2012 Integrated Transmission Plan 10-Year Assessment Report

January 31, 2012

Engineering

Southwest Power Pool

Revision History

Date	Author	Change Description
10/3/2011	SPP staff	Draft presented to the MOPC for review and comment
11/28/2011	SPP staff	Revised draft Presented at the December ITP Workshop
12/14/2011	SPP staff	Revised draft sent to TWG/ESWG
12/19/2011	TWG	Unanimously endorsed by the TWG
1/5/2012	ESWG	Unanimously endorsed by the ESWG
1/9/2012	SPP staff	Revised draft sent to MOPC
1/18/2012	MOPC	Endorsed by the MOPC
1/24/2012	SPP staff	Revised per MOPC requests, draft sent to Board of Directors
1/31/2012	BOD	Approved by Board of Directors

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Executive Summary

The Integrated Transmission Plan (ITP) is a three-year study process that assesses long and near-term infrastructure needs of the SPP Transmission System. The intent of the ITP is to bring about continued development of a cost-effective, flexible, and robust transmission network that will provide efficient, reliable access to the region's diverse generating resources. Along with the Highway/Byway cost allocation methodology, the ITP process as described in Attachment O of the SPP Open Access Transmission Tariff (OATT) promotes transmission investment that will meet reliability, economic, and public policy needs[1]. This report documents the portion of that assessment that focused on SPP's long-term regional needs in the upcoming 10-year horizon.

The first phase of the ITP study process was completed with the SPP Board of Directors (BOD) acceptance of the 2010 ITP 20-year (ITP20) Report on January 25, 2011. The second phase of the ITP study process included the first ITP 10-Year (ITP10) and ITP Near-Term (ITPNT) Assessments performed under the requirements of OATT Attachment O, Section III. The study process for this ITP10 utilized a diverse array of power system and economic analysis tools to evaluate the need for 100 kV and above facility projects that satisfy needs such as:

a) resolving potential criteria violations;
b) mitigating known or foreseen congestion;
c) improving access to markets;
d) staging transmission expansion; and
e) improving interconnections.

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

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

1. **Business As Usual**: This future utilized today's current state and utility renewable goals and targets for 2022, current generation resource plans, and current load forecasts.
2. **EPA Rules with Additional Wind**: This future utilized anticipated increases above the current state renewable targets and approximated the impact of proposed EPA rulemaking (as of April 1, 2011) by imposing retirements on small coal plants[2].

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

The recommended 2012 ITP10 portfolio shown in the figure below was estimated at $1.5 billion engineering and construction cost and includes projects needed to meet potential reliability, economic,

[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] In June 2011, the EPA approved the Cross-State Air Pollution Rule (CSAPR) which imposes new restrictions on emissions. This ruling was well after the start of the 2012 ITP10 analysis and therefore, impacts of this ruling were not incorporated into this study. SPP is currently assessing how to best assess the impact of this rule.

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

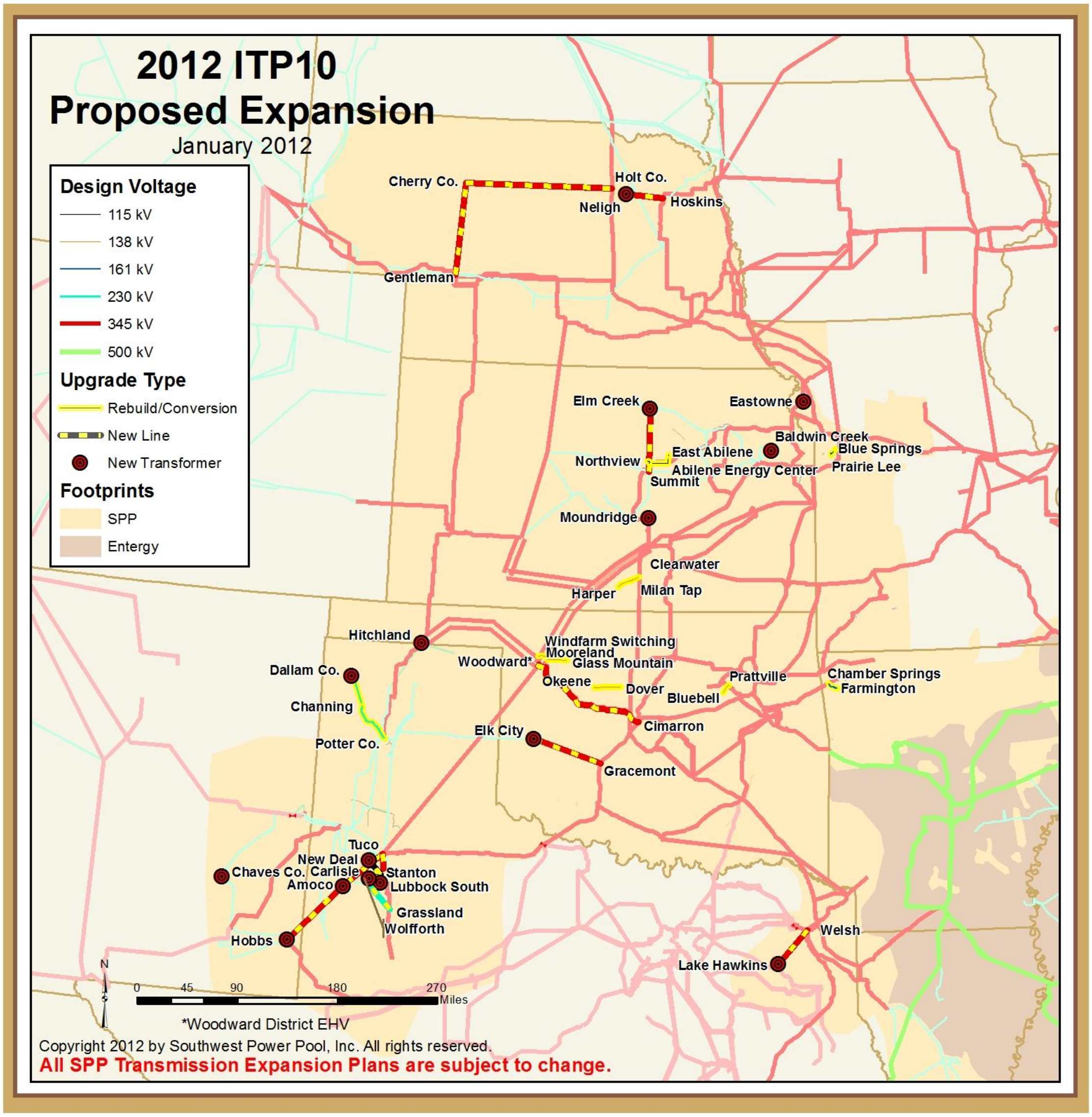
Since the Conditional Notification to Construct[3] (CNTC) Business Practice is under development, SPP recommends an interim procedure for the 2012 ITPNT projects that qualify for CNTCs (above 100 kV and cost estimate over $20 million). SPP will issue NTCs for these projects with language initiating a refined cost estimate analysis, but not directing the start of construction. SPP will send the NTCs to the incumbent Transmission Owner(s) for each project.

A list of ATP projects will be posted on the SPP website contingent upon approval of the ATP Business Practice. Once the ATPs are posted, SPP will include them in future SPP Aggregate Study models in the appropriate model year.

Nine projects make up the greater part of the portfolio:

- Lake Hawkins – Welsh 345 kV line with a 345/138 kV transformer at Lake Hawkins
- Elk City – Gracemont 345 kV line with a 345/230 kV transformer at Elk City
- Woodward – Tatonga – Cimarron 345 kV line, a second circuit
- Summit – Elm Creek 345 kV line with a 345/230 kV transformer at Elm Creek
- Neligh – Hoskins 345 kV line with a 345/115 kV transformer at Neligh
- Gentleman – Cherry Co. – Holt Co. 345 kV line with two substations
- Eastowne Transformer 345/161 kV
- Moundridge Transformer 138/115 kV
- Tuco – Amoco – Hobbs 345 kV with 345/230 kV transformers at Amoco and Hobbs

[3] The Conditional Notifications to Construct concept was developed by the Project Cost Task Force as part of their whitepaper. The whitepaper was approved in July 2011.


2012 ITP10
Proposed Expansion
January 2012
Design Voltage
115 kV
138 kV
161 kV
230 kV
345 kV
500 kV
Upgrade Type
Rebuild/Conversion
New Line
New Transformer
Footprints
SPP
Entergy
Cherry Co.
Holt Co.
Neligh
Hoskins
Gentleman
Elm Creek
Eastowne
Baldwin Creek
Blue Springs
Prairie Lee
Northview
East Abilene
Abilene Energy Center
Summit
Moundridge
Clearwater
Harper
Milan Tap
Hitchland
Windfarm Switching
Mooreland
Glass Mountain
Woodward*
Okeene
Dover
Bluebell
Prattville
Chamber Springs
Farmington
Dallam Co.
Channing
Potter Co.
Elk City
Cimarron
Gracemont
Tuco
New Deal
Chaves Co.
Carlisle
Amoco
Stanton
Lubbock South
Grassland
Wolfforth
Hobbs
Welsh
Lake Hawkins
0 45 90 180 270 Miles
N
*Woodward District EHV
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All SPP Transmission Expansion Plans are subject to change.

PART I: STUDY PROCESS

Section 1: Introduction

1.1: The 10-Year ITP

This report summarizes SPP's first ITP10 study and focuses on the year 2022 (10 years from 2012). The ITP10 study aims to deliver generation to load throughout the footprint in a manner consistent with the transmission expansion vision outlined in the 2010 ITP20.

1.2: 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 demonstrates the findings of the study, empirical results, and conclusions.
- Part III addresses the portfolio specific results, describes the projects that merit consideration, and contains the recommendation of staff, expected benefits, and costs.
- Part IV contains detailed data and holds the report's appendix material.

Two Futures – Two Colors
Throughout this report consistent colors have been utilized to display data for each future. Future 1 data has been presented in light blue and Future 2 in red. When the data for each future is the same the two colors have been combined to form purple.

Future 1	Both Futures	Future 2

SPP Footprint
Within this study, any reference to the SPP footprint refers to the Regional Transmission Organization (RTO) Balancing Authorities and Transmission Owners[4] representing members of the SPP organization unless otherwise noted. Energy markets were similarly modeled for other RTOs in the Eastern Interconnect. Notably, AECI and Entergy operated as stand-alone entities in order to reflect their current operating characteristics and commitments.

Supporting Documents
The development of this study was guided by the supporting documents noted below. These living documents provide structure for this and future ITP assessments:

- SPP 2012 ITP10 Scope
- SPP ITP Manual
- SPP Robustness Metrics Procedural Manual

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

[4] SPP.org > About > Fast Facts > Footprints

Confidentiality and Open Access

Proprietary information is frequently exchanged between SPP and its stakeholders in the course of any study, and is extensively used during the ITP development process. This report does not contain confidential marketing data, pricing information, marketing strategies, or other data considered 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 that are considered non-sensitive data.

1.3: Policy Considerations

In January 2011, SPP published the 2010 ITP20. Four futures were evaluated in that analysis. Those futures each represented different policy assumptions affecting the industry. The policy assumptions included meeting state renewable targets, a federal renewable energy standard (RES), and implementation of carbon reduction initiatives.

For the development of the 2012 ITP10 futures and subsequent analysis, SPP utilized surveyed information gathered by the state commissions in the SPP footprint to determine the expected amount of renewable resources the state and/or the transmission owners in their state would require in 2022 assuming current state and federal policy initiatives. In addition, SPP asked what renewable resources would be required if there was a Federal RES of 20%. The survey was completed in February 2011 and used to guide the development of the resource plans used in the 2012 ITP10 study.

Figure 1.1 shows the amount of renewable generation capacity required by each state in the SPP planning region in 2022 if there are no federal, state or utility policy changes. Figure 1.2 shows the amount of total renewable generation capacity that would be required in 2022 if there is a federal RES. The state of Missouri expects renewable generation in the state only under the current state of Missouri standard which applies a state credit for renewable located in the state. It is expected that a federal RES would supersede the state standard and therefore remove the credit. Under this scenario, it is assumed all of the renewable needed to support the 20% standard in Missouri would be located outside of Missouri in areas more suitable for renewable generation development.

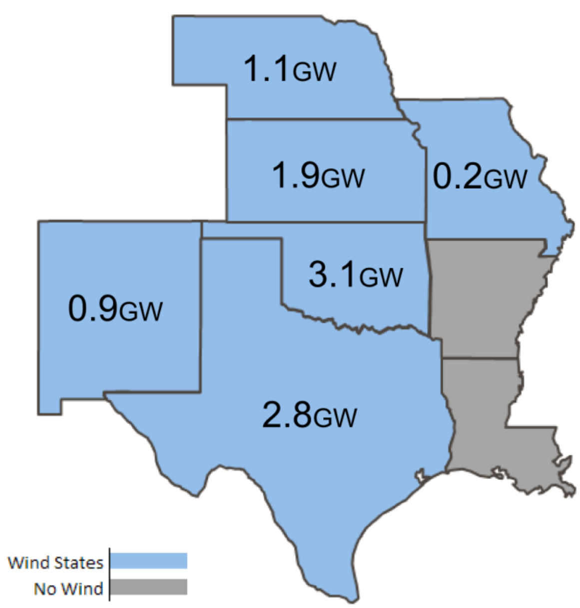


Figure 1.1: Renewable capacity levels required in Future 1

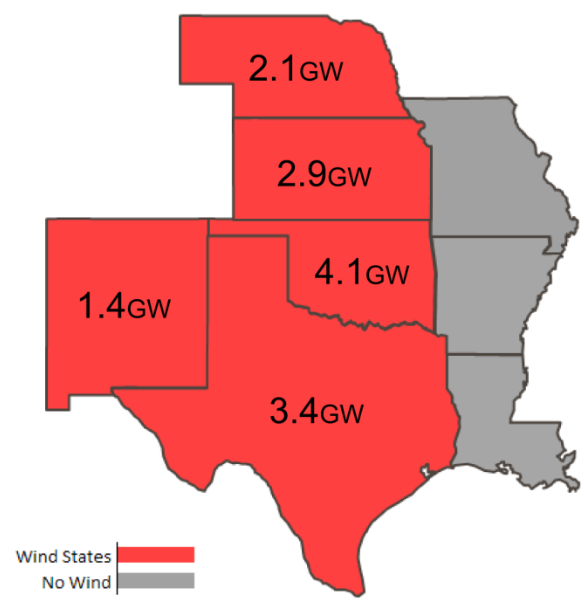


Figure 1.2: Renewable capacity levels required in Future 2

1.4: Process Development

ITP development was driven by the Synergistic Planning Project Team (SPPT), which was created by the SPP BOD to address gaps and conflicts in SPP's transmission planning processes including Generation Interconnection and Transmission Service; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities. The ITP is based on the SPPT's planning principles, which emphasize the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP's future needs. The 2012 ITP10 analysis report addressed the following SPPT's goals:

- Focus on regional needs.
- Utilize a value based approach that analyzes the 10-year out transmission system.
- Identify 100 kV and above solutions stemming from reliability analysis and bridging to the 2010 ITP20 plan.
- Integrate 2010 ITP20 projects with the necessary 100 kV and above facilities to incorporate such needs as:
    - Resolving potential criteria violations
    - Mitigating known or foreseen congestion
    - Improve access to markets
    - Improving interconnections
- Focus on the scenarios considered in ITP20 that are most likely to occur in the 10-year horizon.
- Further refine and establish the timing of 2010 ITP20 projects through economic and reliability analysis.

Printing

This report contains the 2012 ITP10 Project List which is sized for 11 x 17 inch paper. It is recommended that the reader print the document with the output paper size explicitly set 8 ½ x 11 inches and zoom level set to auto to ensure seamless print jobs or the report and list. The list can be printed separately on 11 x 17 inch paper.

Section 2: Consistency with the ITP20

2012 ITP10 Goals

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

SPP staff and stakeholders approached the 2012 ITP10 with goals of improving grid flexibility and cost-effectiveness, increasing reliability, preparing for future needs, and integrating SPP's western and eastern sections by developing a robust transmission system.

The SPP BOD approved the 2010 ITP20 Report on January 25, 2011. The plan 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. The full report is available on SPP.org.[5].

How the 2010 ITP20 plan fits into the 2012 ITP10

Projects from the 2012 ITP10 economic assessment were coupled with the results of the reliability assessment to determine optimal solutions. Issues identified that were not resolved with 100 kV and above solutions were addressed by 2012 ITP Near-Term Assessment.

All projects from the 2010 ITP20 Plan were tested in the 2012 ITP10. Some, listed in Table 2.1, showed significant benefit and have been included in the final portfolio. Criteria for the inclusion of these projects included the mitigation of identified reliability needs, the satisfaction of a policy requirement common to each future or an economic B/C greater than 1.0. *Section 6.6:* includes greater detail on this process.

Other projects did not show adequate benefit in relation to the cost in the 10-year horizon, and did were not included in the 2012 ITP10 final portfolio. *Section 16: 2010 ITP20 Projects in the 2012 ITP10* shows all of the projects in the 2010 ITP20 Plan and whether each project was included in the 2012 ITP10 plan, excluded from the 2012 ITP10 plan, or had a similar project included in the 2012 ITP10.

ITP20 Project	kV	Status in 2012 ITP10	Reason for Inclusion
Gentleman - Hooker Co - Wheeler Co	345	Similar project included	Satisfaction of Policy Goal
Holt Co Substation	345	Included	Satisfaction of Policy Goal
Woodward District EHV - Woodring	345	Similar project included	Mitigation of Reliability Need
Holt Co - Hoskins - Ft. Calhoun	345	Similar project included	Mitigation of Reliability Need
Tuco - Amoco - Lea Co - Hobbs	345	Included	Provides Economic Value
Lea Co Transformer	345/230	Similar project included	Provides Economic Value
Amoco Transformer	345/230	Included	Provides Economic Value

Table 2.1: 2010 ITP20 Projects in 2012 ITP10 Final Portfolio

[5] SPP.org > Engineering > Transmission Planning > 2010 ITP20 Report

Section 3: Stakeholder Collaboration

Assumptions and procedures for the 2012 ITP10 analysis were developed through SPP stakeholder meetings that took place in 2010 and 2011. 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 development 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 and TWG provided technical guidance and review for inputs, assumptions, and findings. Policy level considerations were tendered to groups including the MOPC, SPC, RSC, and BOD. Stakeholder feedback was key to the selection of the 2012 ITP10 projects.

- The TWG was responsible for technical oversight of the load forecasts, transmission topology inputs, constraint selection criteria, reliability assessments, transmission project designs, voltage studies, and the report.
- The ESWG was responsible for technical oversight of the economic modeling assumptions, futures, resource plans and siting, metric development and usage, congestion analysis, economic model review, calculation of benefits, and the report.
- The strategic guidance for the study was provided by the SPC, MOPC, and BOD.

Significant Meetings

In addition to the standard working group meetings, three transmission planning workshops (or summits) were conducted to elicit further input and provide stakeholders with a chance to interact with staff on all related planning topics.

- The key drivers developed by the stakeholders and preliminary identification of projected criteria violations and congestion were presented at the Planning Summit on July 21, 2011[6].
- Potential reliability solutions along with potential economic upgrades were presented at the Planning Summit on September 21, 2011[7].
- Recommended solutions with completed reliability, stability and economic analysis results were presented at the ITP Workshop on December 5, 2011[8].

Project Cost Overview

The project costs utilized in the 2012 ITP10 were developed in accordance with the efforts of the Project Cost Task Force (PCTF), the Design Best Practices and Performance Criteria Task Force (DBPPCTF), and the Project Cost Working Group (PCWG).

[6] SPP.org > Engineering > Transmission Planning > 2011 July Planning Summit
[7] SPP.org > Engineering > Transmission Planning > 2011 September Planning Summit
[8] SPP.org > Engineering > Transmission Planning > 2011 Dec ITP Workshop

Metric Development and Usage

The metrics used to measure the value of each transmission portfolio or individual project in the 2010 ITP20 were further refined by the ESWG. The group simplified the list of metrics in order to narrow the focus of the assessment to three vital areas: cost benefits realized through various generation scenarios; the affect alternative topology will have on ATC capabilities within SPP; and the affect alternative transmission topology and congestion can have on competitiveness in the SPP market[9].

Monetized Cost Benefits

Metrics CM1, 1.1.1, 1.3, and 1.6 were calculated in the annual security constrained economic simulations. The production costs, purchases, and sales of all energy within the eastern interconnect were tracked under each transmission expansion scenario.

Metric No.	Metric Description
CM1	APC Savings
1.1.1	Value of Replacing Previously Approved Projects
1.3	Reduced Losses
1.6	Reduced Capacity Costs
10	Reduction of Emissions Rates and Values

Table 3.1: Monetized Metrics used in the 2012 ITP10

Available Transfer Capability Benefits

The ATC metrics were calculated on the peak hours. Transfers were analyzed between each SPP area as well as between each load center in SPP. Load centers were identified through the use of Geographic Information Systems and approximate the area around each of the large cities in SPP. Results are reported by the largest percentage improvement in each transfer with, the MW increase also provided.

Metric No.	Metric Description
1.1.2	Value of Improved Available Transfer Capabilities
6	Limited Export/Import Improvements
14	Ability to Serve New Load

Table 3.2: Available Transfer Capability Metrics used in the 2012 ITP10

Competitive Benefits

The metrics measuring the opportunity for competition within the footprint focus upon the LMP prices and were calculated as part of the security constrained economic dispatch simulations. The measure records the differences in LMP price from the average and provides a qualitative and relative comparison between plans regarding which plan provides the most opportunities for generators to compete in the market.

Metric No.	Metric Description
2	Levelization of LMP's
3	Improved Competition in SPP Markets

Table 3.3: Competition Metrics used in the 2012 ITP10

[9] During the August 2, 2011 meeting of the ESWG, a motion was taken and unanimously approved to include a selected group of metrics in the 2012 ITP10. This approach was approved by the MOPC during the December 6, 2011.

The metrics in the 2012 ITP10 were used to select between transmission groupings that contained multiple transmission plan options. Often three or four projects are slated to fix the same portions of the grid. The project or grouping with the greatest metric values indicated those of greatest value. See *Section 6: Analysis Methodology* for the methods used to apply each of these metric calculations to the 2012 ITP10.

Section 4: Future Selection

4.1: Uncertainty and Important Issues

A key challenge in designing a transmission expansion plan to meet future needs is the inability to predict the policy environment. In addition to technical uncertainties, such as future load growth and fuel prices, there are political uncertainties related to public policy and technological development. In order to address this challenge, two distinct sets of assumptions were developed and studied as individual "futures" for the 2012 ITP10.

4.2: Futures Descriptions

The two futures utilized in the 2012 ITP10 were developed as a refinement of the four futures used in the 2010 ITP20. Adjustments to the futures were made in response to more up-to-date understandings of key policy issues such as climate legislation, cap & trade, Environmental Protection Agency (EPA) policies, and renewable energy standards. The two futures provide different perspectives on the 10-year study horizon and were adopted because they provide two bookends, to the spectrum of unknowns that could impact the development of transmission.

Future 1: Business as Usual

This future utilized current state and transmission owner renewable targets for 2022, current generation plans and load forecasts. This future's inputs mirrored those of the 2010 ITP20 Business as Usual future by incorporating state renewable targets compiled through a survey of plans to meet existing state requirements and targets. This survey was administered by the CAWG.

Future 2: Federal RES and EPA Regulations

This future anticipated increases above current state renewable targets and approximated the impact of EPA rulemaking by imposing retirements on small coal plants and a tax on carbon emissions. The impact of any one particular EPA regulation was not specifically identified in the development of this future's assumptions. Rather, the future serves as a bookend similar to the 2010 ITP20 RES and carbon mandate future by approximating impacts due to regulations from the EPA on utilities through a carbon tax and a coal plant retirement schedule[10].

4.3: Resource Plan Development

The ESWG approved the use of load forecasts for 2022 and needed capacity additions assuming the SPP RTO must meet the 12% capacity margin requirement outlined in SPP Criteria[11]. Resource plans were developed based on data assumed for summer of 2022 and utilized the resource plan and siting developed in the 2010 ITP20[12]. See *Section 17: Resource Expansion Plan* for complete details regarding the development of the resource plan.

[10] In June 2011, the EPA approved the Cross-State Air Pollution Rule (CSAPR) which imposes new restrictions on emissions. This ruling was well after the start of the 2012 ITP10 analysis and therefore, impacts of this ruling were not incorporated into this study. SPP is currently assessing how to best assess the impact of this rule.

[11] SPP.org > Org Groups > Governing Documents > Criteria and Appendices July 25, 2011

[12] SPP.org > Engineering > Transmission Planning > 2010 ITP20 Report

New Wind Sites

Wind sites were selected by the ESWG. The sites utilized in the 2012 ITP10 were similar to those selected in the 2010 ITP20 because of their potential for high capacity factors. These sites were placed in the model in addition to the existing wind farms currently operating in SPP. Notable changes were made to four locations. Two of the locations used in the 2010 ITP20 were changed for use in the 2012 ITP10 because of planned transmission development in the ERCOT region. Consequently, the sites in Armstrong and Carson counties in Texas from the 2010 ITP20 were placed in Roosevelt and Lea counties in New Mexico for the 2012 ITP10. Two other locations in Nebraska were moved farther north to Cherry Co. from the Hooker Co. locations used in the 2010 ITP10 based upon wind development plans in that state.

Wind Generation Ownership

The ownership of each wind farm's output was consistent with current obligations and purchase power agreements submitted through the SPP GI process. The ownership of the projected wind sites were apportioned to the area which needed the capacity of that wind farm (utilities in Nebraska coordinated the ownership of sites located geographically within NPPD) to meet the parameters of each future[13]. The cost per MWh of generating energy and the sales from each wind farm were credited to the area that owned the wind farm. These values are reflected in the calculation of each area's Adjusted Production Cost (APC).

Future 1 Resource Plan Summary

Future 1 was based on the wind requirements currently set by states and utilities. In the CAWG survey used to compile these wind requirements, SPP members indicated wind energy targets that totaled 30,143 GWh in 2017 and 37,467 GWh in 2022. Assuming an average capacity factor of 42.6%, this equates to a name plate wind capacity of 8.1 GW in 2017 and 10.0 GW in 2022. The 2022 targets were the primary focus of the 2012 ITP10 study, although the 2017 targets have been used to help stage projects driven by renewable energy policy. This future does not assume a federal RES. Of the 10 GW of total wind capacity in Future 1, 3.5 GW was neither in-service nor had a signed Interconnection Agreement. 1,590 MW of natural gas generation was added to meet capacity margin requirements. Figure 4.1 illustrates the amount and location of additional generation for Future 1.

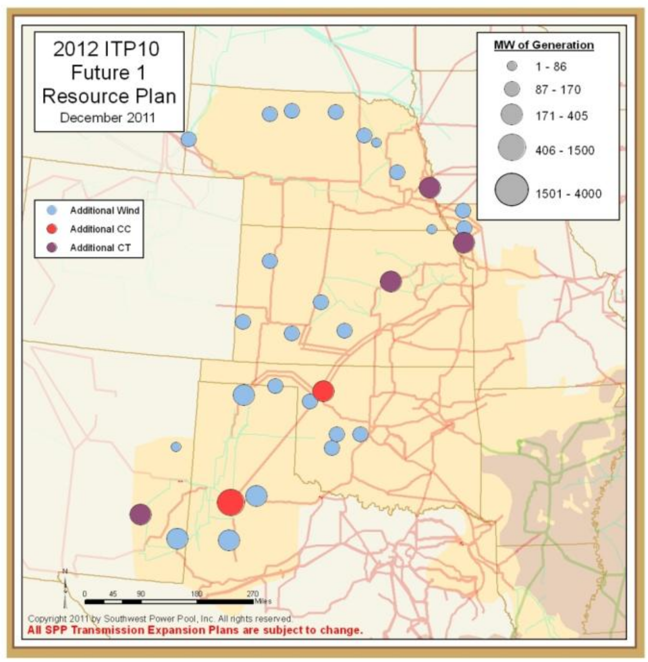


Figure 4.1: Future 1 Resource Plan Summary

Future 2 Resource Plan Summary

Future 2 assumed a federal RES of 20% applied in the SPP region, which results in approximately 14 GW of total wind generation capacity in the SPP footprint (of which 7.5 GW was neither in-service nor had a signed Interconnection Agreement.) This requirement supersedes all state and local renewable

[13] Wind ownership information can be found at SPP.org > Engineering > Transmission Planning > ITP10 Documents > 2011 ITP10 Wind Siting Plan

requirements. In addition to a larger amount of wind than Future 1, wind placement varied slightly. Future 2 does not include additional wind sited in the state of Missouri. As in Future 1, this wind siting and allocation was guided by the CAWG Renewable Survey. 4,270 MW of natural gas generation was added to meet capacity margin requirements. Figure 4.2 shows both the additional wind and other generation added in Future 2.

Future 2 assumed additional regulations mandated by the EPA regarding emissions. As a proxy for these regulations, SPP Staff, working with the ESWG, identified 2.3 GW of coal plant retirements. The retirements identified in this future stemmed from a rule that any SPP coal unit, barring stakeholder exception, less than 200 MW in capacity would be retired in expectation of tighter environmental control regulations. Stakeholders provided key input through the ESWG and in that forum several adjustments were made to the list of units identified by that rule (see Table 17.1 for a complete list). These retirements were for the purposes of the 2012 ITP10 study only and should not be considered as planned by the Generation Owners in any way. Figure 4.3 identifies the location and amounts of the retirements.[14] Additionally, a $35/ton carbon tax was applied to the model.

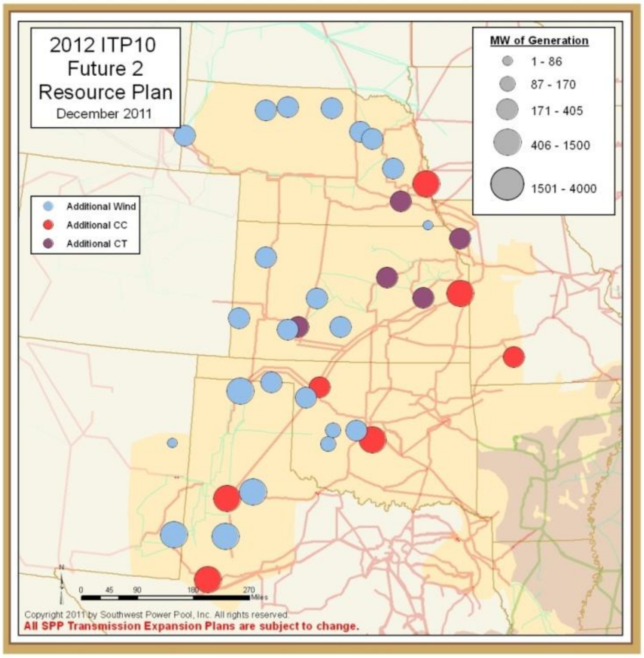


Figure 4.2: Future 2 Resource Plan

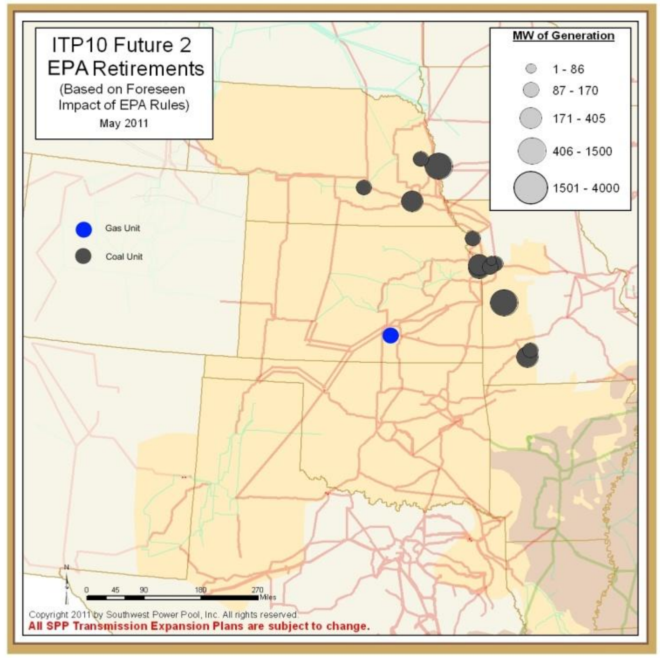


Figure 4.3: 2012 ITP10 Coal and Gas Retirements Considered in Future 2

Overview of Environmental Impacts

The EPA is in the process of introducing a series of new regulations to control coal combustion byproducts, i.e. SO_x, NO_x, mercury, and CO_2, water use, and ash disposal. These regulations may force utilities to choose between retiring units or installing expensive, capacity-reducing equipment to control the pollutants.

[14] In June 2011, the EPA approved the Cross-State Air Pollution Rule (CSAPR) which imposes new restrictions on emissions. This ruling was well after the start of the 2012 ITP10 analysis and therefore, impacts of this ruling were not explicitly incorporated into this study. SPP is currently considering how to best assess the impact of this rule.

Coal

In an attempt to approximate the impacts of EPA regulations on emissions, 2.3 GW (37 units) of coal capacity was retired in the 2012 ITP10 resource plan. Since this resource plan was developed, the EPA Cross State Air Pollution Rule was issued. At the time of this report, evaluation of the expected impacts of that rule was still underway.

EPA Regulations in 2012 ITP10

As a proxy for the some of the EPA regulations a CO_2 tax was applied. This tax impacts the way units are dispatched by making the operation of high producing CO_2 units more expensive.

Section 5: Drivers

5.1: Stakeholder Driven Drivers

Drivers for the 2012 ITP10 were discussed and developed through the stakeholder process in accordance with the 2012 ITP10 Scope and involved stakeholders from several diverse groups. The load, energy, generation, transmission, financial, and market design inputs were considered for their importance in determining the need for and design of transmission. The same peak load, off-peak load, and energy values were utilized in both futures.

5.2: Load & Energy Outlook

Peak and Off-Peak Load

Future electricity usage was forecasted by SPP and collected through the efforts of the Model Development Working Group (MDWG). The highest usage, referred to as the system peak, usually occurs in the summer for SPP. The non-coincident peak load for SPP was forecasted to be 54 GW for 2022. This value was paired with company specific hourly load profiles to produce a coincident peak forecast of 53 GW that was used in the security constrained economic dispatch, reliability assessments, and stability evaluations.

The off-peak load was simulated by through the incorporation of energy usage for the year, forecasted peak load, seasonal load curves, and hourly wind generation profiles. The hour with the highest ratio of wind to total generation was selected as the off-peak hour in order to evaluate grid exposure to significant output from intermittent generation resource with limited access to the voltage and stability control provided by conventional resources. The off-peak load for SPP was forecasted to be 22 GW for 2022.

The incorporation of these assumptions into a load adjustment algorithm allowed the development of hourly loads consistent with the peak energy and demand values. The results of the algorithm indicated that the peak hour for the simulation of 2022 would occur on August 3, 2022 at 5 pm and the off-peak hour would occur May 17, 2022 at 5 am.

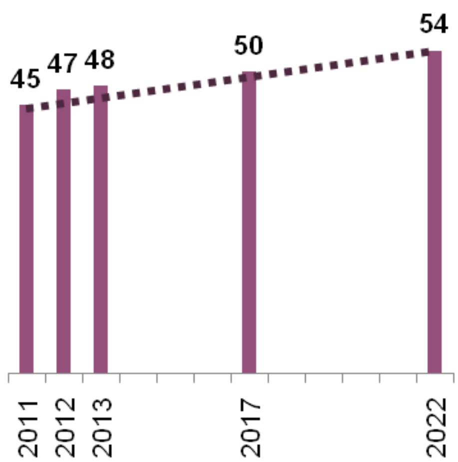


Figure 5.1: SPP non-coincident peak forecast for 2022 and intervening years

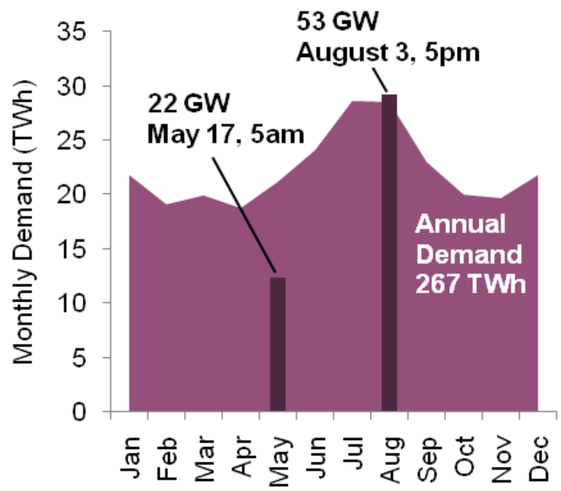


Figure 5.2: SPP Coincident Peak, Off-Peak, and Annual Energy Demand Forecast

Net Energy for Load

The sum of energy used throughout a year, referred to as the net energy for load forecasts, was also forecasted by SPP and obtained through the efforts of the ESWG. This annual net energy for load (including losses) was forecasted at 267 TWh for 2022. Figure 5.1 and Figure 5.2 show the forecasted peak and energy values for 2022 and show the expected growth in peak load for the intervening years.

Major Load Centers in SPP

Table 5.1 shows the percentage of the peak load located in each load center. The largest cities in SPP: Omaha, Kansas City, Wichita, Springfield, Tulsa, and Oklahoma City all lie along the eastern border of SPP and account for 42% of the region's load at peak. Load in west SPP is concentrated primarily in Amarillo and near Lubbock.

City	State	% of Peak
Kansas City	MO	12%
Oklahoma City	OK	7%
Omaha – Lincoln Area	NE	6%
Shreveport	LA	3%
Tulsa	OK	5%
Lubbock Area	TX	4%
Wichita	KS	4%
Fayetteville	AR	3%
Springfield	MO	2%

Table 5.1: Load Centers in SPP

Diverse Peak Demand Growth Rates

The MDWG models included diverse peak load growth rates for each area. Table 5.2 lists the peak load growth rates for the key areas in the model. These forecasted values averaged out to an annual growth rate of 1.40% for SPP.

Area	KACY	SUNC	OKGE	WERE	AEPW	LES	OMPA	NPPD	GRDA
Rate (%)	0.42	0.56	0.85	0.94	1.10	1.11	1.12	1.13	1.16

Area	KCPL	WFEC	EMDE	GMO	OPPD	CUS	SPS
Rate (%)	1.16	1.128	1.31	1.41	1.87	2.26	2.49

Table 5.2: Annual Peak Load Growth Rates in SPP 2011 - 2022 (%)

5.3: Generation Outlook

Generation & Capacity by Future

Future generation capacity was compiled and forecasted through the efforts of the ESWG. Generation technologies represented within the SPP footprint included steam turbine coal (Coal), combined cycle natural gas (CC), combustion turbine natural gas (CT), conventional hydroelectric (Hydro), nuclear, wind, and others.

The state of Missouri expects wind generation in the state only under the current state of Missouri standard which applies a state credit for wind located in the state. It is expected that a federal RES would supersede the state standard and therefore remove the credit. Under this scenario, it is assumed all of the wind needed to support the 20% standard in Missouri would be located outside of Missouri in areas more suitable for wind generation development.

Resource plans were developed specifically for each future. Consequently, difference resources were located in each state depending upon the retirements in that area.

	CC	CT	Wind	Total
KS		180	1,919	2,099
MO		180	213	393
NE		180	1,110	1,290
NM		180	937	1,117
OK	320		3,099	3,419
TX	550		2,761	3,311
SPP	870	720	10,038	11,628

Figure 5.3: Future 1 Capacity Additions by State (MW)

	CC	CT	Wind	Retired	Total
KS	550	540	2,936	494	3,532
MO	300	180	0	1,175	(695)
NE	550	180	2,097	878	1,949
NM			1,453	25	1,428
OK	870		4,157	0	5,027
TX	1,100		3,405	0	4,505
SPP	3,370	900	14,048	2,572	15,746

Figure 5.4: Future 2 Capacity Additions & Retirements by State (MW)

Total	Coal	CC	CT	Hydro	Nuclear	Other
56,883	42%	35%	15%	1%	4%	2%

Figure 5.5: Capacity Common to Each Future by Type (MW)

Resource Plan Additions Outside of SPP

Additional wind capacity outside of SPP was included following collaboration with MISO. Extensive wind generation growth was forecasted for MISO and PJM. Less significant amounts were modeled for SERC and the NYISO. Conventional generation was also added but at a much smaller magnitude based upon the commercially available data provided in the North American Power Reference Case from Ventyx®. Table 5.3 outlines wind capacity additions for each of the regions. These values were utilized in both futures. Values more consistent with the assumptions of Future 2 were not available.

Region	Future 1	Future 2
PJM	22.8	22.8
MISO	13.8	13.8
SPP	6.0	10.0
SERC	5.4	5.4
NYISO	3.9	3.9

Table 5.3: Wind added by region (GW)

Generator Operating Characteristics

Reasonable operating characteristics consistent with each unit type were utilized in the production cost models. Review of these characteristics was facilitated through the ESWG and TWG. An $8/MWh price was utilized for wind sales.

DC Tie Lines

The flows on the DC tie lines into and out of SPP were set to match expected seasonal values based upon historical flows obtained from SPP Operations department and reviewed by DC Tie operators in accordance with the study scope.

5.4: Transmission Outlook

The Transmission Working Group (TWG) and MDWG oversaw the development of the base transmission expansion model. Expansion outside of SPP was coordination with the NERC Multiregional Modeling Working Group (MMWG), Associated Electric Cooperative Inc. (AECI), and the Independent Coordinator of Transmission (ICT) for Entergy Services. The model included all projects with SPP NTCs[15] that were identified in the 2010 SPP reliability assessment, the Balanced Portfolio, the Priority Projects, the AECI 10-Year plan, the MISO expansion in the MMWG models, and the 2011-2013 Entergy Construction Plan.

Figure 5.6: 230 kV & 345 kV Planned Expansion Expected to be Energized by 2022

Planned Expansion

Figure 5.6 illustrates some of the transmission, with NTCs, that were included in the base transmission model. Planned expansion for areas outside of SPP represented in the 2011 series MMWG models was included.[16]

Treatment of SPP Flowgates Included as Initial Constraints

The TWG oversaw the development of initial constraints in the model. Flowgates within the 2011 SPP Book of Flowgates were included. In addition to SPP flowgates, select flowgates in neighboring balancing authorities were included after coordination with AECI, Entergy, and MISO. The TWG reviewed and updated several of the initial flowgates in order to capture flowgates eliminated by expectations of proposed transmission projects with in-service dates prior to 2022.

[15] A Notification to Construct (NTC) is a formal SPP document specifying approval of and notification to build specific network upgrades with specified need dates for commercial operation. An NTC is issued for any project requiring a financial expenditure within the next four years to meet the specified need date.

[16] For instance, this did not include the MISO MVP projects approved in late 2011.

5.5: Financial Outlook

Nominal and Real Dollars

Unless specified otherwise, all dollar amounts reported are in real dollars. The dollar values utilized in the simulations represent the value of fuel prices and operating costs in 2022. To account for effects of inflation upon the U.S. dollar, the values are presented in real terms by applying a deflationary value of 2.5%.

Fuel Price Forecasts

The ESWG developed fuel price forecasts for 2022. The group approved these prices for the simulations of both futures. Sensitivities were used to provide a range of economic benefits in the 2012 ITP10 portfolio(s). Fuel costs for uranium, natural gas, and coal were based upon current market prices and industry forecasts provided in the North American Power Reference Case from Ventyx®. The costs of each fuel were used as inputs in the market APC simulations and contribute to the price per MWh of each generator.

Natural gas price forecasts from Ventyx®, the Department of Energy, L.E. Peabody, and IHS CERA were referenced and the group recommended that a middle ground between the forecasts be utilized. This gas price coincided with the New York Mercantile Exchange (NYMEX) traded value of gas futures for 2022 and the NYMEX monthly traded values for 2022 (as of late April, 2011) were accepted as the expected fuel prices for the simulations. Natural gas prices are the only values varying by month; Ventyx® forecasts were used as the basis for other fuel forecasts and these did not provide the monthly granularity available for natural gas. See Table 5.4 for the price of each fuel type.[17] The fuel prices were the same in each future.

Fuel or Effluent	$/MMBtu	$/short ton
Uranium ($/MMBtu)	0.92	
Natural Gas, Henry Hub ($/MMBtu)	6.21	
Central Appalachian Coal ($/MMBtu)	3.37	
Powder River Basin Coal ($/MMBtu)	0.92	
Fuel Oil	13.69	
SO_2 Emissions		146
NO_X Emissions (CAIR annual)		659
NO_X Emissions (CAIR seasonal only)		218
CO_2 Emissions		27

Table 5.4: Fuel Price & Emissions Charge

Capital Costs and Related Societal Benefits

The financing costs of the renewable and conventional units added in the resource plan (see *Section 4.3: Resource Plan Development*) with their associated societal benefits, such as job creation, increased fuel supply diversity, and others, were not included in the benefit/cost calculations in this report. See *Section 12: Benefits* for a full discussion of the benefits and costs that are included.

Emissions Charge Development

Additionally, the group selected a $27 carbon tax ($35 in 2022) in order to approximate the impacts of EPA regulations upon variable costs of operating coal generation plants. This value was selected

[17] http://www.spp.org/publications/2011_ITP10_Fuels_ESWG_Approved_04-19-11.ppt

The ESWG continued to monitor the NYMEX trading value of natural gas throughout the study year. Despite the fluctuations in price, the values selected as inputs to the study were maintained in order to preserve consistency within the study. The fluctuation of these prices was expected, and although unfortunate makes the utilization of the results more difficult, was unavoidable.

following a rough estimation of impacts upon the fuel price and usage per MWh between gas and coal in 2010 (see Table 5.5). Future 1 did not include a carbon tax.

