2023 INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT

SPP Engineering
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SPP Southwest Power Pool

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
0.1	SPP Staff	Initial Report Posting for TWG and ESWG	Draft
0.2	SPP Staff	Updates to tables, figures, and wording	Draft
0.3	SPP Staff	Updated with working group recommendations	TWG and ESWG approved
0.4	SPP Staff	Updated Figure 0.5 and corrected Ellsworth Tap-Great Bend 115 kV *rebuild* to be Ellsworth Tap-Great Bend 115 kV *structures*	MOPC approved
1.0	SPP Staff	Final Report	Removed duplicate paragraph

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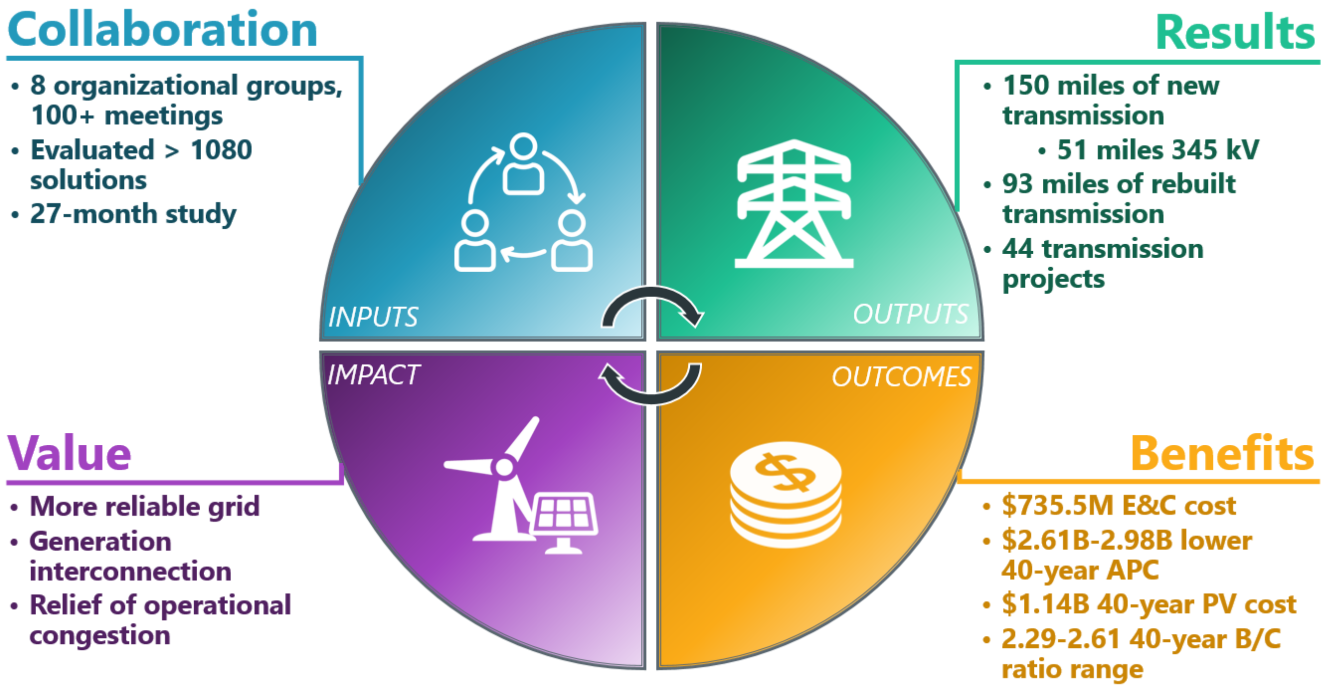

The 2023 Integrated Transmission Planning (ITP) assessment looks ahead 10 years to ensure the SPP region can deliver energy reliably and economically, facilitate public policy objectives and maximize benefits to end-use customers. Proactive transmission planning processes, like the ITP, address challenges caused by SPP’s rapidly changing generation fleet, provide economic load growth opportunities and deliver holistic transmission solutions to meet reliability compliance while providing energy cost savings.

Over 27 months, SPP and its member organizations collaborated on the 2023 ITP. SPP evaluated more than 1,080 solutions. The analysis resulted in the recommendation to approve 44 new transmission projects, including 51 miles of new extra-high-voltage (EHV) transmission and 93 miles of rebuilt high-voltage infrastructure. Three distinct scenarios were considered to account for variations in system conditions over 10 years. These scenarios considered requirements to support firm deliverability of capacity for reliability (base reliability), as well as exploring rapidly evolving technology that may influence the transmission system and energy industry (economic Futures 1 and 2). The scenarios included varied wind projections, utility-scale and distributed solar, energy storage resources, generation retirements and electric vehicles. These futures are briefly described below and further discussed in section 2.

- Future 1: Reference Case
    - Continuation of industry trends and regulations, retiring older conventional fossil fuel generators primarily by age, standard load forecasts and continued additions of renewable resources including wind, solar and storage.
- Future 2: Emerging Technologies Case
    - The emerging technologies future is driven by the emergence of key technologies such as electric vehicles and distributed generation. Fossil fuel generators are retired earlier, and higher additions of solar, wind, and energy storage resources are made compared to the reference case. This future anticipates increased investments in cleaner and more efficient power sources.

This portfolio contains reliability and economic projects that will mitigate 137 system issues. Reliability projects allow the region to meet compliance requirements and keep the lights on through loading relief, voltage support and system protection. Economic projects allow the region to lower energy costs through mitigation of transmission congestion and levelization of market prices.

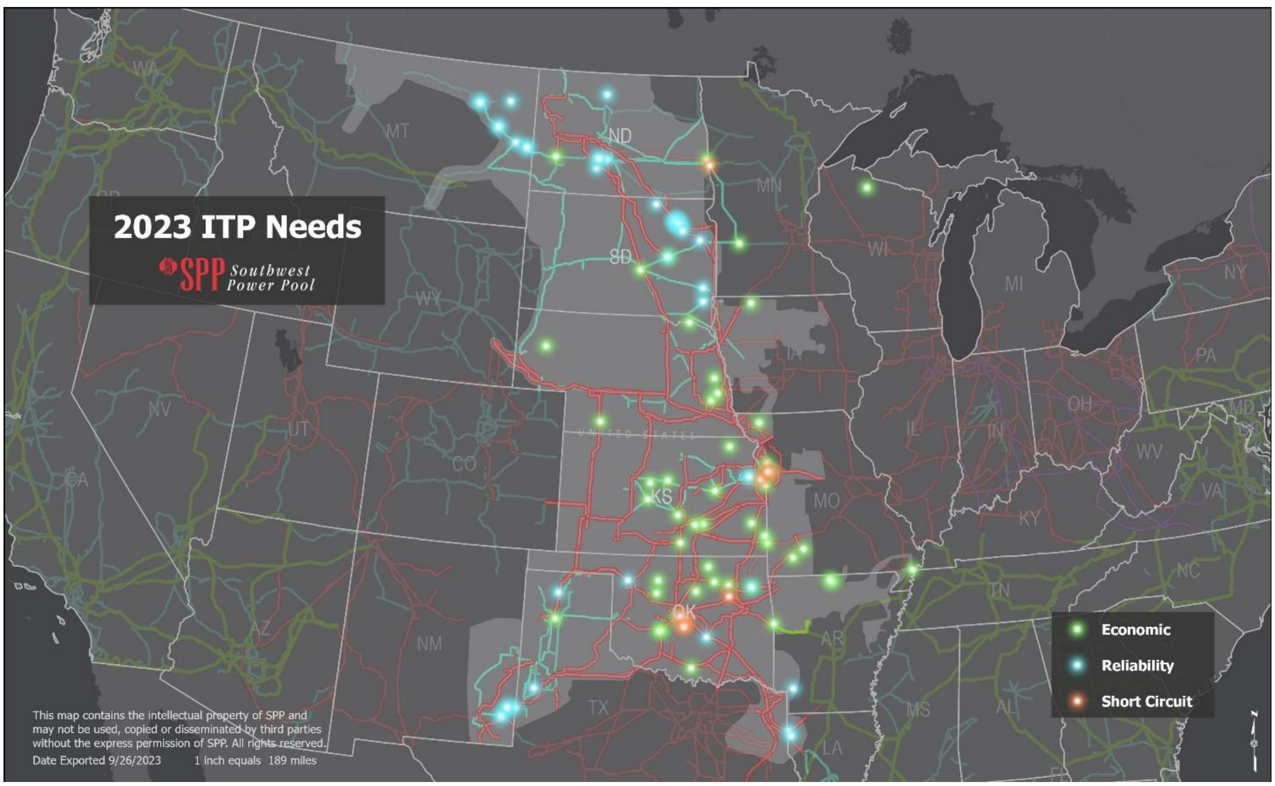

Figure 0.1: 2023 ITP Needs Map

The portfolio addresses reliability and economic issues across the system. The 2023 ITP portfolio was heavily driven by additional renewable generation, which has been historically under-forecasted. Further proving that continued renewable growth is driving overall system congestion is the increase in persistent operational needs observed in the 2023 ITP.

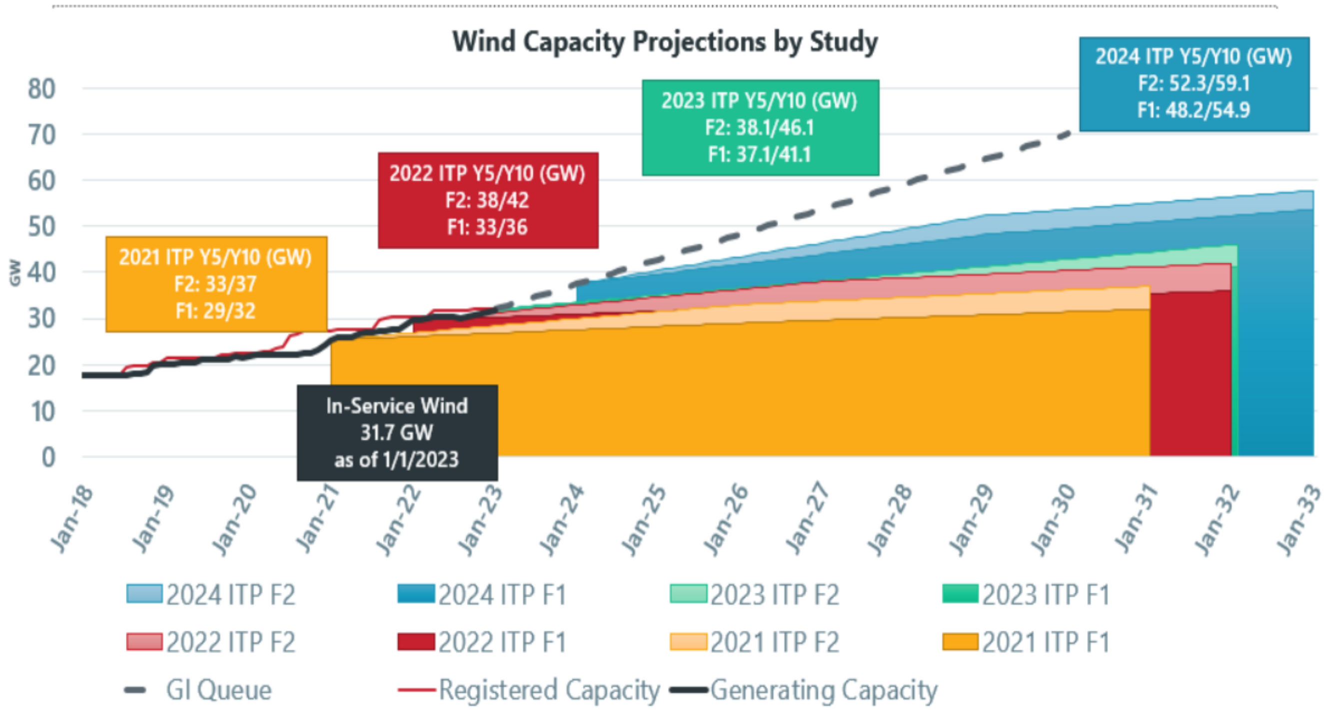

Figure 0.2: Wind Capacity Projections by Study

Unlike more recent ITP assessments, the 2023 ITP recommended portfolio looks to address the limiting system equipment and maximize SPP's existing infrastructure and transmission corridors, especially for projects driven by economic congestion. These lower voltage upgrades, usually addressing the monitored element, are generally more cost effective and deliver lower net benefits; however, in the 2023 ITP, these solutions are showing significant net benefits as well. For example, the 2019 ITP Assessment addressed economic congestion on the Cleveland (GRDA) – Cleveland (AECI) 138 kV bus tie constraint with large EHV solution. This solution drew system flows away from the bus tie and delivered them directly to Tulsa leading SPP to believe congestion had been mitigated long-term. Conversely, continued renewable growth in the central Oklahoma area shows future congestion decreasing once the approved solution is in service in 2027 only to increase again to previous levels in 2032.

The analysis determined that the adjusted production cost (APC) savings for the final portfolio had a 40-year present value (PV) benefit-to-cost (B/C) ratio ranging from 2.29 to 2.61. The net impact to ratepayers is a savings of $0.37 for Future 1 to $0.33 for Future 2 on the average retail residential monthly bill.

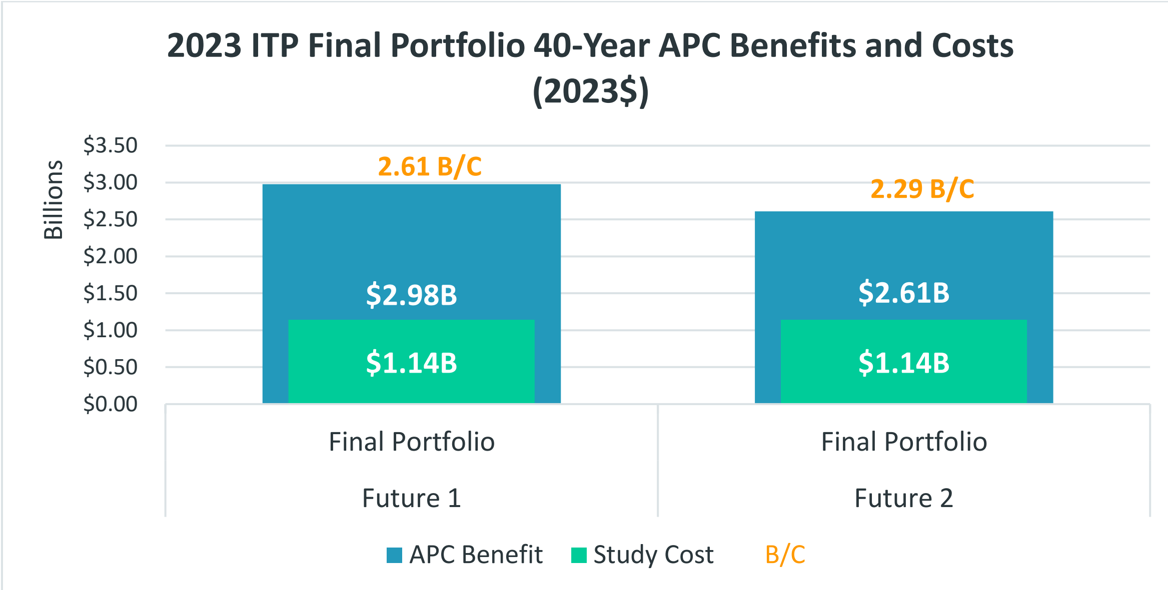

Figure 0.3: 40-Year Adjusted Production Cost Benefit and Cost Ranges

The recommended consolidated portfolio is expected to be cost beneficial within the first year of being placed in-service and to pay back the total investment within the first 10 years.[1]

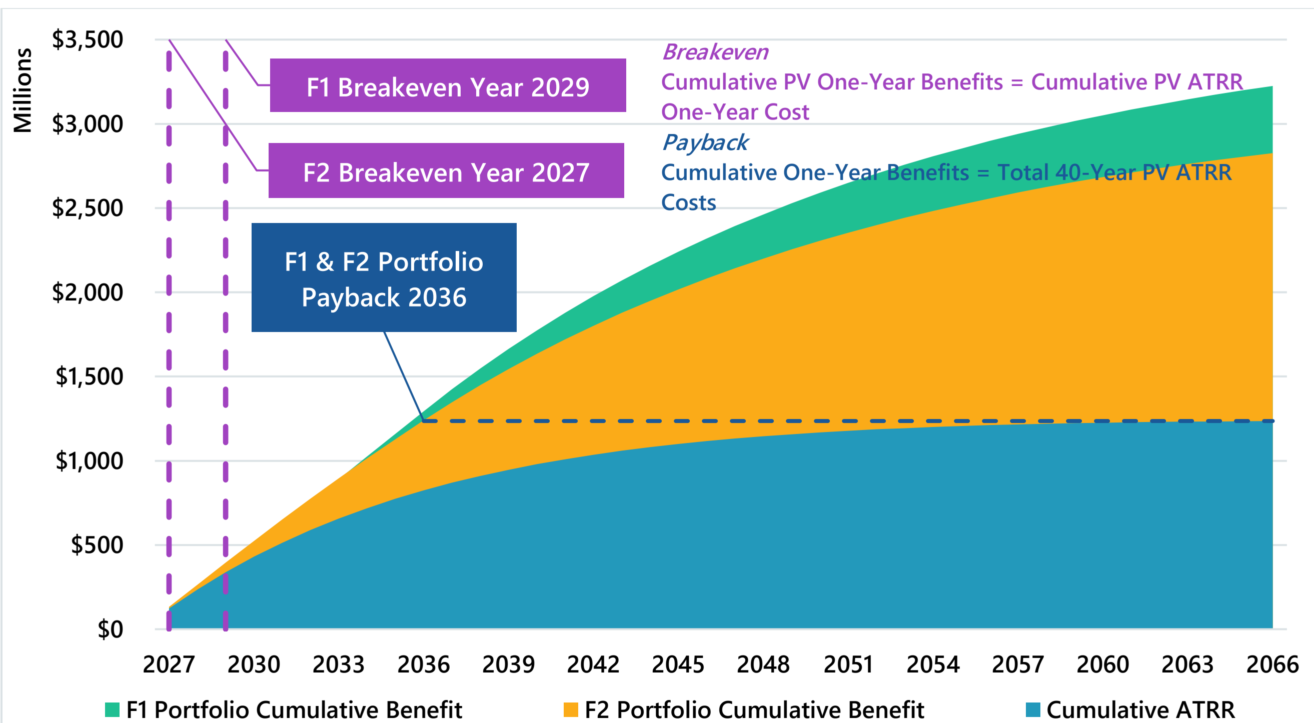

Figure 0.4: Portfolio Breakeven and Payback – APC benefit only

[1] This breakeven and payback period calculation is a conservative estimate that assumes the entire portfolio of solutions is placed in service in Year 5 and is not reflective of NTC issuance and projected in-service dates for each project.

The 2023 ITP recommended portfolio includes the projects shown below in Table 0.1. The recommendation for issuance of a Notice to Construct (with Conditions) (NTC or NTC-C) is shown in the column on the right.

Description	Area	Type	Project Cost (2023$)	Miles	NTC/ NTC-C
Flournoy-Oak Pan-Harr-Longwood 138 kV rebuild	AEPW	R	$20,446,720	12.2	NTC-C
Replace Turk 138/115 kV circuit 1 transformer	AEPW	R	$5,250,000	-	NTC
87th Street 345/115 kV new circuit 2 transformer	EKC	R	$10,200,000		NTC
Extend Craig-West Gardner 345 kV, Clearview-Eudora 115 kV Tap, new 345/115 kV substation	EKC/EM	R	$42,141,390	10.3	NTC-C
Newman Grace Tap and Woodward Nitrogen 69 kV terminal equipment	OKGE	R	$217,311	-	NTC
Pennsylvania-Southgate-Westmoore 138 kV extend line	OKGE	R	$15,160,147	0.76	NTC
Seminole 345/138 kV new circuit 3 transformer	OKGE	R	$8,306,343	-	NTC
Moore Co 115 kV terminal equipment	SPS	R	$210,000	-	NTC
Cunningham-Quahada 115 kV tap line-Buckeye Tap 115 kV new line	SPS	R	$25,715,000	3.2	NTC-C
Lovington 40 MVAR Reactor	SPS	R	$4,457,880	-	No
Sundown Interchange 115 kV terminal equipment	SPS	R	$393,298	-	No
Devaul 115 kV 15 MVAR reactor	WAPA	R	$1,671,705	-	NTC
Dawson County-Fort Peck 230 kV 40 MVAR line reactor	WAPA	R	$4,007,750	-	NTC
Broadland 345 kV 75 MVAR reactor	WAPA	R	$5,445,170	-	NTC
Groton 345 kV 68 MVAR reactor	WAPA	R	$5,162,152	-	NTC
Kerr-Maid 161 kV circuit 1 and 2 rebuild	GRDA	E/R	$20,555,599	5.5	NTC-C

Description	Area	Type	Project Cost (2023$)	Miles	NTC/ NTC-C
Cleveland 138 kV Terminal Equipment	AECI	E/O	$2,530,160	-	No[2]
Anadarko-Gracemont 138 kV circuit 2 and 3 new line	WFEC/OKGE	E/O	$64,000,000	15	NTC-C
Gerald Gentleman Station-Ogallala 230 kV terminal equipment	NPPD	E/O	$1,700,000	-	NTC
Osage-Webb City Tap-Shidler 138 kV rebuild	OKGE/AEPW	E/O	$27,236,410	24.9	NTC-C
Replace Potter County 345/230 kV circuit 1 transformer and new circuit 2 transformer	SPS	E/O	$30,000,000	-	NTC-C
Replace Fort Thompson 345/230 kV circuit 1 and 2 transformers	WAPA	E/O	$33,546,913	-	NTC-C
Benton-Wichita 345 kV terminal equipment	WERE	E/O	$6,830,258	-	NTC
Blackberry-Neosho 345 kV terminal equipment	WERE	E	$6,830,258	-	NTC
Pine & Peoria Tap-46th Street Tap-Tulsa North 138 kV rebuild	AEPW	E	$6,228,906	5.7	NTC
Craig-Lenexa South 161 kV circuit 2 terminal equipment	KCPL	E	$1,902,581	-	NTC
70th & Bluff-Sub 1214 161 kV raise line and replace 70th & Bluff 161/115 kV circuit 1 transformer	LES/OPPD	E	$8,914,179	17.7	NTC
Alliance-Victory Hill 115 kV new line	WAPA-RMR/NPPD	E	$92,007,750	47.9	No
Matthewson-Redbud 345 kV new line	OKGE	E	$110,770,850	38.4	NTC-C
Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake	OKGE	E	$87,000,000	2.8	No
Czech Hall and Cimarron 138 kV terminal equipment	OKGE	E	$138,952	-	NTC

[2] Upgrades to non-SPP tariff facilities will be coordinated with AECI

Description	Area	Type	Project Cost (2023$)	Miles	NTC/ NTC-C
Chisholm Creek-Lone Oak 138 kV new line	OKGE	E	$4,181,870	3.4	No
Fitzgerald Creek-Kenzie 138 kV line tap at Valley	OKGE/AECI	E	$10,500,000	2	NTC
Cleo Corner-Okeene 138 kV new line	OKGE/WFEC	E	$38,483,360	26.4	No
Fremont/Sub 976 115/69 kV new circuit 2 transformer	OPPD/NPPD	E	$5,900,000	-	NTC
Ellsworth Tap-Great Bend 115 kV structures	SEPC	E	$750,000	30.2	NTC
Gavins Point-Yankton 115 kV rebuild	WAPA	E	$2,957,298	4	NTC
Huron B Tap-Huron-Huron West Park 115 kV rebuild	WAPA	E	$12,548,421	10.6	NTC
Butler-Midian 138 kV terminal equipment	WERE	E	$2,658,322	-	NTC
Franklin 161/69 kV new circuit 2 transformer	WERE	E	$3,323,769	-	NTC
Anadarko-Southwestern 138 kV terminal equipment	WFEC	E	$483,360	-	NTC
Blue Valley 161 kV one breaker replacement	KCPL	SC	$310,351	-	NTC
Craig 161 kV five breaker replacements	KCPL	SC	$3,047,451	-	NTC
Lightning Creek 138 kV two breaker replacements	OKGE	SC	$1,418,348	-	NTC
		Total	**$735,540,232**		

Table 0.1: 2023 ITP Consolidated Portfolio

Figure 0.5 depicts the 2023 ITP thermal/voltage reliability projects.

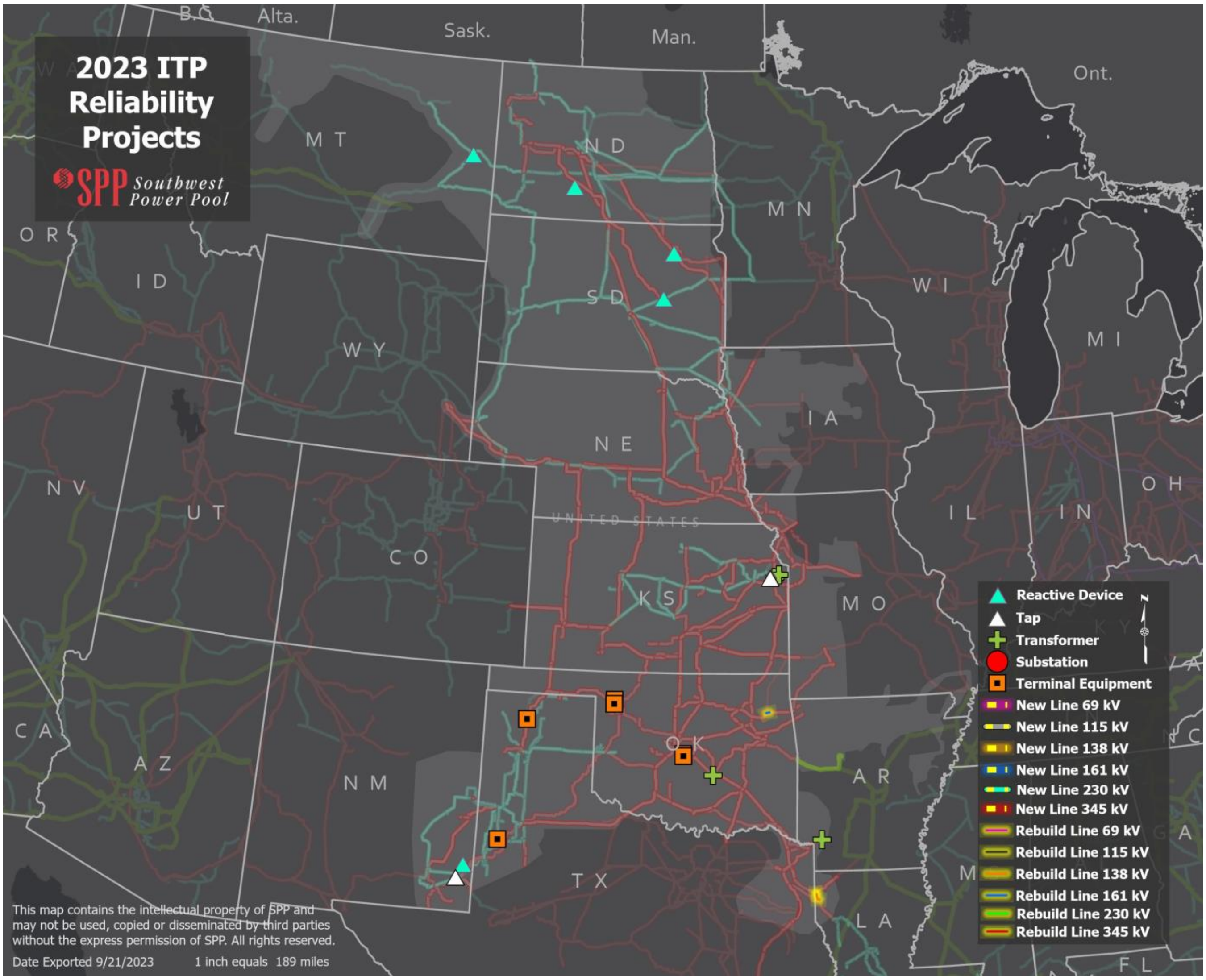

Figure 0.5: 2023 ITP Thermal and Voltage Reliability Projects

Figure 0.6 depicts the 2023 ITP short circuit reliability projects.

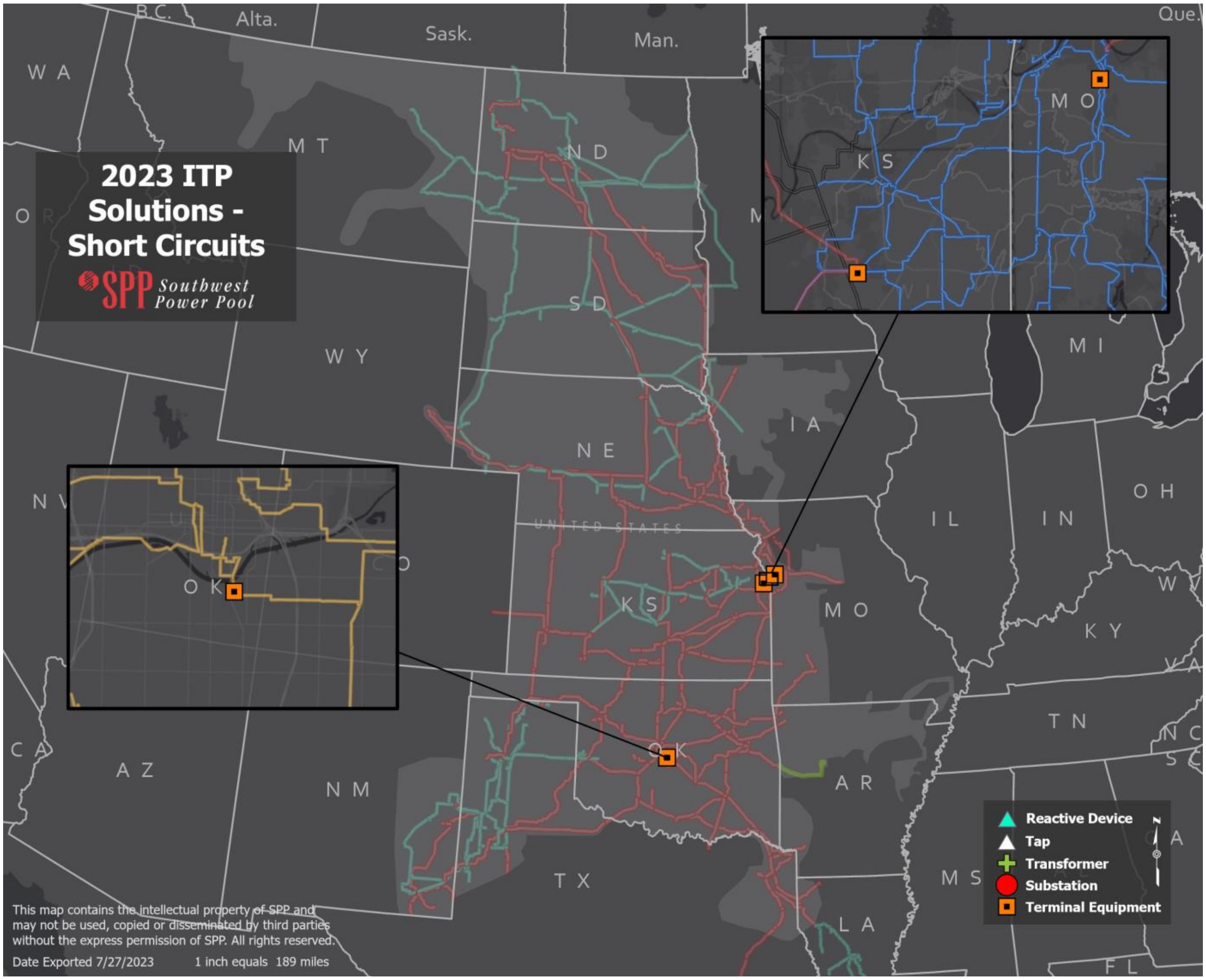

Figure 0.6: 2023 ITP Short Circuit Reliability Projects

Figure 0.7 depicts the 2023 ITP economic projects.

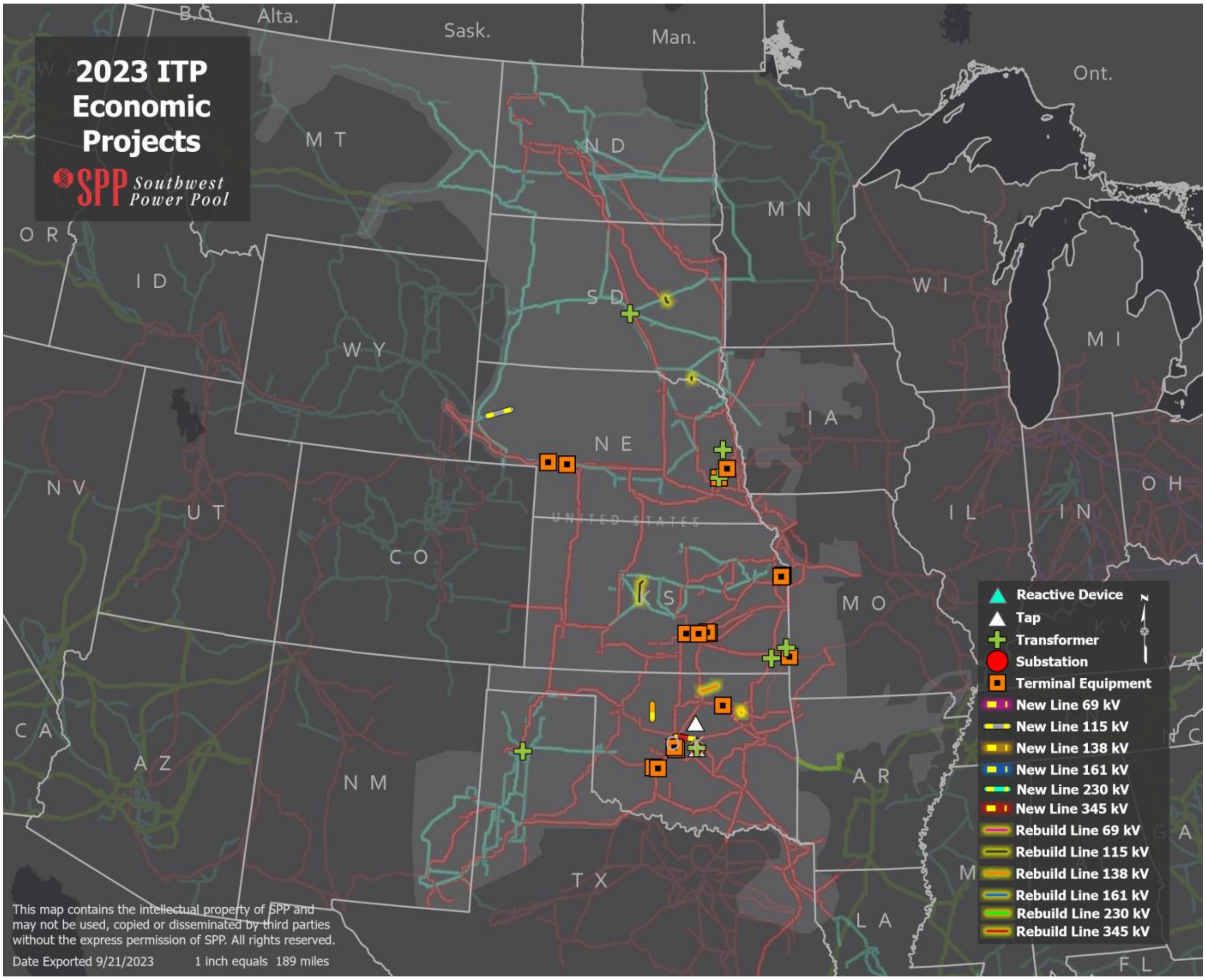

Figure 0.7: 2023 ITP Economic Needs

1 INTRODUCTION

1.1 THE ITP ASSESSMENT

The SPP Integrated Transmission Planning (ITP) process promotes transmission investment to meet near- and long-term reliability, economic, public policy and operational transmission needs. The ITP process coordinates solutions with ongoing compliance, local planning, interregional planning and tariff service processes. The goal is to develop a 10-year regional transmission plan that provides reliable and economic energy delivery and achieves public policy objectives, while maximizing benefits to the end-use customers. The 2023 ITP is guided by requirements defined in Attachment O of the SPP Open Access Transmission Tariff (Tariff),[3] the ITP Manual,[4] and the 2023 ITP scope.[5]

The ITP process is open and transparent, allowing for stakeholder input throughout the assessment. Study results are coordinated with other entities, including those embedded within the SPP footprint and neighboring first-tier entities.

The objectives of the ITP are to:

- Resolve reliability criteria violations
- Improve access to markets
- Improve interconnections with SPP neighbors
- Meet expected load-growth demands
- Facilitate or respond to expected facility retirements
- Synergize with the Generator Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Delivery Point Addition (DPA) processes
- Address persistent operational issues as defined in the scope
- Facilitate continuity in the overall transmission expansion plan
- Facilitate a cost effective, responsive and flexible transmission network

[3] https://spp.etariff.biz:8443/viewer/viewer.aspx
[4] ITP Manual version 2.14; the ITP assessment follows the current ITP Manual and versions may differ throughout the study process. The version that was current at the time of the study was used.
[5] 2023 ITP Scope version 1.0; presents the scope and schedule of work for the 2023 ITP.

1.2 REPORT STRUCTURE

This report describes the 2023 ITP assessment of the SPP transmission system for a 10-year horizon, focusing on years 2024, 2027 and 2032. SPP evaluated these years under a baseline reliability scenario and two future market scenarios (futures). The Model Development and Benchmarking (section 2) summarize modeling inputs and address the concepts behind this study's approach, key procedural steps in analysis development and overarching study assumptions. The Needs Assessment through Project Recommendations (sections 3-0) address specific results, describe projects that merit consideration, and contain portfolio recommendations, benefits and costs. The Informational Portfolio Analysis (section 6) summarizes additional benefits and sensitivities related to the portfolio.

Any reference to the SPP footprint refers to the Balancing Authority Area, as defined in the Tariff, whose transmission facilities are under the functional control of the SPP regional transmission organization (RTO), unless otherwise noted. The study was guided by the 2023 ITP Scope and SPP ITP Manual. All reports and documents referenced in this report are available on the SPP website.[6]

Both SPP's staff and stakeholders frequently exchange proprietary information in the course of any study, and such information is used extensively for ITP assessments. 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

Stakeholders developed the 2023 ITP assumptions and procedures in meetings throughout 2021, 2022, and 2023. Members, liaison members, industry specialists and consultants discussed the assumptions and facilitated a thorough evaluation.

The following SPP organizational groups were involved:

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

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[6] 2023 ITP Scope version 1.0 and ITP Manual version 2.14

SPP staff served as facilitators for these groups and worked closely with stakeholders to ensure all views were heard and considered, consistent with the SPP value proposition.

These working groups tendered policy-level considerations to the appropriate organizational groups, including the MOPC and SPC. Stakeholder feedback was instrumental in the refinement of the 2023 ITP.

1.3.1 PLANNING SUMMITS

In addition to the standard working group meetings and in accordance with Attachment O of the Tariff, SPP held a transmission planning summit in August 2023 to elicit further input and provide stakeholders with additional opportunities to participate in the process of discussing and addressing planning topics.[7]

[7] The 2023 Engineering Planning Summit was held on the afternoon of Wednesday, August 2, 2023. (https://www.spp.org/spp-documents-filings/?id=203134)

2 MODEL DEVELOPMENT AND BENCHMARKING

2.1 BASE RELIABILITY MODELS

2.1.1 GENERATION AND LOAD

Generation and load data in the 2023 ITP base reliability models was incorporated based on specifications documented in the ITP Manual. For items not specified in the ITP Manual, SPP followed the SPP Model Development Advisory Group (MDAG) Procedure Manual.[8] Renewable dispatch amounts are based on historical averages for resources with long-term firm transmission service for the summer and winter seasons. For the light load models, all wind resources with long-term firm transmission service were dispatched to the lesser of the full long-term firm transmission service amount or nameplate amount, with remaining generation coming from conventional resources. In these base reliability models, all entities are required to meet their non-coincident peak demand with firm resources.

The Powerflow Model benchmarking section details the generation dispatch and load in the base reliability models.

2.1.2 TOPOLOGY

Topology data in the 2023 ITP base reliability models includes the existing transmission system, NTC/NTC-C's, outage data according to TPL Standards and the 2021 ERAG MMWG model set with updates from First Tier External Areas. For items not specified in the ITP Manual, SPP followed the MDAG Model Development Procedure Manual. The topology for areas external to SPP was consistent with the 2021 Eastern Interconnection Reliability Assessment Group Multi-regional Modeling Working Group (MMWG) model series.

2.1.3 SHORT-CIRCUIT MODEL

A short-circuit model representative of the year-two, summer peak, was developed for short-circuit analysis. This short-circuit model has all modeled generation and transmission equipment in service to simulate the maximum available fault current, excluding exceptions such as normally open lines or

[8] Model Development Advisory Group (MDAG) Procedure Manual; the MDAG Procedure Manual may differ throughout the study process. The version that was current at the time of the study was used.

retired generation. This model was analyzed in consideration of the North American Electric Reliability Corporation (NERC) TPL-001 standard.[9]

2.2 MARKET MODEL INPUTS

2.2.1 MODEL ASSUMPTIONS AND DATA

2.3.1.1 FUTURES DEVELOPMENT

The ESWG developed two futures with input from the Strategic Planning Committee (SPC) and TWG. The MOPC reviewed both futures in October 2021.

2.2.1.1.1 FUTURE 1: REFERENCE CASE

The reference case future will reflect the continuation of the current industry trends and environmental regulations. For years 5 and 10, subject to review from generator owners, coal generators over the age of 56 will be retired, while gas fired and oil generators over the age of 50 years will be retired. Exceptions will be allowed based on stakeholder-submitted, utility-specific integrated resource plans (IRP). Long-term industry forecasts will be used to determine coal prices. Natural gas prices will be determined per the ITP Manual. Solar and wind additions will exceed current renewabled portfolio standards (RPS) due to economics, public appeal, and current trends reflected in historical renewable installations and Generator Interconnection (GI) requests. Battery energy storage resources will also be included relative to the approved solar amounts.

2.2.1.1.2 FUTURE 2: EMERGING TECHNOLOGIES

The emerging technologies future will be driven primarily by the assumption that electrical vehicles and distributed generation will impact energy growth rates. Coal generators over the age of 52 will be retired, while gas-fired and oil generators over the age of 48 will be retired. Exceptions will be allowed as requested by generator owners and approved by the ESWG. As in the reference case future, current environmental regulations will be assumed and coal prices will use long-term industry forecasts. Natural gas prices will be determined per the ITP Manual. This future also assumes higher solar, wind, and energy storage resource additions than the reference case due to advances in technology that decrease capital costs and increase energy conversion efficiency. This future also accounts for the potential that state and/or federal policies will promote the utilization of these technologies in an effort to modernize the grid. This future will align the renewable resource potential with company IRP goals to the extent possible.

Table 2.1 summarizes the drivers and how they were considered in each future.

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[9] NERC Standard TPL-001-4 - Transmission System Planning Performance Requirements

	Drivers				
Key Assumptions	**Year 2**	**Reference Case** **Year 5**	**Year 10**	**Emerging Technologies** **Year 5**	**Year 10**
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Current forecast	Coal age-based 56+, Gas/Oil age-based 50+, subject to generator owner (GO) review		Coal age-based 52+, Gas/Oil age-based 48+, subject to GO review and ESWG approval	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[10]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		+300MW	+500MW
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Storage	None	20% of projected solar (.88 GW / 2.2 GW)		35% of projected solar (2.1 GW / 5.3 GW)	
Total Renewable Capacity					
Solar (GW)	Existing + RARs	4.4	11	5.9	15
Wind (GW)	Existing + RARs	37	41	38	46

Table 2.1: Future Drivers

2.2.1.2 LOAD AND ENERGY FORECASTS

The 2023 ITP load review focused on load data through 2032. The load data was derived from the base reliability model set, and stakeholders were asked to identify/update the following parameters:

- Assignment of loads to companies
- Forecasted system peak load (MW)
- Loss factors
- Load factors
- Load demand group assignments
- Monthly peak and energy allocations

[10] As defined in the SPP Model Development Procedure Manual: SPP Model Development Procedure Manual

- Station service loads
- Resource planning peak loads and load factors

The ESWG and TWG approved load review was used to update the load information in the market economic models. Figure 2.1 shows the total coincident peak load for all study years. Figure 2.2 shows the monthly energy and annual coincident peak per future for all study years (2024, 2027, and 2032).

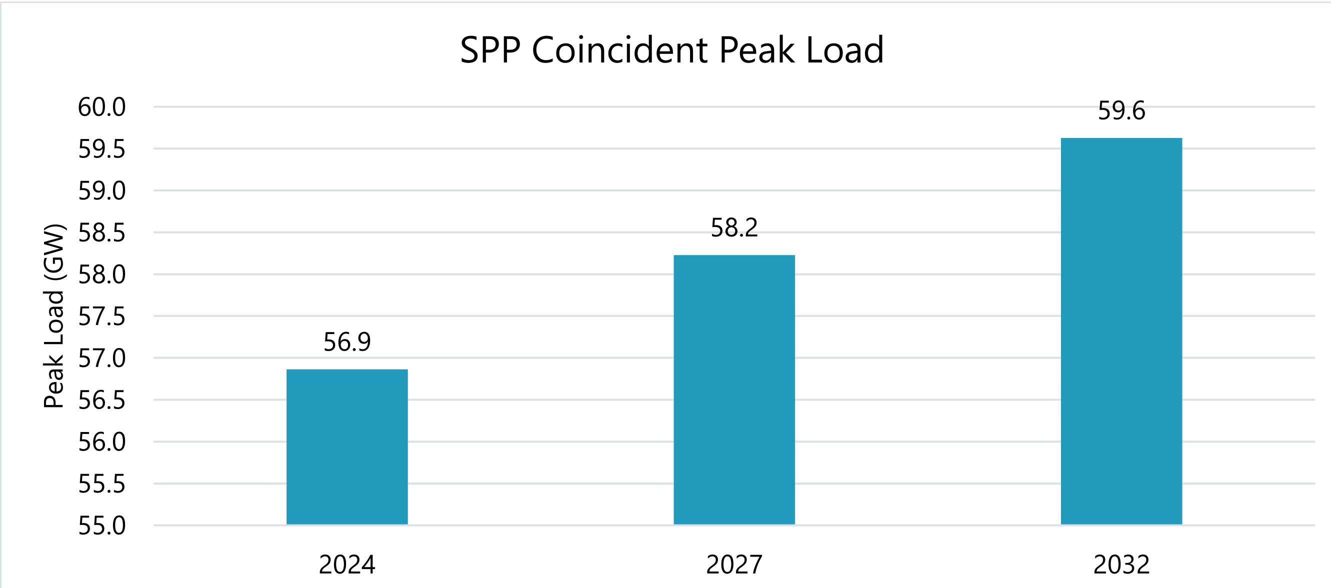

Figure 2.1: Coincident Peak Load

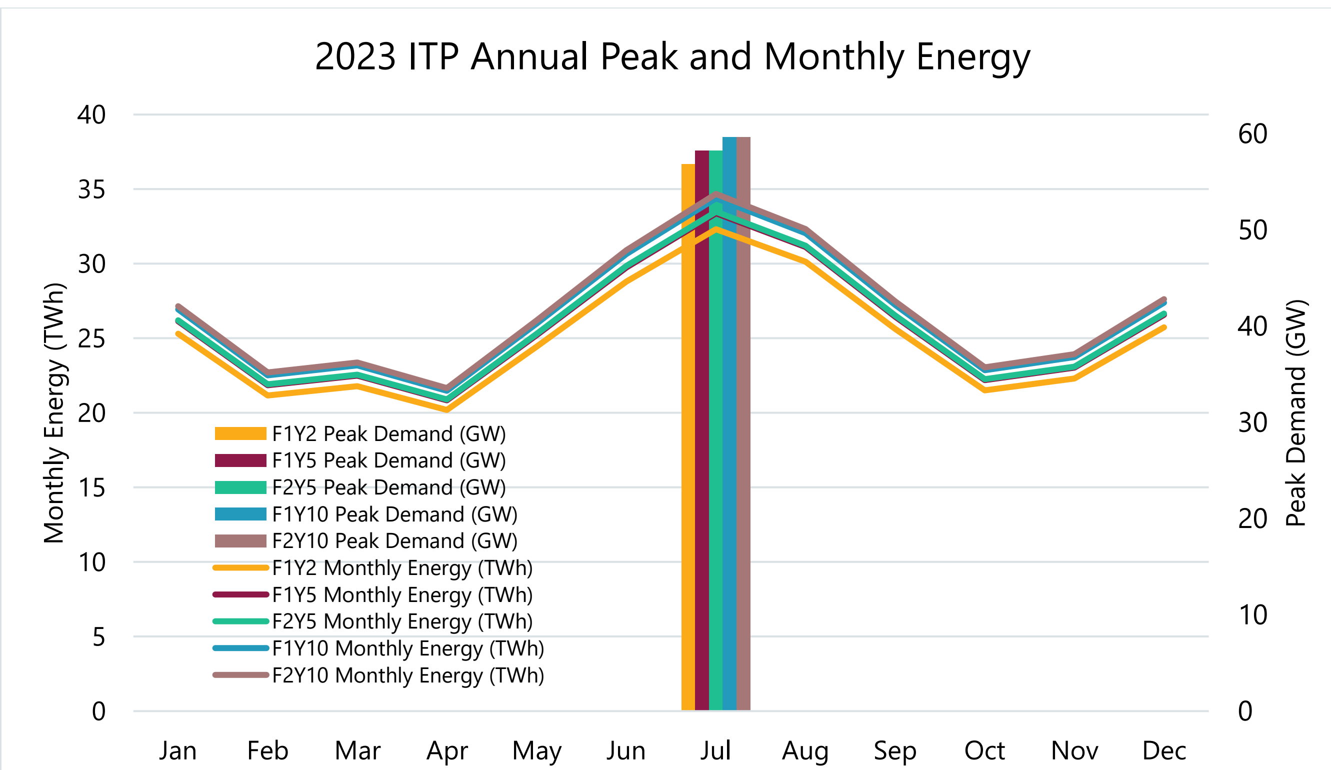

Figure 2.2: 2023 ITP Annual Peak and Monthly Energy

2.2.1.3 RENEWABLE POLICY REVIEW

Renewable policy requirements enacted by state laws, public power initiatives and courts are the only public policy initiatives considered in this ITP via the renewable policy review (RPR). The 2023 ITP Scope defines and outlines these requirements as percentages and the renewable policy standards (RPS) shown below in Table 2.2 were approved by ESWG. The 2023 ITP RPR focused on renewable requirements through 2032.

State	RPS Type	Generation Type[11]	Capacity- or Energy- Based	Year 5 Percent	Year 10 Percent
Kansas	Goal	Both	Capacity (MW)	20%	20%
Minnesota	Mandate	Both	Energy (MWh)	25%	25%
Missouri	Mandate	Both	Energy (MWh)	15%	15%
North Dakota	Goal	Both	Energy (MWh)	10%	10%
New Mexico	Mandate	Both	Energy (MWh)	40%	50%
South Dakota	Goal	Both	Energy (MWh)	10%	10%
Texas	Mandate	Both	Capacity (MW)	5%	5%

Table 2.2: Renewable Policy Review Table

2.2.1.4 GENERATION RESOURCES

Existing generation data originated from the Hitachi Simulation Ready Data Fall 2020 Reference Case and was supplemented with SPP stakeholder information provided through the SPP Model on Demand tool and the generation review.

Figure 2.3 and Figure 2.4 detail the annual nameplate capacity and energy by unit/fuel type, respectively for 2024, 2027 and 2032 for Future 1, and 2027 and 2032 for Future 2.

In addition to resources accepted in the base reliability models, stakeholders were given the chance to request additional generation resources in the ITP models through the Resource Addition Request (RAR) process. As a result of the RAR process, 5.68 GW of wind generation and 250 MW of solar generation was added to the market economic models.

Generator operating characteristics, such as operating and maintenance (O&M) costs, heat rates and energy limits were also provided for stakeholders to review.

[11] A generation type of "Both" indicates that it can be met by wind and/or solar.

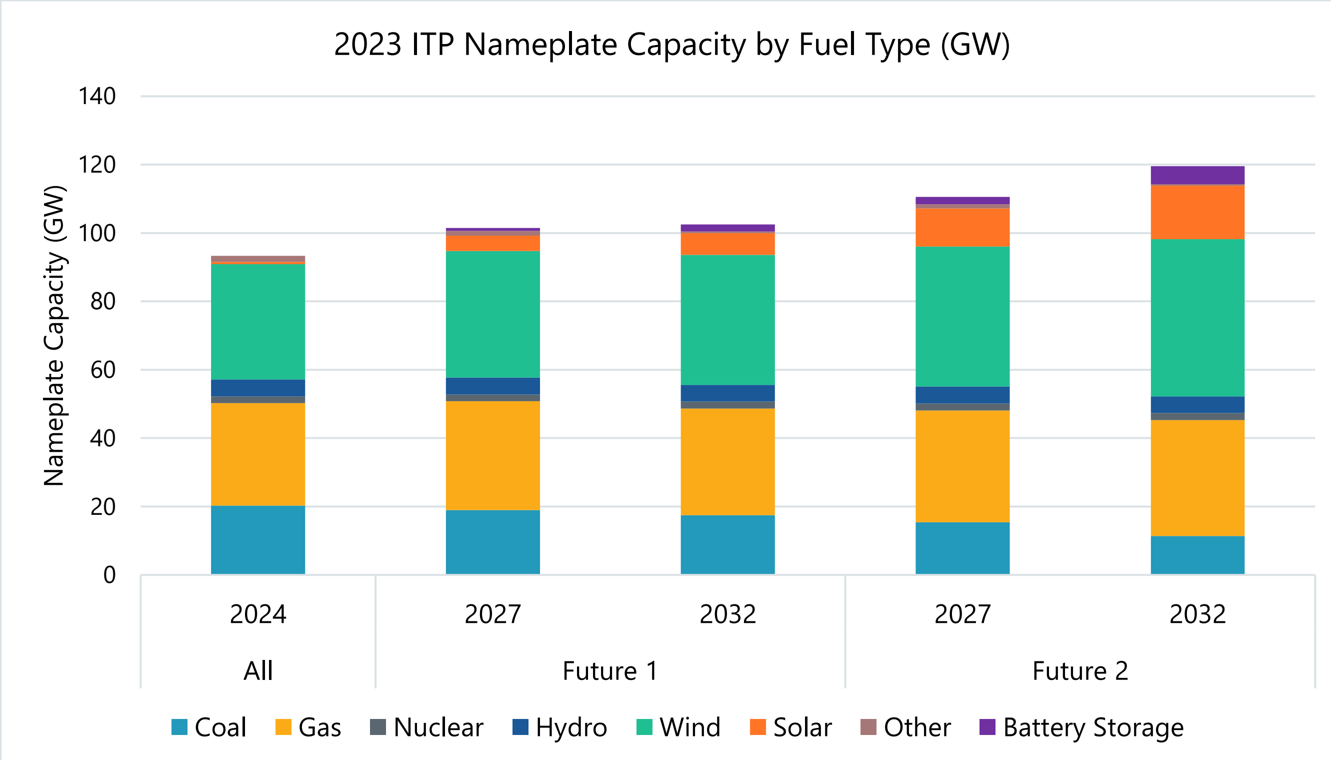

Figure 2.3: Nameplate Capacity by Fuel Type

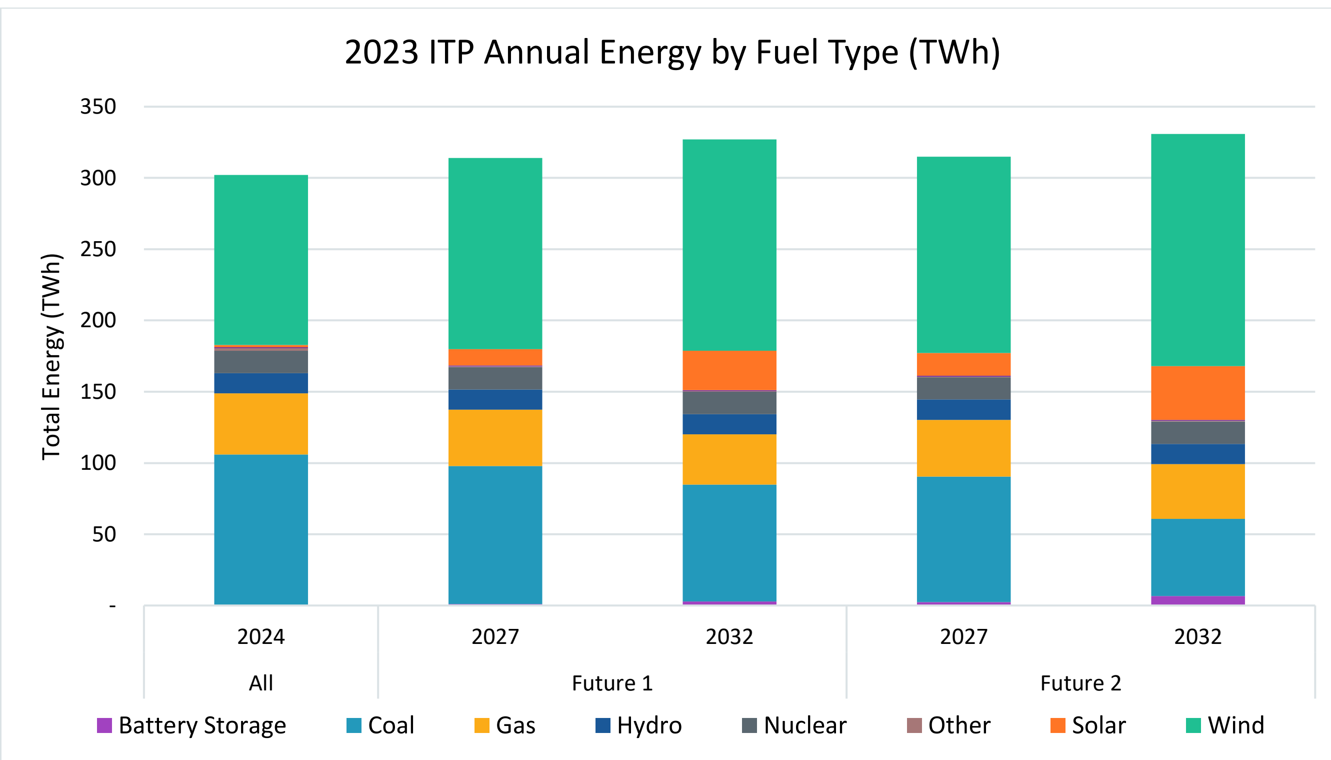

Figure 2.4: Annual Energy by Fuel Type (TWh)

Figure 2.5 dentifies the amount of retired conventional generation compared to retirements identified in the base reliability models. The figure reflects the final set of retirements based on the approved futures assumptions.

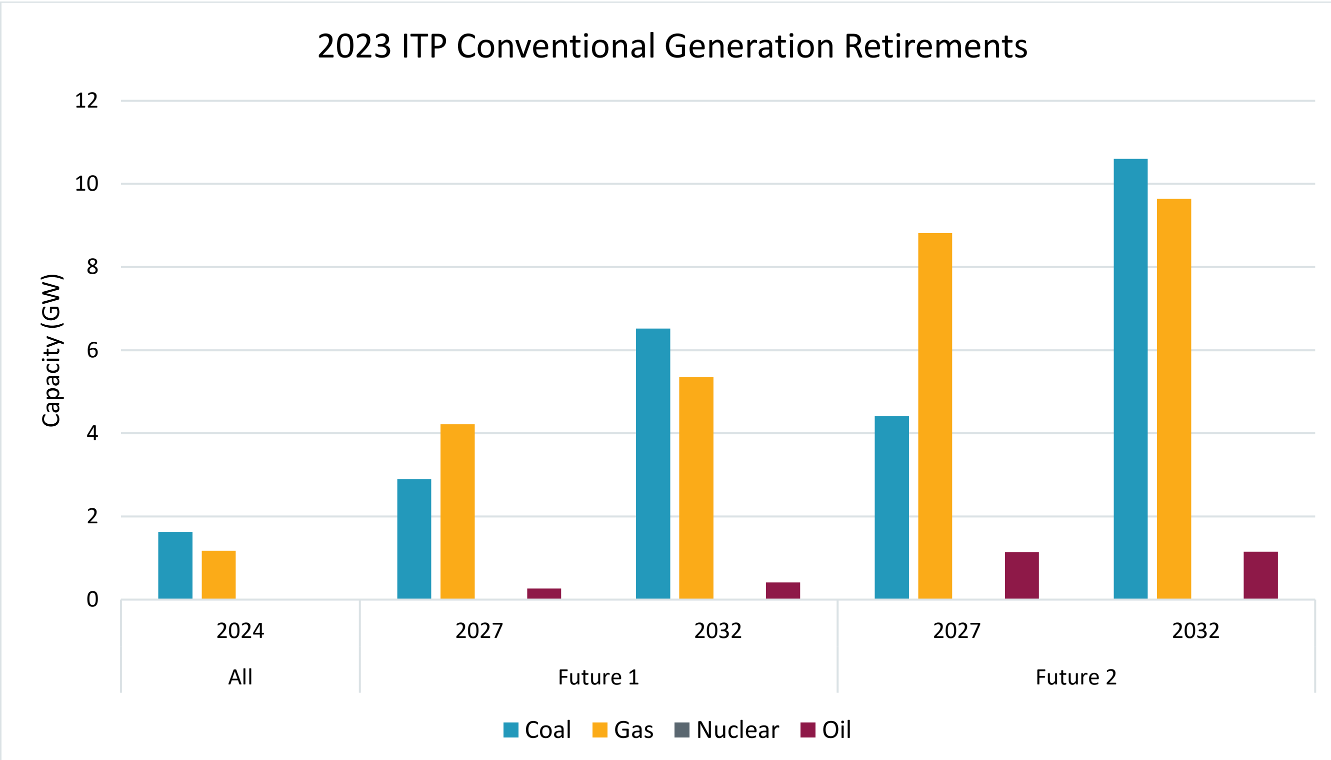

Figure 2.5: Conventional Generation Retirements (GW)

2.2.1.5 *FUEL PRICES*

The Hitachi Simulation Ready Data Fall 2020 Reference Case, Hitachi fundamental forecast (for long-term natural gas price projections), and Wood Mackenzie fundamental forecast (for long-term natural gas price projections) were utilized for the fuel price forecasts. An average of the Hitachi and Wood Mackenzie fundamental forecasts were calculated for use in this study.

Figure 2.6 shows the annual average natural gas and coal prices for the study horizon. Between 2023 and 2033,these prices increase from $4.56 to $5.03 (~1% compound average escalation) and $2.39 to $3.03
(~2.1% compound average escalation) for natural gas and coal, respectively.

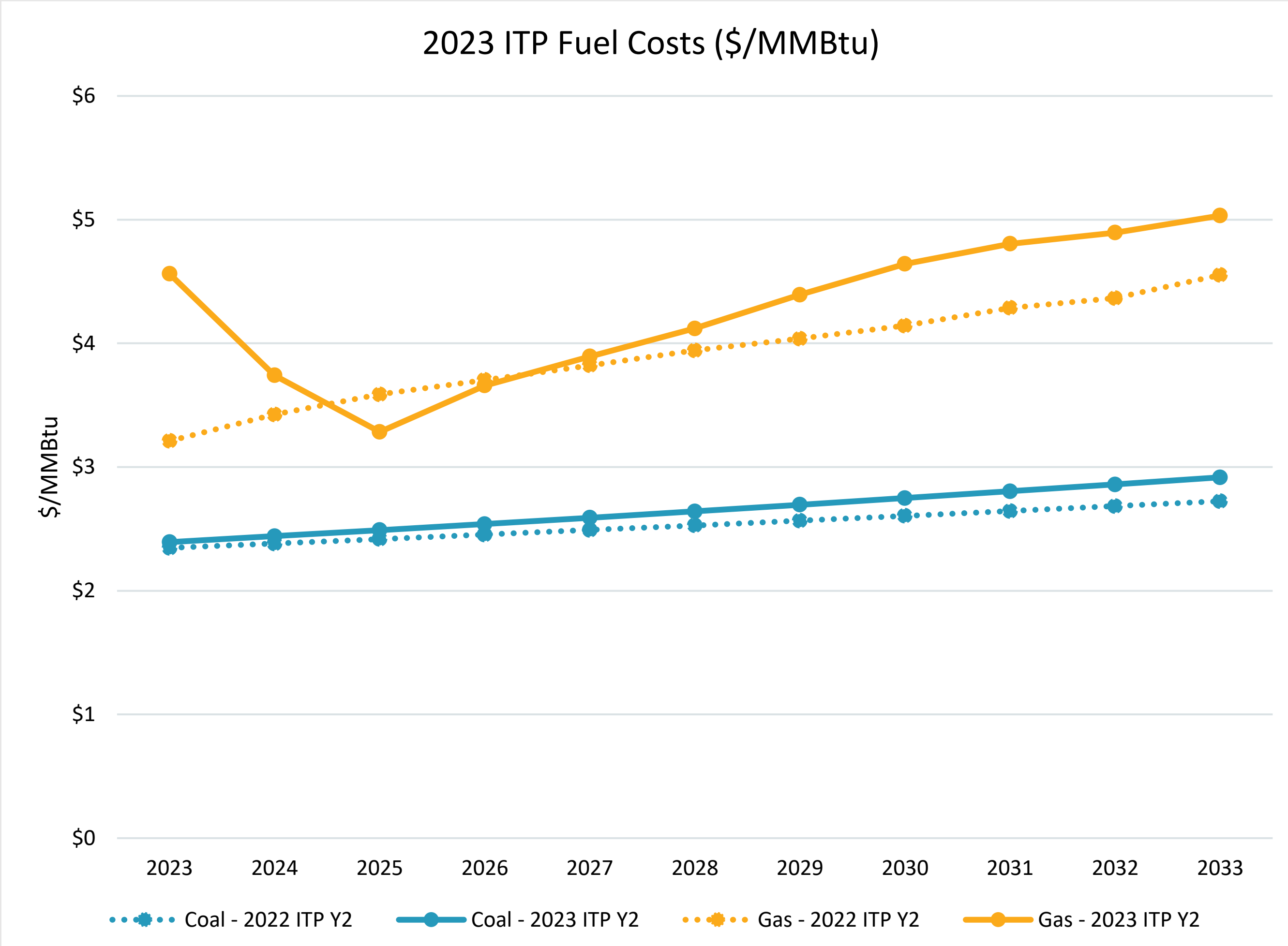

Figure 2.6: Fuel Annual Average Fuel Price Forecast

2.2.2 RESOURCE PLAN

A key component to evaluate the transmission for a 10-year horizon is identifying the resource outlook for each future. The SPP generation portfolio will not be the same in 10 years, due to the changing load forecasts, resource retirements and fast-changing mix of renewable resource additions. SPP developed resource expansion plans to meet renewable portfolio standards, resource reserve margin requirements, and future specific renewable and emerging technology projections.

2.2.2.1 *RENEWABLE RESOURCE EXPANSION PLAN*

SPP analyzed each utility to determine if the assumed renewable mandates and goals identified by the renewable policy review could be met with existing generation and initial resource projections for 2027 and 2032. If the analysis projected a utility would be unable to meet requirements, additional resources were assigned from the total projected renewable amounts to those utilities enabling them to meet renewable portfolio standards. For states with a standard that could be met by either wind or solar generation, a ratio of 50% wind additions to 50% solar additions was utilized. This split was representative of the active GI queue requests for wind and solar resources.

The incremental renewables assigned to meet renewable mandates and goals in the SPP footprint by 2032 were 417.8 MW in Future 1 and 432.8 MW in Future 2.

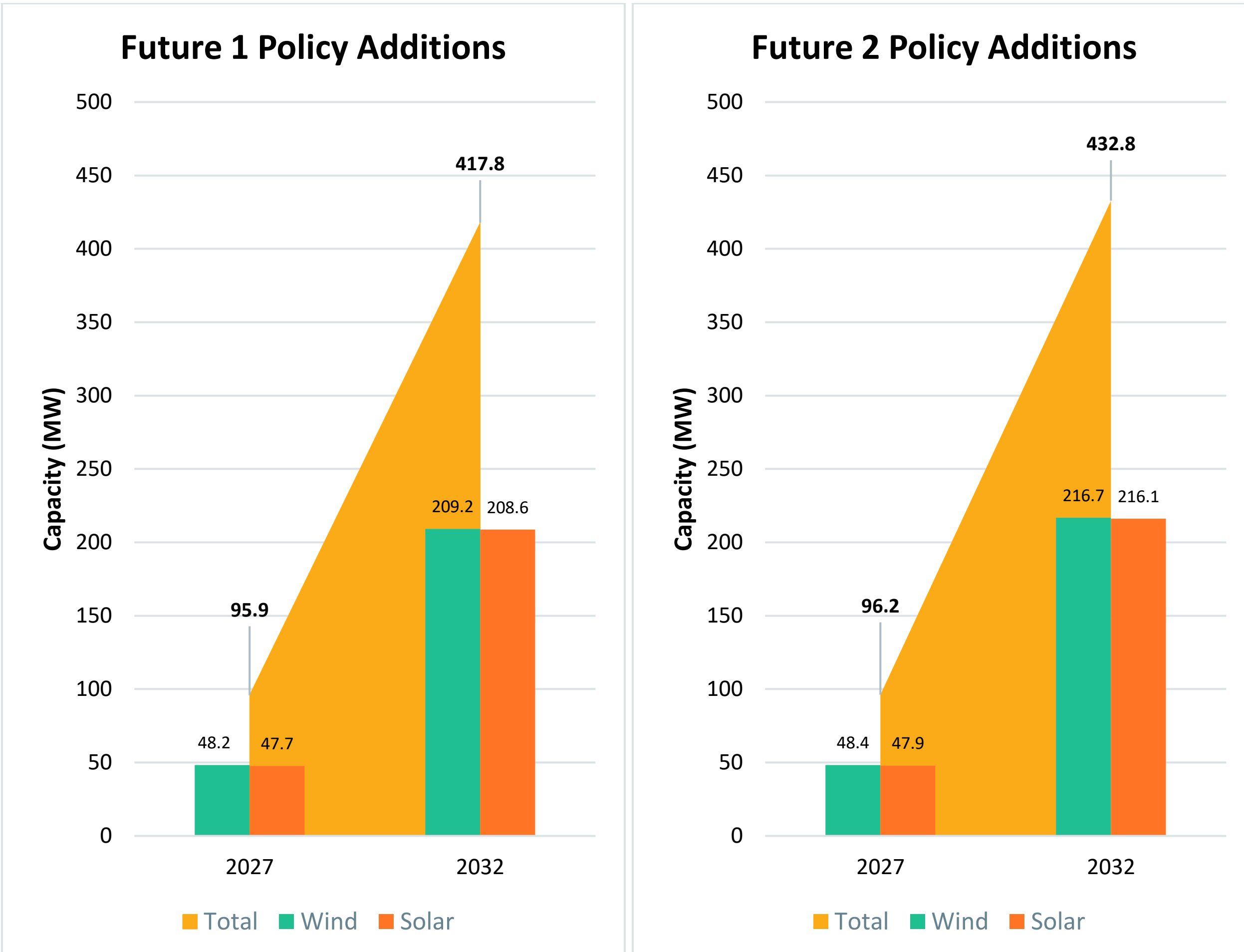

Figure 2.7: SPP Renewable Generation Assignments to meet Mandates and Goals

After SPP ensured renewable portfolio standards were met by assigning renewables, they accredited the remaining projected renewable capacity to each pricing zone.

SPP assigned projected solar additions based on the load-ratio share for each pricing zone. SPP also accredited projected wind additions to deficient zones to maximize the available accreditation of renewables for each zone. Resources were accredited in the following order:

- Existing generation
- Policy wind and solar additions
- Projected solar additions
- Projected storage additions
- Projected wind additions
- Conventional additions

2.2.2.2 CONVENTIONAL RESOURCE EXPANSION PLAN

SPP used the renewable resource expansion plan for each future as an input to the corresponding conventional resource expansion plan to ensure appropriate resource adequacy within the SPP footprint.

Utilities that did not meet the 12% planning reserve margin requirement set by SPP Planning Criteria[12] also received capacity from the conventional resource plan. SPP calculated projected reserve margins for each pricing zone using existing generation, future-specific retirements, projected renewable generation, fleet power purchase agreements, and load projections through 2040. Each zone that was not yet meeting its minimum reserve requirement was assigned conventional resources in 2027 and 2032 for both futures.

Nameplate conventional generation capacity assigned to pricing zones was counted toward each zone's capacity margin requirement.

For the 2023 ITP, SPP determined total accreditation values for wind, solar and energy storage by each resource type's effective load-carrying capability (ELCC). The ELCC is defined by SPP's Resource Adequacy department based upon the nameplate values from the 2023 ITP scope. ELCC identifies the capacity value of resources by determining the amount of load the resources will be able to serve during peak hours. These accreditation amountsare shown below in MW in Table 2.3.

Resource Type	F1 Y5		F1 Y10		F2 Y5		F2 Y10	
	Scoped Amount	ELCC Amount	Scoped Amount	ELCC Amount	Scoped Amount	ELCC Amount	Scoped Amount	ELCC Amount
Wind	35,892	5,476	39,892	5,854	36,892	5,570	44,892	6,327
Solar	4,400	2,919	11,000	6,411	5,900	4,122	15,000	8,047
Energy Storage	880	869	2,200	2,097	2,065	1,983	5,250	4,210

Table 2.3: 2023 Total Accreditation for Wind, Solar and Energy Storage (MW)

Before giving each zone accreditation from the renewable resource plan, the ELCC amounts were reduced by the amount of firm service determined in the generation review. Remaining amounts of accreditation were awarded one MW at a time to each zone until no additional accreditation was available, zones reached their required planning reserve margin, or zones reached their renewable capacity cap of 12%. If a zone did not ultimately meet its planning reserve margin, it was identified as a zonal shortfall and designated to be assigned conventional capacity from the Conventional Resource Plan.

In the analysis of future conventional capacity needs, available resource options were combined cycle (CC) units or fast-start combustion turbine (CT) units. SPP utilized generic resource prototypes from the

[12] SPP Planning Criteria v.4.2

U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2021. These resource prototypes define operating parameters of specific generation technologies to determine the optimal generation mix to add to the region. For the 2023 ITP, the ESWG approved a motion waiving the requirement of a third party software to identify the conventional resource needs, as well as designating the CT units be the standard resource added to each zone. The ESWG also allowed a zone to request a CC replace multiple CTs contingent upon the ESWG's approval.

The ESWG granted one exception request (for SPS in year 5 for both Future 1 and Future 2) to replace CT additions with a CC.

