SECTION 6: PROJECT SUMMARY

6.1 PROJECT DEVELOPMENT SUMMARY

Transmission upgrades submitted through the Order 890 and Order 1000 processes were analyzed, and SPP staff members developed projects to address potential reliability issues that were not mitigated by corrective actions plans or operating guides. Table 4 presents the full list of projects in the 2018 ITPNT.

Reliability Project(s)	Project Area(s)	Cost	Need Date
New Lakeview 69-kV substation. New 14.4 MVAR switched shunt capacitor at Lakeview 69 kV	EREC	$5,617,000	6/1/2019
Reconductor 3 miles of 115-kV line from Richland to Lewis	WAPA/Basin	$105,000[10]	6/1/2019
Replace the 230/115-kV transformer at Lawrence Hill	WERE	$4,896,108	6/1/2019
Construct a new 5.6 mile 161-kV line from Blue Valley to Crosstown	KCPL	$8,951,824	6/1/2020
Replace terminal equipment on the 161-kV line from Olathe to Switzer	KCPL	$1,088,000	6/1/2019
Replace terminal equipment on the 161-kV line from Brookridge to Overland Park	KCPL	$538,000	6/1/2019
New 50 MVAR switched shunt reactor at Brookline 345 kV. Brookline 345-kV Substation expansion	SPRM	$4,175,203	6/1/2019
Rebuild 1.25 miles of 69-kV line from Nixa Downtown - Nixa Espy	SWPA	$1,108,561	6/1/2019
Rebuild 4.2 miles of 69-kV line from VBI North to Figure Five	AEPW	$3,409,700	6/1/2019
Tap Moore-Potter 230-kV line and Exell Tap-Fain 115-kV line and tie into a new substation at McDowell Install a new 230/115-kV transformer at McDowell	SPS	$13,204,182	6/1/2019

[10] The total MDU, WAPA, and Basin estimated cost is $1,105,001.

Reliability Project(s)	Project Area(s)	Cost	Need Date
Replace terminal equipment on the 115-kV line from Carlisle to Murphy	**SPS**	**$319,760**	**6/1/2022**
Replace terminal equipment on the 115-kV line from Clauene to Terry County	**SPS**	**$520,574**	**6/1/2019**
Replace the 230/115-kV transformer at Sundown	**SPS**	**$3,434,979**	**6/1/2019**

Table 4: 2018 ITPNT Projects

6.2: NTC RE-EVALUATION RESULTS SUMMARY

In accordance with Business Practice 7160 Notice to Construct Re-evaluation Review, applicable ITP assessment for NTC re-evaluation: Any NTC meeting the re-evaluation criteria will be reviewed during the next ITP assessment. Each project, except for the Jeffrey – Hoyt 345-kV rebuild, originated from the 2016 ITPNT assessment. The Jeffrey – Hoyt 345-kV rebuild originated from the ATSS (2016-AG1-AFS-3).

Each of the projects listed in Table 5: NTC Re-evaluation Summary was re-evaluated to determine if the project is still required and is the most cost effective project to address the identified needs. The recommendation and justification for each re-evaluated project is found below.

Project Name	Owner	Cost	Source Study	Comments
Blanchard 69-kV Capacitor Bank	**WFEC**	**$950K**	**2016 ITPNT**	**Recommend NTC withdrawal**
Ringwood 69-kV Capacitor Bank	**WFEC**	**$4.5M**	**2016 ITPNT**	**Recommend NTC withdrawal**
Dean Interchange 230/115-kV Station and Transformer	**SPS**	**$12.7M**	**2016 ITPNT**	**Recommend NTC withdrawal**
Jeffrey – Hoyt 345-kV Rebuild	**WERE**	**$34.9M**	**2016-AG1–AFS-3**	**Recommend NTC withdrawal**
Welsh Reserve – Wilkes 138-kV Rebuild	**AEP**	**$24.9M**	**2014 ITPNT**	**Recommend NTC withdrawal**
Chapel Hill REC – Welsh Reserve 138-kV Rebuild	**AEP**	**$6.7M**	**2014 ITPNT**	**Recommend NTC withdrawal**

Table 5: NTC Re-evaluation Summary

BLANCHARD 69-KV CAPACITOR BANK

The Blanchard 69-kV capacitor bank was issued to address the low voltages at the Blanchard 69-kV bus for the loss of Blanchard – Oklahoma University SW 69-kV Ckt 1 and for the loss of Oklahoma University SW 138/69/13.8-kV transformer. The needs observed at the Blanchard 69-kV bus were still present in the 2018 ITPNT posted needs. The recommendation for withdrawal is based on resolution of the observed needs with the issuance of SPP-NTC-C-210485. This NTC-C involves conversion of 69-kV lines to 138-kV lines and the 69-kV capacitor bank is no longer feasible.

RINGWOOD 69-KV CAPACITOR BANK

The Ringwood 69-kV capacitor bank was issued to address the low voltages at the Ringwood 69-kV bus for the loss of Fairview – Okeene 69-kV Ckt 1, Alva – Cherokee SW 69-kV Ckt 1 and Cleo – Junction – Ringwood 69-kV Ckt 1. The contingency that caused the worst per-unit (p.u.) voltage was the loss of Fairview – Okeene 69-kV Ckt 1. In the 2018 ITPNT assessment, no needs were observed at the Ringwood 69-kV bus due to load forecast changes. The recommendation for withdrawal is based on the fact that the need no longer exists.

DEAN INTERCHANGE 230/115-KV STATION AND TRANSFORMER

The Dean Interchange 230/115-kV station and transformer was issued to address the overloads on facilities in the southern part of the Texas Panhandle near Sundown. Due to a slight decrease in load forecast assumptions and the impact of other transmission projects in the area, this project was requested to be re-evaluated. During this evaluation, an alternative project to replace the Sundown 230/115-kV transformer was selected as the preferred solution to address needs in the area. This evaluation and the selected project are discussed in more detail in Section 7: Project Descriptions. Due to this evaluation, the NTC for the Dean Interchange project is being recommended withdrawal.

JEFFREY – HOYT 345-KV REBUILD

The Jeffrey Energy Center – Hoyt 345-kV line was a result of the 2016-AG1-AFS3 study and was determined to be out of bandwidth for its cost estimate prior to the 2018 ITPNT assessment. The transmission service (TS) process determined that the line was no longer needed due to the removal of the S5 summer model from the TS process, and the re-evaluation for the ITP process was determined to be done in the 2018 ITPNT. Overloads for the Jeffrey Energy Center – Hoyt 345-kV line were observed for numerous contingencies; however, these issues were observed only in the S5 summer models. Due to the additional analysis described in Section 5.2, a determination was made to remove the needs identified in the S5 summer models from the 2018 ITPNT assessment; therefore, the recommendation for this project is for an NTC withdrawal.

WELSH RESERVE – WILKES 138-KV REBUILD AND CHAPEL HILL REC – WELSH RESERVE 138-KV REBUILD

The Chapel Hill REC – Welsh Reserve – Wilkes 138-kV rebuild project was needed for the outage of the Lone Star South-Pittsburg 138-kV line. The flow on the Wilkes-Welsh Reserve-Chapel Hill REC 138-kV line is most affected by the load in the Mt. Pleasant and Mt. Pleasant NTEC zones. The primary system conditions in the east Texas area that changed are the forecasted loads for both the AEP and NTEC zones. In the 2014 ITPNT 19S, the combined load of the Mt. Pleasant and Mt.

Pleasant NTEC zone loads was 753 MW (410 MW + 343 MW). In 2018 ITP 22S, the combined load of the Mt. Pleasant and Mt. Pleasant NTEC zone loads was 655 MW (361 MW + 294 MW).

In the 2018 ITPNT 22S0, for the loss of Lone Star South-Pittsburg 138-kV, the line sections of Wilkes-Welsh Reserve-Chapel Hill REC 138-kV loading is 80% and 78% of the 272 MVA emergency rating respectively. With the upgrades removed, no issues were found in the 2018 ITPNT study.

6.3: PROJECT PLAN BREAKDOWN

The figures below show a breakdown of the 2018 ITPNT project plan. There are 21 proposed upgrades making up 13 projects in the project plan. All of the proposed projects will be recommended for issuance of new NTCs. No projects have been identified as needing a modified NTC. Figure 14 shows the breakdown of projects recommended for issuance or withdrawal of an NTC.

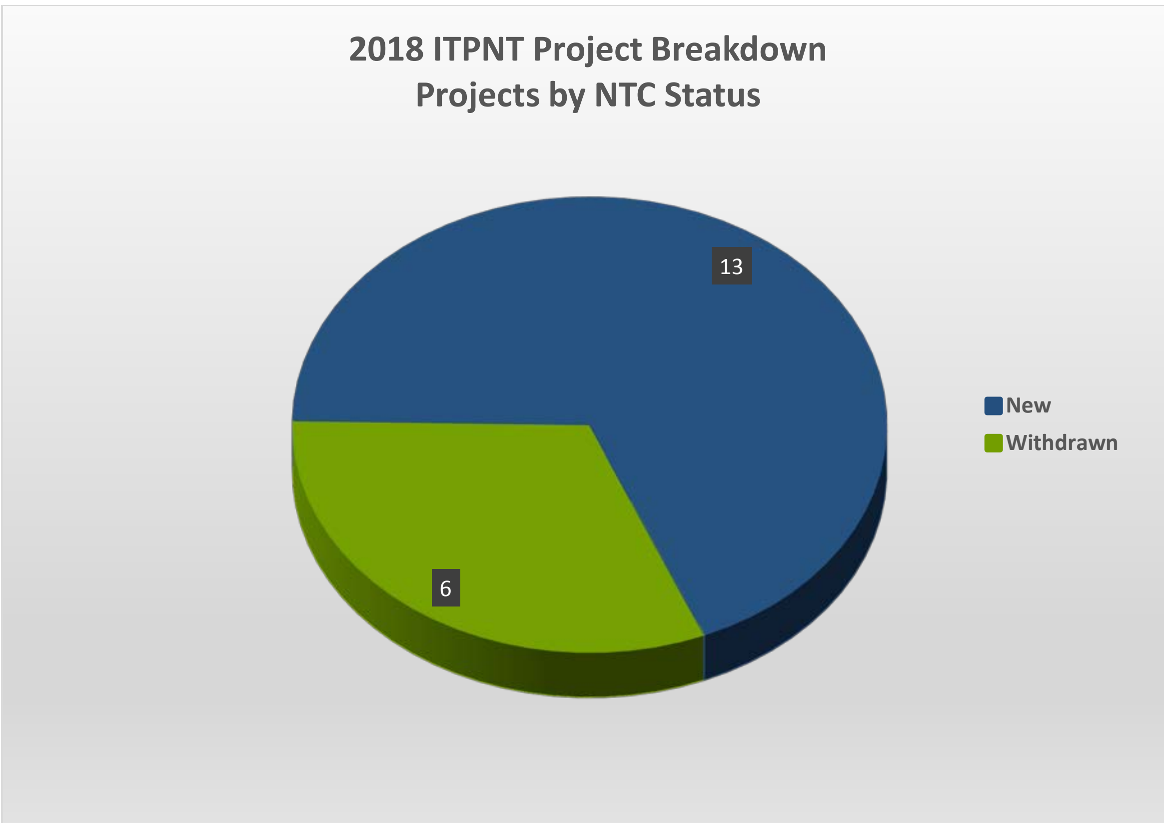

Figure 14: 2018 ITPNT Project Breakdown

Figure 15 illustrates how many miles of existing transmission line that will require a rebuild or reconductor. There are 8.5 miles of rebuild/reconductor in the 2018 ITPNT project plan.

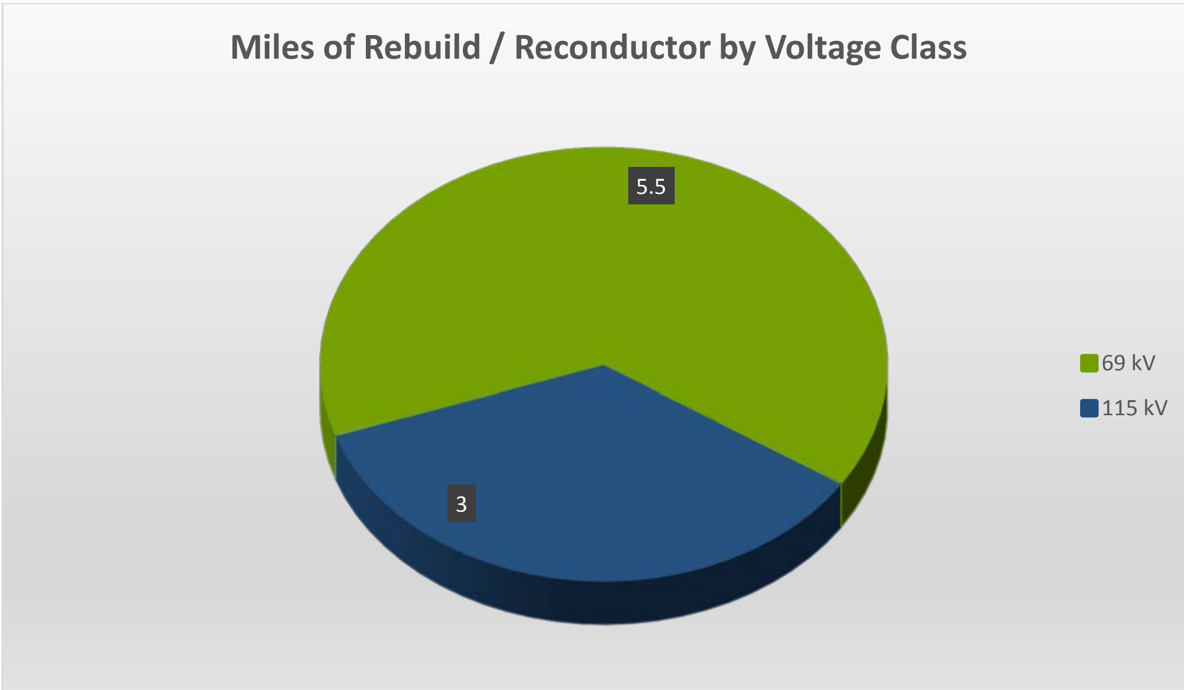

Figure 15: 2018 ITPNT Miles Rebuild/Reconductor by Voltage Class

Zonal reliability projects are required to meet local planning criteria that is more stringent than SPP criteria. There were no projects of this classification identified in this study.

Table 6 shows the cost of new and modified projects of the 2018 ITPNT identified by state.

State	New NTC
MT	$105,000
MN	$0
ND	$0
SD	$5,617,000
NE	$0
WY	$0
IA	$0
KS	$6,522,108
MO	$14,235,588
OK	$0
AR	$3,409,700
TX	$17,479,495
NM	$0
LA	$0
Subtotals:	**$47,368,891**

Table 6: 2018 ITPNT Projects by State

Table 7 shows the net investment amount of new and withdrawn projects of the 2018 ITPNT identified by state.

State	New NTC	Withdrawn NTC	Net Investment
MT	$105,000	$0	$105,000
MN	$0	$0	$0
ND	$0	$0	$0
SD	$5,617,000	$0	$5,617,000
NE	$0	$0	$0
WY	$0	$0	$0
IA	$0	$0	$0
KS	$6,522,108	($34,900,000)	($28,377,892)
MO	$14,235,588	$0	$14,235,588
OK	$0	($5,400,000)	($5,400,000)
AR	$3,409,700	$0	$3,409,700
TX	$17,479,495	($44,262,281)	($26,782,786)
NM	$0	$0	$0
LA	$0	$0	$0
Total	**$47,368,891**	**($84,562,281)**	**($37,193,390)**

Table 7: 2018 ITPNT Net Investment by State

Figure 16 is a representation of the cost of recommended new and withdrawn NTCs from the 2018 ITPNT portfolio by voltage class.

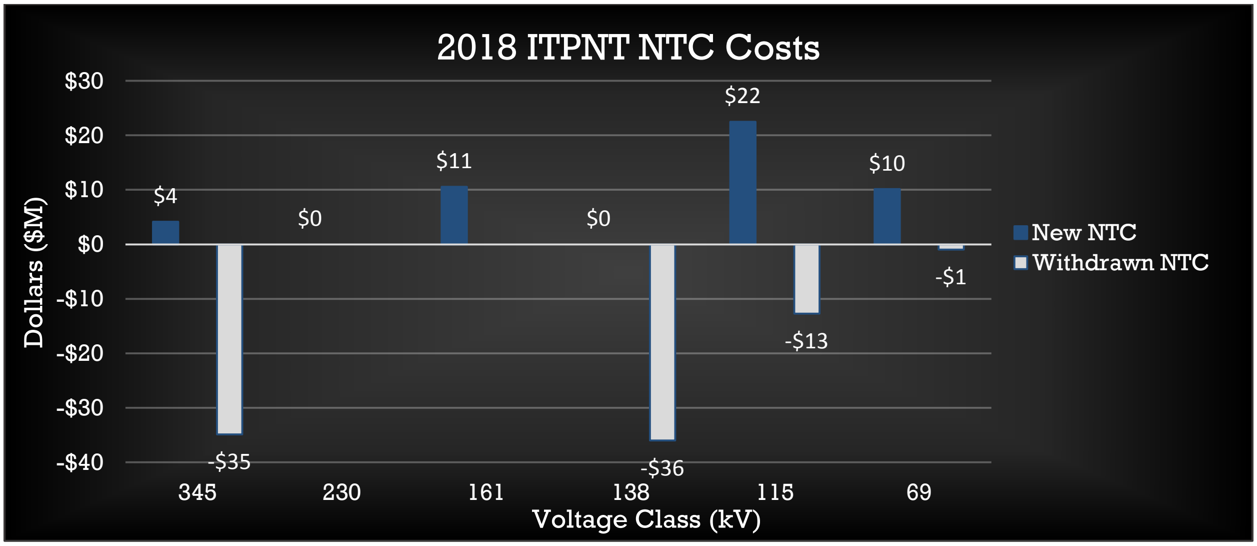

Figure 16: 2018 ITPNT NTC Costs by Voltage Class

Figure 17 shows the 2018 ITPNT projects represented two ways. The blue column represents the number of upgrades by year. The orange column represents the estimated dollars that will be invested to place the projects in service.

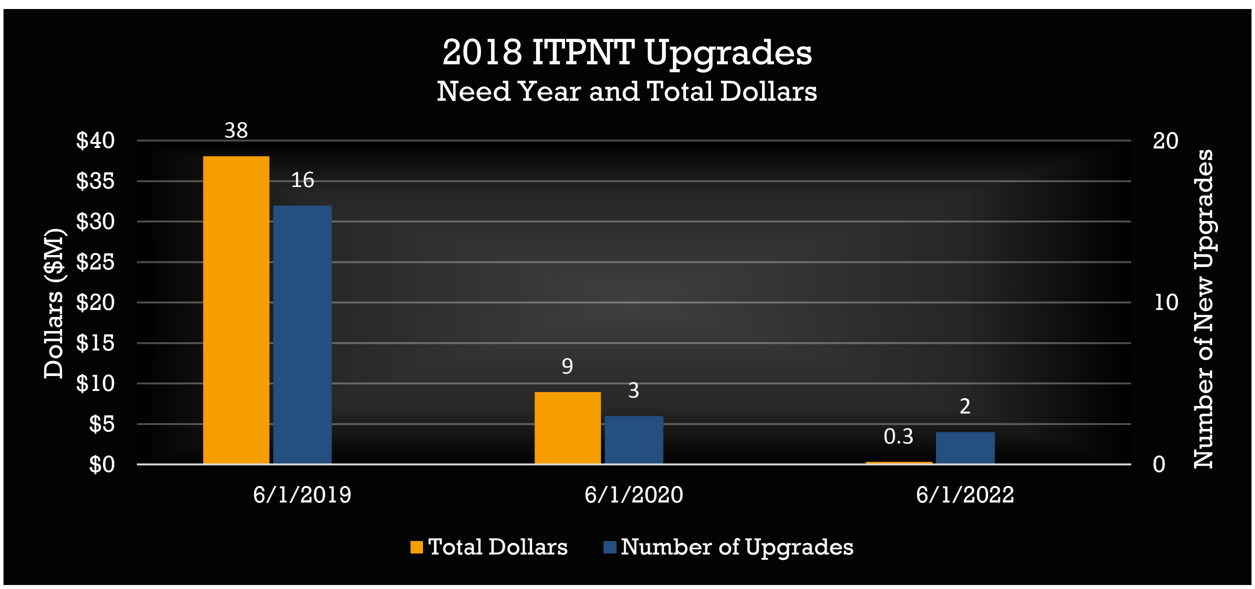

Figure 17: 2018 ITPNT Upgrades by Need Year and Total Dollars

Figure 18 shows the cost allocation of upgrades recommended for new NTCs and withdrawn NTCs by regional and zonal reliability.

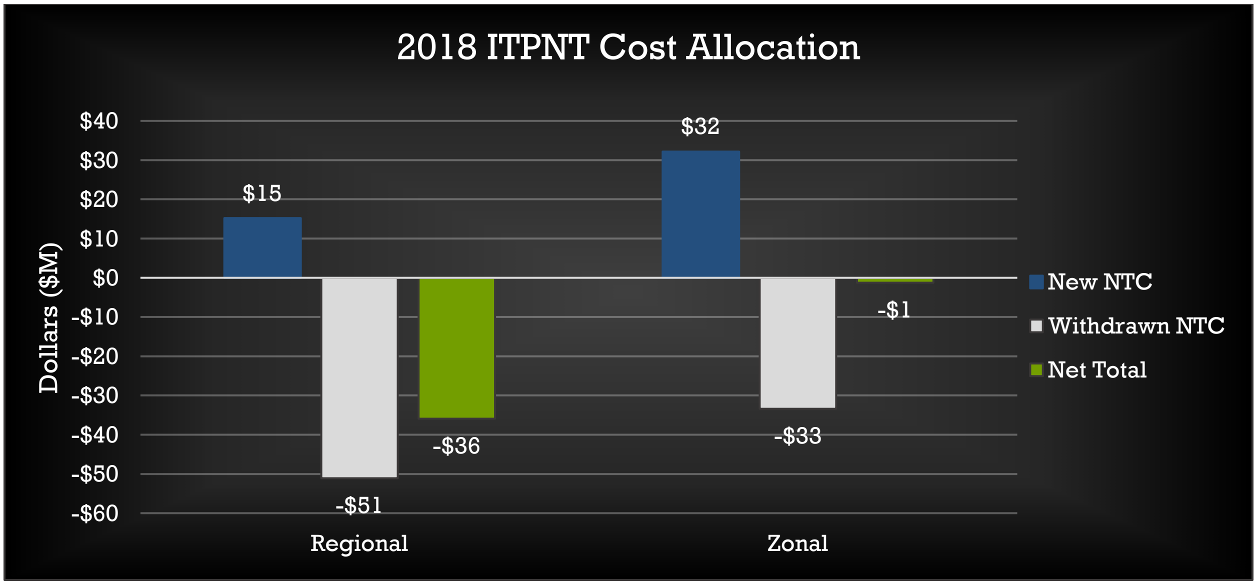

Figure 18: 2018 ITPNT Cost Allocation -- Regional v. Zonal

6.4: RATE IMPACTS ON TRANSMISSION CUSTOMERS

The projected impact of the project plan on the energy bill of a typical residential customer within the SPP region was calculated and reported on a $/kWh basis. The first step in this process is to estimate the zonal cost allocation of the Annual Transmission Revenue Requirement (ATRR). This cost-allocated ATRR is calculated specifically for the ITPNT upgrades using the ATRR forecast (forecast). The forecast allocated 2018 ITPNT upgrade costs to the zones using the highway/byway cost-allocation method. This method allocates costs to the individual zones and to the region based on the voltage level of the upgrade. Transformer costs were allocated based on the low-side voltage. Regional ATRRs are summed and allocated to the zones based on their individual load ratio share percentages.

Highway Byway Cost Allocation

Voltage (kV)	Regional	Zonal
300 and above	100%	0%
100 – 299	33%	67%
Below 100	0%	100%

Table 8: Highway Byway Cost Allocation

The following inputs and assumptions were required to generate the forecast:

- Initial investment of each upgrade
- TO’s estimated individual annual carrying charge percent
- Voltage level of each upgrade
- In-service year of each upgrade

- 2.5 percent annual straight-line rate-base depreciation
- 2.5 percent construction price inflation applied to 2018 base-year estimates
- Mid-year in-service convention

The 2018 ITPNT upgrades were evaluated in the SPP Cost Allocation Forecast model and the peak ATRR impact year was shown to be 2022.

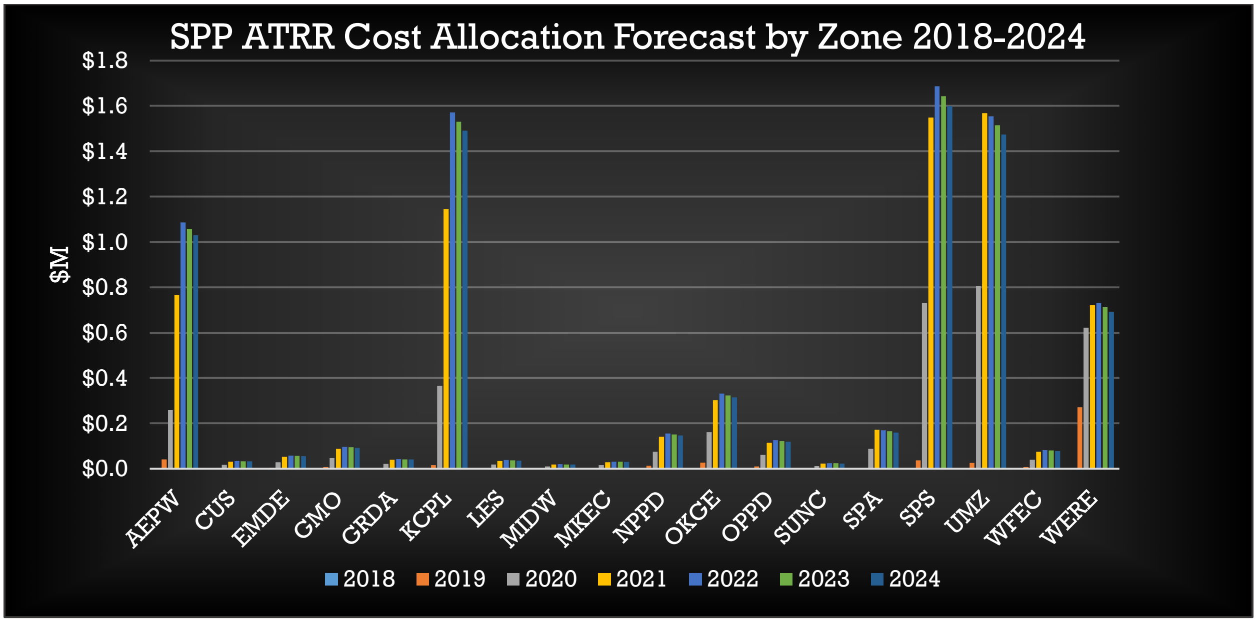

Figure 19: ATRR Cost Allocation Forecast by Zone of the 2018 ITPNT

As shown in the following chart, the majority of the 2018 ITPNT projects will be cost allocated to the zone hosting the upgrade with a smaller amount being cost allocated to the SPP region through the regional rate for all years, 2019-2025:

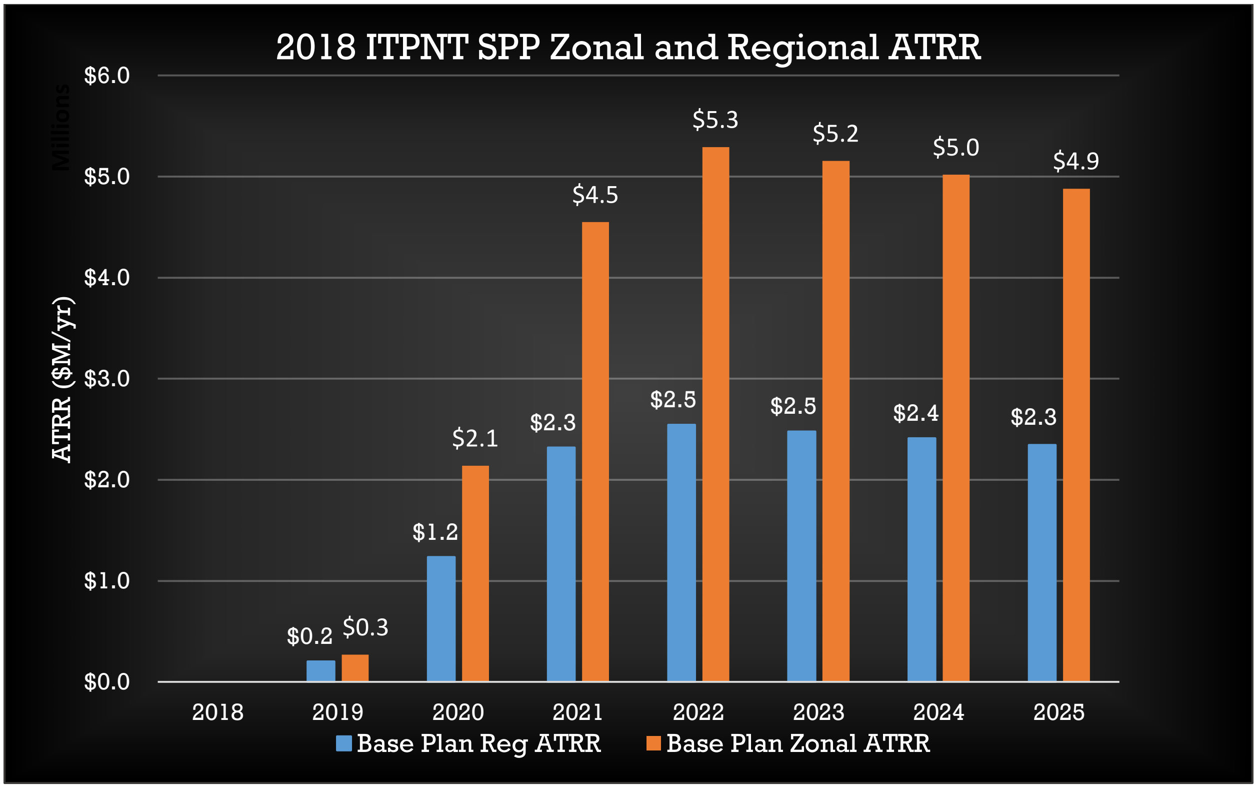

Figure 20: Zonal and Regional ATRR Allocated in SPP

The peak-year ATRR is converted into a monthly impact on a typical 1000 kWh per month retail residential ratepayer. This is done by dividing the ATRR zonal impact by the zonal energy usage as adjusted for typical losses.

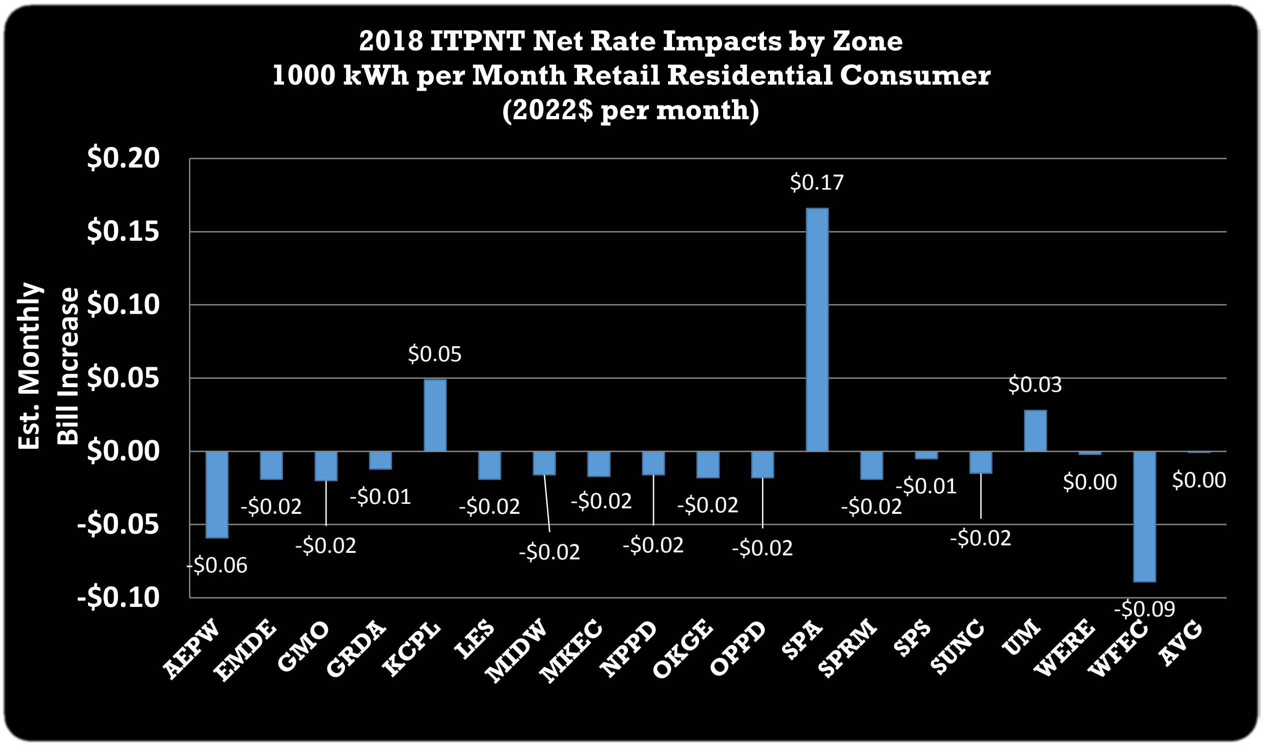

Figure 21: 2018 ITPNT Net Rate Impacts by Zone[11]

[11] The rate calculation for SPA only includes a portion of the load in that zone. Approximately 20% of the load takes long-term network service from SPP.

SECTION 7: PROJECT DESCRIPTIONS

7.1: FINAL PROJECT PORTFOLIO

NEW LAKEVIEW 69-KV SUBSTATION AND CAPACITOR BANK

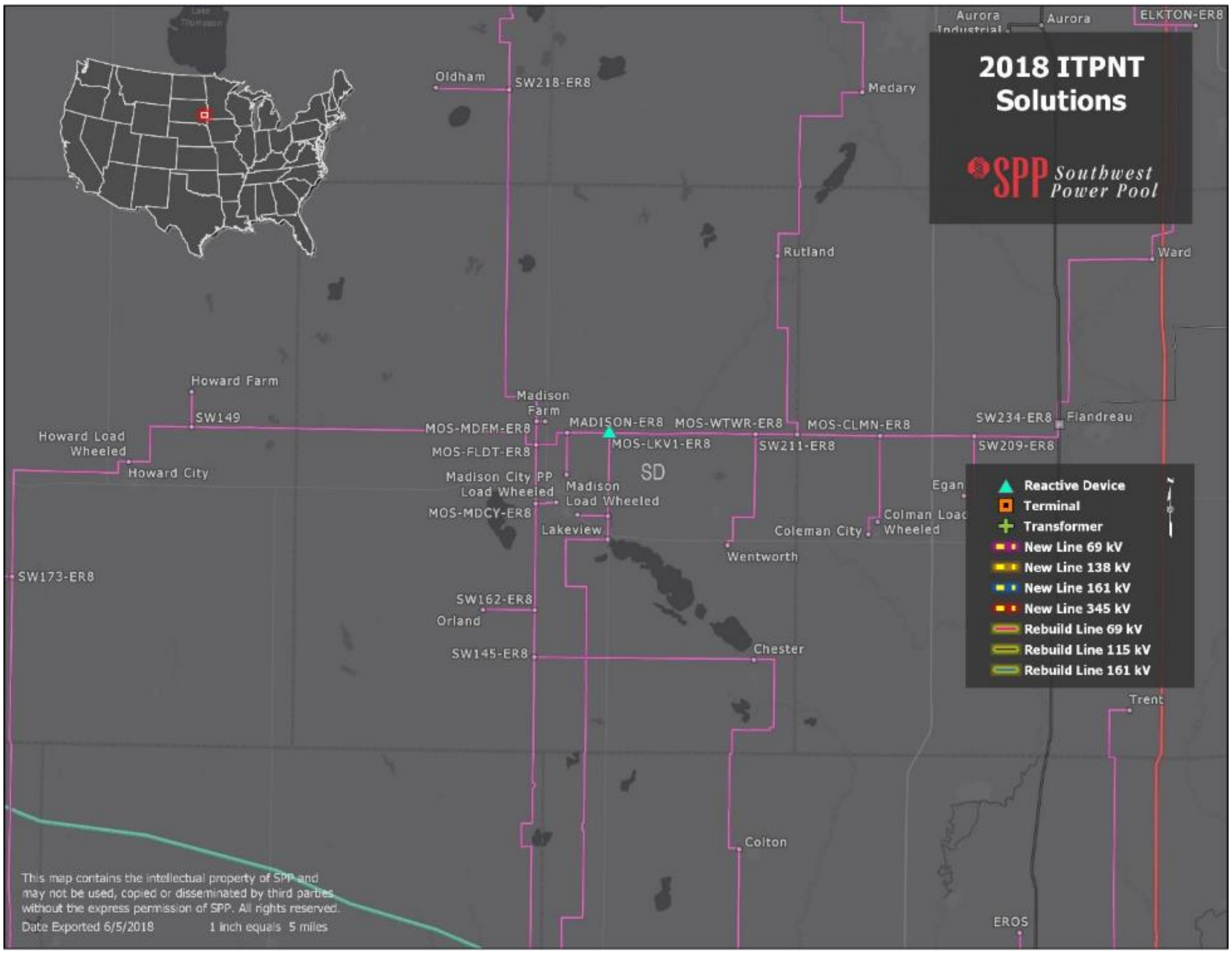

Figure 22: New Lakeview 69-kV substation. New 14.4 MVAR switched shunt at Lakeview 69 kV

Low voltages on the transmission system in the area around Madison, South Dakota, are due to 5 radial loads larger than 6 MW on the 69-kV system concentrated in the Madison area. Updates and corrections to load, specifically the city of Madison, were identified at the end of the 2017 ITPNT and were included in the 2018 ITPNT models. These updates are now causing the low voltages in the Madison area, even under system-intact conditions. The recommended project to add a 14.4 MVAR capacitor bank that will raise voltage in the area will require a new substation about 3.5 miles north of the Madison Southeast substation at the Lakeview Motor-Operated-Switch (MOS).

RECONDUCTOR RICHLAND – LEWIS 115-KV

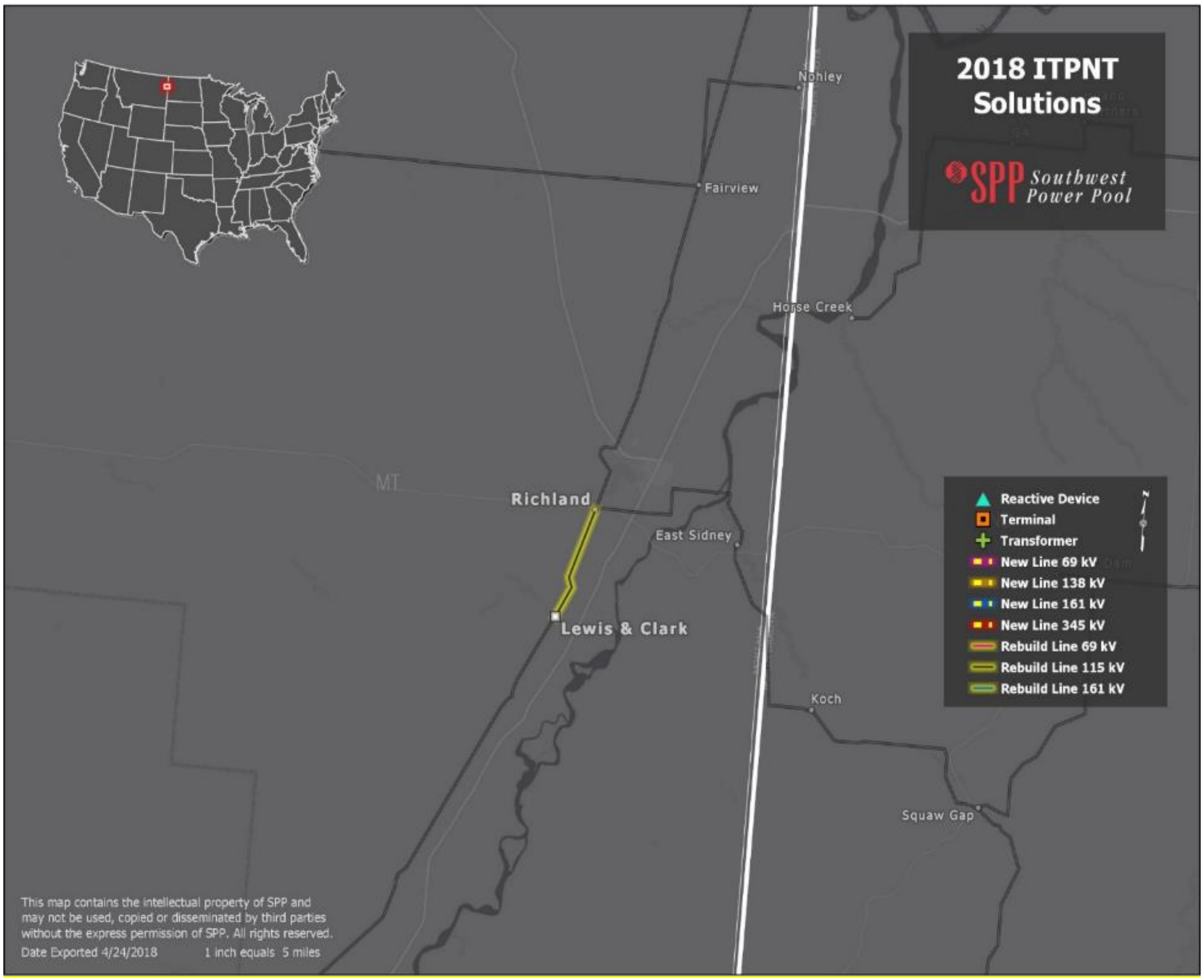

Figure 23: Reconductor 3 miles of 115-kV line from Richland - Lewis

Overloads on the Richland - Lewis & Clark 115-kV line were only identified in the S5 models and are due to power importing from the Miles City DC Tie [~140 megawatts (MW)]. The previous ITPNT assumed power exporting (~135 MW). This change in DC tie flows from export to import resulted in a net change of 270 MW of flow from west to east across the DC tie. The power is flowing north to help feed a major load pocket in North Dakota. The proposed project to reconductor the line, adjust the current transformer (CT) taps to 1200/5 and replace structures as needed increases the line rating.

REPLACE THE LAWRENCE HILL 230/115-KV TRANSFORMER

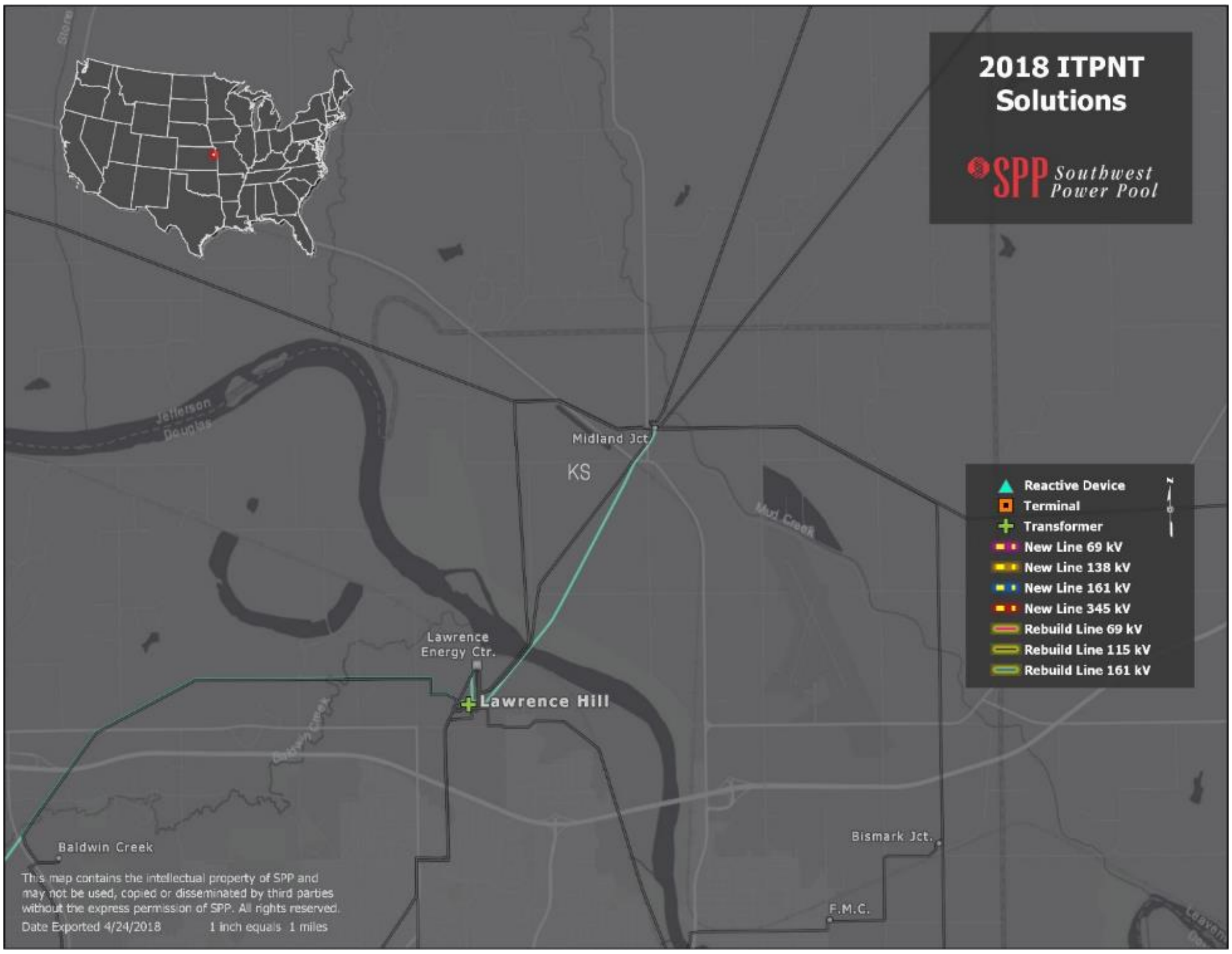

Figure 24: Replace the 230/115-kV transformer at Lawrence Hill

During system intact conditions, the Lawrence Hill and Midland Junction transformers serve local load in Lawrence, Kansas. A large portion of the load in Lawrence is served by firm generation at Lawrence Energy Center (LEC) Units 4 and 5. Unit 5 (408 MW capability) is connected to the 230-kV system, while Unit 4 (123 MW capability) is connected to the 115-kV system. In SPP summer planning models, both generators at Lawrence are dispatched at greater than 85 percent of their max capacity. As peak load conditions arise, more flow from Unit 5 is sent through the transformers to serve the load. When the outage of either the Lawrence Hill – Midland Junction 230-kV line or the Midland Junction 230/115-kV transformer occurs, flows are redirected through the only remaining path to serve the load. As a result, the Lawrence Hill 230/115-kV transformer is observed to be overloaded in the 2019 and 2022 summer peak BR models. During previous ITP studies, an NTC to address violations on the Lawrence Hill and Midland Junction transformers was issued and ultimately withdrawn because the need was no longer observed. Westar Energy has operating guides requiring reduction of Unit 5 to address loading on this transformer for specific N-1 contingency conditions. The operating guide actions were implemented in the planning models and were able to mitigate the need; however, the TWG determined that this operating guide is not a valid long-term solution and ineffective for planning studies because short-term ratings for the facilities in violation are not included in the operating guide. As a result, the proposed project is to replace the existing 230/115-kV transformer at Lawrence Hill with a larger transformer.

NEW BLUE VALLEY – CROSSTOWN 161-KV LINE

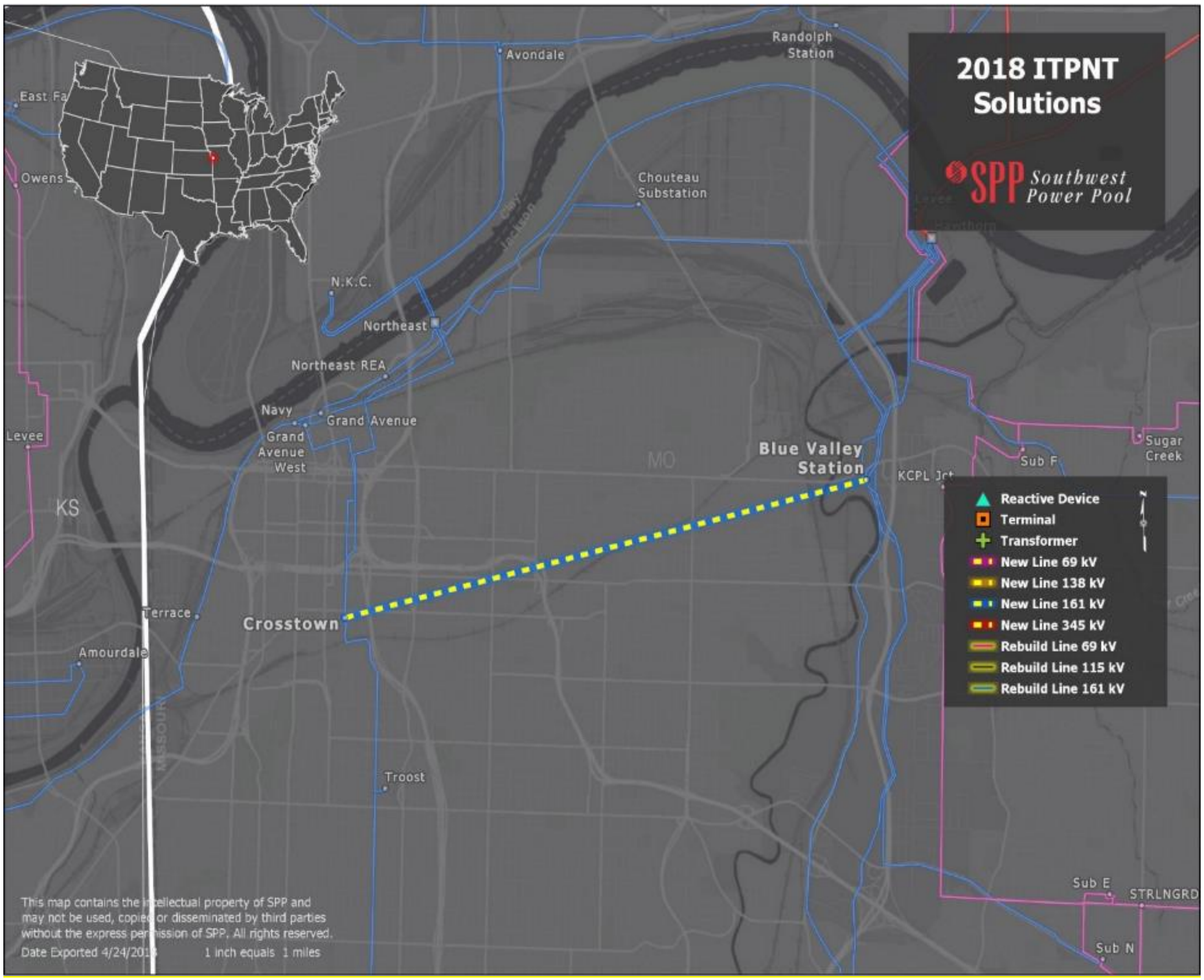

Figure 25: Construct a new 5.6-mile, 161-kV line from Blue Valley – Crosstown

In June 2017, Kansas City Power & Light (KCPL) announced the retirement of six units at three power plants[12]. The retirements of two units at Montrose and three units at Sibley, totaling 340 MW and 463 MW respectively, are set to be effective by Dec. 31, 2018. Due to these retirements, there are units being dispatched in the 2018 ITPNT models that historically have not been. Specifically, the units at Northeast Station are dispatched and create additional north-to-south flow through Kansas City. Overloads on the 161-kV system on the north side of Kansas City were identified for the loss of either the Northeast – Grand Avenue – Navy 161-kV line or the Northeast – Grand Avenue West 161-kV lines that provide a large portion of outlet for the Northeast Station plant. The proposed project is to construct a new 161-kV line from Crosstown to Blue Valley. This project will create a new feed onto the 161-kV system to the south and relieve loading on the 161-kV lines Northeast – Grand Avenue, Grand Avenue – Navy, and Navy – Crosstown. Several alternative

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[12] https://www.kcpl.com/about-kcpl/media-center/2017/june/kcpl-continues-sustainability-commitment-by-announcing-retirement-of-six-units-at-three-power-plants

projects were considered, including rebuilds of the overloaded lines, a new 161-kV line from Navy to the North Kansas City bus, as well as utilizing an existing operating guide. These options requiring construction of new transmission were determined to be infeasible due to the lack of available space in the substations at Navy and Grand Avenue, as well as added challenges and cost to perform major work on the existing lines because they are underground. Implementation of the actions in the operating guide mitigates the need; however, the TWG determined this operating guide is not a valid long-term solution and ineffective due to multiple factors identified by KCPL. The justification provided by KCPL was that the operating guide does not specify an emergency rating, usage of the operating guide would result in a single feed into the high load downtown Kansas City area, as well as operational issues due to loop flows in this area when neighboring utilities are importing regardless of the generation output from the Northeast units.

REPLACE TERMINAL EQUIPMENT ON OLATHE – SWITZER 161-KV AND BROOKRIDGE – OVERLAND PARK 161-KV

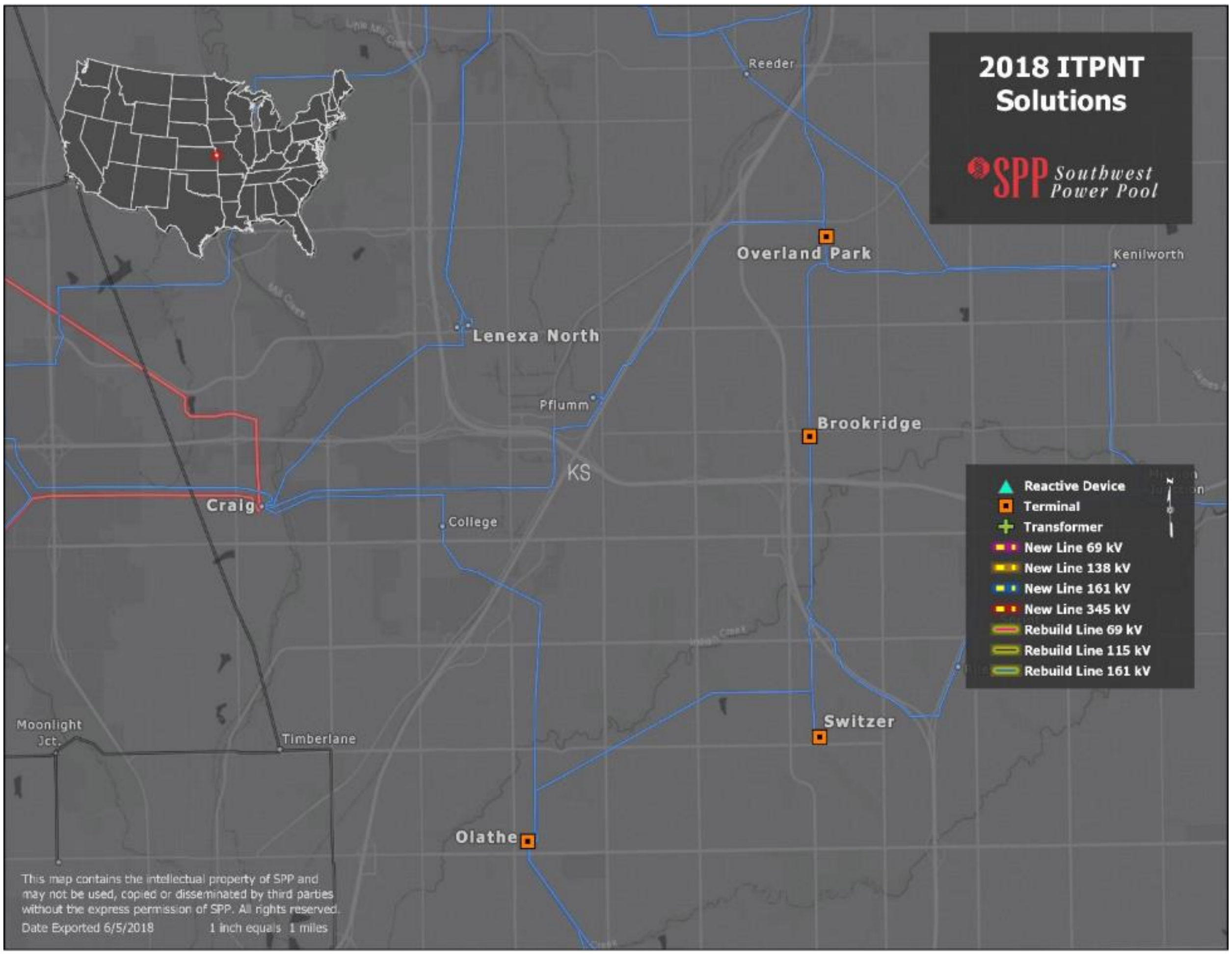

Figure 26: Replace terminal equipment on the 161-kV line from Olathe – Switzer / Replace terminal equipment on the 161-kV line from Brookridge – Overland Park

In the 2019 and 2022 summer cases, the Olathe – Switzer 161-kV and Brookridge – Overland Park 161-kV lines overload for the loss of each other. In previous studies, these lines were rated 557/557 MVA but were de-rated in the 2018 ITPNT models to 348/348 MVA. The limiting element on the Olathe - Switzer line are the CTs at the Olathe sub, so the project being selected is to replace the CTs to achieve a higher rating. The limiting element on the Overland Park – Brookridge line is the 1200 amp breaker switches at the Overland Park sub, so the project being selected is to replace the breaker switches to achieve a higher rating.