Carbon Tax Option ($/ton[18])	$0	$14	$27	$56
Average Coal Generation Cost ($/MWh)	$30	$45	$60	$90
Average Gas Generation Cost ($/MWh)	$35	$45	$55	$75

Table 5.5: Estimate of Carbon Tax Impact upon Fuel Price

Fuel Price Sensitivity & Uncertainty Analysis

Sensitivities to coal price, natural gas price, carbon tax, and demand levels were developed by the ESWG to understand impacts to the proposed transmission plans. Two confidence intervals were developed using historical market prices and demand levels from the NYMEX and FERC Form No. 714. The standard deviation of the log difference from the normal within the pricing datasets was used. Figure 5.7 and Figure 5.8 show the sensitivity bands for coal and gas prices. The values for each of the sensitivities, averaged for the whole year are shown in Table 5.6 for Future 1 and Table 5.7 for Future 2.

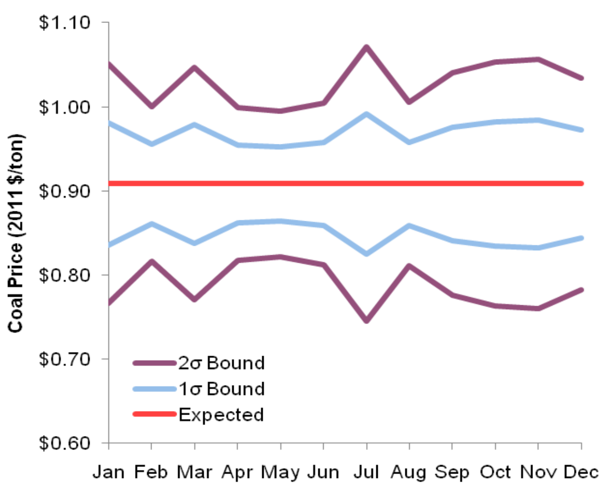


Figure 5.7: Monthly Coal Price & Sensitivity Values

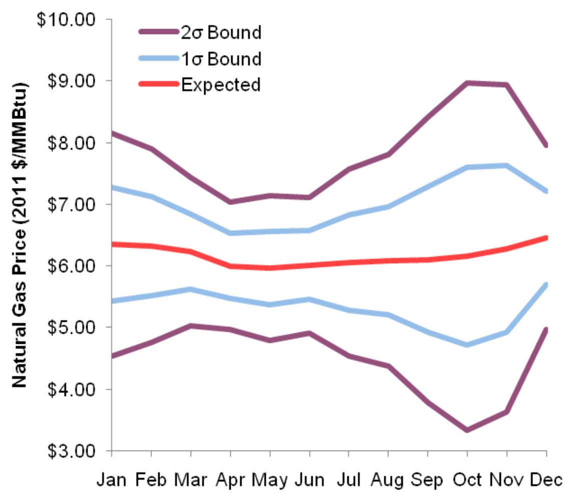


Figure 5.8: Monthly Gas Price & Sensitivity Values

Sensitivity	Gas Price ($/MMBtu)	Carbon Tax ($/ton)	Peak Demand and Energy
High Natural Gas & Demand	$7.87	$0.00	7.6% increase
High Natural Gas	$7.87	$0.00	no change
Expected Natural Gas & Demand	$6.21 (no change)	$0.00	no change
Low Natural Gas & Demand	$4.47	$0.00	7.6% decrease
Low Natural Gas	$4.47	$0.00	no change
High Natural Gas & Demand	$7.87	$0.00	7.6% increase

Table 5.6: Future 1 Sensitivity Value Matrix

[18] SPP utilizes the short ton for all calculations.

Sensitivity	Gas Price ($/MMBtu)	Carbon Tax ($/ton)	Peak Demand and Energy
High Natural Gas & Demand	$7.87	$26.68 (no change)	7.6% increase
High Natural Gas	$7.87	no change	no change
Expected Natural Gas & Demand	$6.21 (no change)	no change	no change
Low Natural Gas & Demand	$4.47	no change	7.6% decrease
Low Natural Gas	$4.47	no change	no change
High Natural Gas & Demand	$7.87	no change	7.6% increase
High Carbon Tax	no change	$41.16	no change
Expected Carbon Tax (F2 Only)	no change	no change	no change
Low Carbon Tax	no change	$10.67	no change

Table 5.7: Future 2 Sensitivity Value Matrix

Inflation, Carrying Charge and Interest Rate Assumptions

An Annual Transmission Revenue Requirement (ATRR) utilized in the economic screening was calculated by multiplying the total investment estimate for each project, already in 2011 dollars, by a generic Net Plant Carrying Charge Rate of 17%. The reductions in ATRR due to depreciation of the asset in Rate Base were not considered in the initial project screenings but were considered in the calculation of the forty-year benefits and costs. In the case of the forty-year financial analysis the costs for each year were calculated using the formula for ATRR. This calculation used the applicable Net Plant Carrying Charge rate (NPCC) for projects. The NPCC for the host zone of a project was applied to the engineering and construction cost, or investment cost, of a project. For the calculation, the projects were fully depreciated over the 40 years of analysis .For all inflation and deflation a 2.5% interest rate was utilized. A 8% discount rate was used for all discounting calculations.

5.6: Treatment of Energy Markets

The development of the Integrated Marketplace and the associated Consolidated Balancing Authority were accounted for in the 2012 ITP10. Each of the current Balancing Authorities within the footprint were committed and dispatched collectively Three of the major components of the Marketplace were accounted for in the study through the use of a security constrained economic dispatch that adhered to a unit commitment process: 1) a reliability unit commitment process, 2) a real-time balancing market, and 3) a consolidated balancing authority.

Within this study, any reference to the SPP footprint refers to the Regional Transmission Organization (RTO) Balancing Authorities and Transmission Owners[19] as defined by SPP membership. Energy markets were similarly modeled for other RTOs in the Eastern Interconnect. Notably, AECI and Entergy operated as stand-alone entities in order to reflect their current operating characteristics and commitments.

Entergy RTO/ISO Membership
In 2011, Entergy announced its intention to join the Midwest ISO (MISO). Entergy's notice to join MISO was announced in the middle of the 2012 ITP10 analysis. Therefore, the Entergy System was treated as a standalone entity and not part of any RTO/ISO.

Hurdle Rates
Additional tariff charges were assumed in the security constrained economic dispatch simulations. The values utilized varied from area to area but all tariff charges (or hurdle rates) between SPP and neighboring areas were kept consistent at $5 for the hourly dispatch rate and $8 for the day ahead commitment rate for flows into and out of the SPP footprint.

5.7: Software & Simulations

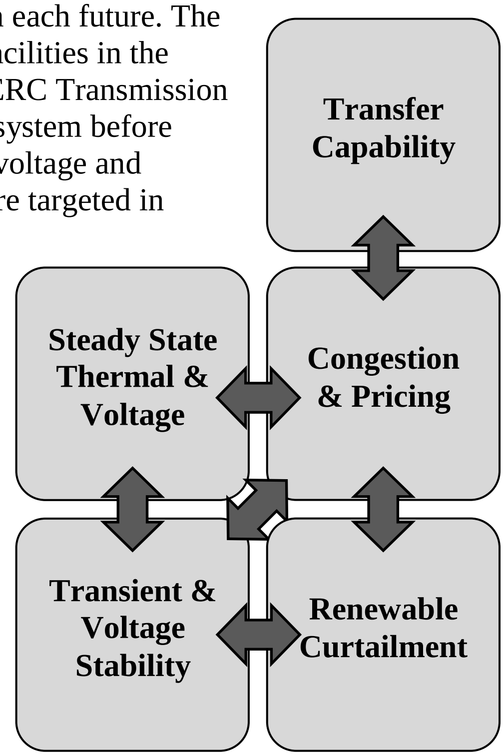
Various software packages were used to complete these studies, including ABB's PROMOD®, PTI's PSS®E, PTI's PSS®MUST package, the Dynamic Security Assessment (DSATools™) from Powertech Labs Inc.and the Power Analysis and Trading (PAT) Tool from Power Analytics Software Inc. Throughout this report, reference to DC and economic simulations refer to runs completed using the PROMOD® software. References to AC simulations indicate usage of PPS®E. References to transfer analyses indicate usage of PSS®MUST. References to voltage or transient stability analysis indicate usage of DSATools™.

[19] SPP.org > About > Fast Facts > Footprints

Section 6: Analysis Methodology

6.1: Five Analytical Approaches

Five perspectives were used to determine the portfolio of transmission projects that would meet the reliability, stability, policy, and economic needs of the system in each future. The thermal integrity of the system was investigated to ensure that facilities in the peak and off-peak cases would not be exposed to category A NERC Transmission Planning (TPL) standard criteria violations. The stability of the system before and after the transmission projects was evaluated to ensure that voltage and transient stability can be maintained. Significant bottlenecks were targeted in an effort to reduce the expected congestion and increase opportunities for competition within the market. Curtailment of wind was measured. Limitations to Available Transfer Capability (ATC) between regions of the footprint were identified. Finally, need dates for each project were determined to insure the projects would precede the associated economic opportunity, policy need, or reliability need.



Each perspective was evaluated in concert with others as shown to the right. For example, transfer capability results were fed into the congestion evaluation, reliability voltage violations were further investigated under the transient situations, and thermal overloads were monitored for congestion.

Priority was given to relieving all of the potential reliability violations seen during hours of high load or wind and to relieving the most congested constraints when cost-justified.

Utilization of Past Studies & Stakeholder Expertise for Solutions
Potential violations were shared with the stakeholders and posted on the SPP password protected TrueShare site for review. SPP collected potential solutions from Transmission Owners throughout the footprint and considered solutions previously identified in the 2010 ITP20, ITP Near-Term, Aggregate Studies, and Generation Interconnection Studies.

Treatment of Individual Projects & Groupings
Assessment of the needs and opportunities in the system was followed by mitigation of the overloads and congestion through individual projects. Each project was tested to ensure the project provided the expected result. Projects were then grouped together to measure the impact of the projects upon similar constraints and overloads. Efficiencies were sought for the projects that would best work together and for projects that eliminate the value captured by another project. This analysis was combined with reliability and stability work to produce a final portfolio of projects that were staged, timed, and analyzed for performance over forty-years and in light of several sensitivities.

6.2: Projecting Potential Criteria Violations

Peak and Off-Peak Conditions Reviewed by the TWG

For each future, a peak and off-peak AC powerflow model was developed. Potential thermal and voltage limits were assessed in accordance with SPP Criteria[20] and potential violations of the criteria identified and communicated with stakeholders. Feedback and discussion of the potential violations were vetted through the TWG to insure legitimate violations were identified.

Development of the AC Powerflow Models

The economic model and AC powerflow model used the same transmission topology, load levels, and generation dispatches within the SPP and Tier 1 footprints. Two hours (peak and off-peak) were selected out of the DC simulation of every hour in 2022 based upon the load levels of those hours (See *Section 5.2: Load & Energy Outlook* for more information regarding these load levels). Each of these hours were converted from the DC solution set to an AC model. The load and generation for SPP and Tier 1 areas were extracted from the DC simulation in order to reflect changes to the system dispatch that may occur in the SPP Integrated Marketplace. The load and generation of areas beyond SPP and Tier 1 balancing authorities were not extracted from the DC simulation, rather these values were scaled such that the interchange between SPP, Tier 1 and these areas was consistent with the DC simulation. This provided a reasonable representation of the entire Eastern Interconnection in the AC powerflow models.

Two AC models were constructed for each future for a total of four models. The peak case was meant to simulate the transmission system under peak load summer conditions. The off-peak case was taken as a high wind case to simulate the transmission system under high wind conditions.

Thermal and Voltage Assessment

The objective of the AC analysis was to identify 100+ kV upgrades needed to ensure the reliability of the system. Staff performed an N-1 contingency analysis for the following voltage levels:

- SPP 69 kV and above
- Entergy and AECI 100 kV and above
- All other Tier 1 areas 230 kV and above

These facilities were monitored during the contingency analyses:

- SPP 69 kV and above
- Entergy and AECI 100 kV and above
- All other first tier area 230 kV and above

Potential violations were determined by using the more restrictive of the NERC Category A Planning Standards, SPP Criteria or the local Planning criteria.

Reliability & Economic Efficiencies

All of the potential reliability upgrades were evaluated in the economic model to determine potential economic benefit. The potential upgrades were developed into portfolios to determine which group of upgrades provided the best overall solution. Potential upgrades were also reviewed to determine if an upgrade with a greater economic benefit could defer or replace an identified reliability solution. The costs associated with deferred projects can be subtracted from total cost of transmission expansion topologies portfolios making them comparable.

[20] SPP.org > Documents & Filings > Governing > Criteria and Appendices

The methodology by which reliability projects were replaced with economic projects followed these steps:

1. Reliability need identified.
2. Reliability mitigation provided and tested to ensure successful mitigation.
3. Congestion in the system identified.
4. Congestion near and related to reliability needs paired in order to compare alternative projects.
5. The value of resolving the congestion with an economic project that also mitigated the reliability need was measured and compared with the difference in costs between the projects.
6. Where cost-effective, the economic project was selected to mitigate the reliability need relieve the congestion.

6.3: Projecting Congestion & Market Prices

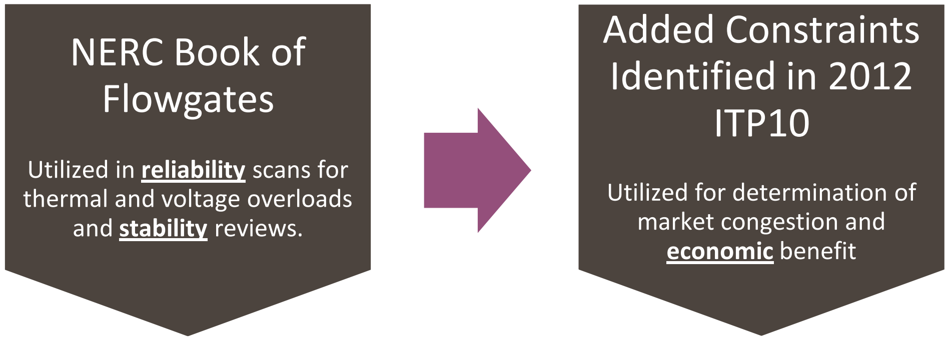
Annual Conditions Reviewed by the ESWG
Congestion was assessed on an annual basis for each future such that the analysis included variables that changed from day to day such as forced and maintenance outages of generating plants and those that changed on an hourly basis such as load curve shapes and wind output profiles. A total of 8,760 hours were evaluated for the year 2022. Feedback and discussion of the congestion was facilitated through the ESWG in order that legitimate congestion behavior would be identified and appropriate projects might be suggested.

Significant congestion was identified through two values: the number of hours congested and the shadow price[21] associated with the congestion in each hour. The shadow price was frequently aggregated for the whole year to a max, min and average bi-directional value.

Congestion Prioritization & Screening
The impact of the top twenty constraints upon the region's APC was measured to identify the depth of the congestion at each constraint and prioritize which constraints provided opportunity for APC savings. This was accomplished by calculating the change in APC with and without the constraint. In this manner, the areas of greatest opportunity for economic projects were identified before stakeholder suggested projects were taken into consideration.

Identification of Additional Constraints
The initial list of constraints was defined from the NERC Book of Flowgates for the SPP region (see *Section 5.4: Transmission Outlook* for more detail). This list of constraints was used to create the economic dispatch utilized in the reliability scans for potential thermal and voltage violations. In addition to this list more constraints were incorporated that would protect the facilities from overloads under different dispatches. These additional constraints, identified in the 2012 ITP10, facilitated the capture of both market congestion and economic benefit and adjusted the flowgate list in expectation of transmission that is not anticipated by the NERC book of Flowgates.

[21] The "Shadow Price" refers to the savings in congestion costs if the constraint limit in question were increased by 1 MW.



This process was necessarily iterative in nature and was applied to simulations of each future. The first pass added facilities that were overloaded for at least 1,000 of the 8,760 hours in the security constrained economic simulation. The second set of additions was derived from the ATC metric analysis (see *Section 6.5: Projecting Transfer Limitations*). The most limiting monitored and contingency pairs for each pre-transfer limited transaction path were added to the list of constraints. Monitored and contingent elements identified in the first pass took precedence over those from the second if the contingent elements were different. The final pass repeated the security constrained economic simulation from the first pass with the 2012 ITPNT and 2012 ITP10 reliability and policy projects added to the topology. These additions increased the precision of the calculations of the APC savings created by the economic projects.

Market Prices Metrics
A quantifiable measure of a generation owner's ability to compete within the SPP market was calculated on the final portfolio. A decrease in the value calculated in these metrics indicates an improvement in the competitiveness of the SPP market.

(i) Metric 2: Levelization of LMP's

Metric 2 provides SPP stakeholders a qualitative indicator of the impact an alternate transmission topology could have on a regional generation owners' ability to compete. An increase in congestion and losses places generators at certain locations at a disadvantage relative to other similar-cost generators, making the market less competitive. This metric measures the levelization of LMPs for each transmission topology using the standard deviation of LMPs across locations for the SPP footprint.

(ii) Metric 3: Improved Competition in SPP Markets

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

6.4: Meeting Policy Requirements

The primary policy focus was the satisfaction of renewable targets and mandates within a future through generation at wind farms throughout the footprint. Each of the wind farms was connected to the nearest transmission facility that could accommodate the entirety of the plant's capacity. In other areas, as much of the wind farm's capacity as possible was connected. In addition, wind farms experienced the effects of congestion in the simulations and were curtailed according to the security constrained economic dispatch.

Thermal Assessment for Connectivity

Wind farms were sited by county and connected to the nearest bus that would accommodate the full capacity of the plant. The bus each wind farm was connected to was determined after consideration of the thermal rating (rate B, the emergency rating for contingency situations, was used) of each transmission line leaving the bus for the loss of any other line or transformer. Wind farms in Future 2 were larger than those in Future 1 and in some cases required a different bus connection that allowed for greater thermal capability but were farther from the site in the county. Figure 6.1 shows highlighted counties which contain non-specific wind farms[22]. In Future 2, the counties highlighted in Missouri do not contain non-specific wind farms. See *Section 17.5: Wind Interconnection Summary* for a detailed list of the interconnection points.

Stability Assessment for Connectivity

Stability limitations that were considered sensitive to intermittent resources were identified by stakeholders (See *Section 8.1:* System Behavior for specifics). In order to reflect the wind congestion and curtailment due to these limitations, in the economic analysis, the step-up transformers at the wind farms were constrained in simulations without additional transmission mitigations. The reliability scans and stability review assumed that all wind farms were interconnected at full capacity in order to detect and mitigate these limitations. See *Section 17.5: Wind Interconnection Summary* for the treatment of the interconnection of each wind farm.

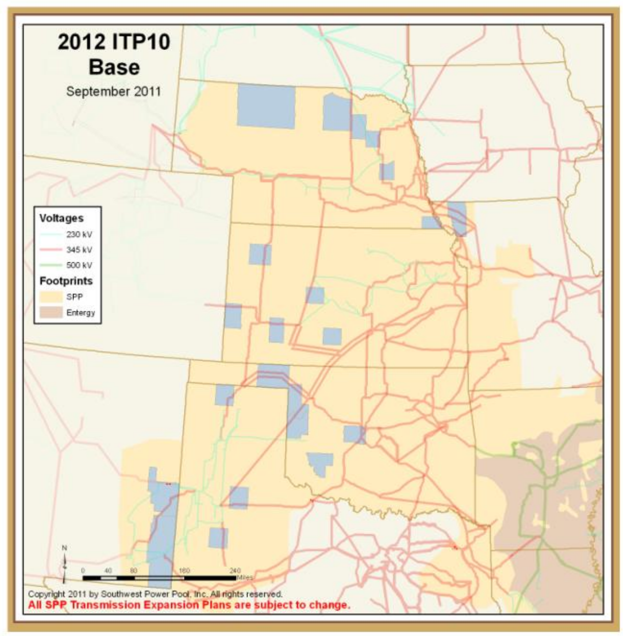


Figure 6.1: Potential Sites for Future Wind Generation

6.5: Projecting Transfer Limitations

Measurement of ATC determined limitations on the system for a range of transfer scenarios. The limiting elements were identified and considered for mitigation with transmission projects. The transfer limitations were used to augment the constraint list for the security constrained economic dispatch and to identify facilities that hinder the various power transfers.

Three sets of transfers were conducted. The first checked for limitations upon transfers within SPP (metric 1.1.2), the second added transfers across the SPP seam (metric 6), and the third took a divergent approach and analyzed the ability to transfer load between the areas (metric 14). Metrics 1.1.2, 6, and 14 demonstrated the affect alternative topology scenarios will have on ATC capabilities within SPP.

See *Section 12.2: Transfer Capability Increases* for the results of these metrics due to the finalized portfolio.

[22] Note that the individual wind farms added in this study are separate from requests submitted to the SPP Generator Interconnection Queue. The level of study used in the 2012 ITP10 does not include the rigor needed for a true GI study. It should not be inferred from these results that wind can be readily developed at any of the locations specified. Generator Interconnect studies would be required per SPP tariff.

Metric 1.1.2: Value of Improved Available Transfer Capabilities

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. Transfers were studied for all possible permutations of the SPP areas with each area serving as an individual point of receipt and point of delivery.

Metric 6: Limited Export/Import Improvements

Metric 6 quantified the change in ATC resulting from the addition of the projects in the finalized portfolio. Three categories of ATC changes were of interest and were addressed by this metric:

- From areas within SPP to areas on the boundary of SPP. This category related to export capability improvements. This included all possible permutations of transfers between SPP areas and areas in Tier 1.
- From areas on the boundary of SPP to areas within SPP. This category relate to import capability improvements. This included all possible permutations of transfers between SPP areas on the SPP border and areas in Tier 1.
- From areas on the boundary of SPP to other areas on the boundary of SPP. This category related to improvements in the ability of SPP to accommodate wheel-through transactions. This included all possible permutations of transfers between areas in Tier 1 and other areas in Tier 1.

Metric 14: Ability to Serve New Load

Metric 14 measures the ability of additional transmission projects and the finalized portfolio to serve new load at levels that are different from those considered in the DC and AC simulations. The metric was used to test load shifts between major load centers within the SPP footprint. The load centers were selected utilizing the SPP GIS system and defined on a bus level. Each load center was selected from load density contours indicated concentrations of load at the peak hour. The transfers studied included all possible permutations of transfers between these centers. The increase in transfer capability due to the additional transmission was measured and averaged for the whole footprint. Table 6.1 lists the cities associated with each of the load centers. The load centers included the surrounding areas outside of each of these cities where load was concentrated.

Fayetteville, AR	Shreveport, LA
Kansas City, MO	Springfield, MO
Lubbock, TX	Tulsa, OK
Oklahoma City, OK	Wichita, KS
Omaha, NE	Amarillo, TX

Table 6.1: City/Regions utilized in Metric 14

6.6: Determining Project Need Dates

Individual projects within the recommended portfolio (see *Section 10: Finalized Portfolio*) provided three kinds of benefits (reliability, economic, and policy). However, for the purpose of staging, the primary benefit provided by each project was selected as the trigger for each project's need by date. The staging was determined on an individual project basis with the needs for and the benefits of each project interpolated from the DC simulations of 2022 and an additional DC simulation expressly developed for 2017 to aid in the staging decisions. All projects were identified in service by 1/1/2022. Project lead times were determined according to historical expectations and reviewed by stakeholders.

Filtering of Future Specific Projects

Simulations performed upon each future yielded different transmission projects (see *Section 8: Projected System Behavior* for details). The selection of projects included in the final portfolio followed these guidelines:

- Reliability projects that were common to both futures and those that relieved an overload above 100% in one future and experienced loading above 95% in the other future
- Economic projects that relieved system congestion in both futures, and had a benefit to cost ratio greater than 1.25 in Future 1
- Policy projects that allowed the region to meet each futures' policy requirements

Projects that were identified in the analysis, but did not meet these criteria were not included in the finalized portfolio.

Staging Reliability Projects

Reliability projects were staged between 2018 and 2022 since the 2012 ITPNT determined upgrades through 2017.

The process used to stage these projects utilized DC models representing the peak hour in Future 1 for two years: 2017 and 2022. The need date for each project was based upon the increase in MW flow for each year, interpolated from the 2017 and 2022 models, upon the primary reliability need mitigated by each project. This increase was applied to the Future 1 reliability scans. The year in which the increase caused the loading of the overloaded facility to exceed 100% loading was identified as the need date. Figure 6.2 provides an example of this process.

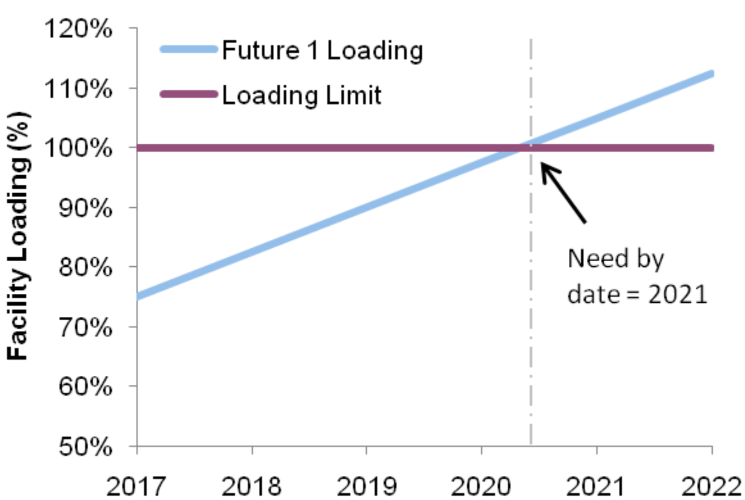


Figure 6.2: Reliability Project Staging Example

Upgrades that relieved an overload above 100% in one future and loading at or above 95% in the other future were staged for the year 2022. Due to shorter lead times, capacitor additions were staged in 2022 since the projects can be advanced if the need is identified in future ITPNT analyses.

Two transmission line upgrades in the final portfolio were identified as a result of voltage issues only. These upgrades were staged using the 2012 ITP10 Future 1 AC case and the 2012 ITPNT 2017 summer and MDWG build 2 light load case.

Staging Economic Projects

The security constrained economic simulation was used to perform a production cost analysis for the years 2017 and 2022 using the Future 1 model. The benefit to cost ratio (B/C) for these two years was determined for each of the economic upgrades in the final portfolio. The incremental benefit of each economic project was calculated with the project considered in addition to the reliability projects. The change in the B/C over time was interpolated from the two points in order to determine the staging dates. Economic upgrades were given an in-service date for the first year that their B/C was greater than 1.0 in Future 1. Figure 6.3 provides an example of this process.

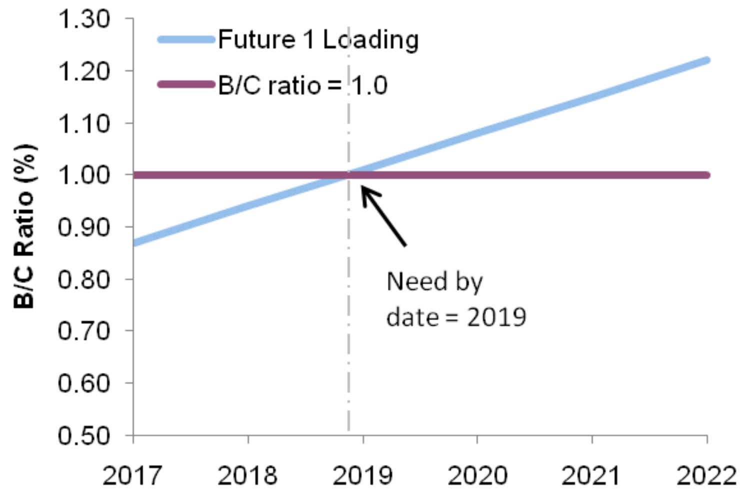


Figure 6.3: Economic Project Staging Example

Staging Policy Upgrades

Policy projects were staged based upon the projected development of wind outlined in the CAWG Renewable Survey from April 2011. The survey indicated 80% of the Future 1 wind (approximately 8 GW for the SPP footprint) is targeted to be in-service by 2017. Note that this amount of wind is about double the amount of wind generation capacity that is currently in service or under construction in SPP.

6.7: Measuring Economic Value

The monetized benefit was measured during several phases of the study. Initial screenings were performed in order to determine which suggested economic projects might provide value, more thorough screenings of the projects in both futures were utilized to narrow the focus between similarly situated projects, project groupings were measured to identify the impact of the groupings upon the economic benefit, and finally the economic benefit of the finalized portfolio was calculated for each future and for several sensitivities. The calculation of the monetized benefit included four key aspects: 1) APC, 2) reduced losses, 3) reduced capacity costs, and 4) reduction of emissions rates and values.

The calculation of these benefits was primarily conducted on the incremental addition of projects of a chiefly economic nature but was also reported for reliability projects, policy projects, and the finalized portfolio as a whole.

Calculation of 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 is determined from using a production cost modeling tool that accounts for hourly commitment and dispatch profiles for one simulation year. The calculation, performed on an hourly basis, is as follows:

$$\textit{Revenue from Sales} = \textit{MW Exported x Zonal LMP}_{\textit{Gen Weighted}}$$

$$\textit{Cost of Purchases} = \textit{MW Imported x Zonal LMP}_{\textit{Load Weighted}}$$

APC captures the monetary cost associated with fuel prices, run times, grid congestion, ramp rates, energy purchases, energy sales, and other factors that directly relate to energy production by generating resources in the SPP footprint.

Metric 1.3: Reduced Losses

Metric 1.3 was used to capture the change in total system losses due to the finalized portfolio. The losses were calculated for each hour of the DC simulation. The difference in production costs due to the change in losses were reflected in the APC calculation. The reduction in capacity capital costs associated with these losses were not captured by this metric or in the APC calculations. This value was captured through the use of Metric 1.6.

Metric 1.6: Reduced Capacity Costs

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. This value was monetized using the savings in capital attributed to the corresponding reduction in installed capacity requirements.

Metric 10: Reduction of Emissions Rates and Values

The APC calculation captured the cost savings associated with reduced SO_2, NO_X, and CO_2 emissions because the allowance prices for these pollutants are inputs to the production cost model simulations. The quantified changes in SO_2, NO_X, and CO_2 emissions were measured and reported in addition to the APC results in order to provide further insight into system expectations.

Methodology for Calculating Economic Benefit Incremental to Reliability

The ESWG considered various methods of capturing the economic value of projects identified in the 2012 ITP10 and directed that the incremental cost and benefit of economic projects above and beyond reliability and policy projects be reported. The methodology for this calculation is outlined in Figure 6.4 and includes treatment of the APC savings, project deferment, and carrying charges associated with economic projects. The calculation assumes that all of the reliability and policy projects are in-service (the base case) and measures the benefit of adding the economic projects to the system (the change case).

The base case included projects with NTCs and reliability projects identified in the 2012 ITPNT and 2012 ITP10, the change case included those same projects minus deferments plus economic projects identified in the 2012 ITP10.

Deferments were identified for any economic project that mitigated the need identified for a reliability project. The value of the deferment was equal to the estimated ATRR associated with the deferred reliability project.

$$\frac{\text{benefit}}{\text{cost}} = \frac{\text{change case}_{apc} - \text{base case}_{apc} + \text{deferment}_{ATRR}}{\text{economic}_{ATRR}}$$

Reliability & Policy Projects

- Includes transmission added for 2012 ITP10 reliability projects, policy projects, and 2012 ITPNT
- Based on peak and off-peak analyses
- Includes 2010 STEP projects
- Does not include economic projects

Incremental Economic Projects

- Includes incremental economic projects
- Removes deferred 2012 ITP10 reliability and policy projects
- Includes transmission added for 2012 ITP10 reliability projects, policy projects, and 2012 ITPNT
- Includes 2010 STEP projects

Figure 6.4: Economic Benefit Incremental to Reliability

PART II: STUDY FINDINGS

Section 7: Benchmarking

Numerous benchmarks were measured to ensure the accuracy of the data produced in the planning simulations. In order to complete the 2012 ITP10 benchmarking effort, a model was developed that reflected transmission in-service as of 2010 and simulation results from that economic model were compared with historical statistics and measurements from the SPP real time data, NERC data and the Energy Information Administration data. The goal of the benchmarking was to provide reasonability checks of the study data.

7.1: Generator Operation

Capacity Factor by Unit Type

Comparison of annual capacity factor is a method for measuring the similarity in planning simulations and operational situations. In addition, capacity factor checks provide a quality control check of differences in modeled unit outages for nuclear units and assumptions regarding renewable, intermittent resources.

When compared with capacity factors as tracked by the EIA for 2007 and previous years, the capacity factor by unit category fell within or near expected ranges. A difference in fuel price assumptions[23] from the actual gas prices in 2007 drove the higher capacity factors for the coal and lower ones for the gas units. Part of the difference is also due to the difference between the unit categories reported to the EIA and those available within the 2012 ITP10 models.

Capacity factors for the 2012 ITP10 were derived from the PROMOD® report agent software. The average capacity factors from the EIA are from the EIA Electric Power Annual for 2005 – 2009 and can be found on the EIA website[24]. The capacity factor from the EIA includes other renewables such as biomass and solar and reflect data submitted by utilities across the Eastern Interconnect.

Unit Category	2012 ITP10 Capacity Factor	EIA Capacity Factor Range
Nuclear	96%	89 – 92%
ST Coal	75%	64 – 74%
Wind	42%	40 – 47%
Combined Cycle	40%	37 – 42%
Hydro	34%	36 – 42%
ST Gas	6%	10 – 11%
CT Gas	2%	10 – 11%

Table 7.1: Benchmarking the Capacity Factor by Unit:

Generation by Unit Category

The share of generation by category throughout the footprint is a basic foundation for measuring the benefits of additional transmission. This generation mix will change as fuel price and congestion vary in the economic dispatches and will drive changes to the APC for each area in SPP.

The generation mix presented in the simulations was in-line with expectations. When compared with last year's generation mix, the share of generation apportioned to each unit category were within an

[23] The benchmarking focused upon the year 2010, while available data for comparison with the EIA was only available for 2007.

[24] eia.gov > Electricity > Electric Power Annual > Average Capacity Factors by Energy Source

acceptable range. A difference in fuel price assumptions from the actual gas prices in 2010 drove the bigger dispatch in coal units in the simulation than in historical data. Coal and combined cycle gas generation sources provided 79% of the total generation in the simulation. Historically, according to the EIA, these sources provided 77%.

Total generated energy by unit category for the 2012 ITP10 were derived from the PROMOD® report agent software for the year 2010. Historical generation output was approximated from EIA-923 data and can be found on the EIA website. Figure 7.1 illustrates the percentage of generation share (by energy) for each unit type.

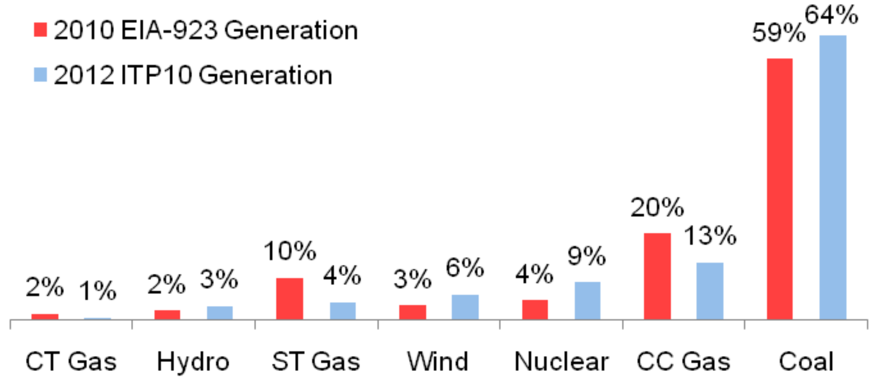


Figure 7.1: Benchmarked Unit Generation by Category

Maintenance Outages

Generator maintenance outages in the simulations were compared with statistics available through the NERC Generating Availability Data System. The proper reflection of generator outages is important to the study because of the direct impact these outages have on flowgate congestion, system flows and the economics of following load levels.

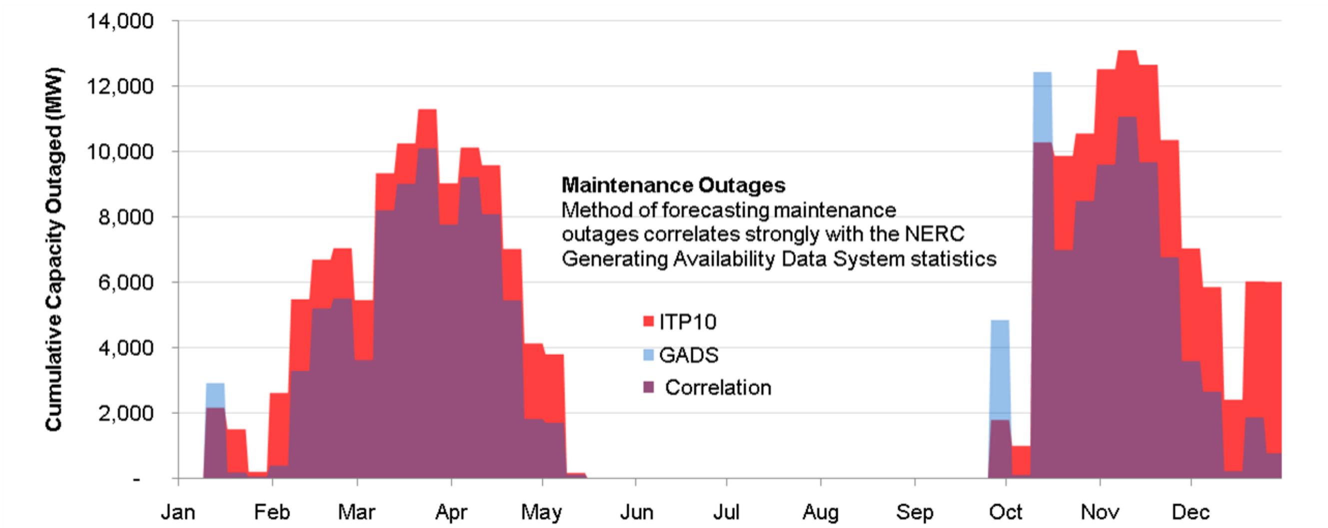


Figure 7.2: Benchmarking Maintenance Outages

Economic Determination of Maintenance Outages

The economic analysis simulates when units will be placed on maintenance outages by analyzing the load needs of each area in the modeled footprint versus what generation would be required to be available to meet those needs. Because these calculations are optimized for economics and satisfaction of load requirements, the maintenance time periods are grouped heavily in the spring and fall months.

Operating & Spinning Reserve Adequate

Operational Reserve is an important reliability need that is modeled to account for capacity that might be needed in the event of a unit contingency. SPP Criteria requires any interconnected unit to supply up to14.7% of its capacity to meet reserve requirements for the reserve sharing footprint. Simulation data matches the requirements set forth by SPP criteria of capacity equal to the largest unit in SPP + 50% of the next largest unit. 50% of this operating reserve must be spinning reserve. PROMOD® reports any unit not on maintenance as available for reserve if it meets the criteria for spinning or quick start. Figure 7.3 shows the quick start and spinning reserve that was available in the benchmarking runs. It far exceeded the requirement.

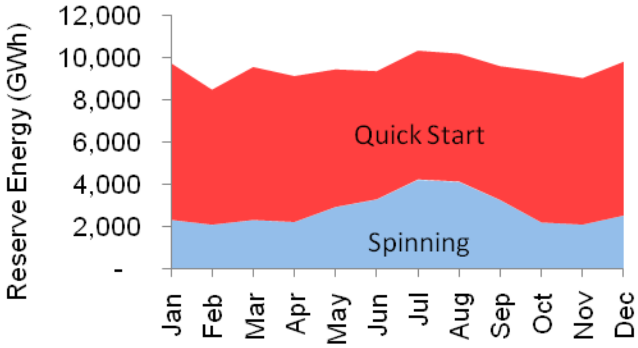


Figure 7.3: Spinning Reserve Adequate

Coal Transportation Costs

The comparison of transportation costs within the model was necessary to ensure that reasonable fuel prices are reflected at the coal plants within the model. A standard linear relationship between the distance of a plant from its coal source was used to simulate reasonableness in fuel prices between coal plants. The outlying data points (four were identified) within the model set were corrected to coincide with an average cost per mile of 0.16¢. Costs for other plants were brought in line with this average for consistency. This information was gathered directly from the Powerbase® tool that was used to model the system. GIS information from SPP's modeling department was utilized to determine the "as the crow flies" distance from each plant to the plant's sourcing mine (Powder River Basin in all cases).

7.2: Reasonable System LMPs

Benchmarking was done on one of the economic model outputs, average Locational Marginal Prices (LMPs) by Area. Figure 7.4 compares the average monthly price of energy in the 2010 EIS market, as well as the 2008 and 2009 EIS market, to the average monthly bus LMPs of the 2012 ITP10 benchmarking runs. This check is important because close correlation between actual LIPs and simulated LMPs for the year benchmarked should exist if the simulations portray SPP accurately.

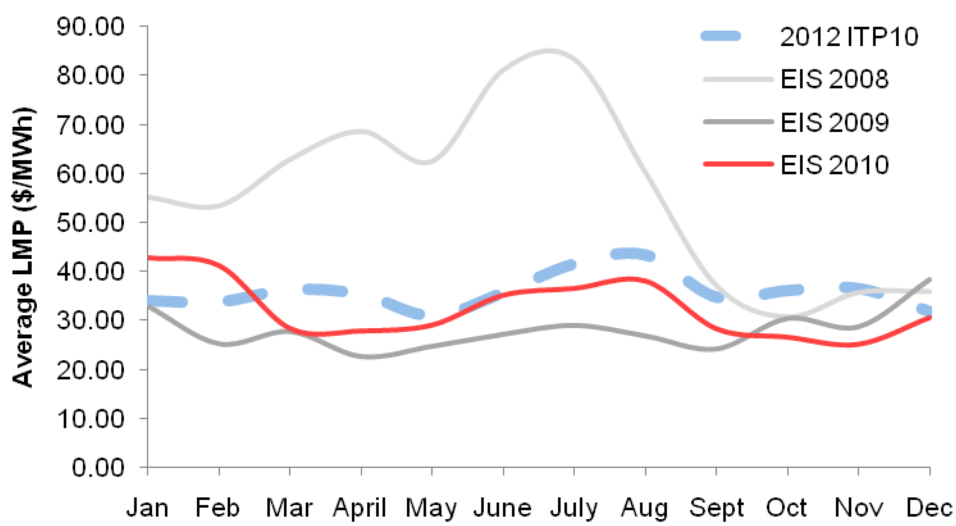


Figure 7.4: Benchmarking LMPs

Historical prices were provided by SPP's Market Monitoring group, simulated LMPs were derived from the PROMOD® report agent software. Based on this data, it was determined that the average LMP for each area in the 2012 ITP10 benchmarking simulations lies within a reasonable bandwidth of the historical trends.

Forecasted LMPs for 2022 Simulations

A simulation of 2022 was conducted and the market prices for that time-frame compared with a current SPP Monthly State of the Market Report. The results indicated that prices seen in the 2022 simulation were higher than in the operations horizon. This was consistent with an expectation that increases in energy usage and fuel price will drive market prices upward.

	Avg. Price	Max Price	Min Price	Avg. On-Peak Price	Av. Off-Peak Price
2010 EIS – State of the Market	$33.17	$ 144.27	$10.64	$38.45	$26.39
2012 ITP10 Future 1	$38.79	$132.10	($17.05)	$45.41	$27.75
2012 ITP10 Future 2	$54.56	$116.87	$32.28	$58.37	$48.21

Table 7.2: Regional Market Prices (values in real dollars)

Section 8: Projected System Behavior

Regions with Notable Behavior

Evaluation of each future from the varied perspectives outlined in *Section 6: Analysis Methodology* was completed. The findings are presented here for violations and congestion that spurred each of the projects in the final portfolio. These observations and suggested mitigations fueled the development of the final portfolio, but not all of the projects listed here were ultimately selected.

8.1: System Behavior

Reliability, Economic, and Policy needs were identified in five regions of the SPP footprint. Individual projects (efficiencies were identified and capitalized upon in the next step of the analysis) were targeted to meet the various system needs outlined in the sections that follow. The needs identified for the SPP footprint fell into these five geographic regions: Northeast Texas, Oklahoma, West Texas, East Kansas & Missouri, and Nebraska. The identified needs and projects to mitigate the needs are summarized on pages 49-55 with one page dealing with each geographic area.

Interpreting the Map Nomenclature

The figures shown in this section utilize five indicators that highlight the congestion, criteria violations, and wind sites in each geographic region. Congestion corridors are shown with a chevron (») pointed in the direction of the flow and represent the results of the DC simulations. Thermal overloads are highlighted with both blue and red colors for the **overloaded** and **contingency** elements and represent the results of the AC simulations. Wind counties are emphasized with a blue background. Voltage violations are indicated with a **V** on the map next to the low or high voltage buses.

Treatment of Unique Future Results & Identification of Efficiencies

Needs were identified on a future specific basis. In many cases the needs identified for Future 1 were also identified for Future 2. Future 2 needs specifically focus on those that were unique to Future 2. The analysis provided insight into opportunities to meet needs in the same region with a regional project that could also fulfill reliability, economic and policy needs in lieu of several smaller projects. Of particular note, the Oklahoma region showed significant opportunities to avoid smaller reconductor projects by creating another 345 kV path from Woodward to Oklahoma City.

