2021 INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT

By SPP ENGINEERING

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Version 1.0

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
11/19/2021 v0.1	SPP	Initial Draft Report - Partial	Posted for stakeholder review
12/16/2021 v0.2	SPP	Final Draft Report	Posted for stakeholder review
12/28/2021 v0.3	SPP	Updated Final Draft Report	Posted for stakeholder review
1/04/2022 v0.4	SPP	Updated Final Draft Report	Updated for TWG/ESWG Joint meeting
1/05/2022 v0.5	SPP	Final Draft Report	Posted for MOPC
1/06/2022 v0.6	SPP	Final Draft Report	Posted for MOPC with update to Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie project cost in Table 0.1
1/10/2022 v0.6	SPP	Final Draft Report	Endorsed by MOPC with the exception of approving the Crossroads-Phantom project for construction. MOPC recommended further evaluation of the Crossroads-Phantom project with updated information, to be brought back to MOPC by July 2022
1/25/2022 v0.6	SPP	Final Report	Approved by SPP board of directors as endorsed by MOPC on 1/10/2022, with further evaluation of the Crossroads-Phantom project with updated information, to be brought back to MOPC by July 2022
3/15/2022 v1.0	SPP	Updated Final Report	• Corrected 2025 & 2030 to be 2026 & 2031 in section 2.2.2.2 • Updated table headings for table 5.2 for futures from 2025 & 2030 to 2026 & 2031 • Updated to correct state zonal rate impact tables 9.6 & 9.7 • Updated East New Town 115 kV 150 MVAR STATCOM need date from 12/1/2031 to 1/1/2023 in Table 10.1 • Updated footnote 5 (Executive Summary, table 0.1) and added footnote 41 (section 10, table 10.1) to reference the further evaluation of the Crossroads-Phantom project

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EXECUTIVE SUMMARY

2021 INTEGRATED TRANSMISSION PLAN

COLLABORATION

8 groups; 100+ meetings
30-month schedule
1,278 solutions reviewed
700+ inquiries processed

BENEFITS

Solve 185 system needs
Facilitate load interconnections
Increase flexibility re: generation mix
Create access to low-cost energy

PROJECTS

28 new projects
397 miles new transmission
380 miles 345 kV
48 miles rebuilt lines
$1.04 billion E&C costs

VALUE

$1.16 - $1.30
Residential bill savings

5.3 - 5.7 to 1
Benefit-to-cost ratio

The 2021 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 30 months, SPP and its member organizations collaborated on the 2021 ITP. SPP evaluated more than 1,278 solutions. The analysis resulted in the recommendation to approve 28 new transmission projects, including 380.3 miles of new extra-high-voltage (EHV) transmission and 48.4 miles of rebuilt high-voltage infrastructure.

Three distinct scenarios were considered to account for variations in system conditions over 10 years. These scenarios consider requirements to support firm deliverability of capacity for reliability (base reliability) while exploring rapidly evolving technology that may influence the transmission system and energy industry (Future 1/Future 2). The scenarios included varied wind projections, utility-scale and distributed solar, energy storage resources, generation retirements and electric vehicles.

This portfolio contains reliability and economic projects that will mitigate 185 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.

The 2021 ITP assessment focuses on two remote geographic areas: in New Mexico (the Southwestern Public Service south region) and in northwestern North Dakota (the Basin Electric Power Cooperative north region). These target areas project higher than average load growth driven by oil and gas exploration in the Permian Basin and Bakken shale formations. Load growth and limited transmission connections to SPP's generation fleet are creating voltage collapse and economic congestion in these areas. The recommended portfolio addresses these issues while providing more connectivity to the rest of the SPP footprint and reducing reliance on critical generators. During the course of this study, information about these target areas changed, causing modifications to the analysis and recommendations (section 8.1).

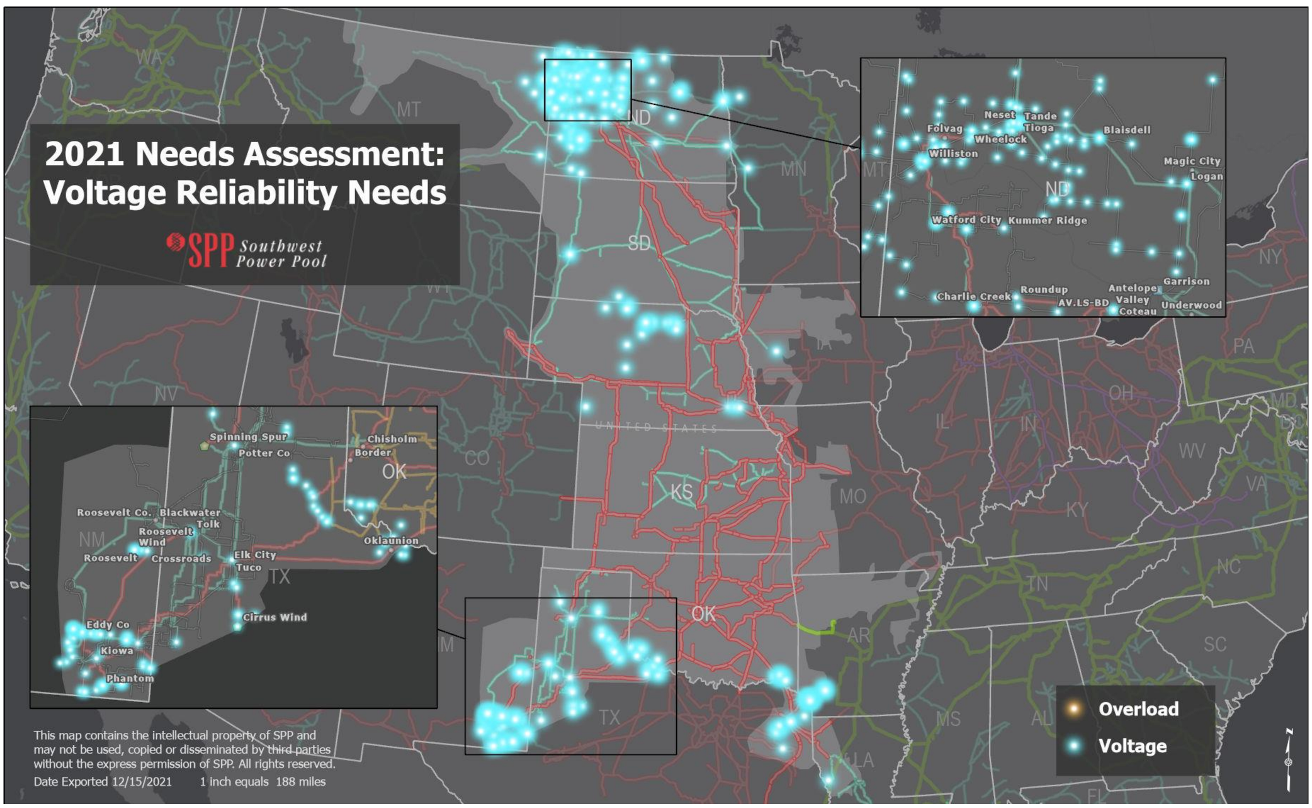

Figure 0.1: Target Area Map

While a large portion of the 2021 ITP focused on the two target areas, the portfolio addresses reliability and economic issues across the system. The 2021 ITP portfolio was heavily driven by reliability issues across the system, with only five economic projects representing just over $25 million of the portfolio cost. Eleven additional projects are needed to address non-target area issues across the remainder of the footprint, totaling approximately $100 million.

The analysis determined that the adjusted production cost (APC) savings for the final portfolio had a 40-year net present value (NPV) benefit-to-cost ratio (B/C) ranging from 5.3 for Future 1 to 5.7 for

Future 2. The net impact to ratepayers is a savings of $1.16 for Future 1 to $1.30 to Future 2 on the average retail residential monthly bill.

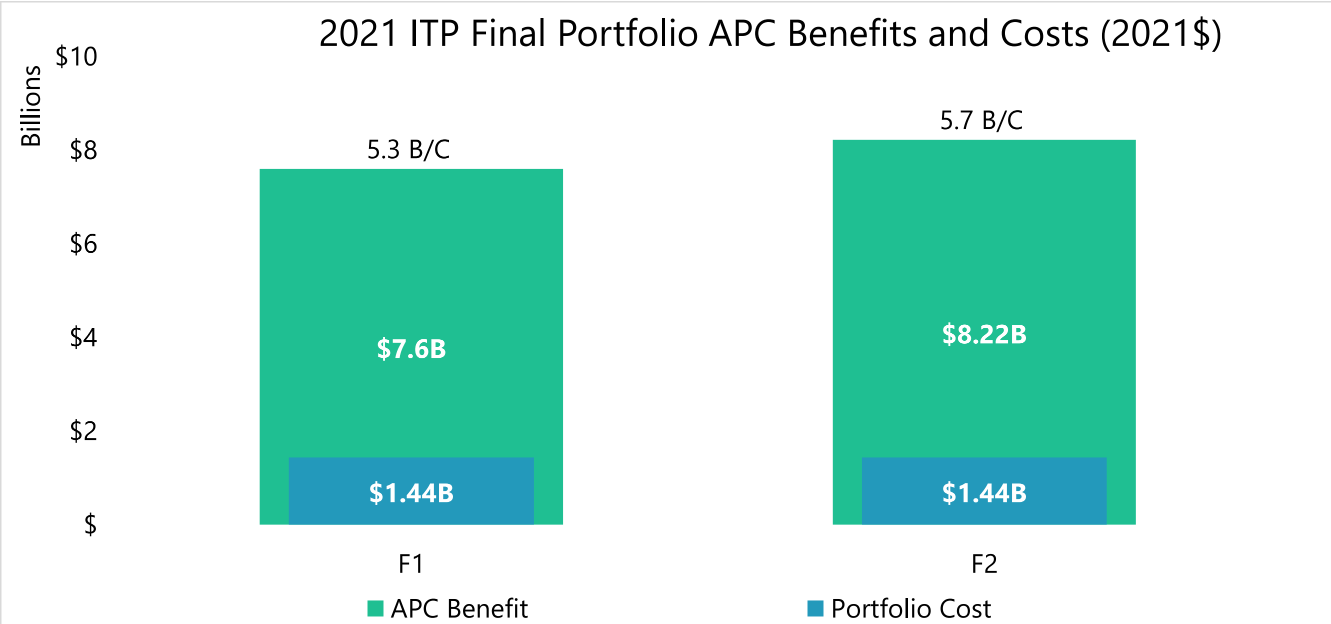

Figure 0.2: 40-Year Adjusted Production Cost Benefit and Cost Ranges

Although the 2021 ITP portfolio is largely reliability driven, the target areas' reliability needs overlap with significant transmission congestion on the system providing an opportunity for substantial APC savings. The recommended portfolio was optimized to ensure reliability can be maintained while simultaneously reducing the end-use customer's energy costs.

SPP assumes a 40-year lifespan for new transmission investments. The break-even year is reflective of the first year that the one-year APC benefits are expected to outweigh the portfolio annual transmission revenue requirement (ATRR). The payback year is reflective of the year that the cumulative APC benefits are expected to exceed the 40-year NPV costs of the portfolio. The consolidated portfolio is expected to breakeven within the first year of being placed in-service and to pay back the total investment within the first 10 years.[1]

[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.

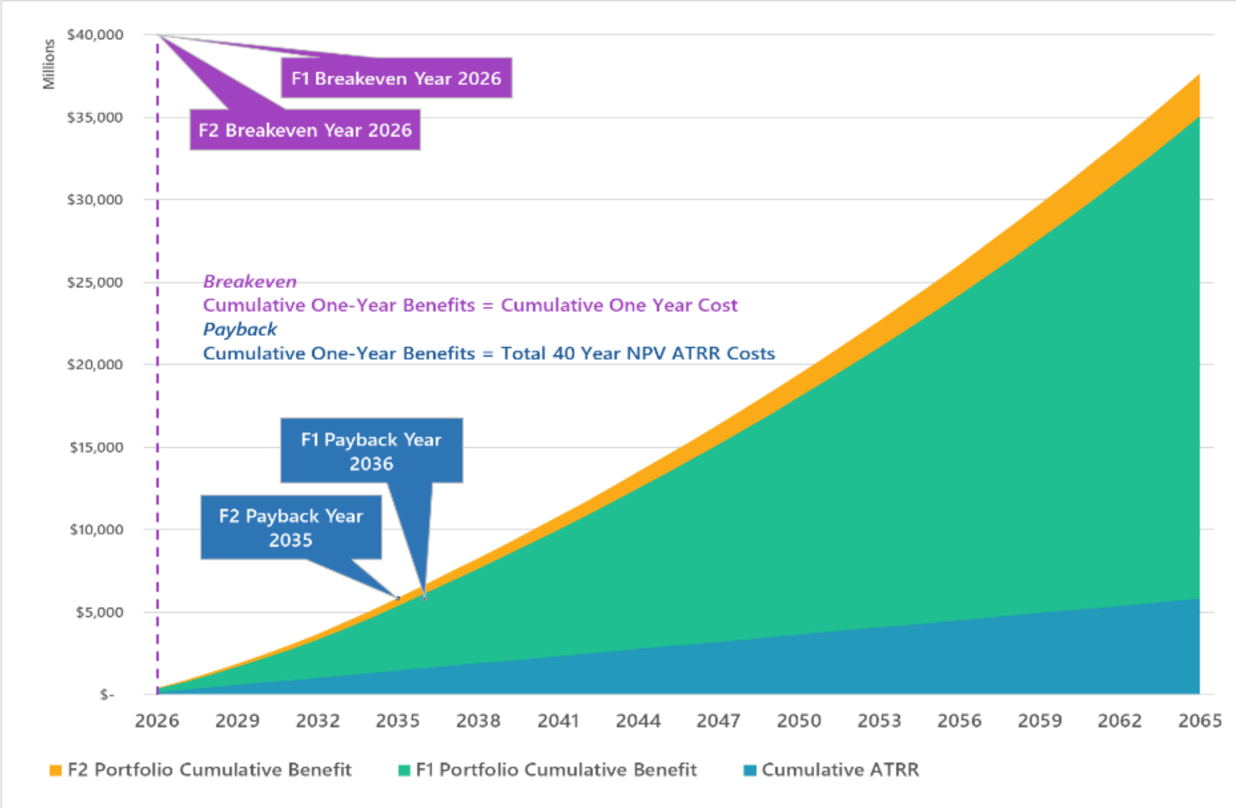

Figure 0.3: Portfolio Breakeven and Payback – APC benefit only

The 2021 ITP includes the following projects:

Project	Area	Type	E & C Cost[2]	Miles	NTC/ NTC-C
Platte City 161 kV switches	EMW	R	$51,502	-	NTC
Blue Circle-Catoosa 69 kV rebuild	AEPW	R	$9,020,000	3.5	NTC
Roswell 115/69 kV transformers circuit 1 and 2 replacement	SPS	R	$4,122,361	-	No
Jones-Lubbock South 230 kV circuit 1 and 2 terminal equipment and increase line clearances	SPS	R	$635,957	-	NTC
Columbus East 230/115 kV transformer replacement	NPPD	E	$4,600,000*	-	NTC
Scottsbluff-Victory Hill 115 kV circuit 2 new line	NPPD	E	$8,870,000	9	NTC

[2] These costs represent engineering and construction (E&C) costs developed during the study period. Those costs were developed by SPP stakeholders or its third-party cost estimator unless noted with an asterisk. Cost estimates with an asterisk (*) are based upon SPP's conceptual cost estimation process using historical information to develop a -50%/+100% cost estimate.

Project	Area	Type	E & C Cost[2]	Miles	NTC/ NTC-C
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase line clearances	WAPA/ BEPC/ EREC/MDU	E	$11,257,083	-	NTC
S3454-S3740 345 kV new line	OPPD	R	$41,684,278	23.3	NTC-C
Replace one breaker at Jarbalo Junction 115 kV	EKC	R	$267,179	-	NTC
Replace two breakers at Shawnee Mission 161 kV	EM	R	$510,150	-	NTC
Replace one breaker at Craig 161 kV	EM	R	$319,002	-	NTC
Moorhead 230 kV substation reconfiguration	MRES	R	$7,935,000*	-	NTC
Powersite-Branson North 161 kV terminal equipment	EMDE	R	$937,800*	-	No
Cleo Corner-Cleo Junction 69 kV terminal equipment	OKGE/ WFEC	E	$168,000	-	NTC
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	BEPC/ MWEC	R/E	$301,043,569	176	NTC-C
Rocky Point-Marietta (OKGE) 138kV rebuild; Marietta (OKGE)-Marietta (WFEC) 138 kV new line	OKGE/ WFEC	R	$18,152,000	16.1	NTC
East New Town 115 kV 150 MVAR STATCOM	BEPC/ MWEC	R/E	$23,000,000	-	NTC-C
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	BEPC/ MWEC	R/E	$34,634,441	4.5	NTC-C
Sioux City 69 kV new breaker CT; Hinton Municipal (K412) 69 kV terminal equipment	NIPCO/ WAPA	R	$746,042*	-	NTC
Gering Tap-Morrill 115 kV rebuild	WAPA-Rocky Mountain Region	R	$17,546,363*	24.2	No
Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie	TSTG/ NPPD	E	$433,392[3]	-	NTC
Joplin West 7th-Stateline 161 kV rebuild	EMDE	R	$5,866,619*	5.5	NTC

[3] The cost estimate was adjusted late in the study process to be $433,392 due to a gap in the study estimate requests received from stakeholders to include NPPD portion. This updated cost estimate is only considered in this executive summary.

Project	Area	Type	E & C Cost[2]	Miles	NTC/ NTC-C
Kummer Ridge-Round Up 345 kV new line	BEPC	R/E	$98,481,715[4]	36	NTC-C
Artesia 115/69 kV transformers circuit 1 and 2 replacement	SPS	R	$5,666,596*	-	No
Midwest-Franklin 138 kV terminal equipment	OKGE/ WFEC	OE	$413,646*	-	NTC Modifi-cation
Quahada 115 kV 100 MVAR synchronous condenser	SPS	R	$27,208,664	-	No
Grassland 115 kV 28.8 MVAR capacitor bank	SPS	R	$2,608,299	-	No
Crossroads-Phantom 345 kV new double-circuit line	SPS	R/E	$409,945,890	150	TBD[5]
Squaw Gap 115 kV 15 MVAR capacitor bank	BEPC	R	$728,280*	-	No
		Total	**$1,036,853,828**		

Table 0.1: 2021 ITP Consolidated Portfolio

[4] This cost estimate also includes the total cost of looping in the existing Patent Gate-Kummer Ridge 345 kV line.
[5] SPP staff recommended issuance of an NTC-C for the Crossroads-Phantom 345 kV line per the narrative outlined in section 8.1.1. The TWG and ESWG approved a motion to not issue an NTC for the Crossroads-Phantom partly due to load forecast uncertainty. The final decision of NTC issuance is determined by the SPP board of directors. The SPP board of directors approved the 2021 ITP recommended plan on January 25, 2022, with the exception of the Crossroads-Phantom project for construction; the SPP board of directors approved further evaluation of the Crossroads-Phantom project with updated information, to be brought back to the MOPC by July 2022.

This map depicts the 2021 ITP thermal/voltage reliability projects:

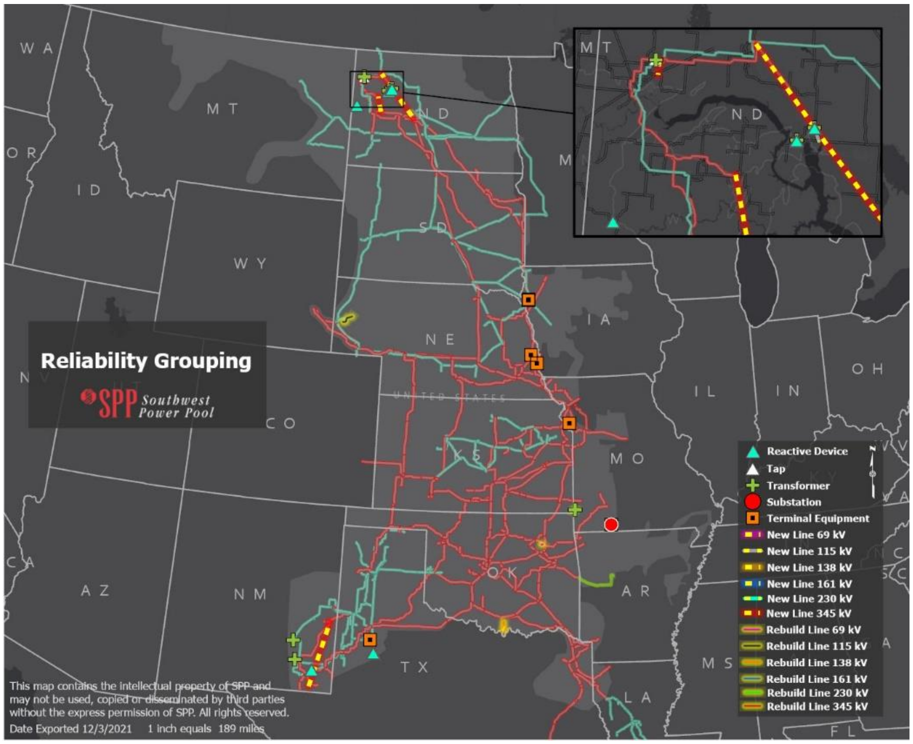

Figure 0.4: 2021 ITP Thermal and Voltage Reliability Projects

This map depicts the 2021 ITP short circuit reliability projects:

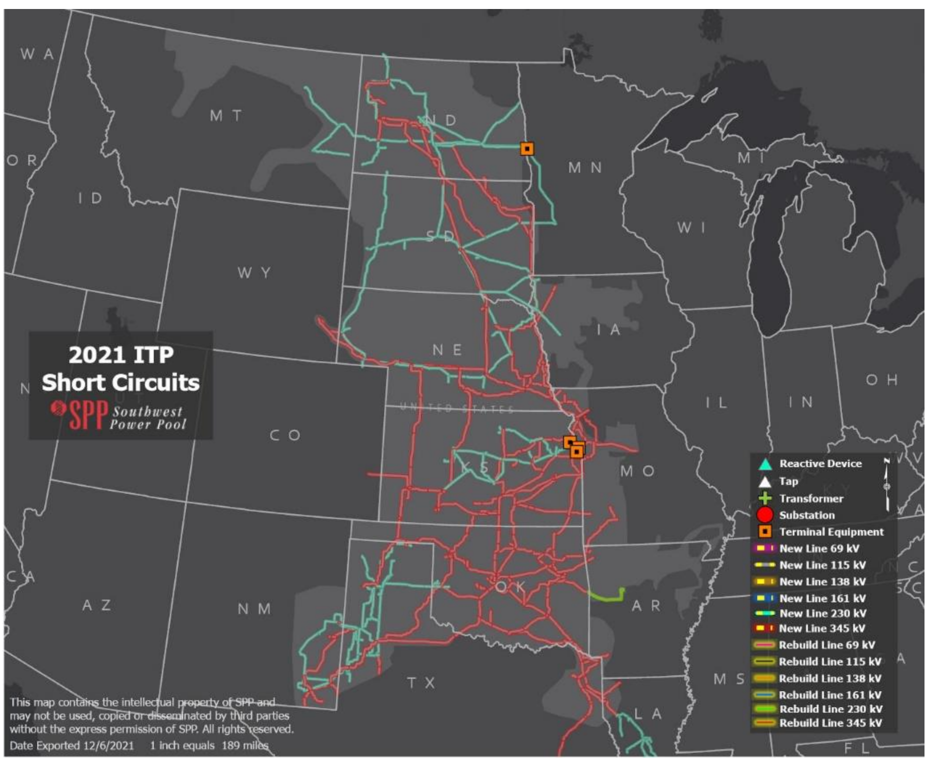

Figure 0.5: 2021 ITP Short Circuit Reliability Projects

This map depicts the 2021 ITP economic projects:

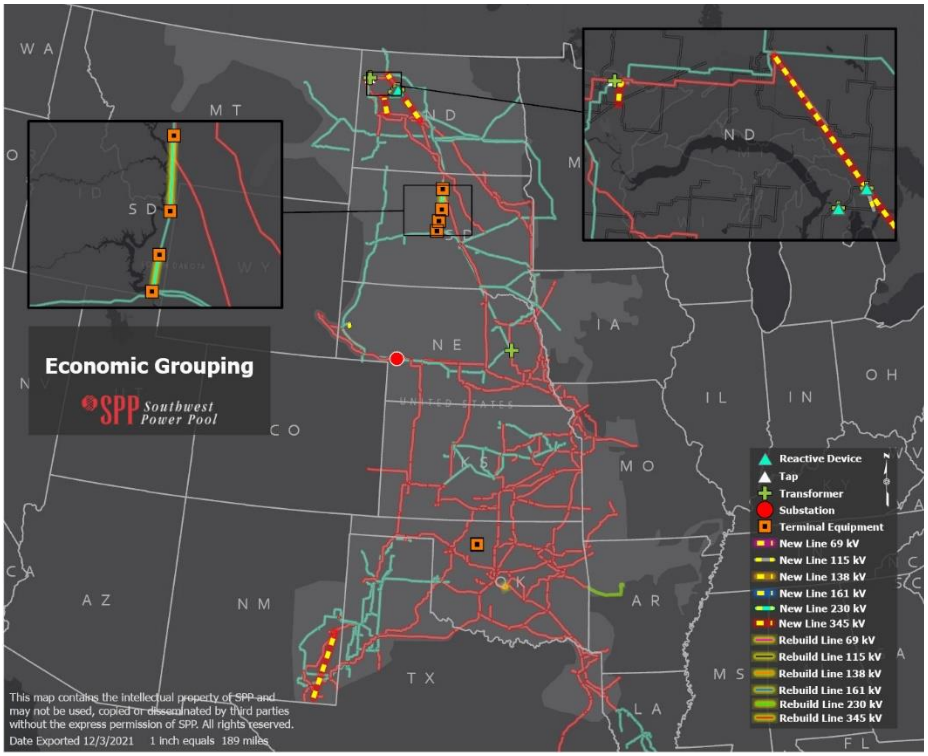

Figure 0.6: 2021 ITP Portfolio-Economic

SPP makes Notification to Construct (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 recommended for an NTC or NTC-C (Notification to Construct with Conditions).

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 2021 ITP is guided by requirements defined in Attachment O to the SPP Open Access Transmission Tariff (Tariff),[6] the ITP Manual,[7] and the 2021 ITP scope.[8]

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.

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[6] https://spp.etariff.biz:8443/viewer/viewer.aspx
[7] ITP Manual version 2.7; 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.
[8] 2021 ITP Scope version 1.1; presents the scope and schedule of work for the 2021 ITP.

1.2 REPORT STRUCTURE

This report describes the 2021 ITP assessment of the SPP transmission system for a 10-year horizon, focusing on years 2023, 2026 and 2031. SPP evaluated these years with a baseline reliability scenario and two future market scenarios (futures). The Model Development and Benchmarking (sections 2 and 3) 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 5 through 8) address specific results, describe projects that merit consideration, and contain portfolio recommendations, benefits and costs.

Within this study, 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 2021 ITP Scope and SPP ITP Manual. All reports and documents referenced in this report are available on the SPP website.[9]

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 2021 ITP assumptions and procedures in meetings throughout 2019, 2020, and 2021. 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)[10]
- Cost Allocation Working Group (CAWG)
- Project Cost Working Group (PCWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)

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[9] 2021 ITP Scope and ITP Manual version 2.7

[10] Formally known as Model Development Working Group (MDWG)

- Regional State Committee (RSC)
- Board of directors (Board)

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 2021 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 September 2021 to elicit further input and provide stakeholders with additional opportunities to participate in the process of discussing and addressing planning topics.[11]

1.4 ITP MITIGATION

The original schedule for the 2021 ITP called for an SPP Board review and approval to occur during the regularly scheduled October 2021 Board meeting. The 2021 ITP encountered many challenges during the study period. As a result, the 2021 ITP scope and associated schedule were adjusted during the study period and were approved at the 2021 April and July MOPC meetings.

The following mitigation measures were implemented to address scheduling challenges while maintaining a high degree of quality work:

- Removal of the market powerflow models (MPM) from the needs assessment
- Increase in the minimum congestion score requirement to be considered an economic need from $50k/megawatt (MW) to $300k/MW
- Waiver of the informational-only benefit metric calculations on the final portfolio
- Waiver of the informational-only sensitivity analysis on the final portfolio
- Extension of the study timeline to complete in December 2021

[11] The 2021 Engineering Planning Summit was held on the afternoon of Monday, September 27, 2021, and the morning of Tuesday, September 28, 2021 (https://www.spp.org/spp-documents-filings/?id=203134)

2 MODEL DEVELOPMENT

2.1 BASE RELIABILITY MODELS

2.1.1 GENERATION AND LOAD

Generation and load data in the 2021 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 Procedure Manual.[12] SPP based renewable dispatch amounts 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

SPP incorporated topology data in the 2021 ITP base reliability models in accordance with the ITP Manual. For items not specified in the ITP Manual, SPP followed the SPP Model Development Procedure Manual. The topology for areas external to SPP was consistent with the 2019 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 retired generation. SPP analyzed this model in consideration of the North American Electric Reliability Corporation (NERC) TPL-001 standard.[13]

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[12] SPP Model Development Procedure Manual; the SPP Model Procedure Manual may differ throughout the study process. The version that was current at the time of the study was used.
[13] NERC Standard TPL-001-4 - Transmission System Planning Performance Requirements

2.2 MARKET ECONOMIC MODEL

2.2.1 MODEL ASSUMPTIONS AND DATA

2.2.1.1 *FUTURES DEVELOPMENT*

Stakeholders determined that the best option was to carry forward the 2020 ITP reference case and emerging technologies framework, with adjustments made to specific assumptions including: fossil fuel retirements and an increase in utility-scale solar, wind and energy storage resource additions.

2.2.1.1.1 FUTURE 1: REFERENCE CASE

The reference case future reflects the continuation of current industry trends and environmental regulations. For years five and 10, 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 subject to review from generator owners. Exceptions will be allowed based on stakeholder review. Long-term industry forecasts will be used for natural gas and coal prices. Solar and wind additions will exceed current renewable portfolio standards due to economics, public appeal, and the anticipation of potential policy changes, as reflected in historical renewable installations. 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 is driven primarily by the assumption that electric vehicles, distributed generation, demand response, and energy efficiency 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 for repowering (life extension) or emissions upgrades, if approved by the ESWG. As in the reference case future, current environmental regulations will be assumed and natural gas and coal prices will use long-term industry forecasts. This future assumes higher solar, wind, and energy storage resource additions than in the reference case due to advances in technology that decrease capital costs and increase energy conversion efficiency.

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

	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

	Drivers				
		Reference Case		Emerging Technologies	
Key Assumptions	**Year 2**	**Year 5**	**Year 10**	**Year 5**	**Year 10**
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 review		Coal age-based 52+, Gas/Oil age-based 48+, subject to repowering or emissions upgrades	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[14]	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		35% of projected solar	
Total Renewable Capacity					
Solar (GW)	Existing + RARs	6	9	7	11
Wind (GW)	Existing + RARs	29	32	33	37

Table 2.1: Future Drivers

2.2.1.2 *LOAD AND ENERGY FORECASTS*

The 2021 ITP load review focused on load data through 2031. SPP derived the load data from the base reliability model set, and stakeholders were asked to identify/update the following parameters:

- Assignment of loads to companies
- Forecast system peak load (MW)
- Loss factors
- Load factors
- Load demand group assignments
- Monthly peak and energy allocations
- Station service loads
- Resource planning peak loads and load factors

The ESWG and TWG approved the load review used to update the load information in the market economic models. Figure 2.1 shows the total coincident peak load for all study years. **Error! Reference source not found.**Figure 2.2 shows the monthly energy per future for all study years (2023, 2026, and 2031).

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

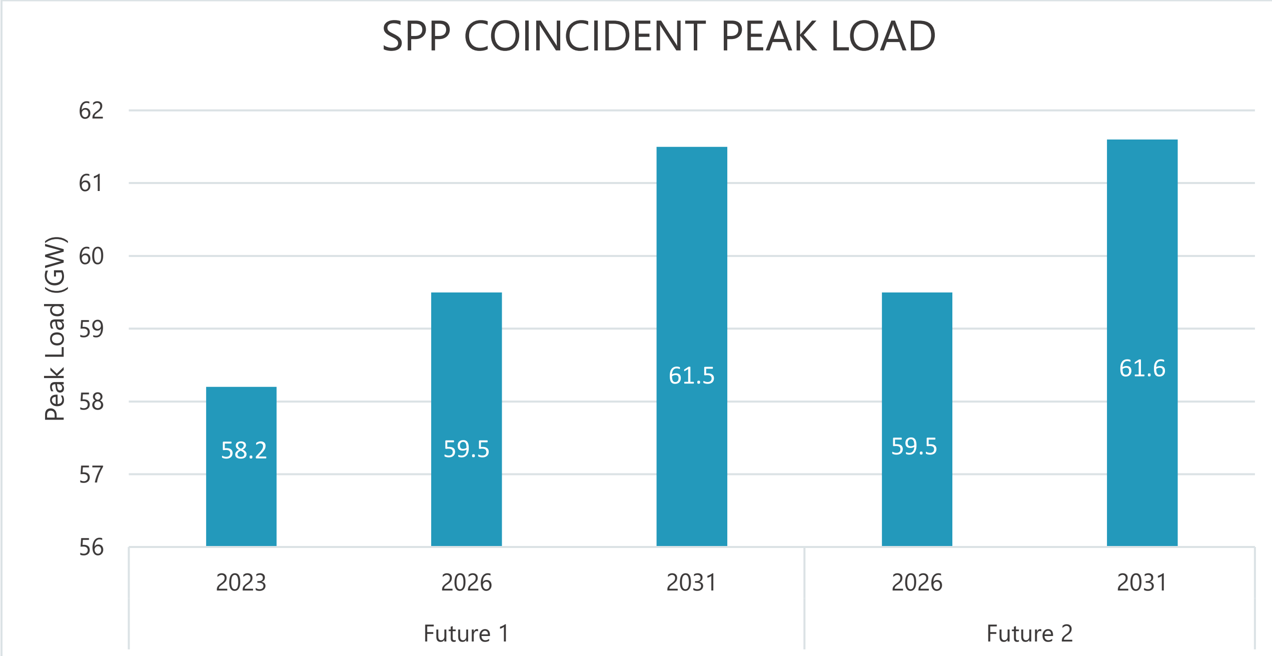

Figure 2.1: 2021 Coincident Peak Load

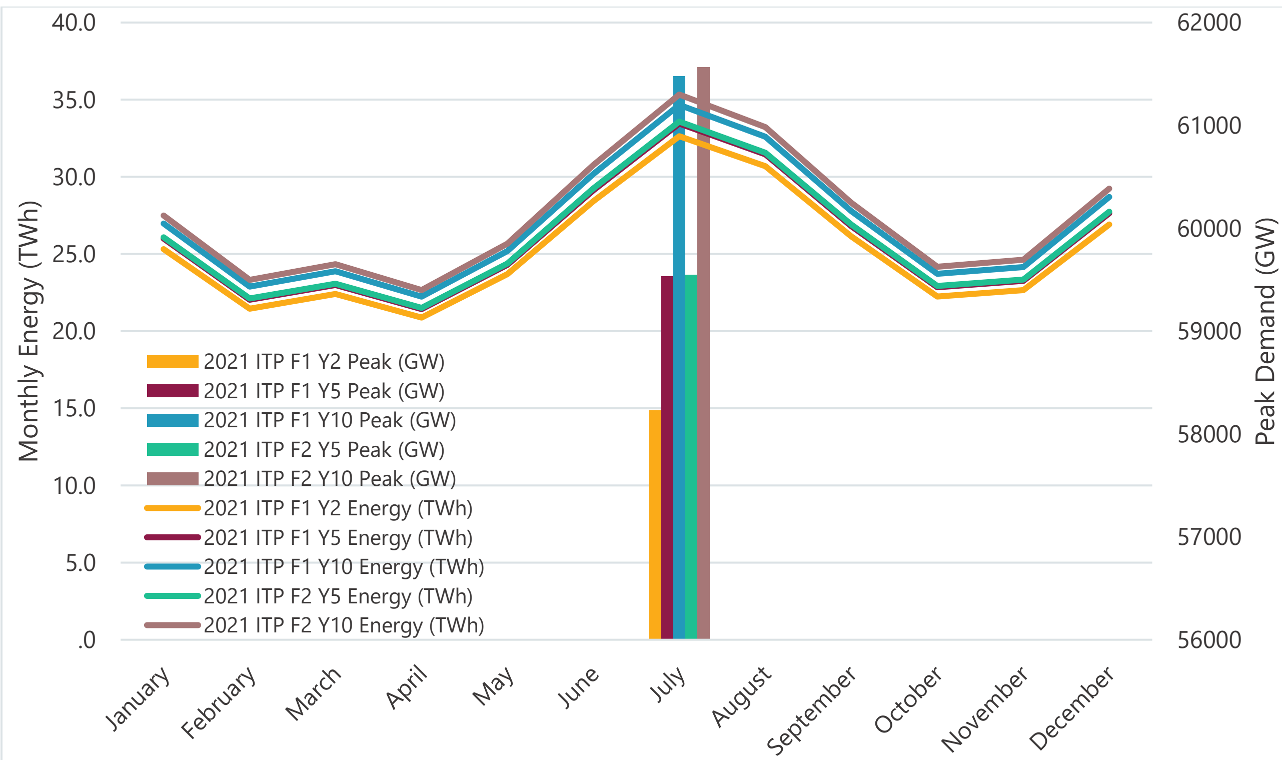

Figure 2.2: 2021 ITP Annual Energy

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 ITP Manual[15] defines and outlines these requirements as percentages. Deviations to the renewable policy standards (RPS) table were approved by CAWG and ESWG for Minnesota and New Mexico. The Minnesota mandate percentage deviated slightly for either wind or solar to increase to 25% in year five.[16] The New Mexico Legislature passed a significant mandate percentage deviation for wind or solar to increase to 40% in year five and 50% in year 10.[17] The 2021 ITP RPR focused on renewable requirements through 2031.

2.2.1.4 *GENERATION RESOURCES*

Existing generation data originated from the ABB Simulation Ready Data Fall 2019 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 2023, 2026 and 2031 for Future 1, and 2026 and 2031 for Future 2.

One set of resources was accepted in the base reliability models. Stakeholders were also able to request additional generation resources in the ITP models through the Resource Addition Request (RAR) process.[18] As a result of the RAR process, 4.5 GW of wind generation was added to the market economic models, all of which was included in the year-two model.

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

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[15] ITP Manual version 2.7: https://www.spp.org/documents/66203/itp%20manual%20version%202.7.pdf
[16] Enabling Statute: Minn. Stat. § 216B.1691
[17] Enabling Statutes: N.M. Stat. Ann. §§ 62-16-1 to -10, 62-15-34 to -37, 74-2-5
[18] See ITP Manual version 2.7, section 2.2.2.1

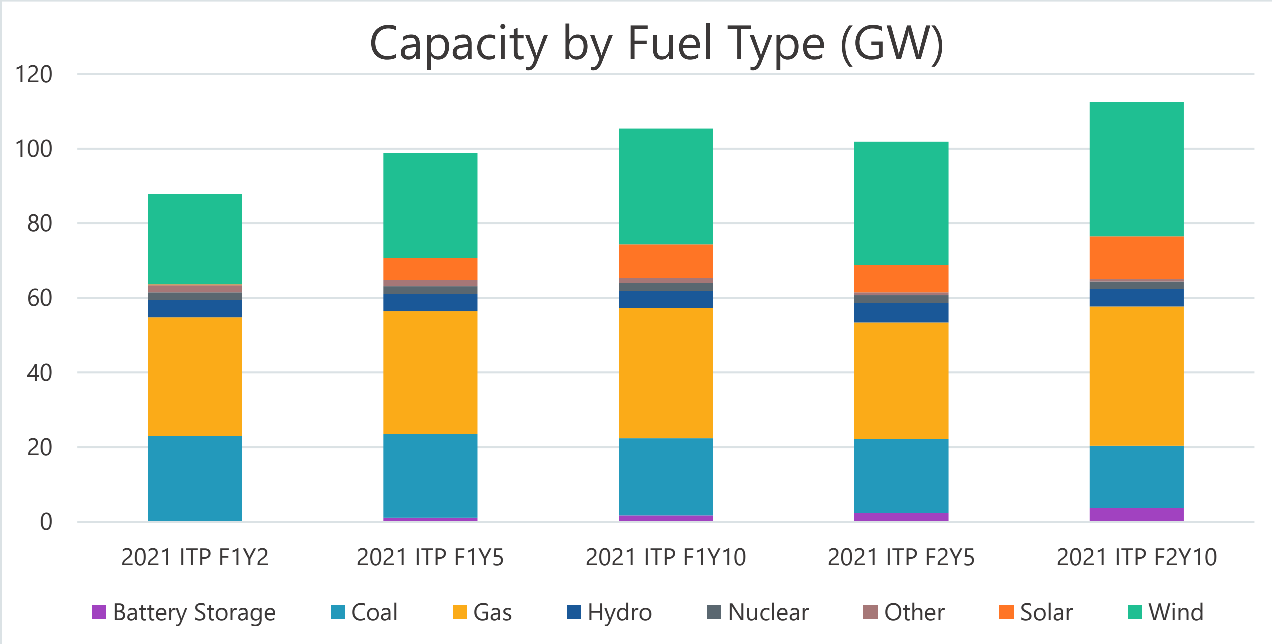


Figure 2.3: Capacity by Fuel Type (GW)

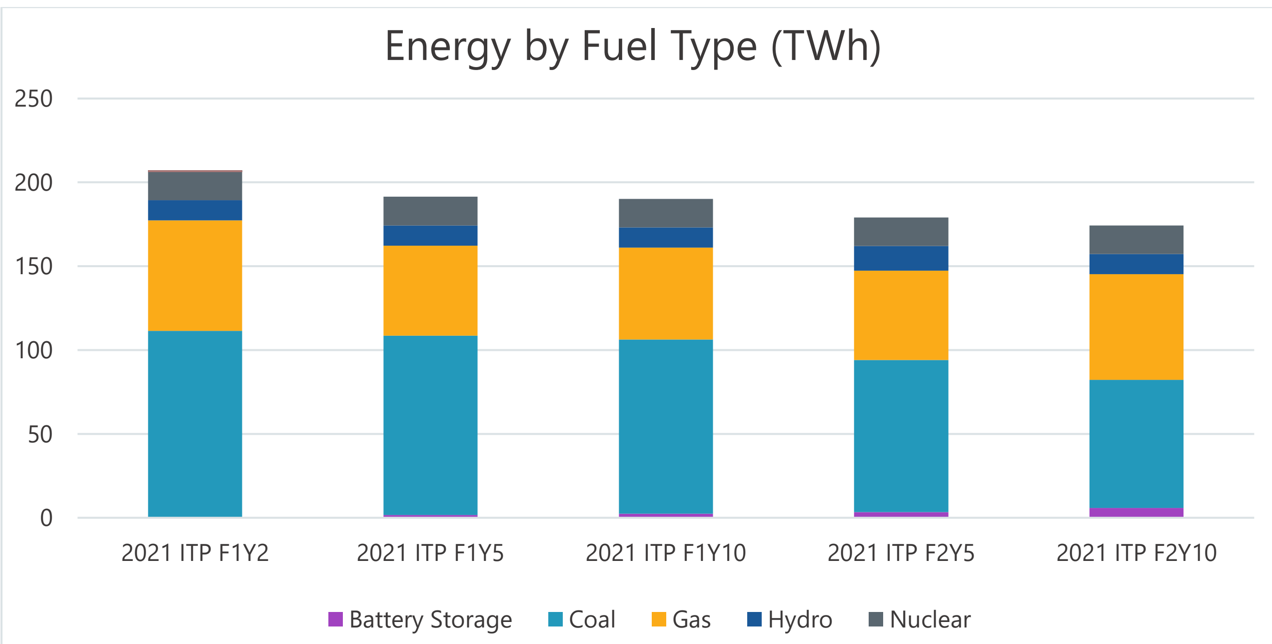


Figure 2.4: Energy by Fuel Type in terawatt hours (TWh)

Figure 2.5 identifies 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.

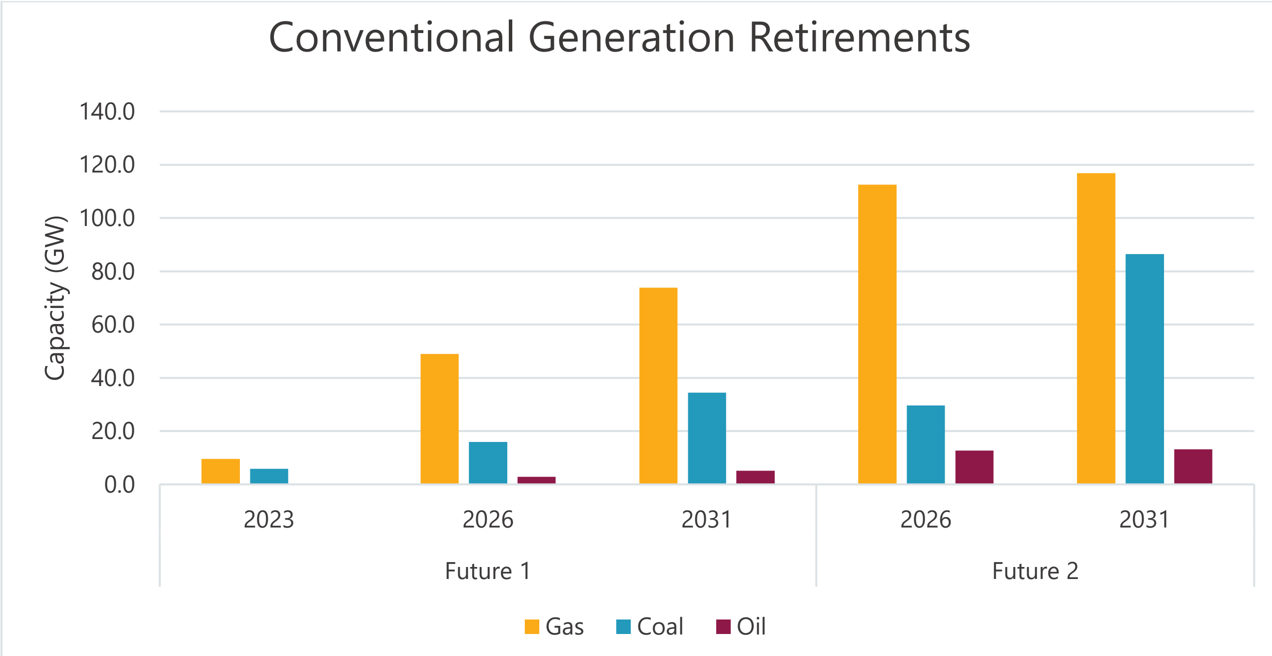


Figure 2.5: Conventional Generation Retirements

2.2.1.5 *FUEL PRICES*

The ABB Simulation Ready Data Fall 2018 Reference Case, ABB fundamental forecast (for long-term natural gas price projections), and Wood Mackenzie fundamental forecast (for long-term natural gas prices projections) were utilized for the fuel price forecasts. SPP averaged the ABB and Wood Mackenzie fundamental forecasts for the average natural gas prices. Figure 2.6 shows the annual average natural gas and coal prices for the study horizon. Between 2021 and 2030, these prices increase from $2.64 to

$4.27 (~5.0% compound average escalation) and $2.27 to $2.71 (~1.8 compound average escalation) for natural gas and coal, respectively.

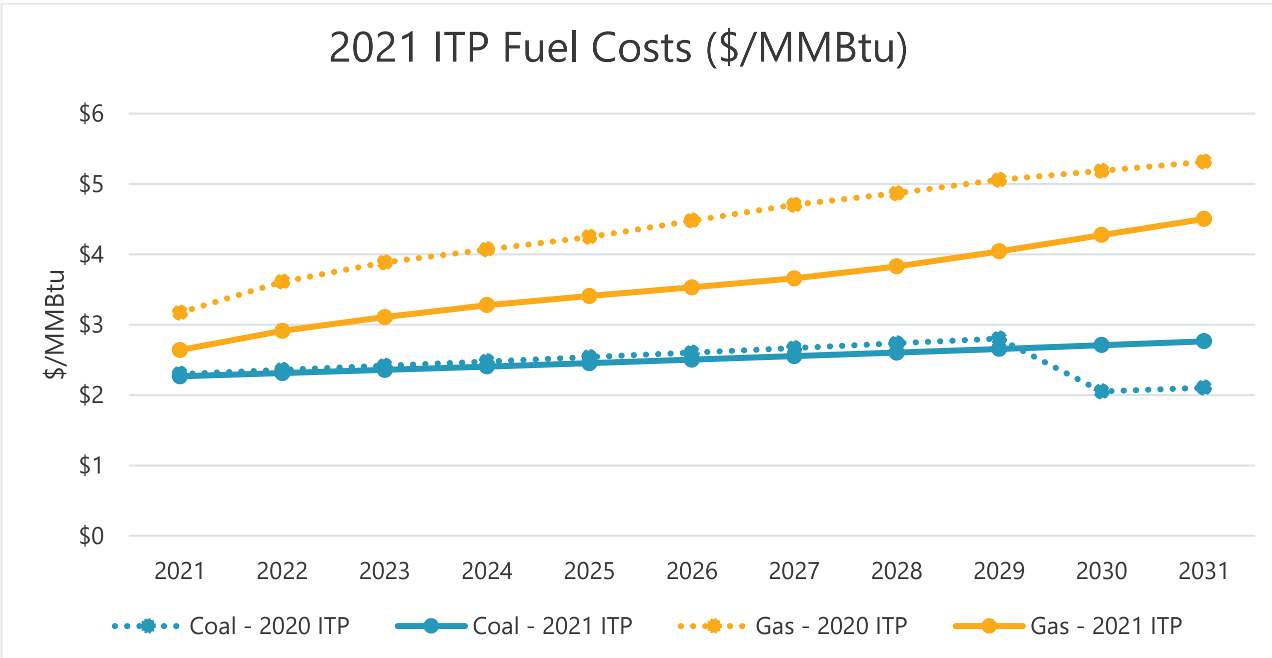


Figure 2.6: ABB Fuel Annual Average Fuel Price Forecast

2.2.2 RESOURCE PLAN

In order to evaluate transmission for a 10-year horizon, a key component begins with 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 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 2026 and 2031. If the analysis projected a utility would be unable to meet requirements, additional resources were assigned to the utilities from the total projected renewable amounts to meet renewable portfolio standards. For states with a standard that could be met by either wind or solar generation, a ratio of 70% wind additions to 30% 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 2031 were 1,143.7 MW in Future 1 and 1,178.5 MW in Future 2.