While both futures represent normal load growth, more resource additions are needed in Future 2 primarily due to the additional unit retirements.

Table 2.4 shows the total nameplate conventional generation additions by zone, future and study year to meet futures definitions and resource adequacy requirements. To limit unnecessary conventional resource additions, SPP identified some zones as sharing capacity from the conventional resource plan. For zones with shared units, the zone with the highest percentage of ownership was identified for the siting milestone.

Zone	Conventional Generation Additions			
	F1 Y5	F1 Y10	F2 Y5	F2 Y10
AEPW	0	0	2370	2844
GRDA	0	0	0	0
OKGE	1422	1422	1422	1422
SPS	0	1083	0	1083
WFEC	0	474	237	237
SPRM	0	0	0	0
EMDE	0	0	0	0
GMO	474	474	474	711
KCPL	0	0	711	1066.5
MIDW	0	237	0	118.5
SUNC	0	0	0	0
WERE	0	711	474	2133
LES	0	0	0	0
NPPD	0	0	0	0
OPPD	948	948	948	1422
UMZ	948	1659	1185	1422
SWPA	0	0	0	0

Table 2.4: Total Nameplate Conventional Generation Additions by Zone, by Future and Study Year

Figure 2.8 shows nameplate generation additions by future, study year and technology for the SPP region while Figure 2.9 shows accredited generation. These values are not incremental.

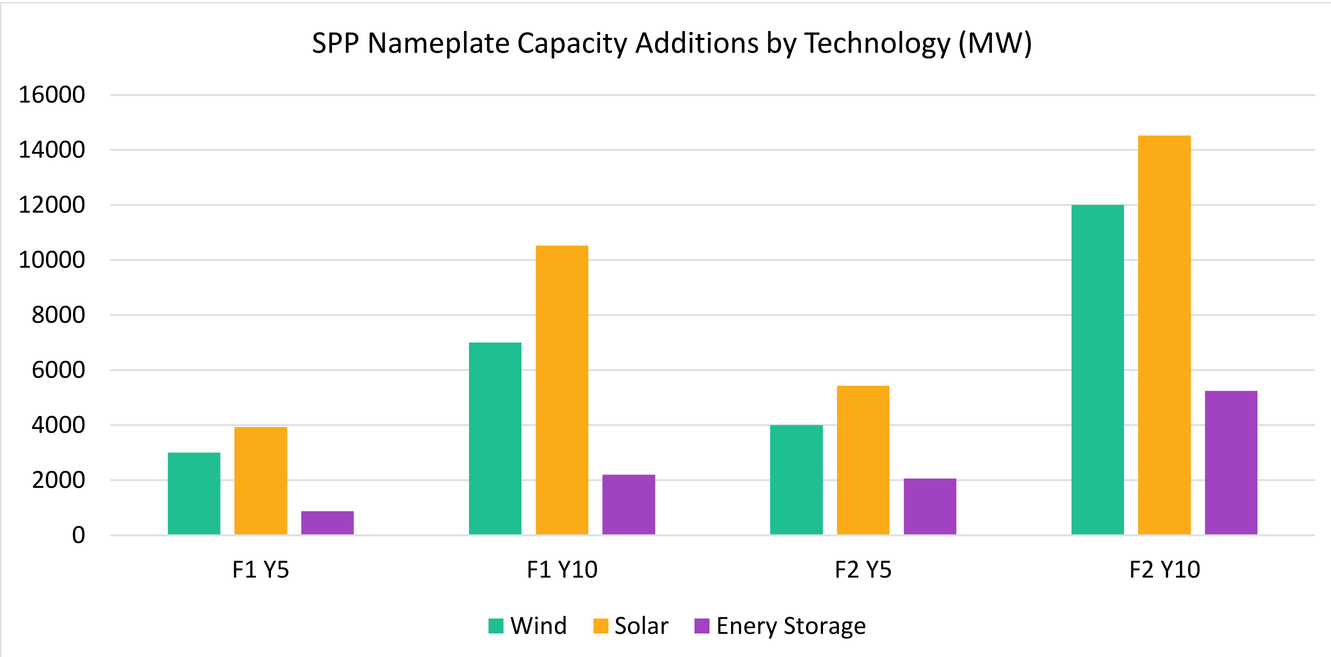

Figure 2.8: SPP Nameplate Capacity Additions by Technology (MW)

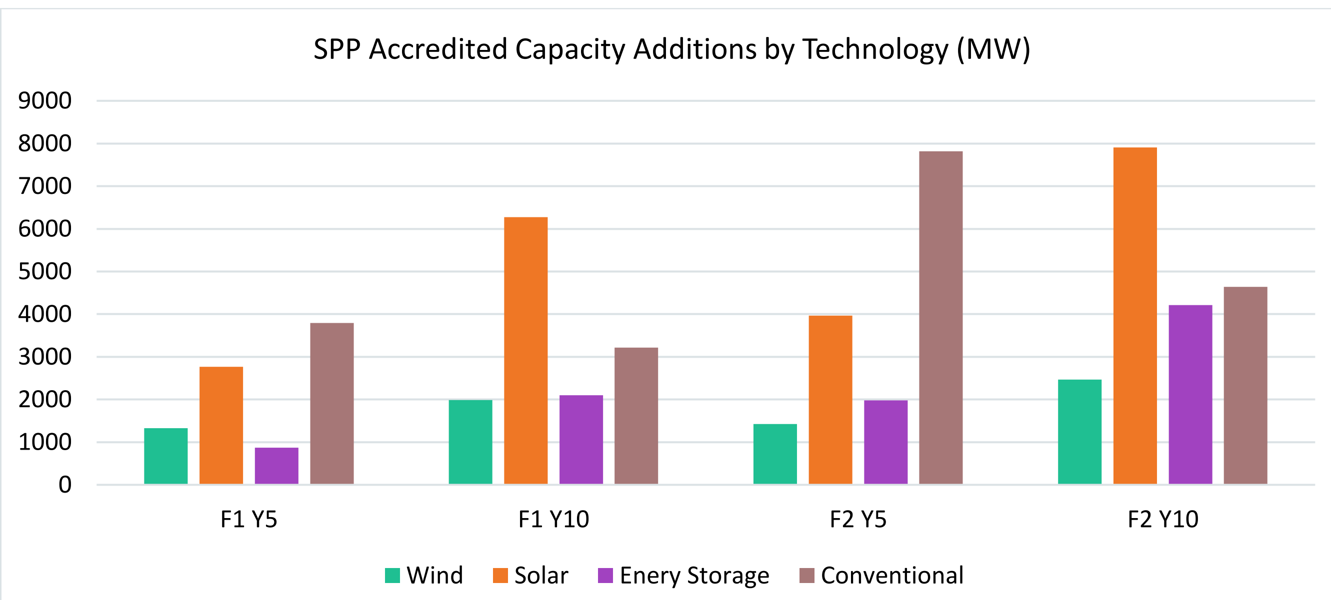

Figure 2.9: Accredited Capacity Additions by Technology (MW)

2.2.2.3 *SITING PLAN*

SPP sited projected renewable and conventional resources according to various site attributes for each technology in accordance with the ITP Resource Siting Manual.[13]

Utility-scale solar was sited according to:

- Allocated generation to each zone as determined by the load-ratio share method
- Data Source (given preference in the following order)
    - SPP and Integrated System (IS) GI queue requests
    - Stakeholder submitted sites
    - Previous ITP sites
    - Other National Renewable Energy Laboratory (NREL) conceptual sites
- Capacity factor
- Generator transfer capability of the potential sites

Following the implementation of this ranking criteria, stakeholders could request exceptions to the results, which SPP reviewed for potential inclusion in the siting plan. Figure 2.10 through Figure 2.13 show the selected siting and allocation of utility solar capacity across the SPP footprint in megawatts.

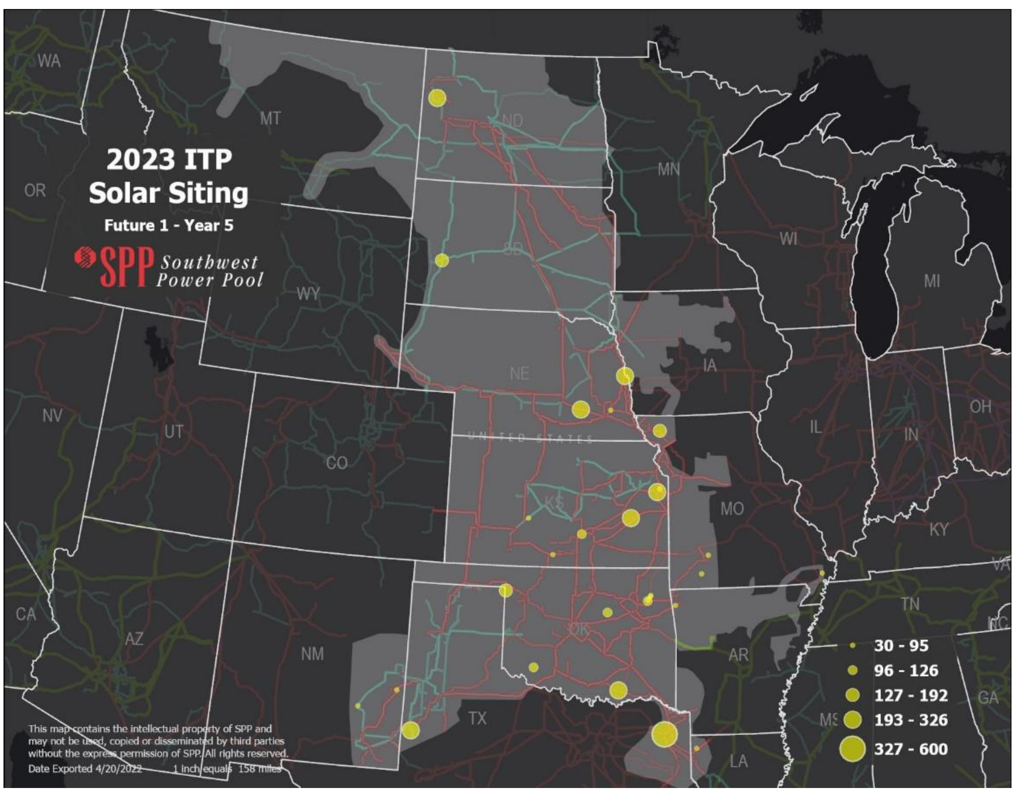

Figure 2.10: Future 1 Year 5 Solar Siting

[13] Documented in the ITP Resource Siting Manual

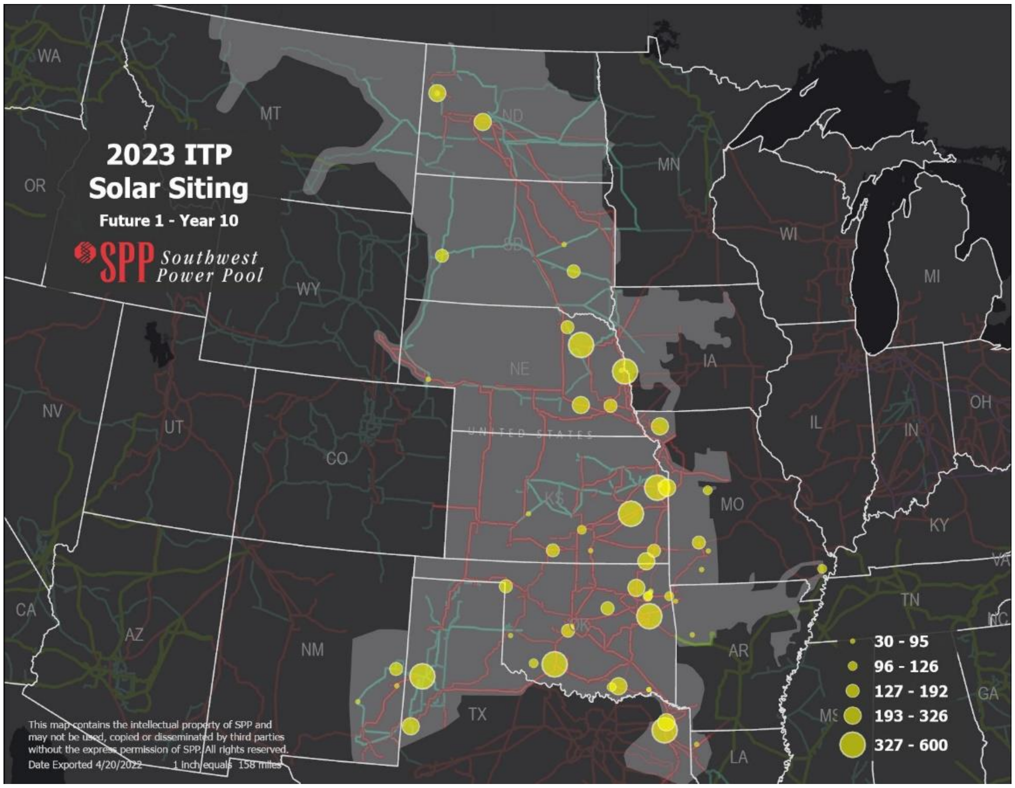

Figure 2.11: Future 1 Year 10 Solar Siting

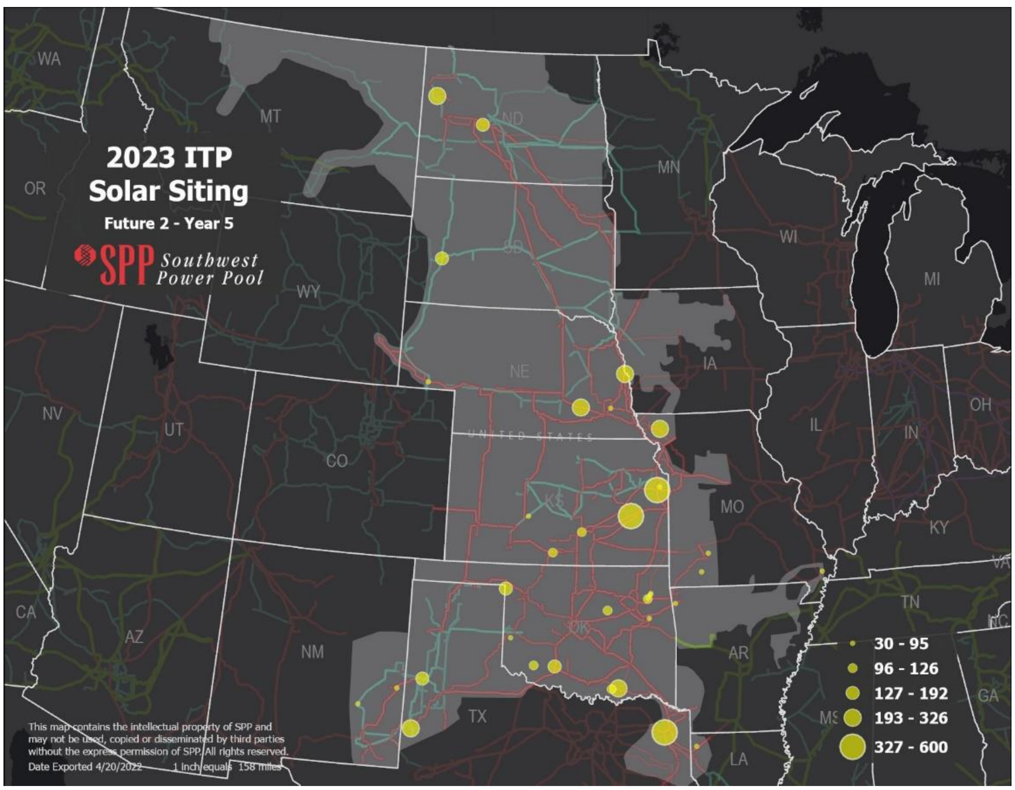

Figure 2.12: Future 2 Year 5 Solar Siting

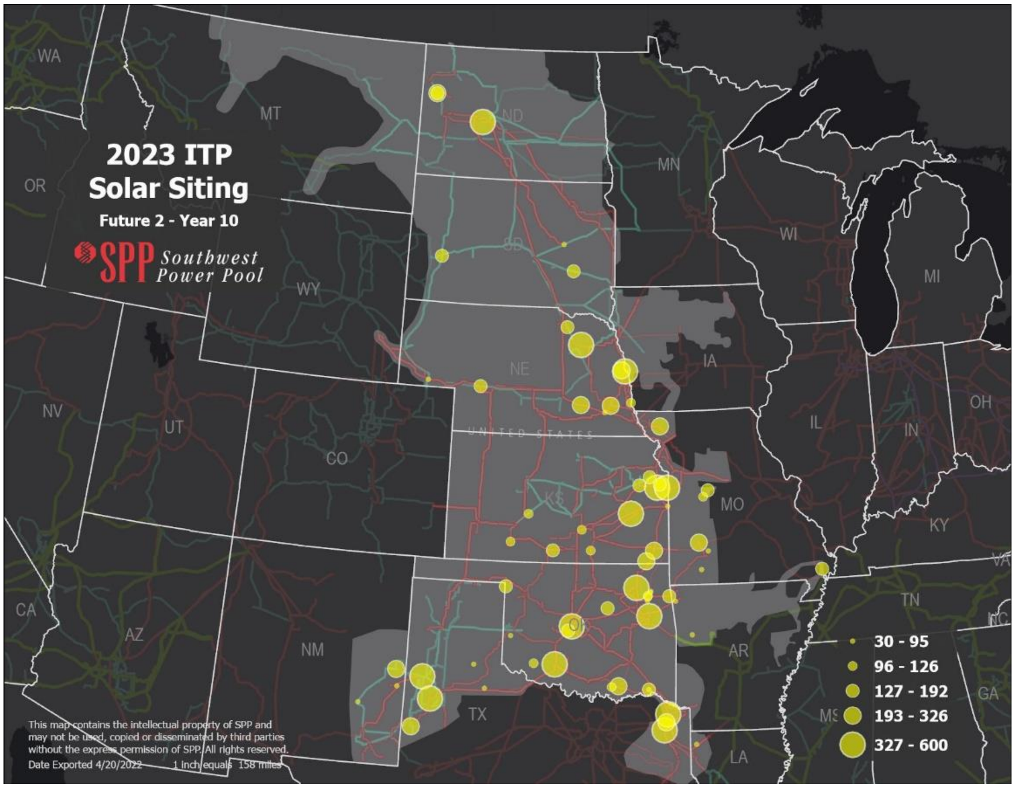

Figure 2.13: Future 2 Year 10 Solar Siting

Wind sites were selected from GI queue requests that required the lowest total interconnection cost[14] per MW of capacity requested, taking into consideration the following:

- Potentially directly-assigned upgrade needed
- Unknown third-party system impacts
- Required generator outlet facilities (GOF)
- Generator Interconnection Agreement (GIA) suspension status

GI queue requests that did not have costs assigned were also considered with respect to their generator outlet capability, scope of related GOFs needed, and relation to recurring issues within the GI grouping.

Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which SPP reviewed for potential inclusion in the siting plan. Figure 2.14 through Figure 2.17 show the selected siting and allocation of wind capacity across the SPP footprint in megawatts.

[14] The total interconnection costs include the total costs assigned for all interconnection related upgrades and network upgrades.

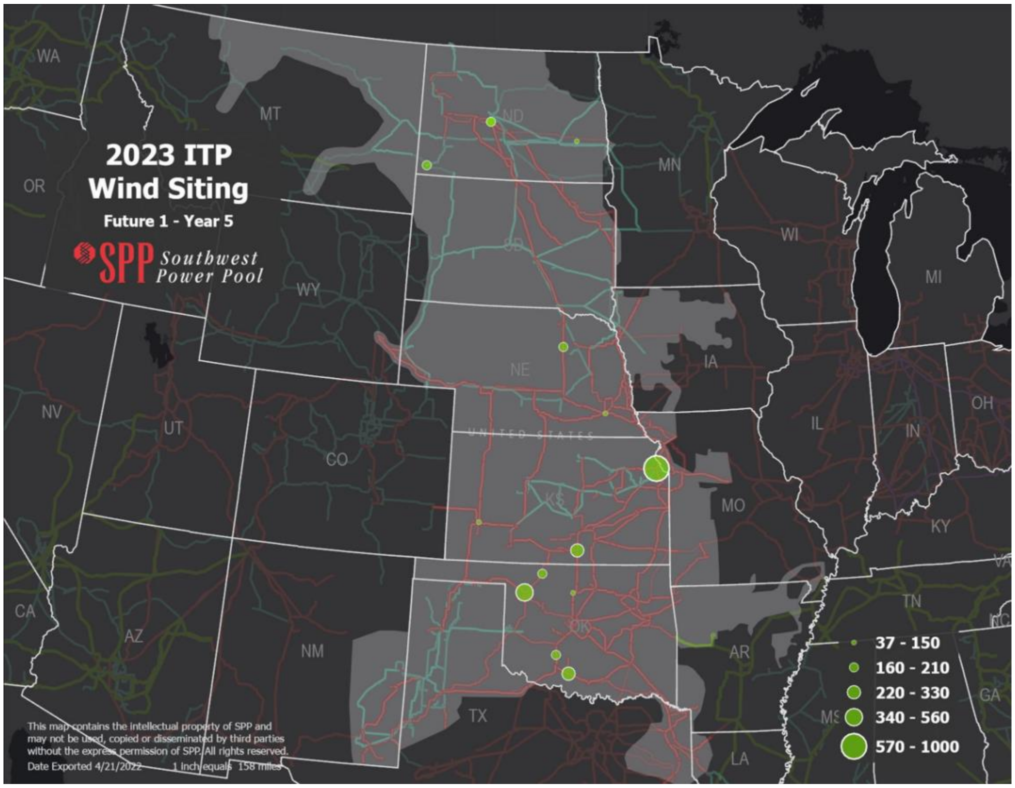

Figure 2.14: Future 1 Year 5 Wind Siting

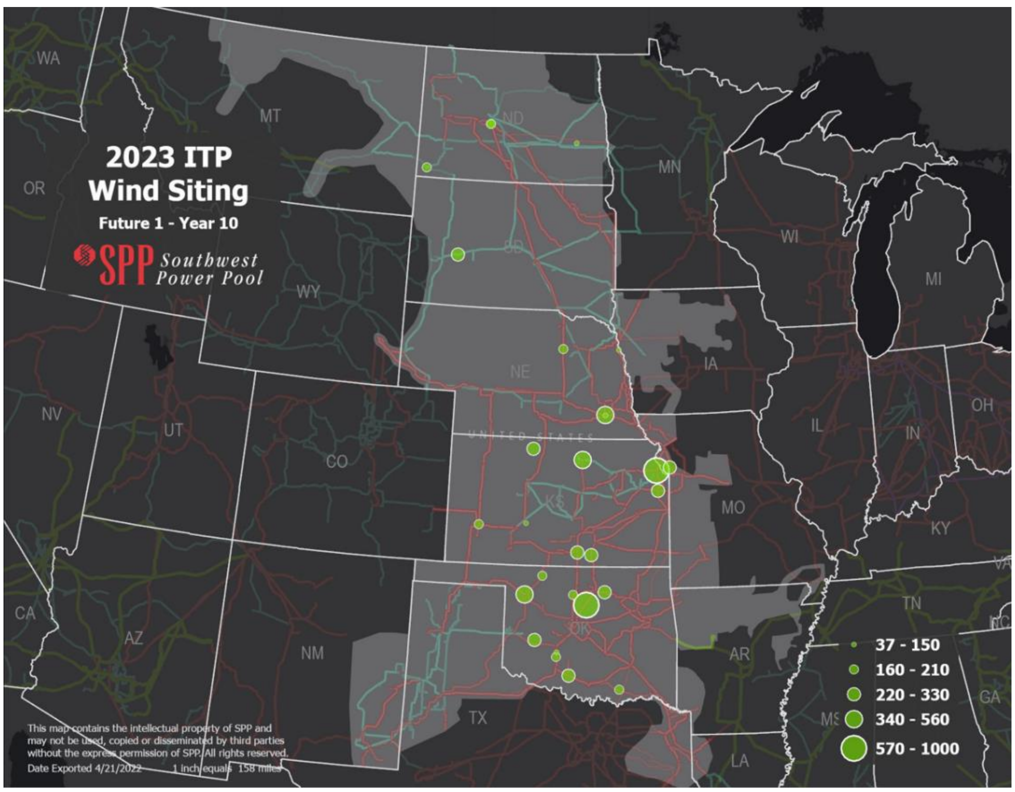

Figure 2.15: Future 1 Year 10 Wind Siting

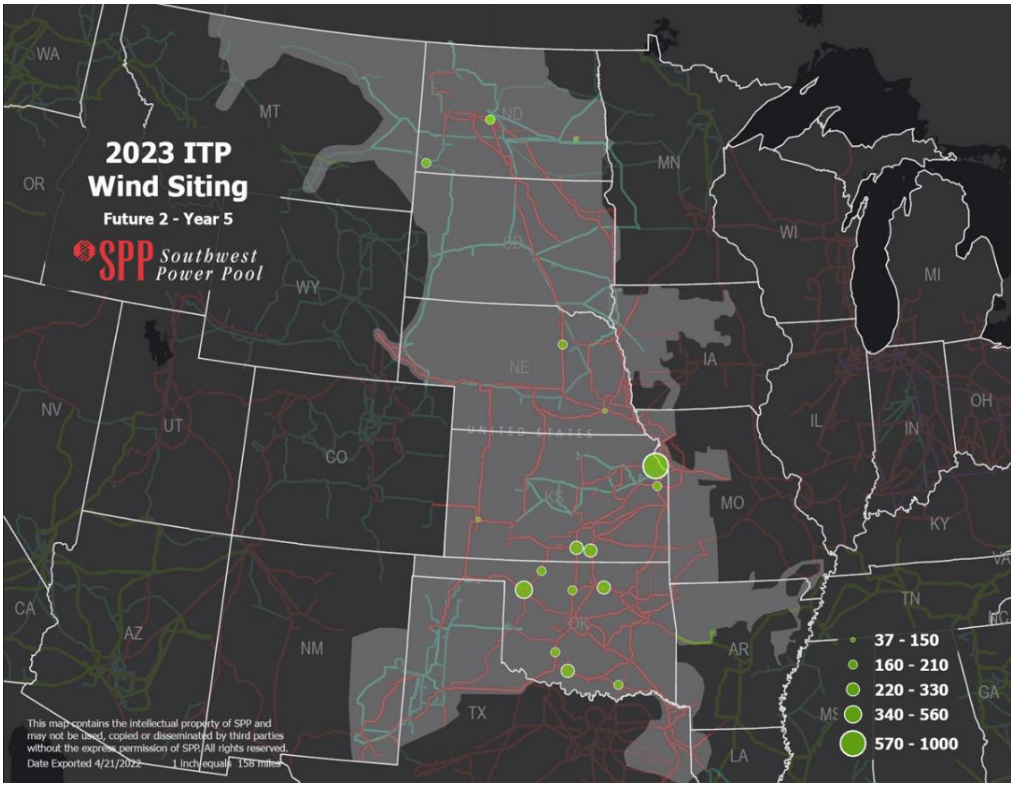

Figure 2.16: Future 2 Year 5 Wind Siting

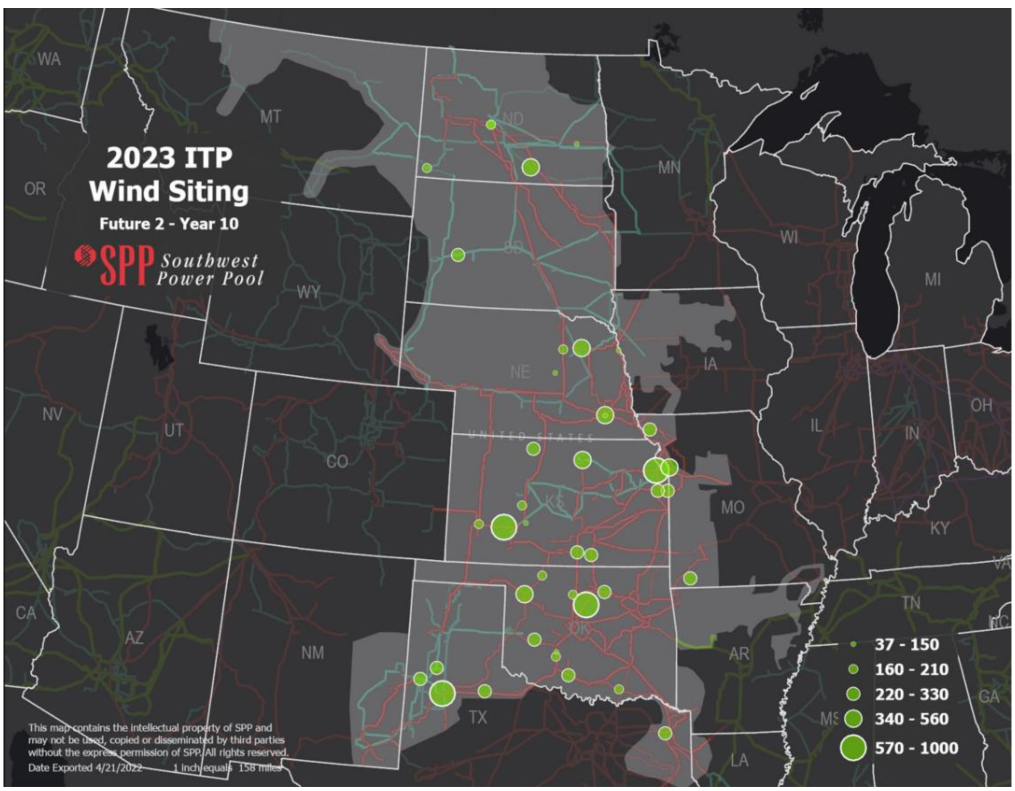

Figure 2.17: Future 2 Year 10 Wind Siting

Conventional generation was sited according to the zone of majority ownership, stakeholder preferences, generator outlet capability, scope of GOFs needed and preference for existing and assumed retirement sites over previous ITP sites. Total conventional capacity at a given site (including existing) was limited to 1,500 MW. Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which SPP reviewed for potential inclusion in the siting plan. Figure 2.18 through Figure 2.21 show the selected sites for conventional generation across the SPP footprint.

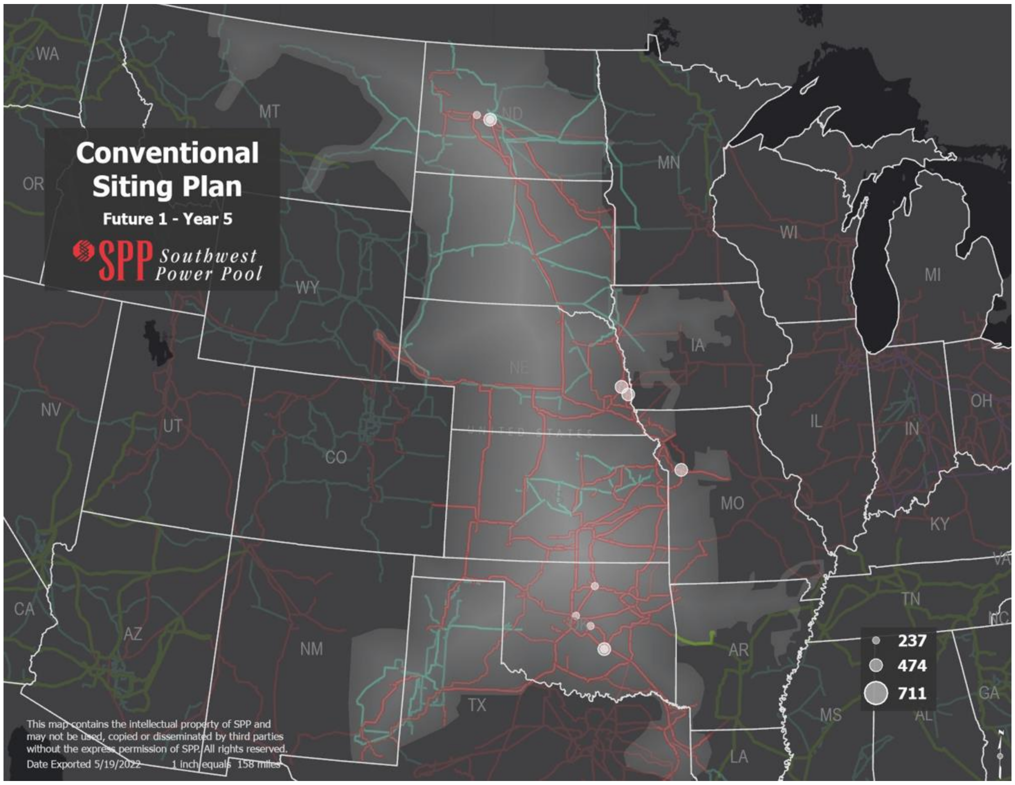

Figure 2.18: Future 1 Year 5 Conventional Siting

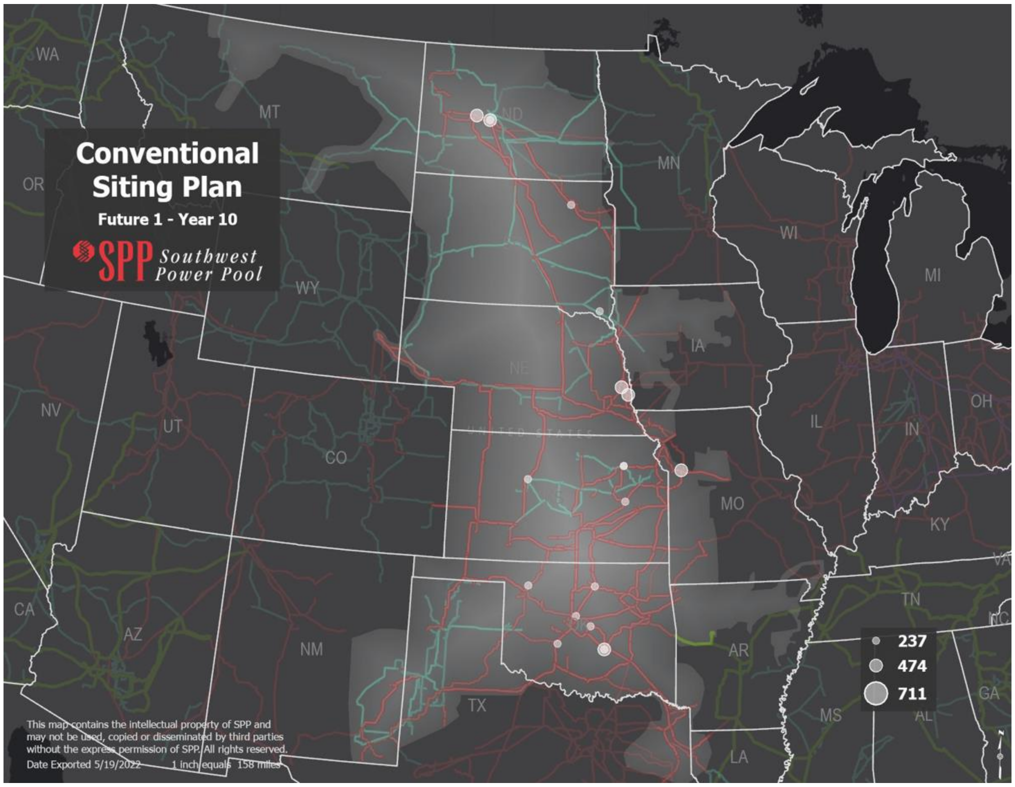

Figure 2.19: Future 1 Year 10 Conventional SIting

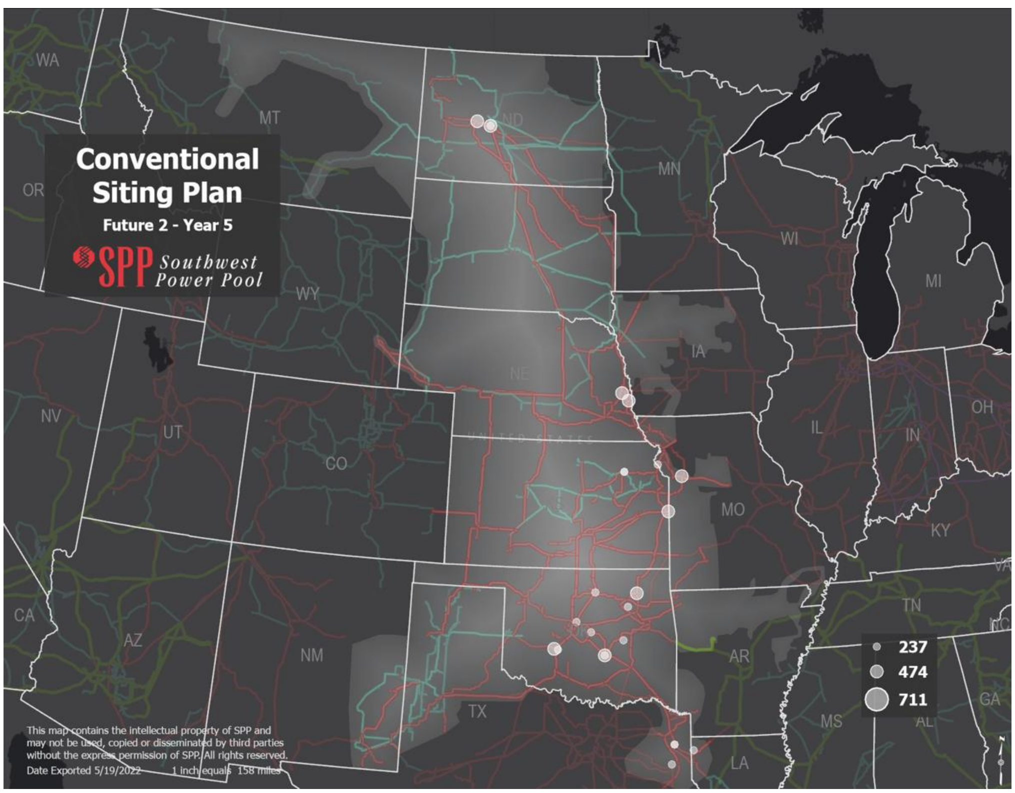

Figure 2.20: Future 2 Year 5 Conventional SIting

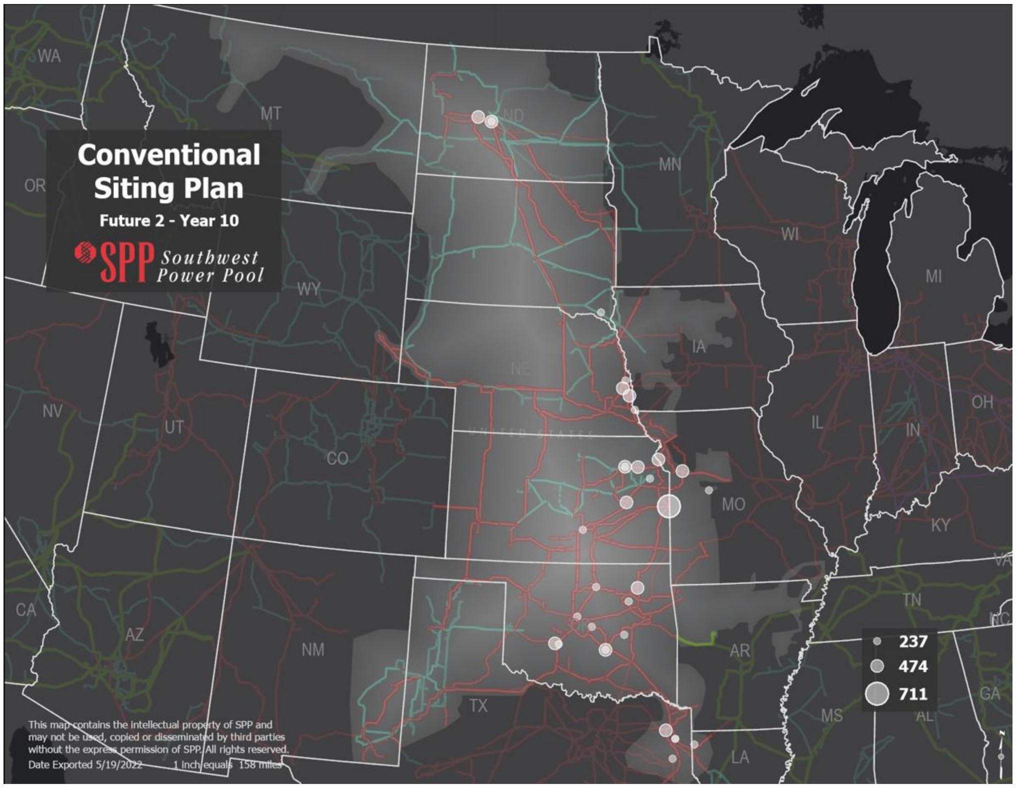

Figure 2.21: Future 2 Year 10 Conventional Siting

Battery sites were selected based on the assumption that battery storage will largely be co-located with wind and solar resources considering transfer capability at available sites that were included in the solar and wind siting plans. A percentage of the sites were also based on battery storage GI queue requests, limiting those resources to two-thirds of the overall projected battery capacity due to the infancy of the technology in the industry. Half of projected battery capacity was associated with solar sites and half was associated with wind sites, with the percentage of the capacity related to battery storage GI queue requests included in those groups where applicable. For sites associated with battery requests, sited battery amounts were capped at the queue request amounts or siting availability. For sites not associated with existing battery GI requests, battery amounts were placed at wind and solar sites in increments of 20 MW (different increments were utilized where needed) and capped at siting availability. Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which SPP reviewed for potential inclusion in the siting plan. Figure 2.22 through Figure 2.25 show the selected sites for battery generation across the SPP footprint.

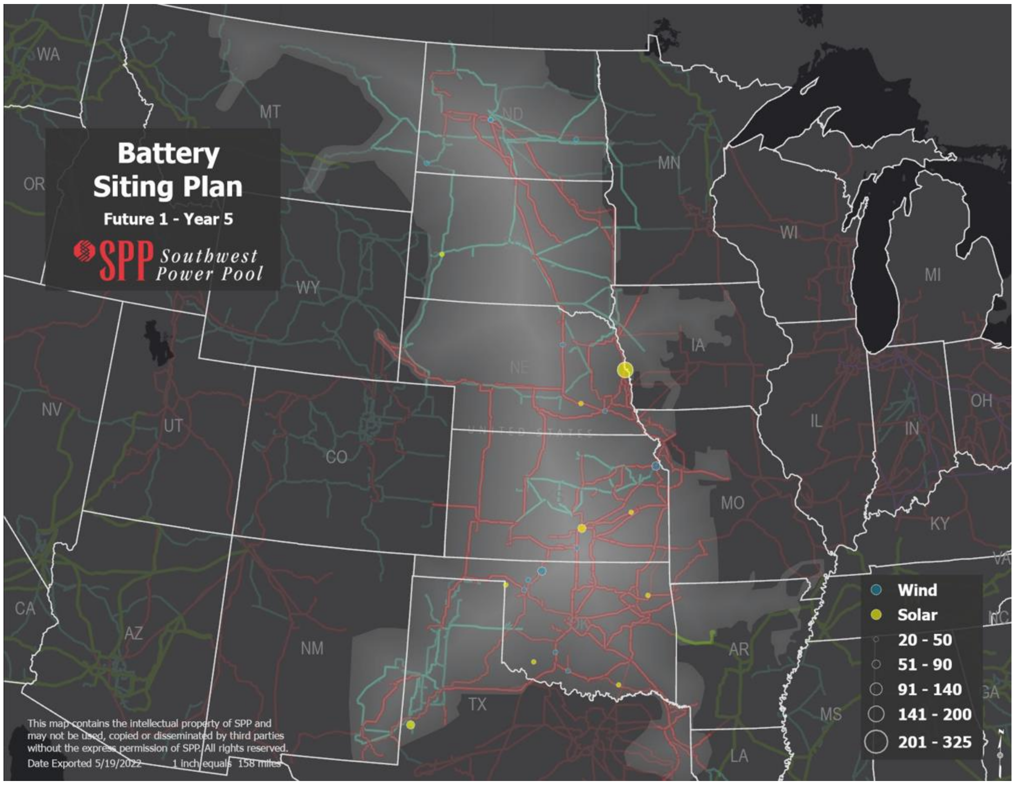

Figure 2.22: Future 1 Year 5 Battery Siting

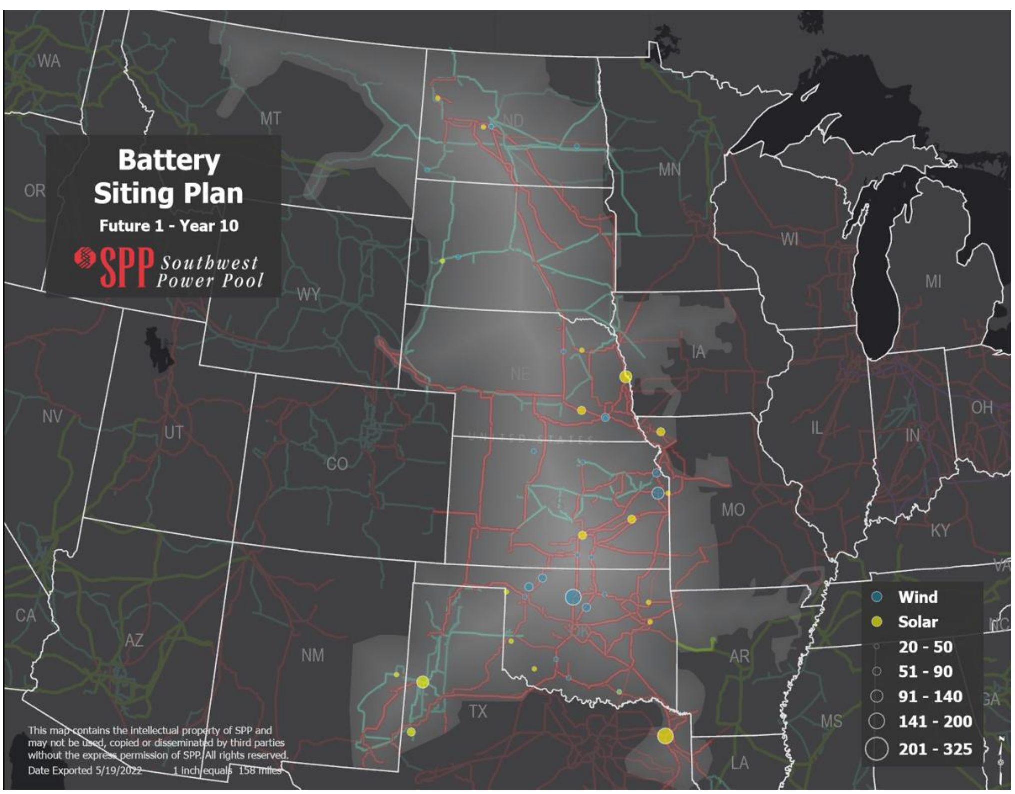

Figure 2.23: Future 1 Year 10 Battery Siting

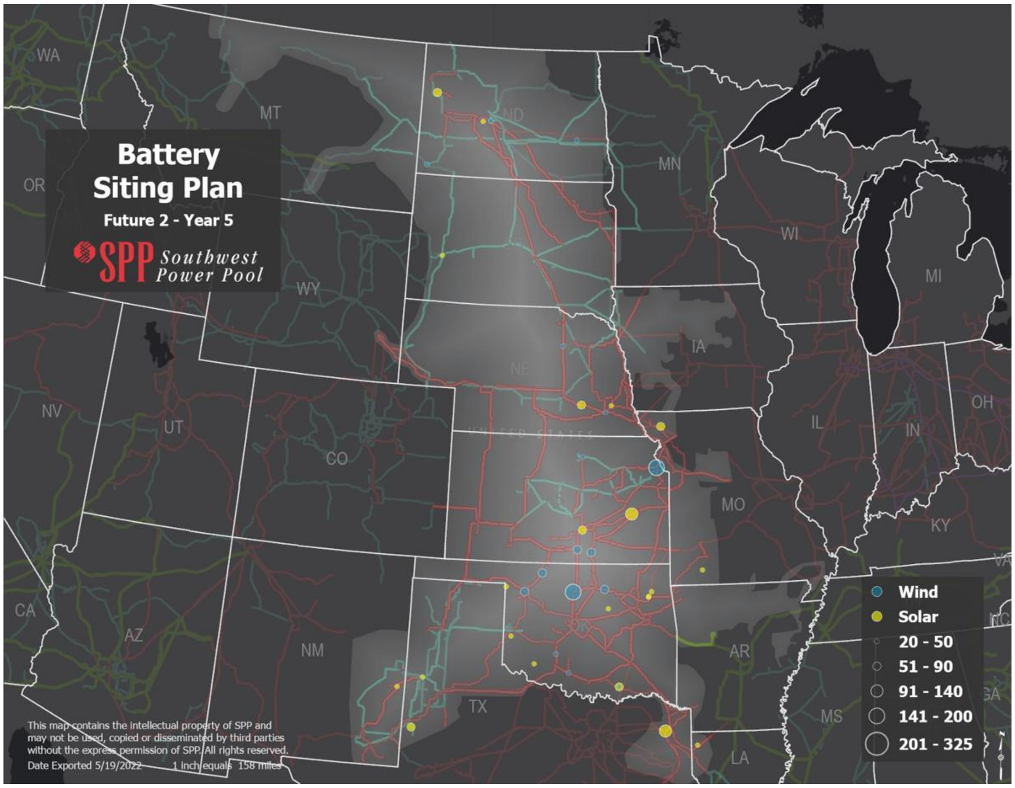

Figure 2.24: Future 2 Year 5 Battery Siting

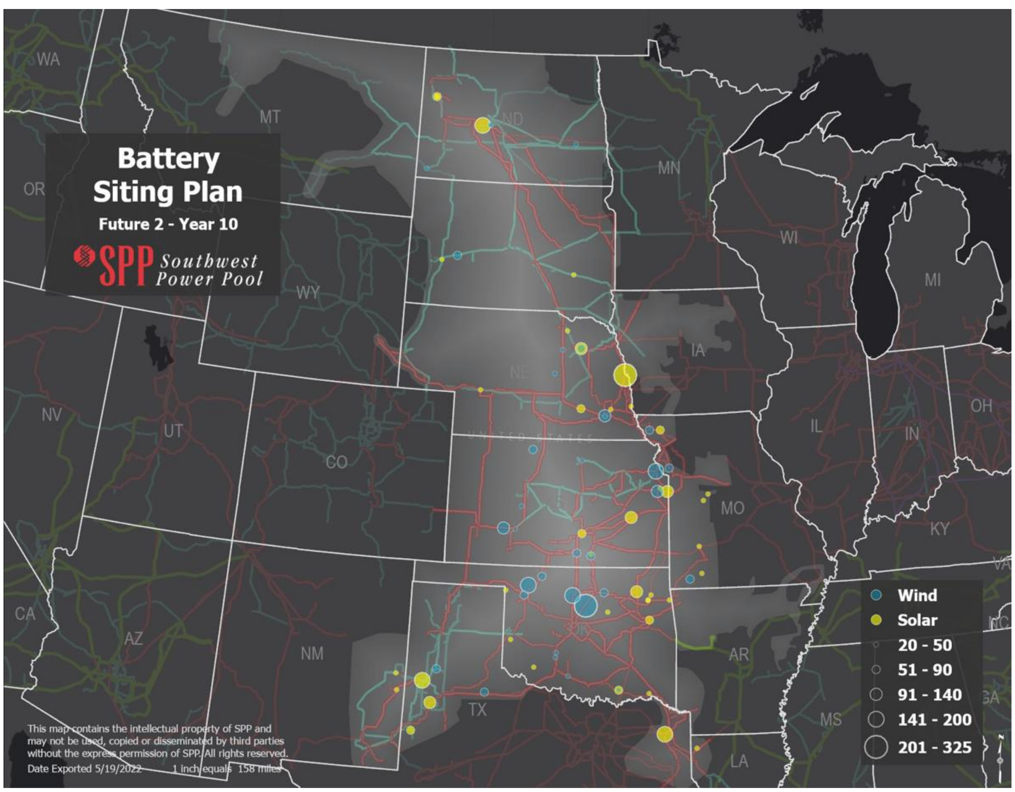

Figure 2.25: Future 2 Year 10 Battery Siting Plan

2.2.2.4 GENERATOR OUTLET FACILITIES

Generator Outlet Facilities (GOFs) are facilities incorporated into the market economic models when necessary to ensure that prospective generation added from the siting plan does not artificially create economic needs on the system. For sites with upgrades identified in a GI study, the associated upgrades were evaluated and had the potential to be recommended as a GOF. In other instances, the site-specific results of the transfer analysis were assessed to determine if a site was capable of reliably allowing a resource to dispatch to the SPP system (siting availability). The GOF upgrades for this study resulted from the siting availability checks and are shown in Table 2.5.

SITES	GOF DESCRIPTION	MW SITED	GOF SOURCE
Roadrunner 115 kV	Rebuild Newhart-Plant X 230 kV to 478/546 MVA for summer, 552.1/607.5 MVA Winter	110 MW	GI Queue*
S1363 161 kV	Rebuild S1281-S1254 161 kV to 352 MVA	474 MW	FCITC

*Table 2.5: Generator Outlet Facilities *Sited amount for all futures/years unless otherwise noted*

2.2.2.5 EXTERNAL REGIONS

When developing renewable resource plans, SPP did not directly consider renewable policy requirements for external regions. However, the Midcontinent Independent System Operator (MISO) and Tennessee Valley Authority (TVA) renewable resource expansion and siting plans were based on the 2021 MISO Transmission Expansion Planning (MTEP21) continued fleet change (CFC) and accelerated fleet change (AFC) futures. Associated Electric Cooperative Inc. (AECI) renewable resource expansion plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI.

SPP also incorporated conventional resource plans for external regions included in the market simulations. SPP surveyed each region for load and generation and assessed each to determine the capacity shortfall. The MISO and TVA resource expansion and siting plans were based on the MTEP21 CFC and AFC futures, while AECI and Saskatchewan Power (SASK) resource expansion and siting plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI.

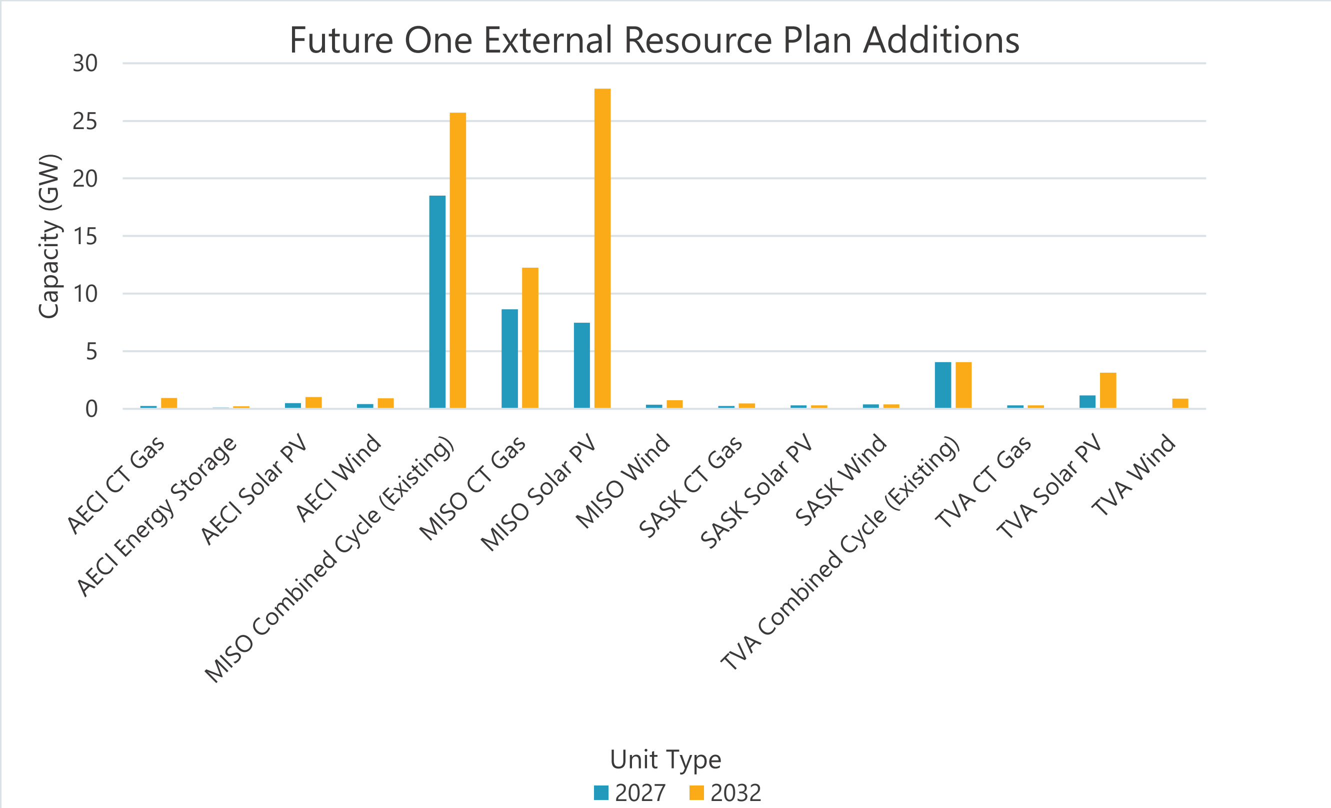

Figure 2.26: Future 1 External Resource Plan Additions

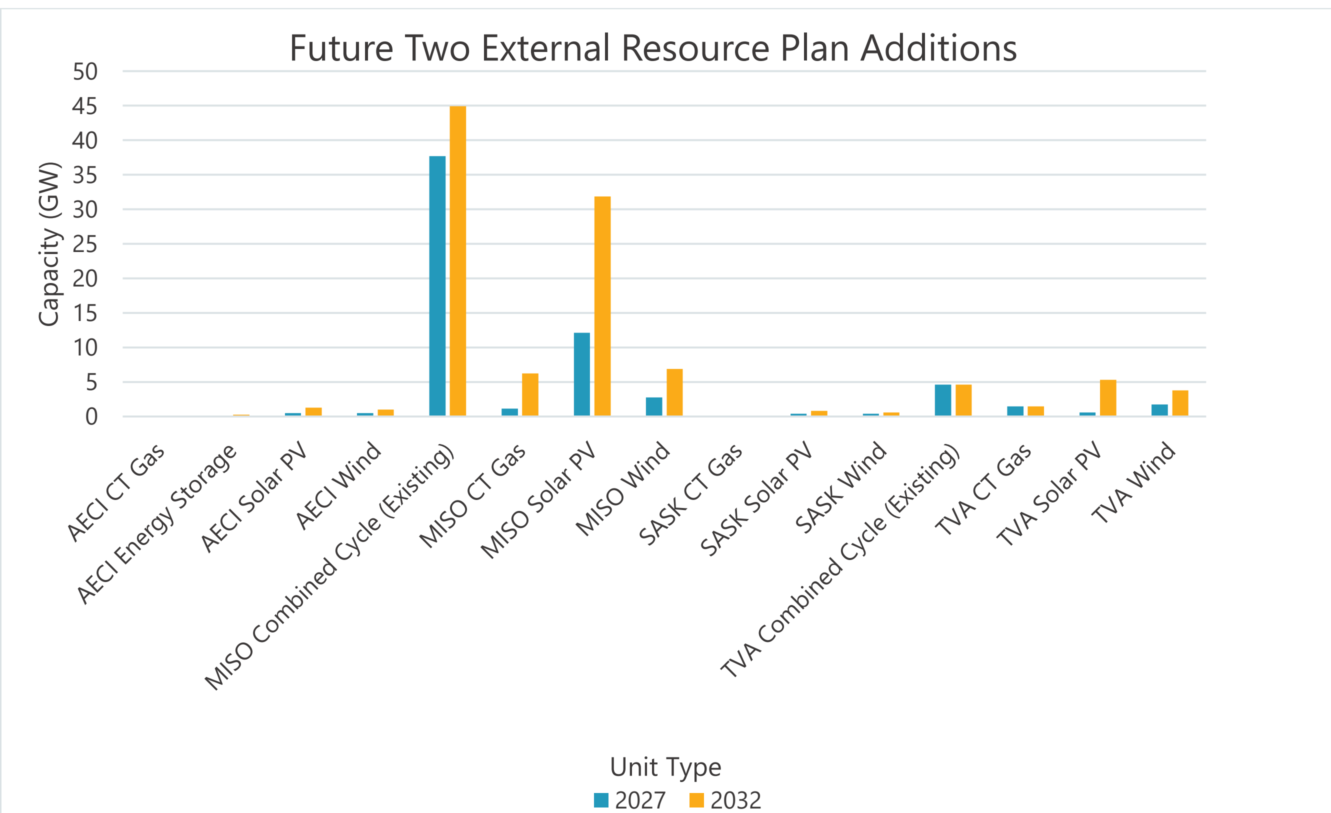

Figure 2.27: Future 2 External Resource Plan Additions

2.2.3 CONSTRAINT ASSESSMENT

SPP considers transmission constraints when reliably managing the flow of energy across physical bottlenecks on the transmission system in the least-costly manner. These study-specific constraints play a critical part in determining economic transmission needs, as the constraint assessment identifies future bottlenecks and fine-tunes the market economic models.

SPP conducted an assessment to develop the list of transmission constraints used in the security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) analysis for all futures and study years. SPP defined the initial list of constraints by leveraging the SPP permanent flowgate list[15], which consists of NERC-defined flowgates that are impactful to modeled regions and recent temporary flowgates identified by SPP in real time. In the 2023 ITP, SPP incorporated stakeholder feedback by widening the criteria used to evaluate contingencies for inclusion, reducing the minimum loading on 200 kV+ equipment from 25% down to 10%. This was done to evaluate the impact of contingencies involving high voltage equipment, even when that equipment experiences relatively low flows. SPP used MTEP21 constraints to help evaluate and validate constraints identified within MISO and other neighboring areas. SPP also considered constraints identified in neighboring areas for inclusion as a part of the ITP study constraint list. The TWG reviewed and approved the identified constraints as potentially limiting the incremental transfer of power throughout the transmission system, both under system intact and contingency situations.

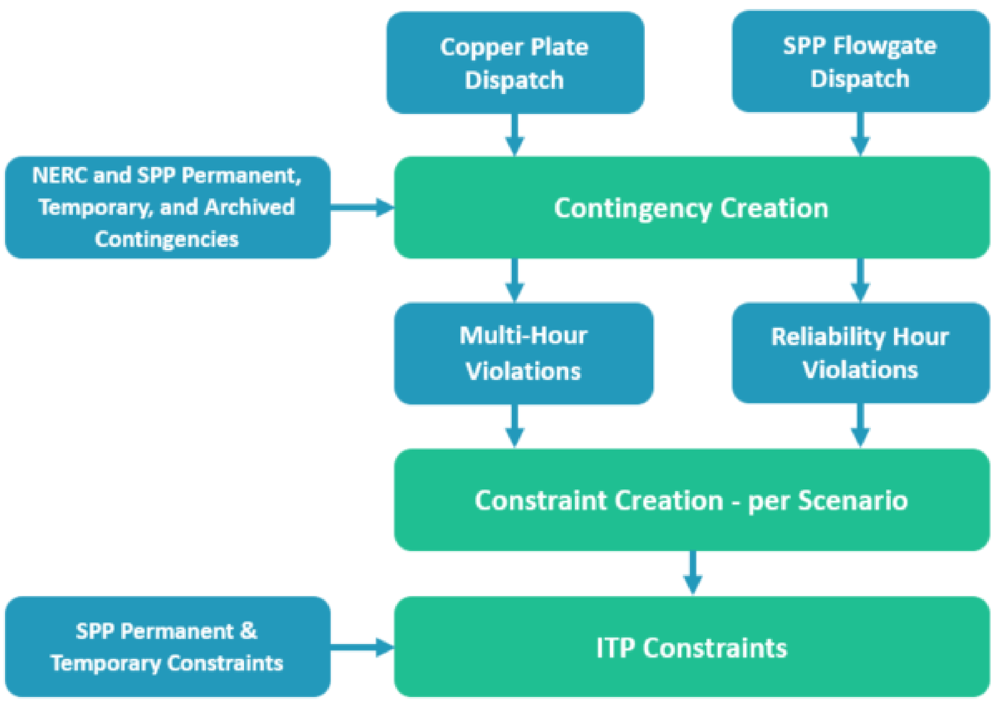

Figure 2.28: High level Constraint Assessment Process[16]

[15] Posted on OASIS: https://www.oasis.oati.com/SWPP/index.html
[16] The Constraint Assessment methodology can be found in the ITP Manual version 2.14

2.3 MARKET POWERFLOW MODEL

SPP used the economic dispatch from each market economic model to develop market powerflow model snapshots representing stressed conditions on the SPP transmission system. Table 2.6 shows the peak and off-peak reliability hours from each future and year of the market economic model simulations chosen for the market powerflow models. The ITP Manual defines the peak hour as "the hour with the highest total megawatt output of wind resources within SPP selected from the top 1% of SPP coincident peak load hours" and the off-peak hour as "the hour with the highest wind penetration between April and May between the hours of 12 a.m. – 6 a.m." For the Final Reliability Assessment, the full market powerflow model set was built.

	OFF-PEAK HOUR	WIND PENETRATION[17]	PEAK HOUR	WIND PENETRATION	SPP LOAD (MW)
Future 1 2024	April 14 at 2:00 AM	87%	June 19 at 2:00 PM	44%	52,675
Future 1 2027	May 15 at 3:00 AM	87%	July 22 at 5:00 PM	46%	55,096
Future 1 2032	April 4 at 4:00 AM	109%	June 23 at 2:00 PM	50%	55,592
Future 2 2027	May 15 at 3:00 AM	88%	July 22 at 5:00 PM	48%	55,160
Future 2 2032	April 4 at 4:00 AM	115%	June 23 at 2:00 PM	53%	55,696

Table 2.6: Reliability Hour Details

2.4 BENCHMARKING

2.4.1 POWERFLOW MODEL

SPP staff performed two benchmarks related to the 2023 ITP Base Reliability powerflow models. The first benchmark was a load and generation value comparison between the 2022 ITP and 2023 ITP Base Reliability powerflow models. The second benchmark was a load and generation value comparison between the 2023 ITP Base Reliability powerflow models and real-time operational data. Model comparisons were conducted to verify the accuracy of the powerflow model data, including:

- Comparison of the summer and winter peak base reliability model load totals (2022 ITP versus 2023 ITP), as shown in Figure 2.29 and Figure 2.30.
- Comparison of the summer and winter peak base reliability model generation dispatch totals for years two, five and 10 (2022 ITP versus 2023 ITP), as shown in Figure 2.31 and Figure 2.32.
- Additionally, the year-10 summer and winter peak generator retirements in the 2023 ITP Base Reliability powerflow models are shown in Figure 2.33.

[17] Wind Penetration = $\frac{Delivered\ Energy}{Load}\ x\ 100\%$, excluding curtailed wind

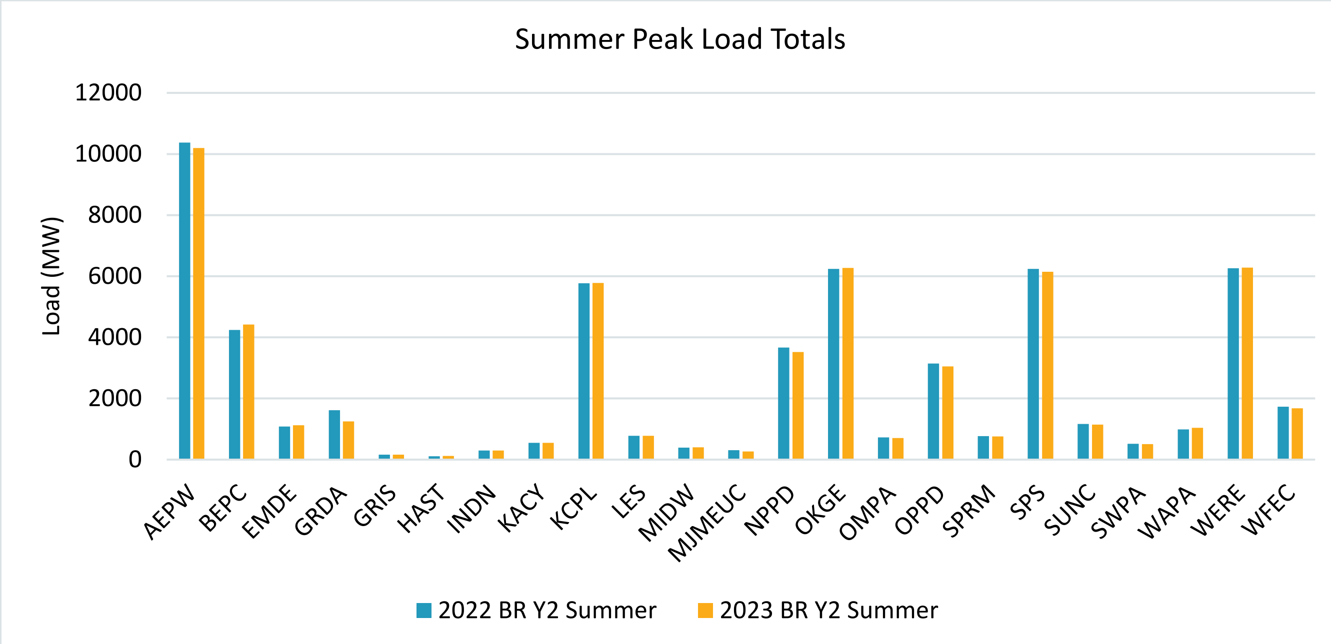

Figure 2.29: Summer Peak Year-Two Load Totals Comparison

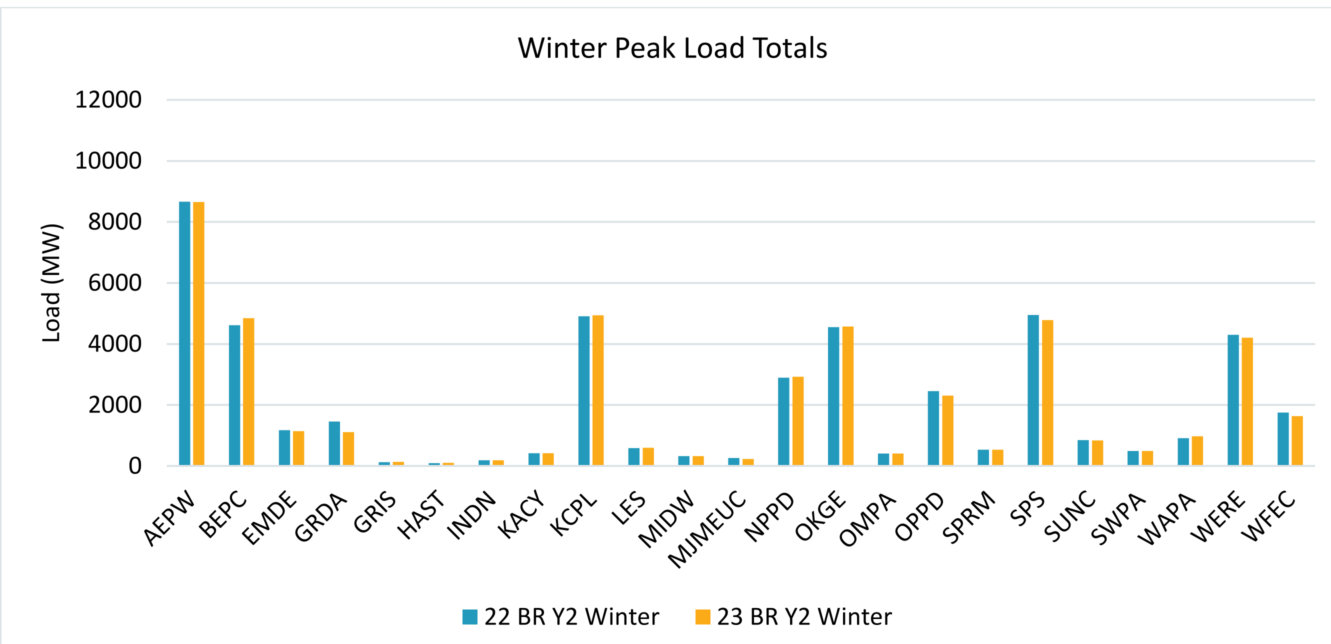

Figure 2.30: Winter Peak Year-Two Load Totals Comparison

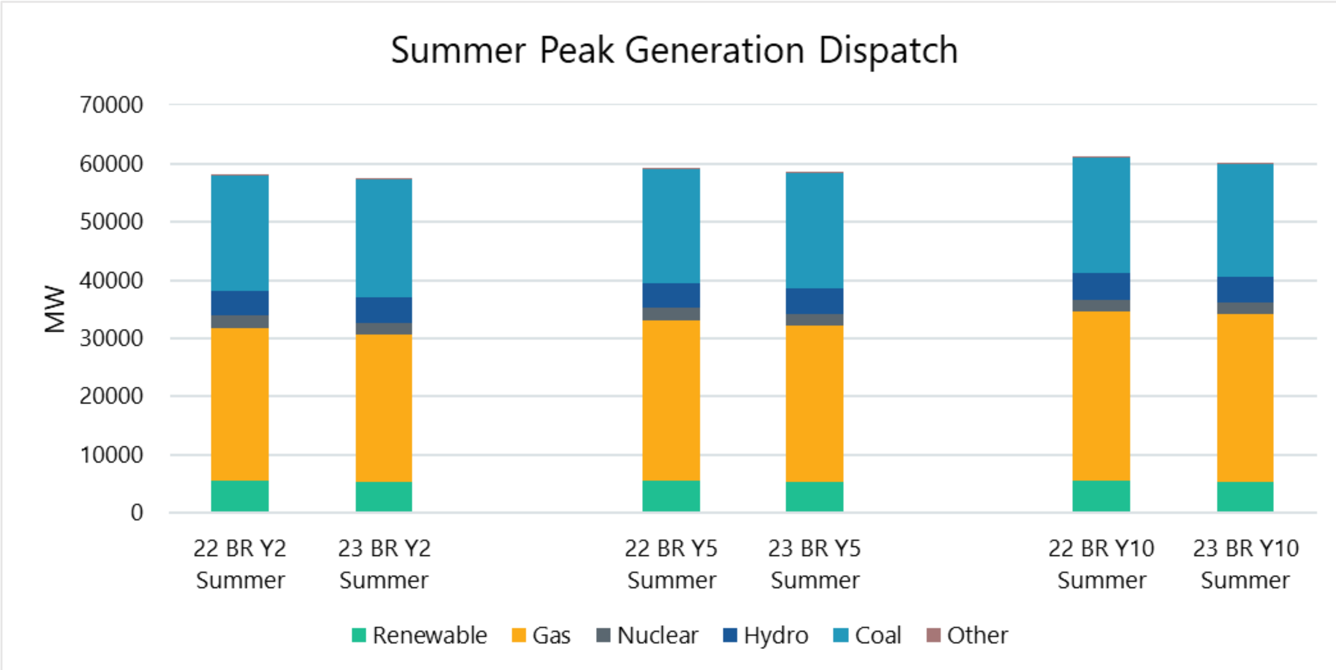

Figure 2.31: Summer Peak (MW) Years two, five, and 10 Generation Dispatch Comparison

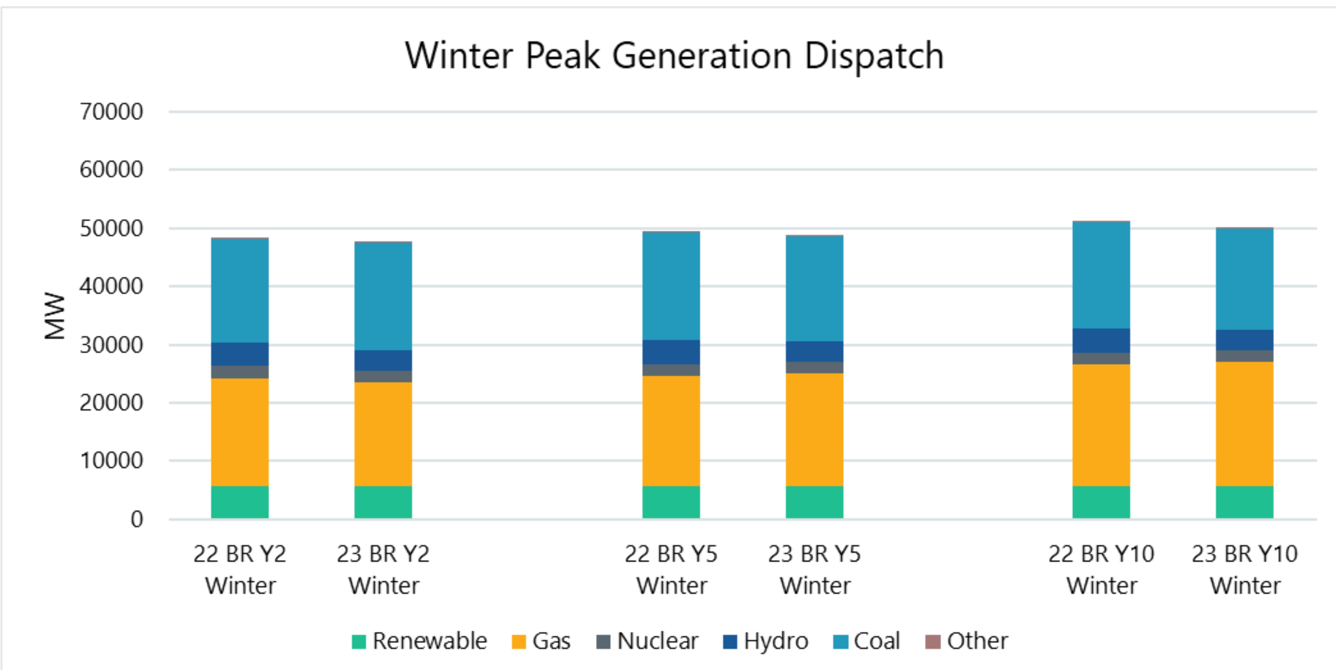

Figure 2.32: Winter Peak (MW) Years two, five, and 10 Generation Dispatch Comparison

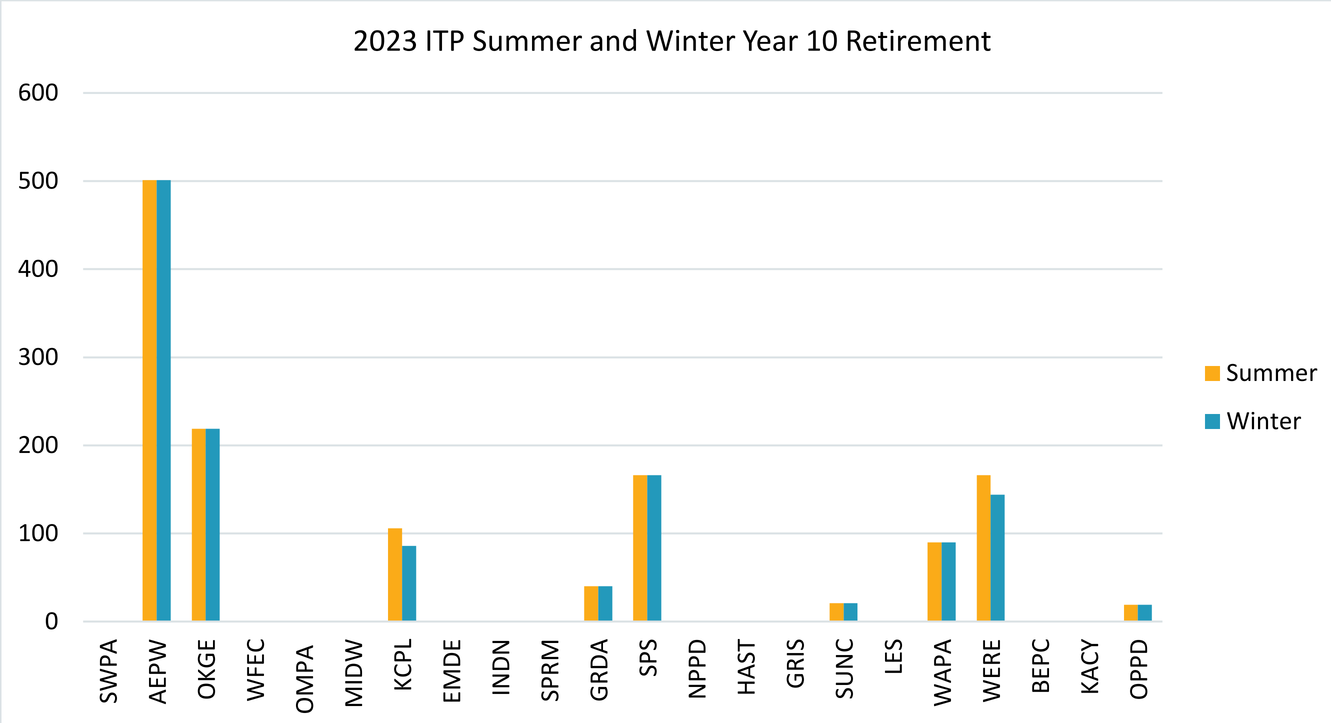

Figure 2.33: 2023 ITP Summer and Winter Year 10 Retirement

Operational model benchmarking for this assessment compared the 2023 summer and winter peak Base Reliability powerflow models against the real-time non-coincident operational data for the 2022-2023 winter and 2023 summer timeframe. Model comparisons were conducted to verify the accuracy of the powerflow model data, including:

- Comparison of the 2023 summer and winter load totals (base reliability model versus real-time non-coincident operational data), as shown in Figure 2.34 and Figure 2.35
- Comparison of the 2023 summer and winter generation dispatch totals (base reliability model vs real-time coincident operational data), as shown in Figure 2.36.