F1	Actual	Target	% of Target
KS	6,471	7,523	
MO	687	701	
NE	3,777	4,467	
NM	2,893	2,981	
OK	11,023	11,567	
TX	9,875	10,229	
SPP	34,726	37,467	

F2	Actual	Target	% of Target
KS	10,403	11,562	
MO	-	-	
NE	6,147	8,506	
NM	4,332	4,596	
OK	13,879	15,605	
TX	11,479	12,652	
SPP	46,240	52,922	

Table 8.1: Wind Energy and Targets (GWh)

Wind Curtailment

The counties with projected wind farms (listed in *Section 17.5: Wind Interconnection Summary*) highlighted with a blue background on the following pages, were found to have adequate transmission capacity in order to connect the wind levels proposed in Future 1 and Future 2 with a few notable exceptions. Those located in Banner Co., NE, Cherry Co., NE, and Kiowa Co., OK experienced significant curtailment due to thermal limits, market congestion, and stability limits. These factors signaled the need for transmission expansion in the area in order that the wind requirements of each future might be met. Table 8.1 shows the wind output and targets for each state and for the region. Wind energy output for the region fell 7% short of the target in Future 1 and 13% short in Future 2.

Transmission Flows

The map in figure 8.1 indicates the direction of power flow in many parts of the system. In this figure, arrows indicate flows predominately in one direction as indicated by the symbol of three arrows pointing the same way. The predominant flow of power on the constraints in these areas is to the east or to the south for nearly all hours of the year. However, flows in Kansas City, on the Tuco–Border line, and between SPP and Entergy at Fort Smith, AR do have a roughly even number of hours flowing in each direction with only a slight bias one way or the other. These areas have two arrows pointing in each direction.

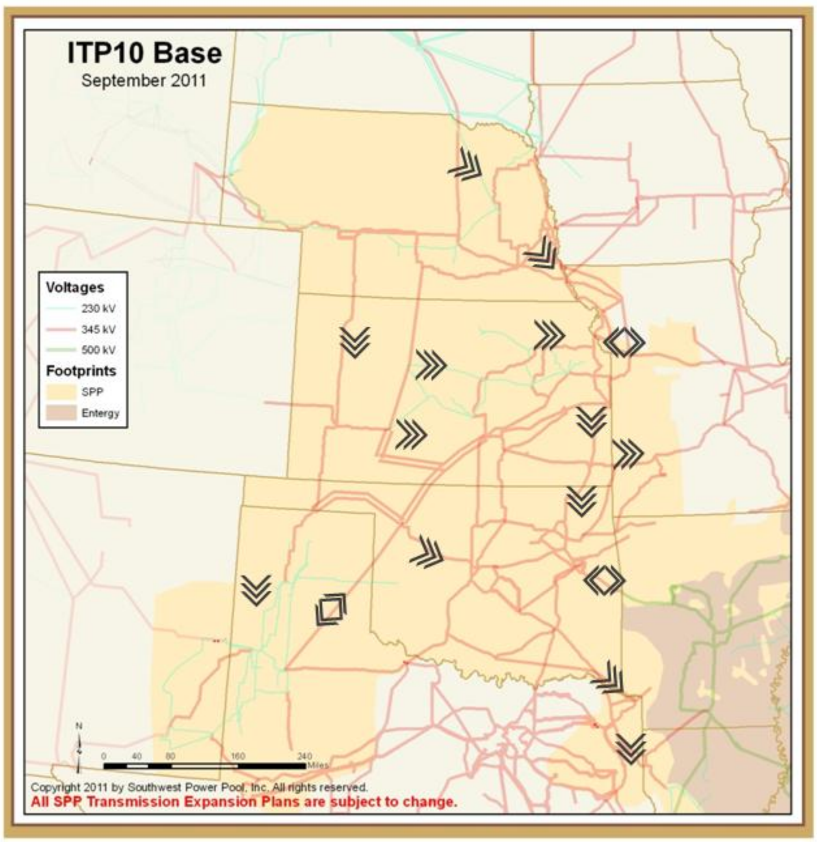


Figure 8.1: Direction of Power Flow

The flow behavior seen on the SPP system, generally from the north to the southeast, has historically been seen in the footprint. One of the factors contributing to this system bias is the the parallel flows imposed on the system due to load and generation outside of the footprint.

8.2: Future 1 System Behavior

Northeast Texas

Several issues were identified for the region west of the Arkansas – Louisiana border in Northeast Texas. Power flowing from the north feeding the load east of Diana created significant flows in one direction. Generation to serve the area from the 345 kV corridor, west of the load, had limited access eastward. Congestion was projected along the Welsh – Diana 345 kV corridor for more than one-third of the study year. Analysis projected this to be the most congested element within the AEP system.

This area is additionally problematic when units are offline for maintenance in the fall and spring – a situation seen in real-time operations (see Figure 2 in the November 2009 and February 2010 State of the Market Reports. SPP.org > Market and Operations > Market Monitoring > Market Reports.)

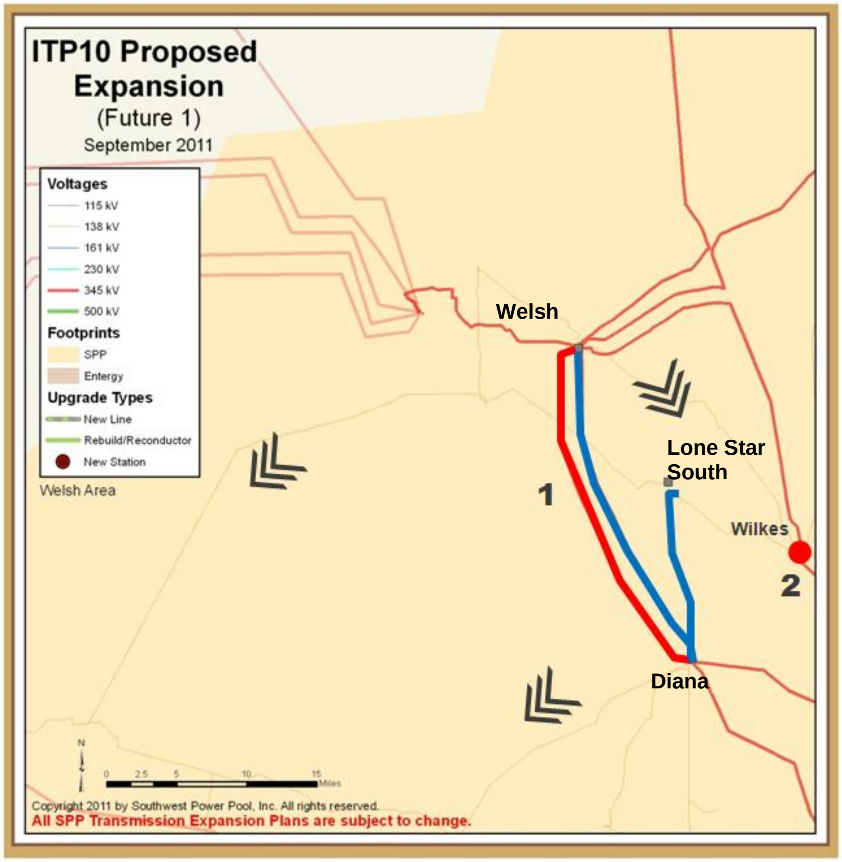


Figure 8.2: Northeast Texas System Behavior in Future 1

Two projects were considered in this area in addition to a 2012 ITPNT project to reconductor Diana – Perdue 138 kV.

Lake Hawkins – Welsh 345 kV

This new line addressed the overload of the Welsh – Diana 345 kV circuit for the loss of the parallel circuit and to address the overload of the Diana - Perdue 138 kV line for the loss of Harrison Road – Liberty City Tap 138 kV and other various contingencies.

Lone Star South – Diana 138 kV reconductor

This reconductor addressed the overload for the outage of Wilkes 345/138 kV transformer. There was only one transformer feeding the 138 kV system at Wilkes. The loss of this device caused more flow to enter the 138 kV system through the three 345/138 kV transformers at Diana, overloading the existing line.

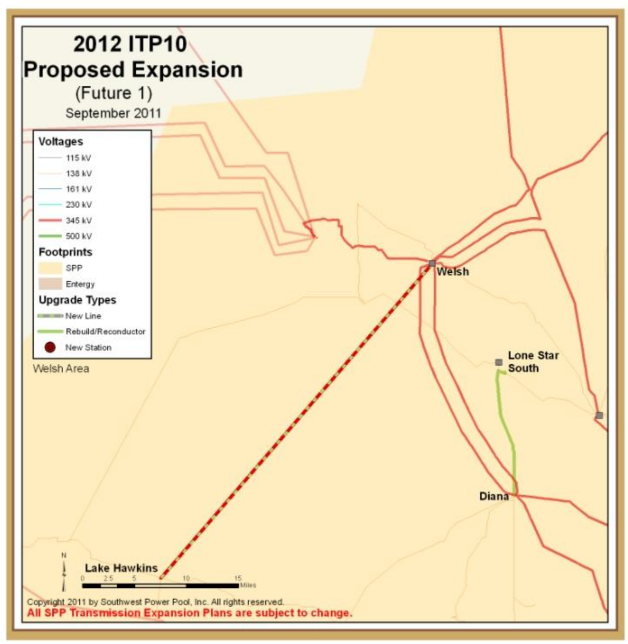


Figure 8.3: Projects Investigated in Northeast Texas

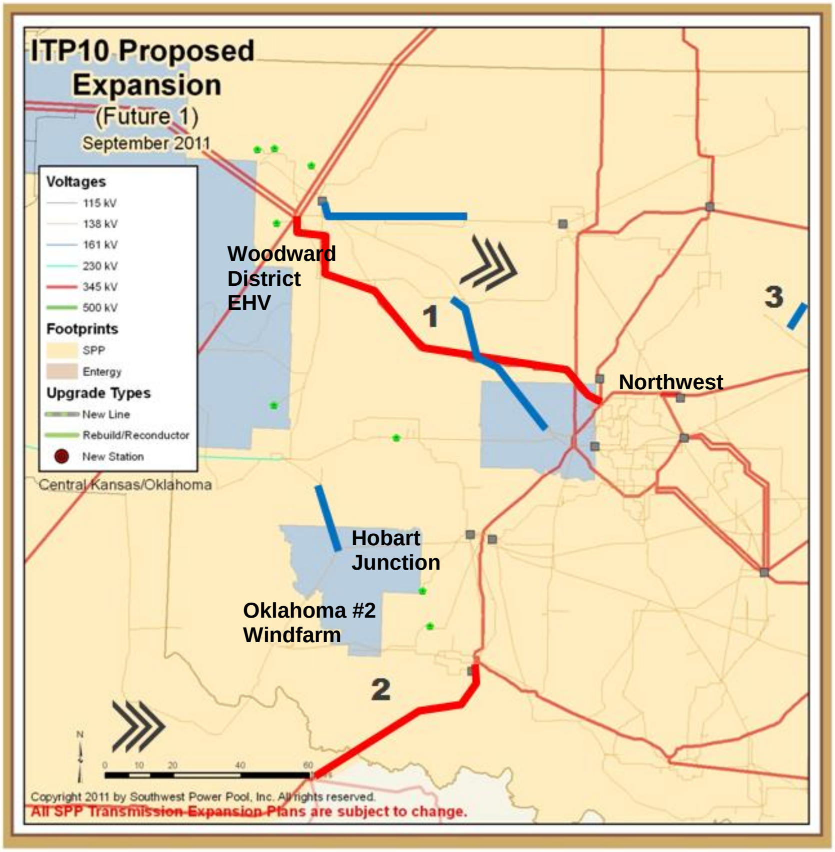


Figure 8.4: Oklahoma System Behavior in Future 1

Oklahoma

Several issues were identified for the region west of Oklahoma City. Significant additions of wind at Woodward (140 MW), Sweetwater (150 MW), and Hobart Junction (129 MW) resulted in thermal limits being exceeded for existing lines going east from Elk City.

Outage of the Woodward District EHV – Tatonga – Northwest 345 kV circuit created overloads throughout the 138 kV system between Woodward and Woodring west of Oklahoma City, OK.

A similar outage of both circuits of the double-circuit line from Woodward District EHV – Thistle creates similar flow on the 138 kV system toward Wichita, KS.

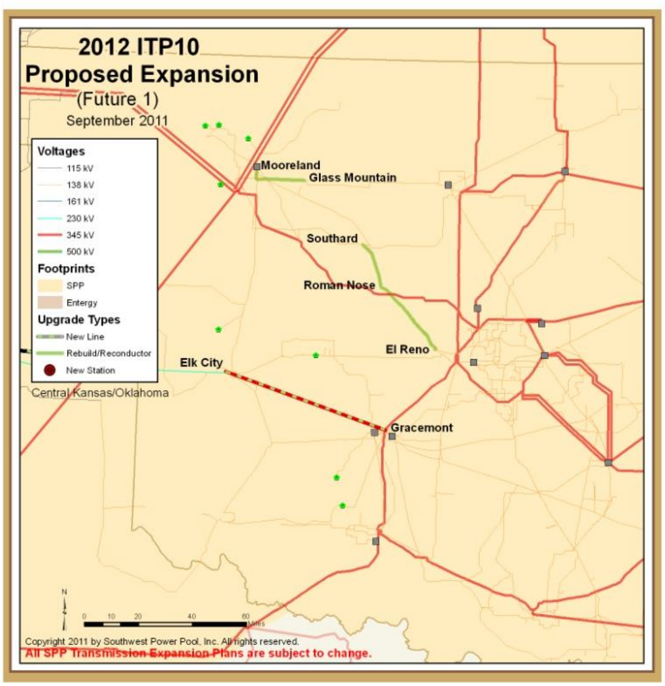


Figure 8.5: Projects Investigated in Oklahoma

<u>Elk City – Gracemont 345 kV</u>

This new line addressed the overload of facilities near the Clinton Air Force Base Tap for the loss of L.E.S. - Oklaunion 345 kV line and other less severe reliability contingencies.

<u>Southard – El Reno 138 kV reconductor</u>

This reconductor addressed the outage of Northwest – Tatonga 345 kV or Tatonga - Woodward District EHV 345 kV and some system intact conditions.

<u>Mooreland – Cleo Corner 138 kV reconductor</u>

This reconductor addressed the overload of Mooreland – Cleo Corner due to multiple outages.

<u>Bluebell – Prattville 138 kV reconductor</u>

This reconductor addressed the overload of Bluebell – Prattville for the loss of Explorer Glenpool – Riverside 138 kV.

West Texas

Several issues were identified for the region south of Lubbock, TX. The most significant congestion on the system was due to the loss of the Grassland Interchange – Jones Station Bus circuit 2 230 kV.

Some of the highest average shadow prices for the footprint were seen for this outage and for the loss of either 230/115 kV transformer at Tuco.

Several transformers were required in the area to provide service to the 115 kV and 230 kV systems.

Four projects were considered in this area:

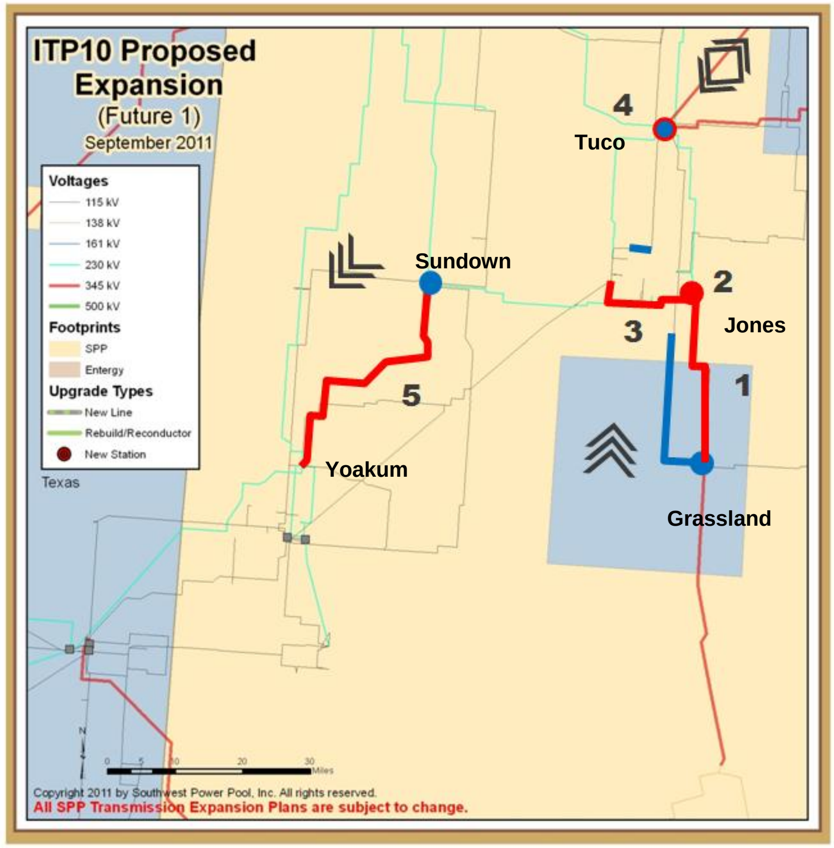


Figure 8.6: West Texas System Behavior in Future 1

<u>Tuco – Amoco – Hobbs 345 kV</u>

This new line mitigated the overload of the Sundown 230/115 kV transformer when any segment of Sundown – Yoakum 230 kV was out of service.

<u>Wolfforth – Grassland 230 kV</u>

This new line addressed the outage of Grassland Interchange – Jones Station Bus circuit 2 230 kV and other contingencies.

<u>Tuco – New Sub 345 kV, New Sub – Stanton 115 kV</u>

These new lines addressed multiple transformer overloads in this area of SPS.

<u>Indiana – Stanton 115 kV reconductor</u>

This reconductor addressed the overload of the Indiana – Stanton line due to the loss of the 230 KV line from Carlisle to Tuco interchange.

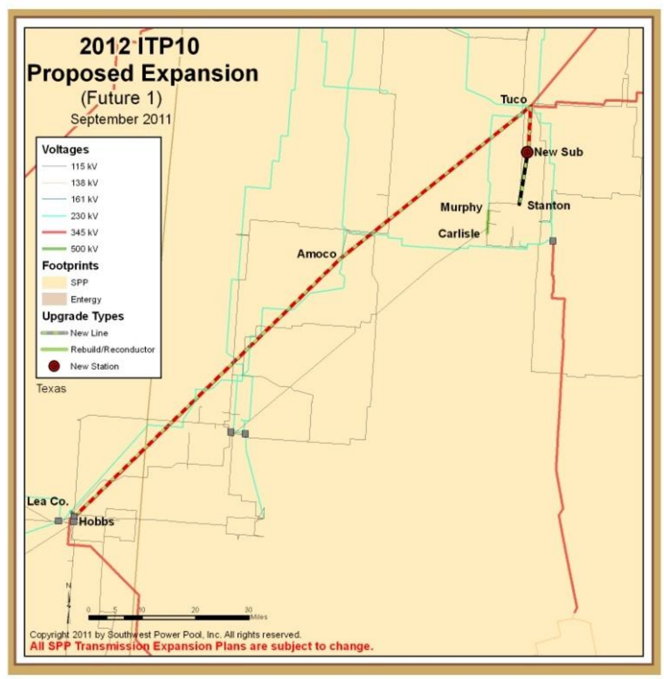


Figure 8.7: Projects Investigated in West Texas

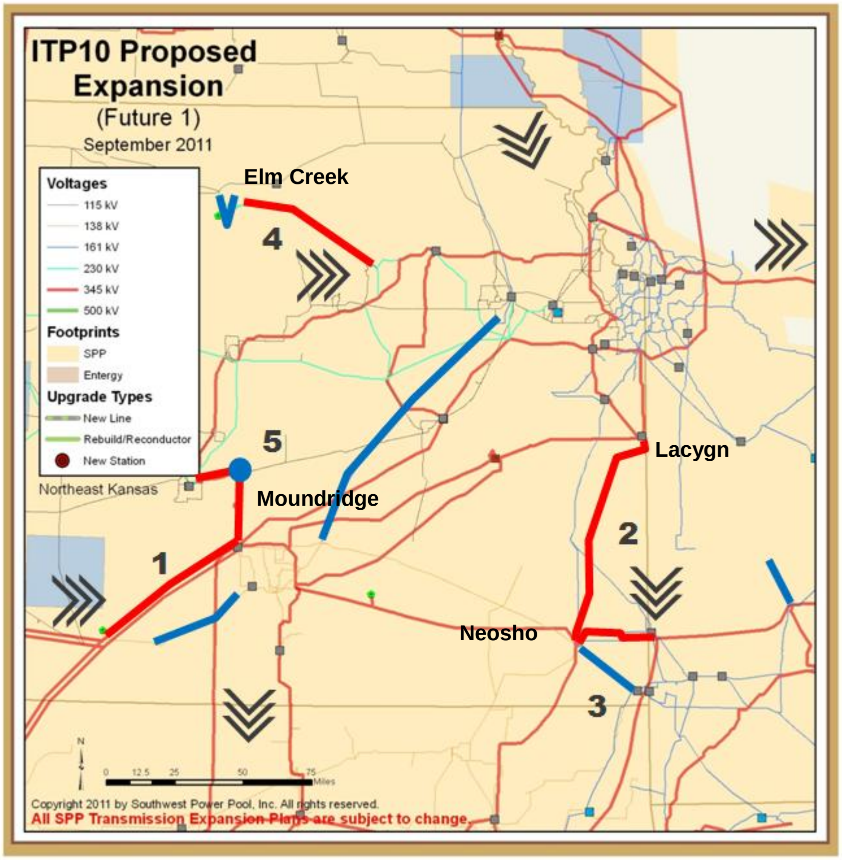


Figure 8.8: Kansas & Missouri System Behavior in Future 1

Kansas & Missouri

Many issues were identified for the east portion of the state of Kansas. The majority of these issues were related to congestion on the following constraints rather than criteria overloads. The number for each item listed below corresponds with those on the map.

1) Harper – Clearwater for the loss of (ftlo)
   Thistle – Wichita
2) Tecumseh – Midian &
   Stockton – Morgan ftlo
   LaCygne – Neosho
3) Neosho – Riverton ftlo
   Neosho – Blackberry
4) Voltage Collapse ftlo
   Elm Creek – JEC
5) Moundridge XFMR ftlo
   Reno Co. – Wichita

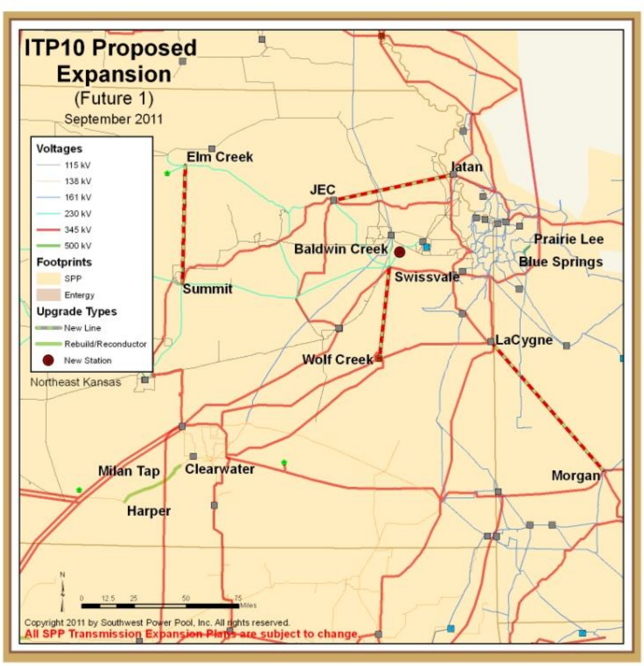


Figure 8.9: Projects Investigated in Kansas & Missouri

<u>LaCygne – Morgan 345 kV</u>

This line relieved congestion due to the loss of the LaCygne – Neosho or Neosho – Blackberry 345 kV lines.

<u>Swissvale – Wolf Creek 345 kV</u>

This line addressed congestion between Tecumseh & Midian for the loss of the LaCygne – Neosho 345 kV.

<u>Elm Creek – Summit 345 kV</u>

This new line addressed voltage collapse at Elm Creek 230 kV for the loss of the Elm Creek - Northwest Manhattan 230 kV line.

<u>JEC – Iatan 345 kV</u>

This new line relieved congestion due to the loss of the Hoyt – JEC 345 kV line.

<u>Baldwin Creek 230/115 kV transformer</u>

This transformer addressed the overload of Lawrence Hill 230/115 kV transformer for the outage of Lawrence Hill-Midland Junction 230 kV.

Western Nebraska

The elements that were overloaded or congested were driven by several contingencies across the state of Nebraska. The number for each list item corresponds with those on the map.

1) Neligh – Battle Creek – Norfolk Corridor ftlo
   Gentleman – Grand Island
   (multiple outages)
2) Bloomfield – Gavins Pt. ftlo
   Battle Creek – Norfolk
   Petersburg – Albion
   (multiple outages)
3) Ft. Randall – Spencer ftlo
   Ft. Thompson – Grand Island
   (multiple outages)

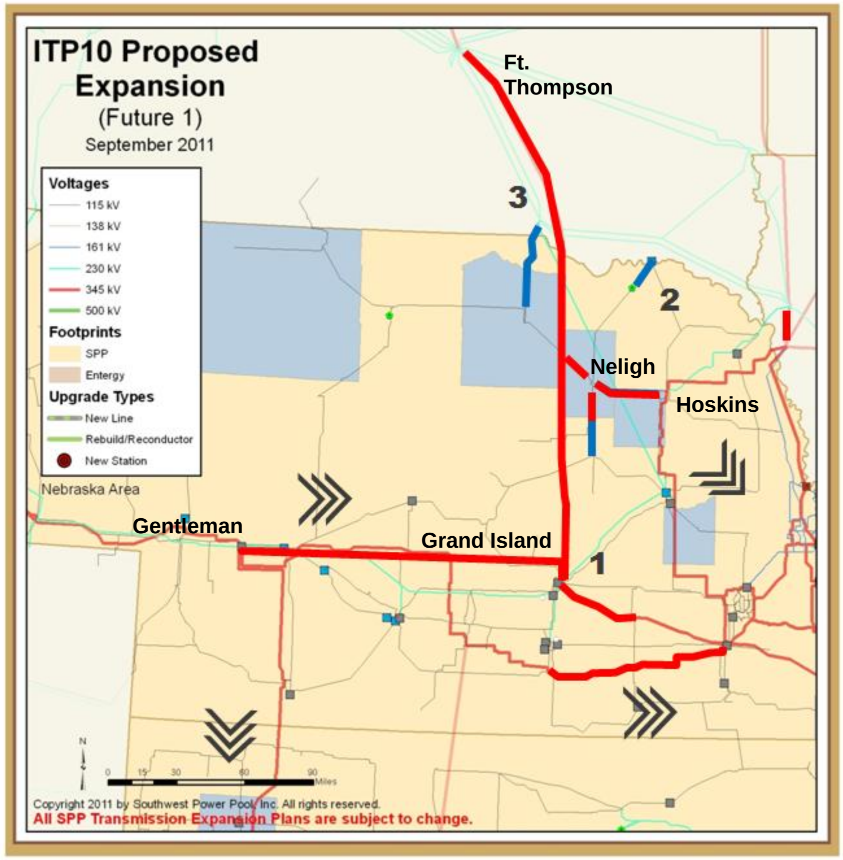


Figure 8.10: Western Nebraska System Behavior in Future 1

Many projects were considered in this area.

Neligh – Hoskins 345 kV and transformer

This new line and transformer addressed several potential overloads in the Neligh area due to contingencies in the Neligh area. These overloads occured primarily in the off-peak hours. The overloads upon the WAPA owned lines occured on peak.

Gentlemen – Cherry Co. – Hoskins 345 kV

This new line enabled wind sited in Cherry County and provided a parallel line to support the west to east corridor in NPPD.

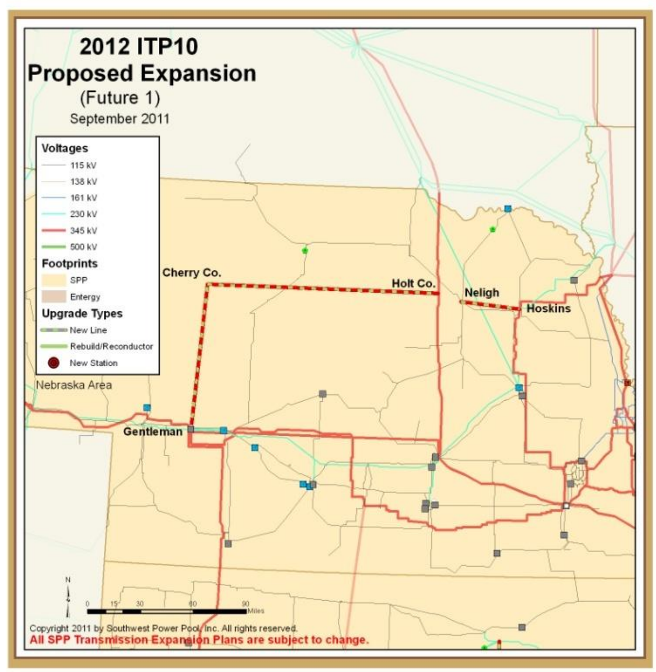


Figure 8.11: Projects Investigated in Western Nebraska

8.3: Future 2 System Behavior

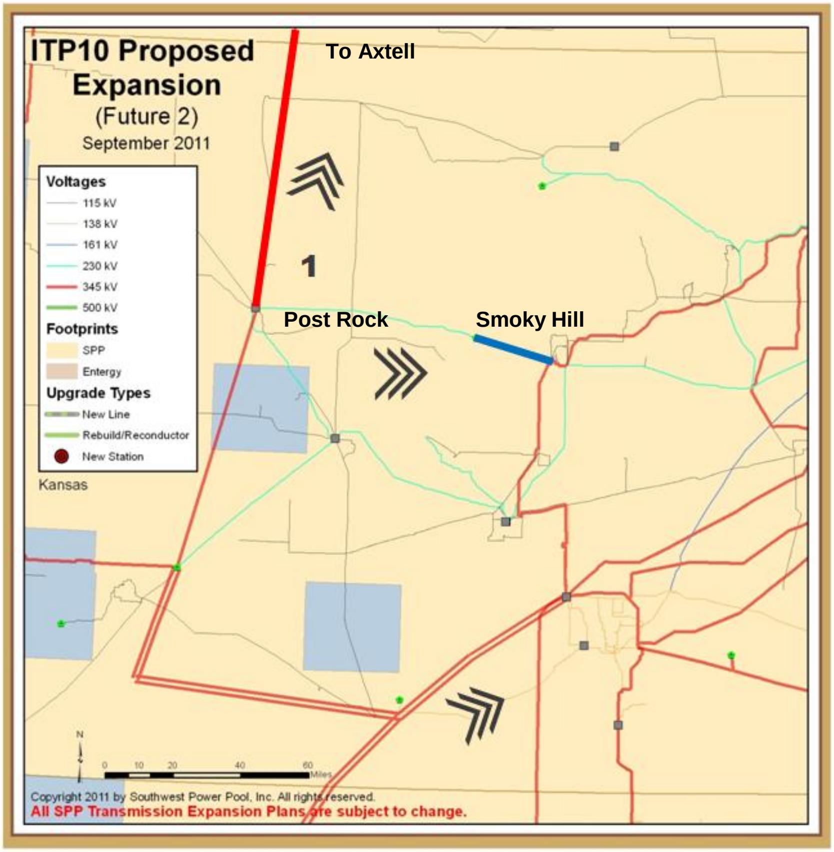


Figure 8.12: Kansas System Behavior in Future 2

Kansas

In addition to the needs identified in Future 1 analysis a significant overload was identified along the 230 kV corridor between the 345 kV stations at Post Rock and Summit. The number for each list item corresponds with those on the map.

1) Smoky Hill – Summit ftlo Post Rock – Axtell (multiple outages)

One project was considered for this overload.

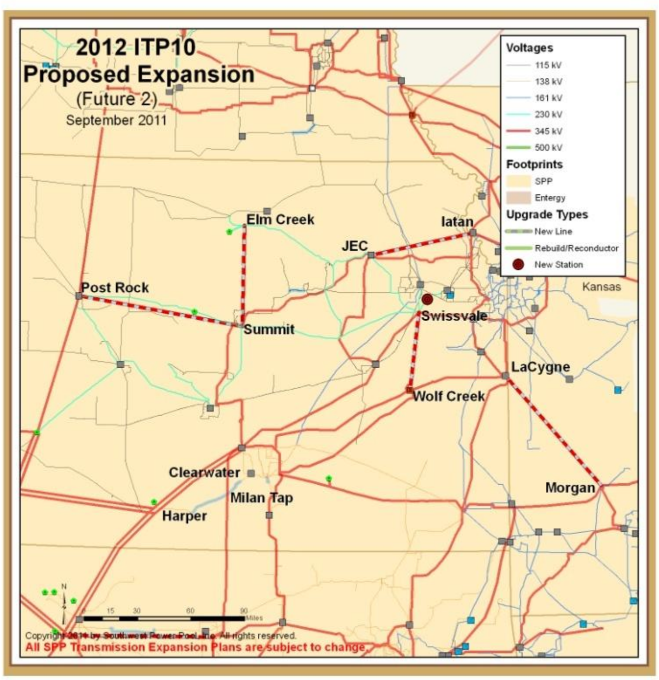


Figure 8.13: Projects Investigated in Kansas

Post Rock – Summit 345 kV

This new line addressed the thermal overload of the 230 kV line running east-west from Summit to Hays when the Post Rock – Axtell line was out of service.

Eastern Nebraska

In addition to the needs identified in Future 1 for western Nebraska the analysis identified the following overloads on the eastern side of the state. The first of these was influenced by unit retirements, unique to this future, at Fremont. The number for each list item corresponds with those on the map.

1) Fremont – Winslow ftlo Schuyler – North Bend (multiple outages)
2) Harbine – Beatrice ftlo Kelly – South Seneca & Kelly – S1399

Two projects were considered for these overloads.

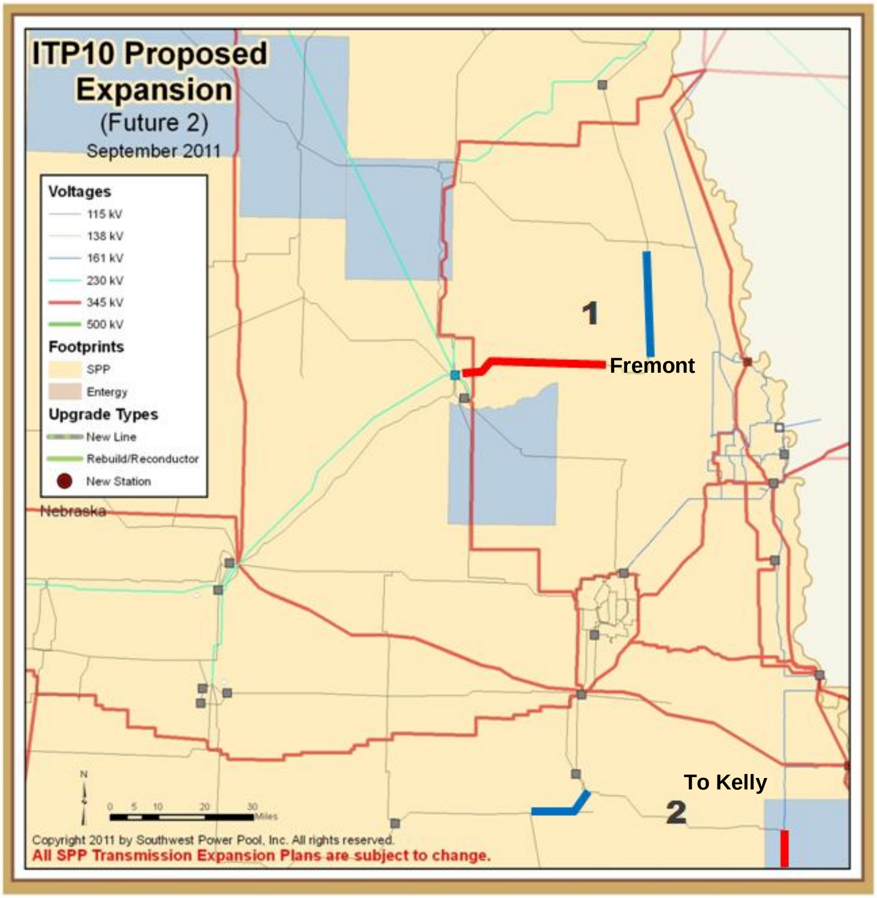


Figure 8.14: Eastern Nebraska System Behavior in Future 2

Ft. Calhoun – Fremont 345 kV

This new line addressed several overloads and voltage issues in the Fremont area due to contingencies in the Fremont area. Note that all but one of the Fremont units was retired in Future 2. When either leg of the 115 kV coming into Fremont was lost, the other overloaded and experienced voltage problems.

Harbine – Beatrice 115 kV reconductor

This reconductor addressed the overload of Beatrice to Harbine for the loss of Kelly – South Seneca 115 kV and Kelly – S1399 161 kV.

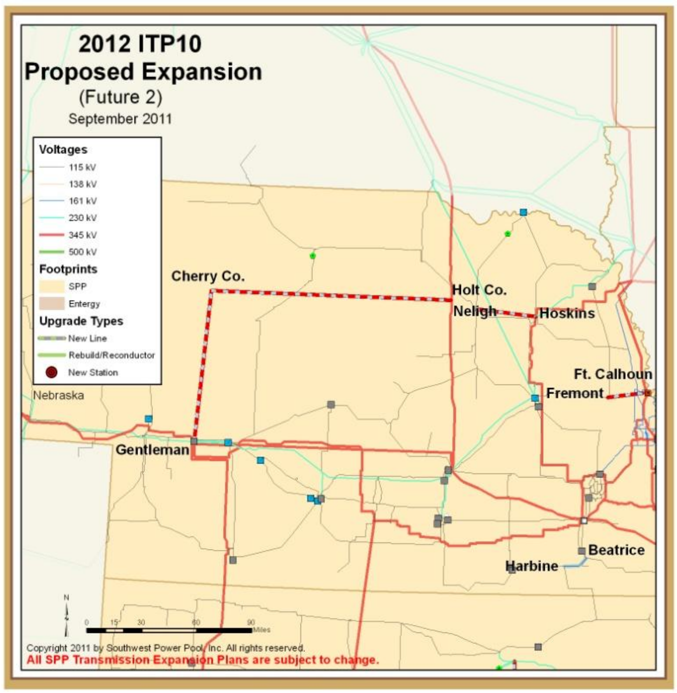


Figure 8.15: Projects Investigated in Nebraska

Preliminary Projects

The preliminary projects identified to address the system behavior outlined above are shown for the footprint in Figure 8.16 and Figure 8.17. These projects were evaluated individually to ensure that the reliability and economic concerns addressed by each project were mitigated.

In sum, the violations and projects identified through the economic, reliability and policy analyses indicated seventeen projects in Future 1 and twenty projects in Future 2 that warranted furthered scrutiny. These projects are shown in Figure 8.16 and Figure 8.17.

The next section of this report, *Part III: Designs & Portfolios* documents the decisions made to develop the final portfolio, discusses the interaction of these projects when considered as part of a whole expansion plan, and provides calculations of the benefits of the finalized portfolio.

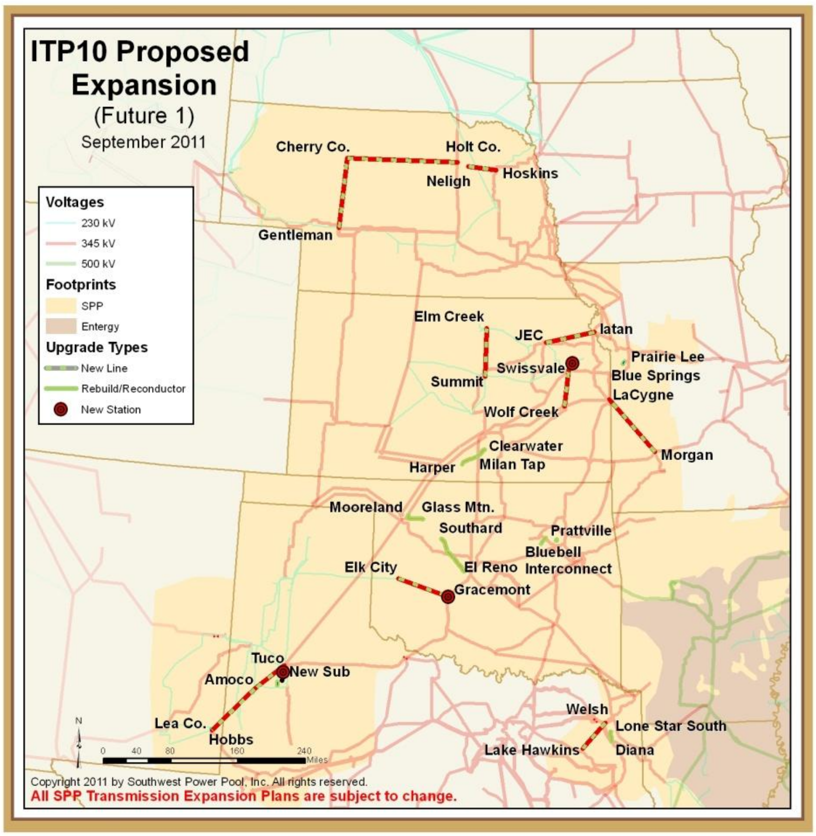


Figure 8.16: Individual Transmission Projects Identified for Further Investigation in Future 1

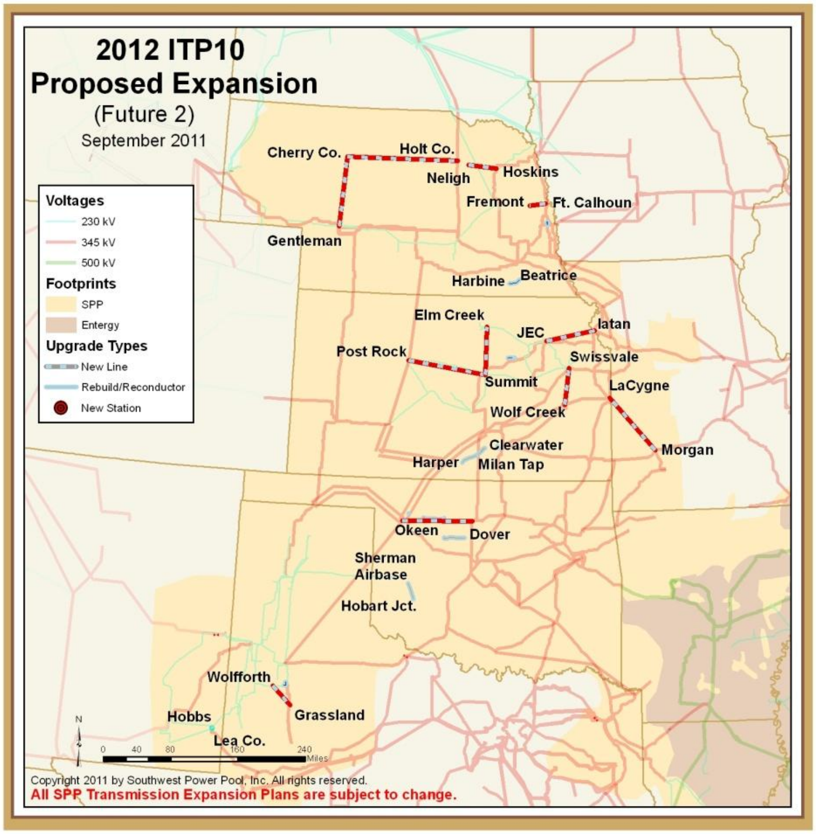


Figure 8.17: Individual Transmission Projects Identified for Further Investigation in Future 2

PART III: DESIGNS & PORTFOLIOS

Section 9: Project Groupings

Grouping of multiple individual projects can have positive effects upon the same congestion and reliability concerns on the grid. In order to find the most efficient manner of mitigating those concerns, the individual projects were combined into preliminary groupings. These groupings illustrate the synergy that occurs between projects that work together, eliminate redundant project cost, and demonstrated how the projects would interact as a whole when considered with all other 2012 ITP10 projects.

Ten preliminary groupings were created from the projects identified and shown in *Section 8: Projected System* Behavior. These groupings were later refined into the final recommended 2012 ITP10 plan. These ten groupings (five for each future) were comprised of individual projects that provided value when studied individually. The criteria for inclusion that create unique groupings are outlined below:

- Preliminary Grouping A: B/Cs greater than 1 and all reliability projects
- Preliminary Grouping B: B/Cs greater than 0.7 and all reliability projects
- Preliminary Grouping C: Projects that were expected to work well together
- Preliminary Grouping D: Projects that address issues on the SPP seam.
- Preliminary Grouping E: Alternative to Grouping A without Wolf Creek projects (see below)

Groupings were designed for each future in order to include projects unique to the reliability needs of that future. The same set of reliability projects were included in each of the groupings for Future 1 and the same set of reliability projects were included in each of the groupings for Future 2. For example, one significant difference between grouping A for Future 1 and Grouping A for Future 2 was the Post Rock to Summit 345 kV line; this project was only needed to address thermal overloads identified in Future 2.

The analysis of Grouping A revealed that at least one of the projects in the grouping was not providing a B/C greater than 1.0. Investigation into the individual projects that made up the grouping revealed that the Wolf Creek - Emporia Energy Center 345 kV line did not prove net beneficial. This project was removed from the grouping to create Grouping E for further analysis of projects that provided B/Cs greater than 1 when considered as part of the grouping. This was the only project that upon inclusion within a group did not prove to fall within the criteria for that group.

Resulting Portfolio

The results of the grouping analysis were further refined following stakeholder feedback and continued analysis. These steps included the development of a portfolio to address the needs of each future in an efficient manner, the continued refinement of termination points, further study of project interactions, and evaluation of economic benefits.

9.1: Preliminary Grouping A (Future 1)

This grouping was constructed of projects that had a preliminary individual B/C ratio of greater than 1.0 in the project screening and any projects identified in the peak and off-peak reliability analyses. Multiple projects qualified under these criteria that met the same objectives. When alternative projects (such as the different options into and out of Wolf Creek) where identified, the one with the highest B/C was included in this grouping.

