2012 SPP Transmission Expansion Plan Report

January 31, 2012

Engineering
## Revision History

<table>
<thead>
<tr>
<th>Date</th>
<th>Author</th>
<th>Change Description</th>
</tr>
</thead>
<tbody>
<tr>
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<td>Staff</td>
<td>Version Draft</td>
</tr>
<tr>
<td>01/18/2012</td>
<td>MOPC</td>
<td>Endorsed</td>
</tr>
<tr>
<td>01/24/2012</td>
<td>Staff</td>
<td>Posted for BOD with changes from MOPC</td>
</tr>
<tr>
<td>01/31/2012</td>
<td></td>
<td>BOD Approved</td>
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Executive Summary

The Southwest Power Pool (SPP) Engineering Organization plays a key role in helping SPP perform its mission of “Helping our members work together to keep the lights on...today and in the future”. Engineering staff works closely with members, regulators, and neighbors whose systems adjoin with ours to plan future transmission system expansion needs and provide transmission and generation interconnection service necessary to facilitate reliable and efficient delivery of generation resources to end-use customers. This work facilitates the provision of a robust transmission system critical to “keeping the lights on” in SPP and surrounding regions.

The 2012 STEP consists of 492 upgrades with a total cost of $7.1 billion. Figure 1 illustrates the cost distribution of the 2012 STEP based on upgrade type. More detail of the total portfolio is listed in Appendix A.

![Figure 1: 2012 STEP Cost by Upgrade Type](image-url)

(APPENDIX A includes a breakdown of projects in the 20-year horizon)

The 2012 SPP Transmission Expansion Plan (STEP) summarizes 2011 activities that impact future development of the SPP transmission grid. Seven distinct areas of transmission planning are discussed in this report, each of which are critical to meeting mandates of either the 2011 SPP Strategic Plan or the nine planning principles in FERC Order 890. These areas are Integrated Transmission Planning, Tariff Studies, Sub-regional and Local Area Planning, Transmission Congestion and Top Flowgates, Interregional Coordination, Project Tracking, and Public Policy Impacts. As a Regional Transmission
Organization (RTO) of the Federal Energy Regulatory Commission (FERC), SPP must meet requirements of FERC and the SPP Open Access Transmission Tariff (OATT).

**2012 Integrated Transmission Planning (ITP)**
The ITP process was designed to maintain reliability and provide economic benefits to the SPP region in both the near and long-term, enabling SPP and its stakeholders to better facilitate the development of a robust transmission grid that will give regional customers improved access to the SPP region’s diverse resources. The first phase of this new process, the ITP20, was conducted in 2010. This study recommended a long-term transmission plan for a 20-year horizon, incorporating a proposed extra high voltage backbone supply system.

The second phase of the ITP assessment, the ITP10, was conducted in 2011. ITP10 resulted in a recommended portfolio of projects for comprehensive regional solutions, local reliability upgrades, and the expected reliability and economic needs of the studied 10-year horizon.

The third phase of ITP assessment, the (ITPNT), was also conducted in 2011. ITPNT evaluated the reliability of the SPP Transmission system and identified needed upgrades. The ITPNT reviewed the transmission needs of the system for the 6-year planning horizon.

**Tariff Studies**
In 2011, transmission expansion projects identified as needed to meet Transmission Service Requests totaled $430 million, and projects needed to meet Generation Interconnection requests totaled $69 million.

Attachment AQ defines a process through which delivery point additions, modifications, or abandonments can be studied without having to go through the Aggregate Study process. During 2011, 84 delivery point requests were made; of which nine required full studies.

Attachment AR defines a screening process used to evaluate potential Long-Term Service Request (LTSR) options or proposed Delivery Point Transfers (DPT). During 2011, two DPT requests were made and granted service. Fifteen LTSR studies were requested; of which thirteen were posted and two were withdrawn.

**Sub-regional and Local Area Planning**
Each year SPP holds a series of local planning meetings to discuss local transmission user needs.

- SPP held a sub-regional planning meeting in Dallas, TX.
- SPP representatives attended a local planning meeting hosted by Southwestern Public Service Company (SPS) in Amarillo, TX.
- SPP attended other local meetings with member cooperatives and American Electric Power

**2011 Transmission Congestion and Top Flowgates**
SPP monitors congestion on the transmission grid and identifies the region’s top 10 congested flowgates. When projects from SPP’s study processes are built, the new facilities often lower production costs and reduce congestion. SPP provides a list of projects that are expected to provide some positive mitigation for the annual top 10 congested flowgates.

**Interregional Coordination:** In addition to regional planning, SPP conducts interregional planning with neighboring systems. Activities included:

- In June 2011, the joint study team consisting of transmission planning engineers from Entergy, SPP ICT, and SPPRTO shared the results of the 2010 Entergy/SPP Regional Planning Process (ESRPP) study efforts.
Executive Summary

- In the August 2011 ESRPP meeting, an overview of initial results for the stakeholder’s regional 2011 economic studies were presented.
- AECI participated on many of the SPP TWG and ESWG calls. AECI worked closely with SPP staff and stakeholders on Branson area project studies, as well as provided input on other seams projects connecting to their territory.
- MISO and SPP increased coordination regarding data sharing to ensure that each organization is modeling the other’s system appropriately.
- In preparation for the 2013 ITP20 SPP and MISO have been working to develop a set of assumptions for a future which will be studied by both SPP and MISO.
- SPP has worked with WAPA in the ITP10 planning cycle, specifically regarding projects in Nebraska which could impact WAPA facilities.
- The Eastern Interconnection Planning Collaborative (EIPC) represents the entire Eastern Interconnection and was initiated by a coalition of NERC-registered regional Planning Authorities.

Project Tracking

After the Board approves transmission expansion projects, or once appropriate agreements are filed with FERC, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners. In 2011, SPP issued 21 NTC letters with estimated construction costs of $854.4 million.

SPP actively monitors the progress of approved projects by soliciting feedback from project owners. In 2011, 99 upgrades were completed.

Public Policy Impacts

From a policy perspective, initiatives such as smart grid, renewable targets and mandates, demand response penetration, and new environmental regulations will continue to impact how the transmission system is planned and operated. In addition to policy implications, NERC and regional standards continue to be written and revised. Other environmental impacts have influenced SPP’s recent decisions, and as the transmission grid continues to expand, SPP should be prepared to consider these environmental issues when planning future transmission projects.

Summary of Network Upgrades

The 2012 STEP summarizes transmission planning efforts including ITP10, ITPNT, local reliability, Generation Interconnection, Transmission Service, Balanced Portfolio, and Priority Projects. This summary also includes information from previous STEP reports which identified projects that are currently in the project tracking stages.

SPP has major 345 kV projects in various stages of approval or sponsorship that were studied during the 2012 Attachment O processes:

- American Electric Power to construct:
  - 33 miles of 345 kV transmission line from Turk in southwest Arkansas to Northwest Texarkana in northeast Texas
  - 76 miles of 345 kV transmission line from Northwest Texarkana to Valliant in southeast Oklahoma
  - 18 miles of 345 kV transmission line from Flint Creek to Shipe Road in northwest Arkansas
55 miles of 345 kV transmission line from Shipe Road to Osage Creek (passing near East Rogers) in northwest Arkansas
55 miles of 345 kV transmission line from Welsh to Lake Hawkins in northeast Texas

American Electric Power and Oklahoma Gas & Electric Company to construct:
93 miles of 345 kV transmission line from Elk City to Gracemont in western Oklahoma

Associated Electric Cooperative to construct:
108 miles of 345 kV transmission line from Blackberry in southwest Missouri to Sportsman in northeast Oklahoma

Kansas City Power & Light to construct:
30 miles of 345 kV transmission line from Iatan to Nashua in northwest Missouri

KCP&L Greater Missouri Operation Company and Omaha Public Power District to construct:
181 miles of 345 kV transmission line from Sibley to Maryville to Nebraska City in northwest Missouri and southeast Nebraska

ITC Great Plains to construct:
19 miles of 345 kV transmission line from Hugo Power Station to Valliant in southeast Oklahoma
90 miles of 345 kV transmission line from Spearville to Post Rock (Knoll) in west Kansas
114 miles 345 kV double circuit transmission line from Spearville to Clark Co to Thistle in southwest Kansas

ITC Great Plains and Nebraska Public Power District to construct:
125 miles of 345 kV transmission line from Post Rock (Knoll) in west Kansas to Axtell in southern Nebraska

ITC Great Plains and Westar Energy to construct:
58 miles of 345 kV transmission line from Elm Creek to Summit in north central Kansas

Nebraska Public Power District to construct:
222 miles of 345 kV transmission line from Gentleman to Cherry County to Holt County in northwestern Nebraska
40 miles of 345 kV transmission line from Neligh to Hoskins in north central Nebraska

Prairie Wind Transmission to construct:
78 miles double circuit 345 kV transmission line from Thistle to Wichita in south Kansas

Oklahoma Gas and Electric Company and Prairie Wind Transmission to construct:
110 miles of double circuit 345 kV transmission line from Thistle to Woodward District EHV in northwest Oklahoma and southwest Kansas

Oklahoma Gas and Electric and Westar Energy to construct:
• 106 miles of 345 kV transmission line from Rose Hill in central Kansas to Sooner in central Oklahoma

• Oklahoma Gas and Electric to construct:
  o 36 miles of 345 kV transmission line from Sooner to Cleveland in central Oklahoma
  o 120 miles of 345 kV transmission line from Hugo to Sunnyside in southern Oklahoma
  o 100 miles of 345 kV transmission line from Seminole to Muskogee in central Oklahoma
  o 5 miles of 345 kV transmission line from Arcadia to Redbud in central Oklahoma
  o 126 miles of 345 kV transmission line from Woodward District EHV to Tatonga to Mathweson to Cimarron in northwestern Oklahoma

• Oklahoma Gas and Electric and Southwestern Public Service Company to construct:
  o 250 miles of 345 kV transmission line from Woodward District EHV in west Oklahoma to Oklahoma/Texas Stateline to Tuco in west Texas
  o 122 miles of double circuit 345 kV transmission line from Hitchland to Woodward EHV in northwest Oklahoma

• Southwestern Public Service Company to construct:
  o 15 miles of 345 kV transmission line from Tuco to New Deal in west Texas
  o 167 miles of 345 kV transmission line from Tuco to Amoco to Hobbs in west Texas

As transmission usage and generation changes, proposed and approved projects are subject to evaluation. Appendix A projects can be re-evaluated by the SPP RTO for “best” regional and/or local area solutions. Even though many are approved, Network Upgrades listed in Appendix A are not considered beyond the scope of re-evaluation. Transmission Network Upgrades approved for construction have the opportunity for additional review on a case-by-case basis. The goal of re-evaluation is to investigate viable alternatives considering new information and then determine if a more regionally-beneficial solution exists. This also takes into account long-term strategy and regional needs.
Section 1: Integrated Transmission Planning

1.1: What is Integrated Transmission Planning?

The Integrated Transmission Plan (ITP) is a three-year study process which assesses the SPP region's transmission needs in the long and near-term with the intention of creating a cost-effective, flexible, and robust transmission network that will improve access to the region’s diverse generating resources. Along with the Highway/Byway cost allocation methodology, the ITP process as described in the SPP Attachment O, approved by the FERC in July 2010, promotes transmission investment that will meet reliability, economic, and public policy needs. This report documents analysis of the ITP process, which focused on planning for SPP’s near-term regional reliability needs.

ITP development was driven by the Synergistic Planning Project Team (SPPT), which was created by the SPP Board of Directors (BOD) to address gaps and conflicts in all of SPP’s transmission planning processes including Generation Interconnection and Transmission Service; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities. The ITP is based on the SPPT’s planning principles, which emphasize the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP’s future needs. The first phase of the ITP process was completed with the BOD’s acceptance of the ITP Report on January 25, 2011. The next phases of the ITP process were developed concurrently (ITP10 and ITPNT) as required by OATT Attachment O Section III.4 and III.5.

