2020 INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT

SPP Engineering
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SPP Southwest Power Pool

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
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10/13/2020 v0.4	SPP Staff	Final Draft Report	Approved by MOPC
10/15/2020 v0.5	SPP Staff	Final Draft Report – Updated	Redlined version: Updated table 6.15 to correct 40-year and net benefit calculations; tables 8.10-8.13 to correct some benefit numbers; changed NTC to NTC-C where appropriate based on MOPC participant feedback; and added footnotes to tables 8.12, 8.13, 8.16 and 8.17 to clarify state level numbers; adding "- APC benefit only" to figures 0.2 and 6.10 and table 6.15.
10/19/2020 v0.5	SPP Staff	Final Draft Report	Posted for SPP Board of Directors
10/27/2020 v1.0	SPP Staff	Final Report	Approved by SPP Board of Directors

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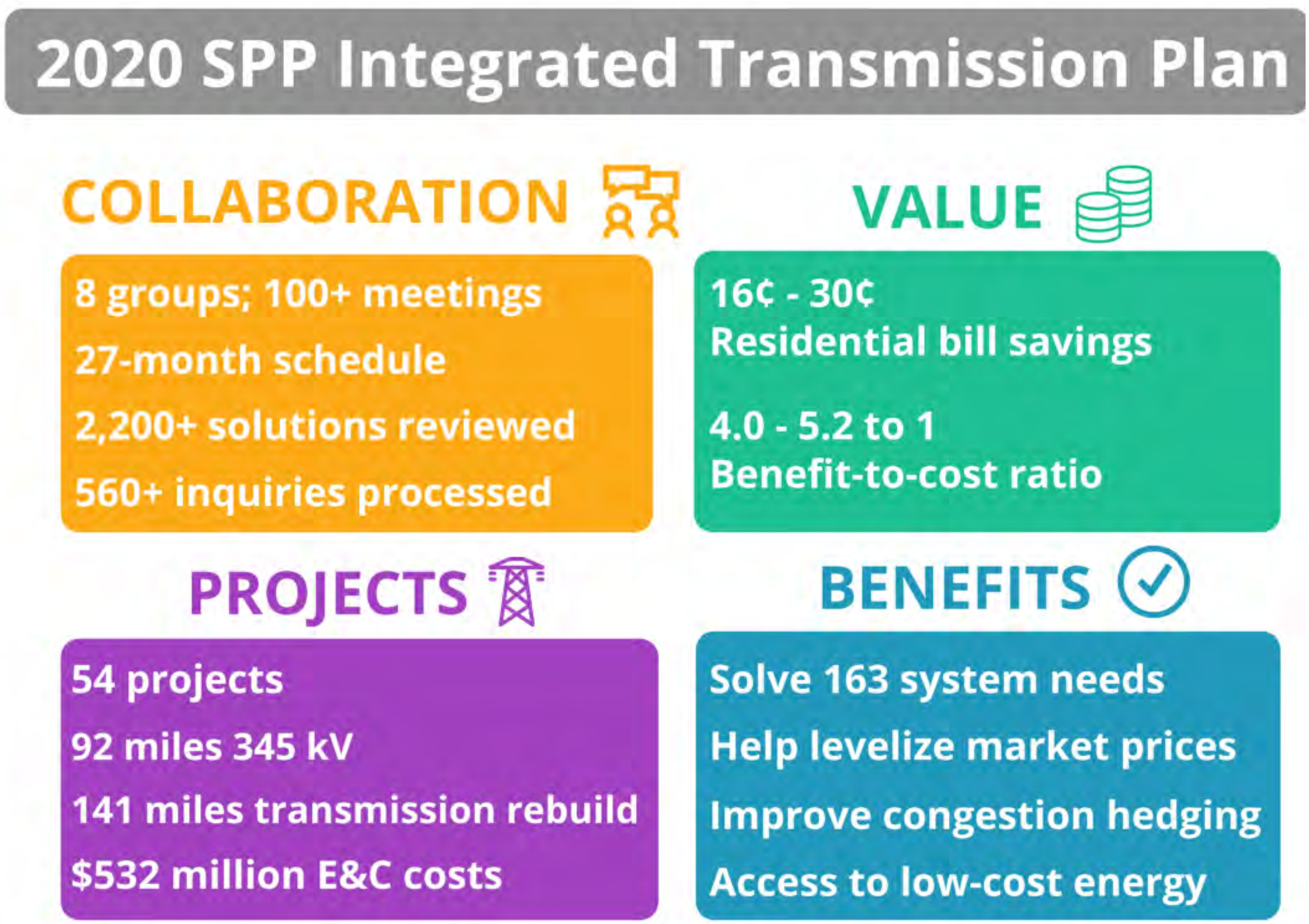

The 2020 Integrated Transmission Plan (ITP) looks ahead 10 years to ensure the SPP region can deliver energy reliably and economically, facilitate public policy objectives, seek solutions with neighboring regions and maximize benefits to end-use customers. Over 27 months, SPP and its member organizations worked together to forecast and analyze the regional transmission system's economic, reliability, operational and public policy needs.

SPP evaluated more than 2,200 solutions. The analysis resulted in the recommendation to approve 54 transmission projects, including 91.8 miles of new extra-high-voltage (EHV) transmission and 140.9[1] miles of rebuilt high-voltage infrastructure.

[1] This mileage number assumes the partial rebuild and new mileage of the Butler-Tioga 138 kV new line. This line is expected to follow the existing Butler-Altoona 138 kV right-of-way and break away towards Tioga at a point that that would minimize transmission costs for the project.

This portfolio contains reliability and economic projects that will mitigate 163 system issues. Reliability projects allow the region to meet compliance requirements and keep the lights on through loading relief, voltage support and system protection.

There are several primary drivers of the economic projects. Many of the projects enable delivery of low-cost renewable resources and reduce price separation in the SPP marketplace caused by congestion. Continued rapid renewable expansion has caused increasing pricing disparity between the western and eastern portions of the SPP system. These disparities have created higher average costs for eastern load centers because of congestion and lack of access to less expensive generation. Price differences have only been marginally delayed by new interconnections seeking opportunity in the east. The recommended economic projects will reduce separation between generator and load locational marginal prices across the region and create reliable transfer capability that will allow the system to realize benefits from low-cost generation.

Previous ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts. Overly conservative forecasts can lead to delayed transmission investment, contributing to persistent congestion. For example, the 2020 consolidated portfolio is expected to address eight congested flowgates identified over the last four quarterly SPP corporate metric updates. For the 2020 ITP assessment, SPP expanded on the 2019 assessment's analysis to better forecast renewables development, which will allow the region to proactively build the infrastructure needed to alleviate congestion and provide access to less expensive energy.

The SPP region has areas of increased load growth due to oil and gas exploration in North Dakota and New Mexico. Some of these areas could experience voltage collapse. Additional transmission capacity is needed to serve this new load. SPP developed projects to address this load growth; some are recommended for construction while others need continued analysis.

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.

The final project portfolio was tested against a wide range of sensitivities, including natural gas prices, generator retirements, renewables development, battery storage and demand. The analysis determined that adjusted production cost savings across all sensitivities had a benefit-to-cost ratio greater than 1.0. When considering all eight benefit metrics, including adjusted production cost savings, the consolidated portfolio is expected to provide a 40-year benefit-to-cost ratio ranging from 4.0 for Future 1 to 5.2 for Future 2. The net impact to ratepayers is a savings of \$0.16 to \$0.30 on the average retail residential monthly bill. See Section 8.3 Sensitivity Analysis for more information.

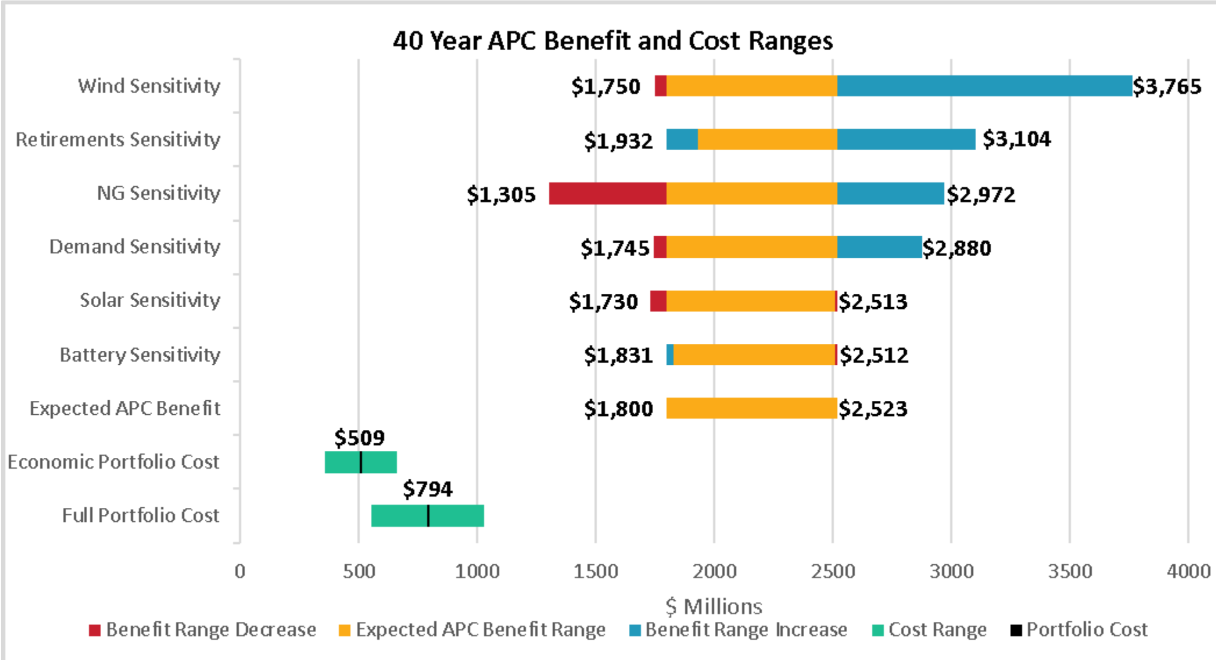

Figure 0.1: 40-Year APC Benefit and Cost Ranges

SPP assumes a 40-year lifespan for new transmission investments. Within 20 years, the SPP region is expected to receive more benefits from the projects than their total investment costs. The projects will begin providing net savings to ratepayers within the first year of being in-service.

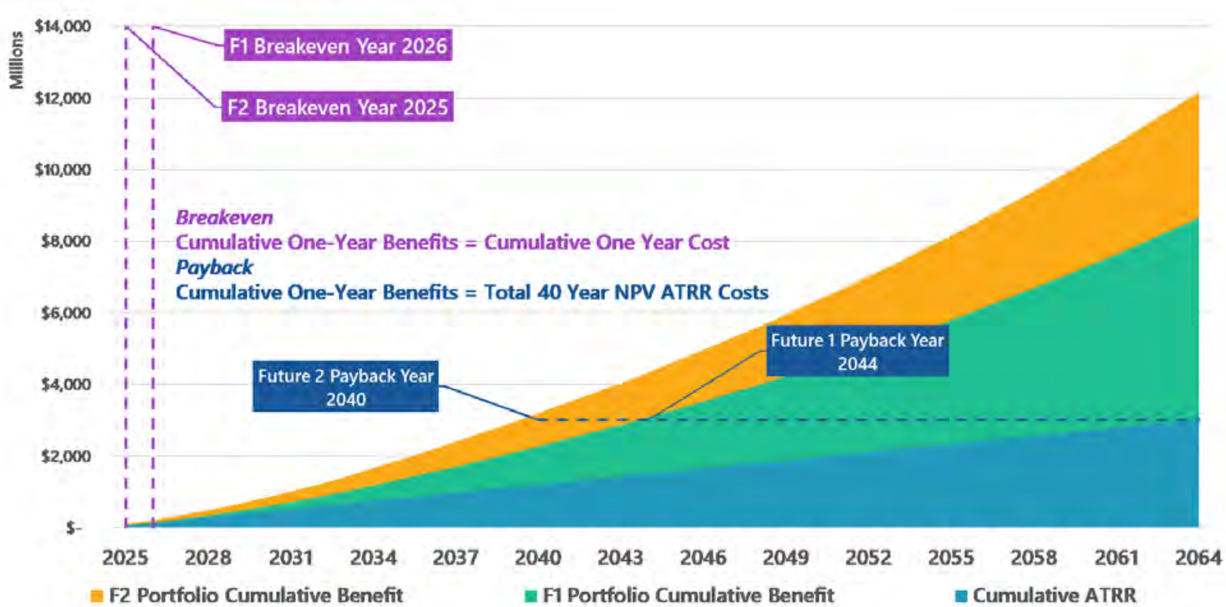

Figure 0.2: Portfolio Breakeven and Payback – APC benefit only

The 2020 ITP Assessment includes the following projects:

Project	Area	Type	Project Cost (2020$)	Miles	NTC/ NTC-C
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	BEPC	R	$3,562,780	-	NTC
Anadarko-Gracemont 138 kV rebuild as double-circuit	WFEC/ OKGE	E	$8,297,502	14.4	NTC Modification
Russett-South Brown 138 kV rebuild	WFEC/ SWPA	E	$10,067,432	18.62	NTC
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	WERE	E	$135,720,424	91.2	NTC-C
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	GRDA	E	$1,410,000	-	NTC
Columbus East 230/115 kV transformer replacement	NPPD	E	$4,600,000	-	No
Franks-South Crocker-Lebanon 161 kV terminal equipment	AECI	E	$5,721,430	-	No
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	AEPW/ OKGE	E	$31,686,685	0.84	NTC-C
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	WFEC	E	$1,617,500	-	NTC
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	OKGE/ WFEC	E	$113,620,907	48	NTC-C
Split Rock 345/115 kV Circuit 10 and 11 terminal equipment	NSPP	E	$4,577,336	-	No
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	EREC/ WAPA /BEPC	E	$1,528,722[2]	-	No
Circleville-Goff 115 kV circuit 1 rebuild	WERE	R	$12,114,772	14.56	NTC
Goff-Kelly 115 kV rebuild	WERE	R	$7,108,395	10.11	NTC
South Shreveport-Wallace Lake 138 kV rebuild	AEPW	R	$23,622,577	11.18	NTC-C
Grady 138 kV capacitor bank	AEPW	R	$688,781	-	NTC
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	EREC/ NWE	R	$11,394,000	14.4	NTC
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	OKGE	R	$5,362,799	5.9	NTC
Bushland-Deaf Smith 230 kV terminal equipment	SPS	R	$923,938	-	NTC
Newhart-Potter County 230 kV terminal equipment	SPS	R	$731,282	-	NTC
Carlisle-Murphy 115 kV rebuild	SPS	R	$4,746,175	4.0	NTC

[2] The cost estimate was adjusted late in the study process to be $3,748,722 due to a gap in the Study Estimate requests sent to stakeholders. This updated cost estimate is only considered in Table 9.1 and the NTC recommendations of this executive summary. See additional information in section 7.3.11.

Project	Area	Type	Project Cost (2020$)	Miles	NTC/ NTC-C
Roswell 115/69 kV replace transformer #1	SPS	R	$2,777,743	-	NTC
S3456-S3458 345 kV terminal equipment	OPPD	R	$678,865	-	No
Meadowlark-Tower 33 115 kV rebuild	WERE	R	$1,342,588	0.93	NTC
Jones-Lubbock South 230 kV terminal equipment circuit 1	SPS	R	$666,728	-	No
Jones-Lubbock South 230 kV terminal equipment circuit 2	SPS	R	$397,668	-	No
Deaf Smith-Plant X 230 kV terminal equipment	SPS	R	$2,100,196	-	NTC
Newhart-Plant X 230 kV terminal equipment	SPS	R	$2,024,293	-	NTC
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	SPS	R	$872,391	-	NTC
Allen-Lubbock South 115 kV rebuild	SPS	R	$6,817,226	6.0	NTC
Allen-Quaker 115 kV rebuild	SPS	R	$4,732,267	3.6	NTC
Russell 115 kV capacitor bank	SEPC	R	$2,841,951	-	NTC
Eddy County-North Loving 345 kV new line	SPS	R	$64,422,600	42.96	No
Maljamar 115 kV capacitor bank	SPS	R	$685,440	-	No
Devil's Lake 115 kV reactor	WAPA	R	$1,190,000	-	NTC
Bismarck 115 kV reactors	WAPA	R	$2,380,700	-	NTC
Moorehead 230 kV reactor	MRES	R	$1,515,440	-	NTC
Agate 115 kV reactor	WAPA	R	$571,200	-	NTC
Replace four breakers at Anadarko 138 kV	WFEC	R	$850,000	-	NTC
Replace three breakers at Northeast 161 kV	KCPL	R	$887,479	-	NTC
Replace one breaker at Stilwell 161 kV	KCPL	R	$566,485	-	NTC
Replace one breaker at Leeds 161 kV	KCPL	R	$566,485	-	NTC
Replace one breaker at Shawnee Mission 161 kV	KCPL	R	$566,485	-	NTC
Replace one breaker at Southtown 161 kV	KCPL	R	$566,485	-	NTC
Replace two breakers at Lake Road 161 kV	KCPL	R	$1,132,970	-	NTC
Replace two breakers at Craig 161 kV	KCPL	R	$1,132,970	-	NTC
Nixa-Nixa Espy 69 kV terminal equipment	GLHP	R	$91,147	-	No
Deaf Smith #6-Hereford 115 kV rebuild	SPS	R	$6,660,556	2.33	NTC
Deaf Smith #6-Friona 115 kV rebuild	SPS	R	$12,626,190	18.9	NTC
Cargill-Friona 115 kV rebuild	SPS	R	$817,466	1.15	NTC
Cargill-Deaf Smith #24 115 kV rebuild	SPS	R	$5,501,901	7.74	NTC
Deaf Smith #24-Parmer 115 kV rebuild	SPS	R	$824,574	1.16	NTC
Deaf Smith #20-Parmer 115 kV rebuild	SPS	R	$5,402,384	7.6	NTC
Curry-Deaf Smith #20 115 kV rebuild	SPS	R	$9,048,993	12.73	No
		Total	**$532,363,304**[3]		

Table 0.1: 2020 ITP Consolidated Portfolio

[3] These costs represent engineering and construction cost provided during the study by SPP stakeholders or its third-party cost estimator.