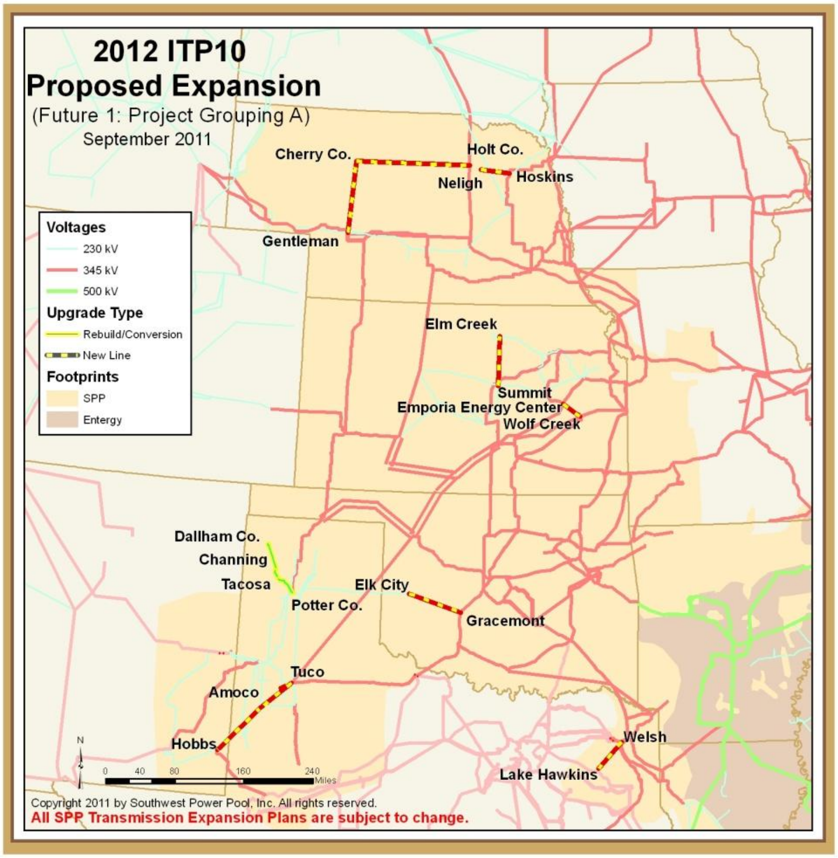


Figure 9.1: Preliminary Grouping A (Future 1)

Projects Grouped that Individually Showed B/C > 1

61 Total Projects

$1.36 Billion ($2011)

345 kV – 736 miles
230 kV – 76 miles
161 kV – 9 miles
138 kV – 129 miles
115 kV – 50 miles

9.2: Preliminary Grouping B (Future 1)

This grouping was constructed of projects that had a preliminary individual B/C ratio of greater than 0.7 in the project screening. Projects identified in the peak and off-peak reliability analyses were included, with the exception of two 138 kV reconductor projects from Glass Mountain to Cleo Corner that were deferred by the Woodward EHV to Woodring 345 kV line. Multiple projects qualified under these criteria that met the same objectives. When alternative projects (such as the different options into and out of Wolf Creek) presented themselves the one with the second highest B/C was included in this grouping to see if its behavior within a portfolio was better than that of the alternative which was included in Grouping A.

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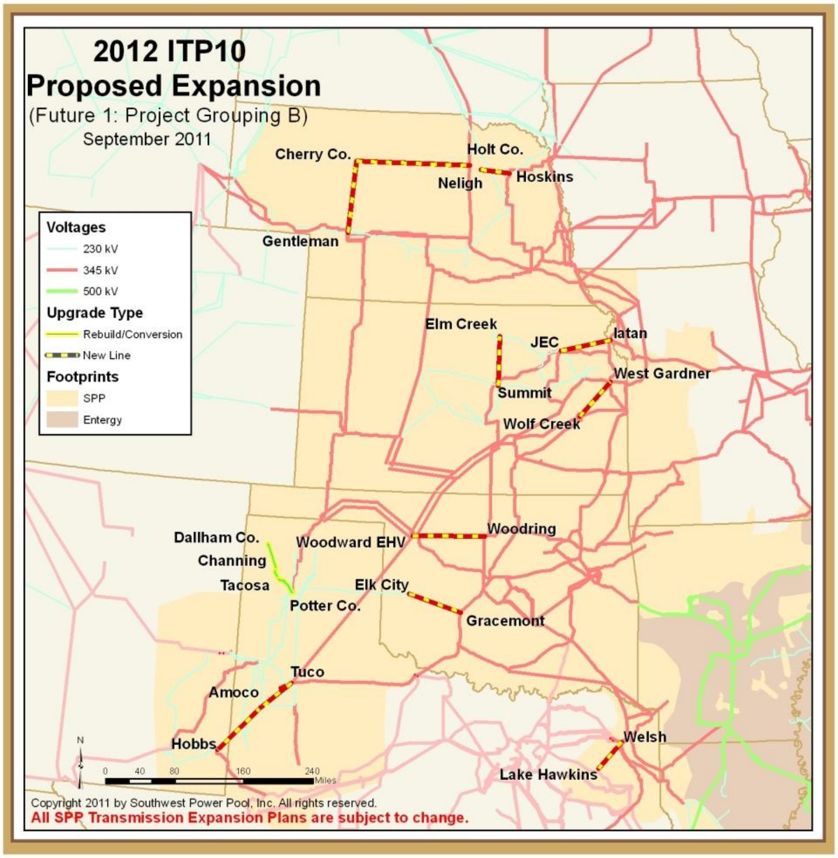


Figure 9.2: Preliminary Grouping B (Future 1)

Projects Grouped that Individually Showed B/C > 0.7

59 Total Projects

$1.66 Billion ($2011)

345 kV – 973 miles
230 kV – 76 miles
161 kV – 9 miles
138 kV – 54 miles
115 kV – 50 miles

9.3: Preliminary Grouping C (Future 1)

This grouping was constructed of projects that utilized common substations and transmission corridors. The individual B/C ratio of each project was not used in determining projects in this grouping. Any projects identified in the peak and off-peak reliability analyses were included, with the exception of two projects that were deferred by the Woodward EHV to Northwest 345 kV line.

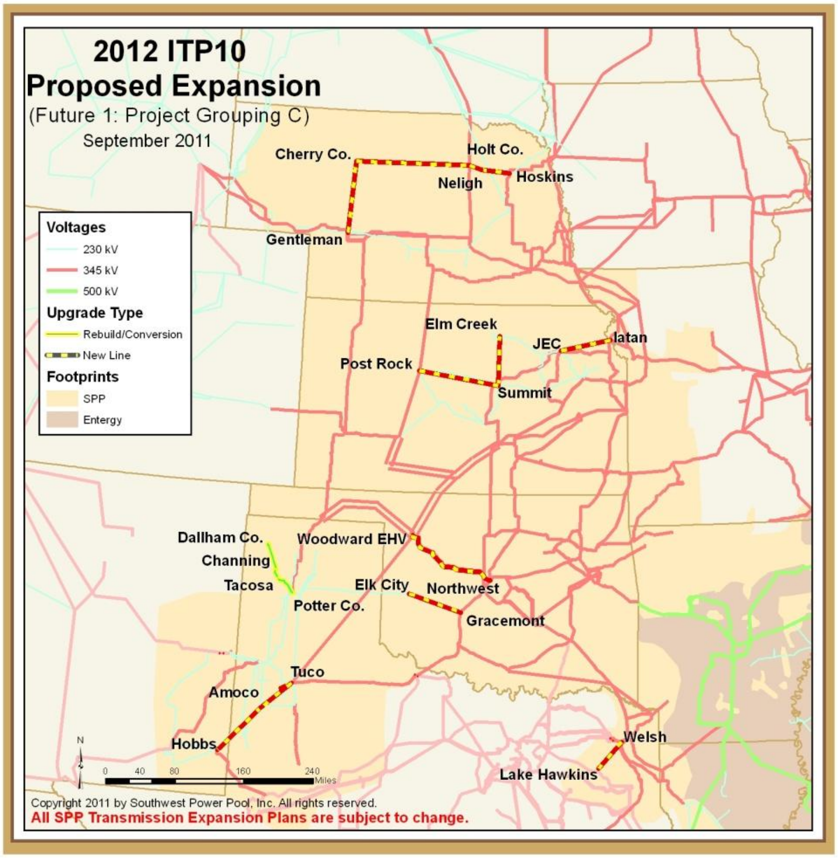


Figure 9.3: Preliminary Grouping C (Future 1)

Complementary Projects Grouped

60 Total Projects

$1.74 Billion ($2011)

345 kV – 1,042 miles
230 kV – 76 miles
161 kV – 9 miles
138 kV – 54 miles
115 kV – 50 miles

9.4: Preliminary Grouping D (Future 1)

This grouping was constructed of projects that addressed issues on the SPP seam. The individual B/C ratio of each project was not used in determining projects in this grouping. Projects identified in the peak and off-peak reliability analyses were included.

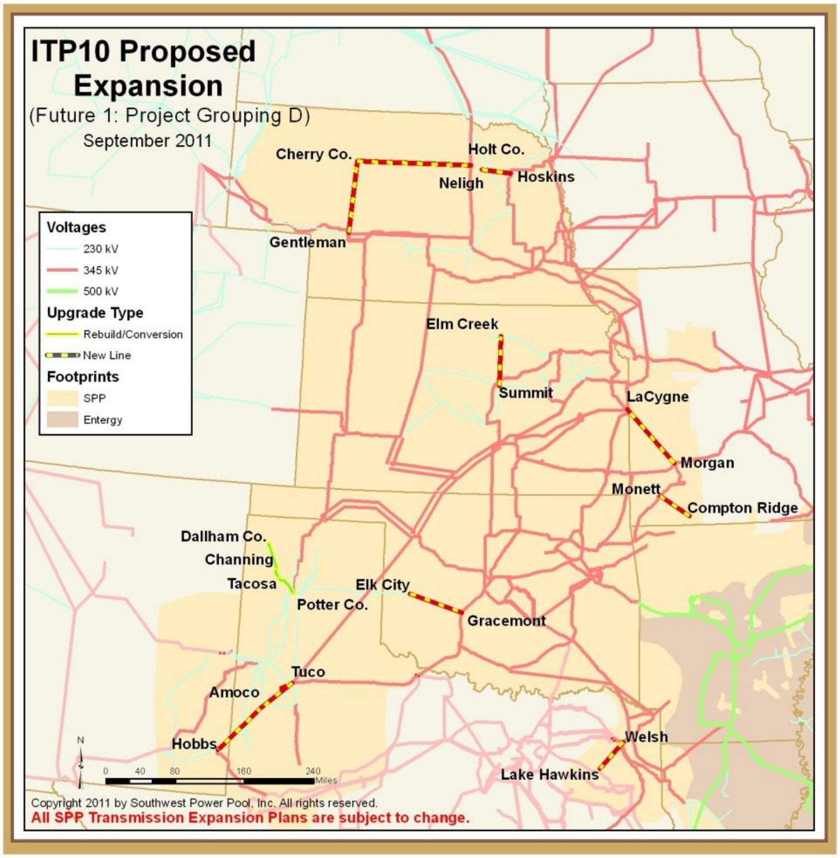


Figure 9.4 Preliminary Grouping D (Future 1)

Seams Projects Grouped

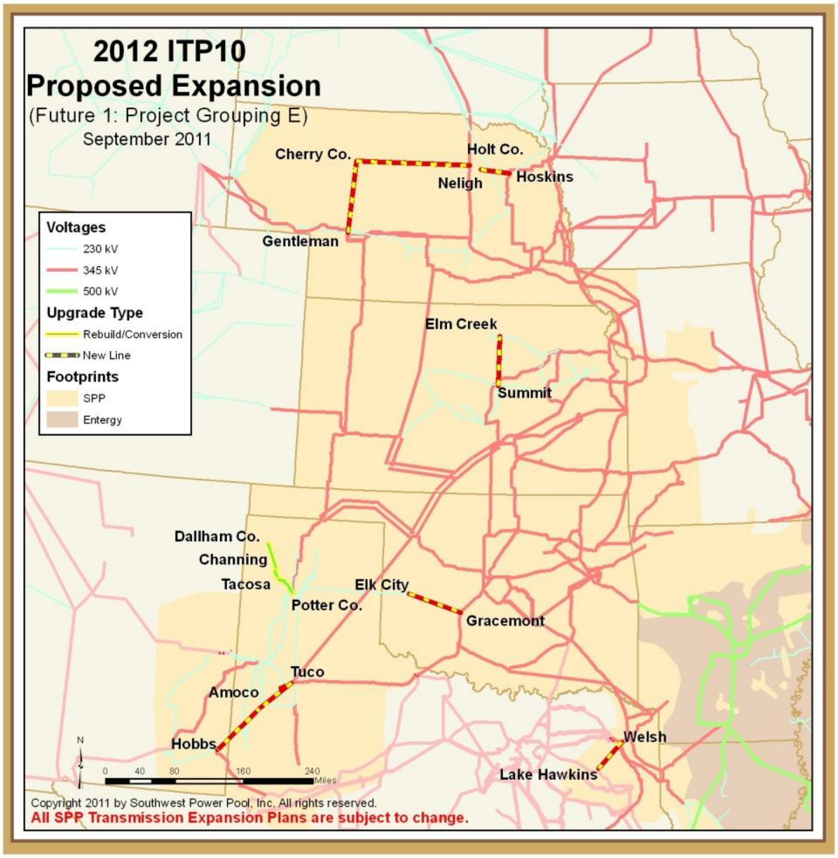
67 Total Projects

$1.62 Billion ($2011)

345 kV – 918 miles
230 kV – 76 miles
161 kV – 32 miles
138 kV – 151 miles
115 kV – 50 miles

9.5: Preliminary Grouping E (Future 1)

This grouping contains the same projects as Grouping A except for the Wolf Creek to Emporia 345 kV line. This line was removed from Grouping A in order to verify that the line did not provide net benefit once rolled into the whole grouping. The line did not provide net benefit, thus Grouping E satisfied the criteria that all projects provide a B/C > 1 that was originally set forth for Grouping A



Refinement of Grouping A for Higher B/C Result

60 Total Projects

$1.31 Billion ($2011)

345 kV – 692 miles
230 kV – 76 miles
161 kV – 9 miles
138 kV – 129 miles
115 kV – 50 miles

Figure 9.5 Preliminary Grouping E (Future 1)

9.6: Preliminary Grouping A (Future 2)

This grouping was constructed of projects that had a preliminary individual B/C ratio of greater than 1.0 in the project screening and any projects identified in the peak and off-peak reliability analyses. Multiple projects that qualified under these criteria met the same objectives. When alternative projects (such as the different options into and out of Wolf Creek) presented themselves, the one with the highest B/C was included in this grouping.

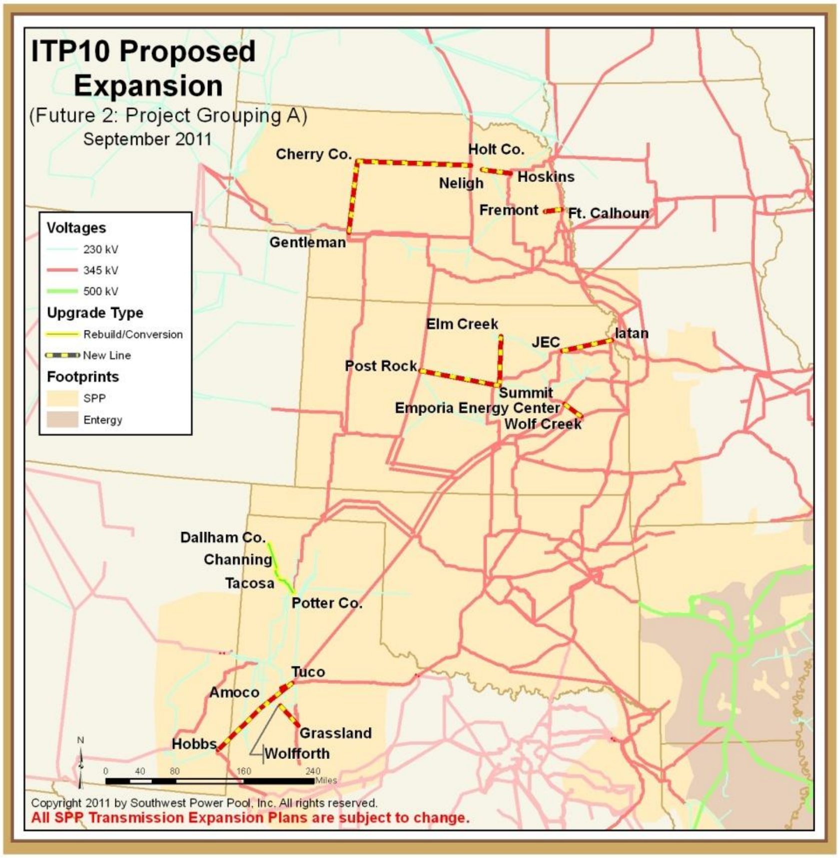


Figure 9.6: Preliminary Grouping A (Future 2)

Projects Grouped that Individually Showed B/C > 1

76 Total Projects

$1.54 Billion ($2011)

345 kV – 804 miles
230 kV – 76 miles
161 kV – 24 miles
138 kV – 193 miles
115 kV – 105 miles

9.7: Preliminary Grouping B (Future 2)

This grouping was constructed of projects that had a preliminary individual B/C ratio of greater than 0.7 in the project screening. Projects identified in the peak and off-peak reliability analyses were included, with the exception of two projects that were deferred by the Woodward EHV to Woodring 345 kV line Multiple projects that qualified under these criteria met the same objectives. When alternative projects (such as the different options into and out of Wolf Creek) presented themselves, the one with the second highest B/C was included in this grouping in order to see if its behavior within a portfolio was better than that of the alternative which was included in Grouping A.

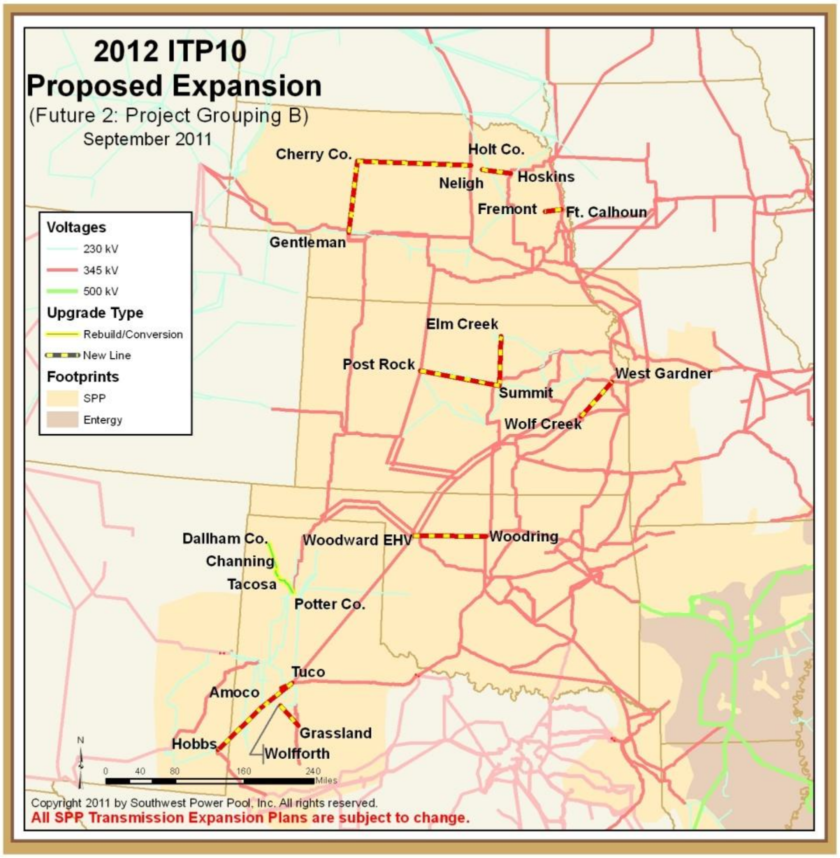


Figure 9.7*: Preliminary Grouping B (Future 2)*

Projects Grouped that Individually Showed B/C > 0.7

72 Total Projects

$1.54 Billion ($2011)

345 kV – 973 miles
230 kV – 76 miles
161 kV – 9 miles
138 kV – 119 miles
115 kV – 105 miles

9.8: Preliminary Grouping C (Future 2)

This grouping was constructed of projects that utilized common terminal points. The individual B/C ratio of each project was not used in determining projects in this grouping. Projects identified in the peak and off-peak reliability analyses were included, with the exception of two projects that were deferred by the Woodward EHV to Northwest 345 kV line.

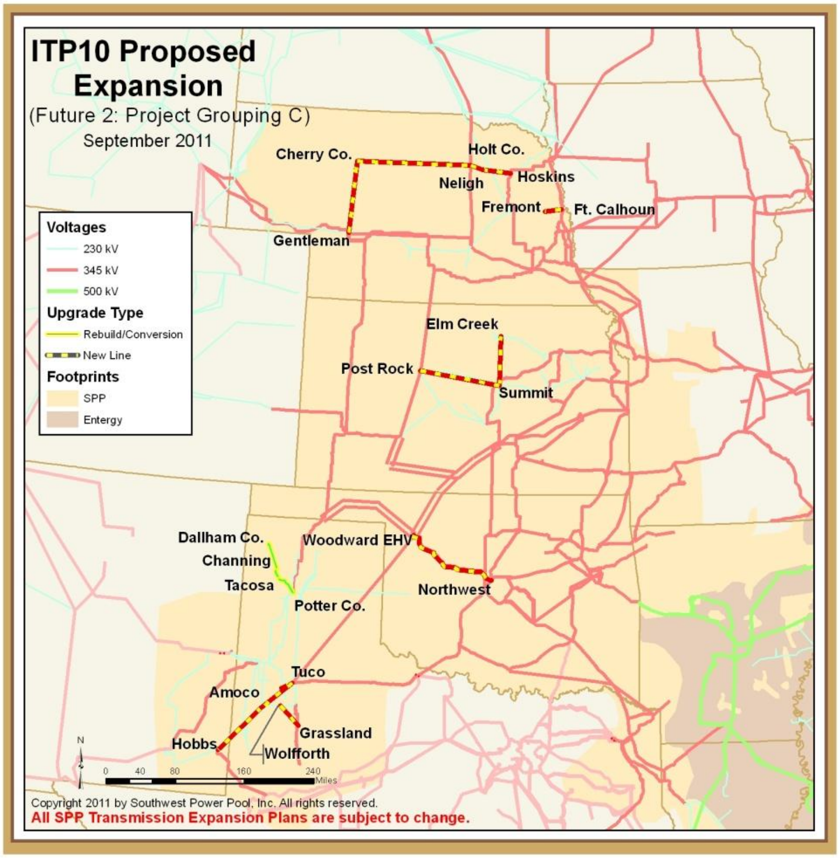


Figure 9.8: Preliminary Grouping C (Future 2)

Complementary Projects Grouped

72 Total Projects

$1.48 Billion ($2011)

345 kV – 870 miles
230 kV – 1 mile
161 kV – 20 miles
138 kV – 119 miles
115 kV – 105 miles

9.9: Preliminary Grouping D (Future 2)

This grouping was constructed of projects that addressed issues on the SPP seam. The individual B/C ratio of each project was not used in determining projects in this grouping. Projects identified in the peak and off-peak reliability analyses were included.

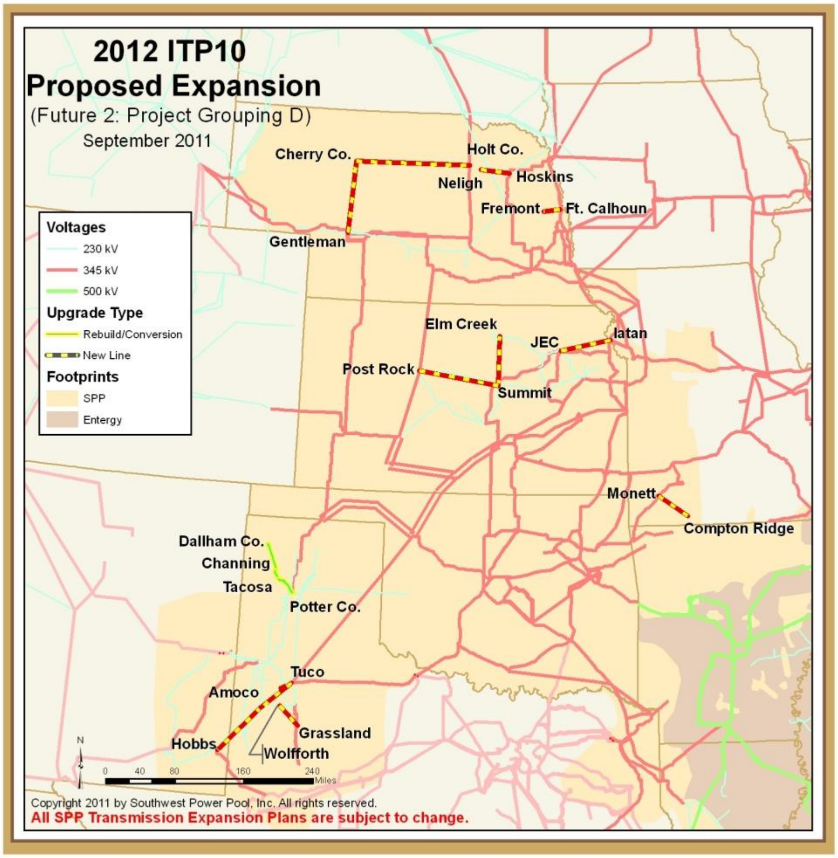


Figure 9.9: Preliminary Grouping D (Future 2)

Seams Projects Grouped

81 Total Projects

$1.62 Billion ($2011)

345 kV – 840 miles
230 kV – 76 miles
161 kV – 47 miles
138 kV – 215 miles
115 kV – 105 miles

9.10: Preliminary Grouping E (Future 2)

This grouping contains the same projects as Grouping A except for the JEC to Iatan and Wolf Creek to Emporia 345 kV lines. These lines were removed from Grouping A in order to verify that the each did not provide net benefit once rolled into the whole grouping. The lines did not provide net benefit, thus Grouping E satisfied the criteria that all projects provide a B/C > 1 that was originally set forth for Grouping A

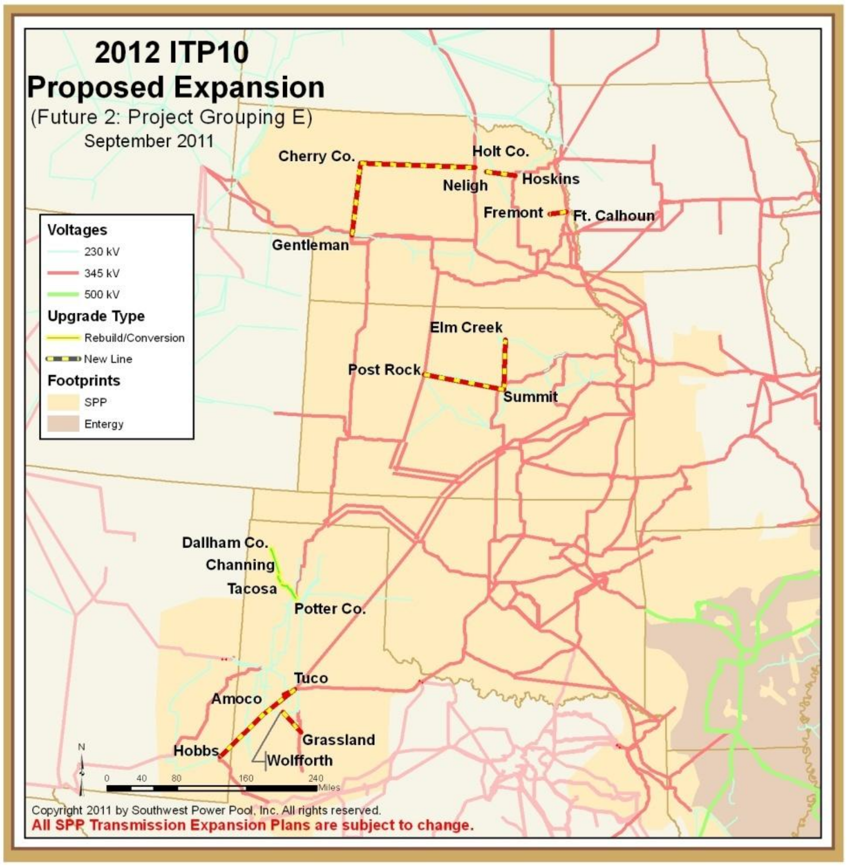


Figure 9.10: Preliminary Grouping E (Future 2)

Refinement of Grouping A for Higher B/C Result

74 Total Projects

$1.34 Billion ($2011)

345 kV – 689 miles
230 kV – 76 miles
161 kV – 24 miles
138 kV – 193 miles
115 kV – 105 miles

9.11: Portfolio Grouping Conclusions

Each grouping was evaluated for reliability and economic efficiencies. Projects that provided economic benefit were re-evaluated within the portfolios following the inclusion of the reliability projects from the 2012 ITPNT and 2012 ITP10 thermal and voltage analysis.

Economic Projects from Consideration

Several economic projects that had previously been identified as beneficial were eliminated from further evaluation. The significant 345 kV projects that dropped out are specified below.

(i) Jeffrey Energy Center – Iatan

This economic project showed some benefit in the initial screenings, with initial B/C's of 0.7 – 1.0. This project was included in some preliminary groupings. When considered with the inclusion of reliability projects from the 2012 ITPNT and other 2012 ITP10 projects, the benefit was less than the cost, and thus this project was not included in the final portfolio.

(ii) Wolf Creek Projects

Building a 345 kV line out of Wolf Creek showed some economic benefit in the initial screenings. Variations of this line were further evaluated and included in project groupings. When considered with the inclusion of reliability projects from the 2012 ITPNT and other 2012 ITP10 projects, the benefit was less than the cost, and thus these projects were not included in the final recommended portfolio. Three new 345 kV lines alternatives were considered out of the Wolf Creek substation each connected to one of the following alternatives: West Gardner, Emporia Energy Center, or Swissvale. Table 9.1 shows how the B/C ratio of this individual project changed when considered as part of the Grouping A and furthermore as part of the finalized portfolio.

Situation	B/C
Initial Screening	2.3
As part of Grouping A	-0.5
As part of Final Portfolio	-0.4

Table 9.1: B/Cs of Wolf Creek - Emporia 345 kV line (Future 1)

(i) LaCygne – Morgan 345 kV Line

This project provided significant APC savings in initial screenings of Future 1, and greatly increased transfer capability along the SPP seam. When considered in light of the full portfolio and in Future 2 the project B/C ratio fell to 0.5. Consequently, the project was not included in the final portfolio.

(ii) Branson Area Projects

Several configurations were considered to mitigate the Brookline transformer limitation, the most limiting element in any of the ATC analysis along the SPP seam, strengthen the west to east transmission paths, and provide benefit to SPP and AECI. The B/C for this project when considered in any of the screenings was consistently less than 1.0.

Developing a Single Portfolio

As the preliminary groupings were specific to the needs of only one of the futures, guidelines were needed to determine which projects should be included in the final recommended portfolio. These guidelines can be found in *Section 6.6: Determining Project Need Dates*.

Deferred Reliability Projects

Reliability projects were found to be mitigated by the two economic projects discussed below. The reliability projects mitigated included reconductor projects along the 138 kV corridor between

Woodward EHV and Oklahoma City and development around the Tuco 345 kV substation in west Texas.

(i) <u>Roman Nose – Southard – El Reno 138 kV reconductor</u>

This reconductor was identified to address the outage of Northwest – Tatonga 345 kV or Tatonga - Woodward District EHV 345 kV lines and system intact conditions. These overloads were completely mitigated by the Woodward - Tatonga – Mathewson – Cimarron 345 kV line, a project that provided greater economic value and corresponded with the 2012 ITP20 plan and current GI queue needs.

(ii) <u>Tuco – Jones 345 kV line and 345/230 kV transformer</u>

This new line was identified to address the overload of a Tuco 345/230 kV transformer for the outage of the parallel transformer, the loss of either Tolk generator, or various other contingencies but did not relieve congestion in the area. As a result, this project was deferred by the Tuco – Amoco – Hobbs 345 kV economic project which relieved congestion due to the loss of 230 kV circuits between Hobbs and Tuco and mitigated the overloads of the Tuco transformers.

Section 10: Finalized Portfolio

10.1: Project Selection

The project grouping analysis (see *Section 9: Project Groupings)* provided insight into the interaction between the projects and guided the determination of the finalized portfolio. As a result economic projects that provided too little benefit when considered as part of a portfolio were removed, reliability projects mitigated by economic projects were deferred, and the economic impact of the portfolio was determined.

The finalized portfolio is a grouping of projects that met needs seen in both futures and provided economic value in both futures (see Section 6.6: Determining Project Need Dates for the criteria used). Three economic projects provided an incremental B/C greater than 1.0 in Future 1 and are listed in Table 10.3Table 10.3: Primarily Policy Projects in the 2012 ITP10 Portfolio

. Projects which were required to meet the renewable targets in either future were included in the finalized portfolio and are listed in Figure 10.1. The reliability projects in the finalized portfolio are listed in Table 10.2. Greater detail for all of these projects is included in *Section 19: 2012 ITP10 Project List*.

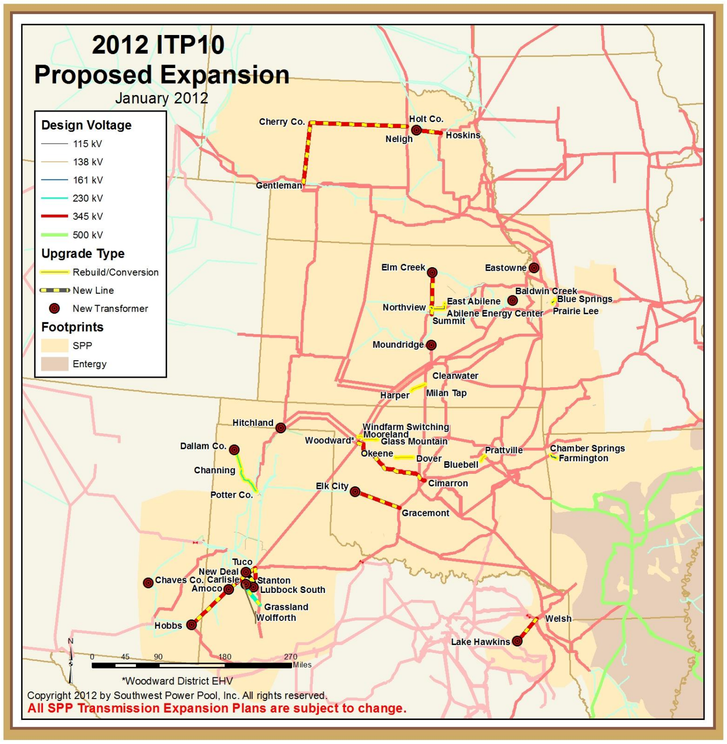


Figure 10.1: 2012 ITP10 Portfolio

Project Breakdown by Primary Function

Most of the projects in the finalized portfolio provide primarily a reliability function. One policy project is outlined in the state of Nebraska, although this project could be considered economic in Future 2. Three projects of primarily economic nature where included.

Function	Upgrades	Miles of New Line	Estimated E&C Cost
Reliability	54	534	$980
Policy	4	146	$289
Economic	6	167	$206

Table 10.1: Tally of Project Elements by Primary Function ($ millions)

Projects Excluded from the Portfolio

Projects to mitigate reliability or policy needs identified only in Future 2 were excluded from the final portfolio. Every reliability project identified in Future 1 also was identified for loading in Future 2 that met the criteria for inclusion in the portfolio. For details regarding some of the larger projects considered, but not included see *Section 9.11: Portfolio Grouping Conclusions*.

10.2: Finalized Portfolio Projects

The following projects were included in the finalized portfolio. Each table represents a set of projects that perform a primarily reliability, economic, or policy function within the finalized portfolio.

Chamber Springs - Farmington REC 161 kV	Carlisle Transformer 230/115/13.2 Ckt 1 Upgrade
Bluebell - Prattville 138 kV	Potter - Channing Ckt 1 115 kV to 230 kV Conversion
Elk City - Gracemont 345 kV	Channing - XIT - Dallam Ckt 1 Conversion to 230 kV
Lake Hawkins - Welsh 345 kV	Dallam County Interchange Transformer 230/115 kV
Blue Springs South - Prairie Lee 161 kV	Indiana - Stanton 115 kV Reconductor
Blue Springs East - Blue Springs South 161 kV	Indiana - SP Eskine 115 kV
Harper – Milan Tap 138 kV Rebuild	Lamb County 69 kV Capacitor
Neligh - Hoskins 345 kV	Dover - Okeene 138 kV
Neligh Transformer 345/115 kV	Elm Creek - Summit 345 kV
Glass Mountain - Mooreland 138 kV	Elm Creek Transformer 345/230 kV
FPL Switch - Woodward District 138 kV	Abilene East - Chapman 115 kV
Classen - Southwest Tap 138 kV	Abilene East - Abilene Energy Center 115 kV
Woodward - Tatonga 345 kV	Abilene Energy Center - Northview 115 kV
Tatonga - Mathewson - Cimarron 345 kV	Northview - North Street 115 kV
Chaves 230/115 kV	Clear Water - Milan Tap 138 kV Rebuild
Jones Bus #2 - Lubbock S Ckt2 Terminal Upgrade	Baldwin Creek Transformer 230/115 kV
Tuco - New Deal 345 kV	Northwest Manhattan Cap 115 kV Capacitor
Lubbock South Transformer 230/115/13.2 kV Ckt 2	Seneca 115 kV Capacitor
Hitchland Transformer 230/115/13.2 Ckt 2	Carlisle - Murphy 115 kV Reconductor
Wolfforth – Grassland 230 kV	Elk City transformer 345/230 kV
Welsh 345/138 kV transformer	

Table 10.2: Primarily Reliability Projects in the 2012 ITP10 Portfolio

Gentleman - Cherry County - Holt County 345 kV

Table 10.3: Primarily Policy Projects in the 2012 ITP10 Portfolio

Tuco - Amoco - Hobbs 345 kV
Amoco Transformer 345/230 kV
Hobbs Transformer 345/230 kV
Moundridge Transformer 138/115 Ckt 2
Eastowne Transformer 345/161 kV

Table 10.4: Primarily Economic Projects in the 2012 ITP10 Portfolio

10.3: Staging Considerations

Section 6.6: Determining Project Need Dates describes the procedure used to stage projects. In addition to this procedure, special considerations were given to these projects as the portfolio was refined with stakeholder input. The need dates for all of the projects can be found in *Section 19:2012 ITP10 Project List*. The project cost by need by date is shown in Figure 10.2.

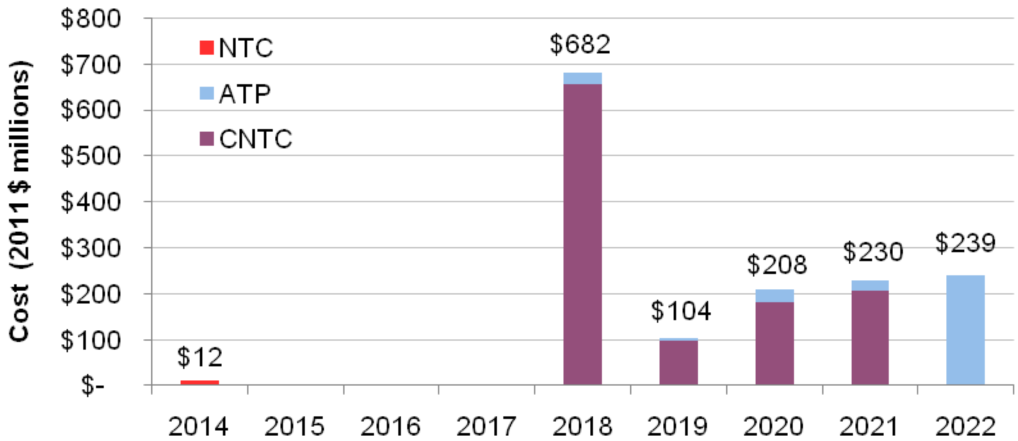


Figure 10.2: Project Costs by Need by Year ($ millions)

Tuco - Amoco - Hobbs 345 kV Line
This project defers the need to build a reliability project (the new 345 kV line from Tuco to Jones).The need date for this primarily economic project was determined to be 1/1/2020 based upon the date at which the reliability project deferred by this project was needed. This project includes a 345/230 kV transformer at both Amoco and Hobbs.

Moundridge 138/115 Transformer (2nd circuit)
The economic staging analysis showed that this project had a B/C greater than 1.25 for every year from 2012 to 2022. An NTC is recommended to be issued for this project immediately.

Gentleman - Cherry Co - Holt Co 345kV Line
This policy project is staged for 2018 based on the projected wind need for 2017 from the CAWG Renewable Survey projections. The survey indicates 80% of the Future 1 wind (approximately 8 GW) is targeted to be in-service for the year 2017. The estimated project lead time of 72 months for the project was greater than the time remaining before 2017. Therefore, this project was given a need date of 1/1/2018 – the earliest the project could be constructed based upon the lead time.

10.4: Cost Allocation for 2012 ITP10 Projects

The anticipated cost allocation for all 2012 ITP10 approved projects is consistent with the approved Highway/Byway cost allocation methodology as outlined by the tariff at the time of project approvals.

Section 11: Stability and Reliability Review

11.1: Review of Transmission Portfolio

In order to ensure that the finalized portfolio did not create transient or voltage stability problems a review was conducted under the guidance of the TWG. The review took three approaches:, measuring the stability of the generating machines due to system faults (transient stability), checking the voltage stability of the system under load transfer stresses into load pockets, and verifying the stability of the system under high wind dispatches. All three aspects of the review demonstrated that the proposed transmission expansion in the final portfolio accounted for transient or voltage stability considerations without modification and did not introduce new problems to the region. A complete report on these three approaches is included in *Section 15: Stability Analysis.*

11.2: Transient Stability

A transient stability assessment was conducted as part of the 2012 ITP10 study conducted on Future 1 Grouping A. Two AC power flow models were developed, Future 1 peak and off-peak, using a security constrained economic dispatch.

Methodology
A transient stability scan was performed, applying N-1 contingencies on transmission lines above 100 kV. The scan was performed by faulting bus A for a specified period of time (see the Table 11.1 for the clearing times and details of the contingencies). Each fault was cleared based on the voltage level of the transmission line. The line was opened from bus A to bus B without re-closing. The simulation was run for 5 seconds. Transient Stability issues should manifest with a few cycles of the fault simulation. Therefore, a 5 second simulation was sufficient to assess basic angular stability.

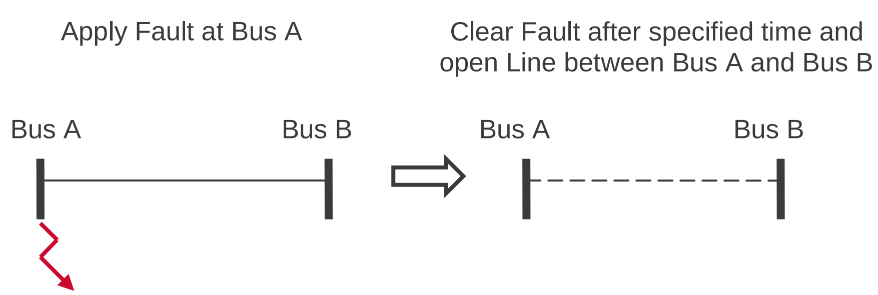


Figure 11.1: Transient Stability Methodology

Voltage Level	Clearing Time
200 - 999 kV	5 cycles
100 - 199 kV	8 cycles

Table 11.1: Clearing Times, contingency details

No Unstable Machines due to Transmission Plan
The 2012 ITP10 Portfolio A peak and off-peak analysis determined no unstable machines inside the SPP footprint.

11.3: Voltage Stability

Eight load areas or "pockets" for the 2012 ITP10 voltage stability analysis are shown in Table 11.2 and graphically in Figure 11.2.

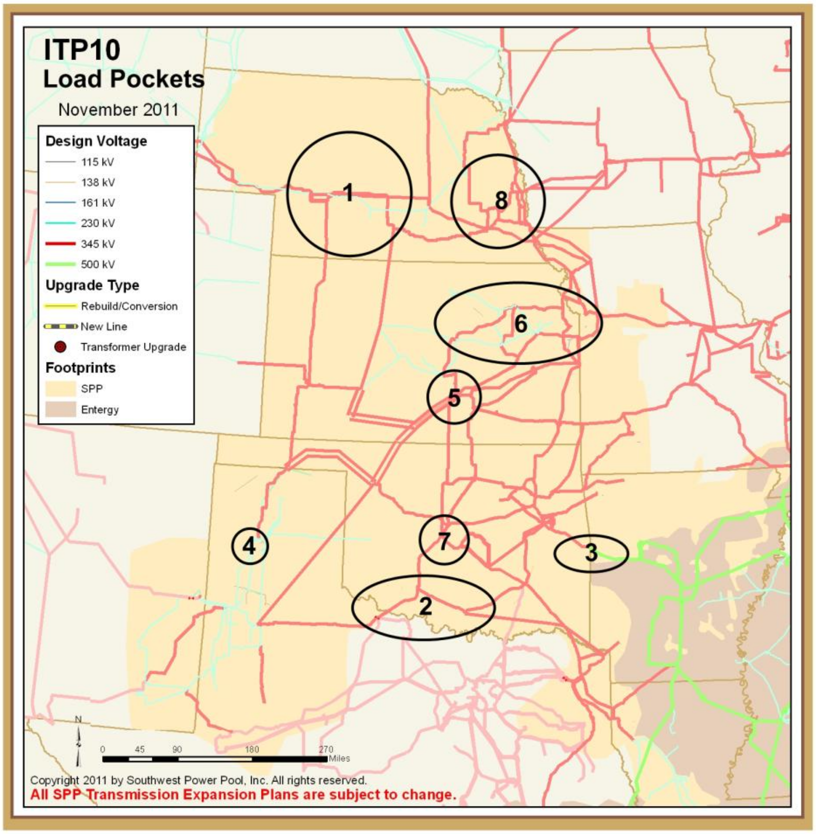


Figure 11.2: Load Areas for 2012 ITP10 analysis

Area	Load Area Name
1	Central Nebraska
2	South Oklahoma
3	West Arkansas
4	SPS – Amarillo
5	South Central Westar
6	Northeast Westar
7	Oklahoma City
8	Lincoln/Omaha

Table 11.2: Load Areas Evaluated for Voltage Stability

The contingencies for the stability analysis were identified through the following process: (1) a single generator contingency analysis was performed to identify the generator outage within the load area that caused the highest degree of voltage instability stress; (2) a generator outage was paired with all transmission line outages within the load area.