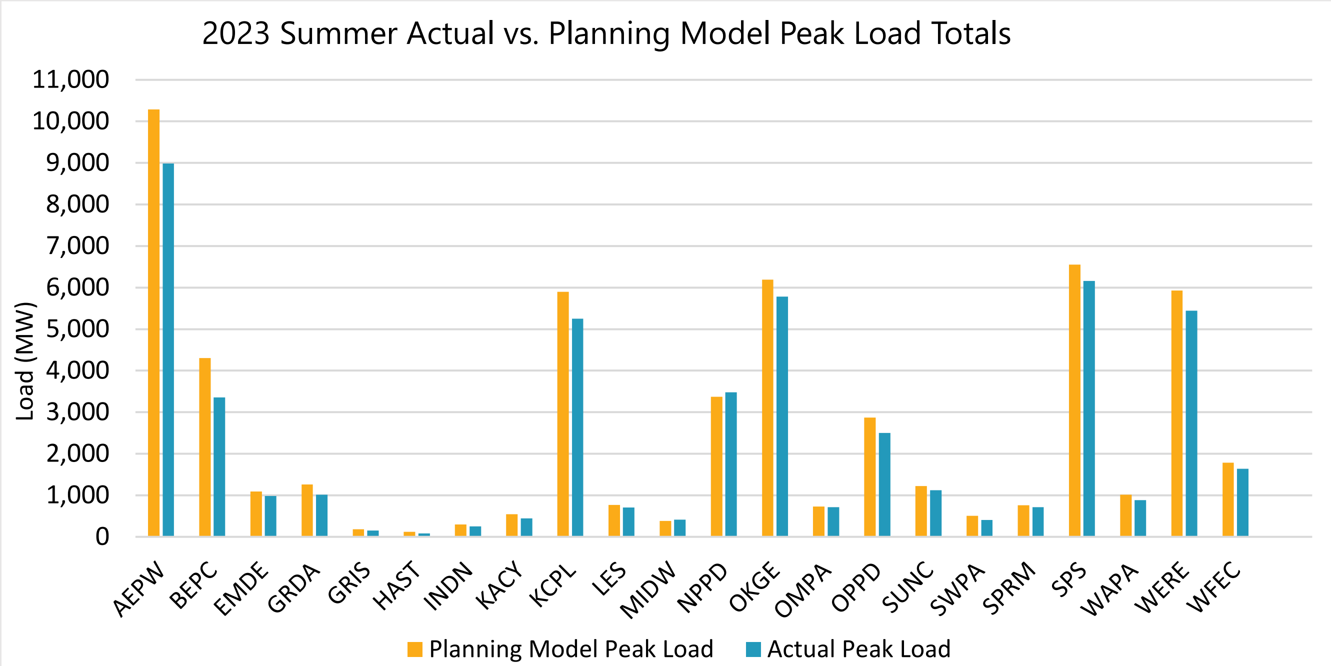

Figure 2.34: 2023 Summer Actual versus Planning Model Peak Load Totals

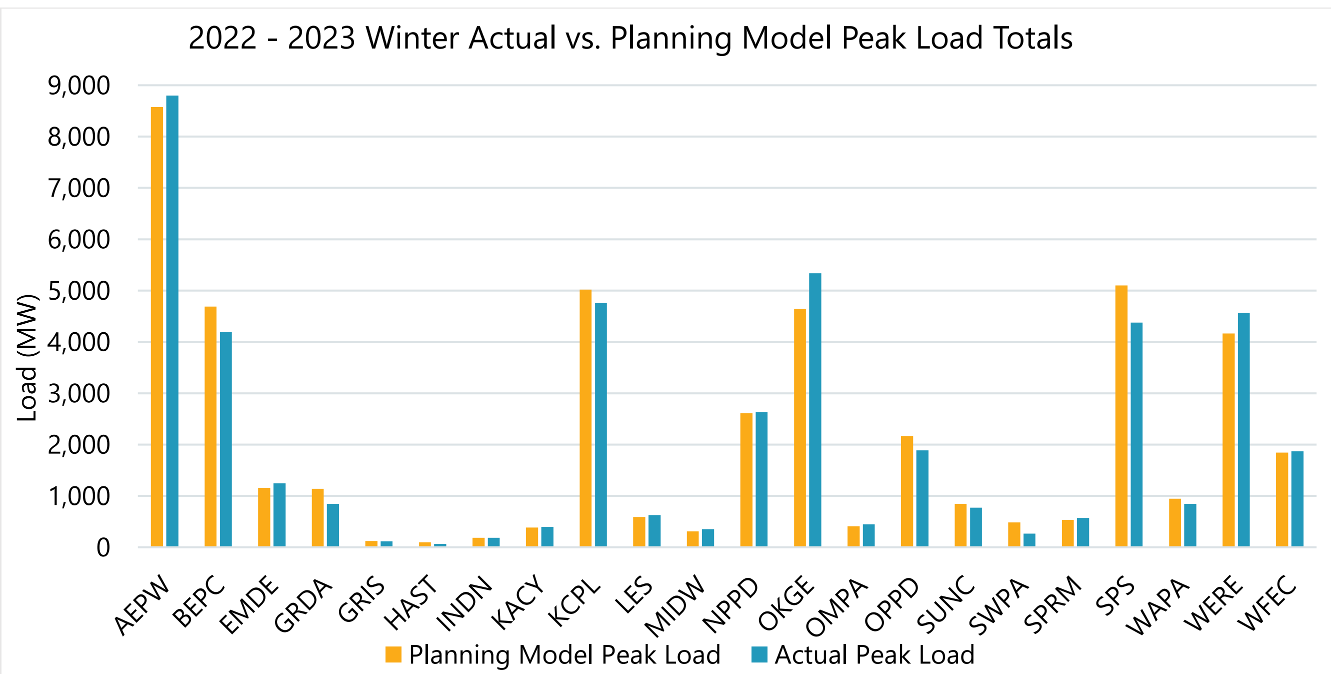

Figure 2.35: 2022-23 Winter Actual versus Planning Model Peak Load Totals

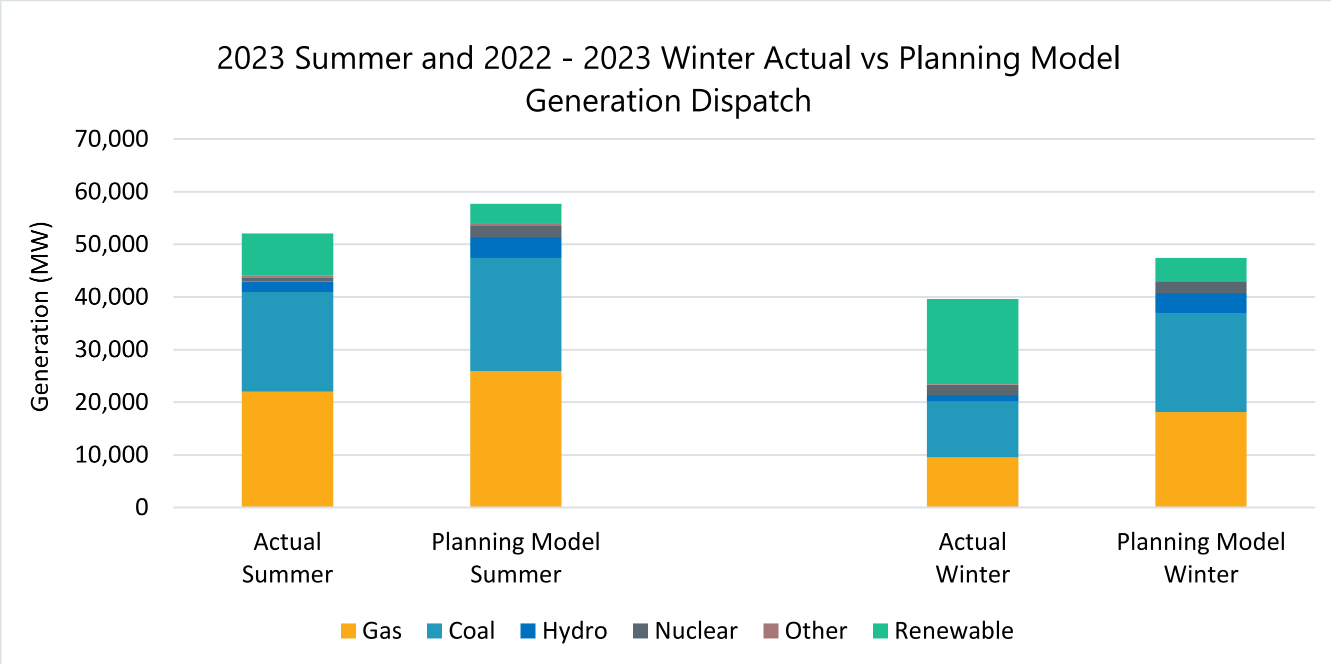

Figure 2.36: 2023 Summer and 2022-2023 Winter Actual vs Planning Model Generation Dispatch

2.4.2 MARKET ECONOMIC MODEL

2.4.2.1 *SYSTEM LOCATIONAL MARGINAL PRICE (LMP)*

Simulated LMPs were benchmarked against simulated LMPs from the 2022 ITP. This data was compared on an average monthly value-by-area basis. Figure 3.13 portrays the results of the benchmarking model for the SPP system. The decrease in LMPs in the 2023 ITP is due to additional renewable energy.

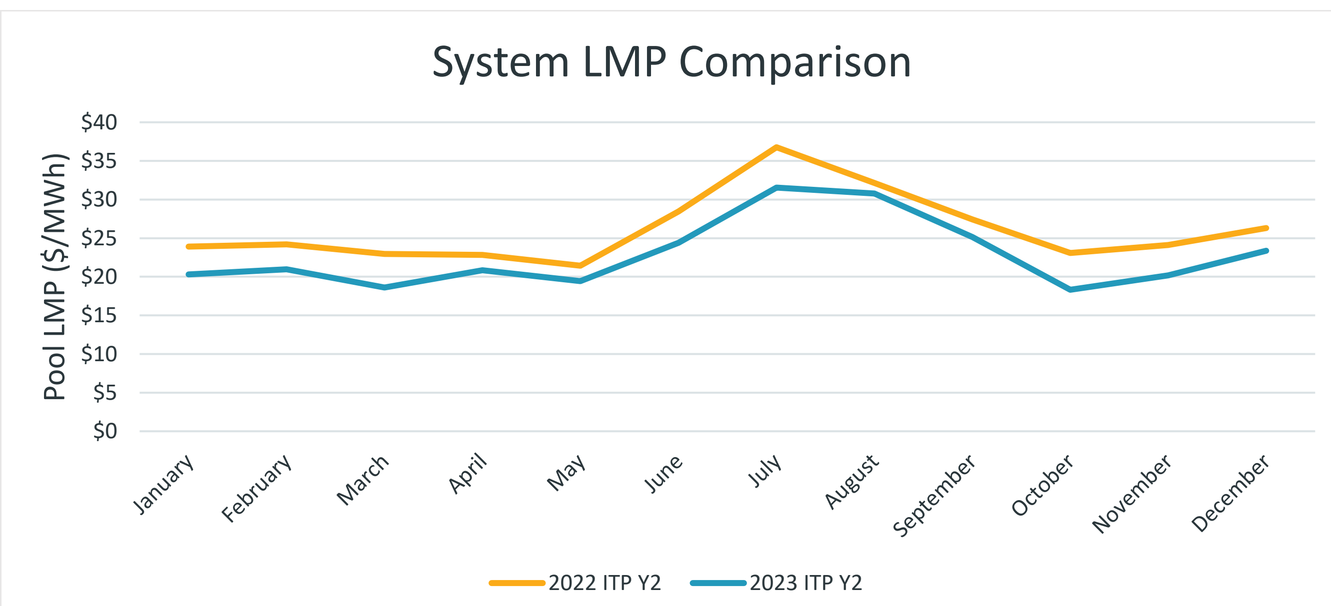

Figure 2.37: System LMP Comparison

2.4.2.2 *ADJUSTED PRODUCTION COST (APC)*

Examining the APC provides insight to which entities generally purchase generation to serve their load and which entities generally sell their excess generation. APC results for SPP zones were overall slightly lower in the 2023 ITP than in the 2022 ITP due to the change in renewable and load forecasts.

The APC on a zonal level both increases and decreases depending on the characteristics of the zone, including level of renewable increase, retirements and zonal load forecast changes. See Figure 2.38 and Figure 2.39 for a summary of regional and zonal APC results.

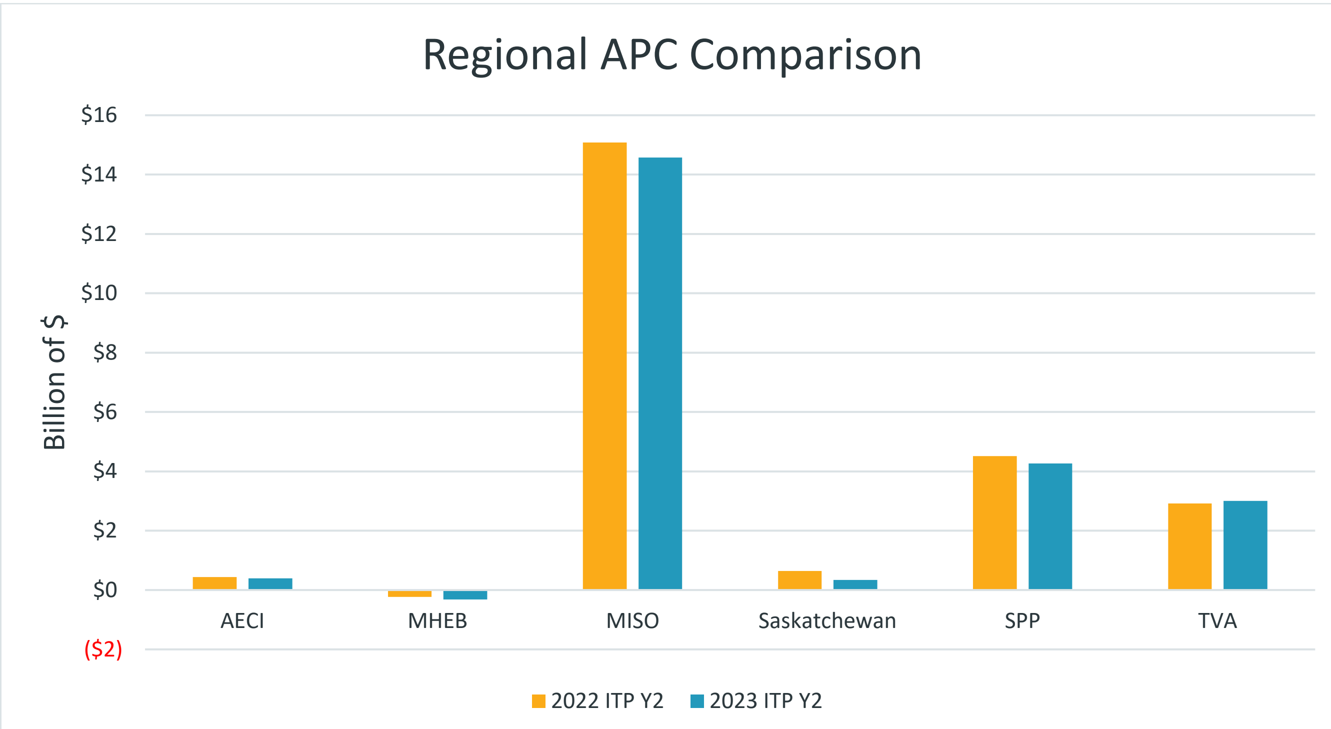

Figure 2.38: Regional APC Comparison

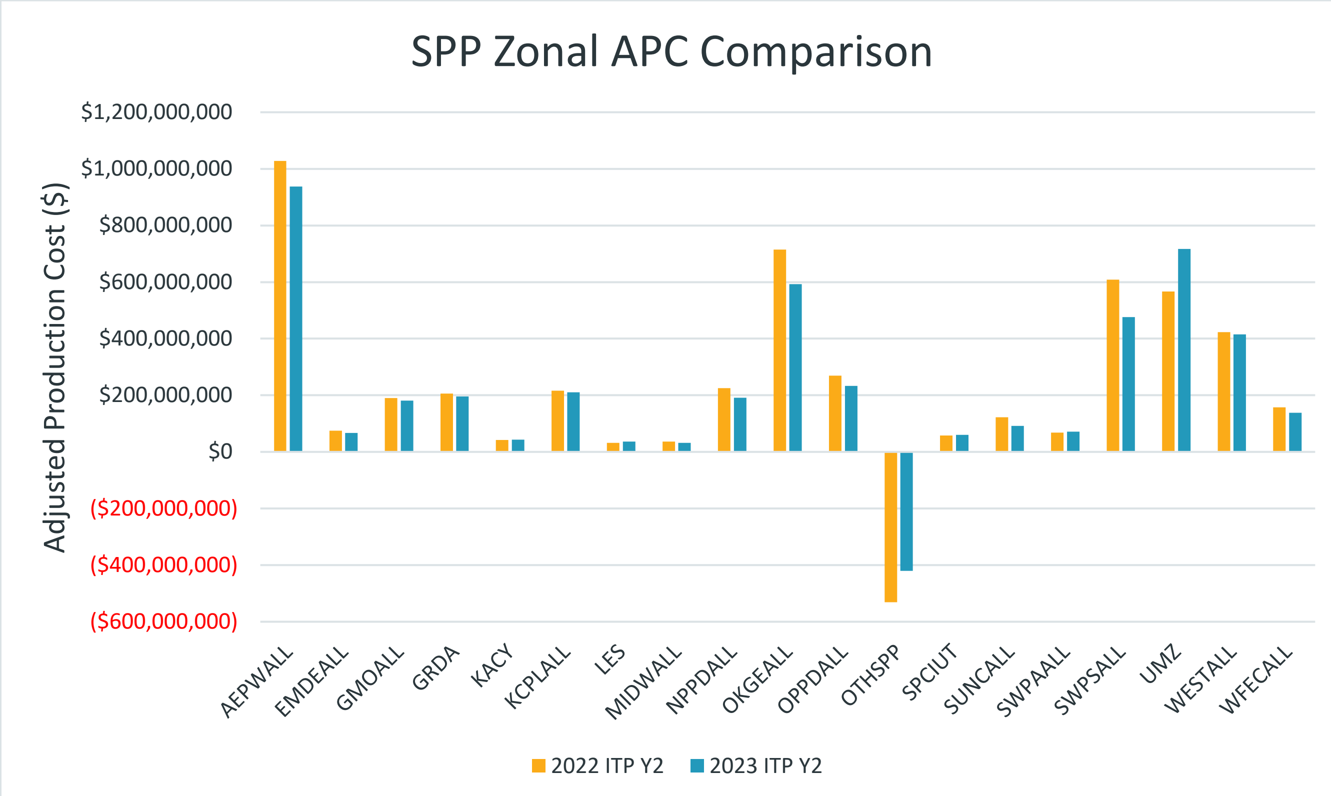

Figure 2.39: SPP Zonal APC Comparison

2.4.2.3 *INTERCHANGE*

The 2023 ITP model interchange was validated against the 2022 ITP and current SPP operations data. The 2023 ITP model is similar in shape and magnitude while overall exports are slightly higher in the 2023 ITP than in the 2022 ITP.

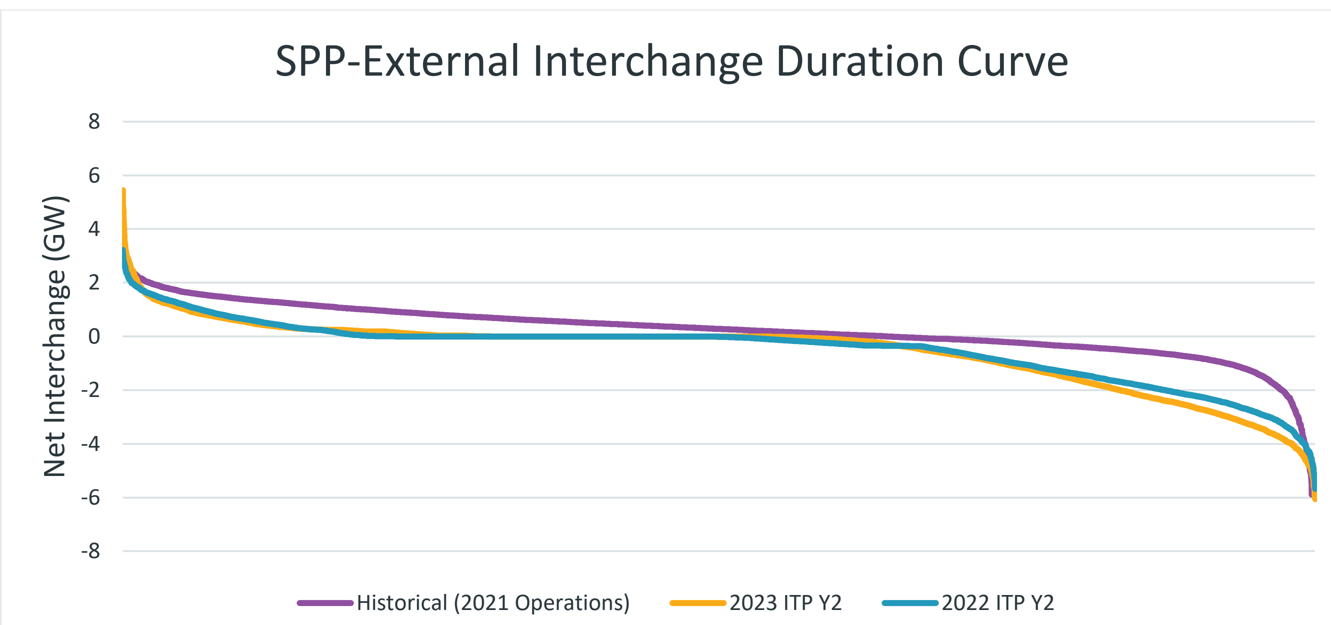

Figure 2.40: Interchange data comparison

2.4.2.4 *GENERATOR OPERATIONS*

2.4.2.4.1 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 compared with capacity factors reported to the EIA for 2021 and resulting from the 2023 ITP study, the capacity factors for conventional generation units fell near the expected values. The difference in capacity factors between the datasets were attributed to differences in load forecasts as well as changes in the generation mix.

Unit Type	Average Capacity Factor		
	2021 EIA	2022 ITP Future 1 2024	2023 ITP Future 1 2024
Nuclear	92.70%	85.76%	88.56%
Combined Cycle	54.40%	43.55%	42.23%
CT Gas	12.10%	4.44%	4.86%
Coal	49.30%	64.16%	58.74%
ST Gas	13.10%	4.72%	3.30%
Wind	34.60%	42.59%	41.50%
Solar	24.60%	23.48%	31.91%

Table 2.7: Generation Capacity Factor Comparison

2.4.2.4.2AVERAGE ENERGY COST

Examining the average cost per MWh by unit type gives insight into what units will be dispatched first (without considering transmission constraints). Overall, the average costs per MWh were lower in the 2023 ITP than in the 2022 ITP due to the load forecasts and the difference in generation mix.

Unit Type	Average Energy Cost ($/MWh)	
	2022 ITP Future 1 2024	2023 ITP Future 1 2024
Nuclear	$13.07	$13.42
Combined Cycle	$28.55	$27.35
CT Gas	$41.95	$38.45
Coal	$20.80	$20.77
ST Gas	$41.05	$40.45

Table 2.8: Average Energy Cost Comparison

2.4.2.4.3 GENERATOR MAINTENANCE OUTAGES

Generator maintenance outages in the simulations were compared to SPP real-time data. These outages have a direct impact on flowgate congestion, system flows and the economics of serving load.

The operations data includes certain outage types that cannot be replicated in these planning models. The difference in magnitude between the real-time data and the market economic simulated outages is due to the additional operational outages beyond those required by annual maintenance or driven by forced (unplanned) conditions. Although the market economic model simulation outages do not have as high of a magnitude as the historical outages provided by SPP operations, the outage rates in the 2023 ITP are very similar to previous ITP assessments. The curves from the historical data and the market economic model simulations complemented each other very well in shape.

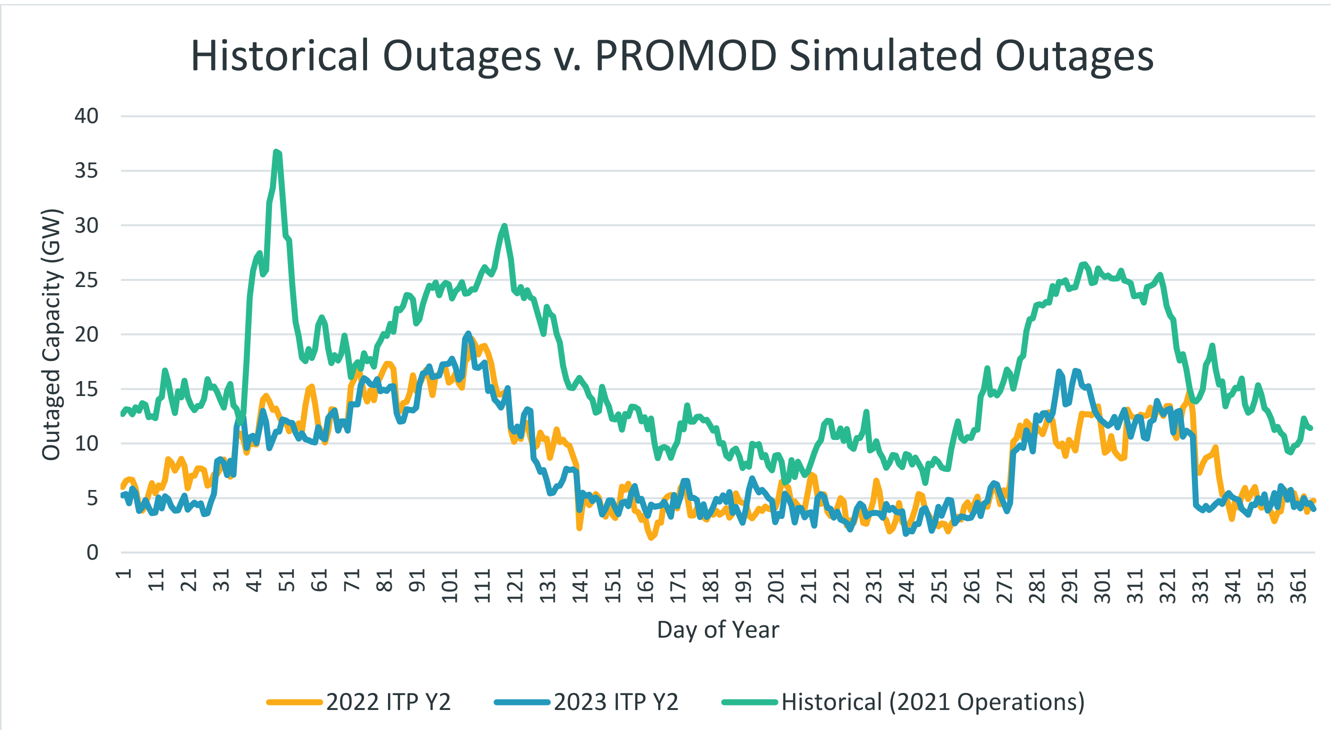

Figure 2.41: Historical Outages v. PROMOD Simulated Outages

2.4.2.4.4 OPERATING AND SPINNING RESERVE ADEQUACY

Operating reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of unplanned unit outages. Operating reserve should meet a capacity requirement equal to the sum of the capacity of the largest unit in SPP and half of the capacity of the next largest unit in SPP. At least half of this requirement must be fulfilled by spinning reserve.

The operating reserve capacity requirement was modeled at 1,646 MW and spinning reserve capacity requirement was modeled at 823 MW. The reserve requirements were met in the market economic models. The graph below represents the operating and spinning reserves for each month**.**

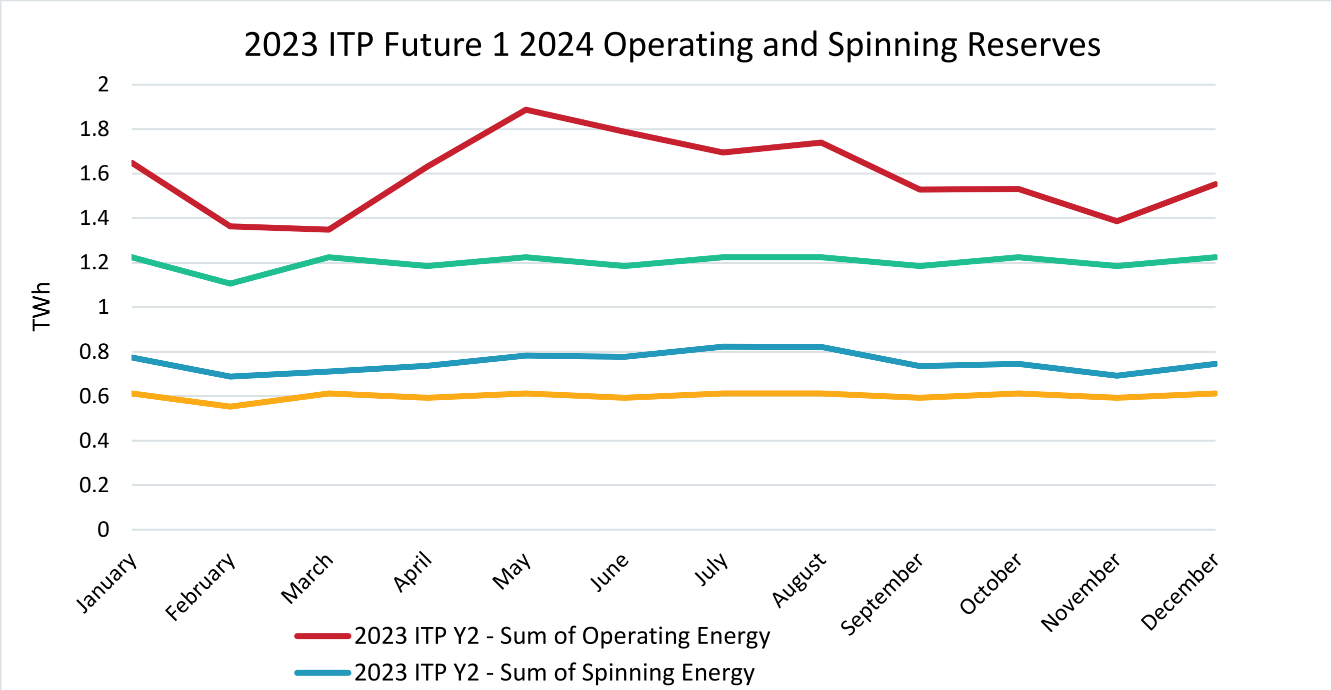

Figure 2.42: 2021 ITP Future 1 2022 Operating and Spinning Reserves

2.4.2.4.5 RENEWABLE GENERATION

Wind and solar energy output is higher in the 2023 ITP than in the 2022 ITP because of additions identified during the generation review milestone. Wind output is noticeably greater due to the amount of installed capacity and approved RARs in 2023 ITP. The solar output is noticeably greater due to the updated methodology for matching the capacity factor to historical operations data.

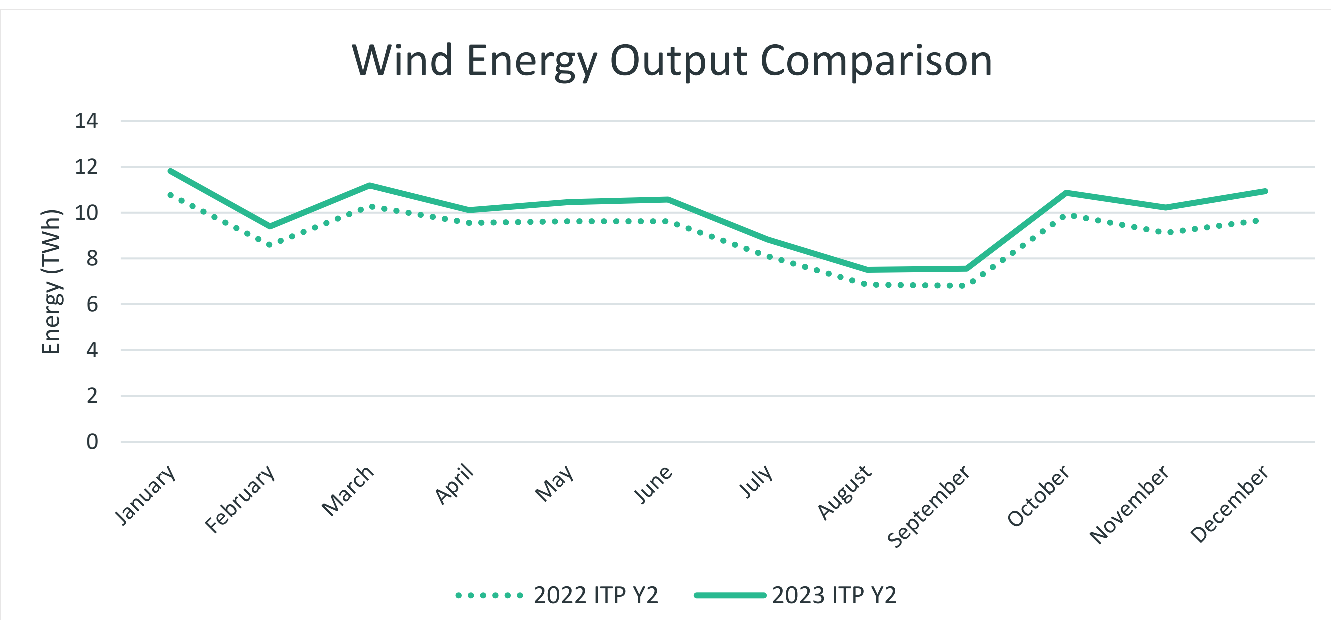

Figure 2.43: Wind Energy Output Comparison

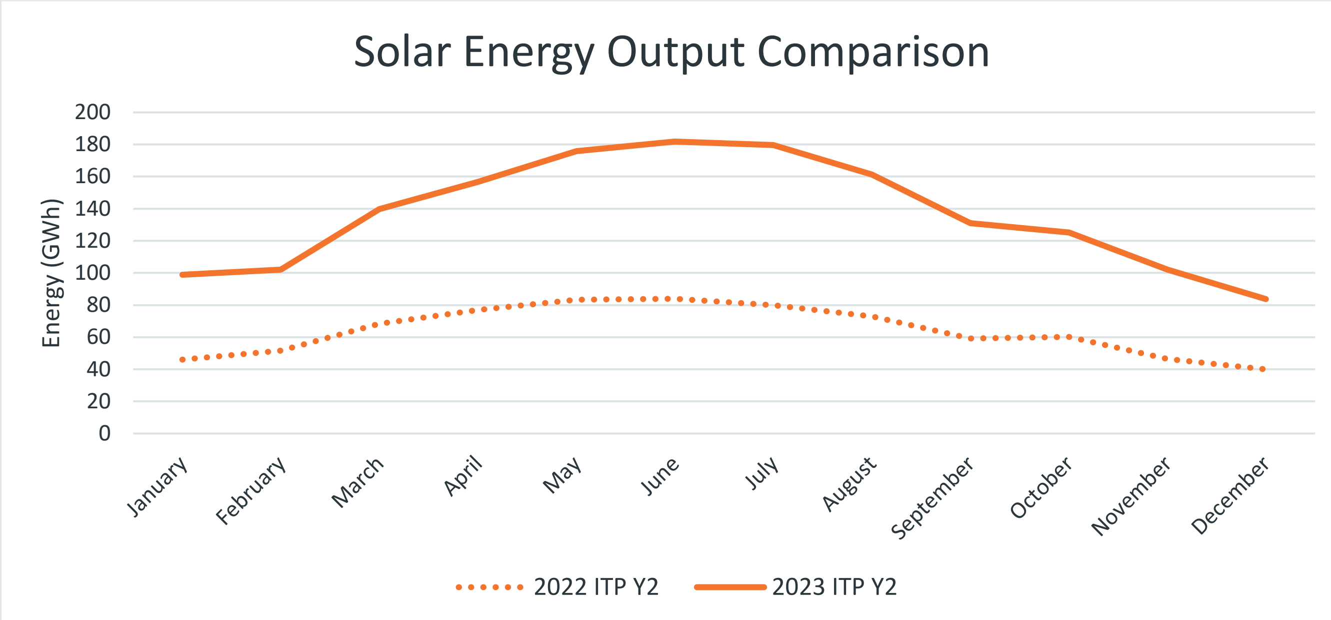

Figure 2.44: Solar Energy Output Comparison

3 NEEDS ASSESSMENT AND SOLUTION EVALUATION

During each ITP assessment, SPP and its member organizations collaborate to develop and analyze the regional transmission system's needs, identify robust solutions and develop a final portfolio.

3.1 ECONOMIC NEEDS

SPP determined economic needs based on the congestion score associated with a constraint (comprised of a monitored element and a contingent element pair). SPP calculated the congestion score by multiplying the number of hours a constraint is congested in the model by the average shadow price of that constraint.

There were 92 total unique constraints (monitored-contingent element pairs) in the 2023 ITP. Unique constraints with a congestion score greater than $50,000/MW were identified as economic needs within each future. Additional constraints with the same monitored element paired with a different contingency were also included if this congestion score threshold was met. Some needs appeared in multiple futures. If a constraint is listed as having no congestion in the tables below, that means the need was observed after one or more of the other constraints were relaxed. These are labeled as related needs.

The trend of larger congestion scores was observed on Central/Northeast Oklahoma's underlying 138kV system, and Central/Southeast Kansas in both futures.

The Operational Economic Needs Assessment identified flowgates with significant congestion that were not identified as constraints during the 2023 ITP Constraint Assessments. This resulted in the particular flowgates not showing up in the needs assessment. After the addition of the events, enough congestion was observed on two of the constraints to identify them as needs, and the other two were posted for informational purposes:

Constraint	Future 1 congestion score			Future 2 congestion score	
	Year 2	Year 5	Year 10	Year 5	Year 10
Benton - Wichita 345 kV circuit 1 FTLO (For The Loss Of) Wolf Creek Generating Station	16,464	194,542	199,291	185,894	164,698
Viola Transformer 345/138 kV Circuit 1 FTLO Wichita - Viola 345 kV Circuit 1	53,787	70,157	105,803	99,564	179,640
Northwest Transformer 345/138 kV circuit 2 FTLO Northwest Transformer 345/138 kV circuit 3	-	-	-	-	-
County Line - Tecumseh Hill East 115 kV circuit 1 FTLO Overton - Sibley 345 kV circuit 1	-	-	-	-	-

Table 3.1: Economic Constraints to aligns with Operational needs

The economic needs identified in the 2023 ITP are shown in Figure 3.1 and Figure 3.2. They are also listed, along with their congestion score, by future in Table 3.1 through Table 3.3.

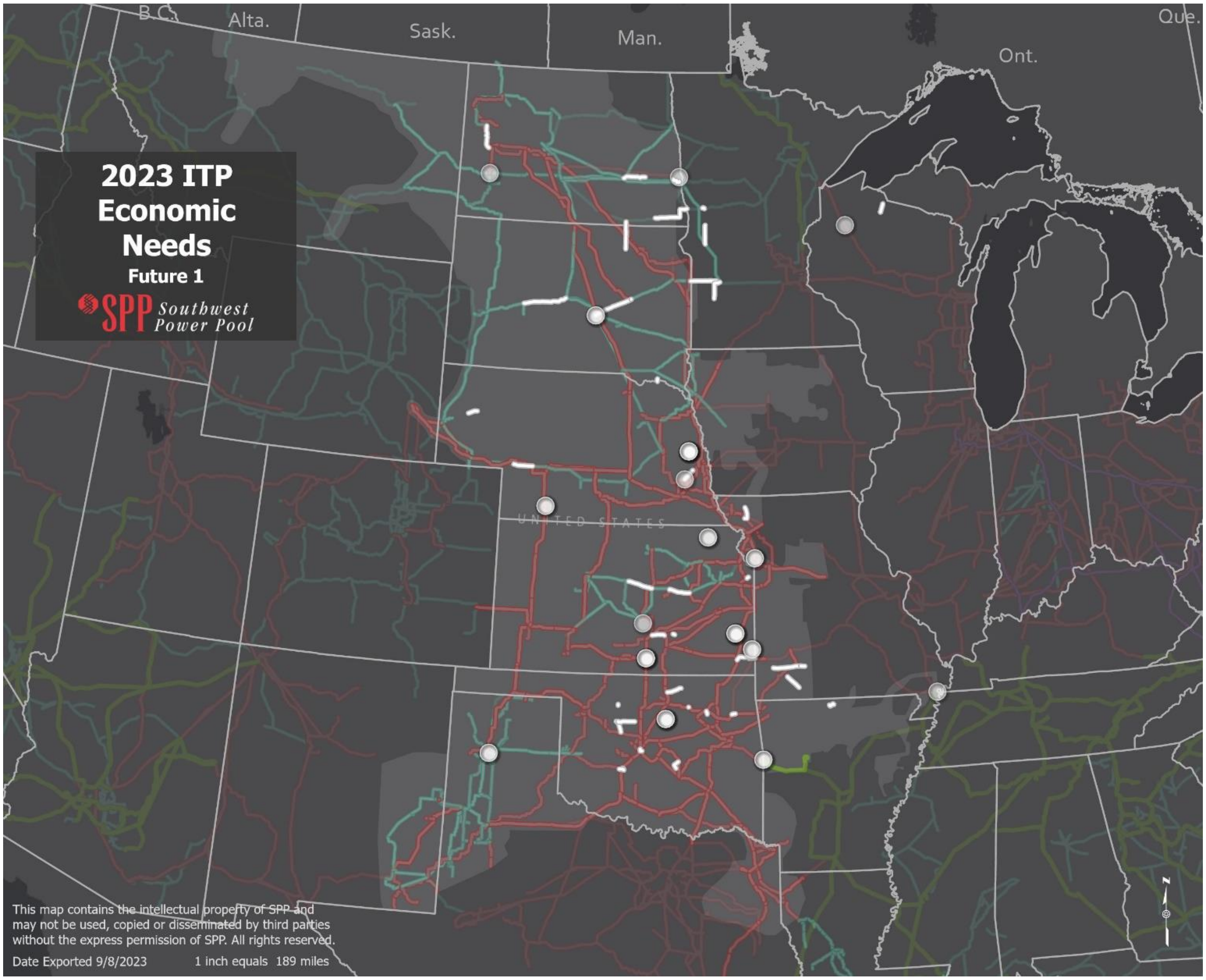

Figure 3.1: Future 1 Economic Needs

Constraint	Future 1 congestion score		
	Year 2	Year 5	Year 10
Alliance-Snake Creek 115 kV circuit 1 FTLO (For The Loss Of) Stegall-Wayside circuit 1	1,303,871	454,465	640,036
Watford City-Charlie Creek 230 kV circuit 1 FTLO Charlie Creek-Patent Gate 345 kV circuit 1	839,021	-	-
Tulsa North-46th Street Tap 138 kV circuit 1 FTLO Tulsa North-Cherokee Data Center West Tap 138 kV circuit 1	137,992	440,097	820,622
Osage-Webb City Tap 138 kV circuit 1 FTLO Cleveland 345 kV-Sooner 345 kV circuit 1	813,566	469,249	788,299
Huron-Huron 'B' Tap 115 kV circuit 1 FTLO Huron-Huron West Park 115 kV circuit 1	424,029	799,181	378,079

Constraint	Future 1 congestion score		
	Year 2	Year 5	Year 10
Forman 230kV-Ybus355 115kV circuit 1 FTLO Hankson - Wahpeton 230kV circuit 1	601,455	239,154	-
Granite Falls-Marshall Tap 115kV circuit 1 FTLO Lyon County 345/115kV Transformer circuit 9	117,569	138,823	532,231
Cleo Corner-Cleo Switchyard 69 kV circuit 1 FTLO Cleo Corner-Cleo Corner Tap 138 kV circuit 1	-	465,359	510,373
Cleveland (GRDA)-Cleveland (AECI) 138 kV circuit Z1 FTLO Tulsa North 345 kV-Cleveland 345 kV circuit 1	372,926	110,908	193,444
Butler-Midian 138 kV FTLO Weaver 138 kV-Tallgrass 115 kV	30,786	167,446	282,018
Craig-Lenexa South 161kV circuit 2 FTLO Craig-Lenexa South 161 kV circuit 1	14,855	86,750	47,821
Stilwell-Hickman 161 kV circuit 1 FTLO Stilwell-Redel 161 kV circuit 1	11,937	500	16,702
Springfield-Clay 161kV circuit 1 FTLO Huben-Morgan 345 kV circuit 1	46,160	102,837	311,434
Hawthorn Transformer 345/161 kV circuit 20 FTLO Hawthorn Transformer 345/161 kV circuit 22	2,853	610	25,376
Fremont-Sub 976 Transformer 115/69 kV circuit 1 FTLO Sub 1226-Sub 1291 161 kV circuit 1	82,428	96,243	165,042
Stillwater Kinze-Kinze 138 kV circuit 1 FTLO Cleveland-Sooner 345 kV circuit 1	222,381	83,095	129,153
Aurora-Reeds Spring 161 kV circuit 1 FTLO Beaver-Eureka Springs 161 kV circuit 1	32,595	52,555	219,581
Sub 1214-70th & Bluff 161 kV circuit 1 FTLO Sub 3454-Wagener 345 kV circuit 1	13,129	45,054	104,990
Nashua transformer 345/161 kV circuit 11 FTLO Hawthorn-Nashua 345 kV circuit 1	20,595	92,224	107,078
Huron-Huron 'B' Tap 115 kV circuit 1 FTLO Groton-Groton South 115 kV circuit 1	24,125	27,943	208,674
Ellsworth Tap-Great Bend 115 kV circuit 1 FTLO Circle-Great Bend 230 kV circuit 1	10,724	3,210	29,531
Maryville-Midway 161 kV circuit 1 FTLO Gentry-Fairport 161 kV circuit 1	174,908	156,830	167,074
Smoky Hills-Summit Ridge 230 kV circuit 1 FTLO Axtell 3-Macon 3 345 kV circuit 1	65,631	77,908	116,945
Aberdeen Junction 7-Ellendale 7 115 kV FTLO Twin Brooks 3-Big Stone South 3 345 kV circuit 1	73,982	154,853	81
West Harvey transformer 138/115 kV circuit 1 FTLO Reno County-Wichita 345 kV circuit 1	37,360	30,645	75,930
Hoot Lake-Fergus Falls 115 kV circuit 1 FTLO Silver Lake-Fergus Falls 230 kV circuit 1	54,514	162,746	-
70th & Bluff Transformer 161kV/115 kV circuit 1 FTLO Sub 3454-Wagener 345 kV circuit 1	21,569	22,822	102,102
Anadarko Switchyard-Southwestern Station 138 kV circuit 1 FTLO Anadarko Switchyard-Gracemont 138 kV circuit 1	105,895	57,337	132,140
Marmaton East 161 kV-Marmaton West 161 kV circuit Z1 FTLO Jayhawk Switch Station-Franklin 161 kV circuit 1	141,239	93,636	90,720
Franklin 161/69 kV transformer FTLO Litchfield-Franklin 161 kV circuit 1	20,543	115,547	140,452

Constraint	Future 1 congestion score		
	Year 2	Year 5	Year 10
Jamestown 7-Valley City 7 115 kV FTLO Hankson 4-Wahpeton XF4 230 kV circuit 1	-	138,430	807
Potter County Interchange transformer 345/230 kV circuit 1 FTLO Hitchland Interchange-Moore County Interchange 230kV circuit 1	28,432	91,298	137,462
Kerr-Maid 161 kV circuit 2 FTLO Kerr-Maid 161kV circuit 1	38,585	22,076	63,931
Fort Thompson transformer 345/230 kV circuit 1 FTLO Fort Thompson transformer 345/230 kV circuit 2	42,564	91,870	129,820
Midway-Bull Shoals 161 kV circuit 1 FTLO Buford Tap-Bull Shoals West 161 kV circuit 1	15,104	25,022	111,854
Gavins Point-Yankton Junction 115 kV circuit 1 FTLO Gavins Point-BEPC-Spirit Mound 115 kV circuit 1	73,063	50,350	120,403
Anadarko Switchyard-Gracemont 138 kV circuit 1 FTLO Minco-Gracemont 345 kV circuit 1	194	16,247	43,114
Gerald Gentleman Station-Ogallala 230 kV circuit 1 FTLO Gerald Gentleman Station-Keystone 345 kV circuit 1	108,637	47,492	119,785
Blackberry-Neosho 345 kV circuit 1 FTLO Blackberry-Wolf Creek 345 kV circuit 1	-	109,358	66,022
Anadarko Switchyard-Gracemont 138 kV circuit 1 FTLO Treasure Island 7-L.E.S 7 345 kV circuit 1	103,594	20,619	44,987
Maple River transformer 345/230 kV circuit 2 FTLO Maple River transformer 345/230 kV circuit 1	-	-	96,549
Ft Smith transformer 345/161 kV circuit 5 FTLO Ft Smith transformer 500/161 kV circuit 1	22,906	73,630	89,927
Red Willow transformer 345/115 kV circuit 1 FTLO Gerald Gentleman Station-Red Willow 345 kV circuit 1	73,649	45,247	63,556
Czech Hall-Cimarron 138 kV circuit 1 FTLO Haymaker-Cimarron 138 kV circuit 1	310	57,637	96,439
Oahe 4-Sully Butte 230kV FTLO LO.LS-CC BE3-CC.LS-LO-BE3-1 345 kV	100,204	38,240	101,131
Sheynne-Mapelton 115 kV circuit 1 FTLO Bison-Buffalo 345 kV circuit 1	48,498	100,044	14,220
Great Bend-Spearville 230 kV circuit 1 FTLO Post Rock-Spearville 345 kV circuit 1	20,073	24,290	31,329
Weber Lake-Norrie 115 kV circuit 1 FTLO Hurley-Gingles 115 kV circuit 1	-	-	93,079
Benton-Wichita 345 kV circuit 1 FTLO Emporia Energy Center-Burns 345 kV circuit 1	10,296	79,769	86,347
Morris County-Grant County 115 kV circuit 1 FTLO Hankson-Wahpeton XF4 230 kV circuit 1	1,577	83,647	-
Springfield-LaRussel 161 kV circuit 1 FTLO Morgan-Jasper 345 kV circuit 1	9,176	81,887	60,726
Earlsboro-Maud 138 kV circuit 1 FTLO Seminole-Muskogee 345 kV circuit 1	-	65,537	81,710
Kelly transformer 161/115 kV circuit 1 FTLO Kelly-Tecumseh Hill 161 kV circuit 1	59,627	25,222	80,410
Southard-Roman Nose 138kV circuit 1 FTLO Base Case	7,767	70,449	79,191
New Madrid Transformer 345/161kV circuit 1 FTLO New Madrid Transformer 345/161kV circuit 2	-	3,245	78,074

Constraint	Future 1 congestion score		
	Year 2	Year 5	Year 10
Czech Hall-Cimarron 138 kV circuit 1 FTLO Cimarron-Draper Lake 345 kV circuit 1	77,396	-	-
Belfield transformer 345/230 kV circuit 1 FTLO Belfield transformer 345/230 kV circuit 2	3,218	30,077	77,241
Southland-Norfork 161 kV circuit 1 FTLO St. Joe-Hilltop 161 kV circuit 1	6,551	16,824	17,925
Fort Thompson-Huron 230 kV circuit 2 FTLO Fort Thompson-Huron 230 kV circuit 1	5,696	6,283	69,948
Morris County-Union Ridge 230 kV circuit 1 FTLO Geary County-Summit 345 kV circuit 1	11,854	24,956	54,036
Beatty-Aberdeen 230 kV circuit 2 FTLO Beatty-Aberdeen 230 kV circuit 1	48,122	68,993	43,903
Dover Switchyard-Okeene Switchyard 138 kV circuit 1 FTLO Watonga Switch Station-Okeene Switchyard 138 kV circuit 1	67,161	-	-
Stone Lake transformer 345kV/161 kV circuit 1 FTLO Base Case	64,461	1,300	-
Stone Lake transformer 345/161 kV circuit 9 FTLO Stone Lake-Gardner Park 345 kV circuit 1	57,991	2,607	-
Sunny Side-Rocky Point 138 kV circuit 1 FTLO Sunny Side-Uniroyal 138 kV circuit 1	-	2,559	30,696
Pelican-Range 69 kV circuit 1 FTLO Cayler-Wisdom 161 kV circuit 1	7,444	26,100	19,545
Granite Falls transformer 230kV/161 kV FTLO Lyon Co - Hawks Nest 345 kV circuit 1	38,638	51,310	-
Skyline-Quail Creek 138 kV circuit 1 FTLO Northwest-Arcadia 345 kV circuit 1	5,041	29,415	45,340
Cimarron transformer 345/138 kV circuit 1 FTLO Cimarron transformer 345/138 kV circuit 2	44,608	5,609	31,045
Haymaker-Cimarron 138 kV circuit 1 FTLO Czech Hall-Cimarron 138 kV circuit 1	119	2,577	28,940
Evans Energy Center North-Maize 138 kV circuit 1 FTLO Benton-Wichita 345 kV circuit 1	3,430	30,470	34,612
Leeds-Wilton Tap 115 kV circuit 1 FTLO Ramsey- Balta 230 kV circuit 1	-	27,013	8,131
Edwardsville transformer 161/115 kV circuit 1 FTLO 87th Street- Craig 345 kV circuit 1	27	3,346	2,462
Tekamah-Sub 1226 161 kV circuit 1 FTLO Raun-Sub 3451 345 kV circuit 1	21,650	23,402	2,211
Litchfield-Asbury 161 kV circuit 1 FTLO Neosho-Riverton 161 kV circuit 1	3,110	6,608	17,490
Marmaton West-Neosho 161 kV circuit 1 FTLO Jayhawk Switch Station-Franklin 161 kV circuit 1	6,411	-	-
Reed Spring-Reeds Spring 161 kV circuit 1 FTLO Beaver-Eureka Springs 161 kV circuit 1	1,185	-	-
Erie-Marmaton West 161 kV circuit 1 FTLO Beaver - Franklin 161 kV circuit 1	-	-	396
Pine & Peoria Tap-46th Street Tap 138 kV circuit 1 FTLO Tulsa North-Cherokee Data Center West Tap 138 kV circuit 1	-	-	-
Moore County Interchange-Rita Blanca S&S 115 kV circuit 1 FTLO Moore County Interchange-McDowell Creek 230 kV circuit 1	-	-	-

Constraint	Future 1 congestion score		
	Year 2	Year 5	Year 10
McDowell Creek-Potter County Interchange 230 kV circuit 1 FTLO Potter County Interchange-Potter County Interchange 230 kV circuit 1	-	-	-
59th St -Gill Energy Center South 138 kV circuit 1 FTLO Benton-Wichita 345 kV circuit 1	-	-	-
Chisholm-Maize 138 kV circuit 1 FTLO Benton-Wichita 345 kV circuit 1	-	-	-
St Joe-Avenue City 161 kV circuit 1 FTLO Gentry-Fairport 161 kV circuit 1	-	-	-
Stilwell-Redel 161 kV circuit 1 FTLO Belton South-Peculiar 161 kV circuit 1	-	-	-
Cambridge-McCook 115 kV circuit 1 FTLO Gerald Gentleman Station-Red Willow 345 kV circuit 1	-	-	-
Dickinson 7-New England 115 kV circuit 1 FTLO Belfield-Daglum 230 kV circuit 1	-	-	-
Hettinger transformer 230/115 kV circuit 1 FTLO Belfield-Daglum 230 kV circuit 1	-	-	-

Table 3.2: Future 1 Economic Needs

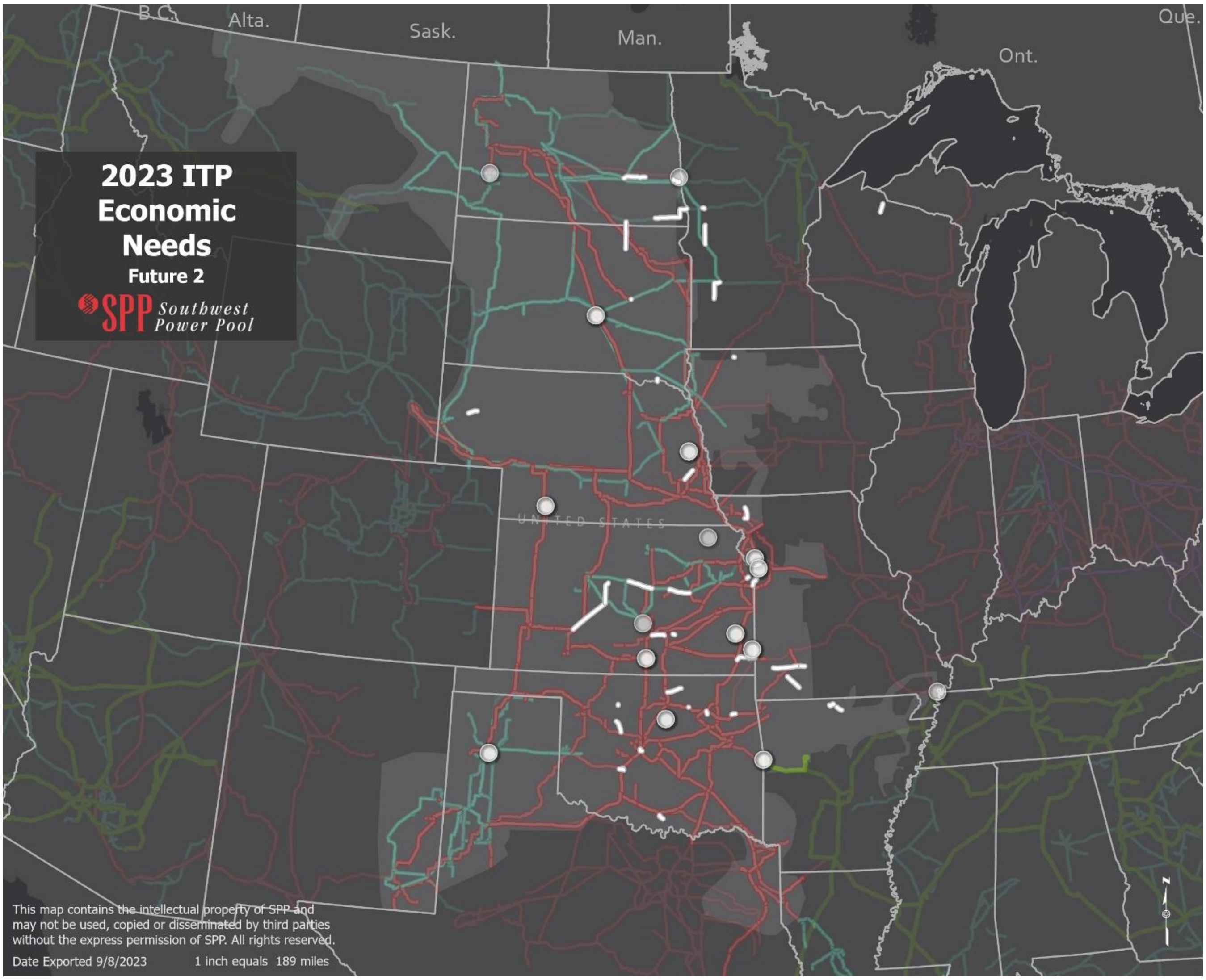

Figure 3.2: Economic Needs – Future 2

Constraint	Future 2 congestion score	
	Year 5	Year 10
Alliance-Snake Creek 115 kV circuit 1 FTLO (For The Loss Of) Stegall-Wayside 230kV circuit 1	452,300	312,263
Watford City-Charlie Creek 230 kV circuit 1 FTLO Charlie Creek 345 kV-Patent Gate 345 kV circuit 1	-	-
Tulsa North-46th Street Tap 138 kV circuit 1 FTLO Tulsa North-Cherokee Data Center West Tap 138 kV circuit 1	342,662	697,530
Osage-Webb City Tap 138 kV circuit 1 FTLO Cleveland 345 kV-Sooner 345 kV circuit 1	516,677	713,420
Huron 115 kV-Huron 'B' Tap 115 kV circuit 1 FTLO Huron-Huron West Park 115 kV circuit 1	711,251	493,159
Forman 230kV-Ybus355 115kV circuit 1 FTLO Hankson-Wahpeton 230kV circuit 1	219,267	-
Granite Falls-Marshall Tap 115 kV circuit 1 FTLO Lyon County 345/115 kV transformer circuit 9	157,752	536,323

Constraint	Future 2 congestion score	
	Year 5	Year 10
Cleo Corner-Cleo Switchyard 69 kV circuit 1 FTLO Cleo Corner-Cleo Corner Tap 138 kV circuit 1	464,737	530,541
Cleveland (GRDA)-Cleveland (AECI) 138 kV circuit Z1 FTLO Tulsa North 345 kV-Cleveland 345 kV circuit 1	128,253	219,789
Butler-Midian 138 kV FTLO Weaver 138 kV-Tallgrass 115 kV	327,046	358,608
Craig 161 kV-Lenexa South 161 kV circuit 2 FTLO Craig 161 kV-Lenexa South 161 kV circuit 1	346,670	255,385
Stilwell-Hickman 161 kV circuit 1 FTLO Stilwell-Redel 161 kV circuit 1	189,265	322,603
Springfield-Clay 161 kV circuit 1 FTLO Huben-Morgan 345 kV circuit 1	97,646	280,760
Hawthorn transformer 345/161 kV circuit 20 FTLO Hawthorn transformer 345/161 kV circuit 22	282,093	270,407
Fremont-Sub 976 transformer 115/69 kV circuit 1 FTLO Sub 1226 161-Sub 1291 161 kV circuit 1	103,423	228,881
Stillwater Kinze-Kinze 138 kV circuit 1 FTLO Cleveland 345 kV-Sooner 345 kV circuit 1	102,203	149,880
Aurora-Reeds Spring 161 kV circuit 1 FTLO Beaver-Eureka Springs 161 kV circuit 1	93,867	153,678
Sub 1214-70th & Bluff 161 kV circuit 1 FTLO Sub 3454-Wagener 345 kV circuit 1	31,451	218,458
Nashua transformer 345/161 kV circuit 11 FTLO Hawthorn-Nashua 345 kV circuit 1	214,874	64,989
Huron-Huron 'B' Tap 115 kV circuit 1 FTLO Groton-Groton South 115 kV circuit 1	54,460	52,957
Ellsworth Tap-Great Bend 115 kV circuit 1 FTLO Circle-Great Bend 230 kV circuit 1	4,329	200,683
Maryville-Midway 161 kV circuit 1 FTLO Gentry-Fairport 161 kV circuit 1	161,018	189,810
Smoky Hills-Summit Ridge 230kV circuit 1 FTLO Axtell 3-Macon 3 345 kV circuit 1	89,216	182,548
Aberdeen Junction 7-Ellendale 7 115 kV FTLO Twin Brooks 3-Big Stone South 3 345 kV circuit 1	175,197	2,046
West Harvey transformer 138/115 kV circuit 1 FTLO Reno County-Wichita 345 kV circuit 1	25,272	168,476
Hoot Lake-Fergus Falls 115 kV circuit 1 FTLO Silver Lake-Fergus Falls 230 kV circuit 1	137,684	303
70th & Bluff-70th & Bluff 115 kV circuit 1 FTLO Sub 3454-Wagener 345 kV circuit 1	15,169	159,648
Anadarko Switchyard-Southwestern Station 138 kV circuit 1 FTLO Anadarko Switchyard -Gracemont 138 kV circuit 1	69,091	151,664
Marmaton East 161 kV-Marmaton West 161 kV circuit Z1 FTLO Jayhawk Switch Station 161 kV-Franklin 69 kV 161 kV circuit 1	65,506	53,726
Franklin 69/161kV circuit 1 FTLO Litchfield 161 kV-Franklin 69 kV 161 kV circuit 1	115,685	130,849
Jamestown 7-Valley City 7 115 kV FTLO Hankson 4-Wahpeton XF4 230kV circuit 1	129,080	2,055
Potter County Interchange transformer 345/230kV circuit 1 FTLO Hitchland Interchange 230kV-Moore County Interchange 230kV circuit 1	92,425	92,573
Kerr 161 kV-Maid 161 kV circuit 2 FTLO Kerr 161 kV-Maid 161 kV circuit 1	17,501	134,712
Fort Thompson transformer 345/230 kV circuit 1 FTLO Fort Thompson transformer 345/230 kV circuit 2	77,658	70,500
Midway-Bull Shoals 161 kV circuit 1 FTLO Buford Tap-Bull Shoals West 161 kV circuit 1	27,208	124,905
Gavins Point 115 kV-Yankton Junction 11kV circuit 1 FTLO Gavins Point 115 kV-BEPC-Spirit Mound 115 kV circuit 1	48,225	94,251
Anadarko Switchyard-Gracemont 138 kV circuit 1 FTLO Gracemont-Minco 345 kV circuit 1	24,651	120,276

Constraint	Future 2 congestion score	
	Year 5	Year 10
Gerald Gentleman Station-Ogallala 230 kV circuit 1 FTLO Gerald Gentleman Station-Keystone 345 kV circuit 1	38,967	35,582
Blackberry-Neosho 345 kV circuit 1 FTLO Blackberry-Wolf Creek 345 kV circuit 1	90,560	62,908
Anadarko Switchyard-Gracemont 138 kV circuit 1 FTLO Treasure Island 7-L.E.S 7 345 kV circuit 1	34,414	29,920
Maple River transformer 345/230 kV circuit 2 FTLO Maple River transformer 345/230 kV circuit 1	-	103,565
Ft Smith transformer 345/161 kV circuit 5 FTLO Ft Smith transformer 500/161 kV circuit 1	102,084	103,545
Red Willow transformer 345/115 kV circuit 1 FTLO Gerald Gentleman Station-Red Willow 345 kV circuit 1	51,475	103,388
Czech Hall-Cimarron 138 kV circuit 1 FTLO Haymaker-Cimarron 138 kV circuit 1	56,957	102,299
Oahe 4-Sully Butte 230kV FTLO LO.LS-CC BE3-CC.LS-LO-BE3-1-345 kV	27,261	48,676
Sheynne-Mapelton 115 kV circuit 1 FTLO Bison-Buffalo 345 kV circuit 1	86,603	8,782
Great Bend-Spearville 230 kV circuit 1 FTLO Post Rock-Spearville 345 kV circuit 1	31,381	94,944
Weber Lake-Norrie 115 kV circuit 1 FTLO Hurley-Gingles 115 kV circuit 1	-	92,860
Benton-Wichita 345 kV circuit 1 FTLO Emporia Energy Center-Burns 345 kV circuit 1	76,745	92,319
Morris County-Grant County 115 kV circuit 1 FTLO Hankson-Wahpeton XF4 230kV circuit 1	62,715	-
Springfield-LaRussel 161 kV circuit 1 FTLO Morgan-Jasper 345 kV circuit 1	75,844	58,419
Earlsboro-Maud 138 kV circuit 1 FTLO Seminole-Muskogee 345 kV circuit 1	32,129	32,101
Kelly transformer 161/115 kV circuit 1 FTLO Kelly-Tecumseh Hill 161 kV circuit 1	39,679	55,529
Southard- Roman Nose 138kV circuit 1 FTLO Base Case	63,974	71,571
New Madrid Transformer 345/161kV circuit 1 FTLO New Madrid Transformer 345/161kV circuit 2	6,420	62,055
Czech Hall-Cimarron 138 kV circuit 1 FTLO Cimarron-Draper Lake 345 kV circuit 1	-	-
Belfield transformer 345/230 kV circuit 1 FTLO Belfield transformer 345/230 kV circuit 2	30,971	61,400
Southland-Norfork 161 kV circuit 1 FTLO St. Joe-Hilltop 161 kV circuit 1	23,746	76,683
Fort Thompson-Huron 230 kV circuit 2 FTLO Fort Thompson-Huron 230 kV circuit 1	11,271	31,080
Morris County-Union Ridge 230 kV circuit 1 FTLO Geary County-Summit 345 kV circuit 1	28,861	69,630
Beatty-Aberdeen 230 kV circuit 2 FTLO Beatty-Aberdeen 230 kV circuit 1	61,797	56,078
Dover Switchyard-Okeene Switchyard 138 kV circuit 1 FTLO Watonga Switch Station-Okeene Switchyard 138 kV circuit 1	-	-
Stone Lake transformer 345/161 kV circuit 1 FTLO Base Case	-	-
Stone Lake transformer 345/161 kV circuit 9 FTLO Stone Lake-Gardner Park 345 kV circuit 1	823	-
Sunny Side 138 kV-Rocky Point 138 kV circuit 1 FTLO Sunny Side 138 kV-Uniroyal 138 kV circuit 1	8,335	54,191
Pelican-Range 69 kV circuit 1 FTLO Cayler-Wisdom 161 kV circuit 1	41,736	51,665
Granite Falls transformer 230kV/161 kV FTLO Lyon Co-Hawks Nest 345 kV circuit 1	32,970	-
Skyline-Quail Creek 138 kV circuit 1 FTLO Northwest-Arcadia 345 kV circuit 1	23,452	49,812

Constraint	Future 2 congestion score	
	Year 5	Year 10
Cimarron transformer 345/138 kV circuit 1 FTLO Cimarron transformer 345/138 kV circuit 2	5,028	37,069
Haymaker-Cimarron 138 kV circuit 1 FTLO Czech Hall-Cimarron 138 kV circuit 1	3,491	42,156
Evans Energy Center North-Maize 138 kV circuit 1 FTLO Benton-Wichita 345 kV circuit 1	19,206	12,707
Leeds 115 kV-Wilton Tap 115 kV circuit 1 FTLO Ramsey- Balta 230kV circuit 1	6,469	1,663
Edwardsville transformer 161/115 kV circuit 1 FTLO 87th Street-Craig 345 kV circuit 1	23,688	2,280
Tekamah-Sub 1226 161 kV circuit 1 FTLO Raun-Sub 3451 345 kV circuit 1	19,910	15,989
Litchfield-Asbury 161 kV circuit 1 FTLO Neosho-Riverton 161 kV circuit 1	6,856	21,974
Marmaton West 161 kV-Neosho 161 kV circuit 1 FTLO Jayhawk Switch Station 161 kV-Franklin 69 kV 161 kV circuit 1	-	-
Reed Spring-Reeds Spring 161 kV circuit 1 FTLO Beaver-Eureka Springs 161 kV circuit 1	-	3
Erie - Marmaton West 161 kV circuit 1 FTLO Beaver - Franklin 161 kV circuit 1	20	-
Pine & Peoria Tap-46th Street Tap 138 kV circuit 1 FTLO Tulsa North-Cherokee Data Center West Tap 138 kV circuit 1	-	-
Moore County Interchange-Rita Blanca S&S 115 kV circuit 1 FTLO Moore County Interchange-McDowell Creek 230 kV circuit 1	-	-
McDowell Creek-Potter County Interchange 230 kV circuit 1 FTLO Potter County Interchange-Potter County Interchange 230 kV circuit 1	-	-
59th St -Gill Energy Center South 138 kV circuit 1 FTLO Benton-Wichita 345 kV circuit 1	-	-
Chisholm-Maize 138 kV circuit 1 FTLO Benton-Wichita 345 kV circuit 1	-	-
St Joe-Avenue City 161 kV circuit 1 FTLO Gentry-Fairport 161 kV circuit 1	-	-
Stilwell 161 kV-Redel 161 kV circuit 1 FTLO Belton South 161 kV-Peculiar 69 kV 161 kV circuit 1	-	-
Cambridge-McCook 115 kV circuit 1 FTLO Gerald Gentleman Station-Red Willow 345 kV circuit 1	-	-
Dickinson 7-New England 115 kV circuit 1 FTLO Belfield-Daglum 230 kV circuit 1	-	-
Hettinger transformer 230/115 kV circuit 1 FTLO Belfield-Daglum 230 kV circuit 1	-	-

Table 3.3: Future 2 Economic Needs

3.2 RELIABILITY NEEDS

3.2.1 BASE RELIABILITY ASSESSMENT

Contingency analysis for the base reliability models consisted of analyzing P0, P1 and P2.1 planning events from Table 1 in the NERC TPL-001-4 standard,[18] as well as remaining events that do not allow for non-consequential load loss or the interruption of firm transmission service.

