2017 INTEGRATED TRANSMISSION PLAN 10-YEAR ASSESSMENT REPORT

SPP Southwest Power Pool

ENGINEERING

REVISION HISTORY

Date	Author	Change Description
11/18/2016	SPP Staff	Posting of Part 1 & 2 for initial review
12/5/2016	SPP Staff	Posting of Part 1 & 2, 2nd draft for review
12/8/2016	SPP Staff	Out for Initial Management Review
12/16/2016	SPP Staff	Part I, II & III Out for review
12/29/2016	SPP Staff	Final Draft Report Posting for ESWG/TWG
1/6/2017	SPP Staff	Final Draft Report for MOPC

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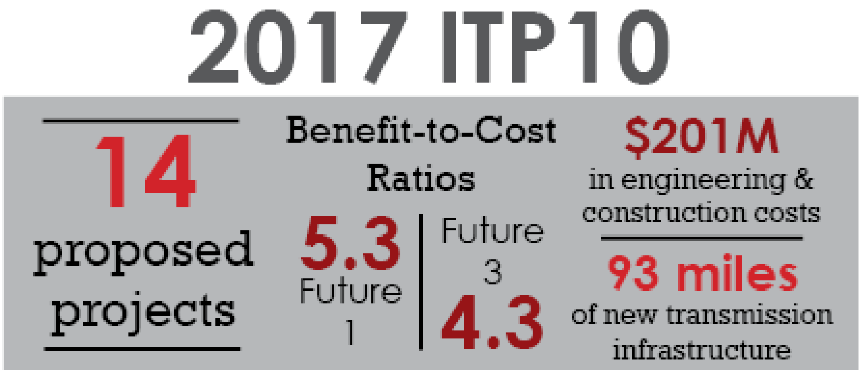
EXECUTIVE SUMMARY



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 (ITP10) focuses on facilities 100 kV and above to meet system needs over a 10-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 investments that will meet reliability, economic, and public policy needs[1] intended 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 10-year Assessment that concludes in January 2017.

Three distinct Futures were considered to account for possible variations in system conditions over the assessment's 10-year horizon. These Futures consider evolving changes in technology, public 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).

and climate changes that may influence the transmission system and energy industry as a whole. The Futures are presented briefly below and further discussed in Section 2.1:

1. Regional Clean Power Plan Solution: Regional implementation of the proposed EPA Clean Power Plan
2. State Level Clean Power Plan Solution: State by State implementation of the proposed EPA Clean Power Plan
3. Reference Case: No implementation of the proposed EPA Clean Power Plan

The recommended 2017 ITP10 portfolio shown in Table 0.1 is estimated at $201 million in engineering and construction cost and includes projects needed to meet potential reliability and economic requirements. These projects will provide approximately 93 miles of new transmission infrastructure. The recommended portfolio consists of fourteen projects. Of these fourteen projects, four projects identified to meet potential reliability and economic requirements have been issued NTCs from other SPP processes. SPP staff recommends these four projects with no changes to the currently issued NTCs.[2] The remaining ten recommended projects will receive an NTC or NTC-C[3].

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage	NTC Status
6	Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line	KCPL	E	$512,500	-	NTC to be Issued
7	Build a new second 230 kV line from Knoll to Post Rock.	MIDW	E	$3,389,019	1	NTC to be Issued

[2] The four projects with NTCs at a cost of $37 million were included in the recommended portfolio as solutions to address regional economic needs. These NTCs were evaluated to assess the regional benefit of addressing economic needs. Three of the four NTC projects are base plan funded with highway/byway cost allocation while one, the 138kV phase shifting transformer at Woodward is a generation interconnection facility upgrade that is not base plan funded. As a result, the incremental cost of the 2017 ITP10 recommended portfolio is $164 million.

[3] This report is for transmission planning purposes only and does not include any determinations of the Transmission Owners for the projects without existing NTCs. The designation of Transmission Owners will be made in accordance with Attachment Y of the SPP Tariff.

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage	NTC Status
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	WR	E	$244,606	-	NTC to be Issued
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	WR/EDE	E	$114,154	-	NTC to be Issued
12	Rebuild 2.1-mile 161 kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE)	AEP/GRDA	E	$5,185,885	2.1	NTC to be Issued
13	Install 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	OGE	E	$7,459,438	-	No Change to Existing NTC
16	Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 138 kV line between the two substations to a summer and winter emergency rating of 169/201 MVA. Upgrade terminal equipment at Lula and/or Tupelo Tap to increase the rating of the line between the substations to 171/192 (SN/SE).	OGE/WFEC	E	$102,500	-	NTC to be Issued
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	SPS	E	$969,942	-	NTC to be Issued

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage	NTC Status
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	SPS	E	$11,961,951	-	No Change to Existing NTC
19	Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	SPS	E/R	$9,953,077	-	No Change to Existing NTC
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	SPS	E	$7,423,880	-	No Change to Existing NTC
25	Install a 345/161 kV transformer at Morgan substation and upgrade the Morgan - Brookline 161 kV line to summer emergency rating of 208 MVA and winter emergency rating of 232 MVA.	AECI	E	$9,481,250	-	NTC to be Issued
26	Upgrade any necessary terminal equipment at Martin, Pantex North, Pantex South, and Highland tap to increase the rating of the 115 kV lines to 159/175 MVA (SN/SE).	SPS	E	$682,034	-	NTC to be Issued
27	Build new 345 kV line from Potter to Tolk[4]	SPS	E	$143,984,174	90	NTC-C to be Issued

Table 0.1: 2017 ITP10 Transmission Plan

[4] In January 2017, the SPP Board of Directors (Board) approved the recommended portfolio with the exception of the new 345 kV line from Potter to Tolk and directed SPP staff to further evaluate the project. In April 2017, the Board accepted staff's recommendation to remove the Potter to Tolk line from the 2017 ITP10 portfolio. The continued need for a solution will be further evaluated pending approval of the commencement of a High Priority study in July 2017.

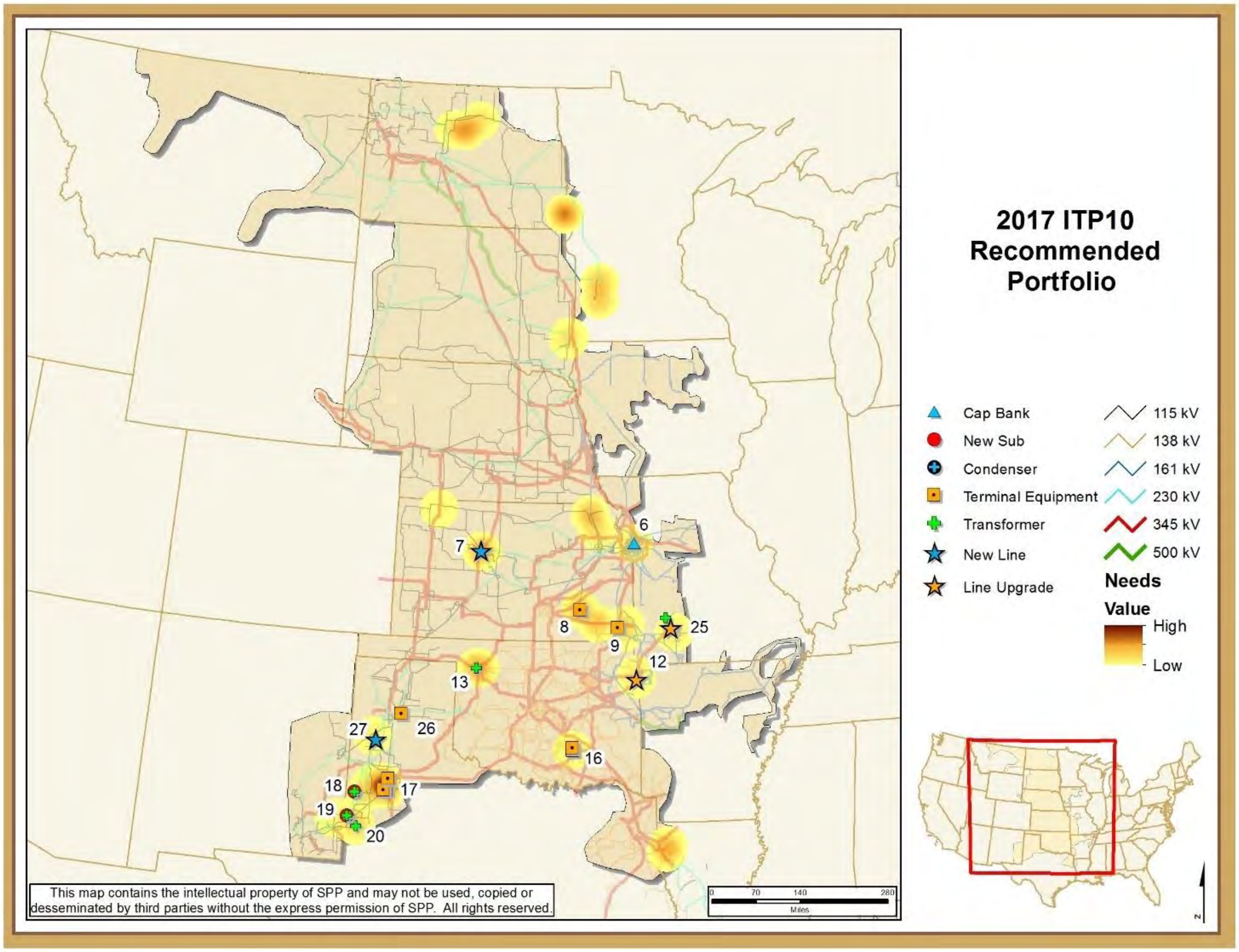


Figure 1.1: 2017 ITP10 Transmission Plan

PART I: STUDY PROCESS

SECTION 1: INTRODUCTION

1.1: The 10-Year Assessment

The Integrated Transmission Planning 10-Year Assessment (ITP10) is designed to develop a transmission expansion portfolio containing projects 100 kV and greater needed to address reliability needs, support policy initiatives, and enable economic opportunities in the SPP transmission system in the 10-year horizon.

The goals of the ITP10 are:

- Focus on regional transmission needs
- Utilize a value-based approach to analyze 10-year out transmission system needs
- Identify 100 kV and above solutions stemming from such needs as:
    - Resolving potential reliability criteria violations
    - Mitigating known or expected congestion
    - Improving access to markets
    - 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: Report Structure

This report focuses on the year 2025 and is divided into multiple sections.

- **Part I** addresses the concepts behind this study's approach and key procedural steps in development of the analysis.
- **Part II** speaks to the overarching assumptions used in the study.
- **Part III** addresses the findings of the study, portfolio specific results (including benefits and costs), supplemental analyses, and SPP staff project recommendations. 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.

Results Reported

Unless otherwise noted, monetary figures reported are in 2017 dollars, and model references and results reported in Parts II-IV are based on the following model assumptions:

Section	Base Model
Section 6: Benchmarking	Base Approved Model
Section 9: Needs Assessment	Base Approved Model
Section 10: Portfolio Development	Base Approved Model + Model Corrections (Base Approved Model in Section 10.2)
Section 11: Staging	Base Approved Model + Model Corrections
Section 12: Benefits	Base Approved Model + Model Corrections
Section 13: Sensitivity Analysis	Base Approved Model + Model Corrections
Section 14: Stability Assessment	Base Approved Model + Model Corrections (less Fort Calhoun Retirement)
Section 15: Supplemental Analysis	Base Approved Model + Model Corrections (Side Bar Models in Section 15.3)
Section 16: Project Recommendations	Base Approved Model + Model Corrections

SPP Footprint

Within this study, any reference to the SPP footprint refers to the set of Transmission Owners[5] (TO) whose transmission facilities are under the functional control of the SPP Regional Transmission Organization (RTO) unless otherwise noted. The Integrated System (IS) joined the SPP RTO in October 2015 and is thus included in the SPP footprint. The IS includes Western Area Power Administration (WAPA), Basin Electric Power Cooperative, and Heartland Consumers Power District.

[5] SPP.org > About Us> Footprint

Energy markets were also modeled for other regions within the Eastern Interconnection. Notably, Associated Electric Cooperatives Inc. (AECI), Mid-Continent Area Power Pool (MAPP), Tennessee Valley Authority (TVA), and Midcontinent Independent System Operator (MISO) were modeled as external energy markets. Entergy and Cleco were modeled within the MISO energy market.

Supporting Documents

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

- SPP 2015 ITP10 Scope
- SPP ITP 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.

1.3: Stakeholder Collaboration

Assumptions and procedures for the 2017 ITP10 analysis were developed through SPP stakeholder meetings that took place in 2015 and 2016. The assumptions were presented and discussed through a series of meetings with members, liaison-members, industry specialists, and consultants to facilitate a thorough evaluation. SPP organizational groups involved in this development included the following:

- Economic Studies Working Group (ESWG)
- Transmission Working Group (TWG)
- Model Development Working Group (MDWG)
- Cost Allocation Working Group (CAWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)
- Regional State Committee (RSC)
- Board of Directors (BOD)

SPP staff served as a facilitator for these groups, worked closely with the chairs to ensure all views were heard, and made sure 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 the BOD. Stakeholder feedback was key to the development of a recommended transmission plan.

- The TWG was responsible for technical oversight of the load forecasts, transmission topology inputs, constraint selection criteria, reliability assessments, transmission project impacts, stability analysis, and the report.
- The ESWG was responsible for technical oversight of the load forecasts, 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 BOD.

1.4: Planning Summits

Four Planning Summits were held over the course of the study to inform and collaborate with stakeholders in an open forum. In August 2015, SPP staff gave stakeholders an update on the status of the initial milestones of the study. At the December 2015 Summit, the topics discussed were model inputs, resource plans, and siting plans. Benchmarking and constraint assessment results were reviewed in March 2016. The final Summit during the process was held in August 2016, when initial project solutions were discussed.

SECTION 2: ASSUMPTIONS DEVELOPMENT

2.1: Futures Development

Development Process

The development of the scenarios to be analyzed within each ITP assessment begins with policy-level direction from the SPC. The ESWG incorporates that direction into discussion of detailed drivers that form the basis of potential Futures of the assessment.

The ESWG and additional participating stakeholders began the process by brainstorming a list of drivers and determining each driver's probability of occurrence based on each participant's own expectation. The initial drivers considered for analysis are as follows:

- Environmental Protection Agency's (EPA) 111(d) (Clean Power Plan)
- competitive wind
- high natural gas supply
- low natural gas supply
- severe weather (drought, extreme winter)
- green future
- technology advancement
- changing renewable portfolio standards
- cost of capital changes
- solar development
- reduced generation capacity availability
- physical security concerns
- extensive WECC connectivity
- load growth
- smart grid technology
- low risk operational guides
- large increase in electric vehicles
- financial expansion cap
- significant deregulation
- environmental regulations due to climate
- economic collapse
- ERCOT becomes synchronous with the Eastern Interconnect

This initial list of drivers was reduced based on the probability ranking, combining similar drivers either by simple description or assumed modeling implementation. The reduced list was incorporated into a matrix of initial Future definitions considering the direction of the SPC to analyze different approaches to Clean Power Plan (CPP) compliance and the general implications of the remaining drivers. This initial list included four defined Futures: a regional approach to CPP compliance, a state approach to CPP compliance, a reference case, and a worst-case scenario. These Futures were then further refined by determining whether each driver would be more appropriately considered in a longer-range assessment or sensitivity analysis. Table 2.1 below defines the remaining drivers and how they were considered in the remaining Futures.

Driver	Future 1	Future 2	Future 3
EPA 111(d) (Clean Power Plan)	Regional	State	No
Competitive Wind	Yes	Yes	Yes
High Natural Gas Supply	Yes	Yes	Yes
Load Growth	Normal	Normal	Normal
Solar Development (Substantial)	Large Scale	Large Scale	Large Scale/Rooftop

Table 2.1: 2017 ITP10 Future Drivers

Future Descriptions

Future 1: Regional Clean Power Plan Solution

This Future assumes that the EPA CPP will be implemented at the regional level by meeting emission targets within the SPP footprint and each of its neighboring regions. Future 1 includes all assumptions from Future 3 with an increase in large-scale solar development and minimal distributed solar development.

Future 2: State-Level Clean Power Plan Solution

This Future assumes that the EPA CPP will be implemented at the state level by meeting emissions targets within each state. It will include all assumptions from Future 3 with an increase in large-scale solar development and minimal distributed solar development as in Future 1 above.

Future 3: Reference Case

This Future assumes no major changes to policies that are currently in place. Future 3 will include all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the Renewable Policy Survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. Additional significant features of this Future include competitive wind and high availability of natural gas.

Emission Reduction Goals

Futures 1 and 2 define scenarios that contain a resource mix capable of producing less carbon emissions than the reference. The level of reduced emissions was determined through leveraging the emission performance rate standards set forth by the EPA's CPP. This plan leverages Section 111(d) of the Clean Air Act to regulate the carbon emission output of certain existing and under construction fossil fuel-fired generators categorized by the EPA as coal steam, oil and gas steam, and natural gas combined cycle and also defined as affected electric generating units (EGU). The EPA calculated state emission goals for years 2022-2030 based on historical operation of these affected EGUs in 2012 and assuming efficiency improvements, increased usage of natural gas combined cycle generation, and renewable potential. Under the final rule, each state would have the option of imposing a weighted average performance standard emission rate, a source-specific performance standard emission rate, or an allocation of emission credits to affected EGUs as a function of the overall state mass target.

In order to better understand how these requirements were utilized in this study, the carbon reduction Futures need to be described in the context of the implementation of a carbon market. For the purposes of this analysis, mass targets were utilized and credits were assumed to be allocated based on historical operation of affected EGUs. In the context of a carbon market, these allocations can be bought or sold by the affected EGUs in order to generate appropriately in the future. Future 1 assumes regional carbon markets in which all affected EGUs operating within a common footprint (generally RTO regions) have the ability to buy and sell with each other. Future 2 assumes state carbon markets in which affected EGUs can only buy and sell allocations with other affected EGUs physically located within the same state. In order to implement these concepts, the mass goals developed by the EPA for each state were re-calculated to fit the construct of each Future as well as the construct of the simulated model (which does not simulate the operation of every resource of every state). These new goals were calculated utilizing the technical supporting documents released with the CPP that contain unit-level historical data and a step-by-step process by which the state goals were derived.

The average annual affected source mass goals and new source complement (to account for mass output of future fossil generation) were targeted in the appropriate years in development of the SPP resource plan for each Future. SPP staff and the ESWG targeted the interim goals in each of the staging and study models as well as the final goal for the purposes of resource planning. The 2022-2024 interim compliance period goal was targeted in the 2020 staging model, the 2025-2027 compliance period goal was targeted in the 2025 study model, and the final goal was targeted during the 15-year resource planning simulations. The mass goals are detailed in Table 2.2.

Region	State/ Sub-region	CPP Implementation	2022-2024	2025-2027	Final (2030)
Southwest Power Pool	AR	Regional	8,043,883	7,357,921	6,636,052
Southwest Power Pool	IA	Regional	1,884,092	1,722,899	1,552,996
Southwest Power Pool	KS	Regional	26,841,465	24,558,051	22,157,984
Southwest Power Pool	LA	Regional	4,388,558	4,082,397	3,795,481
Southwest Power Pool	MO	Regional	24,361,900	22,349,050	20,264,336
Southwest Power Pool	ND	Regional	8,961,201	8,194,526	7,386,430
Southwest Power Pool	NE	Regional	22,213,446	20,321,240	18,331,070
Southwest Power Pool	NM	Regional	2,649,597	2,481,189	2,333,776
Southwest Power Pool	OK	Regional	43,350,447	40,077,413	36,852,593
Southwest Power Pool	SD	Regional	1,498,634	1,397,746	1,305,519
Southwest Power Pool	TX	Regional	33,799,276	31,014,533	28,134,566
Southwest Power Pool	WY	Regional	2,215,170	2,025,651	1,825,894
Southwest Power Pool	SPP	Regional	180,207,662	165,582,610	150,576,693
Associated Electric	AR	Regional	323,838	309,548	301,414

Region	State/ Sub-region	CPP Implementation	2022-2024	2025-2027	Final (2030)
Cooperatives, Inc.					
Associated Electric Cooperatives, Inc.	MO	Regional	14,120,434	12,935,622	11,698,806
Associated Electric Cooperatives, Inc.	OK	Regional	2,342,599	2,205,167	2,092,834
Associated Electric Cooperatives, Inc.	AECI	Regional	16,786,871	15,450,335	14,093,053
SPP and AECI	SPP and AECI[6]	Regional	196,994,526	181,032,940	164,669,741
Eastern Interconnect	AR	State	36,201,457	33,522,923	30,685,529
Eastern Interconnect	IA	State	30,531,021	28,029,257	25,281,881
Eastern Interconnect	KS	State	26,870,692	24,656,648	22,220,823
Eastern Interconnect	LA	State	42,233,941	39,131,613	35,854,322
Eastern Interconnect	MI	State	57,110,175	52,756,905	48,094,303
Eastern Interconnect	MN	State	27,420,731	25,265,233	22,931,174
Eastern Interconnect	MO	State	67,587,294	62,083,903	56,052,813
Eastern Interconnect	ND	State	25,553,843	23,435,224	21,099,678
Eastern Interconnect	NE	State	22,335,063	20,492,045	18,463,445
Eastern Interconnect	OK	State	47,816,049	44,469,397	41,000,853
Eastern Interconnect	TN	State	34,265,553	31,575,934	28,664,994
Eastern Interconnect	MT	State	242,913	222,130	200,225
Eastern Interconnect	NM	State	2,649,597	2,481,189	2,333,776
Eastern Interconnect	SD	State	4,245,056	3,909,198	3,569,307
Eastern Interconnect	TX	State	45,722,084	42,219,576	38,739,163

Table 2.2: Average Annual Affected Source Mass Goals + New Source Complement (CO2 Short Tons)

For the purposes of this assessment, Future 1 assumes a common target for SPP and AECI and Future 2 assumes common targets for each state or the portion of the state operating in the Eastern Interconnection.

2.2: Policy Considerations

Historically, SPP has only considered renewable energy standards as Public Policy initiatives in the ITP studies. The EPA Clean Power Plan would likely be an addition to this term, however, the Supreme Court stayed the implementation of the CPP in February 2016 and the current political climate creates an increased uncertainty around the future of the CPP. For this study, the CPP is not considered a

[6] Emissions goal for Future 1

Public Policy initiative and references to the Futures, models, and portfolios developed through targeting the carbon emission reduction requirements of the CPP will be described as reduced carbon, or carbon reduction, in this report.

Definitions

- *Renewable Statutory/Regulatory Mandate*: Any currently effective state or federal statute or local law or any regulatory rule, directive, or order which requires that an electric utility[7], subject to the jurisdiction of that state, federal, or local law or regulatory body, must use a certain level (e.g. percentage) of renewable energy[8] to serve load. As used in this definition, a regulatory body is:
    - Any state or federal regulatory body with authority over rate-setting, resource planning, and other policy matters for electric utilities within its jurisdiction; or
    - An elected City Council, a publicly-elected Board of Directors, a Board of Directors appointed by a publicly-elected official(s), or other governing body as defined by the appropriate governing statutes with jurisdiction over rates, resource planning, and other regulatory matters.
- *Renewable Statutory/Regulatory Goal*: Any currently effective state or federal statute or local law or any regulatory rule, directive, or order which establishes an aspirational goal to promote the use of a certain level (e.g. percentage) of renewable energy to serve load for an electric utility (subject to the jurisdiction of that state, federal, or local law or regulatory body). This definition does not include renewable energy used by a utility pursuant to Renewable Statutory/Regulatory Mandates, as reported above, or Other Renewables as shown below. As used in this definition, a regulatory body is:
    - Any state or federal regulatory body with authority over rate-setting, resource planning, and other policy matters for electric utilities within its jurisdiction; or
    - An elected City Council, a publicly-elected Board of Directors, a Board of Directors appointed by a publicly-elected official(s), or other governing body as defined by the appropriate governing statutes with jurisdiction over rates, resource planning, and other regulatory matters.

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[6] Some municipalities are exempt.

[8] Some states' renewable requirements are capacity-based instead of energy-based. See Figure 2.1.

Drivers

Renewable energy and capacity requirements are driven by statutory/regulatory standards and court decisions made within each state of the SPP footprint. Figure 2.1 provides a map of the state policy positions.

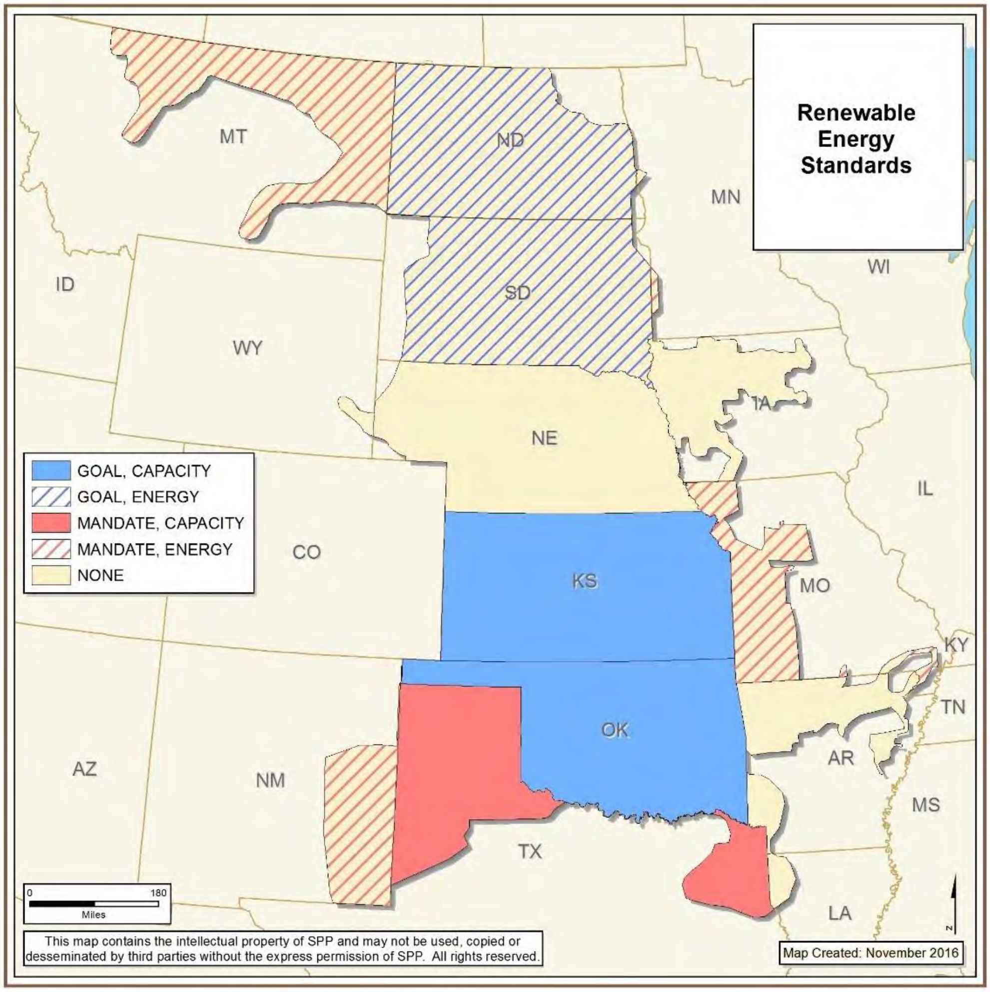


Figure 2.1: Renewable Energy Standards by State

Survey

The 2017 ITP10 Policy Survey focused on planned renewable requirements and additions over the next 10 years. It asked stakeholders to identify:

- Renewable Statutory/Regulatory Mandates for renewable generation through the year 2025
- Renewable Statutory/Regulatory Goals for renewable generation through the year 2025

The results of the 2017 ITP10 Policy Survey were used in the development of resource plans for both conventional and renewable resources as detailed in Section 4:.

2.3: Load and Generation Review

The 2017 ITP10 Load and Generation Reviews focused on existing and planned generation and load through 2025. It asked stakeholders to identify:

- existing generation,
- committed generation,
- expected generation retirements,
- generator operating characteristics,
- system peak load,
- annual energy consumed,
- loss factors, and
- load factors.

The results of the ESWG- and TWG-approved Load and Generation Reviews were used to update the base economic model and used to update generation information used in resource planning.

2.4: Resource Addition Requests

In order to enhance projected generation for the 10-year horizon, the SPP Generation Interconnection (GI) queue was leveraged to supplement information submitted for existing generation. A GI resource and its associated network upgrades were included in the study if an associated company requested it be modeled, it had a FERC-filed interconnection agreement that was not on suspension, and the resource had a firm contract for delivery. Other resources not meeting these criteria were considered by the ESWG and TWG for inclusion based on other levels of certainty.

PART II: MODEL DEVELOPMENT

SECTION 3: MODELING INPUTS

3.1: Introduction

Modeling assumptions for the 2017 ITP10 were discussed and developed through the stakeholder process in accordance with the 2017 ITP10 Scope. Stakeholder load, energy, generation, transmission, and other modeling assumptions were carefully considered in determining the need for and design of future transmission upgrades.

3.2: Load and Energy Forecast

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 ESWG and TWG. 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 58.7 GW for 2020 and 61.3 GW for 2025. Note that all demand figures shown in this section include the loads of the TOs within the SPP OATT footprint as well as all other Load Serving Entities (LSE) within the SPP region.

Peak Load and Energy

The sum of energy used throughout a year, referred to as the net energy for load forecasts, was forecasted by SPP using the load factor data provided and approved by the ESWG contacts. Annual net energy for load (including losses) was forecasted at 293 TWh for 2020 and 307 TWh for 2025. Coincident peak load was forecasted at 56 GW for 2020 and 58.6 GW for 2025. Table 3.1 shows the forecasted SPP peak load (coincident and non-coincident) and annual energy for the staging and study years. Figure 3.1 shows the forecasted monthly energy for 2025.

Year	Non-Coincident Peak Load (GW)	Coincident Peak Load (GW)	Annual Energy (TWh)
2020	58.7	56.0	292.9
2025	61.3	58.6	306.5

Table 3.1: Peak Load and Annual Energy Data for 2020 and 2025

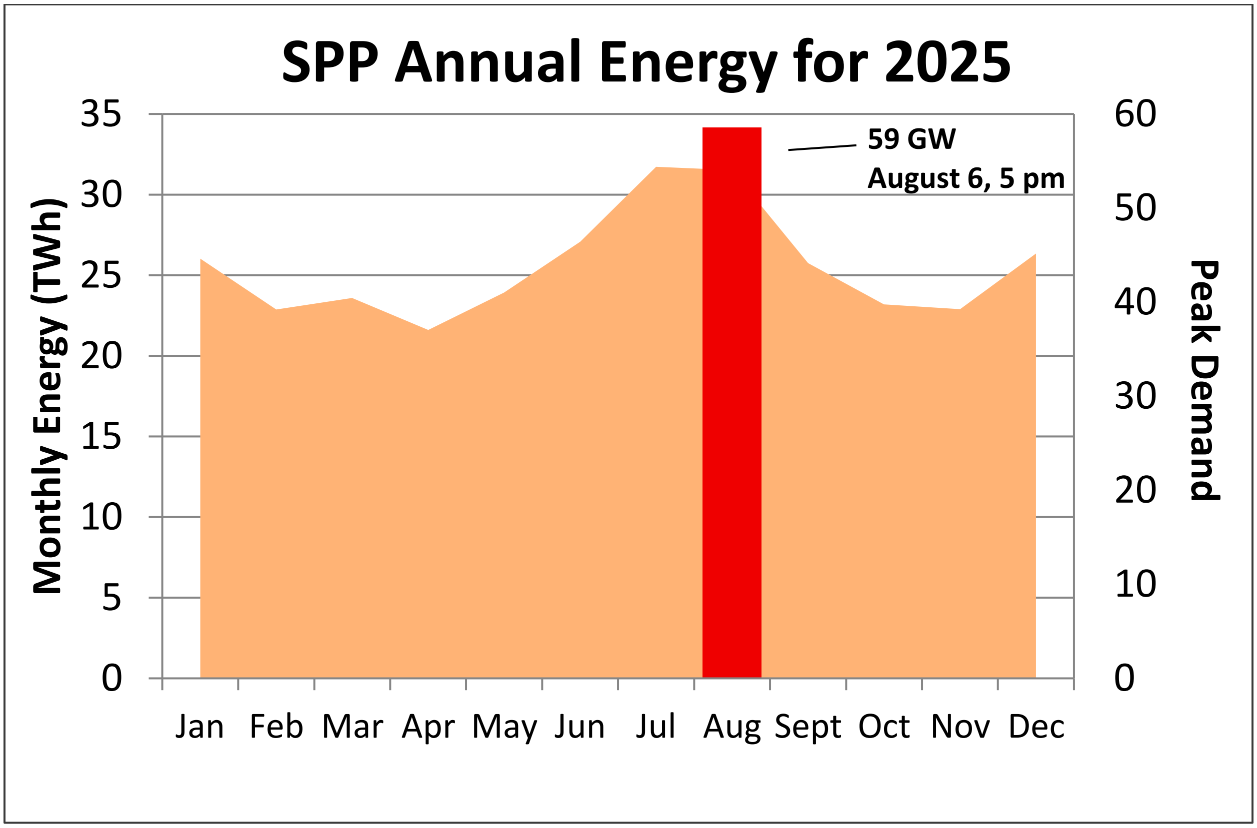


Figure 3.1: 2025 Annual Energy and Coincident Peak Load for SPP

Diverse Peak Demand Growth Rates

The projections included diverse peak load demand rates for each area. Table 3.2 lists the peak load demand rates (including incremental loads) for the key areas in the model. Some areas have demand response initiatives planned that may result in projected peak load growth being zero or negative. The forecasted values result in an average annual growth rate of 0.89% for SPP.

Area	Growth Rate
AEPW	0.92%
BPU	0.12%
CUS	1.04%
EDE	0.03%
GMO	-1.73%
GRDA	1.36%
KCPL	0.09%
LES	1.74%
MIDW	1.18%
MKEC	-0.05%
NPPD	0.90%

Area	Growth Rate
OKGE	1.10%
OPPD	0.99%
SUNC	1.17%
SPA	0.96%
SPS	2.22%
UMZ	1.36%
WESTAR	0.83%
WFEC	-1.69%
SPP Average	**0.89%**

Table 3.2: Annual Peak Load Growth Rates for SPP OATT Transmission Owners 2020 - 2025 (%)

3.3: Powerflow Topology

The 2016 Integrated Transmission Plan Near-Term Assessment (ITPNT) Scenario 0 powerflow models were used as the base for the 2017 ITP10 Assessment. Stakeholders were given the opportunity to provide SPP staff with updates to the 2020 and 2025 models up to October 1, 2015. This date was established by the Regional Allocation Review Task Force (RARTF) for the Regional Cost Allocation Review (RCAR) II Assessment, which utilized the 2017 ITP10 models. Other notable updates to the powerflow models included Notification-to-Construct (NTC) modifications approved at the October 2015 and January 2016 SPP BOD meetings and the addition of generating resources and associated network upgrades from the Generation Review and Resource Plan milestones.

3.4: Market Structure

SPP transitioned to a Consolidated Balancing Authority (CBA) and a Day Ahead Market, referred to as the SPP Integrated Marketplace, in March 2014. This market structure is simulated in PROMOD IV and was an assumption utilized across all Futures.

3.5: Fuel and Emission Prices

Fuel price forecasts for natural gas, coal, oil, and uranium, as well as emission price forecasts for SO_2 and NO_x were based upon ABB Simulation Ready Data – specifically, the Fall 2014 Reference Case Forecast. Modeling adders for carbon in Futures 1 and 2 are detailed in Section 7:.

3.6: Unit Retirements

The 2017 ITP10 Generation Review provided the opportunity for stakeholders to identify generator retirements to implement in the models, as described in Section 2.3. These planned retirements totaled 4 GW of primarily coal generation and were included in all three Futures.

Additional retirements were included in the Future 1 and 2 models to help reduce carbon emissions in those Futures. An additional 1 GW of coal units for SPP were retired in Future 1 and 1.7 GW of additional coal units for SPP were retired in Future 2. The process for determining these retirements is described in Section 4.3: Table 3.3 shows the total unit retirements by Future.

	Unit Retirements (GW)
Future 1	5.0
Future 2	5.7
Future 3	4.0

Table 3.3: Unit Retirements by Future

SECTION 4: RESOURCE EXPANSION PLAN

4.1: Resource Plan Development

Identifying the resource outlook for each Future is a key component of evaluating the transmission system for a 10-year horizon. Due to resource additions and retirements, the SPP generation portfolio will not be the same in 10 years as it is today. Resource expansion plans that include both conventional and renewable generation additions unique to each Future have been developed for use in the study for the SPP and neighboring regions to meet projected future load growth and capacity margin requirements.

4.2: Resource Plan – Phase 1

After accounting for existing/committed renewables as reported in the Generation Review, each utility was analyzed to determine if the renewable mandates and goals as reported in the policy survey were being met in an initial resource plan, or Resource Plan – Phase 1. If a utility was short on renewables, additional resources were added to meet the levels as specified in the survey. These Phase 1 resource additions were identical across Futures.

Existing and Planned Renewables

The Generation Review was used to gather information on existing/committed generation in the SPP system for inclusion in the models. Members reported 15.7 GW of wind expected in the SPP region. Of that capacity, 1.4 GW of generation was reported as currently contracted for export to external entities through firm service and Power Purchase Agreements (PPAs). Members also reported 190 MW of solar expected in the SPP region. This generation was included in the models for all Futures. Resource addition requests, as defined in Section 2.4: , were also used as a baseline for determining resource additions.

Additional Renewables

The Policy Survey was used to gather information on Renewable Statutory/Regulatory mandates and goals with which to comply by 2020 and 2025. Additional wind generation was added to the system when the existing wind was not sufficient to meet the stated mandates and goals. The incremental renewables added in the SPP footprint by 2025 were 387 MW with allocations based on the Policy Survey assumptions. Figure 4.1 shows renewable generation added in all Futures via the first phase of the resource plan.

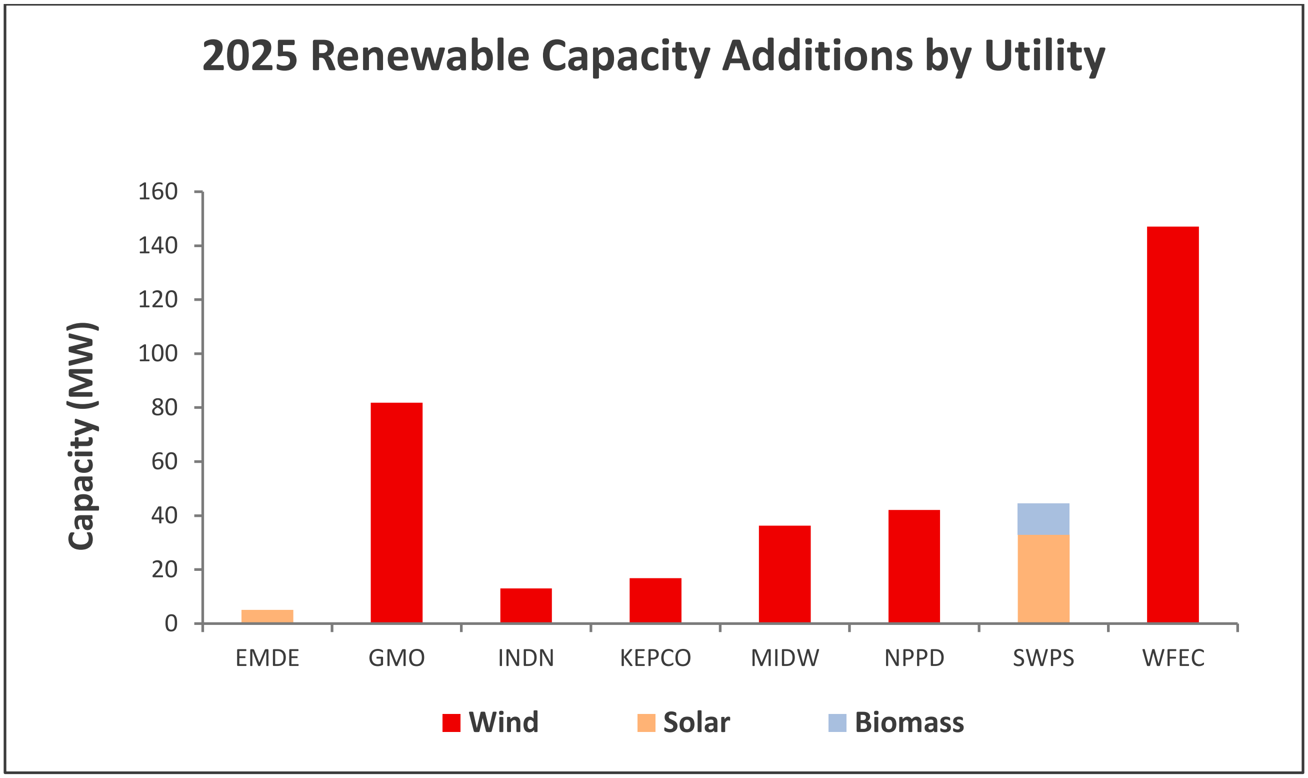


Figure 4.1: SPP Renewable Generation Additions to meet Mandates and Goals by Utility

Information on the siting of resource additions, including those resulting from Resource Plan – Phase 1, is captured in Section 4.4: .

External Regions

External regions were not considered during the first phase of the resource plan.

4.3: Resource Plan – Phase 2

The results of the first phase of the resource plan were utilized as an input into the second phase of the resource plan, or Resource Plan – Phase 2. This second phase was developed individually for each Future for years 2020 and 2025 utilizing generation expansion software.

Approach

SPP Planning Criteria 4.1.9[9] states that each LSE must maintain at least a 12% capacity margin[10]. Resource plans were developed to meet this requirement. Projected capacity margins were calculated

[9] SPP Planning Criteria

for each pricing zone using existing and planned generation and load projections through 2035, although additional resources were only considered through the study year, 2025. Each zone was assessed to ensure that it met the minimum capacity margin requirement. While nameplate conventional generation capacity is counted toward each zone's capacity margin requirement, wind and solar capacity, being intermittent resources, were included at a percentage of nameplate capacity according to the calculations set forth in SPP Planning Criteria 7.1.5.3. These accreditation percentages were surveyed by the stakeholders for existing and planned renewable capacity. For the purposes of this study, future renewable resources were counted at a regional average of accreditation percentages submitted by stakeholders.

The ESWG approved a resource list of generic prototype generators using assumptions from the 2014 Lazard Levelized Cost of Energy Analysis[11]. These prototype generators comprise representative parameters of specific generation technologies and were utilized in resource planning simulations to determine the optimum generation mix to add to each zone. The resources included as available options in the analysis of future needs were nuclear, combined cycle units, fast-start combustion turbine units, wind, and solar. While the approved prototypes included other fossil resources, these were not considered in the resource planning simulations.

Renewable Assumptions

Initial results from phase 2 of the resource plan did not meet Stakeholder expectations for future renewable generation additions. Staff developed a proposal based on expectations and research of the Integrated Resource Plans (IRP) filed by utilities in their respective state(s). Leveraging the SPP Tariff mechanism allowing cost recovery of transmission upgrades required for delivery of wind up to 20 percent of a system's peak load responsibility, this figure was proposed for calculations of wind capacity additions by zone in Future 3. In order to aid in carbon emission reduction goals set for Futures 1 and 2, this figure was increased to 25 percent. The Future drivers also included an expectation of large-scale solar generation for all Futures and distributed-scale solar generation in Future 3. Assumptions were proposed based on research of utility IRP expectations and a review of global horizontal irradiance potential in the SPP footprint. Figure 4.1 shows the future solar projections as a percentage of peak demand.

[10] The SPP capacity margin requirement was changed to a reserve margin requirement set at 12% after the completion and approval of the 2017 ITP10 resource plan. For load serving members whose fleet is comprised of at least 75% hydro-electric generation, the capacity margin is 9%.

[11] See ESWG 6/18/2015 meeting materials for the ESWG approved Prototypes: https://www.spp.org/Documents/28931/eswg%206.18%20agenda%20&%20background%20materials%201.zip

	Utility-Scale Solar		Distributed Solar	
	2020	2025	2020	2025
Future 1	3%	5%	N/A	N/A
Future 2	3%	5%	N/A	N/A
Future 3	1%	3%	0.5%	1%

Table 4.1: Utility and Distributed Solar as a percentage of peak demand

Additional Emission Reduction Measures

In order to meet the required emission goals in Futures 1 and 2, multiple carbon reduction steps were taken. The initial addition of increased renewables in these Futures provided a large reduction in emissions. The next measure involved determining additional retirements that might be expected under a carbon reduction scenario. This involved analyzing multiple scenarios with varying carbon pricing to affect a dispatch that is more reliant on lower carbon emitting resources. Utilizing these simulations and generator commission dates, a list of potential coal steam unit retirements was developed and targeted considering unit age and operational capacity factors. Units in operation more than 40 years and operating below a 30% annual capacity factor were targeted for retirement in the year relative to each simulated year. This list was reviewed for exclusions by the SPP Stakeholders. Retirements were further targeted based on the needs of either the region, in Future 1, or each individual state, in Future 2. Table 4.2 shows the coal capacity retirements for Futures 1 and 2 reflective of SPP owned or purchased MW capacity. Some generation that was slated for retirement by 2025 in the reference case was retired early in order to aid in meeting interim carbon emission reduction goals.

	Retired (MW)	Retired Early (MW)
Future 1	994	414
Future 2	1,694	74

Table 4.2: Additional Coal Steam Capacity Retirements by Future

After including additional renewables and retirements, the last step was to utilize carbon cost adders to further reduce and fine-tune emission outputs to meet the carbon reduction goals set forth for each Future. For the purposes of resource planning, this adder was applied to all thermal units. Discussion on adjustments to this assumption will occur in Section 7:. With limitations on the ability of the simulation to effectively consider multiple carbon cost adders, a common carbon cost adder for all thermal generators was used for both Futures 1 and 2 with the difference in any simulation outputs being driven primarily by the differing retirement assumptions.

Resource Plan Results

Combined cycle (CC) units are generally selected because their moderately low capital cost and low operating costs make them the most economically viable technology for meeting energy needs in these Futures. CC units are primarily selected to supply additional energy to serve load. The combustion turbine (CT) units are generally selected because the very low capital costs associated with these units make them the most economically viable technology for meeting peak capacity requirements. CT units are primarily selected to supply the additional capacity to meet margin requirements.

Future 3 results show a mix of CC and CT generation to meet both energy and capacity requirements. With the carbon cost adders utilized to help drive generation to lower carbon emitting resources, Futures 1 and 2 show large additions of CC resources. With the increase in operating costs on resources with higher carbon emission rates, the CC resources became a more attractive option over existing base load generation to meet future energy requirements.

Figure 4.2 shows new generation additions by Future for the SPP region as a result of phase 2 of the resource plan. Future 1 has 17.3 GW of generation additions, Future 2 has 18.6 GW of generation additions, and Future 3 has 14.5 GW of generation additions by 2025. While all three Futures represent normal load growth, more resource additions are needed in Future 1 and 2 due to the additional unit retirements included to support carbon emission reduction goals. Figure 4.3 shows 2020 and 2025 generation additions by capacity type and Future for the SPP region.

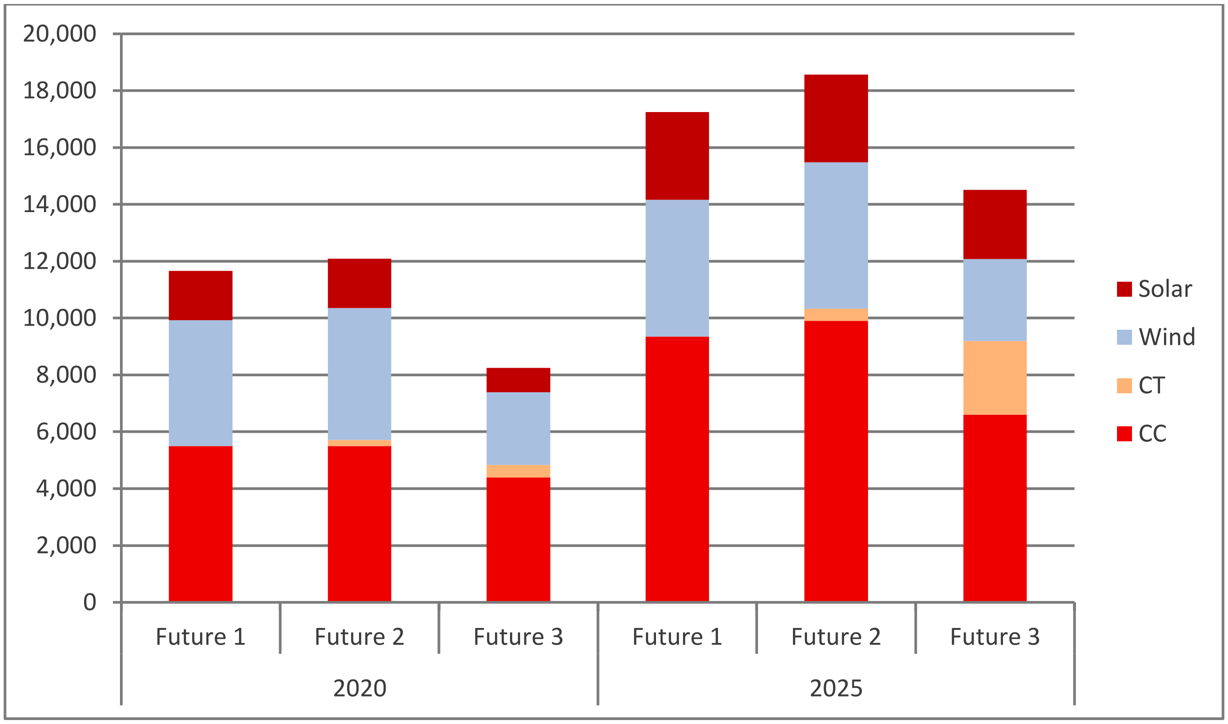


Figure 4.2 : Capacity Additions by Future and Year

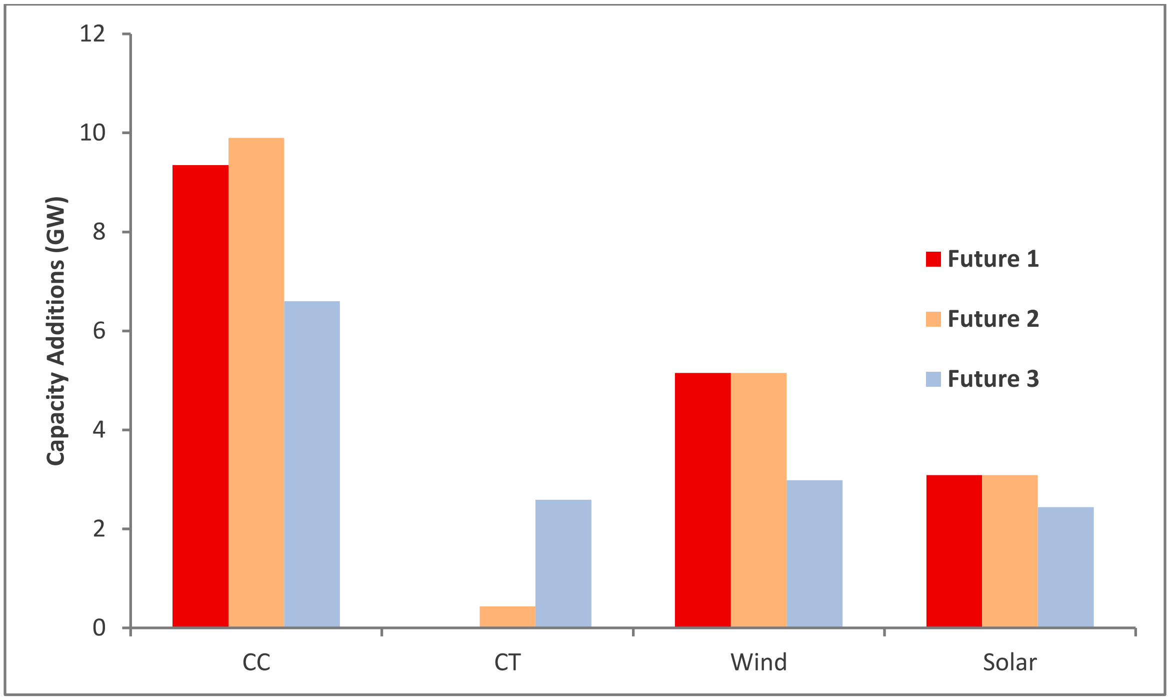
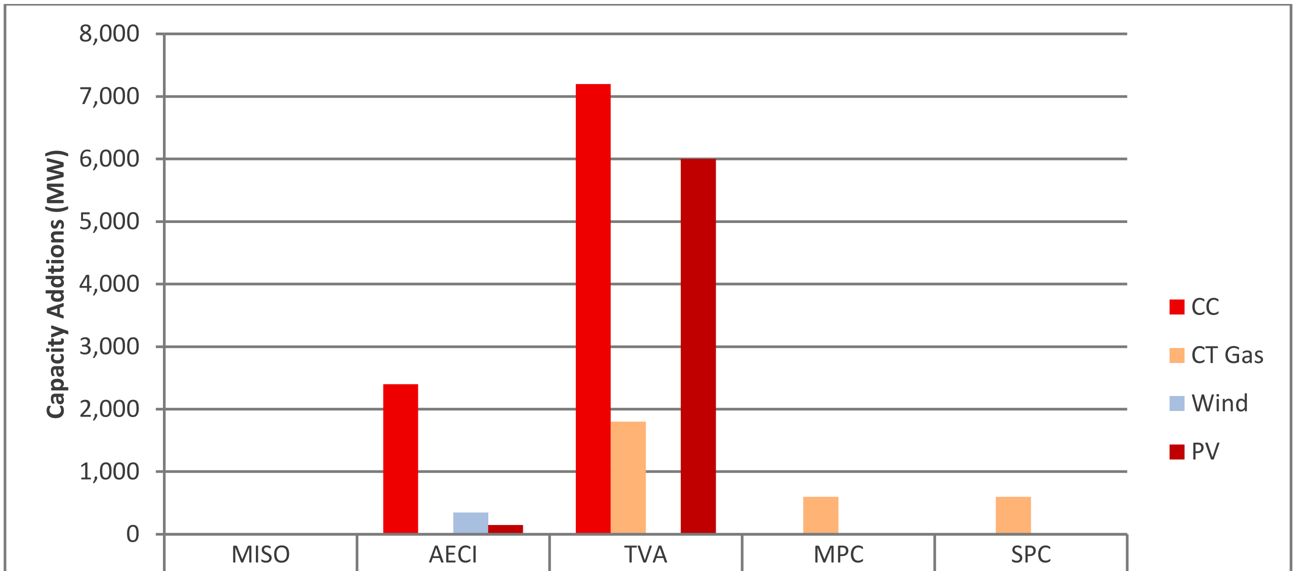


Figure 4.3: 2025 Cumulative Capacity Additions by Unit Type

External Regions

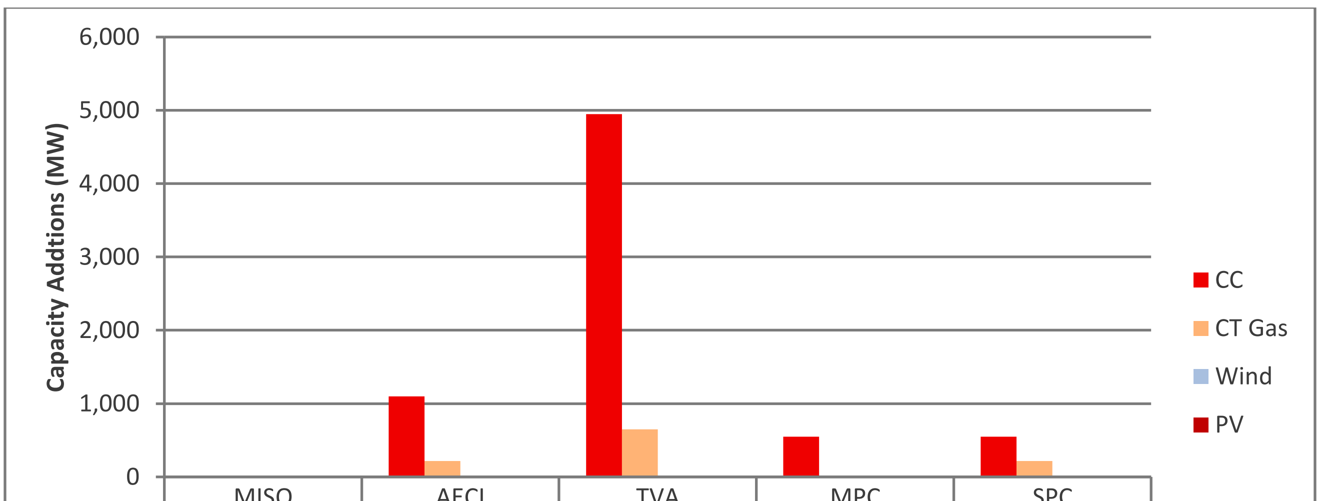
Resource plans were also developed for external regions. Each region was surveyed for load and generation and assessed to determine the capacity short fall before adding units so that each region met its own reserve margin. This analysis was performed for AECI, TVA, Minnkota, MISO, and Saskatchewan Power (SASK). The MISO resource plan was based on the 2016 MISO Transmission Expansion Planning (MTEP16) BAU and sub-regional CPP Futures. Figure 4.4 shows the cumulative capacity additions by unit type for Futures 1 and 2, while

Figure 4.5 shows similar results for each of these external regions for Future 3.