This map depicts the 2020 ITP Assessment thermal/voltage reliability projects:

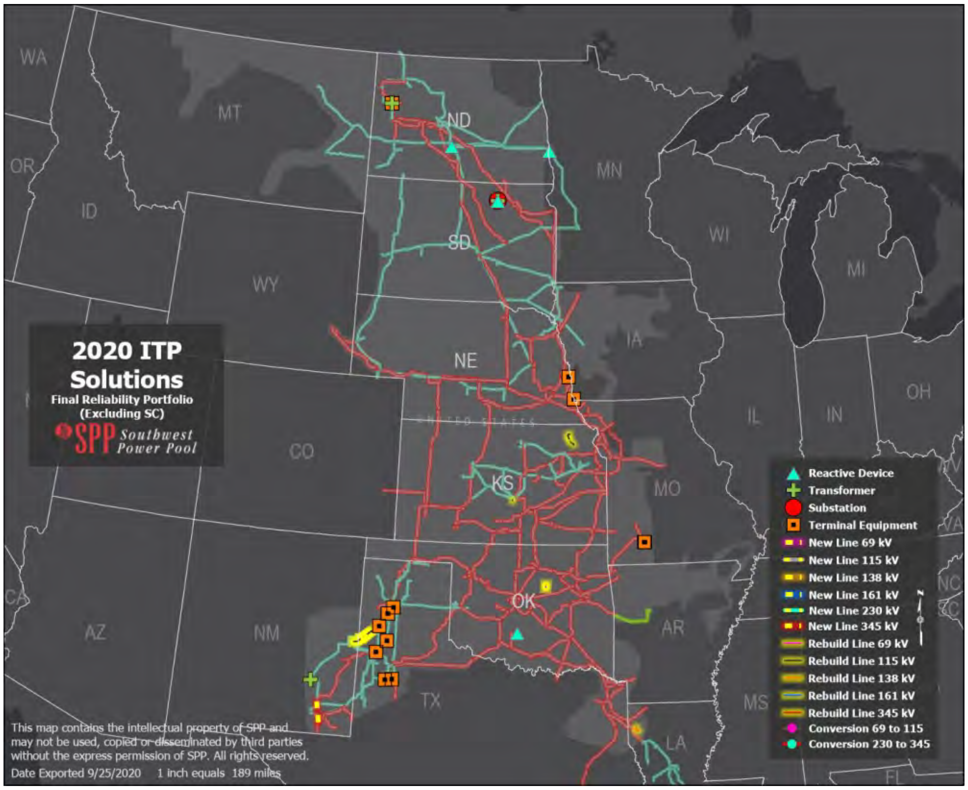

Figure 0.3: 2020 ITP Thermal and Voltage Reliability Projects

This map depicts the 2020 ITP Assessment short circuit reliability projects:

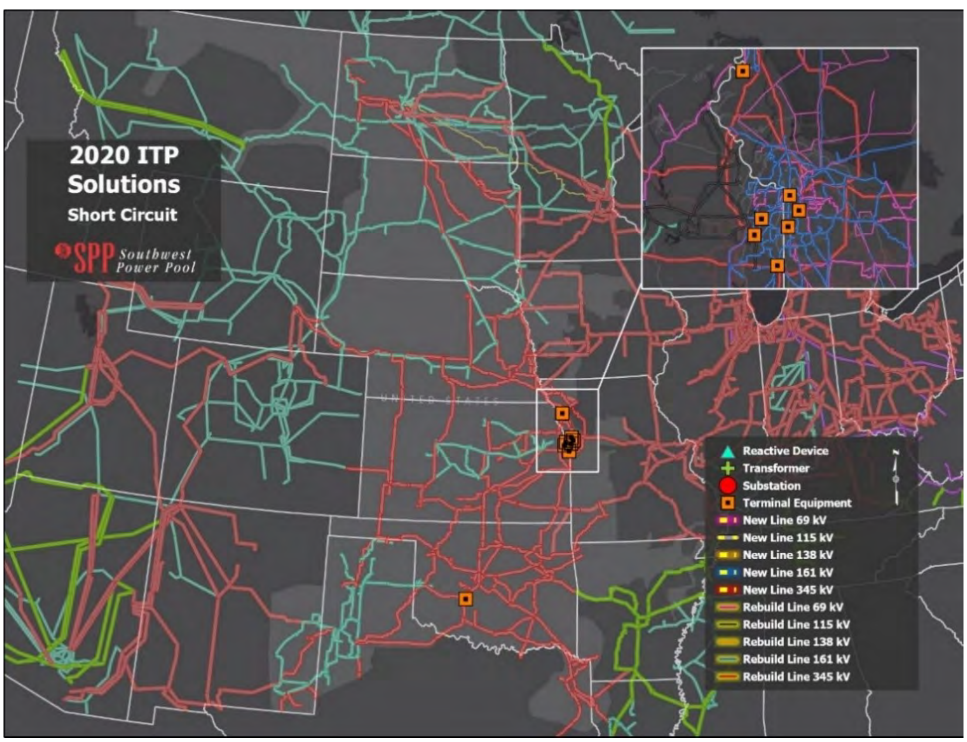

Figure 0.4: 2020 ITP Short Circuit Reliability Projects

This map depicts the 2020 ITP Assessment economic projects:

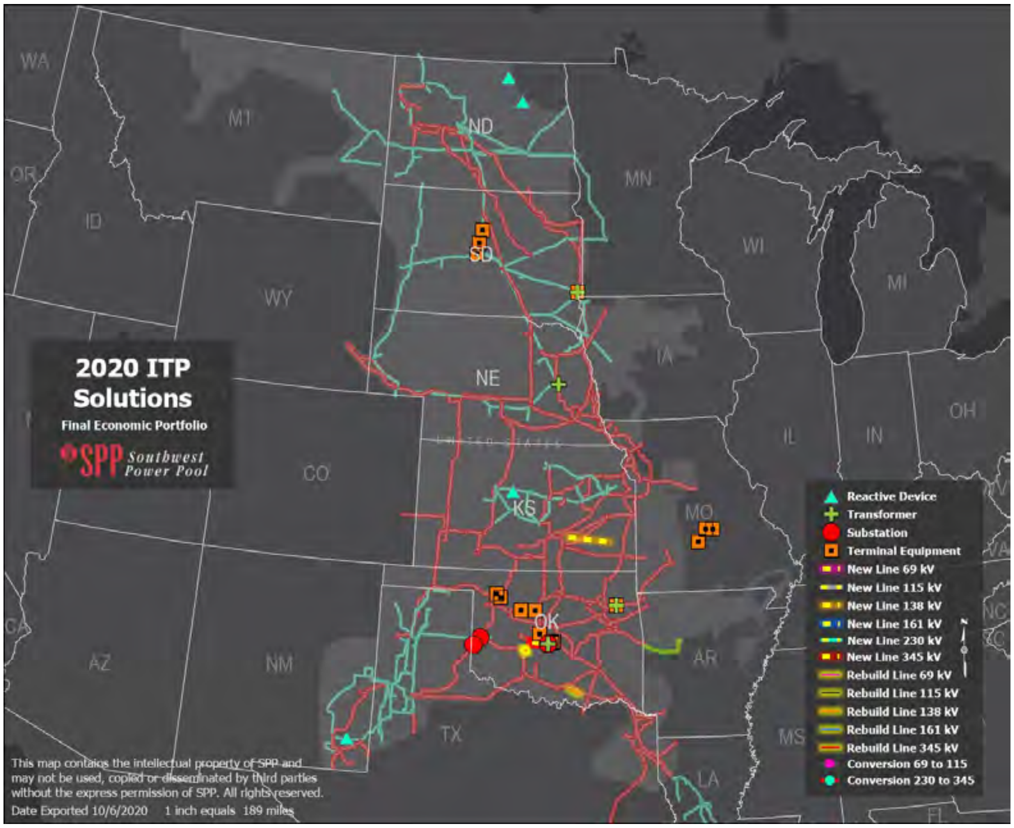

Figure 0.5: 2020 ITP Portfolio-Economic

SPP staff 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 2020 ITP assessment is guided by requirements defined in Attachment O to the SPP Open Access Transmission Tariff (Tariff), the ITP Manual, and the 2020 ITP Scope. Previous improvements to the ITP process were designed by the Transmission Planning Improvement Task Force and implemented beginning in the 2019 ITP.

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 Attachment AQ 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.

1.2 REPORT STRUCTURE

This report describes the ITP assessment of the SPP transmission system for a 10-year horizon, focusing on years 2022, 2025 and 2030. These years were evaluated with a baseline reliability scenario and two future market scenarios (futures). The Model Development and Benchmarking sections 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 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 [2020 ITP Scope] and SPP ITP Manual.[4] All reports and documents referenced in this report are available on the SPP website.[5]

SPP staff and its 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 2020 ITP assessment assumptions and procedures in meetings throughout 2018, 2019, and 2020. 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 Working Group (MDWG)
- Cost Allocation Working Group (CAWG)
- Project Cost Working Group (PCWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)
- Regional State Committee (RSC)
- Board of Directors (Board)

SPP staff served as facilitators for these groups and worked closely with each working group's chairperson 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 2020 ITP.

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[4] https://www.spp.org/Documents/60911/itp%20manual%20version%202.7.docx; the ITP assessment follows the current ITP Manual and versions may differ throughout the study process. The version that was current at the time of the study was used.

[5] https://spp.org/

1.3.1 PLANNING SUMMITS

In addition to the standard working group meetings and in accordance with Attachment O of the Tariff, SPP held multiple transmission planning summits to elicit further input and provide stakeholders with additional opportunities to participate in the process of discussing and addressing planning topics.[6]

[6] 2020 Engineering Planning Summit was held on Wednesday, July 8, 2020 (https://www.spp.org/Documents/62539/Engineering%20Planning%20Summit%20Agenda%20&%20Background%20Materials%2020200708.zip)

2 MODEL DEVELOPMENT

2.1 BASE RELIABILITY MODELS

2.1.1 GENERATION AND LOAD

Generation and load data in the 2020 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 Working Group (MDWG) Procedure Manual.[7] Renewable dispatch amounts are based on historical averages for resources with long-term firm transmission service for the summer and winter seasons. For the light load models, all wind resources with long-term firm transmission service were dispatched to the lesser of the full long-term firm transmission service amount or nameplate amount, with remaining generation coming from conventional resources. In these base reliability models, all entities are required to meet their non-coincident peak demand with firm resources.

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

2.1.2 TOPOLOGY

Topology data in the 2020 ITP base reliability models was incorporated in accordance with the ITP Manual. For items not specified in the ITP Manual, SPP followed the MDWG Model Development Procedure Manual. The topology for areas external to SPP was consistent with the 2018 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. This model was analyzed in consideration of the North American Electric Reliability Corporation (NERC) TPL-001 standard.

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 2019 ITP reference case and emerging technologies framework, while allowing adjustments to specific drivers. SPP staff provided stakeholders with a survey to identify the policy drivers which required adjustments for the 2020 ITP. The drivers considered for adjustment were:

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

- Wind and solar capacity additions
- Energy growth rates
- Natural gas prices
- Age-based retirement assumptions
- Energy storage[8]
- Carbon adder

2.2.1.1.1 Future 1: Reference Case

The reference case future will reflect 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 will be driven primarily by the assumption that electrical vehicles, distributed generation, demand response, and energy efficiency will impact energy growth rates. Coal generators over the age of 56 will be retired, while gas-fired and oil generators over the age of 50 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 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

[8] Energy storage is specific to batteries.

	Drivers				
Key Assumptions	**Year 2**	**Reference Case Year 5**	**Reference Case Year 10**	**Emerging Technologies Year 5**	**Emerging Technologies 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 56+, Gas/Oil age-based 50+, subject to repowering or emissions upgrades	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[9]	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	4	7	5	9
Wind (GW)	Existing + RARs	26	28	30	33

Table 2.1 Future Drivers

2.2.1.2 Load and Energy Forecasts

The 2020 ITP load review focused on load data through 2030. The load data was derived from the base reliability model set, and stakeholders were asked to identify/update the following parameters:

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

The ESWG- and TWG-approved load review was used to update the load information in the market economic models. Figure 2.1 shows the total coincident peak load for all study years. Figure 2.2 shows the monthly energy per future for all study years (2022, 2025, and 2030).

[9] As defined in the MDWG Model Development Procedure Manual: [Model Development Working Group (MDWG) Procedure Manual]

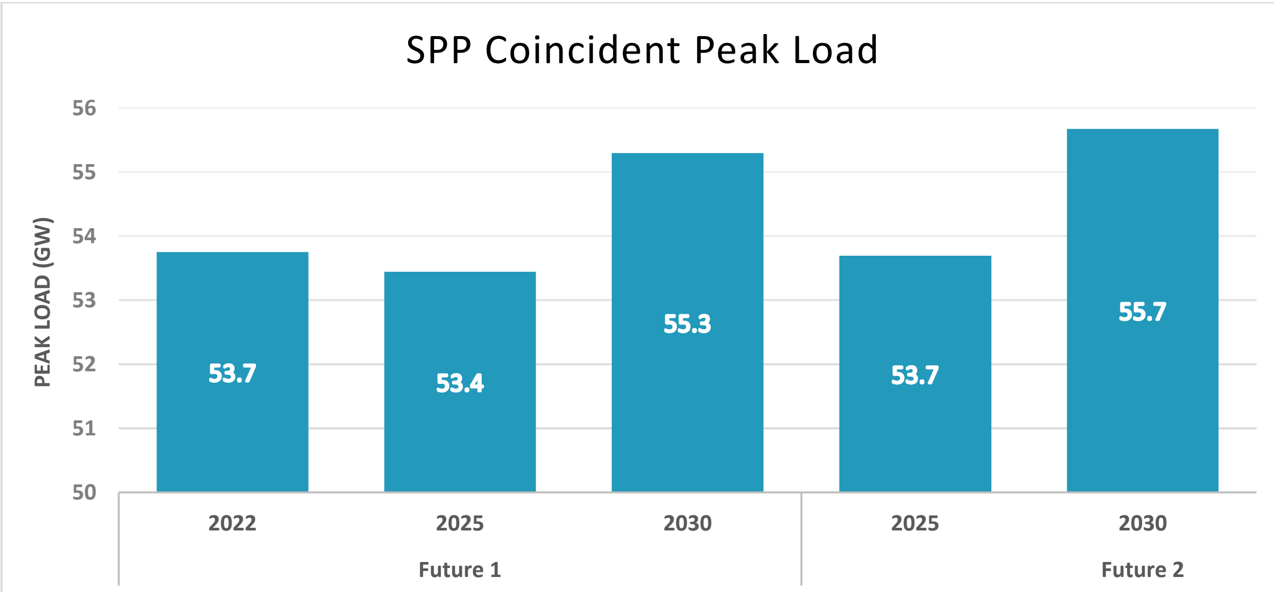

Figure 2.1: Coincident Peak Load

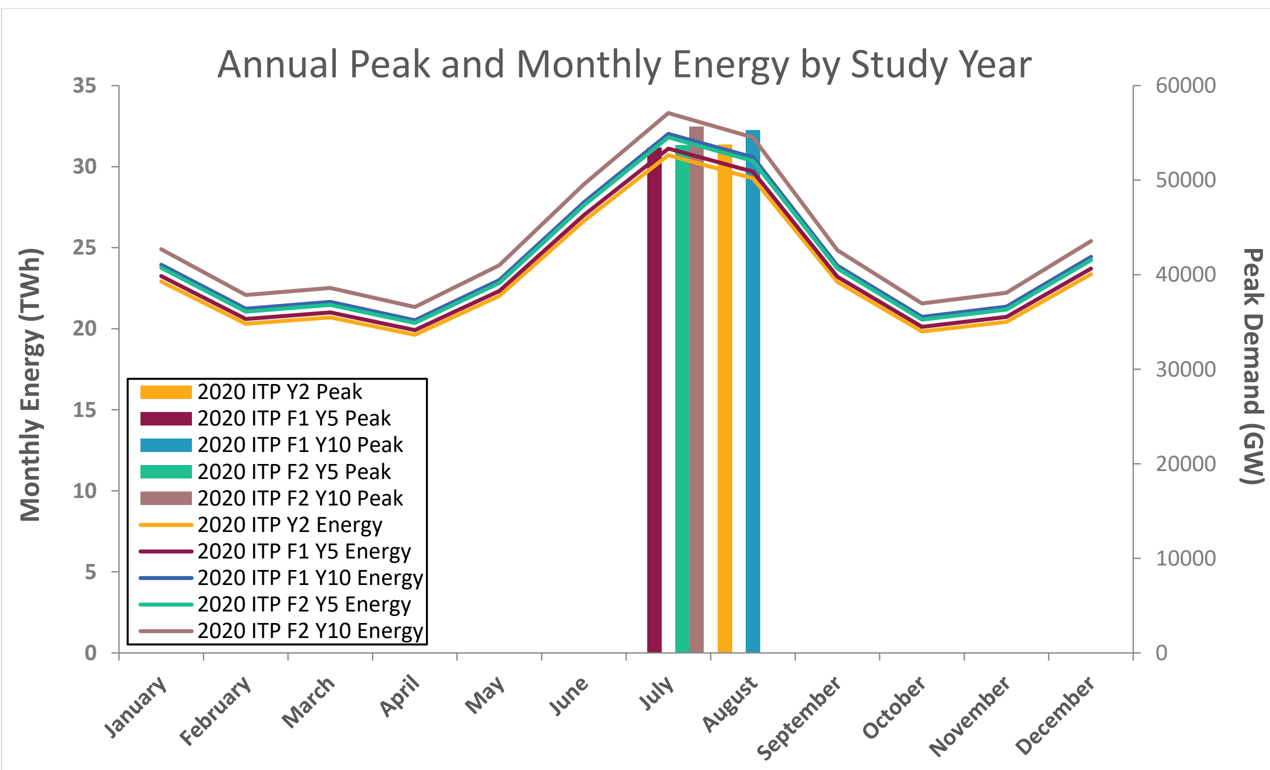

Figure 2.2: 2020 ITP Annual Energy

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. These requirements are defined as percentages and outlined in the ITP manual. The 2020 ITP renewable policy review focused on renewable requirements through 2030.

2.2.1.4 Generation Resources

Existing generation data originated from the ABB Simulation Ready Data Fall 2017 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 2022, 2025 and 2030 for Future 1, and 2025 and 2030 for Future 2.

In addition to resources accepted in the base reliability models, stakeholders were given the chance to request additional generation resources in the ITP models through the Resource Addition Request (RAR) process. As a result of the RAR process, 1.5 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.

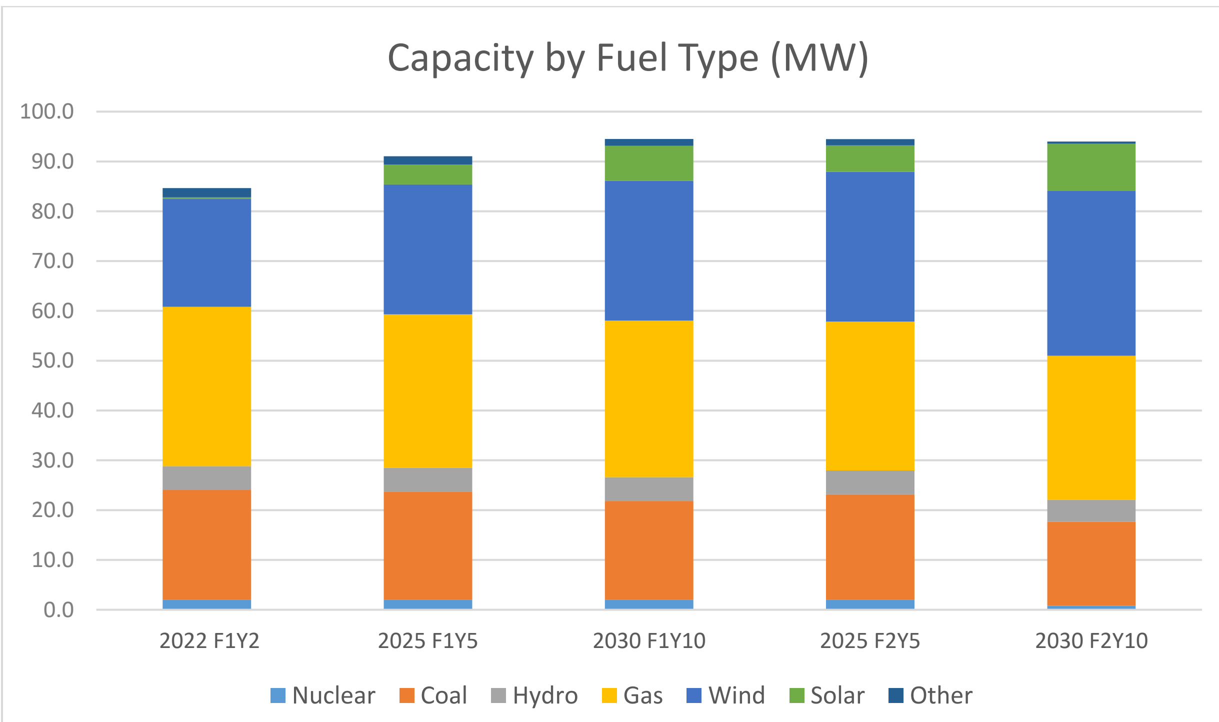

Figure 2.3: Capacity by Fuel Type (MW)

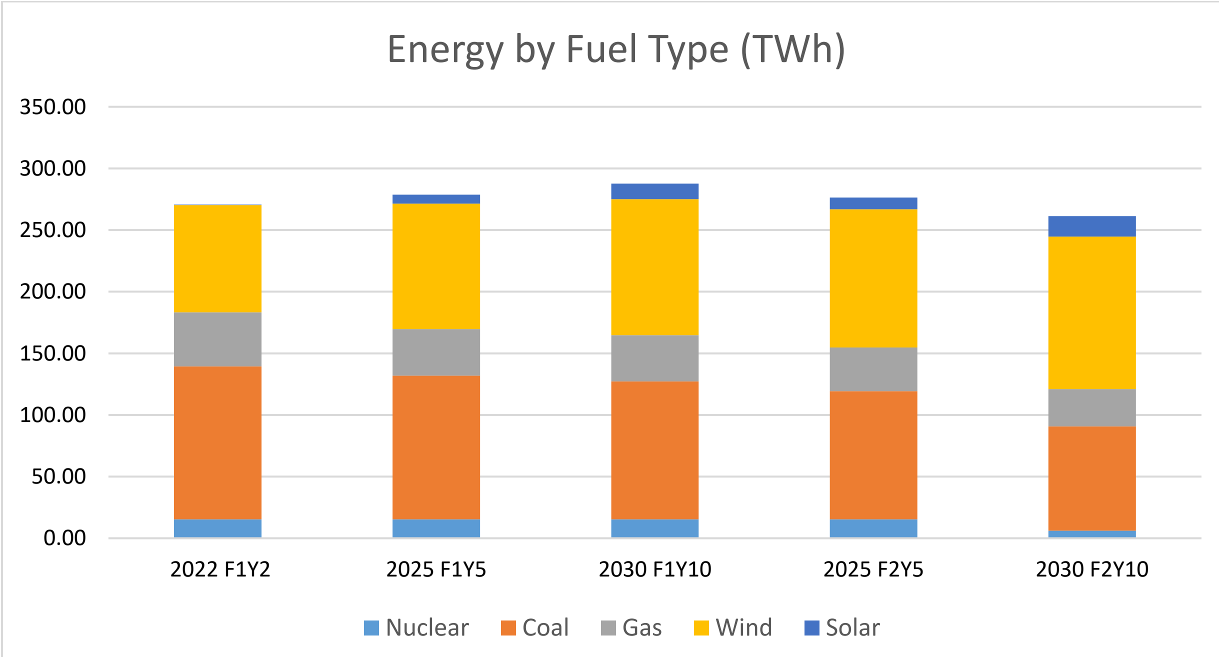

Figure 2.4: Energy by Fuel Type (TWh)

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.