NEW BROOKLINE 345-KV REACTOR

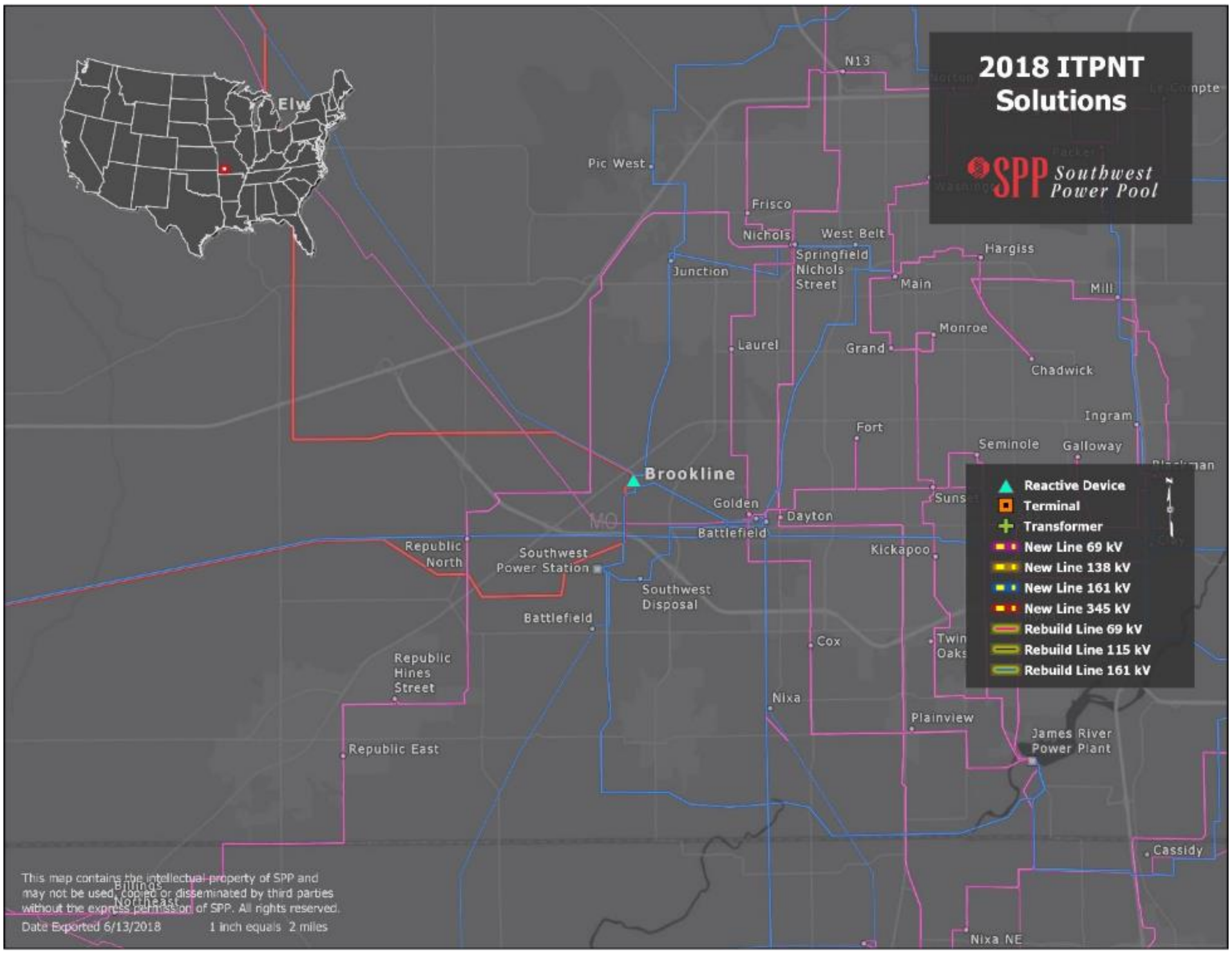

Figure 27: New 50 MVAR switched shunt at Brookline 345 kV. Brookline 345-kV Substation expansion

In real-time operations during lightly loaded seasons, SPP persistently identifies high-voltage issues on the 345-kV transmission system around the Brookline substation in southern Missouri. Agreements have been in place between AECI, City Utilities of Springfield (CU) and American Electric Power (AEP) to reconfigure the transmission system to avoid high voltage since the line existed due to the absence of transmission options. Two occurrences of the historical high voltage were captured in a model and previously studied during the 2016 JCSP with AECI. The 50 MVAR switched shunt reactor proposed to address the high voltage was reaffirmed in the 2018 ITPNT assessment.

REBUILD NIXA DOWNTOWN – NIXA ESPY 69-KV

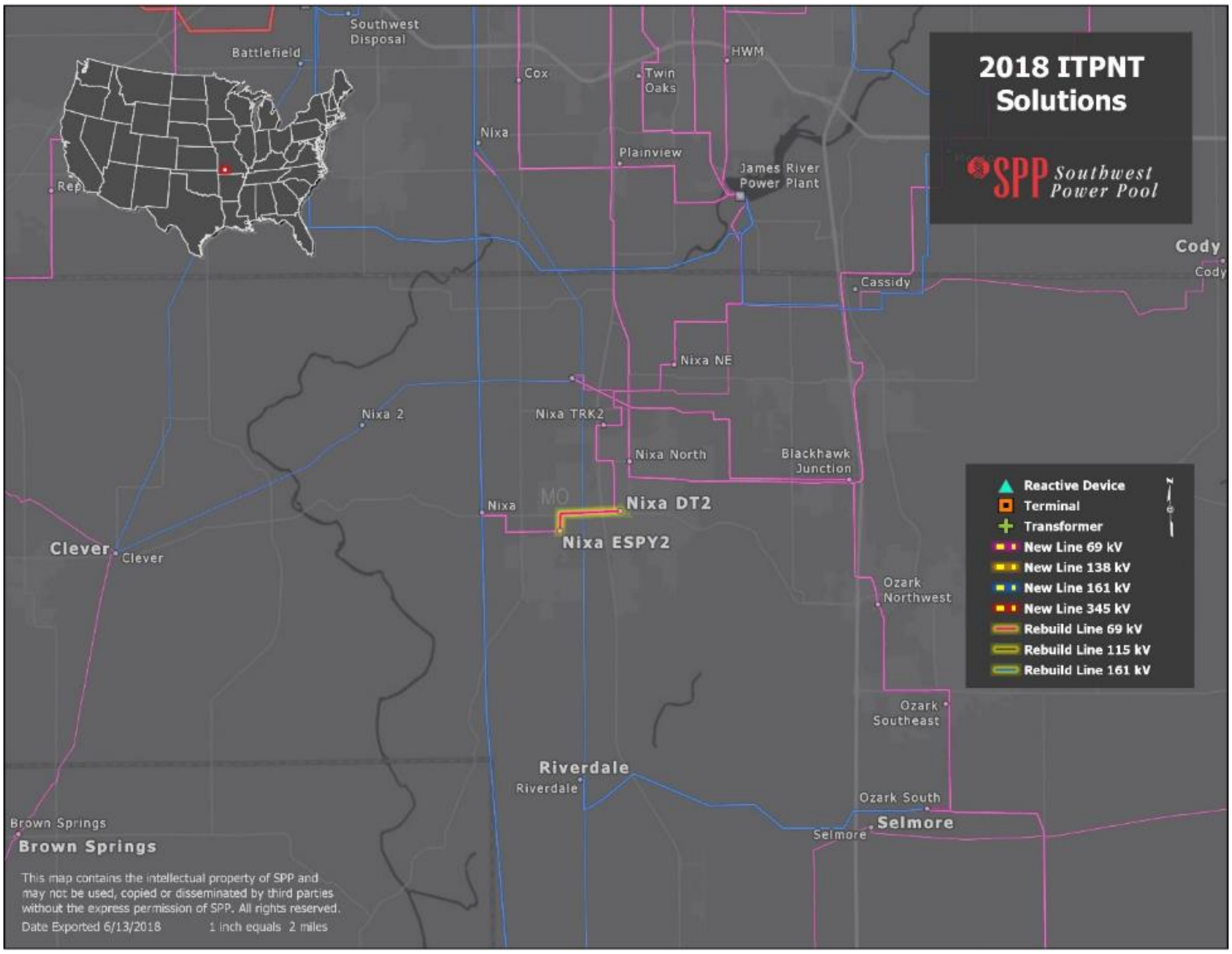

Figure 28: Rebuild 1.25 miles of 69- kV line from Nixa Downtown – Nixa Espy

Near the city of Nixa, Missouri, the Nixa Downtown - Nixa Espy 69-kV line overloads for the loss of the James River 5 unit just south of Springfield, Missouri. This generating plant provides counterflow on the 69-kV system against flows from the 161-kV system stepping down just to the west. This overload was placed under additional scrutiny because it was only identified in the BA model scenario.[13] Based on information provided by CUS at the Engineering Planning Summit and data submitted for the 2019 ITP assessment, the remaining steam gas units (4 and 5) at the James River plant will be retired by early 2019. To support issues expected by CUS, a second James River 161/69-kV transformer will be installed and the 69-kV bus will be split by a normally open breaker. These upgrades and the retirement expectations were not included as an assumption in the 2018 ITPNT model set. The second James River 161/69-kV autotransformer was tested and found to reduce the overloads in the 2018 ITPNT model set but does not solve all the issues, which are expected to get worse under any scenario with the unit retirements. While alternative projects

[13] See Section 5.2 for a discussion on the concerns with the BA model scenario.

were considered, such as a new 69-kV line from Nixa Tracker to AECI's Jamesville substation, the preferred project was ultimately found to be to rebuild the Nixa Downtown – Nixa Espy 69-kV line.

REBUILD FIGURE FIVE – VBI NORTH 69-KV

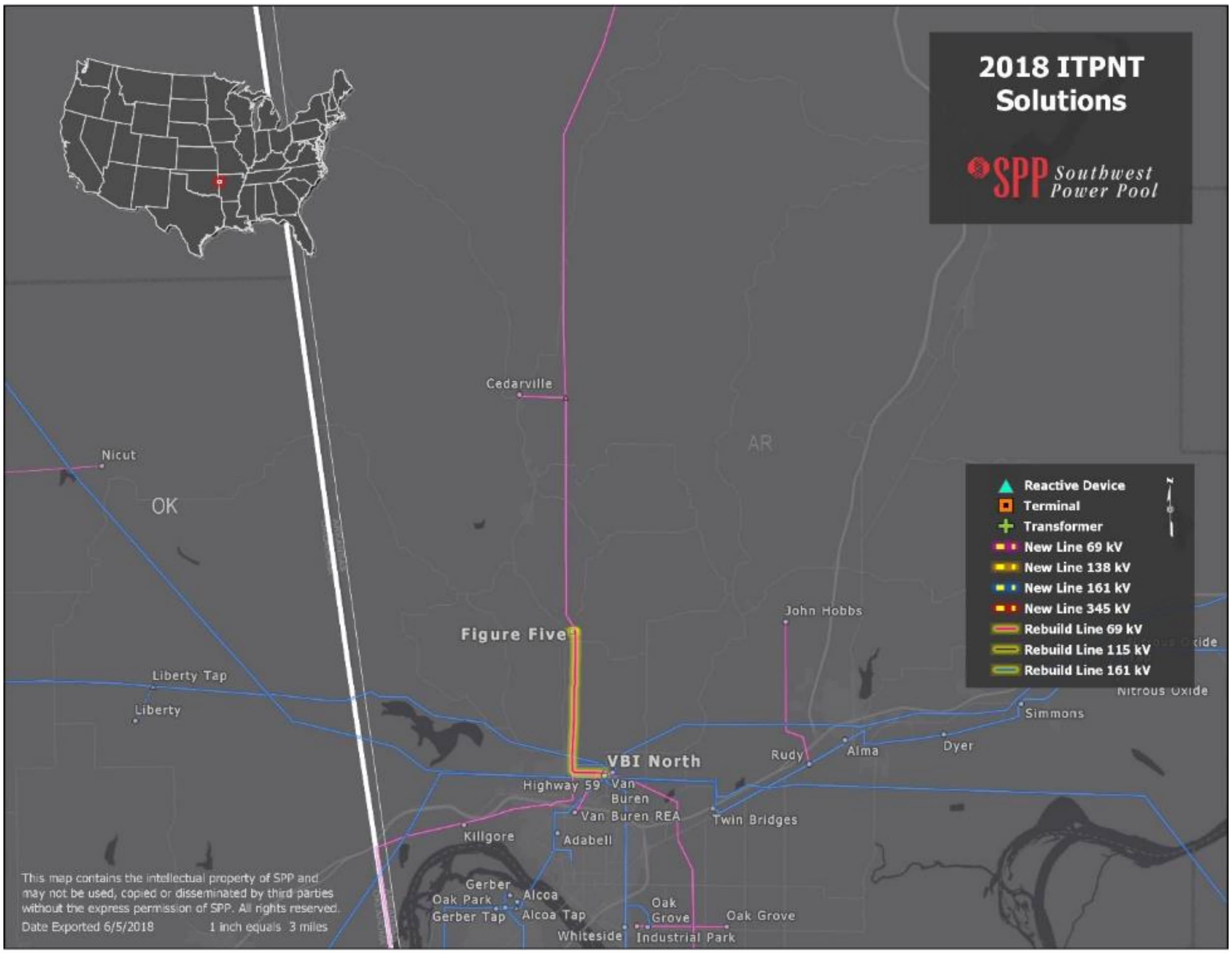

Figure 29: Rebuild 4.2 miles of 69-kV line from Figure Five – VBI North

In the 2019 and 2022 summer BA cases, the Van Buren (VBI) North – Figure Five-69kV line overloads for the loss of the Chamber Springs – Clarksville 345-kV line. These overloads are due to the generation dispatch in the BA series of models as well as a slight increase in load in the area to the north. The VBI North – Figure Five is loaded at 99 percent in the scenario 0 model and appears to be an issue in future models. The project selected is to rebuild the VBI North – Figure Five 69-kV line, including an upgrade of Arkansas Electric Cooperative Corporations (AECC) station conductor at VBI North to achieve a higher rating.

NEW MCDOWELL 230-KV SUBSTATION AND TRANSFORMER

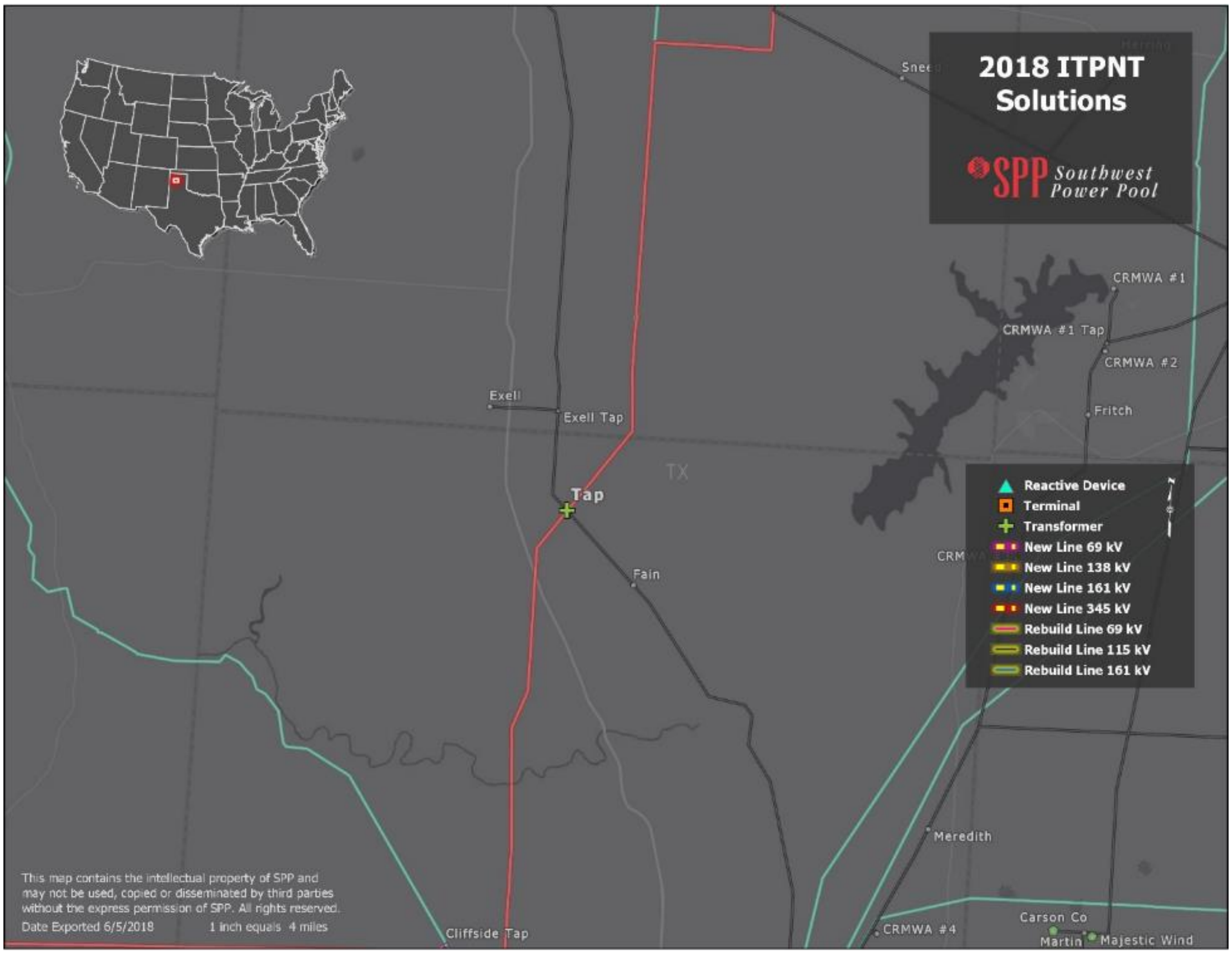

Figure 30: McDowell 230/115-kV Transformer and Substation

The load at Rita Blanca's Stokes and Sheldon (RBSS) substation previously was analyzed through SPP's Attachment AQ delivery-point study process and included in the base model sets. The forecast for the load, primarily oil and gas, has since increased and is now causing low voltage on the 115-kV system north of Nichols when the source from Moore is lost. Initially, a capacitor bank at Dumas was evaluated to raise the system voltage under the Moore – RBSS 115-kV contingency. While this solution was sufficient to address the low voltages defined as needs in this assessment, additional investigation was performed to determine if this was the best long-term solution since the size of capacitor bank necessary to withstand any additional load growth would have been large. It was determined that the better long-term solution was to provide a new source by building a new substation where the Moore – Potter 230-kV line and Exell Tap – Fain 115-kV line cross and installing a step-down transformer. This solution is able to support additional load growth and limits the length of the radial 115-kV line created under the Moore – RBSS outage.

REPLACE TERMINAL EQUIPMENT ON CARLISLE – MURPHY 115-KV

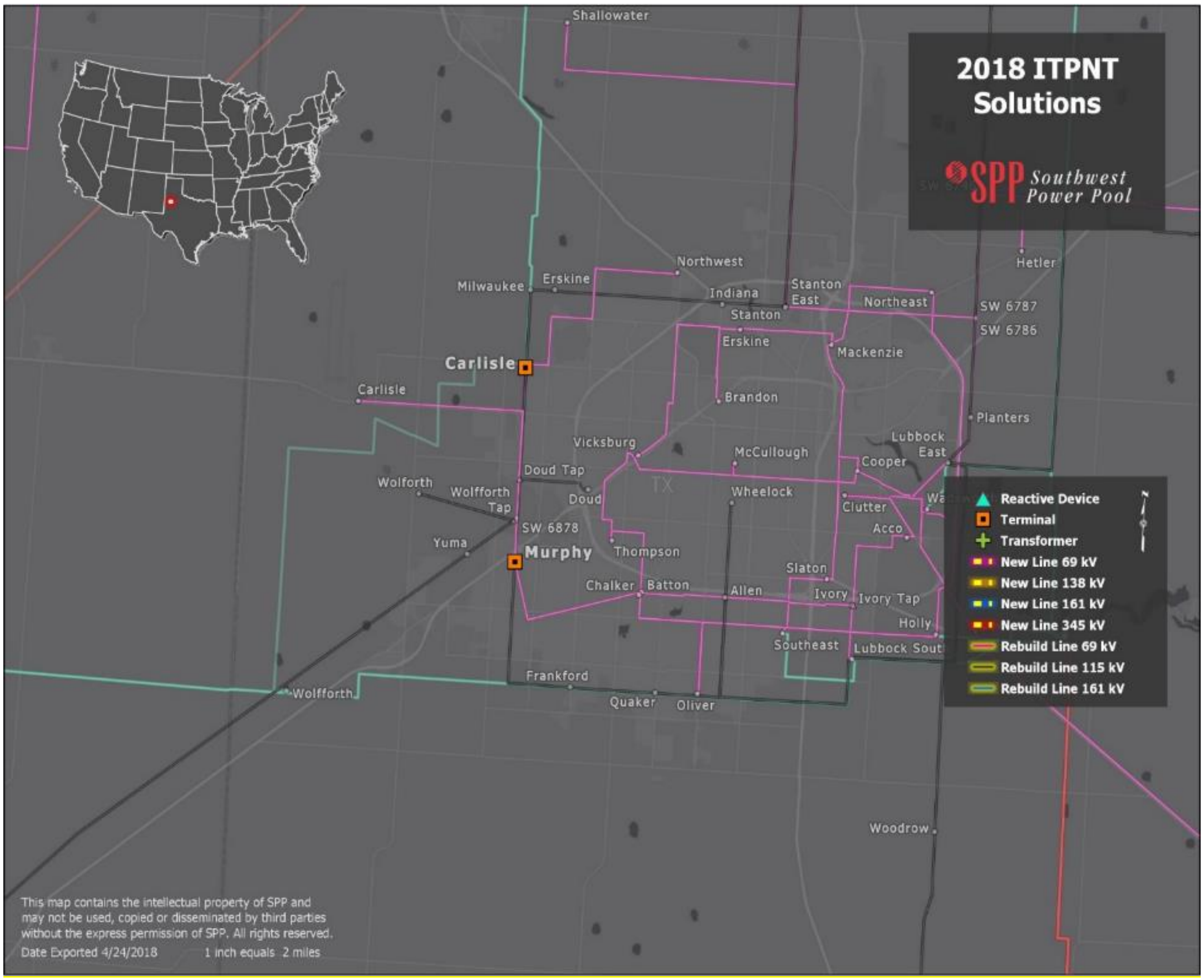

Figure 31: Replace terminal equipment on the 115-kV line from Carlisle – Murphy

A small 115-kV network near Lubbock, Texas, serves load at multiple delivery points. Loads along the 115-kV line from the west at Carlisle to the Allen sub on the south have increased slightly from previous summer peak forecasts. When the feed from the east between Allen and Lubbock South is lost, the load becomes radially served from the west, causing a slight overload on the Carlisle-to-Murphy line. Replacing terminal equipment on this line is sufficient to address the violation.

REPLACE TERMINAL EQUIPMENT ON CLAUENE – TERRY COUNTY 115-KV

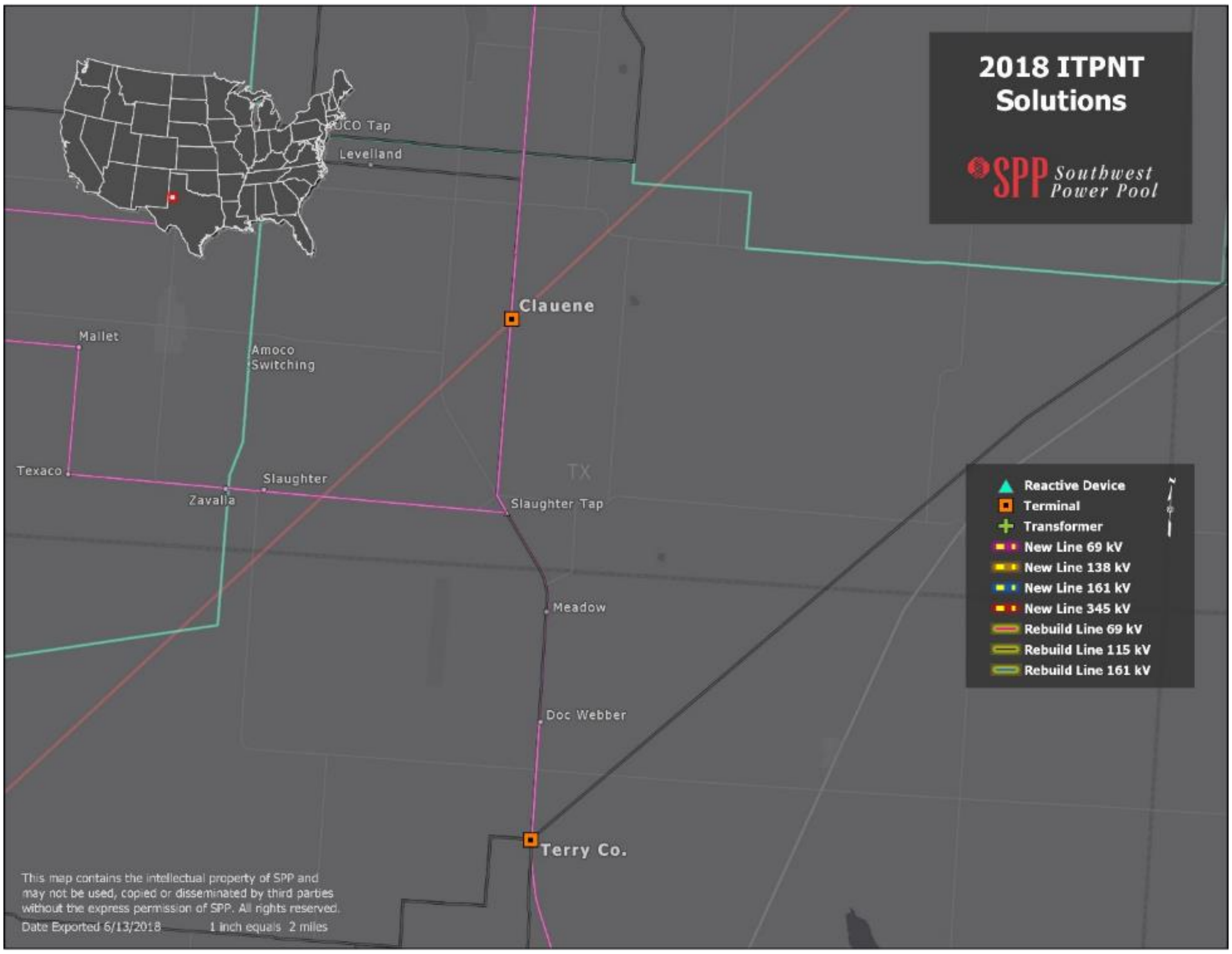

Figure 32: Replace terminal equipment on the 115-kV line at Clauene

The Texas panhandle experiences high north-to-south flows under high-wind, low-load conditions, serving a portion of the load in the south down into New Mexico with wind from north of the SPS system. Under these system conditions, much of the conventional generation to the south is offline compared to higher load conditions. The Clauene - Terry-County 115-kV line is in the middle of the north-south corridor and begins to overload when it has to pick up additional flows from the loss of the Wolfforth - Terry County 115-kV line or the Sundown - Amoco 230-kV line. This issue was further aggravated by a more accurate change in assumptions for the light load model in this study that resulted in the solar generation to the south, which was providing counterflow in previous studies, being turned offline. Replacing terminal equipment on the Clauene – Terry County line is sufficient to address the overload.

REPLACE THE SUNDOWN 230/115-KV TRANSFORMER

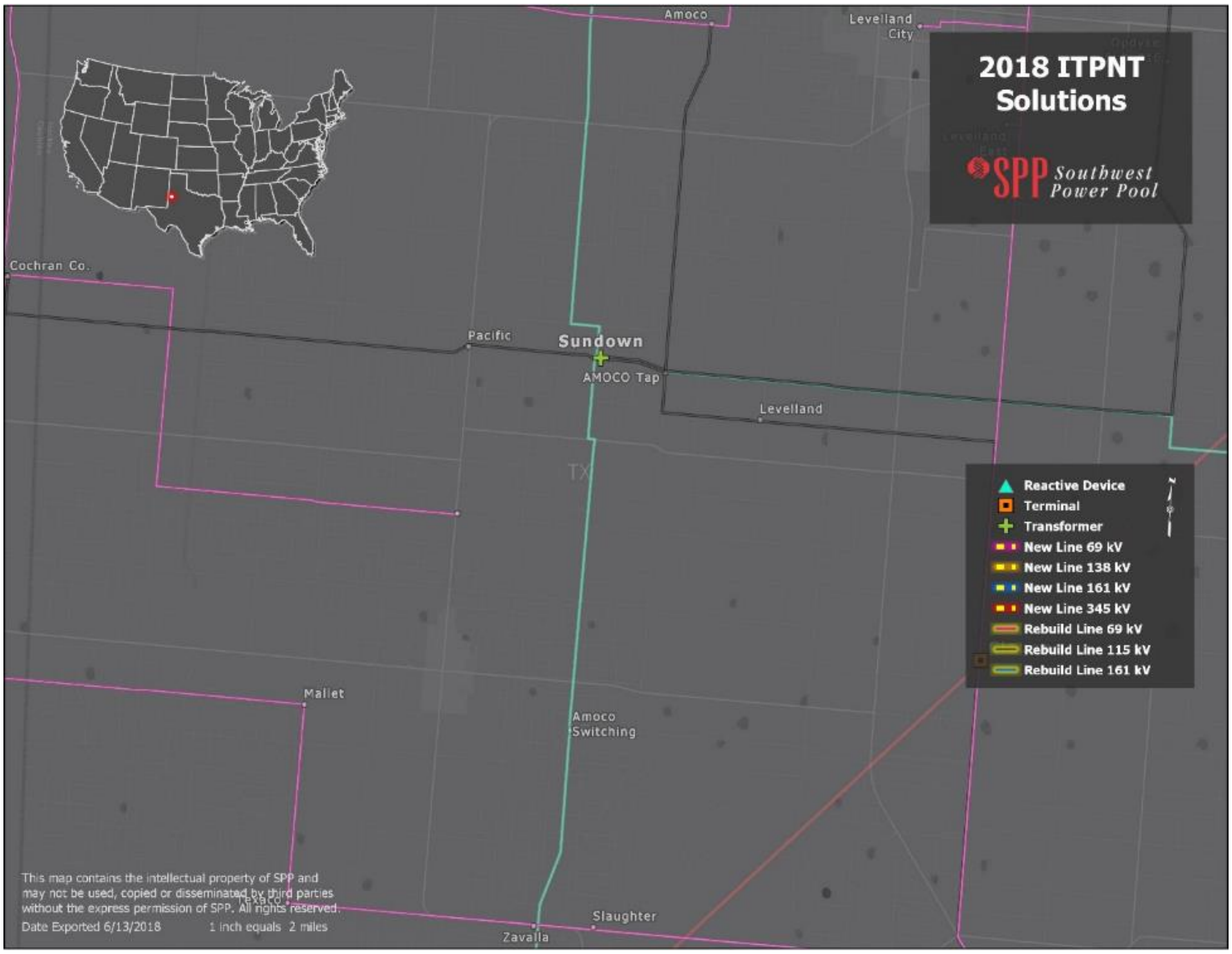

Figure 33: Replace the 230/115-kV transformer at Sundown

Much of the load on the 115-kV and 69-kV systems in the southern part of the Texas panhandle near Sundown is served through the 230-kV transformers at Lamb County, Sundown and Yoakum. When loads are high in the summer peak and the source from Lamb County is lost or the 115-kV loop is severed between Lea County Plains and Yoakum, the Sundown transformer becomes overloaded. This project is an alternative for the Dean Interchange project under re-evaluation that would have created a new 230-kV source in the area. It was selected because it is less costly, performs better, the load forecast in the surrounding area has remained stagnant and the existing transformer is rated well below the standard 230/115-kV transformers in the SPS zone.

7.2 SOUTH-CENTRAL OKLAHOMA LOW VOLTAGES

The load forecast for the member cooperatives of Western Farmers in south-central Oklahoma has increased from the 2017 ITPNT projections. The initial needs assessment produced significant base-case low voltages in all seasons that only worsened when the line from Caney Creek – Texoma Junction 138 kV was lost. During the solution evaluation phase of the study, it was identified that the power factors of the loads in Red River Valley Electric Cooperatives were incorrect. This update resolved the base-case low-voltage violations, but the violations are still present under contingency. Based on new information from Western Farmers, further analysis will be needed based on the most recent forecast and model corrections for this area. In order to determine the best solution for this area, Western Farmers will need to resolve the modeling concerns in a future study. In the interim, Western Farmers has agreed to provide mitigations for the observed 2018 ITPNT low voltages in this area.

7.3 FINAL RELIABILITY ASSESSMENT

All projects in the 2018 ITPNT portfolio were incorporated into the powerflow models and a steady state N-1 contingency analysis of equivalent scope to the analysis described in Section 5 of this document was performed to see if the selected projects caused any new reliability issues. Some needs appeared in the East River area, but those needs were mitigated through a transformer tap change. Therefore, the final reliability assessment showed no needs caused by portfolio projects that would require additional construction.

SECTION 8: 2018 ITPNT PROJECT LIST

The 2018 ITPNT project list is posted as a separate document at the following location:
https://www.spp.org/engineering/transmission-planning/

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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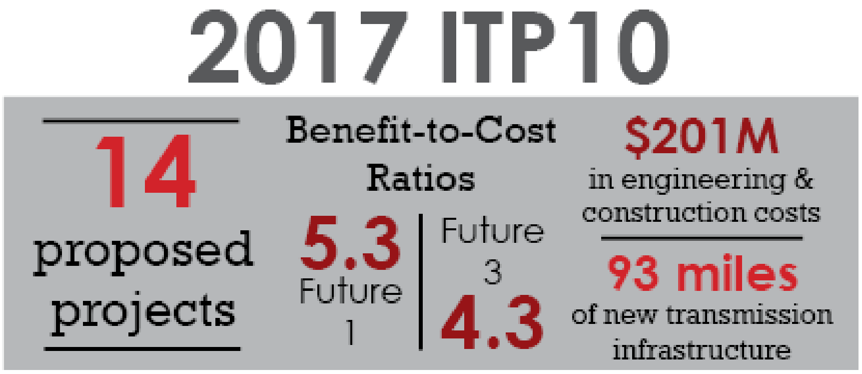
EXECUTIVE SUMMARY



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.

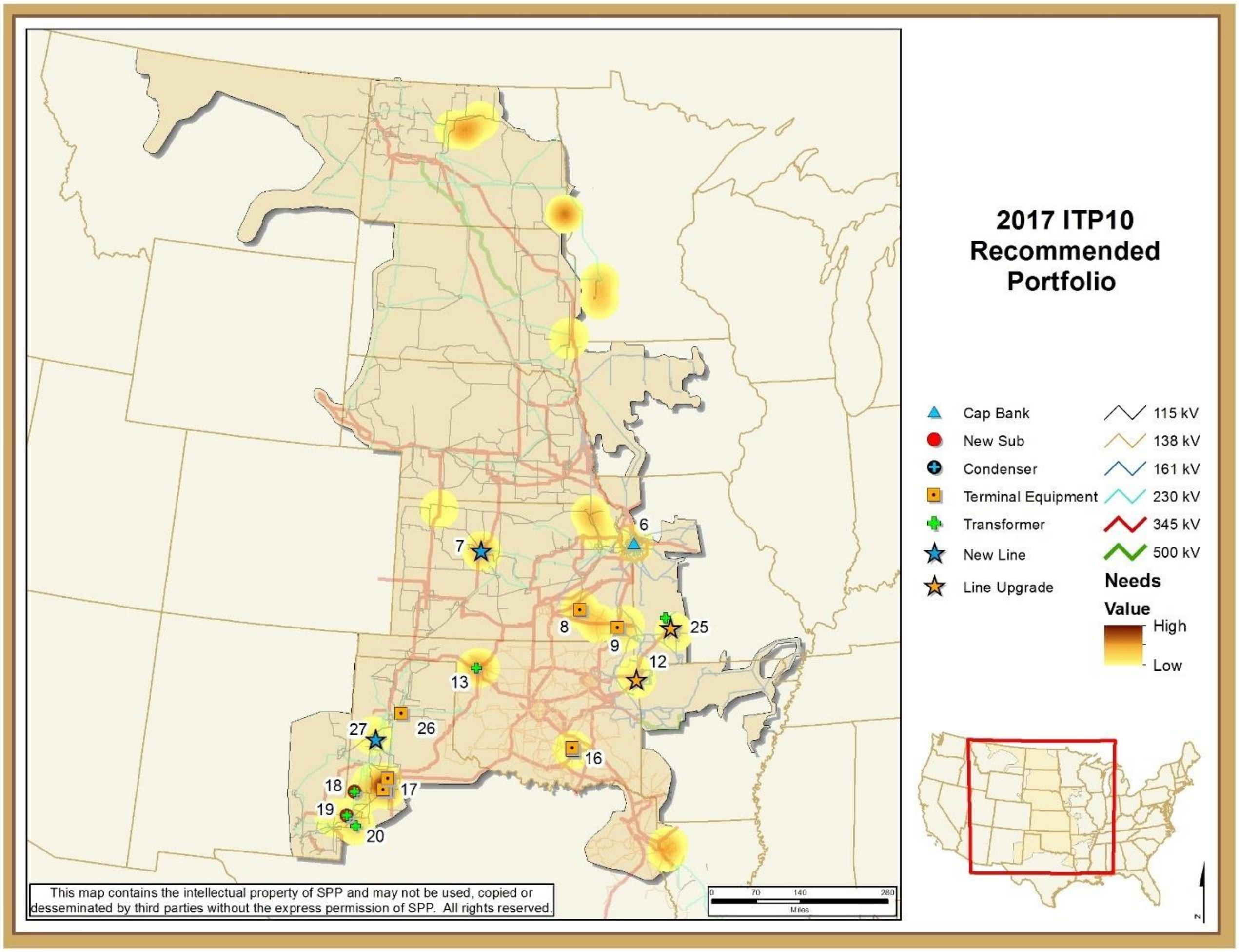


Figure 1.1: 2017 ITP10 Transmission Plan

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.

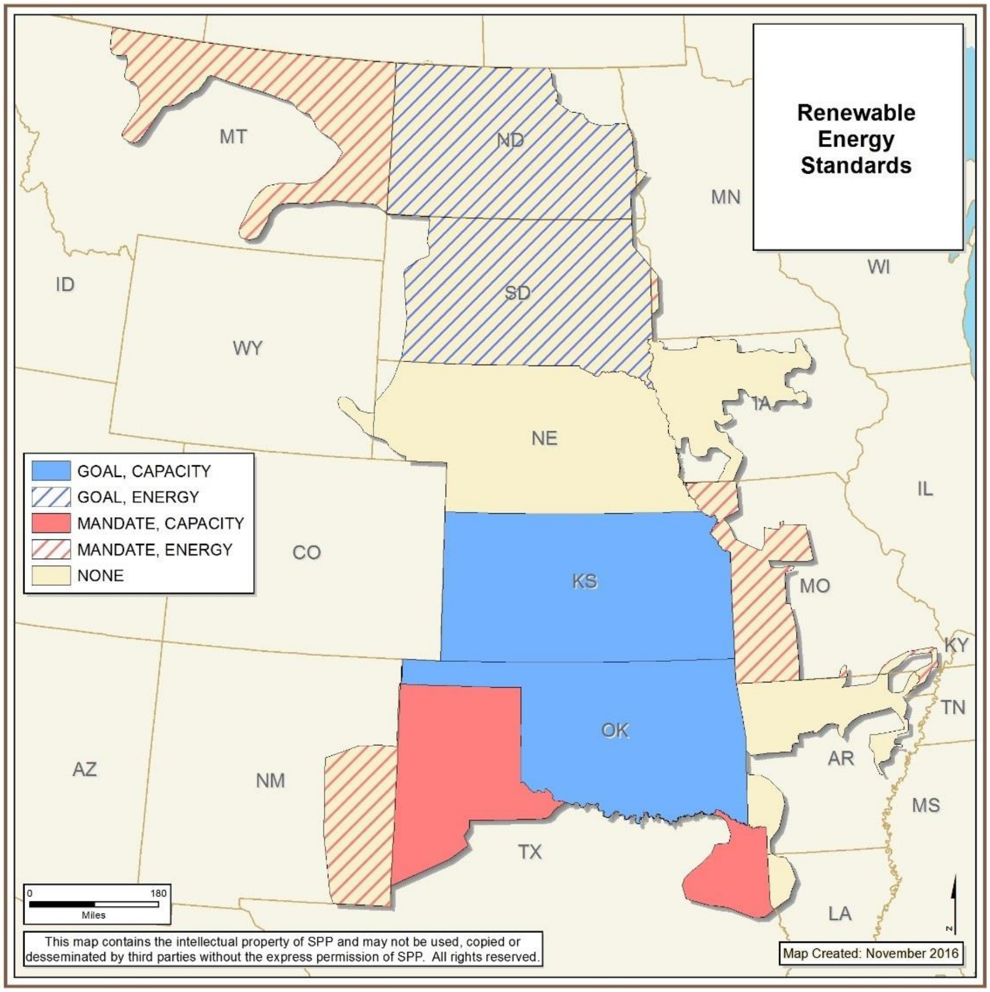

Figure 2.1: Renewable Energy Standards by State

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

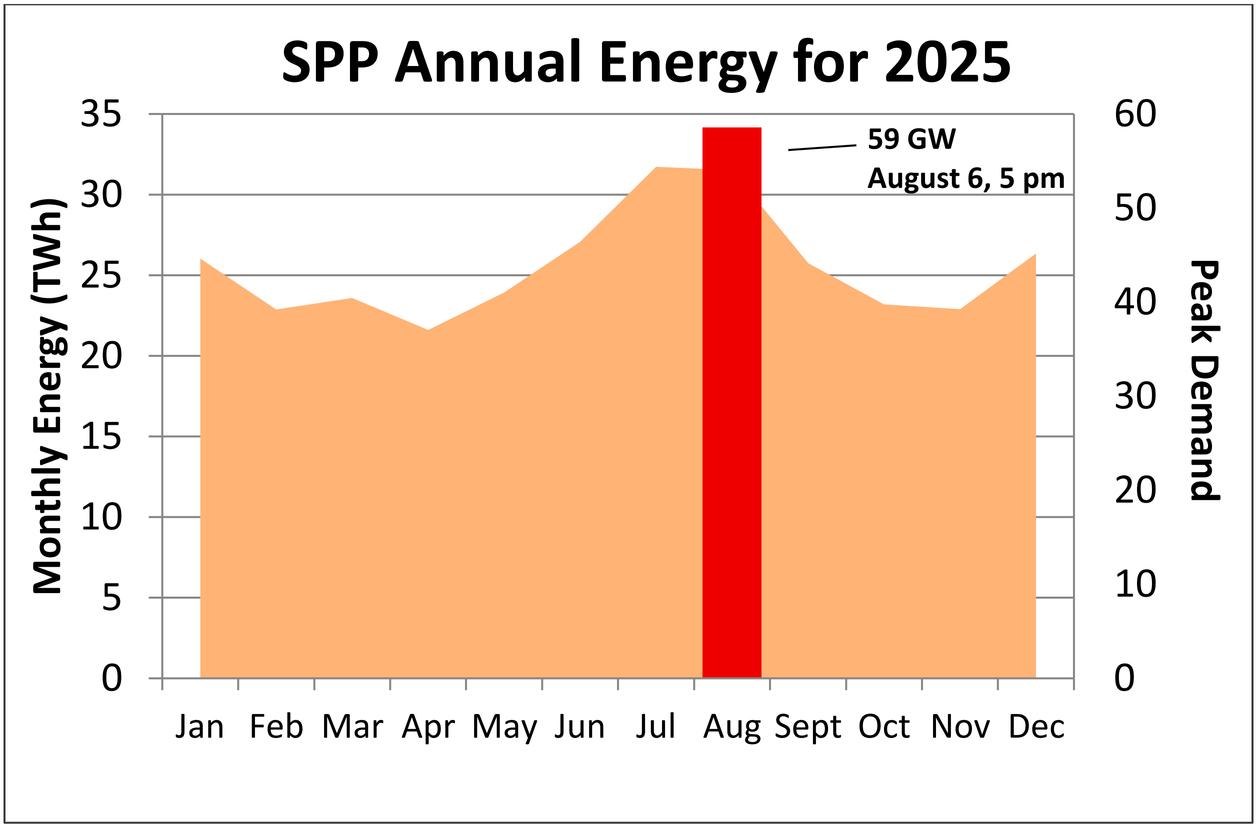

Figure 3.1: 2025 Annual Energy and Coincident Peak Load for SPP

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.

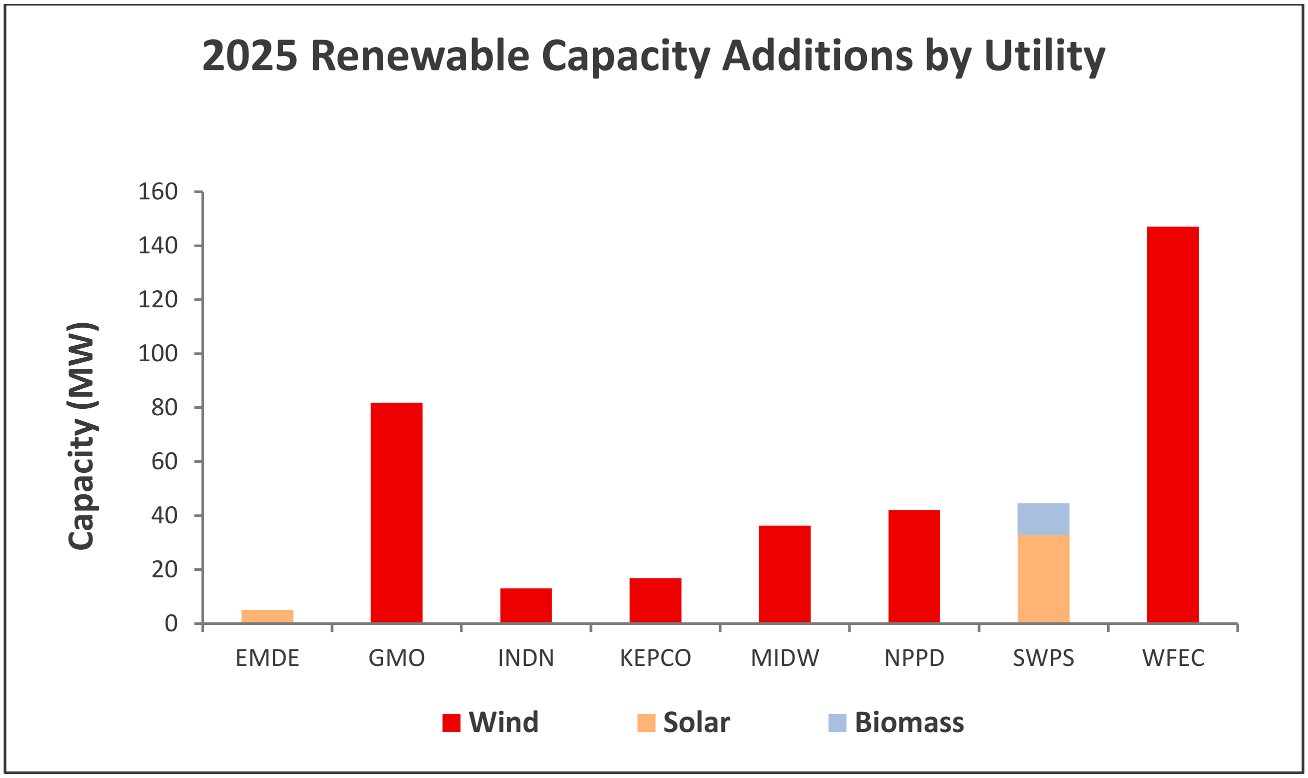

Figure 4.1: SPP Renewable Generation Additions to meet Mandates and Goals by Utility

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.

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[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.

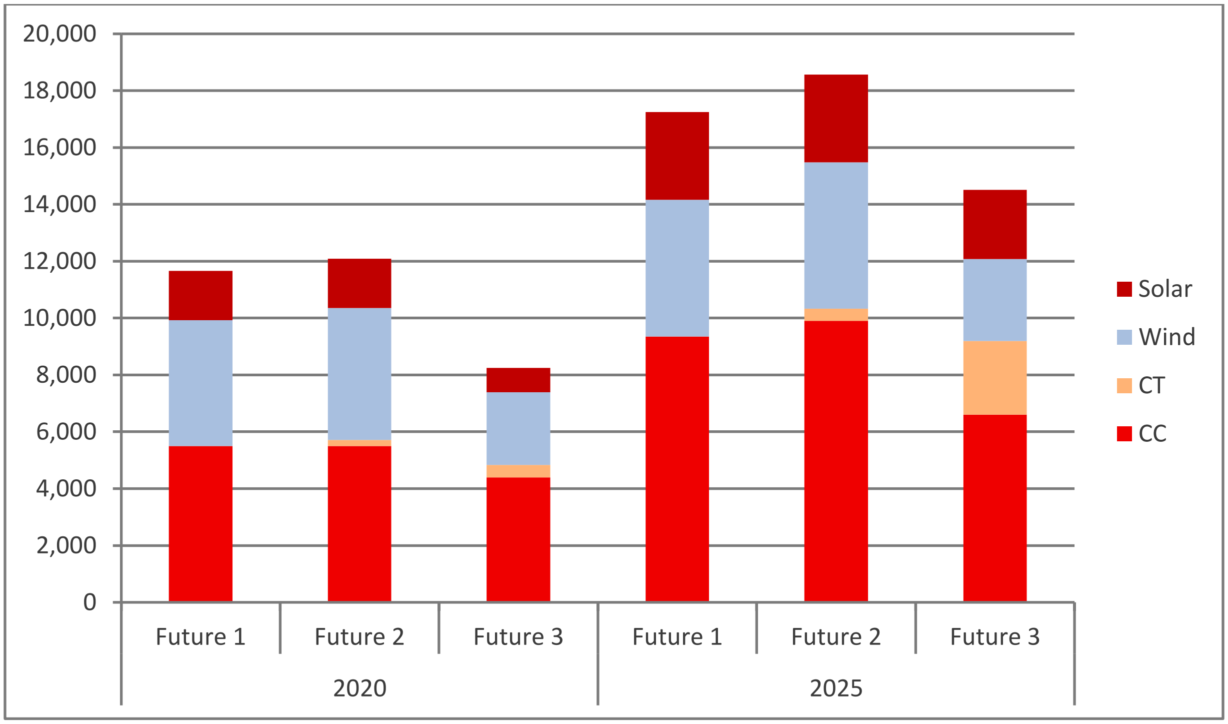


Figure 4.2 : Capacity Additions by Future and Year

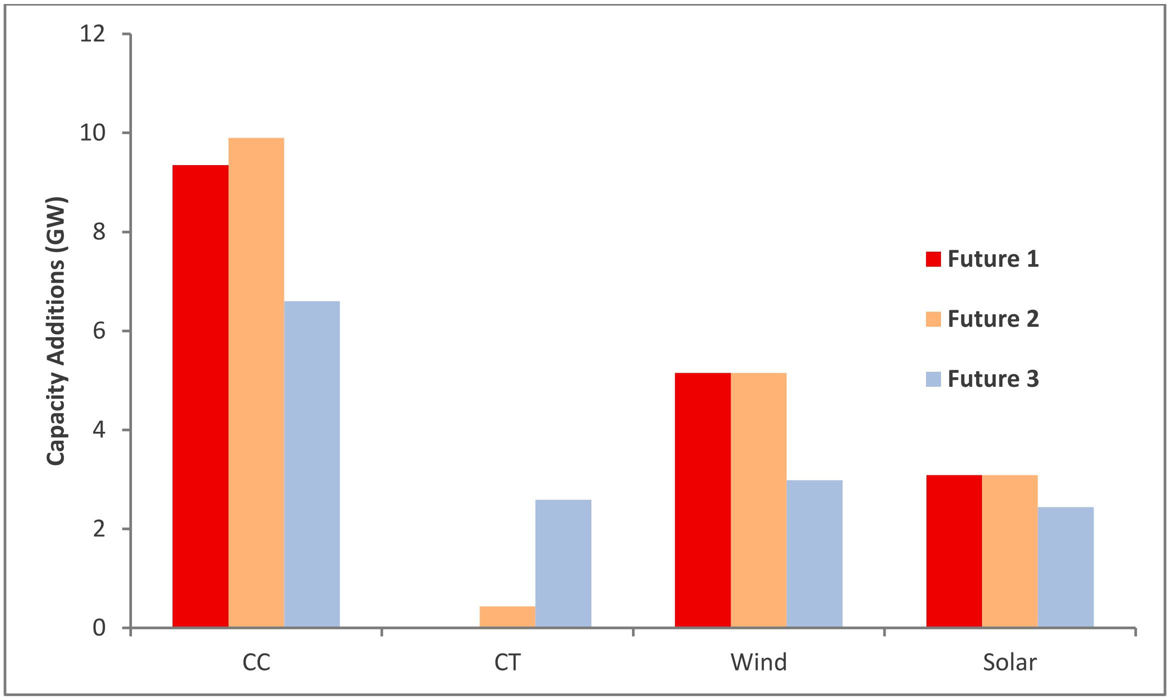
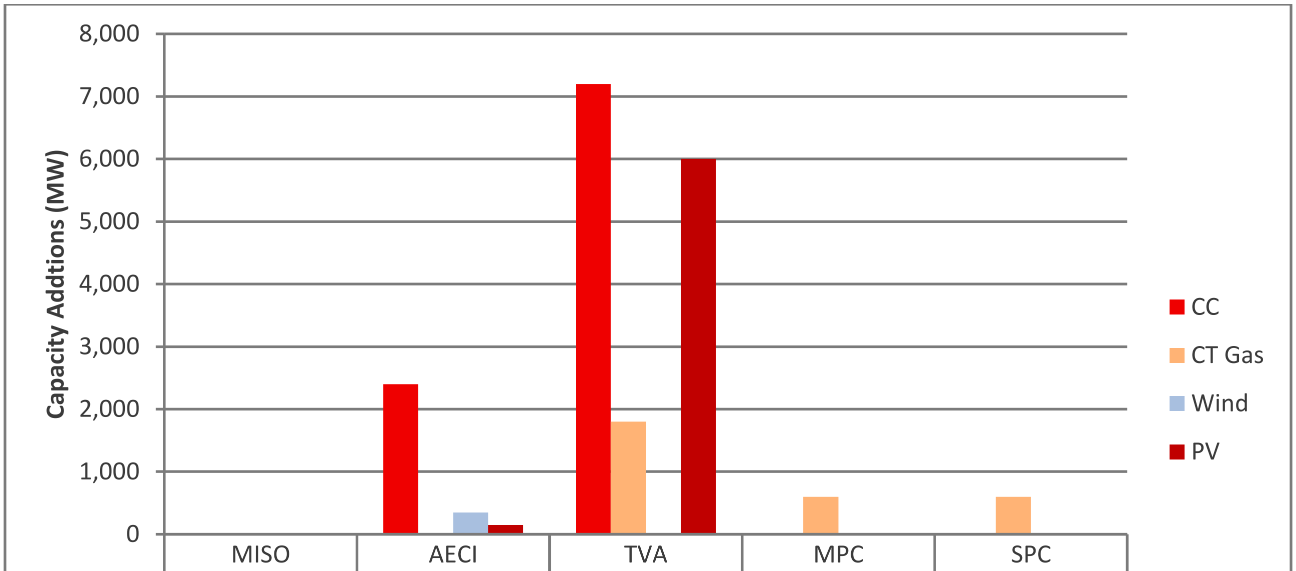