1.2: 2012 ITP Near-Term (ITPNT)

The 2012 ITPNT analyzes the SPP region’s immediate transmission needs. The goals of the ITPNT are to not only preserve grid reliability, in compliance with NERC Reliability Standards and individual transmission owner planning requirements, but to also efficiently bridge SPP’s 10-year and 20-year plans that meet public policy objectives and provide access to more economic energy sources. The ITPNT assesses: (a) regional upgrades required to maintain reliability in accordance with the NERC Reliability Standards and SPP Criteria in the near term horizon, (b) zonal upgrades required to maintain reliability in accordance with more stringent individual Transmission Owner planning criteria in the near term horizon, and (c) coordinated projects with neighboring Transmission Providers.

ITPNT projects are reviewed by SPP’s Transmission Working Group (TWG), Markets and Operations Policy Committee (MOPC) and approved by the Board. Following Board approval, staff will issue Notification to Construct (NTC) letters for projects needed within the four-year financial commitment timeframe. Currently NTC letters direct the start of construction and qualify for full cost recovery of any costs expended for an upgrade. Since the Conditional Notification to Construct (CNTC) Business Practice is under development, SPP recommends an interim procedure for the 2012 ITPNT projects that qualify for CNTCs (above 100 kV and cost estimate over $20 million). SPP will issue NTCs for these projects with language initiating a refined cost estimate analysis, but not directing the start of construction. SPP will send the NTCs to the incumbent Transmission Owner(s) for each project. Projects for which financial commitment is not required within the four-year window will receive an Authorization to Plan (ATP), which authorizes a TO to plan for a project but does not allow any cost

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2 The Conditional Notifications to Construct concept was developed by the Project Cost Task Force as part of their whitepaper. The whitepaper was approved in July 2011.
recovery through the SPP OATT. A list of ATP projects will be posted on the SPP website contingent 
upon approval of the ATP Business Practice. Once the ATPs are posted, SPP will include them in future 
SPP Aggregate Study models in the appropriate model year.

SPP developed models for the 2012 ITPNT analysis based on the SPP Model Development Working 
Group (MDWG) models, for which transmission owners and balancing authorities provided generation 
dispatch and load information. The study scope – approved by the TWG in November 2010 –contains:

- The years and seasons to be modeled, including 2012-2017
- Treatment of upgrades in the models
- Scenario cases to be evaluated
- Description of the contingency analysis and monitored facilities
- Any new special conditions that are modeled or evaluated for the study

SPP performed reliability analyses identifying potential bulk power system problems. These findings 
were presented to Transmission Owners and stakeholders to solicit transmission solutions. Also 
considered were transmission options from other SPP studies, such as the Aggregate Study and 
Generation Interconnection processes. From the resulting list of potential solutions, staff identified the 
best regional solutions for potential reliability violations. Staff presented these solutions for member and 
stakeholder review at SPP’s July and September 2011 the planning summits. Through this process, SPP 
developed a final list of 69 kV and above solutions necessary to ensure the reliability in the SPP region 
in the near-term.

Figure 2 summarizes Engineering and Construction (E&C) cost estimates for new and modified 
reliability projects needed in the years 2012-2017, totaling $251 million. This is in addition to the 
upgrades previously approved by the Board and does not include $190 million in upgrades with active 
NTCs that need to be withdrawn.
1.3: 2012 ITP10

The second phase of the ITP study process included the first ITP 10-Year (ITP10) and ITP Near-Term (ITPNT) Assessments performed under the requirements of OATT Attachment O, Section III. The study process for this ITP10 utilized a diverse array of power system and economic analysis tools to evaluate the need for 100 kV and above facility projects that satisfy needs such as:

a) resolving potential criteria violations;

b) mitigating known or foreseen congestion;

c) improving access to markets;

d) staging transmission expansion; and

e) improving interconnections.

The recommended portfolio included projects ranging from comprehensive regional solutions to local reliability upgrades to address the expected reliability, economic, and policy needs of the studied 10-year horizon.

Two distinct futures were considered to account for possible variations in system conditions over the assessment’s 10-year horizon.

1. Business As Usual: This future utilized today’s current state and utility renewable goals and targets for 2022, current generation resource plans, and current load forecasts.

2. EPA Rules with Additional Wind: This future utilized anticipated increases above the current state renewable targets and approximated the impact of proposed EPA rulemaking (as of April 1, 2011) by imposing retirements on small coal plants.

The futures were approved by the Strategic Planning Committee (SPC) and further refined by the Economic Studies Working Group (ESWG), using data from a Cost Allocation Working Group (CAWG) renewables survey. The Transmission Working Group (TWG) provided oversight on the analysis details and reliability needs.

The recommended 2012 ITP10 portfolio shown in the figure below was estimated at $1.5 billion engineering and construction cost and includes projects needed to meet potential reliability, economic, and policy requirements. Within this portfolio, economic projects, estimated at $206 million engineering and construction cost with a total estimated net present value revenue requirement of $302 million, are expected to provide net benefits of approximately $596 million over the life of the projects under a Future 1 scenario containing 10 GW of wind capacity. Project need dates were identified as early as 2014 and as late as 2022. Several projects were identified for ATP status and one project for NTC status. The remaining projects were identified to receive CNTCs.

Nine projects make up the greater part of the portfolio:

- Lake Hawkins – Welsh 345 kV line with a 345/138 kV transformer at Lake Hawkins
- Elk City – Gracemont 345 kV line with a 345/230 kV transformer at Elk City
- Woodward – Tatonga – Cimarron 345 kV line, a second circuit
- Summit – Elm Creek 345 kV line with a 345/230 kV transformer at Elm Creek
- Neligh – Hoskins 345 kV line with a 345/115 kV transformer at Neligh
- Gentleman – Cherry Co. – Holt Co. 345 kV line with two substations

3 In June 2011, the EPA approved the Cross-State Air Pollution Rule (CSAPR) which imposes new restrictions on emissions. This ruling was well after the start of the 2012 ITP10 analysis and therefore, impacts of this ruling were not incorporated into this study. SPP is currently assessing how to best assess the impact of this rule.
- Eastowne Transformer 345/161 kV
- Moundridge Transformer 138/115 kV
- Tuco – Amoco – Hobbs 345 kV with 345/230 kV transformers at Amoco and Hobbs

Figure 3: 2012 ITP10 Proposed Expansion
**Historical Evolution of the ITP**

The 2012 ITP10 incorporated elements from key studies performed by SPP will continue to mature through each successive ITP10 cycle. Past SPP studies such as the EHV Overlay, Wind Integration Task Force, Balanced Portfolio, Priority Projects, and 2010 ITP20 were designed by the organization’s stakeholders to improve planning and operational aspects of the SPP grid. These studies shared several key goals that have been incorporated into the ITP10 study process as part of the Synergistic Planning Project Team’s vision.

SPP staff and stakeholders approached the ITP10 with goals of improving grid flexibility and cost-effectiveness, increasing reliability, preparing for future needs, and integrating SPP’s western and eastern sections by developing a robust transmission system.

**How Does the ITP10 Compare to the ITP20**

The 2012 ITP10 was similar to the 2010 ITP20. The 2010 ITP20 futures were used as a guide for development of the futures most likely to occur within the current 10-year horizon.

Economic and reliability analysis were utilized to define required projects. Economic analysis determined those projects that are the best project alternatives for the 10-year plan. Projects were placed in the economic model and a full economic assessment was performed. The results from the analysis were used to calculate benefit metrics.

Projects from the economic assessment were coupled with the results of the reliability assessment to determine optimal solutions. Issues identified that are not resolved with 100 kV and above solutions will be deferred and addressed in the ITPNT for resolution.

**2010 ITP20**

The SPP BOD voted to approve the ITP20 Report on January 25, 2011. The cost of the plan was estimated at $1.8 billion through the construction of 1,494 miles of 345 kV lines along with 11 various - 345 kV step-down transformers. The full report is available on [www.spp.org](http://www.spp.org).

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4 [SPP.org > Engineering > Transmission Planning > 2010 ITP20 Report](http://www.spp.org)
Section 2: Tariff Studies

Staff conducts studies to determine if the SPP transmission system can accommodate activity over and above that which is currently in use. Whenever new transmission transactions, modifications to existing transmission transactions, and applicable generation interconnection requests are made, SPP performs tariff studies, including feasibility, system impact, and facilities studies in accordance with SPP’s Aggregate Transmission Study and Generation Interconnection study processes. SPP notifies the requestor of SPP’s approval or denial of the transmission service request.

A cost estimate summary of all Transmission Service Request (TSR) and Generation Interconnection (GI) projects with filed service agreements documented in the 2012 STEP report is shown below:

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<td>(TSR) transmission service*</td>
<td>$433</td>
<td>$550</td>
<td>$455</td>
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<td>(GI) Generation Interconnection</td>
<td>$69</td>
<td>$103</td>
<td>$81</td>
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<td>TSR/GI Sub Total</td>
<td>$502</td>
<td>$653</td>
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*Regional reliability upgrades associated with transmission service are included in the ITP subtotal in this report

2.1: Transmission Service 2011 Overview

During 2011, SPP’s Tariff Studies staff posted Aggregate Facility Studies to meet 60-day study completion deadlines and posted Facilities Studies to meet FERC Order 890 metric requirements. Order 890 requires Transmission Providers to file notice with FERC if more than 20% of the System Impact and Facilities studies in any two consecutive calendar quarters are not completed in the 60-day study window. In 2011, the following percentages were late:

- Quarter 1 – 0%
- Quarter 2 – 0%
- Quarter 3 – 0%
- Quarter 4 – 0%

SPP was not required to file with FERC, as there were no two consecutive quarters in which more than 20% of the studies were late, due in large part to the timely submission of documentation by Transmission Owners. As of December 31, 2011, SPP has posted 12 Aggregate Studies. SPP also posted two delivery point transfer screening studies, which led to transmission service.

2.2: Generation Interconnection 2011 Overview

As of October 30, 2011, SPP received 64 GI requests, similar to the 55 received through the same period in 2010. As of that date, there were 74 active queue requests for 12,006MW under study.

The approval of Priority Projects has facilitated the study process for Generation Interconnection. About 6,500MW of additional generation interconnection agreements were approved based on the existence of Priority Projects and Balanced Portfolio.
2.3: Area Generation Connection Task Force 2011 Overview

In April 2010 MOPC created the Area Generation Connection Task Force (AGCTF) to develop policy to guide SPP staff in determining the optimum method of interconnecting generation, considering the many complex situations including multiple generation developers in a concentrated area that may or may not have nearby transmission lines. At its April 2011 meeting, the MOPC accepted the AGCTF’s recommendation to institute a policy of designating generation collector hubs for more efficient planning of the transmission system. The MOPC acceptance was conditioned on the AGCTF working with the applicable working groups for tariff language and business practices as well as following up with the CAWG for cost allocation. AGCTF work is ongoing.

2.4: Tariff Attachments AQ and AR

During 2010, SPP Tariff attachments AQ and AR were approved by FERC. Attachment AQ became effective in May 2010. Attachment AQ defines a process through which delivery point additions, modifications, or abandonments can be studied without having to go through the Aggregate Study process. Delivery points submitted through the process are examined in an initial assessment to determine if a project is likely to have a significant effect on the transmission system. If necessary, a full study is then performed on the requested delivery points to determine any necessary upgrades. During 2011, 84 delivery point requests were made; of which nine required full studies.

