ITP20

2013 Integrated Transmission Plan
20-Year Assessment Report

July 30, 2013

Engineering

Southwest Power Pool

Revision History

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Executive Summary

The Integrated Transmission Planning (ITP) process is Southwest Power Pool's iterative three-year study process that includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies transmission projects, generally above 300 kV, needed to provide a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year Assessment focuses on facilities 100 kV and above to meet system needs over a ten-year horizon. The Near Term Assessment is performed annually and assesses system upgrades, at all applicable voltage levels, required in the near term planning horizon to address reliability needs. Along with the Highway/Byway cost allocation methodology, the ITP process promotes transmission investment that will meet reliability, economic, and public policy needs[1] to create a cost-effective, flexible, and robust transmission network that will improve access to the region's diverse generating resources. This report documents the 20-year Assessment that concludes in July 2013.

Five distinct futures were considered to account for possible variations in system conditions over the assessment's 20-year horizon. The futures were developed by the Strategic Planning Committee (SPC) and the Economic Studies Working Group (ESWG). The futures are presented briefly below and further discussed in Section 3:

1. **Business-As-Usual**: This future includes renewable resources (approximately 10 GW of nameplate wind capacity) necessary to meet state renewable mandates and targets as identified in the 2012 Policy Survey[2], load growth projected by load serving entities, and the impacts of Environmental Protection Agency (EPA) regulations that are outlined in the Policy Drivers.
2. **Additional Wind**: This future assumes a 20% federal Renewable Electricity Standard (RES). It includes renewable resources (approximately 16.5 GW of nameplate wind capacity) necessary to meet that standard.
3. **Additional Wind plus Exports**: This future includes the 20% RES of Future 2, plus approximately 10 GW of additional wind generation to be exported outside of SPP.
4. **Combined Policy**: This future approximates the effects of additional investment in Demand Side Management and Smart Grid technology. This future include an annual 1 percentage point reduction to the load growth assumed in the other futures, the 20% RES of Future 2, and a carbon constraint, as described in the Policy Drivers section.
5. **Joint SPP/MISO Future:** This future includes coordinated input assumptions and models from SPP's ESWG and MISO's Planning Advisory Committee (PAC). This future is based on the same guidelines as the business as usual future: normal load growth, state mandates and targets for renewable generation, etc. However, some of the actual assumption values vary from Future 1 due to collaboration with MISO.

The recommended 2013 ITP20 portfolio shown in Figure 0.1 is estimated at **$560 million** in engineering and construction cost and includes projects needed to meet potential reliability, economic, and policy

[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] 2012 Policy Survey

requirements. These projects, with a total estimated net present value revenue requirement of **$845 million**, are expected to provide net benefits of approximately **$1.5 billion** over the life of the projects under a Future 1 scenario containing 9 GW of wind capacity.

12 projects make up the portfolio:

Name	Type	Size	Focus
Keystone – Red Willow	New Branch	345 kV	Reliability
Tolk – Tuco	New Branch	345 kV	Reliability
S3459	2nd Transformer	345/161 kV	Economic
Holcomb	2nd Transformer	345/115 kV	Reliability
Maryville	New Transformer	345/161 kV	Reliability
Pecan Creek – Muskogee	Upgrade 2 circuits	345 kV	Reliability
Nashua	Upgrade Transformer	345/161 kV	Reliability
JEC – Auburn – Swissvale	Rebuild (New Auburn transformer)	345 kV, 345/115 kV	Reliability
Clinton – Truman – N Warsaw	Upgrade Branch	161 kV	Seams Project
S3740 - S3454	New Branch	345 kV	Reliability
Chamber Springs - S Fayetteville	New Branch & Transformer	345 KV, 345/161 kV	Economic
Wolf Creek - Neosho	New Branch	345 kV	Economic

Table 0.1: 2013 ITP20 Transmission Plan

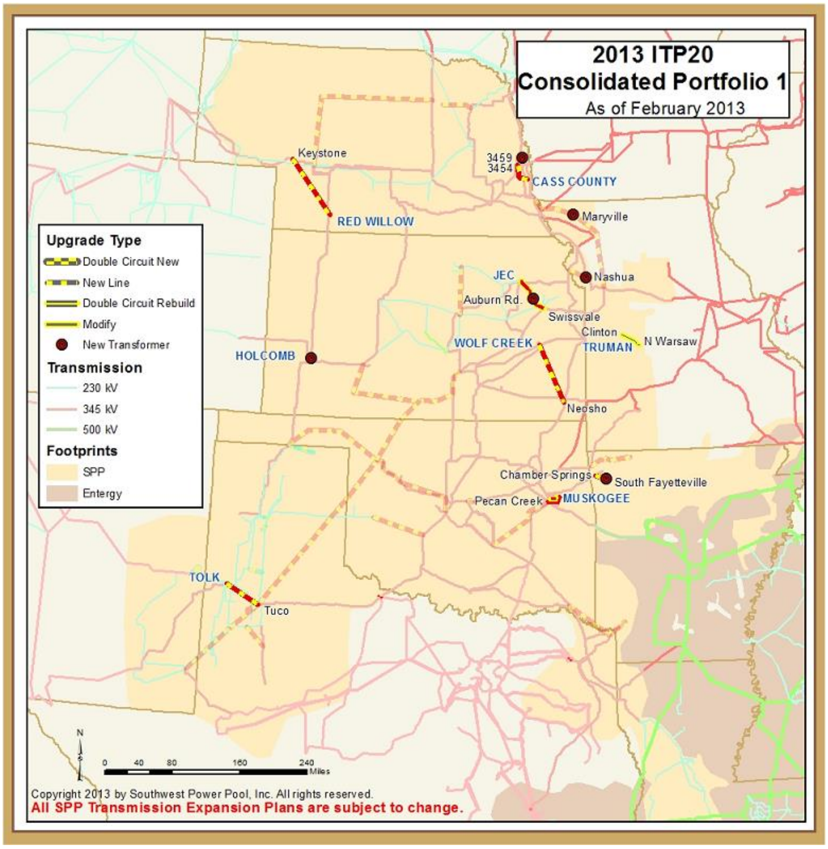


Figure 0.1: 2013 ITP20 Transmission Plan[3]

[3] The S3740 station is labeled in the report maps as Cass County.

PART I: STUDY PROCESS

Section 1: Introduction

1.1: The 20-Year ITP

The 20-Year Integrated Transmission Planning Assessment (ITP20) is designed to identify a transmission expansion portfolio containing primarily Extra High Voltage (EHV) projects needed to address reliability needs, support policy initiatives, and enable economic opportunities in the SPP transmission system within the studied twenty-year horizon.

The portfolio will be used as a roadmap for the development of appropriate EHV projects in the coming years that would provide increased flexibility and value to SPP's members as those needs become better known through the performance of other planning assessments. The ITP20 is not intended to address lower voltage solutions that will be needed to integrate new EHV projects.

The goals of the ITP20 are to:

- Focus on regional needs.
- Utilize a value-based approach to analyze 20-year out transmission system needs.
- Identify 345 kV and above solutions stemming from such needs as:
    - Resolving potential reliability criteria violations
    - Mitigating known or expected congestion
    - Improving access to markets
    - Improving interconnections with SPP's neighbors
    - Meeting expected load growth demands
    - Facilitating or responding to expected facility retirements
- Meet public policy initiatives
- Synergize the Generation Interconnection and Transmission Service Studies with other planning processes

1.2: How to Read This Report

This report focuses on the year 2033 (20 years from 2013) and 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 recommendations, expected benefits, and costs. Please note that negative numbers here are shown in red and in parentheses.
- Part IV contains detailed data and holds the report's appendix material.

SPP Footprint

Within this study, any reference to the SPP footprint refers to the set of Balancing Authorities and Transmission Owners[4] (TO) whose transmission facilities are under the functional control of the SPP Regional Transmission Organization (RTO) unless otherwise noted.

Energy markets were also modeled for other regions in the Eastern Interconnection. Notably, Associated Electric Cooperatives Inc. (AECI) and Mid-Continent Area Power Pool (MAPP) were modeled as stand-alone entities, while Entergy and CLECO were modeled within the Midcontinent ISO (MISO) energy market to reflect their commitments to be a part of MISO's planning region and market.

Supporting Documents

The development of this study was guided by the supporting documents noted below. These documents provide structure for this assessment:

- SPP 2013 ITP20 Scope
- SPP ITP Manual
- SPP Robustness Metrics Procedural Manual
- SPP Metrics Task Force Report

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

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.

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

Section 2: Stakeholder Collaboration

Assumptions and procedures for the 2013 ITP20 analysis were developed through SPP stakeholder meetings that took place in 2012 and 2013. The assumptions were presented and discussed through a series of meetings with members, liaison-members, industry specialists, and consultants to facilitate a thorough evaluation. Groups involved in this development included the following:

- Economic Studies Working Group (ESWG)
- Transmission Working Group (TWG)
- Metrics Task Force (MTF)
- Regional Tariff Working Group (RTWG)
- Cost Allocation Working Group (CAWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)
- SPP Regional State Committee (RSC)
- SPP Board of Directors

SPP Staff served as facilitators for these groups and worked closely with the chairs to ensure all views were heard and that SPP's member-driven value proposition was followed.

The ESWG and TWG provided technical guidance and review for inputs, assumptions, and findings. Policy level considerations were tendered to appropriate organizational groups including the MOPC, SPC, RSC, and Board of Directors. Stakeholder feedback was key to the selection of the 2013 ITP20 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 and policy guidance for the study was provided by the SPC, MOPC, RSC, and Board of Directors.

Planning Workshops

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.

- Key drivers developed by the stakeholders were presented at the planning summit on August 22, 2012[5].
- Potential upgrades were presented at the planning summit on December 4, 2012[6].

[5] SPP.org > Engineering > Transmission Planning > 2012 August Planning Summit

- Recommended solutions with completed reliability, stability and economic analysis results were presented at the planning summit on May 15, 2013[7].

Policy Survey

The 2012 Policy Survey asked stakeholders to identify:

- existing wind farms
- other existing renewable resources
- wind farms coming online by end of year 2013
- state renewable mandates for wind generation through the year 2033
- state renewable targets for wind generation through the year 2033
- projected impacts of EPA regulation on existing generation, including retrofits, retirements, fuel switching, and derates

The results of the 2012 Policy Survey were used in the modeling of EPA regulation impacts on existing generation, as detailed in Section 4.3: . The results were also used in resource planning for both conventional and renewable resources, as detailed in Section 5:. After modeling existing renewables as reported in the survey, each zone was analyzed to see if it met the renewable targets and mandates reported in the survey. If a zone was short on renewables, additional wind was added in order to meet the targets and mandates for each zone.

Project Cost Overview

Project costs utilized in the 2013 ITP20 were developed in accordance with the guidelines of the Project Cost Working Group (PCWG). Conceptual Estimates were prepared by SPP staff based on historical cost information in an SPP database and updated information provided by the TO.

New Benefit Metrics

New benefit metrics were developed by the ESWG and MTF in 2012. The report published by the MTF catalogued eight additional metrics that could be used to assess the value of transmission projects for the Regional Cost Allocation Review (RCAR). ESWG provided direction to use three of these new metrics as part of the 2013 ITP20 for informational purposes, and concluded that using all of the new metrics would add unneeded complexity to the study. Below is a list of metrics used in the 2013 ITP20:

<u>Historical ITP metrics:</u>

- Adjusted Production Cost (APC)
- Reduced capacity expansion costs due to reduced transmission losses on peak
- Reduction of emission rates and values
- Savings due to lower ancillary service needs and ancillary service production costs

<u>Newly developed metrics:</u>

- Mitigation of transmission outage costs
- Assumed benefit of mandated reliability projects
- Benefit from meeting public policy goals

[6] SPP.org > Engineering > Transmission Planning > 2012 December Planning Summit

[7] SPP.org > Engineering > Transmission Planning > 2013 May Planning Summit

Section 3: Future Selection

3.1: Uncertainty and Important Issues

Designing a transmission expansion plan to meet future needs is challenging because of the inability to accurately predict the policy environment, future load growth, fuel prices, and technological development over an extended time period. To address these challenges, five distinct sets of assumptions were developed and studied as individual "futures" for the 2013 ITP20.

3.2: Futures Descriptions

The 2013 ITP20 study was conducted on a set of five futures. These futures consider evolving changes in technology and public policy that may influence the transmission system and energy industry as a whole. By accounting for multiple future scenarios, SPP staff can assess what transmission needs arise for various uncertainties. In all futures, EPA environmental regulations, as known or anticipated at the time of the study, are incorporated and Entergy and CLECO are assumed to be members of MISO.

Future 1: Business as Usual
This future includes state renewable mandates and targets as identified in the 2012 Policy Survey resulting in 9.2 GW of renewable resources modeled in SPP, load growth projected by load serving entities, and SPP member-identified generator retirement projections of approximately 4 GW. This future assumes no major changes to policies that are currently in place.

Future 2: Additional Wind
This future's assumptions build upon the Business as Usual future assumptions. Instead of implementing current state renewable mandates and targets, a 20% Renewable Energy Standard (RES) was implemented for each region in the Eastern Interconnect, resulting in 16.4 GW of renewable resources modeled in SPP. This provides an assessment of the transmission outlook if a similar federal renewable standard were implemented.

Future 3: Additional Wind Plus Exports
Future 3 assumes that SPP will produce and export 10 GW of wind resources above the 20% RES of Future 2 to assist other regions in meeting their RES. This 10 GW was exported to Entergy, PJM, Southern Company, and TVA.

Future 4: Combined Policy
This future examines various policy changes and their impacts that would encourage more "green" generation. A 20% RES for each region is implemented in this future, as well as a carbon constraint of $36/ton. A potential result of these policy changes is a more aggressive demand response/energy efficiency approach than the Business as Usual future. This was implemented through reductions in peak demand and energy usage, as well as a flatter load curve and higher load factor (see *Figure 3.1*).

An annual 1% reduction to the growth of load was applied from 2021 through 2033 for the SPP region such that the load growth during these years was 0.3% instead of 1.3%. This was done to account for efficiencies gained in demand response/energy efficiency technology that might be expected if the carbon constraint is implemented. The decrease in annual energy percentage is approximately half of the decrease in peak demand percentage resulting in a higher load factor than the Business as Usual future. The impact of these two technologies is shown in *Figure 3.1*:

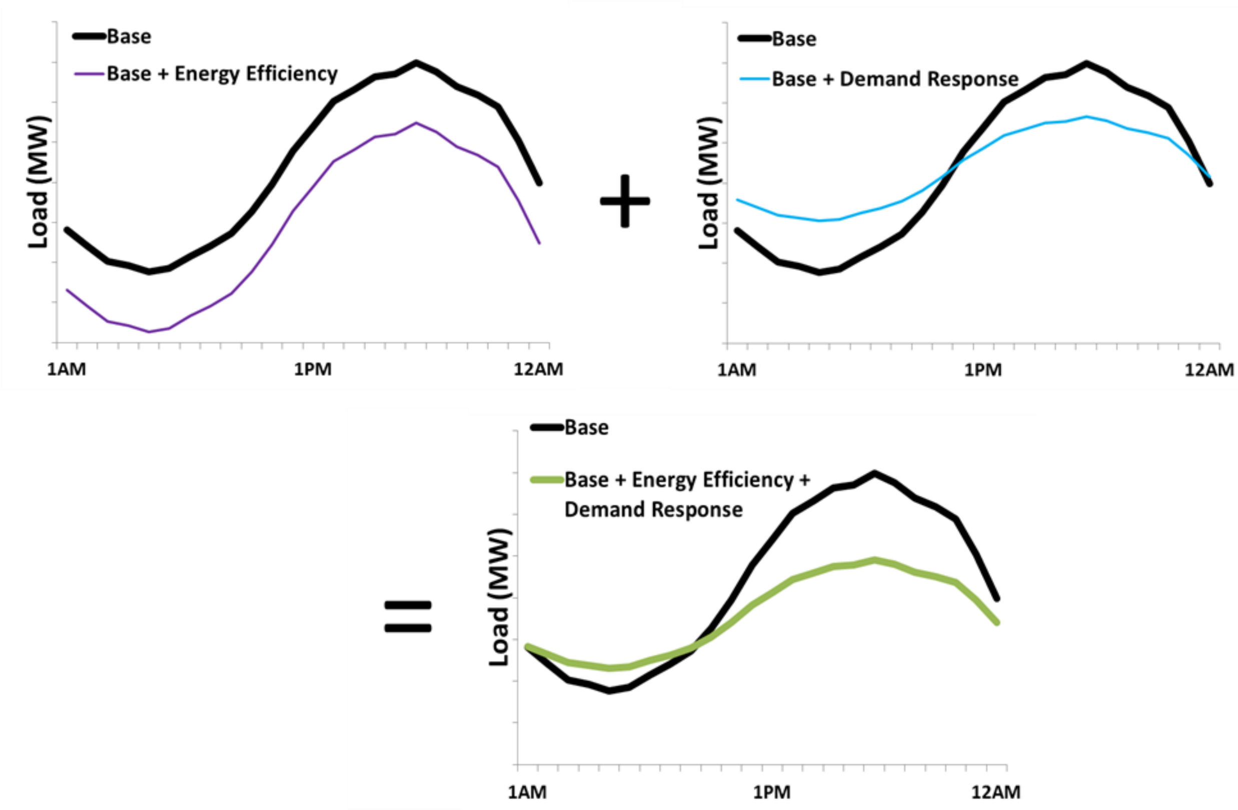


Figure 3.1: Impact of Demand Response & Energy Efficiency Over One Day

Future 5: Joint SPP/MISO Future

The joint future parameters were developed by the SPP ESWG and the MISO Planning Advisory Committee (PAC). The ESWG and PAC determined that the joint model should reflect "business as usual" conditions. This future is based on the same guidelines as Future 1 (normal load growth, state targets for renewable generation, etc.). While the joint future is similar to Future 1, it is not absolutely the same. Some of the assumption values vary from Future 1 due to collaboration with MISO for the joint future. These Future 5 differences include additional transmission constraints outside of SPP, natural gas prices approximately 4 cents less than Future 1 gas prices, and more generation in the MISO region of the resource plan than Future 1.

Data provided by MISO regarding the modeling of the MISO region was also leveraged in the other futures to improve the representation of the MISO region in the SPP model.


F1 Business as Usual
F2 Additional Wind
F3 Additional Wind plus Exports
F4 Combined Policy
F5 Joint Future with MISO

Section 4: Study Drivers

4.1: Introduction

Drivers for the 2013 ITP20 were discussed and developed through the stakeholder process in accordance with the 2013 ITP20 Scope and involved stakeholders from several diverse groups. Stakeholder load, energy, generation, transmission, financial, and market design inputs were carefully considered in determining the need for, and design of, transmission.

4.2: Load & Energy Outlook

Peak and Off-Peak Load

Future electricity usage was forecasted by utilities in the SPP footprint and collected and reviewed 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 59.4 GW for 2023 and 67.7 GW for 2033. Note that all demand figures shown in this section include the loads of the Transmission Owners within the SPP OATT footprint as well as all other Load Serving Entities within the SPP region.

Once inputs such as the peak load values, annual energy values, hourly load curves, and hourly wind generation profiles were incorporated into the model, the economic modeling tool calculated the security-constrained unit commitment and security-constrained economic dispatch (SCUC/SCED) for each of the 8,760 hours in the year 2033.

Four seasonal peak hours were focused upon that uniquely stress the grid:

1) **Summer peak** –The summer hour with the highest load
2) **Winter peak** – The winter hour with the highest load
3) **High wind hour** – The hour with highest ratio of wind output to load, in order to evaluate grid exposure to significant output from these resources.
4) **Low hydro hour** – The hour with the lowest ratio of hydro output to load, in order to evaluate transmission needs arising from hydro power being unavailable to serve load.

These four hours were analyzed for reliability overloads. Hourly load shapes were developed consistent with the peak demand and energy values. The results indicated that the summer peak hour for 2033 would occur on August 3 at 5 p.m., the winter peak hour would occur on December 13 at 7 p.m., the high wind hour would occur on May 9 at 3 a.m., and the low hydro hour would occur on August 30 at 4 a.m.

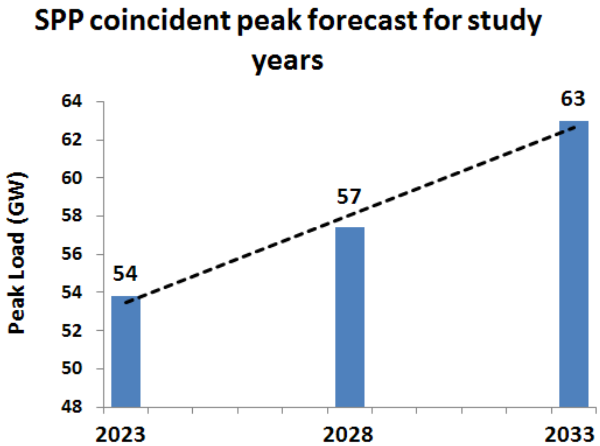


Figure 4.1: SPP coincident peak forecast for 2033 and intervening years

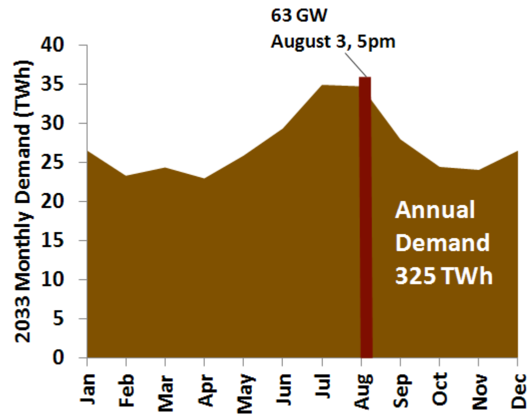


Figure 4.2: SPP Annual Energy Demand Forecast

Peak Load and Energy

The sum of energy used throughout a year, referred to as the net energy for load forecasts, was forecast by SPP using the load factor data provided by SPP members (via EIA-411 forms) and reviewed by the MDWG and ESWG contacts. Annual net energy for load (including losses) was forecasted at 292 TWh for 2023 and 334 TWh for 2033. Coincident peak load was forecasted at 54 GW for 2023 and 63 GW for 2033. Figure 4.1 and Figure 4.2 show the forecasted peak and energy values for 2033 and the expected growth in peak load for the intervening years.

Major Load Centers in SPP

Table 4.2 shows the percentage of the peak load that is located in each load center. The largest cities in SPP: Omaha, Kansas City, Wichita, Tulsa, and Oklahoma City all lie along the eastern border of SPP and account for 28% of the region's load at peak. Load in the western portion of SPP is concentrated primarily in Amarillo and near Lubbock.

City	State	% of Peak
Amarillo	TX	0.98%
Fayetteville	AR	1.35%
Kansas City	MO	9.73%
Lincoln	NE	1.40%
Lubbock	TX	1.88%
Oklahoma City	OK	6.29%
Omaha	NE	4.49%
Shreveport	LA	2.06%
Springfield	MO	1.72%
Tulsa	OK	4.54%
Wichita	KS	3.22%

Table 4.2: Load Centers in SPP

Diverse Peak Demand Growth Rates

The MDWG models included diverse peak load growth rates for each area. Table 4.3 lists the peak load growth rates for the key areas in the model. These forecasted values result in an average annual growth rate of 1.32% for SPP.

Area	SUNC	MKEC	OKGE	WERE	AEPW	LES	NPPD	GRDA
Rate (%)	0.66	0.69	1.34	0.82	1.29	1.11	0.61	2.08
Area	KCPL	MIDW	WFEC	EMDE	GMO	OPPD	CUS	SPS
Rate (%)	0.69	1.54	1.19	1.25	1.72	1.78	1.34	2.02

Table 4.3: Annual Peak Load Growth Rates for SPP OATT Transmission Owners 2012 - 2033 (%)

4.3: Policy Drivers

The potential impacts of the proposed Cross-State Air Pollution Rule (CSAPR)[8], Mercury and Air Toxics Standards (MATS)[9], Section 316(b) of the Clean Water Act[10], and EPA's Regional Haze[11] Program were accounted for in the resource planning, production cost modeling, and benefit metric calculations for all futures using the best information available at the time of the study. Four techniques were employed to capture these potential impacts:

- unit retirements
- unit derates
- unit retrofits
- unit fuel switching
- emission price forecasts for SO_2, NO_X, and CO_2

The unit retirements, derates, and fuel switching decisions were guided by the 2012 Policy Survey. Emission price forecasts for SO_2 and NO_X for the 2033 study year were based upon Ventyx simulation ready data (specifically, the 2012 Spring Reference Case released in May 2012). A CO_2 price was only utilized in Future 4, as this is the only future with the carbon constraint. The CO_2 price in this future was \$36/ton, as determined by the ESWG.

4.4: Utilization of 345 kV AC, 765 kV AC, or HVDC

Voltage Levels and Technology Choice (AC vs. DC)

The ITP20 focuses on developing a long-term EHV transmission backbone for the SPP system. When developing the plans, much consideration was given to the voltage level that would be selected for the projects. Options included the use of AC voltages of 345 kV or 765 kV as well as DC voltages of $\pm$600 kV.

[8] http://epa.gov/airtransport/

[9] http://www.epa.gov/mats/

[10] http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/

[11] http://www.epa.gov/visibility/program.html

EHV Design Considerations

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

NERC N-1 Reliability Standards

SPP designs and operates its transmission system to be capable of withstanding the next transmission outage that may occur – this is called "N-1" planning and is in accordance with NERC planning standards. Due to N-1 planning, any EHV network must be looped so that if one element of the EHV grid is lost, a parallel path will exist to move that power across the grid and avoid overloading the underlying transmission lines. It should be noted that HVDC lines provide the benefit of an inherent N-1 design since, per common practice and NERC reliability standards, the loss of a single "pole" (similar to an AC phase) is considered an N-1 contingency event. In contrast, loss of an entire AC circuit is considered an N-1 event.

Distances within the SPP System and to External Paths

Line lengths are another factor when considering EHV transmission systems. The length of an AC transmission line affects its performance in terms of voltage, loadability, and stability. HVDC transmission lines do not have performance impacts due to line lengths. The longest distance <u>within</u> the SPP system is approximately 500 miles, while distances of over 700 miles are seen between western SPP resource regions and some external paths. When considering line length, it is necessary to consider the proximity of generation to load on the system. In the current SPP system, generation is generally located close to load centers. As wind capacity has increased, some generation is concentrated in areas of high wind potential towards the western part of the system. It has become necessary to connect this generation with a network that is capable of moving power to the eastern portion of the SPP system or the eastern United States where the major load centers are located.

Line Length and Loadability

The length of an AC transmission line has an impact on its performance characteristics. A transmission line's loadability can be estimated based on its length, voltage level, and the type of conductors utilized. As line length increases, loadability decreases. The decrease in loadability can be countered by using higher voltage transmission for longer distances, or using HVDC alternatives that are not impacted by line length.

Capacity Needs

In addition to loadability, capacity needs should be considered when designing EHV transmission. Generally, higher capacity lines are desired for their ability to move power across long distances. The typical capacity of a 345 kV line in the SPP system is 1,200 – 1,800 MVA. Using double circuit 345 kV or a higher voltage such as 765 kV will increase the capacity of those lines. In consideration of longer lines, HVDC transmission lines may be a good option for higher power transfers. When considering EHV designs, system voltage and technology (AC vs. DC) can be a factor in selecting the design.

Voltage Support

A transmission line can either support voltage (produce VARs) or require voltage support from other reactive devices (consume VARs), depending on its loading level. In either case, transmission system design should account for these factors. Under light-load conditions, system voltages may rise due to VARs being produced from long EHV lines.

Shunt reactors would be necessary to help mitigate the rise in voltage. Some lines may need additional support to allow more power to flow through them. Series capacitors may be added to increase the loadability of a transmission line. However, the addition of series compensation can complicate operations and may lead to stability concerns.

Note that HVDC lines do not produce or consume VARs; however, the substations (converter stations) at either end of a HVDC line do require VARs which is typically accommodated by the filters and other reactive power equipment within the design of an HVDC link.

Construction Cost

Cost plays a factor in EHV grid design. Lower-voltage designs cost less to construct initially. Higher voltage lines have a larger initial investment but provide significantly higher capacity and more flexibility in bulk power transport. Lower voltage lines offer more flexibility to act as a collector system for wind generation. A 345 kV substation connection is considerably less costly than a 765 kV connection for a generator due to the costs of the step-up transformers. Along with the initial cost, the lifetime of the asset needs to be considered. Transmission lines are generally assumed to have a 40-year life.

Table 4.4 summarizes some of the key characteristics of line costs for different technologies. Table 4.5 summarizes the additional costs of HVDC converter stations.

Voltage	Approximate Costs/Mile
600 kV HVDC	$2,000,000
765 kV AC	$2,300,000
345 kV AC	$1,200,000

*Table 4.4: Approximate Costs of Different Transmission Line Technologies**

*These costs are for transmission line construction and Right-of-Way only and do not include HVDC converter station costs or costs for AC lines that require reactive compensation or additional station work to accommodate longer lengths.

HVDC Station Type	Approximate Costs for Station
Converter End Station	$300,000,000
Converter Midpoint Station	$100,000,000

Table 4.5: Approximate Costs of HVDC Converter Stations

Due to the cost of converter stations, HVDC solutions can be more expensive than AC alternatives when considering line lengths shorter than about 300 – 350 miles; however, for longer distances, the cost is more competitive with AC alternatives due to lower losses on DC transmission and the need associated with long AC projects to require additional equipment for voltage support when traversing distances greater than 300 – 350 miles.

Facts about Alternative Voltage and Technology Choices

There are several key advantages to higher voltage transmission line alternatives as opposed to lower voltage alternatives. Among the advantages of higher voltage AC lines are higher capacity and loadability, reduced losses, and smaller right-of-way (ROW) needs for an equivalent amount of capacity.

There are also some drawbacks to higher voltage lines, including higher costs, and additional voltage management due to higher voltage AC lines acting as capacitors in light-load situations. HVDC alternatives offer the capability to meet specific, long distance transfer needs without the loadability limitations, higher ROW requirements of multiple low voltage or high voltage AC lines, and lower losses than any other alternative. Drawbacks of HVDC links include higher costs (when considering transmission solutions for distances of less than 300 miles and/or for lower bulk power transfer levels), due to the costs of conversion equipment for the HVDC link.

Voltage Level Selection in the 2013 ITP20

The EHV solutions utilized in the 2013 ITP20 were primarily 345 kV, as this technology provided the increased transfer capacity and robustness for a lower cost than other EHV technologies. The extensive needs of Future 3 resulted in portfolios for that future that included 765 kV AC as well as HVDC technologies.

Section 5: Resource Expansion Plan

5.1: Resource Plan Development

Identifying the resource outlook for each future is a key component of evaluating the transmission system for a 20-year horizon. Resources are added and retired frequently, and the SPP generation portfolio will not look the same in 20 years as it looks today. Resource expansion plans were developed for the SPP region and neighboring regions for use in the study. They include both conventional and renewable generation plans and are unique to each future.

5.2: Conventional Resource Plan

A conventional resource plan was developed for each future for the years 2023, 2028, and 2033 to analyze the 40 year benefit of the recommended transmission portfolio.

Generator Review

An ITP20 generator review was conducted with stakeholders providing information as inputs to the analysis including maximum capacities, ownership, retirements, and other operating characteristics of all generators in SPP. Between the generator review and 2012 Policy Survey, approximately 4 GW of conventional generation in the SPP region was identified as retired by 2033. The existing generation in the SPP region was updated with this information before development of the resource plan.

Conventional Resource Plan Approach

SPP Criteria 2.1.9[12] states that each load serving entity must meet a 12% capacity margin, and this is not expected to change with the implementation of the Integrated Marketplace. The resource plan was developed with this same requirement. Projected capacity margins were calculated for each zone using existing generation and 2033 load projections. Each zone's capacity was assessed to ensure that it met the 12% capacity margin requirement. Only 5% of wind nameplate capacity was counted towards the capacity margin requirement, due to the unpredictability of wind levels. ESWG vetted a resource list of generic prototype generators that comprise representative parameters of specific generation technologies. Prototype generators were utilized in resource planning simulations to determine the optimum generation mix to add to each zone. All new generation identified in the conventional resource plan was natural gas-fired, comprising a combination of combined cycle and fast-start combustion turbine units.

Generation Siting

After new generation was added for each zone, it was sited within these zones based on location of existing gas generation and stakeholder feedback. ESWG and other stakeholders provided input on the locations in their areas that are best suited for additional gas generation and the appropriate buses to place these generators based on space requirements, proximity to gas pipelines, and existing electric transmission.

[12] SPP.org > Org Groups > Governing Documents > Criteria & Appendices January 30, 2012

Conventional Resource Plan – External Regions

Resource plans were also developed for external regions for Futures 1-4. Each region was assessed to determine the capacity shortfall, and natural gas combined cycle and combustion turbine units were added so that each region met a capacity margin of 12%. New units were sited at lines with high transfer capacity. Units were added in Entergy, AECI, TVA, PJM, MISO, MAPP Non-MISO, and SERC. SPP Staff provided the resource plan to WAPA, AECI, and Entergy for their review. No additional changes were provided during the development of these resource plans.

In Future 5, SPP Staff leveraged the resource plan from Future 1 for WAPA, AECI, and Entergy. Otherwise, Future 5 incorporates the resource plan provided by MISO for the MISO region and all other regions. MISO performed the resource plan analysis using a similar tool to the tool used for the SPP region. The MISO results of this analysis were merged into the SPP model.

SPP Capacity Additions by Unit Type by 2033 – Summary

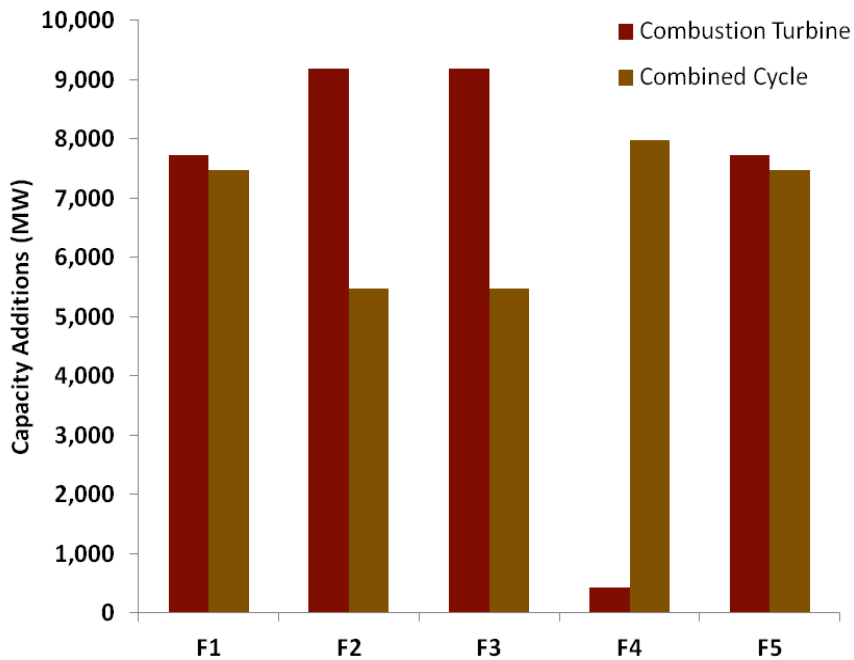


Figure 5.1: Conventional Capacity Additions by Unit Type

Figure 5.1 new generation additions by future for the SPP region. Futures 1 and 5 have 15.2 GW of additional generation, Futures 2 and 3 have 14.7 GW of additional generation, and Future 4 has 8.4 GW of additional generation. The CT units have lower capital costs, while the CC units have lower operating costs. While CC and CT capacities are roughly equal in Future 1, Futures 2 and 3 include more CT generation as a result of having more wind than Future 1. The quick-start CT units are able to ramp up quickly when wind speeds decrease.

Because of the decreased peak and energy levels in Future 4, there is less need for new generation to meet capacity margins. The $36/ton carbon tax in Future 4 contributed to most new generators in this Future being CC's, because of the lower heat rate compared to CT's. This leads to CC's producing more generation output per ton of carbon emissions than CT's, making them the most feasible generation option in this Future.

Futures 1 and 5 Conventional Resource Plan for 2033 – SPP

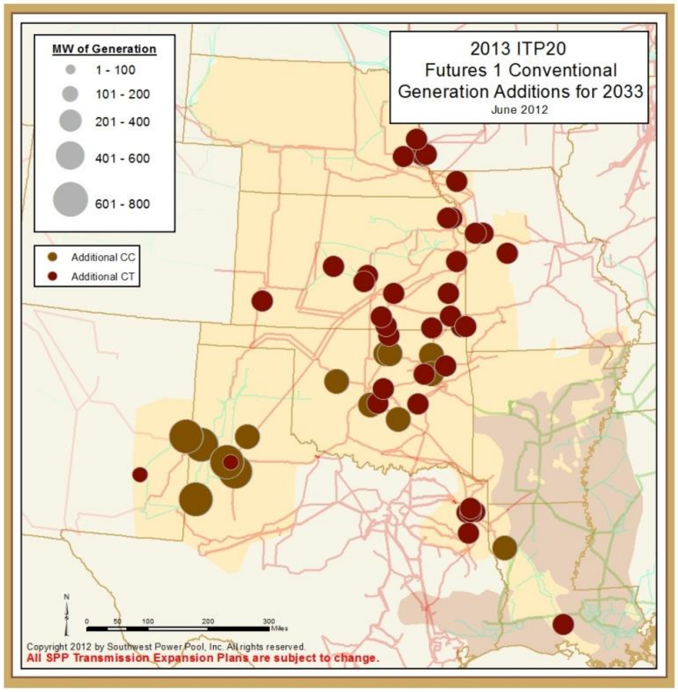


Figure 5.2: Conventional Generation Additions for Futures 1 and 5

Figure 5.2 shows locations and technology type of all new conventional generation added to Futures 1 and 5 for 2033.

- Additional Sites
  - 15 Combined Cycle
  - 37 Combustion Turbine
- Additional Capacity
  - 7.5 GW Combined Cycle
  - 7.7 GW Combustion Turbine

Futures 2 and 3 Conventional Resource Plan for 2033 – SPP

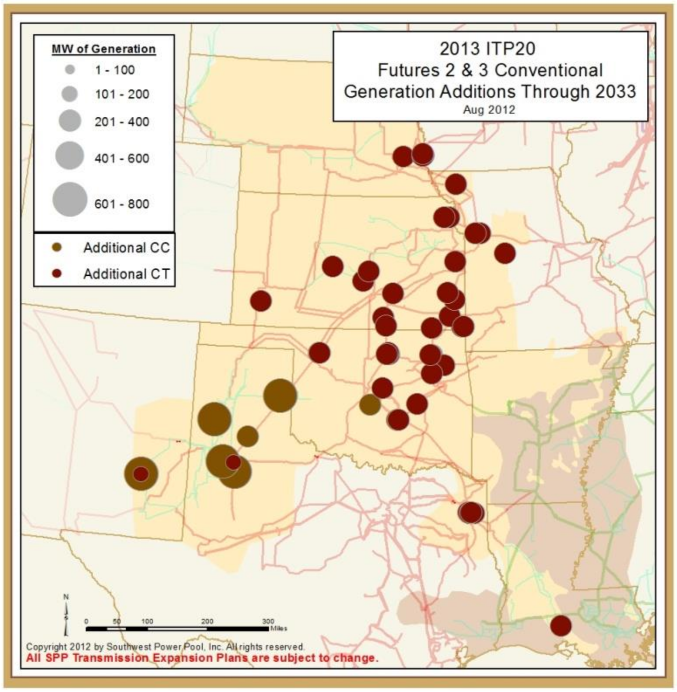


Figure 5.3: Conventional Generation Additions for Futures 2 and 3

Figure 5.3 shows locations and technology type of all new conventional generation added to Futures 2 and 3 for 2033.

- Additional Sites
  - 10 Combined Cycle
  - 44 Combustion Turbine
- Additional Capacity
  - 5.5 GW Combined Cycle
  - 9.2 GW Combustion Turbine

Future 4 Conventional Resource Plan for 2033 – SPP

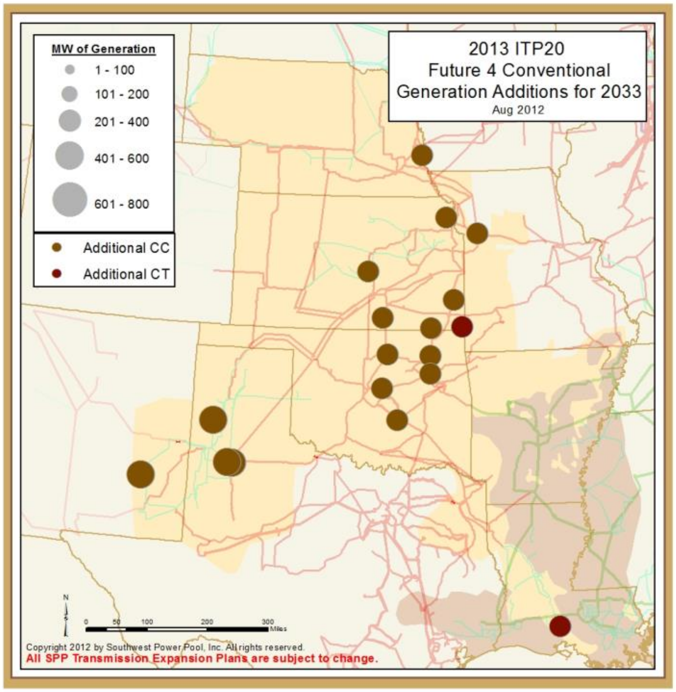


Figure 5.4: Conventional Generation Additions for Future 4

Figure 5.4 shows locations and technology type of all new conventional generation added to Future 4 for 2033.

- Additional Sites
  - 17 Combined Cycle
  - 2 Combustion Turbine
- Additional Capacity
  - 8.0 GW Combined Cycle
  - 0.4 GW Combustion Turbine

Additional information and results of the conventional resource plan are shown in Appendix Z, including generation added by year, generation added by zone, and external region generation addition details.

5.3: Renewable Resource Plan

A renewable resource plan was developed for each future for the years 2023, 2028, and 2033.

Existing Wind

The 2012 Policy Survey was used to gather information on existing wind in the SPP system to include in the models. Existing wind is defined as wind generation that is in-service or currently in development and expected to be in-service by the end of 2013. Members reported 6.3 GW of existing wind in the SPP region. Another 0.8 GW of existing wind generation is currently contracted for export with firm service and was modeled accordingly. The total existing wind reported by members within the SPP region is 7.1GW and was included in the models for all futures[13].

Additional Wind

The 2012 Policy Survey was used to gather information on members' state renewable targets and mandates with which to comply with by 2033. Additional wind generation was added to the system in Futures 1 and 5 when the existing wind was not sufficient to meet state targets and mandates. The total additional wind added in the SPP footprint for Futures 1 and 5 is 2.1 GW. The additional wind energy was allocated to the zones within SPP as needed to meet state renewable targets and mandates.