Figure 4.3: 2025 Cumulative Capacity Additions by Unit Type

External Regions

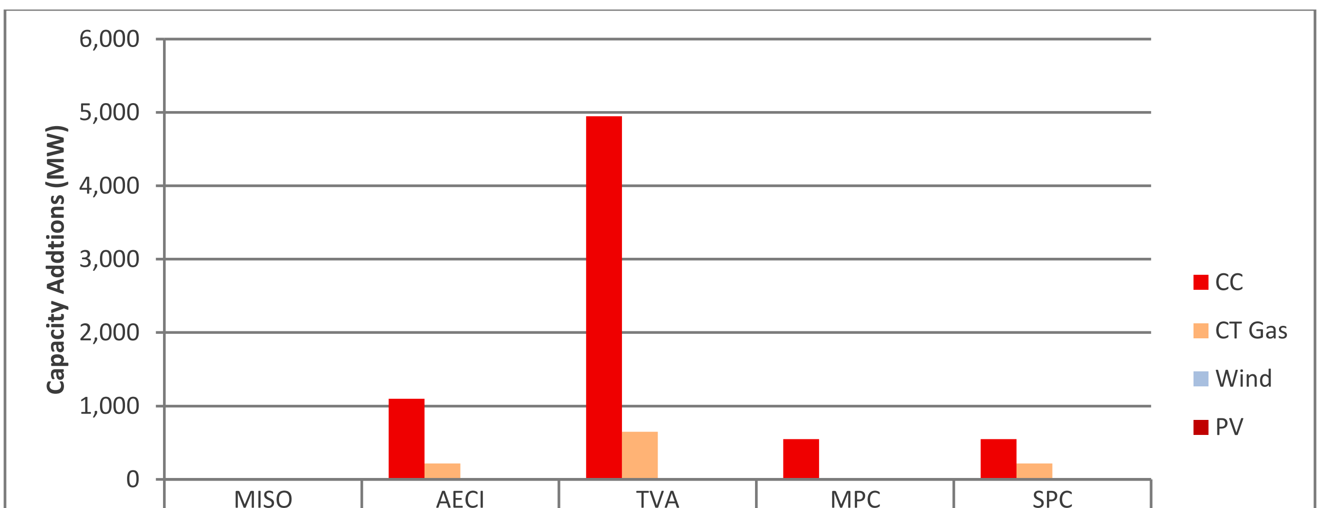
Resource plans were also developed for external regions. Each region was surveyed for load and generation and assessed to determine the capacity short fall before adding units so that each region met its own reserve margin. This analysis was performed for AECI, TVA, Minnkota, MISO, and Saskatchewan Power (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

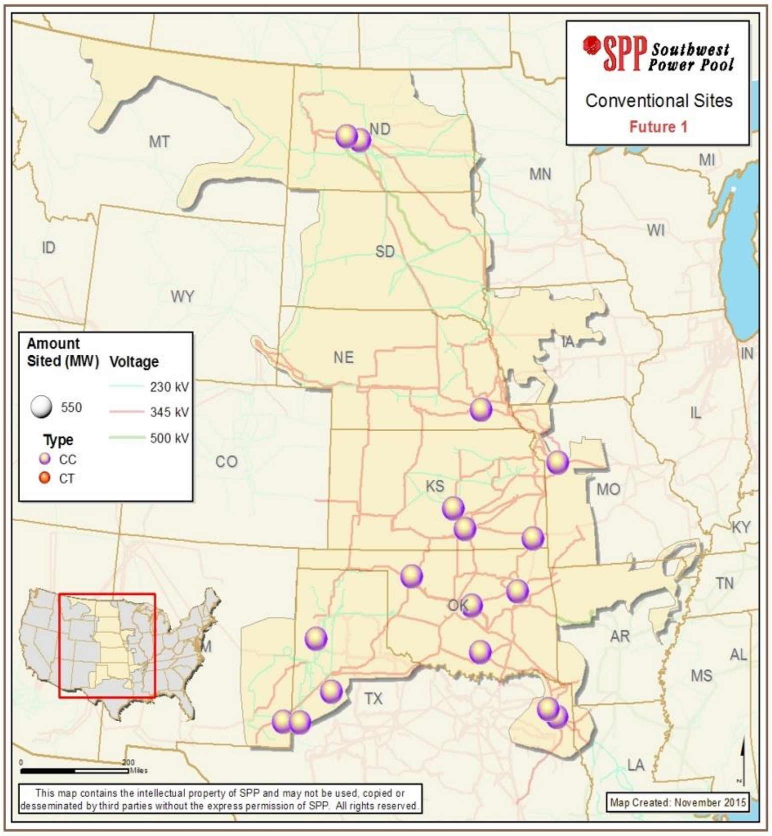


Figure 4.6: 2025 Conventional Generation Siting for Future 1

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

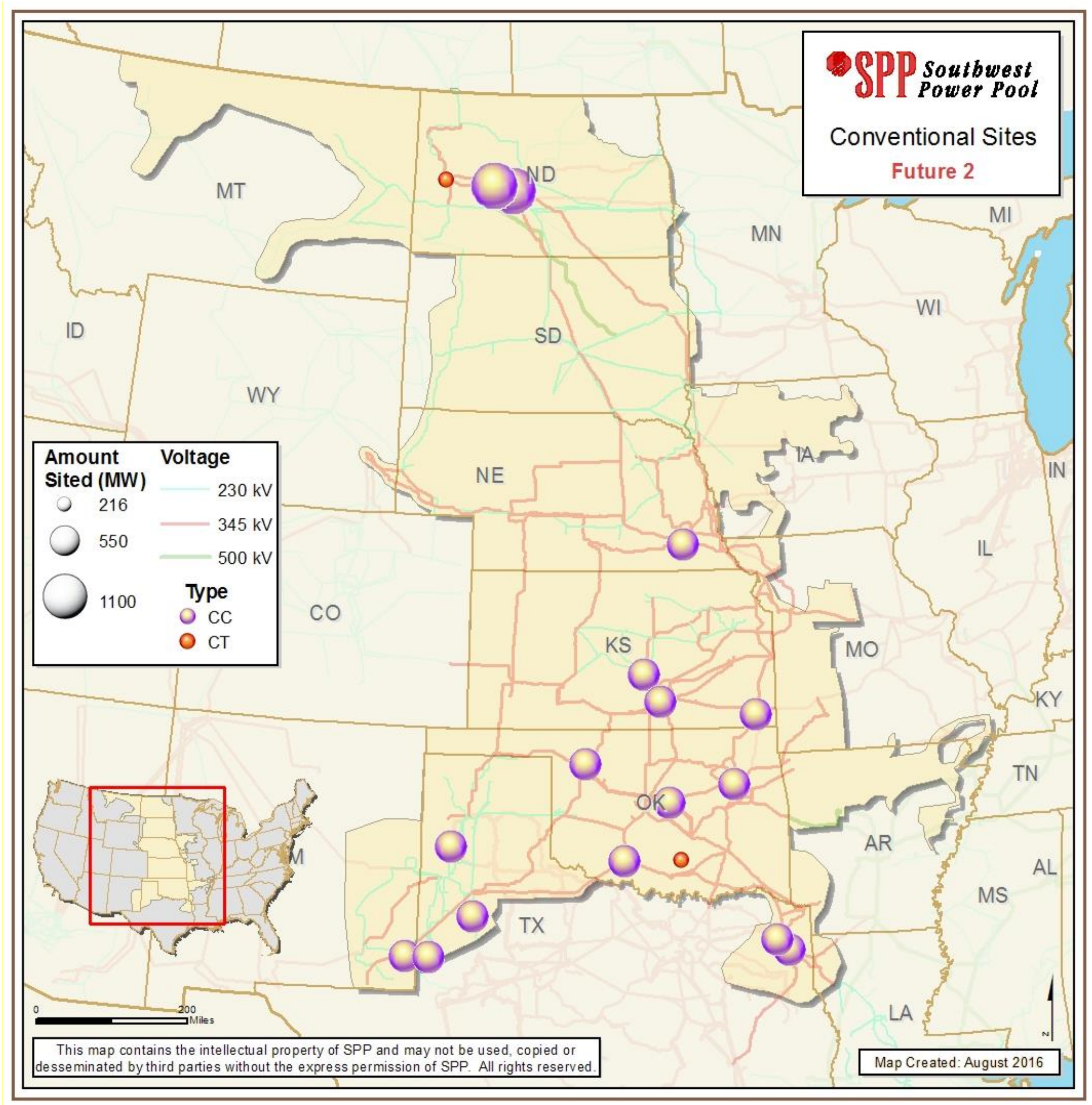


Figure 4.7: 2025 Conventional Generation Siting for Future 2

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

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

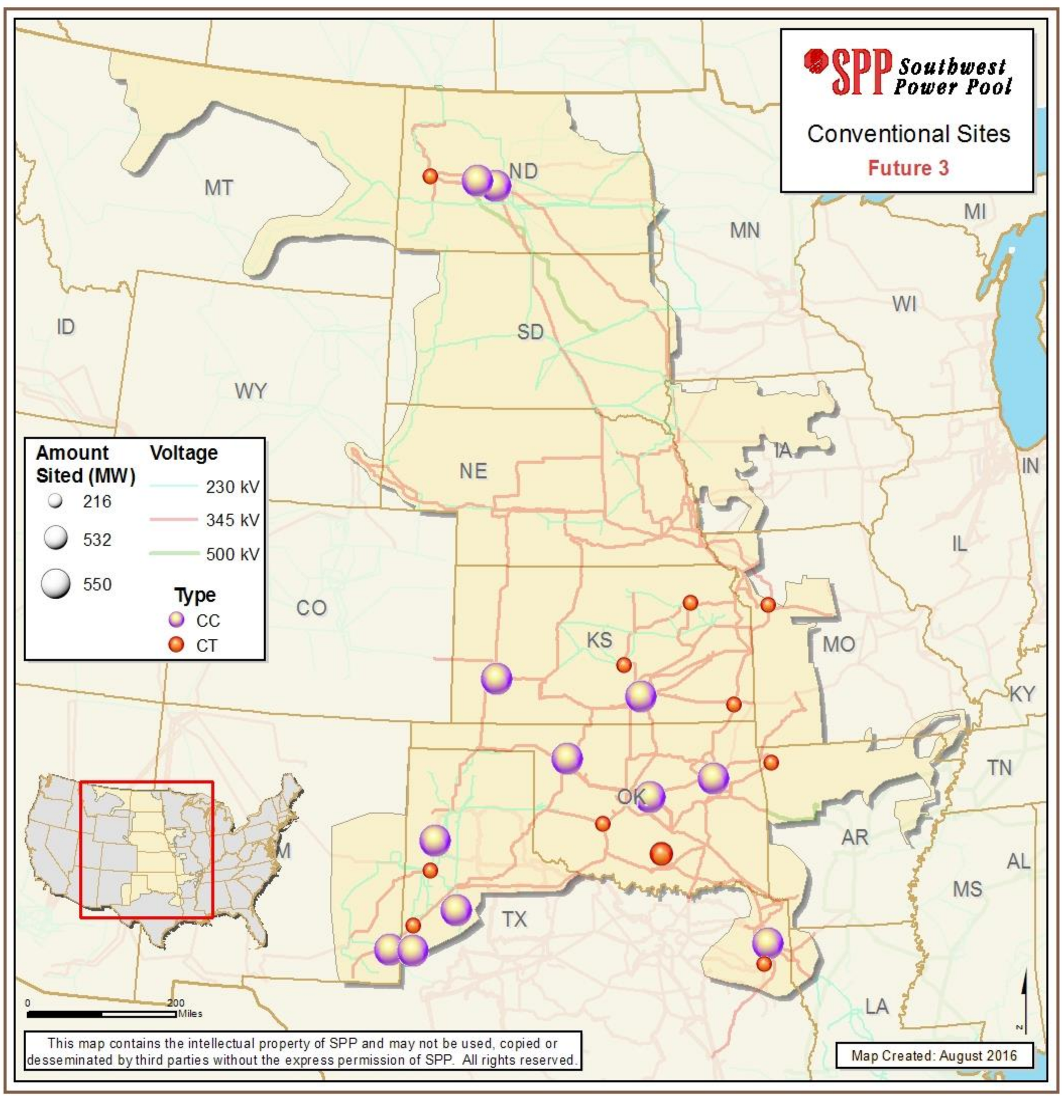


Figure 4.8: 2025 Conventional Generation Siting for Future 3

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.

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

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

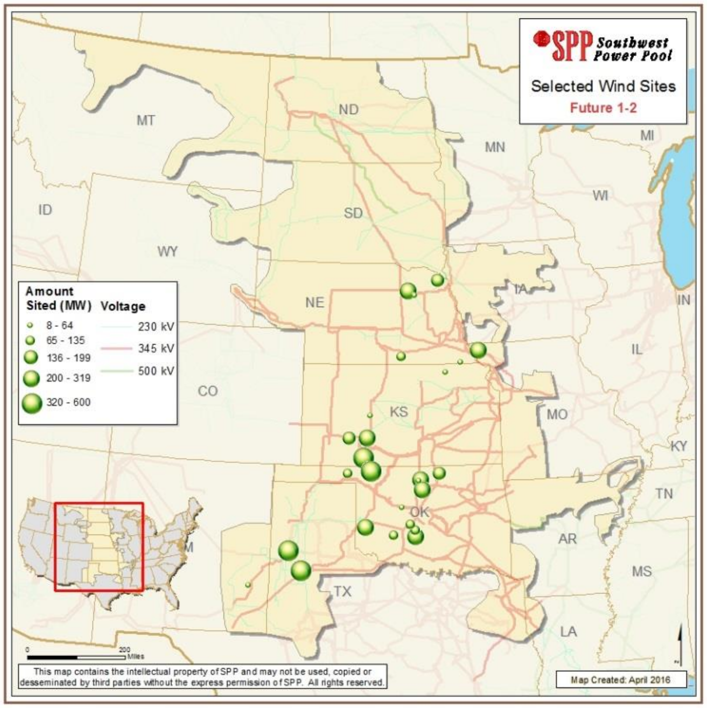


Figure 4.9: 2025 Wind Generation Siting for Futures 1 and 2

<u>For Future 3</u>

- 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)

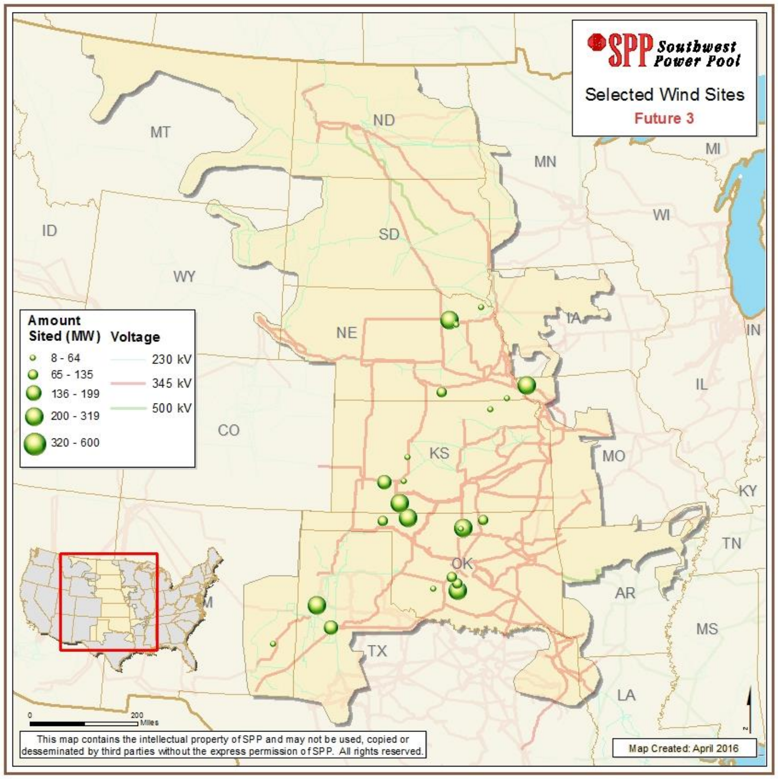


Figure 4.10: Wind Generation Siting for Future 3

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.

For Futures 1 & 2

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

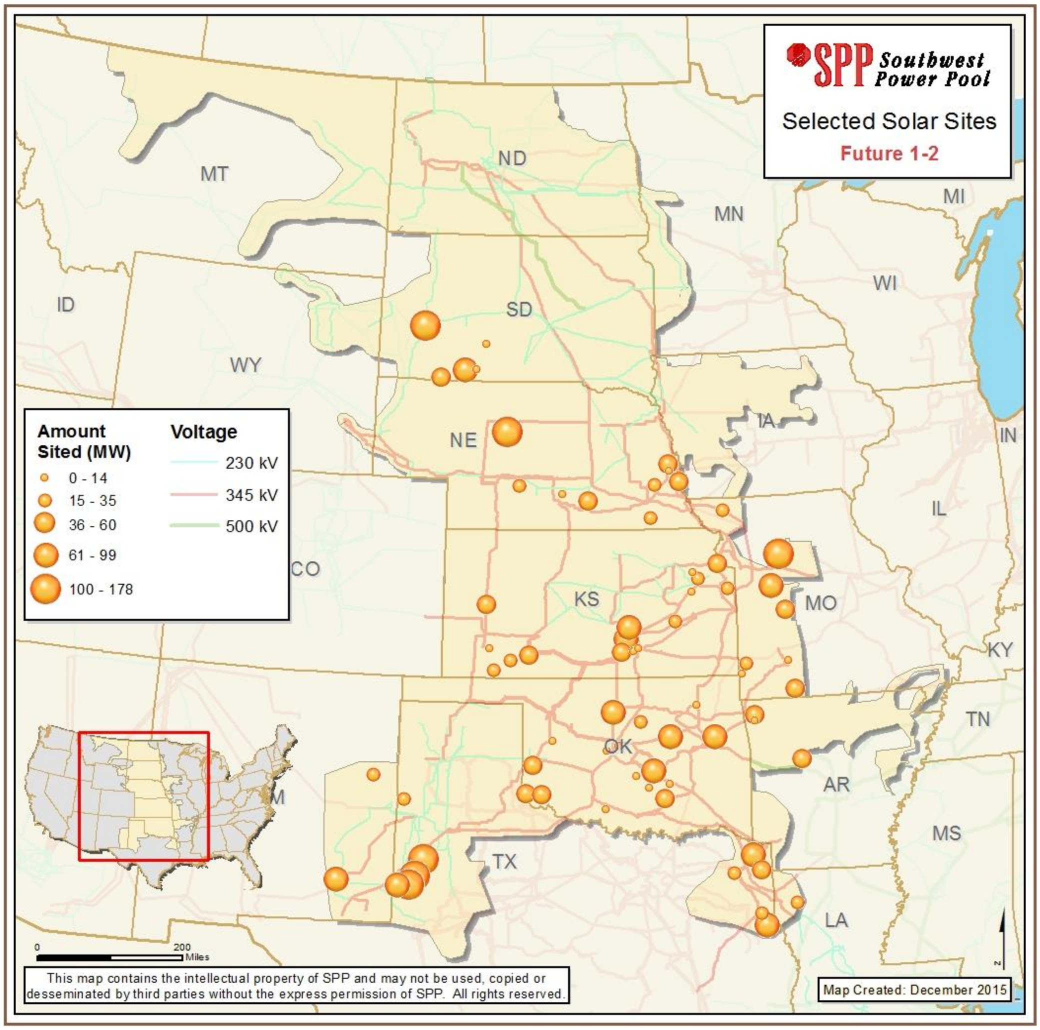


Figure 4.11: Utility Scale Solar Generation Additions for Futures 1 and 2

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)

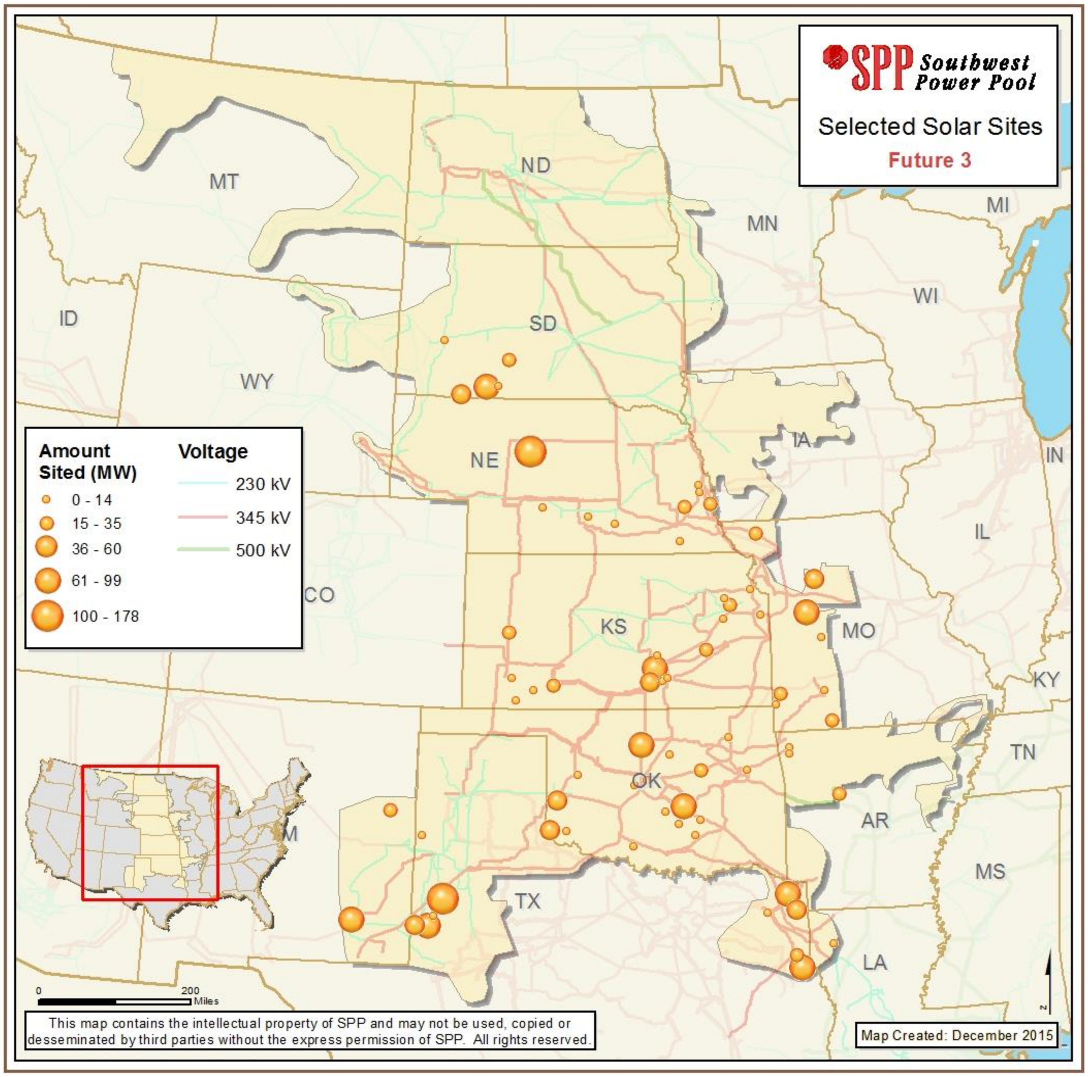


Figure 4.12: Utility Scale Solar Generation Additions for Future 3

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)

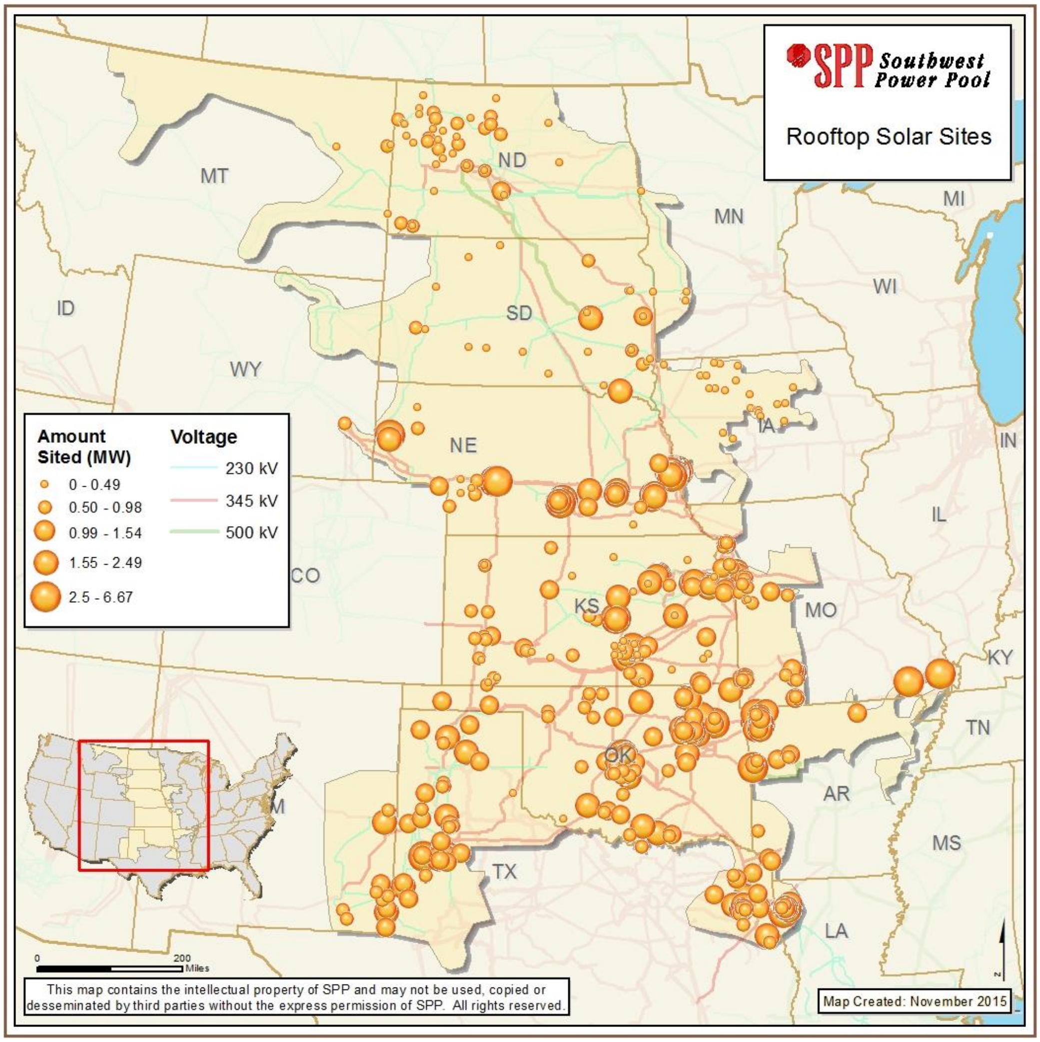


Figure 4.13: Rooftop Solar Generation Additions for Future 3

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

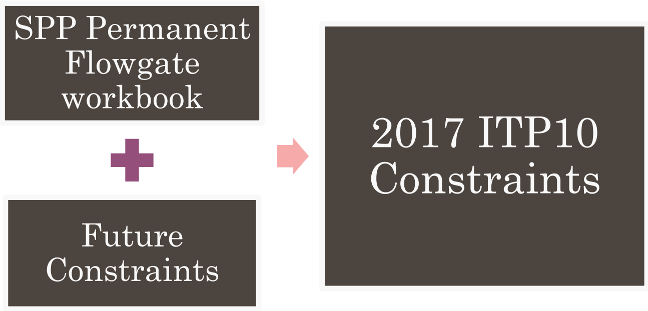


Figure 5.1: Constraint Assessment Process

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.

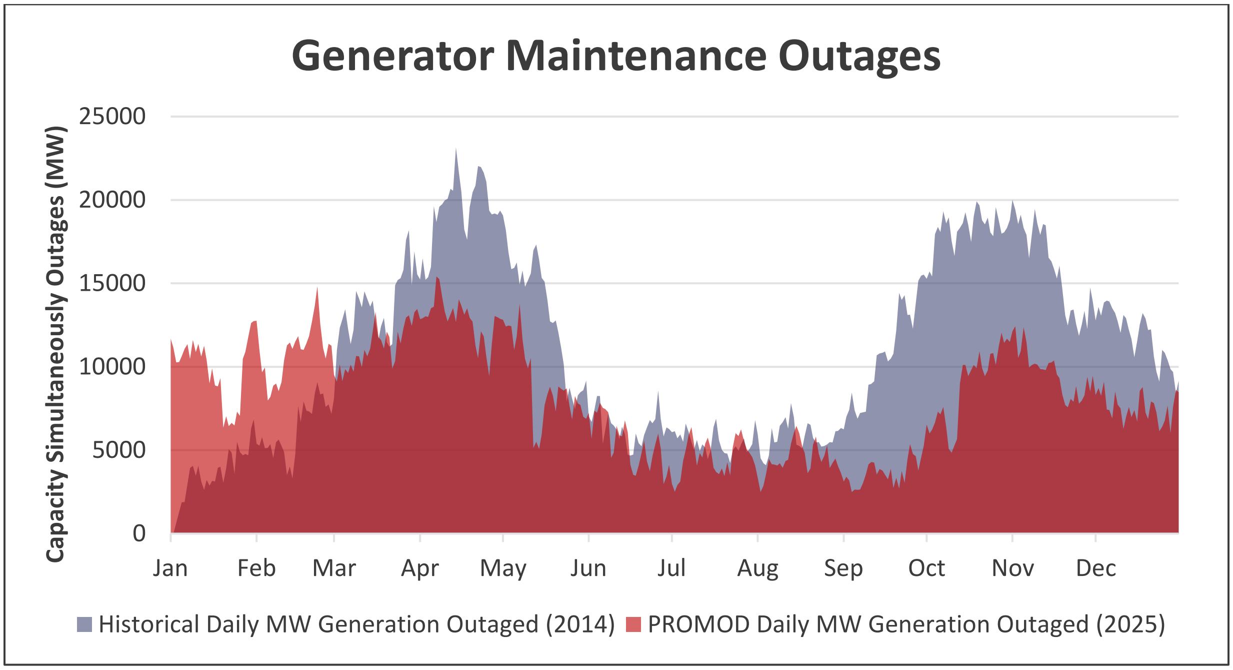


Figure 6.1: Generator Maintenance Outages

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.

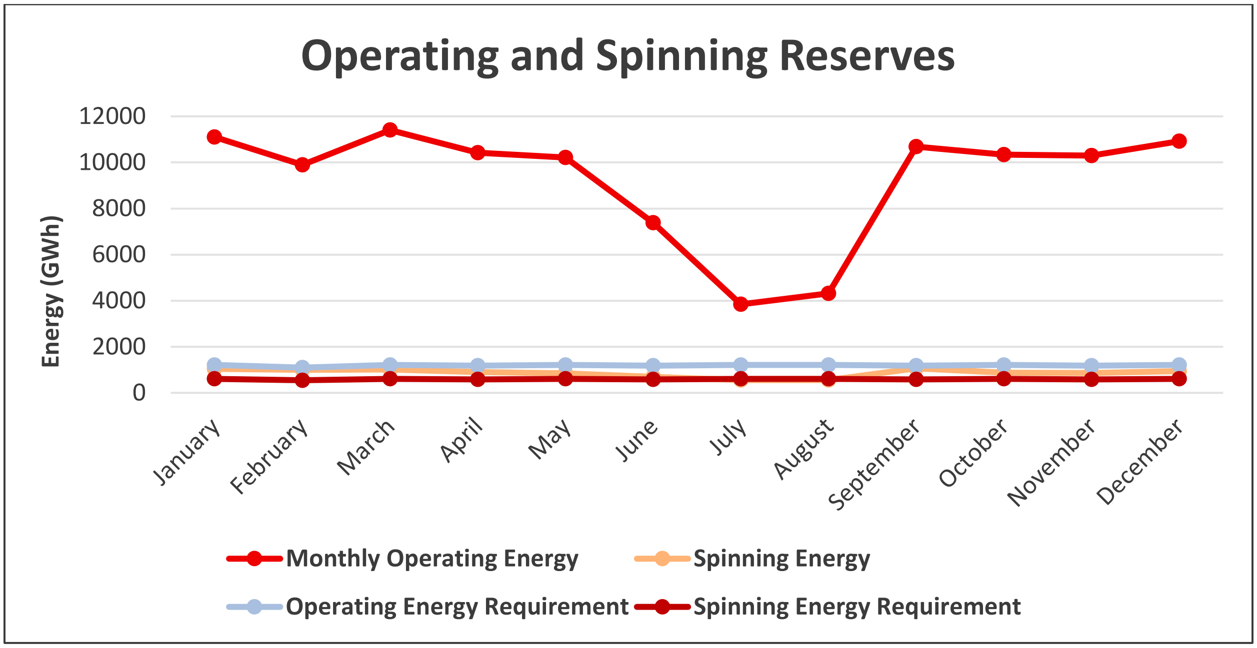


Figure 6.2: Reserve Energy Adequacy

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.

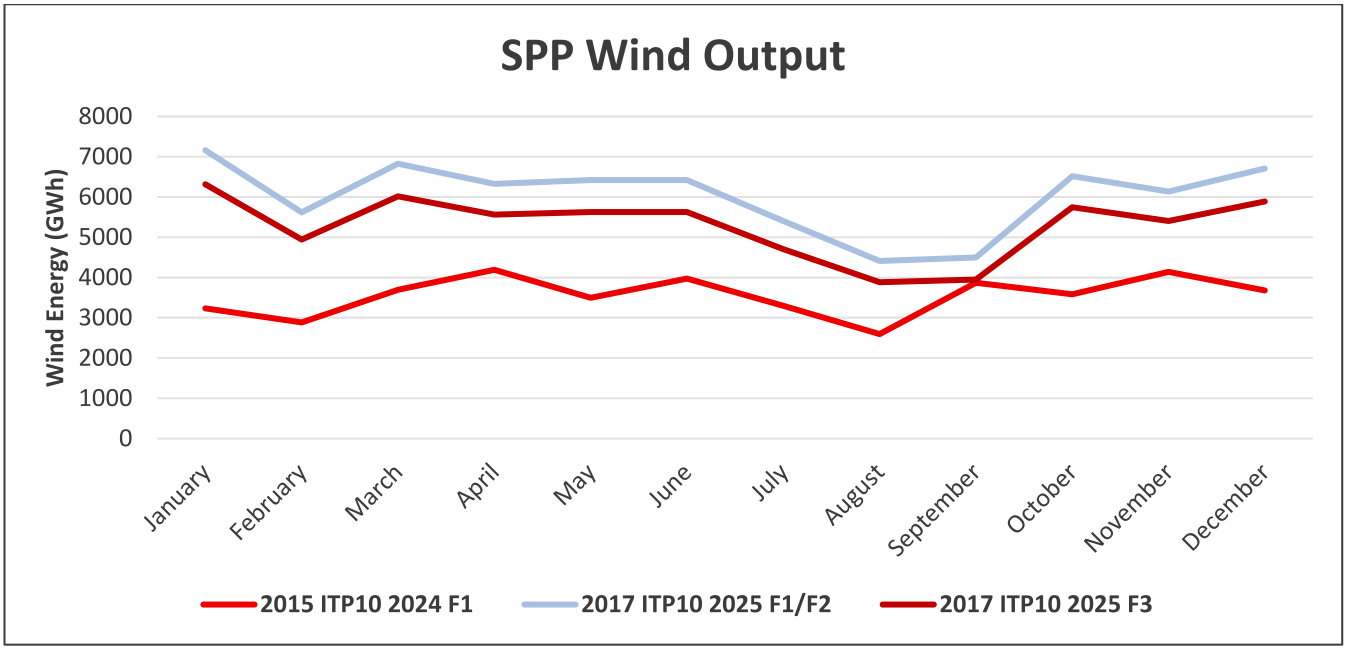


Figure 6.3: 2015 ITP10 v. 2017 ITP10 Energy Output for SPP Wind Units

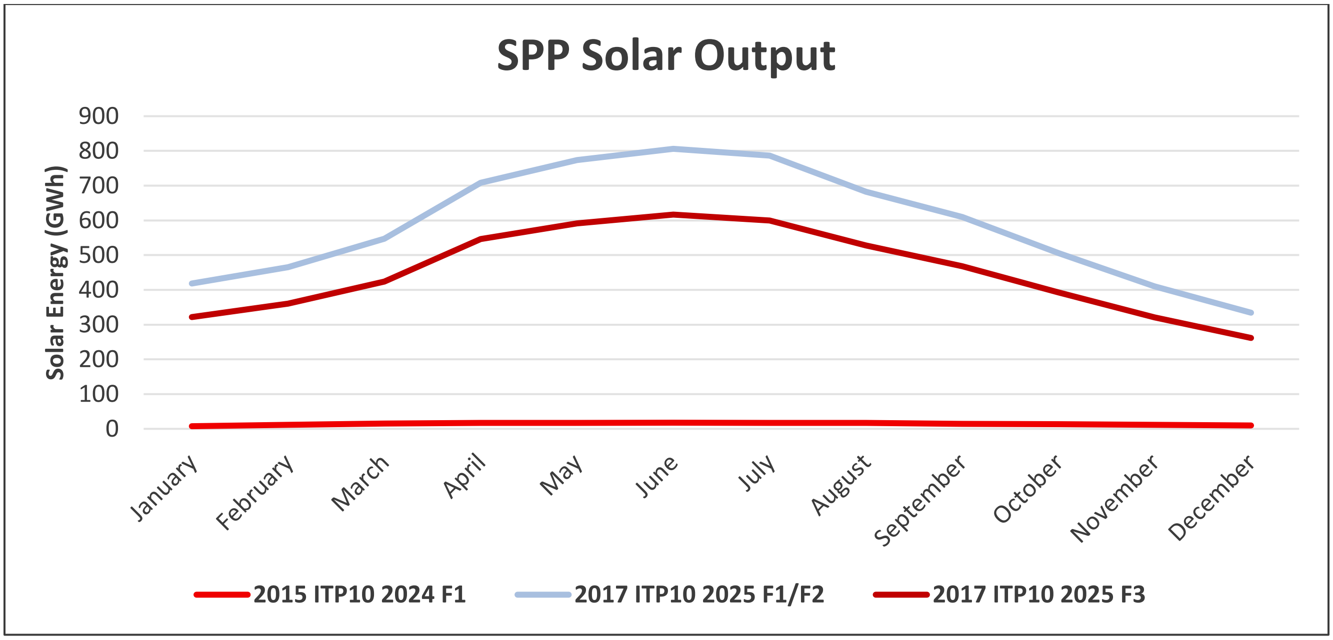


Figure 6.4: 2015 ITP10 v. 2017 ITP10 Energy Output for SPP Solar Units

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.

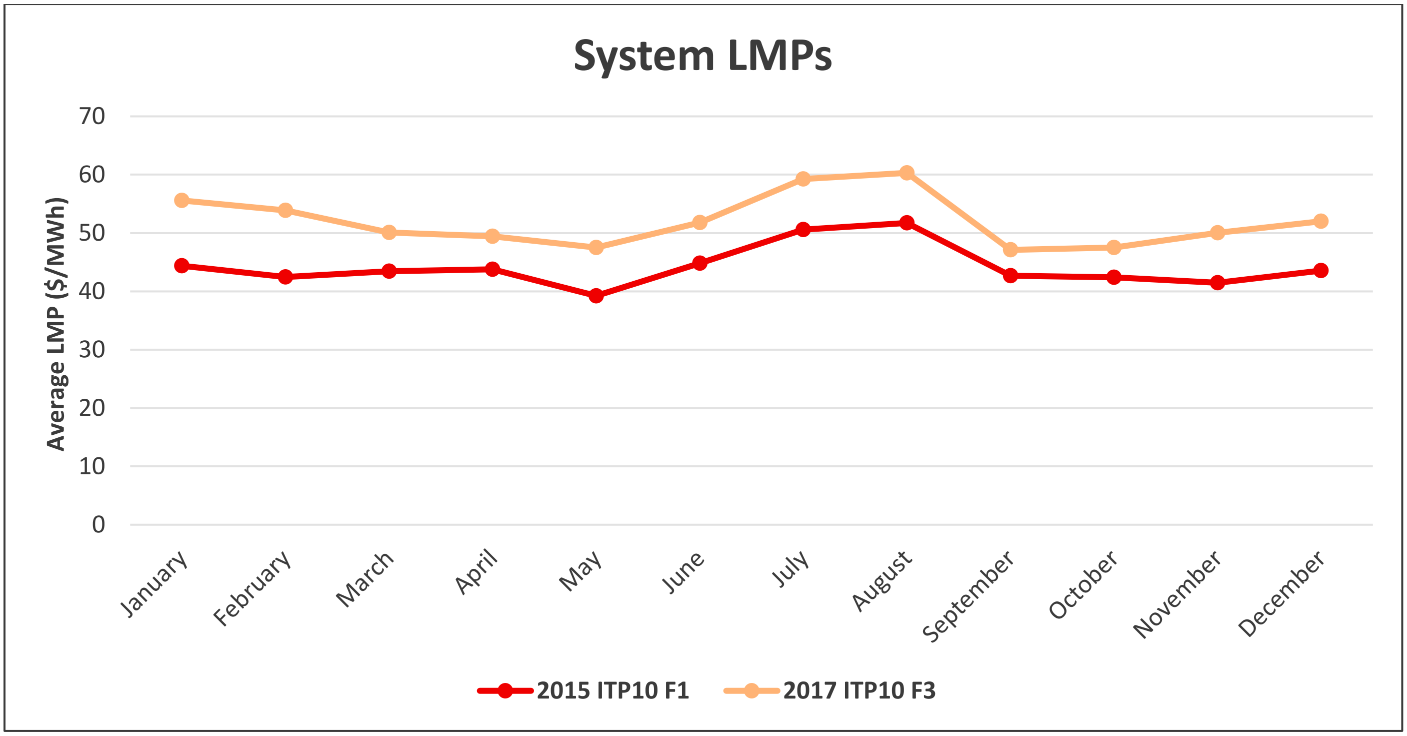


Figure 6.5: LMP Benchmarking Results

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).

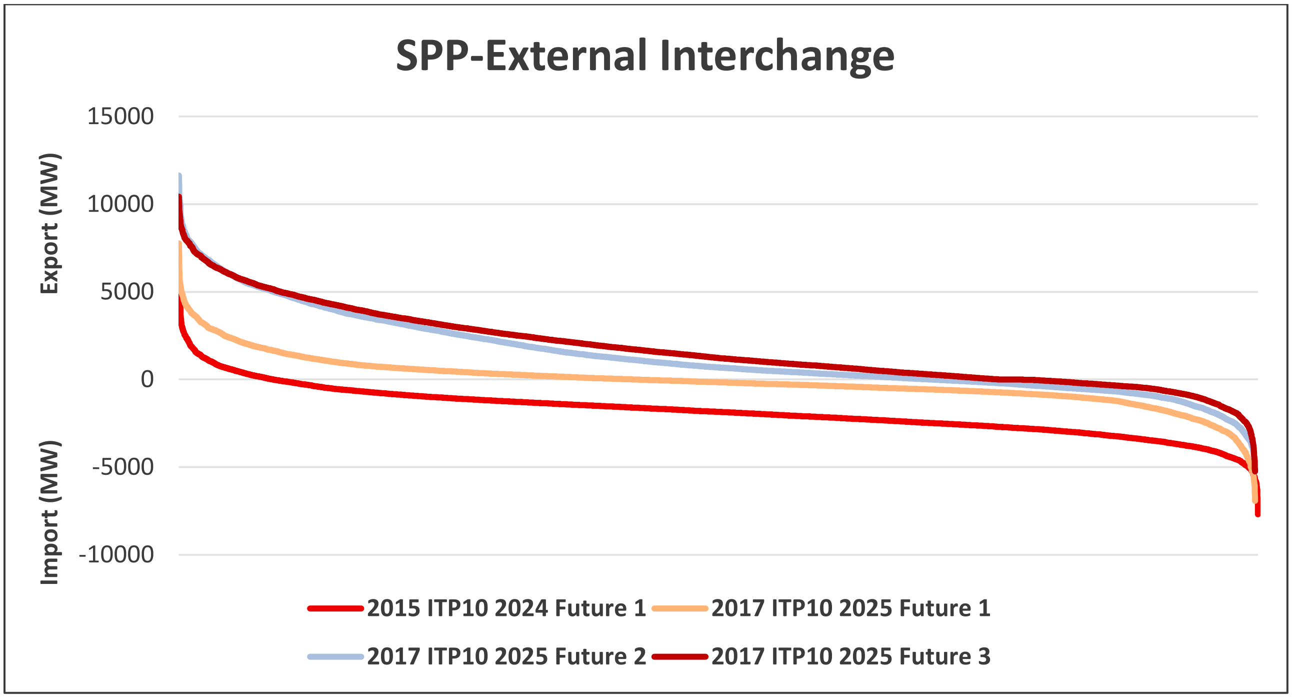


Figure 6.6: Interchange data comparison

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.

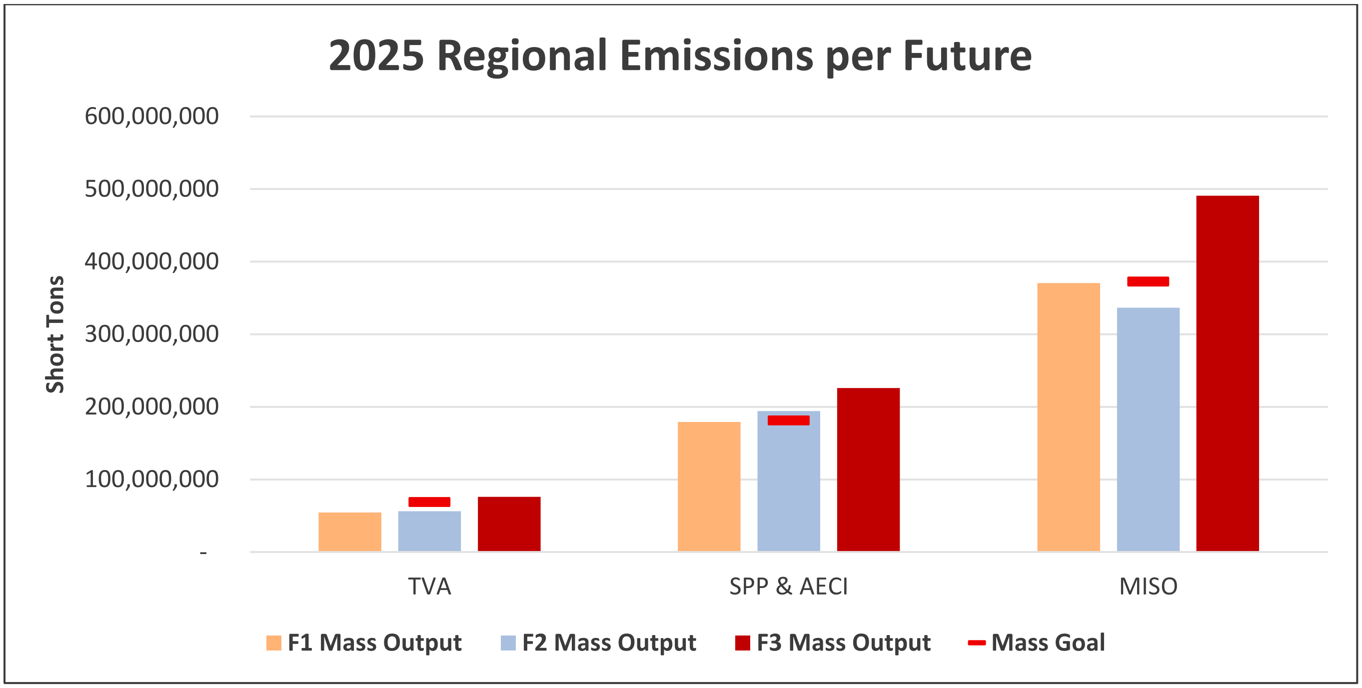


Figure 7.1: 2025 Regional Emissions per Future

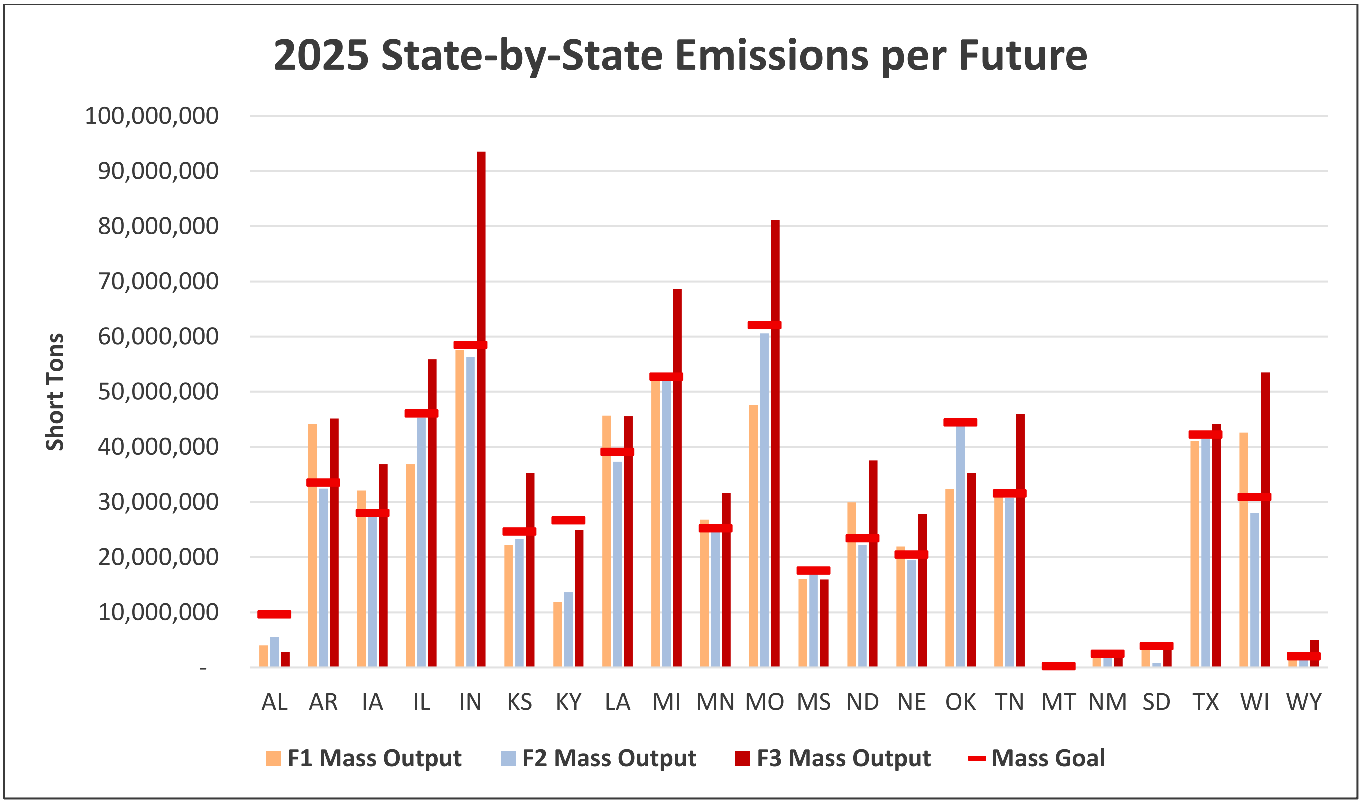


Figure 7.2: 2025 State-by-State Emissions per Future

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.

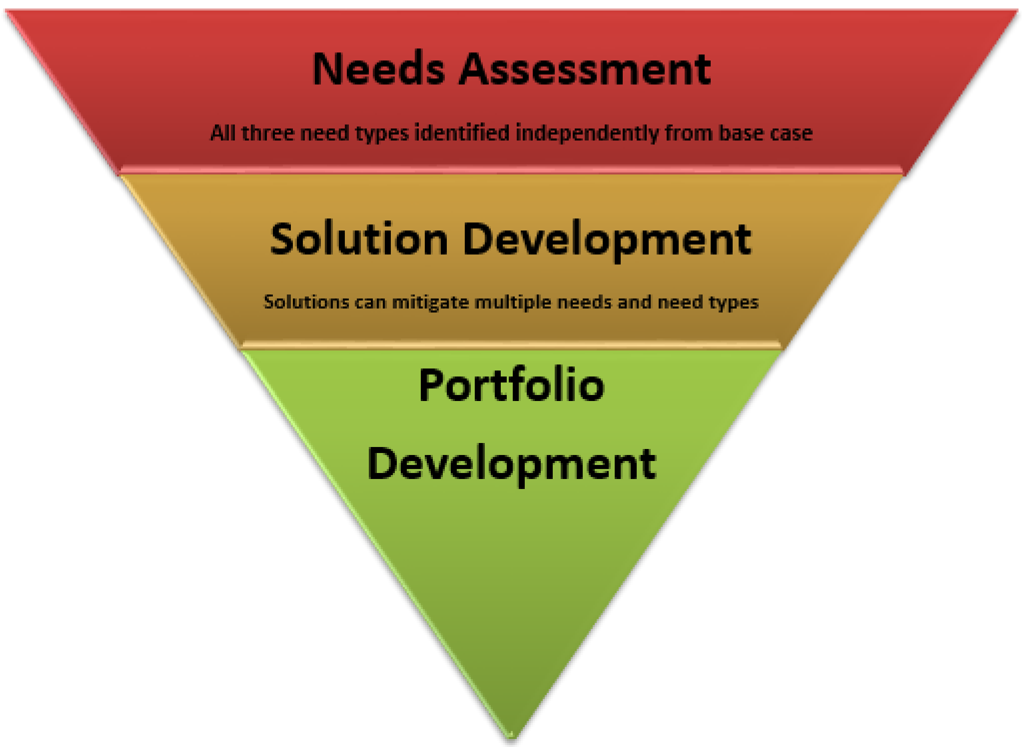


Figure 9.1: Analysis Process

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.

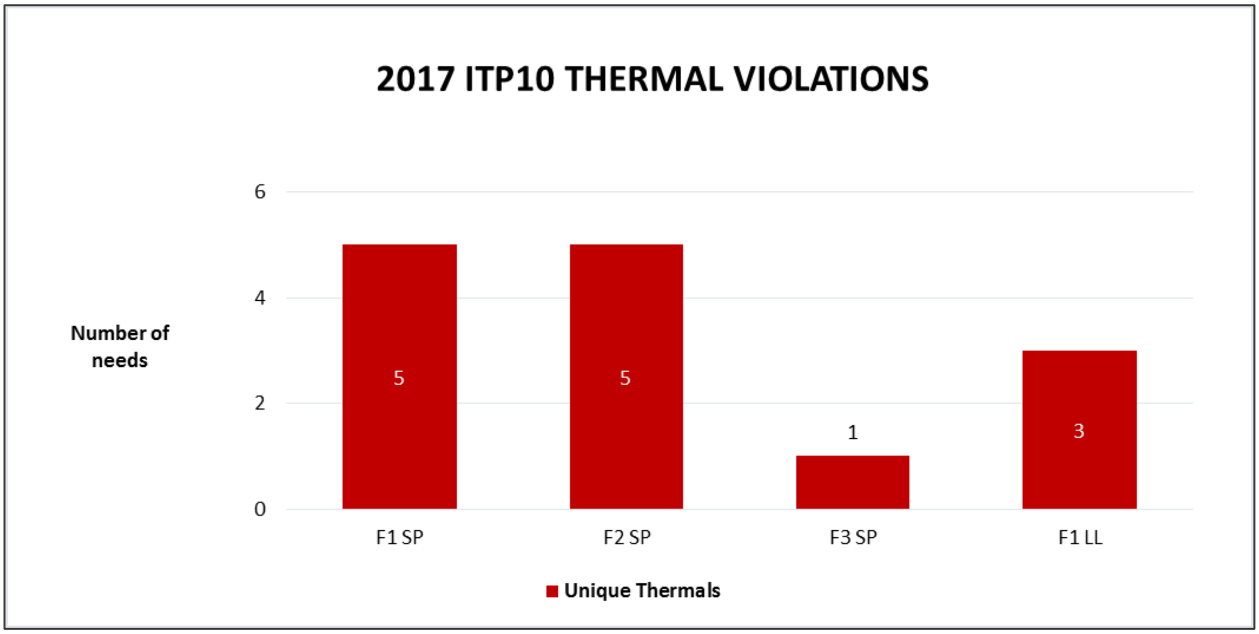


Figure 9.2: 2017 ITP10 Thermal Overload Totals

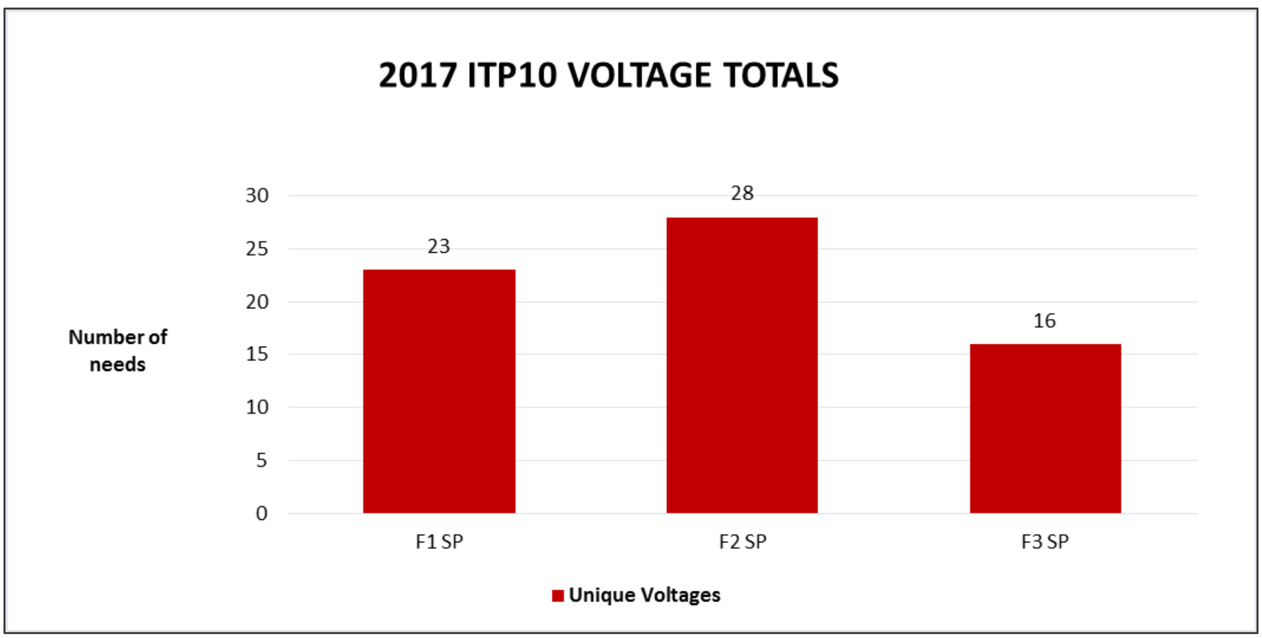


Figure 9.3: 2017 ITP10 Voltage Violation Totals

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.