	MISO	AECI	TVA	MPC	SPC
CC	0	2,400	7,200	0	0
CT Gas	0	0	1,800	600	600
Wind	0	350	0	0	0
PV	0	150	6,000	0	0

Figure 4.4: Capacity Additions by Unit Type – Conventional Plan Futures 1 and 2



	MISO	AECI	TVA	MPC	SPC
CC	0	1,100	4,950	550	550
CT Gas	0	216	648	0	216
Wind	0	0	0	0	0
PV	0	0	0	0	0

Figure 4.5: Capacity Additions by Unit Type – Conventional Plan Future 3

4.4: Siting Plan

After the required generation additions were determined for each zone, the expected location of future generation was considered in areas with appropriate potential based on SPP staff analysis and input from Stakeholders. The selected locations for new renewable and conventional generation will impact the power flow and drive the potential generation dispatch, congestion, thermal violations, and voltage violations.

Conventional Generation Siting

Conventional generation additions were sited within each zone leveraging locations identified during the 2013 ITP20 and the 2015 ITP10 studies and the SPP GI queue. These sites were analyzed for space requirements, proximity to gas pipelines, and existing electric transmission outlet capability. Stakeholder feedback was incorporated and the overall siting plan was presented and approved by the ESWG.

Figure 4.6 shows locations and technology type of all new conventional generation added to Future 1 by 2025.

- Additional Sites
    - 17 Combined Cycle
- Additional Capacity
    - 9.4 GW of Combined Cycle

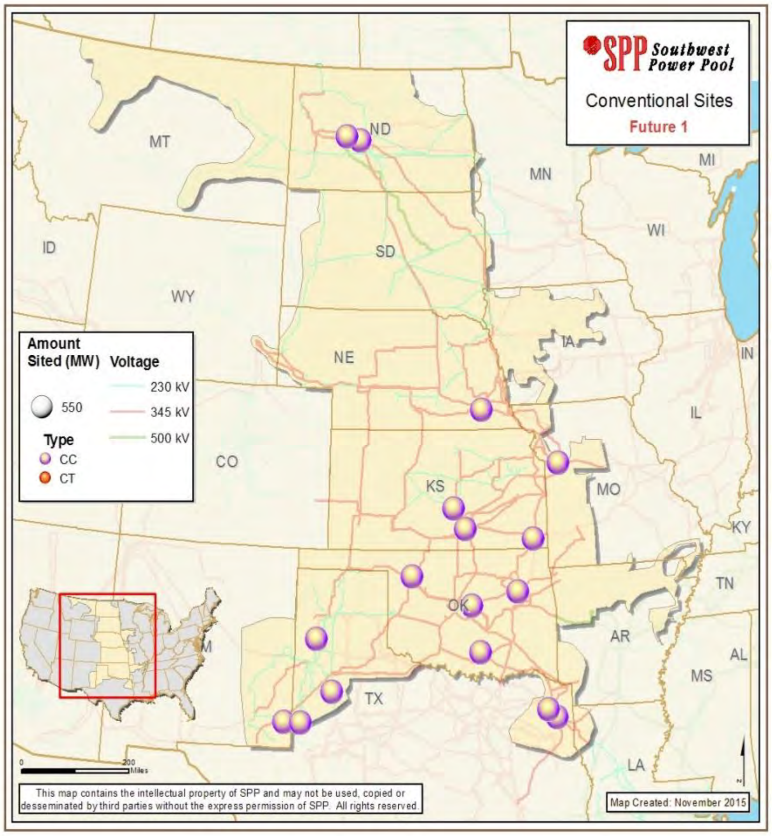


Figure 4.6: 2025 Conventional Generation Siting for Future 1

Figure 4.7 shows locations and technology type of all new conventional generation added to Future 2 for 2025.

- Additional Sites
  - 18 Combined Cycle
  - 2 Combustion Turbine
- Additional Capacity
  - 9.9 GW of Combined Cycle
  - 432 MW of Combustion Turbine

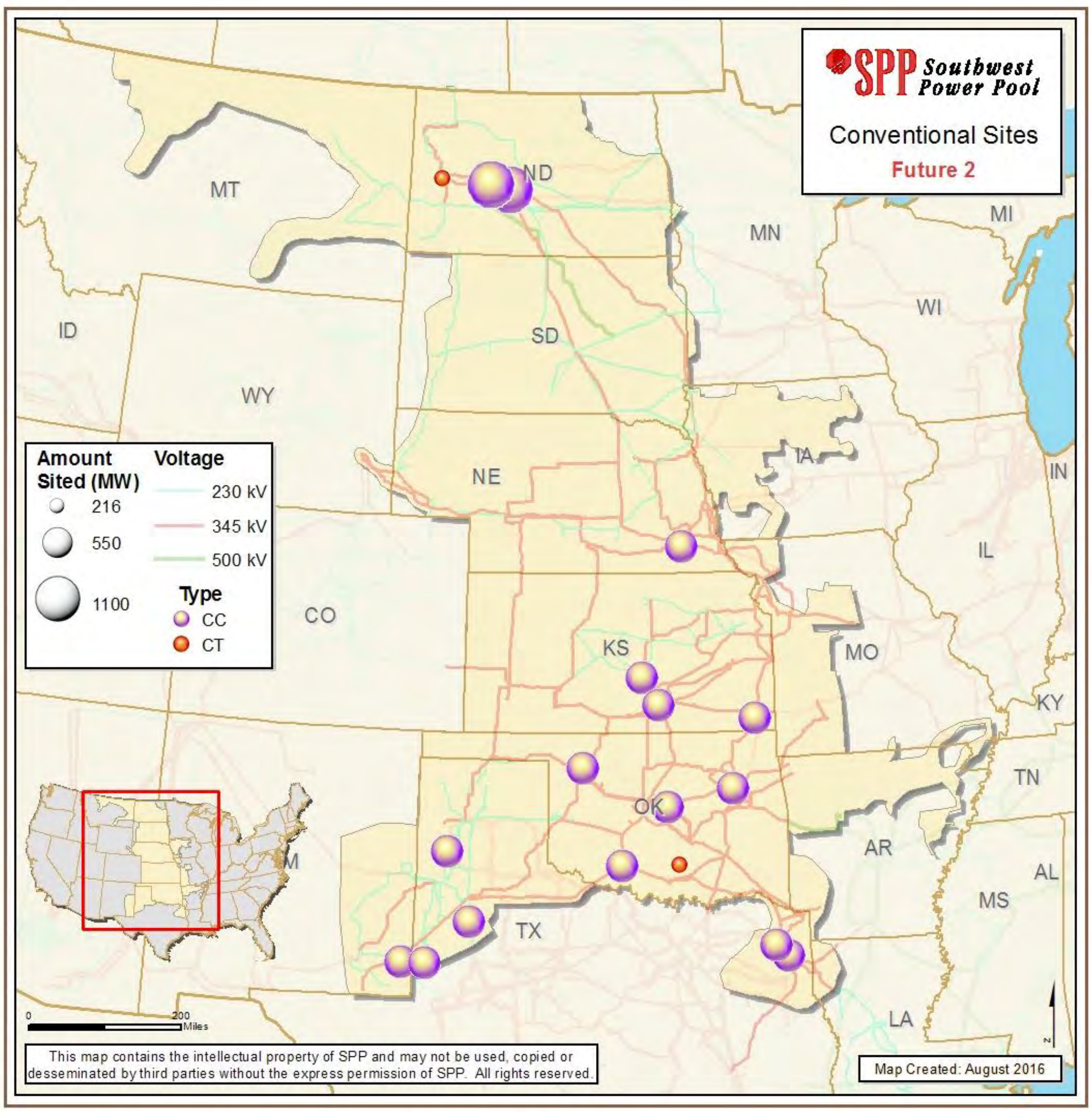


Figure 4.7: 2025 Conventional Generation Siting for Future 2

Figure 4.8 shows locations and technology type of all new conventional generation added to Future 3 by 2025.

- Additional Sites
  - o 12 Combined Cycle
  - o 12 Combustion Turbine
- Additional Capacity
  - o 6.6 GW of Combined Cycle
  - o 2.6 GW of Combustion Turbine

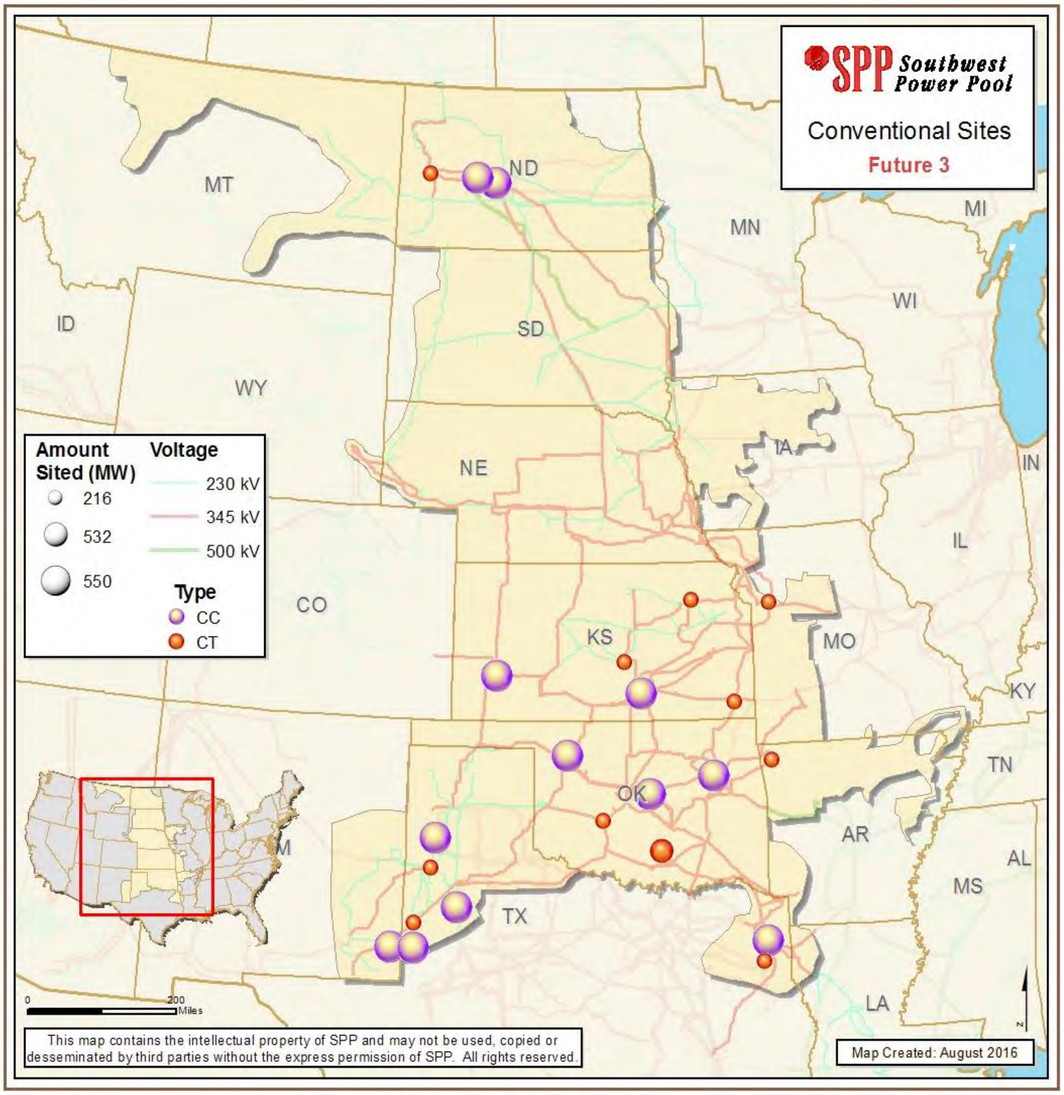


Figure 4.8: 2025 Conventional Generation Siting for Future 3

Wind Generation Siting

To determine the locations of new wind generation, potential sites from the SPP GI queue were ranked by GI status and then by capacity factor, with priority given in the following order:

- Interconnection agreement on-schedule
- Interconnection agreement on-suspension
- Interconnection agreement commercial operation not fully on-line
- Interconnection agreement pending
- Facility study

The highest ranking sites based on these criteria were assigned by pricing zone and then by state(s) in which a utility operates. For example, if a site within SPS was ranked number one with an on-schedule status and the highest capacity factor, this site would first be assigned to fulfill an SPS wind need. Figure 4.9 and Figure 4.10 show the selected sites.

For Futures 1 & 2

- Additional Sites
  - o 29 sites in 2020
  - o 29 sites in 2025 (zero incremental sites)
- Additional Capacity
  - o 4.72 GW in 2020
  - o 5.28 GW in 2025 (560 MW incremental)

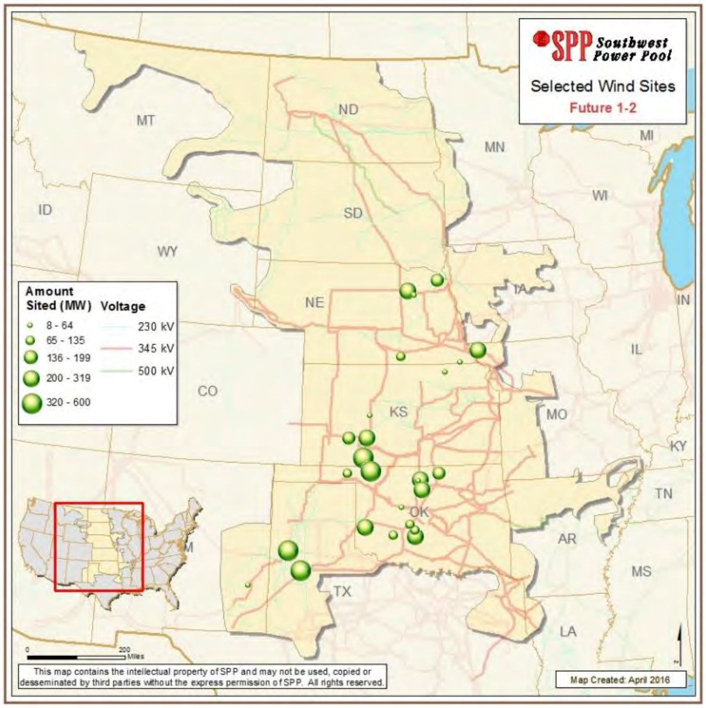


Figure 4.9: 2025 Wind Generation Siting for Futures 1 and 2

For Future 3

- Additional Sites
  - 25 sites in 2020
  - 26 sites in 2025 (1 incremental site)
- Additional Capacity
  - 2.75 GW in 2020
  - 3.17 GW in 2025 (420 MW incremental)

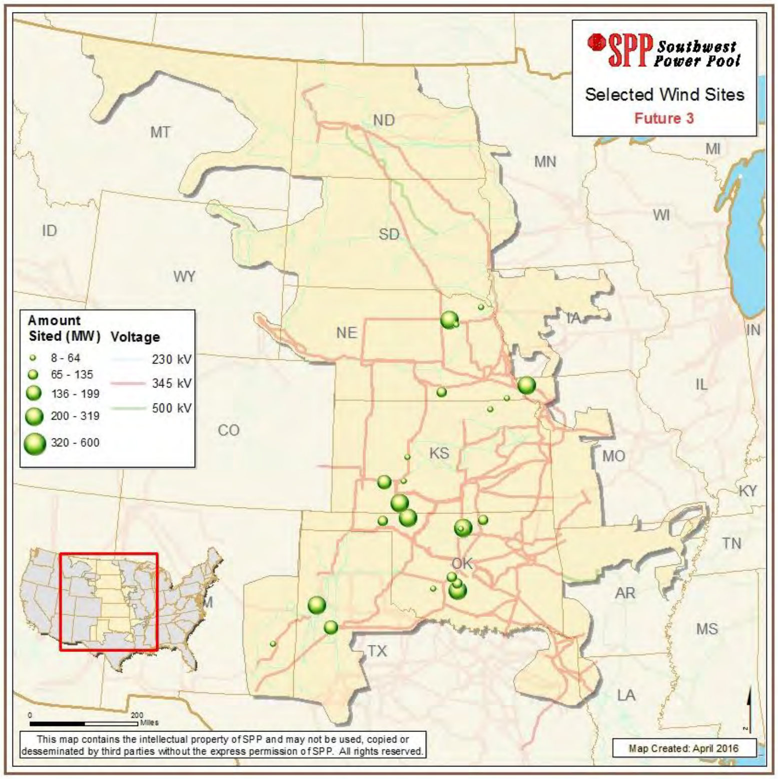


Figure 4.10: Wind Generation Siting for Future 3

Solar Generation Siting

To determine the locations of new utility scale solar generation, potential sites were developed from the 2006 NREL data set utility photovoltaic solar sites. These potential sites were first ranked by the highest capacity factor in each pricing zone and then ranked by the highest voltage level (kV) and highest generator outlet capability. Utility scale solar generation sites were assigned by pricing zone, then by the state(s) in which the utility operates. Pricing zones with average capacity factors below the SPP calculated average threshold were assigned solar sites in zones with the highest capacity factors in order to raise the capacity factor average to fall within the SPP calculated average threshold. This methodology was presented to the ESWG and approved on December 17, 2015.

Figure 4.11 and Figure 4.12 show the selected utility scale solar sites.

<u>For Futures 1 & 2</u>

- Additional Sites
  - o 49 sites in 2020
  - o 71 sites in 2025 (22 incremental sites)
- Additional Capacity
  - o 1.75 GW in 2020
  - o 3.13 GW in 2025 (1.38 GW incremental)

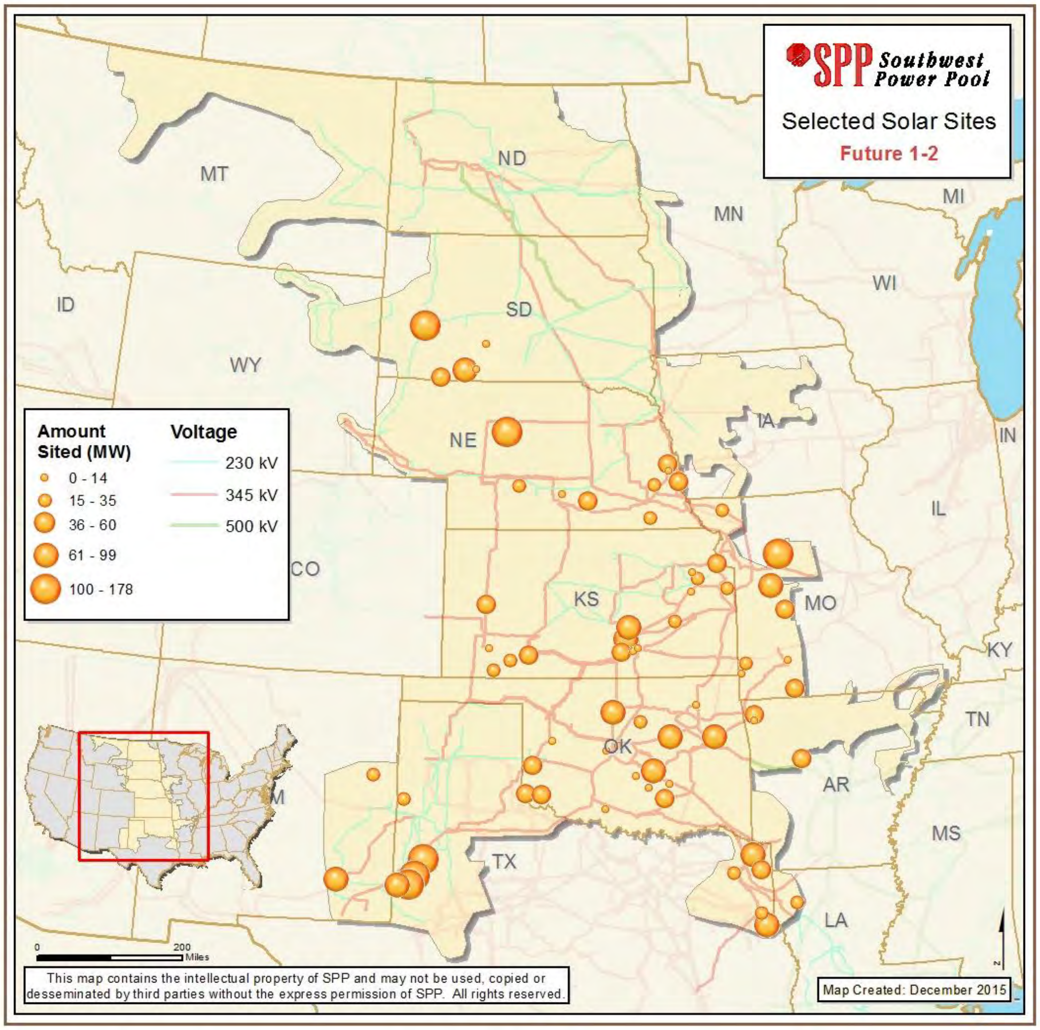


Figure 4.11: Utility Scale Solar Generation Additions for Futures 1 and 2

For Future 3

- Additional Sites
    - 25 sites in 2020
    - 51 sites in 2025 (26 incremental sites)
- Additional Capacity
    - 581 MW in 2020
    - 1.87 GW in 2025 (1.29 GW incremental)

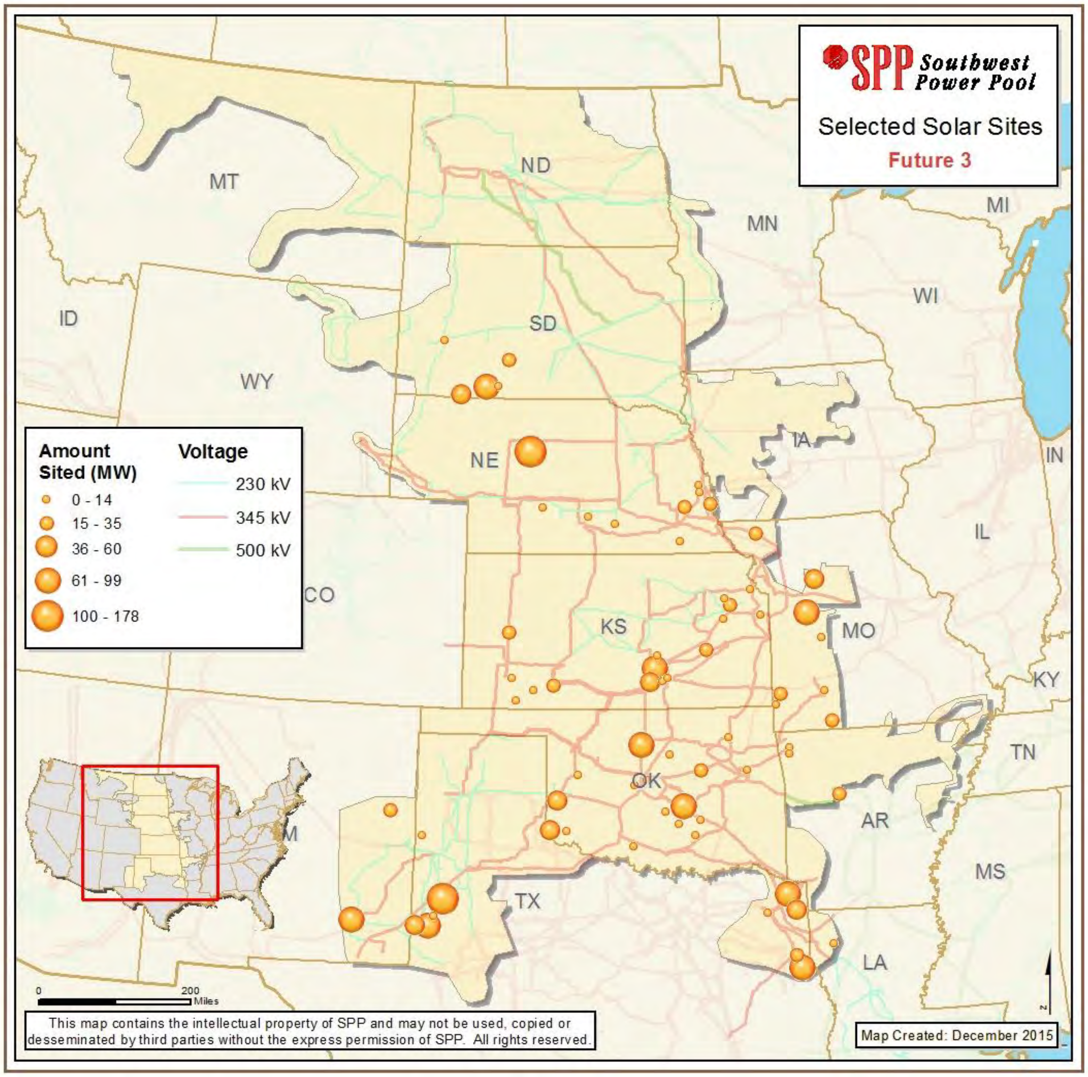


Figure 4.12: Utility Scale Solar Generation Additions for Future 3

To determine the locations for new rooftop solar generation in Future 3, the top 90th percentile load buses were determined for each load area using the ESWG-approved Load Review data. Rooftop solar sites were then assigned to these load buses on a load-ratio share. Distributed photovoltaic hourly profiles from the 2006 NREL dataset were assigned to the rooftop solar on a sub-region and state level. Figure 4.13 shows the selected solar sites for Future 3.

Rooftop Solar Sites

- Additional Sites
  - 550 sites in 2020
  - 550 sites in 2025
- Additional Capacity
  - 299 MW in 2020
  - 615 MW in 2025 (316 MW incremental)

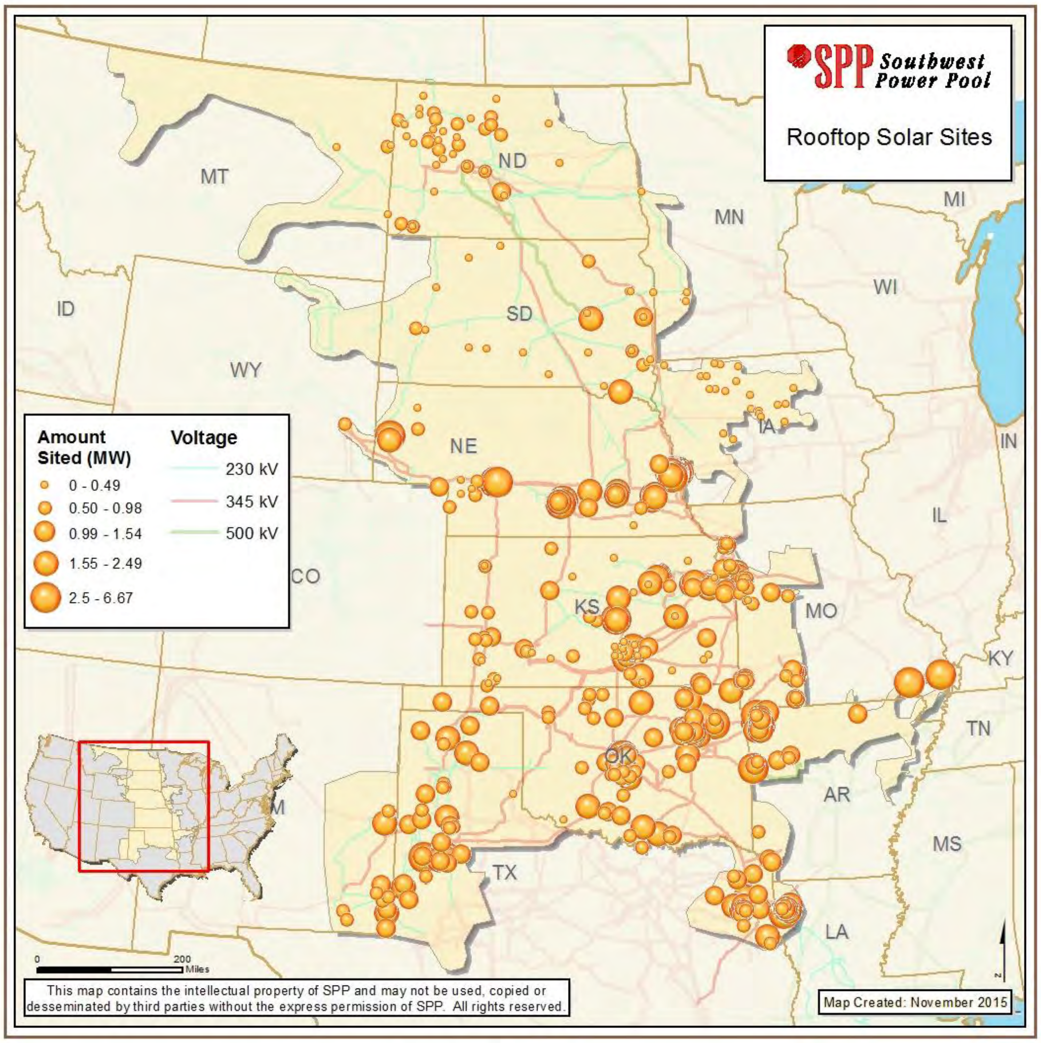


Figure 4.13: Rooftop Solar Generation Additions for Future 3

4.5: Generator Outlet Facilities

Once the new resource plan was applied to the models, Generator Outlet Facilities (GOF) were developed as a proxy for upgrades that would otherwise be proposed through the SPP GI study process. The GOF methodology was developed by staff and approved by the TWG and ESWG to ensure that facilities needed for new resource interconnection were not included as a part of the final recommended plan. Table 4.3 lists the GOF additions by Future as developed by staff and approved by the TWG and applied to the base models. Transmission outlet capability is a weighting factor in considering new interconnection locations. In order to prescreen these potential generation sites, First Contingency Incremental Transfer Capability (FCITC) analysis was performed. This allowed the selection of locations with the most interconnection capability and therefore limiting the amount of GOF assumptions.

GOF Upgrade	Zone	Futures
Oneta Energy Center: Add third 345 kV circuit from OEC	AEP	1,2,3
Holly and Jones Units: 230 kV buildout around Lubbock and terminal upgrades	LP&L	1,3
Hobbs/Gaines (Sidewinder): Convert 230 built at 345 kV to 345 kV operation from Hobbs to Andrews, add 345 kV line from Andrews – Road Runner, Hobbs generator move to 345 kV bus instead of 230 kV	SPS	1,2,3
Mooreland: Tap Woodward – Thistle 345 kV double circuit, place resource at 345 kV tap	WFEC	1,2,3
Deafsmith: Tap Deafsmith-Plant X 230 kV near Deafsmith, tap Newhart-Potter 230 kV and terminate at new station, replace existing 230/115 kV transformer at Deafsmith	SPS	1,2,3

Table 4.3: Generator Outlet Facilities Additions by Future

SECTION 5: CONSTRAINT ASSESSMENT

An assessment was conducted to develop a list of transmission constraints for use in the Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) analysis. Elements that limit the incremental transfer of power throughout the system both under system intact and contingency situations were identified, reviewed, and approved by the TWG. SPP staff defined the initial list of constraints leveraging the SPP Permanent Flowgate workbook, which consists of NERC-defined flowgates that are impactful to SPP and neighboring systems. The assessment is performed to identify transmission corridors that limit the system's ability to transfer power throughout the system. The constraint list was limited to the following types of issues:

- System intact and N-1 situations[12]
- Thermal loading and voltage stability interfaces
- Contingencies of 100+ kV voltages transmission lines
- Contingencies of transformers with a 100+ kV voltage winding
- Monitored facilities of 100+kV voltages only

Neighboring areas were also analyzed for additional constraints to be added to the study-specific constraint list.

SPP utilizes constraints to reliably manage the flow of energy across the physical bottlenecks of the transmission system in the least costly manner. In doing so, SPP calculates a shadow price for each constraint, which indicates the potential reduction in the total market production costs if the constraint limit could be increased by one MW for one hour. Developing these study-specific constraints plays a critical part in determining Transmission Needs, as the constraint assessment identifies future bottlenecks as well as fine tuning the PROMOD Powerbase models.

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

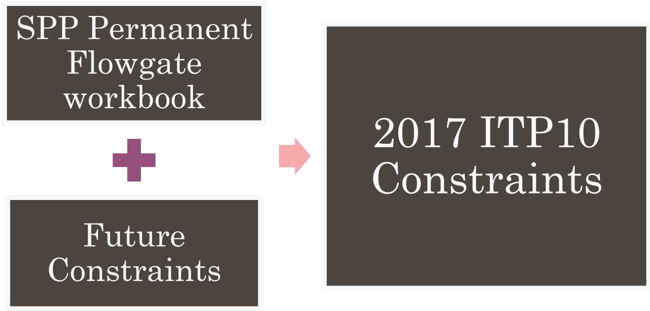


Figure 5.1: Constraint Assessment Process

SECTION 6: BENCHMARKING

Numerous benchmarks were conducted to ensure the accuracy of the data, including:

1. A comparison of simulation results from the current study model with historical statistics and measurements from SPP Operations and the U.S. Energy Information Administration (EIA);
2. A comparison of the current ITP10 study "reference case" model to the previous ITP10 study "business as usual" model; and
3. A validation of the two reduced carbon Futures to check for expected model behavior(s).

6.1: Benchmarking Setup

Benchmarking for this study was implemented as a sort of quality assurance for the economic model build. For the benchmarking process to provide the most value, it was important to compare the current study model against a similar model that had already been benchmarked. It was also important to validate the reduced carbon Futures to achieve confidence in the final results of this study. The current study models in the comparisons were unconstrained.

A checklist was created to provide guidance while benchmarking the model. The checklist was essentially divided into three sections:

1. **Historical Data Comparison**: compare current ITP10 study reference case capacity factors with EIA data, compare PROMOD simulated maintenance outages to SPP Operations data, and make sure the operating and spinning reserve capacities met SPP Operating Criteria;
2. **Benchmark against 2015 ITP10**: compare current ITP10 study reference case capacity factors, unit average cost, renewable generation profiles, system locational marginal prices (LMP), adjusted production cost (APC), and interchange to the previous ITP10 Business as Usual Future (Future 1); and
3. **Reduced Carbon Future Validation**: check the current ITP10 reduced carbon Futures for expected model behavior by examining capacity factors, unit average cost, renewable generation profiles, APC, and interchange in relation to the Reference Case Future.

6.2: Generator Operations

Capacity Factor by Unit Type

Comparing capacity factors is a method for measuring the similarity in planning simulations and historical operations. This benchmark provides a quality control check of differences in modeled outages and assumptions regarding renewable, intermittent resources.

When validating the reduced carbon Futures, most of the resulting capacity factors fell near those output levels from the 2015 ITP10 and those reported to the EIA in 2014. The difference in the PROMOD simulation capacity factors and the capacity factors from the 2014 EIA data is attributed to the difference in generation resource mix projected 10 years from now and the fuel cost projections for natural gas and coal.

Unit Type	2014 EIA Capacity Factor	2015 ITP10 F1 2024 Capacity Factor	2017 ITP10 F1 2025 Capacity Factor	2017 ITP10 F2 2025 Capacity Factor	2017 ITP10 F3 2025 Capacity Factor
Nuclear	76.3%	88.6%	92.6%	92.6%	92.6%
Combined Cycle	36.6%	39.8%	42.9%	47.7%	35.1%
CT Gas	4.1%	2.6%	2.0%	2.4%	2.5%
Coal	69.6%	90.5%	66.5%	69.8%	86.1%
ST Gas	16.4%	3.9%	0.5%	0.8%	1.1%

Table 6.1: Conventional Generation Capacity Factor Comparison

Average Generation Cost

Examining the average cost by unit type gives insight to what units are actually being dispatched. Overall, the average cost per megawatt-hour (MWh) is higher in this study than in the 2015 ITP10 study due to the change in fuel price assumptions between the studies as well as the differing generation resource plans developed based on model inputs for each study.

Unit Type	2015 ITP10 F1 2024 Average Energy Cost ($/MWh)	2017 ITP10 F3 2025 Average Energy Cost ($/MWh)
Nuclear	13.46	13.19
Combined Cycle	41.59	46.04
CT Gas	65.43	71.71
Coal	22.37	26.09
ST Gas	47.07	72.57

Table 6.2: Average Energy Cost Comparison

Generator Maintenance Outages

Generator maintenance outages in the simulations were compared with historical data provided by SPP Operations. These outages have a direct impact on flowgate congestion, system flows, and the economics of following load levels. The curves from the historical data and the PROMOD simulations complemented each other very well in shape though the historical outages were generally higher in magnitude than the simulated outages. Based upon further analysis, the 2014 historical year appears to have a high level of outages compared to other historical years, as shown in Figure 6.1.

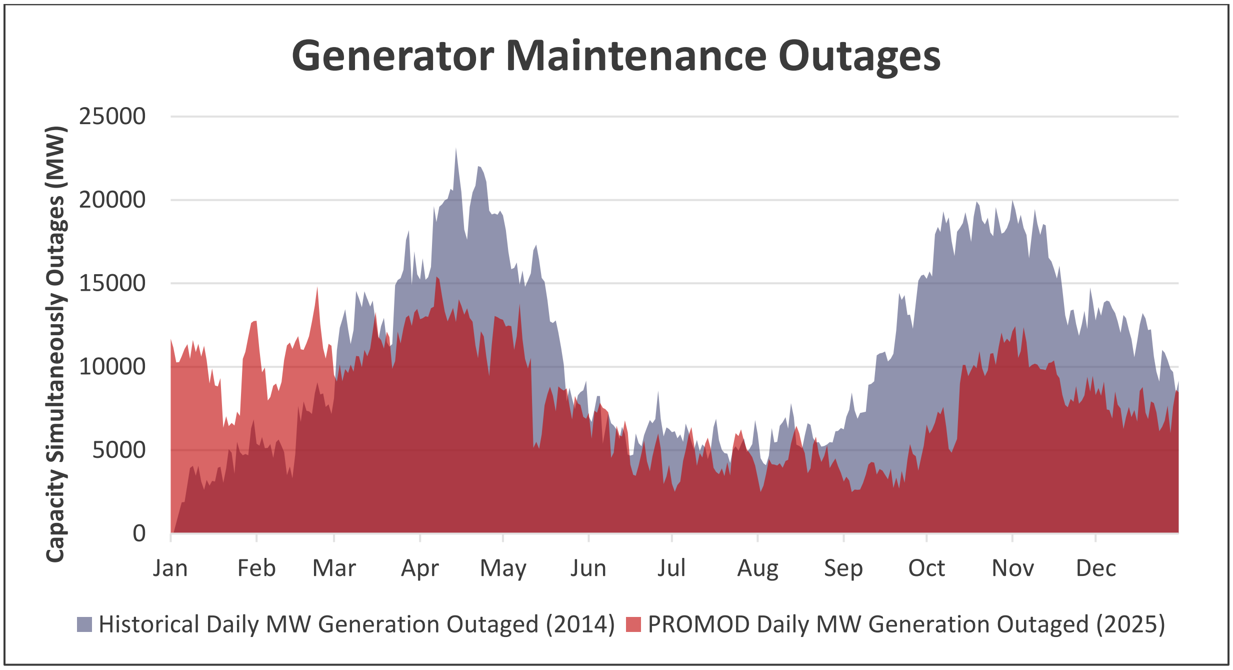


Figure 6.1: Generator Maintenance Outages

Operating & Spinning Reserve Adequacy

Operating reserves are an important reliability requirement that is modeled to account for capacity that might be needed in the event of a unit failure. According to SPP Operating Criteria, operating reserves should meet a capacity requirement equal to the largest unit in SPP + 50% of the next largest unit in SPP, and at least half of this requirement must be fulfilled by spinning reserve. The spinning reserve capacity requirement was modeled as 815 MW and the total operating reserve capacity requirement was modeled as 1,630 MW. As shown in Figure 6.2, the PROMOD simulation operating and spinning reserves were adequate.

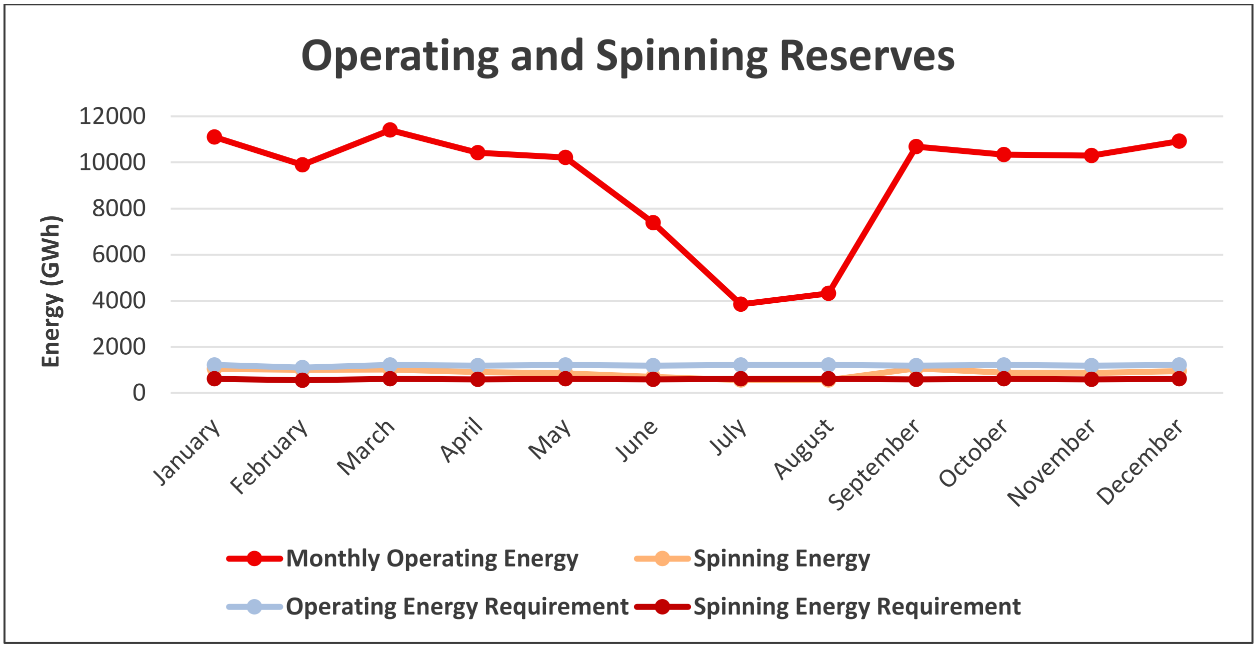


Figure 6.2: Reserve Energy Adequacy

Renewable Generation

Due to the Future drivers in this study and the region's natural progression towards reduced emissions, wind and solar generation were major resource drivers. As a result, annual wind energy for the SPP footprint in Future 3 increased approximately 21,000 gigawatt-hours (GWh) compared to Future 1 of the 2015 ITP10, as shown in Figure 6.3. The amount of wind energy for the SPP footprint is approximately 8,000 GWh greater in the reduced carbon Futures than in the Reference Case Future. This is because of the additional increase in wind generation necessary to aid in meeting carbon reduction requirements and the implementation of the 2012 NREL dataset hourly profiles. Annual solar energy for the SPP footprint was much greater in this study than the 2015 ITP10, as shown in Figure 6.4, due to the increasing need for renewable generation and the implementation of the 2006 NREL dataset hourly profiles.

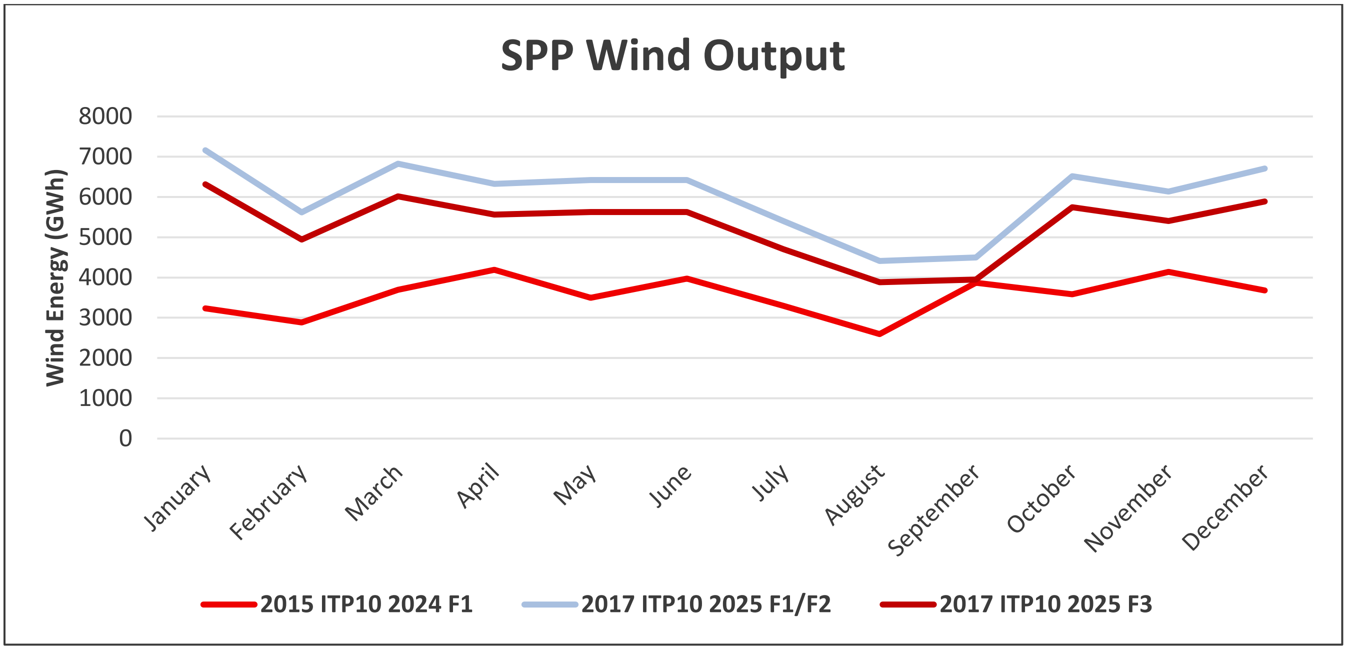


Figure 6.3: 2015 ITP10 v. 2017 ITP10 Energy Output for SPP Wind Units

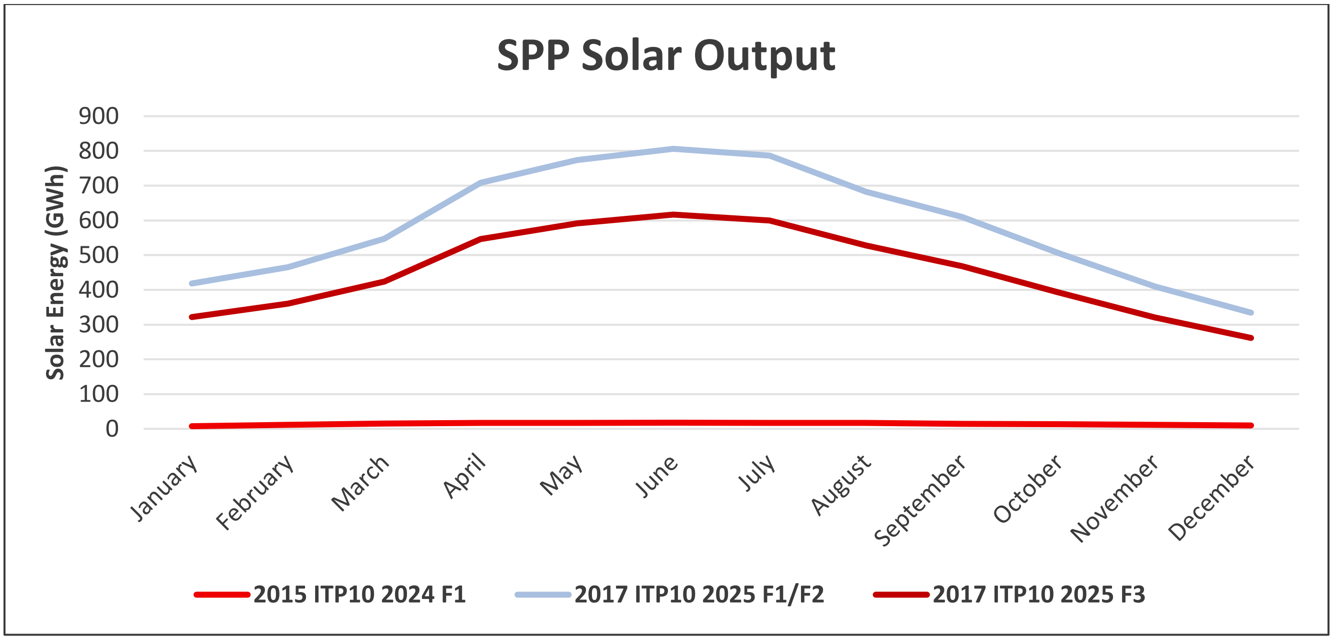


Figure 6.4: 2015 ITP10 v. 2017 ITP10 Energy Output for SPP Solar Units

When compared with capacity factors from the 2015 ITP10 and when validating the reduced carbon Futures, the capacity factors for renewable generation units fell near the expected values. The wind capacity factors were slightly higher than in the 2015 ITP10 due to the assumption of improved wind generation technology as well as utilizing the 2012 NREL dataset for hourly profiles and capacity factors instead of the 2005 NREL dataset. The solar capacity factors were lower than in the previous study due to utilizing the 2006 NREL dataset in the solar siting process instead of using one set of generic parameters.

Renewable	2015 ITP10 2024 F1 Capacity Factor	2017 ITP10 F1 2025 Capacity Factor	2017 ITP10 F2 2025 Capacity Factor	2017 ITP10 F3 2025 Capacity Factor
Wind	43.9%	46.3%	46.3%	46.2%
Solar	27.6%	22.7%	22.7%	20.5%

Table 6.3: Renewable Generation Capacity Factor Comparison

6.3: Locational Marginal Price (LMP)

Simulated LMPs were benchmarked against those of the 2015 ITP10. This data was compared on an average monthly value by area basis. Figure 6.5 compares the average monthly LMP results for the SPP system from the 2015 and 2017 ITP10 benchmarking models. The increase from the 2015 ITP10 to this study is due to the change in fuel prices and the inflation between the two study years.

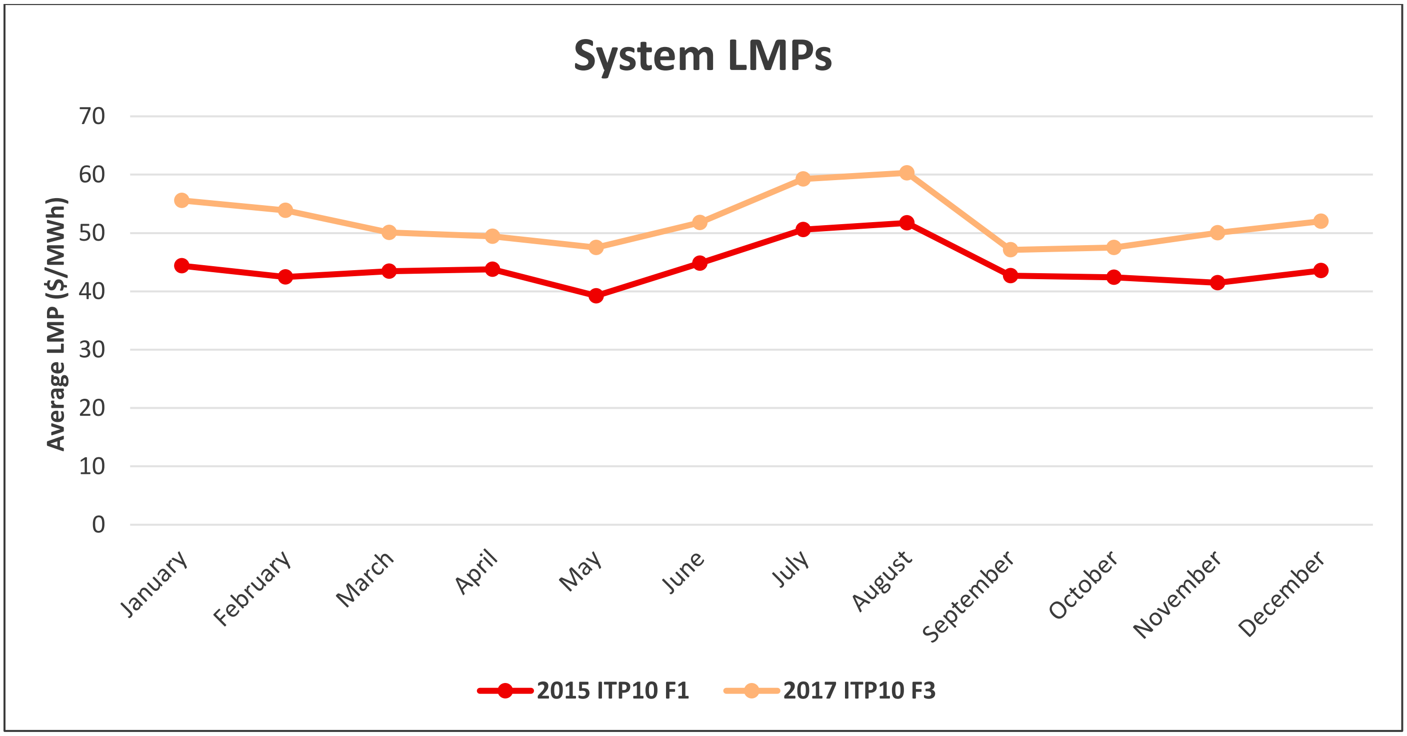


Figure 6.5: LMP Benchmarking Results

6.4: Adjusted Production Cost (APC)

Examining the APC provides insight to which entities purchase generation to serve their load and which entities sell their excess generation. APC results for SPP zones were very similar between the 2015 ITP10 Future 1 model and the 2017 ITP10 Future 3 model. Although there were some small differences, all SPP zonal APC results looked reasonable.

6.5: Interchange

Interchange was one of the most important aspects of this study's benchmarking. The hurdle rates applied to the 2017 ITP10 models are zonal hurdle rates calculated by ABB to correspond with the

2017 ITP10 area structure. ABB's zonal hurdle rates are developed using published OASIS tariffs and a friction adder. The hurdle rates implemented in the 2017 ITP10 models are shown in Table 6.4.

Interface	Fwd Energy ($/MWh)	Off-Peak Fwd Energy ($/MWh)	Back Energy ($/MWh)	Off-Peak Back Energy ($/MWh)
MISO - Manitoba Hydro	0.00	0.00	0.00	0.00
Saskatchewan - SPP	10.60	3.68	7.69	2.23
TVA - AECI	32.31	32.31	8.58	5.35
MISO - TVA	11.88	4.10	32.31	32.31
Manitoba Hydro - Saskatchewan	13.88	5.06	10.60	3.68
SPP - AECI	7.61	2.09	8.58	5.35
MISO - AECI	11.88	4.10	8.58	5.35
MISO - SPP	11.88	4.10	7.61	2.09

Table 6.4: 2017 ITP10 Hurdle Rates

The amount of exports is much greater in the 2017 ITP10 study model than in the 2015 ITP10 model. Several hurdle rate and interchange tests were implemented in order to validate the interchange in the 2017 ITP10 model. The 2015 ITP10 study's hurdle rates were applied to the 2017 ITP10 study model, and the 2017 ITP10 study hurdle rates were applied to the 2015 ITP10 study model to test the behavior of both models with different hurdle rates. While the 2015 ITP10 study hurdle rates did decrease the overall amount of exports when applied to the 2017 ITP10 model, the 2017 ITP10 study hurdle rates did not change the overall magnitude of the 2015 ITP10 study's interchange. Also, based on member feedback, the commitment rates were set to double the amount of the 2017 ITP10 hurdle rates tested in the 2017 ITP10 Future 3 model. The amount of exports increased instead of decreasing as members expected. However, it was confirmed that increasing the commitment rates would cause the SPP resources to be "more attractive" and would result in greater exports. The 2017 ITP10 model interchange was also compared to the MISO-SPP Coordinated System Planning (CSP) model, resulting in very similar import/export values. Based on the interchange testing, it was determined that the increase in exports was less a function of the hurdle rates than other model inputs. See Figure 6.6 for the interchange comparison per model and Future. The x-axis represents all 8,760 hours of the year in the PROMOD simulated models, ranked from highest hour of export to lowest hour of export (highest hour of import).