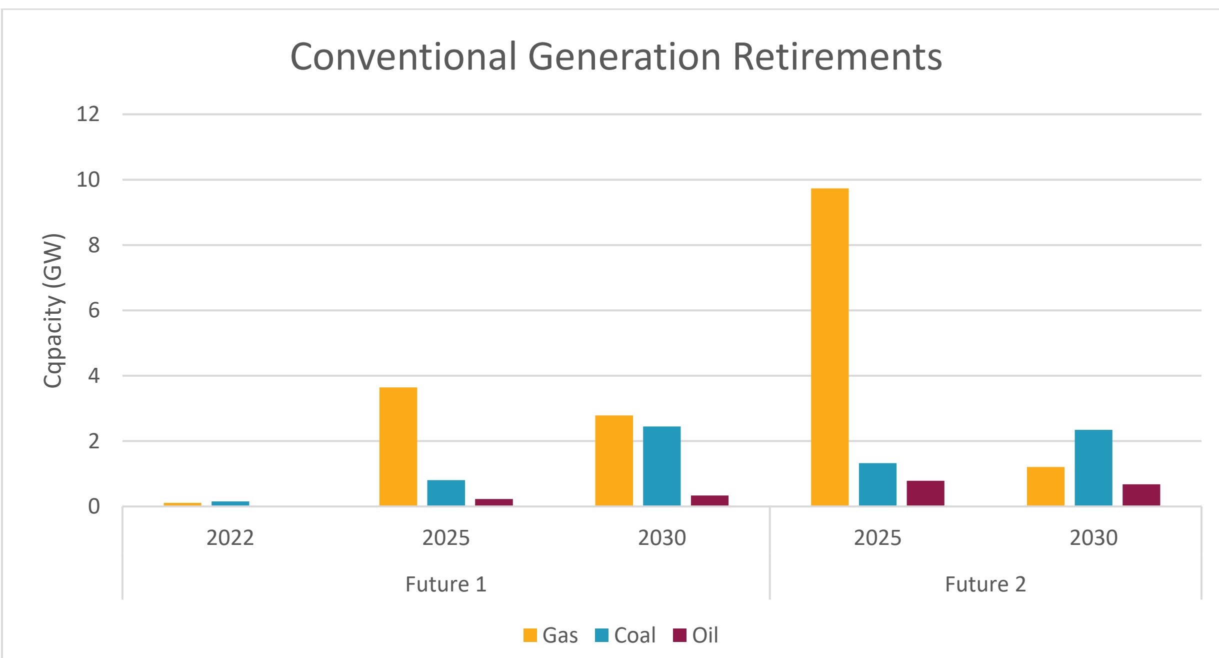

Figure 2.5: Conventional Generation Retirements

2.2.1.5 Fuel Prices

The ABB Simulation Ready Data Fall 2017 Reference Case and ABB fundamental forecast (for long-term natural gas price projections) were utilized for the fuel price forecasts. Figure 2.6 shows the annual average natural gas and coal prices for the study horizon. Between 2021 and 2030, these prices increase from $3.17 to $5.21 (~5.1 percent compound average escalation) and $2.30 to $2.87 (~2.5 compound average escalation) for natural gas and coal, respectively.

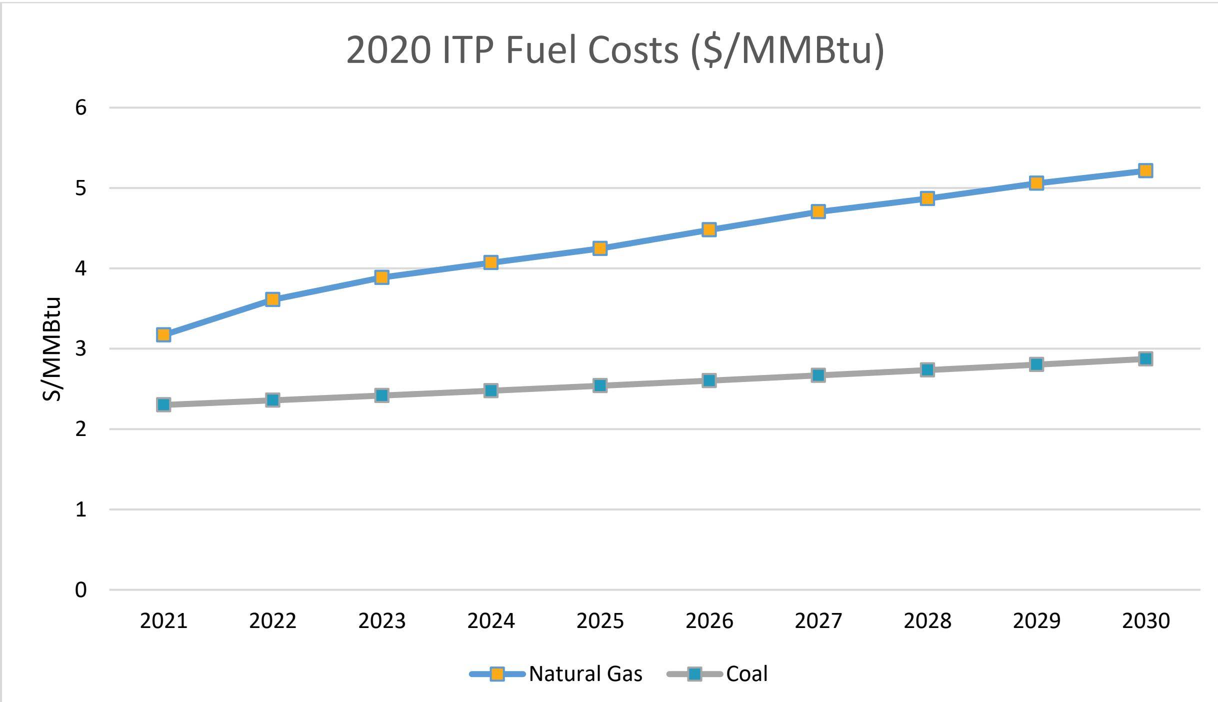

Figure 2.6: ABB Fuel Annual Average Fuel Price Forecast

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 staff 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

Each utility was analyzed 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 2025 and 2030. If a utility was projected to 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 80 percent wind additions to 20 percent 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 2030 were 289.4 MW in Future 1 and 289.9 MW in Future 2.

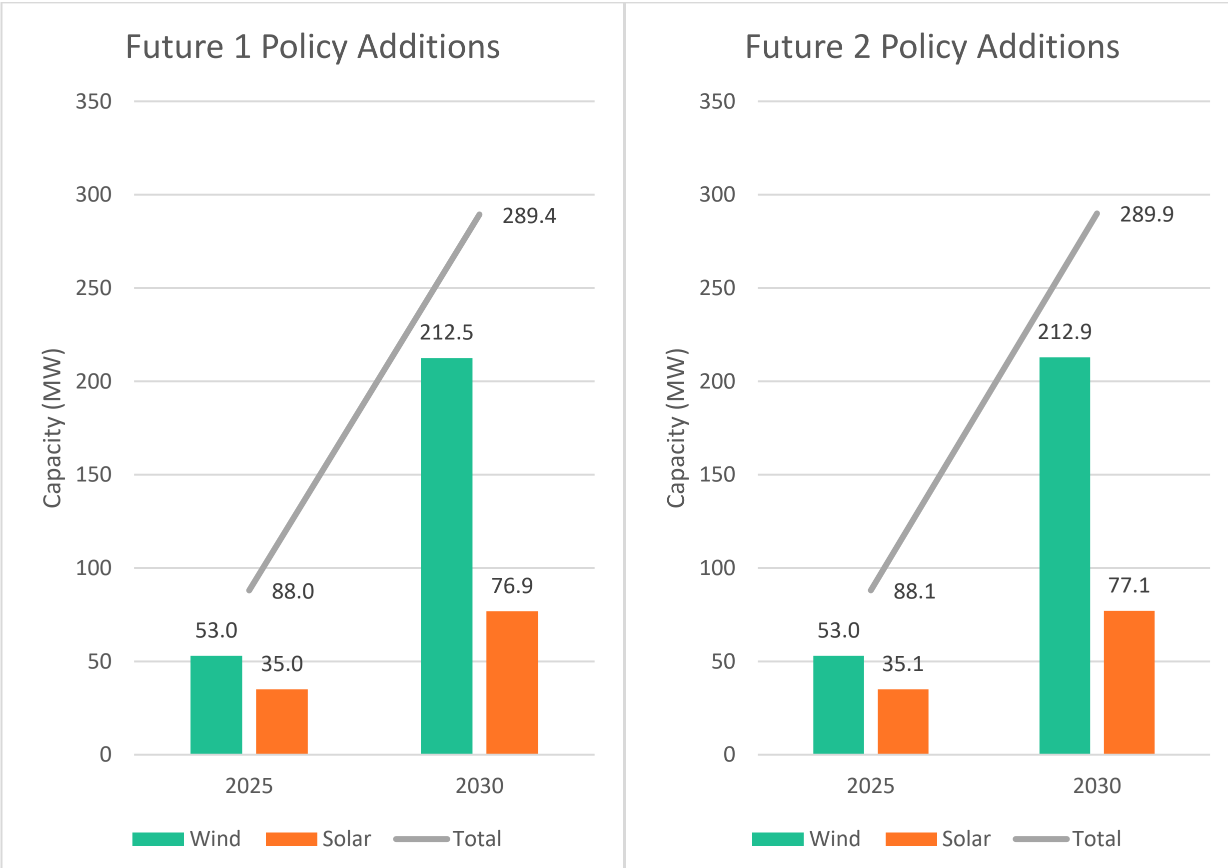

Figure 2.7: SPP Renewable Generation Assignments to meet Mandates and Goals

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

Projected solar additions were assigned based on the load-ratio share for each pricing zone. Projected wind additions were accredited to deficient zones to maximize the available accreditation of renewables for each zone, up to the 12 percent 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

The renewable resource expansion plan for each future was utilized as an input to the corresponding conventional resource expansion plan to ensure appropriate resource adequacy within the SPP footprint. ABB Strategist® software was used to develop the conventional resource expansion plan for each future, assessing a 20-year horizon.

Utilities that did not meet the 12 percent planning reserve margin requirement set by SPP Planning Criteria[10] also received capacity from the conventional resource plan. Projected reserve margins were calculated for each pricing zone using existing generation, 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 2025 and 2030 of both futures.

Nameplate conventional generation capacity assigned to pricing zones were 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 7.1.5.3. SPP stakeholders were surveyed for feedback on accreditation percentages for existing renewable capacity.

In the analysis of future conventional capacity needs, available resource options were combined cycle (CC) units, fast-start combustion turbine (CT) units, and reciprocating engines. Generic resource prototypes from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2018[11] were utilized. These resource prototypes define operating parameters of specific generation technologies to determine the optimal generation mix to add to the region.

CTs were the only technology selected in Futures 1 and 2 to meet capacity requirements. ESWG approved replacing three CTs with one CC located in the Southwestern Public Service Company (SPS) area for each future.

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

Table 2.2 shows the total nameplate generation additions by future and study year to meet futures definitions and resource adequacy requirements. Figure 2.8 shows the nameplate generation additions by future, study year, and capacity type for the SPP region.

	Future 1	Future 2
2025	10.5 GW	23.0 GW
2030	11.6 GW	33.1 GW

Table 2.2: Total Nameplate Generation Additions by Future and Study Year

[10] SPP Planning Criteria
[11] EIA Annual Energy Outlook 2018 Report

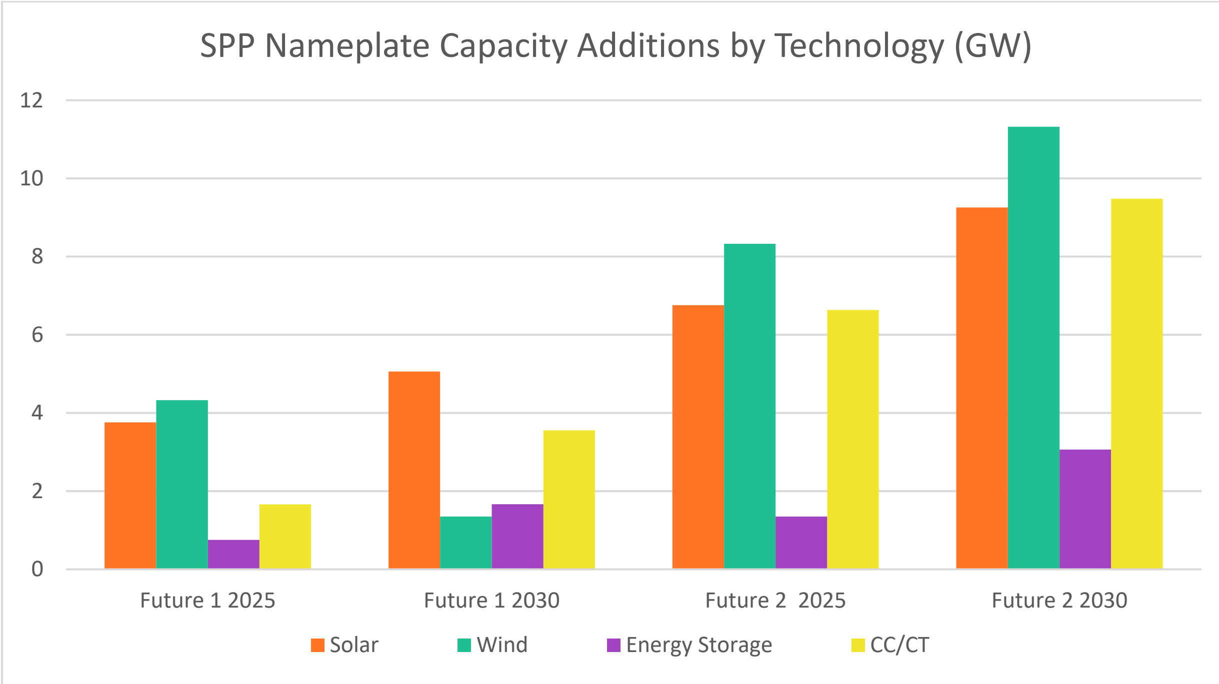

Figure 2.8: SPP Nameplate Capacity Additions by Technology (GW)

Table 2.3 shows the total accredited generation additions by future and study year. Figure 2.9 shows accredited generation additions by future, study year, and technology for the SPP region.

	Future 1	Future 2
2025	5.9 GW	12.7 GW
2030	10.2 GW	16.5 GW

Table 2.3: Total Accredited Generation Additions by Future and Study Year

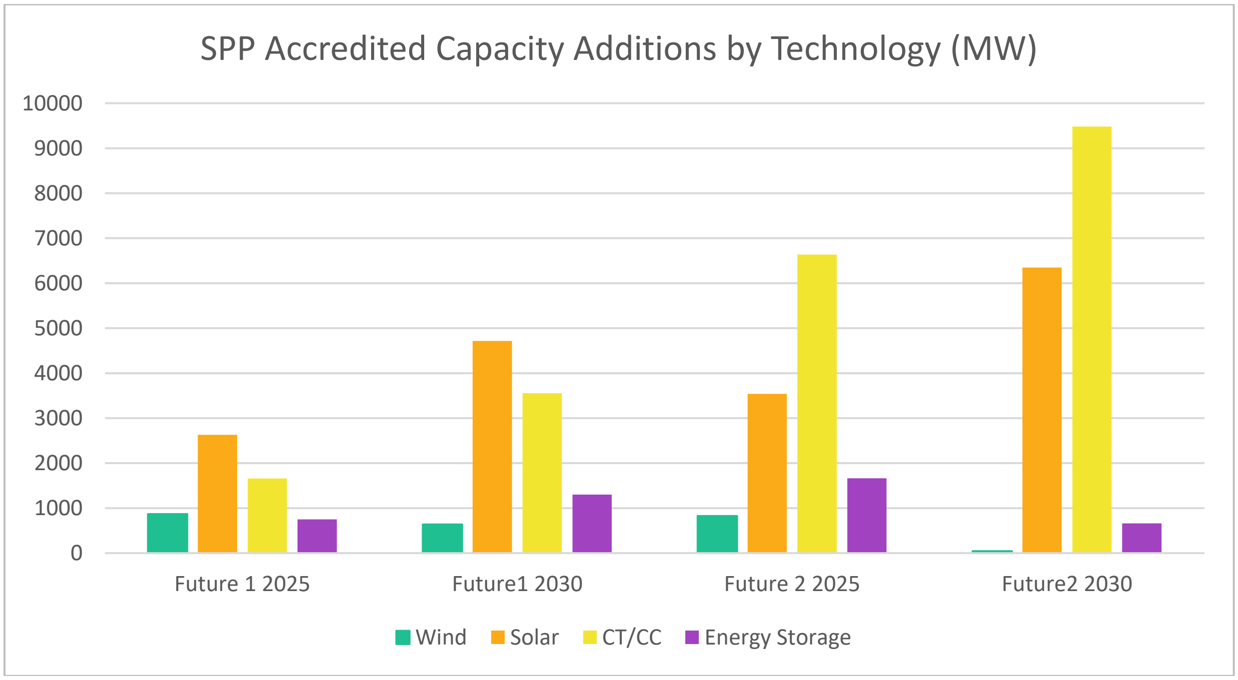

Figure 2.9: Accredited Capacity Additions by Technology

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.[12]

Distributed solar generation, an assumption in Future 2 only, was allocated to the top 10 percent of load buses for each load area on a pro rata basis utilizing load review data. SPP stakeholder feedback was considered 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.

[12] Documented in the [ITP Resource Siting Manual]

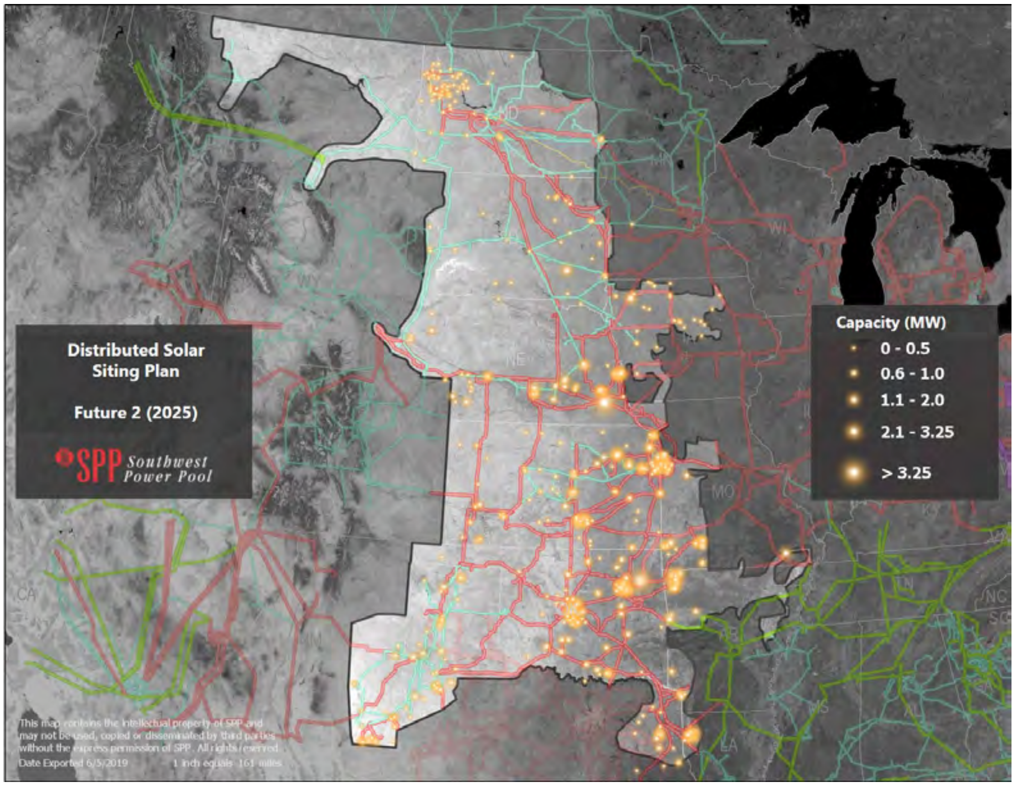

Figure 2.10: 2025 Future 2 Distributed Solar Siting Plan

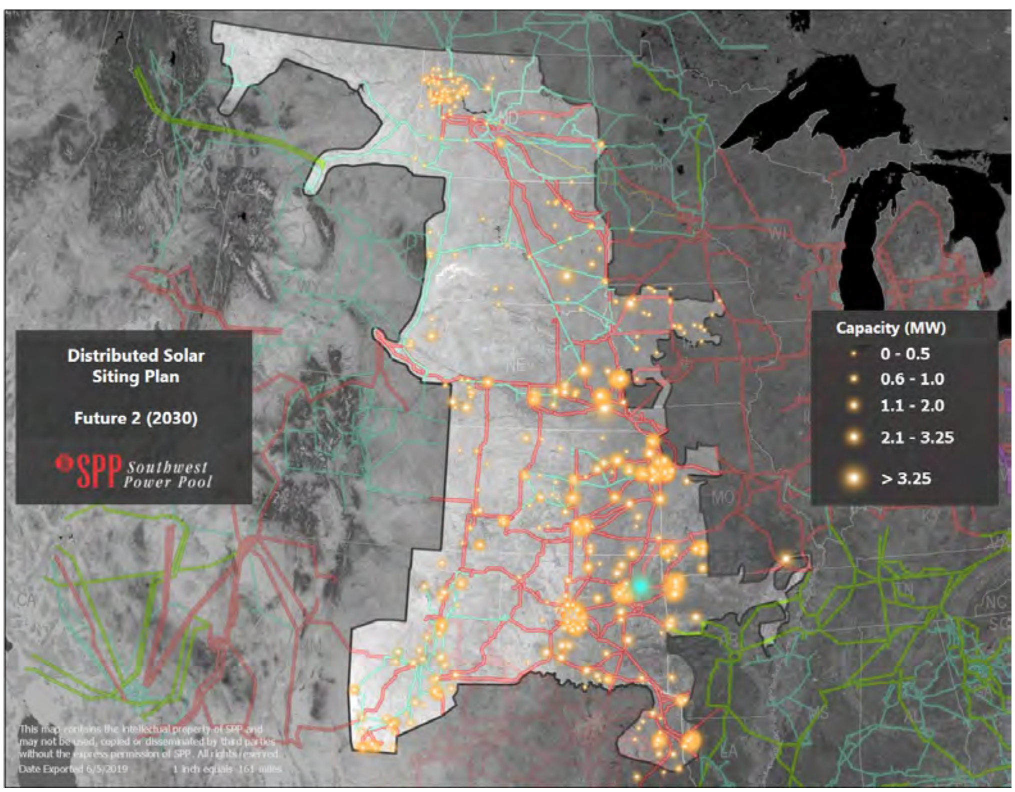

Figure 2.11: 2030 Future 2 Distributed Solar Siting Plan

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 were 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.