Analysis was performed by increasing load within the load pocket while increasing transfer to the load area from adjacent areas until voltage collapse occurs. The system was tested under contingency and non-contingency conditions using the 2012 ITP10 2022 Future 1 summer peak models with and without Future 1 Portfolio A upgrades.

No Voltage Instability in Load Pockets due to Transmission Plan

Based on the projected 2022 load levels, no voltage instability in the eight load pockets was identified for the 2012 ITP10 Portfolio A upgrades. Voltage instability did occur at levels of load increase beyond the 2022 load levels varying between 24% and 85% as shown *Section 15: Stability Analysis*.

11.4: Wind Dispatch Analysis

An assessment was performed to confirm that the wind dispatched for the 2012 ITP10 Future 1 Portfolio A 2022 off-peak case can be achieved without the occurrence of voltage instability. The constraints identified in *Section 6.3: Projecting Congestion* were monitored to determine if voltage instability occurred before flow limits were exceeded.

Method

The method employed to determine the amount of wind generation that could be accommodated in Future 1 Portfolio A was accomplished by reducing wind generation to minimum levels while simultaneously increasing conventional generation to meet SPP load requirements. Next, the wind was increased while the conventional generation was decreased until voltage collapse occurred during both normal conditions and contingencies. The contingencies used were N-1 200kV and above transmission lines as well as constrains defined in *Section 6.3: Projecting Congestion*. All 100 kV and above buses in SPP were monitored for voltage collapse.

Future 1 Wind Dispatch Achievable with Transmission Plan

The wind dispatch in the 2012 ITP10 is feasible from a voltage stability viewpoint. The 2012 ITP10 Future 1 Portfolio A can safely dispatch 11,133MW. Since voltage instability did not occur at wind levels less than the Future 1 wind dispatch level and flowgate limits were not reached, revisions to limits were not required. The name plate capacity of the wind plants to produce this dispatch would be greater that the 11.1 GW identified due the diversity of wind pattern load system considering not all plants would be operating at their maximum capacity.

Section 12: Benefits

The benefits identified for the recommended portfolio ranged from APC savings associated with economic projects and potential overload mitigations provided by reliability projects to wind enabling transmission that met renewable policy goals in each future. Each benefit is specifically addressed in the sections that follow with analytical results obtained from the measurement of the benefit due to the whole portfolio, projects of a primarily reliability nature, projects of a primarily policy meeting nature, and projects of primarily an economic nature.

The three categories of benefit are not always additive when considered separately; and individual projects do provide value in multiple categories. Therefore, the treatment of these benefits was discussed by the ESWG and identified as an important consideration for future cost allocation reviews. In the 2012 ITP10 portfolio the ESWG directed that the B/C results be focused on the incremental benefits provided by the economic projects. As such, the benefit structure shown in Figure 12.1 demonstrates that all of the benefit metrics were calculated for the portfolio expansion plan (including reliability, policy, and economic projects) and the incremental monetized savings due to the economic projects was focused upon.

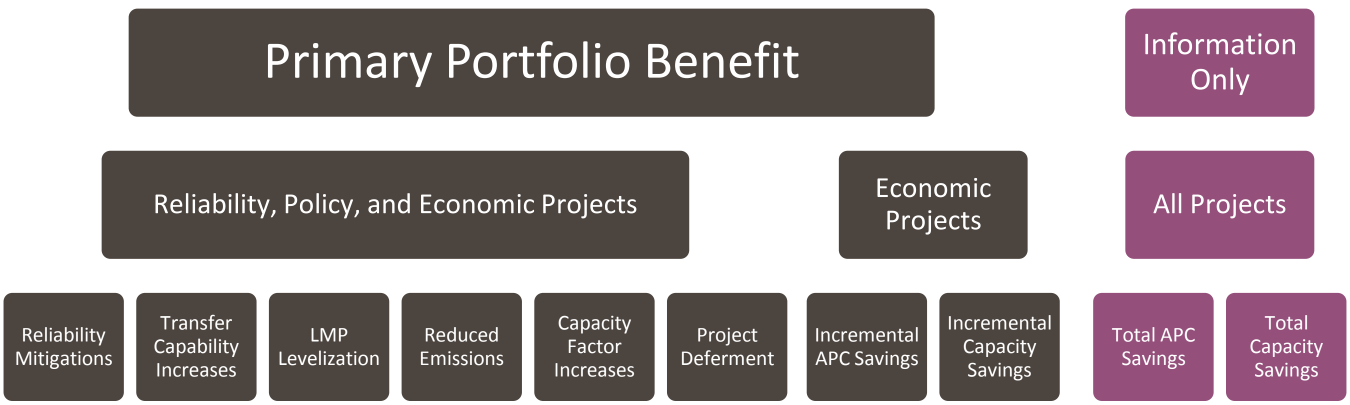


Figure 12.1: Benefit Hierarchy

Benefits Reported on a Portfolio Basis

The inherent challenge to the capture and report of these benefits arises when projects provide substantial value across benefit categories. Three good examples of transmission facilities that provide benefits in each of the categories in the 2012 ITP10 demonstrate this circumstance: 1) the Elk City – Gracemont 345 kV line has been proposed chiefly to aid in relieving reliability issues on the 138 kV system in western Oklahoma, but this line also provided more access for wind in Kiowa County, OK and reduced congestion for west to east flows. 2) the Gentlemen – Cherry Co. – Holt Co. 345 kV line in Nebraska has been proposed chiefly to provide access for wind development in Cherry Co., but this line also provided parallel paths for key contingencies in Nebraska for west to east flows, relieved congestion, increased transfer capability, and mitigated reliability concerns. 3) the Woodward – Tatonga – Mathewson 345 kV line reduced congestion for west to east flows and deferred the need of 138 kV reconductor projects in the area. Analyzing the projects as one portfolio allowed all of these benefits to be captured in the analysis; look to the columns labeled *"2012 ITP10 Portfolio"* for the benefits for all categories for all projects. Columns labeled 'Reliability Projects" report the benefit due to the reliability projects, "Policy Projects" report the benefit of the policy projects incremental to the reliability projects, and "Economic Projects" report the incremental benefit of the economic projects incremental to reliability and policy projects.

12.1: Reliability Mitigations

The AC simulations and the reliability scans performed upon them identified potential criteria violations due to thermal overloads of equipment in the SPP footprint or violations of voltage at specific substations. The results of the scans were thoroughly reviewed by the TWG. At least 61 unique potential violations were mitigated by the finalized portfolio, since only the primary violations are tracked. Many more secondary violations were also mitigated by the portfolio.

12.2: Transfer Capability Increases

As previously discussed in the Metrics Usage section of this report, there are three benefit metrics that measure the power transfer capability increases with the proposed transmission plan. The Available Transfer Capability (ATC) improvements are summarized in Table 12.1. Three different types of transfers were evaluated using powerflow models with the same Future 1 and 2 generation dispatches used to test system reliability.

The first transfer, for Metric 1.1.2, captures the increase in capability between each SPP member area. Generation-to-generation power transfers were performed to and from every SPP member area and all other SPP member areas. For each area, the maximum increase in transfer capability was recorded and then averaged with the maximums seen for all the other areas.

The second transfer, for Metric 6, captures the increase in capability across the SPP seam. Generation-to-generation power transfers were performed from every SPP member area to Tier one entities, from Tier one entities to every SPP member area, and from Tier one entities to the SPP member areas that share a seam with a Tier one entity. For each area, the maximum increase in transfer capability was recorded and then averaged with the maximums seen for all the other areas. This was repeated for the three types of transfers, whose results were averaged.

The third transfer, for Metric 14, captures the increase in load shift capability between load centers. Load-to-Load power transfers were performed to and from ten load centers in the SPP footprint. For each load center, the maximum increase in load shift capability was recorded and then averaged with the maximums seen for all the

Area		Desired	Increase	
From	To	Transfer	F1	F2
AEPW	GMO	1,179	320	780
AEPW	KCPL	2,575	-110	-90
AEPW	NPPD	2,376	-90	-100
GMO	EMDE	256	0	-20
GMO	EMDE	256	-10	0
GMO	SWPA	256	0	-30
GRDA	EMDE	103	0	-10
KCPL	EMDE	418	-10	-20
KCPL	GMO	418	0	20
KCPL	NPPD	418	170	0
KCPL	SWPA	418	-10	-30
NPPD	AEPW	1,267	140	0
NPPD	GMO	1,179	320	0
NPPD	KCPL	1,267	150	0
NPPD	MEC	1,267	50	-70
NPPD	OKGE	1,267	150	0
NPPD	OPPD	1,267	130	-70
NPPD	SUNC	1,267	90	-40
NPPD	WFEC	1,267	150	0
NPPD	WR	1,267	150	0
OKGE	GMO	1,179	320	780
OKGE	KCPL	1,389	90	-90
SPS	GMO	1,179	320	0
SPS	KCPL	3,080	110	-90
SPS	MEC	4,371	-430	50
SPS	SUNC	1,485	-820	20
SPS	WFEC	1,506	0	140
SUNC	CLEC	711	20	30
SUNC	KCPL	711	20	-90
SUNC	WR	711	30	0
WFEC	GMO	1,179	320	780
WFEC	KCPL	1,182	0	-90
WR	AMMO	1,058	440	0
WR	CLEC	1,058	70	0
WR	EES	1,058	60	0
WR	GMO	1,058	560	0
WR	KACY	755	550	0
WR	KCPL	1,058	560	0
WR	MEC	1,058	620	0
WR	NPPD	1,058	280	0
WR	OPPD	1,058	670	0
WR	SUNC	1,058	180	0
WR	WAPA	1,058	720	0

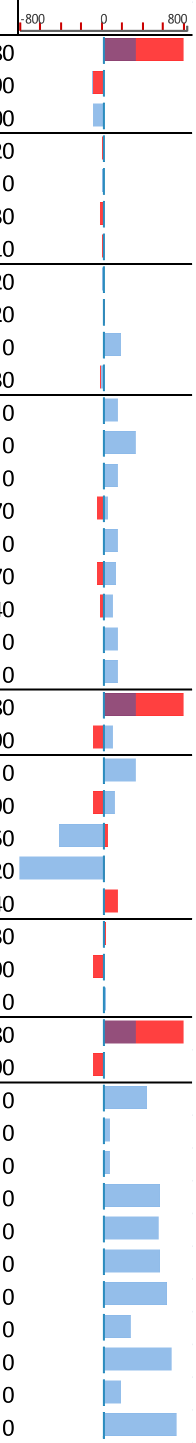


Table 12.1: Metric 1.1.2 - Increase in ATC Transfer Capability by Area for each future

other load centers. This metric captures the ability for the transmission system to serve load at levels other than what was forecasted.

The results of the metric calculations indicated some particularly interesting results surrounding the Brookline transformer near Springfield, MO and the Gerald Gentleman stability interface. The results of the analysis indicate that without a project in the Branson area the Brookline transformers will limit transfers across the SPP seam and internal to the footprint. For instance, in Future 1 778 transfers were evaluated, 246 were limited by the overload of one Brookline 345/161 kV transformer for the loss of the parallel transformer, and this number was reduced to 89 transfers limited with the addition of the LaCygne – Morgan 345 kV line. To a lesser extent the Gerald Gentlemen Stability Interface in Nebraska limited 10 of the transfers; this number was reduced to 3 transfers limited following the addition of the Gentlemen – Cherry Co. – Holt Co. 345 kV line.

Transfer increases captured under Metric 1.1.2 are further detailed in Table 12.1 for each area's transfer capability changed by more than 3%. The transfer limit is highest for high load areas. Transfer levels were selected based upon the available capacity up and down in each of the areas involved in the transfer after the model was economically dispatched. Most increases to transfer capability were witnessed in Future 1 for this metric. Several transfers show improvement.

	F1 (MW)	F1 (%)	F2 (MW)	F2 (%)
Metric 1.1.2	2,150	146%	1,274	399%
Metric 6	2,204	135%	1,315	1,015%
Metric 14	833	287%	1,350	71%

Table 12.2: ATC Improvement due to 2012 ITP10 Finalized Portfolio

12.3: LMP Levelization

The metrics that measure the increased ability for generators to compete in the market are summarized in Table 12.3 and Table 12.4. These metrics provide a qualitative measure of the LMP differences across the grid.

These results indicate congestion in the base case is being relieved by the 2012 ITP10 Portfolio. A congested flowgate will result in the LMP on one side of the flowgate being much higher than the LMP on the other side. Since the 2012 ITP10 portfolio successfully relieves congestion, there are fewer spikes and valleys in the LMP prices and the standard deviation is reduced. For more details about the definition of these metrics, and the benefits of mitigating limitations to market competition, please refer to *Section 6.3: Projecting Congestion & Market Prices*.

	Base	Reliability	Policy	Economic
Future 1: Load LMP	17.11	11.44	11.97	11.07
Future 2: Load LMP	33.21	17.75	18.50	17.72
Future 1: Gen LMP	30.84	27.80	28.33	27.70
Future 2: Gen LMP	33.92	28.95	29.26	28.60

Table 12.3: Metric 2 - Load LMP Levelization

The standard deviation of LMPs for individual generation technologies are shown in Table 12.4, these values demonstrate that the addition of the transmission lowers the standard deviation of LMPs within each category of generation technology, thus increasing the likelihood that generators are more competitive with similar generators.

	Base	Reliability	Policy	Economic
Future 1: LMP CC (Gas)	20.24	17.42	17.60	16.10
Future 2: LMP CC (Gas)	23.73	15.39	15.64	15.47
Future 1: LMP Steam (Gas)	49.87	46.26	46.76	45.93
Future 2: LMP Steam (Gas)	53.23	47.80	48.25	47.70
Future 1: LMP CT (Gas)	27.34	22.75	23.46	23.20
Future 2: LMP CT (Gas)	37.93	21.88	24.76	22.06
Future 1: LMP Steam (Coal)	17.72	15.11	15.60	15.27
Future 2: LMP Steam (Coal)	27.05	17.20	18.67	17.15
Future 1: LMP Wind	117.97	118.21	18.87	17.15
Future 2: LMP Wind	167.67	154.51	65.26	64.64

Table 12.4:Metric 3 - Improved Competition in SPP Markets

12.4: Reduced Emissions

The total emissions (tons) and emission rates (tons/MWh) of each of the portfolios and the base topology are shown in Table 12.5 and Table 12.6. If a portfolio's topology results in a lower fossil fuel burn (or less coal-intensive generation) than the base topology, then SO_2, NO_X, CO_2, and Hg emissions will be lower with the portfolio's topology in place. The results indicated that more fossil fuel was burned in Future 2 as transmission was added, despite the reduction in emission rate. This indicated that the footprint was generating more energy with the additional transmission.

Reductions of CO_2 for Future 1 and Future 2 were 3.4 tons/MWh and 9.7 lbs/MWh. The greater reduction in Future 2 was attributed to that future's increased wind capacity. The reduction in Future 1 was equivalent to avoidance of the annual emissions from the electricity use of 53,001 homes.[25]

Effluent	Base	Reliability	Policy	Economic
Future 1: NO_X	220,367	564	356	-219
Future 2: NO_X	177,395	3,759	3,291	3,264
Future 1: SO_2	285,484	1,235	910	1,057
Future 2: SO_2	221,863	8,129	7,581	7,692
Future 1: CO_2	210,238,295	-24,008	-228,272	-65,354
Future 2: CO_2	189,137,342	1,123,625	556,757	473,883

Table 12.5: Change in Emissions from Base (tons)

Effluent	Base	Reliability	Policy	Economic
Future 1: NO_X	1.61	0	0	0
Future 2: NO_X	1.28	0.02	0.01	0.01
Future 1: SO_2	2.09	0	0	0
Future 2: SO_2	1.6	0.04	0.03	0.04
Future 1: CO_2	1,537.48	-5.09	-8.51	-3.42
Future 2: CO_2	1,360.37	0.04	-10.28	-9.77

Table 12.6: Change in Emission Rates (lbs/MWh)

[25] Calculations based upon the EPA Greenhouse Gas Equivalencies Calculator, October 2010.

12.5: Capacity Factor Improvement

The renewable energy capacity generated without added transmission fell short of the renewable targets specified in each future due to system thermal and voltage limitations across the system. In order to meet the future requirements the amount of wind energy curtailed was measured and the capacity factors of the wind farms compared with the values specified by the CAWG survey (see *Section 4.3: Resource Plan Development*). 3% curtailment was targeted to account for the limitations in modeling techniques. As expected, wind curtailment was highest in Future 2, where the wind targets were highest. The incremental effect of the projects on the wind curtailment is shown in Table 12.7. As noted in Table 12.8, the curtailment of wind energy in Oklahoma, Kansas, and Nebraska did not fall within the 3% range without added transmission. With the addition of the transmission plans, each state in the footprint was able to meet the renewable energy goals and targets outlined in each future.

	Base	Reliability Projects	Economic Projects	Policy Projects
Future 1 Curtailment (%)	7%	5%	4%	3%
Future 2 Curtailment (%)	13%	7%	7%	3%
Future 1 Target / Mandate (GWh)	37,467	37,467	37,467	37,467
Future 2 Target / Mandate (GWh)	52,292	52,292	52,292	52,292
Future 1 Wind Generation (GWh)	34,726	35,448	35,789	36,475
Future 2 Wind Generation (GWh)	46,240	49,464	49,472	51,507

Table 12.7: SPP Wind Energy Curtailment

	Base	Reliability Projects	Economic Projects	Policy Projects
OK	5%	2%	2%	2%
KS	14%	8%	3%	3%
MO	2%	2%	2%	2%
NM	3%	3%	3%	3%
NE	15%	18%	19%	3%
TX	3%	2%	2%	2%
SPP	7%	5%	4%	3%

Table 12.8: SPP Wind Energy Curtailment by State

The capacity factors of wind plants in each state where also monitored. The increase in capacity factors correspond to the reduction in wind energy curtailment and demonstrate how each futures wind targets and mandates were met by the proposed expansion. The increases to capacity factors due to the 2012 ITP10 Finalized Portfolio are shown in Table 12.9.

	Capacity Factor Target	Future 1 Base	Future 1 Improvement	Future 2 Base	Future 2 Improvement
KS	45%	38%	5%	40%	3%
MO	38%	37%	0%	-	-
NM	36%	35%	0%	34%	0%
NE	46%	39%	6%	33%	12%
OK	43%	41%	1%	38%	4%
TX	42%	41%	0%	38%	3%

Table 12.9: Capacity Factor Improvement by State (%)

Table 12.9 shows that the transmission expansion significantly increases the capacity factors of the wind plants modeled for Future 2. The increases in Future 1 were localized to Kansas and Nebraska. Further investigation into the simulation results indicate that all of the project categories contributed to the increase in these values, most markedly the increased to wind output was seen due to the reliability and policy projects. The economic project did not change the amount of wind curtailed in Future 2 and only effected the Future 1 curtailment by 1%. The reason for this was some reliability upgrades were necessary to relieve potential reliability criteria violations in the off-peak powerflow cases containing high amounts of dispatched wind generation. Also, the policy upgrades were primarily needed for their ability to improve wind curtailment. The economic upgrades had to improve wind curtailment and relieve enough potential congestion to be a good financial investment. Only in Kansas, in the case of the 2nd 138/115 transformer at Moundridge did a project provide both significant economic benefit while improving wind curtailment.

Conventonal generation output was recorded by fuel type in order to identify savings gained by the flexibility afforded the simulation due to the transmission expannsion. The largest shift in generation was seen from the natural gas fuel combined cycle and conbustion turbine generator types to coal generation. Table 12.10 records the change in generation for each future.

	Future 1 Base	Future 1 Change	Future 1 Change	Future 2 Base	Future 2 Change	Future 2 Change
Combined Cycle	34,970,344	33,273,320	-1,697,024	53,898,994	49,221,639	-4,677,355
ST Gas	34,970,344	33,273,320	-1,697,024	53,898,994	49,221,639	-4,677,355
CT Gas	6,175,177	5,517,726	-657,451	3,916,002	3,563,750	-352,252
CT Oil	3,779,639	3,577,880	-99,303	4,192,013	3,507,410	-448,358
Nuclear	2,072	1,550	-522	25,469	11,411	-14,058
ST Other	21,892,151	21,896,469	4,319	21,915,837	21,915,655	-183
Internal Combustion	117,343	126,061	8,718	109,951	144,525	34,573
ST Coal	209,054	218,259	9,205	208,560	199,338	-9,222
Total	178,359,205	179,623,801	1,264,596	154,274,174	157,382,535	3,108,362

Table 12.10: Annual conventional generation by technology type (MWh)

12.6: Project Deferment

The cost of the projects that were deferred (see *Section 9.11: Portfolio Grouping Conclusions*) were given Conceptual Estimates and the ATRR calculated for the given year. The value of the deferment was added into the B/C calculations per the formula endorsed by the ESWG. See Table 12.11 for a breakdown of this benefit in Future 1 and Table 12.12 for Future 2.

12.7: APC Savings

One-Year APC Savings

The costs and other information pertinent to the calculation of the benefit to cost ratio for Future 1 are shown in Table 12.11 in accordance with the calculations set forth in *Section 6.7: Measuring Economic Value*. These values pertain only to the study year and do not include the full benefits expected over the life of the projects. The values in the table are represented in an incremental manner. The benefit and cost of the reliability projects were considered incrementally to the transmission outlined in the 2012 ITPNT, the benefit and cost of the policy projects was considered incrementally to the reliability projects, and the benefit and cost of the economic projects was considered increment to the policy projects. The column listing the portfolio considers the complete package of benefits incremental to the 2012 ITPNT projects.

	Reliability Projects	Policy Projects	Economic Projects
APC	$5,643	$5,629	$5,584
Incremental Benefit	$74	$13	$45
Incremental Deferment Benefit	$0	$0	$16
Total Cost	$980	$1,269	$1,475
Incremental Cost	$980	$289	$206
Incremental Carrying Cost	$167	$49	$35
Incremental one-year B/C	0.44	0.27	1.74
Incremental Net Benefit	($93)	($36)	$26

Table 12.11: One-Year APC Summary for SPP ($ millions in Future 1)

	Reliability Projects	Economic Projects
APC	$10,355	$10,242
Incremental Benefit	($59)	$113
Incremental Deferment Benefit	$0	$16
Total Cost	$980	$1,475
Incremental Cost	$980	$496
Incremental Carrying Cost	$167	$84
Incremental one-year B/C	-0.35	1.53
Incremental Net Benefit	($225)	$44

Table 12.12: One-Year APC Summary for SPP ($ millions in Future 2)

Forty-Year Financial Analysis

To calculate the benefits over the expected 40 year life of the projects[26], two years were analyzed, 2017 and 2022[27], and the APC savings calculated. To determine the annual growth for each of the 40 years, the slope between the two points was used to extrapolate the benefits for every year beyond 2022 over a 40 year timeframe. Each year's benefit was then discounted using an 8% discount rate. The sum of all discounted benefits was presented as the Net Present Value (NPV) benefit. This calculation was performed for every zone.

The zonal, state, and regional benefits for the economic projects are shown in Table 12.13 and Table 12.14. The calculation treated the benefit due to the economic and policy projects and the cost of the economic projects as incremental to those of the reliability projects. The policy projects were treated as a sunk cost ($0)[28].

The zonal, state, and regional benefits for the full portfolio are shown in Table 12.15 and Table 12.16. The calculation measured the benefit and cost due to the ITP10 reliability, economic, and policy projects. The policy projects were not treated as a sunk cost.

[26] The SPP OATT requires that the portfolio be evaluated using a forty-year financial analysis.

[27] A simulation of 2027 was also performed but not used, but due to an unrealistic increase in benefit caused by load and generation modeling that was not realistic for the system.

[28] This calculation is very similar to the calculation of the 40-year benefits and costs if the economic projects had been considered as incremental to both reliability and policy projects due to the small economic benefit provided by the policy projects in Future 1.

Zone	NPV Benefit	NPV Cost	Net Benefit	B/C
AEPW	$83,266,109	$57,310,655	$25,955,454	1.45
EMDE	$22,835,765	$6,793,664	$16,042,100	3.36
GMO	-$6,070,791	$10,849,955	-$16,920,746	-0.56
GRDA	-$42,530,388	$5,076,584	-$47,606,972	-8.38
KCPL	$18,849,350	$33,128,283	-$14,278,933	0.57
LES	$5,443,852	$4,827,732	$616,119	1.13
MIDW	$27,361,849	$1,717,080	$25,644,769	15.94
MKEC	-$147,340,551	$3,185,308	-$150,525,859	-46.26
NPPD	$187,703,606	$17,071,259	$170,632,347	11.00
OKGE	$63,643,127	$35,212,582	$28,430,545	1.81
OPPD	$90,844,361	$12,591,920	$78,252,441	7.21
SPCIUT	$17,335,100	$3,931,864	$13,403,236	4.41
SUNC	$62,975,668	$2,612,948	$60,362,720	24.10
SWPS	$267,281,156	$58,386,878	$208,894,278	4.58
WEFA	$50,075,149	$8,386,318	$41,688,831	5.97
WRI	$196,309,605	$41,138,822	$155,170,783	4.77
Total	$897,982,966	$302,221,853	$595,761,114	2.97

Table 12.13: Forty-Year Zonal Benefit & Cost – Economic Projects Only

State	NPV Benefit	NPV Cost	Net Benefit	B/C
AR	$16,903,020	$11,634,063	$5,268,957	1.45
KS	$148,165,765	$64,224,450	$83,941,314	2.31
LA	$10,574,796	$7,278,453	$3,296,343	1.45
MO	$44,090,229	$39,133,473	$4,956,756	1.13
NE	$283,991,819	$34,490,911	$249,500,908	8.23
NM	$64,414,759	$14,071,238	$50,343,521	4.58
OK	$109,086,412	$72,876,725	$36,209,687	1.50
TX	$220,756,166	$58,512,539	$162,243,627	3.77
Total	$897,982,966	$302,221,853	$595,761,114	2.97

Table 12.14: Forty-Year State Benefit & Cost – Economic Projects Only

Zone	NPV Benefit	NPV Cost	Net Benefit	B/C
AEPW	-$46,138,200	$405,892,417	-$452,030,616	-0.11
EMDE	-$7,809,791	$41,503,534	-$49,313,325	-0.19
GMO	-$34,252,090	$69,388,624	-$103,640,714	-0.49
GRDA	-$12,221,504	$31,013,630	-$43,235,134	-0.39
KCPL	$59,798,238	$137,968,977	-$78,170,738	0.43
LES	-$40,388,080	$29,493,354	-$69,881,434	-1.37
MIDW	$37,363,121	$10,489,904	$26,873,217	3.56
MKEC	-$466,583,293	$32,672,105	-$499,255,398	-14.28
NPPD	$972,211,335	$114,639,262	$857,572,073	8.48
OKGE	$68,851,048	$238,238,378	-$169,387,330	0.29
OPPD	$40,768,413	$76,925,964	-$36,157,551	0.53
SPCIUT	$14,998,925	$24,020,360	-$9,021,435	0.62
SUNC	$192,421,082	$15,962,898	$176,458,184	12.05
SWPS	$1,113,154,725	$283,583,751	$829,570,974	3.93
WEFA	$21,444,166	$68,074,870	-$46,630,705	0.32
WRI	$768,574,930	$268,037,068	$500,537,862	2.87
Total	$2,682,193,024	$1,847,905,094	$834,287,930	1.45

Table 12.15: Forty-Year Zonal Benefit & Cost – All Projects

State	NPV Benefit	NPV Cost	Net Benefit	B/C
AR	-$9,366,055	$82,396,161	-$91,762,215	(0.11)
KS	$559,881,011	$392,007,394	$167,873,617	1.43
LA	-$5,859,551	$51,548,337	-$57,407,888	(0.11)
MO	$4,630,111	$208,036,076	-$203,405,965	0.02
NE	$972,591,668	$221,058,579	$751,533,089	4.40
NM	$268,270,289	$68,343,684	$199,926,605	3.93
OK	$75,992,783	$506,778,847	-$430,786,065	0.15
TX	$816,052,769	$317,736,016	$498,316,752	2.57
Total	$2,682,193,024	$1,847,905,094	$834,287,930	1.45

Table 12.16: Forty-Year State Benefit & Cost – All Projects

Sensitivities

The net benefit impact percentages for the 2012 ITP10 Sensitivities are summarized in Table 12.18. The affects of varying inputs (natural gas price, demand, effluent taxes) in the economic models were captured for the incremental addition of economic projects to the reliability projects.

The conclusion that can be reached from this data is that, in the case of future 1, the net benefit provided by the economic projects is greatest when the natural gas price is higher than the expected gas price but the demand levels are at their expected values. The calculation treated the benefit due to the economic and policy projects and the cost of the economic projects as incremental to those of the reliability projects. The policy projects were treated as a sunk cost ($0)[29].

Future 1 Sensitivity	% change in net benefit
High Natural Gas & Demand	8.7%
High Natural Gas	20.4%
Expected Natural Gas & Demand	N/A
Low Natural Gas & Demand	-19.6%
Low Natural Gas	-19.9%

Table 12.17: 2012 ITP10 Future 1 Sensitivity Results (values shown in millions)

Future 2 Sensitivity	% change in net benefit
High Natural Gas & Demand	13.3%
High Natural Gas	12.3%
Expected Natural Gas & Demand	N/A
Low Natural Gas & Demand	-14.1%
Low Natural Gas	-10.4%
High CO_2, SO_2, and NO_X Taxes	15.5%
High Carbon Tax	N/A
Expected Carbon Tax (F2 Only)	-16.3%
Low Carbon Tax	13.3%

Table 12.18: 2012 ITP10 Future 2 Sensitivity Results (values shown in millions)

The range of B/C ratios due to these sensitivities on a forty-year basis for Future 1 are shown in Table 12.18. Under each of the sensitivities, B/C of the economic projects was greater than 1.0.

Future 1 Sensitivity	B/C
High Natural Gas & Demand	3.23
High Natural Gas	3.58
Expected Natural Gas & Demand	2.97
Low Natural Gas & Demand	2.39
Low Natural Gas	2.38

Table 12.19: 2012 ITP10 Future 1 Sensitivity Results (B/C's) – Economic Projects

12.8: Capacity Savings & Reduced Losses

Reduced 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 within the footprint, losses are reduced. Table 12.20 shows losses for the change in system losses due to the transmission portfolios.

	Base	Reliability	Policy	Economic
Future 1	2,896	-54	-10	-25
Future 2	3,509	-61	-10	-24

Table 12.20: Base and Changes in Total System Losses

The 2012 ITP10 recommended portfolio (which includes reliability, policy, and economic projects) eliminated 25 MW of SPP losses in Future 1 and 24 MW of SPP losses in Future 2. The policy projects

[29] This calculation is very similar to the calculation of the 40-year benefits and costs if the economic projects had been considered as incremental to both reliability and policy projects due to the small economic benefit provided by the policy projects in Future 1.

had added substantial losses back into the system, but these additions were more than offset by the savings created by the reliability and economic projects.

Positive Impact on Losses Capacity

Utilizing approximations provided by the Benefit Analysis Techniques Task Force (BATTF)[30] of $750 per kW of installed capacity, the amount saved by offsetting the required capacity through reduction of losses was equal to the decrease in losses of the change case, multiplied by 112% (to account for the reduction in the capacity requirement) and an estimated ATRR for the capacity additions. Table 13.5 shows the savings due to the decreased capacity needed to cover system losses.

	Base	Reliability	Policy	Economic
Future 1	-	7.7	1.	3.6
Future 2	-	8.7	1.4	3.4

Table 12.21: Monetary benefit due to changes in losses ($ millions)

The ITP10 recommended portfolio provides a $3.6 million savings in Future 1 and $3.4 million savings in Future 2 due to the reduced need for capacity to account for system losses.

[30] The functions performed by the BATTF are today handled by the ESWG.

Section 13: Conclusion

The 2012 ITP10 finalized portfolio is a grouping of projects that will meet the projected reliability, economic, and policy needs under a variety of multiple futures. The portfolio outlines transmission that proved flexible enough to meet the criteria requirements, capitalize upon economic opportunities, and fulfill public policy needs of the SPP membership within the next ten years.

The finalized portfolio succeeded in meeting the goals outlined in each of the futures. The projects in the portfolio were studied through a rigorous process that utilized a diverse array of power system and economic analysis tools to evaluate the need for 100 kV and above facility projects that satisfy needs such as:

a) resolving potential criteria violations;
b) mitigating known or foreseen congestion;
c) improving access to markets;
d) staging transmission expansion; and
e) improving interconnections.

Confidence in the findings of the study was encouraged through the use of multiple assessment methodologies that evaluated the system from different perspectives. This brought about thorough vetting of each project. Study tools and drivers were successfully benchmarked against historical expectations, cost estimates were developed with improved rigor, sensitivities were performed upon economic project to ensure their viability in multiple scenarios, stakeholders provided continuous feedback concerning the technical details of needs identified in the system, the study findings and projects selected were consistent with the vision cast by the 2010 ITP20, and the utilization of two futures that book-ended the expected policy climate in the next ten years created a portfolio that was designed to respond to SPP's evolving needs.

Strategic, long-term development of the SPP transmission grid was considered at every stage of the analysis. The projects outlined in the 2010 ITP20 were studied within the 10-year horizon to determine which of the projects would be needed, analysis of the economic impact of the portfolio upon ratepayers and SPP stakeholders was evaluated over the expected life of the transmission projects, and efficiencies were sought across the footprint that multiple short-term mitigations might be deferred by more strategic economic projects.

Stakeholder's provided review, direction, technical expertise, and project suggestions throughout the study process. Multiple meetings, teleconferences, and communications exchanged provided transparency and ensured both regional and local considerations were taken into account.

The 2012 ITP10 by the numbers

- The technical simulations passed each of the **7** benchmarks run against the simulation.
- The projects provided **$834 million of net savings** over their expected 40-year life.
- More than **61** potential reliability issues were mitigated by the projects.
- **Zero** voltage or transient stability concerns were identified related to the portfolio.
- The portfolio reduced CO_2 emissions equivalent to that needed to power **53,001** homes annually.
- The portfolio enabled the achievement of renewable goals and targets in **3** additional states: Oklahoma, Kansas and Nebraska.
- **500** miles of the new transmission in the portfolio coincided with the 2010 ITP20 plan.
- As a result of the portfolio, the average residential customer in SPP will see a decrease in their monthly electric bill of **34¢**.

Project need dates were identified as early as 2014 and as late as 2022. Several projects were identified for ATP status and one project for NTC status. The remaining projects were identified to receive CNTCs. Figure 13.1 shows a timeline of the projects with a magnitude of the expected project costs. The cost of the entire portfolio was estimated at $1.5 billion (engineering and construction costs). The portfolio is shown in Figure 13.2.

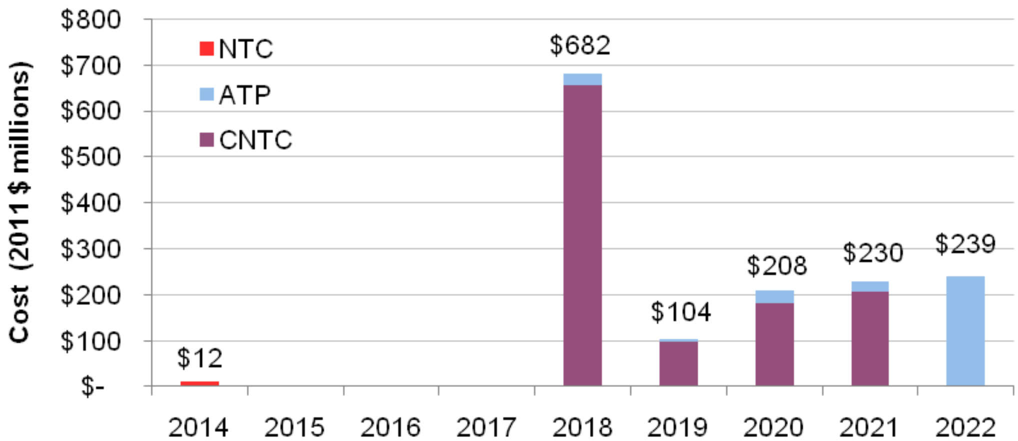


Figure 13.1: Project Costs by Need by Year ($ millions)

Nine projects make up the greater part of the portfolio:

- Lake Hawkins – Welsh 345 kV line with a 345/138 kV transformer at Lake Hawkins
- Elk City – Gracemont 345 kV line with a 345/230 kV transformer at Elk City
- Woodward – Tatonga – Cimarron 345 kV line, a second circuit
- Summit – Elm Creek 345 kV line with a 345/230 kV transformer at Elm Creek
- Neligh – Hoskins 345 kV line with a 345/115 kV transformer at Neligh
- Gentleman – Cherry Co. – Holt Co. 345 kV line with two substations
- Eastowne Transformer 345/161 kV
- Moundridge Transformer 138/115 kV
- Tuco – Amoco – Hobbs 345 kV with 345/230 kV transformers at Amoco and Hobbs

Three of these projects were specifically selected based upon the incremental economic value they provided to the footprint. The Eastowne transformer project relieved significant congestion near Kansas City, MO and provided a net economic benefit of more than $2.5 million. The Moundridge transformer project provided economic benefits of $35 million in Future 1 and $9 million Future 2. This project relieved congestion north of Wichita, KS. The largest economic project, the Tuco – Amoco – Hobbs 345 kV line and transformers, provided benefit in excess of its cost and deferred the need of a reliability project. This project demonstrated an incremental B/C of 2.2 in Future 1 and 1.6 in Future 2.

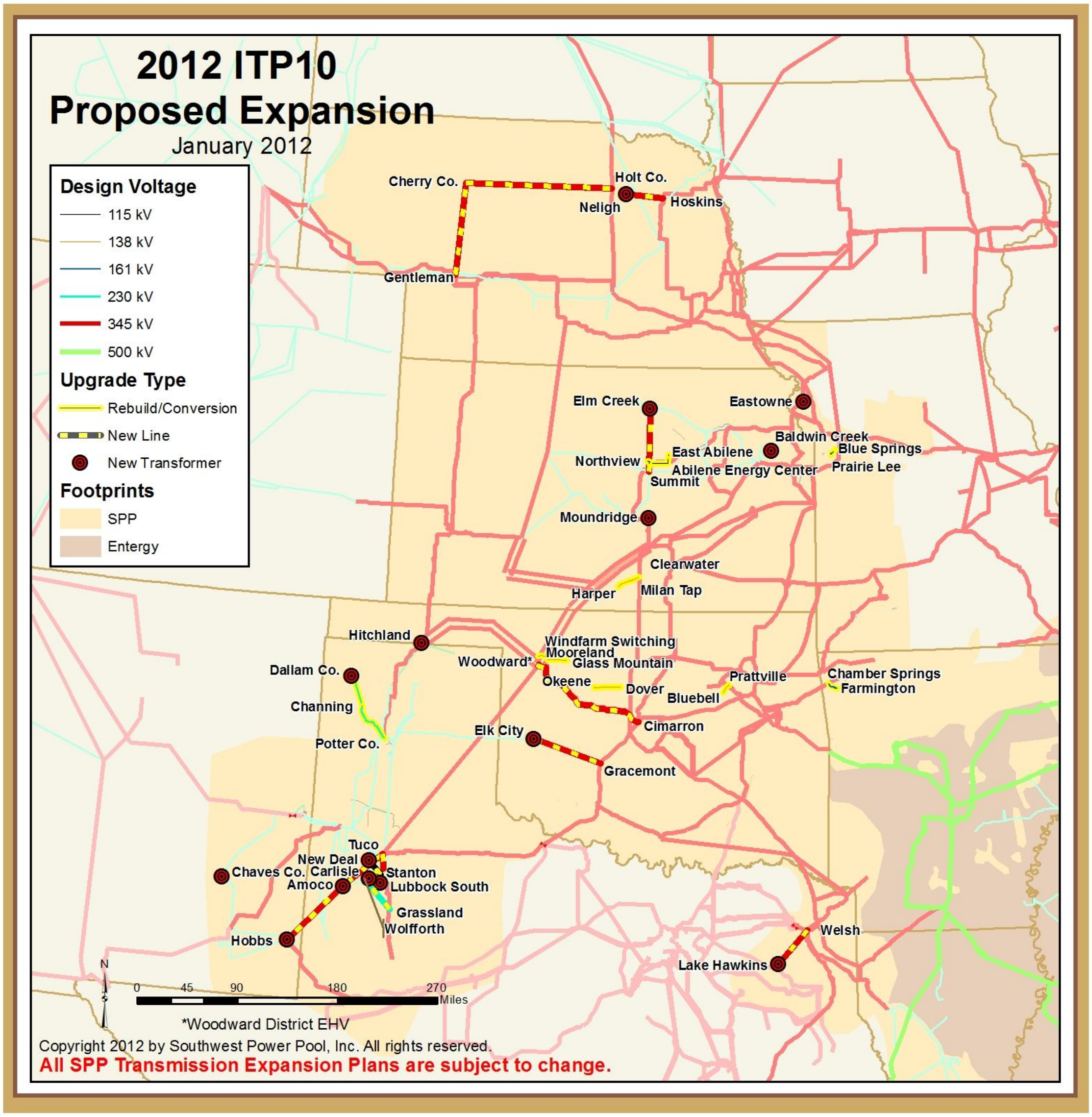


Figure 13.2: Finalized 2012 ITP10 Portfolio

PART IV: APPENDICES

Section 14: Glossary of Terms

The following terms are referred to throughout the report.

Acronym	Description	Acronym	Description
APC	Adjusted Production Cost	**ITPNT**	Integrated Transmission Plan Near-Term Assessment
APC-based B/C	Adjusted Production Cost based Benefit to Cost ratio	**ITP10**	Integrated Transmission Plan 10-Year Assessment
ATC	Available Transfer Capability	**ITP20**	Integrated Transmission Plan 20-Year Assessment
ATSS	Aggregate Transmission Service Studies	**JPC**	Joint Planning Committee
ATRR	Annual Transmission Revenue Requirement	**LIP**	Locational Imbalance Price
BATTF	Benefit Analysis Techniques Task Force	**LMP**	Locational Marginal Price
B/C	Benefit to Cost Ratio	**MDWG**	Model Development Working Group
BA	Balancing Authority	**MISO**	Midwest ISO
BOD	SPP Board of Directors	**MOPC**	Markets and Operations Policy Committee
Carbon Price	The tax burden associated with the emissions of CO_2	**MTF**	Metrics Task Force
CAWG	Cost Allocation Working Group	**MVA**	Mega Volt Ampere (10^6 Volt Ampere)
CFL	Compact Fluorescent Bulb	**MW**	Megawatt (10^6 Watts)
CRA	Charles River Associates	**NERC**	North American Electric Reliability Corporation
EHV	Extra-High Voltage	**NOPR**	Notice of Proposed Rulemaking
EIS	Energy Imbalance Service	**NREL**	National Renewable Energy Laboratory
EPA	Environmental Protection Agency	**NTC**	Notification to Construct
ESRPP	Entergy SPP RTO Regional Planning Process	**OATT**	Open Access Transmission Tariff
ESWG	Economic Studies Working Group	**PCM**	Production Cost Model
EWITS	Eastern Wind Integration and Transmission Study	**RES**	Renewable Electricity Standard
FCITC	First Contingency Incremental Transfer Capability	**ROW**	Right of Way
FERC	Federal Energy Regulatory Commission	**RSC**	SPP Regional State Committee
GI	Generation Interconnection	**RTWG**	Regional Tariff Working Group
GIS	Geographic Information Systems	**SIL**	Surge Impedance Loading

GW	Gigawatt (10^9 Watts)	**SPC**	Strategic Planning Committee
HVDC	High-Voltage Direct Current	**SPP**	Southwest Power Pool, Inc.
SPPT	Synergistic Planning Project Team	**TSR**	Transmission Service Request
STEP	SPP Transmission Expansion Plan	**TVA**	Tennessee Valley Authority
TLR	Transmission Loading Relief	**TWG**	Transmission Working Group
TPL	Transmission Planning NERC Standards	**WITF**	Wind Integration Task Force
TO	Transmission Owner		

Section 15:Stability Analysis

15.1: Introduction

2012 ITP10 solutions will be assessed for reliability by examining thermal, voltage, and angular performance. Thermal and voltage performance are normally assessed through the tools of steady state contingency analysis; however, this analysis does not determine the distance to and location of voltage collapse or voltage instability. This must be determined by examining voltage performance during power transfer into a load area or across an interface. Transient analysis must also be performed to assess angular performance of the 2012 ITP10 solutions. This document provides the methods of study as well as the results of these assessments for the 2012 ITP10 Future 1 cases.

15.2: Background

Power system stability is segmented into three classifications[31], rotor angle, frequency, and voltage, as shown in figure 1. The stability studies for the 2012 ITP10 are concerned with large-disturbance voltage stability and rotor-angle transient stability. Frequency stability is not included in the scope of work.

