
<td>IP</td>
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</table>

**Table 9: Balanced Portfolio Construction Status**
Priority Projects

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

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

The total cost estimate for the projects making up the Priority Projects increased by 1.1% from the previous quarter during the 2nd quarter 2014 update cycle to a total of $1.40 billion. No Priority Projects were completed during the reporting period. The next project expected to be completed is the 122-mile double circuit 345 kV line from Hitchland to Woodward District EHV being constructed by SPS and OGE in western Oklahoma projected to complete by June 2014.

Figure 8 below depicts a historical view of the total estimated cost of the Priority Projects. Table 10 provides a project summary of the projects making up the Priority Projects. Table 11 lists construction status updates for the Priority Projects not yet completed.
Figure 8: Priority Projects Cost Estimate Trend
<table>
<thead>
<tr>
<th>Project ID(s)</th>
<th>Project Owner(s)</th>
<th>Project Name</th>
<th>Project Description</th>
<th>Est. Line Length</th>
<th>BOD Approved Estimates (10/2010)</th>
<th>Q4 2013 Cost Estimates</th>
<th>Q1 2014 Cost Estimates</th>
<th>Var. %</th>
</tr>
</thead>
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<tr>
<td>937</td>
<td>AEP</td>
<td>Tulsa Power Station 138 kV Reactor</td>
<td>N/A</td>
<td>$842,847</td>
<td>$960,895</td>
<td>$960,895</td>
<td>0.00%</td>
<td></td>
</tr>
<tr>
<td>940/941</td>
<td>SPS/OGE</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt</td>
<td>120.0</td>
<td>$221,572,283</td>
<td>$230,019,879</td>
<td>$230,019,879</td>
<td>0.00%</td>
<td></td>
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<tr>
<td>942/943</td>
<td>PW/OGE</td>
<td>Thistle – Woodward District 345 kV Dbl Ckt</td>
<td>109.4</td>
<td>$201,940,759</td>
<td>$192,640,000</td>
<td>$192,640,000</td>
<td>0.00%</td>
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<tr>
<td>945</td>
<td>ITCGP</td>
<td>Spearville – Ironwood – Clark Co. – Thistle 345 kV Dbl Ckt</td>
<td>113.5</td>
<td>$293,235,000</td>
<td>$285,024,557</td>
<td>$300,000,001</td>
<td>5.25%</td>
<td></td>
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<tr>
<td>946</td>
<td>PW</td>
<td>Thistle – Wichita 345 kV Dbl Ckt</td>
<td>77.5</td>
<td>$163,488,000</td>
<td>$136,555,302</td>
<td>$136,555,302</td>
<td>0.00%</td>
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<tr>
<td>936</td>
<td>AEP</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>76.3</td>
<td>$131,451,250</td>
<td>$127,995,000</td>
<td>$127,995,000</td>
<td>0.00%</td>
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<tr>
<td>938/939</td>
<td>OPPD/GMO</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV</td>
<td>181.2</td>
<td>$403,740,000</td>
<td>$407,764,364</td>
<td>$407,764,364</td>
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<tr>
<td><strong>Total</strong></td>
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<td><strong>677.9</strong></td>
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<td><strong>$1,380,959,997</strong></td>
<td><strong>$1,395,935,441</strong></td>
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</table>