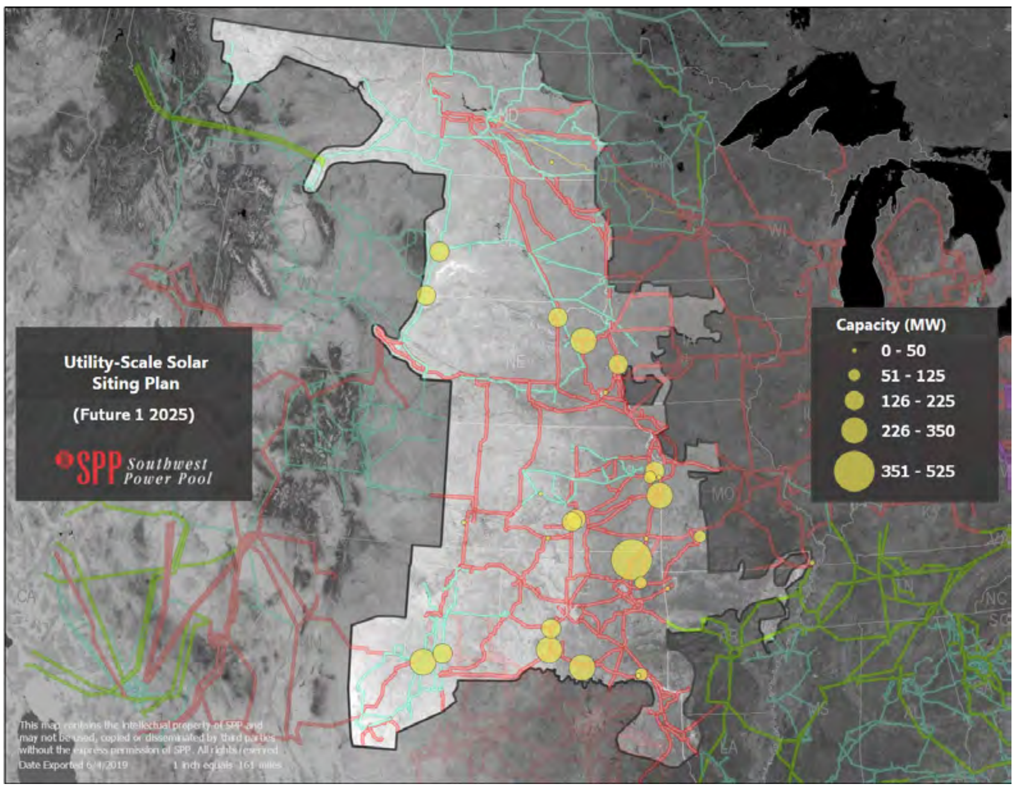

Figure 2.12: 2025 Future 1 Utility-Scale Solar Siting Plan

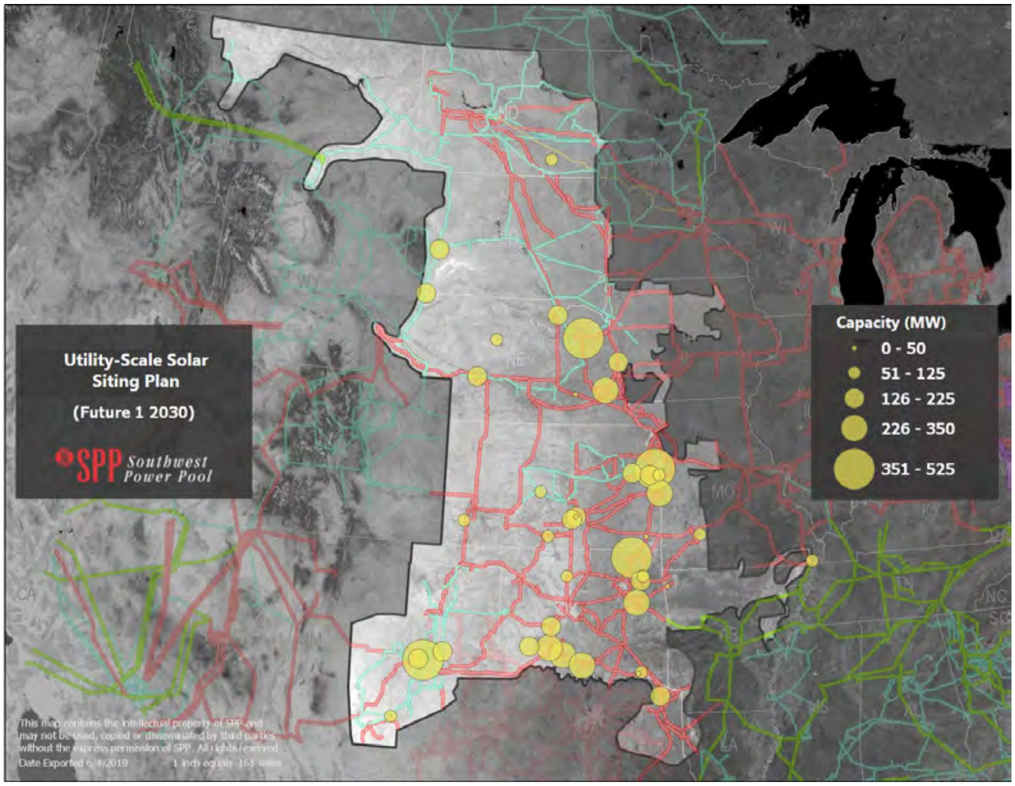

Figure 2.13: 2030 Future 1 Utility-Scale Solar Siting Plan

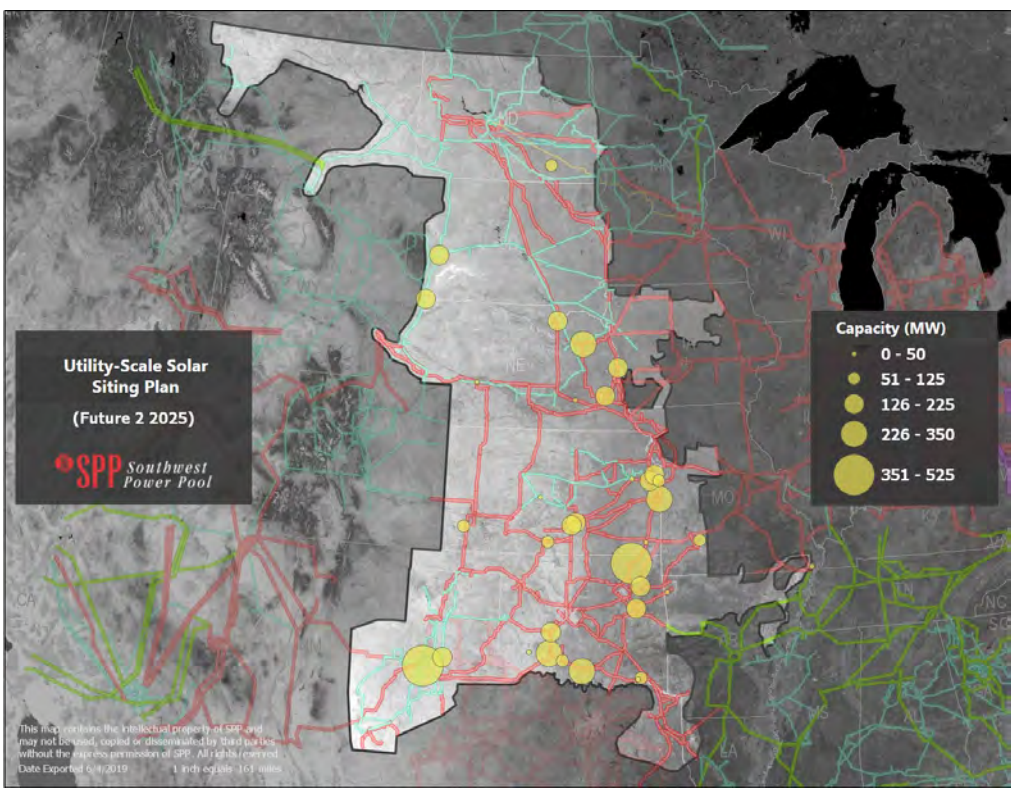

Figure 2.14: 2025 Future 2 Utility-Scale Solar Siting Plan

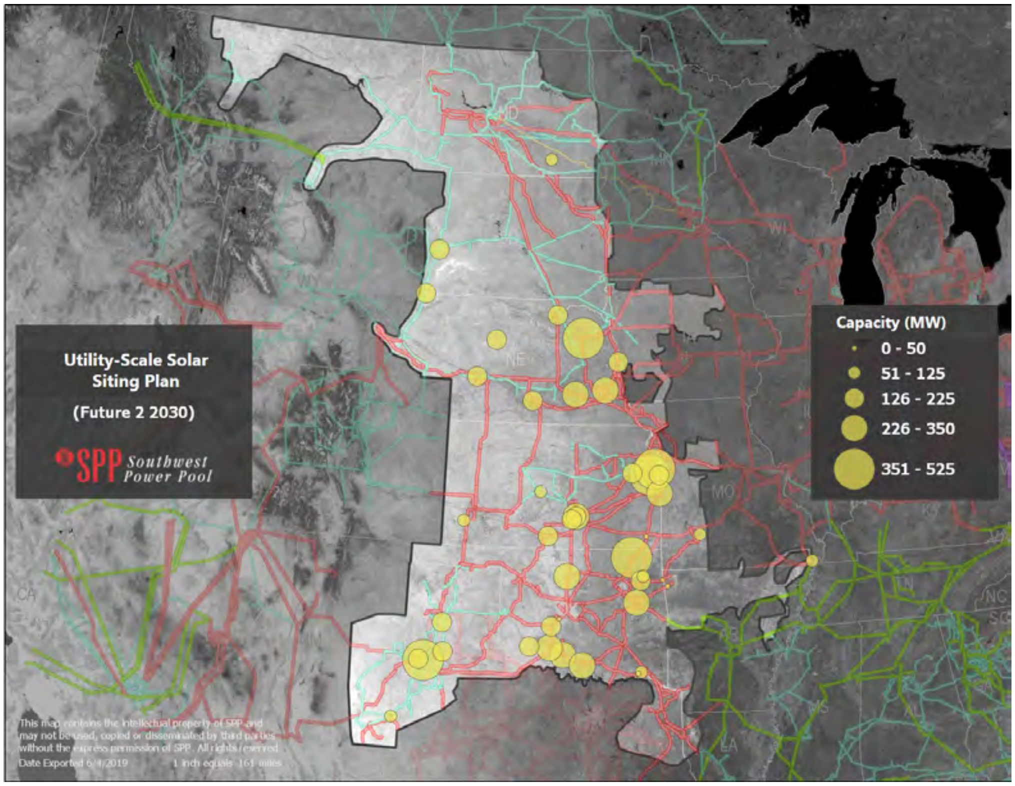

Figure 2.15: 2030 Future 2 Utility-Scale Solar Siting Plan

Wind sites were selected from GI queue requests that required the lowest total interconnection cost[13] 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 were 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.

[13] The total interconnection costs includes the total costs assigned for all interconnection related upgrades and network upgrade.

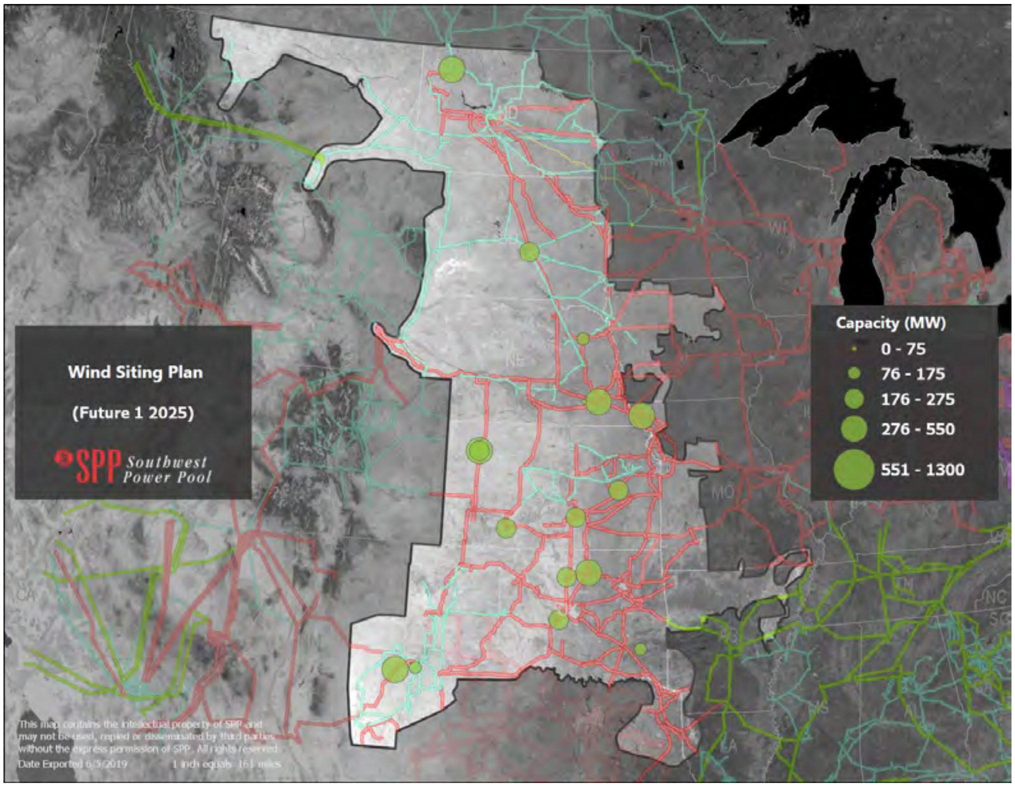

Figure 2.16: 2025 Future 1 Wind Siting Plan

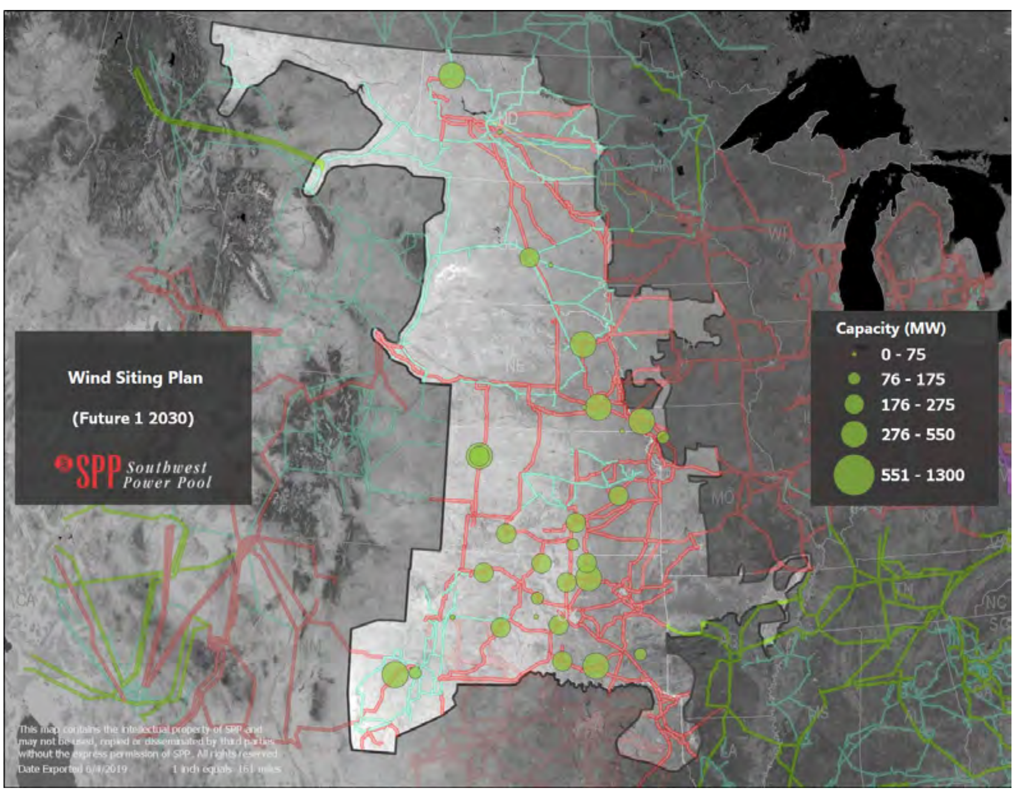

Figure 2.17: 2030 Future 1 Wind Siting Plan

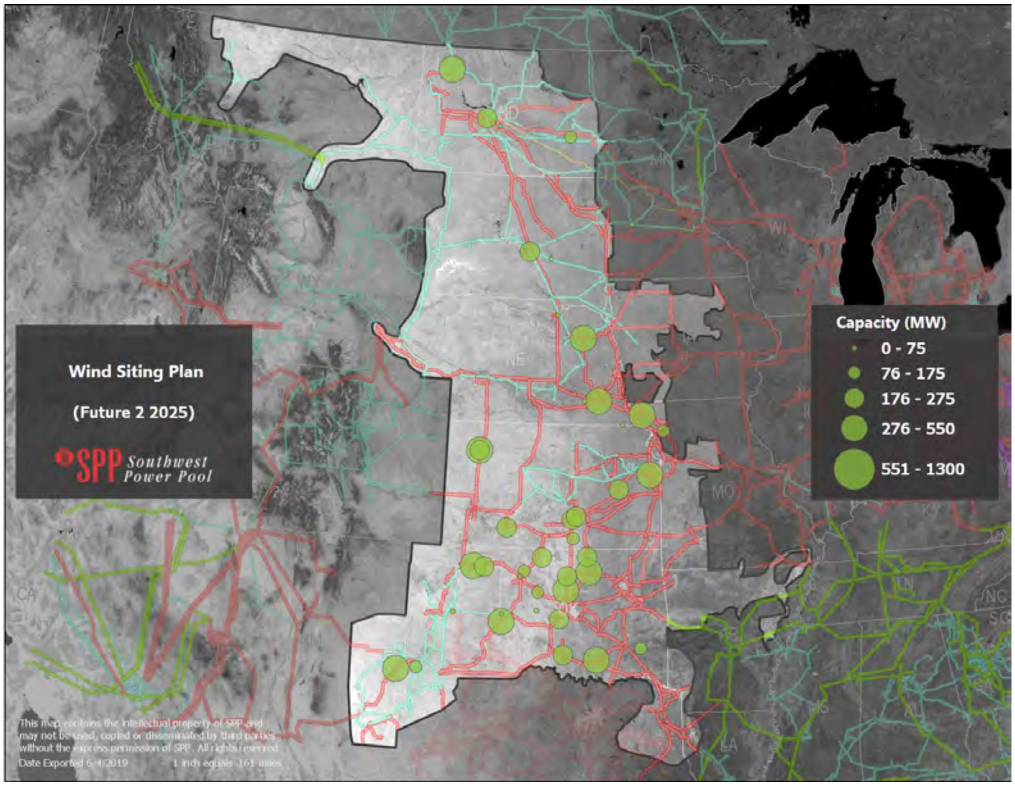

Figure 2.18: 2025 Future 2 Wind Siting Plan

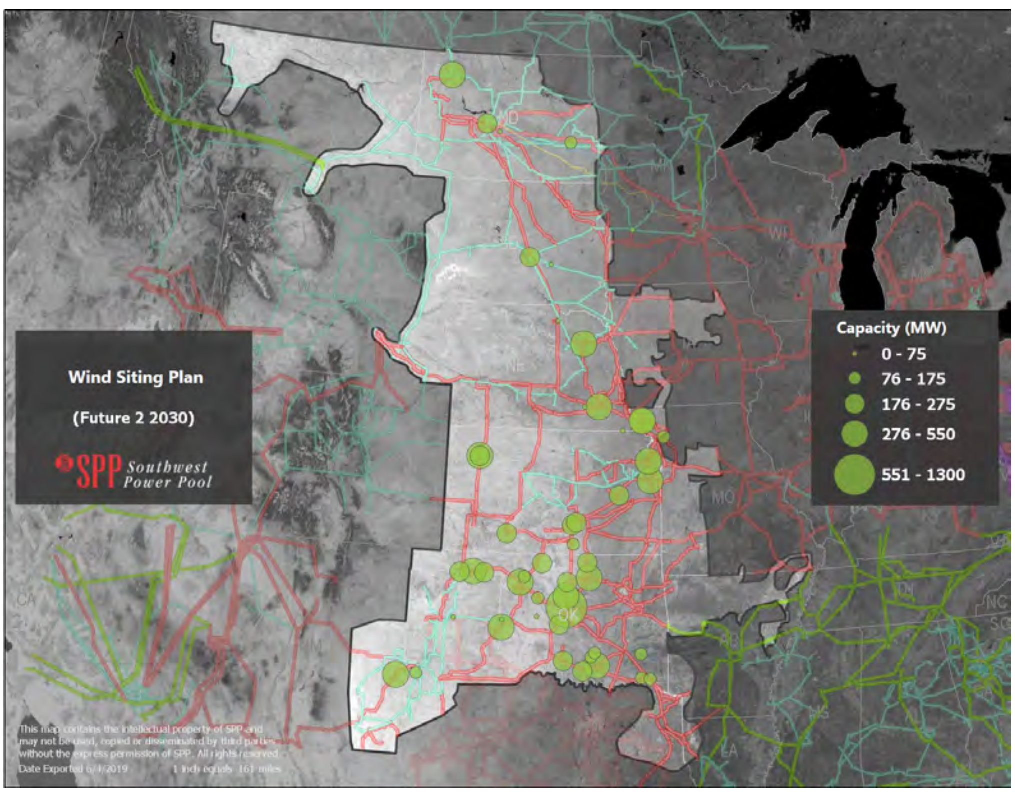

Figure 2.19: 2030 Future 2 Wind Siting Plan

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 were 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.

