ITP20

2010 Integrated Transmission Plan 20-Year Assessment

SPP Southwest Power Pool

Revision History:

Date	Author	Change Description	Comments
9/28/2010	SPP Staff	Initial Draft	Submitted to MOPC for Oct 4, 2010 meeting
12/8/2010	SPP Staff	Updated Draft	Submitted to Stakeholders for Dec 15, 2010 workshop
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1/26/2011	SPP Staff	BOD Accepted Report	Approved by BOD on Jan 25, 2011
6/30/2011	SPP Staff	Correction	The Oklahoma RES is a goal, not a mandate.

The following sections have been updated to provide clearer information and show results obtained since December 15, 2010. Other sections have witnessed minor changes for clarity, completeness or correctness but were not dramatically altered.

Clicking the text will link you to the section or sub-section that has changed:

- Executive Summary
- Section 8: Transmission Analysis Assumptions
  - Economic Calculation Assumptions (Substantial Changes)
- Section 15: Benefits (Substantial Changes)
  - Table 15.2: APC-based B/C by Plan
  - Table 15.3: Forty-year APC Savings and APC-based B/Cs by Plan
  - Table 15.22: Portfolio Performance Dashboard (averaged across all futures)
  - Table 15.23: Incremental Cost over the Cost-Effective Plan (averaged across all futures)
- Section 16: Success Measures
  - Section 16.7: Rate Impacts and Unintended Consequences (Substantial Additions)
- Section 18: Staff Recommendation
- Appendix A3: Metric Results (Substantial Changes)
  - Table A3.1: APC Savings by Future for each plan (2010 $millions)
  - Table A3.2: APC by Future for each plan (2010 $millions)
- Appendix A9: Rate Impact & Unintended Consequences Tables (Substantial Additions)

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Executive Summary

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 recently-approved Highway/Byway cost allocation methodology, the ITP process as embodied in the new SPP Attachment O, approved by the Federal Energy Regulatory Committee (FERC) in July 2010, promotes transmission investment that will meet reliability, economic, and public policy needs[1]. This report documents analysis of the ITP process, which focused on the 20-year horizon with an objective of planning for SPP's long-term regional needs.

ITP development was driven by the Synergistic Planning Project Team (SPPT), which was created by the SPP Board of Directors 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.

This is the first Integrated Transmission Plan looking into the future 20 years as required by OATT Attachment O Section III - 3. This is an expansion on the annual SPP Transmission Plan (STEP), the 10 year transmission expansion plan in place since 2006. SPP has had two previous EHV plans, which like this plan, provide a look into the future that help to form the near term plans. The concept for this 20 year look into the future arose from the 2009 Synergistic Project Planning Team, as a means to develop a flexible EHV backbone network. The process utilizes a diverse array of power system and economic analysis tools to identify cost-effective robust backbone projects which will provide the transmission system flexibility to reasonably accommodate possible changes characterized by the various futures (scenarios) depicted in the assessment. Projects identified in the ITP20 provide benefits to the region across multiple futures, and create flexibility for SPP to meet future needs. The ITP effort has been driven by numerous interactions with stakeholders and with significant support from the ESWG and TWG. This plan differs from the earlier EHV plans in the level of detail and effort that has gone into its preparation.

There will be no Notifications to Construct (NTC's) issued as the result of this report. As provided for in the Integrated Transmission Planning that was approved by FERC on July 15, 2010 (Docket Nos. ER10-1269-000), this 20 year plan will be repeated on a three year cycle; the requisite ITP10 that will be presented at this same time next year will draw from the ITP20 report to present a significantly greater amount of detail concerning the underlying lower voltage grid, and the benefits and costs for the near term plans that will result in NTC's. The ITP Manual does provide for SPP to issue Authorizations to Plan (ATP's), which differ from the NTC's in that ATP's are only given to projects which are outside the 4 year financial commitment window, and ATP's do not require an entity to invest any capital. At this point SPP staff is not recommending the issuance of any ATP's arising from this report. Additional thought and stakeholder input regarding the ATP process is requested before issuing ATP's.

Several distinct generation expansion futures were considered to account for possible variations in system conditions over the assessment's 20-year horizon. The futures were determined 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 four futures are presented briefly below and further discussed in Section 7: Resource Futures and Plan.

1. **Business-As-Usual**: This future assumed no major changes in public policy from the present, and included renewable generation necessary to meet existing state renewable targets (approximately 10.6 GW of nameplate wind).

[1] The Highway/Byway cost allocation approving order is *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010). The approving order for ITP is *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010).

2. **Renewable Electricity Standard**: This future assumed a 20% federal Renewable Electricity Standard (RES). It included renewable resources necessary to meet that standard (approximately 16.5 GW of nameplate wind).

3. **Carbon Mandate**: This future assumed a carbon tax of $73/ton on CO_2 emissions, and included renewable generation necessary to meet existing state renewable targets (approximately 10.6 GW of nameplate wind).

4. **Renewable Electricity Standard + Carbon Mandate**: This future combined the assumptions of Future 2 and Future 3 for a RES of 20% and a carbon tax of $73/ton. It included renewable resources necessary to meet the RES (approximately 16.5 GW of nameplate wind).

Other futures were considered to simulate the effects of load reduction, demand response, and carbon sequestration but not adopted in this study cycle. Future ITP studies may address these effects and will be determined through the SPP stakeholder process.

Several portfolios of EHV projects were developed over the course of the analysis. The initial designs were a set of four Transmission Least Cost Solutions, one per future, that minimized the capital cost of the needed transmission. From the four Least Cost Plans, a portfolio was developed that incorporated elements from all four plans and would be adaptable to all futures. The portfolio was called the Cost-Effective Plan and formed the basis for additional analysis.

After developing the Cost-Effective Plan, a robustness analysis was performed to determine how the transmission plan and various alternatives performed against a variety of metrics. From the robustness analysis, several portfolios of projects were developed. Those portfolios are discussed further in Section 13: Results.

Several metrics were calculated for each portfolio, and the results were compared. These calculations are detailed in Section 15: Benefits. From that comparison, Robust Plan 1 was selected. The line components of Robust Plan 1 are listed below (additional transformers are listed in Appendix A2: Transmission Portfolios & Cost Estimates).

Robust Plan 1 Elements	kV	State
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS
N.W. Texarkana - Ft. Smith	345	AR
Ft. Smith - Chamber Springs	345	AR
Dolet Hills - Messick	345	LA
Turk - McNeil	345	AR
Iatan - Jeffrey Energy Center	345	KS
Wichita - Viola - Rose Hill	345	KS
Spearville - Mullergren - Circle - Reno	345	KS
Cass Co. - S.W. Omaha (aka S3454)	345	NE
Gentleman - Hooker Co. - Wheeler Co.	345	NE
Tolk - Potter Co.	345	TX
Grand Island - Wheeler Co. rebuild[2]	345	NE
Hitchland - Potter Co.	345	TX, OK
Woodward District EHV - Woodring	345	OK
Mingo - Post Rock	345	KS
Holt - Hoskins - Ft. Calhoun	345	NE
Ft Calhoun - S3454	345	NE

[2] Rebuild from 720 MVA to 1,195 MVA.

Robust Plan 1 Elements	kV	State
Tuco - Amoco - Lea County - Hobbs	345	NM, TX
Keystone - Ogallala	345	NE
Wheeler Co. - Shell Creek	345	NE

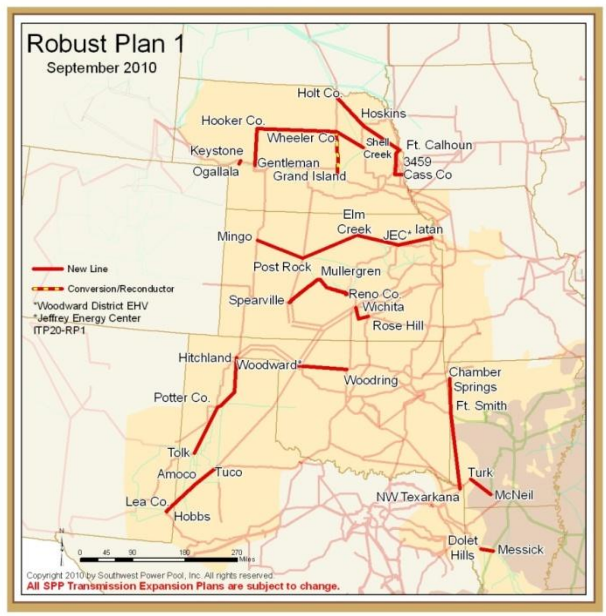
Elements of Robust Plan 1

Robust Plan 1 meets the following goals and is the right step towards the development of a transmission grid which will best accommodate the impacts of all four futures:

- Integrating west to east transfers
- Supporting Aggregate Transmission Service Studies
- Supporting Generation Interconnection queue
- Relieving known congestion

The plan is a high performer on most of the metrics and also yields a high Adjusted Production Cost-based Benefit to Cost ratio (APC-based B/C). The estimated annual transmission construction cost of Robust Plan 1 is $2.45 billion[3] in engineering and construction costs (E&C). The annualized carrying charge is $417 million[4] with annual quantifiable benefits of $1.8 billion and a 40-Year APC-based B/C of 4.06.

In addition to the APC derived benefit, Robust Plan 1 provides substantial qualitative improvement. A presentation of these enhancements and the APC savings is included in Section 15: Benefits of this report.



- Providing a Competitive Environment in SPP Markets
- Increasing System Reliability
- Preparing for Unexpected Shifts in Load
- Anticipating Import and Export Opportunities
- Broadening Resource Siting Options
- Valuing Cleaner Air
- Reducing Risk through Responsible Land Usage
- Increasing Efficiency with Reduced Transmission Losses

This plan enables SPP to respond to potential state and federal policy initiatives such as an RES or carbon mandate. Robust Plan 1 provides transmission upgrades in eight states in the SPP footprint. In addition to the previously described quantitative and qualitative value, the plan also addresses the SPPT's goals for transmission development for the ITP:

- Focus on regional needs, while considering local needs
- Better position SPP to proactively prepare for and respond to national priorities while providing flexibility to adjust expansion plans
- Incorporate a 20-year physical modeling and 40-year financial analysis timeframe

[3] $2.45 billion cost and $637 million in quantifiable benefit are given in real 2010 dollars.
[4] For this calculation an annual carrying charge rate of 17%.

- Design a backbone transmission system to serve known load with known resources in a cost-effective manner

At wind levels above 12 GW, analysis indicated that the system requires substantial reactive compensation beyond reasonable 345 kV design ability. Wind levels in SPP are currently at 4 GW, the adoption of an RES could increase the wind levels beyond this 12 GW to 16.5 GW in future years. To achieve the current renewable targets (Business as Usual future), a robust 345 kV network is required. Robust Plan 1 will allow the region to support the Business as Usual future. In the event that higher renewable levels are required, this plan will additionally serve as a strong base to connect future 765 kV development to the underlying system. Therefore, staff recommends the adoption of Robust Plan 1 and additionally recommends that 765 kV transmission be considered for wind levels beyond the 12 GW.

On January 11, 2011, the Markets and Operations Policy Committee accepted the 2010 ITP20 Report and endorsed the ITP20 Cost Effective Plan.

On January 25, 2011, the SPP Board of Directors approved the 2010 ITP20 Report and approved the ITP20 Cost Effective Plan.

Part I: Study Process

Section 1: Introduction

1.1: The 20-Year ITP

The 20-Year Integrated Transmission Plan (ITP20) is SPP's new long-term planning process, designed to go beyond previous transmission plans by incorporating new value metrics that will allow transmission to become an enabling solution to regional and national issues and extend the study horizon from ten years to twenty years.

This report is the first of the ITP20 studies and focuses on the year 2030 (20 years from 2010). The ITP20 study focused on the continued design of the SPP region's EHV system and development of a backbone system that would provide flexibility and value to SPP's members.

1.2: Policy Considerations

In April 2010, SPP published its Priority Project analysis, which included SPP's most recent planning effort. In that analysis, renewable energy scenarios were developed which considered wind resources within SPP needed to meet SPP states' respective RES targets or goals, and to meet a 20% federal RES.

Since the Priority Project analysis was completed, a number of public policy initiatives have been approved which impact the electric utility industry. Oklahoma has set a goal of 15% renewable capacity[5] by 2015 and Missouri regulators approved rules implementing Proposition C, a statewide initiative for a 15% RES by 2021. In September 2010, the bipartisan Governors' Wind Energy Coalition - representing 26 states including Arkansas, Kansas, New Mexico, and Oklahoma - sent a letter to Senate leaders urging them to pass a strong RES. A bipartisan bill was filed in the Senate on September 21 that would establish a nationwide 15% RES by 2021.

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 (SO_2). Additionally in 2010, the EPA opened rulemaking dockets to develop and implement standards to reduce the transfer of SO_2 and nitrogen oxide (NO_x) 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 which will be borne by industry participants and ratepayers.

Pending climate change legislation may also impact the industry. According to a July 27, 2010 North American Electric Reliability Corporation (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 appeal filed with the United States Supreme Court has challenged the authority of traditional venues to deal with climate change issues. In September 2010, Attorneys General from a dozen states, including Arkansas, Kansas, and Nebraska, filed a brief requesting Supreme Court review of AEP v. Connecticut[6]. This case involves the right of courts to assert jurisdiction over particular cases involving

[5] Correction made on 6-30-2011; the Oklahoma RES is a goal, not a mandate.

[6] See Connecticut v. Am. Elec. Power Co., 582 F.3d 309 (2d Cir. 2009), petition for cert. filed, (U.S. Aug. 2, 2010) (No. 10-174).

issues traditionally delegated to the legislative or executive branches of government, such as the regulation of emissions. The outcome of this case may allow a state or private citizen to sue a utility directly in a state or federal court for determination of issues related to climate change.

In June 2010, FERC opened a Notice of Proposed Rulemaking (NOPR)*, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* (FERC Docket RM10-23) to address multiple issues related to transmission planning and cost allocation. Numerous comments have been filed in response. The NOPR proposed rule would: (1) Provide that local and regional transmission planning processes account for transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) Improve coordination between neighboring transmission planning regions with respect to interregional facilities; and (3) Remove from FERC-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a non-incumbent transmission developer.

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 ITP20 report.

1.3: Process Development Background

Synergistic Planning Project Team

The ITP resulted from the efforts of the Synergistic Planning Project Team (SPPT) to improve SPP's transmission planning processes. This report, the first ITP20 report in a cycle designed to repeat every three years, addresses the SPPT's goals:

- Focus on regional needs,
- Better position SPP to proactively prepare for and respond to national priorities while providing flexibility to adapt expansion plans
- Incorporate a 20-year physical modeling and 40-year financial analysis timeframe
- Design a backbone transmission system to serve known load with known resources in a cost-effective manner:
    - Enhance interconnections between SPP's western and eastern regions
    - Strengthen existing ties to the Eastern Interconnection
    - Provide options for planning and coordination to the Western Electricity Coordinating Council (WECC) and the Electric Reliability Council of Texas (ERCOT) grids in the future

Questions and Comments

SPP encourages all stakeholders to commit to involvement in and providing input to its study processes. Requests for further information, data, and comments pertaining to this report should be directed to the SPP Economic Studies department at planning@spp.org. Stakeholders that have provided comments throughout the study process can find their feedback and staff comments on SPP.org[7]

[7] SPP.org > Engineering > Integrated Transmission Planning > ITP20 Stakeholder Feedback and SPP Comments

1.4: How to Read This Report

Report Sections

This report is divided into multiple sections. Part I addresses the concepts behind this study's approach, key procedural steps in development of the analysis, and overarching assumptions used in the study. Part II describes each study step, empirical results, and conclusions. Part III addresses the portfolio specific results and discusses the robustness metrics and stability results in detail. Part IV includes detailed data and holds the report's appendix material.

Accurately Viewing this Document

In the program used to view this PDF (Adobe Reader 9 is recommended) reset the Page Display resolution preference to 220 pixels/inch using the following the menus: Edit > Preferences > Page Display > Custom resolution. This will ensure that all maps and images retain their clarity.

Supporting Documents

Development of this study was guided by the supporting documents noted below. These living documents exist beyond the completion of this study, and will provide structure for future ITP20 studies:

- SPP ITP 20 Scope / Timeline[8]
- SPP ITP Manual[9]
- SPP Robustness Metrics Procedural Manual[10]
- SPP Futures for ITP Year 20 Assessment[8]
- Black & Veatch ITP 20 Generator Resources Report[11]

All referenced reports and documents contained in this report are available on SPP.org.

Appendices

The appendices contain information vital to the report conclusions. Highly detailed data, such as the outputs from powerflow simulations, are not included unless otherwise specified.

- Appendix A1: Transmission Projects Evaluated
- Appendix A2: Transmission Portfolios & Cost Estimates
- Appendix A3: Metric Results
- Appendix A4: High Resolution Map Images
- Appendix A5: Resource Siting and Plans
- Appendix A6: Results of the CAWG Survey
- Appendix A7: Limited Reliability Assessment
- Appendix A8: ITP20 Stability Analysis
- Appendix A9: Rate Impact & Unintended Consequences Tables
- Appendix A10: Frequently Asked Questions
- Appendix A11: ITP20 Report Glossary

8 SPP.org > Engineering > Transmission Planning > Integrated Transmission Planning > ITP 20-Year Assessment
9 SPP.org > Engineering > Transmission Planning > ITP Manual
10 SPP.org > Engineering > Transmission Planning > Robustness Metrics Manual
11 SPP.org > Engineering > Transmission Planning > Integrated Transmission Planning > ITP20-Year Assessment

- Appendix A12: ITP20 Figures & Tables

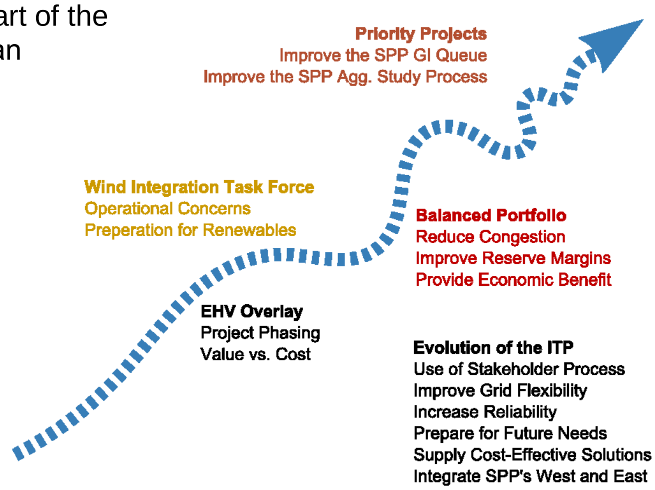
Confidentiality and Open Access

Proprietary information is frequently exchanged between SPP and its stakeholders in the course of any study, and was extensively used during ITP20 development. This report does not contain confidential marketing data, pricing information, marketing strategies, or other data not acceptable for release into the public domain. This report does disclose planning and operational matters, including the outcome of certain contingencies, operating transfer capabilities, and plans for new facilities as those are considered non-sensitive data.

Section 2: Evolution and Direction of EHV Transmission Planning

2.1: Historical Evolution

The ITP20 study process incorporated elements from four key studies performed by SPP; it will continue to mature through each successive ITP20 cycle. Past SPP studies such as the EHV Overlay, Wind Integration Task Force, Balanced Portfolio, and Priority Projects 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 ITP20 study process as part of the Synergistic Planning Project Team's vision for an Integrated Transmission Plan.



SPP staff and stakeholders approached the ITP20 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. The ITP20 process aims to incorporate these diverse goals into a consistent study cycle.

2.2: EHV Overlay Study

2007 EHV Overlay Report

This June 2007 report, prepared by Quanta Technology and PowerWorld, provided a long-range, strategic assessment, resulting in a plan to meet SPP's future reliability and capacity needs through use of a 345 kV, 500 kV, and 765 kV or higher transmission system overlaying the SPP footprint. It also assessed potential integration with neighboring systems.

The study team developed a screening methodology to test many different line configurations. Detailed analysis using on-peak cases was performed on six different alternatives. Alternative 5, the 765 kV plan shown in Figure 2.1, was judged to be the top performing alternative based on the final analysis.

Alternative 5 projects were determined to provide an EHV backbone that would maintain reliability for SPP members and communities; increase the import and export capabilities of SPP to ERCOT, WECC and the Eastern Interconnection; and result in the lowest line losses on peak when compared to the other five alternatives. The full report is available on SPP.org.

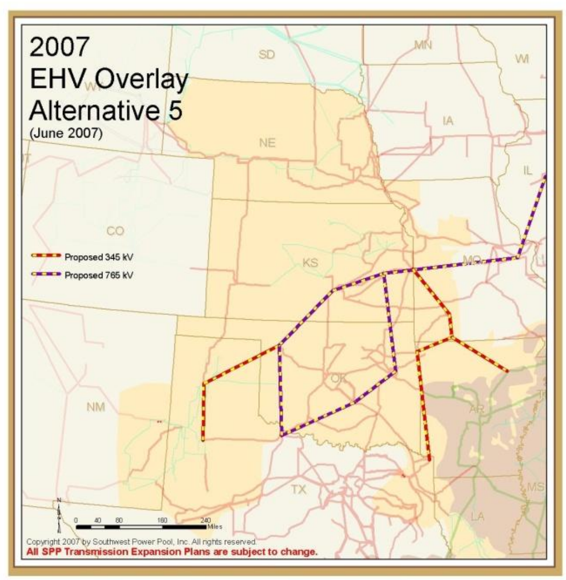


Figure 2.1: Alternative 5 EHV Overlay

Updated SPP EHV Overlay Report

Quanta Technology published a revised EHV Overlay report in March 2008, which evaluated the effects of intensifying wind development activity in portions of the SPP system. The update was based on the EHV recommendation developed in the 2007 EHV Overlay Study. The updated study incorporated decisions regarding the development of certain lines in the western portion of SPP's 2006 "X Plan" (Kansas/Panhandle Sub-Regional Transmission Study).

Quanta Technology evaluated a variety of options to adjust the top-performing design (Alternative 5) from the original EHV Overlay Study. Four designs were developed, and their performance was compared. Mid Point Design 2 and Mid Point Design 4 (Figure 2.2) were recommended for inclusion in the SPP economic benefits evaluation reported in the 2008 SPP EHV Overlay Report. Quanta Technology recommended that all designs be included in the Joint Coordinated System Planning discussions and be considered in inter-regional analysis.

Mid Point Design 2 and Mid Point Design 4 were top-performing designs for the following reasons:

- Provided the best ratio of performance/cost
- Responded as flexible designs that provided beneficial reliability reinforcement to key load centers such as Oklahoma City, Kansas City, and Wichita
- Showed the ability to extend interconnections to the east effectively over a variety of different paths
- Supported the ability of SPP's members, stakeholders, states, and communities within its territory to become leading providers of renewable energy to the U.S.

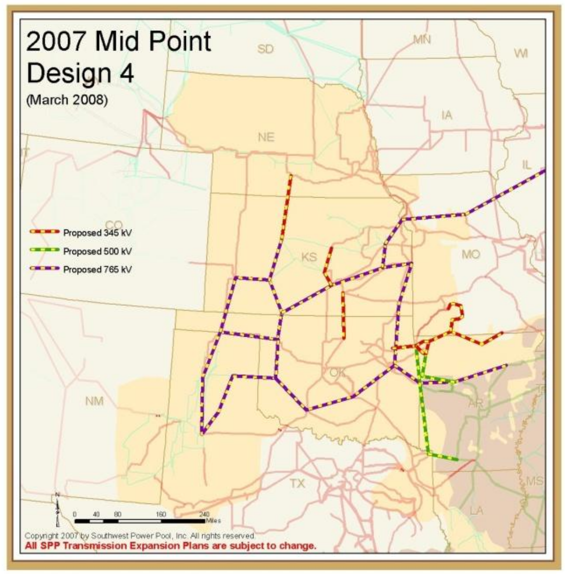


Figure 2.2: Mid Point Design 4

The updated EHV Study developed a construction sequence for the EHV Overlay projects. Quanta Technology identified three main construction packages. The study recommended that projects in Package 1 be constructed for initial operation at 345 kV with ultimate operation at 765 kV. Key construction trigger levels for projects in Package 1 were also identified.

As seen in Appendix 4 of the Updated EHV Overlay Study, Quanta Technology performed an evaluation of a 345 kV build out for the SPP Overlay. The project team used the model from the original EHV Overlay Study and created a plan that used the same terminations and achieved roughly the same level of performance as the top-rated design (Alternative 5) from the original EHV Overlay study.

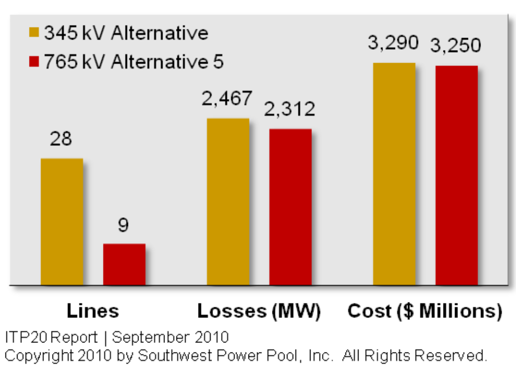


Figure 2.3: Cost Comparison of 345 kV and 765 kV – 2008 Study

To achieve performance similar to Alternative 5, the 345 kV design required twenty-eight lines, compared to Alternative 5's nine lines. The on-peak losses for the 345 kV design was 2,467 MWs versus 2,312 MWs for Alternative 5. Using the cost estimates from the 2007 study, the transmission line-only cost estimate for the 345 kV package was $3.29 billion compared to an estimated $3.25 billion for the transmission lines in Alternative 5 (Figure 2.3). The full report is available on SPP.org.

December 2008 SPP EHV Overlay Report

SPP continued to study the EHV Overlay and published a follow-up report in December 2008. The study was an effort to quantify the benefits of a 765 kV EHV Overlay expansion in the SPP footprint. The study focused on the economic impact of the 765 kV EHV Overlay, going beyond the original reliability impact and feasibility studies completed in the two previous EHV Studies. Adjusted Production Costs (APC) savings were used to measure the impact of the 765 kV EHV Overlay expansion to a particular zone's production cost, taking into account economic purchases and sales of energy between entities.

The study considered three futures of wind expansion in SPP's region. The first future, the low wind scenario, considered 3.3 and 6.6 GW in 2017 and 2027. The second future, the expected wind scenario, considered 7 and 13.5 GW in 2017 and 2027. The third future, the high wind scenario, considered 10.5 and 21 GW in 2017 and 2027. APC analysis was used to determine the expected benefit of transmission expansion projects.

The report showed that a group of 765 kV transmission expansion projects that would accommodate 13.5 GW of wind integration in the 2027 expected wind scenario provided a benefit-to-cost (B/C) ratio greater than 1. A sensitivity analysis that included an extension of the overlay into Nebraska showed a B/C ratio greater than 1 as well.

Figure 2.4 from the 2008 SPP EHV Overlay Report shows the EHV build-out for 2027 with 15.5 GW of expected wind development following the integration of facilities in Nebraska. The full report is available on SPP.org.

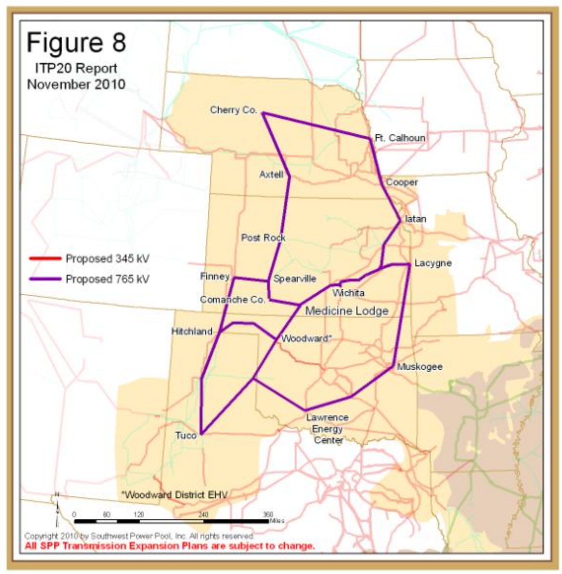


Figure 2.4: Phase 3 - EHV Overlay

2.3: Wind Integration Task Force

The Market and Operations Policy Committee (MOPC) voted to fund a study to review the operational effects of wind on the entire SPP footprint. This study would complement other studies being conducted to consider the effects of additional wind generation in various areas of the SPP footprint. To this end, the MOPC approved the formation and charter of the Wind Integration Task Force (WITF) in 2008.

The WITF conducted studies and reviewed previous studies to determine the impact of integrating wind generation into SPP's transmission system and energy markets. These impacts were both planning and operational in nature.

The goal of the study was to identify the challenges of integrating high levels of wind into the SPP transmission system. Charles River and Associates (CRA) performed the study for the year 2010 with the assumption that SPP would operate as a single Balancing Authority (BA) with a co-optimized energy and Day Ahead market. Three wind penetration levels were studied, and each was compared to the current system conditions (Base Case, with approximately 4% wind penetration). The three penetration levels were 10%, 20%, and 40% by annual energy (10% Case, 20% Case, and 40% Case, respectively). Detailed studies were performed on the 10% and 20% Cases. The 40% Case was examined in those portions of the study that related to wind characteristics. Table 2.1 shows the wind generation capacity for each wind penetration level.

	Base Case	10% Case	20% Case	40% Case
Number of Wind Farms	4	69	100	142
Installed Nameplate Wind Capacity (MW)	2,877	6,840	13,674	25,003
Wind/Non-Wind Nameplate Capacity Ratio	0.046	0.109	0.217	0.397

Table 2.1: Wind Generation Capacity in WITF Study

To meet the study's objective, it was necessary to identify transmission upgrades needed to accommodate the studied wind power additions with minimal curtailment. The study was not treated as an economic study; economic optimization, such as an analysis of the tradeoff between building transmission upgrades and curtailing wind, was not performed. The transmission upgrades implemented in the study were based on the assumed wind plant locations and sizes.

The study led to the identification of transmission upgrades needed to accommodate the wind plant additions associated with each penetration level. The transmission upgrades were studied using several different approaches, including voltage analysis, dynamic stability analysis, and available transfer capability (ATC) analysis. The results of the wind characteristics analysis and transmission analysis were used to analyze the impact of wind power on ancillary services (reserves in particular), as well as their impact on the dynamic system operations via a production simulation. The production simulation analyzed the effects of increased wind power on congestion patterns, unit commitment and dispatch decisions, and forecasting errors. Additionally, intra-hour simulations were performed for a selected day to address the challenges of wind variability.

Due to wind generation resources being primarily concentrated in the western portion of the SPP footprint, the increase in the wind penetration level caused changes in the power flow patterns requiring upgrades and/or reconfigurations to the transmission system. In particular, the power flows from western SPP to eastern SPP increased significantly. A number of transmission expansions were required to accommodate the increased west-to-east flows while meeting the reliability standards of the SPP Criteria. They included new transmission lines totaling 1,260 miles of 345 kV and 40 miles of 230 kV lines for the 10% Case. For the 20% Case, an additional 485 miles of 765 kV, 766 miles of 345 kV, 205 miles of 230 kV, and 25 miles of 115 kV lines were needed.

The study found that, with all needed transmission upgrades in place, integrating the levels of wind studied in the 10% and 20% Cases could be attained without adversely impacting SPP system reliability. Although localized voltage issues and transmission congestion were observed, average wind curtailment levels were around 1% for both the 10% and 20% Cases.

The analytical results of the study showed there were no significant technical barriers to integrating wind generation to a 20% penetration level into the SPP system, provided that sufficient transmission would be built to support it. The study, however, did not include an optimization of the level of transmission expansion required to support wind integration. The full report is available on SPP.org.

2.4: Balanced Portfolio

The Balanced Portfolio[12] was an SPP strategic initiative to develop a cohesive group of economic upgrades that would benefit the SPP region, with a

Figure 2.5: Balanced Portfolio

[12] *See* SPP Open Access Transmission Tariff ("SPP OATT") Attachment J, Section IV.

cost component of allocating upgrade costs regionally. The economic upgrades in the Balanced Portfolio were intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. The economic upgrades could also provide potential additional benefits to the power grid such as increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Balanced Portfolio of projects was approved by the SPP Board of Directors in April 2009, pending issuance of the Balanced Portfolio report. In June 2009, SPP issued Notification to Construct (NTC) letters for the approved projects. The full report and NTCs are available on SPP.org.

2.5: Priority Projects

In April 2009, SPP was directed by the SPP Board of Directors to implement the Synergistic Planning Project Team's recommendations for creating a robust, flexible, and cost-effective transmission system for the region which was large enough in both scale and geography to meet SPP's future needs. The development of Priority Projects was one major recommendation; the others were to develop the ITP process that improves and integrates SPP's existing planning processes, and to implement a new cost allocation methodology.

SPP was charged with identifying, evaluating, and recommending Priority Projects that would improve the SPP transmission system and benefit the region while specifically targeting projects that would reduce grid congestion, improve the Generation Interconnection and Aggregate Study processes, and better integrate SPP's eastern and western regions. The Priority Projects were intended to be an interim measure while the ITP process[13] was developed to ensure momentum gained from past studies and current processes would not be lost, and to tie the eastern and western sections of the region together.

In April 2010, the SPP Board of Directors and Members Committee approved for construction Priority Projects estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years. The projects will improve the regional electric grid by reducing congestion, better integrating SPP's east and west regions, improving SPP members' ability to deliver power to customers, and facilitating the addition of new renewable and non-renewable generation to the electric grid. The full report is available on SPP.org.

Figure 2.6: Priority Projects

[13] *See* SPP OATT Attachment J, Section III, 5 and Attachment O Sections I and III.

Section 3: Utilization of 345, 500, or 765 kV

3.1: Voltage Levels

The ITP20 focuses on developing a long-term EHV transmission backbone for the SPP system. When developing the plan, much consideration was given to the voltage level that would be selected for the projects. Options included the use of 345 kV, 500 kV or 765 kV.

3.2: EHV Design Considerations

When considering the design of an EHV grid, many factors must be considered, such as contingency planning, typical line lengths, line loadability, capacity requirements, voltage, reliability, cost, asset life, and operational issues.

N-1 NERC Reliability Standards

SPP designs and operates its transmission system to be capable of withstanding the next transmission outage that may occur – this is called "N-1" planning and is in accordance with NERC planning standards. Due to N-1 planning, any EHV network must be looped so that if one element of the EHV grid is lost, a parallel path will exist to move that power across the grid and avoid overloading the underlying transmission lines. One EHV line does not provide much in the way of benefit, as it would be assumed to be out of service during a contingency in planning and operational studies.

Distances within the SPP System

Line lengths are another factor when considering EHV transmission systems. The length of a transmission line affects its performance in terms of voltage, loadability, and stability. In the SPP region, the longest line currently in service is the 165 mile Eddy Co. to Tolk 345 kV. Distances between some metropolitan areas in the SPP footprint are listed in Table 3.1; approximately 500 miles is the longest distance within the system. However, EHV line lengths are likely to be in the 200 to 400 mile range.

From	To	Distance (mi)
Wichita, KS	Oklahoma City, OK	150
Tulsa, OK	Topeka, KS	200
Amarillo, TX	Oklahoma City, OK	250
Shreveport, LA	Oklahoma City, OK	300
Lincoln, NE	Fayetteville, AR	350
Oklahoma City, OK	Omaha, NE	400
Amarillo, TX	Kansas City, MO	480
Lubbock, TX	Topeka, KS	500
Lincoln, NE	Texarkana, TX	525
West Kansas Wind	Kansas City, KS	270
Oklahoma Panhandle Wind	Fort Smith, AR	340
Southwest Oklahoma Wind	Shreveport, LA	330

Table 3.1: Distances within the SPP System

When considering line length, it is necessary to consider the proximity of generation to load on the system. In the current SPP system, generation is generally located close to load centers. As wind capacity increases, some generation will concentrate in areas of high wind potential towards the western part of the system. Figure A5.7 in Appendix A5: Resource Siting and Plans shows the distance from the high wind locations to these western cities. It will become necessary to connect this generation with lines that are capable of moving power to the eastern portion of the system where the major load centers are located.

Line Length and Loadability

A line's length impacts its performance. A transmission line's loadibility can be estimated based on its length, voltage level, and the type of conductors utilized. A Surge Impedance Loading (SIL) level can be determined based on those parameters. When loadability is expressed in terms of SIL, a single curve known as the "St. Clair curve" can be used to estimate the maximum permissible loading for a given line length.[14] This measure takes into consideration practical limitations such as voltage drop and steady-state stability, thus providing greater insight into a line's actual transfer capability. Figure 3.1 shows the extended St. Clair curve. The curve is accompanied by a listing of common transmission line designs. The SIL of a new 765 kV line is about 2,400 MW.

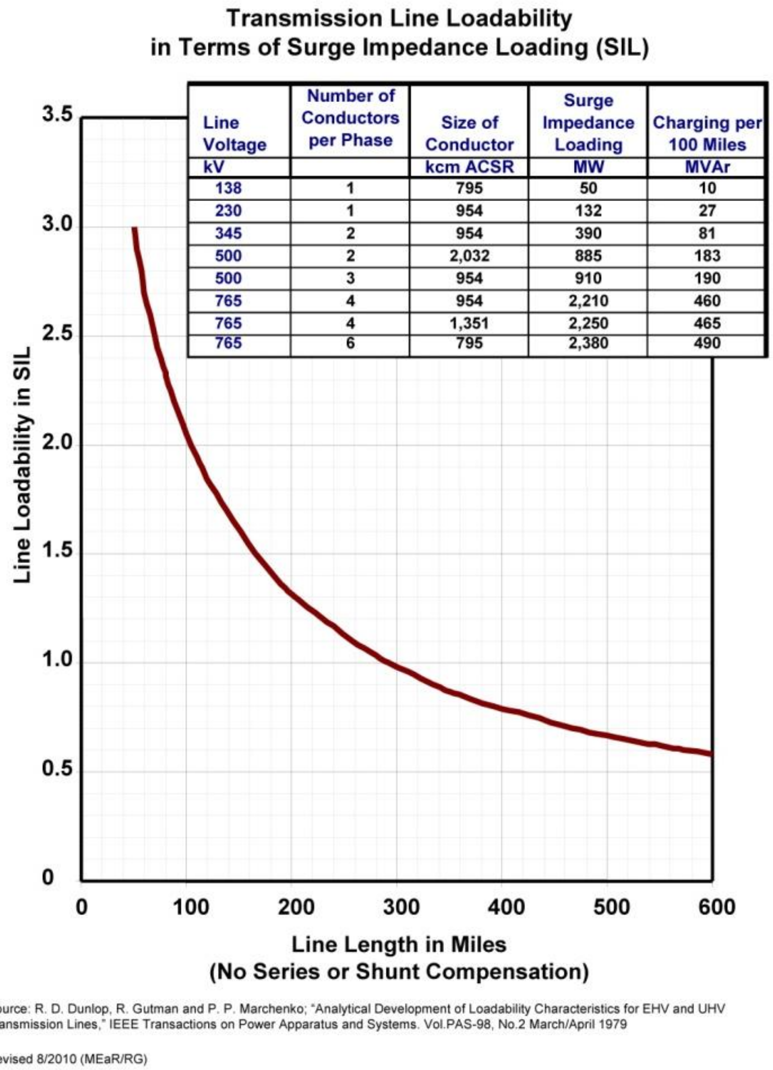


Figure 3.1: Line Loadability Curve

The extended St. Clair curve illustrates that as line length increases, loadability decreases. The decrease in loadability can be countered by using higher voltage transmission for longer distances.

Capacity Needs

In addition to loadability, capacity needs should be considered when designing EHV transmission. Generally, higher capacity lines are desired for their ability to move power across long distances. The typical capacity of a 345 kV line in the SPP system is 1,195 MVA and recently approved lines will use higher capacities of 1,792 MVA. Using double-circuit 345 kV or a higher voltage such as 765 kV will increase the capacity of those lines (see Table 3.2. When considering EHV designs, system voltage can be a factor in selecting the design.

Voltage Support

A transmission line can either support voltage (producing vars) or require voltage support from other reactive devices (consuming vars), depending its loading level. In either case, transmission system design should account for these factors. Under light-load conditions, system voltages may rise due to vars being produced from long EHV lines. Shunt reactors would be necessary to help mitigate the rise in voltage. Some lines may need additional support to allow more power to flow through them. Series capacitors may be added to increase the loadability of a transmission line. However, the addition of series compensation can complicate operations and may lead to stability concerns.

Construction Cost

Cost plays a factor in EHV grid design. Lower-voltage designs cost less to construct initially. Higher voltage lines have a larger initial investment but provide significantly higher capacity and more flexibility in bulk power transport. Lower voltage lines offer more flexibility to act as a collector system for wind generation. A 345 kV substation connection is considerably less costly than a 765 kV connection for a generator due to the costs of the step-up transformers. Along with the initial cost, the lifetime of the

[14] R.D. Dunlop, R. Gutman and P.P. Marchenko, "Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines," IEEE Transactions on Power Apparatus and Systems, Vol. 98, No. 2, March/April 1979.

asset needs to be considered. Transmission lines are generally assumed to have a 40-year life. Consideration should be made as to whether that asset will continue to be used after 40 years. Table 3.2 summarizes some of the key characteristics of 345 kV and 765 kV transmission lines.

	Single Ckt 345 kV	Double Ckt 345 kV	765 kV
Transmission Construction Costs ($/mi)	1,125,000	1,970,000	2,712,000
Substation costs ($)	10,500,000	10,500,000	25,100,000
Capacity (MVA)	1,792	3,584	5,671
Right-of-Way (ROW) Requirement (ft)	150	150	200
ROW for 765 kV equivalent capacity	900	450	200
SIL (MW)	390	780	2,380

Table 3.2: Comparison of Parameters for Line Types

3.3: Facts about Alternative Voltage Choices

There are several key advantages to 765 kV as opposed to a 345 kV transmission lines. Among those are higher capacity and loadability, reduced losses, and smaller right-of-way needs for an equivalent amount of capacity. There are some drawbacks to 765 kV lines, including higher initial costs, the need for a looped 765 kV grid, and voltage management.

Thermal Capacity

765 kV lines have much more thermal capacity than 500 kV or 345 kV lines due to the higher voltage and bundled conductors. In addition to the higher thermal capacity, 765 kV is capable of moving more power over longer distances. As Table 3.3 illustrates, a 300 mile 765 kV line is capable of moving 2,280 MW, compared to the 910 MW a single circuit 500 kV or the 741 MW a double circuit 345 kV line of the same lengths could move.

kV	SIL	50 Mi	100 Mi	150 Mi	200 Mi	250 Mi	300 Mi
765 kV Single Circuit (MW)[15]	2,400	7,200	4,800	3,840	3,120	2,640	2,280
500 kV Single Circuit (MW)[16]	910	2,730	1,820	1,460	1,180	1,000	910
345 kV Double Circuit (MW)[17]	780	2,340	1,560	1248	1,014	858	741
345 kV Single Circuit (MW)[17]	390	1,170	780	624	507	429	371

Table 3.3: Relative loadability for 765 kV and double circuit 345 kV lines of various lengths

Reduced Losses

Some energy loss occurs when power travels across a transmission line. A line's losses increase linearly with resistance, which is directly related to its conductor's design and length. Line losses also increase with loading (current). For an equivalent amount of power, a higher voltage line has a lower current flow, which translates into reduced energy losses. The relationship between energy loss and loading for typical 765 kV and double-circuit 345 kV lines is shown in Figure 3.2.

The reduction in losses can also reduce the need for additional generation capacity, thus reducing emissions the additional generation may produce.

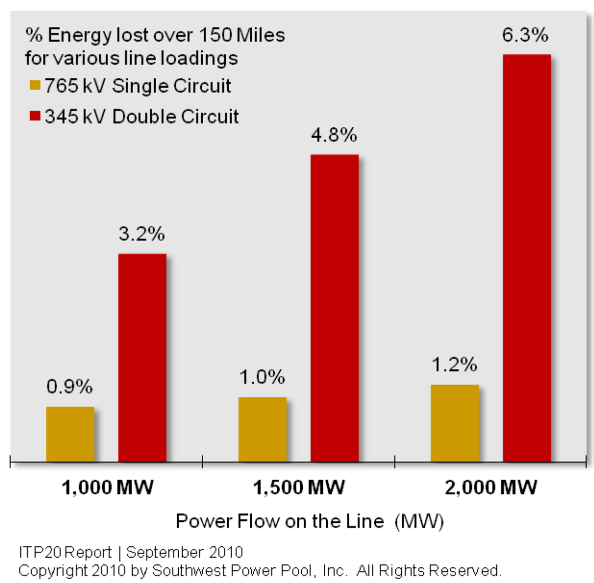


Figure 3.2: Energy Loss Comparison by kV (%)

[15] SIL with 6-795 ACSR conductors per phase
[16] SIL with 3-954 ACSR conductors per phase
[17] SIL with 2-954 ACSR conductors per phase

Several of the robustness metrics involve losses and emissions reductions.

Right-of-Way Needs

In terms of equivalent capacity, 765 kV rights-of-way (ROW) have smaller footprints than those needed for 500 kV or 345 kV. To transfer 2,300 MW over 300 miles, one 765 kV line would be needed compared to three double-circuit 345 kV lines or six single-circuit 345 kV lines. One 765 kV line would require 200 feet of ROW. Three double circuit 345 kV lines would require 450 feet of ROW, and six 345 kV lines would require 900 feet of ROW. Figure 3.3 illustrates the relative ROW for these different types of construction. Although not shown, the expected ROW needs with 500 kV circuits would require three single circuit towers and 600 feet of ROW.

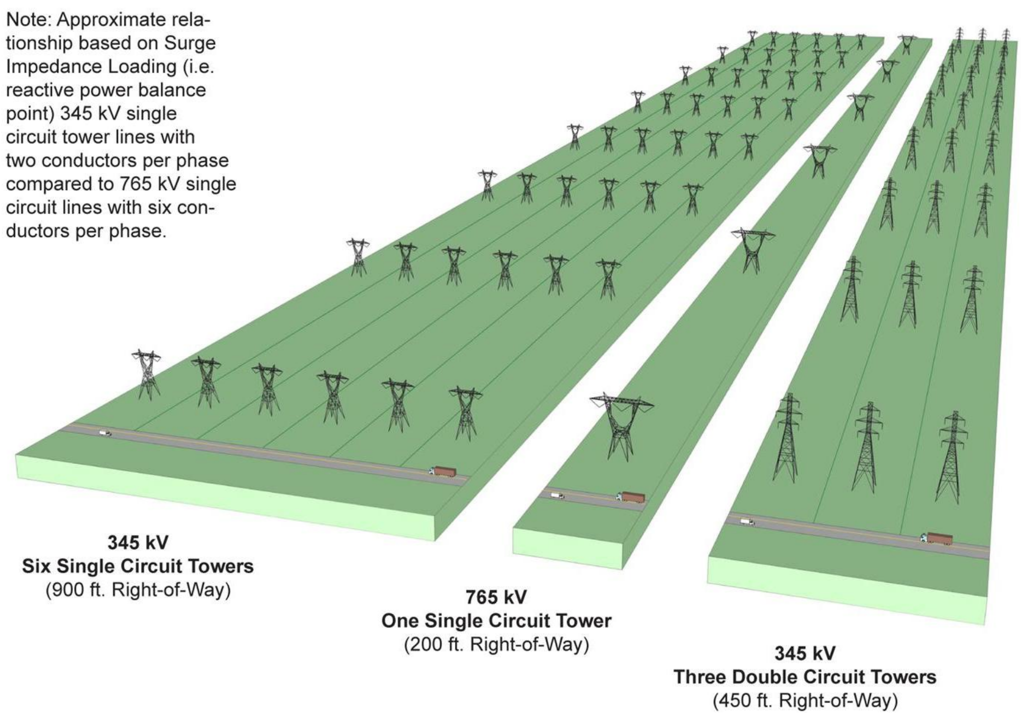


Figure 3.3: Relative right-of-way for equivalent loadability, courtesy AEP

One important aspect when considering ROW needs for transmission is the potential for future expansion, especially if the line is going to pass through an environmentally sensitive area. Once ROW has been acquired for a line, it may be difficult to acquire additional ROW along a particular corridor if needed. With 765 kV, a large amount of capacity is available to accommodate future expansion without the need for acquiring additional ROW.

Higher Costs

Table 3.2 shows the cost per mile for various configurations. 765 kV cost estimates are more than double the cost per mile for a single circuit 345 kV line. In addition to line costs, 765 kV substation equipment and transformers are much more expensive than similar 345 kV equipment.

A Complete Grid

A looped grid would be needed to maximize the capability of 765 kV lines. Parallel paths are needed to ensure continued reliable operation of the 765 kV system in the case of a contingency.

Voltage Management in Low Load Conditions

765 kV transmission lines can contribute to maintaining system voltage, but during periods of light-loads or switching operations, they could potentially cause high voltages on the system. The voltage

can be managed in these situations by the use of shunt reactive devices (an additional capital expense).

Underlying Grid Support of 765 kV

765 kV transmission lines provide a high voltage backbone for the system and will require lower voltage on and off ramps in order to connect the generation and load within the footprint to the backbone.

3.4: Voltage Level Selection in the ITP20

An important question addressed in the ITP20 process was to assess the need for a 765 kV network or further expansion of the 345 kV network within SPP. The process started with the development of expansion plan prototypes, which are discussed further in Section 5: Prototype Designs. From there, the Least-Cost Plans were developed. When the analysis moved into the Robustness testing phase, a 765 kV alternative was developed (Robust Plan 4). This alternative was compared to the 345 kV plans and exhibited significant benefit in many of the metrics that were calculated. However, the cost of the 765 kV alternative is much higher than that of the 345 kV plans being evaluated relative to the gain in projected benefits ($7.35B vs. $2.36B).

As a result of stakeholder feedback, two “right-sized” 765 kV plans were developed and are included as robust plans 5 and 6. Extensive stability analysis was conducted in an effort to fully appreciate the value created by each of the options. An overview of this analysis is presented in Section 14: Stability Analysis. The complete report can be found in Appendix A8: ITP20 Stability Analysis.

Consideration of Priority Projects at 765 kV

When the Priority Projects study was completed, projects were approved at 345 kV. The ITP process assessed whether the V-Plan lines should be constructed at 765 kV instead of double circuit 345 kV. These projects were included at 765 kV in robust plans 4, 5 and 6 presented later in this report.

Double Circuit 345 kV Towers

345 kV circuits could be planned to allow for future expansion along the same ROW through the use of double circuit towers. The first conductor could be strung and used until the extra capacity offered by the second conductor is needed. Construction costs at the outset of the project would be $363,000 per mile less than the construction of both conductors but flexibility along the same ROW would be gained through the tower’s design. The cost of constructing each of the robust plans discussed in this report with double circuit towers is shown in Appendix A2: Transmission Portfolios & Cost Estimates.

Section 4: Operating the Transmission Highway

4.1: The Operational Perspective

The ability of an EHV grid to withstand unexpected operational events is dependent on a design that considers both engineering planning and operational practicality. Both planning and operations are vital, yet different; the two functions need to work together. The ITP will place a greater emphasis on the integration of planning and operations than earlier planning efforts. Unforeseen operational obstacles must be mitigated in the operations horizon. SPP will improve this dynamic within the ITP by incorporating operational expertise and analysis.

Planning and operational analysis timeframes are different. SPP's planning staff performs studies from one to twenty-year timeframes, while SPP's operations staff studies real-time events within the next five-minutes to thirty-days. The challenge will be to incorporate the rich experience gained in the short-term operational horizon into long-range ITP studies, with a goal of minimizing future operational issues.

This ITP20 cycle included discussions with Operations staff regarding the behavior of seams with SPP's neighbors, high voltage transmission line outages, treatment of high wind generation in the spring, and the congestion on market constraints. Future study cycles will expand on those interactions. Initial findings are presented in this section; SPP plans to expand on these findings in future ITP20 cycles.

4.2: Operating Renewables

An expected increase in renewable capacity was accounted for in each of the futures presented in this report. Such an increase in wind generation will create challenges for planning and operational engineers and other personnel; i.e. System Operators. The WITF Wind Integration Study found that power flows from western SPP to eastern SPP increased significantly[18], and anticipated that additional investment in transmission lines, voltage control devices, and unit commitment capabilities would be needed. As wind plants continue to come online, proper consideration should be given to collecting these resources.

Special consideration should be given to SPP's seams with other high wind areas (such as South Dakota and Iowa). In particular, markets that experience an increased amount of wind generation, causing a broad range of parallel flow impacts on neighboring flow gates, should be considered. In these cases the impact on flowgates no longer is related to the load or the amount of point to point transactions in the system but is rather driven by the amount of wind generation. This type of seams interaction was not considered to stakeholder satisfaction in the ITP20, and should be improved in further study cycles. Probabilistic studies will be required to simulate the parallel flow impacts in long term studies from neighboring markets that have an increased amount of wind generation in their market footprint.

4.3: Operating Long Lines

The goal of designing a transmission backbone in the ITP20 necessitated evaluating long transmission lines. Long transmission lines and high voltages pose some unique challenges for operations staff of SPP's Reliability Coordinators, Balancing Authorities, and Transmission Owning organizations.

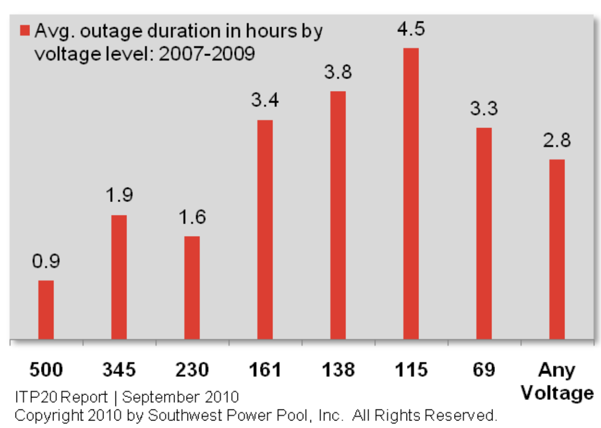


Figure 4.1: Average Outage Duration

[18] SPP.org > Org Groups > Wind Integration Task Force > WITF Documents

Long transmission lines contribute to fluctuations in system voltage levels due to the capacitive effect inherent in long, thin conductors elevated above the ground. When forced into an outage, these lines can serve as large capacitive sources and cause overvoltage conditions on the system. To reconnect the line safely, generation must be redispatched until voltage potentials and phase angles at the ends of the line are synchronized. The farther apart two line terminals are located in the system, the greater the possibility that generation levels must be adjusted. This can lead to less than economic conditions for generation marketers, Balancing Authorities, and participants in energy markets.

As generation shifts are required to re-energize lines, line outages may be prolonged until the generation can be appropriately dispatched. Such prolonged outages due to these system interdependencies occurred in 2010 and included the 345 kV line from Finny to Potter Co. via Hitchland, the 345 kV line from Red Willow to Mingo, and the 230 kV line from Concordia to Elm Creek. Average outage durations within the SPP footprint are shown in Figure 4.1 for each voltage level. SPP will continue to evaluate the interplay of system outage duration and economic dispatch in the continuing ITP cycle.

4.4: Outage Coordination

NERC standards mandate that the grid be planned for and operated so that N-1 conditions (in which one line is out of service) can be sustained. Accordingly, SPP's planning and operations functions thoroughly assess the grid for problems that may arise out of the loss of one line.

An analysis of planned and forced outages[19] in the SPP footprint for 2007-2009 illustrates the extra limitations faced by operations staff. The amount of time the system is operated in a state with at least one contingency leads to operational challenges. The average number of hours per year (of 8,760 possible hours) in which the system experienced at least one planned or forced outage is shown in Figure 4.2. For almost the entire timeframe, operations staff operated with a grid in an N-2 situation. While this fact is understood, the planning process is limited to addressing outages that impact each other, rather than all possible coincident outages.

The development of a robust transmission backbone will help operations staff by providing new, high capacity infrastructure that improves overall reliability.

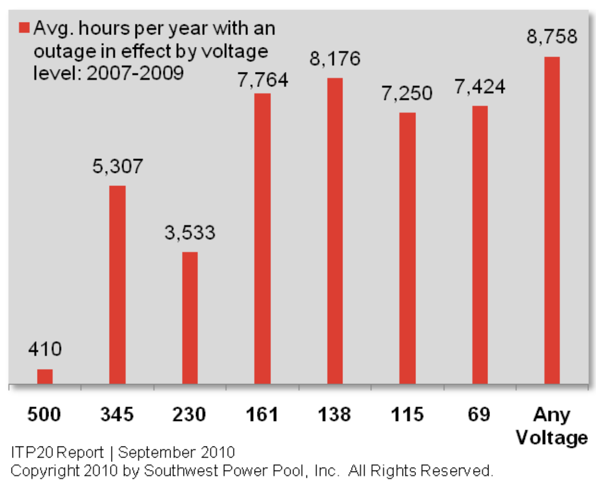


Figure 4.2: Average Outage Hours per Year (2007-2009)

4.5: Operational Awareness

Much of what occurs within a system operations center depends on the operator's ability to see and understand the behavior of the grid in near real-time. This necessity, often referred to as "situational awareness", must be taken into account as the system is planned for future operation. Consequences could be catastrophic if situational awareness is lost. As SPP plans for the future, consideration should be given to how transmission plans might better facilitate system situational awareness. Steps that can accomplish this include the use of unique substation names, avoidance of complicated relaying procedures, and avoidance of special switching schemes for standard operation.

The planning process often identifies transmission improvements which can benefit operations in outage scheduling, system protection, operating guides, and new generation interconnections.

[19] For a definition of forced and planned outages, please consult SPP Criteria.

4.6: Market Differences

As SPP's wholesale energy markets continue to evolve, the tools and assumptions inherent to the planning process must also evolve. Integration of historical market behaviors and future planning forecasts will become key factors in decision-making, and will allow SPP to gain further confidence in analytical results obtained from its toolset. As market operations and future simulations synchronize, the identified robustness of key projects will become apparent.

As a part of the Integrated Marketplace effort, new opportunities for planning coordination may become apparent. SPP plans to offer congestion hedging rights up to one year. Market participants who hold firm transmission rights will be offered Auction Revenue Rights, which can be converted into Transmission Congestion Rights. Firm transmission service will not be awarded in the ITP20 process, so it will have minimal to no impact on SPP's congestion hedging process.

The monthly State of the Market report, published by SPP, includes analysis of operational issues that may be mitigated by planned projects[20].

4.7: Demand Response

Demand response participation is present in the SPP Energy Imbalance Service (EIS) Market, and demand response resources are currently treated equally to generation resources. Although approximately 1,500 MW of demand response participates in the EIS Market, FERC Orders in Docket No. RM07-19 (Order Nos. 719 and 719-A) require SPP to make revisions to its Tariff to further enhance the abilities of demand response resources to participate in the market. Currently, opportunities for SPP's demand response resources are limited due to the nature of the 5-minute dispatched EIS market and the limited nature of regional retail demand response programs. The latest revisions to enhance demand response participation in the EIS Market required by FERC were filed on May 19, 2010 and are pending approval.

SPP is developing an Integrated Marketplace that will include day-ahead and operating reserves markets with unit commitment, scheduled to be implemented by 2014 (pending SPP stakeholder and FERC approval). Proposed market rules incorporate the same requirements that Order No. 719 required for demand response resources as those recently filed for the EIS Market. These provisions will provide for increased demand response opportunities in the Integrated Marketplace. Demand response resources will have more flexibility in the day-ahead market to provide energy and other ancillary services (i.e., ability of demand response resources to plan offers into a day-ahead market and offer different levels of reserve products). It is likely that demand response resources will play a much larger role in the near future. SPP plans to include consideration of demand response resources in its future ITP plans where applicable.

There are activities at several state commissions in the SPP footprint relating to Order No. 719 and 719-A. Arkansas, Kansas, Missouri, and Oklahoma have dockets open to investigate how Order Nos. 719 and 719-A will affect state jurisdictional issues, such as whether laws or regulations permit aggregation of retail customers and whether federal initiatives conflict with state-specific demand response initiatives. The dockets are on hold pending an order from FERC in SPP's May 19, 2010 filing.

4.8: AFC Coordination

A focus on longer EHV lines as part of a system backbone will increase interaction with SPP's neighbors in terms of flowgate impacts across Regional Transmission Organization/Independent System Operator borders. This added challenge should be accounted for in planning analyses. Enhancements to planning and operational coordination are in progress with neighboring transmission

[20] Refer to SPP.org > Market > Market Reports for the latest SPP Monthly State of the Market Report.

entities. Consult Section 12: Seams Coordination for information regarding these interactions in this ITP20 cycle.

4.9: Spares and Replacement Equipment Strategy

There are important logistical concerns related to spare and replacement equipment strategies. The additional use of another voltage level within SPP would cause members to maintain and backup new levels of equipment beyond those employed today. NERC standards continue to be discussed that may change the way replacement equipment is shared, stored, or maintained. The NERC Members Representative Committee recently formed the Spare Equipment Task Force (SETF) . These concerns should be evaluated as new transmission such as HVDC, 765 kV, and 500 kV devices are considered.

Section 5: Prototype Designs

5.1: Overview

To generate discussion among stakeholders and provide the ITP20 with a fresh approach to EHV backbone design, SPP staff presented prototype designs as hypothetical overlays. The designs were non-binding experiments that considered new potential transmission corridors and transmission connections. This section outlines the prototypes that were presented by SPP staff for stakeholder feedback, lists projects that were suggested for other stages of the ITP20, and includes stakeholder comments received in response to these ideas.

5.2: Prototype Development

Staff developed the prototypes with various goals in mind, including integration of SPP's western and eastern sections, efficient overlay shape, efficient use of conductor lengths, concepts gathered from previous SPP EHV designs, techniques used in ongoing studies in other regions, location of key collector grids, awareness of regional benefit and cost allocation, creation of a strong EHV backbone, and opportunities for integration across SPP seams.

5.3: Prototypes

Five prototypes were explored by SPP staff and stakeholders: the Delta Plan, Modified Figure 8, Triangle, Refined Figure 8, and EHV Overlay.

Delta Plan

The Delta Plan prototype, shown in Figure 5.1, was developed to explore greater north to south connections between SPP and South Dakota and between the Western Interconnection and SPP. Like many of the designs, this prototype included a bus bar-like line running from west to east in the northern section of Kansas tying the borders of the system together.

Modified Figure Eight

The Modified Figure 8 prototype, shown in Figure 5.2, was proposed to identify limitations to EHV expansion, depending on the selection of different voltage levels for the Priority Projects within the framework of the 2008 SPP EHV Overlay.

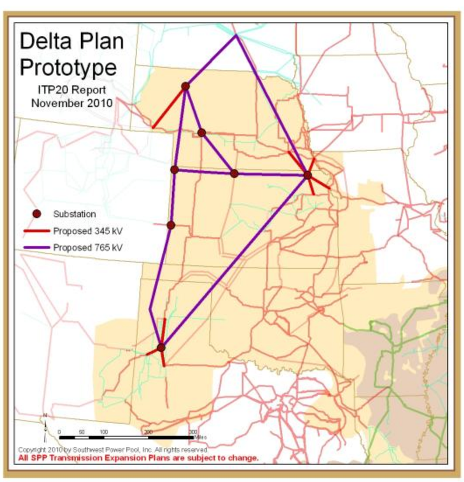


Figure 5.1: Delta Plan Prototype

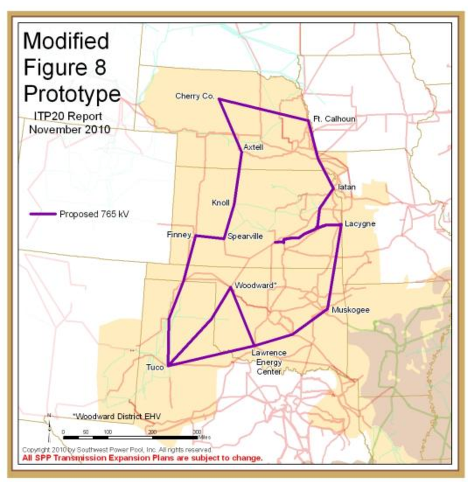


Figure 5.2: Modified Figure 8 Prototype

Triangle

The Triangle prototype, shown in Figure 5.3, was developed as experimentation into the use of truss-like connections in lieu of the standard loops and squares used in most EHV backbone designs. The design gained the benefit of N-1 protection with fewer line miles and substation terminals.

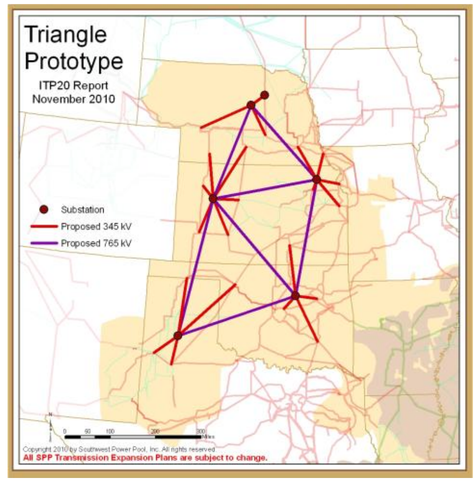


Figure 5.3: Triangle Prototype

Refined Figure 8

The Refined Figure 8 prototype, shown in Figure 5.4, was developed as an evolutionary step from the EHV Overlay concept. The plan introduces the concept of a north - south corridor to the far west of SPP and some primary tie-in points to first tier areas in Iowa, Missouri, and Arkansas.

2008 Figure 8

SPP developed the EHV Overlay concept, shown in Figure 5.5, in 2006 under the direction of the Transmission Working Group (TWG). The original report published in June 2007, along with additional materials and subsequent studies, may be found on SPP.org.

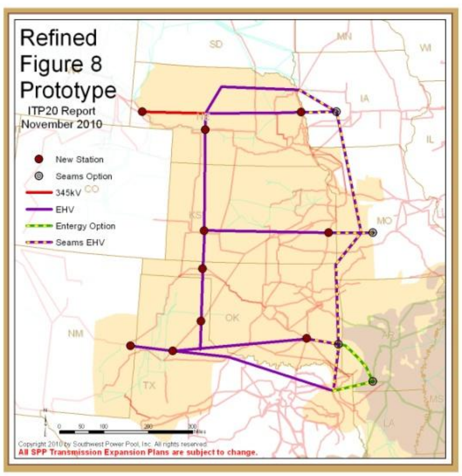


Figure 5.4: Refined Figure 8 Prototype

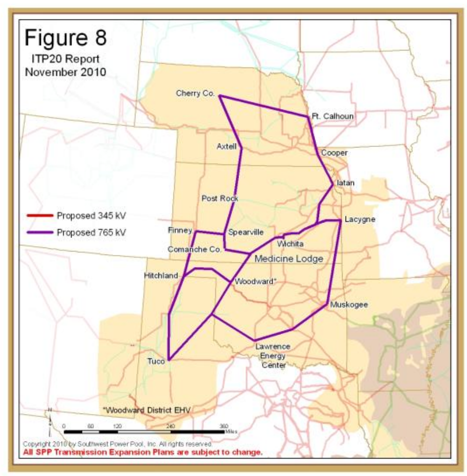


Figure 5.5: Figure 8

5.4: Preliminary Analysis

As a preliminary step to analysis in the least-cost, cost-effective, and robustness evaluations, three First Contingency Incremental Transfer Capability (FCITC) calculations were performed using PTI's MUST package on the prototypes to provide insight into the increase in transfer capability possible for each prototype.