During the needs assessment, potential violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, and identification of invalid contingencies, non-load-serving buses and facilities not under SPP's functional control. Preliminary violations were posted ahead of the needs assessment to provide Transmission Owners with the opportunity to review the violations and provide invalidation feedback prior to the posting of the needs and opening of the detailed project proposals (DPP) window. Stakeholder feedback improved the quality of the final list of identified needs, helped staff remove invalid needs, and improved the pertinence of DPPs submitted by stakeholders.

Figure 3.3 and Figure 3.4 summarize the final quantity of thermal and voltage needs[19] that were unable to be mitigated during the screening process and Figure 3.5 and Figure 3.6 show their locations.

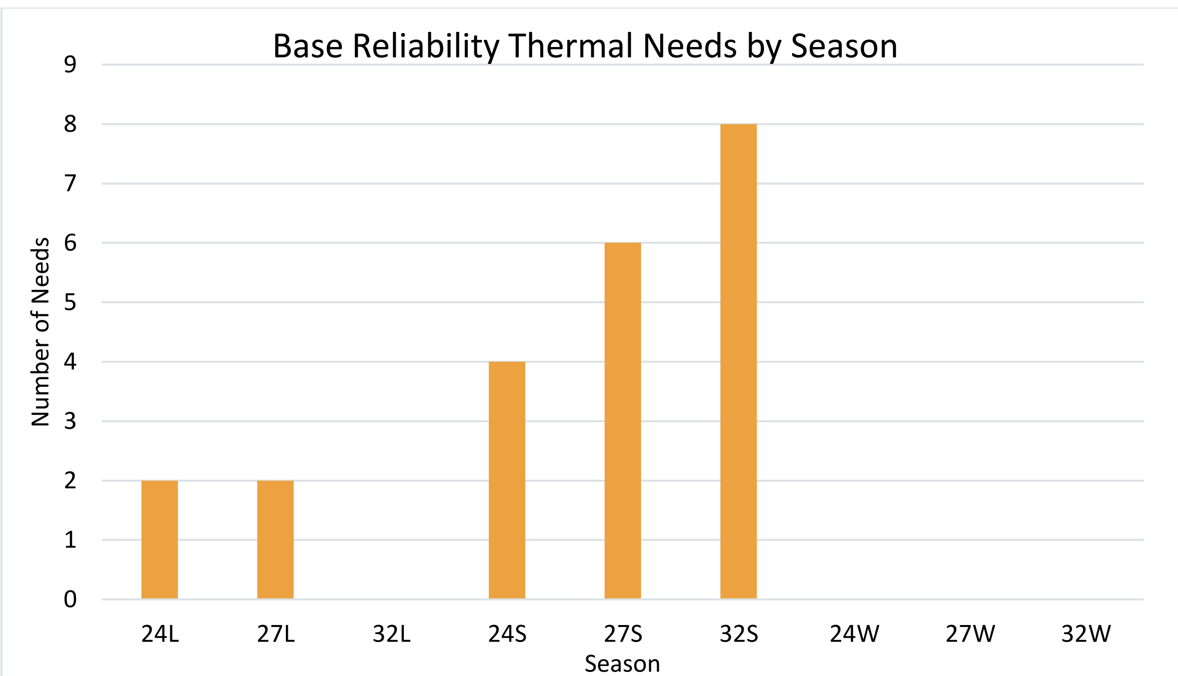

Figure 3.3: Unique Base Reliability Thermal Needs by Season

[18] NERC Standard TPL-001-4 - Transmission System Planning Performance Requirements
[19] Figures summarize unique monitored elements.

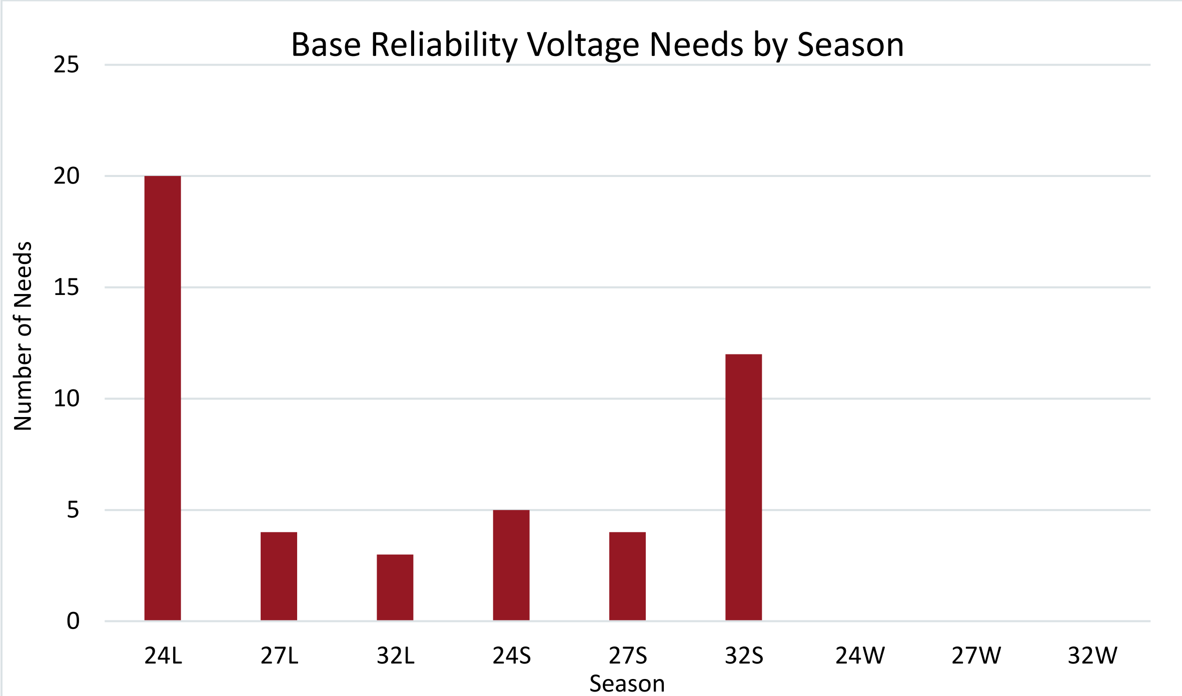

Figure 3.4: Unique Base Reliability Voltage Needs by Season

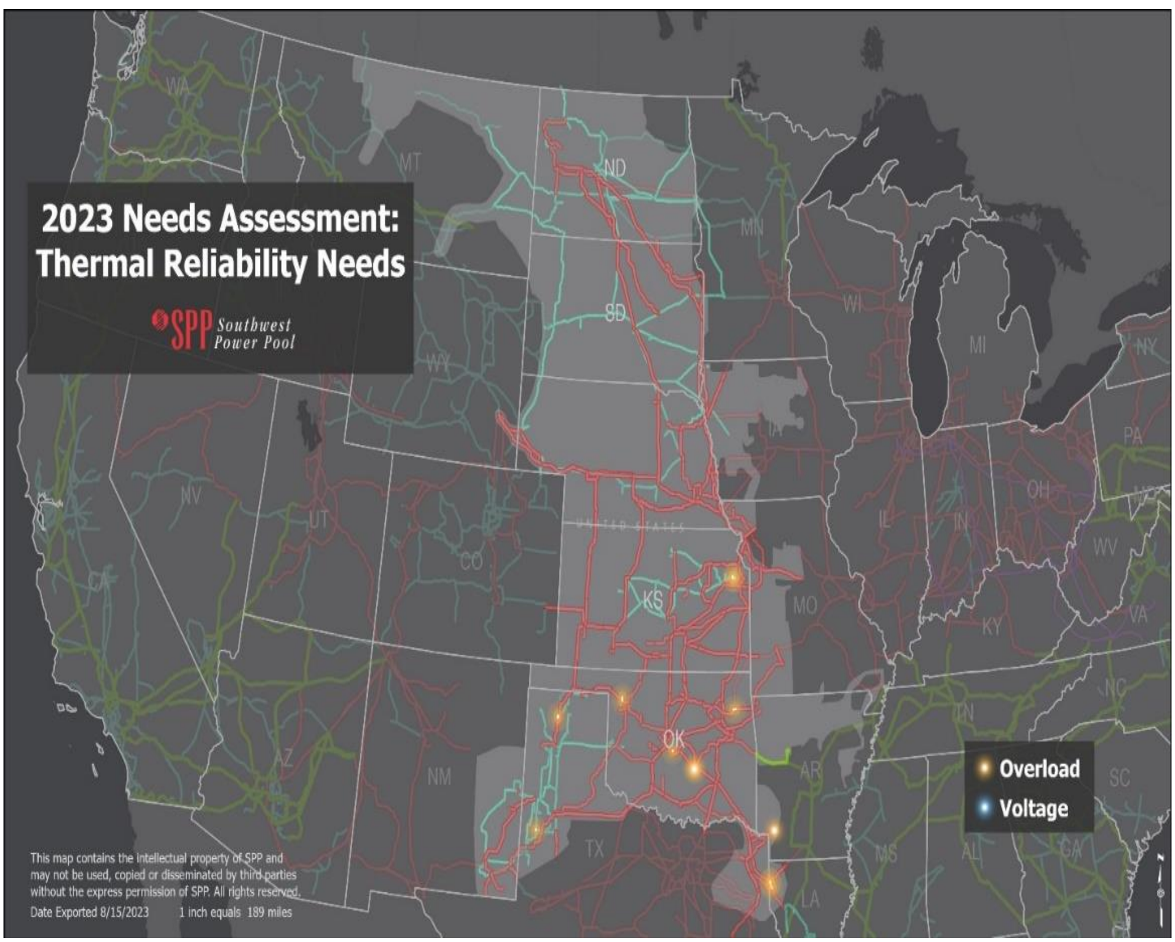

Figure 3.5: Base Reliability Needs - Thermal

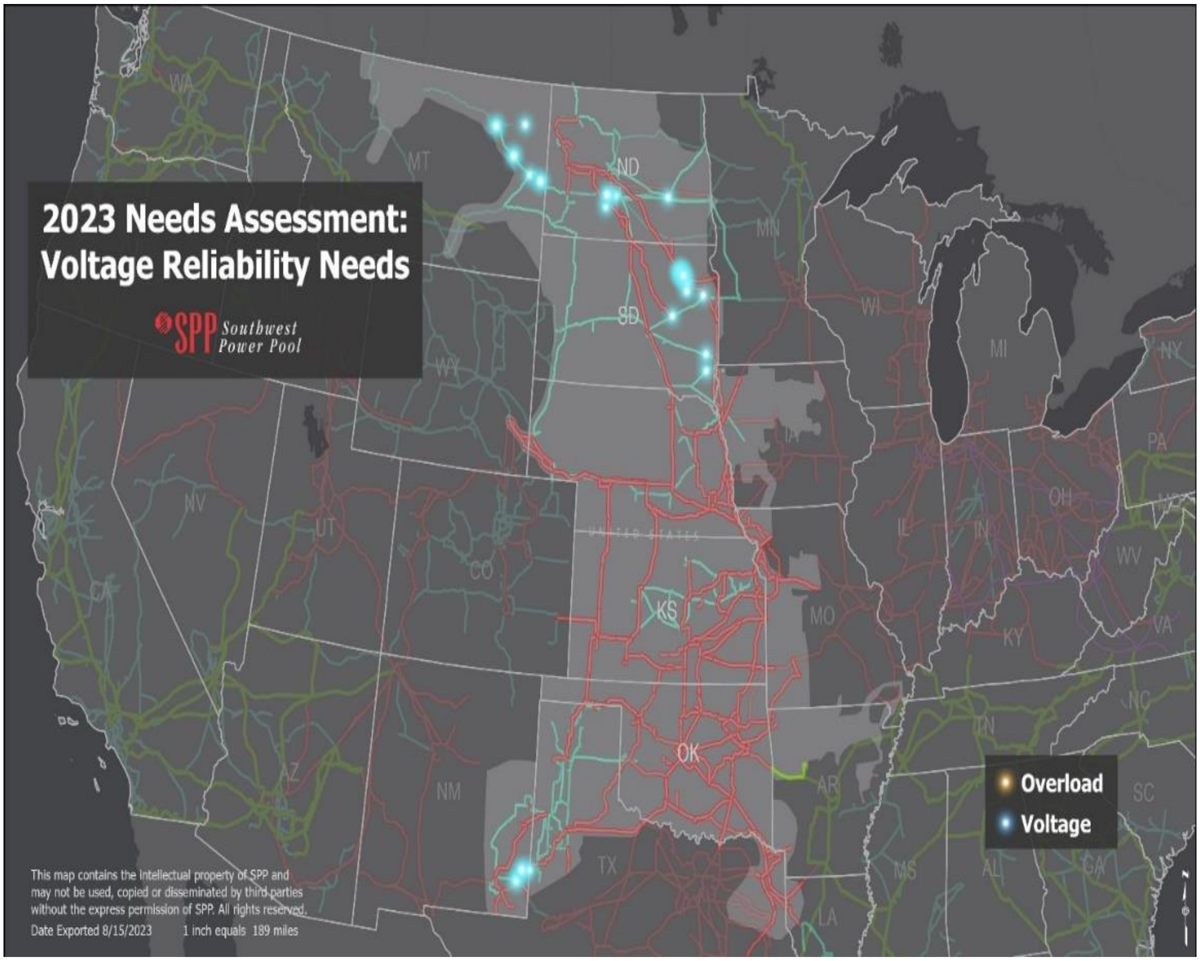

Figure 3.6: Base Reliability Needs – Voltage

Monitored Element	Model	From Bus Area	To Bus Area
TURK 3 - TURK 4 - TURK1 1 115/138 kV CKT 1	24S	AEPW	AEPW
FLOURNY4 - OAKPH 4 138 kV CKT 1	32S	AEPW	AEPW
LONGWD 4 - OAKPH 4 138 kV CKT 1	32S	AEPW	AEPW
KERR GR5 - MAID 5 161 kV CKT 1	27L	GRDA	GRDA
KERR GR5 - MAID 5 161 kV CKT 2	27L	GRDA	GRDA
NEWGRTP2 - WDNITRO2 69 kV CKT 1	24S	OKGE	OKGE
SEMINOL4 - SEMINOL7 - SEMINO11 138/345 kV CKT 1	24S	OKGE	OKGE
SEMINOL4 - SEMINOL7 - SEMINO11 138/345 kV CKT 2	24S	OKGE	OKGE
SW134TP4 - WESTMOR4 138 kV CKT 1	32S	OKGE	OKGE
MOORE_W 3 - RB-S&S 3 115 kV CKT 1	32S	SPS	SPS
BISMARK3 - FAIRGDS3 115 kV CKT 1	32S	WERE	WERE

Monitored Element	Model	From Bus Area	To Bus Area
LWRNCHL3 - WREN 3 115 kV CKT 1	32S	WERE	WERE

Table 3.4: Most Severe Base Reliability Thermal Needs Sorted by Area and Model

MONITORED ELEMENT	MODEL	Area
BUCKEYE 3 115 kV	32S	SPS
BUCKEYE_TP 3 115 kV	32s	SPS
LE-NRTH_INT3 115 kV	32s	SPS
LE-WAITS 3 115 kV	32S	SPS
LE-WEST_SUB3 115 kV	32S	SPS
DEVAUL -MG7 115 kV	27L	WAPA
MANSWTCH-MG7 115 kV	27L	WAPA
NEWSALEM-MG7 115 kV	27L	WAPA
NWMDNTAP-MG7 115 kV	27L	WAPA

Table 3.5: Most Severe Base Reliability Voltage Needs Sorted by Area and Model

3.2.2 NON-CONVERGED CONTINGENCIES

SPP used engineering judgment to resolve non-converged cases from the contingency analysis. All non-converged cases were resolved either through alternate powerflow solve methodologies, model corrections, or the contingencies were determined to be invalid. No contingencies in scope of the 2023 ITP Assessment were identified as a potential driver for voltage collapse.

3.2.3 SHORT-CIRCUIT ASSESSMENT

SPP provided the total bus fault current study results for single-line-to-ground (SLG) and three-phase faults to Transmission Planners (TPs) for review.

TPs were required to evaluate the results and indicate if any fault-interrupting equipment would have its duty ratings exceeded by the maximum available fault current. For equipment that would have its duty ratings exceeded, the TP provided the applicable duty rating of the equipment and the violation was identified as a short-circuit need.

The TPs can perform their own short-circuit analysis to meet the requirements of TPL-001. However, any corrective action plans that result in the recommended issuance of an NTC are based on the SPP short-circuit analysis.

The TPs identifying short-circuit needs were Oklahoma Gas and Electric Company and Evergy Metro. The needs are depicted in Figure 3.7.

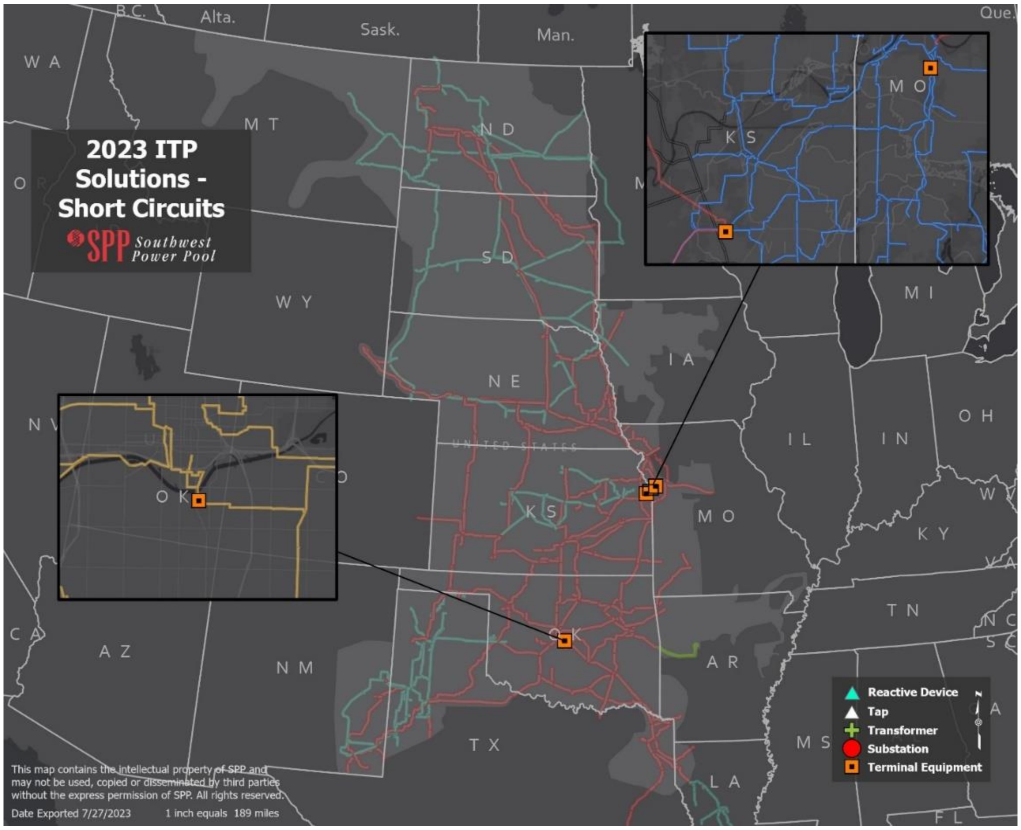

Figure 3.7: Short-Circuit Needs – Over Dutied Breakers

3.3 PUBLIC POLICY NEEDS

Policy needs were analyzed based on the curtailment of renewable energy such that an energy-based renewable portfolio standard is not able to be met. Each zone with an energy mandate or goal was analyzed on a utility-by-state level 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.

All utilities met their overall renewable mandates and goals, thus no policy needs were identified in the 2023 ITP.

3.4 PERSISTENT OPERATIONAL NEEDS

3.4.1 ECONOMIC OPERATIONAL NEEDS

The economic operational needs that did not already have NTCs for the 2023 ITP in Table 3.6 were identified based on flowgates experiencing at least $10 million in congestion costs over the prior 24 months.

Monitored Element	Contingent Element
Nashua 345/161 kV XFMR	Nashua-Hawthorn 345 kV
Hawthorn 345/161 kV XFMR	Hawthorn 345/161 kV XFMR
Nebraska City-Sub 3456 345 kV	Sub 3740-Sub 3455 345kV
Carpenter-Hitchland 345 kV Liberal-Texas County 115 kV Jericho-Kirby SW Station 115 kV Sweetwater-Wheeler 230 kV Shamrock-Mclean South 115 kV Oklaunion-Tuco 345 kV Beaver County-Hitchland #1 345kV Beaver County-Hitchland #2 345kV Border-Tuco 345kV	
Crossroads-Eddy 345 kV Yoakum-Hobbs 345 kV San Juan-Chaves 230 kV Ink Basin-Hobbs 230 kV	
Gentleman-Red Willow 345 kV Gentleman-Sweetwater 345 kV Ckt 1 Gentleman-Sweetwater 345 kV Ckt 2 Gentleman-North Platte 230 kV Ckt 1 Gentleman-North Platte 230 kV Ckt 2 Gentleman-North Platte 230 kV Ckt 3	
Wichita 345/138 kV XF #2	Wichita 345/138 kV XF #1
Fort Thompson 345/230 kV XF #2	Fort Thompson 345/230 kV XF #1
Tahlequah-Highway 59 161 k	Muskogee-Ft Smith 345 kV
Colby-Atwood 115 kV	Mingo-Setab 345 kV
Conway-Kirby 115 kV	Nichols-Grapevine 345 kV
Potter South 345/230 kV XFMR	Hitchland-Moore Co. 230 kV
Northwest 345/138 kV XFMR	Northwest 345/138 kV XFMR
County Line-Tecumseh Hill 115kV	Sibley-Overton 345 kV
Gentleman-Ogallala 230 kV	Gentleman-Keystone 345 kV
Monett-Aurora 161 kV	Blackberry-Jasper 345 kV
Viola 345/138 kV XFMR	Viola-Wichita 345 kV
Nashua-Liberty 161 kV	Hawthorn-Nashua 345kV
Gracemont-Anadarko 138 kV	Washita-SW Station 138 kV
Gracemont-Anadarko 138 kV	Treasure-Lawton 345 kV
Potter 345/230 kV XF	Border-Tuco 345 kV
Wichita-Benton 345 kV	Wolf Creek Unit

Table 3.6: Economic Operational Needs

The constraints in Table 3.7 have associated previously issued future upgrades, which are expected to reduce some or all congestion costs associated with the constraint.

Monitored Element	Contingent Element	Notes
Cimarron 345/138 kV XF 3	Cimarron 345/138 kV XF 2	NTC 210616: Multi - Minco-Pleasant Valley-Draper 345 kV
Midwest-Franklin 138 kV	Cedar Lane-Canadian 138 kV	NTC 210656: Midwest 138 kV Ckt 1 Terminal Upgrades
Bushland-Deaf Smith 230 kV	Potter South-Newhart 230 kV	NTC 210574: Bushland-Deaf Smith 230 kV Terminal Upgrades
Cimarron-Draper 345 kV	Northwest-Arcadia 345 kV	NTC 210616: Multi - Minco-Pleasant Valley-Draper 345 kV
Waverly-Lacynge 345 kV	Neosho Ridge-Neosho 345 kV	NTC 210626: Blackberry-Wolf Creek 345 kV
Russett-S Brown 138 kV	Little City-Brown Tap 138 kV	NTC 210586: Russett-South Brown 138 kV Ckt 1 Rebuild

Table 3.7: Economic Operational Need-Previously Issued

The constraint in Table 3.8 is impacted by previously issued NTCs, which are already in-service. These projects have reduced the cost of congestion on this constraint over the last two years. Although the constraint still meets the need criteria, no congestion cost has been recorded since the upgrades have been in-service. This facility is expected to no longer meet the persistent operational criteria in the future.

Monitored Element	Contingent Element	Notes
Neosho-Riverton 161 kV	Blackberry-Neosho 345 kV	NTC 210570: Line - Neosho-Riverton 161 kV

Table 3.8: Economic Operational Need-Previously Issued

3.4.2 RELIABILITY OPERATIONAL NEEDS

There were not any reliability operational needs identified during the 2023 ITP.

3.5 SOLUTION EVALUATION

Solutions were evaluated in each applicable scenario to determine their effectiveness in mitigating the needs identified in the needs assessment. The solutions assessed included the Federal Energy Regulatory Commission (FERC) Order 1000 and Order 890 solutions submitted by stakeholders, SPP staff-developed solutions, model adjustments, and model corrections. SPP analyzed 677 DPP solutions received from stakeholders and approximately 400 solutions developed by SPP staff. A standardized conceptual cost[20] template was used to calculate a conceptual cost estimate for each project to utilize during screening.

3.5.1 RELIABILITY PROJECT SCREENING

Solutions were tested to determine their ability to mitigate reliability criteria violations in the study horizon. Solutions were deemed effective if they resolved system violations to a level allowed by the SPP Planning Criteria and members' more stringent local planning criteria. Figure 3.8 illustrates the reliability project screening process.

Reliability metrics developed by SPP and stakeholders and approved by the TWG were calculated for each project and used as a tool to aid in developing a portfolio of projects to address all reliability needs. The first metric is a cost per loading relief (CLR) score, which relates the amount of thermal loading relief a solution provides to its engineering and construction (E&C) cost. The second metric is cost per voltage relief (CVR) score, which relates the amount of voltage support a solution provides to its E&C cost.

[20] SPP OATT Business Practices, Section 8

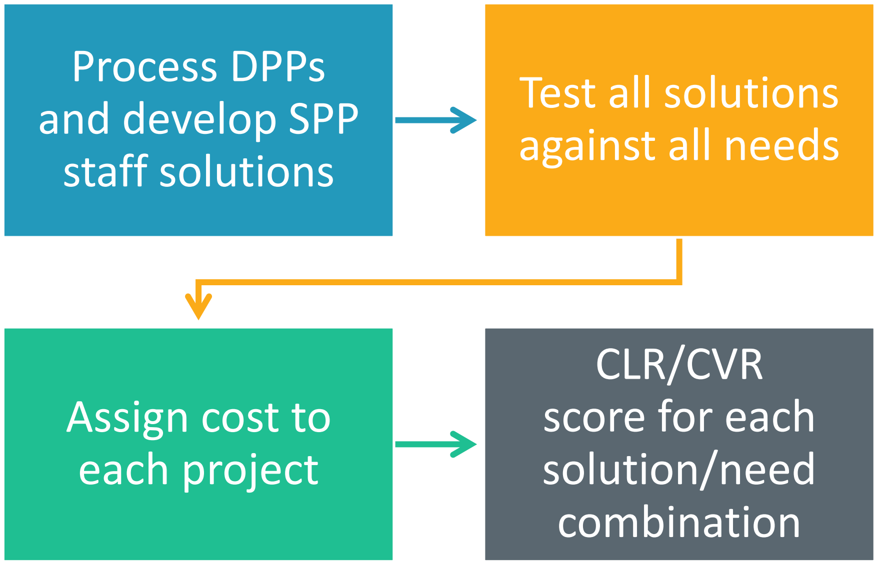

Figure 3.8: Portfolio Development Process

3.5.2 ECONOMIC PROJECT SCREENING

Solutions were evaluated to determine their effectiveness in mitigating transmission congestion in the study horizon. A one-year B/C ratio and a 40-year PV B/C ratio were calculated for each project based on its projected APC savings in each future and study year.

The annual change in APC for all SPP pricing zones is considered the one-year benefit to the SPP region for each study year. The one-year benefit is divided by the one-year cost of the project to develop a one-year B/C ratio for each project. The one-year cost, or projected ATRR, is calculated using a historical SPP average net plant carrying charge (NPCC) multiplied by the project conceptual cost. The NPCC used for this assessment was 16.36%. The 40-year project cost is calculated using this NPCC, an 8% discount rate and a 2.0% inflation rate.

The correlation of congestion in different areas of the system was identified and accounted for during the economic screening process. Where appropriate, this included adding new flowgates to screening simulations to ensure potential congestion created by projects would be captured, as well as pairing certain projects to ensure correlated congestion would be resolved by a more comprehensive solution set. These adjustments ensure the projected benefits of projects are not over- or understated.

Some solutions submitted to address persistent operational economic needs identified in during the needs assessment were also tested on the additional event file that was posted.

3.5.3 SHORT CIRCUIT PROJECT SCREENING

Solutions submitted to address overdutied fault-interrupting equipment were reviewed to ensure the updated fault-interrupting equipment ratings submitted were greater than the maximum available fault current identified in the short-circuit needs assessment.

3.5.4 PUBLIC POLICY PROJECT SCREENING

No public policy needs were identified in the 2023 ITP; therefore, no projects were screened to address public policy needs.

3.5.5 PERSISTENT OPERATIONAL PROJECT SCREENING

The persistent economic operational needs were provided for informational purposes only, however many persistent economic operational needs were also identified as an economic need in the near-term planning horizon. Projects addressing those needs were screened using the economic project screening criteria.

3.5.6 STUDY COST ESTIMATES AND PROJECT SELECTION

Solutions that performed well using the screening assessments in the Solution Development and Evaluation milestone were sent to the incumbent transmission owner(s) for the development of Study Cost Estimates (SCE).[21] In cases where a study cost estimate was not received, conceptual cost estimates were utilized. Study cost estimates received were used for the remainder of the portfolio development process.

[21] SPP OATT Business Practices , Section 8

4 PORTFOLIO DEVELOPMENT AND PROJECT SELECTION

4.1 PORTFOLIO DEVELOPMENT PROCESS

Figure 4.1 shows a high-level overview of the portfolio development process. The process starts with the utilization of project metric results in project grouping and continues through the development of a consolidated portfolio that comprehensively addresses the system's needs.

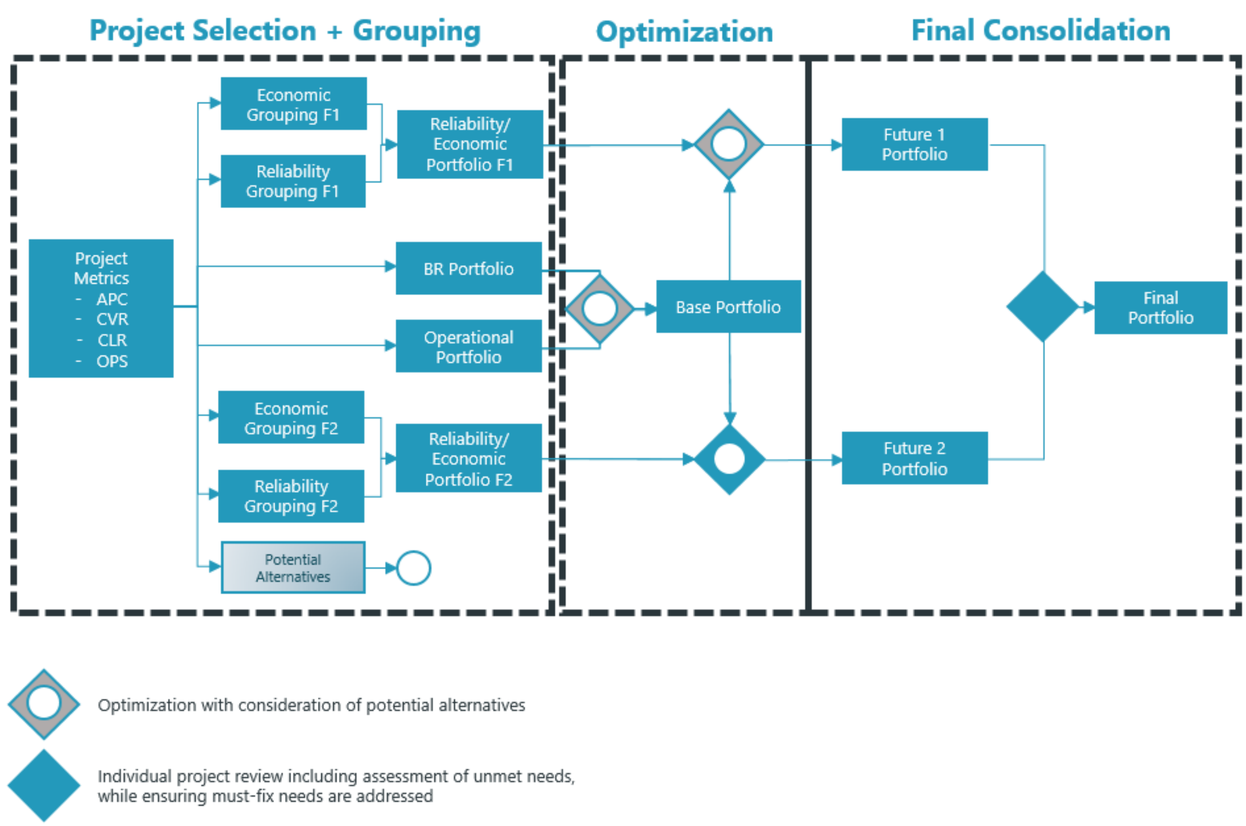

Figure 4.1: Portfolio Development Process

4.2 PROJECT SELECTION AND GROUPING

Once all solutions were screened, draft groupings were developed in parallel to address the different need types across the system. SPP used study estimates and stakeholder feedback from regularly-scheduled working group meetings, the August 2023 SPP transmission planning summit SPP's Request Management System.

4.2.1 STUDY COST ESTIMATES

Solutions that performed well using the screening assessments described in section 3.5, Solution Development and Evaluation, were sent to the incumbent Transmission Owner for the development of Study Cost Estimates (final project cost within ±30%). In cases where the Study Cost Estimates were not received before the August 2023 SPP Transmission Planning Summit, conceptual cost estimates were utilized. Individual project upgrades with the potential to be deemed competitive were sent to a third party cost estimator. Remaining project upgrades were sent to the incumbent transmission owner(s). Once the Study Cost Estimates were received, the project cost was updated so that the Study Cost Estimate was used for the remainder of the portfolio development process.

4.2.2 RELIABILITY GROUPING

SPP used a programmatic method to compare the metric results of the extensive number of solutions being evaluated. Using this solution selection software, a subset of solutions was generated by considering the metrics described in section 3.5.1. During this process, SPP applied engineering judgment to develop a draft list of best solutions high-performing alternate solutions. This analysis was performed for each of the base reliability needs.

The list of reliability solutions was continually refined through stakeholder feedback and review of analysis results. Table 4.1 below shows the final reliability grouping selected to address the reliability needs in the 2023 ITP, while Figure 4.2 shows the approximate location of identified projects within the SPP footprint.

Project	Area	Cost	Scenario[22]
Flournoy-Oak Pan-Harr-Longwood 138 kV rebuild	AEPW	$ 20,446,720	23S/BR
Replace Turk 138/115 kV circuit 1 transformer	AEPW	$5,250,000	24S/BR
Kerr-Maid 161 kV circuit 1 and 2 rebuild	GRDA	$20,555,599	24L/BR/MEM
Newman Grace Tap and Woodward Nitrogen 69 kV terminal equipment	OKGE	$217,311	24S/BR

[22] This is the earliest season.

Project	Area	Cost	Scenario[22]
Pennsylvania-Southgate-Westmoore 138 kV extend line	OKGE	$15,160,147	27S/BR
Seminole 345/138 kV new circuit 3 transformer	OKGE	$8,306,343	24S/BR
Moore Co 115 kV terminal equipment	SPS	$210,000	23S/BR
Cunningham-Quahada 115 kV tap line-Buckeye Tap 115 kV new line	SPS	$25,715,000	24S/BR
Lovington 40 MVAR Reactor	SPS	$4,457,880	23S/BR
Sundown Interchange 115 kV terminal equipment	SPS	$393,298	23S/BR
Devaul 115 kV 15 MVAR reactor	WAPA	$1,671,705	24L/BR
Fort Peck-Dawson County 230 kV 40 MVAR line reactor	WAPA	$4,007,750	24S/BR
Broadland 345 kV 75 MVAR reactor	WAPA	$5,445,170	24L/BR
Groton 345 kV 68 MVAR reactor	WAPA	$5,162,152	24L/BR
Extend Craig-West Gardner 345 kV, Clearview-Eudora 115 kV Tap, new 345/115 kV substation	KCPL/WERE	$42,141,390	27S/BR
	Total	**$159,140,465**	

Table 4.1: Reliability Project Grouping

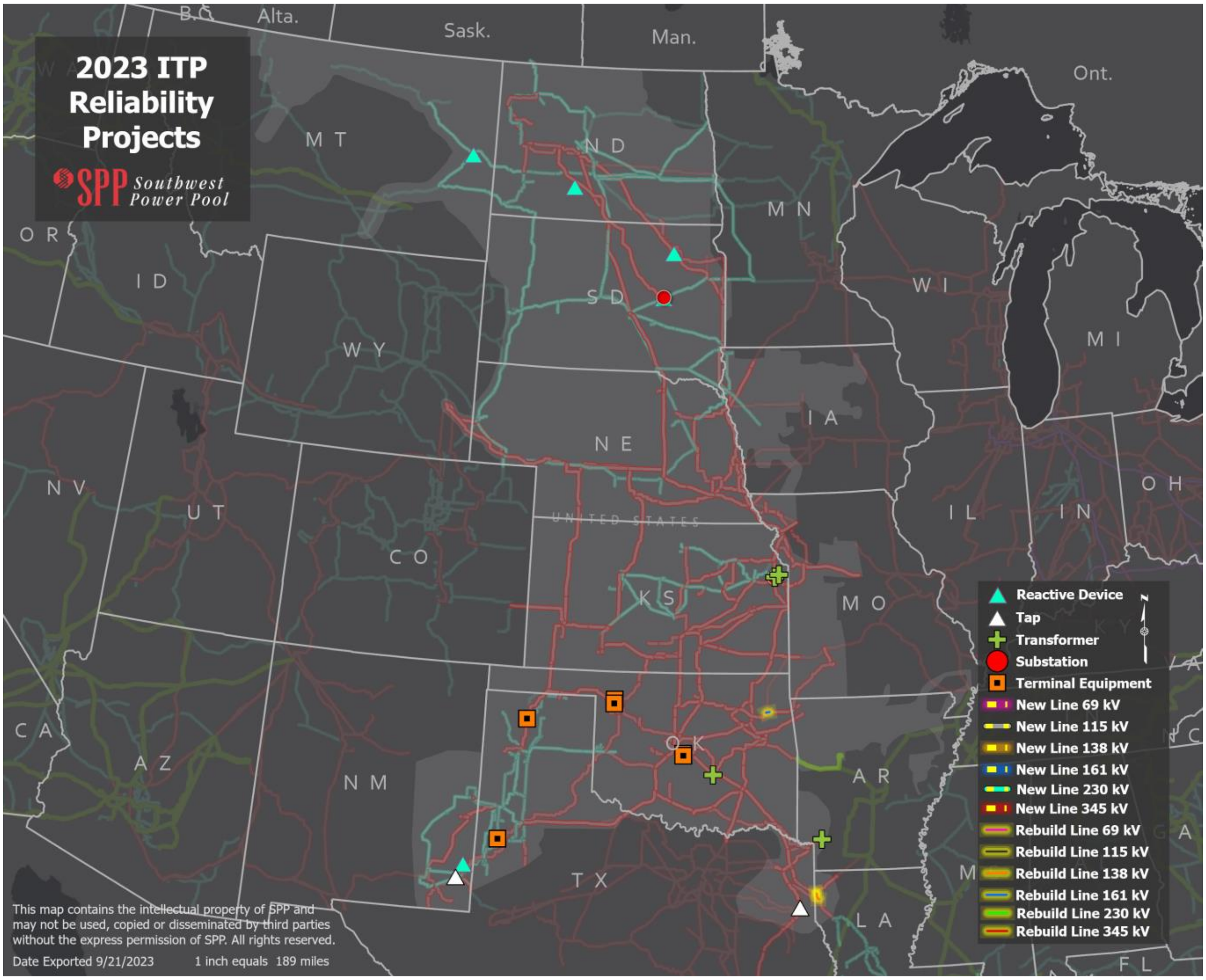

Figure 4.2: Reliability Project Grouping

4.2.3 SHORT-CIRCUIT GROUPING

The solutions submitted to address overdutied fault interrupting equipment identified in the short-circuit needs assessment were grouped together as a set of solutions to address the short-circuit needs. No testing was required for these solutions because the submitted upgrades are only required to be rated higher than the maximum fault current identified in the needs assessment. Table 4.2 summarizes the final short-circuit grouping, while Figure 4.3 shows the approximate location of identified projects within the SPP footprint.

Reliability Project	Area	Cost	Scenario
Blue Valley 161 kV one breaker replacement	KCPL	$310,351	24S / BR
Craig 161 kV five breaker replacements	KCPL	$3,047,451	24S / BR
Lightning Creek 138 kV two breaker replacements	OKGE	$1,418,348	24S / BR
	Total	**$4,776,150**	

Table 4.2: Short-Circuit Project Grouping

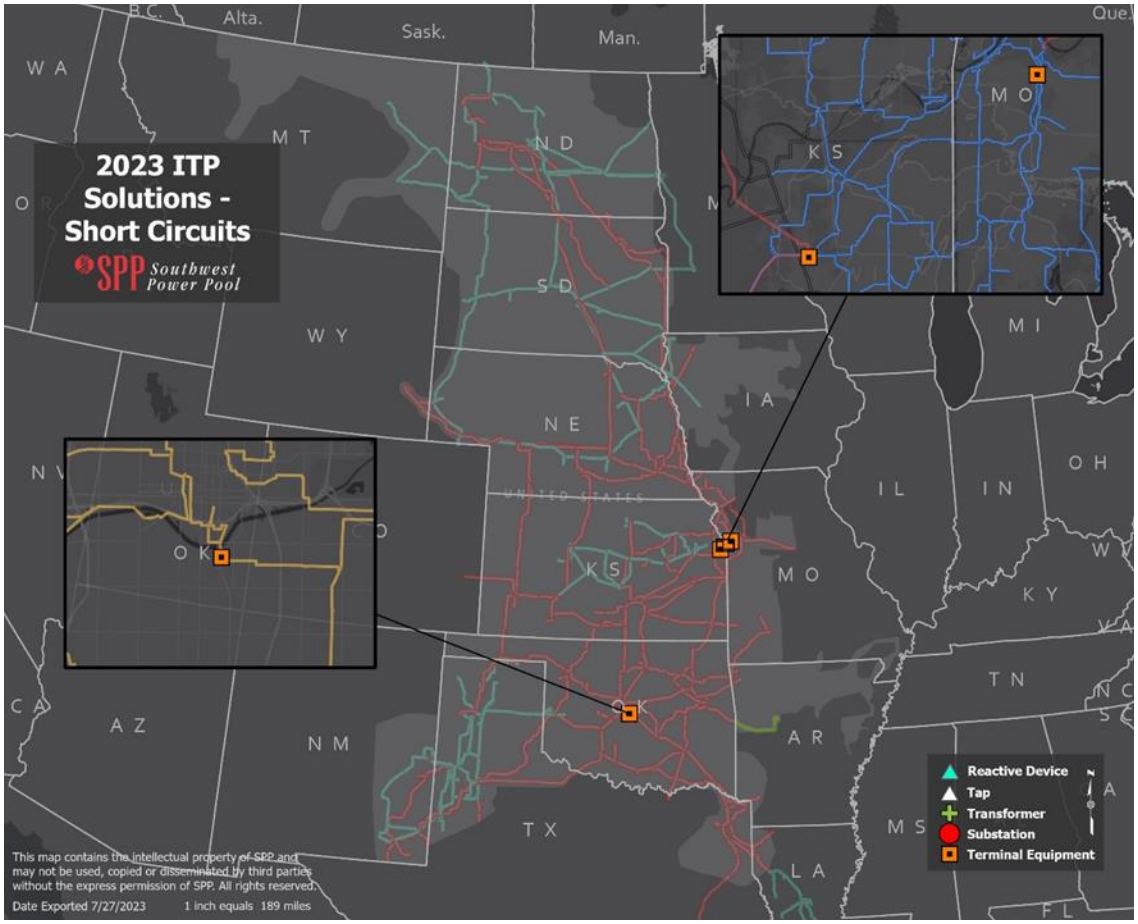

Figure 4.3: Short-Circuit Project Grouping

4.2.4 ECONOMIC GROUPING

All projects with a one-year B/C ratio of at least 0.5 or a 40-year PV B/C ratio of at least 1.0 during the project screening phase were further evaluated while developing project groupings. Projects were evaluated and grouped based on one-year project cost, one-year APC benefit, 40-year project cost, 40-year PV B/C ratio and congestion relief for the economic needs.

Three economic project groupings were developed for each future, resulting in six total groupings:

1. Cost-Effective (CE): Projects with the lowest cost per congestion relief for a single economic need

2. Highest Net APC Benefit (HN): Projects with the highest APC benefit minus project cost, with consideration of overlap if multiple projects mitigate congestion on the same economic needs
3. Multi-variable (MV): Projects selected using data from the two other groupings; including the flexibility to use additional considerations

The following factors were considered when developing and analyzing project groupings per future:

- One-year project cost, APC benefit and B/C ratio
- 40-year PV cost, APC benefit and the B/C ratio
- Congestion relief a project provides for the economic needs of that future and year
- Project overlap, or when two or more projects that relieve the same congestion are in a single portfolio
- Potential for a project to mitigate multiple economic needs
- Any potential routing or environmental concerns with projects
- Any long-term concerns about the viability of projects
- Seams and non-seams project overlap
- Relief of downstream and/or upstream issues, tested by event file modification
- Potential for a project to mitigate reliability, operational or public policy needs
- Potential for a project to address non-thermal issues
- Need for new infrastructure versus leveraging existing infrastructure
- Larger-scale solutions that provide more robustness and additional qualitative benefits

4.2.4.1 *INITIAL ECONOMIC GROUPINGS*

Table 4.3 identifies a comprehensive list of economic projects included in the six initial groupings. All but one project appeared in multiple groupings.

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Osage-Webb City Tap 138 kV rebuild	X	X	X	X	X	X
46Th Street Tap-Pine & Peoria Tap 138 kV rebuild	X	X	X	X	X	X
Kerr-Maid 161 kV Ckt 1 and 2 rebuild	X	X	X	X	-	-
Kerr-Maid 161 kV circuit 3 new line	-	-	-	-	X	X
Cleveland 138 kV Terminal Equipment	X	X	X	X	X	X
Earlsboro-Maud 138 kV terminal equipment	X	X	X	X	X	X
Fitzgerald Creek-Kenzie 138 kV line tap at Valley	X	X	X	X	X	X
Cimarron 345/138 kV circuit 3 transformer	X	X	X	X	X	X
Cimarron-Czech Hall 138 kV rebuild	X	-	-	X	-	-
Czech Hall and Cimmarron 138 kV terminal equipment	-	X	X	-	X	X
Fort Smith 500/345 kV transformer	X	X	X	X	X	X

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Chisholm Creek-Lone Oak 138 kV new line	-	-	-	X	-	-
Rocky Point-Sunnyside 138 kV terminal equipment	-	-	-	X	X	X
Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake	-	X	X	-	X	X
Arcadia-Spring Creek-Matthewson 345 kV new line	-	X	X	-	X	X
Cleo Corner-Okeene 138 kV new line	X	X	X	X	X	X
Okeene-Southard 138 kV new line	-	-	-	X	X	X
Draper-Gracemont 345 kV new line	-	-	X	-	-	X
Anadarko-Gracemont 345 kV new line	-	X	-	-	X	-
Anadarko-Southwestern 138 kV terminal equipment	X	X	-	X	X	-
Potter County 345/230 kV circuit 2 transformer	X	X	-	X	X	-
Potter-Tolk 345 kV new line	-	-	X	-	-	X
Ellsworth Tap-Great Bend 115 kV structures	-	-	-	X	X	X
Great Bend and Spearville 230 kV terminal equipment	-	-	-	X	X	-
West Harvey 138/115 kV transformer	X	X	X	X	X	X
Butler-Midian 138 kV terminal equipment	X	-	-	X	-	-
Butler-Midian 138 kV rebuild	-	X	X	-	X	X
Benton-Wichita 345 kV terminal equipment	X	X	X	X	X	X
Franklin 161/69 kV Circuit 2 transformer	X	X	X	X	X	X
Marmaton East-Marmaton West 161 kV substation rebuild	X	X	X	X	X	X
Blackberry-Neosho 345 kV terminal equipment	X	X	-	X	X	-
Blackberry-Neosho 345 kV rebuild	-	-	X	-	-	X
Craig-Lenexa South 161 kV circuit 2 terminal equipment	X	-	-	X	-	-
Craig-Lenexa South 161 kV circuit 2 rebuild	-	X	X	-	X	X
New 345/161 kV Hawthorn transformer circuit 3	-	-	-	X	X	X
Lyon 115/345 kV transformer	-	X	X	-	-	-
Alliance-Victory Hill 115 kV new line	X	-	-	X	X	-
Red Willow 345/115 kV transformer	X	X	X	X	X	X

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Raun-S3452 345/161 kV Project [23]	-	-	X	-	-	X
Gerald Gentleman Station-Ogallala 230 kV terminal equipment	X	X	X	X	X	X
Fremont/Sub 976 115/69 kV transformer	X	X	X	X	X	X
70th & Bluff-Sub 1214 161 kV raise line and transformer replacement	X	X	X	X	X	X
Victory Hill-Wayside 230 kV new line	-	X	-	-	-	-
Huron B Tap-Huron-Huron West Park 115 kV rebuild	X	X	X	X	X	X
Granite Falls-Marshall Tap 115 kV structures	X	-	-	X	X	X
Gavins Point-Yankton 115 kV rebuild line	X	X	X	X	X	X
Belfield 345/230 kV two transformer replacements	X	X	X	X	X	X
Fort Thompson 345/230 kV transformer	X	-	-	X	-	-
Fargo-Jamestown 230 kV and Enderlin-Valley City 115 kV Line Tap	-	-	-	X	X	X
Broadland-Chapelle-White 345 kV new line	-	X	X	-	X	X
New Underwood-Stegall 345 kV new line	-	-	X	-	-	X
Aberdeen Jct-Ellendale 115 kV rebuild	X	-	-	X	-	-

Table 4.3: Initial Economic Project Grouping

4.2.4.2 *PROJECT SUBTRACTION EVALUATION*

Draft groupings were developed using individual project screening results. This process tests projects by incrementally adding changes to the base market economic models. When assessing a grouping of economic solutions, it was necessary to re-evaluate project performance within the grouping to ensure the projected APC benefit of each project in the grouping met the required B/C ratio thresholds. Subtraction evaluation was used to identify when multiple projects could provide congestion relief to a constraint or projects were dependent on each other to relieve overall system congestion. New sets of base case models were created by adding the entire set of solutions included in each grouping, relevant model adjustments and corrections required to meet the future's needs. All economic projects were then removed from the models individually to determine each project's APC impact compared to the new base case. Projects that did not meet a 1.0 B/C ratio from the subtraction evaluation were removed from the grouping. This subtraction evaluation process was repeated for each grouping until all remaining projects maintained a minimum B/C ratio of 1.0 over 40 years.

[23] Raun-Tekamah-S1226-S1252 161 kV rebuild as double circuit, Raun-S1252 (S3452) 345 kV new line, Routing of S3451-S3454 345 kV into S3452, Routing of S3451-S3459 345 kV into S3452, and S1209-S1231 161 kV rebuild of both circuits

4.2.4.3 *FINAL ECONOMIC GROUPINGS*

The final groupings for each future were selected because of their ability to provide the highest net benefit to the SPP region when comparing APC savings to the cost of the projects. The cost effective grouping was the best performing grouping selected for both Futures 1 and 2. Table 4.4 shows the final list of projects in the economic groupings.

Description	Project Cost (2023$)	Future 1			Future 2		
		CE	HN	MV	CE	HN	MV
Osage-Webb City Tap-Shidler 138 kV rebuild	$27,236,410	X	X	X	X	X	X
Cleveland 138 kV Terminal Equipment	$2,530,160	X	X	X	X	X	X
Fitzgerald Creek-Kenzie 138 kV line tap at Valley	$10,500,000	X	X	X	X	X	X
Pine & Peoria Tap-46th Street Tap-Tulsa North 138 kV rebuild	$6,228,906	X	X	X	X	X	X
Cimarron 345/138 kV circuit 3 transformer	$8,306,343	X	X	X	X	X	X
Cimarron-Czech Hall-Xerox 138 kV rebuild Cimarron-Haymaker-Division 138 kV rebuild	$19,126,196	X	-	-	X	-	-
Huron B Tap-Huron-Huron West Park 115 kV rebuild	$12,548,421	X	X	X	X	X	X
Blackberry-Neosho 345 kV terminal equipment	$6,830,258	X	X	-	X	X	-
Alliance-Victory Hill 115 kV new line	$92,007,750	X	-	-	X	X	-
Cleo Corner-Okeene 138 kV new line	$38,483,360	X	X	X	X	X	X
Granite Falls-Marshall Tap 115 kV structures	$3,346,777	X	-	-	-	X	-
Butler-Midian 138 kV terminal equipment	$2,658,322	X	-	-	X	-	-
Craig-Lenexa South 161 kV circuit 2 terminal equipment	$1,902,581	X	-	-	X	-	-
Fremont/Sub 976 115/69 kV new circuit 2 transformer	$5,900,000	X	X	X	X	X	X
70th & Bluff-Sub 1214 161 kV raise line and replace 70th & Bluff 161/115 kV circuit 1 transformer	$8,914,179	X	X	X	X	X	X
Franklin 161/69 kV circuit 2 transformer	$3,323,769	X	X	X	X	X	X
Marmaton East-Marmaton West 161 kV substation rebuild	$34,442,393	X	-	-	-	-	-
Potter County 345/230 kV circuit 2 transformer	$15,000,000	X	X	-	X	X	-
Gavins Point-Yankton 115 kV rebuild line	$2,957,298	X	X	X	X	X	X
Kerr-Maid 161 kV circuit 1 and 2 rebuild	$20,555,599	X	-	X	X	-	-
Replace Fort Thompson 345/230 kV circuit 1 and 2 transformers	$33,546,913	X	-	-	X	-	-
Gerald Gentleman Station-Ogallala 230 kV terminal equipment	$1,700,000	X	X	X	X	X	X

Description	Project Cost (2023$)	Future 1			Future 2		
		CE	HN	MV	CE	HN	MV
Anadarko-Gracemont 345 kV new line	$70,470,911	X	-	-	-	-	-
Chisholm Creek-Lone Oak 138 kV new line	$4,181,870	-	-	-	X	-	-
Ellsworth Tap-Great Bend 115 kV structures	$750,000	-	-	-	X	X	X
Great Bend and Spearville 230 kV terminal equipment	$292,000	-	-	-	X	X	-
New 345/161 kV Hawthorn transformer circuit 3	$8,306,343	-	-	-	X	X	X
Anadarko-Southwestern 138 kV terminal equipment	$483,360	-	-	-	X	X	-
Rocky Point-Sunnyside 138 kV terminal equipment	$966,720	-	-	-	X	X	X
Czech Hall and Cimarron 138 kV terminal equipment	$138,952	-	X	X	-	X	X
Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake	$87,000,000	-	X	X	-	X	X
Arcadia-Spring Creek-Matthewson 345 kV new line	$110,770,850	-	X	X	-	X	X
Victory Hill-Wayside 230 kV new line	$237,600,000	-	X	-	-	-	-
Butler-Midian 138 kV rebuild	$8,792,496	-	X	X	-	X	-
Craig-Lenexa South 161 kV circuit 2 rebuild	$7,671,884	-	X	X	-	X	X
Okeene-Southard 138 kV new line	$13,675,000	-	-	-	-	X	-
Kerr-Maid 161 kV circuit 3 new line	$9,251,288	-	-	-	-	X	X
Stegall-New Underwood 345 kV new line	$323,257,419	-	-	X	-	-	-
Lyon 115/345 kV transformer	$8,306,343	-	-	X	-	-	-
Potter-Tolk 345 kV new line	$126,603,266	-	-	X	-	-	-
West Harvey 138/115 kV transformer	$35,552,990	-	-	-	-	-	X
Draper-Gracemont 345 kV new line	$105,168,609	-	-	-	-	-	X

Table 4.4: Final Economic Project Grouping

Table 4.5[24] shows a summary of benefits, costs, net APC benefit and B/C ratios. Based on the net APC benefits detailed below, the grouping with the highest net APC benefit (shown in green) in each future was selected as the future's final portfolio.

[24] Some project costs have received updates since the final groupings were developed. The values shown in Table 4.5 and in Figure 4.4 reflect the most up-to-date costs.

Grouping	Y5 Benefit (2023$)	Y10 Benefit (2023$)	Study Cost (2023$)	40-Year PV Benefit (2023$)	40-Year PV Cost (2023$)	40-Year Net Benefit (2023$)	Y5 B/C	Y10 B/C	40-Year B/C	Selected Portfolio
F1 CE	$110M	$168M	$429M	$2,887M	$665M	$2222M	1.59	2.42	4.34	X
F1 HN	$100M	$155M	$600M	$2,672M	$932M	$1740M	1.03	1.59	2.87	
F1 MV	$98M	$152M	$820M	$2,622M	$1272M	$1350M	0.74	1.14	2.06	
F2 CE	$141M	$170M	$335M	$2,781M	$520M	$2260M	2.59	3.13	5.34	X
F2 HN	$136M	$161M	$492M	$2,626M	$763M	$1863M	1.71	2.03	3.44	
F2 MV	$92M	$136M	$492M	$2,317M	$764M	$1553M	1.16	1.70	3.03	

Table 4.5: Final Groupings-Benefit Cost, Net Benefits and B/C Ratios

Figure 4.4 shows a 40-year B/C comparison of all the final groupings.

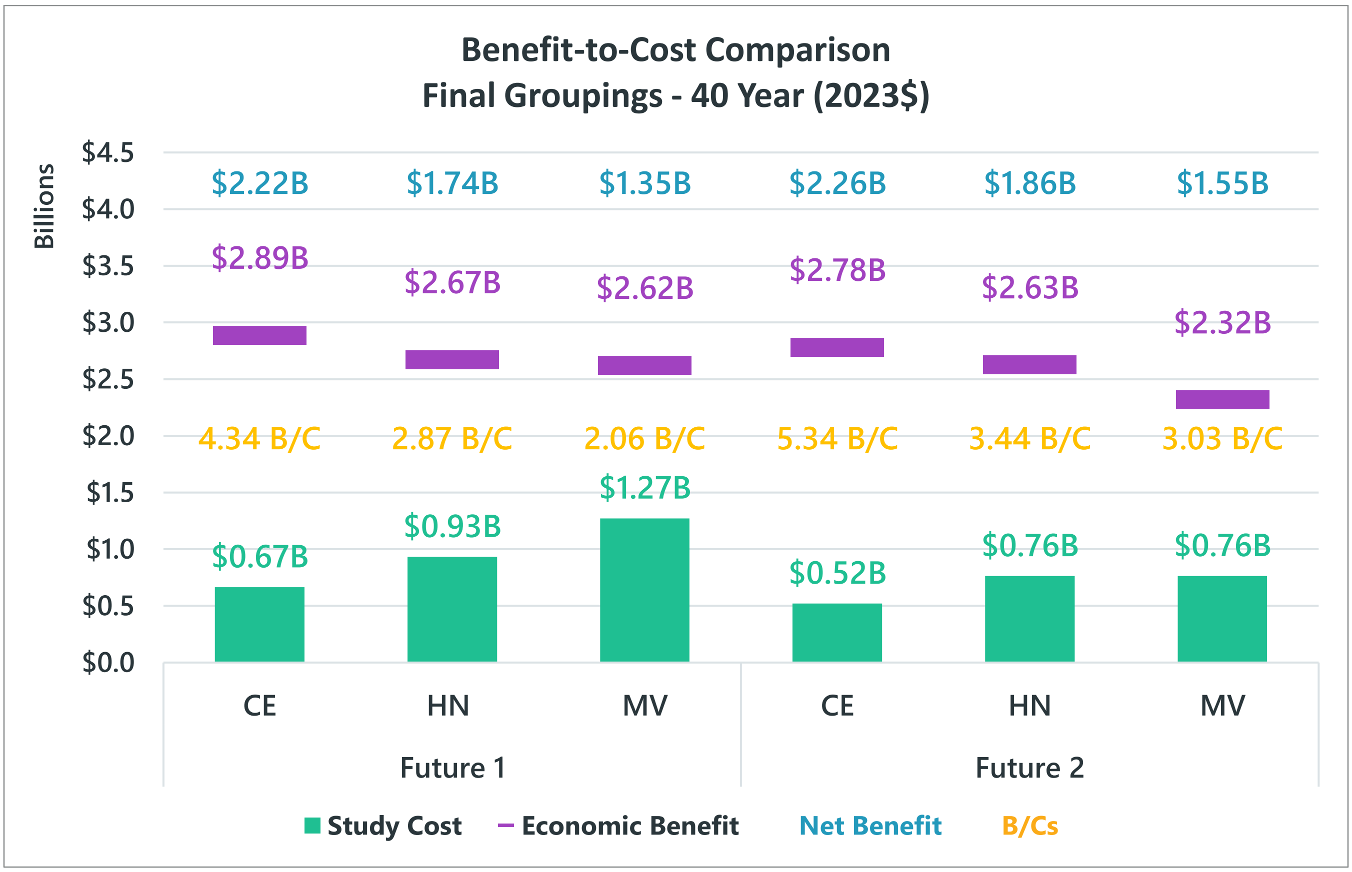

Figure 4.4: B/C Comparison – Final Groupings – 40 Year

4.3 OPTIMIZATION

The projects included in the reliability groupings were selected based on their ability to be cost effective, maintain reliability and meet the system's compliance needs. The economic projects were selected for their ability to provide ratepayer benefits from lower-cost energy by mitigating system congestion and improving markets for both buyers and sellers. The project groupings discussed previously were developed based on criteria specific to their need and model type. Reliability groupings specific to each future were evaluated to determine their impact on each economic grouping. Once those comprehensive, future-specific portfolios were developed, the impact of the base reliability portfolio was assessed. One project, the rebuild of Kerr-Maid 161 kV circuit 1 and 2, was identified in both the reliability and economic portfolios. No additional overlap of economic and reliability needs were identified; therefore, all reliability and economic projects were included in the final optimized portfolios.

4.4 PORTFOLIO CONSOLIDATION

In order to develop a single portfolio for recommendation to stakeholders, the final future-specific portfolios must be consolidated. To help guide decision-making to determine project inclusion in the single portfolio, SPP utilizes a systematic scoring methodology to evaluate project performance. Under this approach, three scenarios can occur during the consolidation of the future-specific portfolios into a single plan:

1. The same project addresses the same or similar needs in both futures
2. Different projects address the same or similar needs in both futures
3. A project addresses certain needs only in one future

Projects applicable to scenario one are automatically considered for inclusion in the consolidated portfolio. Projects applicable to scenarios two and three require additional assessments to determine portfolio eligibility.

To evaluate projects meeting conditions in scenarios two or three, SPP and its stakeholders developed a systematic scoring rubric, which considers both quantitative and qualitative metrics. Quantitative metrics include APC B/C ratios and the percentage of congestion relieved. Qualitative metrics include crediting projects that are able to address operational congestion or non-thermal issues. Table 4.6 details the scoring rubric, as well as some of the minimum criteria projects that must be met to receive points.

No.	Consideration	Possible Points
1	40-year (1-year) APC B/C ratio in selected future	50
	40-year (1-year) APC B/C ratio in opposite future	
	40-year (1-year) APC net benefit in selected future ($M)	
	40-year (1-year) APC net benefit in opposite future ($M)	
2	Congestion relieved in selected future (by need(s), all years)	10
	Congestion relieved in opposite future (by need(s), all years)	10
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10
4	New EHV	7.5
5	Mitigate non-thermal issues	7.5

No.	Consideration	Possible Points
6	Long-term viability (*e.g.*, 20 Year-Assessment) or improved ARR feasibility	5
	Total Points Possible	**100**

Table 4.6: Scoring Rubric

For the 2023 ITP, stakeholders agreed the two futures would be treated equally to determine the consolidated portfolio. All short-circuit and reliability projects were included in the consolidated portfolio; therefore, consolidation considerations in this assessment applied to economic projects only. A detailed description of the consolidation methodology and scoring rubric can be found in the 2023 ITP Scope.

4.4.1 CONSOLIDATION SCENARIO ONE

Twenty-two economic projects were included in both the Future 1 and Future 2 final portfolios; they were also included in the consolidated portfolio. These projects are:

- Kerr-Maid 161 kV circuit 1 and 2 rebuild
- Cleveland 138 kV Terminal Equipment
- Gerald Gentleman Station-Ogallala 230 kV terminal equipment
- Osage-Webb City Tap-Shidler 138 kV rebuild
- Replace Fort Thompson 345/230 kV circuit 1 and 2 transformers
- Blackberry-Neosho 345 kV terminal equipment
- Pine & Peoria Tap-46th Street Tap-Tulsa North 138 kV rebuild
- Craig-Lenexa South 161 kV circuit 2 terminal equipment
- 70th & Bluff-Sub 1214 161 kV raise line and replace 70th & Bluff 161/115 kV circuit 1 transformer
- Alliance-Victory Hill 115 kV new line
- Fitzgerald Creek-Kenzie 138 kV line tap at Valley
- Cleo Corner-Okeene 138 kV new line
- Fremont/Sub 976 115/69 kV new circuit 2 transformer
- Gavins Point-Yankton 115 kV rebuild line
- Huron B Tap-Huron-Huron West Park 115 kV rebuild
- Butler-Midian 138 kV terminal equipment
- Franklin 161/69 kV new circuit 2 transformer

The Cimarron transformer and the rebuild of Division-Haymaker-Cimarron-Czech Hall-Xerox projects were replaced by alternative projects from the Highest Net grouping after receiving feedback from the 2023 SPP Planning Summit about the cost and scope of the Cimarron transformer project's significant increase. The three projects listed were included in both the Future 1 and Future 2 final portfolios.

- Matthewson-Redbud 345 kV new line[25]
- Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake
- Cimarron-Czech Hall terminal upgrades

The Potter County transformer project was modified due to significant congestion observed on the existing transformer for loss of the new transformer. The modified project listed bellow was included in both the Future 1 and Future 2 final portfolios.

- Replace Potter County 345/230 kV circuit 1 transformer and new circuit 2 transformer

One project initially fell out of economic groupings due to negative benefits, but consideration of the persistent operational criteria placed the following project back in both the Future 1 and Future 2 final portfolios.

- Benton-Wichita 345 kV terminal equipment

4.4.2 CONSOLIDATION SCENARIO TWO

When scenario two occurs, different projects address the same or similar needs in both futures. The project achieving the higher score will be considered favorable for consolidation. Scoring parameters are detailed in Table 4.6.

In the 2023 ITP, one instance of scenario two occurred. This instance and its scoring is detailed in Table 4.7. The winning project, based on the consolidation scoring, is shown in bold.

Project	Driving Future	APC Benefit	Congestion Relieved	Operational Congestion	New EHV	Non Thermal	Long-term Viability	Total
Anadarko-Gracemont 345 kV new line	F1	0	20	10	7.5	0	5	42.5
Anadarko-Southwestern 138 kV terminal equipment	**F2**	**50**	**8**	**10**	**0**	**0**	**0**	**68**

Table 4.7: Consolidation Scenario Two Scoring

[25] Originally the Highest Net project was the Arcadia-Matthewson-Spring Creek new 345 kV line, but was later changed to Matthewson-Redbud new 345 kV line after receiving feedback that additional substation work would increase the cost estimate of the project. Redbud was chosen as the more desirable termination point due to ease of getting in/out with a 345 kV terminal available. The updated cost estimate and project modification were unable to be corrected in time for the Rate Impact calculations, which are based upon the original project selected.

The Anadarko-Gracemont 345 kV new line project was changed to a new double-circuit high-capacity 138 kV lines after realizing a cost estimate error for the EHV line, increasing the project cost from $52M to $63M. SPP evaluated different projects for the area and saw that a double-circuit high-capacity line would resolve the majority of congestion, while also providing an additional path from the 345 kV hub at Gracemont. For these reasons, SPP staff recommended moving forward with the Anadarko-Southwest Station 138 kV terminal equipment and the new Anadarko-Gracemont double-circuit high-capacity 138 kV lines to be included in both the Future 1 and Future 2 final portfolios.

4.4.3 CONSOLIDATION SCENARIO THREE

Under scenario three, in instances where a project addresses certain needs only in one future, projects must achieve a minimum score of 70 points to be considered for consolidation. Scoring parameters are detailed in Table 4.6. For the 2023 ITP, eight projects were assessed under scenario three scoring conditions. Only the following two projects met the minimum score requirement for inclusion in the final consolidated portfolio.