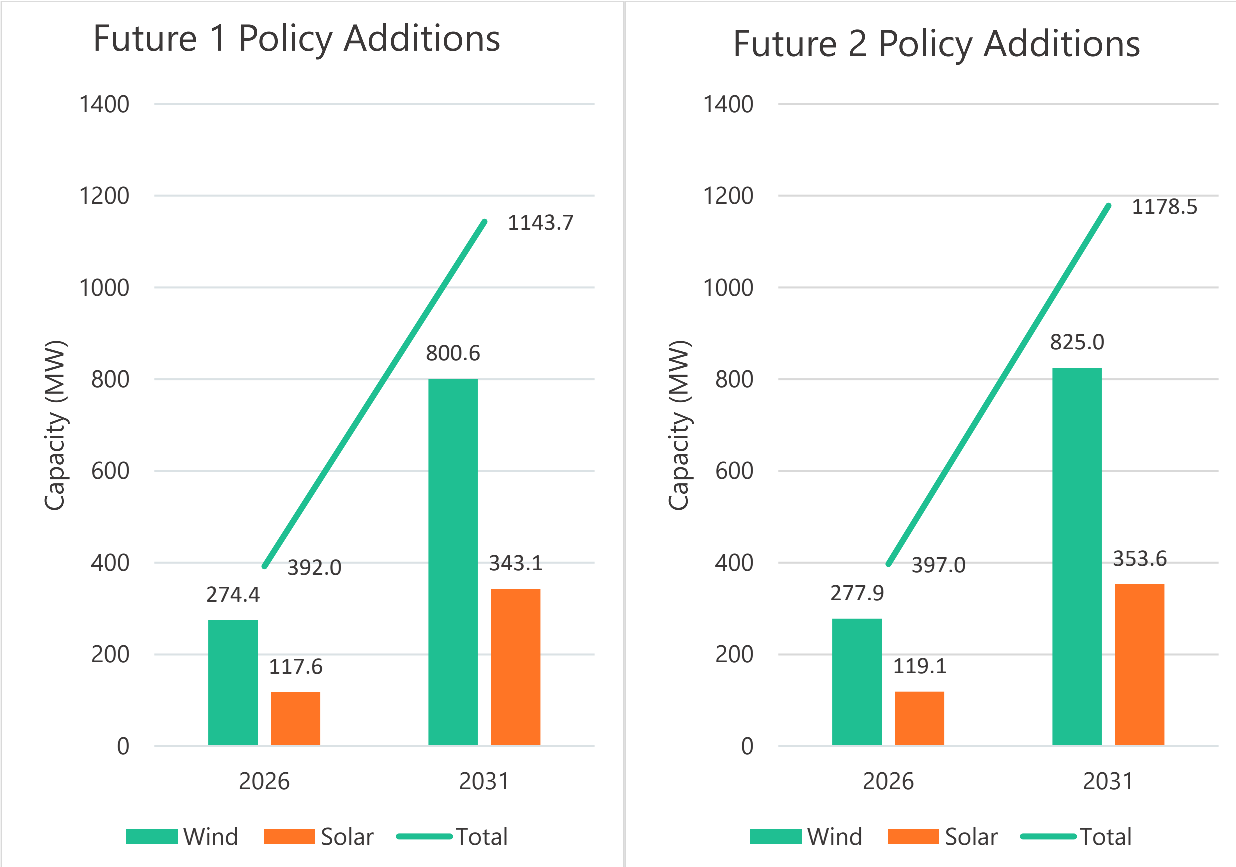


Figure 2.7: SPP Renewable Generation Assignments to meet Mandates and Goals

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, up to the 12% zonal renewable cap defined in the study scope. 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[19] 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 2026 and 2031 of both futures.

Nameplate conventional generation capacity assigned to pricing zones was counted toward each zone's capacity margin requirement. Existing wind and solar capacity, being intermittent resources, were included at a percentage of nameplate capacity, in accordance with the calculations in SPP Planning Criteria 7.1.6.

For the 2021 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's third party analysis, considering the defined values from the 2021 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 amounts, in MW, are shown below in Table 2.2.

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	29.000	4,158	32,000	4,323	33,000	4,540	37,000	4,753
Solar	6,000	3.624	9,000	4.995	7,000	4,130	11.000	5.346
Energy Storage	1,200	1,169	1,800	1,708	2,450	2,256	3,850	3,302

Table 2.2: 2021 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 megawatt 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

[19] SPP Planning Criteria

U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2019.[20] These resource prototypes define operating parameters of specific generation technologies to determine the optimal generation mix to add to the region. For the 2021 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 three exception requests to replace CT additions with a CC shown in the Table 2.3 below.

Area	Quantity of Exception Requests			
	F1 Y5	F1 Y10	F2 Y5	F2 Y10
SPS	1		1	
AEP		1		1
OGE		1	1	

Table 2.3: Exception Requests Granted

While both futures represent normal load growth, more resource additions are needed in Future 2 due primarily 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	227.5	944	3638	1,951.3
GRDA				
OKGE		1,939.4	1,567.3	
SPS	953.5		754	590.1
WFEC				
KACY				
SPRM				47.4

[20] EIA Annual Energy Outlook 2019 Report

Zone	Conventional Generation Additions			
	F1 Y5	F1 Y10	F2 Y5	F2 Y10
EMDE	90.1	71.1	64	59.3
GMO	374.5	189.6	350.8	177.8
KCPL			154.1	260.7
MIDW				
MKEC	260.7		260.7	
SUNC	213.3		118.5	71.1
WERE	237	876.9	431.3	983.6
LES				
NPPD				414.8
OPPD	459.8		651.8	699.2
UMZ	1,445.7	711	1,244.3	1,019.1

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

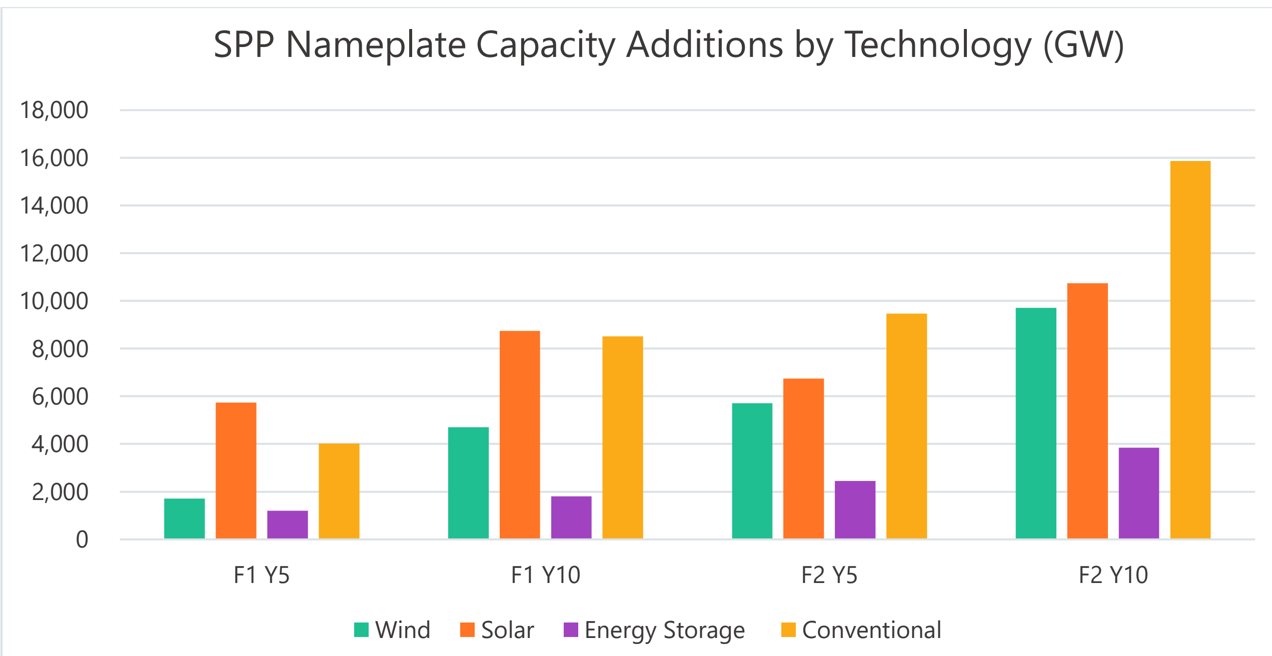


Figure 2.8: SPP Nameplate Capacity Additions by Technology (GW)

Figure 2.9 shows accredited generation additions by future, study year, and technology for the SPP region.

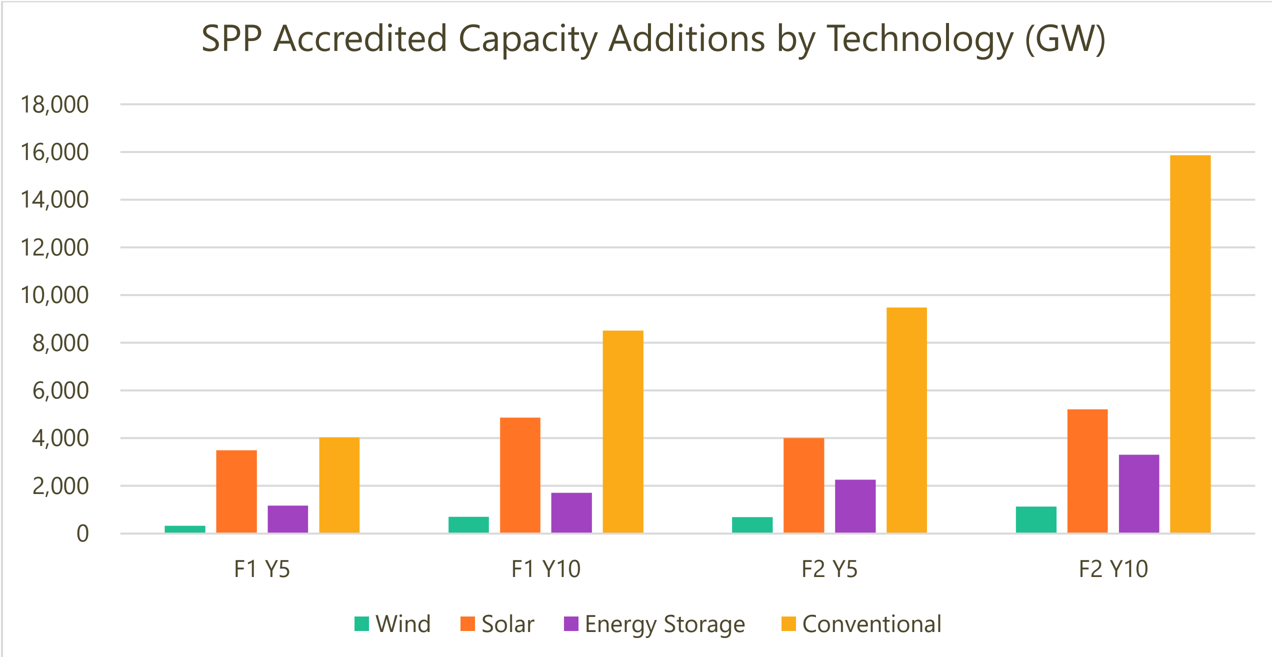


Figure 2.9: Accredited Capacity Additions by Technology

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.[21]

Distributed solar generation, an assumption in Future 2 only, was allocated to the top 10% of load buses for each load area on a pro rata basis utilizing load review data. SPP considered SPP stakeholder feedback in the selection of sites for this technology. Figure 2.10 and Figure 2.11 show the selected sites and allocation of distributed solar capacity across the SPP footprint in megawatts.

[21] Documented in the ITP Resource Siting Manual

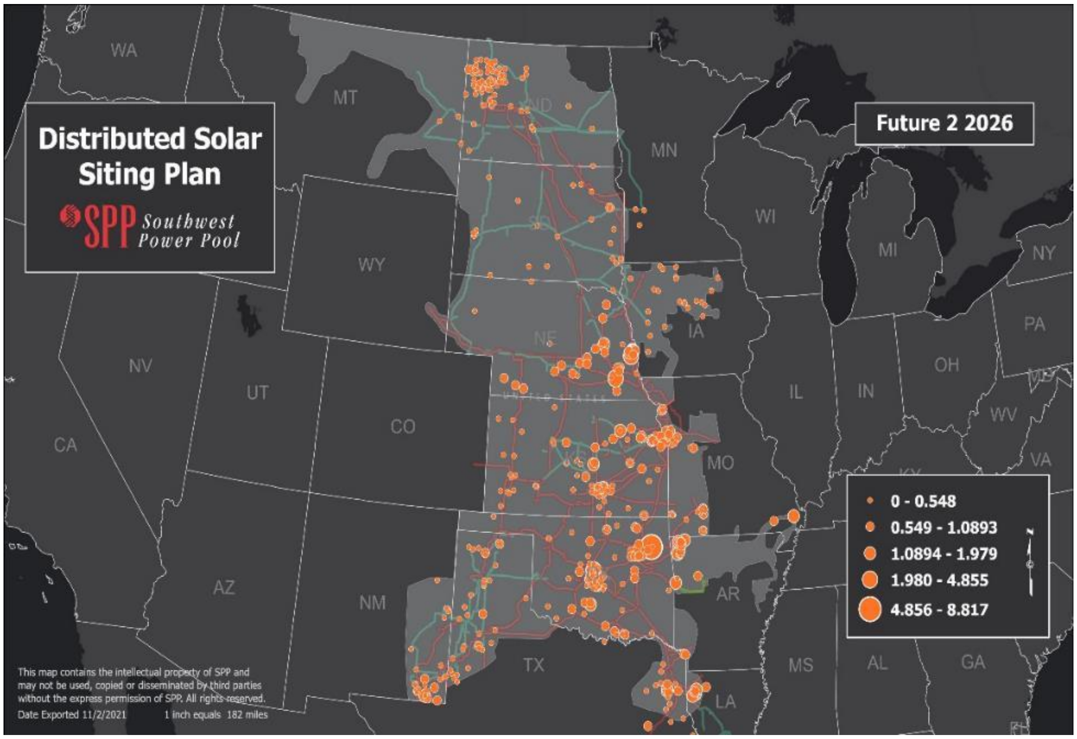


Figure 2.10: 2026 Future 2 Distributed Solar Siting Plan

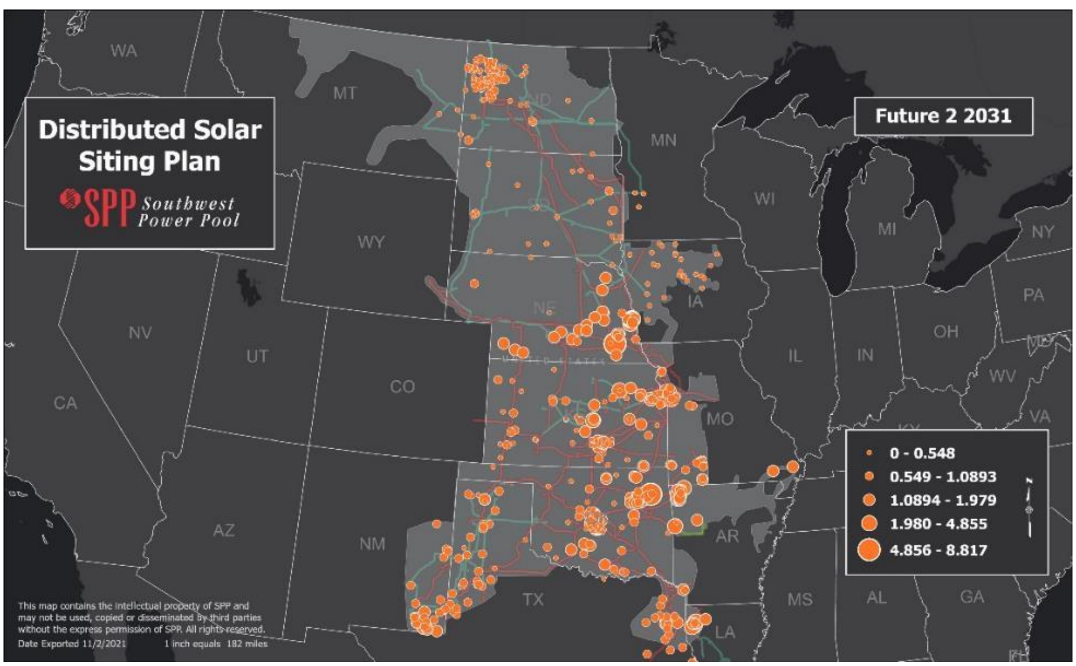


Figure 2.11: 2031 Future 2 Distributed Solar Siting Plan

Utility-scale solar was sited according to:

- Ownership by zone or by state
- 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 2.12 through Figure 2.15 show the selected sited and allocation of utility solar capacity across the SPP footprint in megawatts.

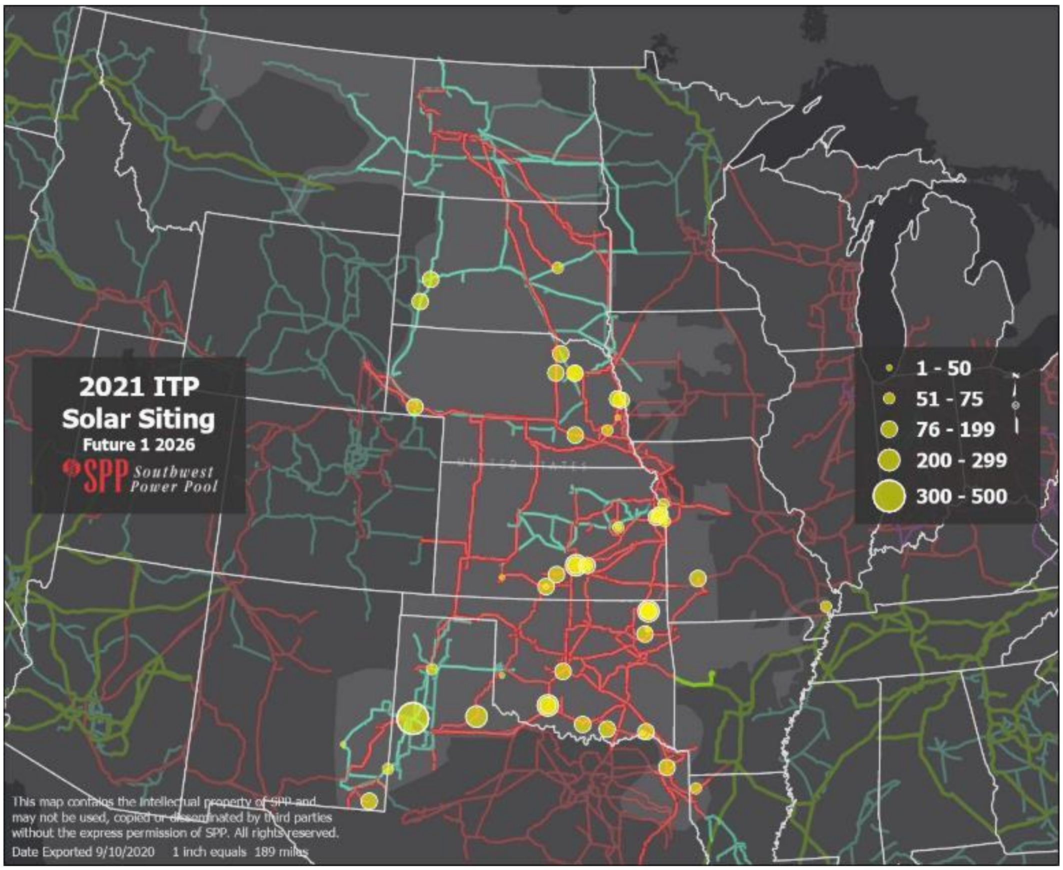


Figure 2.12: 2026 Future 1 Utility-Scale Solar Siting Plan

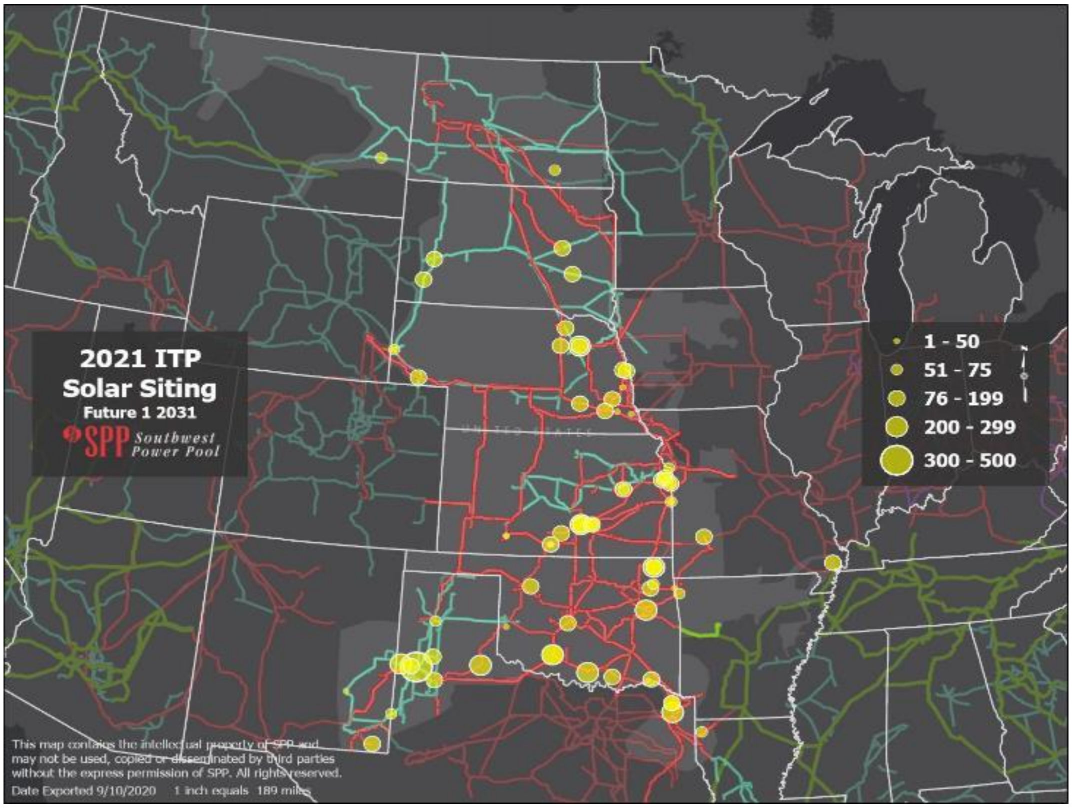


Figure 2.13: 2031 Future 1 Utility-Scale Solar Siting Plan

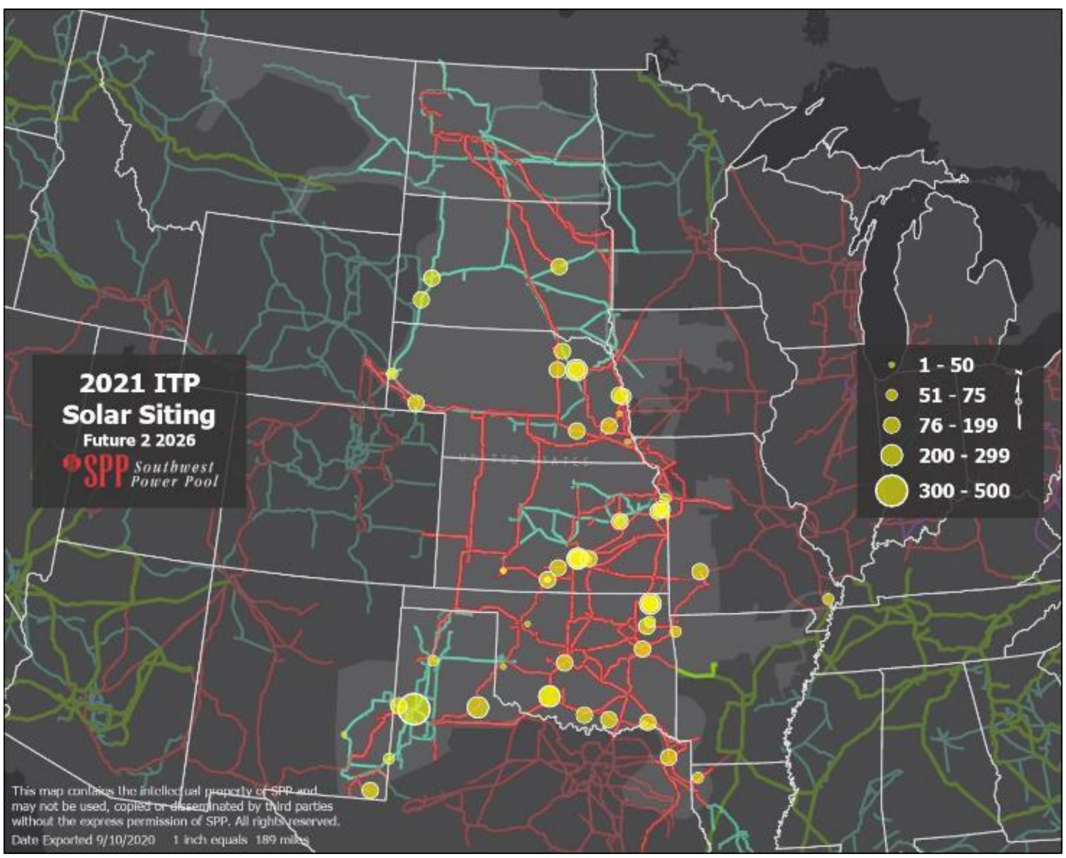


Figure 2.14: 2026 Future 2 Utility-Scale Solar Siting Plan

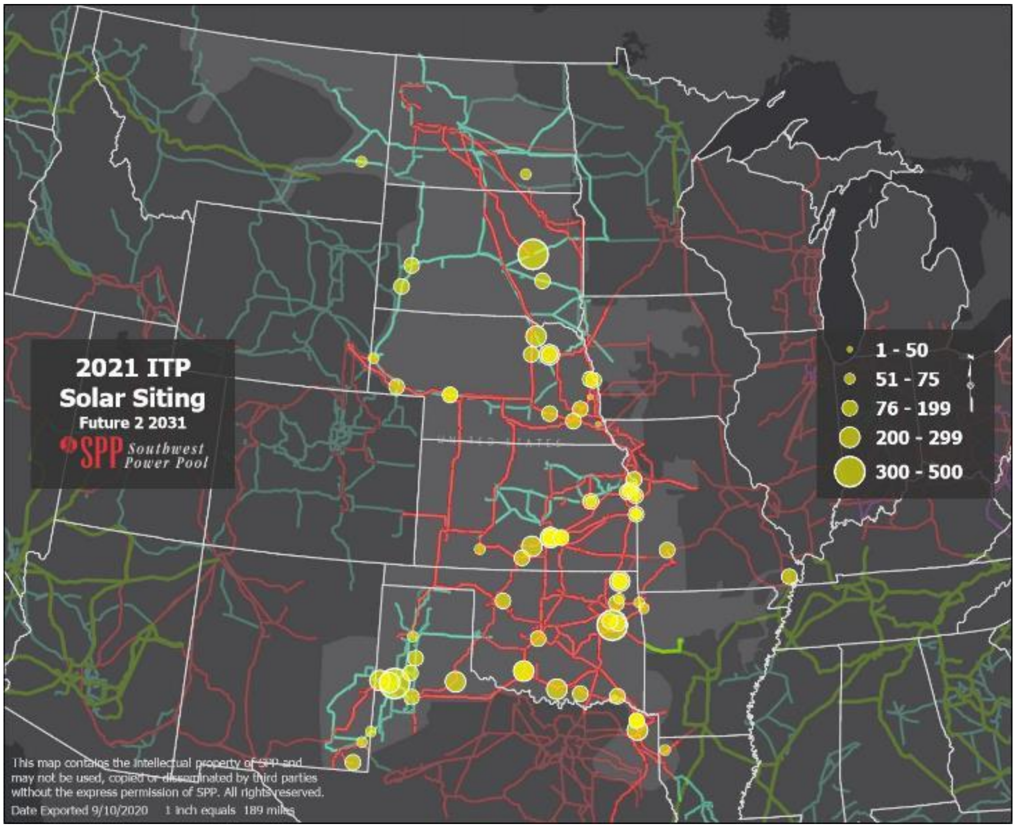


Figure 2.15: 2031 Future 2 Utility-Scale Solar Siting Plan

Wind sites were selected from GI queue requests that required the lowest total interconnection cost[22] per megawatt 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 2.16 through Figure 2.19 show the selected siting and allocation of wind capacity across the SPP footprint in megawatts.

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

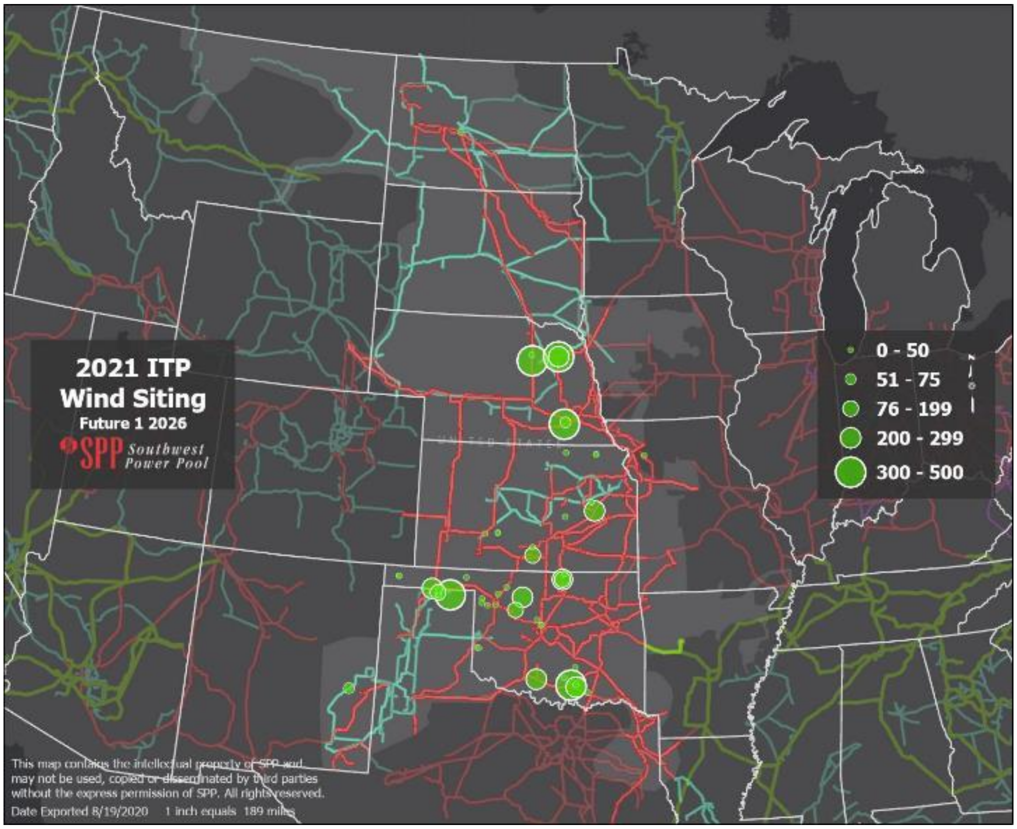


Figure 2.16: 2026 Future 1 Wind Siting Plan

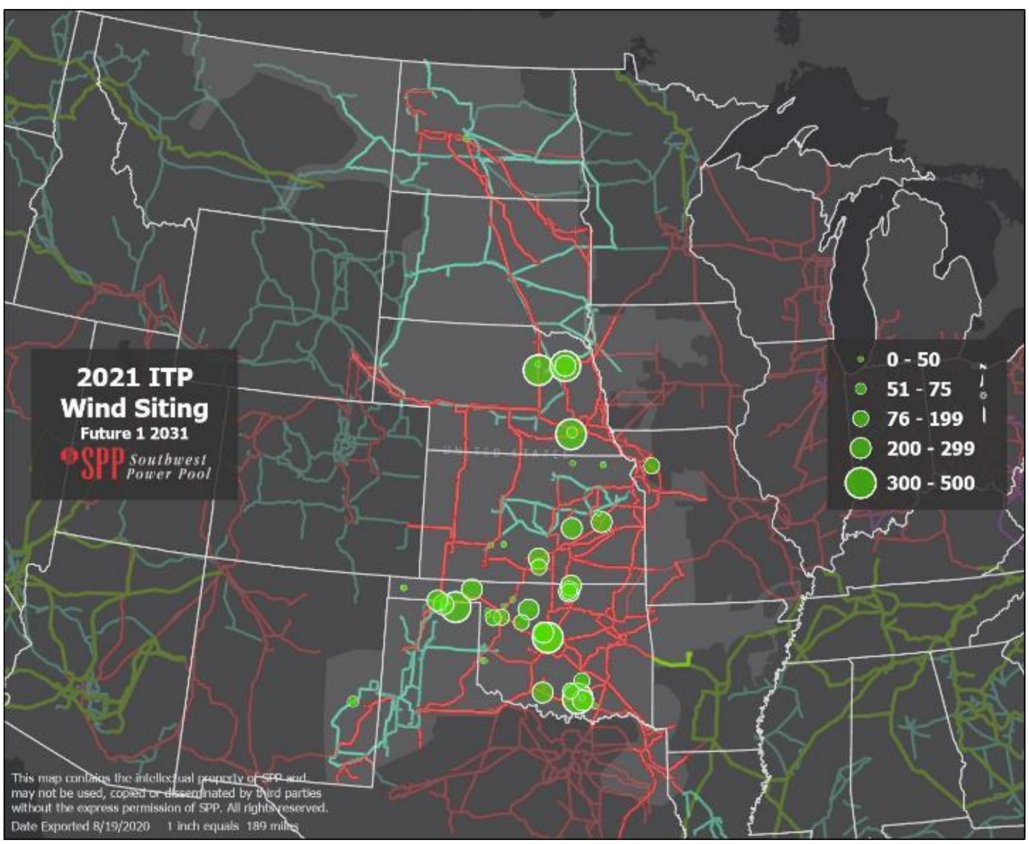


Figure 2.17: 2031 Future 1 Wind Siting Plan

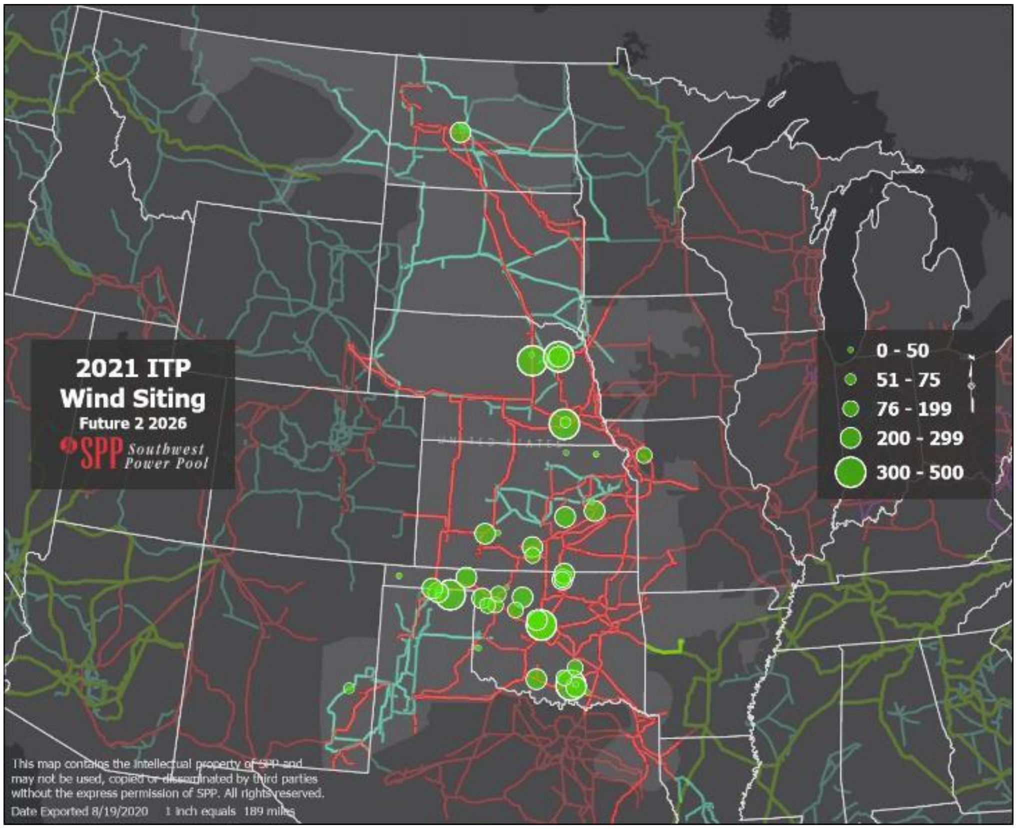


Figure 2.18: 2026 Future 2 Wind Siting Plan

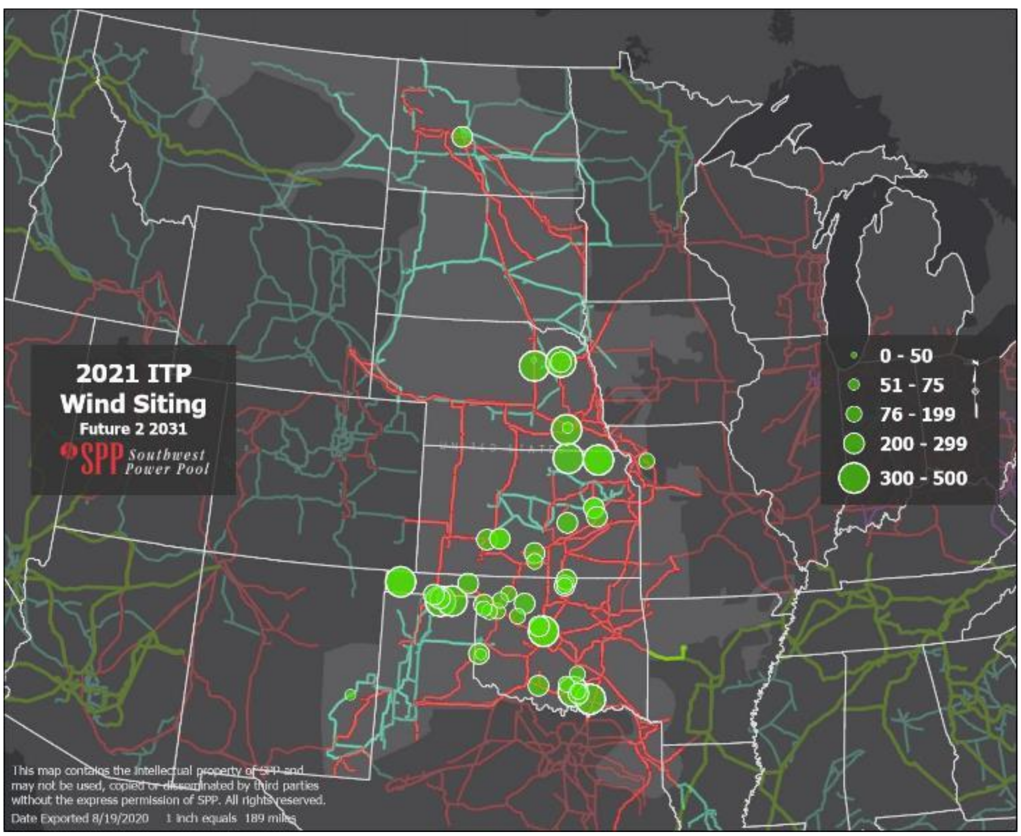


Figure 2.19: 2031 Future 2 Wind Siting Plan

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 2.20 through Figure 2.23 show the selected sites for conventional generation across the SPP footprint.

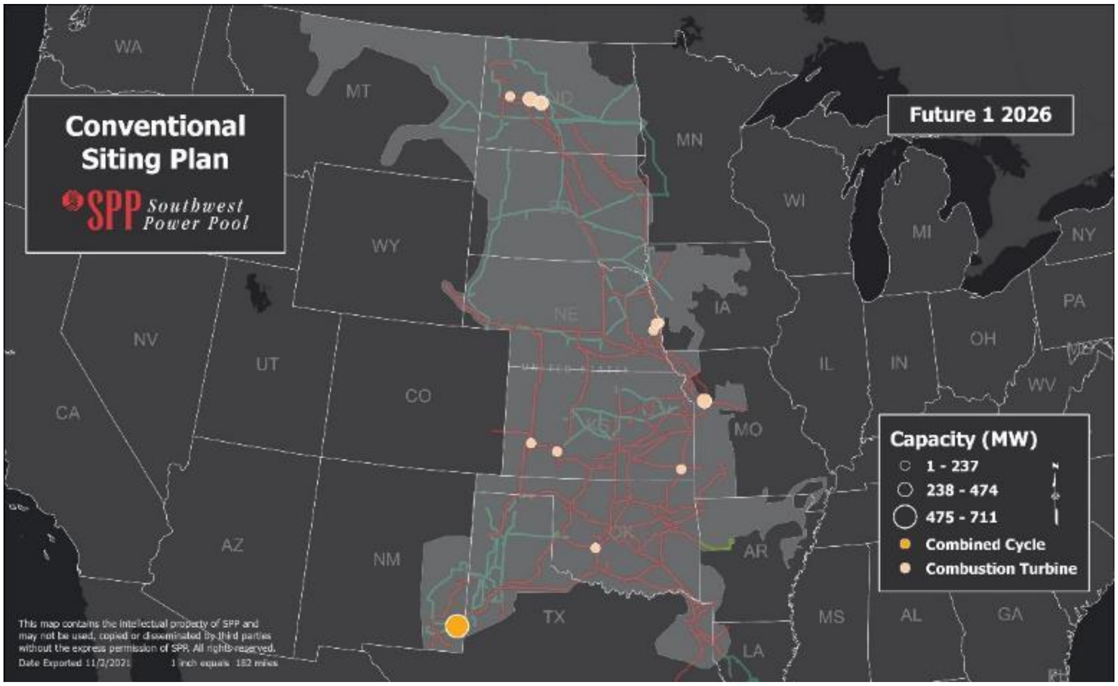


Figure 2.20: 2026 Future 1 Conventional Siting Plan

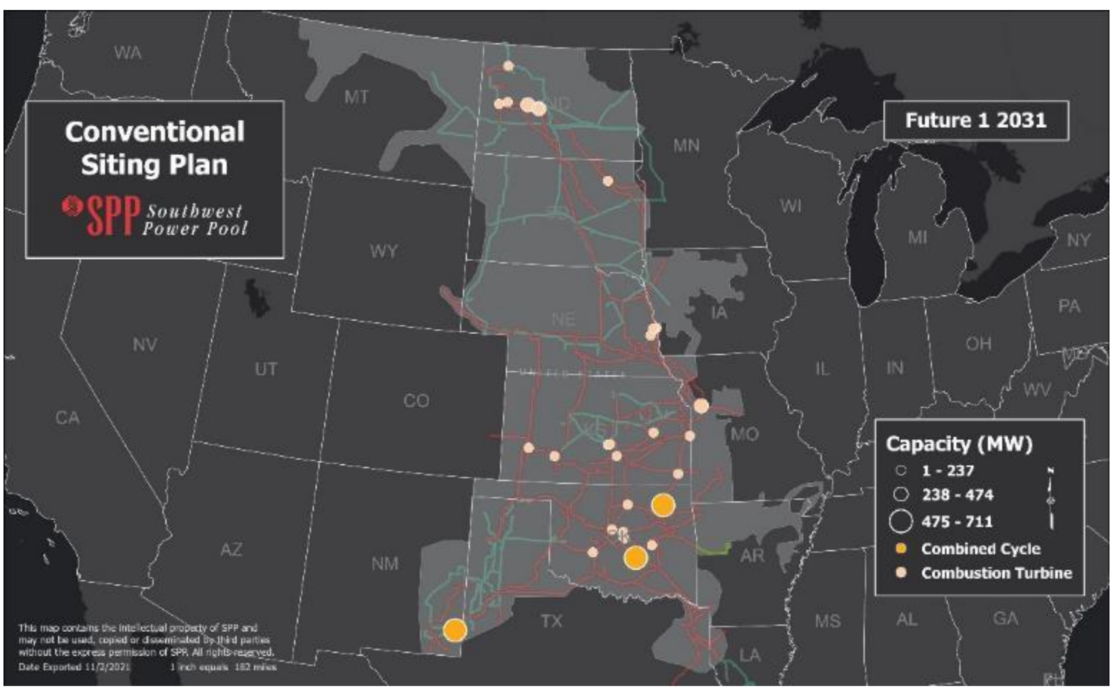


Figure 2.21: 2031 Future 1 Conventional Siting Plan

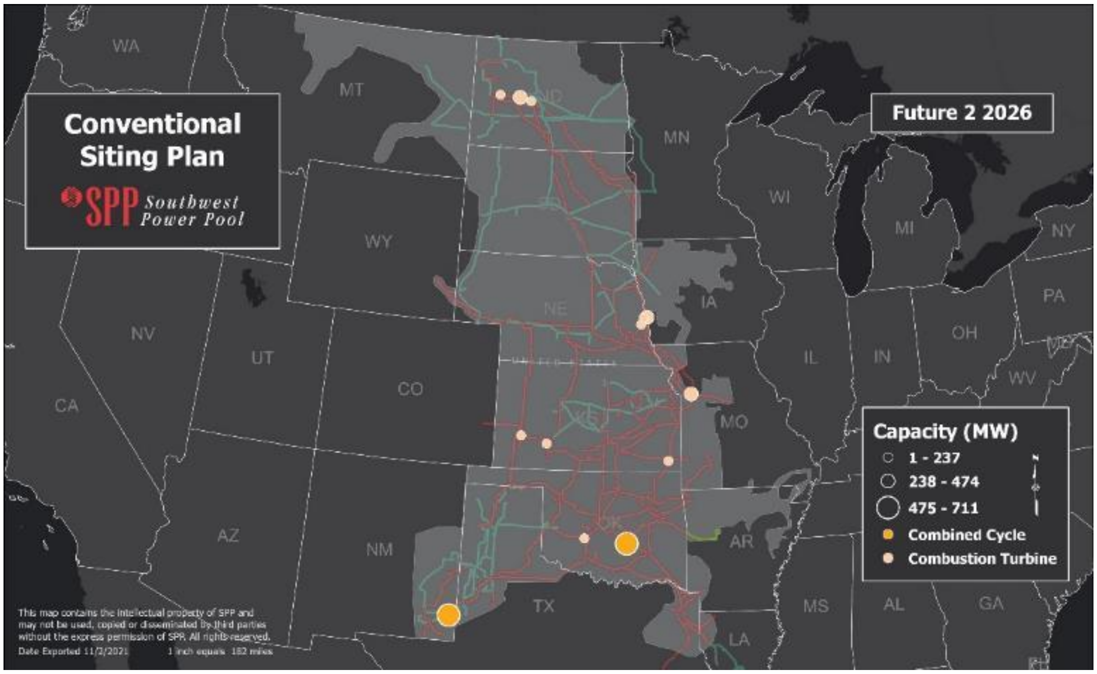


Figure 2.22: 2026 Future 2 Conventional Siting Plan

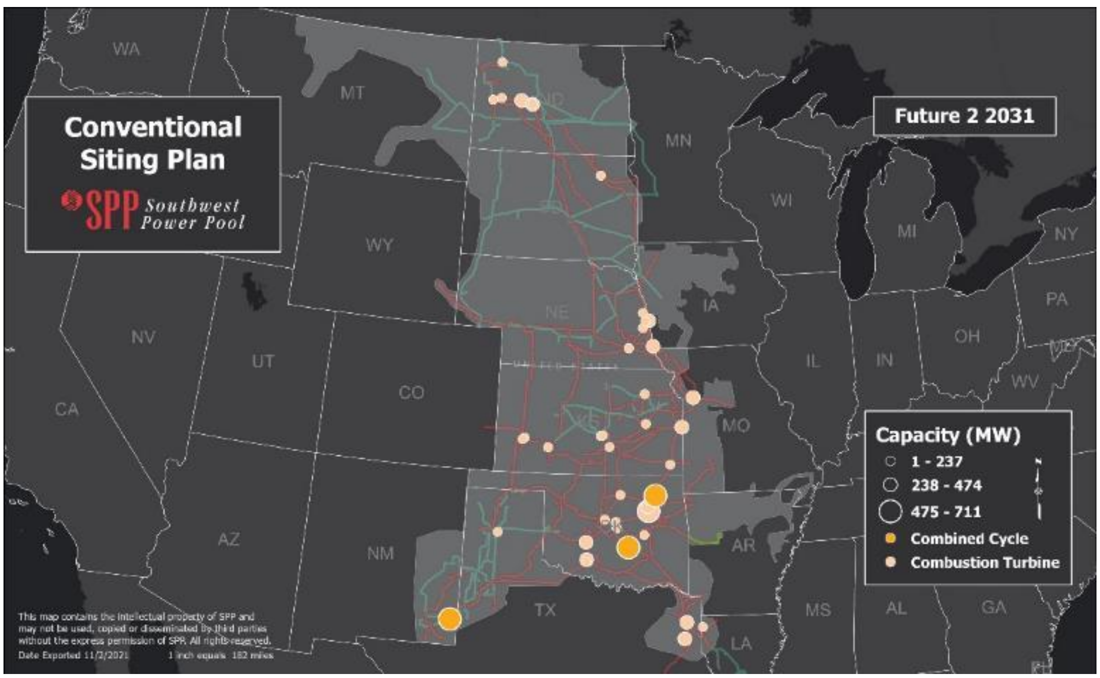


Figure 2.23: 2031 Future 2 Conventional Siting Plan

Battery sites were based on battery storage GI queue requests, the assumption that battery storage will largely be co-located with wind and solar, and transfer capability at available sites with consideration of the solar and wind siting plans. The siting of resources related to battery requests in the GI queue was limited to two-thirds of projected capacity due to the infancy of the technology in the industry. Two-thirds of projected battery capacity was associated with solar sites; one-third was associated with wind sites. 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 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 2.24 through Figure 2.27 show the selected sites for battery generation across the SPP footprint.