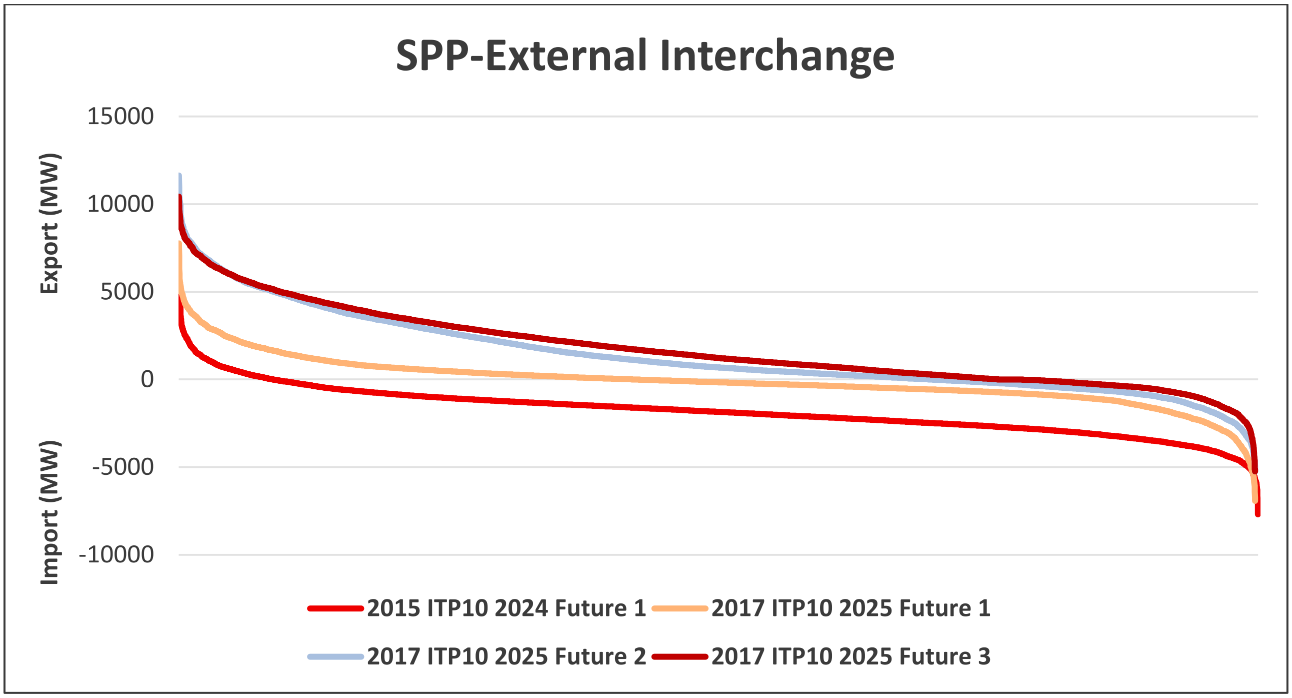


Figure 6.6: Interchange data comparison

SECTION 7: MODELING ADDERS FOR CARBON

7.1: Utilizing the Modeling Adder for Carbon

Development of the models for this assessment assumes that if the CPP were to ultimately become an enforceable regulation, a market would evolve to allow for the trading of carbon allowances or renewable credits allowed in the plan. Under this scenario, an affected generator would incur a cost related to carbon that would need to be recovered. Such a cost could be either a true cost that a generator incurs to purchase carbon allowances to run or an opportunity cost that a generator loses by running instead of selling carbon allowances. This cost could be recovered by the generator including this cost in its market bid, which would affect the overall energy costs to serve system demand.

In order to model this scenario, the modeling adder for carbon was reflected in the energy costs of generators identified as affected EGUs. This adder is included in a generator's production cost and therefore reflected in the adjusted production cost deltas used to assess the benefits of transmission. Generators that would be unaffected by CPP regulations were also considered in this assumption. While those units would not be affected under CPP regulations, an adder was utilized as a modeling technique to affect dispatch in order to account for constraints that may limit operation of these units for other reasons, such as fuel supply restrictions, air permit requirements, and water availability. The modeling adder for carbon placed on these units was not reflected in overall energy costs.

7.2: Reflecting the Modeling Adder for Carbon

After the resource and siting plans were developed and the model was benchmarked, the modeling adder for carbon utilized in the analysis to affect dispatch towards lower carbon emitting resources was further refined during the development of the economic model. Determining the correct adders needed to be more targeted across units than the approximation utilized during the resource plan development as well as broadened geographically to determine the correct pricing for neighboring regions that were not considered during the resource planning simulations and the interaction between systems.[13]

Multiple iterations of simulations were run in order to find a combination of carbon adders that allowed each region or state to meet its emission goal. This was performed on a transmission model absent transmission constraints in order to identify the optimal resource mix without the impact of system congestion. In addition to gaining some consistency with the zonal modeling nature of the resource planning tool, it was assumed that this would better facilitate the development of

[13] External regions were not modeled in the resource planning software simulations, but were considered in the determination of future resources.

transmission to address congestion resulting from the modeling decisions made to reduce carbon. Table 7.1 shows the carbon prices used for the SPP region and SPP states.

Region/State	Future	Modeling Adder for Carbon (2017$/ton)
Southwest Power Pool	1	21
Arkansas	2	21
Iowa	2	18.4
Kansas	2	18.4
Louisiana	2	21
Minnesota	2	21
Missouri	2	10.5
Nebraska	2	23.6
New Mexico	2	15.8
North Dakota	2	23.6
Oklahoma	2	7.9
South Dakota	2	0
Texas	2	18.4
Wyoming	2	23.6

Table 7.1: Modeling Adder for Carbon in SPP by Region and State

7.3: Unit Emissions

Interim mass carbon emission targets were calculated on a regional and a state level for SPP and neighboring regions. The emissions of every affected EGU were summed on a regional and a state level, and compared to the interim mass emission targets. While the region is taking actions that will result in reduced emissions in the future, Future 3 emissions are above the interim EPA CPP goals that this study is striving to achieve in the reduced carbon Futures, which is to be expected. The Future 1 model carbon emissions are below the regional goals in 2025, and the Future 2 model carbon emissions are below the state goals in 2025. Figure 7.1 and Figure 7. and show the regional and state-by-state emissions per Future.

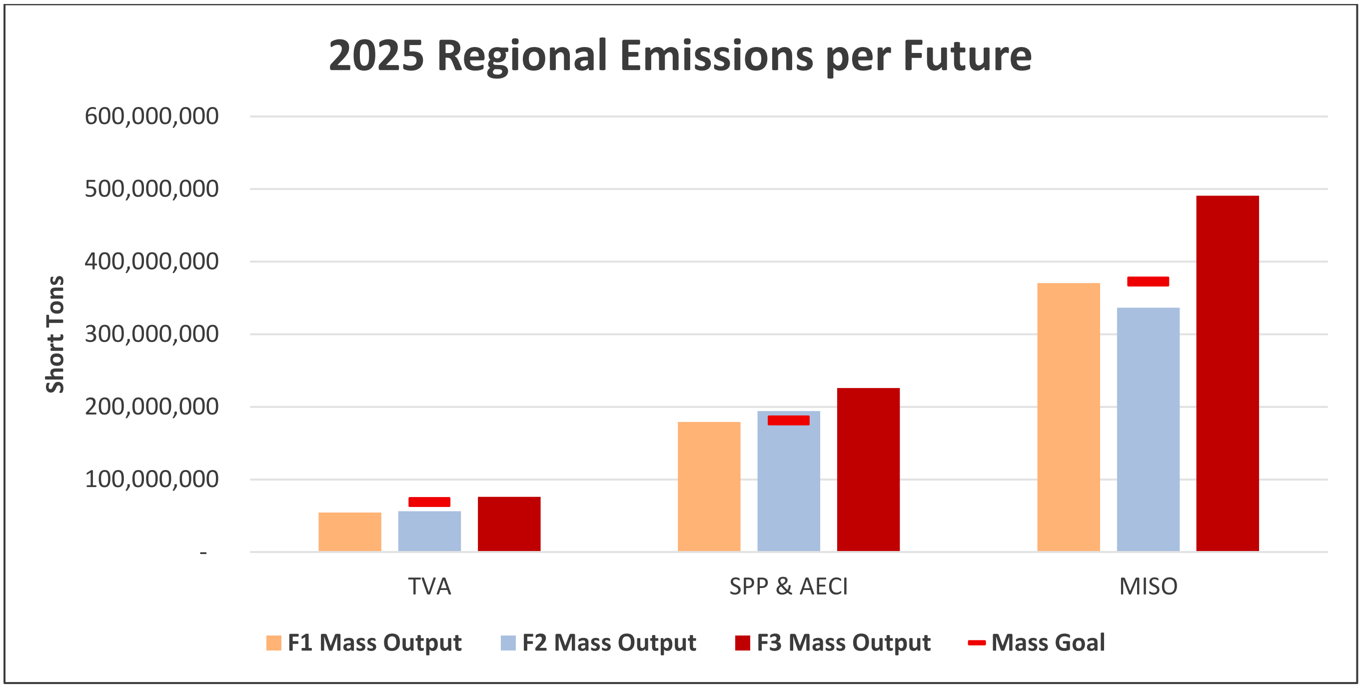


Figure 7.1: 2025 Regional Emissions per Future

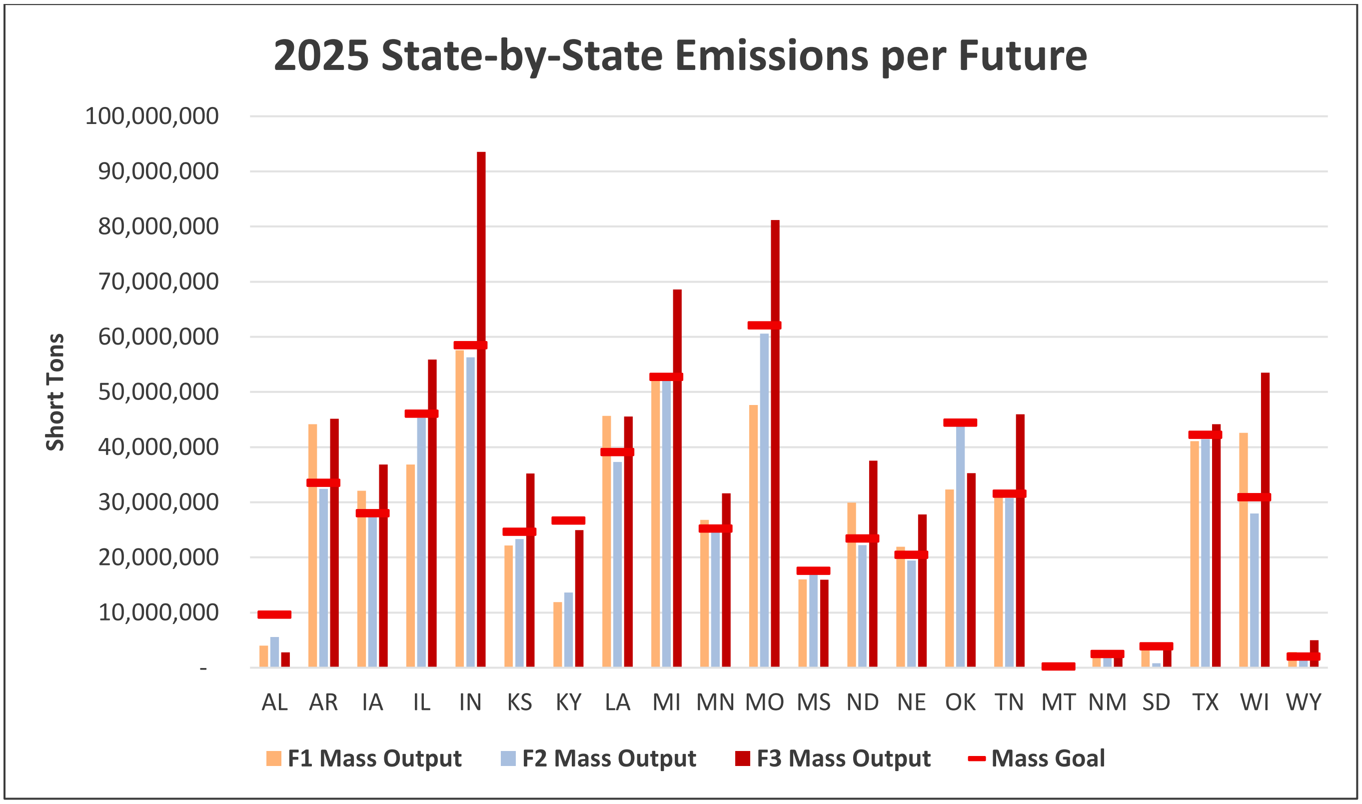


Figure 7.2: 2025 State-by-State Emissions per Future

SECTION 8: AC MODEL DEVELOPMENT

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 SCUC and SCED for each of the 8,760 hours in the year 2025.

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

1) **Summer peak hour:** The summer hour with the highest SPP Coincident load
2) **Off-peak hour:** The hour with the highest ratio of wind output to load, in order to evaluate grid exposure to significant output from these resources

The results indicated that the summer peak hour for 2025 would occur on August 6 at 5:00 p.m. and the high wind hour would occur on January 4 at 5:00 a.m.

8.1: DC-AC Modeling Process

The economic modeling process considers the transmission system in a Direct Current (DC) state and does not consider the systems' voltage response, under system intact and contingency conditions, when determining the unit commitment and dispatch. Because of this gap in the unit commitment and dispatch process, a conversion process is needed to consider the impact in an Alternating Current (AC) powerflow model.

In order to evaluate the economic unit commitment and dispatch on the transmission system, the dispatch and load utilized in each reliability hour were integrated back into the powerflow models. The 2016 ITPNT 2025 Summer and Light Load powerflow models were the designated starting point for topology considerations for the 2017 ITP10 powerflow models.

Member-submitted updates were incorporated into the models as well as any resources and transmission upgrades from the approved Resource Plans and GOF. Stakeholders and SPP staff also completed a rigorous 3-part review process to ensure that the economic dispatch was included properly.

8.2: Reactive Device Setting Review

Because the economic dispatch process does not consider voltage in its unit commitment and economic dispatch, stakeholders were specifically asked to review settings of reactive devices during the powerflow model review. This review included voltage schedules, capacitor bank switching parameters, and automatic tap change settings on applicable transformers. Improving the settings of these devices specific to the topology and dispatch of the model would provide a better voltage response under system intact and N-1 conditions.

PART III: NEEDS ASSESSMENTS & STUDY RESULTS

SECTION 9:NEEDS ASSESSMENT

9.1: Needs Overview

The 2017 ITP10 transmission planning analysis considers three separate types of needs and upgrades: reliability, policy, and economic. Each type of need was identified independently. Solutions were then developed for each need and analyzed individually against the base case. Throughout solution development, projects mitigating multiple needs regardless of need types were noted in an effort to develop an efficient portfolio. Thus, a single project could mitigate multiple reliability or economic needs or simultaneously mitigate a reliability and economic need. In the 2017 ITP10, no policy needs were identified.

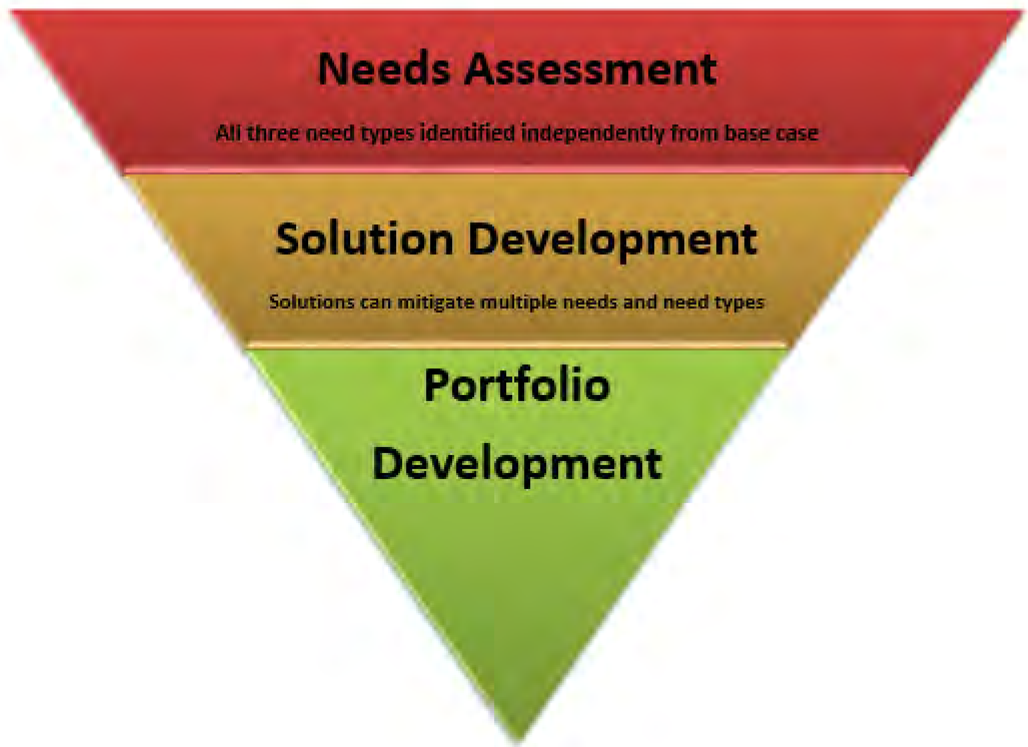


Figure 9.1: Analysis Process

9.2: Reliability Needs

AC contingency analysis was performed on each of the AC converted powerflow models to assess the reliability needs on the SPP system. This analysis considers the impact of the loss of a single element or multi-element contingencies.

Planning Criteria

SPP monitored all transmission lines and transformers 69 kV and above within SPP and all transformers and transmission lines 100 kV and above in first tier to evaluate system loading and per unit bus voltage under system intact conditions and contingency conditions to determine if system response was within acceptable limits.

Thermal loading considered 100 percent of each facility's normal rating for system intact and 100 percent of each facility's emergency rating under contingency. Additionally, bus voltages were monitored for both low voltage and high voltage. The voltage monitoring criteria was less than .95 per unit and greater than 1.05 per unit for system intact and less than .90 per unit and greater than 1.05 per unit for contingency conditions.

For those members that have a more stringent local planning criteria, SPP monitored their facilities using their approved per unit values to develop local planning criteria needs. These needs were sent to the respective entities having more stringent planning criteria to submit solutions.

Invalidation of Select AC Thermal Violations

Prior to beginning the needs assessment, the TWG and ESWG approved a recommendation from SPP staff to invalidate thermal reliability violations observed in the AC contingency analysis if those same overloaded facilities were included in the economic model's DC constraint list, and if the economic model found a re-dispatch solution that did not exceed each facility's thermal limit. The approval ensured that economic consideration was the determining factor for inclusion in the needs assessment when there was evidence that the violation would be avoided by generation re-dispatch. The same exclusion criteria were applied to thermal violations that were considered to be related to a more limiting constraint in the DC constraint list. These potential reliability violations were included in the needs assessment for informational purposes.

Reliability Needs List

A total of 14 unique thermal and 85 unique voltage criteria violations were identified as reliability needs in the 2017 ITP10. Figure 9.2 and Figure 9.3 show the final total of thermal and voltage needs per model as well as the number of unique facilities in violation in the respective model. "SP" represents a summer peak model and "LL" represents a light load model.

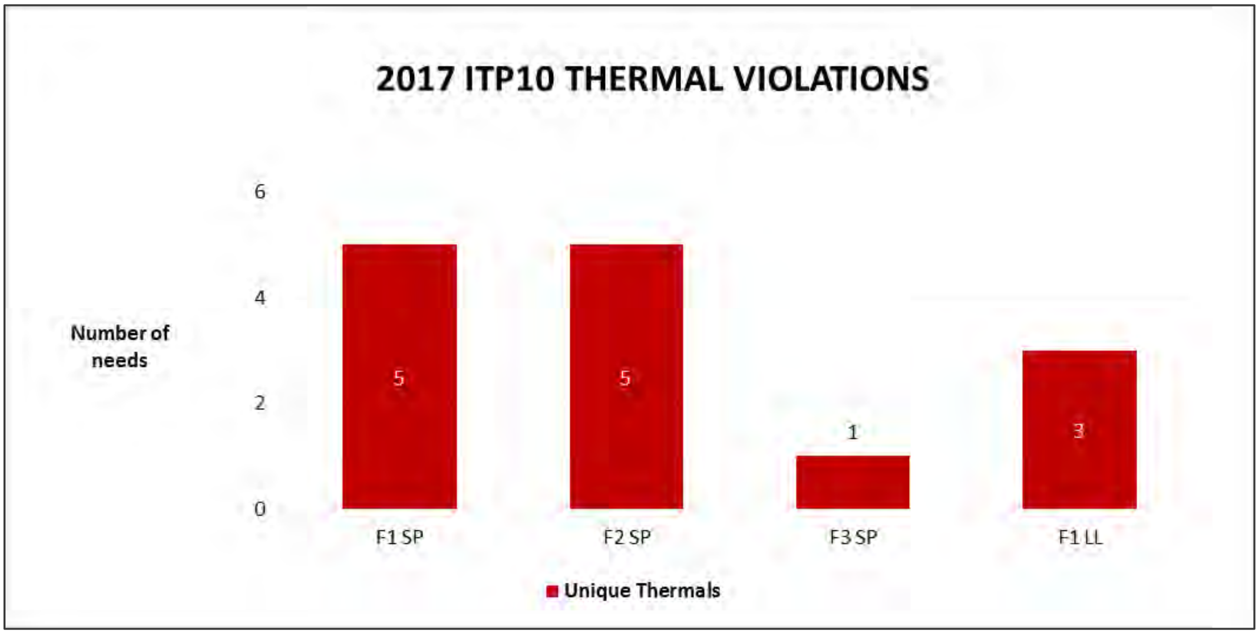


Figure 9.2: 2017 ITP10 Thermal Overload Totals

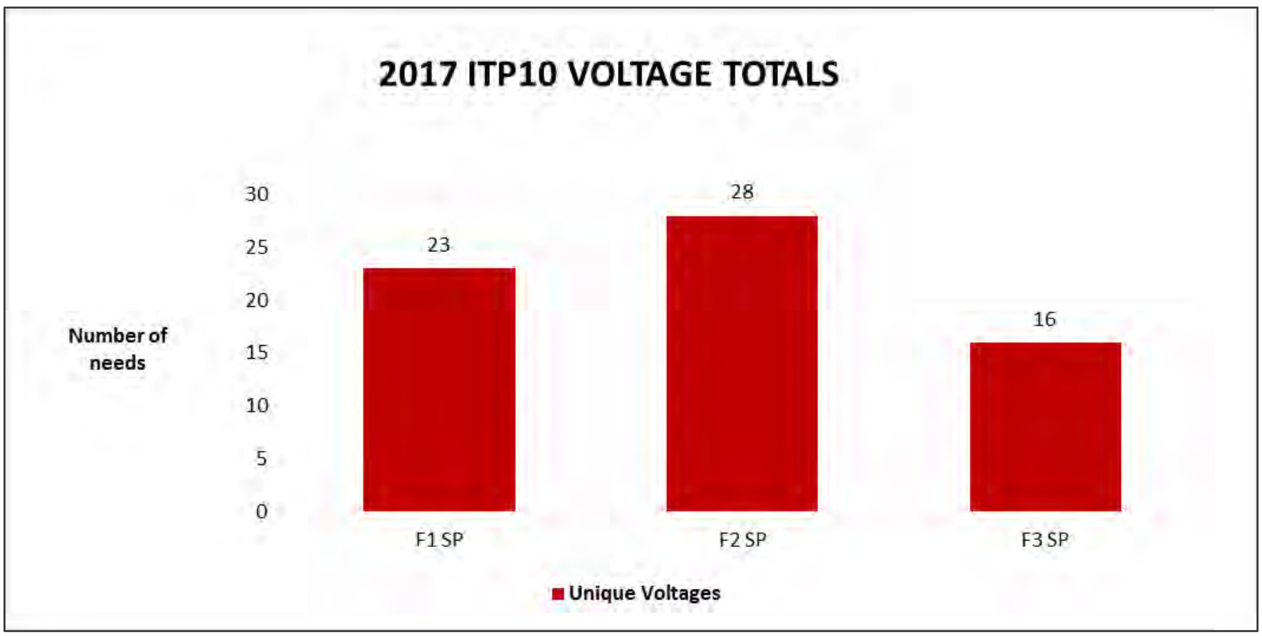


Figure 9.3: 2017 ITP10 Voltage Violation Totals

9.3: Policy Needs

Methodology

Policy needs were analyzed based on the curtailment of renewable energy such that a Regulatory/Statutory Mandate or Goal is not able to be met. Each zone with a Mandate or Goal was analyzed on a utility-by-state level (such as SPS Texas, SPS New Mexico, etc.) for renewable curtailments to determine if they met their Mandate or Goal. Policy needs are the result of an inability to dispatch renewable generation due to congestion, and any utility-by-state not meeting its renewable Mandate or Goal.

Renewable Mandates and Goals, per utility, were determined based on the 2015 Policy Survey. A 3 percent margin was used in determining the thresholds for each utility by state instance. For example, if the models show Utility A in State X had annual renewable energy generation output of at least 97 percent of their Mandate or Goal, they were determined to be meeting their renewable requirements and were not identified as having a policy need. This threshold is utilized to protect against minor curtailments driving transmission needs and projects. Some Mandates and Goals were based on installed capacity requirements only and were met by identifying capacity shortfalls and including the required capacity additions through phase 1 of the resource plan. It is not necessary to analyze capacity requirements for curtailment and thus they were not used to identify policy needs.

Policy Needs and Solutions

The policy needs assessment showed the following wind farms experiencing more than 3 percent annual curtailment are reported in Table 9.1:

Unit Name	Owner & State	Future 1	Future 2	Future 3
Smoky Hills Wind Farm	Multi-Owner, KS	5.08%	3.81%	0%
Flat Water Wind	OPPD, NE	4.74%	0%	0%
Cedar Bluff Wind	WRI, KS	4.65%	4.07%	0%
Centennial Wind Farm	OGE, OK	0%	0%	4.18%
NEW WIND SOUTH #1	AEPW, OK	4.03%	6.08%	3.59%
NEW WIND KSMO #4	AEPW, OK	3.36%	0%	0%

Table 9.1: Future 1 Policy Assessment Results

In spite of these individual wind farm curtailments, all utilities met their overall renewable Mandates and Goals. There were no policy needs and thus no policy projects identified in any of the Futures.

9.4: Economic Needs

Background

The 2017 ITP10 economic needs assessment was performed in parallel with the reliability and policy needs assessments. All needs were identified using a single base model for each Future.

Economic Needs

To assess economic needs, a SCUC and SCED were performed for the full study year. The SCED derived nodal LMPs by dispatching generation economically while honoring the transmission constraints defined for the system. LMPs reflect the congestion occurring on the transmission system's binding or breaching constraints. The simulation results revealed constraints causing the most congestion and additional cost of dispatching around those constraints. The following process was used to filter and rank each Future's congested constraints to target a list of economic needs for the study:

1. Binding constraints were ranked from highest to lowest congestion score per Future. Congestion score is defined as the product of the constraint's average shadow price and the number of hours the constraint is binding in 2025.

Figure 9.4: Congestion Score

2. The list of binding constraints was then reduced to the congested flowgates that have greater than $50,000/MW in annual flowgate congestion score.
3. Constraints with monitored elements not interconnected with the SPP transmission system that provide less than $1 million in annual potential benefit to SPP were removed.[14]
4. The most congested constraint of those with the same monitored element remained in the list, while others were excluded.
5. The remaining constraints up to 25 from each Future were identified as the system's economic needs.

The economic needs identified per Future are shown in Figure 9.6, **Error! Reference source not found.**, and Figure 9.6, as well as Table 9.2, Table 9.3, and Table 9.4.

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[14] Potential benefit is determined by relaxing the rating of the monitored element of a flowgate to relieve congestion.

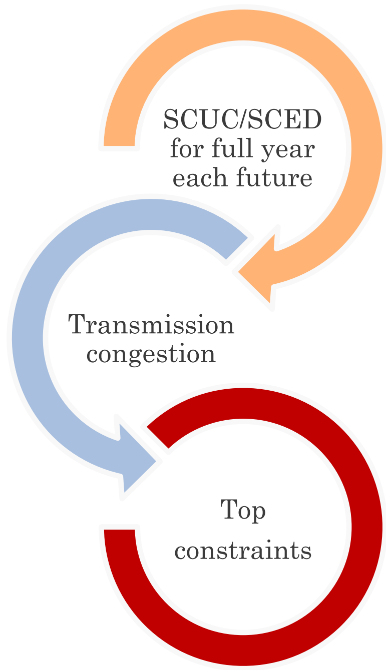

Figure 9.5: Developing Economic Needs

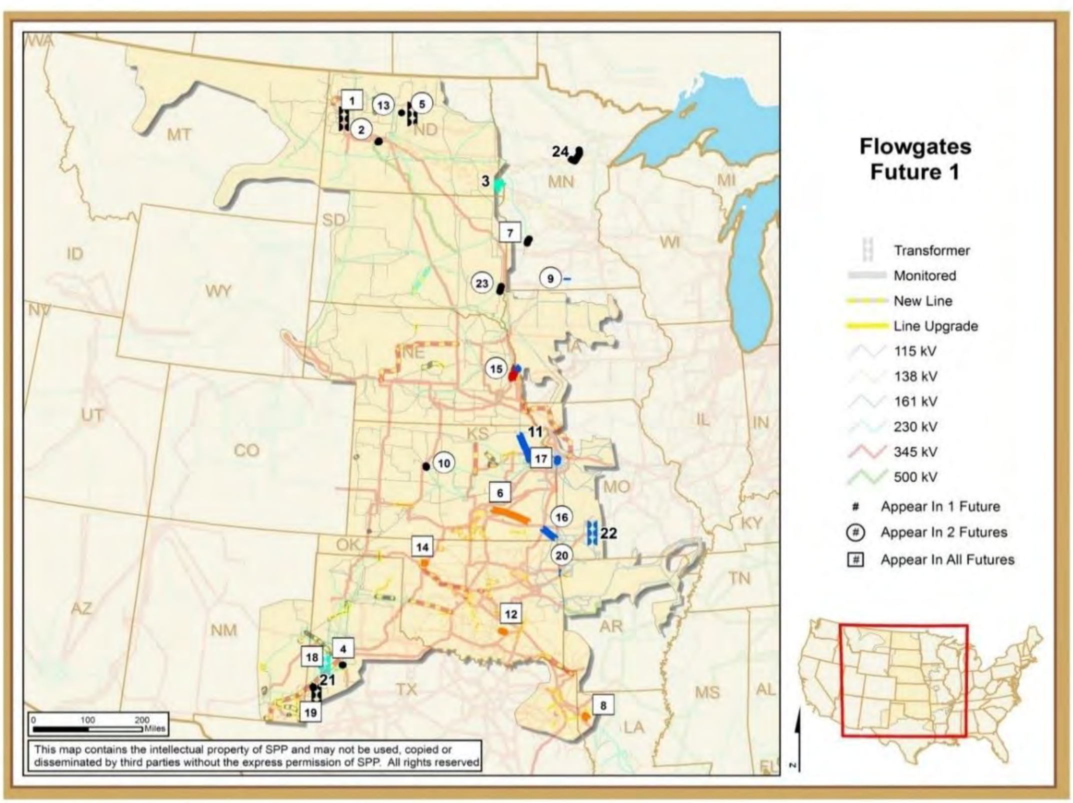

Figure 9.6: Future 1 Economic Needs Identified

Rank	Constraint	Congestion Score
1	Watford City 230/115 Ckt kV Transformer (System Intact Event)	781,727
2	Coyote - Beulah 115 kV FLO Center - Mandan 230 kV	675,574
3	Hankinson - Wahpeton 230 kV FLO Jamestown - Buffalo 345 kV	538,715
4	Stanton - Indiana 115 kV FLO Tuco - Carlisle 230 kV	464,889
5	GRE-McHenry 230/115 kV Transformer (System Intact Event)	408,953
6	Butler - Altoona 138 kV FLO Neosho - Caney River 345 kV	257,440
7	Sub3 - Granite Falls 115 kV Ckt 1 FLO Lyon Co. 345/115 kV Transformer Ckt 1	247,828
8	South Shreveport - Wallace Lake 138 kV FLO Ft Humbug - Trichel 138 kV	194,151
9	Winnebago- Blueeta 161 kV FLO Field - Wilmart 345 kV	188,723
10	Vine Tap - North Hays 115 kV FLO Knoll - Post Rock 230 kV	179,921
11	Kelly - Tecumseh Hill 161 kV FLO Kelly 161/115 kV Transformer	157,061
12	Tupelo Tap - Tupelo 138 kV FLO Pittsburg - Valiant 345 kV	154,155
13	GRE-McHenry - Voltair 115 kV FLO Balta - Rugby 230 kV	149,860
14	Woodward - Windfarm 138 kV FLO Woodward 138/69 kV Transformer	138,491
15	Fort Calhoun Interface	132,450
16	Neosho - Riverton 161 kV FLO Neosho - Blackberry 345 kV	115,799
17	Northeast - Charlotte 161 kV FLO Northeast - Grand Ave West 161 kV	99,579
18	Sundown 230/115 kV Transformer FLO Lamb County - Hockley 115 kV	94,603
19	Seminole 230/115 kV Transformer Ckt 2 FLO Seminole 230/115 kV Ckt 1 Transformer	90,904
20	Siloam City - Siloam Springs 161 kV FLO Flint Creek - Tonnece 345 kV	76,650
21	Denver - Shell 115 kV FLO West Sub3 - Lovington 115 kV	75,257
22	Brookline 345/161 kV Ckt 1 Transformer FLO Brookline 345/161 kV Ckt 2 Transformer	74,465
23	Sioux Falls - Lawrence 115 kV FLO Sioux Falls - Split Rock 230 kV	70,107
24	Grand Rapids - Pokegma 115 kV FLO Forbes - Chisago 500 kV	62,701

Table 9.2: Future 1 Economic Needs Identified

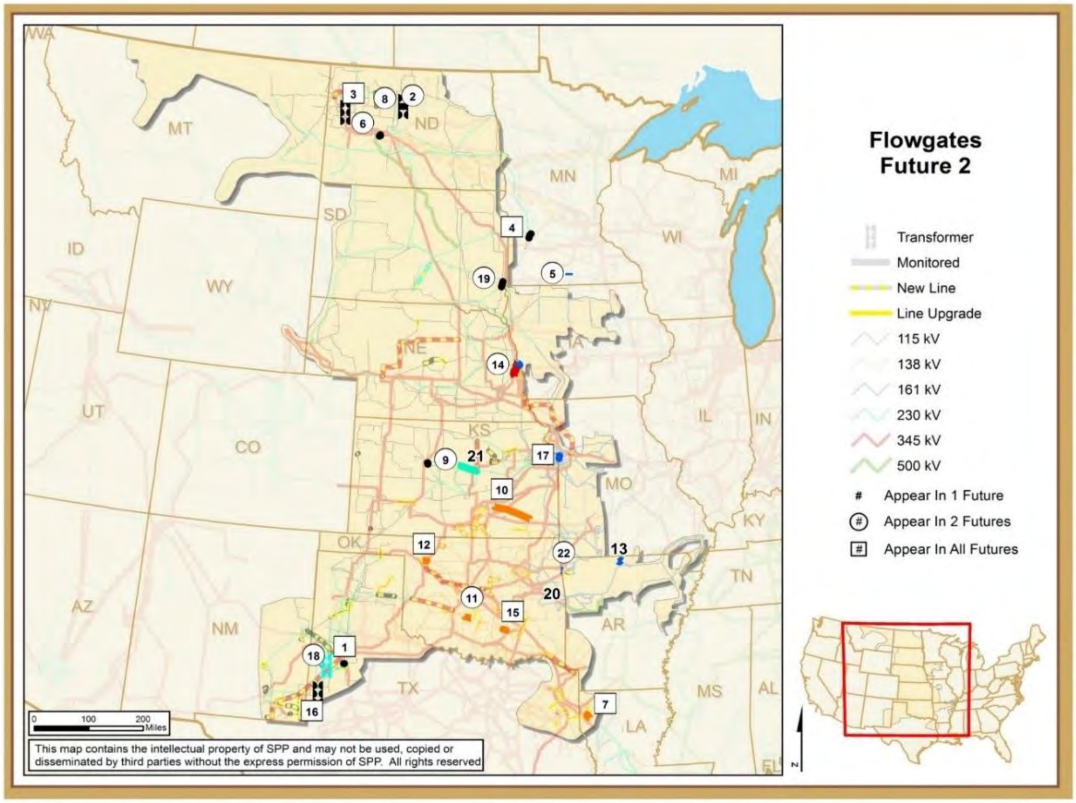

Figure 9.7: Future 2 Economic Needs Identified

Rank#	Constraint	Congestion Score
1	Stanton - Indiana 115 kV FLO Tuco - Carlisle 230 kV	662,310
2	GRE-McHenry 230/115 kV Transformer (System Intact Event)	597,138
3	Watford City 230/115 Ckt kV Transformer (System Intact Event)	536,225
4	Sub3 - Granite Falls 115 kV Ckt 1 FLO Lyon Co. 345/115 kV Transformer Ckt 1	371,481
5	Winnebago- Blueeta 161 kV FLO Field - Wilmart 345 kV	300,035
6	Coyote - Beulah 115 kV FLO Center - Mandan 230 kV	293,122
7	South Shreveport - Wallace Lake 138 kV FLO Ft Humbug - Trichel 138 kV	218,942
8	GRE-McHenry - Voltair 115 kV FLO Balta - Rugby 230 kV	149,813
9	Vine Tap - North Hays 115 kV FLO Knoll - Post Rock 230 kV	134,509
10	Butler - Altoona 138 kV FLO Neosho - Caney River 345 kV	128,073
11	Naples Tap - Cornville Tap 138 kV FLO Sunnyside - G14-057T 345 kV	125,364
12	Woodward - Windfarm 138 kV FLO Woodward 138/69 kV Transformer	110,046
13	Bull Shoals - Midway Jordan 161 kV FLO Bull Shoals - Buford 161 kV	96,338
14	Fort Calhoun Interface	85,756
15	Tupelo Tap - Tupelo 138 kV FLO Pittsburg - Valiant 345 kV	81,181
16	Seminole 230/115 kV Transformer Ckt 2 FLO Seminole 230/115 kV Ckt 1 Transformer	79,960

Rank#	Constraint	Congestion Score
17	Northeast - Charlotte 161 kV FLO Northeast - Grand Ave West 161 kV	79,745
18	Sundown 230/115 kV Transformer FLO Lamb County - Hockley 115 kV	79,392
19	Sioux Falls - Lawrence 115 kV FLO Sioux Falls - Split Rock 230 kV	79,374
20	Highway 59 - VBI North 161 kV FLO Fort Smith - Muskogee 345 kV	71,172
21	Smokey Hills - Summit 230 kV FLO Post Rock - Axtell 345 kV	58,462
22	Siloam City - Siloam Springs 161 kV FLO Flint Creek - Tonnece 345 kV	50,011

Table 9.3: Future 2 Economic Needs Identified

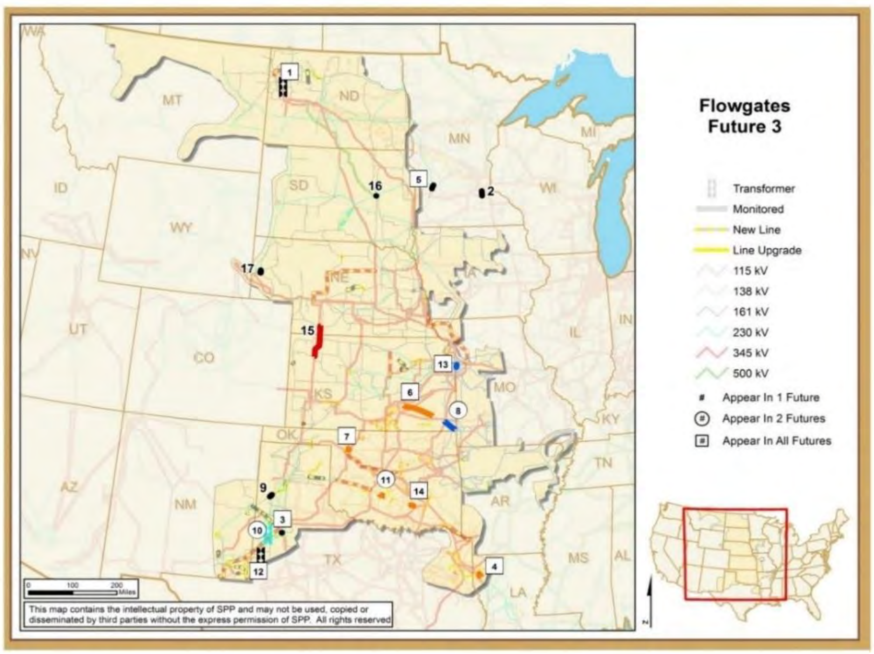

Figure 9.8: Future 3 Economic Needs Identified

Need ID#	Constraint	Congestion Score
1	Watford City 230/115 Ckt kV Transformer (System Intact Event)	821,749
2	Chub Lake - Kenrick 115 kV FLO Helena - Scott Co 345 kV	635,398
3	Stanton - Indiana 115 kV FLO Tuco - Carlisle 230 kV	379,447
4	South Shreveport - Wallace Lake 138 kV FLO Ft Humbug - Trichel 138 kV	274,213
5	Sub3 - Granite Falls 115 kV Ckt 1 FLO Lyon Co. 345/115 kV Transformer Ckt 1	221,315
6	Butler - Altoona 138 kV FLO Neosho - Caney River 345 kV	166,526
7	Woodward - Windfarm 138 kV FLO Woodward 138/69 kV Transformer	109,243

Need ID#	Constraint	Congestion Score
8	Neosho - Riverton 161 kV FLO Neosho - Blackberry 345 kV	103,326
9	Hereford - DS#6 115 kV FLO Deaf Smith PLX Tap - Plant X6 230 kV	94,461
10	Sundown 230/115 kV Transformer FLO Lamb County - Hockley 115 kV	92,582
11	Naples Tap - Cornville Tap 138 kV FLO Sunnyside - G14-057T 345 kV	88,668
12	Seminole 230/115 kV Transformer Ckt 2 FLO Seminole 230/115 kV Ckt 1 Transformer	87,371
13	Northeast - Charlotte 161 kV FLO Northeast - Grand Ave West 161 kV	82,395
14	Tupelo Tap - Tupelo 138 kV FLO Pittsburg - Valiant 345 kV	57,979
15	Red Willow - Mingo Interface	53,504
16	Huron - B Tap 115 kV Ckt 1 FLO Ft. Thompson - Letcher 230 kV Ckt 1	52,591
17	Scottsbluff - Victory Hill 115 kV Ckt 1 FLO Stegall 345/230 kV Transformer Ckt 1	52,309

Table 9.4: Future 3 Economic Needs Identified

SECTION 10: PORTFOLIO DEVELOPMENT

10.1: Process Overview

Upon completion of the reliability, policy, and economic needs assessment, project solutions were analyzed to evaluate the best solutions to mitigate needs. Individual projects were analyzed for their feasibility in mitigating both reliability and economic needs.

After performing screening of potential project solutions across each Future, the projects showing the most promise to mitigate each of the defined needs of the study were further evaluated as multiple project groupings were developed for each Future. These groupings were refined into a single portfolio of projects per Future, and were then consolidated into two final portfolios: a Reduced Carbon portfolio and a Reference Case portfolio.

10.2: Project Screening

Project solutions were evaluated in each Future for effectiveness in mitigating the needs identified in the needs assessment. The project solutions that were assessed included Order 1000 and Order 890 solutions submitted by Stakeholders, solutions proposed by SPP staff, projects submitted in previous planning studies, model corrections submitted by Stakeholders, and NTC projects that were approved after the finalization of the 2017 ITP10 model. Staff analyzed 1,136 DPP solutions received from Stakeholders and approximately 150 staff solutions.

Reliability Project Screening

Each DPP and SPP staff solution was tested against each reliability need identified in the needs assessment. Solutions were identified that mitigated the reliability need consistent with SPP Criteria for either thermal loading or per-unit voltage and a set of reliability metrics was calculated for these solutions.

Reliability metrics were developed by SPP staff and Stakeholders and approved by the TWG for use as a tool in project selection. The reliability metrics coincide with thermal and voltage reliability needs. The first metric is Cost per Loading Relief (CLR), which relates the amount of thermal loading relief a solution provides with the project cost. The second metric is Cost per Voltage Relief (CVR), which relates the amount of voltage support a solution provides to the project cost.

Metrics were calculated for each project’s performance for each need. After the metrics were calculated, the projects were ranked per need and by the lowest CLR or CVR. The project with the highest ranking (lowest CLR or CVR) was identified as the optimal project to address the particular need.

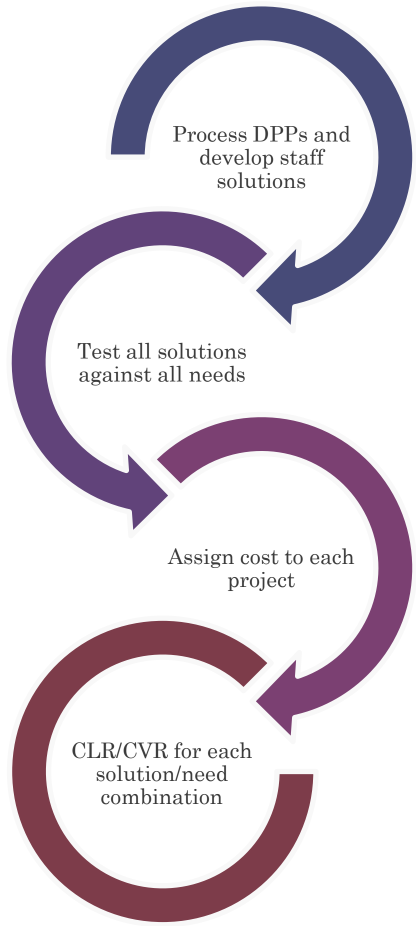

Figure 10.1: Reliability Grouping Process

Economic Project Screening

Each project solution was tested to determine its effectiveness in mitigating system congestion in the SPP footprint. The APC with and without the proposed project was calculated for 2025. The change in SPP APC with the project in service was considered the one-year benefit to the SPP region. The one-year benefit was divided by the one-year cost of the project to develop a benefit-to-cost (B/C) ratio for each project. The one-year cost, or projected annual transmission revenue requirement (ATRR), used for analysis is a historical average net plant carrying charge (NPCC) multiplied by the total project cost. For this study the NPCC used was 17 percent. Projects with B/C ratios less than 0.5 were discarded from further consideration in portfolio development. Projects with a B/C ratio greater than 0.5 were further evaluated in the development of project groupings. The B/C threshold of 0.5 was established by SPP staff and the ESWG with the rationale that a project could show moderate benefit during project screening and show more benefit when grouped with other projects.

Policy Project Screening

No policy needs were identified in the 2017 ITP10, and as a result, there were no policy projects analyzed in the portfolio development.

10.3: Project Grouping

After the screening of all project solutions, draft groupings were developed to include groups of projects to address multiple needs across the system.

Reliability Grouping

A subset of projects was generated by considering project cost as related to the amount of targeted relief the project could provide. Displacement of lower voltage level projects by higher voltage level projects occurred when a higher voltage level project solved needs at lower voltage levels. SPP staff applied engineering judgment to discern if a displaced project should remain in the portfolio. Finally, the subset of projects selected that solved all reliability needs was moved into the portfolio for each Future.

Economic Grouping

All projects showing a one-year B/C of at least 0.5 during the project screening phase were further evaluated during the development of project groupings. Projects were evaluated and grouped based on one-year project cost, one-year APC benefit, and congestion relief for the economic needs. Three different economic project groupings were developed for each Future:

1. Cost-Effective Grouping: Includes projects with the lowest cost per congestion cost relief for a single economic need.
2. Highest Net APC Benefit Grouping: Includes projects with the highest APC benefit minus project cost, with consideration of overlap where multiple projects mitigate congestion on the same economic needs.
3. Multi-variable Grouping: Includes projects selected using data from the two other groupings and includes the flexibility to use additional considerations not previously defined.

Three different groupings per Future were developed in order to look at different approaches to building an optimal portfolio. The following factors were considered in the development and analysis of projects grouping per Future:

- One-year project cost, one-year APC benefit, B/C ratio, and APC benefit
- The congestion relief that a project provides for the economic needs of that Future
- Project overlap – two projects that relieve the same congestion are not both included in a portfolio
- The potential for a project to mitigate multiple economic needs – this was considered during the development of project groupings
- Any potential routing or environmental concerns with projects

- Current operational issues on the transmission system that are causing reliability or economic problems
- Any long-term concerns about the viability of projects
- The need for new infrastructure versus leveraging existing infrastructure
- Any model corrections submitted after the 2017 ITP10 topology model was finalized were considered as mitigations for economic needs, such that no new project was identified as part of the project groupings
- Any transmission projects that were issued NTCs from other planning studies after the 2017 ITP10 topology model was finalized were considered as potential project solutions for economic needs
- Model corrections submitted by members during the project submittal process, whether they mitigated economic needs or not, were added to the models during the project grouping process. APC benefits and B/C ratios from this point on in the study were analyzed with these model corrections included in both the base and change cases.

10.4: Final Portfolios per Future

All economic projects included in the final groupings by Future were tested to ensure that each project had a one-year B/C of at least 0.9 when the other projects in the grouping are included in both the base case and the change case. The economic grouping that achieved the highest net APC benefit as a portfolio was selected along with the reliability portfolio as the final portfolio for each Future. Each project in the tables of this section include a detailed description, zonal location, project type, study cost estimate, and line mileage.

The final portfolio for Future 1 includes reliability projects as well as the Multi-Variable Grouping of economic projects. This Future 1 portfolio consists of 20 projects and 23.6 miles of transmission line. The economic projects have a one-year B/C ratio of 5.06 (considering APC benefits only).

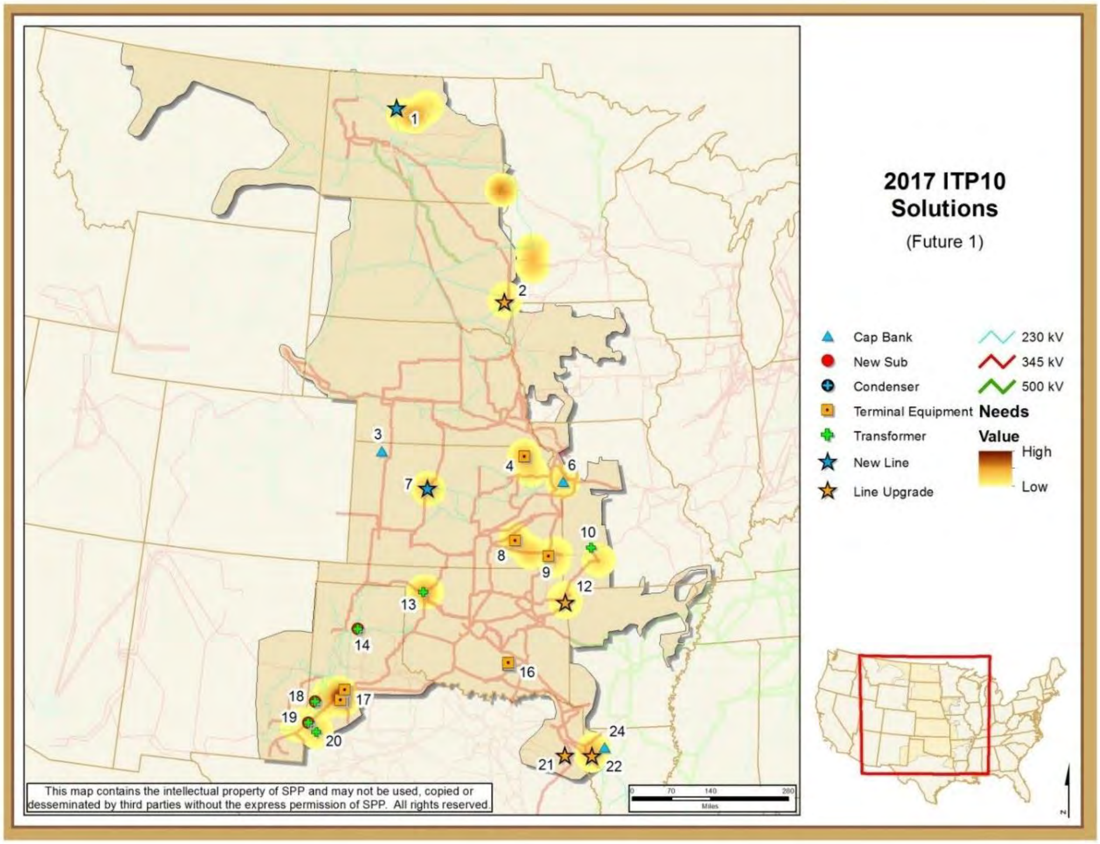

Figure 10.2: Future 1 Portfolio

	Future 1 Portfolio		
	Reliability	**Economic**	**Total***
Total Cost	$38.0M	$79.0M	$107.1M
Total Projects	5	16	20
Total Miles	7.5	16.1	23.6
1-Year Cost		$13.4M	$18.2M
1-Year APC Benefit		$68.0M	$67.4M
1-Year B/C Ratio		5.06	3.70

Table 10.1: Future 1 Portfolio Statistics

*One project is both reliability and economic, and included in both categories. Since this is included only once in the total, the sum of the two costs does not equal the total cost.

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
1	Build a new double circuit 115 kV line from Magic City to a point on the Logan - Mallard 115 kV line that minimizes the distance between the new substation and the cut-in point. Bisect the Logan - Mallard 115 kV line to cut-in the new double circuit 115 kV line.	WAPA/XEL	E	$3,075,000	1.8
2	Rebuild 1.0 mile 115 kV line from Lawrence - Sioux Falls Upgrade terminal equipment at Lawrence and/or Sioux Falls to increase the rating of the line between the substations to 398/398 (SN/SE).	WAPA/XEL	E	$1,383,750	1.0
3	Install two 14.4-MVAR capacitor banks (28.8 total MVAR) at Atwood 115 kV substation. Install 14.4-MVAR capacitor bank at Seguin Tap 115 kV substation.	MIDW	R	$2,389,707	-
4	Upgrade any necessary terminal equipment at Kelly and/or Tecumseh to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 151 MVA.	WR	E	$1,550,993	-
6	Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line.	KCPL	E	$512,500	-
7	Build a new second 230 kV line from Knoll to Post Rock.	MIDW	E	$3,389,019	1.0
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	WR	E	$244,606	-
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	WR/EDE	E	$114,154	-
10	Install a 345/161 kV transformer at Morgan substation.	AECI	E	$8,661,250	-
12	Rebuild 2.1-mile 161 kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE).	AEP/GRDA	E	$5,185,885	2.1

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
13	Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	OGE	E	$7,459,438	-
14	Tap the Nichols to Grapevine 230 kV line to construct new substation. Install a new 230/115 kV transformer at Nichols - Grapevine tap substation. Construct new 2-mile 115 kV line from Martin to Nichols/Grapevine tap substation. Install terminal upgrades at Martin to accommodate new 115 kV line from the Nichols/Grapevine tap substation.	SPS	R	$14,936,215	2.0
16	Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 138 kV line between the two substations to a summer and winter emergency rating of 169/201 MVA. Upgrade terminal equipment at Lula and/or Tupelo Tap to increase the rating of the line between the substations to 171/192 (SN/SE).	OGE/WFEC	E	$102,500	-
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	SPS	E	$969,942	-
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	SPS	E	$11,961,951	-
19	Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	SPS	E/R	$9,953,077	-

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	SPS	E	$7,423,880	-
21	Rebuild 5.5-mile 138 kV line from Knox Lee to South Texas Eastman and upgrade any necessary equipment to increase the branch ratings to 371/470 MVA.	AEP	R	$8,456,250	5.5
22	Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	AEP	E	$17,015,000	11.2
24	Install 28.8-MVAR capacitor bank at Port Robson 138 kV.	AEP	R	$2,306,250	-

Table 10.2: Future 1 Portfolio Projects

The final portfolio for Future 2 includes reliability projects as well as the Cost-Effective Grouping of economic projects. This Future 2 portfolio consists of 15 projects and 30.8 miles of transmission line. The economic projects have a one-year B/C ratio of 5.87 (considering APC benefits only).