4.4.3.1 *GRANITE FALLS-MARSHALL TAP 115 KV STRUCTURES*

The Granite Falls-Marshall Tap 115 kV structures originated from the Future 1 portfolio. The project performed well using the net benefit, B/C ratio and congestion relieved metrics; however, it did not perform well enough with the other considerations to meet the minimum scoring threshold.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future APC net benefit and B/C ratio in opposite future	50	47
2	Congestion relieved in selected future (by need(s), all years) Congestion relieved in opposite future (by need(s), all years)	10 10	14
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 20 Year-Assessment) or improved ARR feasibility	5	0
Total Score (minimum 70 threshold)			**62**

Table 4.8: Granite Falls-Marshall Tap 115 kV structures

4.4.3.2 *MARMATON EAST-MARMATON WEST 161 KV SUBSTATION REBUILD*

The Marmaton East-Marmaton West 161 kV substation rebuild originated from the Future 1 portfolio. The project performed well in the congestion relieve metric; however, it did not meet the B/C ratio criteria, resulting in a score of zero for the net benefit and B/C ratio scoring criteria. Because of the zero points scored in the net benefit and the B/C ratio criteria this project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	0
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 20 Year-Assessment) or improved ARR feasibility	5	0
Total Score (minimum 70 threshold)			**20**

Table 4.9: Marmaton East-Marmaton West 161 kV substation rebuild

4.4.3.3 *CHISHOLM CREEK-LONE OAK 138 KV NEW LINE*

The Chisholm Creek-Lone Oak 138 kV new line originated from the Future 2 portfolio. The project performed well using the net benefit and B/C ratio metrics. It also performed well when compared to expected congestion in both futures. Therefore, the new line was added to the final portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 20 Year-Assessment) or improved ARR feasibility	5	0
Total Score (minimum 70 threshold)			**70**

Table 4.10: Chisholm Creek-Lone Oak 138 kV line Consolidation Scoring

4.4.3.4 *ELLSWORTH TAP-GREAT BEND 115 KV STRUCTURES*

The Ellsworth Tap-Great Bend 115 kV structures project originated from the Future 2 portfolio. The project performed well using the net benefit and B/C ratio metrics. It also performed well when compared to expected congestion in both futures. Therefore, the new line was added to the final portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50

No.	Consideration	Possible Points	Project Score
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years) Congestion relieved in opposite future (by need(s), all years)	10 10	20
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 20 Year-Assessment) or improved ARR feasibility	5	0
Total Score (minimum 70 threshold)			**70**

Table 4.11: Ellsworth Tap-Great Bend 115 kV structures Consolidation Scoring

4.4.3.5 *GREAT BEND AND SPEARVILLE 230 KV TERMINAL EQUIPMENT*

The Great Bend and Spearville 230 kV terminal equipment originated from the Future 2 portfolio. The project did not meet the B/C ratio criteria, resulting in a score of zero for the net benefit and B/C ratio scoring criteria. Because of the zero points scored in the net benefit and the B/C ratio criteria, this project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future APC net benefit and B/C ratio in opposite future	50	0
2	Congestion relieved in selected future (by need(s), all years) Congestion relieved in opposite future (by need(s), all years)	10 10	17
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 20 Year-Assessment) or improved ARR feasibility	5	5
Total Score (minimum 70 threshold)			**22**

Table 4.12: Great Bend and Spearville 230 kV terminal equipment

4.4.3.6 *ROCKY POINT-SUNNYSIDE 138 KV TERMINAL EQUIPMENT*

The Rocky Point-Sunnyside 138 kV terminal equipment originated from the Future 2 portfolio. The project did not meet the B/C ratio criteria, resulting in a score of zero for the net benefit and B/C ratio scoring criteria. Because of the zero points scored in the net benefit and the B/C ratio criteria, this project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	0

No.	Consideration	Possible Points	Project Score
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 20 Year-Assessment) or improved ARR feasibility	5	0
Total Score (minimum 70 threshold)			**20**

Table 4.13: Rocky Point-Sunnyside 138 kV terminal equipment

4.4.3.7 *REPLACE 345/161 KV HAWTHORN TRANSFORMER CIRCUIT 20*

The Replace 345/161 kV Hawthorn transformer circuit 20 originated from the Future 2 portfolio. Originally the project was scoped to add a third transformer at Hawthorn, however during the consolidation process, SPP received information that there was no room to add another transformer, and SPP evaluated replacing the constrained transformer in parallel with portfolio consolidation. The project did not meet the B/C ratio criteria, resulting in a score of zero for the net benefit and B/C ratio scoring criteria. Because of the zero points scored in the net benefit and the B/C ratio criteria, this project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	0
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	7
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	10
4	New EHV	7.5	7.5
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 20 Year-Assessment) or improved ARR feasibility	5	0
Total Score (minimum 70 threshold)			**24.5**

Table 4.14: Replace 345/161 kV Hawthorn transformer circuit 20

4.5 FINAL CONSOLIDATED PORTFOLIO

The consolidated portfolio includes the reliability projects addressing both steady state and short-circuit needs, as well as the consolidated set of economic projects that met the consolidation criteria. The consolidated portfolio totals $735.54 million and is projected to create $2.61 billion to $2.98 billion in 40-Year APC savings under Future 2 and Future 1 assumptions, respectively. Table 4.15 lists the projects included in the final consolidated portfolio along with their classifications and costs. Benefit data reported in this section includes only APC savings.

Description	Classification	Area	Project Cost (2023$)
Flournoy-Oak Pan-Harr-Longwood 138 kV rebuild	Reliability	AEPW	$20,446,720
Replace Turk 138/115 kV circuit 1 transformer	Reliability	AEPW	$5,250,000
87th Street 345/115 kV new circuit 2 transformer[26]	Reliability	EKC	$10,200,000
Extend Craig-West Gardner 345 kV, Clearview-Eudora 115 kV Tap, new 345/115 kV substation	Reliability	EKC/EM	$42,141,390
Newman Grace Tap and Woodward Nitrogen 69 kV terminal equipment	Reliability	OKGE	$217,311
Pennsylvania-Southgate-Westmoore 138 kV extend line	Reliability	OKGE	$15,160,147
Seminole 345/138 kV new transformer	Reliability	OKGE	$8,306,343
Moore Co 115 kV terminal equipment	Reliability	SPS	$210,000
Cunningham-Quahada 115 kV tap line-Buckeye Tap 115 kV new line	Reliability	SPS	$25,715,000
Lovington 40 MVAR Reactor	Reliability	SPS	$4,457,880
Sundown Interchange 115 kV terminal equipment	Reliability	SPS	$393,298
Devaul 115 kV 15 MVAR reactor	Reliability	WAPA	$1,671,705
Dawson County 230kV line reactor	Reliability	WAPA	$4,007,750
Broadland 345 kV 75 MVAR reactor	Reliability	WAPA	$5,445,170
Groton 345 kV 68 MVAR reactor	Reliability	WAPA	$5,162,152
Kerr-Maid 161 kV circuit 1 and 2 rebuild	Economic/Reliability	GRDA	$20,555,599
Cleveland 138 kV Terminal Equipment	Economic/Operational	AECI/GRDA	$2,530,160
Anadarko-Gracemont 138 kV circuit 2 and 3 new line	Economic/Operational	WFEC/OKGE	$64,000,000
Gerald Gentleman Station-Ogallala 230 kV terminal equipment	Economic/Operational	NPPD	$1,700,000
Osage-Webb City Tap-Shidler 138 kV rebuild	Economic/Operational	OKGE/AEPW	$27,236,410

[26] Project identitifed in the Final Reliablity Assessment

Description	Classification	Area	Project Cost (2023$)
Potter County 345/230 kV circuit 1 and 2 transformer replacement	Economic/Operational	SPS	$30,000,000
Fort Thompson 345/230 kV transformer	Economic/Operational	WAPA	$33,546,913
Benton-Wichita 345 kV terminal equipment	Economic/Operational	WERE	$6,830,258
Blackberry-Neosho 345 kV terminal equipment	Economic	AECI/WERE	$6,830,258
Pine & Peoria Tap-46th Street Tap-Tulsa North 138 kV rebuild	Economic	AEPW	$6,228,906
Craig-Lenexa South 161 kV circuit 2 terminal equipment	Economic	KCPL	$1,902,581
70th & Bluff-Sub 1214 161 kV raise line and transformer replacement	Economic	LES/OPPD	$8,914,179
Alliance-Victory Hill 115 kV new line	Economic	WAPA-RMR/NPPD	$92,007,750
Matthewson-Redbud 345 kV new line	Economic	OKGE	$110,770,850
Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake	Economic	OKGE	$87,000,000
Czech Hall and Cimmarron 138 kV terminal equipment	Economic	OKGE	$138,952
Chisholm Creek-Lone Oak 138 kV new line	Economic	OKGE	$4,181,870
Fitzgerald Creek-Kenzie 138 kV line tap at Valley	Economic	OKGE/AECI	$10,500,000
Cleo Corner-Okeene 138 kV new line	Economic	OKGE/WFEC	$38,483,360
Fremont/Sub 976 115/69 kV transformer	Economic	OPPD/NPPD	$5,900,000
Ellsworth Tap-Great Bend 115 kV structures	Economic	SEPC	$750,000
Gavins Point-Yankton 115 kV rebuild line	Economic	WAPA	$2,957,298
Huron B Tap-Huron-Huron West Park 115 kV rebuild	Economic	WAPA	$12,548,421
Butler-Midian 138 kV terminal equipment	Economic	WERE	$2,658,322
Franklin 161/69 kV Circuit 2 transformer	Economic	WERE	$3,323,769
Anadarko-Southwestern 138 kV terminal equipment	Economic	WFEC	$483,360

Description	Classification	Area	Project Cost (2023$)
Blue Valley 161 kV one breaker replacement	Short Circuit	KCPL	$310,351
Craig 161 kV five breaker replacements	Short Circuit	KCPL	$3,047,451
Lightning Creek 138 kV two breaker replacements	Short Circuit	OKGE	$1,418,348
		Total	**$735,540,232**

Table 4.15: Final Consolidated Portfolio

Table 4.16 provides the Future 1 and Future 2 B/C ratios and 40-year net benefits for all economic projects included in the consolidated portfolio using the same process described in Section 3.5.2 for project subtraction evaluation. Except for the Matthewson-Redbud 345 kV new line and the Blackberry-Neosho 345 kV terminal equipment project, which included the corrected line ratings evaluation[27], all other project subtraction results in Table 4.16 contained the Arcadia-Spring Creek-Matthewson 345 kV new line which got replaced by Matthewson-Redbud 345 kV new line project in the final portfolio.

[27] Section 5.2.1.1 provides more details about the Blackberry-Neosho 345 kV terminal equipment ratings discovery.

Project	Project Cost (2023$ M)	40-Year PV Cost (2023$ M)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit (2023$ M)	F1 40-year Net Benefit (2023$ M)	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit (2023$ M)	F2 40-year Net Benefit (2023$ M)
Ellsworth Tap-Great Bend 115 kV structures	$0.75	$1.16	3.28	(1.59)	(5.11)	($5.95)	($7.12)	4.38	22.10	44.95	$52.32	$51.16
Chisholm Creek-Lone Oak 138 kV new line	$4.18	$6.49	0.18	1.37	2.83	$18.34	$11.85	(1.63)	(2.48)	(4.44)	($28.84)	($35.33)
Czech Hall and Cimmarron 138 kV terminal equipment	$0.14	$0.22	50.77	118.19	226.05	$48.75	$48.53	91.23	122.47	214.07	$46.17	$45.95
Fort Thompson 345/230 kV transformer	$33.55	$52.07	1.38	2.04	3.63	$189.09	$137.03	1.14	0.48	0.42	$22.09	($29.97)
46Th Street Tap-Pine & Peoria Tap 138 kV rebuild	$6.23	$9.67	7.29	21.14	41.36	$399.82	$390.15	11.63	29.10	56.11	$542.41	$532.74
Fremont/Sub 976 115/69 kV transformer	$5.90	$9.16	3.59	8.50	16.29	$149.17	$140.01	0.39	10.50	22.23	$203.54	$194.39
70th & Bluff-Sub 1214 161 kV raise line and transformer replacement	$8.91	$13.84	2.09	3.34	6.04	$83.62	$69.78	0.76	5.13	10.57	$146.25	$132.41
Gerald Gentleman Station-Ogallala 230 kV terminal equipment	$1.70	$2.64	32.34	72.46	137.95	$363.97	$361.33	32.09	22.07	30.42	$80.25	$77.61
Matthewson-Redbud 345 kV new line	$110.77	$171.92	0.53	0.97	1.81	$310.58	$138.65	0.62	1.23	2.31	$397.25	$225.32
Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake	$87.00	$135.03	0.09	0.44	0.90	$120.95	($14.08)	0.16	0.38	0.73	$98.77	($36.26)
Kerr-Maid 161 kV Ckt 1 and 2 rebuild	$20.56	$31.90	0.09	0.49	0.99	$31.57	($0.33)	0.11	0.87	1.80	$57.46	$25.55
Fitzgerald Creek-Kenzie 138 kV line tap at Valley	$10.50	$16.30	0.95	2.57	5.00	$81.49	$65.19	2.97	4.79	8.69	$141.63	$125.33
Cleo Corner-Okeene 138 kV new line	$38.48	$59.73	0.82	1.06	1.83	$109.17	$49.44	0.88	1.01	1.70	$101.63	$41.90

Project	Project Cost (2023$ M)	40-Year PV Cost (2023$ M)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit (2023$ M)	F1 40-year Net Benefit (2023$ M)	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit (2023$ M)	F2 40-year Net Benefit (2023$ M)
Craig-Lenexa South 161 kV circuit 2 terminal equipment	$1.90	$2.95	3.96	1.44	1.01	$2.98	$0.03	42.54	18.12	16.51	$48.74	$45.79
Franklin 161/69 kV Circuit 2 transformer	$3.32	$5.16	3.52	0.62	(0.51)	($2.65)	($7.81)	2.10	(2.97)	(7.44)	($38.36)	($43.52)
Benton-Wichita 345 kV terminal equipment	$6.83	$10.60	(1.21)	(5.08)	(10.21)	($108.28)	($118.88)	(1.89)	(4.87)	(9.42)	($99.81)	($110.42)
Butler-Midian 138 kV terminal equipment	$2.66	$4.13	2.32	10.76	21.78	$89.87	$85.75	10.89	6.21	7.57	$31.25	$27.12
Cleveland 138 kV Terminal Equipment	$2.53	$3.93	10.10	30.21	59.28	$232.80	$228.88	10.83	25.11	48.00	$188.50	$184.57
Gavins Point-Yankton 115 kV rebuild line	$2.96	$4.59	5.11	14.14	27.54	$126.42	$121.83	5.95	6.23	10.21	$46.88	$42.29
Huron B Tap-Huron-Huron West Park 115 kV rebuild	$12.55	$19.48	9.15	7.92	12.15	$236.70	$217.23	9.13	7.84	11.98	$233.40	$213.93
Osage-Webb City Tap 138 kV rebuild	$27.24	$42.27	0.08	0.98	2.05	$86.64	$44.37	0.43	0.42	0.67	$28.23	($14.05)
Alliance-Victory Hill 115 kV new line	$92.01	$142.80	1.40	2.15	3.86	$551.52	$408.72	1.48	0.90	1.15	$164.40	$21.59
Blackberry-Neosho 345 kV terminal equipment	$6.83	$10.60	5.62	0.89	(1.02)	($10.82)	($21.42)	3.08	1.68	1.98	$21.02	$10.42
Potter County 345/230 kV circuit 1 and 2 transformer replacement	$30.00	$46.56	2.76	3.78	6.65	$309.56	$263.00	2.78	1.53	1.81	$84.15	$37.59
Anadarko-Gracemont 138 kV circuit 2 and 3 new line and Anadarko-Southwestern 138 kV terminal equipment	$64.48	$100.08	0.23	0.60	1.16	$116.48	$16.39	0.41	0.82	1.55	$154.97	$54.89

Table 4.16: Consolidated Portfolio - APC benefits

Figure 4.5 shows the approximate location of identified projects within the SPP footprint.

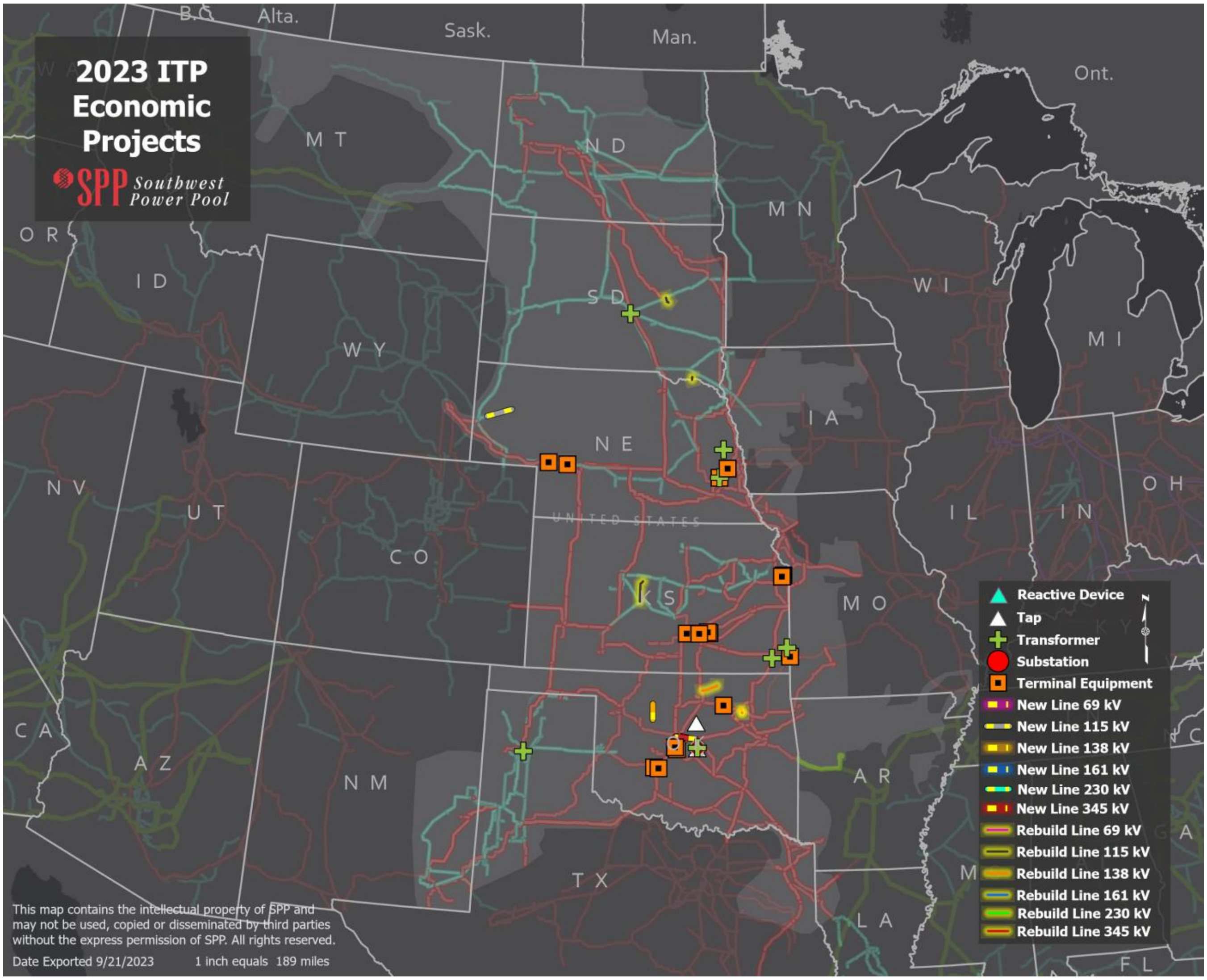

Figure 4.5: 2023 ITP Final Portfolio Economic projects Futures 1 & 2

Figure 4.6 shows the 40-Year B/C ratio of the economic portfolio of projects included in the consolidated portfolio.

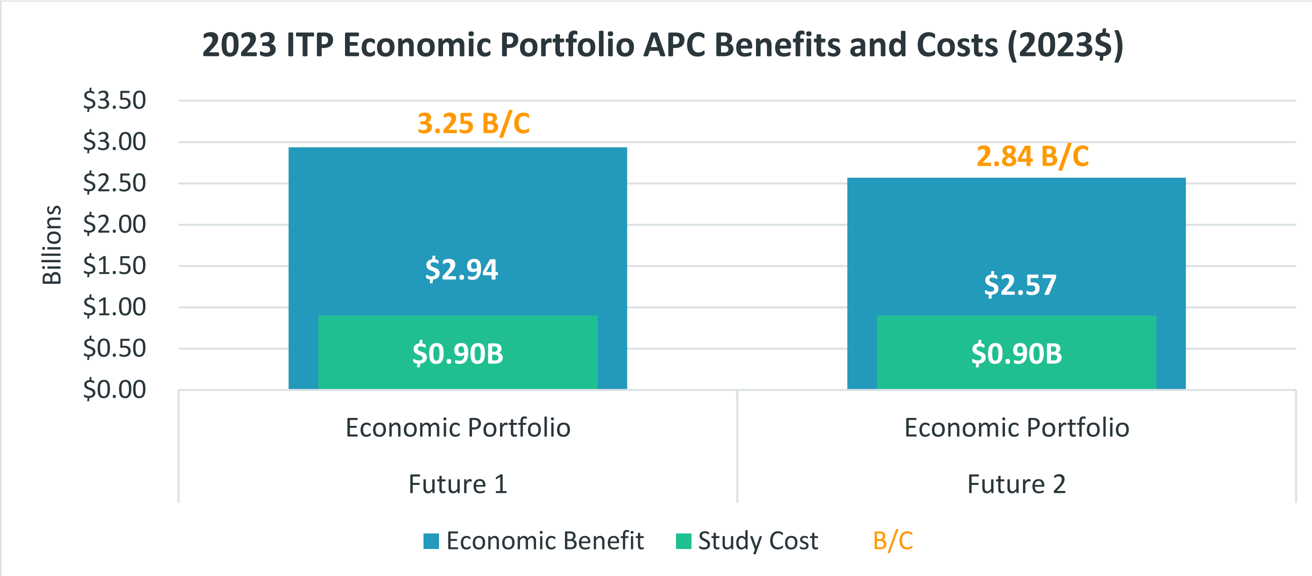

Figure 4.6: Economic Portfolio APC Benefits and Costs

Figure 4.7 shows the 40-Year B/C ratio of the entire consolidated portfolio. As expected, the overall B/C ratio is reduced with the inclusion of the reliability projects, but the consolidated portfolio is still expected to produce benefits well over the cost of the projects.

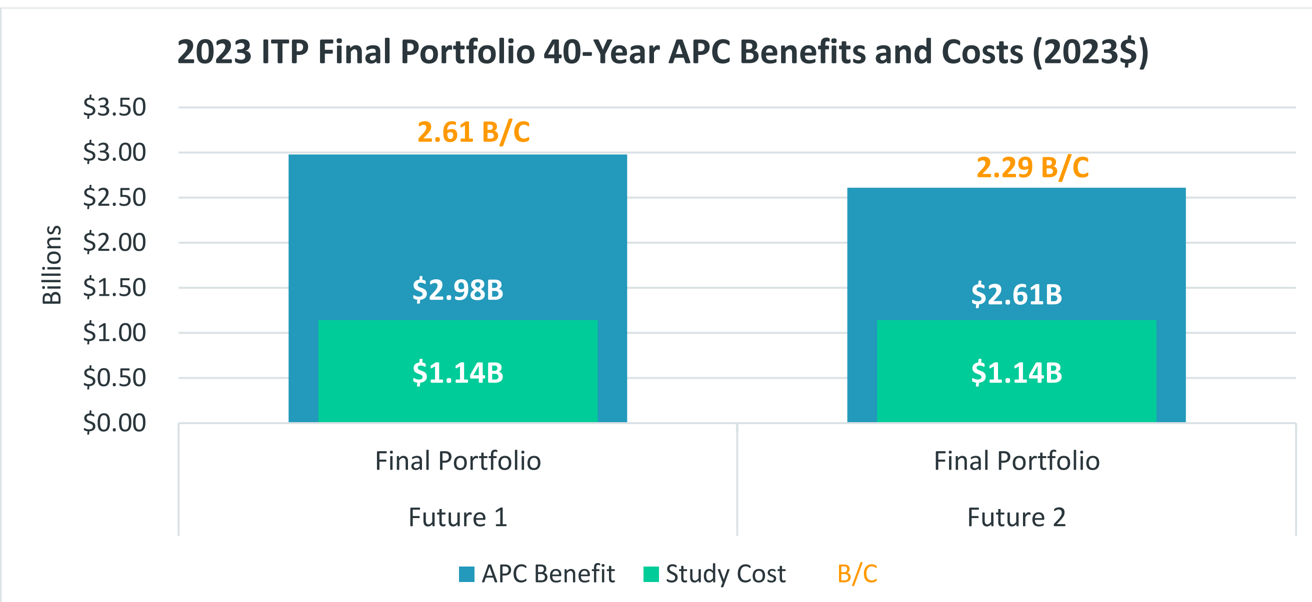

Figure 4.7: Final Consolidated Portfolio APC Benefits and Costs[28]

Figure 4.8 below shows the break-even and payback dates of the consolidated portfolio assuming all projects are placed in-service by 1/1/2027. The break-even year is reflective of the first year that the one-year APC benefits are expected to outweigh the portfolio ATRR. The payback year is reflective of the year that the cumulative APC benefits are expected to exceed the 40-year PV costs of the

[28] The Final Reliability Assessment project 87th Street 345/115 kV new circuit 2 transformer was included in the final portfolio cost, but not in the benefits.

portfolio. The consolidated portfolio is expected to breakeven within the first year of being placed in service and expected to pay back total investment within the first 10 years. This calculation provides a measure of comfort that SPP's members will see a quick return on investement in the recommended portfolio. Realistically, this payback period will not occur because not all projects in the consolidated portfolio will receive an NTC, nor will they be in-service by 2027.

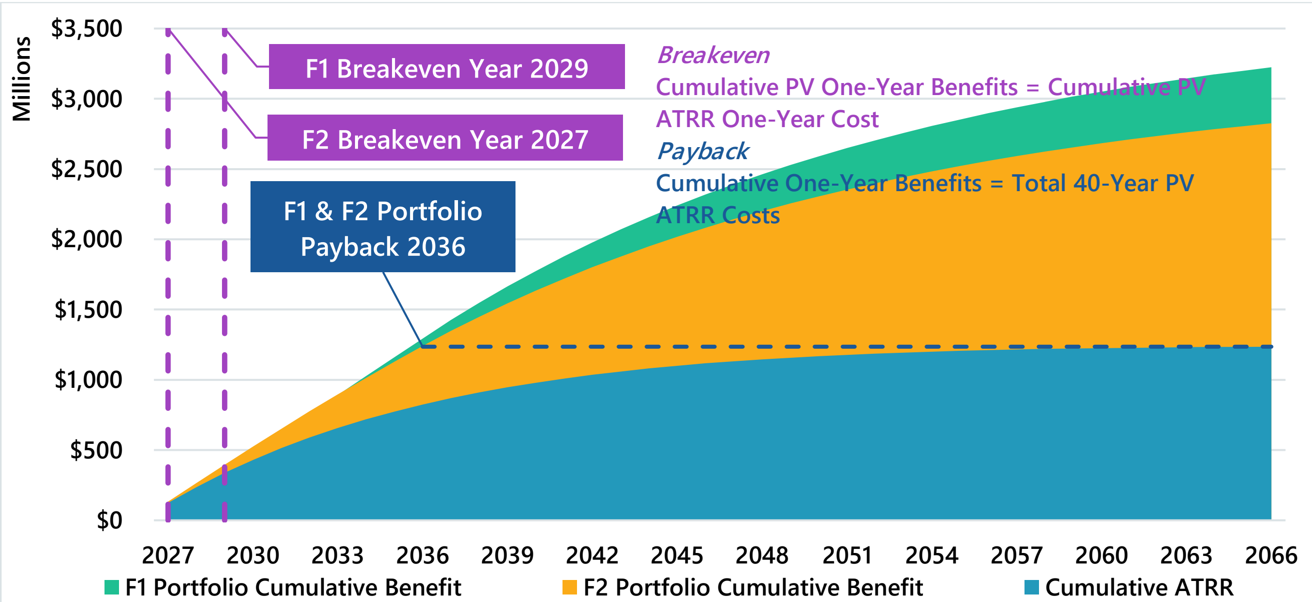

Figure 4.8: Portfolio Breakeven and Payback – APC benefit only

4.6 STAGING

Staging is the process by which the need date for each project is determined. The staging methodology can be found in the ITP Manual.[29]

4.6.1 ECONOMIC PROJECTS

The results of staging for the economic projects are shown in Table 4.17 below. The persisent operational projects are all included in the list of economic projects, and are denoted by an asterisk.

DESCRIPTION	NEED DATE	PROJECTED IN-SERVICE DATE	MODEL
Ellsworth Tap-Great Bend 115 kV structures	1/1/2028	1/1/2028	MEM
Chisholm Creek-Lone Oak 138 kV new line	1/1/2032	1/1/2032	MEM
Czech Hall and Cimarron 138 kV terminal equipment	1/1/2025	5/14/2025	MEM
Fort Thompson 345/230 kV transformer*	11/14/2023	11/14/2025	MEM

[29] ITP Manual version 2.11, section 6.3

DESCRIPTION	NEED DATE	PROJECTED IN-SERVICE DATE	MODEL
Pine & Peoria Tap-46th Street Tap-Tulsa North 138 kV rebuild	1/1/2025	5/14/2026	MEM
Fremont/Sub 976 115/69 kV transformer	1/1/2025	11/14/2025	MEM
70th & Bluff-Sub 1214 161 kV raise line and transformer replacement	1/1/2027	1/1/2027	MEM
Gerald Gentleman Station-Ogallala 230 kV terminal equipment*	11/14/2023	5/14/2025	MEM
Arcadia-Matthewson-Spring Creek 345 kV new line	1/1/2025	11/14/2027	MEM
Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake	1/1/2025	5/14/2027	MEM
Fitzgerald Creek-Kenzie 138 kV line tap at Valley	1/1/2025	5/14/2027	MEM
Anadarko-Southwestern 138 kV terminal equipment	1/1/2025	5/14/2025	MEM
Cleo Corner-Okeene 138 kV new line	1/1/2032	1/1/2032	MEM
Craig-Lenexa South 161 kV circuit 2 terminal equipment	1/1/2025	5/14/2025	MEM
Franklin 161/69 kV circuit 2 transformer	1/1/2025	11/14/2025	MEM
Benton-Wichita 345 kV terminal equipment*	11/14/2023	5/14/2025	MEM
Butler-Midian 138 kV terminal equipment	1/1/2025	5/14/2025	MEM
Cleveland 138 kV Terminal Equipment *	11/14/2023	5/14/2025	MEM
Gavins Point-Yankton 115 kV rebuild line	1/1/2025	5/14/2026	MEM
Huron B Tap-Huron-Huron West Park 115 kV rebuild	1/1/2025	5/14/2026	MEM
Osage-Webb City Tap - Shidler 138 kV rebuild*	11/14/2023	11/14/2026	MEM
Alliance-Victory Hill 115 kV new line	1/1/2025	5/14/2027	MEM
Blackberry-Neosho 345 kV terminal equipment	1/1/2025	5/14/2025	MEM
Anadarko-Gracemont 138 kV circuit 2 and 3 new line *	11/14/2023	5/14/2027	MEM
Potter County 345/230 kV circuit 1 and 2 transformer replacement*	11/14/2023	11/14/2025	MEM

Table 4.17: Project Staging Results-Economic

4.6.2 RELIABILITY PROJECTS

The results of staging the reliability projects are shown in Table 4.18 below.

DESCRIPTION	NEED DATE	PROJECTED IN-SERVICE DATE	MODEL
Pennsylvania-Southgate-Westmoore 138 kV extend line	6/1/2027	6/1/2027	BR
Sundown Interchange 115 kV terminal equipment	6/1/2030	1/1/2032	BR
Moore Co 115 kV terminal equipment	6/1/2027	6/1/2027	BR
Flournoy-Oak Pan-Harr-Longwood 138 kV rebuild	6/1/2028	6/1/2028	BR
Replace Turk 138/115 kV circuit 1 transformer	6/1/2024	11/14/2025	BR
Kerr-Maid 161 kV circuit 1 and 2 rebuild	4/1/2024	5/14/2026	BR
Newman Grace Tap and Woodward Nitrogen 69 kV terminal equipment	6/1/2024	5/14/2025	BR
Cunningham-Quahada 115 kV tap line-Buckeye Tap 115 kV new line	6/1/2024	5/14/2027	BR
Broadland 345 kV 75 MVAR reactor	4/1/2024	11/14/2025	BR
Fort Peck-Dawson County 230 kV 40 MVAR line reactor	6/1/2024	11/14/2025	BR
Groton 345 kV 68 MVAR reactor	4/1/2024	11/14/2025	BR
Seminole 345/138 kV new transformer	6/1/2024	11/14/2025	BR
Devaul 115 kV 15 MVAR reactor	4/1/2024	11/14/2025	BR
Lovington 40 MVAR Reactor	1/1/2030	1/1/2030	BR
Extend Craig-West Gardner 345 kV, Clearview-Eudora 115 kV Tap, new 345/115 kV substation	4/1/2025	11/14/2027	BR

Table 4.18: Project Staging Results-Reliability

4.6.3 POLICY PROJECTS

No public policy needs were identified in the 2023 ITP; therefore, no policy projects were identified in the 2023 ITP.

4.6.4 PERSISTENT OPERATIONAL PROJECTS

The projects associated with persistent operational needs are included in the Economic Projects section.

4.6.5 SHORT-CIRCUIT PROJECTS

The short-circuit projects were all staged with a need date of June 1, 2024 and a projected in-service date of May 14, 2025.

DESCRIPTION	NEED DATE	PROJECTED IN-SERVICE DATE	MODEL
Blue Valley 161 kV breaker	6/1/2024	5/14/2025	BR
Craig 161 kV five breakers	6/1/2024	5/14/2025	BR
Lightning Creek 138 kV two breakers	6/1/2024	5/14/2025	BR

Table 4.19: Short Circuit Projects

5 PROJECT RECOMMENDATION

5.1 RELIABILITY PROJECTS

DESCRIPTION	AREA	E&C COST	MILES
Flournoy-Oak Pan-Harr-Longwood 138 kV rebuild	AEP	$ 20,446,720	12.2
Replace Turk 138/115 kV circuit 1 transformer	AEP	$5,250,000	
87th Street 345/115 kV new circuit 2 transformer	EM	$10,200,000	
Extend Craig-West Gardner 345 kV, Clearview-Eudora 115 kV Tap, new 345/115 kV substation	EKC/EM	$42,141,390	10.3
Kerr-Maid 161 kV circuit 1 and 2 rebuild	GRDA	$20,555,599	5.5
Newman Grace Tap and Woodward Nitrogen 69 kV terminal equipment	OGE	$217,311	
Seminole 345/138 kV new transformer	OGE	$8,306,343	
Pennsylvania-Southgate-Westmoore 138 kV extend line	OGE	$15,160,147	0.76
Lovington 40 MVAR reactor	SPS	$4,457,880	
Cunningham-Quahada 115 kV tap line-Buckeye Tap 115 kV new line	SPS	$25,715,000	3.2
Moore Co 115 kV terminal equipment	SPS	$210,000	
Sundown Interchange 115 kV terminal equipment	SPS	$393,298	
Broadland 345 kV 75 MVAR reactor	WAPA	$5,445,170	
Groton 345 kV 68 MVAR reactor	WAPA	$5,162,152	
Fort Peck-Dawson County 230 kV reactor	WAPA	$4,007,750	
Devaul 115 kV 15 MVAR reactor	WAPA	$1,671,705	

Table 5.1 Reliability Project

5.1.1 AMERICAN ELECTRIC POWER (AEP)

5.1.1.1 *FLOURNOY-OAK PAN-HARR-LONGWOOD 138 KV REBUILD*

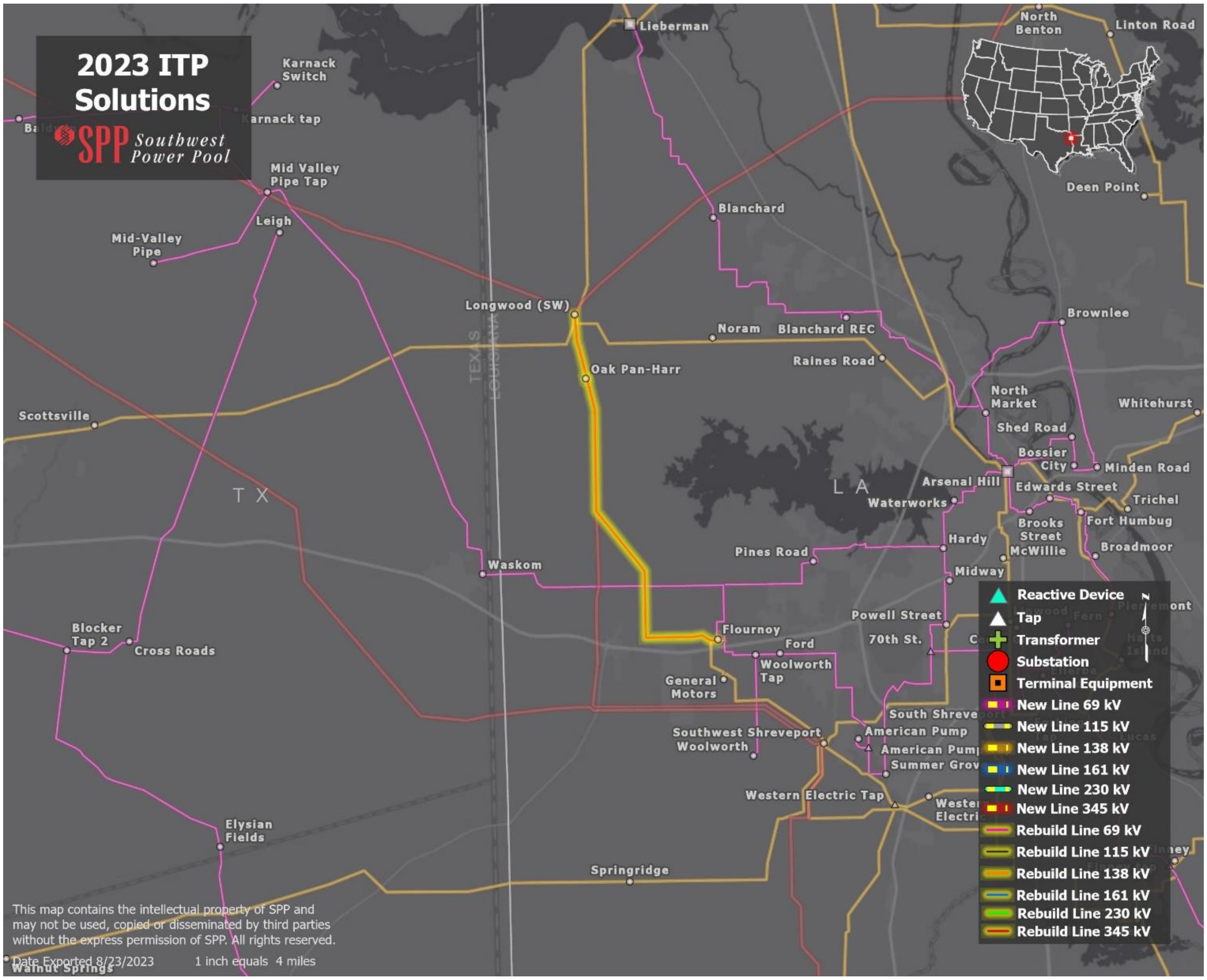

Figure 5.1: Flournoy-Oak Pan-Harr-Longwood 138 kV Rebuild

The Flournoy-Oak Pan-Harr 138 kV and Oak Pan-Harr-Longwood 138 kV lines overload for the loss of the Diana-Southwest Shreveport 345 kV line and the Longwood-Southwest Shreveport 345 kV line under a P23 contingency in the 2032 summer peak model.

The solution chosen to address this need was the rebuild of the Flournoy-Oak Pan-Harr 138 kV and the Oak Pan-Harr-Longwood 138 kV lines. After analysis on this and other solutions that addressed the need, rebuilding the lines was found to be the most feasible and cost effective solution while also providing the required relief on the lines reducing the loading from 102% to 69% and 105% to 61%, respectively.

5.1.1.2 REPLACE TURK 138/115 KV CIRCUIT 1 TRANSFORMER

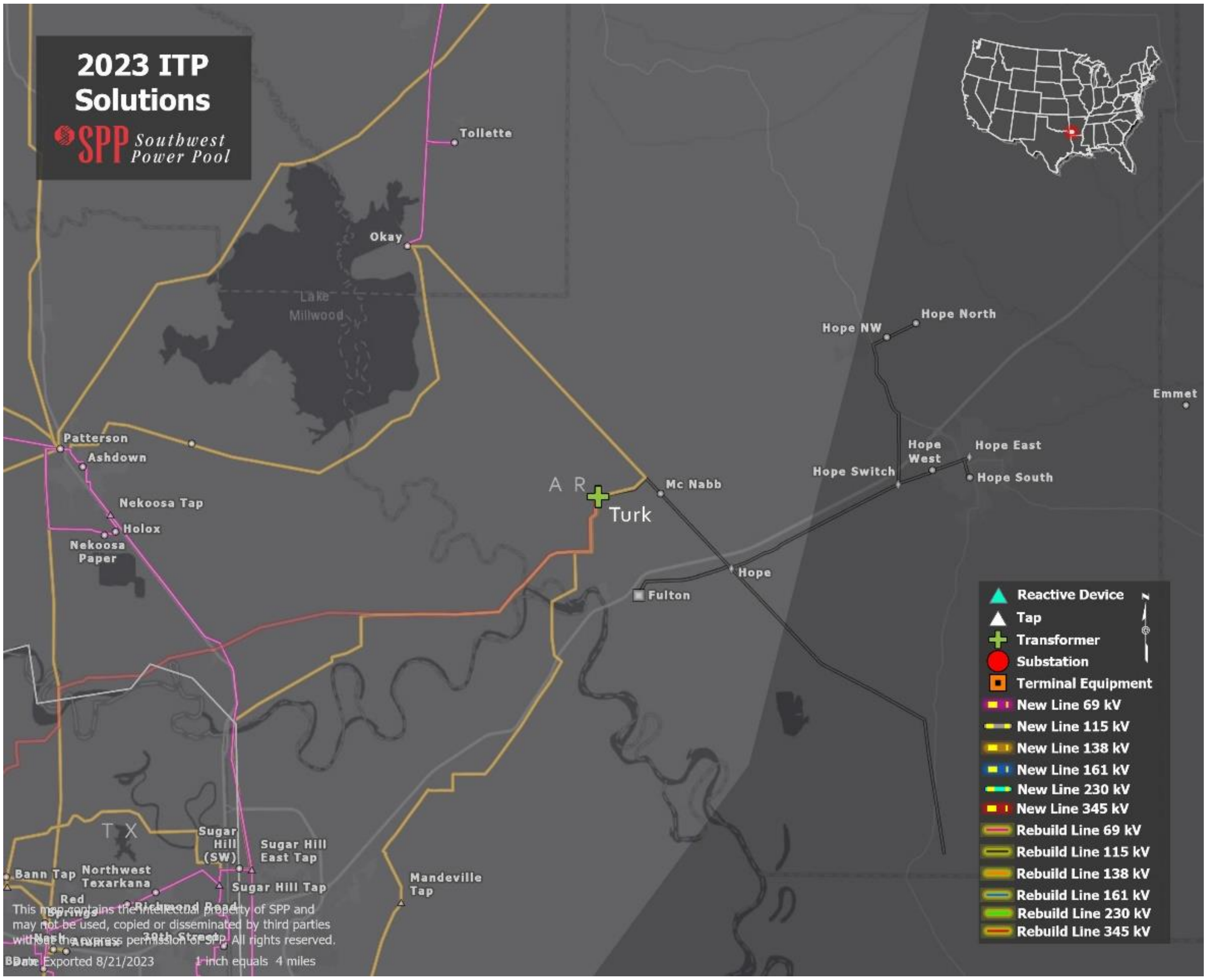

Figure 5.2: Turk 115/138 kV New Transformer

In southwest Arkansas, the Turk 138/115 kV transformer overloads for the loss of the Turk generator and the Longwood-Sarepta 345 kV line in northwest Louisiana. During the 2024 summer peak, there is a notable surge in the load on this transformer, escalating from a baseline of 42% to 109% after the loss of contingent elements.

The solution that provided the needed relief and was most feasible is the replacement of the Turk 138/115 kV transformer. This project reduced the loading on the transformer from the 109% to 78% in a post contingency scenario within that 2024 summer peak model.

5.1.2 EVERGY KANSAS CENTRAL (EKC)

5.1.2.1 *EXTEND & TAP CRAIG-WEST GARDNER 345 KV, CLEARVIEW-EUDORA 115 KV TAP, NEW 345/115 KV SUBSTATION*

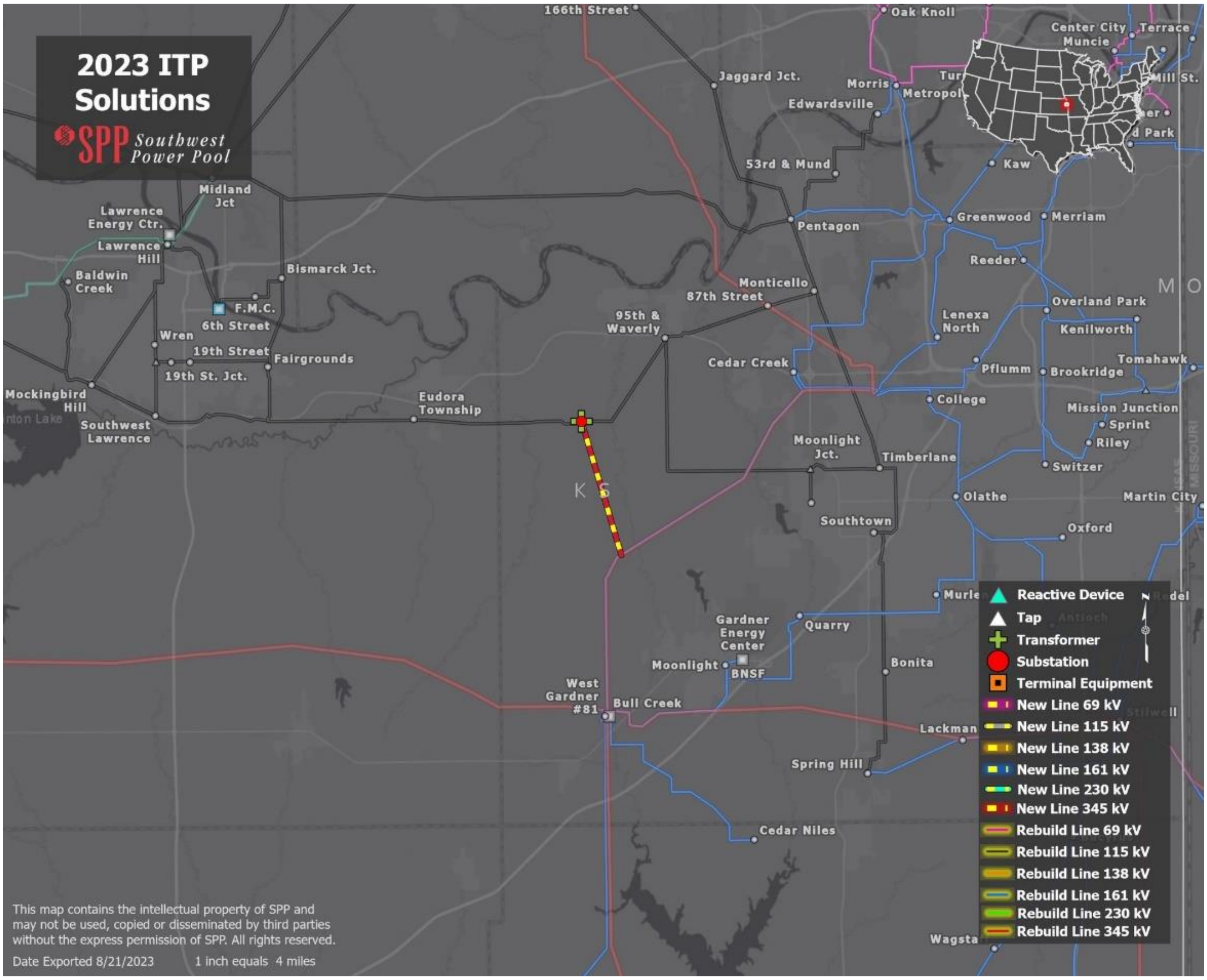

Figure 5.3: Extend and Tap Craig-West Gardner 345 kV, Eudora-Clearview 115 kV Tap, New 345/115 kV Substation

In Lawrence, Kansas, the Lawrence Hill-Wren 115 kV and Bismark-Fairgrounds 115 kV lines overload in the year 5 and year 10 models. Lawrence Hill-Wren 115 kV overloads for the loss of the Fairgrounds-Bismark-Midland Junction 115 kV circuit or the Baldwin Creek-Lawrence Hill 115 kV line. The Bismark-Fairgrounds 115 kV line overloads for the loss of Lawrence Hill-Wren 115 kV. The overloads observed in the ITP models are driven by the delayed retirement of two generating units at the Lawrence Energy Center.

Rebuilding the overloaded lines was not feasible due to right-of-way issues and surrounding topology. Known load additions coming to the area required a holistic solution to address both the new system needs in the area arising from the new loads coming through the Attachment AQ process, as well as the existing ITP needs that are aggrevated by the load additions.

The solution chosen to address all of the needs in the area was to extend the Craig-West Gardner 345 kV line north to the Eudora-Clearview 115 kV line near Clearview, where a new 345/115 kV substation will be built. The new 345/115 kV source will address the two overloaded lines in Lawrence, provide additional transmission capacity for future load growth and is the most feasible to implement.

5.1.3 EVERGY METRO (EM)

5.1.3.1 87TH STREET 345/115 KV NEW CIRCUIT 2 TRANSFORMER

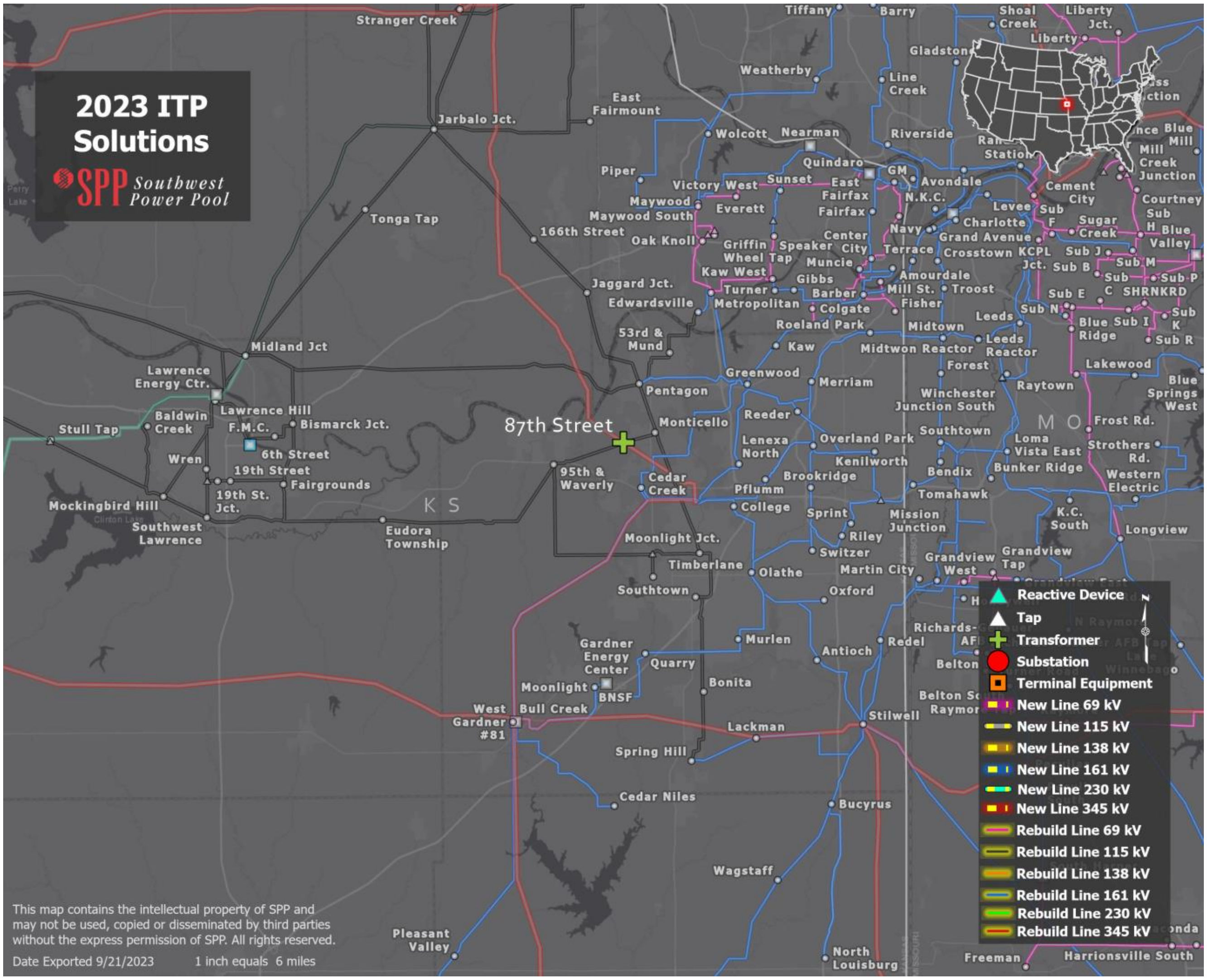

Figure 5.4: 87th Street 345/115 kV New Circuit 2 transformer

In the Final Reliability Assessment, it was determined that the new Craig-West Gardner substation introduces a potential risk on the 115 kV side of the substation for the loss of the 345 kV connections into the area. A holistic approach to addressing the violations in this area was taken, capitalizing on existing projects in the area, which were selected by delivery point studies. The project selected to facilitate the comprehensive resolution of the violations in this area is to install a second 345/115 kV transformer at the 87th Street substation to provide an additional path between the 345 kV and 115 kV systems.

5.1.4 GRAND RIVER DAM AUTHORITY (GRDA)

5.1.4.1 *KERR-MAID 161 KV DOUBLE-CIRCUIT 1 AND 2 REBUILD*

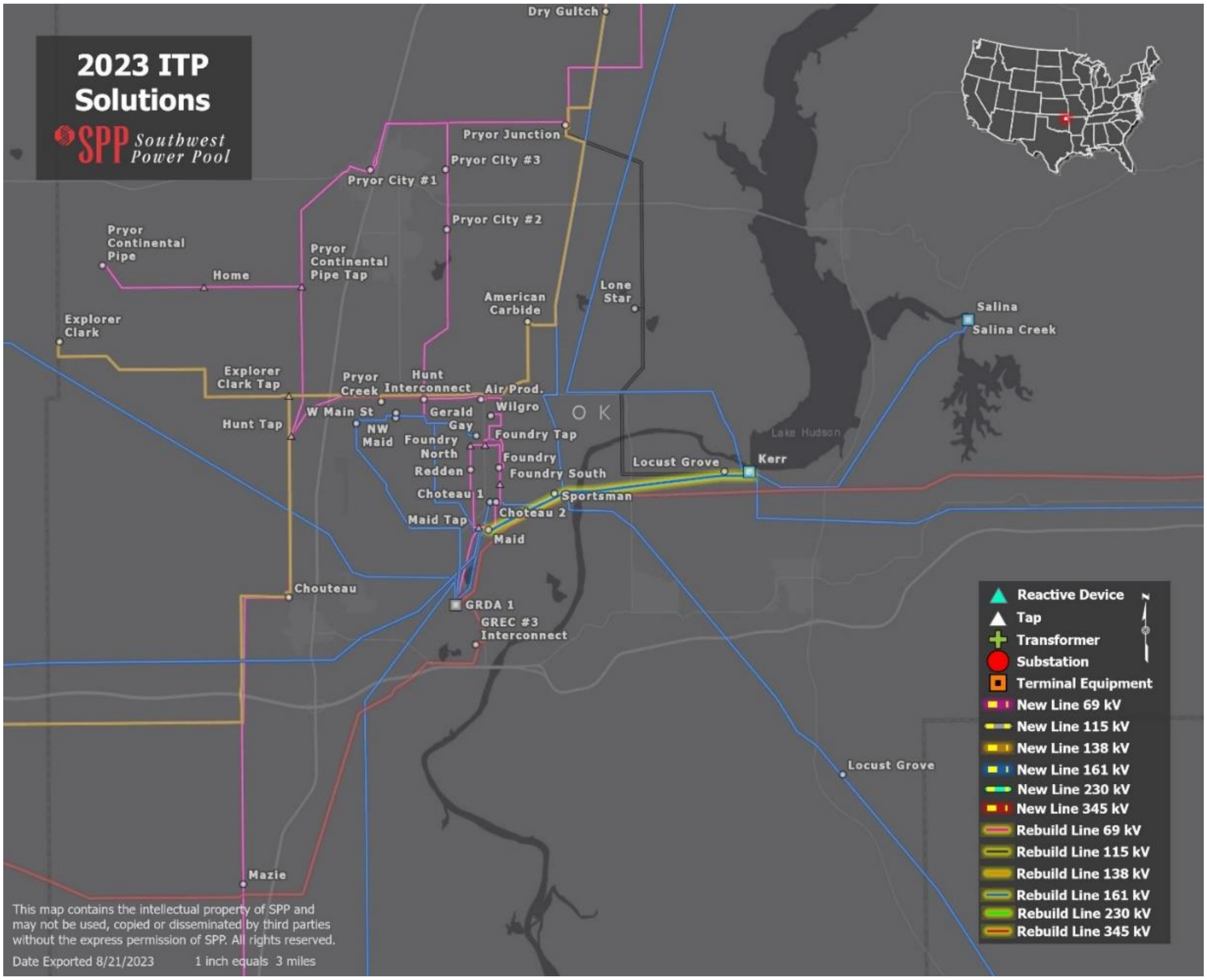

Figure 5.5: Kerr-Maid 161 kV Circuit 1 and 2 Rebuild

In the northeast corner of Oklahoma, the Kerr to Maid 161 kV circuit 1 and 2 each overload for the loss of the other circuit. These overloads are observed in the 2024 and 2027 light load models and are both loaded to 134.1% and 146.2% respectively of the post contingency limit. Rebuilding both circuits at Kerr to Maid relieves the overload in 2024 to 40.03% and in 2027 to 43.6%.

The Kerr to Maid 161 kV circuit 1 and 2 also becomes congested with the loss of the other circuit. The congestion is prevalent in all three of the study years for Futures 1 and 2, except for 2024 when it is only constrained in Future 1. Rebuilding these lines will more than double the line rating, which helps to relieve this congestion in the area.

SPP evaluated and selected this project within the 2022 ITP, but the project ultimately did not receive an NTC due to the overloads being in the year 10 model only.

5.1.5 OKLAHOMA GAS AND ELECTRIC COMPANY (OGE)

5.1.5.1 *PENNSYLVANIA-SOUTHGATE-WESTMOORE 138 KV EXTEND LINE*

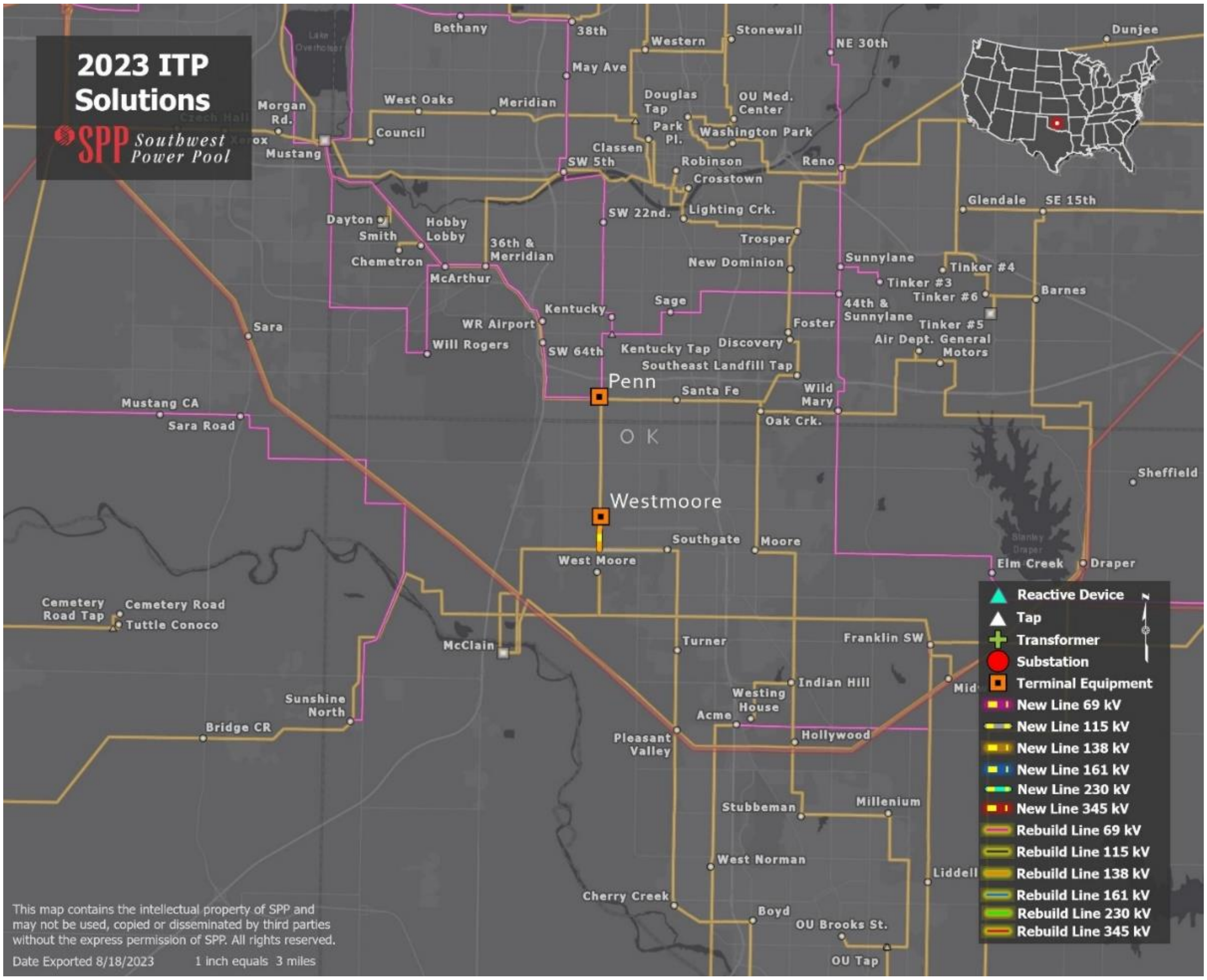

Figure 5.6: New Southgate-Westmoore-McClain 138 kV Line and Westmoore-Penn Terminal Upgrades

The Westmoore-Westmoore Tap 138 kV line is located just south of Oklahoma City, Oklahoma, and overloads for the loss of the Pleasant Valley-Norman Hill 138 kV line. The respective post-contingent overload values for the 2027 and 2032 summer models were 100.7% and 105.6%. In addition to the high post-contingent flows along this line, there is also a base case overload of 101.5% in the 2032 summer model. It should be noted that the overload values trended upward for both the pre- and post-contingent loading values which indicates an increased need for additional power transfer capability along this route.

The project ultimately chosen includes removing the Westmoore Tap (located less than a mile due south of the Westmoore substation) and creating a McClain-Westmoore 138 kV line and a Southgate-Westmoore 138 kV line. This project is intended to use all existing right-of-ways while leveraging the use of all existing transmission lines and requires a 0.76 mile 138 kV line be added between Westmoore and the previous Westmoore Tap location. To fully eliminate the overload, the project also includes terminal upgrades at the Westmoore and Pennsylvania substations. This project was chosen due to its maximization of existing right-of-way and infrastructure leading to a lower project cost. The project also provides significant thermal loading relief by reducing the year 10 summer post-contingent loading to less than 55%.

5.1.5.2 *SEMINOLE 345/138 KV NEW TRANSFORMER*

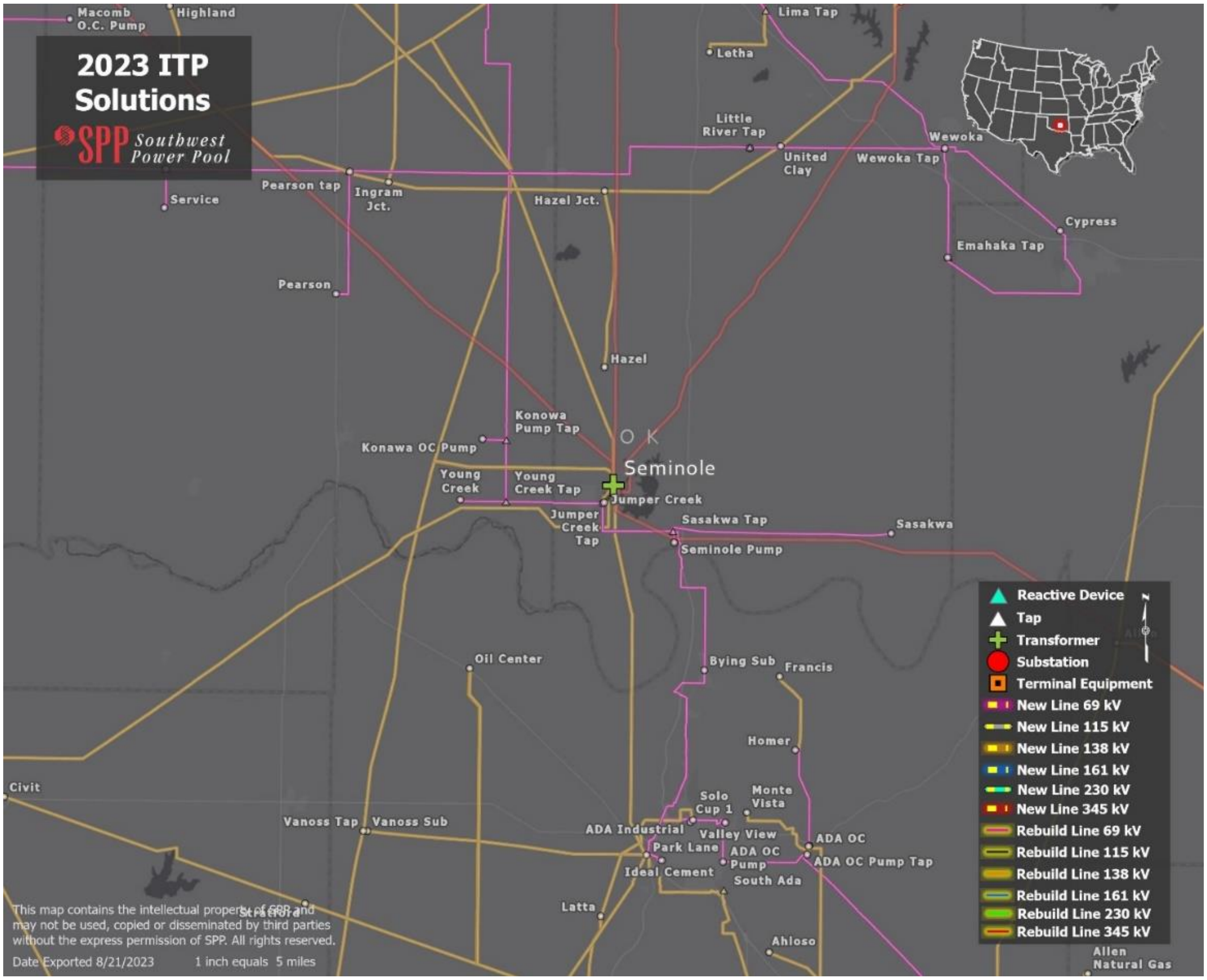

Figure 5.7: Seminole 138/345 kV New Transformer

The two Seminole 345/138 kV transformers, located approximately 50 miles southeast of Oklahoma City, experience a P3 thermal overload for the loss the Seminole generator connected to the low side of the transformers and one of the Seminole transformers. Following the contingency, the other Seminole transformer is overloaded by 106% in the year 2 summer model.

The project ultimately chosen to solve this need is to add a third transformer at the Seminole substation to allow for increased power transfer capability after the P3 contingency. Other projects considered for this need had considerably higher costs and did not provide as much relief comparatively.

5.1.5.3 *NEWMAN GRACE TAP-WOODWARD NITROGEN 69 KV TERMINAL EQUIPMENT UPGRADE*

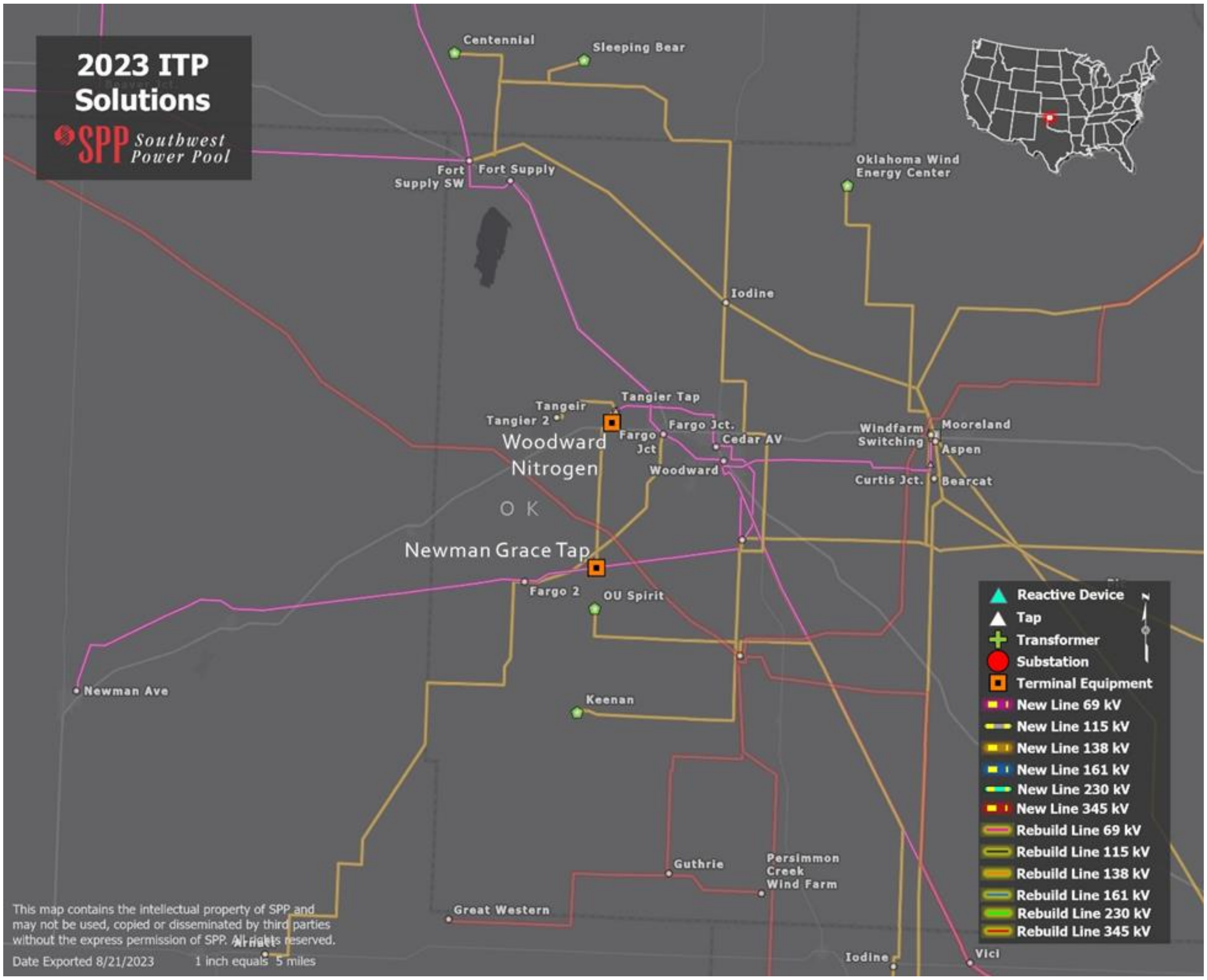

Figure 5.8: Newman Grace Tap-Woodward Nitrogen 69 kV Terminal Upgrade

The Newman Grace Tap-Woodward Nitrogen 69 kV line is located in the northwest region of Oklahoma and overloads for the loss of the parallel Cedar AV-Woodward 69 kV line in the 2024, 2027 and 2032 summer models with respective post-contingent overload values of 103.6%, 102.7% and 102.9%.

Two projects were considered to address this need: (1) a new Cedar AV-Woodward 69 kV line; (2) terminal upgrades at the Newman Grace Tap and Woodward Nitrogen 69 kV substations. The final project selected was the latter due to its cost-effectiveness and its ability to reduce the post-contingent line loading to under 74% in all three summer models.

5.1.6 SOUTHWESTERN PUBLIC SERVICE (SPS)

5.1.6.1 *MOORE COUNTY 115 KV TERMINAL EQUIPMENT UPGRADE*

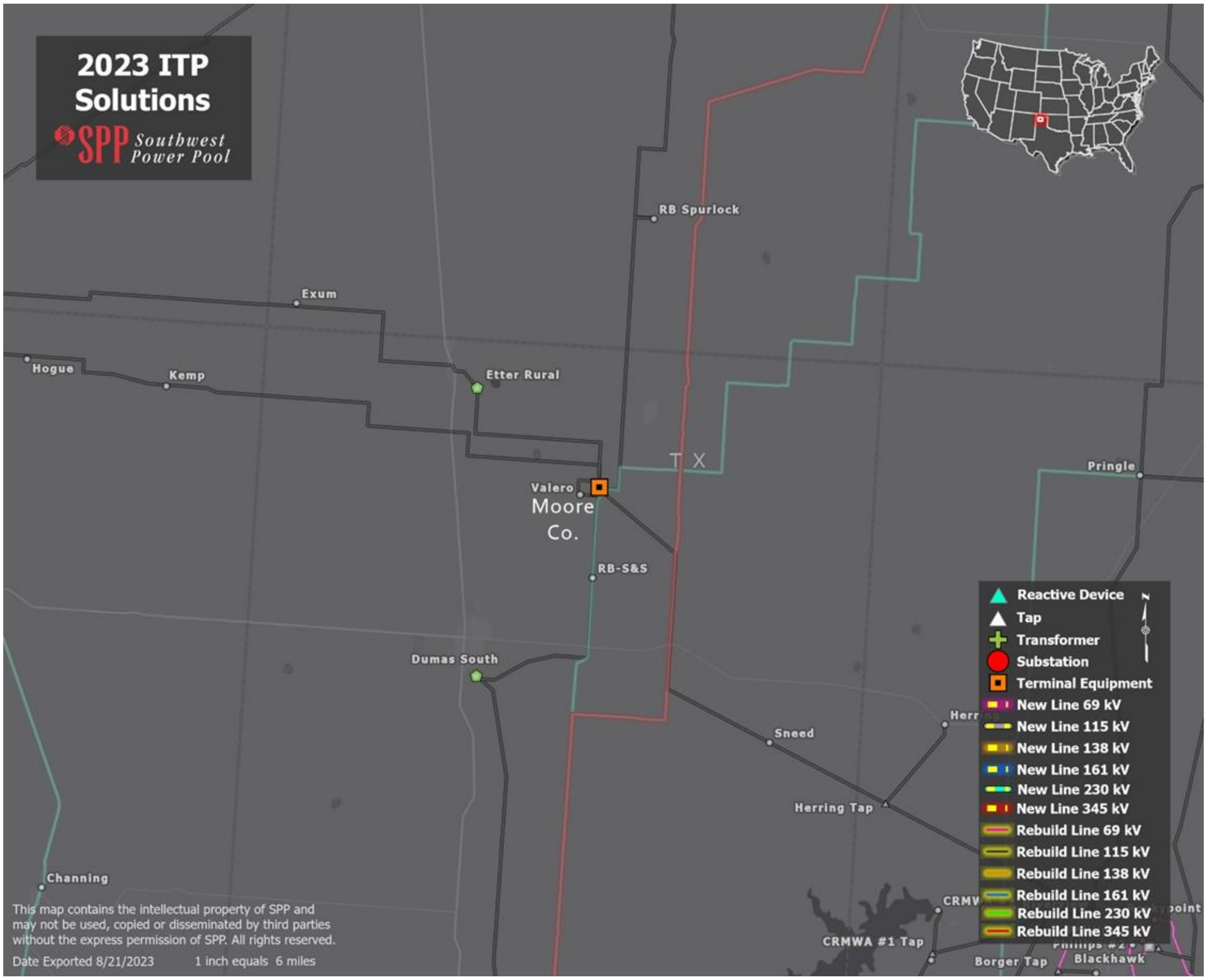

Figure 5.9: Moore County 115 kV Terminal Upgrades

Just north of Amarillo sits the Moore County substation that is pivotal in connecting the 115 kV and 230 kV systems in the Texas panhandle to western Oklahoma and southwestern Kansas.