In Futures 2 – 4, new wind generation was added in order to meet a regional renewable standard of 20%. The additional wind energy was allocated to the zones within SPP as needed to serve 20% of their energy requirements. In Future 3, an additional 9.2 GW of export wind energy was added to wind-rich areas within SPP, bringing the total amount of export wind energy to 10.0 GW. The table below shows wind generation by future:

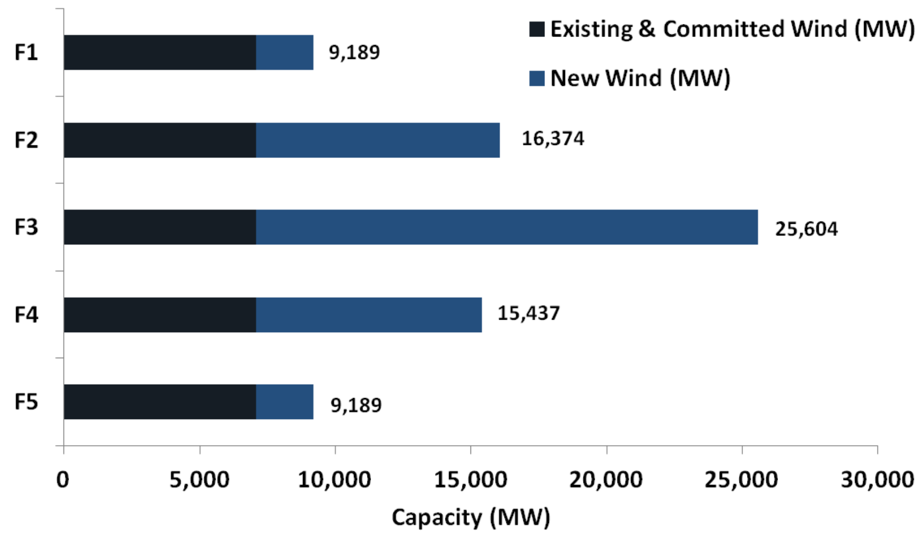


Table 5.1: SPP Wind by Future

Siting of Additional Wind

Generic wind sites were selected by the ESWG based upon the locations selected in previous ITP studies because of their potential for high wind output. The generic sites were added as follows:

- 2.1 GW of additional wind in Futures 1 and 5 was apportioned to 25 additional wind sites in NM, TX, OK, KS, MO, and NE.
- 9.3 GW of additional wind in Future 2 was apportioned to 30 additional wind sites in NM, TX, OK, KS, and NE.

[13] As of April 2013, the total wind capacity in the SPP region has increased to approximately 7.4 GW.

- 18.5 GW of additional wind in Future 3 was apportioned to 30 additional wind sites in NM, TX, OK, KS, and NE.   10 GW of wind is exported in this future.
- 8.3 GW of additional wind in Future 4 was apportioned to 30 additional wind sites in NM, TX, OK, KS, and NE.
- Capacities of these new wind farms were adjusted in each future to meet renewable requirements.

It was anticipated that few new wind farms would be located in Missouri if the state's renewable incentives, available only under Futures 1 and 5 state renewable targets, were to be eliminated. If there is a federal RES, as considered in Futures 2-4, it is anticipated that Missouri would import wind from neighboring states, from which wind is more cost-effective to implement.

Renewable Resource Plan – External Regions

Renewable resource plans were also developed for external regions for all futures. PJM provides Business as Usual renewable data to MISO, and MISO provided SPP with Business as Usual renewable data for MISO and PJM, which includes 31.6 GW of renewables for MISO and 4.8 GW of renewables for PJM. No additional renewable generation was added in Futures 1 and 5. In Futures 2 – 4, wind was added throughout the Eastern Interconnect, in addition to the MISO data, to reach the 20% renewable standard in all regions. Most of the additional renewable energy was assumed to be generated from wind, though biomass was also added in SERC, TVA, and Entergy, due to the lower wind potential in the southeast. These renewable units were sited at high voltage buses with high transfer capacities.

Futures 1 and 5 Renewable Resource Plan for 2033 – SPP

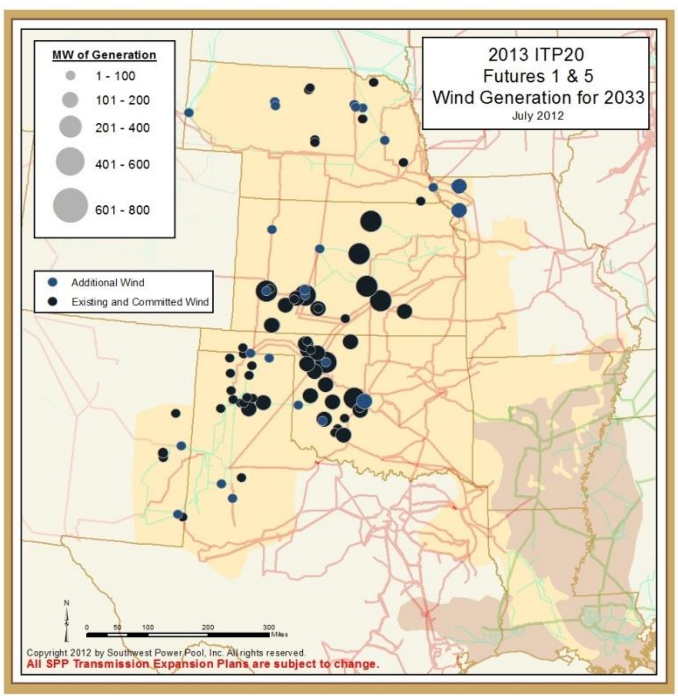


Figure 5.5: Renewable Resource Plan for Futures 1 and 5

Figure 5.5 shows the location of all wind generation for the SPP region for Futures 1 and 5.

- Wind Sites
    - 71 Existing

    - 25 New
- Wind Capacity
    - 7.1 GW Existing
    - 2.1 GW New
    - 9.2 GW Total

Future 2 Renewable Resource Plan for 2033 – SPP

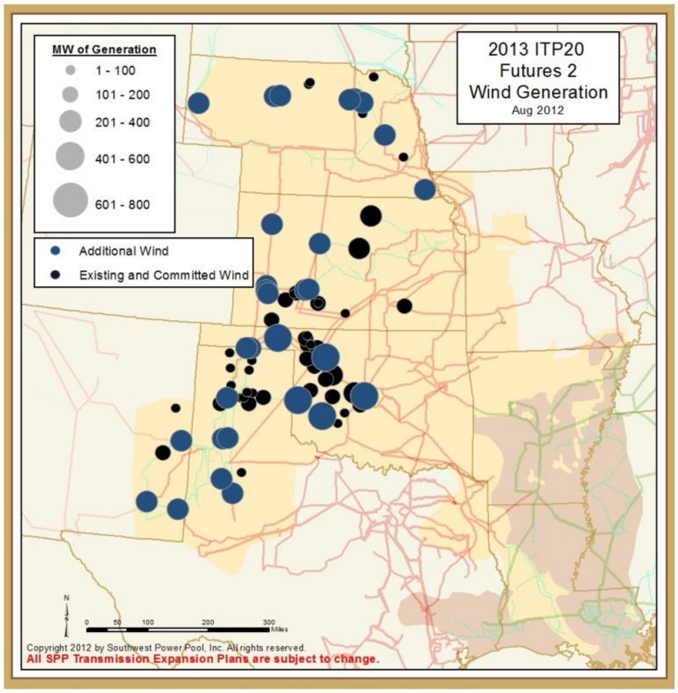


Figure 5.6: Renewable Resource Plan for Future 2

Figure 5.6 shows the location of all wind generation for the SPP region for Future 2.

- Wind Sites
    - 71 Existing
    - 30 New
- Wind Capacity
    - 7.1 GW Existing
    - 9.0 GW New
    - 16.1 GW Total

Future 3 Renewable Resource Plan for 2033 – SPP

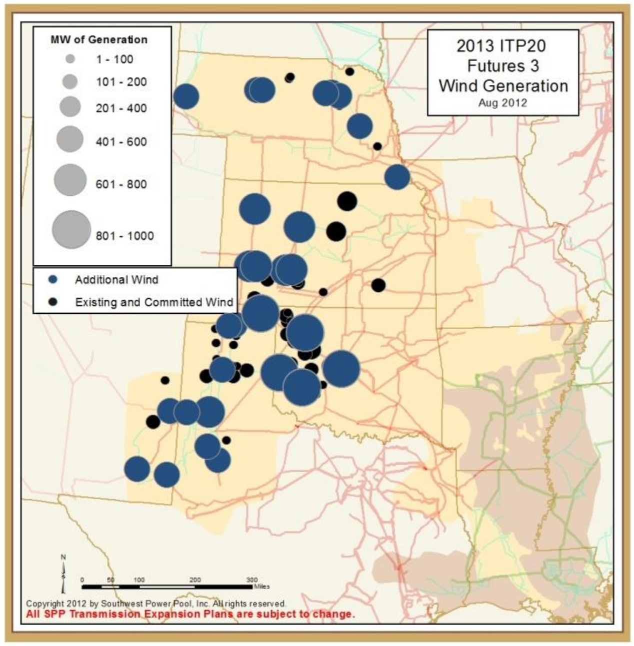


Figure 5.7: Renewable Resource Plan for Future 3

Figure 5.7 shows the location of all wind generation for the SPP region for Future 3.

- Wind Sites
  - 71 Existing
  - 30 New
- Wind Capacity
  - 7.1 GW Existing
  - 18.5 GW New
  - 25.1 GW Total

Future 4 Renewable Resource Plan for 2033 – SPP

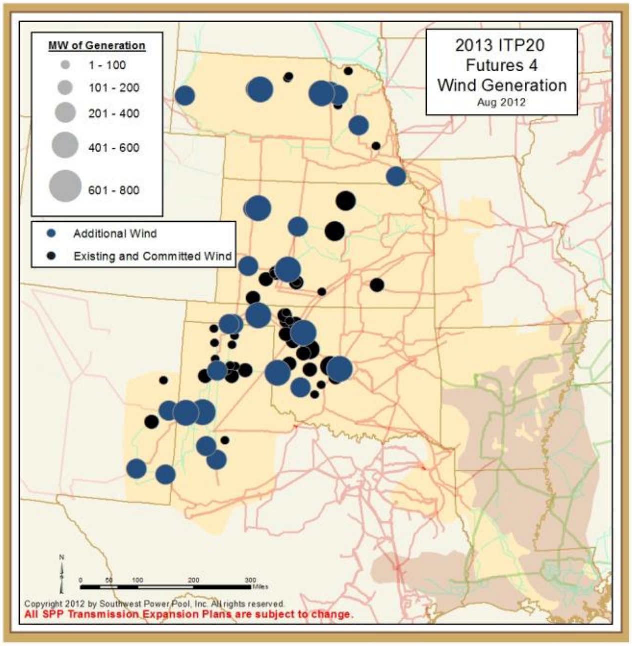


Figure 5.8: Renewable Resource Plan for Future 4

Figure 5.8 shows the location of all wind generation for the SPP region for Future 4.

- Wind Sites
  - 71 Existing
  - 30 New
- Wind Capacity
  - 7.1 GW Existing
  - 8.3 GW New
  - 15.4 GW Total

Additional information and results of the renewable resource plan are shown in Appendix Z, including zonal breakdown of wind, bus locations, and external region details.

Section 6: Analysis Methodology

6.1: Analytical Approaches

SPP transmission system performance was assessed from different perspectives designed to identify transmission expansion projects necessary to accomplish the reliability, policy, and economic objectives of the SPP Regional Transmission Organization (RTO). Among other considerations, the six perspectives ensured that the transmission expansion portfolio would:

- Avoid exposure to Category A and B NERC Transmission Planning (TPL) standard criteria violations during the operation of the system under high stresses;
- Facilitate the use of renewable energy sources as required by policy targets and mandates;
- Contribute to the voltage stability of the system; and
- Reduce congestion and increase opportunities for competition within the SPP Integrated Marketplace.

Priority was given to the relief of all of the potential reliability violations seen during the four seasonal peak hours (summer peak, winter peak, low hydro, and peak wind) and to the facilitation of all state renewable policy goals and requirements. The relief of annual congestion and reduction in market prices were pursued where cost-justified; a transmission expansion project was considered cost-justified when it yielded a benefit-to-cost ratio of at least 1.0. In some cases, there was overlap among these priorities; for example, a project may relieve potential reliability violations AND reduce annual congestion in a cost-justified manner.

SCUC & SCED Analysis for multiple futures

An assessment was conducted to develop a list of constraints for use in the Security Constrained Unit Commitment and Economic Dispatch (SCUC & SCED) analysis. Elements that, under contingency, limit the incremental transfer of power throughout the system were identified, reviewed, and approved by the Transmission Working Group (TWG). Revisions to the constraint definition studies included modification of the contingency definition based upon terminal equipment, normal and emergency rating changes, and removal of invalid contingencies from the constraint definition.

The constraint list included normal and emergency ratings and was limited to the following types of issues:

- System Intact and N-1 situations[14]
- Existing common right-of way and tower contingencies for 300+ kV facilities[15]
- Thermal loading and voltage stability interfaces
- Contingencies of 300+ kV voltages transmission lines
- Contingencies of transformers with a 300+ kV voltage winding

[14] N-1 criterion describes the impact to the system if one element in the system fails or goes out of service

[15] The current NERC Standard TPL-001-0.1 includes outages of any two circuits of a multiple circuit tower line within Category C, and the loss of all transmission lines on a common right-of-way within category D. NERC Standard TPL-001-2 will replace this standard (pending FERC approval) and includes such outages in Category P7 and Table 1 – Steady State & Stability Performance Extreme Events.

- Monitored facilities of 100+kV voltages only

Neighboring areas supplied their respective list of constraints.

All system needs were identified through the use of a SCUC & SCED simulation that accounted for 8,760 hours representing each hour of the year 2033. Line loading was determined using direct current (DC) models[16].

Utilization of Past Studies & Stakeholder Expertise for Solutions
SPP shared potential violations with the stakeholders and posted on the SPP password protected TrueShare site[17] for review. SPP Staff collected potential solutions from stakeholders throughout the footprint, as well as entities outside of the footprint. Additionally, solutions previously identified in the 2012 ITP10, ITP Near-Term, 2010 ITP20, Aggregate Studies, and Generation Interconnection Studies were also considered in this analysis.

Treatment of Individual Projects & Groupings
After assessment of the needs, SPP investigated mitigation of the overloads and congestion through individual projects by performing the following actions:

- Each project was tested to ensure the project provided the expected result.
- Projects were grouped to measure the impact of the projects upon similar constraints and overloads.
- Efficiencies were sought by identifying projects with synergy and projects that duplicated the value captured by another project.
- Combined reliability, policy, and economic analysis to produce a transmission expansion portfolio of projects.

6.2: Projecting Potential Criteria Violations

Reliability Needs
Thermal overloads were identified in four hours that represent situations that uniquely stress the grid[18]. Any constraint that was binding with a shadow price in any of the 4 hours was defined as a reliability need.

- Summer peak – highest coincident load during summer months
- Winter peak – highest coincident load during winter months
- Low hydro – highest ratio of coincident load to hydro output during summer months[19]
- Peak wind – highest ratio of wind output to coincident load

[16] The use of an alternating current (AC) model would provide greater precision in these calculations and yields not only thermal loading, but voltage levels as well. The complexity of such a model development is not justified given the strategic rather than detailed nature of this assessment. An AC model will be utilized for the stability assessment (see below). Apart from the stability assessment to verify line loadability and general system stability, the correction of voltage limitations will be addressed in the ITP10 and ITPNT.

[17] Send an email to questions@spp.org for access to the TrueShare site.

[18] Summer peak, winter peak, low hydro, and high wind situations have been studied in various SPP studies since 2006.

[19] Hydro generation in SWPA and WAPA was included in the calculations to select the low hydro hour.

In addition, any constraints that breached for any hour (indicating that the SCED was unable to honor the facility rating) were identified as reliability needs, as these violations indicate a severe potential for overloading of the facility.

Reliability & Economic Efficiencies

All potential reliability upgrades were evaluated in the economic model to determine potential economic benefit. Potential upgrades were developed into portfolios to determine which group of upgrades provided the best overall solution. Potential upgrades were reviewed to determine if an upgrade with a greater economic benefit could defer or replace an identified reliability solution while still providing mitigation of the reliability issue. Costs associated with deferred projects can be subtracted from the total cost of transmission expansion portfolios.

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

1. Identified reliability need.
2. Provided and tested reliability mitigation.
3. Identified congestion in the system.
4. Paired congestion nearby and related to reliability needs to compare alternative projects.
5. Measured and compared the value of resolving the congestion with an economic project that also mitigated the reliability need.

$$Value\ of\ reliability\ project = Value_{rp} = APC\ Benefit_{rp} - Cost_{rp}$$
$$Value\ of\ economic\ project = Value_{ep} = APC\ Benefit_{ep} - Cost_{ep} - Value_{rp}$$

6. Selected the economic project to mitigate the reliability need and relieve the congestion, where cost-effective.

6.3: Meeting Policy Requirements

For policy requirements, staff focused on satisfying renewable targets and mandates within a future through use of renewable generation as defined by the SPP Members through the 2012 Policy Survey. The primary generation technology used to meet these renewable standards, as provided by the stakeholders, was wind generation.

Wind farms may experience the effects of congestion and be curtailed by the SCED. Shortfalls in the achievement of the renewable requirements of each future due to this curtailment were identified. Renewable resources that experience an annual energy output of less than 97% of the targeted energy were identified as policy needs. The targeted energy is based on maximum capacity, capacity factor, and generation profile.

6.4: Projecting Congestion & Market Prices

Annual Conditions Reviewed by the Economic Studies Working Group (ESWG)

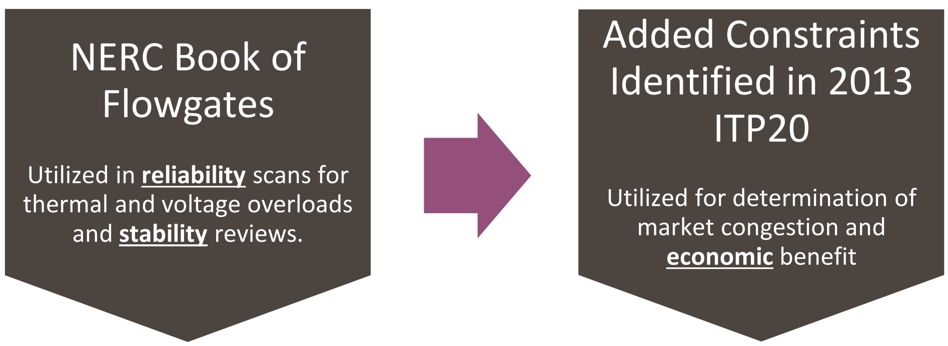
Congestion was assessed on an annual basis for each future including many variables. Some of these variables change on an hourly basis, such as load demand, wind generation, forced outages of generating plants, and maintenance outages of generating plants. A total of 8,760 hours were evaluated for the year 2033.

Relevant congestion of each constraint was identified through two methods:

- The number of hours congested, and the average shadow price[20] associated with the congestion for all binding hours.
- These two numbers were multiplied together to compute an average congestion cost across all hours of the year.
- This average congestion cost was used to rank the severity of the congestion for each constraint.

Identification of Additional Constraints

Staff defined the initial list of constraints from the NERC Book of Flowgates for the SPP region. This list of constraints was used to create the economic dispatch utilized in the reliability scans for potential thermal and voltage violations. Additional constraints were incorporated that would protect the facilities from overloads under many system conditions. These additional constraints 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.



Congestion Prioritization & Screening

The impact of the top 15 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. By targeting the top 15 constraints, the areas of greatest opportunity for economic projects were identified to be considered for improvement.

6.5: Determining Recommended Portfolio

Individual projects within the recommended portfolio provided reliability, economic, and policy benefits within the business as usual future (F1) and at least one other future. Based on the weighting shown in Figure 6.1, a project had to score at least 60% out of 100% to be included in the recommended portfolio.

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

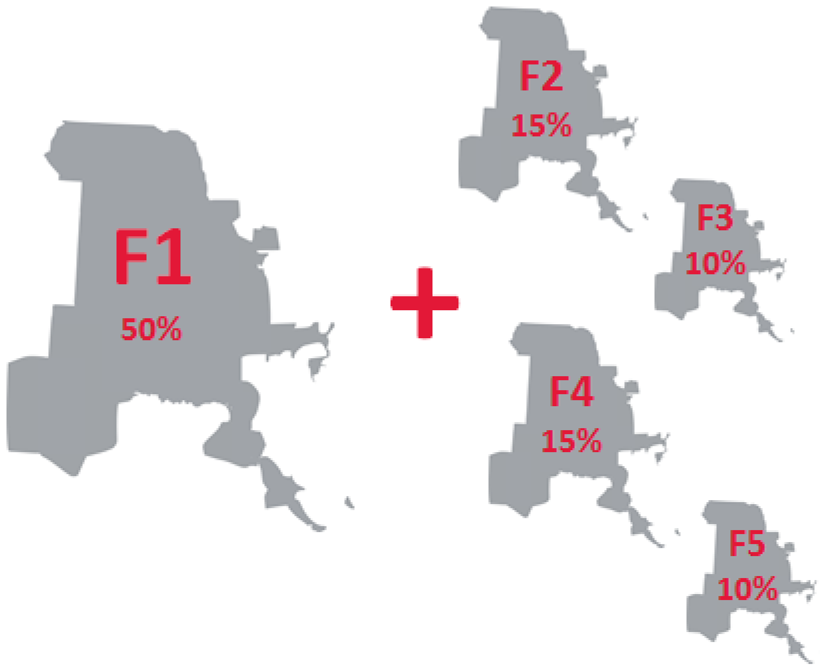


Figure 6.1: Project weighting by future

Project Staging

Project staging is the process by which appropriate in-service dates for new projects are established. Project staging was not performed as part of the 2013 ITP20. The ITP20 study is a broader look at transmission expansion 20 years into the future, while the ITP10 and ITPNT are more refined studies that will help to establish the staging of projects from the ITP20.

6.6: Measuring Economic Value

For the 2013 ITP20, the Metrics Task Force developed several monetized metrics to facilitate better understanding of the financial impacts of proposed projects. The ESWG chose three of the new metrics for inclusion in the 2013 ITP20, to be calculated for informational purposes only.

The metrics suggested by MTF are the following:

Benefit	MTF Metric Name	Current or New?
APC benefits	Adjusted Production Cost (APC)	●
	Marginal energy losses benefits	✓
	Mitigation of transmission outage costs	✓*
Positive impact on capacity required for losses	Reduced capacity expansion costs due to reduced transmission losses on peak	●
Improvements in reliability	Avoided or delayed reliability projects	●
	Capital savings due to reduction of members' Minimum Required Capacity Margin	✓
	Reduced loss of load probability	✓
	Reducing the cost of extreme events	✓
	Assumed benefit of mandated reliability projects	✓*
Reduction of Emission Rates and Values	Reduction of emission rates and values	●
Improvements to Import/Export Limits	Increased wheeling through and out revenues	✓
Public Policy Benefits	Benefit from meeting public policy goals	✓*

● Previously used ITP Metric ✓ New Metric ✓* New Metric calculated solely for informational purposes in 2013 ITP20

While APC benefits were calculated for numerous projects and the final portfolio, the other metrics were calculated only for the final portfolio in each future.

Calculation of Adjusted Production Cost (APC)

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 using a production cost modeling tool that accounts for hourly commitment and dispatch. The calculation, performed on an hourly basis, is as follows:

$$\text{APC} = \text{Production Cost} - \text{Revenue from Sales} + \text{Cost of Purchases}$$

$$\boldsymbol{Revenue\ from\ Sales = MW\ Exported\ x\ Zonal\ LMP_{Gen\ Weighted}}$$

$$\boldsymbol{Cost\ of\ Purchases = MW\ Imported\ x\ Zonal\ LMP_{Load\ Weighted}}$$

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.

Mitigation of transmission outage costs
Metric calculates the benefit of reducing additional congestion based on new transmission projects. Standard production cost simulations assume that transmission lines and facilities are available during all hours of the year and that no planned or unexpected outages of transmission facilities will occur. In practice, however, planned and unexpected transmission outages impose non-trivial additional congestion costs on the system. The benefit of reducing this additional congestion is thus not captured in the standard APC metric. The availability of new transmission projects decreases congestion and increases the operational flexibility of the system to mitigate the impacts of transmission outages. The ESWG provided direction to calculate the results of this metric for informational purposes only, and it is included in the Appendix Section 21:.

Assumed benefit of mandated reliability projects
Metric assumes that benefits are equal to costs for mandated reliability projects. This benefit was only considered for projects under the category of “regional reliability” that were mutually exclusive from any other reliability benefit applied to those same projects. Treating benefits for mandated reliability projects equal to their costs avoids potential undervaluing of the portfolio value of reliability projects which are mandated and thus not justified solely by other economic benefits. The ESWG provided direction to calculate the results of this metric for informational purposes only, and it is included in the Appendix Section 21:.

Benefit from meeting public policy goals
Metric measures benefit of meeting public policy targets and mandates in the SPP region related to renewable energy supplies. Public policy can be met through state law, settlement agreement, or a regulatory determination made by a state regulatory authority. It does not include economic decisions made by individual utilities to acquire renewable energy supplies absent some form of legal requirement. ESWG provided direction to calculate the results of this metric for informational purposes only, and it is included in the Appendix Section 21:.

Reduced Losses
Metric captures the change in total system losses due to the finalized portfolio. Losses were calculated for each hour of the DC simulation. The difference in production costs due to the change in losses was reflected in the APC calculation. The reduction in capacity capital costs associated with these losses was not captured by this metric or in the APC calculations, but was captured through the use of the Reduced Capacity Costs Metric.

Reduced Capacity Costs

Metric captures 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. The Benefits Analysis Techniques Task Force (BATTF) established a $750/kW figure to use as the approximate capital cost of a CT for this calculation.

Reduction of Emissions Rates and Values

Metric captures 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 value of economic projects in the 2013 ITP20 is computed as the incremental cost and benefit of the economic project above and beyond reliability and policy 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 project to the system (the change case).

PART II: STUDY FINDINGS

Section 7: Benchmarking

Numerous benchmarks were conducted to ensure the accuracy of the data produced in the planning simulations. A model was developed that reflected transmission and generation in-service as of 2011 and simulation results from that model were compared with historical statistics and measurements from SPP Operations, the North American Electric Reliability Corporation (NERC) and the Energy Information Administration. The goal was to provide a reasonableness review of the study data.

7.1: Benchmarking Setup

For the results of the benchmarking process to provide value it was important to mimic the assumptions that were realized operationally in 2011. This includes using actual data from 2011 such as fuel prices.

SPP used data provided by SPP Operations and SPP Market Monitoring (MMU) to benchmark against. This data reflects the actual values from 2011 for load, generation, and LMP prices. It is unreasonable to expect that the simulation runs for benchmarking would exactly match 2011 actual data for several reasons. Even though SPP used 2011 input data there are still some differences. The PROMOD IV® simulation models did not capture operational data exactly. Sharp load adjustments such as those that are experienced during and after outages and storms would be captured differently.

One of the major differences between SPP's operations in 2011 and the PROMOD IV® simulation is the type of market. PROMOD IV® models a day-ahead market using a consolidated balancing authority. Since this market structure operates differently than SPP's current market, one would expect different results. Another challenge when benchmarking PROMOD IV® data to SPP's 2011 data is the difference in area definitions. PROMOD IV® will report prices, load, generation, etc. for the whole of the SPP footprint. However the price data provided by MMU only reflects market participants. Therefore the PROMOD IV® results include additional data not included in the Market Monitoring data.

Due to the hurdles and applicability in comparing PROMOD IV® data with 2011 actual data SPP focused more on benchmarking the shape of the data rather than the magnitude of the values. As an example, the load for a particular zone in PROMOD IV® would not match the load of that same zone in the MMU since MMU defines that zone differently. What would be important though is for the shape of that load throughout the year to be consistent. The same application applies to prices and generation. Instead of focusing on the magnitude of generation over the course of the year, this benchmarking effort focuses on capacity factors.

7.2: 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. 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 2011 and previous years, the capacity factor by unit category fell within or near expected ranges. Part of the difference is due to the variation between the unit categories reported to the EIA and those available within the 2013 ITP20 models.

Capacity factors for the 2013 ITP20 were derived from the PROMOD IV® report agent software. The average capacity factors from the EIA are from the EIA Electric Power Annual for 2005 – 2011 and can be found on the EIA website[21]. 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	2013 ITP20 Capacity Factor	EIA Capacity Factor Range
Nuclear	68%	67 – 97%
ST Coal	72%	64 – 74%
Wind	45%	40 – 47%
Combined Cycle	40%	33 – 42%
Hydro	28%	23 – 46%
ST Gas	10%	10 – 15%
CT Gas	5%	10 – 15%

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 the generation mix from 2011, the share of generation apportioned to each unit category was within an acceptable range. Coal and combined cycle gas generation sources provided 82% of the total generation in the simulation. Historically, according to the EIA, these sources provided 77%. It should be noted that in 2011, the Fort Calhoun Nuclear plant suffered flooding and has not been brought online. EIA data for 2011 also shows a 67% capacity factor for nuclear in SPP.

Total generated energy by unit category for the 2013 ITP20 was derived from the PROMOD IV® report agent software for the year 2011. 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.

[21] EIA.gov

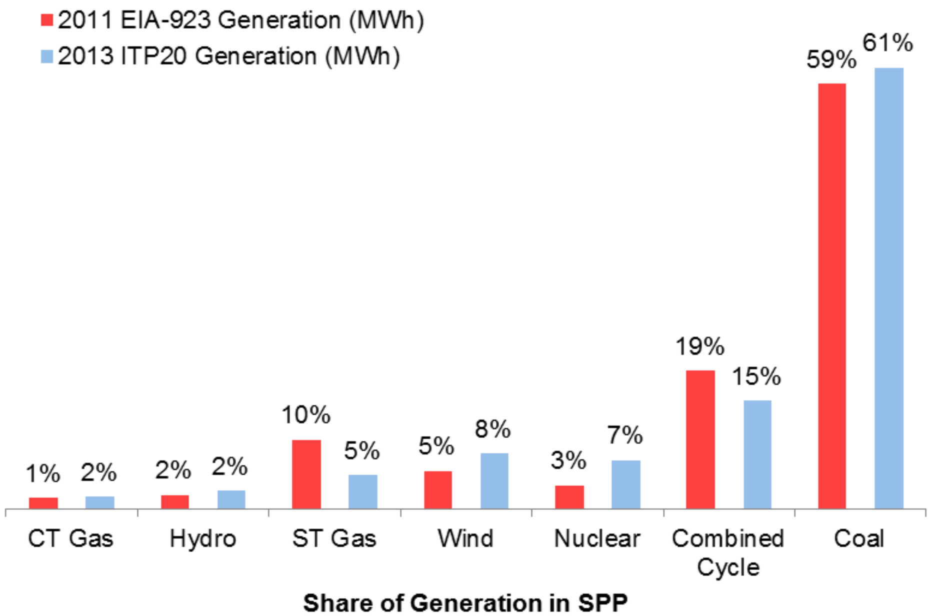


Figure 7.1: Benchmarked Unit Generation by Category

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. The method of forecasting maintenance outages correlated strongly with these statistics. Significant generator outages from 2011 were incorporated in the benchmark model based upon data from SPP Operations. This increased the precision of the benchmarking and accounted for significant weather related and maintenance outages.

Operating & Spinning Reserve Adequacy

Operational Reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of unit failure. 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 as operating reserve. Additionally, 50% of this operating reserve must be in the form of spinning reserve. PROMOD IV® reports any unit not on maintenance as available for reserve if it meets the criteria for spinning or quick start. **Error! Reference source not found.** shows the quick start and spinning reserve that was available n the benchmarking runs, as well as the operating reserve requirement of 1,740 MW and the spinning reserve requirement of 870 MW. The spinning reserve available in the PROMOD IV® runs exceeded not only the spinning reserve requirement, but also the operating reserve requirement.

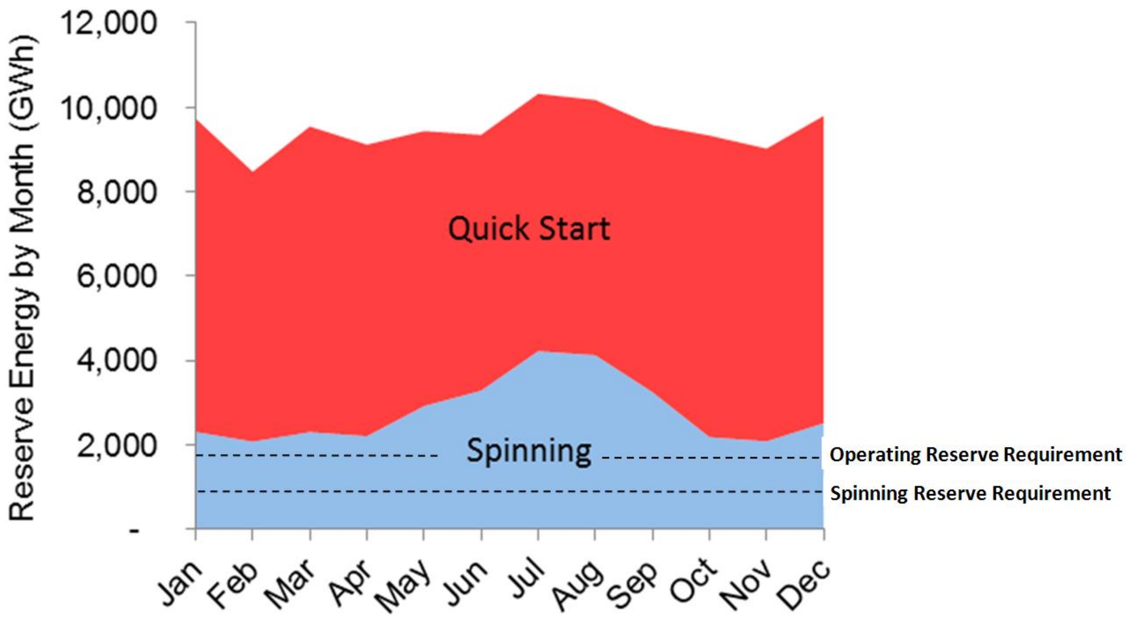


Figure 7.2: Spinning Reserve Adequacy

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 straight line distance from each plant to the plant's sourcing mine (Powder River Basin in all cases).

7.3: Reasonable System LMPs

Benchmarking was done on average Locational Marginal Prices (LMPs) by Area. Figure 7.3 compares the average monthly price of energy in the EIS market from 2009-2011 to the average monthly bus LMPs of the 2013 ITP20 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.

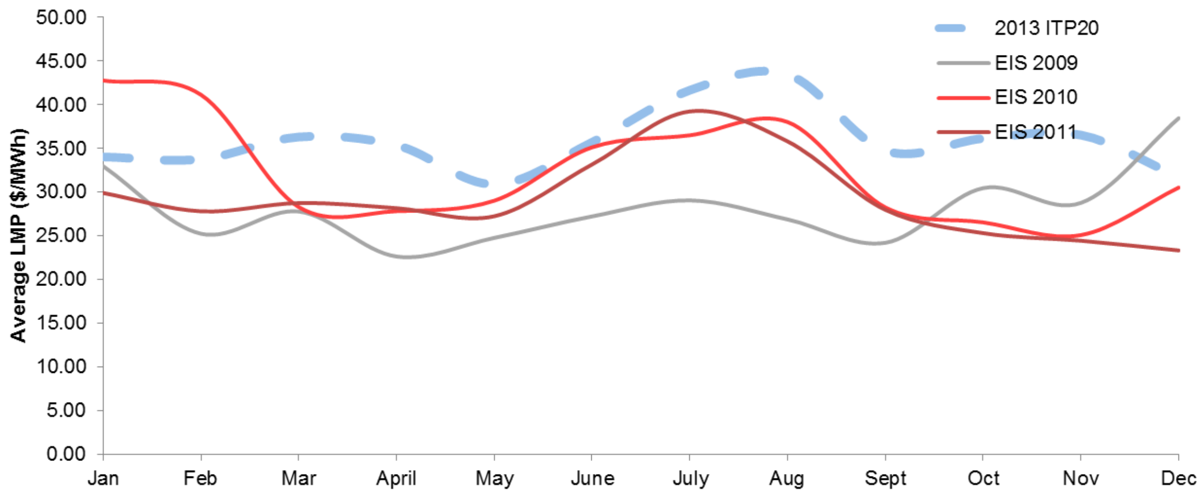


Figure 7.3: Benchmarking LMPs

Historical prices were provided by SPP's Market Monitoring group, simulated LMPs were derived from the PROMOD IV® report agent software. The average LMP for each area in the 2013 ITP20 benchmarking simulations was within a reasonable bandwidth of the historical trends, with two exceptions:

1. Empire District Electric had a difference in PROMOD IV® LMP and MMU LIP for May, 2011. The PROMOD IV® LMP average was $37, while the MMU LIP average was $26. This may be due to loss of load caused by the tornado that went through Joplin during that month. One item to point out is that Empire receives a significant amount of generation from jointly owned units such as Plum Point (a coal plant in Arkansas). Also when compared to the output data from the latest PROMOD IV® runs for the year 2033, the shape is more consistent with the MMU data.
2. Southwestern Public Service (SPS) had LMP shapes consistent with the MMU LIP shapes from 2011. However, the PROMOD IV® LMP value was higher than the MMU LIP value. Multiple possibilities were investigated. One item to note is that the MMU defines the SPS zone differently than it is defined in PROMOD IV®. The PROMOD IV® SPS LMP values do not represent Lubbock and other municipals. The MMU data only represents load in the market. If MMU LIP values are low in Lubbock and other municipals, this could potentially drag down the average LIP values for SPS that are represented in the MMU data.

Forecasted LMPs for 2033 Simulations

A simulation of 2033 was conducted and the shadow prices for binding constraints during that time-frame were compared with a current SPP Monthly State of the Market Report. The results indicated that prices seen in the 2033 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. Figure 7.4 shows that the shadow prices (y-axis) and hours binding (x-axis) for TWG approved constraints were greater and more frequent than experienced in the EIS market in 2011.

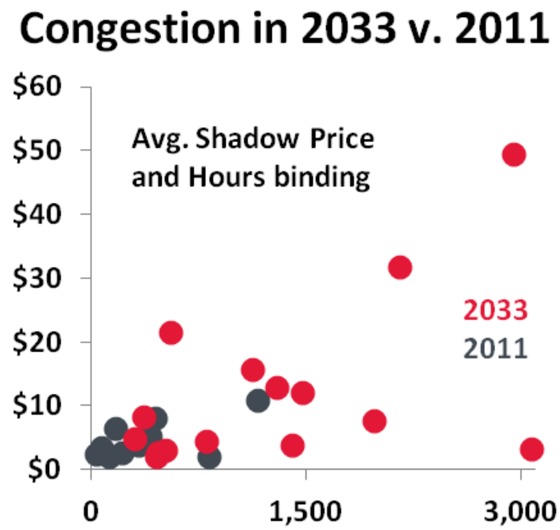


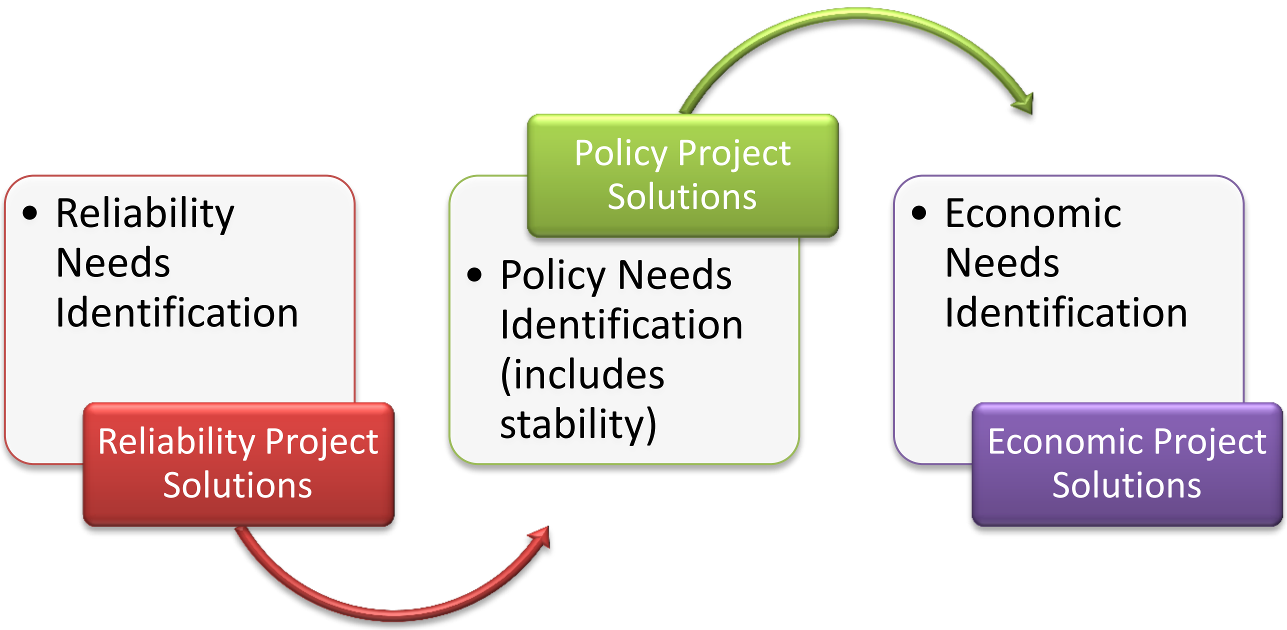
Figure 7.4 Congestion in 2033 was greater than in 2011

PART III: NEEDS & PROJECT SOLUTIONS

Section 8: Overview

8.1: Transmission Needs and Solution Development

The 2013 ITP20 transmission planning analysis considers three separate types of needs and upgrades: reliability, policy, and economic. Reliability needs were identified first, followed by reliability project solutions, which were included in the base case model for policy analysis. Policy needs were then identified, followed by policy project solutions. (An analysis of stability needs and stability project solutions was included as part of the policy analysis.) Reliability and policy solutions were included in the base case model for economic analysis. Economic solutions were then identified to meet economic needs.



8.2: Consideration of Lower Voltage Solutions

While facilities above 100 kV were monitored for overloads and congestion, project solutions in the final portfolio are primarily Extra High Voltage (EHV) solutions in accordance with the SPP tariff.

In the development of project solutions to meet needs, lower voltage solutions (100 kV – 300 kV) were considered and tested in addition to EHV solutions. In several cases, a lower voltage solution and an EHV solution were both tested for the same need, and a preferred solution was selected. While lower voltage solutions were sometimes identified as the preferred solutions for some needs, these lower voltage solutions were generally excluded from the final portfolios. Lower voltage needs are not being mitigated with projects in the final 2013 ITP20 transmission plan, and will be addressed if they are identified in the ITP10 and ITPNT processes.

Section 9: Reliability Needs and Solutions

9.1: Methodology

Reliability needs were identified based on analysis of four hours representing situations where the transmission system is uniquely stressed. An N-1 contingency scan outaged 345 kV branches and transformers in the SPP footprint and monitored 100 kV and above elements to identify binding or breaching constraints. Binding constraints identified in each of these hours during the N-1 contingency scans were identified as reliability needs.