Transfers calculated included existing and generic wind (as modeled in the Priority Projects study) to SPP load, all SPP generation to all other SPP load, and western SPP generation (renewable and conventional) to eastern SPP load. Each transfer specifically studied the increase in transfer capability and did not attempt to identify the exact transfer limit for any particular study.

Existing and generic wind to SPP load

The transfer studied an increase in wind generation at all existing SPP wind plant sites, and at locations identified as generic wind hubs in the 2009 Priority Projects study, to serve load throughout the SPP footprint. The preliminary use of these wind hubs was necessary as the ITP20 resource plan and siting had not yet been completed when these calculations were made.

SPP generation to SPP load

The transfer studied an increase of all conventional generation at existing SPP plant sites to serve load throughout the SPP footprint during peak load conditions. Transfers specifically studied the inter-area transfers possible among SPP's Balancing Authorities. The results reflected the amount of bandwidth gained throughout the system for such transfers.

Western SPP generation to Eastern SPP load

The transfer studied a geographic breakdown of the SPP footprint from west to east in ten sub-regional sections. Transfers from each section to the east were studied and the improvement to the first four FCITC values was studied.

Preliminary Results

The transfers were only calculated for the Triangle, Modified Figure 8, and Delta Plan prototypes, and results indicated the Triangle prototype allowed for the greatest transfer capability. The EHV Overlay and the Refined Figure 8 Plan were not studied, but were used to initiate stakeholder discussions. Table 5.1 lists the increase in available transfer capability (ATC) achieved by the addition of each prototype to the SPP grid. These preliminary studies are addressed in greater detail by robustness metrics 1.1.2, 6, and 14.

Prototype	Existing & Generic Wind to SPP Load (GW)	SPP Generation to SPP Load (GW)	Western SPP to Eastern SPP (GW)
Triangle	1.2	7.2	1.8
Modified Figure 8	1.0	5.0	0.0
Delta Plan	0.9	5.8	0.0

Table 5.1: Wind and Load Transfers Analyzed for Triangle, Modified Figure 8 and Delta Prototypes

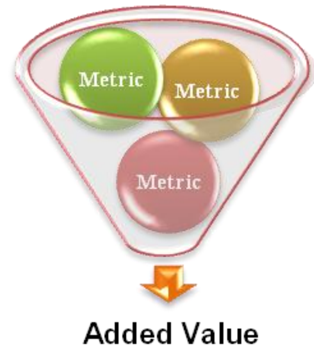
5.5: Stakeholder Feedback

SPP staff received comments that transmission lines to the north of SPP into the Western Area Power Administration region may not be beneficial, as major portions of wind in those regions will be moving towards load centers in the east, rather than south through SPP. Staff also received comments that ties into the southeast corner of SPP should be considered as potential areas for an EHV leg with terminations in near the Texas-Arkansas- Louisiana border.

Section 6: Metric Methodologies

6.1: Introduction

The Economic Studies Working Group (ESWG), through its work with the Metrics Task Force (MTF), developed a list of robustness metrics to capture additional value added by transmission projects. The metrics were provided to Charles River Associates (CRA) to further develop descriptions and methods for their formulation and form a vital portion of the ITP20. Fifteen metrics were provided to CRA; the first comprised six sub-metrics. For more detailed descriptions, including formulas, please consult the Robustness Metrics Procedural Manual[21].



6.2: Metrics used in the ITP20

CRA developed a metrics manual that described how to calculate a number of transmission metrics. Of the metrics in the manual, SPP staff determined that calculating some of them was not possible due to time, data, or other resource constraints. It is expected that these metrics will be reviewed at a later date and may be incorporated into future ITP analyses.

Metric No.	Metric Description
1.1.1	Value of delaying or eliminating reliability projects
1.1.3	Providing a backstop to a catastrophic event
1.4	Increased Effective Capacity Factor
1.5	Reduced Cost of Capacity
1.7	Improved Economic Market Dynamics I
1.8	Improved Economic Market Dynamics II
1.9	Reduction in Market Price Volatility
1.15	Part of the EHV Overlay

Table 6.1: Metrics Deferred to future ITP analyses

6.3: Adjusted Production Cost

Adjusted Production Cost (APC) is a measure of the impact on production cost savings by Locational Marginal Price (LMP), accounting for purchases and sales of energy between each area of the transmission grid. APC was determined using a production cost modeling tool that accounted for 8,760 hourly commitment and dispatch profiles for one simulation year. Nodal analysis from the production cost model was aggregated on a zonal basis using the following formulation. The calculation, performed on an hourly basis, was as follows:

APC captured the monetary cost associated with fuel prices, run times, grid congestion, ramp rates, energy purchases, energy sales, and other factors that directly related to energy production by generating resources in the SPP footprint. The zones used in the analysis are listed in Section 8: Transmission Analysis Assumptions.

[21] SPP.org > Engineering > Transmission Planning > Robustness Metrics Manual

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

6.4: Robustness Metrics

These metrics provide value to the SPP planning processes by instituting a different approach to transmission planning than has been used and capture hidden value that has heretofore not been reported in SPP's planning studies. The robustness metrics also indicate the degree to which projects contribute to the continued economic and reliable operation of the grid under multiple futures and are useful in differentiating between the different ITP plans.

This section lists each of the metrics developed by the MTF and further refined by CRA along with a short description of their purpose and general calculation methodology. Calculations used in these metrics during the ITP20 are further described in Section 11: Robustness Testing as they pertained specifically to this study.

Metric 1: Added value not previously quantified/qualified in SPP's traditional planning methods.

Metric 1.1: Improvements in Reliability (value of improving the ability to keep the lights on)

This metric has three distinct components:

1.1.1 Value of delaying or eliminating the need for previously approved reliability projects: This metric monetized (quantified) the reliability benefit as the avoided cost (or additional cost) in dollars of delaying, canceling, or accelerating previously approved reliability projects.

1.1.2 Value of improved Available Transfer Capabilities (ATCs) of the SPP grid: This metric provided a non-monetized (qualitative) assessment of the added flexibility for the potential redirection of power flows within SPP made possible by ATC increases. The challenge in defining this metric was the development of a meaningful weighting structure of ATC defined for multiple combinations of points of receipt and points of delivery.

1.1.3 Value of providing a backstop to a catastrophic event: This metric provided a qualitative assessment of improved grid reliability and its ability to withstand the impact of catastrophic events electrically expressed as multiple contingencies. Since this metric required a multiple contingency assessment model, it was not calculated for this cycle of the ITP20 Assessment.

Metric 1.2: Enable Efficient Location of New Generation Capacity

Sub-Metric 1.2 was a quantitative measure of the ability of a transmission project or portfolio to provide for the efficient location of new generation capacity. SPP was not able to calculate this metric for conventional generation. For wind resources, SPP measured distance from the transmission hubs to high wind resource zones.

Metric 1.3: Reduced Losses

Relative to a base case transmission expansion plan, each alternative transmission expansion plan impacted total system losses. Sub-Metric 1.3 served as a first step in calculating Sub-Metric 1.6 and gave SPP stakeholders a qualitative measure for evaluating the relationship between a reduction in losses and the monetary and physical savings from reduced capacity and capital costs.

Metric 1.4: Increased Effective Capacity Factor

Sub-Metric 1.4 was a measure of the value of adding transmission to reduce congestion on curtailed resources. The capacity factor may change due to a reduction in congestion.

Metric 1.5: Ability to Reduce Cost of Capacity

Sub-Metric 1.5 will be utilized in future ITP assessments and will capture value from reducing the cost of capacity. This metric is an opportunity to capture value which isn't currently being captured, though it will require additional tools to calculate which are not currently being used by SPP.

Metric 1.6: Positive Impact on Losses Capacity

Sub-Metric 1.6 was used to capture a value for the generation capacity that may no longer be required due to a reduction in losses and capacity margin. The reduced capacity could be reflected in reduced losses and the potential reduction in capacity margins.

Metric 2: Levelization of LMPs

Metric 2 provided SPP stakeholders a qualitative indicator of the impact an alternate transmission topology could make on regional generation owners' ability to compete on equal grounds. In the absence of congestion and losses in the system, any generator has the potential to serve any load, and there will be one single system price in each hour. A transmission system with no constraints and low losses makes the electricity market more competitive, as it provides an equal opportunity to all generators with similar costs to compete for loads. In such transmission systems, the market for new entry will also be more competitive. An increase in congestion and losses places generators at certain locations at a disadvantage relative to other similar-cost generators, making the market less competitive. This metric measured the levelization of LMPs for each transmission topology using the standard deviation of LMPs across locations for the SPP footprint. All else being equal, a decrease in the value of this metric indicates an improvement in the competitiveness of the SPP market.

Metric 3: Improved access to economical resources participating in SPP markets

Metric 3 provided a qualitative measure of competitiveness across the SPP footprint. It analyzed a generating unit's ability to compete within its own technology type. Capacity-weighted LMPs were calculated for generating plants fueled by wind, steam coal, combined cycle, and combustion turbine on an hourly basis, then averaged across 25% of the largest hourly standard deviations.

Metric 4: Change in operating reserves

This metric requires a capacity expansion model such as Strategist to calculate, which SPP does not currently license. This metric will provide an opportunity in future assessments to capture value from reducing operating reserves.

Metric 5: TLR Reduction - Enabling Market Solutions

With the implementation of the Day Ahead market in SPP, the need for Transmission Loading Relief calls between SPP Balancing Authorities will be eliminated. Congestion will be managed by economic security constrained unit commitment and dispatch. Metric 5 was not used in this cycle of the ITP20 Assessment but should be evaluated for use in future assessments.

Metric 6: Limited import/export improvements

Metric 6 quantified the change in available transfer capability (ATC) that corresponded to an alternative topology in the Cost-Effective Plan. Three categories of ATC changes were of interest and addressed by this metric:

- From major generation centers within SPP to key delivery points on the boundary of SPP. This category related to export capability improvements.
- From key external receipt points at the boundary of SPP to load centers within SPP. This category related to import capability improvements.
- From key external receipt points at the boundary of SPP to key delivery points on the boundary of SPP. This category related to improvements in the ability of SPP to accommodate wheel-through transactions.

Metric 7: Improved economic market dynamics not measured in the security constrained economic dispatch model

Metric 7 was not calculated for this ITP20 Assessment; however it should be evaluated for use in future assessments as there is the potential to calculate value not currently being captured by other metrics.

Metric 8: Improved economic market dynamics measured in the nodal security constrained economic dispatch model

Because Metric 8 requires calculating the generation loading distribution factor (GLDF) for every hour, SPP was not able to calculate this metric for this cycle of the ITP20 Assessment. Future assessments should evaluate this metric to capture additional value.

Metric 9: Reduction in market price volatility

Metric 9 requires using a stochastic model which SPP does not currently have the ability to process. Future assessments should reevaluate this metric to determine a calculation method which could be used to capture reductions in market price volatility.[22]

Metric 10: Reduction of emission rates and values

If an alternative topology resulted in a lower fossil fuel burn (or less coal-intensive generation) than the cost-effective topology, then SO_2, NO_X, CO_2, and Hg emissions would be lower with the alternative topology in place. APC captured the cost savings associated with reduced SO_2, NO_X, and CO_2 emissions because the allowance prices for these pollutants were inputs to the production cost model simulations. However, since mercury is not a pollutant subject to an allowance price, changes in coal generation and the corresponding changes in mercury emissions were otherwise not captured in the ITP20 Assessment framework. This metric addressed that analytical deficiency and quantified the changes in mercury emissions. This metric also quantified the changes in SO_2, NO_X, and CO_2 emissions based on the ITP20 Assessment assumptions.

The mercury emissions from a given simulation can be easily calculated if the mercury content of the coal, coal burn, and mercury capture efficiencies of the coal units' pollution controls are known. The production cost tool directly reports SO_2, NO_X, and CO_2 emissions. This metric was calculated as the difference between the cost-effective topology's emissions and the alternative topology's emissions (for each pollutant separately). The change in mercury emissions was not quantified in this study because individual plant emissions rates of mercury were not known. The changes in SO_2, NO_X, and CO_2 emissions were reported in units of tons/year.

Metric 11: Transmission corridor utilization

Alternative transmission expansion plans that effectively utilized existing right-of-way (ROW) and had a topology that largely avoided environmentally sensitive areas were preferable to those that did not, all else being equal.

Metric 11 is comprised of two sub-metrics. The first sub-metric measured the proportion of transmission expansion plan costs that did not effectively utilize existing ROW. The second sub-metric measured the proportion of transmission expansion plan costs that traversed environmentally sensitive areas. For both sub-metrics, the plan costs were discounted to present value (as costs would be staggered over time and require conversion to present value).

Metric 12: Ability to reduce cycling of base load units

Metric 12 evaluated the benefit derived from reducing cycling of large base load generating plants. For purposes of this metric, a cycle occurred each time a unit's output crossed or reached the average output, then receded below this average minus a tolerance during any start-up to shut-down period. Relative to the cost-effective topology, a transmission project that reduced the total number of cycles

[22] The ESWG has discussed the relationship of metric 9 and metric 2 and understands that the levelization of LMPs provides the first glimpse at possible improvements to system volatility but that the measures are not the same.

for a base load unit would reduce maintenance costs and prolong the unit's life span. If SPP had data on the relationship between the number of cycles and operations and maintenance cost, or had a dollar value associated with excessive versus normal or ideal cycling, this metric could be monetized to determine a value to generators from reduced cycling.

Metric 13: Generation resource diversity

An alternative transmission topology that resulted in a more diverse generation capacity expansion plan than the cost-effective transmission expansion plan would add benefit because the power system could respond more flexibly to relative fuel price changes.

Metric 13 was a semi-quantitative metric based on generation mix (energy basis) from the production cost model simulation. For a given future, this metric was a comparison of the generation mixes (energy basis) from the cost-effective topology and an alternative topology. Both the annual generation mix and the fuel-on-the-margin mix were considered. Of particular interest was whether gas-fired generation approached or exceeded a specific percentage of the generation mix, because the level and volatility of gas prices were typically relatively high compared to the level and volatility of coal and nuclear fuel prices.[23] Excessive dependence on gas-fired generation - to the detriment of a more balanced dispatch of gas, oil, coal, and nuclear energy - exposed ratepayers to greater fuel price risk. Note that wind and hydro dispatch was fixed for a given future, notwithstanding curtailments.

Metric 14: Ability to serve unexpected new load

Metric 14 measured the ability of an alternative transmission topology to serve new load at levels that were different from those considered in the derivation APC. The metric tested two types of load changes: an overall incremental load in proportion to load forecast used in the development of each future and load shifts between major load centers.

Metric 15: Part of overall EHV overlay plan

This metric was not developed for this cycle of the ITP20 Assessment.

[23] Oil prices are also volatile, but oil-fired generation is small relative to coal, gas, and nuclear.

Section 7: Resource Futures and Plan

7.1: Four Futures

Future 1: Business as Usual

The Business as Usual or Base Case consisted of no changes to established policies and procedures in place when the study was conducted. This case served as a baseline transmission expansion consistent with no changes to the current political climate, economic variables, regulatory requirements, or expected state statutes. Existing state renewable standards were considered in this case.

The amount of wind generation assumed to satisfy these state renewable standards was 10,645 MW of nameplate capacity as shown in Figure 7.1. The total wind capacity amounts shown for the futures included approximately 4,200 MW of existing wind capacity as of September 2010. The conventional capacities shown for each future are additional to the existing conventional capacities.

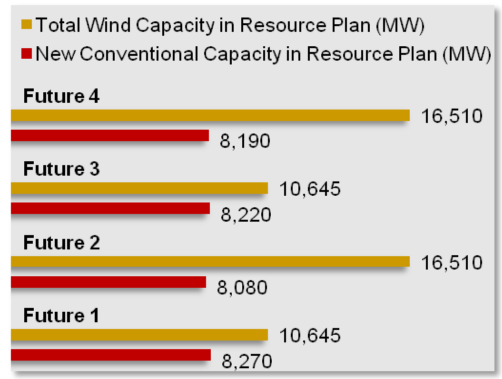


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Figure 7.1: Futures Resource Plan Summary

Future 2: Renewable Electricity Standard

The Renewable Electricity Standard (RES) case considered a fully implemented federally mandated RES (20% of system energy) applied across SPP. Wind resources required to meet the RES were located inside the SPP footprint. The goal of this future was to determine what transmission backbone would be required to deliver this renewable energy to market across SPP's EHV system.

Energy efficiency on the demand side and non-wind renewable were not counted toward the 20% RES in this future. All wind was counted; i.e., no "deductions" for wind generation or associated Renewable Energy Credits (RECs) that might be exported outside the SPP region.

Future 3: Carbon Mandate

This future assumed an additional cost for carbon-based fuels in line with proposed changes in federal regulations. The goal of this future was to determine what transmission backbone is required to deliver resources to market under a carbon mandate, although no cap on carbon dioxide (CO_2) emissions was enforced in the simulations. This study utilized a cost on CO_2 emissions to account for such a mandate.

Future 4: RES and Carbon Mandate

This future was a simultaneous combination of the assumptions and goals of the Renewable Electricity Standard and Carbon Mandate futures.

7.2: Business as Usual (Future 1)

Overview

The Business as Usual future consisted of no changes to established operating and planning policies and procedures already set for the study time frame. This case was a baseline transmission expansion consistent with no dramatic changes to the current political climate. However, it did include planning requirements to meet existing renewable energy targets absent a federal renewable standard.

Objective

The objective of the Business as Usual future was to develop a baseline to be used in the study. This future was used as a basis to develop the other futures and served as a reference case for comparison.

Assumptions
Assumptions for the Business as Usual future were that no major changes would occur to established policies of the utilities and state/ federal authorities in place at the time of the analysis. There were no major changes in resource plans, fuel pricing, renewable targets, carbon price, etc.

Resource plans
Resource plans were an extrapolation of current resource plans and policies established in the SPP footprint. A resource planning tool was used to develop the appropriate resource plans for the base case. These resource plans were reviewed by stakeholders through the ESWG.

Renewable Energy
Renewable energy was modeled in this future using the expected renewable energy targets from the 2010 CAWG survey. Results of the CAWG survey are included in Appendix A6: Results of the CAWG Survey.

7.3: Renewable Electricity Standard (Future 2)

Overview
The Renewable Electricity Standard (RES) future considered a federally mandated 20% RES. This future assumed that requirements for the SPP footprint were met by renewable generation in the SPP region. SPP staff worked with stakeholders through the ESWG and CAWG to determine a reasonable representation for each state and utility considering the resource allocation for this future (i.e., if a state wished to meet its requirements from solely in-state resources.)

Objective
The RES case determined what type of transmission backbone was required to meet a federal RES of 20% for the SPP footprint. The focus of this analysis was to deliver renewable resources to the SPP market, assuming all SPP load would be required to meet this RES. Primary consideration was not be given to the delivery of energy outside the SPP footprint. A robust plan could leverage this potential option for future expansion.

Assumptions
The magnitudes and siting of wind generation was a significant factor in previous SPP economic studies' renewable energy assumptions. The SPP Generation Interconnection (GI) queue has been used in previous SPP studies as a source of information on trending of customer requests in both magnitude of interest and siting locations (See Figure 7.2). Consistent with the assumptions of this future, the amount of wind energy in the SPP region has been steadily increasing in recent years (See Figure 7.3).

The driving assumption for the RES future was a 20% federal RES for the footprint; energy efficiency was not counted toward a renewable mandate for this study.

A driving factor for this case's transmission plan was the siting and location for the renewable resources in the footprint. These assumptions were developed leveraging state surveys conducted by the CAWG, as well as input from stakeholders through the ESWG.

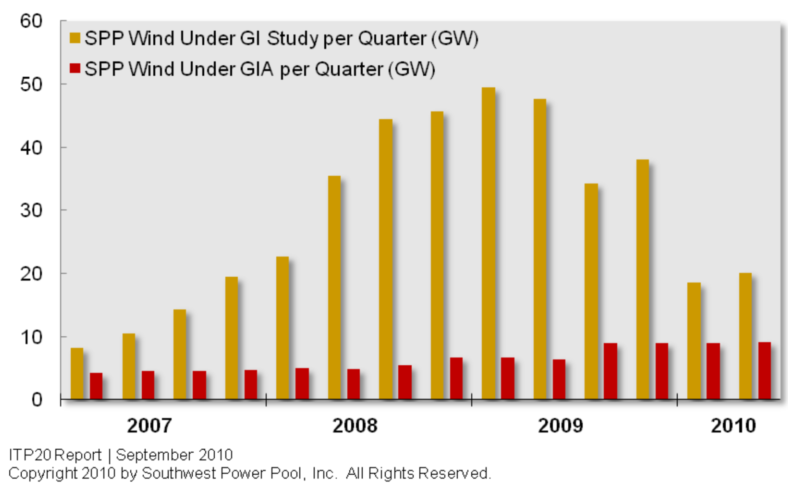


Figure 7.2: SPP Generation Interconnection Queue

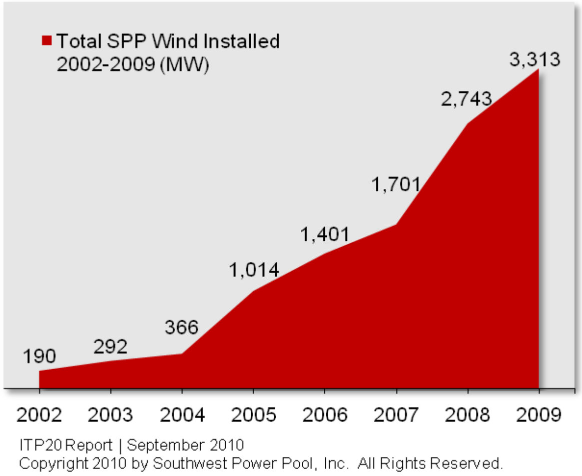


Figure 7.3: SPP Wind Installed

Previous EHV and WITF studies modeled renewables based on the GI queue, resulting in concentrations of wind in the Texas and Oklahoma panhandle areas. For this study, the expected location of new renewable generation was not based entirely on the location of current and proposed renewable generation in the GI queue. Instead, wind generation was modeled based on the assumption that future renewable generation would lie in areas with high wind potential.

Care was taken to avoid providing competitive advantage to one group of generation resources over another. The generation future should be broad and general to provide for the region's needs. Specific generating resources, beyond current commitments, were not targeted for development. The assumptions used for wind locations were high-level, considering only interconnection to the EHV backbone grid and did not envision the transmission required from a lower voltage perspective.

No carbon tax was applied in this future.

Resource plans

Resource plans for the 20% RES future contained a 20% renewable energy portfolio of wind generation. Any generation developed beyond the assumption was developed using resource planning tools and reviewed and modified, as appropriate, by stakeholders through the ESWG.

Renewable Energy

Renewable energy was modeled in this future based on the expected renewable energy targets from the 2010 CAWG survey for a federal 20% RES. The renewable energy targets for this case were further modified by the ESWG to expand the RES to include the entire SPP footprint (including co-ops, municipals, and other entities).

7.4: Carbon Mandate (Future 3)

Overview

Current carbon policy is in the process of being determined in the form of EPA regulations, and is also being considered by federal authorities. To simulate the impact of carbon legislation, a tax on CO_2 emissions was used for this analysis. This legislation is discussed in more detail in Section 1.2: Policy Considerations.

Objective

The Carbon Mandate future was used to determine transmission expansion necessary to deliver resources to the market under a carbon mandate. No cap on CO_2 was enforced in the simulations; rather, a price for carbon was imposed.

Assumptions

The Carbon Mandate future was studied using an ESWG-endorsed tax of $73/short ton (2030 nominal dollars) for CO_2 emissions.

Resource plans

The Carbon Mandate future used the Base Case as a starting point and applied a carbon price to the simulation. A resource planning tool was used to develop the appropriate resource plans for the Base Case. The resource plans were reviewed by stakeholders through the ESWG.

Renewable Energy

Renewable energy was modeled in this future using the same renewable energy targets as used in the Business As Usual case.

7.5: RES + Carbon Mandate (Future 4)

Overview

This future represented a combination of the Carbon Mandate and Renewable Electricity Standard futures. The future considered the impact of a 20% RES and a carbon tax simultaneously.

Objective

This future was used to determine what type of transmission backbone would be required to meet a RES of 20% along with a tax on carbon emissions for the SPP footprint. The focus of this analysis was to deliver the renewable resources to the SPP market, assuming all SPP load would be required to meet this RES.

Assumptions

The Carbon Mandate future was conducted using a $73/short ton (2030 nominal) for the tax on CO_2 emissions and utilized the same RES assumptions used in the RES future.

Resource plans

The RES + Carbon Mandate future used the Base Case as a starting point and applied a carbon tax to the simulation. Additional renewable generation was placed in the resource plans to meet a 20% RES.

Renewable Energy

Renewable energy was modeled in this future using the expected renewable energy targets from the CAWG survey, as detailed in the Renewable Electricity Standard future.

7.6: Resource and Generation Siting Plan

SPP contracted Black & Veatch to complete four 20-year forecasts of generating resource additions to balance load and capacity reserves for zones throughout SPP, based on the four future scenarios defined above. Existing generating resources within the SPP footprint are not adequate to meet the forecast loads and capacity margin requirements in 2030. Therefore, resource forecasts were developed to balance load and capacity. The process for developing those resource plans is described below. For complete details consult the Black & Veatch ITP 20 Generator Resources Report.[24]

Three-Phase Study

Phase 1: Develop a resource expansion plan for each of four futures

A resource expansion plan was developed detailing the capacity requirements of each of the futures. Resources were selected using an optimal generation expansion model that treated SPP as two separate regions (SPP North and SPP South) due to software modeling limitations. For this study, SPP was divided approximately at the Kansas-Oklahoma border. Expansion plans were developed from a resource list of generic prototype generators that were reviewed and vetted through the ESWG. These prototype generators were used as templates for each of the generating technologies used in the analysis.

Phase 2: Generation siting

The resources were spatially located within the SPP pricing areas with the aid of GIS databases displaying locations of transmission lines, natural gas pipelines, railroads, waterways, substations, etc. These generating units were located using siting requirements proposed by the ESWG and detailed in the Black & Veatch Resource Planning report.

[24] SPP.org > Engineering > Transmission Planning > Integrated Transmission Planning > ITP20-Year Assessment

Phase 3: Synchronized with economic study tools

The generators were entered into a PowerBase database and connected to buses in the transmission system. SPP will retain the information for use in future studies.

The supply-side evaluations of generating resource alternatives were performed using the Strategist software (licensed from Ventyx), an optimal generation expansion and production cost model. The Strategist model was used to help determine the lowest-cost resources for the 20-year timeframe, maintaining the capacity margins, renewable requirements, and other parameters for the given futures.

Results

Figure 7.4 shows the results of resource plans for the four futures. In the Business As Usual future and the Renewable Electricity Standard future, without carbon mandates, coal capacity was determined to be part of the lowest-cost resource plans, along with gas-fueled combined cycle technology and natural gas-fueled simple cycle combustion turbines. Wind build-out was a substantial part of the resource additions for all futures analyzed. When CO_2 mandates were considered, CO_2 allowance costs resulted in only natural gas-fueled generator additions. Although nuclear units were considered as additional alternatives for the generating resource build out, they did not prove to be the most economical for any of the futures analyzed.

Conventional generation was sited at existing brownfield sites, and wind capacity was sited in SPP regions with good wind resource potential. This siting effort was conducted as a screening level exercise to identify site areas that generally comply with the approved criteria and was not intended to provide or replace a full scope power plant siting study. Appendix A5: Resource Siting and Plans contains tables showing conventional capacity amounts by zone and siting details for the wind capacity additions.

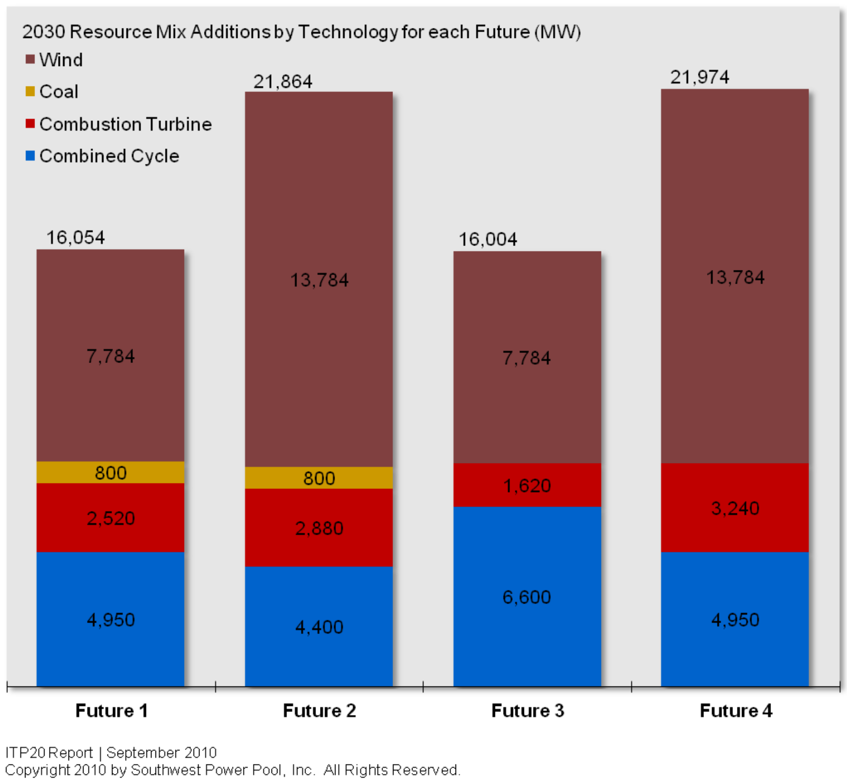


Figure 7.4: 2030 Resource Mix Additions by Technology for each Future

After the resource siting was approved by the ESWG, Black & Veatch conducted Phase III of the engagement, which consisted of populating the SPP database with the resource additions at the approved sites so they could be interconnected in the transmission network model at the appropriate locations and used with the hourly economic analysis.

Section 8: Transmission Analysis Assumptions

8.1: Stakeholder Collaboration

Assumptions and procedures for the ITP20 analysis were developed through SPP stakeholder meetings that took place in 2009 and 2010. The assumptions were presented and discussed through many meetings with members, liaison-members, industry specialists, and consultants to provide a thorough evaluation of those assumptions. Groups involved in the decision making included the following: Economic Studies Working Group (ESWG), Transmission Working Group (TWG), Regional Tariff Working Group (RTWG), Cost Allocation Working Group (CAWG), Markets and Operations Policy Committee (MOPC), Strategic Planning Committee (SPC), the SPP Board of Directors (BOD), and the SPP Regional State Committee (RSC).

The ESWG performed the primary technical work of determining the inputs and assumptions for the ITP20 analysis. For areas beyond the technical scope of the ESWG, the TWG and/or the CAWG were consulted. Policy level considerations were tendered to groups including the MOPC, RSC, and BOD.

- The TWG provided insight in the market constraint selection criteria, limited reliability assessment, and the transmission project designs.
- The RTWG provided tariff oversight in the development of the ITP Manual.
- The SPC and CAWG provided guidance concerning the selection of robustness metrics calculated in this cycle of the ITP20 Assessment.
- The CAWG provided the stakeholder survey used as a baseline for the renewable requirements in each future.
- The strategic guidance for the study was provided by the SPC and BOD.

In addition to these working groups, stakeholders have provided comments throughout the study process. SPP staff has posted this feedback and staff comments on SPP.org[25]

8.2: Futures Variables

Regulatory

The expectation of future state and federal energy legislation and policy decisions by other regulatory bodies led the ESWG and CAWG to develop multiple futures that would simulate the effects of such policies on the bulk transmission system. Legislation such as the Waxman-Markey bill and the Clean Energy Jobs and American Power Act, as well as developing EPA carbon regulations and the FERC's top initiatives, were considered in the development of the Renewable Electricity Standard and Carbon Mandate futures. Other futures were considered to simulate the effects of load reduction, demand response, and carbon sequestration but not adopted in this study cycle.

Study Year

The study focused on modeling and studying the transmission grid with projected transmission systems and economic values for the year 2030. Through the use of economic planning tools, simulations were carried out for each hour from January 1st, 2030 to December 31st, 2030.

[25] SPP.org > Engineering > Integrated Transmission Planning > ITP20 Stakeholder Feedback and SPP Comments

Demand

Energy demand was held constant across the futures. A load reduction in the Carbon Mandate future was discussed at some length but was eventually set aside by the ESWG.

The 2030 peak demand used in the study was estimated at 65,728 MW using the 2019 series Model Development Working Group (MDWG) model load and compound linear growth rates specific to each zone, averaging 1.4% per year overall. Energy growth rate also averaged 1.4% per year. This load forecast was reviewed by the MDWG. Each zone's peak load was extrapolated to 2030 values and the total SPP load was determined by totaling the individual zones.

The energy for the year was simulated within the PROMOD® software to be 293,465,223 MWh using zone and time specific hourly load profiles for all 8,760 hours of the study year.

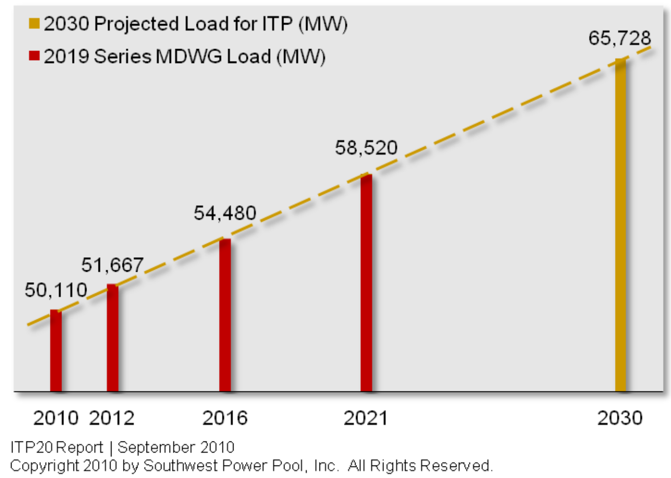


Figure 8.1: 2030 SPP Load Projections

Capacity

The amount of available capacity varied between futures. A resource plan containing all of the assumptions pertaining to conventional and renewable capacity was developed with guidance from the ESWG in order to meet a 12% capacity reserve margin. A description of this plan and the assumptions that were used in its development can be found in Appendix A5: Resource Siting and Plans.

Fuel Cost and Emissions Charge

The ESWG selected fuel costs for uranium, natural gas, and coal in study year dollars based upon current market prices and industry forecasts. The costs of each fuel were used as inputs in the market simulations and contribute to the price per MWh at each generator in the study.

An additional charge for CO_2 emissions of $73/ton, 2030 nominal dollars, was also selected by the ESWG and applied to the futures as appropriate. The decision to use this figure was made after reviewing the latest EPA report of the calculated cost of tradable carbon emission allowances. The EPA calculations took into account pending legislation from the United States Congress.

	Future 1	Future 2	Future 3	Future 4
SO_2 Emissions ($/ton)	533.83	533.83	533.83	533.83
NO_X Emissions ($/ton)	1,888.08	1,888.08	1,888.08	1,888.08
CO_2 Emissions ($/ton)	0.00	0.00	73.00	73.00
Uranium ($/MMBTu)	2.52	2.52	2.52	2.52
Natural Gas ($/MMBTu)	15.68	15.68	15.68	15.68
Coal ($/MMBTu)	1.78	1.78	1.78	1.78

Table 8.1: Fuel Cost and Emissions Charge Assumptions (2030 nominal dollars)

Wind Patterns

Hourly data for year 2006 formed the wind generation patterns as taken from the National Renewable Energy Laboratory (NREL) modeled data base for sites nearby to the selected wind generation sites. Summary of and detailed information for the wind sites modeled for each of the futures can be found in Appendix A5: Resource Siting and Plans.

Base Case Transmission Topology

The most current transmission planning information was utilized in the development of the system topology that was assumed in for the study year. This included all projects with NTCs that were identified in the 2009 SPP Transmission Expansion Plan (STEP), the Balanced Portfolio, and the Priority Projects. Figure 9.2 below details the 345 kV projects that were included as part of the ITP20 base case topology.

Economic Modeling Zones

Throughout this report, the zones included in the "SPP" numbers such as APC, ATC, etc. are American Electric Power (AEPW), Empire District Electric Company (EMDE), KCP&L Greater Missouri Operations Company (GMO), Grand River Dam Authority (GRDA), Kansas City Power & Light Company (KCPL), Lincoln Electric System (LES), Midwest Entergy Inc. (MIDW), Mid0Kansas Electric Company, LLC (MKEC), Nebraska Public Power District (NPPD), Oklahoma Gas and Electric Company (OKGE), Omaha Public Power District (OPPD), City Utilities of Springfield (SPCIUT), Sunflower Electric Power Corporation (SUNC), Xcel Energy (SPS), Western Farmers Electric Cooperative (WFEC) and Westar Energy (WERE).

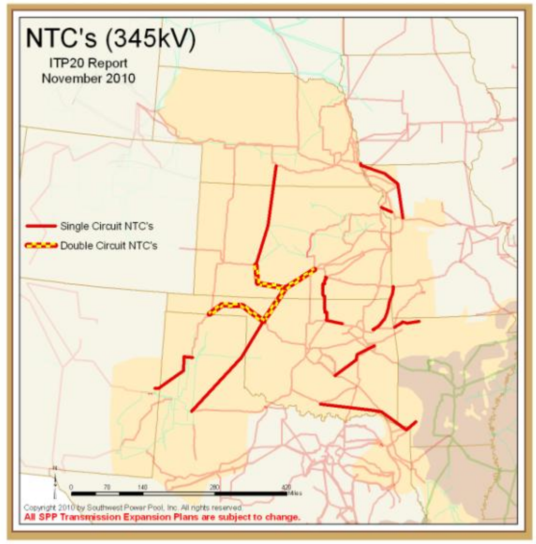


Figure 8.2: 345 kV Projects in the Base Case Topology

Third Party Impacts and Modeling of External Regions

The ITP20 economic models include the entities that are adjacent to SPP, including portions of MISO, PJM, WAPA, AECI, Entergy, TVA and Southern Company. As with the entities within SPP, the modeling data included 2030 demand levels, fuel costs, and emissions costs. This economic modeling data is based on publicly-available information and was obtained from a third-party vendor. The base case transmission topology for external entities was from SPP's 2009 Model Development Working Group model set for the year 2019. Generation was added to the external footprint to account for additional load growth. As with the SPP region, the market structure used in other regions was a day ahead market with a consolidated balancing authority per region. Constraints were monitored on both sides of SPP's border to monitor flows across the SPP interface. While specific simulations were not done to assess the impact from generation of external utilities, the transmission line flows caused by external generation on the SPP system were considered during the economic simulations.

In the external regions, wind generation was held constant between futures at the following levels. Note that the economic models included only two of the six PJM sub-regions, AEP-Dayton and PJM Northern Illinois, based on their proximity to the SPP footprint:

Entity	Wind Capacity (MW)
MISO	6,203
PJM	1,409
WAPA	1,081
AECI	337
Entergy	0
TVA	29
SOCO	0

Table 8.2: Third Party Wind Capacity (MW)

Economic Calculation Assumptions

This section describes the techniques used when calculating APC based Benefit-to-Cost (B/C) ratios during this study. As described in Section 6.3: Adjusted Production Cost, when calculating the B/C, the benefit is the savings in APC and the cost is the cost of the transmission expansion. Note that all dollar figures in this report are 2010 real dollars unless specified otherwise.

The amount of APC savings are calculated in 2030 dollars and the present value was determined by discounting the savings back twenty years using a 2.5% rate for inflation. The savings identified in 2010 real dollars were used in the APC-based B/C calculation. To calculate the cost for the B/C ratio, the Engineering and Construction (E&C) cost estimates for this analysis are based upon the construction costs for generic SPP equipment used in the 2010 STEP, unless noted otherwise. SPP relied upon American Electric Power for cost estimates for 765 kV facilities. Focus was given to transmission mileage and transformer costs. The breaker, capacitor, bus bar, and other detailed circuit equipment costs were not included as separate costs.

Equipment	765 kV	500 kV	345 kV	<345 kV
Single Circuit ($/mi)	2,712,000	1,687,500	1,125,000	562,500
Double Circuit ($/mi)	na	na	1,970,000	na
Transformer ($)	28,194,000	12,000,000	6,000,000	6,000,000
Substation ($)	25,100,000	na	10,500,000	na

Table 8.3: Construction Cost Estimates ($)

Mileage amounts for each transmission line project were derived as 120% of the straight-line-distance as calculated using SPP's GIS databases.

A conservative Annual Transmission Revenue Requirement (ATRR) was calculated by multiplying the total investment estimate for each project, already in 2010 dollars, by a generic Carrying Charge Rate of 17%. The reduction in ATRR due to depreciation of the asset in Rate Base was not considered. The Carrying Charge Rate includes the cost of transmission, spread out over the forty years of asset life. The ATRR is the annual cost of a project; the total amount of revenue that the owner of the project will recover per year from SPP Transmission Customers.

Software

SPP Staff used various software packages to complete these studies, including ABB's PROMOD®, PTI's PSS®E, PTI's MUST package, and Power Analysis and Trading (PAT) Tool. Each set of tools required unique settings and detailed assumptions.

Part II: Project Analysis

Section 9: Transmission Least Cost Solutions

9.1: Overview

The least cost[26] analysis of each future was the first step in analytical development of the Cost-Effective Plan. The analysis developed transmission solutions to meet the requirements of each future. To determine the project that would be needed, analysis considered each future versus the base transmission topology to determine system limitations. Expansion needs for each future were identified and the lowest-cost transmission solution (considering 345 kV and above projects only) was developed.

The study's focus on deliverability of energy to market and development of a transmission highway guided assumptions used in the analysis. Each proposed project developed through the evaluation was chosen to meet the future's requirements. This section describes the assumptions, limitations, and least-cost transmission plans developed for each future.

9.2: Assumptions and Approach

The analysis targeted thermal equipment ratings as limits to the ability of the transmission system to meet the futures' needs. The assumptions and approach were consistent across each future.

Transfers

Multiple source-sink transfers were studied as part of the analysis. The three types of transfers were wind generation that stayed within a state, wind generation from the high-wind states to load centers in low-wind states, and conventional generation within SPP North and SPP South to load in the footprint. To be consistent with the ITP20's resource planning phase, the Kansas-Oklahoma state line was used as the dividing line between north and south sub-regions of the study. The amount of renewable and conventional power being transferred was incremented in three transfer runs to identify the limits that would occur for the different dispatch scenarios.

Monitored Elements

Contingencies of 345 kV and above facilities were considered, and facilities of 100 kV and above were monitored for violations. Double circuit transmission lines were considered as single tower contingencies. Standard pre- and post-contingent line ratings from the MDWG models were used without alteration.

Least Cost

The limiting corridors identified for each future were relieved by the four Least Cost Plans, allowing the transfers to be fully implemented from a transmission highway perspective. In development of these plans, least cost transmission design was the objective. This was done by minimizing the length of new lines and using existing termination points. Only 345 kV and above solutions were considered and an emphasis was given to previously studied projects. Details such as specific requirements at existing termination points and exact mileages derived from specific line routings were not considered.

[26] The use of least cost in this context refers specifically to the capital cost, or investment, incurred in building the lines and is not intended to include the costs associated with transmission losses, generation mixes or maintenance costs.

9.3: Limitations

Future 1: Business as Usual

Outages of 345 kV transmission facilities resulted in thermal violations on 230 kV systems in the Texas panhandle, 138 kV systems in Oklahoma, 230 kV and 138 kV systems in Kansas, and 345 kV and 161 kV systems in Nebraska. These violations required additional transmission to meet the generation capacity requirements of this future. Figure 9.1 illustrates the limiting corridors for the Business as Usual future.

Future 2: Renewable Electricity Standard

The second future's limiting corridors included all of the limitations encountered in the Business as Usual case. The limiting corridors that were common to the two futures increased in need when compared to the first future. Additional violations were encountered on 345 kV and 230 kV systems in Kansas and 345 kV systems in Nebraska. The higher loading of previously identified limiting corridors and the identification of new limiting corridors required multiple additional transmission projects to meet this future's generation requirements. Figure 9.3 illustrates the limiting corridors for the Renewable Electricity Standard future.

Future 3: Carbon Mandate

The third future's limiting corridors were identical to the limitations encountered in the Business as Usual case. This is due primarily to the fact that wind levels were the same. Also, differences in the conventional resource plans were not dramatic enough to trigger different limiting corridors. Figure 9.5 illustrates the limiting corridors for the Carbon Mandate.

Future 4: Renewable Electricity Standard + Carbon Mandate

The fourth future's limiting corridors were similar to the limitations encountered in the Renewable Electricity Standard case. This is due primarily to the fact that the wind levels were the same; however, the conventional resource plans were different enough to trigger one additional 230 kV limiting corridor in Texas. Figure 9.7 illustrates the limiting corridors for the Renewable Electricity Standard + Carbon Mandate future.

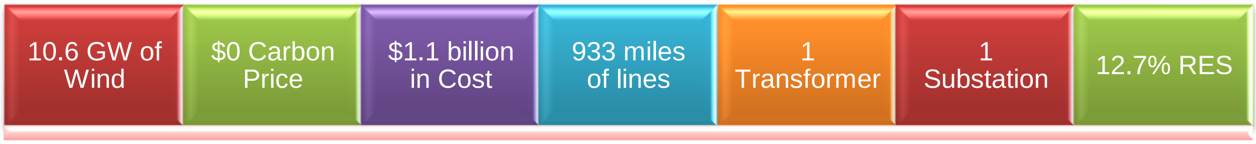
9.4: Transmission Plans

Transmission projects were designed to overcome identified limits, allowing future requirements to be met. Each of the plans is described below, and assumptions that governed the future are listed. The 12.7% and 20% RES numbers indicate the percentage of energy from wind resources that was dispatched, and provide an easy comparison between the futures that did and did not have an RES.

These plans formed the basis for which all other plans within the ITP20 were developed. A complete list of the projects that were evaluated in this phase of the study is included in Appendix A1: Transmission Projects Evaluated.

Future 1: Business as Usual

To relieve all of the limiting corridors shown in Figure 9.1, many combinations of projects were attempted, starting with the least expensive transmission expansion plan. Using this approach, the Future 1 Transmission Least Cost Plan was developed as shown in Figure 9.2.



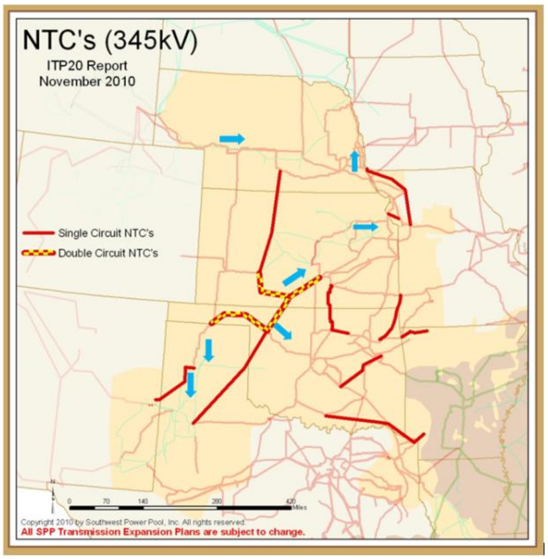


Figure 9.1: Future 1 Limiting Corridors

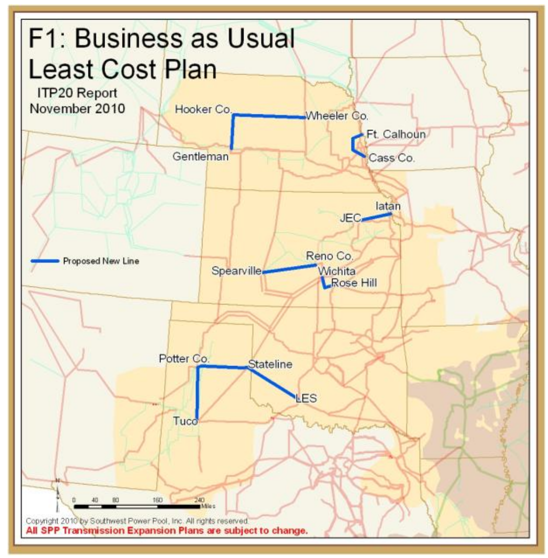


Figure 9.2: Future 1 Least Cost Plan

Project Name	kV	State
Tuco - Potter Co. - Stateline	345	TX
Jeffrey Energy Center - Iatan	345	KS
Gentleman - Hooker Co. - Wheeler Co.	345	NE
Ft. Calhoun - Cass Co.	345	NE
OPPD Sub 3459 Transformer	345/161	NE
Spearville - Reno	345	KS
Wichita - Rose Hill	345	KS
Stateline - Lawton Eastside	345	OK
Wheeler Co. Substation	345	NE

Table 9.1: Business as Usual Least Cost Plan Elements

Future 2: Renewable Electricity Standard

In developing this Transmission Least Cost Plan, some of the same combinations of upgrades used in Future 1 were attempted. As shown in Figure 9.3, there were additional limiting corridors; the limiting corridors that were common to futures 1 and 2 were more-heavily loaded in future 2. As before, various expansion plans were tested to determine if they would relieve the limiting corridors. The Future 2 Transmission Least Cost Plan is shown in Figure 9.4.

16.5 GW of Wind	$0 Carbon Price	$1.7 billion in Cost	1,426 miles of Lines	10 Transformers	3 Substations	20.0% RES

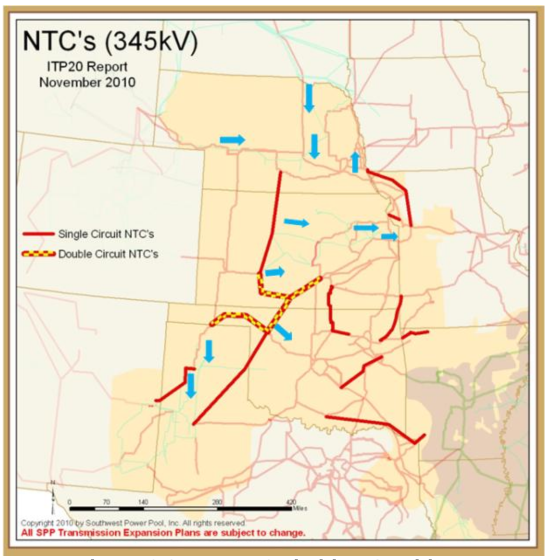


Figure 9.3: Future 2 Limiting Corridors

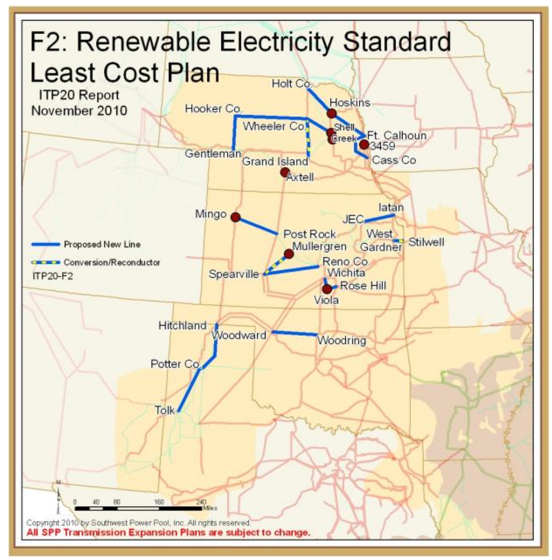


Figure 9.4: Future 2 Least Cost Plan

RES Least Cost Elements	kV	State
Tolk - Potter Co. - Hitchland	345	TX
West Gardner - Stillwell[27]	345	OK
Spearville - Reno	345	KS
Mingo - Post Rock	345	KS
Spearville - Mullergren Conversion[28]	345	KS
Mingo, Mullergren (2) and Viola Transformers	345/161	KS
Medicine Lodge Transformer	345/115	KS
Woodward District EHV - Woodring	345	OK
Gentleman - Hooker Co. - Wheeler Co.	345	NE
Ft. Calhoun - Cass Co.	345	NE
OPPD Sub 3459 Transformer	345/161	NE
Wheeler Co. - Shell Creek	345	NE
Holt Co. - Hoskins - Ft. Calhoun	345	NE

[27] Rebuild from 994 MVA to 1,195 MVA
[28] Conversion from 230 to 345 utilizing the same ROW

RES Least Cost Elements	kV	State
Grand Island - Wheeler Co. (Rebuild)[29]	345	NE
Keystone - Ogallala	345	NE
Woodward - Mooreland	138	OK
Iatan - Jeffrey Energy Center	345	KS
Wichita - Viola - Rose Hill	345	KS
Shell Creek Transformer	345/230	NE
Axtell, Columbus East, and Hoskins Transformers	345/115	NE
Holt Co. Substation	345	NE
Viola Substation	345	NE
Wheeler Co. Substation	345	NE

Table 9.2: Renewable Electricity Standard Least Cost Plan Elements

[29] Rebuild from 720 MVA to 1,195 MVA

Future 3: Carbon Mandate

The limitations identified for this future are shown in Figure 9.5 and were the same as those identified for Future 1. The resulting Future 3 Least Cost Transmission Plan is shown in Figure 9.6 and was the same as the Future 1 Least Cost Plan.

10.6 GW of Wind	$73 Carbon Price	$1.1 billion in Cost	933 miles of Lines	1 Transformer	1 Substation	12.7% RES

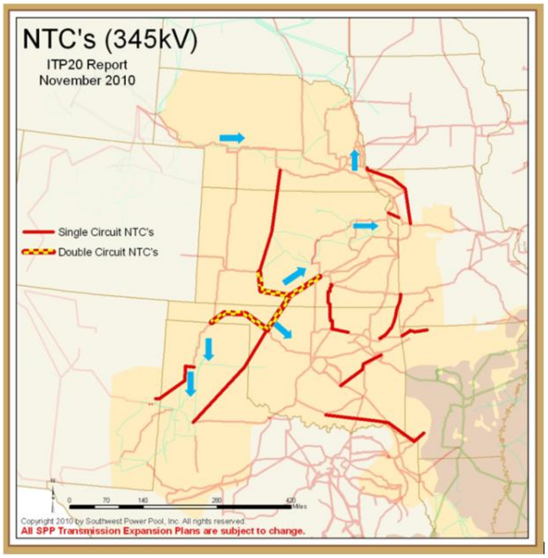


Figure 9.5: Future 3 Limiting Corridors

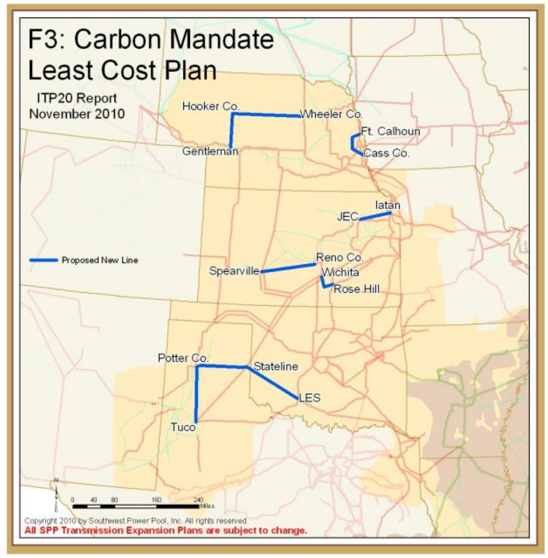


Figure 9.6: Future 3 Least Cost Plan

Project Name	kV	State
Tuco - Potter Co. - Stateline	345	TX
Jeffrey Energy Center - Iatan	345	KS
Gentleman - Hooker Co. - Wheeler Co.	345	NE
Ft. Calhoun - Cass Co.	345	NE
OPPD Sub 3459 Transformer	345/161	NE
Spearville - Reno	345	KS
Wichita - Rose Hill	345	KS
Stateline - Lawton Eastside	345	OK
Wheeler Co. Substation	345	NE

Table 9.3: Carbon Mandate Least Cost Plan Elements

Future 4: Renewable Electricity Standard + Carbon Mandate

The limiting corridors identified for this future are shown in Figure 9.7 and were similar to those in Future 2. The exception was an additional limitation in southern SPS. This limiting corridor required a new 345 kV transmission path from Hobbs to Tuco with step down transformers at Lea County and Amoco. This and all of the projects required for the Future 2 Transmission Least Cost Plan were included in the Future 4 Transmission Least Cost Plan is shown in Figure 9.8.

16.5 GW of Wind	$73 Carbon Price	$1.8 billion in Cost	1,566 miles of Lines	10 Transformers	3 Substations	20.0% RES

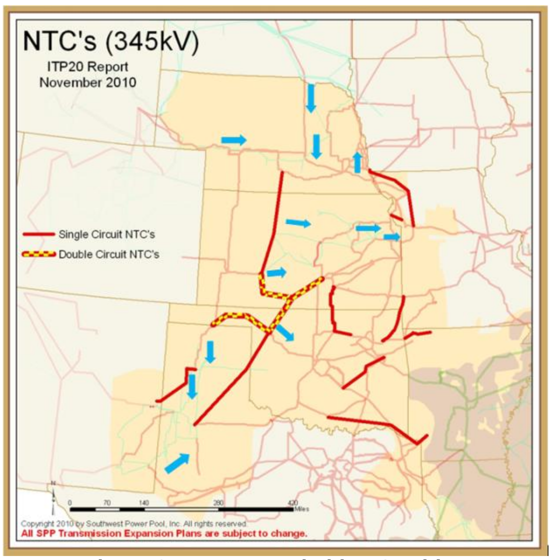


Figure 9.7: Future 4 Limiting Corridors

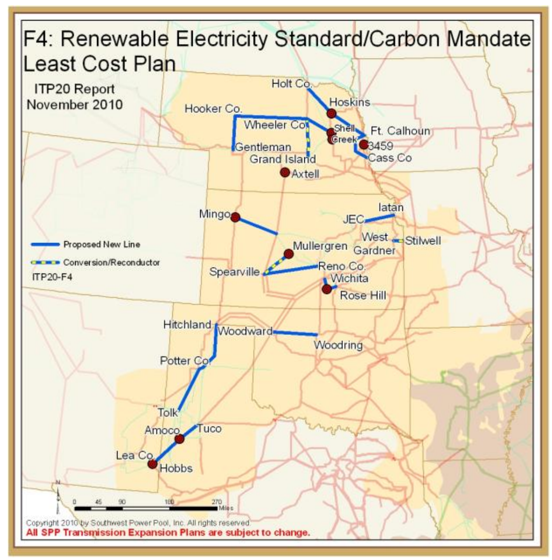


Figure 9.8: Future 4 Least Cost Plans

Project Name	kV	State
Hobbs - Lea Co. - Amoco - Tuco	345	NM, TX
Amoco and Lea Co. Transformers	345/230	NM, TX

Table 9.4: Additional Elements in the RES & Carbon Mandate Least Cost Plan

Section 10: Cost-Effective Analysis

10.1: Overview

The Cost-Effective Plan identified projects that would fulfill needs specified in all of the futures, and provide a starting point for further analysis that would increase system robustness. Projects common to all four Least Cost Plans and projects that fulfilled the remaining needs in the most cost-effective manner where included in the Cost-Effective Plan. This plan was further developed through the use of the robustness metrics defined in Section 6: Metric Methodologies and calculated in Section 11: Robustness Testing.

The first step of the cost-effective analysis identified projects that were common to all four transmission Least Cost Plans. The economic value of each non-common project was then measured. Based on project-related feedback, additional alternatives to the projects in the Least Cost Plans were evaluated. For all of the projects, the reduction in APC was weighed against the estimated project cost through an APC-based B/C calculation. Projects that satisfied needs identified in the transmission least cost planning phase and provided the most economic benefit to their alternatives were rolled forward into robustness testing.

10.2: Common Plan

The common elements of each transmission Least Cost Plan were selected and combined into a plan that served as the base model for further cost-effective valuations. The plan was comprised of any element that appeared in the Least Cost Plan of each future and is referred to hereafter as the Common Plan. These elements are listed in Table 10.2. Because these projects were required in all four futures and selected due to their ability to meet the need with the lowest construction cost, these projects were considered cost-effective without further study.

The plan retained projects in Nebraska, Kansas and Texas that were needed in the non-RES futures and did not contain lines that entered Oklahoma or the extensive addition of lines in Nebraska that were needed with higher levels of wind generation.

The plan formed the basis for further analysis in the ITP20 and was estimated at a cost of $883 million through the construction of 776 miles of 345 kV lines and three 345 kV step-down transformers.

$883 million in Cost	776 miles of Lines	3 Trans-formers	1 Substation

Table 10.1: Common Plan Summary

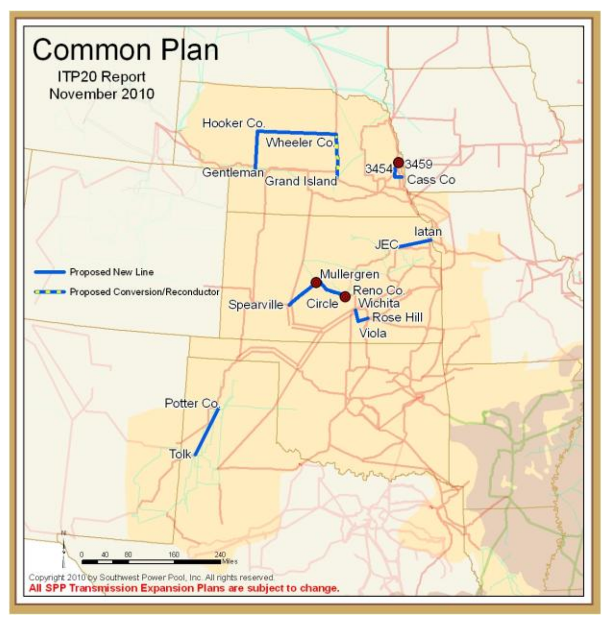


Figure 10.1: The Common Plan

Common Plan Elements	kV	State
Iatan - Jeffrey Energy Center	345	KS
Wichita - Viola - Rose Hill	345	KS
Spearville - Mullergren - Circle - Reno	345	KS
Cass Co. - S.W. Omaha (Sub 3454)	345	NE
Gentleman - Hooker Co. - Wheeler Co.	345	NE
Tolk - Potter Co.	345	TX
Grand Island - Wheeler Co. (Rebuild)[30]	345	NE
S3459-S1209 Transformer	345/161	NE
Mullergren Transformer	345/230	KS
Circle Transformer	345/230	KS
Wheeler Co. Substation	345	NE

Table 10.2: Common Plan Elements

10.3: Cost-Effective Plan Development

Once the common projects were identified, economic and thermal analysis was performed to determine which additional components were required to meet the needs of each future in the most cost-effective manner. To complete this analysis, projects where considered that would fulfill the thermal needs identified using the same multiple source-sink transfer method used to develop the transmission least cost plans. These projects are listed in Table 10.3.

Project Name
Spearville - Comanche – Wichita
Post Rock - Summit conversion
Spearville - Jeffrey Energy Center
Hitchland - Potter Co.
Potter Co. - Stateline
Stateline - Anadarko
Woodward - Woodring
Stateline - Lawton Eastside
Potter - Tuco
Potter Co. - Tuco and Tolk - Tuco
Mingo - Post Rock
Setab - Spearville
Holt - Hoskins - Ft. Calhoun
Ft. Calhoun - S3454
Tuco - Amoco - Lea Co. - Hobbs
Keystone - Ogallala
Wheeler Co. - Shell Creek

Table 10.3: Potential Cost-Effective Projects

Project Alternatives & Selection

Five of these projects were compared to the Spearville - Mullergren - Circle - Reno and Potter Co. - Tolk projects from the Common Plan to determine if a more cost-effective alternative was possible. The Potter Co. to Tolk line in the Common Plan was replaced through this procedure with a Potter Co. to Tuco line. The Post Rock to Summit conversion[31] and Spearville to Wichita via Comanche third circuit proved better economically than the alternatives but did not sufficiently mitigate the thermal overloads in the area. See groups 1 and 2 in Table 10.4 for details.

The remaining projects were evaluated using an APC-based B/C ratio. The Common Plan was used as a reference for both incremental APC savings and construction cost. Projects that met the same thermal need where compared and the one with the higher B/C ratio was selected. See groups 3, 4, and 5 in Table 10.4 for details.

Where only one solution to a thermal need was evaluated the project was selected if the APC-based B/C (with the Common Plan as a base) was greater than one. This showed that the project satisfied the thermal needs and also justified its incremental construction cost above the cost of the Common Plan. See groups 6, 7, 8, 9, and 10 in Table 10.4 for details.

The alternatives that were evaluated, the project they replaced, their incremental APC-based B/C and their selection into the Cost-Effective Plan are shown in Table 10.4. The most cost-effective project alternative from each group was included in the Cost-Effective Plan and is marked with a ✓. Projects

[30] Rebuild from 720 MVA to 1,195 MVA
[31] Conversion from 230 kV to 345 kV utilizing the same ROW

that did not fulfill the need identified in the futures are marked with an ☒. Projects that met the need but were less cost-effective than another alternative are marked with an ×. Based upon the outcomes of this analysis, a group of projects was selected to form the Cost-Effective Plan. The plan is shown in Figure 10.2.