The 115 kV line between Moore County and RB Spurlock overloads in the 2032 summer model with the loss of either 115 kV line between McDowell Creek and Exell tap or Four Way and Exell tap to 108% and 102% respectively. A rebuild and reconductor of the Moore–RB line were both considered for their ability to reduce post-contingent loading to 35% but ultimately both projects were deemed too expensive as compared to a terminal upgrade. Upgrading the terminal equipment at Moore County will increase the rating of the circuit to 174 MVA emergency rating in the summer and bring the loading down to 49% and 46% respective to the contingencies above.

5.1.6.2 *CUNNINGHAM-QUAHADA 115 KV TAP LINE-BUCKEYE TAP 115 KV NEW LINE*

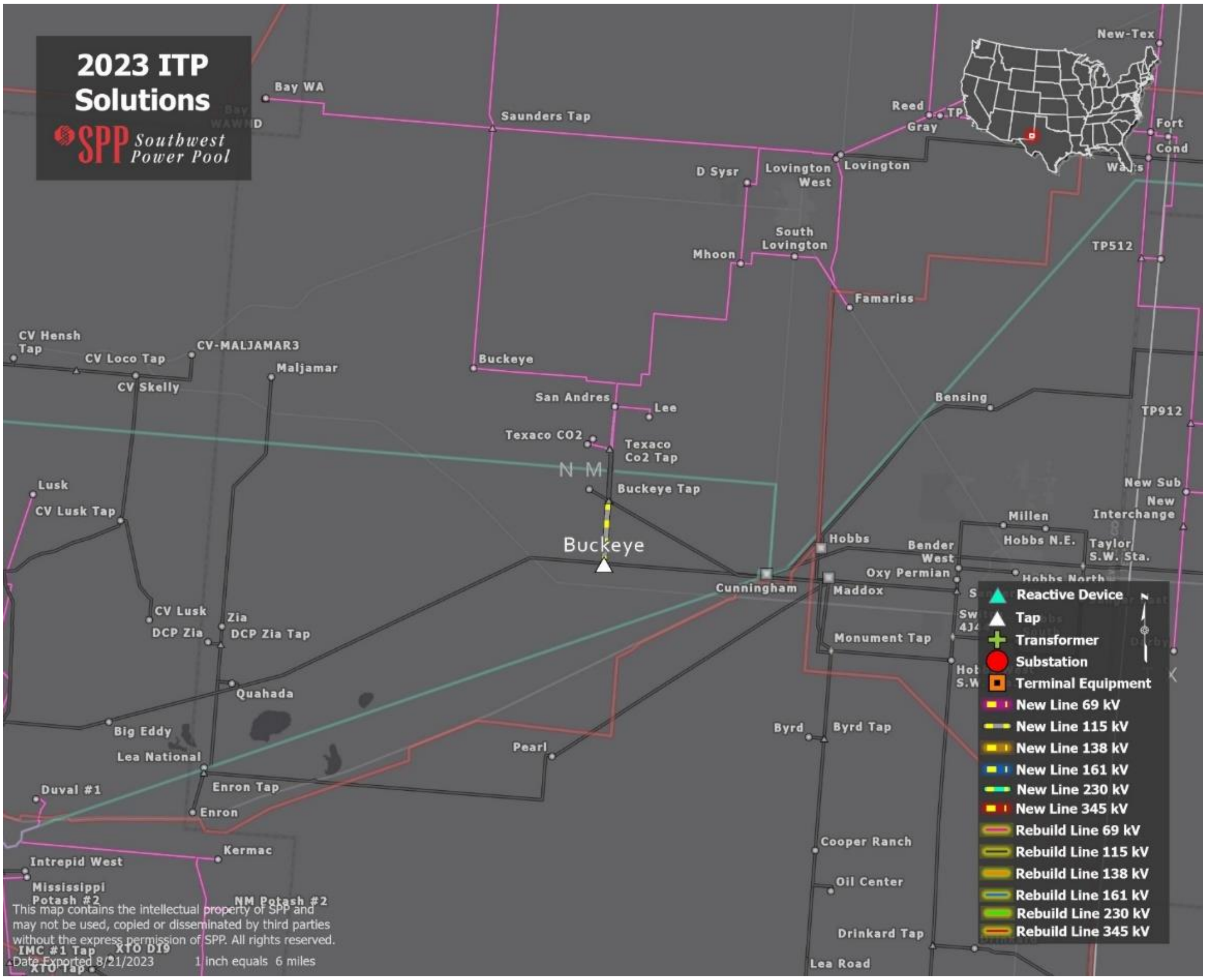

Figure 5.10: Cunningham-Quahada 115 kV Tap Line-Buckeye Tap 115 kV New Line

Multiple low voltage violations emerge in all summer models on the 115 kV system from Buckeye all the way to San Andres and at the Lovington substation with the loss of the 115 kV line between Cunningham and Buckeye Tap. An additional voltage violation occurs at the Lovington Waits bus with the loss of the 115 kV line between Waits and Ink Basin. Tapping into the 115 kV line between Quahada and Cunningham and constructing a 115 kV line from the new tap to Buckeye eliminates all of these violations, while also allowing for an alternate path for power to flow in future years.

5.1.6.3 *LOVINGTON 40 MVAR REACTOR*

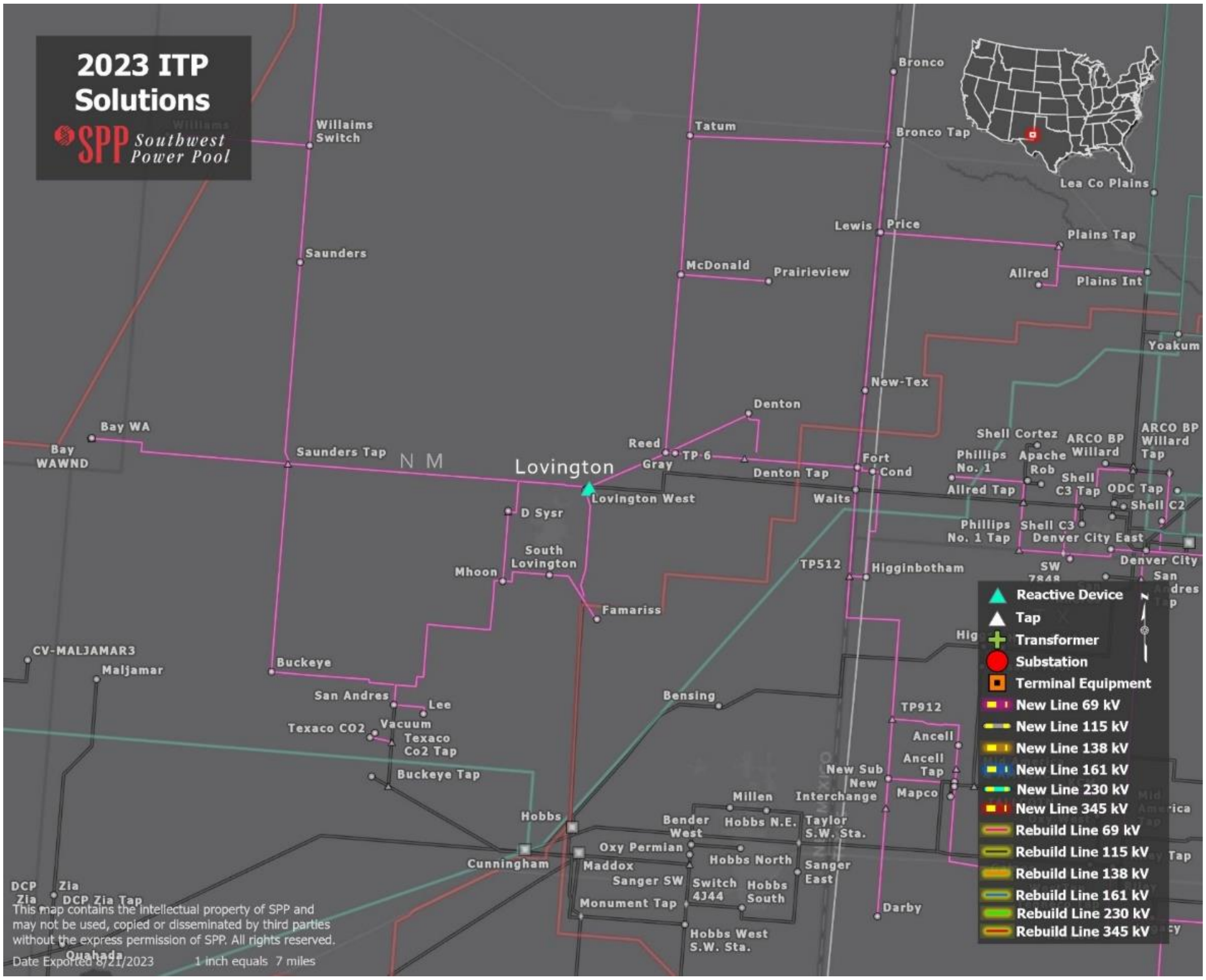

Figure 5.11: Lovington North Capacitor Bank

The Lovington 115 kV substation, located in southeast New Mexico, is one of the few routes for power to flow between southern New Mexico and west Texas. In the 2032 summer model, Lovington North 115 kV experiences low voltage with the loss of a generator and the 115 kV line between Lovington North and Lovington West. Lea County Waits 115 kV bus also experiences low voltage when losing the Sterling Wind generator and the 115 kV line between Waits and Ink Basin. Adding a 40 MVAR reactive device provides ample voltage support to resolve the violations caused by these P3 contingencies. The surrounding area will be bolstered with Lovington's ability to provide voltage support.

5.1.6.4 *SUNDOWN INTERCHANGE 115 KV TERMINAL EQUIPMENT*

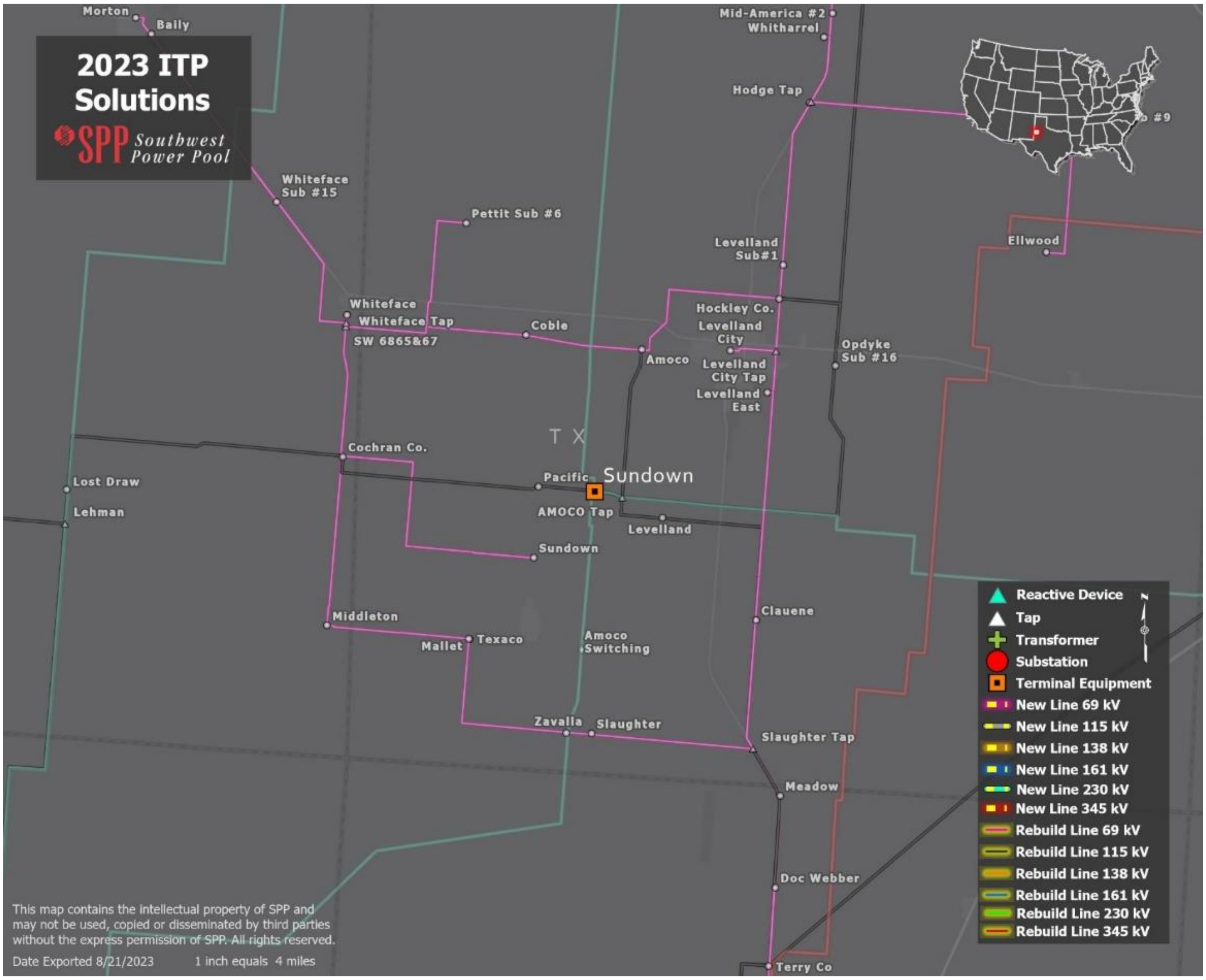

Figure 5.12: Sundown 115 kV Terminal Upgrades

The Sundown substation sits along the New Mexico-Texas border, just below the Texas Panhandle. The Wildcat wind farm is located along a 115 kV path between Sundown and Yoakum to the south. In the 2032 summer model, the Pacific-Sundown 115 kV is overloaded with the outage of the Wildcat generator along with the loss of the 115 kV line between Plains and Yoakum, as all load along the 115 kV path must be served from Sundown. With a terminal equipment upgrade at the Sundown substation increasing the circuit rating, this thermal violation is resolved, going from 104% to 94% loading. This terminal upgrade was chosen because it is cost effective and easily implemented.

5.1.7 WESTERN AREA POWER ADMINISTRATION – UPPER GREAT PLAINS REGION (WAPA-UGPR)

5.1.7.1 *DEVAUL 115 KV 15 MVAR REACTOR*

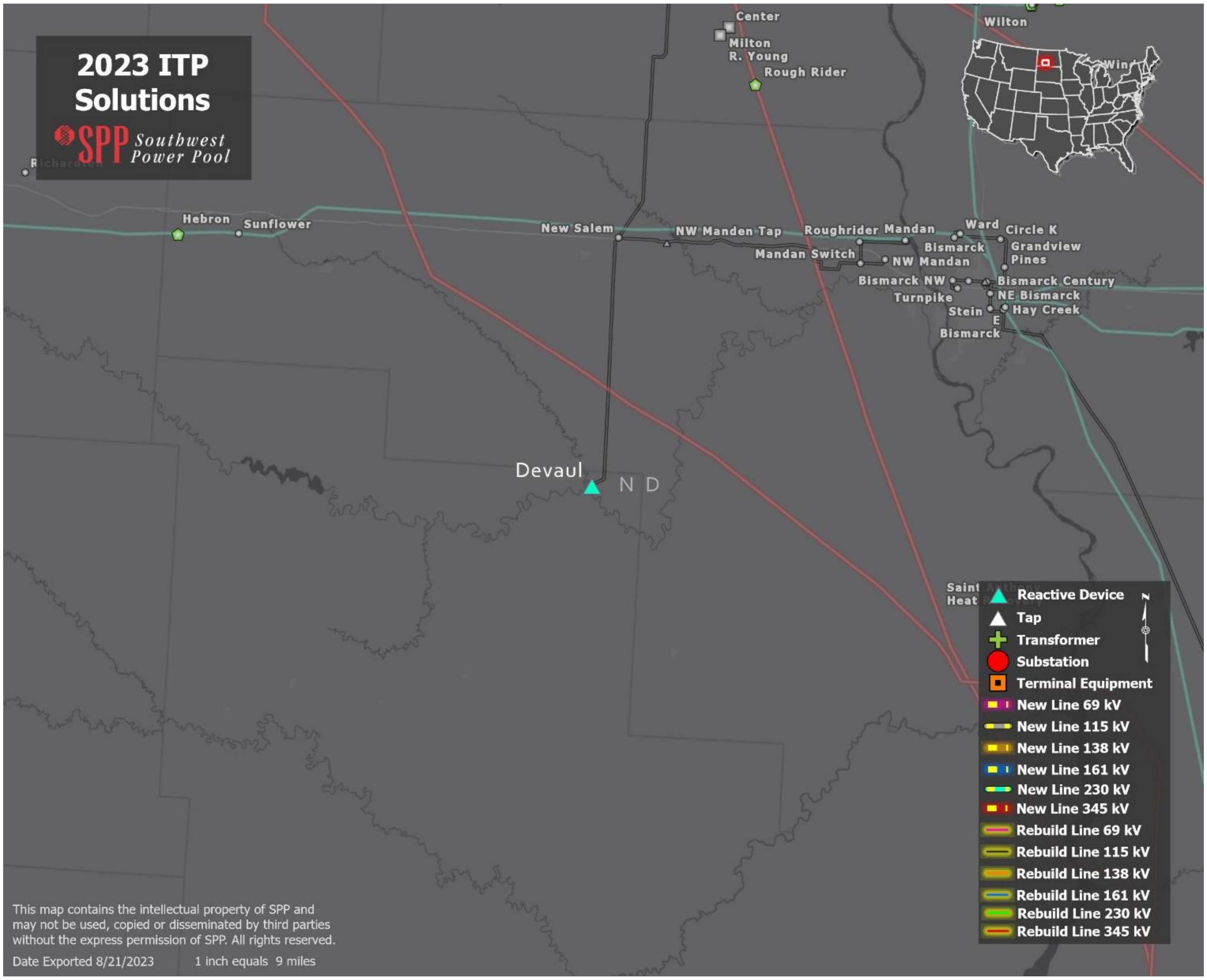

Figure 5.13: Devaul 115 kV Switched Shunt

Devaul is a 115 kV bus in North Dakota near the cirty of Bismarck. Losing the nearby 345/115 kV Leland Olds transformer also takes out the reactor in the same substation, causing high voltages on the connecting 115 kV system. A reactor at New Salem was originally suggested to bring down the voltage in a more central location along the 115 kV path. However, after receiving stakeholder feedback, the location of the reactor was changed to the Devaul substation to more directly address the most severe violation. The Devaul reactor brings the post-contingent voltage of 1.059 pu down to a more secure 0.99 per unit for long-term stability.

5.1.7.2 DAWSON COUNTY-FORT PECK 230 KV 40 MVAR REACTOR

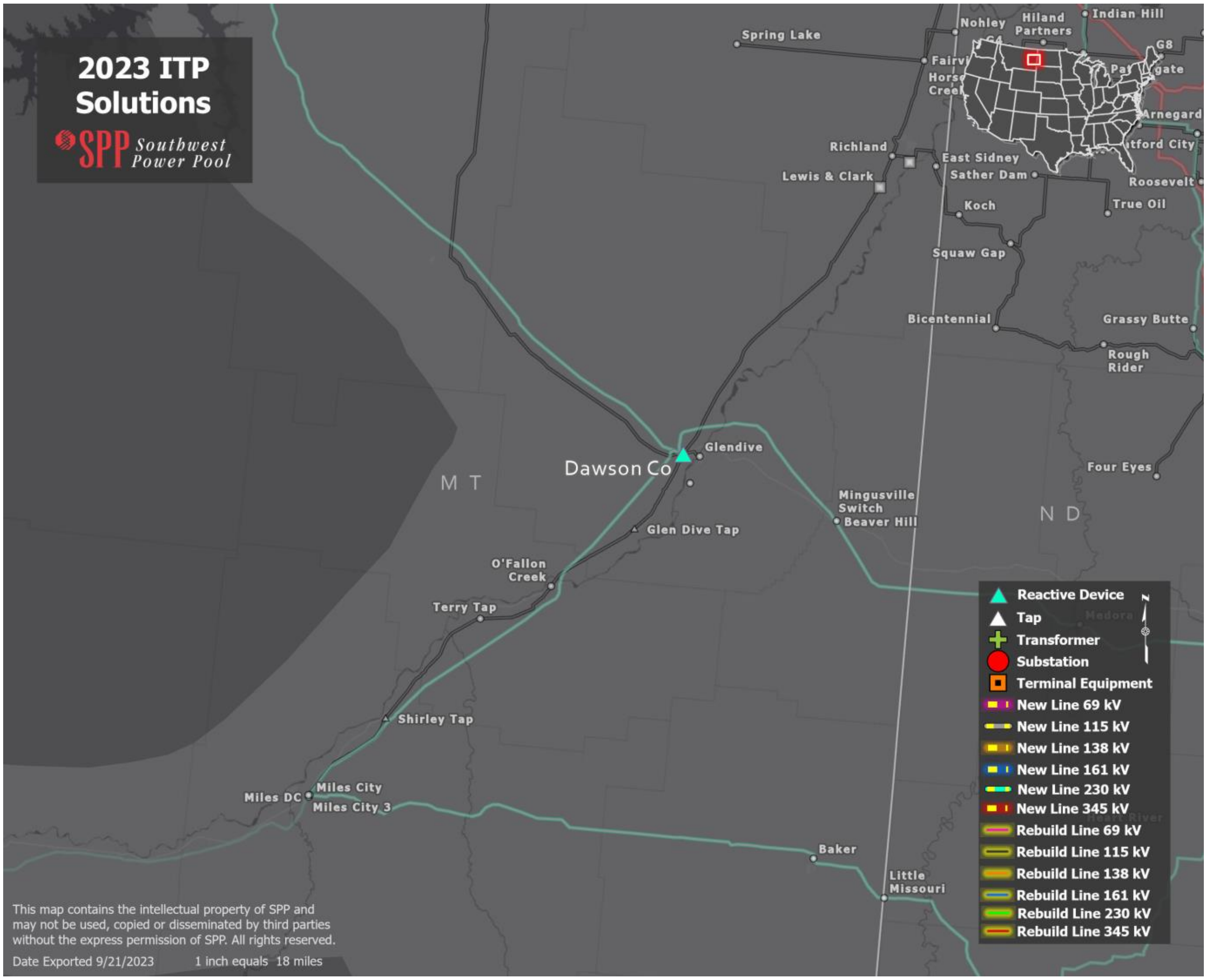

Figure 5.14: Dawson County – Fort Peck 230 kV 40 MVAR Reactor

Fort Peck is a generation substation in Montana connected to the SPP system by a single 230 kV line from Dawson County. The generator at Fort Peck absorbs reactive flows on the nearby 115 kV and 230 kV network maintaining voltages within normal range. Losing this generator in combination with one of several 115 kV lines in the area can result in high voltages in the area. The project originally selected to address this issue was a new reactor at the Fort Peck substation; however after discussions with the transmission owner, the more feasible solution is a line reactor on the Fort Peck – Dawson County 230 kV line to be placed on the Dawson County end of the circuit. This project will bring the post-contingent voltage at Fort Peck from 1.061 pu down to 1.0 pu.

5.1.7.3 *BROADLAND 345 KV 75 MVAR REACTOR*

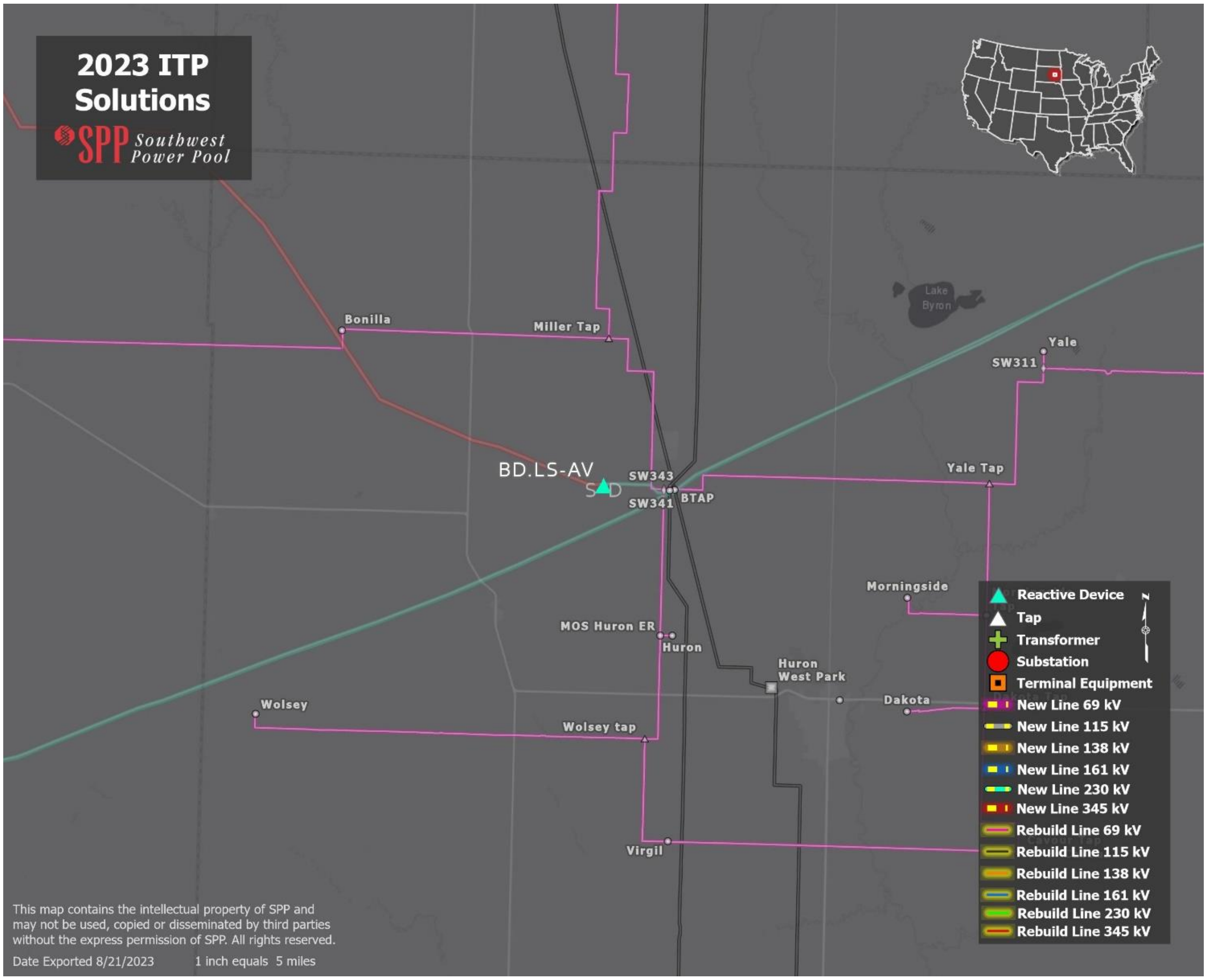

Figure 5.15: Broadland 345 kV 75 MVAR reactor

Antelope-Broadland is a 300 mile 345 kV line between North and South Dakota. When this line loses its in-line reactive support as part of a P3 event, high voltage issues can occur on the the Broadland side of the line. The most severe of these violations was 1.077 pu under contingency of the SVC at Watertown in combination with the reactive support on the Broadland end of the long EHV line. The project to address these needs is an additional reactor at the Broadland side of the line to bring this high voltage down to 1.04 pu.

5.1.7.4 GROTON 345 KV 68 MVAR REACTOR

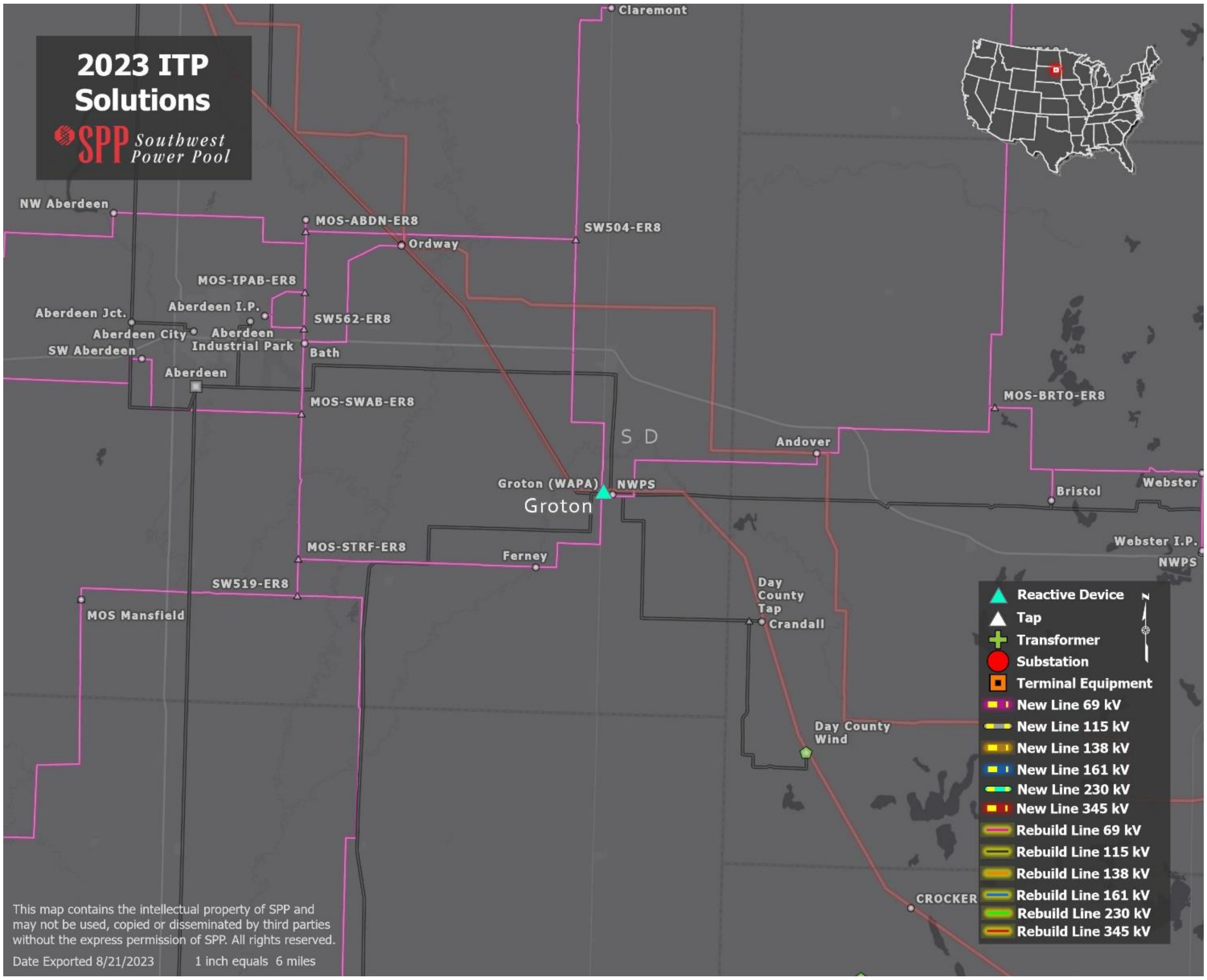

Figure 5.16: Groton 345 kV Switched Shunt

Groton - Leland is a 200 mile 345 kV line between North and South Dakota. Much like the previous project, losing in-line reactive support results in high voltages up to 1.059 pu on the surrounding 345 kV and 115 kV system on the Groton side of the line. The recommended project for this event is a redundant reactor at the Groton substation, which brings the post-contingent voltage back down to 1.04 pu.

5.2 ECONOMIC PROJECTS

DESCRIPTION	AREA	E&C COST	MILES
Blackberry-Neosho 345 kV terminal equipment	AECI	$6,830,258	
Cleveland 138 kV terminal equipment	AECI	$2,530,160	
Pine & Peoria Tap-46th Street Tap-Tulsa North 138 kV rebuild	AEP	$6,228,906	5.7
Osage-Webb City Tap-Shidler 138 kV rebuild	AEP	$27,236,410	24.9
Benton-Wichita 345 kV terminal equipment	EKC	$6,830,258	
Butler-Midian 138 kV terminal equipment	EKC	$2,658,322	
Franklin 161/69 kV circuit 2 transformer	EKC	$3,323,769	
Craig-Lenexa South 161 kV circuit 2 terminal equipment	EM	$1,902,581	
Fremont/Sub 976 115/69 kV new circuit 2 transformer	OPPD	$5,900,000	
Gerald Gentleman Station-Ogallala 230 kV terminal equipment	NPPD	$1,700,000	
Alliance-Victory Hill 115 kV new line	NPPD	$92,007,750	47.9
Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake	OGE	$87,000,000	2.8
Chisholm Creek-Lone oak 138 kV new line	OGE	$4,181,870	3.4
Cimmaron and Czech Hall 138 kV terminal equipment	OGE	$138,952	
Fitzgerald Creek-Kenzie 138 kV line tap at Valley	OGE	$10,000,000	2
Matthewson-Redbud 345 kV new line	OGE	$110,770,850	38.4
Cleo Corner-Okeene 138 kV new line	OGE	$38,483,360	26.4
70th & Bluff-Sub 1214 161 kV raise line and replace 70th & Bluff 161/115 kV circuit 1 transformer	LES/OPPD	$8,914,179	17.7

DESCRIPTION	AREA	E&C COST	MILES
Ellsworth Tap-Great Bend 115 kV structures	SUNC	$750,000	30.2
Anadarko-Gracemont 138 kV circuit 2 and 3 new line	SPS	$64,000,000	15
Replace Potter County 345/230 kV circuit 1 transformer and new circuit 2 transformer	SPS	$30,000,000	
Fort Thompson 345/230 kV circuit 1 and 2 transformers	WAPA	$33,546,913	
Gavins Point-Yankton 115 kV rebuild	WAPA	$2,957,298	4
Huron B Tap-Huron-Huron West Park 115 kV rebuild	WAPA	$12,548,421	10.6

Table 5.2: Economic Projects

5.2.1 ASSOCIATED ELECTRIC COOPERATIVE, INC. (AECI)

5.2.1.1 *BLACKBERRY AND NEOSHO 345 KV TERMINAL EQUIPMENT UPGRADES*

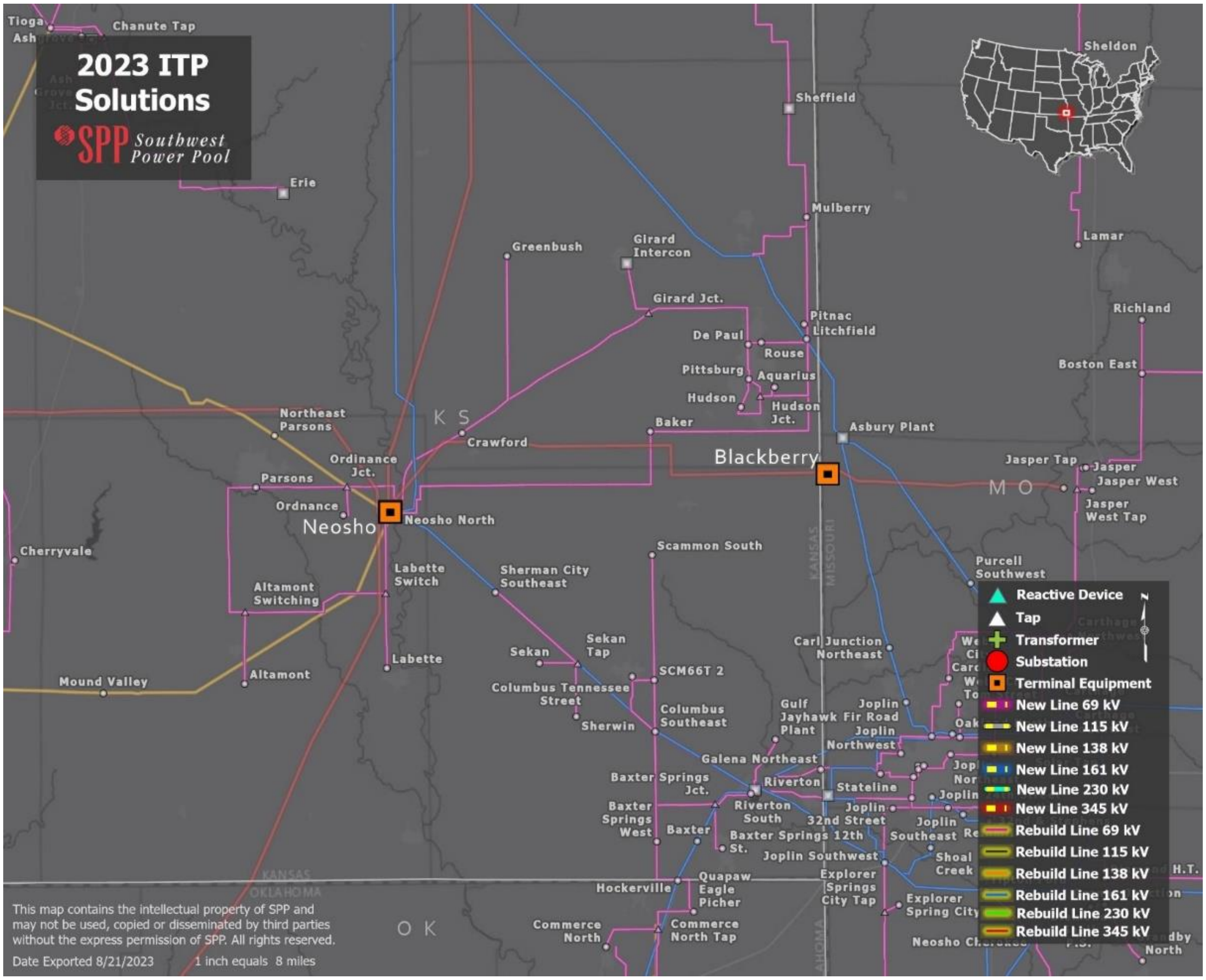

Figure 5.17: Terminal Upgrade Blackberry and Neosho

In the southeast corner of Kansas, the 345 kV line from Blackberry to Neosho experiences congestion for the loss of the 345 kV line from Blackberry to Wolf Creek. The loss of the north to south 345 kV path increases west to east flows from Blackberry to Neosho. To resolve this congestion, the terminal equipment of the Blackberry to Neosho line will need to be upgraded, allowing the circuit to operate at the conductor's MVA rating. Late in the study, SPP discovered this terminal upgrade only provides a limited ratings increase for the winter season. Since SPP will be evaluating deliverability into Southwest Missouri in the 2024 ITP, with a focus on the winter season, SPP recommends still moving forward with the Blackberry – Neosho terminal upgrade.

5.2.1.2 CLEVELAND 138 KV TERMINAL EQUIPMENT

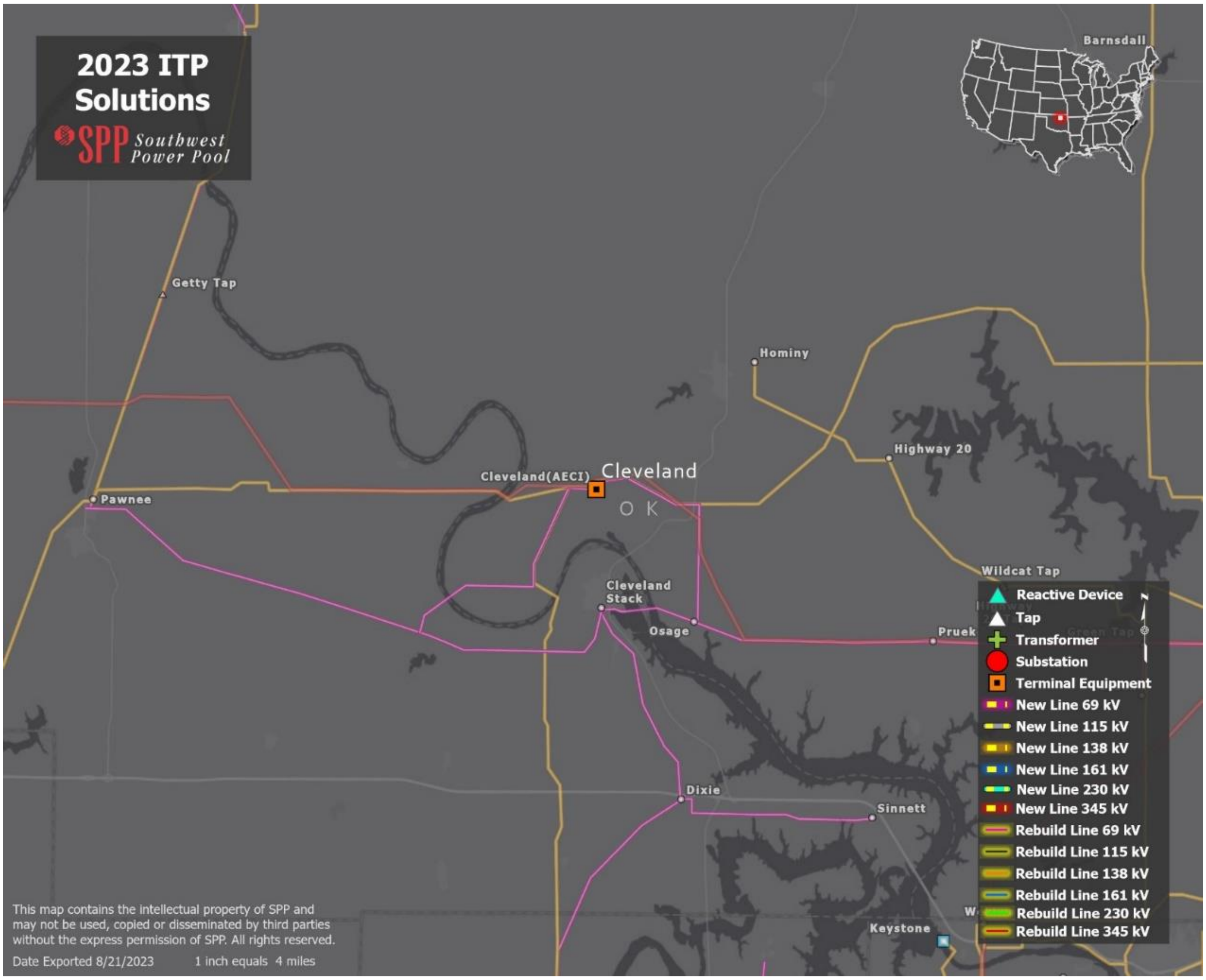

Figure 5.18: 138 kV Cleveland 138 kV Terminal Equipment

The Cleveland substation located in Northeast Oklahoma has become one of the most congested points on the SPP system. The bus tie between AECI and GRDA Cleveland 138 kV buses experiences heavy loading with the loss of the Tulsa North-Cleveland 345 kV line. This congestion is due to power flowing from the 345 kV system onto the 138 kV system on its way to Tulsa North. To resolve this congestion and provide more stability to the Cleveland area, a terminal upgrade at the Cleveland substation is required. Even with a large EHV solution being expected to be in-service prior to year 5, increased congestion on this element appears in year 10. This upgrade eliminates more than 99% of the expected congestion in both futures.

5.2.2 AMERICAN ELECTRIC POWER (AEP)

5.2.2.1 *PINE & PEORIA TAP - 46TH STREET TAP - TULSA NORTH 138 KV REBUILD*

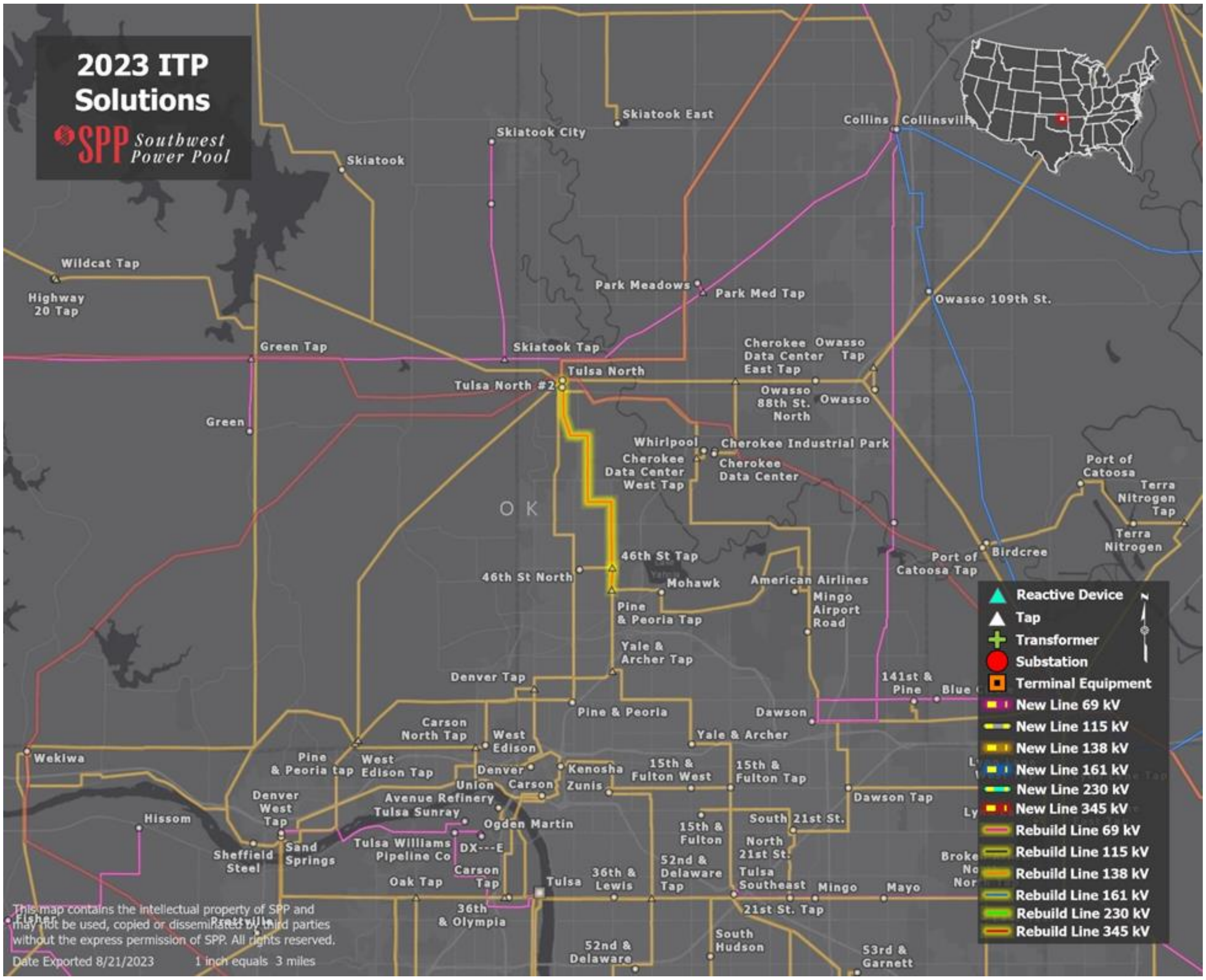

Figure 5.19: Pine & Peoria Tap – 46th Street Tap – Tulsa North 138 kV Rebuild

The Tulsa North- 46th Street Tap 138 kV line is located in Tulsa, Oklahoma and experiences significant congestion after the loss of the Tulsa North-Cherokee Data Center West Tap 138 kV line. The high congestion is due to the large west-to-east flows present in this region and resulted in Future 1 of year 10 having a congestion score of $820,622, which was the highest of all five scenarios.

The project selected to mitigate the congestion is a rebuild of the Tulsa North-46th Street Tap-Pine & Peoria 138 kV lines. This series of rebuilds completely eliminates the congestion in all five scenarios, while also being extremely cost effective by implementing a lower-cost 138 kV rebuild as compared to a higher cost 345 kV project. Additionally, this project was the preferred project in the 2022 20-Year Assessment to address congestion on this facility when compared against other EHV solutions, confirming its potential benefits and ability to address congestion for the long term.

5.2.2.2 *OSAGE-SHDLER-WEBB CITY TAP 138 KV REBUILDS*

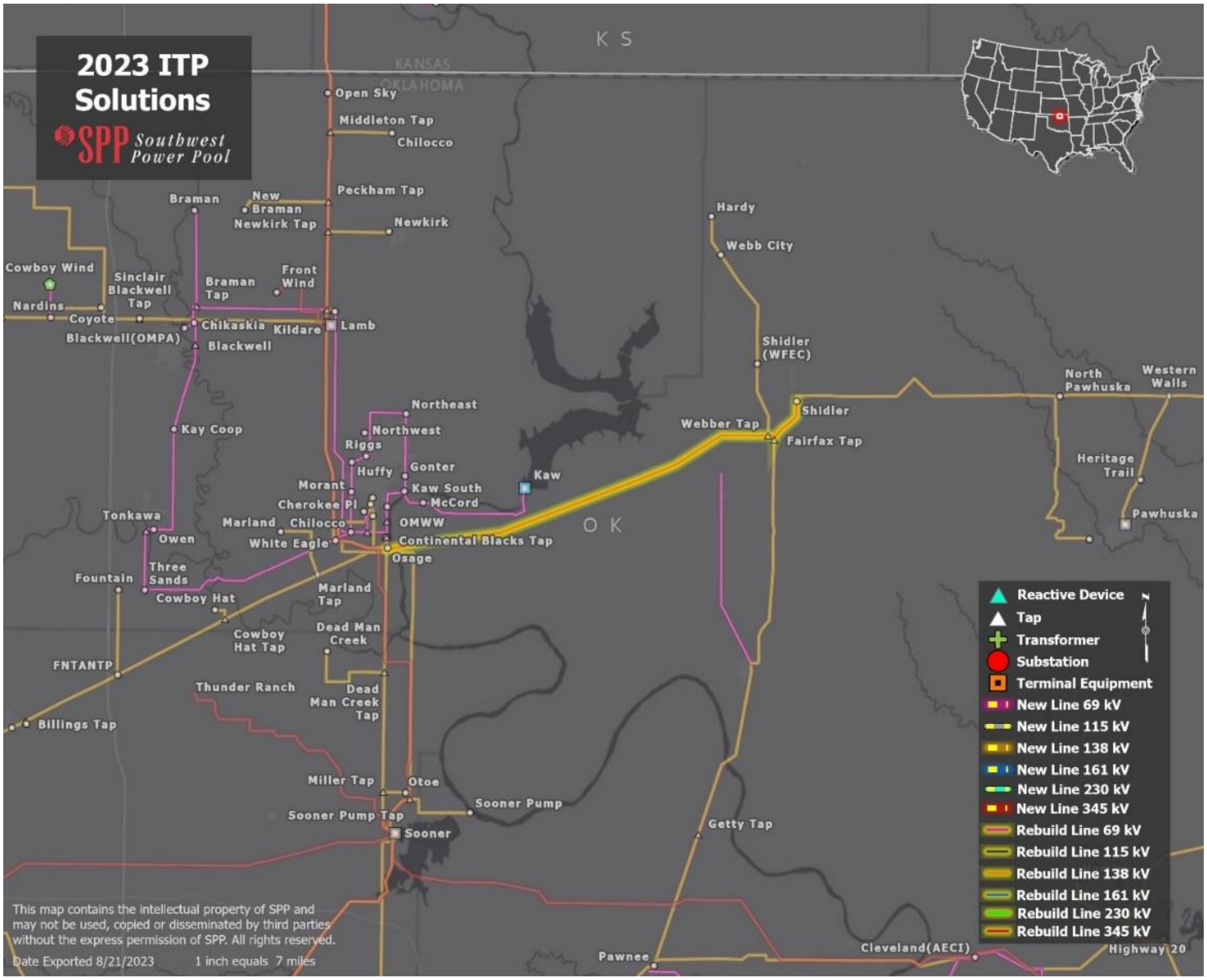

Figure 5.20: Osage-Shidler-Webb City Tap 138 kV Rebuilds

The Osage-Shidler-Webb City Tap 138 kV line rebuilds increases power transfer capability between northwest Oklahoma and Tulsa and provided near complete congestion relief for the Webber Tap-Osage 138 kV line after the loss of the Cleveland-Sooner 345 kV line, which was identified as both an ITP need and an operational need. In addition to being identified as a 2023 ITP economic constraint, it was also identified as a persistent operational constraint that resulted in 62.8 million dollars in congestion over the two-year time frame evaluated for persistent operational needs in the 2023 ITP. This project was chosen for its ability to quickly resolve real-time and projected congestion, while being cost effective by leveraging existing infrastructure to increase transfer capability along this corridor.

5.2.3 EVERGY KANSAS CENTRAL, INC. (EKC)

5.2.3.1 *BENTON-WICHITA 345 KV TERMINAL EQUIPMENT UPGRADE*

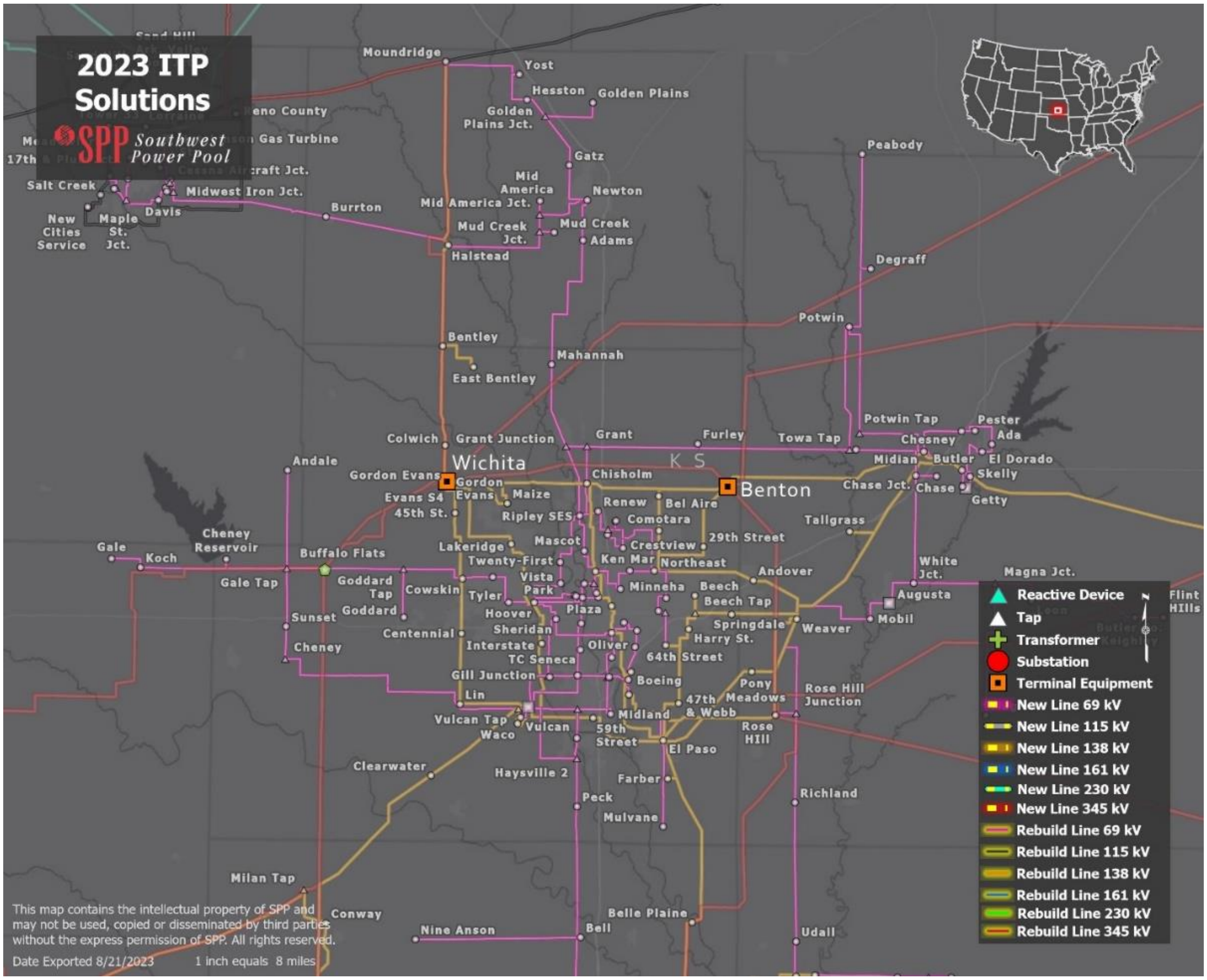

Figure 5.21: Benton-Wichita 345 kV Terminal Equipment

In Wichita, Kansas, the Benton-Wichita 345 kV line becomes congested for the loss of the Wolf Creek generator, in both futures in years 5 and 10. This flowgate has been experiencing persistent economic operational congestion, as increased flow attempts to travel from Wichita to Benton in the absence of flows from Wolf Creek to Benton. To resolve this congestion and better supply the 138 kV system connected to the Benton substation, the terminal equipment of the Benton-Wichita 345 kV line will be upgraded, allowing the circuit to operate at the conductor's MVA rating.

5.2.3.2 *NEW 161/69 KV TRANSFORMER AT FRANKLIN CIRCUIT 2*

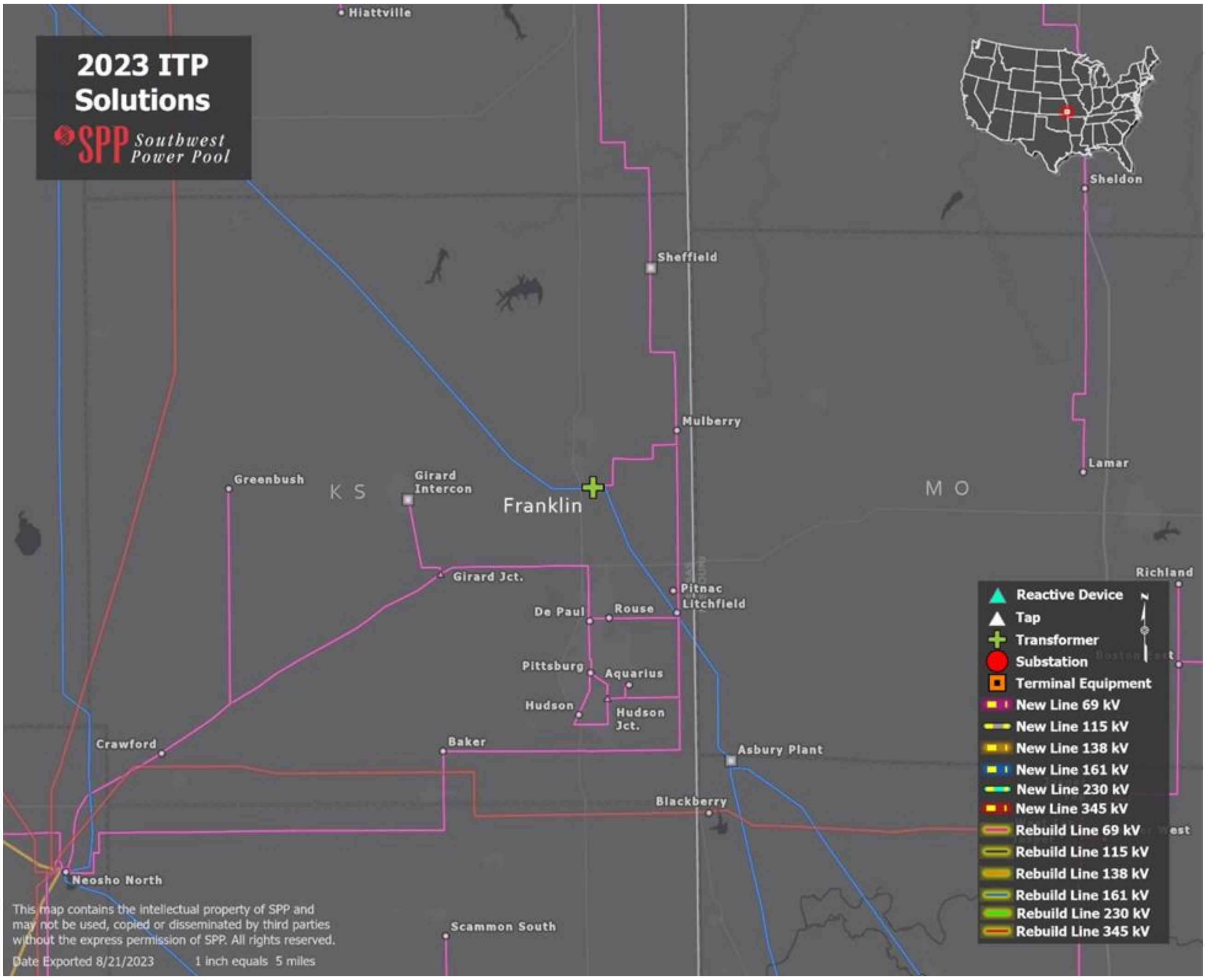

Figure 5.22: New 161/69 kV Transformer at Franklin Circuit 2

In the southeast corner of Kansas, the Franklin circuit 1 transformer becomes congested for the loss of the 161 kV line from Franklin to Litchfield. The loss of this line results in the loss of the connection to the 161 kV system, and funnels all west to east flows from the Jayhawk substation to the 69 kV system at Franklin. To resolve this congestion by increasing capacity between the 161 kV and 69 kV systems, a second 161/69 kV transformer will be installed at the Franklin substation.

5.2.3.3 *BUTLER-MIDIAN 138 KV TERMINAL EQUIPMENT UPGRADE*

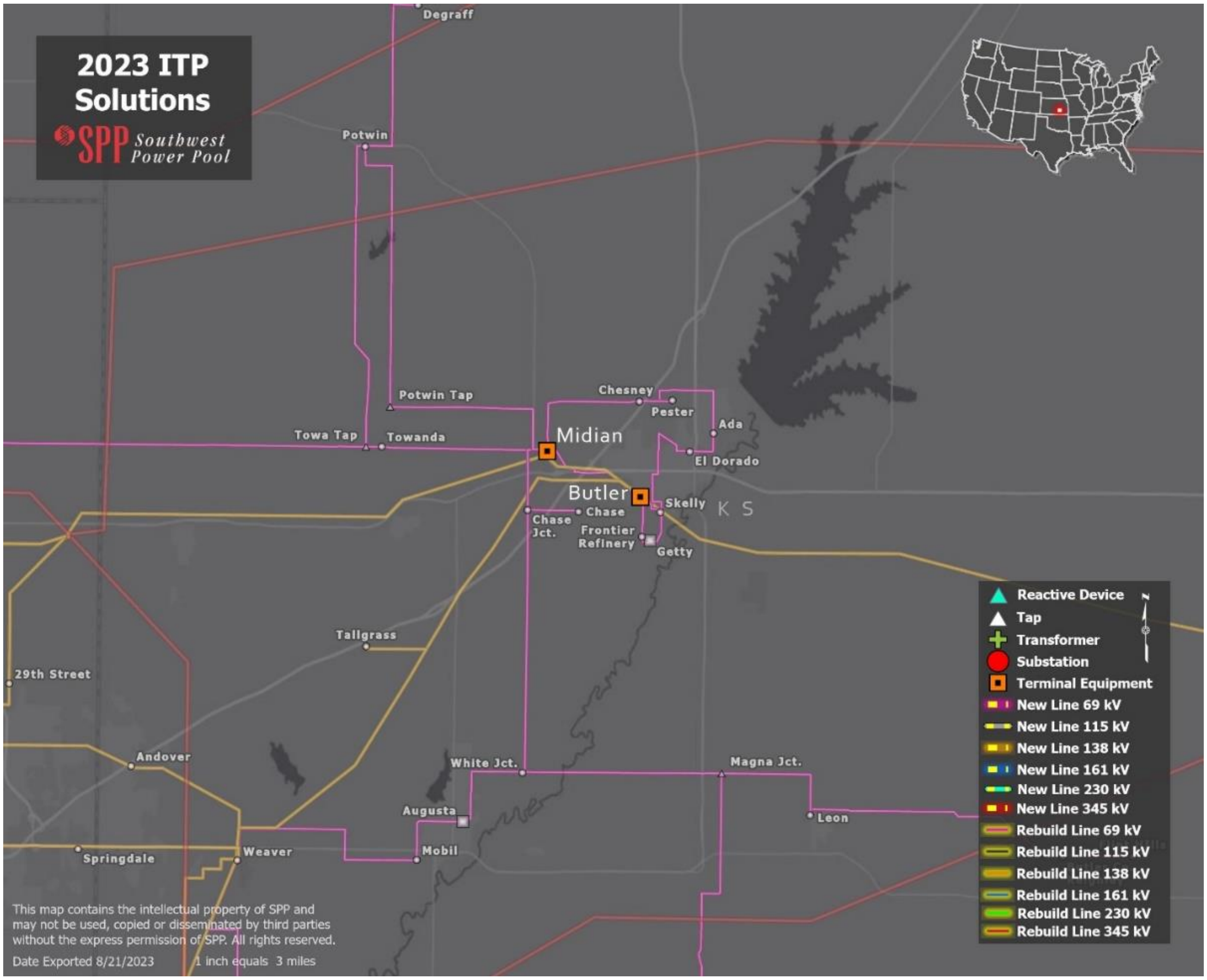

Figure 5.23: Butler-Midian 138 kV Terminal Equipment

Northeast of Wichita, Kansas, the 138 kV line from Butler to Midian experiences congestion for the loss of the 138 kV line from Weaver to Tallgrass. The loss of 138 kV support from the south causes increased flows on the west to east Midian to Butler line in an effort to serve the load at Butler. To resolve this congestion, the terminal equipment on the Butler to Midian line will be upgraded, allowing the circuit to operate at the conductor's MVA rating. This project was also recommended over an EHV solution in the 2022 20-Year Assessment. Similarly, this project is expected to bring significant net benefits and lasting congestion relief.

5.2.4 EVERGY METRO (EM)

5.2.4.1 *CRAIG 161 KV & LENEXA SOUTH 161 KV TERMINAL EQUIPMENT UPGRADES*

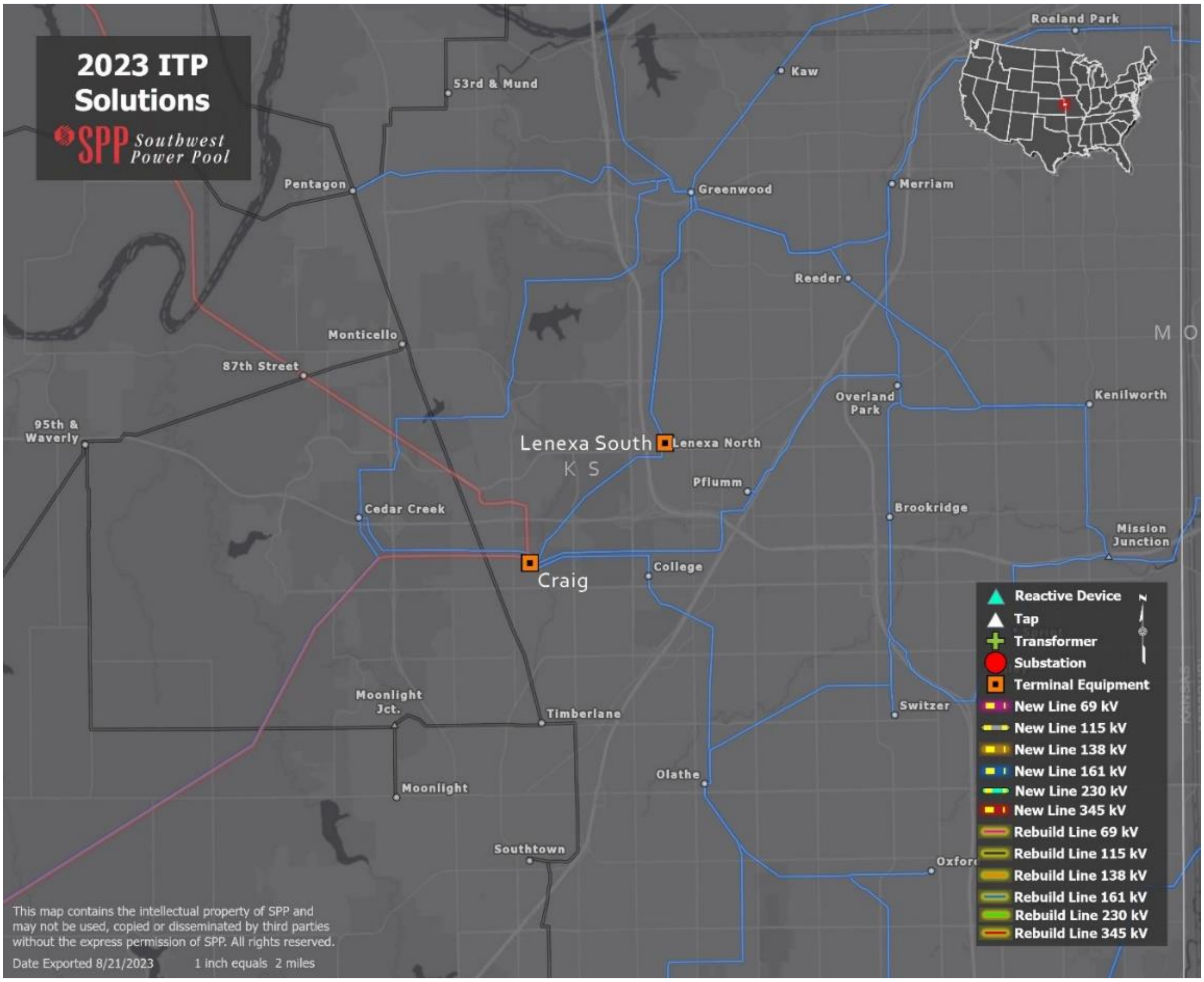

Figure 5.24: Craig 161 kV and Lenexa South 161 kV Terminal Equipment Upgrades

The Craig-Lenexa South 161 kV line is located in the eastern region of Kansas and experiences significant congestion in Future 2 due to the age-based retirement of Northeast Station. While congestion was present in all five scenarios, Future 2 of year 5 had the highest congestion score of $346,670 followed by Future 2 of year 10 with a congestion score of $255,385.

The project ultimately chosen to resolve the congestion included terminal upgrades at the Craig and Lenexa South substations, which provides increased power transfer capability for the congested element and eliminates the congestion in all five scenarios. In addition to the congestion relief provided by this solution, it was also found to be the most cost effective solution given the low costs of the terminal upgrades.

5.2.5 NEBRASKA PUBLIC POWER DISTRICT (NPPD)

5.2.5.1 *GENTLEMAN AND OGALALA 230 KV TERMINAL EQUIPMENT UPGRADES*

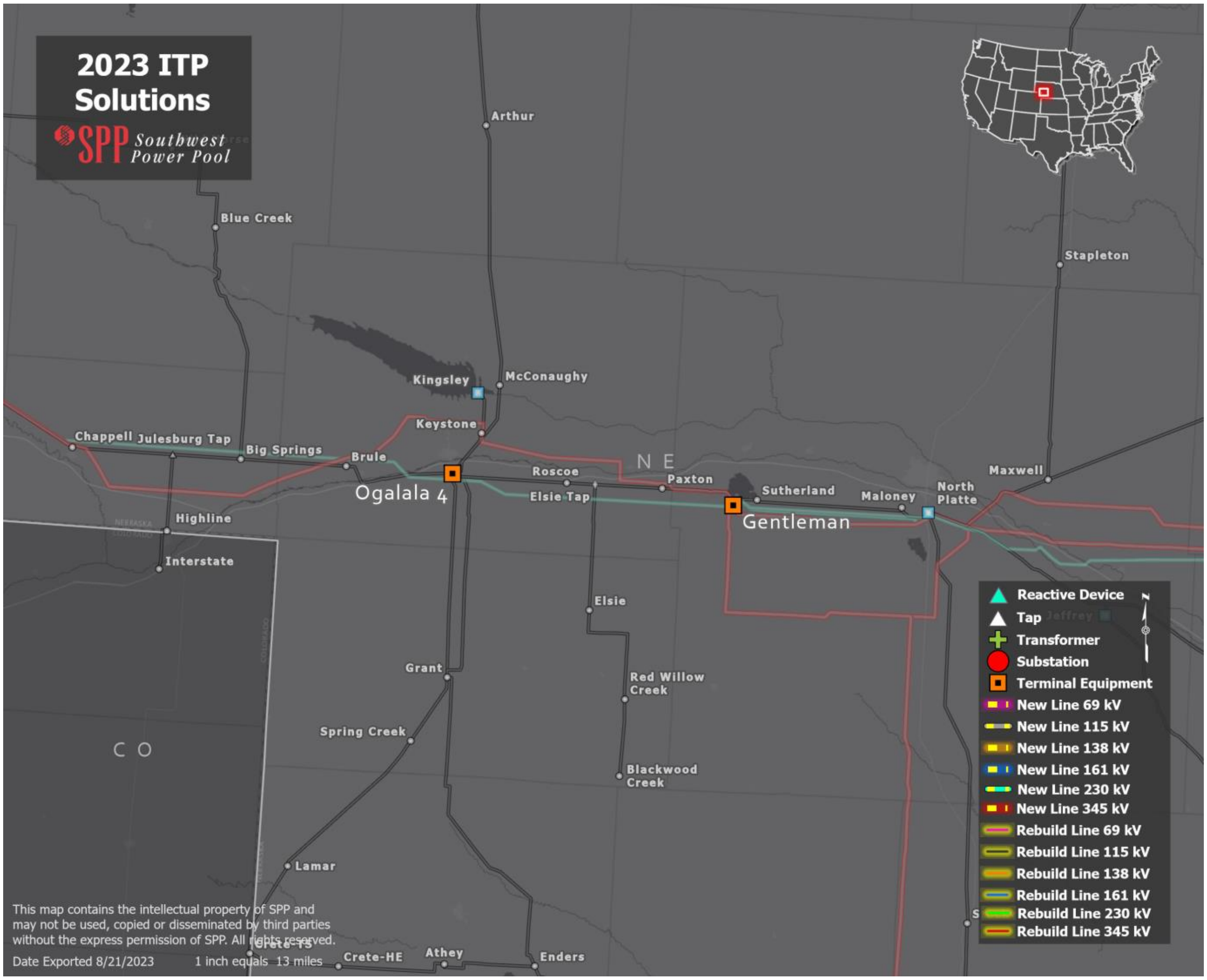

Figure 5.25: Terminal equipment upgrade at Gentleman and Ogalala 230 kV

The Ogalala-Gentleman 230 kV line is located in southwest Nebraska and becomes congested after the loss of the parallel Gentleman-Keystone 345 kV line. Congestion is present in all five scenarios, but is most severe in Future 1 of year 10 with a congestion score of $118,897. The primary driver for high congestion is flows dropping down from the 345 kV onto the 230 kV system.