Any reliability need of a radial facility was ignored. If generation connected to a transformer caused the transformer to bind, then the need was ignored since the placement of the generator at a different bus of the transformer could mitigate the need.

Hours used to determine Reliability Needs were:

- **Summer and winter peak hours** represent the highest coincident load during summer and winter months
- **Low hydro hour** represents the highest ratio of coincident load to hydro output during summer months (This included hydro generation in SWPA and WAPA)
- **Peak wind hour** represents the highest ratio of wind output to coincident load

The Table 9.1 summarizes the coincident load, wind and hydro generation in each hour.

HOUR	SIMULATED HOUR	LOAD	WIND	HYDRO
Summer Peak	Aug. 3, 17:00	66.3	1.7	2.8
Winter Peak	Dec. 13, 19:00	46.4	4.1	2.4
Low Hydro	Aug. 30, 4:00	33.5	3.7	0.0
Peak Wind	May 9, 3:00	27.9	8.1	0.3

[Values in GW for 2033]

Table 9.1: Four reliability peak hours

Additionally, any constraints that breach at any hour (indicating that the Security Constrained Economic Dispatch (SCED) was unable to honor the facility rating) were identified as reliability needs.

9.2: Reliability Needs

The number of reliability needs identified for each future is shown in Figure 9.1. It includes all binding elements in the four peak hours and all breaching elements in any hour. This includes facilities within SPP as well as SPP tie lines.

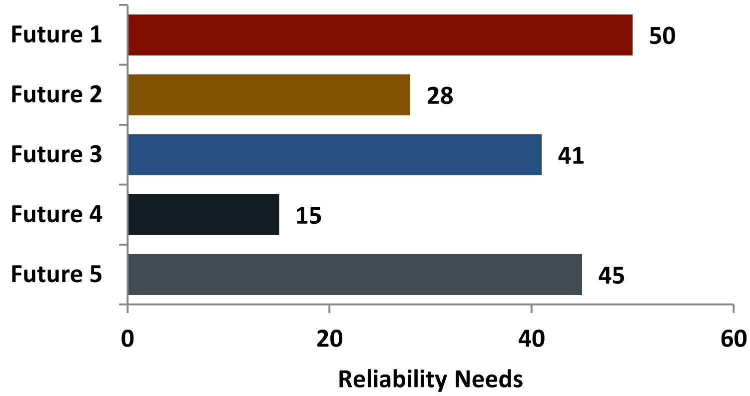


Figure 9.1: Reliability Needs Summary by Future

Table 9.2 to 9.6 summarize the reliability needs identified for each future. Included in each table is a listing of: the peak hour(s) in which the binding occurs, the constrained and contingent elements and their area locations, and the direction of flow across the constrained element. A positive (+) flow means power is flowing from the first listed element to the second, and negative (-) indicates power flow from the second listed element to the first. For transformers, (+) flow indicates power is flowing from the high side to low side, and (-) flow indicates power is flowing from the low side to the high side.

Hour(s)	Constraint	Constraint Area(s)	Direction of Flow	Event (Contingency)	Contingency Area(s)
SP	Farmington - Chamber Springs 161 kV	AEPW	(-)	Chamber Springs - Tontitown 345 kV	AEPW
SP	Avoca - East Rogers 161 kV	AEPW	(-)	Shipe Road - Kings River 345 kV	AEPW
SP	Hackett - Bonanza 161 kV	AEPW	(-)	Base Case	-
WP	Fitzhugh - Ozark Dam 161 kV	AEPW-SWPA	(-)	Base Case	-
HW	Elk City - Red Hills Wind 138 kV	AEPW-WFEC	(-)	Base Case	-
WP	St. Joe - Midway 161 kV	GMO	(+)	Fairport - St. Joe 345 kV	AECI-GMO
WP, SP	Truman - N Warsaw 161 kV	SWPA-GMO	(+)	Overton - Sibley 345 kV	AMMO-GMO
LH	Shawnee - Metropolitan 161 kV	KCPL-KACY	(-)	87th Street - Craig 345 kV	WERE-KCPL
SP, HW	Nashua 345/161 kV transformer	KCPL	(+)	Hawthorne - Nashua 345 kV	KCPL
SP	Huntsville - HEC 115 kV	MIDW-WERE	(-)	Reno - Wichita 345 kV	WERE
SP	Beatrice - Harbine 115 kV	NPPD	(+)	McCool 345/115 kV transformer	NPPD
SP	Spencer - Ft. Randle 115 kV	NPPD-WAPA	(-)	Base Case	-
SP	Keystone - Ogallala 115 kV	NPPD	(+)	Gentleman - Keystone 345 kV	NPPD
WP, SP	Muskogee - Pecan Creek 345 kV	OKGE	(+)	Clarksville - Muskogee 345 kV	AEPW-OKGE
SP	S1221 - S1255 161 kV	OPPD	(-)	S3459 345/161 transformer	OPPD
SP	Sundown 230/115 kV transformer	SPS	(+)	Amoco - Hobbs 345 kV	SPS
SP	Plant X 230/115 kV transformer	SPS	(+)	Base Case	-
HW, LH	Sundown - Amoco 230 kV	SPS	(+)	Tuco - Amoco 345 kV	SPS
SP	Chaves - Samson 115 kV	SPS	(+)	Base case	-
SP	Chaves - Urton 115 kV	SPS	(+)	Base case	-
SP	Eagle Creek - Eddy 115 kV	SPS	(-)	Base case	-
SP, LH, HW	Cimarron River Tap - East Liberal 115 kV	SUNC	(+)	Conestoga - Finney 345 kV	SPS
SP, LH	Holcomb 345/115 kV transformer	SUNC	(-)	Holcomb - Setab 345 kV	SUNC
LH, HW	Harper - Milan Tap 138 kV	SUNC	(+)	Wichita - Flat Ridge 345 kV	WERE-SUNC
HW, LH	North Dodge - East Dodge 115 kV	SUNC	(+)	Base Case	-
SP	Goodyear Jct. - Northland 115 kV	WERE	(-)	Hoyt - Stranger Creek 345 kV	WERE
LH	Centennial - Paola 161 kV	KCPL	(+)	Neosho - LaCygne 345 kV	WERE-KCPL
HW	Swisher - Tuco 230 kV	SPS	(+)	Woodward EHV - Border 345 kV	OKGE
SP	Litchfield - Franklin 161 kV	WERE	(-)	Neosho - LaCygne 345 kV	WERE-KCPL
SP, HW, LH	Morgan - Stockton 161 kV	AECI-SWPA	(-)	Neosho - LaCygne 345 kV	WERE-KCPL
SP	S3455 - S3740 345 kV	OPPD	(-)	S3456 - S3458 345 kV	OPPD
SP	Maryville - Maryville 161 kV	AECI-GMO	(+)	Overton - Sibley 345 kV	AMMO-GMO
SP	Bull Shoals - Midway 161 kV	SWPA-EES	(+)	ANO - Pleasant Hill 500 kV	EES
SP	Overton - Jacksonville 138 kV	AEPW	(+)	Tenaska Switch - Crockett 345 kV	AEPW
SP	Bushland - Deaf Smith 230 kV	SPS	(+)	Woodward EHV - Border 345 kV	OKGE
SP	Prairie Lee - Blue Springs South 161 kV	GMO	(+)	Sibley 345/161 kV transformer	GMO
HW	Fulton - Patmos West 115 kV	AEPW-EES	(+)	Sarepta - Longwood 345 kV	AEPW-EES
HW	Neosho - Riverton 161 kV	WERE-EMDE	(+)	Blackberry - Neosho 345 kV	AECI-WERE
HW	Ft. Calhoun Interface	OPPD	(+)	Base Case	-

Table 9.2: Future 1 Reliability Needs

Hour(s)	Constraint	Constraint Area(s)	Direction of Flow	Event (Contingency)	Contingency Area(s)
SP	Farmington - Chamber Springs 161 kV	AEPW	(-)	Chamber Springs - Tontitown 345 kV	AEPW
LH, HW	Carnegie - Hobart Junction 138 kV	AEPW	(-)	Elk City - Gracemont 345 kV	AEPW-OKGE
SP	Oologah - Northeastern 138 kV	AECI-AEPW	(-)	Chamber Springs - Clarksville 345 kV	AEPW
HW	Neosho - Riverton 161 kV	WERE-EMDE	(+)	Blackberry - Neosho 345 kV	AECI-WERE
SP	Neosho - Tipton Ford 161 kV	SWPA-EMDE	(-)	Chamber Springs - Clarksville 345 kV	AEPW
WP	St. Joe - Midway 161 kV	GMO	(+)	Fairport - St. Joe 345 kV	AECI-GMO
SP, LH, HW	Clinton - Truman 161 kV	AECI-SWPA	(+)	Overton - Sibley 345 kV	AMMO-GMO
SP	Truman - N Warsaw 161 kV	SWPA-GMO	(+)	Overton - Sibley 345 kV	AMMO-GMO
SP	Nashua 345/161 kV transformer	KCPL	(+)	Hawthorne - Nashua 345 kV	KCPL
HW	Smoky Hills - Summit 230 kV	MIDW-WERE	(+)	Post Rock - Spearville 345 kV	MIDW-SUNC
SP	Keystone - Ogallala 115 kV	NPPD	(+)	Base Case	-
HW	Kenzie - McElroy 138 kV	OKGE	(-)	Cleveland - Sooner 345 kV	GRDA-OKGE
HW	Cimarron - Draper 345 kV	OKGE	(+)	Northwest - Arcadia 345 kV	OKGE
SP, WP	Muskogee - Pecan Creek 345 kV	OKGE	(+)	Clarksville - Muskogee 345 kV	AEPW-OKGE
SP	S1221 - S1255 161 kV	OPPD	(-)	S3459 345/161 transformer	OPPD
LH	Sundown 230/115 kV transformer	SPS	(-)	Amoco - Hobbs 345 kV	SPS
HW, LH	Potter 345/230 kV transformer	SPS	(+)	Border - Tuco 345 kV	OKGE-SPS
WP	Sundown - Amoco 230 kV	SPS	(+)	Tuco - Amoco 345 kV	SPS
WP, SP	Pioneer Tap - SATMKEC3 115 kV	SUNC	(+)	Base case	-
SP	Essex - Idalia 161 kV	AECI-SWPA	(+)	Base Case	-
LH	Morgan - Stockton 161 kV	AECI-SWPA	(-)	Neosho - LaCygne 345 kV	WERE-KCPL
SP	S3455 - S3740 345 kV	OPPD	(-)	S3456 - S3458 345 kV	OPPD

Table 9.3: Future 2 Reliability Needs

Hour(s)	Constraint	Constraint Area(s)	Direction of Flow	Event (Contingency)	Contingency Area(s)
HW	Welsh - Diana 345 kV	AEPW	(+)	Welsh - Diana 345 kV	AEPW
SP	Farmington - Chamber Springs 161 kV	AEPW	(-)	Chamber Springs - Tontitown 345 kV	AEPW
SP	Owasso 109th - Northeastern 138 kV	AEPW	(-)	Cleveland - Sooner 345 kV	GRDA-OKGE
HW	Lone Oak - Enogex Wilburton Tap 138 kV	AEPW	(+)	Pittsburg - Valiant 345 kV	AEPW
SP	Weleetka - Weleetka 138 kV	SWPA-AEPW	(-)	Chamber Springs - Clarksville 345 kV	AEPW
HW	Webber Tap - Osage 138 kV	AEPW-OKGE	(-)	Cleveland - Sooner 345 kV	GRDA-OKGE
HW	Snyder 138/69 kV transformer	AEPW	(+)	Elk City - Gracemont 345 kV	AEPW-OKGE
HW	Altus Jct. - Parklane 138 kV	AEPW-OMPA	(+)	Elk City - Gracemont 345 kV	AEPW-OKGE
HW	Lawton Eastside - Sunnyside 345 kV	AEPW-OKGE	(+)	Base Case	-
HW	Lawton 112 & W Gore - Lawton Air Tap 138 kV	AEPW	(+)	Lawton Eastside - Gracemont 345 kV	AEPW-OKGE
HW	Cornville Tap - Paoli 138 kV	WFEC	(+)	Lawton Eastside - Sunnyside	AEPW-OKGE
SP	Catoosa - Terra Nitrogen Tap 138 kV	AEPW	(-)	Base Case	-
SP	Terra Nitrogen Tap - Verdigris 138 kV	AEPW	(-)	Base Case	-
SP	Claremore Transok - Northeastern 138 kV	AEPW	(-)	Base Case	-
SP	Owasso 86th - Northeastern 138 kV	AEPW	(-)	Base Case	-
LH	Conestoga - Hitchland 345 kV	SPS	(+)	Spearville - Buckner 345 kV	SUNC
HW	Neosho - Riverton 161 kV	WERE-EMDE	(+)	Blackberry - Neosho 345 kV	AECI-WERE
WP	St. Joe - Midway 161 kV	GMO	(+)	Fairport - St. Joe 345 kV	AECI-GMO
WP, SP	Truman - N Warsaw 161 kV	SWPA-GMO	(+)	Neosho - LaCygne 345 kV	WERE-KCPL
LH, SP	Nashua 345/161 kV transformer	KCPL	(+)	Hawthorne - Nashua 345 kV	KCPL
HW	Smoky Hills - Summit 230 kV	MIDW-WERE	(+)	Wichita - Flat Ridge 345 kV	WERE-SUNC
LH	Woodward - Windfarm Switching 138 kV	OKGE	(-)	Tatonga - Mathewson 345 kV	OKGE
SP	Woodward - Windfarm Switching 138 kV	OKGE	(-)	Woodward EHV - Flat Ridge 345 kV	OKGE-SUNC
SP, WP	Muskogee - Pecan Creek 345 kV	OKGE	(+)	Clarksville - Muskogee 345 kV	AEPW-OKGE
SP	S1221 - S1255 161 kV	OPPD	(-)	S3459 345/161 transformer	OPPD
LH	Potter 345/230 kV transformer	SPS	(+)	Woodward EHV - Border 345 kV	OKGE
LH	Sundown - Amoco 230 kV	SPS	(+)	Tuco - Amoco 345 kV	SPS
SP	Pioneer Tap - SATMKEC3 115 kV	SUNC	(+)	Base case	-
LH	North Dodge - East Dodge 115 kV	SUNC	(+)	Base case	-
SP	Springfield - Clay 161 kV	SWPA-SPRM	(+)	Huben - Morgan 345 kV	AECI
WP	Russellville - Dardanelle 161 kV	EES-SWPA	(+)	ANO - Fort Smith 500 kV	EES-OKGE
SP	Goodyear Jct. - Northland 115 kV	WERE	(-)	Hoyt - Stranger Creek 345 kV	WERE
LH	Centennial - Paola 161 kV	KCPL	(+)	Neosho - LaCygne 345 kV	WERE-KCPL
SP	Butler - Midian 138 kV	WERE	(-)	Benton - Rose Hill 345 kV	WERE
LH	El Paso - Farber 138 kV	WERE	(+)	Rose Hill - Sooner Tap 345 kV	WERE-OKGE
HW	Kelly - King Hill 115 kV	WERE	(+)	St. Joe - Cooper 345 kV	GMO-NPPD
LH	Morgan - Stockton 161 kV	AECI-SWPA	(-)	Neosho - LaCygne 345 kV	WERE-KCPL
SP	S3455 - S3740 345 kV	OPPD	(-)	S3456 - S3458 345 kV	OPPD

Table 9.4: Future 3 Reliability Needs

Hour(s)	Constraint	Constraint Area(s)	Direction of Flow	Event (Contingency)	Contingency Area(s)
HW	Carnegie - Hobart Junction 138 kV	AEPW	(-)	Elk City - Gracemont 345 kV	AEPW-OKGE
SP	Prairie Lee - Blue Springs South 161 kV	GMO	(+)	Pleasant Hill - Sibley 345 kV	GMO
SP	Clinton - Truman 161 kV	AECI-SWPA	(+)	Overton - Sibley 345 kV	AMMO-GMO
SP	Truman - N Warsaw 161 kV	SWPA-GMO	(+)	Neosho - LaCygne 345 kV	WERE-KCPL
SP	Missouri City - Eckles Road 161 kV	AECI-INDN	(-)	St. Joe - Fairport 345 kV	GMO-AECI
SP	Nashua 345/161 kV transformer	KCPL	(+)	Hawthorne - Nashua 345 kV	KCPL
HW	Smoky Hills - Summit 230 kV	MIDW-WERE	(+)	Wichita - Flat Ridge 345 kV	WERE-SUNC
HW	Cimarron - Draper 345 kV	OKGE	(+)	Northwest - Arcadia 345 kV	OKGE
HW	Jensen Tap - Jensen 138 kV	OKGE	(-)	Elk City - Gracemont 345 kV	AEPW-OKGE
HW	Potter 345/230 kV transformer	SPS	(+)	Woodward EHV - Border 345 kV	OKGE
HW, LH	Essex - Idalia 161 kV	AECI-SWPA	(+)	New Madrid 345/161 transformer	AECI
SP	Bull Shoals - Midway 161 kV	SWPA-EES	(+)	ANO - Pleasant Hill 500 kV	EES
SP	Springfield - Clay 161 kV	SWPA-SPRM	(+)	Huben - Morgan 345 kV	AECI
HW	Middleton Tap - Creswell 138 kV	OKGE-WERE	(-)	Rose Hill - Sooner Tap 345 kV	WERE-OKGE

Table 9.5: Future 4 Reliability Needs

Hour(s)	Constraint	Constraint Area(s)	Direction of Flow	Event (Contingency)	Contingency Area(s)
SP	Farmington - Chamber Springs 161 kV	AEPW	(-)	Chamber Springs - Tontitown 345 kV	AEPW
WP	Avoca - Beaver 161 kV	AEPW	(-)	Chamber Springs - Clarksville 345 kV	AEPW
SP	Hackett - Bonanza 161 kV	AEPW	(-)	Base Case	-
SP	Truman - N Warsaw 161 kV	AECI-SWPA-GMO	(+)	Overton - Sibley 345 kV	AMMO-GMO
SP	Beatrice - Harbine 115 kV	NPPD	(+)	McCool 345/115 kV transformer	NPPD
HW	Harper - Milan Tap 138 kV	SUNC	(+)	Wichita - Thistle 345 kV	WERE-SUNC
HW, LH	North Dodge - East Dodge 115 kV	SUNC	(+)	Base Case	-
SP	S3455 - S3740 345 kV	OPPD	(-)	S3456 - S3458 345 kV	OPPD
SP	Muskogee - Pecan Creek 345 kV	OKGE	(+)	Clarksville - Muskogee 345 kV	AEPW-OKGE
SP	S1221 - S1255 161 kV	OPPD	(-)	S3459 345/161 kV transformer	OPPD
SP	Sundown 230/115 kV transformer	SPS	(+)	Amoco - Hobbs 345 kV	SPS
HW, LH, SP	Cimarron River Tap - East Liberal 115 kV	SUNC-SPS	(+)	Conestoga - Finney 345 kV	SPS
LH	Holcomb 345/115 kV transformer	SUNC	(-)	Holcomb - Finney 345 kV	SUNC
SP, WP	Essex - Idalia 161 kV	AECI-SWPA	(+)	New Madrid 345/161 kV transformer	AMMO-AECI
SP	Missouri City - Eckles Road 161 kV	AECI-INDN	(-)	Fairport - St. Joe 345 kV	AECI-GMO
SP	Oologah - Northeastern 138 kV	AECI-AEPW	(-)	Chamber Springs - Clarksville 345 kV	AEPW
SP	Reves Road - Hackett 161 kV	AEPW	(+)	Base Case	-
SP	Weleetka - Weleetka 138 kV	SWPA-AEPW	(-)	Base Case	-
SP	Woodward - Windfarm Switching 138 kV	OKGE	(-)	Base Case	-
HW	Jensen Tap - Jensen 138 kV	OKGE	(-)	Elk City - Gracemont 345 kV	AEPW-OKGE
WP	Midwest - Franklin 138 kV	OKGE-WFEC	(+)	Minco - Gracemont 345 kV	OKGE
SP	Hitchland 230/115 kV transformer	SPS	(+)	Hitchland - Potter 345 kV	SPS
HW	South Dodge - West Dodge 115 kV	SUNC	(-)	Spearville - Buckner 345 kV	SUNC
SP	Victory Hill 230/115 kV transformer	NPPD	(+)	Wayside - Stegall 230 kV	NPPD-MAPP
SP	Allen - Lubbock South 115 kV	SPS	(-)	Tuco - New Deal 345 kV	SPS
LH, WP	Blue Springs East - Duncan Road 161 kV	GMO	(-)	Pleasant Hill - Sibley 345 kV	GMO
LH	Mingo - Red Willow 345 kV	SUNC-NPPD	(-)	Post Rock - Axtell 345 kV	NPPD-MIDW
SP	Great Bend Tap - Seward 115 kV	SUNC	(+)	Conestoga - Finney 345 kV	SPS
LH	East Manhattan - JEC 230 kV	WERE	(+)	JEC - Summit 345 kV	WERE
SP	Tuco - Carlisle 230 kV	SPS	(+)	Tuco - Amoco 345 kV	SPS
SP, LH	Stanton - Indiana 115 kV	SPS	(+)	Amoco - Hobbs 345 kV	SPS
LH	Morgan - Stockton 161 kV	AECI-SWPA	(-)	Neosho - LaCygne 345 kV	WERE-KCPL
SP	Litchfield - Franklin 161 kV	WERE	(-)	Neosho - LaCygne 345 kV	WERE-KCPL
LH	Marmaton - Centerville 161 kV	WERE-KCPL	(-)	Neosho - LaCygne 345 kV	WERE-KCPL
LH	Nashua 345/161 kV transformer	KCPL	(+)	Nashua - Hawthorne 345 kV	KCPL
HW	Neosho - Riverton 161 kV	WERE-EMDE	(+)	Blackberry - Neosho 345 kV	AECI-WERE
SP	Hereford - Deaf Smith 115 kV	SPS	(+)	Tuco - Border 345 kV	SPS
LH	Clinton - Truman 161 kV	AECI-SWPA	(+)	Neosho - LaCygne 345 kV	WERE-KCPL
SP	Maryville - Maryville 161 kV	AECI-GMO	(+)	Fairport - St. Joe 345 kV	AECI-GMO

Table 9.6: Future 5 Reliability Needs

9.3: Reliability Solutions

Project solutions were developed by stakeholders and staff. 100 kV and above projects were considered as solutions for reliability needs. To test the reliability solutions, a project was added to the model for the hour in which the overload occurred. Loading on the constrained element was assessed. The solution was considered valid if the element was no longer binding or breaching the limit. Multiple solutions were considered for many needs, and engineering judgment was used to determine the solution that provided the best fit for the region.

The following Table 9.7 through 9.11 summarize the reliability project solutions for each future, including the constrained element that is being relieved by each project.

Reliability Project	Project Area(s)	Constrained Element	Miles Added/ Modified
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Farmington - Chamber Springs 161 kV	18
Reconductor Avoca - East Rogers 161 kV	AEPW	Avoca - East Rogers 161 kV	6
Reconductor Bonanza - Hackett 161 kV	AEPW	Hackett - Bonanza 161 kV	2
Reconductor Fitzhugh - Ozark Dam 161 kV	AEPW-SWPA	Fitzhugh - Ozark Dam 161 kV	2
Reconductor Red Hills Wind - Elk City 138 kV	AEPW-WFEC	Elk City - Red Hills Wind 138 kV	35
New Maryville 345/161 kV transformer	GMO-AECI	St. Joe - Midway 161 kV	0
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Truman - N Warsaw 161 kV	31
New Wolf Creek - Neosho 345 kV line	WERE	Morgan - Stockton 161 kV, Litchfield - Franklin 161 kV, Centennial - Paola 161 kV	99
Reconductor Shawnee - Metropolitan 161 kV	KCPL-KACY	Shawnee - Metropolitan 161 kV	5
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Nashua 345/161 kV transformer	0
Reconductor HEC - Huntsville 115 kV	MIDW-WERE	Huntsville - HEC 115 kV	29
Reconductor Beatrice - Harbine 115 kV	NPPD	Beatrice - Harbine 115 kV	14
Reconductor Ft. Randall - Spencer 115 kV	WAPA-NPPD	Spencer - Ft. Randle 115 kV	20
New Keystone - Red Willow 345 kV	NPPD	Keystone - Ogallala 115 kV	110
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new Auburn 345/115 kV transformer	WERE	Goodyear Jct. - Northland 115 kV	47
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Muskogee - Pecan Creek 345 kV	23
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Muskogee - Pecan Creek 345 kV	16
New 2nd S3459 345/161 kV transformer	OPPD	S1221 - S1255 161 kV	0
New 2nd Sundown 230/115 kV transformer	SPS	Sundown 230/115 kV transformer	0
New 2nd Plant X 230/115 kV transformer	SPS	Plant X 230/115 kV transformer	0
New Tolk - Tuco 345 kV	SPS	Swisher - Tuco 230 kV	64
Reconductor Chaves - Samson 115 kV	SPS	Chaves - Samson 115 kV	8
Reconductor Chaves - Urton 115 kV	SPS	Chaves - Urton 115 kV	4
Reconductor Eagle Creek - Eddy 115 kV	SPS	Eagle Creek - Eddy 115 kV	10
Reconductor Cimarron River Tap - East Liberal - Texas Co 115 kV	SUNC-SPS	Cimarron River Tap - East Liberal 115 kV	12
New 2nd Holcomb 345/115 kV transformer	SUNC	Holcomb 345/115 kV transformer	0
Reconductor Harper - Milan Tap 138 kV	SUNC	Harper - Milan Tap 138 kV	22
Reconductor North Dodge - East Dodge 115 kV	SUNC	North Dodge - East Dodge 115 kV	5
New S3740 - S3454 345 kV	OPPD	S3455 - S3740 345 kV	28
Reconductor Maryville - Maryville 161 kV	AECI-GMO	Fairport - St. Joe 345 kV	1
Reconductor Bull Shoals - Midway 161kV	SWPA-EES	Bull Shoals - Midway 161 kV	7
Reconductor Overton - Jacksonville 138 kV	AEPW	Overton - Jacksonville 138 kV	30
Reconductor Bushland - Deaf Smith 230 kV	SPS	Bushland - Deaf Smith 230 kV	33
Replace wavetrap for Prairie Lee - Blue Springs South 161 kV	GMO	Prairie Lee - Blue Springs South 161 kV	3
Reconductor Sundown - Amoco 230 kV	SPS	Sundown - Amoco 230 kV	5

Reconductor Fulton - Patmos 115 kV	AEPW-EES-EAI	Sarepta - Longwood 345 kV	15
Reconductor Neosho - Riverton 161 kV	WERE-EMDE	Neosho - Riverton 161 kV	28
New S1251 - S1252 161 kV	OPPD	Ft. Calhoun Interface	19

Table 9.7: Future 1 Reliability Solutions

Reliability Project	Project Area(s)	Constrained Element	Miles Added/ Modified
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Farmington - Chamber Springs 161 kV	18
Reconductor Carnegie - Hobart Junction 138 kV	AEPW	Carnegie - Hobart Junction 138 kV	26
Reconductor Oologah - Northeastern 138 kV	AECI-AEPW	Oologah - Northeastern 138 kV	3
Reconductor Neosho - Riverton 161 kV	WERE-EMDE	Neosho - Riverton 161 kV	28
Reconductor Neosho - Tipton Ford 161 kV	SWPA-EMDE	Neosho - Tipton Ford 161 kV	11
New Maryville 345/161 kV transformer	GMO-AECI	St. Joe - Midway 161 kV	0
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Clinton - Truman 161 kV, Truman - N Warsaw 161 kV	31
New Wolf Creek - Neosho 345 kV line	WERE	Morgan - Stockton 161 kV	99
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Nashua 345/161 kV transformer	0
New Summit - Post Rock 345 kV	MIDW-WERE	Smoky Hills - Summit 230 kV	112
New Keystone - Red Willow 345 kV	NPPD	Keystone - Ogallala 115 kV	110
Reconductor Kenzie to McElroy 138 kV	OKGE	Kenzie - McElroy 138 kV	2
Replace wavetraps for Cimarron - Draper 345 kV	OKGE	Cimarron - Draper 345 kV	36
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Muskogee - Pecan Creek 345 kV	23
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Muskogee - Pecan Creek 345 kV	16
New 2nd S3459 345/161 kV transformer	OPPD	S1221 - S1255 161 kV	0
New 2nd Sundown 230/115 kV transformer	SPS	Sundown 230/115 kV transformer	0
New Potter - Tolk 345 kV	SPS	Potter 345/230 kV transformer	111
New Tolk - Tuco 345 kV	SPS	Sundown - Amoco 230 kV	64
Reconductor Pioneer Tap to SATMKEC3 115 kV	SUNC	Pioneer Tap - SATMKEC3 115 kV	12
Reconductor Essex - Idalia 161 kV	AECI-SWPA	Essex - Idalia 161 kV	1
New S3740 - S3454 345 kV	OPPD	S3455 - S3740 345 kV	28

Table 9.8: Future 2 Reliability Solutions

Reliability Project	Project Area(s)	Constrained Element	Miles Added/ Modified
New Welsh - Lake Hawkins 345 kV, new 345/138 kV transformer at Lake Hawkins	AEPW	Welsh - Diana 345 kV	44
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Farmington - Chamber Springs 161 kV	18
Reconductor Lone Oak - Enogex Wilburton Tap 138 kV	AEPW	Lone Oak - Enogex Wilburton Tap 138 kV	1
Reconductor Weleetka - Weleetka 138 kV	SWPA-AEPW	Weleetka - Weleetka 138 kV	3
Reconductor Webber Tap - Osage 138 kV	AEPW-OKGE	Webber Tap - Osage 138 kV	22
Upgrade Snyder 138/69 kV transformer	AEPW	Snyder 138/69 kV transformer	0
Reconductor Altus Jct. - Parklane 138 kV	AEPW-OMPA	Altus Jct. - Parklane 138 kV	3
Replace CT for Lawton Eastside - Sunnyside 345 kV	AEPW-OKGE	Lawton Eastside - Sunnyside 345 kV	72
Reconductor Lawton 112 & W Gore - Lawton Air Tap 138 kV	AEPW	Lawton 112 & W Gore - Lawton Air Tap 138 kV	1
Reconductor Cornville Tap - Paoli 138 kV	WFEC	Cornville Tap - Paoli 138 kV	32
Reconductor Catoosa - Terra Nitrogen Tap - Verdigris 138 kV	AEPW	Catoosa - Terra Nitrogen Tap 138 kV, Terra Nitrogen Tap - Verdigris 138 kV	9
Replace wavetrap for Claremore Transok - Northeastern 138 kV	AEPW	Claremore Transok - Northeastern 138 kV	13
Reconductor Owasso 86th - Northeastern - Owasso 109th 138 kV	AEPW	Owasso 109th - Northeastern 138 kV, Owasso 86th - Northeastern 138 kV	24
Reconductor Neosho - Riverton 161 kV	WERE-EMDE	Neosho - Riverton 161 kV	28
New Maryville 345/161 kV transformer	GMO-AECI	St. Joe - Midway 161 kV	0
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Truman - N Warsaw 161 kV	31
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Nashua 345/161 kV transformer	0
New Summit - Post Rock 345 kV	MIDW-WERE	Smoky Hills - Summit 230 kV	112
Reconductor Woodward to Windfarm Switching 138kV	OKGE	Tatonga - Mathewson 345 kV	12
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Muskogee - Pecan Creek 345 kV	23
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Muskogee - Pecan Creek 345 kV	16
New 2nd S3459 345/161 kV transformer	OPPD	S1221 - S1255 161 kV	0
New Potter - Tolk 345 kV	SPS	Potter 345/230 kV transformer	111
New Buckner - Beaver 345 kV, new Beaver 345/115 kV transformer	SUNC-SPS	Conestoga - Hitchland 345 kV	86
New Tolk - Tuco 345 kV	SPS	Sundown - Amoco 230 kV	64
Reconductor Pioneer Tap to SATMKEC3 115 kV	SUNC	Pioneer Tap - SATMKEC3 115 kV	12
Reconductor North Dodge - East Dodge 115 kV	SUNC	North Dodge - East Dodge 115 kV	5
Replace terminal equipment for Springfield - Clay 161 kV	SWPA-SPRM	Springfield - Clay 161 kV	7

Reconductor Russellville - Dardanelle 161 kV	EES-SWPA	Russellville - Dardanelle 161 kV	3
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new Auburn 345/115 kV transformer	WERE	Goodyear Jct. - Northland 115 kV	47
New Wolf Creek - Neosho 345 kV line	WERE	Morgan - Stockton 161 kV, Centennial - Paola 161 kV	99
Reconductor Butler - Midian 138kV	WERE	Butler - Midian 138 kV	3
Reconductor El Paso - Farber 138 kV	WERE	El Paso - Farber 138 kV	3
Reconductor Kelly - King Hill 115 kV	WERE	Kelly - King Hill 115 kV	10
New S3740 - S3454 345 kV	OPPD	S3455 - S3740 345 kV	28

Table 9.9: Future 3 Reliability Solutions

Reliability Project	Project Area(s)	Constrained Element	Miles Added/ Modified
Reconductor Carnegie - Hobart Junction 138 kV	AEPW	Carnegie - Hobart Junction 138 kV	26
Replace wavetrap for Prairie Lee - Blue Springs South 161 kV	GMO	Prairie Lee - Blue Springs South 161 kV	3
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Clinton - Truman 161 kV, Truman - N Warsaw 161 kV	31
Reconductor Missouri City - Eckles Road 161 kV	AECI-INDN	Missouri City - Eckles Road 161 kV	6
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Nashua 345/161 kV transformer	0
New Summit - Post Rock 345 kV	MIDW-WERE	Smoky Hills - Summit 230 kV	112
Replace wavetraps for Cimarron - Draper 345 kV	OKGE	Cimarron - Draper 345 kV	36
Replace wavetraps for Jensen Tap - Jensen 138 kV	OKGE	Jensen Tap - Jensen 138 kV	5
New Potter - Tolk 345 kV	SPS	Potter 345/230 kV transformer	111
Reconductor Essex - Idalia 161 kV	AECI-SWPA	Essex - Idalia 161 kV	1
Reconductor Bull Shoals - Midway 161 kV	SWPA-EES	Bull Shoals - Midway 161 kV	7
Replace terminal equipment for Springfield - Clay 161 kV	SWPA-SPRM	Springfield - Clay 161 kV	7
Reconductor Middleton Tap - Creswell 138 kV	OKGE-WERE	Middleton Tap - Creswell 138 kV	9

Table 9.10: Future 4 Reliability Solutions

Reliability Project	Project Area(s)	Constrained Element	Miles Added/ Modified
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Farmington - Chamber Springs 161 kV	18
Reconductor Avoca - Beaver 161 kV	AEPW	Avoca - Beaver 161 kV	6
Reconductor Bonanza - Hackett 161 kV	AEPW	Hackett - Bonanza 161 kV	2
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Truman - N Warsaw 161 kV	31
New Wolf Creek - Neosho 345 kV line	WERE	Morgan - Stockton 161 kV, Litchfield - Franklin 161 kV, Marmaton - Centerville 161 kV	99
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Nashua 345/161 kV transformer	0
Reconductor Beatrice - Harbine 115 kV	NPPD	Beatrice - Harbine 115 kV	14
New Maryville 345/161 kV transformer	GMO-AECI	St. Joe - Midway 161 kV	0
Reconductor Neosho - Riverton 161 kV	WERE-EMDE	Neosho - Riverton 161 kV	28
Reconductor Harper - Milan Tap 138 kV	SUNC	Harper - Milan Tap 138 kV	22
Reconductor North Dodge - East Dodge 115 kV	SUNC	North Dodge - East Dodge 115 kV	5
New S3740 - S3454 345 kV	OPPD	S3455 - S3740 345 kV	28
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Muskogee - Pecan Creek 345 kV	23
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Muskogee - Pecan Creek 345 kV	16
New 2nd S3459 345/161 kV transformer	OPPD	S1221 - S1255 161 kV	0
New 2nd Sundown 230/115 kV transformer	SPS	Sundown 230/115 kV transformer	0
New Tolk - Tuco 345 kV	SPS	Sundown - Amoco 230 kV	64
Reconductor Cimarron River Tap - East Liberal - Texas Co 115 kV	SUNC-SPS	Cimarron River Tap - East Liberal 115 kV	12
New 2nd Holcomb 345/115 kV transformer	SUNC	Holcomb 345/115 kV transformer	0
Reconductor Essex - Idalia 161 kV	AECI-SWPA	Essex - Idalia 161 kV	1
Reconductor Missouri City - Eckles Road 161 kV	AECI-INDN	Missouri City - Eckles Road 161 kV	6
Reconductor Oologah - Northeastern 138 kV	AECI-AEPW	Oologah - Northeastern 138 kV	3
Reconductor Reves Road - Hackett 161 kV	AEPW	Reves Road - Hackett 161 kV	5
Reconductor Weleetka - Weleetka 138 kV	SWPA-AEPW	Weleetka - Weleetka 138 kV	3
Reconductor Woodward - Windfarm Switching 138 kV	OKGE	Woodward - Windfarm Switching 138 kV	12
Replace wavetraps for Jensen Tap - Jensen 138 kV	OKGE	Jensen Tap - Jensen 138 kV	5
Replace terminal equipment for Midwest - Franklin 138 kV	OKGE-WFEC	Midwest - Franklin 138 kV	1

New 2nd Hitchland 230/115 kV transformer	SPS	Hitchland 230/115 kV transformer	0
Reconductor South Dodge - West Dodge 115 kV	SUNC	South Dodge - West Dodge 115 kV	9
New 2nd Victory Hill 230/115 kV transformer	NPPD	Victory Hill 230/115 kV transformer	0
Reconductor Allen - Lubbock South 115 kV	SPS	Allen - Lubbock South 115 kV	6
Reconductor Blue Springs East - Duncan Road 161 kV	GMO	Blue Springs East - Duncan Road 161 kV	2
Reconductor Mingo - Red Willow 345 kV	SUNC-NPPD	Mingo - Red Willow 345 kV	76
Reconductor Great Bend Tap - Seward 115 kV	SUNC	Great Bend Tap - Seward 115 kV	12
Reconductor East Manhattan - JEC 230 kV	WERE	East Manhattan - JEC 230 kV	27
Reconductor Tuco - Carlisle 230 kV	SPS	Tuco - Carlisle 230 kV	27
Reconductor Stanton - Indiana 115 kV	SPS	Stanton - Indiana 115 kV	1

Table 9.11: Future 5 Reliability Solutions

Section 10: Policy Needs and Solutions

10.1: Methodology

Policy needs and their corresponding transmission solutions were developed based on the curtailment of renewable energy that has been installed to meet a Renewable Energy Standard (RES) policy target or mandate in each future. A wind farm was identified as a policy need when the annual energy output was less than 97% of the scheduled energy output, due to congestion. Targeted energy is based on maximum capacity, capacity factor and generation profile. For all futures assessed, the curtailment results were based on a full year Security Constrained Economic Dispatch (SCED) simulation which included all identified reliability projects. Policy needs primarily reflect the inability to dispatch wind generation due to congestion. This requires the addition of new transmission projects onto the SPP system to mitigate these problems.

After reliability projects were incorporated into the models, Table 10.1 shows the number of wind farms by area not meeting the energy output requirement of 97% of targeted energy per future.

Area	F1	F2	F3	F4	F5
MIDW	-	-	1	-	-
MKEC	1	5	7	4	1
NPPD	-	1	2	-	-
OKGE	-	-	-	-	-
OPPD	-	-	2	-	-
SUNC	-	4	6	-	-
SPS	-	-	4	-	-
WFEC	-	-	1	-	-
WRI	1	1	1	1	1
TOTAL	2	11	24	5	2

Table 10.1: Number of Wind Farms Curtailing

Once policy needs were identified, potential transmission solutions targeted at reducing congestion around the identified wind farms were developed. Transmission solutions were developed based on congestion results as reported by PROMOD IV®. Transmission solutions could be targeted at a specific wind farm or at a region where multiple wind farms were identified based on the particular future. The full year SCED simulation was then executed with the proposed transmission solutions implemented. All wind farms within the SPP footprint were then once again checked to confirm that the annual energy output exceeded 97% of the scheduled energy output. New or alternative transmission solutions were then developed for any wind farms with less than 97% of the scheduled energy output.

10.2: Future 1 Needs and Solutions

In Future 1, existing state targets and mandates were utilized for expected wind generation. Policy needs were minimal with the inclusion of the reliability projects. Two wind farms were identified as not meeting 97% of their scheduled energy output due to congestion. Figure 10.1 shows the location of the Future 1 policy needs in relation to the SPP footprint.

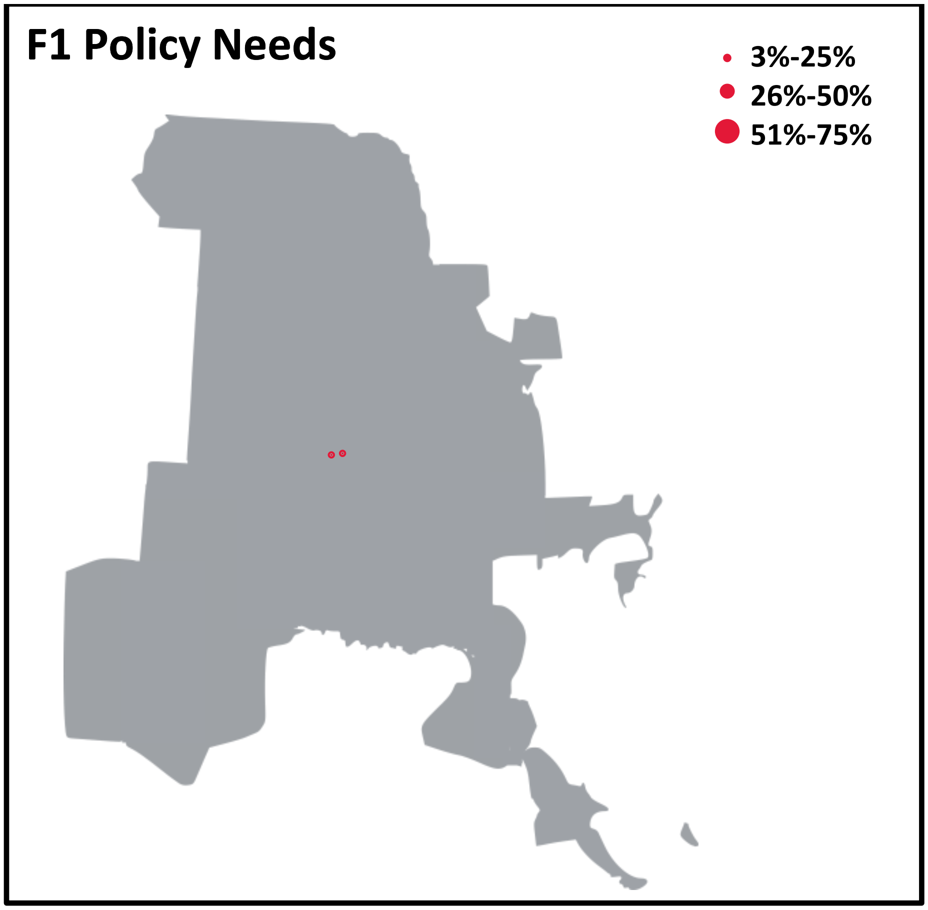


Figure 10.1: Future 1 Policy Needs

Both wind farms were identified in the 3%-25% curtailment range. Since both wind farms were in the same local area, only one transmission solution (non-EHV) was necessary to address the need.