Group	Project Alternative	Replaces Project in Common Plan	Incremental APC-based B/C[32]	Selection Status
1	Spearville - Comanche - Wichita	Spearville - …- Reno[33]	11.89	☒
1	Post Rock - Summit Conversion	Spearville - …- Reno[33]	2.40[34]	☒
1	Spearville - Jeffrey Energy Center	Spearville - …- Reno[33]	2.32	☒
2	Potter Co. - Tuco	Potter Co. - Tolk	22.92	✓
2	Potter Co. - Tuco & Tolk - Tuco	Potter Co. - Tolk	3.87	×
3	Hitchland - Potter Co.		4.33	✓
3	Potter Co. - Stateline		3.85	×
4	Stateline - Anadarko		3.58	×
4	Woodward District EHV - Woodring		4.42	✓
4	Stateline - Lawton Eastside		0.05	×
5	Mingo - Post Rock		4.93	✓
5	Setab - Spearville		4.77	×
6	Holt - Hoskins - Ft. Calhoun		4.91	✓
7	Ft. Calhoun - S3454		9.52	✓
8	Tuco - Amoco - Lea Co. - Hobbs		1.47	✓
9	Keystone - Ogallala		41.03	✓
10	Wheeler Co. - Shell Creek		14.83	✓

Table 10.4: Cost-Effective Project Selection matrix

The Cost-Effective plan showed flexibility by satisfying all of the future's thermal needs and was developed through the use of independently cost-effective projects. The plan formed the basis for further analysis in the ITP20 and was estimated at a cost of $1.8 billion through the construction of 1,494 miles of 345 kV lines along with 11 various 345 kV step-down transformers. A detailed list of the projects, their estimated mileage and cost, and location is given in Appendix A2: Transmission Portfolios & Cost Estimates. A high-resolution image of the plan is included in Appendix A4: High Resolution Map Images.

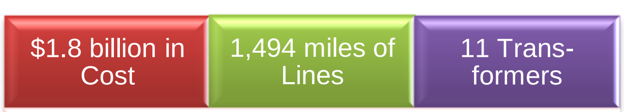


Figure 10.2: Cost-Effective Plan

[32] Averaged across all futures
[33] Spearville - Mullergren - Circle - Reno
[34] This project's APC-based B/C is shown not as an incremental value for this project but for the entire plan because the cost difference between the Common Plan and this alternative was negative.

Section 11: Robustness Testing

11.1: Overview

Robustness testing identified additional projects that would add incremental value and flexibility beyond the Cost-Effective Plan. Value was measured by the metrics described in Section 6: Metric Methodologies and included calculations of monetary and qualitative values. The calculation methods and assumptions that were used in the metric calculations are listed below.

In total, 23 separate projects were studied to determine which projects would add value to the Cost-Effective Plan as measured by the robustness metrics. All comparisons shown in the data refer to a difference between the Cost-Effective Plan with the project under study and the Cost-Effective Plan without the project.

11.2: Potential Robustness Projects

After the Cost-Effective Plan was developed, additional projects were evaluated to determine what additional steps could be taken to build a more robust system. The projects listed in Table 11.1 were individually studied using the robustness metrics. The Cost-Effective Plan was used as a base to which these projects were individually added, and any comparisons were made against that plan.

The projects were gathered from stakeholder submissions, previous studies, and an analysis of congestion within the grid and ranked according to their performance.

Large Scale Projects

Four of the projects were extensive in scope and require further explanation of their design.

The 765 kV Alternative (Robust Plan 4 later in this report) was studied independently as an "all in" alternative; several 345 kV facilities in the original Cost-Effective Plan were replaced by similarly located 765 kV elements. Table 11.4 shows the projects affected by this plan

The Ozark Plan was adapted from the Option B plan recommended as part of the SPP Ozark Transmission Study in 2007[35]. This design showed reliability benefits in past studies and bridged several system boundaries.

The 765 kV Y-Plan provided an alternative to the

Potential Robustness Projects	kV
Big Cajun 2 - Cocodrie	230
Chamber Springs - Ft. Smith	345
Delaware - Afton	345
Dolet Hills - Messick	345
Gentleman - Post Rock	345
Grand Island - Columbus East	345
Holt Co - Sioux City	345
ISES - Osage Creek 500kV	500
Jeffrey Energy Center - Auburn	345
Jeffrey Energy Center - Auburn - Swissvale	345
Jeffrey Energy Center - Swissvale	345
Jeffrey Energy Center - Hoyt - Iatan	345
Lacygne - Mariosa Delta	345
Messick Transformer	500/230
N.W. Texarkana - Ft. Smith	345
Ozark Plan	345, 500
Post Rock - Elm Creek - Jeffrey Energy Center	345
Post Rock - Elm Creek - Summit	345
Turk - McNeil	345
Welsh - Barton Chapel	345
765 kV Y-Plan	765
765 kV Boxed Y-Plan	765
765 kV Alternative	765

Table 11.1: Potential Robustness Projects

35 Details concerning the Ozark Transmission Study can be found on SPP.org.

double circuit 345 kV lines terminating at Medicine Lodge in the Base Case. This included the Woodward District EHV to Wichita via Medicine Lodge and the Spearville to Medicine Lodge via Comanche line segments. The 765 kV Boxed Y-Plan built on this by also incorporating 765 kV paths from Wichita to Rose Hill and from Rose Hill to Sooner (in lieu of the planned 345 kV line in the Base Case).

Projects Effected by 765 kV Large Scale Projects	kV	State
Hitchland – Woodward District EHV double circuit	345	OK
Spearville - Comanche - Medicine Lodge - Wichita double circuit	345	KS
Comanche - Woodward District EHV double circuit	345	KS, OK
Woodward District EHV - Tuco	345	OK, TX
Sooner - Rose Hill	345	KS, OK
Medicine Lodge Transformer	345/138	KS
Woodward District EHV - Tuco Transformers	345/230	KS, OK
Hitchland Transformer	345/230	OK
Comanche Substation	345	KS

Table 11.2: NTCs Effected by Large Scale 765 kV Projects

11.3: Calculation Methods and Top Performers

The assumptions and calculation methods used and top performing projects for each metric are described here for each of the metrics evaluated. The Y-Plan and Boxed Y-Plan are not listed in the top-performing tables because the alteration of the Base Case topology due to these plans changed the basis by which the performances of the plans were measured. These plans were chiefly evaluated for performance in the stability studies presented in Section 14: Stability Analysis.

Metric 1.1.2: Value of Improved ATCs of the SPP grid

This metric evaluated the ability to transfer power between areas in the SPP grid from a thermal loading perspective. Each balancing authority inside the SPP grid was chosen as both a generation and load center. Transfers from generation centers to generation centers and generation centers to load centers were simulated with PSS/MUST to evaluate the average change in ATC for each transfer path due to each project. The flowgates identified for use in the PROMOD models were utilized in this analysis as well. The ATC improvement percentages shown in Table 11.3 reflect the maximum improvement to transfers out of an area, averaged across all areas relative to the ATC available in the Cost-Effective Plan. This concept is explained in more detail in Section 15.5: Increasing System Reliability.

Top Ten Projects for Metric 1.1.2	ATC Δ (%)	ATC Δ (MW)
Delaware - Afton	21	1,102
Lacygne - Mariosa Delta	21	1,286
Messick Transformer	18	1,170
Ozark Plan	18	1,291
Jeffrey Energy Center - Hoyt - Iatan	15	1,001
Post Rock - Elm Creek - Summit	14	1,063
Post Rock - Elm Creek - Jeffrey Energy Center	14	995
Big Cajun 2 - Cocodrie	13	499
Welsh - Barton Chapel	13	751
ISES - Osage Creek 500kV	12	785

Table 11.3: Top Ten Projects that for Metric 1.1.2

Metric 1.2: Enable Efficient Location of New Generation Capacity

This metric examined if proposed transmission line additions lay within a 25 mile distance of any National Renewable Energy Laboratory (NREL) wind survey site. The capacity factor figures were based on profiles obtained from the NREL EWITS dataset. The proposed transmission lines, along with the NREL survey sites were loaded into the SPP Geographic Information System (GIS), and a query was run to determine which sites fell within a 25 mile radius of the proposed transmission lines. This data was aggregated by capacity factor to indicate which plans potentially offer greater access to higher capacity factor wind. SPP did not calculate this metric for thermal generation since SPP did not have the raw data for determining thermal generation locations. This metric was run on portfolios rather than on individual projects.

Metric 1.6: Positive Impact on Losses Capacity

For each project, the powerflow case representing the project was loaded into PSS®E and the total losses data for the SPP footprint were calculated. The difference in losses between the Cost-Effective Plan and each project was determined. The Cost-Effective Plan was also compared to the base case model to determine what portion of the change in losses was due to this plan. The powerflow case reflected 2019 level summer peak load and utilized one possible hour of generation dispatch. The results of this sub-metric were minor since the impact on losses capacity by adding each of the projects in addition to the Cost-Effective Plan was relatively small. A list of the top ten performing projects for this metric is below in Table 11.4.

Top Ten Projects for Metric 1.6	Losses Δ (MW)
Welsh - Barton Chapel	14.4
Ozark Plan	14.3
ISES - Osage Creek	9.6
765 kV Alternative	5.2
Jeffrey Energy Center - Auburn - Swissvale	5.1
Post Rock - Elm Creek - Jeffrey Energy Center	4.6
Jeffrey Energy Center - Auburn	4.1
Jeffrey Energy Center - Swissvale	3.8
Gentleman - Post Rock	3.6
Chamber Springs - Ft. Smith	2.8

Table 11.4: Top Ten Projects that for Metric 1.6

Metric 2: Levelization of LMPs

SPP calculated the levelization of LMPs using output from PROMOD, which reported both the load-weighted and generation-weighted LMP values for each hour of the year for the SPP region. SPP then calculated the standard deviation of the load-weighted and generation-weighted LMPs for each hour of the studied year. Using the largest 25% of all hours the average load-weighted and generation-weighted standard deviations were calculated. These calculations were performed on the output for the base case, Cost-Effective Plan, and all of the potential robustness projects added to the Cost-Effective Plan in futures 1 and 4.

A list of the top ten projects that reduced the standard deviation of LMPs when added to the Cost-Effective Plan is below in Table 11.5.

Top Ten Projects for Metric 2	Std. Dev. Δ ($)
Ozark Plan	-6.99
N.W. Texarkana - Ft. Smith	-4.26
Post Rock - Elm Creek - Jeffrey Energy Center	-2.73
Grand Island - Columbus East	-2.36
765 kV Alternative	-2.2
Lacygne - Mariosa Delta	-1.84
Welsh - Barton Chapel	-1.18

Top Ten Projects for Metric 2	Std. Dev. Δ ($)
Messick Transformer	-1.12
ISES - Osage Creek	-1.05
Dolet Hills - Messick	-0.19

Table 11.5: Top Ten Projects for Metric 2

The Ozark Plan reduced the standard deviation of LMPs more than any other project when added to the Cost-Effective Plan.

Metric 3: Improved Competition in SPP Markets

This metric was calculated using output from PROMOD which reported the LMP at all SPP generation buses. The average capacity-weighted LMP and standard deviation for generation plants by type -- wind, steam coal, combined cycle, and combustion turbine were calculated on an hourly basis. The average hourly standard deviation was calculated using 25% of the largest hourly standard deviations. These calculations were performed on the output for the base case, Cost-Effective Plan, and all of the potential robustness projects added to the Cost-Effective Plan in futures 1 and 4.

Since Metric 2 and Metric 3 use much of the same data, these results are similar. Both metrics utilize the generation weighted LMPs. However Metric 3 is a more focused look at the generation weighted LMPs. Metric 3 compares how LMPs are levelized within generation types while Metric 2 looks at LMP levelization across the whole of the SPP footprint. A list of the top performing projects as averaged across all generation types is contained in Table 11.6. Certain lines provide more or less value in reducing the standard deviation across specific generation types.

Top Ten Projects for Metric 3
Ozark Plan
N.W. Texarkana - Ft. Smith
Post Rock - Elm Creek 3 - Jeffrey Energy Center
765 kV Alternative
Grand Island - Columbus East
Lacygne - Mariosa Delta
Welsh - Barton Chapel
Messick Transformer
Turk - McNeil
Jeffrey Energy Center - Swissvale

Table 11.6: Top Ten Projects for Metric 3

Metric 6: Limited Import/Export Improvements

This metric evaluates the region's ability to export and import power from neighboring regions. There were three types of transfers performed in this metric:

1. SPP areas to SPP Tier 1 areas (Incremental Export ATC)
2. SPP Tier 1 to SPP areas (Incremental Import ATC)
3. SPP Tier 1 to areas inside SPP that have transmission ties to the Tier 1 area (Incremental Wheel-Through ATC)

All three of the transfers above were performed using Siemens PSS/MUST software. Table 11.7 lists the top ten performing projects for this metric.

Top Ten Projects for Metric 6	ATC Δ (MW)
Ozark Plan	3.02

Top Ten Projects for Metric 6	ATC Δ (MW)
ISES - Osage Creek	1.91
Dolet Hills - Messick	1.77
Turk - McNeil	1.16
Big Cajun 2 - Cocodrie	1.10
Jeffrey Energy Center - Hoyt - Iatan	0.66
Lacygne - Mariosa Delta	0.57
Welsh - Barton Chapel	0.43
Post Rock - Elm Creek - Jeffrey Energy Center	0.35
N.W. Texarkana - Ft. Smith	0.33

Table 11.7: Top Ten Projects for Metric 6

Metric 10: Reduction of Emission Rates and Values

SPP used PROMOD to determine the amount of emissions produced in each of the futures. This was calculated for CO_2, NO_X, and SO_2 in metric tons. The top ten projects shown were ranked according to the average reduction of all three effluents.

Top Ten Projects for Metric 10
Jeffrey Energy Center - Auburn
Post Rock - Elm Creek - Summit
Big Cajun 2 - Cocodrie
Gentleman - Post Rock
Jeffrey Energy Center - Auburn - Swissvale
Grand Island - Columbus East
Jeffrey Energy Center - Swissvale
Jeffrey Energy Center - Hoyt - Iatan
Post Rock - Elm Creek - Jeffrey Energy Center
Welsh - Barton Chapel

Table 11.8: Top Ten Projects for Metric 10

Metric 11: Transmission Corridor Utilization

This metric assesses which portions of the proposed transmission plans either impact environmentally sensitive areas or require new transmission corridors.

To determine whether the proposed transmission plans impact environmentally sensitive areas, information pertaining to environmental boundaries was obtained using PAD-US 1.1 (CBI Edition)[36]. The PAD-US 1.1 (CBI Edition) data set portrays the nation's environmentally sensitive areas, or protected areas, with a standardized spatial geometry and numerous valuable attributes on land ownership, management designations, and conservation status (using national GAP and international IUCN coding systems). The PAD-US 1.1 (CBI Edition) defines protected areas to include all lands dedicated to the preservation of biological diversity and to other natural, recreation and cultural uses, and managed for these purposes through legal or other effective means. The proposed transmission lines were analyzed to determine how many line miles from these proposed projects pass through protected areas.

To determine where new transmission corridors were required, current SPP transmission corridors were compared with the proposed transmission lines. Where a path exists between two points on the transmission system, it was assumed that those corridors would be utilized for the new projects. For

[36] More information regarding these data sets can be found through on The GAP Analysis Program's website.

other paths, it was assumed that new right-of-way (ROW) would be required. The sum of the new ROW required for all the transmission projects in a portfolio was aggregated.

The new ROW required and the impact on protected areas for each portfolio is presented in Section 15: Benefits (and details in Table A2.9). This metric was utilized on project groupings and not on individual projects.

Metric 14: Ability to Serve New Load

This metric measures the ability of an alternative transmission topology to serve new load or the shift of load between areas. Transfers between areas were simulated using Siemens PSS/MUST. Load shifts were setup between every control area and the maximum ability to shift load was calculated. This analysis was performed on all new transmission expansion topologies. A list of the top ten performing projects for this metric is in Table 11.9.

Top Ten Project for Metric 14	Change in ATC (MW)
Lacygne - Mariosa Delta	4.32
Dolet Hills - Messick	2.74
765 kV Alternative	2.63
Ozark Plan	2.31
N.W. Texarkana - Ft. Smith	1.79
ISES - Osage Creek	1.22
Chamber Springs - Ft. Smith	0.84
Gentleman - Post Rock	0.73
Post Rock - Elm Creek - Jeffrey Energy Center	0.72
Post Rock - Elm Creek - Summit	0.64

Table 11.9: Top Ten Projects for Metric 14

Part III: Results & Portfolios

Section 12: Seams Coordination

12.1: Overview of Coordination

The ITP20 Assessment considered seams impacts in accordance with FERC Order 890 principles. Per the study scope, SPP contacted neighboring parties to coordinate the inputs and results of the analysis. SPP analyzed whether alternative interregional projects would more efficiently or effectively meet SPP's needs than projects contained only within the region's boundaries. This coordination should help improve the coordination of proposed interregional upgrades, identify more efficient and cost-effective solutions along the seams, and potentially reduce the cost of transmission plans for both parties.

SPP considered projects which may have an impact on one or more of the SPP seams. These projects have been considered in either the least-cost, cost-effective, or robustness development stage of the analysis. The seams projects considered are listed in Table 12.1.

Seams Project	kV	Areas
Ozark Plan		AECI - SPP - EES
ISES - Osage Creek	500	EES - SPP
N.W. Texarkana - Ft. Smith	345	EES - SPP
Dolet Hills - Messick	345	EES - SPP
Lacygne - Mariosa Delta	345	AECI - SPP
Holt Co - Sioux City	345	MISO - SPP
Turk - McNeil	345	EES - SPP
Messick Transformer	500/230	EES - SPP
Delaware - Afton	345	SPP - AECI
Big Cajun 2 - Cocodrie	230	EES - SPP
Grand Island - Wheeler Co. rebuild[37]	345	WAPA - SPP
Tapping Grand Island - Ft Thompson	345	WAPA - SPP

Table 12.1: Seams Projects Considered in Robustness Testing

ITP20 coordination with WAPA, BEPC, Entergy, AECI and MISO included updates on the process and purpose of the 20-Year Assessment. AECI provided input to the ITP20 process and verified the results of the resource plan for the year 2030 as being acceptable inputs into the production cost model. SPP also met with WAPA, BEPC, Entergy, AECI and MISO during various stages of this study to discuss the results and plans being developed. SPP has shared the Cost-Effective and Robustness designs and results with WAPA, BEPC, Entergy, AECI and MISO and looks forward to feedback and planning of collaborative long range EHV system designs.

12.2: Tier 1 Benefits

The ITP20 focused on SPP benefits rather than Tier 1 benefits. As such, the Tier 1 modeling data was more generic than the SPP data. For example, fuel prices, emissions output, unit capacities, generation expansion and load growth were modeling inputs that were not developed as thoroughly for the Tier 1 entities. Also, since a 2019 powerflow model was used in the base case, the Tier 1 zones do not have a twenty-year transmission expansion plan. Therefore, congestion was not relieved in Tier 1 as it was for SPP. These modeling assumptions led to the Tier 1 zones incurring APC related costs due to SPP's twenty-year transmission expansion plan.

[37] Rebuild from 720 MVA to 1,195 MVA

12.3: Import / Export Results

Energy was transferred between SPP and Tier 1 zones throughout the simulation. Although the ITP20 scope did not warrant focus upon the export or import of a certain amount of energy, the energy traded over the borders did result in a net export from SPP to all Tier 1 zones. The energy exported is shown in Table 12.2.

	Future 1	Future 2	Future 3	Future 4
Base Case	35	34	38	38
Cost-Effective Plan	44	49	47	51
Robust Plan 1	49	56	51	57
Robust Plan 2	47	53	50	57
Robust Plan 3	47	54	50	57
Robust Plan 4	46	52	50	55
Robust Plan 5	49	56	51	57
Robust Plan 6	49	56	51	57

Table 12.2: Annual Exports from SPP to surrounding zones in millions of MWh

Section 13: Results

13.1: Robust Portfolio Development

The application of the robustness metrics to the potential robust projects in Section 11: Robustness Testing identified projects that excelled at certain metrics and added value to the Cost-Effective Plan. These projects were studied in relation to the Base Case to determine the most robust combination of projects. The sets of projects were grouped into portfolios for the analysis.

Six portfolios were designed; one with only the highest APC improving projects; one with borderline projects to determine project interaction; one with the projects that performed well across all metrics; and three plans involving 765 kV alternatives to the Cost-Effective Plan.

Portfolio Descriptions

Robustness metrics and APC-based B/C calculations were used evaluate the projects listed in Table 11.1. Projects with similar performance were grouped into three portfolios to capture their coincident behavior with other projects and the Cost-Effective Plan. Projects which kept the APC-based B/C of the Cost-Effective Plan in relation to the Base Case above 1.0 and showed benefit across most of the metrics were placed in Robust Plan 1. Projects which performed marginally across most metrics when evaluated individually were placed in Robust Plan 2 to determine if grouping the projects would increase their performance. Projects which provided an incremental increase in APC-based B/C in relation to the Cost-Effective Plan were placed in Robust Plan 3. The 765 kV alternatives to the Cost-Effective Plan that included an all-in 765 kV approach made up Robust Plan 4. The 765 kV projects identified as the Y-Plan and Boxed Y-Plan were studied as part of a portfolio with the projects identified for Robust Plan 1 and constituted Robust Plan 5 and Robust Plan 6.

A complete list of the projects included in each portfolio and their details are included in Appendix A2: Transmission Portfolios & Cost Estimates.

765kV Portfolio Development

Robust plans 4, 5 and 6 include design elements at 765 kV. These projects were developed as an outgrowth of studies conducted by SPP over the past five years.

Project Name	kV	State
ISES - Osage Creek	500	AR
Messick Transformer	500/230	AR
Welsh - Barton Chapel	345	TX
Post Rock - Elm Creek - Summit	345	KS
Grand Island - Columbus East	345	NE

Table 13.1: Projects Eliminated by Incremental APC Threshold

Robust Plan 5 directly finds roots in studies such as the Lincoln Circle 230kV Project studied in Kansas in June 2005, the Kansas Electric Transmission Authority (KETA) Study in April of 2007, the Oklahoma Electric Power Transmission Task Force (OEPTF) Study in March 2008, the EHV Overlay Studies in June 2007 and March 2008, the Balanced Portfolio Study in June 2009 and the Priority Projects Study in April 2010. These lines strengthen the ties between the western and eastern sides of the SPP footprint and provide an alternative to double-circuit 345 kV lines currently being considered to handle the heavy loadings expected in the area due to generation development.

Robust Plan 6 was developed by staff as an evolution of the concepts in Robust Plan 5, chiefly to introduce a loop of 765 kV lines to provide greater reliability and transfer capability. Both this plan and Robust Plan 5 utilized the projects comprising Robust Plan 1 following staff’s recommendation in October 2010.

Incremental APC Threshold

Each project was evaluated for its ability to improve the APC savings. Projects that did not provide an APC savings in any future in relation to the Cost-Effective Plan when added to the Cost-Effective Plan were eliminated from further consideration. This counter-intuitive result occurs when a project creates flow or counter-flow upon an initially unconstrained area in the system and causes a less-efficient generation dispatch.

The illustration in Figure 13.1 shows a before-and-after example of a transmission line changing the flows of the system such that a low cost resource becomes more limited. If cheaper resources are more limited, the LMPs of the system will increase and the cost of energy reflected in the APC will rise.

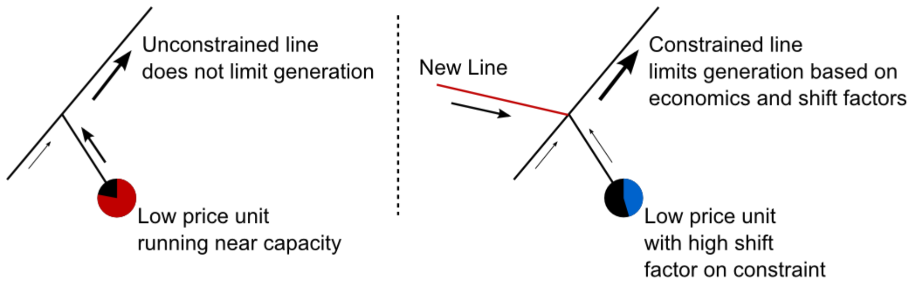


Figure 13.1: Transmission Line Increases APC

Ranking by Metric Performance

Projects that were not eliminated by the incremental APC threshold were evaluated with the robustness metrics and ranked according to their performance. Six of the projects clearly fell out as the lowest performing projects and are listed in Table 13.2: Projects with lowest metric performance. The remaining projects were ranked according to their performance and grouped into the project portfolios.

Project Name	kV	State
Jeffrey Energy Center - Auburn	345	KS
Gentleman - Post Rock	345	KS, NE
Delaware - Afton	345	OK
Big Cajun 2 - Cocodrie	230	LA
Jeffrey Energy Center - Hoyt - Iatan	345	KS
Holt Co - Sioux City	345	NE, IA

Table 13.2: Projects with lowest metric performance

The calculation results were extensive for this selection process and are not included in this report. The results of this analysis can be requested via planning@spp.org if further details are needed.

The project groupings are referred to as Robust Plan 1 (RP1), Robust Plan 2 (RP2), etc. and were evaluated as full portfolios to determine the cooperative nature of the projects. The performance of the robust plans as a cooperative group is discussed in Section 15: Benefits. Table 13.3 shows the projects and the portfolio into which they were placed.

Project Name	RP1	RP2	RP3	RP4	RP5	RP6
Post Rock - Elm Creek - Jeffrey Energy Center	✓	✓			✓	✓
N.W. Texarkana - Ft. Smith	✓				✓	✓
Ft. Smith - Chamber Springs	✓				✓	✓
Dolet Hills - Messick	✓		✓		✓	✓
Turk - McNeil	✓		✓		✓	✓
Messick Transformer	✓		✓		✓	✓
McNeil Transformer	✓		✓		✓	✓
Ozark Plan		✓				
Jeffrey Energy Center - Auburn - Swissvale		✓				
765 kV Alternative				✓		
765 kV Y-Plan					✓	
765 kV Boxed Y-Plan						✓

Table 13.3: Project Assignment to each Portfolio

13.2: Robust Portfolio Descriptions

Robust Plan 1

Projects that appeared as strong candidates for robustness were included in Robust Plan 1. Robust Plan 1 costs estimates are listed in Table 13.4. Figure 13.2 shows the projects added to the Cost-Effective Plan to make Robust Plan 1

Upgrades	Quantity	Cost
Miles of 345 kV lines	2,078	$2,325,150,000
345 kV transformers	12	$72,000,000
500 kV transformers	3	$36,000,000
345 kV substations	2	$21,000,000
Total Cost:		**$2,454,150,000**

Table 13.4: Robust Plan 1 Cost Estimate

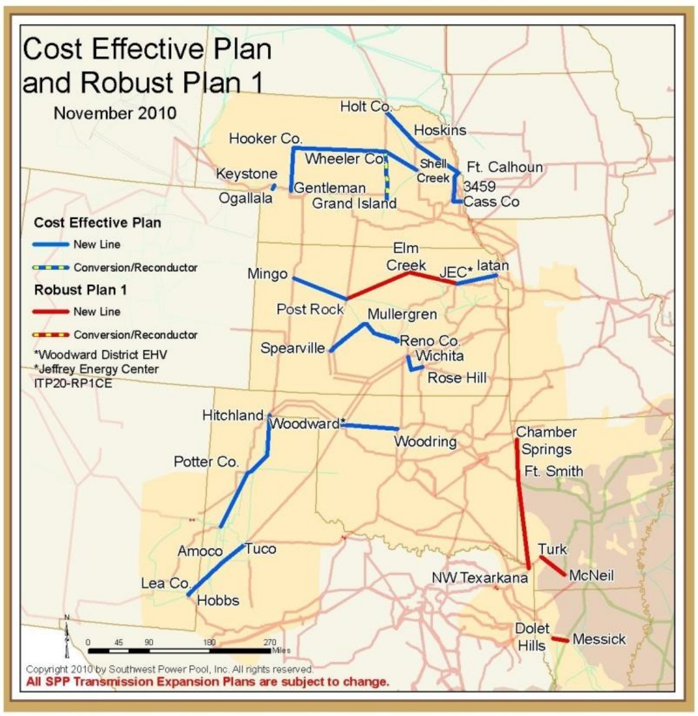


Figure 13.2: Robust Plan 1

Listed below are the Robust Plan 1 elements that were added to the Cost-Effective Plan:

Additions to the Cost-Effective Plan	kV	State
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS
N.W. Texarkana - Ft. Smith	345	AR
Ft. Smith - Chamber Springs	345	AR
Dolet Hills - Messick	345	LA
Turk - McNeil	345	AR
Messick Transformer	500/345	LA
McNeil Transformer	500/345	AR
Elm Creek Transformer	345/230	KS

Table 13.5: Additions to the Cost-Effective Plan that make up Robust Plan 1

Robust Plan 2

Projects that appeared to be less beneficial but still qualified under the initial thresholds were included in Robust Plan 2. Robust Plan 2 costs estimates are listed in Table 13.6. Figure 13.3 shows the projects added to the Cost-Effective Plan to make Robust Plan 2.

Upgrades	Quantity	Cost
Miles of 345 kV lines	2,488	$2,786,400,000
Miles of 500 kV lines	138	$232,875,000
345 kV transformers	22	$132,000,000
500 kV transformers	4	$48,000,000
345 kV substations	2	$21,000,000
Total Cost:		**$3,220,275,000**

Table 13.6: Robust Plan 2 Cost Estimate

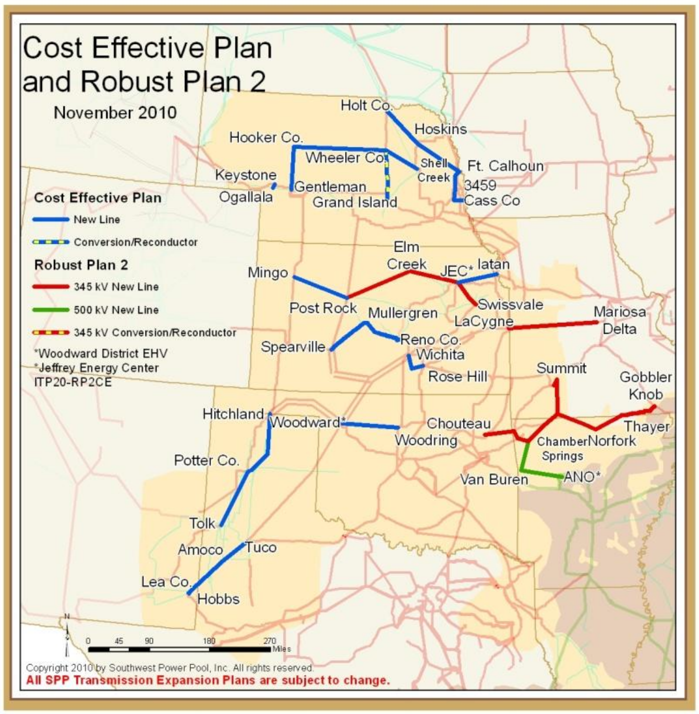


Figure 13.3: Robust Plan 2

Listed below are the Robust Plan 2 elements that were added to the Cost-Effective Plan:

Additions to the Cost-Effective Plan	kV	State
Ozark Plan	345	AR, OK, MO
Jeffrey Energy Center - Auburn - Swissvale	345	KS
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS
Lacygne - Mariosa Delta	345	KS, MO

Table 13.7: Additions to the Cost-Effective Plan that make up Robust Plan 2

Robust Plan 3

Projects with the highest incremental APC reduction for construction cost were included in Robust Plan 3. Robust Plan 3 costs estimates are listed in Table 13.8. Figure 13.4 shows the projects added to the Cost-Effective Plan to make Robust Plan 3.

Upgrades	Quantity	Cost
Miles of 345 kV lines	1,574	$1,758,150,000
345 kV transformers	11	$66,000,000
500 kV transformers	3	$36,000,000
345 kV substations	2	$21,000,000
Total Cost:		**$1,881,150,000**

Table 13.8: Robust Plan 3 Cost Estimate

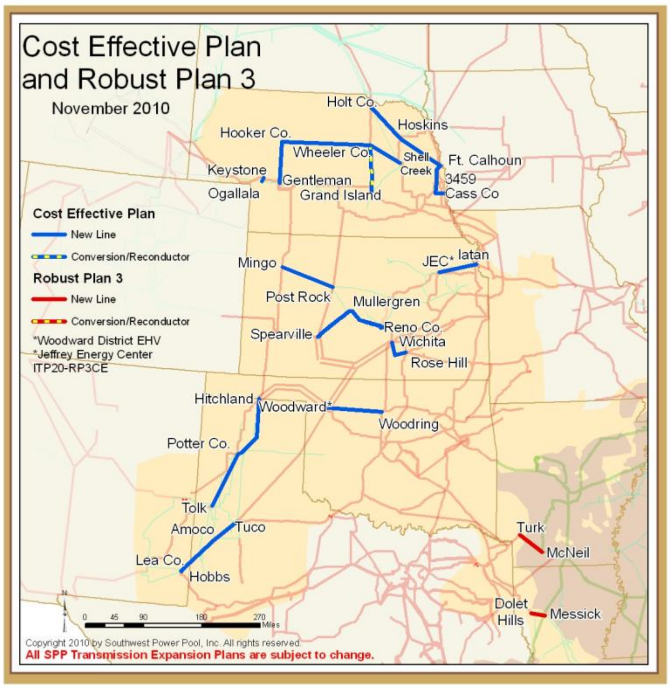


Figure 13.4: Robust Plan 3

Listed below are the Robust Plan 3 elements that were added to the Cost-Effective Plan:

Additions to the Cost-Effective Plan	kV	State
Dolet Hills - Messick	345	LA
Turk - McNeil	345	AR
Messick Transformer	500/345	LA
McNeil Transformer	500/345	AR

Table 13.9: Additions to the Cost-Effective Plan that make up Robust Plan 3

Robust Plan 4

This portfolio reconfigured the design of existing circuits with NTC's in the Base Case. These projects would be constructed at 765 kV. Robust Plan 4 cost estimate are listed in Table 13.10 along with descriptions of the offsets to planned project costs. Figure 13.5 is a map of Robust Plan 4. A complete list of projects that make up this plan can be found in Appendix A2: Transmission Portfolios & Cost Estimates.

Upgrades	Quantity	Cost
Miles of 345 kV lines	492	$562,500,000
Miles of 765 kV lines	2398	$6,434,491,200
Miles of Double Circuit 345 kV lines with NTC's now that would be cancelled	376	($740,720,000)
Miles of Single Circuit 345 kV lines with NTC's now that would be cancelled	250	($281,250,000)
345 kV transformers	8	$48,000,000
765 kV transformers	30	$845,790,000
345 kV transformers with NTC's now that would be cancelled	3	($18,000,000)
345 kV substations	1	$10,500,000
765 kV substations	1	$25,100,000
345 kV substations with NTC's now that would be cancelled	1	($10,500,000)
Total		**$6,875,911,200**

Table 13.10: Robust Plan 4 Cost Estimate

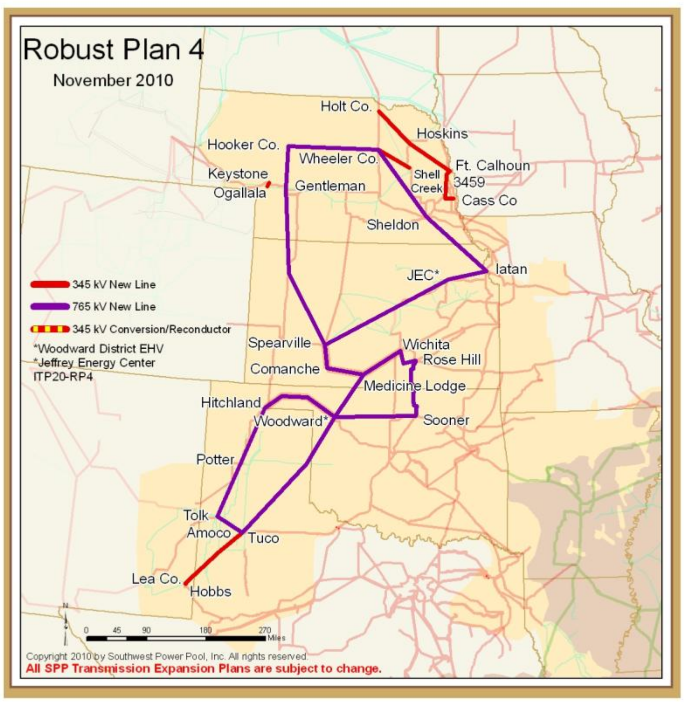


Figure 13.5: Robust Plan 4

Each individual element of this plan is presented in Appendix A2: Transmission Portfolios & Cost Estimates.

Robust Plan 5

This portfolio contained the second of the 765 kV designs.

Upgrades	Quantity	Cost
Miles of 345 kV lines	2078	$2,325,150,000
Miles of 765 kV lines	240	$650,880,000
Miles of Double Circuit 345 kV lines with NTC's now that would be cancelled	240	($472,800,000)
345 kV transformers	12	$72,000,000
500 kV transformers	3	$36,000,000
765/345 kV transformers	4	$112,776,000
345 Substations	2	$21,000,000
Total Cost:		**$2,745,006,000**

Table 13.11: Robust Plan 5 Cost Estimate

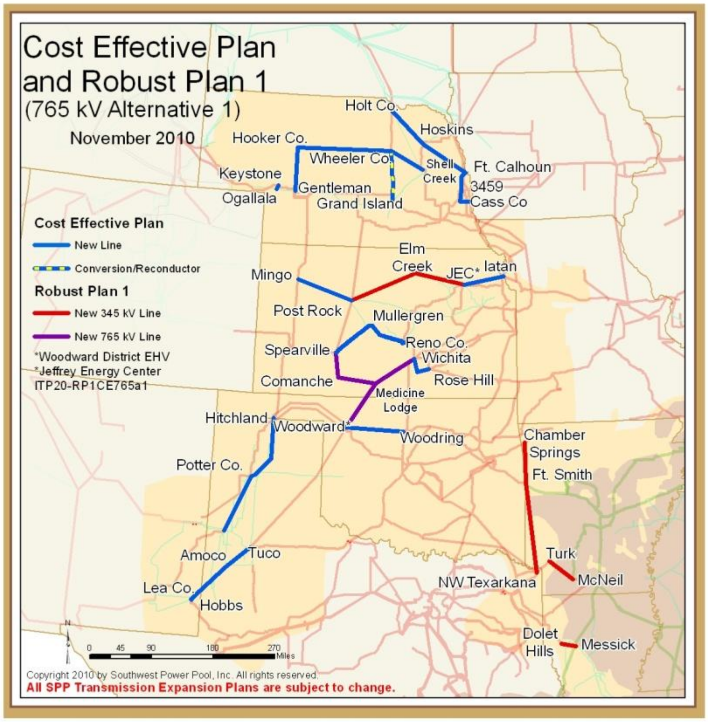


Figure 13.6: Robust Plan 5

Listed below are the Robust Plan 5 elements that were added to the Cost-Effective Plan:

Additions to the Cost-Effective Plan	kV	State
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS
N.W. Texarkana - Ft. Smith	345	AR
Ft. Smith - Chamber Springs	345	AR
Dolet Hills - Messick	345	LA
Turk - McNeil	345	AR
Messick Transformer	500/345	LA
McNeil Transformer	500/345	AR
765 kV Y-Plan	765	KS, OK

Table 13.12: Additions to the Cost-Effective Plan that make up Robust Plan 1

Robust Plan 6

This portfolio contained the third of the 765 kV designs.

Upgrades	Quantity	Cost
Miles of 345 kV lines	1,882	$2,104,650,000
Miles of 765 kV lines	576	$1,494,312,000
Miles of Double Circuit 345 kV lines with NTC's now that would be cancelled	240	($472,800,000)
345 kV transformers	12	$72,000,000
500 kV transformers	3	$36,000,000
765/345 kV transformers	8	$225,552,000
345 Substations	2	$21,000,000
Total Cost:		**$3,480,714,000**

Table 13.13: Robust Plan 6 Cost Estimate

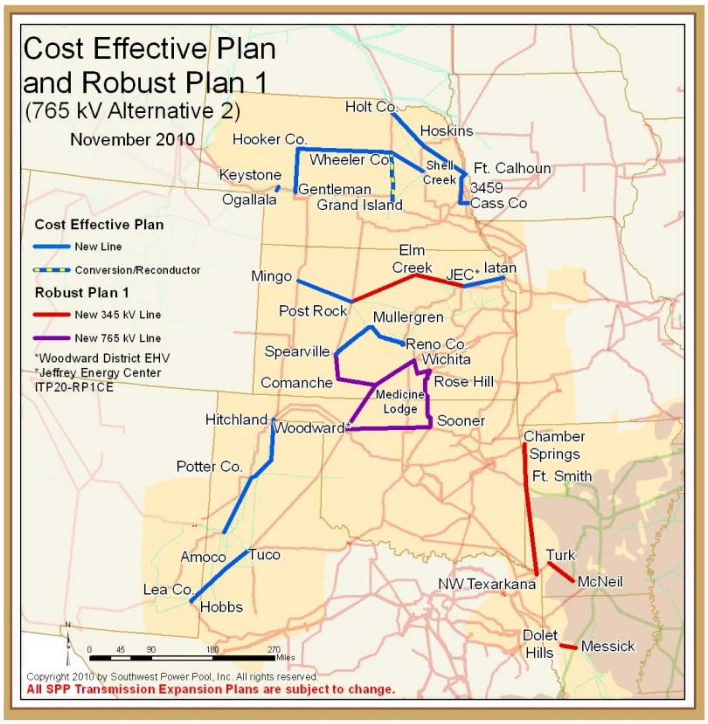


Figure 13.7: Robust Plan 6

Listed below are the Robust Plan 6 elements that were added to the Cost-Effective Plan:

Additions to the Cost-Effective Plan	kV	State
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS
N.W. Texarkana - Ft. Smith	345	AR
Ft. Smith - Chamber Springs	345	AR
Dolet Hills - Messick	345	LA
Turk - McNeil	345	AR
Messick Transformer	500/345	LA
McNeil Transformer	500/345	AR
765 kV Boxed Y-Plan	765	KS, OK

Table 13.14: Additions to the Cost-Effective Plan that make up Robust Plan 1

Section 14: Stability Analysis

14.1: Summary

Voltage and rotor angle stability studies were performed to determine the stability impacts of 17 GW of new renewable generation transfers across the SPP footprint for multiple scenario topologies. Commercial software was utilized to perform the studies and voltage and rotor angle stability were the stability measures used. The results revealed the limiting transfer to maintain voltage stability for each of the scenarios. Transient stability was also performed for two of the scenarios for a 4 GW and 10 GW transfer level to determine rotor angle stability. Lastly, comparisons were made revealing the relative amount of transfer capabilities and reactive compensation requirements among the different scenarios.

14.2: Results

The voltage stability transfer limits for the various scenarios are shown in Table A8.6. The Current Topology will provide a 7.75 GW transfer under contingency conditions, which is approximately 46% of the 17 GW study required for a 20% renewable standard. The analysis shows that RP1 can transfer 60% more energy than the Current Topology at a minimal project cost increase. The results also indicate that the 345kV RP1 plan provides as much or more transfer capability than either the 765kV "Y" or "Box" plan. In addition, the increased transfer capability is obtained at a significantly lower incremental cost up to its transfer performance limitation of approximately 12 GW. The 765kV "Full" plan provides more transfer capability than all other studied scenarios, and provides the ability to exceed the 12 GW transfer limitation of the 345kV design; however, at a higher incremental cost.

Transient stability analysis for both plans studied showed that there were no synchronous generator rotor angle stability problems inside the SPP footprint during fault conditions for the design configurations studied.

Therefore; considering voltage stability and rotor angle stability, scenario RP1 appears to offer the most transfer capability at the lowest incremental cost when compared to all other scenarios studied.

RP1 yields the most cost effective performance up to 12.2GW; moreover, there is an inherent limitation that should be understood. Results indicate that the 345kV RP1 design hits a hard limit to contingent west-east transfer levels somewhere around 12 GW, which is a reasonable approximation based upon the assumptions and results. Slight increases may be gained through the use of series compensation and fine tuning of the location of the devices. However, at this level, the technology presents operational complexities, increased system losses, limited life expectancy, and synchronous resonance issues that must be considered. This solution method is considered a short term remedy intended to stretch existing system capabilities until a more viable long term solution is proven. Therefore, it is concluded that expansion at 345kV is limited to the 12 GW transfer level.

Should more transfer capability be required beyond 12GW, it appears that the 765kV options would provide a viable expansion technology; however, the results show that only the "Full" RP4 765kV design configuration provided significant improvements in transfer capability. It is therefore concluded that should 765kV technology be pursued, significantly more study is required to determine the best design configuration weighing both technical and economic benefit. The amount of reactive compensation for any 765kV design would be significantly more than that of a 345kV design. Further study would be required to determine the appropriate amount and location of reactive compensation. Alternative 765kV design configurations other than those discussed herein can yield different performance results in both transfer capability and reactive compensation requirements.

Underlying areas of the grid were identified that exhibited reactive power deficiencies during transfers. These deficiencies merit additional transmission enhancements that will require further study in the upcoming ITP10 efforts or the next ITP20 iteration.

During the course of the analysis, some areas of the SPP footprint were unable to sustain acceptable voltages at high transfer levels causing some underlying systems as shown below to depress and collapse: :

- AEPW/WFEC/OMPA – Old WTU-N system in the Texas Panhandle
- AEPW – South Oklahoma
- AEPW – AECC area in western Arkansas
- NPPD – Northwest and Central area of Nebraska

ITP20 solutions were not specifically designed to address these local areas exhibiting reactive deficiencies. However, further analysis should be conducted within the scope of the ITP10 with those findings rolling into the next cycle of the ITP20. During the ITP10 process, existing and new stakeholder recommended modifications to the various robustness plans should also be analyzed for effectiveness in enhancing and strengthening the underlying system.

Finally, individual line loadability studies were not addressed as part of the ITP20 study. Loadability studies will be required to determine power transfer limitations on any new transmission line, particularly for those 100 miles or more in length. This analysis will be done in the future.

The complete stability report is presented in Appendix A8: ITP20 Stability Analysis.

Section 15: Benefits

15.1: Introduction

This section discusses the impacts of the robust plans on the SPP footprint. The measurement of the benefit or cost associated with each metric is presented. Metric calculation methods are discussed in greater detail in Section 11: Robustness Testing. The discussions correlate with each of the metrics as provided in Table 15.1, which shows the benefit discussed and the metric number. All monetary values are in 2010 nominal dollars.

Benefit Discussion	Metric(s)
Creating Adjusted Production Cost Savings	-
Offering Lasting Savings	-
Providing a Competitive Environment	2, 3
Increasing System Reliability	1.1.2
Preparing for Unexpected Shifts in Load	14
Anticipating Import and Export Opportunities	6
Broadening Resource Siting Options	1.2
Valuing Cleaner Air	10
Reducing Risk through Responsible Land Usage	11
Increasing Efficiency with Reduced Transmission Losses	1.6

Table 15.1: Benefits and Metrics Correlation

15.2: Creating Adjusted Production Cost Savings

Adjusted Production Cost considers the expense associated with producing, selling and purchasing energy for the ever-changing system load. These costs are incurred by power purchasers and paid to power producers for every MWh of energy used. Savings are created through changes to the transmission grid or generating resources that increase the efficiency of the overall system not by reducing the energy consumed, but by producing that same amount of energy using more economical means.

Savings per MWh

APC savings created by plans in the ITP20 are reported in dollars and represent the cost of energy production for the entire study year. The product of the LMP and the number of MWh sold or purchased at a point in the system form the basis of the APC. Estimations of a U.S. household's annual energy usage by the Energy Information Administration (EIA) provide everyday context for these numbers[38].

The annual energy consumed by SPP zones under the Business as Usual future, without added transmission, was 293 million MWh at a cost of $3.5 billion in APC. Each robust plan created an annual average APC savings of $607 million dollars averaged across all futures. This is equivalent to the annual energy use of 26.5 million U.S. households (about one-quarter of the households in the U.S.) and an average savings of $23 per household.[39]

APC Savings equivalent to $23 saved annually by 1/4 of all U.S. Households

Figure 15.1: Equivalent APC Savings averaged across all futures

[38] According to the EIA website the annual energy usage of U.S. residences was 11,040 kWh in 2008; November 2nd, 2010
[39] According to the U.S. Census Bureau website the number of households was 105,480,101 in 2000, November 2nd, 2010

Savings by Future

The production cost savings varied among the futures and was highest in those that included the higher wind capacities and the carbon tax. Figure 15.2 compares the savings created by each plan across all futures.

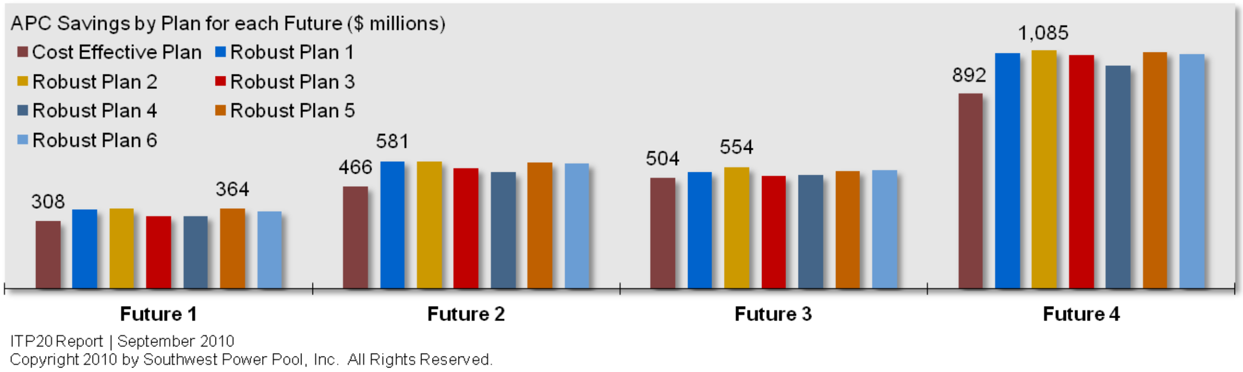


Figure 15.2: APC Savings by Plan for each Future ($ millions)

The APC savings of each plan were compared to the construction costs to determine APC-based B/C ratios shown in Table 15.2. These calculations represent one year of benefit compared to a yearly carrying charge rate of 17%. See Section 8: Transmission Analysis Assumptions for details regarding the rates utilized in these calculations. The APC savings and total APC are shown for each plan and future in Appendix A3: Metric Results.

	Future 1	Future 2	Future 3	Future 4	Average
Cost-Effective Plan	2.93	4.44	4.80	8.50	5.17
Robust Plan 1	2.47	3.96	3.63	7.30	4.34
Robust Plan 2	1.89	3.02	2.88	5.64	3.36
Robust Plan 3	2.95	4.88	4.56	9.48	5.47
Robust Plan 4	0.81	1.29	1.26	2.47	1.46
Robust Plan 5	2.22	3.50	3.28	6.57	3.89
Robust Plan 6	1.70	2.75	2.60	5.15	3.05

Table 15.2: APC-based B/C by Plan

APC Reducing Transmission

The APC savings created by these plans reduce the production cost of energy needed by the footprint and can be immediately compared dollar-for-dollar against the construction costs of each plan to determine if the benefits due solely to APC savings justify the cost of the plans. The robust plans increase the efficiency of the grid for most of the futures and promise a reduction in the energy production costs carried by SPP's members.

15.3: Offering Lasting Savings

In June 2008 Puget Sound Energy (PSE) began construction of a 115 kV substation in Factoria, WA to replace a functioning fifty-year old substation that has been serving the area since 1950. The replacement of the original equipment was undertaken to add capacity and operational flexibility in the area[40]. Substations, transformers and transmission lines of all voltages are long-lasting assets that perform well past their initial design expectations. This fact highlights the conservative nature of the APC savings calculation when considered for only one year of operation. The potential growth in APC savings over time for the life of these projects and the full term of these projects' life were ignored.

In order to capture the growth in benefit over time and the cumulative APC savings over the whole life of the asset the savings growth was approximated for an expected life of forty-years. This approximation did not include the continued maintenance costs or the necessary project staging that would occur as the projects are built, but when combined with the forty-year estimate, which is arguably average, the high return on the transmission asset investment is reasonable.

Figure 15.3 shows the APC savings and carrying costs over the full forty-year period for Robust Plan 1 and demonstrates the long-lasting value of the transmission over this time period.

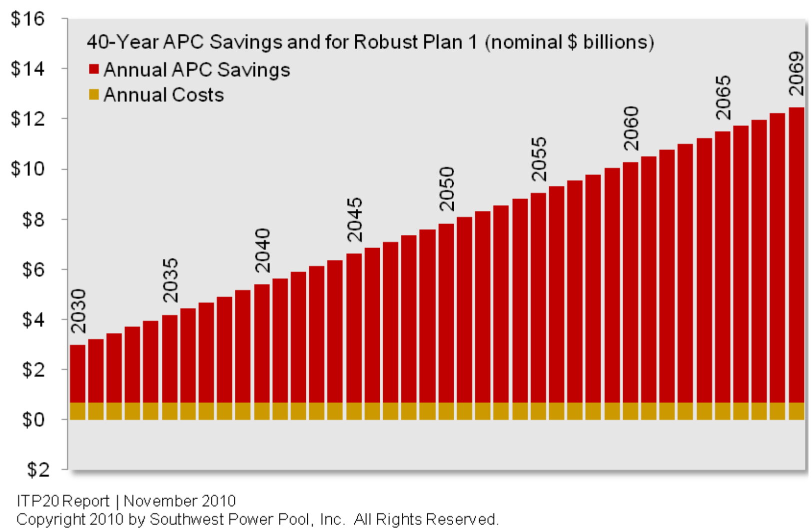


Figure 15.3: APC Savings averaged across all futures (nominal $ billions)

Benefit Growth

The calculation of the APC-based B/Cs for the forty-years utilized an average APC savings curve that was interpolated from the APC savings calculated for the years 2025, 2030 and 2035. This curve was applied across all futures in order to find the APC savings for each of the forty-years, starting with 2030 and ending with 2069. The sum of the APC savings for each of the forty-years is the total APC savings over the life of the asset. A similar methodology was utilized in the Balanced Portfolio and Priority Projects studies.

Carrying Costs

The carrying cost was determined by calculating an ATRR value from the construction costs. To determine the 2030 construction cost, the 2010 cost estimates were escalated to their 2030 value using a 2.5% rate for inflation. The sum of these values equaled the total cost of each Robust Plan.

Table 15.3 shows the APC-based B/Cs for a variety of the plans and demonstrates the excess savings created by this additional transmission over the entire life of the asset.

	APC Savings ($ billions)	40-Year APC-based B/C
Cost Effective Plan	65.7	5.22
Robust Plan 1	71.3	4.06
Robust Plan 2	71.9	3.11
Robust Plan 3	70.0	5.19
Robust Plan 4	69.1	1.40
Robust Plan 5	71.4	3.63
Robust Plan 6	71.2	2.85

Table 15.3: Forty-year APC Savings and APC-based B/Cs by Plan

[40] For more details visit the PSE website, December 2010.

15.4: Providing a Competitive Environment

The metrics measuring the levelization of LMP's are qualitative indicators of each plan's impact on generation owners' ability, across the SPP footprint, to compete on equal grounds due to the removal of congestion across the grid as a whole. This metric is indicative of the reduction in magnitude of price differences between load pockets. Two variations of this metric were considered: the first compared all LMPs within the system, the second compared LMPs at resources with similar fuel types.

Understanding Standard Deviation

The metrics measuring the competitiveness of resources did so by reporting the standard deviation of LMPs across the system. Standard deviation measures the variability or consistency of the data and maintains the dollar as the unit of measure. A large standard deviation implies that the LMPs are rather inconsistent and could be hard to predict; a small standard deviation indicates that LMPs are stable and consistent across the system. Figure 15.4 shows how a plan creates an environment that fosters competition by bringing the LMPs of the system more in-line with the average system LMP. The prices paid to the generation plants due to system congestion move closer together as the LMP's are levelized.

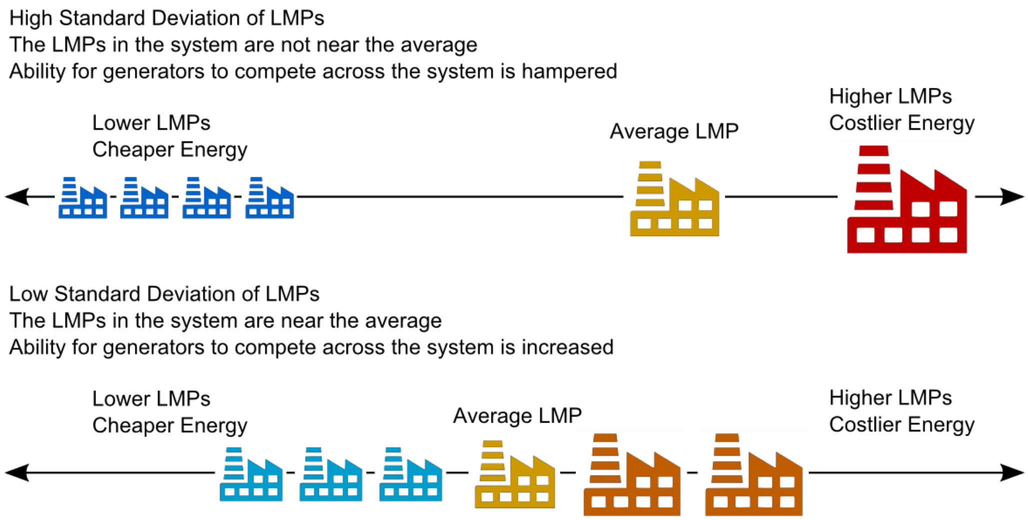


Figure 15.4: Standard Deviation of LMPs Example

The standard deviations calculated for each future and plan are listed in Appendix A3: Metric Results. These values were used to demonstrate the volatility of the system and the impact of each plan.

Geographic Variability Today and in 2030

The annual and monthly State of the Market Reports[41] for the SPP EIS market contains information paralleling this measurement of competitive equality. The measurement of regional volatility provided in these reports represent the standard deviation of the hourly price divided by the mean and while different, provide a point of reference to the standard deviation of LMPs across the system obtained in the ITP20. For the purposes of the ITP20, geographic variability can be similarly defined.

$$\text{Geographic Variability} = \frac{\text{Standard Deviation of the system LMPs}}{\text{Average of the system LMPs}}$$

The standard deviation calculated in the ITP20 under the Business as Usual future, without added transmission, was $110 and corresponded to a geographic variability of 51% given an average hourly LMP of $215 per MWh. The standard deviation and average LMP values are presented in Appendix A3: Metric Results.

[41] Refer to SPP.org > Market > Market Reports for the latest State of the Market Reports.

Visualizing LMP Geographic Variability

The variability of LMPs across the SPP system in real-time are presented on the SPP LIP Contour Map[42]. At specific 5-minute intervals the visualization changes to reflect the congestion on the system. The more varied these images, the greater the variability of the prices in the system. Within the ITP20, 8,760 discrete hours with unique LMPs were calculated. If these hours could be visualized similarly to the real-time prices, a reduction in variability would result in a consistent picture shown in every hourly snapshot.

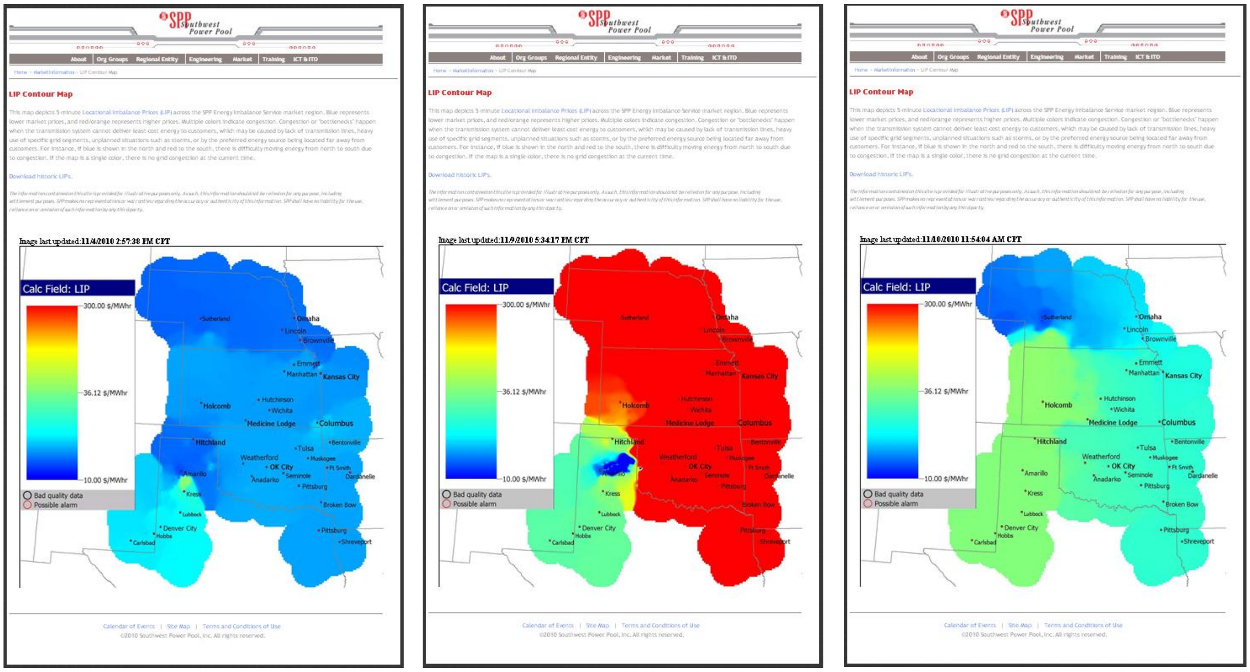


Figure 15.5: The SPP LIP Contour Map Visualizes Congestion at Different Times

System Wide Geographic Variability

The values in Table 15.4 reflect the reduction in system volatility due to each plan. Both load-weighted and generation-weighted LMPs were used in this calculation and given equal weight. A greater reduction indicated that the plan levelized LMPs to a greater extent and created a more level playing field to all generators within the footprint.

	Future 1	Future 2	Future 3	Future 4	Average
Base Case	51.2%	50.7%	44.0%	43.2%	51.2%
Cost-Effective Plan	47.7%	54.2%	41.0%	42.4%	47.7%
Robust Plan 1	44.1%	52.7%	37.5%	42.5%	44.1%
Robust Plan 2	45.5%	56.2%	38.7%	42.8%	45.5%
Robust Plan 3	45.4%	55.3%	38.0%	43.7%	45.4%
Robust Plan 4	43.4%	51.9%	35.2%	40.0%	43.4%
Robust Plan 5	42.6%	54.8%	37.6%	41.5%	42.6%
Robust Plan 6	45.1%	53.0%	36.6%	41.4%	45.1%

Table 15.4: LMP Volatility by Plan (%)

Technology Specific Geographic Variability

The values in Table 15.5 reflect the reduction in price volatility among similarly powered generators due to each plan. Both load-weighted and generation-weighted LMPs were used in this calculation and

[42] Refer to SPP.org > Market > LIP Contour Map for the latest LIP contour map.

given equal weight. A greater reduction indicated that the plan levelized LMPs to a greater extent and created a more level playing field among similar generators within the footprint.

	Future 1	Future 2	Future 3	Future 4	Average
Base Case	46.9%	50.3%	40.2%	41.4%	46.9%
Cost-Effective Plan	47.8%	55.8%	40.4%	42.6%	47.8%
Robust Plan 1	43.2%	55.2%	38.2%	43.0%	43.2%
Robust Plan 2	44.7%	58.2%	39.2%	43.3%	44.7%
Robust Plan 3	46.2%	58.4%	38.7%	45.3%	46.2%
Robust Plan 4	43.3%	53.7%	35.9%	40.4%	43.3%
Robust Plan 5	41.9%	56.6%	38.2%	42.2%	41.9%
Robust Plan 6	45.1%	54.9%	36.8%	42.5%	45.1%

Table 15.5: LMP Volatility by Plan (%)

Stabilizing Transmission

Inconsistent and unpredictable LMPs signify an unequal competitive field for generating resources and discourage generation development within the footprint because high price fluctuations cast uncertainty upon the future of these investments. Plans which stabilize prices will tend to eliminate price pockets in the region and promote generation development within SPP.

Each robust plan decreased the volatility, with the highest reductions coming in futures 1 and 3. On average, across all futures, the plans reduced the standard deviation of LMPs by $14. This reduction represents a 23% reduction in system volatility.

15.5: Increasing System Reliability

The measurement of the ability for power transfers to pass unhindered between zones while maintaining N-1 system integrity provided an indicator of each plan's impact upon long-term system reliability. Although minimum compliance with NERC TPL standards is maintained through the development of Near-Term ITP projects, actual system reliability and responsiveness to the N-2, 3 and 4 situations encountered every day in the operational horizon can be greatly improved through the selection of plans that provide additional transmission options and relieve congested corridors.

Understanding ATC Percentage Improvements

The metrics measuring the increased reliability provided by each plan did so by reporting the First Contingency Incremental Transfer Capability (FCITC) between each of the zones within SPP. The FCITC values represent the mega-watts of power that can be transferred from one zone in SPP to another without creating any thermal overloads due to the loss of a single line. Improvement due to each plan was determined by subtracting the transfer capability in the Base Case from the transfer capability due to the proposed plan for each zone. These values were aggregated in order to reflect a system-wide improvement in available transfer capability (ATC).

Figure 15.6 and its accompanying table provide an example of the system-wide aggregation used to determine the ATC improvement. The maximum ATC improvement out of an area was calculated by finding the difference between the capabilities before and after a transmission plan was applied. The result was then converted to a percentage of the original flow and averaged across all zones to provide a system-wide ATC improvement. In the example the system-wide ATC showed an improvement of 150%. Improvements to transfers B & F were averaged since they showed individually the highest improvement[43] for the transfers out of their zones.

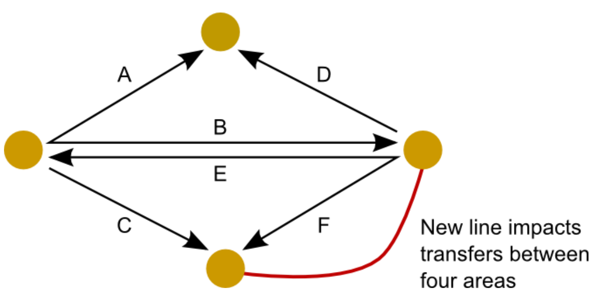


Figure 15.6: Illustration of ATC Transfer Calculations

Transfer:	A	B	C	D	E	F
Before (MW)	100	20	50	30	30	20
After (MW)	101	40	60	40	40	60
ATC Δ (MW)	1	20	10	10	10	40
ATC Δ (%)	1	100	20	25	25	200

Table 15.6: Illustration of ATC transfer calculations

Maximum ATC Improvement

The Improved Reliability metric captures the value of improved Available Transfer Capabilities (ATC) between areas in the SPP grid. This metric was performed only on a generic scenario and not any specific future because of software limitations that limited the ability for measurement of ATCs in each future and each generation dispatch scenario. These ATC do not take into account the availability of generation but only characterize the ability of the transmission system to accommodate changes in generation dispatch (and loads) if those were feasible.