**Table 10: Priority Projects Summary**

<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Project Description</th>
<th>Projected In-Service Date</th>
<th>Engineering</th>
<th>Siting and Routing</th>
<th>Environmental Studies</th>
<th>Permits</th>
<th>Material Procurement</th>
<th>Construction</th>
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</thead>
<tbody>
<tr>
<td>940</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt (SPS)</td>
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<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
</tr>
<tr>
<td>941</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt (OGE)</td>
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<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
</tr>
<tr>
<td>942</td>
<td>Thistle – Woodward District 345 kV Dbl Ckt (OGE)</td>
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<td>12/31/2014</td>
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<td>C</td>
<td>C</td>
<td>IP</td>
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<tr>
<td>943</td>
<td>Thistle – Woodward District 345 kV Dbl Ckt (PW)</td>
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<td>C</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
</tr>
<tr>
<td>945</td>
<td>Spearville – Ironwood – Clark Co. – Thistle 345 kV Dbl Ckt</td>
<td></td>
<td>12/31/2014</td>
<td>IP</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
</tr>
<tr>
<td>946</td>
<td>Thistle – Wichita 345 kV Dbl Ckt</td>
<td></td>
<td>12/31/2014</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
</tr>
<tr>
<td>936</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td></td>
<td>5/1/2015</td>
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<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
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<tr>
<td>938</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (GMO)</td>
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<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
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<td>Nebraska City – Mullin Creek – Sibley 345 kV (OPPD)</td>
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<td>C</td>
<td>IP</td>
<td>IP</td>
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**Table 11: Priority Projects Construction Status**
<table>
<thead>
<tr>
<th>Project Name</th>
<th>Description</th>
<th>Start Date</th>
<th>End Date</th>
<th>Actual Cost</th>
<th>Budget Cost</th>
<th>Duration</th>
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<tbody>
<tr>
<td>Safety Springs 138 kV Substation</td>
<td>Regional Reliability</td>
<td>6/30/2014</td>
<td>4/1/2015</td>
<td>$15,000,000</td>
<td>$15,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>DOVER - DOVER SW 138 kV Substation</td>
<td>Regional Reliability</td>
<td>1/27/2010</td>
<td>2/27/2009</td>
<td>$17,000,000</td>
<td>$17,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>POTTERIES - RAYMOND - DOVER 161 kV Substation</td>
<td>Regional Reliability</td>
<td>4/14/2014</td>
<td>12/30/2014</td>
<td>$13,000,000</td>
<td>$13,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>Chamber Springs 161 kV Transformer 2</td>
<td>Regional Reliability</td>
<td>6/30/2014</td>
<td>6/30/2015</td>
<td>$12,000,000</td>
<td>$12,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>CHAMBER SPRINGS - FARMINGTON 161 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>5/9/2014</td>
<td>6/30/2015</td>
<td>$14,000,000</td>
<td>$14,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>Brownlee - North Market 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2015</td>
<td>$12,000,000</td>
<td>$12,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>Johnson - Massard 161 kV Substation</td>
<td>Regional Reliability</td>
<td>3/29/2013</td>
<td>6/1/2015</td>
<td>$3,000,000</td>
<td>$3,000,000</td>
<td>24 months</td>
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<tr>
<td>Evenside - Northwest Henderson 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>6/1/2018</td>
<td>6/1/2018</td>
<td>$12,000,000</td>
<td>$12,000,000</td>
<td>24 months</td>
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<tr>
<td>Maid - Redden 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>5/1/2014</td>
<td>6/1/2013</td>
<td>$1,100,000</td>
<td>$1,100,000</td>
<td>12 months</td>
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<td>Kilgore - VBI 69 kV Ckt 1 #2</td>
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<td>6/1/2013</td>
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<td>$10,000</td>
<td>COMPLETE</td>
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<td>MUSKOGEE - SEMINOLE 345 kV Ckt 1</td>
<td>Balanced Portfolio</td>
<td>12/31/2013</td>
<td>6/19/2009</td>
<td>$131,000,000</td>
<td>$170,000,000</td>
<td>40 months</td>
</tr>
<tr>
<td>DOVER - DOVER SW 138 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2016</td>
<td>$14,000,000</td>
<td>$14,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>Tuco - Woodward 345 kV Ckt 1</td>
<td>Balanced Portfolio</td>
<td>5/19/2014</td>
<td>6/19/2009</td>
<td>$64,000,000</td>
<td>$64,000,000</td>
<td>40 months</td>
</tr>
<tr>
<td>Chaves County 230/115 kV Transformer 4</td>
<td>Regional Reliability - SPS</td>
<td>2/20/2013</td>
<td>4/1/2012</td>
<td>$2,591,900</td>
<td>$2,591,900</td>
<td>18 months</td>
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<tr>
<td>Gill - Interstate 138 kV Substation</td>
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<td>5/19/2014</td>
<td>6/19/2009</td>
<td>$15,000,000</td>
<td>$15,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>Waterloo - Warren 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>6/1/2015</td>
<td>6/1/2016</td>
<td>$14,000,000</td>
<td>$14,000,000</td>
<td>24 months</td>
</tr>
<tr>
<td>Merrill - El Dorado 69 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>5/18/2012</td>
<td>6/1/2015</td>
<td>$14,000,000</td>
<td>$14,000,000</td>
<td>24 months</td>
</tr>
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<td>3/31/2013</td>
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<td>737</td>
<td>3/31/2013</td>
<td>3/31/2013</td>
<td>$3,067,575</td>
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<td>736</td>
<td>3/31/2013</td>
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<td>$3,067,575</td>
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<td>3/31/2013</td>
<td>3/31/2013</td>
<td>$3,067,575</td>
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<td>734</td>
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<td>3/31/2013</td>
<td>$3,067,575</td>
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</table>