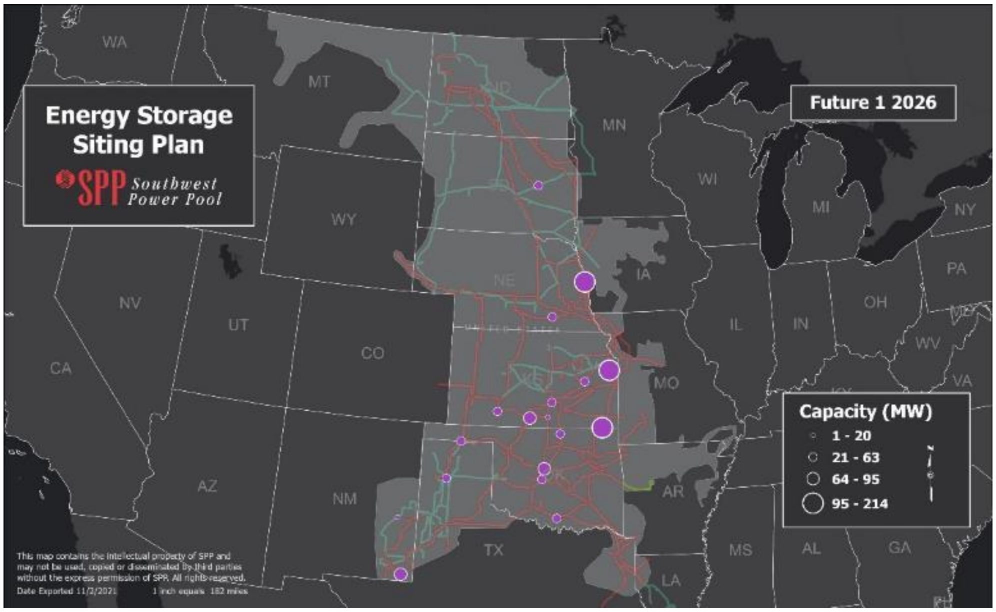


Figure 2.24: 2026 Future 1 Energy Storage Siting Plan

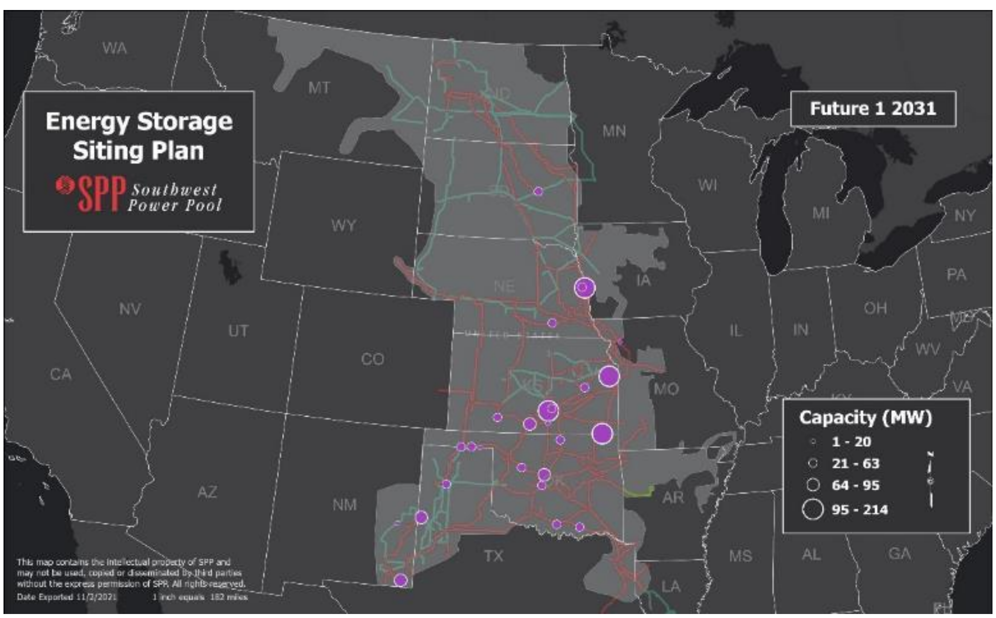


Figure 2.25: 2031 Future 1 Energy Storage Siting Plan

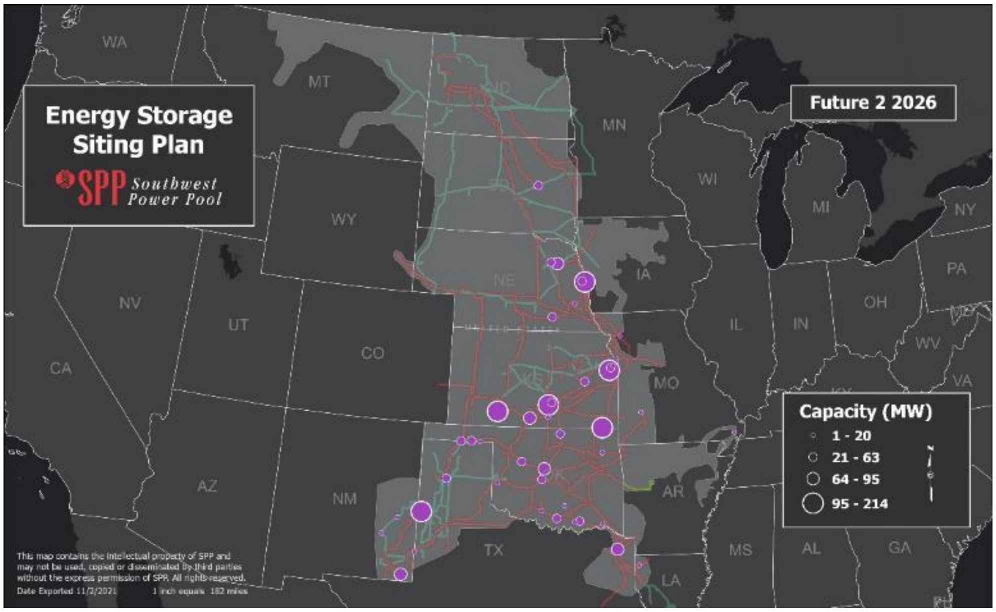


Figure 2.26: 2026 Future 2 Energy Storage Siting Plan

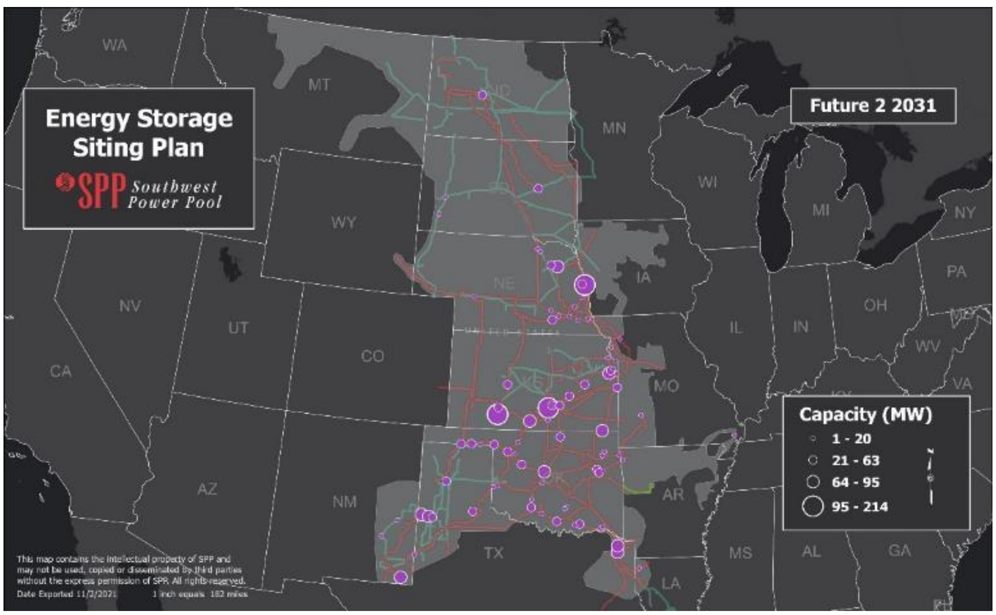


Figure 2.27: 2031 Future 2 Energy Storage Siting Plan

2.2.2.4 *GENERATOR OUTLET FACILITIES (GOF)*

For SPP to incorporate the siting plan into the market models, GOFs were necessary. GOFs are required when overloads on the system were not identified due to the sited generation. The GOF selection process was intended as a proxy for the GI process. For sites with upgrades identified in a GI study, the associated upgrades were evaluated and potentially 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 results of the GOF analysis determined the upgrades shown in Table 2.5.

SITES	GOF DESCRIPTION	MW SITED	GOF SOURCE
Badger 345 kV Mooreland-Knob Hill 138 kV Woodward-Badger 345 kV Cleo Corner 138 kV	Cleo Corner-Cleo Tap 138 kV terminal upgrades	F1 Y10: 200 MW F2 Y5: 200 MW F2 Y10: 200 MW	GI Queue
Dover Switchyard 138 kV	Dover-Hennessey 138 kV terminal upgrades	288 MW	GI Queue
Ranch Road 345 kV	Ranch Road-Sooner 345 kV terminal upgrades	F1 Y10: 151.8 MW F2 Y5: 151.8 MW F2 Y10: 151.8 MW	GI Queue
Gaines Co. 230 kV	Voltage Conversion of Hobbs-Andrews from 230 kV to 345 kV	702 MW	FCITC
	Andrews-Roadrunner 345 kV		
	New Gaines Co. 345 kV substation		
Caney River-Neosho 345 kV	Neosho-Caney River 345 kV	300 MW	GI Queue
Crossroads 345 kV	275 MegaVAR (MVAR) reactive support at Border 345 kV	522 MW	GI Queue
	200 MVAR reactive support at Oklaunion 345 kV		
	100 MVAR reactive support at Tuco 230 kV		
	100 MVAR reactive support at Deaf Smith 115 kV		
	Tolk 345/230 kV circuit 2 transformer		
	Tolk West-Plant X 230 kV rebuild		
	Tolk East-Plant X 230 kV rebuild		
	Tolk East-Tuco 230 kV rebuild		

*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 2020 MISO Transmission Expansion Planning (MTEP20) 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 MTEP20 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 2.28 and Figure 2.29 show the cumulative capacity additions in 2031 by unit type of these external regions for Futures 1 and 2.

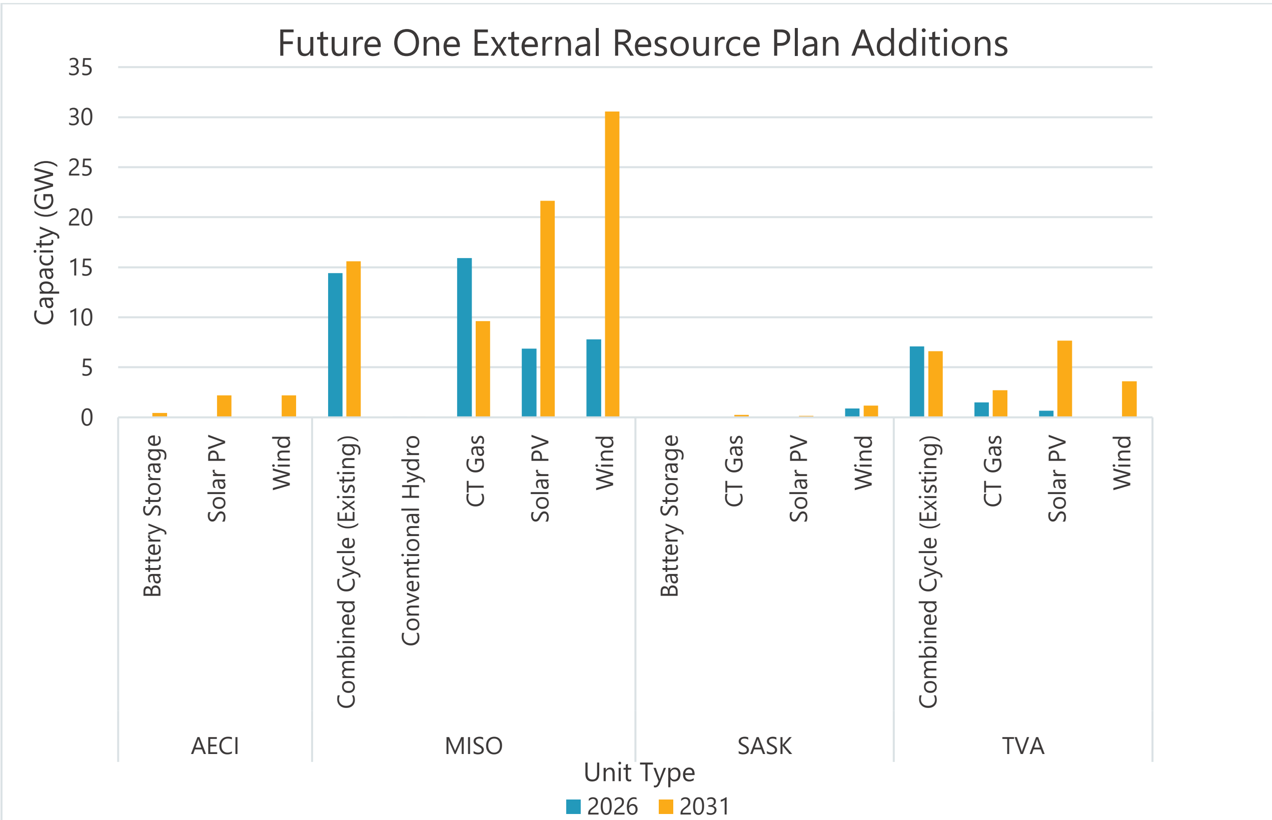


Figure 2.28: Capacity Additions by Unit Type-Future 1

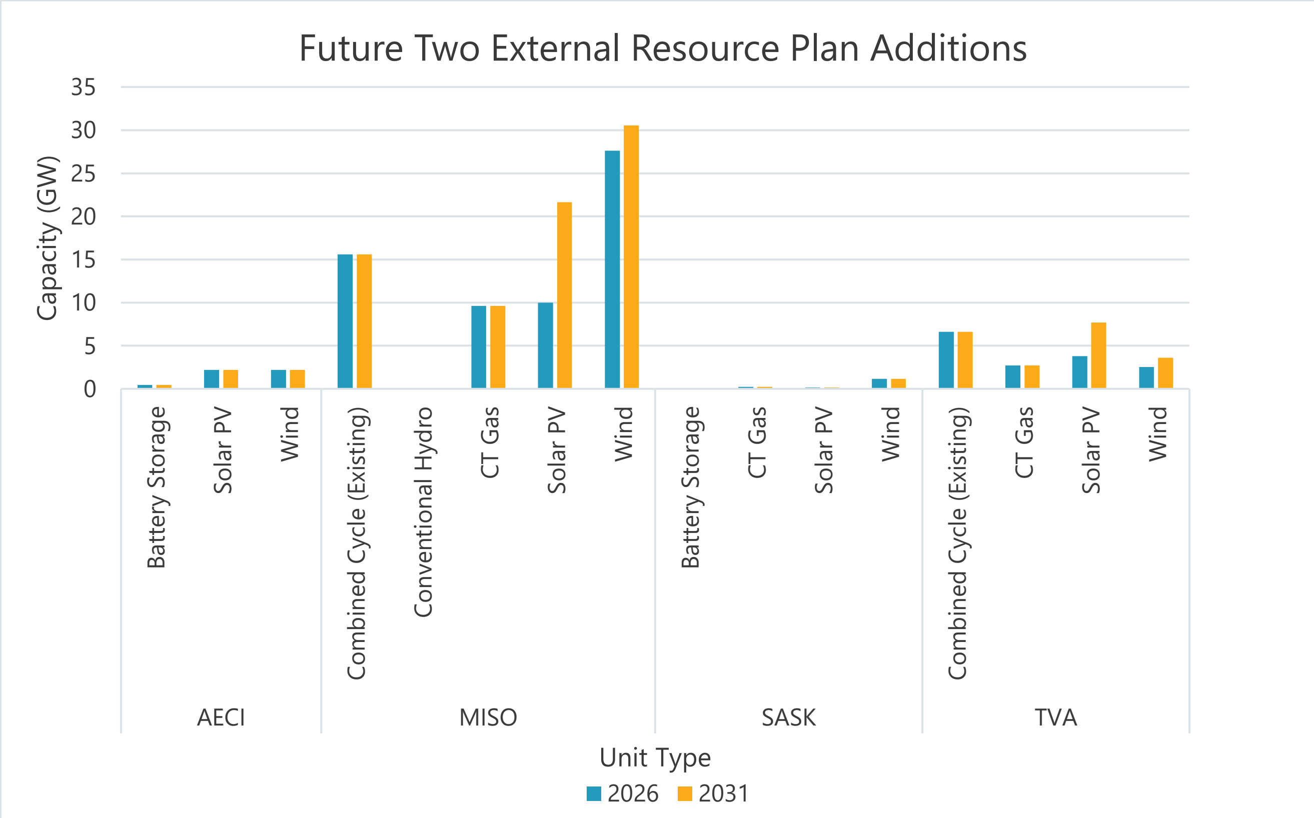


Figure 2.29: Capacity Additions by Unit Type-Future 2

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. Developing these study-specific constraints plays a critical part in determining 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. The TWG reviewed and approved elements identified in this assessment as limiting the incremental transfer of power throughout the transmission system, both under system intact and contingency situations. SPP defined the initial list of constraints leveraging the SPP permanent flowgate list,[23] which consists of NERC-defined flowgates that are impactful to modeled regions and recent temporary flowgates identified by SPP in real time. SPP used MTEP20 constraints to help evaluate and validate constraints identified within MISO and other neighboring areas. SPP also

[23] Posted on SPP OASIS

considered constraints identified in neighboring areas for inclusion as a part of the ITP study constraint list.

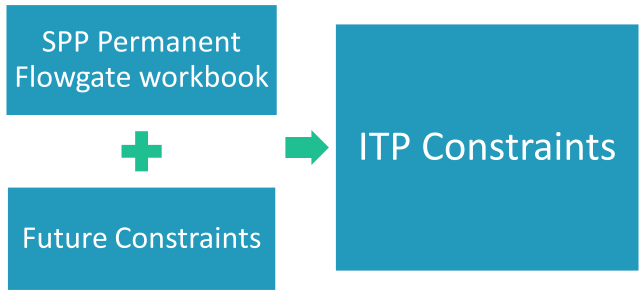


Figure 2.30: Constraint Assessment Process

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. Due to the removal of the market powerflow models from the 2021 ITP reliability needs assessment, the number of models was reduced from 10 to three. Table 2.6 shows the peak and off-peak reliability hours as defined in the ITP Manual from each future and year of the market economic model simulations chosen for the market powerflow models. For the Final Reliability Assessment, the full market powerflow model set was built.

	OFF-PEAK HOUR	WIND PENETRATION[24]	PEAK HOUR	SPP LOAD (MW)
Future 1 2023	April 5 at 2:00 AM	94.2%	June 22 at 5:00 PM	50,040
Future 1 2026	-	-	July 22 at 6:00 PM	54,322

Table 2.6: Reliability Hour Details

[24] Wind Penetration = $\frac{Potential\ Delivered\ Energy}{Load}\ x\ 100\%$

3 BENCHMARKING

3.1 POWERFLOW MODEL

SPP performed two benchmarks related to the 2021 ITP base reliability powerflow models. The first benchmark was a load and generation value comparison between the 2020 ITP and 2021 ITP base reliability powerflow models. The second benchmark was a load and generation value comparison between the 2021 ITP base reliability powerflow models and real-time operational data. SPP conducted model comparisons to verify the accuracy of the powerflow model data, including:

- Comparing the summer and winter peak base reliability model load totals (2020 ITP versus 2021 ITP), as shown in Figure 3.1 and Figure 3.2.
- Comparing the summer and winter peak base reliability model generation dispatch totals for years two, five and 10 (2020 ITP versus 2021 ITP), as shown in Figure 3.3 and Figure 3.4.

Additionally, the year-10 summer and winter peak generator retirements in the 2021 ITP base reliability powerflow models are shown in Figure 3.5.

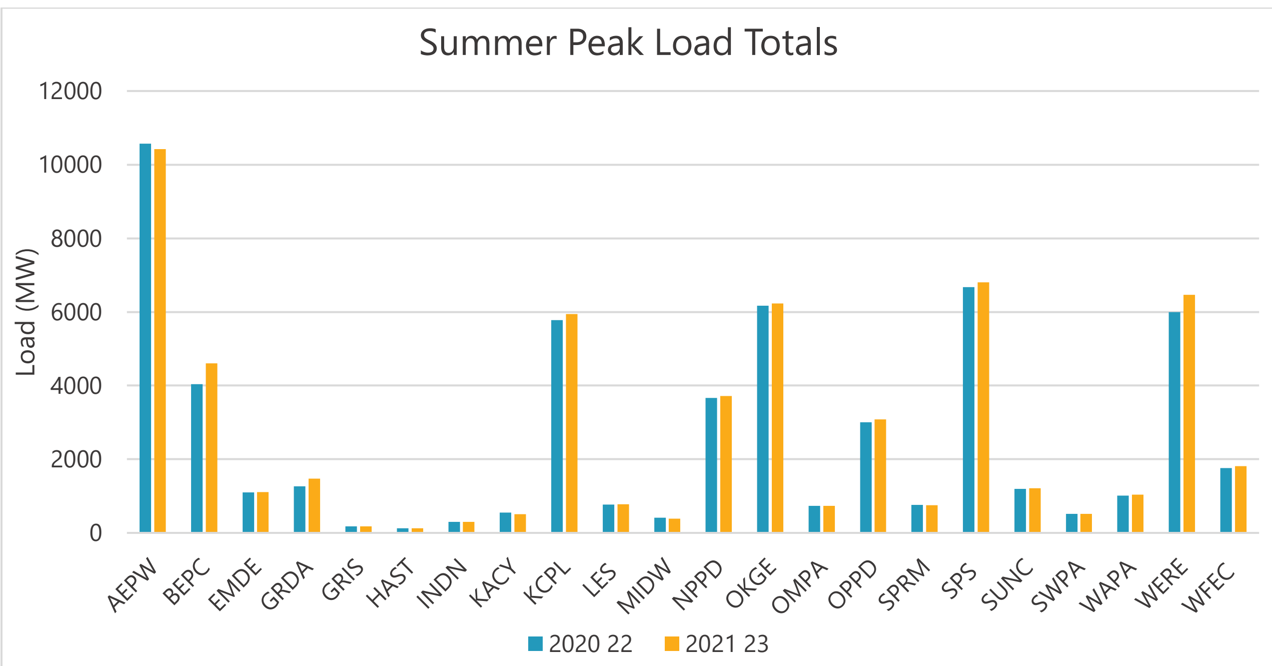


Figure 3.1: Summer Peak Year-Two Load Totals Comparison

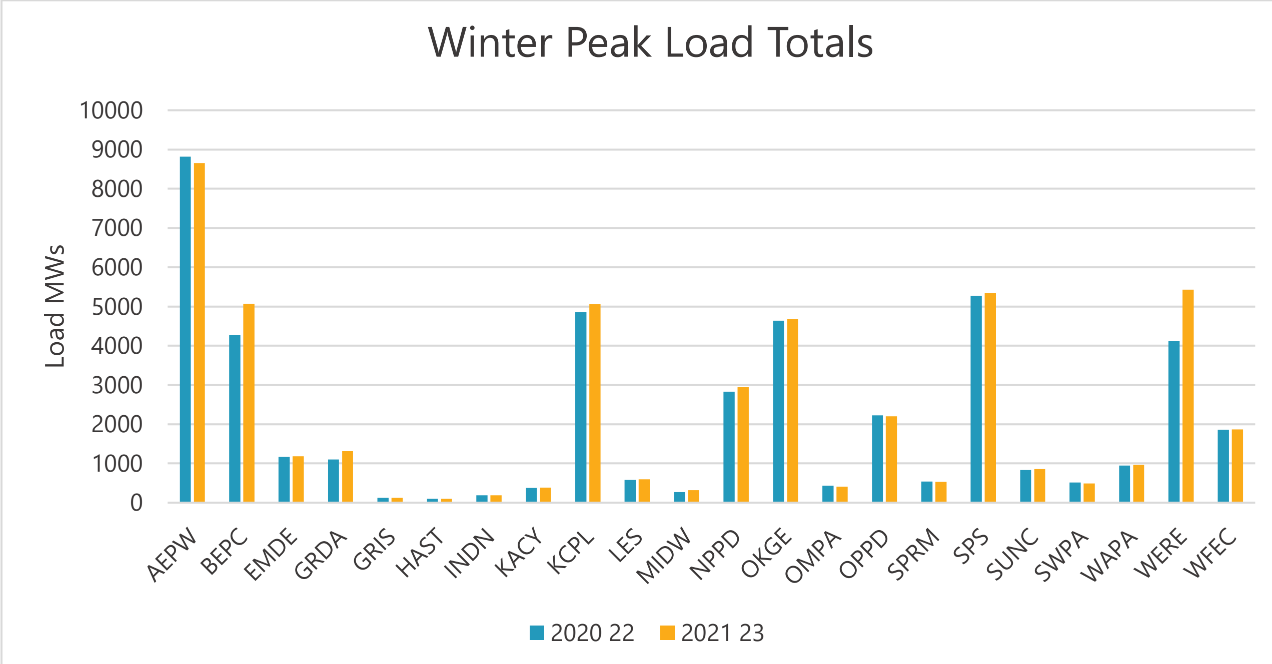


Figure 3.2: Winter Peak Year-Two Load Totals Comparison

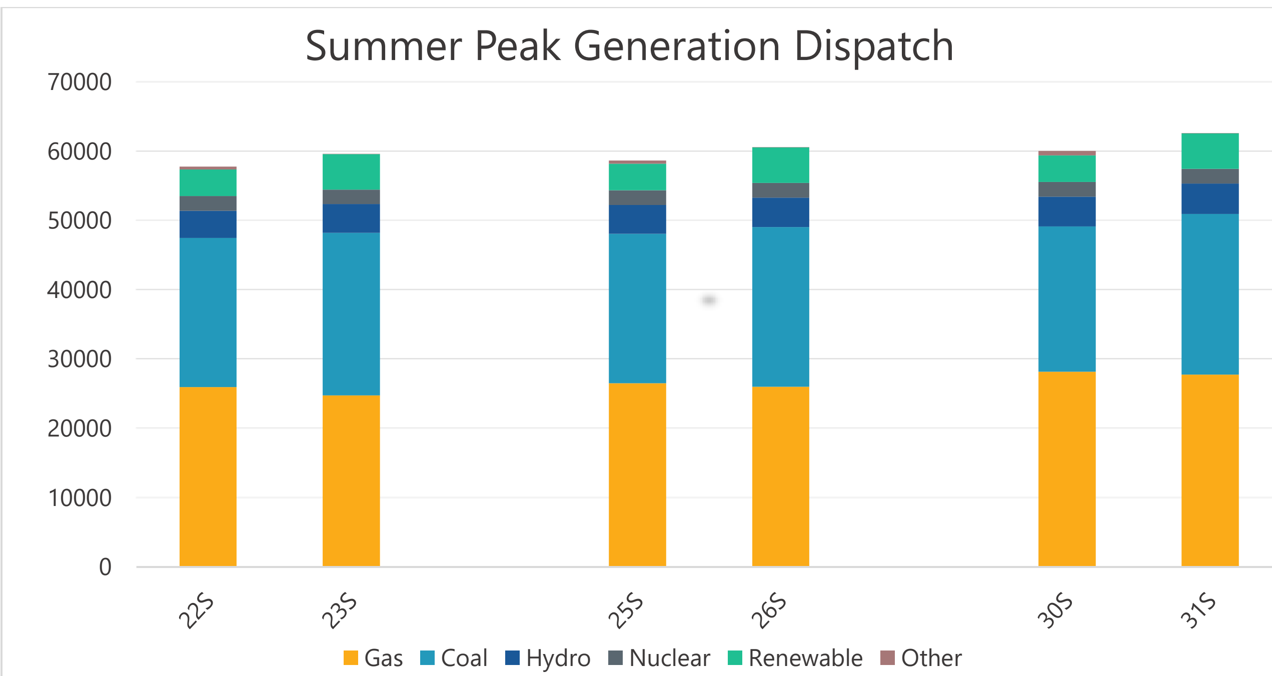


Figure 3.3: Summer Peak (MW) Years two, five and 10 Generation Dispatch Comparison

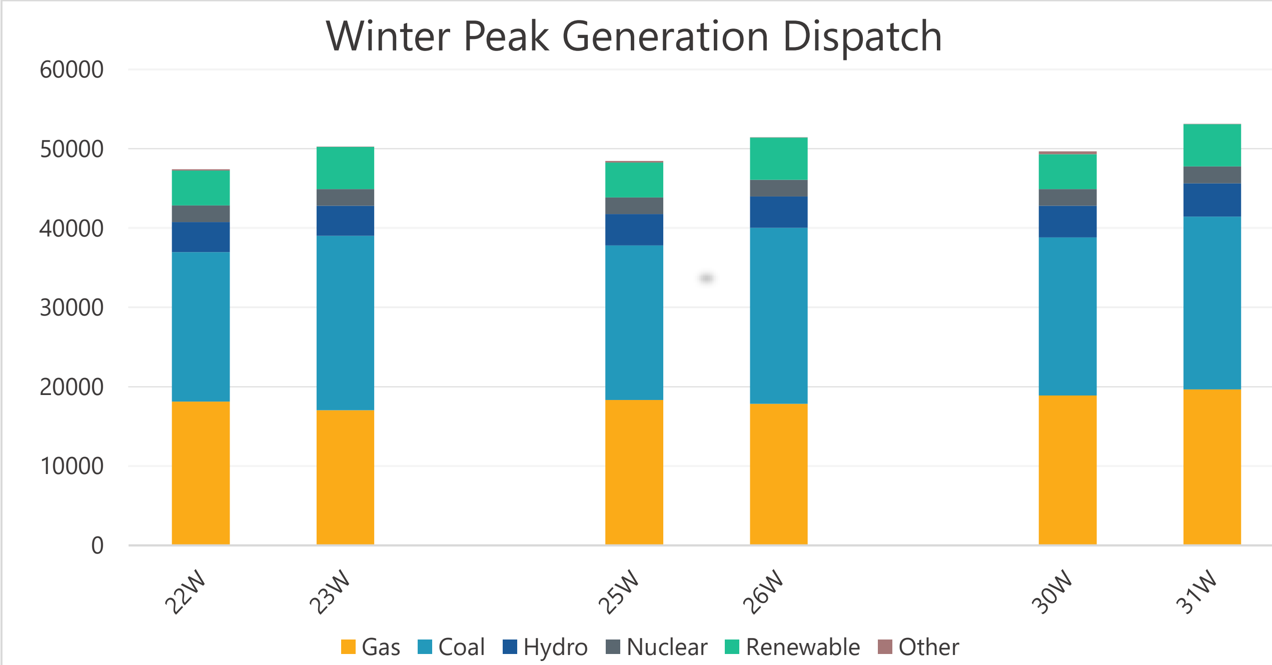


Figure 3.4: Winter Peak (MW) Years two, five and 10 Generation Dispatch Comparison

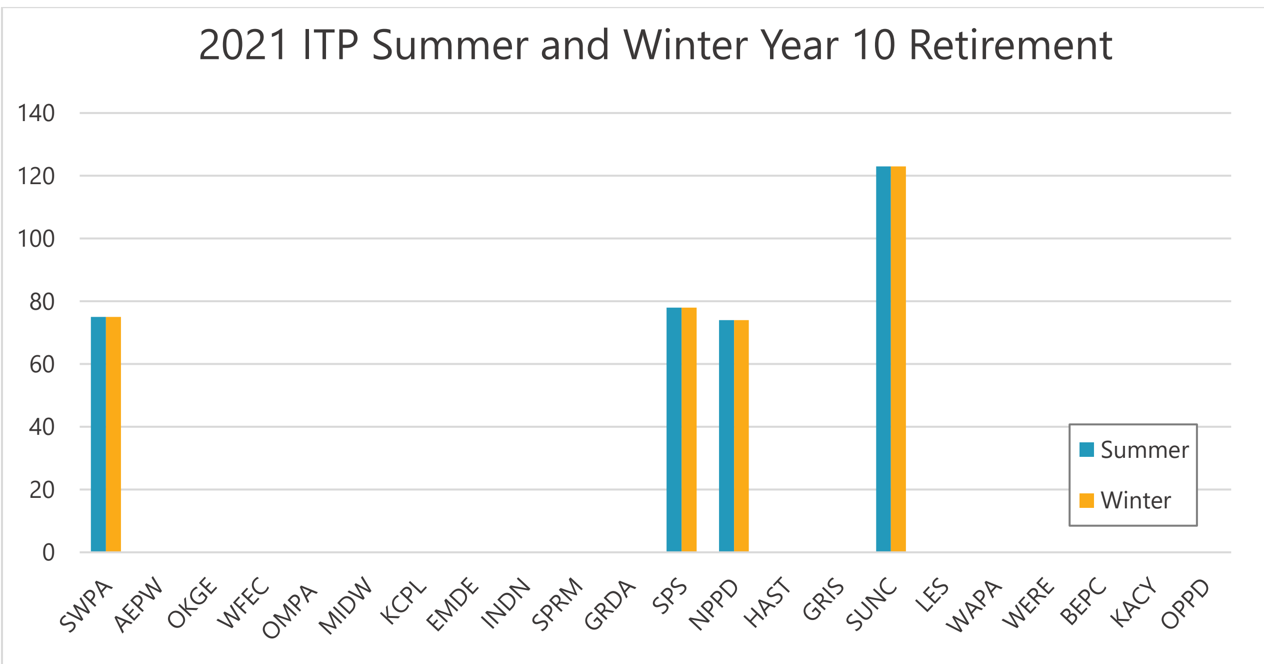


Figure 3.5: 2021 ITP Summer and Winter Year 10 Retirement

Operational model benchmarking for this assessment compared the 2021 summer and winter peak base reliability powerflow models against the real-time operational data for the 2020-2021 winter and 2021 summer timeframe. SPP conducted model comparisons to verify the accuracy of the powerflow model data, including:

- Comparing the 2021 summer and winter load totals (base reliability model versus real-time operational data (non-coincident), as shown in Figure 3.6 and Figure 3.7

- Comparing the 2021 summer and winter generation dispatch totals (base reliability model versus real-time operational data (non-coincident), as shown in Figure 3.8

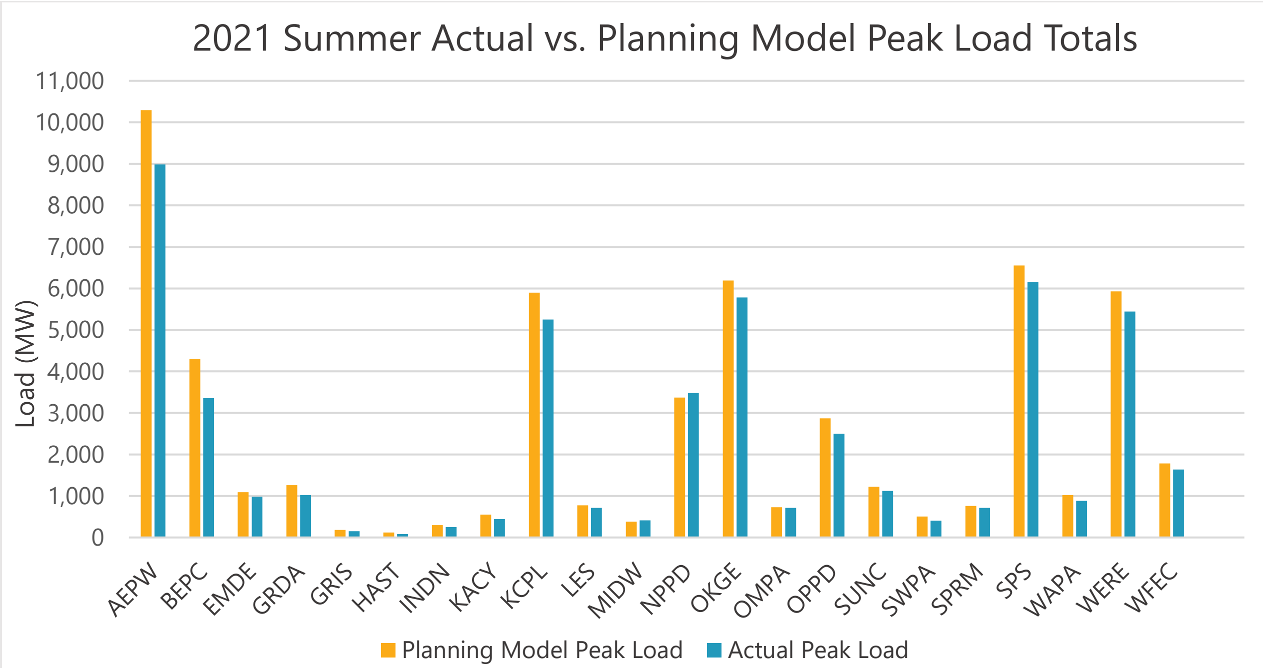


Figure 3.6: 2021 Summer Actual versus Planning Model Peak Load Totals

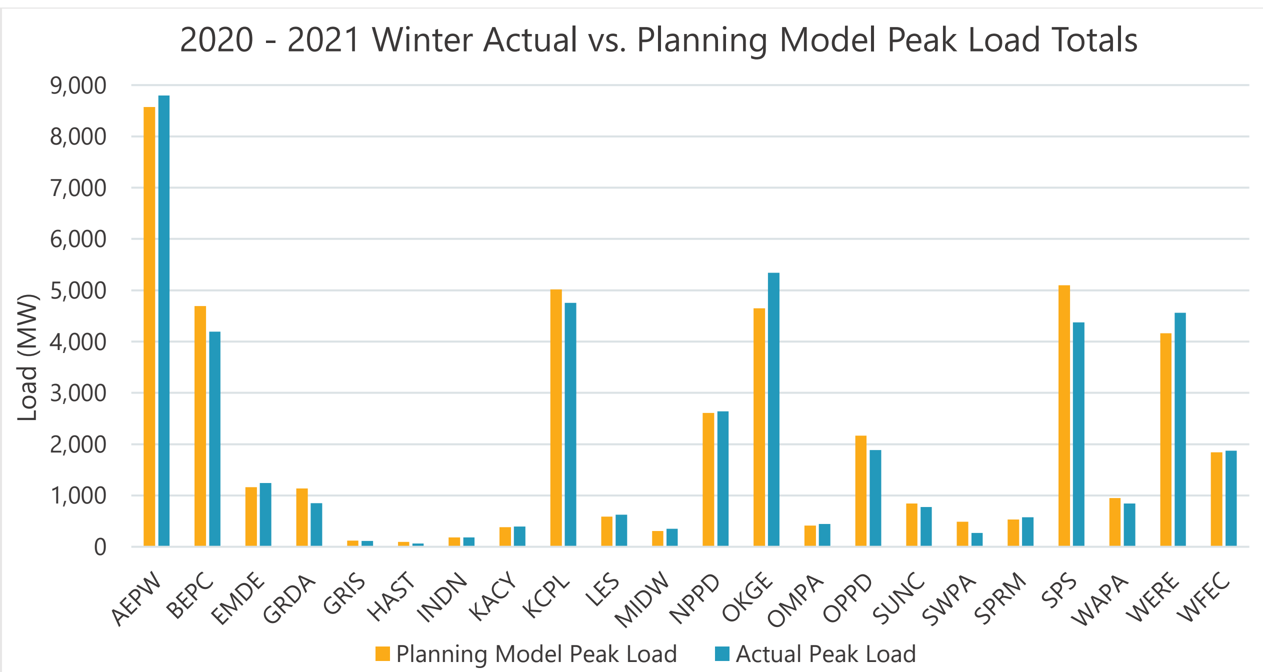


Figure 3.7: 2021 Winter Actual versus Planning Model Peak Load Totals

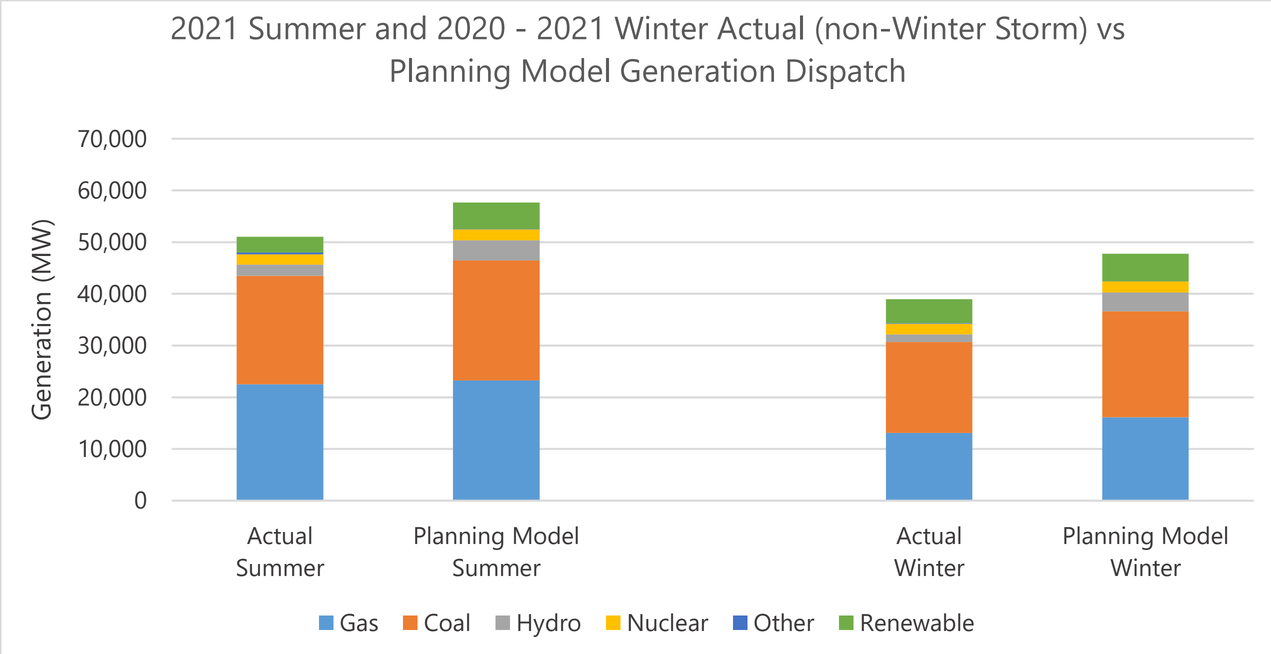


Figure 3.8: 2021 Actual versus Planning Model Generation Dispatch Comparison

3.2 MARKET ECONOMIC MODEL

SPP performed benchmarking for 2021 ITP on the year-two Future 1 market economic model. To increase the value of the benchmarking process, SPP compared the current study model against previous ITP modeling outputs before the Constraint Assessment, EIA data and historical SPP real-time data. SPP conducted numerous benchmarks to ensure the accuracy of the market economic modeling data, including:

- Comparing generation capacity factors with EIA data comparing simulated maintenance outages to SPP real-time data, and ensuring operating and spinning reserve capacities meet SPP Planning Criteria
- Comparing generation capacity factors, generating unit average cost, renewable generation profiles, system locational marginal prices (LMP), APC, and interchange between the 2020 ITP and the 2021 ITP

3.2.1 GENERATOR OPERATIONS

3.2.1.1 *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 2019 and resulting from the 2021 ITP study, the capacity factors for conventional generation units fell near the expected values. SPP attributed the difference in capacity factors between the datasets to differences in fuel and load forecasts as well as changes in the generation mix.

Unit Type	Average Capacity Factor		
		2020 ITP	2021 ITP
	2019 EIA	Future 1 (2022)	Future 1 (2023)
Nuclear	93.50%	85.98%	95.16%
Combined Cycle	56.80%	39.76%	54.71%
CT Gas	11.80%	4.74%	6.16%
Coal	47.50%	63.25%	57.18%
ST Gas	14.30%	3.09%	7.11%
Wind	34.80%	51.28%	44.88%
Solar	24.50%	23.69%	23.40%

Table 3.1: Generation Capacity Factor Comparison

3.2.1.2 *AVERAGE ENERGY COST*

SPP's examination of the average cost per MWh by unit type provided insight into what units will be dispatched first (without considering transmission constraints). Overall, the average costs per MWh were lower in the 2021 ITP than in the 2020 ITP due to the fuel and load forecasts and the difference in generation mix.

Unit Type	Average Energy Cost ($/MWh)	
	2020 ITP	2021 ITP
	Future 1 (2022)	Future 1 (2023)
Nuclear	$16.02	$16.06
Combined Cycle	$29.99	$25.72
CT Gas	$43.45	$34.84
Coal	$22.80	$22.04
ST Gas	$44.26	$34.99

Table 3.2: Average Energy Cost Comparison

3.2.1.3 *GENERATOR MAINTENANCE OUTAGES*

SPP compared generator maintenance outages in the simulations 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 a magnitude as the historical outages provided by SPP operations, the outage rates in the 2021 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.

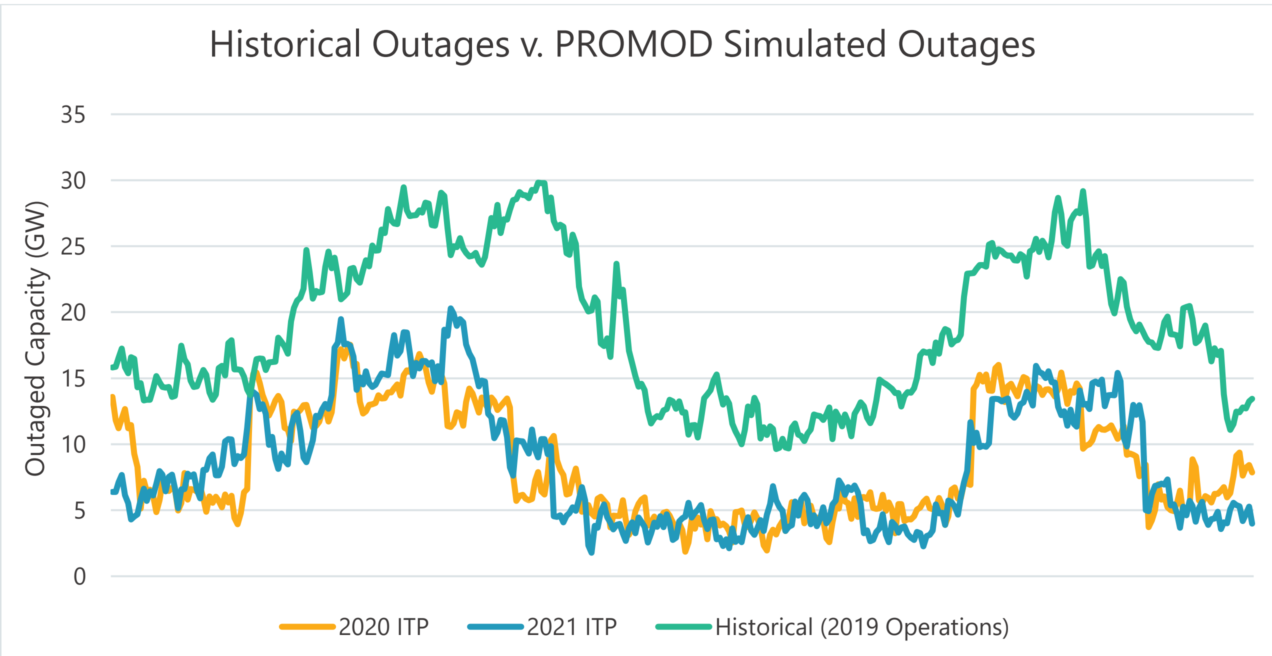


Figure 3.9: Historical Outages v. PROMOD Simulated Outages

3.2.1.4 *OPERATING AND SPINNING RESERVE ADEQUACY*

Operating reserve is an important reliability requirement that SPP modeled to account for capacity that might be needed in the event of unplanned unit outages. According to SPP Planning Criteria, operating reserves should meet a capacity requirement equal to the sum of the capacity of largest unit in SPP and half of the capacity of the next largest unit in SPP. Spinning reserve must fulfill at least half of this requirement.