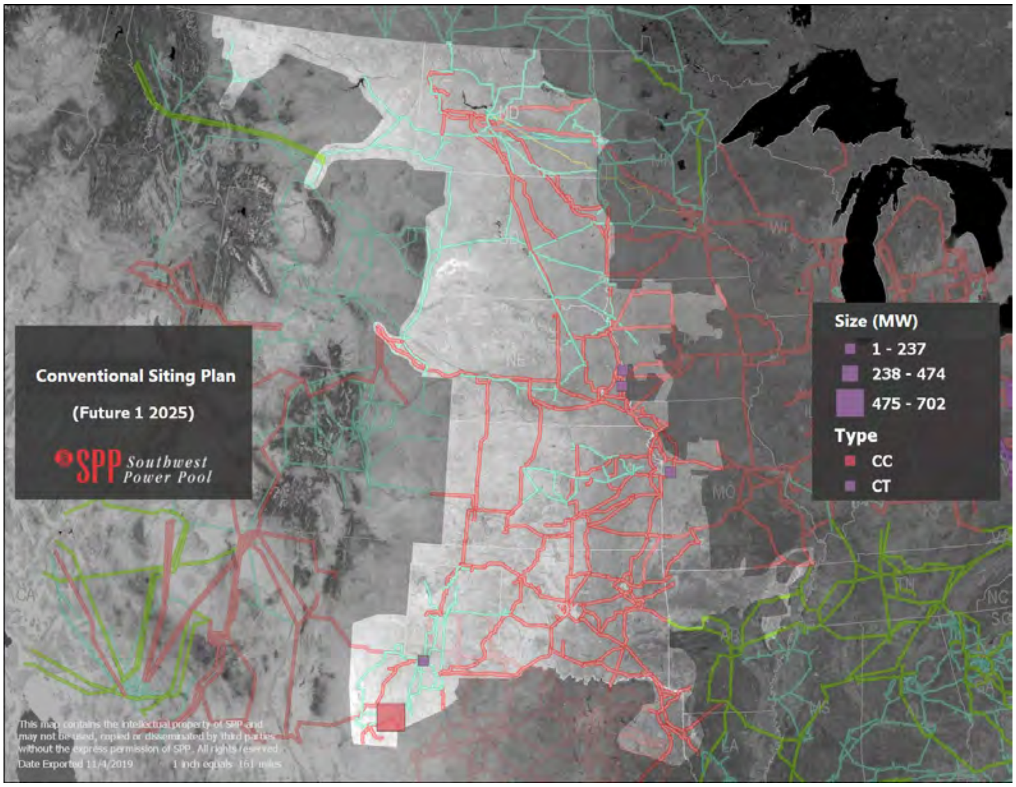

Figure 2.20: 2025 Future 1 Conventional Siting Plan

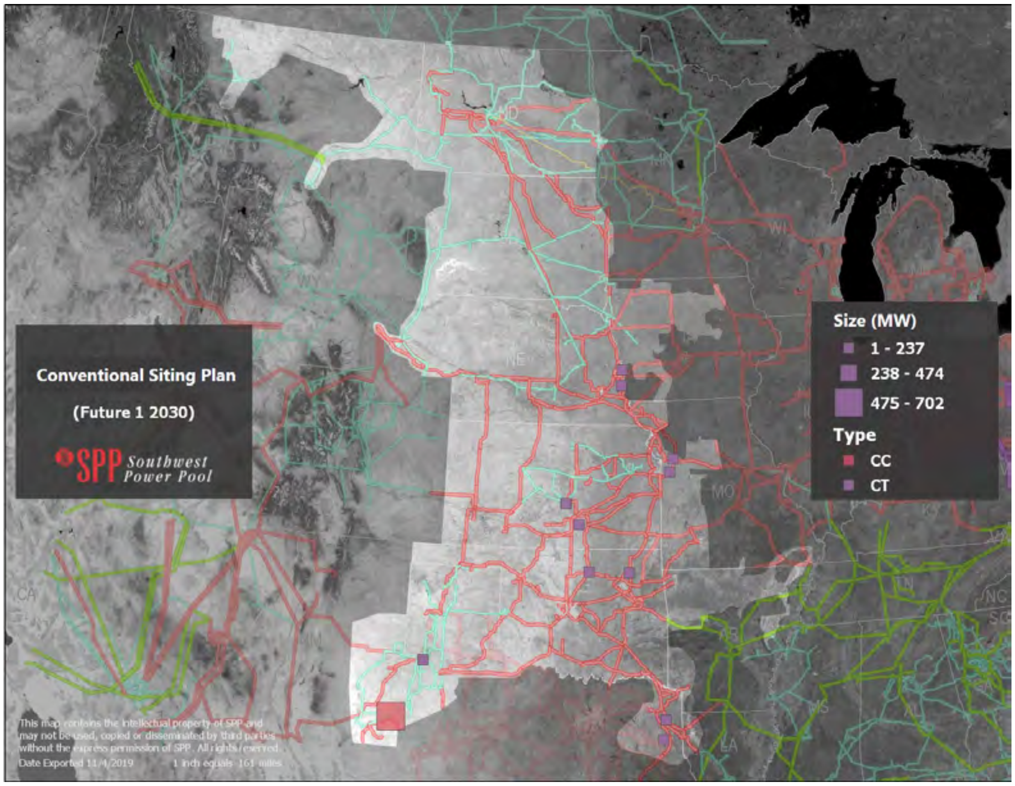

Figure 2.21: 2030 Future 1 Conventional Siting Plan

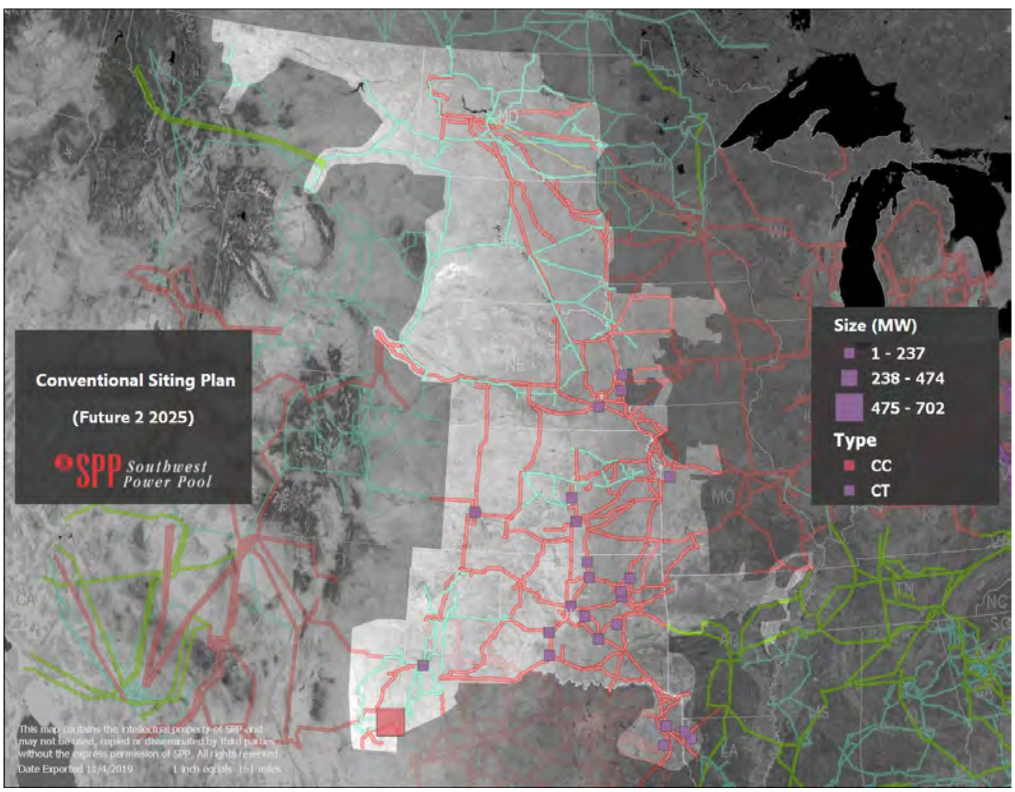

Figure 2.22: 2025 Future 2 Conventional Siting Plan

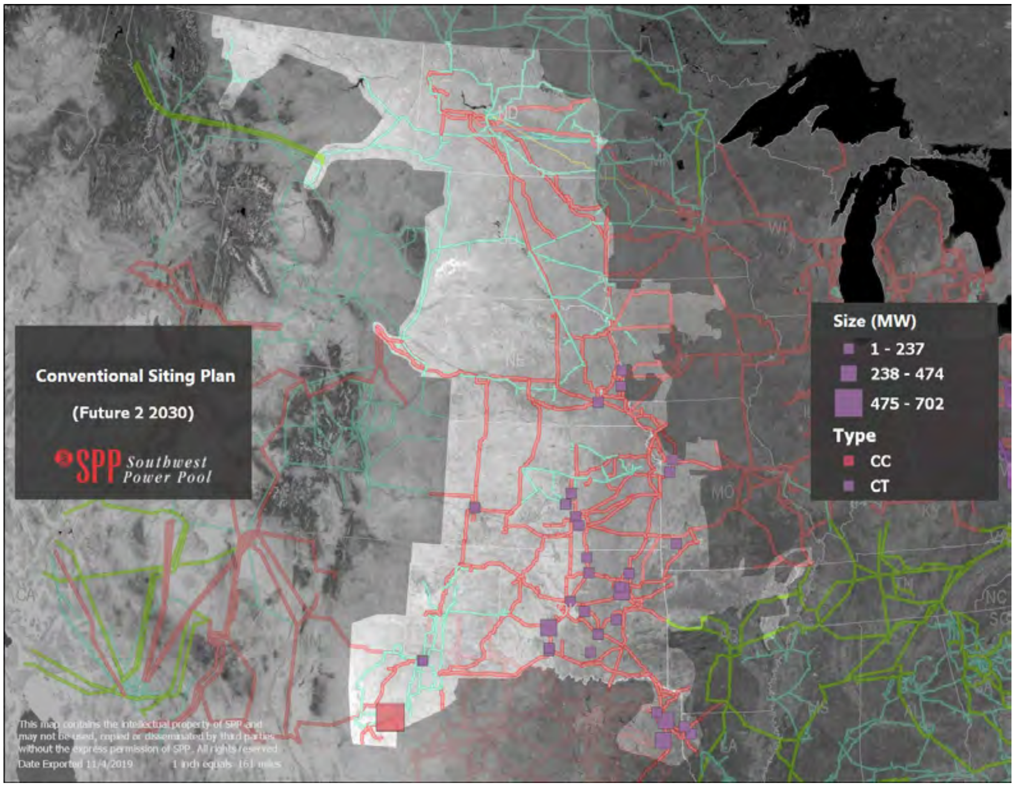

Figure 2.23: 2030 Future 2 Conventional Siting Plan

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 megawatts and capped at siting availability. Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which were 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.

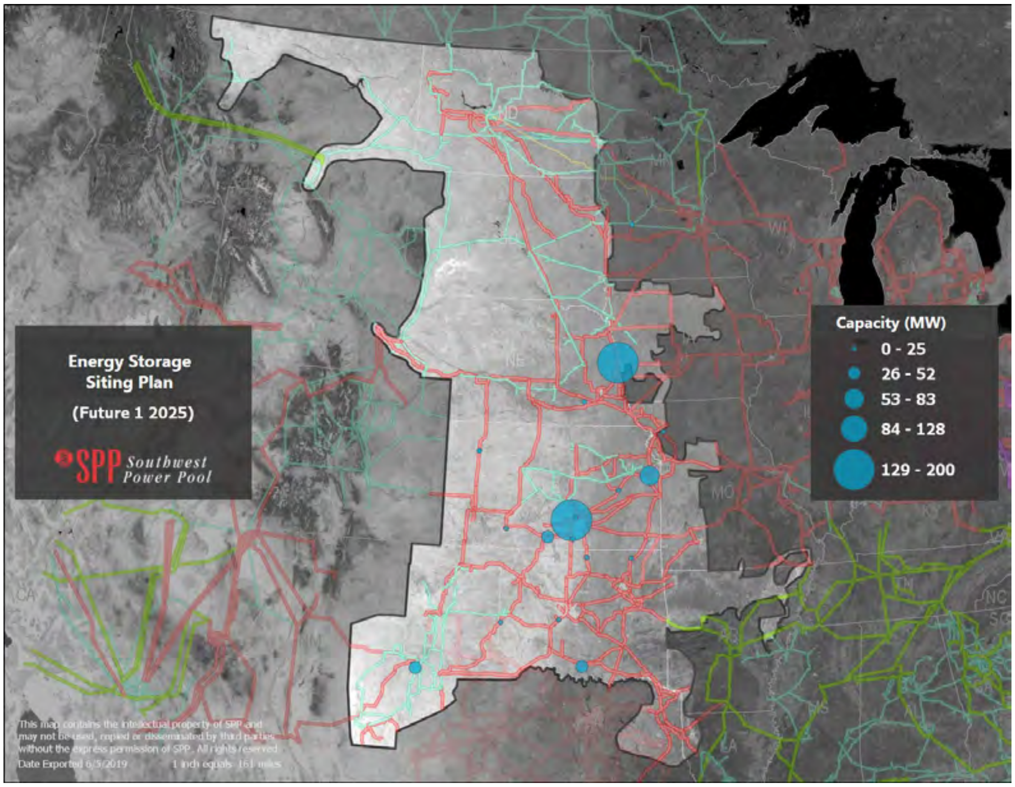

Figure 2.24: 2025 Future 1 Energy Storage Siting Plan

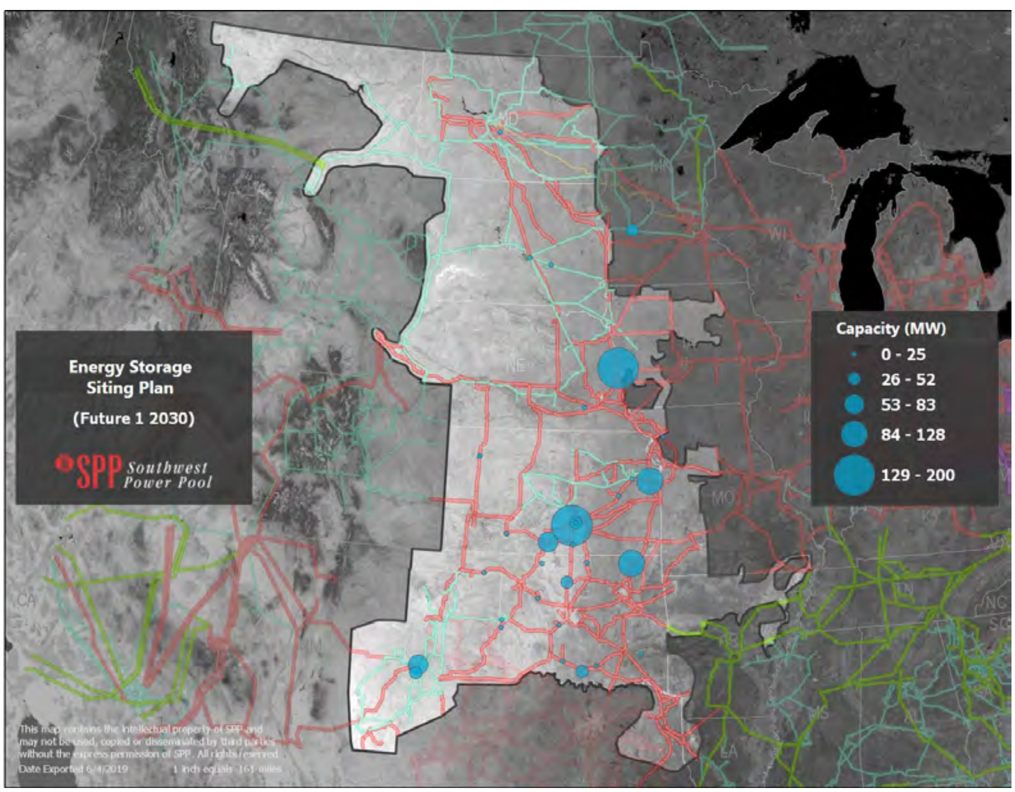

Figure 2.25: 2030 Future 1 Energy Storage Siting Plan

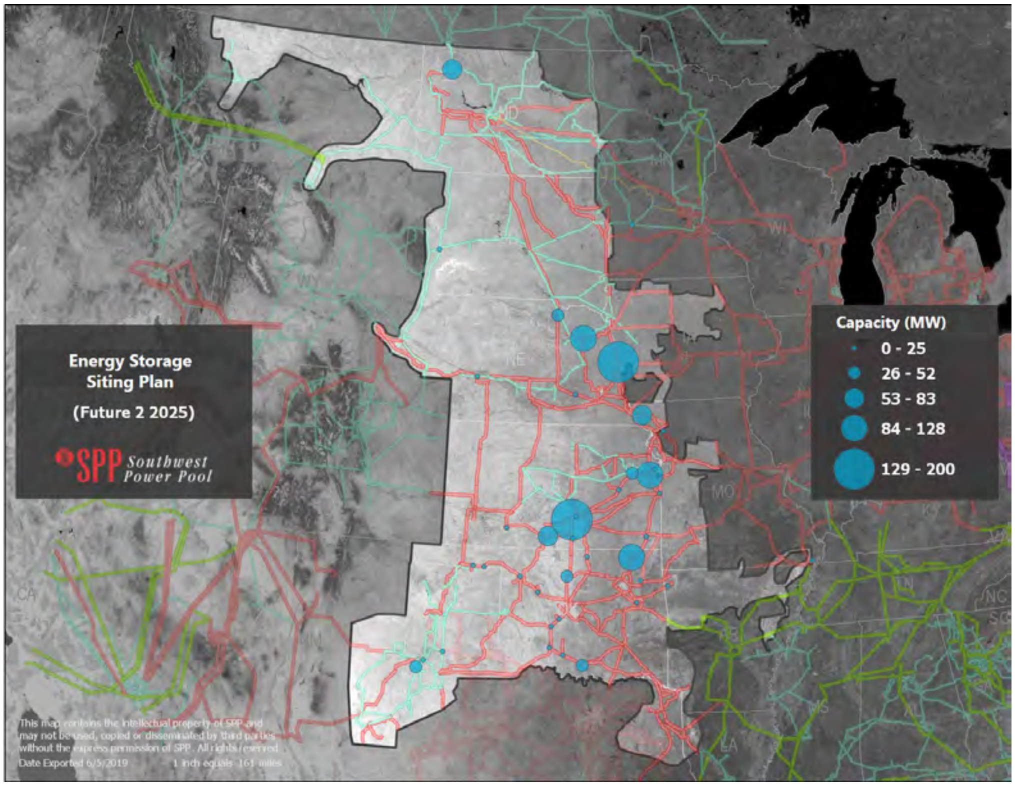

Figure 2.26: 2025 Future 2 Energy Storage Siting Plan

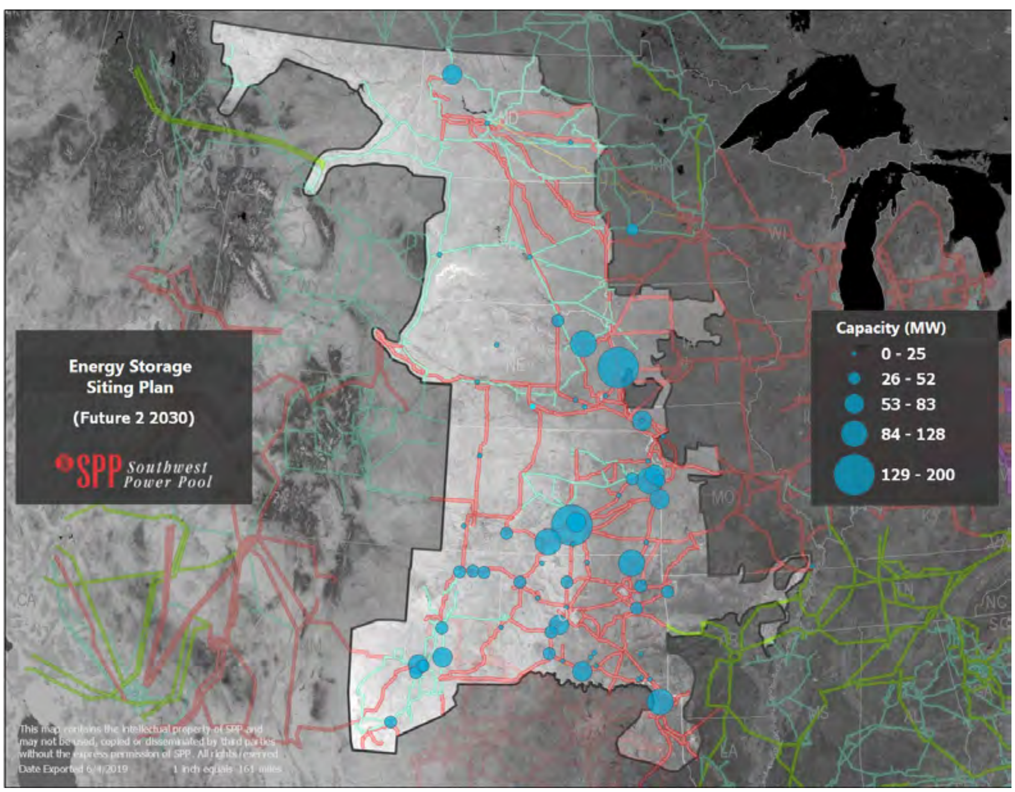

Figure 2.27: 2030 Future 2 Energy Storage Siting Plan

2.2.2.4 Generator Outlet Facilities (GOF)

To incorporate the siting plan into the market models, generator outlet facilities (GOFs) were necessary. GOFs are required such that 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 2.4.