**Note**: The data includes the completion dates and costs associated with different projects. The costs are listed in USD and are provided for each project. The completion dates range from March 31, 2013, to March 31, 2013, with varying costs ranging from $3,067,575 to $3,067,575. Each project appears to be part of a series or batch, as indicated by the consistent dates and costs.


200808 791 11839 SPS Multi - New Hart Interchange 230/115 kV CASTRO COUNTY INTERCHANGE - RENWART 115KV CKT 1 Regional Reliability 3/28/2014 6/1/2010 2/14/2010 $10,000,000 $12,460,000 24 months COMPLETE


200808 791 11845 SPS Multi - New Hart Interchange 230/115 kV AMERIND INTERCHANGE - NEWHART 115KV CKT 1 Regional Reliability 12/30/2014 6/1/2011 2/8/2010 $1,890,000 $3,000,000 30 months COMPLETE

201305 791 11846 SPS Multi - New Hart Interchange 230/115 kV SPS XFR - Kingsmill 115/69 kV KINGSMILL INTERCHANGE 115/69KV TRANSFORMER CKT 2 Regional Reliability 6/1/2013 2/14/2013 $2,258,000 $2,540,905 18 months COMPLETE


The Midwest Transmission Project (Sibley-Nebraska City) is on schedule. A final route with 336.4 ACSR.

The Valley Substation will be replaced with a 115/34.5 kV transformer which will limit a 138 kV GOAB switch. The transformer will be replaced with a 138 kV GOAB switch in existing (drilled) cost.

Warmsley Switching Station - 138 kV switch replacement - 36 week lead time equipment.

The temporary operating guide provided.

The Valley Substation will be replaced with a 115/34.5 kV transformer which will limit a 138 kV GOAB switch. The transformer will be replaced with a 138 kV GOAB switch in existing (drilled) cost.

The temporary operating guide provided.