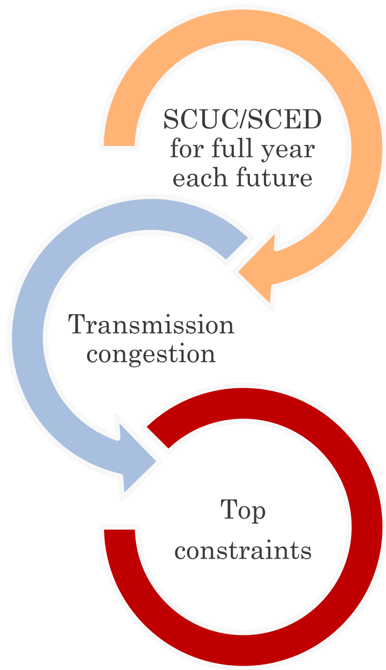

Figure 9.5: Developing Economic Needs

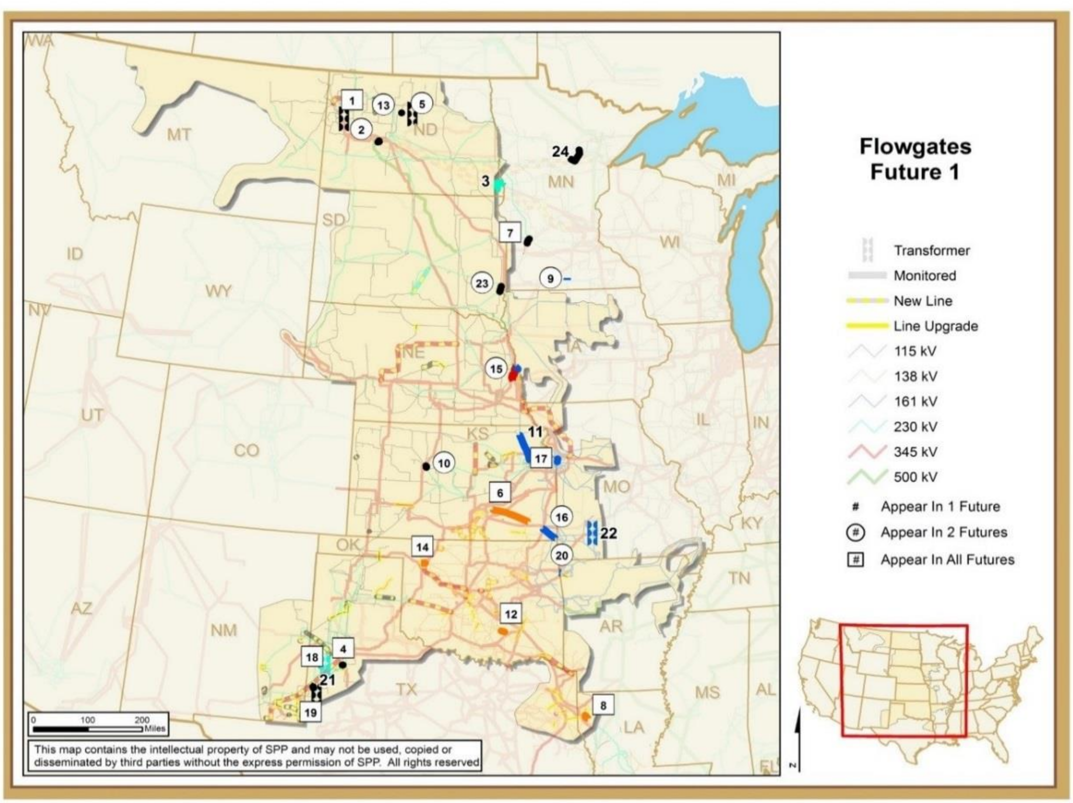

Figure 9.6: Future 1 Economic Needs Identified

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

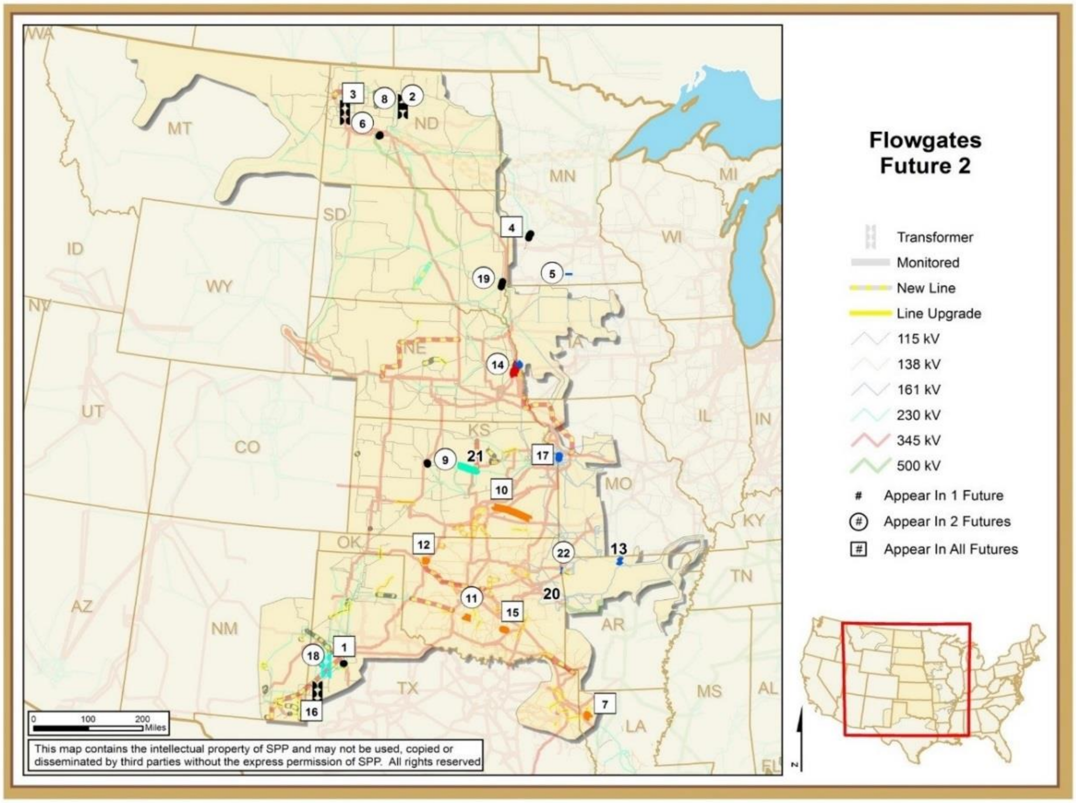

Figure 9.7: Future 2 Economic Needs Identified

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

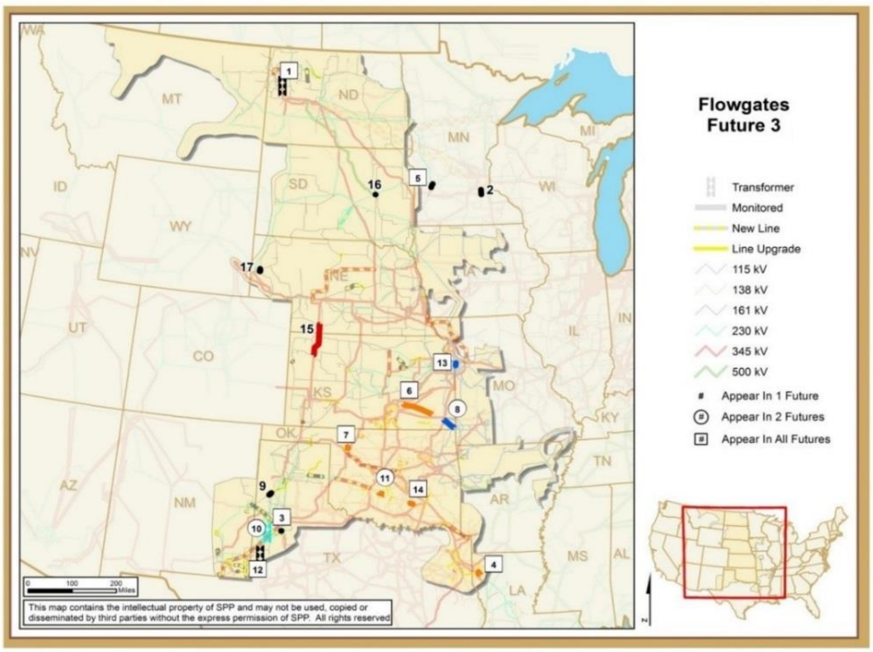

Figure 9.8: Future 3 Economic Needs Identified

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.

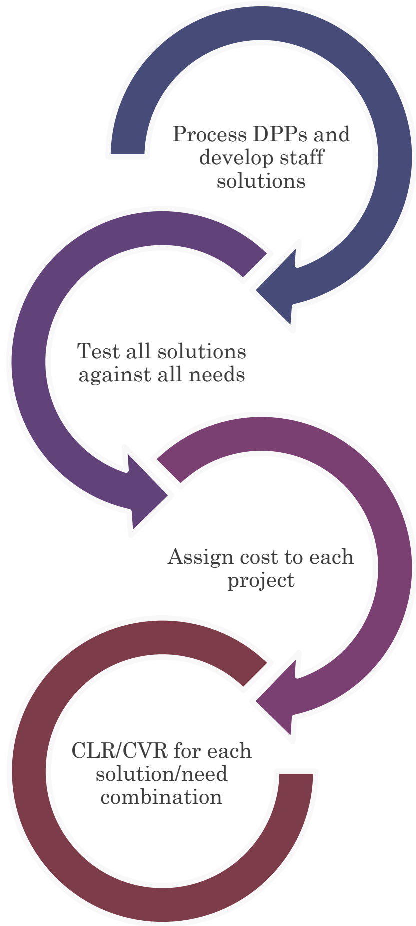

Figure 10.1: Reliability Grouping Process

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).

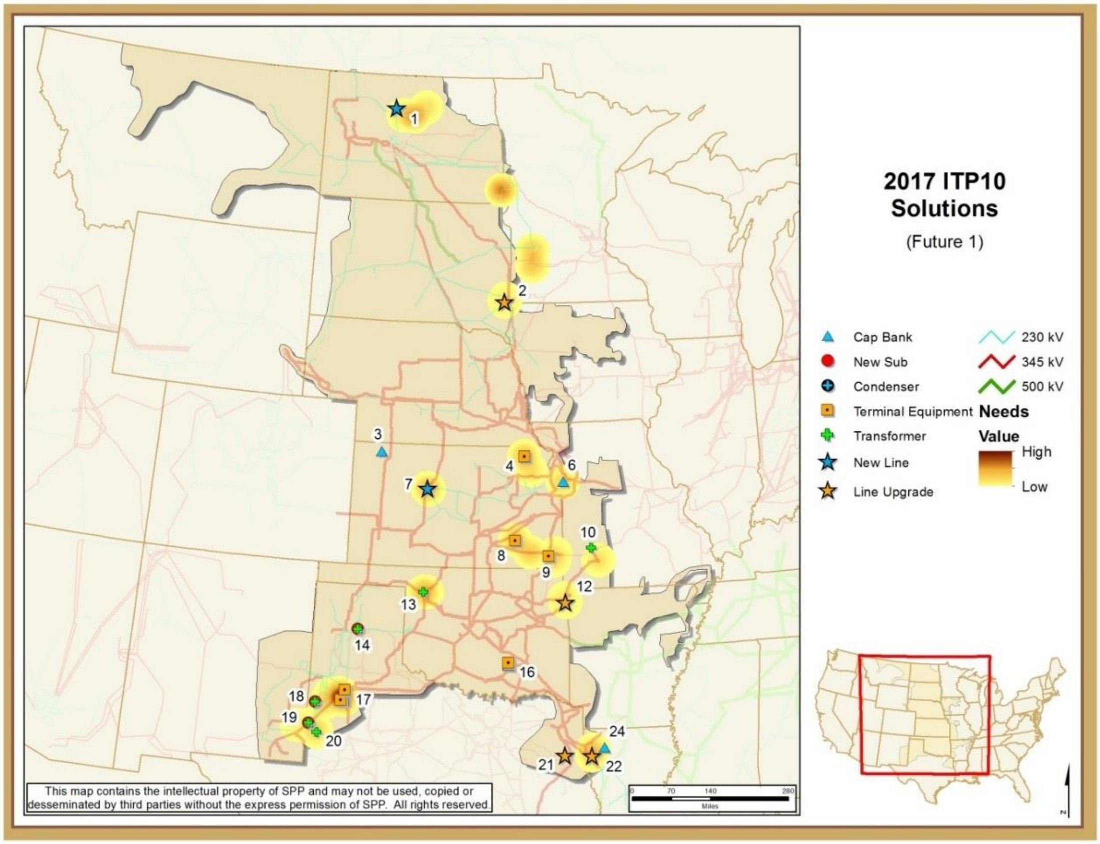

Figure 10.2: Future 1 Portfolio

	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).

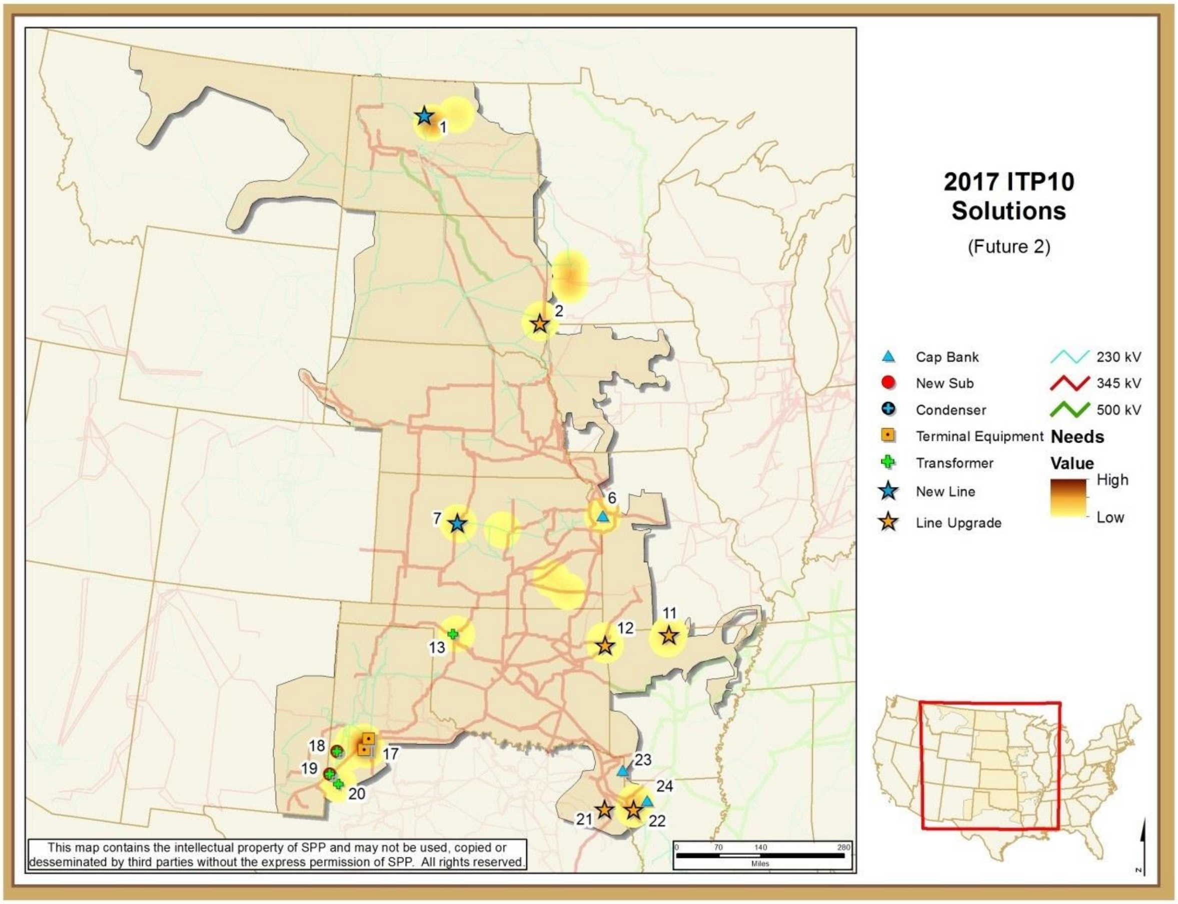

Figure 10.3: Future 2 Portfolio

	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).

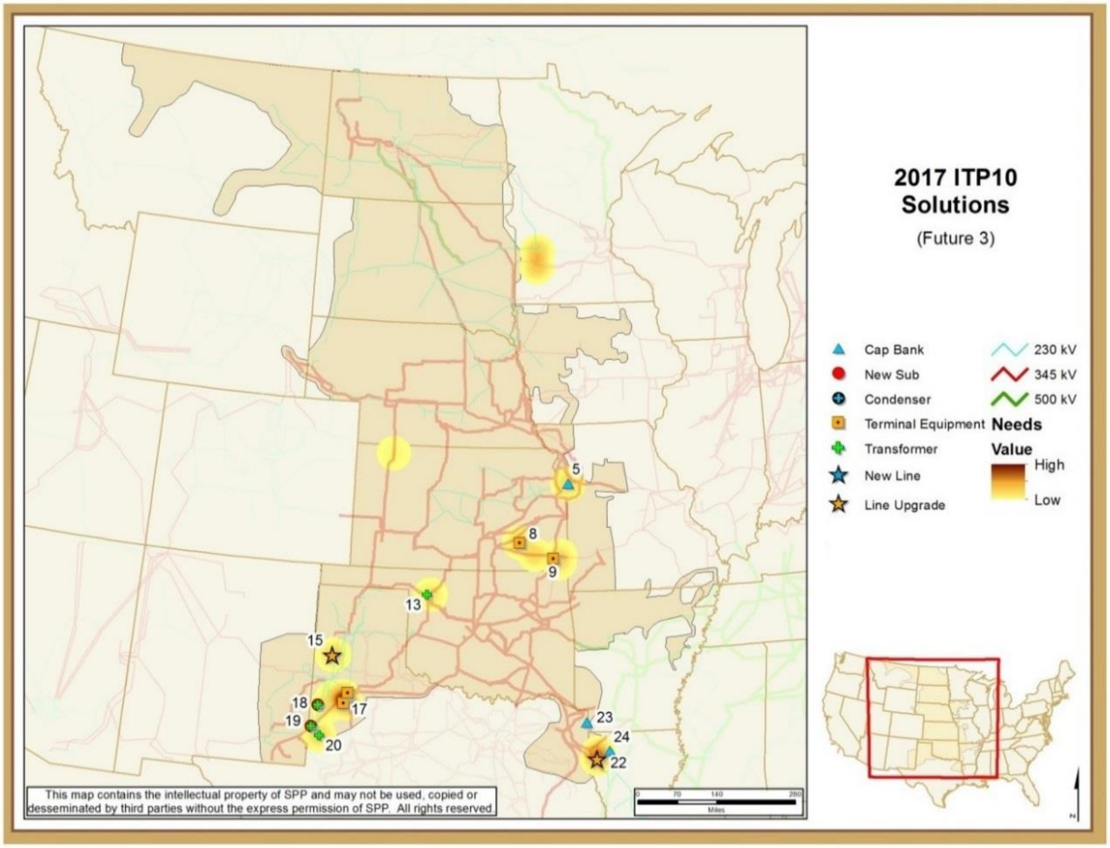

Figure 10.4: Future 3 Portfolio

	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).

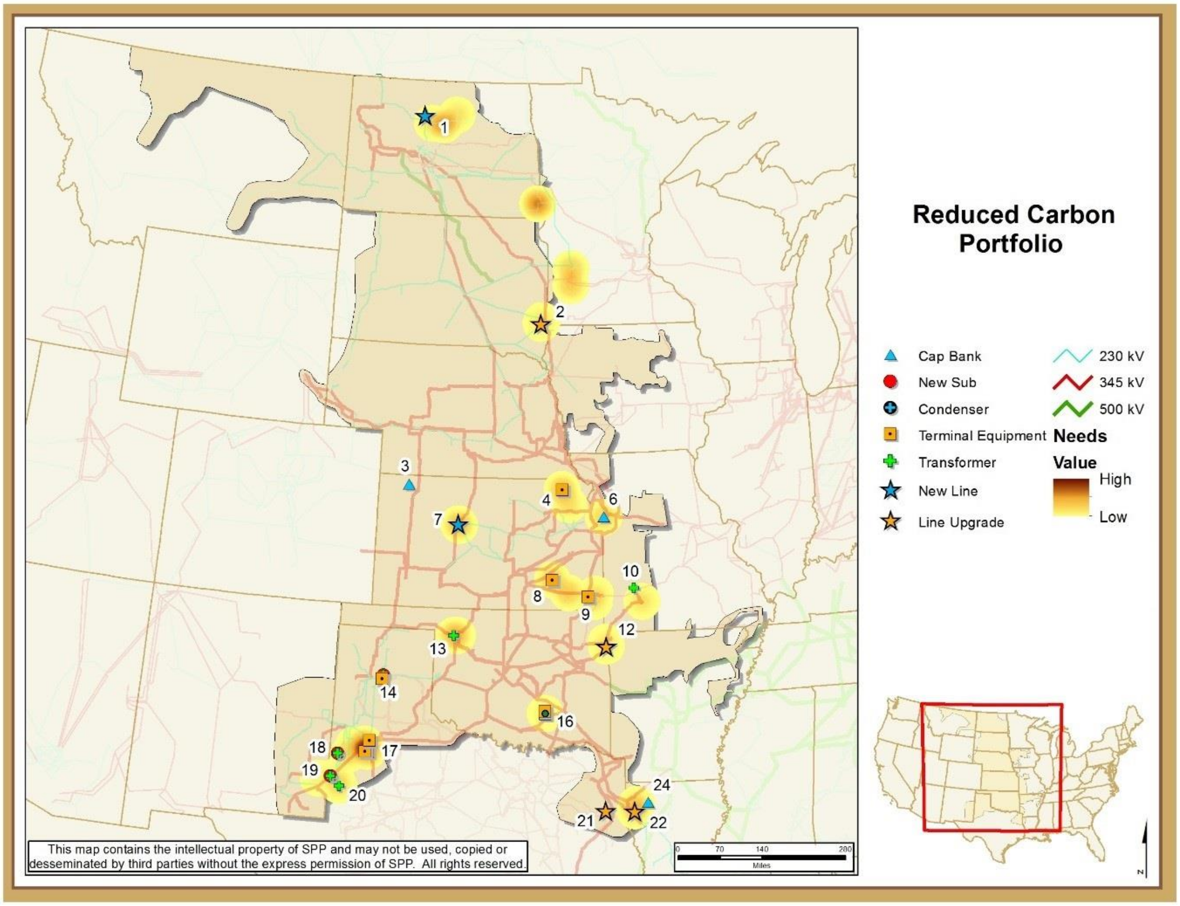

Figure 10.5: Reduced Carbon Portfolio

	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.

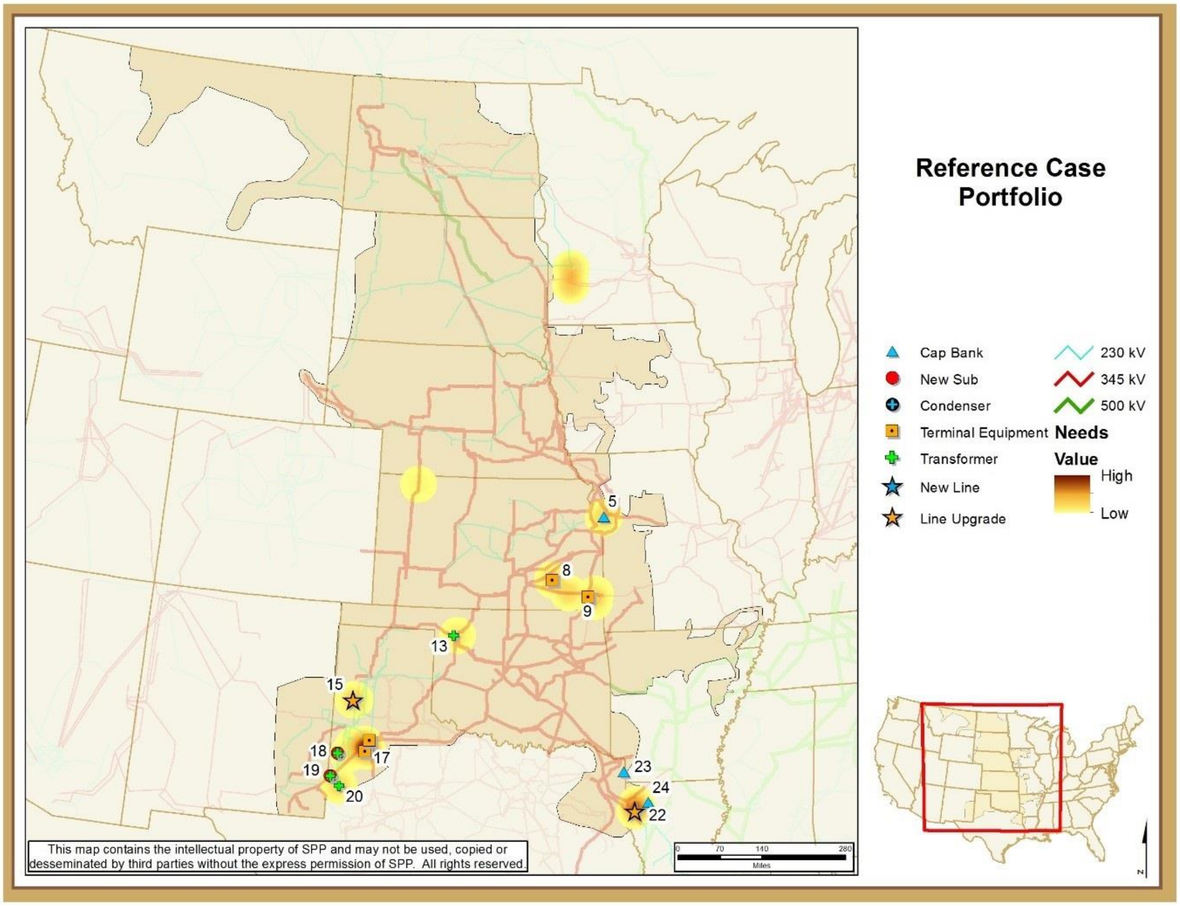

Figure 10.6: Reference Case Portfolio

	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.

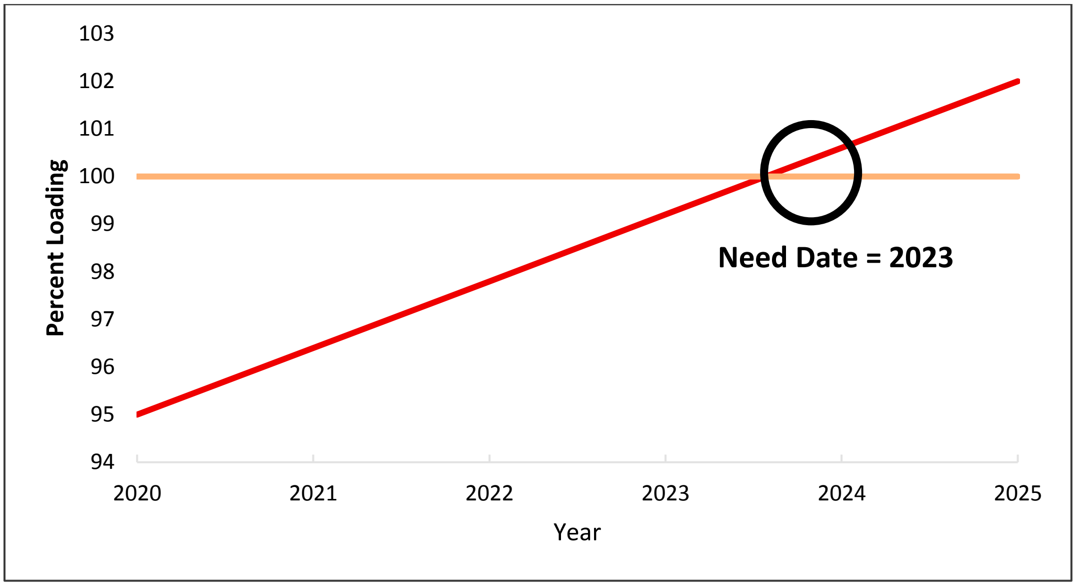

Figure 11.1: Reliability Project Staging Interpolation Example

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.

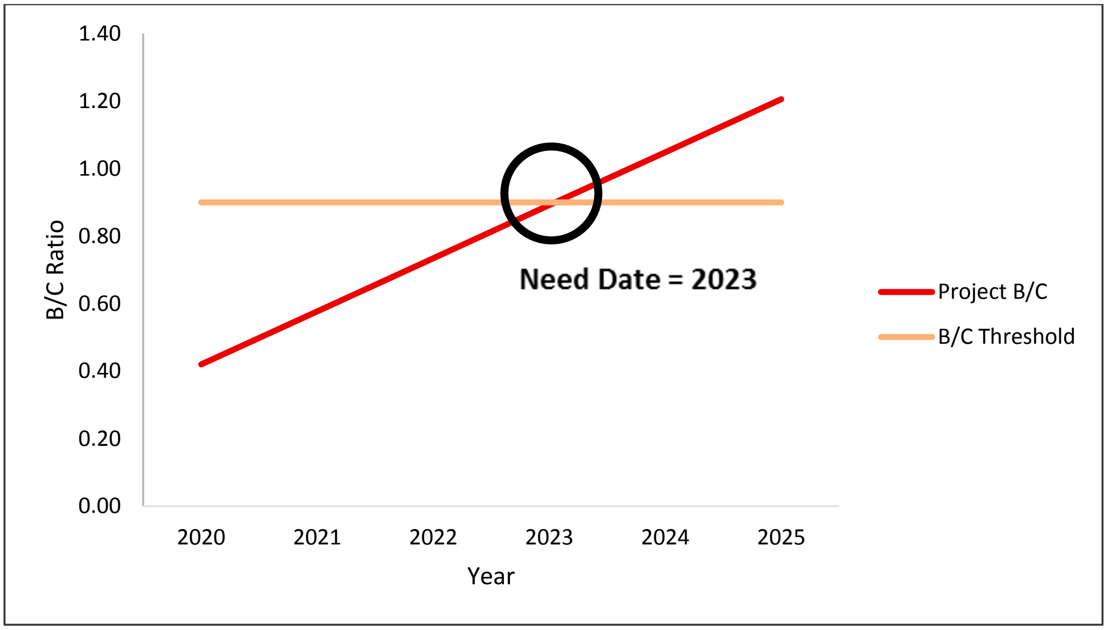

Figure 11.2: Economic Project Staging Interpolation Example

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:

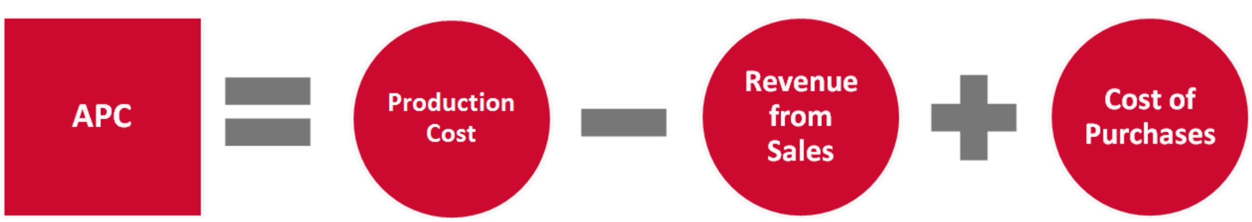

Figure 12.2: APC Calculation

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.

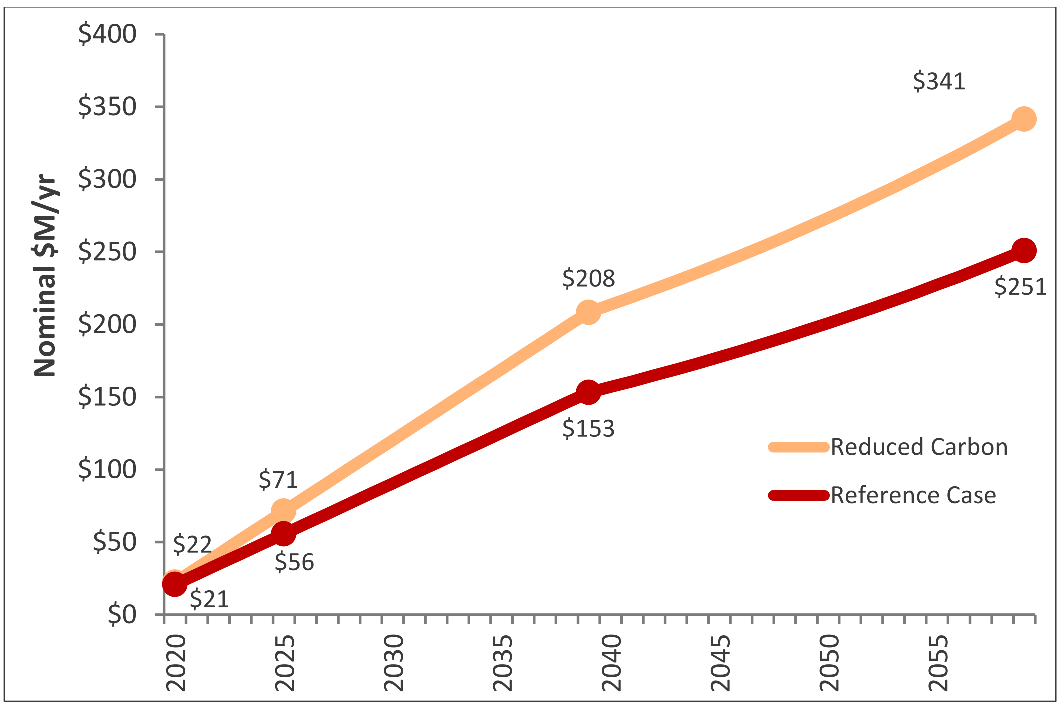

Figure 12.3: Regional APC Savings Estimated for the 40-year Study Period

[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 ($M)	Reduced Carbon Portfolio 2025 ($M)	Reduced Carbon Portfolio 40-yr NPV ($2017M)	Reference Portfolio 2020 ($M)	Reference Portfolio 2025 ($M)	Reference Portfolio 40-yr NPV ($2017M)
AEPW	$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 ($M)	Reduced Carbon Portfolio 2025 ($M)	Reduced Carbon Portfolio 40-yr NPV ($2017M)	Reference Portfolio 2020 ($M)	Reference Portfolio 2025 ($M)	Reference Portfolio 40-yr NPV ($2017M)
AEPW	$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)

Zone	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. Benefit/ Cost Ratio
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)

Zone	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. Benefit/ Cost Ratio
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	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	NPV 40-yr ATRRs	Net Benefit	Est. B/C Ratio
Reduced Carbon Portfolio - Present Value of 40-yr Benefits (2017 $M)												
	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(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	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	NPV 40-yr ATRRs	Net Benefit	Est. B/C Ratio
Reference Case Portfolio - Present Value of 40-yr Benefits (2017 $M)												
	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(2017 $M)	(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.

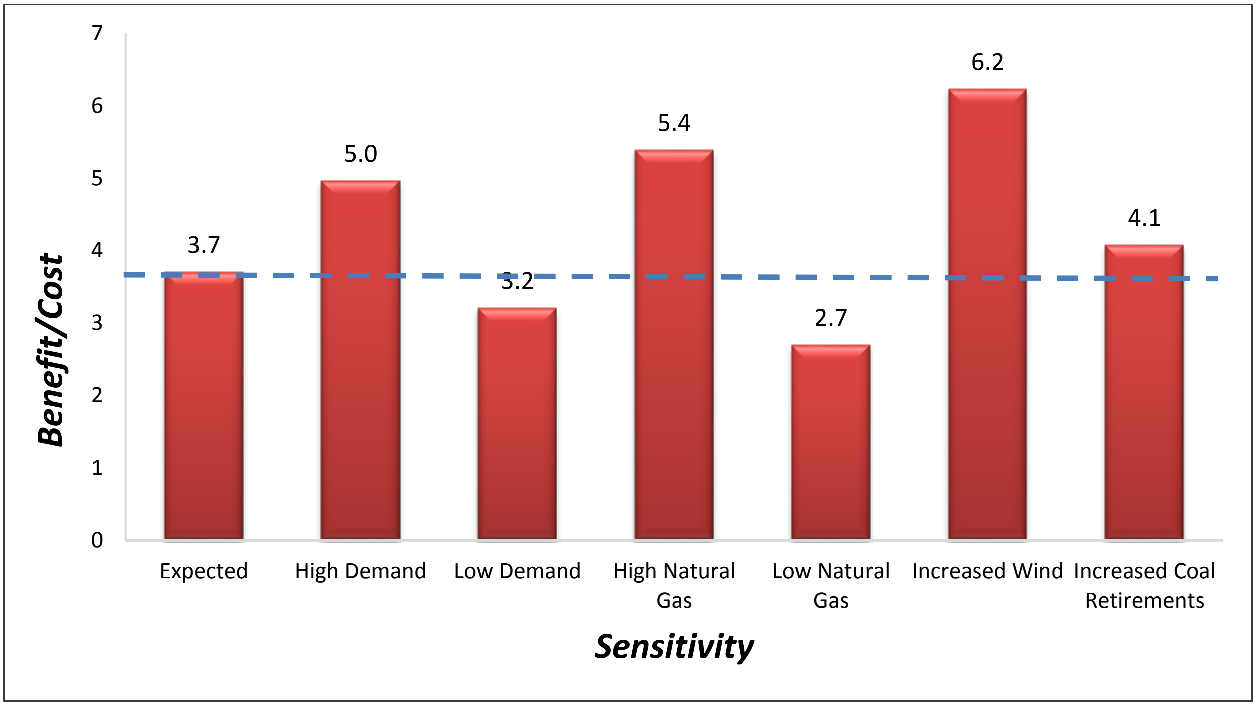

Figure 13.1: 1-Year Benefit-to-Cost Ratios for Sensitivities (Reduced Carbon)

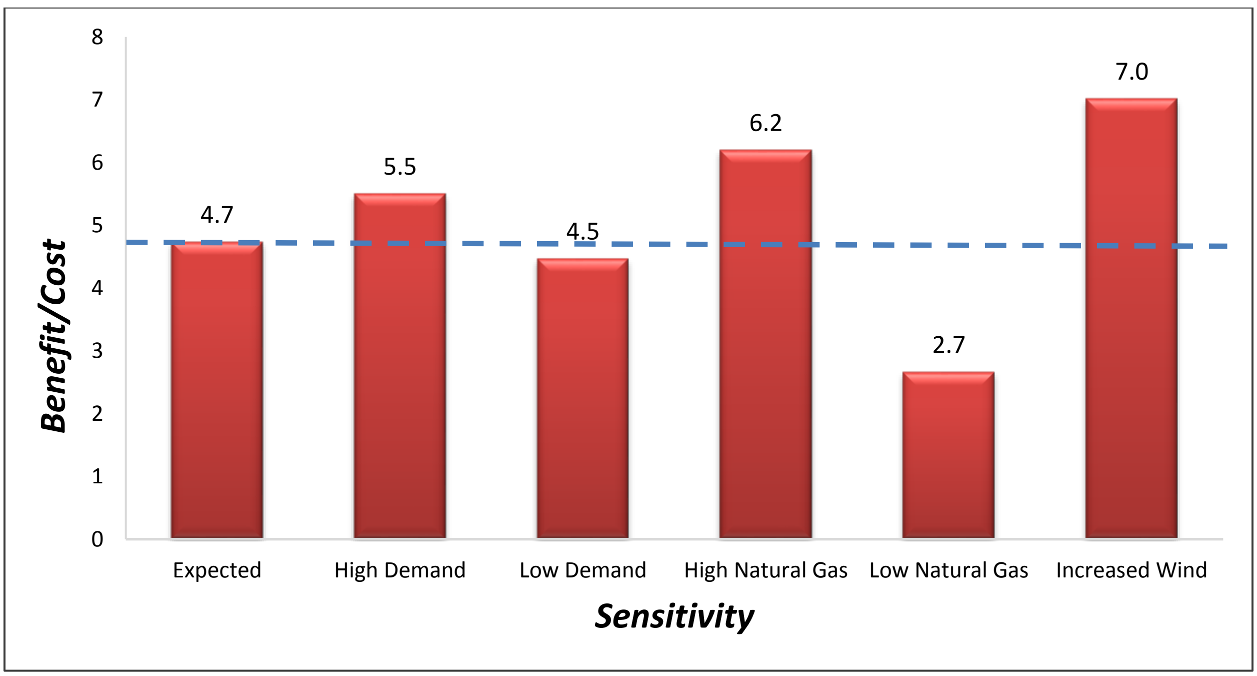

Figure 13.2: 1-Year Benefit-to-Cost Ratios for Sensitivities (Reference Case)

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)

[23] SPP Regional

[24] Henry Hub 2025 average of monthly data

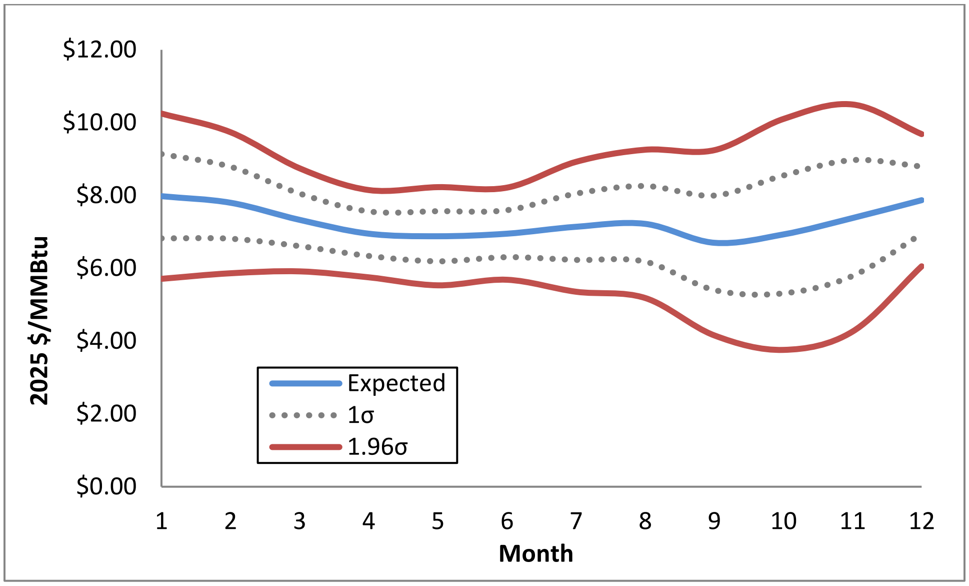

Figure 13.3: Monthly Henry Hub Natural Gas Price Values (2025)

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.

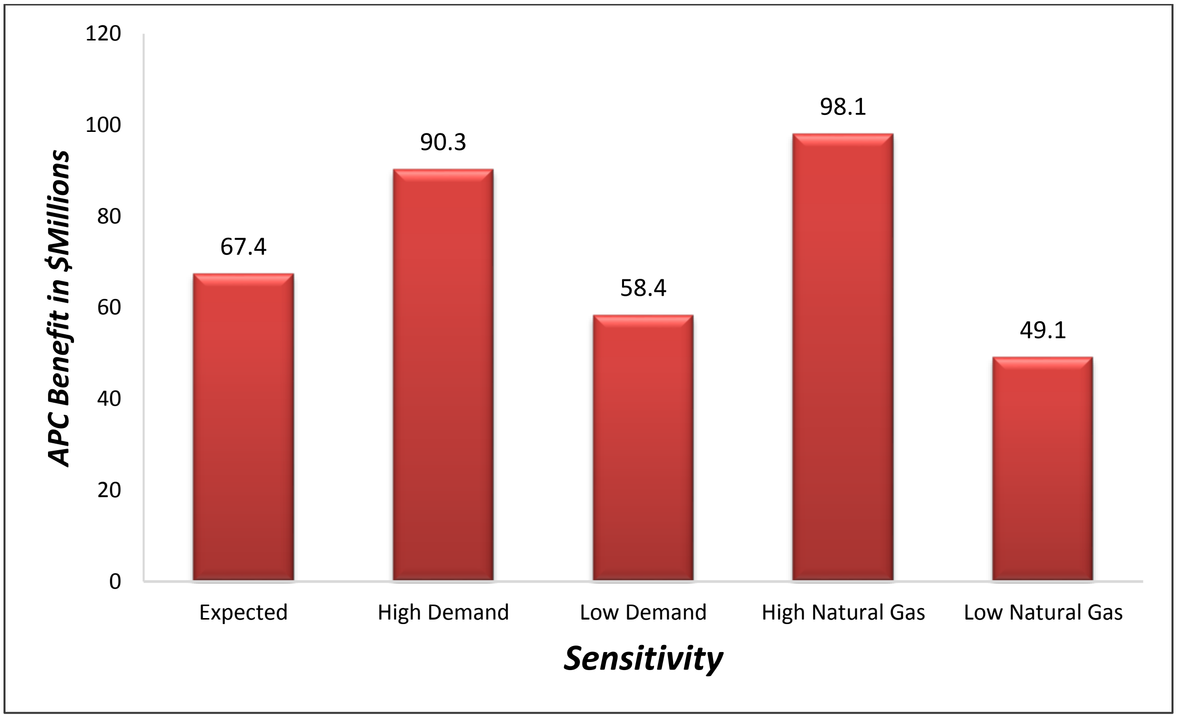

Figure 13.4: 1-Year Benefits of Reduced Carbon Portfolio for Demand and Natural Gas Sensitivities

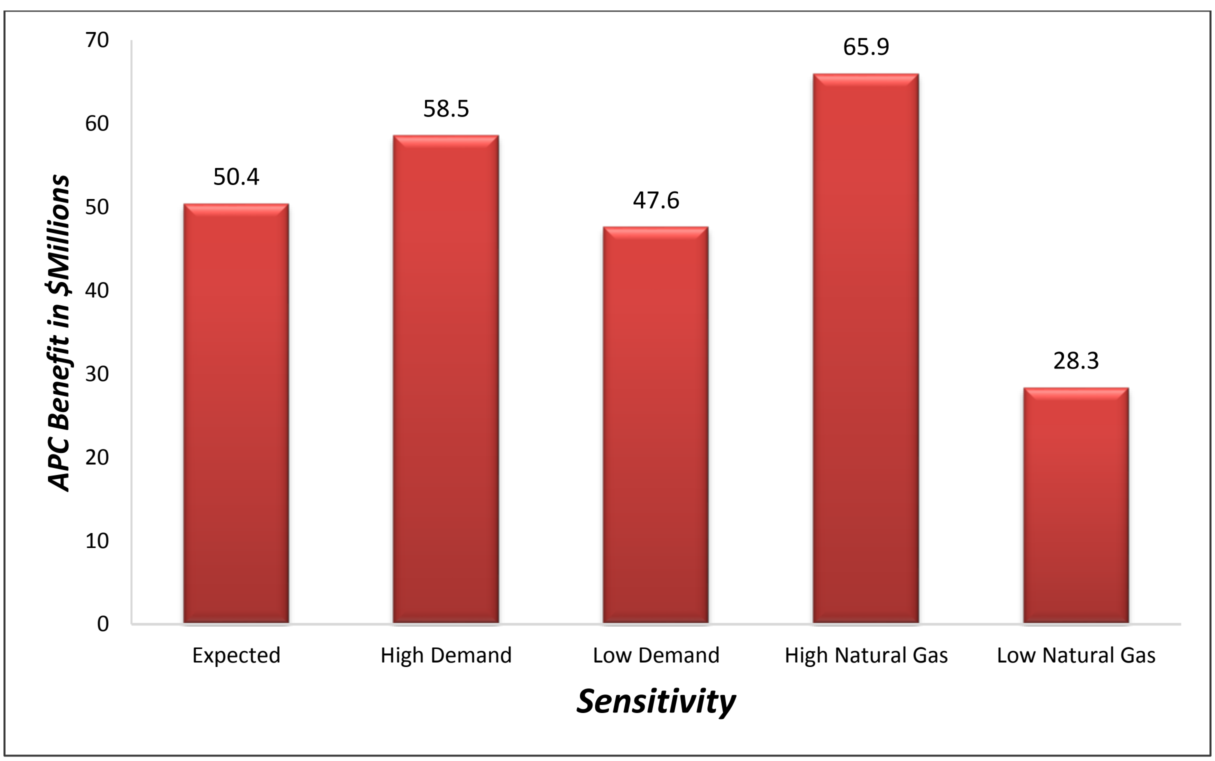

Figure 13.5: 1-Year Benefits of Reference Case Portfolio for Demand and Natural Gas Sensitivities

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.

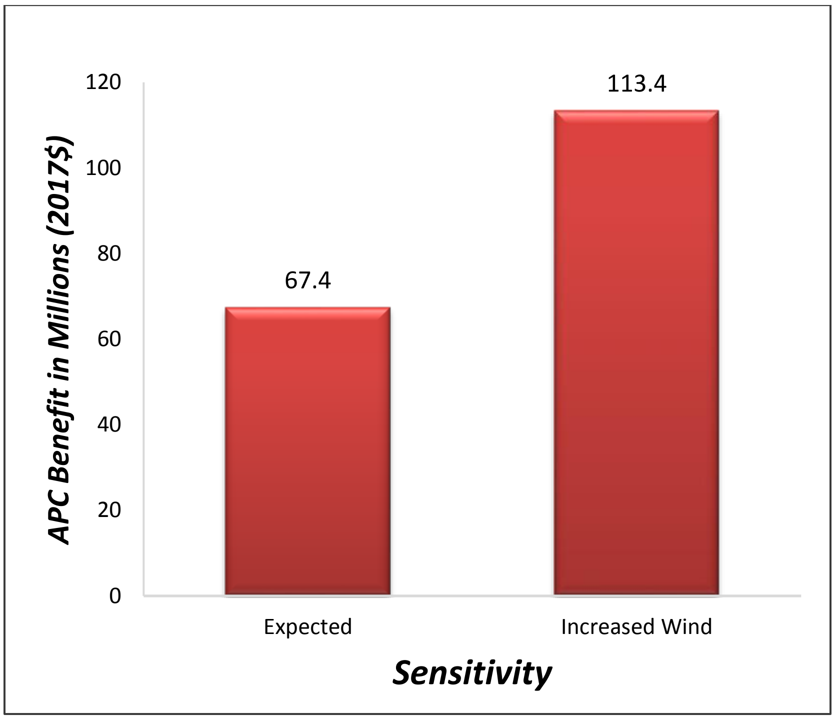

Figure 13.6: 1-Year Benefits of Reduced Carbon Portfolio for Additional Wind Sensitivity

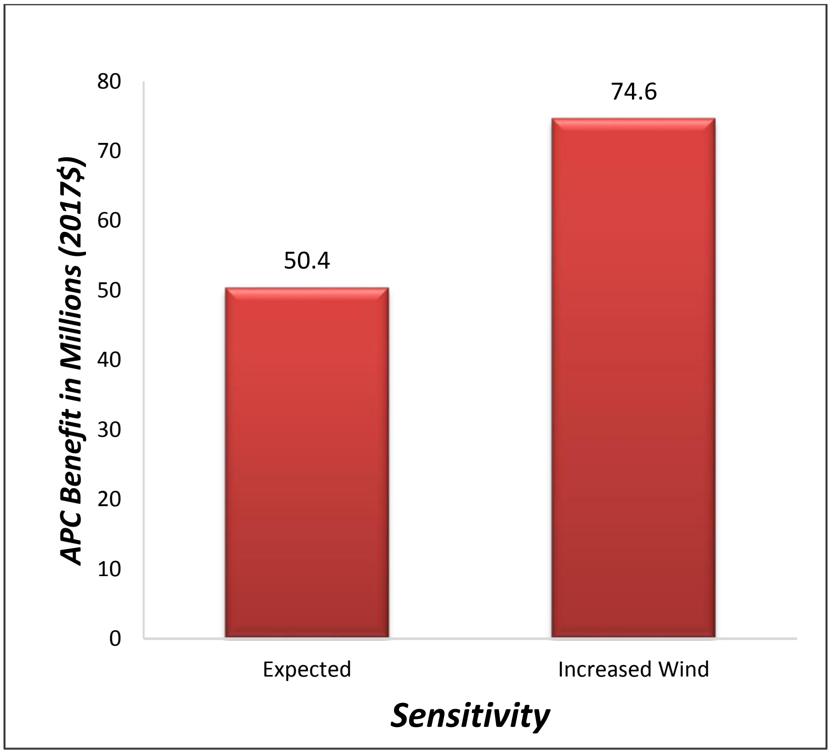

Figure 13.7: 1-Year Benefits of Reference Portfolio for Additional Wind Sensitivity

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.

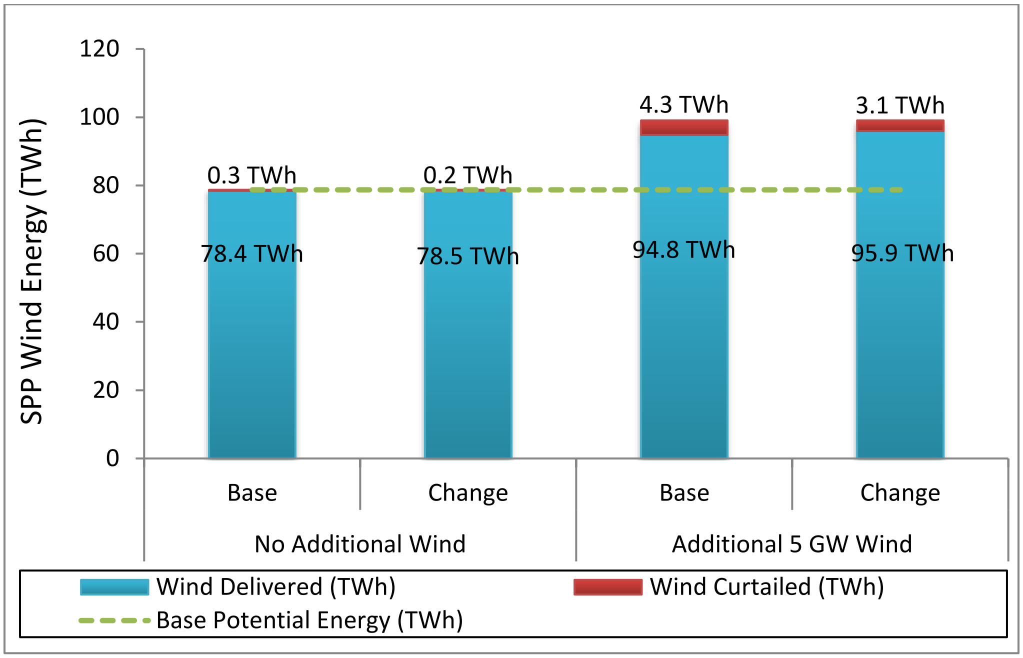

Figure 13.8: SPP Annual Wind Energy for Reduced Carbon Portfolio (2025)

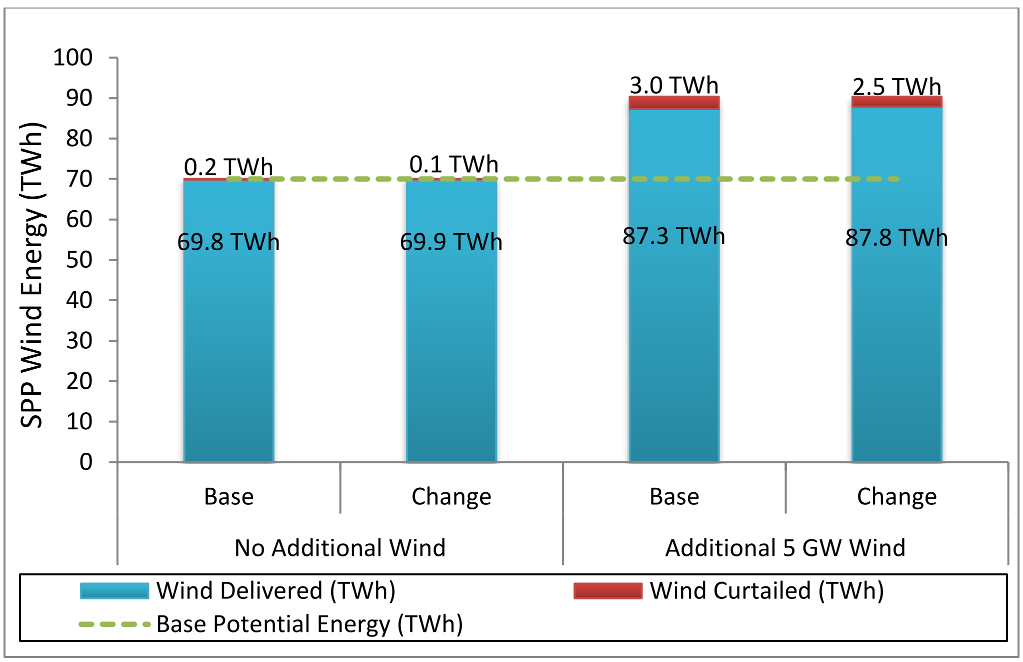

Figure 13.9: SPP Annual Wind Energy for Reference Case Portfolio (2025)

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.