The project ultimately chosen to mitigate this issue consists of terminal upgrades at Ogalala and Gentleman 230 kV substations. This project relieves all congestion in all five scenarios and was extremely cost effective due to the low cost of terminal upgrades and significant increase in power transfer capability.

5.2.5.2 *ALLIANCE-VICTORY HILL 115 KV NEW LINE*

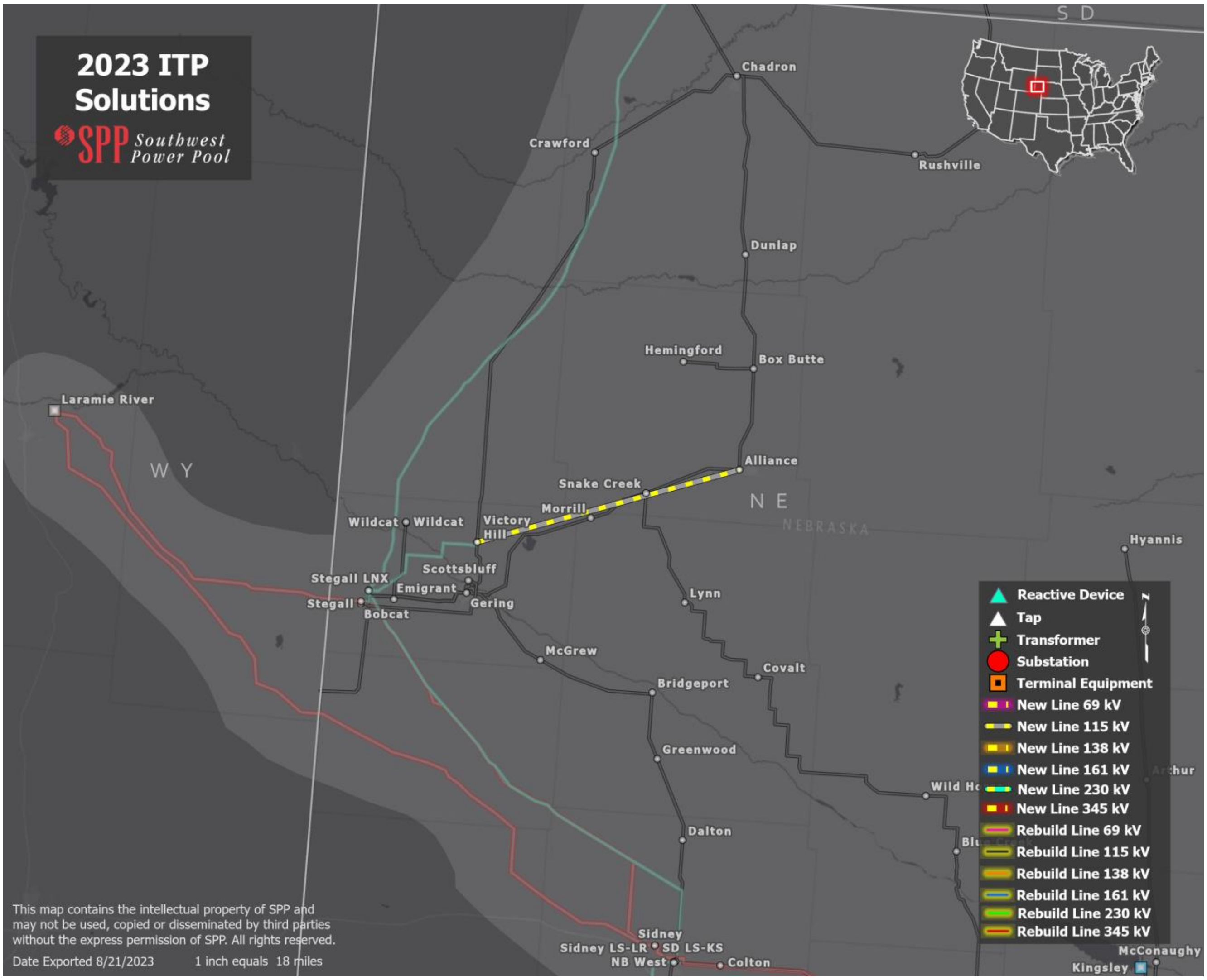

Figure 5.26: Alliance-Victory Hill 115 kV New Line

Located in Western Nebraska, this new 115 kV line from Victory Hill to Alliance is important to provide power economically to the North. In all scenarios, the 115kV line from Alliance to Victory Hill experiences congestion due to the loss of the 230 kV line from Stegall to Wayside. There are several elements in the area limiting flow to the North, Snake Creek to Alliance being the most limiting. SPP evaluated multiple alternatives, including a rebuild of the constrained facility, and 230 and 345 kV flyovers. Timely rebuilds of all the constrained facilities would be challenging, as they are non-SPP facilities, which limits the viable solutions to meet the needs of the area. Because of this, SPP is recommending a new 115 kV line from Alliance to Victory Hill.

5.2.6 OKLAHOMA GAS AND ELECTRIC (OGE)

5.2.6.1 *TIE ARCADIA-SEMINOLE 345 KV CIRCUIT 1 AND DRAPER-SEMINOLE 345 KV CIRCUIT 3 INTO HORSESHOE LAKE SUBSTATION*

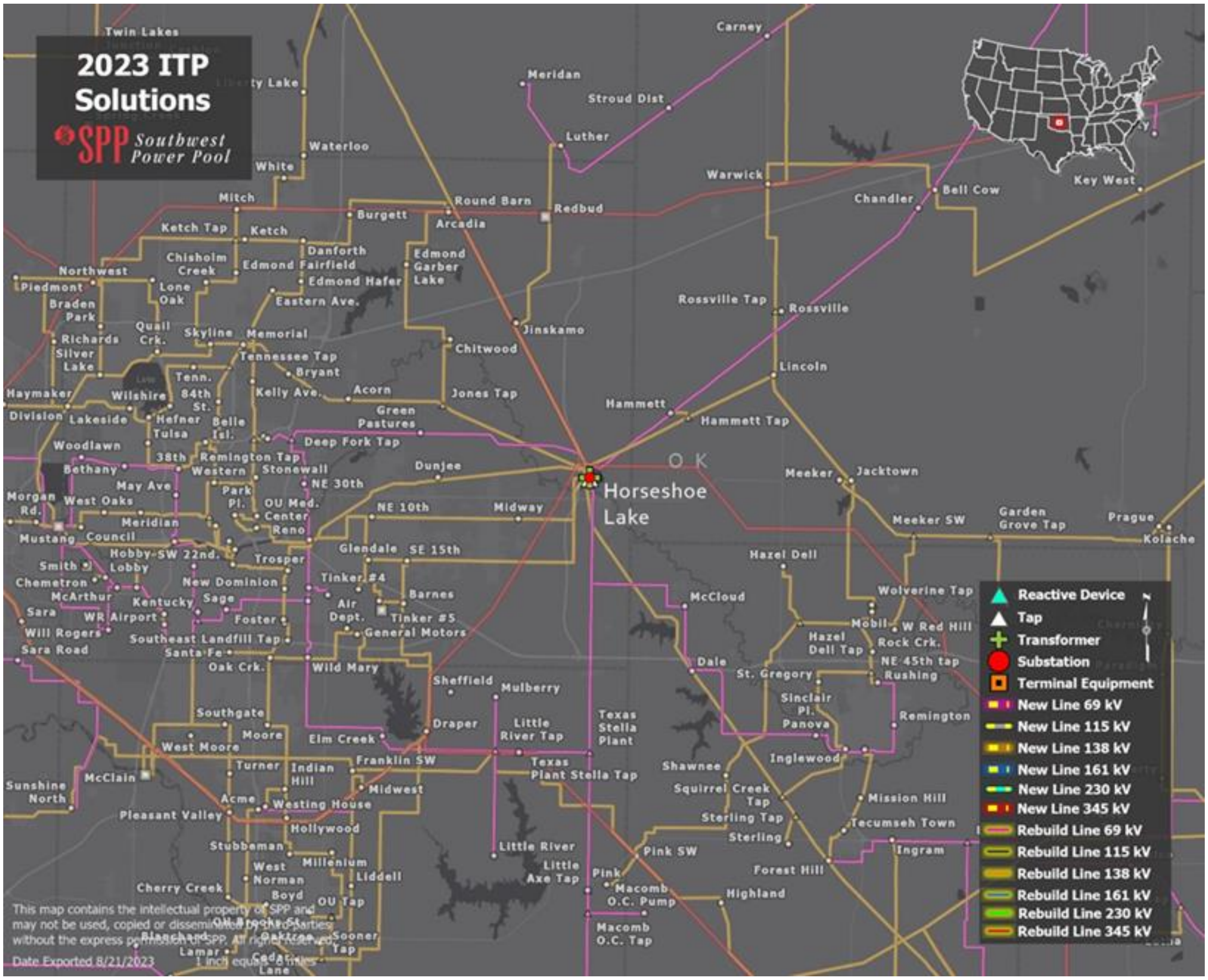

Figure 5.27: Tie Arcadia-Seminole 345 kV Ckt 1 an Draper-Seminole 345 kV Ckt 3 Into Horseshoe Lake Substation

The Horseshoe Lake substation project enhances the power system in the Oklahoma City, Oklahoma area by tapping into one circuit of the Draper-Seminole 345 kV line and one circuit of the Arcadia-Seminole 345 kV line and tying them into the nearby Horseshoe Lake 138 kV substation. The project requires the existing Horseshoe Lake substation to be expanded to accommodate the required 345 kV equipment. It also requires approximately 2.8 miles of new 345 kV line to be added to accommodate the distance from the tap location to the substation.

This project provides relief to multiple constraints within Oklahoma City, including Skyline-Quail Creek 138 kV FTLO Northwest-Arcadia 345 kV, Cimarron – Czech Hall 138 kV FTLO Cimarron – Haymaker 138 kV and Cimarron – Haymaker 138 kV FTLO Cimarron – Czech Hall 138 kV. Adding a new 345/138 kV source on the east side of the city reduces the load-serving burden from those facilities in the West. This project was chosen for its ability to utilize existing 345 kV infrastructure to create a cost effective solution that helps solve multiple economic constraints, while creating a more robust transmission system.

After consolidation of the final portfolio, OGE identified short-circuit issues arising from tying the 345 kV and 138 kV buses together after planned re-powers of generators at Horseshoe Lake. Resolving these issues would require a rebuild of the 138 kV substation at Horseshoe Lake, significantly increasing the cost and delaying the expected benefits of the project. For these reasons, SPP will not recommend an NTC for this project and evaluate further in future ITP studies.

5.2.6.2 *CIMARRON 138 KV AND CZECH HALL 138 KV TERMINAL EQUIPMENT UPGRADE*

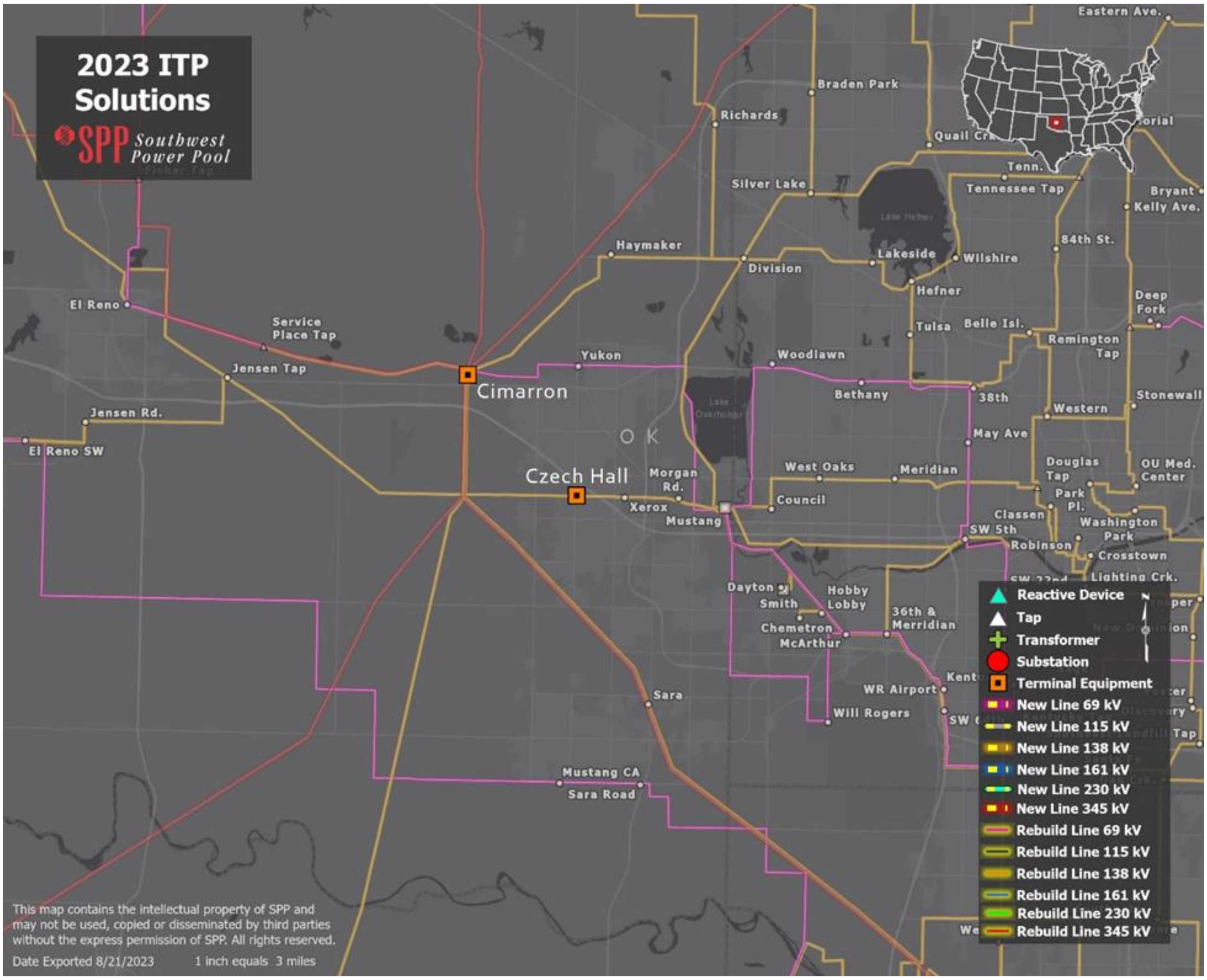

Figure 5.28: Cimarron 138 kV and Czech Hall 138 kV Terminal Equipment

The Czech Hall-Cimarron 138 kV line is located in Oklahoma City, Oklahoma and experiences significant congestion after the loss of the Haymaker-Cimarron 138 kV line. Both of these lines are two of the primary 138 kV feeders for the western portion of Oklahoma City, and when one of these lines is lost, the other line has to accommodate for the loss of transfer capability. All five scenarios showed congestion trending upward, with the highest congestion score of $102,299 occurring in Future 2 of year 10.

The project ultimately chosen to resolve the congestion included terminal upgrades at the Cimarron and Czech Hall substations. The alternative project was to rebuild four 138 kV lines, however with the addition of the Matthewson-Redbud 345 kV line, only the terminal upgrade is required to address the 138 kV congestion. In addition to the congestion relief provided by this solution, it was also found to be the most cost effective solution given the low costs of the terminal upgrades.

5.2.6.3 *CHISHOLM CREEK-LONE OAK 138 KV LINE*

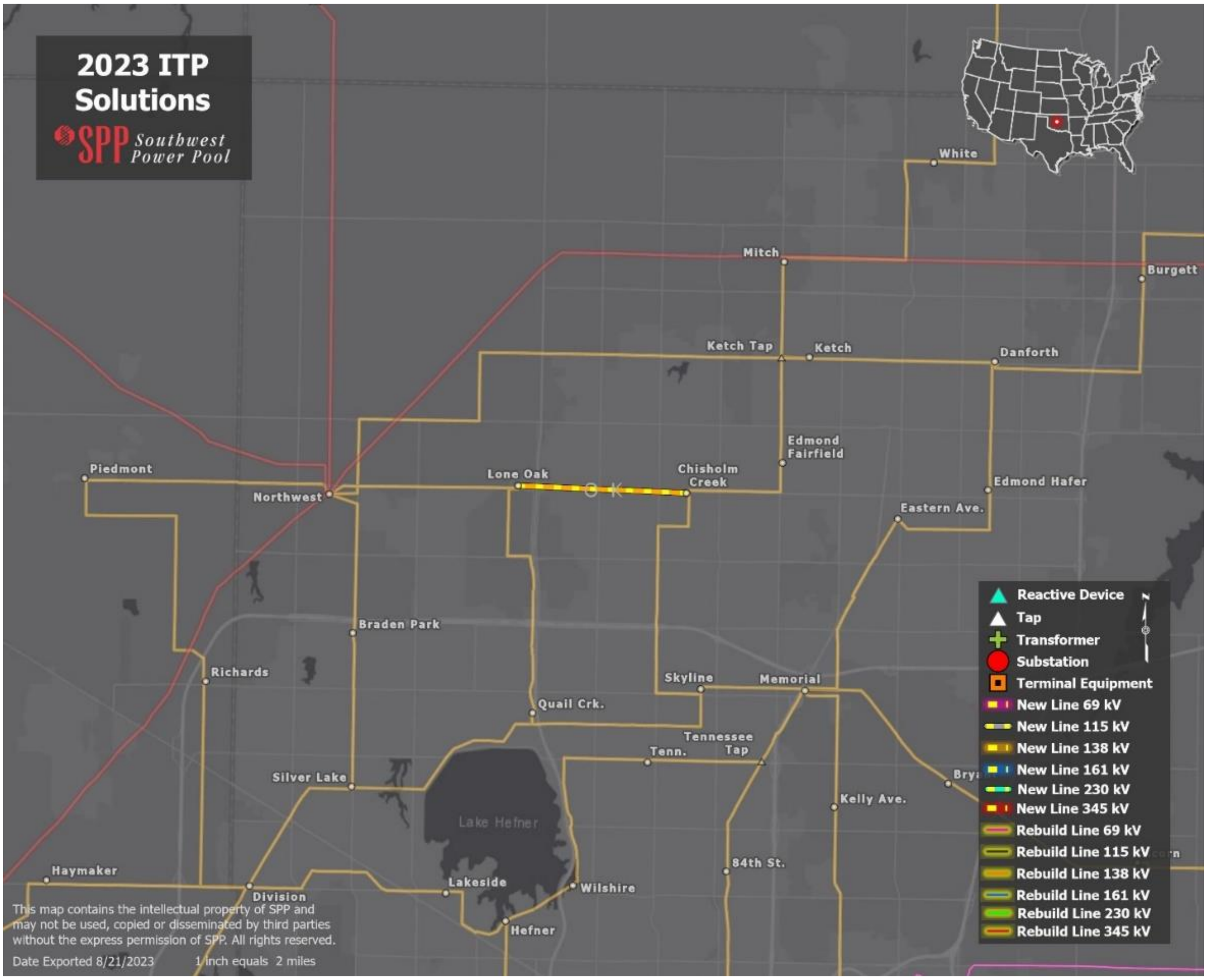

Figure 5.29: New Chisholm Creek-Lone Oak- 138 kV Line

The Skyline-Quail Creek 138 kV line is located in Oklahoma City, where considerable congestion is observed after the loss of the Northwest-Arcadia 345 kV line. The loss of the 345 kV branch forces a portion of the power to drop down to the 138 kV system. This particular constraint showed congestion scores continually trending upward in all five scenarios and showed a base congestion score of $54,168 for Future 2 of year 10.

The project ultimately chosen to mitigate this constraint is a new Chisholm Creek-Lone Oak 138 kV line spanning approximately 2.8 miles. The project provides an increase in power transfer capability by providing a parallel path for power to flow and reduces the congestion score to $0 in all five scenarios.

5.2.6.4 *TAP FITZGERALD-KENZIE 138 KV LINE AND TIE INTO THE VALLEY 138 KV SUBSTATION*

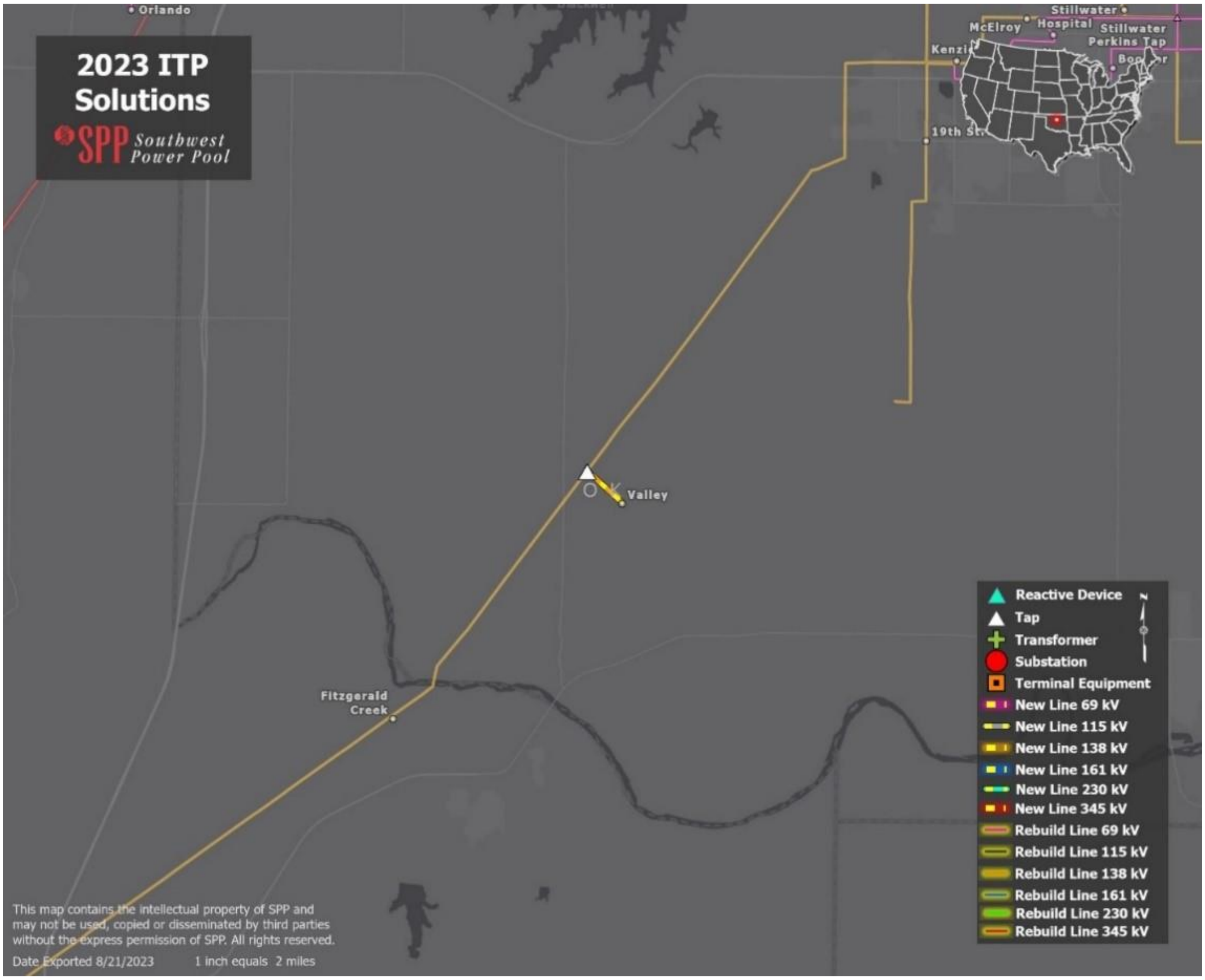

Figure 5.30: Tap Fitzgerald-Kenzie 138 kV Line and Tie Into the Valley 138 kV Substation

Approximately 30 miles north of Oklahoma City, Oklahoma, the Fitzgerald-Kenzie 138 kV line becomes highly congested due to the west-to-east flows dropping down to the 138 kV system after the loss of the Cleveland-Sooner 345 kV line. Future 2 of year 10 had a congestion score of $152,127, which was the highest score between years 5 and 10.

The project ultimately chosen to mitigate this constraint is to tap the existing Fitzgerald-Kenzie 138 kV line and tie into the nearby Valley substation creating additional paths and increased transfer capability to alleviate congestion in this area. The selected project eliminates all congestion in all scenarios while remaining cost effective.

5.2.6.5 *MATTHEWSON-REDBUD 345 KV NEW LINE*

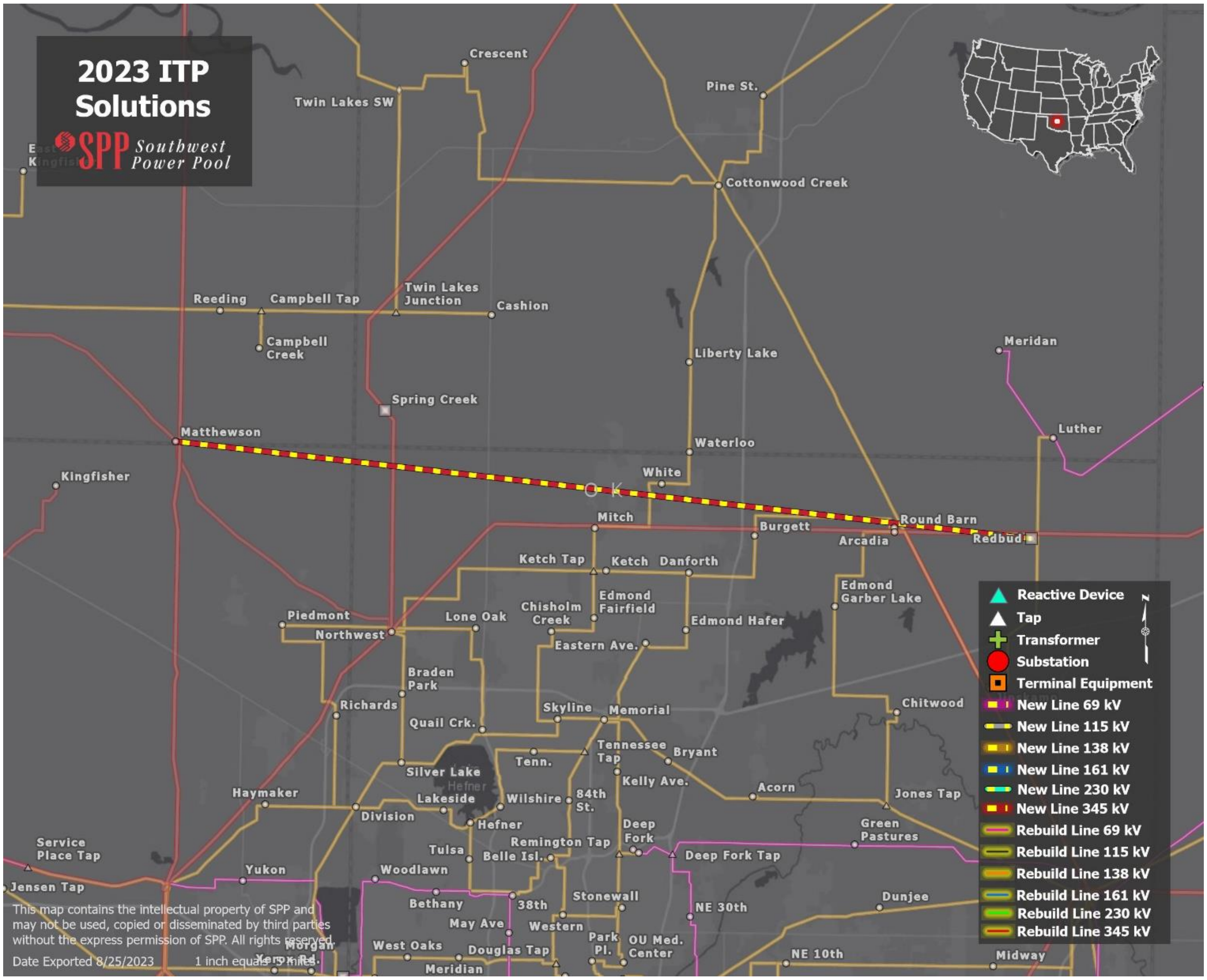

Figure 5.31: New Matthewson-Redbud 345 kV Line

This project is located just outside of Oklahoma City, Oklahoma and consists of a new Matthewson-Redbud 345 kV line spanning approximately 38 miles. This project was chosen for its ability to provide significant congestion relief for multiple constraints by providing an alternative path for energy to serve more of the Oklahoma City load from the east side of the city. The project also assists in transferring renewable energy from western Oklahoma toward the larger load centers further east.

This 345 kV project addresses loading from the 345 kV system at Cimarron down to the 138 kV system toward Czech Hall and Haymaker. It also eliminates potential future congestion on the Northwest to Arcadia 345 kV line once the 138 kV congestion is completely addressed.

The solution for the Cimarron – Czech Hall and Cimarron – Haymaker took a few iterations until the proper project was identified. Originally SPP had selected rebuilds of the congested 138 kV facilities as a cost effective option, however a cost and scope increase of adding a transformer at Cimarron shifted the project to a 345 kV option. After evaluating Arcadia-Matthewson-Spring Creek 345 kV and further identifying substation expansions needed, SPP eventually landed on Matthewson-Redbud 345 kV to address the issues in Oklahoma City, which maximizes the benefit to SPP.

5.2.6.6 *NEW CLEO CORNER-OKEENE SW 138 KV LINE*

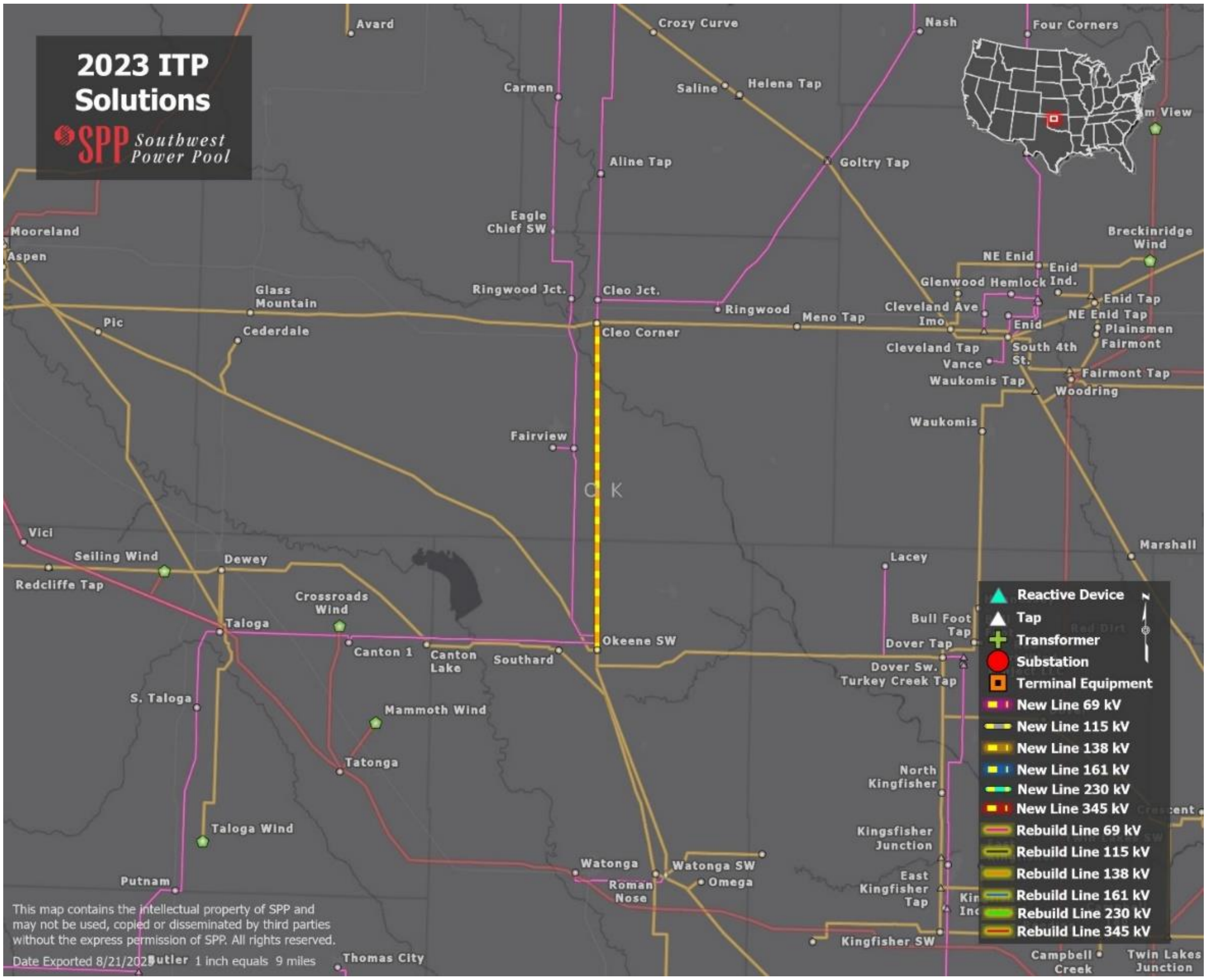

Figure 5.32: New Cleo Corner-Okeene SW 138 kV Line

The Cleo Corner-Cleo Junction 69 kV line is located approximately 70 miles northwest of Oklahoma City, Oklahoma and becomes severely congested due to flows dropping down to the 69 kV system after the loss of the Cleo Corner-Cleo Plant 138 kV line. The primary driver for this need is the lack of transfer capability to support the dispatch of large amounts of wind generation located west of the large Tulsa and Oklahoma City load centers. Congestion was observed in all five scenarios but was highest in Future 2 of year 10 with a base congestion score of $532,783.

The project ultimately chosen to mitigate this need was to add a 22 mile Cleo Corner-Okeene SW 138 kV line to provide an alternative path for power to move from west to east. After the project was implemented in the study, it reduced the congestion score by 91.5% down to $45,294.

5.2.7 OMAHA PUBLIC POWER DISTRICT (OPPD)

5.2.7.1 *NEW 115/69 KV TRANSFORMER AT FREMONT CKT 2*

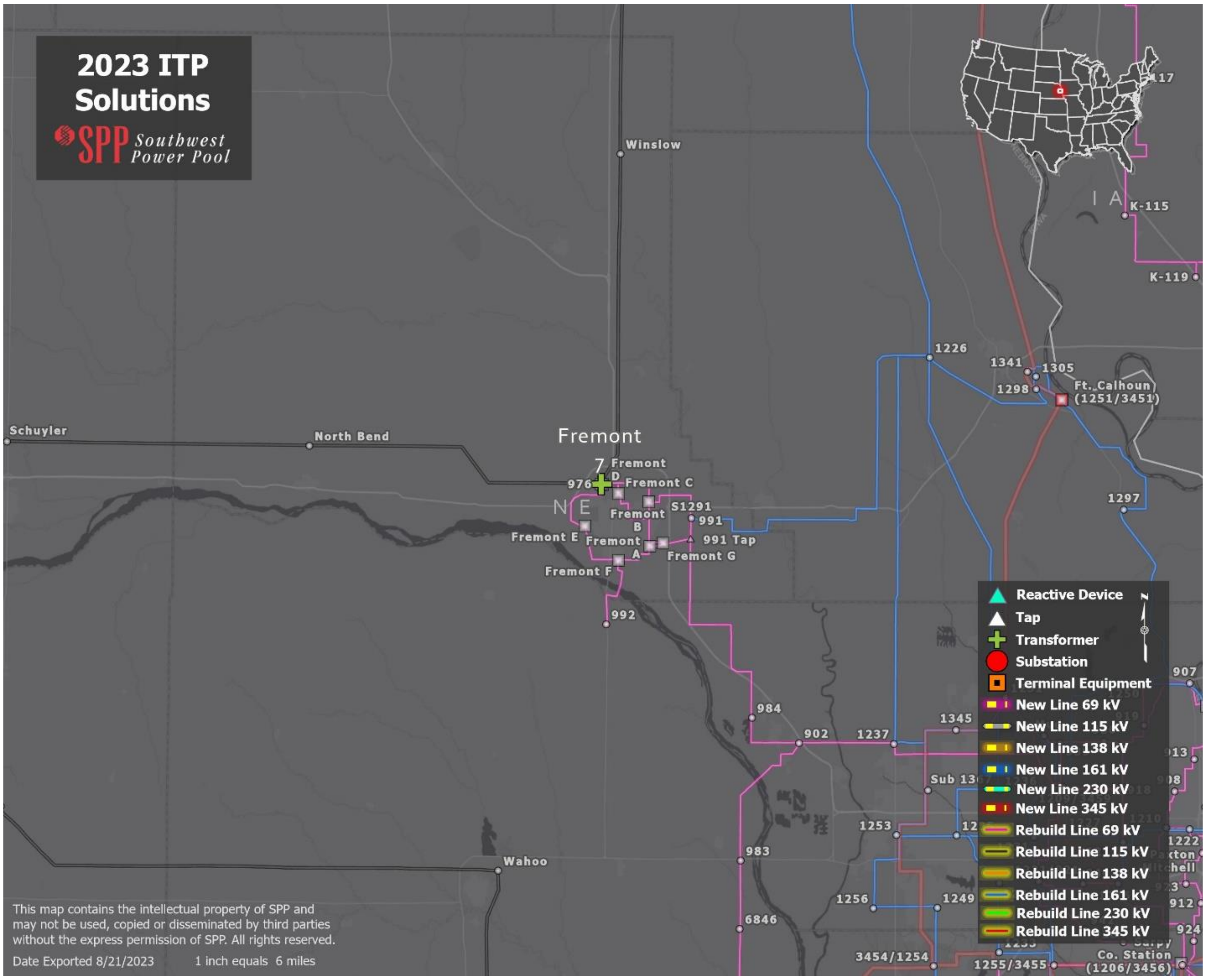

Figure 5.33: New 115/69 kV circuit 2 transformer at Fremont

The Fremont 115/69 kV transformer is located just northwest of Omaha, Nebraska and becomes congested after the loss of the Sub 1226-Sub 1291 161 kV line. The congestion is driven by a reduced ability to deliver power to the City of Fremont after the failure of an aged transformer, leading to more costly local generation to be utilized to serve load. This need showed congestion scores that trended upward in all five scenarios with the highest congestion score of $228,881 being in Future 2 of year 10.

The project ultimately chosen to mitigate this constraint was to add a second 115/69 kV Fremont transformer to provide an additional parallel path for power flow. This project provided over 99% congestion relief in all five scenarios and was chosen for its ability to eliminate nearly all of the congestion in this area, while adding redundancy to the system to further enhance power transfer capability.

5.2.7.2 RAISE 70TH & BLUFF – SUB 1214 161 KV STRUCTURES AND TRANSFORMER REPLACEMENT

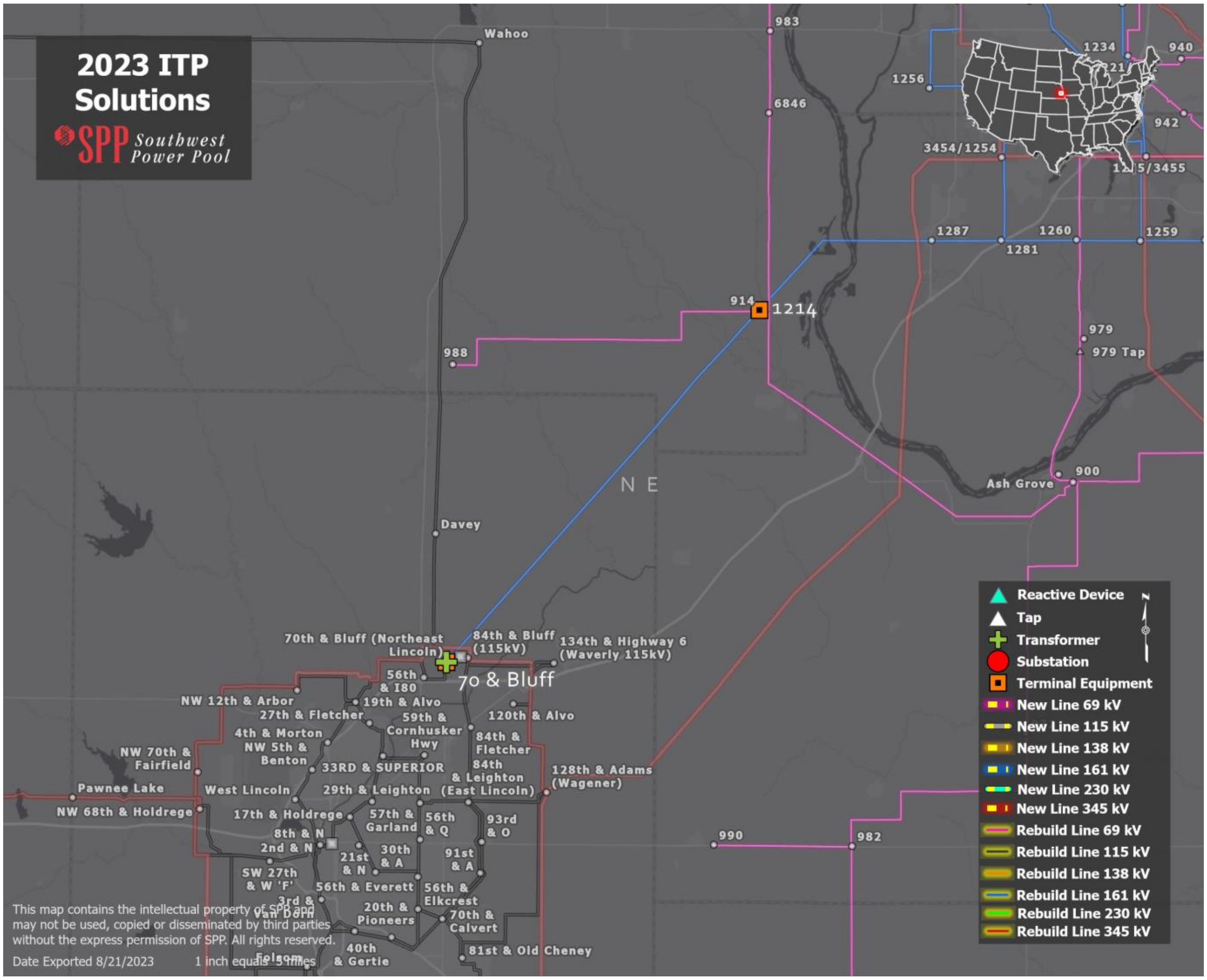

Figure 5.34: Rebuild 70th & Bluff – Sub 1214 161 kV and transformer replacement

The 70th and Bluff – Sub 1214 161 kV line is located between Lincoln and Omaha, Nebraska and becomes congested after the loss of the Sub 3454 – Wagener 345 kV line. The congestion is from a lack of power transfer capability between Lincoln and Omaha when the 345 kV route is unavailable. This need showed congestion scores that trended upward in all five scenarios with the highest congestion score of $218,458 being in Future 2 of year 10.

The transformer at 70th and Bluff is in series with the line to Sub 1214 and also showed as a need, since it is the next limiting element in the area when the line is upgraded.

The project ultimately chosen to mitigate this constraint was to replace the transformer and perform the necessary structural upgrades to raise the line to match the rating of the new transformer. This project provided over 90% congestion relief in all five scenarios and was chosen as the most cost effective solution for this area.

5.2.8 SOUTHWESTERN PUBLIC SERVICE (SPS)

5.2.8.1 *POTTER COUNTY 345/230 KV TRANSFORMER REPLACEMENT AND SECOND TRANSFORMER*

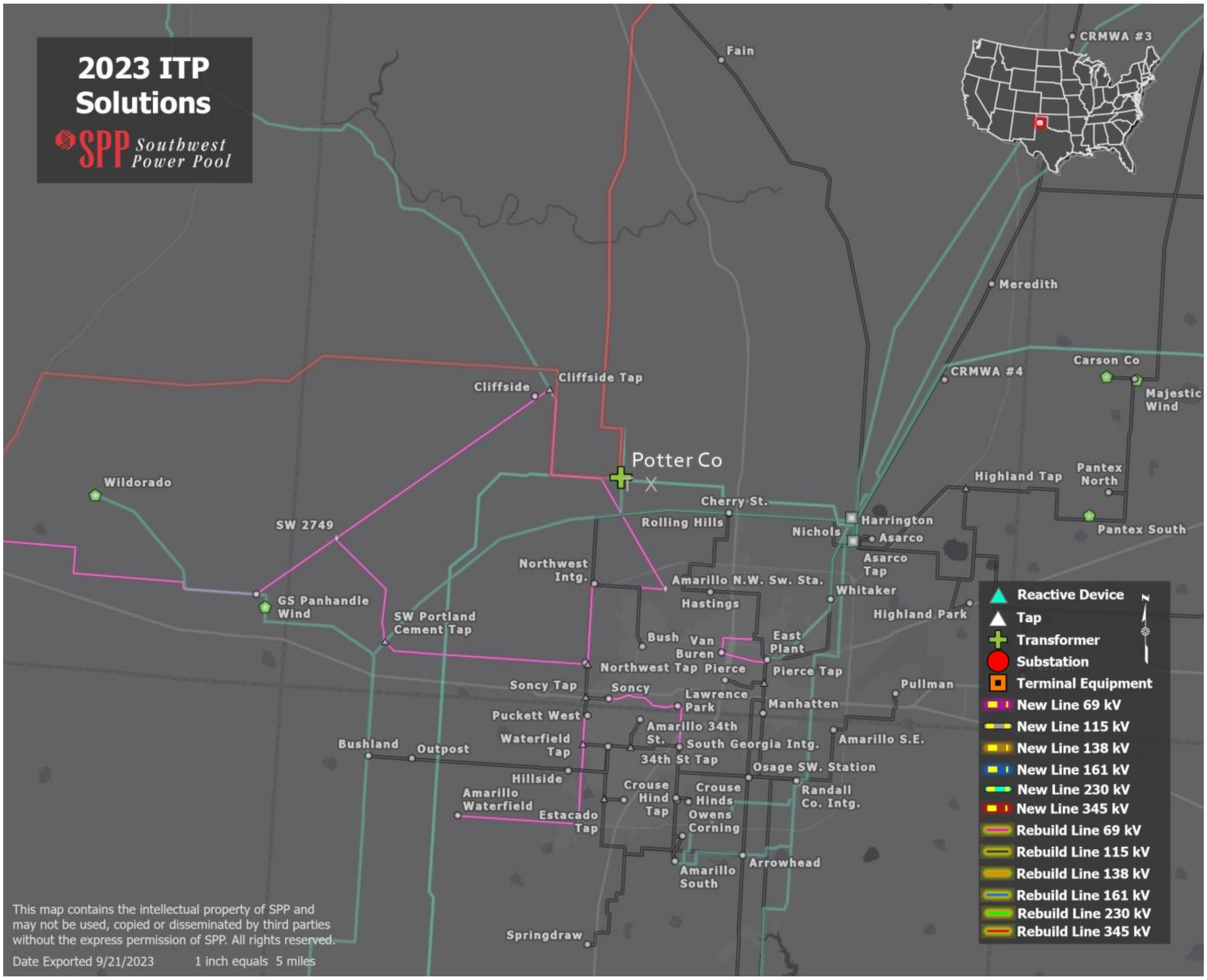

Figure 5.35: Potter County 345/230 kV Transformer Replacement

Located Northwest of Amarillo, the Potter County 345/230 kV transformer is important in providing power flow to the Texas panhandle, as it is the final stop of a long series of 345 kV transmission. In all years in both Future 1 and Future 2, the Potter County 345/230 kV transformer experiences congestion when the Moore Co.-Hitchland 230 kV line is lost. This constraint was also identified as an operational constraint. The congestion is caused by all of the power flow being routed through Potter County, rather than Moore Co.-Hitchland, to serve Amarillo and loads to the north.

The original project to address this congestion was to add a second 345/230 kV transformer at Potter County. When it was discovered that loss of the transformer would overload the existing transformer, a replacement of the existing transformer was added to the project to provide complete congestion relief.

5.2.9 SUNFLOWER ELECTRIC (SUNC)

5.2.9.1 *ELLSWORTH TAP-GREAT BEND 115 KV STRUCTURES*

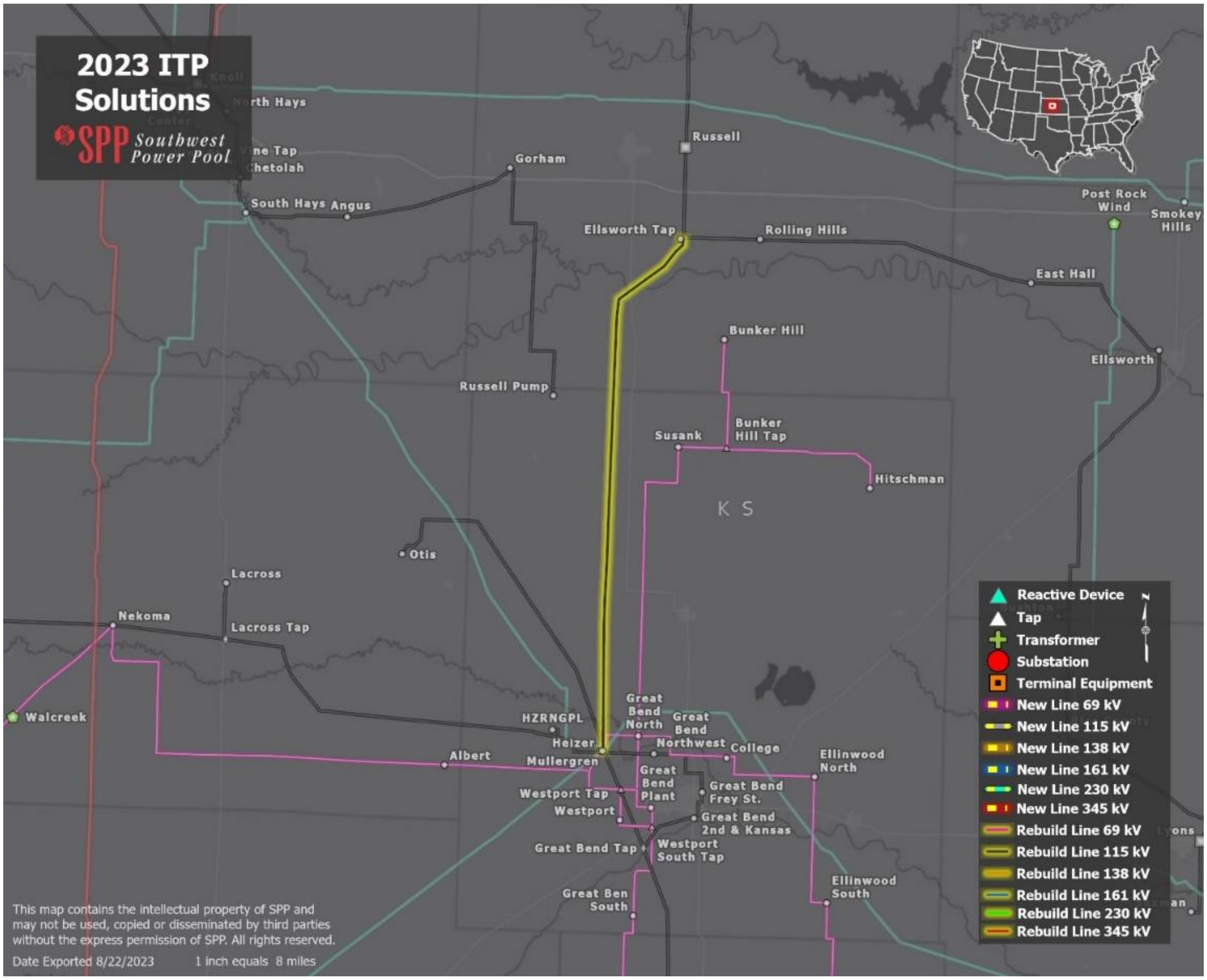

Figure 5.36: Ellsworth Tap-Great Bend 115 kV structures

In Great Bend, Kansas, the Ellsworth Tap-Great Bend 115 kV line becomes congested for the loss of Circle-Great Bend 230 kV. This area is impacted by west-to-east system flows. The loss of Circle-Great Bend 230 kV forces flows north at Great Bend, onto the 115 kV system. The Ellsworth Tap-Great Bend 115 kV line is limited by conductor clearance issues. The project selected to mitigate the congestion is to raise the conductor height of approximately 25 structures. This increases the conductor limit and relieves all of the congestion on the line.

5.2.10 WESTERN AREA POWER ADMINSITRATION (WAPA)

5.2.10.1 FORT THOMPSON 345/230 KV TRANSFORMER REPLACEMENTS

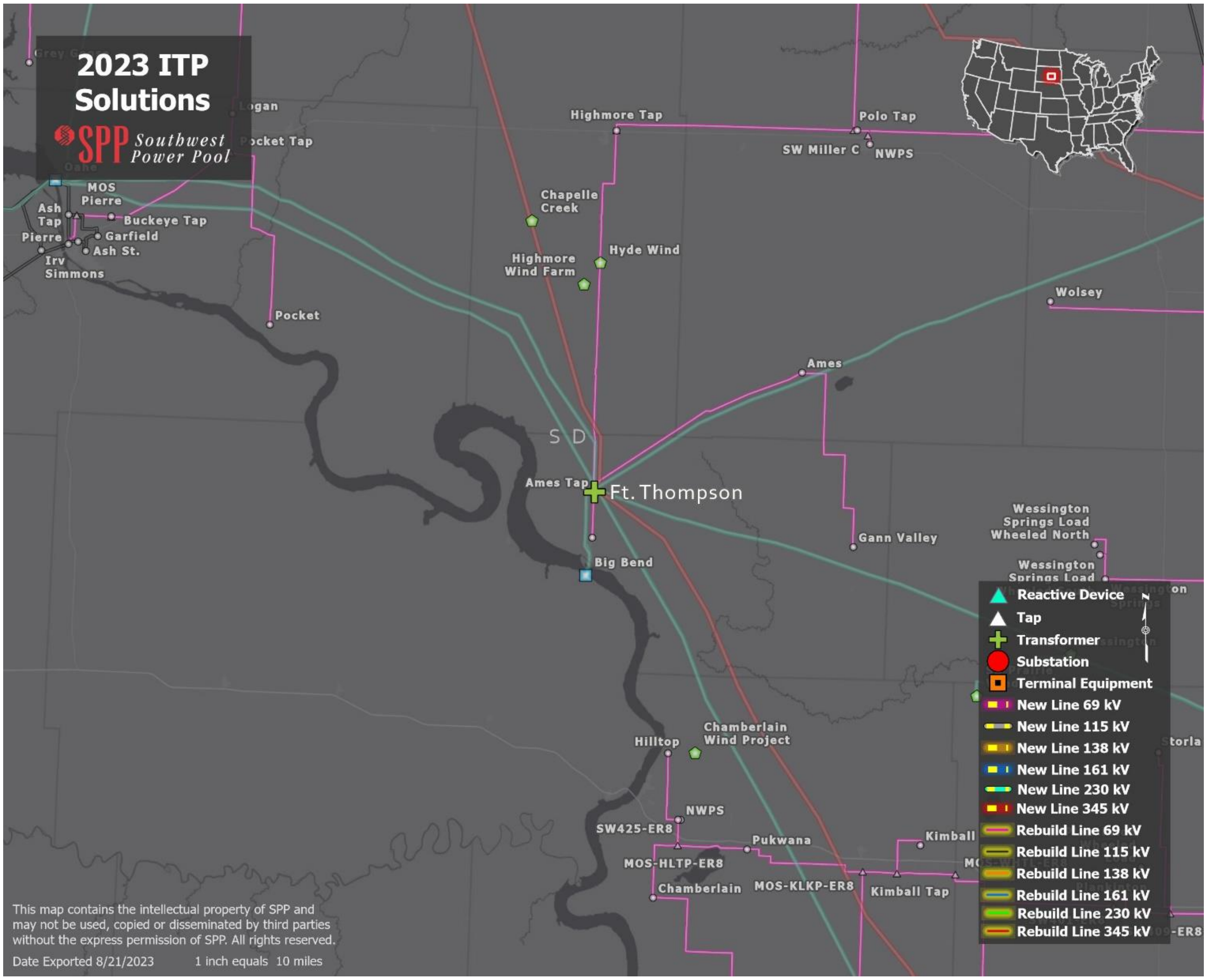

Figure 5.37: Fort Thompson 345/230 kV transformer replacements

Located in South Dakota, both Fort Thompson transformers are currently rated for 250 (Normal) MVA. In all years in both Future 1 and Future 2, one of the Fort Thompson transformers experiences substantial congestion due to the loss of the other Ft. Thompson transformer. This constraint was also identified as an operational constraint. The congestion is caused by more power flow being routed through the remaining available transformer. Replacing these transformers with 600 (Normal) MVA transformers completely eliminates congestion at this location in all futures.

5.2.10.2 *GAVINS POINT-YANKTON 115 KV REBUILD*

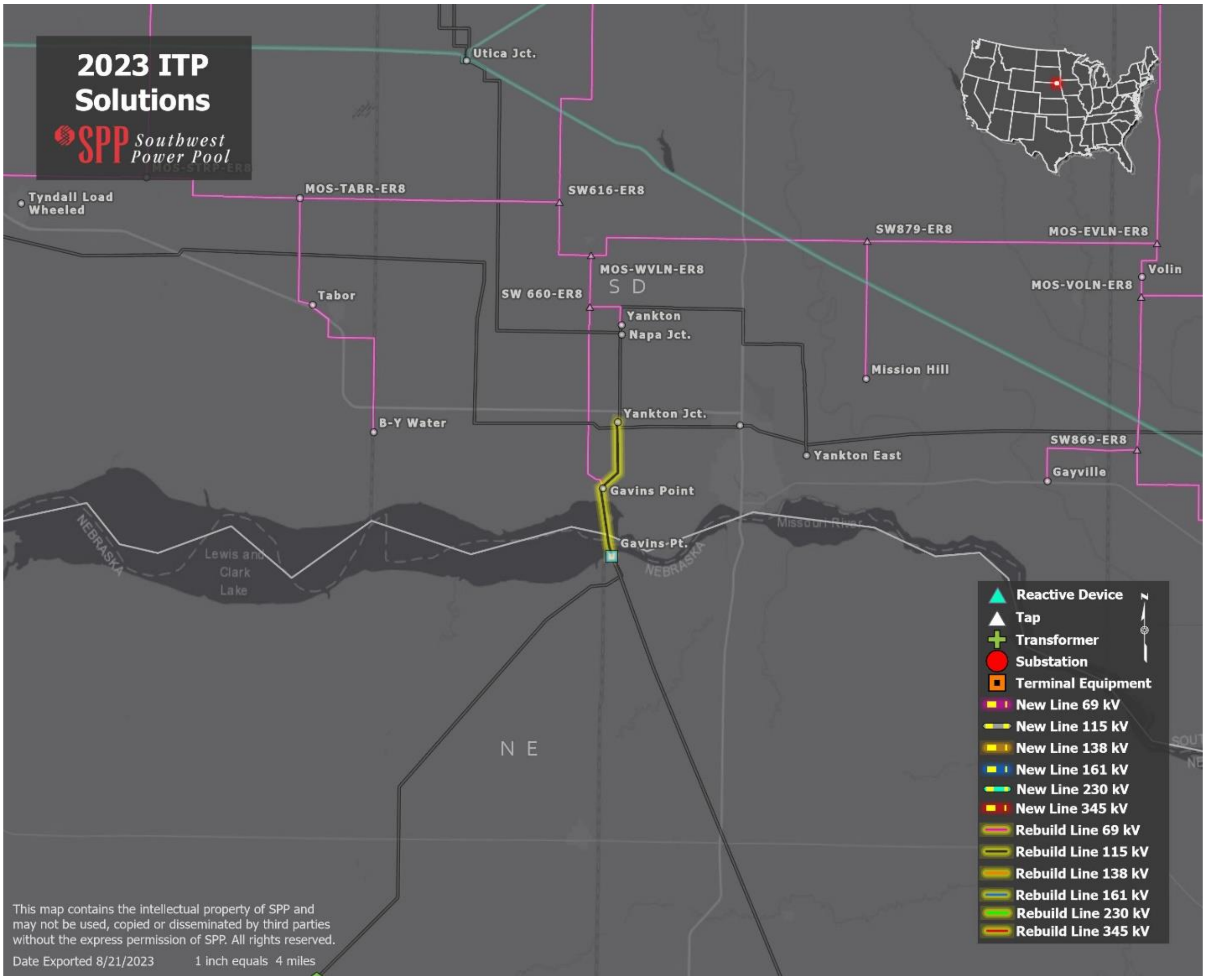

Figure 5.38 Gavins Point-Yankton 115 kV rebuild

Located in Northeastern Nebraska and South Dakota, this 115 kV line rebuild from Gavins Point to Yankton is important to provide power economically to Northeastern Nebraska. In all years in both Future 1 and Future 2, the 115kV lines from Gavins Point to Yankton experience congestion due to the loss of Gavins Point to Spirit Mound. The congestion is caused by more power flow being routed through Gavins Point to Yankton 115kV line, to serve the loads in the Northeastern Nebraska. Rebuilding the 115kV line from Gavins Point to Yankton eliminates this congestion entirely.

5.2.10.3 *HURON TAP-HURON-HURON WEST PARK 115 KV REBUILD*

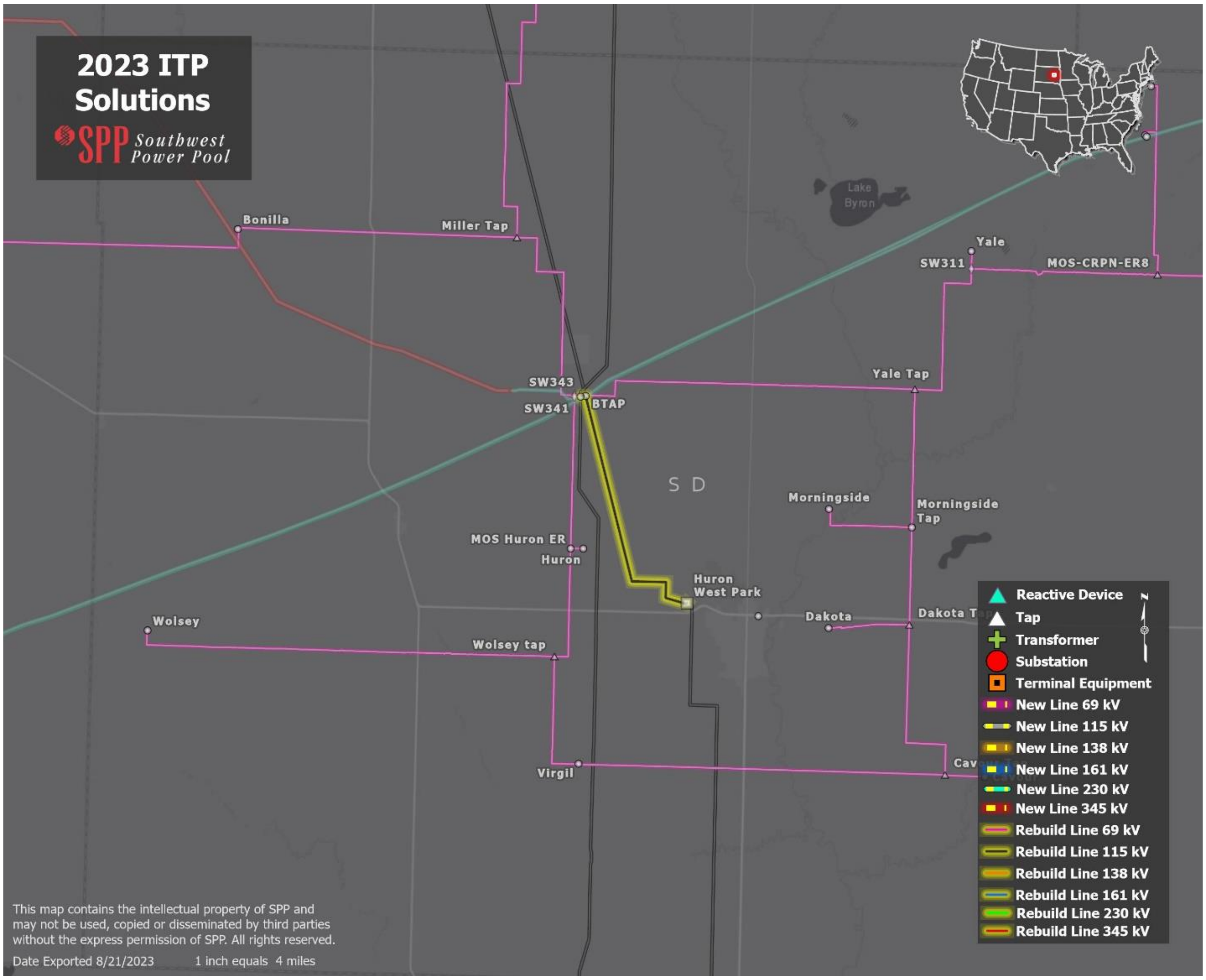

Figure 5.39 Huron Tap – Huron – Huron West Park 115 kV rebuild

Located in South Dakota, the 115 kV line from Huron to Huron West Park and the line from Huron to the Huron Tap are important to provide power economically to Eastern South Dakota. In all years in both Future 1 and Future 2, the 115kV lines from Huron to Huron West Park and Huron to the Huron Tap experience substantial congestion due to the loss of Groton to Groton South, or Huron to Huron West Park. The congestion is caused by more power flow being routed through the remaining available 115kV lines, to serve the loads, either North towards Groton or South toward Mitchel. Rebuilding the 115kV lines from Huron to Huron West Park and the line from Huron to the Huron Tap eliminates this congestion entirely.

5.2.11 WESTERN FARMERS ELECTRIC COOPERATIVE (WFEC)

5.2.11.1 *ANADARKO-GRACEMONT 138 KV CIRUIT 2 AND 3 NEW LINE*

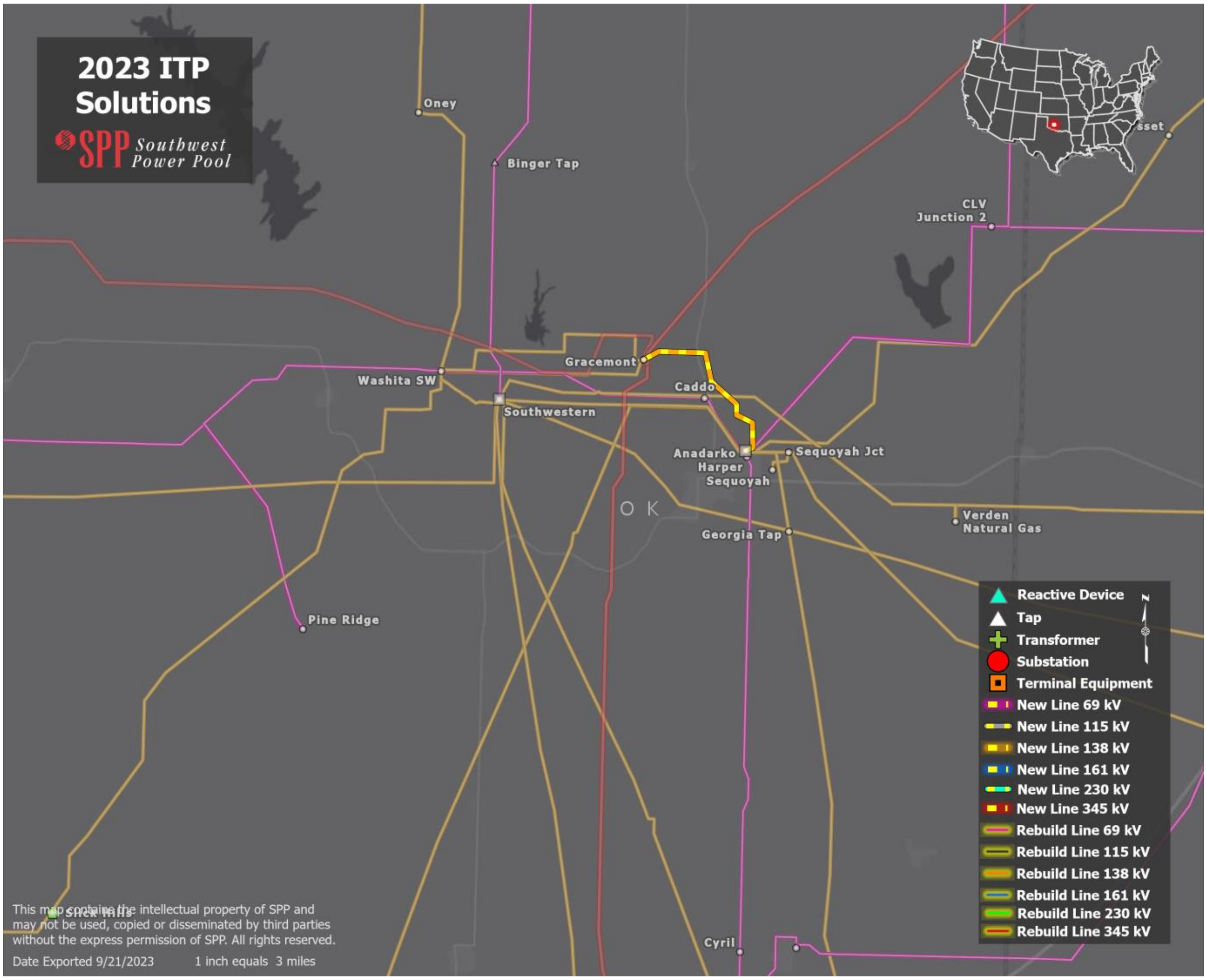

Figure 5.40 Anadarko – Gracemont 138 kV Double Circuit New Line

The Anadarko-Gracemont 138 kV line is located 45 miles southwest of Oklahoma City, Oklahoma and experiences significant congestion after the loss of the Gracemont-Minco 345 kV line. After the loss of the 345 kV line, the flows shift down to the 138 kV system and continue to flow toward Oklahoma City. This constraint showed congestion in all five scenarios with congestion scores trending upward from year 2 to year 10 with Future 2 of year 10 having the highest congestion score of $120,276.

This congestion was originally addressed in the 2020 ITP with a double-circuit rebuild of the existing Anadarko-Gracemont 138 kV line. This project has met numerous challenges in construction, mainly stemming from the circuit passing through land owned by the Bureau of Indian Affairs, making modifications to the right-of-way infeasible. The 2020 ITP project was then submitted for re-evaluation in the 2023 ITP to identify if there are other projects that can address this congestion.

Various alternative projects were evaluated to resolve this congestion. In the 2022 20-Year Assessment, a new 345 kV line from Anadarko to Gracemont was recommended, and that project was cost-beneficial initially. However, planned repowers of projected generation retirements in the area have lessened the benefits of the EHV project. SPP also looked at single-circuit high-capacity 138 kV transmission, however there was still prevalent congestion on the existing 138 kV line. SPP then turned their attention to double-circuit high-capacity 138kV.

The project chosen to mitigate the congestion consists of adding a new double-circuit 2000 Amp 138 kV line from Anadarko-Gracemont. This will result in a total of three 138 kV circuits to relieve the bottle neck between the Anadarko and Gracemont busses. The project provided over 97% congestion relief in Future 2 of year 10 and provide 100% congestion relief in the remaining scenarios. This project was chosen for its ability to provide significant congestion relief, while being the most cost effective solution.

5.3 PERSISTENT OPERATIONAL PROJECTS

There are seven economic projects that address Persistent Operational needs in 2023. These were captured in the economic section.

DESCRIPTION	AREA	E&C COST	MILES
Cleveland 138 kV Terminal Equipment	**AECI**	**$2,530,160**	**-**
Anadarko-Gracemont 138 kV circuit 2 and 3 new line	WFEC/OKGE	$64,000,000	15
Gerald Gentleman Station-Ogallala 230 kV terminal equipment	NPPD	$1,700,000	-
Osage-Webb City Tap-Shidler 138 kV rebuild	OKGE/AEPW	$27,236,410	25
Replace Potter County 345/230 kV circuit 1 transformer and new circuit 2 transformer	SPS	$30,000,000	-
Replace Fort Thompson 345/230 kV circuit 1 and 2 transformers	WAPA	$33,546,913	-
Benton-Wichita 345 kV terminal equipment	WERE	$6,830,258	-

Table 5.3: Persistent Operational Projects

5.4 SHORT-CIRCUIT PROJECTS

5.4.1 SHORT-CIRCUIT PROJECT PORTFOLIO

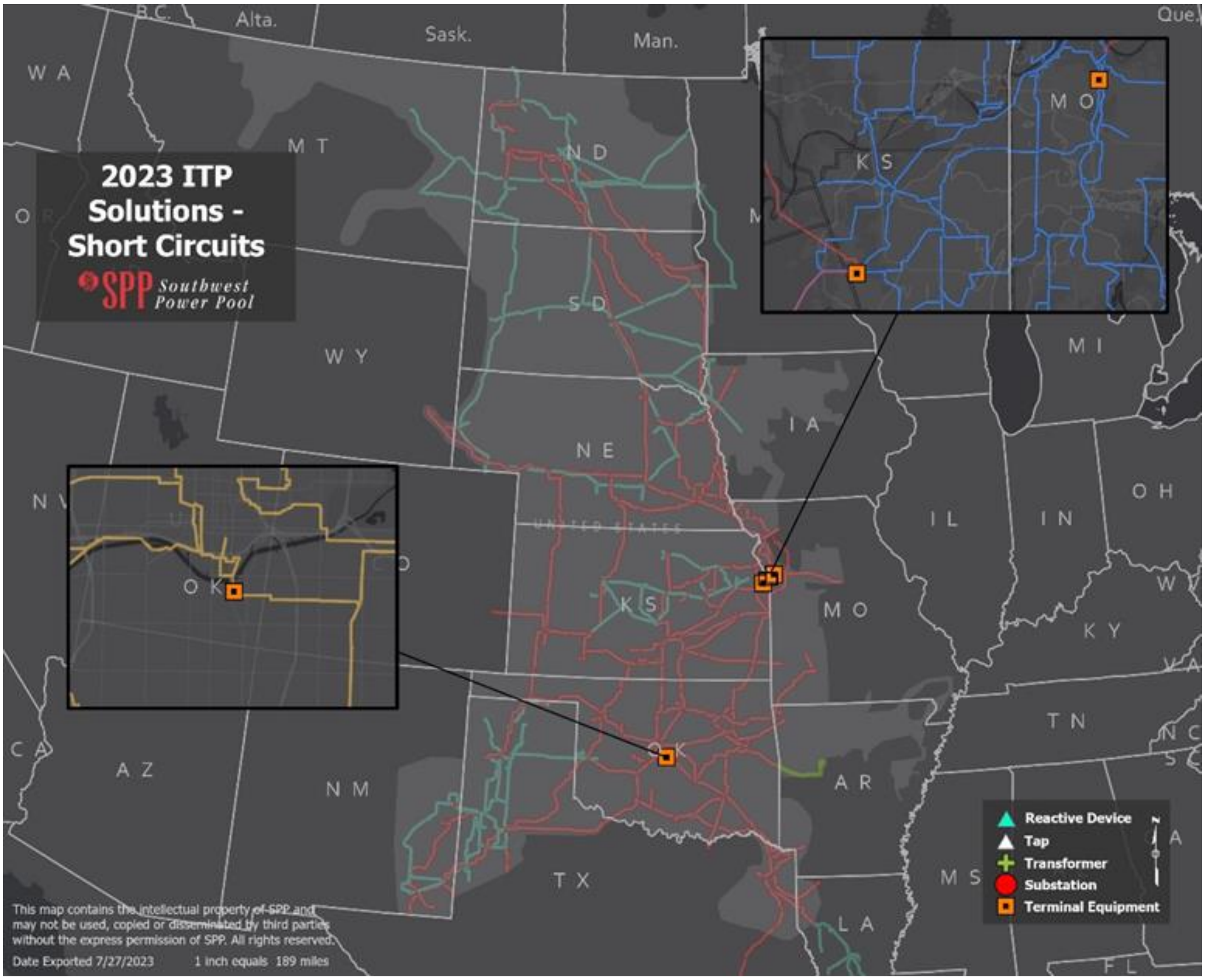

Figure 5.41: Short-Circuit Project portfolio

2023 ITP short-circuit projects consist of eight overdutied fault interputing equipment upgrades. These upgrades ensure SPP's members can meet short-circuit analysis requirements in the NERC TPL-001-5 standard.