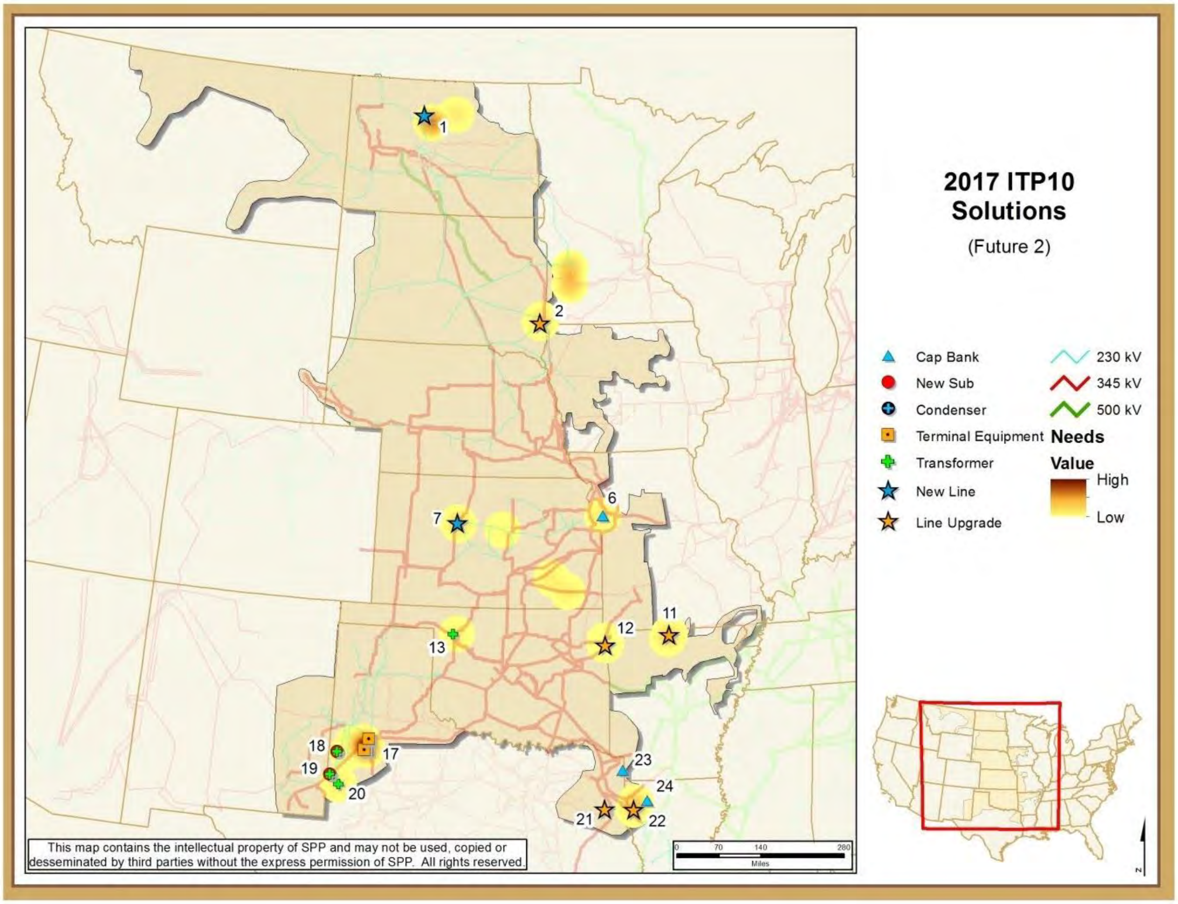

Figure 10.3: Future 2 Portfolio

	Future 2 portfolio		
	Reliability	**Economic**	**Total**
Total Cost	$22.0M	$66.5	$88.5M
Total Projects	4	11	15
Total Miles	5.5	25.3	30.8
1-Year Cost		$11.3M	$15.0M
1-Year APC Benefit		$66.4M	$71.0M
1-Year B/C Ratio		5.87	4.72

Table 10.3: Future 2 Portfolio Statistics

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
1	Build a new double circuit 115 kV line from Magic City to a point on the Logan - Mallard 115 kV line that minimizes the distance between the new substation and the cut-in point. Bisect the Logan - Mallard 115 kV line to cut-in the new double circuit 115 kV line.	WAPA/XEL	E	$3,075,000	1.8
2	Rebuild 1.0 mile 115 kV line from Lawrence - Sioux Falls. Upgrade terminal equipment at Lawrence and/or Sioux Falls to increase the rating of the line between the substations to 398/398 (SN/SE).	WAPA/XEL	E	$1,383,750	1.0
6	Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line.	KCPL	E	$512,500	-
7	Build a new second 230 kV line from Knoll to Post Rock.	MIDW	E	$3,389,019	-
11	Rebuild 9.2-mile 161 kV line from Bull Shoals to Midway Jordan and upgrade any necessary equipment to increase the summer emergency rating to 335 MVA.	SPA/EES	E	$8,089,406	9.2
12	Rebuild 2.1-mile 161 kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE).	AEP/GRDA	E	$5,185,885	2.1
13	Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment and all associated and miscellaneous materials.	OGE	E	$7,459,438	-
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	SPS	E	$969,942	-
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	SPS	E	$11,961,951	-

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
19	Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	SPS	R	$9,953,077	-
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	SPS	E	$7,423,880	-
21	Rebuild 5.5-mile 138 kV line from Knox Lee to South Texas Eastman and upgrade any necessary equipment to increase the branch ratings to 371/470 MVA.	AEP	R	$8,456,250	5.5
22	Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	AEP	E	$17,015,000	11.2
23	Install 28.8-MVAR capacitor bank at IPC 138 kV.	AEP	R	$1,270,836	-
24	Install 28.8-MVAR capacitor bank at Port Robson 138 kV.	AEP	R	$2,306,250	-

Table 10.4: Future 2 Portfolio Projects

The final portfolio for Future 3 includes reliability projects as well as the Cost-Effective Grouping of economic projects. This Future 3 portfolio consists of 12 projects and 18.3 miles of transmission line. The economic projects have a 1-year B/C ratio of 5.51 (considering APC benefits only).

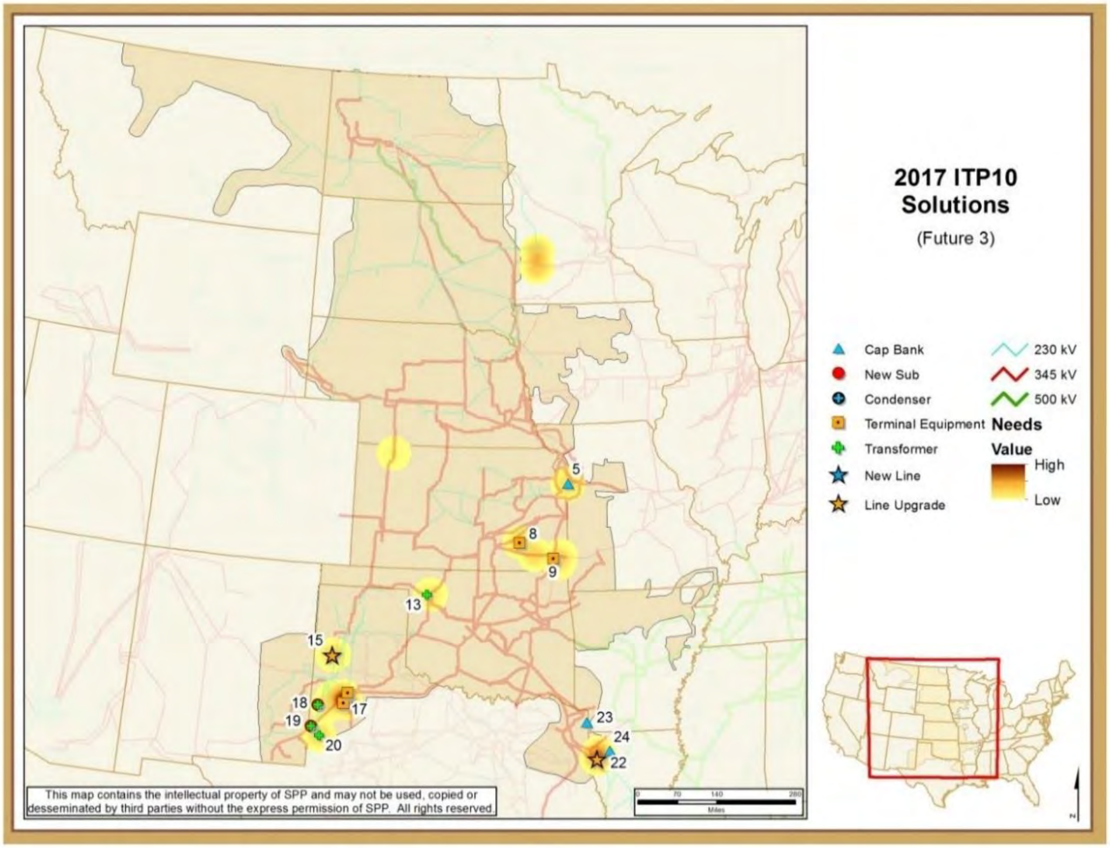

Figure 10.4: Future 3 Portfolio

	Future 3 portfolio		
	Reliability	**Economic**	**Total**
Total Cost	$13.5M	$49.1M	$62.6M
Total Projects	3	9	12
Total Miles	0	18.3	18.3
1-Year Cost		$8.4M	$10.6M
1-Year APC Benefit		$46.0M	$50.4M
1-Year B/C Ratio		5.51	4.73

Table 10.5: Future 3 Portfolio Statistics

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
5	Add 1 ohm Series reactor to Northeast - Charlotte 161 kV line.	KCPL	E	$512,500	-
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	WR	E	$244,606	-
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	WR/EDE	E	$114,154	-
13	Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment and all associated and miscellaneous materials.	OGE	E	$7,459,438	-
15	Rebuild 7.12-mile 115 kV transmission line from Hereford to DS#6 and upgrade any necessary equipment to increase the summer emergency rating to 240 MVA.	SPS	E	$3,359,671	7.1
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	SPS	E	$969,942	-
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	SPS	E	$11,961,951	-
19	Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	SPS	R	$9,953,077	-
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	SPS	E	$7,423,880	-
22	Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch	AEP	E	$17,015,000	11.2

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
	ratings to 371/478 MVA.				
23	Install 28.8-MVAR capacitor bank at IPC 138 kV.	AEP	R	$1,270,836	-
24	Install 28.8-MVAR capacitor bank at Port Robson 138 kV.	AEP	R	$2,306,250	-

Table 10.6: Future 3 Portfolio Projects

10.5: Portfolio Consolidation

After developing a final project grouping for each Future, projects were consolidated across multiple Futures in order to draw one step closer to a final recommendation on an ITP10 project portfolio. The Future 1 and Future 2 portfolios were consolidated into a single Reduced Carbon portfolio to be analyzed across both Reduced Carbon Futures; the Future 3 portfolio was not consolidated with the Future 1 or 2 portfolios. As detailed in **Error! Reference source not found.** and Section 13:, the assessment of benefit metrics and sensitivities described in the study scope were calculated for the Reduced Carbon and Reference Case portfolios.

Economic Project Consolidation Criteria

- Economic projects with a one-year B/C ratio greater than 0.9 calculated by taking 75% of the project's benefit in Future 1 and 25% of the project's benefit in Future 2 were included in the Reduced Carbon portfolio.
- Economic projects with a one-year B/C ratio greater than 0.9 in Future 3 were included in the Reference Case portfolio.

Reliability Project Consolidation Criteria

- Reliability projects were included in the Reduced Carbon portfolio if they mitigate a thermal/voltage violation in Future 1.
- Future 2 reliability projects were included in the Reduced Carbon portfolio if they mitigate a thermal violation in Future 2 and mitigate loading above a 95% threshold in Future 1.
- Future 2 projects mitigating a voltage limit violation in Future 2 and voltage below 0.92 per unit in Future 1 were included in the Reduced Carbon portfolio.

Summary

The Reduced Carbon portfolio includes reliability and economic projects that met the consolidation criteria for Futures 1 and 2. This portfolio consists of 20 projects and 23.6 miles of transmission line. The economic projects have a one-year B/C ratio of 5.06 (considering APC benefits only).

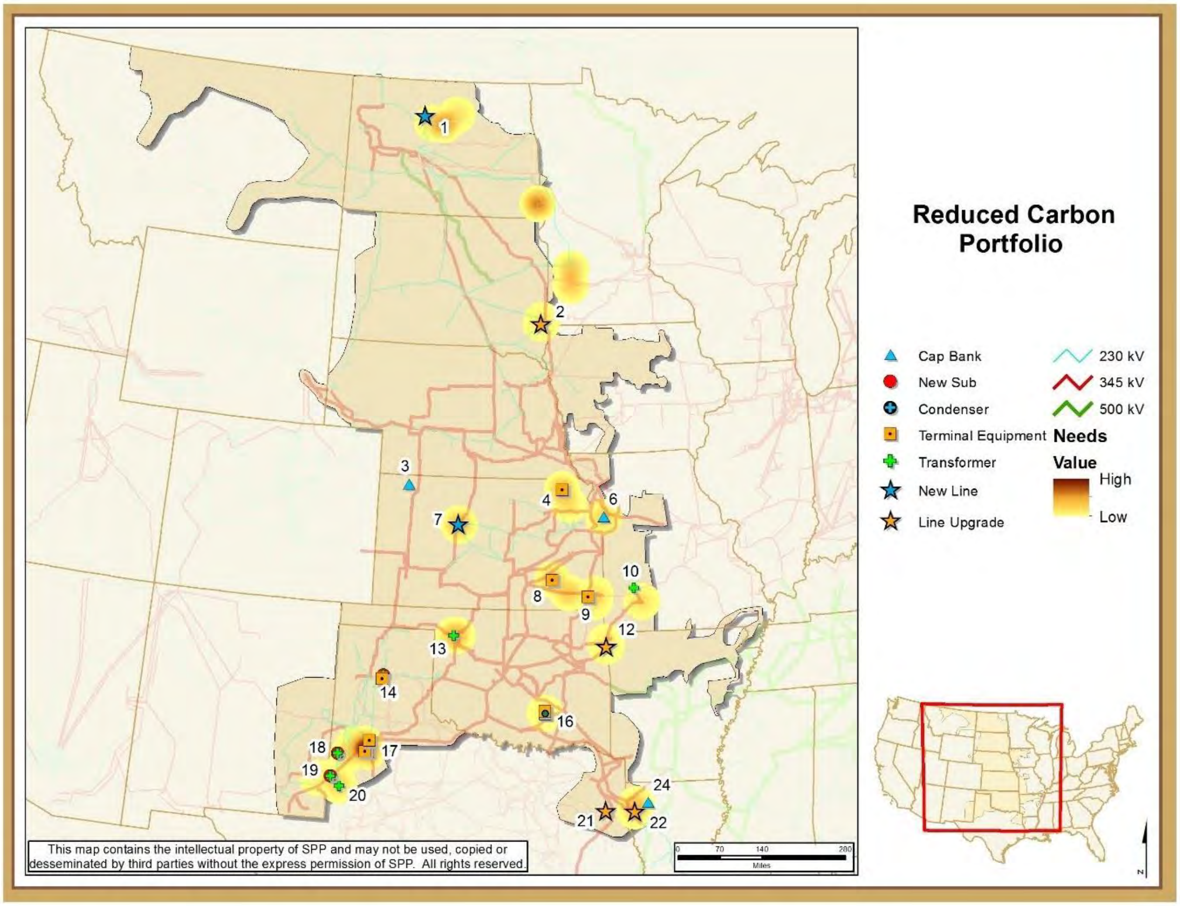

Figure 10.5: Reduced Carbon Portfolio

	Reduced Carbon Portfolio		
	Reliability	**Economic**	**Total***
Total Cost	$38.0M	$79.0M	$107.1M
Total Projects	5	16	20
Total Miles	7.5	16.1	23.6
1-Year Cost		$13.4M	$18.2M
1-Year APC Benefit		$68.0M	$67.4M
1-Year B/C Ratio		5.06	3.70

Table 10.7: Reduced Carbon Portfolio Statistics

*One project is both reliability and economic, and included in both categories. Since this is included only once in the total, the sum of the two numbers does not equal the total.

Label	Project Description	Area(s)	Type	Cost Estimate	Mileage
1	Build a new double circuit 115 kV line from Magic City to a point on the Logan - Mallard 115 kV line that minimizes the distance between the new substation and the cut-in point. Bisect the Logan - Mallard 115 kV line to cut-in the new double circuit 115 kV line.	WAPA/XEL	E	$3,075,000	1.8
2	Rebuild 1.0 mile 115 kV line from Lawrence - Sioux Falls. Upgrade terminal equipment at Lawrence and/or Sioux Falls to increase the rating of the line between the substations to 398/398 (SN/SE).	WAPA/XEL	E	$1,383,750	1.0
3	Install two (2) 14.4-MVAR capacitor banks (28.8 total MVAR) at Atwood 115 kV substation. Install 14.4-MVAR capacitor bank at Seguin Tap 115 kV substation.	MIDW	R	$2,389,707	-
4	Upgrade any necessary terminal equipment at Kelly and/or Tecumseh to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 151 MVA.	WR	E	$1,550,993	-
6	Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line.	KCPL	E	$512,500	-
7	Build a new second 230 kV line from Knoll to Post Rock.	MIDW	E	$3,389,019	1.0
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	WR	E	$244,606	-
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	WR/EDE	E	$114,154	-
10	Install a 345/161 kV transformer at Morgan substation.	AECI	E	$8,661,250	-
12	Rebuild 2.1-mile 161 kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE).	AEP/GRDA	E	$5,185,885	2.1

Label	Project Description	Area(s)	Type	Cost Estimate	Mileage
13	Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment and all associated and miscellaneous materials.	OGE	E	$7,459,438	-
14	Tap the Nichols to Grapevine 230 kV line to construct new substation. Install a new 230/115 kV transformer at Nichols - Grapevine tap substation. Construct new 2-mile 115 kV line from Martin to Nichols/Grapevine tap substation. Install terminal upgrades at Martin to accommodate new 115 kV line from the Nichols/Grapevine tap substation.	SPS	R	$14,936,215	2.0
16	Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 138 kV line between the two substations to a summer and winter emergency rating of 169/201 MVA. Upgrade terminal equipment at Lula and/or Tupelo Tap to increase the rating of the line between the substations to 171/192 (SN/SE).	OGE/WFEC	E	$102,500	-
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	SPS	E	$969,942	-
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	SPS	E	$11,961,951	-

Label	Project Description	Area(s)	Type	Cost Estimate	Mileage
19	Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	SPS	E/R	$9,953,077	-
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	SPS	E	$7,423,880	-
21	Rebuild 5.5-mile 138 kV line from Knox Lee to South Texas Eastman and upgrade any necessary equipment to increase the branch ratings to 371/470 MVA.	AEP	R	$8,456,250	5.5
22	Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	AEP	E	$17,015,000	11.2
24	Install 28.8-MVAR capacitor bank at Port Robson 138 kV.	AEP	R	$2,306,250	-

Table 10.8: Reduced Carbon Portfolio Projects

The Reference Case Portfolio projects are shown in Figure 10.6 and Table 10.10.

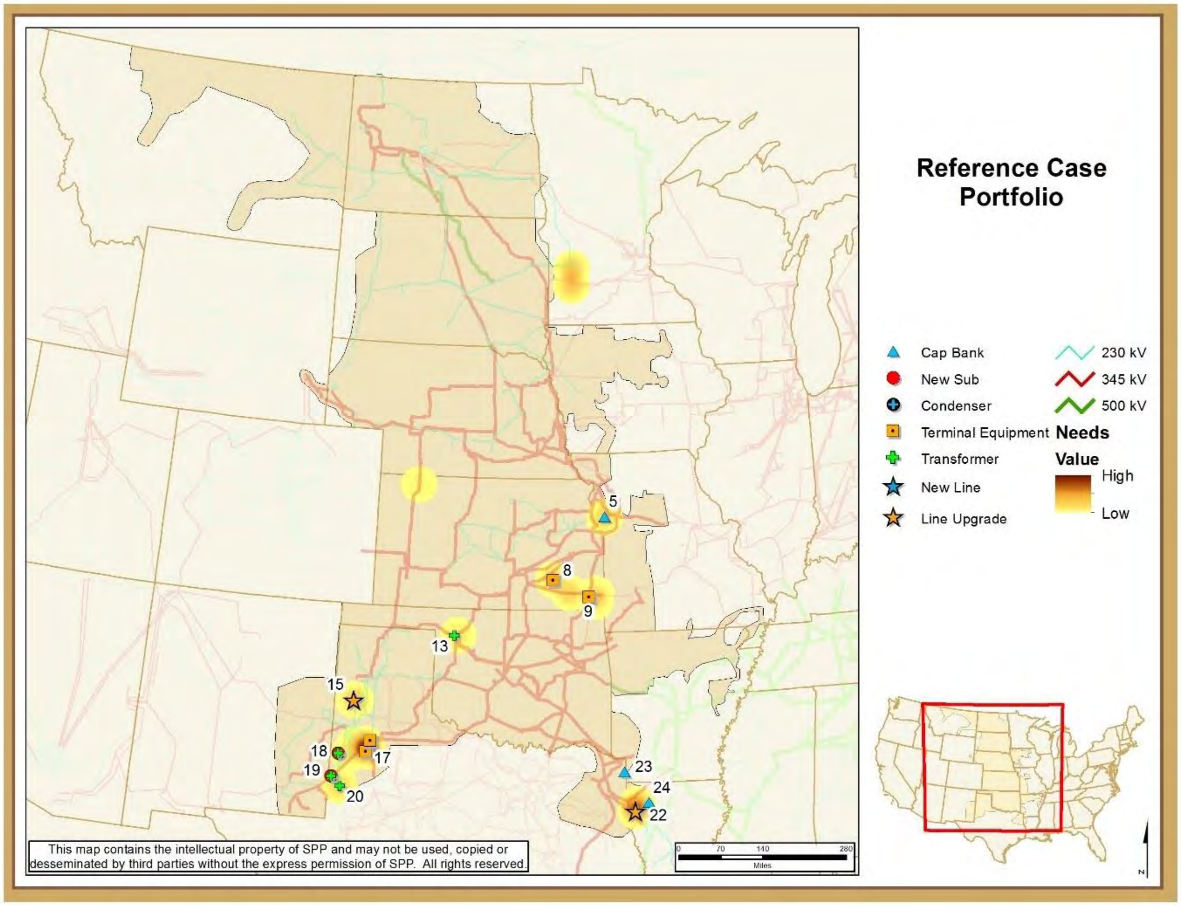

Figure 10.6: Reference Case Portfolio

	Reference Case Portfolio		
	Reliability	**Economic**	**Total**
Total Cost	$13.5M	$49.1M	$62.6M
Total Projects	3	9	12
Total Miles	0	18.3	18.3
1-Year Cost		$8.4M	$10.6M
1-Year APC Benefit		$46.0M	$50.4M
1-Year B/C Ratio		5.51	4.73

Table 10.9: Reference Case Portfolio Statistics

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
5	Add 1 ohm Series reactor to Northeast - Charlotte 161 kV line.	KCPL	E	$512,500	-
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	WR	E	$244,606	-
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	WR/EDE	E	$114,154	-
13	Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment and all associated and miscellaneous materials.	OGE	E	$7,459,438	-
15	Rebuild 7.12-mile 115 kV transmission line from Hereford to DS#6 and upgrade any necessary equipment to increase the summer emergency rating to 240 MVA.	SPS	E	$3,359,671	7.1
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	SPS	E	$969,942	-
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	SPS	E	$11,961,951	-
19	Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	SPS	R	$9,953,077	-
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	SPS	E	$7,423,880	-

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
22	Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	AEP	E	$17,015,000	11.2
23	Install 28.8-MVAR capacitor bank at IPC 138 kV.	AEP	R	$1,270,836	-
24	Install 28.8-MVAR capacitor bank at Port Robson 138 kV.	AEP	R	$2,306,250	-

Table 10.10: Reference Case Portfolio Projects

SECTION 11: STAGING

11.1: Methodology

A project need date is determined, or staged, based on the project classification(s) and considering the Future from which the project was derived. In this study, a project can be classified as economic, policy, or reliability depending on which of these needs it mitigates. Multiple classifications can be carried by a single project if it mitigates multiple need types. For example, if a single project simultaneously mitigated economic and reliability needs, per the criteria described in Sections 9.2: through 0In spite of these individual wind farm curtailments, all utilities met their overall renewable Mandates and Goals. There were no policy needs and thus no policy projects identified in any of the Futures.

Economic Needsof this report, the project would be classified as both economic and reliability. Multiple classification projects were staged to meet the earliest need date established through the single project classification process, as described in the following sub-sections. Project lead times were determined according to historical expectations and Stakeholder review.

Staging Reliability Projects

Reliability projects were staged between 2020 and 2025, as defined in the Scope. The process to stage reliability projects utilized the 2017 ITP10 powerflow models representing the summer peak and off-peak hours in Future 1 for two years: 2020 and 2025. Thermal projects were staged based on linear interpolation of thermal loadings from 2020 to 2025. The year in which the loading of the constrained facility exceeded 100 percent was identified as the need date. Similar to the thermal staging process, voltage needs were staged based on linear interpolation of voltage per unit values from 2020 to 2025. The year in which the voltage was less than 0.95 per unit for base case conditions, or less than 0.90 per unit for contingency conditions was identified as the need date. In the case where a project mitigated thermal and voltage needs, the project was staged to meet the earliest occurrence of either the thermal or voltage need. Figure 11.1 provides an example of reliability project need date determination.

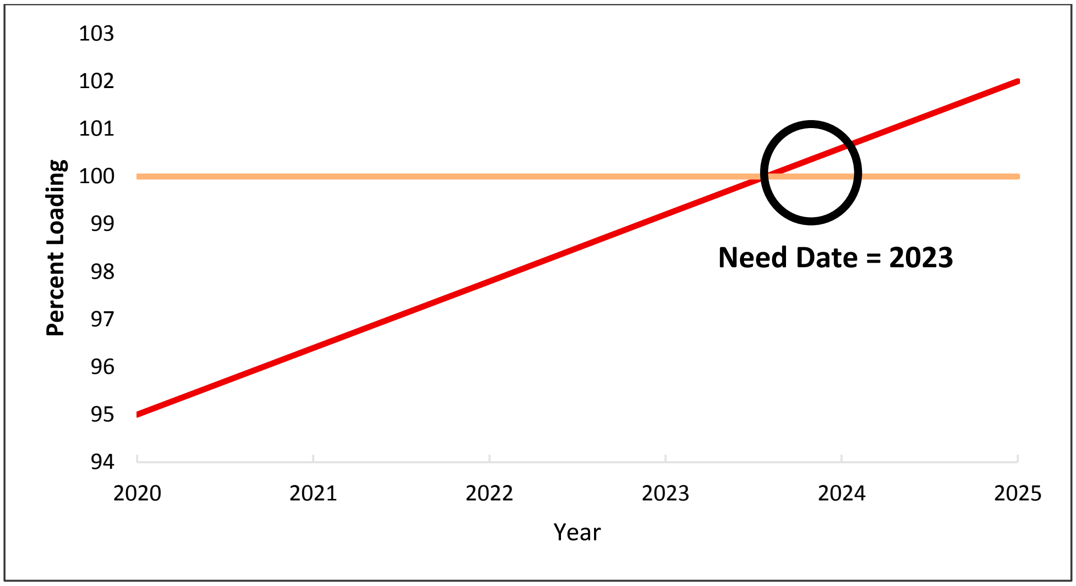

Figure 11.1: Reliability Project Staging Interpolation Example

11.2: Staging Economic Projects

The security constrained economic simulation was used to perform a production cost analysis for the years 2020 and 2025, as defined in the Scope, using the Future 3 model for the Reference Case portfolio, and Future 1 and Future 2 models for the Reduced Carbon portfolio. The incremental benefit of each economic project was calculated with the project considered in the respective Future model; reliability projects are included in the base and change cases. Future 1/Future 2 project benefits were weighted consistently with the consolidation process (75% of benefit in Future 1, and 25% of the benefit in Future 2). Economic projects were given an in-service date for the first year that the B/C ratio was greater than 1.0 based on interpolation between the staging and study year results. Figure 11.2 provides an example of economic project need date determination.

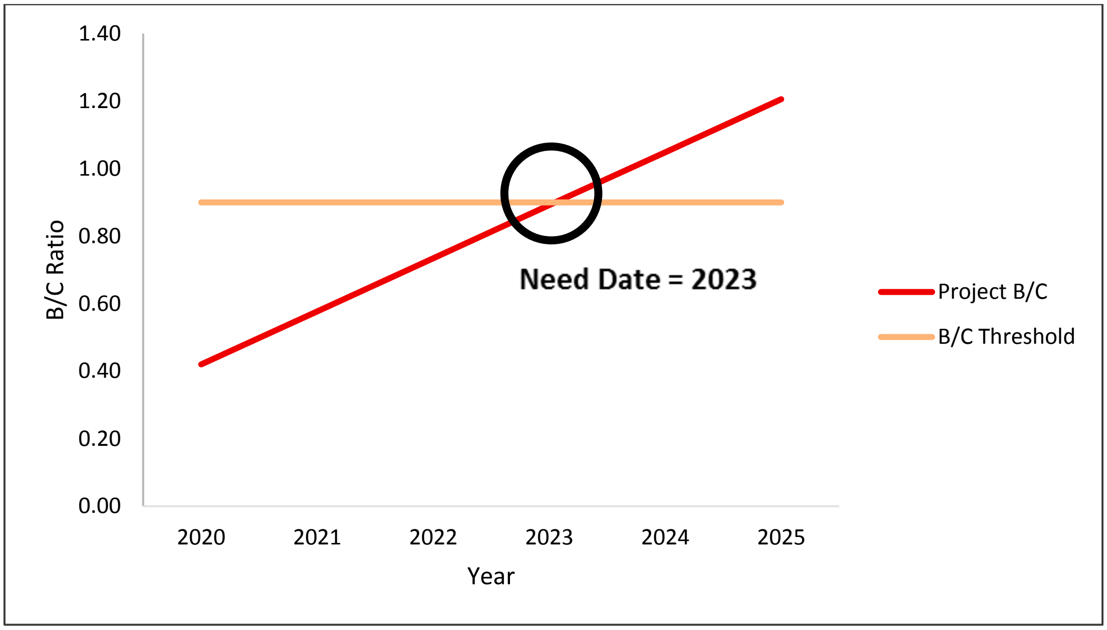

Figure 11.2: Economic Project Staging Interpolation Example

11.3: Staging Policy Upgrades

No policy needs were identified.

11.4: Staging Results

Error! Reference source not found. and Table 11.1 provide the staging data for each project in the Reduced Carbon portfolio and the Reference Case portfolio respectively.

General Description	Lead Time	Location (Zone)	Staging Date
Rebuild 5.5-mile 138 kV line from Knox Lee to South Texas Eastman and upgrade any necessary equipment to increase the branch ratings to 371/470 MVA.	24 months	AEP	6/1/2022
Install 28.8-MVAR capacitor bank at Port Robson 138 kV.	24 months	AEP	6/1/2025
Install two 14.4-MVAR capacitor banks (28.8 total MVAR) at Atwood 115 kV substation. Install 14.4-MVAR capacitor bank at Seguin Tap 115 kV substation.	24 months	MIDW	6/1/2024
Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	24 months	SPS	1/1/2020
Tap the Nichols to Grapevine 230 kV line to construct new substation. Install a new 230/115 kV transformer at Nichols - Grapevine tap substation. Construct new 2-mile 115 kV line from Martin to Nichols/Grapevine tap substation. Install terminal upgrades at Martin to accommodate new 115 kV line from the Nichols/Grapevine tap substation.	24 months	SPS	1/1/2020

General Description	Lead Time	Location (Zone)	Staging Date
Install a 345/161 kV transformer at Morgan substation.	36 months	AECI	1/1/2020
Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	24 months	AEP	1/1/2023
Rebuild 2.1-mile 161 kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE).	24 months	AEP/GRDA	1/1/2020
Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line.	24 months	KCPL	1/1/2020
Build a new second 230 kV line from Knoll to Post Rock.	24 months	MIDW	1/1/2020
Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment and all associated and miscellaneous materials.	18 months	OGE	1/1/2020
Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 138 kV line between the two substations to a summer and winter emergency rating of 169/201 MVA.	18 months	SPA/WFEC	1/1/2020
Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	18 months	SPS	1/1/2020
Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	24 months	SPS	1/1/2020
Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	24 months	SPS	1/1/2020
Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	24 months	SPS	1/1/2020
Build a new double circuit 115 kV line from Magic City to a point on the Logan - Mallard 115 kV line that minimizes the distance between the new substation and the cut-in point. Bisect the Logan - Mallard 115 kV line to cut-in the new double circuit 115 kV line.	24 months	WAPA/XEL	1/1/2021
Rebuild 1.0 mile 115 kV line from Lawrence - Sioux Falls Upgrade terminal equipment at Lawrence and/or Sioux Falls to increase the rating of the line between the substations to 398/398 (SN/SE).	24 months	WAPA/XEL	1/1/2021
Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	18 months	WR	1/1/2020

General Description	Lead Time	Location (Zone)	Staging Date
Upgrade any necessary terminal equipment at Kelly and/or Tecumseh to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 151 MVA.	18 months	WR	1/1/2021
Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	18 months	WR/EDE	1/1/2020

Table 11.1: Reduced Carbon Portfolio Staging Results

General Description	Lead Time	Location (Zone)	Staging Year
Install 28.8-MVAR capacitor bank at Port Robson 138 kV.	24 months	AEP	6/1/2025
Install 28.8-MVAR capacitor bank at IPC 138 kV[15].	24 months	AEP	1/1/2020
Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	24 months	SPS	6/1/2020
Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	24 months	AEP	1/1/2022
Add 1 ohm Series reactor to Northeast - Charlotte 161 kV line.	24 months	KCPL	1/1/2020
Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment and all associated and miscellaneous materials.	18 months	OGE	1/1/2020
Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to	18 months	SPS	1/1/2020

[15] Project addresses local planning criteria needs.

General Description	Lead Time	Location (Zone)	Staging Year
a summer emergency rating of 175 MVA.			
Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	24 months	SPS	1/1/2020
Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	24 months	SPS	1/1/2024
Rebuild 7.12-mile 115 kV transmission line from Hereford to DS#6 and upgrade any necessary equipment to increase the summer emergency rating to 240 MVA.	24 months	SPS	1/1/2020
Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	18 months	WR	1/1/2020
Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	18 months	WR/EDE	1/1/2020

Table 11.2: Reference Case Portfolio Staging Results

SECTION 12: BENEFITS

12.1: Methodology

Benefit metrics were used to measure the value and economic impacts of the portfolios. The ESWG directed that the 2017 ITP10 B/C ratios be calculated for the final Reduced Carbon portfolio using the Future 1 model and also on the Reference Case portfolio using the Future 3 model, including reliability and economic projects. The benefit structure shown in Figure 12.1 illustrates the metrics calculated as the incremental benefit of the projects included in the portfolios.

Metric Description
APC Savings
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emission Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Figure 12.1: Benefit Metrics for the 2017 ITP10

12.2: APC Savings

Adjusted Production Cost (APC) is a measure of the impact on production cost savings, considering purchases and sales of energy between each area of the transmission grid. The APC metric is determined using a production cost modeling tool that accounts for hourly commitment and dispatch profiles for the simulation year. The calculation, performed on an hourly basis, is summarized in

Figure *12.2* as follows:

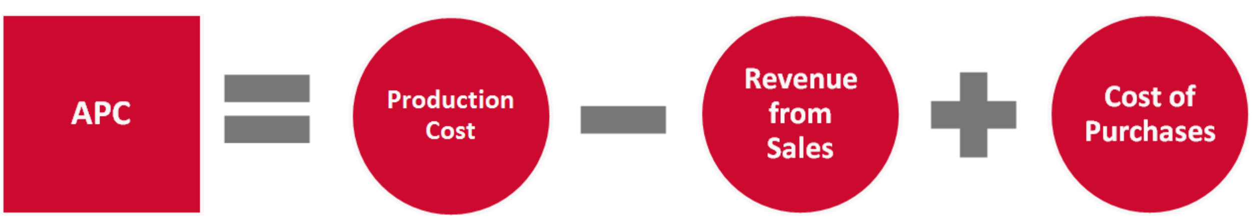

Figure 12.2: APC Calculation

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 through a combination of economical generation dispatch, economical purchases, and optimal revenue from sales.

To calculate benefits over the expected 40-year life of the projects[16], two years were analyzed, 2020 and 2025, and the APC savings were calculated accordingly for these years. The benefits were extrapolated and interpolated for the initial 20-year period based on the slope between the two points; for the remaining years the benefits are assumed to grow at an inflation rate of 2.5 percent per year. Each year's benefit was then discounted using an 8 percent discount rate. The sum of all discounted benefits was presented as the net present value (NPV) benefit. This calculation was performed for every zone.

Figure 12.3 shows the regional APC savings for the portfolios over 40 years, and Table 12.1 provides the zonal breakdown and the NPV estimates.

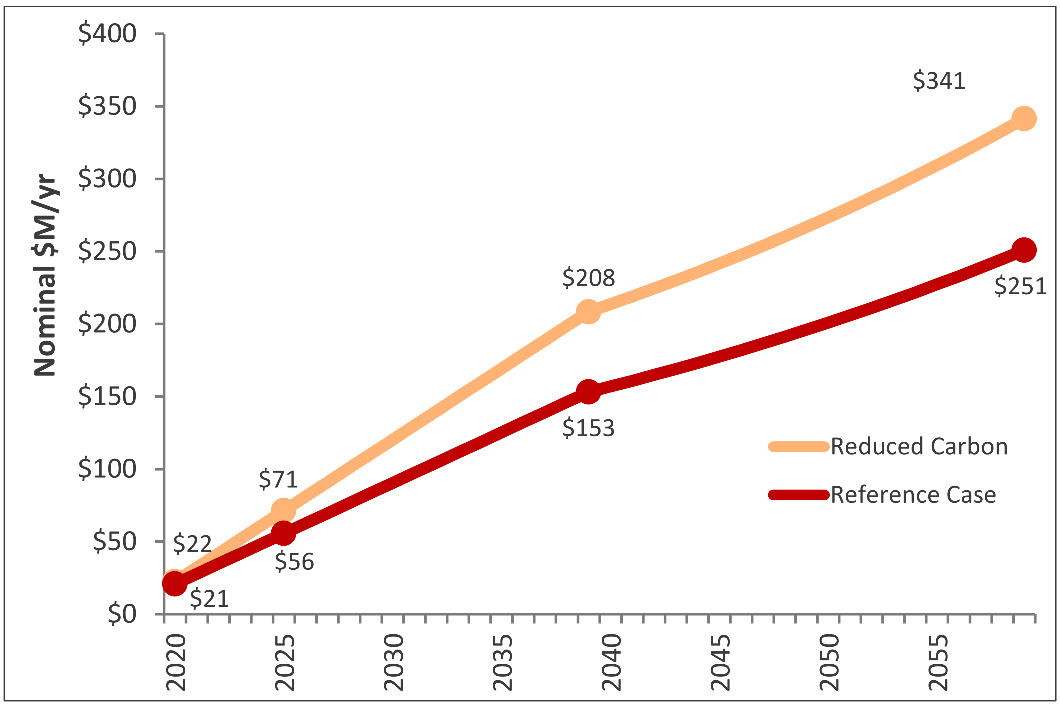

Figure 12.3: Regional APC Savings Estimated for the 40-year Study Period

[16] The SPP OATT requires that a 40-year financial analysis be performed on the portfolios.

Zone	Reduced Carbon Portfolio 2020 ($M)	Reduced Carbon Portfolio 2025 ($M)	Reduced Carbon Portfolio 40-yr NPV ($2017M)	Reference Portfolio 2020 ($M)	Reference Portfolio 2025 ($M)	Reference Portfolio 40-yr NPV ($2017M)
AEPW	$2.0	$9.6	$203.8	($1.3)	$11.1	$278.6
CUS	$0.4	$2.3	$50.6	$0.1	$0.1	$2.1
EDE	$0.6	$1.3	$23.3	$1.3	$1.8	$28.6
GMO	$0.2	$0.8	$18.1	($0.6)	($0.1)	$3.2
GRDA	$2.2	$2.7	$39.6	$0.2	$0.3	$3.7
KCPL	$4.9	$5.6	$78.1	$3.7	$5.4	$87.4
LES	$0.2	($0.1)	($5.4)	$0.3	$0.2	$2.6
MIDW	$0.5	$1.6	$33.1	($0.5)	($0.5)	($6.5)
MKEC	($1.5)	($2.0)	($30.8)	($2.1)	($2.0)	($24.7)
NPPD	$2.4	$2.9	$40.4	$2.3	$2.6	$36.1
OKGE	($0.1)	($0.1)	($1.4)	$1.3	$2.0	$33.5
OPPD	$0.2	($2.0)	($49.8)	($0.0)	($0.6)	($14.8)
SUNC	($0.3)	($0.7)	($13.5)	($0.1)	($0.1)	($2.5)
SWPS	$8.1	$24.6	$492.1	$13.1	$25.2	$449.1
UMZ	$0.1	$12.2	$288.3	($0.0)	($0.5)	($11.6)
WFEC	$9.8	$10.5	$138.4	$8.9	$7.9	$88.1
WRI	$0.9	$2.2	$42.1	$3.2	$2.9	$31.6
TOTAL	**$30.6**	**$71.3**	**$1,347.0**	**$29.8**	**$55.7**	**$984.7**

Table 12.1: APC Savings by Zone

12.3: Reduction of Emission Rates and Values

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.

12.4: Savings Due to Lower Ancillary Service Needs and Production Costs

Ancillary services (A/S) such as spinning reserves, ramping up and down, regulation, and 10-minute quick start are essential for the reliable operation of the electrical system. Additional transmission can decrease the A/S costs by reducing the A/S quantity needed or reducing the procurement costs for that quantity.

The A/S needs in SPP are determined according to SPP's market protocols and currently do not change based on transmission. Therefore, the savings associated with the "quantity" effect are assumed to be zero.

The costs of providing A/S are captured in the APC metrics since the production cost simulations set aside the static levels of resources to provide regulation and spinning reserves. As a result, the benefits related to "procurement cost" effect are already included as a part of the APC savings presented in this report.

12.5: Avoided or Delayed Reliability Projects

Potential reliability needs are reviewed to determine if the upgrades proposed for economic or policy reasons defer or replace any reliability upgrades. The avoided or delayed reliability project benefit represents the costs associated with these additional reliability upgrades that would otherwise have to be pursued.

To estimate the avoided or delayed reliability projects benefit for the portfolios, the 2020 and 2025 powerflow models developed for Futures 1 and 3 are utilized. Excluding the proposed economic projects from these models resulted in one thermal overload in both of the model runs. Table 12.2 lists the economic upgrade that resulted in a thermal reliability violation when excluded from the model.

Network Upgrade Name
Hobbs - Yoakum Tap 230 kV Substation Hobbs - Yoakum Tap 230/115 kV Transformer

Table 12.2: Economic Upgrades resulting in Thermal Reliability Violations

Table 12.3 shows the list of avoided or delayed reliability projects that would be needed to address the identified reliability violation. A standardized ITP cost template was used to estimate the total costs of the avoided or delayed project. The benefits are assumed to be equal to the 40-year PV of associated ATRR of the avoided or delayed reliability project for 2017–2056. They are allocated to zones based on the ratios that would have been applied for the costs of the reliability project under the Highway/Byway methodology.

At the regional level, the 40-year present value of benefits for avoided reliability projects totals $1.3 million. ___ Table 12.4 **Error! Reference source not found.Error! Reference source not found.**shows the zonal allocations of these benefits.

Portfolio	Project Name	Zone	PV 40-Yr ATRRs ($ M)	Project In % Load	Project Out % Load	% Difference
Reduced Carbon	Yoakum - Plains 115 kV Line	SPS	$1.3	42.3	102.6	60.3
Reference	Yoakum - Plains 115 kV Line	SPS	$1.3	39.2	101	61.8

Table 12.3: Avoided or Delayed Reliability Projects

Zone	40-yr NPV (2017 $M)
AEPW	$0.09
CUS	$0.01
EDE	$0.01
GMO	$0.02
GRDA	$0.01
KCPL	$0.03
LES	$0.01
MIDW	$0.00
MKEC	$0.01
NPPD	$0.03
OKGE	$0.06
OPPD	$0.02
SUNC	$0.00
SWPS	$0.91
UMZ	$0.04
WFEC	$0.01
WRI	$0.04
TOTAL	**$1.29**

Table 12.4: Benefits of Avoided or Delayed Reliability Projects

12.6: Capacity Cost Savings Due to Reduced On-Peak Transmission Losses

Transmission line losses result from the interaction of line materials with the energy flowing on 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. Transmission projects often reduce the losses during peak load conditions, which lowers the costs associated with additional generation capacity needed to meet the capacity requirements.

The capacity cost savings for the consolidated portfolio are calculated based on the on-peak losses estimated in the 2020 and 2025 powerflow models. The loss reductions are then multiplied by 112 percent, based on the reserve margin, to estimate the reduction in installed capacity requirements.

The value of capacity savings is calculated by applying a net cost of new entry (CONE) of $69.6/kW-year. The net CONE value was calculated as the difference between an estimated gross CONE value and the expected operating margins (energy market revenues net of variable operating costs, also referred to as "net market revenues" and non-spinning reserve revenue) for an advanced technology combustion turbine (per EIA's Annual Energy Outlook data).

The average of the net CONE estimates for 2011-2015 was used for this study. A gross CONE value of $88.5/kW-year was obtained by levelizing the capital and fixed operating costs of a new advanced combustion turbine as reported in EIA Annual Energy Outlook 2013. Average net market revenues of $18.8/kW-year were estimated based on the historical data for energy margins and non-spinning reserve revenues.

Zone	Reduced Carbon Portfolio 2020 ($M)	2025 ($M)	40-yr NPV ($2017M)	Reference Portfolio 2020 ($M)	2025 ($M)	40-yr NPV ($2017M)
AEPW	$0.1	$0.2	$2.8	$0.1	$0.1	$0.9
CUS	$0.0	$0.0	($0.1)	$0.0	$0.0	$0.0
EDE	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0
GMO	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.1)
GRDA	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0
KCPL	$0.0	$0.0	$0.7	$0.0	$0.0	$0.2
LES	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MIDW	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MKEC	$0.0	$0.0	$0.4	($0.0)	($0.0)	($0.1)
NPPD	($0.0)	$0.0	$0.7	$0.0	($0.0)	($0.3)
OKGE	($0.1)	$0.0	$1.6	($0.1)	$0.1	$2.2
OPPD	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SUNC	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.1
SWPS	$0.2	$0.3	$5.1	$0.2	$0.4	$7.4
IS	$0.0	$0.0	($0.5)	$0.0	$0.0	($0.1)
WEFA	$0.2	$0.2	$1.3	$0.3	$0.1	($0.8)
WRI	$0.0	$0.0	($0.2)	($0.0)	($0.0)	($0.3)
TOTAL	**$0.7**	**$0.9**	**$13.2**	**$0.5**	**$0.6**	**$9.1**

Table 12.5 summarizes the on-peak loss reductions and associated capacity savings for the region in the Reduced Carbon portfolio and Reference Case portfolio. The 40-year benefits are estimated by extrapolating the results for the first 20 years using the slope between the two points and applying inflation after that. This calculation was performed for every zone separately. The zonal distribution of the NPV of this benefit sums up to $13.2 million in the Reduced Carbon portfolio and $9.1 million in the Reference Case portfolio for the entire SPP footprint.

Zone	Reduced Carbon Portfolio 2020 ($M)	2025 ($M)	40-yr NPV ($2017M)	Reference Portfolio 2020 ($M)	2025 ($M)	40-yr NPV ($2017M)
AEPW	$0.1	$0.2	$2.8	$0.1	$0.1	$0.9

CUS	$0.0	$0.0	($0.1)	$0.0	$0.0	$0.0
EDE	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0
GMO	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.1)
GRDA	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0
KCPL	$0.0	$0.0	$0.7	$0.0	$0.0	$0.2
LES	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MIDW	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MKEC	$0.0	$0.0	$0.4	($0.0)	($0.0)	($0.1)
NPPD	($0.0)	$0.0	$0.7	$0.0	($0.0)	($0.3)
OKGE	($0.1)	$0.0	$1.6	($0.1)	$0.1	$2.2
OPPD	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SUNC	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.1
SWPS	$0.2	$0.3	$5.1	$0.2	$0.4	$7.4
IS	$0.0	$0.0	($0.5)	$0.0	$0.0	($0.1)
WEFA	$0.2	$0.2	$1.3	$0.3	$0.1	($0.8)
WRI	$0.0	$0.0	($0.2)	($0.0)	($0.0)	($0.3)
TOTAL	**$0.7**	**$0.9**	**$13.2**	**$0.5**	**$0.6**	**$9.1**

Table 12.5: On-Peak Loss Reduction and Associated Capacity Cost Savings

12.7: Assumed Benefit of Mandated Reliability Projects

This metric monetizes the reliability benefits of mandated reliability projects. The regional benefits are assumed to be equal to 40-year NPV of ATRRs for the reliability projects, adding up to $28.5 million in the Reduced Carbon portfolio and $3.5 million in the Reference Case portfolio.

The ESWG[17] and BOD[18] approved an allocation of region-wide benefits based on a hybrid approach to reflect different characteristics of higher and lower voltage reliability upgrades:

- **300 kV or above**: 1/3 based on System Reconfiguration and 2/3 based on Load Ratio Share,

[17] https://www.spp.org/documents/22820/eswg%206%2024%2014%20minutes%20&%20attachments.pdf

[18] https://www.spp.org/documents/22963/bocmc%20minutes%20072914.pdf

- **Between 100 kV and 300 kV**: 2/3 based on System Reconfiguration and 1/3 based on Load Ratio Share, and
- **Below 100 kV**: 100 percent based on System Reconfiguration.

The system reconfiguration approach utilizes the powerflow models to measure the incremental flows shifted onto the existing system during outage of the proposed reliability upgrade. This is used as a proxy for how much each upgrade reduces the flows on the existing transmission facilities owned by the zones. The results in production cost simulations are used to determine hourly flow direction on upgrades and then applied for the weighting.

Table 12.6 and Table 12.7 summarize the system reconfiguration analysis results and the benefit allocation factors for different voltage levels.

	< 100 kV	100–300 kV			> 300 kV			All NTC Projects	
SPP-wide Benefit	$0	$28.5			$0			$28.5	
Zone	100% SR	67% SR	33% LRS	Wtd. Avg.	33% SR	67% LRS	Wtd. Avg.	Overall Allocation	Benefit 2017 $m
AEP	0.0%	19.1%	20.8%	19.6%	0.0%	20.8%	13.9%	**19.6%**	**$5.6**
CUS	0.0%	2.0%	1.3%	1.8%	0.0%	1.3%	0.9%	**1.8%**	**$0.5**
EDE	0.0%	3.2%	2.3%	2.9%	0.0%	2.3%	1.5%	**2.9%**	**$0.8**
GMO	0.0%	0.0%	3.7%	1.2%	0.0%	3.7%	2.5%	**1.2%**	**$0.4**
GRDA	0.0%	0.1%	1.7%	0.6%	0.0%	1.7%	1.2%	**0.6%**	**$0.2**
KCPL	0.0%	2.3%	7.4%	4.0%	0.0%	7.4%	4.9%	**4.0%**	**$1.1**
LES	0.0%	1.4%	1.9%	1.6%	0.0%	1.9%	1.2%	**1.6%**	**$0.4**
MIDW	0.0%	0.2%	0.8%	0.4%	0.0%	0.8%	0.5%	**0.4%**	**$0.1**
MKEC	0.0%	0.0%	1.3%	0.4%	0.0%	1.3%	0.9%	**0.4%**	**$0.1**
NPPD	0.0%	5.7%	6.0%	5.8%	0.0%	6.0%	4.0%	**5.8%**	**$1.7**
OGE	0.0%	26.4%	13.2%	22.0%	0.0%	13.2%	8.8%	**22.0%**	**$6.3**
OPPD	0.0%	0.5%	4.7%	1.9%	0.0%	4.7%	3.1%	**1.9%**	**$0.5**
SEPC	0.0%	0.4%	0.9%	0.6%	0.0%	0.9%	0.6%	**0.6%**	**$0.2**
SPS	0.0%	12.9%	11.5%	12.4%	0.0%	11.5%	7.6%	**12.4%**	**$3.5**
UMZ	0.0%	8.9%	9.0%	8.9%	0.0%	9.0%	6.0%	**8.9%**	**$2.5**
WFEC	0.0%	11.1%	3.4%	8.5%	0.0%	3.4%	2.3%	**8.5%**	**$2.4**
WR	0.0%	6.0%	10.1%	7.4%	0.0%	10.1%	6.7%	**7.4%**	**$2.1**
Total	**0.0%**	**100.0%**	**100.0%**	**100.0%**	**0.0%**	**100.0%**	**66.7%**	**100.0%**	**$28.5**

Table 12.6: System Reconfiguration Analysis Results and Benefit Allocation Factors (Reduced Carbon Portfolio)

	< 100 kV	100–300 kV			> 300 kV			All NTC Projects	
SPP-wide Benefit	$0	$3.5			$0			$3.5	
Zone	100% SR	67% SR	33% LRS	Wtd. Avg.	33% SR	67% LRS	Wtd. Avg.	Overall Allocation	Benefit 2017 $m
AEP	0.0%	98.1%	20.8%	72.3%	0.0%	20.8%	13.9%	**72.3%**	**$2.5**
CUS	0.0%	0.0%	1.3%	0.4%	0.0%	1.3%	0.9%	**0.4%**	**$0.0**
EDE	0.0%	0.0%	2.3%	0.8%	0.0%	2.3%	1.5%	**0.8%**	**$0.0**
GMO	0.0%	0.0%	3.7%	1.2%	0.0%	3.7%	2.5%	**1.2%**	**$0.0**
GRDA	0.0%	0.2%	1.7%	0.7%	0.0%	1.7%	1.2%	**0.7%**	**$0.0**
KCPL	0.0%	0.2%	7.4%	2.6%	0.0%	7.4%	4.9%	**2.6%**	**$0.1**
LES	0.0%	0.0%	1.9%	0.6%	0.0%	1.9%	1.2%	**0.6%**	**$0.0**
MIDW	0.0%	0.0%	0.8%	0.3%	0.0%	0.8%	0.5%	**0.3%**	**$0.0**
MKEC	0.0%	0.0%	1.3%	0.4%	0.0%	1.3%	0.9%	**0.4%**	**$0.0**
NPPD	0.0%	0.0%	6.0%	2.0%	0.0%	6.0%	4.0%	**2.0%**	**$0.1**
OGE	0.0%	0.0%	13.2%	4.4%	0.0%	13.2%	8.8%	**4.4%**	**$0.2**
OPPD	0.0%	0.1%	4.7%	1.6%	0.0%	4.7%	3.1%	**1.6%**	**$0.1**
SEPC	0.0%	0.1%	0.9%	0.4%	0.0%	0.9%	0.6%	**0.4%**	**$0.0**
SPS	0.0%	0.0%	11.5%	3.8%	0.0%	11.5%	7.6%	**3.8%**	**$0.1**
UMZ	0.0%	0.0%	9.0%	3.0%	0.0%	9.0%	6.0%	**3.0%**	**$0.1**
WFEC	0.0%	1.3%	3.4%	2.0%	0.0%	3.4%	2.3%	**2.0%**	**$0.1**
WR	0.0%	0.0%	10.1%	3.4%	0.0%	10.1%	6.7%	**3.4%**	**$0.1**
Total	**0.0%**	**100.0%**	**100.0%**	**100.0%**	**0.0%**	**100.0%**	**66.7%**	**100.0%**	**$3.5**

Table 12.7: System Reconfiguration Analysis Results and Benefit Allocation Factors (Reference Case Portfolio)

12.8: Benefit from Meeting Public Policy Goals

This metric represents the economic benefits provided by the transmission upgrades for facilitating public policy goals. For the purpose of this study, the scope is limited to meeting public policy goals related to renewable energy and the system-wide benefits are assumed to be equal to the cost of policy projects.

Since no policy projects are identified as a part of the final portfolios, the associated benefits are estimated to be zero.

12.9: Mitigation of Transmission Outage Costs

The standard production cost simulations used to estimate APC savings assume that transmission lines and facilities are available during all hours of the year, and thereby ignore the added congestion-relief and production cost benefits of new transmission facilities during the planned and unplanned outages of existing transmission facilities.

To estimate the incremental savings associated with the mitigation of transmission costs, the production cost simulations can be augmented for a realistic level of transmission outages. Due to the significant effort that would be needed to develop these augmented models for each case, the findings from the first RCAR study were used to calculate this benefit metric for the Reduced Carbon portfolio and Reference Case portfolio as a part of this ITP10.

In the RCAR analysis, adding a subset of historical transmission outage events to the production cost simulations increased the APC savings by 11.3 percent.[19,20] Applying this ratio to the APC savings estimated for the portfolios translates to a 40-year NPV of benefits of $162.1 million for the Reduced Carbon portfolio and $122.2 million for the Reference Case portfolio.

This incremental benefit is allocated to zones based on their load ratio share, because it is difficult to develop normalized transmission outage data that reliably reflects the outage events expected in each zone over the study horizon. Using load ratio shares as an allocation approach for this metric was initially recommended by the Metrics Task Force and then approved by the ESWG.[21] Table 12.8 shows the outage mitigation benefits allocated to each SPP zone.

	Reduced Carbon Portfolio 40-yr NPV (2017 $M)	Reference Case Portfolio 40-yr NPV (2017 $M)
AEPW	$31.6	$23.1
CUS	$2.0	$1.5
EDE	$3.5	$2.5
GMO	$5.6	$4.1
GRDA	$2.6	$1.9
KCPL	$11.2	$8.2
LES	$2.8	$2.1
MIDW	$1.2	$0.9
MKEC	$1.9	$1.4
NPPD	$9.0	$6.6
OKGE	$20.0	$14.6
OPPD	$7.2	$5.2

[19] SPP Regional Cost Allocation Review Report, October 8, 2013 (pp. 36–37).

[20] As directed by ESWG, SPP will periodically review historical outage data and update additional APC savings ratio for future studies.

[21] https://www.spp.org/documents/22820/eswg%206%2024%2014%20minutes%20&%20attachments.pdf

	Reduced Carbon Portfolio 40-yr NPV (2017 $M)	Reference Case Portfolio 40-yr NPV (2017 $M)
SUNC	$1.3	$1.0
SWPS	$17.4	$12.7
WFEC	$5.1	$3.8
WRI	$15.3	$11.2
UMZ	$13.7	$10.0
TOTAL	**$151.6**	**$110.8**

Table 12.8: Transmission Outage Cost Mitigation Benefits by Zone (40-year NPV)

12.10: Increased Wheeling Through and Out Revenues

Increasing Available Transfer Capability (ATC) with neighboring regions improves import and export opportunities for the SPP footprint. Increased inter-regional transmission capacity that allows increased through and out transactions will also increase SPP wheeling revenues.