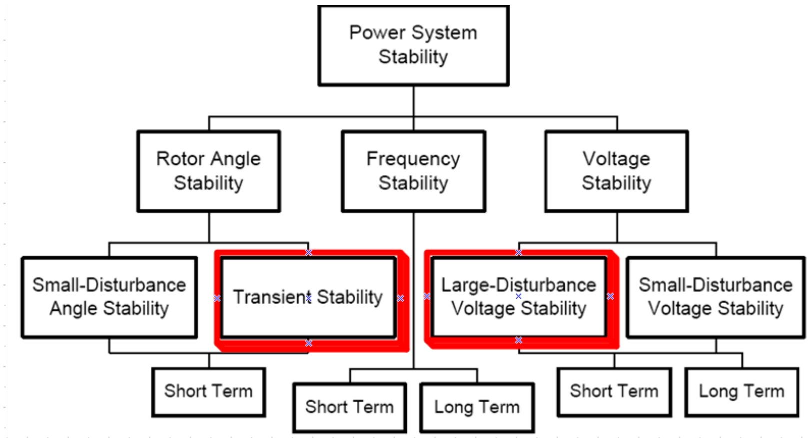


Figure 15.1: Classifications of Power System Stability

Voltage stability is defined as a power system's ability to control voltages following a large disturbance such as a fault or contingency. Voltage stability requires that system voltage characteristics be maintained during periods of high load, large power transfers, or sudden disturbances such as a loss of a generator and/or transmission line.

Transient stability is defined as a power system's ability to remain in synchronism following a large disturbance such as a fault or contingency.

System disturbances can cause a loss of machine synchronism and is dependent on initial conditions such as voltage and power flow, fault location, fault duration, and fault magnitude.

Voltage stability analysis was performed using Voltage Security Assessment Tool (VSAT) and the transient stability analysis was performed using Transient Security Assessment Tool (TSAT). These tools are Powertech Labs, Inc.'s Dynamic Security Assessment (DSA) Tools.

[31] B.C. Ummels, TU Delft, *Power System Operation with Large-Scale Wind Power in Liberalised Environments Thesis*, We@Sea, project 2004-012.

15.3: Objective

The objective of the 2012 ITP10 Stability Analysis is threefold:

Wind Dispatch Analysis:
Confirm that the dispatched generation in the 2012 ITP10 Future 1 Base and Portfolio A 2022 Off-Peak cases can be dispatched without the occurrence of voltage instability.

Load Area Voltage Stability Analysis:
Determine voltage stability limitations and reactive reserve within high load areas in the SPP footprint. This analysis will be assessed using the 2012 ITP10 Future 1 Base and Portfolio A 2022 Summer Peak Cases.

Transient Stability Analysis:
Assess transient stability limitations under contingency conditions for the Future 1 Base and Portfolio A 2022 Summer Peak and Off-Peak Cases.

15.4: Wind Dispatch Analysis

Voltage stability assessments of SPP long and short-term planning efforts provide important insights into the viability and robustness of planning solutions. This year, a wind penetration level assessment was required as part of the 2012 ITP10 planning effort. Specifically, the request was made to determine the amount of wind that could be dispatched in the 2022 Future 1 Base Case and the 2022 Future 1 Portfolio A Case, (October 7, 2011), that will allow sufficient margin to voltage collapse. These cases were provided as output of the PROMOD® security constrained economic dispatch. In addition, the monitoring of NERC flowgates, circuits, and interfaces in the NERC event file was required to determine if voltage instability occurred before flow limits were exceeded.

Method
The method employed to determine the amount of wind generation that could be accommodated in the cases was accomplished in two parts.
As a preparatory step, the wind generation was reduced to minimum levels while simultaneously increasing conventional generation to meet SPP load requirements. At the point of minimum wind generation the case was saved. The saved case was used as the starting point for the transfer study. The wind was increased while the conventional generation was decreased until voltage collapse occurred.

A contingency file was assembled that provided outages on all branches above 200kV as well as all SPP flowgate contingencies as per the latest NERC event file and member suggestions. Monitored elements included all SPP interfaces, circuits, and flowgates that are contained in the NERC event file as well as those additional flowgates that were added by members.

Existing SPP conventional generation was decreased to offset the wind increase. In general base load units were not scaled. Modal analysis was performed at the point of maximum stable transfer with and without the contingency.

The results shown in figure 2 reveal that voltage collapse occurs at 10,473 MW of wind generation in the 2012 ITP10 Future 1 Base Case. The security limit, which is defined as the amount of wind generation that can be safely dispatched, was found to be 10,424 MW. The Future 1 wind case is capable of dispatching approximately 1 GW more than is currently dispatched in the original case which has 9402 MW of Wind. No additional reactive support is required to attain the transfer.

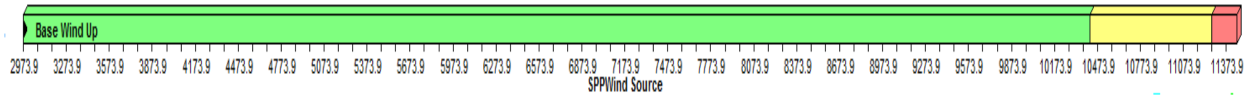


Figure 15.2: Wind Dispatch in Future 1 Base Case

Figure 3 depicts the voltage as a function of the transfer (wind displaces conventional gen), otherwise known as the PV curve, for the most limiting contingency. The buses participating in the collapse are also shown graphically in figure 4.

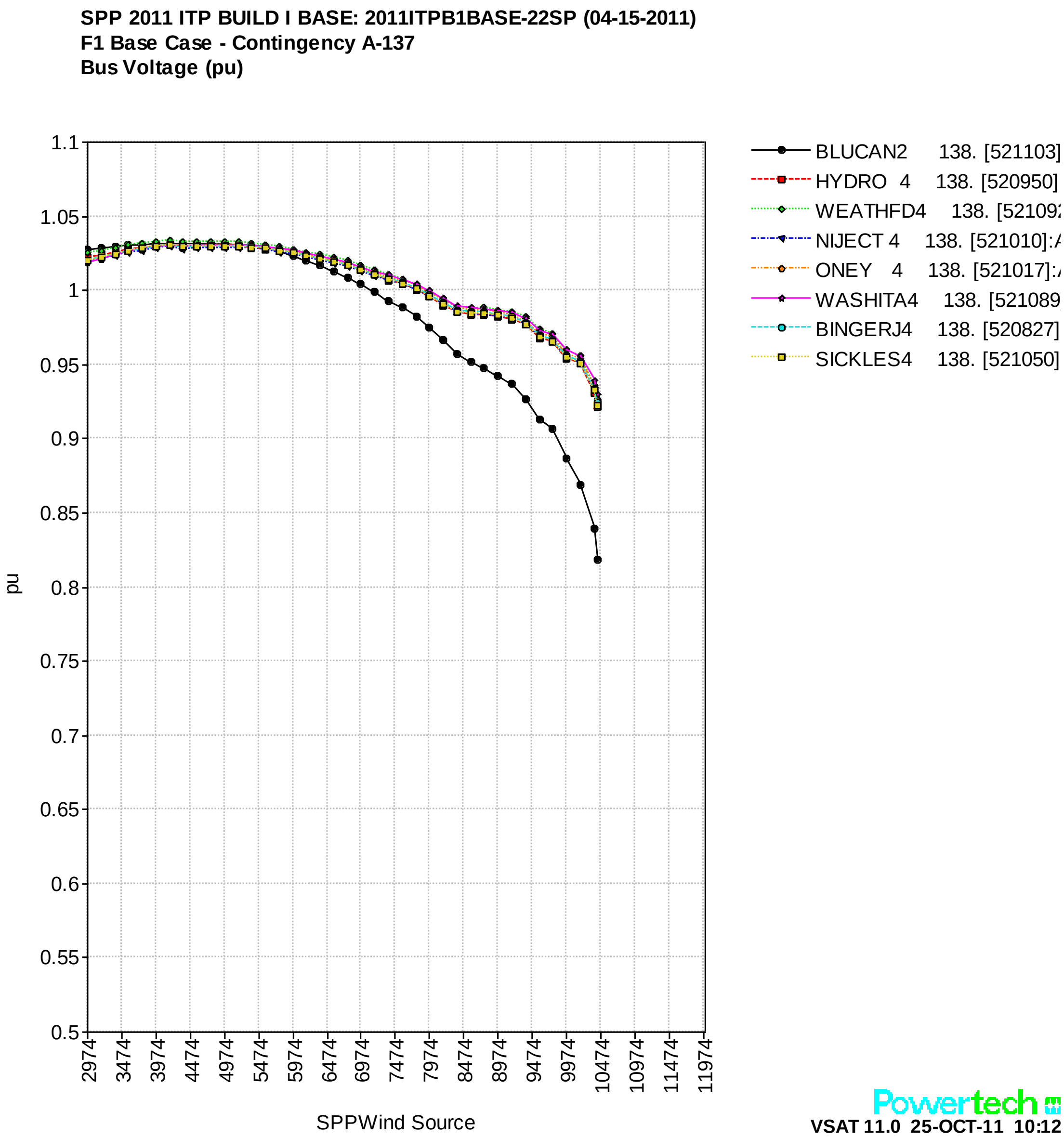


Figure 15.3: Wind Dispatch Voltage Collapse at selected buses for Future 1 Base Case (Contingency A–137: Northwest to Tatonga 345kV)

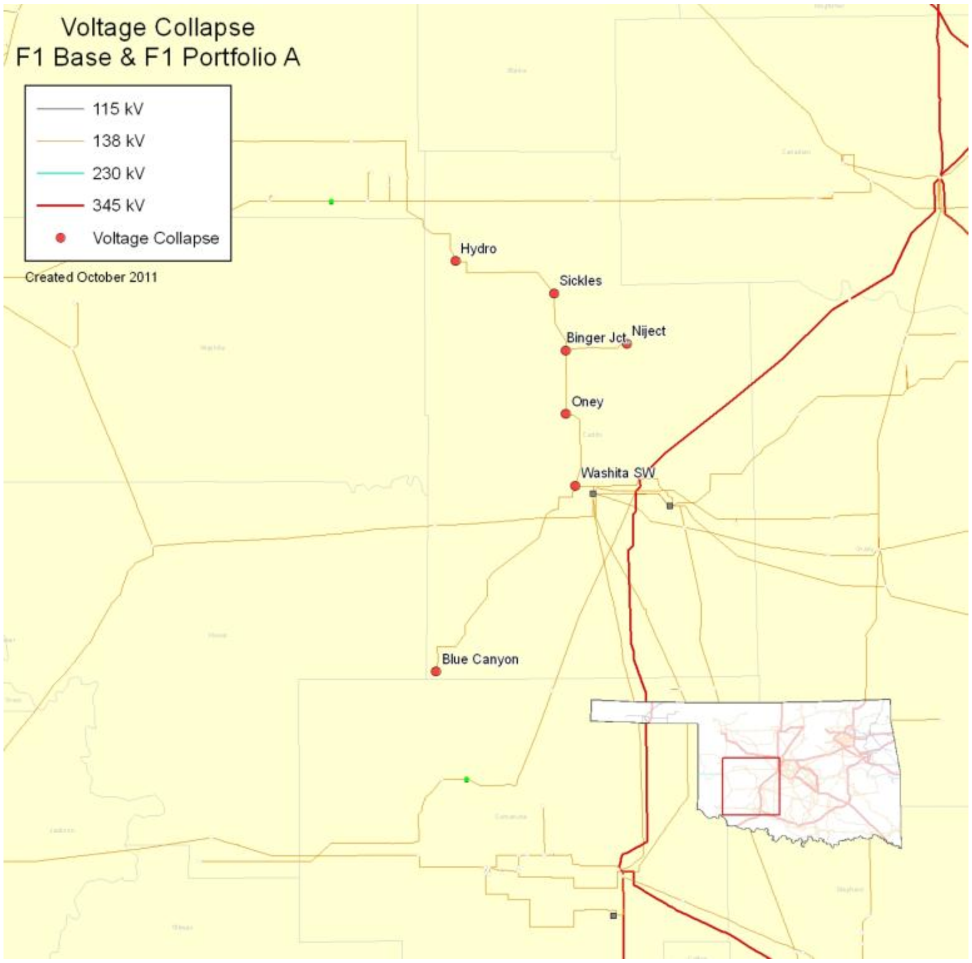


Figure 15.4: Wind Dispatch collapse area for Base and Portfolio A Case

The results shown in figure 5 indicate that instability occurs at the 11,283MW wind generation level in the 2012 ITP10 Future 1 Portfolio A Case. The security limit was found to be 11,133MW. The Future 1 wind case is capable of dispatching approximately 1.9 GW more than is currently dispatched in the original case and 709MW more than the Base Case. No additional reactive support is required to attain the transfer.

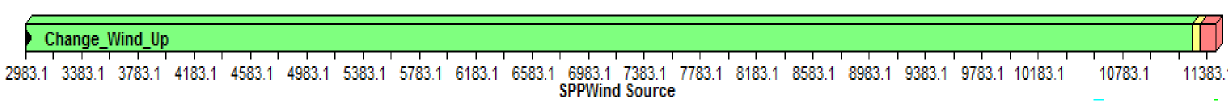


Figure 15.5: Wind Dispatch in Future 1 Portfolio A

Voltage Collapse occurs at a wind output of 11,133 MW in pre-contingency. The PV curves for the areas of collapse are shown in figure 6. In this case the collapse occurred in pre-contingency.

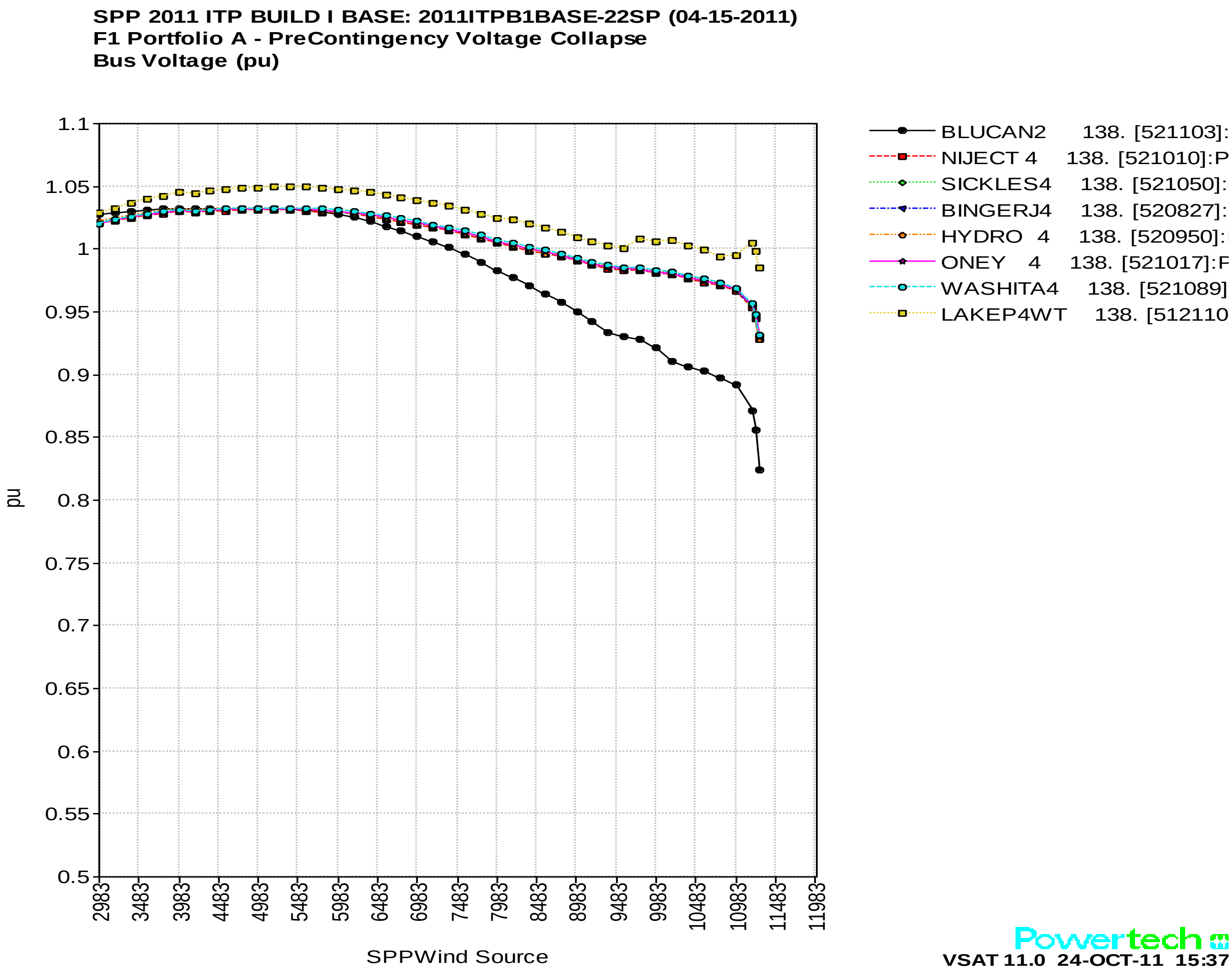


Figure 15.6: Wind Dispatch Voltage Collapse at selected buses for Future 1 Portfolio A

It should be noted the areas of collapse in both the Future 1 (F1) Base Case and F1 Portfolio A cases are almost identical, and are also shown graphically in Figure 15.6 (Pre-contingency voltages for selected buses).

The amount of wind that could be dispatched in the 2022 Future 1 Portfolio A Case, (October 7, 2011), is 709 MW more than is dispatched in the Future 1 Base Case.

15.5: Load Area Analysis

A total of eight load areas, or "pockets" were selected and prioritized for the 2012 ITP10 voltage stability analysis. These load areas are shown in table 1 and figure 7. Analysis was performed by increasing load within the load pocket while increasing transfer to the load area from adjacent areas. The transfer was increased while under contingency until voltage collapse occurred on the transmission system inside the load area. This provides a load area increase limit as well as the amount of reactive reserve available at the collapse point.

Load increase margins to collapse as well as reactive reserve margins have not been used in this study since criteria for these margins have not been specified in the SPP Criteria documentation.

Scenario	Load Area
1	Central Nebraska
2	South Oklahoma
3	West Arkansas
4	SPS - Amarillo
5	South Central Westar
6	Northeast Westar
7	Oklahoma City
8	Lincoln/Omaha

Table 15.1: Load Areas

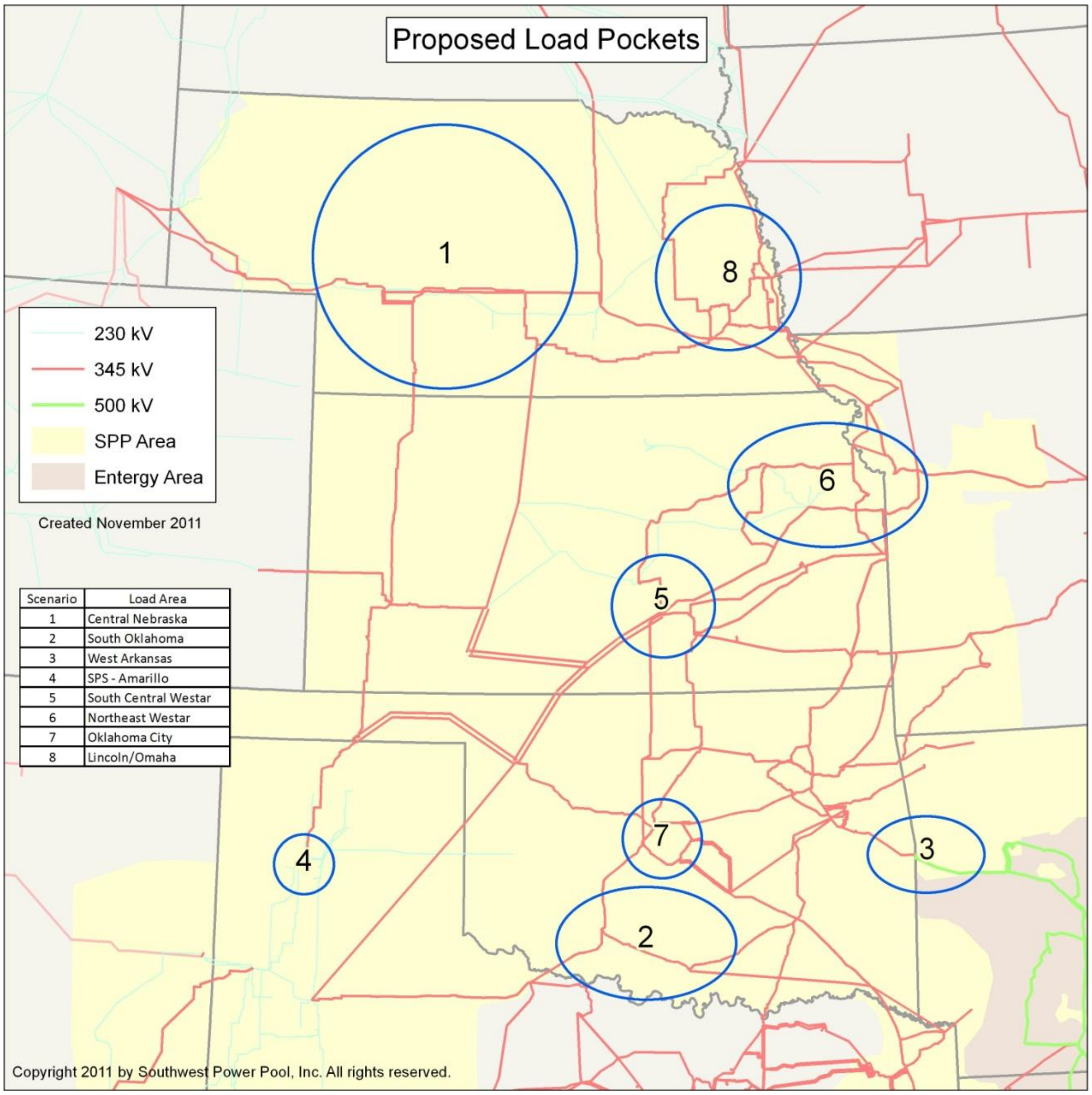


Figure 15.7: Load Areas for 2012 ITP10 Analysis

The contingencies consist of a selected single generation outage (G-1) with all branch outages (T-1), or one generator and one transmission branch within the load area removed from service. The selected G-1 outage is the generator within the load area that, when compared to others within the load area, causes the highest degree of voltage instability stress during the transfer. This generator was paired with all T-1 contingencies, which consisted of all branches greater than 100 kV within the load area.

Central Nebraska

The Central Nebraska load area under this study is defined by the following area in table 2:

Area	Zone
640 NPPD	All

Table 15.2: Central Nebraska Load Area

Voltage instability was found in area 640 during the ITP20 Voltage stability analysis and a recommendation was made by the Transmission Working Group (TWG) that further analysis should be performed in the 2012 ITP10.

The 2012 ITP10 load area analysis was performed by importing generation into the Central Nebraska area while increasing both real and reactive load in the load area in proportion to the initial MW output of each source generator for both the F1 base case and the F1 Portfolio A Case. Voltage instability occurs on the 115kV transmission system subsequent to a load pocket increase of approximately 24.1% or 840 MW.

Figure 8 shows the 115kV buses that have the highest participation in the collapse for both the base and upgrade case.

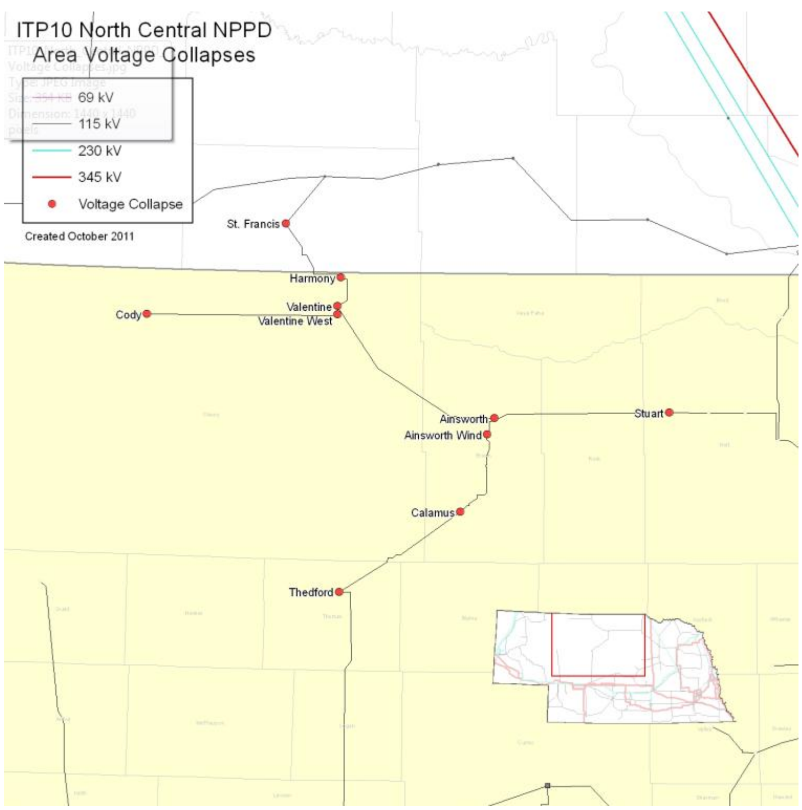


Figure 15.8: Central Nebraska Load Area Buses Experiencing Voltage Collapse

The P-V curves shown below in figure 9 are provided for the 115kV buses in figure 8 above for the limiting contingency.

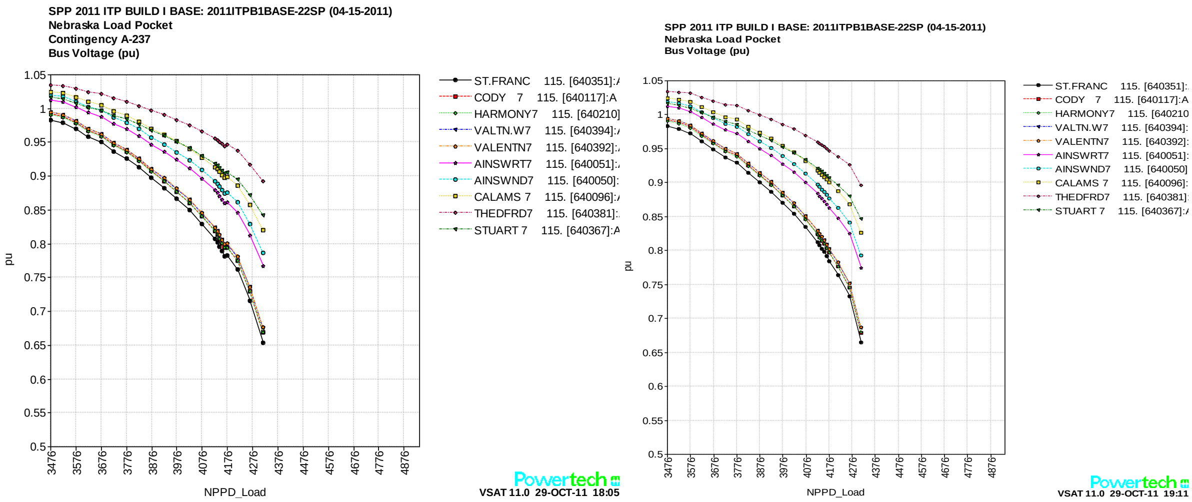


Figure 15.9: Central Nebraska Load Area PV Curves for F1 Base and F1 Portfolio A Cases (G-1, T-1 Contingency: Gentleman 1 and St. Francis to Mission 115kV)

South Oklahoma

The South Oklahoma load area under this study is defined by the following zones:

Area	Zone
520 AEPW	533 WTU
	549 PSO Western
525 WFEC	589 AEP CS
	590 AEP KP
	591 FLA
	592 AEP IM-I

Table 15.3: South Oklahoma Load Area

During the 2010 ITP20 wind transfer analysis, voltage instability was found in the table 3 zones and a recommendation was made by the Transmission Working Group that further analysis should be performed for this load area in the 2012 ITP10 analysis.

Load area analysis was performed by importing generation into the South Oklahoma load area and increasing both real and reactive load in proportion to the initial MW output of each source generator for both the F1 Base Case and the F1 Portfolio A Case. The 69 kV loads were equivalenced to the 138 kV system buses in the load zones. Voltage instability occurs on the 138kV transmission system subsequent to a load pocket increase of approximately 47.6% or 830 MW.

Figure 10 shows the 138kV buses that have the highest participation in the collapse for both the base and upgrade case.

Figure 15.10: South Oklahoma Load Area Buses Experiencing Voltage Collapse

The P-V curves shown below in figure 11 are provided for the 138kV buses in figure 10 above for the limiting contingency.

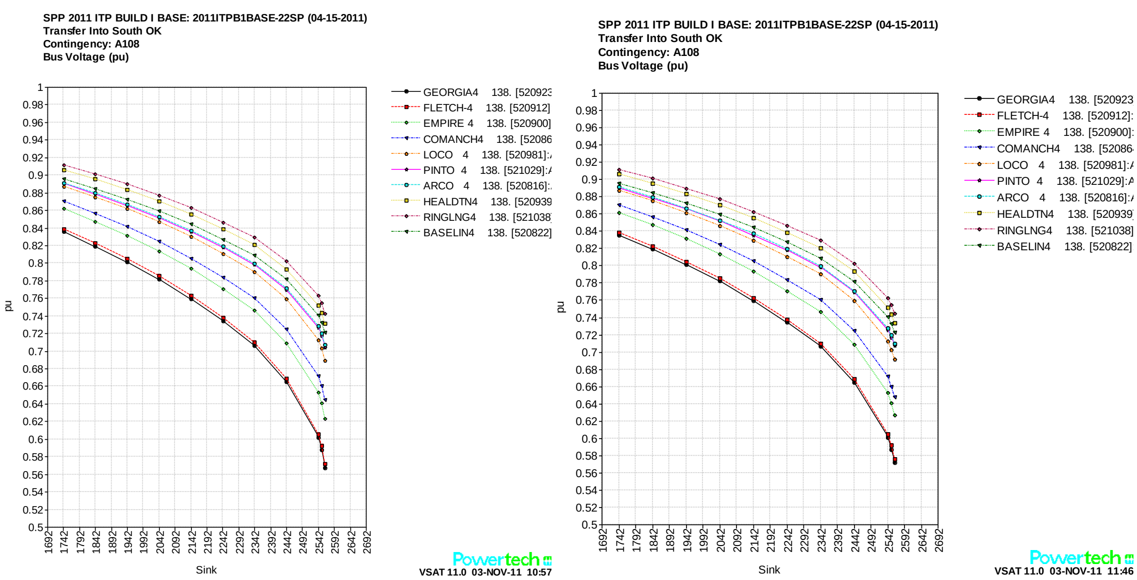


Figure 15.11: South Oklahoma Load Area PV Curves for Base and Portfolio A Cases (G-1, T-1 Contingency: SWS 3 and Anadarko to Georgia 138kV)

West Arkansas

The West Arkansas load area under this study is defined by the following zones:

Area	Zone
520 AEPW	525 Greenwood
	526 S. Arkansas
	543 Greenwood AECC
	544 S. Arkansas AECC
	548 PSO Eastern
524 OKGE	565 Muskogee
	570 Ft. Smith
525 WFEC	593 AEP CS I

Table 15.4: West Arkansas Load Area

During the ITP20 wind transfer analysis, voltage instability was found in the table 4 zones and recommendation was made by the Transmission Working Group that further analysis should be performed for this load area in the 2012 ITP10.

Load area analysis was performed by importing generation into the East OK/West AR area while increasing both real and reactive load in proportion to the initial MW output of each generator for both the F1 Base Case and the F1 Portfolio A Case. The 69 kV loads were equivalenced to the 161 kV system buses in the load zones. Voltage instability occurs on the 161 kV transmission system subsequent to a load pocket increase of approximately 45.1% or 1,271 MW.

Figure 12 shows the 161 kV buses that have the highest participation in the collapse for both the base and upgrade case.

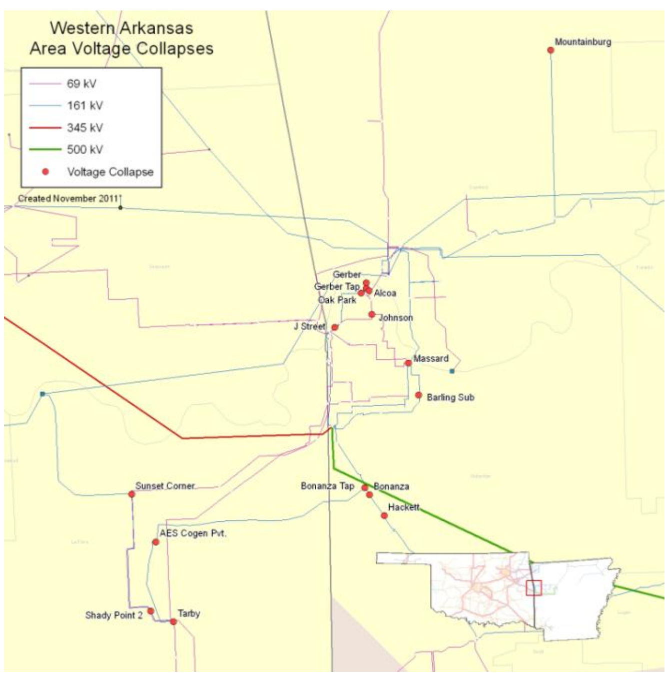


Figure 15.12: Western AR Load Area Buses Experiencing Voltage Collapse

The P-V curves shown below in figure 13 are provided for the 161 kV buses in Figure 12 above for the limiting contingency.

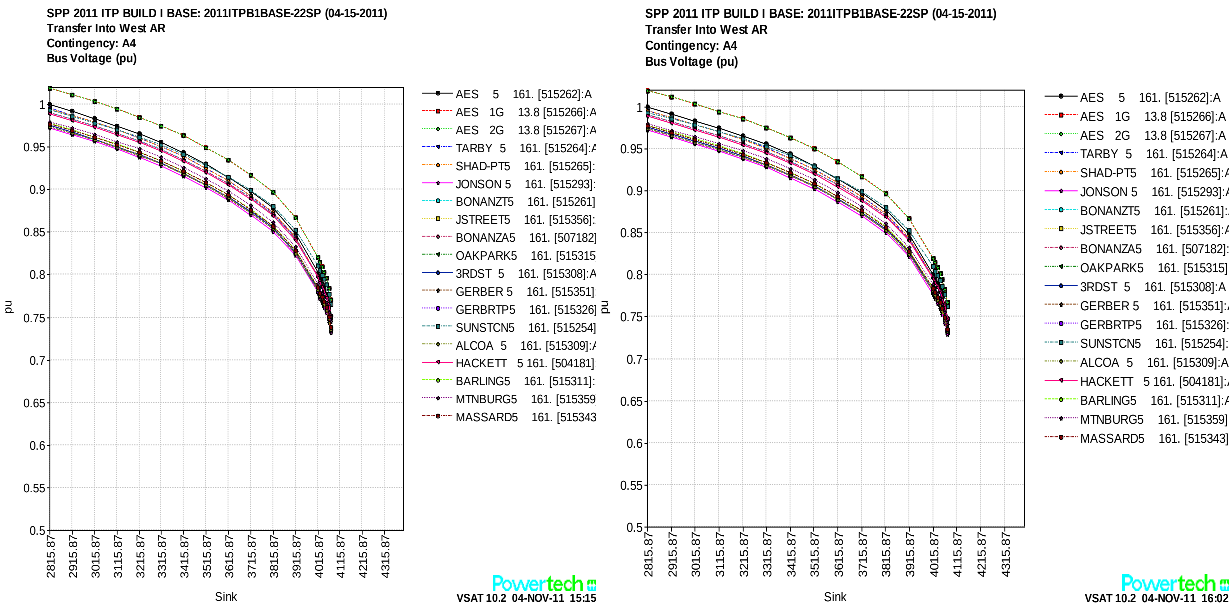


Figure 15.13: Western AR Load Area PV Curves for Base and Portfolio A Cases (G-1, T-1 Contingency: FITZ CT1 and Ft. Smith to ANO 500 kV)

SPS Amarillo

The SPS Amarillo, TX load area under this study is defined by the following zone in table 5:

Area	Zone
526 SPS	1503 Amarillo

Table 15.5: SPS Amarillo, TX Load Area

The Load area analysis was performed by importing generation into the Amarillo, TX area while increasing both real and reactive load in proportion to the initial MW output of each source generator for both the F1 Base Case and the F1 Portfolio A Case. Voltage instability occurs on the 115 kV transmission system subsequent to a load pocket increase of approximately 82.4% or 630 MW in the F1 Base Case and 85.0% or 650 MW in the F1 Portfolio A Case.

Figure 14 shows the 115 kV buses that have the highest participation in the collapse for both the base and upgrade case.

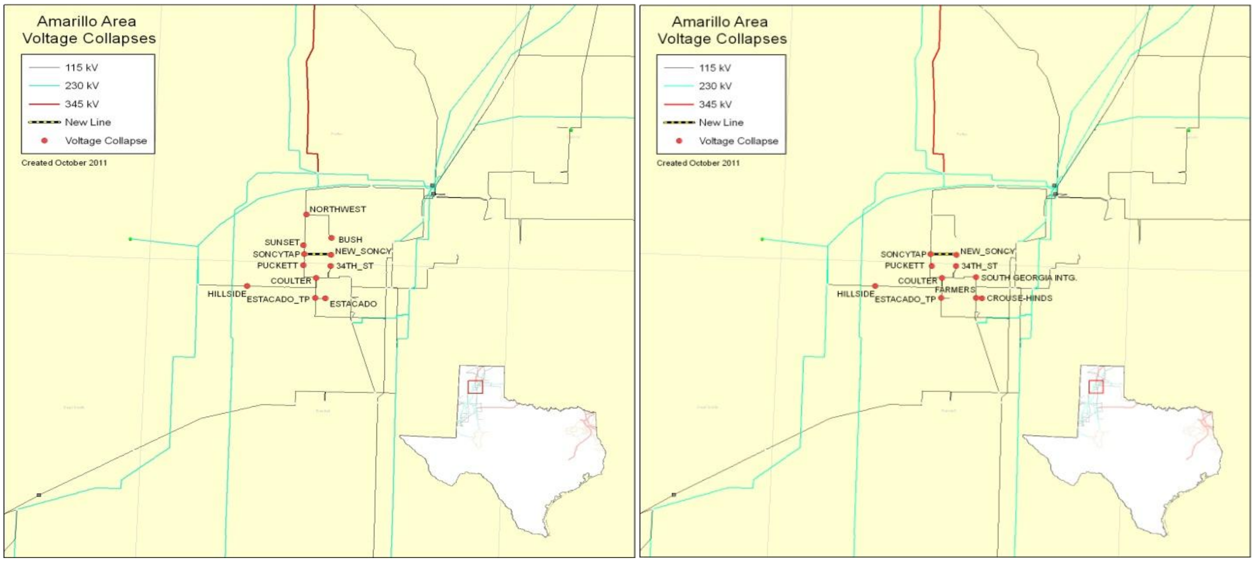


Figure 15.14: Amarillo Load Area Buses Experiencing Voltage Collapse for F1 Base and Grouping A

The P-V curves shown below in figure 15 are provided for the 115kV buses in figure 14 above for the limiting contingency.

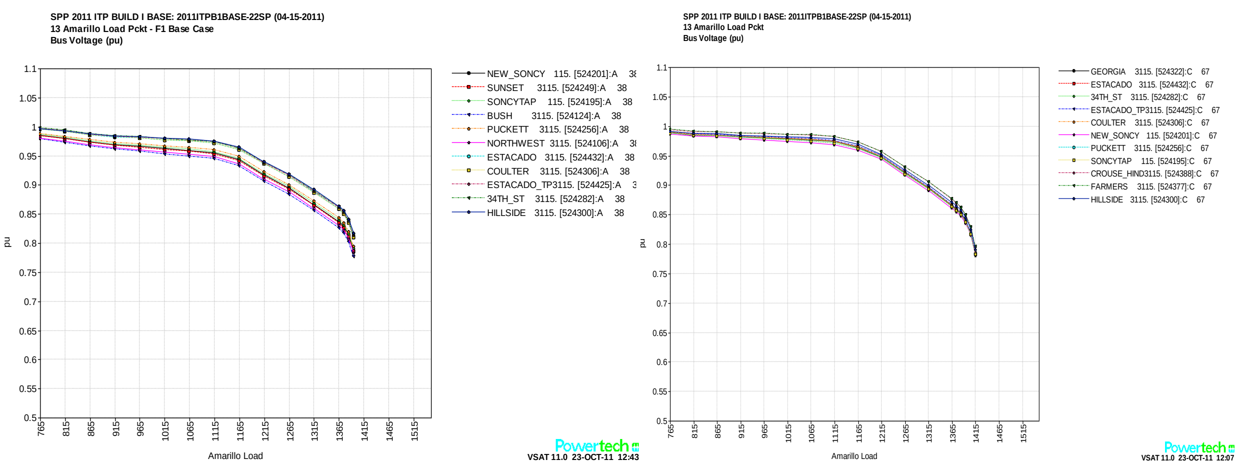


Figure 15.15: Amarillo Load Area PV Curves for F1 Base and F1 Portfolio A Case
(F1 Base Case G-1, T-1 Contingency: Harrington2 and Cherry to Northwest 115 kV)
(F1 Portfolio A Case G-1, T-1 Contingency: Harrington3 and Georgia to Randall 115 kV)

South Central Westar

The South Central Westar Wichita, KS load area under this study is defined by the following zone in table 6:

Area	Zone
536 WERE	1537 South Central

Table 15.6: Wichita, KS Load Area

Load area analysis was performed by importing generation into the Wichita, KS area in South Central Westar while increasing both real and reactive load in proportion to the initial MW output of each source generator for both the F1 Base Case and the F1 Portfolio A Case. The 69 kV load in zone 1537 is equivalenced to the 138 kV system buses. Voltage instability occurs on the 138 kV transmission system subsequent to a load pocket increase of approximately 23.6% or 540 MW in the F1 Base Case and the F1 Portfolio A Case.

Figure 15 shows the 138 kV buses that have the highest participation in the collapse for both the base and upgrade case.

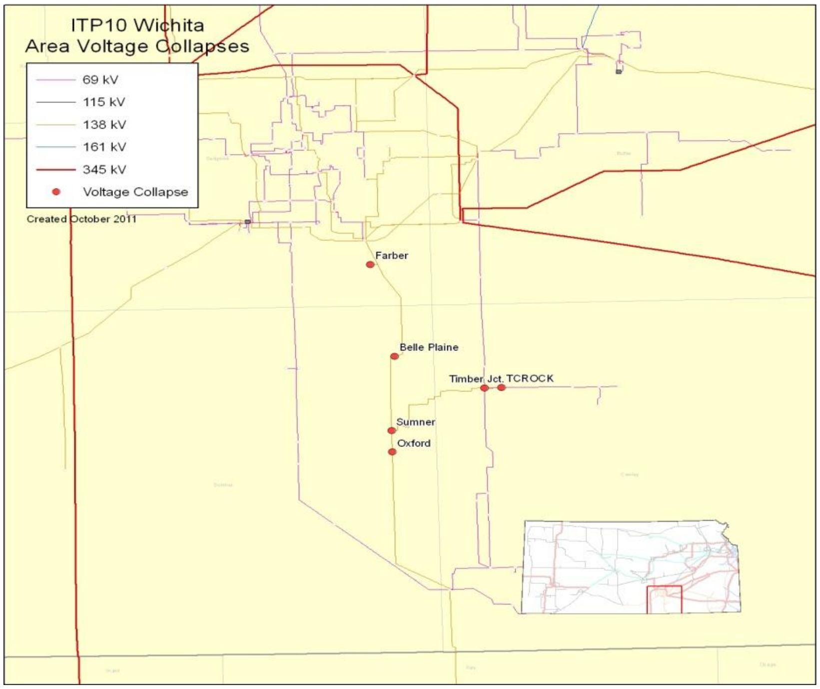


Figure 15.16: Wichita Load Area Buses Experiencing Voltage Collapse

The P-V curves shown below in figure 17 are provided for the 138 kV buses in figure 16 above for the limiting contingency.

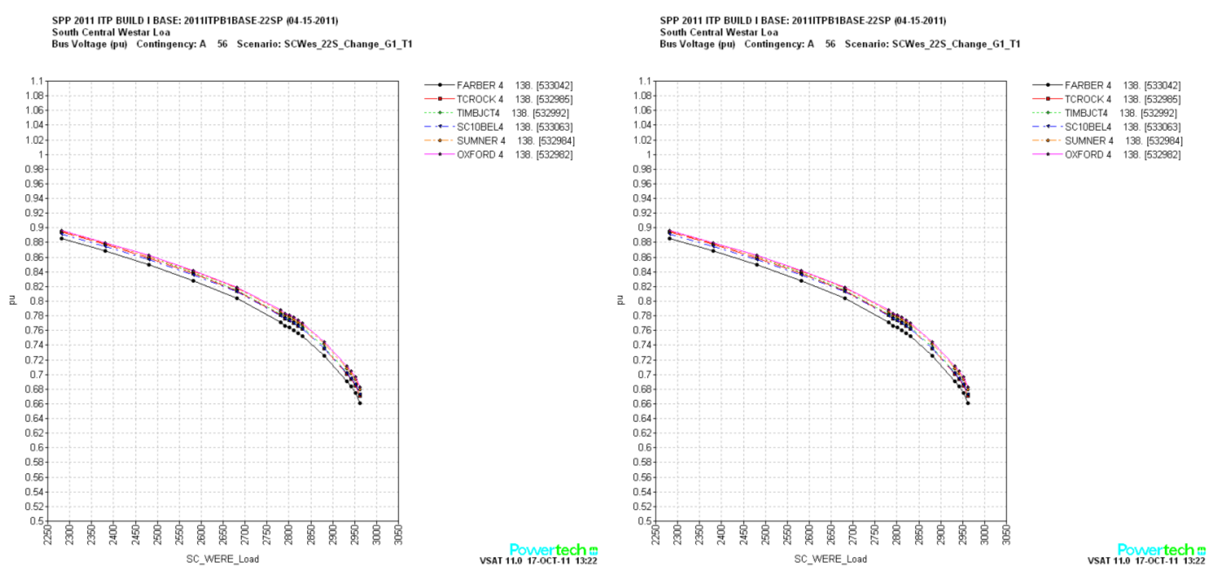


Figure 15.17: Wichita Load Area PV Curves for F1 Base and F1 Portfolio A Case
(G-1, T-1 Contingency: Gorgon Evans U2 and El Paso to Farber 138 kV)

North East Westar

The North East Westar Topeka, KS load area under this study is defined by the following zone in table 7:

Area	Zone
536 WERE	1533 Topeka

Table 15.7: Topeka, KS Load Area

Load area analysis was performed by importing generation into the into Topeka, KS while increasing both real and reactive load in proportion to the initial MW output of each source generator for both the F1 Base Case and the F1 Portfolio A Case. The 69 kV load in zone 1533 is equivalenced to the 115 kV system buses. The 69 kV load from Rock Creek to Wathena is not scaled in this analysis. Voltage instability occurs on the 115 kV and 69 kV transmission system subsequent to a load pocket increase of approximately 78.4% or 1,245 MW in the F1 Base Case and the F1 Portfolio A Case.