GOF Description	Site	MW Sited	GOF Source
Cleo Corner-Cleo Tap 138 kV terminal upgrades	Badger 345 kV Mooreland-Knob Hill 138 kV Hitchland 345 kV	376 MW (F1,Y10 & F2,Y5) 624 MW (F2, Y10)	GI Queue
Arbuckle 138 kV circuit 2 new tap	Blue River 138 kV Arbuckle-Blue River 138 kV	323 MW (F2, Y10)	GI Queue
Dover-Hennessey 138 kV terminal upgrades	Dover Switchyard 138 kV	288 MW (F2, Y5&Y10)	GI Queue
Tolk 345/230 kV second transformer	Crossroads 345 kV	522 MW	Siting Availability
Tolk-Crossroads-Eddy County 345 kV terminal upgrades			
Neset 345/230 kV replace transformer	Tande 345 kV	300 MW (F1, Y5&Y10), 374 MW (F2, Y5&Y10)	Siting Availability
Neset-Tande 230 kV rebuild			
Greenwood-Lee's Summit 161 kV rebuild	Greenwood 161 kV	237 MW	Siting Availability
Pleasant Hill-Lake Winnabago 161 kV terminal upgrades			
Hobbs-Andrews 230 kV voltage conversion	Sidewinder 345 kV	702 MW	Siting Availability
Andrews-Roadrunner 345 kV new line			

*Table 2.4: 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 2019 MISO Transmission Expansion Planning (MTEP19) 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.

Conventional resource plans were incorporated for external regions included in the market simulations. Each region was surveyed for load and generation and assessed to determine the capacity shortfall. The MISO and TVA resource expansion and siting plans were based on the MTEP19 CFC and AFC futures, while AECI 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 2030 by unit type of these external regions for Futures 1 and 2.

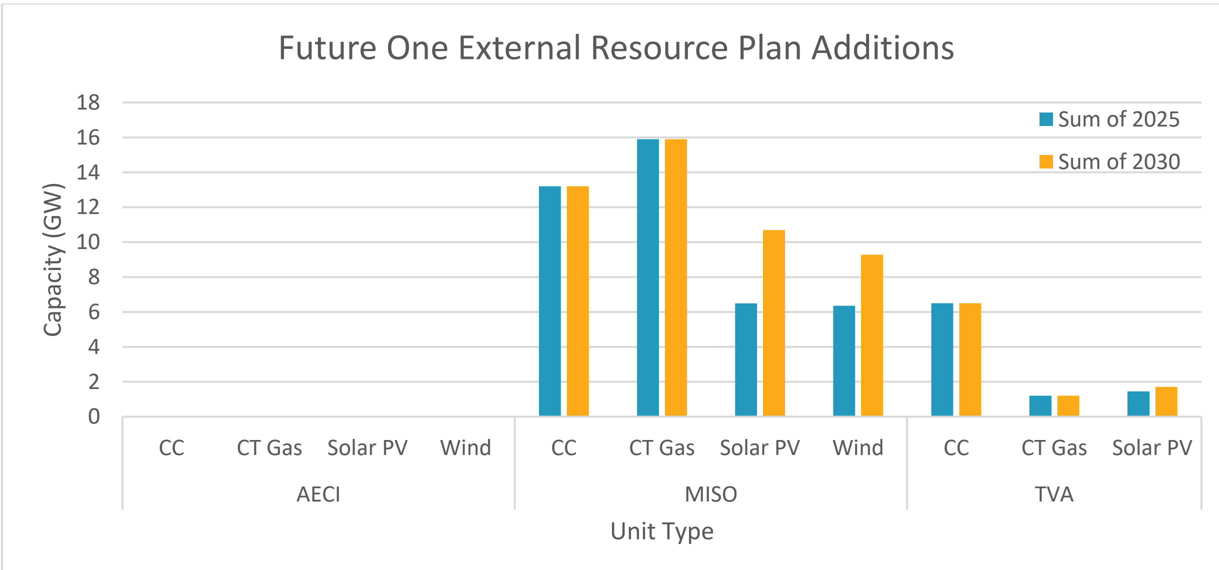

Figure 2.28: Capacity Additions by Unit Type-Future 1

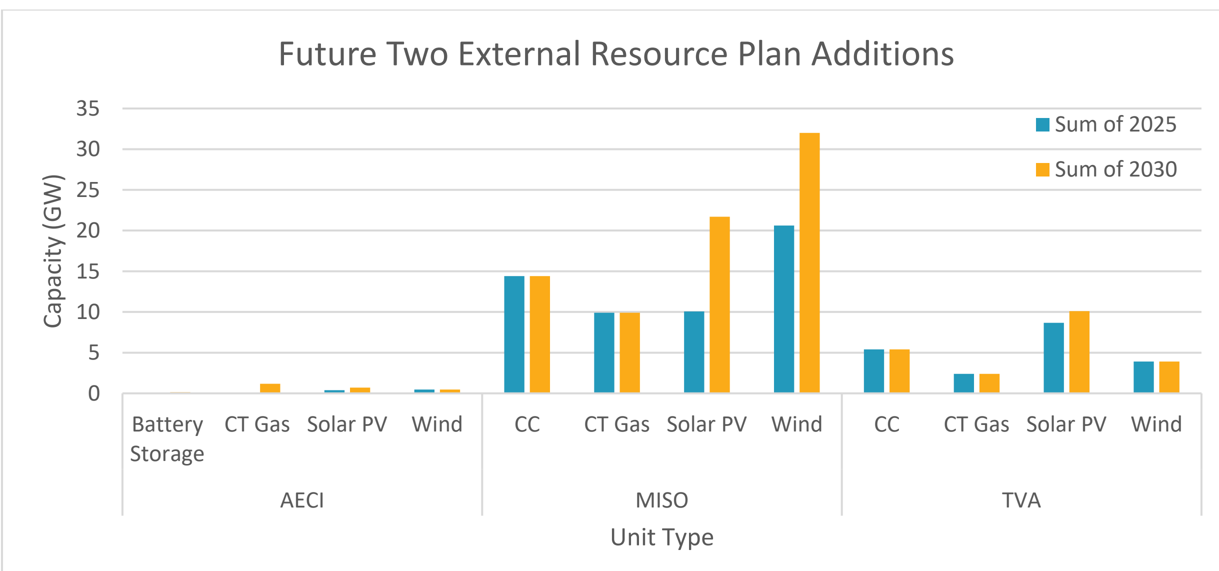

Figure 2.29: Capacity Additions by Unit Type-Future 2

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 staff defined the initial list of constraints leveraging the SPP permanent flowgate list,[14] which consists of NERC-defined flowgates that are impactful to modeled regions and recent temporary flowgates identified by SPP in real-time.

MTEP19 constraints were used to help evaluate and validate constraints identified within MISO and other neighboring areas. Constraints identified in neighboring areas were considered for inclusion as a part of the ITP study constraint list.

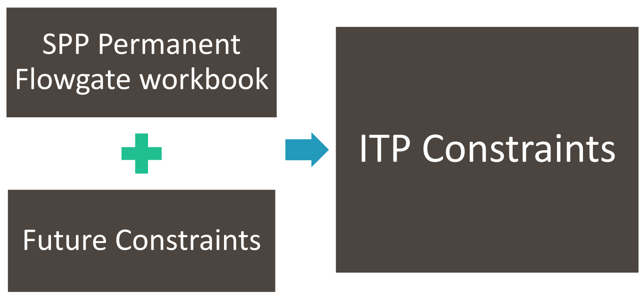

Figure 2.30: Constraint Assessment Process

2.3 MARKET POWERFLOW MODEL

The economic dispatch from each market economic model was used to develop market powerflow model snapshots representing stressed conditions on the SPP transmission system. Table 2.5 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.

	Off-Peak Hour	Wind Penetration[15]	Peak Hour	SPP Load (MW)
Future 1 2022	April 3 at 4:00 AM	92.3%	August 27 at 6:00 PM	51,639
Future 1 2025	April 5 at 1:00 AM	103.2%	July 23 at 6:00 PM	52,534
Future 1 2030	April 1 at 1:00 AM	110.7%	July 24 at 6:00 PM	53,216
Future 2 2025	April 5 at 1:00 AM	113.9%	July 23 at 6:00 PM	52,433
Future 2 2030	April 1at 2:00 AM	133.5%	July 24 at 6:00 PM	53,210

Table 2.5: Reliability Hour Details

[14] Posted on SPP OASIS
[15] Wind Penetration = Potential Delivered Energy / Load

3 BENCHMARKING

3.1 POWERFLOW MODEL

SPP staff performed two benchmarks related to the 2020 ITP base reliability powerflow models. The first benchmark was a load and generation value comparison between the 2019 ITP and 2020 ITP base reliability powerflow models. The second benchmark was a load and generation value comparison between the 2020 ITP base reliability powerflow models and real-time operational data. Model comparisons were conducted to verify the accuracy of the powerflow model data, including:

- Comparison of the summer and winter peak base reliability model load totals (2019 ITP versus 2020 ITP), as shown in Figure 3.1 and Figure 3.2.
- Comparison of the summer and winter peak base reliability model generation dispatch totals for years two, five and 10 (2019 ITP versus 2020 ITP), as shown in Figure 3.3 and Figure 3.4.
- Additionally, the year-10 summer and winter peak generator retirements in the 2020 ITP base reliability powerflow models are shown in Figure 3.5.