While the benefit of increased exports is captured in APC savings (which values exports at the weighted average generation LMP of the exporting zone), APC savings do not capture increases in wheeling out or wheeling through revenues associated with increased transfer capability.

Collected wheeling revenues are not counted in either the exporting or importing region's APC. Increased wheeling revenues are a benefit as they offset part of transmission projects' revenue requirements. Currently, SPP collects wheeling revenues through Schedules 7 and 11 for firm through and out transactions.

To evaluate increased wheeling revenues based on long-term firm TSRs, a First Contingency Incremental Transfer Capability (FCITC) analysis is conducted to determine the change in ATC for exports. Increases in ATC due to the transmission upgrades are used to project future long-term transmission service revenues.

The 2020 and 2025 powerflow models are utilized for the FCITC analysis. The ratio of TSRs sold as a percent of the increase in export ATC is capped at 100 percent, as incremental TSR sales would not be expected to exceed the amount of increase in export ATC. The Reduced Carbon portfolio did not increase the export ATCs, and accordingly, no wheeling revenue benefits are estimated for that Future. In the Reference Case portfolio, the proposed upgrades increase the export ATC by 13 MW in 2020 but did not increase the export ATC in 2025.

The 40-year NPV of benefits is estimated to be zero in the Reduced Carbon portfolio and $1.2 million in the Reference Case portfolio. These benefits are allocated based on the current revenue sharing method in SPP Tariff. Table 12.9 shows the distribution of wheeling revenue benefits for each SPP zone.

	Reduced Carbon Portfolio 40-yr NPV (2017 $M)	Reference Case Portfolio 40-yr NPV (2017 $M)
AEPW	$0.00	$0.31
CUS	$0.00	$0.01
EDE	$0.00	$0.01
GMO	$0.00	$0.02
GRDA	$0.00	$0.02
KCPL	$0.00	$0.05
LES	$0.00	$0.01
MIDW	$0.00	$0.01
MKEC	$0.00	$0.01
NPPD	$0.00	$0.04
OKGE	$0.00	$0.13
OPPD	$0.00	$0.03
SUNC	$0.00	$0.01
SWPS	$0.00	$0.31
WFEC	$0.00	$0.09
WRI	$0.00	$0.02
UMZ	$0.00	$0.10
TOTAL	**$0.00**	**$1.18**

Table 12.9: Increased Wheeling Revenue Benefits by Zone (40-year NPV)

12.11: Marginal Energy Losses Benefit

The standard production cost simulations used to estimate APC do not reflect the impact of transmission upgrades on MWh quantity of transmission losses. To make run-times more manageable, the load in market simulations is “grossed up” to include average transmission losses for each zone. These loss assumptions do not change with additional transmission. Therefore, the traditional APC metric does not capture the benefits from reduced MWh quantity of losses.

APC savings due to such energy loss reductions can be estimated by post-processing the Marginal Loss Component (MLC) of the LMPs in PROMOD simulation results and applying the methodology approved by the ESWG and BOD, which accounts for losses on generation and market imports. The 40-year NPV of benefits is estimated to be $84.6 million in the Reduced Carbon portfolio and $31.7 million in the Reference Case portfolio, as shown in Table 12.10 below.

Zone	Reduced Carbon Portfolio 40-yr NPV (2017 $M)	Reference Case Portfolio 40-yr NPV (2017 $M)
AEPW	$48.7	$23.7
CUS	$9.7	$0.2
EDE	$10.8	$0.3
GMO	$0.5	$3.6
GRDA	$2.5	$1.4
KCPL	($0.8)	$12.7
LES	$2.4	$3.7
MIDW	($0.5)	($0.4)
MKEC	($2.2)	$0.3
NPPD	$7.6	$11.0
OKGE	$27.4	$10.8
OPPD	$0.3	$6.6
SUNC	($1.3)	($1.7)
SWPS	($46.2)	($70.8)
UMZ	$62.6	$20.8
WFEC	$7.1	$3.4
WRI	($43.9)	$6.1
TOTAL	**$84.6**	**$31.7**

Table 12.10: Energy Losses Benefit by Zone (40-year NPV)

12.12: Summary

Table 12.11 and Table 12.12 summarize the 40-year NPV of the estimated benefit metrics and costs and the resulting B/C ratios for each SPP zone.

For the region, the B/C ratio is estimated to be 11.29 in the Reduced Carbon portfolio and 14.63 in the Reference Case portfolio. Higher B/C ratio in Future 1 is driven by the APC savings due to higher congestion-relief provided by the Reduced Carbon portfolio.

Reduced Carbon Portfolio - Present Value of 40-yr Benefits (2017 $M)													
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy	Mitigation of Transmission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	NPV 40-yr ATRRs	Net Benefit	Est. Benefit/ Cost Ratio
Zone	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	
AEPW	$203.8	$0.1	$2.8	$5.6	$0.0	$32.0	$0.0	$48.7	$293.0	$39.2	$253.7	7.47
CUS	$50.6	$0.0	($0.1)	$0.5	$0.0	$2.0	$0.0	$9.7	$62.7	$0.7	$62.0	83.70
EDE	$23.3	$0.0	$0.4	$0.8	$0.0	$3.5	$0.0	$10.8	$38.8	$1.3	$37.5	30.22
GMO	$18.1	$0.0	$0.5	$0.4	$0.0	$5.6	$0.0	$0.5	$25.1	$2.1	$23.0	12.06
GRDA	$39.6	$0.0	$0.3	$0.2	$0.0	$2.6	$0.0	$2.5	$45.2	$5.5	$39.7	8.26
KCPL	$78.1	$0.0	$0.7	$1.1	$0.0	$11.2	$0.0	($0.8)	$90.4	$4.7	$85.8	19.43
LES	($5.4)	$0.0	$0.0	$0.4	$0.0	$2.8	$0.0	$2.4	$0.3	$1.0	($0.8)	0.25
MIDW	$33.1	$0.0	$0.0	$0.1	$0.0	$1.2	$0.0	($0.5)	$33.9	$5.7	$28.2	5.96
MKEC	($30.8)	$0.0	$0.4	$0.1	$0.0	$1.9	$0.0	($2.2)	($30.6)	$0.7	($31.3)	(42.61)
NPPD	$40.4	$0.0	$0.7	$1.7	$0.0	$9.0	$0.0	$7.6	$59.4	$3.3	$56.1	17.78
OKGE	($1.4)	$0.1	$1.6	$6.3	$0.0	$20.0	$0.0	$27.4	$53.9	$13.4	$40.5	4.01
OPPD	($49.8)	$0.0	$0.0	$0.5	$0.0	$7.2	$0.0	$0.3	($41.7)	$2.6	($44.4)	(15.79)
SUNC	($13.5)	$0.0	$0.1	$0.2	$0.0	$1.3	$0.0	($1.3)	($13.2)	$0.5	($13.7)	(26.95)
SWPS	$492.1	$0.9	$5.1	$3.5	$0.0	$17.4	$0.0	($46.2)	$472.9	$42.4	$430.5	11.16
UMZ	$288.3	$0.0	($0.5)	$2.5	$0.0	$13.7	$0.0	$62.6	$366.7	$11.1	$355.6	32.94
WFEC	$42.1	$0.0	$1.3	$2.4	$0.0	$5.1	$0.0	$7.1	$58.0	$2.1	$56.0	28.07
WRI	$138.4	$0.0	($0.2)	$2.1	$0.0	$15.3	$0.0	($43.9)	$111.8	$7.6	$104.2	14.65
TOTAL	**$1,347.0**	**$1.3**	**$13.2**	**$28.5**	**$0.0**	**$151.4**	**$0.0**	**$84.6**	**$1,626.0**	**$144.0**	**$1,482.5**	**11.29**

Table 12.11: Estimated 40-year NPV of Benefit Metrics and Costs – Zonal (Reduced Carbon)

Reference Case Portfolio - Present Value of 40-yr Benefits (2017 $M)													
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy	Mitigation of Transmission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	NPV 40-yr ATRRs	Net Benefit	Est. Benefit/ Cost Ratio
Zone	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	
AEPW	$278.6	$0.1	$0.9	$2.5	$0.0	$23.1	$0.3	$23.7	$329.3	$24.0	$305.3	13.72
CUS	$2.1	$0.0	$0.0	$0.0	$0.0	$1.5	$0.0	$0.2	$3.8	$0.3	$3.5	11.10
EDE	$28.6	$0.0	$0.0	$0.0	$0.0	$2.5	$0.0	$0.3	$31.5	$0.6	$30.9	53.23
GMO	$3.2	$0.0	($0.1)	$0.0	$0.0	$4.1	$0.0	$3.6	$10.9	$1.0	$9.9	11.33
GRDA	$3.7	$0.0	$0.0	$0.0	$0.0	$1.9	$0.0	$1.4	$7.0	$0.4	$6.6	15.71
KCPL	$87.4	$0.0	$0.2	$0.1	$0.0	$8.2	$0.1	$12.7	$108.7	$2.4	$106.3	44.76
LES	$2.6	$0.0	$0.0	$0.0	$0.0	$2.1	$0.0	$3.7	$8.4	$0.5	$8.0	17.57
MIDW	($6.5)	$0.0	$0.0	$0.0	$0.0	$0.9	$0.0	($0.4)	($6.0)	$0.2	($6.2)	(28.83)
MKEC	($24.7)	$0.0	($0.1)	$0.0	$0.0	$1.4	$0.0	$0.3	($23.1)	$0.3	($23.4)	(69.86)
NPPD	$36.1	$0.0	($0.3)	$0.1	$0.0	$6.6	$0.0	$11.0	$53.5	$1.5	$52.0	34.79
OKGE	$33.5	$0.1	$2.2	$0.2	$0.0	$14.6	$0.1	$10.8	$61.5	$9.5	$52.0	6.50
OPPD	($14.8)	$0.0	$0.0	$0.1	$0.0	$5.2	$0.0	$6.6	($2.9)	$1.2	($4.1)	(2.38)
SUNC	($2.5)	$0.0	$0.1	$0.0	$0.0	$1.0	$0.0	($1.7)	($3.1)	$0.2	($3.3)	(13.62)
SWPS	$449.1	$0.9	$7.4	$0.1	$0.0	$12.7	$0.3	($70.8)	$399.7	$29.7	$370.0	13.46
UMZ	($11.6)	$0.0	($0.1)	$0.1	$0.0	$10.0	$0.1	$20.8	$19.4	$2.3	$17.0	8.32
WFEC	$31.6	$0.0	($0.8)	$0.1	$0.0	$3.8	$0.1	$3.4	$38.2	$0.9	$37.3	43.63
WRI	$88.1	$0.0	($0.3)	$0.1	$0.0	$11.2	$0.0	$6.1	$105.3	$3.0	$102.4	35.60
TOTAL	**$984.7**	**$1.3**	**$9.1**	**$3.5**	**$0.0**	**$110.8**	**$1.2**	**$31.7**	**$1,142.3**	**$78.1**	**$1,064.0**	**14.63**

Table 12.12: Estimated 40-year NPV of Benefit Metrics and Costs – Zonal (Reference Case)

State	APC Savings (2017 $M)	Avoided or Delayed Reliability Projects (2017 $M)	Capacity Savings from Reduced On-peak (2017 $M)	Assumed Benefit of Mandated Reliability Projects (2017 $M)	Benefit from Meeting Public Policy (2017 $M)	Mitigation of Trans-mission Outage Costs (2017 $M)	Increased Wheeling Through and Out Revenues (2017 $M)	Marginal Energy Losses Benefits (2017 $M)	Total Benefits (2017 $M)	NPV 40-yr ATRRs (2017 $M)	Net Benefit (2017 $M)	Est. B/C Ratio
Reduced Carbon Portfolio - Present Value of 40-yr Benefits (2017 $M)												
Arkansas	$41.2	$0.0	$0.8	$2.0	$0.0	$9.0	$0.0	$13.6	$66.5	$9.6	$56.9	6.92
Iowa	$49.4	$0.0	($0.1)	$0.4	$0.0	$2.3	$0.0	$10.7	$62.9	$1.9	$61.0	32.92
Kansas	$71.3	$0.1	$0.7	$3.1	$0.0	$25.5	$0.0	($47.7)	$53.0	$16.9	$36.0	3.13
Louisiana	$27.3	$0.0	$0.4	$0.8	$0.0	$4.2	$0.0	$6.5	$39.2	$5.3	$34.0	7.46
Minnesota	$3.5	$0.0	($0.0)	$0.0	$0.0	$0.2	$0.0	$0.8	$4.4	$0.1	$4.3	32.94
Missouri	$129.3	$0.0	$1.1	$2.2	$0.0	$16.5	$0.0	$19.3	$168.4	$6.4	$162.0	26.52
Montana	$14.2	$0.0	($0.0)	$0.1	$0.0	$0.7	$0.0	$3.1	$18.1	$0.5	$17.5	32.94
Oklahoma	$272.1	$0.1	$4.3	$10.4	$0.0	$38.7	$0.0	$52.7	$378.4	$36.6	$341.8	10.34
Nebraska	$17.8	$0.1	$0.7	$2.9	$0.0	$20.6	$0.0	$17.3	$59.3	$8.3	$51.0	7.15
New Mexico	$135.3	$0.2	$1.4	$1.0	$0.0	$4.8	$0.0	($12.7)	$130.0	$11.6	$118.4	11.16
North Dakota	$114.5	$0.0	($0.2)	$1.0	$0.0	$5.4	$0.0	$24.9	$145.7	$4.4	$141.2	32.94
South Dakota	$71.6	$0.0	($0.1)	$0.6	$0.0	$3.4	$0.0	$15.5	$91.1	$2.8	$88.3	32.92
Texas	$397.0	$0.7	$4.3	$3.9	$0.0	$20.1	$0.0	($20.0)	$406.0	$39.5	$366.5	10.28
Wyoming	$2.5	$0.0	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.5	$3.2	$0.1	$3.1	32.94
TOTAL	**$1,347.0**	**$1.3**	**$13.2**	**$28.5**	**$0.0**	**$151.6**	**$0.0**	**$84.6**	**$1,626.1**	**$144.0**	**$1,482.1**	**11.29**

Table 12.13: Estimated 40-year NPV of Benefit Metrics and Costs – State (Reduced Carbon)

State	APC Savings (2017 $M)	Avoided or Delayed Reliability Projects (2017 $M)	Capacity Savings from Reduced On-peak (2017 $M)	Assumed Benefit of Mandated Reliability Projects (2017 $M)	Benefit from Meeting Public Policy (2017 $M)	Mitigation of Trans-mission Outage Costs (2017 $M)	Increased Wheeling Through and Out Revenues (2017 $M)	Marginal Energy Losses Benefits (2017 $M)	Total Benefits (2017 $M)	NPV 40-yr ATRRs (2017 $M)	Net Benefit (2017 $M)	Est. B/C Ratio
Reference Case Portfolio - Present Value of 40-yr Benefits (2017 $M)												
Arkansas	$60.8	$0.0	$0.5	$0.5	$0.0	$6.6	$0.1	$6.1	$74.6	$6.0	$68.6	12.37
Iowa	($2.0)	$0.0	($0.0)	$0.0	$0.0	$1.7	$0.0	$3.6	$3.3	$0.4	$2.9	8.38
Kansas	$43.1	$0.1	($0.2)	$0.2	$0.0	$18.7	$0.1	$10.4	$72.3	$5.0	$67.3	14.51
Louisiana	$37.4	$0.0	$0.1	$0.3	$0.0	$3.1	$0.0	$3.2	$44.1	$3.2	$40.9	13.72
Minnesota	($0.1)	$0.0	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.3	$0.2	$0.0	$0.2	8.33
Missouri	$75.4	$0.0	($0.0)	$0.1	$0.0	$12.0	$0.1	$10.5	$98.2	$3.1	$95.2	32.00
Montana	($0.6)	$0.0	($0.0)	$0.0	$0.0	$0.5	$0.0	$1.0	$1.0	$0.1	$0.8	8.33
Oklahoma	$247.2	$0.1	$1.7	$1.3	$0.0	$28.3	$0.4	$22.3	$301.3	$20.3	$281.0	14.87
Nebraska	$22.5	$0.1	($0.3)	$0.2	$0.0	$15.0	$0.1	$23.6	$61.1	$3.5	$57.6	17.49
New Mexico	$123.5	$0.2	$2.0	$0.0	$0.0	$3.5	$0.1	($19.5)	$109.9	$8.2	$101.8	13.46
North Dakota	($4.6)	$0.0	($0.0)	$0.0	$0.0	$4.0	$0.0	$8.3	$7.7	$0.9	$6.8	8.33
South Dakota	($2.9)	$0.0	($0.0)	$0.0	$0.0	$2.5	$0.0	$5.2	$4.9	$0.6	$4.3	8.39
Texas	$385.1	$0.7	$5.4	$0.7	$0.0	$14.7	$0.3	($43.5)	$363.3	$26.8	$336.5	13.56
Wyoming	($0.1)	$0.0	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.2	$0.2	$0.0	$0.1	8.33
TOTAL	**$984.7**	**$1.3**	**$9.1**	**$3.5**	**$0.0**	**$110.8**	**$1.2**	**$31.7**	**$1,142.2**	**$78.1**	**$1,064.1**	**14.63**

Table 12.14: Estimated 40-year NPV of Benefit Metrics and Costs – State (Reference Case)

Note that state level results are based on load allocations by zone, by state. For example, 11% of UMZ load is in Nebraska, and as a result, 11% of UMZ benefits are attributed to Nebraska.

The Nebraska benefits thuus look differently than if one were to assume that Nebraska were composed only of the LES, NPPD, and OPPD pricing zones.

12.13: Rate Impacts

The rate impact to the average retail residential ratepayer in SPP was computed for the Consolidated Portfolio. Rate impact costs and benefits[22] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kWh per month. Benefits and costs for the 2025 study year were used to calculate rate impacts. All 2025 benefits and costs are shown in 2017 $ discounting at a 2.5 percent inflation rate.

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

Zone	1-Yr ATRR Costs ($K)	1-Yr Benefit ($K)	Rate Impact - Costs ($)	Rate Impact - Benefit ($)	Net Impact ($)
AEPW	$3,740	$7,838	$0.07	$0.15	($0.08)
CUS	$71	$1,899	$0.02	$0.57	($0.55)
EDE	$122	$1,048	$0.02	$0.20	($0.18)
GMO	$198	$687	$0.03	$0.09	($0.06)
GRDA	$515	$2,227	$0.08	$0.35	($0.27)
KCPL	$443	$4,604	$0.03	$0.27	($0.25)
LES	$99	($101)	$0.02	($0.03)	$0.05
MIDW	$484	$1,335	$0.22	$0.62	($0.39)
MKEC	$68	($1,632)	$0.02	($0.45)	$0.47
NPPD	$318	$2,351	$0.02	$0.14	($0.12)
OKGE	$1,273	($87)	$0.04	($0.00)	$0.04
OPPD	$252	($1,636)	$0.02	($0.13)	$0.15
SUNC	$47	($591)	$0.02	($0.19)	$0.21
SWPS	$3,987	$20,185	$0.09	$0.45	($0.36)
IS	$1,048	$9,993	$0.03	$0.30	($0.27)
WEFA	$197	$8,603	$0.02	$0.98	($0.96)
WRI	$723	$1,813	$0.03	$0.06	($0.04)

[22] APC Savings are the only benefit included in the rate impact calculations.

TOTAL	$13,587	$58,536	$0.05	$0.21	($0.16)

Table 12.15 and

Zone	1-Yr ATRR Costs ($K)	1-Yr Benefit ($K)	Rate Impact - Costs ($)	Rate Impact - Benefit ($)	Net Impact ($)
AEPW	$2,264	$9,133	$0.04	$0.18	($0.13)
CUS	$32	$100	$0.01	$0.03	($0.02)
EDE	$56	$1,507	$0.01	$0.29	($0.28)
GMO	$90	($112)	$0.01	($0.01)	$0.03
GRDA	$42	$212	$0.01	$0.03	($0.03)
KCPL	$229	$4,449	$0.01	$0.26	($0.25)
LES	$45	$196	$0.01	$0.05	($0.04)
MIDW	$20	($414)	$0.01	($0.19)	$0.20
MKEC	$31	($1,669)	$0.01	($0.46)	$0.47
NPPD	$145	$2,154	$0.01	$0.13	($0.12)
OKGE	$890	$1,677	$0.03	$0.05	($0.02)
OPPD	$115	($519)	$0.01	($0.04)	$0.05
SUNC	$21	($121)	$0.01	($0.04)	$0.05
SWPS	$2,790	$20,656	$0.06	$0.47	($0.40)
IS	$219	($419)	$0.01	($0.01)	$0.02
WEFA	$82	$6,505	$0.01	$0.74	($0.73)
WRI	$278	$2,339	$0.01	$0.08	($0.07)
TOTAL	**$7,349**	**$45,675**	**$0.03**	**$0.16**	**($0.14)**

Table 12.16. There is a monthly net benefit for the average SPP residential ratepayer of 16 cents for the Reduced Carbon portfolio. There is a monthly net benefit for the average SPP residential ratepayer of 14 cents for the Reference Case portfolio.

Zone	1-Yr ATRR Costs ($K)	1-Yr Benefit ($K)	Rate Impact - Costs ($)	Rate Impact - Benefit ($)	Net Impact ($)
AEPW	$3,740	$7,838	$0.07	$0.15	($0.08)
CUS	$71	$1,899	$0.02	$0.57	($0.55)
EDE	$122	$1,048	$0.02	$0.20	($0.18)
GMO	$198	$687	$0.03	$0.09	($0.06)
GRDA	$515	$2,227	$0.08	$0.35	($0.27)
KCPL	$443	$4,604	$0.03	$0.27	($0.25)
LES	$99	($101)	$0.02	($0.03)	$0.05
MIDW	$484	$1,335	$0.22	$0.62	($0.39)
MKEC	$68	($1,632)	$0.02	($0.45)	$0.47
NPPD	$318	$2,351	$0.02	$0.14	($0.12)
OKGE	$1,273	($87)	$0.04	($0.00)	$0.04

OPPD	$252	($1,636)	$0.02	($0.13)	$0.15
SUNC	$47	($591)	$0.02	($0.19)	$0.21
SWPS	$3,987	$20,185	$0.09	$0.45	($0.36)
IS	$1,048	$9,993	$0.03	$0.30	($0.27)
WEFA	$197	$8,603	$0.02	$0.98	($0.96)
WRI	$723	$1,813	$0.03	$0.06	($0.04)
TOTAL	**$13,587**	**$58,536**	**$0.05**	**$0.21**	**($0.16)**

Table 12.15: Reduced Carbon Portfolio 2025 Retail Residential Rate Impacts by Zone (2017 $)

Zone	1-Yr ATRR Costs ($K)	1-Yr Benefit ($K)	Rate Impact - Costs ($)	Rate Impact - Benefit ($)	Net Impact ($)
AEPW	$2,264	$9,133	$0.04	$0.18	($0.13)
CUS	$32	$100	$0.01	$0.03	($0.02)
EDE	$56	$1,507	$0.01	$0.29	($0.28)
GMO	$90	($112)	$0.01	($0.01)	$0.03
GRDA	$42	$212	$0.01	$0.03	($0.03)
KCPL	$229	$4,449	$0.01	$0.26	($0.25)
LES	$45	$196	$0.01	$0.05	($0.04)
MIDW	$20	($414)	$0.01	($0.19)	$0.20
MKEC	$31	($1,669)	$0.01	($0.46)	$0.47
NPPD	$145	$2,154	$0.01	$0.13	($0.12)
OKGE	$890	$1,677	$0.03	$0.05	($0.02)
OPPD	$115	($519)	$0.01	($0.04)	$0.05
SUNC	$21	($121)	$0.01	($0.04)	$0.05
SWPS	$2,790	$20,656	$0.06	$0.47	($0.40)
IS	$219	($419)	$0.01	($0.01)	$0.02
WEFA	$82	$6,505	$0.01	$0.74	($0.73)
WRI	$278	$2,339	$0.01	$0.08	($0.07)
TOTAL	**$7,349**	**$45,675**	**$0.03**	**$0.16**	**($0.14)**

Table 12.16: Reference Case Portfolio 2025 Retail Residential Rate Impacts by Zone (2017 $)

SECTION 13: SENSITIVITY ANALYSIS

13.1: Methodology

The 2017 ITP10 portfolios were tested under select sensitivities to understand the economic impacts associated with variations in certain model inputs. These sensitivities were not used to develop transmission projects nor filter out projects, but rather to measure the performance of the Reduced Carbon and Reference Case portfolios (including economic and reliability projects) under different uncertainties. The following sensitivities were performed:

- High natural gas price
- Low natural gas price
- High demand
- Low demand
- Increased wind
- Increased coal retirements (Reduced Carbon portfolio only)

The demand and natural gas price sensitivities were included as part of the 2017 ITP10 Scope, however, there was interest in seeing the effects of the portfolios in increased wind and increased coal retirement scenarios.

The Reduced Carbon portfolio was tested in Future 1 while the Reference Case portfolio was tested in Future 3. The economic impacts of variation in the model inputs were captured for the simulations. One-year B/C ratios are shown for all sensitivity and non-sensitivity runs in Figure 13.1 and Figure 13.2. APC is the only benefit metric reported in these ratios. The blue dashed bar in the figures represents the expected B/C ratio for comparison to the sensitivity B/C ratios.

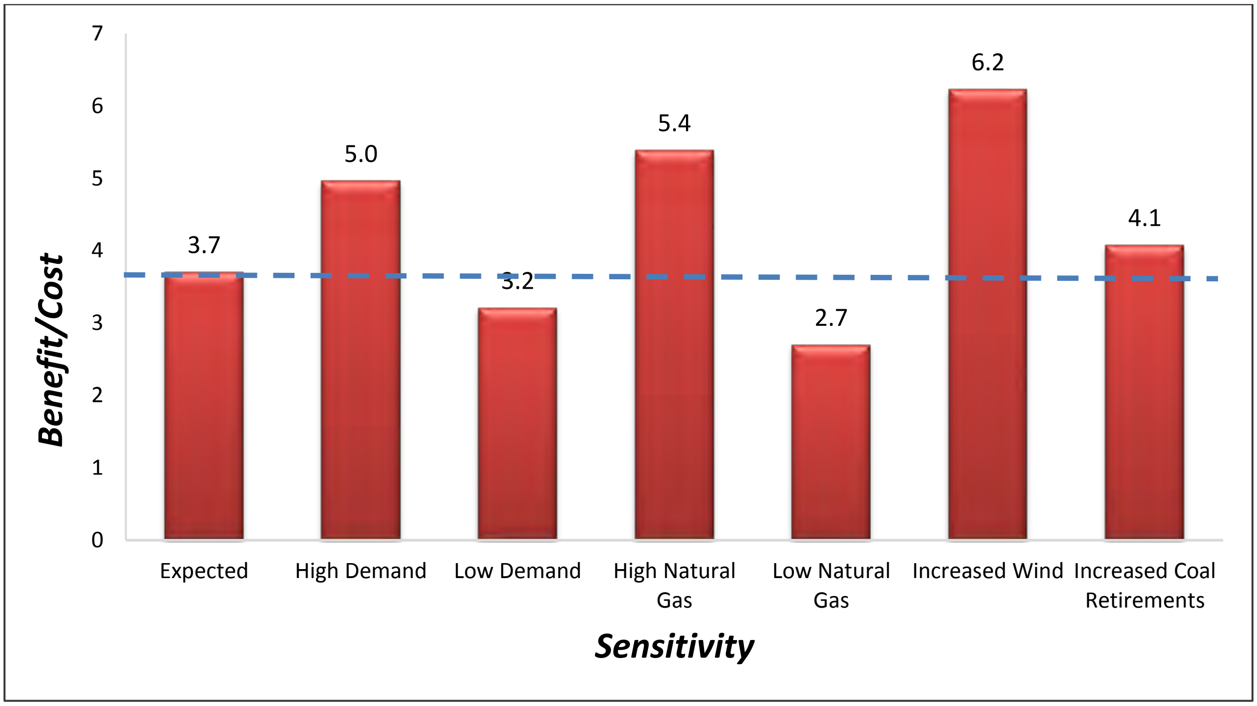

Figure 13.1: 1-Year Benefit-to-Cost Ratios for Sensitivities (Reduced Carbon)

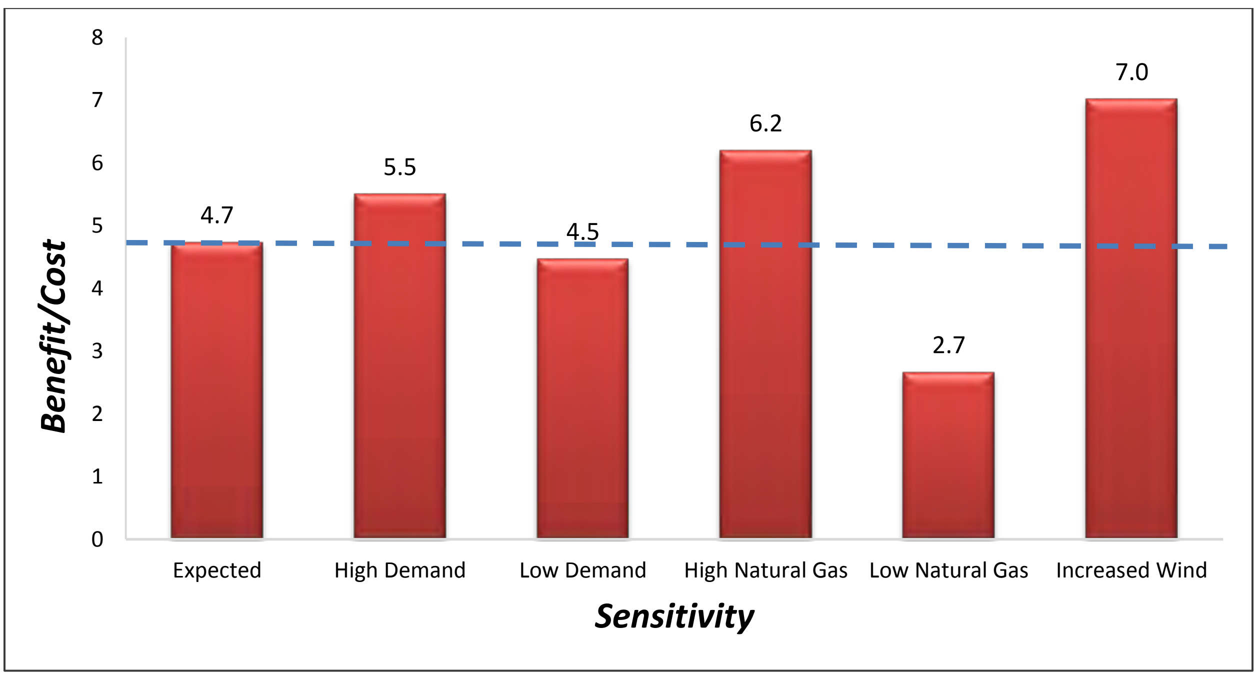

Figure 13.2: 1-Year Benefit-to-Cost Ratios for Sensitivities (Reference Case)

All sensitivity results show one-year benefits and costs rather than 40-year benefits and costs. The results show that the portfolios have positive benefit for all sensitivities, however, the highest one-year B/C ratios resulted from the increased wind, high gas price, and high demand assumptions. For detailed discussion on these results, see the following sections.

13.2: Demand and Natural Gas

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 sensitivities had a 95 percent confidence interval (1.96 standard deviations) in the positive and negative directions, while the demand sensitivities had a 67 percent confidence interval (1 standard deviation) in the positive and negative directions.

The resulting assumptions are shown in Table 13.1 and **Error! Reference source not found.**.

Sensitivity	2025 Annual Energy[23]	2025 Natural Gas Price ($/MMBtu)[24]
Expected Case	No change	No change
High Demand	8.0% Increase	No change
Low Demand	6.7% Decrease	No change
High Natural Gas	No change	$1.99 Increase
Low Natural Gas	No change	$1.99 Decrease

Table 13.1: Natural Gas and Demand Changes (2025)

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[23] SPP Regional

[24] Henry Hub 2025 average of monthly data

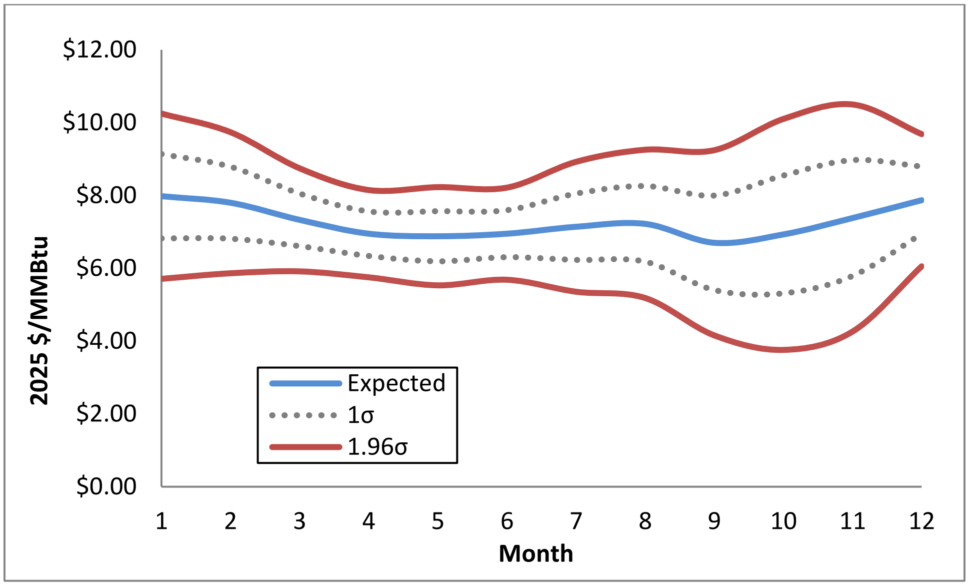

Figure 13.3: Monthly Henry Hub Natural Gas Price Values (2025)

The change in peak demand and energy shown in

Sensitivity	2025 Annual Energy	2025 Natural Gas Price ($/MMBtu)
Expected Case	No change	No change
High Demand	8.0% Increase	No change
Low Demand	6.7% Decrease	No change
High Natural Gas	No change	$1.99 Increase
Low Natural Gas	No change	$1.99 Decrease

Table 13.1 reflects the SPP regional average volatility based on historical data. The high and low bands show a deviation from the projected 2025 load forecasts developed by the MDWG and reviewed by the ESWG, and were implemented on the load company level. For those companies without available data, the SPP regional average confidence interval was used.

These high and low band values were included as inputs to the Future 1 and Future 3 base models with and without the final Reduced Carbon and Reference Case portfolios. The results of the demand and natural gas sensitivities are reflected in Figure 13.4 and Figure 13.5 and show an increase in one-year APC benefit for the high demand and high natural gas cases. Low demand and low natural gas assumptions result in less APC benefit than the expected case.

An increase in demand creates an increase in congestion on the SPP system resulting in higher congestion costs for the portfolios to mitigate, thus increasing the benefit. The opposite is true for the low demand case. An increase in gas prices has a similar result as an increase in demand, but also reflects an increase in the overall price of energy while causing a similar increase in congestion on the system. The high natural gas sensitivity shows the ability of the portfolio to reduce overall energy costs by relieving system congestion and allowing for a more economical generation dispatch. This is the same effect of the portfolio performance in the expected case, but is amplified by the increase in energy prices, thus showing more benefit. The low natural gas sensitivity has the opposite effect.

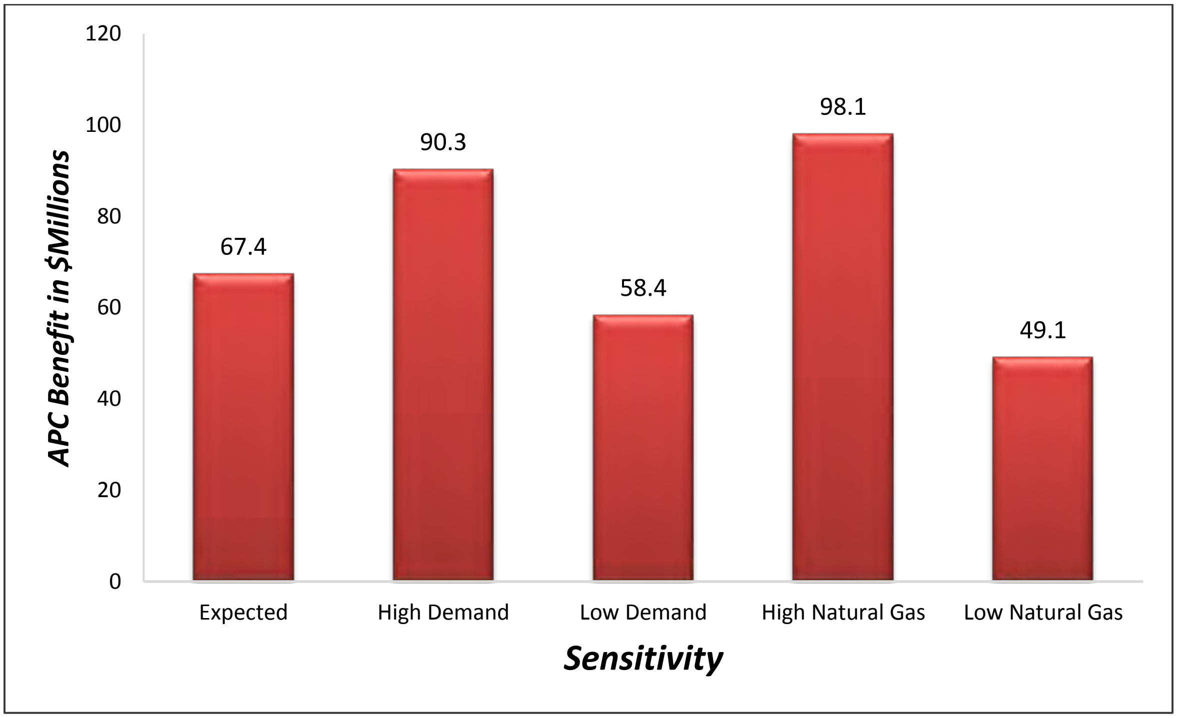

Figure 13.4: 1-Year Benefits of Reduced Carbon Portfolio for Demand and Natural Gas Sensitivities

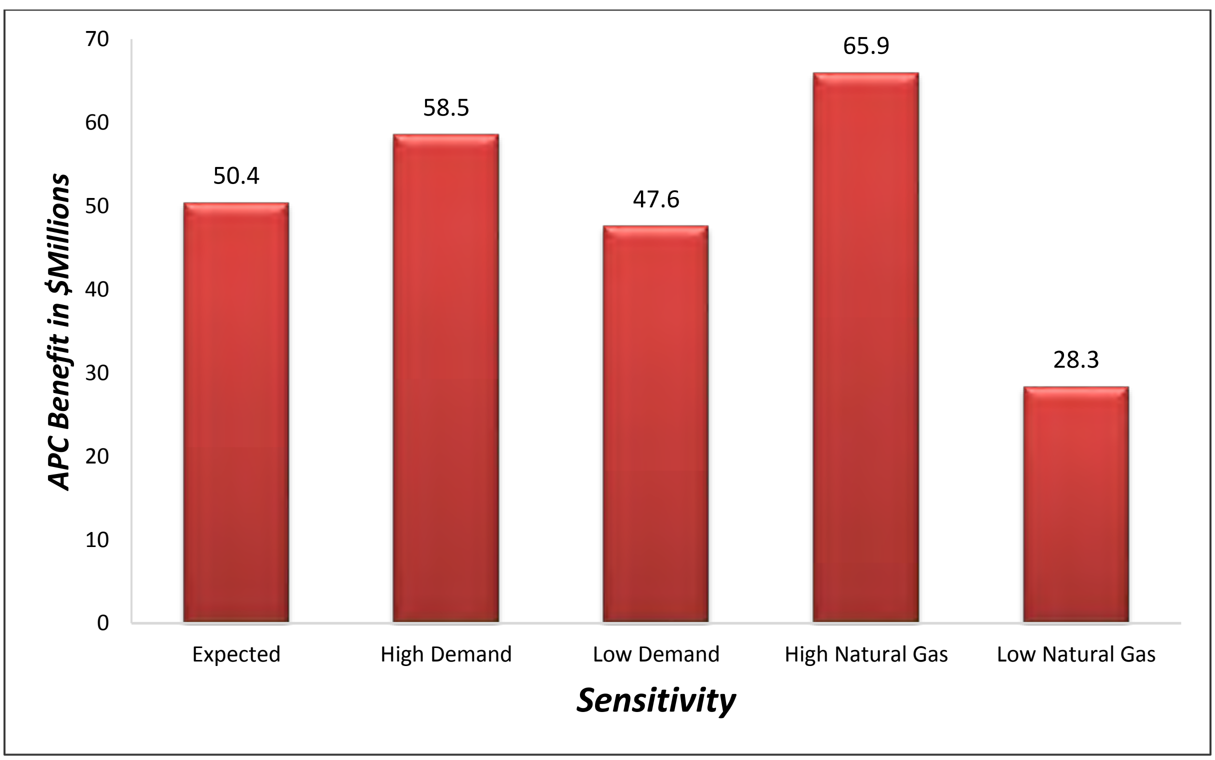

Figure 13.5: 1-Year Benefits of Reference Case Portfolio for Demand and Natural Gas Sensitivities

13.3: Additional Wind

The 2017 ITP10 renewable energy forecast projects a modest increase in wind additions on the SPP system over the next 10 years. However, historical wind additions have increased at a more aggressive pace. As a result, a wind sensitivity was conducted to test each portfolio's performance under higher wind conditions. In this sensitivity, wind was scaled up at existing sites to amount to an additional 5 GW installed on the SPP system. This additional wind was added to each site on a pro rata basis based on the existing capacity in the base assumptions. APC results of this increased wind are shown in Figure 13.6 and Figure 13.7.

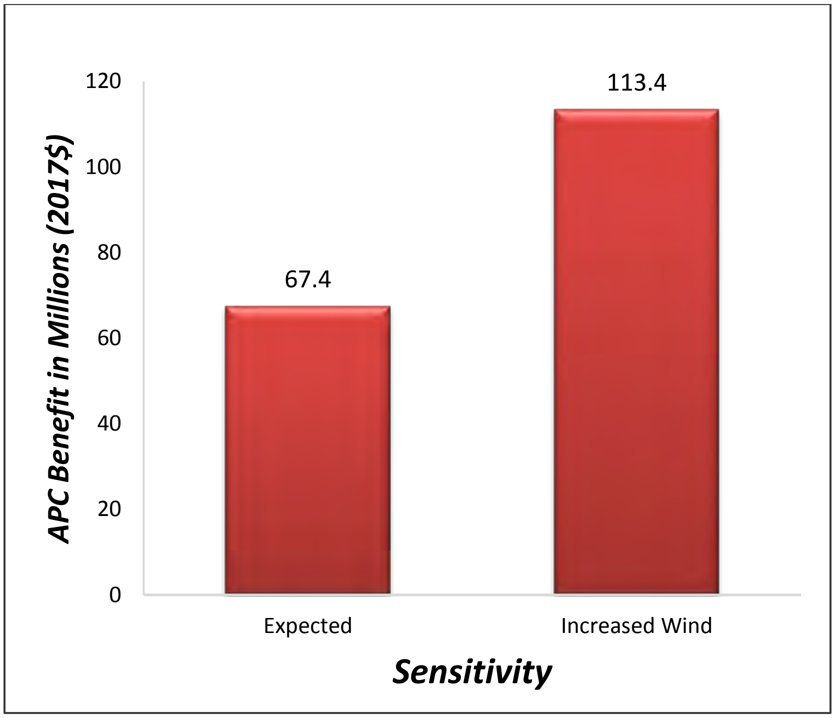

Figure 13.6: 1-Year Benefits of Reduced Carbon Portfolio for Additional Wind Sensitivity

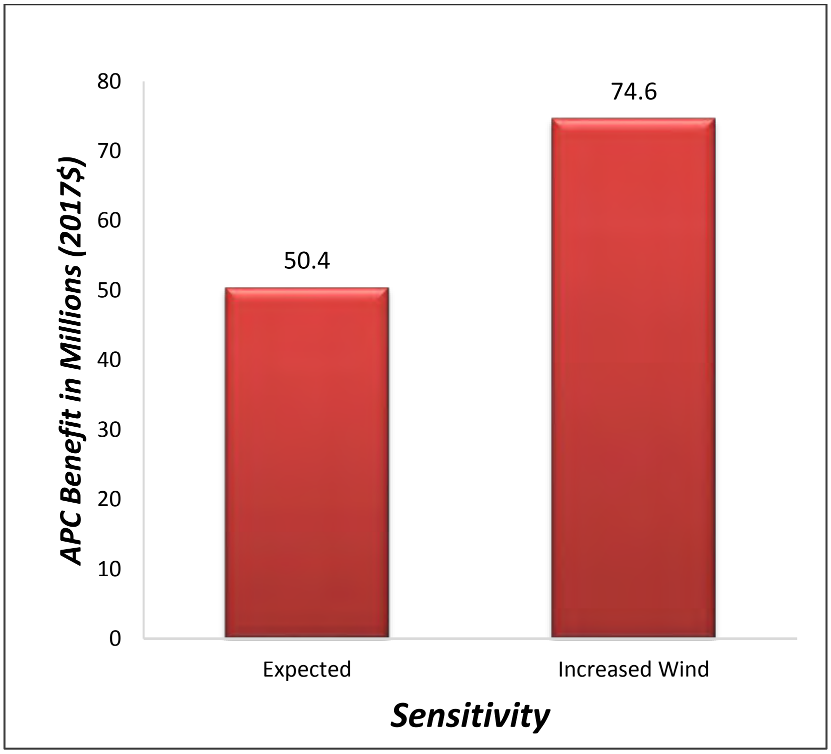

Figure 13.7: 1-Year Benefits of Reference Portfolio for Additional Wind Sensitivity

Testing the additional wind on both portfolios showed an increase in APC benefit. This influx of additional energy increases congestion in the base cases leaving more congestion to be addressed by the portfolio of projects. The increase in benefit for both portfolios confirms that wind would be facilitated by these specific sets of projects. See Figure 13.8 and Figure 13.9 for the total wind delivered and curtailed under the additional wind scenarios compared to the base scenarios.

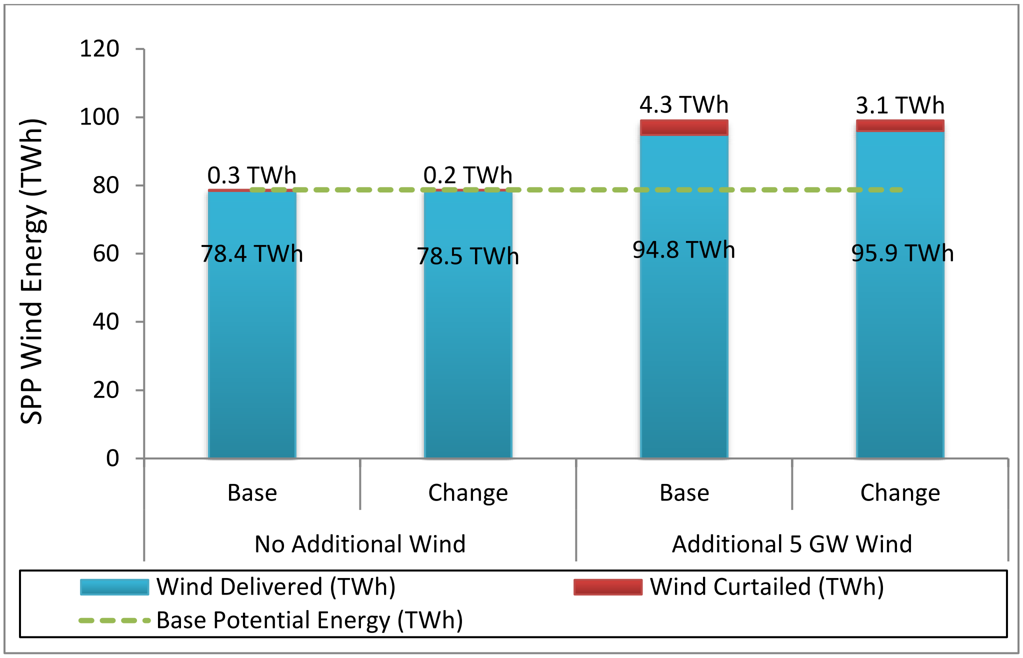

Figure 13.8: SPP Annual Wind Energy for Reduced Carbon Portfolio (2025)

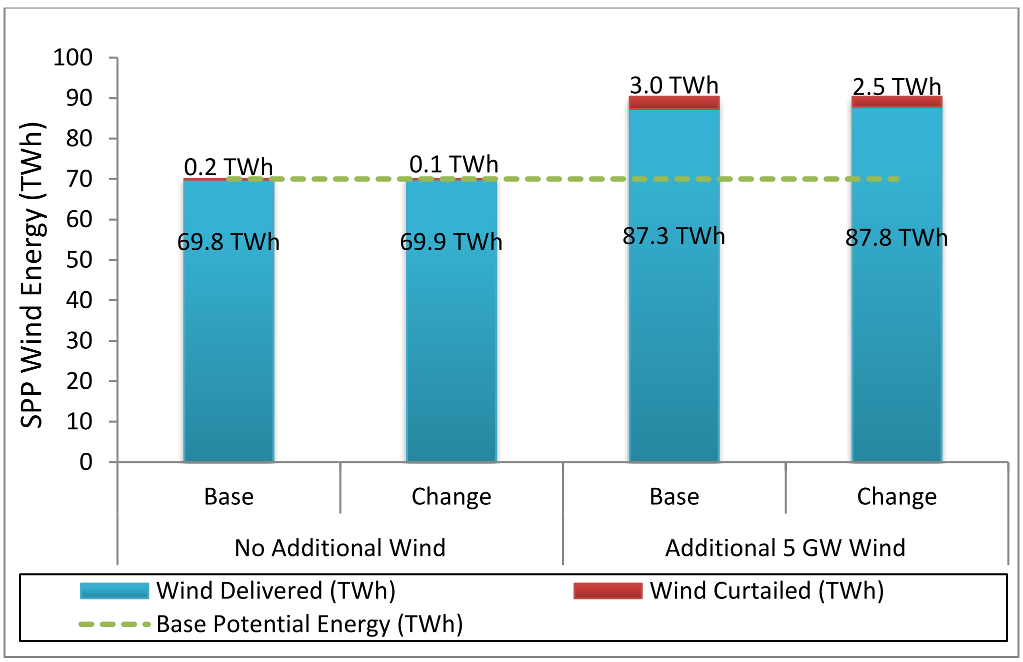

Figure 13.9: SPP Annual Wind Energy for Reference Case Portfolio (2025)

Although more energy is curtailed under the additional wind sensitivity, more wind energy is delivered overall. The percentage of curtailments to the total potential energy roughly stays the same and the majority of the energy from the wind additions is able to be delivered, further affirming wind facilitation.

13.4: Coal Retirements

During the resource planning phase of the 2017 ITP10, SPP projected coal retirements in the carbon constrained Futures based on resource age and capacity factors determined in model simulations. However, a number of these retirements were excluded per Stakeholder request. These exclusions were applied to the resource plan and models. The coal retirement sensitivity was conducted to measure the potential impact of the initial coal retirement forecast by replacing all coal units projected for retirement without consideration of exclusions. The additional retirement sites within 10 miles of a natural gas pipeline were used as potential sites for CC additions to maintain SPP zonal capacity margin requirements. This amounted to 10 GW of coal retirements, most of which are located along the eastern part of the SPP footprint. The CC units utilized in the resource plan were the prototypes used for this analysis.

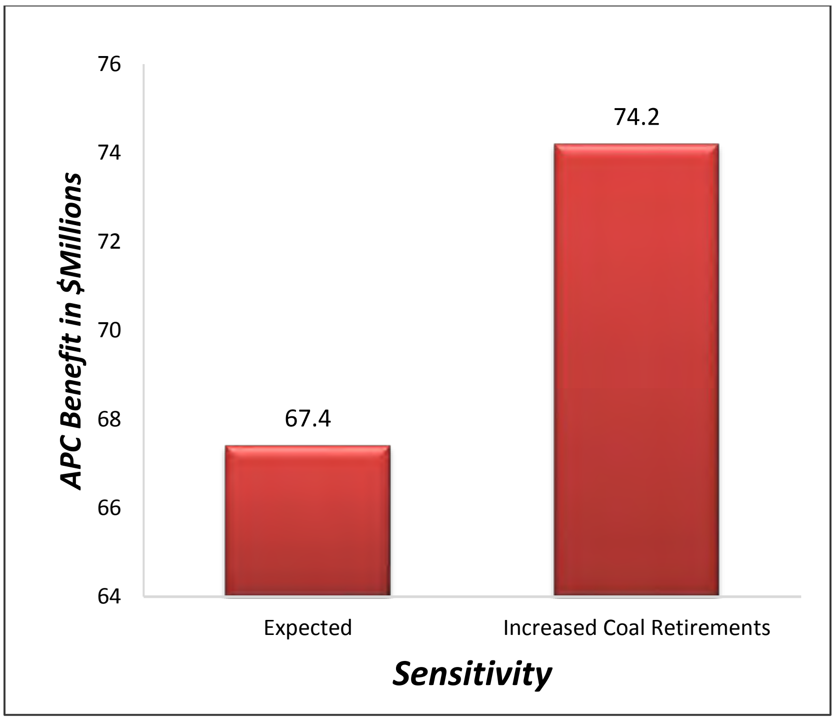

Figure 13.10: 1-Year Benefits of Reduced Carbon Portfolio for Coal Retirement Sensitivity

In the base case, the additional retirements resulted in a significant increase in congestion on three of the identified economic needs, leaving more benefit to be realized with the addition of a project portfolio. Because of this additional congestion relief, there is an additional $6.8 million in APC benefit from the Reduced Carbon portfolio. Figure 13.11 shows the increase in congestion score[25] of the economic needs from the original base case to the retirement base case and subsequently the roughly similar total congestion score in the change cases.

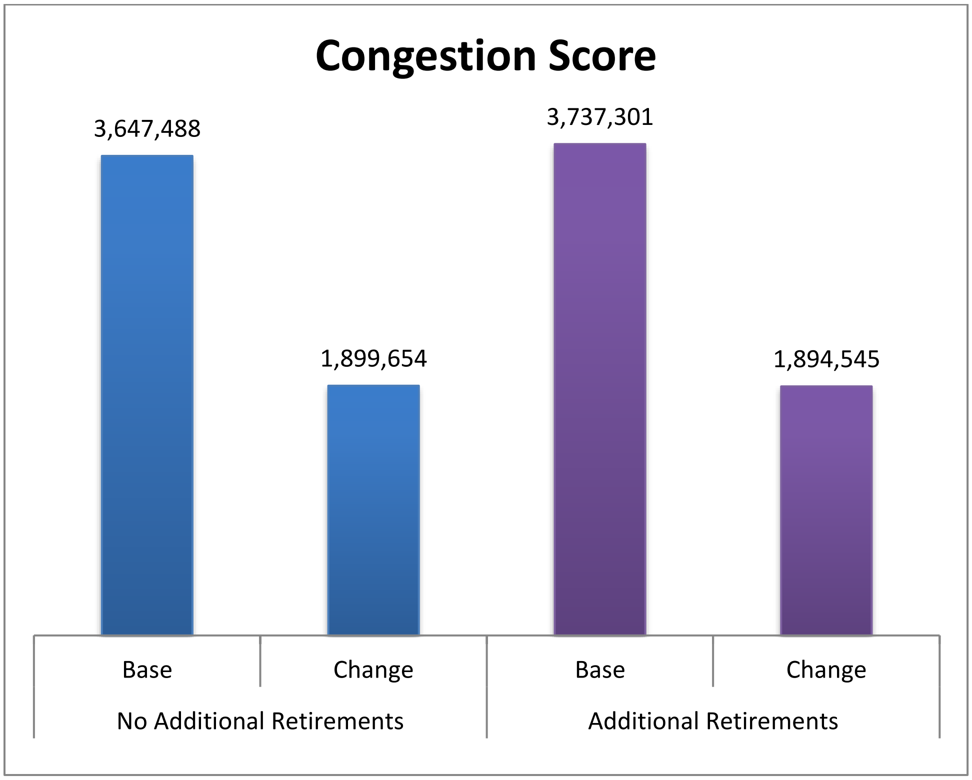

Figure 13.11: Sum of Economic Need Congestion Scores With and Without the Reduced Carbon Portfolio

[25] Congestion score is defined as the product of the constraint's average shadow price and the number of hours the constraint is binding in the model year.

SECTION 14: STABILITY ASSESSMENT

14.1: Final Stability Assessment

A voltage stability assessment was conducted on the Reduced Carbon portfolio in the Future 1 model and Reference Case portfolio in the Future 3 model to assess transfer limits (MW) from north to south, south to north, and west to east across the SPP footprint[26]. The assessment was performed to confirm that the generation dispatched with the final portfolios does not adversely impact system voltage stability. The assessment was intentionally scoped in such a way to provide a different look at how the planned system performs for both conventional and renewable dispatch differences as a result of the Reduced Carbon Futures and to compliment other system voltage stability assessments[27].