SPP modeled the operating reserve capacity requirement at 1,675 MW and spinning reserve capacity requirement at 823 MW. The reserve requirements were met in the market economic models.

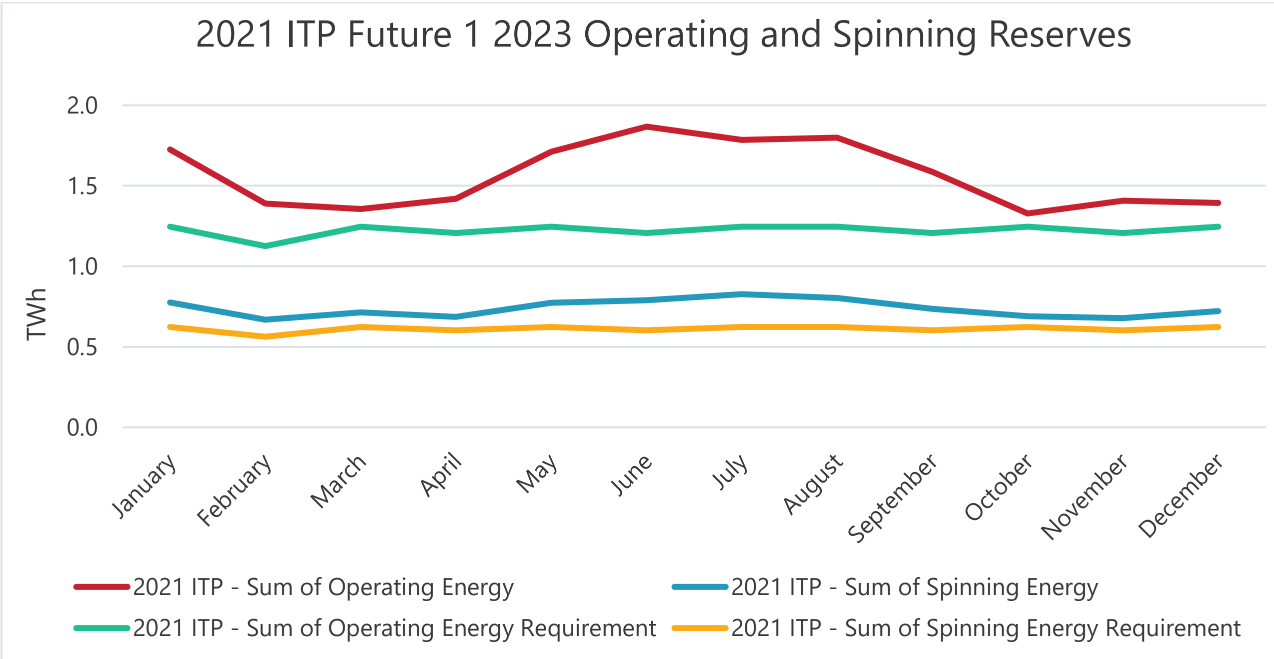


Figure 3.10: 2021 ITP Future 1 2022 Operating and Spinning Reserves

3.2.1.5 *RENEWABLE GENERATION*

Wind and solar energy output is higher in the 2021 ITP than in the 2020 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 2021 ITP.

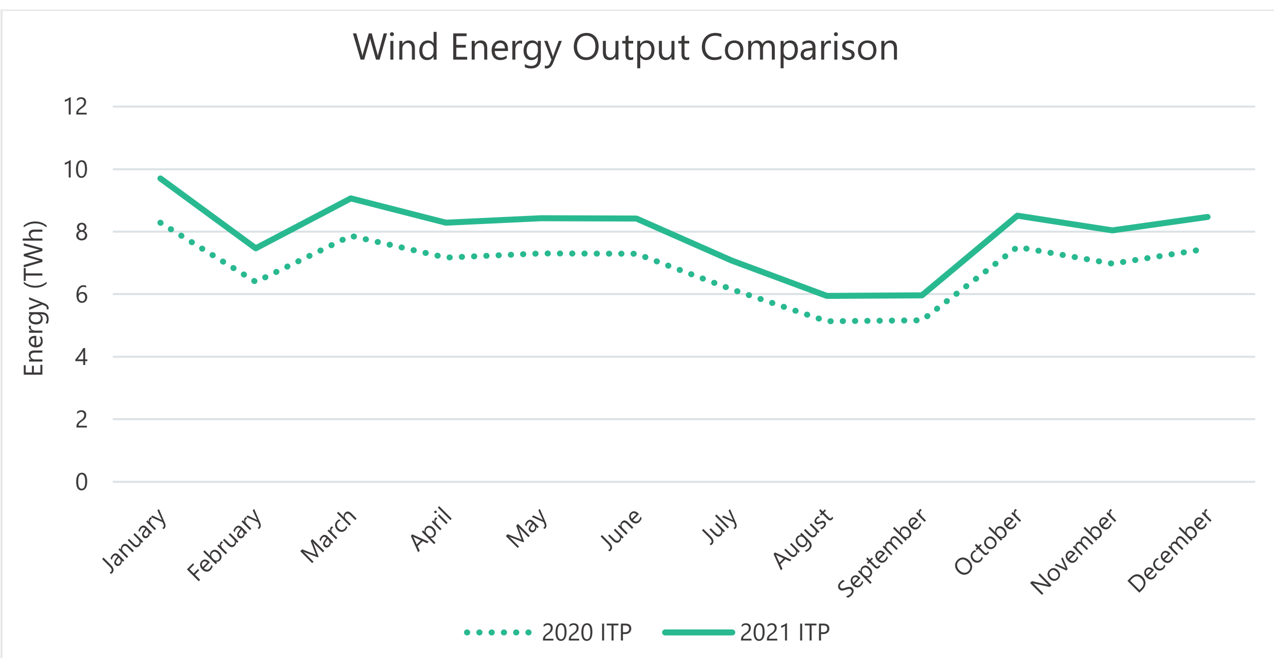


Figure 3.11: Wind Energy Output Comparison

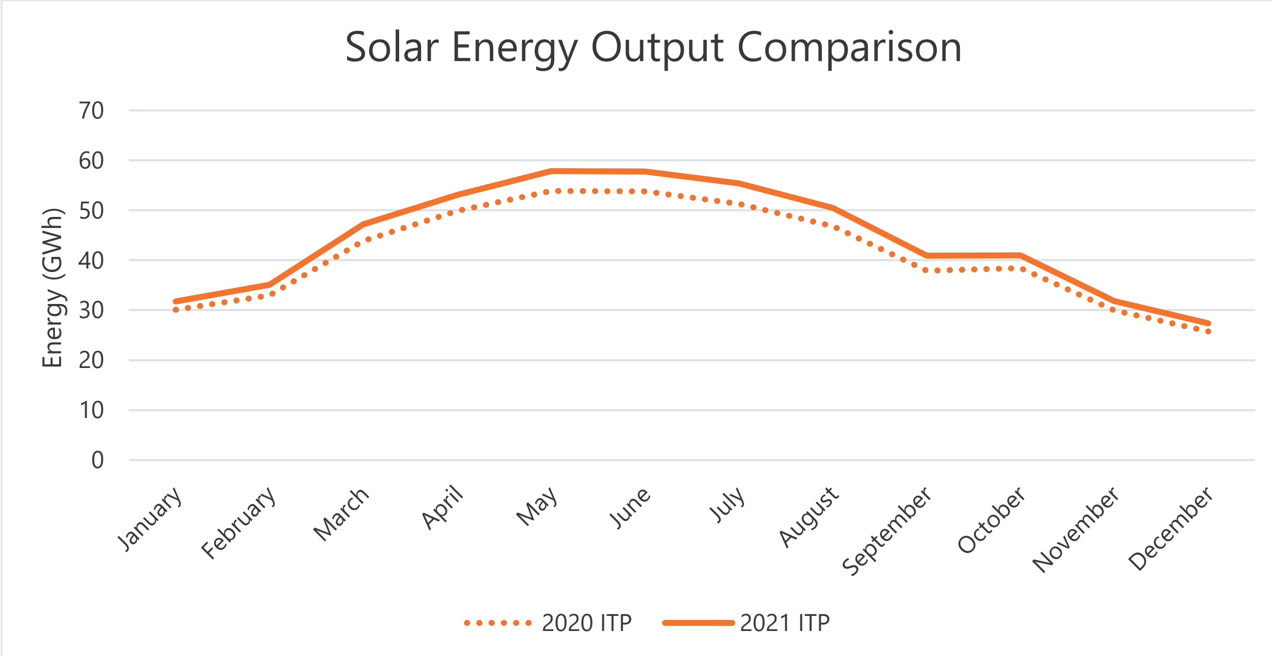


Figure 3.12: Solar Energy Output Comparison

3.2.2 SYSTEM LOCATIONAL MARGINAL PRICE (LMP)

SPP benchmarked 2021 ITP simulated LMPs against simulated LMPs from the 2020 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 2021 ITP is due to a slight decrease in natural gas price fuel forecasts and additional renewable energy.

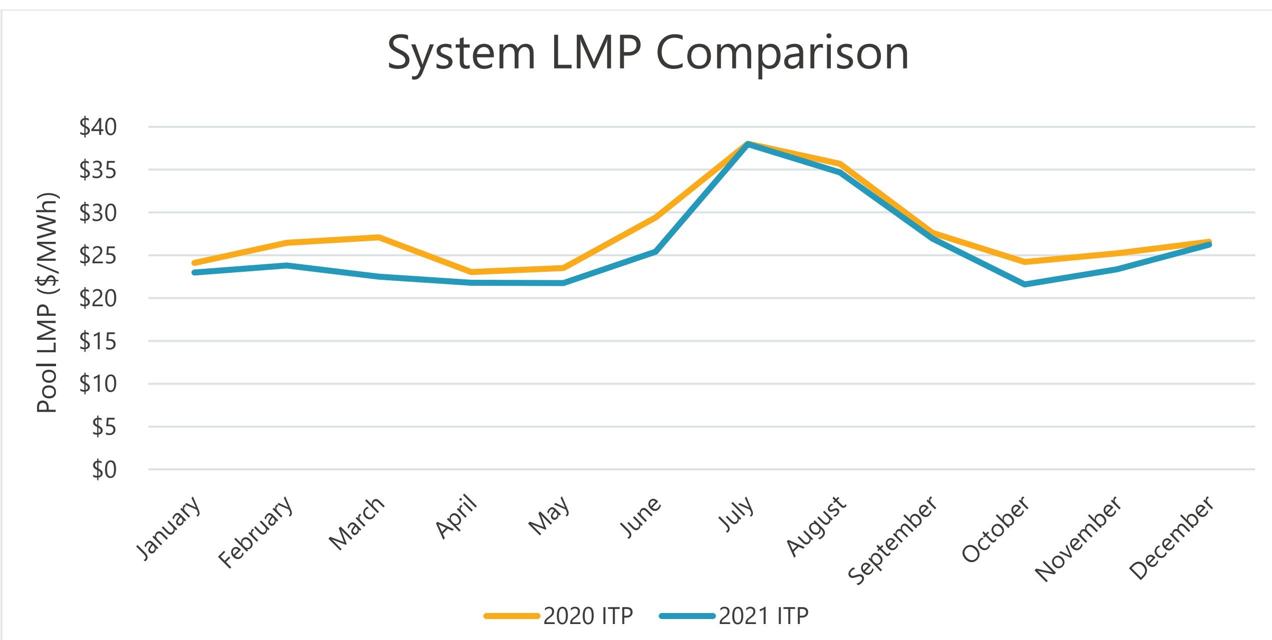


Figure 3.13: System LMP Comparison

3.2.3 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 2021 ITP than in the 2020 ITP due to the change in fuel and renewable 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 3.14 and Figure 3.15 for a summary of regional and zonal APC results.

The SPP "other" zone includes merchant generation (without contractual arrangements with load-serving entities) and additional renewable resource plan wind resources.

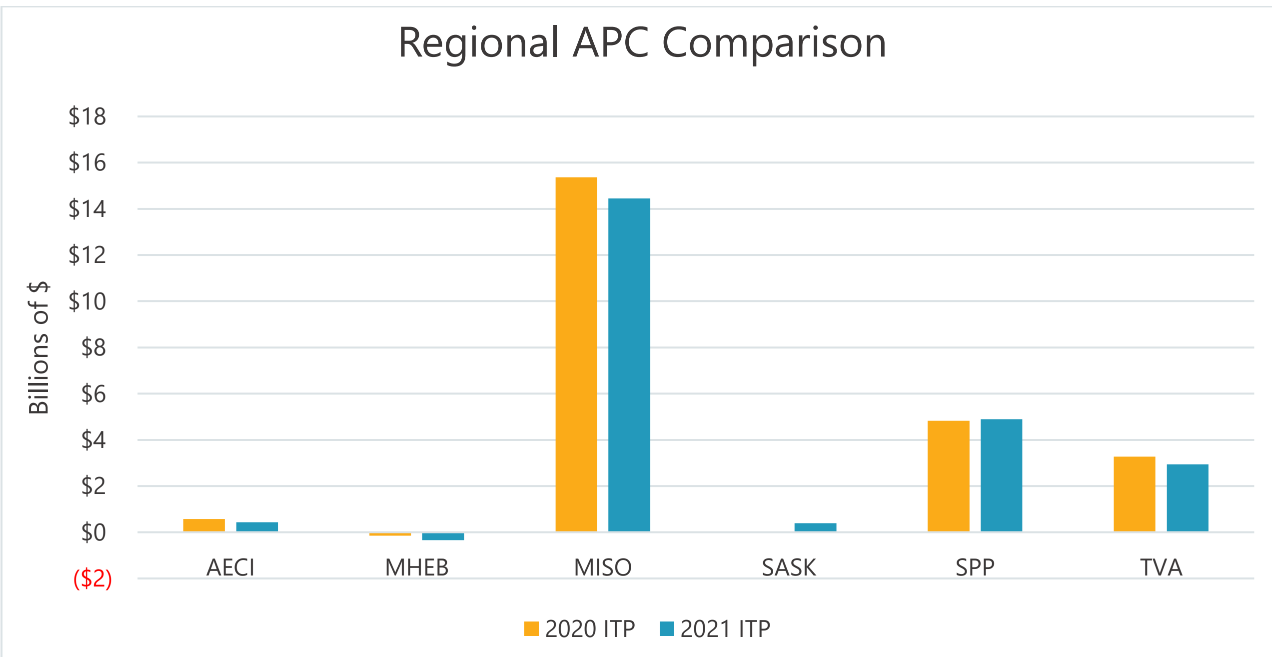


Figure 3.14: Regional APC Comparison

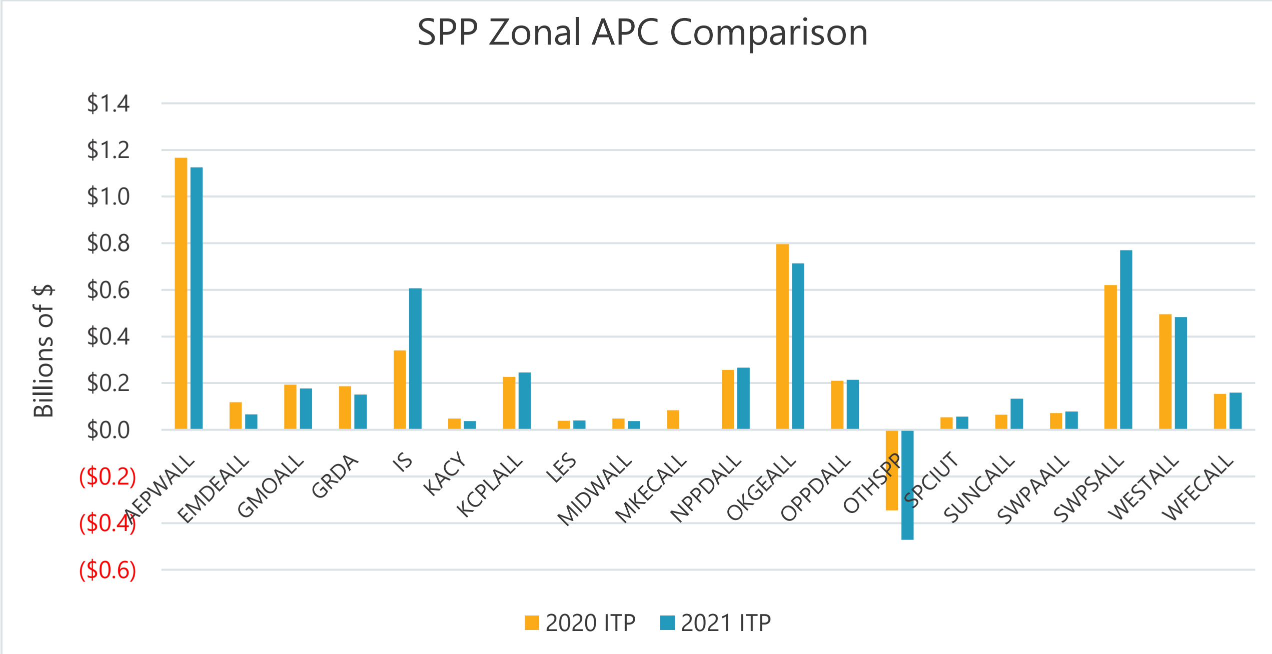


Figure 3.15: SPP Zonal APC Comparison[25]

3.2.4 INTERCHANGE

SPP validated the 2021 ITP model interchange against the 2020 ITP and current SPP operations data. The 2021 ITP model is similar in shape and magnitude while overall exports are higher in the 2021 ITP than in the 2020 ITP.

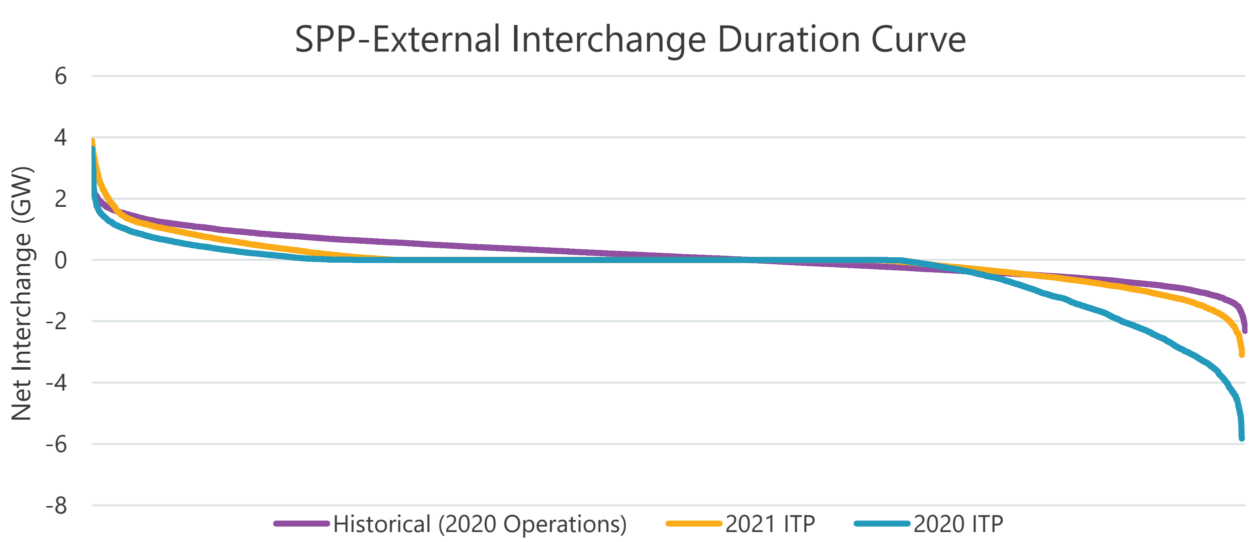


Figure 3.16: Interchange data comparison

[25] Any reference to the Integrated System (IS) legacy system is currently being assessed and is equivalent to the UMZ.

4 TARGET AREAS AND SENSITIVITY MODELS

4.1 TARGET AREAS

During the Needs Assessment for the 2021 ITP, SPP identified two target areas, which require additional efforts of SPP and stakeholders to identify and recommend the optimal solution. These areas were identified based upon the following drivers:

- Integrated Marketplace congestion
- Unresolved transmission limits identified in previous ITP assessments
- Operational evaluation(s)
- Historical and projected congested flowgates in area
- Steady-state reliability violations
- Parallel and in-series relationships between flowgates/transmission corridors
- Power transfer distribution factor flowgates used to represent thermal, stability or contractual limitations
- Impacted heavily by critical EHV contingencies
- Uncertainty of load forecasts
- Uncertainty of planned new/retired generation
- Area shortfall
- Generator interconnection queue limitations

4.1.1 TARGET AREA 1 – SPS SOUTH TARGET AREA OVERVIEW

The Southwestern Public Service Company (SPS) South target area is a multifaceted problem, including real and reactive power supply issues, combined with the potential for considerable regional economic benefits to be realized by allowing for the region's vast renewable generation fleet to serve the New Mexico load with economic energy.

During the base reliability model build, SPP discovered that the SPS area did not have enough generation from Network Resources to serve its Network Load throughout the study period resulting from planned retirements submitted during the generation review. These retirements were located in the southernmost portion of the SPS area in New Mexico. This resulted in a deficiency of generation equal to 941.9 MW in the year 10 summer model. In accordance with ITP Manual section 2.1.1, generation was dispatched to address the generation shortfall from independent power producers and the remaining unused, dispatchable generation within the SPP footprint, causing power transfers into the SPS region. This portion of the SPS system has also experienced higher than average load growth due to drilling activity related to the Permian Basin oil and gas formations.

The SPS area has three defined interfaces that exist to monitor and limit power flows into different areas of the SPS zone located in the southwest portion of the SPP footprint. The focus of the 2021 ITP was the southern portion of SPS where the SPS New Mexico Ties (SPSNMTIES) interface monitors flow into the most remote portion of the SPS system. The SPSNMTIES interface limits imports into southeastern New Mexico in SPP market operations via the Crossroads-Eddy 345 kV, Yoakum-Hobbs 345 kV, San Juan-Chaves 230 kV, and Ink Basin-Hobbs 230 kV lines. The intent of the interface is to maintain transmission system voltage stability in southeastern New Mexico under system intact and N-1 conditions. For the purposes of the assessment, the interface was limited to 825 and 865 MW for summer and winter seasons, respectively. These seasonal ratings proxy the power transfer limits that maintain pre- and post-contingent voltage limits on the transmission system in southeastern New Mexico and surrounding transmission system for system intact, generation loss, and contingency conditions related to the loss of select 230 or 345 kV lines. As a result of the generation deficit, the SPSNMTIES interface was overloaded in 8 out of 9 BR models. A description of each interface is included below:

Name	Definition	Monitors	Seasonal Rating (S/W)
SPSNMTIES	San Juan Tap-Chaves County 230 kV	North-to-south flow into New Mexico	895/825
	Crossroads-Eddy County 345 kV		
	Ink Basin-Hobbs 230 kV		
	Yoakum-Hobbs 345 kV		
SPPSPSTIES	Border-Tuco 345 kV	North-to-south flow from SPP region into the SPS area	1345/1345
	Beaver County-Hitchland circuit 1&2 345 kV		
	Carpenter-Hitchland 345 kV		
	Jericho-Kirby 115 kV		
	E-Liberman-Texas Panhandle 115 kV		
	Oklaunion-Tuco 345 kV		
	Sham-McLean 115 kV		
	Sweetwater-Wheeler 230 kV		
SPSNORTH_STH	Amarillo South-Swisher 230 kV	East-to-west flow within SPS	1645/1645
	Bushland-Deaf Smith 230 kV		
	Newhart-Potter County 230 kV		
	Randall-Canyon E Tap 115 kV		
	Randall-Palo Duro 115 kV		

Table 4.1: SPSNMTIES Interface Area Flowgates

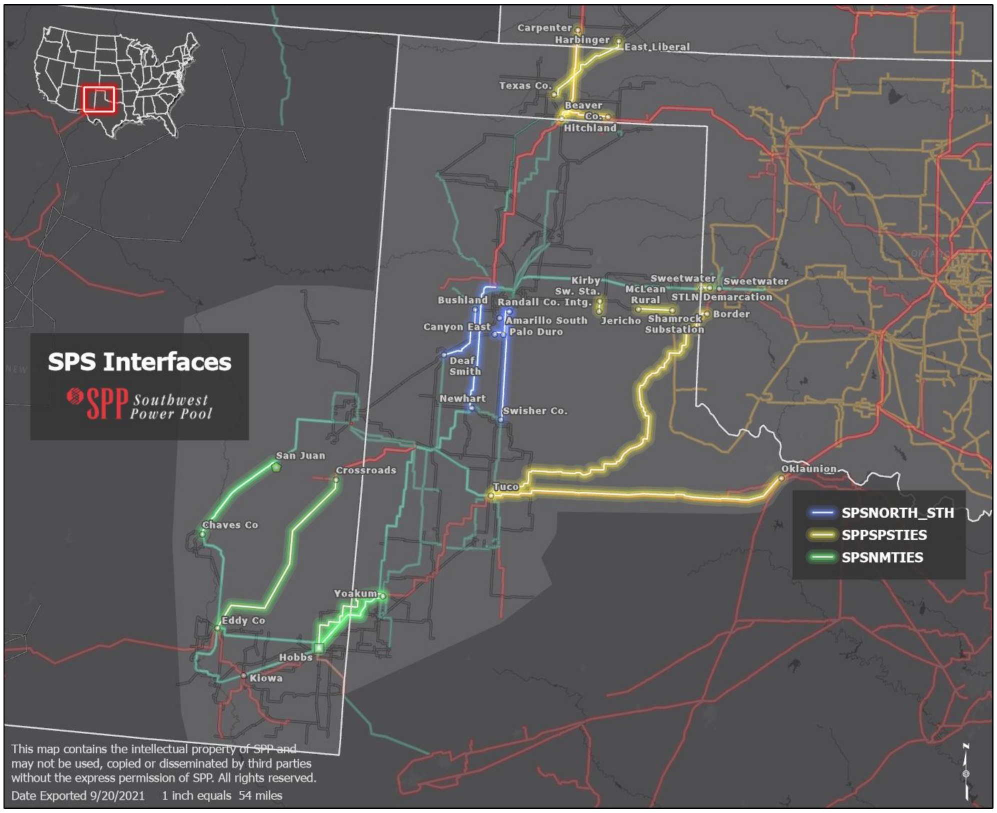


Figure 4.1: 2021 SPS New Mexico Ties Flowgates

SPP also identified three additional complicating factors as impactful to the SPSNMTIES target area:

- The 2021 ITP MEM series included a proxy combined cycle resource approved in the conventional resource plan. This is further complicated by the need for transmission upgrades necessary as GOFs[26]
- Planned retirements in the 2021 ITP were removed from the 2022 ITP generation review milestone completed after the 2021 ITP model sets were approved
- The Delivery Point Addition process has received load addition requests in the area that are not accounted for in the 2021 or 2022 ITP models

4.1.2 TARGET AREA 2 – BAKKEN TARGET AREA OVERVIEW

In the Bakken shale formation area (Bakken) of North Dakota (primarily in the Basin Electric Power Cooperative footprint), gas and oil productions have been rapidly increasing, driving significant load growth in the northwest corner of the SPP footprint. This load increase, combined with local wind and gas generation availability during winter-peaking conditions drove the need for additional analysis in

[26] The generator outlet facilities included the conversion of the existing Hobbs-Andrews 230 kV line to 345 kV operation and a new 51-mile 345 kV line from Andrews-Roadrunner. The proxy resource was interconnected on the converted Hobbs-Andrews line.

the area. Further complicating the Bakken area concerns were issues related to cold weather such as winter peak loads and generator outages. These winter conditions created additional contingencies that SPP assessed and posted as informational data in the Needs Assessment.

The Bakken target area also has complicating factors:

- Generation serving the load pocket is not located within the load pocket
- Limited delivery points in the area to serve the load

4.2 SENSITIVITY MODELS

To address the uncertainties associated with both target areas, SPP developed powerflow and economic sensitivity models, in which adjustments were made to account for the specific uncertainties associated with each target area. SPP used the sensitivity models to provide additional information on the performance of the recommended solutions and guide SPP in the determination of projects that should be recommended for a NTC. SPP provided these models to stakeholders as part of the Needs Assessment posting to support the external development of solutions.

4.2.1 POWERFLOW SENSITIVITY MODELS

SPP created an updated set of base reliability models to account for the load uncertainty in the Bakken target area. Instead of using the 2021 ITP load data, SPP updated the powerflow sensitivity models with the recently finalized 2022 ITP load data, which reflected a lower load forecast in the Bakken target area. As a result of this lower load forecast, the two proxy static VAR compensators included in the approved base reliability model set to allow the cases to solve, were no longer necessary.

4.2.2 SPSNMTIES INCREMENTAL TRANSFER SENSITIVITY MODELS

Although the base reliability models monitor the three interfaces discussed previously, SPP calculated the SPSNMTIES interface rating using specific assumptions based upon normal market conditions. Specifically, the nearby Mustang unit was lowered to a maximum of 400 MW of generation output. To properly evaluate the ability of projects to decrease the interface loading or increase the interface rating, SPP created transfer sensitivity cases to account for the initial condition used to develop the rating as well as higher transfer scenarios where incremental amounts generation in the target area were reduced or taken offline requiring additional generation from outside the SPS area.

The higher level transfer cases were unable to be solved using SPP’s powerflow software due to the reactive support deficiencies caused by the lack of generation available in the target area. SPP expects projects with the ability to solve these models while preventing powerflow violations also have the ability to increase the interface rating for the economic analysis and may be able to provide additional economic benefits.

SPP posted supplemental information with the needs assessment explaining the SPSNMTIES interface and outlining solution evaluation and additional analysis needed to aid stakeholders with their solution submittals. The 2021 ITP SPS South Target Area Study Scope and Interface Guidelines[27] included a rigorous AC Power transfer thermal and voltage analysis and results with 0.02 per unit voltage safety margin applied to low voltage monitoring criteria. The study analysis and deliverables were required to support new SPSNMTIES interface ratings for economic solution evaluation.

4.2.3 ECONOMIC SENSITIVITY MODELS

SPP created a second set of economic models to remove some of the assumptions approved in the initial economic models. For the economic sensitivity models, SPP made adjustments to both target areas because the two areas are electrically isolated and geographically remote from each other. SPP made the following changes to the economic models:

- CC unit and associated GOFs in Target Area 1 were removed
- Retired resources in SPS were recommissioned to maintain resource adequacy for the SPS Zone. These assumptions align with 2022 ITP BR model assumptions and 2023 ITP Gen review and ESWG approved retirement assumption exceptions.
- Peak load and annual energy totals in the Bakken area were updated to values from the stakeholder-approved 2022 ITP load review, leading to the load reduction of 590 MW, from 2.59 GW to 1.9 GW in 2031.

[27] The needs assessment transmittal, which included the location of this scope document and the 2021 ITP needs assessment on GlobalScape, was posted on May 10, 2021: https://www.spp.org/documents/64626/2021%20itp%20needs%20assessment%20transmittal%20(5-10-2021).pdf

5 NEEDS ASSESSMENT

SPP and its stakeholders worked together to forecast and analyze the regional transmission system's economic, reliability, operational and public policy needs.

5.1 ECONOMIC NEEDS

SPP determines economic needs based on the congestion score associated with a constraint (comprised of a monitored element and contingent element pair). SPP calculates the congestion score by multiplying the number of hours a constraint is congested in the model by the average shadow price of that constraint. In most ITP assessments, constraints with a congestion score greater than $50k/MW are considered economic needs; however, due to the mitigation of the 2021 ITP, a mitigation scope was approved by the ESWG and the TWG, and subsequently by the MOPC in July 2021. This scope increased the threshold for economic needs from $50k/MW to $200k/MW. SPP included additional constraints that did not meet the $200k/MW score as needs if they met any of the following criteria:

- The SPP-MISO Joint Targeted Interconnection Queue (JTIQ) study
- The SPS South or Bakken target areas
- Addressed reliability or operational needs

The economic needs identified per future are shown in Figure 5.1 and Figure 5.2, and Table 5.1 and Table 5.2.

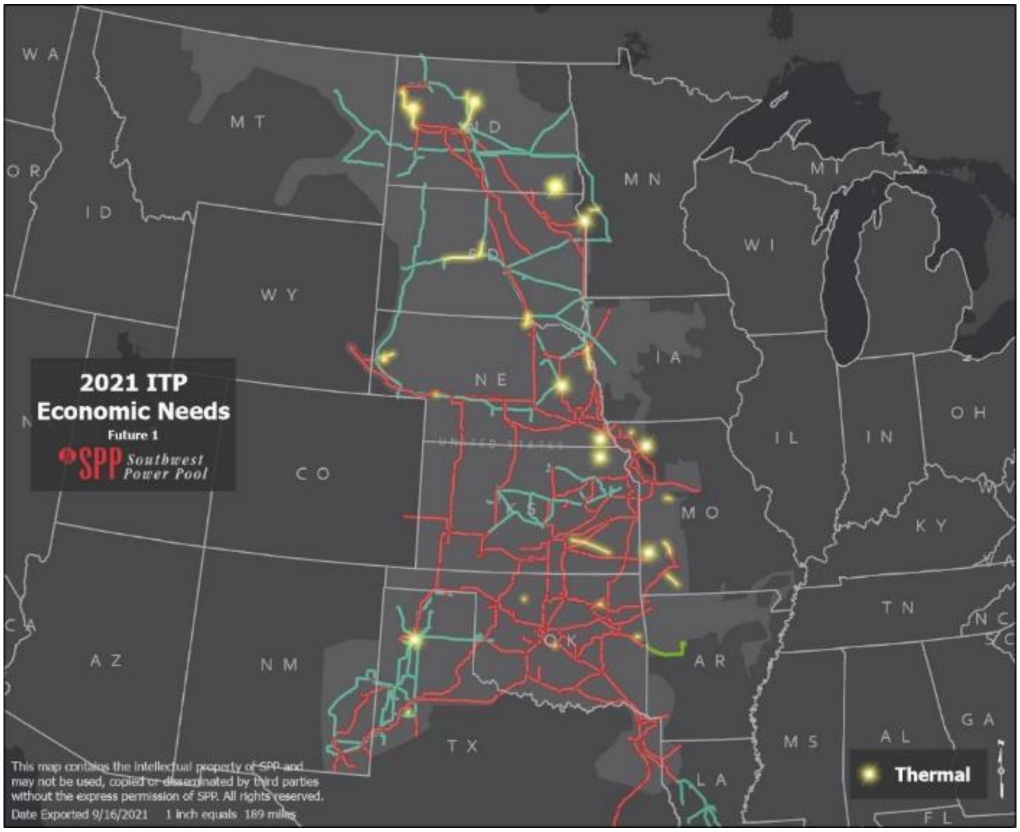


Figure 5.1: Future 1 Economic Needs

Case	Constraint	2023 Congestion Score	2026 Congestion Score	2031 Congestion Score
Base	Lamar 161 kV/69 kV transformer for the loss of (FTLO) Morgan-Jasper 345 kV	21,223	489,825	1,095,024
Base	Butler-Altoona 138 kV FTLO Neosho-Neosho Tap 345 kV	418,087	641,023	981,838
Base	Cleo Corner-Cleo Junction 2 69 kV FTLO Renfrow (OKGE)-Renfrow (WFEC)138 kV	34	958,332	219,591
Base	Watford-Charlie Creek 230 kV FTLO Charlie Creek-Patent Gate 345 kV	354,159	338,066	528,991
Base	Graceville Johnson Junction-Morris 115 kV FTLO Hankson- Wahpeton 230 kV	219,272	381,856	124,852
Base	SPSNMTIES	346,699	75,553	175,493
Base	Warrensburg East-W Warrenburg Air Force Tap West 161 kV FTLO Overton-Sibley 345 kV	340,703	277,204	316,941
Base	Akins-Sallisaw 161 kV FTLO Muskogee-Ft. Smith 345 kV	15,157	103,423	292,469

Case	Constraint	2023 Congestion Score	2026 Congestion Score	2031 Congestion Score
Base	Aurora-Reeds Spring 161 kV FTLO Beaver - Eureka 161 kV	150,846	161,638	200,235
Base	Big Stone-Brownsville 230 kV FTLO Oakes-Ellendale 230 kV	134,058	207,451	65,127
Base	Raun-Tekamah 161 kV FTLO Raun-S3451 345 kV	17,894	17,105	29,522
Base	Ogallala 115 kV bus tie line FTLO Ogallala-Grant 115 kV	110,403	68,756	183,042
Base	Columbus East 230/115 kV transformer FTLO Columbus East-Shell Creek 345 kV	117,201	169,171	143,581
Base	Oahe-Sully Buttes 230 kV FTLO a Leland Olds tie line	6,484	34,591	103,785
Base	Big Stone-Brownsville 230 kV FTLO Twin Breaks-Ellen Shunt 345 kV	88,087	125,261	59,737
Base	Tulsa North-Cherokee Data Center East Tap 138 kV FTLO Grand River Energy Center-Grand River Energy Center Tap 345 kV	1,737	41,053	101,763
Base	Watford-Williston 230 kV FTLO Charlie Creek-Patent Gate 345 kV	-	50,417	135,164
Base	Morgan-Stockton 161 kV FTLO Morgan-Jasper 345 kV	-	4,730	18,529
Base	Souris-Magic City 115 kV FTLO Mallard-Nelson 115 kV	-	82,604	152,216
Base	Wiliston-Judson 230 kV FTLO Charlie Creek-Patent Gate 345 kV	-	132,267	55,226
Base	Forman-Elliott 115 kV FTLO Hankson-Wahpeton 230 kV	6,822	3,504	62,903
Base	Potter County 345/230 kV transformer FTLO Hitchland-Moore County 230 kV	827	9,589	25,811
Base	McHenry-Voltair 115 kV FTLO Souris-Magic City 115 kV	-	19,517	111,826
Base	Nodway-Maryville 161 kV FTLO Maryville-Maryville 161 kV	101,304	109,863	5,015
Base	Lamar 161/69 kV transformer FTLO Clark-Lamar 161 kV	-	7,268	55,101

Case	Constraint	2023 Congestion Score	2026 Congestion Score	2031 Congestion Score
Base	Humbolt 161/69 kV transformer FTLO W. Brock-S1280 161 kV	484	1,775	1,373
Base	Scottsbluff-Victory Hill 115 kV FTLO Stegall 4-Stegall 230 kV	56,079	86,106	97,147
Base	Morrill-Scottsbluff 115 kV FTLO Wayside-Stegall 230 kV	19,799	19,443	91,377
Base	Carlisle-Doud Tap FTLO the Wolfforth 230/115 kV transformer	92,587	7,480	48,394
Base	Souris-Magic City 115 kV FTLO Leland-Logan 230 kV	3,536	31,464	75,878
Base	Kelly 161 kV/115 kV transformer FTLO Kelly-Tecumseh Hill 161 kV	16,727	11,839	37,772
Base	Fairport 161 kV bus tie line FTLO Fairport-St. Joe 345 kV	56,540	86,051	77,697
Base	Kelly 161/115 kV transformer FTLO Tecumseh Hill 161/115 kV transformer	10,316	30,588	84,876
Base	Forman 230 kV/115 kV transformer FTLO Hankson-Wahpeton 230 kV	-	-	44,984
Base	McHenry 230/115 kV transformer FTLO Magic City 230/115 kV transformer	3,841	75,894	-
Base	Humbolt 161/69 kV transformer FTLO W. Brock-S1263 69 kV	25	86	-
Base	Spencer-Fort Randal FTLO Ainsworth-Bassett 115 kV	11,870	17,004	32,618
Base	Mallard-Logan 115 kV FTLO Leland Olds-Logan 230 kV	11,121	49,401	8
Base	Watford 230 /115 kV transformer 2 FTLO Watford 230 /115 kV transformer 1	56,043	27,413	-
Base	Forman 230 /115 kV transformer FTLO Hankson-Wahpeton 230 kV	50,369	20,704	-
Base	Midwest-Franklin 138 kV FTLO Canadian-Cedar Lane 138 kV	52	555	2,001
Base	Mallard-Logan 115 kV FTLO Mallard-Ruthville 115 kV	-	581	19
Sensitivity	Watford-Charlie Creek 230 kV FTLO Charlie Creek-Patent Gate 345 kV	259,829	271,043	440,523

Case	Constraint	2023 Congestion Score	2026 Congestion Score	2031 Congestion Score
Sensitivity	Graceville Johnson Junction-Morris 115 kV FTLO Hankson-Wahpeton 230 kV	244,372	422,128	146,326
Sensitivity	SPSNMTIES	266,160	174,437	453,100
Sensitivity	Big Stone-Brownsville 230 kV FTLO Oakes-Ellendale 230 kV	124,806	191,701	56,678
Sensitivity	Oahe-Sully Buttes 230 kV FTLO a Leland Olds tie line	6,225	32,377	99,222
Sensitivity	Big Stone-Brownsville 230 kV FTLO Twin Breaks-Ellen Shunt 345 kV	84,115	117,679	56,648
Sensitivity	Watford-Williston 230 kV FTLO Charlie Creek-Patent Gate 345 kV	-	22,867	41,540
Sensitivity	Souris-Magic City 115 kV FTLO Mallard-Nelson 115 kV	-	72,117	137,220
Sensitivity	Wiliston-Judson 230 kV FTLO Charlie Creek-Patent Gate 345 kV	-	73,450	18,179
Sensitivity	Forman-Elliott 115 kV FTLO Hankson-Wahpeton 230 kV	10,085	4,245	64,510
Sensitivity	Potter County 345/230 kV transformer FTLO Hitchland-Moore County 230 kV	495	10,785	27,358
Sensitivity	McHenry-Voltair 115 kV FTLO Souris-Magic City 115 kV	-	14,569	107,359
Sensitivity	Scottsbluff-Victory Hill 115 kV FTLO Stegall 4-Stegall 230 kV	50,125	77,587	87,587
Sensitivity	Morrill-Scottsbluff 115 kV FTLO Wayside-Stegall 230 kV	12,303	13,688	48,373
Sensitivity	Carlisle-Doud Tap FTLO the Wolfforth 230 kV/115 kV transformer	62,529	4,825	35,102
Sensitivity	Souris-Magic City 115 kV FTLO Leland-Logan 230 kV	-	22,166	52,017
Sensitivity	Forman 230 kV/115 kV transformer FTLO Hankson-Wahpeton 230 kV	-	-	28,348
Sensitivity	McHenry 230 115 kV transformer FTLO Magic City 230/115 kV transformer	-	775	68,931
Sensitivity	Mallard-Logan 115 kV FTLO Leland Olds-Logan 230 kV	8	7,850	43,603

Case	Constraint	2023 Congestion Score	2026 Congestion Score	2031 Congestion Score
Sensitivity	Watford 230/115 kV transformer 2 FTLO Watford 230/115 kV transformer 1	-	62,224	37,555
Sensitivity	Forman 230/115 kV transformer FTLO Hankson-Wahpeton 230 kV	33,521	12,153	-
Sensitivity	Mallard-Logan 115 kV FTLO Mallard-Ruthville 115 kV	-	353	112

Table 5.1: Future 1 Economic Needs

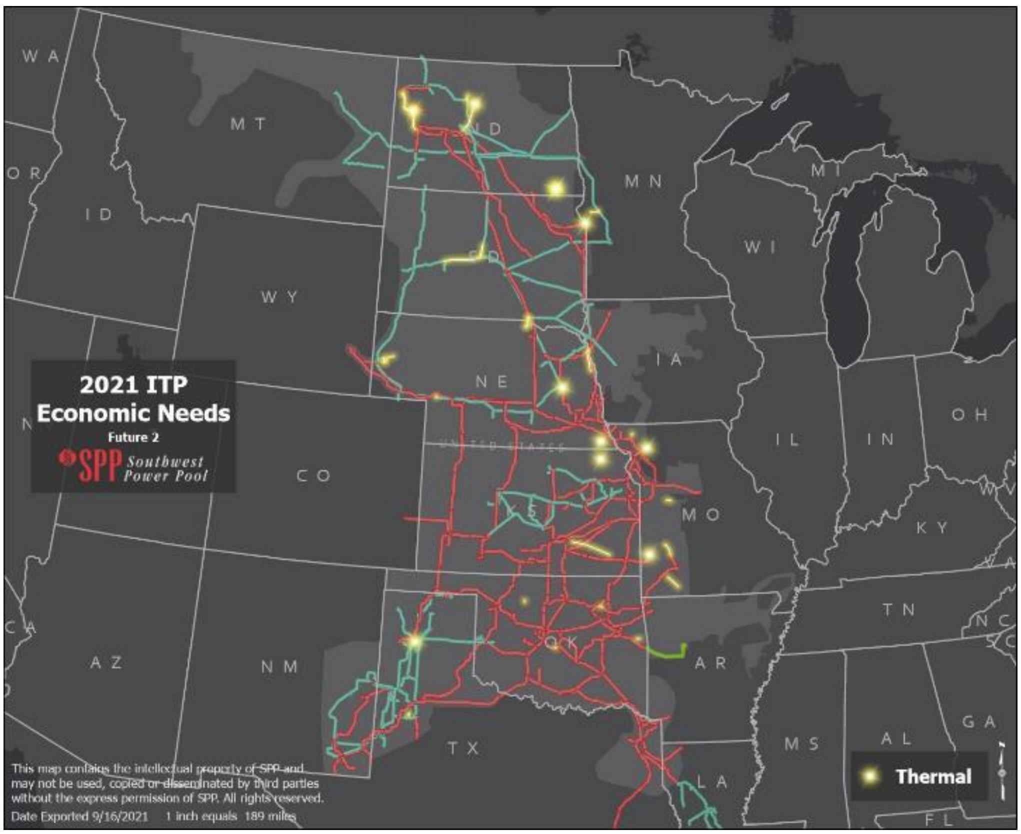


Figure 5.2: Future 2 Economic Needs

Case	Constraint	2026 Congestion Score	2031 Congestion Score
Base	Lamar 161/69 kV transformer circuit 1 FTLO Morgan-Jasper 345 kV	566,137	1,569,085
Base	Butler-Altoona 138 kV FTLO Neosho-Neosho Tap 345 kV	836,853	714,815
Base	Cleo Corner-Cleo Junction 2 69 kV FTLO Renfrow (OKGE)-Renfrow (WFEC) 138kV	676,988	153,279

Case	Constraint	2026 Congestion Score	2031 Congestion Score
Base	Watford-Charlie Creek 230 kV FTLO Charlie Creek-Patent Gate 345 kV	326,982	479,797
Base	Graceville Johnson Junction-Morris 115 kV FTLO Hankson-Wahpeton 230 kV	357,276	48,707
Base	SPSNMTIES	174,914	193,223
Base	Warrensburg East-Warrensburg Air Force Tap West 161 kV FTLO Overton-Sibley 345 kV	290,026	224,060
Base	Akins-Sallisaw 161 kV FTLO Muskogee-Ft. Smith 345 kV	201,014	273,754
Base	Aurora-Reeds Spring 161 kV FTLO Beaver-Eureka 161 kV	279,795	286,733
Base	Big Stone-Brownsville 230 kV FTLO Oakes-Ellendale 230 kV	283,379	61,637
Base	Raun-Tekamah 161 kV FTLO Raun-S3451 345 kV	53,606	233,699
Base	Ogallala 115 kV bus tie line FTLO Ogallala-Grant 115 kV	59,136	46,615
Base	Columbus East transformer 230/115 kV FTLO Columbus East-Shell Creek 345 kV	135,637	177,432
Base	Oahe-Sully Buttes 230 kV FTLO Leland Olds tie line	35,545	174,649
Base	Big Stone-Brownsville 230 kV FTLO Twin Breaks-Ellen Shunt 345 kV	170,591	668
Base	Tulsa North-Cherokee Data Center East Tap 138 kV FTLO Grand River Energy Center-Grand River Energy Center Tap 345 kV	72,900	163,460
Base	Watford-Williston 230 kV FTLO Charlie Creek-Patent Gate 345 kV	73,247	161,442
Base	Morgan-Stockton 161 kV FTLO Morgan-Jasper 345 kV	3,498	160,033
Base	Souris-Magic City 115 kV FTLO Mallard-Nelson 115 kV	90,500	153,283
Base	Wiliston-Judson 230 kV FTLO Charlie Creek-Patent Gate 345 kV	135,040	50,323
Base	Forman-Elliott 115 kV FTLO Hankson-Wahpeton 230 kV	13,651	127,648
Base	Potter County 345/230 kV transformer FTLO Hitchland-Moore County 230 kV	28,648	113,078
Base	McHenry-Voltair 115 kV FTLO Souris-Magic City 115 kV	96,202	83,465
Base	Nodway-Maryville 161 kV FTLO Maryville-Maryville 161 kV	59,352	808
Base	Lamar 161/69 kV transformer FTLO Clark-Lamar 161 kV	63,712	103,779
Base	Humbolt 161/69 kV transformer FTLO W. Brock-S1280 161 kV	238	100,384

Case	Constraint	2026 Congestion Score	2031 Congestion Score
Base	Scottsbluff-Victory Hill 115 kV FTLO Stegall (NPPD) -Stegall (WAPA) 230 kV	69,212	39,314
Base	Morrill-Scottsbluff 115 kV FTLO Wayside-Stegall 230 kV	41,334	96,093
Base	Carlisle-Doud Tap FTLO the Wolfforth 230/115 kV transformer	13,073	64,461
Base	Souris-Magic City 115 kV FTLO Leland-Logan 230 kV	46,131	92,294
Base	Kelly 161/115 kV transformer FTLO Kelly-Tecumseh Hill 161 kV	88,702	28,592
Base	Fairport 161 kV bus tie line FTLO Fairport-St. Joe 345 kV	74,698	12,863
Base	Kelly 161/115 kV transformer FTLO Tecumseh Hill 161/115 kV transformer	3,042	74,187
Base	Forman 230/115 kV transformer FTLO Hankson-Wahpeton 230 kV	-	78,808
Base	Big Stone-Brownsville 230 kV FTLO Ellendale 345/230 kV transformer	78,674	-
Base	McHenry 230/115 kV transformer FTLO Magic City 230/115 kV transformer	68,230	1,091
Base	Humbolt 161 kV/69 kV transformer FTLO W. Brock-S1263 69 kV	67,558	-
Base	Spencer-Fort Randall 115 kV FTLO Ainsworth-Bassett 115 kV	57,643	18,170
Base	Mallard-Logan 115 kV FTLO Leland Olds-Logan 230 kV	57,128	10,468
Base	Watford 230/115 kV transformer circuit 2 FTLO Watford 230/115 kV transformer circuit 1	26,908	56,419
Base	Forman 230/115 kV transformer FTLO Hankson-Wahpeton 230 kV	31,039	-
Base	Midwest-Franklin 138 kV FTLO Canadian-Cedar Lane 138 kV	1,566	1,247
Base	Mallard-Logan 115 kV FTLO Mallard-Ruthville 115 kV	992	731
Sensitivity	Watford-Charlie Creek 230 kV FTLO Charlie Creek-Patent Gate 345 kV	275,794	382,800
Sensitivity	Graceville Johnson Junction-Morris 115 kV FTLO Hankson-Wahpeton 230 kV	411,844	60,336
Sensitivity	SPSNMTIES	487,772	459,256
Sensitivity	Big Stone-Brownsville 230 kV FTLO Oakes-Ellendale 230 kV	263,472	55,606
Sensitivity	Oahe-Sully Buttes 230 kV FTLO a Leland Olds tie line	31,955	165,174
Sensitivity	Big Stone-Brownsville 230 kV FTLO Twin Breaks-Ellen Shunt 345 kV	166,703	589

Case	Constraint	2026 Congestion Score	2031 Congestion Score
Sensitivity	Watford-Williston 230 kV FTLO Charlie Creek-Patent Gate 345 kV	29,466	70,427
Sensitivity	Souris-Magic City 115 kV FTLO Mallard-Nelson 115 kV	79,960	137,631
Sensitivity	Wiliston-Judson 230 kV FTLO Charlie Creek-Patent Gate 345 kV	75,580	15,638
Sensitivity	Forman-Elliott 115 kV FTLO Hankson-Wahpeton 230 kV	19,262	128,714
Sensitivity	Potter County 345 kV/230 kV transformer FTLO Hitchland-Moore County 230 kV	31,476	37,960
Sensitivity	McHenry-Voltair 115 kV FTLO Souris-Magic City 115 kV	91,893	80,230
Sensitivity	Scottsbluff-Victory Hill 115 kV FTLO Stegall (NPPD)-Stegall (WAPA) 230 kV	63,896	37,704
Sensitivity	Morrill-Scottsbluff 115 kV FTLO Wayside-Stegall 230 kV	27,095	65,976
Sensitivity	Carlisle-Doud Tap FTLO the Wolfforth 230/115 kV transformer	17,782	47,856
Sensitivity	Souris-Magic City 115 kV FTLO Leland-Logan 230 kV	29,334	55,746
Sensitivity	Forman 230/115 kV transformer FTLO Hankson-Wahpeton 230 kV	-	60,578
Sensitivity	Big Stone-Brownsville 230 kV FTLO Ellendale 345/230 kV transformer	-	73,599
Sensitivity	McHenry 230/115 kV transformer FTLO Magic City 230/115 kV transformer	3,233	59,873
Sensitivity	Mallard-Logan 115 kV FTLO Leland Olds-Logan 230 kV	9,022	48,468
Sensitivity	Watford 230/115 kV transformer circuit 2 FTLO Watford 230/115 kV transformer circuit 1	61,743	34,623
Sensitivity	Forman 230/115 kV transformer FTLO Hankson-Wahpeton 230 kV	20,385	-
Sensitivity	Mallard-Logan 115 kV FTLO Mallard-Ruthville 115 kV	875	525

Table 5.2: Future 2 Economic Needs

5.1.1 SPS SOUTH TARGET AREA ECONOMIC NEEDS REVIEW

The market economic models show congestion on the SPSNMTIES interface in all scenarios, however the sensitivity cases reveal higher congestion scores, which are more reflective of the planned reality with limited retirements in the SPS area and the exclusion of a proxy combined cycle unit. The higher congestion scores are caused by the recommissioning of the uneconomic SPS units and the removal of the more economic proxy combined cycle unit and associated transmission upgrades. Because the sensitivity cases model more realistic system conditions, focus should be given to those results over that of the base case for the SPS South target area.