Policy Project	Project Area(s)	Miles Added/ Modified
Reconductor Milan Tap - Clearwater 138 kV	SUNC-WERE	12

Table 10.2: Future 1 Policy Projects

10.3: Future 2 Needs and Solutions

With an assumed federal Renewable Energy Standard (RES) policy of 20 percent of energy served via renewable energy, the installed nameplate wind capacity increases by approximately 7 GW beyond the Business as Usual wind capacity of 9 GW. The additional 7 GW of wind capacity is located in similar geographic locations as the 9 GW of Business as Usual wind, which focused transmission congestion to the same relative area. There were 30 wind farms modeled in Future 2, as opposed to 25 wind farms modeled in Future 1. Some of the Future 1 wind farms had additional capacity in Future 2, and the additional wind sites added in Future 2 were in similar geographic locations as Future 1 wind sites. Future 2 policy needs increased substantially in comparison with Future 1. The majority of curtailment was seen in South Central and South West Kansas. Eleven wind farms were identified as not meeting 97% of their scheduled energy output. Figure 10.2 shows the location of the Future 2 policy needs in relation to the footprint.

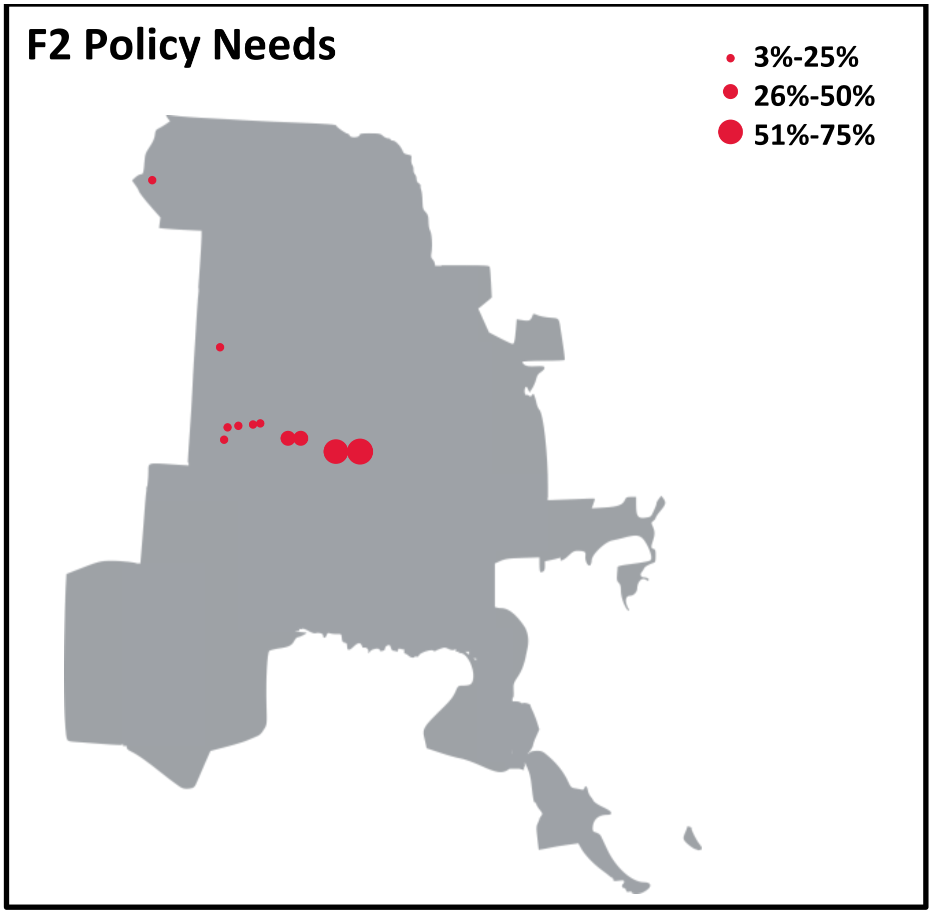


Figure 10.2: Future 2 Policy Needs

The two wind farms identified in Future 1 increased to a curtailment range of 51%-75%. Nine more wind farms were identified in Future 2, two of which showed a curtailment range of 26%-50% and seven of which showed a curtailment range of 3%-25%. Proposed transmission solutions for the Future 2 policy needs used a combination of new EHV projects and upgrades of existing facilities.

Policy Project	Project Area(s)	Miles Added/ Modified
Rebuild Spearville - Great Bend - Circle - Reno 230 kV as Spearville - Great Bend - Rice - Circle - Reno 345 kV double circuit, add 345/230 transformers at Great Bend, Circle, and Rice	MIDW-WERE-SUNC	273
New Rice - Summit 345 kV double circuit	MIDW-WERE	120
New 2nd Victory Hill 230/115 kV transformer	NPPD	0
Reconductor Victory Hill - Crawford - Chadron - Wayside 115 kV	NPPD	96
New Woodward - Woodring 345 kV double circuit	OKGE	204
New Thistle - Viola Tap 345 kV double circuit	SUNC-WERE	90
New Thistle - Flat Ridge 345 kV, new Flat Ridge 345/138 kV transformer	SUNC	5
New Ironwood - North Dodge 345 kV, new North Dodge 345/115 kV transformer	SUNC	16
New Mingo - Post Rock 345 kV double circuit	SUNC-MIDW	210
New North Dodge - West Dodge 345 kV, new West Dodge 345/115 kV transformer	SUNC	10
Reconductor Haggard - GycoTap - West Dodge - South Dodge - Fort Dodge - DC Beef - East Dodge - North Dodge - NW Dodge - West Dodge 115 kV, reconductor Ingalls - Pierceville - Plymell 115 kV	SUNC	74
New Viola Tap - Neosho 345 kV double circuit	WERE	426

Table 10.3: Future 2 Policy Projects

10.4: Future 3 Needs and Solutions

Future 3 increases the installed nameplate wind capacity across the SPP footprint by an additional 10 GW above Future 2 levels. This is a 180 percent increase over Future 1 installed capacity and a 56 percent increase over Future 2 installed capacity. Future 3 included a significant escalation in policy needs in comparison with Futures 1 and 2. Similar to Future 2, the majority of curtailment was seen in South Central and South West Kansas. Twenty-four wind farms were identified as not meeting 97% of their scheduled energy output. Figure 10.3 shows the location of the Future 3 policy needs in relation to the footprint.

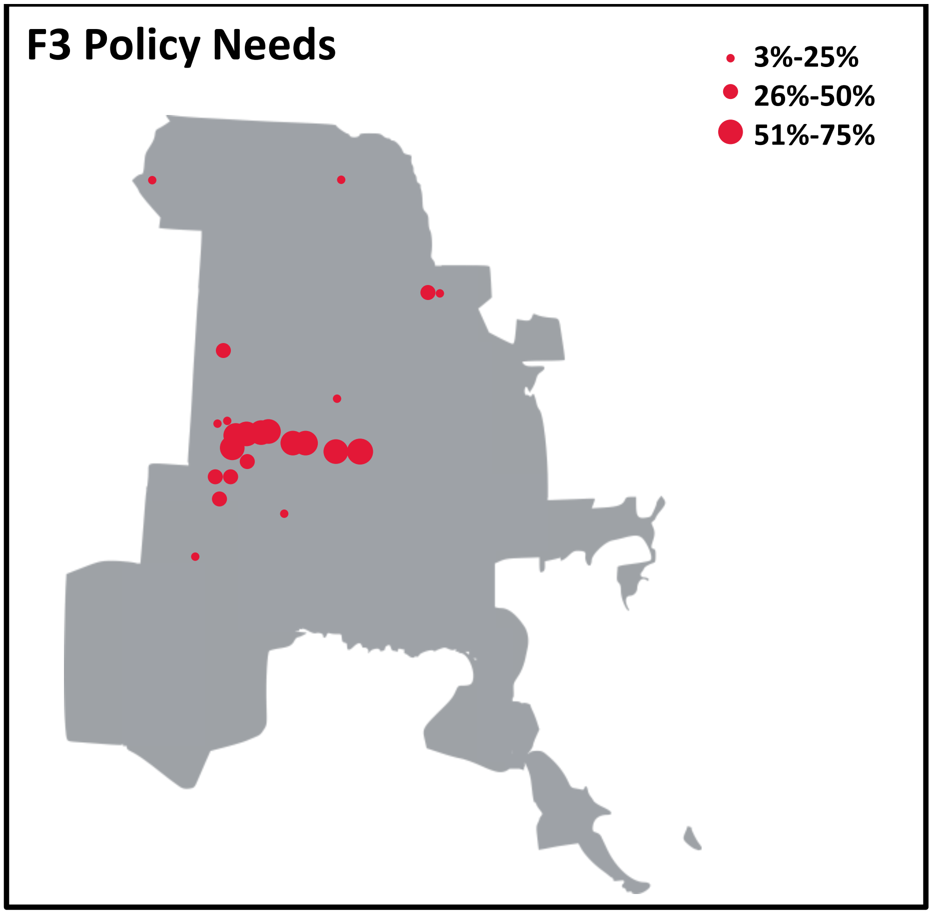


Figure 10.3: Future 3 Policy Needs

Nine wind farms were identified in curtailment range of 51%-75%, seven wind farms were identified in curtailment range of 26%-50%, and eight were identified in curtailment range of 3%-25%. Similar to Future 2, proposed transmission solutions for the Future 3 policy needs used a combination of new EHV projects and upgrades of existing facilities. The new EHV projects were developed to provide additional paths to, and, or around the curtailed wind farms to relieve congestion on the transmission system near the wind farms. Major EHV projects were considered in exporting the wind energy outside the footprint.

Policy Project	Project Area(s)	Miles Added/ Modified
Reconductor Holt - Grand Island 345 kV	NPPD	85
New Holt - Raun - Hazelton 345 kV double circuit	NPPD-MEC-ALTW	842
New Woodward - Woodring 345 kV double circuit	OKGE	204
New Thistle - Flat Ridge 345 kV, new Flat Ridge 345/138 kV transformer	SUNC	5
New Ironwood - North Dodge 345 kV, new North Dodge 345/115 kV transformer	SUNC	16
New Mingo - Post Rock 345 kV double circuit	SUNC-MIDW	210
New North Dodge - West Dodge 345 kV, new West Dodge 345/115 kV transformer	SUNC	10
New Woodward - Sooner Wind 345 kV, new 345/138 kV transformer at Sooner Wind	OKGE	12
New Elk City - Canadian Hills Wind - Mathewson 345 kV	OKGE - AEPW	114
New Mathewson - Shelby 600 kV DC bi-pole	OKGE - TVA	700
New Spearville - Palmyra Tap - Sullivan 600 kV DC double circuit	SUNC - AMMO - AEPW	760

Table 10.4: Future 3 Policy Projects

10.5: Future 4 Needs and Solutions

Similar to Future 2, Future 4 includes the 20% federal RES mandate. However, load reduction due to demand response and energy conservation helps relieve some of the congestion created by the increase in nameplate wind capacity. Future 4 showed a minor increase in policy needs in comparison with Future 1 but a decrease in policy needs in comparison to Future 2. The majority of curtailment was seen in South Central and South West Kansas. Five wind farms were identified as not meeting 97% of their scheduled energy output. Figure 10.4 shows the location of the Future 4 policy needs in relation to the footprint.

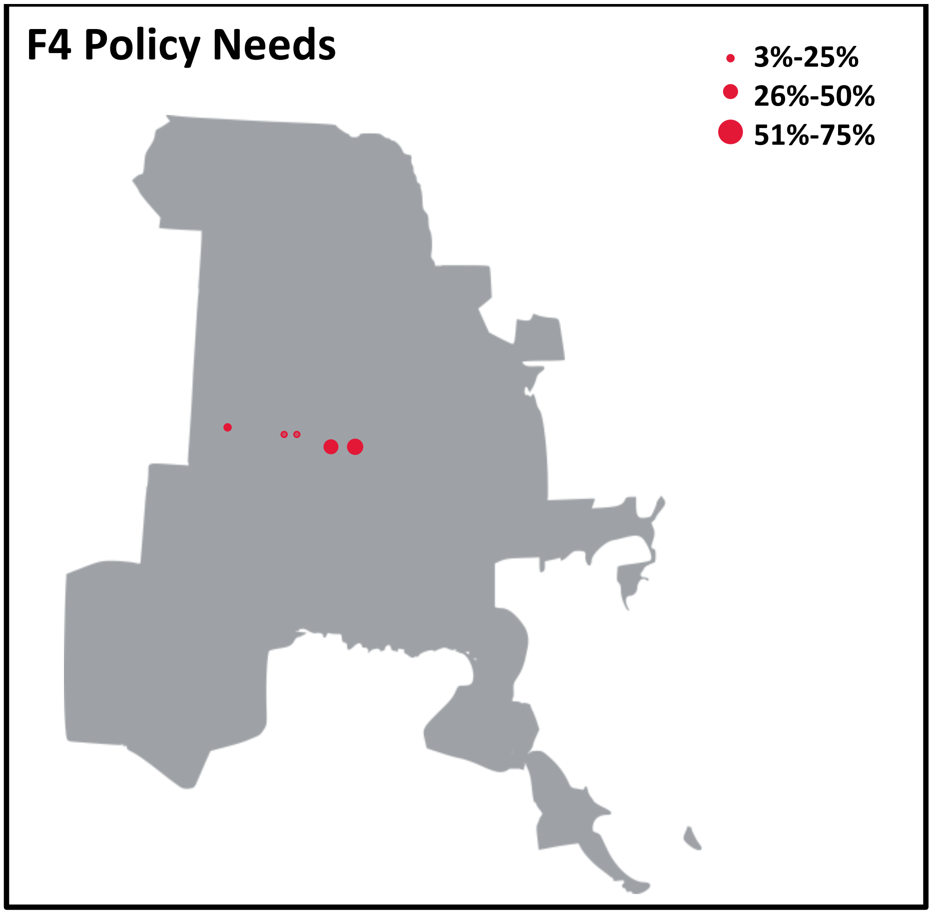


Figure 10.4: Future 4 Policy Needs

The two wind farms identified in Future 1 increased to a curtailment range of 51%-75%. Three additional wind farms were identified in Future 4, all of which showed a curtailment range of 3%-25%. Proposed transmission solutions for the Future 4 policy needs used a combination of new EHV projects and upgrades of existing facilities. The new EHV projects were developed to provide additional paths to, and, or around the curtailed wind farms to relieve congestion on the transmission system near the wind farms.

Policy Project	Project Area(s)	Miles Added/ Modified
Reconductor Haggard - GycoTap - West Dodge - South Dodge - Fort Dodge - DC Beef - East Dodge - North Dodge - NW Dodge - West Dodge 115 kV, reconductor Ingalls - Pierceville - Plymell 115 kV	SUNC	74
New Ironwood - North Dodge 345 kV, new North Dodge 345/115 kV transformer	SUNC	16
New North Dodge - West Dodge 345 kV, new West Dodge 345/115 kV transformer	SUNC	10
New Thistle - Flat Ridge 345 kV, new Flat Ridge 345/138 kV transformer	SUNC	5
New Thistle - Viola Tap 345 kV double circuit	SUNC-WERE	90
New 2nd Victory Hill 230/115 kV transformer	NPPD	0
Reconductor Victory Hill - Crawford - Chadron - Wayside 115 kV	NPPD	96
Rebuild Spearville - Great Bend - Circle - Reno 230 kV as Spearville - Great Bend - Circle - Reno 345 kV double circuit, add 345/230 transformers at Great Bend and Circle	WERE-SUNC	267

Table 10.5: Future 4 Policy Projects

10.6: Future 5 Needs and Solutions

Future 5 was similar to Future 1 in that existing state targets and mandates were utilized for expected wind generation. Policy needs were minimal with the inclusion of the reliability projects. Two wind farms were identified as not meeting 97% of their scheduled energy output due to congestion. Figure 10.5 shows the location of the Future 5 policy needs in relation to the SPP footprint.

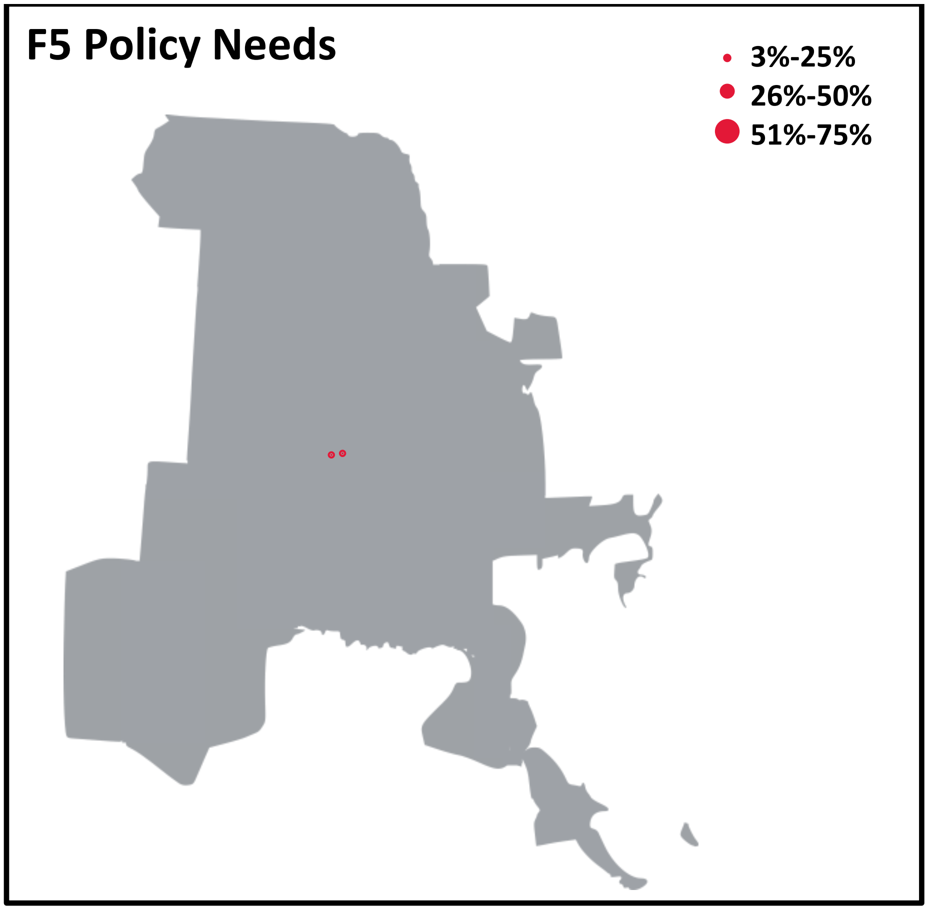


Figure 10.5: Future 5 Policy Projects

Both wind farms were identified in the 3%-25% curtailment range. Since both wind farms were in the same local area, only one transmission solution (non-EHV) was necessary to address the need. This project is identical to the Future 1 policy project.

Policy Project	Project Area(s)	Miles Added/ Modified
Reconductor Milan Tap - Clearwater 138 kV	SUNC-WERE	12

Table 10.6: Future 5 Policy Projects

Section 11: Economic Needs and Solutions

11.1: Background

Following the identification of reliability and policy transmission projects, any project that relieved the remaining congestion or was suggested by stakeholders as a potential economic project was screened to determine whether or not it provided economic value. An economic project is justified when its benefits to SPP stakeholders are greater than the cost. Therefore any justified economic project in the 2013 ITP20 must have a 40-year benefit-to-cost (B/C) ratio greater than 1. Benefits were measured as the difference in the Adjusted Production Cost (APC) with and without the potential economic project. Reliability and policy projects were included in runs both with and without the potential economic project.

11.2: Economic Needs

To assess economic needs, a security constrained unit commitment and economic dispatch (SCUC/SCED) were performed for the full study year, based on the transmission constraints defined for the system. The SCED derived nodal Locational Marginal Prices (LMPs) by dispatching generation economically. LMPs reflect the congestion occurring on the transmission system's binding constraints. The simulation results showed which constraints caused the most congestion, and the additional cost of dispatching around these constraints. The following process was used:

1. Binding constraints were ranked from most expensive to least expensive, based on the average shadow price of the congestion over the full year.
2. The top 15 most expensive constraints[22] in the SPP system were identified as the economic needs of the system.
3. Potential economic project solutions were developed based on this list of 15 constraints.

This procedure was performed for each future to identify the economic needs specific to each future.

[22] This specific criteria was identified in the study scope, prior to analysis of economic needs. The top 15 binding constraints were chosen to be targeted in order to better understand what parts of the system would be best suited for the testing and development of economic projects. Parts of the system with minimal congestion are less likely to have project solutions with B/C ratios greater than 1.0.

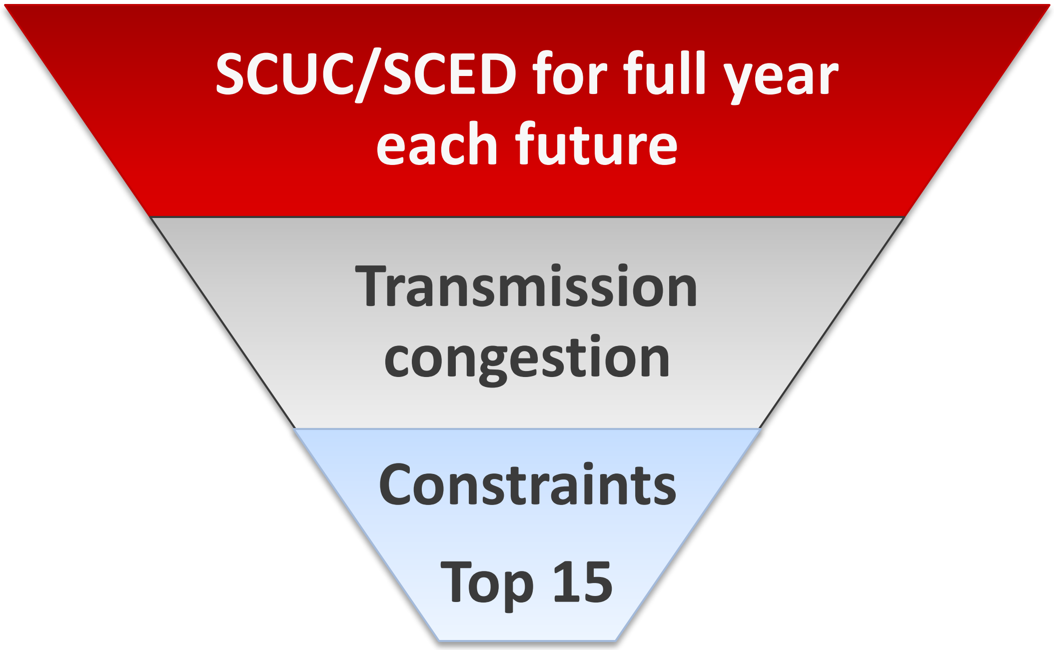


Figure 11.1: Developing Economic Needs

If generation connected to a transformer caused enough congestion at the transformer to make it a Top 15 constraint, then that economic need was ignored since the placement of the generator at a different bus of the transformer could mitigate the need.

Identification of the Top 15 constraints was conducted without the inclusion of ITP20 reliability or policy projects in the models. Therefore, some of the Top 15 needs that arose have already been addressed through reliability or policy projects. Table 11.1- Table 11.5 show the economic needs by future. All shadow prices are in $/MWh. The congestion score is the product of the binding hours and average shadow price during binding hours, to provide an average shadow price across all hours of the year.

Constraint	Constraint Area(s)	Event (Contingency)	Binding Hours	Avg Shadow Price	Congestion Score
Avoca - East Rogers 161 kV	AEPW	Shipe Road - Kings River 345 kV	5,686	$361	2,052,355
Essex - Idalia 161 kV	AECI-SWPA	New Madrid 345/161 transformer	2,518	$531	1,338,089
Harper - Milan Tap 138 kV	AEPW	Wichita - Flat Ridge 345 kV	3,770	$307	1,157,865
S1221 - S1255 161 kV	OPPD	S3459 345/161 transformer	802	$739	592,329
Sundown - Amoco 230 kV	SPS	Tuco - Amoco 345 kV	3,110	$155	480,893
Morgan - Stockton 161 kV	AECI-SWPA	Neosho - LaCygne 345 kV	2,651	$181	478,804
Springfield - Clay 161 kV	SWPA-SPRM	Huben - Morgan 345 kV	1,140	$408	465,152
Clinton - Truman 161 kV	AECI-SWPA	Neosho - LaCygne 345 kV	616	$654	402,644
Truman - N Warsaw 161 kV	SWPA-GMO	Overton - Sibley 345 kV	1,599	$237	378,579
Chaves - Eddy 230 kV	SPS	Tolk - Mescalero Ridge 345 kV	6,151	$55	337,169
Victory Hill 230/115 kV transformer	NPPD	Stegall - Wayside 230 kV	1,230	$264	324,696
Wolfforth - Terry County 115 kV	SPS	Tuco - Amoco 345 kV	395	$683	269,825
Sundown 230/115 kV transformer	SPS	Amoco - Hobbs 345 kV	2,461	$92	226,271
North Platte - Stockville 115 kV	NPPD	Gentleman - Red Willow 345 kV	892	$228	202,996
Farmington - Chamber Springs 161 kV	AEPW	Chamber Springs - Tontitown 345 kV	432	$394	170,263

Table 11.1: Future 1 Economic Needs

Constraint	Constraint Area(s)	Event (Contingency)	Binding Hours	Avg Shadow Price	Congestion Score
Harper - Milan Tap 138 kV	AEPW	Wichita - Flat Ridge 345 kV	6,051	$664	4,020,716
Avoca - East Rogers 161 kV	AEPW	Shipe Road - Kings River 345 kV	3,817	$269	1,027,345
Essex - Idalia 161 kV	AECI-SWPA	New Madrid 345/161 transformer	2,515	$361	908,618
S1221 - S1255 161 kV	OPPD	S3459 345/161 transformer	758	$892	676,165
Morgan - Stockton 161 kV	AECI-SWPA	Morgan - Brookline 345 kV	1,793	$305	546,001
Morgan - Stockton 161 kV	AECI-SWPA	Neosho - LaCygne 345 kV	2,830	$192	542,840
Sundown - Amoco 230 kV	SPS	Tuco - Amoco 345 kV	2,375	$140	333,459
Wolfforth - Terry County 115 kV	SPS	Tuco - Amoco 345 kV	545	$596	325,071
Clinton - Truman 161 kV	AECI-SWPA	Neosho - LaCygne 345 kV	796	$394	313,798
Truman - N Warsaw 161 kV	SWPA-GMO	Overton - Sibley 345 kV	1,284	$224	287,736
Southwestern - Washita 138 kV	AEPW-WFEC	Lawton Eastside - Gracemont 345 kV	3,040	$84	254,878
Sundown 230/115 kV transformer	SPS	Amoco - Hobbs 345 kV	2,606	$90	233,541
Springfield - Clay 161 kV	SWPA-SPRM	Huben - Morgan 345 kV	596	$384	229,080
Victory Hill 230/115 kV transformer	NPPD	Stegall - Wayside 230 kV	944	$221	209,082
Mingo 345/115 kV transformer	SUNC	Mingo - Setab 345 kV	2,329	$89	207,771

Table 11.2: Future 2 Economic Needs

Constraint	Constraint Area(s)	Event (Contingency)	Binding Hours	Avg Shadow Price	Congestion Score
Harper - Milan Tap 138 kV	AEPW	Wichita - Flat Ridge 345 kV	7,021	$1,186	8,323,724
Avoca - East Rogers 161 kV	AEPW	Shipe Road - Kings River 345 kV	4,107	$293	1,201,647
S1221 - S1255 161 kV	OPPD	S3459 345/161 transformer	840	$793	665,848
Truman - N Warsaw 161 kV	SWPA-GMO	Overton - Sibley 345 kV	1,857	$246	456,642
Springfield - Clay 161 kV	SWPA-SPRM	Huben - Morgan 345 kV	1,085	$392	425,618
Potter 345/230 kV transformer	SPS	Woodward EHV - Border 345 kV	3,394	$120	407,936
Wolfforth - Terry County 115 kV	SPS	Tuco - Amoco 345 kV	374	$999	373,623
Mingo 345/115 kV transformer	SUNC	Mingo - Setab 345 kV	2,702	$133	360,560
Southwestern - Washita 138 kV	AEPW-WFEC	Lawton Eastside - Gracemont 345 kV	3,781	$92	345,992
Sundown - Amoco 230 kV	SPS	Tuco - Amoco 345 kV	1,789	$146	260,770
Victory Hill 230/115 kV transformer	NPPD	Stegall - Wayside 230 kV	1,160	$224	259,497
Sundown 230/115 kV transformer	SPS	Amoco - Hobbs 345 kV	2,220	$104	231,949
Chaves - Eddy 345 kV	SPS	Mescalero Ridge - Eddy 345 kV	4,408	$46	202,486
Farmington - Chamber Springs 161 kV	AEPW	Chamber Springs - Tontitown 345 kV	395	$381	150,442
Goodyear Jct. - Northland 115 kV	WERE	Hoyt - Stranger Creek 345 kV	438	$254	111,444

Table 11.3: Future 3 Economic Needs

Constraint	Constraint Area(s)	Event (Contingency)	Binding Hours	Avg Shadow Price	Congestion Score
Harper - Milan Tap 138 kV	AEPW	Wichita - Flat Ridge 345 kV	5,569	$883	4,919,829
Avoca - East Rogers 161 kV	AEPW	Shipe Road - Kings River 345 kV	5,311	$231	1,225,180
Springfield - Clay 161 kV	SWPA-SPRM	Huben - Morgan 345 kV	1,754	$246	432,200
Essex - Idalia 161 kV	AECI-SWPA	New Madrid 345/161 transformer	2,714	$139	375,921
Southwestern - Washita 138 kV	AEPW-WFEC	Lawton Eastside - Gracemont 345 kV	2,708	$123	332,022
Jensen Tap - Jensen 138 kV	OKGE	Elk City - Gracemont 345 kV	2,638	$90	237,625
S1221 - S1255 161 kV	OPPD	S3459 345/161 transformer	520	$385	200,150
Chaves - Eddy 345 kV	SPS	Mescalero Ridge - Eddy 345 kV	6,095	$33	199,911
Potter 345/230 kV transformer	SPS	Woodward EHV - Border 345 kV	2,499	$77	192,369
Litchfield - Franklin 161 kV	WERE	Neosho - LaCygne 345 kV	4,878	$38	187,440
Tuco - Jones 230 kV	SPS	Tuco - Amoco 345 kV	5,997	$27	162,116
North Dodge - East Dodge 115 kV	SUNC	Base Case	2,818	$38	106,970
Victory Hill 230/115 kV transformer	NPPD	Stegall - Wayside 230 kV	571	$149	85,081
St. Joe - Midway 161 kV	GMO	Fairport - St. Joe 345 kV	1,397	$56	78,798
Sundown - Amoco 230 kV	SPS	Tuco - Amoco 345 kV	247	$275	67,905

Table 11.4: Future 4 Economic Needs

Constraint	Constraint Area(s)	Event (Contingency)	Binding Hours	Avg Shadow Price	Congestion Score
Essex - Idalia 161 kV	AECI-SWPA	New Madrid 345/161 transformer	4,335	$496	2,150,470
Morgan - Stockton 161 kV	AECI-SWPA	Morgan - Brookline 345 kV	2,962	$289	856,458
Harper - Milan Tap 138 kV	AEPW	Wichita - Flat Ridge 345 kV	2,548	$283	719,968
S1221 - S1255 161 kV	OPPD	S3459 345/161 transformer	859	$603	518,196
Avoca - East Rogers 161 kV	AEPW	Shipe Road - Kings River 345 kV	1,687	$240	404,994
Victory Hill 230/115 kV transformer	NPPD	Stegall - Wayside 230 kV	1,079	$341	368,291
North Platte - Stockville 115 kV	NPPD	Gentleman - Red Willow 345 kV	1,411	$234	329,620
Farmington - Chamber Springs 161 kV	AEPW	Chamber Springs - Tontitown 345 kV	605	$456	275,582
Sundown 230/115 kV transformer	SPS	Amoco - Hobbs 345 kV	1,303	$186	242,160
JEC - East Manhattan 230 kV	WERE	JEC - Summit 345 kV	1,823	$126	229,747
Blue Springs East - Duncan Road 161 kV	GMO	Pleasant Hill - Sibley 345 kV	2,436	$73	178,152
North Dodge - East Dodge 115 kV	SUNC	Base Case	3,857	$35	136,191
Haynes - North Liberal Tap 115 kV	SUNC	Conestoga - Hitchland 345 kV	3,651	$32	115,366
Truman - N Warsaw 161 kV	SWPA-GMO	Overton - Sibley 345 kV	284	$363	103,081
Tuco - Jones 230 kV	SPS	Tuco - Amoco 345 kV	3,727	$26	96,047

Table 11.5: Future 5 Economic Needs

The tables above indicate that several constraints are top 15 constraints in multiple futures. This suggests that there are some similar congestion points across all futures.

11.3: Economic Solutions

Economic projects were proposed based on their potential to mitigate congestion of the top 15 constraints and stakeholder recommendations. For each economic project, the APC for the SPP footprint was calculated with and without the proposed economic project for all 8,760 hours of 2033. The change in APC with the project in-service was considered the one-year benefit. The one-year benefit was divided by the one-year carrying charge of the project to develop a B/C ratio for each project. Any project that had a B/C ratio less than 1 was removed from further consideration. For the projects with a B/C ratio greater than 1, the 40-year B/C ratio and net benefit were computed.

While lower voltage projects (100 kV – 300 kV) were considered as solutions for reliability and policy needs, only EHV projects were tested as potential economic solutions. All EHV reliability and policy projects were included in base and change case runs for the testing of economic solutions. Although they were identified as the preferred solutions, lower voltage reliability projects will not be included in any ITP20 portfolios, and the needs are expected to be addressed in future ITP10 and ITPNT studies.

In addition to projects targeting the top 15 constraints, all EHV reliability and policy projects from Future 1 were analyzed for economic benefit.

Future 1 Economic Projects

Table 11.6 shows the economic projects that were analyzed in Future 1. When testing projects that were not already included as reliability or policy projects, all reliability and policy projects were included in the base and change cases. When testing the economic value of projects that were previously identified as reliability or policy projects, the base case included all reliability and policy projects minus the project under test, while the change case included all reliability and policy projects including the project under test. Reliability and policy projects were included in the base and change cases in order to provide a more conservative approach to calculating their benefit; if the reliability and policy projects are expected to be built in the 20 year horizon, the benefit of economic projects for that time frame should be measured with these already in the model.

Project Tested	Project Area(s)	B/C > 1.0?
New Jasper - Monett City 345 kV	AECI-EMDE	No
New JEC - Matters Corner 345 kV, new Matters Corner 345/115 kV transformer	WERE	No
New JEC - Matters Corner - Elm Creek 345 kV, new Matters Corner 345/115 kV transformer	WERE-SUNC	No
Rebuild JEC - E Manhattan N Manhattan - Elm Creek 230 kV to 345 kV	WERE-SUNC	No
New Cass - S3454 345 kV	OPPD	No
New 2nd S3459 345/161 kV transformer	OPPD	Yes
New LaCygne - Morgan 345 kV	KCPL-AECI	Yes
New Wolf Creek - Neosho 345 kV	WERE	Yes
New Morgan 345/161 kV transformer	AECI	No
New Stegall - Cherry 345 kV	WAPA-NPPD	No
New Stegall - Scottsbluff - Victory Hill 345 kV, new Stegall 345/115 transformer	WAPA-NPPD	No
New Stegall - Victory Hill 345 kV, new 345/115 kV transformer at Victory Hill	WAPA-NPPD	No
New Stegall - Victory Hill - Alliance 345 kV, new 345/115 kV transformers at Victory Hill and Alliance	WAPA-NPPD	No
New Tolk - Potter 345 kV	SPS	No
New Tolk - Amoco 345 kV	SPS	No
New Chamber Springs - S Fayetteville 345 kV, new S Fayetteville 345/161 kV transformer	AEPW	Yes
New Keystone - Red Willow 345 kV	NPPD	No
New Tolk - Tuco 345 kV	SPS	No
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new Auburn 345/115 kV transformer	WERE	No
Rebuild Spearville - Great Bend - Reno 230 kV to 345 kV	SUNC-WERE	No
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA	Yes

Table 11.6: Economic Projects Screened in Future 1

Note that LaCygne – Morgan 345 kV and Wolf Creek – Neosho 345 kV are alternative projects; each project provides a B/C ratio > 1.0 only when the other is excluded from the runs. While both projects mitigate the same reliability needs, Wolf Creek – Neosho 345 kV has the higher economic benefit and is the project included in the Future 1 portfolio (see Table 13.3 for comparison of projects).

Four Future 1 reliability projects are also economic projects. Their primary classification going forward is as economic projects. They are the only economic projects in Future 1, since no other projects screened provided a one-year B/C > 1.0. Table 11.7 shows the economic projects for Future 1.

Economic Project	Project Area(s)	Constrained Element	Miles Added/ Modified	One Year B/C
New Chamber Springs - S Fayetteville 345 kV, new S Fayetteville 345/161 kV transformer	AEPW	Farmington - Chamber Springs 161 kV	18	3.73
New Wolf Creek - Neosho 345 kV	WERE	Morgan - Stockton 161 kV, Litchfield - Franklin 161 kV, Centennial - Paola 161 kV	99	1.41
New 2nd S3459 345/161 kV transformer	OPPD	S1221 - S1255 161 kV	0	27.76

Table 11.7: Future 1 Economic Projects

Future 2 Economic Projects

Most of the top 15 economic needs in Future 2 were addressed by reliability and policy projects. This means that in addition to mitigating reliability and policy needs, these projects also captured most of the opportunities for economic benefit. Three potential projects were tested for economic benefit, with none having a one-year B/C greater than 1.0.

Project Tested	Project Area(s)	B/C > 1.0?
New Morgan 345/161 kV transformer	AECI	✗
New Tolk - Amoco 345 kV	SPS	✗
New Amoco - New Deal 345 kV	SPS	✗

Table 11.8: Economic Projects Screened in Future 2

Future 3 Economic Projects

Most of the top 15 economic needs in Future 3 were addressed by reliability and policy projects. This means that in addition to mitigating reliability and policy needs, these projects also captured most of the opportunities for economic benefit. Two potential projects were tested for economic benefit, with neither having a one-year B/C greater than 1.0.

Project Tested	Project Area(s)	B/C > 1.0?
New Amoco - New Deal 345 kV	SPS	✗
New Tolk - Amoco 345 kV	SPS	✗

Table 11.9: Economic Projects Screened in Future 3

Future 4 Economic Projects

Six potential economic projects were tested in Future 4 based on the top 15 economic needs.

Project Tested	Project Area(s)	B/C > 1.0?
New 2nd S3459 345/161 kV transformer	OPPD	✓
New LaCygne - Morgan 345 kV	KCPL-AECI	✗
New Wolf Creek - Neosho 345 kV	WERE	✗
New Tolk - Amoco 345 kV	SPS	✗
Reconductor Oneta - OEC 345 kV	AEPW	✗
Rebuild Tuco - Jones 230 kV to 345 kV, new Jones 345/230 kV transformer	SPS	✓

Table 11.10: Economic Projects Screened in Future 4

Two of the projects had a one-year B/C greater than 1.0 and were included as economic projects for Future 4.

Economic Project	Project Area(s)	Constrained Element	Miles Added/ Modified	One Year B/C
New 2nd S3459 345/161 kV transformer	OPPD	S1221 - S1255 161 kV	0	4.02
Rebuild Tuco - Jones 230 kV to 345 kV, new Jones 345/230 kV transformer	SPS	Tuco - Jones 230 kV	30	2.26

Table 11.11: Future 4 Economic Projects

Future 5 Economic Projects

Four potential economic projects were tested in Future 5 based on the top 15 economic needs.

Project Tested	Project Area(s)	B/C > 1.0?
New 2nd S3459 345/161 kV transformer	OPPD	✓
New Chamber Springs - S Fayetteville 345 kV, new S Fayetteville 345/161 kV transformer	AEPW	✗
New Keystone - Red Willow 345 kV	NPPD	✗
New Wolf Creek - Neosho 345 kV	WERE	✗

Table 11.12: Economic Projects Screened in Future 5

One of the projects had a one-year B/C greater than 1.0 and was included as an economic project for Future 5. This economic project is also a reliability project; its primary classification going forward will be as an economic project.

Economic Project	Project Area(s)	Constrained Element	Miles Added/ Modified	One Year B/C
New 2nd S3459 345/161 kV transformer	OPPD	S1221 - S1255 161 kV	0	20.80

Table 11.13: Future 5 Economic Projects

Section 12: Stability Needs and Projects

12.1: Introduction

A voltage stability assessment was conducted on the base case model (no new transmission) to assess the transfer limit (MW) due to transfer of wind west to east across the SPP footprint. Additionally, a stability analysis was conducted for the 2013 ITP20 solution set to assess system stability by examining thermal and voltage 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 the location of voltage collapse or instability. These must be determined by examining voltage performance during power transfer into a load area or across an interface.

12.2: Objectives

The objective of the 2013 ITP20 Stability Analysis is twofold:

Stability Assessment:
The stability assessment consists of a wind dispatch analysis to confirm that the dispatched wind generation in the 2013 ITP20 2023 Summer-Peak case[23] in all futures can be dispatched without the occurrence of voltage collapse or thermal violations. This will determine what is needed to avoid these violations.

Stability Analysis:
The voltage stability analysis was conducted for the final portfolio in 2013 ITP20 2023 Summer-Peak case to assess thermal and voltage violations. The results of this final stability analysis are detailed in Section 17.2: .

12.3: Stability Assessment

Stability assessments of long and short-term planning efforts by SPP Staff provided important insights into the viability and robustness of planning solutions. A wind transfer assessment was required as part of the 2013 ITP20 planning effort. Specifically, the request was made to determine the amount of wind that could be dispatched in the 2023 Summer-Peak Base Case for all the futures that will allow sufficient margin to voltage collapse. An N-1 analysis was performed involving all the 345 kV transmission lines and transformers to determine if voltage collapse and thermal violations occurred before flow limits were exceeded. Voltage collapse and thermal analysis was performed using the Voltage Security Assessment Tool (VSAT).

Methodology
The method employed to determine the amount of wind generation that could be accommodated in the ITP20 Study for all futures was accomplished in two parts:

1. Increasing wind and decreasing conventional (i.e. coal, gas, etc.) generation in the SPP footprint

[23] A 2023 summer peak model was utilized because there is not a 2033 off peak model to use. A 2023 summer peak model should have similar load to a 2033 off-peak (high wind) hour.

2. Increasing wind generation in the SPP region and increasing the load in load pockets outside of the SPP region

Table 12.1 shows the maximum capacity of wind generation per future.