Flow chart diagram for AQ Studies
SPP Tariff attachment AR became effective in February 2010. Attachment AR defines a screening process used to evaluate potential Long-Term Service request (LTSR) options or proposed Delivery Point Transfers (DPT). The LTSR option provides customers with a tool to determine which LTSR to pursue in the Aggregate Study process. The DPT option enables customers to implement a DPT via issuance of a service agreement more expeditiously pending the results of the screening. Both of these screening tools allow for a more streamlined aggregate study process by reducing the number of requests in the studies. During 2011, two DPT requests were made and granted service. Fifteen LTSR studies were requested; of which thirteen were posted and two were withdrawn.

Flow Chart for AR process
Section 3: Sub-Regional Planning

Based on FERC Order 890 and Section III.2.b of Attachment O of the OATT, sub-regional areas were defined and local area planning meetings were held during 2011. To reduce travel requirements on members, all SPP sub-regional meetings were conducted in conjunction with the SPP planning summits. In addition, SPP staff attended local meetings held by members.

The purpose of local area planning meetings is to identify unresolved local issues and transmission solutions at a more granular level than can be accomplished at general regional planning meetings. Local area planning meetings provide stakeholders with local needs the opportunity to give advice and recommendations to the Transmission Provider and Transmission Owners. Local area planning meetings are open, coordinated, and transparent, providing a forum to review local area planning criteria as specified in Section II of the OATT, Attachment O. Feedback offered at each sub-regional meeting is taken into consideration by SPP staff when developing the regional reliability plan.

3.1: Stakeholders Process and Forums

Notices for the sub-regional planning meetings are posted on SPP.org and distributed to email distribution lists. Sub-regional planning meetings are open to all entities. Any regulatory agency having utility rates or services jurisdiction over an SPP member is invited and encouraged to fully participate.

The map above represents the SPP region broken into three local areas. Local Area 3 has two components (3 and 3a) – the SPP RTO and SPP Independent Coordinator of Transmission (Entergy) footprints.
3.2: 2011 Sub-regional Meetings

On July 21, 2011, SPP held a sub-regional planning meeting in Dallas, TX. Meetings for all sub-regions were held concurrently after the SPP spring planning summit. Subject matter experts from SPP staff were present at all of the meetings to receive suggestions, answer questions, and discuss any concerns that stakeholders had about the transmission needs in their respective region.

On September 15, 2011, SPP representatives attended a local planning meeting hosted by Southwestern Public Service Company (SPS) in Amarillo, TX. SPS representatives provided several presentations which included updates on their construction plans.

Two meetings were held with the East Texas Electric Cooperative on March 10, 2011 and on October 8, 2011. The meetings were attended by the member cooperatives, American Electric Power, and SPP staff. SPP staff provided an update on current SPP planning activities and fielded questions from meeting attendees.
Section 4: Transmission Congestion and Top Flowgates

4.1: SPP 2011 Transmission Congestion

SPP staff identifies congested areas by monitoring flowgates and analyzing their causes and effects. The graphic below is a typical Energy Imbalance Services market price contour map for the SPP footprint. The map is from the October 2011 Monthly State of the Market Report and shows the average Locational Imbalance Prices (LIPs) from November 2010 to October 2011. The regions with the brighter shades (red, orange, and yellow) have higher LIPs. The areas with transmission congestion, on this annual basis, occur at the points between different shades of colors. Note that market prices vary over time and that the graphic shows the average price at the nodes.

Congestion occurs for a variety of reasons in different parts of the SPP footprint depending on the time of year. One of the drivers of new and future congestion in the SPP footprint is increased wind generation. Wind currently represents about 4% of generation in the SPP region, and is continually developing. As wind farms in the western part of SPP continue to develop, the congestion in that region should increase until adequate transmission is in place.

Congestion in all parts of the footprint can sometimes be attributed to generation and line outages or general load growth. During the non-peak seasons, there are several scheduled transmission and generation outages for maintenance which contributes to localized congestion. For example congestion in the Texas Pandhandle was exacerbated by the outage of the Randall County Interchange – Palo Duro
line, which was being reconducted with a completion date at year-end. In general, the north to south flow on this flowgate can become greater with the fluctuating wind generation in the northern part of the Texas Panhandle.

Factors causing congestion in the Greater Kansas City area included transmission line outages due to scheduled maintenance in the region along with high external impacts. Another contributing factor was heavy north to south flows from Nebraska into the Kansas City area.

Some of the congestion in western Kansas was due to scheduled outages of transmission in the area along with unexpected forced generation outages in the area.

Much of the summer congestion in Oklahoma, near Oklahoma and Tulsa, was due to unplanned outages caused by strong storms coupled with high temperatures and high loads.

Some of the congestion on the Brookline transformers flowgate was due to winter weather that caused several 345 kV line outages in the region.

High north to south flow from inexpensive coal generation caused congestion in Western Nebraska.

4.2: SPP Top 10 Flowgates

SPP monitors more than 260 flowgates. From these, the 10 SPP flowgates with the highest “shadow price” over the previous twelve months are shown in SPP’s Monthly State of the Market Reports posted on www.spp.org>Market and Operations>Market Reports. A shadow price is the amount of value, measured in dollars, of relieving a constraint by a small amount. The value of relieving a constraint is generally that lower-priced power can be used, so the value is reflected in the difference in Locational Imbalance Prices on either side of the constraint.

The table below shows the annual top 10 flowgates from the October 2011 Monthly State of the Market Report. This table includes a list of projects that are expected to provide some positive mitigation to the flowgates. This list of projects is sorted by the estimated in-service date. As described by the upgrade type, the upgrades were planned to provide one or more benefits, such as reliability or regional economic enhancements, but not necessarily to directly solve all congestion on the particular flowgate listed. SPP has directed project owners to begin construction on the projects shown in this table via NTCs. For more information about these projects, please refer to the Project Tracking & NTCs page on www.spp.org.
<table>
<thead>
<tr>
<th>Region</th>
<th>Flowgate Name</th>
<th>Flowgate Location (kV)</th>
<th>Average Hourly Shadow Price ($/MWh)</th>
<th>Total % Intervals (Breached or Binding)</th>
<th>Projects Expected to Provide Some Positive Mitigation (Estimated In Service Date – Upgrade Type)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Texas Panhandle</td>
<td>RANPALAMASWI</td>
<td>Randall County - Palo Duro (115) ftlo Amarillo – Swisher (230) [SPS]</td>
<td>$ 44.13</td>
<td>29.0%</td>
<td>1. Rebuild Randall Co–Palo Duro 115 kV line (Dec 2011 - no NTC but is Sponsored)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. Tuco Int. – Woodward 345 kV line (May 2014 - Balanced Portfolio)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3. Swisher Co. Int. – Newhart 230 kV line (April 2015 - Regional Reliability)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. Castro County Int. – Newhart 115 kV line (April 2015 - Regional Reliability)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. Iatan – Nashua 345 kV line (June 2015 - Balanced Portfolio)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3. Nebraska City – Maryville – Sibley 345 kV line (June 2017 - Priority Projects)</td>
</tr>
<tr>
<td></td>
<td>IASCLKNASJHA</td>
<td>Iatan – Stranger Creek (345)[KCPL] ftlo Lake Road – Nashua (161), St. Joe – Hawthorne (345) [GMOC-KCPL]</td>
<td>$ 4.90</td>
<td>8.9%</td>
<td>1. Iatan – Nashua 345 kV line (June 2015 - Balanced Portfolio)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. Nebraska City – Maryville – Sibley 345 kV line (June 2017 - Priority Projects)</td>
</tr>
<tr>
<td>SW Kansas</td>
<td>HOLPLYHOLSPE</td>
<td>Holcomb – Plymell Switch [SECI] (115) ftlo Holcomb - Spearville [SECI] (345)</td>
<td>$ 3.93</td>
<td>2.0%</td>
<td>1. Rebuild Holcomb – Plymell Switch 115 kV line (June 2012 - Regional Reliability)</td>
</tr>
<tr>
<td>Western Nebraska</td>
<td>GENTLMREDWIL</td>
<td>Gentleman to Red Willow (345) [NPPD]</td>
<td>$ 3.54</td>
<td>5.2%</td>
<td>1. Axtell – Post Rock – Spearville 345 kV lines (June 2013 - Balanced Portfolio)</td>
</tr>
<tr>
<td>Tulsa Area</td>
<td>OKMHENOKMKEL</td>
<td>Okmulgee – Henryetta (138) ftlo Okmulgee – Kelco (138) [CSWS]</td>
<td>$ 2.87</td>
<td>2.4%</td>
<td>1. Tap Pittsburg – Muskogee 345 kV line and add new Canadian River substation and 345/138 kV transformer (June 2013 – Regional Reliability)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. Seminole – Muskogee 345 kV line (December 2013 – Balanced Portfolio)</td>
</tr>
</tbody>
</table>
## Transmission Congestion and Top Flowgates

### Wichita Area

<table>
<thead>
<tr>
<th>ELPFARWICWDR</th>
<th>El Paso – Farber [WR] (138) ftlo Wichita – Woodring [WR-OGE] (345)</th>
<th>$2.76</th>
<th>2.0%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1. Rose Hill – Sooner 345 kV line (June 2012 - Regional Reliability)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2. Two Woodward – Thistle – Wichita 345 kV lines (Dec 2014 - Priority Projects)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Western Oklahoma

<table>
<thead>
<tr>
<th>ELKXFRTUCOKU</th>
<th>Elk City Transformer (230/138) ftlo Tuco – Oklaunion (345) [CSWS]</th>
<th>$2.27</th>
<th>6.2%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1. Elk City – Gracemont 345 kV line and Elk City 345/230 kV Transformer (March 2018 – ITP10) (pending Board)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Southwest Missouri

<table>
<thead>
<tr>
<th>BRKXF1BRKXF2</th>
<th>Brookline Xfmr Ckt1 (345/161) ftlo Brookline Xfmr Ckt2 (345/161) [SPA/AECI]</th>
<th>$2.14</th>
<th>0.4%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1. Flint Creek – Centerton – Osage Creek 345 kV line (June 2016 – Regional Reliability)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The annual top 10 flowgates as of October 2011 are detailed below.
The **RANPALAMASAWI** flowgate, located in the Texas Panhandle, monitors the 115 kV transmission line from Randall County to Palo Duro for the loss of the 230 kV line from Amarillo to Swisher. The percentage of total intervals breached or binding over the last twelve months is 29%. This flowgate had an average shadow price of $44.13.

The Randall County to Palo Duro 115 kV line is being rebuilt with a larger conductor and this work is expected to be complete by the end of December 2011. This upgrade is expected to provide some positive mitigation for this congestion. Another project that is expected to provide some mitigation is the Tuco to Woodward 345 kV line, a new link between Texas and Oklahoma that is part of the Balanced Portfolio that should be in service in 2014. A third project expected to provide some mitigation is the Swisher County Interchange to Newhart 230 kV line in the southern part of the Texas Panhandle, a regional reliability upgrade that should be in service in 2015.
The **OSGCANBUSDEA** flowgate, located in the Texas Panhandle, monitors the 115 kV transmission line from Osage Switch to Canyon East for the loss of the 230 kV line from Bushland to Deaf Smith. The percentage of total intervals breached or binding over the last twelve months is 19.2%. This flowgate had the highest average shadow price at $21.36.

The Tuco to Woodward 345 kV line, a new link between Texas and Oklahoma that is part of the Balanced Portfolio, is expected to provide some positive mitigation for this congestion when it goes into service in 2014. Another project that is expected to provide some mitigation is the Castro County Interchange to Newhart 115 kV line in the southern part of the Texas Panhandle, a regional reliability project that should be in service in 2015.
The **LAKALASTJHAW** flowgate, located in the Kansas City area, monitors the 161 kV transmission line from Lake Road to Alabama for the loss of the 345 kV line from St. Joe to Hawthorn. The percentage of total intervals breached or binding over the last twelve months is 1.9%. This flowgate had an average shadow price of $6.90.