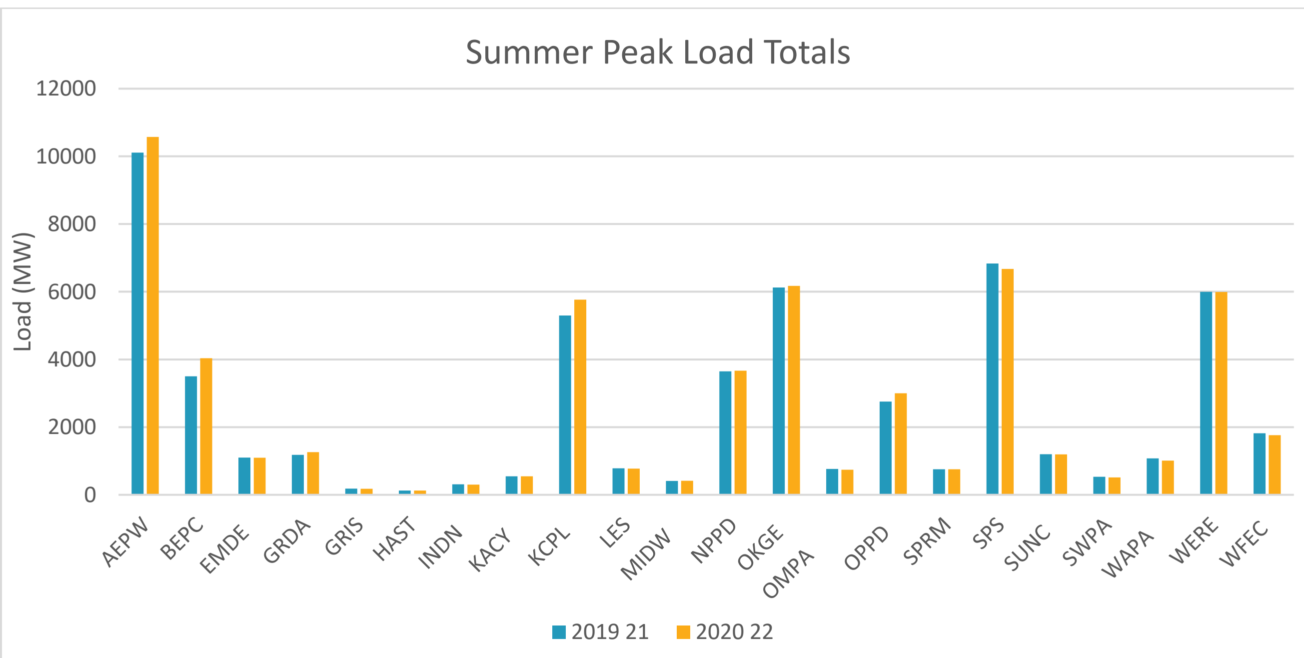

Figure 3.1: Summer Peak Year-Two Load Totals Comparison

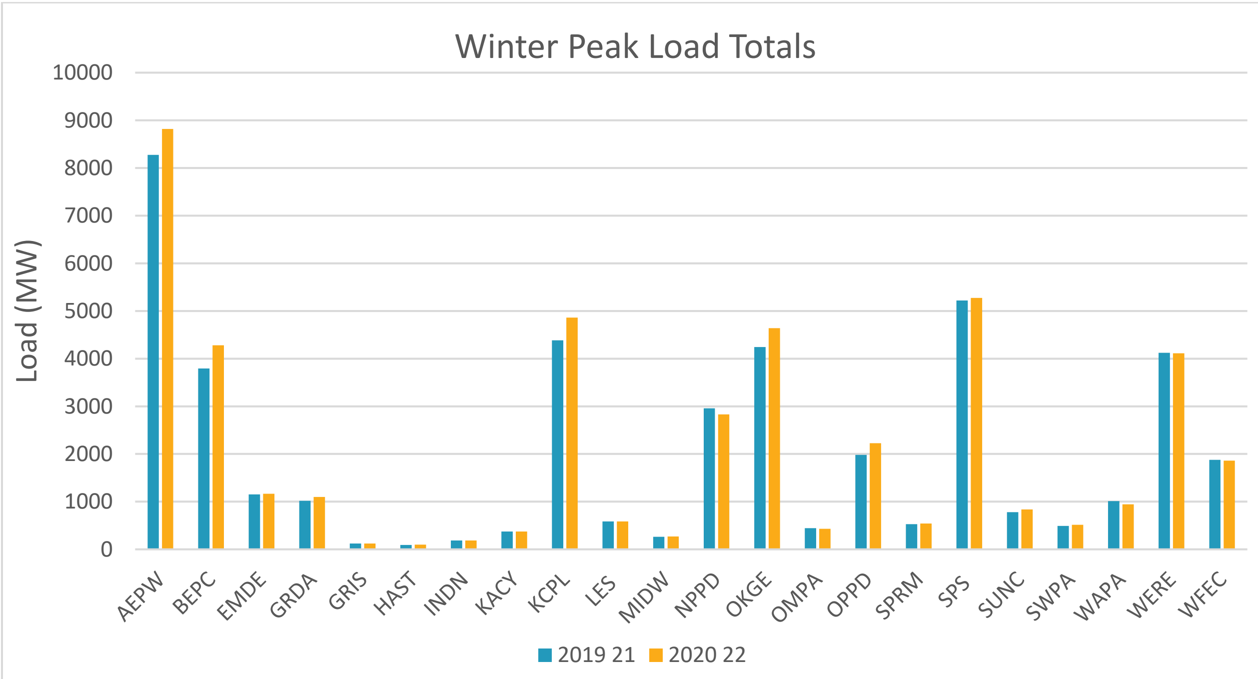

Figure 3.2: Winter Peak Year-Two Load Totals Comparison

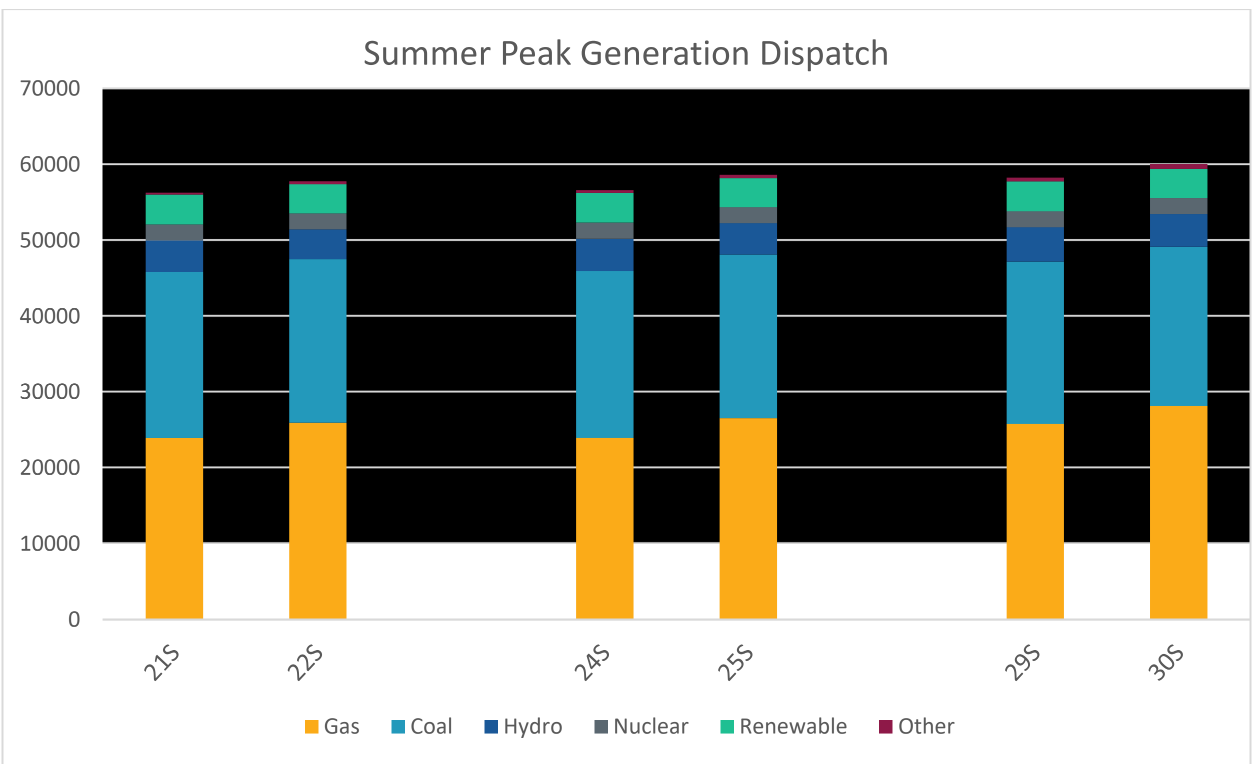

Figure 3.3: Summer Peak Years two, five and 10 Generation Dispatch Comparison

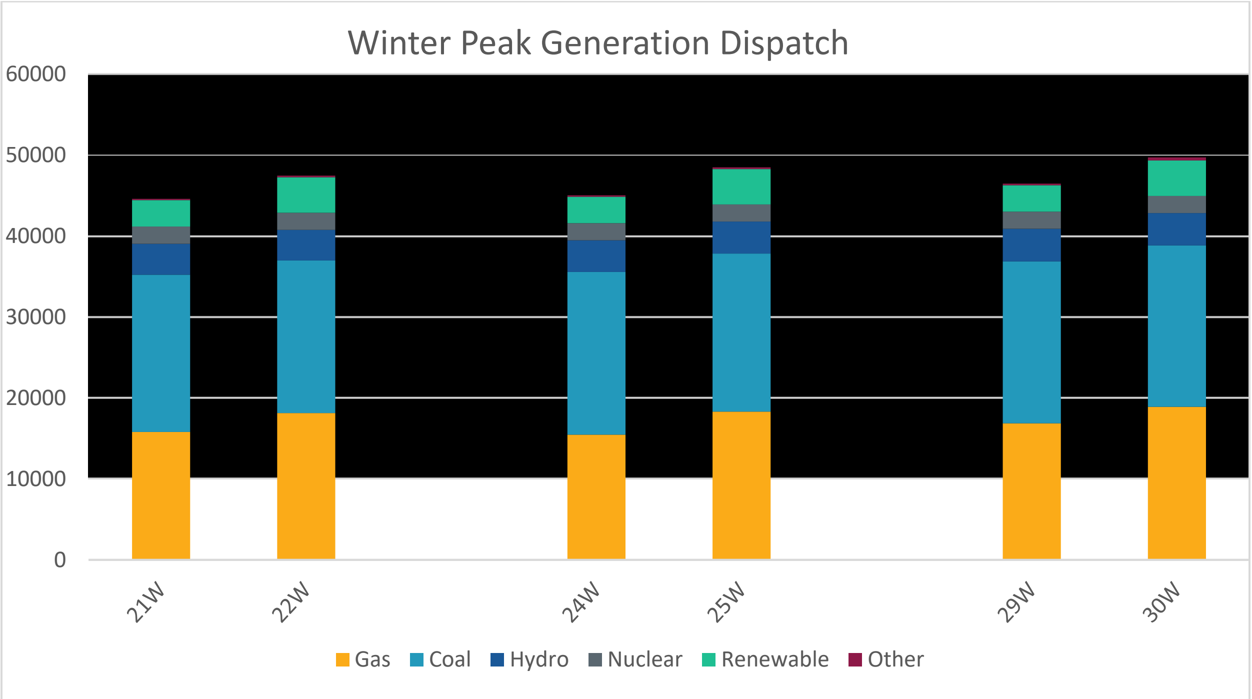

Figure 3.4: Winter Peak Years two, five and 10 Generation Dispatch Comparison

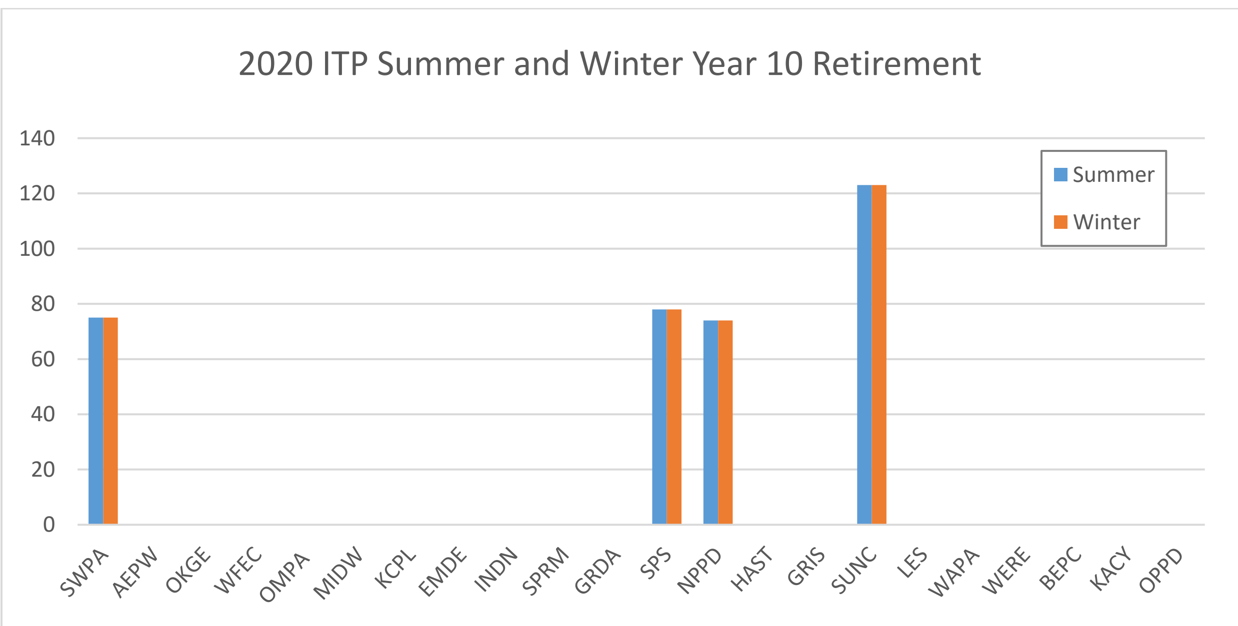

Figure 3.5: 2020 ITP Summer and Winter Year 10 Retirement

Operational model benchmarking for this assessment compared the 2020 summer and winter peak base reliability powerflow models against the real-time operational data for the 2019-2020 winter and 2020 summer timeframe. Model comparisons were conducted to verify the accuracy of the powerflow model data, including:

- Comparison of the 2020 summer and winter load totals (base reliability model versus real-time operational data), as shown in Figure 3.6 and Figure 3.7

- Comparison of the 2020 summer and winter generation dispatch totals (base reliability model vs real-time operational data), as shown in Figure 3.8

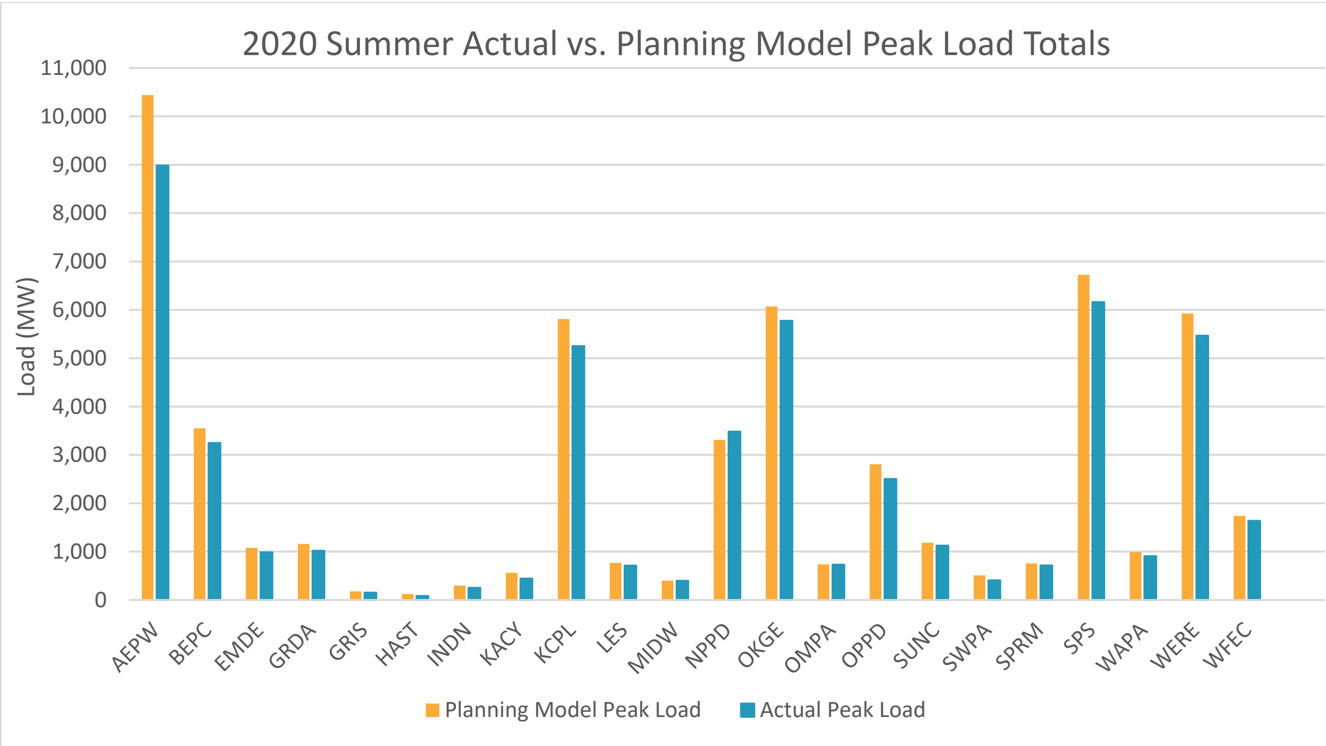

Figure 3.6: 2020 Summer Actual versus Planning Model Peak Load Totals

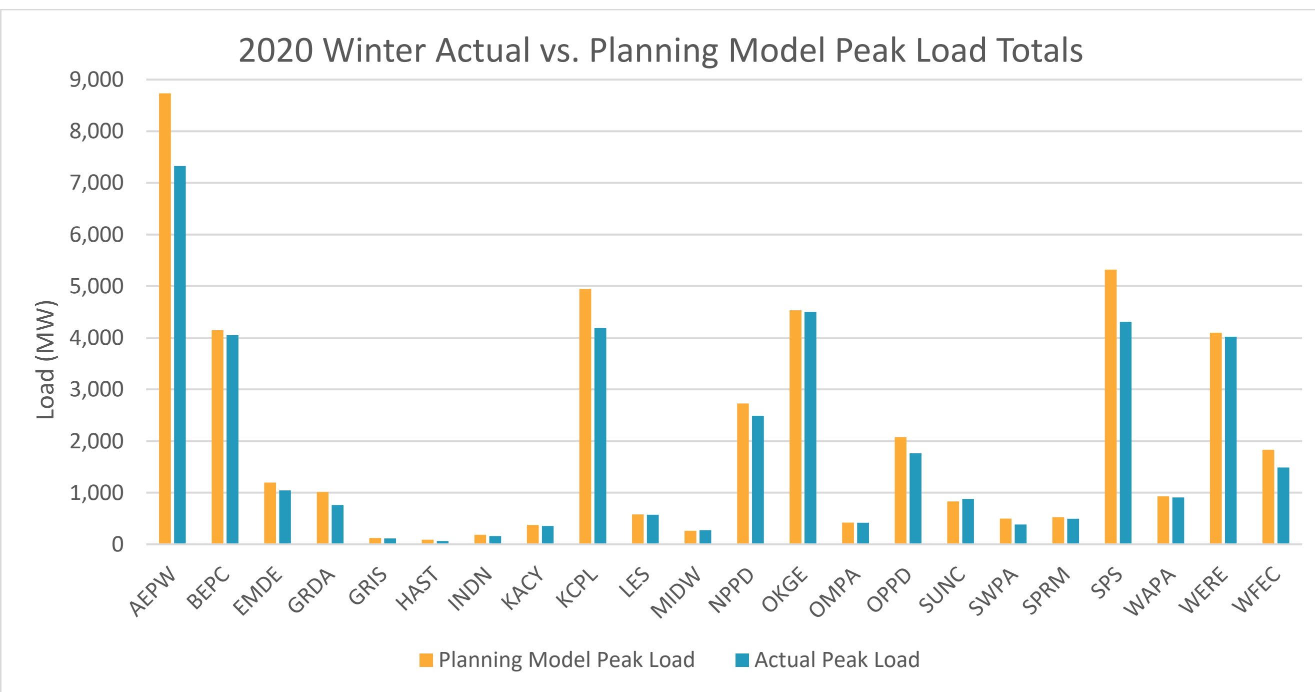

Figure 3.7: 2020 Winter Actual versus Planning Model Peak Load Totals

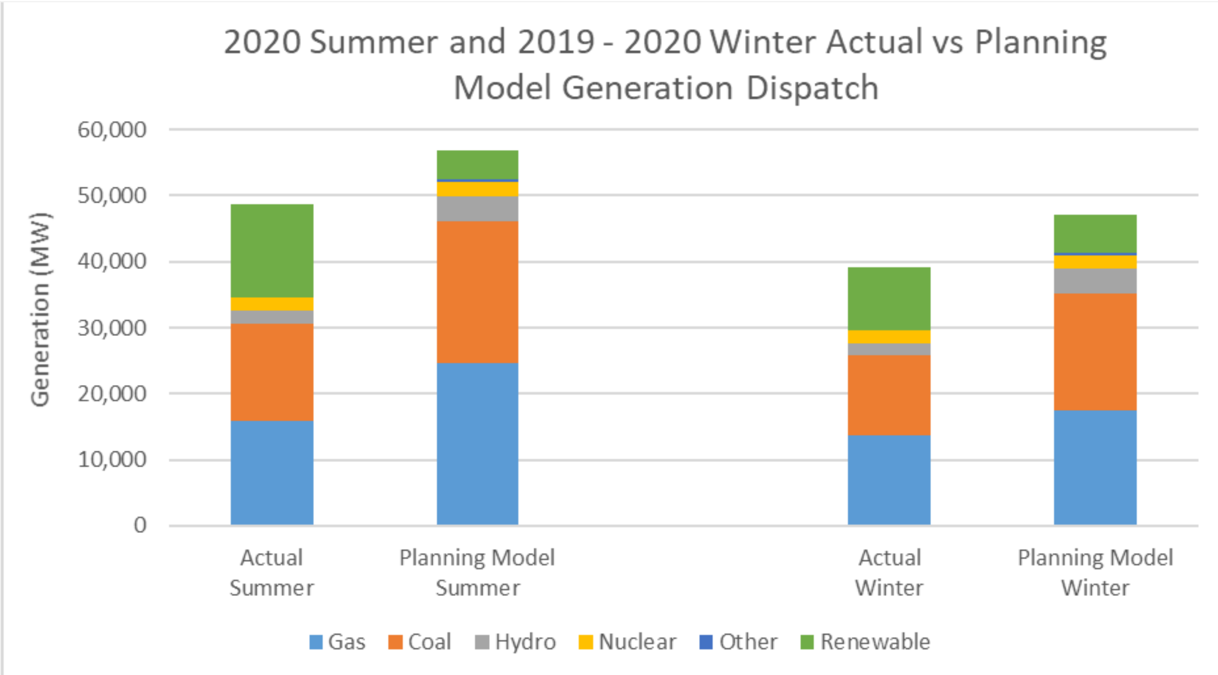

Figure 3.8: 2020 Actual versus Planning Model Generation Dispatch Comparison

3.2 MARKET ECONOMIC MODEL

Benchmarking for this study was performed on the year-two Future 1 market economic model. For the benchmarking process to provide the most value, it was important to compare the current study model against previous ITP modeling outputs and historical SPP real-time data. Numerous benchmarks were conducted 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 Criteria
- Comparing generation capacity factors, generating unit average cost, renewable generation profiles, system locational marginal prices (LMP), adjusted production cost (APC), and interchange between the 2020 ITP and the 2019 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 2018 and resulting from the 2020 ITP study, the capacity factors for conventional generation units fell near the expected values. The difference in capacity factors between the datasets were attributed to differences in fuel and load forecasts as well as changes in the generation mix.

	Average Capacity Factor		
Unit Type	2018 EIA	2019 ITP Future 1 2021	2020 ITP Future 1 2022
Nuclear	93%	93%	90%
Combined Cycle	57%	41%	42%
CT Gas	12%	3%	4%
Coal	54%	61%	67%
ST Gas	14%	3%	4%
Wind	37%	46%	46%
Solar	26%	23%	24%

Table 3.1: Generation Capacity Factor Comparison

3.2.1.2 Average Energy Cost

Examining the average cost per MWh by unit type gives insight into what units will be dispatched first (without considering transmission constraints). Overall, the average costs per MWh were lower in the 2020 ITP than in the 2019 ITP due to the fuel and load forecasts and the difference in generation mix.

Unit Type	Average Energy Cost ($/MWh)	
	2019 ITP Future 1 2021	2020 ITP Future 1 2022
Nuclear	$15	$16
Combined Cycle	$31	$31
CT Gas	$44	$43
Coal	$24	$24
ST Gas	$41	$42

Table 3.2: Average Energy Cost Comparison

3.2.1.3 Generator Maintenance Outages

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

The operations data includes certain outage types that cannot be replicated in these planning models. The difference in magnitude between the real-time data and the market economic simulated outages is due to the additional operational outages beyond those required by annual maintenance or driven by forced (unplanned) conditions. Although the market economic model simulation outages do not have as high a magnitude as the historical outages provided by SPP operations, the outage rates in the 2020 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.

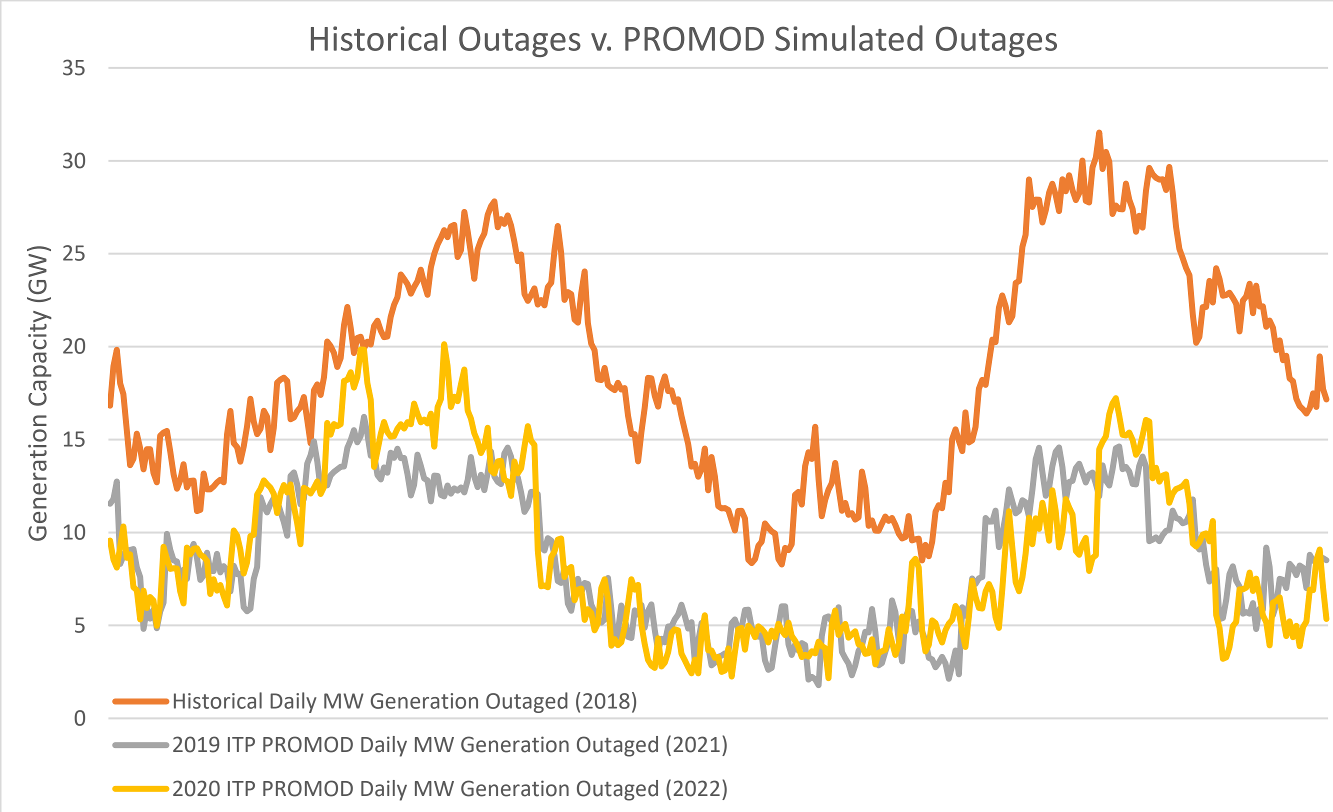

Figure 3.9: Historical Outages v. PROMOD Simulated Outages

3.2.1.4 Operating and Spinning Reserve Adequacy

Operating reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of unplanned unit outages. According to SPP 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. At least half of this requirement must be fulfilled by spinning reserve.