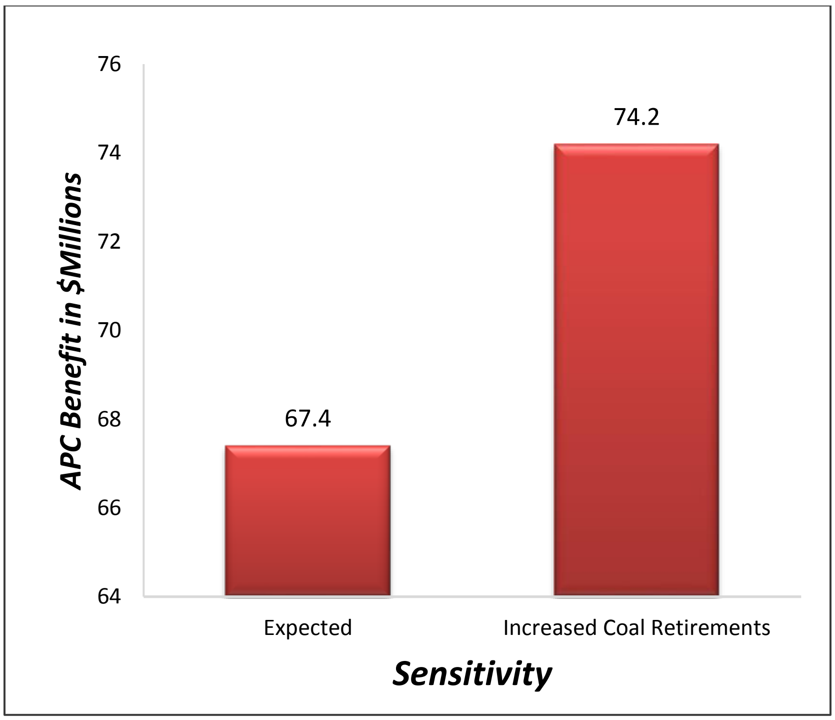

Figure 13.10: 1-Year Benefits of Reduced Carbon Portfolio for Coal Retirement Sensitivity

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.

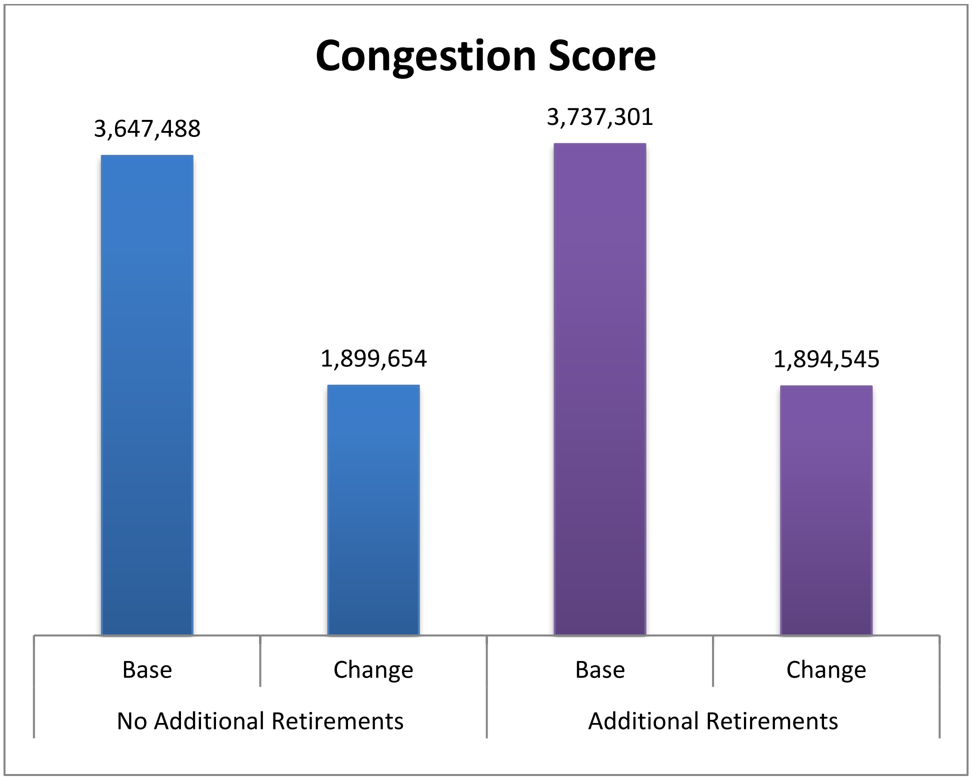

Figure 13.11: Sum of Economic Need Congestion Scores With and Without the Reduced Carbon Portfolio

[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

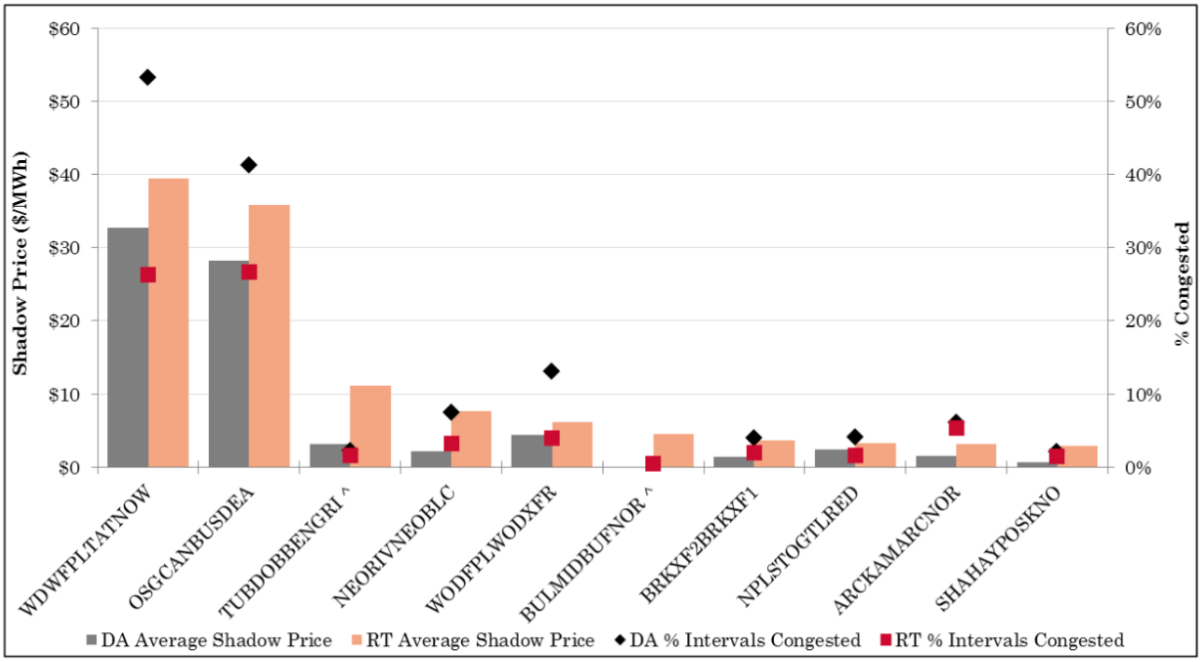

Figure 15.1: Top 10 Congested Flowgates from 2015 ASOM Report

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

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[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.

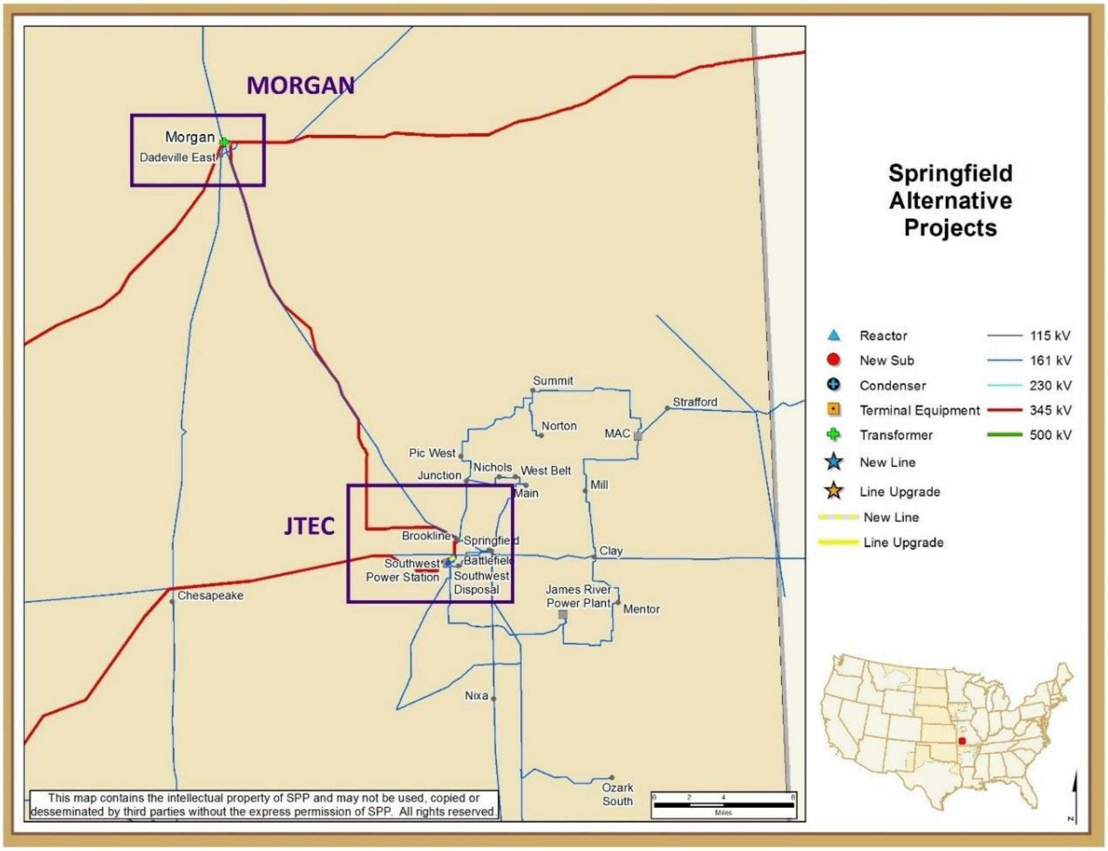

Figure 15.2: Springfield Alternative Projects

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

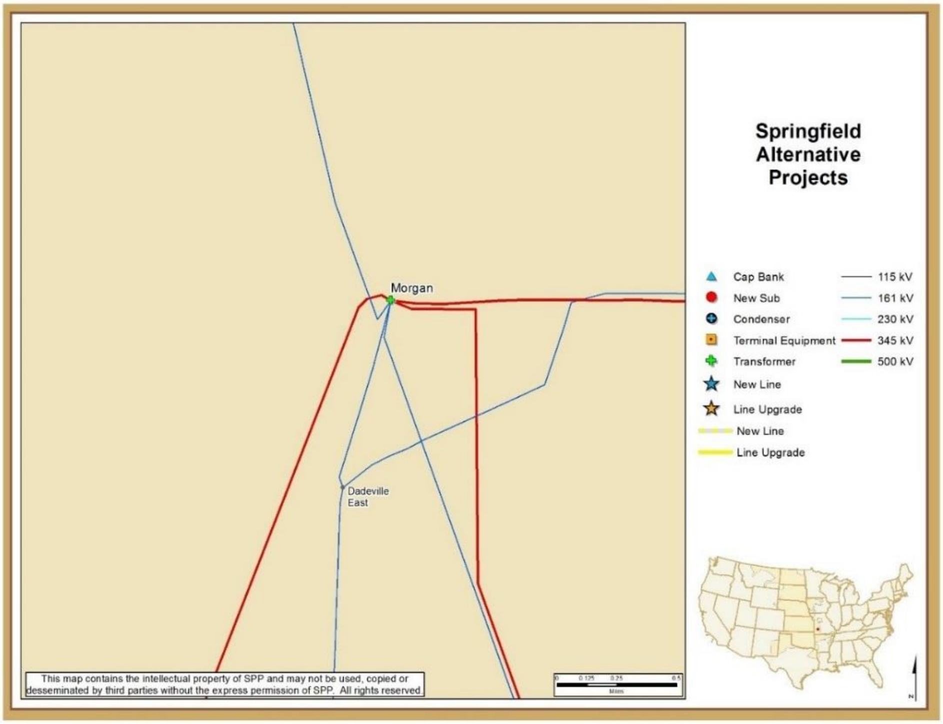

Figure 15.3: Springfield Alternative Project – Morgan

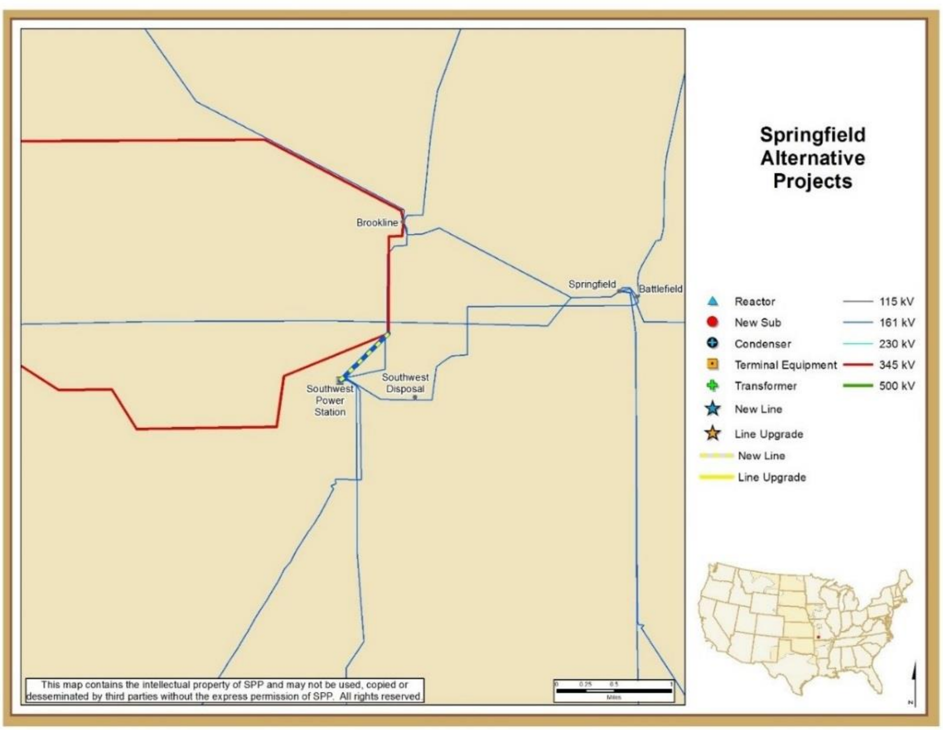

Figure 15.4: Springfield Alternative Project – JTEC

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.

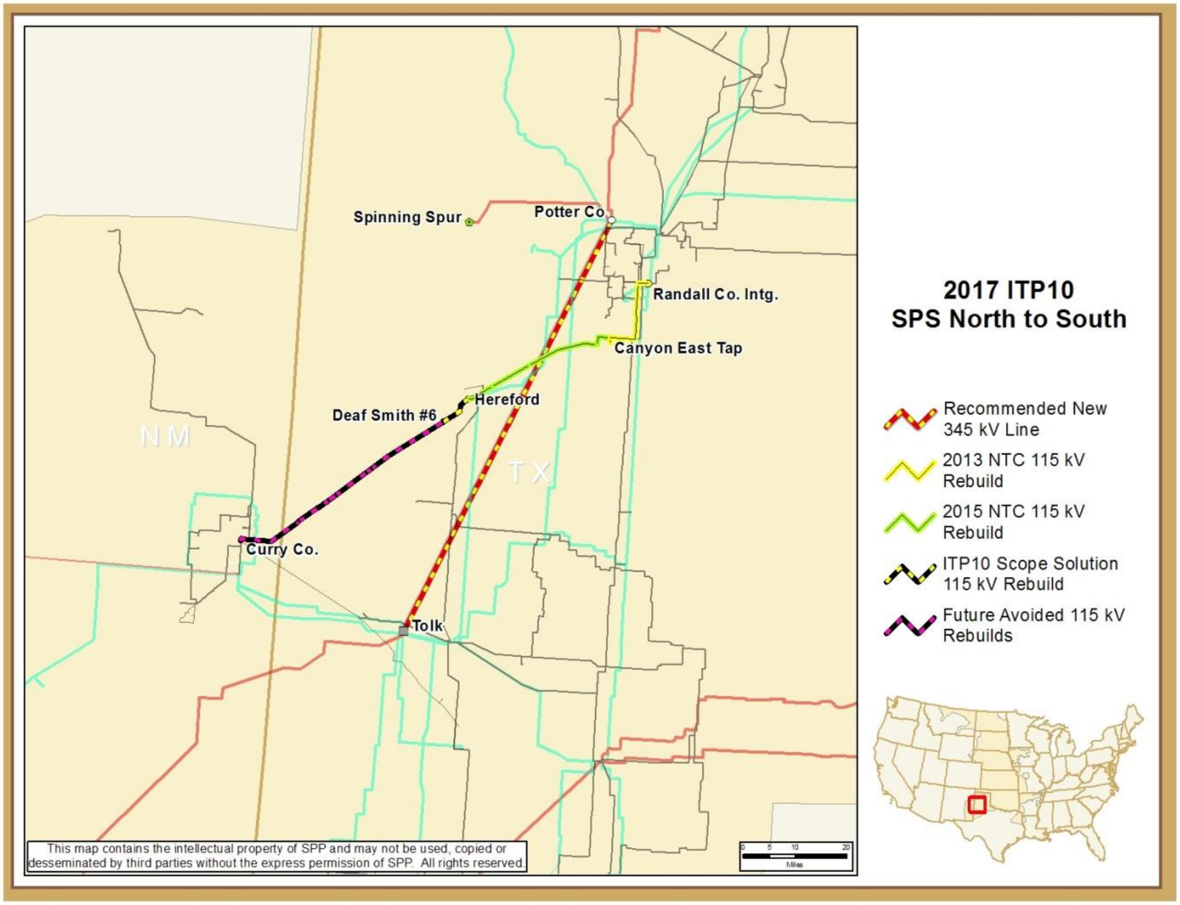

Figure 15.5: Transmission Map of Texas Panhandle with Potential Solutions

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

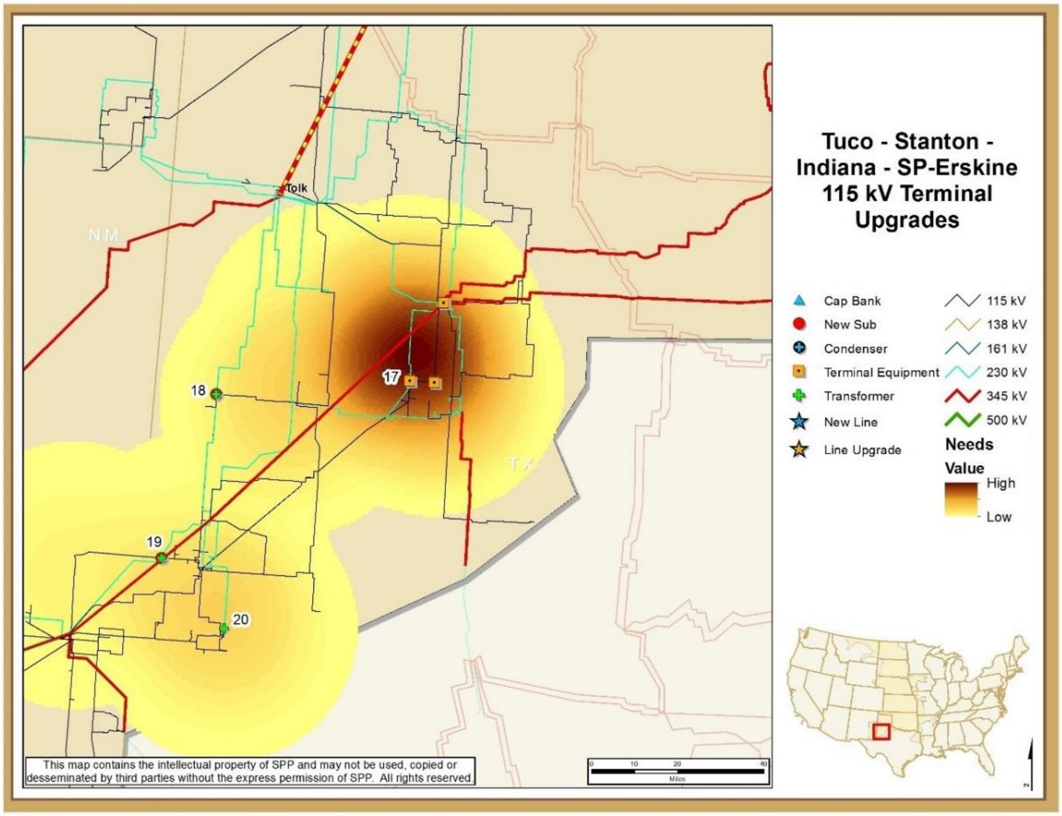

Figure 16.1: Tuco - Stanton - Indiana - SP-Erskine 115 kV Terminal Upgrades

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.

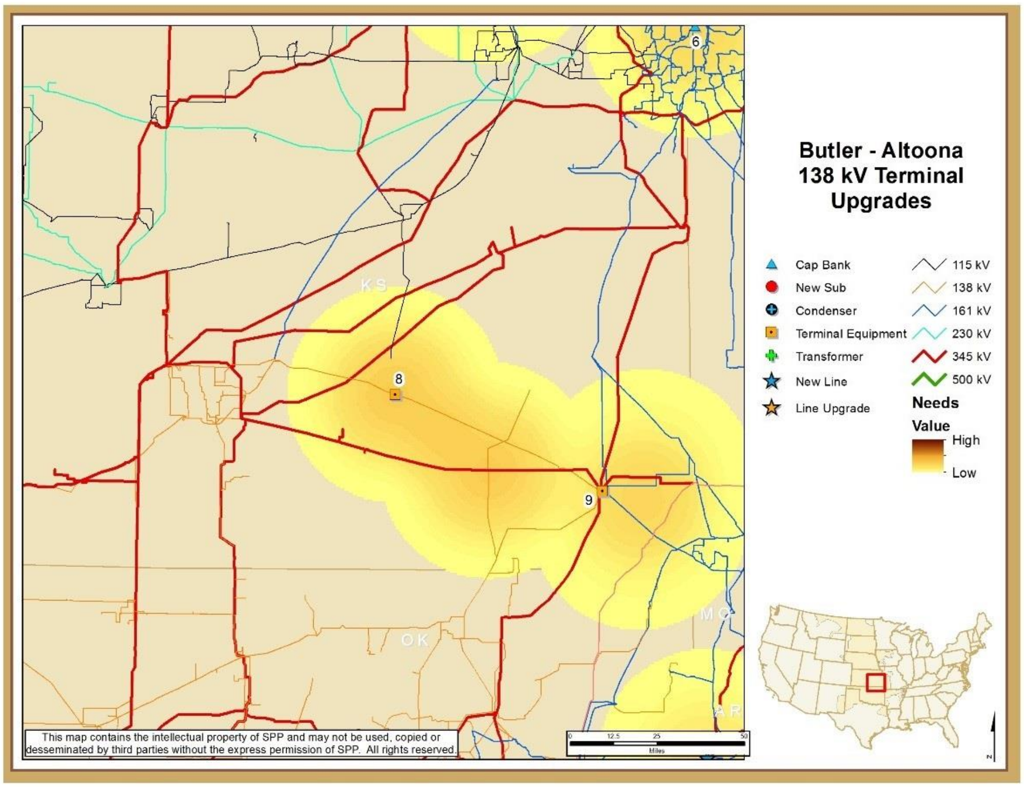

Figure 16.2: Butler - Altoona 138 kV Terminal Upgrades

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.

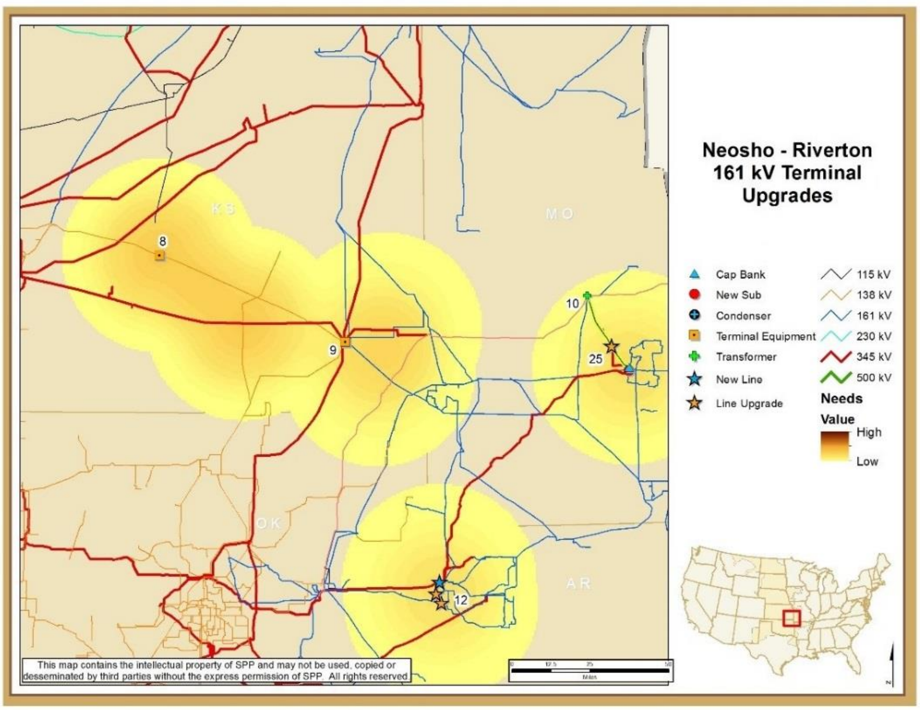

Figure 16.3: Neosho - Riverton 161 kV Terminal Upgrades

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.

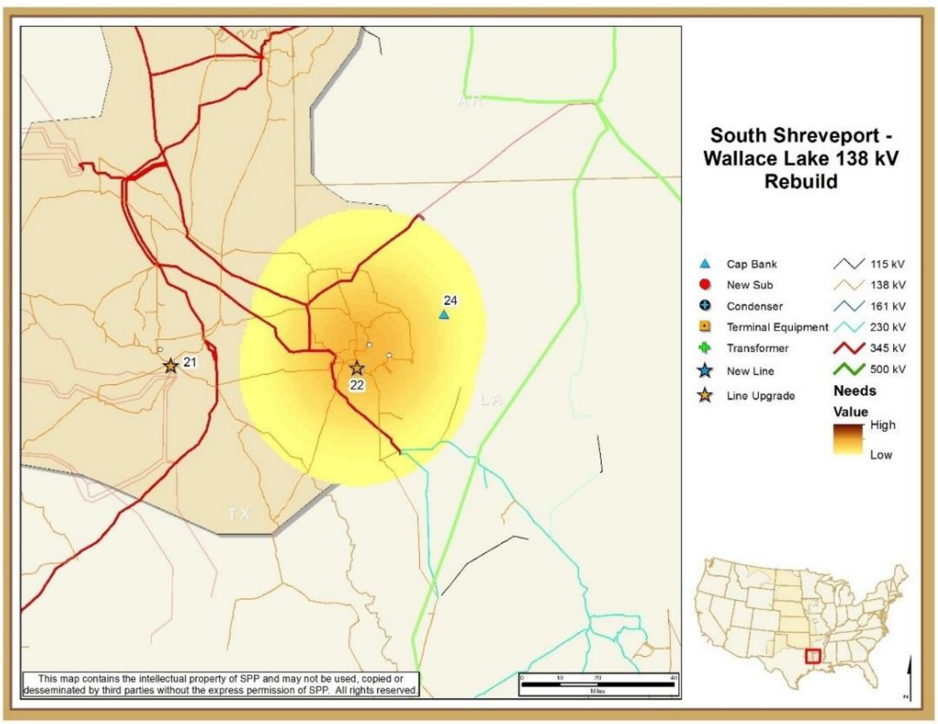

Figure 16.4: South Shreveport - Wallace Lake 138 kV Rebuild

[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

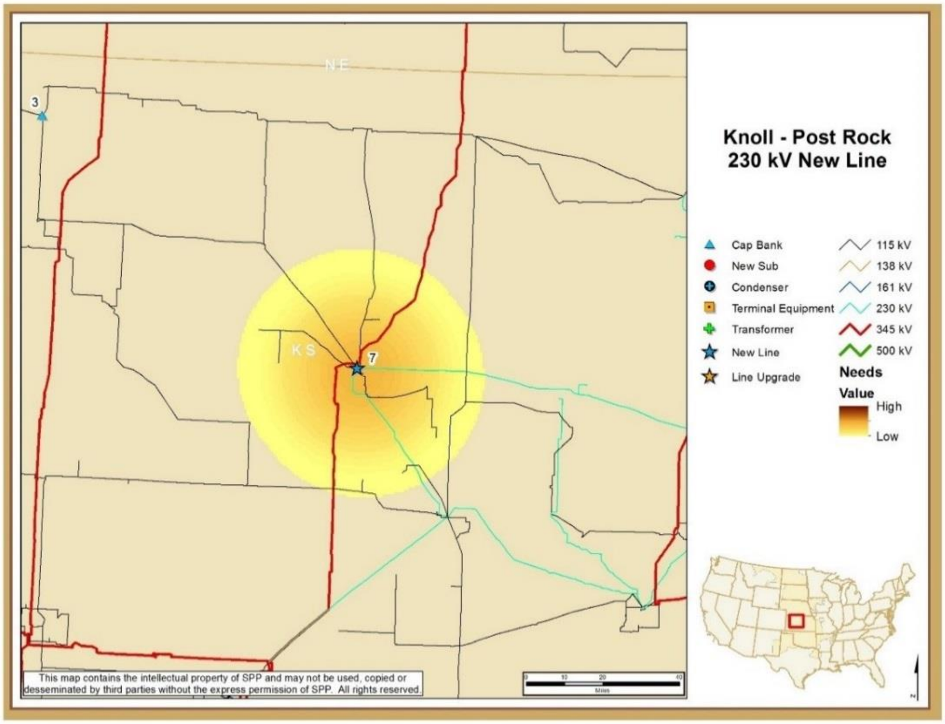

Figure 16.5: Knoll - Post Rock 230 kV New Line

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.

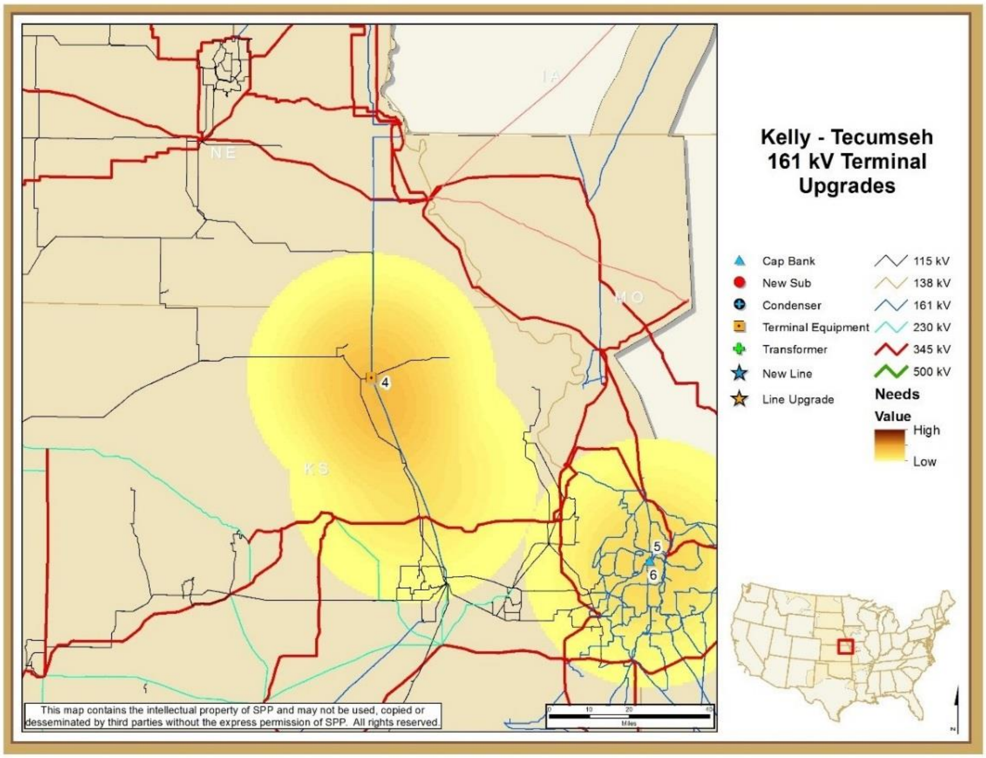

Figure 16.6: Kelly - Tecumseh 161 kV Terminal Upgrades

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

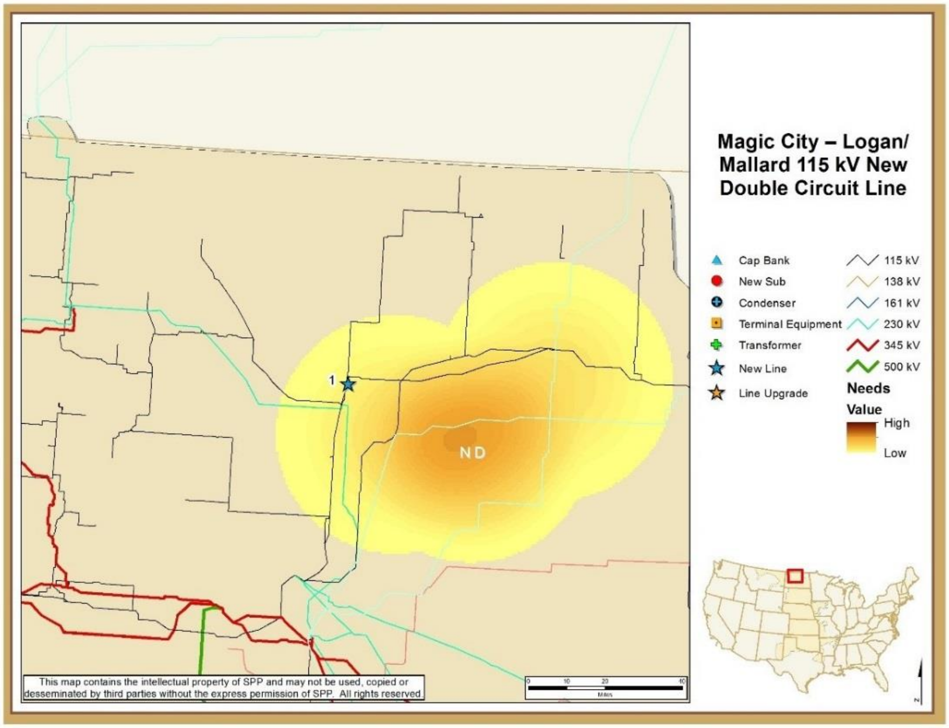

Figure 16.7: Magic City – Logan/Mallard 115 kV New Double Circuit Line

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.

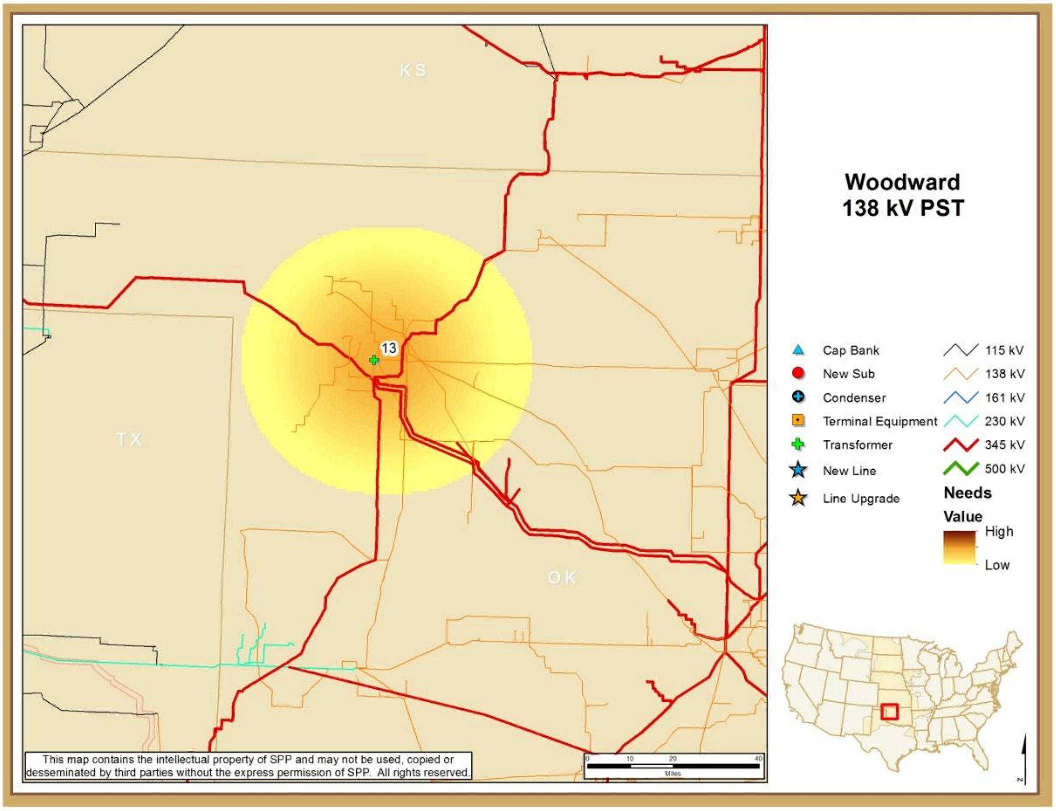

Figure 16.8: Woodward 138 kV PST

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.

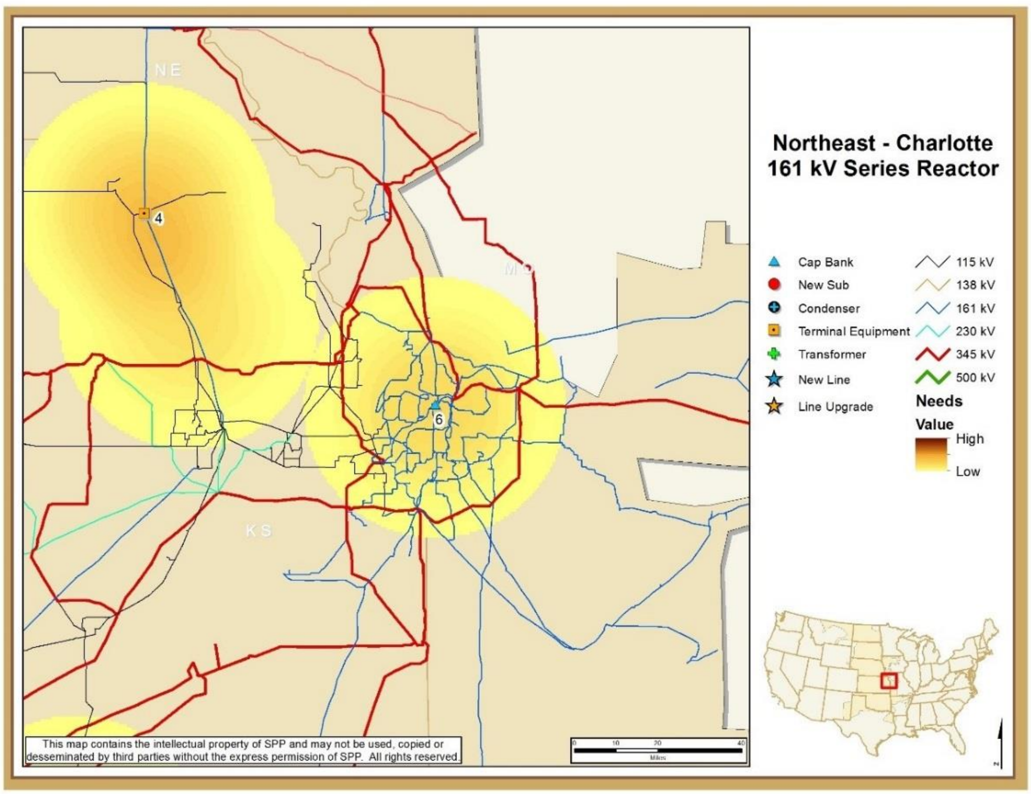

Figure 16.9: Northeast - Charlotte 161 kV Series Reactor

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.*

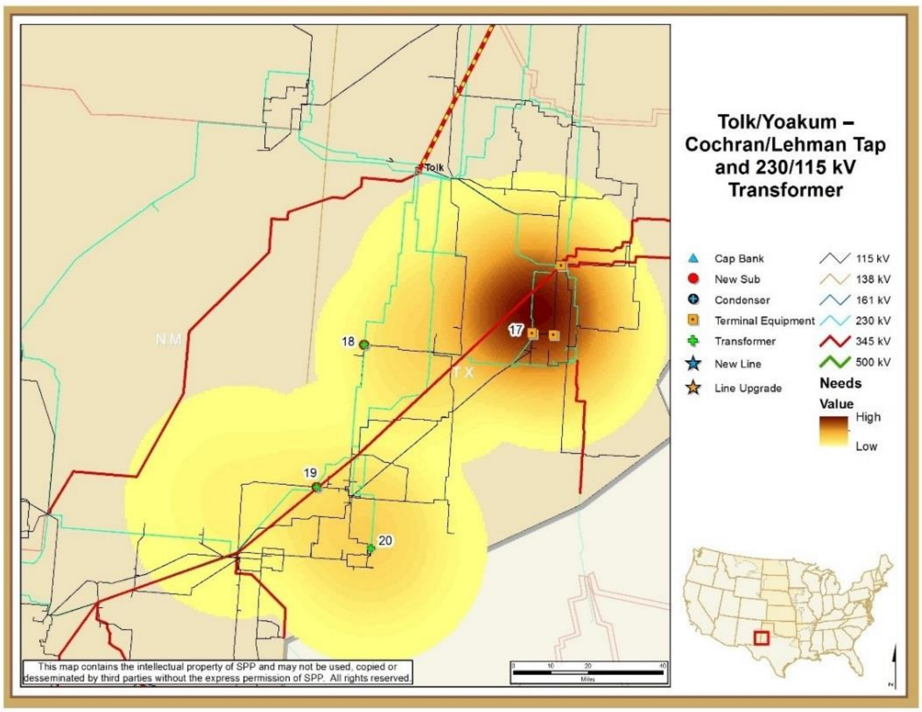

Figure 16.10: Tolk/Yoakum – Cochran/Lehman Tap and 230/115 kV Transformer

[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

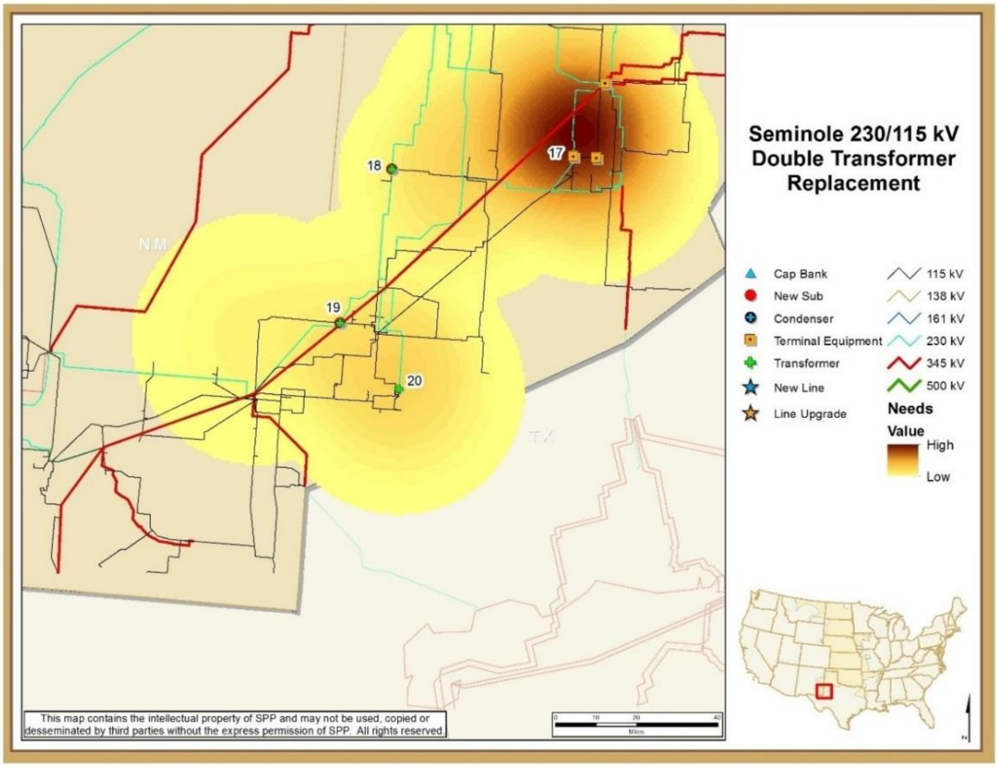

Figure 16.11: Seminole 230/115 kV Double Transformer Replacement

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.

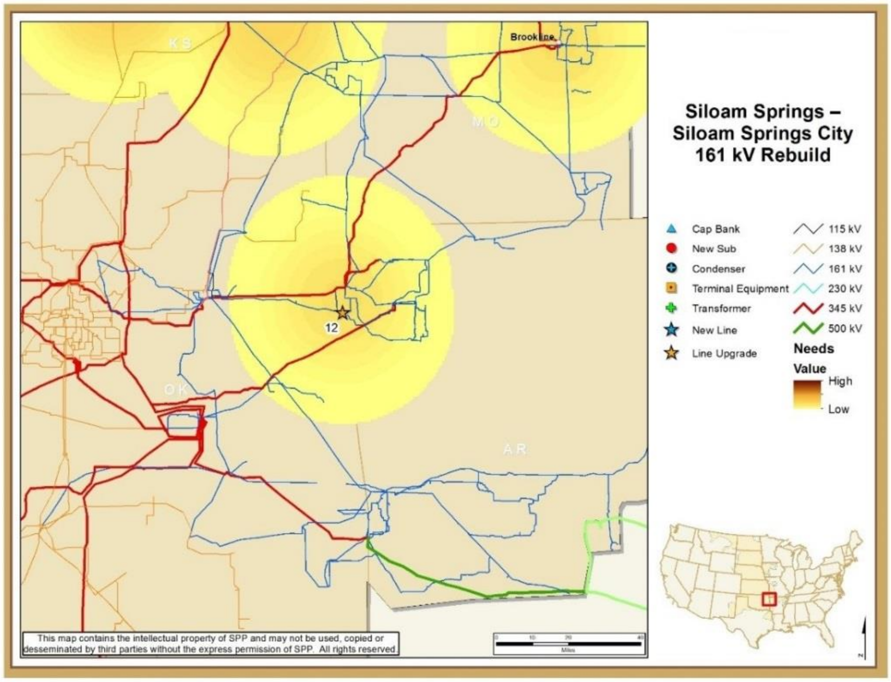

Figure 16.12: Siloam Springs – Siloam Springs City 161 kV Rebuild

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.

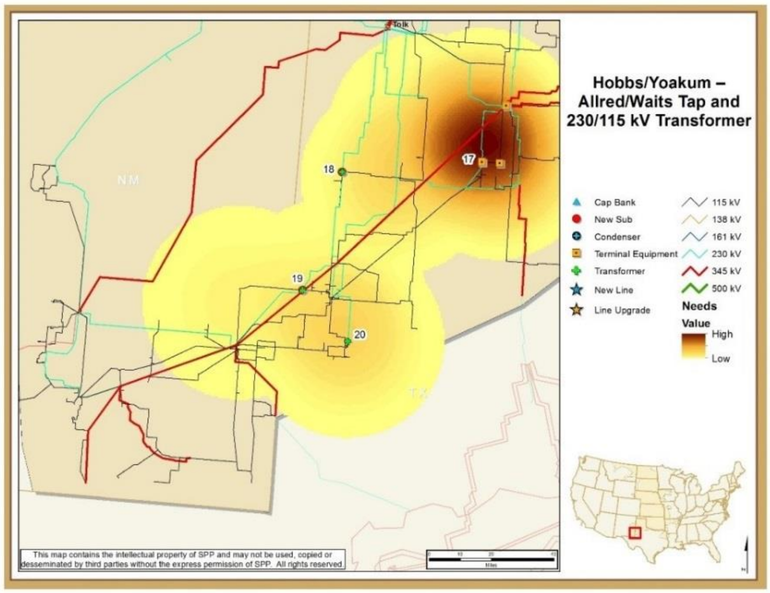

Figure 16.13: Hobbs/Yoakum – Allred/Waits Tap and 230/115 kV Transformer

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.

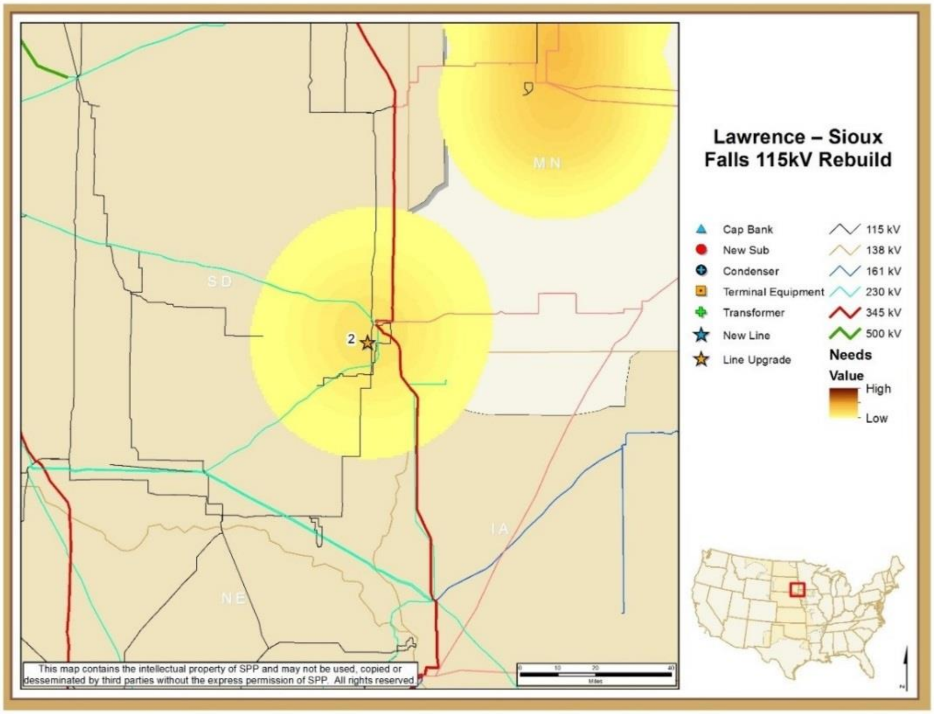

Figure *16.14*: Lawrence – Sioux Falls 115kV Rebuild Project**Tupelo – Tupelo Tap – Lula 138 kV Terminal Upgrades**

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.

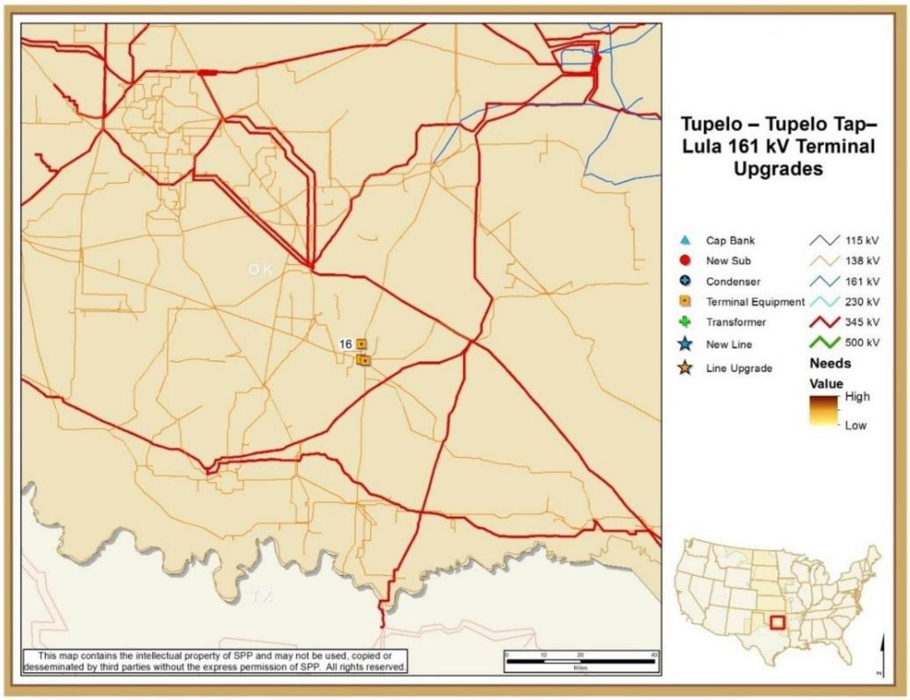

Figure 16.15: Tupelo – Tupelo Tap – Lula 138 kV Terminal Upgrades

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.

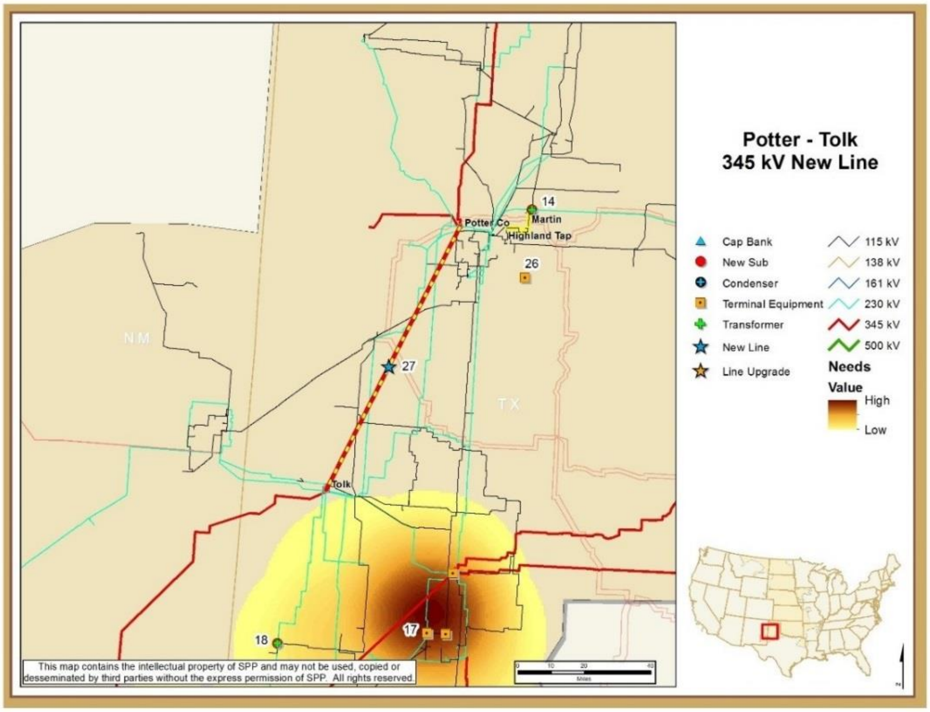

Figure 16.16: Potter – Tolk 345 kV New Line

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.

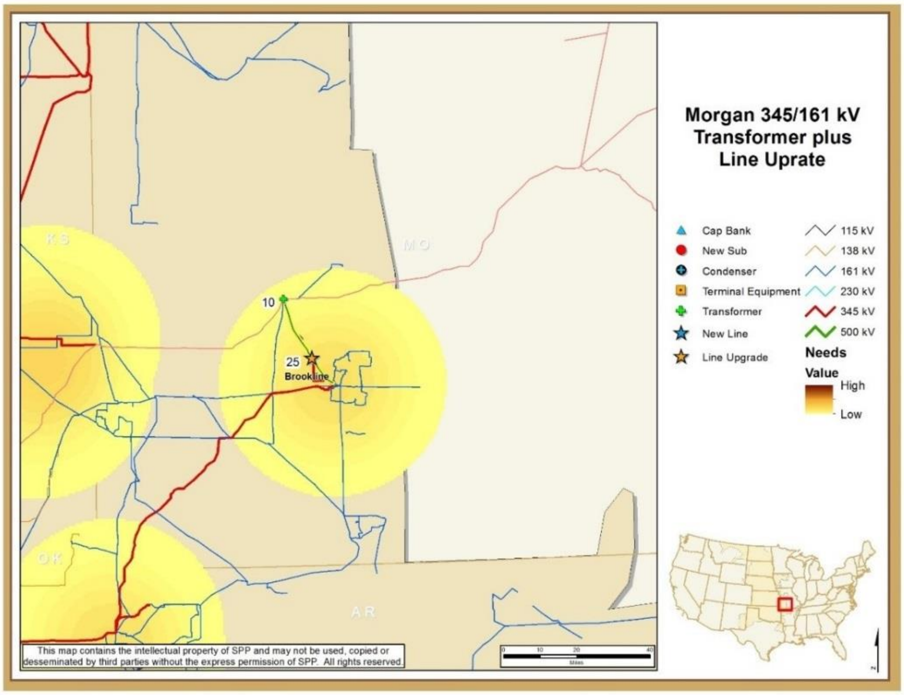

Figure 16.17: Morgan 345/161 kV Transformer plus Line Uprate

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.