Some Balanced Portfolio and Priority Project upgrades spanning Nebraska, Kansas, and Oklahoma are expected to provide some positive mitigation for this congestion when all are in service in 2014. These upgrades include the Axtell to Post Rock to Spearville 345 kV line, the Spearville to Comanche County to Thistle to Wichita double-circuit 345 kV, and Thistle to Woodward double-circuit 345 kV lines. Another project that is expected to provide some mitigation is the Iatan to Nashua 345 kV line north of Kansas City, part of the Balanced Portfolio that should be in service in 2015. Other projects expected to provide some mitigation are the Nebraska City to Maryville to Sibley 345 kV lines running from southeastern Nebraska to northwestern Missouri, a Priority Project which is estimated to be in service by 2017.
The IASCLKNASJHA flowgate, located in the Kansas City area, monitors the 345 kV transmission line from Iatan to Stranger Creek for the loss of the 161 kV line from Lake Road to Nashua and the 345 kV line from St. Joe to Hawthorn. The percentage of total intervals breached or binding over the last twelve months is 8.9%. This flowgate had an average shadow price of $4.90.

The Iatan to Nashua 345 kV line north of Kansas City, part of the Balanced Portfolio that should be in service in 2015, is expected to provide some positive mitigation for this congestion. Other upgrades that are expected to provide some mitigation are the Nebraska City to Maryville to Sibley 345 kV lines running from southeastern Nebraska to northwestern Missouri, a Priority Project which is estimated to be in service by 2017.
The **HOLPLYHOLSPE** flowgate, located in Southwest Kansas, monitors the 115 kV transmission line from Holcomb to Plymell Switch for the loss of the 345 kV line from Holcomb to Spearville. The percentage of total intervals breached or binding over the last twelve months is 2.0%. This flowgate had an average shadow price of $3.93.

The Holcomb to Plymell Switch 115 kV line will be rebuilt with a larger conductor in 2012 for regional reliability, which is expected to provide some positive mitigation for this congestion.
The **GENTLMREDWIL** flowgate, located in Western Nebraska, monitors the 345 kV transmission line from Gentleman to Red Willow. The percentage of total intervals breached or binding over the last twelve months is 5.2%. This flowgate had an average shadow price of $3.54.

The Axtell to Post Rock to Spearville 345 kV lines, part of the Balanced Portfolio that should be in service in 2013, are expected to provide some positive mitigation for this congestion. These lines will provide additional transmission capacity between southern Nebraska and Kansas.
The **OKMHENOKMKEL** flowgate, located in the Tulsa area, monitors the 138 kV transmission line from Okmulgee to Henryetta for the loss of the 138 kV line from Okmulgee to Kelco. The percentage of total intervals breached or binding over the last twelve months is 2.4%. This flowgate had an average shadow price of $2.87.

The new Canadian River substation and 345/138 kV transformer that is being tapped into the Pittsburg to Muskogee 345 kV line is expected to provide some positive mitigation for this congestion. This is a regional reliability upgrade south of Tulsa with an in service date of 2013. Another upgrade that is expected to provide some mitigation is the new 345 kV line from Seminole to Muskogee in central Oklahoma, part of the Balanced Portfolio which is estimated to be in service by 2013.
The **ELPFARWICWDR** flowgate, located in the Wichita area, monitors the 138 kV transmission line from El Paso to Farber for the loss of the 345 kV line from Wichita to Woodring. The percentage of total intervals breached or binding over the last twelve months is 2.0%. This flowgate had an average shadow price of $2.76.

The Rose Hill to Sooner 345 kV line, a regional reliability upgrade that crosses the Kansas/Oklahoma border, is expected to provide some positive mitigation for this congestion when it goes into service in 2012. Other upgrades that are expected to provide some mitigation are the double-circuit 345 kV lines from Woodward to Thistle to Wichita in northwestern Oklahoma and southern Kansas, part of the Priority Project upgrades which are estimated to be in service by 2014.
The ELKXFRTUCOKU flowgate, located in Western Oklahoma, monitors the 230/138 kV transformer at Elk City for the loss of the 345 kV line from Tuco to Oklaunion. The percentage of total intervals breached or binding over the last twelve months is 6.2%. This flowgate had an average shadow price of $2.27.

At this time, there are no approved upgrades expected to provide significant mitigation. However, a new 345 kV line from Elk City to Gracemont and a new 345/230 kV transformer at Elk City, would be expected to provide some positive mitigation. These upgrades are being proposed for approval as part of the 2012 ITP10 Portfolio and would go into service in 2018.
The **BRKXF1BRKXF2** flowgate, located in Southwest Missouri, monitors the first 345/161 kV transformer at Brookline for the loss of the second 345/161 kV transformer at Brookline. The percentage of total intervals breached or binding over the last twelve months is 0.4%. This flowgate had an average shadow price of $2.14.

The Flint Creek to Centerton to Osage Creek 345 kV lines, regional reliability upgrades in Northwestern Arkansas, are expected to provide some positive mitigation for this congestion when they go into service in 2016.
Section 5: Interregional Coordination

As SPP pursues its strategy of building a robust transmission system, coordination between SPP and systems neighboring our footprint will become increasingly critical. In 2010, MOPC formed the Seams Steering Committee (SSC) to provide direction regarding development and implementation of SPP’s seams agreements. The SSC will continue to focus on further development of seams coordination, particularly improved modeling of neighboring transmission systems, coordinated development of interregional solutions, and sharing costs of projects that comprise interregional solutions.

To achieve a robust transmission grid, transmission expansion at or near SPP’s seams will be necessary. Interregional funding will be necessary to achieve these objectives. SPP staff needs to be fully engaged in these efforts.

5.1: SPP RTO and Entergy ICT

As the Independent Coordinator of Transmission (ICT) for Entergy Services, Inc. (Entergy), SPP facilitates transmission planning for Entergy. The SPP RTO and ICT coordinate planning study conclusions and look for opportunities to collaborate on seams-related transmission improvements. These investigations include evaluation of third-party impacts identified from transmission service requests on both systems. The SPP RTO and ICT continue to work closely on the Joint Coordinated System Plan study, and both groups are involved in the SERC Reliability Corporation’s planning processes.

5.2: Entergy/SPP Regional Planning Process

In accordance with FERC Order 890, SPP OATT Attachment O, and Entergy OATT Attachment K, the Entergy/SPP Regional Planning Process (ESRPP) was created to identify system enhancements that could relieve interregional congestion between Entergy and SPP, and to share system plans to ensure they are simultaneously feasible and otherwise use consistent assumptions and data.

Up to five high-level studies can be requested annually to provide screening to identify constraints and needed upgrades, and to approximate costs and timelines. Based on the results of these high level studies, stakeholders may request a more detailed study to be undertaken in the following planning cycle which will provide detailed cost estimates and timelines.

In June 2011, the joint study team consisting of transmission planning engineers from Entergy, SPP ICT, and SPP RTO, shared the results of the 2010 ESRPP study efforts. These five ESRPP studies were discussed:

- Transfer of 3000 MW from Arkansas IPPs (Hot Springs, Magnet Cove, and PUPP) to SPP South (AEP and OG&E)
- Transfer of 700 MW from AEPW to Entergy Arkansas
- Transfer of 700 MW from Entergy Arkansas to AEPW
- Transmission Upgrade: Messick 500/230 kV Transformer
- Transmission Upgrade: Turk – McNeil 345kV Line
The transfer analysis results were presented along with project cost estimates. For example, the total project cost to enable the transfer of 3000 MW from the Arkansas IPPs to SPP South was $815 million. The ESRPP projects developed from these analyses can be used to optimize the SPP ITP studies and the Entergy Construction Plan.

The ESRPP kicked-off its 2011 efforts at the same June 2011 meeting. Via email vote in July 2011, stakeholders chose the five regional economic studies to be performed in 2011 for either high-level studies or more detailed analyses:

**Detailed Studies as a continuation from 2010 ESRPP;**

- Transfer of 2408 MW from Arkansas IPPs (Hot Springs, Magnet Cove, and PUPP) to SPP South (AEP and OG&E)
- Transfer of 1117 MW from AEPW to Entergy Arkansas

**New High-level Studies**

- Transfer of 500 MW from Entergy to EMDE
- Transfer of 3000 MW from Nebraska to Entergy
- Transfer of 3000 MW from Entergy to Nebraska

In the August 2011 ESRPP meeting, an overview of the initial results for the stakeholders’ regional 2011 economic studies was presented. At this meeting, the stakeholders provided modeling updates and feedback about how to better present the study results. In the first quarter of 2012, it is expected that the ESRPP 2011 Report will be completed and presented at an ESRPP meeting.

**5.3: AECI Interaction**

AECI participated on many of the SPP TWG and ESWG calls. AECI worked closely with SPP staff and stakeholders on Branson area project studies, as well as provided input on other seams projects connecting to their territory.

**5.4: MISO Data Coordination**

MISO and SPP increased coordination regarding data sharing to ensure that each organization is modeling the other’s system appropriately. Since SPP and MISO use the same or similar modeling software, each RTO was able to simply send each other their modeling database. SPP incorporated the MISO data into the SPP model, increasing the confidence in the modeling of the seam between SPP and MISO.

In preparation for the 2013 ITP20, SPP and MISO are developing a set of assumptions for a future that will be studied by both SPP and MISO. This joint future will allow each RTO to examine the benefits of a transmission project while using the same assumptions.

**5.5: WAPA- Basin Electric Interaction**

SPP has worked with WAPA in the ITP10 planning cycle, specifically regarding projects in Nebraska that could impact WAPA facilities. One project in particular is recommended to interconnect with WAPA’s 345 kV line from Ft. Thompson to Grand Island. SPP shared modeling data with WAPA and WAPA has performed analysis regarding the impact the SPP proposed project would have on WAPA’s system.
5.6: Eastern Interconnection Planning Collaborative

The Eastern Interconnection Planning Collaborative (EIPC) represents the entire Eastern Interconnection and was initiated by a coalition of NERC-registered regional Planning Authorities. The EIPC was founded to be a broad-based, transparent collaborative process among all interested stakeholders:

- State and federal policy makers
- Consumer and environmental interests
- Transmission Planning Authorities
- Market participants within the Eastern Interconnection

The EIPC builds on the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities. This approach provides coordinated interregional analysis for the entire Eastern Interconnection guided by the consensus input of an open and transparent stakeholder process.

The EIPC represents a first of its kind effort to involve Eastern Interconnection Planning Authorities in modeling the impact on the grid of various policy options determined to be of interest by state, provincial, and federal policy makers and other stakeholders. This work will build on, rather than replace, current local and regional transmission planning processes developed by the Planning Authorities and associated regional stakeholder groups within the Eastern Interconnection. Those processes will be informed by EIPC efforts, including the interconnection-wide review of existing regional plans and development of transmission options associated with the various policy options.

The EIPC will establish processes for aggregating the entire Eastern Interconnection’s modeling and regional transmission plans. The EIPC will also establish processes for performing interregional analyses to identify potential opportunities for efficiencies between regions in serving the needs of electrical customers. This interconnection-wide analysis will also serve as the reference case for modeling alternative grid expansions based on scenarios guided by stakeholder input and consensus recommendations of a multi-constituency stakeholder steering committee. The analysis will aid states and other stakeholders in assessing interregional options and policy decisions.

The project will benefit power system stakeholders by providing modeling and analysis considering the entire Eastern Interconnection, identifying potential opportunities for efficiencies between regional transmission plans, providing coordinated analysis of scenarios of interest to policy makers and stakeholders, and developing potential transmission expansion options and cost estimates to inform their decisions.