Figure 18 shows the 138 kV buses that have the highest participation in the collapse for both the base and upgrade case.

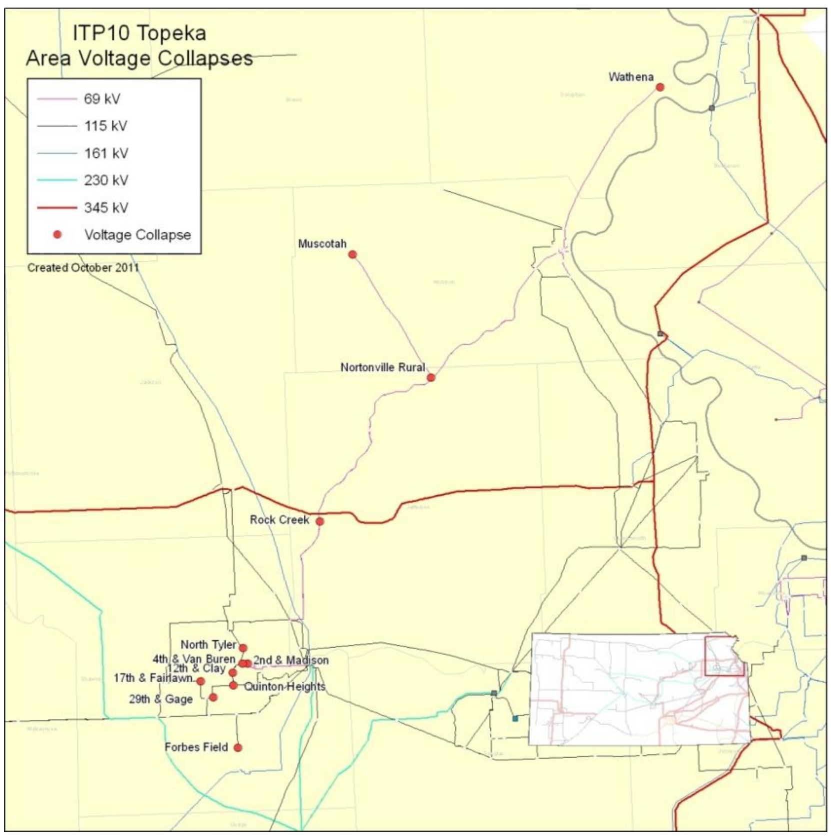
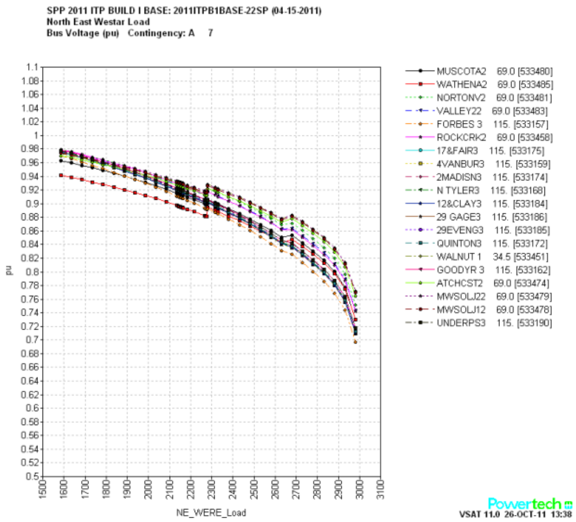


Figure 15.18: Topeka Load Area Buses Experiencing Voltage Collapse

The P-V curves shown below in figure 19 are provided for the 115 kV and 69 kV buses in figure 18 above for the limiting contingency.



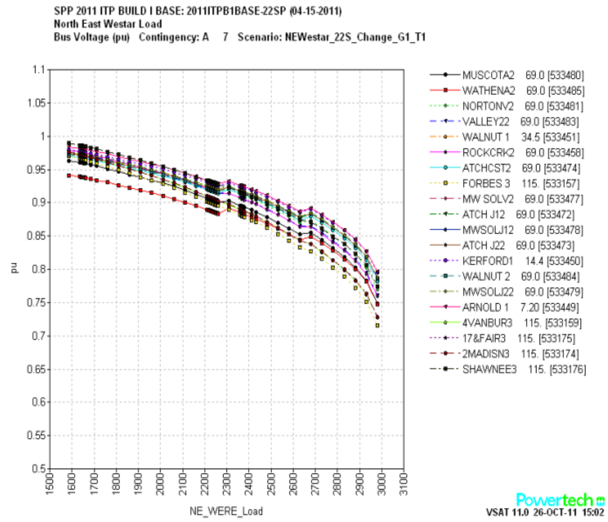


Figure 15.19: Topeka Load Area PV Curves for Base and Portfolio A Cases
(G-1, T-1 Contingency: LEC 5 and Stranger to Iatan 345 kV)

Oklahoma City

The Oklahoma City, OK load area under this study is defined by the following zone in table 8:

Area	Zone
524 OKGE	569
	572

Table 15.8: Oklahoma City, OK Load Area

Load area analysis was performed by importing generation into Oklahoma City in OKGE while increasing both real and reactive load in proportion to the initial MW output of each source generator for both the F1 Base Case and the F1 Portfolio A Case. The 69 kV load in zones 569 and 572 were equivalenced to the 138 kV system buses. Voltage instability occurs on the 138 kV transmission system subsequent to a load pocket increase of approximately 48.7% or 1,550 MW in the F1 Base Case and the F1 Portfolio A Case.

Figure 19 shows the 138 kV buses that have the highest participation in the collapse for both the base and upgrade case.

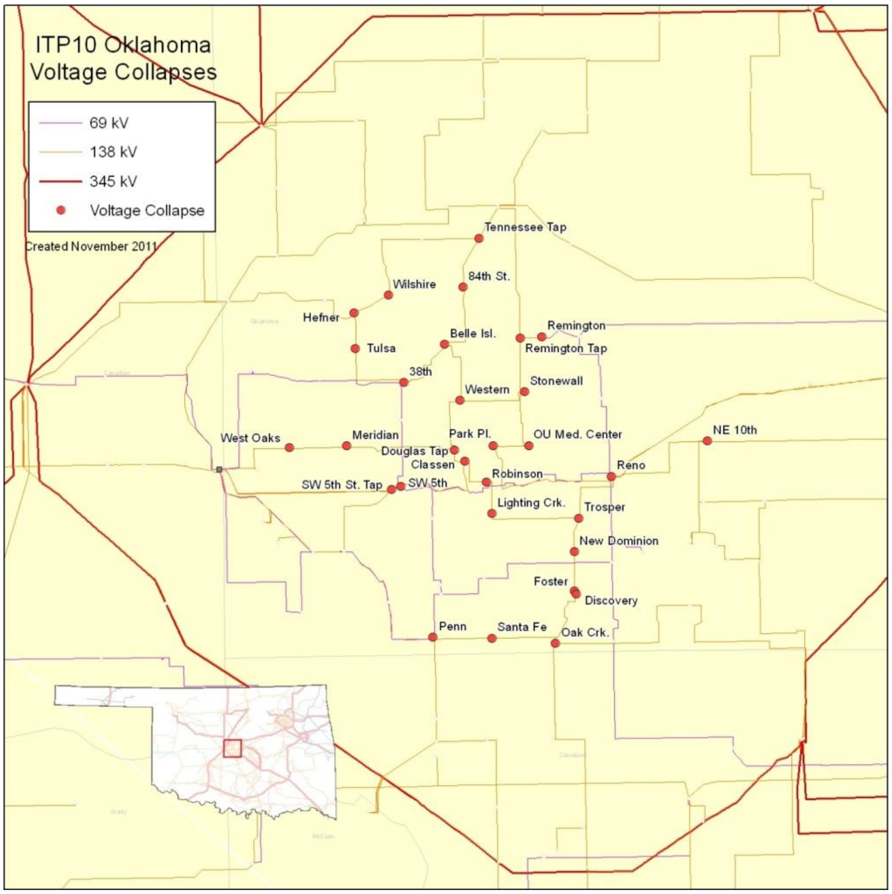


Figure 15.20: Oklahoma City Load Area Buses Experiencing Voltage Collapse

The P-V curves shown below in figure 21 are provided for the 138 kV buses in figure 20 above for the limiting contingency.

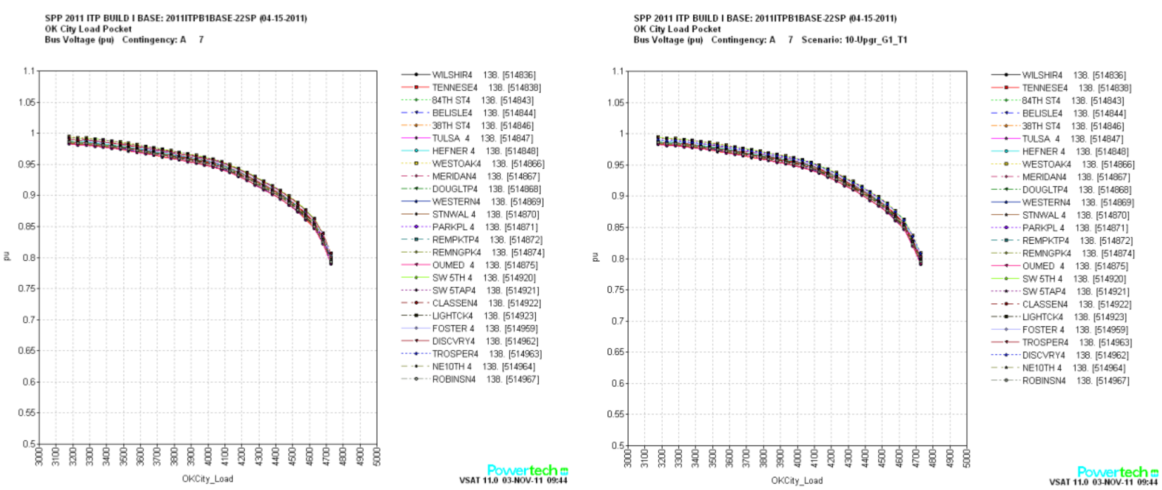


Figure 15.21: PV Curves for F1 Base and F1 Portfolio A Cases
(G-1, T-1 Contingency: HSL 8G and North West to Spring Creek 345 kV)

Lincoln/Omaha Nebraska

The Lincoln/Omaha, NE load area under this study is defined by the following zone in table 9:

Area	Zone
645 OPPD	All
650 LES	All

Table 15.9: Lincoln/Omaha, NE Load Area

Load area analysis was performed by importing generation into the Lincoln/Omaha, NE while increasing both real and reactive load in proportion to the initial MW output of each source generator for both the F1 Base Case and the F1 Portfolio A Case. The load buses below 69 kV in areas 645 and 650 were equivalenced to the 69 kV system buses. Voltage instability occurs on the 69 kV transmission system subsequent to a load pocket increase of approximately 55.9% or 2,070 MW in the F1 Base Case and approximately 56.3% or 2,085 MW in the F1 Portfolio A Case.

Figure 22 shows the 69 kV buses that have the highest participation in the collapse for both the base and upgrade case.

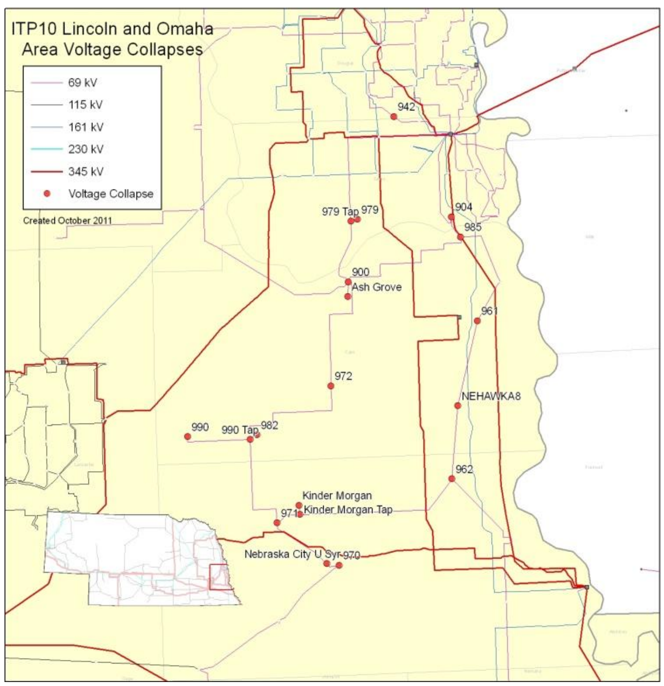


Figure 15.22: Lincoln/Omaha Load Area Buses Experiencing Voltage Collapse

The P-V curves shown below in figure 23 are provided for the 69 kV buses in figure 22 above for the limiting contingency.

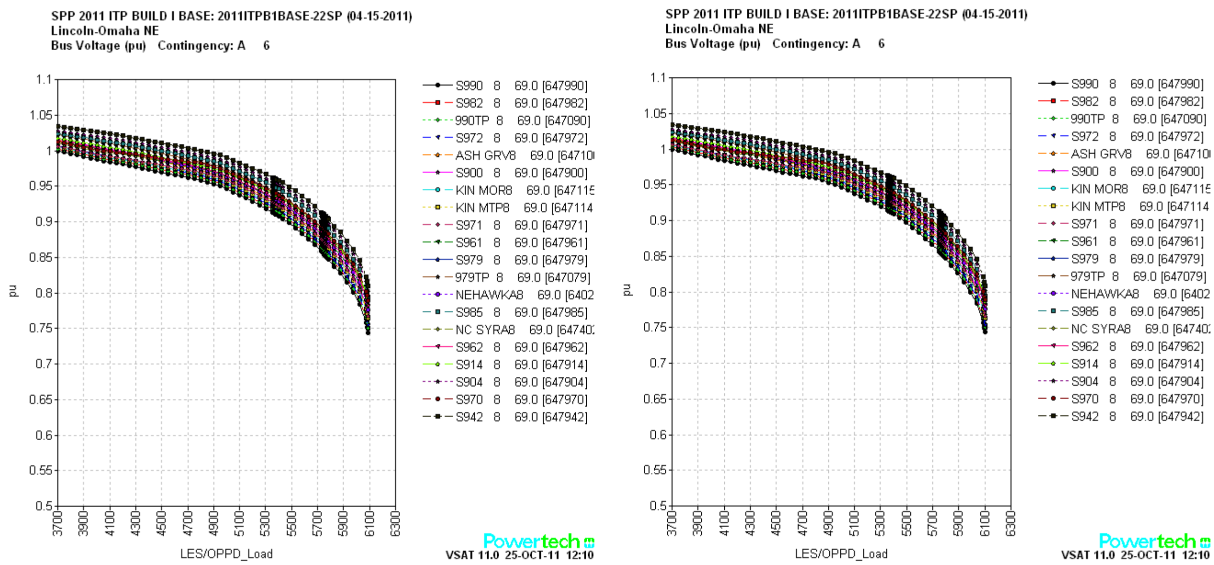


Figure 15.23: Lincoln/Omaha Load Area PV Curves for F1 Base and F1 Portfolio A Cases (G-1, T-1 Contingency: Ft. Calhoun 1G and Raun to S3451 345 kV)

15.6: Transient Analysis

The model used in the ITP 10 Transient Stability Assessment includes Portfolio “A” Economic and F1 Reliability projects as of October 4, 2011. Two power flow cases, Future 1 Peak and Off-Peak, were developed from this model using the PROMOD software using security constrained economic dispatch.

The contingencies applied to the cases were N-1 transmission lines above 100 kV. The scan is done by faulting Bus A for a specified period of time, and then clearing the fault and opening the line from bus A to bus B without re-closing and running the simulations for 5 seconds.

2012 ITP10 Off-Peak Case Results

The 2012 ITP10 off-peak transient stability scan revealed no unstable machines inside the SPP footprint.

2012 ITP10 Peak Case Results

The 2012 ITP10 Peak transient stability scan revealed an unstable machine, 12512 S1, in the SPP footprint. This machine is associated with a new combined cycle unit added to the power flow case as new conventional generation for Future 1. The combined cycle output was reduced by 48 MWs, re-dispatched, and resulted in a stable solution. In the final solution, the machine was moved from the lower voltage system to the Woodward District EHV to Thistle 345 kV transmission line. This solution was stable and allowed the full output of this proposed resource.

15.7: Conclusion

The wind dispatch in the 2012 ITP10 is feasible from a voltage stability viewpoint. There was no voltage instability in the load areas in the 2012 ITP10 within SPP. The 2012 ITP10 transient stability studies resulted in no unstable machines inside the SPP footprint.

Section 16: 2010 ITP20 Projects in the 2012 ITP10

ITP20 Project	kV	Status in 2012 ITP10 Recommended Plan
Iatan - Jeffrey Energy Center	345	Not Included
Wichita - Viola - Rose Hill	345	Not Included
Spearville - Mullergren - Circle - Reno	345	Not Included
Cass Co - S.W. Omaha (aka S3454)	345	Not Included
Gentleman - Hooker Co - Wheeler Co	345	Similar project included; Gentleman - Cherry Co - Holt Co 345 kV
Tolk - Potter Co	345	Not Included
Grand Island - Wheeler Co rebuild	345	Not Included
Hitchland - Potter Co	345	Not Included
Woodward District EHV - Woodring	345	Similar project included; Woodward - Tatonga - Mathewson - Cimarron 345 kV Ckt 2
Mingo - Post Rock	345	Not Included
Holt Co - Hoskins - Ft. Calhoun	345	Similar project included for Holt Co - Hoskins line; Holt Co - Neligh - Hoskins 345 kV
Ft. Calhoun - S3454	345	Not Included
Tuco - Amoco - Lea Co - Hobbs	345	Included as Tuco - Amoco - Hobbs 345 kV
Keystone - Ogallala	345	Not Included
Wheeler Co - Shell Creek	345	Not Included
S3459-S1209 Transformer	345/161	Not Included
Mullergren Transformer	345/230	Not Included
Circle Transformer	345/230	Not Included
Hoskins Transformer	345/230	Not Included
Hoskins Transformer	345/115	Not Included
Ogallala Transformer	345/230	Not Included
Shell Creek Transformer	345/230	Not Included
Columbus East Transformer	345/115	Not Included
Lea Co Transformer	345/230	Similar project included; Hobbs 345/230 kV transformer
Post Rock Transformer	345/230	Not Included
Amoco Transformer	345/230	Included
Holt Co Substation	345	Included
Wheeler Substation	345	Not Included

Table 16.1: Status of Projects in the 2010 ITP20

Section 17: Resource Expansion Plan

17.1: Process Overview

ESWG Approved Resource Plan

The ESWG utilized the load forecasts for 2022 and calculated the needed generation capacity additions assuming the SPP RTO must meet the 12% capacity margin requirement outlined in SPP criteria[32]. The process[33] was performed for the summer of 2022. Capacity needs were identified in several SPP zones for each future. Southwest Public Service Company, Kansas City Power and Light, and Westar Energy, Inc. had the largest needs in Future 1. In addition, Omaha Public Power District demonstrated a need for additional generation capacity in Future 2. Future 2 required more new generation than Future 1 because of the additional unit retirements anticipated if expected EPA rules are enacted. Forty-one units were identified by stakeholders as retired in Future 2. The decision to retire these units was based upon a rule that any unit coal unit less than 200-MW in capacity be retired. Exemptions to this rule, based upon stakeholder feedback are listed in Table 17.1. The results of the process were posted on SPP.org[34]

Wind Siting

Generic wind sites were selected by the ESWG based upon the locations selected in the 2010 ITP20. These sites are in addition to the existing and under construction wind farms in SPP and were selected in the ITP20 because of their potential for high capacity factors. The siting[35] of the generic wind sites, performed on a county basis, was the same in both futures, except that sites in Missouri were not utilized in Future 2. Also note that two of the sites were moved from Texas, where they were located in the ITP20, to New Mexico due to planned transmission development by ERCOT in the area of the original locations.

Designated Resources

Designated resources were identified through the CAWG survey. The ownership of the generation at each wind farm was first given to zones which have identified those wind farms as designated resources for their footprints. Any wind capacity left after all designated resources were accounted for was apportioned to zones which needed the capacity of that wind farm, starting with the zones in the same state as the wind farm. The ownership process was reviewed by stakeholders and posted on SPP.org[35].

Future 2 Wind Sites

The additional renewable energy needed to satisfy the Future 2's 20% federal Renewable Electricity Standard (RES) requirement was apportioned to the twenty-five generic wind sites in New Mexico, Texas, Oklahoma, Kansas, and Nebraska. The additional wind energy from the generic wind sites was allocated to the zones as needed to serve 20% of their demand energy. The energy provided by the Missouri sites in Future 1 was provided by wind sites in other states. It is expected that few new wind farms would be located in Missouri if the state's renewable incentives, available only under Future 1's state renewable targets, were to be eliminated.

[32] SPP.org > Org Groups > Governing Documents > Criteria & Appendices July 25, 2011
[33] SPP.org > Engineering > Transmission Planning > ITP10 Documents > 2011 ITP10 Resource Plan Process - ESWG Approved.pdf
[34] SPP.org > Engineering > Transmission Planning > ITP10 Documents > 2011 ITP10 Resource Plan - ESWG Approved
[35] SPP.org > Engineering > Transmission Planning > ITP10 Documents > 2011 ITP10 Wind Siting Plan - ESWG Approved.xls

17.2: Future 1 Resource Plan Summary

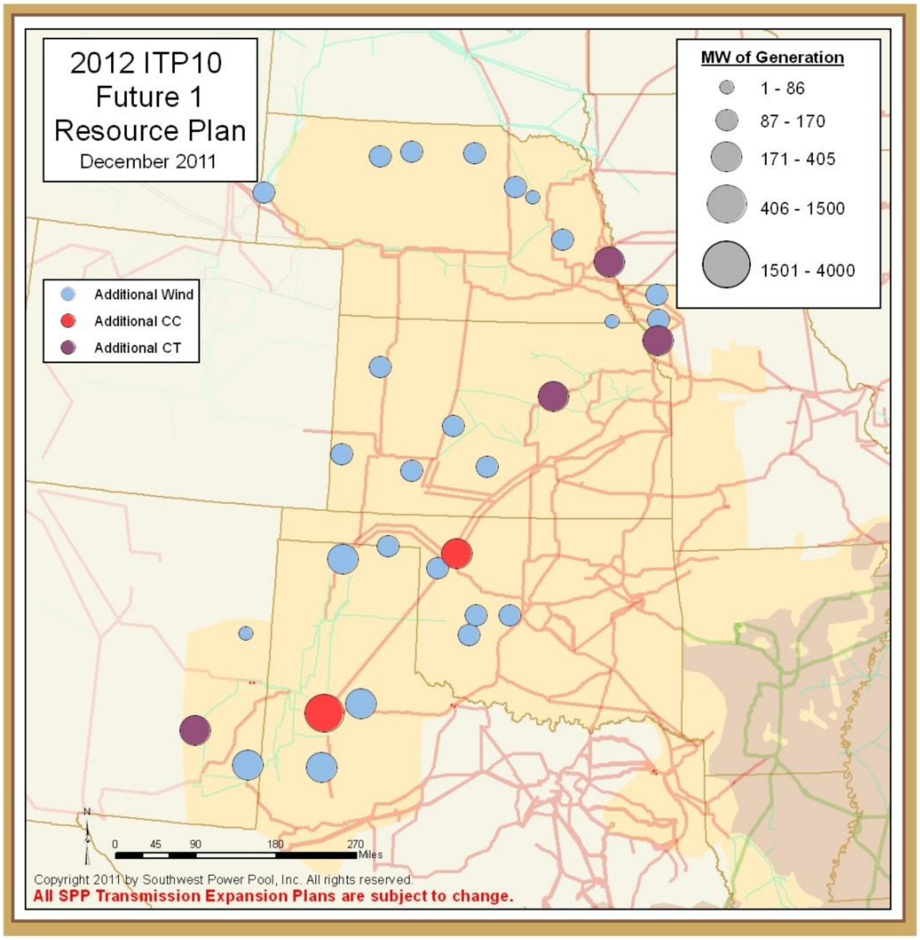


Figure 17.1: 2012 ITP10 Future 1 Resource Plan Map

Future 1 Resource Plan Statistics

- Additional Sites
  - 25 Wind
  - 2 Combined Cycle
  - 4 Combustion Turbine
- Additional Capacity
  - 1,590 MW Natural Gas
- Total Wind Capacity
  - 10,038 MW
- Total Conventional Capacity
  - 58,814 MW

17.3: Future 2 Retirement Summary

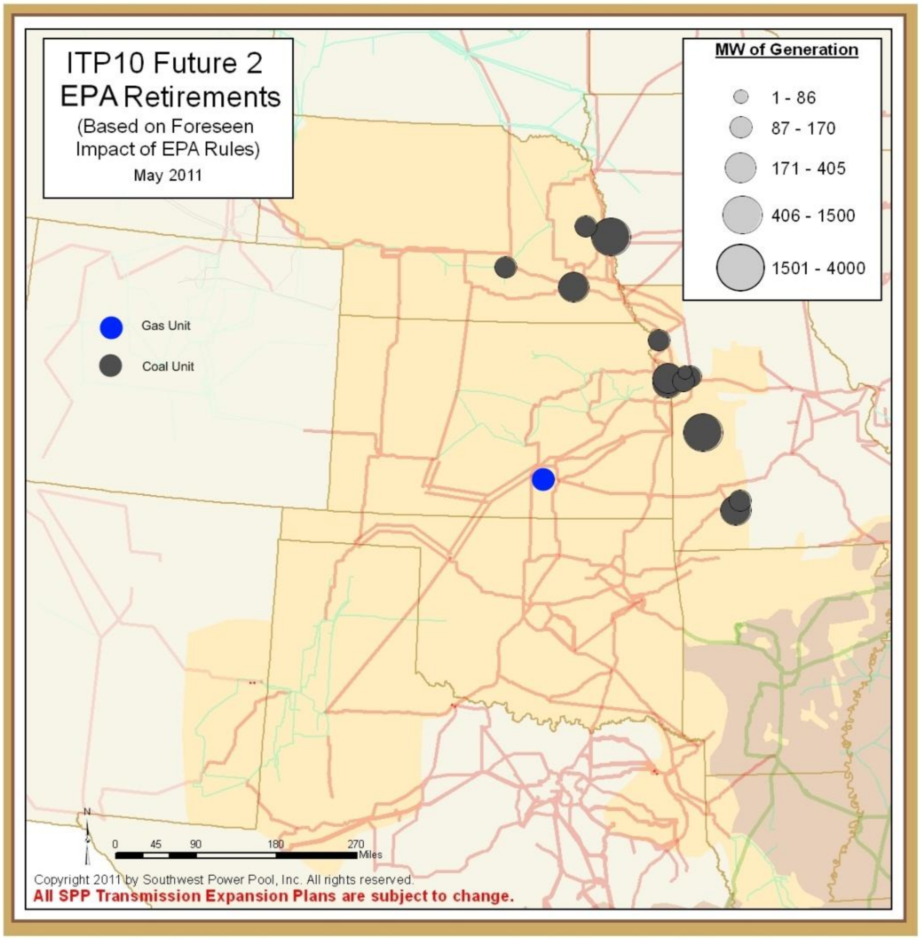


Figure 17.2: 2012 ITP10 Future 2 Coal and Gas Retirements Map

Retirement Locations
37 units
15 locations

Capacity Retired
Coal: 2,316 MW
Gas: 256 MW

Area	Name	Type	Max Capacity	Action Taken
WR	Lawrence 3	ST Coal	49	Not Retired
WR	Lawrence 4	ST Coal	108	Not Retired
WR	Tecumseh 7	ST Coal	75	Not Retired
WR	Tecumseh 8	ST Coal	129	Not Retired
NPPD	Whelan Energy Center 1	ST Coal	80	Not Retired
EMDE	Asbury 1	ST Coal	189	Not Retired

Table 17.1: Units exempted from retirement rules in Future 2

17.4: Future 2 Resource Plan Summary

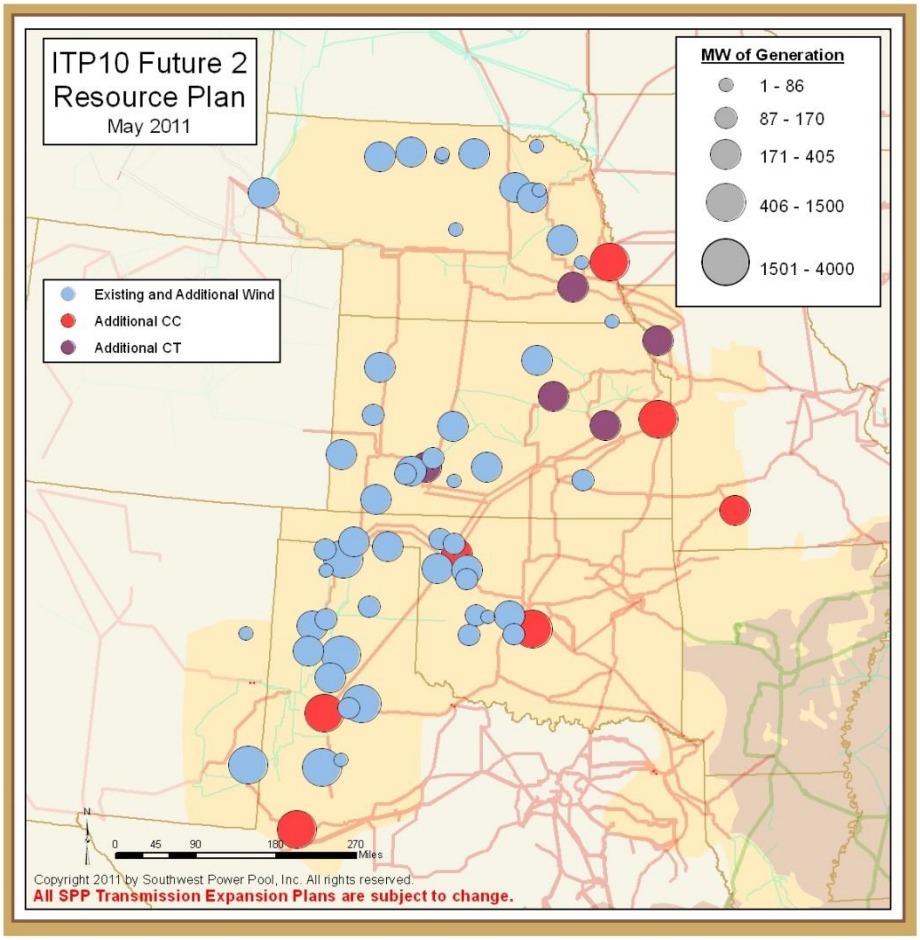


Figure 17.3: 2012 ITP10 Future 2 Resource Plan Map

Future 2 Resource Plan Statistics

- Additional Sites
  - 25 Wind
  - 7 Combined Cycle
  - 5 Combustion Turbine
- Additional Capacity
  - 4,270 MW Natural Gas
- Total Wind Capacity
  - 14,048 MW
- Total Conventional Capacity
  - 61,494 MW

17.5: Wind Interconnection Summary

The point of interconnection on the transmission network for each of the wind farms utilized in the study is included in this section. The wind farms that exist or have signed Interconnection Agreements are shown in Table 17.2, these wind farms were modeled identically in each of the futures. The projected wind farms added for the purposes of the transmission plan are shown in Table 17.3 for Future 1 and in Table 17.4 for Future 2. Note that some of the interconnection points are different in Future 2 than in Future 1 because of the larger size of the wind farms. Interconnection points identified with an * indicate that the interconnection point was used in the reliability and stability studies but not in the economic portion of the study due to system limitations (see *Section 8: Projected System Behavior* for details in each case).

Description	State	CF	MW	MWh Target	Interconnection
Central Plains WF ALL	KS	46%	99	401,544	Central Plains Wind Sub 115 kV
Novus Wind KS	KS	46%	399	1,593,829	Finney Switching Station 345 kV
Flat Ridge WF ALL	KS	44%	100	385,892	Flat Ridge Substation 138 kV
Gray County 1	KS	35%	112	343,588	Haggard 115 KV
Elk River WF WT	KS	43%	150	569,551	Latham 345 kV
Meridian Way WF ALL	KS	46%	201	815,729	Meridian Way Phase 1 230 kV
Smoky Hills WF ALL	KS	45%	250	981,590	Smoky Hills 230 kV
Spearville	KS	47%	149	606,426	Spearville 230 KV
Greenburg WF	KS	46%	13	50,406	Spearville 345 kV
Lincoln Wind	NE	44%	1	5,060	56th & I80 115 kV
Springview WF	NE	45%	3	11,944	Ainsworth
NPPD Ainsworth Wind	NE	46%	60	241,846	Ainsworth 115 kV
Elkhorn Ridge PH1	NE	42%	81	298,015	Bloomfield 115 kV
Crofton Hills ALL	NE	47%	40	163,637	Bloomfield 115 kV
Broken Bow	NE	43%	80	302,746	Broken Bow
Petersburg WF	NE	46%	41	163,908	Petersburg North 115 kV
Laredo Ridge WF	NE	46%	80	323,770	Petersburg North 115 kV
Flat Water WF	NE	44%	60	233,524	Sub 1399 161 kV
Caprock Wind	NM	44%	80	308,962	Caprock Wind Gen 115 kV
Wildcat Wind	NM	34%	29	86,661	Lea County Interchange 230 kV
Mesalands	NM	35%	2	4,658	San Juan Mesa Tap 230 kV
Llanco Estacado Texico	NM	35%	2	6,092	San Juan Mesa Tap 230 kV
San Juan Mesa Wind 120	NM	35%	120	372,020	San Juan Mesa Tap 230 kV
Chaves Wind	NM	34%	60	180,333	San Juan Mesa Tap 230 kV
Taloga Wind	OK	40%	130	460,588	Dewey 138 kV
Oklahoma Wind Egy	OK	43%	100	372,996	FPL Switch 138 kV
Sleeping Bear WF 45	OK	39%	95	325,821	FT. Supply 138 kV
Elk CIty PH1	OK	47%	123	509,560	Grapevine Interchange 230 kV
Novus Wind I Ph 1	OK	41%	170	616,678	Hitchland Interchange 345 kV
Novus Wind VIII	OK	40%	8	29,794	Hitchland Interchange 345 kV
Novus Wind I Ph 2	OK	45%	199	781,843	Hitchland Interchange 345 kV
Rocky Ridge Wind	OK	41%	150	538,083	Lawton Eastside 345 kV
Blue Canyon Wind III	OK	48%	100	420,592	Lawton Eastside 345 kV
Minco WF	OK	39%	99	341,166	Minco 345 kV

Description	State	CF	MW	MWh Target	Interconnection
Red Hills WP PH1	OK	42%	123	447,397	Red Hills 138 kV
Blue Canyon Wind	OK	40%	74	257,493	Washita 138 kV
Blue Canyon Wind II	OK	48%	151	635,936	Washita 138 kV
Weatherford WF	OK	41%	147	531,676	Weatherford Wind Farm 138 kV
Centennial OGE	OK	41%	120	433,276	Woodward 138 kV
Keenan WF PH1	OK	43%	152	566,481	Woodward 138 kV
OU Spirit PH1	OK	40%	101	357,449	Woodward 138 kV
Buffalo Bear WF PH1	OK	41%	96	342,863	Woodward EHV 345 kV
Crossroads	OK	40%	228	805,132	Woodward EHV 345 kV
South Buffalo	OK	41%	20	70,362	Woodward EHV 345 kV
Wildorado Wind Ranch LTI	TX	43%	161	600,249	Bushland Interchange 230 kV
Wildorado Wind Ranch 2	TX	43%	79	294,532	Bushland Interchange 230 kV
High Plains Wind 1	TX	40%	10	35,215	Carson Sub 115 kV
Ralls WF	TX	44%	10	38,255	Crosby Co. Inter. 115 kV
Happy Whiteface West WF	TX	38%	239	789,575	Deaf Smith Co. Inter. 230 kV
DWS	TX	45%	20	77,982	DWS Frisco 115
Sunray WF ALL	TX	45%	9	35,644	Etter Rural Sub115 kV
Buffalo Point Wind	TX	40%	60	210,555	Grassland Interchange 230 kV
Hansford WF	TX	43%	80	303,084	Hansford Co. 115 kV
Conestoga	TX	37%	198	638,982	Hitchland Interchange 345 kV
Noble Great Plains PH1	TX	37%	114	369,097	Hitchland Interchange 345 kV
JD Wind 4 ALL	TX	45%	100	391,747	Hitchland Interchange 345 kV
Llano Estacado 1	TX	44%	80	311,786	Llano Estacado Wind Gen 115 kV
Majestic WF PH1	TX	40%	80	278,707	Martin Sub 115 kV
Spinning Spur WF	TX	45%	161	637,342	Potter County Interchange 345 kV
Aeolus	TX	36%	3	9,524	Pringle Interchange 230 kV
Higher Power WF	TX	46%	400	1,622,352	Swisher Co. Inter. 230 kV
Rio Blanco WF	TX	42%	150	551,486	Tuco Inter. 345 kV

Table 17.2 Windfarms in service or with signed Interconnection Agreements

Description	State	CF	MW	MWh Target	Interconnection
Kansas #3 WF	KS	45%	89	354,928	Holcomb 345 kV
Kansas #4 WF	KS	44%	93	354,928	Mingo 345 kV
Kansas #2 WF	KS	46%	88	354,928	Mullergren 230 KV
Kansas #5 WF	KS	43%	94	354,928	Pratt Co. 115 kV
Kansas #1 WF	KS	49%	83	354,929	Spearville 230 KV
Missouri #4 WF	MO	39%	103	350,400	Maryville 161 KV
Missouri #1 WF	MO	37%	109	350,400	Midway 161 KV
Nebraska #4 WF	NE	47%	88	363,363	Columbus East 345 kV
Nebraska #1 WF	NE	48%	86	363,363	County Line 115 kV
Nebraska #5 WF	NE	47%	89	363,363	Gerald Gentleman Station 345 kV*
Nebraska #6 WF	NE	47%	89	363,363	Keystone 345 kV*
Nebraska #3 WF	NE	46%	90	363,363	Neligh 115 kV
Nebraska #8 WF	NE	44%	46	179,171	S1299 161 kV

Description	State	CF	MW	MWh Target	Interconnection
Nebraska #2 WF	NE	46%	90	363,363	Stuart 115 kV
Nebraska #7 WF	NE	48%	86	363,363	Victory Hill 230 kV*
New Mexico #2 WF	NM	35%	332	1,010,921	Hobbs Interchange 230 kV
New Mexico #1 WF	NM	37%	313	1,010,922	Roosevelt Co. Inter. 230 kV
Oklahoma #5 WF	OK	39%	158	544,293	Cimarron 345 kV
Oklahoma #2 WF	OK	48%	129	544,293	Lawton Eastside 345 kV
Oklahoma #4 WF	OK	46%	136	544,293	Perryton Interchange 115 kV
Oklahoma #3 WF	OK	42%	150	544,293	Tatonga 345 kV
Oklahoma #1 WF	OK	44%	140	544,293	Woodward EHV 345 kV
Texas #1 WF	TX	38%	302	1,010,922	Grassland Interchange 230 kV
Texas #5 WF	TX	44%	260	1,010,921	Hitchland Interchange 345 kV
Texas #2 WF	TX	47%	245	1,010,922	Tuco Interchange 345 kV

Table 17.3: Projected Wind Farm (Future 1)

Description	State	CF	MW	MWh Target	Interconnection
Kansas #3 WF	KS	45%	292	1,162,690	Holcomb 345 kV
Kansas #4 WF	KS	44%	303	1,162,690	Mingo 345 kV
Kansas #2 WF	KS	46%	287	1,162,690	Spearville 345 kV
Kansas #5 WF	KS	43%	309	1,162,690	Spearville 345 kV
Kansas #1 WF	KS	49%	273	1,162,690	Spearville 230 KV
Nebraska #4 WF	NE	47%	217	890,786	Columbus East 345 kV
Nebraska #1 WF	NE	48%	210	890,786	Hoskins 345 kV
Nebraska #5 WF	NE	47%	219	890,786	Gerald Gentleman Station 345 kV*
Nebraska #6 WF	NE	47%	219	890,786	Keystone 345 kV*
Nebraska #3 WF	NE	46%	220	890,786	Neligh 115 kV
Nebraska #8 WF	NE	44%	135	526,018	S1299 161 kV
Nebraska #2 WF	NE	46%	221	890,786	Hoskins 345 kV
Nebraska #7 WF	NE	48%	211	890,786	Victory Hill 230 kV*
New Mexico #2 WF	NM	35%	597	1,818,683	Hobbs Interchange 230 kV
New Mexico #1 WF	NM	37%	563	1,818,683	Roosevelt Co. Inter. 230 kV
Oklahoma #5 WF	OK	39%	392	1,352,055	Cimarron 345 kV
Oklahoma #2 WF	OK	48%	322	1,352,055	Lawton Eastside 345 kV
Oklahoma #4 WF	OK	46%	338	1,352,055	Hitchland Interchange 345 kV
Oklahoma #3 WF	OK	42%	372	1,352,055	Tatonga 345 kV
Oklahoma #1 WF	OK	44%	348	1,352,055	Woodward EHV 345 kV
Texas #1 WF	TX	38%	543	1,818,684	Grassland Interchange 345 kV
Texas #5 WF	TX	44%	468	1,818,683	Hitchland Interchange 345 kV
Texas #2 WF	TX	47%	441	1,818,683	Tuco Interchange 345 kV

Table 17.4: Projected Wind Farm (Future 2)

Section 18: Project Staging Maps

Section 6.6 details the process used in staging the different projects in the 2012 ITP10 recommended portfolio. This section includes maps to show the results of the staging by year. The project list attached in *Section 19:2012 ITP10 Project List* provides the official list of need dates and project details.