	ATC Δ (%)
Cost-Effective Plan	253%
Robust Plan 1	255%
Robust Plan 2	261%
Robust Plan 3	254%
Robust Plan 4	269%
Robust Plan 5	257%
Robust Plan 6	257%

Table 15.7: Maximum ATC Improvement due to each plan

ATC Improvement by Zone

A more detailed look at the improvements to ATC due to each plan indicates that the plans generally increase not only

[43] The ESWG is currently discussing the usage of average improvement rather than the maximum improvement to ATC.

the maximum ATC but also the average ATC for all of the defined transfers. Figure 15.7 shows the trend of improvements in each zone due to Robust Plan 1. The maximum ATC due to the plan is marked by the top of the blue bar, the mimumum ATC due to the plan is marked by the bottom of the blue bar, and the red horizontal bar marks the average ATC due to the plan. The black wider bar and the yellow horizontal bar provide similar direction for the Base Case. Similar charts for each plan are included in Appendix A3: Metric Results.

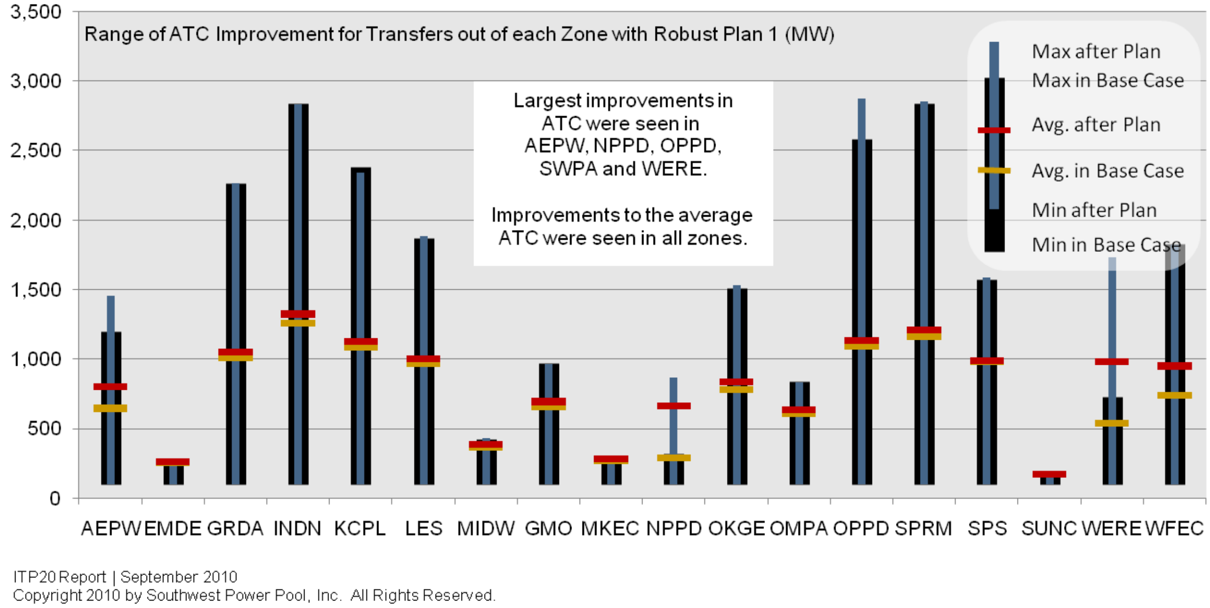


Figure 15.7: Range of ATC Improvement Gauge

MVA Design Efficiency

Each of the lines within the plans was rated at a certain MVA according to the voltage of the line. The sum of the projects' MVA can be compared against the total system-wide increase in ATC to determine how efficiently the line MVA capability was used. The MVA rating of a line is frequently compared to the MW flow over that line in stable conditions. The system-wide increase was calculated by summing the average change in each transfer for all zones. The highest efficiency was seen with Robust Plan 1 which created 45,597 MW of capacity with only 31,070 MVA of additional capacity 147% efficiency).

	Added Capacity (MVA)	System ATC Δ (MW)	Efficiency
Cost-Effective Plan	23,900	34,604	145%
Robust Plan 1	31,070	45,597	147%
Robust Plan 2	44,440	48,190	108%
Robust Plan 3	26,290	32,682	124%
Robust Plan 4	138,798	48,071	35%
Robust Plan 5	40,913	42,681	104%
Robust Plan 6	45,389	41,165	91%

Table 15.8: Comparison of MVA Design Efficiency

Reliability Focused Transmission Expansion

The maximum ATC improvement presented in Table 15.7 is one measurement of the increased ability for the system to respond to contingencies. Plans that substantially increase the ability of the grid to transfer power between each zone will increase the probability of reliable operation in the future.

15.6: Preparing for Unexpected Shifts in Load

The Ability to Serve New Load metric captures the value of the ability to serve new load at levels that are different from those considered in the economic analysis. Since the twenty-year load forecasts will be too high or too low for what actually occurs in 2030, it is important for the transmission system to be robust enough to handle a range of load levels.

To calculate this metric, all areas inside the SPP grid were setup as load centers. Load-to-Load transfers were setup between every control area, using Siemens PSS/MUST. The maximum ability to shift load was calculated by determining the transfer level that triggered a thermal overload.

Table 15.9 shows that, with the expansion plans, the average SPP area was able to shift a maximum between 350% and 380% more load than it previously could to a particular area, depending on the expansion plan. The table also shows that the average SPP area could have a maximum of 80% to 106% more load shifted to it from a particular area. Most SPP areas were able to shift over 100% more to another area, but only a few areas were able to receive over 100% more from another area. That is the reason that there is a difference between the two percentages for each expansion plan.

	Transfer to Load Centers	Transfer away from Load Centers
Cost-Effective Plan	80%	357%
Robust Plan 1	104%	352%
Robust Plan 2	106%	350%
Robust Plan 3	80%	357%
Robust Plan 4	79%	380%
Robust Plan 5	102%	372%
Robust Plan 6	102%	374%

Table 15.9: Ability to Serve New Load

15.7: Anticipating Import and Export Opportunities

The Limited Import/Export Improvements metric captures SPP's ability to increase both imports and exports with expansion plans. Though the focus of the ITP20 is to deliver energy to market within SPP, a robust grid will be able to facilitate the transfer of power across the seams.

To calculate this metric, the SPP areas, as well as all SPP Tier 1 control areas, were set up as generation centers. There were three types of generation-to-generation transfers performed using Siemens PSS/MUST:

- SPP areas to SPP Tier 1 areas (Incremental Export ATC)
- SPP Tier 1 to SPP areas (Incremental Import ATC)
- SPP Tier 1 to areas inside SPP that have transmission ties to the Tier 1 area (Incremental Wheel-Through ATC)

The maximum ATC was calculated by determining the transfer level that triggered a thermal overload. Table 15.10 shows that, with the expansion plans, the average SPP area had a maximum ATC increase between 160% and 174% to export to a Tier 1 area, depending on the expansion plan. Limited Import/Export Improvements metric captures the ability to increase both imports and exports.

	ATC Δ (%)
Cost-Effective Plan	166%
Robust Plan 1	174%
Robust Plan 2	160%
Robust Plan 3	172%
Robust Plan 4	170%
Robust Plan 5	173%
Robust Plan 6	174%

Table 15.10: Average ATC Increase Across Seams

Table 15.11 shows that, with the expansion plans, the average Tier 1 area had a maximum ATC increase between 376% and 397% to import to an SPP area, depending on the expansion plan. The reason for the larger percentages in the import table, compared to the export table, is that there were more than four times as many SPP areas for the Tier 1 areas to attempt transfers to. Therefore, the percentages between plans should be compared and not percentages between imports and exports. Also, these tables show that the expansion plans increase both the ability to import and export power across the seams.

	ATC Δ (%)
Cost-Effective Plan	381%
Robust Plan 1	387%
Robust Plan 2	382%
Robust Plan 3	378%
Robust Plan 4	397%
Robust Plan 5	376%
Robust Plan 6	376%

Table 15.11: Average Increase of ATC that can be Imported

	ATC Δ (%)
Cost-Effective Plan	26%
Robust Plan 1	32%
Robust Plan 2	92%
Robust Plan 3	27%
Robust Plan 4	24%
Robust Plan 5	29%
Robust Plan 6	29%

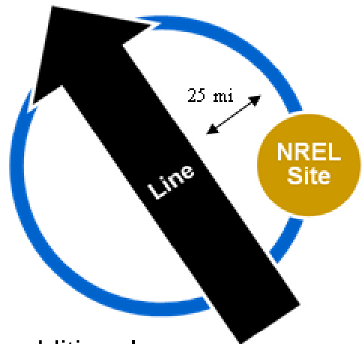
Table 15.12: Average Increase of ATC that can be Imported (Wheel-through)

Table 15.12 shows that, with the expansion plans, the average Tier 1 area had a maximum ATC increase between 26% and 92% to import to an SPP area with transmission tie(s), depending on the expansion plan. The reason for the smaller percentages in the wheel-through import table, compared to the previous import table, is that there were fewer SPP areas for the Tier 1 areas to attempt transfers to. Only transfers between areas that had transmission ties were considered. Therefore, the percentages between plans should be compared and not percentages between the two types of import analyses. Robust Plan 2 had a larger increase in ATC that can be imported from Tier 1 areas with direct ties primarily because of the Ozark plan and LaCygne to Mariosa Delta 345 kV line. Also, the plans that had the Turk to McNeil 345 kV project and the Dolet Hills to Messick 345 kV project had higher imports from Entergy.

15.8: Broadening Resource Siting Options

The Enable Efficient Location of New Generation Capacity metric is an indicator of the ability of the respective transmission plans to access high capacity resources. This metric specifically targets renewable resources in high wind areas.

Scoring Method



A scoring methodology is used to evaluate each plan for this metric. Every wind location within 25 miles of a proposed transmission line received a score based on the expected capacity factor of that wind location. A greater than 42% capacity factor = 4, 38% - 42% = 3, 34% - 38% = 2, and all others = 1. E.g., for Cost-Effective Plan a score of 317 is calculated as follows: (43 x 4) + (41 x 3) + (11 x 2) + (0 x 1) = 317.

This metric provides a relative evaluation of the ability of the transmission plans to access high capacity wind locations. Access to high capacity wind locations will allow utilities to meet renewable standards more efficiently. With additional information regarding high value locations for thermal generation it will be possible to calculate this metric for thermal generation as well. Robust Plan 5 and Robust Plan 6 follow the same proposed ROW as Robust Plan 1.

	Number of 42% + Capacity Factor Areas	Number of 38 - 42% Capacity Factor Areas	Number of 34 - 38% Capacity Factor Areas	Number of Below 34% Capacity Factor Areas	Score
Cost-Effective Plan	43	41	11	0	317
Robust Plan 1	42	42	11	7	323
Robust Plan 2	44	45	13	15	352
Robust Plan 3	43	41	11	0	317
Robust Plan 4	50	69	16	0	439
Robust Plan 5	42	42	11	7	323
Robust Plan 6	42	42	11	7	323

Table 15.13: Enable Efficient Location of New Generation Capacity

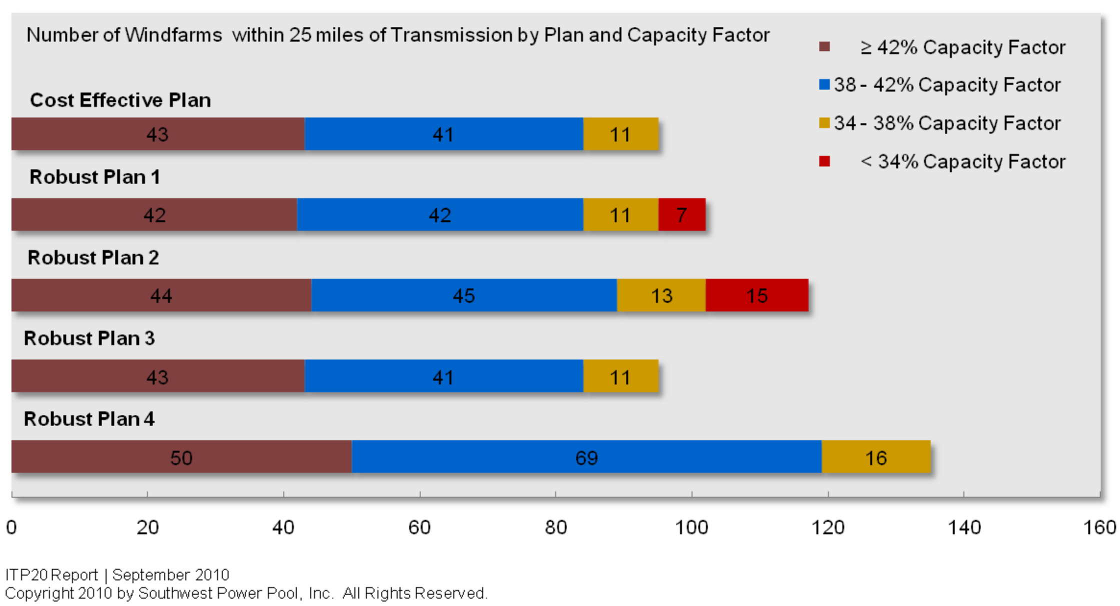


Figure 15.8: Number of Windfarms within 25 miles by Plan and Capacity Factor

15.9: Valuing Cleaner Air

Emission rates across the SPP footprint are a direct result of the generation mix utilized in each hour of year and can be reduced by the efficient selection of cleaner burning power plants. As transmission expansion enables cleaner generation to reach load centers, the amount of carbon dioxide (CO_2), sulphur dioxide (SO_2), nitrogen oxides (NO_X), and other effluents bleeding into the air will be reduced. Flagged as potential health and environmental hazards by organizations such as the U.S. Environmental Protection Agency (EPA), these effluents can be reduced by making a priority of ensuring that transmission limitations are not the cause of inefficient generation schemes.

Understanding Emissions Rates

Emission rates captured in the ITP20 are reported in short tons (tons) and lbs per megawatt hour (lbs/MWh). The estimations shown in Figure 15.9 provide everyday context to these numbers.[44] Gross emission rates for all SPP resources are shown in tons; emission rates per megawatt hour are shown in lbs/MWh to allow comparisons between futures with different exports from SPP.

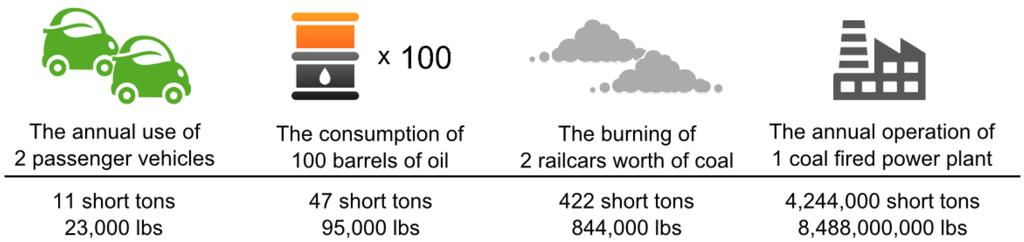


Figure 15.9: Carbon Dioxide Emission Rates in Everyday Terms

Carbon Dioxide (CO_2)

The emission of carbon dioxide is a natural consequence of the burning of fossil fuels such as coal and natural gas. The EPA has catalogued the increase in global atmospheric concentrations of CO_2 for many years and identified the reduction of this greenhouse gas as a priority due to the impact this gas may be having upon the temperature of the atmosphere and its known health effects.

Sulphur Dioxide (SO_2)

Fossil fueled power plants and industrial facilities constitute the largest sources of SO_2 emissions in the US and have been regulated by the EPA since 1971.[45] Like carbon dioxide, the gas has been identified as a potential health hazard and emissions are limited by EPA regulations.

Nitrogen Oxides (NO_X)

This family of gases includes nitric oxide (NO) and nitrogen dioxide (NO_2). These gases contribute to the formation of ozone in the warm or sunlit environments and are recognized as a respiratory health hazard. According to the EPA, 22% of NO_X emissions are a result of utilities.[46] Emissions of NO_2 are regulated through the Clean Air Act by the EPA.

SPP Emissions in Everyday Terms

Emissions rates were highest in future 1 for all tested transmission plans and lowest in future 4 for all topologies except the Base Case. The annual emissions of the SPP footprint under the Business as Usual future, without added transmission, was equivalent to the annual use of more than 21 million passenger vehicles or the operation of 56 coal fired power plants.

Each robust plan decreased emissions rates. The highest reductions were seen in futures 2 and 4 due to the added wind capacity. On average, across all futures, the plans reduced emissions by 39

[44] Calculations based upon the EPA Greenhouse Gas Equivalencies Calculator, October 2010.
[45] Regulation information concerning SO_2 can be found at the EPA's website, October 2010.
[46] Nitrogen Oxides sources from the EPA website, October 2010.

lbs/MWh or 9.5 million tons annually. This reduction equivalently offsets the emissions of more than 2 coal-fired power plants operated each year.

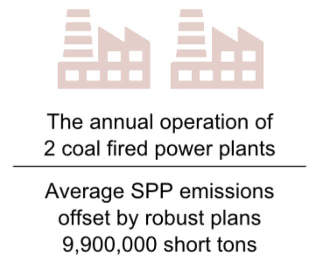


Figure 15.10: Emissions offset by robust plans

The Dollar Cost of Emissions

The APC benefit described in Section 15.2: Creating Adjusted Production Cost Savings captures the monetary cost associated with emission rates. The allowance costs imposed upon producers of these gases form a substantial part of the total APC. The relationship between the total APC and the portion of the APC directly related to emissions allowances is shown in Figure 15.11. The sharp increase in emissions related costs in futures 3 and 4 was a product of the carbon tax (see Section 7: Resource Futures and Plan). ;Costs related to emissions constituted more than half of total APC for futures including the carbon tax and only a small portion of the total APC in the other futures when no additional transmission was added.

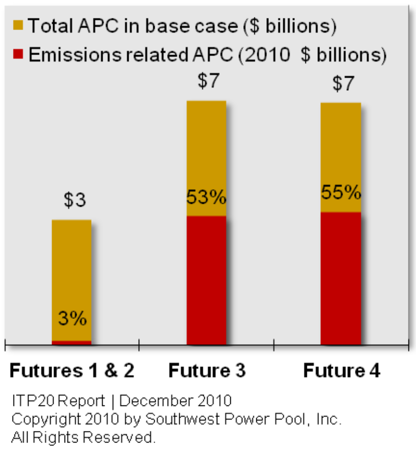


Figure 15.11: Emissions Costs versus the total APC in the Base Case

Transmission expansion that reduces emissions rates will drive the APC down and create opportunities to provide greater savings if stricter climate legislation with higher taxes is enacted. The robust transmission plans reduced emissions from Base Case levels in all of the futures and provided an average annual savings of $83 million to SPP. Emissions rates were consistent across each of the futures but due to wind capacity increases and added carbon taxes the savings were primarily in futures 3 and 4. Detailed simulation results regarding the reduction of effluents per future with each transmission plan can be found in Appendix A3: Metric Results. Figure 15.12 shows the dollar savings relative to the Base Case in each future.

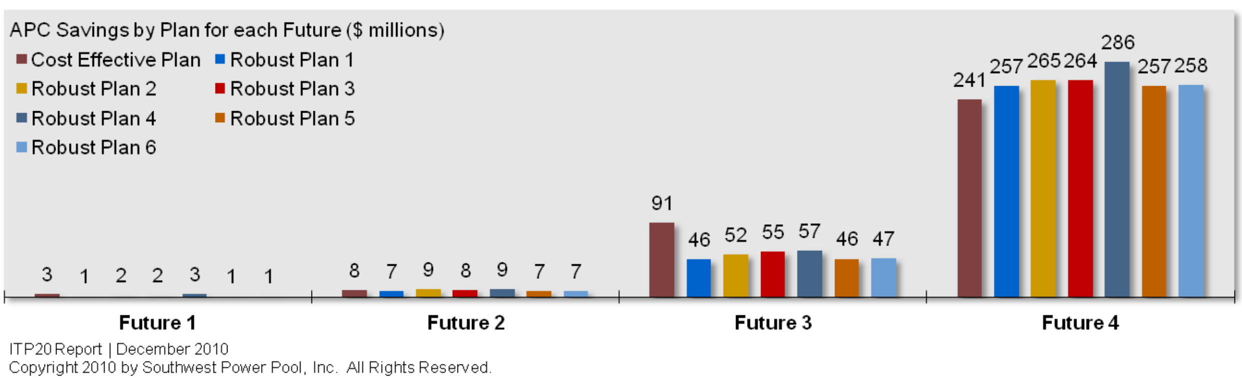


Figure 15.12: Emissions Savings by Plan for each Future ($ millions) relative to the Base Case

Emissions Reducing Transmission

The Reduction of Emission Rates metric captures the ability of the robust plans to respond to policy and economic decisions which require the reduction of emissions. Electric generation and load are forecasted to continue increasing throughout the county and the transmission grid's role in the continued management of the resulting effluents may become an even more important role in the future. All four of the robust plans provide the flexibility to respond to policy decisions and promise to equip SPP with improved air quality and a decreased tax burden through the reduction of emissions due to the generation of electricity.

15.10: Reducing Risk through Responsible Land Usage

Whenever transmission is built land must be acquired upon which the towers are erected. The risk of running into complications in the acquisition of this right-of-way (ROW) can be minimized by the appropriate selection of termination points and equipment voltages for each proposed transmission project. Management of the needs of citizens and communities near proposed transmission routes, habitats and environments of native species and the economics and scheduling constraints of project construction is required of SPP's members throughout the construction process. By remaining vigilant in the proposal of termination points and voltage levels SPP can reduce the risks that the completion of the project might not be timely or within the expected cost.

Helping our Members Reduce Risk

Detailed siting analysis and routing decisions are performed by SPP's members during the design of transmission projects. The selection of termination points and voltage levels for these projects, during the planning phase by SPP staff, can unnecessarily limit the options available to SPP members as they seek to balance the economic, environmental and societal factors that inform their transmission siting decisions. Four opportunities to minimize these risks were considered in the ITP20: a reduction in total line length through selection of termination points, identification of environmentally sensitive areas, utilization of existing ROW, and minimization of ROW width by the selection of higher voltage circuits.

Utilizing Existing Right of Way

Existing, constructed EHV Transmission throughout the nine-state SPP footprint currently includes more than 6,700 miles of lines 345 kV and above.[47] The proposed robust transmission plans would augment that existing grid by adding from 1,494 to 2,626 additional miles of transmission. Not all of this transmission mileage exists on its own ROW. In fact, transmission owners frequently search for efficiencies by locating transmission on shared ROWs. Generally speaking, acquiring new ROW is more difficult than the utilization or expansion of existing ROWs and can be expensive and time consuming.

Figure 15.13 compares the mileage of transmission proposed in each of the four robust plans and the Cost-Effective Plan with the length of the Mississippi River[48]. New ROW is denoted with dashed lines, corridors that may be routed along existing ROWs within SPP are shown with solid lines.

Figure 15.13: Total ROW by Plan Compared to Mississippi River Length

Environmental Concerns

A second component of the Transmission Corridor Utilization metric is reviewing the number of miles of the SPP transmission plans that potentially pass through nationally protected areas. Acquiring ROW through these areas may be more difficult than privately owned areas. Lines which are currently planned to route through these sensitive areas may need to be rerouted, which could add additional cost to the plan. This metric provides a review of those plans which have the highest risk of additional cost being added due to

[47] SPP.org > About > Fast Facts
[48] According to the National Park Service website, October 2010.

routing around environmentally sensitive areas. A comparison of the ROW through sensitive areas needed by each robust plan to the size of Manhattan's Central Park is shown in Figure 15.14. A ROW width of 150 ft and 200 ft are assumed for 345 kV and 765 kV lines.

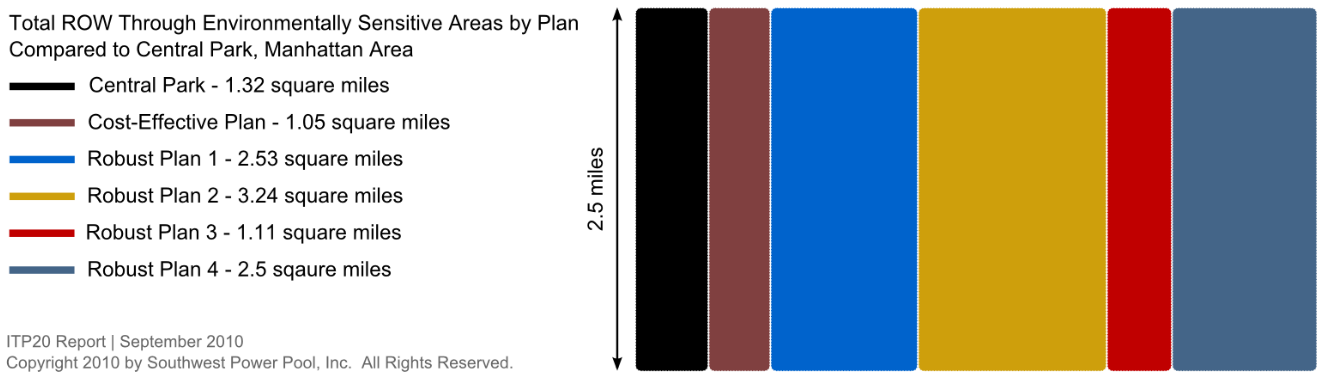


Figure 15.14: Total ROW through Environmentally Sensitive Areas by Plan Compared to Central Park

ROW Usage Equivalents

The ESWG determined to augment the use of sensitive ROW through an additional calculation that highlights the total plan land usage by providing an equivalent ratio of total ROW mileage and sensitive ROW. A cursory review with OPPD staff members who deal with ROW issues indicated that sensitive ROW might be ten times more difficult to obtain than non-sensitive ROW. This factor was utilized in order to find the total equivalent miles of ROW for each plan (shown in Table 15.14).

	Sensitive Miles	Non-Sensitive Miles	Equivalent Miles
Cost Effective Plan	37	1,457	1,827
Robust Plan 1	89	1,989	2,879
Robust Plan 2	114	2,512	3,652
Robust Plan 3	39	1,535	1,925
Robust Plan 4	66	2,824	3,484
Robust Plan 5	89	1,989	2,879
Robust Plan 6	89	1,989	2,879

Table 15.14: ROW Usage Equivalent (miles)

ROW Capacity Efficiency

An additional approach to efficient land use measures the ability of the same ROW to support more capacity due to different transmission technologies (see Section 3: Utilization of 345, 500, or 765 kV, particularly Figure 3.3, for a more complete discussion). The sum of the projects' MVA can be compared against the total ROW length to determine how efficiently the line MVA capability was used. The highest efficiency was seen with Robust Plan 4 which utilized the most 765 kV lines.

	Added Capacity (MVA)	ROW Usage (mi)	Efficiency (MVA/mi)
Cost-Effective Plan	23,900	1,494	16.00
Robust Plan 1	31,070	2,078	14.95
Robust Plan 2	44,440	2,626	16.92
Robust Plan 3	26,290	1,574	16.70
Robust Plan 4	138,798	2,890	48.03
Robust Plan 5	40,913	2,078	19.69
Robust Plan 6	45,389	2,078	21.84

Table 15.15: Comparison of ROW Capacity Efficiency

Efficiently Routed Transmission

The efficient use of existing ROW and the avoidance of environmentally sensitive areas capture the costs to the environment due to the ROW for each plan. The robust plans utilize new, existing, or expanding ROWs.

Typically plans with the most additional new transmission will require more miles of new ROW than those with less additional transmission. However, Robust Plan 2 which requires the most miles of additional ROW also uses the highest percentage of existing ROW. Robust Plan 5 and 6 utilize the same ROW as Robust Plan 1 but add more capacity for the same ROW usage.

15.11: Increasing Efficiency with Reduced Transmission Losses

Transmission line losses result from the physical interaction of line materials with the energy flowing over the line and constitute an inefficiency that is inherent to all standard conductors. Line losses across the SPP system are directly related to system impedance. When additional lines are added to create parallel paths with the footprint, losses are reduced.

Understanding Transmission Losses

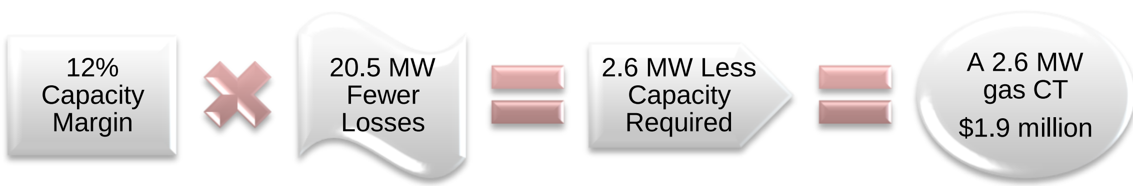
Losses result primarily from heat created by power flows across transmission lines. These losses are similar to the energy lost during the use of an incandescent light bulb. Compared to a compact fluorescent bulb (CFL), an incandescent bulb emits a good deal of heat. The heat felt when changing the incandescent bulb is lost energy, just like transmission line losses. Additional transmission can increase system efficiency and reduce the amount of energy lost to heat just as CFLs decrease residential electric lighting bills.

Total SPP transmission losses in the Base Case (at summer peak with 2019 load) were 1,900 MW. This was equivalent to the capacities of two coal fired plants and one combustion turbine similar to those adopted in the resource plan (See Appendix A5: Resource Siting and Plans).

The Dollar Cost of Losses

The APC benefit described in Section 15.2: Creating Adjusted Production Cost Savings captures the monetary cost associated with the reduced need for energy due to lower losses. The benefit of offsetting installed capacity is not captured by the APC calculations but instead can be estimated by calculating the 12% capacity margin offset by the reduced need for the installed capacity. Please note that this approximation was not calculated with a complete resource plan and could change if all resource options for all SPP capacity needs were reconsidered.

Utilizing approximations provided by the Benefit Analysis Techniques Task Force (BATTF) of $750 per kW hour of installed capacity, the amount saved by offsetting the required capacity through reduction of losses was equivalent to a 2.5 MW generator, or approximately $1.9 million in annual savings.



Robust Plan 2 provided the greatest losses reduction. All of robust plans reduced losses by more than 20.5 MW as shown in Figure 15.15.

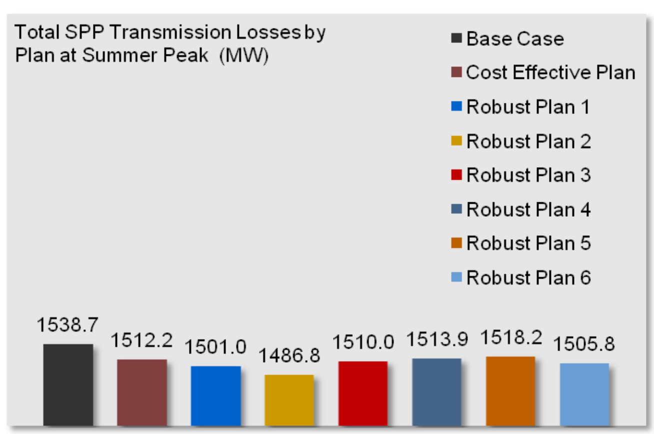


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Figure 15.15: Total SPP Transmission Losses by Plan at Summer Peak (MW)

15.12: Portfolio Performance

Metric Weighting

The ESWG determined the importance of each of the calculated metrics by performing a simple member vote. The resulting weights are presented in Table 15.16. The metrics are sorted by the weighting. Voting results by ESWG member are presented in Appendix A3: Metric Results.

Metric No.	Metric Description	Weighting
1.1.2	Value of Improved ATCs in the SPP Grid	202.33
2	Levelization of LMPs	133.33
6	Limited Import/Export Improvements	112.50
14	Ability to Serve New Load	108.00
3	Improved Competition in SPP Markets	93.33
1.6	Positive Impact on Losses Capacity	92.00
1.2	Enable Efficient Location of New Generation	81.83
11.1	Existing ROW Utilization	58.00
13	Generation Resource Diversity	57.00
11.2	Sensitive ROW Utilization	32.00
10	Reduction of Emission Rates and Values	29.67

Table 15.16: ESWG determined Metric Weights

Metric Scoring

Eleven metrics were calculated for the robust plans. Many of the metrics were calculated using different units with a wide range of magnitudes. To better compare the plans and the metrics, SPP scored the values using a scale of 100. The top performing plan in a given metric received a score of 100. The additional plans were then given a score as they related to the top performing plan (i.e. if the top performing plan had a value of 200 and the second best performing plan had a value of 180, the top performing plan's score would be 100 with the second plan receiving a score of 90). That is, each of the metrics was normalized to the top performing plan in that metric. Table 15.17 summarizes the performance of each plan in each of the metrics. These scores were based on averaging the results of the analysis in all four futures. The table headers CE, RP1, RP2, etc. refer to the Cost-Effective Plan and the robust plans by number.

Metric No.	Unit	CE	RP1	RP2	RP3	RP4	RP5	RP6
1.1.2	%	253%	255%	261%	254%	269%	257%	257%
2	$	-$12	-$15	-$14	-$12	-$23	-$16	-$15
6	%	191%	198%	211%	192%	197%	192%	193%
14	%	218%	228%	228%	218%	230%	237%	238%
3	$	-$9	-$12	-$9	-$8	-$20	-$12	-$12
1.6	MW	-27	-38	-52	-29	-25	-21	-33
1.2	score	317	323	352	317	439	323	323
11.1	%	44%	39%	36%	45%	30%	39%	39%
13	$	$0.018	$0.011	$0.019	$0.029	$0.001	$0.011	$0.013
11.2	%	98%	96%	96%	98%	98%	96%	96%
10	lbs/MWh	35.43	39.48	40.06	39.83	40.20	39.50	39.50

Table 15.17: Portfolio Performance Benchmarks

Scoring Values & Methods

Normalization of these numbers was obtained through two separately taken avenues by the ESWG. Further development will occur in future ITP cycles and this analysis is primarily presented in order to lead-the-way in treating results in future studies. The first method proposed was a linear scaling of the values based upon the highest scoring plan for each metric. The second was a normalized scoring that utilized the mean and standard deviation of each set of metric scores.

Linear Scoring

A linear scale was derived for each metric's data such that each value for all of the plans was divided by the highest scoring plan's score for that metric. This created a linear scale of zero to one-hundred percent.

Metric No.	Weight	CE	RP1	RP2	RP3	RP4	RP5	RP6
1.1.2	20.2%	94%	95%	97%	94%	100%	96%	96%
2	13.3%	52%	65%	61%	52%	100%	70%	65%
6	11.3%	82%	91%	100%	88%	83%	85%	86%
14	10.8%	92%	96%	96%	92%	96%	100%	100%
3	9.3%	45%	60%	45%	40%	100%	60%	60%
1.6	9.2%	51%	73%	100%	55%	48%	39%	63%
1.2	8.2%	72%	74%	80%	72%	100%	74%	74%
11.1	5.8%	99%	88%	81%	100%	67%	88%	88%
13	5.7%	0%	100%	100%	100%	100%	0%	0%
11.2	3.2%	100%	98%	98%	100%	100%	98%	98%
10	3.0%	88%	98%	100%	99%	100%	98%	98%
Total	**100%**	**775%**	**938%**	**958%**	**892%**	**994%**	**808%**	**828%**

Table 15.18: Linear Metric Scores

Normalized Scoring

A normalized method was devised based upon the normal distribution rules used in statistical analysis. In this calculation the mean and standard deviation of each metric's scores for all of the plans was determined. The distance of each score from the mean, in standard deviations, determined the score for that plan. Each standard deviation represented a 25% change in score.

Metric No.	Weight	CE	RP1	RP2	RP3	RP4	RP5	RP6
1.1.2	20.2%	25%	25%	63%	25%	75%	38%	38%
2	13.3%	25%	38%	38%	25%	100%	50%	38%
6	11.3%	25%	50%	100%	25%	38%	25%	25%
14	10.8%	0%	38%	50%	0%	50%	75%	75%
3	9.3%	25%	50%	25%	25%	100%	50%	50%
1.6	9.2%	25%	63%	75%	38%	25%	0%	50%
1.2	8.2%	63%	50%	38%	63%	0%	50%	50%
11.1	5.8%	75%	50%	25%	75%	0%	50%	50%
13	5.7%	50%	50%	50%	50%	50%	50%	50%
11.2	3.2%	75%	25%	25%	75%	75%	25%	25%
10	3.0%	0%	50%	63%	50%	63%	50%	50%
Total	**100%**	**388%**	**489%**	**552%**	**451%**	**576%**	**463%**	**501%**

Table 15.19: Normalized Metric Scores

These methods were discussed extensively by the ESWG. The group determined that the scoring methods are necessary until a consistent unit is available for all of the metrics (preferably dollars). The linear method provides insight into the similar performance achieved by each plan, but the normalized method highlights that a small linear difference may actually indicate a substantial performance change. As the metrics are developed in future ITP cycles more clarity will be gained in these aspects.

Metric Performance Rankings

The metric weights were applied to each scoring method to determine a final ranking of each project by the metrics. This ranking indicated that the most extensive transmission upgrades and use of 765 kV transmission lines in Robust Plan 4 achieved the highest metric performance. Robust plans 1 and 2 showed the highest performance in plans not utilizing 765 kV elements.

Method	CE	RP1	RP2	RP3	RP4	RP5	RP6
Linear	715	779	801	726	853	753	771
Normalized	277	409	479	332	526	391	435

Table 15.20: Weighted Metric Scoring Results by Plan

A comparison of the ranking of each plan according to the robustness metrics indicated that the use of a linear or normalized scoring method introduced little change to the rankings for the plans studied.

Method	CE	RP1	RP2	RP3	RP4	RP5	RP6
Linear	7	3	2	6	1	5	4
Normalized	7	4	2	6	1	5	3

Table 15.21: Weighted Metric Rankings by Plan

Portfolio Dashboard

In addition to the performance of the portfolios across robustness metrics, the ESWG considered the ranking of each design according to APC savings, cost, and APC-based B/C, average across all futures. For additional information the group has included the incremental cost and benefit above the Cost-Effective Plan for each of the robust plans. The future specific data corresponding to these tables is shown in Appendix A3: Metric Results.

	CE	RP1	RP2	RP3	RP4	RP5	RP6
Cost ($ millions)	$1,755	$2,454	$3,220	$1,881	$6,876	$2,745	$3,480
APC Savings ($ millions)	$1,542	$1,811	$1,837	$1,748	$1,703	$1,816	$1,804
APC-based B/C	5.17	4.34	3.36	5.47	1.46	3.89	3.05
Linear Metric Score	715	779	801	726	853	753	771
Normalized Metric Score	277	409	479	332	526	391	435
Cost Rank	1	3	5	2	7	4	6
APC-base B/C Rank	2	3	5	1	7	4	6
Linear Metric Rank	7	3	2	6	1	5	4
Normalized Metric Rank	7	4	2	6	1	5	3

Table 15.22: Portfolio Performance Dashboard (averaged across all futures)

	RP1	RP2	RP3	RP4	RP5	RP6
Incremental Cost ($ millions)	$699	$1,465	$126	$5,121	$990	$1,726
Annual Incremental Cost ($ millions)	$119	$349	$21	$871	$168	$293
Incremental APC Savings ($ millions)	$269	$295	$206	$161	$274	$262
Annual Net Cost ($ millions)	$-150	$54	$-185	$710	$-106	$31
Incremental APC-based B/C	2.26	0.85	9.81	0.18	1.63	0.89

Table 15.23: Incremental Cost over the Cost-Effective Plan (averaged across all futures)

Section 16: Success Measures

16.1: Integrating West to East Transfer

The SPP transmission system has large potential for renewable resources in the western portion of the region. However, the large load centers in the system are primarily located in the east. Integrating the western and eastern portions of the system will allow for the transfer of renewable resources to those load centers in the east. This integration could also support the transfer of energy beyond the SPP borders. Several of the robustness metrics used to examine the transmission system were based on transfer capability analysis. Those were:

- Metric 1.1.2: Improvement in Reliability
- Metric 6: Limited Import/Export Improvements
- Metric 14: Ability to Serve Unexpected New Load

The listed metrics are discussed in further detail in Section 6: Metric and results are shown in Section 15: Benefits. Results of the metrics indicated that transfer capability increased throughout the footprint once the recommended Robust Plan was added.

16.2: Supporting Aggregate Transmission Service Studies

Aggregate transmission service studies (ATSS or aggregate study) often identify upgrades required for the granting of transmission service. The ITP projects identified may be similar to or may address similar transmission constraints as those identified and proposed in the aggregate study. Adding those correlating upgrades or fixing those common issues in the ITP may allow greater access to the transmission system by customers. Table 16.1 details a few examples.

Aggregate Transmission Service Study Project				ITP20 Project		
NTC	**Area**	**Project**	**Description**	**Project**	**Description**	**Correlation to ATSS**
20116	KCPL	Stilwell - West Gardner 345 kV CKT1	Upgrade Stilwell terminal equipment to 2000A	Stilwell - West Gardner 345 kV CKT1	Need for new terminal equipment showed up in ITP20 analysis as well	If the ATSS had not identified this upgrade, then the ITP20 would have, as the overload also showed up in ITP20 results. The upgrade of the terminal equipment addressed the thermal issues.
20108	WERE	East Manhattan - Jeffrey Energy Center 230 kV CKT1	Rebuild existing line to 345 kV operated as 230 kV, replace terminal equipment	Post Rock - Elm Creek - Jeffrey Energy Center	Build new 345 kV transformer at Elm Creek, build 276 miles of 345 kV line	This ITP20 project could replace the ATSS project or be modified to account for it, as they are both being added to the same transmission corridor.
20055	OKGE	Rose Hill - Sooner 345 kV CKT1	Build approximately 100 miles of 345 kV.	Rose Hill - Sooner 765 kV	Build approximately 100 miles of 765 kV.	This new 345 kV line upgrade that came out of ATSS was very important in ITP20 high voltage analysis. If 765 kV backbone plan is used (Robust Plan 4), this proposed line would be one of the main pieces of that backbone.

Table 16.1: ATSS and ITP20 Project Correlation

Due to the strong correlation between the Aggregate Study projects and the ITP, the ITP20 plan will provide the necessary foundation for addressing SPP's Aggregate Transmission Service needs.

16.3: Supporting Generation Interconnection Queue

Similar to the aggregate study, the generator interconnection (GI) process often identifies transmission upgrades that are required in order to support the construction of new generating units. There may be ITP projects that support or remove the need for some of the upgrades that are commonly identified in the GI study process. To the extent the ITP contains some of those correlating projects or fixes some of the common issues identified, generator interconnections may be more easily accommodated.

There are a number of projects in our current plan that either accomplish the same objective as the GI upgrade or mitigate an issue commonly identified in the GI studies. Table 16.2 details a few examples.

Generation Interconnection Study Project			ITP20 Project		
Int Request	Upgrade	Description	Project	Description	Correlation to GIS
GEN-2009-063	Woodward District EHV - Woodring 345 kV CKT1	Build approximately 100 miles of 345 kV.	Woodward District EHV - Woodring 345 kV	Build 99.6 miles of 345 kV	The 345 kV Woodward District EHV - OKC constraint showed up in both studies and so the 345 kV Woodward District EHV - Woodring line was proposed in both.
GEN-2010-029	Mullergren - Spearville 230 kV CKT2	Build approximately 62 miles of 230 kV, second circuit.	Spearville - Mullergren - Circle – Reno	Build new 345 kV xfmr's at Mullergren & Circle, build 158 miles of 345 kV line	The need for additional transfer capacity from Spearville - Mullergren was identified in both studies. In a GI study, it was mitigated with an additional 230 kV line. In the ITP20 it is mitigated with 345 kV line.
FCS-2009-003	Spearville - Reno 345 kV	Build 100+ mile new 345 kV line.	Spearville - Mullergren - Circle – Reno	Build new 345 kV xfmr's at Mullergren & Circle, build 158 miles of 345 kV line	GI study identified need for new 345 kV line to get new wind generation from west to east. ITP20 also identified need for new 345 kV west-east line here and has it routed a little differently.

Table 16.2: GIS and ITP20 Project Correlation

Due to the strong correlation between the GI study projects and the ITP, the ITP20 plan will provide a good transmission basis to satisfy the needs of the new generation interconnection requests.

16.4: Relieving Known Congestion

Congestion on the transmission system may cause higher electricity prices, redispatches, or curtailments. By relieving this congestion, more generation may be able to participate in the market, which could reduce total cost to customers. Reduction in congestion can be measured by congestion costs and levelization of LMPs. For the recommended plan to succeed, a reduction in these measures is desired.

Congestion Cost Reduction

Congestion cost is a component of APC but may be measured individually to illustrate the reduction in congestion. Congestion cost is the difference in demand cost and generation cost. One measure of congestion cost is to calculate the difference in load-weighted LMP and generation-weighted LMP. Table 16.3 shows how the measure of congestion has a lower value when comparing the robust plans to the Base Case, with no ITP20 expansion plan. To compile the data for this table, the average generation-weighted LMP in each area was calculated and averaged across the footprint and subtracted from the average load-weighted LMP in each area.

Plan	Load and Gen LMPs Δ
Base Case	7.11
Robust Plan 1	3.05
Robust Plan 2	2.61
Robust Plan 3	3.20
Robust Plan 4	1.56
Robust Plan 5	3.08
Robust Plan 6	3.21

Table 16.3: Difference between load and gen LMPs

Levelization of LMPs

Levelization of LMPs is a measure of the difference between the maximum and minimum LMPs on the system. As the difference between the maximum and minimum LMPs is reduced, the energy cost to consumers is likely to be reduced as well. The results in Figure 17.1 illustrate the levelization of LMPs. The standard deviation of the LMPs was decreased by each of the robust plans.

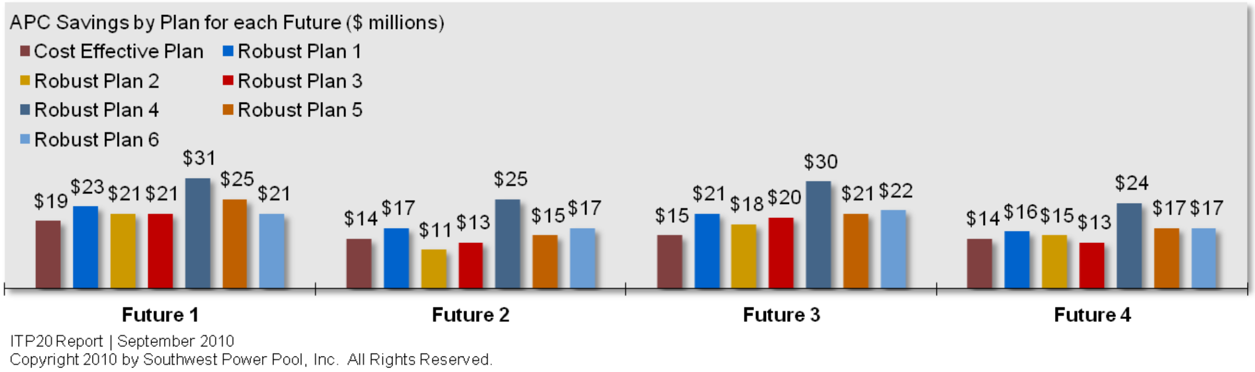

Figure 16.1: Standard Deviation Reduction of LMPs by plan

16.5: Byway System Accessing the Transmission Highway

A transmission highway system that does not provide adequate deliverability to the underlying system will provide limited benefits. In order to ensure the byway system will have access to the EHV overlay, key connection points will be identified. Those connection points will be evaluated to determine if they provide adequate capability for moving power to and from the EHV overlay system. While attempts have been made in the ITP20 to place EHV connections at stations with adequate deliverability, the study focused primarily on 345 kV and higher projects. The Ten-Year ITP (ITP10) study will focus more on the byway system, and how that system will integrate with the ITP20 projects. This measure will be revisited in the next ITP20 cycle.

16.6: Land Use Policy Task Force

The Land Use Policy Task Force (LUPTF) was proposed and approved by the Markets and Operations Policy Committee (MOPC) to establish policy recommendations regarding land use issues associated with future EHV transmission expansion planning projects. Some of the LUPTF recommendations approved by the MOPC on October 13th, 2010 described guidelines already being followed during the ITP20 process. For example, SPP staff held many stakeholder meetings to identify preferred transmission expansion corridors and obtain optimal routing of proposed projects. Also, an effort was made to reduce the number of parallel paths and minimize needed right-of-way. This was achieved by considering voltage conversion projects, reconductor projects, and projects that relieved congestion while also minimizing the transmission mileage needed for wind collection. By definition, the ITP20 identifies SPP's long-term EHV expansion plan and shows where new lines are required and where existing right-of-way can be utilized.

16.7: Rate Impacts and Unintended Consequences

The ITP20's impact on end-use customers' rates and unintended consequences are important concerns. This review is staff's first attempt at such an effort and, while introductory and preliminary, at best, should grow in quality and content over time with input from stakeholders and further development of tools used in the analysis. Now and as ITP20 planning matures, it is possible to begin analyzing the costs and benefits of the added facilities, addressing rate impacts, and mitigating any unintended consequences.

Section III. D. of Attachment J to the Tariff prescribes a formal review of the base plan cost allocation methodology, including determination of any imbalanced zonal cost allocation. This discussion of benefits and costs is **not** that review. Rather, this discussion is a preliminary, general examination of the issue of unintended consequences in an ITP20 context.

The ITP20 will establish a target EHV backbone topology that best addresses needs from a range of probable futures. Whether these projects are built depends on a number of variables that remain uncertain. Key assumptions about the future that drive the selection of these projects, as described in other sections of this report, include: the location and magnitude of load growth, the type and location of future generation facility additions necessary to provide sufficient capacity and energy to serve load growth, changes in fuel costs during this interim period, and the existence and type of renewable energy standards.

These projects will never be built in isolation. The set of transmission facilities actually constructed between now and 2030 would include a number of underlying projects to move energy from this backbone system to load, as well as a set of reliability-based upgrades which are not included in these calculations. The resulting backbone system, underlying facilities and reliability-based upgrades will affect: costs and benefits to ratepayers, transmission service granted (including interconnection service), charges incurred and benefits realized by loads and generators in various zones, and outcomes in the SPP market.

These uncertainties notwithstanding, Robust Plan 1 is the primary recommendation for the future backbone system to be in place by 2030. For the purpose of this exercise, Future 1, that is the business as usual case, was selected to determine the impact on rates and unintended consequences. This future was chosen merely as a representative of what might occur under these conditions and is only meant to be a glimpse of one possible future, not to be an indication of any likelihood of outcomes or preferred future. Furthermore, it is expected that similar outcomes would happen under the additional futures scenarios in this report.

Rate Impacts

The rate impact analysis presented here accounts for the impacts already sustained by customers for previously-committed upgrades, the mitigation of those impacts as initial investment in them depreciates over time, and the impacts of adding the ITP20 upgrades. The impact of added transmission facilities on end-use customers' charges is a relatively straightforward analysis, driven by facilities' installed cost, estimated capital cost, and other components of ownership cost and timing of installation. For each year of the analysis, the revenue requirement associated with each upgrade is determined and allocated to zones in accordance with applicable SPP Tariff provisions. The portion of total revenue requirement allocated to each zone that is allocable to the residential customer class of the zonal retail provider is then used to determine the resulting impact on a typical residential monthly bill.

Table A9.1 shows the cumulative cost impact of the addition of all known network upgrades required by the SPP Tariff on residential customers' monthly bills (1,000 kWh per month) from 2010, through the addition of the ITP 20 upgrades in 2030. These cost impacts are expressed in nominal dollars, capturing an estimate of the bill impacts for each year. This analysis does not include any quantitative or qualitative benefits from these upgrades that would reduce customers' monthly bills. With the exception of Southwestern Public Service Company customers, the cumulative impact of these upgrades remains below the $5.00 per month datum, adjusted for inflation. It should be noted that Southwestern Public Service Company customers are expected to enjoy substantial benefits.

Impacting Unintended Consequences

The unintended consequences assessment determined any deviation of the zonal distribution of production cost savings and other benefits through installation of the upgrades (benefits) from the corresponding allocation of the upgrade cost (cost). The analysis in Table A9.2 identifies any current imbalance in the distribution of cost and benefit associated with known upgrades committed to date that are expected to exist in 2030 prior to addition of the ITP20 upgrades. It sets out the degree to which installation of the ITP20 upgrades result in a better balance of accumulated costs and benefits for each zone. Analysis of cost is a relatively straightforward endeavor. Determining zonal cost impacts from adding one or more upgrades involves distributing the associated revenue requirement to the zones pursuant to the cost allocation provisions of the SPP Tariff. The analysis of benefit, by zone, can be calculated for a discrete set of upgrades and has been completed for the Robust Plan 1 upgrade set. The benefits amounts are derived from production cost savings, reliability upgrade deferrals or displacements and decreased losses. These benefit amounts exclude wind, gas price and local economic benefit categories.

Table A9.2 first depicts estimates of costs and benefits at year 2030 associated with all previously-committed upgrades, excluding costs and benefits of ITP20 upgrades. A benefit-to-cost ratio for that circumstance is computed for each zone. Then the cumulative 2030 revenue requirement, including the first year revenue requirement of the ITP20 upgrades, is depicted. Only the projected adjusted production cost savings are considered zonal benefits and included in the cumulative zonal benefit, and the resultant benefit to cost ratio for that circumstance is computed for each zone.

The benefit to cost characteristics for AEP, NPPD, OPPD and LES are substantially improved by the addition of the ITP 20 upgrades.

Since the analysis shows four zones that continue to reflect a cumulative benefit-to-cost ratio less than one, a theoretical set of transfer payments are calculated to adjust benefits by zone to result in a minimum benefit-to-cost ratio of 1 for all zones. These transfers are similar in magnitude to the transfers required for the Balanced Portfolio project set, adjusted for inflation.

Summary

The above generalizations are rough estimates of the expected impacts if Robust Plan 1 upgrades were installed. Rate impacts and unintended consequences will remain a concern and should continue to be investigated in the ITP process.

Cost Effective Plan Endorsed

At its January 11, 2011 meeting, the MOPC endorsed the ITP 20 Cost Effective Plan. Staff has completed an analysis of the related rate impacts and unintended consequences of that plan using the same data sources and techniques used in the analysis of the Robust Plan 1. Appendix A9: Rate Impact & Unintended Consequences Tables has been supplemented to include a set of tables to set out the results of that analysis in the same format as used for Robust Plan 1. Tables A9.1, A9.2, and A9.3 set out the results for the Robust Plan 1 upgrade set. Tables A9.4, A9.5, and A9.6 set out the results for the Cost Effective Plan 1 upgrade set.

Section 17: Comparison of ITP20 Results to Prior Studies

17.1: EHV Overlay

The ITP20 study evaluated projects at both 345 kV and 765 kV voltage levels. A 345 kV solution, Robust Plan 1, was chosen as the recommended expansion plan. The decision considered a number of factors, including estimated transmission construction costs, production cost benefits, transfer capability, and reliability impacts. While the 765 kV plan in past EHV Overlay studies demonstrated that 765 kV was cost-beneficial for the SPP region, 765 kV plans in the ITP20 were not cost-beneficial. There are several reasons for this difference:

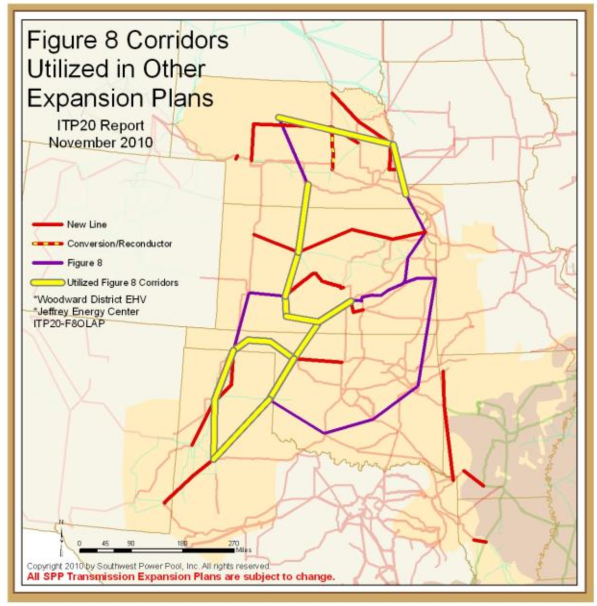

Figure 17.1: EHV Overlay Proposed Lines Included in ITP20 Recommendation

- A number of the projects identified in the 2008 EHV Overlay plan have been approved in other planning processes, such as Balanced Portfolio and Priority Projects, at 345 kV instead of 765 kV. These approved projects have fulfilled a portion of the needed transmission identified by the EHV Overlay study and have reduced the need seen by the ITP20 study for additional EHV projects.
- Since previously-approved EHV projects are included in the base case for ITP20 analyses, the netted benefit of these projects is not included when additional projects are considered. Section 8: Transmission Analysis Assumptions details the projects that were included in the base case.
- Cost estimates for 765 kV construction have increased significantly since the release of the 2008 EHV Overlay report. This equates to increased cost for such facilities in the ITP20 studies.

The ITP20 recommendation continues to build upon the paths identified in the EHV Overlay plan. Figure 17.1 highlights the lines proposed by the EHV Overlay study that have been directly and indirectly incorporated into the ITP20 recommendation.

17.2: Wind Integration Task Force

The Wind Integration Task Force (WITF) report indicated a need for certain 765 kV facilities to accommodate wind growth in SPP. The ITP20 analysis considered wind penetrations of up to 20% within SPP and demonstrated a possible need for 765 kV facilities at those wind levels.

The WITF assumed wind generation would connect to the system based on the generation interconnection queue, resulting in higher concentrations of wind generation placement in SPP's Western region. Conversely, the ITP20 did not use the queue as the basis, but placed wind in locations with high capacity factors as sited via the resource siting plan approved by the ESWG.

The additional diversity in wind locations in the ITP20 analysis contributed to the decision to use 345 kV instead of 765 kV facilities to accommodate the lower wind levels, since loading requirements were more diversified over SPP's western region. The concentration of the 13 GW of wind studied in the WITF recommended 765 kV lines because multiple circuit 345 kV lines were needed in some areas to dispatch the 13 GW of wind studied.

The concentration of the 13 GW of wind studied in the WITF resulted in a recommendation of single circuit 765 kV lines rather than the multiple circuit 345 kV lines that would otherwise be required between some points.

Section 18: Staff Recommendation

Staff recommends Robust Plan 1 due to its ability to achieve specified performance requirements cost-effectively as directed by the SPC and the BOD while also providing top performance scores in the robustness metrics analysis.

Robust Plan 1 incorporates a combination of moderate cost but high value transmission lines which will provide SPP flexibility to meet future 20-year grid challenges. This plan which is the Cost-Effective Plan with additional robustness projects provides significant value as measured by the robustness metrics.

The Cost-Effective Plan was developed to meet the four futures as directed by the SPPT. The estimated E&C cost of this plan is $1.76 billion. Assuming an annual 17% carrying charge rate, the Annual Transmission Revenue Requirement is $289 million. This plan effectively allows SPP to develop a transmission grid which will best accommodate impacts of the four future scenarios.

As outlined in the ITP manual, there are three distinct study phases. The cost-effective analysis is an intermediate phase to the complete process. The ITP manual directs changes to the cost-effective transmission plans resulting in added flexibility. These changes are measured using the robustness metrics, while also evaluating the incremental cost and benefits. Therefore, after development of the Cost-Effective Plan, projects were considered which add additional reliability and economic value to the transmission system that are not captured in APC B/C. These additional projects result in development of a more robust transmission grid, as determined by the robustness metrics defined by the ESWG's Metric Task Force. Four circuits were added to provide robustness at an additional cost of $699 million. Many of the new robust projects worked in concert with the Cost-Effective circuits to provide enhanced robustness and overall performance.

Robust Plan 1 is a high performer on most of the metrics while also yielding a high APC-based B/C and provides an economically prudent blend of robustness and APC savings. The plan meets the following goals and is the right step towards the development of a transmission grid which will accommodate the impacts of all four futures:

- Integrating west to east transfers
- Supporting Aggregate Transmission Service Studies
- Supporting Generation Interconnection queue
- Relieving known congestion

The estimated transmission construction cost of Robust Plan 1, which includes all of the projects in the Cost-Effective Plan, is $2.45 billion E&C. The annualized carrying charge is $417 million[49] with annual quantifiable benefits of $1,811 million which is an APC B/C of 4.34.[50]

In addition to the APC derived benefit, Robust Plan 1 provides substantial qualitative improvement by:

- Providing a Competitive Environment in SPP Markets
- Increasing System Reliability
- Preparing for Unexpected Shifts in Load
- Anticipating Import and Export Opportunities
- Broadening Resource Siting Options
- Valuing Cleaner Air
- Reducing Risk through Responsible Land Usage

[49] For this calculation an annual carrying charge rate of 17% was used.
[50] All dollars are in 2010 values.

- Increasing Efficiency with Reduced Transmission Losses

This plan enables SPP to respond to potential state and federal policy initiatives such as an RES or carbon mandate. Robust Plan 1 provides transmission upgrades in eight states in the SPP footprint. In addition to the previously described quantitative and qualitative value, the plan also addresses all of the SPPT's goals for transmission development for the ITP:

- Focus on regional needs, while considering local needs
- Better position SPP to proactively prepare for and respond to national priorities while providing flexibility to adjust expansion plans
- Incorporate a 20-year physical modeling and 40-year financial analysis timeframe
- Design a backbone transmission system to serve known load with known resources in a cost-effective manner

At wind levels above 12 GW, analysis indicated that the system requires substantial reactive compensation beyond reasonable 345 kV design ability. To achieve the current renewable targets (Business as Usual future), a robust 345 kV network is required. Robust Plan 1 will allow the region to support the Business as Usual future, and additionally serve as a strong base to connect future 765 kV development to the underlying system in the event higher renewable levels are required. Therefore, staff recommends the adoption of Robust Plan 1, as shown in Figure 18.2, and additionally strongly recommends that 765 kV transmission be considered for wind levels beyond the 12 GW of capacity.

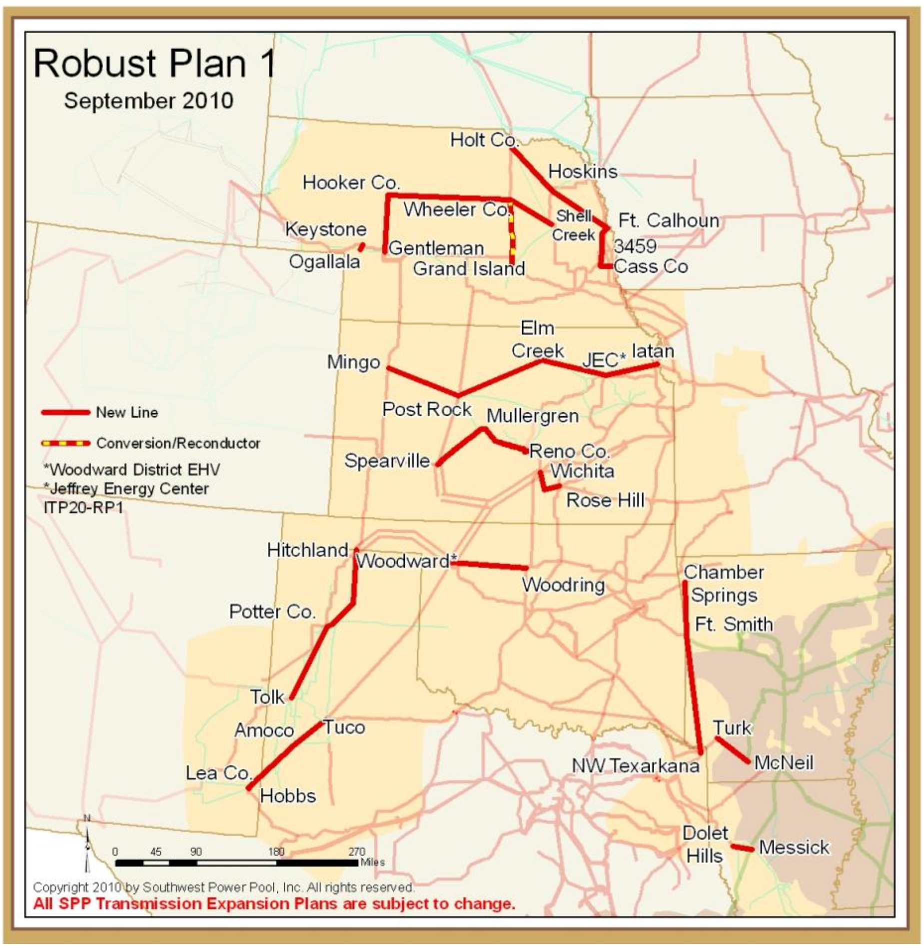

Figure 18.2: Robust Plan 1

Table 18.1 lists the elements that make up Robust Plan 1.

Robust Plan 1 Elements	kV	State
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS
N.W. Texarkana - Ft. Smith	345	AR
Ft. Smith - Chamber Springs	345	AR
Dolet Hills - Messick	345	LA
Turk - McNeil	345	AR
Iatan - Jeffrey Energy Center	345	KS
Wichita - Viola - Rose Hill	345	KS
Spearville - Mullergren - Circle - Reno	345	KS
Cass Co. - S.W. Omaha (aka S3454)	345	NE
Gentleman - Hooker Co. - Wheeler Co.	345	NE
Tolk - Potter Co.	345	TX
Grand Island - Wheeler Co. rebuild[51]	345	NE
Hitchland - Potter Co.	345	TX, OK
Woodward District EHV - Woodring	345	OK
Mingo - Post Rock	345	KS
Holt - Hoskins - Ft. Calhoun	345	NE
Ft Calhoun - S3454	345	NE
Tuco - Amoco - Lea County - Hobbs	345	NM, TX
Keystone - Ogallala	345	NE
Wheeler Co. - Shell Creek	345	NE

Table 18.1: Elements of Robust Plan 1

[51] Rebuild from 720 MVA to 1,195 MVA.

Part IV: Appendices

Appendix A1: Transmission Projects Evaluated

This table provides a list of all transmission projects analyzed in ITP20, as well as which stage(s) of the process the analysis took place. This list includes transmission line projects only; transformer projects are not included in this table.