The following list is comprised of economic constraints located in the SPS South target area that are likely to become congested as a result of relieving congestion on the SPS South needs.

- McDowell Creek-Potter County 230 kV FTLO Potter County 345/230 kV transformer
- Frisco Wind-Lasley 115 kV FTLO Potter County 345/230 kV transformer
- Bushland 230/115 kV transformer FTLO Bushland-Potter County 230 kV
- Potter 345/230 kV transformer FTLO Woodward EHV-Woodward-Border Tap
- SPPSPSTIES Interface
- Moore County-McDowell Creek 230 kV FTLO Potter County 345/230 kV transformer
- Deaf Smith #20-Curry 115 kV FTLO Deaf Smith-Plant X 230 kV
- Moore-Rita Blanca S&S 115 kV FTLO Moore County-McDowell Creek 230 kV
- Spearman-Pringle 115 kV FTLO Potter County 345/230 kV transformer
- Red Bluff-Road Runner 115 kV FTLO Road Runner 345/115 kV transformer
- Deaf Smith Plant X 230 kV FTLO Newhart-Plant X 230 kV
- Kress Interchange-Hale County 115 kV FTLO Swisher-Tuco Interchange 230 kV
- Hillside-Arnot 115 kV FTLO Potter County-Bushland 230 kV
- Plant X-Lamb County 115 kV FTLO Lamb County 230/115 kV transformer
- Bailey County-Earth Interchange-Plant X 115 kV FTLO Deaf Smith-Plant X 230 kV
- Potter County 345/230 kV transformer FTLO Border-Woodward-Border Tap 345 kV
- Rita Blanca-Spurlock-Moore East 115 kV FTLO Hitchland-Moore County 230 kV
- Wheeler-Stateline-Demarcation 230 kV FTLO Potter 345/230 kV transformer
- Lamb Country-Hockley 115 kV FTLO Plant X-Sundown 230 kV
- Spearman-Hansford 115 kV FTLO Potter 345/230 kV transformer
- Wolfforth-Terry County 115 kV FTLO Tuco Interchange-Yoakum 345 kV
- Carlisle-LP Doud 115 kV FTLO Tuco Interchange-Yoakum 345 kV

5.1.2 ADDITIONAL ECONOMIC CONSTRAINTS IN BAKKEN TARGET AREA

The following list is comprised of economic constraints located in the Bakken target area that are likely to become congested as a result of relieving congestion on the Bakken target area needs.

- Williston-Williston FTLO Stateline-Mont 115 kV
- Johnson Junction-Morris 115 kV FTLO Big Stone-Blair 230 kV
- Souris-Magic City 115 kV FTLO McHenry-Coal Creek 230 kV
- Oahe-Sully Buttes 230 kV FTLO Maurine-Bison 230 kV
- Scottsbluff-Victory Hill 230 kV FTLO Dry Creek-North Underwood 230 kV + Stegall-Stegall 230 kV

- Alliance-Snake Creek 115 kV FTLO Stegall-Wayside 230 kV
- Souris-Magic City 115 kV FTLO McHenry-Balta 230 kV
- Mallard-East Ruthville 115 kV FTLO Mallard-Logan 115 kV
- Maurine 230/115 kV transformer FTLO Maurine-North Underwood 230 kV
- Mallard-Logan 115 kV FTLO Charlie Creek-Patent Gate 345 kV
- Big Stone-Browns Valley 230 kV FTLO Big Stone South-Astoria 345 kV
- Johnson Junction-Morris 115 kV FTLO Granite-Morris 230 kV
- Velva Wind Tap-McHenry 115 kV FTLO Magic City 230/115 kV transformer
- Watford 230/115 kV transformer circuit 1 FTLO Watford 230/115 kV transformer circuit 2
- Sully Buttes-Whitlock 230 kV FTLO Leland Olds-Chapelle 345 kV
- Elliot-Enderline 115 kV FTLO Hankson-Wahpeton 230 kV
- Forman-Forman 115 kV FTLO Hankson-Wahpeton 230 kV

5.2 RELIABILITY NEEDS

5.2.1 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,[28] 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, SPP solved or marked invalid potential violations were 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. Figure 5.3 and Figure 5.4 summarize the number of remaining thermal and voltage needs[29] that were unable to be mitigated during the screening process. It's important to note that the SPSNMTIES interface introduced earlier in this report was found to be in violation of its season rating in eight out of nine base reliability models. A major contributing factor to these thermal interface loading violations was the generation shortfall discussed in the SPS target area overview.

Additional models were included in the reliability assessment in order to analyze the two target areas. These additional models include transfer cases (noted with '_T0' below) built to simulate real-time interfaces seen in the New Mexico area.

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

[29] Figures summarize unique monitored elements.

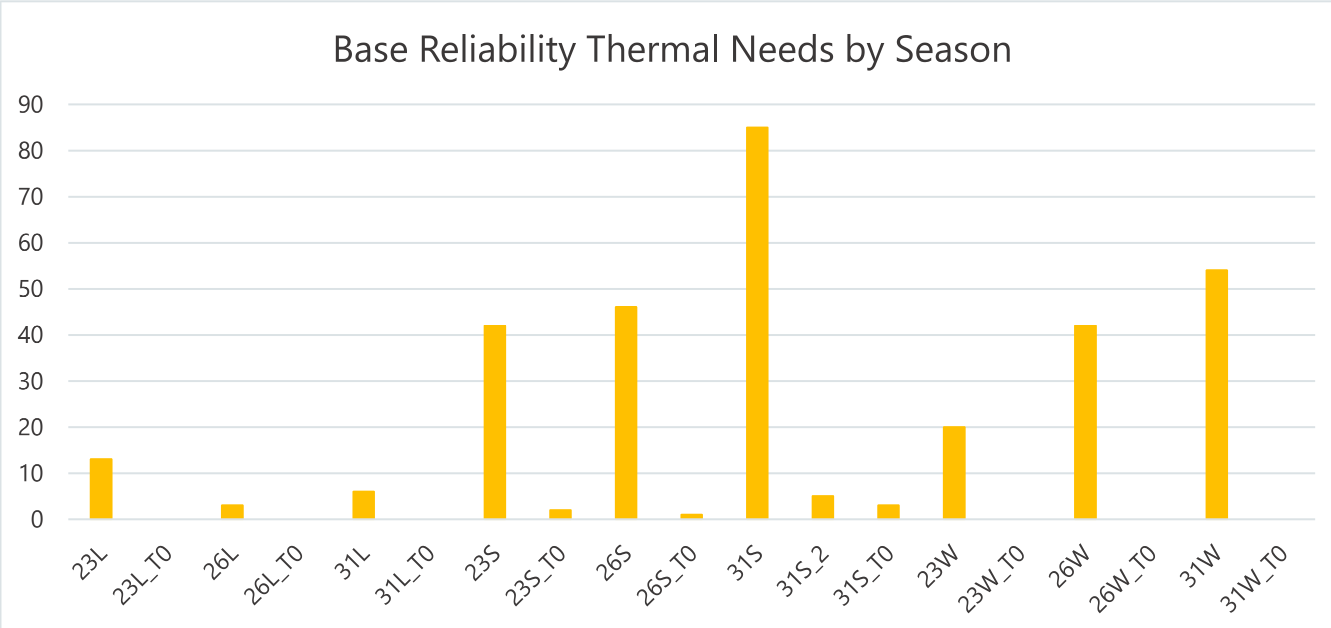


Figure 5.3: Unique Base Reliability Thermal Needs by Season

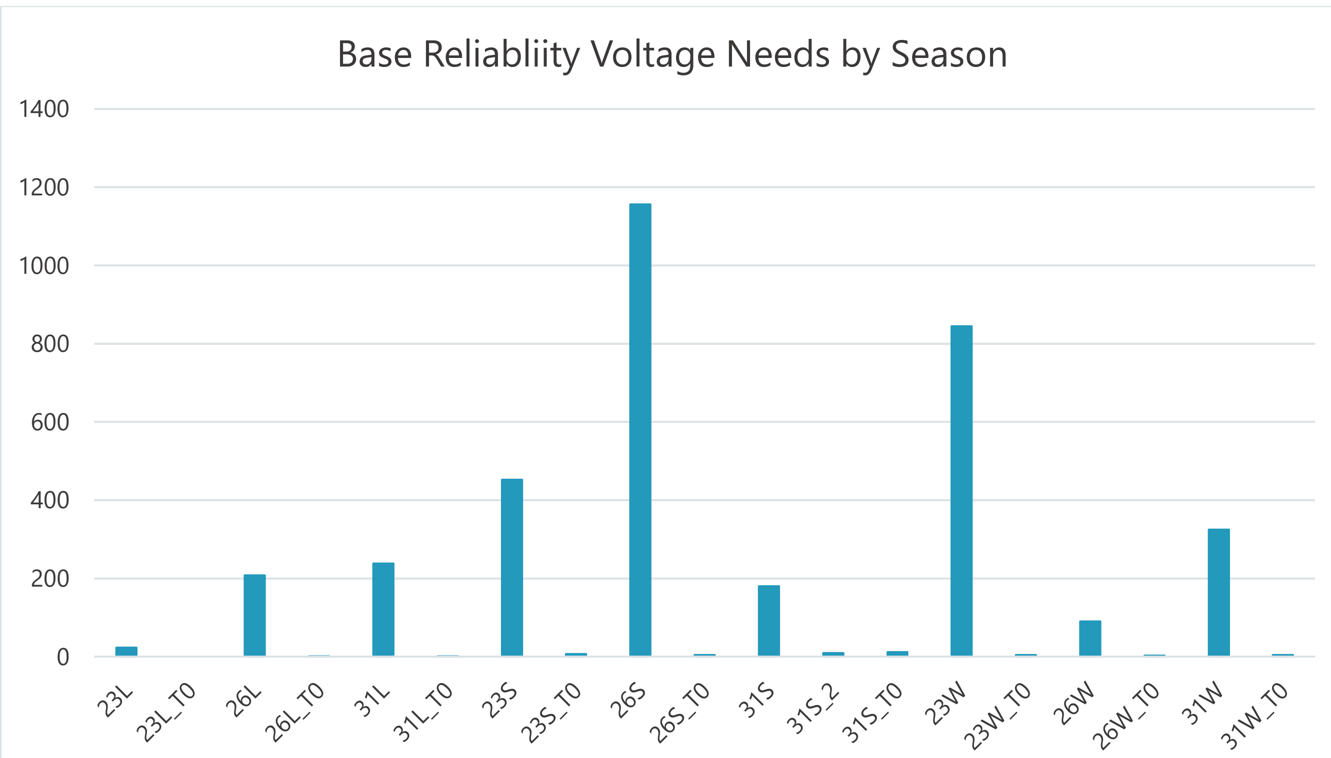


Figure 5.4: Unique Base Reliability Voltage Needs

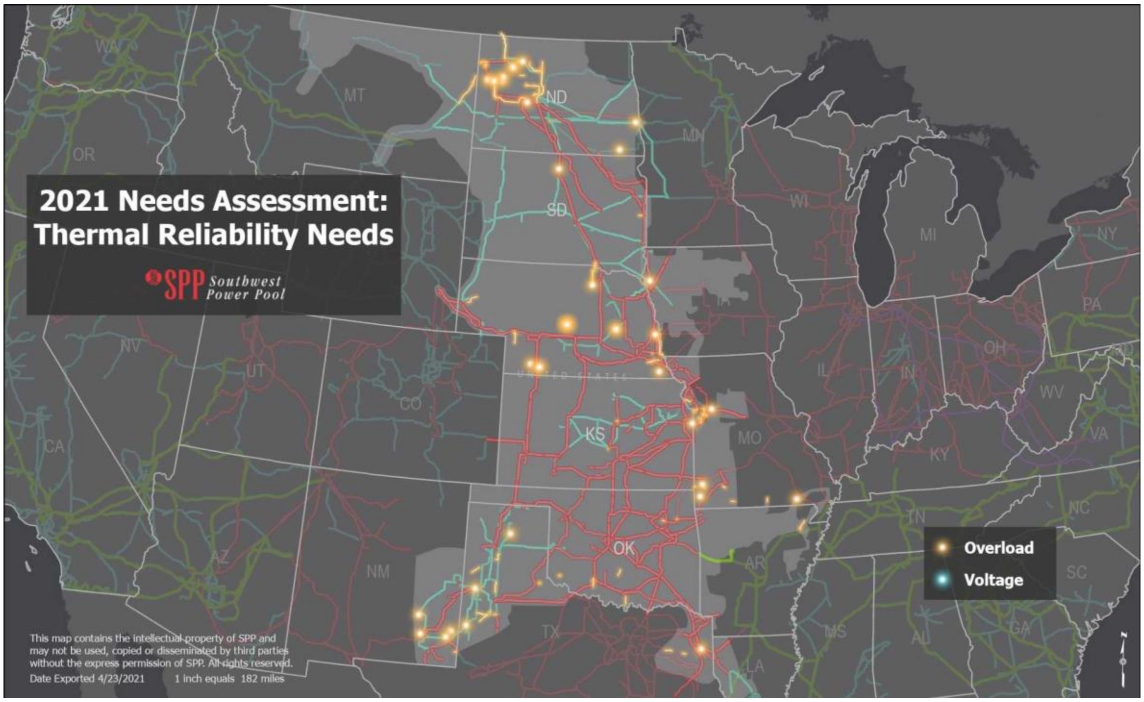


Figure 5.5: Base Reliability Needs - Thermal

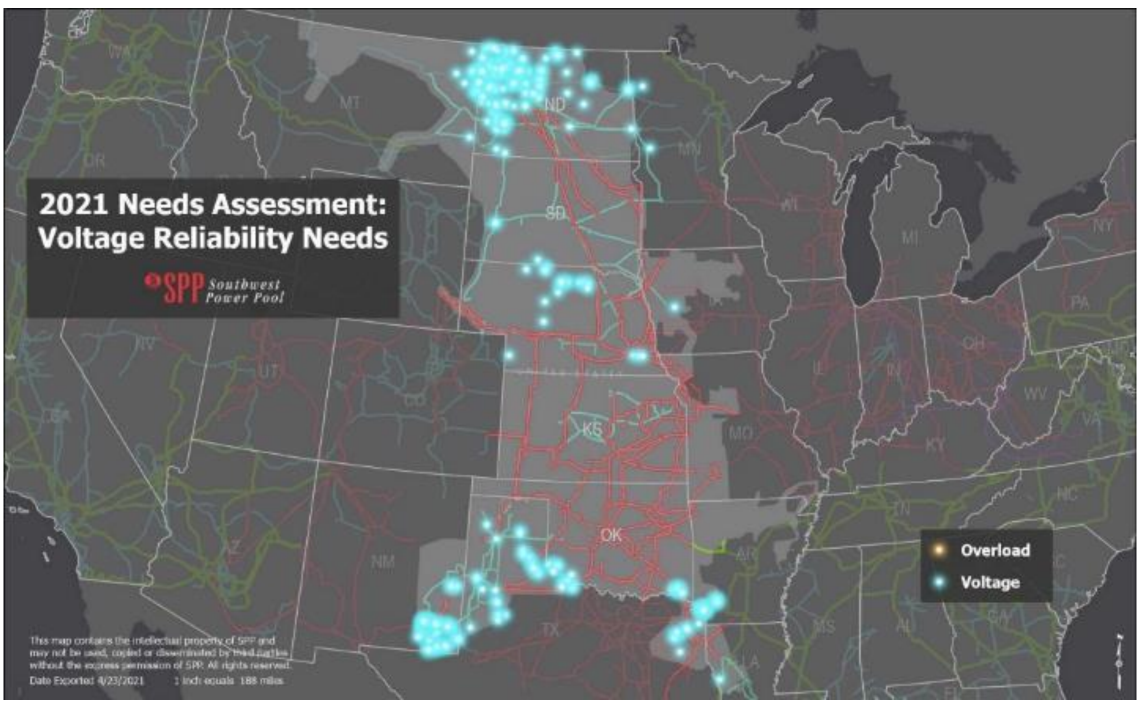
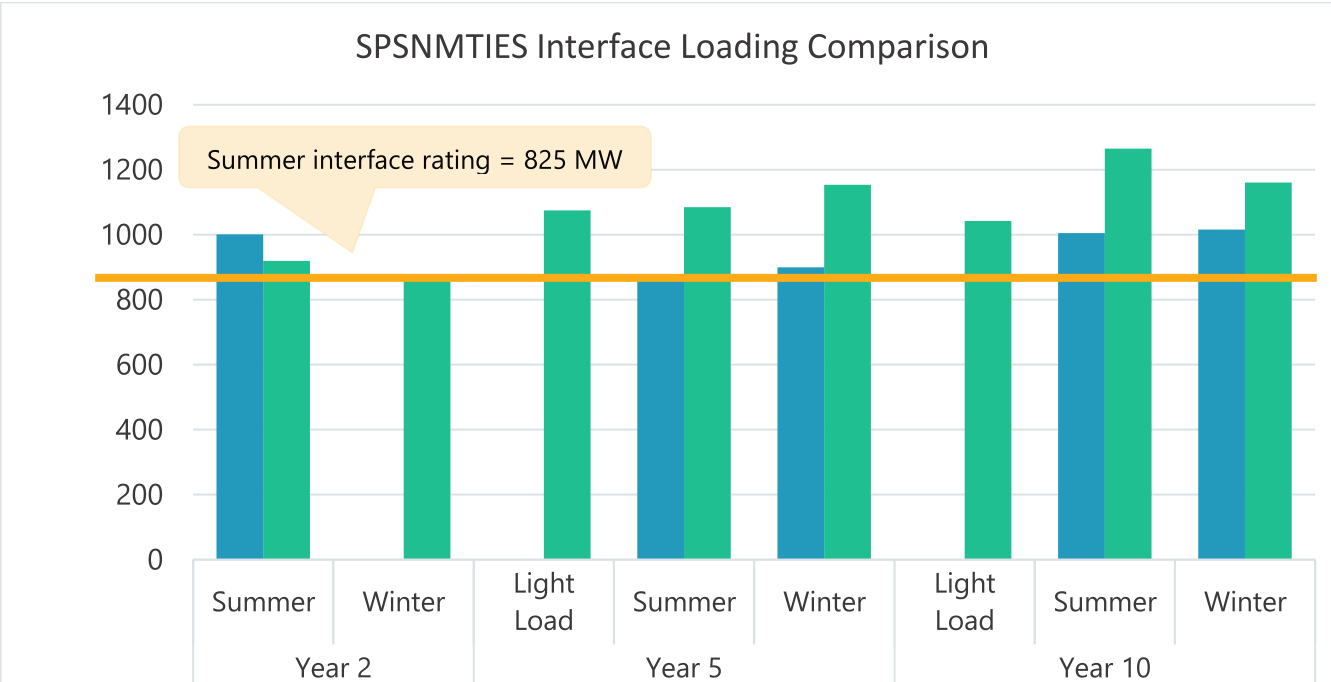


Figure 5.6: Base Reliability Needs - Voltage

5.2.1.1 *SPS SOUTH TARGET AREA RELIABILITY NEEDS OVERVIEW*

In the BR models, the SPS South target area experiences thermal overloads and insufficient voltage support, leading to voltage collapse, for numerous contingency situations. Planned resource retirements in Year 10 are the main driver of the thermal and voltage needs. These conditions are further exacerbated because the New Mexico area is experiencing higher than average load growth when compared the SPP region. As a result, the SPSNMTIES interface is overloaded in eight out of nine BR models under system intact conditions.



	Year 2		Year 5			Year 10		
	Summer	Winter	Light Load	Summer	Winter	Light Load	Summer	Winter
2020 ITP	1000.8			861.3	900		1005.3	1016.3
2021 ITP	919	865	1075	1085	1154	1042	1265	1161

Figure 5.7: Interface Loading Comparison

5.2.1.2 *BAKKEN TARGET AREA RELIABILITY NEEDS OVERVIEW*

The Bakken target area in North Dakota is characterized by aggressive load growth in an area remote from supporting generation resources. This area experiences many thermal and voltage violations in the base case and many contingency cases in the Base Reliability models. Voltage collapse is also an issue in some single-contingency situations as power is delivered from the remote generation to the growing load. The Base Reliability models also contain two proxy static VAR compensator (SVC) devices to allow the base case powerflow to solve in Year 10 due to the lack of nearby reactive support in the region.

5.2.2 MARKET POWERFLOW ASSESSMENT

As previously agreed, the market powerflow models were not included in the needs assessment.

5.2.3 NON-CONVERGED CONTINGENCIES

SPP used engineering judgment to resolve non-converged cases from the contingency analysis. Some non-converged cases could not be solved due to the contingency taken. These scenarios revolved around contingencies near the New Mexico border and the Bakken area. These needs were represented in the assessment as potential voltage collapse needs.

5.2.4 SHORT-CIRCUIT ASSESSMENT

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

The 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 a NTC are based on the SPP short-circuit analysis.

The two TPs identifying short-circuit needs were Evergy and Missouri River Energy Services (MRES). The needs are depicted in Figure 5.8.

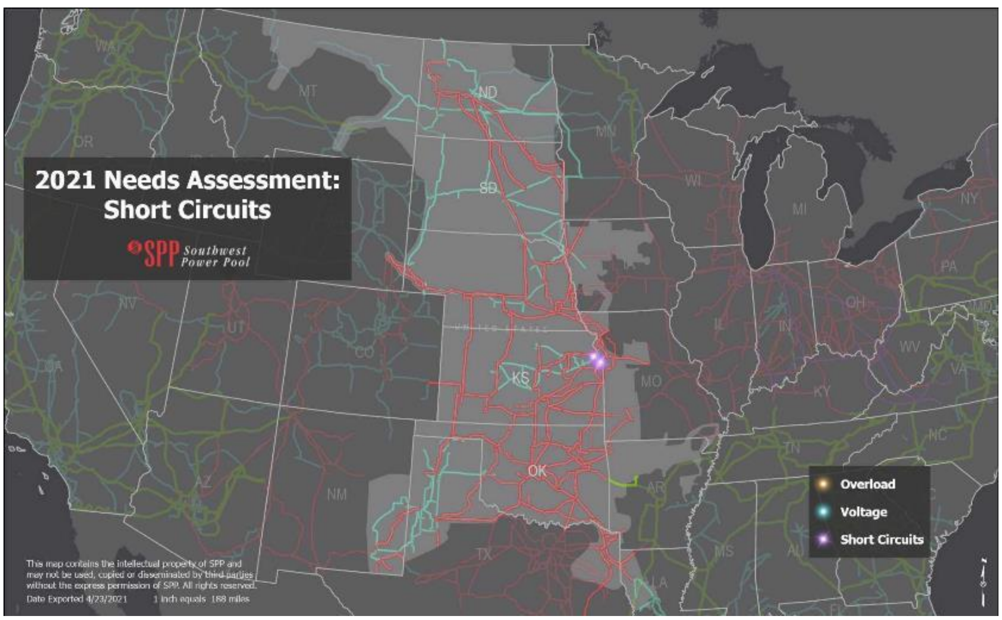


Figure 5.8: Short-Circuit Needs

5.3 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.

5.4 PERSISTENT OPERATIONAL NEEDS

5.4.1 ECONOMIC OPERATIONAL NEEDS

The lone economic operational need identified for the 2021 ITP in Table 5.3 was posted for informational purposes only.

MONITORED ELEMENT	CONTINGENT ELEMENT
Midwest-Franklin 138 kV	Cedar Lane-Canadian 138 kV

Table 5.3: Economic Operational Need-Informational Only

The constraints in Table 5.4 had associated future upgrades which are expected to reduce some or all congestion cost associated with the constraint.

MONITORED ELEMENT	CONTINGENT ELEMENT	APPROVED UPGRADE
Waverly-La Cygne 345 kV	Caney River-Neosho 345 kV	New Wolf Creek-Blackberry 345 kV line (2019 ITP)
Cimarron 345/138 kV	Cimarron 345/138 kV	New Minco-Pleasant Valley-Draper 345 line (2020 ITP)
Cleveland 138 kV Bus Tie	Cleveland-Tulsa North 345 kV	New Sooner-Wekiwa 345 kV line (2019 ITP)
Dover Switch-Okeene 138 kV	Waukomis Tap-Waukomis 138 kV	Dover Switch-Okeene 138 kV Terminal Upgrades (2020 ITP)
Neosho-Riverton 161 kV	Neosho-Blackberry 345 kV	Neosho-Riverton 161 kV Rebuild (October 2023, 2019-AG1-AFS-2)
Stonewall-Tupelo 138 kV	Seminole-Pittsburg 345 kV	Tupelo 138 kV Terminal Upgrades (2017 ITP10)
Gerald Gentlemen Station Stability Interface *Gentleman-Red Willow 345 kV* *Gentleman-Sweetwater 345 kV Circuits 1 and 2* *Gentleman-North Platte 230 kV Circuits 1, 2 and 3*	Power Transfer Distribution Factor	New Gentleman-Cherry County-Holt 345 kV line (2012 ITP10)
Stonewall-Tupelo 138 kV	Pittsburg-Valliant 345 kV	Tupelo 138 kV terminal upgrades (2017 ITP10)

MONITORED ELEMENT	CONTINGENT ELEMENT	APPROVED UPGRADE
Russett-South Brown 138 kV	Little City-Brown Tap 138 kV	Russett-South Brown 138 kV rebuild (2020 ITP)
Mathewson-Northwest 345 kV	Mathewson-Cimarron 345 kV	Mathewson-Northwest 345 kV terminal upgrades (2019 ITP)
Anadarko-Gracemont 138 kV	Washita-Southwestern 138 kV	Anadarko-Gracemont 138 kV rebuild (2020 ITP)
Wolf Creek-Waverly 345 kV	Wolf Creek 345/69 kV	New Wolf Creek-Blackberry 345 kV line (2019 ITP)

Table 5.4: Economic Operational Needs-Constraints

The constraint in Table 5.5 has previously issued NTCs in-service, which has reduced the cost of congestion 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
Amoco-Sundown 230 kV	Tolk-Yoakum 230 kV	Sundown-Amoco 230 kV terminal upgrades (2016 ITPNT)

Table 5.5: Economic Operational Need-Previously Issued

5.4.2 RELIABILITY OPERATIONAL NEEDS

There was one reliability operational need identified during the 2021 ITP. This need was posted June 1, 2021, after the initial DPP window closed. This need was later invalidated.

MONITORED ELEMENT	RECONFIGURATION	PERCENTAGE	NOTES
Knoll-North Hays 115 kV	Open South Hays 230 kV CB 6003 to reduce post-contingent flows on IDC 5527, Knoll-North Hays 115 kV FTLO Post Rock-South Hays 230 kV	96.2%	Reconfiguration prevents flows from looping through the 115 kV system and onto the 230 kV system. When excluding days that Mingo-Setab and Postrock-Spearville were out of service, the reconfiguration was still in place 49.8% of the time.

Table 5.6: Reliability Operational Need

5.5 NEED OVERLAP

Relationships identified among the various need types aid in development of the most valuable regional solutions. SPP identified relationships among the economic needs to both the base reliability needs and informational economic operational needs.

OVERLAPPING RELIABILITY AND ECONOMIC NEEDS
SPSNMTIES Interface
Morrill-Gering 115 kV FTLO Wayside-Stegall 230 kV
Carlisle-LP Doud Tap 115 kV FTLO Wolfforth 230/115 kV transformer
Watford 230/115 kV transformer circuit 2 FTLO Watford 230/115 kV transformer circuit 1
Watford-Charlie Creek 230 kV FTLO Charlie Creek-Patent Gate 345 kV
Ogallala (NPPD)-Ogallala-TS7 115 kV FTLO Ogallala (NPPD)-Grant 115 kV
Mallard 7-Logan 115 kV FTLO Leland-Logan 230 kV
Wiliston-Judson 230 kV FTLO Charlie Creek-Patent Gate 345 kV
Humbolt 161/69 kV transformer FTLO S1263-S1280 161 kV

Table 5.7: Base Reliability and Economic Need Overlap

Overlapping Informational Operational and Economic Needs
Midwest-Franklin 138 kV FTLO Canadian-Cedar Lane 138 kV

Table 5.8: Overlapping Informational Operational and Economic Needs

5.6 ADDITIONAL ASSESSMENTS

Additional assessments were performed to satisfy SPP Tariff requirements involving parts of the transmission system that were not included in the approved model sets.

5.6.1 GRIDLIANCE HIGH PLAINS

GridLiance High Plains (GLHP) performed its local planning process assessment in 2020 and identified four new transmission upgrades required to meet local planning process needs. To satisfy its own NERC and tariff requirements, GLHP requested SPP to exercise the requirements under FAC-002 and Attachment O, section II.1 (e), of the tariff to perform a no-harm analysis on the proposed upgrades and coordinate the upgrades with the potential solutions of the 2021 ITP.

An analysis was performed to satisfy these obligations by determining the impact of including the proposed local planning process upgrades in the 2021 ITP base reliability set. After performing the no-harm study on the projects, voltage violations were identified upon applying one the GLHP local planning projects. GLHP provided a reactive setting adjustment to mitigate the potential violation. As a result, no new transmission needs or violations were identified on the existing system due to the proposed local planning process upgrades.

UPGRADES	COST EST. (MILLIONS)	LOCATION	PROPOSED ISD
Add breaker at Powell Corner 115 kV bus	0.6	Oklahoma Panhandle	2022
Replace terminal equipment at Thrash 69 kV station	0.1	Oklahoma Panhandle	2022
New approximately 30-mile 115 kV line from Rose-SUNC Liberal	31.0	Oklahoma Panhandle	2025
New approximately 16-mile 115 kV line from Dry Trails-Hovey	15.8	Oklahoma Panhandle	2026

Table 5.9: Upgrades Identified In GridLiance Local Planning Assessment in 2020

6 SOLUTION DEVELOPMENT AND EVALUATION

Solutions were evaluated in each applicable scenario and modeled to determine their effectiveness in mitigating the needs identified in the needs assessment. The project solutions assessed included the Federal Energy Regulatory Commission (FERC) Order 1000 and Order 890 solutions submitted by stakeholders. SPP developed solutions, projects submitted in previous planning studies, and model adjustments/ corrections. SPP analyzed 783 Detailed Project Proposals (DPP) solutions received from stakeholders and approximately 500 additional solutions were developed by SPP. SPP developed a standardized conceptual cost template to calculate a conceptual cost estimate for each project to utilize during screening.

6.1 RELIABILITY PROJECT SCREENING

Solutions were tested to determine their ability to mitigate reliability criteria violations in the study horizon. To be considered effective, a solution must have been able to address the needs such that the identified facilities were within acceptable limits defined in the SPP Planning Criteria and members' more stringent local planning criteria. Figure 6.1 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 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.

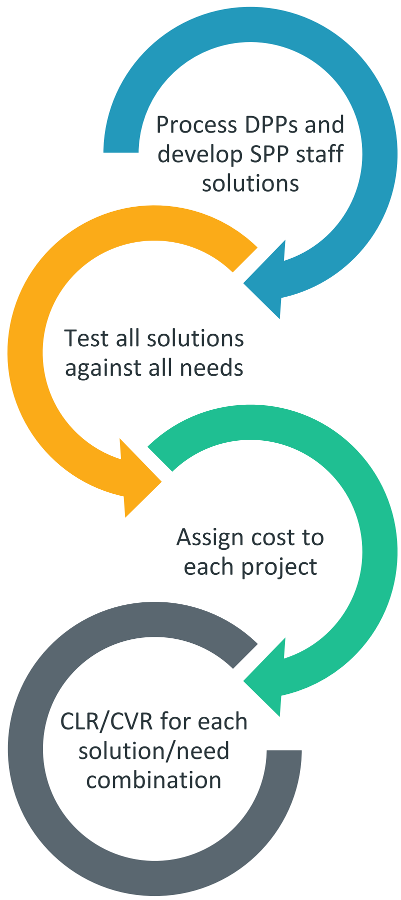


Figure 6.1: Reliability Screening Process

6.2 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 NPV 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 16.19%. 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 the SPS target area were tested on both the base MEM and sensitivity MEM in order to evaluate the impact of removing the proxy combined cycle resource and its associated transmission upgrades. The decision to assess these projects was based upon the submitter's recommendation to study the target area without the GOF topology or the performance of the project in the base MEM. This additional screening allowed SPP to identify if the submitted solution was dependent on the GOF in the SPS target area or performed well without it.

6.3 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.

6.4 PUBLIC POLICY PROJECT SCREENING

No public policy needs were identified in the 2021 ITP; therefore, no projects were screened to address public policy needs.

6.5 PERSISTENT OPERATIONAL PROJECT SCREENING

The persistent economic operational needs were provided for informational purposes only, therefore no solutions were screened.

7 PORTFOLIO DEVELOPMENT

7.1 PORTFOLIO DEVELOPMENT PROCESS

Error! Reference source not found. Figure 7.1 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.

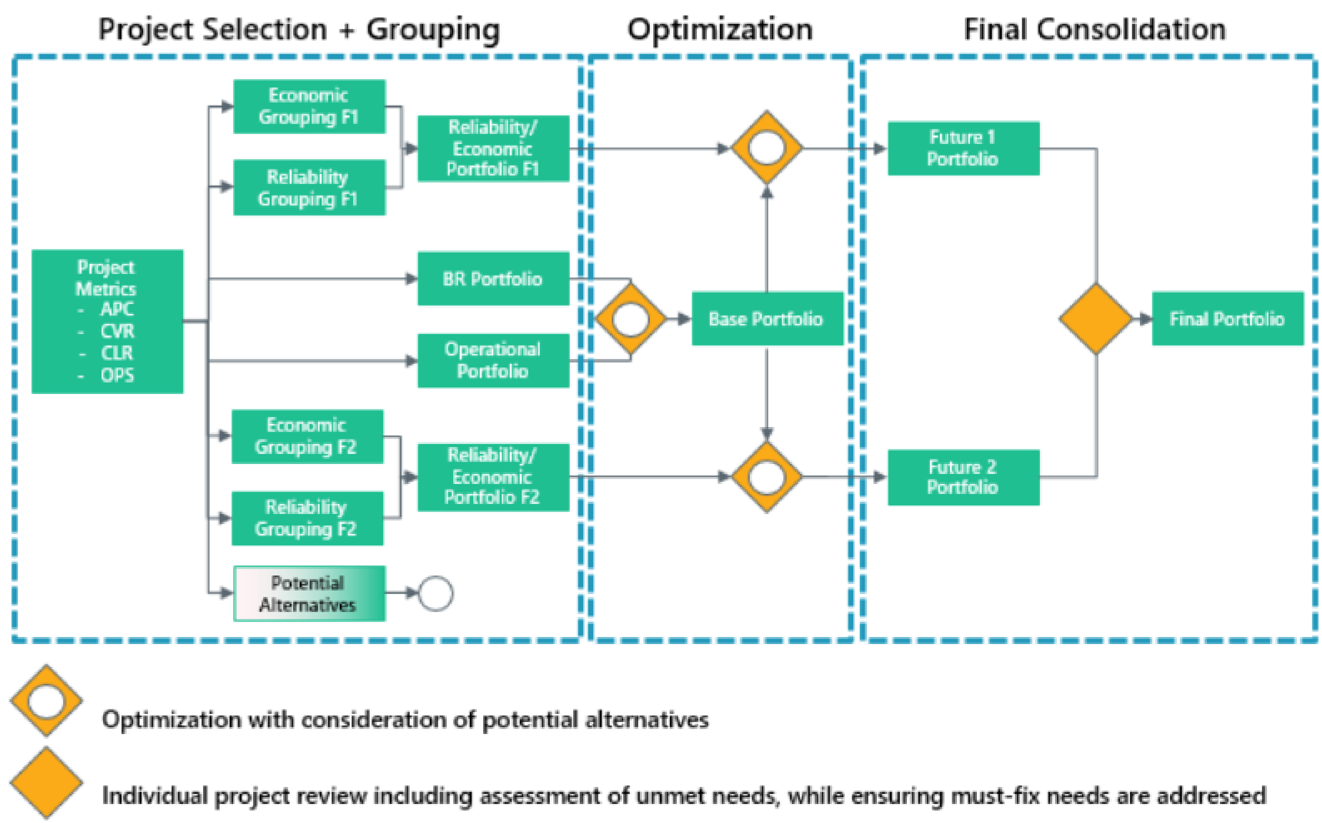


Figure 7.1: Portfolio Development Process

7.2 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 September 2021 SPP transmission planning summit, and SPP's Request Management System.

7.2.1 STUDY ESTIMATES

Solutions that performed well using the screening assessments described in section 6, Solution Development and Evaluation, were sent out for the development of Study Estimates (final project cost within ±30%). In cases where the cost estimate was not received before the September 2021, 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 estimates were received that cost was used for the remainder of the portfolio development process.

7.2.2 RELIABILITY GROUPING

A programmatic method was used to compare the metric results for the extensive number of solutions to be evaluated. Using this solution selection software, a subset of solutions was generated by considering the metrics described in section 6.1. During this process, SPP applied engineering judgment to develop a draft list of selected and high-performing alternate solutions. This analysis was performed for each of the base reliability, Future 1 and Future 2 reliability needs.

The list of reliability solutions was continually refined through stakeholder feedback and review of analysis results. Figure 7.2 below shows the final reliability grouping selected to address the valid list of reliability needs in the 2021 ITP.

Project	Area	Cost	Scenario[30]
Platte City 161 kV switches	EMW	$51,502	23S / BR
Blue Circle-Catoosa 69 kV rebuild	AEPW	$9,020,000	23S / BR
Roswell 115/69 kV transformers circuit 1 and 2 replacement	SPS	$ 4,122,361	23S / BR
Jones-Lubbock South 230 kV circuit 1 and 2 terminal equipment and increase line clearances	SPS	$ 635,957	23S / BR
S3454-S3740 345 kV new line	OPPD	$41,684,278	26S / BR
Powersite-Branson North 161 kV terminal equipment	EMDE	$ 937,800	31S / BR
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	BEPC/MWEC	$301,043,569	23S / BR
Rocky Point-Marietta (OGE) 138kV rebuild; Marietta (OGE)-Marietta (WFEC) 138 kV new line	OGE/WFEC	$18,152,000	23S / BR

[30] This is the earliest season.

Project	Area	Cost	Scenario[30]
East New Town 115 kV 150 MVAR STATCOM	BEPC/MWEC	$23,000,000	31W / BR
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	BEPC/MWEC	$34,634,441	31L / BR
Sioux City 69 kV new breaker CT; Hinton Municipal (K412) 69 kV terminal equipment	NIPCO/WAPA	$746,042	23S / BR
Gering Tap-Morrill 115 kV rebuild	WAPA-Rocky Mountain Region	$17,546,363	23S / BR
Joplin West 7th-Stateline 161 kV rebuild	EMDE	$5,866,619	26S / BR
Kummer Ridge-Round Up 345 kV new line	BEPC	$98,481,715	23L / BR
Artesia 115/69 kV transformers circuit 1 and 2 replacement	SPS	$ 5,666,596	23S / BR
Quahada 115 kV 100 MVAR synchronous condenser	SPS	$27,208,664	31S / BR
Grassland 115 kV 28.8 MVAR capacitor bank	SPS	$2,608,299	23S / BR
Crossroads-Phantom 345 kV new double-circuit lines	SPS	$409,945,890	31S / BR
Squaw Gap 115 kV 15 MVAR capacitor bank	BEPC	$ 728,280	31S / BR

Table 7.1: Reliability Project Grouping

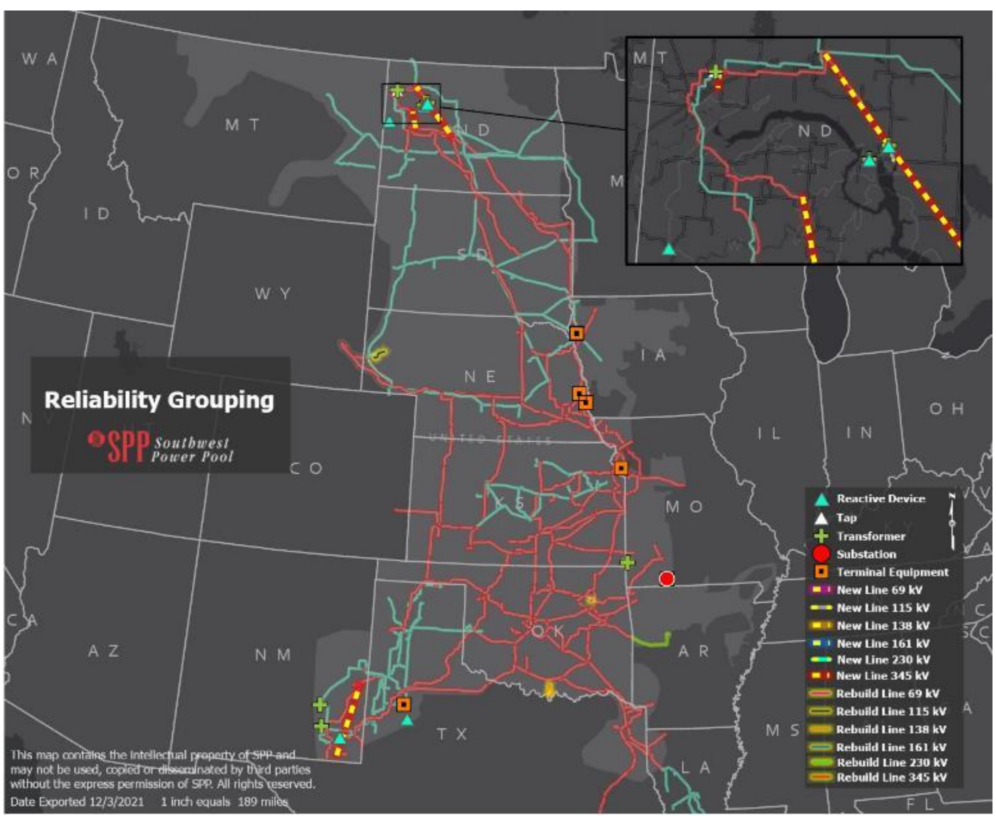


Figure 7.2: Reliability Project Grouping

7.2.3 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 only need to be rated higher than the maximum fault current identified in the needs assessment. Table 7.2 summarizes the final short-circuit grouping, while Figure 7.3 shows the approximate location of identified projects within the SPP footprint.

Reliability Project	Area	Cost	Scenario
Replace one breaker at Jarbalo Junction 115 kV	EKC	$267,179	23S / BR
Replace two breakers at Shawnee Mission 161 kV	EM	$ 510,150	23S / BR
Replace one breaker at Craig 161 kV	EM	$ 319,002	23S / BR
Moorhead 230 kV substation reconfiguration	MRES	$7,935,000	23S / BR

Table 7.2: Short-Circuit Project Grouping

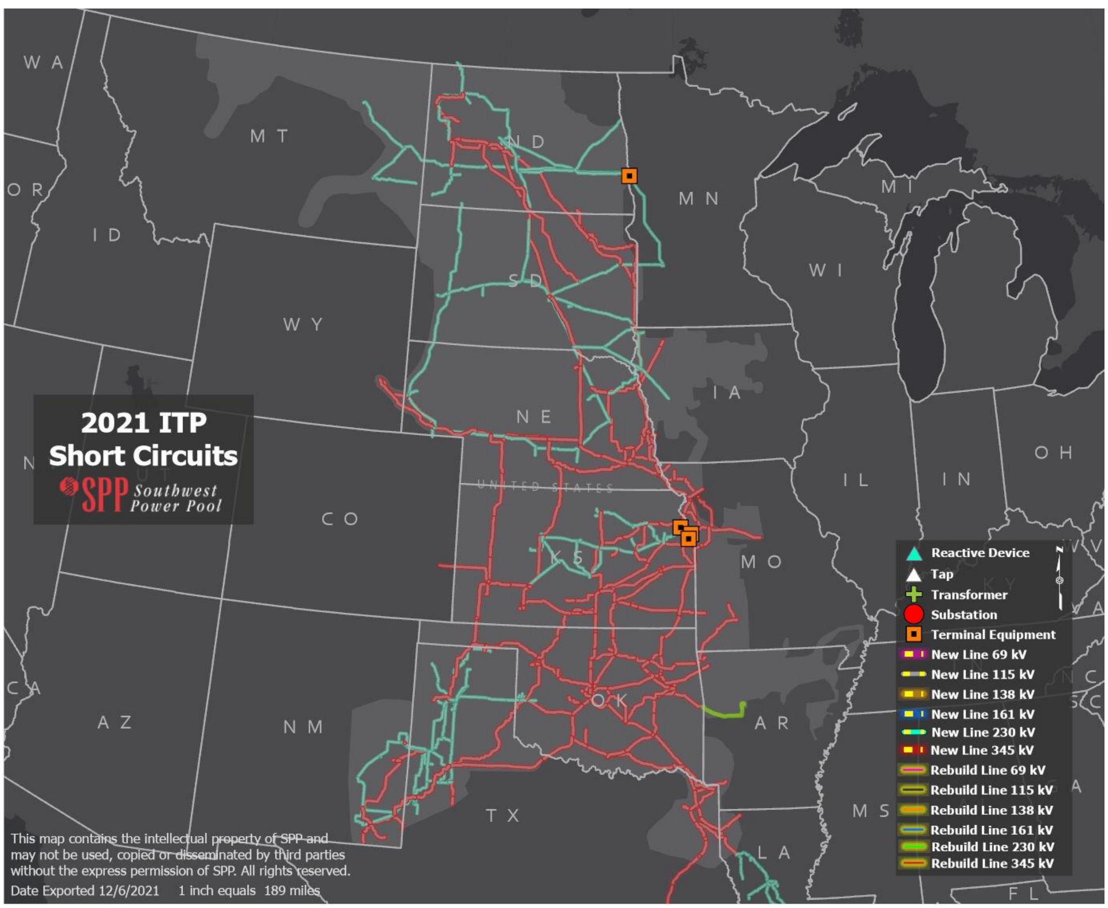


Figure 7.3: Short-Circuit Project Grouping

7.2.4 ECONOMIC GROUPING

All projects with a one-year B/C ratio of at least 0.5 or a 40-year NPV 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 NPV 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 NPV 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, which covers current market congestion
- 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

Table 7.3 identifies a comprehensive list of economic projects included in the six initial groupings. Some projects appeared in multiple groupings.