FUTURE	WIND GENERATION (GW)
1	9.2
2	16.4
3	25.6
4	15.4
5	9.2

Table 12.1: Wind generation per future

To prepare for the first procedure (wind and conventional generation in the SPP Footprint), wind generation was reduced to minimum levels while conventional generation was simultaneously increased to meet SPP load requirements, and 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. All branches and transformers were monitored to detect thermal violations, overloading the elements by more than 105%.

In the second procedure (Wind generation in the SPP region and load pockets outside of the SPP region), wind in the SPP region and the load in the external areas were increased until voltage collapse or thermal violations occurred, following the same methodology presented in the first procedure.

A contingency file was created that provided outages on all branches and transformers above 300 kV, as well as all flowgate contingencies in the SPP region, per the latest NERC event file and member suggestions. Monitored elements included all interfaces, circuits, and flowgates in the SPP region that are contained in the NERC Book of Flowgates as well as those additional flowgates that were added by members.

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

The reactive power generated by the wind farms was limited to avoid unrealistic transfers due to lack of or over generation of reactive power.

In both analyses, the amount of wind transferred represented the worst case scenario in each future. Based on this assumption, the thermal violations were treated not as a need, but as an indicator of possible violations when this event occurs. In other words, all the wind generators in the SPP footprint have to be dispatched at one hundred percent of their capacity simultaneously. The main reason to only select overloads above one hundred and five percent, is to reduce the amount of indicators of violations in the system due to the unrealistic probability of maximum wind dispatch occurring. Most of the constraints detected during the stability assessment will be mitigated by projects used to mitigate economic, reliability, and policy needs. The stability needs have a reduced impact to developing projects for the 2013 ITP20 study.

The results shown in

FUTURE	TRANSFER (GW)
1	9.2
2	12.9
3	11.9
4	12.9
5	9.2

Table 12.2 summarize maximum wind generation transfers where voltage collapse occurs in the 2013 ITP20 Base Case in all futures, increasing wind generation and reducing conventional generation.

FUTURE	TRANSFER (GW)
1	9.2
2	12.9
3	11.9
4	12.9
5	9.2

Table 12.2: Wind transfers limit based on voltage collapse

12.4: Results

Additional EHV transmission lines were added in Future 3 to mitigate the voltage collapse and increase the wind transfers to the maximum transfer desired. These additions are shown in Table 12.3.

Stability Project	Project Area(s)	Miles Added/ Modified
Reconductor L.E.S. - Sunnyside 345 kV circuit 1	AEPW-OKGE	72
New L.E.S. to Sunnyside 345 kV circuit 2	AEPW-OKGE	72
New Elk City - Border 345 kV	AEPW-OKGE	41
New L.E.S. - Gracemont 345 kV circuit 2	AEPW-OKGE	36
New Potter - Elk City 345 kV	SPS-AEPW	148

Table 12.3: Future 3 Stability Projects - Line

Reactive support is also needed in all futures to increase the wind transfers and boost the voltage in the SPP area. In Future 3 specifically, the only way to sink 15 GW into the SPP area and export 10 GW of wind to external areas is by adding a substantial amount of Static VAR Compensators (SVCs) in the SPP footprint. Figure 12.1 shows the SVC additions by future, and Table 12.4 shows locations of SVC additions for all futures. Stability projects are classified as policy projects, as they are needed to facilitate wind transfer to meet renewable policy requirements.

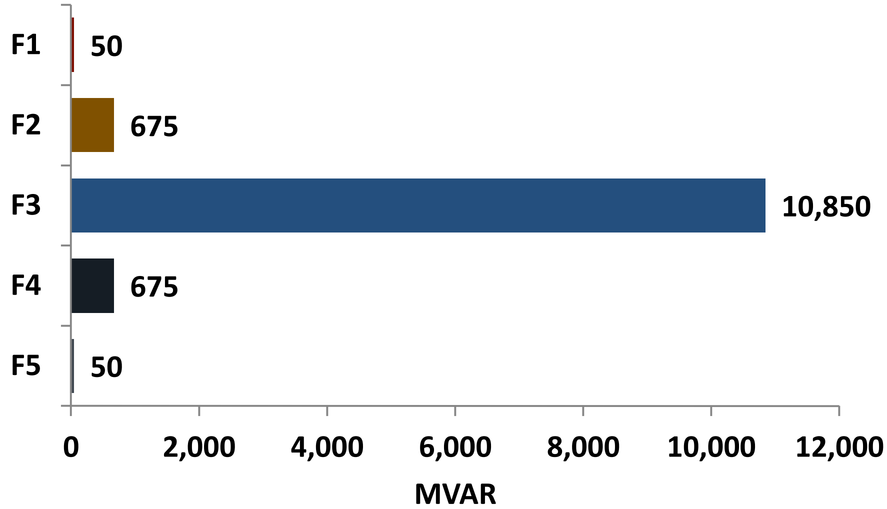


Figure 12.1: SVC Additions by Future

Location of SVC Addition	Project Area	MVAR	Future(s)
Elk City 345 kV	AEPW	200	F2, F4
Elk City 345 kV	AEPW	850	F3
Beaver Co 345 kV	SPS	650	F3
Cherry Co 345 kV	NPPD	500	F3
Conestoga 345 kV	SPS	400	F3
Finney 345 kV	SPS	200	F2, F3, F4
Gracemont 345 kV	OKGE	600	F3
Hitchland 345 kV	SPS	350	F3
Holt Co 345 kV	NPPD	600	F3
Mingo 345 kV	SUNC	200	F2, F3, F4
Shamrock 138 kV	AEPW	25	F3
Spearville 345 kV	SUNC	1000	F3
Tuco 345 kV	SPS	500	F3
Victory Hill 230 kV	NPPD	50	F1
Victory Hill 230 kV	NPPD	25	F3
Victory Hill 230 kV	NPPD	75	F2, F4
Woodring 345 kV	OKGE	700	F3
Woodward EHV 345 kV	OKGE	1200	F3
Fort Smith 500 kV	OKGE	25	F3
Mathewson 345 kV	OKGE	1000	F3
Franks 345 kV	AECI	-200	F3
AEP GBE HVDC 345 kV	AEP	650	F3
SPP GBE HVDC 345 kV	SUNC	1400	F3
Thomas Hill 22 kV	AECI	200	F3
WPL City 69 kV	AECI	-50	F3
Purdy South	EMDE	25	F3

Table 12.4: Stability Projects - SVC

Reliability and policy needs in Future 3 were mitigated with reliability and policy projects; however, this specific Future indicated the need for a 765 kV loop in the SPP footprint if we are to dispatch 25 GW of wind simultaneously while avoiding a high number of SVCs. The SVCs indicate the need for more transmission lines in this scenario. However, due to the aggressive nature of this stability analysis, in which all wind is gradually ramped up to 100% capacity factor, SVC's are utilized here rather than additional transmission.

The wind dispatch in the 2013 ITP20 Future 1 is feasible from a voltage stability viewpoint. There was no voltage instability in the load areas in Future 1 within SPP and all the wind transfers from west to east reached the maximum capacity without voltage collapse.

Section 13: Future Portfolios

Reliability, policy, and economic projects for each future were grouped together into portfolios unique to each future. In assessing needs and project solutions, there was some overlap among the classification of projects. Some reliability projects were also good economic projects, for example, because relieving significant congestion of a single constraint can mitigate a reliability problem and provide significant economic benefit. Some policy projects were also economic projects, because relieving congestion of wind generation can enable renewable policy mandates to be met, and provide significant economic benefit due to cheaper wind resources displacing more expensive generation. Despite this overlap among the classification of certain projects, each project was classified as primarily reliability, policy, or economic, based on the primary need it targets, and the primary benefit it provides.

13.1: Project Solutions from Previous ITP Studies

Many of the project solutions that were developed matched approved solutions from previous ITP studies that did not receive NTCs. Projects that were issued ATP's in the 2012 ITP10 were not included in the base case model for the 2013 ITP20. As a result, many of the same needs and solutions arose again in the 2013 ITP20. Table 13.1 shows 2013 ITP20 projects that were included in at least one future for which an equivalent project was included in the 2012 ITP10 approved portfolio and received an ATP.

2013 ITP20 Solution	Future(s)	2012 ITP10 Approved ATP Solution
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	F1, F2, F3, F5	Reconductor Chamber Springs - Farmington 161 kV
New Welsh - Lake Hawkins 345 kV, new 345/138 kV transformer at Lake Hawkins	F3	New Welsh - Lake Hawkins 345 kV, new 345/138 kV transformer at Lake Hawkins
Replace wavetrap for Prairie Lee - Blue Springs South 161 kV	F1, F4	Reconductor/substation equipment upgrade for Prairie Lee - Blue Springs 161 kV
Reconductor Harper - Milan Tap - Clearwater 138 kV	F1, F5	Reconductor Harper - Milan Tap - Clearwater 138 kV
Reconductor Woodward to Windfarm 138kV	F3, F5	Reconductor/substation equipment upgrade for Woodward - Windfarm 138 kV

Table 13.1: 2013 ITP20 Projects with Equivalent 2012 ITP10 Approved Solutions

Table 13.2 shows 2013 ITP20 projects that were included in at least one future for which an equivalent project was included in the 2010 ITP20 approved Cost Effective Plan.

2013 ITP20 Solution	Future(s)	2010 ITP20 Approved Solution
New Potter - Tolk 345 kV	F2, F3, F4	New Potter - Tolk 345 kV
New S3740 - S3454 345 kV	F1, F2, F3, F5	New S3740 - S3454 345 kV
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new 345/115 kV transformer at Auburn	F1, F3	New JEC - Iatan 345 kV
New Mingo - Post Rock 345 kV double circuit	F2, F3	New Mingo - Post Rock 345 kV

Rebuild Spearville - Great Bend - Circle - Reno 230 kV to 345 kV double circuit, add 345/230 transformers at Great Bend and Circle	F2, F4	New Spearville - Mullergren - Circle - Reno 345 kV, new Mullergren and Circle 345/230 transformers
New S3459 345/161 kV transformer	F1, F2, F3, F4, F5	New S3459 345/161 kV transformer
New Keystone - Red Willow 345 kV	F1, F2	New Keystone - Ogallala 345 kV, new 345/115 kV transformer at Ogallala
New Woodward - Woodring 345 kV double circuit	F2, F3	New Woodward - Woodring 345 kV
Reconductor Grand Island - Holt 345 kV	F3	Reconductor Grand Island - Wheeler 345 kV

Table 13.2: 2013 ITP20 Projects with Equivalent 2010 ITP20 Approved Solutions

13.2: Treatment of Lower Voltage Solutions

As described in Section 8.2: , lower voltage solutions (100 kV – 300 kV) were considered and developed alongside EHV solutions to mitigate reliability and policy needs. However, since the final ITP20 expansion plan is intended to consist of primarily EHV solutions, the lower voltage solutions (with the exception of Clinton – Truman – N Warsaw 161 kV reconductor) have been left out of the Future Portfolios and the final Consolidated Portfolio. The needs they are targeting will be addressed in future ITP10 and ITPNT studies, should they continue to arise in those studies.

Seams projects provide an opportunity to distribute the cost of a transmission project beyond the SPP region if it provides value to a neighboring transmission provider. Therefore, the Clinton – Truman – N Warsaw 161 kV reconductor project is included in the Future Portfolios and the final Consolidated Portfolio. This project provides SPP with an additional opportunity to collaborate with one of our seams neighbors to address a joint need.

13.3: Future 1 Portfolio

Reliability, policy, and economic projects developed for Future 1 were grouped together into a single Future 1 Grouping D portfolio.

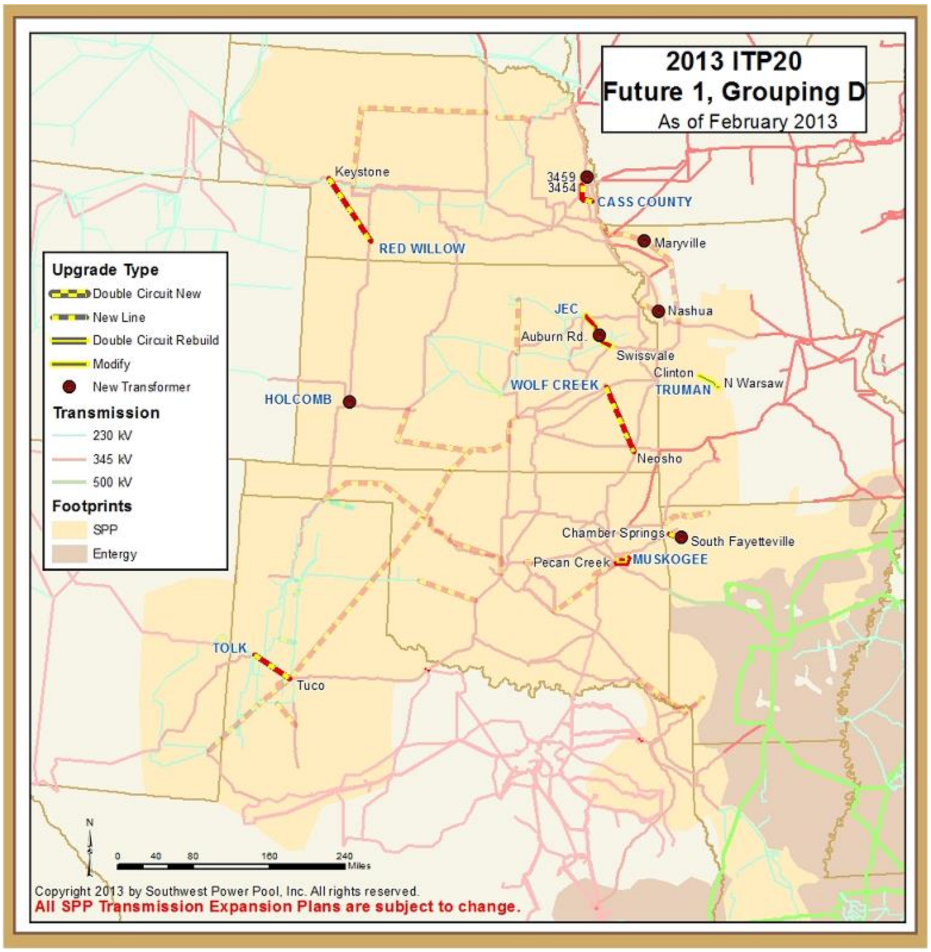


Figure 13.1: Future 1 Grouping D

Future 1 Grouping D

Total Cost: $560M
Reliability Cost: $396M
Policy Cost: $0
Economic Cost: $164M

Total Mileage: 436
Reliability Miles: 319
Policy Miles: 0
Economic Miles: 117

Total Transformers: 6

Unlike the other futures, Future 1 showed minimal need for any policy projects due to the lower forecasted wind levels. The only policy project that was needed was a reconductor of the Harper – Milan Tap – Clearwater 138 kV system, and this project was left out of the Future 1 portfolio because it is a lower voltage solution.

In the Future 1 analysis, LaCygne – Morgan 345 kV and Wolf Creek – Neosho 345 kV both mitigated multiple reliability needs and provided economic benefit when tested independently from each other, as shown in Table 13.3.

		Wolf Creek - Neosho 345 kV	LaCygne - Morgan 345 kV
Estimated Length		99 miles	118 miles
Reliability	Mitigates Paolo - Centennial 161 ftlo LaCygne - Neosho 345	Y	Y
	Mitigates Franklin - Litchfield 161 ftlo LaCygne - Neosho 345	Y	Y
	Mitigates Morgan - Stockton 161 ftlo LaCygne - Neosho 345	Y	Y
Economic	40-Year B/C	2.94	2.25
	40-Year Net Benefit	$366M	$282M

Table 13.3: Comparison of Wolf Creek – Neosho and LaCygne – Morgan Projects

Individually LaCygne – Morgan 345 kV and Wolf Creek – Neosho 345 kV are each cost effective solutions to mitigate multiple reliability issues and provide economic value. However, both projects are not needed concurrently. Wolf Creek – Neosho 345 kV was chosen for the Future 1 portfolio because it provided a greater economic benefit. However, LaCygne – Morgan 345 kV is a seams project, and would provide the potential for reduced costs due to cost sharing with our seams neighbor, AECI. The LaCygne – Morgan 345 kV project also avoids environmentally sensitive regions in Southeast Kansas. SPP has reviewed this project with AECI, and AECI will evaluate the value this project provides to AECI. Although Wolf Creek – Neosho 345 kV is included as the preferred solution in the 2013 ITP20 study, the LaCygne – Morgan 345 kV alternative project is likely to be assessed as well in future studies.

Table 13.4 shows details for all Future 1 portfolio projects.

Project	Area(s)	Type	Mileage	Cost
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Economic	18	$33,895,800
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Economic	31	$16,784,175
New Maryville 345/161 kV transformer	GMO-AECI	Reliability	0	$12,600,000
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Reliability	0	$12,600,000
New Keystone - Red Willow 345 kV	NPPD	Reliability	110	$130,141,000
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Reliability	23	$20,408,475
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Reliability	16	$14,197,200
New 2nd S3459 345/161 kV transformer	OPPD	Economic	0	$12,600,000
New Wolf Creek - Neosho 345 kV line	WERE	Economic	99	$117,126,900
New Tolk - Tuco 345 kV	SPS	Reliability	64	$75,718,400
New 2nd Holcomb 345/115 kV transformer	SUNC	Reliability	0	$12,600,000
New S3740 - S3454 345 kV	OPPD	Reliability	28	$33,126,800
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new Auburn 345/115 kV transformer	WERE	Reliability	47	$68,205,700
Total			436	$560,004,450

Table 13.4: Future 1 Portfolio Projects

13.4: Future 2 Portfolio

Reliability, policy, and economic projects developed for Future 2 were grouped together into a single Future 2 Grouping D portfolio.

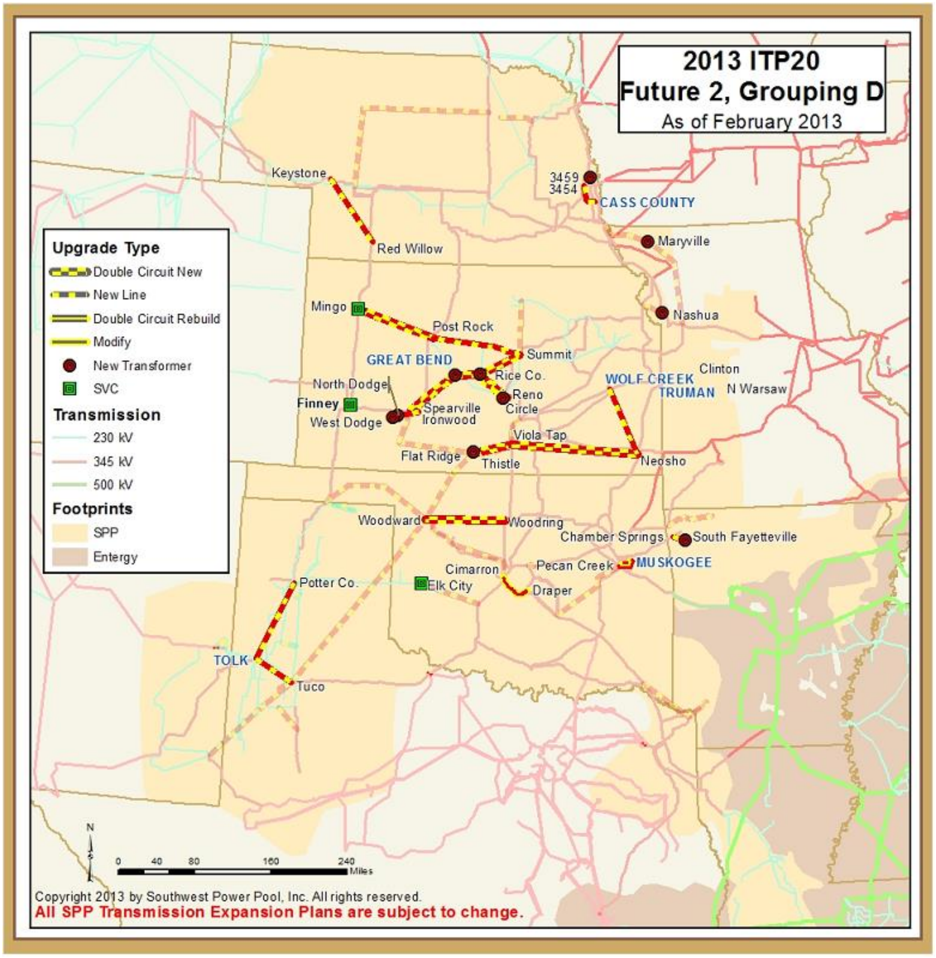


Figure 13.2: Future 2 Grouping D

Future 2 Grouping D

<u>Total Cost: $2.5B</u>
Reliability Cost: $642M
Policy Cost: $1.8B
Economic Cost: $0

<u>Total Mileage: 2,002</u>
Reliability Miles: 536
Policy Miles: 1,466
Economic Miles: 0

Total Transformers: 10

Future 2 had a similar number of reliability projects as Futures 1 and 3. However, Future 2 had significantly more policy projects than Future 1, with over 1,300 miles of policy project upgrades at a cost of $1.7B. These upgrades are needed to deliver the 16 GW of projected Future 2 wind within the SPP system to load centers.

Table 13.5 shows details for all Future 2 portfolio projects.

Project	Area(s)	Type	Mileage	Cost
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Reliability	18	$33,895,800
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Reliability	31	$16,784,175
New Maryville 345/161 kV transformer	GMO-AECI	Reliability	0	$12,600,000
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Reliability	0	$12,600,000
New Keystone - Red Willow 345 kV	NPPD	Reliability	110	$130,141,000
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Reliability	23	$20,408,475
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Reliability	16	$14,197,200
New 2nd S3459 345/161 kV transformer	OPPD	Reliability	0	$12,600,000
New Wolf Creek - Neosho 345 kV line	WERE	Reliability	99	$117,126,900
New Tolk - Tuco 345 kV	SPS	Reliability	64	$75,718,400
New S3740 - S3454 345 kV	OPPD	Reliability	28	$33,126,800
Elk City 345 kV - 200 MVAR addition	AEPW	Policy	0	$6,000,000
Rebuild Spearville - Great Bend - Circle - Reno 230 kV as Spearville - Great Bend - Rice - Circle - Reno 345 kV double circuit, add 345/230 transformers at Great Bend, Circle, and Rice	MIDW-WERE-SUNC	Policy	273	$361,235,878
New Rice - Summit 345 kV double circuit	MIDW-WERE	Policy	120	$141,972,000
New Woodward - Woodring 345 kV double circuit	OKGE	Policy	204	$241,352,400
New Thistle - Viola Tap 345 kV double circuit	SUNC-WERE	Policy	90	$106,479,000
New Thistle - Flat Ridge 345 kV, new Flat Ridge 345/138 kV transformer	SUNC	Policy	5	$18,870,430
New Ironwood - North Dodge 345 kV, new North Dodge 345/115 kV transformer	SUNC	Policy	16	$31,056,360
New Mingo - Post Rock 345 kV double circuit	SUNC-MIDW	Policy	210	$248,451,000
New North Dodge - West Dodge 345 kV, new West Dodge 345/115 kV transformer	SUNC	Policy	10	$24,431,000
New Viola Tap - Neosho 345 kV double circuit	WERE	Policy	426	$504,000,600
Finney 345 kV - 200 MVAR addition	SPS	Policy	0	$6,000,000
Mingo 345 kV - 200 MVAR addition	SUNC	Policy	0	$6,000,000
New Summit - Post Rock 345 kV	MIDW-WERE	Policy	112	$132,507,200
Replace wavetraps for Cimarron - Draper 345 kV	OKGE	Reliability	36	$31,943,700
New Potter - Tolk 345 kV	SPS	Reliability	111	$131,324,100
Total			2,002	$2,470,822,418

Table 13.5: Future 2 Portfolio Projects

13.5: Future 3 Portfolio

Two different groupings of reliability, policy, and economic projects were developed to meet the needs of Future 3. The Future 3 Grouping C portfolio consists solely of AC projects, while Future 3 Grouping D includes two HVDC projects, in addition to AC projects. These HVDC projects are policy projects, and led to a reduction of the AC policy projects needed to export wind in Grouping C.

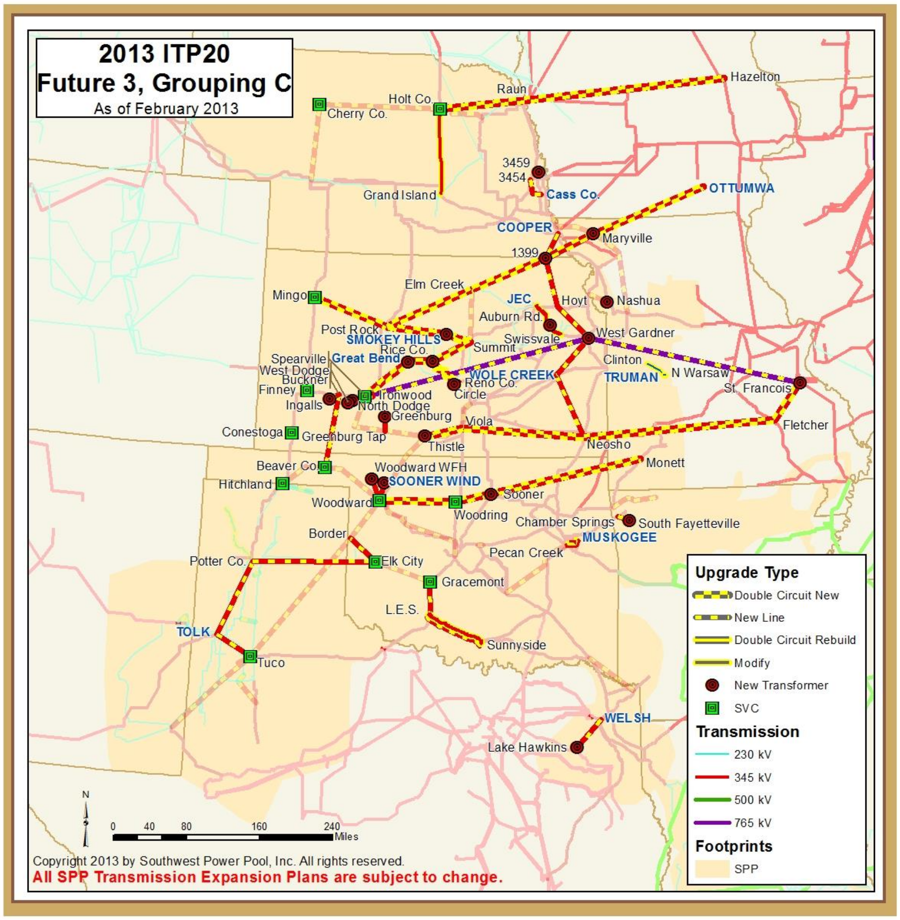


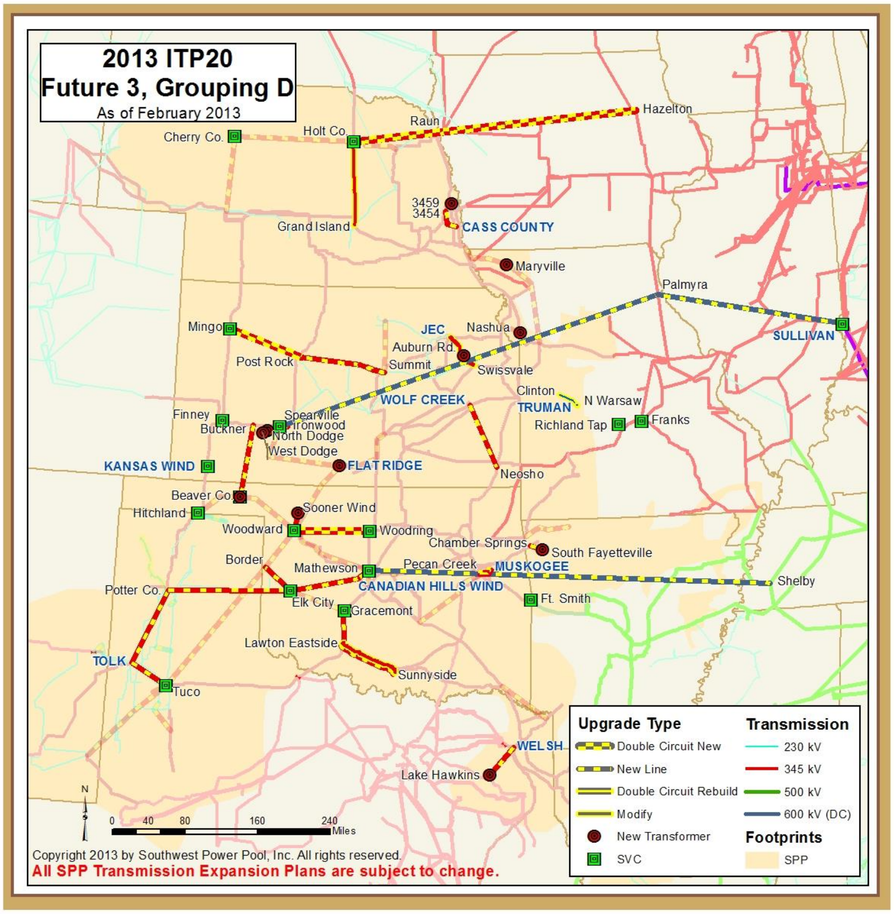
Figure 13.3: Future 3 Grouping C

Future 3 Grouping C

<u>Total Cost: $9.0B</u>
Reliability Cost: $937M
Policy Cost: $8.05B
Economic Cost: $0

<u>Total Mileage: 6,766</u>
Reliability Miles: 762
Policy Miles: 6,004
Economic Miles: 0

Total Transformers: 22



Future 3 Grouping D

<u>Total Cost: $7.5B</u>
Reliability Cost: $937M
Policy Cost: $6.59B
Economic Cost: $0

<u>Total Mileage: 3,904</u>
Reliability Miles: 762
Policy Miles: 3,140
Economic Miles: 0

Total Transformers: 11

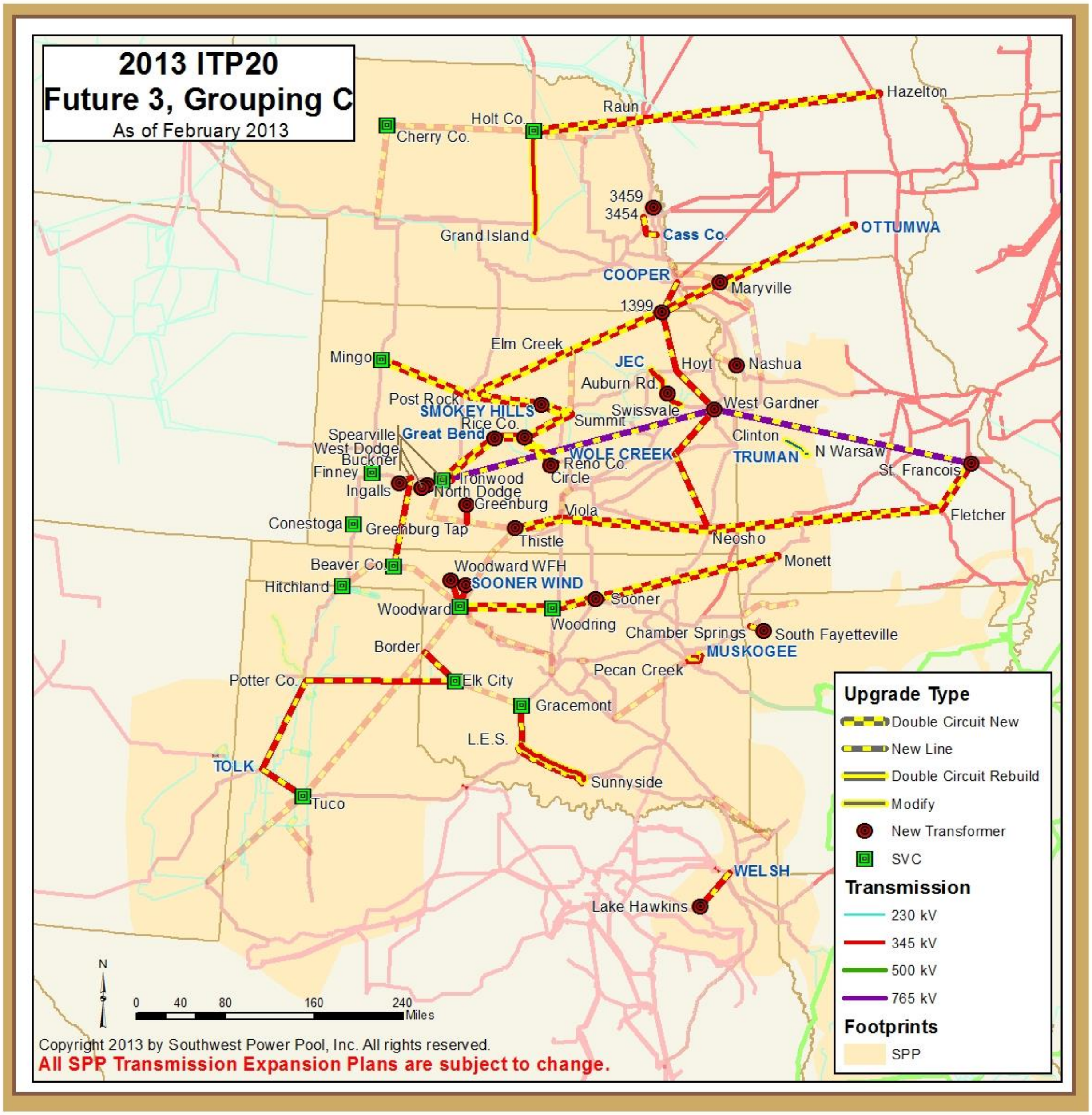
Figure 13.4: Future 3 Grouping D

The economic benefits and costs of the policy projects in Groupings C and D were analyzed, and are shown in Table 13.6:

	Grouping C	Grouping D
40-Year NPV Cost	$8.0B	$6.6B
40-Year NPV Benefit	$10.3B	$12.7B
40-Year B/C Ratio	1.28	1.93

Table 13.6: Comparison of Future 3 Groupings C and D

In discussing different solutions with ESWG, there was agreement to include both Grouping C and D as Future 3 portfolios in the 2013 ITP20 report. Both are viable options, and plans are shown considering different technologies (AC and HVDC). The Future 3 portfolios have the most transmission projects and highest cost of any Future



portfolio. While this Future resulted in a similar number of reliability needs and projects as Futures 1 and 2, it has significantly more policy projects than any other Future. These projects are required to mitigate significant curtailment of the 25 GW of installed wind, and to enable the export of 10 GW of that installed wind. Although there are no projects classified as economic projects, the numerous policy projects are projecting significant economic benefit as a whole, showing a 40-year Net Present Value (NPV) benefit of $10 – 13 billion.

Table 13.7 shows details for all Future 3 Grouping C projects, and Table 13.8 shows details for all Future 3 Grouping D projects.

Project	Area(s)	Type	Mileage	Cost
New Welsh - Lake Hawkins 345 kV, new 345/138 kV transformer at Lake Hawkins	AEPW	Reliability	55	$77,670,500
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Reliability	18	$33,895,800
Replace CT for Lawton Eastside - Sunnyside 345 kV	AEPW-OKGE	Reliability	72	$63,887,400
New Maryville 345/161 kV transformer	GMO-AECI	Reliability	0	$12,600,000
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Reliability	31	$16,784,175
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Reliability	0	$12,600,000
New Summit - Post Rock 345 kV	MIDW-WERE	Reliability	112	$132,507,200
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Reliability	23	$20,408,475
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Reliability	16	$14,197,200
New 2nd S3459 345/161 kV transformer	OPPD	Reliability	0	$12,600,000
New Potter - Tolk 345 kV	SPS	Reliability	111	$131,324,100
New Buckner - Beaver 345 kV, new Beaver 345/115 kV transformer	SUNC-SPS	Reliability	86	$114,346,600
New Tolk - Tuco 345 kV	SPS	Reliability	64	$75,718,400
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new Auburn 345/115 kV transformer	WERE	Reliability	47	$68,205,700
New Wolf Creek - Neosho 345 kV line	WERE	Reliability	99	$117,126,900
New S3740 - S3454 345 kV	OPPD	Reliability	28	$33,126,800
Reconductor Holt - Grand Island 345 kV	NPPD	Policy	85	$75,156,428
New Holt - Raun - Hazelton 345 kV double circuit	NPPD-MEC-ALTW	Policy	842	$996,170,200
New Woodward - Woodring 345 kV double circuit	OKGE	Policy	204	$241,352,400
New Thistle - Flat Ridge 345 kV, new Flat Ridge 345/138 kV transformer	SUNC	Policy	5	$18,870,430
New Ironwood - North Dodge 345 kV, new North Dodge 345/115 kV transformer	SUNC	Policy	16	$31,056,360
New Mingo - Post Rock 345 kV double circuit	SUNC-MIDW	Policy	210	$248,451,000
New North Dodge - West Dodge 345 kV, new West Dodge 345/115 kV transformer	SUNC	Policy	10	$24,431,000
New Woodward - Sooner Wind 345 kV, new 345/138 kV transformer at Sooner Wind	OKGE	Policy	12	$26,880,017
New Woodring - Monett 345 kV double circuit	OKGE - EMDE	Policy	594	$702,761,400
New Rice - Summit 345 kV double circuit	MIDW - WERE	Policy	120	$141,972,000
Reconductor L.E.S. - Sunnyside 345 kV circuit 1	AEPW-OKGE	Policy	72	$63,505,850
New L.E.S. to Sunnyside 345 kV circuit 2	AEPW-OKGE	Policy	72	$84,674,467
New Elk City - Border 345 kV	AEPW-OKGE	Policy	41	$48,270,480
New L.E.S. - Gracemont 345 kV circuit 2	AEPW-OKGE	Policy	36	$42,638,924
New Potter - Elk City 345 kV	SPS-AEPW	Policy	148	$175,098,800
New Cooper - S1399 - Hoyt - West Gardner 345 kV, new 345/161 kV transformer at S1399	NPPD - OPPD - WERE - KCPL	Policy	152	$192,431,200
New Woodward - Woodward WFH 345 kV, new 345/138 kV transformer at Woodward WFH	WFEC - OKGE	Policy	24	$40,994,400

New Post Rock - Elm Creek - S1399 - Maryville - Ottumwa 345 kV double circuit	SUNC - OPPD - GMO - MIDW - ALTW	Policy	930	$1,100,283,000
New Viola Tap - Neosho - Fletcher - St. Francois 345 kV double circuit	WERE - AECI	Policy	1,060	$1,254,086,000
New West Gardner - Wolf Creek 345 kV	WERE - KCPL	Policy	75	$88,732,500
New Thistle - Viola Tap 345 kV double circuit	SUNC - WERE	Policy	90	$106,479,000
New Spearville - West Gardner - St. Francois 765 kV, new 765/345 kV transformers at Spearville, West Gardner, and St. Francois	SUNC - KCPL - AMMO	Policy	590	$1,451,887,500
New Greensburg Tap on Clark Co - Thistle 345 kV double circuit, new Greenburg - Greensburg Tap 345 kV double circuit, new 345/115 kV transformer at Greensburg	SUNC	Policy	220	$69,388,800
New Buckner - Ingalls 345 kV, new 345/115 kV transformer at Ingalls	SUNC	Policy	12	$26,797,200
New Summit - Smoky Hills - Post Rock 345 kV circuit 2, new 345/230 kV transformer at Smoky Hills	SUNC - MIDW - WERE	Policy	112	$145,107,200
Rebuild Spearville - Great Bend - Circle - Reno 230 kV as Spearville - Great Bend - Rice - Circle - Reno 345 kV double circuit, add 345/230 kV transformers at Great Bend, Rice, Circle	MIDW - WERE - SUNC	Policy	273	$361,235,878
Cherry Co 345 kV - 575 MVAR addition	NPPD	Policy	0	$17,250,000
Holt Co 345 kV - 825 MVAR addition	NPPD	Policy	0	$24,750,000
Woodward 345 kV - 1,500 MVAR addition	OKGE	Policy	0	$45,000,000
Hitchland 345 kV - 425 MVAR addition	SPS	Policy	0	$12,750,000
Elk City 345 kV - 850 MVAR addition	AEPW	Policy	0	$25,500,000
Woodring 345 kV - 1,000 MVAR addition	OKGE	Policy	0	$30,000,000
Gracemont 345 kV - 1,000 MVAR addition	OKGE	Policy	0	$30,000,000
Finney 345 kV - 200 MVAR addition	SPS	Policy	0	$6,000,000
Conestoga 345 kV - 425 MVAR addition	SPS	Policy	0	$12,750,000
Tuco 345 kV - 600 MVAR addition	SPS	Policy	0	$18,000,000
Beaver Co 345 kV - 975 MVAR addition	SPS	Policy	0	$29,250,000
Mingo 345 kV - 200 MVAR addition	SUNC	Policy	0	$6,000,000
Spearville 345 kV - 1000 MVAR addition	SUNC	Policy	0	$30,000,000
Total			6,767	$8,982,961,684

Table 13.7: Future 3 Grouping C Projects

Project	Area(s)	Type	Mileage	Cost
New Welsh - Lake Hawkins 345 kV, new 345/138 kV transformer at Lake Hawkins	AEPW	Reliability	55	$77,670,500
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Reliability	18	$33,895,800
Replace CT for Lawton Eastside - Sunnyside 345 kV	AEPW-OKGE	Reliability	72	$63,887,400
New Maryville 345/161 kV transformer	GMO-AECI	Reliability	0	$12,600,000
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Reliability	31	$16,784,175
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Reliability	0	$12,600,000
New Summit - Post Rock 345 kV	MIDW-WERE	Reliability	112	$132,507,200
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Reliability	23	$20,408,475
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Reliability	16	$14,197,200
New 2nd S3459 345/161 kV transformer	OPPD	Reliability	0	$12,600,000
New Potter - Tolk 345 kV	SPS	Reliability	111	$131,324,100
New Buckner - Beaver 345 kV, new Beaver 345/115 kV transformer	SUNC-SPS	Reliability	86	$114,346,600
New Tolk - Tuco 345 kV	SPS	Reliability	64	$75,718,400
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new Auburn 345/115 kV transformer	WERE	Reliability	47	$68,205,700
New Wolf Creek - Neosho 345 kV line	WERE	Reliability	99	$117,126,900
New S3740 - S3454 345 kV	OPPD	Reliability	28	$33,126,800
Reconductor Holt - Grand Island 345 kV	NPPD	Policy	85	$75,156,428
New Holt - Raun - Hazelton 345 kV double circuit	NPPD-MEC-ALTW	Policy	842	$996,170,200
New Woodward - Woodring 345 kV double circuit	OKGE	Policy	204	$241,352,400
New Thistle - Flat Ridge 345 kV, new Flat Ridge 345/138 kV transformer	SUNC	Policy	5	$18,870,430
New Ironwood - North Dodge 345 kV, new North Dodge 345/115 kV transformer	SUNC	Policy	16	$31,056,360
New Mingo - Post Rock 345 kV double circuit	SUNC-MIDW	Policy	210	$248,451,000
New North Dodge - West Dodge 345 kV, new West Dodge 345/115 kV transformer	SUNC	Policy	10	$24,431,000
New Woodward - Sooner Wind 345 kV, new 345/138 kV transformer at Sooner Wind	OKGE	Policy	12	$26,880,017
New Elk City - Canadian Hills Wind - Mathewson 345 kV	OKGE - AEPW	Policy	114	$134,873,400
New Mathewson - Shelby 600 kV DC bi-pole	OKGE - TVA	Policy	515	$1,730,000,000
New Spearville - Palmyra Tap - Sullivan 600 kV DC bi-pole	SUNC - AMMO - AEPW	Policy	760	$2,320,000,000
Reconductor L.E.S. - Sunnyside 345 kV circuit 1	AEPW-OKGE	Policy	72	$63,505,850
New L.E.S. to Sunnyside 345 kV circuit 2	AEPW-OKGE	Policy	72	$84,674,467
New Elk City - Border 345 kV	AEPW-OKGE	Policy	41	$48,270,480
New L.E.S. - Gracemont 345 kV circuit 2	AEPW-OKGE	Policy	36	$42,638,924
New Potter - Elk City 345 kV	SPS-AEPW	Policy	148	$175,098,800
Elk City 345 kV - 850 MVAR addition	AEPW	Policy	0	$25,500,000
Beaver Co 345 kV - 650 MVAR addition	SPS	Policy	0	$19,500,000
Cherry Co 345 kV - 500 MVAR addition	NPPD	Policy	0	$15,000,000

Conestoga 345 kV - 400 MVAR addition	SPS	Policy	0	$12,000,000
Finney 345 kV - 200 MVAR addition	SPS	Policy	0	$6,000,000
Gracemont 345 kV - 600 MVAR addition	OKGE	Policy	0	$18,000,000
Hitchland 345 kV - 350 MVAR addition	SPS	Policy	0	$10,500,000
Holt Co 345 kV - 600 MVAR addition	NPPD	Policy	0	$18,000,000
Mingo 345 kV - 200 MVAR addition	SUNC	Policy	0	$6,000,000
Spearville 345 kV - 1,000 MVAR addition	SUNC	Policy	0	$30,000,000
Tuco 345 kV - 500 MVAR addition	SPS	Policy	0	$15,000,000
Woodring 345 kV - 700 MVAR addition	OKGE	Policy	0	$21,000,000
Woodward EHV 345 kV - 1,200 MVAR addition	OKGE	Policy	0	$36,000,000
Fort Smith 500 kV - 25 MVAR addition	OKGE	Policy	0	$750,000
Mathewson 345 kV - 1,000 MVAR addition	OKGE	Policy	0	$30,000,000
Franks 345 kV - (-200) MVAR addition	AECI	Policy	0	$6,000,000
AEP GBE HVDC 345 kV - 650 MVAR addition	AEP	Policy	0	$19,500,000
SPP GBE HVDC 345 kV - 1,400 MVAR addition	SUNC	Policy	0	$42,000,000
Total			3,904	$7,529,179,006

Table 13.8: Future 3 Grouping D Projects

13.6: Future 4 Portfolio

Reliability, policy, and economic projects developed for Future 4 were grouped together into a single Future 4 Grouping C portfolio.