The Valley Substation will be replaced with a 115/34.5 kV transformer which will limit a 138 kV GOAB switch. The transformer will be replaced with a 138 kV GOAB switch in existing (drilled) cost.
<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Description</th>
<th>Location</th>
<th>Start Date</th>
<th>End Date</th>
<th>Status</th>
<th>Notes</th>
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<tbody>
<tr>
<td>20001</td>
<td>WR Device - Esquandale Cap 69 kV</td>
<td>Regional Reliability</td>
<td>6/1/2014</td>
<td>6/1/2014</td>
<td>$243,000</td>
<td>12 months</td>
<td>COMPLETE</td>
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<tr>
<td>20002</td>
<td>WR Device - Athens 69 kV</td>
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<td>6/1/2013</td>
<td>$607,500</td>
<td>12 months</td>
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<td>20003</td>
<td>OGE XFR - Ft Smith 500/161 kV Ckt</td>
<td>Transmission Service</td>
<td>6/1/2017</td>
<td>6/1/2017</td>
<td>$11,000,000</td>
<td>24 months</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>20004</td>
<td>MKEC XFR - Medicine Lodge 138/115 kV</td>
<td>Transmission Service</td>
<td>2/1/2013</td>
<td>1/1/2010</td>
<td>$5,625,000</td>
<td>24 months</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>20005</td>
<td>WR Line - Cowskin - Centennial 138 kV</td>
<td>Regional Reliability</td>
<td>5/19/2013</td>
<td>6/1/2012</td>
<td>$3,676,071</td>
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<tr>
<td>20006</td>
<td>OGE Line - VBI - VBI North 69 kV</td>
<td>Transmission Service</td>
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<td>6/1/2017</td>
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<td>NPPD Device - Ainsworth 115 kV</td>
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<tr>
<td>20008</td>
<td>NPPD Device - Cozad 115 kV</td>
<td>Regional Reliability</td>
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<td>6/1/2014</td>
<td>$677,370</td>
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<tr>
<td>20009</td>
<td>AEP XFR - Diana 345/138 kV ckt 3</td>
<td>Transmission Service</td>
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<td>6/1/2013</td>
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<td>20010</td>
<td>LES Line - 17th &amp; Holdrege - 30th &amp; A 115 kV</td>
<td>Zonal - Sponsored</td>
<td>10/8/2013</td>
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<td>$17,318,000</td>
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<td>20011</td>
<td>WR XFR - Auburn Road 230/115 kV Transformer Ckt 1</td>
<td>Auto Upgrade Regional Reliability</td>
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<td>6/1/2014</td>
<td>$25,845,600</td>
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<td>COMPLETE</td>
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<tr>
<td>20012</td>
<td>MIDW Device-Pawnee 115 kV</td>
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<td>6/1/2011</td>
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<tr>
<td>20013</td>
<td>AEP Sub - Cornville 138 kV</td>
<td>Zonal - Sponsored</td>
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<td>-</td>
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<td>12 months</td>
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<tr>
<td>20014</td>
<td>AEP Line - Clinton Junction 138 kV</td>
<td>Generation Interconnection</td>
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<tr>
<td>20015</td>
<td>AEP Sub - Cornville 138 kV</td>
<td>Zonal - Sponsored</td>
<td>12/31/2014</td>
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<tr>
<td>20016</td>
<td>AEP Device - Logansport 138 kV</td>
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<td>6/1/2016</td>
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<td>20017</td>
<td>NPPD XFR - Ogallala 230/115kV Replacement</td>
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<td>Zonal - Sponsored</td>
<td>12/31/2014</td>
<td>-</td>
<td>$4,770,000</td>
<td>12 months</td>
<td>COMPLETE</td>
</tr>
</tbody>
</table>

**Notes:**
- **COMPLETE:** Project completed.
- **DELAY - MITIGATION:** Project delayed due to various reasons.
- **ON SCHEDULE < 4:** Project on schedule with potential for mitigation.
- **NOTE:** Additional notes and details are included for each project.
AEP Device - Coweta 69 kV Capacitor
Coweta 69 kV Regional Reliability 6/1/2014 6/1/2014 4/9/2012 $1,318,601 $1,428,440 12 months

Multi - Woodward District EHV - Tatonga - Matthewson - Cimarron
4/9/2012 $605,551 $561,667

This is one of multiple components of the "rPLAN" project cost. Line reactor costs are

AEP Multi - Chisholm - Gracemont 345 kV Chisholm 230 kV ITP10 3/1/2018 2/6/2014 $5,326,722

OGE

NPPD Multi - Gentleman - Cherry Co. - Holt Co. 345 kV Cherry Co. Substation 345 kV ITP10 1/1/2018 1/1/2018 3/11/2013 $6,000,000 $11,896,383 72 months

COMPLETE

MKEC Multi - Ellsworth - Bushton - Rice 115 kV Ellsworth Substation 115 kV Regional Reliability 6/1/2015 6/1/2012 4/9/2012 $2,669,385 24 months

ITCGP Multi - Elm Creek - Summit 345 kV Elm Creek 345/230 kV Transformer ITP10 12/31/2016 3/1/2018 3/21/2013 $5,403,707 $5,405,101 48 months

This is one of multiple components of the "rPLAN" project cost. Line Reactor costs are

OGE Multi - Chisholm - Gracemont 345 kV Chisholm - Gracemont 345 kV Ckt 1 (OGE) ITP10 3/1/2018 3/1/2018 12/20/2013 $75,486,000 $43,853,500 60 months

Transmission line to utilize previously obtained Right of Way along the existing

NPPD Multi - Gentleman - Cherry Co. - Holt Co. 345 kV Cherry Co. - Holt Co. 345 kV Ckt 1 ITP10 1/1/2018 1/1/2018 3/11/2013 $172,360,000 $146,065,000 72 months

OGE

NPPD Multi - Hoskins - Neligh 345 kV Neligh 345/115 kV Substation Regional Reliability 6/1/2016 6/1/2016 2/19/2014 $35,497,400 $12,118,564 39 months

TA-11/05/12; Q2-2013 Cost estimate remains valid. TRM 2/15/13. Q3-2013 Updated estimate reflects the medium route. The exact route of the line will be determined upon receipt of the final route survey. The line mileage is an estimate.