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Columbus East 230/115 kV transformer replacement	X	X	X	X	X	X
Scottsbluff-Victory Hill 115 kV circuit 2 new line	X	-	-	X	-	-

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase line clearances	X	-	-	X	-	-
Cleo Corner-Cleo Junction 69 kV terminal equipment	X	X	X	X	X	X
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	X	X	X	X	X	X
Gering Tap-Morrill 115 kV rebuild	X	-	-	X	-	-
Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie	X	-	-	X	-	-
Midwest-Franklin 138 kV terminal equipment	X	-	X	X	-	X
Belfield-Maurine-New Underwood-Stegall 345 kV	-	X	-	-	X	-
Belfield-Maurine-New Underwood-Stegall 345 kV, Maurine-Winner-Thedford ("H") project	-	-	X	-	-	X
Install new 161/69 kV transformer and necessary terminal equipment at Humbolt	X	X	X	X	X	X
Quahada 115 kV 100 MVAR synchronous condenser, Yoakum 345 kV 450 MVAR synchronous condenser, Crossroads-Hobbs 345 kV, Potter-Tolk 345 kV, and model or system adjustments (No GOF)	X	X	-	X	X	-
Quahada 115 kV 100 MVAR synchronous condenser, Yoakum 345 kV 450 MVAR synchronous condenser, Crossroads-Hobbs high efficiency (HE) double-circuit 345 kV, Potter-Tolk HE double-circuit 345 kV, and model or system adjustments (No GOF)	-	-	X	-	-	X
Build an 88.2-mile 345 kV line from Raun-S3452. Reroute existing S3451-S3459 345 kV and S3451-S3454 345 kV into new S3452 345 kV sub by expanding existing S1252 to accommodate three 345 kV terminals	X	X	-	X	X	-
Build an 88.2-mile double-circuit 345/161 kV line from Raun-S3452. Using existing 161kV Raun 5-Tekamah 5 S1226 5-S1252 5. Reroute existing S3451-S3454 345 kV and S3451-S3459 345 kV into new S3452 345 kV substation by expanding existing S1252 to accommodate three 345 kV terminals	-	-	X	-	-	X
Rebuild the 3.3-mile double-circuit 161 kV line from S1209-S1231	X	X	X	X	X	X
Build a new 12.38-mile line from Carthage-Jasper 161 kV	X	-	-	X	-	-
Install 345/161 kV transformer at Blackberry and build a 2.7-mile line to Asbury 161kV	-	X	-	-	X	-

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Tap the 345 kV line from Flint Creek-Brookline and build the 345 kV Monett substation. Build a 54.5-mile 345 kV line from Monett-Blackberry	-	-	X	-	-	X
Upgrade terminal equipment at Carthage and/or La Russell 161 kV	X	X	-	X	X	-
Rebuild 20.5 miles 161 kV line from Aurora-Reeds Spring and upgrade any necessary terminal equipment	X	X	X	X	X	X
Install new 161/115kV circuit 2 transformer and necessary terminal equipment at Kelly	X	-	-	X	-	-
Rebuild the 52.6-mile 161 kV line from Kelly-Tecumseh Hill	-	-	-	X	-	-
Build an 85.2-mile 345 kV line from Elm Creek-Tobias	-	X	X	-	X	X
Upgrade terminal equipment on the 161 kV line from Warrensburg East-Whiteman Air Force Base East-Whiteman Air Force Base West-Sedalia	X	X	X	X	X	X
New substation at Bowen345 345 kV; Tap branch from Fairport-St. Joseph 345 kV; Tap branch from Mullen Creek-Ketchem 345 kV	-	-	-	X	X	X
Rebuild the 161 kV line from Gore-Muskogee Tap-Muskogee. Rebuild the 161 kV line from Tahlequah-Highway 59. Rebuild the 161 kV line from VBI-Adabell. Rebuild the 161 kV line from VBI-Van Buren	X	-	-	X	-	-
Build a 57.8-mile 345 kV line from Muskogee 7-Fort Smith 7 circuit 2	-	X	X	-	X	X
Build a 3.0-mile 138kV line from McClain-Bailey. Switch out Midwest-Franklin 138kV	-	X	-	-	X	-

Table 7.3: Initial Economic Project Grouping

7.2.4.1 *PROJECT SUBTRACTION EVALUATION*

Draft groupings were developed using individual project screening results, which tests projects by incrementally adding changes to the base market economic models. When assessing a grouping of economic solutions, it was necessary to reevaluate project performance within the grouping to ensure the projected APC benefit of each project in the grouping meets the required B/C ratio thresholds. Subtraction evaluation was used to identify when multiple projects can provide congestion relief to a constraint or projects that are dependent on each other to relieve overall system congestion. New sets of base cases were created by adding the entire set of solutions included in each grouping along with relevant model adjustments, corrections, and market powerflow model projects 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.

7.2.4.2 *FINAL ECONOMIC GROUPINGS*

The selected grouping for each future was the grouping that provided the highest net benefit to the SPP region when comparing APC savings to the cost of the projects. The cost-effective and highest net APC benefit groupings ended up sharing the same projects and were the best performing groupings selected for both Futures 1 and 2. Table 7.4 shows the final list of projects in the economic groupings.

Description	Future 1		Future 2	
	CE/HN	MV	CE/HN	MV
Columbus East 230/115 kV transformer replacement	X	X	X	X
Scottsbluff-Victory Hill 115 kV circuit 2 new line	X	X	-	-
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase line clearances	X	X	X	X
Cleo Corner-Cleo Junction 69 kV terminal equipment	-	-	X	X
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	X	X	X	X
East New Town 115 kV 150 MVAR STATCOM	X	X	X	X
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	X	X	X	X
Gering Tap-Morrill 115 kV rebuild	X	X	X	X
Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie	X	X	X	X
Kummer Ridge-Round Up 345 kV new line	X	X	X	X
Warrensburg East-Whiteman Air Force Base East-Whiteman Air Force Base West-Sedalia 161 kV terminal equipment	X	X	-	-
Quahada 115 kV 100 MVAR synchronous condenser, Yoakum 345 kV 450 MVAR synchronous condenser, Crossroads-Hobbs 345 kV, Potter-Tolk 345 kV, and model or system adjustments, Sulphur Springs 115 kV 14.4 MVAR capacitor bank; Grassland 115 kV 28.8 MVAR capacitor bank; Johnson Draw 115 kV 14.4 MVAR capacitor bank; Plains Interchange 115 kV 39 MVAR capacitor bank (No GOF)	X	-	X	-
Quahada 115 kV 100 MVAR synchronous condenser, Yoakum 345 kV 450 MVAR synchronous condenser, Crossroads-Hobbs HE double-circuit 345 kV, Potter-Tolk HE double-circuit 345 kV, and model or system adjustments (No GOF)	-	X	-	X
Kelly 161 kV terminal equipment	-	-	X	X
Humbolt 161/69 kV transformer, terminal equipment	-	-	X	X
Tulsa North-CDC East Tap 138 kV reconductor; Tulsa North terminal equipment	-	-	X	X

Description	Future 1		Future 2	
	CE/HN	MV	CE/HN	MV
Raun-S3452 345/161 kV double-circuit new line; S3451-S3454 345 kV tap at S3452; S3451-S3459 345 kV tap at S3452	-	-	X	X
S1209-S1231 161 kV double-circuit rebuild	-	-	X	X

Table 7.4: Final Economic Project Grouping

Table 7.5 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.

Grouping	Y5 Benefit ($M) (2026$)	Y10 Benefit ($M) (2031$)	40-Year Benefit ($M) (2026$)	40-Year NPV Cost ($M) (2026$)	40-Year Net Benefit ($M) (2026$)	Y5 B/C	Y10 B/C	40-Year B/C	Selected Portfolio
F1 CE/HN	$359	$568	$8,566	$1,723	$6,843	2.00	2.86	4.97	X
F1 MV	$367	$589	$8,896	$2,213	$6,683	1.59	2.31	4.02	
F2 CE/HN	$410	$654	$9,874	$1,974	$7,900	1.99	2.88	5.00	X
F2 MV	$424	$670	$10,104	$2,465	$7,640	1.65	2.36	4.10	

Table 7.5: Final Groupings-Benefit Cost, Net Benefits and B/C Ratios

Figure 7.4 shows a 40-year B/C comparison of all the final groupings.[31]

[31] The 40-year costs represented in this figure are based upon the final net plant carrying charge.

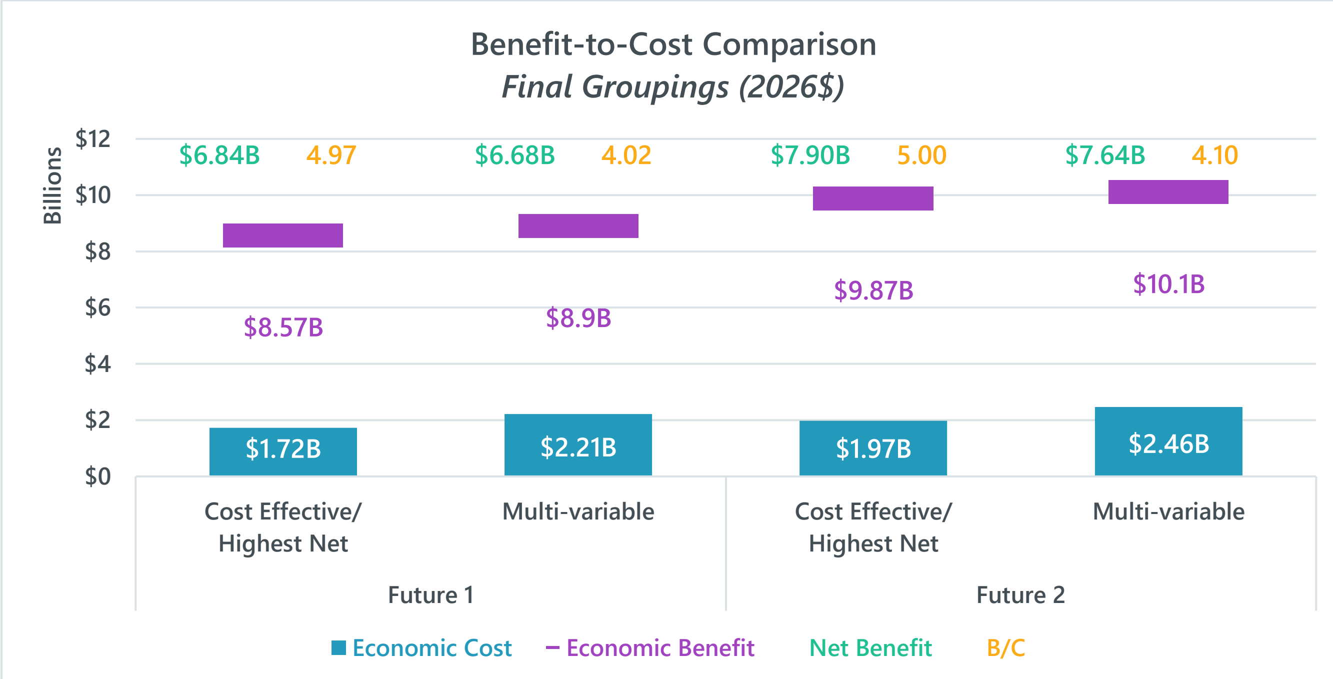


Figure 7.4: Final Groupings-Benefits and Costs Comparison

7.3 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.

Due to the extreme correlation between reliability and economic issues within both target areas, the Optimization milestone considered initial reliability solutions as well as other high-performing alternatives. Alternatives included lines with different termination points and multiple variables such as high-efficiency conductors, double-circuits, etc. Economic project subtraction analysis was performed to allow the opportunity to differentiate between the alternate solutions. The selected target area solutions were the same in the reliability and the economic portfolio. The target area optimization process is explained further in the following section of the report. One project, the rebuild of the Gering Tap-Morrill 115 kV line, 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

Three marginal economic projects were identified as needing to be removed from the final economic portfolios due to no longer meeting the required 40-year NPV B/C ratio thresholds for economic grouping. Table 7.6 shows a summary of costs, and B/C ratios of these three projects:

Project	Project Cost (E&C)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C
Warrensburg East-Whiteman Air Force Base East-Whiteman Air Force Base West-Sedalia 161 kV terminal equipment	$95,429	(59.25)	(48.46)	(74.04)	-	-	-
Kelly 161 kV terminal equipment	$93,042	-	-	-	(42.11)	(12.88)	(9.25)
Tulsa North-Cherokee Data Center East Tap 138 kV reconductor; Tulsa North terminal equipment	$6,752,000	-	-	-	2.25	0.84	0.79

Table 7.6: Optimized Economic projects - Cost and B/C Ratios

Two economic projects were identified as needing to be added to opposite future’s final economic portfolio for meeting the B/C ratio thresholds. Cleo Corner-Cleo Junction 69 kV terminal equipment upgrade is a small capital cost project that meets the one-year B/C ratio requirement. The one-year APC benefit observed in the SPP region is three-four times the project (E&C) cost. AEP's planned Sundance wind farm drives 40-year APC benefit but is not reflected in the B/C ratios below due to its assignment to the SPP Other zone in the 2021 ITP. Table 7.7 shows a summary of costs, and B/C ratios of these two projects:

Project	Project Cost (E&C)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 Y5 B/C	F1 Y10 B/C	F2 40-year B/C
Cleo Corner-Cleo Junction 69 kV terminal equipment	$168,000	17.9	(1.1)	(9.3)	23.1	(9.3)	(27.8)
Scottsbluff-Victory Hill 115 kV circuit 2 new line	$8,870,000	3.0	2.7	4.2	1.7	1.1	1.6

Table 7.7: Optimized Economic projects - Cost and B/C Ratios

7.3.1 TARGET AREA OPTIMIZATION

As noted in the portfolio development process flowchart, additional high performing alternative projects are given additional consideration during the Optimization milestone. For the SPS South target area, the reliability grouping and future-specific economic groupings were not equivalent, requiring a determination of the best overall project for the region. As noted previously in this report, the SPS South target area was characterized by changing plans for existing resources and new delivery point requests. During the optimization milestone this additional information was heavily considered, including testing the selected grouping solutions and other high-performing alternatives, while also making modeling changes to account for the known information related to the target area. After incorporating these additional model changes, the reliability benefits and qualitative considerations for a double-circuit 345 kV line from Crossroads-Phantom outweighed the merits for a single circuit line, both having approximately equivalent economic performance. See section 8.1.1 for additional information on the Crossroads-Phantom double-circuit 345 kV line.

The Bakken target area solutions for the reliability grouping and the future-specific economic groupings were equivalent and no project optimization was necessary.

7.4 PORTFOLIO CONSOLIDATION

In order to develop a single portfolio for recommendation to stakeholders, the final future-specific portfolios (including base reliability (BR), market economic (ME) and market powerflow), as well as overlap projects, must be consolidated. To help guide decision-making to determine project inclusion in the single plan, 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 is addressing the same or similar needs in both futures
2. Different projects are addressing 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 assessment to determine portfolio eligibility.

To evaluate projects meeting scenario two or three conditions, SPP and its stakeholders developed a systematic scoring rubric considering both quantitative and qualitative metrics. Quantitative metrics include APC B/C ratios and the percentage of congestion relieved. Qualitative metrics include crediting projects able to address operational congestion or non-thermal issues. Table 7.8 details the scoring rubric, as well as some of the minimum criteria projects must meet to receive points.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C ratio in selected future	50	1.0 (0.9)
	40-year (1-year) APC B/C ratio in opposite future		0.8 (0.7)
	40-year (1-year) APC net benefit in selected future ($M)		N/A
	40-year (1-year) APC net benefit in opposite future ($M)		N/A
2	Congestion relieved in selected future (by need(s), all years)	10	N/A
	Congestion relieved in opposite future (by need(s), all years)	10	N/A
3	Operational congestion costs or reconfiguration ($M/year or hours/year)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate non-thermal issues	7.5	Y/N
6	Long-term viability (*e.g.*, 2013 ITP20) or improved Auction Revenue Right (ARR) feasibility	5	Y/N
	Total Points Possible	**100**	

Table 7.8: Consolidated Portfolio Scoring Consolidation Scenario One

For the 2021 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 2021 ITP Scope.

Five 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:

- Scottsbluff-Victory Hill 115 kV circuit 2 new line
- Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase clearances
- Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie
- Columbus East 230/115 kV transformer replacement
- Cleo Corner-Cleo Junction 69 kV terminal equipment

7.4.1 CONSOLIDATION SCENARIO TWO

For two projects applicable to scenario two, the project achieving the higher score will be considered favorable for consolidation. Scoring parameters are detailed in Table 7.9.

There were no projects meeting scenario two criteria for consolidation in the 2021 ITP.

7.4.2 CONSOLIDATION SCENARIO THREE

Projects applicable to scenario three must achieve a minimum score of 70 points to be considered for consolidation. Scoring parameters are detailed in Table 7.9.

For the 2021 ITP, two projects were assessed under scenario three scoring conditions.

Humbolt 161/69 kV transformer circuit 2

The Humbolt 161/69 kV transformer circuit 2 replacement originated from the Future 2 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-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	40
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.*, 2013 ITP20) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**60**

Table 7.9: Humbolt 161/69 kV transformer Consolidation Scoring

Raun-S3452 345/161 kV double-circuit new line; S3451-S3454 345 kV tap at S3452; S3451-S3459 345 kV tap at S3452; S1209-S1231 161 kV double-circuit rebuild

The Raun-S3452 345/161 kV double-circuit new line; S3451-S3454 345 kV tap at S3452; S3451-S3459 345 kV tap at S3452; S1209-S1231 161 kV double-circuit rebuild project was found to have a negative B/C ratio in Future 1, which led to the project receiving zero points for the net benefit and B/C metric. Because of the low net benefit and B/C score, 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	20
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	8.9
4	New EHV	7.5	7.5
5	Mitigate non-thermal issues	7.5	7.5
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	5
		Total Score (minimum 70 threshold)	**48.9**

Table 7.10: Raun-S3452 345/161 kV double-circuit new line; S3451-S3454 345 kV tap at S3452; S3451-S3459 345 kV tap at S3452; S1209-S1231 161 kV double-circuit rebuild

7.5 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 $1.037 billion and is projected to create $8 billion to $9 billion in APC savings under Future 1 or Future 2 assumptions, respectively. Table 7.11 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	Project Cost (2021$)
Platte City 161 kV switches	Reliability	$51,502
Blue Circle-Catoosa 69 kV rebuild	Reliability	$9,020,000
Roswell 115/69 kV transformers circuit 1 and 2 replacement	Reliability	$4,122,361
Jones-Lubbock South 230 kV circuit 1 and 2 terminal equipment and increase line clearances	Reliability	$635,957
S3454-S3740 345 kV new line	Reliability	$41,684,278
Powersite-Branson North 161 kV terminal equipment	Reliability	$937,800
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	Reliability	$301,043,569
Rocky Point-Marietta (OGE) 138kV rebuild; Marietta (OGE)-Marietta (WFEC) 138 kV new line	Reliability	$18,152,000
East New Town 115 kV 150 MVAR STATCOM	Reliability	$23,000,000
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	Reliability	$34,634,441
Sioux City 69 kV new breaker CT; Hinton Municipal (K412) 69 kV terminal equipment	Reliability	$746,042
Gering Tap-Morrill 115 kV rebuild	Reliability	$17,546,363
Joplin West 7th-Stateline 161 kV rebuild	Reliability	$5,866,619
Kummer Ridge-Round Up 345 kV new line	Reliability	$98,481,715
Artesia 115/69 kV transformers circuit 1 and 2 replacement	Reliability	$5,666,596
Quahada 115 kV 100 MVAR synchronous condenser	Reliability	$27,208,664
Grassland 115 kV 28.8 MVAR capacitor bank	Reliability	$2,608,299
Crossroads-Phantom 345 kV new double-circuit lines	Reliability	$409,945,890
Squaw Gap 115 kV 15 MVAR capacitor bank	Reliability	$728,280
Midwest-Franklin 138 kV terminal equipment	Operational	$413,646

Description	Classification	Project Cost (2021$)
Replace one breaker at Jarbalo Junction 115 kV	Short Circuit	$267,179
Replace two breakers at Shawnee Mission 161 kV	Short Circuit	$510,150
Replace one breaker at Craig 161 kV	Short Circuit	$319,002
Moorhead 230 kV substation reconfiguration	Short Circuit	$7,935,000
Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie	Economic	$117,977
Cleo Corner-Cleo Junction 69 kV terminal equipment	Economic	$168,000
Columbus East 230/115 kV transformer replacement	Economic	$4,600,000
Scottsbluff-Victory Hill 115 kV circuit 2 new line	Economic	$8,870,000
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase line clearances	Economic	$11,257,083
	Total	**$1,036,538,413**

Table 7.11: Final Consolidated Portfolio

Table 7.12 provides the Future 1 and Future 2 40-year B/C ratios and net benefits for all economic projects included in the consolidated portfolio. Details on the project subtraction evaluation process are described in section 7.2.4.1.

Project	Project Cost (E&C)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit (2026$)	F1 40-year Net Benefit (2026$)	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit (2026$)	F2 40-year Net Benefit (2026$)
Cleo Corner-Cleo Junction 69 kV terminal equipment	$168,000	17.9	(1.1)	(9.3)	($2,343,437)	($2,595,388)	23.1	(9.3)	(27.8)	($7,008,530)	($7,260,481)
Scottsbluff-Victory Hill 115 kV circuit 2 new line	$8,870,000	3.0	2.7	4.2	$56,126,168	$42,823,791	1.7	1.1	1.6	$21,012,068	$7,709,691
Columbus East 230/115 kV transformer replacement	$4,600,000	8.0	7.9	12.8	$88,247,007	$81,348,368	4.3	4.3	7.0	$48,519,986	$41,621,346
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase clearances	$11,257,083	1.8	4.2	7.7	$129,898,863	$113,016,567	1.6	3.5	6.4	$107,481,174	$90,598,879
Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie	$117,977	55.8	204.8	389.8	$68,962,737	$68,785,807	70.1	119.1	211.9	$37,485,460	$37,308,530

Table 7.12: Consolidated Portfolio – Economic projects APC benefit only

Figure 7.5 displays the 40-year B/C ratios, APC benefits and portfolio cost for economic projects included in the consolidated portfolio.

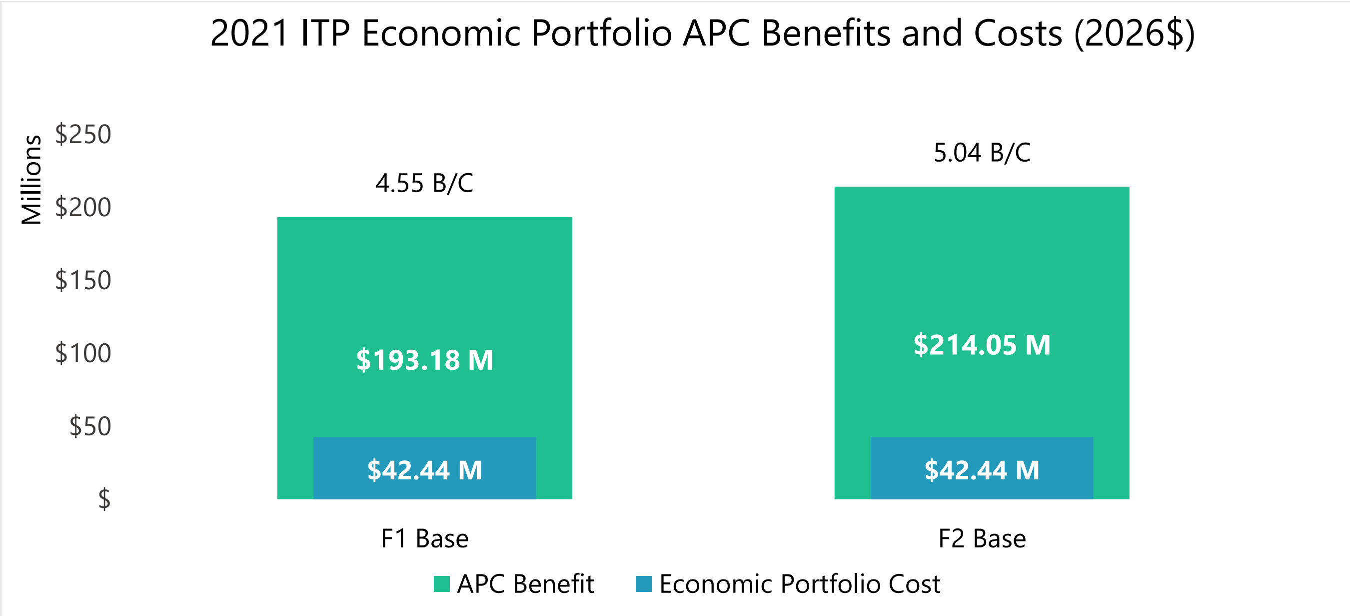
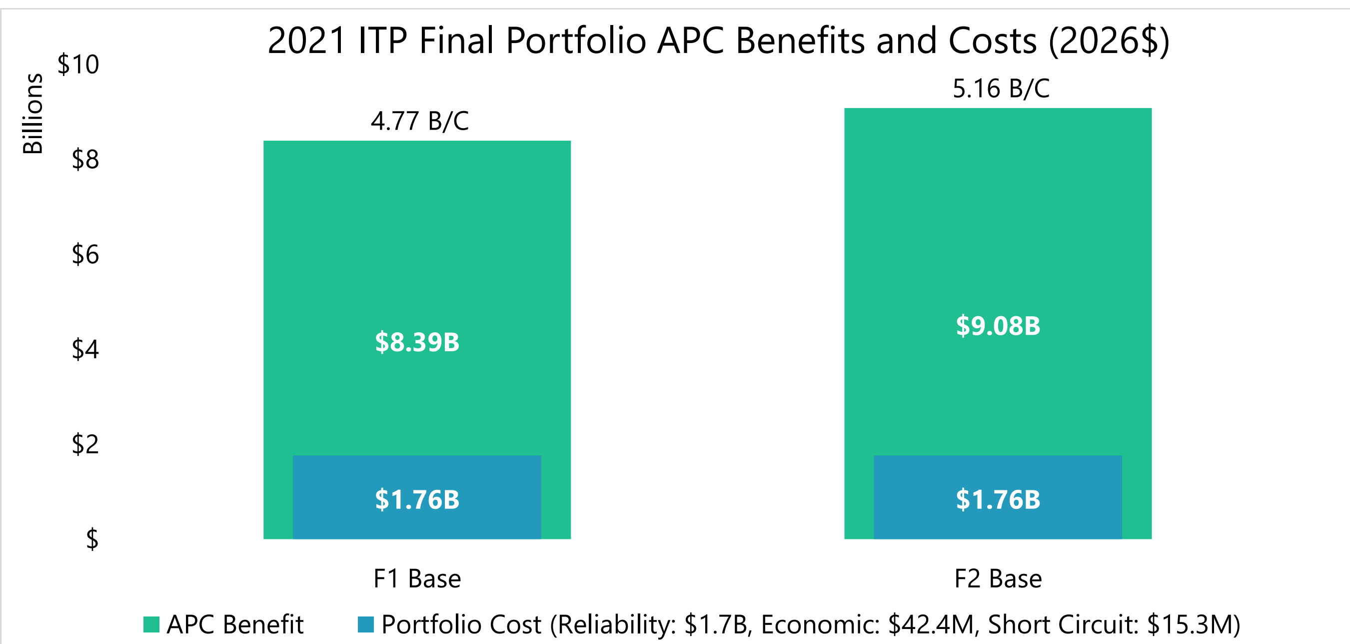


Figure 7.5: Economic Portfolio APC Benefits and Costs

Figure 7.6 displays portfolio costs, APC benefits and 40-year B/C ratios[32] for the entire consolidated portfolio.



[32] The benefits, costs, and B/C ratios shown in Figure 7.6 utilize an average regional Net Plant Carrying Charge value utilized during portfolio development and are shown in 2026 dollars because the staging process was not yet complete.

Figure 7.6: Final Consolidated Portfolio APC Benefits and Costs

Figure 7.7Figure 7.7 captures the break-even and payback dates for the consolidated portfolio. The break-even year is reflective of the first year that the one-year APC benefits are expected to outweigh the portfolio annual transmission revenue requirement (ATRR). The payback year is reflective of the year that the cumulative APC benefits are expected to exceed the 40-year NPV costs of the portfolio. The consolidated portfolio is expected to breakeven within the first year of being placed in-service and to pay back the total investment within the first 10 years.

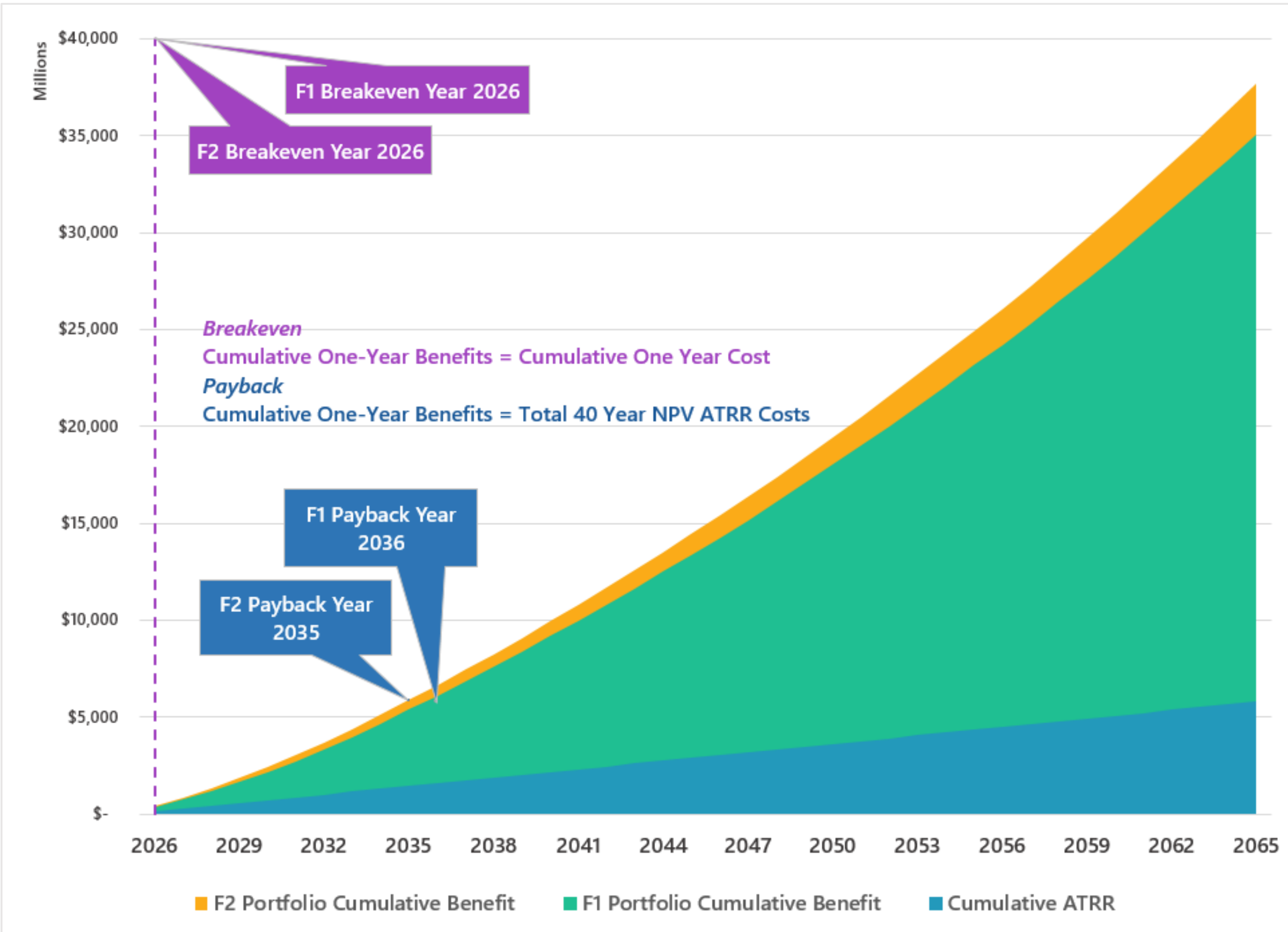


Figure 7.7: Portfolio Breakeven and Payback – APC benefit only

7.6 STAGING

Staging is the process by which the need date and projected in-service date for each project is determined. The staging methodology can be found in the ITP Manual.[33]

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[33] ITP Manual version 2.7 section 6.3

7.6.1 ECONOMIC PROJECTS

The results of staging for the economic projects are shown in Table 7.13 below.

Description	Need Date	Projected In-Service Date	Model
Columbus East 230/115 kV transformer replacement	1/1/2023	3/10/2024	F1/F2
Scottsbluff-Victory Hill 115 kV circuit 2 new line	1/1/2023	9/10/2025	F1/F2
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase line clearances	1/1/2025	1/1/2025	F1/F2
Cleo Corner-Cleo Junction 69 kV terminal equipment	1/1/2023	9/10/2023	F1/F2
Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie	1/1/2023	9/10/2023	F1/F2
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	1/1/2023	3/15/2026	F1/F2
East New Town 115 kV 150 MVAR STATCOM	1/1/2023	3/15/2026	F1/F2
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	1/1/2023	3/15/2026	F1/F2
Kummer Ridge-Round Up 345 kV new line	1/1/2023	3/15/2026	F1/F2
Crossroads-Phantom 345 kV new double-circuit lines	1/1/2023	3/15/2026	F2

Table 7.13: Project Staging Results-Economic

7.6.2 POLICY PROJECTS

There were no policy-driven projects in the 2021 ITP.

7.6.3 RELIABILITY PROJECTS

The results of staging for the reliability projects are shown in Table 7.14 below.

Description	Need Date	Projected In-Service Date	Model
Platte City 161 kV switches	6/1/2023	9/11/2023	BR
Blue Circle-Catoosa 69 kV rebuild	6/1/2023	9/11/2024	BR
Roswell 115/69 kV transformers circuit 1 and 2 replacement	6/1/2023	3/12/2024	BR
Jones-Lubbock South 230 kV circuit 1 and 2 terminal equipment and increase line clearances	6/1/2023	9/11/2023	BR

Description	Need Date	Projected In-Service Date	Model
S3454-S3740 345 kV new line	6/1/2024	3/15/2026	BR
Powersite-Branson North 161 kV terminal equipment	6/1/2029	9/11/2023	BR
Rocky Point-Marietta (OGE) 138kV rebuild; Marietta (OGE)-Marietta (WFEC) 138 kV new line	6/1/2023	3/14/2025	BR
Sioux City 69 kV new breaker CT; Hinton Municipal (K412) 69 kV terminal equipment	6/1/2023	9/11/2023	BR
Gering Tap-Morrill 115 kV rebuild	6/1/2023	3/14/2025	BR
Joplin West 7th-Stateline 161 kV rebuild	6/1/2026	3/12/2024	BR
Quahada 115 kV 100 MVAR synchronous condenser	6/1/2030	3/15/2026	BR
Grassland 115 kV 28.8 MVAR capacitor bank	6/1/2023	3/12/2024	BR
Squaw Gap 115 kV 15 MVAR capacitor bank	6/1/2029	3/12/2024	BR
Artesia 115/69 kV transformers circuit 1 and 2 replacement	6/1/2023	3/12/2024	BR
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR series compensation; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	See 7.6.3.1		BR
East New Town 115 kV 150 MVAR STATCOM; East New Town 115 kV substation expansion; East New Town-New Town Stat 115/32.5 kV new transformer	See 7.6.3.1		BR
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	See 7.6.3.1		BR
Kummer Ridge-Round Up 345 kV new line	See 7.6.3.1		BR
Crossroads-Phantom 345 kV new double-circuit lines	See 7.6.3.1		BR

Table 7.14: Project Staging Results-Reliability

7.6.3.1 *RELIABILITY STAGING GAP*

The reliability staging process requires the base models to converge in order to identify valid per unit values to use for interpolation between years. The numerous voltage collapse conditions were included in the reliability needs assessment by assigning a 0.01 p.u. voltage value to a select set of critical buses for contingencies causing the collapse. When voltage collapse occurs, the interpolation process breaks down, and an alternative method is needed to determine when violations are expected to occur. A new methodology was tested to determine reliability staging dates for the Crossroads-Phantom 345 kV double-circuit project in SPS South. The following two options were evaluated:

- Option 1: Start with models containing voltage collapse (e.g. year 10) and scale down load within the target area incrementally based on annual load growth rates until the model converges
  - Example: Start with a year 10 model and reduce loads to create a year 9 model
  - Perform interpolation using newly converged models to identify need date
- Option 2: Start with converged models and scale up load incrementally until violations appear
  - Example: Start with a year 5 model and increase loads to create a year 6 model
  - Perform interpolation using last converged incremental models to identify need date

Option 1 and 2 determined need dates of 6/1/2029 and 6/1/2030, respectively, for the Crossroads-Phantom project.

Similar system conditions existed in the Bakken target area, however the powerflow sensitivity cases were used to identify need dates in accordance with the standardized reliability methodology. Table 7.15 identifies the need dates using the lower load forecast implementend in the powerflow sentivity cases.

Description	Reliability Need Date
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	12/1/2031
East New Town 115 kV 150 MVAR STATCOM	12/1/2031
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	4/1/2027
Kummer Ridge-Round Up 345 kV new line	4/1/2023

Table 7.15: Relibility Staging of Bakken Solutions

7.6.4 PROJECT STAGING RESULTS FOR RELIABILITY/ECONOMIC SOLUTIONS

Projects identified as meeting the criteria for inclusion in the consolidated portfolio solving economic and reliability needs are staged at the earliest need date identified during either staging process. Table 7.16 below shows the selected need date for each project in green.

Description	Reliability Need Date	Economic Need Date
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	12/1/2031	1/1/2023
East New Town 115 kV 150 MVAR STATCOM	12/1/2031	1/1/2023
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	4/1/2027	1/1/2023
Kummer Ridge-Round Up 345 kV new line	4/1/2023	1/1/2023
Crossroads-Phantom 345 kV new double-circuit lines	6/1/2028	1/1/2023

Table 7.16: Reliability and Economic Projects

7.6.5 OPERATIONAL PROJECTS

The Midwest-Franklin 138 kV terminal equipment was staged at the expected date of NTC issuance, 3/10/2022, in accordance with ITP Manual section 6.3.1.[34]

7.6.6 SHORT-CIRCUIT PROJECTS

The short-circuit projects were all staged with need dates and projected in-service dates of June 1, 2023.

7.6.7 ENHANCED TARGET AREA STAGING

7.6.7.1 *ENHANCED STAGING FOR SPS SOUTH TARGET AREA*

An enhanced staging analysis to determine the recommended need date of the SPS South target area solution was performed to account for impactful model adjustments, identified during portfolio development, used to inform the recommended projects. The staging results previously shown do not reflect these additional considerations, which included the recommissioning of planned generation retirements in the 2021 ITP BR models and known Delivery Point Addition (SPP Tariff Attachment AQ, or AQ) requests in the SPS South area.

The following updates were made to the staging process in order to identify the most appropriate need date:

- Reliability: Utilize summer peak models to develop non-study year models that include

[34] ITP Manual version 2.7 section 6.3.1

  - Switch off in-line shunt reactors (395 MVAR) Modify BR Year 5 (484 MW) Year 10 (697 MW) SPS-owned conventional generation retirement assumptions
  - Various reactive device (*i.e.*, transformer tap changes)
  - Definitive GI Network Upgrades
    - Second Tolk 345/230 kV transformer
    - Border 345 kV 275 MVARs
    - Oklaunion 345 kV 200 MVARs)
  - Load addition requests in the SPS south area not included in base models
- Economic: Consider the sensitivity MEM that includes
  - An adjusted SPS resource plan to account for the removal of a proxy combined-cycle plant in the load pocket
  - Retired resources in SPS were recommissioned to maintain resource adequacy for the SPS Zone, consistant with approved 2022 ITP BR model assumptions and 2023 ITP generation review exceptions
  - Bakken load forecast reductions based on 2022 ITP data

Table 7.17 below shows each load addition request's transmission service agreement status and MW amount.

AQ Load	Service Agreement Status	Amount (MW)
1	Complete	57
2	In Progress	30
3	No	80

Table 7.17: Load addition requests status

Table 7.18 shows the critical contingencies and associated models where voltage collapse conditions occur. The NERC TPL P3.2 event, the loss of Hobbs 3 unit combined with Crossroads-Eddy County 345 kV line outage, is the critical planning event need that determines the Crossroads-Phantom need date. The event combines the loss of 236 MW and 150 MVAR of real and reactive power in the New Mexico area and critical EHV outages of lines capable of delivering energy to load and supporting system voltage.

Critical Reliability Needs	Approved Model		Approved Model with Model and System Adjustments		Approved Model with Model and System Adjustments and AQ Load	
	Y5 BR	Y10 BR	Y5 BR	Y10 BR	Y5 BR	Y10 BR
P3.2 Hobbs 3 + Crossroads-Eddy County 345 kV	Blown up	Blown up		Blown up	Blown up	Blown up
P3.2 Hobbs 3 + Kiowa-N. Loving 345 kV	Low Voltages	Blown up			Blown up	Blown up

Critical Reliability Needs	Approved Model		Approved Model with Model and System Adjustments		Approved Model with Model and System Adjustments and AQ Load	
	Y5 BR	Y10 BR	Y5 BR	Y10 BR	Y5 BR	Y10 BR
P3.2 Hobbs 3 + Kiowa-Roadrunner 345 kV		Blown up				Blown up
P3.2 Hobbs 3 + N. Loving-China Draw 345 kV		Blown up				Blown up
P3.2 Hobbs 3 + Hobbs Interchange-Kiowa 345 kV		Blown up				Blown up
P3.2 Hobbs 3 + Hobbs Interchange-Yoakum 345 kV		Blown up				Blown up

Table 7.18: Critical Contingencies

Table 7.19 below, shows the enhanced staging results for the voltage collapse contingencies.

Description	Option 1	Option 2
No AQ Load Addition	6/1/2029	6/1/2030
AQ Load 1 Addition	6/1/2027	6/1/2028
AQ Load 1, 2, and 3 Addition	6/1/2025	6/1/2025

Table 7.19: AQ Load Additions

The recommended reliability need date for Crossroads-Phantom is 6/1/2027 based on leveraging methodology option one and the addition of one load connection request. Option 1 was selected in order to ensure reliability due to its more conservative result of the new staging methodologies. Only one load connection request was included to reflect only load committed via inclusion in a Service Agreement.

The economic analysis provided additional benefit ranges to consider when recommending a need date. These are shown in Table 7.20.

Project	E&C Study Cost ($M)	NPV 40-Year Cost* ($M)	Economic Model	Y2 B/C	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C
Crossroads – Phantom double-circuit 345 kV	$409.9	$695.6	Base	1.48	0.41	0.66	**1.17**	1.05	0.81	**1.21**
	$409.9	$695.6	Sensitivity	1.15	0.75	2.05	**3.82**	2.61	1.95	**2.88**

Table 7.20: Crossroads-Phantom 345 kV B/C Comparsion for Base vs Sensitivity models

This benefits can be explained by the increasing congestion scores and the number of hours congested over the course of the study horizon in both the base and sensitivity models. The high percentage of hours causes concern operationally when considering the persistent operational needs portion of the ITP Manual.[35] From a reliability perspective, the high number of hours highlights the frequency of a high impact voltage stability limit where in-line reactors in the area must be tuned appropriately to optimize system voltage. From an economic operational perspective, the 2021 ITP production cost software simulations assume system intact conditions for the transmission system and a predetermined set of generation outages for the entire study. The double-circuit Crossroads-Phantom 345 kV line provides additional flexibility and congestion mitigation that will be beneficial in real-time where transmission and generation outages occur in both planned and unplanned situations.

Market Economic Model (MEM) Scenario	SPSNMTIES Interface	
	Congested Hours	Congestion Score
Future 1 – Year 2 Base	3,774	346,699
Future 1 – Year 5 Base	3,089	75,553
Future 1 – Year 5 Base	4,181	175,493
Future 2 – Year 5 Base	3,386	174,914
Future 2 – Year 10 Base	3,381	193,223
Future 1 – Year 2 Sensitivity	3,667	266,160
Future 1 – Year 5 Sensitivity	4,744	174,437
Future 1 – Year 10 Sensitivity	6,183	453,100
Future 2 – Year 5 Sensitivity	4,937	487,772
Future 2 – Year 10 Sensitivity	6,120	459,256

Table 7.21: 2021 Economic Needs

Initial economic project staging produced a need date of 1/01/2023 based on a greater than 1.0 B/C ratio in year 2 and an interpolated date from Future 2 that resulted in a downward trend line. This was cause for concern, especially since the results showed a reduced B/C ratio in years 5 and 10.

The economic sensitivity model represents adjustments to the SPS resource plan that are more consistent with the information supplied to modify the base reliability models. The information shows

[35] ITP Manual version 2.7 section 4.4 Operational Needs Assessment

1-year B/C ratios above a 1.0 and higher 40-year B/C ratios when comparing the sensitivity results to the base model results. The sensitivity model provided more definitive results that support the year-2 recommendation, both from 1-year and 40-year results in Future 2. Based upon the information used in the enhanced staging analysis for the SPS South target area, the recommended need date for Crossroads-Phantom double-circuit 345 kV remains 1/01/2023.

7.6.7.2 *ENHANCED STAGING FOR BAKKEN TARGET AREA*

An enhanced staging analysis to determine the recommended need date of the Bakken target area solution was performed to account for impactful load forecast adjustments. Load forecasts submitted for the upcoming ITP assessments were used to inform the recommended projects.

At the time initial staging was completed for the Bakken solution, the decreased load forecast submitted for the 2022 ITP was the most up to date and considered more accurate. While a portfolio of projects was developed to address the needs identified using the 2021 ITP models, the 2022 ITP forecasts suggested only a subset of those projects were needed, and the additional projects needed to support 2021 ITP load projections were staged for the end of the planning horizon.

During late stages of portfolio development, information was provided that the 2023 ITP load forecasts are expected to increase back to near-2021 ITP levels. Additionally, load connection requests were reviewed in detail and over 300 MW of new load was identified for potential future inclusion in the area. This information was taken into account to adjust the project recommendations and leveraged for an adjustment to the staging results.

Table 7.22 shows the previously reported need date compared to the need date determined by leveraging the 2023 ITP models.

Project	Initial Need Date	Enhanced Need Date
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR series compensation; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	12/1/2031	4/1/2027
East New Town 115 kV 150 MVAR STATCOM	12/1/2031	4/1/2027
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	4/1/2027	4/1/2027
Kummer Ridge-Round Up 345 kV new line	4/1/2023	4/1/2023

Table 7.22: Bakken target area solution reliability need dates

The 2022 and 2023 ITP load forecasts are not as aggressive as the 2021 ITP, but results indicate low voltages in the Williston area that would need to be resolved. These could potentially be addressed with smaller-scale solutions than the 345 kV lines between Leland Olds and Tande and the STATCOM at East New Town, but considering the comprehensive information on Bakken target area load and the potential for over 300 MW of additional load seeking to connect in the future, the project scopes were not adjusted. The reliability need dates do not consider the additional load connection requests as no qualitative analysis considering them was performed.

Economic staging leveraged the base and sensitivity models described in the previous section, essentially covering a range of lower than expected and higher than expected load forecasts. These results determined no change to the 1/01/2023 need date was required.

Based upon the information used in the enhanced staging analysis for the Bakken target area, the recommended need date for the Bakken target area solutions remains 1/01/2023.