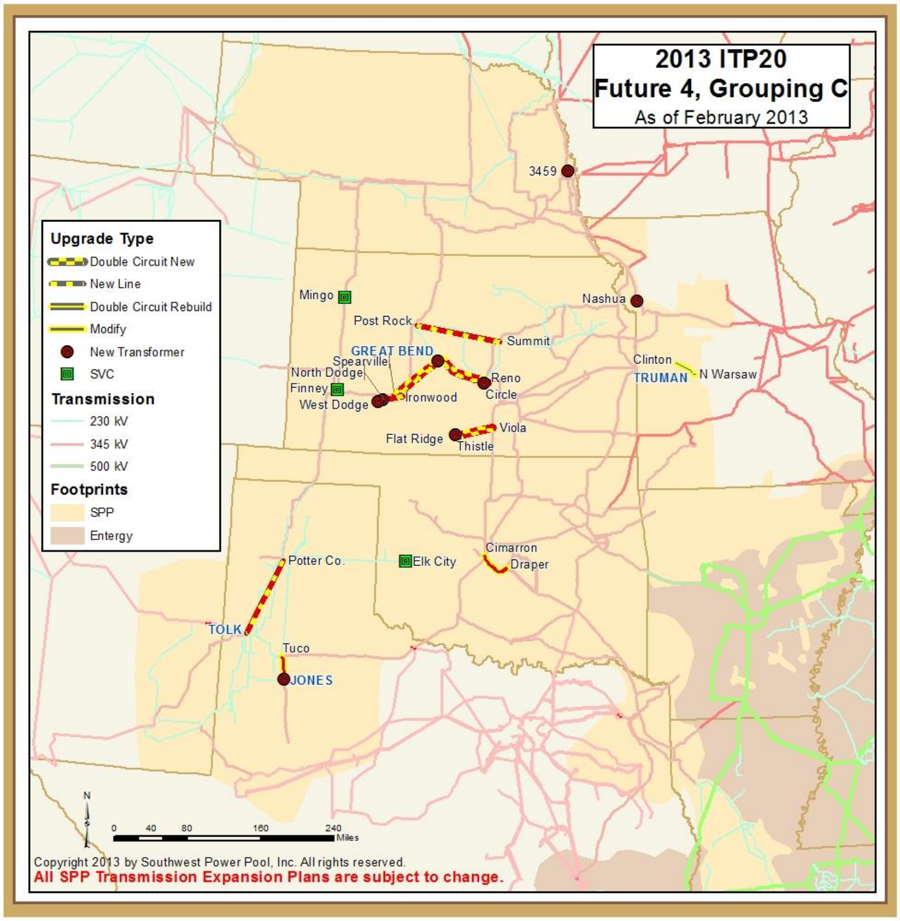


Figure 13.5: Future 4 Grouping C

Future 4 Grouping C

<u>Total Cost: $926M</u>
Reliability Cost: $325M
Policy Cost: $540M
Economic Cost: $61M

<u>Total Mileage: 708</u>
Reliability Miles: 290
Policy Miles: 388
Economic Miles: 30

Total Transformers: 8

Future 4 has 15 GW of wind installed in SPP, very similar to Future 2. As a result, there are more policy projects in this future than there are in the Business as Usual future. However, Future 4 has fewer policy projects than Futures 2 and 3, and has fewer reliability projects than Futures 1, 2, and 3. The driver behind fewer needs and projects in Future 4 is the more aggressive demand response and energy efficiency programs assumed in this future, resulting in decreases in peak load and energy. With decreased load and decreased generation running in Future 4, there is less congestion.

Table 13.9 shows details for all Future 4 portfolio projects.

Project	Area(s)	Type	Mileage	Cost
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Reliability	31	$16,784,175
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Reliability	0	$12,600,000
New Summit - Post Rock 345 kV	MIDW-WERE	Reliability	112	$132,507,200
Replace wavetraps for Cimarron - Draper 345 kV	OKGE	Reliability	36	$31,943,700
New Potter - Tolk 345 kV	SPS	Reliability	111	$131,324,100
New Ironwood - North Dodge 345 kV, new North Dodge 345/115 kV transformer	SUNC	Policy	16	$31,056,360
New North Dodge - West Dodge 345 kV, new West Dodge 345/115 kV transformer	SUNC	Policy	10	$24,431,000
New Thistle - Flat Ridge 345 kV, new Flat Ridge 345/138 kV transformer	SUNC	Policy	5	$18,870,430
New Thistle - Viola Tap 345 kV double circuit	SUNC-WERE	Policy	90	$106,479,000
Rebuild Spearville - Great Bend - Circle - Reno 230 kV as Spearville - Great Bend - Circle - Reno 345 kV double circuit, add 345/230 transformers at Great Bend and Circle	WERE-SUNC	Policy	267	$341,560,940
Elk City 345 kV - 200 MVAR addition	AEPW	Policy	0	$6,000,000
Finney 345 kV - 200 MVAR addition	SPS	Policy	0	$6,000,000
Mingo 345 kV - 200 MVAR addition	SUNC	Policy	0	$6,000,000
New 2nd S3459 345/161 kV transformer	OPPD	Economic	0	$12,600,000
Rebuild Tuco - Jones 230 kV to 345 kV, new Jones 345/230 kV transformer	SPS	Economic	30	$48,093,000
Total			708	$926,249,905

Table 13.9: Future 4 Portfolio Projects

13.7: Future 5 Portfolio

Reliability, policy, and economic projects developed for Future 5 were grouped together into a single Future 5 Grouping A portfolio.

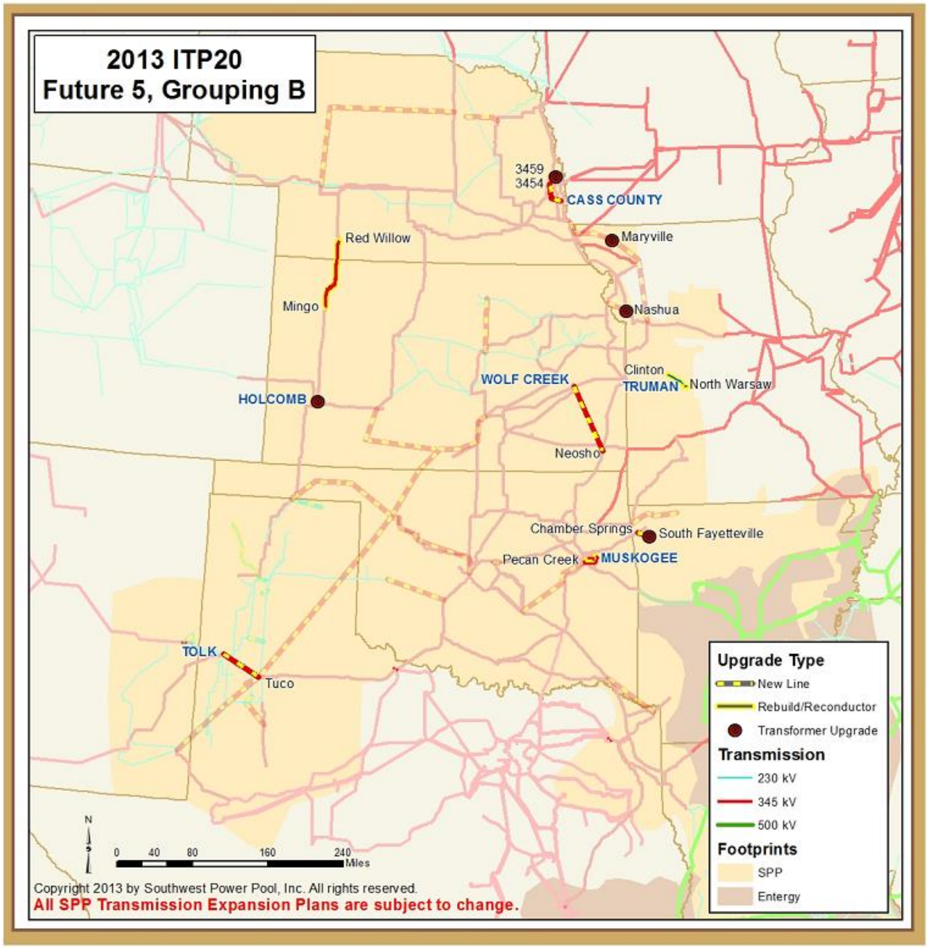


Figure 13.6: Future 5 Grouping B

Future 5 Grouping B

Total Cost: $429M
Reliability Cost: $416M
Policy Cost: $0
Economic Cost: $13M

Total Mileage: 355
Reliability Miles: 355
Policy Miles: 0
Economic Miles: 0

Total Transformers: 5

The Future 5 portfolio was very similar to the Future 1 portfolio. There are no EHV policy projects in the Future 5 portfolio due to the lower wind capacity assumed. The system behavior of Future 5 was very similar to Future 1, while the main differences are due to the additional MISO constraints and the additional MISO generation included in the Future 5 resource plan. The additional MISO generation exceeds the future MISO generation additions that SPP included in Future 1. This change led to MISO serving more of their own load in Future 5, due to the extra generation available and the additional constraints that reduced SPP exports serving MISO load. This in turn led to SPP running less generation and having fewer exports in Future 5.

Table 13.10 shows details for all Future 5 portfolio projects.

Project	Area(s)	Type	Mileage	Cost
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Reliability	18	$33,895,800
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Reliability	31	$16,784,175
New Maryville 345/161 kV transformer	GMO-AECI	Reliability	0	$12,600,000
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Reliability	0	$12,600,000
Reconductor Mingo - Red Willow 345 kV	NPPD	Reliability	76	$67,135,010
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Reliability	23	$20,408,475
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Reliability	16	$14,197,200
New 2nd S3459 345/161 kV transformer	OPPD	Economic	0	$12,600,000
New Wolf Creek - Neosho 345 kV line	WERE	Reliability	99	$117,126,900
New Tolk - Tuco 345 kV	SPS	Reliability	64	$75,718,400
New 2nd Holcomb 345/115 kV transformer	SUNC	Reliability	0	$12,600,000
New S3740 - S3454 345 kV	OPPD	Reliability	28	$33,126,800
Total			355	$428,792,760

Table 13.10: Future 5 Portfolio Projects

Section 14: Consolidated Portfolio

14.1: Development

The five Future portfolios were consolidated into a single final portfolio to be analyzed across all futures.

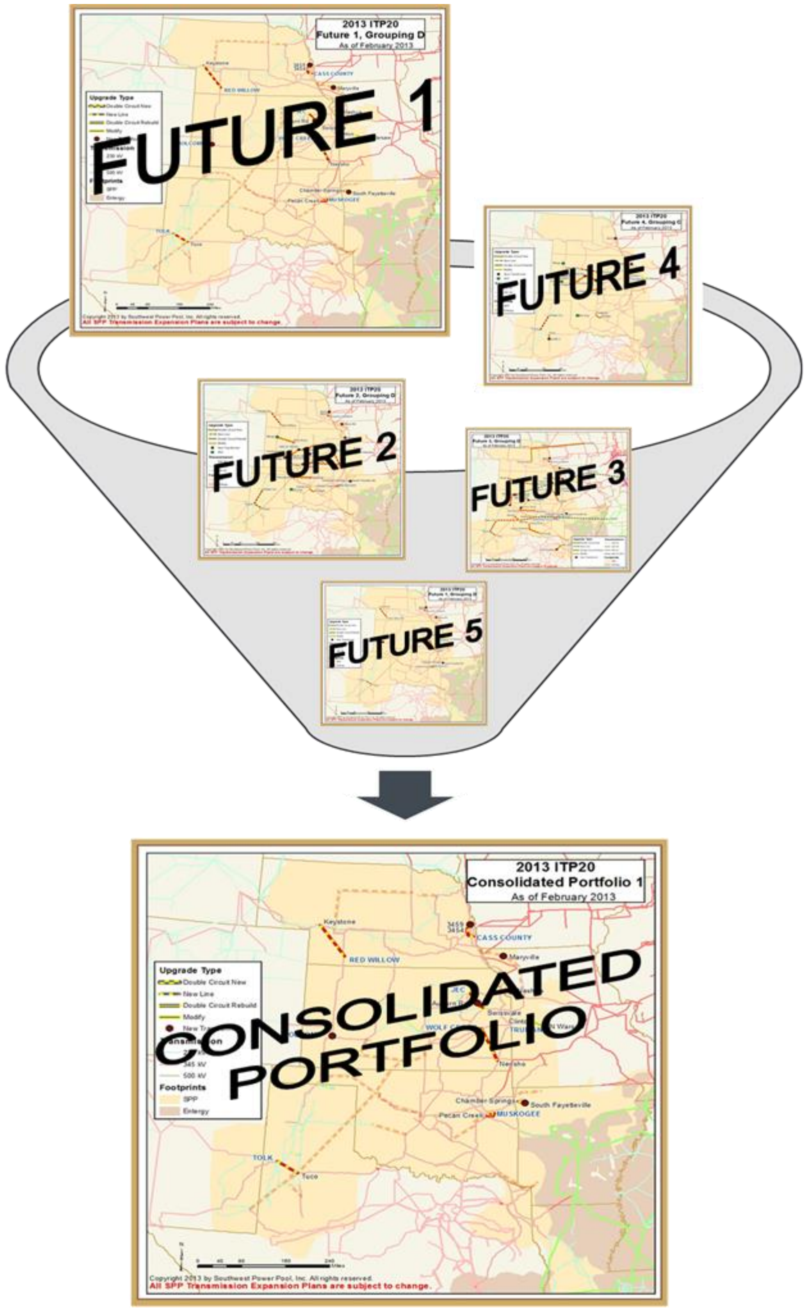


Figure 14.1: Consolidation of Portfolios

This Consolidated Portfolio was developed by weighting each of the futures based on their probability and magnitude of impact. Each future was weighted using a percentage, such that the sum of weights for all futures was 100%. A threshold value of 60% was used along with the weights to consolidate projects across futures. The weightings of each future and the threshold, as approved by the ESWG, are shown in Table 14.1. This table also shows two examples of how projects are treated using these values.

Portfolio	Weighting	Threshold	Project X	Project Y
Future 1	50%		✓	✗
Future 2	15%		✗	✓
Future 3	10%		✓	✓
Future 4	15%		✗	✓
Future 5	10%		✓	✗
Total	100%		70%	40%
Consolidated		60%	✓	✗

Table 14.1: Weightings and Threshold for Consolidated Portfolio Development

Project X is in the Futures 1, 3, and 5 Portfolios, and has a summed weighting of 70%. This exceeds the 60% threshold to be included in the Consolidated Portfolio. Project Y is in the Futures 2, 3, and 4 Portfolios, and has a summed weighting of 40%. This does not meet the 60% threshold, and the project would not be included in the Consolidated Portfolio. Using these weightings, a project will not be included in the Consolidated Portfolio if it is not included in the Future 1 Portfolio. All of the projects that were included in the Future 1 portfolio were also included in at least one other Future Portfolio. As a result, the Consolidated Portfolio projects are equivalent to the Future 1 Portfolio projects.

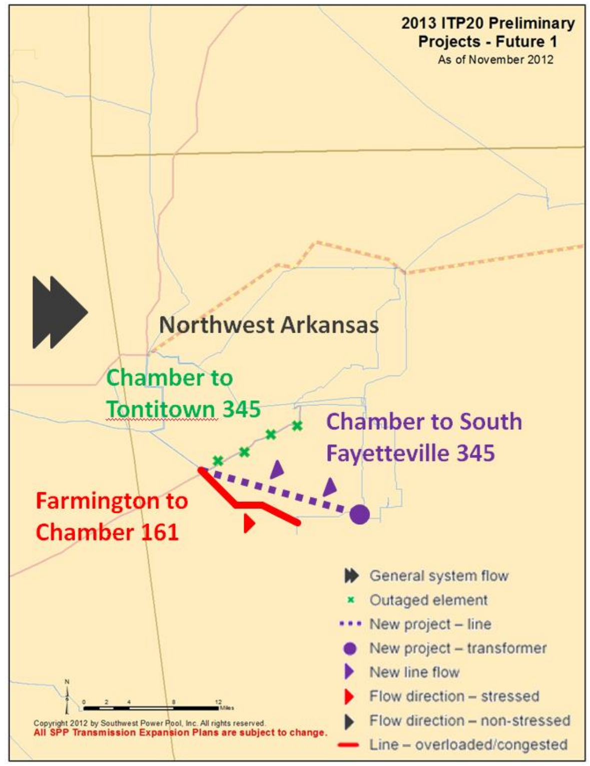
14.2: Projects

The Consolidated Portfolio projects are shown in Table 14.2.

Project	Area(s)	Type	Future(s)	Mileage	Cost
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Economic	F1, F2, F3, F5	18	$33,895,800
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Reliability	F1, F2, F3, F4, F5	31	$16,784,175
New Maryville 345/161 kV transformer	GMO-AECI	Reliability	F1, F2, F3, F5	0	$12,600,000
Increase Nashua 345/161 kV transformer size to 650/715 MVA	KCPL	Reliability	F1, F2, F3, F4, F5	0	$12,600,000
New Keystone - Red Willow 345 kV	NPPD	Reliability	F1, F2	110	$130,141,000
Reconductor Pecan Creek - Muskogee 345 kV circuit 1	OKGE	Reliability	F1, F2, F3, F5	23	$20,408,475
Reconductor Pecan Creek - Muskogee 345 kV circuit 2	OKGE	Reliability	F1, F2, F3, F5	16	$14,197,200
New 2nd S3459 345/161 kV transformer	OPPD	Economic	F1, F2, F3, F4, F5	0	$12,600,000
New Wolf Creek - Neosho 345 kV line	WERE	Economic	F1, F2, F3, F5	99	$117,126,900
New Tolk - Tuco 345 kV	SPS	Reliability	F1, F2, F3, F5	64	$75,718,400
New 2nd Holcomb 345/115 kV transformer	SUNC	Reliability	F1, F5	0	$12,600,000
New S3740 - S3454 345 kV	OPPD	Reliability	F1, F2, F3, F5	28	$33,126,800
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new Auburn 345/115 kV transformer	WERE	Reliability	F1, F3	47	$68,205,700
Total				436	$560,004,450

Table 14.2: Consolidated Portfolio Projects

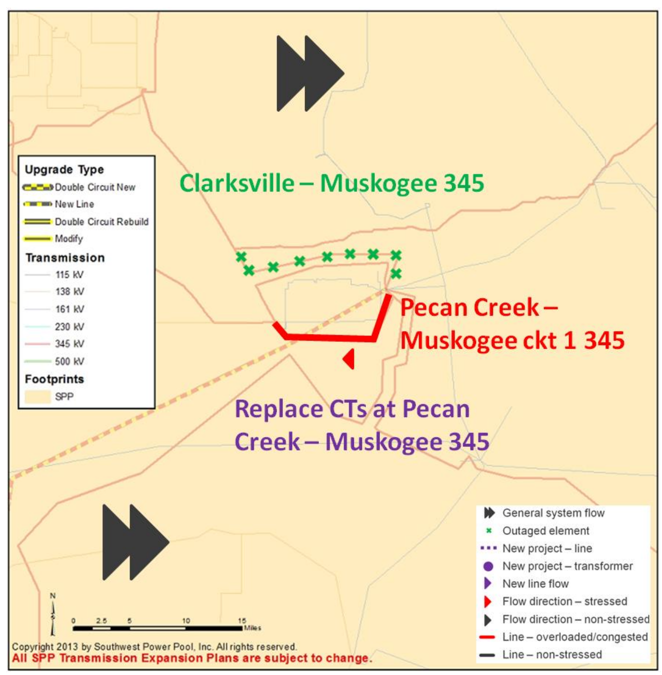
The project details that follow summarize the 2033 system behavior both with and without each project for Future 1.



Chamber Springs – South Fayetteville 345 kV

Northwest Arkansas shows a general west to east flow of power. When the Chamber Springs – Tontitown 345 kV line is in outage, there is a 161 kV line from Chamber Springs – Farmington – South Fayetteville that delivers most of the power east to south Fayetteville and east Fayetteville, resulting in congestion of the Chamber Springs – Farmington 161 kV line. This constraint is a reliability need for the Summer Peak hour, and is also a Top 15 economic need.

The addition of the 18 mile Chamber Springs – South Fayetteville 345 kV line and 345/161 kV transformer at south Fayetteville provides a more robust path to serve load across south Fayetteville and east Fayetteville for the loss of Chamber Springs – Tontitown 345 kV. It also provides future flexibility for a 345 kV loop around the Northwest Arkansas area, if that need should arise. This project mitigates the reliability need, and has a one-year B/C ratio of 3.73.



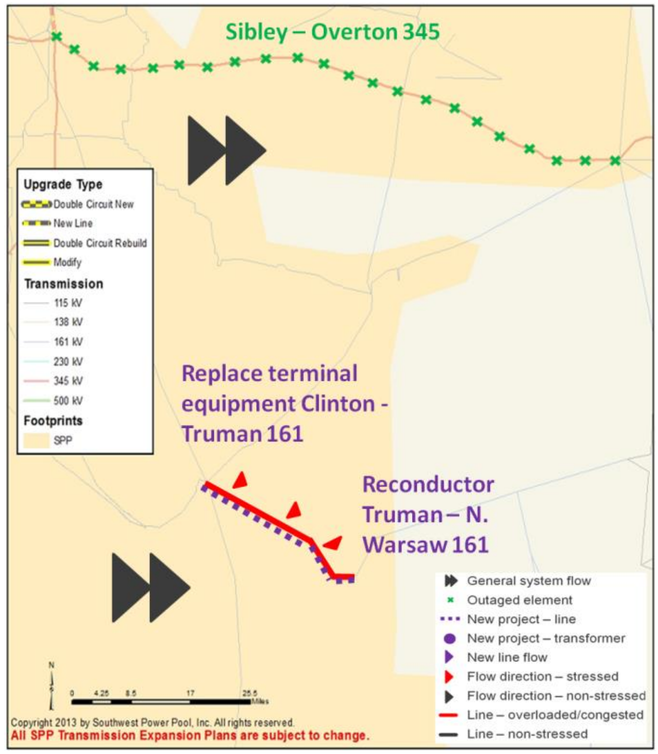
Pecan Creek – Muskogee 345 kV

Eastern Oklahoma shows a general west to east flow of power. Muskogee has significant generation; on the 345 kV system, power flows from Muskogee outward to Clarksville, Fort Smith, Canadian River, and Pecan Creek. For the outage of Clarksville – Muskogee 345 kV, there is increased power flow on the two circuits from Muskogee – Pecan Creek, causing binding constraints on these lines.

The reconductor of Pecan Creek and Muskogee will increase the limits on these 345 kV lines from 717/717 MVA to 1195/1195 MVA, mitigating the congestion.

Clinton – Truman – N Warsaw 161 kV

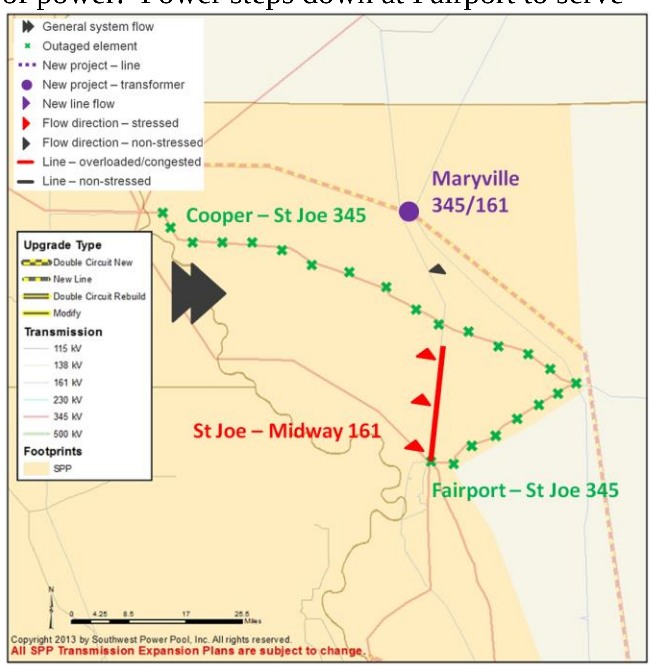
On the east side of Kansas City, Missouri shows a general west to east flow of power. The only EHV lines to facilitate this flow of power are Sibley–Overton 345 kV and Neosho – Morgan – Huben 345 kV. When the Sibley – Overton 345 kV line is in outage, there is significant west to east flow on the underlying 161 kV system, particularly the Clinton – Truman and Truman – N Warsaw 161 kV lines. These two constraints are both Top 15 economic needs, and Truman – N Warsaw 161 kV is a binding constraint for the Summer Peak and Winter Peak hours.



Upgrading the 31 mile Clinton – Truman – N Warsaw 161 kV line and substation equipment mitigates the west to east congestion on this line, provides a one-year benefit of $25.9M, and provides a one-year B/C of 8.87. This project includes a reconductor of the two mile Truman – N Warsaw 161 kV, and substation equipment upgrades at Truman 161 kV. This lower voltage project is included in the 2013 ITP20 Consolidated Portfolio since there is a potential to share the cost with AECI. SPP has reviewed this project with AECI. Throughout 2013 SPP will work with AECI to evaluate the potential benefit that this project may provide to both regions.

Maryville 345/161 kV Transformer

Northwest Missouri shows a general west to east flow of power. Power steps down at Fairport to serve the 161 kV system in this area. When the two 345 kV lines into Fairport are in outage (Cooper – Fairport 345 kV and St. Joe – Fairport 345 kV), flows increase on some of the 161 kV lines. St. Joe – Midway 161 kV is binding for the loss of these two lines, due to south to north flows to serve load in the Maryville area.

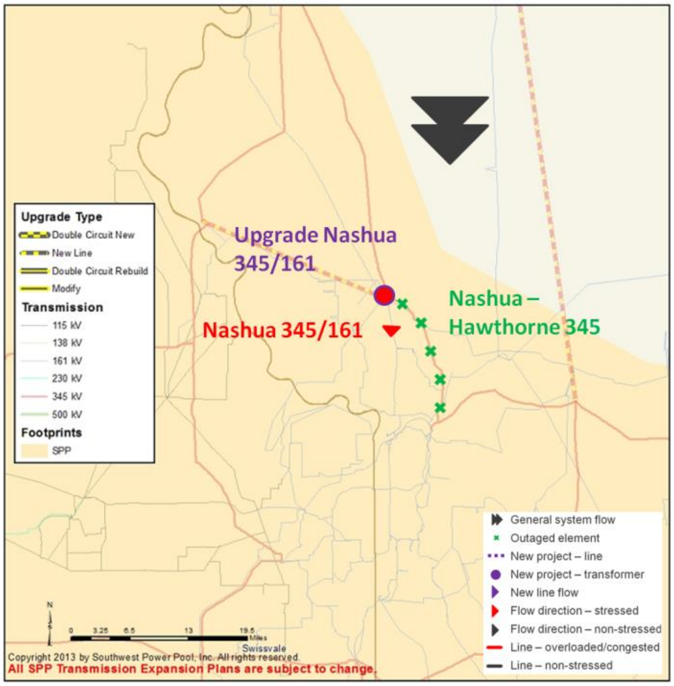


The addition of the Maryville 345/161 kV transformer along with the Nebraska City – Sibley 345 kV line (NTC's issued in 2010) mitigates the congestion of the St. Joe – Midway 161 kV reliability need. It does so by providing counter flow to the south to north flows on the 161 kV systems that are serving load in the Maryville area.

Upgrade Nashua 345/161 kV Transformer

The north side of Kansas City shows a general north to south flow of power into the city. The Nashua – Hawthorne 345 kV line delivers significant power south to Hawthorne, where it steps down to the 161 kV system in Kansas City. When the Nashua – Hawthorne 345 kV line is out of service, it causes increased power flow to step down at the Nashua 345/161 kV transformer to serve the load in northern Kansas City. This transformer is a binding reliability need.

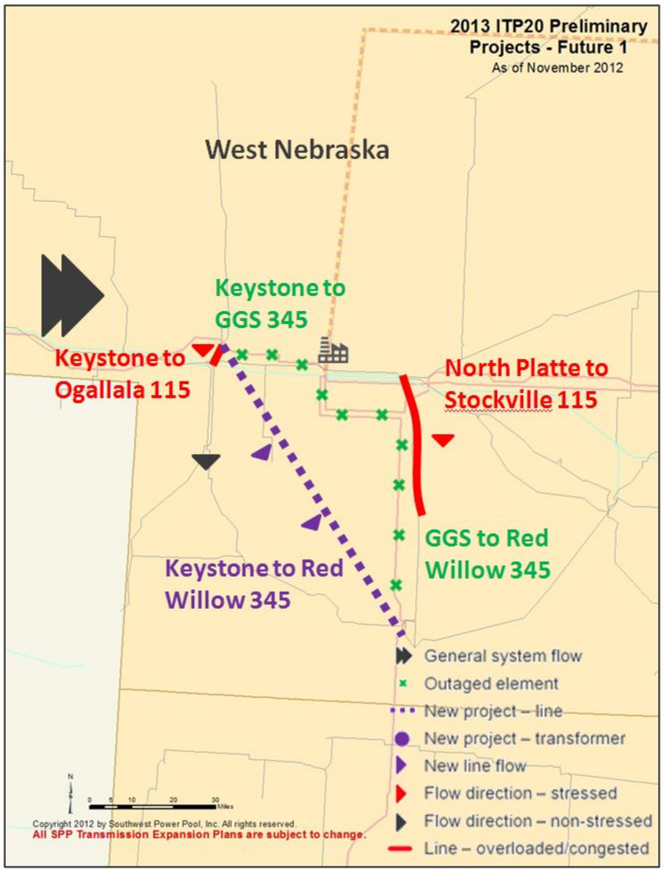
Upgrading the Nashua 345/161 kV transformer to 650/715 MVA provides the necessary capacity to mitigate the congestion at this transformer due to the loss of the Nashua – Hawthorne 345 kV line.



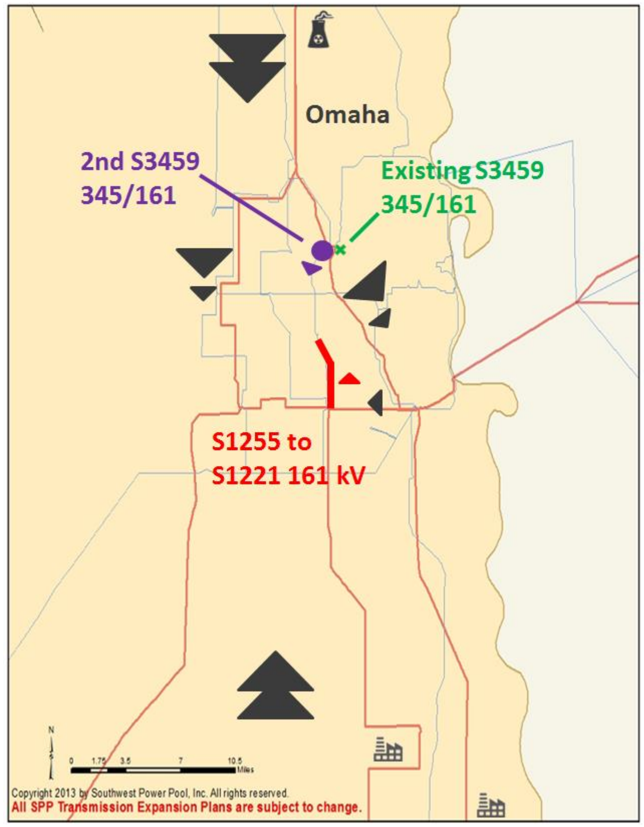
Keystone – Red Willow 345 kV

Western Nebraska shows a general west to east flow of power, due largely to the Laramie River generation in Wyoming and the Gerald Gentleman generation. There is also some north to south flow from the Gerald Gentleman area. When one of the Gentleman – Red Willow 345 kV or Gentleman – Keystone 345 kV lines is out of service, there is significant north to south flow on the 115 kV network in this area. Two separate elements in this 115 kV network experience congestion: Keystone – Ogallala 115 kV is binding for the Summer Peak hour, and North Platte – Stockville 115 kV is a Top 15 economic need.

The addition of the 110 mile Keystone – Red Willow 345 kV line provides an alternative north to south EHV path when one of the Gentleman – Red Willow 345 kV or Gentleman – Keystone 345 kV lines go out of service. This relieves the congestion on the underlying 115 kV system at Keystone – Ogallala and at North Platte – Stockville.



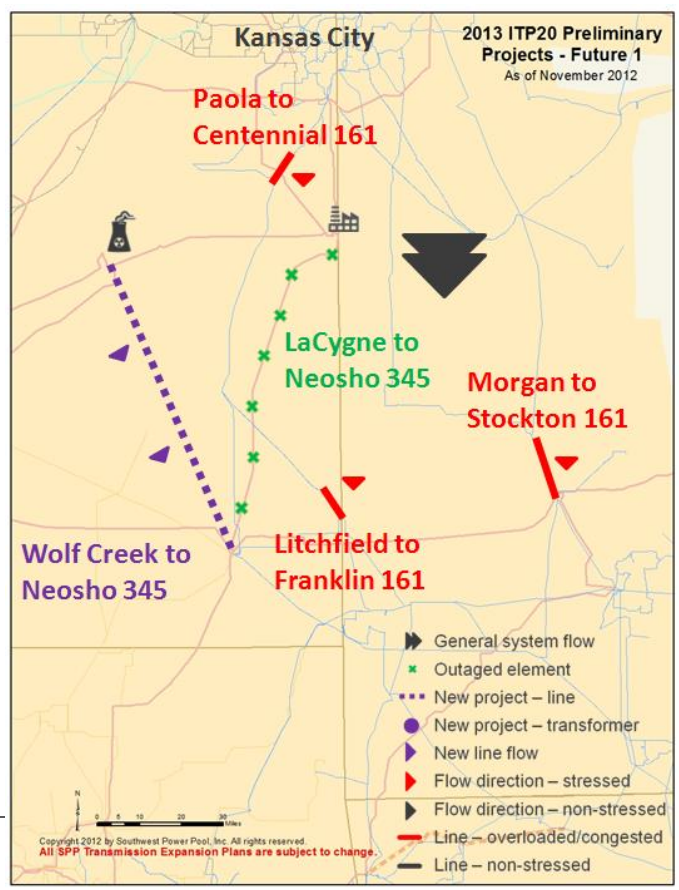
S3459 345/161 kV Transformer



Omaha Nebraska shows a general north to south flow of power into the city from Ft. Calhoun and Raun generation, and a south to north flow of power into the city from Cass Co and Nebraska City generation. When the S3459 345/161 kV transformer is out of service, much of the power flowing on EHV network from the north into the city must loop around to the south to step down to a lower voltage level. This is the same area in which power is being delivered from the Cass Co and Nebraska City generators in the south, creating a large bottleneck in this area. The S1221 – S1255 161 kV line delivers much of the power that flows into central Omaha. This is an area of heavy congestion, as it is a top 5 economic need and is a reliability need for the Summer Peak hour.

The addition of a second S3459 345/161 kV transformer provides a backup to the first transformer going out of service. An EHV transformer in this area is critical, as it helps deliver power from the north to the load in central Omaha without the need for power to loop around to south Omaha to step down to lower voltage. This project mitigates the reliability need and has a one-year B/C ratio of 27.76.

Wolf Creek – Neosho 345 kV



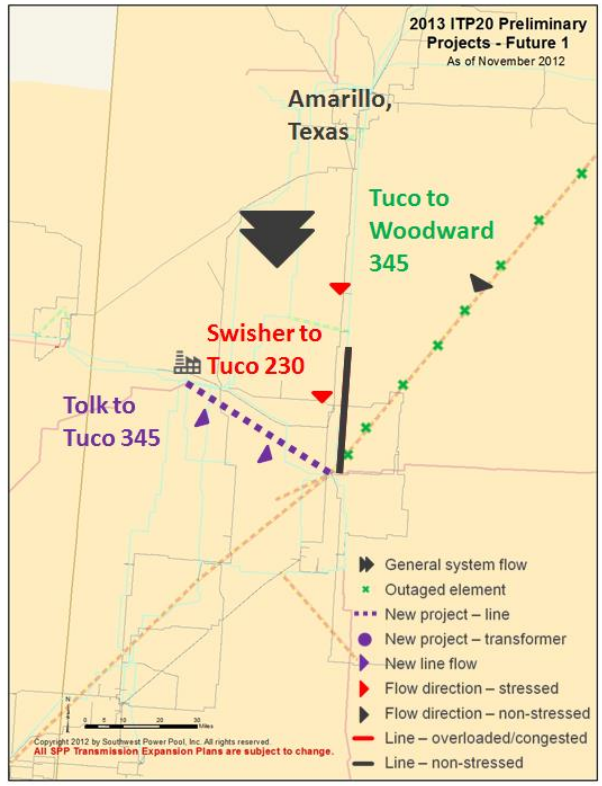
The area south of Kansas City shows a general north to south flow of power. The large Wolf Creek and LaCygne generators deliver significant power south on the LaCygne – Neosho 345 kV line. When this line is out of service, the large flows on the underlying 161 kV network result in three different elements binding as reliability needs: Paola – Centennial 161 kV, Litchfield – Franklin 161 kV, and Morgan – Stockton 161 kV. Morgan – Stockton 161 kV is also a Top 15 economic need.

The addition of the 99 mile Wolf Creek – Neosho 345 kV line mitigates congestion on all three of these 161 kV elements by providing an alternative EHV path for north to south flow when LaCygne – Neosho 345 kV is out of service. This project also has a one-year B/C ratio of 1.41.

Tolk – Tuco 345 kV

North Texas shows a general north to south flow of power. When the Tuco – Woodward 345 kV line is out of service, the 230 kV and 115 kV lines between Amarillo and Lubbock have large north to south flows. The Swisher – Tuco 230 kV line is binding in the High Wind hour for this contingency.

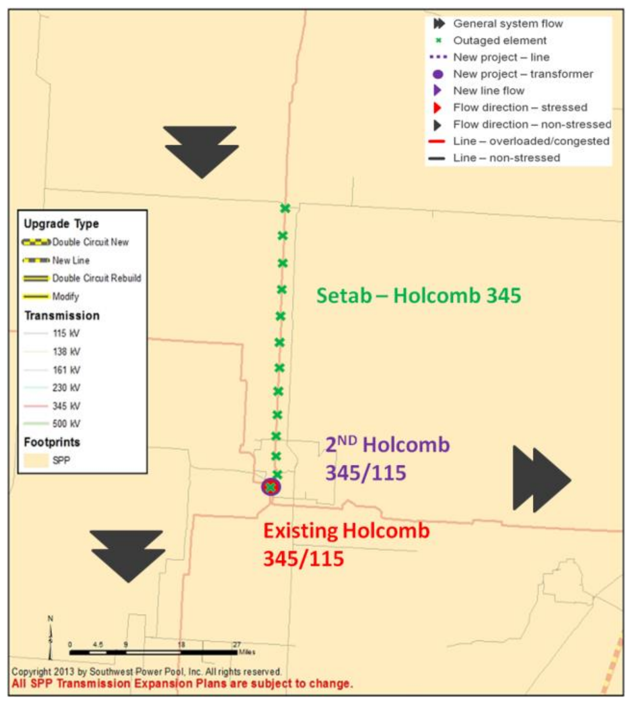
The addition of the 64 mile Tolk – Tuco 345 kV line allows for the large Tolk generator to deliver power east to Tuco. This relieves the north to south congestion of the Swisher – Tuco 230 kV line by delivering power west to east from the Tolk generation.



Holcomb 345/115 kV Transformer

West Kansas shows a general north to south flow of power, and a west to east flow of power. Holcomb has significant generation. Some serves local load through the 115 kV system, and some steps up to the 345 kV system to deliver power to the south and to the west. When the Setab – Holcomb 345 kV line is out of service, there is significant power stepping up on the Holcomb 345/115 kV transformer, causing it to overload.