SPP Engineering Involvement

The SPP Engineering department has been actively involved in multiple aspects of the EIPC effort. Having participated in the construction of the steady state load flow models, the Steady State Model Load Flow Working Group (SSMLFWG) submitted their work to the EIPC at the end of 2010. In 2011, SPP participated in quarterly Stakeholder Planning Committee (SPC) meetings and provided input and advice during the macroeconomic resource expansion analysis. This analysis produced more than 80 possible scenarios, from which three were selected in 2011 for transmission build-out in 2012. In 2012, SPP will remain involved in EIPC process by participating in SPC meetings and assisting in the transmission build-out and production cost analysis studies.
Section 6: Project Tracking

Project Cost Overview
With the implementation of SPP’s Highway/Byway cost allocation methodology, additional scrutiny is warranted in reviewing changes to regionally funded project cost estimates for projects that were a result of an SPP process. In the past, transmission cost estimates tended to remain internal to each member utility, subject only to the utility’s internal review processes and any applicable obligations to its regulatory authorities. At its October 25, 2010, meeting, the SPP Regional State Committee (RSC) passed five motions to provide an evaluation of costs for regionally funded projects:

- **Motion 1:** SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.
- **Motion 2:** SPP review the Novation Process and report to the RSC by April 2011.
- **Motion 3** SPP consider establishing design and construction standards for transmission projects at 200 kV and above that are regionally funded.
- **Motion 4:** SPP evaluate how cost estimates are established for transmission projects before cost benefit analyses are performed.
- **Motion 5:** CAWG to study various methods on how costs that exceed some standard can be addressed with different cost allocation mechanisms and recommend strategies to the RSC.

Project Cost Task Force (PCTF)
The MOPC formed the (PCTF) to address the RSC motions 1 and 4. The PCTF and SPP staff were charged with creating a standardized and transparent method for the development of transmission project cost estimates associated with regionally funded projects. The group developed multiple enhancements to the tracking and cost estimate processes for projects upon which SPP will perform cost benefit analyses.

The PCTF whitepaper that details the new cost estimation process and project tracking enhancements was approved by the MOPC at its July 2011 meeting. Any project that is issued an NTC or CNTC after this date is subject to the processes described within the whitepaper.

Design Best Practices and Performance Criteria Task Force (DBPPCTF)
The DBPPCTF was approved by the SPC to address RSC motion 3. The DBPPCTF was tasked with establishing Design Best Practices and Performance Criteria (DBP&PC) to be used by the SPP Transmission Owner (TO) in developing study estimates for SPP footprint projects rated at voltages at 100 kV and greater. The DBP&PC would be intended to promote consistency in TO study stage estimates.

With this charge, the DBPPCTF developed the SPP Design Best Practices, Performance Criteria and Scoping Guidelines for Transmission Facilities outline. In addition to the DBP&PC, the document also contains scoping guidelines for the conceptual and study estimate phases. These guidelines are intended to promote mutual understanding of the project definition between SPP and the TO as the project is developed and estimates are prepared for the applicable phase of the potential project.

The TO study estimate assumptions are detailed in the Standardized Cost Estimate Reporting Template (SCERT) as used by the SPP project cost tracking process.
**Project Cost Working Group (PCWG)**

The role of the PCWG was defined in the PCTF whitepaper as a stakeholder group that would be responsible for reviewing projects that have experienced a cost variance that exceeds a specified bandwidth. Initially, the PCWG will review only projects rated with a voltage at 300 kV and above and a cost estimate greater than $20 million. After the process is refined, the criteria will expand to include projects rated with a voltage at 100 kV and above and a cost estimate greater than $20 million.

If the PCWG recommends a restudy and/or changes or revocation of an NTC, the recommendation to the MOPC would follow SPP’s existing processes for approval to the BOD. The BOD will make the final determination on whether to restudy and/or change or revoke the NTC.

The PCWG is also responsible for maintaining the SCERT that was established in the PCTF whitepaper and the Study Estimate Design Guide (SEDG) that was developed by the DBPPCTF. In its first meeting on September 15, 2011, the PCWG reviewed a new version of the SCERT that consolidated the original version located in Appendix A of the PCTF whitepaper with the Study Estimate Scope Requirements listed in the SEDG. SPP Staff issued the updated SCERT for TOs to use for providing study estimates for potential ITP10 projects.

**ITP10 Study Estimates**

The cost data provided in ITP 10 is based on the Study Estimates received from the TOs that were designated to each project.

Should the BOD approve an ITP10 project with a voltage rating above 100 kV and with a study estimate greater than $20 million, SPP will issue that project’s Designated Transmission Owner (DTO) a CNTC. The PCTF whitepaper defines the expected precision bandwidth of a study estimate to be +/- 30%. The CNTC issuance is an initiative to the DTO(s) to perform any cost estimate analysis not previously done to improve the accuracy of the study estimate such that the DTO(s) will be within a +/- 20% precision bandwidth. The updated cost estimate, referred to as the CNTC Project Estimate (CPE), should be submitted to SPP no later than four months prior to the start of the next ITP10 process cycle.

If the CPE variance bandwidth of +/- 20% does not exceed the study estimate variance bandwidth of +/- 30%, the project’s cost variance will be deemed acceptable and will be immediately issued an NTC by SPP staff. This will be the authorization for the DTO to proceed with the project.

If the CPE variance bandwidth exceeds the variance bandwidth of the study estimate, SPP staff will re-evaluate this project using the new cost estimate data and will make a recommendation to the BOD at its next scheduled quarterly meeting. SPP staff’s recommendation could be but is not limited to one of the following actions:

1. Accept the cost variance and approve the project as is
2. Modify the existing project
3. Replace the project with an alternative solution
4. Cancel the project

The study estimate received from the DTO for these projects will be used as the initial baseline for measuring final project approval. If the cost variation of the CPE is accepted by the BOD, the CPE will be used as a final baseline for reporting all cost estimate changes during the project tracking process and will be the basis for determining project variance.

For approved ITP10 projects with a voltage rating below 100 kV or a Study Estimate less than $20 million, SPP will issue that project’s DTO a NTC. If the DTO accepts the NTC, it shall respond as
prescribed in the NTC letter and provide SPP with a refined study cost estimate. This estimate is referred to as the NTC Project Estimate (NPE).

The NPE received from the DTO for these projects will be used as the final baseline for reporting all cost estimate changes during the project tracking process and will be the basis for determining project variance.

After the BOD approves a transmission project and a NTC is issued, SPP tracks and monitors the projects to ensure they continue to provide the best regional transmission solutions and, where applicable, are following cost recovery requirements under the OATT. SPP provides quarterly project status updates to the BOD on approved transmission projects.

**NTC Letters Issued in 2011**

The NTC, previously called a Letter of Authorization, informs transmission project owners of their responsibility for constructing BOD approved network upgrades. NTCs were requested by project owners to assist them in the regulatory and cost recovery process. In 2011, 21 NTCs were issued with current estimated engineering and construction costs of $854.4 million. Of this $854.4 million, $275.4 million was identified for regional reliability, $27.8 million for transmission service, $25.8 million for zonal reliability, and $1 million for generation interconnection. Two of the 21 NTCs were issued for Priority Projects with an estimated cost of $524 million, but these were modified NTCs to reflect the novation of projects to ITC Great Plains and Prairie Wind.

**Projects Completed in 2011**

As of the fourth quarter of 2011, 99 upgrades had been completed. Of the upgrades completed in 2011, 26 were identified for regional reliability, 35 for zonal- sponsored/reliability needs, 22 for transmission service, eight for generation interconnection agreements, four for interregional, three for regional reliability-non OATT, and the first Priority Project.

The total estimated engineering and construction cost for upgrades completed in 2011 was $410 million, with $159.7 million for regional reliability, $64.7 million for transmission service, $111.9 million for zonal-sponsored/reliability upgrades, $52.4 million for generation interconnection agreements, $14 million for interregional, $6.3 million for regional reliability-non OATT, and $960,895 for the Priority Project.
Section 7: Public Policy Impacts

Public Policy and Long-term Transmission Planning

Public policy initiatives related to RES and governmental regulation of emissions, environmental impacts, and public health could affect the future of long-term transmission planning. For instance, in June 2010, the Environmental Protection Agency (EPA) announced an emissions standard that will impact coal-fired electric generation facilities. Under this new standard, emissions from power plants and other industrial facilities will be required to meet a new “1-hour standard” designed to reduce short-term exposure to Sulfur Dioxide (SO₂). Additionally in 2010, the EPA opened rulemaking dockets to develop and implement standards to reduce the transfer of SO₂ and nitrogen oxide (NOₓ) through the air and to regulate coal-ash, which is a by-product of traditional electric generation processes. These proposed rules, once implemented, will have an associated compliance cost that will be borne by industry participants and ratepayers.

SPP has sent two letters to the EPA regarding the pending regulation; the first was sent on July 19, 2011. This letter expressed the concern of SPP and its members regarding the multiple pending regulations. The regulations of concern that the letter addressed include: the Clean Air Transport Rule, now finalized as the Cross-State Air Pollution Rule (CSAPR); the Coal Combustion Residuals Rule; revisions to section 316(b) of the Clean Water Act; and the Hazardous Air Pollutants changes for the regulation of mercury emissions from electricity generation units.

The finalized CSAPR utilized the EPA’s Integrated Planning Model (IPM), and a review by SPP found the model did not dispatch several key generators in the SPP footprint. The removal of those generators from the SPP region caused major reliability issues in SPP’s current summer peak load flow models.

SPP sent a letter regarding these issues to the EPA on September 20, 2011. The reliability issues included N-1 contingency violations totaling 1047 circumstances where voltage was 90% of nominal on 167 different buses and 220 cases where line ratings exceeded the 100% applicable emergency rating. An even clearer representation of reliability violations was found by applying higher operability limits of 120% to the overloads, in which there were 16 such overloads on the system. Using a similar out of normal range, there were 93 circumstances where voltage dropped below 85% of nominal. These “clear-cut” examples of reliability standards violations represent well-founded concerns regarding the timeline with which the CSAPR would be instituted. In addition to these issues, there were 11 reliability cases that could not be solved in SPP’s models. Such violations are clearly indicative of the EPA IPM’s failure to account for reliability standard thresholds that SPP is required to maintain in accordance with Federal Energy Regulatory Commission approved standards.

SPP’s members continue to evaluate and determine how they will individually comply with the CSAPR. Those individual compliance plans have not yet been evaluated from a SPP regional reliability perspective. SPP expects to evaluate those plans when they become available.

Pending climate change legislation may also impact the industry. According to a July 27, 2010, NERC report, Reliability Impacts of Climate Change Initiatives, “meeting carbon emission targets will have significant and varying regional impacts. In some cases, resource portfolios would be dramatically changed due to different energy supply characteristics, and regional resource availability and agreements, along with other aspects that are not under federal jurisdiction. System planners will need to change their approaches to ensure that operational flexibility is available to integrate variable plants, along with other location-constrained resources.”
A recent United States Supreme Court opinion left open the question of whether individual parties and states may attempt to force regulation of greenhouse gas emissions in court under state nuisance law. In September 2010, attorneys general from several states, including Arkansas, Kansas, and Nebraska, filed a brief requesting that the Supreme Court review the decision of the U.S. Court of Appeals for the Second Circuit in Connecticut v. AEP,\(^5\) in which the Second Circuit Court determined that state and private plaintiffs can seek abatement of greenhouse gas emissions from power plants under the “federal common law of nuisance.” In its opinion, the Supreme Court determined that a lawsuit to abate emissions of greenhouse gases cannot be brought under the federal common law of nuisance because the Clean Air Act displaces the federal common law. However, the Supreme Court did not address the plaintiffs’ alternative request for relief under state nuisance law, leaving the issue “open for consideration on remand.”


1. participate in a regional transmission planning process that produces a regional transmission plan;
2. consider transmission needs driven by public policy requirements in local and regional transmission planning processes;
3. remove from FERC-approved tariffs and agreements any language creating a federal right of first refusal for an incumbent transmission provider to construct certain transmission facilities that are identified in a regional transmission plan for purposes of cost allocation;
4. improve coordination between neighboring transmission planning regions for new interregional transmission facilities; and
5. adopt cost allocation methods for regional and interregional transmission facilities that comply with six cost allocation principles outlined in Order No. 1000.