Projects Analyzed as part of ITP20	Analysis Type Included		
	Least Cost	Cost-Effective	Robustness
Big Cajun 2 - Cocodrie 230			x
Bull Shoals - Norfork 345			x
Cass Co. - S.W. Omaha (aka S3454) 345	x	x	x
Chamber Springs - Ft Smith 345			x
Chamber Springs - S Fayetteville 345			x
Concordia - Cooper 345	x		x
Delaware - Afton 345			x
Dolet Hills - Messick 345			x
Elm Creek -Iatan 345	x		x
Elm Creek -Summit 345	x		x
Emporia - Wolf Creek	x		
Finney - Holcomb 345	x		
Flint Creek - Chamber Springs 345			x
Flint Creek - Chouteau 345			x
Frio Draw – Tolk	x		
Frio-Draw - Hitchland 345			x
Ft Calhoun - S3454 345	x	x	x
Gentleman – Axtell	x		
Gentleman - Hooker Co. - Wheeler Co. 345	x	x	x
Gentlemen - Post Rock 345			x
Grand Island - Columbus East 345			x
Grand Island - Wheeler Co. 345 rebuild[52]	x	x	x
GRDA - Flint Creek 345			x
GRDA1 - Tontitown - Flint Creek	x		
Harrington - Hitchland 345	x		
Hitchland - Potter Co. 345		x	x
Holt - Hoskins - Ft. Calhoun 345	x	x	x
Holt Co - Sioux City 345			x
Hooker Co - Holt Co	x		
Hooker Co – Sweetwater	x		
Iatan - Jeffrey Energy Center 345	x	x	x
ISES - Osage Creek 500			x
Jeffrey Energy Center - Auburn - Swissvale 345	x		x
Jeffrey Energy Center - Hoyt - Iatan 345			x
Keystone - Ogallala 345	x	x	x

[52] Rebuild from 720 MVA to 1,195 MVA

Projects Analyzed as part of ITP20	Analysis Type Included		
	Least Cost	Cost-Effective	Robustness
Post Rock - Concordia 345	x		x
Post Rock - Elm Creek - Jeffrey Energy Center 345	x		x
Post Rock - Iatan 345			x
Post Rock - Smoky Hills - Summit[53]	x		
Post Rock – Summit Conversion[53]	x	x	
LaCygne - Mariosa Delta 345			x
Medicine Lodge - Viola 345	x		x
Mingo - Post Rock 345	x	x	x
Mullergren - Rice 230	x		
Muskogee - Ft Smith - Flint Creek 345	x		
Norfork - Thayer 345			x
N.W. Texarkana - Ft Smith 345			x
Osage Creek - Table Rock 345			x
Potter Co. - Harrington 345	x		
Potter Co. - Stateline 345	x	x	
Red Willow – Axtell	x		
Rice County - Elm Creek 345	x		x
Rice County - Smoky Hills - Elm Creek 230	x		
S Fayetteville - Osage Creek 345			x
S Fayetteville - Van Buren 500			x
Setab - Spearville 345	x	x	
Spearville - Comanche - Wichita 3rd Circuit 345	x	x	
Spearville - Mullergren - Circle - Reno 345		x	x
Spearville - Mullergren - Circle[53]	x		
Spearville - Mullergren - Jeffrey Energy Center 345	x	x	
Spearville - Mullergren[53]	x		
Spearville - Reno 345	x		
Spearville - Wichita 345	x		
Stateline - Anadarko 345	x	x	
Stateline - LES 345	x	x	
Summit, MO - Brookline 345			x
Table Rock - Bull Shoals 345			x
Table Rock - Summit MO 345			x
Thayer - Gobbler Knob 345			x
Tolk - Potter Co. 345	x	x	x
Tolk - Tuco 345	x	x	
Tuco - Amoco - Lea County - Hobbs 345	x	x	x
Tuco - Lea County - Hobbs 345	x		
Tuco - Potter Co. 345	x	x	
Tuco - Yoakum - Lea County - Hobbs 345	x		

[53] Conversion from 230 to 345 utilizing the same ROW

Projects Analyzed as part of ITP20	Analysis Type Included		
	Least Cost	Cost-Effective	Robustness
Turk - McNeil 345			x
Van Buren - ANO 500			x
Welsh - Barton Chapel 345			x
West Gardner - Stilwell 345[54]	x		
Wheeler Co. - Shell Creek 345	x	x	x
Wichita - Rose Hill 345	x		
Wichita - Viola - El Paso - Rose Hill 345	x		
Wichita - Viola - Rose Hill 345	x	x	x
Woodward District EHV - Woodring 345	x	x	x
Tolk-Tuco 765			x
Tolk-Potter Co. 765			x
Potter Co. - Hitchland 765			x
Hitchland - Woodward District EHV 765			x
Woodward District EHV - Stateline - Tuco 765			x
Woodward District EHV - Sooner 765			x
Spearville - Comanche - Medicine Lodge - Wichita 765			x
Comanche - Woodward District EHV 765			x
Spearville - Mingo 765			x
Mingo - Gentlemen 765			x
Gentlemen - Hooker Co 765			x
Hooker - Wheeler Co 765			x
Wheeler Co - Sheldon 765			x
Sheldon - Iatan 765			x
Iatan - Jeffrey Energy Center 765			x
Jeffrey Energy Center - Spearville 765			x
Sooner - Rose Hill 765			x
Rose Hill - Wichita 765			x

Table A1.1: Projects analyzed as part of the ITP20

[54] Rebuild from 994 MVA to 1,195 MVA

Appendix A2: Transmission Portfolios & Cost Estimates

This appendix contains the project lines, transformer and substation costs per plan.

A2.1: Common Plan

Common Plan Elements	kV	State	Estimated Cost ($)
Iatan - Jeffrey Energy Center	345	KS	79,875,000
Wichita - Viola - Rose Hill	345	KS	108,000,000
Spearville - Mullergren - Circle - Reno	345	KS	178,200,000
Cass Co. - S.W. Omaha (S3454)	345	NE	36,750,000
Gentleman - Hooker Co. - Wheeler Co.	345	NE	265,950,000
Tolk - Potter Co.	345	TX	121,500,000
Grand Island - Wheeler Co. rebuild	345	NE	64,125,000
S3459-S1209 Transformer	345/161	NE	6,000,000
Mullergren Transformer	345/230	KS	6,000,000
Circle Transformer	345/230	KS	6,000,000
Wheeler Substation	345	NE	10,500,000
Total Common Plan Estimated Cost			**882,900,000**

Table A2.1: Common Plan Elements and Cost Estimates

A2.2: Cost-Effective Plan

Cost-Effective Plan Elements	kV	State	Estimated Cost ($)
Iatan - Jeffrey Energy Center	345	KS	79,875,000
Wichita - Viola - Rose Hill	345	KS	108,000,000
Spearville - Mullergren - Circle - Reno	345	KS	178,200,000
Cass Co. - S.W. Omaha (aka S3454)	345	NE	36,750,000
Gentleman - Hooker Co. - Wheeler Co.	345	NE	265,950,000
Tolk - Potter Co.	345	TX	121,500,000
Grand Island - Wheeler Co. rebuild	345	NE	64,125,000
Hitchland - Potter Co.	345	TX, OK	133,875,000
Woodward District EHV - Woodring	345	OK	112,500,000
Mingo - Post Rock	345	KS	121,500,000
Holt Co. - Hoskins - Ft. Calhoun	345	NE	166,125,000
Ft Calhoun - S3454	345	NE	46,875,000
Tuco - Amoco - Lea County - Hobbs	345	NM, TX	157,500,000
Keystone – Ogallala	345	NE	5,625,000
Wheeler Co. - Shell Creek	345	NE	69,750,000
S3459-S1209 Transformer	345/161	NE	6,000,000
Mullergren Transformer	345/230	KS	6,000,000
Circle Transformer	345/230	KS	6,000,000
Hoskins Transformer	345/230	NE	6,000,000
Hoskins Transformer	345/115	NE	6,000,000
Ogallala Transformer	345/230	NE	6,000,000
Shell Creek Transformer	345/230	NE	6,000,000
Columbus East Transformer	345/115	NE	6,000,000

Cost-Effective Plan Elements	kV	State	Estimated Cost ($)
Lea Co. Transformer	345/230	NM	6,000,000
Post Rock Transformer	345/230	KS	6,000,000
Amoco Transformer	345/230	NM	6,000,000
Holt Co. Substation	345	NE	10,500,000
Wheeler Substation	345	NE	10,500,000
Total Cost-Effective Plan Estimated Cost			**$1,755,150,000**

Table A2.2: Cost-Effective Plan Elements and Cost Estimates

A2.3: Robust Plan 1

Robust Plan 1 Elements	kV	State	Estimated Cost ($)
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS	310,500,000
N.W. Texarkana - Ft. Smith	345	AR	175,500,000
Ft. Smith - Chamber Springs	345	AR	81,000,000
Dolet Hills – Messick	345	LA	29,250,000
Turk – McNeil	345	AR	60,750,000
Iatan - Jeffrey Energy Center	345	KS	79,875,000
Wichita - Viola - Rose Hill	345	KS	108,000,000
Spearville - Mullergren - Circle - Reno	345	KS	178,200,000
Cass Co. - S.W. Omaha (aka S3454)	345	NE	36,750,000
Gentleman - Hooker Co. - Wheeler Co.	345	NE	265,950,000
Tolk - Potter Co.	345	TX	121,500,000
Grand Island - Wheeler Co. rebuild	345	NE	64,125,000
Hitchland - Potter Co.	345	TX, OK	133,875,000
Woodward District EHV - Woodring	345	OK	112,500,000
Mingo - Post Rock	345	KS	121,500,000
Holt Co. - Hoskins - Ft. Calhoun	345	NE	166,125,000
Ft Calhoun - S3454	345	NE	46,875,000
Tuco - Amoco - Lea County - Hobbs	345	NM, TX	157,500,000
Keystone – Ogallala	345	NE	5,625,000
Wheeler Co. - Shell Creek	345	NE	69,750,000
S3459-S1209 Transformer	345/161	NE	6,000,000
Mullergren Transformer	345/230	KS	6,000,000
Circle Transformer	345/230	KS	6,000,000
Hoskins Transformer	345/230	NE	6,000,000
Hoskins Transformer	345/115	NE	6,000,000
Ogallala Transformer	345/230	NE	6,000,000
Shell Creek Transformer	345/230	NE	6,000,000
Columbus East Transformer	345/115	NE	6,000,000
Lea Co. Transformer	345/230	NM	6,000,000
Post Rock Transformer	345/230	KS	6,000,000
Amoco Transformer	345/230	NM	6,000,000
Elm Creek Transformer	345/230	KS	6,000,000
Messick Transformer (2)	500/345	LA	24,000,000
McNeil Transformer	500/345	AR	12,000,000
Holt Co. Substation	345	NE	10,500,000

Robust Plan 1 Elements	kV	State	Estimated Cost ($)
Wheeler Substation	345	NE	10,500,000
Total Robust Plan 1 Estimated Cost			**$2,454,150,000**

Table A2.3: Robust Plan 1 Elements and Cost Estimates

A2.4: Robust Plan 2

Robust Plan 2 Elements	kV	State	Estimated Cost ($)
Jeffrey Energy Center - Auburn - Swissvale	345	KS	49,500,000
LaCygne - Mariosa Delta	345	KS, MO	177,750,000
Flint Creek – Chouteau	345	AR, OK	54,000,000
Flint Creek - Chamber Springs	345	AR	20,250,000
Chamber Springs - S Fayetteville	345	AR	20,250,000
S Fayetteville - Osage Creek	345	AR	54,000,000
Osage Creek - Table Rock	345	AR, MO	54,000,000
Table Rock - Summit	345	MO	87,750,000
Summit - Brookline	345	MO	13,500,000
Table Rock - Bull Shoals	345	MO, AR	81,000,000
Bull Shoals - Norfork	345	AR	27,000,000
Norfork - Thayer	345	AR, MO	87,750,000
Thayer - Gobbler Knob	345	MO	81,000,000
S Fayetteville - Van Buren	500	AR	101,250,000
Van Buren - ANO	500	AR	131,625,000
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS	310,500,000
Iatan - Jeffrey Energy Center	345	KS	79,875,000
Wichita - Viola - Rose Hill	345	KS	108,000,000
Spearville - Mullergren - Circle - Reno	345	KS	178,200,000
Cass Co. - S.W. Omaha (aka S3454)	345	NE	36,750,000
Gentleman - Hooker Co. - Wheeler Co.	345	NE	265,950,000
Tolk - Potter Co.	345	TX	121,500,000
Grand Island - Wheeler Co. rebuild	345	NE	64,125,000
Hitchland - Potter Co.	345	TX, OK	133,875,000
Woodward District EHV - Woodring	345	OK	112,500,000
Mingo - Post Rock	345	KS	121,500,000
Holt Co. - Hoskins - Ft. Calhoun	345	NE	166,125,000
Ft Calhoun - S3454	345	NE	46,875,000
Tuco - Amoco - Lea County - Hobbs	345	NM, TX	157,500,000
Keystone - Ogallala	345	NE	5,625,000
Wheeler Co. - Shell Creek	345	NE	69,750,000
S3459-S1209 Transformer	345/161	NE	6,000,000
Mullergren Transformer	345/230	KS	6,000,000
Circle Transformer	345/230	KS	6,000,000
Hoskins Transformer	345/230	NE	6,000,000
Hoskins Transformer	345/115	NE	6,000,000
Ogallala Transformer	345/230	NE	6,000,000
Shell Creek Transformer	345/230	NE	6,000,000

Robust Plan 2 Elements	kV	State	Estimated Cost ($)
Columbus East Transformer	345/115	NE	6,000,000
Lea Co. Transformer	345/230	NM	6,000,000
Post Rock Transformer	345/230	KS	6,000,000
Amoco Transformer	345/230	NM	6,000,000
Elm Creek Transformer	345/230	KS	6,000,000
Chouteau Transformer	345/138	OK	6,000,000
Chouteau Transformer	345/138	OK	6,000,000
Chouteau Transformer	345/138	OK	6,000,000
Auburn Transformer	345/230	KS	6,000,000
Table Rock Transformer	345/161	MO	6,000,000
Summit Transformer	345/161	MO	6,000,000
Bull Shoals Transformer	345/161	AR	6,000,000
Norfork Transformer	345/161	AR	6,000,000
S Fayetteville Transformer	345/161	AR	6,000,000
Thayer Transformer	345/161	MO	6,000,000
S Fayetteville Transformer	500/345	AR	12,000,000
S Fayetteville Transformer	500/345	AR	12,000,000
Van Buren Transformer	500/161	AR	12,000,000
Van Buren Transformer	500/161	AR	12,000,000
Holt Co. Substation	345	NE	10,500,000
Wheeler Substation	345	NE	10,500,000
Total Robust Plan 2 Estimated Cost			**$3,220,275,000**

Table A2.4: Robust Plan 2 Elements and Cost Estimates

A2.5: Robust Plan 3

Robust Plan 3 Elements	kV	State	Estimated Cost ($)
Dolet Hills - Messick	345	LA	29,250,000
Turk - McNeil	345	AR	60,750,000
Iatan - Jeffrey Energy Center	345	KS	79,875,000
Wichita - Viola - Rose Hill	345	KS	108,000,000
Spearville - Mullergren - Circle - Reno	345	KS	178,200,000
Cass Co. - S.W. Omaha (aka S3454)	345	NE	36,750,000
Gentleman - Hooker Co. - Wheeler Co.	345	NE	265,950,000
Tolk - Potter Co.	345	TX	121,500,000
Grand Island - Wheeler Co. rebuild	345	NE	64,125,000
Hitchland - Potter Co.	345	TX, OK	133,875,000
Woodward District EHV - Woodring	345	OK	112,500,000
Mingo - Post Rock	345	KS	121,500,000
Holt Co. - Hoskins - Ft. Calhoun	345	NE	166,125,000
Ft Calhoun - S3454	345	NE	46,875,000
Tuco - Amoco - Lea County - Hobbs	345	NM, TX	157,500,000
Keystone - Ogallala	345	NE	5,625,000
Wheeler Co. - Shell Creek	345	NE	69,750,000
S3459-S1209 Transformer	345/161	NE	6,000,000
Mullergren Transformer	345/230	KS	6,000,000

Robust Plan 3 Elements	kV	State	Estimated Cost ($)
Circle Transformer	345/230	KS	6,000,000
Hoskins Transformer	345/230	NE	6,000,000
Hoskins Transformer	345/115	NE	6,000,000
Ogallala Transformer	345/230	NE	6,000,000
Shell Creek Transformer	345/230	NE	6,000,000
Columbus East Transformer	345/115	NE	6,000,000
Lea Co. Transformer	345/230	NM	6,000,000
Post Rock Transformer	345/230	KS	6,000,000
Amoco Transformer	345/230	NM	6,000,000
Messick Transformer (2)	500/345	LA	24,000,000
McNeil Transformer	500/345	AR	12,000,000
Holt Co. Substation	345	NE	10,500,000
Wheeler Substation	345	NE	10,500,000
Total Robust Plan 3 Estimated Cost			**$1,881,150,000**

Table A2.5: Robust Plan 3 Elements and Cost Estimates

A2.6: Robust Plan 4

Robust Plan 4 Elements	kV	State	Estimated Cost ($)
Cass Co. - S.W. Omaha (aka S3454)	345	NE	36,750,000
Holt Co. - Hoskins - Ft. Calhoun	345	NE	166,125,000
Ft Calhoun - S3454	345	NE	46,875,000
Tuco - Amoco - Lea County - Hobbs	345	TX, NM	157,500,000
Keystone - Ogallala	345	NE	5,625,000
Wheeler Co. - Shell Creek	345	NE	69,750,000
Iatan - Jeffrey Energy Center	345	KS	79,875,000
Tolk - Tuco	765	TX	162,720,000
Tolk - Potter Co.	765	TX	273,912,000
Hitchland - Potter Co.	765	OK, TX	357,984,000
Hitchland - Woodward District EHV	765	OK	364,492,800
Woodward District EHV - Stateline - Tuco	765	OK, TX	678,000,000
Woodward District EHV - Sooner	765	OK	423,072,000
Spearville - Comanche - Medicine Lodge - Wichita	765	KS	509,313,600
Medicine Lodge - Woodward District EHV	765	KS, OK	233,232,000
Spearville - Mingo	765	KS	390,528,000
Mingo - Gentleman	765	KS, NE	439,344,000
Gentleman - Hooker Co.	765	NE	205,027,200
Hooker Co. - Wheeler Co.	765	NE	436,089,600
Wheeler Co. - Sheldon	765	NE	455,616,000
Sheldon - Iatan	765	NE, KS	390,528,000
Iatan - Spearville	765	KS	694,272,000
Rose Hill - Wichita	765	KS	216,960,000
Sooner - Rose Hill voltage conversion	765	OK, KS	203,400,000
S3459-S1209 Transformer	345/161	NE	6,000,000
Hoskins Transformer	345/230	NE	6,000,000

Robust Plan 4 Elements	kV	State	Estimated Cost ($)
Hoskins Transformer	345/115	NE	6,000,000
Ogallala Transformer	345/230	NE	6,000,000
Shell Creek Transformer	345/230	NE	6,000,000
Columbus East Transformer	345/115	NE	6,000,000
Lea County Transformer	345/230	NM	6,000,000
Amoco Transformer	345/230	NM	6,000,000
Tolk Transformers (2)	765/345	TX	56,386,000
Hitchland Transformers (2)	765/345	OK	56,386,000
Woodward District EHV Transformers (2)	765/345	OK	56,386,000
Tuco Transformers (2)	765/345	TX	56,386,000
Spearville Transformers (2)	765/345	KS	56,386,000
Medicine Lodge Transformers (2)	765/138	KS	56,386,000
Wichita Transformers (2)	765/345	KS	56,386,000
Mingo Transformers (2)	765/345	KS	56,386,000
Gentleman Transformers (2)	765/345	NE	56,386,000
Wheeler Transformers (2)	765/345	NE	56,386,000
Sheldon Transformers (2)	765/345	NE	56,386,000
Iatan Transformers (2)	765/345	KS	56,386,000
Sooner Transformers (2)	765/345	OK	56,386,000
Rose Hill Transformers (2)	765/345	KS	56,386,000
Potter Transformers (2)	765/345	TX	56,386,000
Wheeler Substation	765	NE	25,100,000
Holt Co. Substation	345	NE	10,500,000
Total Robust Plan 4 Estimated Cost			**$7,926,381,200**

Table A2.6: Robust Plan 4 Elements and Cost Estimates

Projects Replaced by Robust Plan 4 That Currently Have NTC's	kV	State	Estimated Cost ($)
Hitchland - Woodward District EHV (double circuit)	345	OK	263,980,000
Spearville - Comanche - Medicine Lodge - Wichita (double circuit)	345	KS	370,360,000
Woodward District EHV - Tuco	345	OK, TX	281,250,000
Comanche - Woodward District EHV (double circuit)	345	KS, OK	106,380,000
Medicine Lodge Transformer	345/138	KS	6,000,000
Woodward District EHV Transformer	345/138	OK	6,000,000
Tuco Transformer	345/230	TX	6,000,000
Comanche Substation	345	KS	10,500,000
Total Robust Plan 4 Savings			**$1,050,470,000**

Table A2.7: Projects Replaced by Robust Plan 4 and Cost Savings

A2.7: Robust Plan 5

Robust Plan 5 Elements	kV	State	Estimated Cost ($)
Post Rock - Elm Creek - Jeffrey Energy	345	KS	310,500,000

Center			
N.W. Texarkana - Ft. Smith	345	AR	175,500,000
Ft. Smith - Chamber Springs	345	AR	81,000,000
Dolet Hills - Messick	345	LA	29,250,000
Turk - McNeil	345	AR	60,750,000
Iatan - Jeffrey Energy Center	345	KS	79,875,000
Wichita - Viola - Rose Hill	345	KS	108,000,000
Spearville - Mullergren - Circle - Reno	345	KS	178,200,000
Cass Co. - S.W. Omaha (aka S3454)	345	NE	36,750,000
Gentleman - Hooker Co. - Wheeler Co.	345	NE	265,950,000
Tolk - Potter Co.	345	TX	121,500,000
Grand Island - Wheeler Co. rebuild	345	NE	64,125,000
Hitchland - Potter Co.	345	TX, OK	133,875,000
Woodward District EHV - Woodring	345	OK	112,500,000
Mingo - Post Rock	345	KS	121,500,000
Holt Co. - Hoskins - Ft. Calhoun	345	NE	166,125,000
Ft Calhoun - S3454	345	NE	46,875,000
Tuco - Amoco - Lea County - Hobbs	345	NM, TX	157,500,000
Keystone - Ogallala	345	NE	5,625,000
Wheeler Co. - Shell Creek	345	NE	69,750,000
Spearville - Medicine Lodge	765	KS	216,960,000
Medicine Lodge - Wichita	765	KS	200,688,000
Medicine Lodge - Woodward District EHV	765	KS, OK	233,232,000
S3459-S1209 Transformer	345/161	NE	6,000,000
Mullergren Transformer	345/230	KS	6,000,000
Circle Transformer	345/230	KS	6,000,000
Hoskins Transformer	345/230	NE	6,000,000
Hoskins Transformer	345/115	NE	6,000,000
Ogallala Transformer	345/230	NE	6,000,000
Shell Creek Transformer	345/230	NE	6,000,000
Columbus East Transformer	345/115	NE	6,000,000
Lea Co. Transformer	345/230	NM	6,000,000
Post Rock Transformer	345/230	KS	6,000,000
Amoco Transformer	345/230	NM	6,000,000
Elm Creek Transformer	345/230	KS	6,000,000
Messick Transformer (2)	500/345	LA	24,000,000
McNeil Transformer	500/345	AR	12,000,000
Woodward District EHV Transformer	765/345	OK	28,194,000
Spearville Transformer	765/345	KS	28,194,000
Medicine Lodge Transformer	765/345	KS	28,194,000
Wichita Transformer	765/345	KS	28,194,000
Holt Co. Substation	345	NE	10,500,000
Wheeler Substation	345	NE	10,500,000
Total Robust Plan 5 Estimated Cost			**$3,217,806,000**

Table A2.8.1: Robust Plan 5 Elements and Cost Estimates

Projects Replaced by Robust Plan 5 That Currently Have NTC's	kV	State	Estimated Cost ($)
Medicine Lodge - Wichita (double circuit)	345	KS	145,780,000
Medicine Lodge - Spearville (double circuit)	345	KS	157,600,000
Medicine Lodge - Woodward District EHV (double circuit)	345	KS, OK	169,420,000
Total Robust Plan 5 Savings			**$472,800,000**

Table A2.9: Projects Replaced by Robust Plan 5 and Cost Savings

A2.8: Robust Plan 6

Robust Plan 6 Elements	kV	State	Estimated Cost ($)
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS	310,500,000
N.W. Texarkana - Ft. Smith	345	AR	175,500,000
Ft. Smith - Chamber Springs	345	AR	81,000,000
Dolet Hills - Messick	345	LA	29,250,000
Turk - McNeil	345	AR	60,750,000
Iatan - Jeffrey Energy Center	345	KS	79,875,000
Spearville - Mullergren - Circle - Reno	345	KS	178,200,000
Cass Co. - S.W. Omaha (aka S3454)	345	NE	36,750,000
Gentleman - Hooker Co. - Wheeler Co.	345	NE	265,950,000
Tolk - Potter Co.	345	TX	121,500,000
Grand Island - Wheeler Co. rebuild	345	NE	64,125,000
Hitchland - Potter Co.	345	TX, OK	133,875,000
Mingo - Post Rock	345	KS	121,500,000
Holt Co. - Hoskins - Ft. Calhoun	345	NE	166,125,000
Ft Calhoun - S3454	345	NE	46,875,000
Tuco - Amoco - Lea County - Hobbs	345	NM, TX	157,500,000
Keystone - Ogallala	345	NE	5,625,000
Wheeler Co. - Shell Creek	345	NE	69,750,000
Spearville - Medicine Lodge	765	KS	216,960,000
Medicine Lodge - Wichita	765	KS	200,688,000
Medicine Lodge - Woodward District EHV	765	KS, OK	233,232,000
Woodward District EHV - Sooner	765	OK	423,072,000
Rose Hill - Wichita	765	KS	216,960,000
Sooner - Rose Hill rebuild	765	OK, KS	203,400,000
S3459-S1209 Transformer	345/161	NE	6,000,000
Mullergren Transformer	345/230	KS	6,000,000
Circle Transformer	345/230	KS	6,000,000
Hoskins Transformer	345/230	NE	6,000,000
Hoskins Transformer	345/115	NE	6,000,000
Ogallala Transformer	345/230	NE	6,000,000
Shell Creek Transformer	345/230	NE	6,000,000
Columbus East Transformer	345/115	NE	6,000,000
Lea Co. Transformer	345/230	NM	6,000,000
Post Rock Transformer	345/230	KS	6,000,000
Amoco Transformer	345/230	NM	6,000,000

Robust Plan 6 Elements	kV	State	Estimated Cost ($)
Elm Creek Transformer	345/230	KS	6,000,000
Messick Transformer (2)	500/345	LA	24,000,000
McNeil Transformer	500/345	AR	12,000,000
Woodward District EHV Transformer	765/345	OK	28,194,000
Woodward District EHV Transformer	765/345	OK	28,194,000
Spearville Transformer	765/345	KS	28,194,000
Medicine Lodge Transformer	765/345	KS	28,194,000
Wichita Transformer	765/345	KS	28,194,000
Sooner Transformer	765/345	OK	28,194,000
Sooner Transformer	765/345	OK	28,194,000
Rose Hill Transformer	765/345	KS	28,194,000
Holt Co. Substation	345	NE	10,500,000
Wheeler Substation	345	NE	10,500,000
Total Robust Plan 6 Estimated Cost			**$3,953,514,000**

Table A2.10: Robust Plan 6 Elements and Cost Estimates

Projects Replaced by Robust Plan 6 That Currently Have NTC's	kV	State	Estimated Cost ($)
Medicine Lodge - Wichita (double circuit)	345	KS	145,780,000
Medicine Lodge - Spearville (double circuit)	345	KS	157,600,000
Medicine Lodge - Woodward District EHV (double circuit)	345	KS, OK	169,420,000
Total Robust Plan 6 Savings			**$472,800,000**

Table A2.11: Projects Replaced by Robust Plan 6 and Cost Savings

A2.9: 345 kV Double Circuit Tower Construction

Consideration has been given to constructing the new 345kV single circuit lines in these plans using 345kV double circuit towers. In this scenario, the new lines would be operated as 345kV single circuit, and only single circuit conductors would be installed. However, this construction would provide the flexibility to convert any of the new 345kV single circuit lines to double circuit without the need for new tower construction; only additional conductor installation would be necessary.

Table X.X shows the cost of each plan using double circuit towers for all proposed 345kV lines, compared to single circuit towers, as well as the cost increase to construct with double circuit towers rather than single circuit towers.

Cost	CEP	R1	R2	R3	R4	R5	R6
Standard 345kV Single Circuit Construction	$1.755B	$2.454B	$3.220B	$1.881B	$6.876B	$2.745B	$3.481B
345kV Double Circuit Towers Construction	$2.461B	$3.444B	$4.398B	$2.627B	$7.106B	$3.735B	$4.375B
Cost Increase	**$706.6M**	**$989.8M**	**$1.178B**	**$745.4M**	**$229.6M**	**$9.898M**	**$894.8M**

Appendix A3: Metric Results

As shown below, the Robustness Metrics created vast amounts of data for each future and each transmission project analyzed.

Adjusted Production Cost Savings

The following tables provide information determined in the calculation of the APC. Table A3.1 shows the APC dollar savings in millions due to each plan relative to the Base Case.

	Future 1	Future 2	Future 3	Future 4	Average
Cost-Effective Plan	875	1,326	1,433	2,536	1,543
Robust Plan 1	1,029	1,654	1,513	3,047	1,811
Robust Plan 2	1,035	1,653	1,575	3,087	1,837
Robust Plan 3	942	1,560	1,460	3,031	1,748
Robust Plan 4	947	1,506	1,471	2,886	1,703
Robust Plan 5	1,036	1,633	1,531	3,064	1,816
Robust Plan 6	1,008	1,627	1,538	3,044	1,804

Table A3.1: APC Savings by Future for each plan (2010 $millions)

Table A3.2 shows the APC for each future and plan.

	Future 1	Future 2	Future 3	Future 4	Average
Base Case	9,941	9,800	19,459	19,270	14,618
Cost-Effective Plan	9,066	8,485	18,026	16,734	13,075
Robust Plan 1	8,912	8,146	17,946	16,223	12,807
Robust Plan 2	8,906	8,147	17,885	16,184	12,780
Robust Plan 3	8,999	8,241	18,000	16,239	12,870
Robust Plan 4	8,994	8,294	17,988	16,384	12,915
Robust Plan 5	8,905	8,167	17,929	16,206	12,802
Robust Plan 6	8,933	8,173	17,922	16,226	12,814

Table A3.2: APC by Future for each plan (2010 $millions)

Metric 2: Levelization of LMPs

The following tables and provide the standard deviations and averages of LMPs. Table A3.3 shows the standard deviation of load weighted LMPs averaged across all 8,760 hours of the year.

	Base	CE	RP1	RP2	RP3	RP4	RP5	RP6
Future 1	110	91	87	89	89	79	85	89
Future 2	109	95	92	98	96	84	94	92
Future 3	110	95	89	92	90	80	89	88
Future 4	107	93	91	92	94	83	90	90

Table A3.3: Standard Deviations of Avg Load Weighted LMPs (2030 $)

Table A3.4 shows the standard deviation of generation weighted LMPs averaged across all 8,760 hours of the year.

	Base	CE	RP1	RP2	RP3	RP4	RP5	RP6
Future 1	120	107	102	101	108	96	99	106
Future 2	121	112	113	116	119	104	115	113
Future 3	118	109	106	105	107	98	106	104
Future 4	116	109	109	106	114	102	108	110

Table A3.4: Standard Deviations of Avg Gen Weighted LMPs (2030 $)

Metric 3: Improved Competition in SPP Markets

Table A3.5 provides the standard deviations by fuel type of the average LMPs.

	Base	CE	RP1	RP2	RP3	RP4	RP5	RP6
Future 1: LMP CC	94	92	83	89	90	85	82	88
Future 2: LMP CC	94	99	99	105	105	96	100	97
Future 3: LMP CC	93	93	89	91	93	88	89	86
Future 4: LMP CC	93	95	94	94	100	92	93	95
Future 1: LMP STG	96	97	89	94	95	93	89	90
Future 2: LMP STG	97	105	102	113	109	103	104	101
Future 3: LMP STG	93	98	93	97	94	90	94	90
Future 4: LMP STG	94	99	98	101	107	98	100	98
Future 1: LMP CT	127	110	103	104	105	99	97	107
Future 2: LMP CT	129	115	108	115	112	104	109	110
Future 3: LMP CT	129	114	108	115	105	102	104	104
Future 4: LMP CT	125	110	103	109	104	101	102	103
Future 1: LMP STC	114	98	95	95	103	83	94	102
Future 2: LMP STC	115	102	106	107	111	88	107	104
Future 3: LMP STC	109	98	98	98	100	85	98	96
Future 4: LMP STC	108	98	101	96	108	88	99	102
Future 1: LMP Wind	73	59	57	55	60	34	56	58
Future 2: LMP Wind	105	68	67	67	70	43	66	65
Future 3: LMP Wind	78	65	66	65	66	43	67	66
Future 4: LMP Wind	93	66	64	65	68	40	63	64

Table A3.5: Standard Deviations of Avg. Capacity Weighted LMPs by Generation Type ($)

Table A3.6 shows the average load-weighted LMPs for each future and plan

	Future 1	Future 2	Future 3	Future 4
Base	214.95	214.82	249.84	247.97
Cost-Effective Plan	190.97	175.27	231.90	219.47
Robust Plan 1	197.46	174.69	237.46	214.05
Robust Plan 2	195.62	174.24	238.02	215.00
Robust Plan 3	195.91	173.50	236.94	214.88
Robust Plan 4	181.93	161.71	227.15	207.26
Robust Plan 5	199.64	171.63	236.90	216.65
Robust Plan 6	197.42	173.66	240.49	217.36

Table A3.6: Average Load-Weighted LMPs by future and plan (2030 $)

Table A3.7 shows incremental costs and APC-based savings for each future.

	RP1	RP2	RP3	RP4	RP5	RP6
Incremental Annual Cost	$119	$249	$21	$871	$168	$293
Future 1 Incremental Savings	$154	$160	$67	$72	$161	$133
Future 2 Incremental Savings	$328	$328	$234	$181	$308	$302
Future 3 Incremental Savings	$80	$141	$26	$38	$97	$104
Future 4 Incremental Savings	$511	$550	$494	$350	$528	$508

Future Average Incremental Savings	$268	$295	$205	$160	$273	$262

Table A3.7: Incremental Robust Plan Cost and Savings over the Cost-Effective Plan (2010 $ millions)

Metric 1.1.2: Value of Improved ATCs of the SPP Grid

The following tables and charts provide further information regarding the calculation of the increased transfer capability measured by this metric. Table A3.8 shows the percentage and MW maximum improvement of transfers per plan. The improvement for each zone in MWs is shown in the figures that follow.

	Generation to Load		Generation to Generation		Equally Weighted	
	ATC Δ (MW)	ATC Δ (%)	ATC Δ (MW)	ATC Δ (%)	ATC Δ (MW)	ATC Δ (%)
Cost-Effective Plan	514	247%	578	259%	546	253%
Robust Plan 1	538	246%	600	265%	569	255%
Robust Plan 2	662	254%	618	269%	640	261%
Robust Plan 3	509	247%	585	260%	547	254%
Robust Plan 4	516	263%	614	276%	565	269%
Robust Plan 5	535	252%	591	262%	563	257%
Robust Plan 6	537	253%	589	261%	563	257%

Table A3.8: Percentage increase in ATC to/from another SPP Area based on Transfer type

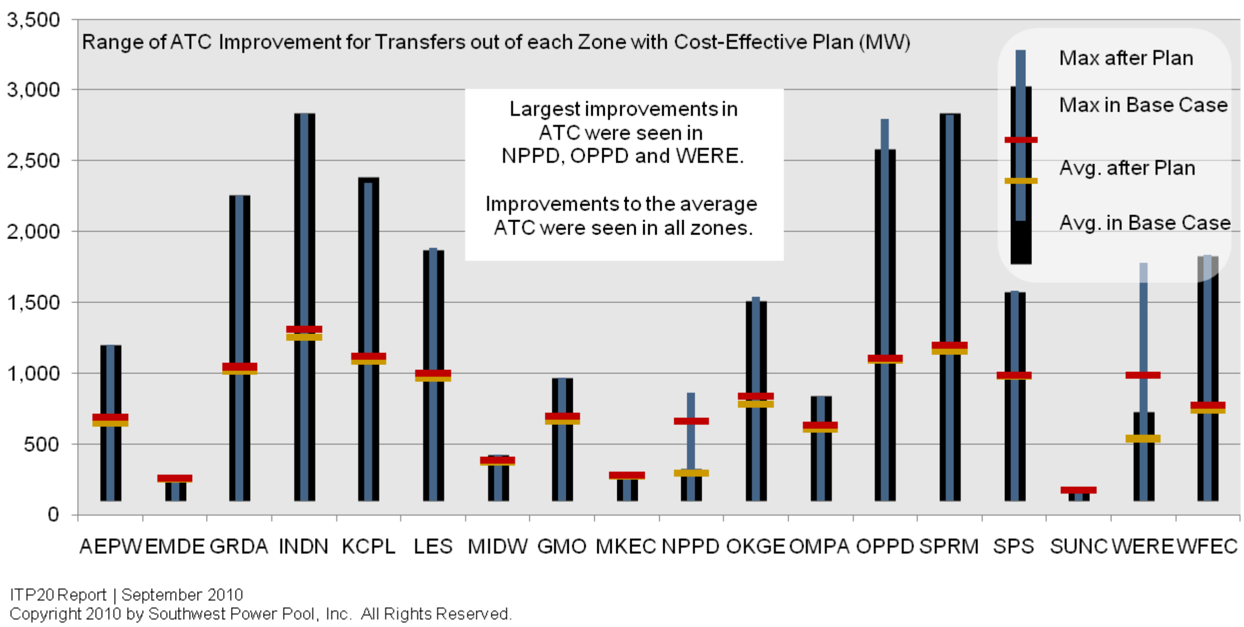

Figure A3.1: ATC Improvement for the Cost-Effective Plan by Zone (MW)

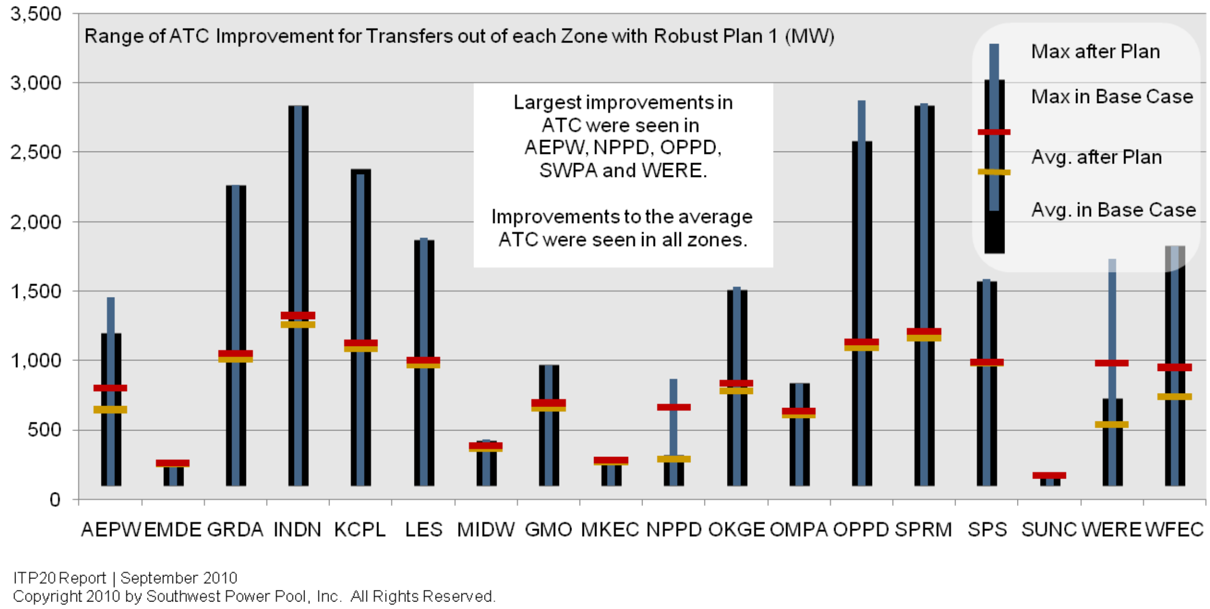

Figure A3.2: ATC Improvement for Robust Plan 1 by Zone (MW)

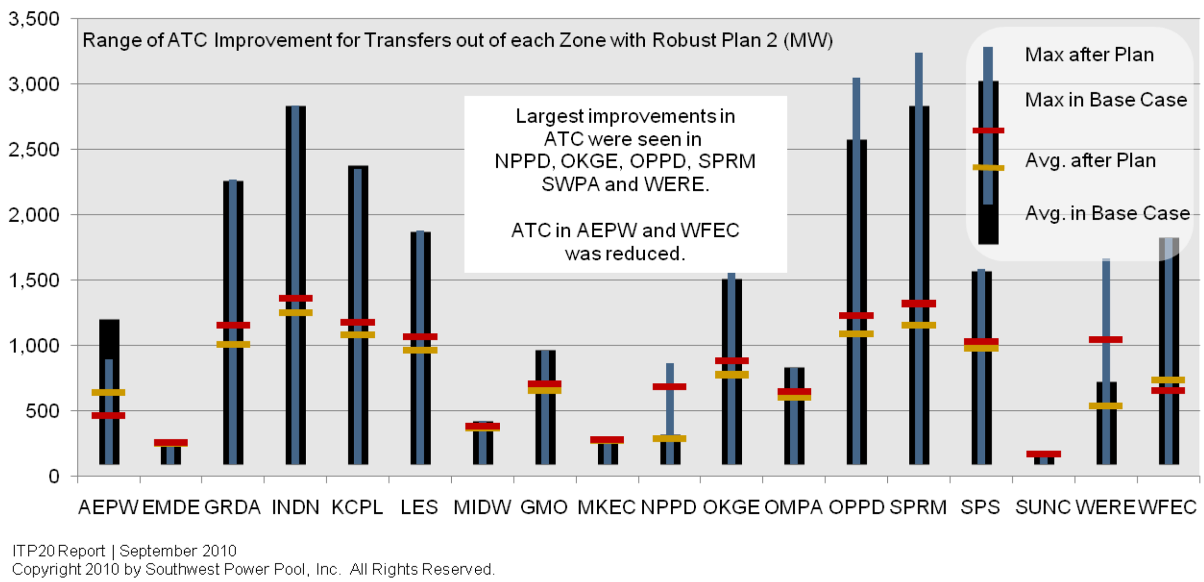

Figure A3.3: ATC Improvement for Robust Plan 2 by Zone (MW)

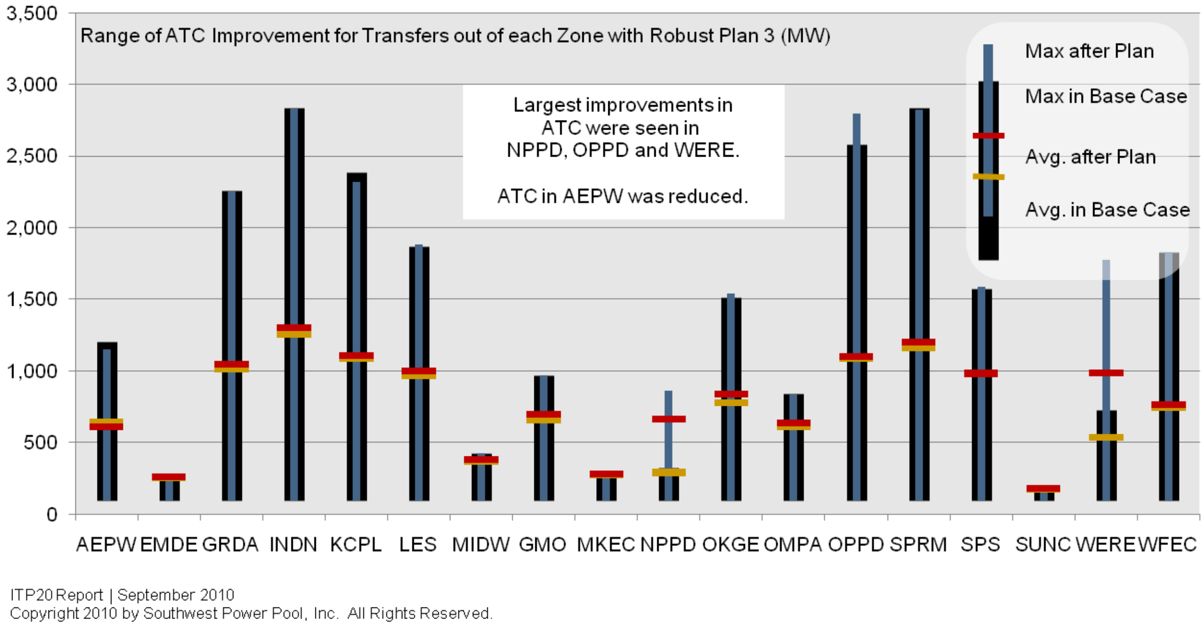

Figure A3.4: ATC Improvement for Robust Plan 3 by Zone (MW)

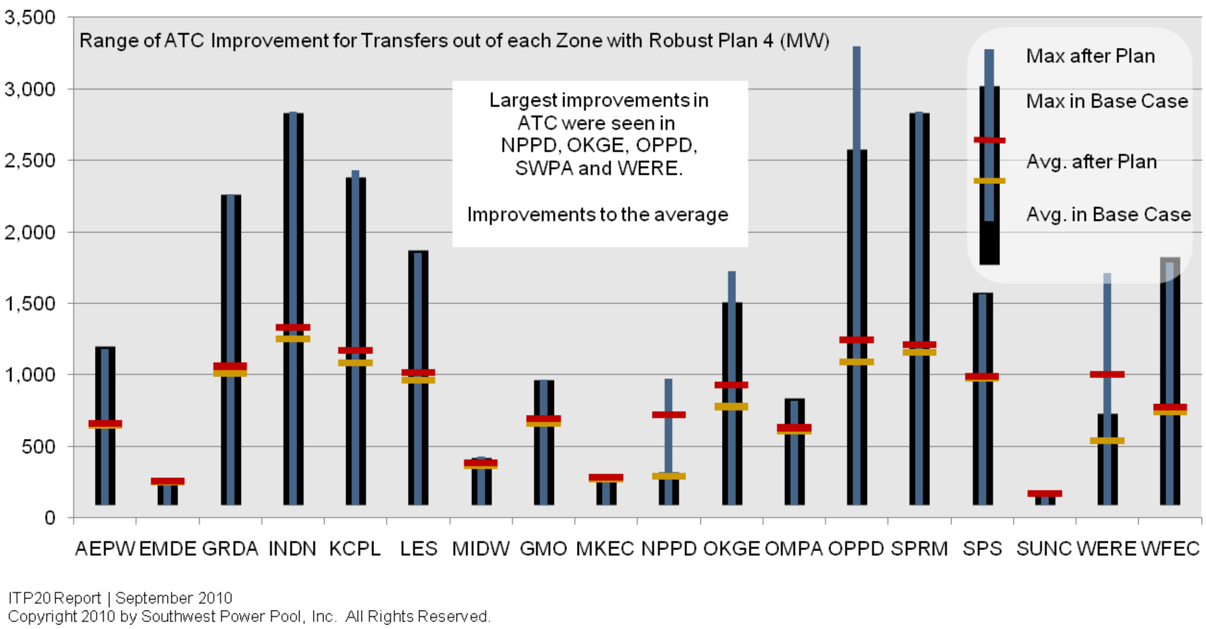

Figure A3.5: ATC Improvement for the Robust Plan 4 by Zone (MW)

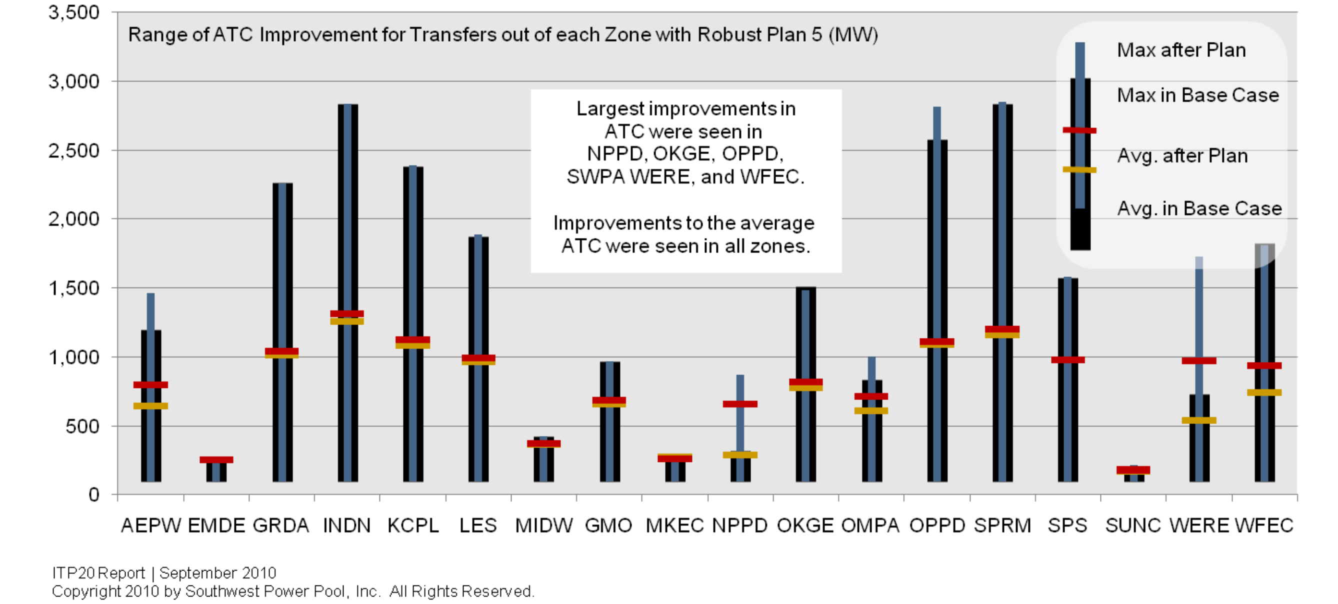

Figure A3.6: ATC Improvement for Robust Plan 5 by Zone (MW)

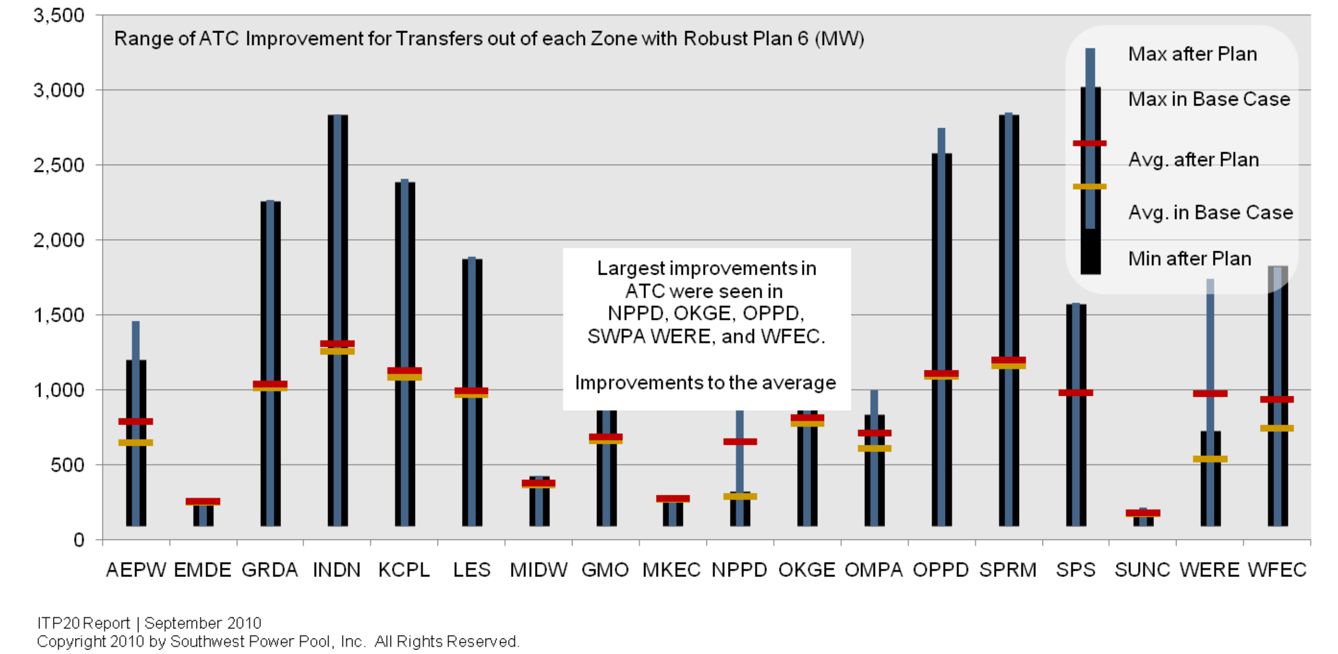

Figure A3.7: ATC Improvement for Robust Plan 6 by Zone (MW)

Metric 14: Ability to Serve New Load

The following chart provides more detail regarding the calculation of this metric.

Ability to Serve New Load	Avg. level of load that can be shifted to load centers (MW)	Increase from Base (%)	Avg. level of load that can be shifted away from load centers (MW)	Increase from Base (%)
Cost-Effective Plan	189	80%	627	357%
Robust Plan 1	317	104%	646	352%
Robust Plan 2	389	106%	1132	350%
Robust Plan 3	185	80%	622	357%
Robust Plan 4	205	79%	587	380%

Robust Plan 5	316	102%	643	372%
Robust Plan 6	305	102%	638	374%

Table A3.9: Percentage increase in Load-to-Load Transfer Capability to/from another SPP Area

Metric 6: Limited Import/Export Improvements

The following table provides more detail regarding the calculation of this metric.

	Generation to Load		Generation to Generation		Equally Weighted	
	ATC Δ (MW)	ATC Δ (%)	ATC Δ (MW)	ATC Δ (%)	ATC Δ (MW)	ATC Δ (%)
Cost-Effective Plan	393	166%	142	26%	1334	381%
Robust Plan 1	549	174%	188	32%	1335	387%
Robust Plan 2	375	160%	405	92%	1490	382%
Robust Plan 3	519	172%	142	27%	1335	378%
Robust Plan 4	445	170%	108	24%	1328	397%
Robust Plan 5	535	173%	177	29%	1213	376%
Robust Plan 6	544	174%	178	29%	1238	376%

Table A3.10: Percentage increase in ATC from a Tier 1 Area to an SPP Area

Metric 1.2: Enable Efficient Location of New Generation

The following table provides more detail regarding the calculation of this metric.

	Number of 42% + Capacity Factor Areas	Number of 38 - 42% Capacity Factor Areas	Number of 34 - 38% Capacity Factor Areas	Number of Below 34% Capacity Factor Areas	Score
Cost-Effective Plan	43	41	11	0	317
Robust Plan 1	42	42	11	7	323
Robust Plan 2	44	45	13	15	352
Robust Plan 3	43	41	11	0	317
Robust Plan 4	50	69	16	0	439
Robust Plan 5	42	42	11	7	323
Robust Plan 6	42	42	11	7	323

Table A3.11: Enable Efficient Location of New Generation Capacity

Metric 10: Reduction of Emission Rates and Values

The following tables provide more detail regarding the calculation of this metric. CE and RP in the header refer to the Cost-Effective and robust plans.

Reduction of Emission Rates	Base	CE	RP1	RP2	RP3	RP4	RP5	RP6
Future 1: NOX	1.37	1.29	1.3	1.29	1.29	1.29	1.3	1.3
Future 2: NOX	1.37	1.23	1.21	1.21	1.21	1.2	1.21	1.21
Future 3: NOX	1.28	1.21	1.21	1.21	1.21	1.21	1.21	1.21
Future 4: NOX	1.3	1.16	1.13	1.14	1.13	1.13	1.13	1.13
Future 1: SO2	1.98	1.87	1.87	1.87	1.87	1.86	1.87	1.87
Future 2: SO2	1.98	1.79	1.76	1.75	1.74	1.74	1.76	1.75
Future 3: SO2	1.84	1.74	1.74	1.74	1.74	1.73	1.74	1.74
Future 4: SO2	1.86	1.67	1.63	1.63	1.62	1.62	1.63	1.62
Future 1: CO2	1,433	1,359	1,360	1,358	1,359	1,357	1,360	1,360
Future 2: CO2	1,431	1,287	1,263	1,259	1,261	1,259	1,263	1,263
Future 3: CO2	1,359	1,292	1,293	1,292	1,292	1,293	1,293	1,293

Future 4: CO2	1,381	1,242	1,215	1,215	1,214	1,214	1,215	1,215

Table A3.12: Emission Rates based on Effluent Type (lbs/MWh)

Emission Values	Base	CE	RP1	RP2	RP3	RP4	RP5	RP6
Future 1: NOX	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Future 2: NOX	0.22	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Future 3: NOX	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Future 4: NOX	0.22	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Future 1: SO2	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
Future 2: SO2	0.32	0.31	0.31	0.3	0.3	0.3	0.31	0.31
Future 3: SO2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Future 4: SO2	0.31	0.29	0.29	0.28	0.28	0.28	0.29	0.28
Future 1: CO2	235.12	229.44	232.9	231.2	231.71	230.45	232.86	232.85
Future 2: CO2	234.51	220.11	220.67	218.27	219.18	217.39	220.64	220.61
Future 3: CO2	225.49	219.87	222.66	222.29	222.09	221.99	222.64	222.58
Future 4: CO2	229.08	214.08	213.08	212.57	212.66	211.25	213.06	212.99

Table A3.13: Emission Values based on Effluent Type (millions of tons)

Metric 11.1: Existing ROW Utilization

This table shows the additional mileage required in each plan and the mileage that could use existing ROW. Robust Plan 5 and 6 utilize the same ROW as Robust Plan 1.

	Total Miles	New ROW Miles	Existing ROW Miles	% of Existing ROW
Cost-Effective Plan	1,494	830	664	44.44%
Robust Plan 1	2,078	1,259	819	39.41%
Robust Plan 2	2,626	1,669	957	36.44%
Robust Plan 3	1,574	865	709	45.04%
Robust Plan 4	2,890	2,016	874	30.24%
Robust Plan 5	2,078	1,259	819	39.41%
Robust Plan 6	2,078	1,259	819	39.41%

Table A3.14: Transmission Corridor Utilization (ROW)

The projects that could share existing right of ways are shown in this table.

Cost-Effective Plan Lines	kV	State	230 kV and above lines that can share all or part of the required ROW
Iatan - Jeffrey Energy Center	345	KS	Jeffrey Energy Center-Hoyt-Stranger Creek-Iatan 345 kV
Wichita - Viola - Rose Hill	345	KS	Wichita - Woodring 345 kV
Cost-Effective Plan Lines	kV	State	230 kV and above lines that can share all or part of the required ROW
Spearville - Mullergren - Circle - Reno	345	KS	Spearville - Mullergren - Circle 230 kV
Tolk - Potter Co.	345	TX	Potter Co. - Plant X - Tolk 230 kV
Grand Island - Wheeler Co. rebuild[55]	345	NE	Grand Island - Ft Thompson 345 kV
Hitchland - Potter Co.	345	TX, OK	Hitchland - Potter Co. 345 kV
Ft Calhoun - S3454	345	NE	Ft Calhoun - S3454 345 kV

[55] Rebuild from 720 MVA to 1,195 MVA

Tuco - Amoco - Lea County - Hobbs	345	NM, TX	Sundown - Amoco - Lea County - Hobbs 230 kV, Tuco - Carlisle 230 kV
Robust Plan 1 lines in addition to Cost-Effective Plan	**kV**	**State**	**230 kV and above lines that can share all or part of the required ROW**
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS	JEC - E Manhattan - N.W. Manhattan - Elm Creek 230 kV
Dolet Hills - Messick	345	LA	Dolet Hills - Carrol - Messick 230 kV
Robust Plan 2 lines in addition to Cost-Effective Plan	**kV**	**State**	**230 kV and above lines that can share all or part of the required ROW**
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS	Jeffrey Energy Center - E Manhattan - N.W. Manhattan - Elm Creek 230 kV
Jeffrey Energy Center - Auburn - Swissvale	345	KS	Jeffrey Energy Center - Auburn - Swissvale 230 kV
Flint Creek - Chouteau	345	AR, OK	Flint Creek - GRDA1 345 kV
Thayer - Gobbler Knob	345	MO	Thayer - Gobbler Knob 345 kV
Robust Plan 3 lines in addition to Cost-Effective Plan	**kV**	**State**	**230 kV and above lines that can share all or part of the required ROW**
Dolet Hills - Messick	345	LA	Dolet Hills - Carrol - Messick 230 kV
Robust Plan 4 lines	**kV**	**State**	**230 kV and above lines that can share all or part of the required ROW**
Ft Calhoun - S3454	345	NE	Ft Calhoun - S3454 345 kV
Tuco - Amoco - Lea County - Hobbs	345	TX	Sundown - Amoco - Lea County - Hobbs 230 kV, Tuco - Carlisle 230 kV
Tolk-Tuco	765	TX	Tolk - Tuco 230 kV
Tolk-Potter Co.	765	TX	Tolk - Plant X - Potter Co. 230 kV
Potter Co. - Hitchland	765	TX, OK	Potter Co. - Hitchland 345 kV
Hitchland - Woodward District EHV	765	OK	Displaces existing project: Hitchland - Woodward District EHV 345 kV double circuit
Woodward District EHV - Stateline - Tuco	765	OK, TX	Displaces existing project: Woodward District EHV - Tuco 345 kV
Woodward District EHV - Sooner	765	OK	Woodring - Sooner 345 kV
Spearville - Comanche - Medicine Lodge - Wichita	765	KS	Displaces existing project: Spearville - Comanche - Medicine Lodge - Wichita 345 kV double circuit
Comanche - Woodward District EHV	765	KS, OK	Displaces existing project: Comanche - Woodward District EHV 345 kV double circuit
Robust Plan 4 lines	**kV**	**State**	**230 kV and above lines that can share all or part of the required ROW**
Mingo - Gentlemen	765	KS, NE	Mingo - Red Willow - Gentleman 345 kV
Iatan - Jeffrey Energy Center	765	MO, KS	Jeffrey Energy Center -Hoyt-Stranger Creek-Iatan 345 kV
Jeffrey Energy Center - Spearville	765	KS	Spearville - Mullergren 230 kV, Summit - Jeffrey Energy Center 345 kV
Sooner - Rose Hill	765	OK, KS	Displaces existing project: Sooner - Rose Hill 345 kV
Rose Hill - Wichita	765	KS	Wichita - Woodring 345 kV

Table A3.15: Projects that share ROW with existing transmission

Metric 11.2: Sensitive ROW Utilization

This table shows the additional mileage required in each plan that passes through environmentally protected areas. Robust Plan 5 and Robust Plan 6 utilize the same ROW as Robust Plan 1

	Total Miles	Sensitive Miles	Non-Sensitive Miles	% of Non-Sensitive Miles
Cost-Effective Plan	1,494	37	1,457	97.52%
Robust Plan 1	2,078	89	1,989	95.72%
Robust Plan 2	2,626	114	2,512	95.66%
Robust Plan 3	1,574	39	1,535	97.52%
Robust Plan 4	2,890	66	2,824	97.72%
Robust Plan 5	2,078	89	1,989	95.72%
Robust Plan 6	2,078	89	1,989	95.72%

Table A3.16: Mileage of ROW through environmentally sensitive areas

The projects that affect environmentally sensitive areas are shown in this table.

Cost-Effective Plan Lines with Sensitive ROW	kV	State	Miles of Sensitive ROW
Iatan - Jeffrey Energy Center	345	KS	16
Gentleman - Hooker Co. - Wheeler Co.	345	NE	9.7
Tolk - Potter Co.	345	TX	0.8
Woodward District EHV - Woodring	345	OK	2.4
Mingo - Post Rock	345	KS	1
Ft Calhoun - S3454	345	NE	1.1
Tuco - Amoco - Lea County - Hobbs	345	NM, TX	6
		Totals:	37
Robust Plan 1 with Sensitive ROW in Addition to Cost-Effective Plan	kV	State	Miles of Sensitive ROW
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS	7.5
Chamber Springs - Ft. Smith	345	AR	7.4
N.W. Texarkana - Ft. Smith	345	TX, AR	35
Turk - McNeil	345	LA	1.9
		Totals:	51.8
Robust Plan 2 with Sensitive ROW in Addition to Cost-Effective Plan	kV	State	Miles of Sensitive ROW
Post Rock - Elm Creek - Jeffrey Energy Center	345	KS	7.5
Robust Plan 2 with Sensitive ROW in Addition to Cost-Effective Plan	kV	State	Miles of Sensitive ROW
LaCygne - Mariosa Delta	345	KS, MO	5.4
Jeffrey Energy Center - Auburn - Swissvale	345	KS	1.6
Flint Creek - Chouteau	345	AR, OK	3.3
Flint Creek - Chamber Springs	345	AR	2.1
Chamber Springs - S Fayetteville	345	AR	5.6
S Fayetteville - Osage Creek	345	AR	0.3
Osage Creek - Table Rock	345	AR	4.4
Table Rock - Summit MO	345	MO	2
Table Rock - Bull Shoals	345	MO, AR	19.4
Bull Shoals - Norfork	345	AR	1.5
S Fayetteville - Van Buren	500	AR	10.9
Van Buren - ANO	500	AR	13
		Totals:	77
Robust Plan 3 with Sensitive ROW in Addition to Cost-Effective Plan	kV	State	Miles of Sensitive ROW
Turk - McNeil	345	LA	1.9
		Totals:	1.9
Robust Plan 4 Lines with Sensitive ROW	kV	State	Miles of Sensitive ROW
Ft Calhoun - S3454	345	NE	1.1
Tuco - Amoco - Lea County - Hobbs	345	TX	6

Potter Co. - Hitchland	765	TX, OK	4.4
Hitchland - Woodward District EHV	765	OK	6.9
Woodward District EHV - Stateline - Tuco	765	OK, TX	8.1
Woodward District EHV - Sooner	765	OK	1.7
Comanche - Woodward District EHV	765	KS, OK	0.7
Gentlemen - Hooker Co	765	NE	4
Hooker - Wheeler Co	765	NE	5.7
Wheeler Co - Sheldon	765	NE	1.3
Sheldon - Iatan	765	NE, KS, MO	0.2
Iatan - Jeffrey Energy Center	765	MO, KS	16.2
Jeffrey Energy Center - Spearville	765	KS	9.1
Sooner - Rose Hill	765	OK, KS	1
		Totals:	66.4

Table A3.17: Projects with Mileage through Environmentally Sensitive Areas

Metric 1.6: Positive Impact on Losses Capacity

The following table shows the MW losses for each plan

Losses Capacity	Base	CE	RP1	RP2	RP3	RP4	RP5	RP6
Total SPP Losses	1538	1512	1501	1486	1510	1513	1518	1505

Table A3.18: Transmission System Losses (MW)

ESWG Metric Voting Results

The ESWG members performed a membership vote where each member was given 100 points to assign across the metrics. The members' votes were summed together to find the weighting for each metric. Ten members voted for a total of 1000 points across the 11 metrics.