AEP Sub - Move lines from Lea Co 230/115 kV sub to Hobbs Interchange 230/115 kV
Move lines from Lea County to Hobbs 230/115 kV Regional Reliability 6/1/2014 6/1/2014 4/9/2012 $2,278,297 $105,786,384 24 months DELAY - MITIGATION

On schedule for indicated In-Service date

SPS Multi - Tuco - Amoco - Hobbs 345 kV Amoco - Tuco 345 kV Ckt 1 ITP10 1/1/2020 1/1/2020 4/9/2012 $88,198,879 72 months

NTP - COMMITMENT WINDOW

The new Sulphur-KC 115kV transmission line has one mile of new double circuit with the Harrisburg Substation to the new Sulphur Substation. This includes two 115kV bays in a ring bus configuration. The estimate includes modifying the existing Hoskins substation for a new Neligh 345kV line route has not been determined at this time, therefore, the line mileage is an estimate. The estimate includes modifying the existing Hoskins substation for a new Neligh 345kV line to Woodring. Mathewson substation will start with

Those costs are included in the Mathewson Substation network upgrade PID 30364 & UID 50458.

Those costs are included in the Mathewson Substation network upgrade PID 30364 & UID 50458.

On schedule for indicated In-Service date

On schedule for indicated In-Service date

The final line routes have not been determined at this time; hence, the line mileage is an estimate.

This portion of the estimate includes 4 - 115kV bays in a ring bus configuration.

The estimate includes modifying the existing Mathewson Substation for a new Mathewson substation.

The estimate includes modifying the Mathewson Substation for a new substation.

The estimate includes modifying the existing Mathewson Substation for a new substation.

The new Sulphur-KC 115kV transmission line has one mile of new double circuit with the Harrisburg Substation to the new Sulphur Substation. This includes two 115kV bays in a ring bus configuration. The estimate includes modifying the existing Hoskins substation for a new Neligh 345kV line route has not been determined at this time, therefore, the line mileage is an estimate. The estimate includes modifying the existing Hoskins substation for a new Neligh 345kV line to Woodring. Mathewson substation will start with

Those costs are included in the Mathewson Substation network upgrade PID 30364 & UID 50458.

On schedule for indicated In-Service date

On schedule for indicated In-Service date

The final line routes have not been determined at this time; hence, the line mileage is an estimate.

This portion of the estimate includes 4 - 115kV bays in a ring bus configuration.

The estimate includes modifying the existing Mathewson Substation for a new substation.

The estimate includes modifying the Mathewson Substation for a new substation.

On schedule for indicated In-Service date

On schedule for indicated In-Service date

The final line routes have not been determined at this time; hence, the line mileage is an estimate.

This portion of the estimate includes 4 - 115kV bays in a ring bus configuration.

The estimate includes modifying the existing Mathewson Substation for a new substation.

The estimate includes modifying the Mathewson Substation for a new substation.

On schedule for indicated In-Service date

On schedule for indicated In-Service date

The final line routes have not been determined at this time; hence, the line mileage is an estimate.

This portion of the estimate includes 4 - 115kV bays in a ring bus configuration.

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On schedule for indicated In-Service date

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The final line routes have not been determined at this time; hence, the line mileage is an estimate.

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On schedule for indicated In-Service date

On schedule for indicated In-Service date

The final line routes have not been determined at this time; hence, the line mileage is an estimate.

This portion of the estimate includes 4 - 115kV bays in a ring bus configuration.

The estimate includes modifying the existing Mathewson Substation for a new substation.

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On schedule for indicated In-Service date

On schedule for indicated In-Service date

The final line routes have not been determined at this time; hence, the line mileage is an estimate.

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On schedule for indicated In-Service date

On schedule for indicated In-Service date

The final line routes have not been determined at this time; hence, the line mileage is an estimate.

This portion of the estimate includes 4 - 115kV bays in a ring bus configuration.

The estimate includes modifying the existing Mathewson Substation for a new substation.