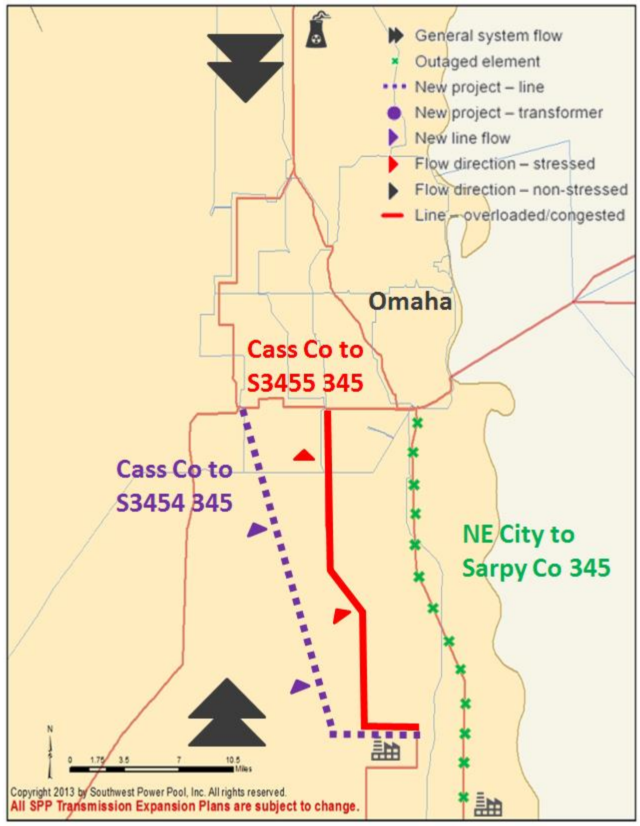
The addition of the 2nd Holcomb 345/115 kV transformer allows for greater power transfer to the 345 kV system, to serve loads to the east and to the south. This project relieves the congestion at the existing Holcomb 345/115 kV transformer and mitigates the reliability need.



S3740 – S3454 345 kV

Omaha, Nebraska shows a general south to north flow of power into the city from Cass Co and Nebraska City generation. When the Nebraska City – Sarpy Co 345 kV line is out of service, the S3740 – S3455 345 kV line is the primary path for the Nebraska City and Cass Co generation that is delivered to Omaha, causing a binding constraint in the Summer Peak hour.

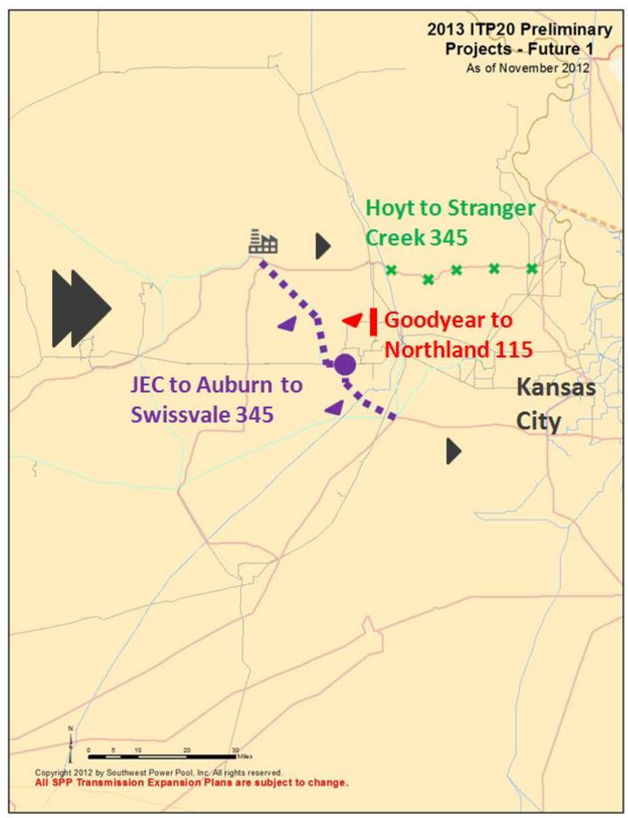
The addition of the 28 mile S3740 (Cass Co) – S3454 (SW Omaha) 345 kV line creates an alternative path for the Nebraska City and Cass Co generation to be delivered to Omaha, mitigating this reliability need for the loss of the Nebraska City – Sarpy 345 kV line.



JEC – Auburn – Swissvale 345 kV

The area west of Kansas City shows a general west to east flow of power. When the Hoyt – Stranger Creek 345 kV line is out of service, much of the west to east flow of power on the JEC – Hoyt – Stranger 345 kV line then steps down to the 115 kV system at Hoyt. This causes large flows on the 115 kV system, and the Goodyear – Northland 115 kV line is a reliability need for the Summer Peak hour.

A rebuild of the 47 mile JEC – Auburn– Swissvale 230 kV line to 345 kV, along with a 345/115 kV transformer at Auburn, provides an additional west to east path for delivering power to Lawrence and Kansas City when one of the JEC – Hoyt or Hoyt – Stranger Creek 345 kV lines is out of service. This project mitigates the Goodyear – Northland 115 kV reliability need by providing counter flow north of Swissvale to the Lawrence area.



Section 15: Potential Project Plans

Portfolios for Futures 2 – 4 include numerous projects that are not included in the Consolidated Portfolio. These additional projects are needed for the delivery of increased wind generation in these futures. Three groupings of potential projects were developed, highlighting projects that would be needed to facilitate additional wind capacity beyond the 9 GW of wind assumed in Future 1. These groupings do not include all upgrades necessary to meet the high wind needs of all futures. Instead they highlight the main areas of transmission expansion that would be needed in higher wind scenarios.

Potential Plan 1 includes projects shown to be needed in most or all of Futures 2 – 4 to help accommodate increased wind levels of 9 – 15 GW in SPP.

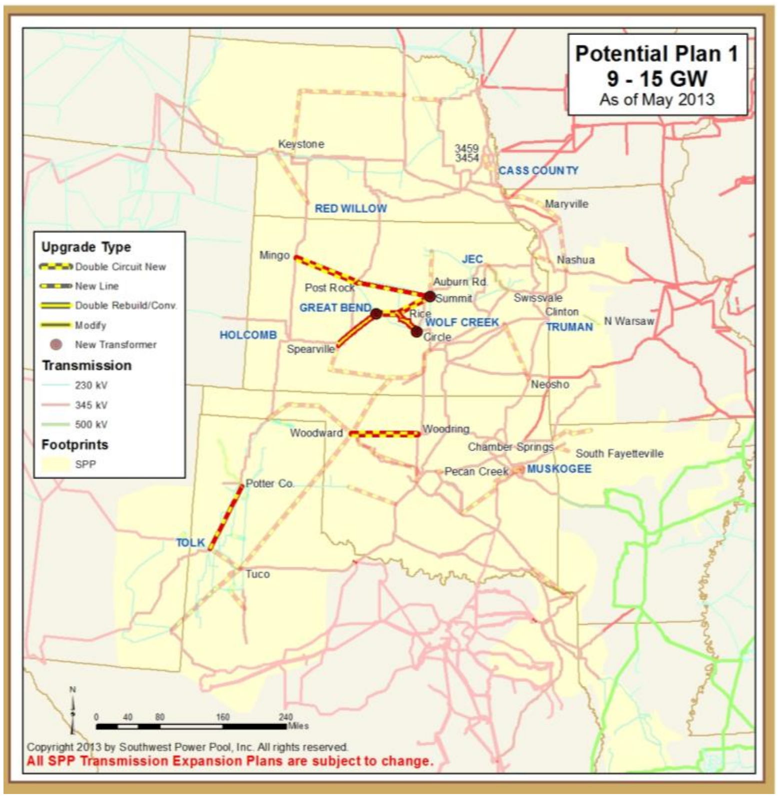


Figure 15.1: Potential Plan 1

Potential Plan 1

9 – 15 GW Wind

Incremental Cost: $1.3B

Potential Plan 2 includes additional AC upgrades needed for 15 – 25 GW of wind in SPP. These upgrades are geared toward wind exports, similar to Future 3.

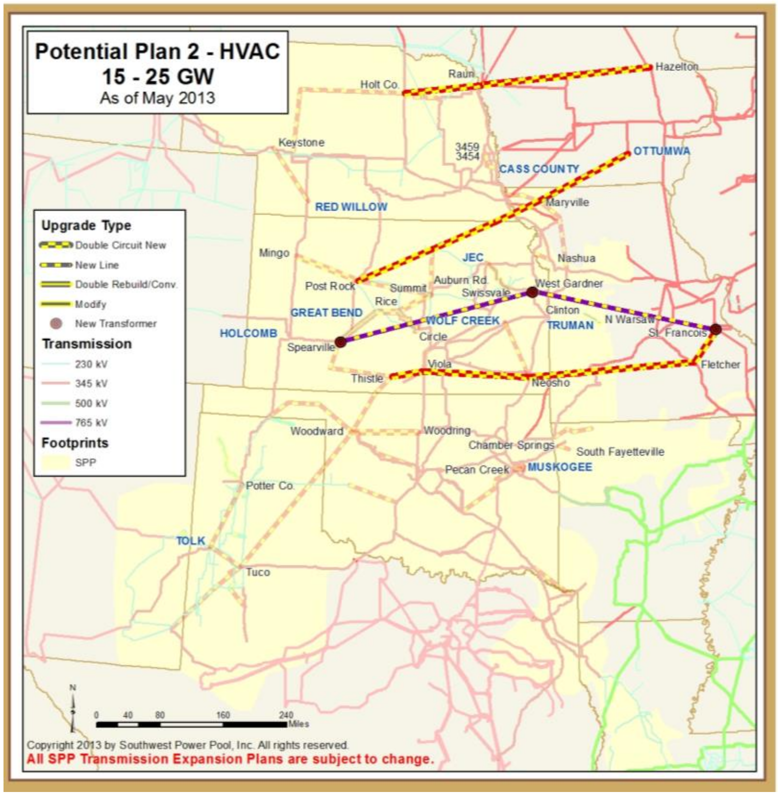


Figure 15.2: Potential Plan 2

Potential Plan 2

15 – 25 GW Wind

Incremental Cost: $4.9B

Potential Plan 3, similar to Potential Plan 2, includes upgrades needed to support 15 – 25 GW of wind capacity in SPP. These upgrades are geared toward wind exports, similar to Future 3. The Potential Plan 3 upgrades are primarily DC projects, and include two HVDC lines from wind-rich areas in the western portions of SPP to higher load areas east of SPP.

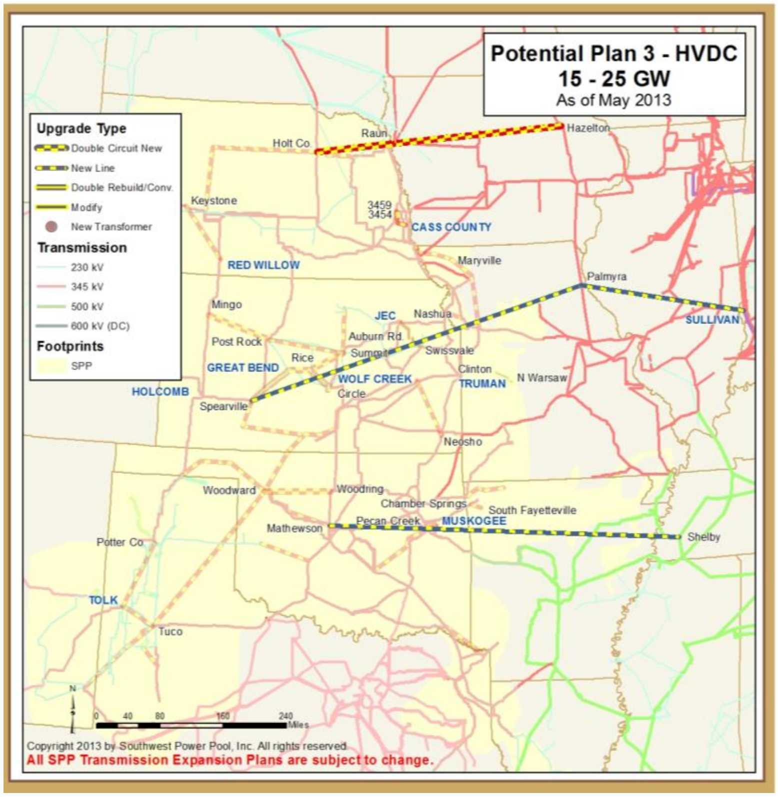


Figure 15.3: Potential Plan 3

Potential Plan 3

15 – 25 GW Wind

Incremental Cost: $5.1B

Although Potential Plan projects are not included in the recommended Consolidated Portfolio, these plans show projects that would be valuable to SPP should the "business as usual" change to include higher wind levels.

Section 16: Benefits

Multiple metrics were used to identify benefits for the Consolidated Portfolio. The ESWG directed that the 2013 ITP20 benefit/cost results be focused on the final portfolio projects, including reliability, policy and economic projects. The benefit structure shown in Figure 16.1 illustrates the benefit metrics that were calculated as incremental benefit due to the Consolidated Portfolio projects.

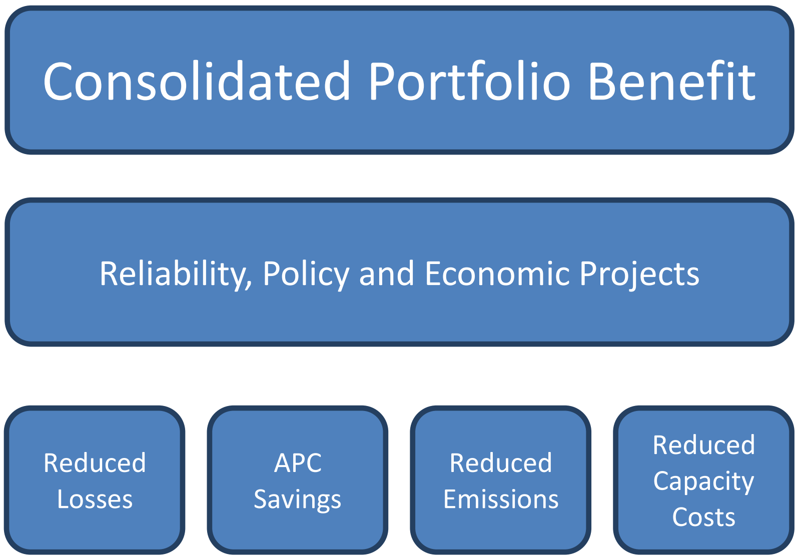
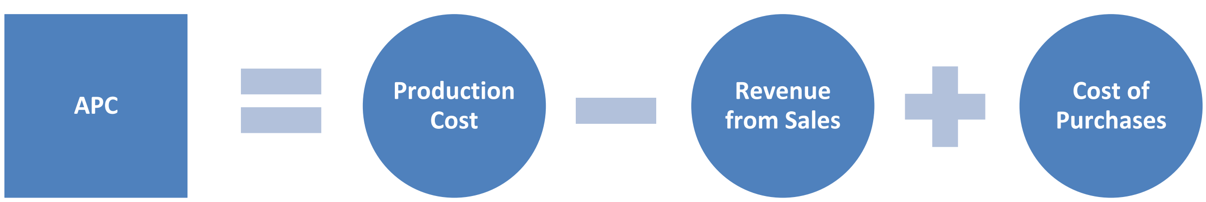


Figure 16.1: Benefit Hierarchy

16.1: APC Savings

Adjusted Production Cost (APC) is a measure of the impact on production cost savings by Locational Marginal Prices (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 during the simulation year. The calculation, performed on an hourly basis, is as follows:



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

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

Figure 16.2: APC Calculation

APC captures the monetary cost associated with fuel prices, run times, grid congestion, unit operating costs, energy purchases, energy sales, and other factors that directly relate to energy production by generating resources in the SPP footprint. Additional transmission projects aim to relieve system congestion and reduce costs via some combination of a more economical generation dispatch, more economical purchases, and optimal revenue from sales.

To calculate the benefits over the expected 40-year life of the projects[24], three years were analyzed, 2023, 2028 and 2033, and the APC savings calculated. To determine the annual growth for each of the 40 years:

- The slope between the three points was used to extrapolate the benefits for every year beyond 2033 over a 40-year timeframe, with a terminal value used after year 20.
- Each year's benefit was then discounted to 2033 using an 8% discount rate.
- The sum of all discounted 2033 benefits was further deflated to 2013, using a 2.5% inflation rate and presented as the Net Present Value (NPV) benefit.
- Project cost were depreciated linearly over the 40-year timeframe
- Each year's depreciated costs were then discounted and deflated to 2013 using the same assumptions (8% discount rate and 2.5% inflation rate) that were used to develop the 40-Year benefit results.

Four different values are calculated and shown in Table 16.1 for each future:

- Benefit
    - 40-Year Net Present Value (NPV) benefit showing the full APC benefit expected over the 40 year lifetime of the transmission projects
- Cost
    - 40-Year NPV costs showing the full costs expected to be paid over the 40 year lifetime of the transmission projects
- Net Benefit
    - Benefit minus cost
- B/C
    - Benefit divided by cost

	Future 1	Future 2	Future 3	Future 4	Future 5
Benefit	$2.36	$2.00	$2.76	$1.48	$2.11
Cost	$0.85	$0.85	$0.85	$0.85	$0.85
Net Benefit	$1.51	$1.16	$1.91	$0.63	$1.26
B/C	2.79	2.37	3.26	1.75	2.49

Table 16.1: APC Results for SPP ($ are in Billions)

Figure 16.3 shows the APC benefit and B/C by future. The dashed line shows the point at which APC benefit matches the cost of the projects (B/C = 1.0). The Consolidated Portfolio provides the SPP region with APC benefits that exceed the costs, for all futures.

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

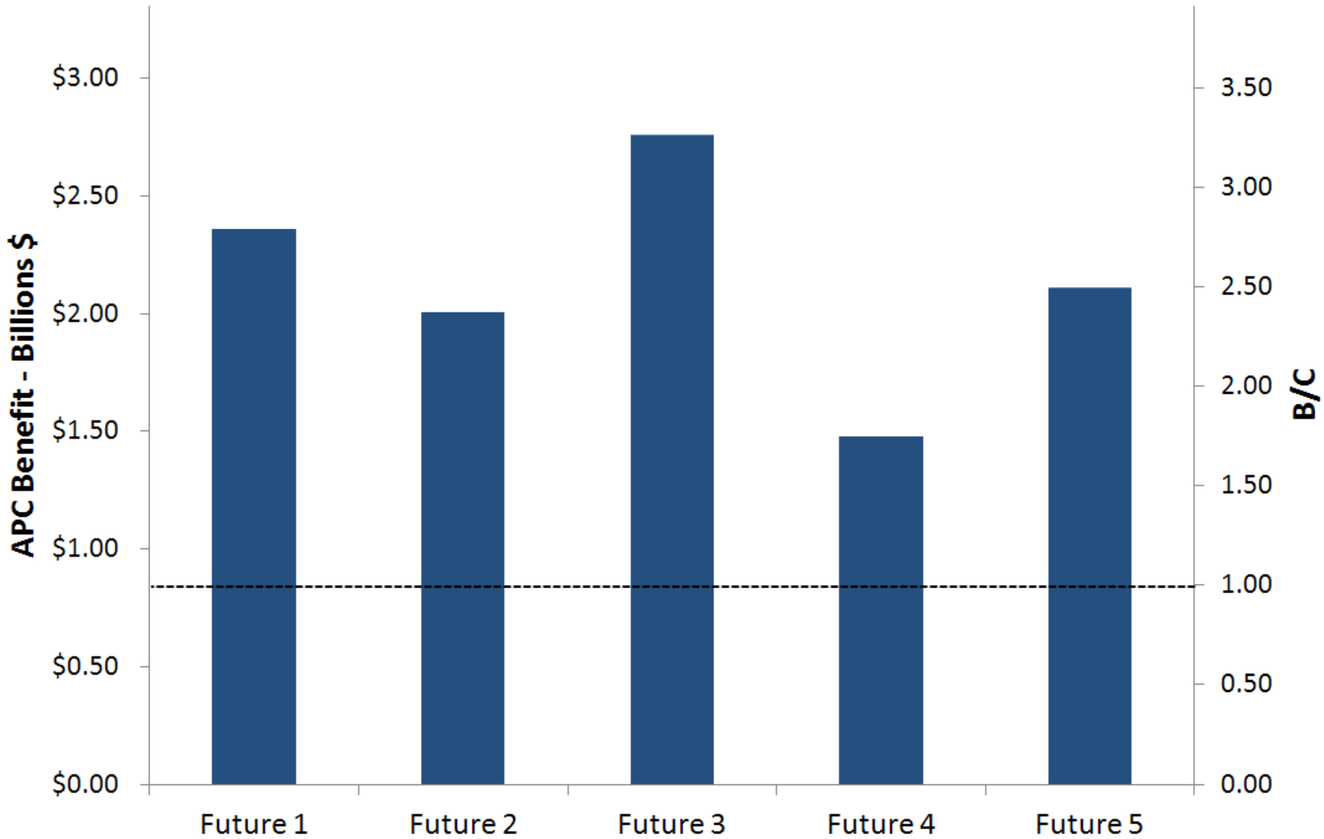


Figure 16.3: APC Benefits and B/C for SPP

16.2: Reduced Emissions

Additional transmission may result in a lower fossil fuel burn (for example, less coal-intensive generation), resulting in less SO_2, NO_X, and CO_2 emissions. Such a reduction in emissions is a benefit that is already monetized through the APC savings metric, based on the assumed allowance prices for these effluents. (Note that a CO_2 allowance price is only utilized in Future 4).

The allowance market dynamics that take place separately from events in the energy market is not considered in this metric. Rather, a simplified approach, that assumes allowances are sold and purchased at known market clearing price, is applied and these allowance prices are included in the calculation of marginal production costs.

The changes in emissions associated with the Consolidated Portfolio are shown in Table 16.2 for all futures. Note that negative values for decreases in emissions indicate increases in emissions. The results indicated that emissions increased in all futures except Future 4 when the Consolidated Portfolio was added.

Future	Effluent	Unit of Measure	Base	Consolidated Portfolio	Decrease in Emissions	% Decrease in Emissions
F1	NO_X	Thousands of Tons	149	150	-1.85	-1.2%
F2	NO_X	Thousands of Tons	142	144	-1.79	-1.3%
F3	NO_X	Thousands of Tons	138	140	-2.28	-1.7%
F4	NO_X	Thousands of Tons	95	94	1.02	1.1%
F5	NO_X	Thousands of Tons	94	96	-1.92	-2.0%
F1	SO_2	Thousands of Tons	196	198	-2.50	-1.3%
F2	SO_2	Thousands of Tons	183	185	-2.32	-1.3%
F3	SO_2	Thousands of Tons	175	178	-3.11	-1.8%
F4	SO_2	Thousands of Tons	119	118	1.07	0.9%
F5	SO_2	Thousands of Tons	131	133	-2.64	-2.0%
F1	CO_2	Millions of Tons	228	231	-2.75	-1.2%
F2	CO_2	Millions of Tons	213	216	-2.78	-1.3%
F3	CO_2	Millions of Tons	209	212	-3.68	-1.8%
F4	CO_2	Millions of Tons	176	176	0.14	0.1%
F5	CO_2	Millions of Tons	130	131	-1.51	-1.2%

Table 16.2: Reduction in Emissions with Consolidated Portfolio (2033)

The change in emission rates for each future is shown in Table 16.3.

Future	Effluent	Unit of Measure	Base	Consolidated Portfolio	Decrease in Emission Rate	% Decrease in Emission Rate
F1	NO_X	Lbs/GWh Gen	991	993	-1.70	-0.2%
F2	NO_X	Lbs/GWh Gen	1039	1040	-1.25	-0.1%
F3	NO_X	Lbs/GWh Gen	1035	1035	-0.59	-0.1%
F4	NO_X	Lbs/GWh Gen	737	726	11.07	1.5%
F5	NO_X	Lbs/GWh Gen	676	685	-9.76	-1.4%
F1	SO_2	Lbs/GWh Gen	1305	1308	-2.67	-0.2%
F2	SO_2	Lbs/GWh Gen	1340	1342	-1.67	-0.1%
F3	SO_2	Lbs/GWh Gen	1314	1317	-2.34	-0.2%
F4	SO_2	Lbs/GWh Gen	922	910	12.19	1.3%
F5	SO_2	Lbs/GWh Gen	936	949	-13.37	-1.4%
F1	CO_2	Lbs/MWh Gen	1523	1525	-2.06	-0.1%
F2	CO_2	Lbs/MWh Gen	1563	1565	-2.52	-0.2%
F3	CO_2	Lbs/MWh Gen	1567	1569	-2.53	-0.2%
F4	CO_2	Lbs/MWh Gen	1360	1353	6.96	0.5%
F5	CO_2	Lbs/MWh Gen	927	932	-5.36	-0.6%

Table 16.3: Change in Emission Rates (2033)

These rates indicate the pounds of effluent released per GWh of total generation in the region. The results indicate an increase in emission rates for all futures except Future 4 when the Consolidated Portfolio was added.

Further analysis shows that SPP is generating more and exporting more when the Consolidated Portfolio is in place. Figure 16.4 shows the increases in generation by type under Future 1 for the SPP footprint when the Consolidated Portfolio is in place.

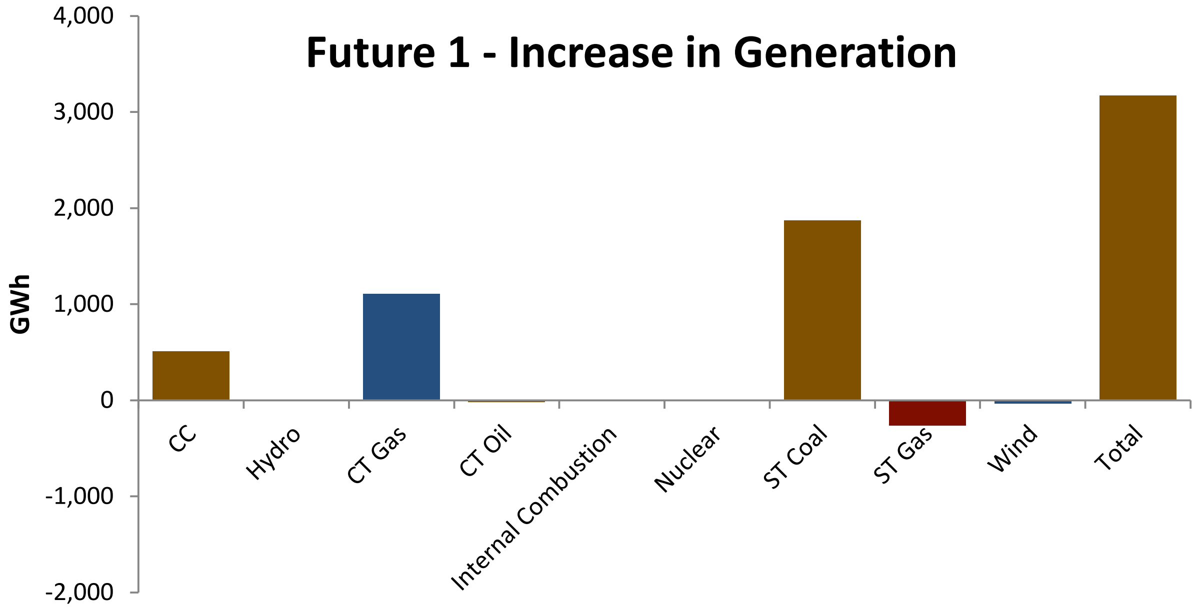


Figure 16.4: Future 1- Increase in Generation with Consolidated Portfolio (2033)

The inclusion of the Consolidated Portfolio leads to over 3,000 GWh of additional generation for 2033, including over 1,800 GWh of additional coal for 2033. The increase in generation associated with additional energy exports leads to increased emissions. Thus there is no reduced emissions benefit in Futures 1, 2, 3, and 5. Future 4 shows reduced emissions with the Consolidated Portfolio in place, because the carbon tax assumed in this future restricts increases in coal and other generation with high carbon emissions.

16.3: Reduced Losses

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes 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. Figure 16.5 shows the annual change in system losses due to the transmission portfolios.

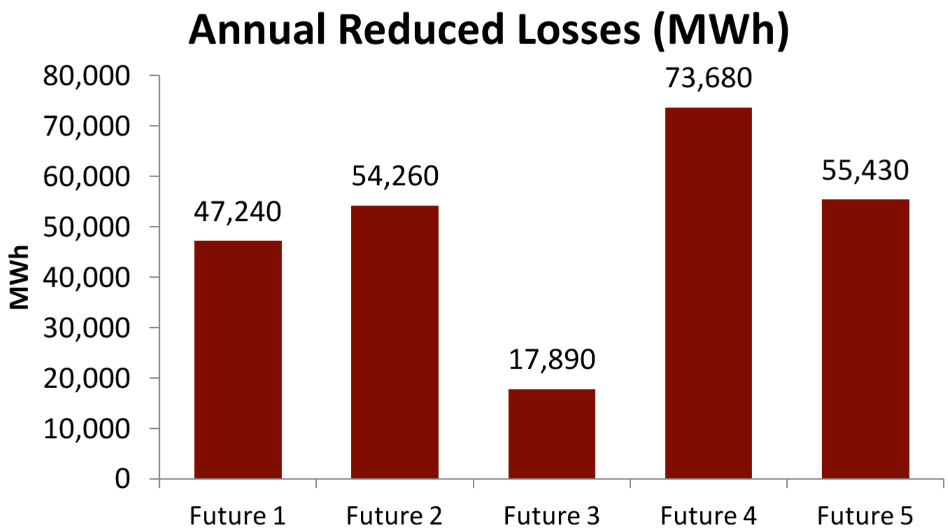


Figure 16.5: Annual Reduction in Losses

The Consolidated Portfolio provides a reduction in annual losses for every future ranging from 17 GWh to 74 GWh.

16.4: Reduced Capacity Cost Due to Losses

Utilizing approximations provided by the Benefit Analysis Techniques Task Force (BATTF)[25] of $750 per kW of installed capacity, the savings achieved by reducing the need for capacity through reduction of losses was estimated to be equal to the peak hour decrease in losses of the change case, multiplied by 112% (to account for the reduction in the planning capacity requirement) also multiplied by an assumed net plant carrying charge (NPCC). The calculation is as follows:

Figure 16.6: Calculating Reduced Capacity Cost Due to Losses

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

Figure 16.7 shows the savings due to the decreased capacity needed to cover system losses.

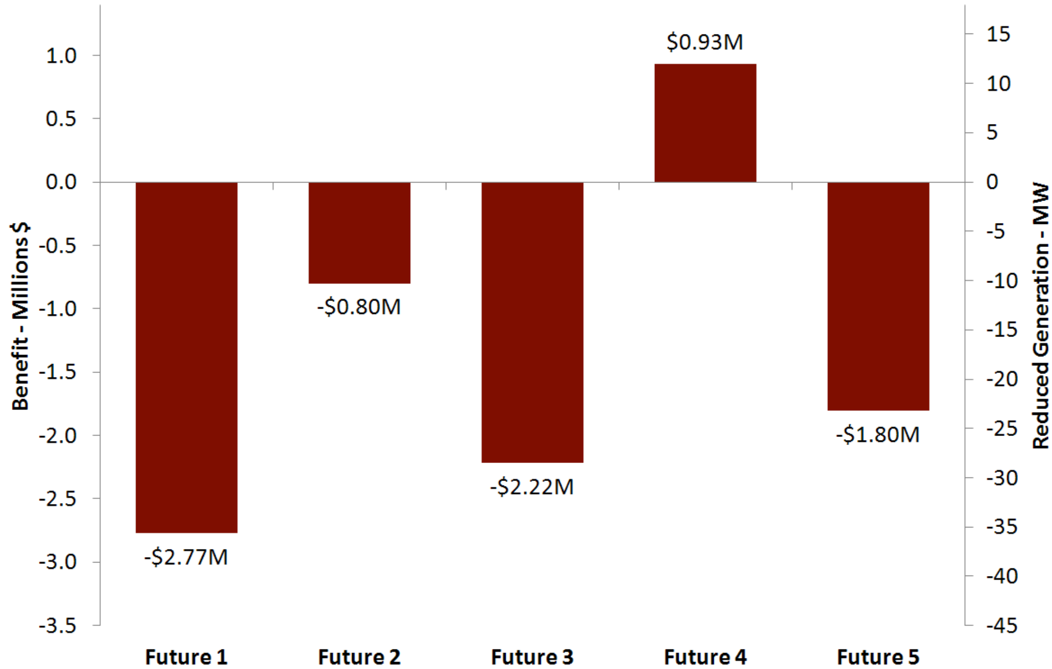


Figure 16.7: Reduced Capacity Cost Savings ($ millions)

Futures 1, 2, 3, and 5 actually show an increase in peak hour losses with the Consolidated Portfolio, even though they show a decrease in net annual losses. This increase in losses leads to a negative benefit for this metric. Future 4, however, shows a decrease in peak hour losses with the Consolidated Portfolio, leading to a positive benefit of $930K for reduced capacity costs. While adding a new transmission plan is expected to provide a reduction in losses, there is some fluctuation for the hour to hour figures between increasing and decreasing loss values, while the net annual loss figures are all showing reduced losses with the Consolidated Portfolio. For all futures, it should be noted that the Reduced Capacity Cost savings (or cost) is very minimal compared with APC savings, ranging from only -$3 million to +$1 million.

16.5: Additional Metrics

Three additional metrics developed by the MTF were recommended by the ESWG for inclusion in the 2013 ITP20. The ESWG further recommended these new metrics be computed for informational purposes only in this study. Because of this, these metrics are included in the Appendix Section 21: rather than the Benefits section of this report.

16.6: Monetized Metric Summary

The results of the monetized benefit metrics are shown in comparison to the portfolio cost in Table 16.4. The benefits are driven by APC savings, and the reduced capacity costs metric has minimal impact.

	Future 1	Future 2	Future 3	Future 4	Future 5
APC Savings	$2,357	$2,002	$2,760	$1,478	$2,107
Reduced Capacity Costs	-$3	-$1	-$2	$1	-$2
Total Benefit	$2,355	$2,001	$2,757	$1,479	$2,105
Total Cost (40-Year)	$845	$845	$845	$845	$845
Net Benefit	$1,509	$1,156	$1,912	$634	$1,260
B/C	2.79	2.37	3.26	1.75	2.49

Table 16.4: Monetized Metric Summary (Millions of $)

16.7: Zonal and State APC Benefits and Costs

The zonal and state breakdown of 40-year APC benefits and costs were computed for the Consolidated Portfolio in Future 1 and are summarized in Table 16.5 and Table 16.6, respectively.

The costs of all projects (economic and reliability) were calculated by zone and state, and compared to the APC savings of the projects by zone and state. Even though reliability projects do not primarily target APC savings, they are still included in the costs here as compared to APC savings.

Project costs were allocated by zone based on the Highway/Byway cost allocation methodology. The Clinton – Truman – N Warsaw 161 kV project is a seams project. If this project were to receive an NTC in the future, it is expected that cost sharing would take place between the SPP RTO, AECI, and SPA. Even though upgrades would take place solely on AECI and SPA facilities, this project provides economic benefit to SPP by enabling the west to east flow of power to neighboring areas. The costs of this project have been assigned solely to SPP in the figures shown in this report, to provide conservative estimates. For illustrative purposes, the costs of this project were allocated by zone using Highway funding, since it is a seams project and does not have a host zone.

Zone	NPV Benefit	NPV Cost	Net Benefit	B/C
AEPW	$236,947,164	$194,689,101	$42,258,064	1.22
EMDE	($5,432,474)	$23,078,647	($28,511,121)	(0.24)
GMO	($114,646,969)	$36,858,206	($151,505,175)	(3.11)
GRDA	($20,904,825)	$17,245,583	($38,150,408)	(1.21)
KCPL	$825,841,736	$69,912,239	$755,929,497	11.81
LES	($30,047,741)	$16,400,211	($46,447,952)	(1.83)
MIDW	($17,128,119)	$5,833,065	($22,961,183)	(2.94)
MKEC	($9,186,590)	$10,820,758	($20,007,348)	(0.85)
NPPD	$93,257,228	$57,992,498	$35,264,730	1.61
OKGE	$100,923,910	$119,620,094	($18,696,185)	0.84
OPPD	$1,170,193,994	$42,775,808	$1,127,418,186	27.36
SPCIUT	($52,323,686)	$13,356,873	($65,680,559)	(3.92)
SUNC	$2,254,680	$8,876,403	($6,621,723)	0.25
SWPS	$45,919,679	$97,978,579	($52,058,900)	0.47
WFEC	$5,643,254	$28,489,026	($22,845,772)	0.20
WRI	$126,074,231	$101,444,603	$24,629,628	1.24
Total	$2,357,385,471	$845,371,691	$1,512,013,780	2.79

Table 16.5: 40-Year APC Benefits & Costs by Zone ($)

State	NPV Benefit	NPV Cost	Net Benefit	B/C
AR	$48,100,274	$39,521,887	$8,578,387	1.22
KS	$490,159,818	$159,833,580	$330,326,238	3.07
LA	$30,092,290	$24,725,516	$5,366,774	1.22
MO	$265,292,991	$110,347,212	$154,945,779	2.40
NE	$1,233,403,481	$117,168,516	$1,116,234,964	10.53
NM	$11,066,643	$23,612,838	($12,546,195)	0.47
OK	$182,788,630	$246,062,845	($63,274,216)	0.74
TX	$96,481,345	$124,099,296	($27,617,951)	0.78
Total	$2,357,385,471	$845,371,691	$1,512,013,780	2.79

Table 16.6: 40-Year APC Benefits & Costs by State ($)

16.8: Rate Impacts

The rate impact to the average retail residential ratepayer in SPP was computed for the Consolidated Portfolio. With all projects currently staged for 2033, the first year benefits and first year costs were used to calculate rate impacts. Benefits typically grow over time, and costs are depreciated over the 40-year life of the asset. Because 2033 represents the year with the maximum costs and the minimum benefit, the rate impact results are conservative. All 2033 benefits and costs are shown in 2013 $ using a 2.5% inflation rate.

Rate impact costs and benefits are allocated to the average retail residential ratepayer in each zone using residential retail allocation percentages specific to each zone. Costs and benefits allocated to each zone are divided by zone-specific sales projections to determine the impact per kWh of consumption, and then multiplied by the average monthly consumption in each zone:

$$Rate\ Impact\ Cost\ (\frac{\$}{mo})_{Zone\ A} = \frac{Annual\ ATRR\ Cost_{Zone\ A} * Monthly\ Consumption_{Zone\ A}}{Sales_{Zone\ A}}$$

$$Rate\ Impact\ Benefit\ (\frac{\$}{mo})_{Zone\ A} = \frac{Annual\ Benefit_{Zone\ A} * Monthly\ Consumption_{Zone\ A}}{Sales_{Zone\ A}}$$

The retail residential rate impact benefit is subtracted from the retail residential rate impact cost, to obtain a net rate impact cost by zone. If the net rate impact cost is negative, it indicates a net benefit to the zone. The rate impact costs and benefits are shown in Table 16.7.

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact - Cost	Rate Impact - Benefit	Net Rate Impact Cost (Cost Minus Benefit)
AEPW	$20,533,454	$10,367,486	$0.63	$0.32	$0.31
EMDE	$2,434,057	($830,579)	$0.38	($0.13)	$0.51
GMO	$3,887,358	($5,491,930)	$0.53	($0.75)	$1.29
GRDA	$1,818,856	($664,992)	$0.03	($0.01)	$0.03
KCPL	$7,373,498	$36,095,797	$0.51	$2.49	($1.99)
LES	$1,729,696	($1,026,476)	$0.40	($0.24)	$0.64
MIDW	$615,201	($1,434,950)	$0.38	($0.88)	$1.26
MKEC	$1,141,243	($723,374)	$0.23	($0.15)	$0.38
NPPD	$6,116,348	$3,930,450	$0.32	$0.21	$0.12
OKGE	$12,616,082	$4,037,146	$0.35	$0.11	$0.24
OPPD	$4,511,475	$47,941,360	$0.39	$4.10	($3.71)
SPCIUT	$1,408,722	($2,150,290)	$0.34	($0.60)	$0.94
SPS	$10,333,597	$8,102,669	$0.31	$0.37	($0.06)
SUNC	$936,176	$330,869	$0.29	$0.10	$0.18
WFEC	$3,004,678	$333,208	$0.30	$0.03	$0.27
WRI	$10,699,151	$6,336,240	$0.48	$0.29	$0.20
Totals	$89,159,591	$105,152,633			**(0.09)**

Table 16.7: Retail Residential Rate Impacts by Zone

There is a monthly net benefit for the average residential ratepayer in SPP of 9 cents. The 9 cents is an average for all SPP zones based on load ratio share. This benefit is representative of a conservative 2033 year in which costs are at their highest while benefits are at their lowest.

16.9: Sensitivities

Sensitivities to natural gas price and demand levels were developed by the ESWG to understand the economic impacts associated with variations in certain model inputs. These sensitivities were not used to develop transmission projects or filter out projects. 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 to provide a confidence interval. The Natural Gas Price sensitivity had a 95% confidence interval (1.96 standard deviations) in the positive and negative directions while the Demand Level sensitivity had a 67% confidence interval (1 standard deviation) in the positive and negative directions.

The resulting assumptions are shown in Table 16.8.

Sensitivity	Henry Hub Gas Price 2033 ($/MMBtu)	Peak Demand and Energy
Expected Natural Gas & Demand	$5.79 (no change)	No change
High Natural Gas	$7.38	No change
Low Natural Gas	$4.19	No change
High Demand	No change	7.5% increase
Low Demand	No change	7.5% decrease

Table 16.8: Sensitivities Utilized in 2013 ITP20

The economic impacts of variation in the model inputs (natural gas price, demand) were captured for the Consolidated Portfolio projects (economic and reliability) within each future. The changes in APC and one-year benefit due to these sensitivities are shown for each future in Figure 16.8 through Figure *16.12*.