The planned system supports the Future-specific generation dispatches prior to voltage collapse, reaching thermal limits prior to reaching voltage stability limits[28]. However, the results illustrate known limits of the planned system that will likely need to be considered further in future planning assessments by either including these limits in the system constraints list[29] or by simply being situationally aware of the system limit when making future project recommendation decisions.[30]

Method

To determine the amount of generation transfer that could be accommodated in the ITP10 study for Futures 1 and 3, generation in the source zone was increased and generation in the sink zone was decreased. Table 14.1 identifies the transfer zones and boundaries. The north

[26] See TWG 12/7/2016 meeting materials for the TWG approved 2017 ITP10 Voltage Stability Report: https://www.spp.org/Documents/45153/twg%20agenda%20&%20background%20materials%2020161207.zip

[27] The focus of the 2015 ITP10 final stability assessment was to determine how the planned system performs under increased bulk exports of wind and at the time of this study, SPP is in the process of performing the 2017 Variable Generation Integration Study where the primary focus is determining how the planned system performs under increased levels of variable generation.

[28] Voltage stability margins are greater than 5%.

[29] Consistent with the Transmission Planning Improvement Task Force White Paper

[30] A clear example of a need to include the limit in the system constraint list would be the Oklaunion – Lawton Eastside 345 kV outage where the thermal violation only marginally precedes the voltage stability limit. More information on this critical contingency can be found in the 2017 Variable Generation Integration Study.

transfer zone was expanded to include tier 1 north generation[31] to allow for greater transfer levels in order to be more reflective of what causes the north flow patterns that attribute to voltage violations that occur in real time.

Transfer Zones	Zone Boundaries
North	SPP Nebraska, UMZ, and North Tier 1
South	Kansas and South
West	SPP
East	First Tier and Second Tier

Table 14.1: Generation Zones

Table 14.2 ***Error! Reference source not found.***shows the three transfers that were performed on the Future 1 and Future 3 summer and light load models by scaling all online generation from source zone to the sink zone (excluding nuclear generation and rooftop solar).

Source Zone	Sink Zone
North	South
South	North
West	East

Table 14.2: Transfers

Single contingencies (N-1) for all SPP branches, transformers, and ties equal to or greater than 345 kV were analyzed, which included 233 transformers and 392 lines. SPP facilities 100 kV and above were monitored for voltage and thermal violations. The initial condition for each model is the source zone sum of real power generation (MW). The maximum source zone transfer capability is the online real power maximum generation (Pmax). The sum of off-line source zone generation represents additional real power resources available for transfer analysis. The transfers were performed on each model in 100 MW steps until voltage collapse occurred in the pre-contingency and post-contingency (N-1, 345 kV and 500 kV facilities) conditions. The last stable transfer was continued in increments of 10 MW to the Voltage Stability Limit (VSL). Each Future was evaluated for increasing generation transfer amounts to determine different voltage collapse points of the transmission system, with the final consolidated portfolio in service using AC power flows. Source generation was increased on a pro-rata basis for each specific hour analyzed, to reach the pre-contingency maximum power transfer limit or VSL. Multiple transfer limits were determined based on the worst N-1 contingency and

[31] Tier 1 includes external systems adjacent to the SPP Nebraska and UMZ areas.

independently evaluating the next worst contingency to determine the top 5 post-contingency VSL.

Summary

Table 14.3 shows a summary of the voltage stability assessment limits by Future and reliability hour by transfer path. The table includes the transfer path, source generation pre-transfer levels, the critical contingency, the post transfer level where thermal violations and voltage stability limits are reached, the incremental transfer limit amount, and the percent increase in transfer relative to the source generation pre-transfer levels. The table shows in all instances a thermal limit is reached prior to the voltage stability limit.

Transfer Path Source-->Sink	Pre-Transfer GW	Critical Contingency	Violation Type	Post-Transfer GW	Transfer GW	Transfer %
Future 1: 2025 Light Load						
N-->S	16.7	Mullncr - Sibley 345 kV	Thermal Violation	18.0	1.3	7
			Voltage Collapse	21.7	5.0	23
S-->N	19.1	Oklaunion - LawtonEastside 345kV	Thermal Violation	20.7	1.6	8
			Voltage Collapse	23.2	4.1	17
W-->E	25.2	Oklaunion - LawtonEastside 345kV	Thermal Violation	26.5	1.4	5
			Voltage Collapse	26.7	1.5	6
Future 1: 2025 Summer Peak						
N-->S	26.0	Gentleman - RedWillow 345kV	Thermal Violation	26.2	0.3	1
			Voltage Collapse	29.7	3.8	13
S-->N	43.7	Mingo - Setab 345kV	Thermal Violation	49.9	6.2	12
			Voltage Collapse	52.7	9.0	17
W-->E	55.0	FlintCreek - Brookline 345kV	Thermal Violation	58.1	3.1	5
			Voltage Collapse	63.0	8.0	13
Future 3: 2025 Light Load						
N-->S	15.9	Neosho - Laycyne 345kV	Thermal Violation	20.5	4.6	22
			Voltage Collapse	23.0	7.1	31
S-->N	19.6	Hartburg - Layfield 500 kV	Thermal Violation	21.4	1.8	9
			Voltage Collapse	24.4	4.8	20
W-->E	25.7	Hartburg - Layfield 500 kV	Thermal Violation	27.4	1.7	6
			Voltage Collapse	28.5	2.8	10
Future 3: 2025 Summer Peak						
N-->S	25.9	Holt- Grand Prairie 345kV	Thermal Violation	27.3	1.4	5
			Voltage Collapse	30.3	4.4	14

S-->N	42.9	Hoyt - JEC 345 kV	Thermal Violation	44.8	1.9	4
			Voltage Collapse	49.5	6.6	13
W-->E	54.2	Muskogee - Fort Smith 345kV	Thermal Violation	57.5	3.3	6
			Voltage Collapse	63.4	9.3	15

Table 14.3: Post-Contingency Thermal and Voltage Stability Transfer Limit summary

SECTION 15:SUPPLEMENTAL ANALYSIS[32]

15.1: Operational Considerations

Planning studies typically focus on future issues on the transmission system as observed in planning models. Additional analysis was conducted in the 2017 ITP10 to evaluate the current congestion on the system as observed in the SPP market, and compare that to the congestion seen in the ITP10 models. Figure 15.1 shows the top 10 most congested flowgates in SPP in 2015, as noted in the 2015 Annual State of the Market (ASOM) Report[33].

[32] This analysis is outside of the approved scope for the 2017 ITP10 analysis.

[33] https://www.spp.org/documents/41597/spp_mmu_state_of_the_market_report_2015.pdf

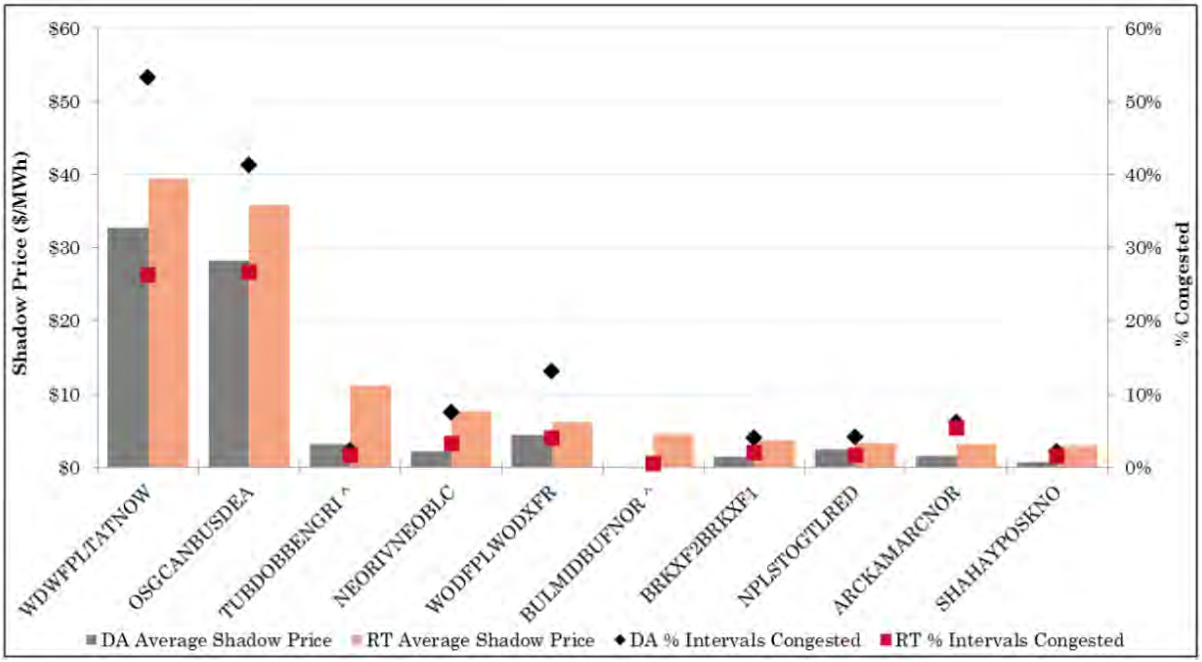

Figure 15.1: Top 10 Congested Flowgates from 2015 ASOM Report

Several of the top 10 congested flowgates in 2015 are also economic needs, or closely related to economic needs, in the 2017 ITP10. **Error! Reference source not found.** shows the top 10 congested flowgate locations, and shows that eight of the top 10 flowgates were equivalent or similar to economic needs in at least one Future of the ITP10 analysis.

Flowgate Name	Region	Flowgate Location	ITP10 Future(s) in which flowgate (or equivalent) was observed as economic need
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)	F1, F2, F3
OSGCANBUSDEA	Texas Panhandle	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)	F3
TUBDOBBENGRI ^	East Texas	Tubular-Dobbins (138) ftlo Dobbin-Grimes (138)	-
NEORIVNEOBLC	SE Kansas	Neosho-Riverton (161) ftlo Neosho-Blackberry (345)	F1, F3
WODFPLWODXFR	Western Oklahoma	Woodward-FPL Switch (138) ftlo Woodward Xfmr (138/69)	F1, F2, F3
BULMIDBUFNOR ^	Arkansas-Missouri border	Bull Shoals-Midway (161) ftlo Buford-Norfork (161)	F2
BRKXF2BRKXF1	SW Missouri	Brookline Xfmr 2 (345/161) ftl Brookline Xfmr 1 (345/161)	F1
NPLSTOGTLRED	Western Nebraska	North Platte-Stockville (115) ftlo Gentleman-Red Willow (345)	F3

ARCKAMARCNOR	Oklahoma	Arcadia-Jones KAMO (138) ftlo Arcadia-Northwest Station (345)	-
SHAHAYPOSKNO	Central Kansas	South Hays-Hays (115) ftlo Knoll Xfmr (230/115)	F1, F2

^ MISO Market-to-Market Flowgate

Table 15.1: SPP Flowgate Locations

Table 15.2 shows a list of projects included in the Future 1, Future 2, or Future 3 final portfolios that address top 10 congested flowgates or equivalent:

Flowgate	Project Selected	Future Portfolio	Comments
Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)	Install one (1) 138 kV phase shifting transformer at Woodward	F1, F2, F3	
Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)	Rebuild 7-mile 115 kV line from Hereford to Deaf Smith	F3	Further analyzed in Alternative Project Analysis
Tubular-Dobbins (138) ftlo Dobbin-Grimes (138)	-	-	Need was not observed in ITP10
Neosho-Riverton (161) ftlo Neosho-Blackberry (345)	Upgrade terminal equipment at Neosho and/or Riverton 161 kV	F1, F3	
Woodward-FPL Switch (138) ftlo Woodward Xfmr (138/69)	Install one (1) 138 kV phase shifting transformer at Woodward	F1, F2, F3	
Bull Shoals-Midway (161) ftlo Buford-Norfork (161)	Rebuild 9-mile 161 kV line from Bull Shoals to Midway Jordan	F2	
Brookline Xfmr 2 (345/161) ftl Brookline Xfmr 1 (345/161)	Install a 345/161 kV transformer at Morgan	F1	Further analyzed in Alternative Project Analysis
North Platte-Stockville (115) ftlo Gentleman-Red Willow (345)	-	-	No project was selected for this need in Future 3
Arcadia-Jones KAMO (138) ftlo Arcadia-Northwest Station (345)	-	-	Need was not observed in ITP10
South Hays-Hays (115) ftlo Knoll Xfmr (230/115)	Build new 1-mile 230 kV 2nd circuit line from Knoll to Post Rock	F1, F2	

Table 15.2: ITP10 Projects Addressing Top 10 Flowgates

When analyzing projects to determine their inclusion in the final recommended plan, their performance in mitigating a top 10 congested flowgate was an important additional consideration. The rationale for recommendation of projects mitigating a current top congested flowgate is included in 0.

15.2: Alternative Project Analysis

Methodology

An Alternative Project Analysis (APA) was conducted by SPP staff in addition to the original scope of the portfolio development process. The APA included additional focus and evaluation of transmission projects in two target areas, the eastern seam of SPP and the Texas panhandle. This analysis was conducted to support SPP initiatives such as addressing the SPP seams, current operational issues, and zonal deficiencies identified through the Regional Cost Allocation Review (RCAR) process.

The APA resulted in two alternative project recommendations that differed from the results of the consolidated portfolios.

Eastern Seams

There were two corridors along the eastern seam of SPP that were further analyzed as part of the APA: southeast Kansas to southwest Missouri, and northeast Oklahoma to northwest Arkansas. This area was selected for further analysis for multiple reasons:

- There were six different constraints in this area that were identified as economic needs in at least one Future of the 2017 ITP10, as detailed in Table 15.3.
- Three of these economic needs were among the top 10 most congested constraints in SPP in 2015, as indicated in the 2015 ASOM Report[34].

Constraint	Corridor	Future(s) of Need	Flowgate Rank in 2015 ASOM Report
Neosho-Riverton (161) ftlo Neosho-Blackberry (345)	Southeast KS - Southwest MO	F1, F3	4
Bull Shoals-Midway (161) ftlo Buford-Norfork (161)	Northeast OK - Northwest AR	F2	6
Brookline Xfmr 2 (345/161) ftlo Brookline Xfmr 1 (345/161)	Southeast KS - Southwest MO	F1	7
Butler-Altoona (138) ftlo Neosho-Caney River (345)	Southeast KS - Southwest MO	F1, F2, F3	N/A
Siloam City-Siloam Springs (161) ftlo Flint Creek-Tonnece (345)	Northeast OK - Northwest AR	F1, F2	N/A

[34] https://www.spp.org/documents/41597/spp_mmu_state_of_the_market_report_2015.pdf

Highway 59-VBI (161) ftlo Fort Smith-Muskogee (345)	Northeast OK - Northwest AR	F2	N/A

Table 15.3: 2017 ITP10 Economic Needs in Eastern Seams

Within these two corridors, the Brookline area of Springfield received the primary emphasis for the following reasons:

- The Brookline 345/161 kV transformer #2 for the loss of the Brookline 345/161 kV transformer #1 economic need is in the City Utilities of Springfield (CUS) zone. CUS showed a zonal deficiency for costs and benefits in the RCAR 2[35]. As a result, project solutions in this zone were evaluated as potential remedies for this deficiency.
- The project grouping and consolidation process identified a project in Future 1 to address the Brookline transformer need. The project is a new Morgan 345/161 kV transformer. While this project provides positive economic benefit in Future 1, it shows negative benefit in Future 3 that creates uncertainty around the need to recommend an NTC for the project. Identifying a project that performs well in multiple Future scenarios is preferred.
- The Brookline transformer need is significantly impacted by hydro generation in Missouri and Arkansas. No hydro sensitivities were performed as part of the portfolio development process as scoped.

During the portfolio development process, multiple projects were evaluated for performance in addressing the Brookline transformer need. The Morgan 345/161 kV transformer was the project selected to meet this need because it performed the best from an economic perspective. The Additional Project Analysis included the following:

- Adding new constraints in the Springfield area for economic project evaluation
- Evaluating different variations of previously-tested project solutions for the Brookline transformer need
- Evaluating economic performance of certain projects under hydro sensitivity scenarios
- Performing an FCITC sensitivity to determine the ability of preferred projects to accommodate CUS load growth

[35] http://www.spp.org/Documents/40313/rcar%202%20report%20draft%20(rtwg_rartf_mopc%20reviewed).zip

- Evaluating project performance in providing thermal relief on Springfield facilities in summer peak models
- Engaging AECI in preliminary discussions regarding interest in a seams project in this area

Some project solutions were evaluated as part of the APA to see if they provided congestion relief for not just the Brookline constraint, but the Neosho-Riverton and/or Butler-Altoona constraints as well. Unfortunately, most all projects evaluated that provided congestion relief for the Brookline constraint did not provide congestion relief for either of the other two constraints. The exceptions were some variations of a comprehensive 345 kV solution ranging from east KS to as far away as southeast MO. Some of these project variations mitigated congestion at Brookline as well as one or both of the Neosho-Riverton and Butler-Altoona constraints. Though these projects provided significant benefits, the costs of these comprehensive 345 kV solutions were well in excess of their benefits, and as a result, were not pursued further.

The Morgan 345/161 kV transformer project shows negative benefit in Future 3 because a contingency of the Morgan – Brookline 345 kV line leads to significant flow on the new Morgan transformer to the 161 kV system. This, in turn, causes significant congestion on the Morgan – Brookline 161 kV line. Through the additional project testing, two projects emerged above the others as superior alternatives to the Morgan 345/161 kV transformer project:

- Morgan Project: Add a new Morgan 345/161 kV transformer and uprate the Brookline to Morgan 161 kV transmission line to achieve an emergency summer rating of 208MVA, and an emergency winter rating of 232 MVA. Note that this is different than the original Morgan 345/161 kV transformer project in that it also includes the 161 kV line uprate
- JTEC Project: Tap the 345 kV transmission line from Flint Creek to Brookline, and add a new substation with a 345/161 kV transformer. Add a 0.5 mile 161 kV connection from the new sub to JTEC 161 kV.

These two project alternatives have positive benefits in screening as well as hydro sensitivity runs in Futures 1 and 3, and have higher B/C ratios than other projects evaluated. The location of the two projects, relative to the city of Springfield, is shown in Figure 15.2.

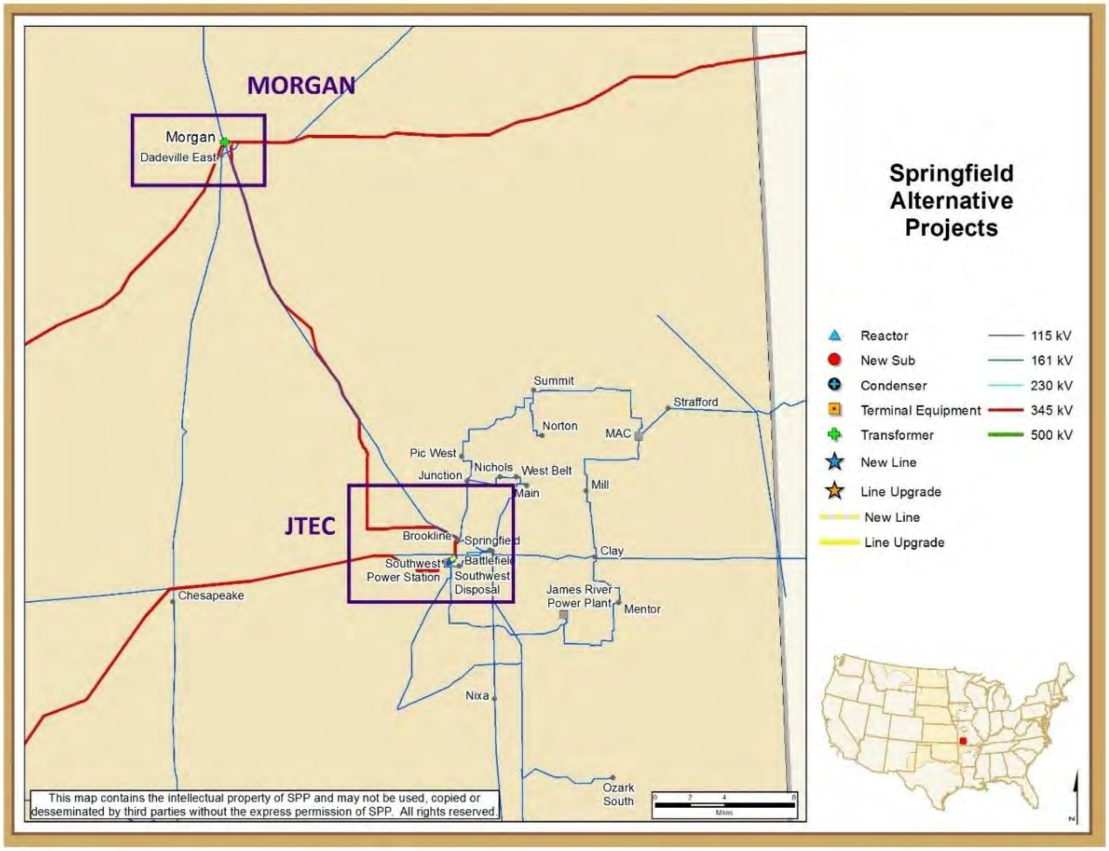

Figure 15.2: Springfield Alternative Projects

These two project alternatives are shown in closer detail in Figure 15.3 and Figure 15.4.

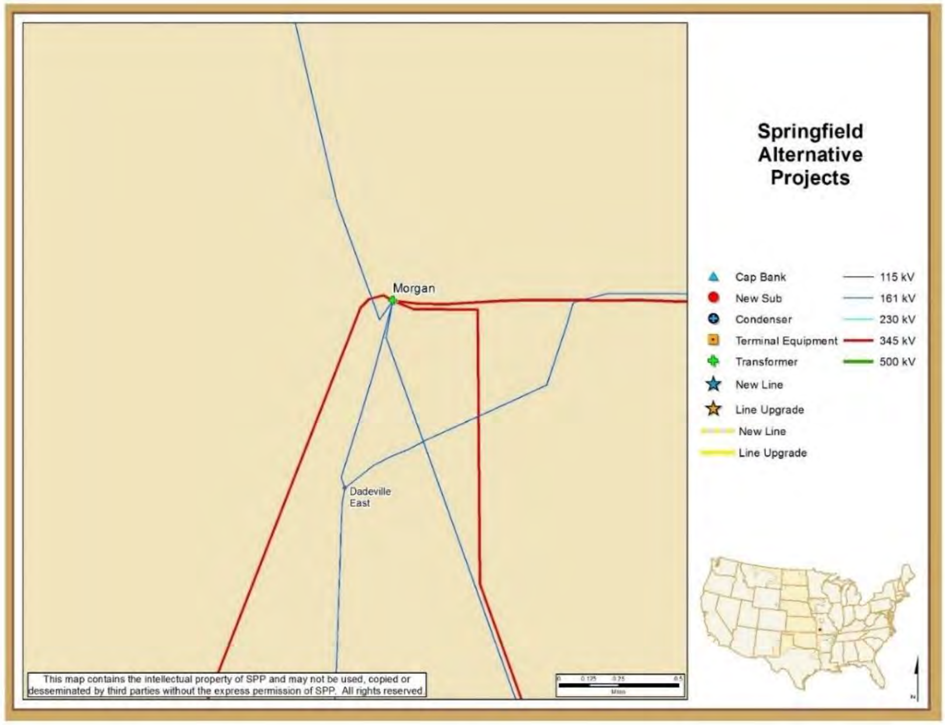

Figure 15.3: Springfield Alternative Project – Morgan

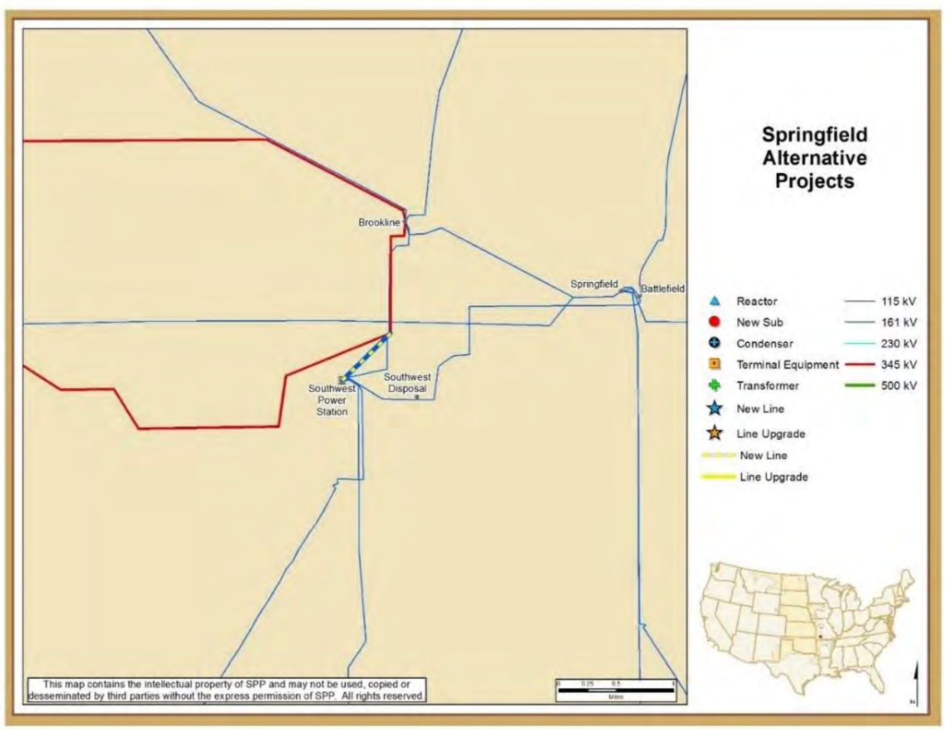

Figure 15.4: Springfield Alternative Project – JTEC

Although analysis of the Morgan project indicates net benefits when assuming SPP fully funds the cost of the project, net benefits will increase should SPP and AECI come to an agreement to jointly fund the project.

The economic model includes several SWPA hydro units near this area with transactions associated with other areas. Two hydro sensitivities were evaluated for both of the alternate projects[36]:

- Hydro Operation Sensitivity: All of the SWPA hydro transactions were modified from load following to peaking, adjusting the dispatch pattern of the hydro generation while maintaining the same monthly hydro energy. The peaking transaction pattern is expected to be slightly more accurate in terms of achieving hydro dispatch in the model that better approximates actual operational dispatch.
- Hydro Reduction Sensitivity: The SWPA hydro transactions were modified from load following to peaking, and the overall energy of the White River Basin hydro units in SWPA were reduced by 25 percent in order to approximate the impact of low water availability.

Table 15.4 shows the economic performance of the two alternate projects under the initial hydro configuration as well as the hydro sensitivities. All simulations were conducted considering additional adjustments to the approved 2017 ITP10 model and constraints. Additional constraints were added around the Springfield area in all simulations in order to avoid overloads on previously unmonitored facilities. The screening models are the approved ITP10 base case models with the additional constraints around the Springfield area; they do not include model corrections submitted by members during the project submittal process, and do not include other ITP10 projects. The hydro sensitivity simulations include the model corrections submitted by members as well as the ITP10 projects identified in the consolidated portfolios. The Future 1 hydro sensitivities include all Reduced Carbon portfolio projects in the base and change cases, except for the original Morgan 345/161 kV project. The Future 3 hydro sensitivities include all Reference Case portfolio projects in the base and change cases. These

[36] Section 5.3.3 of the 2015 Annual State of the Market Report: "…the Brookline 345/161kV #2 transformer for the loss of Brookline 345/161 #1 transformer in SW Missouri have several factors that can lead to loading in these areas. Loading in NW Arkansas and SW Missouri, high exports, and limited hydro and Springfield generation can lead to these constraints becoming congested."

calculations do not assume interregional cost sharing of either projects, as a conservative assumption.

Project	Future	1-year Project Cost	Base Case		Hydro Operation Sensitivity		Hydro Reduction Sensitivity	
			SPP Benefit	SPP 1-yr B/C	SPP Benefit	SPP 1-yr B/C	SPP Benefit	SPP 1-yr B/C
Morgan Project	F1	$1.6M	$2.2M	1.4	$4.4M	2.7	$4.5M	2.8
Morgan Project	F3	$1.6M	$1.6M	1.0	$2.1M	1.3	$2.3M	1.4
JTEC Project	F1	$4.2M	$3.7M	0.9	$4.4M	1.0	$3.4M	0.8
JTEC Project	F3	$4.2M	$1.6M	0.4	$2.4M	0.6	$1.6M	0.4

Table 15.4: Springfield Alternate Projects – Economic Testing and Sensitivity Results

Note that all costs and benefits included in this Table are for the 2025 study year only. While the Morgan project is cost-justifiable based on 1-year benefits and costs, the JTEC project is not. 40-year benefits and costs were analyzed for both projects, and both projects have a 40-year B/C greater than 1.0 in Futures 1 and 3, as shown in Table 15.5. Under these assumptions, both Springfield alternate projects are cost-justifiable.

Project	Future	APC Benefit ($M) 40-Year	Cost ($M) 40-Year	Net Benefit ($M) 40-Year	B/C 40-Year
Morgan Project	F1	$43.3	$14.7	$28.6	2.94
Morgan Project	F3	$70.1	$14.7	$55.4	4.76
JTEC Project	F1	$80.1	$38.6	$41.5	2.08
JTEC Project	F3	$42.4	$38.6	$3.8	1.10

Table 15.5: Springfield Alternative Projects - 40-Year Benefits and Costs

An FCITC sensitivity was conducted to determine the ability of the preferred projects to accommodate CUS load growth by increasing the SPP generation outside of CUS while increasing the load in CUS. The Brookline transformers are the primary path for power outside of CUS to flow into the city. The sensitivity assesses the increase in CUS load it would take before the Brookline transformer overloads with each alternate project included and assuming CUS would import additional power to serve the additional load. The headroom for the Brookline transformer provided by each project is shown in Table 15.6.

Project	Future	CUS load increase above 2025 peak that is required to overload the Brookline transformer
Morgan Project	F1	15%

Project	Future	CUS load increase above 2025 peak that is required to overload the Brookline transformer
Morgan Project	F3	24%
JTEC Project	F1	> 38%
JTEC Project	F3	> 38%

Table 15.6: Springfield Alternate Projects – CUS Load Growth Sensitivity

Both projects provide adequate transfer capability into Springfield in the event of future load growth beyond the 2025 projections.

The two alternate projects were tested to evaluate the relief that each provides on three key Springfield area constraints. Table 15.7 shows the loading on each constraint with and without each project. Green indicates that the project relieves loading of the facility, while red indicates the project aggravated loading on the facility.

Model	Springfield – Clay (Con: James River – Southwest 161 kV)		Brookline – Junction (Con: Battlefield – Main 161 kV)		Brookline Transformer Ckt 1 (Con: Brookline 345/161 kV Transformer Ckt 2)	
	Morgan	JTEC	Morgan	JTEC	Morgan	JTEC
F1 Peak	< 80%	< 80%	96.40%	96.40%	108.40%	108.40%
			94.30%	96.70%	87%	65.20%
F2 Peak	100.30%	100.30%	101.30%	101.30%	98.50%	98.50%
	102.20%	103.50%	99.30%	101.70%	66.30%	57.30%
F3 Peak	97.60%	97.60%	105.20%	105.20%	103.70%	103.70%
	99.60%	100.70%	102.90%	105.70%	65.80%	58.60%

Table 15.7: Springfield Alternate Projects – CUS Loading Relief Sensitivity

Both projects provide significant relief on the Brookline constraint, with the JTEC project providing more relief. Neither project has a significant impact on the loading of the Springfield – Clay 161 kV and Brookline – Junction 161 kV constraints.

In conclusion, both the Morgan project and the JTEC project are good projects that provide significant congestion relief of the Brookline transformer, which is a top 10 most congested constraint in the 2015 ASOM Report[37]. Each project is cost-justifiable over the 40-year life of the project in both Future 1 and Future 3.

The Morgan project provides better B/C ratios and also has the potential for cost sharing with AECI as a seams project, further improving the B/C ratios and net benefits for SPP. The JTEC project provides better transfer capability into the city of Springfield in the event of increased load growth beyond what is expected in the current forecast, provides more loading relief on the Brookline transformers, and provides more flexibility for additional upgrades to facilitate Springfield imports should those upgrades become needed in the future.

If agreement cannot be reached between SPP and AECI on cost sharing, SPP Staff would recommend the alternative JTEC solution which includes tapping the Brookline to Flint Creek 345 kV line, installing a new sub with a 345/161 kV transformer, and building a 161 kV line from the new sub to the JTEC substation.

Texas Panhandle[38]

Since 2011, SPP planning studies have identified reliability issues resulting in the rebuilds of a 115 kV corridor just south of Amarillo, Texas, as seen in Figure 15.5**Error! Reference source not found.**. In the Aggregate Transmission Service Study, SPP -2011-AG3-AFS-11[39], the first rebuilds identified were to the northern most portion of the corridor: Randall to Canyon East and Canyon East to Canyon West. Subsequently, in the 2015 and 2016 ITP Near-Term studies[40][41],

[37] https://www.spp.org/documents/41597/spp_mmu_state_of_the_market_report_2015.pdf

[38] For more background information about the Texas Panhandle transmission corridor, please refer to SPP Quarterly and Annual State of the Market Reports posted on SPP.org.

[39] http://sppoasis.spp.org/documents/swpp/transmission/AggTransStudies.cfm?YearType=2011 Aggregate Facility Study

[40] https://www.spp.org/documents/30445/final_2015_itpnt_assessment_bod_approved.pdf

[41] https://www.spp.org/documents/42676/final%202016%20itp%20near-term%20assessment%20spp%20board%20approved.pdf

additional segments were identified for rebuild: Canyon West to Dawn, Dawn to Panda, and Panda to Deaf Smith. The remaining portion of the corridor is projected to remain a severely congested constraint, even in light of the planned rebuilds.

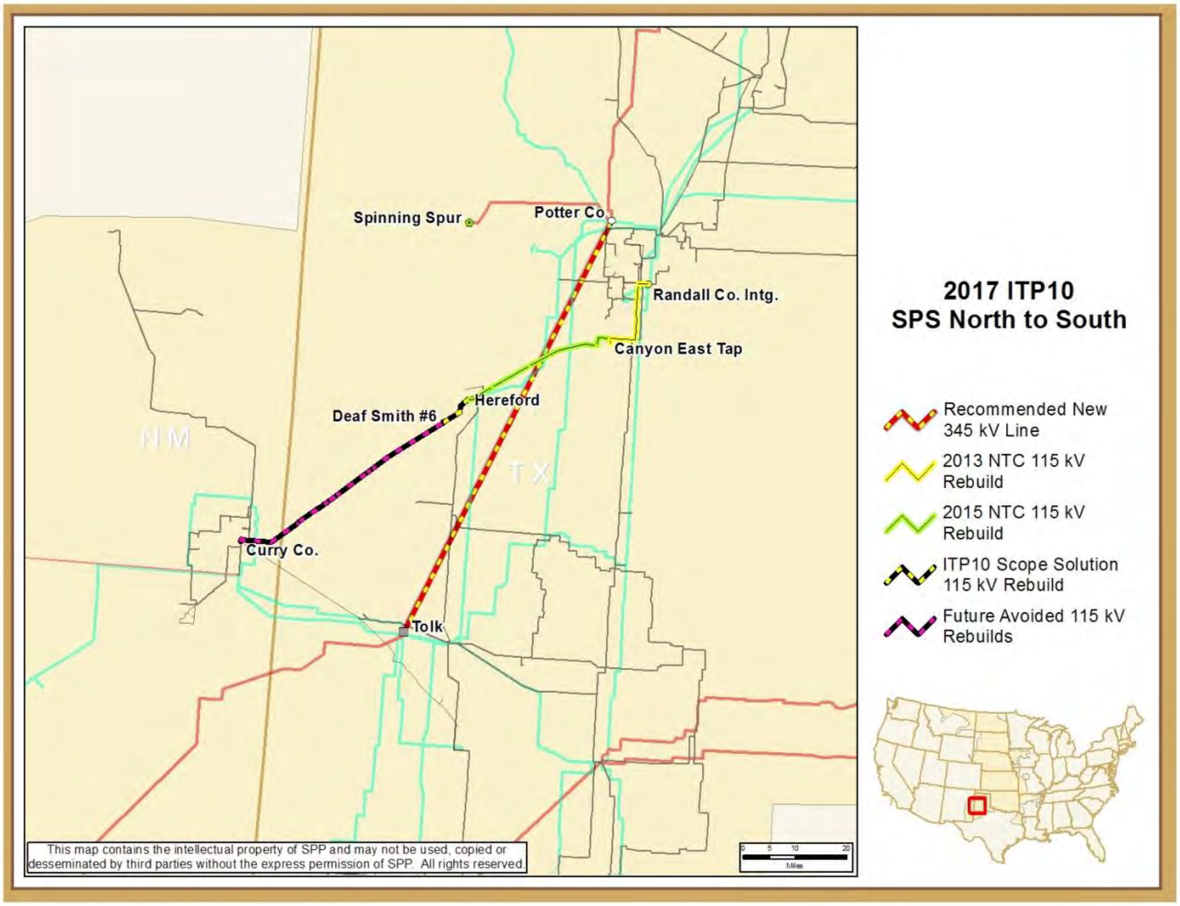

Figure 15.5: Transmission Map of Texas Panhandle with Potential Solutions

In this study, the 115 kV line from DS #6 to Hereford for the loss of the Deaf Smith to Plant X 230 kV line is congested and considered an economic need in Future 3. Through the approved process, the rebuild of this line was selected as part of the Reference Case portfolio. In light of the prior identification of rebuilds of this corridor and the fact that the SPS North-South remains highly constrained, SPP staff investigated the merits of a more robust solution.

Previous SPP long-range studies (2010 ITP20 and 2013 ITP20[42]) identified a new 345 kV line from Potter to Tolk to resolve issues in the Texas panhandle. This previously approved long-term solution was chosen as the focus of analysis to address these issues.

The project was tested in Future 3 with the Reference Case portfolio; the DS #6 to Hereford rebuild was removed to value the benefit of selecting the new line in place of the rebuild in conjunction with the portfolio. Due to the uncertainty around the type and associated operational and economic characteristics of generation that may ultimately materialize in the area south of the corridor, and the potential for transmission customers to site generation north of the study corridor, or purchase energy off-system, additional states of the system were created in which to test the Potter to Tolk line. In order to remove the direct impact of the resource plan assumed for the area, the CC sited at Deaf Smith was moved north of the area to Moore County, an RCAR II 2035 site. In addition to testing the new line under the new base assumptions, SPP staff also performed the analysis under additional states of the system:

- Retiring Tolk 1 and replacing it with a new CC;
- Converting the CC sited at Hobbs to three CTs; and

All of the tested approaches would have a similar effect in the Texas panhandle. Table 15.8 shows the APC benefit results of this additional analysis. Also included in Table 15.8, is an estimated cost of reliability projects that would need to be displaced in order to achieve a 0.9 1-year B/C for Potter to Tolk, consistent with the threshold used for projects in the consolidation phase[43].

Sensitivity	SPP APC Benefit	SPP 1-Yr B/C	Displaced Reliability Projects for 0.9 1-Yr B/C
Base	$14.6M	0.6	$43.9M
Deaf Smith CC Move Only	$13.6M	0.6	$49.9M
Deaf Smith CC Move & Tolk 1	$21.6M	0.9	$2.4M

[42] The "New Potter - Tolk 345 kV" was included in Futures 2, 3, and 4 of the 2013 ITP20. Table 13.2 of the 2013 ITP20 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.
https://www.spp.org/documents/20438/20130730_2013_itp20_report_clean.pdf

[43] This approach utilizes the approved Avoided or Delayed Reliability Projects benefit metric as described in the SPP Benefit Metrics Manual. https://www.spp.org/Documents/44031/20161108_Metrics_Manual_rev1.doc

Retirement and CC Replacement			
Deaf Smith CC Move & Hobbs CC Conversion to CTs	$14.3M	0.6	$45.7M

Table 15.8: APC Benefit Results for New Potter - Tolk 345 kV Line

Through an FCITC analysis with a transfer from SPP to southern SPS, it is possible to anticipate incremental network upgrades of this corridor that might be identified in future studies. A conceptual cost estimate of these rebuilds exceeds $88M, more than the cost of avoided projects needed to achieve a 1-year B/C of 0.9, further affirming the need for a comprehensive solution in the area. Table 15.9 shows the future potential avoided upgrades identified in the analysis.

Upgrade Name	Upgrade Type	Miles	High Conceptual Estimate ($M)	Low Conceptual Estimate ($M)
DEAF SMITH REC-#6 - HEREFORD INTERCHANGE 115KV CKT 1	Terminal Equipment	7.1	0.5	0.5
DEAF SMITH REC-#6 - HEREFORD INTERCHANGE 115KV CKT 1	Rebuild	7.1	5.2	5.2
MANHATTAN SUB - RANDALL COUNTY INTERCHANGE 115KV CKT 1	Terminal Equipment	4.1	0.5	0.5
COULTER INTERCHANGE - HILLSIDE 115KV CKT 1	Terminal Equipment	2.1	0.5	0.5
DEAF SMITH REC-#6 - FRIONA SUB 115KV CKT 1	Rebuild	18.2	13.3	13.3
MOORE COUNTY INTERCHANGE 230/115KV TRANSFORMER CKT 1	Replace Transformer	N/A	5.7	5.7
BUSHLAND INTERCHANGE - DEAF SMITH COUNTY INTERCHANGE 230KV CKT 1	Terminal Equipment and Rebuild*	33.4	35.1	3.5
MOORE COUNTY INTERCHANGE 230/115 TRANSFORMER CKT 1	Replace Transformer	N/A	5.7	5.7
BUSHLAND INTERCHANGE - HILLSIDE 115KV CKT 1	Terminal Equipment	9.0	0.5	0.5
CARGILL SUB - FRIONA SUB 115KV CKT 1	Rebuild	1.2	0.8	0.8
BUSHLAND INTERCHANGE - POTTER COUNTY INTERCHANGE 230KV CKT 1	Terminal Equipment and Partial Rebuild	19.0	2.0	2.0
BUSHLAND INTERCHANGE 230/115KV TRANSFORMER CKT 1	Replace Transformer	N/A	5.7	5.7
BUSHLAND INTERCHANGE 230/115KV TRANSFORMER CKT 1	Replace Transformer	N/A	5.7	5.7
NEWHART 230 - POTTER COUNTY INTERCHANGE 230KV CKT 1	Terminal Equipment and Partial Rebuild	67.3	6.4	6.4
DEAF SMITH COUNTY INTERCHANGE - PLANT X STATION 230KV CKT 1	Terminal Equipment	6.8	0.5	0.5

Upgrade Name	Upgrade Type	Miles	High Conceptual Estimate ($M)	Low Conceptual Estimate ($M)
CARGILL SUB - DEAF SMITH REC-#24 115KV CKT 1	Rebuild	7.7	5.7	5.7
DEAF SMITH REC-#24 - PARMER COUNTY SUB 115KV CKT 1	Rebuild	1.2	0.8	0.8
POTTER COUNTY INTERCHANGE 345/230KV TRANSFORMER CKT 1	Add Second Transformer	N/A	9.3	9.3
DEAF SMITH REC-#20 - PARMER COUNTY SUB 115KV CKT 1	Rebuild	7.6	5.6	5.6
CURRY COUNTY INTERCHANGE - DEAF SMITH REC-#20 115KV CKT 1	Rebuild	12.7	9.3	9.3
AMARILLO SOUTH INTERCHANGE - SWISHER COUNTY INTERCHANGE 230KV CKT 1	Terminal Equipment	57.9	0.5	0.5
EAST PLANT INTERCHANGE - MANHATTAN SUB 115KV CKT 1	Terminal Equipment	2.2	0.5	0.5
* Full cost reflected only in high conceptual estimate		Total:	119.8	88.2

Table 15.9: Future Potential Avoided Reliability Upgrades

In the analyses mentioned above, SPP staff determined that the NTCs issued for the first segments of this corridor would still be needed in conjunction with this EHV solution to fully resolve congestion. However, further rebuilds of this corridor would be deferred with a new Potter to Tolk 345 kV line.

This proposed alternative project would not only provide the region the enhanced ability to exchange economic energy to (and from) this south part of the SPP footprint, but would also provide strength to the transmission system under what is seen as one of the most congested corridors today in SPP.

15.3: Sidebar Analysis

Purpose

The purpose of the Sidebar analysis was to assess how out of cycle[44] changes to the 2017 ITP10 study modeling assumptions impact the needs identified and solutions developed. The

[44] Specifically, the 2016 ITPNT recommended portfolio of NTCs that were approved in April 2016 and NTC reevaluations that were approved in July 2016 after major portions of the 2017 ITP10 powerflow and economic models were complete.

assessment was also intended to help make a more informed decision to develop a comprehensive, flexible, and cost-effective transmission expansion plan to meet the requirements of the SPP footprint under the 2017 ITP10 Futures.

The study assessed these out of cycle changes in the following areas: model development, constraint assessment, economic and reliability analysis, transmission plan development, seams impact review, and various sensitivities. Once the out of cycle modeling changes were incorporated, comparisons were made between the transmission needs of the Sidebar analysis and the transmission needs in the as scoped portion of the study to evaluate and guide a final portfolio of project recommendations to the Market Operations and Policy Committee (MOPC) and the Board of Directors (BOD).

The scope for the Sidebar analysis included seven (7) major tasks:

- Task 1: Powerflow and Economic Model Development and Comparisons (Only 2025 Model)
- Task 2: Constraint Assessment and Comparisons
- Task 3: Economic Needs Assessment and Comparisons
- Task 4: Reliability Assessment Models and Comparisons
- Task 5: Reliability Needs Assessment and Comparisons
- Task 6: Review and Correlate Reliability and Economic Needs
- Task 7: Transmission Plan Development Options considering impactful need difference

Powerflow and Economic Model Development

The powerflow and economic model development included known out of cycle updates received since the approved powerflow and economic models were finalized, as well as a limited amount of fundamental economic model assumption updates to attain more realistic impacts of hydro generation, external systems, and wind generation on SPP transmission network. The system topology updates included 2016 ITPNT NTCs and other SPP Expansion Plan NTC changes, significant changes to existing resources[45], approved MISO Transmission Expansion Plan (MTEP) projects related to needs in the 2017 ITP10 Needs Assessment, and

[45] The side bar models include OPPD's announced retirement of Ft Calhoun with an assumption to extend the operation of OPPD's North Omaha Units 1, 2, and 3 into the 2025 study year. http://www.oppd.com/news-resources/news-releases/2016/june/oppd-board-votes-to-decommission-fort-calhoun-station/

model corrections received during the 2017 ITP10 DPP submittal window. The economic model assumption updates included the removal of proxy external transactions between simulated portions and non-simulated portions of the eastern interconnection aimed to improve DC and AC powerflow mismatches, the remodeling of SWPA and WAPA Hydro Transactions as percent ownership of units aimed to improve hydro generation operation[46], an update of Manitoba Hydro DC line limits to allow for more appropriate operation, and hourly profile updates for existing and future wind resources in the SPP region to reflect the correct time zone[47].

Constraint Assessment

The updated economic model was used to re-perform the SPP constraint assessment process where the results were compared to the 2017 ITP10 constraint assessment process results to identify constraints for 100 kV and above facility outages within SPP and first tier neighbor systems.

Benchmarking

Comparisons of input powerflow models, economic models, constraint assessments, were made to ensure that changes were applied appropriately. The objective was to evaluate the impact of the changes in economic modeling assumptions prior to performing the reliability and economic assessments. A limited economic assessment was performed to analyze congested facilities on the SPP transmission system. The results were reviewed to determine if the congestion differences between the 2017 ITP10 and Sidebar economic analysis were reasonable.

Economic Assessment Comparison and Discussion

Table 15.10, Table 15.11, and Table 15.12 show comparisons of congestion scores for 2017 ITP10 economic needs in each respective Future. The tables also include new constraints that would represent a new economic need if the out of cycle changes would have been considered at the onset of the 2017 ITP10 study. The tables include congestion scores from the 2017 ITP10 economic study model as approved, with model corrections, and with wind profile updates to

[46] For future studies, SPP Staff will be further investigating economic model impacts as well as alternatives to remodeling of SWPA and WAPA hydro transactions as percent ownership of units.

[47] Refinement of SWPA and WAPA hydro modeling and the wind profile updates were applied to economic model after the side bar constraint assessment. See ESWG 11/17/2016 meeting minutes for further discussion on wind profile updates.

show the progression leading up to the congestion scores in the Sidebar model[48]. Congestion scores with a N/A denote that the constraint was not included in the respective economic model simulation. Congestion scores with a "-" denote that the constraint was fully relieved in the respective economic model simulation.

[48] The final sidebar model includes both the model corrections and wind profile updates. Congestion scores from this sidebar model are shown in the last column of the tables.

Line #	From/To Area	Future 1 Constraints	Constraint Source	ITP10 model congestion Score without model corrections	ITP10 model congestion Score with model corrections	ITP10 model congestion score with wind profile update	ITP10 side bar model congestion score
1	UMZ/UMZ	Watford City 230/115kV Transformer (System Intact Event)	ITP10	$ 781,727	$ -	$ 778,264	$ -
2	MDU/MDU	Coyote - Beulah 115kV FLO Center - Mandan 230kV	ITP10	$ 675,574	$ -	$ 680,072	$ -
3	OTP/OTP	Hankinson - Wahpeton 230kV FLO Jamestown - Buffalo 345kV	ITP10	$ 538,715	$ 651,961	$ 547,124	$ 441,081
4	SWPS/SWPS	Stanton - Indiana 115kV FLO Tuco - Carlisle 230kV	ITP10	$ 464,889	$ 462,150	$ 517,127	$ 431,297
5	GRE/GRE	GRE-McHenry 230/115kV Transformer (System Intact Event)	ITP10	$ 408,953	$ 58,673	$ 401,089	$ 55,276
6	WERE/WERE	Butler - Altoona 138kV FLO Neosho - Caney River 345kV	ITP10	$ 257,440	$ 271,183	$ 308,760	$ 308,921
7	UMZ/UMZ	Sub3 - Granite Falls 115kV Ckt1 FLO Lyon Co. 345/115 kV Transformer Ckt1	ITP10	$ 247,828	$ 306,656	$ 243,591	$ 297,564
8	AEPW/AEPW	South Shreve Port - Wallace Lake 138kV FLO Ft Humbug - Trichel 138kV	ITP10	$ 194,151	$ 190,495	$ 186,666	$ 139,798
9	NSP/ALTW	Winnebago- Blueeta 161kV FLO Field - Wilmart 345kV	ITP10	$ 188,723	$ 412,074	$ 176,865	$ 468,598
10	MIDW/MIDW	Vine Tap - North Hayes 115kV FLO Knoll - Post Rock 230kV	ITP10	$ 179,921	$ 174,079	$ 183,645	$ 179,477
11	WERE/WERE	Kelly - Tecumseh Hill 161kV FLO Kelly 161/115kV Transformer	ITP10	$ 157,061	$ 106,386	$ 143,538	$ 74,162
12	SWPA/WFEC	Tupelo Tap - Tupelo 138kV FLO Pittsburg - Valiant 345kV	ITP10	$ 154,155	$ 49,649	$ 159,492	$ 43,462
13	GRE/UMZ	GRE-McHenry - Voltair 115kV FLO Balta - Rugby 230kV	ITP10	$ 149,860	$ 190,691	$ 156,967	$ 12,344
14	OKGE/OKGE	Woodward - Windfarm 138kV FLO Woodward 138/69kV Transformer	ITP10	$ 138,491	$ 142,520	$ 158,794	$ -
15	OPPD	Fort Cal Interface	ITP10	$ 132,450	$ -	$ 133,100	N/A
16	WERE/EMDE	Neosho - Riverton 161kV FLO Neosho - Blackberry 345kV	ITP10	$ 115,799	$ 111,724	$ 119,038	$ 130,326
17	KCPL/KCPL	Northeast - Charlotte 161kV FLO Northeast - Grand Ave West 161kV	ITP10	$ 99,579	$ 102,201	$ 90,374	$ 86,389
18	SWPS/SWPS	Sundown 230/115kV Transformer FLO Lamb County - Hockley 115kV	ITP10	$ 94,603	$ 24,237	$ 124,743	N/A
19	SWPS/SWPS	Seminole 230/115kV Transformer Ckt 2 FLO Seminole 230/115kV Ckt 1 Transformer	ITP10	$ 90,904	$ 88,022	$ 88,107	N/A
20	AEPW/GRDA	Siloam City - Siloam Springs 161kV FLO Flint Creek - Tonnece 345kV	ITP10	$ 76,650	$ 74,152	$ 77,933	$ 84,608
21	SWPS/SWPS	Denver - Shell 115kV FLO West Sub3 - Lovington 115kV	ITP10	$ 75,257	$ 62,267	$ 74,685	N/A
22	SPRM/SPRM	Brookline 345/161kV Ckt 1 Transformer FLO Brookline 345/161kV Ckt 2 Transformer	ITP10	$ 74,465	$ 82,630	$ 87,490	$ 97,027
23	UMZ/NSP	Sioux Falls - Lawrence 115kV FLO Sioux Falls - Split Rock 230kV	ITP10	$ 70,107	$ 85,738	$ 65,302	$ 71,499
24	MP/GRE	Grand Rapids - Pokegma 115kV FLO Forbes - Chisago 500kV	ITP10	$ 62,701	$ -	$ 56,678	N/A
25	OPPD/MEC	Tekamah - Raun 161kV FLO Raun-S3451 345kV	Side Bar	$ 12,502	$ 201,805	$ 8,592	$ 70,785
26	OKGE/WFEC	Gracemont - Anadarko 138kV FLO S.W.S. - Washita 138kV	Side Bar	$ 3,831	$ 69,028	$ 8,941	$ 79,851
27	EES/EES	Longmire - Ponderosa 138kV FLO Ponderosa- Conroe Bulk 138kV	Side Bar	N/A	N/A	N/A	$ 181,420
28	SWPS/SWPS	Pantex South - Highland Tap FLO Hutchison Co. Intg. - Martin 115 kV	Side Bar	N/A	$ 37,985	N/A	$ 53,849
29	NSP/NSP	Magic City - Velva Tap FLO GRE-McHenry - Voltair 115kV	Side Bar	N/A	N/A	N/A	$ 62,416
30	GRE/GRE	GRE-McHenry 230/115kV Transformer FLO Balta - Rugby 230kV	Side Bar	N/A	N/A	N/A	$ 464,643

Table 15.10: Future 1 Congestion Score Comparisons

Line #	From/To Area	Future 2 Constraints	Constraint Source	ITP10 model congestion Score without model corrections	ITP10 model congestion Score with model corrections	ITP10 model congestion score with wind profile update	ITP10 side bar model congestion score
1	SWPS/SWPS	Stanton - Indiana 115kV FLO Tuco - Carlisle 230kV	ITP10	$ 662,310	$ 672,610	$ 710,582	$ 577,366
2	GRE/GRE	GRE-McHenry 230/115kV Transformer (System Intact Event)	ITP10	$ 597,138	$ 70,938	$ 601,276	$ 81,598
3	UMZ/UMZ	Watford City 230/115kV Transformer (System Intact Event)	ITP10	$ 536,225	$ -	$ 530,150	$ -
4	UMZ/UMZ	Sub3 - Granite Falls 115kV Ckt1 FLO Lyon Co. 345/115 kV Transformer Ckt1	ITP10	$ 371,481	$ 459,243	$ 375,649	$ 474,260
5	NSP/ALTW	Winnebago- Blueeta 161kV FLO Field - Wilmart 345kV	ITP10	$ 300,035	$ 581,998	$ 312,862	$ 658,231
6	MDU/MDU	Coyote - Beulah 115kV FLO Center - Mandan 230kV	ITP10	$ 293,122	$ -	$ 285,343	$ -
7	AEPW/AEPW	South Shreve Port - Wallace Lake 138kV FLO Ft Humbug - Trichel 138kV	ITP10	$ 218,942	$ 224,818	$ 201,737	$ 164,893
8	GRE/UMZ	GRE-McHenry - Voltair 115kV FLO Balta - Rugby 230kV	ITP10	$ 149,813	$ 175,849	$ 148,311	$ 10,066
9	MIDW/MIDW	Vine Tap - North Hayes 115kV FLO Knoll - Post Rock 230kV	ITP10	$ 134,509	$ 130,143	$ 141,473	$ 125,676
10	WERE/WERE	Butler - Altoona 138kV FLO Neosho - Caney River 345kV	ITP10	$ 128,073	$ 144,986	$ 143,621	$ 139,836
11	WFEC/WFEC	Naples Tap - Cornville Tap 138kV FLO Sunnyside - G14-057T 345kV	ITP10	$ 125,364	$ 8,646	$ 136,481	$ 6,546
12	OKGE/OKGE	Woodward - Windfarm 138kV FLO Woodward 138/69kV Transformer	ITP10	$ 110,046	$ 108,989	$ 127,951	$ -
13	SPWA/EES	Bull Shoals - Midway Jordan 161kV FLO Bull Shoals - Buford 161kV	ITP10	$ 96,338	$ 97,148	$ 119,920	$ 79,817
14	OPPD	Fort Cal Interface	ITP10	$ 85,756	$ -	$ 83,096	N/A
15	SWPA/WFEC	Tupelo Tap - Tupelo 138kV FLO Pittsburg - Valiant 345kV	ITP10	$ 81,181	$ 11,255	$ 75,991	$ 2,953
16	SWPS/SWPS	Seminole 230/115kV Transformer Ckt 2 FLO Seminole 230/115kV Ckt 1 Transformer	ITP10	$ 79,960	$ 78,768	$ 67,580	N/A
17	KCPL/KCPL	Northeast - Charlotte 161kV FLO Northeast - Grand Ave West 161kV	ITP10	$ 79,745	$ 64,604	$ 62,402	$ 48,211
18	SWPS/SWPS	Sundown 230/115kV Transformer FLO Lamb County - Hockley 115kV	ITP10	$ 79,392	$ 23,150	$ 129,385	N/A
19	UMZ/NSP	Sioux Falls - Lawrence 115kV FLO Sioux Falls - Split Rock 230kV	ITP10	$ 79,374	$ 89,314	$ 78,054	$ 79,219
20	OKGE/OKGE	Highway 59 - VBI North 161kV FLO Fort Smith - Muskogee 345kV	ITP10	$ 71,172	$ -	$ 68,022	N/A
21	MIDW/WERE	Smokey Hills - Summit 230kV FLO Post Rock - Axtell 345kV	ITP10	$ 58,462	$ 63,959	$ 50,959	$ 56,825
22	AEPW/GRDA	Siloam City - Siloam Springs 161kV FLO Flint Creek - Tonnece 345kV	ITP10	$ 50,011	$ 52,467	$ 52,373	$ 64,916
23	MEC/OPPD	Sub 701 - Sub 1211 161kV FLO Council Bluffs -Sub 3456 345kV	Side Bar	$ 30,199	$ 66,251	$ 19,614	$ 54,184
24	OKGE/WFEC	Gracemont - Anadarko 138kV FLO S.W.S. - Washita 138kV	Side Bar	$ 4,747	$ 69,243	$ 8,752	$ 72,698
25	EES/EES	Longmire - Ponderosa 138kV FLO Ponderosa- Conroe Bulk 138kV	Side Bar	N/A	N/A	N/A	$ 279,455
26	NSP/NSP	Magic City - Velva Tap FLO GRE-McHenry - Voltair 115kV	Side Bar	N/A	N/A	N/A	$ 96,234
27	GRE/GRE	GRE-McHenry 230/115kV Transformer FLO Balta - Rugby 230kV	Side Bar	N/A	N/A	N/A	$ 457,039

Table 15.11: Future 2 Congestion Score Comparisons

Line #	From/To Area	Future 3 Constraints	Constraint Source	ITP10 model congestion Score without model corrections	ITP10 model congestion Score with model corrections	ITP10 model congestion score with wind profile update	ITP10 side bar model congestion score
1	UMZ/UMZ	Watford City 230/115kV Transformer (System Intact Event)	ITP10	$ 821,749	$ -	$ 817,813	$ -
2	NSP/NSP	Chub Lake - Kenrick 115kV FLO Helena - Scott Co 345kV	ITP10	$ 635,398	$ -	$ 612,685	N/A
3	SWPS/SWPS	Stanton - Indiana 115kV FLO Tuco - Carlisle 230kV	ITP10	$ 379,447	$ 364,279	$ 441,490	$ 420,522
4	AEPW/AEPW	South Shreve Port - Wallace Lake 138kV FLO Ft Humbug - Trichel 138kV	ITP10	$ 274,213	$ 284,236	$ 283,175	$ 206,395
5	UMZ/UMZ	Sub3 - Granite Falls 115kV Ckt1 FLO Lyon Co. 345/115 kV Transformer Ckt1	ITP10	$ 221,315	$ 248,925	$ 219,886	$ 241,405
6	WERE/WERE	Butler - Altoona 138kV FLO Neosho - Caney River 345kV	ITP10	$ 166,526	$ 176,320	$ 175,719	$ 176,721
7	OKGE/OKGE	Woodward - Windfarm 138kV FLO Woodward 138/69kV Transformer	ITP10	$ 109,243	$ 104,541	$ 115,678	$ -
8	WERE/EMDE	Neosho - Riverton 161kV FLO Neosho - Blackberry 345kV	ITP10	$ 103,326	$ 100,552	$ 100,159	$ 96,378
9	SWPS/SWPS	Hereford - DS#6 115kV FLO Deaf Smith PLX Tap - Plant X6 230kV	ITP10	$ 94,461	$ 98,666	$ 93,853	$ 105,505
10	SWPS/SWPS	Sundown 230/115kV Transformer FLO Lamb County - Hockley 115kV	ITP10	$ 92,582	$ 36,233	$ 138,894	N/A
11	WFEC/WFEC	Naples Tap - Cornville Tap 138kV FLO Sunnyside - G14-057T 345kV	ITP10	$ 88,668	$ 3,960	$ 83,704	$ 1,037
12	SWPS/SWPS	Seminole 230/115kV Transformer Ckt 2 FLO Seminole 230/115kV Ckt 1 Transformer	ITP10	$ 87,371	$ 80,567	$ 84,289	N/A
13	KCPL/KCPL	Northeast - Charlotte 161kV FLO Northeast - Grand Ave West 161kV	ITP10	$ 82,395	$ 65,986	$ 70,601	$ 61,757
14	SWPA/WFEC	Tupelo Tap - Tupelo 138kV FLO Pittsburg - Valiant 345kV	ITP10	$ 4,702	$ 2,637	$ 7,243	$ 190
15	SWPA/WFEC	Tupelo Tap - Tupelo 138kV FLO Pittsburg - Valiant 345kV	ITP10	$ 57,979	N/A	$ 57,644	$ -
16	NPPD/SUNC	Redwillow Mingo Interface	ITP10	$ 53,504	$ 44,425	$ 46,508	$ 41,852
17	UMZ/UMZ	Huron - B Tap 115kV Ckt1 FLO Ft. Thompson - Letcher 230kV Ckt 1	ITP10	$ 52,591	$ -	$ 47,481	N/A
18	NPPD/NPPD	Scottsbluff - Victory Hill 115kV Ckt1 FLO Stegall 345/230kV Transformer Ckt 1	ITP10	$ 52,309	$ 3,355	$ 52,981	$ 3,145
19	NSP/ALTW	Winnebago- Blueeta 161kV FLO Field - Wilmart 345kV	Side Bar	$ 31,246	$ 127,515	$ 181,693	$ 145,801
20	OKGE/WFEC	Gracemont - Anadarko 138kV FLO S.W.S. - Washita 138kV	Side Bar	$ 11,860	$ 87,093	$ 8,752	$ 85,754
21	EES/EES	Longmire - Ponderosa 138kV FLO Ponderosa- Conroe Bulk 138kV	Side Bar	N/A	N/A	N/A	$ 170,828
22	MDU/MDU	Green River Junction - Westmoreland FLO Belfield - Charlie Creek 345kV	Side Bar	N/A	N/A	N/A	$ 50,220

Table 15.12: Future 3 Congestion Score Comparison

Many of the economic needs are very similar between the approved 2017 ITP10 model and various modified model updates, whereas others progressively change due to relatable model corrections or NTC additions or withdrawals. SPP staff has reviewed each of these to determine if the differences would cause a need to modify the recommended portfolio. It is SPP staff's conclusion that these differences do not represent a significant need to modify the recommended portfolio.