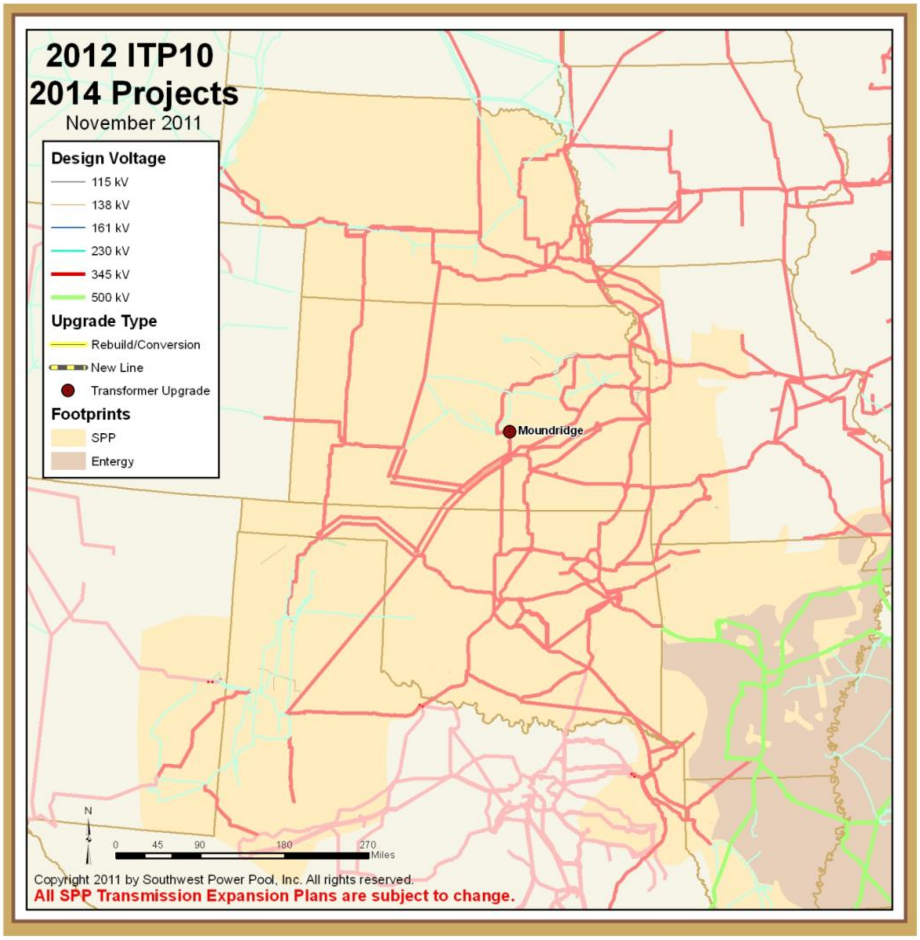


Figure 18.1: 2014 Projects

Projects staged for 2014:

Moundridge Transformer 138/115 Ckt 2

Jones Bus #2 - Lubbock S Ckt2 Terminal Upgrade

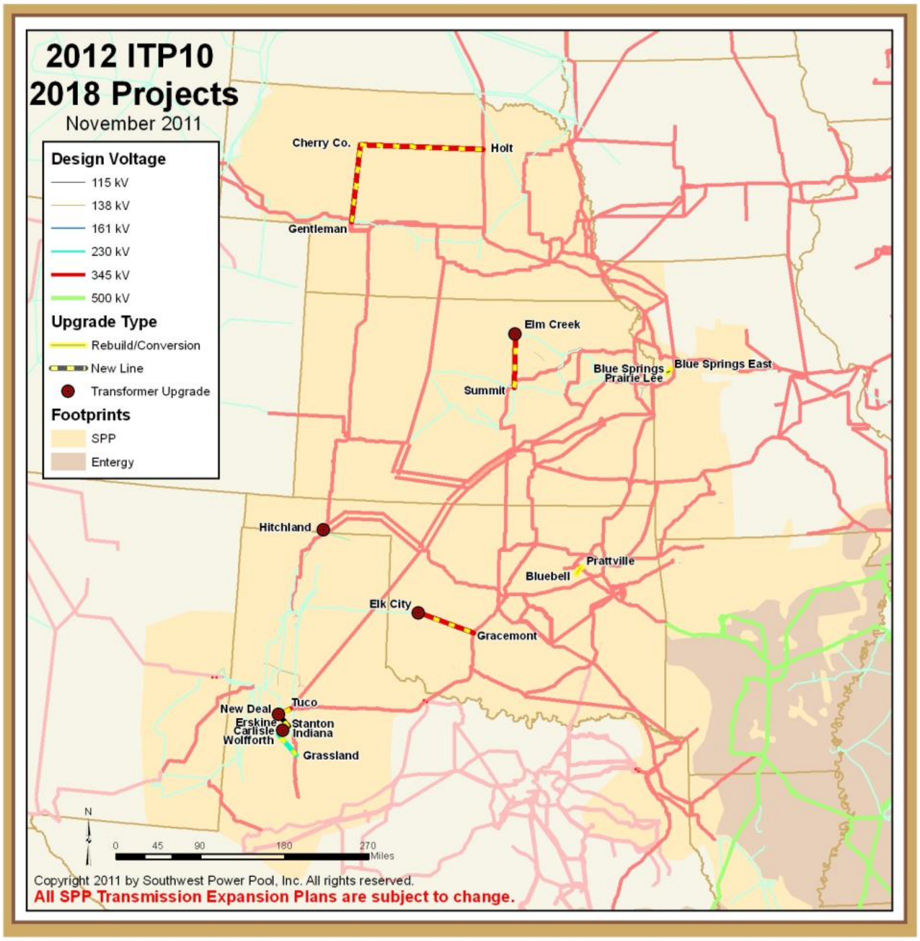


Figure 18.2: 2018 Projects

Projects staged for 2018:

Gentleman - Cherry County - Holt County 345 kV

Elm Creek - Summit 345 kV

Elm Creek Transformer 345/230 kV

Elk City – Gracemont 345 kV

Blue Springs South - Prairie Lee 161 kV

Blue Springs East - Blue Springs South 161 kV

Bluebell - Prattville 138 kV

Hitchland Transformer 230/115/13.2 Ckt 2

Tuco - New Deal 345 kV

New Deal/Stanton 345/115 kV transformer

Wolfforth – Grassland 230 kV

Indiana - Stanton 115 kV reconductor

Indiana - SP Eskine 115 kV

Carlisle Transformer 230/115/13.2 Ckt 1 upgrade

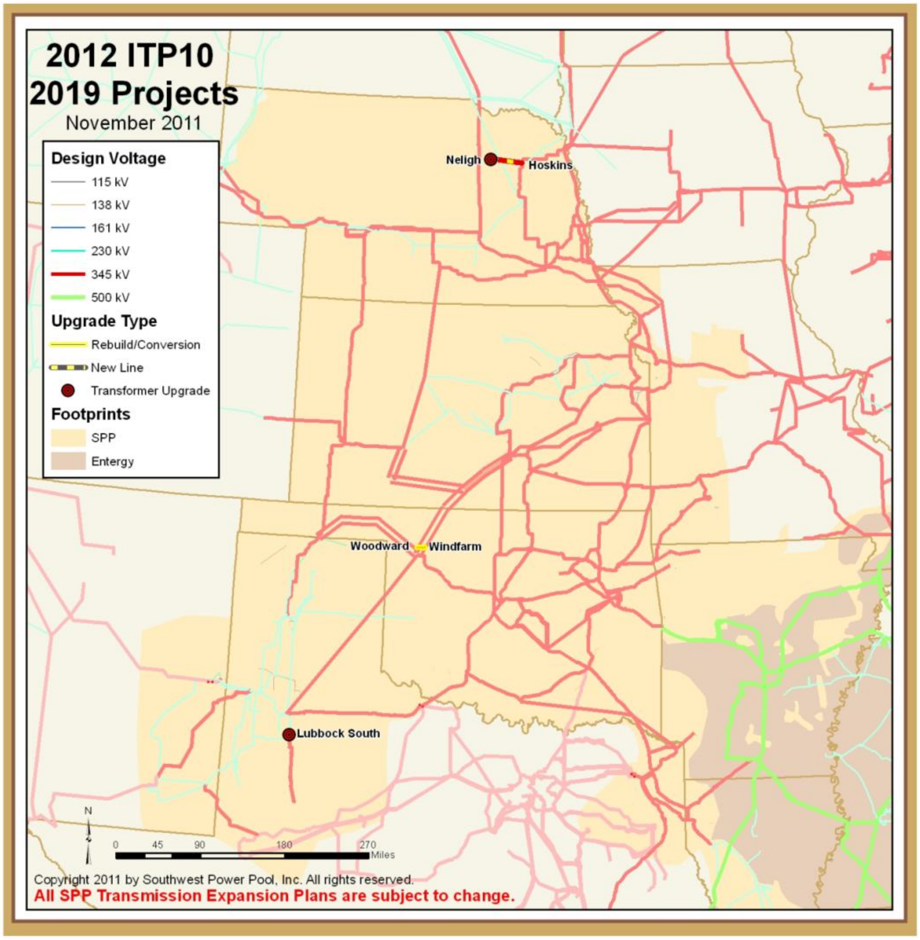


Figure 18.3: 2019 Projects

Projects staged for 2019:

Neligh - Hoskins 345 kV

Neligh Transformer 345/115 kV

Windfarm – Woodward District 138 kV

Lubbock South Transformer 230/115/13.2 kV Ckt 2

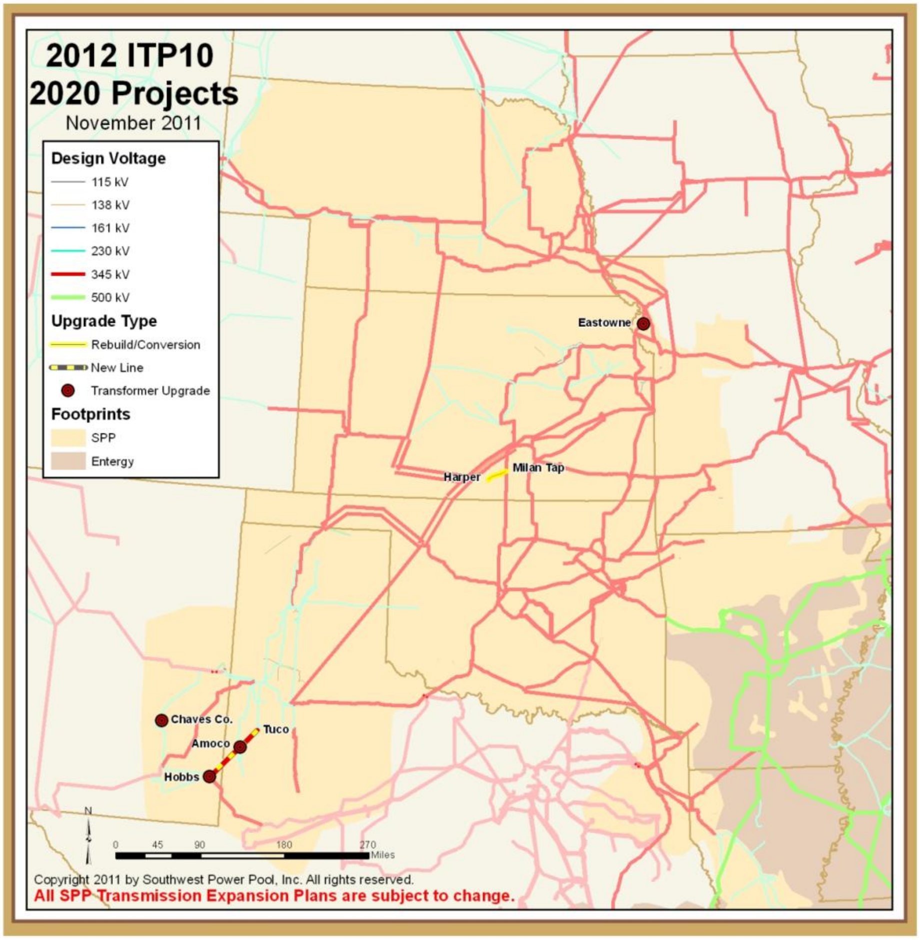


Figure 18.4: 2020 Projects

Projects staged for 2020:

Eastowne transformer 345/161 kV

Chaves transformer 230/115 kV

Tuco - Amoco - Hobbs 345 kV

Amoco transformer 345/230 kV

Hobbs transformer 345/230 kV

Harper – Milan Tap 138 kV Rebuild

Classen - Southwest Tap 138 kV

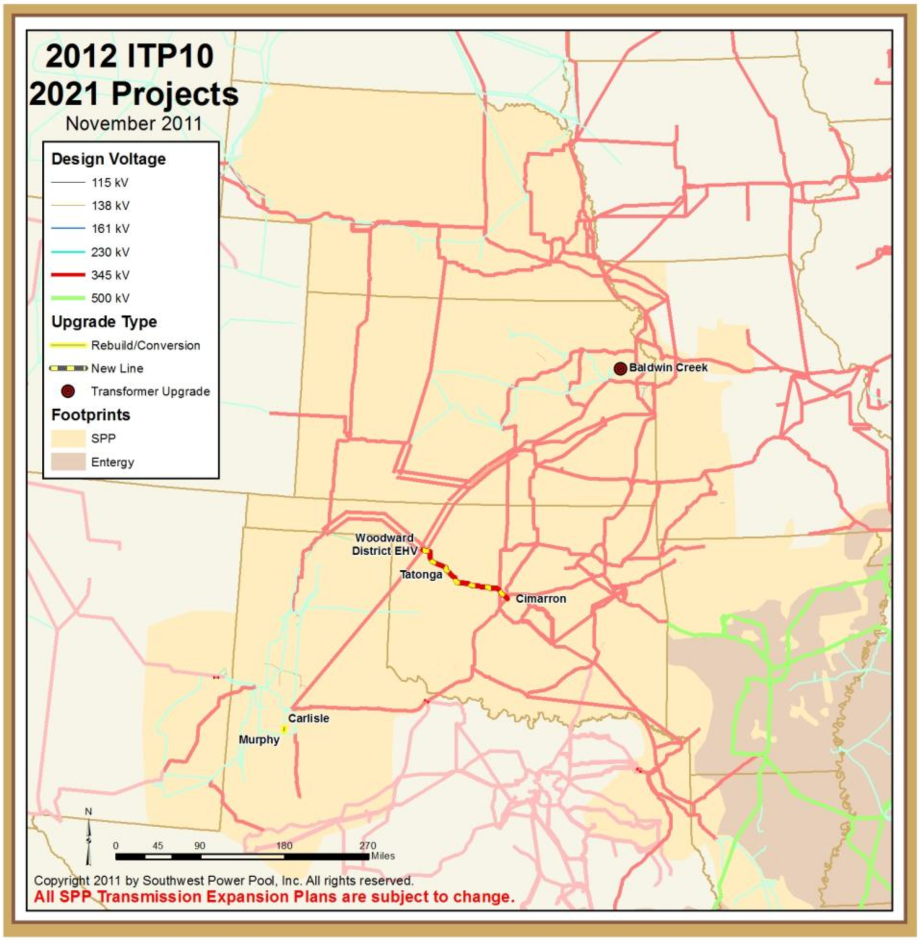


Figure 18.5: 2021 Projects

Projects staged for 2021:

Baldwin Creek Transformer 230/115 kV

Woodward - Tatonga 345 kV

Tatonga - Mathewson - Cimarron 345 kV

Carlisle - Murphy 115 kV Reconductor

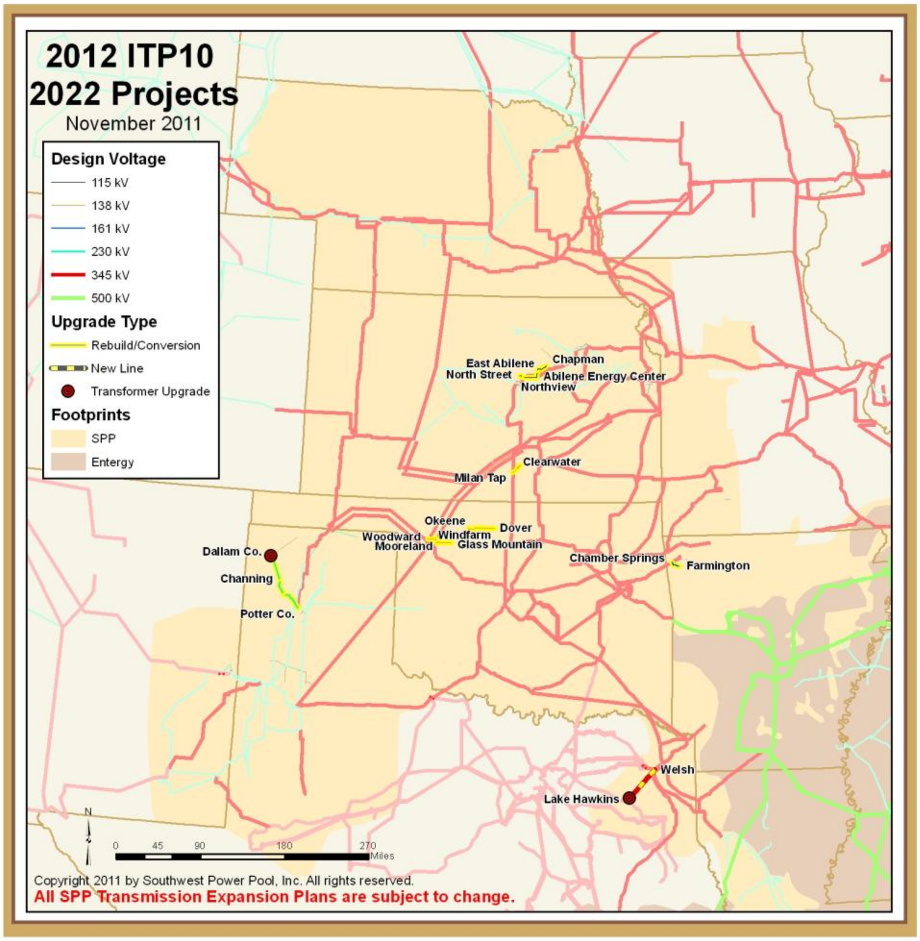


Figure 18.6: 2022 Projects

Projects staged for 2022:

Dallam County Interchange Transformer 230/115 kV

Potter - Channing Ckt 1 115 kV to 230 kV conversion

Channing - XIT - Dallam Ckt 1 conversion to 230 kV

Elk City transformer 345/230 kV

Lake Hawkins - Welsh 345 kV

Lake Hawkings 345/138 kV transformer

Chamber Springs - Farmington REC 161 kV

Clear Water - Milan Tap 138 kV Rebuild

Abilene East - Abilene Energy Center 115 kV

Abilene East - Chapman 115 kV

Abilene Energy Center - Northview 115 kV

Northview - North Street 115 kV

Dover - Okeene 138 kV

Glass Mountain - Mooreland 138 kV

Lamb County 69 kV Capacitor

Northwest Manhattan Cap 115 kV Capacitor

Seneca 115 kV Capacitor

Section 19: 2012 ITP10 Project List

The project list showing in-service dates, facility owners, project costs, and other pertinent information such as projects identified in only one future and those projects suggested by stakeholders are included in this section.

19.1: 2012 ITP10 Recommended Projects

The list of projects recommended by SPP staff, along with requested Board of Director Action is shown in Table 19.3. The list include the staging, technical, and financial information for each project.

Three dates related to the staging and timing of each project were utilized in the development of the project list. For clarity, the definition and reason for each date are provided here:

- Stage Date: this date was determined through the staging process outlined in *Section 6.6: Determining Project Need Dates*.
- Need Date: this date was the official need date that will be entered into the Quarterly SPP Project Tracking.
- Proposed In-Service Date: This date was determined following calculation of the staging date, and accounted for lead times that exceeded the time available between the recommendation of the project and the stage date.

In every case, the Need Date corresponded with the Proposed In-Service Date. Most of the Need Dates also corresponded with the Stage Dates, exceptions were noted in Table 19.3

19.2: Single Future Overloads

The projects that were selected to mitigate overloads that occurred in only one of the two futures are shown in Table 19.3. The cost of projects with a future loading between 95% and 100% was $149,698,817, these four projects where included in the 2012 ITP10 recommended portfolio. The other projects were not included in the recommended portfolio.

Facility Owner	Project Name	F1 Loading	F2 Loading	In Final Portfolio	SPP Cost Estimate
AECC	Line - Chamber Springs - Farmington 161 kV	99.7%	110.7%	Yes	$24,880
AEP	Line - Chamber Springs - Farmington 161 kV	99.7%	110.7%	Yes	$15,870,489
AEP	Multi - Lake Hawkins - Welsh 345 kV	95.7%	111.1%	Yes	$117,171,144
ITCGP- WR	Line - Post Rock - Summit 345 kV	76.1%	111.1%	No	$153,277,136
NPPD	Line - Beatrice - Harbine 115 kV reconductor	89.0%	110.5%	No	$7,980,000
OPPD	Line - Fremont - Ft. Calhoun 345 kV	48.0%	166.0%	No	$53,200,000
OPPD	XFR - Fremont 345/115 kV	48.0%	166.0%	No	$15,190,000
OPPD	Line - Sub 1221 - Sub 1255 161 kV Ckt 1	88.0%	107.4%	No	$6,480,000
SPS	Line - Lubbock South - Lubbock East 115 kV Ckt 1	90.0%	102.7%	No	$3,850,875
WR	Line - El Paso - Farber 138 kV	94.2%	106.3%	No	$6,480,000
WR	Line - West Junction City - West Junction City Junction 115 kV	74.6%	106.1%	No	$147,750
WR	Line - Chapman - West Junction City Junction (West) 115 kV Ckt 1	71.0%	101.2%	No	$6,648,750
WR	Line - Abilene East - Chapman 115 kV	96.3%	126.5%	Yes	$11,501,055

Facility Owner	Project Name	F1 Loading	F2 Loading	In Final Portfolio	SPP Cost Estimate
WR	Line - North Street - Northview 115 kV	96.0%	100.3%	Yes	$5,131,249

Table 19.1: Status of reliability projects that only overloaded in one future

19.3: Transformer Justification

As requested by the SPP stakeholders, the justification for each of the fifteen ITP10 transformers has been compiled in Table 19.2. Many of the transformers were needed to meet reliability criteria requirements. Four of the ITP10 transformers were required to relieve congestion and provided significant economic benefit to the footprint.

Facility Owner	Substation Name	Voltages (kV)	Transformer Justification	Cost Estimate*
AEP	Elk City 345 kV	345/230	Reliability	$18,060,547
AEP	Lake Hawkins (or Perdue) 345 kV	345/138	Reliability	$16,666,456
ITCGP	Elm Creek 345 kV	345/230	Reliability	$5,403,707
KCPL	EASTOWN7 345kV	345/161	Economic benefit in Future 1 of more than $2.5 Million	$12,809,443
NPPD	Neligh 345kV	345/115	Reliability	$35,497,400
SPS	Tuco New Deal 345 kV	345/115	Reliability	$15,550,000**
SPS	Hitchland 230 kV	230/115	Reliability	$4,220,694
SPS	Carlisle 230 kV	230/115	Reliability	$3,644,914
SPS	Lubbock South	230/115	Reliability	$3,942,881
SPS	AMOCO7 345kV	345/230	Provides congestion relief in local area around SPS's Amoco substation.	$15,550,000**
SPS	HOBBS7 345kV	345/230	Economic Project: There is no existing 345 kV transformer at Hobbs for the termination of this 345 kV line.	$15,550,000**
SPS	Chaves	230/115	Reliability	$3,644,914
SPS	Dallam 230 kV	230/115	Reliability	$3,583,825
WR	MOUNDRG3 115kV	138/115	Economic benefit in Future 1 of more than $35 Million. Economic benefit in Future 2 of more than $9 Million	$12,197,900
WR	Baldwin Creek 230kV	230/115	Reliability	$18,343,600
2012 ITP10 Transformer and Associated Substation Work Total Cost				$184,666,281

Table 19.2: Justifications for Transformers in the Final Portfolio

*Includes the cost of a new substation or substation expansion required to install the new transformer.
**SPP Cost Estimate

19.4: Stakeholder Suggested Projects

Projects submitted by stakeholders for study within the 2012 ITP10 are included in Tab 3 of spreadsheet: SPP.org > Engineering > Transmission Planning > ITP10 Documents > 2012 ITP10 Project List and Report 12-14-11.

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
ATP	AECC	Rebuild and reconductor 11.1 mile Chamber Springs-Farmington REC 161 kV line with 2156 ACSR. Replace wave traps at Chamber Springs and bus at Farmington REC.	36	6/1/2022	$24,880	AECC	Regional Reliability	504020	Farmington REC			1	161	0.075			520/729
CNTC	AEP	Build new 46.5 mile 345 kV line from Elk City to Gracemont (AEP portion).	60	3/1/2018	$81,514,845	AEP	Regional Reliability	700345	Elk City 345 kV	515800	Gracemont 345 kV	1	345		46.5		1792/1792
CNTC	AEP	Expand Elk City substation (or build new station). Install a 345/230 kV 675 MVA transformer at Elk City	60	3/1/2018	$18,060,547	AEP	Regional Reliability	700345	Elk City 345 kV	511490	Elk City 230 kV	1	345/ 230				675
ATP	AEP	Rebuild 9.0 mile Prattville-Bluebell 138 kV line from 795 ACSR to 1590 ACSR.	24	6/1/2018	$8,764,621	AEP	Regional Reliability	515242	Bluebell 138 kV	509758	Prattville 138 kV	1	138	9			287/287
ATP	AEP	Build 55 mile new 345 kV line from Welsh to Lake Hawkins (or Perdue).	60	3/1/2022	$100,504,688	AEP	Regional Reliability	700346	Lake Hawkins (or Perdue) 345 kV	508359	Welsh 345 kV	345	345		55		1792/1792
ATP	AEP	Expand Lake Hawkins (or Perdue) substation (or build new station). Install a 345/138 kV transformer at Lake Hawkins (or Perdue).	60	3/1/2022	$16,666,456	AEP	Regional Reliability	700346	Lake Hawkins (or Perdue) 345 kV	508358	Lake Hawkins (or Perdue) 138 kV	1	345/ 138				675
ATP	AEP	Rebuild and reconductor 11.1 mile Chamber Springs-Farmington REC 161 kV line with 2156 ACSR. Replace wave traps at Chamber Springs and bus at Farmington REC.	36	6/1/2022	$15,870,489	AEP	Regional Reliability	506944	Chamber Springs	504020	Farmington REC	1	161	11.1			520/729
ATP	GMO	Reconductor 3.21 miles from Blue Springs to Prairie Lee 161 kV to 795 ACSS. Upgrade substation equipment to 2000 Amps	24	6/1/2018	$2,983,952	GMO	Regional Reliability	541206	Blue Springs South	541211	Prairie Lee	1	161	3.21			558/558

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
ATP	GMO	Reconductor 2.5 mile from Blue Springs South - Blue Springs East 161 kV to 795 ACSS. Upgrade substation equipment to 2000 Amps	24	6/1/2018	$2,399,248	GMO	Regional Reliability	541211	Blue Springs South	541205	Blue Springs East	1	161	2.5			558/558
CNTC	ITCGP	Build new 345 kV line from Elm Creek to Summit (ITCGP portion)	60	3/1/2018	$28,580,803	ITCGP	Regional Reliability	750011	Elm Creek 345 kV	532773	Summit 345 kV	1	345		28		1792/1792
CNTC	ITCGP	Install 345/230 kV transformer at Elm Creek	60	3/1/2018	$5,403,707	ITCGP	Regional Reliability	750011	Elm Creek 345 kV	539639	Elm Creek 230 kV	1	345/ 230				448/448
CNTC	ITCGP	Bus work on 345 kV side at Elm Creek substation	60	3/1/2018	$8,015,964	ITCGP	Regional Reliability	750011	Elm Creek 345 kV			1	345				
CNTC	ITCGP	Bus work on 230 kV side at Elm Creek substation	60	3/1/2018	$697,163	ITCGP	Regional Reliability	539639	Elm Creek 230 kV			1	230				
ATP	KCPL	Install new 345/161 kV transformer at new Eastowne sub, tapping the Iatan - St. Joe 345 kV and connects to the existing 161 kV in the area and switches out Lake Rd. - Alabama 161 kV	24	1/1/2020	$12,809,443	KCPL	Economic	541400	EASTOW N7 345kV	541401	EASTOW N5 161kV	1	345/ 161				400/440
ATP	MKEC	Reconductor Harper to Milan Tap 138 kV line.	36	3/1/2020	$9,613,332	MKEC	Regional Reliability	539668	Harper 138 kV	539675	Milan Tap 138 kV	1	138	22.1			261/314
ATP	MKEC	Rebuild MKEC portion of the Clearwater-Milan Tap 138 kV with bundled 1192.5 kcmil ACSR conductor (Bunting)	24	3/1/2022	$2,501,569	MKEC	Regional Reliability	533036	Clearwate r 138 kV	539675	Milan Tap 138 kV	1	138	5.6			261/314
CNTC	NPPD	Construct new 345 kV Transmission Line from GGS 345 kV Substation to a new Cherry County 345 kV Substation (Estimate includes 76 miles of S/C construction)	72	1/1/2018 Stage date was 1/1/2017	$92,660,000	NPPD	Policy	640183	Gentlema n 345kV	640500	Cherry County 345kV	1	345		76		1792/1792

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
CNTC	NPPD	Construct 345 kV Terminal at GGS 345 kV substation to accomodate new 345 kV line from GGS to new Cherry County 345 kV Substation	72	1/1/2018 Stage date was 1/1/2017	$1,380,000	NPPD	Policy	640183	Gentleman 345kV				345				
CNTC	NPPD	Construct new Cherry County 345 kV Substation. Initial 3-terminal ring bus, expandable to breaker and one half; 1-terminal to GGS, 1-terminal to Holt County, 1-terminal for future use.	72	1/1/2018 Stage date was 1/1/2017	$6,000,000	NPPD	Policy	640500	Cherry County 345kV				345				
CNTC	NPPD	Construct new 345 kV Transmission Line from new Cherry County 345 kV Substation to new 345 kV Holt County Substation. (Estimated 146 miles of S/C construction)	72	1/1/2018 Stage date was 1/1/2017	$172,360,000	NPPD	Policy	640500	Cherry County 345kV	640503	Holt County	1	345		146		1792/1792
CNTC	NPPD	Construct new Holt County 345 kV Substation, interconnecting to WAPA GI-Ft. Thompson 345 kV Line. Initial 5-terminal breaker and one half; 1-terminal to Cherry County, 1-terminal to Hoskins, 2-terminals to WAPA, 2 - 345 kV Line Reactors; 1-terminal location for future.	72	1/1/2018 Stage date was 1/1/2017	$16,880,000	NPPD	Policy	640503	Holt County				345				
CNTC	NPPD	Build a 345 kV line from Neligh to Hoskins	60	3/1/2019	$61,205,000	NPPD	Regional Reliability	750034	Neligh 345kV	640226	Hoskins 345kV	1	345		50		1792/1792
CNTC	NPPD	Install a 345/115 kV transformer at Neligh	60	3/1/2019	$35,497,400	NPPD	Regional Reliability	750034	Neligh 345kV	640293	Neligh 115kV	1	345/ 115				458/474
CNTC	OGE	Build new 46.5 mile 345 kV line from Elk City to Gracemont (OGE portion).	60	3/1/2018	$75,486,000	OGE	Regional Reliability	700345	Elk City 345 kV	515800	Gracemont 345 kV	1	345		46.5		1792/1792

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
ATP	OGE	Replace 800 amp CT and wave trap at Classen substation.	12	6/1/2020	$341,500	OGE	Regional Reliability	514922	Classen 138 kV	514921	SW 5 Tap	1	138				268/287
ATP	OGE	Reconductor 26 mile Glass Mountain - Mooreland line to 795 AS33	36	3/1/2022	$15,990,000	SPP	Regional Reliability	520999	Mooreland	514788	Glass Mountain	1	138	26			268/286
ATP	OGE	Reconductor 12.08 miles to 1590AS52, replace switches and other terminal equipment in Windfarm Sw and Mooreland Substation	24	3/1/2022	$7,760,000	SPP	Regional Reliability	514785	Woodward	515785	Windfarm	1	138	12.08			404/485
CNTC	OGE	Woodward - Tatonga 345kV Ckt2	72	3/1/2021	$71,876,622	OGE	Regional Reliability	515375	WWRDE HV7 345kV	515407	TATONG A7	2	345		49		1792/1792
CNTC	OGE	Build new Tatonga - Mathewson 61 mile 345 kV line.	72	3/1/2021	$82,139,900	OGE	Regional Reliability	515407	TATONG A7	750035	Mathewson 345 kV	2	345		61		1792/1792
CNTC	OGE	Build new 16 mile Mathewson - Cimmaron 345kV line.	72	3/1/2021	$32,780,617	OGE	Regional Reliability	750035	Mathewson 345 kV	514901	CIMARO N7	2	345		16		1792/1792
CNTC	OGE	Build new Mathewson substation.	72	3/1/2021	$20,169,602	OGE	Regional Reliability	750035	Mathewson 345 kV				345				
ATP	SPS	Upgrade Line trap at both Jones Bus # 2and Lubbock South iInterchange	12	6/1/2018	$110,240	SPS	Regional Reliability	526338	Jones Bus #2	526269	Lubbock S Interchange	2	230				478/502
CNTC	SPS	New 345/115kV transformer between Tuco and Stanton	36	6/1/2018	$37,490,796	SPS	Regional Reliability	525836	Tuco New Deal 345 kV	525837	New Deal 115kV	1	345/ 115				458/474
CNTC	SPS	Build new 345kV line between Tuco and high side of new transformer between Tuco and Stanton	36	6/1/2018		SPS	Regional Reliability	525832	Tuco 345kV	525836	Tuco New Deal 345 kV	1	345		15		1792/1792
CNTC	SPS	Build new 115kV line between Stanton and low side of new transformer between Tuco and Stanton	36	6/1/2018		SPS	Regional Reliability	525837	New Deal 115kV	526076	Stanton	1	115		17		174/192
ATP	SPS	Reconductor 1.5 miles line from Indiana to Stanton	24	6/1/2018	$1,581,080	SPS	Regional Reliability	526146	Indiana 115 kV	526076	Stanton	1	115	1.5			240/240

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
ATP	SPS	Reconductor 4 miles from Indiana to SP-Erskine	24	6/1/2018	$1,604,810	SPS	Regional Reliability	526146	Indiana 115 kV	526109	SP-Erskine 115 kV	1	115	4			240
ATP	SPS	Install a second 230/115/13.2 kV transformer at Hitchland	24	6/1/2018	$4,220,694	SPS	Regional Reliability	523095	Hitchland 230 kV	523093	Hitchland 115 kV	2	230/ 115/ 13.2				250/250
ATP	SPS	Upgrade the Carlisle 230/115/13.2 transformer - 250 MVA	24	6/1/2018	$3,644,914	SPS	Regional Reliability	526161	Carlisle 230 kV	526160	Carlisle 115 kV	1	230/ 115/ 13.2				250/250
CNTC	SPS	Build new 230 kV line from Wolfforth to Grassland	54	3/1/2018	$50,068,309	SPS	Regional Reliability	526525	Wolfforth 230 kV	526677	Grassland 230 kV	1	230		44		478/478
ATP	SPS	Install a second 230/115/13.2 kV transformer at Lubbock South	24	6/1/2019	$3,942,881	SPS	Regional Reliability	526269	Lubbock South	526268	Lubbock South	2	230/ 115/ 13.2				252/290
CNTC	SPS	Build new 345 kV line from Tuco - Amoco 67 miles	72	1/1/2020	$181,415,883	SPS	Economic	525832	TUCO_INT 7 345kV	750014	Amoco 345 kV	1	345		67		1792/1792
CNTC	SPS	Build new 345 kV line from Amoco - Hobbs 100 miles	72	1/1/2020		SPS	Economic	750014	Amoco 345 kV	750015	HOBBS7 345kV	1	345		100		1792/1792
CNTC	SPS	Install new 345/230 kV transformer at Amoco (New 345kV Amoco bus)	72	1/1/2020		SPS	Economic	750014	AMOCO7 345kV	526460	AMOCO_SS 6 230kV	1	345/ 230				448/448
CNTC	SPS	Install new 345/230 kV transformer at Hobbs (New 345kV Hobbs bus)	72	1/1/2020		SPS	Economic	750015	HOBBS7 345kV	527894	HOBBS_INT 6 230kV	1	345/ 230				448/448
ATP	SPS	Upgrade Chaves230/115 KV to 225/258 MVA	24	6/1/2020	$3,644,914	SPS	Regional Reliability	527483	Chaves	527482	Chaves	2	230/ 115				250/250
ATP	SPS	Reconductor 3.98 miles of Carlisle - Murphy 115 kV	24	6/1/2021	$4,714,312	SPS	Regional Reliability	526160	Carlisle 115 kV	526192	Murphy 115 kV	1	115	3.98			273/300
ATP	SPS	Convert 40 miles Potter - Channing 115 kV to 230 kV, Terminal equipment at Potter	48	6/1/2022	$6,707,552	SPS	Regional Reliability	523959	Potter County 230 kV	523869	Channing 230 kV	1	230			40	492/541
ATP	SPS	Convert 35 miles Channing - XIT - Dallam 115 kV to 230 kV	48	6/1/2022	$828,700	SPS	Regional Reliability	523869	Channing 230 kV	523229	Dallam 230 kV	1	230			35	492/541
ATP	SPS	Install 230/115/13.2 kV transformer at Dallam County Jr. (XIT) Sub	48	6/1/2022	$3,583,825	SPS	Regional Reliability	523229	Dallam 230 kV	523228	Dallam County Interchange 115 kV	1	230/ 115/ 13.2				168/168

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
ATP	SPS	Install 28.8 Mvar capacitor at Lamb County 69 kV	12	6/1/2022	$944,754	SPS	Regional Reliability	526036	Lamb County 69 kV				69				28.8 Mvar
ATP	SPS	Install 14.4 Mvar capacitor at Eagle Creek 115 kV	12	6/1/2022	$697,688	SPS	Regional Reliability	527711	Eagle Creek 115 kV				115				14.4 Mvar
ATP	SPS	Line - Allen Sub - Lubbock South Interchange 115 kV Ckt 1	24	6/1/2019	$3,528,552	SPS	Regional Reliability	526268	Lubbock South Interchange	526213	Allen	1	115	6			273/300
ATP	WFEC	Reconductor Okeene - Dover Switching Station 138 kV to 795 ACSS.	36	3/1/2022	$16,666,500	SPP	Regional Reliability	520882	Dover 138 kV	521016	Okeene 138 kV	1	138	27.1			286/286
NTC	WR	Install second 138/115 kV transformer at Moundridge.	24	12/1/2014 Stage date was 1/1/2012	$12,197,900	WR	Economic	533429	MOUNDRG3 115kV	533013	MOUND4 138kV	2	138/115				110/125
CNTC	WR	Build new 345 kV line from Elm Creek to Summit (Westar portion)	60	3/1/2018	$62,110,152	WR	Regional Reliability	750011	Elm Creek 345 kV	532773	Summit 345 kV	1	345		30		1792/1792
ATP	WR	Tap Lawrence Hill - Swissvale 230 kV line near Baldwin Creek substation and install Baldwin Creek 230/115 kV transformer	24	6/1/2021	$18,343,600	WR	Regional Reliability	532858	Baldwin Creek 230kV	533232	Baldwin Creek 115kV	1	230/115				280/308
ATP	WR	Rebuild Westar portion of the Clearwater-Milan Tap 115 kV with bundled 1192.5 kcmil ACSR conductor (Bunting)	24	3/1/2022	$7,951,703	WR	Regional Reliability	533036	Clearwater 138 kV	539675	Milan Tap 138 kV	1	138	6.1			261/314
ATP	WR	Tear down/rebuild as single circuit with bundled 1192 ACSR conductor.	36	6/1/2022	$11,501,055	WR	Regional Reliability	533365	Abilene East 115 kV	533362	Chapman 115 kV	1	115	12.3			240/240
ATP	WR	Tear down/rebuild as single circuit with bundled 1192 ACSR conductor.	24	6/1/2022	$3,806,178	WR	Regional Reliability	533365	Abilene East 115 kV	533361	Abilene Energy Center 115 kV	1	115	3.33			240/240
ATP	WR	Tear down/rebuild as single circuit with bundled 1192 ACSR conductor.	36	6/1/2022	$19,949,242	WR	Regional Reliability	533361	Abilene Energy Center 115 kV	533371	Northview 115 kV	1	115	21.75			240/240
ATP	WR	Tear down/rebuild as single circuit with bundled 1192 ACSR conductor.	24	6/1/2022	$5,131,249	WR	Regional Reliability	533371	Northview 115 kV	533370	North Street 115 kV	1	115	3.2			240/240
ATP	WR	Install 1 stage of 15 Mvar	12	6/1/2022	$957,660	WR	Zonal Reliability	533347	Northwest Manhattan				115				15 Mvar

Table 19.3: 2012 ITP10 Recommended Project List

19.5: Conditional Notification to Construct Project List

The MOPC requested a list of recommended projects that specifically listed only those upgrades with a requested board action of CNTC. Table 19.4 lists the upgrades as requested. The total cost of projects recommended for CNTC was estimated at $1,141,793,310.

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
CNTC	AEP	Build new 46.5 mile 345 kV line from Elk City to Gracemont (AEP portion).	60	3/1/2018	$81,514,845	AEP	Regional Reliability	700345	Elk City 345 kV	515800	Gracemont 345 kV	1	345		46.5		1792/1792
CNTC	AEP	Expand Elk City substation (or build new station). Install a 345/230 kV 675 MVA transformer at Elk City	60	3/1/2018	$18,060,547	AEP	Regional Reliability	700345	Elk City 345 kV	511490	Elk City 230 kV	1	345/ 230				675
CNTC	ITCGP	Build new 345 kV line from Elm Creek to Summit (ITCGP portion)	60	3/1/2018	$28,580,803	ITCGP	Regional Reliability	750011	Elm Creek 345 kV	532773	Summit 345 kV	1	345		28		1792/1792
CNTC	ITCGP	Install 345/230 kV transformer at Elm Creek	60	3/1/2018	$5,403,707	ITCGP	Regional Reliability	750011	Elm Creek 345 kV	539639	Elm Creek 230 kV	1	345/ 230				448/448
CNTC	ITCGP	Bus work on 345 kV side at Elm Creek substation	60	3/1/2018	$8,015,964	ITCGP	Regional Reliability	750011	Elm Creek 345 kV			1	345				
CNTC	ITCGP	Bus work on 230 kV side at Elm Creek substation	60	3/1/2018	$697,163	ITCGP	Regional Reliability	539639	Elm Creek 230 kV			1	230				
CNTC	NPPD	Construct new 345 kV Transmission Line from GGS 345 kV Substation to a new Cherry County 345 kV Substation (Estimate includes 76 miles of S/C construction)	72	1/1/2018 Stage date was 1/1/2017	$92,660,000	NPPD	Policy	640183	Gentleman 345kV	640500	Cherry County 345kV	1	345		76		1792/1792
CNTC	NPPD	Construct 345 kV Terminal at GGS 345 kV substation to accomodate new 345 kV line from GGS to new Cherry County 345 kV Substation	72	1/1/2018 Stage date was 1/1/2017	$1,380,000	NPPD	Policy	640183	Gentleman 345kV				345				

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
CNTC	NPPD	Construct new Cherry County 345 kV Substation. Initial 3-terminal ring bus, expandable to breaker and one half; 1-terminal to GGS, 1-terminal to Holt County, 1-terminal for future use.	72	1/1/2018 Stage date was 1/1/2017	$6,000,000	NPPD	Policy	640500	Cherry County 345kV				345				
CNTC	NPPD	Construct new 345 kV Transmission Line from new Cherry County 345 kV Substation to new 345 kV Holt County Substation. (Estimated 146 miles of S/C construction)	72	1/1/2018 Stage date was 1/1/2017	$172,360,000	NPPD	Policy	640500	Cherry County 345kV	640503	Holt County	1	345		146		1792/1792
CNTC	NPPD	Construct new Holt County 345 kV Substation, interconnecting to WAPA GI-Ft. Thompson 345 kV Line. Initial 5-terminal breaker and one half; 1-terminal to Cherry County, 1-terminal to Hoskins, 2-terminals to WAPA, 2 - 345 kV Line Reactors; 1-terminal location for future.	72	1/1/2018 Stage date was 1/1/2017	$16,880,000	NPPD	Policy	640503	Holt County				345				
CNTC	NPPD	Build a 345 kV line from Neligh to Hoskins	60	3/1/2019	$61,205,000	NPPD	Regional Reliability	750034	Neligh 345kV	640226	Hoskins 345kV	1	345		50		1792/1792
CNTC	NPPD	Install a 345/115 kV transformer at Neligh	60	3/1/2019	$35,497,400	NPPD	Regional Reliability	750034	Neligh 345kV	640293	Neligh 115kV	1	345/ 115				458/474
CNTC	OGE	Build new 46.5 mile 345 kV line from Elk City to Gracemont (OGE portion).	60	3/1/2018	$75,486,000	OGE	Regional Reliability	700345	Elk City 345 kV	515800	Gracemont 345 kV	1	345		46.5		1792/1792
CNTC	OGE	Woodward - Tatonga 345kV Ckt2	72	3/1/2021	$71,876,622	OGE	Regional Reliability	515375	WWRDE HV7 345kV	515407	TATONG A7	2	345		49		1792/1792
CNTC	OGE	Build new Tatonga - Mathewson 61 mile 345 kV line.	72	3/1/2021	$82,139,900	OGE	Regional Reliability	515407	TATONG A7	750035	Mathewson 345 kV	2	345		61		1792/1792

Requested Board Action	Facility Owner	Project Description	Lead Time (Months)	Need Date	Cost Estimate	Estimated Cost Source	Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Ckt	kV	Reconductor (mi)	New (mi)	kV Conversion (mi)	Rating
CNTC	OGE	Build new 16 mile Mathewson - Cimmaron 345kV line.	72	3/1/2021	$32,780,617	OGE	Regional Reliability	750035	Mathewson 345 kV	514901	CIMARO N7	2	345		16		1792/1792
CNTC	OGE	Build new Mathewson substation.	72	3/1/2021	$20,169,602	OGE	Regional Reliability	750035	Mathewson 345 kV				345				
CNTC	SPS	New 345/115kV transformer between Tuco and Stanton	36	6/1/2018	$37,490,796	SPS	Regional Reliability	525836	Tuco New Deal 345 kV	525837	New Deal 115kV	1	345/ 115				458/474
CNTC	SPS	Build new 345kV line between Tuco and high side of new transformer between Tuco and Stanton	36	6/1/2018		SPS	Regional Reliability	525832	Tuco 345kV	525836	Tuco New Deal 345 kV	1	345		15		1792/1792
CNTC	SPS	Build new 115kV line between Stanton and low side of new transformer between Tuco and Stanton	36	6/1/2018		SPS	Regional Reliability	525837	New Deal 115kV	526076	Stanton	1	115		17		174/192
CNTC	SPS	Build new 230 kV line from Wolfforth to Grassland	54	3/1/2018	$50,068,309	SPS	Regional Reliability	526525	Wolfforth 230 kV	526677	Grassland 230 kV	1	230		44		478/478
CNTC	SPS	Build new 345 kV line from Tuco - Amoco 67 miles	72	1/1/2020	$181,415,883	SPS	Economic	525832	TUCO_INT 7 345kV	750014	Amoco 345 kV	1	345		67		1792/1792
CNTC	SPS	Build new 345 kV line from Amoco - Hobbs 100 miles	72	1/1/2020		SPS	Economic	750014	Amoco 345 kV	750015	HOBBS7 345kV	1	345		100		1792/1792
CNTC	SPS	Install new 345/230 kV transformer at Amoco (New 345kV Amoco bus)	72	1/1/2020		SPS	Economic	750014	AMOCO7 345kV	526460	AMOCO_SS 6 230kV	1	345/ 230				448/448
CNTC	SPS	Install new 345/230 kV transformer at Hobbs (New 345kV Hobbs bus)	72	1/1/2020		SPS	Economic	750015	HOBBS7 345kV	527894	HOBBS_INT 6 230kV	1	345/ 230				448/448
CNTC	WR	Build new 345 kV line from Elm Creek to Summit (Westar portion)	60	3/1/2018	$62,110,152	WR	Regional Reliability	750011	Elm Creek 345 kV	532773	Summit 345 kV	1	345		30		1792/1792

Table 19.4: 2012 ITP10 Recommended CNTC Only Project List

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