With respect to public policy requirements, Order No. 1000 requires each local and regional transmission planning process to consider, at a minimum, transmission needs driven by public policies adopted in state and federal statutes and regulations. Each public utility transmission provider is required to submit compliance filings adopting the necessary tariff revisions to comply with the Order No. 1000 requirements or to demonstrate how existing tariff provisions comply. SPP’s compliance filing to adopt reforms related to the regional requirements of Order No. 1000 is due on October 11, 2012, and its compliance filing to address the interregional requirements of Order No. 1000 is due on April 11, 2013.

The dialogue on these and numerous other public policy issues continues to evolve among legislators, businesses, state and federal regulators, industry organizations, and interested parties, all with different and often widely disparate views. The complexity of incorporating such considerations will be challenging. For instance, transmission providers, particularly RTOs serving multiple states, will be required to consider and balance the needs and interests of multiple and sometimes conflicting public policy mandates. Clarity in public policy is illusive, and this lack of clarity has resulted in minimal, if any, public policy impacts in the result of the 2011 STEP report.

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Appendix A includes a comprehensive listing of transmission projects identified by the SPP RTO. Not all projects in Appendix A have been approved by the Board, but all Board-approved projects are included in the list. Appendix A also includes Tariff study projects, economic projects, zonal projects, and associated interregional projects.

Projects in Appendix A are categorized in the column labeled “Project Type Exp” by the following designations:

- **Balanced Portfolio** – Projects identified through the Balanced Portfolio process
- **Generation Interconnect** – Projects associated with a FERC-filed Generation Interconnection Agreement
- **Interregional** – Projects developed with neighboring Transmission Providers (Appendix A only)
- **High priority** – Projects identified in the high priority process
- **ITP** – Projects needed to meet regional reliability, economic, or policy needs in the ITP study processes
- **ITP – non-OATT** – Projects to maintain reliability for SPP members not participating under the SPP OATT
- **Transmission service** – Projects associated with a FERC-filed Service Agreement
- **Zonal Reliability** – Projects identified to meet more stringent local Transmission Owner criteria
- **Zonal – sponsored** – Projects sponsored by facility owner with no Project Sponsor Agreement

The complete Network Upgrade list includes two dates.

1. **In-service**: Date Transmission Owner has identified as the date the upgrade is planned to be in-service.

2. **2012 ITP Date**: Date upgrade was identified as needed based on the 2012 ITPNT and ITP10 analyses.

   - M: Upgrade was in the base load flow model,

The cost estimates highlighted in yellow were estimated by SPP.
Facility owner abbreviations used in Appendix A:

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Identification</th>
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<tbody>
<tr>
<td>AECC</td>
<td>Arkansas Electric Cooperatives</td>
</tr>
<tr>
<td>AECI</td>
<td>Associated Electric Cooperative, Incorporated</td>
</tr>
<tr>
<td>AEP</td>
<td>American Electric Power</td>
</tr>
<tr>
<td>CUS</td>
<td>City Utilities, Springfield Missouri</td>
</tr>
<tr>
<td>DETEC</td>
<td>Deep East Texas Electric Cooperative</td>
</tr>
<tr>
<td>EDE</td>
<td>Empire District Electric Company</td>
</tr>
<tr>
<td>GMO</td>
<td>KCP&amp;L Greater Missouri Operations Company</td>
</tr>
<tr>
<td>GRDA</td>
<td>Grand River Dam Authority</td>
</tr>
<tr>
<td>GRIS</td>
<td>Grand Island Electric Department (GRIS)</td>
</tr>
<tr>
<td>INDN</td>
<td>City Power &amp; Light, Independence, Missouri</td>
</tr>
<tr>
<td>ITCGP</td>
<td>ITC Great Plains</td>
</tr>
<tr>
<td>KCPL</td>
<td>Kansas City Power and Light Company</td>
</tr>
<tr>
<td>LEA</td>
<td>Lea County Cooperative</td>
</tr>
<tr>
<td>LES</td>
<td>Lincoln Electric System</td>
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<tr>
<td>MIDW</td>
<td>Midwest Energy, Incorporated</td>
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<tr>
<td>MKEC</td>
<td>Mid-Kansas Electric Company</td>
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<tr>
<td>NPPD</td>
<td>Nebraska Public Power District</td>
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<tr>
<td>OGE</td>
<td>Oklahoma Gas and Electric Company</td>
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<td>OMPA</td>
<td>Oklahoma Municipal Power Authority</td>
</tr>
<tr>
<td>OPPD</td>
<td>Omaha Public Power District</td>
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<tr>
<td>PW</td>
<td>Prairie Wind Transmission</td>
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<tr>
<td>RCEC</td>
<td>Rayburn Electric Cooperative</td>
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<td>SEPC</td>
<td>Sunflower Electric Power Corporation</td>
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<td>SPS</td>
<td>Southwestern Public Service Company</td>
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<td>SWPA</td>
<td>Southwestern Power Administration</td>
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<tr>
<td>WFEC</td>
<td>Western Farmers Electric Cooperative</td>
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<td>WR</td>
<td>Westar Energy</td>
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### Appendix A Summaries

<table>
<thead>
<tr>
<th>2012 STEP (Nearest 10 Million)</th>
<th>Upgrade Type</th>
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<tr>
<td>$1,440</td>
<td>2010 Priority Projects</td>
</tr>
<tr>
<td>$870</td>
<td>2009 Balanced Portfolio</td>
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<tr>
<td>$500</td>
<td>Transmission Service Request and Generation Interconnection Service Agreements</td>
</tr>
<tr>
<td>$2,500</td>
<td>ITP - Base Plan</td>
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<tr>
<td>$1,590</td>
<td>ITP - Other</td>
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<tr>
<td>$210</td>
<td>Sponsored Upgrades</td>
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<tr>
<td>$7.11B</td>
<td>SPP Subtotal</td>
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<tr>
<td>$120</td>
<td>non-OATT upgrades*</td>
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<tr>
<td>$7.23B</td>
<td>Appendix A - TOTAL</td>
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</table>

*Includes Southwestern Power Administration projects

Has filed Service Agreement or is Board-approved

### Cost by Facility Type (Billions)

$7.1 Billion

<table>
<thead>
<tr>
<th>Facility Type</th>
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<tbody>
<tr>
<td>New Line</td>
</tr>
<tr>
<td>Transformer</td>
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<tr>
<td>Rebuild/Re-Conductor</td>
</tr>
<tr>
<td>Substation</td>
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<tr>
<td>Voltage Conversion</td>
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<tr>
<td>Capactive/Reactive Devices</td>
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<tr>
<td>Raise Line/Line Work</td>
</tr>
</tbody>
</table>

![Graph of cost by facility type (billions)](image-url)
Appendix A  Southwest Power Pool, Inc.

Project Cost by Facility Type

- New Line: 77%
- Raise Line/Line Work: 0.004%
- Capacitive/Reactive Devices: 1%
- Voltage Conversion: 3%
- Substation: 4%
- Rebuild/Re-Conductor: 8%
- Transformer: 8%

Costs of Line Upgrades

- 2012: $900M
- 2013: $600M
- 2014: $1200M
- 2015: $300M
- 2016: $300M
- 2017: $600M
- 2018: $300M
- 2019: $300M
- 2020: $300M
- 2021: $300M
- 2022: $300M
- 2023: $300M
- 2024: $300M
- 2025: $300M
- 2026: $300M
- 2027: $300M
- 2028: $300M
- 2029: $300M
- 2030: $1500M
Appendix A

2012 STEP Report

History of Total Miles

History of New Lines

Miles

2009STEP  2010STEP  2012STEP

Miles

2009STEP  2010STEP  2012STEP
Costs of Capacitive and Reactive Devices

## Appendix A - Complete List of Network Upgrades

### 2012 SPP Transmission Expansion Plan

<table>
<thead>
<tr>
<th>Project Description/Comments</th>
<th>Projected In-Service</th>
<th>SPP Determined Need Date</th>
<th>From Bus Name</th>
<th>To Bus Name</th>
<th>To Bus Name</th>
<th>Circuit</th>
<th>Voltage (KV)</th>
<th>Miles of Conductor</th>
<th>Miles of New Line</th>
<th>Miles of Voltage Conversion</th>
<th>Ratings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Add 50 MVA 161/69 kV transformer Ckt 2 at Afton.</td>
<td>5/09/2012</td>
<td>6/1/2012</td>
<td>510911 VALLIANT 345 KV</td>
<td>509783 RIVERSIDE STATION 138KV</td>
<td></td>
<td></td>
<td>345</td>
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<tr>
<td>Upgrade the South Harper 161 kV substation breaker scheme to breaker and load tap changer in preparation for the 1200/138 kV line connection to Crowley Water substation.</td>
<td>6/1/2012</td>
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<tr>
<td>Add approximately 3 miles of 5-654 ACSR from Turk to NW Texarkana.</td>
<td>9/1/2012</td>
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<tr>
<td>Upgrade the 138 kV substation breaker scheme to breaker and load tap changer.</td>
<td>12/31/2012</td>
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<tr>
<td>Install (3) 7.2 Mvar capacitors for a total of 21.6 Mvar at Tahlequah 138 kV substation.</td>
<td>6/1/2012</td>
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<td>12/31/2012</td>
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<tr>
<td>Install 345 kV terminal equipment at Valliant substation.</td>
<td>6/1/2012</td>
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<tr>
<td>Upgrade the Red River 161 kV substation breaker scheme to breaker and load tap changer.</td>
<td>12/31/2012</td>
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<td>12/31/2012</td>
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</tbody>
</table>
13639 50409 GADA Generation connection $5,900,000 AFFECTED SYSTEMS FACILITIES CONSTRUCT ON AGREEMENT New 345/115 kV Transformer - new 345 kV Transformer 15 MVA, 2000 amp. Ratings for 345 kV, and 2200 amp. Ratings for 115 kV, same as original equipment. 1310/1360 M 0.08 2 5 300139 Fairfax 700001

13640 50409 GADA Generation connection $3,900,000 AFFECTED SYSTEMS FACILITIES CONSTRUCT ON AGREEMENT New Transformer - new 345 kV Transformer 15 MVA, 2000 amp. Ratings for 345 kV, and 2200 amp. Ratings for 115 kV, same as original equipment. 1310/1360 M 0.08 2 5 300139 Fairfax 700001

13641 50405 ITCGP Transmission service $12,230,000 WISEC Install new 16.8MVA from Valley Station 115 kV to Hugo Power Plant with 3 miles of bundled 165 kV ACSR conductor. Note that this is the building line from Valley Station 115 kV to Hugo Power Plant. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13642 50405 ITCGP Transmission service $2,420,000 WISEC Install new 115 kV breaker at Hugo and interchange line. 1311/1361 M 0.08 2 4 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13643 50405 ITCGP Transmission service $8,420,000 WISEC Install new 115kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13644 50405 ITCGP Transmission service $19,800,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13645 50405 ITCGP Transmission service $2,170,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13646 50405 ITCGP Transmission service $190,860 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13647 50405 ITCGP Transmission service $190,800 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13648 50405 ITCGP Transmission service $1,223,080 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13649 50405 ITCGP Transmission service $1,090,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13650 50405 ITCGP Transmission service $150,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13651 50405 ITCGP Transmission service $150,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13652 50405 ITCGP Transmission service $150,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13653 50405 ITCGP Transmission service $150,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13654 50405 ITCGP Transmission service $150,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13655 50405 ITCGP Transmission service $150,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13656 50405 ITCGP Transmission service $150,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

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13660 50405 ITCGP Transmission service $1,090,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

13661 50405 ITCGP Transmission service $1,090,000 WISEC Install new 115 kV breaker at Hugo and interchange line. Updated for approved route inference; refit additions of conductor at Hugo Federal. 1311/1361 M 0.08 4 3 542998 LOMA VISTA EAST 161 KV 543009 WINCHESTER JUNCTION NORTH 161 KV