8 PROJECT RECOMMENDATIONS

8.1 TARGET AREA PROJECTS

8.1.1 SPS SOUTH TARGET AREA: CROSSROADS-PHANTOM 345 KV NEW DOUBLE-CIRCUIT LINES

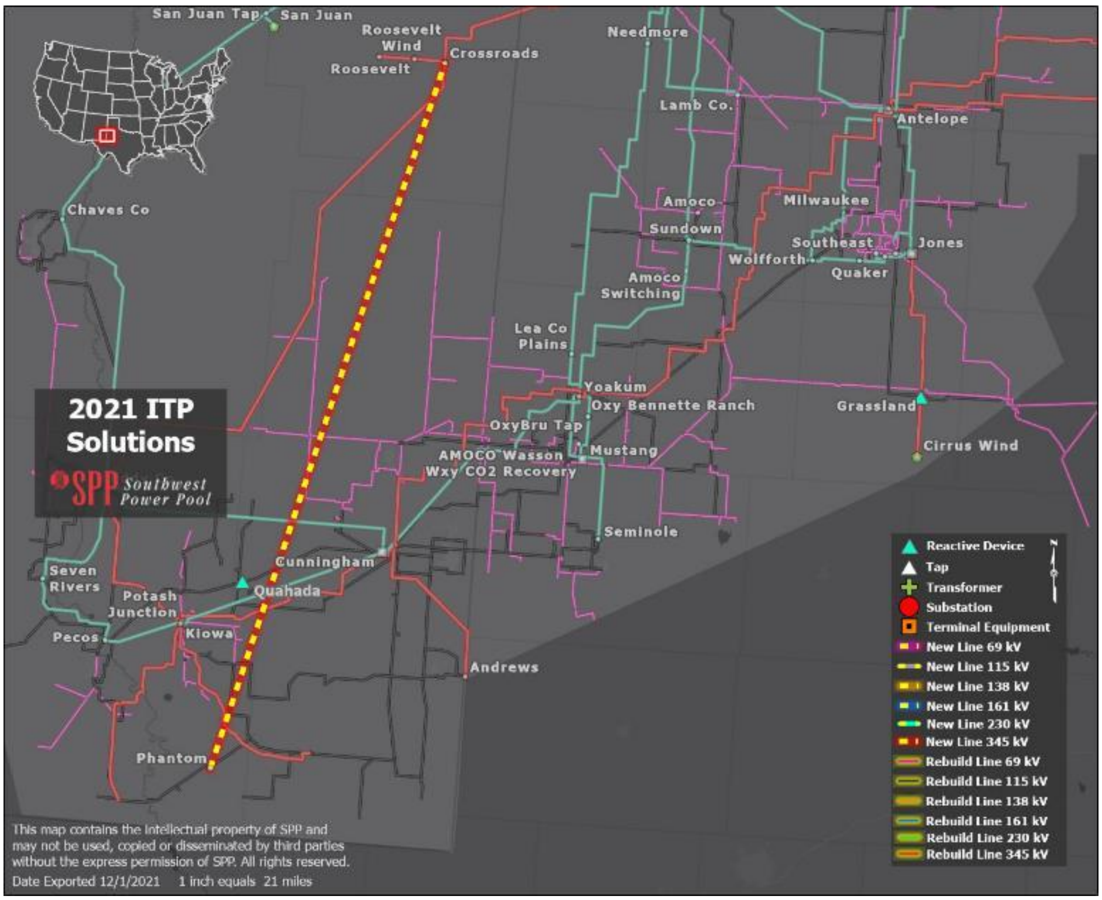

Figure 8.1: SPS target area solution

The SPS zone has been an area of focus over the course of numerous SPP regional studies dating back to the completion of the 2013 ITP20 Assessment. Without a forward-thinking, proactive approach to transmission solutions in this area, SPP can expect to continually observe incremental needs with reactive solution proposals. These reactive solutions provide limited short-term relief to system needs where continued growth is expected to occur.

As previously discussed in section 7.3.1, the double-circuit line from Crossroads-Phantom was selected to mitigate the current and future reliability and economic needs of the SPS South target area during the optimization milestone. This facility will be located along the eastern border of New Mexico, providing an alternative north-to-south 345 kV path for energy to serve loads in the remote portions of SPS.

The double-circuit 345 kV line from Crossroads-Phantom provides twice the capacity of the single circuit, while only incrementally increasing the (E&C) cost from $330.2 million to $409.9 million. The Crossroads-Phantom double-circuit 345 kV line eliminates the criticality of each of the P3 planning events identified in Table 7.21 by providing a low resistance, parallel path for delivery of low cost energy to the SPS South load pocket.[36]

Table 8.1 below, shows the project performance results of a single circuit and double-circuit 345 kV line from Crossroads-Phantom in both the base and sensitivity economic models. As expected, the B/C ratios in the sensitivity cases are significantly higher and warrant more consideration because system conditions reflect future expectations.

Project	E&C Study Cost ($M)	Model	Future 1 B/C			Future 2 B/C		
			Y5	Y10	40-year	Y5	Y10	40-year
Crossroads-Phantom 345 kV	$330.2	Base	0.40	0.77	**1.39**	1.12	0.88	**1.33**
	$330.2	Sensitivity	0.88	2.41	**4.50**	3.07	2.27	**3.35**
Crossroads-Phantom double-circuit 345 kV	$409.9	Base	0.41	0.66	**1.17**	1.05	0.81	**1.21**
	$409.9	Sensitivity	0.75	2.05	**3.82**	2.61	1.95	**2.88**

Table 8.1: 2021 Crossroads-Phantom base and sensitivity economic B/C

The initial reliability project selection included a synchronous condenser at Quahada along with a capacitor bank at Grassland. The needs assessment posting considered the Quahada bus as an informational need with a per unit value above the 0.90 per unit, but below the .02 safety margin, to proxy the voltage limit of the interface. After additional analysis, it was determined this facility is a local need not related to the target area and the per unit value of these buses under contigency do not require the need for additional reactive support. The Grassland bus was identified as non-load serving and does not require mitigation in accordance with SPP Criteria.

[36] See section 4.4: *Utilization of 345 kV, 500 kV, or 765 kV for the SPP* in the 2010 ITP20 Report: Surge impedance loading for the single circuit 150-mile line is a concern. The additional $80 million in cost for double-circuit 345 kV line is equivalent to a 450 MVAR synchronous condenser at Yoakum 345 kV bus, which was considered as a solution to address the reactive losses on the Tuco-Yoakum-Hobbs 345 kV line with only a marginal increase in real power flow on the line. The double-circuit 345 kV line reduces the impedance by half, and doubles the surge impedance loading. Double-circuit 345 kV line increases the real power delivery and reduces both the MW and, more importantly, the MVAR losses.

8.1.2 BAKKEN TARGET AREA

As mentioned previously in the Base Reliability Needs Assessment (section 5.2.1), the area known as the Bakken Formation in western North Dakota has forecasted a high rate of load increase over the 2021 ITP study horizon. Delivering power to the Watford City area and the city of Williston creates large power flows from the generators located east of the Bakken towards the loads in the west. Low voltages in the base case are also observed, which are aggravated under contingency conditions. Multiple contingencies in the area result in voltage collapse to the load-heavy region. The root of the issues in the Bakken target area is the lack of transmission to accommodate the level of transfers required to serve the forecasted load in the future, contributing to a weak system unable to maintain acceptable voltage levels. A solution for this area should both eliminate potential overloads on the 115 kV system, as well as reinforce the transmission system to keep voltages within tolerable levels.

The most critical contingency in the area is the Charlie Creek-Patent Gate 345 kV line. This line segment is the only EHV corridor that feeds into the city of Williston from the south and is critical to support voltage in the Watford and Williston areas. Loss of this segment results in thermal overloads and voltage collapse in the winter peak periods. An ideal solution for the Bakken target area would provide a parallel path to this line in order to lessen the severity of an unexpected outage of the facility.

The voltage collapse and prevalent low voltage issues over a wide area make the Bakken primarily a reliability problem. While there are economic constraints in the target area and a proper solution is sure to create substantial economic benefit, the approach to solving the issues in the Bakken is to rely on the ITP reliability metrics to identify the least-costly comprehensive solution to ensuring power is deliverable to the growing load in the region.

For much of the 2021 ITP, SPP and its stakeholders were aware of the high load forecast in the 2021 ITP followed by a heavily reduced forecast in the 2022 ITP. This knowledge led to the development of the powerflow sensitivity cases described in Section 4.2.1 and 4.2.3. The understood direction for the Bakken target area solution for the 2021 ITP was to use the 2021 ITP base models to create a long-term comprehensive plan to address the high load levels. Once finalized, analysis leveraging the sensitivity powerflow models along with the sensitivity MEM cases would determine which transmission solution should be recommended for NTC issuance. Table 8.2 describes the 2021 ITP long-term solutions for the Bakken target area along with the expected reliability benefits each solution is expected to provide.

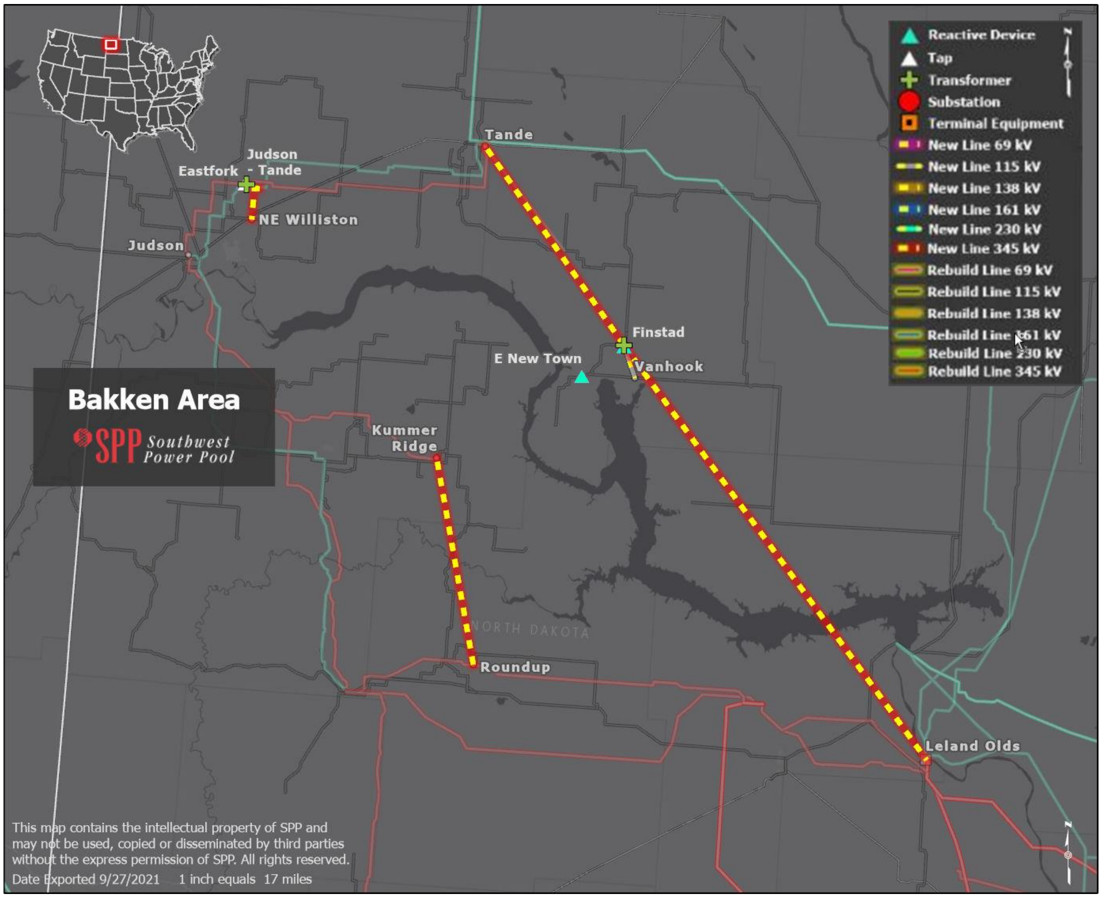

Figure 8.2: Comprehensive Bakken target area solutions

DESCRIPTION	RELIABILITY BENEFITS
Kummer Ridge-Round Up 345 kV new line	Provides an alternate 345 kV south-to-north pathway to the McKenzie county area (west of Lake Sakakawea) for system flows if the Charlie Creek substation experiences bus faults
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	Creates a 345 kV loop around the north side of Lake Sakakawea between two existing 345 kV stations where no 345 kV transmission exists today, and provides an alternative connection point at Finstad between the load-serving 115 kV network and 345 kV system (located on the north side of Lake Sakakawea)
East New Town 115 kV 150 MVAR STATCOM	Provides dynamic voltage support on the north side of Lake Sakakawea to the 115 kV system, which is electrically remote from the EHV transmission system
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	Provides voltage support from the EHV network to the load serving 115 kV system on the eastern side of the city of Williston

DESCRIPTION	RELIABILITY BENEFITS
Squaw Gap 115 kV 15 MVAR capacitor bank	Provides the necessary voltage support to address the loss of the Richland-East Sidney 115 kV line (not recommended for NTC issuance)

Table 8.2: 2021 ITP long-term solutions for the Bakken target area

Despite the high cost of the comprehensive plan of solutions for the 2021 ITP, the recommended set of solutions for the 2021 ITP create significant cost savings for end-use customers in the SPP region.

8.2 NON-TARGET AREA RELIABILITY PROJECTS

8.2.1 PLATTE CITY-WESTON 161 KV SWITCHES

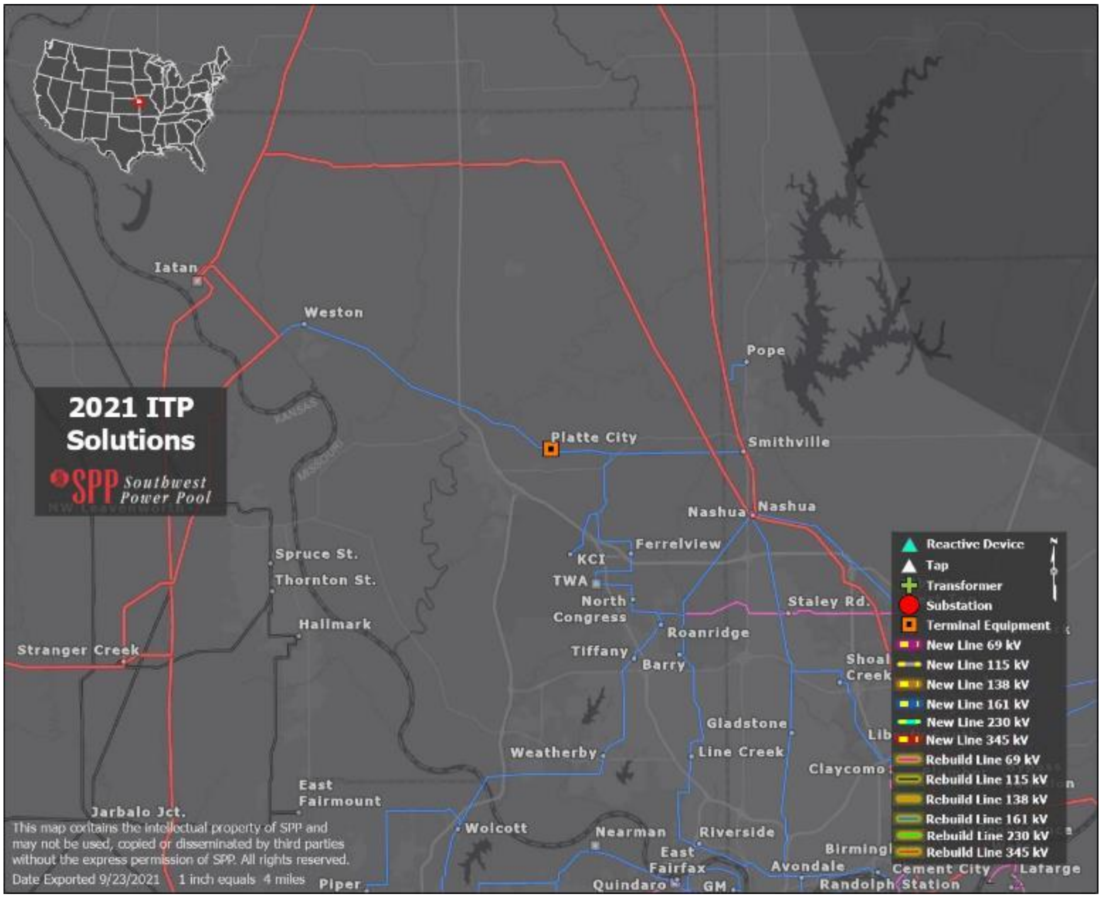

Figure 8.3: Platte City-Weston 161 kV terminal upgrades

Located along the Kansas/Missouri border in Platte City township, the Platte City-Weston 161 kV line overloads in the summer peaks for the loss of the 345 kV lines from Iatan-Nashua and Iatan-Eastown. The loss of these 345 kV lines causes flow to redirect to the 161 kV system to serve load in the Kansas City area. The selected project upgrades the necessary 161 kV terminal equipment at Platte City and Weston and increases the Platte City-Weston 161 kV line rating to 557/557 (SN/SE) MVA.

8.2.2 CATOOSA-BLUE CIRCLE 69 KV REBUILD

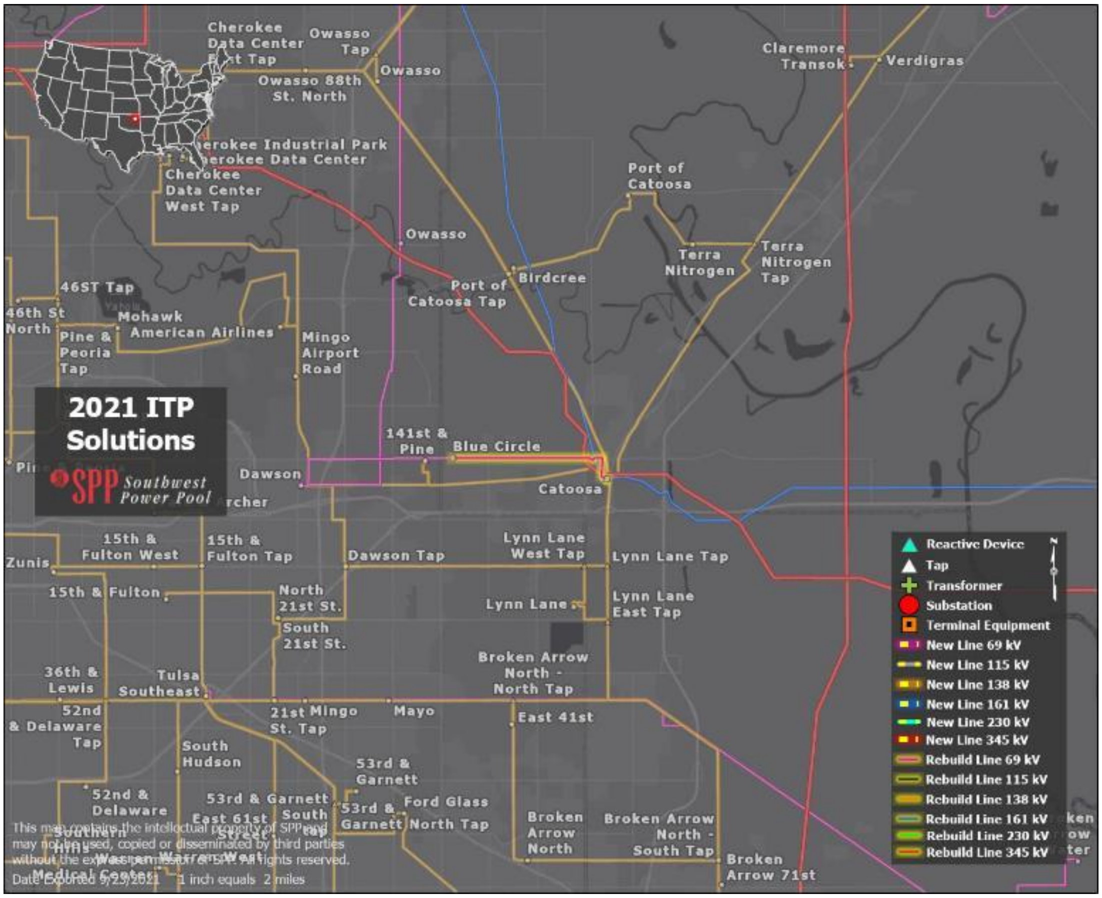

Figure 8.4: Catoosa-Blue Circle 69 kV rebuild

On the northeast side of Tulsa, Oklahoma, the Blue Circle-Catoosa 69 kV line overloads for the loss of Lynn Lane West Tap-Dawson Tap 138 kV during the summer peak. Loss of this 138 kV line redirects flows to the 69 kV system along the parallel east-to-west path of Catoosa-Blue Circle. A rebuild of the Blue Circle-Catoosa 69 kV line will mitigate the issue by increasing the rating of the circuit.

8.2.3 S3454-S3740 345 KV NEW LINE

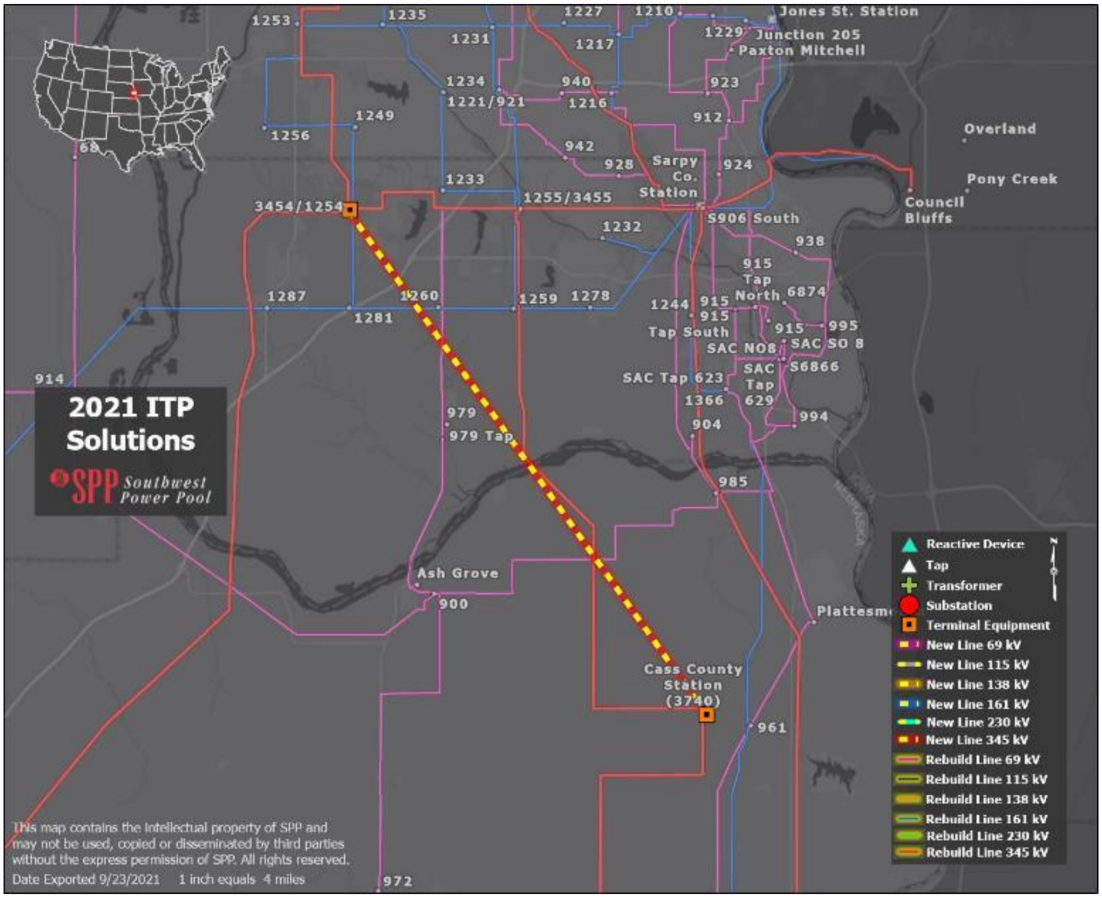

Figure 8.5: S3454-S3740 345 kV new line

On the south side of Omaha, Nebraska, the 345 kV Sarpy County-Nebraska City line overloads for the loss of the parallel 345 kV S3455-Cass County line. The project selected to mitigate this overload is new a 345 kV transmission line from S3454-Cass County, which provides an alternate path for the south-to-north flows in this area.

8.2.4 POWERSITE-BRANSON NORTH 161 KV TERMINAL EQUIPMENT

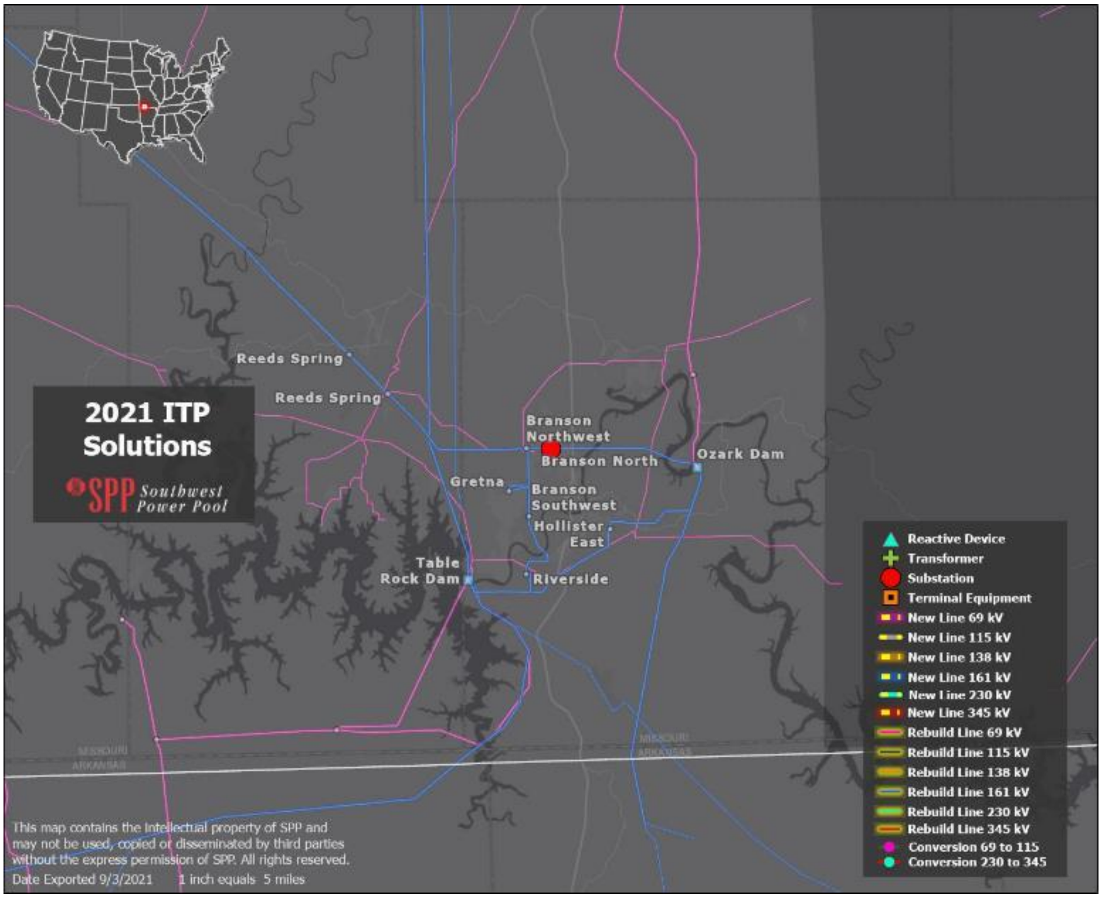

Figure 8.6: Powersite-Branson North 161 kV terminal upgrades

In Branson, Missouri, the Ozark Dam Powersite-Branson 161 kV line is overloaded for the loss of Branson Southwest-Riverside 161 kV. The loss of this line removes the southern path and forces power to flow around Branson, overloading the west-to-east Branson-Ozark Dam Powersite 161 kV line. The project selected to mitigate this issue is to upgrade the necessary 161 kV terminal equipment at Branson and Ozark Dam Powersite substations to increase the rating of the Powersite-Branson line.

8.2.5 ROCKY POINT-MARIETTA (OGE) 138 KV REBUILD; MARIETTA (OGE)-MARIETTA (WFEC) 138 KV NEW

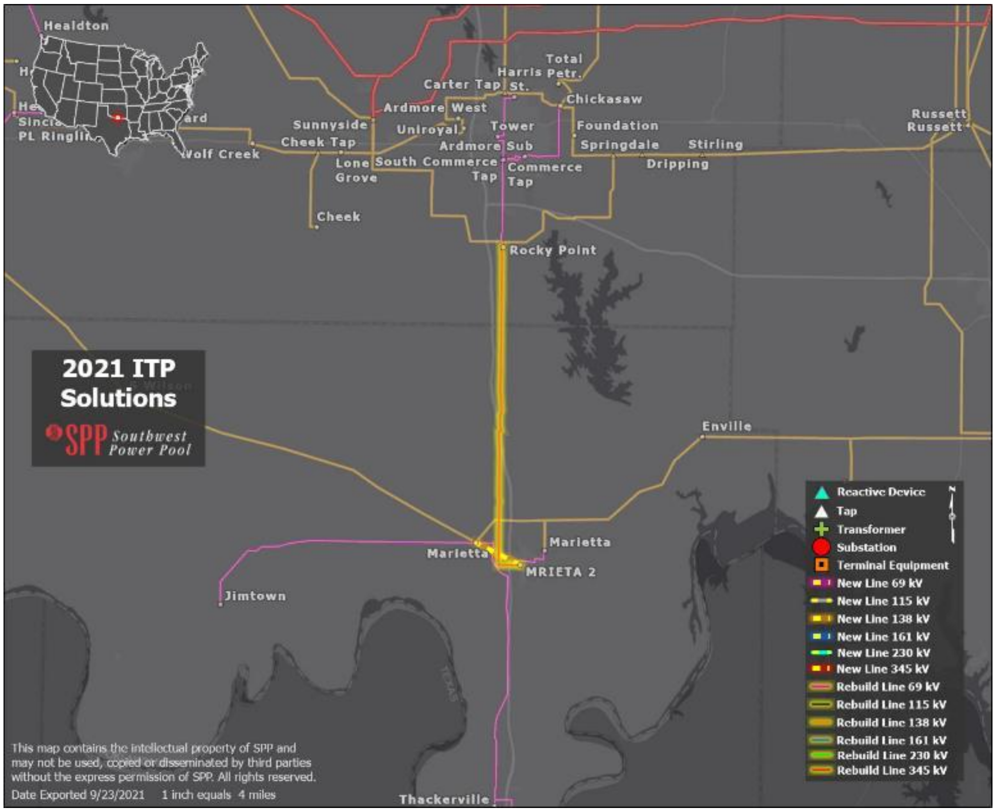

Figure 8.7: Rocky Point-Marietta 138 kV rebuild, Marietta-Marietta 138 kV new line

Along the south central border of Oklahoma, the Rocky Point-Marietta 69 kV line is overloaded for the loss of the Caney Creek-Texoma 138 kV line during the summer and light load cases. The loss of this short line creates a long 138 kV radial, increasing north-to-south flows on the Rocky Point-Marietta 69 kV line. Rebuilding the Rocky Point-Marietta 69 kV line at 138 kV and constructing a new Marietta-Marietta 138 kV line relieves this overload by increasing the transmission capability of the system.

8.2.6 SIOUX CITY 69 KV NEW BREAKER CT; HINTON MUNICIPAL (K412) 69 KV TERMINAL EQUIPMENT

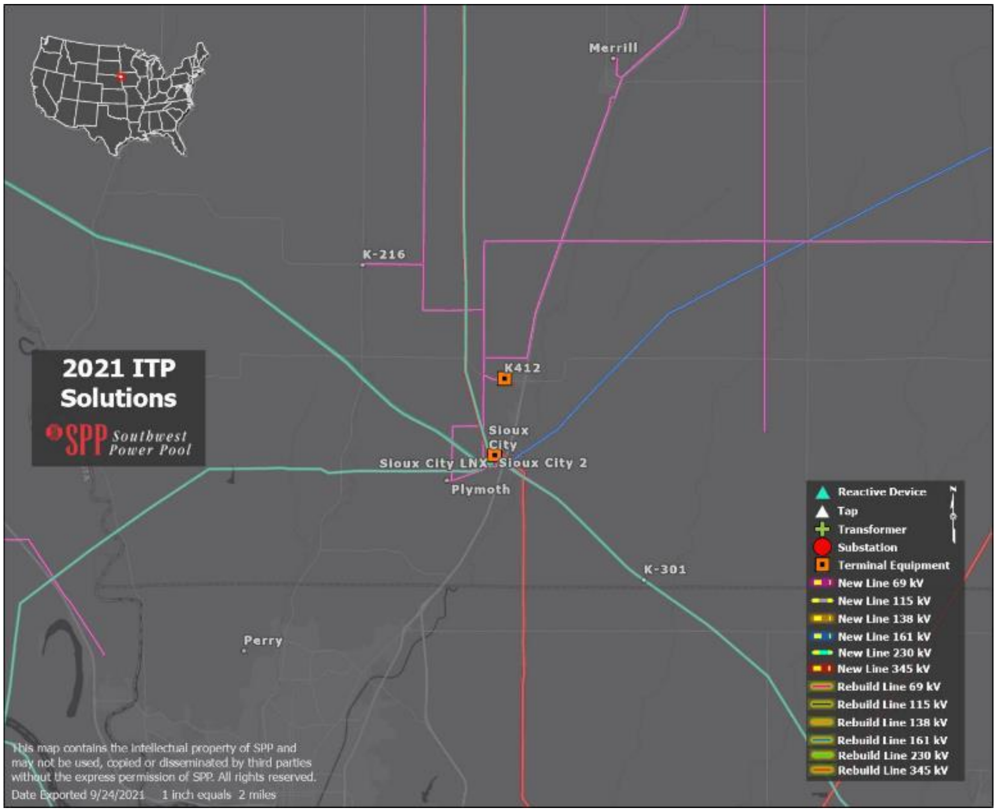

Figure 8.8: Sioux City-Hinton Municipal 69 kV terminal upgrades

In western Iowa, the Sioux City-Hinton Municipal 69 kV line is overloaded for the loss of the Little Sioux 161/69 kV transformer The outage of this transformer redirects flows to load on the 69 kV system through the 161/69 kV transformer at Sioux City and puts additional stress on the Sioux City-Hinton Municipal 69 kV line. This overload can be mitigated through the installation of a new breaker CT at Sioux City and new terminal equipment at Hinton Municipal. This project will increase the line rating to the limit imposed by the conductor in the summer; however, the breaker CT will be the most limiting equipment in the winter.

8.2.7 JOPLIN WEST 7TH-STATELINE 161 KV REBUILD

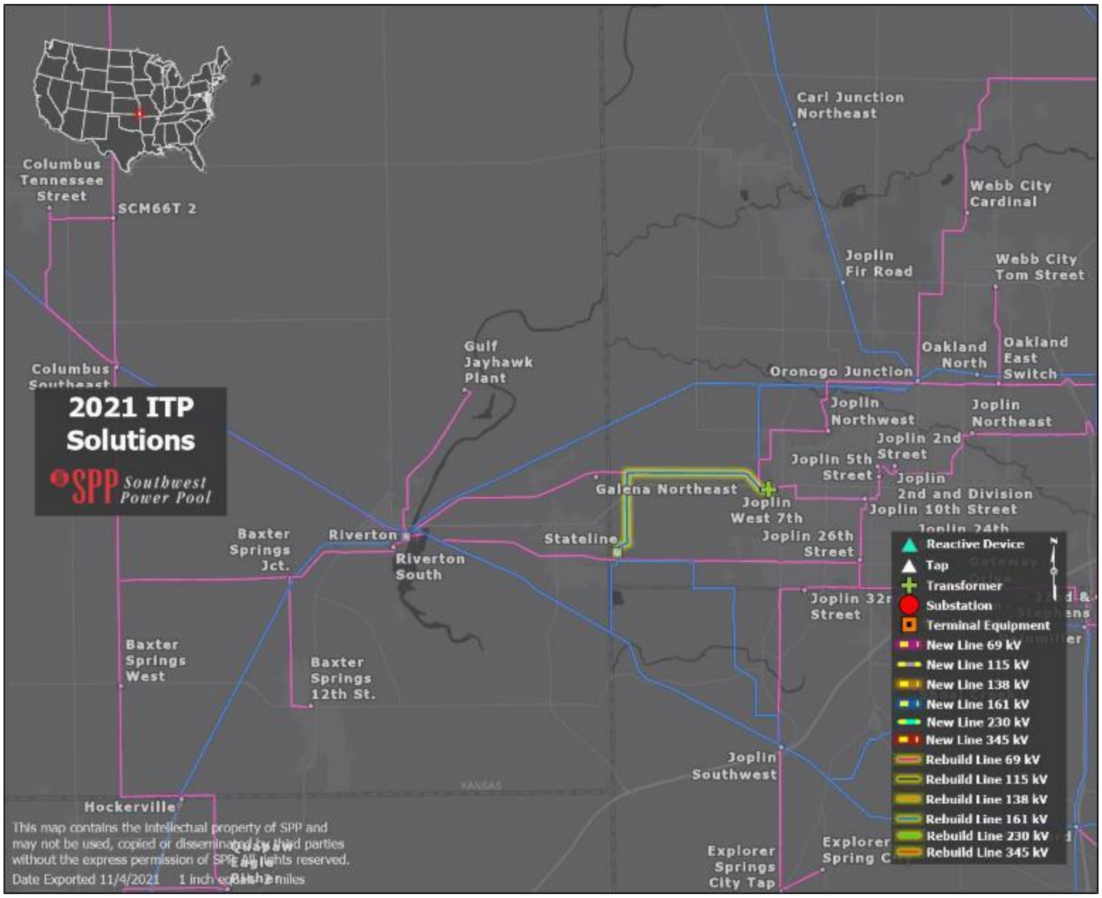

Figure 8.9: Joplin West 7th-Stateline 161 kV rebuild

In the southwest corner of Missouri, the Joplin West 7th-Stateline 161 kV line overloads for the loss of Oronogo Junction-Riverton 161 kV. The loss of this 161 kV circuit redirects flow through the city of Joplin, overloading the Joplin-7th Stateline 161 kV parallel path. A rebuild of the Joplin West 7th-Stateline 161 kV line will mitigate the issue by increasing the transmission capability of the circuit.

8.2.8 ROSWELL 115/69 KV TRANSFORMERS CIRCUIT 1 AND 2 REPLACEMENT

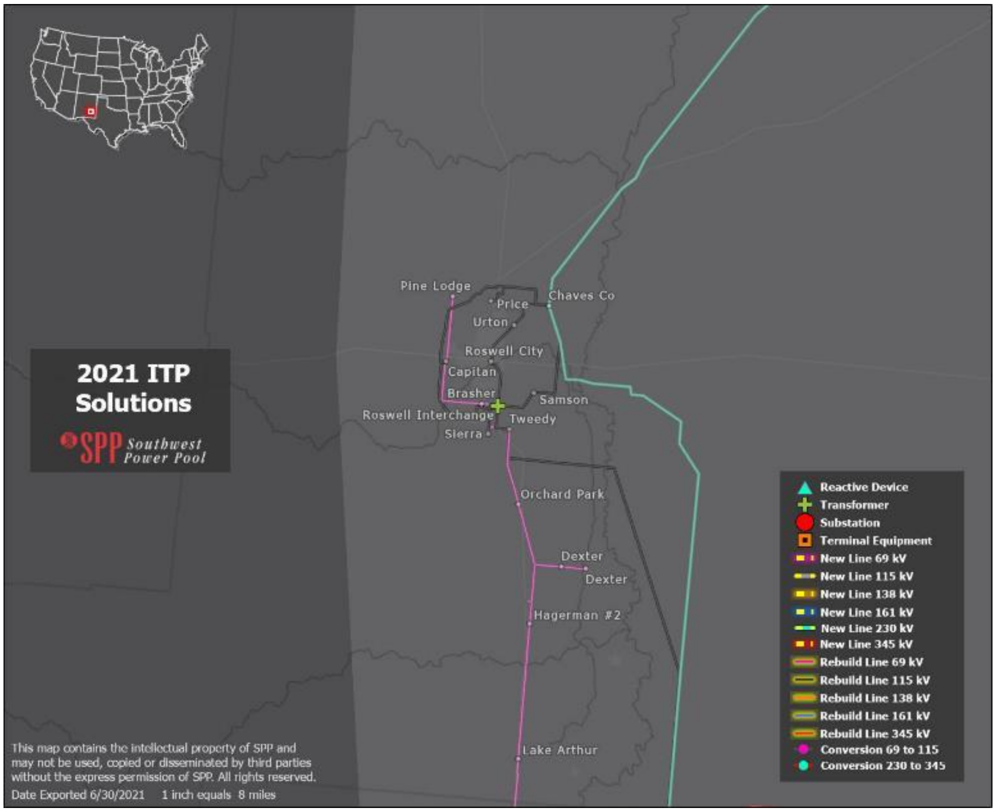

Figure 8.10: Replace Roswell 115/69 kV transformer circuit 1 and circuit 2

Near the city of Roswell, New Mexico, the parallel 115/69 kV Roswell transformers overload for the loss of each other. Load levels in the city of Roswell cannot be served with the existing transformation capacity, even with the parallel redundancy. Replacing the both transformers to increase the capacity to serve the 69 kV system will mitigate this issue.

8.2.9 ARTESIA 115/69 KV TRANSFORMERS CIRCUIT 1 AND 2 REPLACEMENT

Figure 8.11: Replace Artesia 115/69 kV transformer circuit 1 and Circuit 2

In southeastern New Mexico, parallel transformers at Artesia overload for the loss of each other. Neither of the existing transformers alone have sufficient capacity to supply adequate power to the 69 kV system. These overloads are mitigated by replacing both transformers to increase the transformation capacity to the 69 kV system.

8.2.10 JONES-LUBBOCK SOUTH 230 KV CIRCUIT 1 AND 2 TERMINAL EQUIPMENT AND INCREASE LINE CLEARANCES

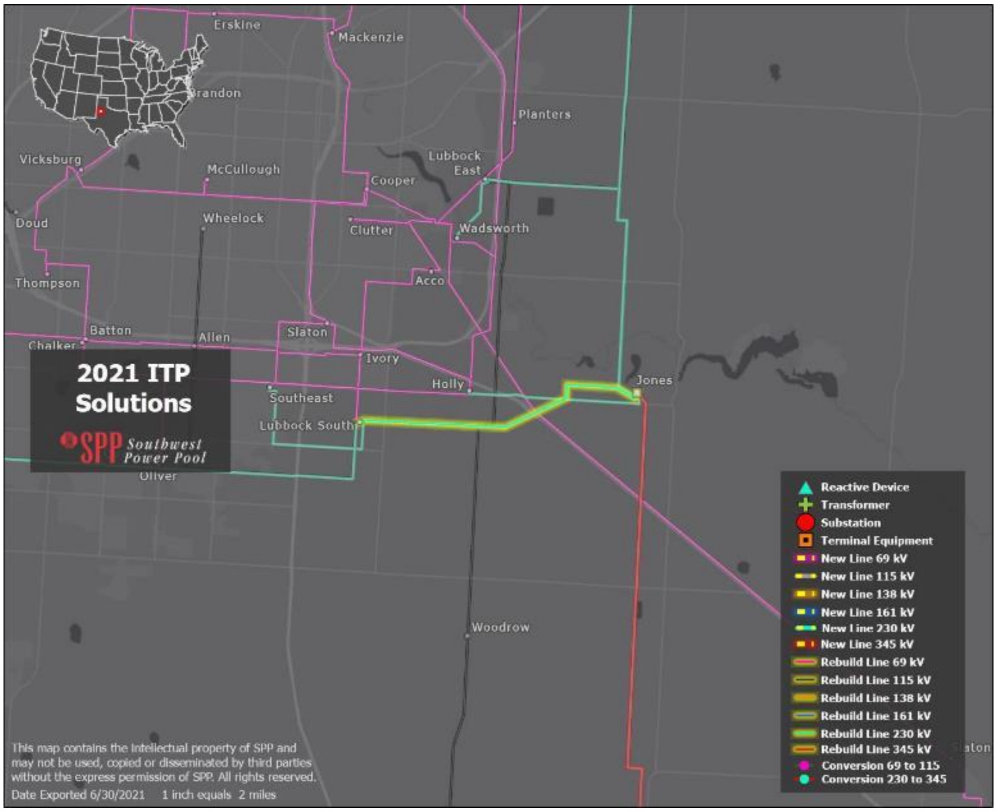

Figure 8.12: Lubbock South-Jones 230 kV terminal equipment and clearance increase

On the south end of Lubbock, Texas, in the Texas Panhandle, two parallel 230 kV circuits from Jones-Lubbock South each overload for the loss of each other. This 230 kV corridor is a common pass-through to deliver energy to the SPS South area. In addition, the fact that the Lubbock South substation feeds a large portion of the Lubbock load center, combined with maximum output of the Jones plant, causes these circuits to overload during contingency conditions in the long-term summer peak models. The flows on these lines necessitate the replacement of terminal equipment at the Lubbock South and Jones substations and an increase in the clearances of the conductor.

8.2.11 GERING TAP-MORRILL 115 KV REBUILD

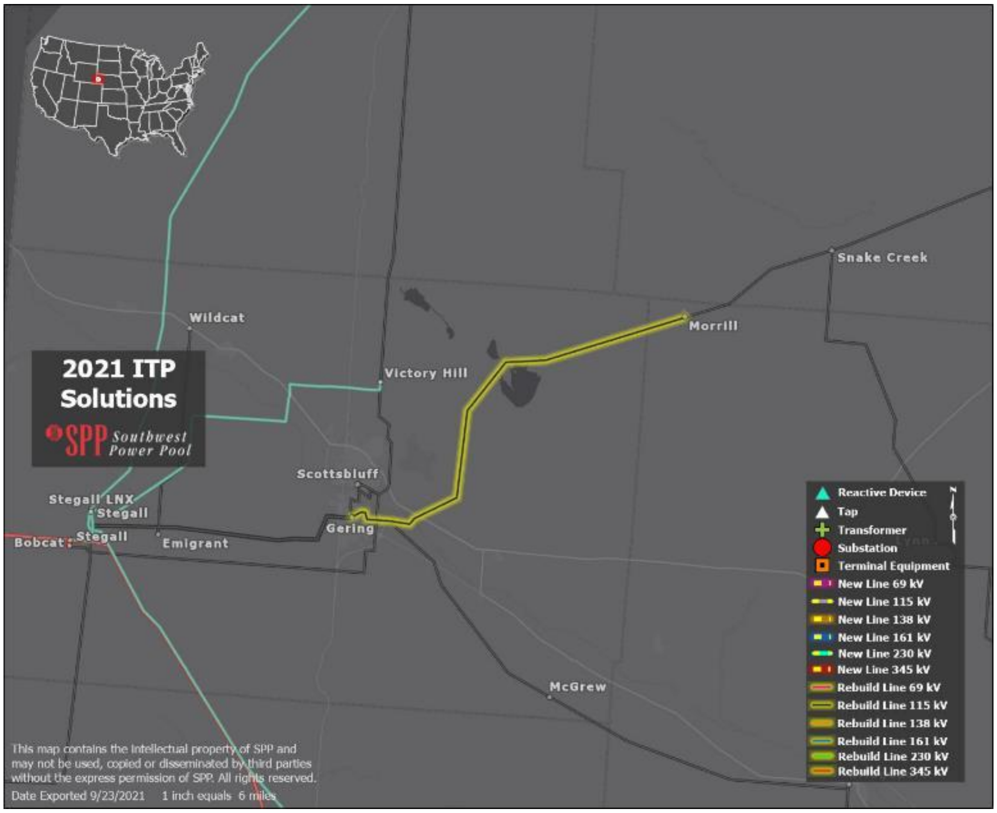

Figure 8.13: Gering Tap-Morrill 115 kV rebuild

In far western border of Nebraska, in the Nebraska Panhandle region, close to the Stegall DC tie. The Gering Tap-Morrill 115 kV will overload for the loss of Stegall-Wayside 230 kV line. This need was identified as a reliability and an economic constraint. This area is impacted by south-to-north system flows for loss of the Stegall-Wayside 230 kV line. The project selected to mitigate the issue is a rebuild of the 24-mile Gering Tap-Morrill 115 kV to increase the transmission capability of that circuit.

8.3 ECONOMIC PROJECTS

8.3.1 SCOTTSBLUFF-VICTORY HILL 115 KV CIRCUIT 2 NEW LINE

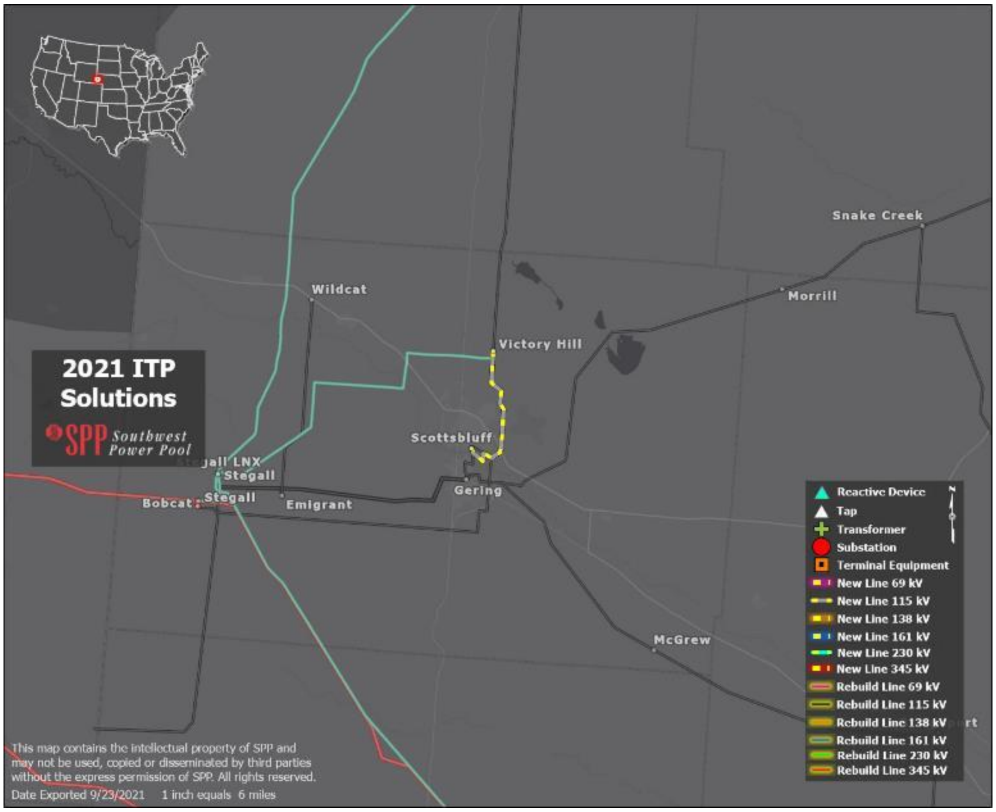

Figure 8.14: Scottsbluff-Victory Hill 115 kV new Circuit 2 line

In Scottsbluff city, in the Nebraska Panhandle region near the western border of Nebraska, close to the Stegall DC tie, the Scottsbluff-Victory Hill 115 kV line becomes congested for the loss of the Stegall-Stegall 230 kV line. This area is mostly impacted by south-to-north system flows coming from generation in the Laramie River area and western Kansas going to the north. Losing the Stegall-Stegall 230 kV line or the Stegall-Wayside 230 kV line diverts power from the Stegall 345 kV substation to the Bobcat Canyon-Scottsbluff 115 kV line. Which results in high congestion of the Scottsbluff-Victory Hill 115 kV line trying to go north towards Wayside. The project selected to mitigate this issue is a second circuit 115 kV line from Scottsbluff-Victory Hill, which provides an additional path for the south-to-north flows in this area.