Short-Circuit Project	Area	Scenario*
Blue Valley 161 kV one breaker replacement	Evergy (KCPL_	24S / BR
Craig 161 kV five breaker replacements	Evergy (KCPL)	24S / BR
Lightning Creek 138 kV two breaker replacements	OGE	24S / BR

Table 5.4: Short-Circuit Projects

5.5 POLICY PROJECTS

No policy projects are required for the 2023 ITP.

6 INFORMATIONAL PORTFOLIO ANALYSIS

6.1 BENEFITS

6.1.1 METHODOLOGY

Benefit metrics were used to measure the value and economic impacts of the final portfolio. The Benefit Metrics Manual[30] provides the definitions, concepts, calculations, and allocation methodologies for all approved metrics. The ESWG directed that the 2023 ITP benefit-to-cost ratios be calculated for the final portfolio using the Future 1 and Future 2 models. The benefit analysis is performed on all reliability and economic projects passed through the consolidation process. The benefit structure shown in Table 6.1 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 Emissions Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 6.1: Benefit Metrics

6.1.2 APC SAVINGS

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

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congestion and reduce costs through a combination of a more economical generation dispatch, more economical purchases and optimal revenue from sales.

To calculate benefits over the expected 40-year life of the projects[31], two years were analyzed, 2027 and 2032. APC savings were calculated accordingly for these years. The benefits are extrapolated for the initial five-year period based on the slope between the two points. After that, they are assumed to grow at an inflation rate of 2.0% per year. Each year's benefit was then discounted to 2027 using an 8% discount rate, and a 2.0% inflation rate from 2027 back to 2023. The sum of all discounted benefits was presented as the PV benefit. This calculation was performed for every zone.

Table 6.2 provides the zonal breakdown and the PV estimates. Future 2 has higher congestion compared to Future 1. Therefore, the projects in the recommended portfolio provide more congestion relief in Future 2 than in Future 1, resulting in larger APC savings.

Zone	Reference Case (Future 1)			Emerging Technologies (Future 2)		
	2027 ($2023M)	2032 ($2023M)	40-yr PV ($2023M)	2027 ($2023M)	2032 ($2023M)	40-yr PV ($2023M)
AEPW	$19.25	$35.97	$640.68	$18.46	$40.35	$734.36
EMDE	($2.02)	($1.10)	($12.38)	($1.84)	($0.64)	($4.00)
GMO	$4.71	$2.13	$20.00	$8.95	$4.63	$50.16
GRDA	$22.53	$25.95	$418.97	$26.13	$27.69	$436.62
KACY	$2.03	$0.92	$8.74	$4.83	$2.42	$25.49
KCPL	($2.22)	$0.02	$11.46	$7.41	$3.19	$28.24
LES	$0.79	$0.79	$12.16	$1.09	($0.83)	($22.49)
MIDW	($3.57)	($3.76)	($59.25)	($3.67)	($3.47)	($52.71)
NPPD	$1.56	$2.49	$43.21	$0.75	($2.82)	($61.47)
OKGE	$11.83	$19.89	$348.30	$12.92	$29.72	$544.29
OPPD	$8.32	$9.93	$161.79	$8.51	$22.14	$410.95
SPRM	$1.04	$0.61	$7.23	$1.16	$0.77	$10.04
SPS	$15.06	$18.40	$301.66	$12.66	$5.42	$47.68
SUNC	($8.67)	($8.82)	($137.33)	($8.50)	($5.67)	($73.61)
SWPA	($0.42)	($0.76)	($13.48)	($1.04)	($0.61)	($7.37)
UMZ	$43.76	$67.65	$1,167.01	$43.89	$36.75	$533.21
WERE	($6.75)	($4.24)	($53.07)	($6.30)	($5.76)	($86.56)
WFEC	$4.09	$6.66	$116.03	$3.35	$6.95	$125.70
TOTAL:	**$111.32**	**$172.73**	**$2,981.75**	**$128.76**	**$160.24**	**$2,638.52**

Table 6.2: APC Savings by Zone

[31] The SPP OATT requires that the portfolio be evaluated using a 40-year financial analysis.

6.1.3 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, NOX, 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 neither ITP future assumes any allowance prices for CO_2.

6.1.4 SAVINGS DUE TO LOWER ANCILLARY SERVICE NEEDS AND PRODUCTION COSTS

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

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

The costs of providing ancillary services are captured in the APC metrics. 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.

6.1.5 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 calculate the avoided or delayed reliability project benefit for the recommended portfolio, the ability for economic projects to avoid or delay a base reliability project is analyzed and identified in the optimization milestone. No overlap was identified, therefore, no avoided or delayed reliability projects were identified, and the associated benefits are estimated to be zero.

6.1.6 CAPACITY COST SAVINGS DUE TO REDUCED ON-PEAK TRANSMISSION LOSSES

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes an inefficiency inherent to all standard conductors. Line losses across the SPP system are directly related to system impedance. Transmission projects often reduce 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 recommended portfolio are calculated based on the on-peak losses estimated in the base reliability powerflow model. The loss reductions are then multiplied by 112% to estimate the reduction in installed capacity requirements. The value of capacity savings is monetized by applying a net cost of new entry (net CONE) of $85.61/kW-yr in 2018 dollars. The net CONE value was obtained from Attachment AA Resource Adequacy–Attachment AA Section 14 of the tariff. The net cone was assumed to grow at an inflation rate of 2.0% for each study year, $1.1 for 2027, and $1.4 for 2032. Table 6.3 displays the associated capacity savings for each zone in each study year and the 40-year PV.

ZONE	2027 (NOM. $M)	2032 (NOM. $M)	40-YR PV (IN 2023 $M)
AEPW	$0.1	$0.2	$2.4
EMDE	$0.0	$0.0	$0.0
GMO	$0.0	$0.0	$0.0
GRDA	$0.0	$0.0	$0.3
KACY	$0.0	$0.0	$0.0
KCPL	($0.1)	($0.1)	($1.2)
LES	($0.0)	($0.0)	($0.4)
MIDW	$0.0	$0.0	$0.0
NPPD	$0.2	$0.3	$3.6
OKGE	$0.9	$1.2	$16.2
OPPD	$0.0	$0.0	$0.6
SPRM	$0.0	$0.0	$0.0
SPS	($0.0)	$0.0	$0.7
SUNC	$0.0	$0.0	$0.4
SWPA	$0.0	$0.0	$0.3
UMZ	($0.1)	($0.1)	($0.9)
WERE	($0.2)	($0.2)	($1.9)
WFEC	$0.0	$0.1	$0.9
Sub-Total	$1.1	$1.5	$21.1

Table 6.3: On-Peak Loss Reduction and Associated Capacity Cost Savings

6.1.7 ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

This metric monetizes the benefits of reliability projects required to meet compliance and mitigate SPP Criteria violations. The regional benefits are assumed to be equal to the 40-year PV of ATRRs of the projects, totaling **$159 million** in 2023 dollars.

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

Assumed Benefit of Mandated Reliability Projects									
SPP-wide Benefit	< 100 kV $0.22	100–300 kV $98			> 300 kV $61			All NTC Projects $159	
Zone	100% SR	66.7% SR	33.3% LRS	Wtd. Avg.	33.3% SR	66.7% LRS	Wtd. Avg.	Overall Allocation	Benefit (in 2023 $M)
AEPW	0.46%	16.2%	16.2%	16.2%	11.0%	16.2%	14.5%	**15.5%**	**$24.67**
EMDE	2.61%	2.4%	1.9%	2.2%	0.4%	1.9%	1.4%	**1.9%**	**$3.1**
GMO	8.71%	4.1%	3.6%	3.9%	6.7%	3.6%	4.6%	**4.2%**	**$6.7**
GRDA	0.03%	3.6%	3.1%	3.4%	0.3%	3.1%	2.2%	**3.0%**	**$4.7**
KACY	0.26%	0.1%	0.8%	0.4%	0.8%	0.8%	0.8%	**0.5%**	**$0.9**
KCPL	3.53%	3.4%	5.8%	4.2%	13.0%	5.8%	8.2%	**5.7%**	**$9.1**
LES	1.87%	0.8%	1.2%	0.9%	0.9%	1.2%	1.1%	**1.0%**	**$1.6**
MIDW	1.76%	0.5%	0.7%	0.6%	0.6%	0.7%	0.7%	**0.6%**	**$1.0**
NPPD	9.74%	6.2%	6.1%	6.2%	7.8%	6.1%	6.7%	**6.4%**	**$10.2**
OKGE	47.27%	19.8%	11.5%	17.1%	19.3%	11.5%	14.1%	**16.0%**	**$25.4**
OPPD	0.00%	0.2%	5.8%	2.1%	3.0%	5.8%	4.9%	**3.1%**	**$5.0**
SPRM	2.49%	2.0%	1.0%	1.7%	0.4%	1.0%	0.8%	**1.3%**	**$2.1**
SPS	0.16%	19.4%	9.6%	16.1%	0.6%	9.6%	6.6%	**12.4%**	**$19.7**
SUNC	10.78%	3.5%	2.1%	3.1%	0.4%	2.1%	1.5%	**2.5%**	**$4.0**
SWPA	0.38%	3.5%	1.1%	2.7%	2.6%	1.1%	1.6%	**2.3%**	**$3.6**
UMZ	0.08%	8.1%	15.3%	10.5%	20.7%	15.3%	17.1%	**13.0%**	**$20.7**
WERE	8.09%	3.4%	9.7%	5.5%	7.6%	9.7%	9.0%	**6.8%**	**$10.9**
WFEC	1.78%	2.8%	4.4%	3.4%	4.0%	4.4%	4.2%	**3.7%**	**$5.9**
Total	**100.00%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**$159.1**

Table 6.4 summarizes the system reconfiguration analysis results and the benefit allocation factors for different voltage levels. The table shows the overall zonal benefits calculated by applying these allocation factors.

Assumed Benefit of Mandated Reliability Projects									
SPP-wide Benefit	**< 100 kV $0.22**	**100–300 kV $98**			**> 300 kV $61**			**All NTC Projects $159**	
Zone	**100% SR**	**66.7% SR**	**33.3% LRS**	**Wtd. Avg.**	**33.3% SR**	**66.7% LRS**	**Wtd. Avg.**	**Overall Allocation**	**Benefit (in 2023 $M)**
AEPW	0.46%	16.2%	16.2%	16.2%	11.0%	16.2%	14.5%	**15.5%**	**$24.67**
EMDE	2.61%	2.4%	1.9%	2.2%	0.4%	1.9%	1.4%	**1.9%**	**$3.1**
GMO	8.71%	4.1%	3.6%	3.9%	6.7%	3.6%	4.6%	**4.2%**	**$6.7**
GRDA	0.03%	3.6%	3.1%	3.4%	0.3%	3.1%	2.2%	**3.0%**	**$4.7**
KACY	0.26%	0.1%	0.8%	0.4%	0.8%	0.8%	0.8%	**0.5%**	**$0.9**
KCPL	3.53%	3.4%	5.8%	4.2%	13.0%	5.8%	8.2%	**5.7%**	**$9.1**
LES	1.87%	0.8%	1.2%	0.9%	0.9%	1.2%	1.1%	**1.0%**	**$1.6**
MIDW	1.76%	0.5%	0.7%	0.6%	0.6%	0.7%	0.7%	**0.6%**	**$1.0**
NPPD	9.74%	6.2%	6.1%	6.2%	7.8%	6.1%	6.7%	**6.4%**	**$10.2**
OKGE	47.27%	19.8%	11.5%	17.1%	19.3%	11.5%	14.1%	**16.0%**	**$25.4**
OPPD	0.00%	0.2%	5.8%	2.1%	3.0%	5.8%	4.9%	**3.1%**	**$5.0**
SPRM	2.49%	2.0%	1.0%	1.7%	0.4%	1.0%	0.8%	**1.3%**	**$2.1**
SPS	0.16%	19.4%	9.6%	16.1%	0.6%	9.6%	6.6%	**12.4%**	**$19.7**
SUNC	10.78%	3.5%	2.1%	3.1%	0.4%	2.1%	1.5%	**2.5%**	**$4.0**
SWPA	0.38%	3.5%	1.1%	2.7%	2.6%	1.1%	1.6%	**2.3%**	**$3.6**
UMZ	0.08%	8.1%	15.3%	10.5%	20.7%	15.3%	17.1%	**13.0%**	**$20.7**
WERE	8.09%	3.4%	9.7%	5.5%	7.6%	9.7%	9.0%	**6.8%**	**$10.9**
WFEC	1.78%	2.8%	4.4%	3.4%	4.0%	4.4%	4.2%	**3.7%**	**$5.9**
Total	**100.00%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**$159.1**

Table 6.4: Mandated Reliability Benefits

6.1.8 BENEFIT FROM MEETING PUBLIC POLICY GOALS

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

Since no policy projects were identified as a part of the recommended portfolio, the associated benefits are estimated to be zero.

6.1.9 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, ignoring 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 outage costs, the production cost simulations can be augmented for a realistic level of transmission outages. Due to the significant effort needed to develop these augmented models for each case, the findings from the RCAR II study were used to calculate this benefit metric for the consolidated portfolio as a part of this ITP assessment. In the RCAR analysis, adding a subset of historical transmission outage events to the production cost simulations increased the APC savings by 3.34%.[32,33] Applying this ratio to the APC savings estimated for the recommended portfolio translates to a 40-year PV of benefits of **$99.6 million** for Future 1 and **$88.1 million** for Future 2 in 2023 dollars. These benefits are allocated based upon the load ratio share of the region.

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

33 As directed by ESWG, SPP will periodically review historical outage data and update additional APC savings ratio for future studies. Although the outage data was not updated for the 2015 ITP10, it is being reviewed and updated for the RCAR II assessment.

Zone	Future 1: Reference Case	Future 2: Emerging Technologies
	(in 2023 $M)	(in 2023 $M)
AEPW	$16.1	$14.3
EMDE	$1.9	$1.7
GMO	$3.6	$3.2
GRDA	$3.1	$2.8
KACY	$0.8	$0.7
KCPL	$5.8	$5.1
LES	$1.1	$1.0
MIDW	$0.7	$0.7
NPPD	$6.1	$5.4
OKGE	$11.5	$10.2
OPPD	$5.8	$5.1
SPRM	$1.0	$0.9
SPS	$9.5	$8.4
SUNC	$2.1	$1.9
SWPA	$1.1	$1.0
UMZ	$15.2	$13.5
WERE	$9.6	$8.5
WFEC	$4.4	$3.8
TOTAL	**$99.6**	**$88.1**

Table 6.5 shows the outage mitigation benefits allocated to each SPP zone.

Zone	Future 1: Reference Case	Future 2: Emerging Technologies
	(in 2023 $M)	(in 2023 $M)
AEPW	$16.1	$14.3
EMDE	$1.9	$1.7
GMO	$3.6	$3.2
GRDA	$3.1	$2.8
KACY	$0.8	$0.7
KCPL	$5.8	$5.1
LES	$1.1	$1.0
MIDW	$0.7	$0.7
NPPD	$6.1	$5.4
OKGE	$11.5	$10.2
OPPD	$5.8	$5.1
SPRM	$1.0	$0.9
SPS	$9.5	$8.4
SUNC	$2.1	$1.9
SWPA	$1.1	$1.0
UMZ	$15.2	$13.5
WERE	$9.6	$8.5
WFEC	$4.4	$3.8
TOTAL	**$99.6**	**$88.1**

Table 6.5: Transmission Outage Cost Mitigation Benefits by Zone

6.1.10 INCREASED WHEELING THROUGH AND OUT REVENUES

Increasing ATC with a neighboring region improves import and export opportunities for the SPP footprint. Increased interregional transmission capacity that allows for increased through and out transactions will also increase SPP wheeling revenues. The results of this wheeling metric show a reduction of interregional transfer capacity in Year 10. After discussion with the TWG and ESWG, stakeholders and staff agreed to use zero benefits for this metric because no additional transmission service could be sold with reduced levels of transfer capability. The zero dollar benefit is reflected in the summary in Table 6.9 through Table 6.12. However, the process defined in the Benefit Metrics Manual produces an upward trajectory plus inflation for 40 years, which result in positive benefits. The information below will show the results of the defined process. A review of this benefit metric should be done to ensure this outcome was considered.

To estimate how increased ATC could affect the wheeling services sold, the historical long-term firm transmission service request (TSR) allowed by the historical NTC projects are analyzed and compared against the ATC increase in the 2014 powerflow models estimated based on a FCITC analysis. As summarized in Table 6.6, the NTC projects that have been put in-service under SPP's highway/byway cost allocation methodology enabled 13 long-term TSRs to be sold between 2010 and 2014. The TSRs remain active for 2023. The amount of capacity granted for these TSRs add up to 1,402 MW. The associated wheeling revenues are estimated to be $56 million annually based on current SPP tariff rates. The results of the FCITC analysis are summarized in Table 6.7. The export ATC increase in the 2014 powerflow models is calculated to be 1,402 MW, which is comparable to the amount of firm capacity granted for the incremental TSRs sold historically for 2023.

Point of Delivery	Number of Firm PtP Service Requests	MW Capacity Granted	2014 Wheeling Revenues in (2023 $million)			
			Sch 7 Zonal	Sch 11 Reg-Wide	Sch 11 Thru & Out Zonal	TOTAL
AECI	6	716	$11.9	$9.9	$6.0	$27.8
KACY	1	100	$2.4	$1.4	$0.8	$4.7
Entergy	6	586	$10.4	$8.1	$4.9	$23.5
Total:	13	1,402	$24.8	$19.4	$11.8	$56.0

Table 6.6: Estimated Wheeling Revenues from Incremental Long-Term TSRs Sold (2010–2014)

Export ATC in 2014 Base Case	1,630 MW
Export ATC in 2014 Change Case	2,943 MW
Increase in Export ATC due to NTCs	1,313 MW
Incremental TSRs Sold due to NTCs	1,402 MW
TSRs Sold as a Percent of Increase in Export ATC	107%

Table 6.7: Historical Ratio of TSRs Sold against Increase in Export ATC

The 2027 and 2032 base reliability powerflow models were utilized for the FCITC analysis on the consolidated portfolio. The ratio of TSRs sold as a percent of increase in export ATC is capped at 100%, as incremental TSR sales would not be expected to exceed the amount of increase in export ATC. The recommended portfolio decreased the export ATC by 289 MW in 2027 and 4 MW in 2032.

Performing the process as defined in the Benefit Metrics Manual produced benefits with an upward trajectory plus inflation for 40 years, starting at year 11; however, the results of this wheeling metric show a reduction of interregional transfer capacity. Based up the inability to sell transmission service to external customers the information below will show the results for the wheeling through and out benefit metric is $0 for the 2023 ITP Assessment.

6.1.11 MARGINAL ENERGY LOSSES BENEFIT

The standard production cost simulations used to estimate APC do not reflect the impact of transmission upgrades on the MWh quantity of transmission losses. To make run-times more manageable, the load in the production cost simulations is “grossed up” for 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 from simulation results and applying a methodology[34] for marginal energy losses, which accounts for losses on generation and market imports. The 40-year PV of benefits is estimated to be $279.6 million in future 1 and -$46.8 million in Future 2, as shown in Table 6.8 below.

	Future 1 Reference Case	Future 2 Emerging Technologies
	40-yr PV	40-yr PV
Zone	(in 2023 $M)	(in 2023 $M)
AEPW	$80.9	$13.3
EMDE	$12.3	($1.4)
GMO	($10.8)	($13.0)
GRDA	$5.4	($0.4)
KACY	$8.3	($4.1)
KCPL	($41.8)	$20.7
LES	($12.1)	$7.8
MIDW	$0.3	$0.6
NPPD	$28.6	$0.8
OKGE	$27.5	$10.0
OPPD	$7.5	($74.8)
SPRM	$2.5	$0.2
SPS	$24.6	($50.1)
SUNC	$1.9	($5.7)
SWPA	$0.9	($0.3)
UMZ	$26.5	$34.9
WERE	$106.1	$7.3
WFEC	$11.0	$7.4
TOTAL	$279.6	($46.8)

Table 6.8: Energy Losses Benefit by Zone

6.1.12 SUMMARY

Table 6. through Table 6.12 summarize the 40-year PV of the estimated benefit metrics and costs and the resulting benefit-to-cost ratios for each SPP zone.

For the region, the benefit-to-cost ratio is estimated to be 5.6 in Future 1 and 4.5 in Future 2. The higher benefit-to-cost ratio in Future 2 is driven by the APC savings due to higher congestion relief.

[34] As described in the Benefit Metric Manual

Future 1: Reference Case											
Zone	Present Value of 40-yr Benefits for the 2027-2066 Period (in 2023 $M)								**Total Benefits**	**Present Value of 40-yr ATRRs (in 2023 $M)**	**Established Benefit/ Cost Ratio**
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
AEPW	$640.68	$0	$2.44	$24.7	$0	$16.13	$0	$80.87	$765	$93	**8.2**
EMDE	($12.38)	$0	$0.00	$3.1	$0	$1.93	$0	$12.33	$5	$8	**0.6**
GMO	$20.00	$0	$0.00	$6.7	$0	$3.58	$0	($10.78)	$19	$13	**1.5**
GRDA	$418.97	$0	$0.34	$4.7	$0	$3.13	$0	$5.42	$433	$7	**62.8**
KACY	$8.74	$0	$0.00	$0.9	$0	$0.84	$0	$8.31	$19	$3	**5.7**
KCPL	$11.46	$0	($1.25)	$9.1	$0	$5.76	$0	($41.82)	($17)	$32	**(0.5)**
LES	$12.16	$0	($0.40)	$1.6	$0	$1.15	$0	($12.07)	$2	$5	**0.5**
MIDW	($59.25)	$0	$0.00	$1.0	$0	$0.75	$0	$0.27	($57)	$3	**(21.7)**
NPPD	$43.21	$0	$3.58	$10.2	$0	$6.10	$0	$28.59	$92	$25	**3.6**
OKGE	$348.30	$0	$16.22	$25.4	$0	$11.47	$0	$27.48	$429	$61	**7.0**
OPPD	$161.79	$0	$0.57	$5.0	$0	$5.79	$0	$7.47	$181	$16	**11.0**
SPRM	$7.23	$0	$0.00	$2.1	$0	$1.03	$0	$2.50	$13	$5	**2.7**
SPS	$301.66	$0	$0.73	$19.7	$0	$9.51	$0	$24.60	$356	$92	**3.9**
SUNC	($137.33)	$0	$0.40	$4.0	$0	$2.13	$0	$1.93	($129)	$11	**(11.6)**
SWPA	($13.48)	$0	$0.34	$3.6	$0	$1.08	$0	$0.94	($8)	$3	**(2.7)**
UMZ	$1,167.01	$0	($0.85)	$20.7	$0	$15.22	$0	$26.48	$1,229	$65	**18.8**
WERE	($53.07)	$0	($1.93)	$10.9	$0	$9.65	$0	$106.06	$72	$159	**0.5**

Future 1: Reference Case											
Zone	Present Value of 40-yr Benefits for the 2027-2066 Period (in 2023 $M)								**Total Benefits**	**Present Value of 40-yr ATRRs (in 2023 $M)**	**Established Benefit/ Cost Ratio**
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
WFEC	$116.03	$0	$0.91	$5.9	$0	$4.35	$0	$11.00	$138	$31	**4.4**
Total	**$2,982**	**$0.0**	**$21**	**$159**	**$0**	**$100**	**$0**	**$280**	**$3,541**	**$634**	**5.6**

Table 6.9: Future 1 - Estimated 40-year PV of Benefit Metrics and Costs – Zonal

Future 1: Reference Case											
State	**Present Value of 40-yr Benefits for the 2027-2066 Period (in 2023 $M)**								**Total Benefits**	**Present Value of 40-yr ATRRs (in 2023 $M)**	**Established Benefit/ Cost Ratio**
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
Arkansas	$168	$0	$2	$9	$0	$5	$0	$21	$206	$28	7.4
Colorado	$3	$0	$0	$0	$0	$0	$0	$0	$3	$0	17.0
Iowa	$175	$0	($0)	$3	$0	$2	$0	$5	$185	$10	18.0
Kansas	($203)	$0	($2)	$22	$0	$17	$0	$98	($68)	$193	-0.4
Louisiana	$86	$0	$0	$3	$0	$2	$0	$11	$102	$12	8.2
Minnesota	$39	$0	($0)	$1	$0	$1	$0	$1	$41	$2	18.5
Missouri	$13	$0	($0)	$18	$0	$10	$0	($19)	$22	$43	0.5
Montana	$61	$0	($0)	$1	$0	$1	$0	$1	$64	$3	18.8
Oklahoma	$1,052	$0	$16	$42	$0	$23	$0	$72	$1,206	$124	9.7
Nebraska	$231	$0	$4	$17	$0	$13	$0	$24	$288	$47	6.1
New Mexico	$115	$0	$0	$7	$0	$4	$0	$10	$136	$34	4.0
North Dakota	$514	$0	($0)	$9	$0	$7	$0	$12	$541	$29	18.8
South Dakota	$362	$0	($0)	$6	$0	$5	$0	$8	$381	$20	18.8
Texas	$366	$0	$1	$20	$0	$11	$0	$37	$434	$87	5.0
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	$0	-	-
TOTAL	**$2,982**	**$0**	**$21**	**$159**	**$0**	**$100**	**$0**	**$280**	**$3,541**	**$634**	**5.6**

Table 6.10: Future 1 - Estimated 40-year PV of Benefit Metrics and Costs – State

Future 2: Emerging Technologies											
Zone	Present Value of 40-yr Benefits for the 2027-2066 Period (in 2023 $M)								Total Benefits	Present Value of 40-yr ATRRs (in 2023 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
AEPW	$734.36	$0	$2.44	$24.7	$0	$14.27	$0	$13.28	$789	$93	**8.5**
EMDE	($4.00)	$0	$0.00	$3.1	$0	$1.71	$0	($1.38)	($1)	$8	**(0.1)**
GMO	$50.16	$0	$0.00	$6.7	$0	$3.17	$0	($13.01)	$47	$13	**3.5**
GRDA	$436.62	$0	$0.34	$4.7	$0	$2.77	$0	($0.37)	$444	$7	**64.4**
KACY	$25.49	$0	$0.00	$0.9	$0	$0.74	$0	($4.06)	$23	$3	**7.0**
KCPL	$28.24	$0	($1.25)	$9.1	$0	$5.09	$0	$20.73	$62	$32	**1.9**
LES	($22.49)	$0	($0.40)	$1.6	$0	$1.02	$0	$7.82	($12)	$5	**(2.4)**
MIDW	($52.71)	$0	$0.00	$1.0	$0	$0.66	$0	$0.57	($50)	$3	**(19.1)**
NPPD	($61.47)	$0	$3.58	$10.2	$0	$5.40	$0	$0.79	($42)	$25	**(1.7)**
OKGE	$544.29	$0	$16.22	$25.4	$0	$10.15	$0	$9.95	$606	$61	**9.9**
OPPD	$410.95	$0	$0.57	$5.0	$0	$5.12	$0	($74.79)	$347	$16	**21.1**
SPRM	$10.04	$0	$0.00	$2.1	$0	$0.91	$0	$0.22	$13	$5	**2.8**
SPS	$47.68	$0	$0.73	$19.7	$0	$8.42	$0	($50.12)	$26	$92	**0.3**
SUNC	($73.61)	$0	$0.40	$4.0	$0	$1.88	$0	($5.73)	($73)	$11	**(6.6)**
SWPA	($7.37)	$0	$0.34	$3.6	$0	$0.95	$0	($0.30)	($3)	$3	**(1.0)**
UMZ	$533.21	$0	($0.85)	$20.7	$0	$13.47	$0	$34.86	$601	$65	**9.2**
WERE	($86.56)	$0	($1.93)	$10.9	$0	$8.54	$0	$7.27	($62)	$159	**(0.4)**

Future 2: Emerging Technologies											
Zone	Present Value of 40-yr Benefits for the 2027-2066 Period (in 2023 $M)								**Total Benefits**	**Present Value of 40-yr ATRRs (in 2023 $M)**	**Established Benefit/ Cost Ratio**
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
WFEC	$125.70	$0	$0.91	$5.9	$0	$3.85	$0	$7.43	$144	$31	**4.6**
Total	**$2,639**	**$0.0**	**$21**	**$159**	**$0**	**$88**	**$0**	**($47)**	**$2,860**	**$634**	**4.5**

Table 6.11: Future 2 - Estimated 40-year PV of Benefit Metrics and Costs - Zonal

Future 2: Emerging Technologies											
State	Present Value of 40-yr Benefits for the 2027-2066 Period (in 2023 $M)								Total Benefits	Present Value of 40-yr ATRRs (in 2023 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
Arkansas	$211	$0	$2	$9	$0	$5	$0	$4	$231	$28	8.3
Colorado	$1	$0	$0	$0	$0	$0	$0	$0	$1	$0	7.9
Iowa	$78	$0	($0)	$3	$0	$2	$0	$5	$89	$10	8.7
Kansas	($137)	$0	($2)	$22	$0	$15	$0	$6	($97)	$193	-0.5
Louisiana	$98	$0	$0	$3	$0	$2	$0	$2	$106	$12	8.5
Minnesota	$18	$0	($0)	$1	$0	$0	$0	$1	$20	$2	9.2
Missouri	$64	$0	($0)	$18	$0	$9	$0	($2)	$88	$43	2.0
Montana	$28	$0	($0)	$1	$0	$1	$0	$2	$31	$3	9.2
Oklahoma	$1,285	$0	$16	$42	$0	$21	$0	$18	$1,383	$124	11.1
Nebraska	$335	$0	$4	$17	$0	$12	$0	($66)	$301	$47	6.4
New Mexico	$39	$0	$0	$7	$0	$3	$0	($14)	$36	$34	1.1
North Dakota	$235	$0	($0)	$9	$0	$6	$0	$15	$265	$29	9.2
South Dakota	$165	$0	($0)	$6	$0	$4	$0	$11	$187	$20	9.2
Texas	$218	$0	$1	$20	$0	$9	$0	($30)	$218	$87	2.5
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	$0	-	-
TOTAL	**$2,639**	**$0**	**$21**	**$159**	**$0**	**$88**	**$0**	**($47)**	**$2,860**	**$634**	**4.5**

Table 6.12: Future 2 - Estimated 40-year PV of Benefit Metrics and Costs – State

6.2 RATE IMPACTS

The rate impact to an average retail residential ratepayer in SPP was computed for the recommended portfolio. Rate impact costs and benefits[35] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kilowatt hours (kWh) per month. Benefits and costs for the 2032 study year were used to calculate rate impacts. All 2032 benefits and costs are shown in 2023 dollars, discounting at a 2.0% 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 Table 6.9 through Table 6.12. There is a monthly net benefit for the average SPP residential ratepayer of $0.37 for Future 1. There is a monthly net benefit for the average SPP residential ratepayer of $0.33 for Future 2.

[35] APC savings are the only benefit included in the rate impact calculations; although Reduction of Emission Rates & Values and Savings due to Lower Ancillary Service Needs & Production Costs are included in the APC calculation.

Zone	One-Year ATRR Costs 2032 ($thousands)	One-Year Benefit 2032 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2023$)
AEPW	$10,421	$35,974	$0.21	$0.73	($0.52)
EMDE	$756	($1,098)	$0.13	($0.18)	$0.31
GMO	$1,235	$2,127	$0.11	$0.19	($0.08)
GRDA	$2,974	$25,953	$0.31	$2.70	($2.39)
KACY	$292	$921	$0.11	$0.36	($0.24)
KCPL	$2,476	$17	$0.14	$0.00	$0.14
LES	$1,306	$786	$0.37	$0.22	$0.15
MIDW	$238	($3,764)	$0.10	($1.64)	$1.75
NPPD	$8,614	$2,489	$0.46	$0.13	$0.33
OKGE	$8,563	$19,890	$0.24	$0.56	($0.32)
OPPD	$1,641	$9,930	$0.09	$0.56	($0.47)
SPRM	$423	$607	$0.13	$0.19	($0.06)
SPS	$6,184	$18,404	$0.21	$0.63	($0.42)
SUNC	$771	($8,820)	$0.12	($1.35)	$1.47
SWPA	$247	($760)	$0.07	($0.23)	$0.30
UMZ	$5,724	$67,651	$0.12	$1.45	($1.32)
WERE	$4,274	($4,240)	$0.14	($0.14)	$0.29
WFEC	$2,787	$6,663	$0.21	$0.50	($0.29)
TOTAL	**$58,926**	**$172,729**	**$0.19**	**$0.56**	**($0.37)**

Table 6.9: Future 1 - Retail Residential Rate Impacts by Zone

State	One-Year ATRR Costs 2032 ($thousands)	One-Year Benefit 2032 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2023$)
Arkansas	$3,253	$9,435	$0.21	$0.60	($0.39)
Colorado	$20	$154	$0.16	$1.28	($1.12)
Iowa	$1,028	$10,122	$0.14	$1.38	($1.24)
Kansas	$7,079	($13,789)	$0.14	($0.27)	$0.41
Louisiana	$1,396	$4,819	$0.21	$0.73	($0.52)
Minnesota	$197	$2,269	$0.12	$1.43	($1.31)

State	One-Year ATRR Costs 2032 ($thousands)	One-Year Benefit 2032 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2023$)
Missouri	$3,711	$1,164	$0.12	$0.04	$0.08
Montana	$298	$3,521	$0.12	$1.45	($1.32)
Oklahoma	$16,874	$61,734	$0.24	$0.86	($0.63)
Nebraska	$11,443	$14,004	$0.28	$0.35	($0.06)
New Mexico	$2,443	$6,948	$0.21	$0.60	($0.39)
North Dakota	$2,523	$29,811	$0.12	$1.45	($1.32)
South Dakota	$1,784	$20,997	$0.12	$1.44	($1.32)
Texas	$6,879	$21,539	$0.21	$0.66	($0.45)
Wyoming	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	**$58,926**	**$172,729**	**$0.19**	**$0.56**	**($0.37)**

Table 6.10: Future 1 - Retail Residential Rate Impacts by State

Zone	One-Year ATRR Costs 2032 ($thousands)	One-Year Benefit 2032 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2023$)
AEPW	$10,421	$40,353	$0.21	$0.81	($0.60)
EMDE	$756	($643)	$0.13	($0.11)	$0.24
GMO	$1,235	$4,634	$0.11	$0.42	($0.31)
GRDA	$2,974	$27,693	$0.31	$2.88	($2.57)
KACY	$292	$2,423	$0.11	$0.94	($0.83)
KCPL	$2,476	$3,189	$0.14	$0.18	($0.04)
LES	$1,306	($832)	$0.37	($0.24)	$0.61
MIDW	$238	($3,469)	$0.10	($1.51)	$1.62
NPPD	$8,614	($2,818)	$0.46	($0.15)	$0.61
OKGE	$8,563	$29,723	$0.24	$0.84	($0.60)
OPPD	$1,641	$22,136	$0.09	$1.24	($1.15)
SPRM	$423	$774	$0.13	$0.24	($0.11)
SPS	$6,184	$5,419	$0.21	$0.19	$0.03
SUNC	$771	($5,668)	$0.12	($0.87)	$0.98
SWPA	$247	($613)	$0.07	($0.19)	$0.26

Zone	One-Year ATRR Costs 2032 ($thousands)	One-Year Benefit 2032 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2023$)
UMZ	$5,724	$36,746	$0.12	$0.79	($0.66)
WERE	$4,274	($5,764)	$0.14	($0.19)	$0.34
WFEC	$2,787	$6,954	$0.21	$0.52	($0.31)
TOTAL	**$58,926**	**$160,237**	**$0.19**	**$0.52**	**($0.33)**

Table 6.11: Future 2 - Retail Residential Rate Impacts by Zone

State	One-Year ATRR Costs 2032 ($thousands)	One-Year Benefit 2032 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2023$)
Arkansas	$3,253	$11,492	$0.21	$0.73	($0.52)
Colorado	$20	$80	$0.16	$0.67	($0.51)
Iowa	$1,028	$5,413	$0.14	$0.74	($0.60)
Kansas	$7,079	($8,576)	$0.14	($0.17)	$0.31
Louisiana	$1,396	$5,406	$0.21	$0.81	($0.60)
Minnesota	$197	$1,245	$0.12	$0.79	($0.66)
Missouri	$3,711	$5,839	$0.12	$0.19	($0.07)
Montana	$298	$1,913	$0.12	$0.79	($0.66)
Oklahoma	$16,874	$73,929	$0.24	$1.03	($0.80)
Nebraska	$11,443	$19,012	$0.28	$0.47	($0.19)
New Mexico	$2,443	$3,031	$0.21	$0.26	($0.05)
North Dakota	$2,523	$16,193	$0.12	$0.79	($0.66)
South Dakota	$1,784	$11,401	$0.12	$0.78	($0.66)
Texas	$6,879	$13,860	$0.21	$0.42	($0.21)
Wyoming	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	**$58,926**	**$160,237**	**$0.19**	**$0.52**	**($0.33)**

Table 6.12: Future 2 - Retail Residential Rate Impacts by State

6.3 VOLTAGE STABILITY ASSESSMENT

A voltage stability assessment was conducted with the recommended portfolio using Future 1 and 2 market powerflow models to assess the transfer limit (GW) from renewables in SPP to conventional thermal generation in SPP, and from renewables in SPP to conventional thermal generation in external areas.[36] The assessment was performed to determine whether the generation dispatch with the recommended portfolios adversely impacts system voltage stability. The assessment was intentionally scoped to determine how the planned system performs under high renewable dispatch, given the projected renewable amounts assumed for the 2023 ITP.

The planned system is expected to support the future-specific renewable generation dispatches observed in the reliability hours after modeling the consolidated portfolio, reaching either minimum internal conventional thermal generation levels or thermal limits before reaching voltage stability limits.

6.3.1 METHODOLOGY

To determine the amount of generation transfer that could be accommodated by the planned system, generation in the source zone was increased and generation in the sink zone was decreased. Table 6.13 identifies the transfer zones and boundaries.

Transfer Scenario	Transfer Zones	Zone Boundaries
Transfer Scenario 1	SPP renewables	SPP conventional thermal generation
Transfer Scenario 2	SPP renewables	First-Tier conventional thermal generation

Table 6.13: Generation Zones

Table 6.14 shows the transfers that were performed on the 2032 light load and 2032 summer models by scaling both online and offline renewables from the source zone and scaling down the sink zone. Utility scale solar was not included in the source zone for the 2032 light load model due to the reliability hour being identified as 4:00 a.m.

Model	Source Zone	Sink Zone
2032 Light Load	SPP renewables (Wind)	SPP conventional thermal generation
2032 Light Load	SPP renewables (Wind)	First-Tier conventional thermal generation
2032 Summer	SPP renewables (Wind and Utility Scale Solar)	SPP conventional thermal generation
2032 Summer	SPP renewables (Wind and Utility Scale Solar)	First-Tier and conventional thermal generation

Table 6.14: Transfers by Model

Single contingencies (N-1) for all SPP branches, transformers, and ties greater than or equal to 345 kV were analyzed. SPP and first-tier 100 kV and above facilities were monitored for voltage and thermal violations. The initial condition for each model was the source zone sum of real power generation output (MW). The maximum source zone transfer capability was sum of the SPP renewable's real power maximum generation (Pmax). The transfers were performed on each model in 200 MW steps

[36] See TWG 11/13/2018 meeting minutes and attachments for the TWG-approved 2020 ITP Voltage Stability Scope.

until voltage collapse occurred in the pre-contingency and post-contingency (N-1, 345 kV and 500 kV facilities) conditions. Each future was evaluated for increasing generation transfer amounts to determine different voltage collapse points of the transmission system. Source and sink generation was scaled on a pro-rata basis to reach the pre-contingency maximum power transfer limit, or the voltage stability limit (VSL). Multiple transfer limits were determined based on the worst N-1 contingency and independently evaluating the next worst contingency to determine the top five post-contingency VSL.

6.3.2 SUMMARY

Table 6.15 shows a summary of the voltage stability assessment limits by future, model and transfer path. The table includes the transfer path, source and sink generation pre-transfer levels, critical contingency, post transfer level when VSL is reached, incremental transfer limit amount and whether or not thermal overloads occur prior to voltage collapse. The table shows minimum internal conventional thermal generation levels were reached or when a thermal limit was reached before the VSL in summer peak models.

Transfer Source --> Sink	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
Future 1: 2032 Light Load							
Wind --> Internal Thermal	23.3	2.8	Mark Moore-Tobias	24.3	2.1	1	Yes
"	23.3	2.8	Gentleman-Red Willow	24.3	2.1	1	Yes
"	23.3	2.8	Grec Tap-Igloo	24.3	2.1	1	Yes
Wind --> External Thermal	23.3	8.8	Ft. Smith Transformer 345 kV	24.2	8.3	0.9	Yes
"	23.3	8.8	Summit-Geary	24.2	8.3	0.9	Yes
"	23.3	8.8	Mark Moore-Tobias	24.1	8.3	0.8	Yes
Future 1: 2032 Summer Peak							
Solar & Wind --> Internal Thermal	22.0	16.8	Reached minimum SPP internal Sink				N/A
Solar & Wind -->	22.0	22.1	Buffalo Flats Transformer 138 kV	31.6	14.3	9.6	Yes

Transfer Source --> Sink	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
External Thermal							
"	22.0	22.1	Summit Transformer 230 kV	31.6	14.3	9.6	Yes
"	22.0	22.1	Ft. Smith Transformer 345 kV	31.6	14.3	9.6	Yes
Future 2: 2032 Light Load							
Wind --> Internal Thermal	23.8	1.4	Gracemont Transformer 138 kV	23.8	1.4	0	N/A
"	23.8	1.4	Ft. Smith Transformer 345 kV	23.8	1.4	0	N/A
"	23.8	1.4	Ft. Thompson-Grand Prairie	23.8	1.4	0	N/A
Wind --> External Thermal	23.8	7.8	Gracemont Transformer 138 kV	23.8	7.8	0	N/A
"	23.8	7.8	Ft. Smith Transformer 345 kV	23.8	7.8	0	N/A
"	23.8	7.8	Ft. Thompson-Grand Prairie	23.8	7.8	0	N/A
Future 2: 2032 Summer Peak							
Solar & Wind --> Internal Thermal	22.2	12.5	Reached minimum SPP internal Sink				N/A
Solar & Wind --> External Thermal	22.3	16.2	Gracemont Transformer 138 kV	29.4	10.6	7.1	Yes
"	22.3	16.2	Ft. Smith Transformer 345 kV	29.4	10.6	7.1	Yes
"	22.3	16.2	Cleveland Transformer 138 kV	29.4	10.6	7.1	Yes

Table 6.15: Post-Contingency Voltage Stability Transfer Limit Summary

Table 6.16 shows a summary of the voltage stability assessment limits and thermal limits by future, model and transfer path. The table includes the transfer path, total renewable capacity, post transfer level when thermal violations and VSLs are reached and a comment summarizing either the minimum internal conventional thermal generation levels or when a thermal limit is reached prior to the VSL.

Transfer Source-->Sink	Total Renewable Capacity (GW)	VSL Limit (GW)	Thermal Limit (GW)	Comment
Future 1: 2032 Light Load				
Wind-->Internal Thermal	47.3	24.3	2.1	
Wind-->External Thermal	47.3	24.3	8.3	
Future 1: 2032 Summer Peak				
Solar & Wind --> Internal Thermal	49.0	N/A	N/A	Reached minimum SPP internal Sink
Solar & Wind --> External Thermal	49.0	31.6	31.4	
Future 2: 2032 Light Load				
Wind--> Internal Thermal	47.8	23.8	1.4	
Wind--> External Thermal	47.8	23.8	7.8	
Future 2: 2032 Summer Peak				
Solar & Wind --> Internal Thermal	68.3	N/A	N/A	Reached minimum SPP internal Sink
Solar & Wind --> External Thermal	68.3	29.4	29.2	

Table 6.16: Voltage Stability Results Summary

6.3.3 CONCLUSION

The analysis demonstrates the planned system does not reach a VSL prior to system thermal limits in the summer peak models; therefore, the potential benefits attributed to the consolidated portfolio are validated. Voltage collapse occurs at renewable levels less than the projected renewable capacity amounts. However, thermal issues (*i.e.*, justification for renewable curtailments) occur prior to voltage collapse when thermal issues are captured in the market economic models as congestion. The APC benefit of the consolidated portfolio is generally derived from relieving congestion on thermal issues. Voltage collapse occurs at aggregate renewable levels greater than what is observed in the reliability hours after modeling the consolidated portfolio. As for the light load models, due to the continually decreasing amount of conventional units being needed in these simulated periods, the analysis does not show an accurate representation of how the system will act under these conditions.

Additionally, after reviewing the system dispatch associated with the Future 2 2032 Light Load case, the model shows a renewable penetration greater than 114% with more than 10 GW of wind already curtailed. This shows the SPP system is already exporting significant amounts of renewables to its neighbors.

6.4 FINAL RELIABILITY ASSESSMENT

6.4.1 METHODOLOGY

All projects in the 2023 ITP recommended portfolio and model adjustments identified during solution development were incorporated into the base reliability, short-circuit and market powerflow models. A contingency analysis of equivalent scope to the analysis described in sections 4.2.1 and 4.2.2 of the ITP Manual was performed to determine if the selected projects caused any new reliability violations.

6.4.1.1 *SHORT-CIRCUIT MODEL*

A proxy automatic sequencing fault calculation (ASCC) short-circuit analysis was performed on the 2023 ITP year-two summer maximum fault current model to find percent increases in fault currents in relation to the base case model on which the needs assessment was performed. All consolidated portfolio projects expected to alter or need zero sequence data were added to the model regardless of their in-service dates. After performing this analysis, SPP found that 244 of the 10,362 buses monitored experienced a 5% increase in fault current. Only eight of the 244 buses appeared to exceed common breaker duty ratings of 20kA and 40kA. The subsequent short-circuit analysis performed in the next ITP will confirm whether or not the duty ratings are exceeded given the latest modeling assumptions.

6.4.2 SUMMARY

6.4.2.1 *BASE RELIABILITY MODELS*

The resulting thermal and voltage violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, and identification of invalid contingencies, non-load-serving buses and facilities not under SPP’s functional control. However, the extension of the Craig-West Gardner 345 kV line to the new tap near the Clearview 115 kV does introduce a new potential overload. Losing the 345 kV outlet from the new tap forces the flow from West Gardner down to the 115 side of the tap, causing overloads on the line to Clearview. Additionally, losing the 87th Street 345/115 kV transformer draws more flow onto the same line. These issues are addressed by the addition of upgrades associated with new load interconnecting in the area. Therefore, one of the projects from that load study will be included the final reliability portfolio for the study: a second 345/115 kV transformer at 87th street.

6.4.2.2 *SHORT-CIRCUIT MODEL*

The final reliability assessment for the short-circuit model did not show any new fault-interrupting equipment to have its duty ratings exceeded by the maximum available fault current (potential violation) due to the addition of the consolidated portfolio.

6.4.3 CONCLUSION

The final reliability assessment showed one new reliability violation caused by the 2023 ITP recommended portfolio that required an additional project recommendation.

6.5 SENSITIVITY ANALYSIS

6.5.1 SENSITIVITY INPUT DATA

Sensitivity models were developed to assess how versatile the plan is in handling a range of uncertainties. SPP created economic sensitivity models to adjust some of the initial assumptions. Adjusted assumptions include load demand amounts, Henry Hub gas prices, and renewable resource capacity.

Figure 6.1 shows the Henry Hub gas prices for the base case and sensitivities. Adjustments were based on the 2023 EIA AEO High and Low Oil and Gas Supply cases.[37] The High Price case reflects limited supply, increasing the cost of natural gas. Alternitavley, the Low Price case reflects ample supply, therefore reducing natural gas prices.

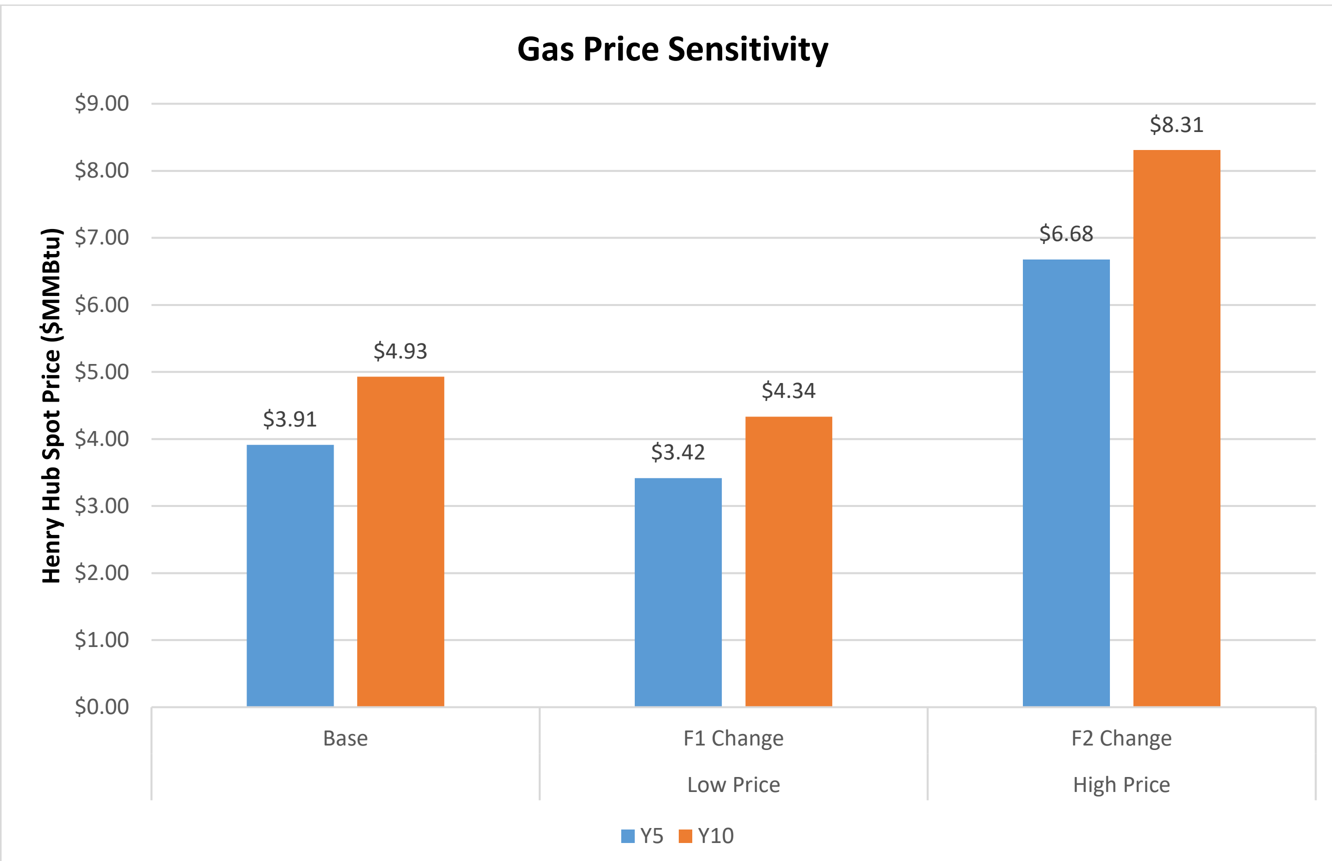

Figure 6.1: Gas Prices Sensitivity, All Cases

Figure 6.2 shows the demand levels base case and sensitivities. Adjustments were based on the 2023 EIA AEO High and Low Economic Growth cases.

[37] EIA Annual Energy Outlook 2023: https://www.eia.gov/outlooks/aeo/

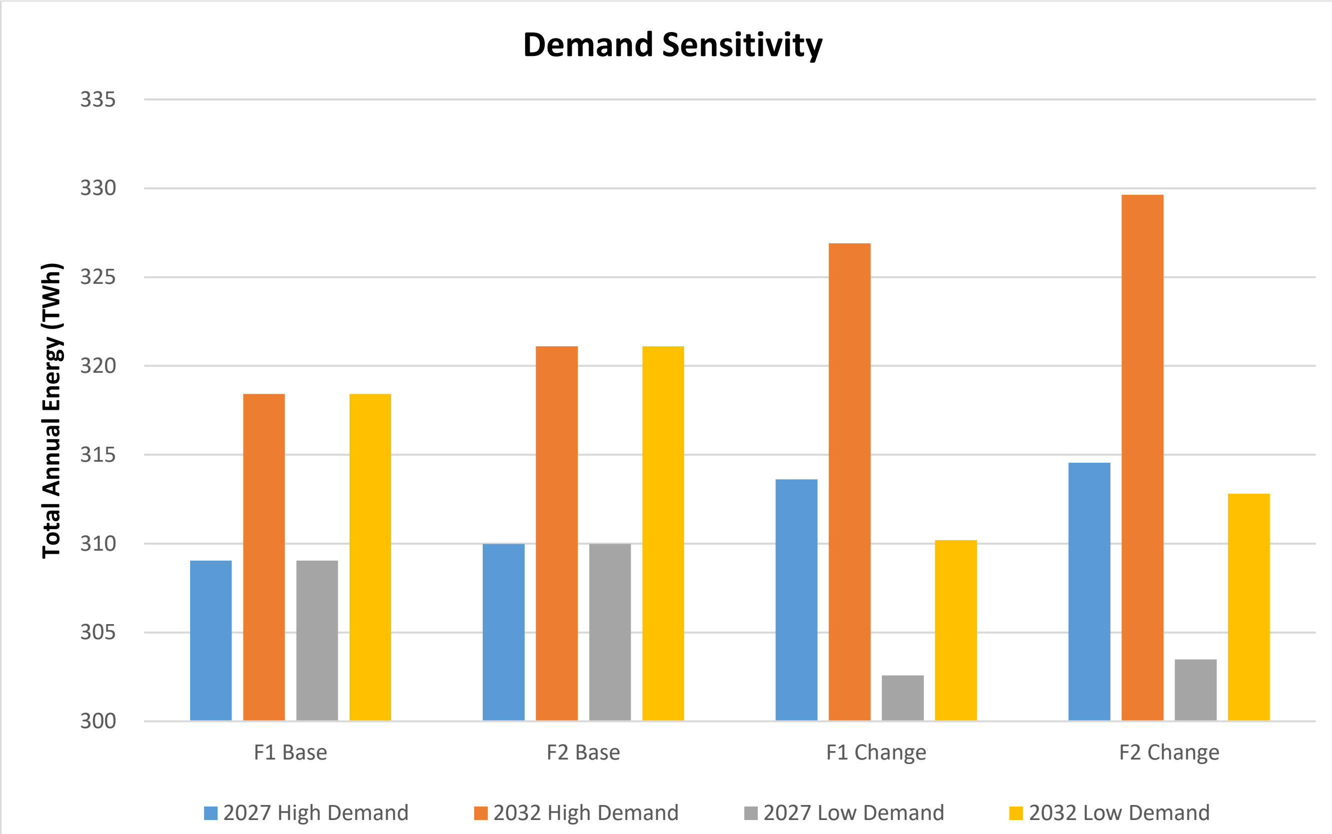

Figure 6.2: Demand Sensitivity

Figure 6.3 and Figure 6.4 shows the capacity change for solar and wind in the base case and sensitivities (reflected by total annual energy changes). Adjustments were based on the 2023 EIA AEO High and Low Zero-Carbon Technology cost cases.

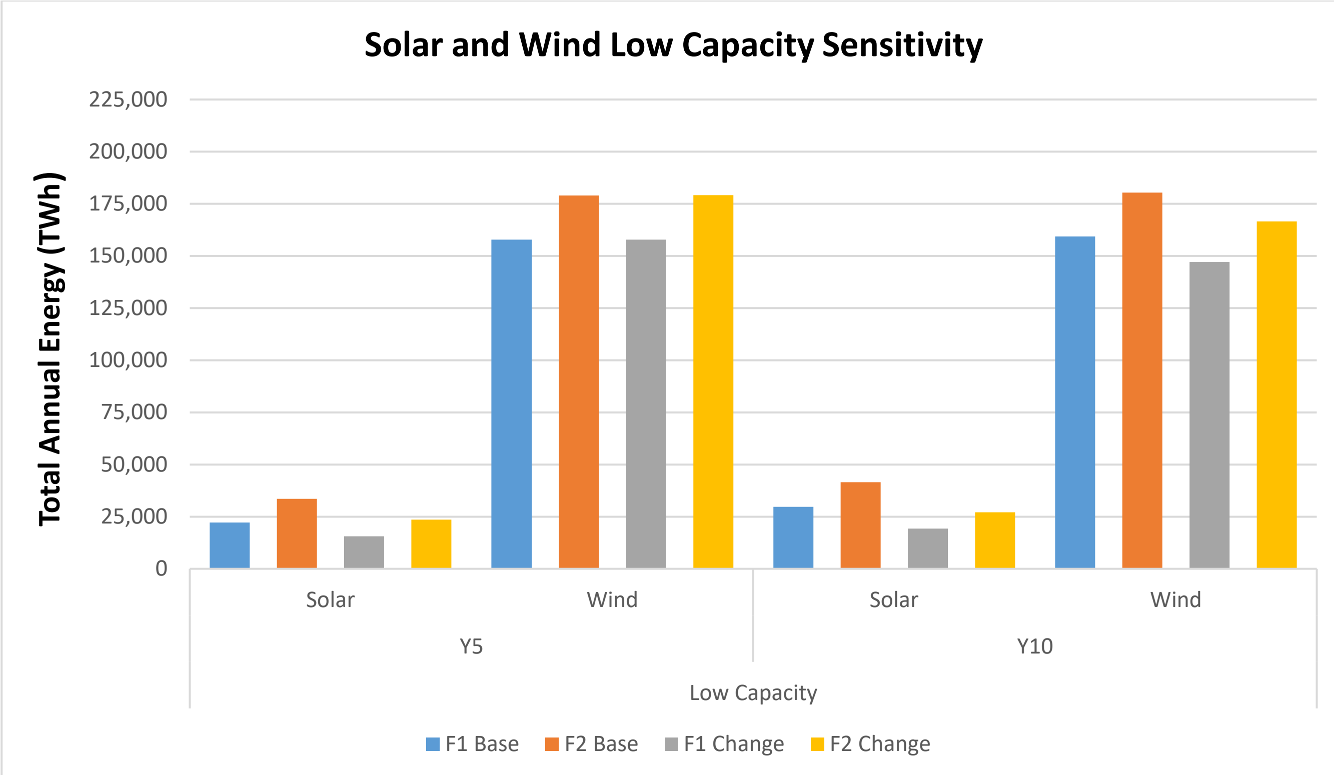

Figure 6.3: Solar and Wind Low Capacity Sensitivity

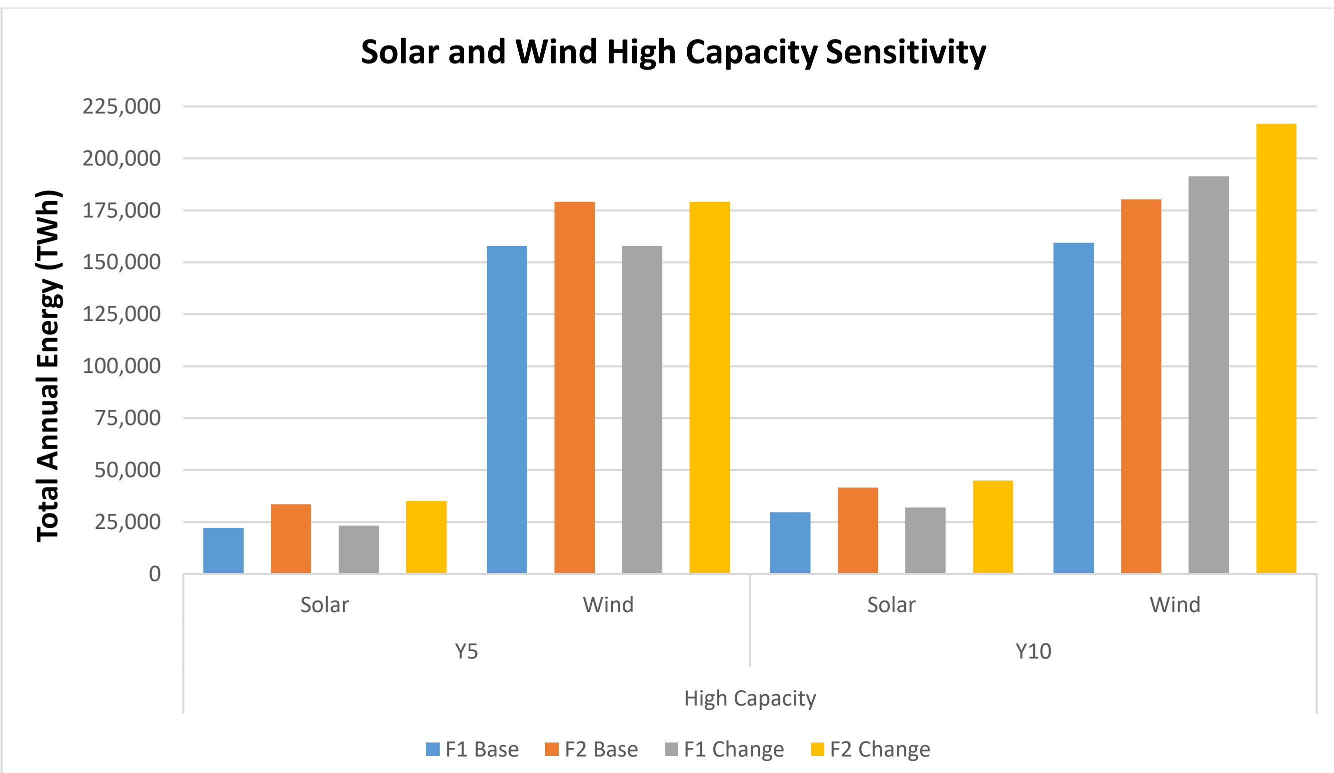

Figure 6.4: Solar and Wind High Capacity Sensitivity

6.5.2 SENSITIVITY RESULTS

Each sensitivity was tested with the final portfolio. The portfolio was run under both futures using each of the sensitivities to show the range of benefits provided by each portfolio under the alternative forecasts.

Benefit ranges for each sensitivity are shown alongside the expected portfolio costs with a +/- 30% range to cost applied. Results are indicative of the expected range of APC benefits that project portfolios will have in each future for the differing senstitivities. Costs and Benefits shown below are in in 40 Year dollars.

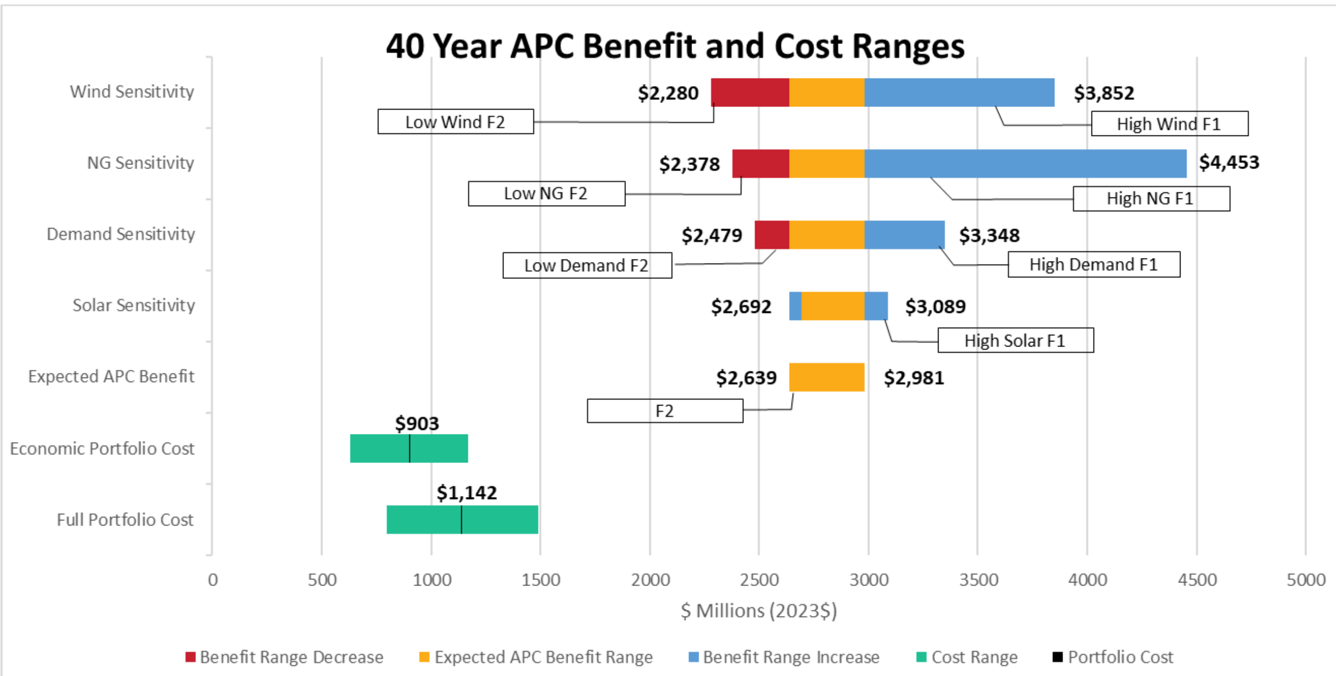

Figure 6.5: Sensitivity Analysis Results[38]

[38] The Final Reliability Assessment (FRA) project 87th Street 345/115 kV new circuit 2 transformer was included in the final portfolio cost, but not in the benefits shown in the sensitivity analysis results.

7 NTC RECOMMENDATIONS

SPP makes NTC recommendations for projects included in the consolidated portfolio based on results from the staging process and SPP Business Practice 7060. If financial expenditure is required within four years from Board approval, the project is generally recommended for an NTC or NTC-C. To determine the date when financial expenditure is required, the project's lead time is subtracted from its need date. Expected lead times for transmission projects are determined using historical data on construction timelines from SPP's project tracking process. NTC-Cs are issued for projects with an operating voltage greater than 100 kV and a Study Estimate greater than $20 million.

Table 7.1 below shows SPP's NTC recommendations when considering staging results, expected lead times and other qualitative information related to the recommended projects.

Description	Need Date	Lead Time (months)	NTC/ NTC-C
70th & Bluff-Sub 1214 161 kV raise line and transformer replacement	1/1/2027	24	NTC
87th Street 345/115 kV new circuit 2 transformer	4/1/2025	24	NTC
Alliance-Victory Hill 115 kV new line	1/1/2025	42	No
Anadarko-Gracemont 138 kV circuit 2 and 3 new line*	11/14/2023	42	NTC-C
Anadarko-Southwestern 138 kV terminal equipment	1/1/2025	18	NTC
Arcadia-Seminole 345 kV and Draper Lake-Seminole 345 kV tap line at Horseshoe Lake	1/1/2025	42	No
Matthewson-Redbud 345 kV	1/1/2025	48	NTC-C
Benton-Wichita 345 kV terminal equipment*	11/14/2023	18	NTC
Blackberry-Neosho 345 kV terminal equipment	1/1/2025	18	NTC
Butler-Midian 138 kV terminal equipment	1/1/2025	18	NTC
Chisholm Creek-Lone Oak 138 kV new line	1/1/2032	42	No
Cimarron and Czech Hall 138 kV terminal equipment	1/1/2025	18	NTC
Cleo Corner-Okeene 138 kV new line	1/1/2032	42	No
Cleveland 138 kV Terminal Equipment*	11/14/2023	18	No[39]
Craig-Lenexa South 161 kV circuit 2 terminal equipment	1/1/2025	18	NTC
Ellsworth Tap-Great Bend 115 kV structures	1/1/2028	18	NTC
Fitzgerald Creek-Kenzie 138 kV line tap at Valley	1/1/2025	24	NTC
Fort Thompson 345/230 kV transformer*	11/14/2023	24	NTC
Franklin 161/69 kV circuit 2 transformer	1/1/2025	24	NTC

[39] Upgrades to non-SPP tariff facilities will be coordinated with AECI

Description	Need Date	Lead Time (months)	NTC/ NTC-C
Fremont/Sub 976 115/69 kV transformer	1/1/2025	24	NTC
Gavins Point-Yankton 115 kV rebuild line	1/1/2025	30	NTC
Gerald Gentleman Station-Ogallala 230 kV terminal equipment*	11/14/2023	18	NTC
Huron B Tap-Huron-Huron West Park 115 kV rebuild	1/1/2025	30	NTC
Osage-Shidler-Webb City Tap 138 kV rebuild*	11/14/2023	36	NTC
Pine & Peoria Tap-46th Street Tap - Tulsa North 138 kV rebuild	1/1/2025	30	NTC
Potter County 345/230 kV circuit 1 and 2 transformer replacement*	11/14/2023	24	NTC-C

Table 7.1: 2023 Economic NTC Recommendations

Description	Need Date	Lead Time (months)	NTC/ NTC-C
Broadland 345 kV 75 MVAR reactor	4/1/2024	24	NTC
Extend Craig-West Gardner 345 kV, Clearview-Eudora 115 kV Tap, new 345/115 kV substation	4/1/2025	42	NTC-C
Cunningham-Quahada 115 kV tap line-Buckeye Tap 115 kV new line	6/1/2024	48	NTC-C
Devaul 115 kV 15 MVAR reactor	4/1/2024	24	NTC
Flournoy-Oak Pan-Harr-Longwood 138 kV rebuild	6/1/2028	24	NTC-C
Fort Peck-Dawson County 230kV 40 MVAR line reactor	6/1/2024	24	NTC
Groton 345 kV 68 MVAR reactor	4/1/2024	24	NTC
Kerr-Maid 161 kV circuit 1 and 2 rebuild	4/1/2024	24	NTC-C
Lovington 40 MVAR Reactor	1/1/2030	24	No
Moore Co 115 kV terminal equipment	6/1/2027	18	NTC
Newman Grace Tap and Woodward Nitrogen 69 kV terminal equipment	6/1/2024	18	NTC
Replace Turk 138/115 kV circuit 1 transformer	6/1/2024	24	NTC
Seminole 345/138 kV new transformer	6/1/2024	24	NTC
Pennsylvania-Southgate-Westmoore 138 kV extend line	6/1/2027	24	NTC
Sundown Interchange 115 kV terminal equipment	6/1/2030	18	No

Table 7.2: 2023 Reliability NTC Recommendations

Description	Need Date	Lead Time (months)	NTC/ NTC-C
Blue Valley 161 kV breaker	6/1/2024	18	NTC
Craig 161 kV five breakers	6/1/2024	18	NTC
Lightning Creek 138 kV two breakers	6/1/2024	18	NTC

Table 7.3: 2023 Short Circuit NTC Recommendations

8 GLOSSARY

Acronym	Name
ABB	ABB Group licenses the PROMOD enterprise software SPP uses for economic simulations
APC	Adjusted production cost = Production Cost $ + Purchases $-Sales $
ARR	Auction Revenue Rights
ATC	Available transfer capacity
BAA	Balancing Authority Area
BAU	Business as usual
B/C	Benefit-to-Cost Ratio
BES	Bulk-Electric System
CC	Combined cycle
CLR	Cost per loading relief
CT	Combustion turbine
CVR	Cost per voltage relief
DPP	Detailed Project Proposal
E&C	Engineering and construction cost
ERCOT	Electric Reliability Council of Texas (ERCOT)
EHV	Extra-high voltage
ESWG	Economic Studies Working Group
FCITC	First contingency incremental transfer capacity
FERC	Federal Energy Regulatory Commission
FTLO	For the loss of
GI	Generator Interconnection
GIA	Generator Interconnection Agreement

Acronym	Name
GOF	Generator outlet facilities
GW	Gigawatt
GWh	Gigawatt hour
HV	High voltage
IFTS	Interruption of firm transmission service
IRP	Integrated resource plan
IS	Integrated System, which includes the Western Area Power Administration’s Upper Great Plains Region (Western-UGP), Basin Electric Power Cooperative, and the Heartland Consumers Power District
ITP	Integrated Transmission Planning
ITP Manual	Integrated Transmission Planning Manual
kV	Kilovolt
LMP	Locational Marginal Price = the market-clearing price for energy at a given Price Node equivalent to the marginal cost of serving demand at the Price Node, while meeting SPP Operating Reserve requirements
MISO	Midcontinent Independent System Operator
MTEP19	2019 MISO Transmission Expansion Plan
MTEP20	2020 MISO Transmission Expansion Plan
MTEP	MISO Transmission Expansion Plan
MDAG	Model Development Advisory Group
MMWG	Multi-regional Modeling Working Group
MOPC	Markets and Operations Policy Committee
MW	Megawatt
NERC	North American Electric Reliability Corporation
NITSA	Network Integration Transmission Service Agreement
PV	Present value
NREL	National Renewable Energy Laboratory

Acronym	Name
NCLL	Non-consequential load loss
NTC	Notification to Construct
PPA	Power Purchase Agreement
PST	Phase-shifting transformer
RCAR	Regional Cost Allocation Review
RPS	Renewable portfolio standards
SASK	Saskatchewan Power
SPC	Strategic Planning Committee
SPP OATT	SPP Open Access Transmission Tariff
TO	Transmission Owner
TSR	Transmission Service Request
TVA	Tennessee Valley Authority
TWG	Transmission Working Group
US EIA	United States Energy Information Administration
VSL	Voltage stability limit

Table 8.1: Glossary