Reliability Assessment

Reliability Assessment powerflow models were developed with a market dispatch under coincident peak and off peak load from the Sidebar economic simulations using the SPP DC to AC conversion process. Steady state AC contingency analysis was conducted using the reliability assessment powerflow models. All facilities 69 kV and above in the models were monitored within SPP and all facilities 100 kV and above were monitored in the first-tier regions for this analysis. The results were compared to the 2017 ITP10 AC contingency analysis of the approved models to identify new AC overloads and voltage violations.

The peak reliability hour of the Sidebar remained the same, however, the off peak reliability hour of Sidebar was determined to be November 11th at 0200hrs (the approved 2017 ITP10 off peak reliability hour following the scope was January 4th at 0500hrs). The difference in the off peak reliability hour was caused by the wind profile update which created a slight change in the wind total as percentage of the load.

Reliability Assessment Comparison and Discussion

SPP observed a reduced number of potential violations using the Sidebar powerflow models due to approved projects from the 2016 ITPNT as well as model corrections submitted during the 2017 ITP10 DPP window and wind profile updates. As a result, SPP saw five unique new facilities that resulted in potential violations. Some potential violations appeared in multiple Futures. Below is a list of unique facilities that were observed to be overloaded in the Sidebar models that did not show up during the ACCC for the needs assessment on the approved models. The list of potential overloads was also compared to the constraint list for the Sidebar models. A similar process was followed as described in the Invalidation of Select AC Thermal Violations section. The resulting potential thermal violations from the sidebar model are shown in Table 15.13.

Potential Thermal Violations from Sidebar Model	Area
MALONEY - SUTHERLAND 115KV CKT 1	NPPD
PAXTON- SUTHERLAND 115KV CKT 1	NPPD
WINNER - WITTEN 115KV CKT 1	WAPA
WITTEN 230/115 KV TRANSFORMER CKT 1	WAPA

Potential Thermal Violations from Sidebar Model	Area
NEOSHO 161/138 KV TRANSFORMER CKT 1	WERE

Table 15.13: Potential Thermal Violations from Sidebar Model

A total of 38 unique buses were identified as potential violations of SPP per unit voltage criteria in the AC contingency analysis on the Sidebar models that were not included in the original AC contingency analysis of the approved models. Seven of these buses were identified for voltage values that fell below the .90 per unit criteria. The other unique buses were identified for voltages that rose above the 1.05 per unit criteria. It is important to note, however, that no projects were included in any portfolio to address high voltage needs. Table 15.14 shows the seven unique buses where new potential violations were observed for low voltage conditions.

Potential Voltage Violations from Sidebar Model	Area
CAPLIS 138 KV	AEPW
SOUTH PLAINS REC-WOODDROW INTERCHANGE 115 KV	SPS
BROOKBANK 115 KV	WAPA
MOE 115 KV	WAPA
RATLAKE 115 KV	WAPA
WHITEEARTHTAP 115 KV	WAPA
DUNNING 115 KV	WAPA

Table 15.14: Potential Voltage Violations from Sidebar Model

Transmission Portfolio Impact

Table 15.15 and Table 15.16 show comparisons of one-year B/C ratios for each economic project individually within the Reduced Carbon and Reference Case portfolios. The tables include one -year B/C ratios from the 2017 ITP10 economic study model with model corrections and with wind profile updates to show the progression leading up to the one -year B/C ratios calculated using the Sidebar model. One-year B/C ratios equal to “NTC” or “MTEP” denotes that the economic project was assumed as a base assumption in the Sidebar economic model simulation.

Map Label	Project Description	ITP10 model 1-year B/C ratios with model corrections	ITP10 model 1-year B/C ratios with wind profile update	ITP10 Sidebar model 1-year B/C ratios
1	Build a new double circuit 115 kV line from Magic City to a point on the Logan - Mallard 115 kV line that minimizes the distance between the new substation and the cut-in point. Bisect the Logan - Mallard 115 kV line to cut-in the new double circuit 115 kV line.	10.1	7.2	MTEP
2	Rebuild 1.0 mile 115 kV line from Lawrence - Sioux Falls Upgrade terminal equipment at Lawrence and/or Sioux Falls to increase the rating of the line between the substations to 398/398 (SN/SE)	30.6	14.2	21.0
4	Upgrade any necessary terminal equipment at Kelly and/or Tecumseh to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 151 MVA.	12.4	1.3	0.8
6	Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line	31.5	6.1	7.3
7	Build a new second 230 kV line from Knoll to Post Rock.	16.2	9.6	9.3
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	1.6	16.8[49]	1.0
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	57.3	16.8	16.6

[49] The Butler to Altoona 138 kV terminal equipment upgrade was paired with the Neosho to Riverton 138 kV terminal equipment upgrade for the economic study model with the wind profile update to attain a one-year B/C greater than 0.9. Study work has shown that these two projects perform well when paired together

Map Label	Project Description	ITP10 model 1-year B/C ratios with model corrections	ITP10 model 1-year B/C ratios with wind profile update	ITP10 Sidebar model 1-year B/C ratios
12	Rebuild 2.1-mile 161 kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE)	2.8	1.8	5.7
13	Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	7.3	6.8	NTC
16	Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 138 kV line between the two substations to a summer and winter emergency rating of 169/201 MVA. Upgrade terminal equipment at Lula and/or Tupelo Tap to increase the rating of the line between the substations to 171/192 (SN/SE).	144.0	2.3	73.8
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	61.7	70.7	65.6
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	1.9	1.8	NTC
19	Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	2.4	2.1	NTC
20	Install a 345/161 kV transformer at Morgan substation	2.8	2.8	2.2

Map Label	Project Description	ITP10 model 1-year B/C ratios with model corrections	ITP10 model 1-year B/C ratios with wind profile update	ITP10 Sidebar model 1-year B/C ratios
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	1.7	1.3	NTC
22	Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	2.5	2.2	2.2

Table 15.15: Future 1 1-year B/C ratio comparisons

Map Label	Project Description	ITP10 model 1-year B/C ratios with model corrections	ITP10 model 1-year B/C ratios with wind profile update	ITP10 Sidebar model 1-year B/C ratios
5	Add 1 ohm Series reactor to Northeast - Charlotte 161 kV line	28.6	20.3	22.5
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	37.0	57.0[50]	41.9
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	140.8	57.0	156.2
13	Install one (1) 138 kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	7.8	8.0	NTC

[50] The Butler to Altoona 138 kV terminal equipment upgrade was paired with the Neosho to Riverton 138 kV terminal equipment upgrade for the economic study model with the wind profile update to attain a one-year B/C greater than 0.9. Study work has shown that these two projects perform well when paired together

Map Label	Project Description	ITP10 model 1-year B/C ratios with model corrections	ITP10 model 1-year B/C ratios with wind profile update	ITP10 Sidebar model 1-year B/C ratios
15	Rebuild 7.12-mile 115 kV transmission line from Hereford to DS#6 and upgrade any necessary equipment to increase the summer emergency rating to 240 MVA.	1.1	1.6	2.5
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	63.4	66.4	65.6
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	2.1	2.8	NTC
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	1.2	1.0	NTC
22	Rebuild 11.2-mile 138 kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	3.5	3.1	3.1

Table 15.16: Future 3 1-year B/C ratio comparisons

Conclusion

The economic and reliability assessment results of the Sidebar assessment were reviewed to identify any impactful changes in needs or individual project performance to determine target areas where focus should be given in adjusting the final consolidated portfolio recommendation. As a result of this review, SPP staff concluded that no significant adjustments to the final consolidated portfolio were warranted. Minor adjustments to the final portfolio recommendations are detailed in **Error! Reference source not found.**. SPP staff also identified specific new congested flowgates and reliability criteria violations as a direct result of the model updates, however, SPP staff does not believe that these new issues represent a risk of over or under stating the projected benefits from final recommended portfolio.

SECTION 16: PROJECT RECOMMENDATIONS

The project details that follow summarize 2025 system behavior both with and without each project, and which projects are included in the final portfolio recommendation. This section also includes details of the Additional Project Analysis and Sidebar analyses.

16.1: Economic Projects

Tuco - Stanton - Indiana - SP-Erskine 115 kV Terminal Upgrades

The transmission system flows in the Tuco area typically flow from North to South to serve a large local load. When the 230 kV line from Tuco to Carlisle is out of service, flows increase on the 115 kV system out of Tuco, creating severe congestion on the Stanton to Indiana 115 kV transmission line.[51] Generation in the area that can relieve the constraint has a high operational cost and would increase overall energy costs when dispatched. Upgrading the terminal equipment at Stanton, Tuco, Indiana, and SP-Erskine 115 kV provides more transmission capacity in the area at a relatively low cost and prevents congestion on the 115 kV system during the Tuco to Carlisle 230 kV transmission line outage.

The terminal equipment upgrades are included in the recommended portfolio. Congestion on the constraint in the Sidebar models was similar to the congestion in the 2017 ITP10 approved models, and because this flowgate currently experiences congestion in the SPP market, the recommended need date has been moved forward to 2017. The Stanton area terminal equipment upgrade project is number 17 in Figure 16.1.

[51] Needs 2017ITP10-E1N0004, 2017ITP10-E2N0001, and 2017ITP10-E3N0003

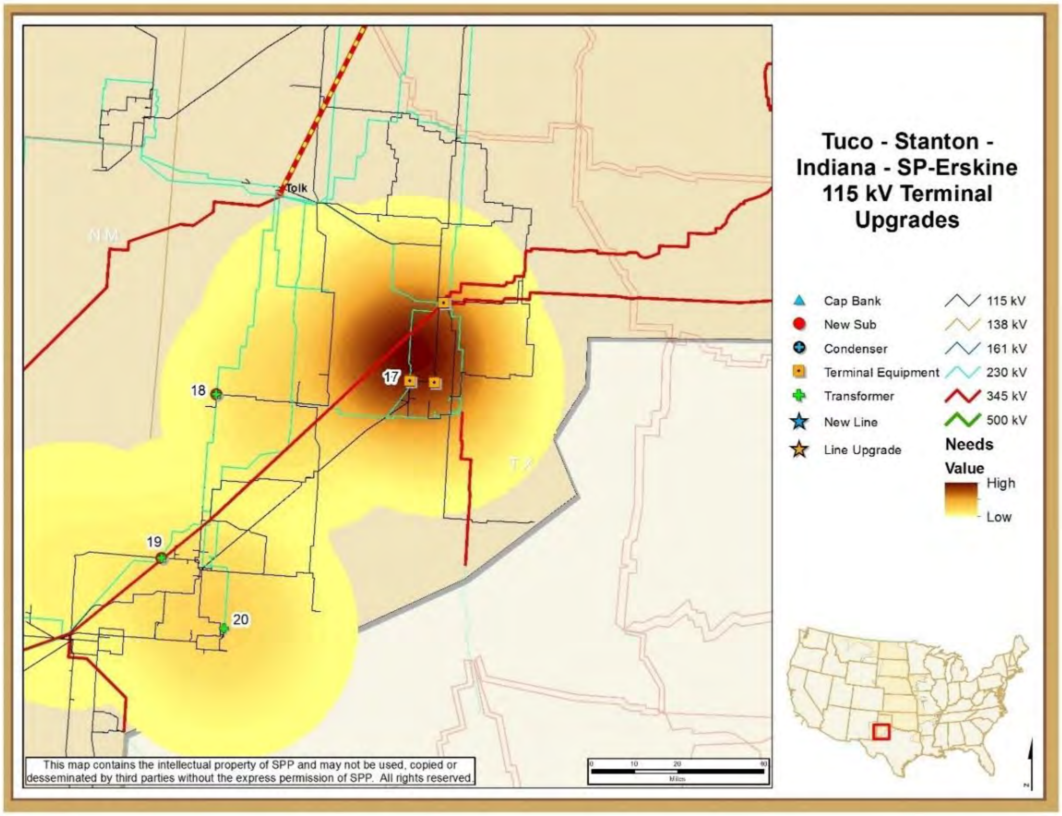

Figure 16.1: Tuco - Stanton - Indiana - SP-Erskine 115 kV Terminal Upgrades

Butler - Altoona 138 kV Terminal Upgrades

The EHV transmission system in southeast Kansas between Wichita to Joplin supports a fair amount of bulk power transfers from west to east. When the 345 kV line from Caney River to Neosho is out of service, the lower voltage system is utilized, causing congestion on the 138 kV line from Butler to Altoona.[52] Relieving generation, mostly gas, has a high dispatch cost, and constraining wind generation is being curtailed. Upgrading the Butler and Altoona terminal limits provides additional transmission capacity at a relatively low cost and prevents congestion on the transmission line from Butler to Altoona during the Caney River to Neosho 345 kV transmission line outage.

[52] Needs 2017ITP10-E1N0006, 2017ITP10-E2N0010, and 2017ITP10-E3N0006

This project is included in the final recommended portfolio. The project performs well in both the Reduced Carbon and Reference Case portfolios, and works well in conjunction with alleviation of the Neosho to Riverton 161 kV constraint. Congestion on the constraint in the Sidebar models was similar to the congestion in the 2017 ITP10 approved models, and because this flowgate currently experiences congestion in the SPP market, the recommended need date has been moved forward to 2017. The Butler and Altoona terminal equipment upgrade project is number 8 in Figure 16.2.

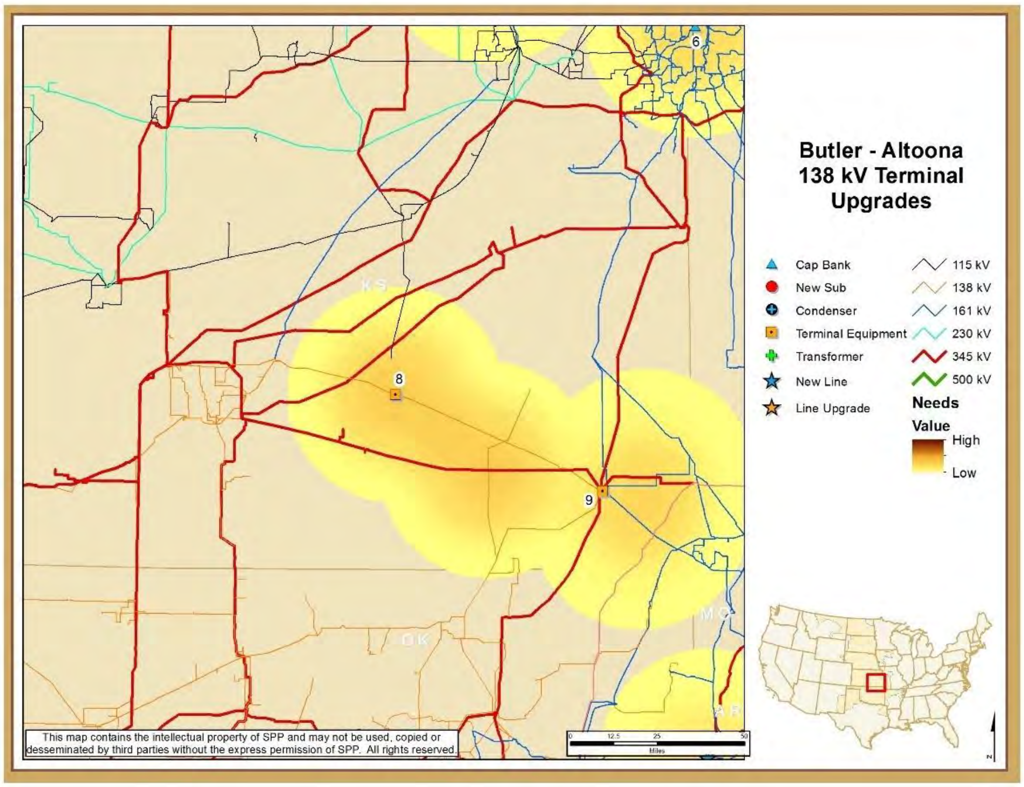

Figure 16.2: Butler - Altoona 138 kV Terminal Upgrades

Neosho - Riverton 161 kV Terminal Upgrades

The Neosho area in Kansas is a crossing point between west to east and north to south flows in the SPP System. When the 345 kV line from Blackberry to Neosho is out of service, the flow on the 161 kV line from Neosho to Riverton[53] increases. Relieving generation is maximizing its output to reduce

[53] Needs 2017ITP10-E1N0016 and 2017ITP10-E3N0008

congestion, and the constraining wind generation at Caney River is being curtailed. Upgrading the terminal limits at Neosho and Riverton increases transmission capacity at a relatively low cost and prevents congestion on the transmission line from Neosho to Riverton during the Blackberry to Neosho 345 kV transmission line outage.

This project is included in the final recommended portfolio. The project performs well in both the Reduced Carbon and Reference Case portfolios, and congestion on the constraint in the Sidebar models was similar to the congestion in the 2017 ITP10 approved models. Because this flowgate currently experiences congestion in the SPP market, the recommended need date has been moved forward to 2017. The Neosho and Riverton terminal equipment upgrade project is number 9 in Figure 16.3.

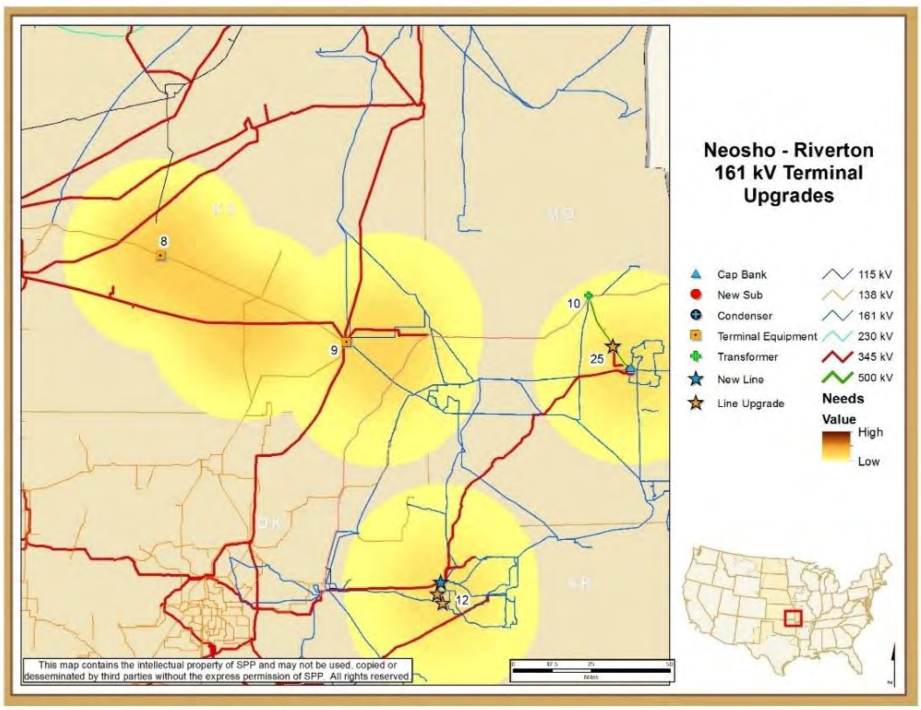

Figure 16.3: Neosho - Riverton 161 kV Terminal Upgrades

South Shreveport - Wallace Lake 138 kV Rebuild

The area of Shreveport, Louisiana, experiences west to east flows that serve a number of loads along a 138 kV transmission loop. When the 138 kV line from Fort Humbug to Trichel is out of service, the northern end of the loop is segmented, diverting flow to the southern portion of the loop and causing congestion on to the 138 kV transmission line from Shreveport to Wallace Lake.[54] Rebuilding the Shreveport to Wallace Lake 138 kV transmission line to a higher rating allows those flows to redirect without causing congestion.

This project is not included in the final recommended portfolio. A contributing factor to this need is a significant projected increase in industrial load in the area, which may require a modification to an existing delivery point. As a result, this load increase should be studied consistent with Attachment AQ of the SPP Tariff. The South Shreveport to Wallace Lake rebuild project is number 22 in Figure 16.4.

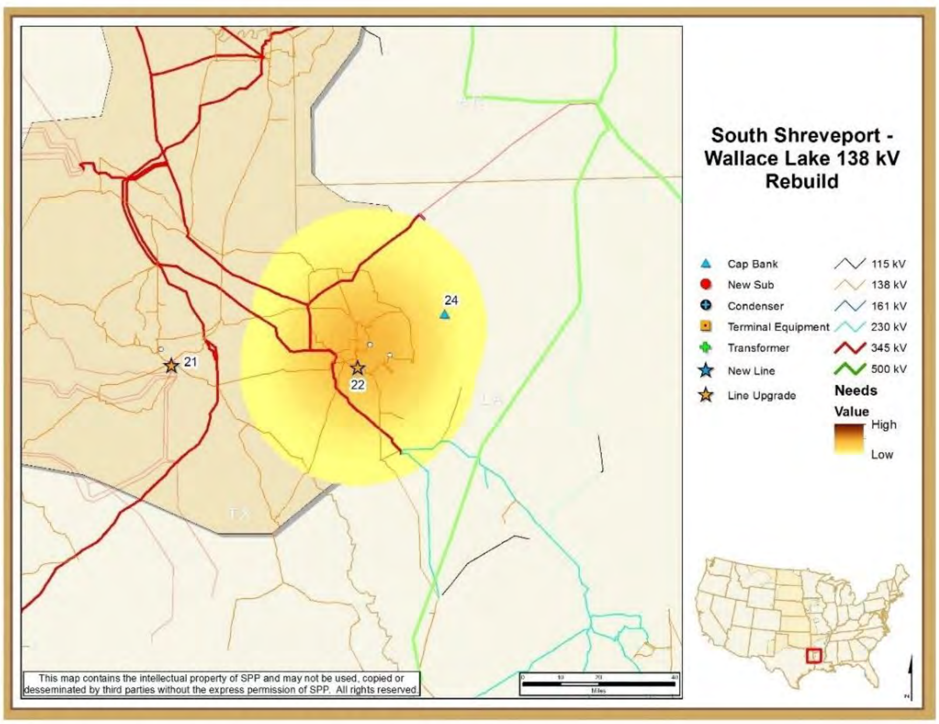

Figure 16.4: South Shreveport - Wallace Lake 138 kV Rebuild

[54] Needs 2017ITP10-E1N0008, 2017ITP10-E2N0007, and 2017ITP10-E3N0004

Knoll - Post Rock 230 kV New Line

A network of load in northwest Kansas is partially sourced by the EHV hub north of Hays, Kansas. When the 230 kV line from Knoll to Post Rock is out of service, power reroutes to the 115 kV path south of Hays. This increases south to north flow on the system causing congestion on the 115 kV line from Vine Tap to North Hays.[55] The generation at Goodman Energy Center provides some congestion relief, but other available relieving generation would increase overall energy costs. Building a short second 230 kV circuit from Post Rock to Knoll parallels the existing outage and allows the load to the northwest to be served from north of Hays for the outage of the existing circuit, bypassing the limiting 115 kV path south near the city.

This project is included in the final recommended portfolio. Although this constraint was not identified as a need in Future 3, the project performs well in both the Reduced Carbon and Reference Case portfolios, and the congestion on the constraint in the Sidebar model was similar to the congestion in the 2017 ITP10 approved models. Because this flowgate currently experiences congestion in the SPP market, the recommended need date has been moved forward to 2017. The Knoll to Post Rock second circuit project is number 7 in Figure 16.5.

[55] Needs 2017ITP10-E1N0010 and 2017ITP10-E2N0009

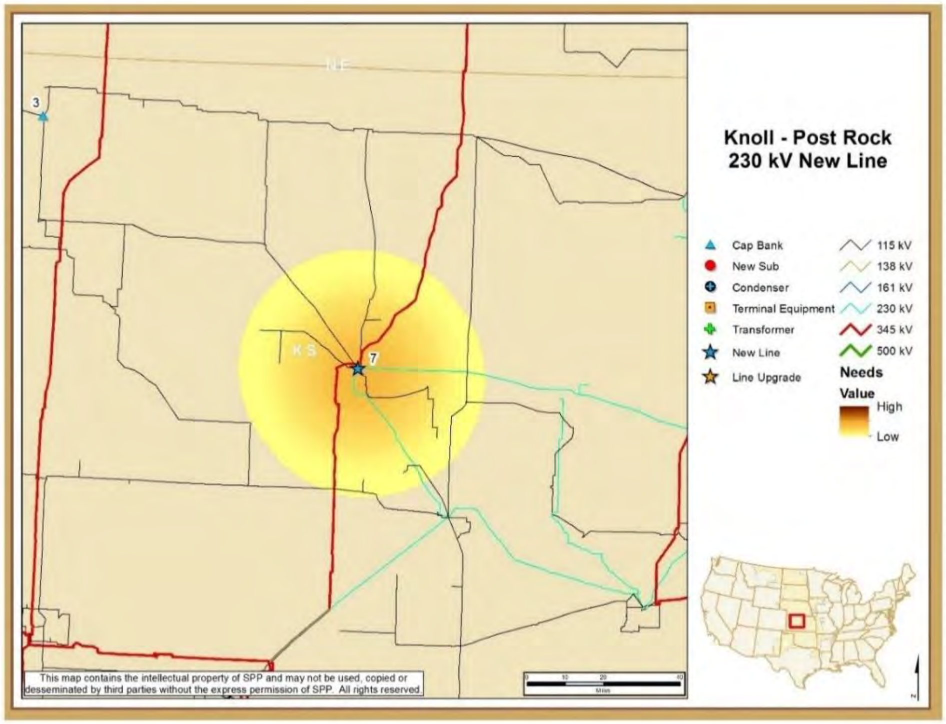

Figure 16.5: Knoll - Post Rock 230 kV New Line

Kelly - Tecumseh 161 kV Terminal Upgrades

Inexpensive base load and renewable generation in the north flows south into Kansas. These flows increase with the modeling assumptions of Future 1 and create a unique combination of increased renewables in the north, continued base load generation from the north, and more expensive (and retired) coal generation in Kansas in Oklahoma. When the 161/115 kV transformer at Kelly is out of service, flows are unable to disperse directly to the 115 kV system in northern Kansas causing congestion on the 161 kV line from Kelly to Tecumseh.[56] Upgrading the terminal limits at Kelly and Tecumseh Hill provides additional transmission capacity at a low cost and prevents congestion on the 161 kV line.

This project is not included in the final recommended portfolio. The project performs well in the Future 1 2017 ITP10 approved model, but congestion on the constraint in the Sidebar model is reduced

[56] Need 2017ITP10-E1N0011

by 50%. While this project would aid in mitigating current market congestion, it would not eliminate the need for system reconfigurations currently implemented by SPP operations. Also, the Nebraska City to Sibley 345 kV transmission line project is expected to aid in mitigating current market congestion in the area. The Kelly and Tecumseh Hill terminal upgrade project is number 4 in Figure 16.6.

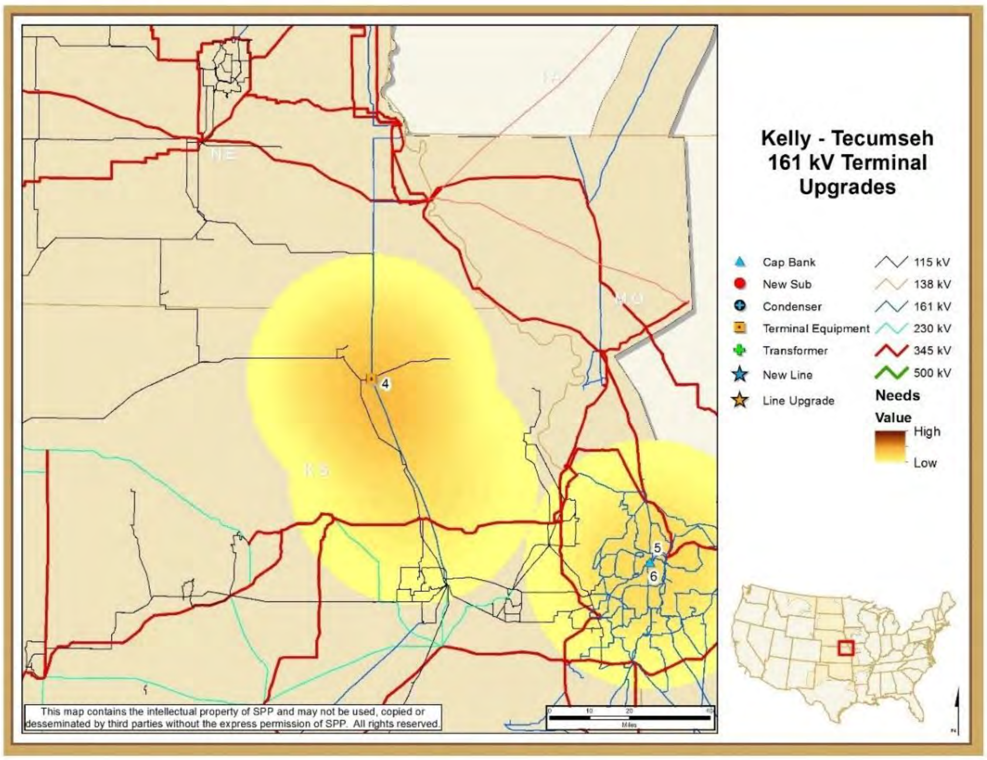

Figure 16.6: Kelly - Tecumseh 161 kV Terminal Upgrades

Magic City – Logan/Mallard 115 kV New Double Circuit Line

In central northern North Dakota, much of the load is served by coal units south of the area. The 230 kV system thins out from south to north, leaving two 230 kV inlets to the 115 kV system. When the eastern Balta to Rugby 230 kV line supplying this region is outaged, congestion is created on the McHenry to Voltair line. The McHenry 230/115 kV transformer also binds under system intact conditions.[57] Almost all of the generation north of the constraint to help relieve the congestion is non-dispatchable renewables, calling for a shunt to the power flowing on this path. Independent of this study, Basin Electric Power Cooperatives and Xcel Energy approved a project that partially addresses the needs in the area. The Xcel portion of the project entailed tapping the existing 115 kV line from Velva Tap to Souris at a new substation with transformation to 230 kV, a new 230 kV line from McHenry to this new substation. The Basin portion of the project entailed a new 115 kV line from the new substation to the existing Logan to Mallard 115 kV line. The complete project diverts the flow at the McHenry station, but only mitigates some of the congestion in the area

This project is not included in the final recommended portfolio. Although this project was beneficial in the Reduced Carbon portfolio, a large driver for this project was proxy resource plan wind units added for MISO in the carbon constrained Futures. Also, the APC benefit in Future 3 was negative and this was not a significant operational issue, so the recommendation excludes this project. The Magic City to Logan/Mallard project is number 1 in Figure 16.7.

[57] Needs 2017ITP10-E1N0005/2017ITP10-E2N0002 and 2017ITP10-E1N0013/ 2017ITP10-E2N0008

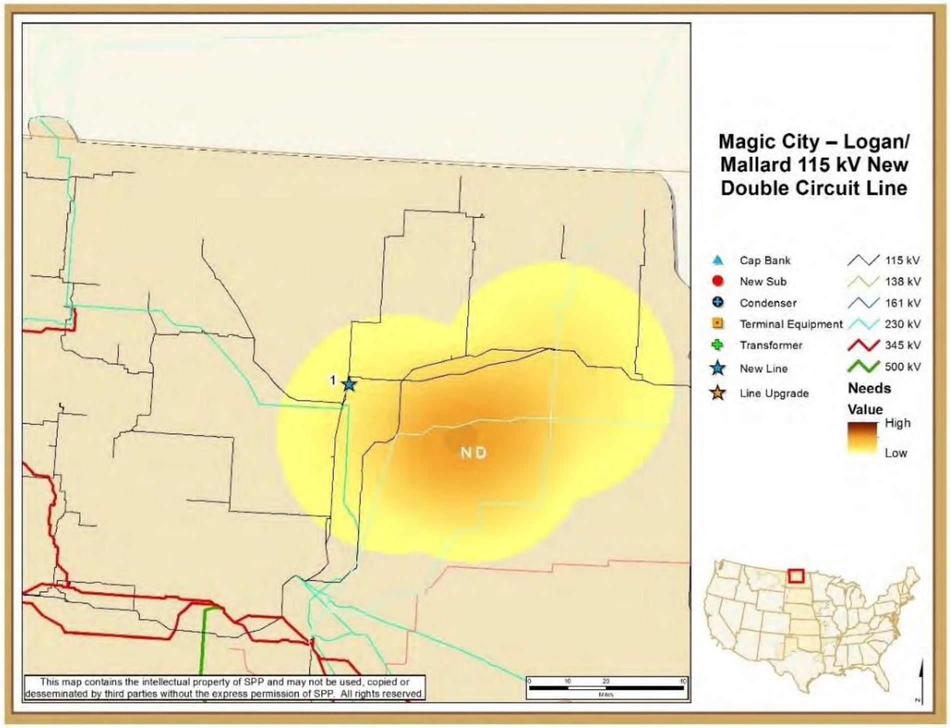

Figure 16.7: Magic City – Logan/Mallard 115 kV New Double Circuit Line

Woodward 138 kV PST

This project has an NTC that was issued from the Generation Interconnection (GI) process after the brightline date for ITP10 model topology updates. The 2017 ITP10 analysis supports the need for the project. The Woodward-Windfarm 138 kV line for the loss of Woodward 138/69 kV transformer constraint was an economic need in all three Futures, and is very similar to the Woodward to Windfarm 138 kV for the loss of Tatonga to Northwest 345 kV need that was the most congested flowgate in SPP in 2015, based on the 2015 ASOM Report.

The installation of the 138 kV phase shifting transformer (PST) at Woodward alleviates congestion on the 138 kV system that is driven by significant wind in the Woodward area. Wind energy throughout the Woodward area flows through the two 138 kV circuits connecting Woodward and Woodward. The PST acts to redirect flows outside of this Woodward area 138 kV path, without the need for any generation dispatch. This results in significant APC benefit.

The 138 kV Woodward PST project performs well in all three Futures, helps to relieve a top congested flowgate, and was recently issued an NTC through the GI process in 2016. This project is being included in the final recommended portfolio with the recommendation that the NTC remain with the existing need date in 2017. The Woodward PST project is number 13 in Figure 16.8.

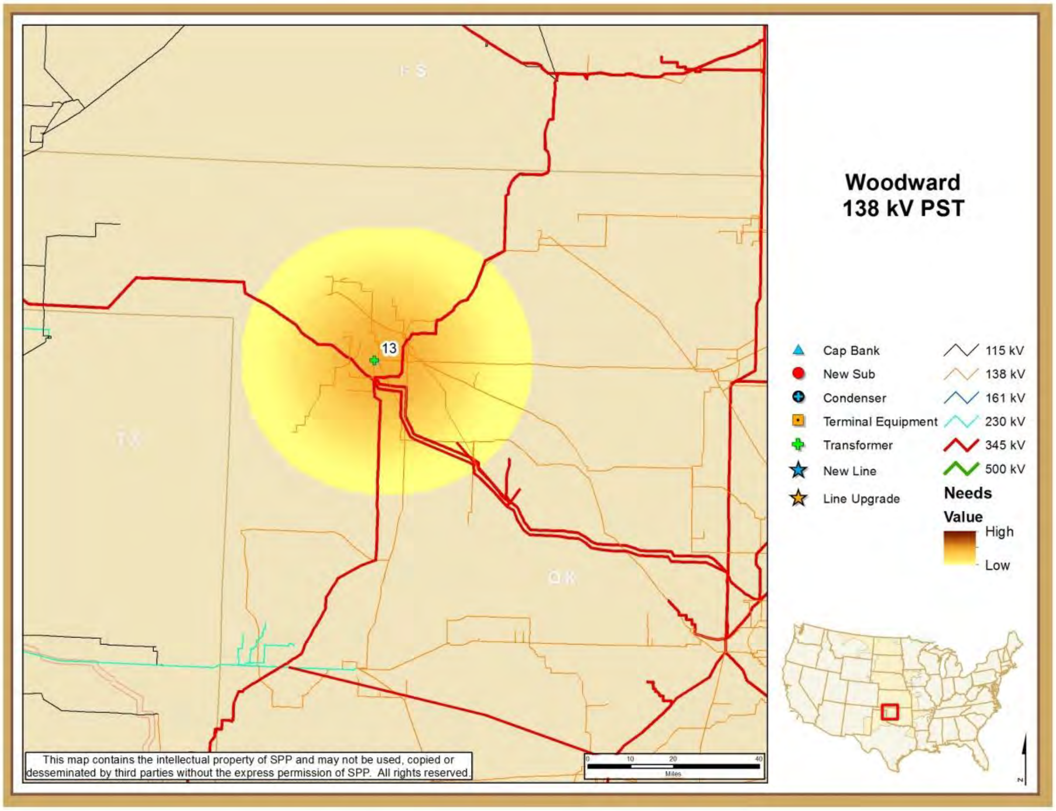

Figure 16.8: Woodward 138 kV PST

Northeast - Charlotte 161 kV Series Reactor

The Kansas City area experiences heavy bulk power transfers from north to south. The 161 kV system experiences the effect of these transfers. When the 161 kV line from Northeast to Grand Avenue West is out of service, the flow on the 161 kV line from Northeast to Charlotte increases and becomes congested with the future load that is planned to be located on the south end of the constraint at Charlotte.[58] Installing a reactor on the Northeast to Charlotte 161 kV transmission line provides additional impedance needed in the area to redirect flows away from the Northeast to Charlotte 161 kV transmission line. This low cost solution provides significant congestion relief on the 161 kV system that represents part of the underground transmission system in Kansas City.

[58] 2017ITP10-E1N0017, 2017ITP10-E2N0017, and 2017ITP10-E3N0013

Two different size reactors were identified in the Reduced Carbon and Reference Case portfolios: a 2 ohm reactor for Futures 1 and 2 and a 1 ohm reactor for Future 3. Both sizes perform similarly in each portfolio. While the 1 ohm series reactor appears to have a better B/C ratio, it does not alleviate all congestion on the Northeast to Charlotte 161 kV transmission line, therefore, the 2 ohm series reactor project is included in the final recommended portfolio. The constraint congestion in the Sidebar model was an average of 20 percent lower than the congestion in the 2017 ITP10 approved models, but the project still performs well in both the Reduced Carbon and Reference Case portfolios. The recommended need date for this project has been moved to 2018 because the load driving the increase in congestion in the area is expected to be in service in 2018. The Northeast to Charlotte series reactor project is number 6 in Figure 16.9.

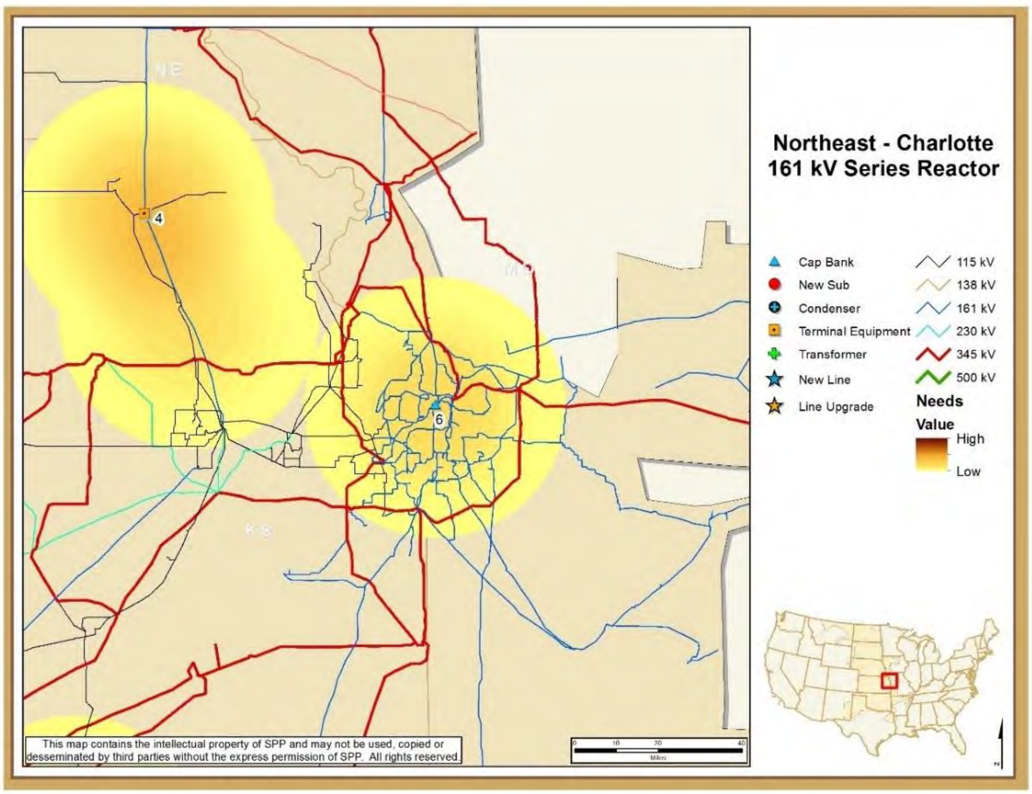

Figure 16.9: Northeast - Charlotte 161 kV Series Reactor

Tolk/Yoakum – Cochran/Lehman Tap and 230/115 kV Transformer

In the south part of the Texas panhandle, much of the load on the 69 kV and 115 kV systems are served through the Sundown and Lamb County 230/115 kV transformers. When the 115 kV inlet to this load at Lamb County is outaged, congestion is created on the Sundown transformer.[59] The new 230/115 kV substation at a tap of the Tolk to Yoakum 230 kV line and the Cochran to Lehman 115 kV line provides another source to this load.

This project has an NTC issued from the 2016 ITPNT study. The 2017 ITP10 analysis supports the need for the project with no changes to the current need date in 2018. The Tolk to Yoakum project is number 18 in

Figure *16.10.*

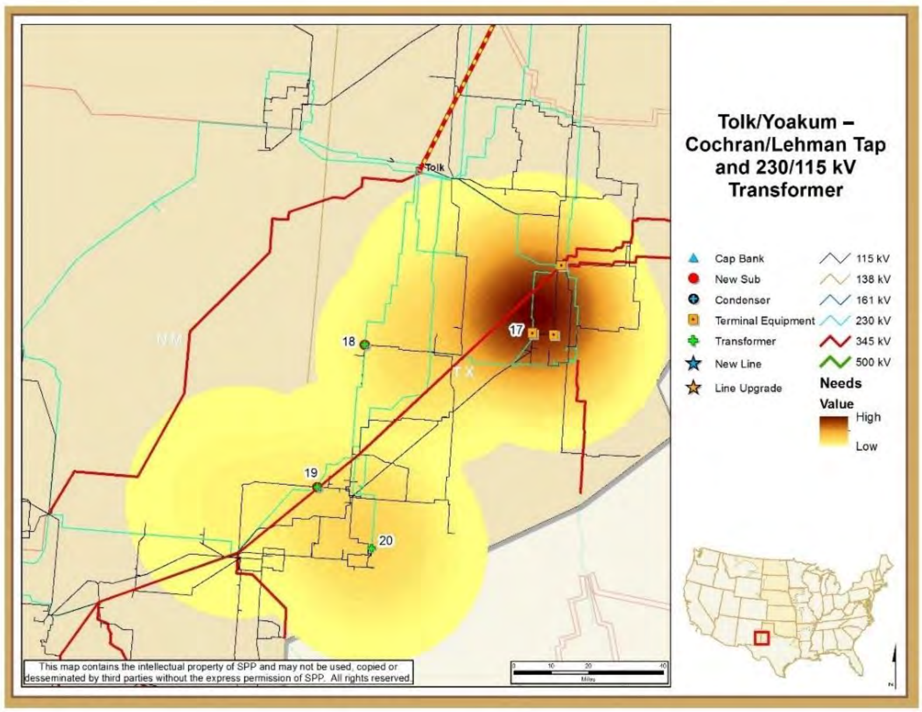

Figure 16.10: Tolk/Yoakum – Cochran/Lehman Tap and 230/115 kV Transformer

[59] Needs 2017ITP10-E1N0018, 2017ITP10-E2N0018, and 2017ITP10-E3N0010

Seminole 230/115 kV Double Transformer Replacement

There are two 230/115 kV transformers at Seminole that serve load to the south of the substation. When the second transformer is out of service, the first transformer becomes congested.[60] Although both transformers have the same rating, the impedance on the first transformer is greater than the second, which causes less flow on the first transformer. Relieving generation in the area is expensive to operate or is expected to be retired for this study. Replacing both existing transformers allows one transformer to carry the load for the loss of the other transformer.

This project has and NTC issued from the 2016 ITPNT study. The 2017 ITP10 analysis supports the need for the project with no changes to the current need date in 2017. The Seminole transformers upgrade project is number 20 in Figure 16.11 below.

[60] Needs 2017ITP10-E1N0019, 2017ITP10-E2N0016, and 2017ITP10-E3N0012

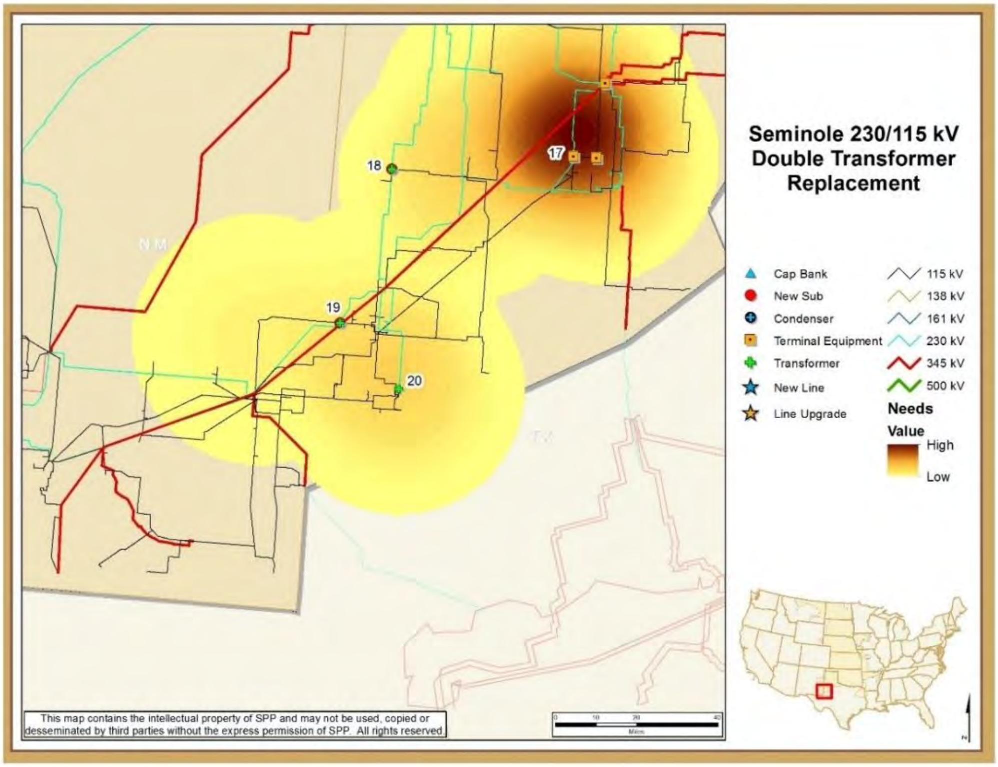

Figure 16.11: Seminole 230/115 kV Double Transformer Replacement

Siloam Springs – Siloam Springs City 161 kV Rebuild

When the Flint Creek to Tonnece 345 kV transmission line is out of service, the flows transfer to the 161 kV transmission system causing congestion on the line from Siloam Springs City to Siloam Springs.[61] Relieving generation is the area is running at maximum capacity, and generation congesting the flowgate has a low operational cost. Rebuilding the Siloam Springs to Siloam Springs City 161 kV transmission line provides the additional transmission capacity needed to alleviate congestion.

This project is included in the final portfolio recommendation. The congestion on the constraint was 10 percent higher in the Sidebar model than the congestion in the 2017 ITP10 approved models. Although this constraint is not a need in Future 3, the project performs well in both the Reduced Carbon and Reference Case portfolios. Since this flowgate currently experiences congestion in the SPP

[61] Needs 2017ITP10-E1N0020 and 2017ITP10-E2N0022

market, the recommended need date has been moved to 2017. The Siloam Springs to Siloam Springs City rebuild project is number 12 in Figure 16.12.

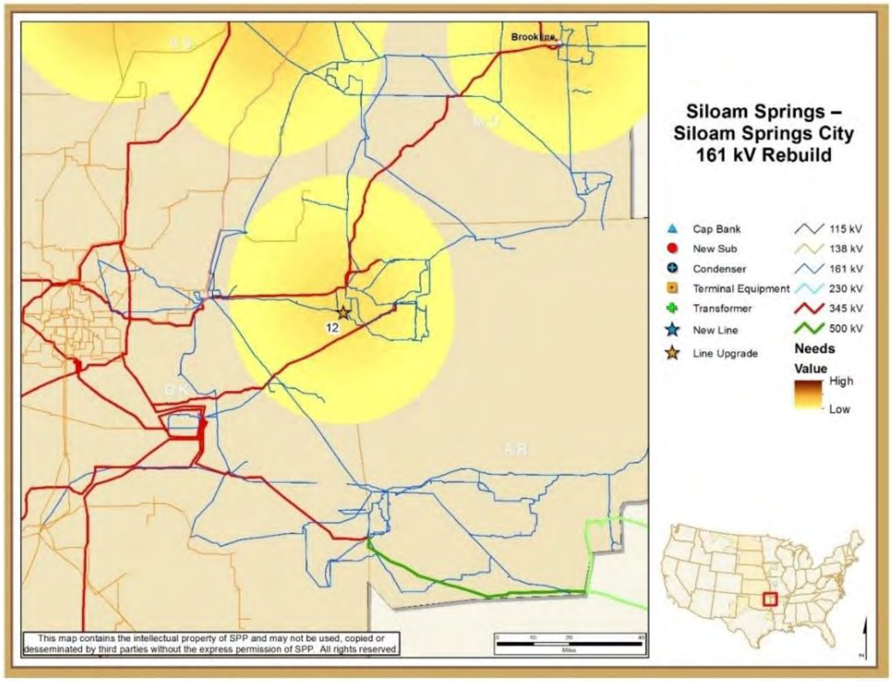

Figure 16.12: Siloam Springs – Siloam Springs City 161 kV Rebuild

Hobbs/Yoakum – Allred/Waits Tap and 230/115 kV Transformer

Base condition flows in the southwest Texas panhandle flows east to west from West Sub 3 to Lovington to serve the load on the Lovington substation. Losing West Sub 3 to Lovington[62] causes a need for power in the east to serve this load, which is on a series path from Denver to Shell to Shell Tap to Allred Tap to Waits to Lovington. This series line has load at Shell C2, which reduces the amount of flow on the rest of the series branch, keeping downstream elements from overloading. Relieving generation has a high operational cost or is assumed to be retired in this study, and negatively impacting generation has a low operational cost. Tapping the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits and installing a 230/115 kV transformer

[62] Need 2017ITP10-E1N0021

at the new Hobbs-Yoakum Tap substation provides another source to serve the load at Lovington, and relieves the reliability issues in the area.