Metric No.	Total ESWG	LES	AECI	OMPA	WR	AEP	NPPD	SECI	OGE	EMDE	ITC
1.1.2	202.33	30	40	16	18.33	15	13	10	20	25	15
1.2	81.83	20	10	4	3.33	12.5	7	15	5		5
1.6	92	10		2		10	10	12	13	20	15
2	133.33		15	18	13.33	10	7	20	25	10	15
3	93.33			18	23.33	5	7	15	10		15
3	112.5		15	10	20	12.5	13	10	3	25	4
10	29.67			2	6.67	5	6	4	2		4
11.1	58	10		10	0	5	10	4	15		4
11.2	32			2	5	5	10	4	2		4
13	57			2	10	5	4	1		20	15
14	108	30	20	16		15	13	5	5		4
Total	**1000**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**

Appendix A4: High Resolution Map Images

This appendix contains larger versions of the maps of the Common Plan, Cost-Effective Plan and the six robust plans.

A4.1: Common Plan

Figure A4.1: Common Plan

A4.2: Cost-Effective Plan

Figure A4.2: Cost-Effective Plan

A4.3: Robust Plan 1

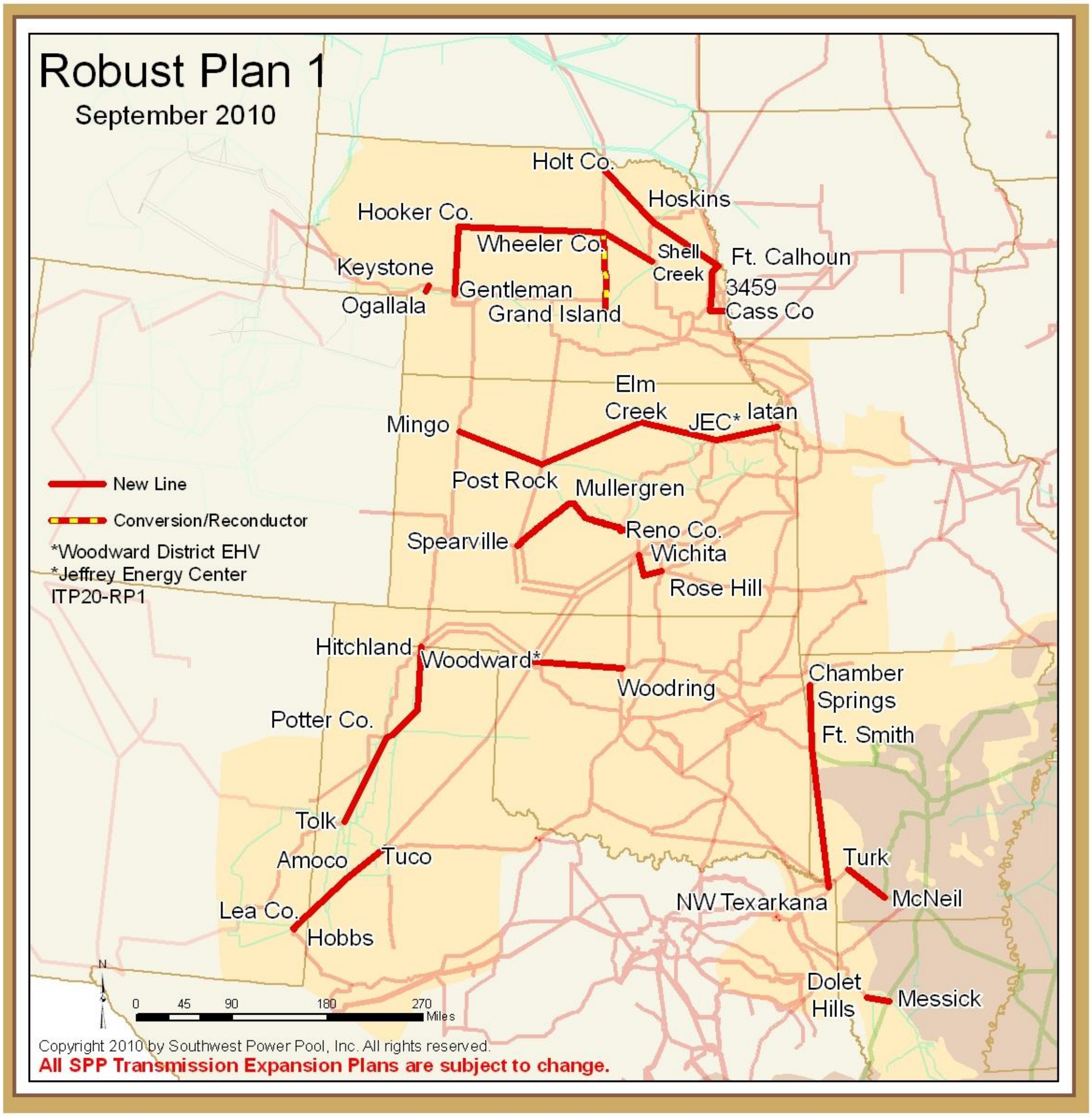

Figure A4.3: Robust Plan 1

A4.4: Robust Plan 2

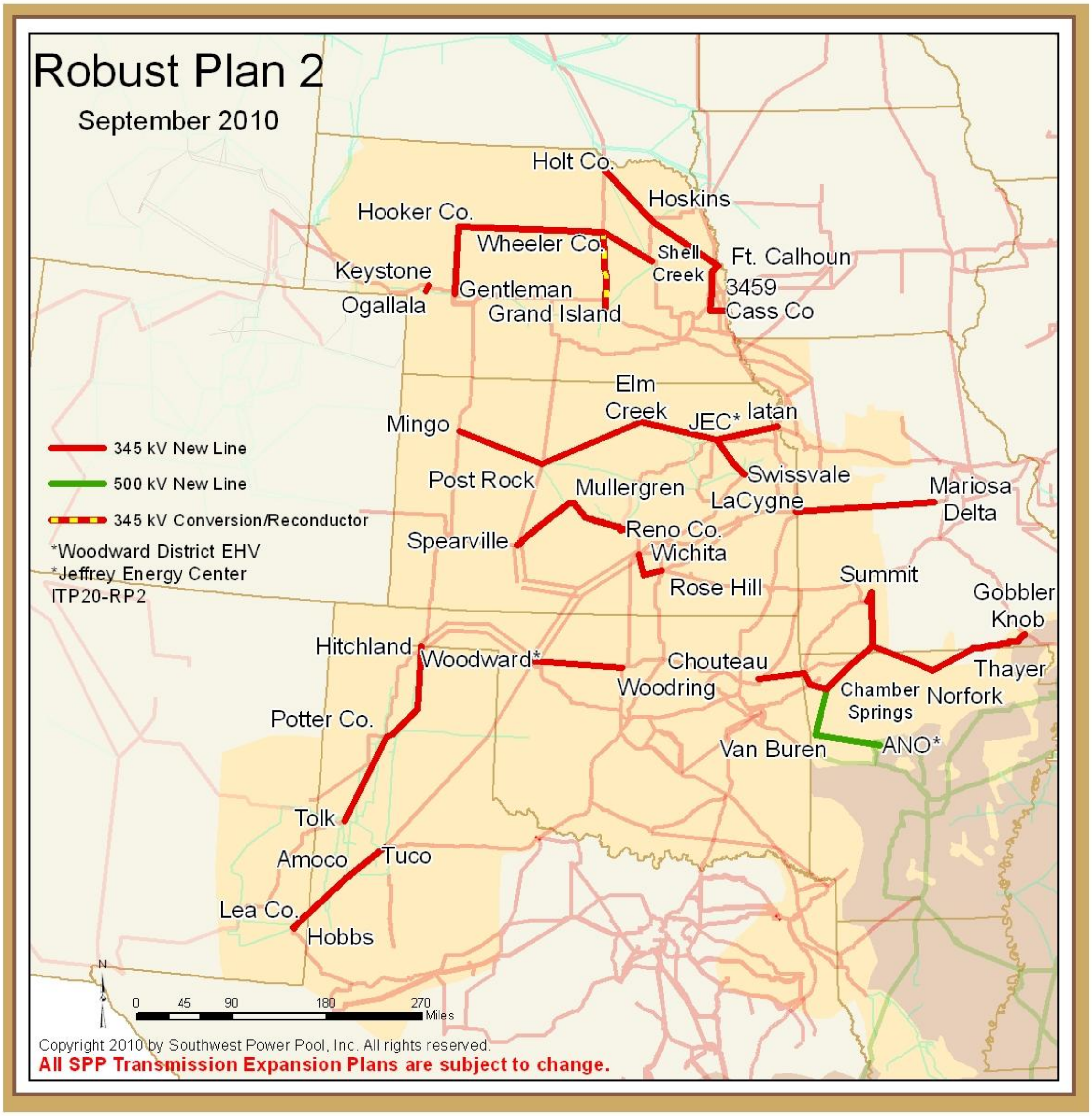

Figure A4.4: Robust Plan 2

A4.5: Robust Plan 3

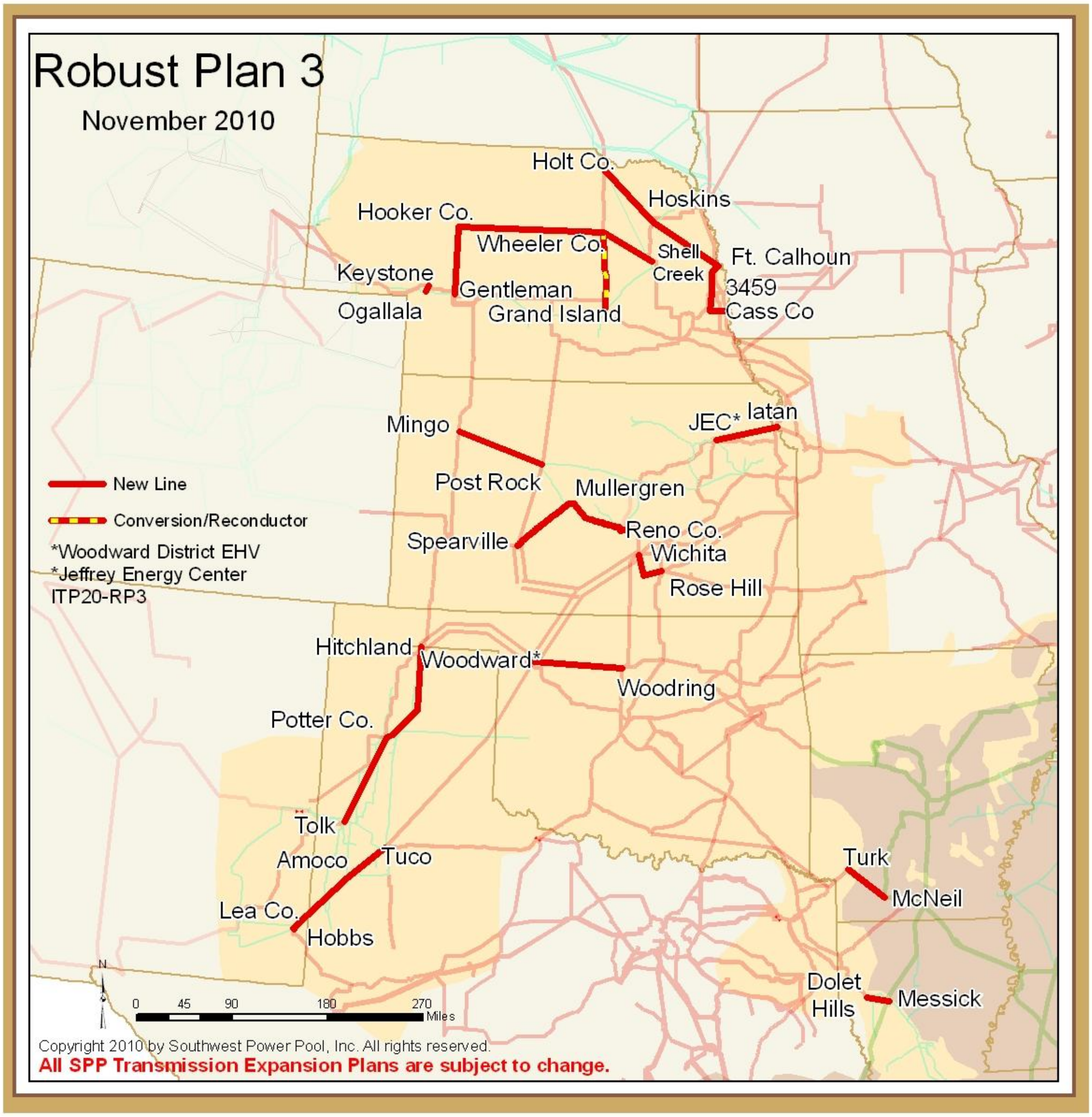

Figure A4.5: Robust Plan 3

A4.6: Robust Plan 4

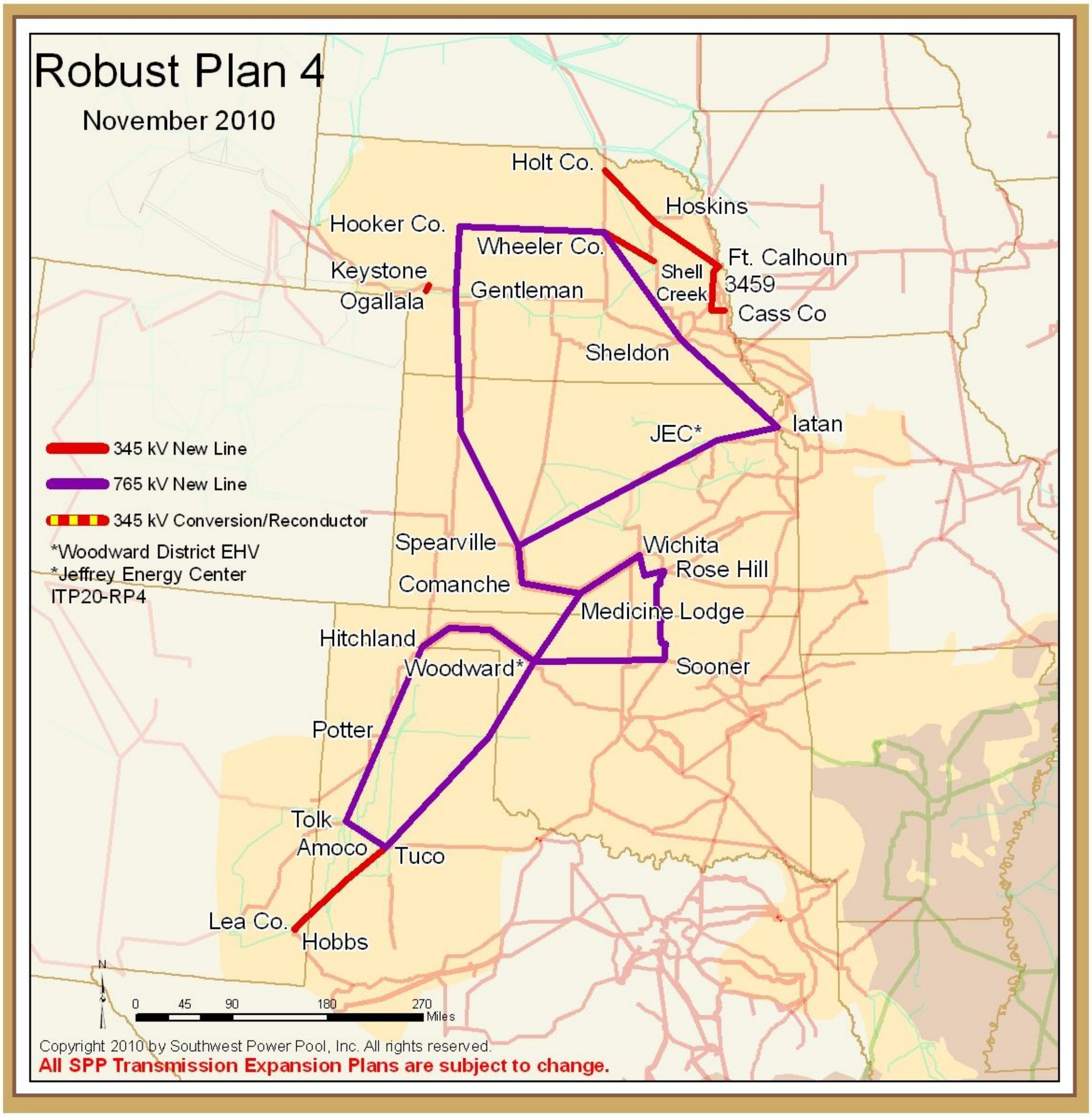

Figure A4.6: Robust Plan 4

A4.7: Robust Plan 5

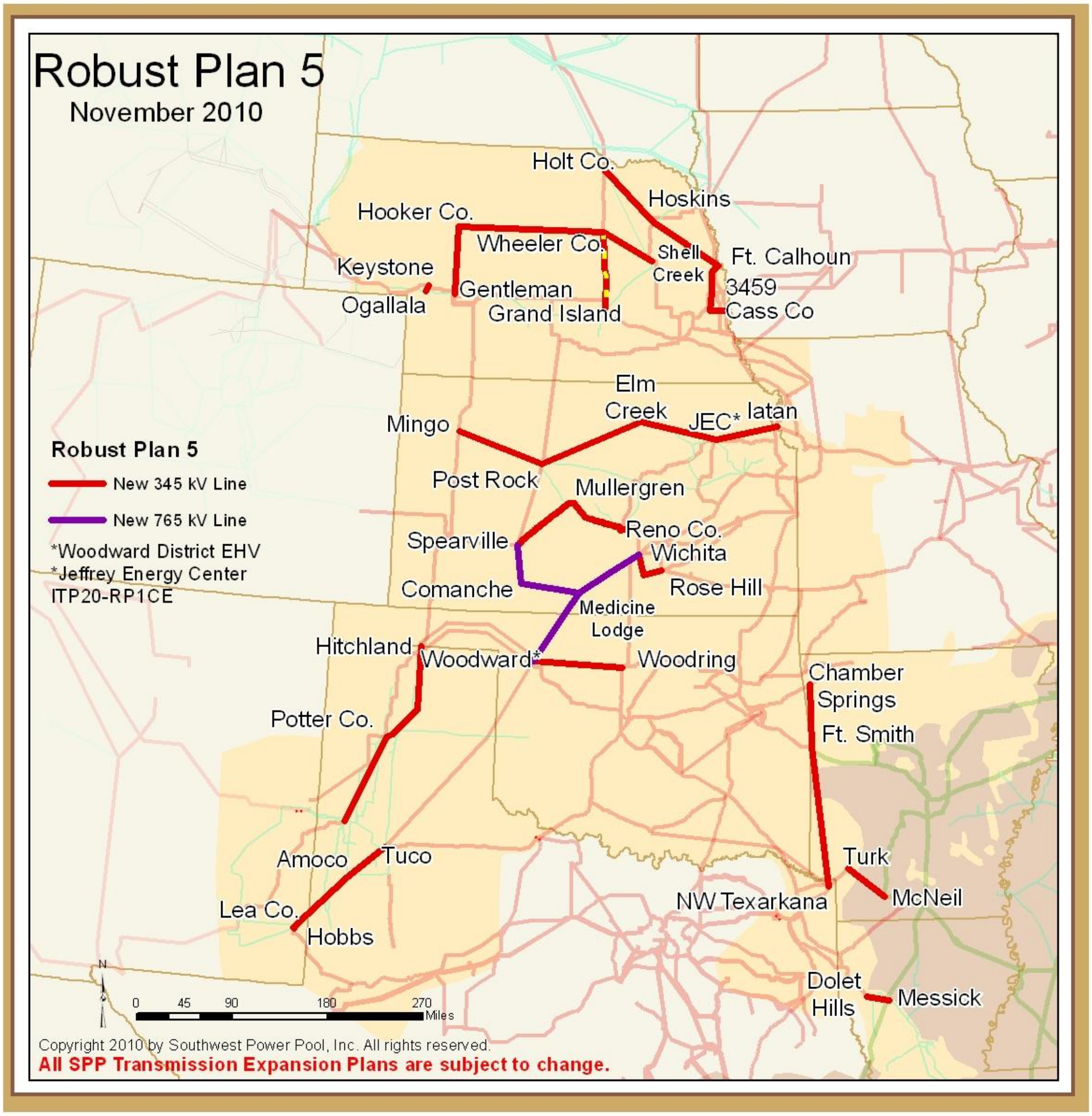

Figure A4.7: Robust Plan 5

A4.8: Robust Plan 6

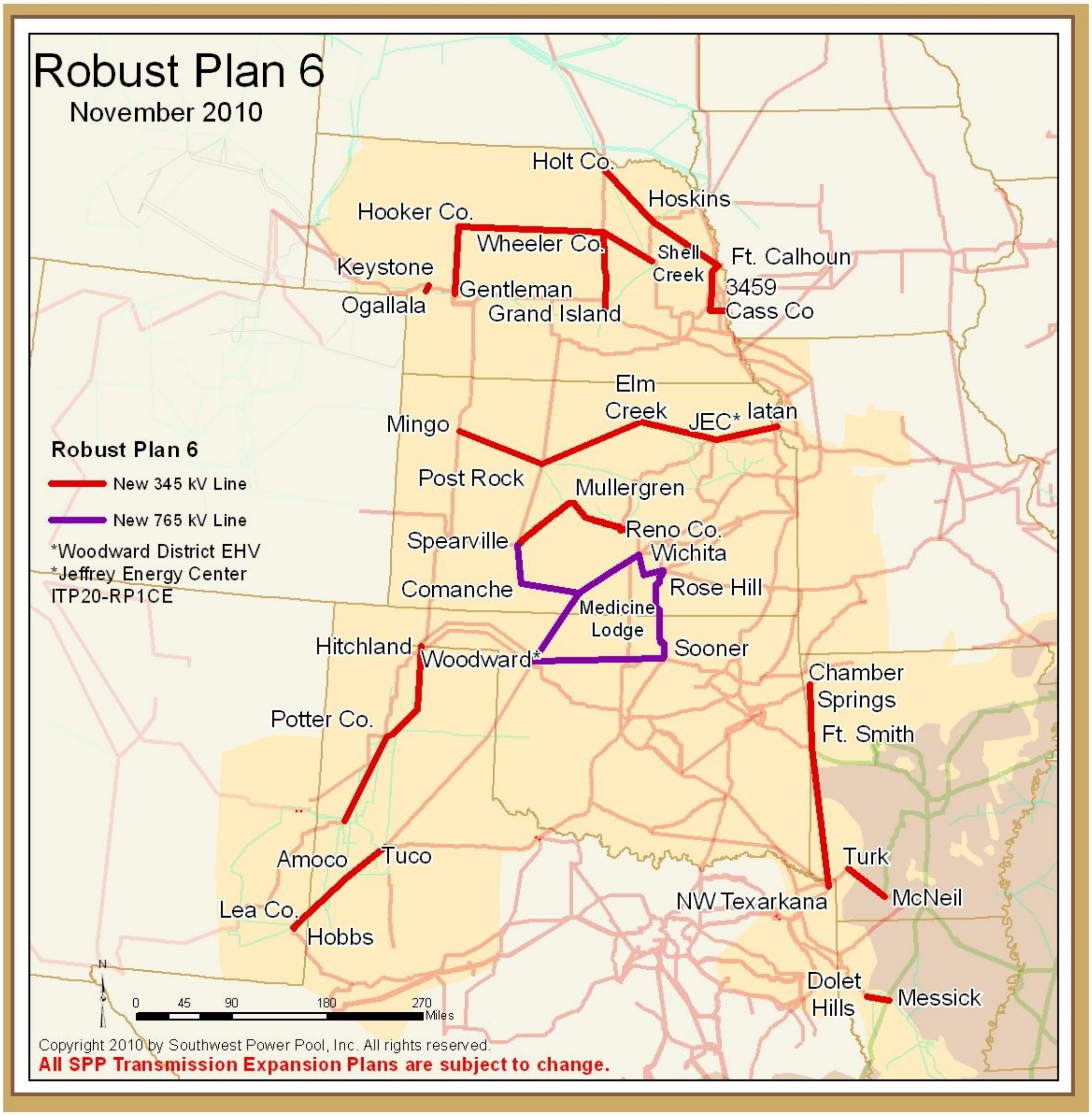

Figure A4.8: Robust Plan 6

Appendix A5: Resource Siting and Plans

Refer to Section 7: Resource Futures and Plan for the background regarding development of these plans.

Summary by Future

This chart summarizes the additional conventional and renewable capacity that was added to the SPP footprint in order to maintain a 12% capacity reserve margin. Full details of the plan can be found in the ITP20 Generator Resources Report published by Black & Veatch for SPP[56].

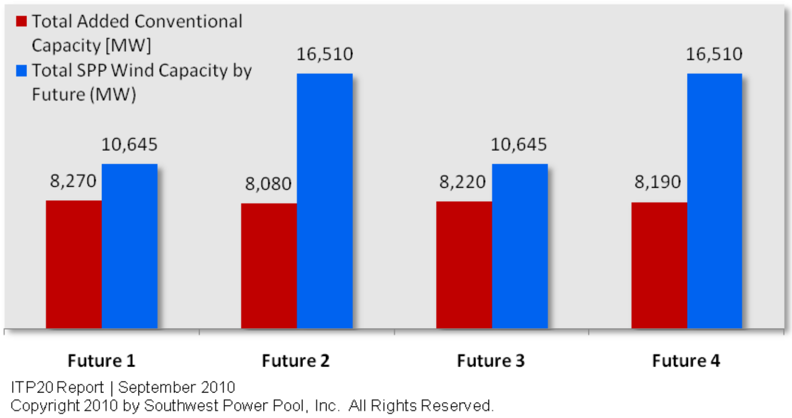

Figure A5.1: Total Capacities for each future from the Resource Plan (MW)

Brownfield sites were used for all additional conventional units following the application of the ESWG's siting criteria. Each future included the addition of at least 9 combined cycle units, 9 combustion turbines and 26 new wind farms. A coal unit was added in futures 1 and 2.

Capacity Types Added

Black & Veatch considered different technology types but only four specific technologies were added to the resource plan:

- 550 MW capacity Natural Gas Combined Cycle (CC)
- 180 MW capacity Natural Gas Combustion Turbine (CT)
- 800 MW capacity Coal SCPC without Carbon Capture & Sequestration (Coal)
- Various MW capacity Wind farms based on NREL profile data and state renewable needs

Additions by Technology for each Future

The assumptions of each future and the criteria used to select the units produced four distinct, but similar resource plans. Table A6.1 summarizes the amount of conventional capacity added to SPP's resource plan.

Technology	Future 1	Future 2	Future 3	Future 4
CC	4,950	4,400	6,600	4,950
CT	2,520	2,880	1,620	3,240
Coal	800	800	0	0
Total	**8,270**	**8,080**	**8,220**	**8,190**

Table A5.1: Added Conventional Capacity by Type for each Future (MW)

[56] SPP.org > Engineering > Transmission Planning > Integrated Transmission Planning > ITP20-Year Assessment

Additions by Zone for each Future

The location of each generator was decided by criteria specified by the ESWG and applied by Black & Veatch. The capacity added by zone is shown in Table A5.2. The geographic locations of each additional resource are shown in Figure A5.2.

Zone	Future 1	Future 2	Future 3	Future 4
AEPW	730	730	730	730
BPU	0	0	0	0
CUS-MO	180	180	180	180
EDE	550	360	550	360
GMO	180	180	180	360
KCPL	550	550	550	550
LES	0	0	0	180
MKEC	180	180	550	180
MWE	180	180	180	180
NPPD	180	180	180	180
OGE & GRDA	960	960	960	960
OPPD	550	550	550	550
SPS	2,070	2,070	1,830	1,820
Sunflower	180	180	0	180
WFEC	320	320	320	320
WR	1,460	1,460	1,460	1,460
Total	8,270	8,080	8,220	8,190

Table A5.2: Added Conventional Capacity by Zone for each Future (MW)

Wind Capacity by State for each Future

Additional wind capacity was located within states based upon the data contained in the CAWG Survey and criteria set forth by the ESWG. Table A6.3 contains the amount of wind generation by state for each future. It is important to note that the wind capacity numbers shown are the total wind within SPP, not additional to existing wind (approximately 4,200 MW as of September 2010).

State	Future 1	Future 2	Future 3	Future 4	2010 Existing and Under Construction Wind (GW)
Arkansas	190	0	190	0	0
Kansas	2,627	3,921	2,627	3,921	1,024
Missouri	671	0	671	0	0
Nebraska	1,389	3,847	1,389	3,847	443
New Mexico	204	204	204	204	204
Oklahoma	3,566	4,905	3,566	4,905	1,599
Texas	1,998	3,634	1,998	3,634	974
Total	10,645	16,510	10,645	16,510	4,243

Table A5.3: Total wind capacity by State for each Future (MW)

Wind Locations

Wind was sited according to ESWG criteria and wind profiles were approximated using National Renewable Energy Laboratory (NREL) datasets[57]. Specific bus interconnection points for study purposes were selected by SPP Staff based upon proximity to existing transmission circuits and

[57] Eastern Wind Integration and Transmission Study (EWITS) & Western Wind and Solar Integration Study (WWSIS)

substations and vetted by the ESWG. Table A5.4 and Table A5.5 show the existing and new wind farms with capacity factors and profiles used from the NREL datasets for each future. New wind farms were identified by the nearest county in each state. The geographic locations of each additional wind site are shown in Figure A5.2, existing sites are not shown. Larger renderings of these maps are shown later in this appendix. To request powerflow bus locations of these wind sites contact SPP staff at planning@spp.org.

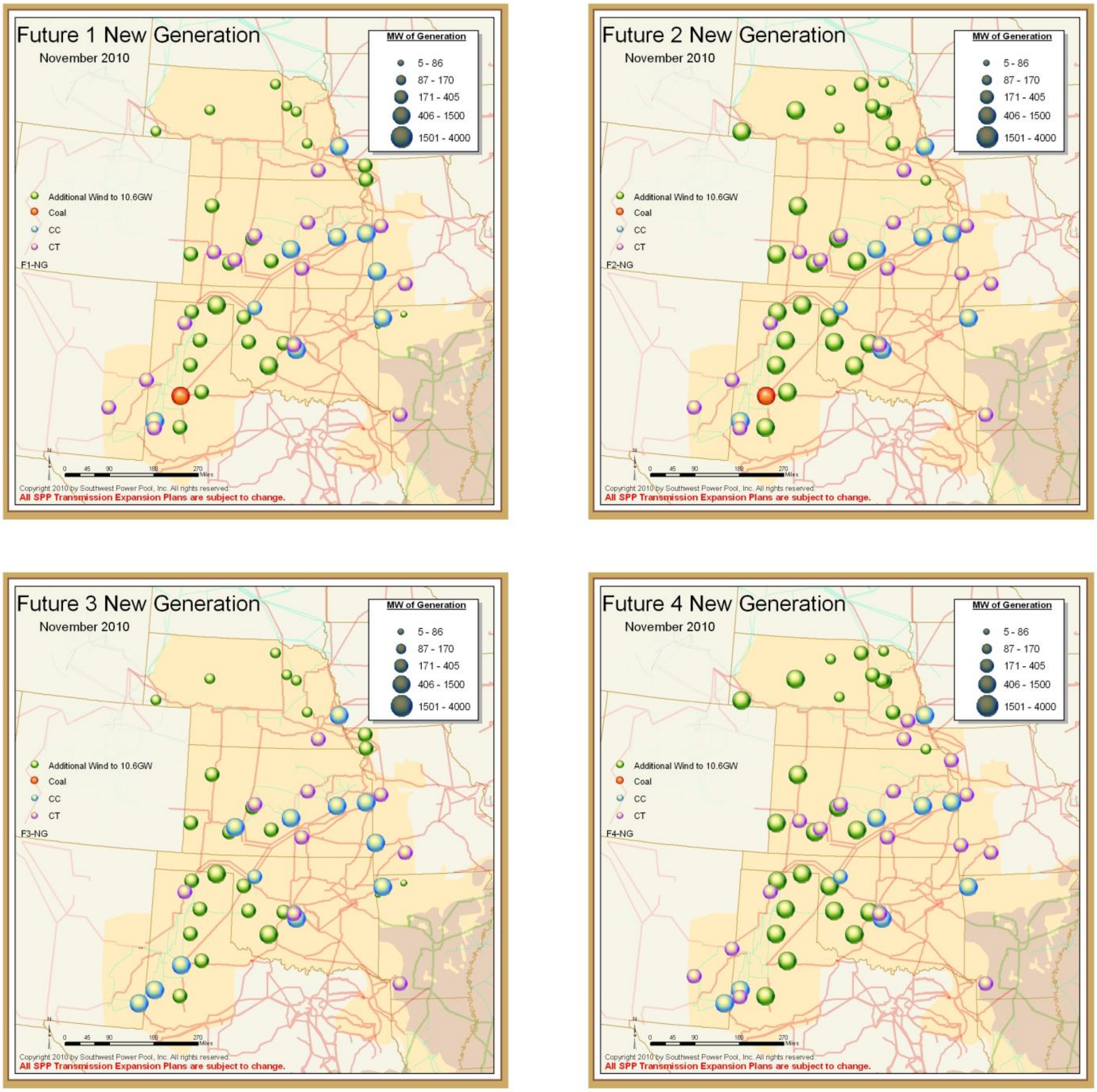

Figure A5.2: Additional Capacity Sites by Technology Type for each Future

Futures 1 and 3 Wind Locations

Wind Farm Name	State	NREL Study	NREL Site ID	CF	Capacity (MW)	New Location
Arkansas #1	AR	EWITS	5038	33%	63.6	Washington County, AR
Arkansas #2	AR	EWITS	4356	35%	66.1	Carroll County, AR
Arkansas #3	AR	EWITS	5374	32%	60.2	Benton County, AR
Missouri #1	MO	EWITS	4217	37%	325.0	Andrew County, MO

Wind Farm Name	State	NREL Study	NREL Site ID	CF	Capacity (MW)	New Location
Missouri #4	MO	EWITS	3504	39%	346.0	Nodaway County, MO
Elkhorn Ridge	NE	EWITS	70	42%	81.0	
Ainsworth	NE	EWITS	245	41%	60.0	
Flat Water (Richardson Co.)	NE	EWITS	1149	39%	60.0	
Crofton Hills	NE	EWITS	70	42%	42.0	
Laredo Ridge	NE	EWITS	47	42%	80.0	
Petersburg	NE	EWITS	47	42%	40.0	
Broken Bow	NE	EWITS	76	42%	80.0	
Hoskins 1	NE	EWITS	22	43%	116.8	Madison County, NE
Hoskins 2	NE	EWITS	143	41%	116.8	Holt County, NE
Hoskins 3	NE	EWITS	205	41%	116.8	Antelope County, NE
Hoskins 4	NE	EWITS	208	41%	116.8	Butler County, NE
Gentleman 1	NE	EWITS	76	42%	159.7	Hooker County, NE
Gentleman 2	NE	EWITS	160	41%	159.7	Hooker County, NE
Gentleman 3	NE	EWITS	695	39%	159.7	Kimball County, NE
Aeolus	TX	WWSIS	6524	36%	3.0	
Conestoga	TX	WWSIS	6764	37%	198.0	
DWS	TX	WWSIS	1460	44%	18.9	
Hansford:WIED1	TX	EWITS	1075	43%	80.0	
Higher Plains Power Wind 1	TX	WWSIS	4848	40%	10.0	
JD Wind 4 ALL	TX	WWSIS	1357	45%	100.0	
Llano Estacado 1	TX	WWSIS	1481	44%	80.0	
Majestic WF PH1	TX	WWSIS	4921	40%	79.5	
Noble Great Plains PH1	TX	WWSIS	6837	37%	114.0	
Sunray Wind 1	TX	WWSIS	1482	45%	7.5	
Sunray Wind 2	TX	WWSIS	1638	45%	7.5	
Sunray Wind 3	TX	WWSIS	1548	43%	34.5	
Wildorado Wind Ranch LTI	TX	WWSIS	4259	43%	161.0	
Wildorado Wind Ranch 2	TX	WWSIS	4259	43%	80.0	
Texas #1	TX	EWITS	3060	38%	175.5	Lynn County, TX
Texas #2	TX	EWITS	27	47%	216.1	Floyd County, TX
Texas #3	TX	EWITS	470	45%	206.0	Armstrong County, TX
Texas #4	TX	EWITS	34	49%	222.6	Carson County, TX
Texas #5	TX	EWITS	573	44%	203.7	Sherman County, TX
Elk City Wind	OK	EWITS	115	47%	99.0	
Weatherford WF	OK	EWITS	1271	41%	40.5	
Centennial OGE	OK	EWITS	2134	41%	120.0	
Oklahoma Wind Egy	OK	EWITS	1272	43%	100.0	
OU Spirit	OK	EWITS	2407	40%	101.0	
Taloga Wind	OK	EWITS	2029	40%	130.0	
Blue Canyon Wind	OK	EWITS	2399	40%	74.3	
Blue Canyon Windpower II:WND1	OK	EWITS	14	48%	151.2	

Wind Farm Name	State	NREL Study	NREL Site ID	CF	Capacity (MW)	New Location
Blue Canyon Windpower III:WND1	OK	EWITS	14	48%	100.0	
Buffalo Bear WF PH1	OK	EWITS	2398	41%	96.0	
Red Hills WP PH1	OK	EWITS	1438	42%	123.0	
Sleeping Bear WF 45	OK	EWITS	2342	39%	94.5	
South Buffalo:WIED2	OK	EWITS	1712	41%	19.0	
Keenan	OK	EWITS	1272	43%	152.0	
Crossroads	OK	EWITS	2029	40%	198.0	
Oklahoma #1	OK	EWITS	632	44%	398.4	Ellis County, OK
Oklahoma #2	OK	EWITS	14	48%	431.7	Kiowa County, OK
Oklahoma #3	OK	EWITS	1438	42%	373.2	Roger Mills, OK
Oklahoma #4	OK	EWITS	365	46%	410.1	Beaver County, OK
Oklahoma #5	OK	EWITS	2342	39%	354.3	Canadian County, OK
Flat Ridge WF ALL	KS	EWITS	761	44%	100.0	
Gray County 1	KS	WWSIS	8019	35%	112.0	
Spearville	KS	EWITS	441	47%	100.0	
Smoky Hills WF ALL	KS	EWITS	669	45%	250.0	
Central Plains WF ALL	KS	EWITS	504	46%	99.0	
Greenburg WF	KS	EWITS	342	46%	12.0	
Elk River WF WT	KS	EWITS	751	43%	150.0	
Meridian Way WF ALL	KS	EWITS	240	46%	201.0	
Kansas #1	KS	EWITS	62	49%	343.1	Gray County, KS
Kansas #2	KS	EWITS	444	46%	326.9	Rush County, KS
Kansas #3	KS	EWITS	583	45%	320.5	Hamilton County, KS
Kansas #4	KS	EWITS	1330	44%	309.2	Thomas County, KS
Kansas #5	KS	EWITS	1449	43%	303.6	Pratt County, KS
Caprock Wind	NM	EWITS	387	44%	80.0	
San Juan Mesa Wind 120	NM	WWSIS	1198	35%	120.0	
Llanco Estacado Texico	NM	WWSIS	30656	35%	2.0	
Mesalands	NM	WWSIS	30629	35%	1.5	

Table A5.4: Wind Siting, Capacity Factor and Capacity for Futures 1 & 3

Futures 2 and 4 Wind Locations

Wind Farm Name (Futures 2 & 4)	State	NREL Study	NREL Site ID	CF	Capacity (MW)	New Location
Arkansas #1	AR	EWITS	5038	33%	0.0	Washington County, AR
Arkansas #2	AR	EWITS	4356	35%	0.0	Carroll County, AR
Arkansas #3	AR	EWITS	5374	32%	0.0	Benton County, AR
Missouri #1	MO	EWITS	4217	37%	0.0	Andrew County, MO
Missouri #4	MO	EWITS	3504	39%	0.0	Nodaway County, MO
Elkhorn Ridge	NE	EWITS	70	42%	224.3	
Ainsworth	NE	EWITS	245	41%	166.1	
Flat Water (Richardson Co.)	NE	EWITS	1149	39%	166.1	
Crofton Hills	NE	EWITS	70	42%	116.3	
Laredo Ridge	NE	EWITS	47	42%	221.5	

Petersburg	NE	EWITS	47	42%	110.8	
Broken Bow	NE	EWITS	76	42%	221.5	
Hoskins 1	NE	EWITS	22	43%	323.4	Madison County, NE
Hoskins 2	NE	EWITS	143	41%	323.4	Holt County, NE
Hoskins 3	NE	EWITS	205	41%	323.4	Antelope County, NE
Hoskins 4	NE	EWITS	208	41%	323.4	Butler County, NE
Gentleman 1	NE	EWITS	76	42%	442.3	Hooker County, NE
Gentleman 2	NE	EWITS	160	41%	442.3	Hooker County, NE
Gentleman 3	NE	EWITS	695	39%	442.3	Kimball County, NE
Aeolus	TX	WWSIS	6524	36%	3.0	
Conestoga	TX	WWSIS	6764	37%	198.0	
DWS	TX	WWSIS	1460	44%	18.9	
Hansford:WIED1	TX	EWITS	1075	43%	80.0	
Higher Plains Power Wind 1	TX	WWSIS	4848	40%	10.0	
JD Wind 4 ALL	TX	WWSIS	1357	45%	100.0	
Llano Estacado 1	TX	WWSIS	1481	44%	80.0	
Majestic WF PH1	TX	WWSIS	4921	40%	79.5	
Noble Great Plains PH1	TX	WWSIS	6837	37%	114.0	
Sunray Wind 1	TX	WWSIS	1482	45%	7.5	
Sunray Wind 2	TX	WWSIS	1638	45%	7.5	
Sunray Wind 3	TX	WWSIS	1548	43%	34.5	
Wildorado Wind Ranch LTI	TX	WWSIS	4259	43%	161.0	
Wildorado Wind Ranch 2	TX	WWSIS	4259	43%	80.0	
Texas #1	TX	EWITS	3060	38%	455.8	Lynn County, TX
Texas #2	TX	EWITS	27	47%	561.4	Floyd County, TX
Texas #3	TX	EWITS	470	45%	535.2	Armstrong County, TX
Texas #4	TX	EWITS	34	49%	578.1	Carson County, TX
Texas #5	TX	EWITS	573	44%	529.2	Sherman County, TX
Elk City Wind	OK	EWITS	115	47%	99.0	
Weatherford WF	OK	EWITS	1271	41%	40.5	
Centennial OGE	OK	EWITS	2134	41%	120.0	
Oklahoma Wind Egy	OK	EWITS	1272	43%	100.0	
OU Spirit	OK	EWITS	2407	40%	101.0	
Taloga Wind	OK	EWITS	2029	40%	130.0	
Blue Canyon Wind	OK	EWITS	2399	40%	74.3	
Blue Canyon Windpower II:WND1	OK	EWITS	14	48%	151.2	
Blue Canyon Windpower III:WND1	OK	EWITS	14	48%	100.0	
Buffalo Bear WF PH1	OK	EWITS	2398	41%	96.0	
Red Hills WP PH1	OK	EWITS	1438	42%	123.0	
Sleeping Bear WF 45	OK	EWITS	2342	39%	94.5	
South Buffalo:WIED2	OK	EWITS	1712	41%	19.0	
Keenan	OK	EWITS	1272	43%	152.0	
Crossroads	OK	EWITS	2029	40%	198.0	

Oklahoma #1	OK	EWITS	632	44%	669.4	Ellis County, OK
Oklahoma #2	OK	EWITS	14	48%	725.3	Kiowa County, OK
Oklahoma #3	OK	EWITS	1438	42%	627.1	Roger Mills, OK
Oklahoma #4	OK	EWITS	365	46%	689.1	Beaver County, OK
Oklahoma #5	OK	EWITS	2342	39%	595.4	Canadian County, OK
Flat Ridge WF ALL	KS	EWITS	761	44%	100.0	
Gray County 1	KS	WWSIS	8019	35%	112.0	
Spearville	KS	EWITS	441	47%	100.0	
Smoky Hills WF ALL	KS	EWITS	669	45%	250.0	
Central Plains WF ALL	KS	EWITS	504	46%	99.0	
Greenburg WF	KS	EWITS	342	46%	12.0	
Elk River WF WT	KS	EWITS	751	43%	150.0	
Meridian Way WF ALL	KS	EWITS	240	46%	201.0	
Kansas #1	KS	EWITS	62	49%	619.9	Gray County, KS
Kansas #2	KS	EWITS	444	46%	590.6	Rush County, KS
Kansas #3	KS	EWITS	583	45%	579.1	Hamilton County, KS
Kansas #4	KS	EWITS	1330	44%	558.7	Thomas County, KS
Kansas #5	KS	EWITS	1449	43%	548.5	Pratt County, KS
Caprock Wind	NM	EWITS	387	44%	80.0	
San Juan Mesa Wind 120	NM	WWSIS	1198	35%	120.0	
Llanco Estacado Texico	NM	WWSIS	30656	35%	2.0	
Mesalands	NM	WWSIS	30629	35%	1.5	

Table A5.5: Wind Siting, Capacity Factor and Capacity for Futures 2 & 4

Summary Sheets for Each Resource Plan

The following sheets provide an at-a-glance summary of each resource plan showing the MW capacity, number of sites and site locations for each future.

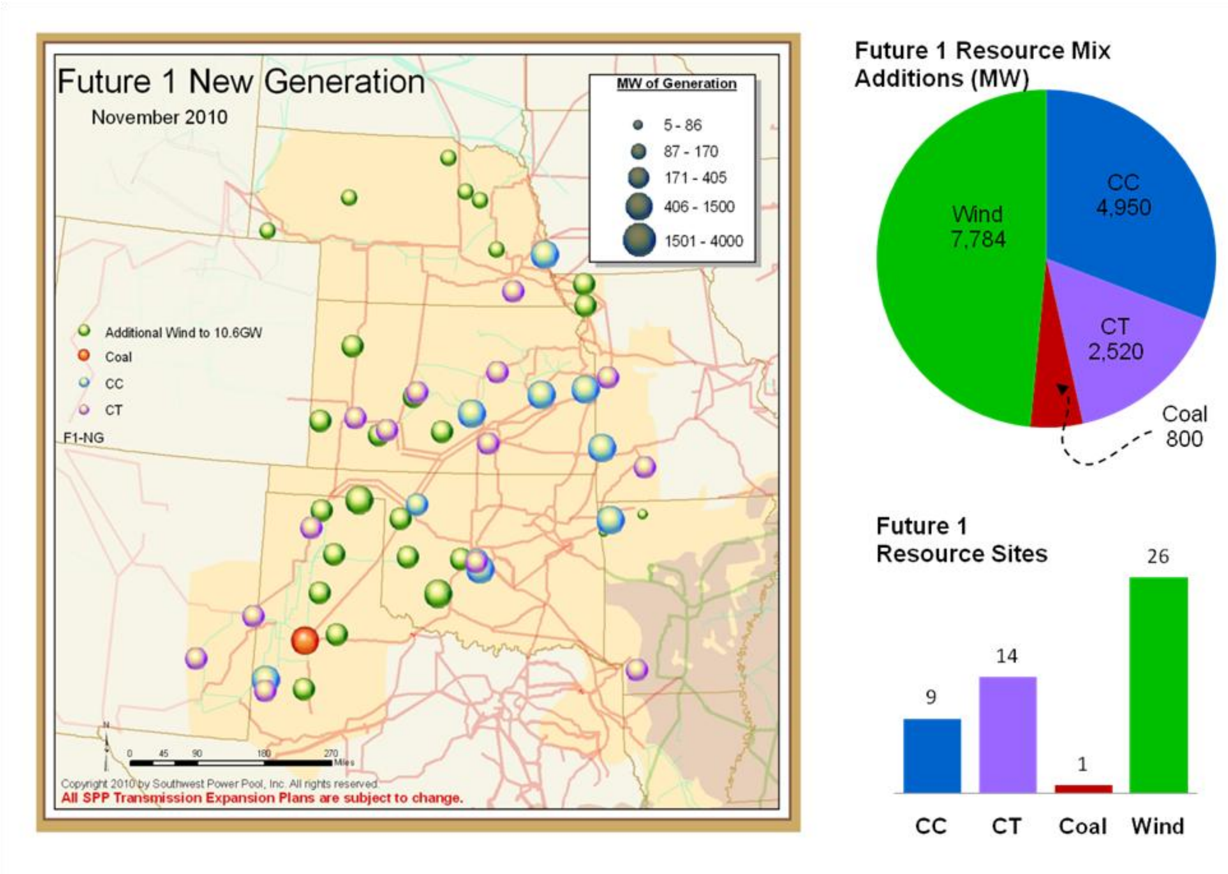

Figure A5.3: Business as Usual Resource Plan at-a-glance

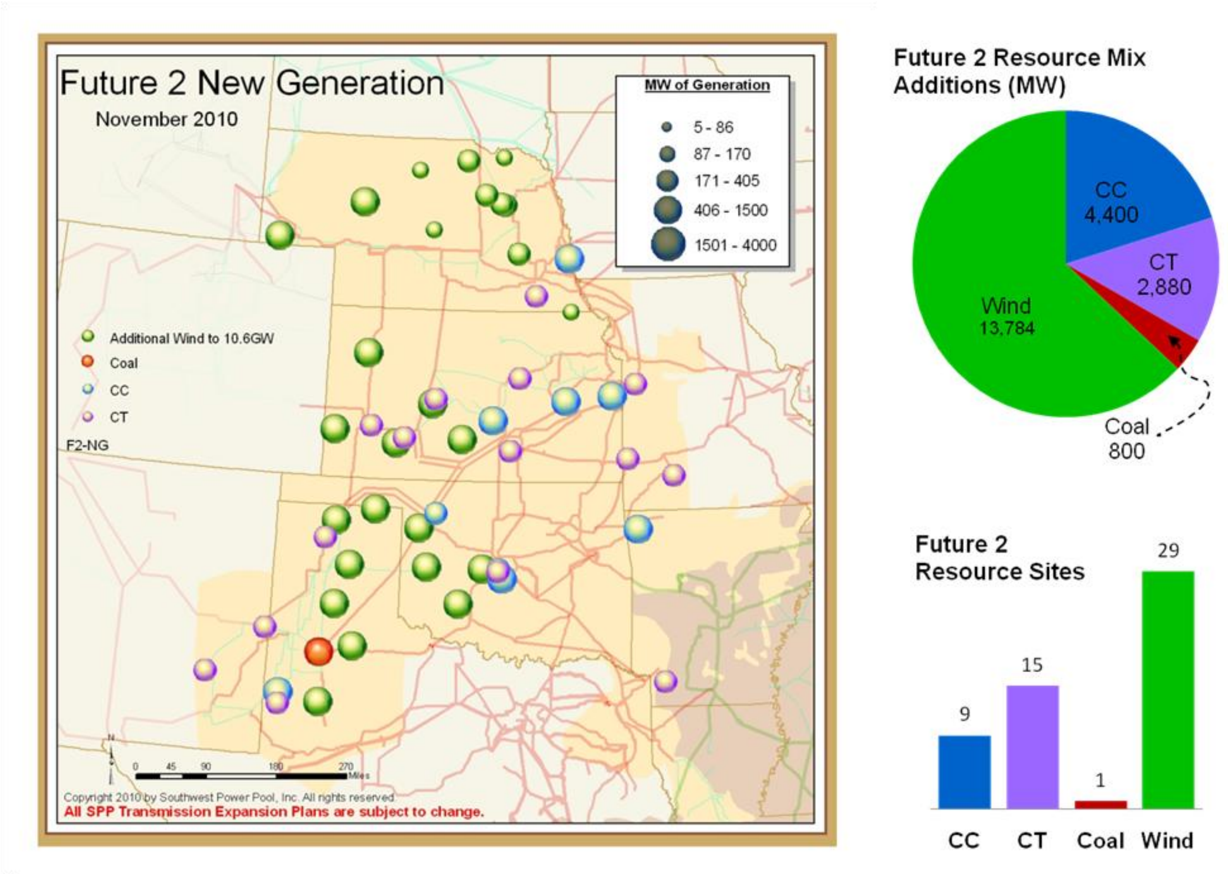

Figure A5.4: Renewable Electricity Standard Resource Plan at-a-glance

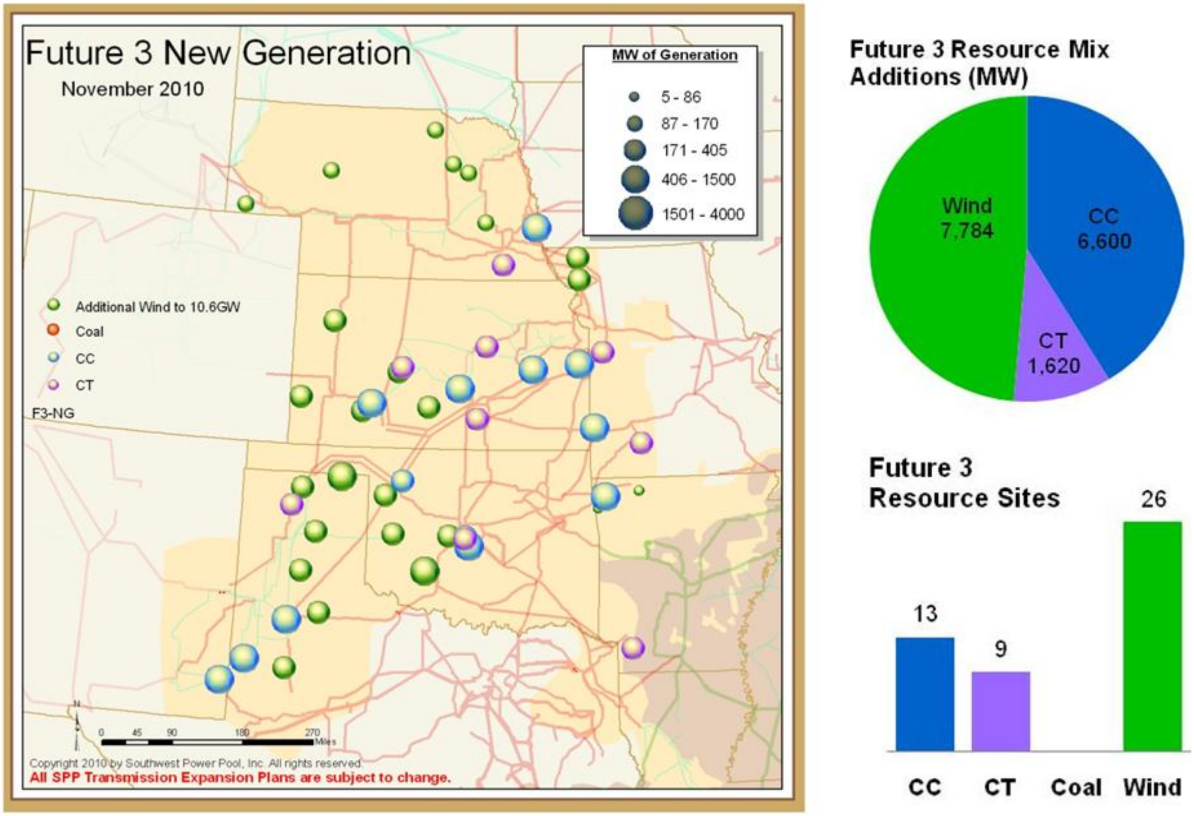

Figure A5.5: Carbon Mandate Resource Plan at-a-glance

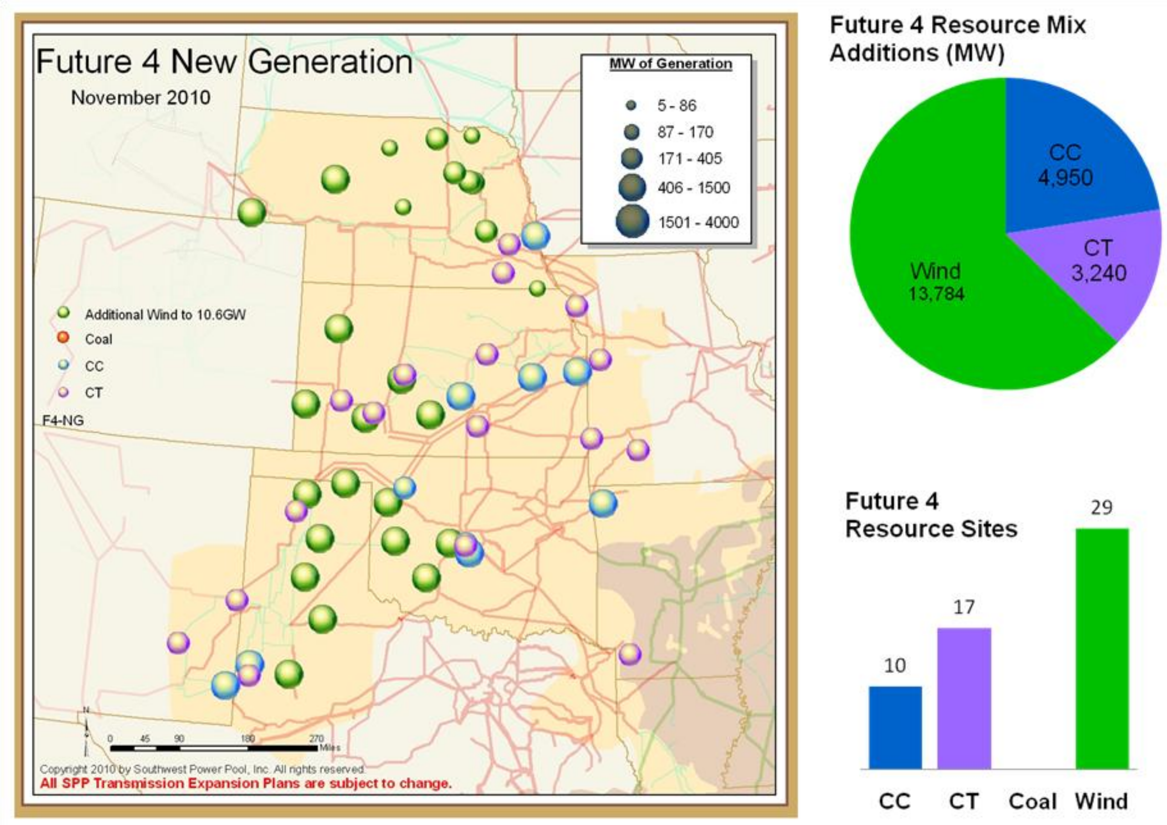

Figure A5.6: RES & Carbon Mandate Resource Plan at-a-glance

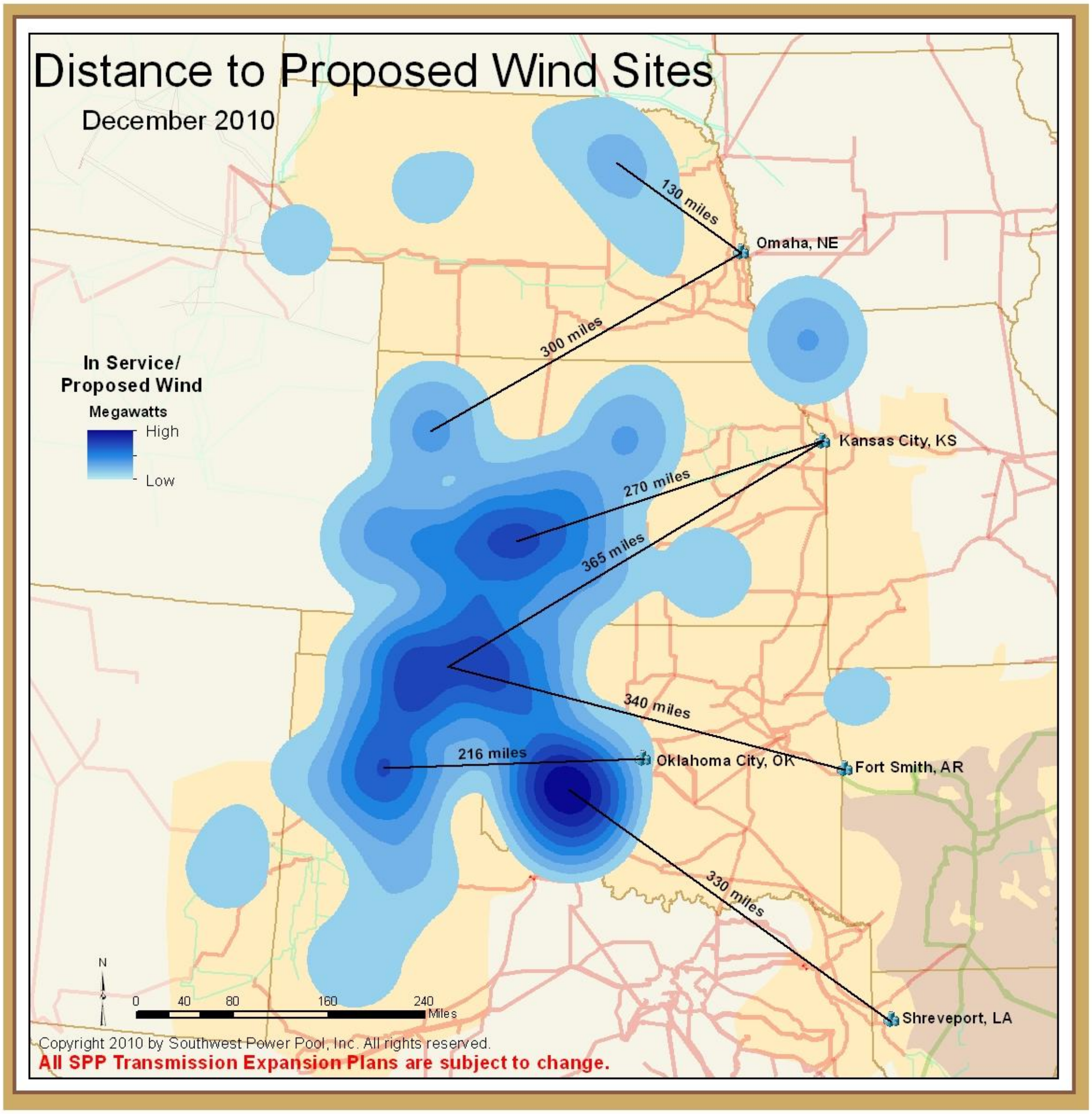

Figure A5.7: Distance from Proposed Wind Sites to Major Load Centers in the Business as Usual future

Appendix A6: Results of the CAWG Survey

The CAWG survey on renewable energy provided some important data on what the expectations are for the states and individual utilities on the expected levels of wind power in the SPP footprint with and without a Federal RES. The wind energy targets from the CAWG survey are detailed in the tables below. The columns in the table list the wind targets through various areas for each state. The Wind per zone column is the sum of the wind targets for wind to be contained within the balancing authorities in the state. The Wind by state column is the sum of the wind targets to be contained within the state, but external to the reported balancing authority. The Wind by region column is the sum of the wind targets to be external to both the state and the balancing authority. The sum of these three numbers, Wind per zone, Wind by state, and Wind by region, represent the total amount of wind that each balancing authority within the state need to meet their designated targets.

Future 1: Business as Usual

State	Wind per zone (MWh)	Wind by state (MWh)	Wind by region (MWh)
KS	3,102,486	5,839,900	400,160
MO	-	2,216,280	1,665,124
NE	2,874,327	1,149,100	-
OK	5,052,000	4,963,141	2,507,900
TX	4,180,491	1,263,500	1,073,500
NM	473,040	-	-
LA	-	-	1,697,000
AR	-	552,300	650,100
Total	**15,682,344**	**15,984,221**	**7,993,784**

Table A6.1: CAWG Survey as it applied to the Business as Usual case (Future 1)

Future 2: Renewable Electricity Standard

State	Wind per zone (MWh)	Wind by state (MWh)	Wind by region (MWh)
KS	3,102,486	5,839,900	421,127
MO	-	2,216,280	3,608,022
NE	4,773,262	3,007,400	-
OK	5,052,000	4,963,141	2,528,866
TX	4,180,491	2,563,500	1,073,500
NM	473,040	-	-
AR	-	683,300	1,052,710
LA	-	-	1,697,000
Total	**17,581,279**	**19,273,521**	**10,381,225**

Table A6.2: CAWG Survey as it applied to the Renewable Electricity Standard case (Future 2)

Future 3: Carbon Mandate

Renewable energy will be modeled in this future, using the same renewable energy targets as the Business as Usual case.

Future 4: Renewable Electricity Standard + Carbon Mandate

Renewable energy will be modeled in this future, using the expected renewable energy targets from the CAWG survey, as detailed in Future 2, the Renewable Electricity Standard case.

Appendix A7: Limited Reliability Assessment

A7.1: Overview

The majority of 20-Year Integrated Transmission Plan (ITP20) Assessment focuses on economics. In addition, a limited reliability assessment has been performed to identify the impact that recommended transmission plans may have upon system reliability. The following report summarizes the findings of this assessment.

A reliability analysis was conducted on Robust Plan 1 as recommended from the economic analysis. The assessment was performed in two parts:

1. A Linear (DC) Analysis using models extracted from the economic data. It focuses on thermal loadings created by Robust Plan 1 during the high load and generation dispatch as modeled in the economic analysis.
2. An AC Analysis using STEP models. It focuses on both thermal and voltage impacts in relation to the ongoing 10-Year Regional Reliability effort.

Those issues within SPP that are not addressed in this assessment will be passed to the 2011 ITP 10-Year Assessment for further evaluation.

Note that the FCITC benchmark assessment listed in the original scope has been addressed and reported separately in the main ITP20 report Robustness Metrics section, Sub-metric 1. The stability analysis listed in the original scope is also reported separately in the main ITP20 report.

A7.2: Projects Studied

Economic analysis produced a recommended set of proposed projects known as Robust Plan 1. This plan consisted of the elements identified in Appendix A2: Transmission Portfolios & Cost Estimates.