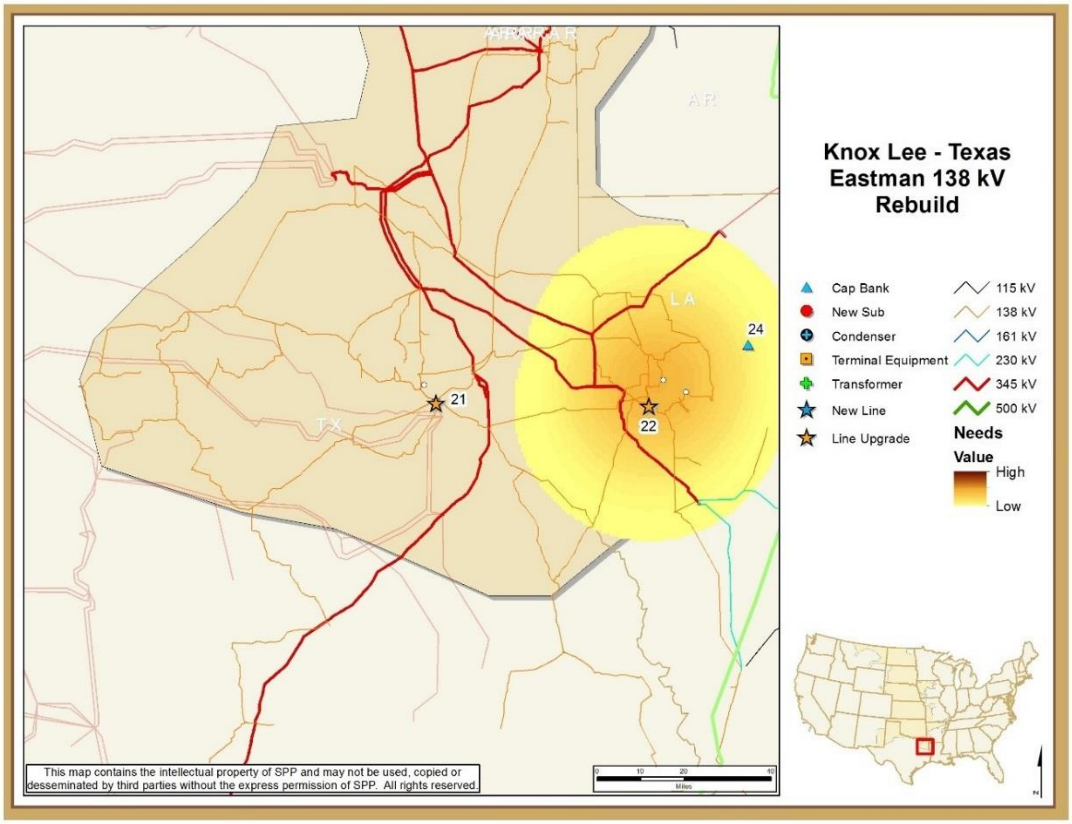

Figure 16.188: Knox Lee - Texas Eastman 138 kV Rebuild

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.

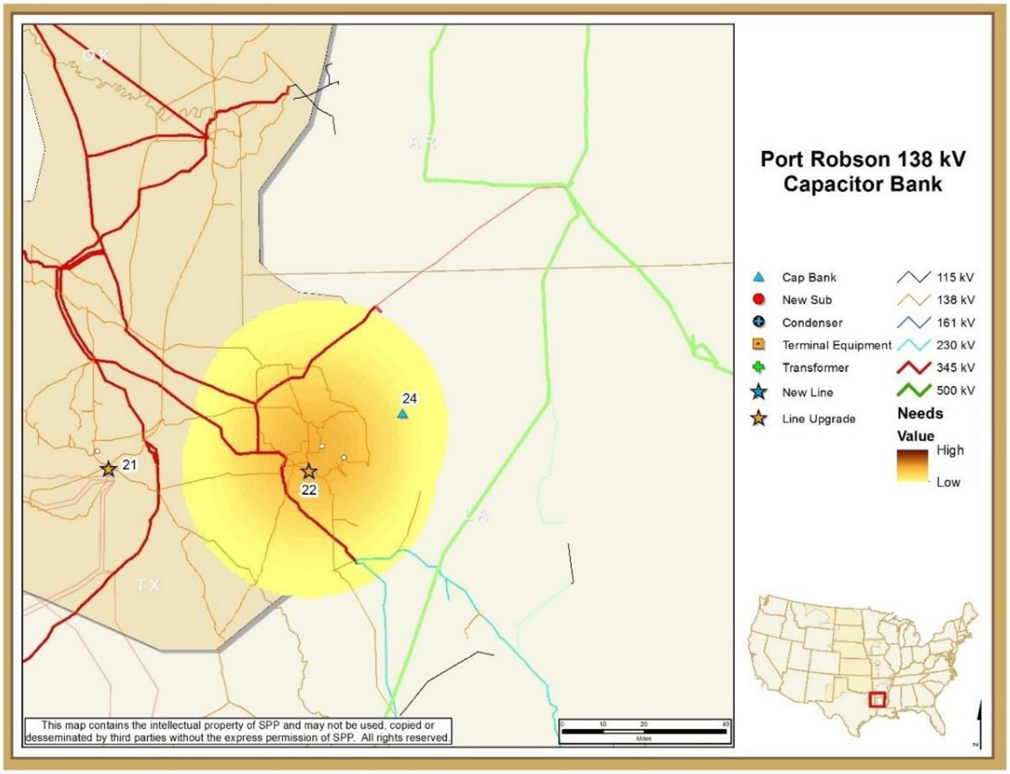

Figure 16.19: Port Robson 138 kV Capacitor Bank

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.

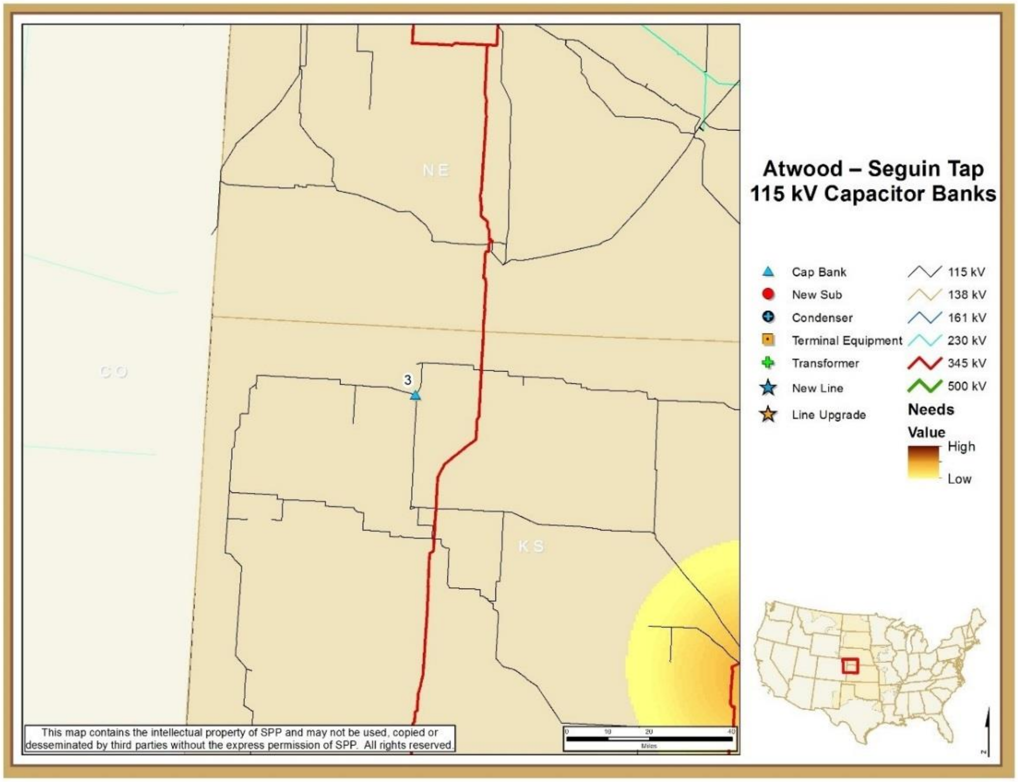

Figure 16.190: Atwood – Seguin Tap 115 kV Capacitor Banks

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.

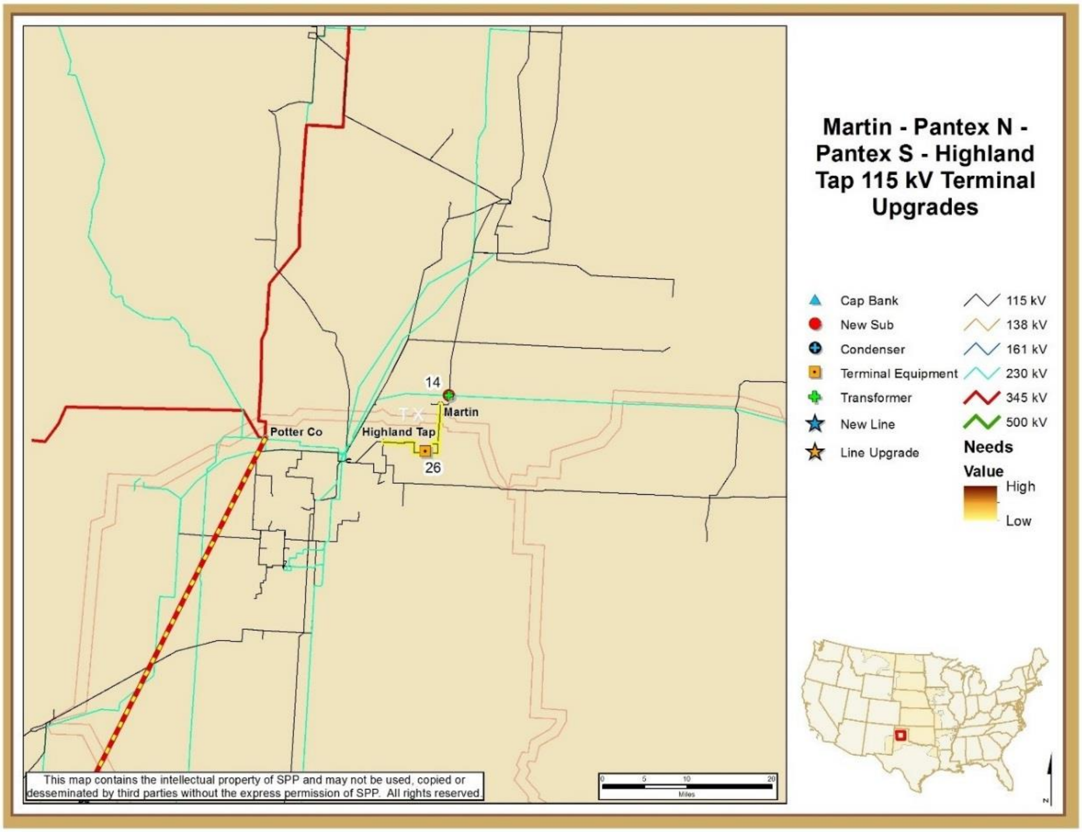

Figure 16.201: Martin – Pantex N – Pantex S – Highland Tap 115 kV Terminal Upgrades

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.

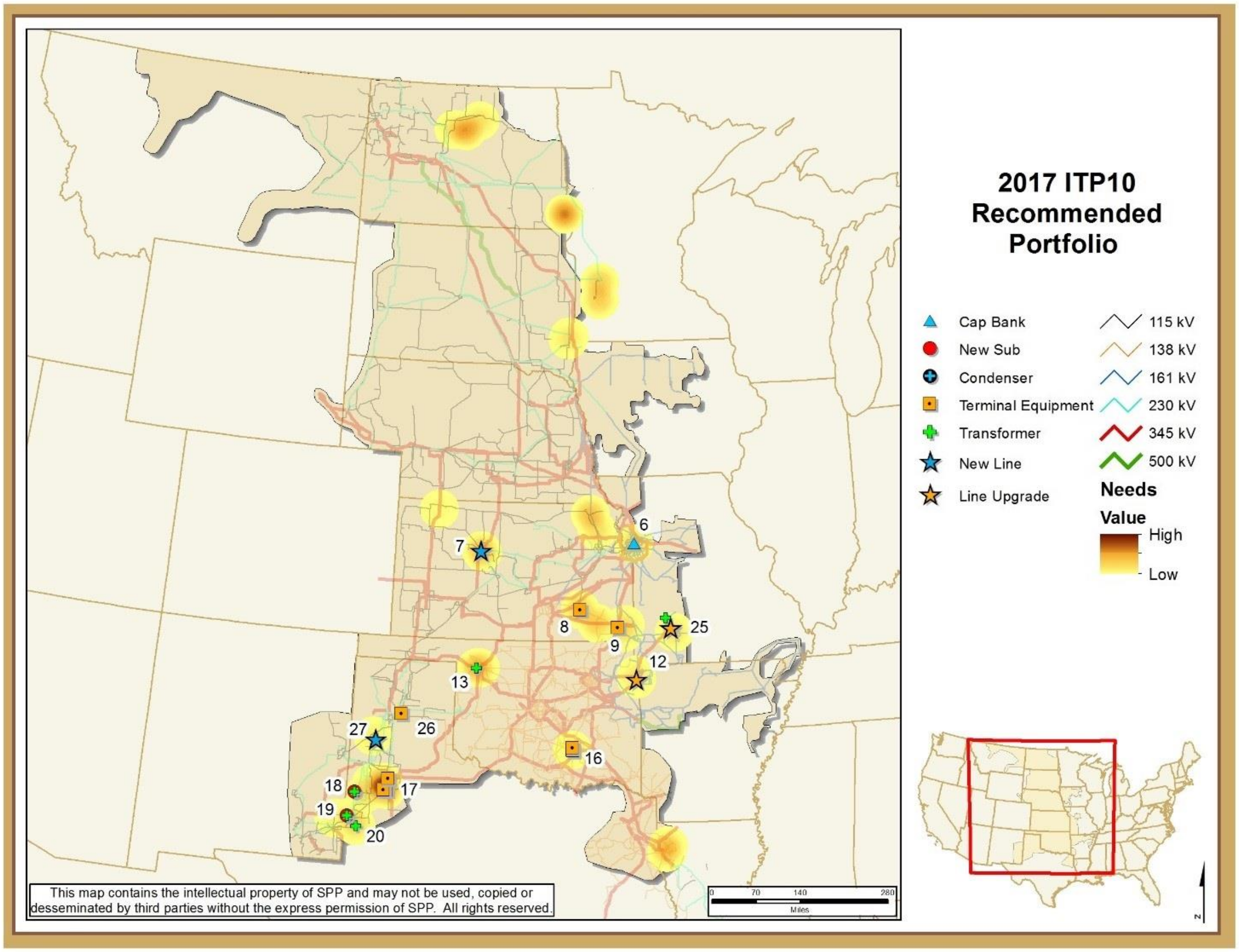

Figure 16.212: 2017 ITP10 Recommended Portfolio

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

ITP20

2013 Integrated Transmission Plan 20-Year Assessment Report

July 30, 2013

Engineering

Southwest Power Pool

Revision History

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Executive Summary

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

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

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

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

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

[2] 2012 Policy Survey

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

12 projects make up the portfolio:

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

Table 0.1: 2013 ITP20 Transmission Plan

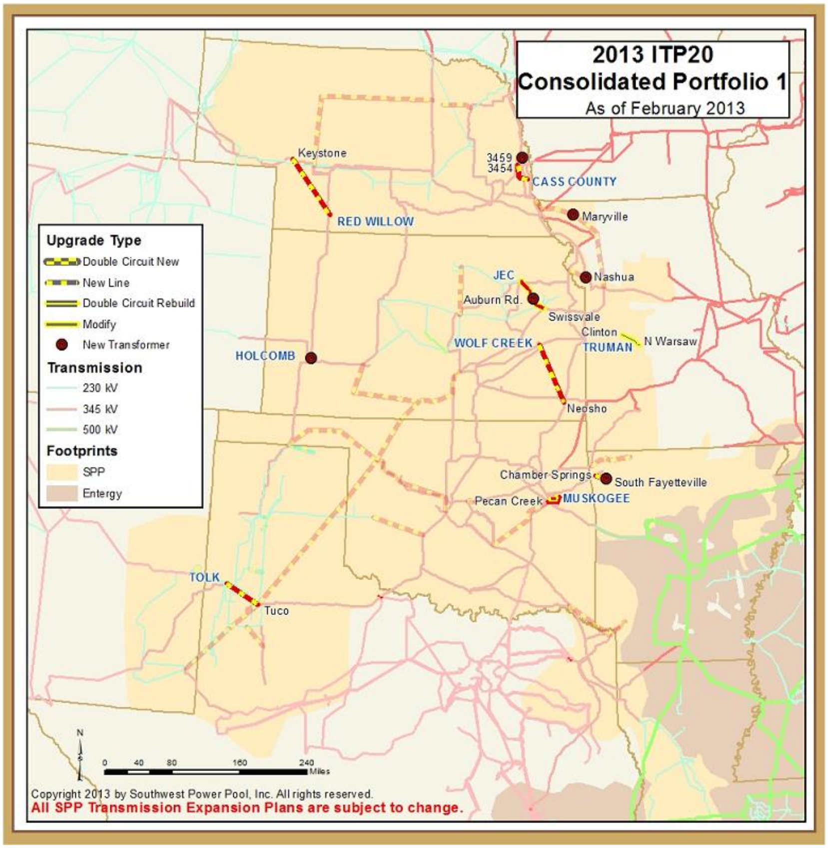

Figure 0.1: 2013 ITP20 Transmission Plan[3]

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

PART I: STUDY PROCESS

Section 1: Introduction

1.1: The 20-Year ITP

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

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

The goals of the ITP20 are to:

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

1.2: How to Read This Report

This report focuses on the year 2033 (20 years from 2013) and is divided into multiple sections.

- Part I addresses the concepts behind this study's approach, key procedural steps in development of the analysis, and overarching assumptions used in the study.
- Part II demonstrates the findings of the study, empirical results, and conclusions.
- Part III addresses the portfolio specific results, describes the projects that merit consideration, and contains recommendations, expected benefits, and costs. Please note that negative numbers here are shown in red and in parentheses.
- Part IV contains detailed data and holds the report's appendix material.

SPP Footprint

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

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

Supporting Documents

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

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

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

Confidentiality and Open Access

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

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

Section 2: Stakeholder Collaboration

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

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

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

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

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

Planning Workshops

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

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

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

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

Policy Survey

The 2012 Policy Survey asked stakeholders to identify:

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

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

Project Cost Overview

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

New Benefit Metrics

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

Historical ITP metrics:

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

Newly developed metrics:

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

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

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

Section 3: Future Selection

3.1: Uncertainty and Important Issues

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

3.2: Futures Descriptions

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

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

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

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

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

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

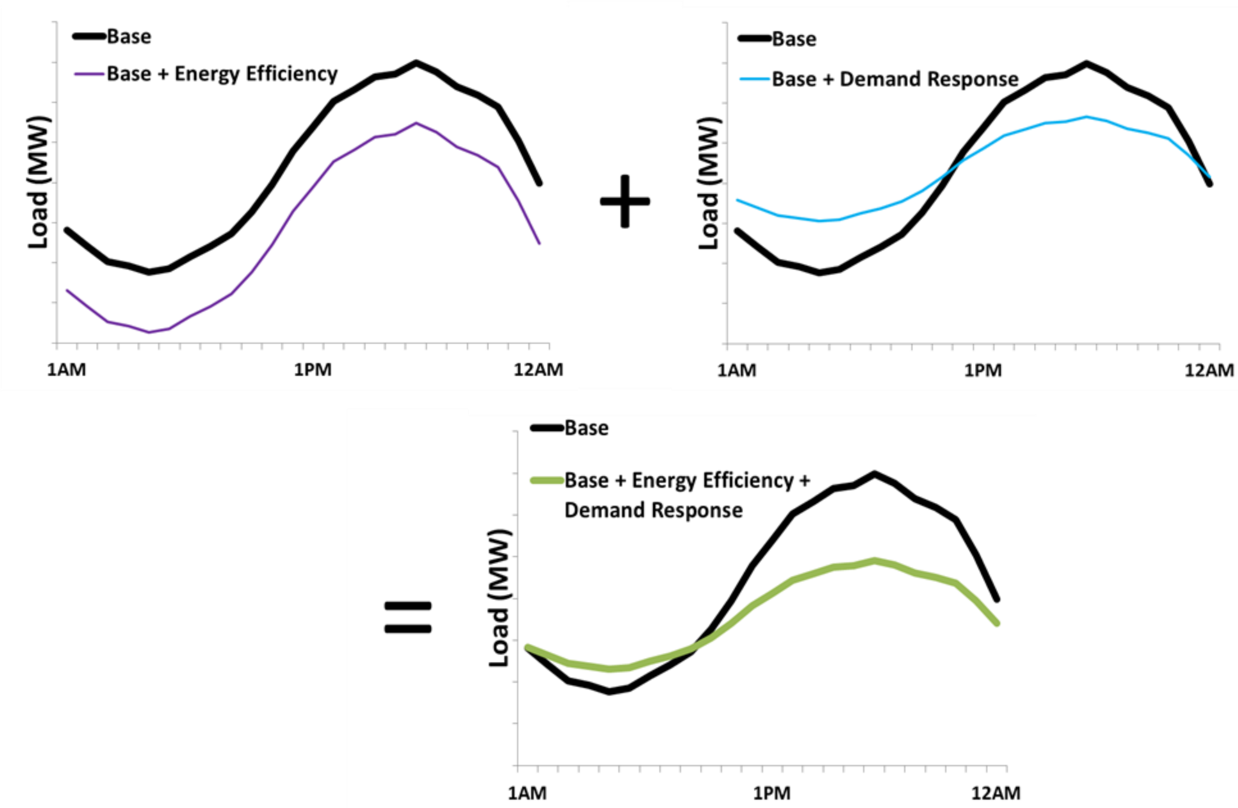

Figure 3.1: Impact of Demand Response & Energy Efficiency Over One Day

Future 5: Joint SPP/MISO Future

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

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


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

Section 4: Study Drivers

4.1: Introduction

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

4.2: Load & Energy Outlook

Peak and Off-Peak Load

Future electricity usage was forecasted by utilities in the SPP footprint and collected and reviewed through the efforts of the Model Development Working Group (MDWG). The highest usage, referred to as the system peak, usually occurs in the summer for SPP. The non-coincident peak load for SPP was forecasted to be 59.4 GW for 2023 and 67.7 GW for 2033. Note that all demand figures shown in this section include the loads of the Transmission Owners within the SPP OATT footprint as well as all other Load Serving Entities within the SPP region.

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

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

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

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

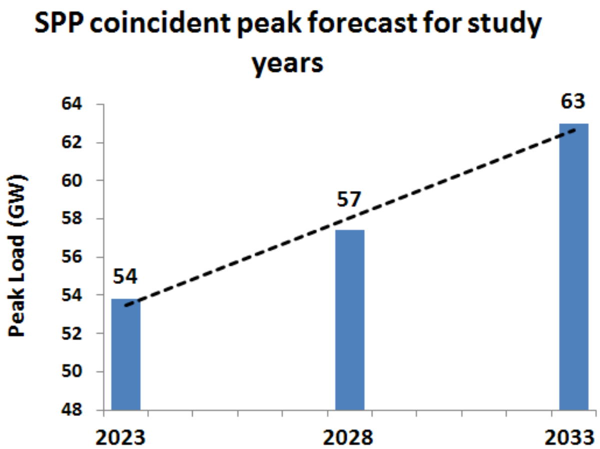

Figure 4.1: SPP coincident peak forecast for 2033 and intervening years

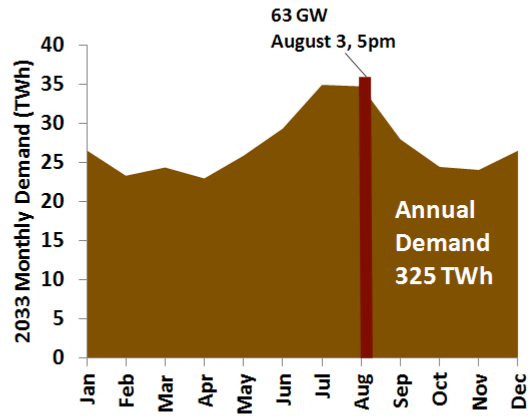

Figure 4.2: SPP Annual Energy Demand Forecast

Peak Load and Energy

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

Major Load Centers in SPP

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

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

Table 4.2: Load Centers in SPP

Diverse Peak Demand Growth Rates

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

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

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

4.3: Policy Drivers

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

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

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

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

Voltage Levels and Technology Choice (AC vs. DC)

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

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

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

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

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

EHV Design Considerations

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

NERC N-1 Reliability Standards

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

Distances within the SPP System and to External Paths

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

Line Length and Loadability

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

Capacity Needs

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

Voltage Support

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

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

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

Construction Cost

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

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

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

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

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

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

Table 4.5: Approximate Costs of HVDC Converter Stations

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

Facts about Alternative Voltage and Technology Choices

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

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

Voltage Level Selection in the 2013 ITP20

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

Section 5: Resource Expansion Plan

5.1: Resource Plan Development

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

5.2: Conventional Resource Plan

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

Generator Review

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

Conventional Resource Plan Approach

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

Generation Siting

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

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

Conventional Resource Plan – External Regions

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

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

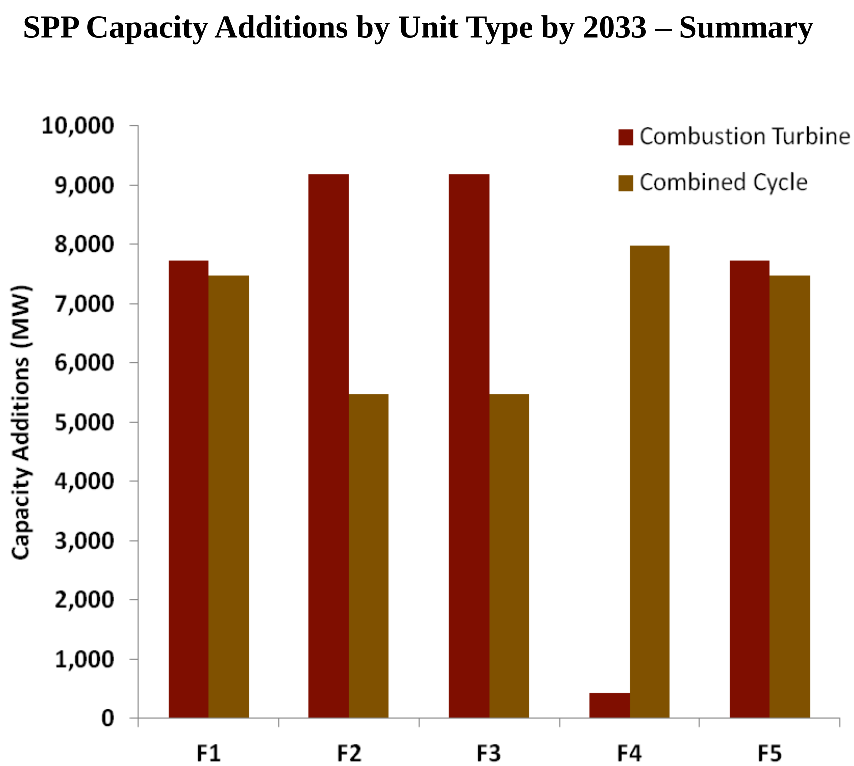


Figure 5.1: Conventional Capacity Additions by Unit Type

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

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

Futures 1 and 5 Conventional Resource Plan for 2033 – SPP

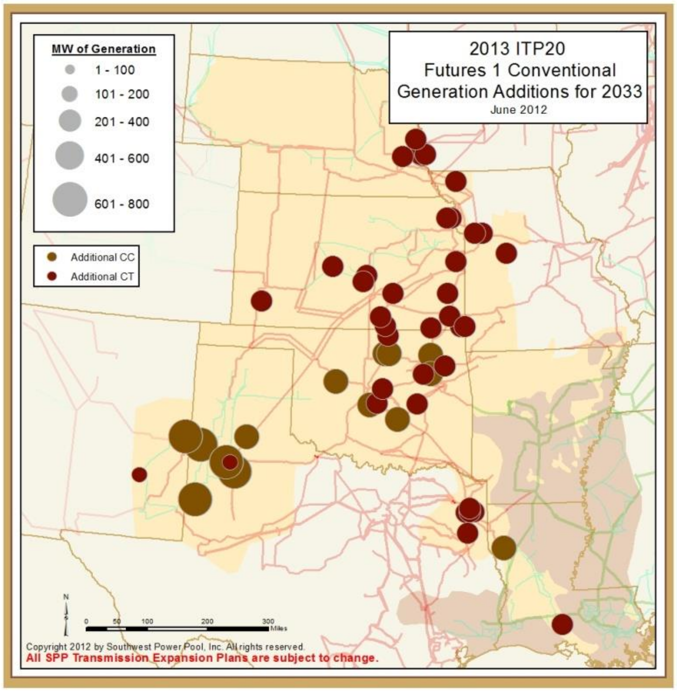


Figure 5.2: Conventional Generation Additions for Futures 1 and 5

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

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

Futures 2 and 3 Conventional Resource Plan for 2033 – SPP

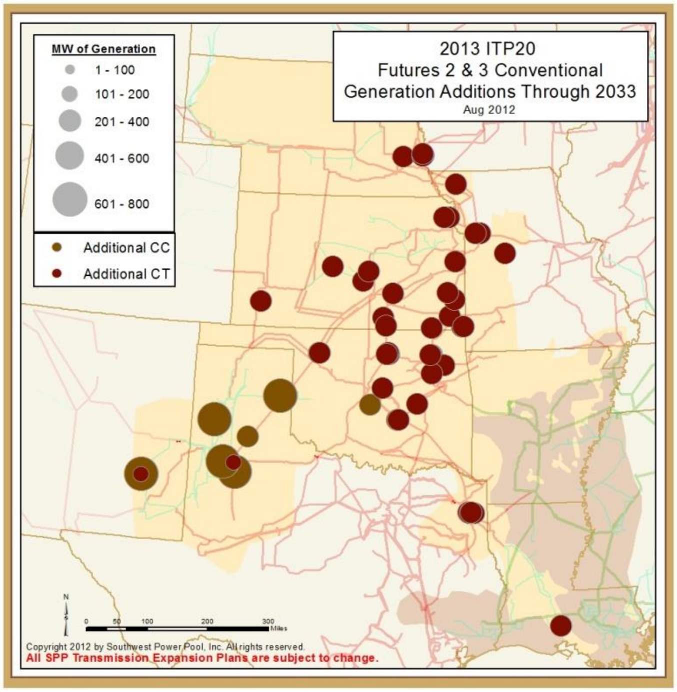


Figure 5.3: Conventional Generation Additions for Futures 2 and 3

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

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

Future 4 Conventional Resource Plan for 2033 – SPP

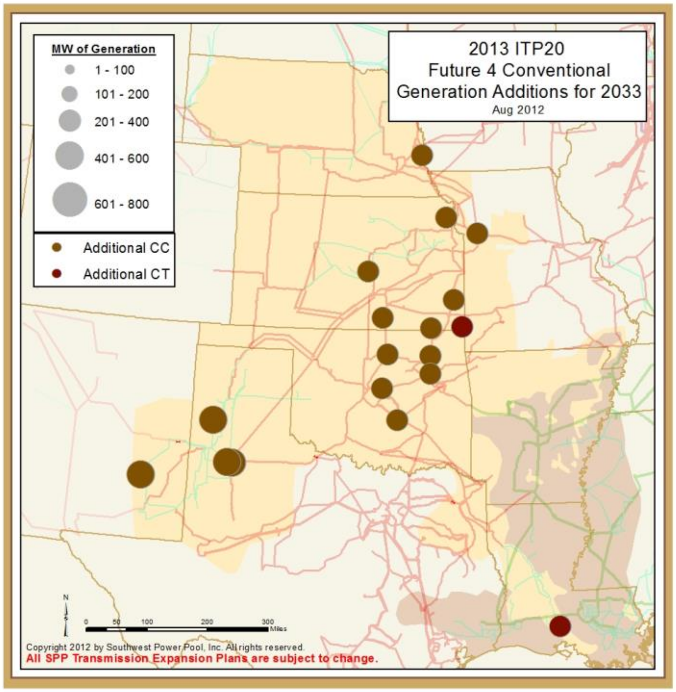


Figure 5.4: Conventional Generation Additions for Future 4

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

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

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

5.3: Renewable Resource Plan

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

Existing Wind

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

Additional Wind

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

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

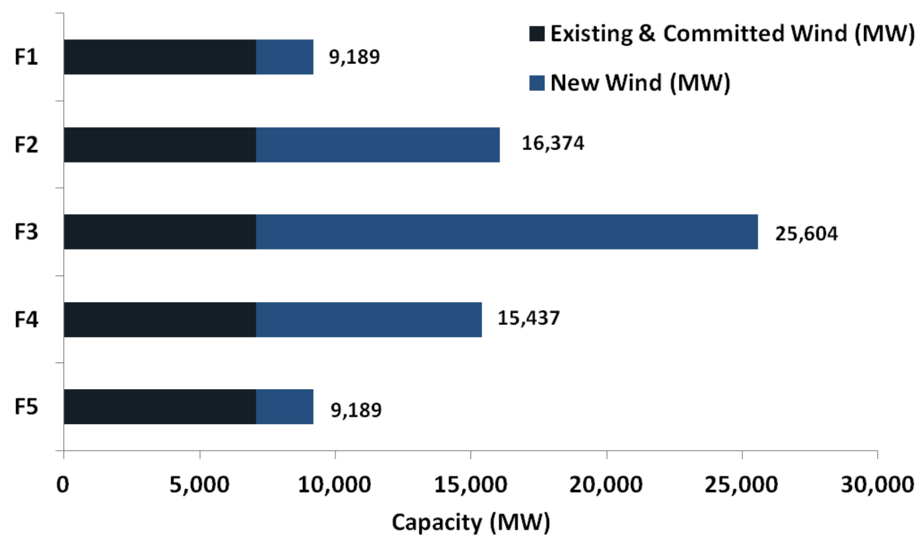


Table 5.1: SPP Wind by Future

Siting of Additional Wind

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

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

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

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

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

Renewable Resource Plan – External Regions

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

Futures 1 and 5 Renewable Resource Plan for 2033 – SPP

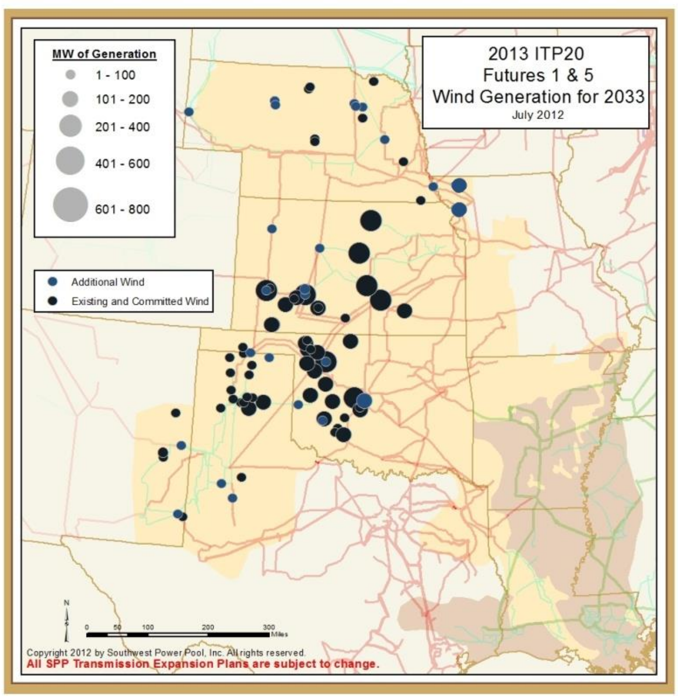


Figure 5.5: Renewable Resource Plan for Futures 1 and 5

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

- Wind Sites
  - 71 Existing

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

Future 2 Renewable Resource Plan for 2033 – SPP

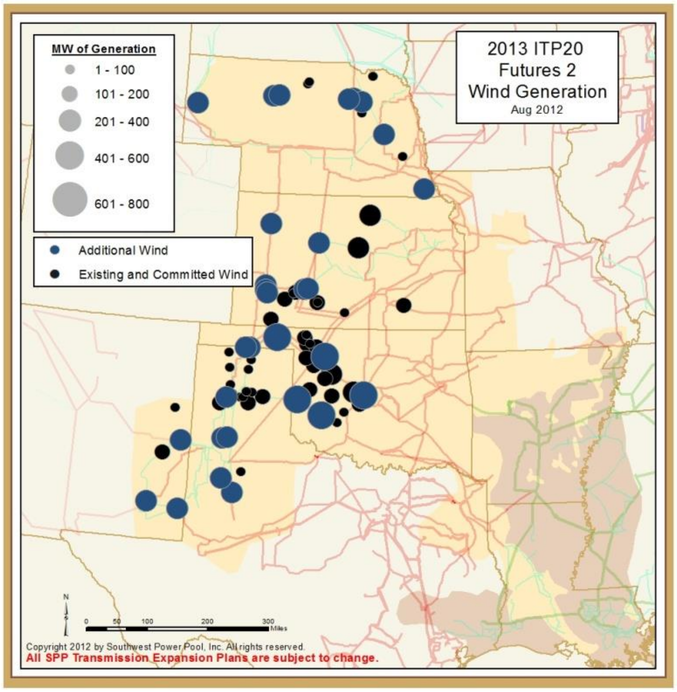


Figure 5.6: Renewable Resource Plan for Future 2

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

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

Future 3 Renewable Resource Plan for 2033 – SPP

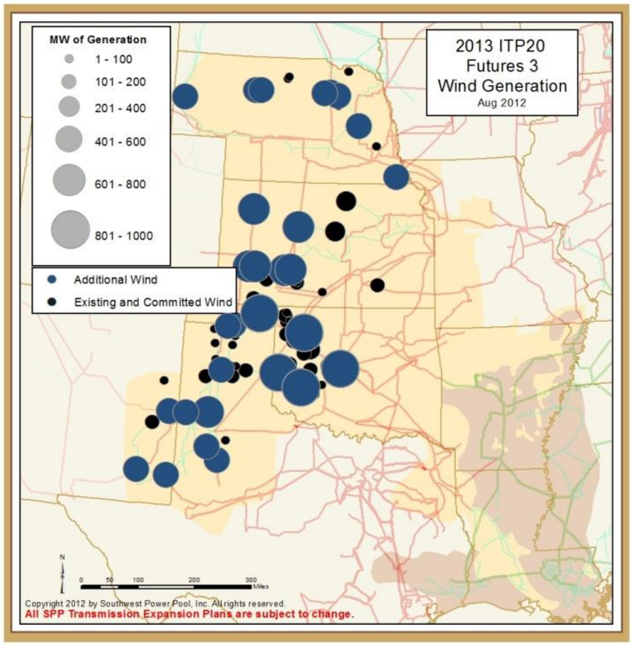


Figure 5.7: Renewable Resource Plan for Future 3

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

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

Future 4 Renewable Resource Plan for 2033 – SPP

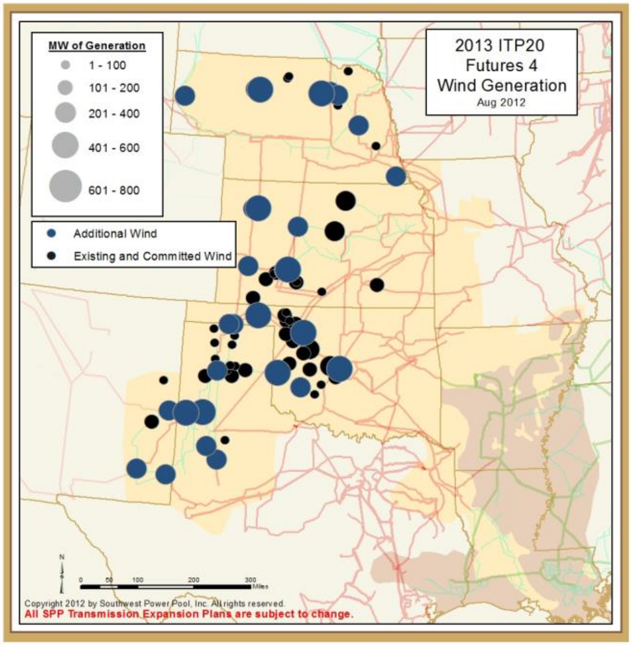


Figure 5.8: Renewable Resource Plan for Future 4

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

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

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

Section 6: Analysis Methodology

6.1: Analytical Approaches

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

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

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

SCUC & SCED Analysis for multiple futures

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

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

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

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

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

- Monitored facilities of 100+kV voltages only

Neighboring areas supplied their respective list of constraints.

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

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

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

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

6.2: Projecting Potential Criteria Violations

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

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

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

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

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

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

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

Reliability & Economic Efficiencies

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

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

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

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

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

6.3: Meeting Policy Requirements

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

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

6.4: Projecting Congestion & Market Prices

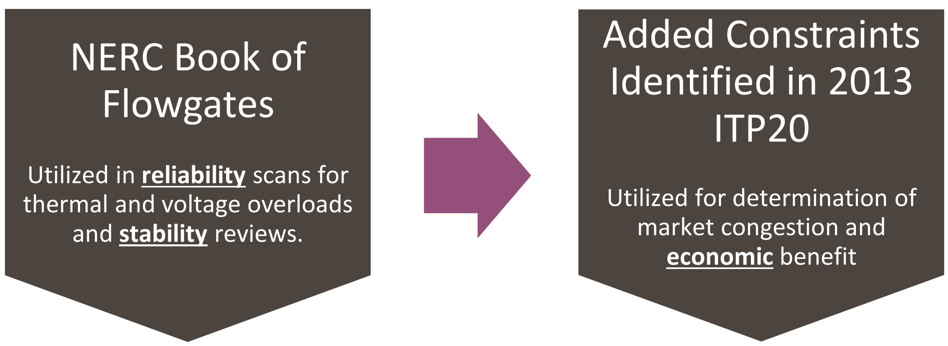
Annual Conditions Reviewed by the Economic Studies Working Group (ESWG)

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

Relevant congestion of each constraint was identified through two methods:

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

Identification of Additional Constraints
Staff defined the initial list of constraints from the NERC Book of Flowgates for the SPP region. This list of constraints was used to create the economic dispatch utilized in the reliability scans for potential thermal and voltage violations. Additional constraints were incorporated that would protect the facilities from overloads under many system conditions. These additional constraints facilitated the capture of both market congestion and economic benefit and adjusted the flowgate list in expectation of transmission that is not anticipated by the NERC Book of Flowgates.



Congestion Prioritization & Screening
The impact of the top 15 constraints upon the region's APC was measured to identify the depth of the congestion at each constraint and prioritize which constraints provided opportunity for APC savings. This was accomplished by calculating the change in APC with and without the constraint. By targeting the top 15 constraints, the areas of greatest opportunity for economic projects were identified to be considered for improvement.

6.5: Determining Recommended Portfolio

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

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

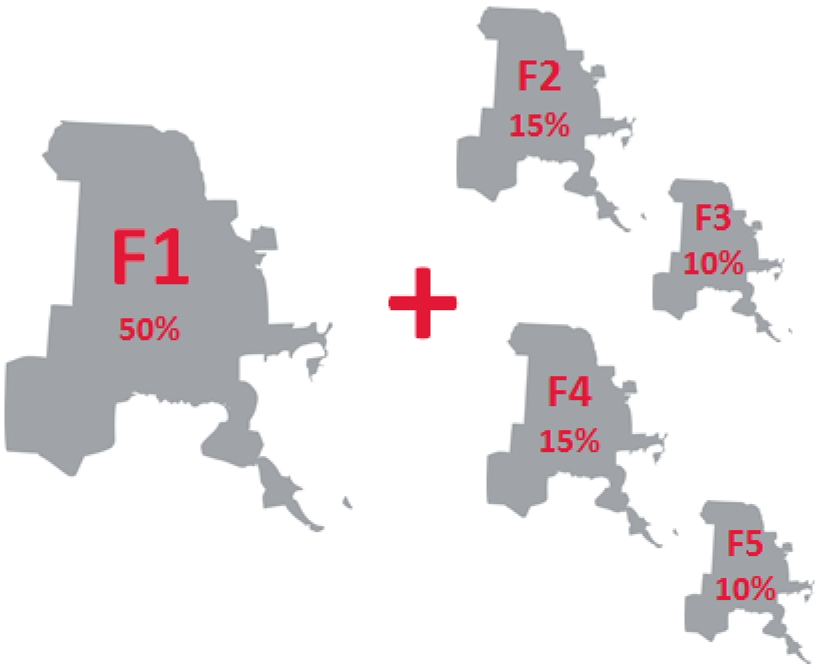


Figure 6.1: Project weighting by future

Project Staging

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

6.6: Measuring Economic Value

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

The metrics suggested by MTF are the following:

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

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

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

Calculation of Adjusted Production Cost (APC)

APC is a measure of the impact on production cost savings by Locational Marginal Price (LMP), accounting for purchases and sales of energy between each area of the transmission grid. APC is determined using a production cost modeling tool that accounts for hourly commitment and dispatch. The calculation, performed on an hourly basis, is as follows:

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

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

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

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

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

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

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

Reduced Capacity Costs

Metric captures a value for the generation capacity that may no longer be required due to a reduction in losses and capacity margin. The reduced capacity could be reflected in reduced losses and the potential reduction in capacity margins. This value was monetized using the savings in capital attributed to the corresponding reduction in installed capacity requirements. The Benefits Analysis Techniques Task Force (BATTF) established a $750/kW figure to use as the approximate capital cost of a CT for this calculation.

Reduction of Emissions Rates and Values

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

Methodology for Calculating Economic Benefit Incremental to Reliability

The value of economic projects in the 2013 ITP20 is computed as the incremental cost and benefit of the economic project above and beyond reliability and policy projects. The calculation assumes that all of the reliability and policy projects are in-service (the base case) and measures the benefit of adding the economic project to the system (the change case).

PART II: STUDY FINDINGS

Section 7: Benchmarking

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

7.1: Benchmarking Setup

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

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

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

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

7.2: Generator Operation

Capacity Factor by Unit Type

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

When compared with capacity factors as tracked by the EIA for 2011 and previous years, the capacity factor by unit category fell within or near expected ranges. Part of the difference is due to the variation between the unit categories reported to the EIA and those available within the 2013 ITP20 models.

Capacity factors for the 2013 ITP20 were derived from the PROMOD IV® report agent software. The average capacity factors from the EIA are from the EIA Electric Power Annual for 2005 – 2011 and can be found on the EIA website[21]. The capacity factor from the EIA includes other renewables such as biomass and solar and reflect data submitted by utilities across the Eastern Interconnect.

Unit Category	2013 ITP20 Capacity Factor	EIA Capacity Factor Range
Nuclear	68%	67 – 97%
ST Coal	72%	64 – 74%
Wind	45%	40 – 47%
Combined Cycle	40%	33 – 42%
Hydro	28%	23 – 46%
ST Gas	10%	10 – 15%
CT Gas	5%	10 – 15%

Table 7.1: Benchmarking the Capacity Factor by Unit

Generation by Unit Category

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

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

Total generated energy by unit category for the 2013 ITP20 was derived from the PROMOD IV® report agent software for the year 2011. Historical generation output was approximated from EIA-923 data and can be found on the EIA website. Figure 7.1 illustrates the percentage of generation share (by energy) for each unit type.

[21] EIA.gov

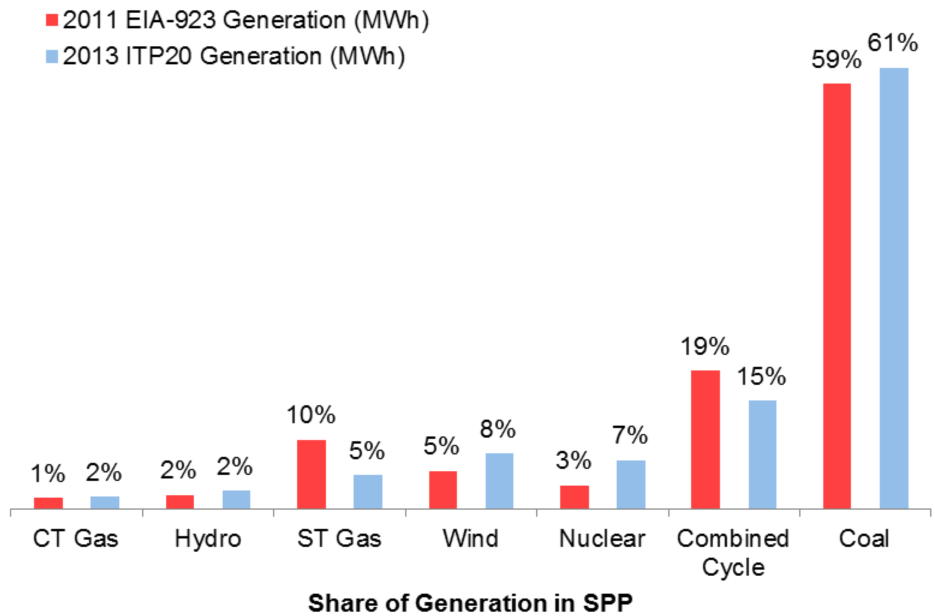


Figure 7.1: Benchmarked Unit Generation by Category

Maintenance Outages

Generator maintenance outages in the simulations were compared with statistics available through the NERC Generating Availability Data System. The proper reflection of generator outages is important to the study because of the direct impact these outages have on flowgate congestion, system flows and the economics of following load levels. The method of forecasting maintenance outages correlated strongly with these statistics. Significant generator outages from 2011 were incorporated in the benchmark model based upon data from SPP Operations. This increased the precision of the benchmarking and accounted for significant weather related and maintenance outages.

Operating & Spinning Reserve Adequacy

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

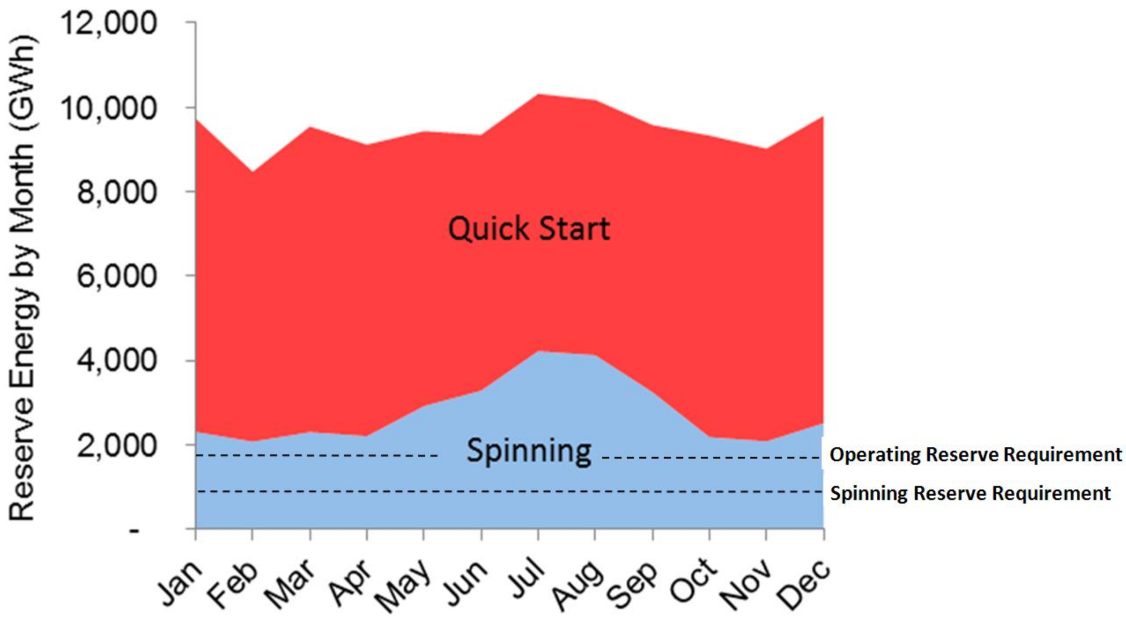


Figure 7.2: Spinning Reserve Adequacy

Coal Transportation Costs

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

7.3: Reasonable System LMPs

Benchmarking was done on average Locational Marginal Prices (LMPs) by Area. Figure 7.3 compares the average monthly price of energy in the EIS market from 2009-2011 to the average monthly bus LMPs of the 2013 ITP20 benchmarking runs. This check is important because close correlation between actual LIPs and simulated LMPs for the year benchmarked should exist if the simulations portray SPP accurately.

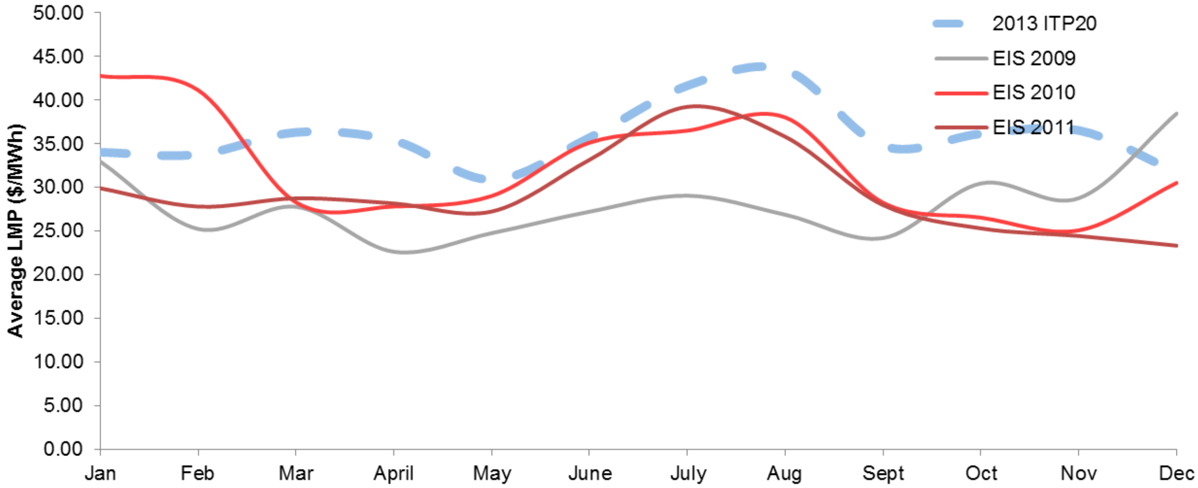


Figure 7.3: Benchmarking LMPs

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

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

Forecasted LMPs for 2033 Simulations

A simulation of 2033 was conducted and the shadow prices for binding constraints during that time-frame were compared with a current SPP Monthly State of the Market Report. The results indicated that prices seen in the 2033 simulation were higher than in the operations horizon. This was consistent with an expectation that increases in energy usage and fuel price will drive market prices upward. Figure 7.4 shows that the shadow prices (y-axis) and hours binding (x-axis) for TWG approved constraints were greater and more frequent than experienced in the EIS market in 2011.