This project has an NTC issued from the 2016 ITPNT study. The 2017 ITP10 analysis supports the need for the project with no changes to the current need date in 2017. This project is number 19 in Figure 16.13.

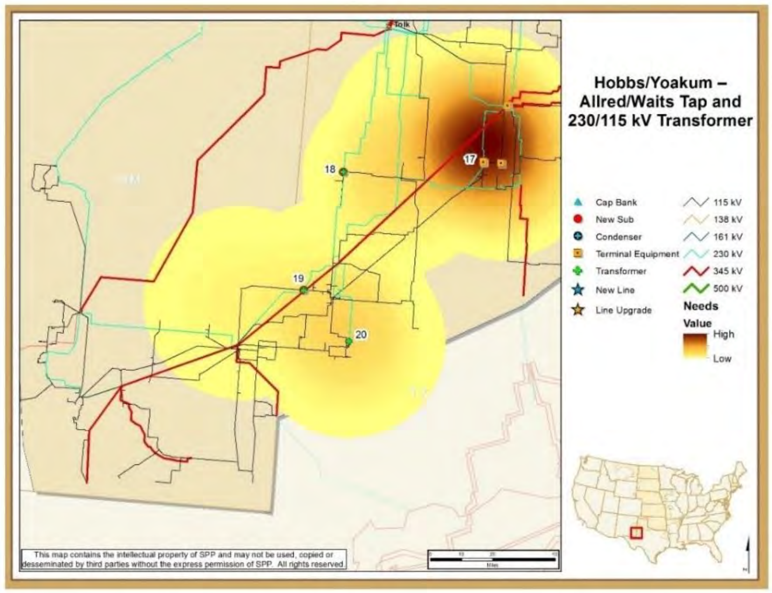

Figure 16.13: Hobbs/Yoakum – Allred/Waits Tap and 230/115 kV Transformer

Lawrence – Sioux Falls 115kV Rebuild

In the Sioux Falls area in southeastern South Dakota, power coming in from the west comes mainly through the Sioux Falls station. Power coming in from the east is generally coming into the Split Rock station. The 230 kV line connecting the two stations generally allows the west to be easily served by east power and vice versa. With this line outaged, the power must flow on the 115 kV system from the Split Rock station south around the city to the Lawrence station and back north to Sioux Falls, creating congestion on the Lawrence to Sioux Falls line.[63] This line is rated lower than others in the area and a rebuild of the line is projected to be the most economic solution to resolve the congestion.

[63] Needs 2017ITP10-E1N0023 and 2017ITP10-E2N0019

This project is not included in the final portfolio recommendation. A large driver for the benefit in Futures 1 and 2 are the additional proxy resource plan wind units for MISO to the east of the city. The Lawrence to Sioux Falls rebuild project is number 2 in Figure 16.14.

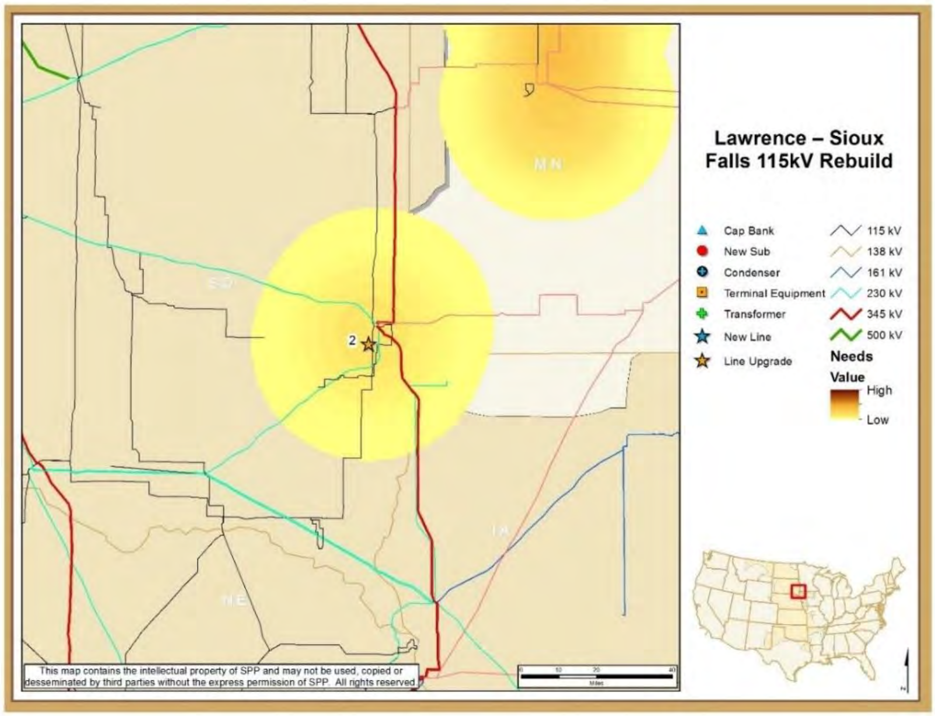

Figure *16.14*: Lawrence – Sioux Falls 115kV Rebuild Project**Tupelo – Tupelo Tap – Lula 138 kV Terminal Upgrades**

The wind in south Oklahoma causes large west to east flows in the SPP region. When the Pittsburg to Valiant 345 kV transmission line is out of service, the west to east flows from Oklahoma City to north Texas cause congestion on the 138 kV transmission line from Tupelo Tap to Tupelo.[64] Replacing terminal equipment at Tupelo, Tupelo Tap, and Lula 138 kV creates additional transmission capacity at a relatively low cost and prevents congestion on the line from Tupelo to Tupelo Tap.

This project is included in the final portfolio recommendation, with a need date in 2020. Although this constraint is not a need in Future 3, the project exceeds the B/C threshold criteria in both the Reduced

[64] Needs 2017ITP10-E1N0012, 2017ITP10-E2N0015 and 2017ITP10-E3N0014

Carbon and Reference Case portfolios. The congestion on the constraint in the Sidebar model was an average of 20 percent lower than the congestion in the 2017 ITP10 approved models, but the project performance in both portfolios justifies the need for the project. The Tupelo area terminal equipment upgrade project is number 16 in Figure 16.15.

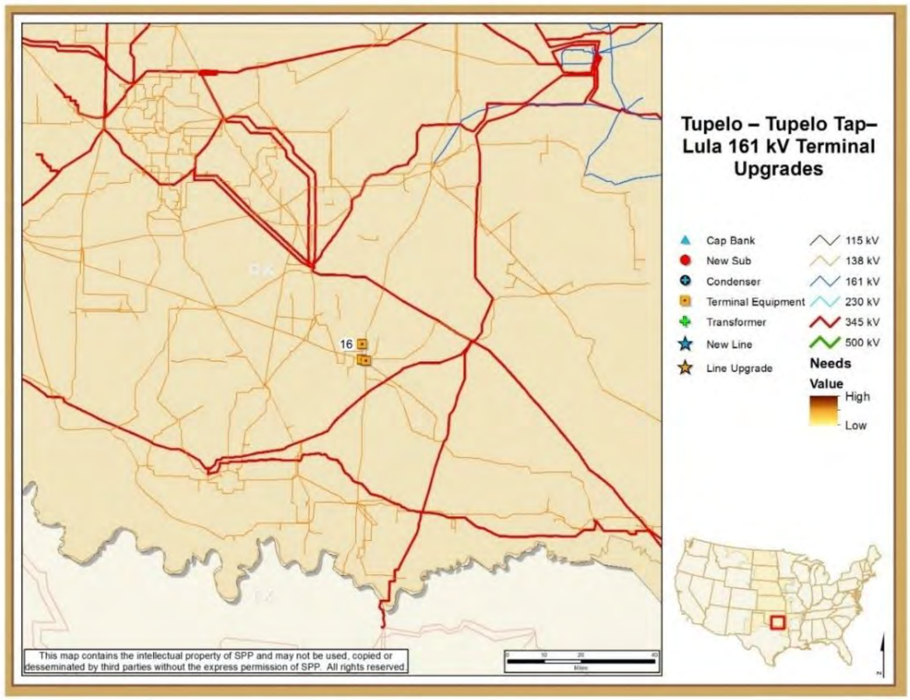

Figure 16.15: Tupelo – Tupelo Tap – Lula 138 kV Terminal Upgrades

Hereford – DS#6 115 kV Rebuild

In the Texas panhandle, power flows from the generation heavy north to the load heavy south. In the center of this area is a set of three 230 kV lines and two 115 kV corridors isolating the south from the north (including the remainder of the Eastern Interconnect). These five lines make up the SPS North South stability interface. When the Deaf Smith to Plant X 230 kV line is outaged, Hereford to DS #6[65] binds. The rebuild of this segment arose as the most economic project to solve this economic need.

[65] Need 2017ITP10-E3N0009

This project is not included in the final portfolio recommendation. Through consideration of operational processes to address this need and other additional analyses detailed in Section 15.2: of this report, the Potter to Tolk 345 kV line is recommended in place of this project, with a need date in 2017. The Potter to Tolk recommended alternative project is represented in Figure 16.16.

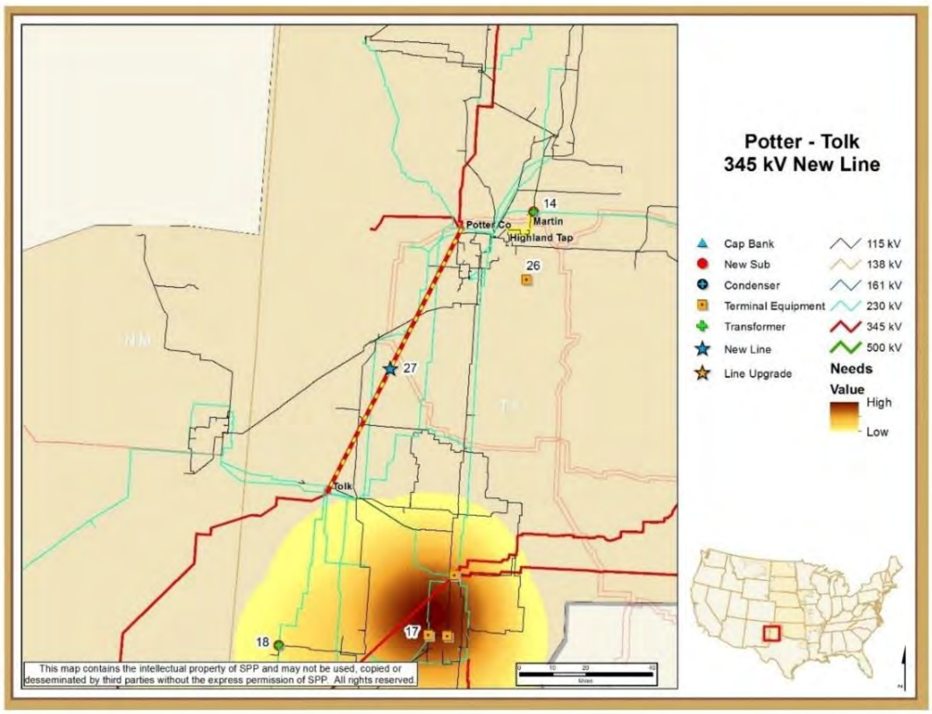

Figure 16.16: Potter – Tolk 345 kV New Line

Morgan 345/161 kV Transformer

When one of the 345/161 kV transformers at Brookline[66] is out of service, the other transformer at the Brookline substation binds. There is limited amount of impactful generation to relieve the constraint. This area in Missouri is greatly impacted by the coal retirements in Future 1. Installing a transformer at the Morgan substation provides relief on the Brookline substation for the loss of one of its transformers.

[66] Need 2017ITP10-E1N0022

This project is not included in the final portfolio recommendation. Through consideration of operational processes to address this need and other additional analyses detailed in Section 15.2: of this report, a modification of the Morgan project that consists of an up-rate of the Brookline to Morgan 161 kV transmission line in addition to the 345/161 kV transformer at Morgan is recommended in place of this project, with a need date in 2017. The Morgan transformer with line uprate recommended alternative project is represented in Figure 16.177.

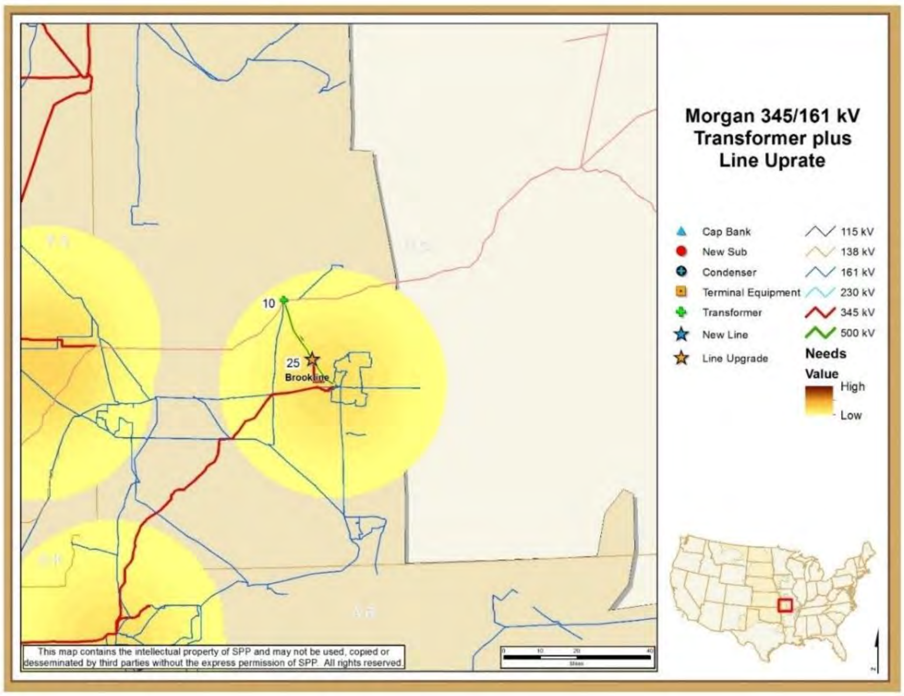

Figure 16.17: Morgan 345/161 kV Transformer plus Line Uprate

16.2: Reliability Projects

Knox Lee - Texas Eastman 138 kV Rebuild

An overload of the Knox Lee to Texas Eastman 138 kV line was included in the 2017 ITP10 needs assessment. This constraint did not meet the requirements in the approved constraint assessment criteria. Once the overloads were observed in the needs assessment this line was added to the constraint list to determine its impact in the Sidebar models. The flowgate was not congested in the Sidebar models, invalidating this constraint as a reliability need. This project is not included in the final portfolio recommendation. The Knox Lee to Texas Eastman rebuild project is number 21 in Figure 16.188.

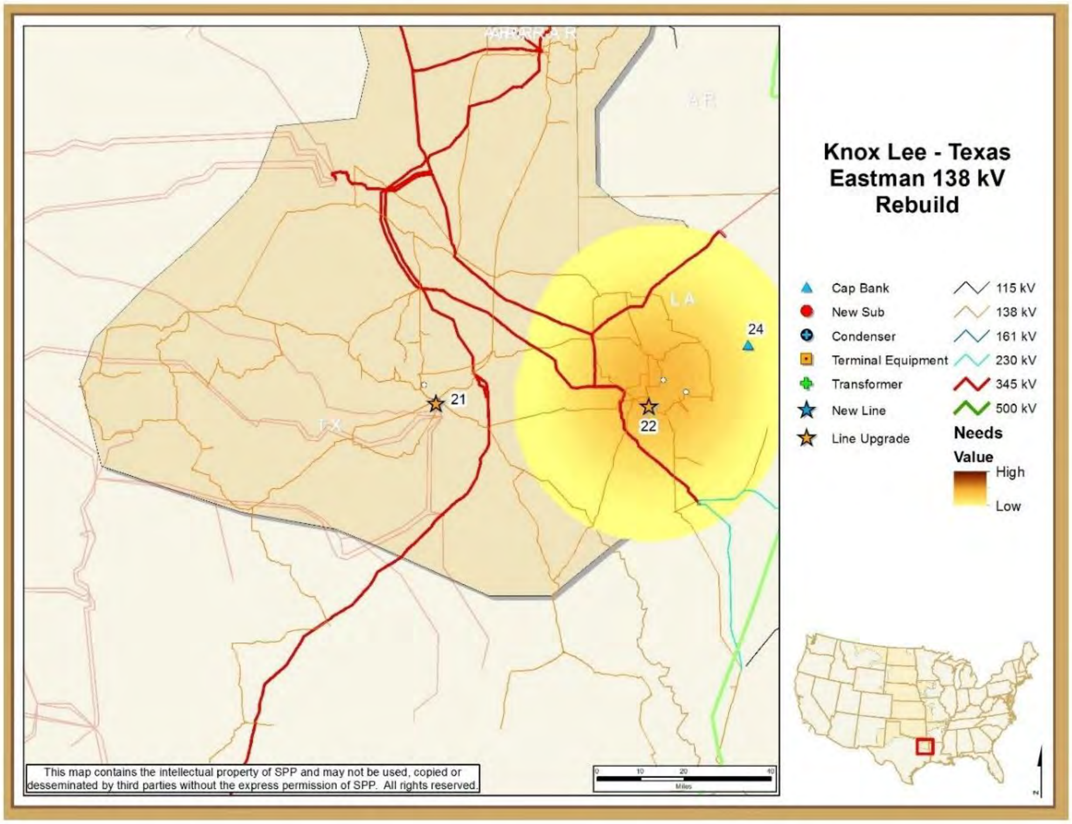

Figure 16.188: Knox Lee - Texas Eastman 138 kV Rebuild

Port Robson 138 kV Capacitor Bank

The need for the capacitor bank is driven mainly by a large industrial load in the area. The load is served by two transmission lines. When one of the lines is lost, the load is served radially causing the voltage to drop below SPP's voltage criteria limit of .90 per unit. A contributing factor to this need is a significant projected increase in industrial load in the area, which may require a modification to an existing delivery point. As a result, this load increase should be studied consistent with Attachment AQ of the SPP Tariff. The Port Robson capacitor bank project is number 24 in Figure 16.19.

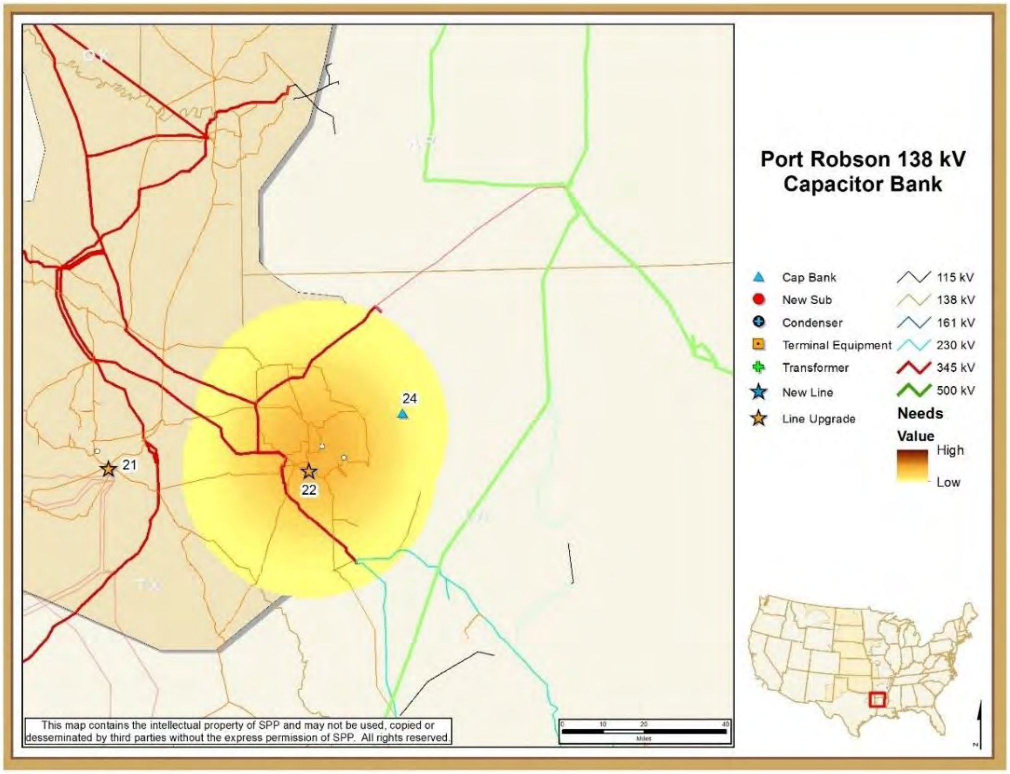

Figure 16.19: Port Robson 138 kV Capacitor Bank

Atwood – Seguin Tap 115 kV Capacitor Banks

Because the low voltage appears at the Colby substation, the Colby station would be the best location for the capacitor bank to be placed. However, placing any cap banks at the Colby 115 kV bus would be cost-prohibitive. Locating the capacitor banks at Atwood and Seguin Tap resolve the low voltage issues. In Futures 2 and 3 voltage values observed for the same contingency were similar to the Future 1 voltage value, but did not cross the threshold for inclusion in the needs assessment.

This project is not included in the final portfolio recommendation. Under contingency situations in the Future 1 approved model, a large load at the Colby substation is served radially causing the voltage in the area to fall below the threshold. Under the same contingency conditions in the Sidebar models, the per unit voltage at Colby 115 kV does not fall below the .90 per unit threshold in any of the three Futures. The Atwood and Sequin Tap capacitor bank project is number 3 in Figure 16.190.

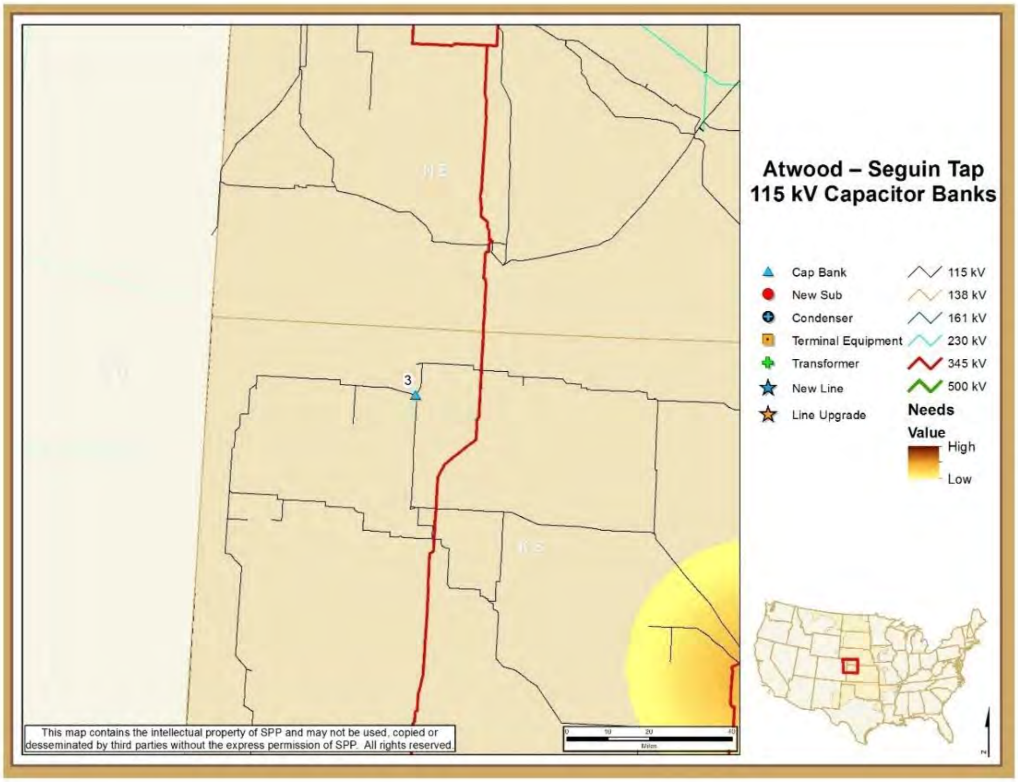

Figure 16.190: Atwood – Seguin Tap 115 kV Capacitor Banks

Nichols/Grapevine – Martin Tap and 230/115 kV Transformer

This project is not included in the final recommended portfolio. In the sidebar models, a constraint was added to the economic assessment to determine if the need should be reliability or economic. The congestion scores from the sidebar models on Pantex South to Highland Tap 115 kV transmission line for the loss of the Martin to Hutchinson 115 kV transmission line meets the economic needs criteria. Therefore, the need was reclassified from reliability to economic, and an alternate project is recommended to upgrade terminal equipment on the Pantex South to Highland Tap 115 kV and Pantex North to Martin 115 kV line at a relatively low cost which provides significant congestion relief. Because this flowgate currently experiences congestion in the SPP market[67] the recommended

[67] A Remedial Action Scheme (RAS) has also been proposed in the area due to current operational curtailments.

need date has been moved forward to 2017. The Pantex area terminal upgrades project is represented in **Error! Reference source not found.**1.

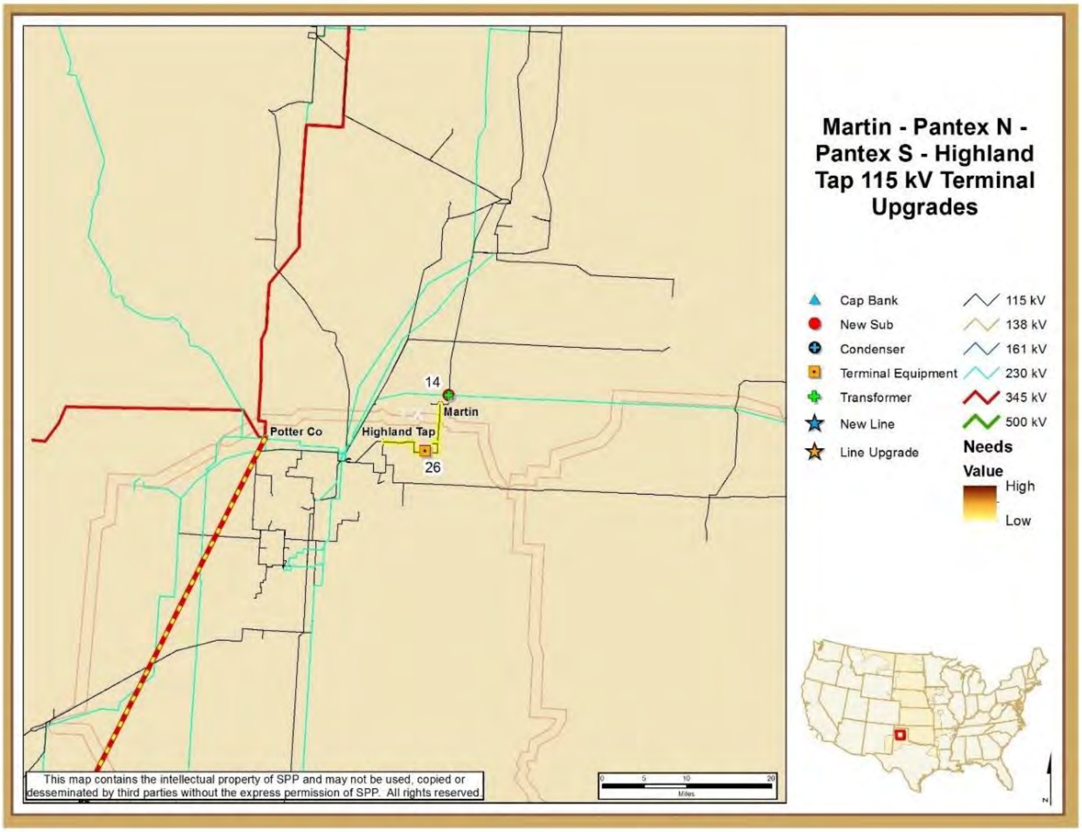

Figure 16.201: Martin – Pantex N – Pantex S – Highland Tap 115 kV Terminal Upgrades

16.3: Recommended Portfolio Summary

The recommended portfolio, including reliability and economic projects, is shown in Figure 16.212. It consists of 14 projects and approximately 93 miles of transmission line. The total cost is $201 million.

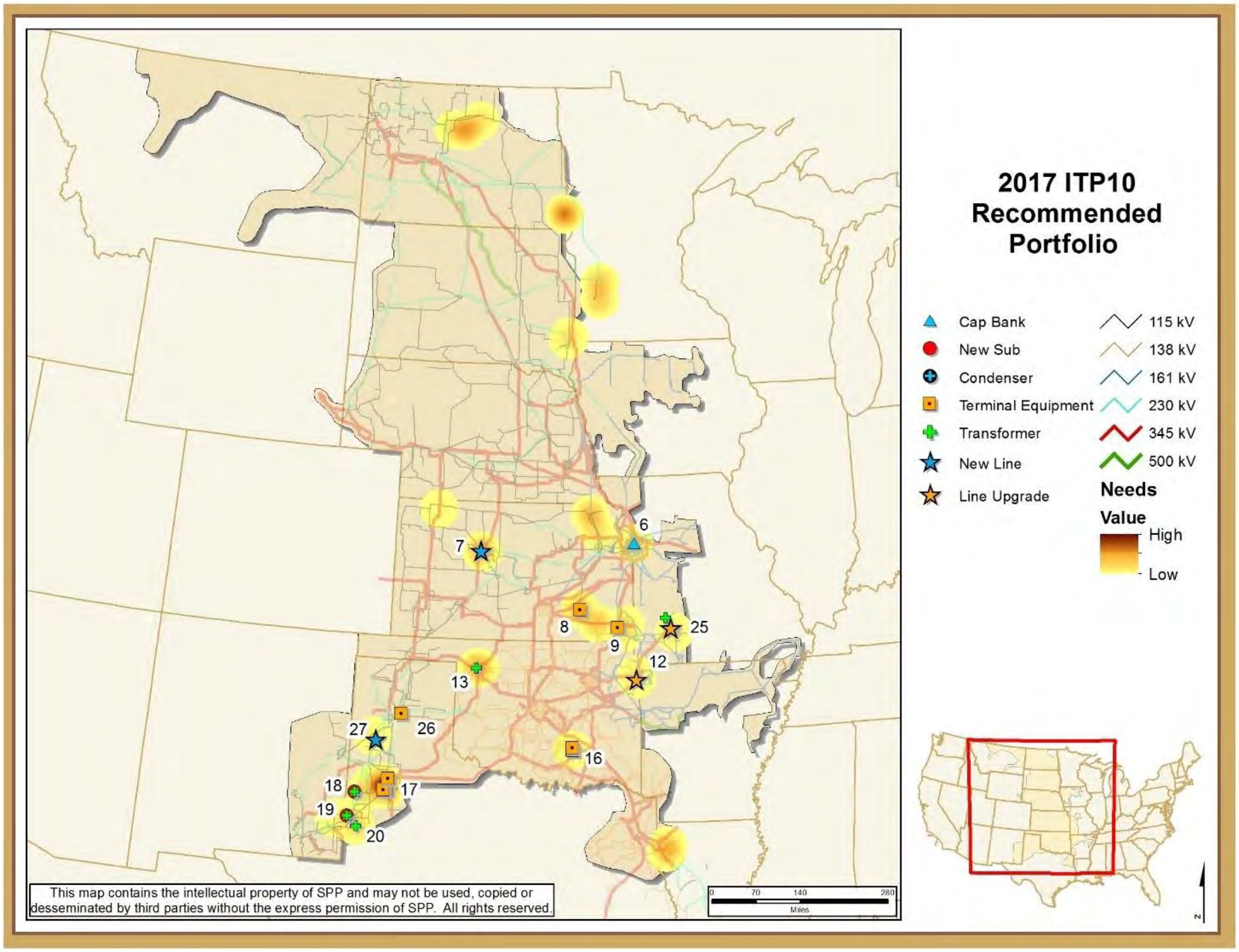

Figure 16.212: 2017 ITP10 Recommended Portfolio

Label	Project Description	Area(s)	Type	Cost Estimate	Mileage	Lead Time	Need Date
6	Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line	KCPL	E	$512,500	-	24	1/1/2018
7	Build a new second 230 kV line from Knoll to Post Rock.	MIDW	E	$3,389,019	1	24	1/1/2017
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to	WR	E	$244,606	-	18	1/1/2017

Label	Project Description	Area(s)	Type	Cost Estimate	Mileage	Lead Time	Need Date
	increase the rating of the 138kV line between the two substations to a summer emergency rating of 110 MVA.						
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161kV line between the two substations to a summer emergency rating of 243 MVA.	WR/EDE	E	$114,154	-	18	1/1/2017
12	Rebuild 2.1-mile 161kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE)	AEP/GRDA	E	$5,185,885	2.1	24	1/1/2017
13	Install one (1) 138kV phase shifting transformer at Woodward along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	OGE	E	$7,459,438	-	18	6/1/2018
16	Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 138kV line between the two substations to a summer and winter emergency rating of 169/201 MVA. Upgrade terminal equipment at Lula and/or Tupelo Tap to increase the rating of the line between the substations to 171/192	OGE/WFEC	E	$102,500	-	18	1/1/2020

Label	Project Description	Area(s)	Type	Cost Estimate	Mileage	Lead Time	Need Date
	(SN/SE).						
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115kV line between the two substations to a summer emergency rating of 175 MVA.	SPS	E	$969,942	-	18	1/1/2017
18	Tap the intersection of the 230kV line from Tolk to Yoakum and the 115kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115kV transformer at new substation.	SPS	E	$11,961,951	-	24	6/1/2018
19	Tap the existing 230kV line from Hobbs to Yoakum and the existing 115kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115kV transformer at new Hobbs - Yoakum Tap substation.	SPS	E/R	$9,953,077	-	24	6/1/2017

Label	Project Description	Area(s)	Type	Cost Estimate	Mileage	Lead Time	Need Date
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	SPS	E	$7,423,880	-	24	6/1/2017
25	Install a 345/161 kV transformer at Morgan substation and upgrade the Morgan - Brookline 161 kV line to summer emergency rating of 208 MVA and winter emergency rating of 232 MVA.	AECI	E	$9,481,250		36	1/1/2017
26	Upgrade any necessary terminal equipment at Martin, Pantex North, Pantex South, and Highland tap to increase the rating of the 115 kV lines to 175/175 MVA (SN/SE).	SPS	R	$682,034		18	1/1/2017
27	Build new 345 kV line from Potter to Tolk[68]	SPS	E	$143,984,174	90	72	1/1/2017

Table 16.1: 2017 ITP10 Recommended Portfolio

[68] In January 2017, the SPP Board of Directors (Board) approved the recommended portfolio with the exception of the new 345 kV line from Potter to Tolk, and directed SPP staff to further evaluate the project. In April 2017, the Board accepted staff's recommendation to remove the Potter to Tolk line from the 2017 ITP10 portfolio. The continued need for a solution will be further evaluated pending approval of the commencement of a High Priority study in July 2017.

	2017 ITP10 Recommended Portfolio		
	Reliability	Economic	Total[69]
Total Cost	$10.0 M	$201.5 M	$201.5 M
Total Projects	1	14	14
Total Miles	0	93.1	93.1
1-Year Cost			$34.2 M
		Future 1	Future 3
1-Year APC Benefit		$58.9M	$59.0M
1-Year B/C Ratio		1.7	1.7

Table 16.2: 2017 ITP10 Recommended Portfolio Statistics

16.4: Recommended Portfolio Benefit Metrics

In order to provide information on the value and economic impact of the recommended portfolio, SPP staff assessed the feasibility and value of calculating all of the benefit metrics, as listed in Section 12. Due to the time constraints of the additional analysis, a subset of these metrics was performed. For the scoped Reduced Carbon and Reference Case portfolios, the Adjusted Production Cost, Mitigation of Transmission Outage Costs, and Marginal Energy Losses benefit metrics account for over 95% of the total benefits. Because the calculation of these benefit metrics fit within the time constraints, they were performed on the recommended portfolio in the Future 1 and Future 3 models.

Adjusted Production Costs

Adjusted Production Cost was calculated on the recommended portfolio. Two years were analyzed, 2020 and 2025, and the APC savings were calculated accordingly for these years. Table 16.3 provides the zonal breakdown and the 40-year NPV estimates.

[69] One project is both reliability and economic, and included in both categories. Since this is included only once in the total, the sum of the two costs does not equal the total cost.

Zone	Future 1 2020 ($M)	Future 1 2025 ($M)	Future 1 40-yr NPV ($2017M)	Future 3 2020 ($M)	Future 3 2025 ($M)	Future 3 40-yr NPV ($2017M)
AEPW	$1.4	$5.4	$111.9	$0.1	($0.5)	($12.9)
CUS	$2.6	$4.2	$71.2	$1.3	$1.1	$11.4
EDE	$0.4	$0.7	$12.3	$2.0	$2.8	$45.3
GMO	($0.1)	$0.0	$1.8	($1.0)	($0.3)	$4.2
GRDA	$1.2	$2.2	$37.6	$1.5	$1.3	$13.9
KCPL	$4.7	$5.2	$69.3	$5.9	$8.2	$127.2
LES	$0.4	$0.2	$0.2	$0.6	$0.6	$7.5
MIDW	$0.3	$1.3	$28.1	($0.6)	($0.6)	($7.2)
MKEC	($2.2)	($2.9)	($43.8)	($3.5)	($4.0)	($54.5)
NPPD	$2.1	$2.1	$26.2	$4.3	$5.8	$87.9
OKGE	$1.2	$1.7	$27.4	$0.2	($0.4)	($11.3)
OPPD	$0.0	($2.1)	($51.0)	$0.5	($1.1)	($32.3)
SUNC	($0.5)	($1.0)	($19.1)	($0.3)	($0.5)	($7.7)
SWPS	$19.3	$34.6	$604.2	$21.0	$36.2	$623.0
IS	$0.2	($0.1)	($5.3)	($0.4)	($1.4)	($27.3)
WEFA	$11.9	$13.5	$185.8	$9.5	$8.8	$100.8
WRI	$0.9	$1.9	$35.8	$4.6	$5.0	$66.0
TOTAL	**$43.6**	**$66.8**	**$1,092.7**	**$45.7**	**$61.1**	**$933.8**

Table 16.3: Recommended Portfolio APC Savings by Zone

Mitigation of Transmission Outage Costs

Mitigation of Transmission Outage Costs benefits were calculated using the same ratio that was applied to the scoped portfolios. Applying 11.3% to the APC savings estimated for the recommended portfolio translates to a 40-year NPV of benefits of $123 million in the Future 1 model and $105.1 million in the Future 3 model. This incremental benefit is allocated to zones based on their load ratio share, Table 16.4 shows the outage mitigation benefits allocated to each SPP zone.

	Future 1 40-yr NPV (2017 $M)	Future 3 40-yr NPV (2017 $M)
AEPW	$25.6	$21.9
CUS	$1.6	$1.4
EDE	$2.8	$2.4
GMO	$4.6	$3.9
GRDA	$2.1	$1.8
KCPL	$9.1	$7.7
LES	$2.3	$2.0
MIDW	$1.0	$0.8
MKEC	$1.6	$1.3
NPPD	$7.3	$6.3
OKGE	$16.2	$13.9
OPPD	$5.8	$5.0
SUNC	$1.1	$0.9
SWPS	$14.1	$12.1
WFEC	$4.2	$3.6
WRI	$12.4	$10.6
UMZ	$11.1	$9.5
TOTAL	**$123.0**	**$105.1**

Table 16.4: Recommended Portfolio Transmission Outage Cost Mitigation Benefits by Zone (40-year NPV)

Marginal Energy Losses

Saving due to the reduction of energy losses was the third metric calculated for the recommended portfolio. The 40-year NPV of benefits is estimated to be $107.4 million in the Future 1 model and $36.0 million in the Future 3 model, as shown in Table 16.5 below.

Zone	Future 1 40-yr NPV (2017 $M)	Future 3 40-yr NPV (2017 $M)
AEPW	$29.66	$26.42
CUS	($6.33)	($1.77)
EDE	$4.11	$7.22
GMO	$9.38	$7.20
GRDA	$0.97	$2.32
KCPL	$25.45	$21.16
LES	$5.47	$5.76
MIDW	$2.77	($0.53)
MKEC	$4.38	$0.76
NPPD	$24.46	$14.22
OKGE	$28.68	$19.79
OPPD	$13.20	$10.41
SUNC	($0.46)	($2.42)
SWPS	($88.21)	($108.04)
UMZ	$31.69	$23.37
WFEC	$9.23	$2.82
WRI	$12.94	$7.31
TOTAL	**$107.38**	**$36.02**

Table 16.5: Recommended Portfolio Energy Losses Benefit by Zone (40-year NPV)

Summary

Table 16.6 and Table 16.7 summarize the 40-year NPV of the estimated benefit metrics and costs and the resulting B/C ratios for each SPP zone.

For the region, the B/C ratio is estimated to be 5.27 in the Future 1 model and 4.28 in the Future 3 model.

Recommended Portfolio in Future 1 - Present Value of 40-yr Benefits (2017 $M)							
Zone	APC Savings (2017 $M)	Mitigation of Trans-mission Outage Costs (2017 $M)	Marginal Energy Losses Benefits (2017 $M)	Total Benefits (2017 $M)	NPV 40-yr ATRRs (2017 $M)	Net Benefit (2017 $M)	Est. Benefit/ Cost Ratio
AEPW	$111.9	$25.6	$29.7	$167.2	$47.0	$120.2	3.56
CUS	$71.2	$1.6	($6.3)	$66.5	$3.0	$63.5	22.15
EDE	$12.3	$2.8	$4.1	$19.2	$5.0	$14.2	3.85
GMO	$1.8	$4.6	$9.4	$15.7	$8.0	$7.7	1.97
GRDA	$37.6	$2.1	$1.0	$40.7	$8.0	$32.7	5.09
KCPL	$69.3	$9.1	$25.5	$103.9	$16.0	$87.9	6.49
LES	$0.2	$2.3	$5.5	$7.9	$4.0	$3.9	1.98
MIDW	$28.1	$1.0	$2.8	$31.9	$4.0	$27.9	7.96
MKEC	($43.8)	$1.6	$4.4	($37.8)	$3.0	($40.8)	(12.61)
NPPD	$26.2	$7.3	$24.5	$58.0	$13.0	$45.0	4.46
OKGE	$27.4	$16.2	$28.7	$72.3	$33.0	$39.3	2.19
OPPD	($51.0)	$5.8	$13.2	($32.0)	$10.0	($42.0)	(3.20)
SUNC	($19.1)	$1.1	($0.5)	($18.5)	$2.0	($20.5)	(9.23)
SWPS	$604.2	$14.1	($88.2)	$530.1	$47.0	$483.1	11.28
UMZ	($5.3)	$11.1	$31.7	$37.5	$19.0	$18.5	1.97
WFEC	$185.8	$4.2	$9.2	$199.3	$7.0	$192.3	28.46
WRI	$35.8	$12.4	$12.9	$61.1	$22.0	$39.1	2.78
TOTAL	**$1,092.7**	**$123.0**	**$107.4**	**$1,323.0**	**$251.0**	**$1,072.0**	**5.27**

Table 16.6: Estimated 40-year NPV of Benefit Metrics and Costs of Recommended Portfolio – Zonal (Future 1)

Recommended Portfolio in Future 3 - Present Value of 40-yr Benefits (2017 $M)							
Zone	APC Savings (2017 $M)	Mitigation of Trans-mission Outage Costs (2017 $M)	Marginal Energy Losses Benefits (2017 $M)	Total Benefits (2017 $M)	NPV 40-yr ATRRs (2017 $M)	Net Benefit (2017 $M)	Est. Benefit/ Cost Ratio
AEPW	($12.9)	$21.9	$26.4	$35.4	$47.0	($11.6)	0.75
CUS	$11.4	$1.4	($1.8)	$11.1	$3.0	$8.1	3.68
EDE	$45.3	$2.4	$7.2	$54.9	$5.0	$49.9	10.98
GMO	$4.2	$3.9	$7.2	$15.3	$8.0	$7.3	1.91
GRDA	$13.9	$1.8	$2.3	$18.0	$8.0	$10.0	2.25
KCPL	$127.2	$7.7	$21.2	$156.1	$16.0	$140.1	9.75
LES	$7.5	$2.0	$5.8	$15.2	$4.0	$11.2	3.81
MIDW	($7.2)	$0.8	($0.5)	($6.9)	$4.0	($10.9)	(1.73)
MKEC	($54.5)	$1.3	$0.8	($52.4)	$3.0	($55.4)	(17.47)
NPPD	$87.9	$6.3	$14.2	$108.4	$13.0	$95.4	8.34
OKGE	($11.3)	$13.9	$19.8	$22.4	$33.0	($10.6)	0.68
OPPD	($32.3)	$5.0	$10.4	($16.9)	$10.0	($26.9)	(1.69)
SUNC	($7.7)	$0.9	($2.4)	($9.2)	$2.0	($11.2)	(4.61)
SWPS	$623.0	$12.1	($108.0)	$527.0	$47.0	$480.0	11.21
UMZ	($27.3)	$9.5	$23.4	$5.6	$19.0	($13.4)	0.29
WFEC	$100.8	$3.6	$2.8	$107.2	$7.0	$100.2	15.31
WRI	$66.0	$10.6	$7.3	$84.0	$22.0	$62.0	3.82
TOTAL	**$933.8**	**$105.1**	**$36.0**	**$1,074.9**	**$251.0**	**$823.9**	**4.28**

Table 16.7: Estimated 40-year NPV of Benefit Metrics and Costs of Recommended Portfolio – Zonal (Future 3)

Recommended Portfolio in Future 1 - Present Value of 40-yr Benefits (2017 $M)							
State	APC Savings (2017 $M)	Mitigation of Trans-mission Outage Costs (2017 $M)	Marginal Energy Losses Benefits (2017 $M)	Total Benefits (2017 $M)	NPV 40-yr ATRRs (2017 $M)	Net Benefit (2017 $M)	Est. B/C Ratio
Arkansas	$26.3	$7.3	$9.8	$43.3	$13.8	$29.5	3.14
Iowa	($0.9)	$1.9	$5.4	$6.4	$3.3	$3.2	1.98
Kansas	$36.6	$20.7	$32.2	$89.5	$39.2	$50.3	2.28
Louisiana	$15.0	$3.4	$4.0	$22.4	$6.3	$16.1	3.56
Minnesota	($0.1)	$0.1	$0.4	$0.5	$0.2	$0.2	1.97
Missouri	$119.3	$13.4	$19.7	$152.4	$23.6	$128.8	6.45
Montana	($0.3)	$0.5	$1.6	$1.8	$0.9	$0.9	1.97
Oklahoma	$306.3	$31.4	$45.3	$383.0	$64.4	$318.5	5.94
Nebraska	($25.2)	$16.7	$46.7	$38.1	$29.1	$9.0	1.31
New Mexico	$166.1	$3.9	($24.3)	$145.8	$12.9	$132.8	11.28
North Dakota	($2.1)	$4.4	$12.6	$14.9	$7.5	$7.3	1.97
South Dakota	($1.3)	$2.8	$7.9	$9.3	$4.7	$4.6	1.98
Texas	$453.0	$16.3	($54.1)	$415.2	$44.7	$370.5	9.28
Wyoming	($0.0)	$0.1	$0.3	$0.3	$0.2	$0.2	1.97
TOTAL	**$1,092.7**	**$123.0**	**$107.4**	**$1,323.0**	**$251.0**	**$1,072.0**	**5.27**

Table 16.8: Estimated 40-year NPV of Benefit Metrics and Costs of Recommended Portfolio – State (Future 1)

Recommended Portfolio in Future 3 - Present Value of 40-yr Benefits (2017 $M)							
State	APC Savings (2017 $M)	Mitigation of Trans-mission Outage Costs (2017 $M)	Marginal Energy Losses Benefits (2017 $M)	Total Benefits (2017 $M)	NPV 40-yr ATRRs (2017 $M)	Net Benefit (2017 $M)	Est. B/C Ratio
Arkansas	($2.7)	$6.2	$8.0	$11.6	$13.8	($2.2)	0.84
Iowa	($4.6)	$1.6	$4.0	$1.0	$3.3	($2.3)	0.31
Kansas	$62.3	$17.7	$15.8	$95.8	$39.2	$56.6	2.44
Louisiana	($1.7)	$2.9	$3.5	$4.7	$6.3	($1.6)	0.75
Minnesota	($0.3)	$0.1	$0.3	$0.1	$0.2	($0.2)	0.29
Missouri	$120.8	$11.4	$22.7	$154.9	$23.6	$131.2	6.56
Montana	($1.3)	$0.5	$1.2	$0.3	$0.9	($0.7)	0.29
Oklahoma	$114.3	$26.9	$30.8	$172.0	$64.4	$107.6	2.67
Nebraska	$59.9	$14.3	$33.0	$107.2	$29.1	$78.0	3.68
New Mexico	$171.3	$3.3	($29.7)	$144.9	$12.9	$132.0	11.21
North Dakot	($10.8)	$3.8	$9.3	$2.2	$7.5	($5.3)	0.29
South Dakot	($6.7)	$2.4	$5.8	$1.5	$4.7	($3.2)	0.31
Texas	$433.7	$14.0	($68.9)	$378.8	$44.7	$334.0	8.47
Wyoming	($0.2)	$0.1	$0.2	$0.0	$0.2	($0.1)	0.29
TOTAL	**$933.8**	**$105.1**	**$36.0**	**$1,074.9**	**$251.0**	**$823.9**	**4.28**

Table 16.9: Estimated 40-year NPV of Benefit Metrics and Costs of Recommended Portfolio – State (Future 3)

Note that state level results are based on load allocations by zone, by state. For example, 11% of UMZ load is in Nebraska, and as a result, 11% of UMZ benefits are attributed to Nebraska. The Nebraska benefits thus look differently than if one were to assume that Nebraska were composed only of the LES, NPPD, and OPPD pricing zones.

Rate Impacts

The rate impact to the average retail residential ratepayer in SPP was computed for the recommended portfolio. Rate impact costs and benefits[70] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kWh per month. Benefits and costs for the 2025 study year were used to calculate rate impacts. All 2025 benefits and costs are shown in 2017 $ discounting at a 2.5 percent inflation rate.

[70] APC Savings are the only benefit included in the rate impact calculations.

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 16.10 and Table 16.11. The recommended portfolio has a monthly net benefit for the average SPP residential ratepayer of 10 cents in the Future 1 model. The recommended portfolio has a monthly net benefit for the average SPP residential ratepayer of 9 cents in the Future 3 model.

Zone	1-Yr ATRR Costs ($K)	1-Yr Benefit ($K)	Rate Impact - Costs ($)	Rate Impact - Benefit ($)	Net Impact ($)
AEPW	$4,653	$4,417	$0.09	$0.09	$0.00
CUS	$287	$3,484	$0.09	$1.05	($0.97)
EDE	$491	$584	$0.09	$0.11	($0.02)
GMO	$796	$13	$0.11	$0.00	$0.10
GRDA	$764	$1,775	$0.12	$0.28	($0.16)
KCPL	$1,626	$4,227	$0.10	$0.25	($0.15)
LES	$399	$148	$0.10	$0.04	$0.06
MIDW	$444	$1,075	$0.21	$0.50	($0.29)
MKEC	$275	($2,363)	$0.08	($0.66)	$0.73
NPPD	$1,278	$1,723	$0.08	$0.10	($0.03)
OKGE	$3,322	$1,398	$0.10	$0.04	$0.06
OPPD	$1,011	($1,763)	$0.08	($0.14)	$0.22
SUNC	$188	($853)	$0.06	($0.28)	$0.34
SWPS	$4,634	$28,408	$0.11	$0.64	($0.53)
IS	$1,931	($109)	$0.06	($0.00)	$0.06
WEFA	$743	$11,052	$0.09	$1.26	($1.17)
WRI	$2,194	$1,575	$0.08	$0.06	$0.02
TOTAL	**$25,035**	**$54,791**	**$0.09**	**$0.20**	**($0.11)**

Table 16.10: Recommended Portfolio 2025 Retail Residential Rate Impacts by Zone in Future 1 (2017 $)

Zone	1-Yr ATRR Costs ($K)	1-Yr Benefit ($K)	Rate Impact - Costs ($)	Rate Impact - Benefit ($)	Net Impact ($)
AEPW	$4,653	($405)	$0.09	($0.01)	$0.10
CUS	$287	$889	$0.09	$0.27	($0.18)
EDE	$491	$2,331	$0.09	$0.45	($0.35)
GMO	$796	($240)	$0.11	($0.03)	$0.13
GRDA	$764	$1,051	$0.12	$0.16	($0.04)
KCPL	$1,626	$6,699	$0.10	$0.40	($0.30)
LES	$399	$497	$0.10	$0.12	($0.02)
MIDW	$444	($485)	$0.21	($0.23)	$0.43
MKEC	$275	($3,267)	$0.08	($0.91)	$0.98
NPPD	$1,278	$4,734	$0.08	$0.28	($0.21)
OKGE	$3,322	($299)	$0.10	($0.01)	$0.11
OPPD	$1,011	($922)	$0.08	($0.07)	$0.15
SUNC	$188	($398)	$0.06	($0.13)	$0.19
SWPS	$4,634	$29,747	$0.11	$0.67	($0.57)
IS	$1,931	($1,111)	$0.06	($0.03)	$0.09
WEFA	$743	$7,196	$0.09	$0.82	($0.73)
WRI	$2,194	$4,096	$0.08	$0.15	($0.07)
TOTAL	**$25,035**	**$50,114**	**$0.09**	**$0.18**	**($0.09)**

Table 16.11: Recommended Portfolio 2025 Retail Residential Rate Impacts by Zone in Future 3 (2017 $)

SECTION 17:GLOSSARY OF TERMS

Acronym	Description
A/S	Ancillary Services
AECI	Associated Electric Cooperatives, Inc.
APA	Alternative Project Analysis
APC	Adjusted Production Cost
ASOM	Annual State of the Market
ATC	Available Transfer Capability
ATRR	Annual Transmission Revenue Requirement
B/C	Benefit to Cost Ratio
BOD	SPP Board of Directors
Carbon Price	The imposed financial burden associated with the emissions of CO_2 in a future scenario
CAWG	Cost Allocation Working Group
CC	Combined Cycle
CLR	Cost Per Loading Relief
CONE	Cost of New Entry
CPP	Clean Power Plan
CSP	Coordinated System Planning
CT	Combustion Turbine

Acronym	Description
CVR	Cost Per Voltage Relief
DPP	Detailed Project Proposal
EGU	Electric Generating Units
EHV	Extra-High Voltage
EIA	U.S. Energy Information Administration
EPA	Environmental Protection Agency
ESRPP	Entergy SPP RTO Regional Planning Process
ESWG	Economic Studies Working Group
FCITC	First Contingency Incremental Transfer Capability
FERC	Federal Energy Regulatory Commission
GI	Generation Interconnection
GOF	Generator Outlet Facilities
GW	Gigawatt (10^9 Watts)
HVDC	High-Voltage Direct Current
IRP	Integrated Resource Plan
ITP10	Integrated Transmission Plan 10-Year Assessment
ITP20	Integrated Transmission Plan 20-Year Assessment
ITPNT	Integrated Transmission Plan Near-Term Assessment
LMP	Locational Marginal Price

Acronym	Description
LSE	Load Serving Entity
MDWG	Model Development Working Group
MISO	Midcontinent Independent System Operator, Inc.
MLC	Marginal Loss Component
MOPC	Markets and Operations Policy Committee
MTEP	MISO Transmission Expansion Plan
MTF	Metrics Task Force
MVA	Mega Volt Ampere (10^6 Volt-Ampere)
MW	Megawatt (10^6 Watts)
NERC	North American Electric Reliability Corporation
NPCC	Net Plant Carrying Charge
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NTC	Notification to Construct
NYMEX	New York Mercantile Exchange
OATT	Open Access Transmission Tariff
PCM	Production Cost Model
Pmax	Online Real Power Maximum Generation
PPA	Power Purchase Agreement

Acronym	Description
PST	Phase Shifting Transformer
RARTF	Regional Allocation Review Task Force
RCAR	Regional Cost Allocation Review
RSC	SPP Regional State Committee
SASK	Saskatchewan Power
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SPC	Strategic Planning Committee
SPP	Southwest Power Pool, Inc.
TO	Transmission Owner
TSR	Transmission Service Request
TVA	Tennessee Valley Authority
TWG	Transmission Working Group
VSL	Voltage Stability Limit