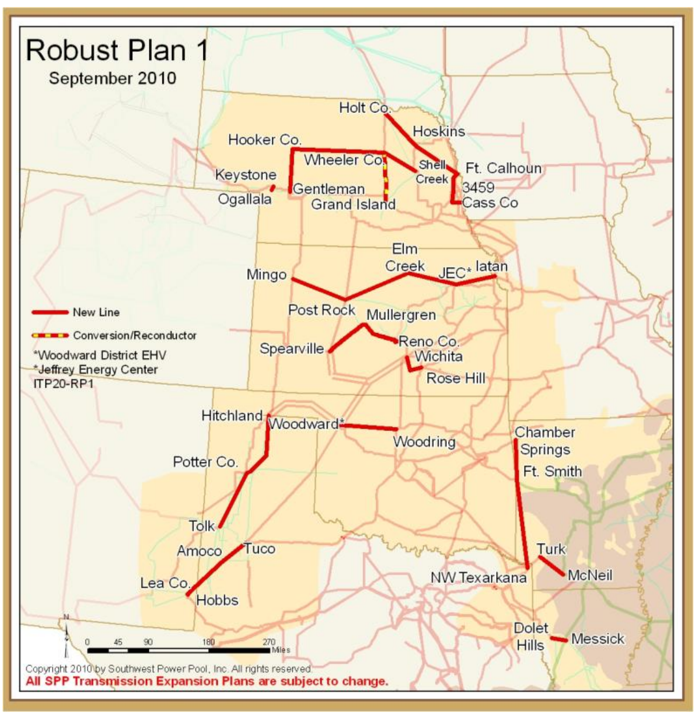

Figure A7.1: Robust Plan 1 Studied in the Reliability Assessment

A7.3: Study Scope

DC Analysis

- Models were extracted from the economic data (using its load, commitment and dispatch)
- One summer peak model and one spring model was selected for each of the four futures
  - Summer Peak hour chosen was the highest load hour of the year
  - Spring hour chosen had the highest wind-to-load ratio for the year
- Futures 1-4
- Normal and single contingency (N-1)
- Contingencies: 345 kV and up in SPP and 1st tier, including autotransformers
- Monitored: 115 kV and up in SPP and 1st tier including autotransformers
- Cutoff settings: a normal to N-1 flow change of 3%
- Compared results from Robust Plan 1 to results from base case with no plan
- Results used to identify new constraints for economic modeling

AC Analysis

- Assessed the reliability impacts in relation to the ongoing 10-Year Regional Reliability effort
- Evaluated in the year 11 (2021) summer peak STEP model
- Normal and single contingency (N-1)
- Contingencies: 100 kV and up in SPP and 1st tier
- Monitored: 100 kV and up in SPP and 1st tier
- Cutoff settings: a normal to N-1 change of 1 MW and a normal to N-1 change of 0.005puV
- Compared results from Robust Plan 1 to results from base case with no plan

A7.4: Primary Analysis

At present, a year 20 powerflow model has not been developed. Due to the lack of an available AC model, a year 11 powerflow model was substituted as a proxy for the year 20 model so that both voltage and thermal concerns were evaluated. In order to be sure that the various futures and year 20 load levels were considered, analysis was also performed on the year 20 economic models.

In order to capture more aspects of the reliability assessment, the study was divided into two portions. The first was performed on the year 20 economic model using the scope shown above. This analysis simulated the year 20 load levels and dispatch. The analysis consisted of a DC contingency analysis, with and without the identified transmission plans. The second portion of the analysis was performed on a year 11 powerflow model. This analysis consisted of an AC contingency analysis, with and without the identified transmission plans.

Those issues within SPP that were not addressed in this assessment will be passed to the 10 Year ITP Study for further evaluation.

DC Analysis

This analysis was performed using the Power Analysis and Trading (PAT) tool. The peak load hour was chosen from the economic data (5:00 p.m. August 1). Additionally, a spring hour was chosen based on the highest ratio of wind generation to load. For futures 1 & 3, this was 4:00 a.m. April 21; for futures 2

& 4, this was 3:00 a.m. April 12. An N-1 contingency analysis was performed on models which included Robust Plan 1 and on base case models without the ITP plan. These results were then compared to each other to determine new thermal overloads resulting from the addition of Robust Plan 1.

Each element was tested to determine if it met the requirements to be added as a new economic constraint. The requirements were:

- More than 10% overloaded
- More than 60 hours overloaded
- Not system-intact overloaded
- Not the same path as another defined constraint
- SPP element

The overloaded elements found here and listed in the table below will be added as monitored elements in the economic model to help refine its dispatch of generation.

Future	Season	Overloaded Element	Hours Over Limit	% Loading
Future 1	Spring	4TOLEDO 138 - VP TAP 4 138 CKT 1 (EES-CELE)	433	117
Future 1	Spring	CLARN 6 230 - MESSICK6 230 CKT 1 (CELE)	520	148
Future 1	Summer Peak	SPRGFLD5 161 - CLAY 161 CKT 1 (SWPA-SPRM)	3,113	114
Future 2	Spring	L.E.S.-7 345 - SUNNYSD7 345 CKT 1 (AEPW-OKGE)	669	113
Future 2	Spring	CIMARON7 345 - DRAPER 7 345 CKT 1 (OKGE)	1,008	115
Future 2	Spring	5CLEVCOV 161 - TABLE R5 161 CKT 1 (AECI-SWPA)	1,645	114
Future 2	Summer Peak	4GIBSON 138 - RAMOS 4 138 CKT 1 (EES-CELE)	86	143
Future 3	Summer Peak	3PATMOS# 115 - FULTON 115 CKT 1 (EES-AEPW)	602	124
Future 4	Summer Peak	CLARN 6 230 - MESSICK6 230 CKT 1 (CELE)	199	121
Future 4	Summer Peak	3DODSON 115 - JELDWEN 115 CKT 1 (EES-CELE)	104	117

Table A7.1: DC Analysis – New Overloads in Robust Plan 1 added to PROMOD Event File

Also note that many of the issues were at the edges of the SPP system. Tier 1 issues were generally a result of this ITP 20-year plan interfacing with areas for which we have no 20-year plan. They show limits on the outer boundaries of the plan.

AC Analysis

This analysis was performed using PSS®E. The 2021 summer peak model from the 2010 SPP Transmission Expansion Plan (STEP) was used as a starting point. No additional generation resources from the ITP20 were included in the model. It contained upgrades identified to date through the 2010 STEP process. An N-1 contingency analysis was performed on both this model and the same model with Robust Plan 1 projects added. These results were then compared to each other to determine new thermal and voltage overloads resulting from the addition of Robust Plan 1. The table of results is shown below.

The results show several new high voltages that are primarily grouped near EHV connection points. We plan to address these high voltages in more detail in the ITP 10-Year Analysis. The analysis also determined some mitigated overloads, demonstrating reliability benefits. However, the long timeline of ITP20 projects prevents deferral of any existing projects.

Results and Conclusions

The reliability analysis identified new elements which need to be monitored in the economic model. These additions will be made to refine the dispatch of generation and increase the accuracy of output from the economic model.

This analysis also identified new high voltage problems related to the new EHV lines in Robust Plan 1. Currently, we plan to address these high voltages in more detail in the ITP 10-Year Analysis.

A7.5: AC Analysis Result Tables

FACILITY_NAME	AREA	BUSNUM	KV	VOLTAGE	CONTINGENCY NAME
CENT 4 138.00 138KV	OKGE	515363	138	1.05022	BASE CASE
WWRDEHV4 138.00 138KV	OKGE	515376	138	1.05104	BASE CASE
WWRDEHV4 138.00 138KV	OKGE	515376	138	1.05104	BASE CASE
WWRDEHV4 138.00 138KV	OKGE	515376	138	1.05104	BASE CASE
KEENAN 4 138.00 138KV	OKGE	515394	138	1.05123	BASE CASE
OUSPRT 4 138.00 138KV	OKGE	515398	138	1.05116	BASE CASE
OGEWND14 138.00 138KV	OKGE	515426	138	1.05123	BASE CASE
OGEWND24 138.00 138KV	OKGE	515429	138	1.05123	BASE CASE
POTTER COUNTY INTERCHANGE 345KV	SPS	523961	345	1.07578	POTTER COUNTY INTERCHANGE (WAUK 90343-A) 345/230/13.2KV TRANSFORMER CKT
POTTER COUNTY INTERCHANGE 345KV	SPS	523961	345	1.07578	POTTER COUNTY INTERCHANGE (WAUK 90343-A) 345/230/13.2KV TRANSFORMER CKT
POTTER COUNTY INTERCHANGE 345KV	SPS	523961	345	1.07578	POTTER COUNTY INTERCHANGE (WAUK 90343-A) 345/230/13.2KV TRANSFORMER CKT
SAN JUAN MESA TAP 230KV	SPS	524885	230	1.05081	OASIS INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1
SAN JUAN MESA WIND GEN 230KV	SPS	524889	230	1.05078	OASIS INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1
SAN JUAN MESA WIND GEN 230KV	SPS	524889	230	1.05078	OASIS INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.07096	KNOLL 230 (KNOLL T1) 230/115/11.49KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.07096	KNOLL 230 (KNOLL T1) 230/115/11.49KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.07096	KNOLL 230 (KNOLL T1) 230/115/11.49KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.06736	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.06736	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.06736	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.06736	KNOLL 230 - SMOKYHL6 230.00 230KV CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.06736	KNOLL 230 - SMOKYHL6 230.00 230KV CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.06736	KNOLL 230 - SMOKYHL6 230.00 230KV CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.06672	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
KNOLL 230 230KV	MIDW	530558	230	1.06672	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
KNOLL 230 230KV	MIDW	530558	230	1.06672	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
KNOLL 230 230KV	MIDW	530558	230	1.06641	GEN530600 02-SMKYP2G1 0.6900
KNOLL 230 230KV	MIDW	530558	230	1.06641	GEN530600 02-SMKYP2G1 0.6900
KNOLL 230 230KV	MIDW	530558	230	1.06641	GEN530600 02-SMKYP2G1 0.6900
KNOLL 230 230KV	MIDW	530558	230	1.06085	BASE CASE
KNOLL 230 230KV	MIDW	530558	230	1.06085	BASE CASE
KNOLL 230 230KV	MIDW	530558	230	1.06085	BASE CASE
KNOLL 230 230KV	MIDW	530558	230	1.055	POSTROCK7 345.00 (POSTROCK T1) 345/230/13.8KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.055	POSTROCK7 345.00 (POSTROCK T1) 345/230/13.8KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.055	POSTROCK7 345.00 (POSTROCK T1) 345/230/13.8KV TRANSFORMER CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.05243	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.05243	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
KNOLL 230 230KV	MIDW	530558	230	1.05243	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
S HAYS6 230.00 230KV	MIDW	530582	230	1.06651	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
S HAYS6 230.00 230KV	MIDW	530582	230	1.06646	KNOLL 230 (KNOLL T1) 230/115/11.49KV TRANSFORMER CKT 1
S HAYS6 230.00 230KV	MIDW	530582	230	1.06603	CIRCLE 7 345.00 - RENO COUNTY 345KV CKT 1
S HAYS6 230.00 230KV	MIDW	530582	230	1.06555	KNOLL 230 - SMOKYHL6 230.00 230KV CKT 1
S HAYS6 230.00 230KV	MIDW	530582	230	1.06553	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
S HAYS6 230.00 230KV	MIDW	530582	230	1.06531	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
S HAYS6 230.00 230KV	MIDW	530582	230	1.06009	BASE CASE
S HAYS6 230.00 230KV	MIDW	530582	230	1.05005	ELMCRK 7 345.00 - POSTROCK7 345.00 345KV CKT 1
POSTROCK7 345.00 345KV	MIDW	530583	345	1.07528	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
POSTROCK7 345.00 345KV	MIDW	530583	345	1.07513	KNOLL 230 (KNOLL T1) 230/115/11.49KV TRANSFORMER CKT 1
POSTROCK7 345.00 345KV	MIDW	530583	345	1.07492	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
POSTROCK7 345.00 345KV	MIDW	530583	345	1.07333	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
POSTROCK7 345.00 345KV	MIDW	530583	345	1.06817	BASE CASE
POSTROCK7 345.00 345KV	MIDW	530583	345	1.06264	MINGO - POSTROCK7 345.00 345KV CKT 1
POSTROCK7 345.00 345KV	MIDW	530583	345	1.05473	ELMCRK 7 345.00 - POSTROCK7 345.00 345KV CKT 1
POSTROCK6 230.00 230KV	MIDW	530584	230	1.07106	KNOLL 230 (KNOLL T1) 230/115/11.49KV TRANSFORMER CKT 1
POSTROCK6 230.00 230KV	MIDW	530584	230	1.06851	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
POSTROCK6 230.00 230KV	MIDW	530584	230	1.06779	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
POSTROCK6 230.00 230KV	MIDW	530584	230	1.06764	KNOLL 230 - SMOKYHL6 230.00 230KV CKT 1
POSTROCK6 230.00 230KV	MIDW	530584	230	1.06715	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
POSTROCK6 230.00 230KV	MIDW	530584	230	1.06672	GEN530600 02-SMKYP2G1 0.6900
POSTROCK6 230.00 230KV	MIDW	530584	230	1.06127	BASE CASE
POSTROCK6 230.00 230KV	MIDW	530584	230	1.05503	POSTROCK7 345.00 (POSTROCK T1) 345/230/13.8KV TRANSFORMER CKT 1
SMOKYHL6 230.00 230KV	MIDW	530592	230	1.05146	GEN530600 02-SMKYP2G1 0.6900
SMOKYHL6 230.00 230KV	MIDW	530592	230	1.05146	GEN530600 02-SMKYP2G1 0.6900
SMKYP1 6 230.00 230KV	MIDW	530593	230	1.0514	GEN530600 02-SMKYP2G1 0.6900
SMKYP2 6 230.00 230KV	MIDW	530599	230	1.05144	GEN530600 02-SMKYP2G1 0.6900
MINGO 115KV	SUNC	531429	115	1.05868	MINGO REACTORS 13KV SWITCHED SHUNT
MINGO 115KV	SUNC	531429	115	1.05868	MINGO REACTORS 13KV SWITCHED SHUNT
SETAB 345KV	SUNC	531465	345	1.06648	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
SETAB 345KV	SUNC	531465	345	1.06302	SETAB 345KV SWITCHED SHUNT
SETAB 345KV	SUNC	531465	345	1.0568	SETAB (SETAB) 345/115/13.8KV TRANSFORMER CKT 1
SETAB 345KV	SUNC	531465	345	1.05584	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
SETAB 345KV	SUNC	531465	345	1.05534	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
SETAB 345KV	SUNC	531465	345	1.055	PSCO LAMAR DC TIE 345KV SWITCHED SHUNT
SETAB 345KV	SUNC	531465	345	1.05443	SCOTT CITY - SETAB 115KV CKT 1
WOLF CREEK 345KV	WERE	532797	345	1.03308	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
WOLF CREEK 345KV	WERE	532797	345	1.03308	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
CIRCLE 230KV	WERE	532871	230	1.05284	CIRCLE 7 345.00 - RENO COUNTY 345KV CKT 1
RENO COUNTY 115KV	WERE	533416	115	1.0516	RENO COUNTY - WICHITA 345KV CKT 1
RENO COUNTY 115KV	WERE	533416	115	1.0516	RENO COUNTY - WICHITA 345KV CKT 1
CLIFTON 115KV	MKEC	539656	115	1.05533	CLIFTON - GREENLEAF 115KV CKT 1
CLIFTON 115KV	MKEC	539656	115	1.05533	CLIFTON - GREENLEAF 115KV CKT 1
CLIFTON 115KV	MKEC	539656	115	1.05275	GREENLEAF - KNOB HILL 115KV CKT 1
CLIFTON 115KV	MKEC	539656	115	1.05275	GREENLEAF - KNOB HILL 115KV CKT 1
CLIFTON 115KV	MKEC	539656	115	1.05057	ELMCREK6 230.00 - NWMANHT6 230.00 230KV CKT 1
CLIFTON 115KV	MKEC	539656	115	1.05057	ELMCREK6 230.00 - NWMANHT6 230.00 230KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.0741	ELMCREK6 230.00 - NWMANHT6 230.00 230KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.0741	ELMCREK6 230.00 - NWMANHT6 230.00 230KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.0741	ELMCREK6 230.00 - NWMANHT6 230.00 230KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.0741	ELMCREK6 230.00 - NWMANHT6 230.00 230KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.07044	CLIFTON - CONCORDIA 115KV CKT 1

FACILITY_NAME	AREA	BUSNUM	KV	VOLTAGE	CONTINGENCY NAME
CONCORDIA 115KV	MKEC	539657	115	1.07044	CLIFTON - CONCORDIA 115KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.07044	CLIFTON - CONCORDIA 115KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.07044	CLIFTON - CONCORDIA 115KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.06417	CONCORDIA (CONCORD3) 115/34.5/5.11KV TRANSFORMER CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.06417	CONCORDIA (CONCORD3) 115/34.5/5.11KV TRANSFORMER CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.06417	CONCORDIA (CONCORD3) 115/34.5/5.11KV TRANSFORMER CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.06417	CONCORDIA (CONCORD3) 115/34.5/5.11KV TRANSFORMER CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.0615	GEN539655 1-CLIFTON GENERATOR
CONCORDIA 115KV	MKEC	539657	115	1.0615	GEN539655 1-CLIFTON GENERATOR
CONCORDIA 115KV	MKEC	539657	115	1.0615	GEN539655 1-CLIFTON GENERATOR
CONCORDIA 115KV	MKEC	539657	115	1.0615	GEN539655 1-CLIFTON GENERATOR
CONCORDIA 115KV	MKEC	539657	115	1.05626	BASE CASE
CONCORDIA 115KV	MKEC	539657	115	1.05626	BASE CASE
CONCORDIA 115KV	MKEC	539657	115	1.05626	BASE CASE
CONCORDIA 115KV	MKEC	539657	115	1.05626	BASE CASE
CONCORDIA 115KV	MKEC	539657	115	1.0508	MRWYG21 34.500 34KV SWITCHED SHUNT
CONCORDIA 115KV	MKEC	539657	115	1.0508	MRWYG21 34.500 34KV SWITCHED SHUNT
CONCORDIA 115KV	MKEC	539657	115	1.0508	MRWYG21 34.500 34KV SWITCHED SHUNT
CONCORDIA 115KV	MKEC	539657	115	1.0508	MRWYG21 34.500 34KV SWITCHED SHUNT
CONCORDIA 115KV	MKEC	539657	115	1.05075	ELMCRK 7 345.00 - POSTROCK7 345.00 345KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.05075	ELMCRK 7 345.00 - POSTROCK7 345.00 345KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.05075	ELMCRK 7 345.00 - POSTROCK7 345.00 345KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.05075	ELMCRK 7 345.00 - POSTROCK7 345.00 345KV CKT 1
CONCORDIA 115KV	MKEC	539657	115	1.05019	MRWYG11 34.500 34KV SWITCHED SHUNT
CONCORDIA 115KV	MKEC	539657	115	1.05019	MRWYG11 34.500 34KV SWITCHED SHUNT
CONCORDIA 115KV	MKEC	539657	115	1.05019	MRWYG11 34.500 34KV SWITCHED SHUNT
CONCORDIA 115KV	MKEC	539657	115	1.05019	MRWYG11 34.500 34KV SWITCHED SHUNT
GREENLEAF 115KV	MKEC	539665	115	1.05162	GREENLEAF - KNOB HILL 115KV CKT 1
GREENLEAF 115KV	MKEC	539665	115	1.05162	GREENLEAF - KNOB HILL 115KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.07011	CIRCLE 7 345.00 - RENO COUNTY 345KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.07011	CIRCLE 7 345.00 - RENO COUNTY 345KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.07011	CIRCLE 7 345.00 - RENO COUNTY 345KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.07011	CIRCLE 7 345.00 - RENO COUNTY 345KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.06463	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.06463	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.06463	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.06463	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.059	BASE CASE
MULLERGREN 230KV	MKEC	539679	230	1.059	BASE CASE
MULLERGREN 230KV	MKEC	539679	230	1.059	BASE CASE
MULLERGREN 230KV	MKEC	539679	230	1.059	BASE CASE
MULLERGREN 230KV	MKEC	539679	230	1.05384	HEIZER - MULLERGREN 115KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05384	HEIZER - MULLERGREN 115KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05384	HEIZER - MULLERGREN 115KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05384	HEIZER - MULLERGREN 115KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05297	HEIZER 6 230.00 (HEIZER T1) 230/115/12.5KV TRANSFORMER CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05297	HEIZER 6 230.00 (HEIZER T1) 230/115/12.5KV TRANSFORMER CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05297	HEIZER 6 230.00 (HEIZER T1) 230/115/12.5KV TRANSFORMER CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05297	HEIZER 6 230.00 (HEIZER T1) 230/115/12.5KV TRANSFORMER CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05294	HEIZER 6 230.00 - MULLERGREN 230KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05294	HEIZER 6 230.00 - MULLERGREN 230KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05294	HEIZER 6 230.00 - MULLERGREN 230KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05294	HEIZER 6 230.00 - MULLERGREN 230KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05164	MULGREN7 345.00 - SPEARVILLE 345KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05164	MULGREN7 345.00 - SPEARVILLE 345KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05164	MULGREN7 345.00 - SPEARVILLE 345KV CKT 1
MULLERGREN 230KV	MKEC	539679	230	1.05164	MULGREN7 345.00 - SPEARVILLE 345KV CKT 1
CARLTON JUNCTION 115KV	NPPD	640105	115	1.0503	FAIRBURY - NORTH HEBRON 115KV CKT 1
CLATONIA 115KV	NPPD	640111	115	1.0517	BEATRICE POWER STATION - CLATONIA 115KV CKT 1
COLUMEAST 345KV	NPPD	640125	345	1.07098	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
COLUMEAST 345KV	NPPD	640125	345	1.07042	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
COLUMEAST 345KV	NPPD	640125	345	1.06997	HOSKINS - SHELL CREEK 345KV CKT 1
COLUMEAST 345KV	NPPD	640125	345	1.06479	BASE CASE
COLUMEAST 345KV	NPPD	640125	345	1.05948	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
COLUMEAST 345KV	NPPD	640125	345	1.05526	SHELL CREEK - WHEELER7 345.00 345KV CKT 1
COLUMEAST 345KV	NPPD	640125	345	1.05324	COLUMEAST - SHELL CREEK 345KV CKT 1
COLUMEAST 230KV	NPPD	640126	230	1.08876	COLUMEAST - KELLY 230KV CKT 1
COLUMEAST 230KV	NPPD	640126	230	1.0777	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
COLUMEAST 230KV	NPPD	640126	230	1.07702	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
COLUMEAST 230KV	NPPD	640126	230	1.07676	COLUMWEST - KELLY 230KV CKT 1
COLUMEAST 230KV	NPPD	640126	230	1.07597	HOSKINS - SHELL CREEK 345KV CKT 1
COLUMEAST 230KV	NPPD	640126	230	1.07086	BASE CASE
COLUMEAST 230KV	NPPD	640126	230	1.0655	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
COLUMEAST 230KV	NPPD	640126	230	1.06207	SHELL CREEK - WHEELER7 345.00 345KV CKT 1
COLUMWEST 230KV	NPPD	640131	230	1.07515	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
COLUMWEST 230KV	NPPD	640131	230	1.07368	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
COLUMWEST 230KV	NPPD	640131	230	1.07315	COLUMWEST 230/34.5KV TRANSFORMER CKT 1
COLUMWEST 230KV	NPPD	640131	230	1.06792	BASE CASE
COLUMWEST 230KV	NPPD	640131	230	1.06245	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
COLUMWEST 230KV	NPPD	640131	230	1.05951	SHELL CREEK - WHEELER7 345.00 345KV CKT 1
KELLY 230KV	NPPD	640133	230	1.07622	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
KELLY 230KV	NPPD	640133	230	1.07547	COLUMWEST - KELLY 230KV CKT 1
KELLY 230KV	NPPD	640133	230	1.07546	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
KELLY 230KV	NPPD	640133	230	1.06944	BASE CASE
KELLY 230KV	NPPD	640133	230	1.06404	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
KELLY 230KV	NPPD	640133	230	1.06059	SHELL CREEK - WHEELER7 345.00 345KV CKT 1
GERALD GENTLEMAN STATION 345KV	NPPD	640183	345	1.07049	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
GERALD GENTLEMAN STATION 345KV	NPPD	640183	345	1.07049	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
GERALD GENTLEMAN STATION 345KV	NPPD	640183	345	1.05407	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
GERALD GENTLEMAN STATION 345KV	NPPD	640183	345	1.05407	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1

FACILITY_NAME	AREA	BUSNUM	KV	VOLTAGE	CONTINGENCY NAME
GERALD GENTLEMAN STATION 230KV	NPPD	640184	230	1.05533	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
GERALD GENTLEMAN STATION 230KV	NPPD	640184	230	1.05163	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
GRAND ISLAND 230KV	NPPD	640200	230	1.06626	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
GRAND ISLAND 230KV	NPPD	640200	230	1.06039	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
GRAND ISLAND 230KV	NPPD	640200	230	1.05276	BASE CASE
HASTINGS 230KV	NPPD	640214	230	1.05794	HASTINGS 230/115KV TRANSFORMER CKT 1
HASTINGS 230KV	NPPD	640214	230	1.05722	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
HASTINGS 230KV	NPPD	640214	230	1.0513	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
HASTINGS 230KV	NPPD	640214	230	1.05115	E 7TH ST - HASTINGS CITY 115KV CKT 1
HOSKINS 345KV	NPPD	640226	345	1.06501	HOSKINS - RAUN 345KV CKT 1
HOSKINS 345KV	NPPD	640226	345	1.05714	BASE CASE
HOSKINS 230KV	NPPD	640227	230	1.06287	HOSKINS - TWIN CHURCH 230KV CKT 1
HOSKINS 230KV	NPPD	640227	230	1.0616	HOSKINS - RAUN 345KV CKT 1
HOSKINS 230KV	NPPD	640227	230	1.05453	BASE CASE
KEYSTONE 345KV	NPPD	640252	345	1.05895	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
MCCOOL 345KV	NPPD	640271	345	1.06569	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
MCCOOL 345KV	NPPD	640271	345	1.05716	BASE CASE
MCCOOL 345KV	NPPD	640271	345	1.05171	GRAND ISLAND - MCCOOL 345KV CKT 1
MOORE 345KV	NPPD	640277	345	1.0584	MOORE (MOORE T1) 345/115/13.8KV TRANSFORMER CKT 1
MOORE 345KV	NPPD	640277	345	1.05306	BASE CASE
SHELDON 115KV	NPPD	640278	115	1.05446	BASE CASE
NORTH PLATTE 230KV	NPPD	640286	230	1.0517	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
PAULINE 345KV	NPPD	640312	345	1.07449	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
PAULINE 345KV	NPPD	640312	345	1.06897	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
PAULINE 345KV	NPPD	640312	345	1.06187	BASE CASE
PAULINE 345KV	NPPD	640312	345	1.05153	AXTELL - PAULINE 345KV CKT 1
SHELL CREEK 345KV	NPPD	640342	345	1.07464	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
SHELL CREEK 345KV	NPPD	640342	345	1.0737	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
SHELL CREEK 345KV	NPPD	640342	345	1.07356	HOSKINS - SHELL CREEK 345KV CKT 1
SHELL CREEK 345KV	NPPD	640342	345	1.06763	BASE CASE
SHELL CREEK 345KV	NPPD	640342	345	1.06175	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
SHELL CREEK 345KV	NPPD	640342	345	1.05654	SHELL CREEK - WHEELER7 345.00 345KV CKT 1
SHELL CREEK 230KV	NPPD	640343	230	1.07576	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
SHELL CREEK 230KV	NPPD	640343	230	1.07551	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
SHELL CREEK 230KV	NPPD	640343	230	1.07445	HOSKINS - SHELL CREEK 345KV CKT 1
SHELL CREEK 230KV	NPPD	640343	230	1.06919	BASE CASE
SHELL CREEK 230KV	NPPD	640343	230	1.06356	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
SHELL CREEK 230KV	NPPD	640343	230	1.05941	SHELL CREEK - WHEELER7 345.00 345KV CKT 1
NW68TH & HOLDREGE 345KV	LES	650114	345	1.05268	BASE CASE
70TH & BLUFF 161KV	LES	650169	161	1.05394	70TH & BLUFF - SUB 1214 161KV CKT 1
WAGENER 345KV	LES	650185	345	1.05284	SUB 3454 - WAGENER 345KV CKT 1
103RD & ROKEBY 345KV	LES	650189	345	1.05022	BASE CASE
NW68TH & HOLDREGE 115KV	LES	650214	115	1.05137	BASE CASE
27TH & PINE LAKE 115KV	LES	650229	115	1.05108	BASE CASE
SW7TH & PLEASANT HILL 115KV	LES	650242	115	1.05048	BASE CASE
40TH & ROKEBY 115KV	LES	650250	115	1.05871	40TH & ROKEBY - 56TH & PINE LAKE 115KV CKT 1
40TH & ROKEBY 115KV	LES	650250	115	1.05822	27TH & PINE LAKE - 40TH & ROKEBY 115KV CKT 1
40TH & ROKEBY 115KV	LES	650250	115	1.0527	BASE CASE
56TH & PINE LAKE 115KV	LES	650255	115	1.05044	BASE CASE
84TH & LEIGHTON 115KV	LES	650267	115	1.05022	BASE CASE
84TH & BLUFF 115KV	LES	650275	115	1.0501	BASE CASE
120TH & ALVO 115KV	LES	650280	115	1.05161	BASE CASE
WAVERLY 115KV	LES	650283	115	1.05072	BASE CASE
84TH & FLETCHER 115KV	LES	650284	115	1.05019	BASE CASE
WAGENER 115KV	LES	650285	115	1.05349	BASE CASE
ROKEBY 115KV	LES	650290	115	1.0569	ROKEBY - SW7TH & PLEASANT HILL 115KV CKT 1
ROKEBY 115KV	LES	650290	115	1.0513	BASE CASE
RUGBY 115KV	WAPA	652452	115	1.05022	RUGBCPC - RUGBY 115KV CKT 1
GRAND ISLAND 345KV	NPPD	652571	345	1.07117	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
GRAND ISLAND 345KV	NPPD	652571	345	1.06505	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
GRAND ISLAND 345KV	NPPD	652571	345	1.05762	BASE CASE
GRAND ISLAND 345KV	NPPD	652571	345	1.05262	AXTELL - SWEETWATER 345KV CKT 1
GRAND ISLAND 345KV	NPPD	652571	345	1.05134	GRAND ISLAND - SWEETWATER 345KV CKT 1
GRAND ISLAND 345KV	NPPD	652571	345	1.0507	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
GRAND ISLAND 345KV	NPPD	652571	345	1.0505	GRAND ISLAND - WHEELER7 345.00 345KV CKT 1
SIDNEY 115KV	NPPD	652572	115	1.05664	GEN659134 1-SIDNEY
SIDNEY*4 230.00 230KV	NPPD	659136	230	1.05671	GEN659134 1-SIDNEY
HOOK CO 7 345.00 345KV	NPPD	700310	345	1.16089	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
HOOK CO 7 345.00 345KV	NPPD	700310	345	1.10544	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
HOOK CO 7 345.00 345KV	NPPD	700310	345	1.09226	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
HOOK CO 7 345.00 345KV	NPPD	700310	345	1.07907	BASE CASE
HOOK CO 7 345.00 345KV	NPPD	700310	345	1.07362	GERALD GENTLEMAN STATION - SWEETWATER 345KV CKT 2
HOOK CO 7 345.00 345KV	NPPD	700310	345	1.07269	GERALD GENTLEMAN STATION - RED WILLOW 345KV CKT 1
HOLT CO 7 345.00 345KV	NPPD	700315	345	1.08557	FT THOMPSON - HOLT CO 7 345.00 345KV CKT 1
HOLT CO 7 345.00 345KV	NPPD	700315	345	1.08047	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
HOLT CO 7 345.00 345KV	NPPD	700315	345	1.07834	FT THOMPSON - SELBY 3345.00 345KV CKT 1
HOLT CO 7 345.00 345KV	NPPD	700315	345	1.07753	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
HOLT CO 7 345.00 345KV	NPPD	700315	345	1.07201	BASE CASE
HOLT CO 7 345.00 345KV	NPPD	700315	345	1.06424	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
HOLT CO 7 345.00 345KV	NPPD	700315	345	1.0549	HOLT CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
WHEELER7 345.00 345KV	NPPD	700316	345	1.09872	GERALD GENTLEMAN STATION - HOOK CO 7 345.00 345KV CKT 1
WHEELER7 345.00 345KV	NPPD	700316	345	1.09329	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
WHEELER7 345.00 345KV	NPPD	700316	345	1.08947	GRAND ISLAND - WHEELER7 345.00 345KV CKT 1
WHEELER7 345.00 345KV	NPPD	700316	345	1.08861	FT THOMPSON - HOLT CO 7 345.00 345KV CKT 1
WHEELER7 345.00 345KV	NPPD	700316	345	1.0884	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
WHEELER7 345.00 345KV	NPPD	700316	345	1.0824	BASE CASE
WHEELER7 345.00 345KV	NPPD	700316	345	1.06883	HOOK CO 7 345.00 - WHEELER7 345.00 345KV CKT 1
HARRNG_EST7 345.00 345KV	SPS	700319	345	1.09996	HARRNG_EST7 345.00 - POTTER COUNTY INTERCHANGE 345KV CKT 1
HARRNG_EST7 345.00 345KV	SPS	700319	345	1.07876	POTTER COUNTY INTERCHANGE (WAUK 90343-A) 345/230/13.2KV TRANSFORMER CKT
HARRNG_EST7 345.00 345KV	SPS	700319	345	1.05309	TOLK STATION (ABBXNL844501) 345/230/13.2KV TRANSFORMER CKT 1

FACILITY_NAME	AREA	BUSNUM	KV	VOLTAGE	CONTINGENCY NAME
ELMCRK 7 345.00 345KV	WERE	700320	345	1.09638	ELMCREK6 230.00 - NWMANHT6 230.00 230KV CKT 1
ELMCRK 7 345.00 345KV	WERE	700320	345	1.09559	ELMCRK 7 345.00 345/230KV TRANSFORMER CKT 1
ELMCRK 7 345.00 345KV	WERE	700320	345	1.09069	CONCORDIA (CONCORD6) 230/115/13.8KV TRANSFORMER CKT 1
ELMCRK 7 345.00 345KV	WERE	700320	345	1.0896	CONCORDIA - ELMCREK6 230.00 230KV CKT 1
ELMCRK 7 345.00 345KV	WERE	700320	345	1.08156	BASE CASE
ELMCRK 7 345.00 345KV	WERE	700320	345	1.07644	JEFFERY ENERGY CENTER - SUMMIT 345KV CKT 1
ELMCRK 7 345.00 345KV	WERE	700320	345	1.07078	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1
ELMCRK 7 345.00 345KV	WERE	700320	345	1.06946	ELMCRK 7 345.00 - POSTROCK7 345.00 345KV CKT 1
MULGREN7 345.00 345KV	MKEC	700321	345	1.0772	CIRCLE 7 345.00 - RENO COUNTY 345KV CKT 1
MULGREN7 345.00 345KV	MKEC	700321	345	1.06841	CIRCLE 7 345.00 - MULGREN7 345.00 345KV CKT 1
MULGREN7 345.00 345KV	MKEC	700321	345	1.06705	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
MULGREN7 345.00 345KV	MKEC	700321	345	1.06103	BASE CASE
MULGREN7 345.00 345KV	MKEC	700321	345	1.0555	COMANCHE-SPE
CIRCLE 7 345.00 345KV	WERE	700322	345	1.06884	CIRCLE 7 345.00 - RENO COUNTY 345KV CKT 1
OGALALA3 345.00 345KV	NPPD	700327	345	1.058	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2

Appendix A8: ITP20 Stability Analysis

A8.1: Introduction

For the ITP20 EHV designs to be reliable under a range of economic dispatch hours and transfer conditions, the network elements must be assessed for thermal, voltage, and angular performance. First, thermal performance was conducted during the benefit analysis and initial design phase of the ITP20 process using an iterative process of PROMOD and PAT. This identified where system overloads occur and new lines were needed to split and balance the loading for maximum economic dispatch utilization. Once these basic thermal design enhancements were identified, additional studies were required to assess if the power system could maintain acceptable voltages and generator rotor angles under high transfer levels and contingency conditions. This report provides the analysis for the more advanced stability assessments.

Voltage and rotor angle stability are technical concerns with any new EHV system design configuration. This additional analysis identifies the weak areas of the grid where reactive power production and generation performance may be unable to maintain stability due to high stress levels when powerflow is forced through the network from economic generation dispatch biases. More specifically, the EHV design alternatives in this ITP20 study were tested to determine capability of moving large amounts of energy from the west side of the SPP system to the east side of the system assessing EHV west/east corridors allowing any user of the grid to access the low cost energy resources on the system.

To conduct the analyses, the various EHV transmission alternatives (RP1, RP4, RP5, and RP6) were tested using PV/QV and transient analysis software. This section provides details on these designs, the study assumptions and approach, as well as the results obtained.

Powertech Labs was initially engaged by SPP to provide assistance in building the cases and determining the approach to be used for the stability analyses. Once the case models were constructed and the approach was determined, SPP staff completed the analysis and provided resulting conclusions.

A8.2: Objective

The overarching objective of this study is to identify and analyze stability gaps in the various Robustness Plans under consideration and their performance limitations. The achievement of the following sub-objectives fulfills this overarching objective.

1. Determine voltage stability limitations in grid designs and the reactive compensation required to ensure voltage stability during contingency conditions with a west to east transfer across the SPP transmission system.
2. Determine rotor angle stability limitations in grid designs during fault conditions with a west to east transfer across the SPP transmission system
3. Assess the base level stability performance of the current power system and the benchmark improvement gained by addition of facilities for the different scenario design configurations.

A8.3: Background

The two stability issues that will be addressed in these studies are voltage stability and rotor angle stability.

A power system's ability to remain at acceptable voltage levels subsequent to system disturbances resulting in voltage excursions within the system is defined as voltage stability. This is important since system collapse can occur if mitigating steps are not initiated. The disturbance, for purposes of this study, is a contingency (N-1) on the system as power transfer is increased.

Classical power system theory emphasizes the relationship between power transfer and system voltage. Should a system be deficient in reactive power capability, a contingency may cause voltages to fall to unacceptable levels. A system with transmission lines of length greater than 100 miles can exacerbate these potential problems as long lines can require additional reactive support. Since a contingency during increasingly larger power transfers will directly affect voltage at some level, it is prudent that the power transfer/voltage relationship be studied.

A disturbance on the power system can cause the rotor angles of the system generators to differ with respect to the synchronously rotating reference frame of the grid. During a disturbance, the rotor angles will oscillate about their operating points. Some disturbances will stress the system more than others, and some may result in instability. Instability occurs when a generator rotor angle cannot be brought back to or near its original operating point, resulting in a generator disconnect from the system. This study will include dynamic transient analysis to determine the system's rotor angle stability response to N-1 contingency disturbances on the system during increasing power transfers.

A8.4: Study Scenarios

A number of scenarios were studied as part of this effort. These scenarios are outlined below and are in order of increasing expansion from 345kV to 765kV.

1. Current Topology
2. Robust Plan 1 (RP1, 345kV)
3. Robust Plan 5 (RP5, RP1 w/limited Y 765kV addition)
4. Robust Plan 6 (RP6, RP1 w/limited box 765kV addition)
5. Robust Plan 4 (RP4, full 765kV design)

Current Approved Topology (identified as "Current Topology")

This Current Topology for this discussion will include existing topology along with projects having approved NTCs, including 2009 approved Balanced Portfolio projects, 2010 approved Priority Projects, and current approved STEP reliability upgrades at the time of this analysis. The topology for this case is shown in Figure 14.1 and was selected for this study based on its preliminary benefit ranking.

Robust Plan 5 (RP5)

This is considered to be the 765kV "Y" Plan. It is one of two minimized 765kV enhancements to RP1. The intent is to examine the technical and economic benefits of 765kV with reduced topology from the full 765kV plan of RP4. The 765kV topology for this case extends from north Oklahoma into south Kansas and is shown in Figure 14.2. The transformation from 345kV to 765kV is included.

Some 345kV projects required by RP1 with NTCs will be upgraded to 765kV in the RP5 design; therefore, they are replaced with 765kV projects. Table A8.1 outlines these replaced projects.

Projects Replaced by Robust Plan 5 That Currently Have NTC's	kV	State
Medicine Lodge - Wichita (double circuit)	345	KS
Medicine Lodge - Spearville (double circuit)	345	KS
Medicine Lodge - Woodward District EHV (double circuit)	345	KS, OK

Table A8.1: Projects replaced by Robust Plan 5 that currently have NTCs

Robust Plan 6 (RP6)

This scenario is considered to be the 765kV "Box" Plan. It is the second of two minimized 765kV enhancements to RP1. The intent is to examine the technical and economic benefits of 765kV with reduced topology from the full 765kV plan of RP4. This effectively extends the RP5 topology by providing a 765kV loop into east Oklahoma and Texas.

The 345kV projects required by RP1 with NTCs will be upgraded to 765kV in the RP6 design; therefore, they are replaced with 765kV projects. Table A8.2 outlines these replaced projects.

Projects Replaced by Robust Plan 6 That Currently Have NTC's	kV	State
Medicine Lodge - Wichita (double circuit)	345	KS
Medicine Lodge - Spearville (double circuit)	345	KS
Medicine Lodge - Woodward District EHV (double circuit)	345	KS, OK

Table A8.2: Projects replaced by Robust Plan 6 that currently have NTCs

Robust Plan 4 (RP4)

This case is considered to be the 765kV "Full" Plan. It includes the 765kV topology of RP6; however, two additional 765kV loops are added, one extending into south Texas and eastern New Mexico, as well as one extending north through Kansas and into Nebraska. Additional transformation from 345kV to 765kV is included.

Some 345kV projects required by RP1 with NTCs will be replaced by 765kV circuits for the RP4 design. Table A8.3 outlines these replaced projects.

Projects Replaced by Robust Plan 4 That Currently Have NTC's	kV	State
Hitchland – Woodward District EHV double circuit	345	OK
Spearville - Comanche - Med Lodge - Wichita double circuit	345	KS
Comanche - Woodward District EHV double circuit	345	KS, OK
Woodward District EHV - Tuco	345	OK, TX
Sooner - Rose Hill	345	KS, OK
Medicine Lodge Transformer	345/138	KS
Woodward District EHV - Tuco Transformers	345/230	KS, OK
Hitchland Transformer	345/230	OK
Comanche Substation	345	KS

Table A8.3: Projects replaced by Robust Plan 4 that currently have NTCs

A8.5: Assumptions

During the study process, certain assumptions were made to provide clarity to the results. Unless specified otherwise, the assumptions apply to all scenarios.

- Existing wind plants were in-service and power output was dispatched at 2 GW.
- New wind generation totaling approximately 17 GW was added on the west side of the SPP footprint and initially dispatched at 0 MW.
- New wind generation facilities were increased in 400MW increments during the simulations.
- New wind generation was proportioned as follows:
  - Kansas – 3.3 GW
  - Nebraska – 5.3 GW
  - Oklahoma – 4.6 GW
  - Texas – 3.8 GW
- The new wind generation was forced to move west to east across the SPP footprint and was the only generation scenario studied.
- New wind generation was connected at various bus voltages including 345kV, 161kV, and 115kV.

- All branches 345kV or higher within SPP were included in the N-1 contingency scan
- All branches 345kV or higher within the SPP area were monitored during contingencies
- Reactive compensation (SVCs) was added as necessary for voltage support within the SPP footprint.
- Thermal overloads were ignored during the voltage stability assessment.
- New dynamic wind machines for the 17GW transfer were modeled as variable speed wind turbines.
- Applied faults were three phase -2e^9 MVA for 5 cycles

A8.6: Methodology

This section describes the software tool used and the method by which the studies were performed.

Voltage Security Assessment

The studies were performed using Powertech Labs Inc.'s Voltage Security Assessment Tool (VSAT). VSAT is a tool for the assessment of power system voltage security.

The analysis goal was to move 17GW of renewable energy across the SPP system. This involved increasing the generation in the western area of SPP, thus providing the source for the transfer.

To minimize the stress on the eastern interconnect, a load and SVC (See Table A8.4) were added at the boundary bus of all 345kV and 500kV interfaces with SPP. The SVC MVAR output values shown are pre-transfer and pre-contingency values. These SVCs have been adjusted for each scenario to provide voltage support for maximum transfer capability within SPP. During the transfer, the loads were scaled up, essentially providing 60% of the sink for the transfer. The remaining 40% was absorbed by decreasing the generation east of SPP.

							Scenario MVAR Output				
Bus			Base	Terminal	MVAr		Base	RP1	RP5-Y	RP6-Box	RP4-Full
Name	Number	ID	kV	Voltage	Max	Min	Mvar	Mvar	Mvar	Mvar	Mvar
7BLACKBERRY 345.	300739	SP	345	1.0350	99999	-99999	**-60**	**-64**	**-26**	**-36**	**-31**
7ELDEHV 345.	337562	SP	345	1.0350	99999	-99999	**-16**	**-18**	**104**	**104**	**106**
7FAIRPT 345.	300039	SP	345	1.0350	99999	-99999	**-11**	**-22**	**72**	**72**	**64**
7GRIMES 345.	334028	SP	345	1.0350	99999	-99999	**118**	**116**	**375**	**376**	**377**
7MORGAN 345.	300045	SP	345	1.0350	99999	-99999	**101**	**98**	**176**	**176**	**179**
7OSAGECK 345.	338683	SP	345	1.0350	99999	-99999	**71**	**68**	**122**	**122**	**124**
7OVERTON 345.	345408	SP	345	1.0350	99999	-99999	**11**	**7**	**112**	**112**	**113**
7SPORTSMAN 345.	300740	SP	345	1.0350	99999	-99999	**393**	**385**	**679**	**673**	**680**
8ANO 50 500.	337909	SP	500	1.0350	99999	-99999	**36**	**5**	**401**	**401**	**399**
8MCNEIL 500.	337515	SP	500	1.0350	99999	-99999	**32**	**60**	**340**	**340**	**281**
8WELLS 500.	335368	SP	500	1.0200	99999	-99999	**197**	**198**	**198**	**198**	**198**
ATCHSNT3 345.	635017	SP	345	1.0350	99999	-99999	**-251**	**-259**	**-130**	**-130**	**-138**
FTTHOMP3 345.	652506	SP	345	1.0350	99999	-99999	**-34**	**-23**	**114**	**114**	**105**
MESSICK 500.	100404	SP	500	1.0350	99999	-99999	**-137**	**-82**	**114**	**114**	**-39**
RAUN 3 345.	635200	SP	345	1.0350	99999	-99999	**-276**	**-282**	**150**	**150**	**133**
						Total=	**173**	**189**	**2801**	**2784**	**2550**

Table A8.4: Pre-Contingency Boundary SVC Requirements

Voltage collapses outside the SPP footprint necessitated the need for static var compensation at the interface as previously discussed. Severely limited transfers due to issues within the SPP footprint were resolved by adding SVCs near the problem areas, and are shown in Table A8.7.

							Scenario MVAR Output				
Bus			Base	Terminal	MVAr		Base	RP1	RP5-Y	RP6-Box	RP4-Full
Name	Number	ID	kV	Voltage	Max	Min	Mvar	Mvar	Mvar	Mvar	Mvar
COMNCHE9 765.	521151	1	765	1.0350	9999	-2000	-	-	**-449**	**-449**	**-449**
GENTLMN3 345.	640183	SV	345	1.0147	1000	-50	**0**	**OFF**	**-3**	-	-
GENTLMN9 765.	100413	1	765	1.0350	9999	-2000	-	-	-	**-3**	**-460**
HITCHLD9 765.	523098	1	765	1.0350	9999	-2000	-	-	-	-	**-843**
HOOK CO9 765.	100414	1	765	1.0350	9999	-2000	-	-	-	-	**-127**
IATAN9 765.	100418	1	765	1.0350	9999	-2000	-	-	-	-	**-970**
MED-LDG9 765.	100411	1	765	1.0350	9999	-2000	-	-	**-290**	**-290**	**-299**
MINGO9 765.	100412	1	765	1.0350	9999	-2000	-	-	-	-	**-700**
ROSEHIL9 765.	100420	1	765	1.0350	9999	-2000	-	-	-	**-166**	**-167**
SHELDON9 765.	100416	1	765	1.0350	9999	-2000	-	-	-	-	**-858**
SOONER9 765.	100419	1	765	1.0350	9999	-2000	-	-	-	**-426**	**-414**
SPERVIL9 765.	100492	1	765	1.0350	9999	-2000	-	-	**85**	**84**	**-1106**
STLINE 9 765.	523772	1	765	1.0350	9999	-2000	-	-	-	-	**-694**
TOLK 9 765.	100410	1	765	1.0350	9999	-2000	-	-	-	-	**-1104**
TUCO 9 765.	525836	1	765	1.0350	9999	-2000	-	-	-	-	**-208**
WHEELER9 765.	100415	1	765	1.0350	9999	-2000	-	-	-	-	**-621**
WICHITA9 765.	532783	1	765	1.0350	9999	-2000	-	-	**182**	**-65**	**-67**
WWRDEHV7 345.	515375	SV	345	-	1000	-50	**OFF**	**OFF**	-	-	-
WWRDEHV9 765.	521150	1	765	1.0350	9999	-2000	-	-	**155**	**-194**	**-784**
						Total=	**0**	**0**	**-319**	**-1508**	**-9871**

Table A8.5: SPP SVC Requirements for Maximum Transfer

Transfers were increased in 400 MW increments and a complete N-1 contingency scan was performed at each increment until the initial voltage collapse occurred. At this point the program reverts to the previous point and changes its increment to 50 MW. This method provides a more precise collapse point for this approach. Subsequently, the program continues with the 400MW increments to the next collapse point for each contingency evaluated. Previous unstable contingencies were ignored in subsequent incremental transfers. The objective was to identify the most prominent voltage collapses within SPP, thus giving the transfer limitation based on the most limiting contingency event. At the point prior to the collapse, the reactive power injection for each SVC shown in Table A8.7 was retrieved and totals were calculated.

Rotor Angle Security Assessment

The dynamic transient stability studies were performed using Powertech Labs Inc.'s Transient Security Assessment Tool (TSAT). TSAT is a tool for the assessment of power system transient security.

Scenarios RP1 and RP6 were chosen for transient stability analysis. The two scenarios were chosen as the focus of this portion of the stability analysis for their fundamental representation of the 345kV and 765kV topologies. Contingency analysis was conducted on these case topologies with generation dispatched to represent 4 GW and 10 GW transfer scenarios. For the accuracy level of this process, this was considered a reasonable level of stress on the grid for checking generation performance during contingency events applying a non-economic dispatch bias West to East.

The two transfer level simulations were executed under all contingencies 345kV and above within SPP. Each contingency event consists of a 5 cycle, three phase fault at the "from" terminal bus of each contingent branch. The fault is cleared by tripping the faulted branch with no reclosing. The simulation is continued for five (5) seconds unless an unstable condition occurred.

A8.7: Simulation Results

The transfer limit results, shown below in Table A8.6, provided the approximate transfer limits for both the pre-contingency and the contingency conditions for all scenarios. A more detailed analysis of the results for each scenario is given in subsequent paragraphs.

Scenario	Base Transfer Limit (MW)	Contingency Limit (MW)
Current Topology	9,350	7,750
Robust Plan 1	12,600	12,200
Robust Plan 5	12,900	11,300
Robust Plan 6	14,600	12,200
Robust Plan 4	16,200	14,600

Table A8.6: Transfer Limits

Current Topology

Voltage Security Assessment

The results in Table A8.6 indicate a transfer limit of approximately 8 GW under contingency. Table A8.7 provides detail concerning the specific contingencies causing voltage collapse. Modal analysis is used to determine the geographical area of instability. Initial areas of instability, produced by contingencies A28, A58, and A60, are external to SPP's footprint. Contingency A201, SWEET W3 345 – GR ISLD3 345, is the limiting contingency resulting in voltage collapse in the underlying system within SPP (Area 640 – NPPD) in northwest and central Nebraska. Further voltage deterioration within Nebraska occurs during transfers greater than the 7,750 MW limit.

Transfer		Limiting Contingency		Contingency Element		CKT		
No.	Source X	Contingency	Violation Type	From Bus Name	To Bus Name	ID	From Bus	To Bus
1	2100		Security Limit					
2	2150	A 28	Voltage Collapse	7GRIMES 345.	CROCKET7 345.	1	334028	509241
3	5350	A 58	Voltage Collapse	LEBROCK7 345.	TENRUSK7 345.	1	508572	508585
4	5350	A 60	Voltage Collapse	TENRUSK7 345.	CROCKET7 345.	1	508585	509241
5	7750	A 201	Voltage Collapse	SWEET W3 345.	GR ISLD3 345.	1	640374	652571
6	8150	A 191	Voltage Collapse	GENTLMN3 345.	SWEET W3 345.	1	640183	640374
7	8550	A 7	Voltage Collapse	HOLT CO 7 345.	FTTHOMP3 345.	1	100315	652506
8	8550	A 85	Voltage Collapse	O.K.U.-7 345.	L.E.S.-7 345.	1	511456	511468
9	8550	A 184	Voltage Collapse	AXTELL 3 345.	SWEET W3 345.	1	640065	640374
10	8550	A 192	Voltage Collapse	GENTLMN3 345.	SWEET W3 345.	2	640183	640374
11	8550	A 197	Voltage Collapse	MCCOOL 3 345.	GR ISLD3 345.	1	640271	652571
12	8950	A 5	Voltage Collapse	HOLT CO 7 345.	WHEELER7 345.	1	100315	100316
13	8950	A 9	Voltage Collapse	WHEELER7 345.	GR ISLD3 345.	1	100316	652571

14	8950	A 86	Voltage Collapse	O.K.U.-7 345.	TUCO_INT 7345.	1	511456	525832
15	8950	A 100	Voltage Collapse	NORTWST7 345.	TATONGA7 345.	1	514880	515407
16	8950	A 116	Voltage Collapse	WWRDEHV7 345.	TATONGA7 345.	1	515375	515407
17	8950	A 134	Voltage Collapse	HOLCOMB7 345.	SPERVIL7 345.	1	531449	531469
18	8950	A 139	Voltage Collapse	HOYT 7 345.	JEC N 7 345.	1	532765	532766
19	8950	A 183	Voltage Collapse	AXTELL 3 345.	PAULINE3 345.	1	640065	640312
20	8950	A 190	Voltage Collapse	GENTLMN3 345.	REDWILO3 345.	1	640183	640325
21	8950	A 195	Voltage Collapse	KEYSTON3 345.	SIDNEY 3 345.	1	640252	659133
22	8950	A 196	Voltage Collapse	MCCOOL 3 345.	MOORE 3 345.	1	640271	640277
23	8950	A 198	Voltage Collapse	MOORE 3 345.	PAULINE3 345.	1	640277	640312
24	9350	Pre Contingency	Voltage Collapse					

Table A8.7: Base 345 kV Contingency Transfer Results

Interface flows between SPP and adjacent regions just prior to the 8 GW limit are shown in Table A8.8.

345kV Interface	MW Flow for Contingency (A201)
SPP to WAPA	639
SPP to MEC	1,967
SPP to AMMO	830
SPP to EES	2,902
SPP to AECI	1,359
Total Interface Flow	**7,967**

Table A8.8: Interface Flows

It is readily observed from Table A8.8 that the interface flows to WAPA and MEC total 1.7 GW, or 34% of the total export. Since Nebraska is the collapse area within SPP, these flows contribute to the collapse in the underlying voltages.

Total reactive compensation required to support the 8 GW transfer across SPP for the Current Topology is shown in Table A8.9.

Location	MVAR
At Interface of Eastern Interconnect	1,400
Within SPP	250
Total	**1,650**

Table A8.9: Reactive Compensation Requirements for Current Topology

Robust Plan 1 - 345kV

Voltage Security Assessment

The results in Table A8.6 indicate a transfer limit of approximately 12.2 GW under contingency conditions. Table A8.10 provides detail concerning the specific contingencies causing voltage collapse. Initial areas of voltage collapse, produced by contingency transfers up to 12.2 GW, are external to SPP's footprint. Contingency A6, HOLTCO7 345 – HOSKINS3 345, is the limiting contingency resulting in voltage collapse in the underlying system within SPP. Area 640 (NPPD) in central Nebraska is the area of collapse within SPP for transfers of 12.2 GW or greater.

Transfer		Limiting Contingency		Contingency Element		CKT		
No.	Source X	Contingency	Violation Type	From Bus Name	To Bus Name	ID	From Bus	To Bus
1	2150		Security Limit					
2	2200	A 28	Voltage Collapse	7GRIMES 345.	CROCKET7 345.	1	334028	509241

Transfer		Limiting Contingency		Contingency Element		CKT		
3	4600	A 58	Voltage Collapse	LEBROCK7 345.	TENRUSK7 345.	1	508572	508585
4	4600	A 60	Voltage Collapse	TENRUSK7 345.	CROCKET7 345.	1	508585	509241
5	9400	A 3	Voltage Collapse	HOOK CO 7 345.	WHEELER7 345.	1	100310	100316
6	9800	A 4	Voltage Collapse	HOOK CO 7 345.	GENTLMN3 345.	1	100310	640183
7	11000	A 85	Voltage Collapse	O.K.U.-7 345.	L.E.S.-7 345.	1	511456	511468
8	11400	A 86	Voltage Collapse	O.K.U.-7 345.	TUCO_INT 7345.	1	511456	525832
9	11400	A 201	Voltage Collapse	SWEET W3 345.	GR ISLD3 345.	1	640374	652571
10	11800	A 5	Voltage Collapse	HOLT CO 7 345.	WHEELER7 345.	1	100315	100316
11	11800	A 8	Voltage Collapse	WHEELER7 345.	SHELCRK3 345.	1	100316	640342
12	11800	A 183	Voltage Collapse	AXTELL 3 345.	PAULINE3 345.	1	640065	640312
13	11800	A 184	Voltage Collapse	AXTELL 3 345.	SWEET W3 345.	1	640065	640374
14	11800	A 191	Voltage Collapse	GENTLMN3 345.	SWEET W3 345.	1	640183	640374
15	11800	A 192	Voltage Collapse	GENTLMN3 345.	SWEET W3 345.	2	640183	640374
16	12200	A 1	Voltage Collapse	VIOLA 7 345.	ROSEHIL7 345.	1	100300	532794
17	12200	A 2	Voltage Collapse	VIOLA 7 345.	WICHITA7 345.	1	100300	532796
18	12200	A 6	Voltage Collapse	HOLT CO 7 345.	HOSKINS3 345.	1	100315	640226
19	12200	A 7	Voltage Collapse	HOLT CO 7 345.	FTTHOMP3 345.	1	100315	652506
20	12200	A 9	Voltage Collapse	WHEELER7 345.	GR ISLD3 345.	1	100316	652571
21	12200	A 12	Voltage Collapse	ELMCRK 7 345.	WOLF 7 345.	1	100320	530583
22	12200	A 13	Voltage Collapse	ELMCRK 7 345.	JEC N 7 345.	1	100320	532766
23	12200	A 14	Voltage Collapse	MULGREN7 345.	CIRCLE 7 345.	1	100321	100322
24	12200	A 15	Voltage Collapse	MULGREN7 345.	SPERVIL7 345.	1	100321	531469
25	12200	A 16	Voltage Collapse	CIRCLE 7 345.	RENO 7 345.	1	100322	532771
26	12200	A 21	Voltage Collapse	MCNEIL7 345.	HEMPSTD7 345.	1	100403	507455
27	12200	A 23	Voltage Collapse	7FAIRPT 345.	ST JOE 3 345.	1	300039	541199
28	12200	A 26	Voltage Collapse	7BLACKBERRY 345.	NEOSHO 7 345.	1	300739	532793
29	12200	A 30	Voltage Collapse	8ANO 50 500.	FTSMITH8 500.	1	337909	515305
30	12200	A 37	Voltage Collapse	FLINTCR7 345.	GRDA1 7 345.	1	506935	512650
31	12200	A 38	Voltage Collapse	FLINTCR7 345.	MON383 7 345.	1	506935	547481
32	12200	A 40	Voltage Collapse	CHAMSPR7 345.	CLARKSV7 345.	1	506945	509745
33	12200	A 48	Voltage Collapse	NWTXARK7 345.	VALIANT7 345.	1	508072	510911
34	12200	A 51	Voltage Collapse	LYDIA 7 345.	VALIANT7 345.	1	508298	510911
35	12200	A 69	Voltage Collapse	R.S.S.-7 345.	REDBUD 7 345.	1	509782	514909
36	12200	A 75	Voltage Collapse	T.NO.--7 345.	GRDA1 7 345.	1	509852	512650
37	12200	A 76	Voltage Collapse	T.NO.--7 345.	CLEVLND7 345.	1	509852	512694
38	12200	A 77	Voltage Collapse	DELWARE7 345.	N.E.S.-7 345.	1	510380	510406
39	12200	A 78	Voltage Collapse	DELWARE7 345.	NEOSHO 7 345.	1	510380	532793
40	12200	A 79	Voltage Collapse	PITTSB-7 345.	VALIANT7 345.	1	510907	510911
41	12200	A 82	Voltage Collapse	PITTSB-7 345.	SEMINOL7 345.	1	510907	515045
42	12200	A 84	Voltage Collapse	VALIANT7 345.	HUGO PP7 345.	1	510911	521157

Transfer		Limiting Contingency		Contingency Element		CKT		
43	12200	A 87	Voltage Collapse	L.E.S.-7 345.	SUNNYSD7 345.	1	511468	515136
44	12200	A 89	Voltage Collapse	CLEVLND7 345.	SOONER 7 345.	1	512694	514803
45	12200	A 90	Voltage Collapse	WOODRNG7 345.	SOONER 7 345.	1	514715	514803
46	12200	A 91	Voltage Collapse	WOODRNG7 345.	CIMARON7 345.	1	514715	514901
47	12200	A 92	Voltage Collapse	WOODRNG7 345.	WWRDEHV7 345.	1	514715	515375
48	12200	A 99	Voltage Collapse	NORTWST7 345.	ARCADIA7 345.	1	514880	514908
49	12200	A 100	Voltage Collapse	NORTWST7 345.	TATONGA7 345.	1	514880	515407
50	12200	A 101	Voltage Collapse	CIMARON7 345.	DRAPER 7 345.	1	514901	514934
51	12200	A 102	Voltage Collapse	CIMARON7 345.	GRACMNT7 345.	1	514901	515800
52	12200	A 110	Voltage Collapse	SEMINOL7 345.	MUSKOGE7 345.	1	515045	515224
53	12200	A 111	Voltage Collapse	SUNNYSD7 345.	HUGO PP7 345.	1	515136	521157
54	12200	A 114	Voltage Collapse	MUSKOGE7 345.	FTSMITH7 345.	1	515224	515302
55	12200	A 116	Voltage Collapse	WWRDEHV7 345.	TATONGA7 345.	1	515375	515407
56	12200	A 117	Voltage Collapse	WWRDEHV7 345.	HITCHLAND 7345.	1	515375	523097
57	12200	A 118	Voltage Collapse	WWRDEHV7 345.	HITCHLAND 7345.	2	515375	523097
58	12200	A 119	Voltage Collapse	WWRDEHV7 345.	TUCO_INT 7345.	&1	515375	525832
59	12200	A 124	Voltage Collapse	WWRDEHV7 345.	TUCO_INT 7345.	&1	515375	525832
60	12200	A 130	Voltage Collapse	WOLF 7 345.	MINGO 7 345.	1	530583	531451
61	12200	A 132	Voltage Collapse	WOLF 7 345.	AXTELL 3 345.	1	530583	640065
62	12200	A 133	Voltage Collapse	HOLCOMB7 345.	SETAB 7 345.	1	531449	531465
63	12200	A 134	Voltage Collapse	HOLCOMB7 345.	SPERVIL7 345.	1	531449	531469
64	12200	A 135	Voltage Collapse	MINGO 7 345.	SETAB 7 345.	1	531451	531465
65	12200	A 136	Voltage Collapse	MINGO 7 345.	REDWILO3 345.	1	531451	640325
66	12200	A 137	Voltage Collapse	SPERVIL7 345.	COMANCH5 345.	1	531469	765341
67	12200	A 138	Voltage Collapse	SPERVIL7 345.	COMANCH5 345.	2	531469	765341
68	12200	A 139	Voltage Collapse	HOYT 7 345.	JEC N 7 345.	1	532765	532766
69	12200	A 140	Voltage Collapse	HOYT 7 345.	STRANGR7 345.	1	532765	532772
70	12200	A 142	Voltage Collapse	JEC N 7 345.	SUMMIT 7 345.	1	532766	532773
71	12200	A 143	Voltage Collapse	JEC N 7 345.	IATAN 7 345.	1	532766	542982
72	12200	A 146	Voltage Collapse	EMPEC 7 345.	SWISVAL7 345.	1	532768	532774
73	12200	A 147	Voltage Collapse	EMPEC 7 345.	WICHITA7 345.	1	532768	532796
74	12200	A 148	Voltage Collapse	RENO 7 345.	SUMMIT 7 345.	1	532771	532773
75	12200	A 149	Voltage Collapse	RENO 7 345.	WICHITA7 345.	1	532771	532796
76	12200	A 152	Voltage Collapse	SWISVAL7 345.	W.GRDNR7 345.	1	532774	542965
77	12200	A 155	Voltage Collapse	BENTON 7 345.	WICHITA7 345.	1	532791	532796
78	12200	A 156	Voltage Collapse	BENTON 7 345.	WOLFCRK7 345.	1	532791	532797
79	12200	A 157	Voltage Collapse	NEOSHO 7 345.	LATHAMS7 345.	1	532793	532800
80	12200	A 159	Voltage Collapse	ROSEHIL7 345.	WOLFCRK7 345.	1	532794	532797
81	12200	A 160	Voltage Collapse	ROSEHIL7 345.	LATHAMS7 345.	1	532794	532800
82	12200	A 161	Voltage Collapse	WICHITA7 345.	MED-LDG5 345.	1	532796	765342

Transfer		Limiting Contingency		Contingency Element		CKT		
83	12200	A 162	Voltage Collapse	WICHITA7 345.	MED-LDG5 345.	2	532796	765342
84	12200	A 163	Voltage Collapse	WOLFCRK7 345.	LACYGNE7 345.	1	532797	542981
85	12200	A 165	Voltage Collapse	PECULR 7 345.	PHILL 7 345.	1	541198	541200
86	12200	A 166	Voltage Collapse	PECULR 7 345.	STILWEL7 345.	1	541198	542968
87	12200	A 168	Voltage Collapse	ST JOE 3 345.	IATAN 7 345.	1	541199	542982
88	12200	A 170	Voltage Collapse	PHILL 7 345.	SIBLEY 7 345.	1	541200	541201
89	12200	A 173	Voltage Collapse	W.GRDNR7 345.	CRAIG 7 345.	1	542965	542977
90	12200	A 174	Voltage Collapse	W.GRDNR7 345.	LACYGNE7 345.	1	542965	542981
91	12200	A 175	Voltage Collapse	STILWEL7 345.	LACYGNE7 345.	1	542968	542981
92	12200	A 177	Voltage Collapse	NASHUA 7 345.	IATAN 7 345.	1	542980	542982
93	12200	A 178	Voltage Collapse	MON383 7 345.	BROOKLINE 7345.	1	547481	549984
94	12200	A 179	Voltage Collapse	CBLUFFS3 345.	S3456 3 345.	1	635000	645456
95	12200	A 180	Voltage Collapse	ATCHSNT3 345.	COOPER 3 345.	1	635017	640139
96	12200	A 181	Voltage Collapse	RAUN 3 345.	HOSKINS3 345.	1	635200	640226
97	12200	A 182	Voltage Collapse	RAUN 3 345.	S3451 3 345.	1	635200	645451
98	12200	A 185	Voltage Collapse	COLMB.E3 345.	SHELCRK3 345.	1	640125	640342
99	12200	A 186	Voltage Collapse	COLMB.E3 345.	NW68HOLDRG3 345.	1	640125	650114
100	12200	A 187	Voltage Collapse	COOPER 3 345.	MOORE 3 345.	1	640139	640277
101	12200	A 189	Voltage Collapse	GENTLMN3 345.	KEYSTON3 345.	1	640183	640252
102	12200	A 190	Voltage Collapse	GENTLMN3 345.	REDWILO3 345.	1	640183	640325
103	12200	A 193	Voltage Collapse	HOSKINS3 345.	SHELCRK3 345.	1	640226	640342
104	12200	A 194	Voltage Collapse	HOSKINS3 345.	S3451 3 345.	1	640226	645451
105	12200	A 195	Voltage Collapse	KEYSTON3 345.	SIDNEY 3 345.	1	640252	659133
106	12200	A 196	Voltage Collapse	MCCOOL 3 345.	MOORE 3 345.	1	640271	640277
107	12200	A 197	Voltage Collapse	MCCOOL 3 345.	GR ISLD3 345.	1	640271	652571
108	12200	A 198	Voltage Collapse	MOORE 3 345.	PAULINE3 345.	1	640277	640312
109	12200	A 200	Voltage Collapse	MOORE 3 345.	103&ROKEBY3 345.	1	640277	650189
110	12200	A 207	Voltage Collapse	S3454 3 345.	WAGENER 3 345.	1	645454	650185
111	12200	A 210	Voltage Collapse	S3456 3 345.	S3458 3 345.	1	645456	645458
112	12200	A 212	Voltage Collapse	S3458 3 345.	S3740 3 345.	1	645458	645740
113	12200	A 213	Voltage Collapse	S3458 3 345.	103&ROKEBY3 345.	1	645458	650189
114	12200	A 214	Voltage Collapse	NW68HOLDRG3 345.	WAGENER 3 345.	1	650114	650185
115	12200	A 216	Voltage Collapse	COMANCH5 345.	MED-LDG5 345.	1	765341	765342
116	12200	A 217	Voltage Collapse	COMANCH5 345.	MED-LDG5 345.	2	765341	765342
117	12200	A 218	Voltage Collapse	8MCNEIL 500.	MCNEIL7 345.	1	337515	100403
118	12600	Pre Contingency	Voltage Collapse					

Table A8.10: Base 345kV Contingency Transfer Results

Table A8.15 indicates that the interface flows to WAPA and MEC total 1,654 MW, or 34% of the total export. Since Nebraska is the collapse area within SPP, these flows contribute to the collapse of the underlying system; however future grid expansion in neighboring systems could provide support that is not captured in this analysis.