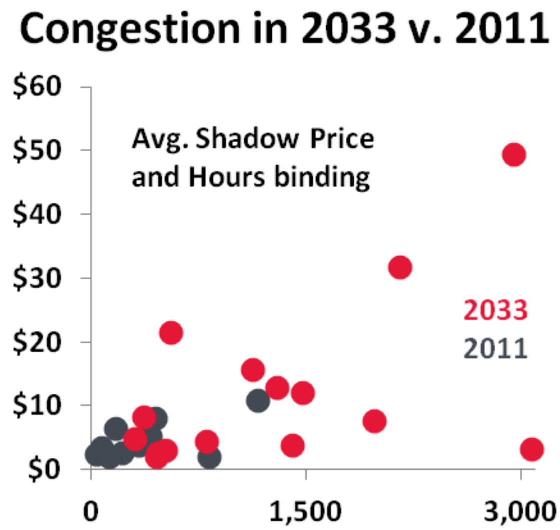


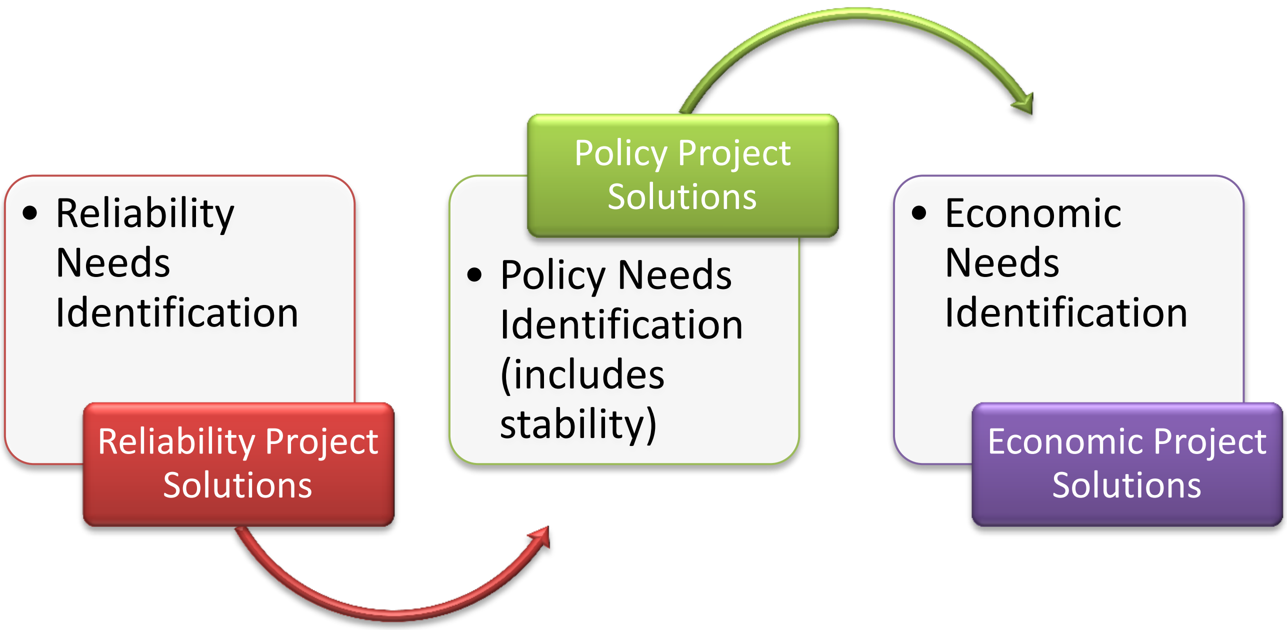
Figure 7.4 Congestion in 2033 was greater than in 2011

PART III: NEEDS & PROJECT SOLUTIONS

Section 8: Overview

8.1: Transmission Needs and Solution Development

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



8.2: Consideration of Lower Voltage Solutions

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

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

Section 9: Reliability Needs and Solutions

9.1: Methodology

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

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

Hours used to determine Reliability Needs were:

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

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

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

[Values in GW for 2033]

Table 9.1: Four reliability peak hours

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

9.2: Reliability Needs

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

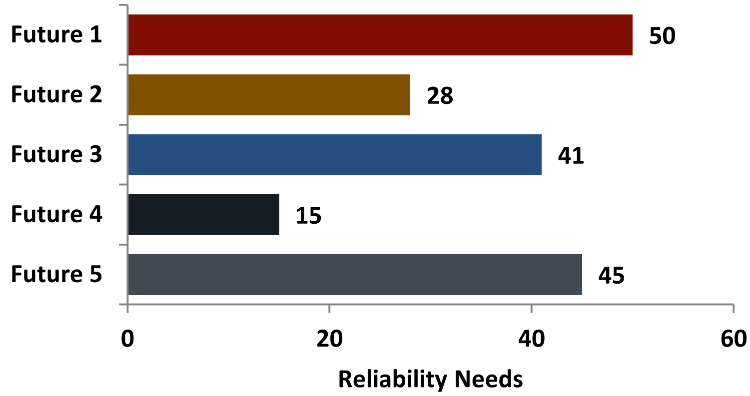


Figure 9.1: Reliability Needs Summary by Future

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

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

Table 9.2: Future 1 Reliability Needs

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

Table 9.3: Future 2 Reliability Needs

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

Table 9.4: Future 3 Reliability Needs

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

Table 9.5: Future 4 Reliability Needs

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

Table 9.6: Future 5 Reliability Needs

9.3: Reliability Solutions

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

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

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

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

Table 9.7: Future 1 Reliability Solutions

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

Table 9.8: Future 2 Reliability Solutions

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

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

Table 9.9: Future 3 Reliability Solutions

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

Table 9.10: Future 4 Reliability Solutions

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

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

Table 9.11: Future 5 Reliability Solutions

Section 10: Policy Needs and Solutions

10.1: Methodology

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

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

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

Table 10.1: Number of Wind Farms Curtailing

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

10.2: Future 1 Needs and Solutions

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

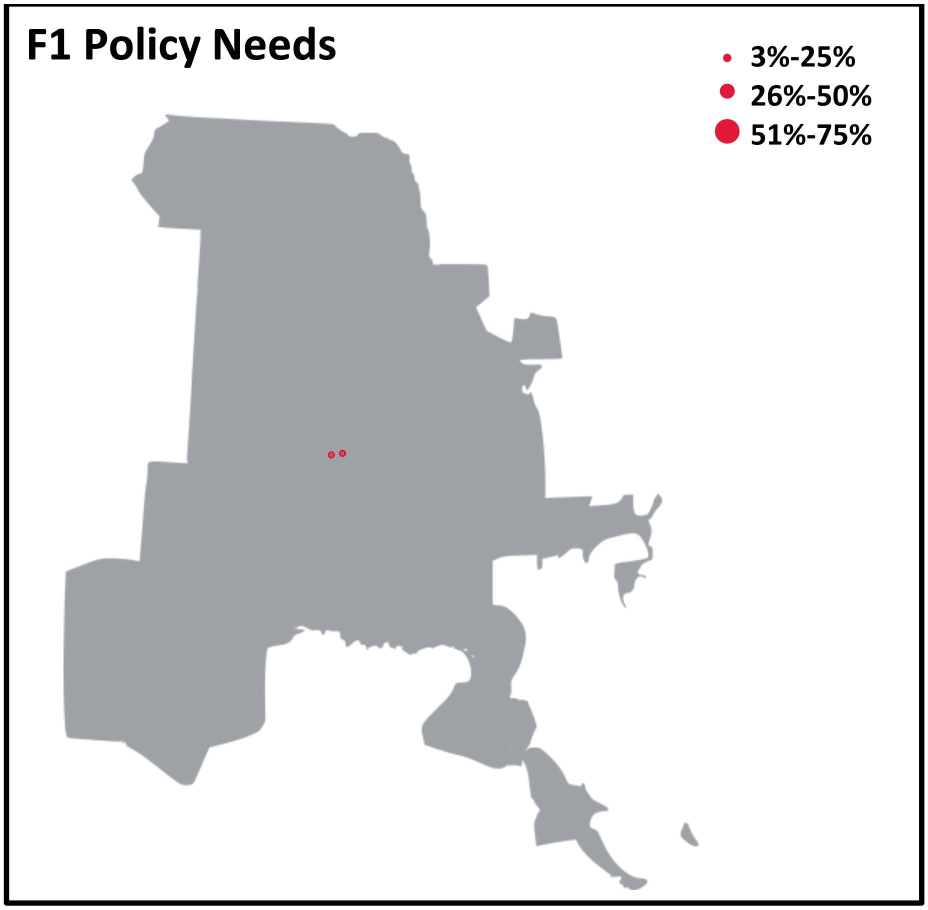


Figure 10.1: Future 1 Policy Needs

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

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

Table 10.2: Future 1 Policy Projects

10.3: Future 2 Needs and Solutions

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

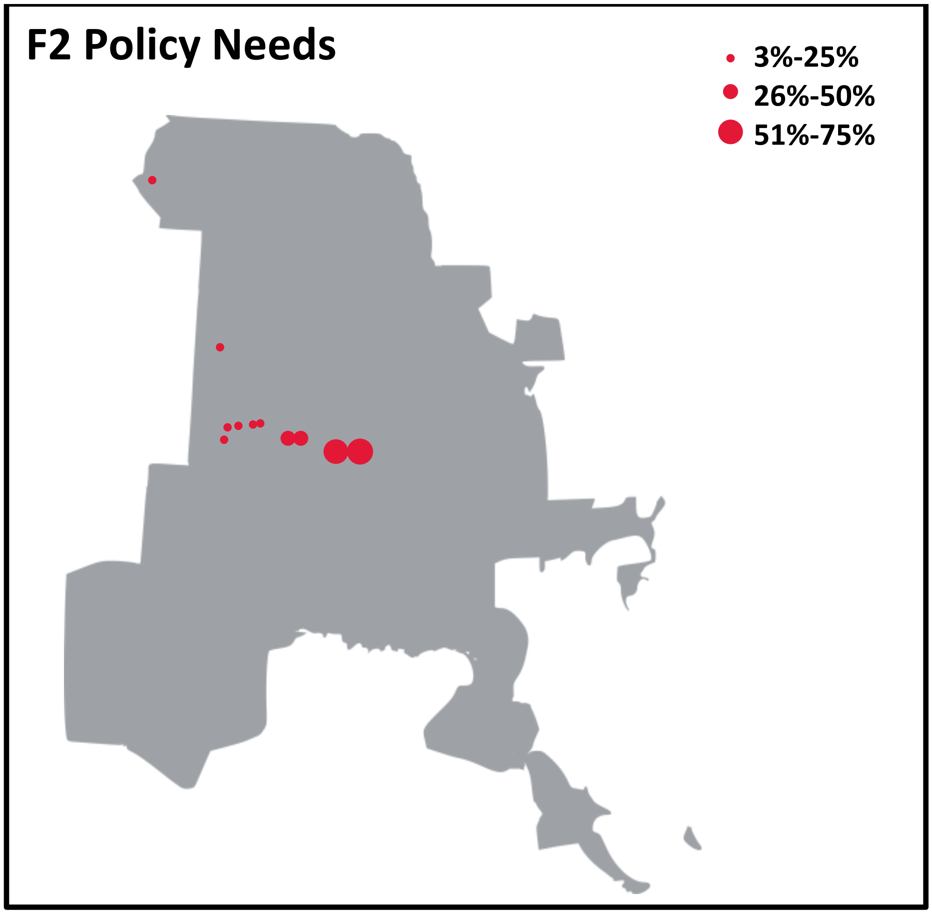


Figure 10.2: Future 2 Policy Needs

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

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

Table 10.3: Future 2 Policy Projects

10.4: Future 3 Needs and Solutions

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

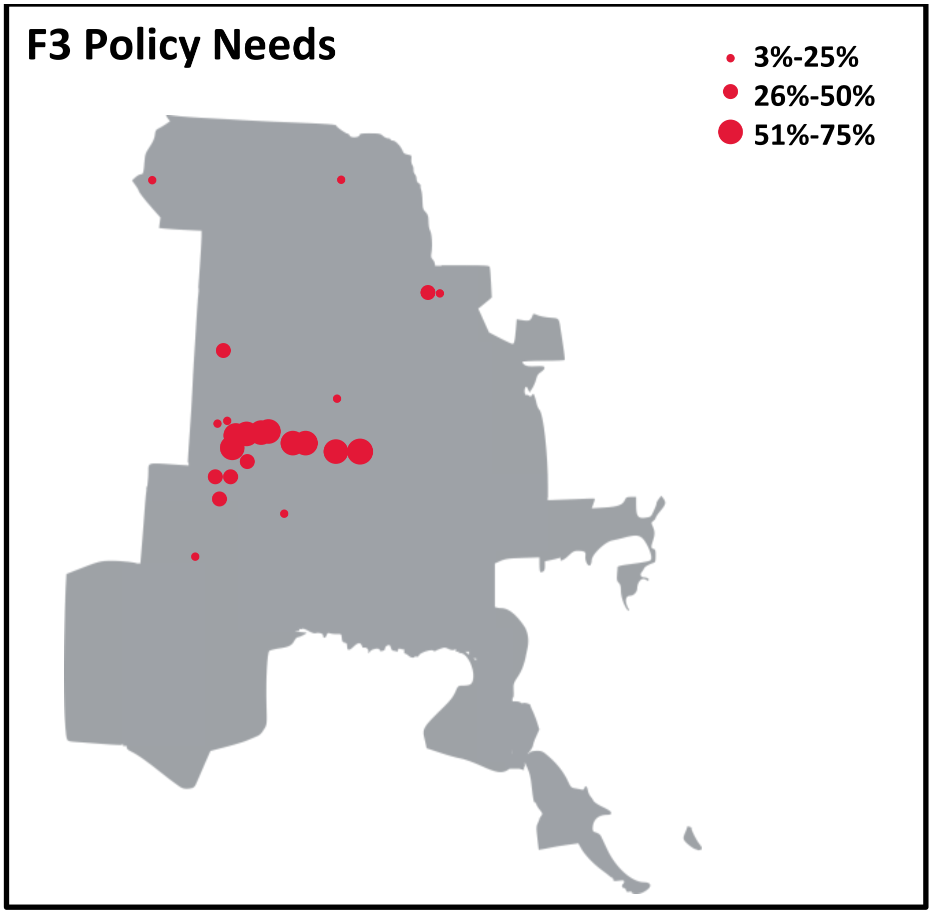


Figure 10.3: Future 3 Policy Needs

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

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

Table 10.4: Future 3 Policy Projects

10.5: Future 4 Needs and Solutions

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

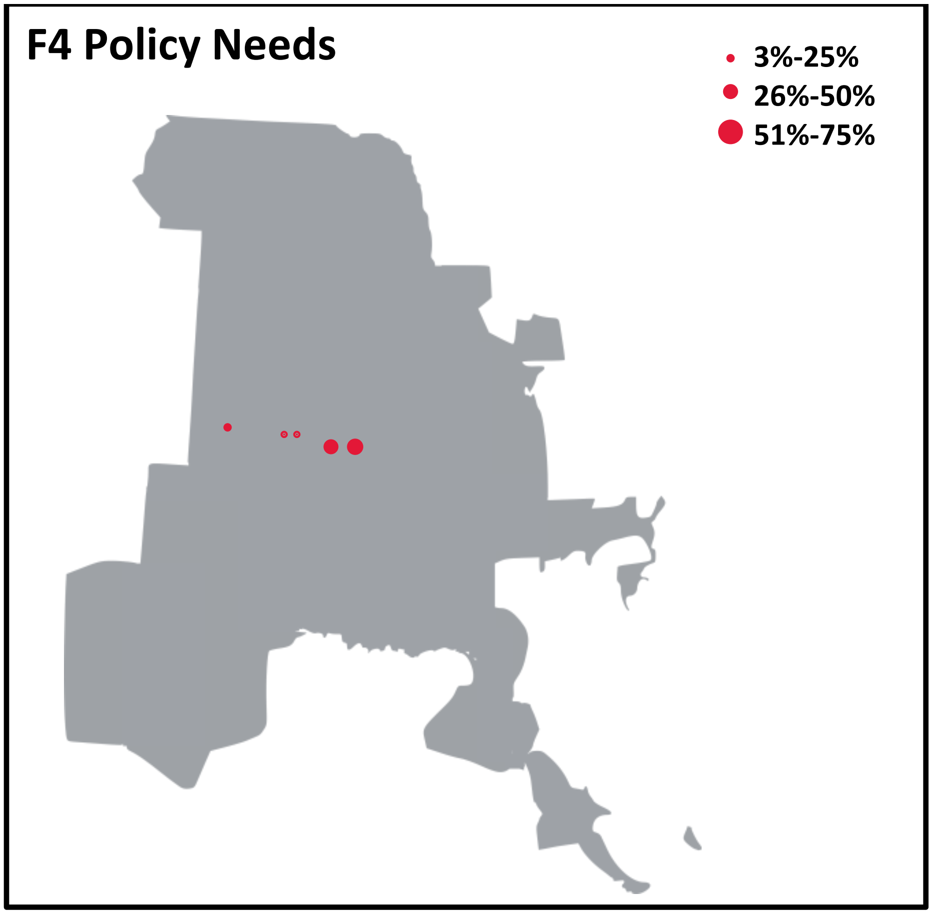


Figure 10.4: Future 4 Policy Needs

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

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

Table 10.5: Future 4 Policy Projects

10.6: Future 5 Needs and Solutions

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

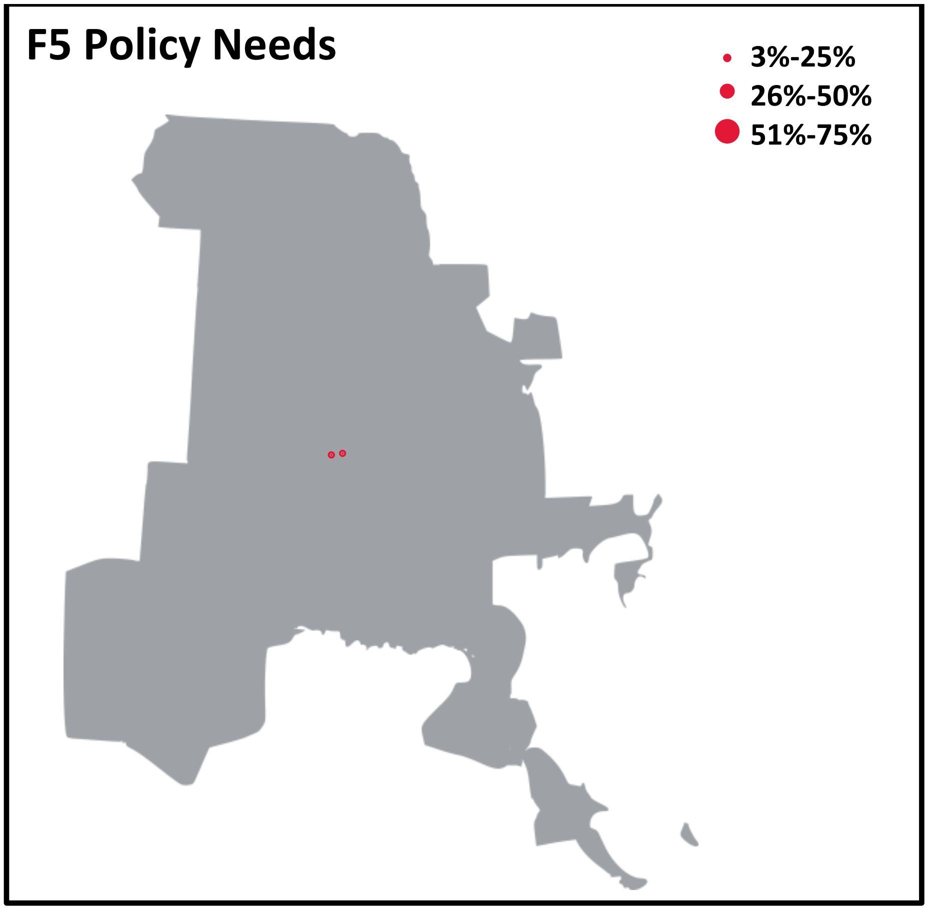


Figure 10.5: Future 5 Policy Projects

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

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

Table 10.6: Future 5 Policy Projects

Section 11: Economic Needs and Solutions

11.1: Background

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

11.2: Economic Needs

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

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

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

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

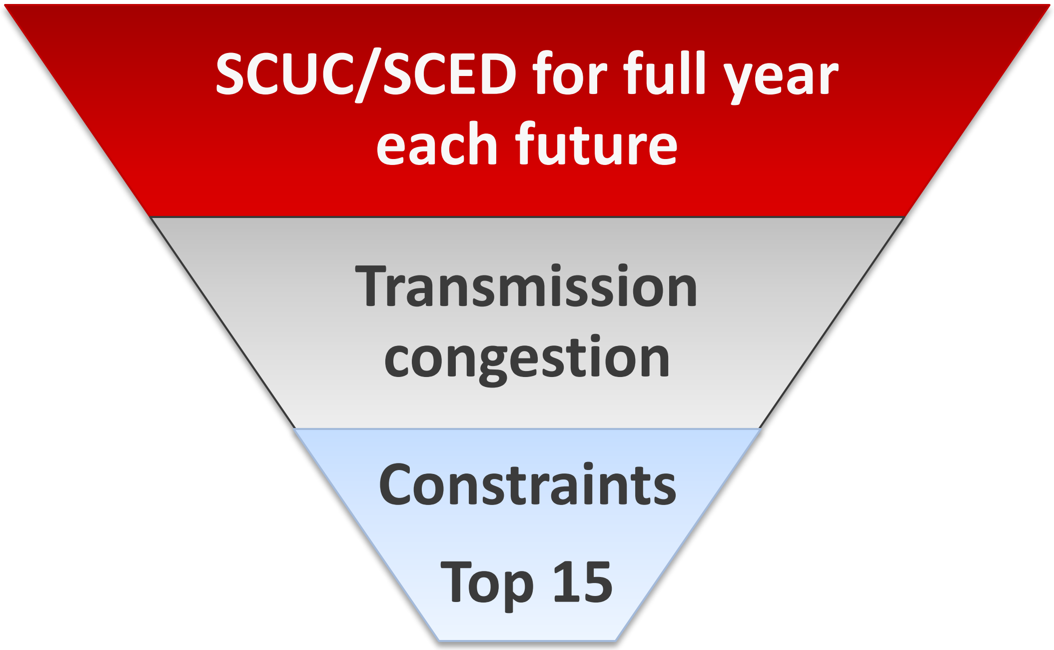


Figure 11.1: Developing Economic Needs

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

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

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

Table 11.1: Future 1 Economic Needs

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

Table 11.2: Future 2 Economic Needs

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

Table 11.3: Future 3 Economic Needs

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

Table 11.4: Future 4 Economic Needs

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

Table 11.5: Future 5 Economic Needs

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

11.3: Economic Solutions

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

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

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

Future 1 Economic Projects

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

Project Tested	Project Area(s)	B/C > 1.0?
New Jasper - Monett City 345 kV	AECI-EMDE	✗
New JEC - Matters Corner 345 kV, new Matters Corner 345/115 kV transformer	WERE	✗
New JEC - Matters Corner - Elm Creek 345 kV, new Matters Corner 345/115 kV transformer	WERE-SUNC	✗
Rebuild JEC - E Manhattan N Manhattan - Elm Creek 230 kV to 345 kV	WERE-SUNC	✗
New Cass - S3454 345 kV	OPPD	✗
New 2nd S3459 345/161 kV transformer	OPPD	✓
New LaCygne - Morgan 345 kV	KCPL-AECI	✓
New Wolf Creek - Neosho 345 kV	WERE	✓
New Morgan 345/161 kV transformer	AECI	✗
New Stegall - Cherry 345 kV	WAPA-NPPD	✗
New Stegall - Scottsbluff - Victory Hill 345 kV, new Stegall 345/115 transformer	WAPA-NPPD	✗
New Stegall - Victory Hill 345 kV, new 345/115 kV transformer at Victory Hill	WAPA-NPPD	✗
New Stegall - Victory Hill - Alliance 345 kV, new 345/115 kV transformers at Victory Hill and Alliance	WAPA-NPPD	✗
New Tolk - Potter 345 kV	SPS	✗
New Tolk - Amoco 345 kV	SPS	✗
New Chamber Springs - S Fayetteville 345 kV, new S Fayetteville 345/161 kV transformer	AEPW	✓
New Keystone - Red Willow 345 kV	NPPD	✗
New Tolk - Tuco 345 kV	SPS	✗
Rebuild JEC - Auburn - Swissvale 230 kV to 345 kV, new Auburn 345/115 kV transformer	WERE	✗
Rebuild Spearville - Great Bend - Reno 230 kV to 345 kV	SUNC-WERE	✗
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA	✓

Table 11.6: Economic Projects Screened in Future 1

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

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

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

Table 11.7: Future 1 Economic Projects

Future 2 Economic Projects

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

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

Table 11.8: Economic Projects Screened in Future 2

Future 3 Economic Projects

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

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

Table 11.9: Economic Projects Screened in Future 3

Future 4 Economic Projects

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

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

Table 11.10: Economic Projects Screened in Future 4

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

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

Table 11.11: Future 4 Economic Projects

Future 5 Economic Projects

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

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

Table 11.12: Economic Projects Screened in Future 5

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

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

Table 11.13: Future 5 Economic Projects

Section 12: Stability Needs and Projects

12.1: Introduction

A voltage stability assessment was conducted on the base case model (no new transmission) to assess the transfer limit (MW) due to transfer of wind west to east across the SPP footprint. Additionally, a stability analysis was conducted for the 2013 ITP20 solution set to assess system stability by examining thermal and voltage performance. Thermal and voltage performance are normally assessed through the tools of steady state contingency analysis; however, this analysis does not determine the distance to and the location of voltage collapse or instability. These must be determined by examining voltage performance during power transfer into a load area or across an interface.

12.2: Objectives

The objective of the 2013 ITP20 Stability Analysis is twofold:

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

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

12.3: Stability Assessment

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

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

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

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

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

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

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

Table 12.1: Wind generation per future

To prepare for the first procedure (wind and conventional generation in the SPP Footprint), wind generation was reduced to minimum levels while conventional generation was simultaneously increased to meet SPP load requirements, and the case was saved. The saved case was used as the starting point for the transfer study. The wind was increased while the conventional generation was decreased until voltage collapse occurred. All branches and transformers were monitored to detect thermal violations, overloading the elements by more than 105%.

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

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

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

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

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

The results shown in

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

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

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

Table 12.2: Wind transfers limit based on voltage collapse

12.4: Results

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

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

Table 12.3: Future 3 Stability Projects - Line

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

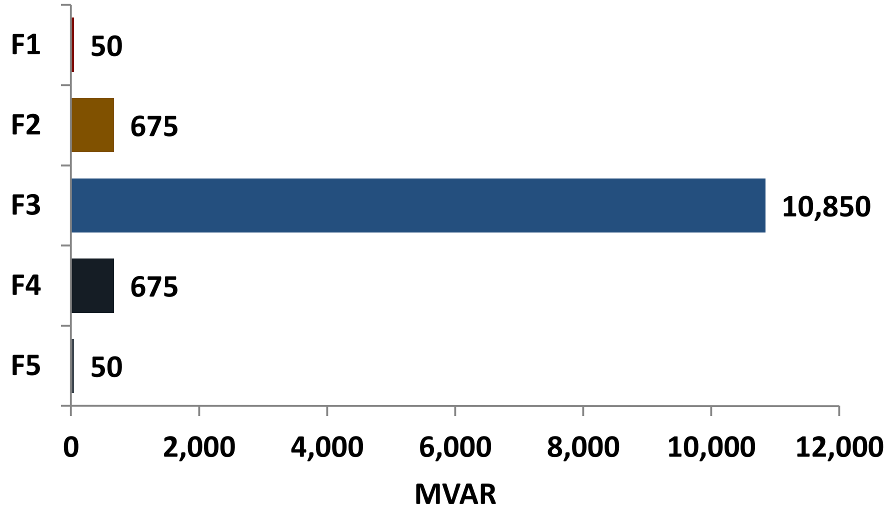


Figure 12.1: SVC Additions by Future

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

Table 12.4: Stability Projects - SVC

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

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

Section 13: Future Portfolios

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

13.1: Project Solutions from Previous ITP Studies

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

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

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

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

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

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

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

13.2: Treatment of Lower Voltage Solutions

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

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

13.3: Future 1 Portfolio

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

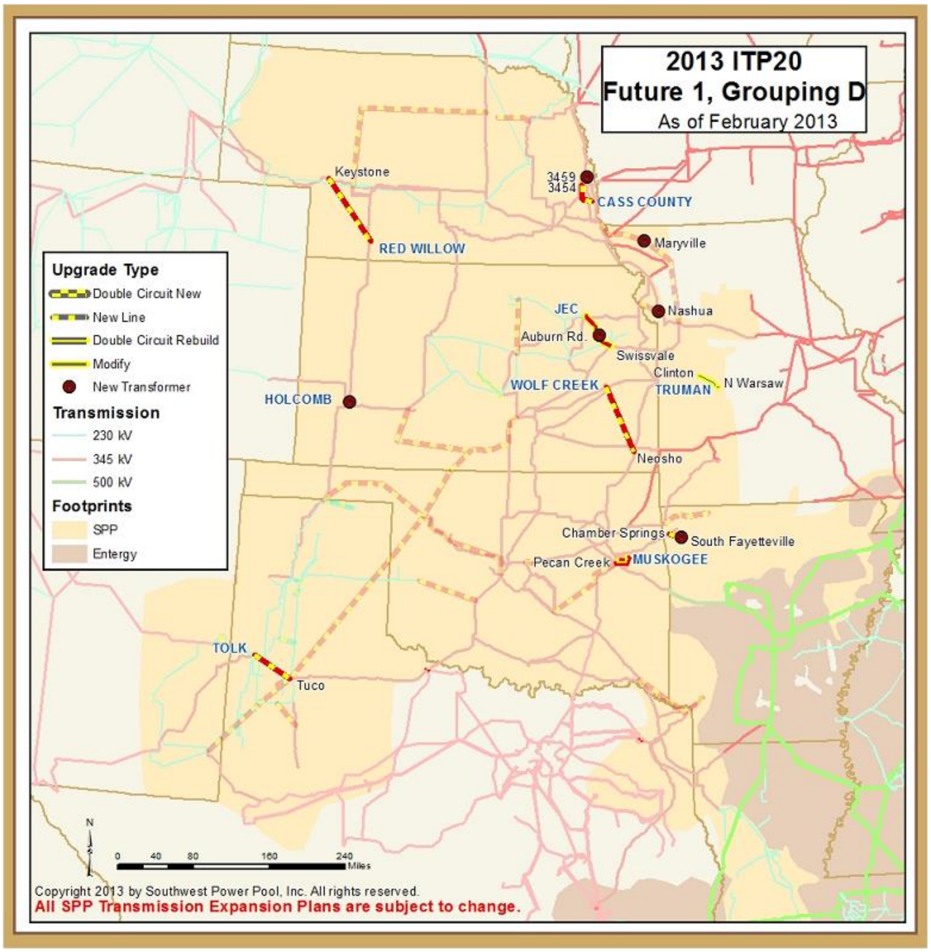


Figure 13.1: Future 1 Grouping D

Future 1 Grouping D

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

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

Total Transformers: 6

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

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

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

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

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

Table 13.4 shows details for all Future 1 portfolio projects.

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

Table 13.4: Future 1 Portfolio Projects

13.4: Future 2 Portfolio

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

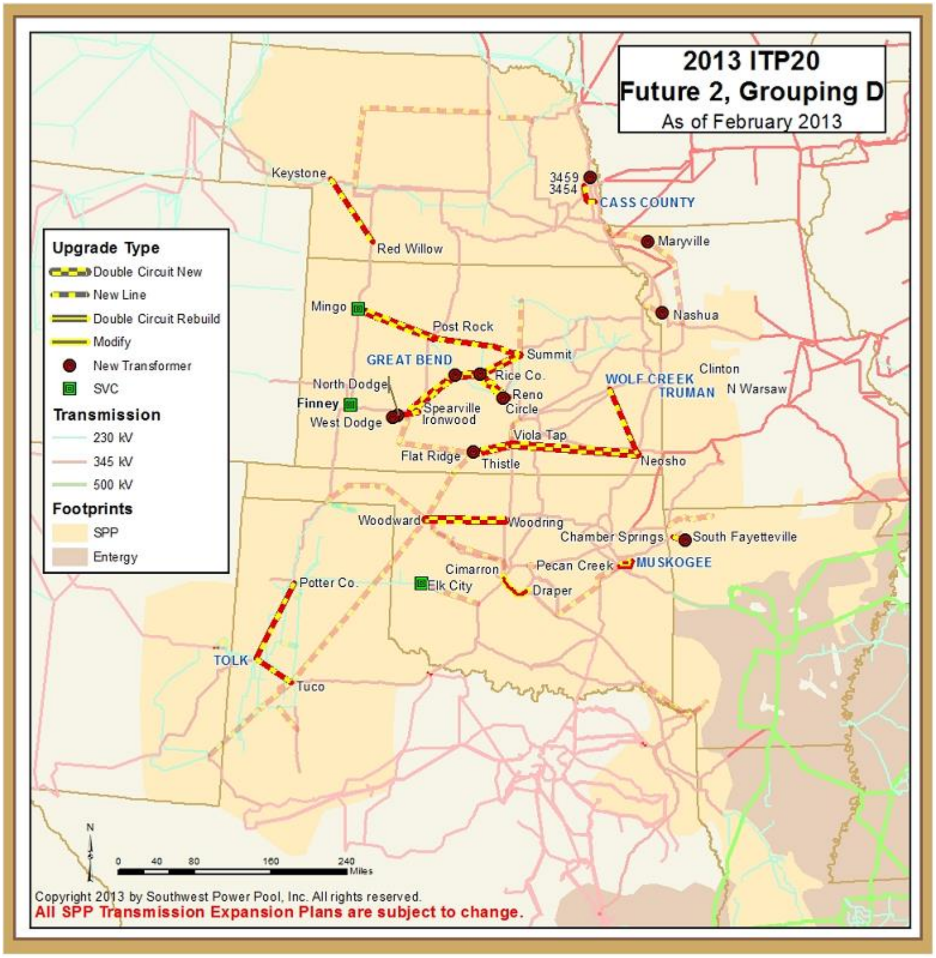


Figure 13.2: Future 2 Grouping D

Future 2 Grouping D

Total Cost: $2.5B
Reliability Cost: $642M
Policy Cost: $1.8B
Economic Cost: $0

Total Mileage: 2,002
Reliability Miles: 536
Policy Miles: 1,466
Economic Miles: 0

Total Transformers: 10

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

Table 13.5 shows details for all Future 2 portfolio projects.

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

Table 13.5: Future 2 Portfolio Projects

13.5: Future 3 Portfolio

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

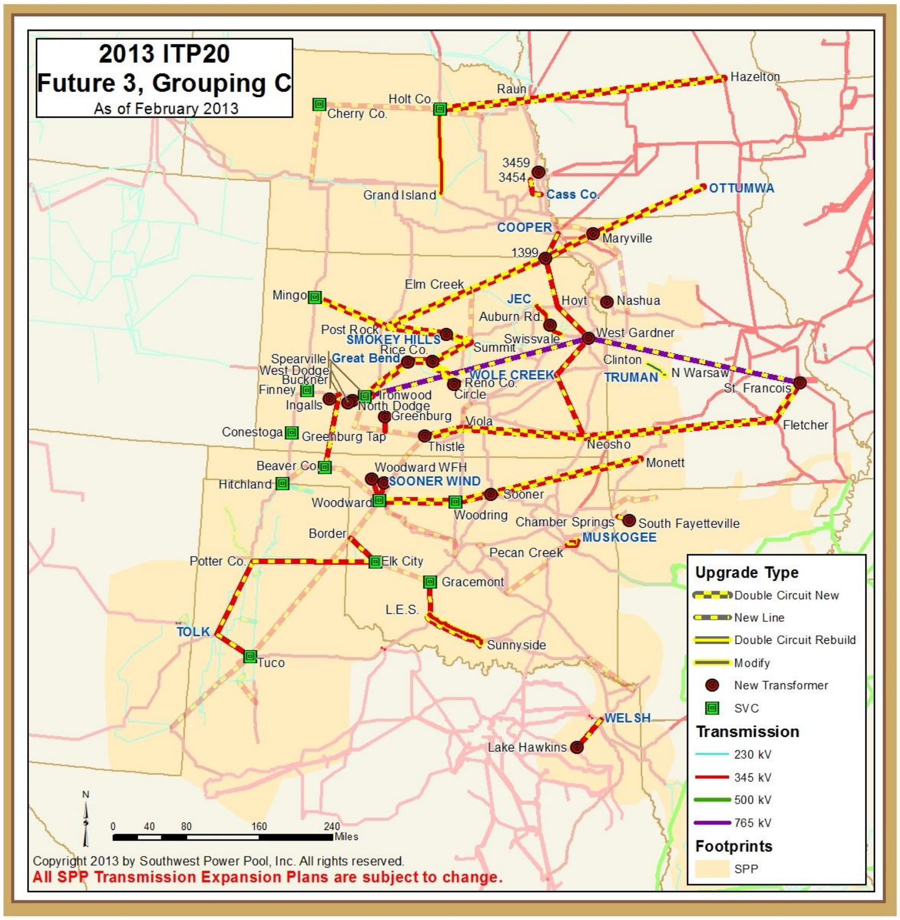


Figure 13.3: Future 3 Grouping C

Future 3 Grouping C

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

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

Total Transformers: 22

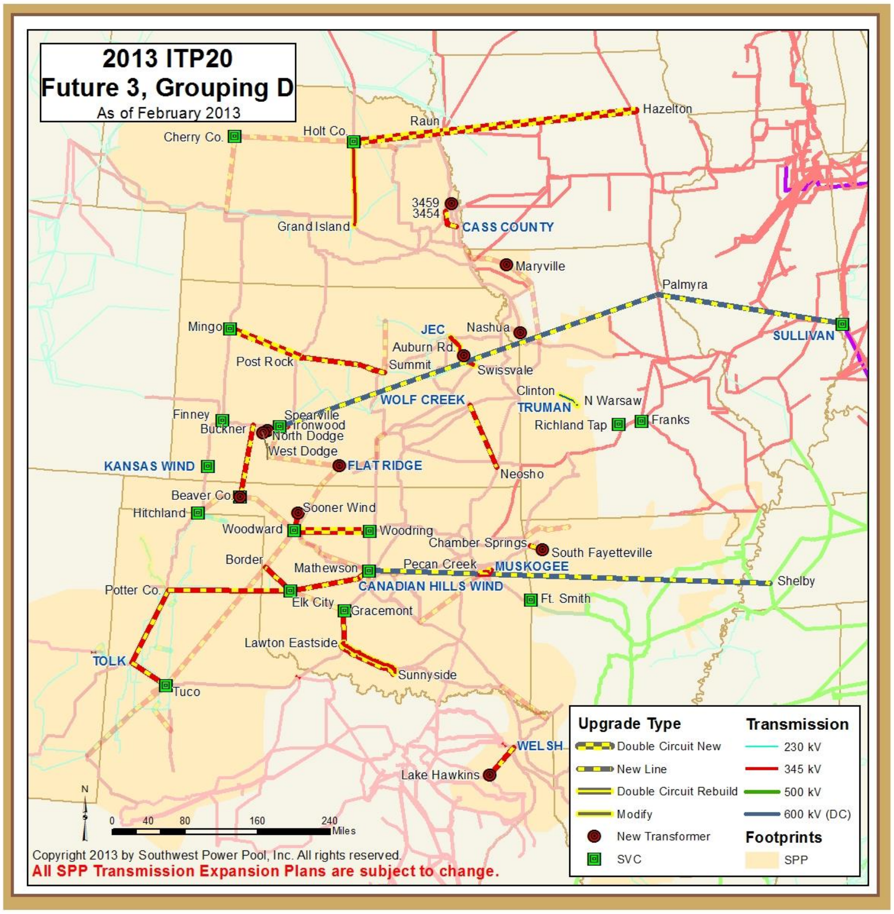


Figure 13.4: Future 3 Grouping D

Future 3 Grouping D

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

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

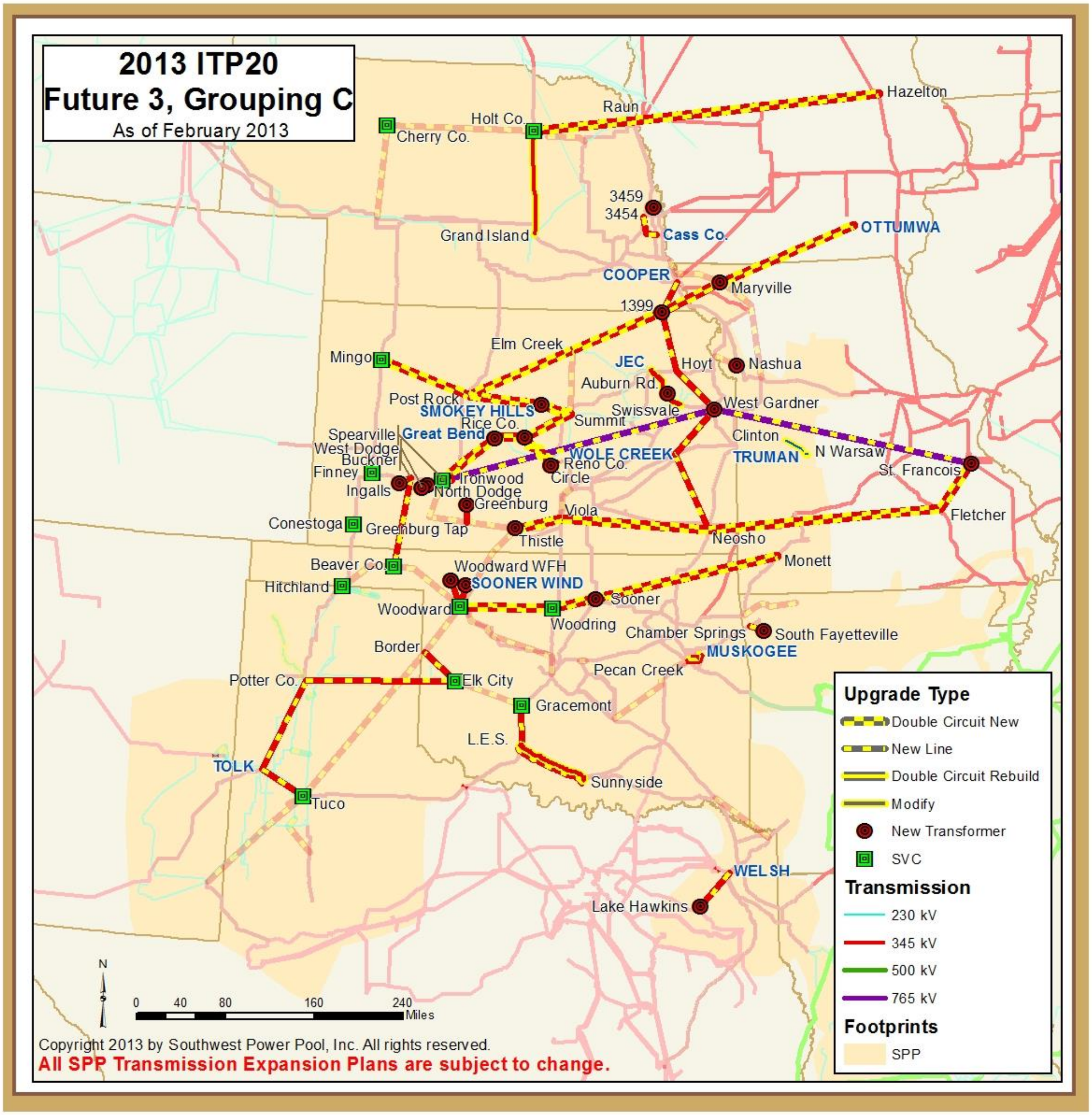
Total Transformers: 11

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

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

Table 13.6: Comparison of Future 3 Groupings C and D

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



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

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

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

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

Table 13.7: Future 3 Grouping C Projects

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

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

Table 13.8: Future 3 Grouping D Projects

13.6: Future 4 Portfolio

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

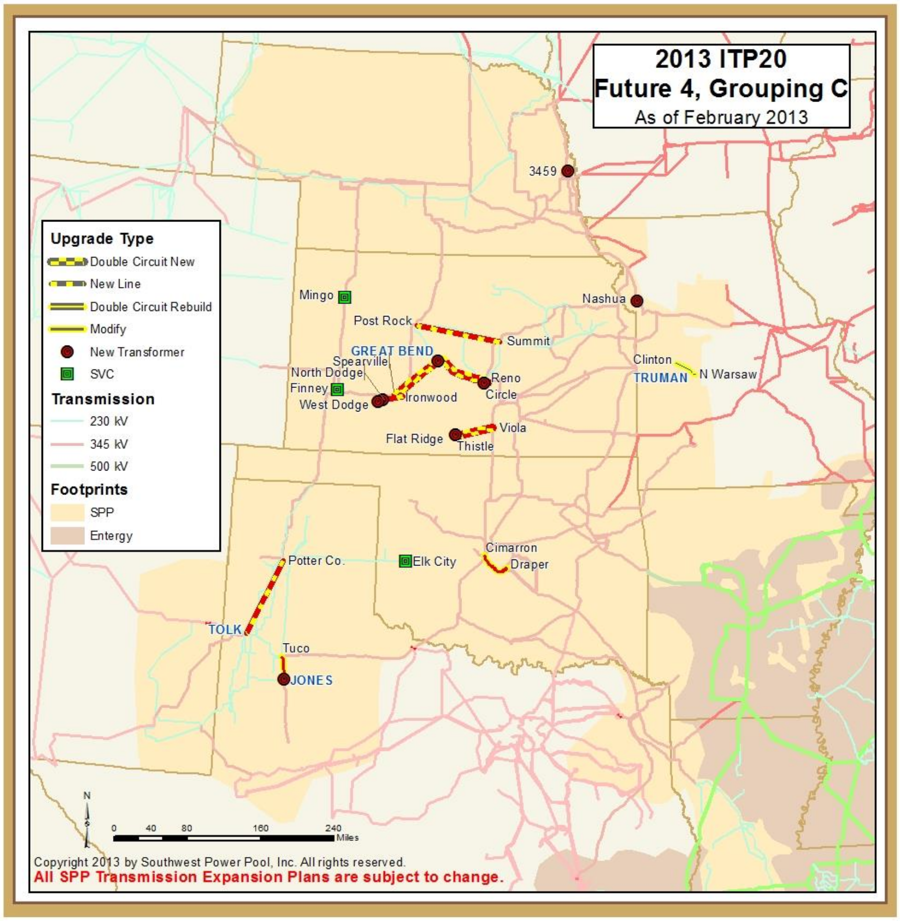


Figure 13.5: Future 4 Grouping C

Future 4 Grouping C

Total Cost: $926M
Reliability Cost: $325M
Policy Cost: $540M
Economic Cost: $61M

Total Mileage: 708
Reliability Miles: 290
Policy Miles: 388
Economic Miles: 30

Total Transformers: 8

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

Table 13.9 shows details for all Future 4 portfolio projects.

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

Table 13.9: Future 4 Portfolio Projects

13.7: Future 5 Portfolio

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

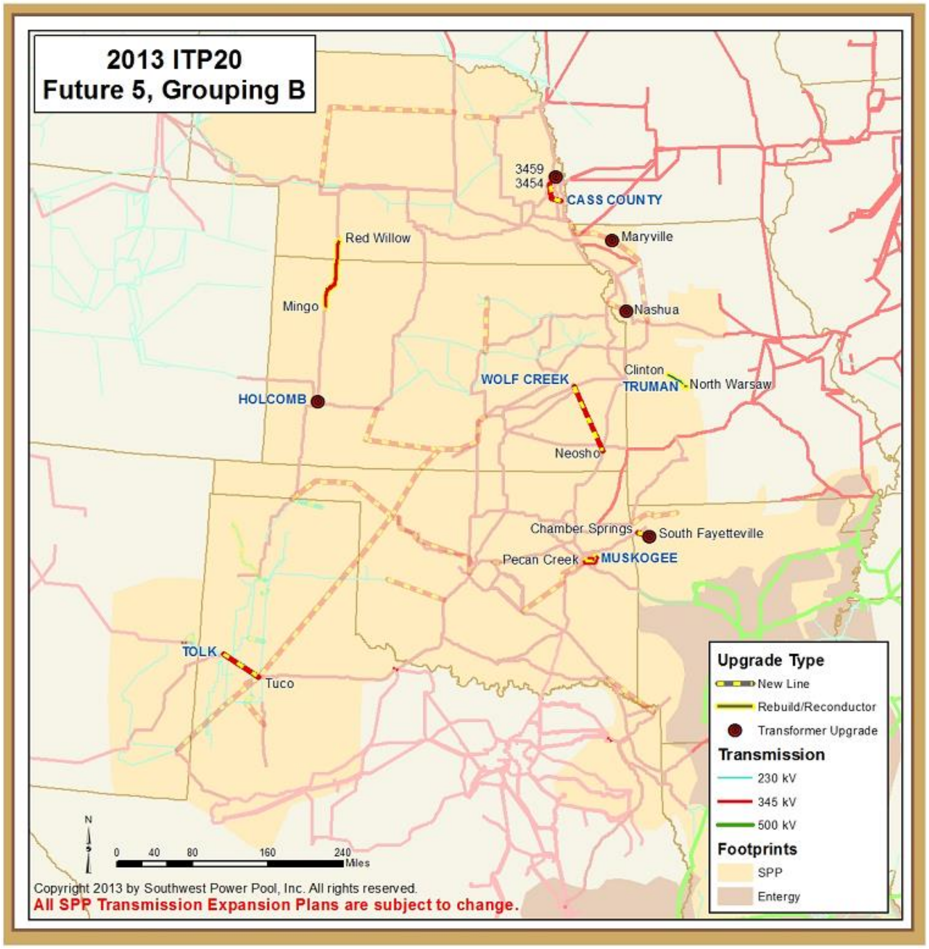


Figure 13.6: Future 5 Grouping B

Future 5 Grouping B

<u>Total Cost: $429M</u>
Reliability Cost: $416M
Policy Cost: $0
Economic Cost: $13M

<u>Total Mileage: 355</u>
Reliability Miles: 355
Policy Miles: 0
Economic Miles: 0

Total Transformers: 5

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

Table 13.10 shows details for all Future 5 portfolio projects.

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

Table 13.10: Future 5 Portfolio Projects

Section 14: Consolidated Portfolio

14.1: Development

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

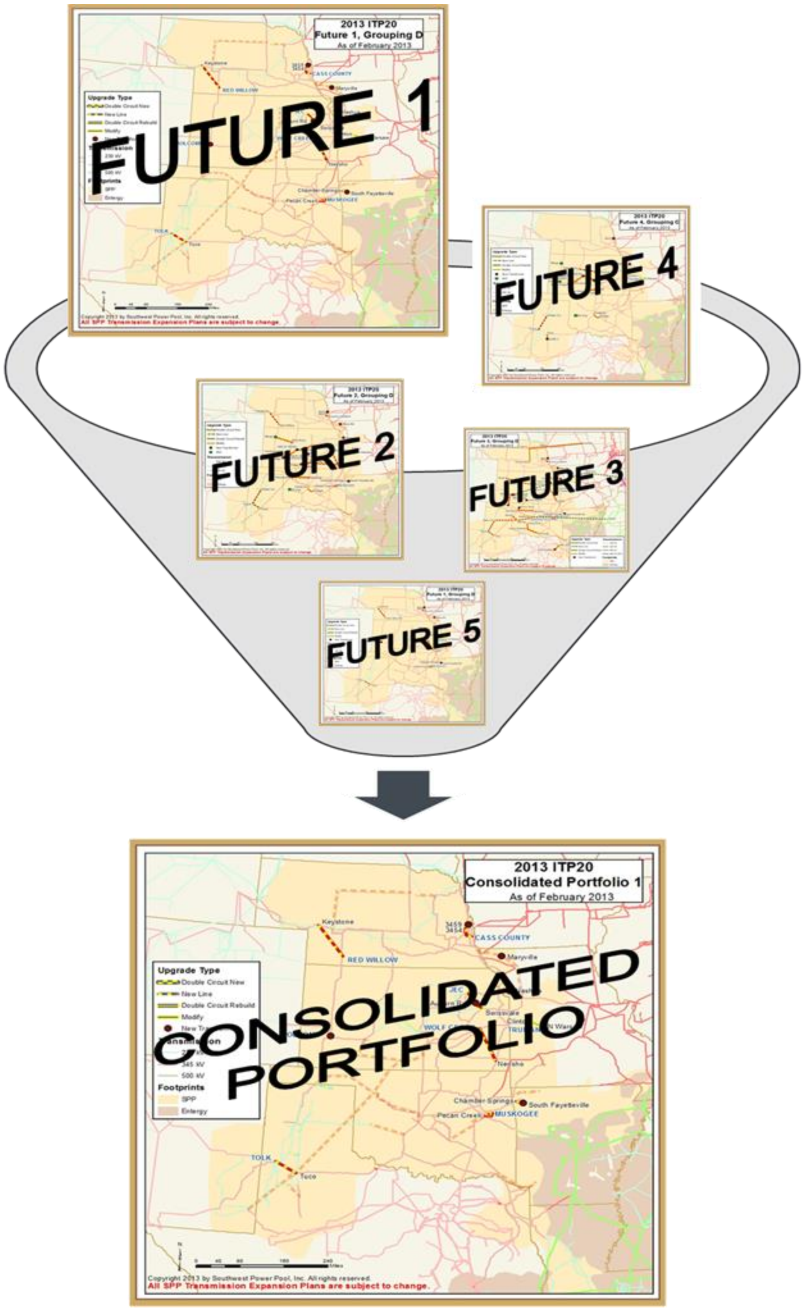


Figure 14.1: Consolidation of Portfolios

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

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

Table 14.1: Weightings and Threshold for Consolidated Portfolio Development

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

14.2: Projects

The Consolidated Portfolio projects are shown in Table 14.2.

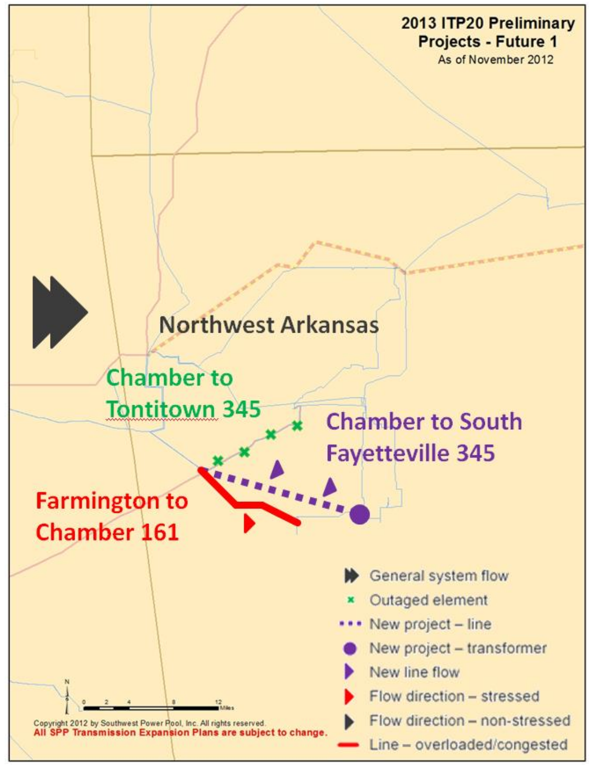
Project	Area(s)	Type	Future(s)	Mileage	Cost
New Chamber Springs - S Fayetteville 345 kV, new 345/161 kV transformer at S Fayetteville	AEPW	Economic	F1, F2, F3, F5	18	$33,895,800
Reconductor Clinton - Truman - N Warsaw 161 kV	AECI-SWPA-GMO	Reliability	F1, F2, F3, F4, F5	31	$16,784,175
New Maryville 345/161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

Table 14.2: Consolidated Portfolio Projects

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

Chamber Springs – South Fayetteville 345 kV

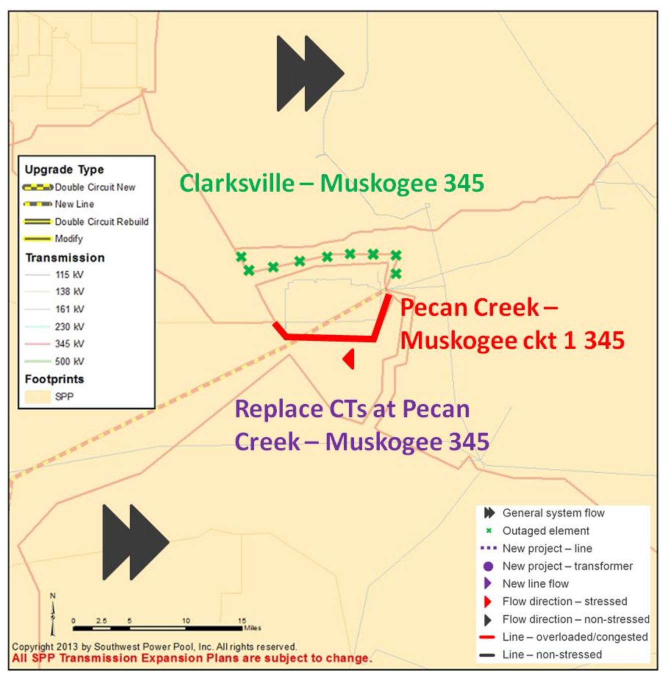
Northwest Arkansas shows a general west to east flow of power. When the Chamber Springs – Tontitown 345 kV line is in outage, there is a 161 kV line from Chamber Springs – Farmington – South Fayetteville that delivers most of the power east to south Fayetteville and east Fayetteville, resulting in congestion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



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

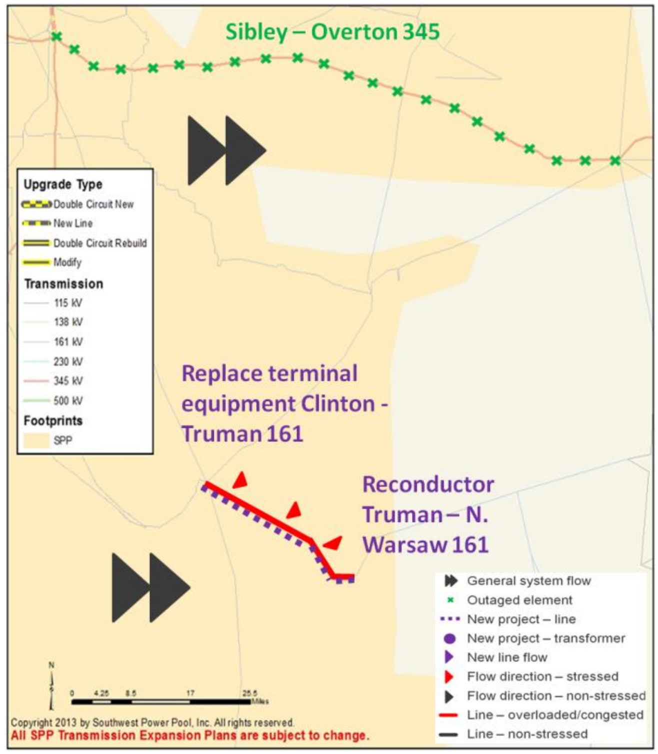
Pecan Creek – Muskogee 345 kV

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



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

Clinton – Truman – N Warsaw 161 kV

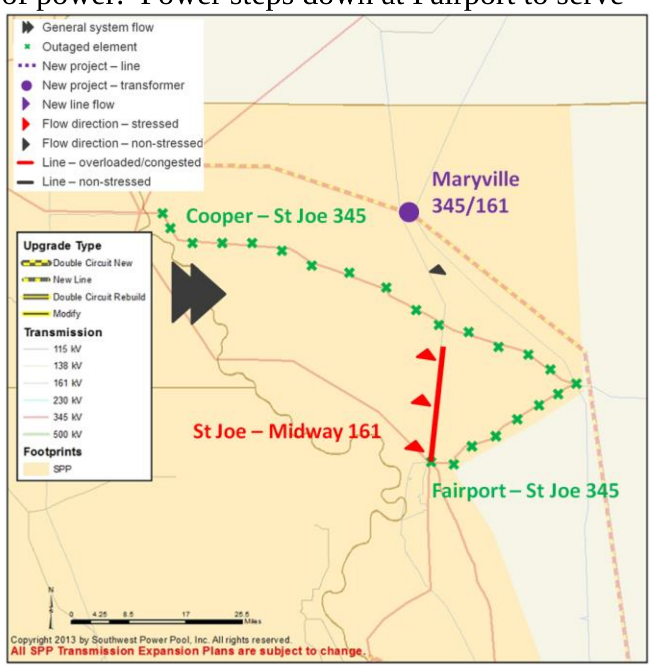


On the east side of Kansas City, Missouri shows a general west to east flow of power. The only EHV lines to facilitate this flow of power are Sibley–Overton 345 kV and Neosho – Morgan – Huben 345 kV. When the Sibley – Overton 345 kV line is in outage, there is significant west to east flow on the underlying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

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

Maryville 345/161 kV Transformer

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

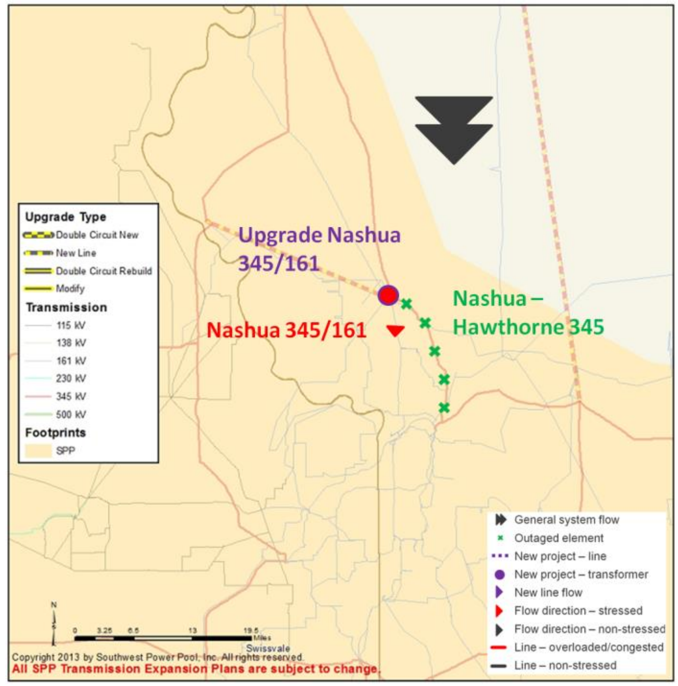


The addition of the Maryville 345/161 kV transformer along with the Nebraska City – Sibley 345 kV line (NTC's issued in 2010) mitigates the congestion of the St. Joe – Midway 161 kV reliability need. It does so by providing counter flow to the south to north flows on the 161 kV systems that are serving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

Upgrade Nashua 345/161 kV Transformer

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

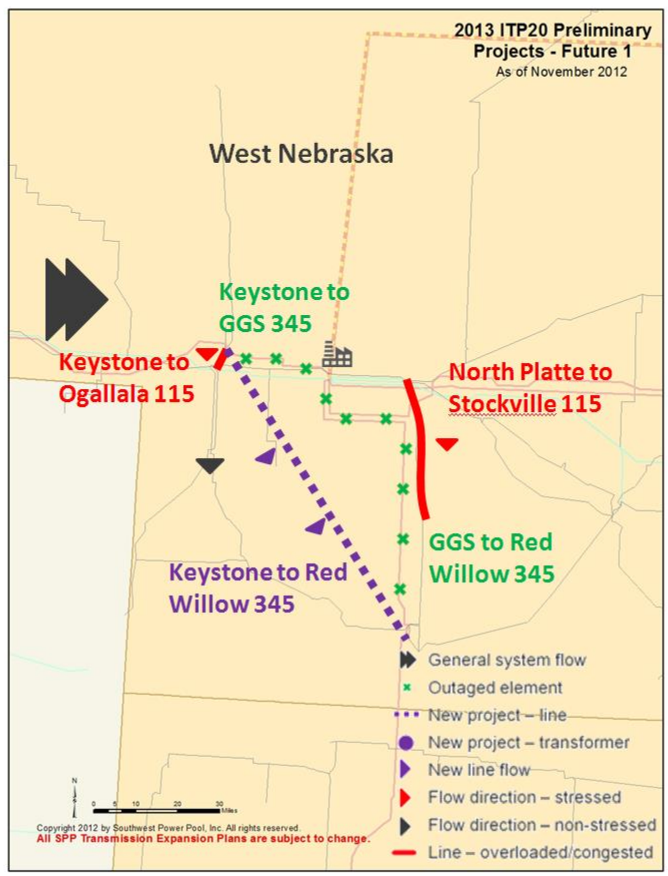
Upgrading the Nashua 345/161 kV transformer to 650/715 MVA provides the necessary capacity to mitigate the congestion at this transformer due to the loss of the Nashua – Hawthorne 345 kV line.