Appendix A - Complete List of Network Upgrades
<table>
<thead>
<tr>
<th>Date</th>
<th>Project Description</th>
<th>MVAR</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>3/31/2012</td>
<td>Install 2 Mvar capacitor bank at Gordon substation 115 kV bus.</td>
<td>510</td>
<td>Gordon to reduce 3/1 phase interconnection</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Replace relay in OGE's Alva substation</td>
<td>115</td>
<td>3 Mvar</td>
</tr>
<tr>
<td>11/1/2012</td>
<td>Add 2nd 345/138 KV Auto Transformer</td>
<td>520</td>
<td>520 Mvar</td>
</tr>
<tr>
<td>12/31/2012</td>
<td>Increase size of Paoli 138/69 kV bus tie to full 50 MVA</td>
<td>150</td>
<td>150 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Add 230 kV line from Hitchland to Ochilltree - 541 MVA.</td>
<td>541</td>
<td>541 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Build new 3 mile 69 kV line from Artesia Town - Artesia South Rural 69 kV.</td>
<td>60</td>
<td>60 Mvar</td>
</tr>
<tr>
<td>4/30/2012</td>
<td>Convert 8 miles of 69 kV to 115 kV from Carlsbad Interchange - Ocotillo.</td>
<td>54/54</td>
<td>54/54 Mvar</td>
</tr>
<tr>
<td>11/1/2012</td>
<td>Install 2-Winding 230/115 kV transformer at Ochilltree  172.5 MVA</td>
<td>172</td>
<td>172 Mvar</td>
</tr>
<tr>
<td>11/1/2012</td>
<td>Rebuild 15 mile Holcomb - Pioneer Tap 115kV.</td>
<td>138</td>
<td>138 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Install a 9 Mvar capacitor bank at Gordon substation 115 kV bus.</td>
<td>9</td>
<td>9 Mvar</td>
</tr>
<tr>
<td>3/31/2012</td>
<td>Install 2 Mvar capacitor bank at Decker substation 115 kV bus.</td>
<td>2</td>
<td>2 Mvar</td>
</tr>
<tr>
<td>4/1/2012</td>
<td>Build new 5.5 mile 115 kV Ckt 2 from Twin Church to new South Sioux 115 kV.</td>
<td>5.5</td>
<td>5.5 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Add 18 Mvar capacitor bank at Clark substation 115 KV.</td>
<td>18</td>
<td>18 Mvar</td>
</tr>
<tr>
<td>5/1/2012</td>
<td>Install third Arcadia 345/138 kV autotransformer.</td>
<td>84</td>
<td>84 Mvar</td>
</tr>
<tr>
<td>4/30/2012</td>
<td>Rebuild 12 mile Holcomb - Plymell 115 kV.</td>
<td>138</td>
<td>138 Mvar</td>
</tr>
<tr>
<td>4/1/2012</td>
<td>Install 0.19 miles 115 kV line and install terminal equipment at Ochiltree</td>
<td>10</td>
<td>10 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Add Mvar support at Kolache 69 kV substation to have a total of 9 Mvar</td>
<td>9</td>
<td>9 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Add 18 Mvar capacitor bank at Clark substation 115 KV.</td>
<td>18</td>
<td>18 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Install a 9 Mvar capacitor bank at Gordon substation 115 kV bus.</td>
<td>9</td>
<td>9 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Add 2 Mvar capacitor bank at Little River Lake 69 kV.</td>
<td>2</td>
<td>2 Mvar</td>
</tr>
<tr>
<td>3/31/2012</td>
<td>Balanced Portfolio - build new site for Sequential.</td>
<td>36</td>
<td>36 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Install 6 Mvar capacitor bank at Little River Lake 69 kV.</td>
<td>6</td>
<td>6 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Balanced Portfolio - build new site for Sequential.</td>
<td>10</td>
<td>10 Mvar</td>
</tr>
<tr>
<td>11/1/2012</td>
<td>Balanced Portfolio - build new site for Sequential.</td>
<td>5</td>
<td>5 Mvar</td>
</tr>
<tr>
<td>3/31/2012</td>
<td>Balanced Portfolio - build new site for Sequential.</td>
<td>10</td>
<td>10 Mvar</td>
</tr>
<tr>
<td>6/1/2012</td>
<td>Balanced Portfolio - build new site for Sequential.</td>
<td>5</td>
<td>5 Mvar</td>
</tr>
<tr>
<td>4/1/2012</td>
<td>Balanced Portfolio - build new site for Sequential.</td>
<td>10</td>
<td>10 Mvar</td>
</tr>
</tbody>
</table>

**Appendix A - Complete List of Network Upgrades**

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Convert 15 mile Channing - Tascosa line from 69 kV to 115 kV with 795 ACSR.

Build new 4 mile AEP Snyder - WFEC Snyder 138 kV.

Rebuild 15.6 mile Creswell - Oxford 138 kV line.

Reconductor 3.7 miles of 1/0 ACSR to 556.5 ACSR from Lindsay to

Move load from Muleshoe 69 kV to Muleshoe 115 kV.

Rebuild 3.4 mile Cowskin to Centennial 138 kV line.

Install 2nd 112 MVA auto in parallel with existing Unit

Install 230/115 kV 112/128 MVA XF in Potter substation and terminal

Reconductor 6.5 mile El Reno - El Reno SW 69 kV line from 1/0 to 336.4 kcmil ACSR conductor.

Install new 84 MVA 115/69 kV transformer at new Cedar Lake

Install 12 Mvar capacitor at Latta Junction 138 kV.

Install 12 Mvar capacitor at Comanche 138 kV bus.

Replace CT at WFEC Russell

Switch 6/1/2012 M 159/160

Install 2nd 112 MVA auto in parallel with existing Unit

ITP - non OATT $10,095,750 SPP

Install two 50 Mvar capacitors at Bushland Interchange 230 kV. 6/1/2012 100 Mvar

Install 2 stages of 5 MVAR and 2 stages of 10 MVAR reactor at Norton

Install 1 stage 5 MVAR and 1 stage of 10 MVAR reactor at Norton

Install new 64 MVA transformer at new Cedar Lake

Install two 50 Mvar capacitors at Bushland Interchange 230 kV. 6/1/2012 100 Mvar

Install 2 stages of 5 MVAR and 2 stages of 10 MVAR reactor at Norton

Install 1 stage 5 MVAR and 1 stage of 10 MVAR reactor at Norton

Install new 64 MVA transformer at new Cedar Lake

Appendix A - Complete List of Network Upgrades
2012 SPP Transmission Expansion Plan
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Appendix A - Complete List of Network Upgrades

2013

243 10367 Interconnection $8,217,684 AECI The proposed line connects to the Orange - Neosho 345kV line near the Kansas border – This is the proposed Blackberry Sub. From Blackberry the 345kV line connects to Chouteau 450kV bus which connects via a 5 mile 345/115/14.4 kV three-winding transformers to Chouteau 161kV substation. At the Chouteau 345kV bus a 345/161 transformer connects to Chouteau 345kV substation.
3/30/2013 M 12 300370 Blackberry 300370 Sportsman Acres
1/30/2013

2027 443 10047 AECI ITP $2,800,000 AEP Replace line double circuiting end of Line near Turkey Track Substation.
2/28/2013 M 24 304790 Cap Rock Road 345 304790 Ship Road 161 1 161 1 5 428/428

2007 767 11031 AECI ITP $4,946,000 AEP Replace double circuiting end of Line near Turkey Track Substation.
6/1/2013 M 36 301496 Canadian River 138 301496 Canadian River 138
1/31/2013

2007 767 11032 AECI ITP $9,533,000 AEP Replace double circuiting end of Line near Turkey Track Substation.
6/1/2013 M 36 301496 Canadian River 138 301496 Canadian River 138
1/31/2013

2007 767 11033 AECI ITP $4,946,000 AEP Replace double circuiting end of Line near Turkey Track Substation.
6/1/2013 M 36 301496 Canadian River 138 301496 Canadian River 138
1/31/2013

2007 767 11034 AECI ITP $4,946,000 AEP Replace double circuiting end of Line near Turkey Track Substation.
6/1/2013 M 36 301496 Canadian River 138 301496 Canadian River 138
1/31/2013

2000 744 11126 AECI ITP $1,402,000 AEP Replace line double circuiting end of Line near Turkey Track Substation.
6/1/2013 M 24 301496 Canadian River 138 301496 Canadian River 138
1/31/2013

2019 1022 11144 AECI ITP $1,402,000 AEP Replace line double circuiting end of Line near Turkey Track Substation.
6/1/2013 M 24 301496 Canadian River 138 301496 Canadian River 138
1/31/2013

2019 1022 11145 AECI ITP $1,402,000 AEP Replace line double circuiting end of Line near Turkey Track Substation.
6/1/2013 M 24 301496 Canadian River 138 301496 Canadian River 138
1/31/2013
Build new 345 kV line from Wolf to interception point of Axtell to Wolf line (Kansas Border). Includes substation expansion at Axtell and line reactor. 6/1/2013 M 48 524010 Cherry Sub 230 kV 524009 Cherry Sub 115 kV 1 115 4.3 578/518

Add 3.25-mile 115 kV line from 17th & Holdrege to 30th & A. 4/30/2013 M 24 54335 ROYAL 115 115 168/194

Rebuild 4.2 mile Olathe - Switzer 161kV line. 6/30/2013 M 24 524365 Randall County Interchange 230 kV 524415 Amarillo South Interchange 230 kV 1 230 18 26/214

Build new 26 mile Frio - Draw - Roosevelt County 230 kV line. 5/31/2013 M 30 524770 Pleasant Hill 230 kV 524909 Roosevelt County Interchange NORTH 230 kV 1 230 26 541/502

Build new 16 mile Pleasant Hill - Oasis 230 kV line. 6/30/2013 M 20 524010 Cherry Sub 230 kV 523959 Potter County Interchange 230 kV 1 230 0.1 478/502

Add 3 138KV CIRCUIT BREAKERS TO SHIDLER SUBSTATION AND CONVERT TO 4 BREAKER RING. PROVIDE A NEW TERMINAL FOR LINE TO NOT BE CONSIDERED. 6/30/2013 M 20 515422 Canadian River 345kv 1 345 345/345

Build new 345 kV line from Axtell to interception point of Axtell to Wolf line (Kansas Border). Includes substation expansion at Axtell and line reactor. 6/1/2013 M 48 483501 POST ROCK 345 KV 1 345 780/780

Add 3.25-mile 115 kV line from 17th & Holdrege to 30th & A. 4/30/2013 M 24 54335 ROYAL 115 115 168/194

Upgrade the Spearman transformer to 84/100 MVA. 5/31/2013 M 1 524920 Midland Lodge 115 kV 115 1 180/206

Install second 115/69 kV transformer rated 75/86 MVA at Kingsmill. 3/31/2013 M 24 523712 Kingsmill Interchange 115 kV 523711 Kingsmill Interchange 69 kV 2 115/69 75/86

Install Canadian River 345 kV terminal equipment at new Canadian River substation. 6/30/2013 M 30 515422 Canadian River 345kv 1 345 345/345

Rebuild 26 mile line
Add 3.25-mile 115 kV line from 17th & Holdrege to 30th & A.