8.3.2 OAHE-SULLY BUTTES-WHITLOCK-GLENHAM 230 KV TERMINAL EQUIPMENT AND INCREASE LINE CLEARANCES

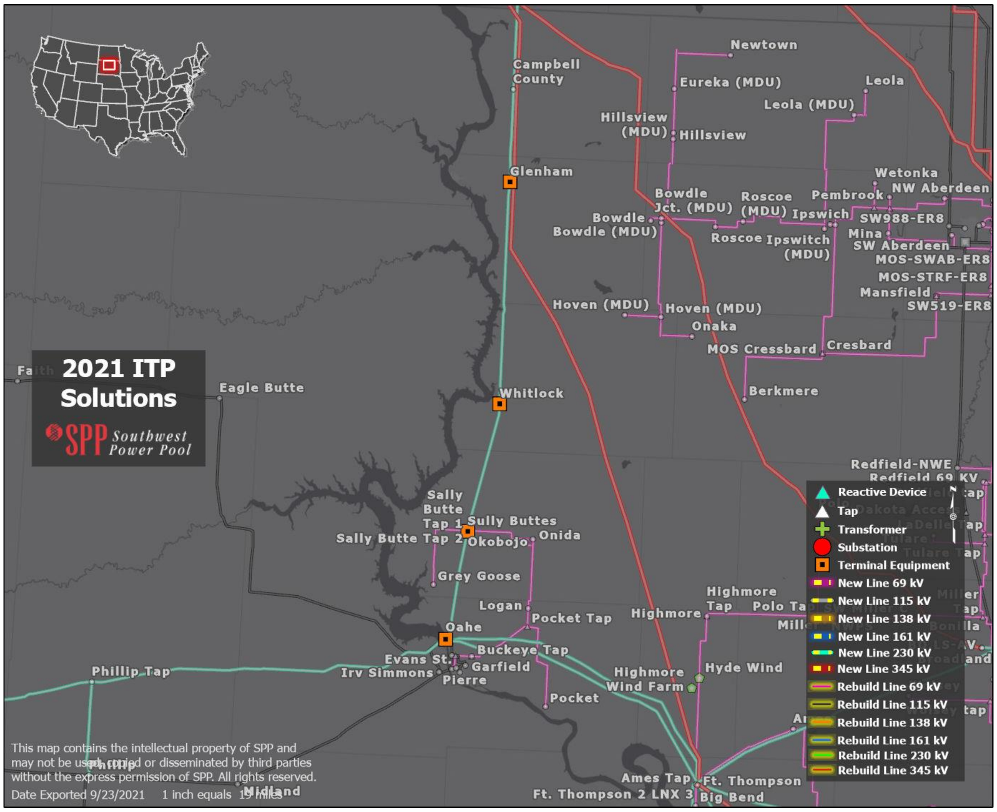

Figure 8.15: Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase clearances

To the north of Pierre, South Dakota, multiple transmission paths help to serve load centers in the north toward Bismarck, North Dakota. The Oahe-Sully Buttes 230 kV line becomes congested for the loss of the Fort Thompson-Leland Olds 345 kV line. This issue is prevalent today and is seen as flows moving north. This issue was analyzed in the 2020 ITP study but the project was not cost-beneficial enough to receive an NTC at the time. The 230 kV segments from Oahe moving north are all limited by elements other than the transmission conductor. Solutions were tested to determine the number of segments that would need to be upgraded to relieve congestion in a cost-beneficial manner on the full 230 kV path to the north. The optimal solution is to replace terminal equipment at Oahe, Sully Buttes, and Glenham and increase line clearances on the Oahe-Sully Buttes-Whitlock 230 kV line sections.

8.3.3 OGALLALA (TRI STATE)-OGALLALA (NPPD) 115 KV REBUILD BUS TIE

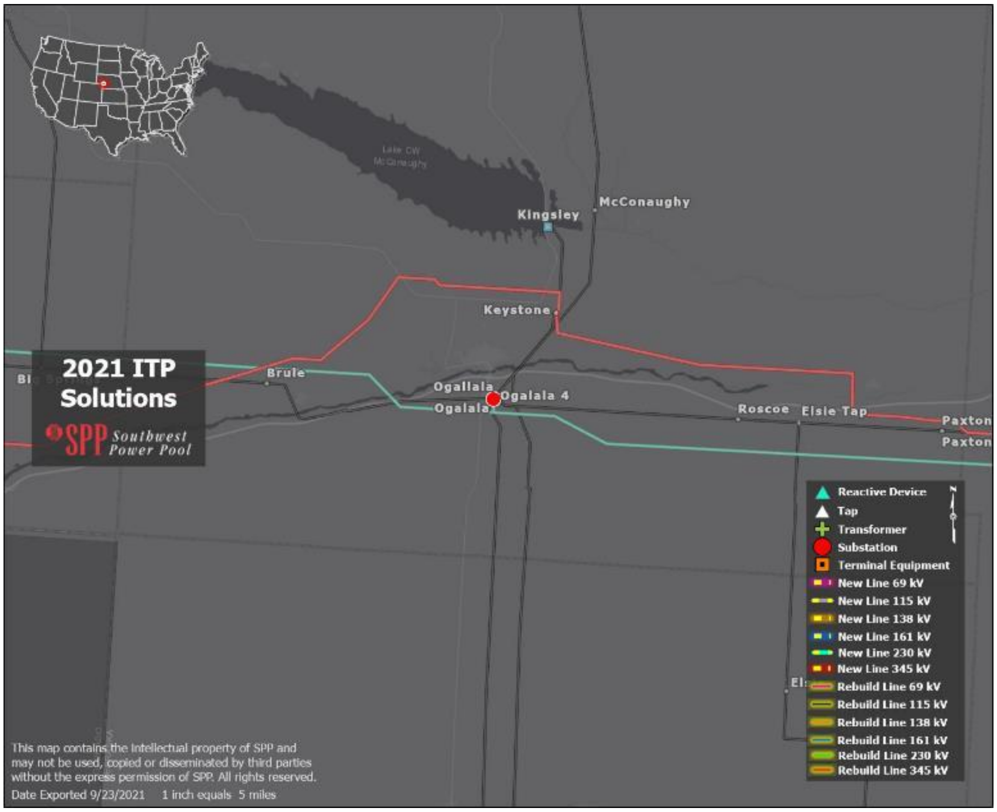

Figure 8.16: Ogallala Tri State-Ogallala NPPD 115 kV rebuild tie

Southeast of Ogallala, Nebraska, the 115 kV tie connecting the NPPD and Tri State's Ogallala substations becomes congested for the loss of Ogallala-Grant 115 kV. This area is impacted by north-to-south system flows coming from 345 kV system at Keystone and east-to-west system flows coming from existing generation at the Gentleman station on the 230 kV system, all going through the Ogallala bus tie. The project selected to mitigate the issue is to replace the Ogallala 115 kV bus tie to allow more flow on the tie.

8.3.4 COLUMBUS EAST 230/115 KV TRANSFORMER REPLACEMENT

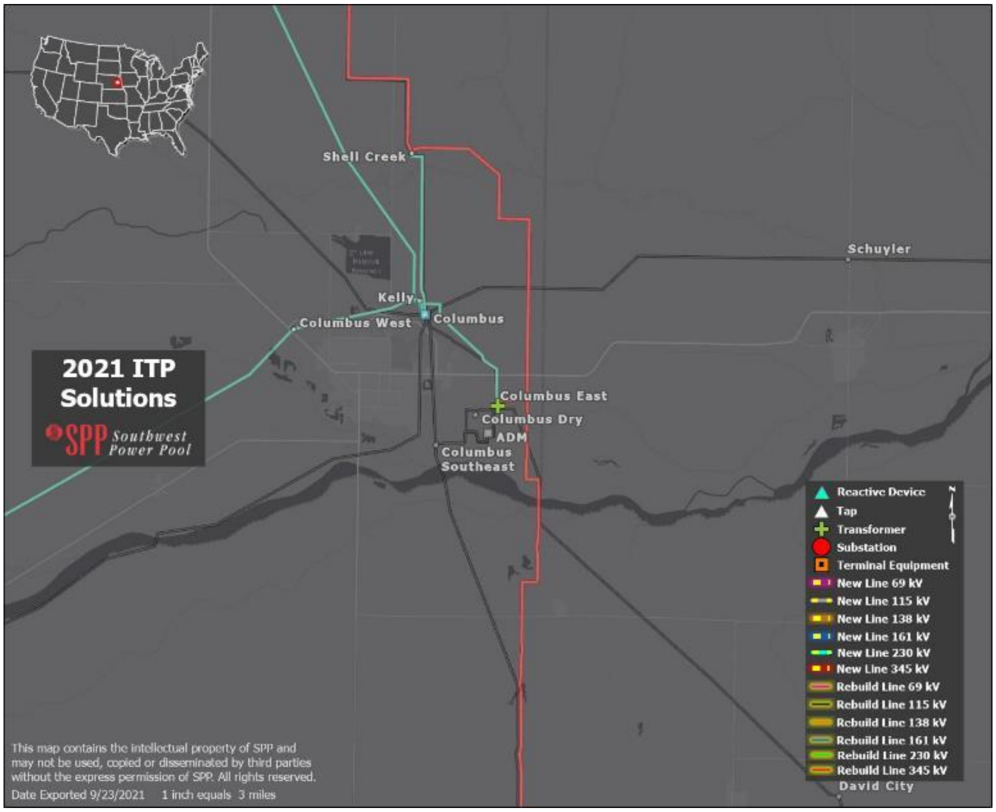

Figure 8.17: Columbus East 230/115 kV transformer replacement

Northwest of Omaha and Lincoln, Nebraska, the Columbus East 230/115 kV transformer becomes congested for the loss of the Columbus East-Shell Creek 345 kV line. This area experiences north-to-south system flows that are diverted with the loss of the 345 kV connection and has seen system congestion in real-time operations. This flowgate was identified as a need in the 2020 ITP but the project selected was staged outside the NTC issuance window. With increased congestion on the line due to increased flows in the area and the Haystack wind farm going online in the 2021 ITP, this project became more cost-beneficial to the region. The project selected to address the congestion is to replace the Columbus East transformer, consistent with the solution analyzed in the 2020 ITP, in order to better utilize the HV system that feeds into Columbus, Lincoln and Omaha, Nebraska, load centers.

8.3.5 CLEO CORNER-CLEO JUNCTION 69 KV TERMINAL EQUIPMENT

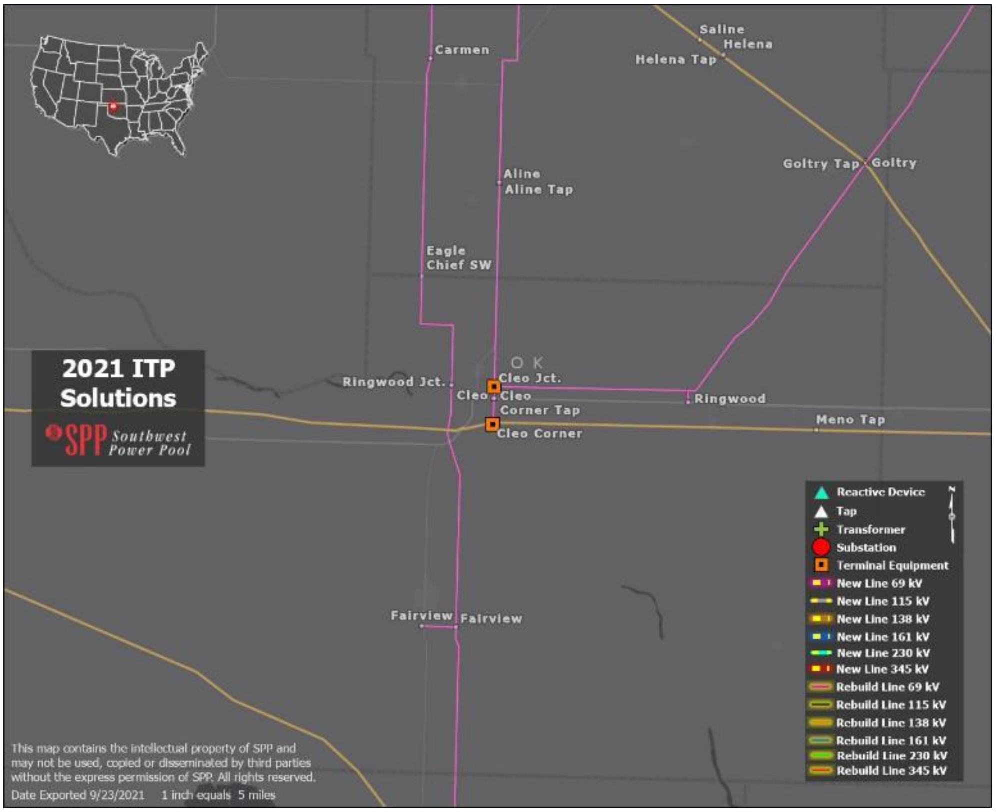

Figure 8.18: Cleo Corner-Cleo Junction 69 kV terminal equipment

In north-central Oklahoma, east of Enid, the Cleo Corner-Cleo Junction 69 kV line becomes congested for the loss of the 138 kV line connecting the OGE and Western Farmers' Renfrow substations. Losing the northern 138 kV source from Renfrow to the 69 kV system in the area forces more flow from the 138 kV system to step down at Cleo Corner, congesting the 69 kV line. This flowgate was issued an NTC in the 2019 ITP assessment to upgrade terminal equipment, but with increased congestion on the line due to increased flows in the area and the Sundance wind farm going online in the 2021 ITP, this necessitated incremental upgrade on different terminal equipment at Cleo Corner and Cleo Junction to increase the line rating incremental to the previously issued NTC to mitigate this issue.

8.4 OPERATIONAL PROJECTS

8.4.1 MIDWEST-FRANKLIN 138 KV TERMINAL EQUIPMENT

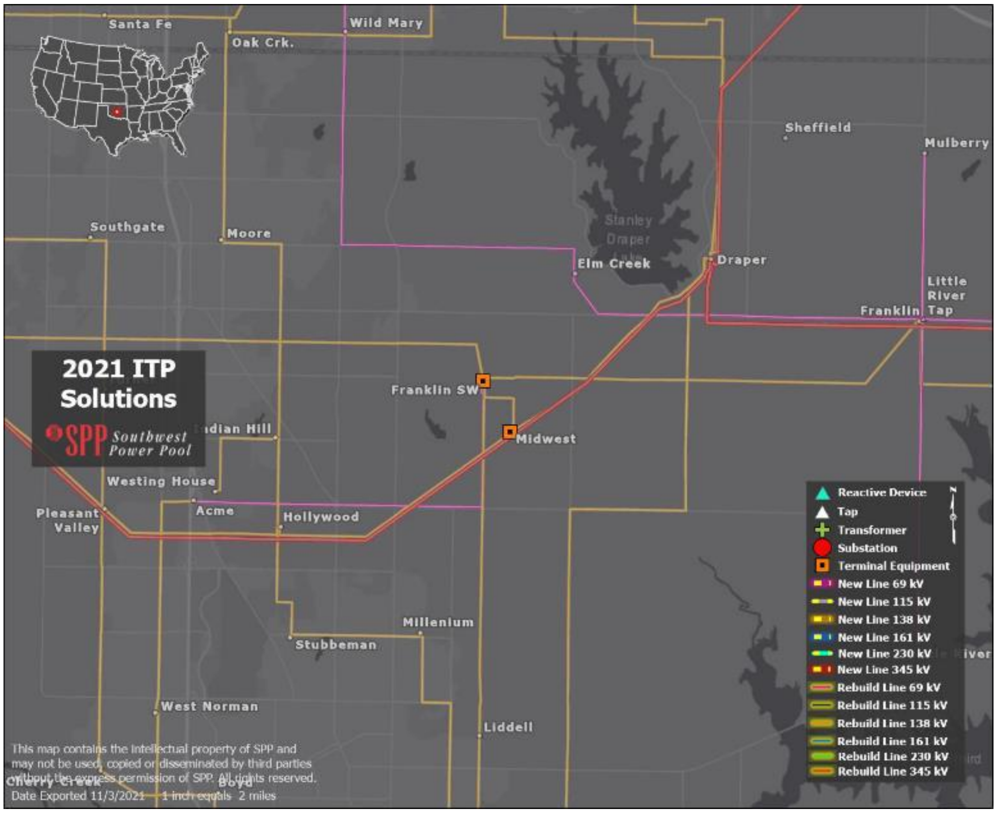

Figure 8.19: Midwest and/or Franklin 138 kV terminal upgrades Circuit 1

In Oklahoma City, operational congestion on the Midwest-Franklin 138 kV line has been observed for the loss of the 138 kV line from Cedar Lane-Canadian.

In the 2020 ITP, an NTC was issued to upgrade the terminal equipment at Midwest and Franklin, bringing the summer ratings to 268/308 (SN/SE) MVA. Based on the operational analysis conducted in the 2021 ITP, it was identified that operational congestion in the summer and winter periods warranted both a modification and an acceleration of the existing NTC. The ratings of the Midwest-Franklin line also need to be increased to mitigate the congestion in the winter seasons and accelerated to address the current day operational issues. This will be accomplished through modifying the existing NTC to specify upgrading the terminal equipment at Midwest and/or Franklin to achieve an MVA rating of 347/375 (WN/WE) and accelerating the need date to 3/10/2022.

8.5 SHORT-CIRCUIT PROJECTS

8.5.1 SHORT-CIRCUIT PROJECT PORTFOLIO

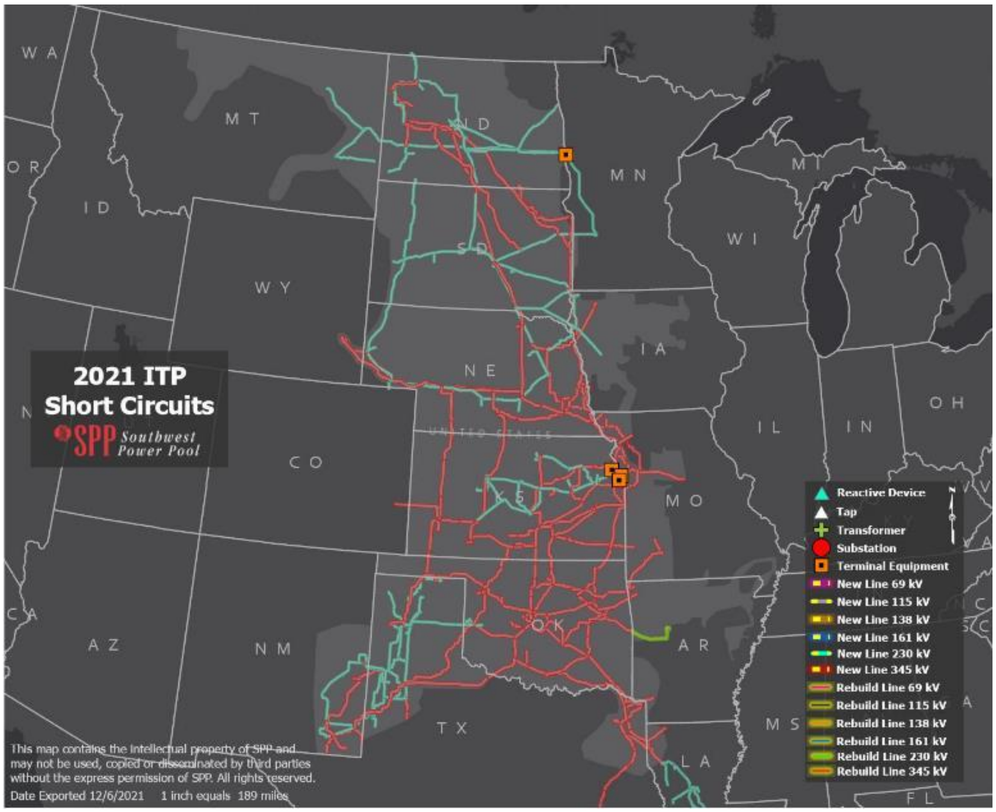

Figure 8.20: Short-Circuit Project portfolio

2021 ITP short-circuit projects consist of four overdutied fault interputing equipment upgrades and a substation reconfiguration for three overdutied circuit switchers. These upgrades ensure SPP's members can meet short-circuit analysis requirements in the NERC TPL-001-4 standard.

SHORT-CIRCUIT PROJECT	AREA	SCENARIO*
Replace one breaker at Jarbalo Junction 115 kV	Evergy (Westar)	23S / BR
Replace two breakers at Shawnee Mission 161 kV	Evergy (KCPL)	23S / BR
Replace one breaker at Craig 161 kV	Evergy (KCPL)	23S / BR
Reconfigure the Moorhead 230 kV substation	MRES	23S / BR

Table 8.3: Short-Circuit Projects

8.6 POLICY PROJECTS

No policy projects are required for the 2021 ITP.

9 INFORMATIONAL PORTFOLIO ANALYSIS

9.1 BENEFITS

9.1.1 METHODOLOGY

Benefit metrics were used to measure the value and economic impacts of the final portfolio. The Benefit Metrics Manual[37] provides the definitions, concepts, calculations, and allocation methodologies for all approved metrics. The ESWG directed that the 2021 ITP B/C 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 in the final portfolio (regardless of NTC recommendation). The only benefit metric performed was the APC saving metric due to the mitigation plan approved by MOPC in July 2021.

9.1.2 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 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,[38] two years were analyzed, 2026 and 2031. APC savings were calculated accordingly for these years. The benefits are extrapolated to the 15th year 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 2026 using an 8% discount rate, and a 2.0% inflation rate from 2026 back to 2021. The sum of all discounted benefits was presented as the NPV benefit. This calculation was performed for every zone.

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37 Benefit Metrics Manual

38 The SPP OATT requires that the portfolio be evaluated using a 40-year financial analysis. Values are presented in 2021 dollars.

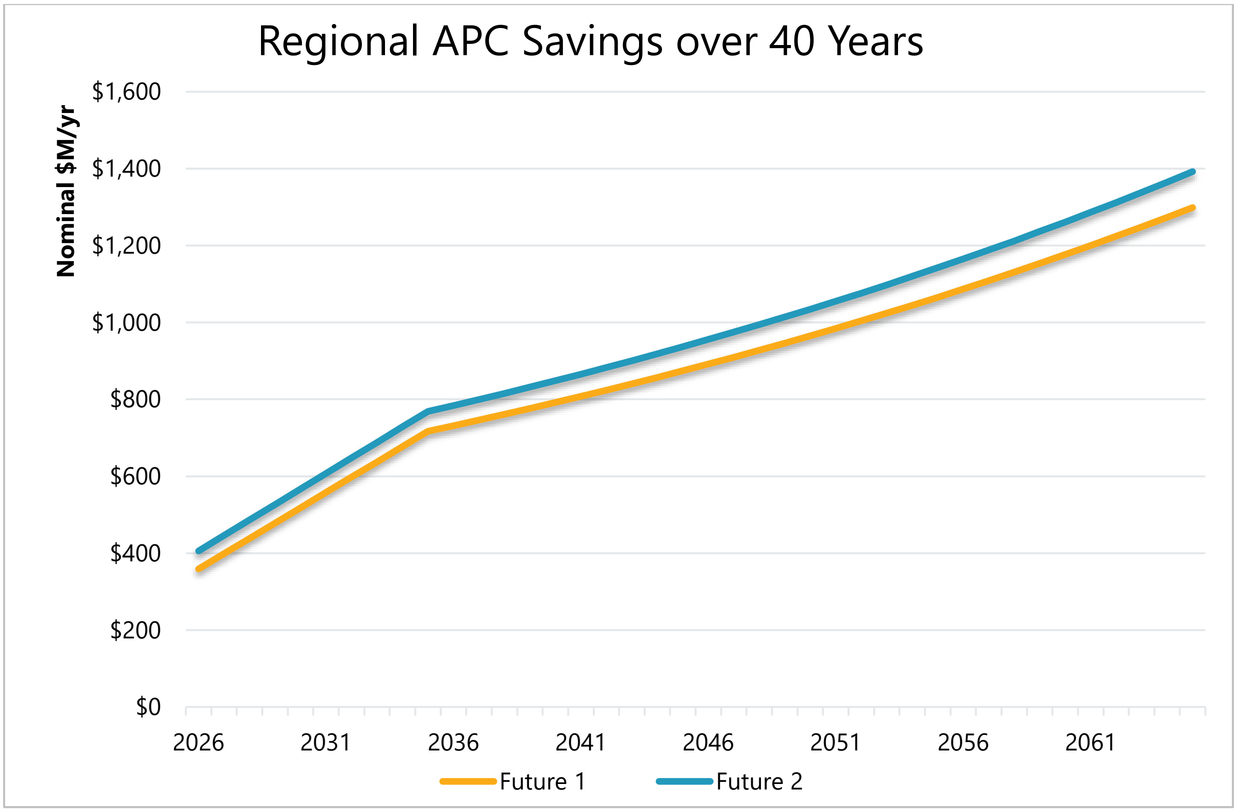

Figure 9.1 shows the regional APC savings for the recommended portfolio over 40 years.

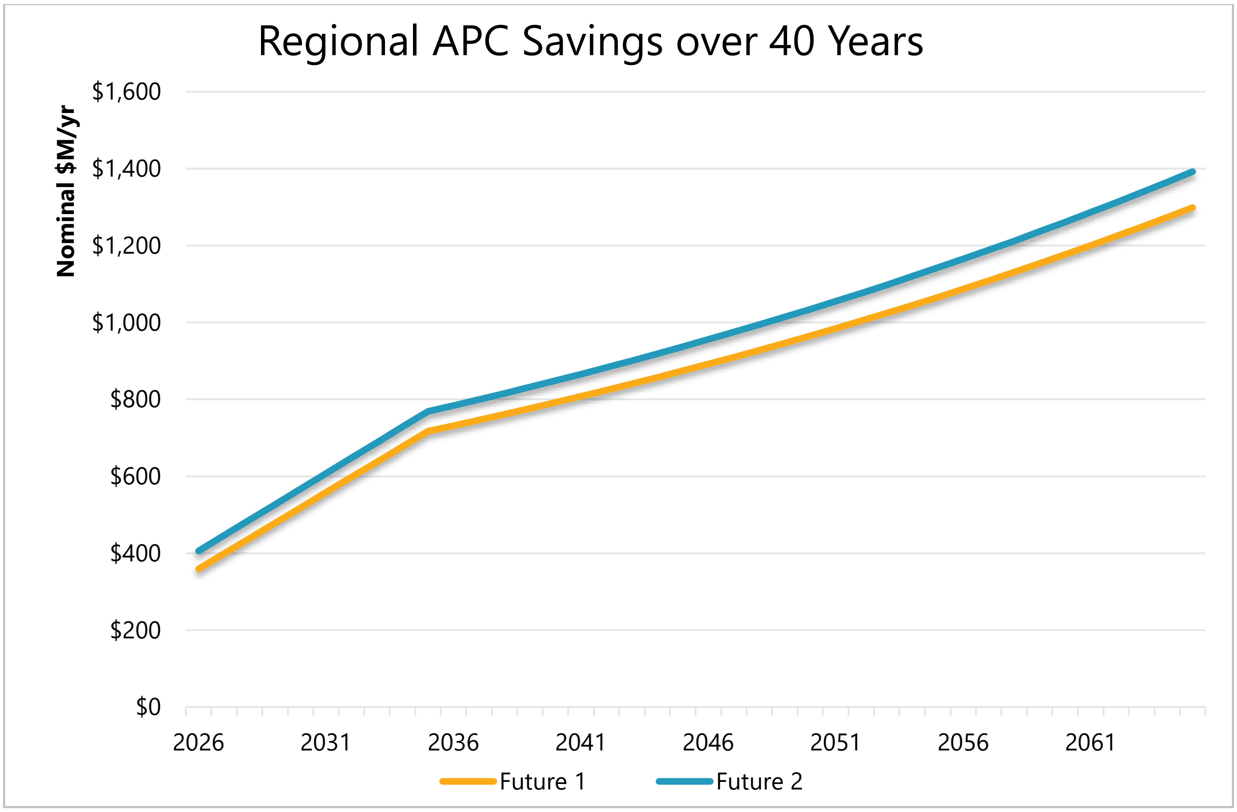

Figure 9.1: Regional APC Savings for the 40-Year Study Period

Table 9.1 provides the zonal breakdown and the NPV 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)		
	2026 ($M)	2031 ($M)	40-year NPV ($2021M)	2026 ($M)	2031 ($M)	40-year NPV ($2021M)
AEPW	$11.05	$9.30	$109.23	$14.38	$13.13	$158.42
EMDE	$1.16	$1.23	$15.42	$0.94	$1.36	$18.26
GMO	$5.64	$5.92	$74.31	$5.82	$6.21	$78.28
GRDA	$1.08	$0.77	$8.42	$1.39	$1.05	$11.77
KACY	$0.43	$0.61	$8.24	$0.77	$0.51	$5.42
KCPL	$3.25	$5.08	$69.28	$3.38	$4.17	$54.38
LES	$2.32	$2.33	$28.91	$2.13	$2.36	$29.99
MIDW	$0.60	$0.60	$7.47	$0.68	$0.63	$7.58
NPPD	$6.11	$8.25	$109.67	$5.23	$6.07	$78.11
OKGE	$6.74	$7.72	$99.09	$7.71	$6.81	$81.34
OPPD	$9.58	$10.67	$135.92	$10.22	$17.78	$246.27
SPRM	$0.89	$1.19	$15.69	$0.65	$0.87	$11.62
SPS	$33.13	$58.54	$812.85	$72.12	$60.78	$714.27
SUNC	$2.02	$2.24	$28.44	$2.65	$1.59	$16.04
SWPA	$0.68	$0.68	$8.48	$0.69	$0.75	$9.46
UMZ	$266.24	$432.67	$5,934.15	$267.88	$473.20	$6,570.13
WERE	$5.58	$7.58	$100.76	$6.56	$7.55	$96.89
WFEC	$2.45	$2.53	$31.70	$2.51	$2.58	$32.22
TOTAL	**$358.93**	**$557.90**	**$7,598.03**	**$405.71**	**$607.37**	**$8,220.46**

Table 9.1: APC Savings by Zone

Table 9.2 provides the zonal breakdown and the NPV estimates for the SPP "other" zone. This zone includes merchant generation (without contractual arrangements with load-serving entities) and additional renewable resource plan wind resources. The calculation for this zone is 100% production cost minus sales to other zones (revenue).

	Reference Case (F1)			Emerging Technologies (F2)		
Zone	2026 ($M)	2031 ($M)	40-year NPV	2026 ($M)	2031 ($M)	40-year NPV
OTHSPP	$5.7	$69.9	$1086.9	$85.6	$53.6	$554.8

Table 9.2: Other SPP APC Benefit

9.1.3 SUMMARY

Table 9.3**Error! Reference source not found.** summarizes the 40-year NPV of the estimated benefit metrics and costs and the resulting B/C ratios for each SPP zone and state, respectively.

For the region, the B/C ratio is estimated to be 5.3 in Future 1 and 5.7 in Future 2. The higher B/C ratio in Future 2 is driven by the APC savings due to higher congestion relief.

Present Value of 40-yr Benefits for the 2025-2065 Period						
Zone	Reference Case (Future 1)			Reference Case (Future 2)		
	40-year NPV	Value of 40-year ATRRs	Benefit/Cost Ratio	40-year NPV	Value of 40-year ATRRs	Benefit/Cost Ratio
AEPW	$109.23	$260.26	0.4	$158.42	$260.26	0.6
EMDE	$15.42	$34.10	0.5	$18.26	$34.10	0.5
GMO	$74.31	$45.73	1.6	$78.28	$45.73	1.7
GRDA	$8.42	$22.87	0.4	$11.77	$22.87	0.5
KACY	$8.24	$11.04	0.7	$5.42	$11.04	0.5
KCPL	$69.28	$89.19	0.8	$54.38	$89.19	0.6
LES	$28.91	$17.69	1.6	$29.99	$17.69	1.7
MIDW	$7.47	$9.15	0.8	$7.58	$9.15	0.8
NPPD	$109.67	$89.69	1.2	$78.11	$89.69	0.9
OKGE	$99.09	$172.95	0.6	$81.34	$172.95	0.5
OPPD	$135.92	$61.90	2.2	$246.27	$61.90	4.0
SPRM	$15.69	$16.04	1.0	$11.62	$16.04	0.7
SPS	$812.85	$184.12	4.4	$714.27	$184.12	3.9
SUNC	$28.44	$27.58	1.0	$16.04	$27.58	0.6
SWPA	$8.48	$7.33	1.2	$9.46	$7.33	1.3
UMZ	$5,934.15	$221.10	26.8	$6,570.13	$221.10	29.7
WERE	$100.76	$122.69	0.8	$96.89	$122.69	0.8
WFEC	$31.70	$44.14	0.7	$32.22	$44.14	0.7
TOTAL	**$7,598.03**	**$1,437.54**	5.3	**$8,220.46**	**$1,437.54**	5.7

Table 9.3: Estimated 40-year NPV of Benefit Metrics and Costs-Zonal

9.2 RATE IMPACTS

The rate impact to an average retail residential ratepayer in SPP was computed for the recommended portfolio. Rate impact costs and benefits[39] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kilowatt hours (kWh) per month. Benefits and

[39] APC savings are the only benefit included in the rate impact calculations.

costs for the 2031 study year were used to calculate rate impacts. All 2031 benefits and costs are shown in 2021 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 9.4 through Table 9.7. There is a monthly net benefit for the average SPP residential ratepayer of $1.16 for Future 1. There is a monthly net benefit for the average SPP residential ratepayer of $1.30 for Future 2.

Zone	One-Year ATRR Costs 2031 ($thousands)	One-Year Benefit 2031 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2021$)
AEPW	$22,831	$7,628	$0.71	$0.24	$0.47
EMDE	$3,007	$1,006	$0.54	$0.18	$0.36
GMO	$4,027	$4,855	$0.45	$0.54	($0.09)
GRDA	$2,014	$628	$0.24	$0.07	$0.16
KACY	$972	$504	$0.40	$0.21	$0.19
KCPL	$7,854	$4,169	$0.47	$0.25	$0.22
LES	$1,557	$1,911	$0.43	$0.53	($0.10)
MIDW	$805	$495	$0.40	$0.25	$0.16
NPPD	$7,842	$6,771	$0.46	$0.39	$0.06
OKGE	$15,179	$6,335	$0.46	$0.19	$0.27
OPPD	$5,451	$8,749	$0.35	$0.56	($0.21)
SPRM	$1,413	$972	$0.47	$0.32	$0.15
SPS	$16,007	$48,024	$0.38	$1.13	($0.76)
SUNC	$2,428	$1,833	$0.38	$0.28	$0.09
SWPA	$645	$559	$0.20	$0.17	$0.03
UMZ	$19,298	$354,937	$0.40	$7.44	($7.04)
WERE	$10,802	$6,215	$0.42	$0.24	$0.18
WFEC	$3,872	$2,079	$0.36	$0.19	$0.17
TOTAL	**$126,006**	**$457,669**	**$0.44**	**$1.60**	**($1.16)**

Table 9.4: Future 1 2031 Retail Residential Rate Impacts by Zone

Zone	One-Year ATRR Costs 2031 ($thousands)	One-Year Benefit 2031 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2021$)
AEPW	$22,831	$10,771	$0.71	$0.33	$0.37
EMDE	$3,007	$1,114	$0.54	$0.20	$0.34
GMO	$4,027	$5,094	$0.45	$0.56	($0.12)
GRDA	$2,014	$858	$0.24	$0.10	$0.14
KACY	$972	$418	$0.40	$0.17	$0.23
KCPL	$7,854	$3,419	$0.47	$0.20	$0.26
LES	$1,557	$1,933	$0.43	$0.54	($0.10)
MIDW	$805	$514	$0.40	$0.26	$0.15
NPPD	$7,842	$4,980	$0.46	$0.29	$0.17
OKGE	$15,179	$5,588	$0.46	$0.17	$0.29
OPPD	$5,451	$14,582	$0.35	$0.94	($0.59)
SPRM	$1,413	$717	$0.47	$0.24	$0.23
SPS	$16,007	$49,858	$0.38	$1.18	($0.80)
SUNC	$2,428	$1,303	$0.38	$0.20	$0.17
SWPA	$645	$614	$0.20	$0.19	$0.01
UMZ	$19,298	$388,187	$0.40	$8.14	($7.74)
WERE	$10,802	$6,190	$0.42	$0.24	$0.18
WFEC	$3,872	$2,116	$0.36	$0.20	$0.16
TOTAL	**$126,006**	**$498,255**	**$0.44**	**$1.74**	**($1.30)**

Table 9.5: Future 2 2031 Retail Residential Rate Impacts by Zone

State	One-Year ATRR Costs 2031 ($thousands)	One-Year Benefit 2031 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2021$)
Arkansas	$6,731	$2,506	$0.68	$0.25	$0.42
Iowa	$3,073	$55,528	$0.40	$7.19	($6.80)
Kansas	$18,588	$11,238	$0.39	$0.24	$0.15
Louisiana	$3,123	$1,043	$0.71	$0.24	$0.47
Minnesota	$316	$5,820	$0.40	$7.44	($7.04)
Missouri	$13,182	$10,141	$0.78	$0.60	$0.18
Montana	$365	$6,706	$0.40	$7.44	($7.04)
Oklahoma	$29,218	$12,212	$0.42	$0.17	$0.24
Nebraska	$16,082	$41,196	$0.20	$0.50	($0.31)
New Mexico	$5,332	$15,996	$6.61	$19.83	($13.22)
North Dakota	$9,474	$174,245	$0.40	$7.44	($7.04)
South Dakota	$4,582	$84,172	$0.41	$7.44	($7.03)
Texas	$15,736	$33,119	$1.69	$3.56	($1.87)
Wyoming	$204	$3,745	$0.40	$7.44	($7.04)
TOTAL	**$126,006**	**$457,669**	**$0.44**	**$1.60**	**($1.16)**

Table 9.6: Future 1 2031 Retail Residential Rate Impacts by State (2021$)

Zone	One-Year ATRR Costs 2031 ($thousands)	One-Year Benefit 2031 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2021$)
Arkansas	$6,731	$3,114	$0.68	$0.31	$0.36
Iowa	$3,073	$60,780	$0.40	$7.87	($7.48)
Kansas	$18,588	$10,371	$0.39	$0.22	$0.17
Louisiana	$3,123	$1,474	$0.71	$0.33	$0.37
Minnesota	$316	$6,365	$0.40	$8.14	($7.74)
Missouri	$13,182	$9,864	$0.78	$0.58	$0.20
Montana	$365	$7,334	$0.40	$8.14	($7.74)
Oklahoma	$29,218	$13,148	$0.42	$0.19	$0.23
Nebraska	$16,082	$47,437	$0.20	$0.58	($0.38)
New Mexico	$5,332	$16,607	$6.61	$20.59	($13.98)
North Dakota	$9,474	$190,568	$0.40	$8.14	($7.74)
South Dakota	$4,582	$92,055	$0.41	$8.14	($7.73)
Texas	$15,736	$35,040	$1.69	$3.77	($2.08)
Wyoming	$204	$4,096	$0.40	$8.14	($7.74)
TOTAL	**$126,006**	**$498,255**	**$0.44**	**$1.74**	**($1.30)**

Table 9.7: Future 2 2031 Retail Residential Rate Impacts by State (2021$)

9.3 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.[40] 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 2021 ITP.

The planned system supports 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.

9.3.1 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 9.8 identifies the transfer zones and boundaries.

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

Table 9.8: Generation Zones

Table 9.9 shows the transfers that were performed on the 2031 light load and 2031 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 2031 light load model due to the reliability hour being identified as 4:00 a.m.

Model	Source Zone	Sink Zone
2031 Light Load	SPP renewables (Wind)	SPP conventional thermal generation
2031 Light Load	SPP renewables (Wind)	First-Tier conventional thermal generation
2031 Summer	SPP renewables (Wind and Utility Scale Solar)	SPP conventional thermal generation
2031 Summer	SPP renewables (Wind and Utility Scale Solar)	First-Tier and conventional thermal generation

Table 9.9: Transfers by Model

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

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 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.

9.3.2 SUMMARY

Table 9.10 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 in all instances either the minimum internal conventional thermal generation levels were reached or when a thermal limit was reached before the VSL.

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: 2031 Light Load							
Wind --> Internal Thermal	15.5	5.8	Reached minimum Sink				N/A
Wind --> External Thermal	15.5	17.2	Terry Road-Sunnyside	16.7	16.3	1.2	Yes
"	15.5	17.2	Terry Road-Sunnyside	21.5	17.0	1.8	Yes
"	15.5	17.2	Overton-Sibley	17.1	16	1.6	Yes
Future 1: 2031 Summer Peak							
Solar & Wind -->	16.1	27.2	Reached Maximum Source				N/A

Transfer Source --> Sink	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
Internal Thermal							
Solar & Wind --> External Thermal	21.1	72.1	Ketchem-Sibley	26.7	67.5	5.4	Yes
"	16.1	43	Waverly-La Cygne	21.4	38.8	5.3	Yes
"	16.1	43	Postrock-Axell	21.6	38.6	5.5	Yes
Future 2: 2031 Light Load							
Wind --> Internal Thermal	12.7	4.5	Cleveland-Sooner	13.5	3.9	0.8	Yes
"	12.7	4.5	Wolf Creek-Blackberry	13.7	3.7	1	Yes
"	12.7	4.5	Chisholm-Gracemont	13.7	3.7	1	Yes
Wind --> External Thermal	12.7	17.5	Cleveland-Sooner	13.5	17	0.8	Yes
"	12.7	17.5	Wolf Creek-Blackberry	13.7	16.8	1	Yes
"	12.7	17.5	LES-Gracemont	13.6	16.7	0.9	Yes
Future 2: 2031 Summer Peak							
Solar & Wind --> Internal Thermal	15.5	21.5	Mingo-Red Willow	20	17.5	4.5	Yes
"	15.5	21.5	Postrock-Axell	20.6	17	5.1	Yes
"	15.5	21.5	Terry Road-Sunnyside	21	16.7	5.5	
Solar & Wind --> External Thermal	15.5	42.4	Mingo-Red Willow	18.6	40.1	3.1	Yes
"	15.5	42.4	GRDA1-Tonece	18.8	39.9	3.3	Yes
"	15.5	42.4	Blackberry-Wolf Creek	19	39.8	3.5	Yes

Table 9.10: Post-Contingency Voltage Stability Transfer Limit Summary

Table 9.11 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: 2031 Light Load				
Wind-->Internal Thermal	**22.9**	N/A	N/A	Reached Minimum Sink
Wind-->External Thermal	**22.9**	16.7	16.5	
Future 1: 2031 Summer Peak				
Solar & Wind --> Internal Thermal	**23.2**	N/A	N/A	Reached Minimum Sink
Solar & Wind --> External Thermal	**23.2**	21.1	20.3	
Future 2: 2031 Light Load				
Wind--> Internal Thermal	**22.7**	13.5	13.3	
Wind--> External Thermal	**22.7**	13.5	13.3	
Future 2: 2031 Summer Peak				
Solar & Wind --> Internal Thermal	**22.6**	20	18.6	
Solar & Wind --> External Thermal	**22.6**	18.6	18.0	

Table 9.11: Voltage Stability Results Summary

9.3.3 CONCLUSION

The analysis demonstrates the planned system does not reach a VSL prior to system thermal limits; 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.

9.4 FINAL RELIABILITY ASSESSMENT

9.4.1 METHODOLOGY

All projects in the 2021 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.

9.4.1.1 *SHORT-CIRCUIT MODEL*

A proxy automatic sequencing fault calculation (ASCC) short-circuit analysis was performed on the 2021 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 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.

9.4.2 SUMMARY

9.4.2.1 *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.

9.4.2.2 *MARKET POWERFLOW MODELS*

The resulting thermal and voltage violations identified in the market powerflow portfolio rebuilt models were generated using the same methods in the base reliability powerflow assessment. A portion of the resulting thermal and voltage violations caused by the 2021 ITP consolidated portfolio were solved or marked invalid through the same methods utilized for the base reliability powerflow models. The remaining thermal overload violations were given additional review and not considered to be new reliability violations based on ITP Manual section 4.2.5 violation filtering criteria. No additional voltage violations were observed and no supplementary solutions were developed to accommodate the market powerflow models.

9.4.2.3 *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.

9.4.3 CONCLUSION

The final reliability assessment showed no new reliability violations caused by the 2021 ITP recommended portfolio that require additional project recommendations.

10 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 10.1 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)	Financial Expenditure Date	NTC/ NTC-C
Platte City 161 kV switches	6/1/2023	18	3/10/2022	NTC
Blue Circle-Catoosa 69 kV rebuild	6/1/2023	30	3/10/2022	NTC
Roswell 115/69 kV transformers circuit 1 and 2 replacement	6/1/2023	24	3/10/2022	No
Jones-Lubbock South 230 kV circuit 1 and 2 terminal equipment and increase line clearances	6/1/2023	30	3/10/2022	NTC
Columbus East 230/115 kV transformer replacement	1/1/2023	24	3/10/2022	NTC
Scottsbluff-Victory Hill 115 kV circuit 2 new line	1/1/2023	42	3/10/2022	NTC
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment and increase line clearances	1/1/2025	18	7/1/2023	NTC
S3454-S3740 345 kV new line	6/1/2024	48	3/10/2022	NTC-C
Replace one breaker at Jarbalo Junction 115 kV	6/1/2023	18	3/10/2022	NTC
Replace two breakers at Shawnee Mission 161 kV	6/1/2023	18	3/10/2022	NTC
Replace one breaker at Craig 161 kV	6/1/2023	18	3/10/2022	NTC
Moorhead 230 kV substation reconfiguration	6/1/2023	18	3/10/2022	NTC
Powersite-Branson North 161 kV terminal equipment	6/1/2029	18	12/1/2027	No
Cleo Corner-Cleo Junction 69 kV terminal equipment	1/1/2023	18	3/10/2022	NTC
Leland Olds-Finstad-Tande 345 kV new line; Finstad 25 MVAR reactor; Finstad 345 kV substation expansion; Finstad 345/115 kV new circuit 1 and 2 transformers; Finstad-Vanhook 115 kV new line	1/1/2023	48	3/10/2022	NTC-C
Rocky Point-Marietta (OGE) 138kV rebuild; Marietta (OGE)-Marietta (WFEC) 138 kV new line	6/1/2023	42	3/10/2022	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC/ NTC-C
East New Town 115 kV 150 MVAR STATCOM	1/1/2023	30	6/1/2029	NTC-C
NE Williston-Folvag 115 kV new line; Tap Judson-Tande 345 kV; Eastfork 115 kV new substation	1/1/2023	42	10/1/2023	NTC-C
Sioux City 69 kV new breaker CT; Hinton Municipal (K412) 69 kV terminal equipment	6/1/2023	18	3/10/2022	NTC
Gering Tap-Morrill 115 kV rebuild	6/1/2023	36	3/10/2022	No
Ogallala (TSTG)-Ogallala (NPPD) 115 kV rebuild bus tie	1/1/2023	18	3/10/2022	NTC
Joplin West 7th-Stateline 161 kV rebuild	6/1/2026	30	12/1/2023	NTC
Kummer Ridge-Roundup 345 kV new line	1/1/2023	48	3/10/2022	NTC-C
Artesia 115/69 kV transformers circuit 1 and 2 replacement	6/1/2023	24	3/10/2022	No
Midwest-Franklin 138 kV terminal equipment	3/10/2022	18	3/10/2022	NTC Modifi-cation
Quahada 115 kV 100 MVAR synchronous condenser	6/1/2030	30	12/1/2027	No
Grassland 115 kV 28.8 MVAR capacitor bank	6/1/2023	24	3/10/2022	No
Crossroads-Phantom 345 kV new double-circuit line	1/1/2023	48	3/10/2022	TBD[41]
Squaw Gap 115 kV 15 MVAR capacitor bank	6/1/2029	24	6/1/2027	No

Table 10.1: 2021 NTC Recommendations

[41] The SPP board of directors approved the 2021 ITP recommended plan on January 25, 2022, with the exception of the Crossroads-Phantom project for construction; the SPP board of directors approved further evaluation of the Crossroads-Phantom project with updated information, to be brought back to the MOPC by July 2022.

11 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
GOF	Generator outlet facilities
GW	Gigawatt

Acronym	Name
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
NPV	Net present value
NREL	National Renewable Energy Laboratory
NCLL	Non-consequential load loss
NTC	Notification to Construct
PPA	Power Purchase Agreement
PST	Phase-shifting transformer

Acronym	Name
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 11.1: Glossary