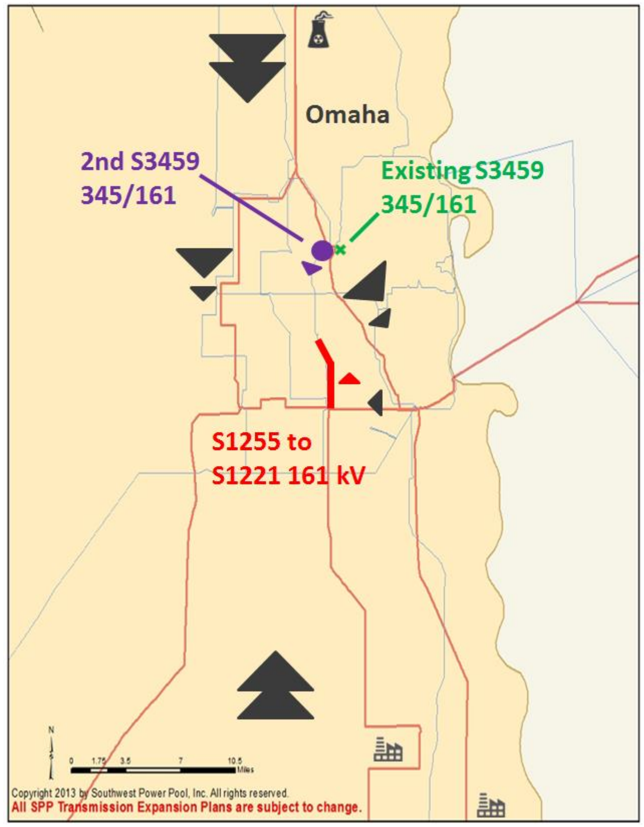
Keystone – Red Willow 345 kV

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

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



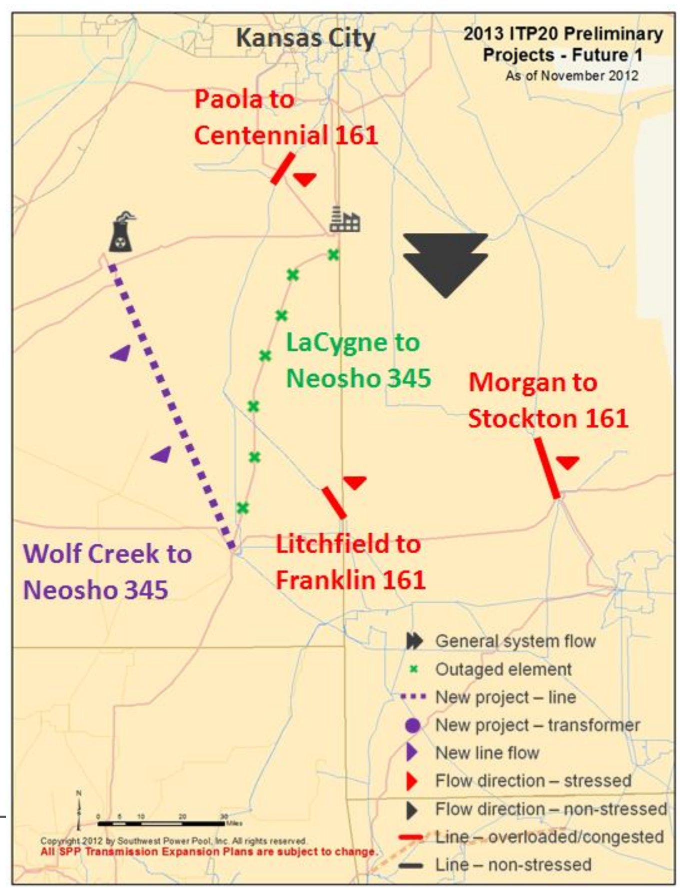
S3459 345/161 kV Transformer



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

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

Wolf Creek – Neosho 345 kV



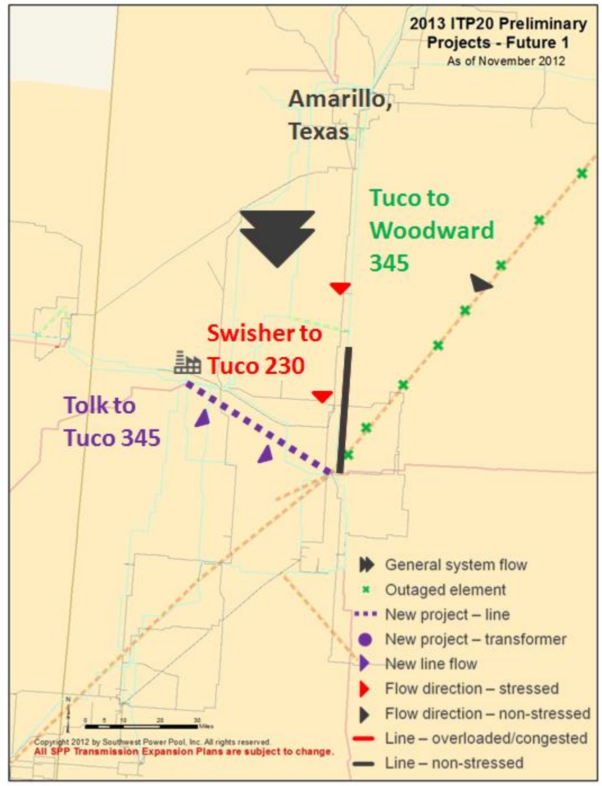
The area south of Kansas City shows a general north to south flow of power. The large Wolf Creek and LaCygne generators deliver significant power south on the LaCygne – Neosho 345 kV line. When this line is out of service, the large flows on the underlying 161 kV network result in three different elements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

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

Tolk – Tuco 345 kV

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

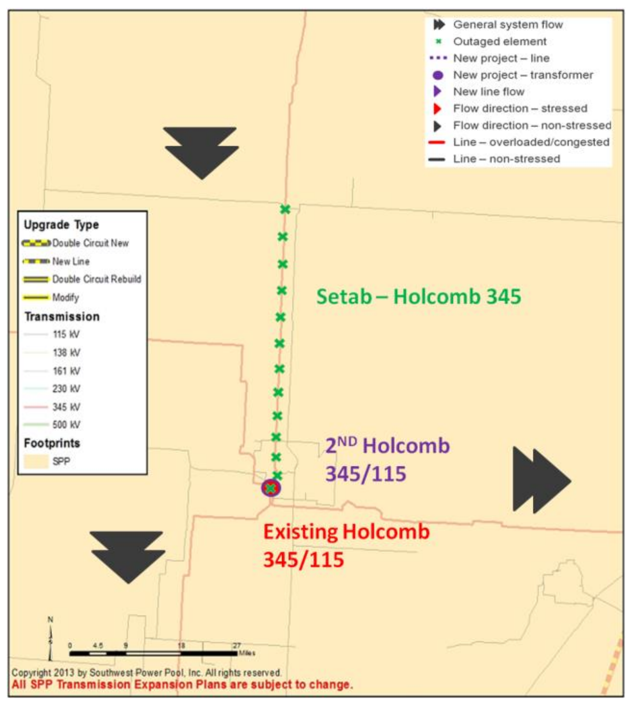
The addition of the 64 mile Tolk – Tuco 345 kV line allows for the large Tolk generator to deliver power east to Tuco. This relieves the north to south congestion of the Swisher – Tuco 230 kV line by delivering power west to east from the Tolk generation.



Holcomb 345/115 kV Transformer

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

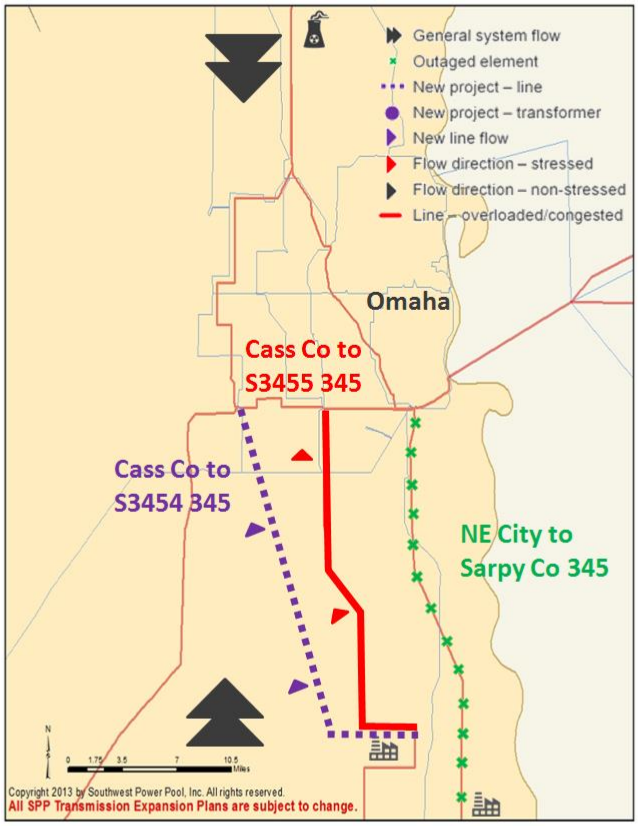
The addition of the 2nd Holcomb 345/115 kV transformer allows for greater power transfer to the 345 kV system, to serve loads to the east and to the south. This project relieves the congestion at the existing Holcomb 345/115 kV transformer and mitigates the reliability need.



S3740 – S3454 345 kV

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

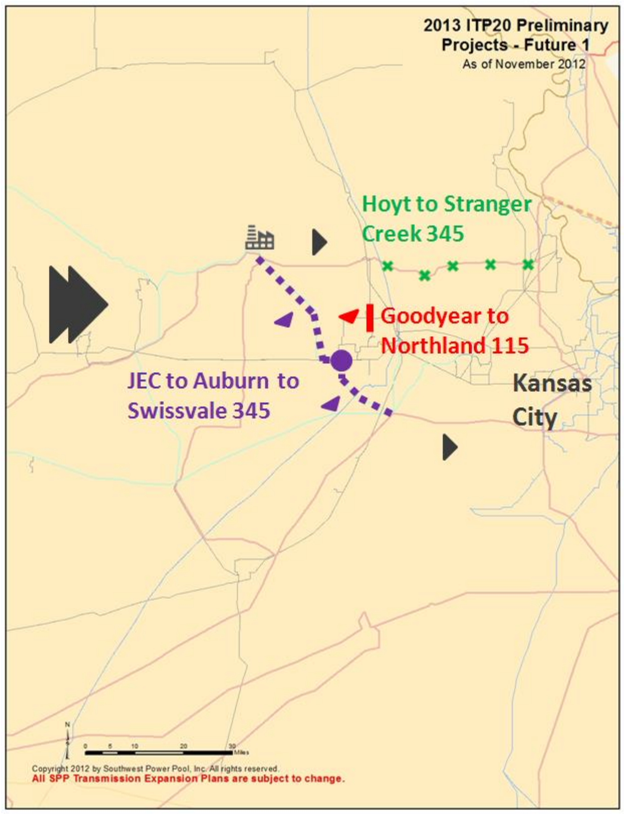
The addition of the 28 mile S3740 (Cass Co) – S3454 (SW Omaha) 345 kV line creates an alternative path for the Nebraska City and Cass Co generation to be delivered to Omaha, mitigating this reliability need for the loss of the Nebraska City – Sarpy 345 kV line.



JEC – Auburn – Swissvale 345 kV

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

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



Section 15: Potential Project Plans

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

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

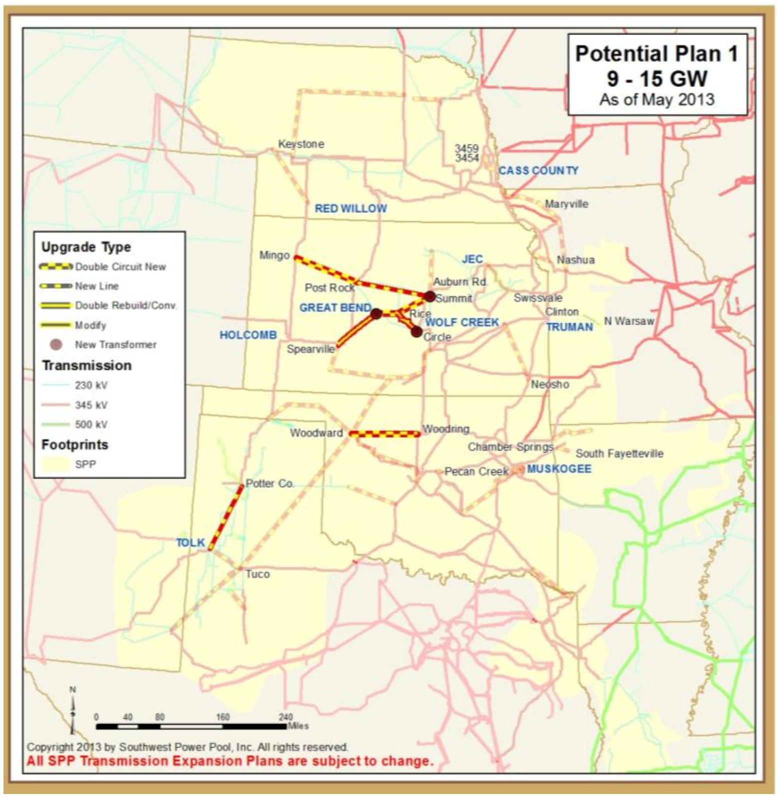


Figure 15.1: Potential Plan 1

Potential Plan 1

9 – 15 GW Wind

Incremental Cost: $1.3B

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

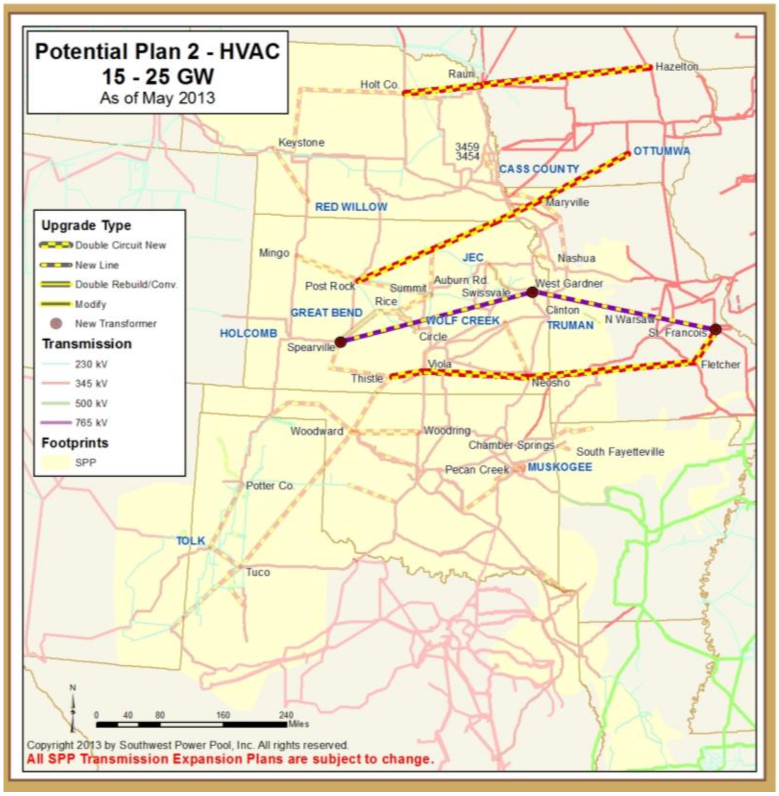


Figure 15.2: Potential Plan 2

Potential Plan 2

15 – 25 GW Wind

Incremental Cost: $4.9B

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

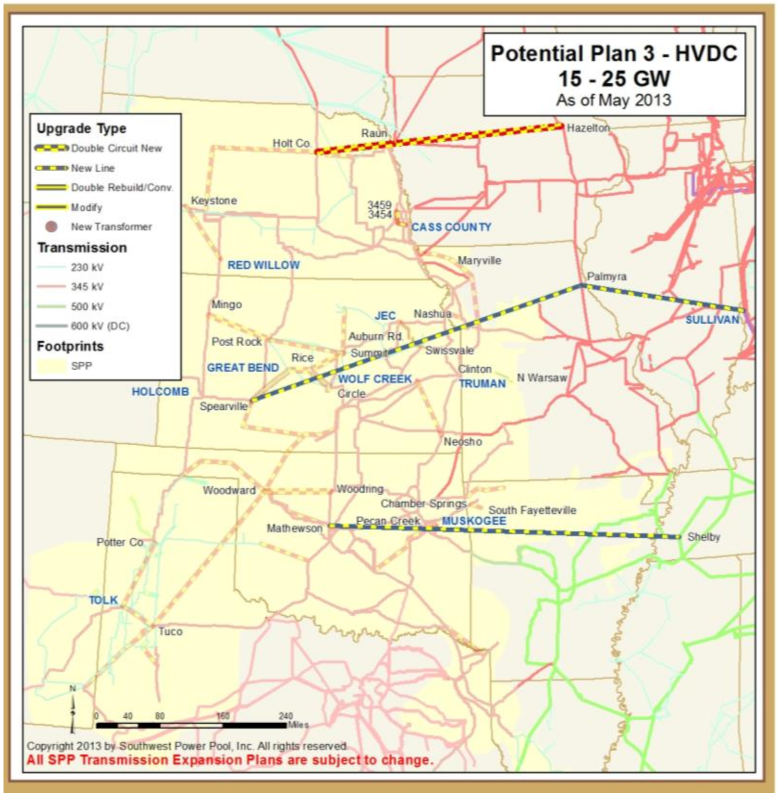


Figure 15.3: Potential Plan 3

Potential Plan 3

15 – 25 GW Wind

Incremental Cost: $5.1B

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

Section 16: Benefits

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

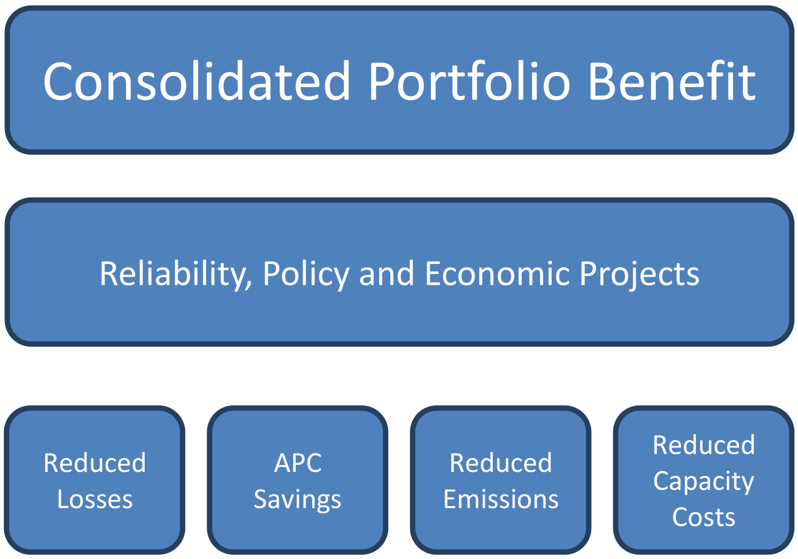
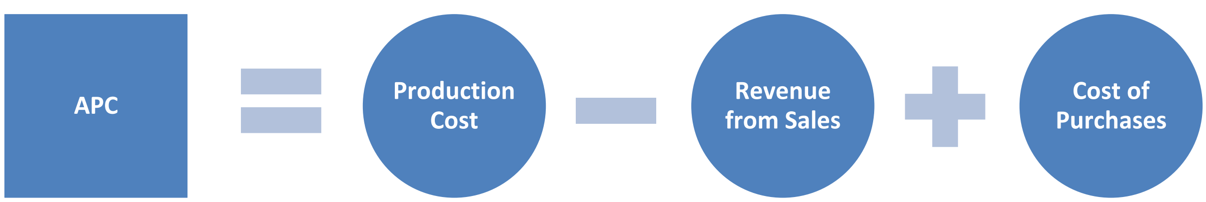


Figure 16.1: Benefit Hierarchy

16.1: APC Savings

Adjusted Production Cost (APC) is a measure of the impact on production cost savings by Locational Marginal Prices (LMP), accounting for purchases and sales of energy between each area of the transmission grid. APC is determined from using a production cost modeling tool that accounts for hourly commitment and dispatch profiles during the simulation year. The calculation, performed on an hourly basis, is as follows:



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

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

Figure 16.2: APC Calculation

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

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

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

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

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

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

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

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

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

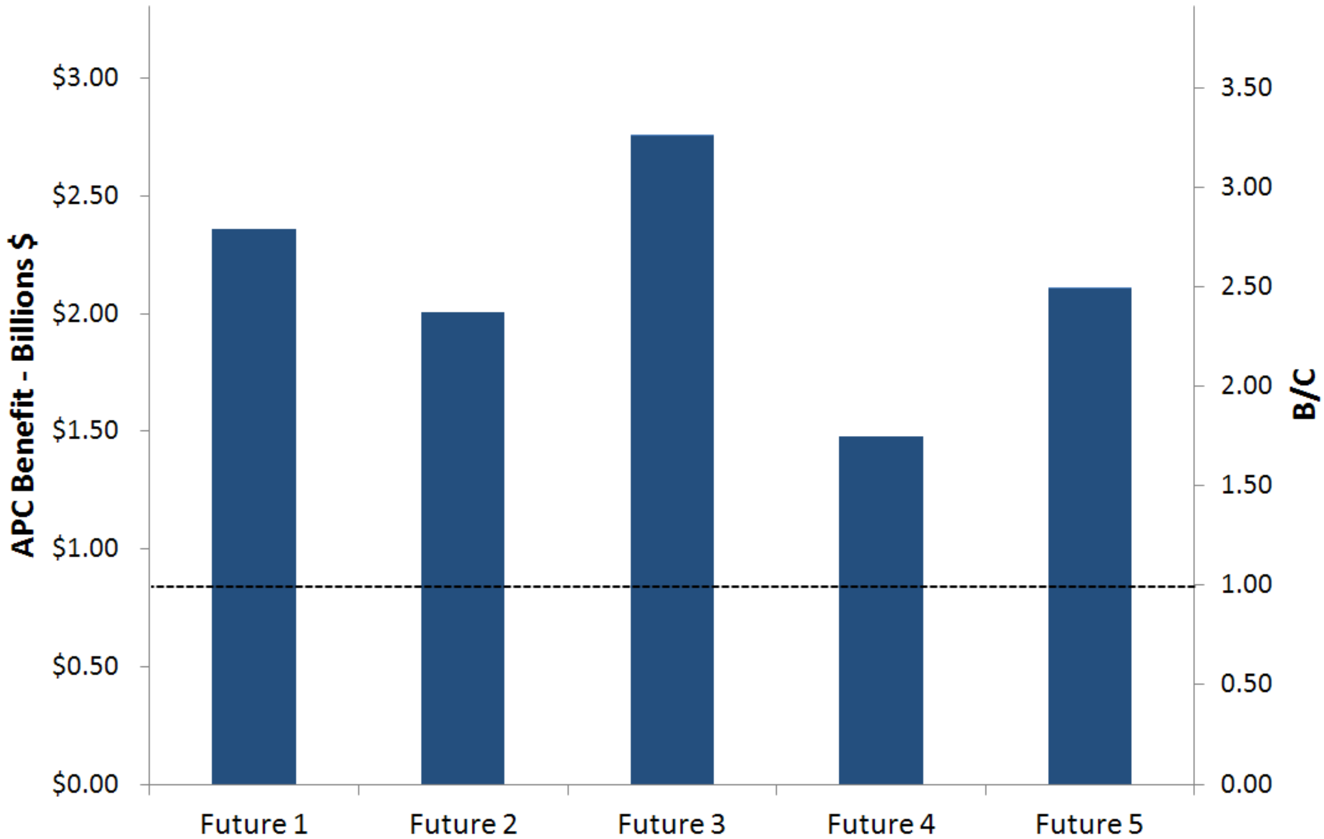


Figure 16.3: APC Benefits and B/C for SPP

16.2: Reduced Emissions

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

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

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

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

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

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

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

Table 16.3: Change in Emission Rates (2033)

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

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

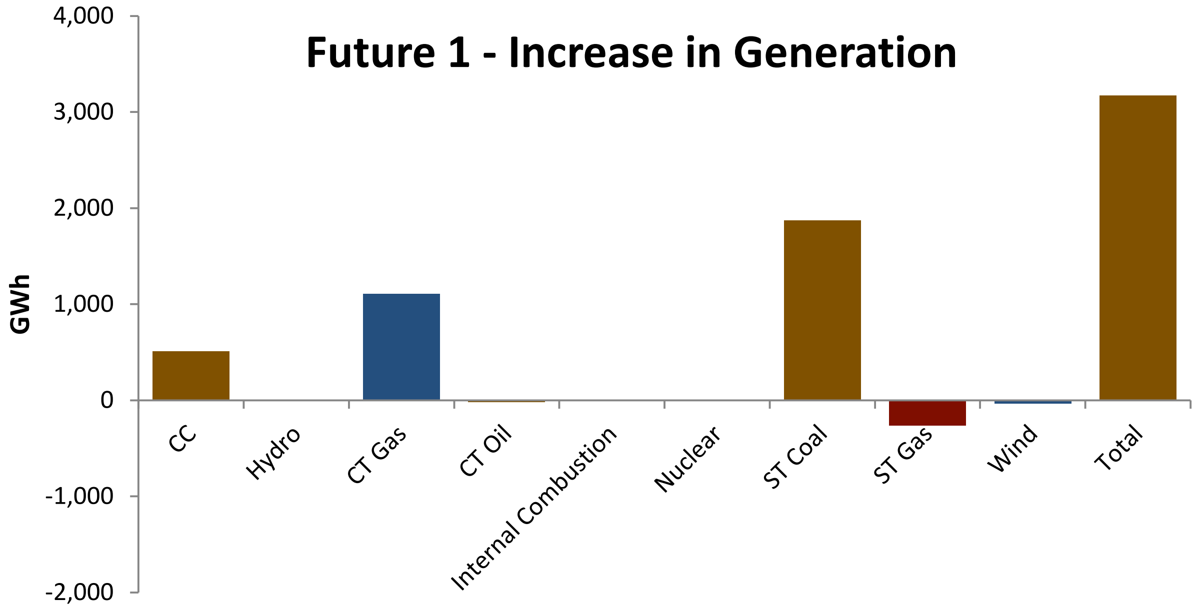


Figure 16.4: Future 1- Increase in Generation with Consolidated Portfolio (2033)

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

16.3: Reduced Losses

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes an inefficiency that is inherent to all standard conductors. Line losses across the SPP system are directly related to system impedance. When additional lines are added to create parallel paths within the footprint, losses are reduced. Figure 16.5 shows the annual change in system losses due to the transmission portfolios.

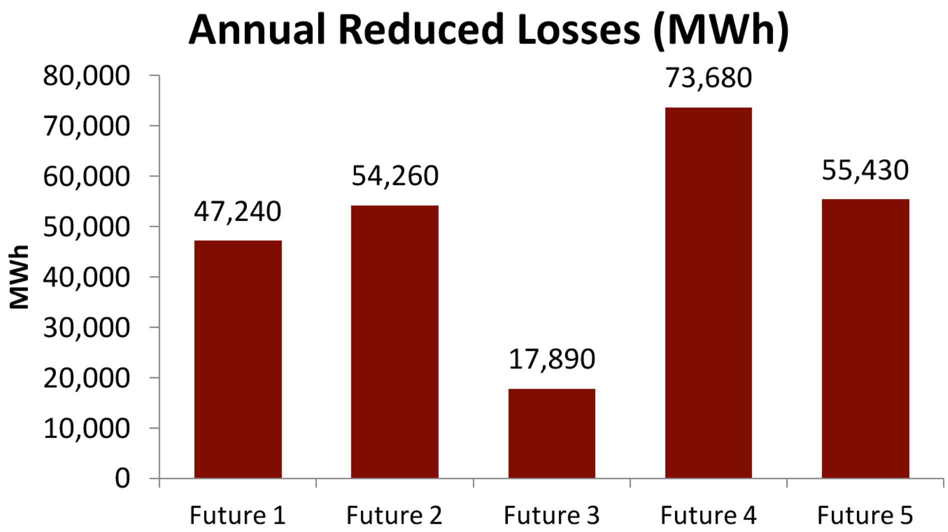


Figure 16.5: Annual Reduction in Losses

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

16.4: Reduced Capacity Cost Due to Losses

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

Figure 16.6: Calculating Reduced Capacity Cost Due to Losses

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

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

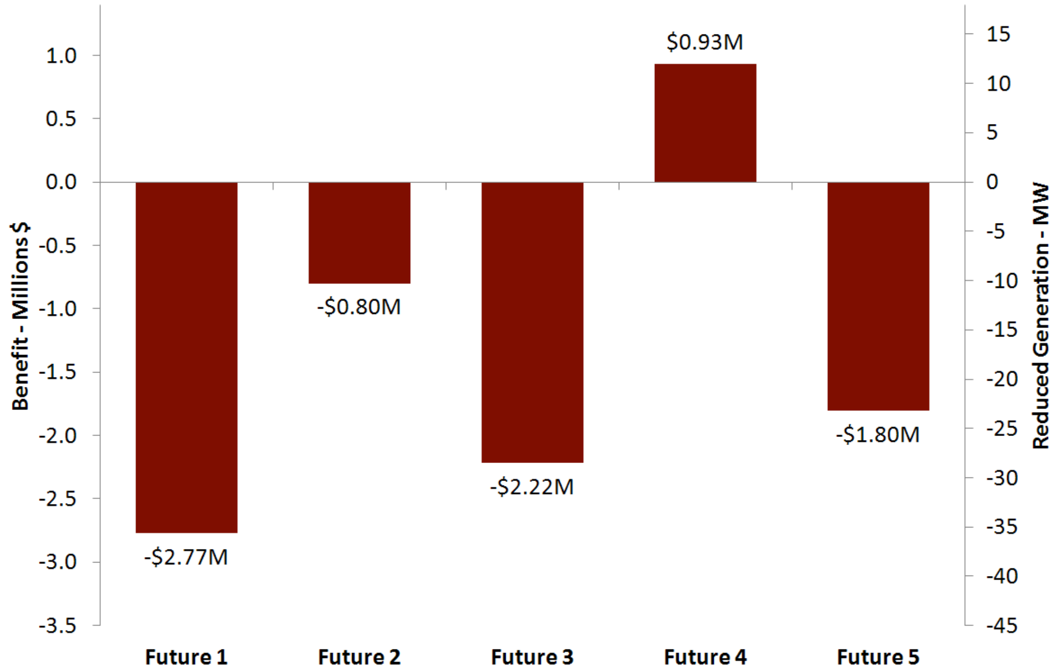


Figure 16.7: Reduced Capacity Cost Savings ($ millions)

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

16.5: Additional Metrics

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

16.6: Monetized Metric Summary

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

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

Table 16.4: Monetized Metric Summary (Millions of $)

16.7: Zonal and State APC Benefits and Costs

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

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

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

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

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

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

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

16.8: Rate Impacts

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

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

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

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

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

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

Table 16.7: Retail Residential Rate Impacts by Zone

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

16.9: Sensitivities

Sensitivities to natural gas price and demand levels were developed by the ESWG to understand the economic impacts associated with variations in certain model inputs. These sensitivities were not used to develop transmission projects or filter out projects. Two confidence intervals were developed using historical market prices and demand levels from the NYMEX and FERC Form No. 714. The standard deviation of the log difference from the normal within the pricing datasets was used to provide a confidence interval. The Natural Gas Price sensitivity had a 95% confidence interval (1.96 standard deviations) in the positive and negative directions while the Demand Level sensitivity had a 67% confidence interval (1 standard deviation) in the positive and negative directions.

The resulting assumptions are shown in Table 16.8.

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

Table 16.8: Sensitivities Utilized in 2013 ITP20

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

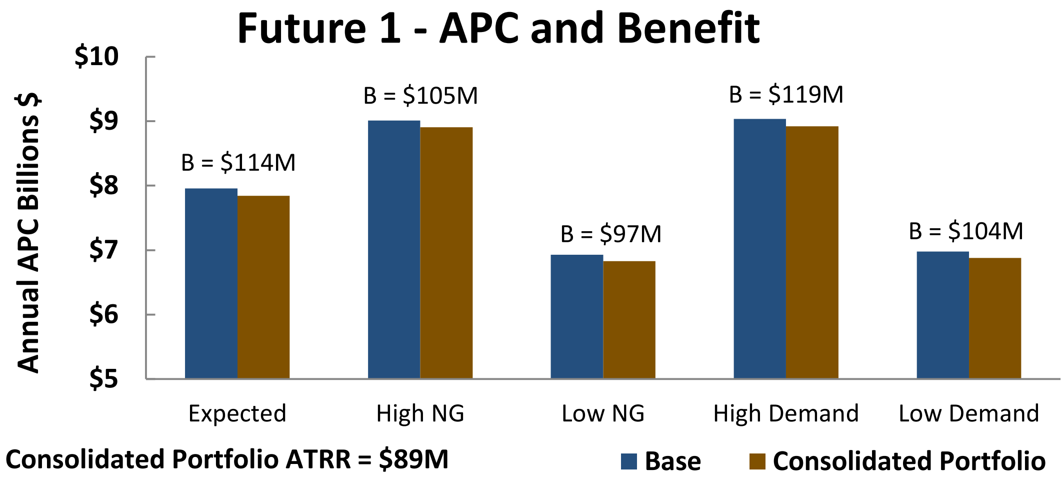


Figure 16.8: Future 1 Sensitivities – APC and Benefit

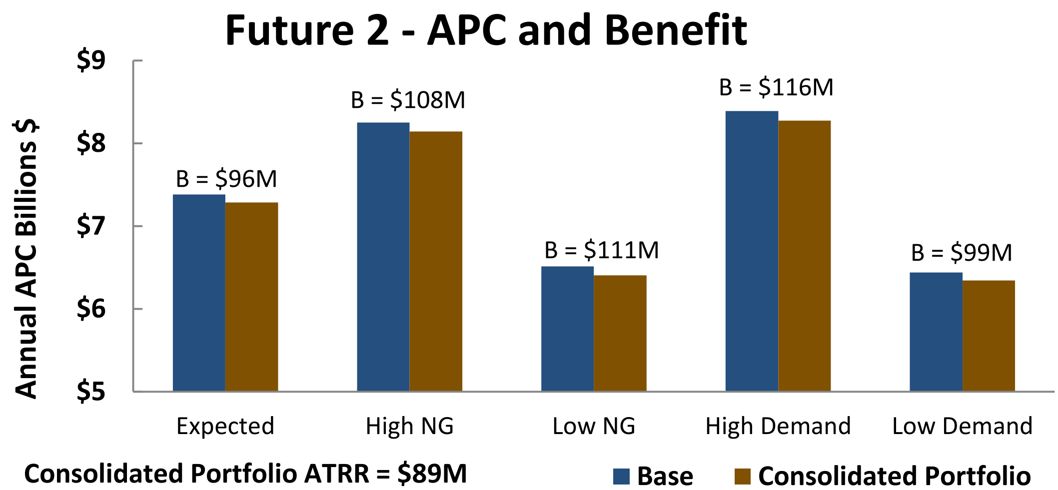


Figure 16.9: Future 2 Sensitivities – APC and Benefit

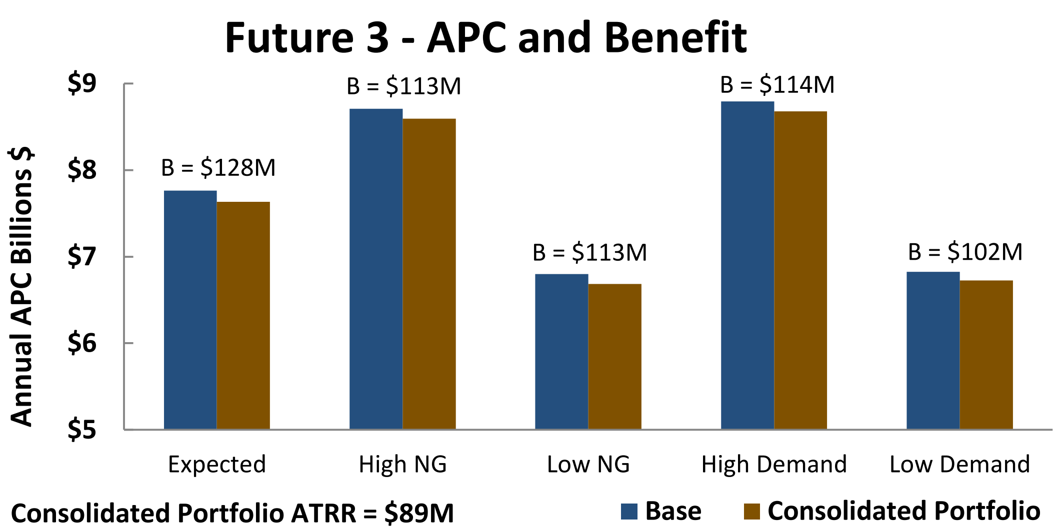


Figure 16.10: Future 3 Sensitivities – APC and Benefit

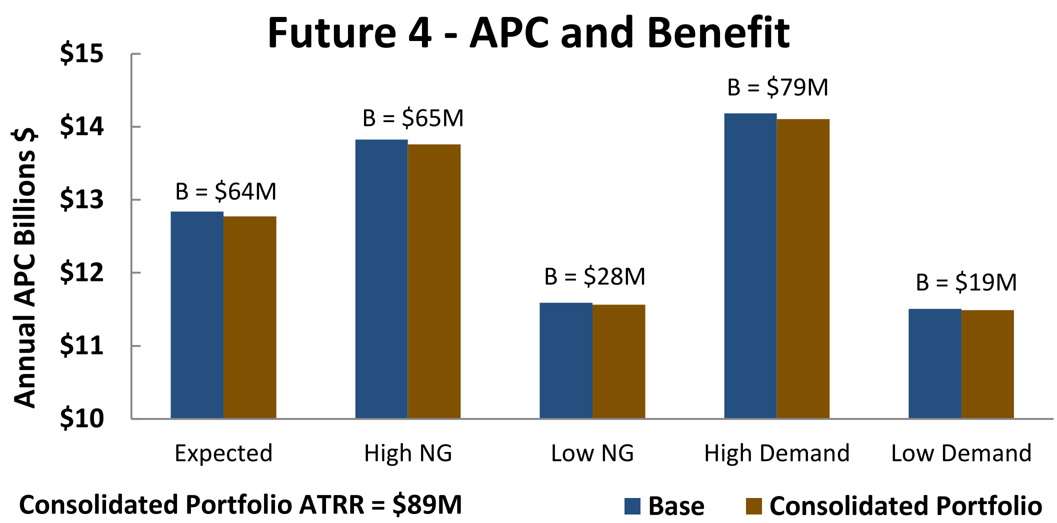


Figure 16.11: Future 4 Sensitivities – APC and Benefit

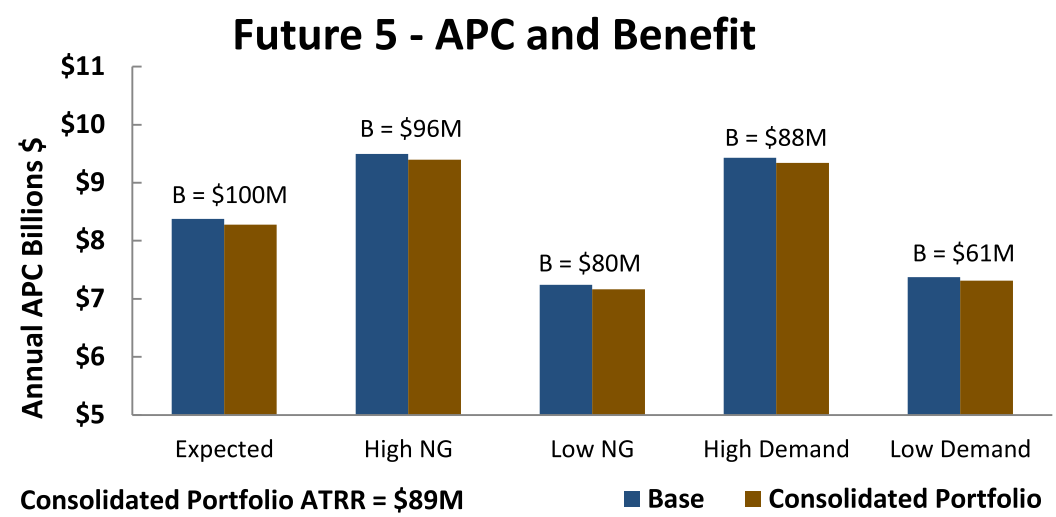


Figure 16.12: Future 5 Sensitivities – APC and Benefit

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

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

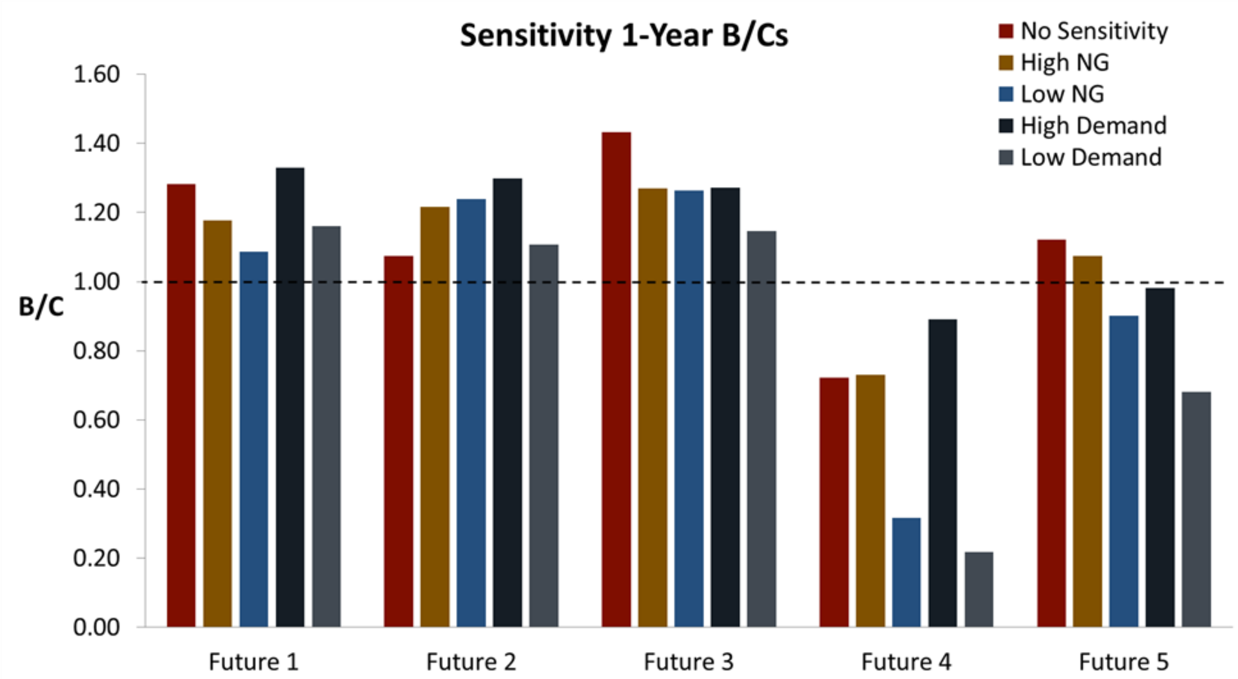


Figure 16.13: One-Year B/C's for all Futures and Sensitivities

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

Section 17: Final Assessments

17.1: Final Reliability Assessment

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

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

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

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

17.2: Final Stability Assessment

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

Method

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

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

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

Wind Dispatch Achievable with Consolidated Portfolio

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

Section 18: Conclusion

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

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

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

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

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

Table 18.1: 2013 ITP20 Projects

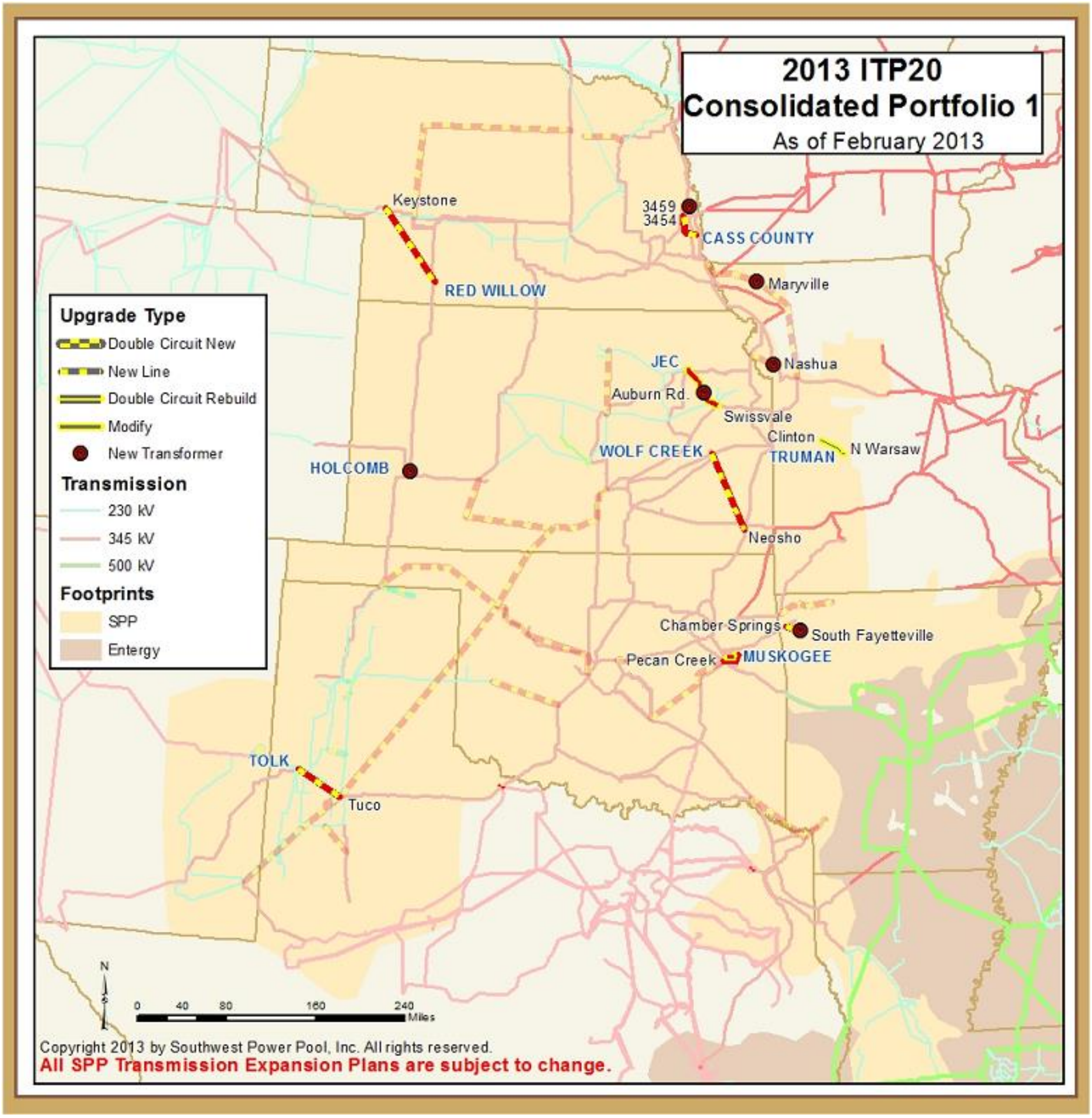


Figure 18.1 2013 ITP20 Consolidated Portfolio

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PART IV: APPENDICES

Section 19: Glossary of Terms

The following terms are referred to throughout the report.

Acronym	Description	Acronym	Description
APC	Adjusted Production Cost	**ITPNT**	Integrated Transmission Plan Near-Term Assessment
APC-based B/C	Adjusted Production Cost based Benefit to Cost ratio	**ITP10**	Integrated Transmission Plan 10-Year Assessment
ATC	Available Transfer Capability	**ITP20**	Integrated Transmission Plan 20-Year Assessment
ATSS	Aggregate Transmission Service Studies	**JPC**	Joint Planning Committee
ATRR	Annual Transmission Revenue Requirement	**LIP**	Locational Imbalance Price
BATTF	Benefit Analysis Techniques Task Force	**LMP**	Locational Marginal Price
B/C	Benefit to Cost Ratio	**MDWG**	Model Development Working Group
BA	Balancing Authority	**MISO**	Midcontinent Independent System Operator, Inc.
BOD	SPP Board of Directors	**MOPC**	Markets and Operations Policy Committee
Carbon Price	The tax burden associated with the emissions of CO_2	**MTF**	Metrics Task Force
CAWG	Cost Allocation Working Group	**MVA**	Mega Volt Ampere (10^6 Volt Ampere)
CFL	Compact Fluorescent Bulb	**MW**	Megawatt (10^6 Watts)
CRA	Charles River Associates	**NERC**	North American Electric Reliability Corporation
EHV	Extra-High Voltage	**NOPR**	Notice of Proposed Rulemaking
EIS	Energy Imbalance Service	**NREL**	National Renewable Energy Laboratory
EPA	Environmental Protection Agency	**NTC**	Notification to Construct

ESRPP	Entergy SPP RTO Regional Planning Process	**OATT**	Open Access Transmission Tariff
ESWG	Economic Studies Working Group	**PCM**	Production Cost Model
EWITS	Eastern Wind Integration and Transmission Study	**RES**	Renewable Energy Standard
FCITC	First Contingency Incremental Transfer Capability	**ROW**	Right of Way
FERC	Federal Energy Regulatory Commission	**RSC**	SPP Regional State Committee
GI	Generation Interconnection	**RTWG**	Regional Tariff Working Group
GIS	Geographic Information Systems	**SIL**	Surge Impedance Loading
GW	Gigawatt (10^9 Watts)	**SPC**	Strategic Planning Committee
HVDC	High-Voltage Direct Current	**SPP**	Southwest Power Pool, Inc.
SPPT	Synergistic Planning Project Team	**TSR**	Transmission Service Request
STEP	SPP Transmission Expansion Plan	**TVA**	Tennessee Valley Authority
TLR	Transmission Loading Relief	**TWG**	Transmission Working Group
TPL	Transmission Planning NERC Standards	**WITF**	Wind Integration Task Force
TO	Transmission Owner		

Section 20: Final Reliability Assessment Results

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

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

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

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

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

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

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

Section 21: Additional Metrics

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

21.1: Assumed Benefit of Mandated Reliability Projects

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

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

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

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

21.2: Benefit from Meeting Public Policy Goals

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

21.3: Mitigation of Transmission Outage Costs

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

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

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

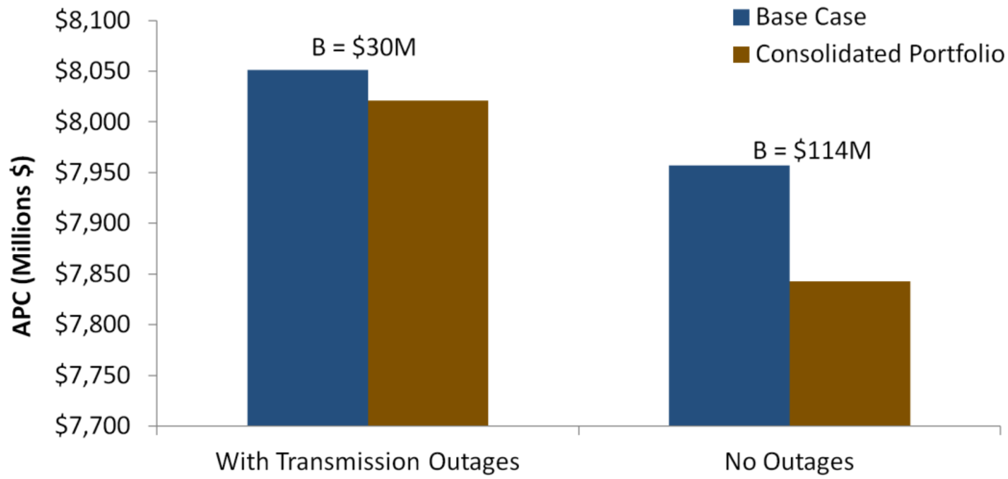

Figure 21.1: Mitigation of Transmission Outages

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

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