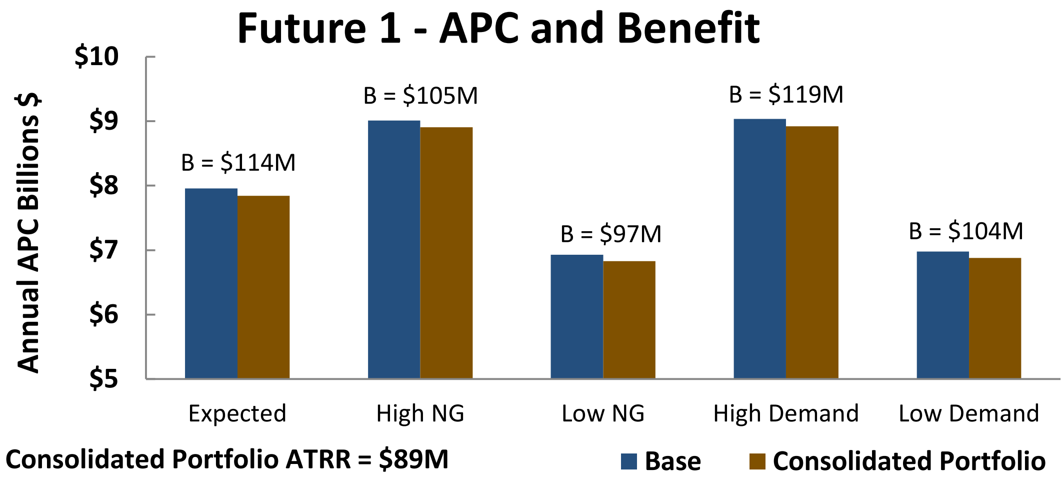


Figure 16.8: Future 1 Sensitivities – APC and Benefit

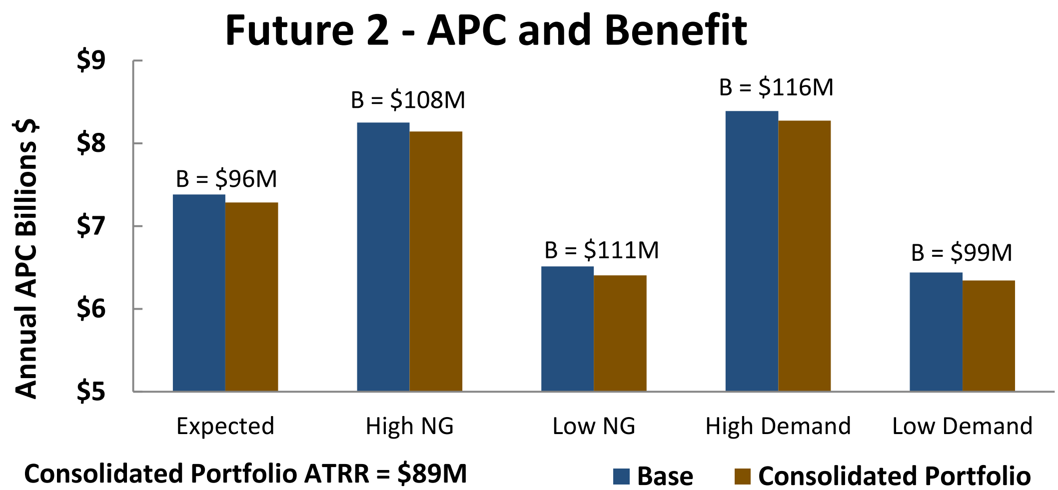


Figure 16.9: Future 2 Sensitivities – APC and Benefit

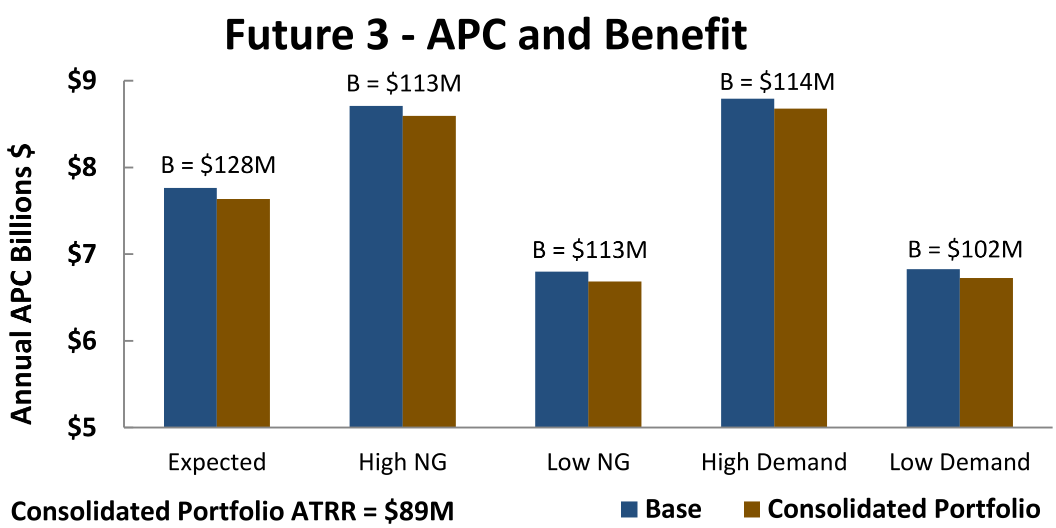


Figure 16.10: Future 3 Sensitivities – APC and Benefit

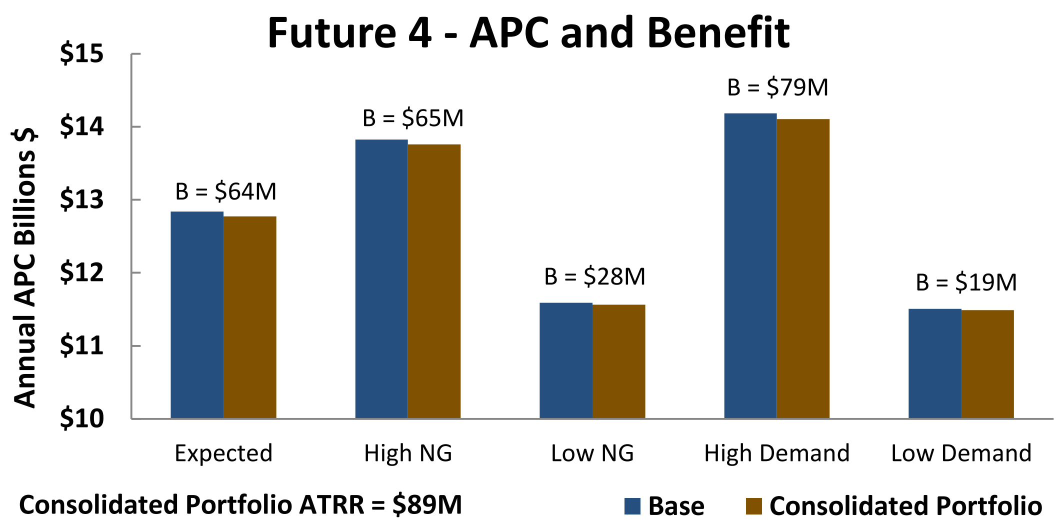


Figure 16.11: Future 4 Sensitivities – APC and Benefit

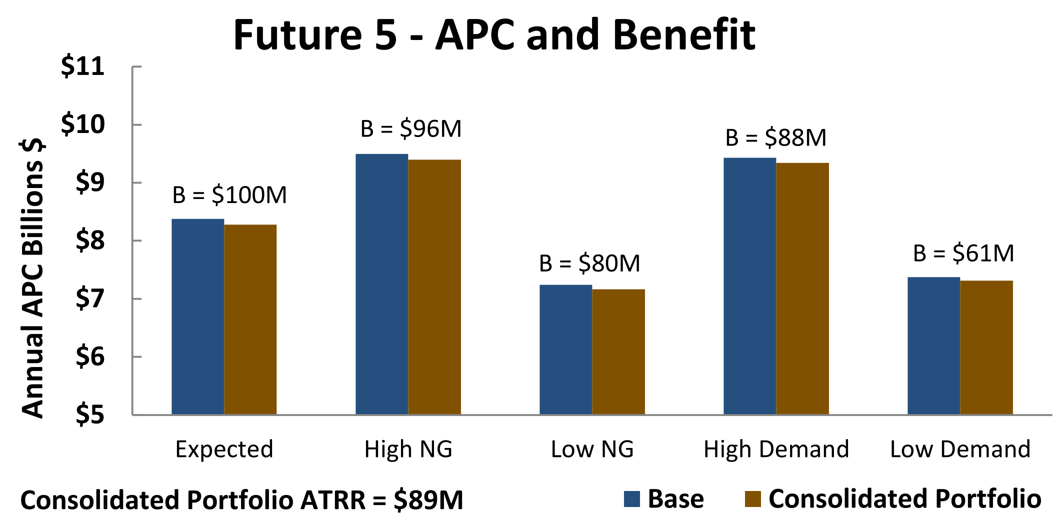


Figure 16.12: Future 5 Sensitivities – APC and Benefit

All sensitivity results show one-year benefits and costs, rather than 40-year benefits and costs as shown in Figure 16.3. The results show significant increases in APC for high gas prices or high demand, and significant decreases in APC for low gas prices or low demand. This is true for the base case and the Consolidated Portfolio for all futures. The results also show that the Consolidated Portfolio has positive benefit for all sensitivities in each future. In some of these cases, the one-year benefit is less than the one-year cost of $89M.

One-year B/C ratios are shown for all sensitivity and non-sensitivity runs in Figure 16.13. It also shows all sensitivities in which the one-year B/C is less than 1.0.

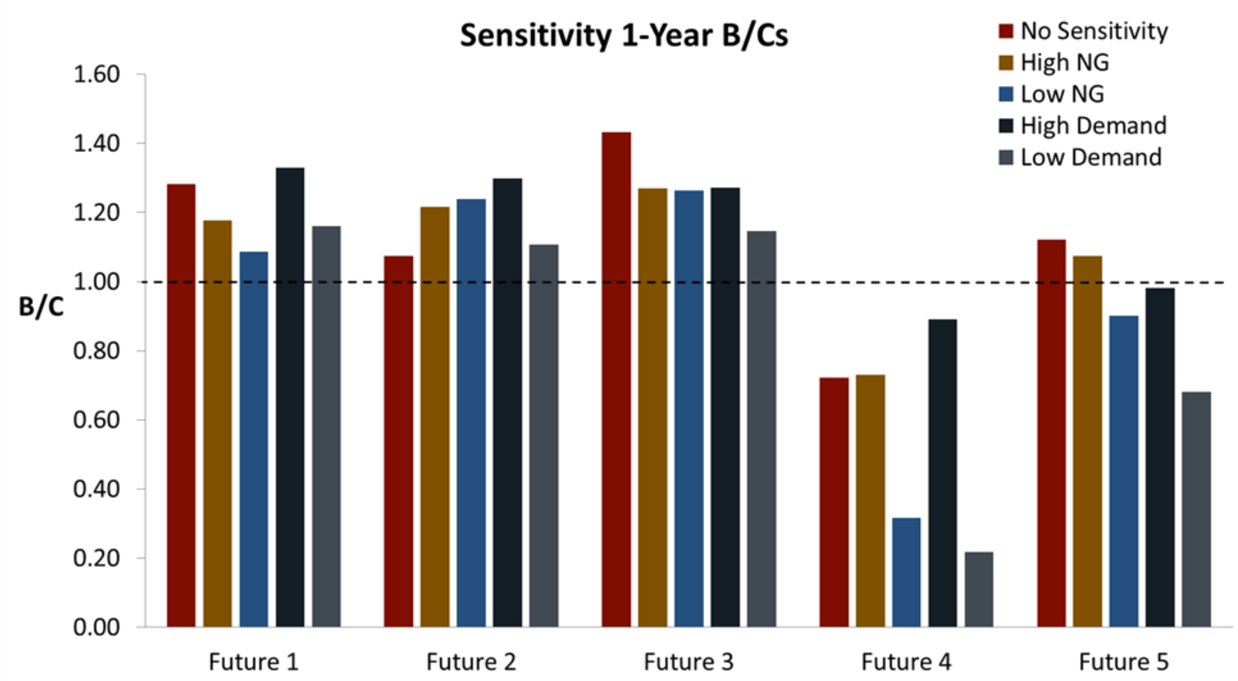


Figure 16.13: One-Year B/C's for all Futures and Sensitivities

The non-sensitivity runs all show one-year B/C's that are less than the 40-year B/C's. The one-year B/C's are still greater than 1.0 for all futures except Future 4. Future 4 shows less benefit from the Consolidated Portfolio than the other futures, primarily due to the reduced load and energy in this future. Most sensitivity runs are showing minimal variation in economic benefit for fluctuations in demand or gas prices.

Section 17: Final Assessments

17.1: Final Reliability Assessment

A final reliability assessment was conducted on the Consolidated Portfolio in order to identify the binding and breaching system constraints with the recommended plan in place. This assessment was conducted for informational purposes; there were no additional projects developed as part of the final reliability assessment. The following details guided the final reliability assessment:

- Analyzed the same 4 peak hours that were analyzed for the reliability needs and projects development (Summer Peak, Winter Peak, High Wind, and Low Hydro)
- Analyzed Future 1 for 2033 only
- Analyzed only the Consolidated Portfolio

The results are included in the Appendix Section 20:. The results show a total of 103 binding or breaching facilities:

- 25 of these facilities were mitigated by lower voltage solutions earlier in the study; however, these lower voltage solutions were not included in the final 20-year expansion plan which targets primarily EHV solutions.
- Many of these binding or breaching constraints, or a close variation of them, appear in multiple hours.
- The inclusion of the Consolidated Portfolio will create an alternative dispatch than the dispatch generated from the base case. This change in dispatch will lead to some new binding or breaching constraints than were observed in the main reliability needs and project development phase. A project may mitigate major congestion in one area while creating minor congestion in another area.
- The results show 100 kV and above facilities for which an SPP RTO zone has at least partial ownership of.

17.2: Final Stability Assessment

An assessment was performed to confirm that the wind dispatched for the 2013 ITP20 Consolidated Portfolio 2023 Summer-Peak case[26] can be achieved without the occurrence of voltage instability.

Method

The method employed to determine the amount of wind generation that could be accommodated in the Consolidated Portfolio was accomplished by reducing wind generation to minimum levels while simultaneously increasing conventional generation to meet SPP load requirements. Next, the wind was incrementally increased up to the 9.2 GW of installed capacity in Future 1, while conventional generation was incrementally decreased. The system was monitored for the voltage collapse point for

[26] A 2023 summer peak model was utilized because there is not a 2033 off peak model to use. A 2023 summer peak model should have similar load to a 2033 off-peak (high wind) hour.

both normal conditions and contingencies. N-1 contingencies of 345kV facilities were utilized. All 100 kV and above buses in SPP were monitored for voltage collapse.

Wind Dispatch Achievable with Consolidated Portfolio

The Future 1 wind dispatch in the ITP20 is feasible from a voltage stability viewpoint. There was no voltage instability in the load areas within SPP. The 2013 ITP20 Consolidated Portfolio can reliably dispatch 9.2 GW of wind.

Section 18: Conclusion

The 2013 ITP20 Consolidated Portfolio is a grouping of projects that is projected to meet the reliability, policy, and economic needs over a 20-year horizon. The projects in the Consolidated Portfolio were studied through a rigorous process that utilized a diverse array of power system and economic analysis tools to evaluate the need for EHV projects that satisfy needs such as:

- resolving potential criteria violations;
- mitigating known or foreseen congestion;
- enabling renewable energy standards to be met.

Multiple assessment methodologies were used to evaluate the system from different perspectives and encourage confidence in the findings of the study. Study tools and drivers were successfully benchmarked against historical expectations, sensitivities were performed to ensure the viability of the portfolio in multiple scenarios, stakeholders provided continuous feedback concerning the technical details of the modeling needs and projects, inter-regional needs were addressed and discussed with external regions, and a portfolio was designed to respond to SPP's evolving needs.

The Consolidated Portfolio is a primarily EHV backbone system that fulfills the strategic, long-term vision of the ITP20. The ITP20 is not intended to address the lower voltage solutions that will be needed as a result of new EHV backbone projects. The Consolidated Portfolio projects are expected to provide economic benefit across multiple futures scenarios and multiple sensitivities, even though more than half of the projects are primarily addressing reliability needs. The projects are expected to provide $1.5B in net benefit over the expected 40-year life, with an expected B/C ratio of 2.79. As a result, the average residential customer in SPP will see a decrease in their monthly electric bill of 9¢.

Name	Type	Size	Focus
Keystone – Red Willow	New Branch	345 kV	Reliability
Tolk – Tuco	New Branch	345 kV	Reliability
S3459	2nd Transformer	345/161 kV	Economic
Holcomb	2nd Transformer	345/115 kV	Reliability
Maryville	New Transformer	345/161 kV	Reliability
Pecan Creek – Muskogee	Upgrade 2 circuits	345 kV	Reliability
Nashua	Upgrade Transformer	345/161 kV	Reliability
JEC – Auburn – Swissvale	Rebuild (New Auburn transformer)	345 kV, 345/115 kV	Reliability
Clinton – Truman – N Warsaw	Upgrade Branch	161 kV	Seams Project
S3740 - S3454	New Branch	345 kV	Reliability
Chamber Springs - S Fayetteville	New Branch & Transformer	345 KV, 345/161 kV	Economic
Wolf Creek - Neosho	New Branch	345 kV	Economic

Table 18.1: 2013 ITP20 Projects

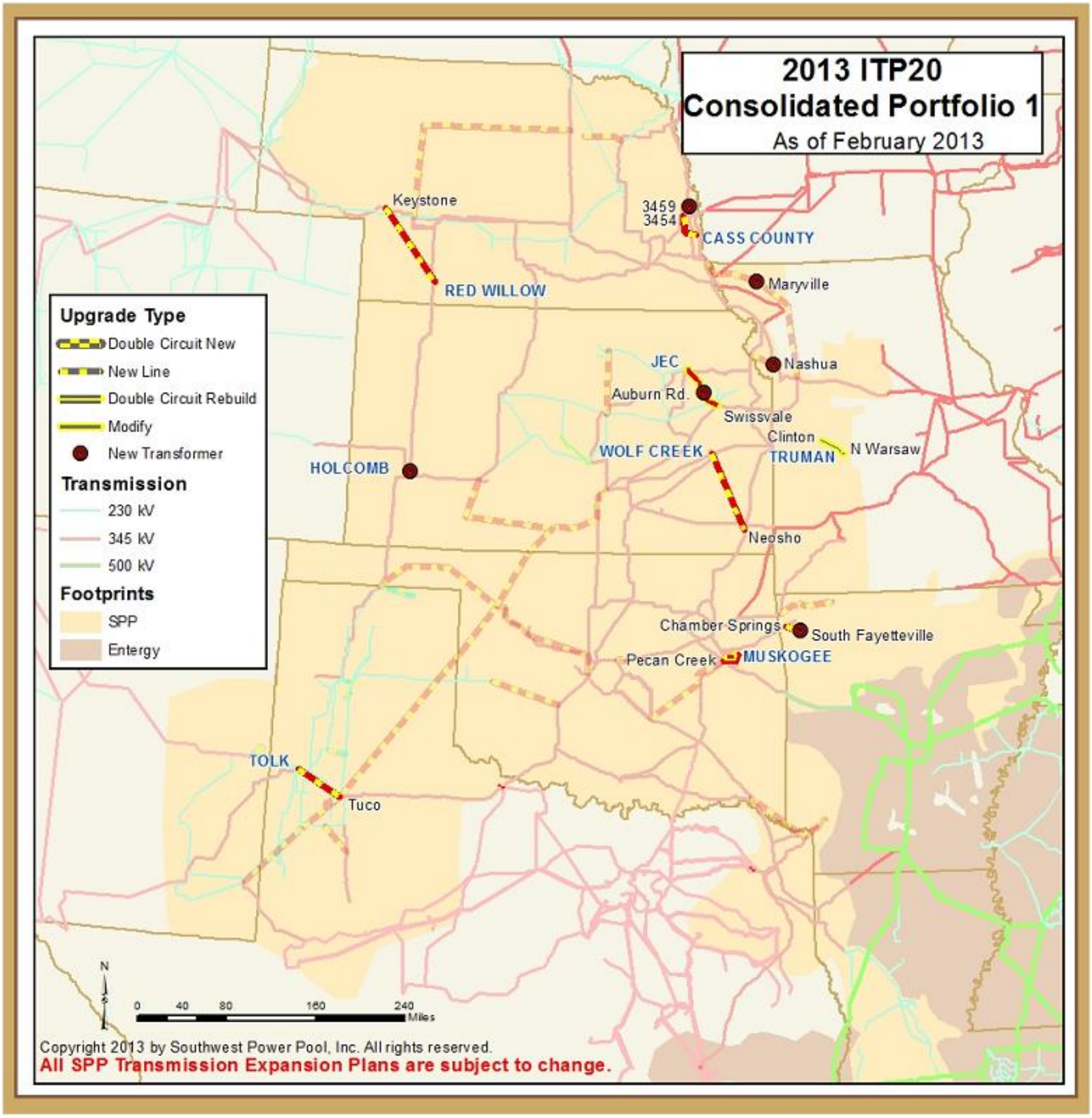


Figure 18.1 2013 ITP20 Consolidated Portfolio

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PART IV: APPENDICES

Section 19: 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**	Midcontinent Independent System Operator, Inc.
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 Energy 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 20: Final Reliability Assessment Results

This section includes the results for the final reliability assessment described in Section 17.1:

- The binding or breaching constraints highlighted in yellow were mitigated by lower voltage solutions earlier in the study. These lower voltage solutions were not included in the final 20-year expansion plan which targets primarily EHV solutions.
- YBUS represents a 3-winding transformer in PROMOD IV® or PAT.

Constraints	Contingency	Flow (MW)	Lower Bound	Upper Bound	Shadow Price ($/MW)	Violation (MW)	Hour
300075 505434 [1] 5ESSEX 161- IDALIA 5 161 (AECI-SWPA)	69: 5NEWMAD - 7NEWMAD 1 161/345 (AECI)	335	-335	335	-41.06		HW
300101 505498 [1] 5MORGAN 161- STOCKTN5 161 (AECI-SWPA)	256: NEOSHO 7 - LACYGNE7 1 345 (WERE-KCPL)	-167	-167	167	353.94		LH
301402 541314 [1] 5WARSAW_ 161- NWARSAW5 161 (AECI-GMO)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	-317	-317	317	4541.25		SP
301402 541314 [1] 5WARSAW_ 161- NWARSAW5 161 (AECI-GMO)	262: 7OVERTON - SIBLEY 7 1 345 (AMMO-GMO)	-353.88	-317	317	6000	36.88	SP
301402 541314 [1] 5WARSAW_ 161- NWARSAW5 161 (AECI-GMO)	74: 7OVERTON - SIBLEY 7 1 345 (AMMO-GMO)	-353.88	-317	317	6000	36.88	SP
301402 541314 [1] 5WARSAW_ 161- NWARSAW5 161 (AECI-GMO)	262: 7OVERTON - SIBLEY 7 1 345 (AMMO-GMO)	-317	-317	317	272.41		WP
344558 543060 [1] 5EX SPRN 161- CAROLTN5 161 (AMMO-KCPL)	74: 7OVERTON - SIBLEY 7 1 345 (AMMO-GMO)	189.7	-167	167	-6000	22.7	SP
345408 541201 [1] 7OVERTON 345- SIBLEY 7 345 (AMMO-GMO)	15: NEOSHO 7 - LACYGNE7 1 345 (WERE-KCPL)	-993.92	-956	956	6000	37.92	SP
345408 541201 [1] 7OVERTON 345- SIBLEY 7 345 (AMMO-GMO)	17: MUSKOGE7 - FTSMITH7 1 345 (OKGE)	-987.2	-956	956	6000	31.2	SP
345408 541201 [1] 7OVERTON 345- SIBLEY 7 345 (AMMO-GMO)	Base case	-956	-956	956	2303.28		SP
345408 541201 [1] 7OVERTON 345- SIBLEY 7 345 (AMMO-GMO)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	-1010.64	-956	956	6000	54.64	SP
504020 506944 [1] FARMNGTN 161- CHAMSPR5 161 (AEPW)	343: CHAMSPR7 345 - SFAYTVL8 345[1] (AEPW)	-317	-317	317	4710.28		SP
504181 507185 [1] HACKETT 161- REVESRD5 161 (AEPW)	Base case	174.55	-158	158	-6000	16.55	SP
505480 506932 [1] BEAVER 5 161- EUREKA 5 161 (SWPA-AEPW)	167: SHIPERD7 - KINGRIV7 1 345 (AEPW)	282.77	-247	247	-6000	35.77	SP
505486 547472 [1] NEO SPA5 161- TIP292 5 161	260: CHAMSPR7 - CLARKSV7 1 345 (AEPW)	-222	-222	222	4144.83		SP

(SWPA-EMDE)							
505492 547479 [1] SPRGFLD5 161- LAR382 5 161 (SWPA-EMDE)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	-183.22	-167	167	6000	16.22	SP
505492 547479 [1] SPRGFLD5 161- LAR382 5 161 (SWPA-EMDE)	342: MON383 7 345 - BROOKLIN 345[1] (EMDE-SPRM)	-168.34	-167	167	6000	1.34	SP
505492 547479 [1] SPRGFLD5 161- LAR382 5 161 (SWPA-EMDE)	332: FLINTCR7 345 - MON383 7 345[1] (AEPW-EMDE)	-168.34	-167	167	6000	1.34	SP
505492 549970 [1] SPRGFLD5 161- CLAY 161 (SWPA-SPRM)	74: 7OVERTON - SIBLEY 7 1 345 (AMMO-GMO)	167	-167	167	-68.49		SP
505492 549970 [1] SPRGFLD5 161- CLAY 161 (SWPA-SPRM)	196: 7HUBEN - 7MORGAN 1 345 (AECI)	242.12	-167	167	-6000	75.12	SP
505492 549970 [1] SPRGFLD5 161- CLAY 161 (SWPA-SPRM)	196: 7HUBEN - 7MORGAN 1 345 (AECI)	167	-167	167	-25.8		WP
505522 515339 [1] VAN BUR5 161- VBI 5 161 (SWPA-OKGE)	17: MUSKOGE7 - FTSMITH7 1 345 (OKGE)	341.45	-335	335	-6000	6.45	SP
505592 510902 [1] WELEETK4 138- WELETK4 138 (SWPA-AEPW)	Base case	-172	-172	172	2207.16		SP
507185 507189 [1] REVESRD5 161- NHUNTNT5 161 (AEPW)	Base case	164.68	-158	158	-6000	6.68	SP
507456 99296 [1] TURK 3 115- YBUS702 100 (AEPW)	23: 7SAREPT - LONGWD 7 1 /345 (EES-AEPW)	-202	-202	202	615.13		SP
508548 509059 [1] KNOXLEE4 138- CHEROKE4 138 (AEPW)	Base case	225.8	-214	214	-6000	11.8	SP
508840 99250 [1] WILKES 4 138- YBUS748 100 (AEPW)	333: LONGWD 7 345 - WILKES 7 345[1] (AEPW)	-493	-493	493	5789.19		SP
509059 509087 [1] CHEROKE4 138- TATUM 4 138 (AEPW)	Base case	214	-214	214	-2177.35		SP
509080 509242 [1] OVERTON4 138- JACKSNV4 138 (AEPW)	168: LEBROCK7 - TENRUSK7 1 345 (AEPW)	235	-235	235	-4448.11		SP
509080 509242 [1] OVERTON4 138- JACKSNV4 138 (AEPW)	269: TENRUSK7 345 - CROCKET7 345(1) (AEPW)	235	-235	235	-6000	0	SP
509786 509804 [1] BA.N-ST4 138- LLANETP4 138 (AEPW)	260: CHAMSPR7 - CLARKSV7 1 345 (AEPW)	212	-212	212	-6000	0	SP
509786 509804 [1] BA.N-ST4 138- LLANETP4 138 (AEPW)	34: CHAMSPR7 - CLARKSV7 1 345 (AEPW)	212	-212	212	-1360.23		SP
509807 509836 [2] ONETA--7 345- OEC 7 345 (AEPW)	281: ONETA--7 345 - OEC 7 345(1) (AEPW)	-1195	-1195	1195	12.24		WP
510877 515055 [1] FIXCT4 138- MAUD 4 138 (AEPW-OKGE)	Base case	-89.81	-88	88	6000	1.81	SP
511477 521089 [1] S.W.S.-4 138- WASHITA4 138 (AEPW-WFEC)	295: L.E.S.-7 - GRACEMNT7 1 345 (AEPW-OKGE)	-287	-287	287	49.37		HW
512650 512750 [1] GRDA1 7 345- TONECE7 345 (GRDA)	34: CHAMSPR7 - CLARKSV7 1 345 (AEPW)	1100.53	-1064	1064	-6000	36.53	SP
514785 515785 [1] WOODWRD4 138- WINDFRM4 138 (OKGE)	Base case	-133	-133	133	467.33		SP

514820 514821 [1] JENSENT4 138- JENSEN 4 138 (OKGE)	297: ELKCITY7 345 - GRACMNT7 345(1) (AEPW-OKGE)	-191	-191	191	25.71		HW
514876 514887 [1] SW134TP4 138- WESTMOR4 138 (OKGE)	Base case	268	-268	268	-1141.7		SP
514901 514934 [1] CIMARON7 345- DRAPER 7 345 (OKGE)	332: NORTWST7 345 - ARCADIA7 345[1] (OKGE)	717	-717	717	-2.24		HW
515008 515009 [1] KINZE 4 138- MCELROY4 138 (OKGE)	337: CLEVLND7 345 - SOONER 7 345[1] (GRDA-OKGE)	-222	-222	222	2635.27		SP
515224 515302 [1] MUSKOGE7 345- FTSMITH7 345 (OKGE)	34: CHAMSPR7 - CLARKSV7 1 345 (AEPW)	748.92	-717	717	-6000	31.92	SP
515224 515302 [1] MUSKOGE7 345- FTSMITH7 345 (OKGE)	169: CLARKSV7 - MUSKOGE7 1 345 (AEPW-OKGE)	717	-717	717	-2285.82		SP
515228 515250 [1] 5TRIBES5 161- HANCOK-5 161 (OKGE)	17: MUSKOGE7 - FTSMITH7 1 345 (OKGE)	228.94	-223	223	-6000	5.94	SP
523797 98987 [1] HOWARD 115- YBUS1011 100 (SPS)	Base case	-40	-40	40	623.97		SP
523797 98987 [1] HOWARD 115- YBUS1011 100 (SPS)	Base case	-40	-40	40	1.97		LH
523797 98987 [1] HOWARD 115- YBUS1011 100 (SPS)	Base case	-40	-40	40	40.47		WP
524622 98967 [2] DEAFSMIT 115- YBUS1031 100 (SPS)	Base case	-168	-168	168	2960.97		SP
525326 98948 [1] COX 115- YBUS1050 100 (SPS)	Base case	-84	-84	84	748.94		SP
525326 98948 [1] COX 115- YBUS1050 100 (SPS)	Base case	-84	-84	84	0.63		LH
525326 98948 [1] COX 115- YBUS1050 100 (SPS)	Base case	-84	-84	84	20.63		WP
526298 98920 [1] LUBBCK_E 115- YBUS1078 100 (SPS)	Base case	-84	-84	84	637.58		SP
526298 98920 [1] LUBBCK_E 115- YBUS1078 100 (SPS)	Base case	-84	-84	84	124.66		LH
526298 98920 [1] LUBBCK_E 115- YBUS1078 100 (SPS)	Base case	-84	-84	84	42.38		WP
527483 527799 [1] CHAVES_C 230- EDDY_NOR 230 (SPS)	Base case	319	-319	319	-40.51		WP
527799 527800 [1] EDDY_NOR 230- EDDY_SOU 230 (SPS)	252: TUCO_INT 345 - AMOCO_SS 345(1) (SPS)	478	-478	478	-4.24		LH
530593 98858 [1] SMKYP1 6 230- YBUS1140 100 (MIDW)	Base case	-115	-115	115	526.56		SP
530593 98858 [1] SMKYP1 6 230- YBUS1140 100 (MIDW)	Base case	-115	-115	115	78.8		WP
531378 531472 [1] HICKOCK3 115- AMOCO 3 115 (SUNC)	Base case	-170	-170	170	334.67		SP
531445 98840 [1] GRDNCTY3 115- YBUS1158 100	Base case	-41	-41	41	296.99		SP

(SUNC)							
531445 98840 [1] GRDNCTY3 115- YBUS1158 100 (SUNC)	Base case	-41	-41	41	12.91		HW
531445 98840 [1] GRDNCTY3 115- YBUS1158 100 (SUNC)	Base case	-41	-41	41	44.52		LH
531449 531448 [2] HOLCOMB7 345- HOLCOMB3 115 (SUNC)	Base case	-435	-435	435	367.27		SP
532987 532990 [1] BUTLER 4 138- MIDIAN 4 138 (WERE)	319: BENTON 7 345 - ROSEHIL7 345(1) (WERE)	-143	-143	143	1004.86		SP
539667 98726 [1] HAGGARD3 115- YBUS1272 100 (SUNC)	Base case	-28	-28	28	79.39		WP
539673 539760 [1] MED-LDG3 115- BARBER 3 115 (SUNC)	301: CONESTOG 345 - FINNEY 345(1) (SPS)	79.7	-79.7	79.7	-16.62		HW
539688 539699 [1] S-DODGE3 115- W-DODGE3 115 (SUNC)	304: SPERVIL7 345 - BUCKNER7 345(1) (SUNC)	-129.5	-129.5	129.5	12.87		HW
539692 539696 [1] SEWARD 3 115- ST-JOHN3 115 (SUNC)	247: CONESTOG 345 - HITCHLAN 345(1) (SPS)	87.6	-87.6	87.6	-4285.39		SP
539695 98738 [1] SPEARVL6 230- YBUS1260 100 (SUNC)	Base case	-75	-75	75	22.77		HW
539695 98738 [1] SPEARVL6 230- YBUS1260 100 (SUNC)	Base case	-75	-75	75	79.02		LH
542972 542980 [1] HAWTH 7 345- NASHUA 7 345 (KCPL)	340: SMARYVL7 345 - SIBLEY 7 345[1] (GMO)	-1136	-1136	1136	2829.12		SP
542972 542980 [1] HAWTH 7 345- NASHUA 7 345 (KCPL)	176: STRANGR7 - IATAN 7 1 345 (WERE-KCPL)	-1136	-1136	1136	45.66		HW
547468 547480 [1] AUR124 5 161- MON383 5 161 (EMDE)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	-234.68	-223	223	6000	11.68	SP
547469 98665 [1] RIV4525 161- YBUS1333 100 (EMDE)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	120.19	-100	100	-6000	20.19	SP
547469 98665 [1] RIV4525 161- YBUS1333 100 (EMDE)	Base case	114.41	-100	100	-6000	14.41	SP
547476 547491 [1] ASB349 5 161- PUR421 5 161 (EMDE)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	223	-223	223	-5974.98		SP
599809 533151 [2] AUBURN 7 345- AUBURN 3 115 (WERE)	38: HOYT 7 - JEC N 7 1 345 (WERE)	435	-435	435	-2248.56		SP
640302 659134 [1] OGALALA4 230- SIDNEY 4 230 (NPPD)	181: KEYSTON3 - SIDNEY 3 1 345 (NPPD-WAPA)	-320	-320	320	11.12		HW
338813 505460 [1] 5MIDWY J 161- BULL SH5 161 (EES-EAI-SWPA)	78: 8KEO - 8HOLBT 1 500 (EES-EAI-EES)	-162	-162	162	813.66		WP
503912 338875 [1] FULTON 115- 3PATMOS. 115 (AEPW-EES-EAI)	190: 7SAREPTA% - LONGWD 7 1 345 (AEPW-EES)	178.12	-157	157	-6000	21.12	SP
503912 338875 [1] FULTON 115- 3PATMOS. 115 (AEPW-EES-EAI)	190: 7SAREPTA% - LONGWD 7 1 345 (AEPW-EES)	157	-157	157	-39.54		HW
503912 338875 [1] FULTON 115- 3PATMOS. 115 (AEPW-EES-EAI)	190: 7SAREPTA% - LONGWD 7 1 345 (AEPW-EES)	157	-157	157	-0.36		LH

504000 506931 [1] AVOCA 161- EROGERS5 161 (AEPW)	167: SHIPERD7 - KINGRIV7 1 345 (AEPW)	-225.88	-220	220	6000	5.88	SP
504181 507182 [1] HACKETT 161- BONANZA5 161 (AEPW)	33: 8ANO - FTSMITH8 1 /500 (EES-OKGE)	-199.99	-178	178	6000	21.99	SP
504181 507182 [1] HACKETT 161- BONANZA5 161 (AEPW)	Base case	-198.76	-158	158	6000	40.76	SP
511458 521116 [1] ELKCTY-4 138- RHWIND4 138 (AEPW-WFEC)	Base case	-144	-144	144	20.13		HW
525480 98943 [1] PLANT_X 115- YBUS1055 100 (SPS)	171: O.K.U.-7 - L.E.S.-7 1 345 (AEPW)	-239	-239	239	4325.28		SP
527482 527546 [1] CHAVES_C 115- SAMSON 115 (SPS)	Base case	120	-120	120	-4403.16		SP
532937 547469 [1] NEOSHO 5 161- RIV4525 161 (WERE-EMDE)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	223	-223	223	-3661.41		SP
532937 547469 [1] NEOSHO 5 161- RIV4525 161 (WERE-EMDE)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	223	-223	223	-230.59		HW
532937 547469 [1] NEOSHO 5 161- RIV4525 161 (WERE-EMDE)	9: 7BLACKBERRY - NEOSHO 7 1 345 (AECI-WERE)	223	-223	223	-74.33		LH
539652 539672 [1] CMRIVTP3 115- E-LIBER3 115 (SUNC)	248: CONESTOG 345 - FINNEY 345(1) (SPS)	119.5	-119.5	119.5	-8.28		HW
539652 539672 [1] CMRIVTP3 115- E-LIBER3 115 (SUNC)	248: CONESTOG 345 - FINNEY 345(1) (SPS)	119.5	-119.5	119.5	-11.39		LH
539668 539675 [1] HARPER 4 138- MILANTP4 138 (SUNC)	27: WICHITA7 - FLATRDG 7 1 345/ (WERE-SUNC)	108.91	-95.6	95.6	-6000	13.31	SP
539668 539675 [1] HARPER 4 138- MILANTP4 138 (SUNC)	27: WICHITA7 - FLATRDG 7 1 345/ (WERE-SUNC)	95.6	-95.6	95.6	-156.66		HW
539668 539675 [1] HARPER 4 138- MILANTP4 138 (SUNC)	41: THISTLE7 - THISTLE4 4 345 /138 (SUNC)	95.6	-95.6	95.6	-93.46		LH
539680 539740 [1] N-DODGE3 115- EDODGE 3 115 (SUNC)	Base case	83.9	-83.9	83.9	-10.43		HW
539680 539740 [1] N-DODGE3 115- EDODGE 3 115 (SUNC)	Base case	83.9	-83.9	83.9	-38.1		LH
541206 541211 [1] PRALEE 5 161- BLSPS 5 161 (GMO)	165: SIBLEY 1 345/161 (GMO)	224	-224	224	-589.64		SP
543031 546742 [1] SHWNMSN5 161- METRO 5 161 (KCPL-KACY)	16: 87TH 7 - CRAIG 7 1 345 (WERE-KCPL)	-224	-224	224	41.22		LH
640349 652510 [1] SPENCER7 115- FTRANDL7 115 (NPPD-WAPA)	Base case	-102.65	-95	95	6000	7.65	SP
526435 526460 [1] SUNDOWN 230- AMOCO_SS 230 (SPS)	303: TUCO_INT 345 - AMOCO_SS 345(1) (SPS)	351	-351	351	-101.25		HW
526435 526460 [1] SUNDOWN 230- AMOCO_SS 230 (SPS)	303: TUCO_INT 345 - AMOCO_SS 345(1) (SPS)	351	-351	351	-11.59		LH

Section 21: Additional Metrics

The Metrics Task Force (MTF) developed new benefit metrics for use in the Regional Cost Allocation Review (RCAR) conducted in 2012 – 2013. The ESWG provided direction to calculate 3 of these new metrics as part of the 2013 ITP20 as well, but for informational purposes only.

21.1: Assumed Benefit of Mandated Reliability Projects

This benefit was only utilized for projects categorized as reliability. This metric assumes that benefits are equal to costs for mandated reliability projects. Treating benefits for mandated reliability projects equal to their costs avoids potential undervaluing of the portfolio value of reliability projects which are mandated and thus not justified solely by other economic benefits.

To calculate the costs over the expected 40-year life of the reliability projects:

- Each project's total cost was multiplied by the expected carrying charge.
- This carrying charge was escalated out to 2033 $ using a 2.5% inflation rate.
- Costs were depreciated linearly over the 40-year timeframe
- Each year's cost was then discounted using an 8% discount rate.
- The sum of all discounted costs was calculated as the Net Present Value (NPV) cost.
- This 2033 40-year NPV cost was brought back to real dollars using a 2.5% inflation rate.

The Assumed Benefit of Mandated Reliability Projects for the SPP region was equal to the 2013 40-year NPV cost of **$572M**.

21.2: Benefit from Meeting Public Policy Goals

The benefit of meeting public policy goals in the SPP region related to renewable energy supplies is measured by this metric. Since the Consolidated Portfolio did not include any policy projects, the Benefit from Meeting Public Policy Goals was $0.

21.3: Mitigation of Transmission Outage Costs

This metric calculates the benefit from new transmission projects by reducing additional congestion during unplanned outages. Standard production cost simulations assume that transmission lines and facilities are available during all hours of the year and that no planned or unexpected outages of transmission facilities will occur. In practice, however, planned and unexpected transmission outages impose non-trivial additional congestion costs on the system. The benefit of reducing this additional congestion is thus not captured in the standard APC metric. The Mitigation of Transmission Outage Costs metric measures the additional value that projects provide in reducing this additional congestion through the following equation:

$$Benefit_{Mitigation\ Transmission\ Outage\ Costs} = Benefit_{With\ Transmission\ Outages} - Benefit_{No\ Outages} = (APC_{Base\ Case,\ Transmission\ Outages} - APC_{Change\ Case,\ Transmission\ Outages}) - (APC_{Base\ Case,\ No\ Outages} - APC_{Change\ Case,\ No\ Outages})$$

This metric was used to compute one-year benefit only, for Future 1 only. The results are shown in Figure 21.1.

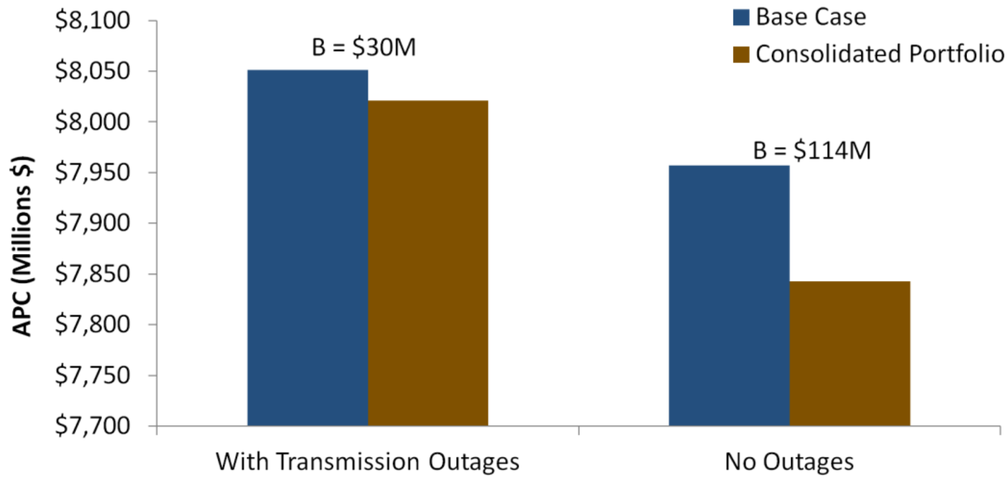

Figure 21.1: Mitigation of Transmission Outages

The results show an increase in APC when transmission outages are introduced, as expected. However, the results also show less benefit with transmission outages than with no outages. This leads to a negative benefit for Mitigation of Transmission Outage Costs of **-$84M**. The Consolidated Portfolio projects were analyzed and optimized to mitigate significant congestion in the runs without outages. When transmission outages are introduced, the system congestion shifts to other areas. This results in the Consolidated Portfolio projects mitigating less congestion in the runs without outages (benefit reduces from $114M to $30M).

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