The estimate includes modifying the Mathewson Substation for a new substation.
### Regional Reliability

<table>
<thead>
<tr>
<th>Project Description</th>
<th>EIS/RFP</th>
<th>FDP</th>
<th>Start Date</th>
<th>End Date</th>
<th>Cost</th>
<th>Prior Cost</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Align - EIS Pass - Farber 138kV G1 1</td>
<td>EIS</td>
<td>RFP</td>
<td>3/1/2014</td>
<td>2/20/2015</td>
<td>$5,561,163</td>
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<td>12 months</td>
</tr>
<tr>
<td>Align - EIS Pass - Farber 138kV G1 2</td>
<td>EIS</td>
<td>RFP</td>
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<td>2/20/2015</td>
<td>$5,561,163</td>
<td>$5,561,163</td>
<td>12 months</td>
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<tr>
<td>Koch Substation Voltage Conversion</td>
<td>EIS</td>
<td>RFP</td>
<td>3/1/2014</td>
<td>2/20/2015</td>
<td>$28,500,855</td>
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<td>Regional Reliability 3/15/2014</td>
<td>EIS</td>
<td>RFP</td>
<td>3/1/2013</td>
<td>12/20/2012</td>
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<td>RFP</td>
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<td>$571,210</td>
<td>$587,690</td>
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<td>RFP</td>
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<td>2/20/2013</td>
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<td>RFP</td>
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<td>2/20/2013</td>
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<td>12 months</td>
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<td>Regional Reliability 6/1/2018</td>
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<td>RFP</td>
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<td>9/10/2013</td>
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<td>Midland REC - North Huntington 69kV Ckt 1 Regional Reliability</td>
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<td>New Gladewater - Perdue 138kV Ckt 1 Regional Reliability</td>
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<td>RFP</td>
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<td>6/1/2016</td>
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<td>$1,000,000</td>
<td>12 months</td>
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</tbody>
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### Delayed Projects

- **OGE Line - Arcadia - Redbud 345 kV Arcadia 345 kV Terminal Upgrades Regional Reliability**
  - Start Date: 11/17/2013
  - End Date: 6/1/2013
  - Prior Cost: $1,010,523
  - Cost: $1,010,523
  - Status: 12 months
  - Delay Mitigation

- **OGE Line - Arcadia - Redbud 345 kV Arcadia 345 kV Terminal Upgrades Regional Reliability**
  - Start Date: 12/20/2013
  - End Date: 12/20/2013
  - Prior Cost: $1,010,523
  - Cost: $1,010,523
  - Status: 12 months
  - Delay Mitigation

- **Multi - Renfrow 345/138 kV substation and Renfrow - Grant 138 kV Market St. - South Portales 115 kV Ckt 1 Regional Reliability**
  - Start Date: 3/15/2014
  - End Date: 3/1/2013
  - Prior Cost: $4,998,388
  - Cost: $4,998,388
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 9/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 3/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 3/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 9/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 3/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 1/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 1/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 1/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 1/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 1/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 1/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation

- **Multi - Viola 345/138kV Transformer and 138 kV Lines to Chapman Junction - Grant County 138/69 kV Transformer Ckt 1 Regional Reliability**
  - Start Date: 1/1/2014
  - End Date: 3/1/2013
  - Prior Cost: $11,659,600
  - Cost: $11,659,600
  - Status: COMPLETE
  - Delay Mitigation
200252 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200253 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200254 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200255 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200256 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200257 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200258 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200259 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200260 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200261 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200262 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200263 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200264 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200265 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200266 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200267 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200268 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200269 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months

200270 06/06 06/09 NPPD Multi - 345kV/115kV and 115kV - Stegall Substation 115kV 345kV/115kV 115kV Transformer Ckt 1 Regional Reliability 6/1/2014 2/19/2014 $6,048,000 $5,800,000 48 months
<table>
<thead>
<tr>
<th>Project Name</th>
<th>Location</th>
<th>Description</th>
<th>Regional Reliability</th>
<th>Estimated Start Date</th>
<th>Estimated End Date</th>
<th>Cost Estimate</th>
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<td>WR Line - Wellington - Creswell 69 kV</td>
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<td>S924 - S912 69 kV</td>
<td>Terminal Upgrades</td>
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The costs are subject to change and are based on current estimates provided by the respective utilities. The projects are scheduled to be completed by the estimated end dates.