345kV Interface	MW Flow for Contingency (A6)
SPP to WAPA	520
SPP to MEC	1,134
SPP to AMMO	537
SPP to EES	1,635
SPP to AECI	937
Total Interface Flow	**4,763**

Table A8.11: Interface Flows for RP1

Total reactive compensation required to support the 12.2 GW transfer across the SPP system for RP1 is shown in Table A8.16.

Location	Amount (MVAR)
SVCs at Interface of Eastern Interconnect	2,460
SPP 345kV SVCs	280*
Total	**2,740**

*Limited by a maximum of 280 MVAR

Table A8.12: Reactive Compensation Requirements for RP1

Rotor Angle Stability Assessment

The first transient stability analysis was performed for a 4,000 MW dispatch and a 10,000 MW dispatch of new renewable energy from west-to-east across the SPP system under contingency conditions. The results showed no events resulting in rotor angle instability.

RP5 - 765kV "Y" Plan

Voltage Security Assessment

The results in Table A8.6 show that the transfer limit is approximately 11,300 MW under contingency conditions. Table A8.13 provides detail concerning the specific contingencies causing voltage collapse. Initial areas of voltage instability, produced by contingency transfers up to 11,300 MW, are external to SPP's footprint. Contingency A218, Woodward District EHV 345/765kV transformer, is the limiting contingency resulting in voltage collapse within SPP. The underlying system in area 520 (AEPW) in the Texas panhandle is the area of collapse within SPP for transfers of 11,300 MW or greater.

Transfer		Limiting Contingency		Contingency Element		CKT		
No.	Source X	Contingency	Violation Type	From Bus Name	To Bus Name	ID	From Bus	To Bus
1	2100		Security Limit					
2	2150	A 29	Voltage Collapse	7GRIMES 345.	CROCKET7 345.	1	334028	509241
3	4550	A 59	Voltage Collapse	LEBROCK7 345.	TENRUSK7 345.	1	508572	508585
4	4550	A 61	Voltage Collapse	TENRUSK7 345.	CROCKET7 345.	1	508585	509241
5	9750	A 2	Voltage Collapse	HOOK CO 7 345.	GENTLMN3 345.	1	100310	640183
6	11350	A 21	Voltage Collapse	MED-LDG9 765.	COMNCHE9 765.	1	100411	521151
7	11350	A 218	Voltage Collapse	WWRDEHV7 345.	WWRDEHV9 765.	1	515375	521150
8	11750	A 1	Voltage Collapse	HOOK CO 7 345.	WHEELER7 345.	1	100310	100316
9	11750	A 22	Voltage Collapse	MED-LDG9 765.	WICHITA9 765.	1	100411	532783
10	11750	A 120	Voltage Collapse	WWRDEHV9 765.	COMNCHE9 765.	1	521150	521151

Transfer		Limiting Contingency		Contingency Element		CKT		
11	11750	A 220	Voltage Collapse	WICHITA7 345.	WICHITA9 765.	1	532796	532783
12	12150	A 88	Voltage Collapse	L.E.S.-7 345.	SUNNYSD7 345.	1	511468	515136
13	12150	A 90	Voltage Collapse	CLEVLND7 345.	SOONER 7 345.	1	512694	514803
14	12150	A 93	Voltage Collapse	WOODRNG7 345.	WWRDEHV7 345.	1	514715	515375
15	12150	A 100	Voltage Collapse	NORTWST7 345.	TATONGA7 345.	1	514880	515407
16	12150	A 133	Voltage Collapse	HOLCOMB7 345.	SPERVIL7 345.	1	531449	531469
17	12550	A 13	Voltage Collapse	MULGREN7 345.	SPERVIL7 345.	1	100321	531469
18	12550	A 27	Voltage Collapse	7BLACKBERRY 345.	NEOSHO 7 345.	1	300739	532793
19	12550	A 35	Voltage Collapse	7OVERTON 345.	SIBLEY 7 345.	1	345408	541201
20	12550	A 70	Voltage Collapse	R.S.S.-7 345.	REDBUD 7 345.	1	509782	514909
21	12550	A 77	Voltage Collapse	T.NO.--7 345.	CLEVLND7 345.	1	509852	512694
22	12550	A 82	Voltage Collapse	PITTSB-7 345.	JOHNCO 7 345.	1	510907	514809
23	12550	A 83	Voltage Collapse	PITTSB-7 345.	SEMINOL7 345.	1	510907	515045
24	12550	A 84	Voltage Collapse	PITTSB-7 345.	C-RIVER7 345.	1	510907	515422
25	12550	A 86	Voltage Collapse	O.K.U.-7 345.	L.E.S.-7 345.	1	511456	511468
26	12550	A 89	Voltage Collapse	L.E.S.-7 345.	GRACMNT7 345.	1	511468	515800
27	12550	A 91	Voltage Collapse	WOODRNG7 345.	SOONER 7 345.	1	514715	514803
28	12550	A 92	Voltage Collapse	WOODRNG7 345.	CIMARON7 345.	1	514715	514901
29	12550	A 94	Voltage Collapse	WOODRNG7 345.	WICHITA7 345.	1	514715	532796
30	12550	A 95	Voltage Collapse	SOONER 7 345.	SPRNGCK7 345.	1	514803	514881
31	12550	A 97	Voltage Collapse	NORTWST7 345.	SPRNGCK7 345.	1	514880	514881
32	12550	A 99	Voltage Collapse	NORTWST7 345.	ARCADIA7 345.	1	514880	514908
33	12550	A 101	Voltage Collapse	CIMARON7 345.	DRAPER 7 345.	1	514901	514934
34	12550	A 102	Voltage Collapse	CIMARON7 345.	GRACMNT7 345.	1	514901	515800
35	12550	A 110	Voltage Collapse	SEMINOL7 345.	MUSKOGE7 345.	1	515045	515224
36	12550	A 111	Voltage Collapse	SUNNYSD7 345.	HUGO PP7 345.	1	515136	521157
37	12550	A 115	Voltage Collapse	MUSKOGE7 345.	C-RIVER7 345.	1	515224	515422
38	12550	A 116	Voltage Collapse	WWRDEHV7 345.	TATONGA7 345.	1	515375	515407
39	12550	A 117	Voltage Collapse	WWRDEHV7 345.	HITCHLAND 7345.	1	515375	523097
40	12550	A 118	Voltage Collapse	WWRDEHV7 345.	HITCHLAND 7345.	2	515375	523097
41	12550	A 119	Voltage Collapse	WWRDEHV7 345.	TUCO_INT 7345.	&1	515375	525832
42	12550	A 121	Voltage Collapse	HITCHLAND 7345.	FINNEY 7345.	1	523097	523853
43	12550	A 123	Voltage Collapse	WWRDEHV7 345.	TUCO_INT 7345.	&1	515375	525832
44	12550	A 124	Voltage Collapse	FINNEY 7345.	HOLCOMB7 345.	1	523853	531449
45	12550	A 132	Voltage Collapse	HOLCOMB7 345.	SETAB 7 345.	1	531449	531465
46	12550	A 134	Voltage Collapse	MINGO 7 345.	SETAB 7 345.	1	531451	531465
47	12550	A 143	Voltage Collapse	EMPEC 7 345.	SWISVAL7 345.	1	532768	532774
48	12550	A 149	Voltage Collapse	SWISVAL7 345.	W.GRDNR7 345.	1	532774	542965
49	12550	A 152	Voltage Collapse	BENTON 7 345.	WICHITA7 345.	1	532791	532796
50	12550	A 154	Voltage Collapse	NEOSHO 7 345.	LATHAMS7 345.	1	532793	532800

Transfer		Limiting Contingency		Contingency Element		CKT		
51	12550	A 155	Voltage Collapse	NEOSHO 7 345.	LACYGNE7 345.	1	532793	542981
52	12550	A 157	Voltage Collapse	ROSEHIL7 345.	LATHAMS7 345.	1	532794	532800
53	12550	A 158	Voltage Collapse	WOLFCRK7 345.	LACYGNE7 345.	1	532797	542981
54	12550	A 196	Voltage Collapse	SWEET W3 345.	GR ISLD3 345.	1	640374	652571
55	12950	Pre Contingency	Voltage Collapse					

Table A8.13: Contingency Transfer Results for RP5

Table A8.14 shows that the interface flows to all regions adjacent to SPP. These flows contribute to the voltage collapses on the underlying voltage system within SPP; however future grid expansion in neighboring systems could provide support that is not captured in this analysis.

345kV Interface	MW Flow for Contingency (A218)
SPP to WAPA	538
SPP to MEC	1,973
SPP to AMMO	822
SPP to EES	2,799
SPP to AECI	1325
Total Interface Flow	**7,457**

Table A8.14: Interface Flows

Total reactive compensation required to support the 11,300 MW transfer across the SPP system for RP5 is shown in Table A8.15.

Location	Amount (MVAR)
SVCs at Interface of Eastern Interconnect	4,800
SPP 765kV SVCs	520
SPP 345kV SVCs	160
Total	**5,480**

Table A8.15: Reactive Compensation Requirements for RP5

RP6 - 765kV "Box" Plan

Voltage Security Assessment

The results in Table A8.6 show that the transfer limit is approximately 12.2 GW under contingency. Table A8.16 provides detail concerning the specific contingencies causing voltage collapse. Initial areas of voltage collapse, produced by contingency transfers up to 12.2 GW, are external to SPP's footprint. Contingency A1, HOOK CO 7 345 – WHEELER7 345, is the limiting contingency resulting in voltage collapse in the underlying system within SPP area 640 (NPPD) in northwest Nebraska, and area 520 (AEPW) in the Texas panhandle for transfers of 12.2 GW or greater.

Transfer		Limiting Contingency		Contingency Element		CKT		
No.	Source X	Contingency	Violation Type	From Bus Name	To Bus Name	ID	From Bus	To Bus
1	2200		Security Limit					
2	2250	A 29	Voltage Collapse	7GRIMES 345.	CROCKET7 345.	1	334028	509241
3	4250	A 61	Voltage Collapse	TENRUSK7 345.	CROCKET7 345.	1	508585	509241
4	4650	A 59	Voltage Collapse	LEBROCK7 345.	TENRUSK7 345.	1	508572	508585
5	9850	A 2	Voltage Collapse	HOOK CO 7 345.	GENTLMN3 345.	1	100310	640183
6	11850	A 1	Voltage Collapse	HOOK CO 7 345.	WHEELER7 345.	1	100310	100316

Transfer		Limiting Contingency		Contingency Element		CKT		
7	13050	A 196	Voltage Collapse	SWEET W3 345.	GR ISLD3 345.	1	640374	652571
8	13450	A 86	Voltage Collapse	O.K.U.-7 345.	L.E.S.-7 345.	1	511456	511468
9	13450	A 90	Voltage Collapse	CLEVLND7 345.	SOONER 7 345.	1	512694	514803
10	13450	A 117	Voltage Collapse	WWRDEHV7 345.	HITCHLAND 7345.	1	515375	523097
11	13450	A 118	Voltage Collapse	WWRDEHV7 345.	HITCHLAND 7345.	2	515375	523097
12	13450	A 133	Voltage Collapse	HOLCOMB7 345.	SPERVIL7 345.	1	531449	531469
13	13850	A 3	Voltage Collapse	HOLT CO 7 345.	WHEELER7 345.	1	100315	100316
14	13850	A 5	Voltage Collapse	HOLT CO 7 345.	FTTHOMP3 345.	1	100315	652506
15	13850	A 6	Voltage Collapse	WHEELER7 345.	SHELCRK3 345.	1	100316	640342
16	13850	A 21	Voltage Collapse	MED-LDG9 765.	COMNCHE9 765.	1	100411	521151
17	13850	A 23	Voltage Collapse	SPERVIL9 765.	COMNCHE9 765.	1	100492	521151
18	13850	A 77	Voltage Collapse	T.NO.--7 345.	CLEVLND7 345.	1	509852	512694
19	13850	A 88	Voltage Collapse	L.E.S.-7 345.	SUNNYSD7 345.	1	511468	515136
20	13850	A 89	Voltage Collapse	L.E.S.-7 345.	GRACMNT7 345.	1	511468	515800
21	13850	A 97	Voltage Collapse	NORTWST7 345.	SPRNGCK7 345.	1	514880	514881
22	13850	A 102	Voltage Collapse	CIMARON7 345.	GRACMNT7 345.	1	514901	515800
23	13850	A 119	Voltage Collapse	WWRDEHV7 345.	TUCO_INT 7345.	&1	515375	525832
24	13850	A 123	Voltage Collapse	WWRDEHV7 345.	TUCO_INT 7345.	&1	515375	525832
25	13850	A 178	Voltage Collapse	AXTELL 3 345.	PAULINE3 345.	1	640065	640312
26	13850	A 179	Voltage Collapse	AXTELL 3 345.	SWEET W3 345.	1	640065	640374
27	13850	A 186	Voltage Collapse	GENTLMN3 345.	SWEET W3 345.	1	640183	640374
28	13850	A 187	Voltage Collapse	GENTLMN3 345.	SWEET W3 345.	2	640183	640374
29	13850	A 190	Voltage Collapse	KEYSTON3 345.	SIDNEY 3 345.	1	640252	659133
30	13850	A 192	Voltage Collapse	MCCOOL 3 345.	GR ISLD3 345.	1	640271	652571
31	13850	A 193	Voltage Collapse	MOORE 3 345.	PAULINE3 345.	1	640277	640312
32	13850	A 213	Voltage Collapse	SOONER9 765.	WWRDEHV9 765.	1	100419	521150
33	13850	A 217	Voltage Collapse	SPERVIL7 345.	SPERVIL9 765.	1	531469	100492
34	14250	A 224	Voltage Collapse	WWRDEHV7 345.	WWRDEHV9 765.	2	515375	521150
35	14250	A 4	Voltage Collapse	HOLT CO 7 345.	HOSKINS3 345.	1	100315	640226
36	14250	A 8	Voltage Collapse	HARRNG_EST7 345.	HITCHLAND 7345.	1	100319	523097
37	14250	A 9	Voltage Collapse	HARRNG_EST7 345.	POTTER_CO 7345.	1	100319	523961
38	14250	A 10	Voltage Collapse	ELMCRK 7 345.	WOLF 7 345.	1	100320	530583
39	14250	A 11	Voltage Collapse	ELMCRK 7 345.	JEC N 7 345.	1	100320	532766
40	14250	A 12	Voltage Collapse	MULGREN7 345.	CIRCLE 7 345.	1	100321	100322
41	14250	A 13	Voltage Collapse	MULGREN7 345.	SPERVIL7 345.	1	100321	531469
42	14250	A 14	Voltage Collapse	CIRCLE 7 345.	RENO 7 345.	1	100322	532771
43	14250	A 22	Voltage Collapse	MED-LDG9 765.	WICHITA9 765.	1	100411	532783
44	14250	A 24	Voltage Collapse	7FAIRPT 345.	ST JOE 3 345.	1	300039	541199
45	14250	A 26	Voltage Collapse	7MORGAN 345.	BROOKLINE 7345.	1	300045	549984
46	14250	A 27	Voltage Collapse	7BLACKBERRY 345.	NEOSHO 7 345.	1	300739	532793

Transfer		Limiting Contingency		Contingency Element		CKT		
47	14250	A 31	Voltage Collapse	8ANO 50 500.	FTSMITH8 500.	1	337909	515305
48	14250	A 35	Voltage Collapse	7OVERTON 345.	SIBLEY 7 345.	1	345408	541201
49	14250	A 37	Voltage Collapse	FLINTCR7 345.	CENTRTN7 345.	1	506935	506979
50	14250	A 38	Voltage Collapse	FLINTCR7 345.	GRDA1 7 345.	1	506935	512650
51	14250	A 41	Voltage Collapse	CHAMSPR7 345.	CLARKSV7 345.	1	506945	509745
52	14250	A 42	Voltage Collapse	CHAMSPR7 345.	FTSMITH7 345.	1	506945	515302
53	14250	A 48	Voltage Collapse	NWTXARK7 345.	WELSH 7 345.	1	508072	508359
54	14250	A 50	Voltage Collapse	NWTXARK7 345.	FTSMITH7 345.	1	508072	515302
55	14250	A 51	Voltage Collapse	LYDIA 7 345.	WELSH 7 345.	1	508298	508359
56	14250	A 52	Voltage Collapse	LYDIA 7 345.	VALIANT7 345.	1	508298	510911
57	14250	A 63	Voltage Collapse	CLARKSV7 345.	ONETA--7 345.	1	509745	509807
58	14250	A 65	Voltage Collapse	WEKIWA-7 345.	T.NO.--7 345.	1	509755	509852
59	14250	A 70	Voltage Collapse	R.S.S.-7 345.	REDBUD 7 345.	1	509782	514909
60	14250	A 74	Voltage Collapse	ONETA--7 345.	N.E.S.-7 345.	1	509807	510406
61	14250	A 75	Voltage Collapse	T.NO.--7 345.	N.E.S.-7 345.	1	509852	510406
62	14250	A 76	Voltage Collapse	T.NO.--7 345.	GRDA1 7 345.	1	509852	512650
63	14250	A 80	Voltage Collapse	PITTSB-7 345.	VALIANT7 345.	1	510907	510911
64	14250	A 82	Voltage Collapse	PITTSB-7 345.	JOHNCO 7 345.	1	510907	514809
65	14250	A 83	Voltage Collapse	PITTSB-7 345.	SEMINOL7 345.	1	510907	515045
66	14250	A 84	Voltage Collapse	PITTSB-7 345.	C-RIVER7 345.	1	510907	515422
67	14250	A 87	Voltage Collapse	O.K.U.-7 345.	TUCO_INT 7345.	1	511456	525832
68	14250	A 91	Voltage Collapse	WOODRNG7 345.	SOONER 7 345.	1	514715	514803
69	14250	A 92	Voltage Collapse	WOODRNG7 345.	CIMARON7 345.	1	514715	514901
70	14250	A 93	Voltage Collapse	WOODRNG7 345.	WWRDEHV7 345.	1	514715	515375
71	14250	A 94	Voltage Collapse	WOODRNG7 345.	WICHITA7 345.	1	514715	532796
72	14250	A 95	Voltage Collapse	SOONER 7 345.	SPRNGCK7 345.	1	514803	514881
73	14250	A 96	Voltage Collapse	JOHNCO 7 345.	SUNNYSD7 345.	1	514809	515136
74	14250	A 98	Voltage Collapse	NORTWST7 345.	CIMARON7 345.	1	514880	514901
75	14250	A 99	Voltage Collapse	NORTWST7 345.	ARCADIA7 345.	1	514880	514908
76	14250	A 100	Voltage Collapse	NORTWST7 345.	TATONGA7 345.	1	514880	515407
77	14250	A 101	Voltage Collapse	CIMARON7 345.	DRAPER 7 345.	1	514901	514934
78	14250	A 103	Voltage Collapse	ARCADIA7 345.	REDBUD 7 345.	1	514908	514909
79	14250	A 104	Voltage Collapse	ARCADIA7 345.	REDBUD 7 345.	2	514908	514909
80	14250	A 105	Voltage Collapse	ARCADIA7 345.	HSL 7 345.	1	514908	514943
81	14250	A 106	Voltage Collapse	DRAPER 7 345.	SEMINOL7 345.	1	514934	515045
82	14250	A 107	Voltage Collapse	DRAPER 7 345.	SEMINOL7 345.	2	514934	515045
83	14250	A 108	Voltage Collapse	DRAPER 7 345.	SEMINOL7 345.	3	514934	515045
84	14250	A 109	Voltage Collapse	HSL 7 345.	SEMINOL7 345.	1	514943	515045
85	14250	A 110	Voltage Collapse	SEMINOL7 345.	MUSKOGE7 345.	1	515045	515224
86	14250	A 111	Voltage Collapse	SUNNYSD7 345.	HUGO PP7 345.	1	515136	521157

Transfer		Limiting Contingency		Contingency Element		CKT		
87	14250	A 114	Voltage Collapse	MUSKOGE7 345.	FTSMITH7 345.	1	515224	515302
88	14250	A 115	Voltage Collapse	MUSKOGE7 345.	C-RIVER7 345.	1	515224	515422
89	14250	A 116	Voltage Collapse	WWRDEHV7 345.	TATONGA7 345.	1	515375	515407
90	14250	A 120	Voltage Collapse	WWRDEHV9 765.	COMNCHE9 765.	1	521150	521151
91	14250	A 121	Voltage Collapse	HITCHLAND 7345.	FINNEY 7345.	1	523097	523853
92	14250	A 122	Voltage Collapse	HITCHLAND 7345.	POTTER_CO 7345.	1	523097	523961
93	14250	A 124	Voltage Collapse	FINNEY 7345.	HOLCOMB7 345.	1	523853	531449
94	14250	A 127	Voltage Collapse	POTTER_CO 7345.	TOLK 7 345.	1	523961	525549
95	14250	A 129	Voltage Collapse	WOLF 7 345.	MINGO 7 345.	1	530583	531451
96	14250	A 130	Voltage Collapse	WOLF 7 345.	SPERVIL7 345.	1	530583	531469
97	14250	A 131	Voltage Collapse	WOLF 7 345.	AXTELL 3 345.	1	530583	640065
98	14250	A 132	Voltage Collapse	HOLCOMB7 345.	SETAB 7 345.	1	531449	531465
99	14250	A 134	Voltage Collapse	MINGO 7 345.	SETAB 7 345.	1	531451	531465
100	14250	A 136	Voltage Collapse	HOYT 7 345.	JEC N 7 345.	1	532765	532766
101	14250	A 137	Voltage Collapse	HOYT 7 345.	STRANGR7 345.	1	532765	532772
102	14250	A 139	Voltage Collapse	JEC N 7 345.	SUMMIT 7 345.	1	532766	532773
103	14250	A 140	Voltage Collapse	JEC N 7 345.	IATAN 7 345.	1	532766	542982
104	14250	A 143	Voltage Collapse	EMPEC 7 345.	SWISVAL7 345.	1	532768	532774
105	14250	A 144	Voltage Collapse	EMPEC 7 345.	WICHITA7 345.	1	532768	532796
106	14250	A 145	Voltage Collapse	RENO 7 345.	SUMMIT 7 345.	1	532771	532773
107	14250	A 149	Voltage Collapse	SWISVAL7 345.	W.GRDNR7 345.	1	532774	542965
108	14250	A 152	Voltage Collapse	BENTON 7 345.	WICHITA7 345.	1	532791	532796
109	14250	A 154	Voltage Collapse	NEOSHO 7 345.	LATHAMS7 345.	1	532793	532800
110	14250	A 155	Voltage Collapse	NEOSHO 7 345.	LACYGNE7 345.	1	532793	542981
111	14250	A 157	Voltage Collapse	ROSEHIL7 345.	LATHAMS7 345.	1	532794	532800
112	14250	A 158	Voltage Collapse	WOLFCRK7 345.	LACYGNE7 345.	1	532797	542981
113	14250	A 160	Voltage Collapse	PECULR 7 345.	PHILL 7 345.	1	541198	541200
114	14250	A 161	Voltage Collapse	PECULR 7 345.	STILWEL7 345.	1	541198	542968
115	14250	A 163	Voltage Collapse	ST JOE 3 345.	IATAN 7 345.	1	541199	542982
116	14250	A 165	Voltage Collapse	PHILL 7 345.	SIBLEY 7 345.	1	541200	541201
117	14250	A 167	Voltage Collapse	W.GRDNR7 345.	STILWEL7 345.	1	542965	542968
118	14250	A 169	Voltage Collapse	W.GRDNR7 345.	LACYGNE7 345.	1	542965	542981
119	14250	A 170	Voltage Collapse	STILWEL7 345.	LACYGNE7 345.	1	542968	542981
120	14250	A 171	Voltage Collapse	HAWTH 7 345.	NASHUA 7 345.	1	542972	542980
121	14250	A 172	Voltage Collapse	NASHUA 7 345.	IATAN 7 345.	1	542980	542982
122	14250	A 174	Voltage Collapse	CBLUFFS3 345.	S3456 3 345.	1	635000	645456
123	14250	A 175	Voltage Collapse	ATCHSNT3 345.	COOPER 3 345.	1	635017	640139
124	14250	A 176	Voltage Collapse	RAUN 3 345.	HOSKINS3 345.	1	635200	640226
125	14250	A 177	Voltage Collapse	RAUN 3 345.	S3451 3 345.	1	635200	645451
126	14250	A 181	Voltage Collapse	COLMB.E3 345.	NW68HOLDRG3 345.	1	640125	650114

Transfer		Limiting Contingency		Contingency Element		CKT		
127	14250	A 182	Voltage Collapse	COOPER 3 345.	MOORE 3 345.	1	640139	640277
128	14250	A 185	Voltage Collapse	GENTLMN3 345.	REDWILO3 345.	1	640183	640325
129	14250	A 188	Voltage Collapse	HOSKINS3 345.	SHELCRK3 345.	1	640226	640342
130	14250	A 189	Voltage Collapse	HOSKINS3 345.	S3451 3 345.	1	640226	645451
131	14250	A 191	Voltage Collapse	MCCOOL 3 345.	MOORE 3 345.	1	640271	640277
132	14250	A 195	Voltage Collapse	MOORE 3 345.	103&ROKEBY3 345.	1	640277	650189
133	14250	A 202	Voltage Collapse	S3454 3 345.	WAGENER 3 345.	1	645454	650185
134	14250	A 205	Voltage Collapse	S3456 3 345.	S3458 3 345.	1	645456	645458
135	14250	A 208	Voltage Collapse	S3458 3 345.	103&ROKEBY3 345.	1	645458	650189
136	14250	A 211	Voltage Collapse	ROSEHIL9 765.	WICHITA9 765.	1	100420	532783
137	14250	A 218	Voltage Collapse	WWRDEHV7 345.	WWRDEHV9 765.	1	515375	521150
138	14250	A 220	Voltage Collapse	WICHITA7 345.	WICHITA9 765.	1	532796	532783
139	14250	A 221	Voltage Collapse	ROSEHIL9 765.	ROSEHIL7 345.	1	100420	532794
140	14250	A 222	Voltage Collapse	SOONER9 765.	SOONER 7 345.	1	100419	514803
141	14250	A 223	Voltage Collapse	SOONER9 765.	SOONER 7 345.	2	100419	514803
142	14650	Pre Contingency	Voltage Collapse					

Table A8.16: Contingency Transfer Results for RP6

Table A8.17 shows that the interface flows to all regions adjacent to SPP. These flows contribute to the voltage collapses on the underlying voltage system within SPP; however future grid expansion in neighboring systems could provide support that is not captured in this analysis.

345kV Interface	MW Flow for Contingency (A1)
SPP to WAPA	522
SPP to MEC	2,045
SPP to AMMO	858
SPP to EES	3,080
SPP to AECI	1,467
Total Interface Flow	**7,972**

Table A8.17: Interface Flows for RP6

Total reactive compensation required to support the 12.2 GW transfer across the SPP system for RP6 is shown in Table A8.18.

Location	Amount (MVAR)
SVCs at Interface of Eastern Interconnect	5,200
SPP 765kV SVCs	1,740
SPP 345kV SVCs	70
Total	**7,010**

Table A8.18: Reactive Compensation Requirements for RP6

Rotor Angle Stability Assessment

The transient stability analysis for this scenario was performed for a 4,000 MW dispatch and a 10,000 MW dispatch of new renewable energy from west-to-east across the SPP system under contingency conditions. The results showed that there were no events resulting in rotor angle instability.

RP4 765kV "Full" Plan

Voltage Security Assessment

The results in Table A8.6 show that the transfer limit is approximately 14.6 GW under contingency. Cursory level engineering assessment indicates with some addition of series compensation, the 765kV design can achieve the full 17 GW transfer level. This amount would need refined analysis to determine best location and configuration. Table A8.19 provides detail concerning the specific contingencies causing voltage collapse. Initial areas of voltage collapse, produced by contingency transfers up to 14.6 GW, are external to SPP's footprint. Contingency A37, 8ANO 50 500 – FTSMITH8 500, is the limiting contingency resulting in the first voltage collapse in the underlying system within SPP area 520 (AEPW) in western Arkansas. Transfers greater than 14,600 MW result in the collapse voltages in the underlying system of area 525 (WFEC) in south Oklahoma.

Transfer		Limiting Contingency		Contingency Element				
No.	Source X	Contingency	Violation Type	From Bus Name	To Bus Name	CKT ID	From Bus	To Bus
1	2850		Security Limit					
2	2900	A 35	Voltage Collapse	7GRIMES 345.	CROCKET7 345.	1	334028	509241
3	6500	A 63	Voltage Collapse	LEBROCK7 345.	TENRUSK7 345.	1	508572	508585
4	6500	A 65	Voltage Collapse	TENRUSK7 345.	CROCKET7 345.	1	508585	509241
89	9400	A 211	Voltage Collapse	HOOK CO9 765.	HOOK CO 7 345.	1	100414	100310
2998	14600	A 37	Voltage Collapse	8ANO 50 500.	FTSMITH8 500.	1	337909	515305
3053	14600	A 94	Voltage Collapse	CLEVLND7 345.	SOONER 7 345.	1	512694	514803
3465	15400	A 27	Voltage Collapse	SOONER9 765.	WWRDEHV9 765.	1	100419	521150
3515	15400	A 81	Voltage Collapse	T.NO.--7 345.	CLEVLND7 345.	1	509852	512694
3526	15400	A 92	Voltage Collapse	L.E.S.-7 345.	SUNNYSD7 345.	1	511468	515136
3533	15400	A 100	Voltage Collapse	NORTWST7 345.	SPRNGCK7 345.	1	514880	514881
3538	15400	A 105	Voltage Collapse	CIMARON7 345.	GRACMNT7 345.	1	514901	515800
3553	15400	A 120	Voltage Collapse	WWRDEHV9 765.	COMNCHE9 765.	1	521150	521151
3554	15400	A 121	Voltage Collapse	WWRDEHV9 765.	HITCHLD9 765.	1	521150	523098
3692	15800	A 17	Voltage Collapse	MED-LDG9 765.	COMNCHE9 765.	1	100411	521151
3693	15800	A 18	Voltage Collapse	MED-LDG9 765.	WICHITA9 765.	1	100411	532783
3697	15800	A 22	Voltage Collapse	HOOK CO9 765.	WHEELER9 765.	1	100414	100415
3700	15800	A 25	Voltage Collapse	IATAN9 765.	SPERVIL9 765.	1	100418	100492

Transfer		Limiting Contingency		Contingency Element				
3707	15800	A 33	Voltage Collapse	7BLACKBERRY 345.	NEOSHO 7 345.	1	300739	532793
3713	15800	A 41	Voltage Collapse	7OVERTON 345.	SIBLEY 7 345.	1	345408	541201
3744	15800	A 74	Voltage Collapse	R.S.S.-7 345.	REDBUD 7 345.	1	509782	514909
3753	15800	A 84	Voltage Collapse	PITTSB-7 345.	VALIANT7 345.	1	510907	510911
3755	15800	A 86	Voltage Collapse	PITTSB-7 345.	JOHNCO 7 345.	1	510907	514809
3756	15800	A 87	Voltage Collapse	PITTSB-7 345.	SEMINOL7 345.	1	510907	515045
3761	15800	A 93	Voltage Collapse	L.E.S.-7 345.	GRACMNT7 345.	1	511468	515800
3762	15800	A 95	Voltage Collapse	WOODRNG7 345.	SOONER 7 345.	1	514715	514803
3763	15800	A 96	Voltage Collapse	WOODRNG7 345.	CIMARON7 345.	1	514715	514901
3765	15800	A 98	Voltage Collapse	SOONER 7 345.	SPRNGCK7 345.	1	514803	514881
3769	15800	A 103	Voltage Collapse	NORTWST7 345.	TATONGA7 345.	1	514880	515407
3770	15800	A 104	Voltage Collapse	CIMARON7 345.	DRAPER 7 345.	1	514901	514934
3778	15800	A 113	Voltage Collapse	SEMINOL7 345.	MUSKOGE7 345.	1	515045	515224
3779	15800	A 114	Voltage Collapse	SUNNYSD7 345.	HUGO PP7 345.	1	515136	521157
3782	15800	A 117	Voltage Collapse	MUSKOGE7 345.	FTSMITH7 345.	1	515224	515302
3783	15800	A 118	Voltage Collapse	MUSKOGE7 345.	C-RIVER7 345.	1	515224	515422
3785	15800	A 122	Voltage Collapse	WWRDEHV9 765.	STLINE 9 765.	1	521150	523772
3788	15800	A 125	Voltage Collapse	STLINE 9 765.	TUCO 9 765.	1	523772	525836
3816	15800	A 154	Voltage Collapse	NEOSHO 7 345.	LATHAMS7 345.	1	532793	532800
3817	15800	A 155	Voltage Collapse	NEOSHO 7 345.	LACYGNE7 345.	1	532793	542981
3819	15800	A 157	Voltage Collapse	ROSEHIL7 345.	LATHAMS7 345.	1	532794	532800
3820	15800	A 158	Voltage Collapse	WOLFCRK7 345.	LACYGNE7 345.	1	532797	542981
3891	15800	A 230	Voltage Collapse	SOONER9 765.	SOONER 7 345.	1	100419	514803
3892	15800	A 231	Voltage Collapse	SOONER9 765.	SOONER 7 345.	2	100419	514803
3893	15800	A 232	Voltage Collapse	ROSEHIL9 765.	ROSEHIL7 345.	1	100420	532794

Transfer		Limiting Contingency		Contingency Element				
3903	16200	Pre Contingency	Voltage Collapse					

Table A8.19: Contingency Transfer Results – RP4

Table A8.20 shows the interface flows to all regions adjacent to SPP. These flows contribute to the voltage collapses on the underlying voltage system within SPP; however future grid expansion in neighboring systems could provide support that is not captured in this analysis.

345kV Interface	MW Flow for Contingency (A37)
SPP to WAPA	697
SPP to MEC	2,882
SPP to AMMO	1,314
SPP to EES	1,746
SPP to AECI	2,070
Total Interface Flows	**8,709**

Table A8.20: Interface Flows for RP4

Total reactive compensation required to support the 14,600 MVAR transfer across the SPP system for RP4 is shown in Table A8.21.

Location	Amount (MVAR)
SVCs at Interface of Eastern Interconnect	6,530
SPP 765kV SVCs	6,120
SPP 345kV SVCs	0
Total	**12,560**

Table A8.21: Reactive Compensation Requirements for RP4

A8.8: Summary

These studies were performed to determine the stability impacts of 17GW of new renewable generation transfers across the SPP footprint for multiple scenario topologies. Commercial software was utilized to perform the studies and Voltage and Rotor Angle stability were the stability measures used. The results revealed the limiting transfer to maintain voltage stability for each of the scenarios. Transient stability was also performed for two of the scenarios for a 4 GW and 10 GW transfer level to determine rotor angle stability. Lastly, comparisons were made revealing the relative amount of transfer capabilities and reactive compensation requirements among the different scenarios.

A8.9: Conclusion

The voltage stability transfer limits for the various scenarios are shown in Table A8.6. The Current Topology will provide a 7.75 GW transfer under contingency conditions, which is approximately 46% of the 17 GW study required for a 20% renewable standard. The analysis shows that RP1 can transfer 60% more energy than the Current Topology at a minimal project cost increase. The results also indicate that the 345kV RP1 plan provides as much or more transfer capability than either the 765kV “Y” or “Box” plan. In addition, the increased transfer capability is obtained at a significantly lower incremental cost up to its transfer performance limitation of approximately 12 GW. The 765kV “Full” plan provides more transfer capability than all other studied scenarios, and provides the ability to exceed the 12 GW transfer limitation of the 345kV design; however, at a higher incremental cost.

Transient stability analysis for both plans studied showed that there were no synchronous generator rotor angle stability problems inside the SPP footprint during fault conditions for the design configurations studied.

Therefore; considering voltage stability and rotor angle stability, scenario RP1 appears to offer the most transfer capability at the lowest incremental cost when compared to all other scenarios studied.

RP1 yields the most cost effective performance up to 12.2GW; moreover, there is an inherent limitation that should be understood. Results indicate that the 345kV RP1 design hits a hard limit to contingent west-east transfer levels somewhere around 12 GW, which is a reasonable approximation based upon the assumptions and results. Slight increases may be gained through the use of series compensation and fine tuning of the location of the devices. However, at this level, the technology presents operational complexities, increased system losses, limited life expectancy, and synchronous resonance issues that must be considered. This solution method is considered a short term remedy intended to stretch existing system capabilities until a more viable long term solution is proven. Therefore, it is concluded that expansion at 345kV is limited to the 12 GW transfer level.

Should more transfer capability be required beyond 12GW, it appears that the 765kV options would provide a viable expansion technology; however, the results show that only the “Full” RP4 765kV design configuration provided significant improvements in transfer capability. It is therefore concluded that should 765kV technology be pursued, significantly more study is required to determine the best design configuration weighing both technical and economic benefit. The amount of reactive compensation for any 765kV design would be significantly more than that of a 345kV design. Further study would be required to determine the appropriate amount and location of reactive compensation. Alternative 765kV design configurations other than those discussed herein can yield different performance results in both transfer capability and reactive compensation requirements.

Underlying areas of the grid were identified that exhibited reactive power deficiencies during transfers. These deficiencies merit additional transmission enhancements that will require further study in the upcoming ITP10 efforts or the next ITP20 iteration.

During the course of the analysis, some areas of the SPP footprint were unable to sustain acceptable voltages at high transfer levels causing some underlying systems as shown below to depress and collapse:

- AEPW/WFEC/OMPA – Old WTU-N system in the Texas Panhandle
- AEPW – South Oklahoma
- AEPW – AECC area in western Arkansas
- NPPD – Northwest and Central area of Nebraska

ITP20 solutions were not specifically designed to address these local areas exhibiting reactive deficiencies. However, further analysis should be conducted within the scope of the ITP10 with those findings rolling into the next cycle of the ITP20. During the ITP10 process, existing and new stakeholder recommended modifications to the various robustness plans should also be analyzed for effectiveness in enhancing and strengthening the underlying system.

Finally, individual line loadability studies were not addressed as part of the ITP20 study. Loadability studies will be required to determine power transfer limitations on any new transmission line, particularly for those 100 miles or more in length. This analysis will be done in the future.

Appendix A9: Rate Impact & Unintended Consequences Tables

A9.1: Rate Impact on a Residential Customers' Monthly Bill – Robust Plan 1

Note: Rate impacts reflect impacts of all upgrade additions and the offsetting impact of depreciation of those upgrades during the period. There are no quantitative or qualitative benefits in the data used to generate this table. This assumes a 1,000 kWh monthly usage per residence.

Ŧ This column refers to the $5.00 Datum Adjusted for Inflation

	Ŧ	SPS	NPPD	AEPW	GMO	KCPL	OKGE	OPPD	WERE	EDE	LES	SUNC	MKEC	SPRM	MIDW	WFEC
2010	$5.00	$1.47	$1.82	$1.13	$0.49	$0.59	$0.57	$0.67	$1.35	$1.20	$0.45	$1.29	$1.05	$0.41	$0.61	$1.89
2011	$5.13	$2.22	$1.87	$1.35	$0.81	$0.75	$0.68	$0.94	$1.78	$1.47	$0.55	$1.44	$1.35	$0.50	$0.75	$2.25
2012	$5.26	$3.54	$2.43	$2.60	$1.00	$1.11	$1.58	$1.15	$2.59	$1.68	$0.65	$1.93	$1.78	$0.68	$1.12	$3.82
2013	$5.39	$5.04	$2.81	$3.29	$1.39	$1.66	$2.17	$1.59	$3.66	$1.94	$0.95	$2.44	$4.04	$1.00	$1.65	$4.34
2014	$5.52	$7.02	$4.18	$5.29	$2.91	$3.36	$3.53	$3.17	$5.42	$3.23	$2.77	$3.47	$5.10	$2.36	$3.59	$5.44
2015	$5.66	$7.15	$3.96	$5.23	$2.65	$3.26	$3.48	$2.93	$5.30	$3.33	$2.33	$3.59	$5.00	$2.15	$4.11	$5.26
2016	$5.80	$7.05	$3.75	$5.44	$2.40	$3.19	$3.47	$2.68	$5.09	$3.96	$1.88	$3.59	$4.90	$2.14	$4.08	$5.38
2017	$5.95	$7.69	$4.32	$6.35	$3.13	$3.91	$3.99	$3.36	$5.78	$5.01	$2.82	$4.02	$5.31	$2.71	$4.70	$5.75
2018	$6.10	$7.60	$4.16	$6.28	$3.08	$3.81	$3.84	$3.24	$5.54	$4.84	$2.73	$3.92	$5.18	$2.74	$4.60	$5.48
2019	$6.25	$7.31	$4.00	$6.23	$2.93	$3.71	$3.68	$3.11	$5.39	$4.60	$2.57	$3.80	$5.29	$2.64	$4.46	$5.19
2020	$6.41	$6.95	$3.78	$6.02	$2.78	$3.54	$3.49	$2.92	$5.03	$4.36	$2.39	$3.66	$5.10	$2.47	$4.30	$4.89
2021	$6.57	$6.59	$3.57	$5.81	$2.65	$3.36	$3.37	$2.80	$4.81	$4.11	$2.21	$3.52	$4.90	$2.34	$4.15	$4.61
2022	$6.73	$6.25	$3.37	$5.60	$2.53	$3.18	$3.26	$2.68	$4.59	$3.88	$2.05	$3.38	$4.70	$2.21	$4.01	$4.34
2023	$6.90	$5.92	$3.17	$5.39	$2.40	$3.01	$3.15	$2.56	$4.37	$3.66	$1.89	$3.24	$4.51	$2.09	$3.87	$4.07
2024	$7.07	$5.60	$2.98	$5.18	$2.28	$2.84	$3.03	$2.44	$4.15	$3.44	$1.73	$3.10	$4.32	$1.97	$3.73	$3.82
2025	$7.25	$5.29	$2.80	$4.98	$2.16	$2.68	$2.92	$2.32	$3.93	$3.23	$1.58	$2.96	$4.13	$1.85	$3.59	$3.58
2026	$7.43	$4.99	$2.62	$4.77	$2.03	$2.53	$2.81	$2.20	$3.72	$3.03	$1.44	$2.83	$3.94	$1.74	$3.45	$3.35
2027	$7.62	$4.70	$2.45	$4.57	$1.91	$2.38	$2.70	$2.09	$3.51	$2.83	$1.30	$2.70	$3.75	$1.62	$3.32	$3.13
2028	$7.81	$4.42	$2.28	$4.37	$1.79	$2.24	$2.59	$1.97	$3.29	$2.64	$1.17	$2.57	$3.57	$1.52	$3.18	$2.92
2029	$8.01	$4.15	$2.12	$4.17	$1.68	$2.10	$2.48	$1.86	$3.08	$2.46	$1.04	$2.44	$3.39	$1.41	$3.05	$2.71
2030	$8.21	$6.97	$4.62	$8.13	$5.17	$5.04	$5.11	$5.20	$6.85	$4.71	$4.81	$4.53	$5.64	$3.88	$6.15	$4.43

Table A9.1: Rate Impact (expressed in nominal dollars) – Robust Plan 1

A9.2: Analysis of Cost and Benefits at 2030 from the Ratepayer Perspective – Robust Plan 1

This table shows the costs and benefits before and after the addition of the ITP20 projects, as well as with and without transfer payments.

Note: Benefits amounts include APC, Reliability and Losses benefits and exclude wind and gas price benefits (BP and PP refer to the Balanced Portfolio and Priority Projects).

Zone	AEPW	GRDA	OKGE	WFEC	SWPS	MIDW	SUNC	WERE	WEPL	GMO	KCPL	EMDE	SPRM	NPPD	OPPD	LES	Totals
BP Benefits	$54	$2	$37	$6	$124	$26	$9	$38	$24	$0	$16	$1	$0	$7	$3	($6)	$341
PP Benefits	($23)	($16)	$67	$35	$168	($1)	($2)	$29	$3	$16	($3)	$11	($7)	$1	($2)	($6)	$270
Subtotal Project Benefits	$31	($14)	$104	$41	$292	$25	$7	$67	$27	$16	$13	$12	($7)	$8	$1	($12)	$611
Total ATRR All Projects	$266	$22	$163	$46	$163	$9	$14	$141	$20	$37	$80	$32	$14	$69	$47	$18	$1,141
ATRR ITP20	$136	$12	$87	$20	$72	$5	$7	$71	$8	$26	$49	$16	$9	$39	$31	$15	$603
ATRR Excluding ITP20	$130	$10	$76	$26	$91	$4	$7	$70	$12	$11	$31	$16	$5	$30	$16	$3	$538
B/C Ratio Prior to ITP20	0.2	(1.4)	1.4	1.6	3.2	6.3	1.0	1.0	2.3	1.5	0.4	0.8	(1.4)	0.3	0.1	(4.0)	1.1
ITP20 Benefits	$648	($4)	$113	$15	$91	$27	$32	$326	$51	$76	$23	($2)	($7)	$94	$170	$83	$1,736
Total Benefits	$679	($18)	$217	$56	$383	$52	$39	$393	$78	$92	$36	$10	($14)	$102	$171	$71	$2,347
B/C Ratio All	2.6	(0.8)	1.3	1.2	2.3	5.8	2.8	2.8	3.9	2.5	0.5	0.3	(1.0)	1.5	3.6	3.9	2.1
B/C Ratio ITP20	4.8	(0.3)	1.3	0.8	1.3	5.4	4.6	4.6	6.4	2.9	0.5	(0.1)	(0.8)	2.4	5.5	5.5	2.9
Transfer Payment (Adjusted)	($41)	$40	($6)	($1)	($22)	($4)	($3)	($25)	($6)	($6)	$45	$22	$28	($3)	($12)	($5)	$1
All Projects Benefits (Adjusted)	$638	$22	$211	$55	$361	$48	$36	$368	$72	$86	$81	$32	$14	$99	$159	$66	$2,348
B/C Ratio All (Adjusted)	2.4	1.0	1.3	1.2	2.2	5.3	2.6	2.6	3.6	2.3	1.0	1.0	1.0	1.4	3.4	3.7	2.1

Table A9.2: Cost and Benefits (2030 $ millions) – Robust Plan 1

A9.3: Analysis of Cost and Benefits at 2030 on a State Level

This table shows the costs and benefits before and after the addition of the ITP20 projects by state, as well as with and without transfer payments.

Note: Benefits amounts include APC, Reliability and Losses benefits and exclude wind and gas price benefits (BP and PP refer to the Balanced Portfolio and Priority Projects).

State	AR	KS	LA	MO	NE	NM	OK	TX	Totals
BP Benefits	$11	$105	$7	$9	$4	$30	$69	$106	$341
PP Benefits	($5)	$28	($3)	$18	($7)	$40	$79	$119	$270
Subtotal Project Benefits	$6	$132	$4	$28	($3)	$70	$148	$225	$611
Total ATRR All Projects	$54	$222	$34	$125	$134	$39	$342	$191	$1,141
ATRR ITP20	$28	$114	$17	$77	$85	$17	$175	$89	$603
ATRR Excluding ITP20	$26	$108	$17	$48	$49	$22	$166	$102	$538
B/C Ratio Prior to ITP20	0.2	1.2	0.2	0.6	(0.1)	3.2	0.9	2.2	1.1
ITP20 Benefits	$132	$447	$82	$79	$347	$22	$390	$238	$1,737
Total Benefits	$138	$579	$86	$107	$344	$92	$537	$464	$2,347
B/C Ratio All	2.6	2.6	2.6	0.9	2.6	2.3	1.6	2.4	2.1
B/C Ratio ITP20	4.8	3.9	4.8	1.0	4.1	1.3	2.2	2.7	2.9
Transfer Payment (Adjusted)	($8)	($17)	($5)	$68	($20)	($5)	$16	($27)	$1
All Projects Benefits (Adjusted)	$130	$562	$81	$175	$324	$87	$553	$436	$2,348
B/C Ratio All (Adjusted)	2.4	2.5	2.4	1.4	2.4	2.2	1.6	2.3	2.1

Table A9.3: Cost and Benefits by State (2030 $ millions) – Robust Plan 1

A9.4: Rate Impact on a Residential Customers' Monthly Bill – Cost Effective Plan

Note: Rate impacts reflect impacts of all upgrade additions and the offsetting impact of depreciation of those upgrades during the period. There are no quantitative or qualitative benefits in the data used to generate this table. This assumes a 1,000 kWh monthly usage per residence.

Ŧ This column refers to the $5.00 Datum Adjusted for Inflation

	Ŧ	SPS	NPPD	AEPW	GMO	KCPL	OKGE	OPPD	WERE	EDE	LES	SUNC	MKEC	SPRM	MIDW	WFEC
2010	$5.00	$1.47	$1.83	$1.13	$0.49	$0.59	$0.57	$0.70	$1.36	$1.15	$0.45	$1.29	$1.06	$0.42	$0.61	$1.89
2011	$5.13	$2.30	$1.94	$1.43	$0.88	$0.83	$0.75	$0.86	$1.87	$1.48	$0.65	$1.49	$1.40	$0.57	$0.81	$2.31
2012	$5.26	$3.88	$2.71	$2.93	$1.31	$1.42	$1.83	$1.32	$2.93	$1.88	$1.06	$2.12	$1.99	$0.95	$1.38	$4.05
2013	$5.39	$5.36	$3.08	$3.62	$1.69	$1.97	$2.41	$1.76	$3.99	$2.13	$1.34	$2.62	$4.24	$1.25	$1.91	$4.56
2014	$5.52	$7.42	$4.52	$5.70	$3.29	$3.74	$3.84	$3.42	$5.83	$3.48	$3.26	$3.70	$5.35	$2.67	$3.92	$5.71
2015	$5.66	$7.22	$4.02	$5.30	$2.70	$3.33	$3.53	$2.87	$5.38	$3.16	$2.41	$3.63	$5.05	$2.21	$4.17	$5.31
2016	$5.80	$7.11	$3.81	$5.51	$2.46	$3.25	$3.52	$2.63	$5.16	$3.80	$1.96	$3.63	$4.95	$2.19	$4.14	$5.42
2017	$5.95	$7.76	$4.38	$6.42	$3.19	$3.98	$4.03	$3.31	$5.95	$4.85	$2.90	$4.06	$5.35	$2.76	$4.76	$5.79
2018	$6.10	$7.66	$4.21	$6.35	$3.13	$3.87	$3.89	$3.19	$5.61	$4.65	$2.81	$3.96	$5.22	$2.78	$4.65	$5.52
2019	$6.25	$7.37	$4.05	$6.29	$2.99	$3.77	$3.72	$3.07	$5.45	$4.43	$2.65	$3.84	$5.33	$2.69	$4.51	$5.23
2020	$6.41	$7.00	$3.83	$6.08	$2.83	$3.60	$3.53	$2.88	$5.09	$4.19	$2.45	$3.70	$5.14	$2.52	$4.35	$4.93
2021	$6.57	$6.65	$3.62	$5.87	$2.70	$3.41	$3.41	$2.76	$4.87	$3.96	$2.28	$3.55	$4.94	$2.38	$4.20	$4.64
2022	$6.73	$6.30	$3.41	$5.65	$2.57	$3.23	$3.30	$2.64	$4.64	$3.73	$2.11	$3.41	$4.74	$2.25	$4.06	$4.37
2023	$6.90	$5.97	$3.22	$5.44	$2.45	$3.06	$3.18	$2.53	$4.42	$3.52	$1.95	$3.27	$4.54	$2.13	$3.91	$4.10
2024	$7.07	$5.64	$3.02	$5.24	$2.32	$2.89	$3.07	$2.41	$4.20	$3.31	$1.79	$3.13	$4.35	$2.00	$3.77	$3.85
2025	$7.25	$5.33	$2.84	$5.03	$2.20	$2.73	$2.96	$2.29	$3.99	$3.11	$1.64	$2.99	$4.16	$1.89	$3.63	$3.61
2026	$7.43	$5.03	$2.66	$4.82	$2.08	$2.57	$2.85	$2.18	$3.77	$2.91	$1.49	$2.86	$3.97	$1.77	$3.49	$3.38
2027	$7.62	$4.74	$2.48	$4.62	$1.96	$2.42	$2.74	$2.07	$3.56	$2.72	$1.35	$2.73	$3.78	$1.66	$3.36	$3.15
2028	$7.81	$4.46	$2.32	$4.42	$1.83	$2.27	$2.63	$1.95	$3.34	$2.54	$1.22	$2.60	$3.60	$1.55	$3.22	$2.94
2029	$8.01	$4.18	$2.15	$4.22	$1.71	$2.13	$2.52	$1.84	$3.13	$2.37	$1.08	$2.47	$3.42	$1.44	$3.09	$2.74
2030	$8.21	$6.05	$3.83	$6.88	$4.09	$4.12	$4.29	$4.11	$5.66	$3.87	$3.65	$3.87	$4.91	$3.11	$5.18	$3.86

Table A9.4: Rate Impact (expressed in nominal dollars) – Cost Effective Plan

A9.5: Analysis of Cost and Benefits at 2030 from the Ratepayer Perspective – Cost Effective Plan

This table shows the costs and benefits before and after the addition of the ITP20 projects, as well as with and without theoretical transfer payments.

Note: Benefits amounts include APC, Reliability and Losses benefits and exclude wind and gas price benefits (BP and PP refer to the Balanced Portfolio and Priority Projects). Conceptual – For Discussion Only. Statistics pertain only to this section of the report.

Zone	AEPW	GRDA	OKGE	WFEC	SWPS	MIDW	SUNC	WERE	WEPL	GMO	KCPL	EMDE	SPRM	NPPD	OPPD	LES	Totals
BP Benefits	$54	$2	$37	$6	$124	$26	$9	$38	$24	$0	$16	$1	$0	$7	$3	($6)	$341
PP Benefits	($23)	($16)	$67	$35	$168	($1)	($2)	$29	$3	$16	($3)	$11	($7)	$1	($2)	($6)	$270
Subtotal Project Benefits	$31	($14)	$104	$41	$292	$25	$7	$67	$27	$16	$13	$12	($7)	$8	$1	($12)	$611
Total ATRR All Projects	$225	$18	$137	$40	$142	$7	$12	$120	$17	$29	$66	$26	$11	$57	$37	$14	$958
ATRR ITP20	$94	$8	$60	$14	$50	$3	$5	$49	$6	$18	$34	$11	$6	$27	$21	$10	$416
ATRR Excluding ITP20	$131	$10	$77	$26	$92	$4	$7	$71	$11	$11	$32	$15	$5	$30	$16	$4	$542
B/C Ratio Prior to ITP20	0.2	(1.4)	1.4	1.6	3.2	6.3	1.0	0.9	2.5	1.5	0.4	0.8	(1.4)	0.3	0.1	(3.0)	1.1
ITP20 Benefits	$476	$6	$39	$18	$87	$28	$24	$301	$54	$78	$8	($1)	($4)	$73	$160	$86	$1,433
Total Benefits	$507	($8)	$143	$59	$379	$53	$31	$368	$81	$94	$21	$11	($11)	$81	$161	$74	$2,044
B/C Ratio All	2.3	(0.4)	1.0	1.5	2.7	7.6	2.6	3.1	4.8	3.2	0.3	0.4	(1.0)	1.4	4.4	5.3	2.1
B/C Ratio ITP20	5.1	0.8	0.7	1.3	1.7	9.3	4.8	6.1	9.0	4.3	0.2	(0.1)	(0.7)	2.7	7.6	8.6	3.4
Transfer Payment (Adjusted)	($25)	$26	($1)	($2)	($21)	($4)	($2)	($23)	($6)	($6)	$45	$15	$23	($2)	($11)	($5)	$1
All Projects Benefits (Adjusted)	$482	$18	$142	$57	$358	$49	$29	$345	$75	$88	$66	$26	$12	$79	$150	$69	$2,045
B/C Ratio All (Adjusted)	2.1	1.0	1.0	1.4	2.5	7.0	2.4	2.9	4.4	3.0	1.0	1.0	1.1	1.4	4.1	4.9	2.1

Table A9.5: Cost and Benefits (2030 $ millions) – Cost Effective Plan

A9.6: Analysis of Cost and Benefits at 2030 on a State Level – Cost Effective Plan

This table shows the costs and benefits before and after the addition of the ITP20 projects by state, as well as with and without transfer payments.

Note: Benefits amounts include APC, Reliability and Losses benefits and exclude wind and gas price benefits (BP and PP refer to the Balanced Portfolio and Priority Projects).

State	AR	KS	LA	MO	NE	NM	OK	TX	Totals
BP Benefits	$11	$105	$7	$9	$4	$30	$69	$106	$341
PP Benefits	($5)	$28	($3)	$18	($7)	$40	$79	$119	$270
Subtotal Project Benefits	$6	$132	$4	$28	($3)	$70	$148	$225	$611
Total ATRR All Projects	$46	$187	$29	$101	$108	$34	$289	$165	$958
ATRR ITP20	$19	$79	$12	$53	$58	$12	$121	$62	$416
ATRR Excluding ITP20	$27	$108	$17	$48	$50	$22	$168	$103	$542
B/C Ratio Prior to ITP20	0.2	1.2	0.2	0.6	(0.1)	3.2	0.9	2.2	1.1
ITP20 Benefits	$97	$411	$60	$77	$319	$21	$258	$190	$1,433
Total Benefits	$103	$543	$64	$105	$316	$91	$406	$415	$2,044
B/C Ratio All	2.3	2.9	2.3	1.0	2.9	2.7	1.4	2.5	2.1
B/C Ratio ITP20	5.1	5.2	5.1	1.5	5.5	1.7	2.1	3.1	3.4
Transfer Payment (Adjusted)	($5)	($14)	($3)	$56	($18)	($5)	$13	($22)	$1
All Projects Benefits (Adjusted)	$98	$529	$61	$161	$298	$86	$419	$393	$2,045
B/C Ratio All (Adjusted)	2.1	2.8	2.1	1.6	2.8	2.5	1.4	2.4	2.1

Table A9.6: Cost and Benefits by State (2030 $ millions) – Cost Effective Plan

Appendix A10: Frequently Asked Questions

The following questions and answers have been collected from Stakeholders throughout the study by SPP staff and are listed here in an effort to provide clear and transparent communication.

Working Groups

Q: Which working group meeting should I attend to provide input into this study process?

A: Several groups provide input into the study process. Chief among these are the Economic Studies Working Group (ESWG) and the Transmission Working Group (TWG). See Section 8: Transmission Analysis Assumptions for more details. SPP stakeholder meetings are generally open to the public and schedules and registration information can be found on the SPP website.

Project Selection

Q: How can I recommend a transmission line or project for study in the ITP process?

A: Participation in the ESWG or TWG meetings or submittal of your project to those groups is the ideal forum for such submissions.

Analysis Methods & Assumptions

Q: What software did SPP use in this analysis?

A: For details regarding the software, settings, and formulas used in this study, consult Section 8: Transmission Analysis Assumptions.

Q: Are we assuming in this analysis, that wind/solar/biomass/etc. resources within SPP will not be developed for exports to support a national mandate? How can we rationalize that assumption as being realistic based on DOE, NREL, etc. studies to date? If that is true, it needs to be explained because studies like this are the reason for the FERC NOPR in RM10-23.

A: Solar, biomass and other burgeoning renewable resources were not considered in this cycle of the ITP20.

Q: Were exports considered in any futures in this study?

A: Exports were considered but not specifically set within the study assumptions per direction from the RSC and BOD to focus upon SPP resources to SPP load.

Q: Why was the lower voltage (less than 345 kV) system not studied for reliability/

A: The ITP10 scope includes a reliability based study that will consider components of NERC reliability standards. The ITP10 will address those needs.

Powerflow & Topology

Q: Are recent SPP projects with Notice to Construct (NTC) letters included in this study?

A: SPP projects with NTCs were included in the study base case.

Q: What projects were studied as part of the ITP20?

A: For details regarding projects that were analyzed during each phase of the ITP20 please refer to Transmission Projects Evaluated.

Q: How much wind was studied in this analysis?

A: Various levels of wind were studied through the use of multiple futures. Please refer to Section 7: Resource Futures and Plan for details.

Results

Q: Where can I find the results of the robustness metrics?

A: See Appendix A3:Metric Results

Seams Benefits and Costs

Q: For the purpose of project cost, are all projects in the robustness analysis assumed to be paid for entirely by SPP members?

A: No cost allocation approaches have been taken to allocate cost external to SPP. This will be a future consideration and is currently an action item for the CAWG.

NTCs, ATPs and Construction Sequence

Q: In what sequence does SPP anticipate the projects identified in the recommended plan will be constructed?

A: No sequence was determined for this ITP20 study. Please refer to Section 16.7: Rate Impacts and Unintended Consequences.

Appendix A11: ITP20 Report Glossary

The following terms are referred to throughout the report.

Acronym	Full Term \ Explanation
AECI	Associated Electric Cooperative Inc.
APC	Adjusted Production Cost
APC-based B/C	Adjusted Production Cost based Benefit to Cost ratio
ATC	Available Transfer Capability
ATSS	Aggregate Transmission Service Studies
ATRR	Annual Transmission Revenue Requirement
BATTF	Benefit Analysis Techniques Task Force
B/C	Benefit to Cost Ratio
BA	Balancing Authority
BOD	SPP Board of Directors
Carbon Price	The tax burden associated with the emissions of CO_2
CAWG	Cost Allocation Working Group
CFL	Compact Fluorescent Bulb
CRA	Charles River Associates
EES	Entergy Corp.
EHV	Extra-High Voltage
EIS	Energy Imbalance Service
EPA	Environmental Protection Agency
ESRPP	Entergy SPP RTO Regional Planning Process
ESWG	Economic Studies Working Group
EWITS	Eastern Wind Integration and Transmission Study
FCITC	First Contingency Incremental Transfer Capability
FERC	Federal Energy Regulatory Commission
GI	Generation Interconnection
GIS	Geographic Information Systems
GW	Gigawatt (10^9 Watts)
HVDC	High-Voltage Direct Current
ITP	Integrated Transmission Plan
ITP10	Integrated Transmission Plan 10-Year Assessment
ITP20	Integrated Transmission Plan 20-Year Assessment
JPC	Joint Planning Committee
LIP	Locational Imbalance Price
LMP	Locational Marginal Price
MDWG	Model Development Working Group
MISO	Midwest ISO
MOPC	Markets and Operations Policy Committee
MTF	Metrics Task Force
MVA	Mega Volt Ampere (10^6 Volt Ampere)

Acronym	Full Term \ Explanation
MW	Megawatt (10^6 Watts)
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NREL	National Renewable Energy Laboratory
NTC	Notification to Construct
OATT	Open Access Transmission Tariff
PCM	Production Cost Model
RES	Renewable Electricity Standard
ROW	Right of Way
RSC	SPP Regional State Committee
RTWG	Regional Tariff Working Group
SIL	Surge Impedance Loading
SPC	Strategic Planning Committee
SPP	Southwest Power Pool, Inc.
SPPT	Synergistic Planning Project Team
STEP	SPP Transmission Expansion Plan
TLR	Transmission Loading Relief
TPL	Transmission Planning NERC Standards
TO	Transmission Owner
TSR	Transmission Service Request
TVA	Tennessee Valley Authority
TWG	Transmission Working Group
WAPA	Western Area Power Administration
WITF	Wind Integration Task Force

Table A11.1: Glossary of Terms

Appendix A12: ITP20 Figures & Tables

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