Reconductor to 229/335 MVA. 6/1/2012 M 1 524920 Midland Lodge 115 kV 115 1 180/206

ITP $16,725,836 SPS 157/173

Build new 345 kV line from Wolf to interception point of Axtell to Wolf line (Kansas Border). Includes substation expansion at Axtell and line reactor. 6/1/2013 M 48 483501 POST ROCK 345 KV 1 345 780/780

Upgrade transformer

Install 138°-transformers at Olathe and Switzer substations to effect higher rating. 6/1/2013 M 24 524378 Harrington Station Mid Bus 230 kV 524365 Randall County Interchange 230 kV 1 230 768/768

Build new 26 mile Frio - Draw - Roosevelt County 230 kV line. 5/31/2013 M 30 524770 Pleasant Hill 230 kV 524909 Roosevelt County Interchange NORTH 230 kV 1 230 26 541/502

ITP - non OATT $2,250,000 SPP 206/206

ITP $2,650,000 OGE 376/376

Rebuild 11.1 miles of the 18.3 mile Fletcher - Holcomb 115 kV line with 13.8/14.6 kV subtransmission line. 6/30/2013 M 24 524365 Randall County Interchange 230 kV 524415 Amarillo South Interchange 230 kV 1 230 25/287

Build new 3.7 mile Hastings - East Plant 115kV line. 5/31/2013 M 1 526656 Lynn County Interchange 115 kV 115 1 71/71
Appendix A - Complete List of Network Upgrades
Build a new 36 mile double circuit 345 kV line with at least 3000 A capacity from the Spearville substation to the new Clark County substation. Build the Comanche County 345 kV substation with a ring bus and necessary terminal equipment.

Build a new 86 mile double circuit 345 kV line with at least 3000 A capacity from the Thistle 345 kV substation to the new Clark County substation. Build a new 345 kV substation at Thistle near Flat Ridge with the necessary breakers and terminal equipment for connecting the Spearville-Thistle-Wichita double circuit transmission lines and for connecting to the Woodward District EHV 345 kV double circuit transmission lines.

Build a new 92 mile double circuit 345 kV line with at least 3000 A capacity from the Woodward District EHV substation to the SPS interception from the Hitchland substation. Upgrade the Woodward District EHV substation with the necessary breakers and terminal equipment.

Build a new 1 mile 138 kV line from new Thistle substation to Flat Ridge.

Build a new 79 mile double circuit 345 kV line with at least 3000 A capacity from the Woodward District EHV substation to the Kansas/Oklahoma state border towards the Medicine Lodge substation. Upgrade the Woodward District EHV substation with the necessary breakers and terminal equipment.

Build a new 30.4 mile double circuit 345 kV line with at least 3000 A capacity from the Thistle substation to the Kansas/Oklahoma state border towards the Woodward District EHV substation.

Install a 400 MVA 345/138 kV transformer at the new 345 kV Thistle substation. 12/31/2014 138 1

Build a new 2.4 mile double circuit 345 kV line with at least 3000 A capacity from the Spearville substation to the new Clark County substation. Build the Clark County 345 kV substation with a ring bus and necessary terminal equipment. 12/31/2014 2 345 86

Install a 30 Mvar capacitor bank at Holdrege substation 115 kV bus. 6/1/2014 M 24 640224 Holdrege 115 30 Mvar 818,000

Build a new 3 mile Overland Park - Merriam 161 kV line.

Build a 1 mile 138 kV line from new Thistle substation to Flat Ridge.

Build a new midpoint reactor station at interception point of Woodward to Kansas/Oklahoma state border.

Build a new 30.4 mile double circuit 345 kV line with at least 3000 A capacity from the Thistle substation to the Kansas/Oklahoma state border towards the Woodward District EHV substation. 12/31/2014 2 138 2 1792/1792

Build a new 2.4 mile double circuit 345 kV line with at least 3000 A capacity from the Spearville substation to the new Clark County substation. Build the Clark County 345 kV substation with a ring bus and necessary terminal equipment. 12/31/2014 M 2 345 86

Upgrade the Woodward District EHV substation with the necessary breakers and terminal equipment. 6/30/2014 M 2 345 92

Build a new 345 kV substation at Thistle near Flat Ridge with the necessary breakers and terminal equipment for connecting the Spearville-Thistle-Wichita double circuit transmission lines and for connecting to the Woodward District EHV 345 kV double circuit transmission lines.

Build a new 86 mile double circuit 345 kV line with at least 3000 A capacity from the Thistle 345 kV substation to the new Clark County substation. Build a new 345 kV substation at Thistle near Flat Ridge with the necessary breakers and terminal equipment for connecting the Spearville-Thistle-Wichita double circuit transmission lines and for connecting to the Woodward District EHV 345 kV double circuit transmission lines.

Build a new 3 mile Overland Park - Merriam 161 kV line.

Build a new 1 mile 138 kV line from new Thistle substation to Flat Ridge.

Build the Woodward District EHV substation with the necessary breakers and terminal equipment. 12/31/2014 M 2 345 86

Build a new 3 mile Overland Park - Merriam 161 kV line.

Build a new 345 kV substation at Thistle near Flat Ridge with the necessary breakers and terminal equipment for connecting the Spearville-Thistle-Wichita double circuit transmission lines and for connecting to the Woodward District EHV 345 kV double circuit transmission lines.

Build a new 1 mile 138 kV line from new Thistle substation to Flat Ridge.

Build a new 86 mile double circuit 345 kV line with at least 3000 A capacity from the Thistle 345 kV substation to the new Clark County substation. Build a new 345 kV substation at Thistle near Flat Ridge with the necessary breakers and terminal equipment for connecting the Spearville-Thistle-Wichita double circuit transmission lines and for connecting to the Woodward District EHV 345 kV double circuit transmission lines.

Build a new 3 mile Overland Park - Merriam 161 kV line.

Build a new 86 mile double circuit 345 kV line with at least 3000 A capacity from the Thistle 345 kV substation to the new Clark County substation. Build a new 345 kV substation at Thistle near Flat Ridge with the necessary breakers and terminal equipment for connecting the Spearville-Thistle-Wichita double circuit transmission lines and for connecting to the Woodward District EHV 345 kV double circuit transmission lines.

Build a new 3 mile Overland Park - Merriam 161 kV line.

Build a new 86 mile double circuit 345 kV line with at least 3000 A capacity from the Thistle 345 kV substation to the new Clark County substation. Build a new 345 kV substation at Thistle near Flat Ridge with the necessary breakers and terminal equipment for connecting the Spearville-Thistle-Wichita double circuit transmission lines and for connecting to the Woodward District EHV 345 kV double circuit transmission lines.
Build a new 78 mile double circuit 345 kV line with at least 3000 A capacity from the Wichita substation to ITC Great Plains' Thistle 345 kV substation.

Upgrade the Wichita substation with the necessary breakers and terminal equipment to accommodate two new 345 kV circuits from the new Thistle 345 kV substation.

Upgrade Happy County 115/69 kV Transformer #2 to 84/96 MVA.

Add 2nd transformer Eddy Co 230-115 kV CKT 2

Install 6 Mvar capacitor at Esquandale 69 kV.

Install a second 345/230 kV transformer at Hitchland substation.

Install 30 MVAR capacitor at Twin Oaks Substation.

Build new 10 mile Cox - Kiser 115 kV line unit.

Install second 138/115 kV transformer at Moundridge. Operate both Elmore - Paoli Rebuild 3/0 to 336 ACSR - 10.8 miles.

Install 1 stage 15 Mvar capacitor at Northwest Manhattan 115 kV

Move load at East Clovis from 69 kV bus to 115 kV bus.

Add 6 Mvar Cap bank at Altoona East

Replace Halstead 138/69 kV transformer with 100/110 MVA unit.
Build new 6-mile Sub 383 - Monett 5 161 kV line as part of multi line upgrade.

Construct new Holt Co 345 kV substation.

Tear down the Riverton - Joplin 59 69 kV line, rebuild as 161 kV from EDE 547437 SUB 473 - Stateline to outside Joplin 59 substation 6/1/2018 M 48 547498 SUB 439 - STATELINE to Joplin 59 161 kV 1 1.78 218/268

Install second stage 14.4 Mvar capacitor at Etter Rural 115 kV.

Build new Cherry County 345 kV Substation.

Rebuild James River to South Highway 65 69 kV.

Reconductor 4.1 miles of 6.1 miles from Randall County to South Highway 65.

Build new 1.06-mile 69 kV line (second of double circuit for approx 0.72 mi, then single circuit for 0.34 mi) from new Monett 161 kV substation to existing 69 kV on south side of city of Monett which will self-feed radially to substation PUR 390.

Build new 0.72-mile 69 kV line from new Monett S. substation to existing 69 kV on SW corner of city of Monett.

Install third 345/138 kV transformer in Northwest Substation.

Upgrade switches - 1200 A rated.

Upgrade existing Swisher 230/115 kV transformer to 252 MVA.

Install 3-winding transformer connecting Monett 376 161 kV bus to Monett 470 69 kV bus as part of multi line upgrade.

Install 3-winding transformer connecting Monett 376 161 kV bus to Monett 470 69 kV bus as part of multi line upgrade.

Build new 14.4 Mvar capacitor at Etter Rural 115 kV.

Upgrade existing Swisher 230/115 kV transformer to 252 MVA.

Install second stage 14.4 Mvar capacitor at Etter Rural 115 kV.

Build new Cherry County 345 kV Substation.

Rebuild James River to South Highway 65 69 kV.

Reconductor 4.1 miles of 6.1 miles from Randall County to South Highway 65.

Build new 1.06-mile 69 kV line (second of double circuit for approx 0.72 mi, then single circuit for 0.34 mi) from new Monett 161 kV substation to existing 69 kV on south side of city of Monett which will self-feed radially to substation PUR 390.

Build new 0.72-mile 69 kV line from new Monett S. substation to existing 69 kV on SW corner of city of Monett.

Install third 345/138 kV transformer in Northwest Substation.

Upgrade switches - 1200 A rated.

Upgrade existing Swisher 230/115 kV transformer to 252 MVA.

Install 3-winding transformer connecting Monett 376 161 kV bus to Monett 470 69 kV bus as part of multi line upgrade.

Install 3-winding transformer connecting Monett 376 161 kV bus to Monett 470 69 kV bus as part of multi line upgrade.

Build new 14.4 Mvar capacitor at Etter Rural 115 kV.

Upgrade existing Swisher 230/115 kV transformer to 252 MVA.

Install second stage 14.4 Mvar capacitor at Etter Rural 115 kV.

Build new Cherry County 345 kV Substation.

Rebuild James River to South Highway 65 69 kV.

Reconductor 4.1 miles of 6.1 miles from Randall County to South Highway 65.

Build new 1.06-mile 69 kV line (second of double circuit for approx 0.72 mi, then single circuit for 0.34 mi) from new Monett 161 kV substation to existing 69 kV on south side of city of Monett which will self-feed radially to substation PUR 390.

Build new 0.72-mile 69 kV line from new Monett S. substation to existing 69 kV on SW corner of city of Monett.

Install third 345/138 kV transformer in Northwest Substation.

Upgrade switches - 1200 A rated.

Upgrade existing Swisher 230/115 kV transformer to 252 MVA.

Install 3-winding transformer connecting Monett 376 161 kV bus to Monett 470 69 kV bus as part of multi line upgrade.

Install 3-winding transformer connecting Monett 376 161 kV bus to Monett 470 69 kV bus as part of multi line upgrade.
Appendix A - Complete List of Network Upgrades

2012 SPP Transmission Expansion Plan

12 of 13
<table>
<thead>
<tr>
<th>Project Description</th>
<th>Location</th>
<th>Cost</th>
<th>Start Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Build new 345/115 kV Transformer at new Eastowne sub, tapping the existing 115 kV line into the new 345 kV line</td>
<td>Eastowne</td>
<td>$12,809,443 KCPL</td>
<td>6/1/2022</td>
</tr>
<tr>
<td>Build new 1192.5 kcmil ACSR conductor (Bunting)</td>
<td>3/1/2022</td>
<td>48 533036 CLEARWATER 138 KV 539675 Milan Tap 138 KV</td>
<td>1 138 5.6 261/314</td>
</tr>
<tr>
<td>1 345/161</td>
<td>345 6 Mvar</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>