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

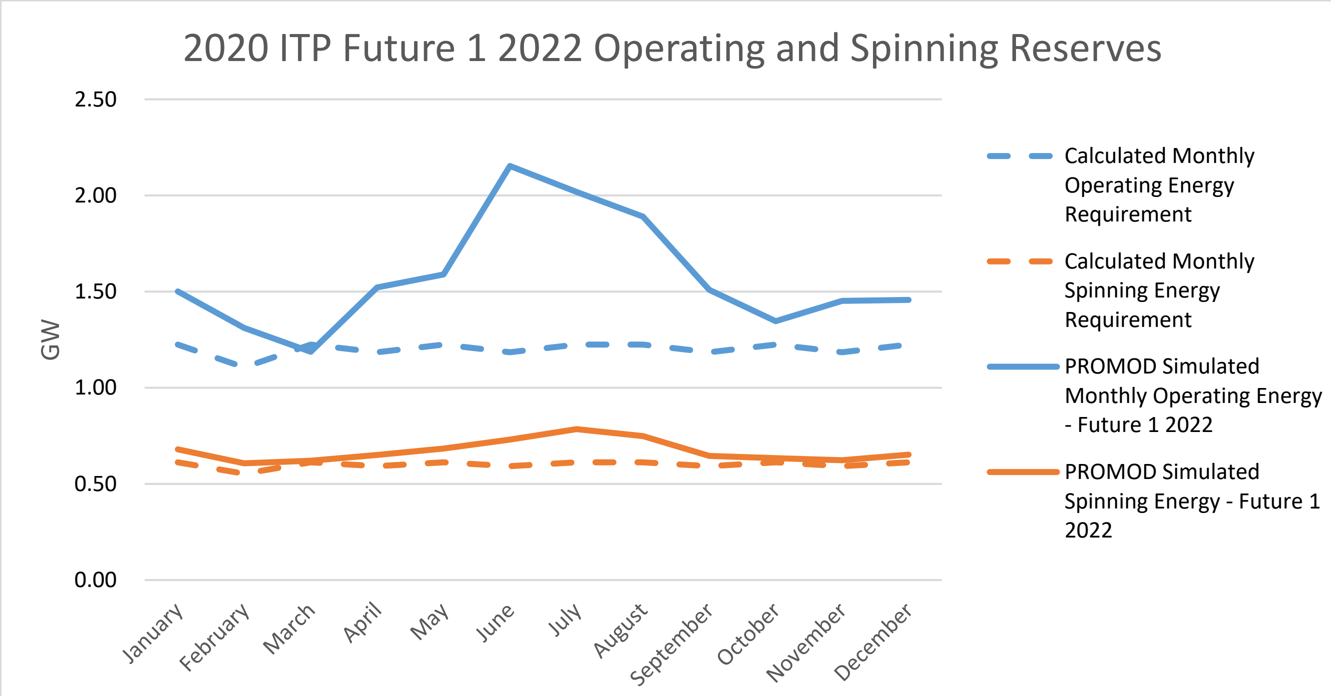

Figure 3.10: 2020 ITP Future 1 2022 Operating and Spinning Reserves

3.2.1.5 Renewable Generation

Wind and solar energy output is higher in the 2020 ITP than in the 2019 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 2020 ITP.

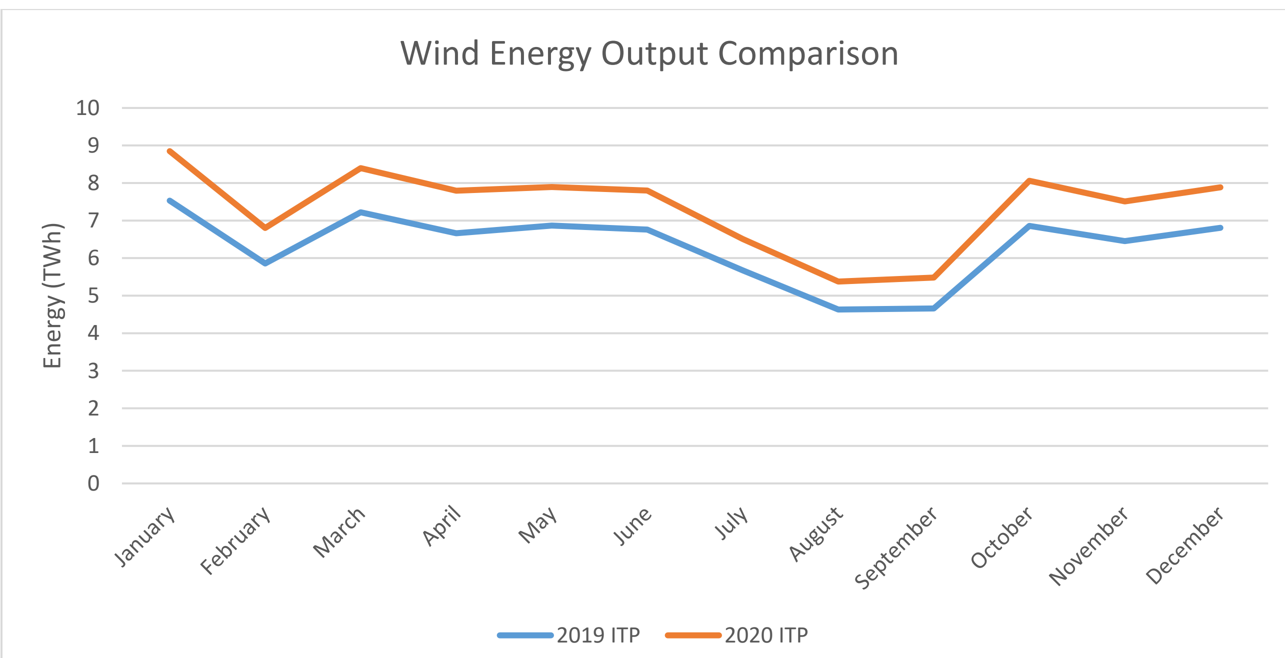

Figure 3.11: Wind Energy Output Comparison

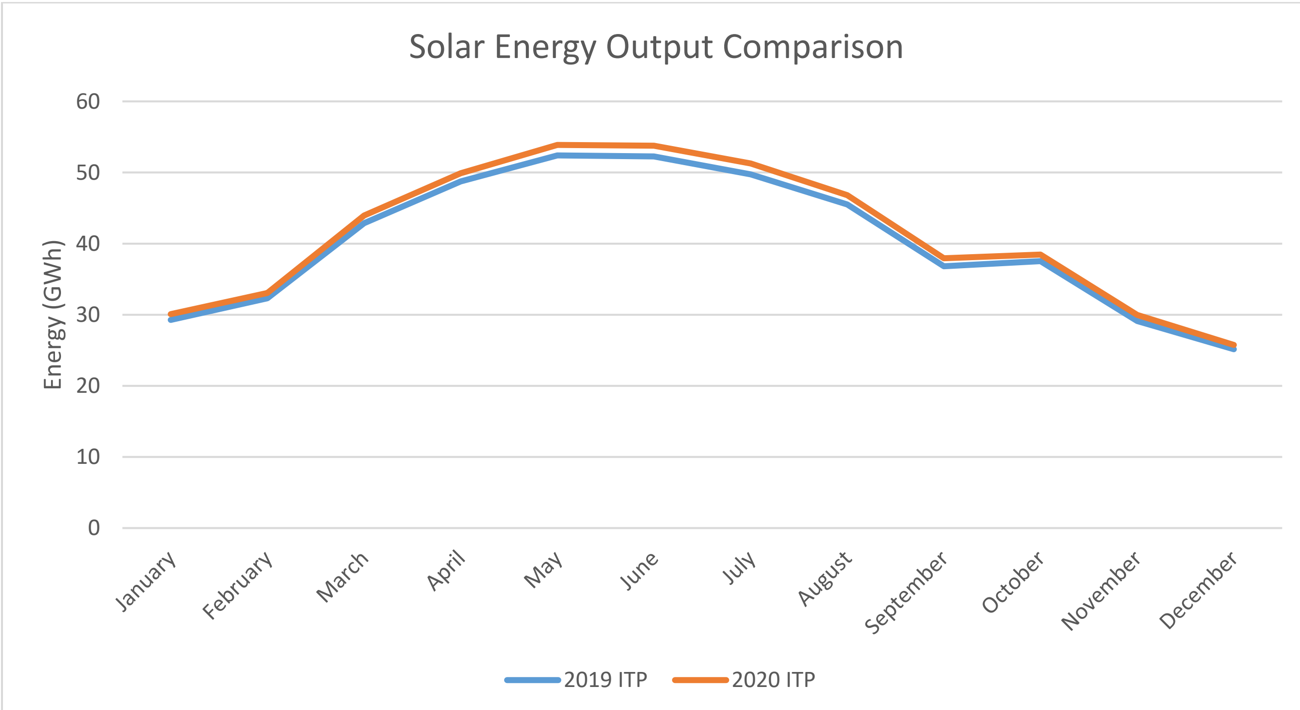

Figure 3.12: Solar Energy Output Comparison

3.2.2 SYSTEM LOCATIONAL MARGINAL PRICE (LMP)

Simulated LMPs were benchmarked against simulated LMPs from the 2019 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 2020 ITP is due to a slight decrease in natural gas price fuel forecasts and additional renewable energy.

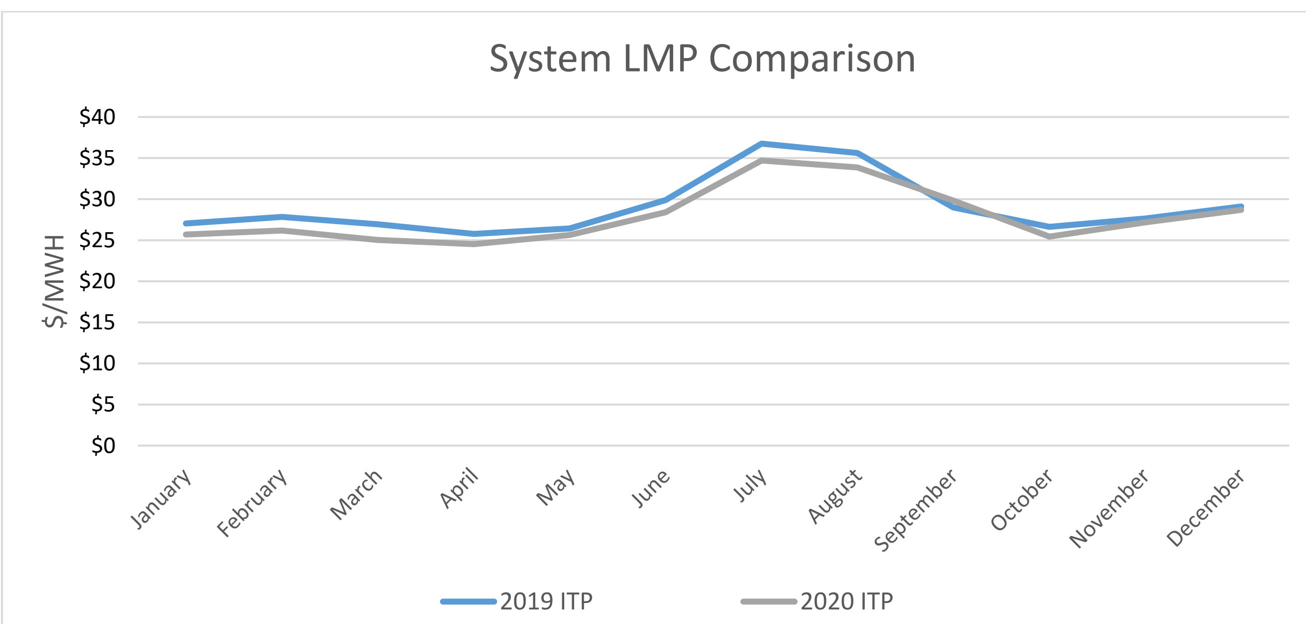

Figure 3.13: System LMP Comparison

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 2020 ITP than in the 2019 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.

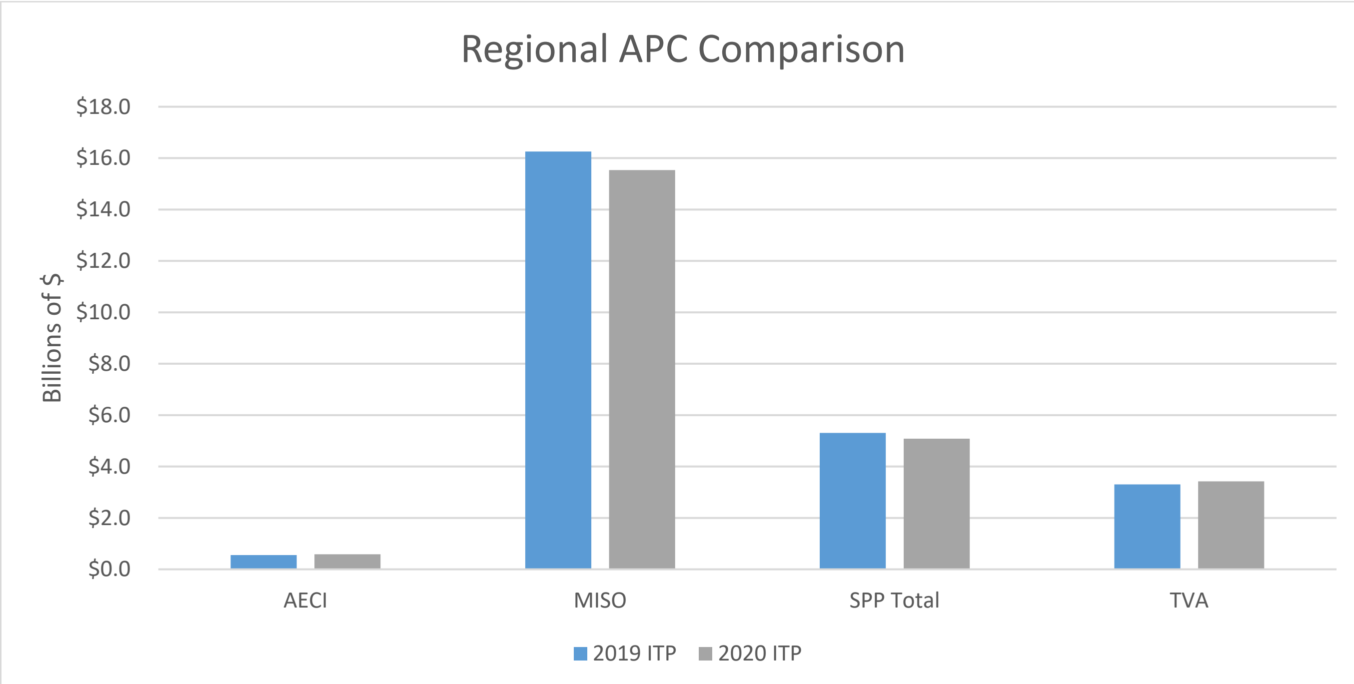

Figure 3.14: Regional APC Comparison

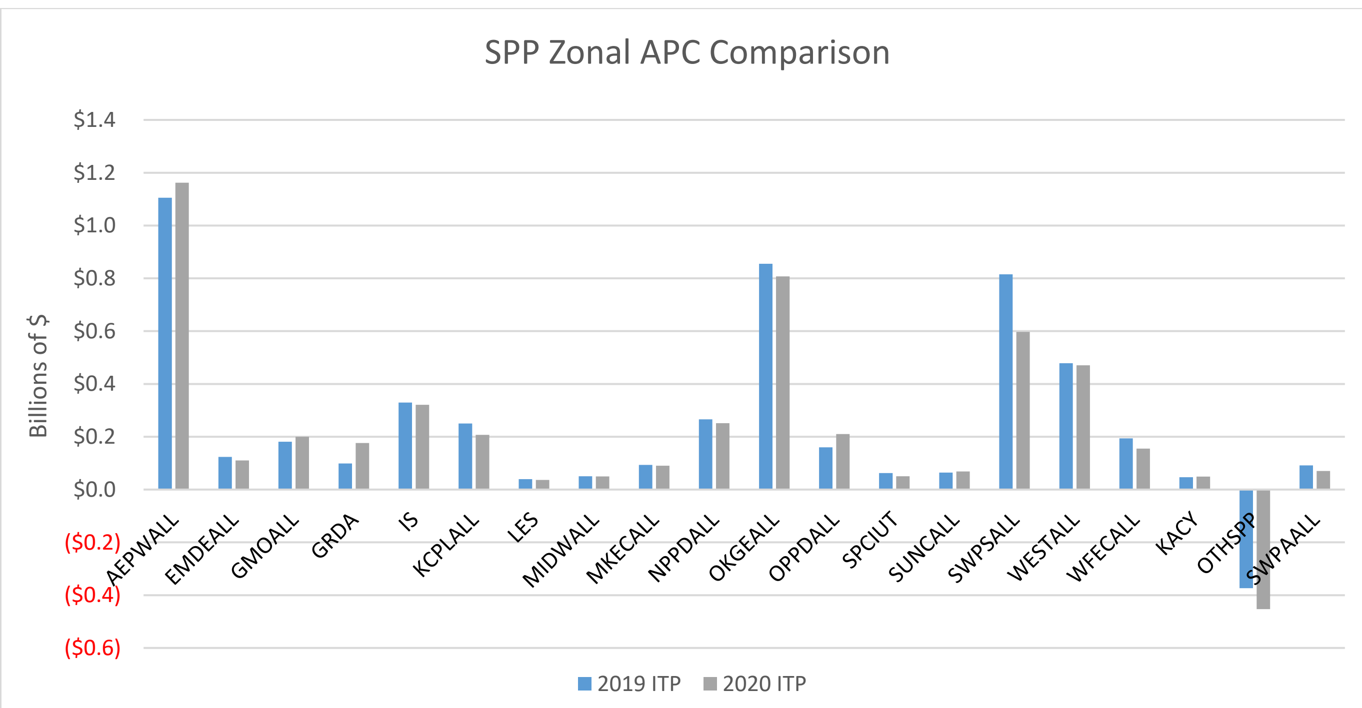

Figure 3.15: SPP Zonal APC Comparison[16]

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

3.2.4 INTERCHANGE

The 2020 ITP model interchange was validated against the 2019 ITP and current SPP operations data. The 2020 ITP model is similar in shape and magnitude while overall exports are higher in the 2020 ITP than in the 2019 ITP.

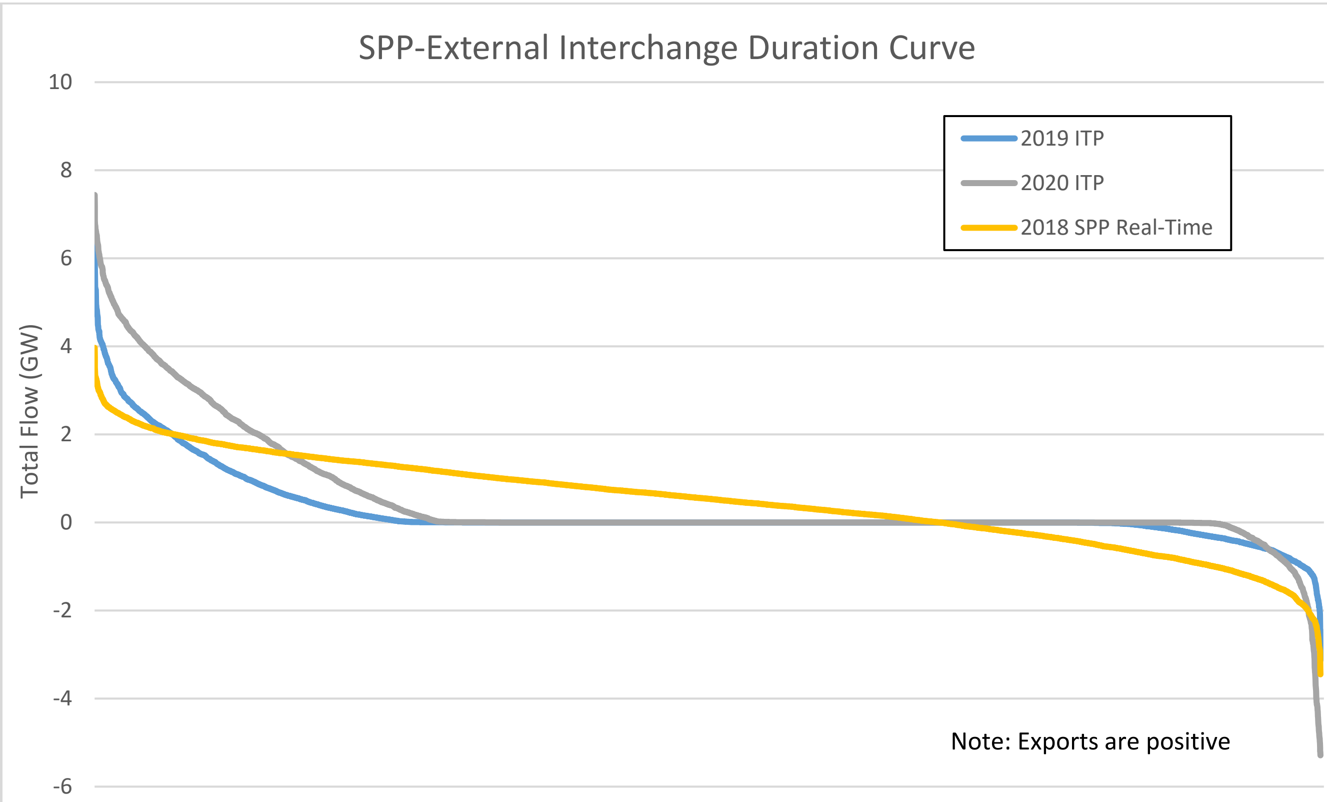

Figure 3.16: Interchange data comparison

4 NEEDS ASSESSMENT

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

4.1 ECONOMIC NEEDS

SPP determines economic needs based on the congestion score associated with a constraint (monitored element/contingent element pair). The congestion score is calculated by multiplying the number of hours a constraint is congested in the model by the average shadow price of that constraint. Constraints with a calculated congestion score greater than 50k are considered an economic need. Additional constraints were identified that did not meet the 50k score, because they were related to the SPP-MISO Coordinated System Plan (CSP). The economic needs identified per future are shown in Figure 4.1 and Figure 4.2, and Table 4.1 and Table 4.2.

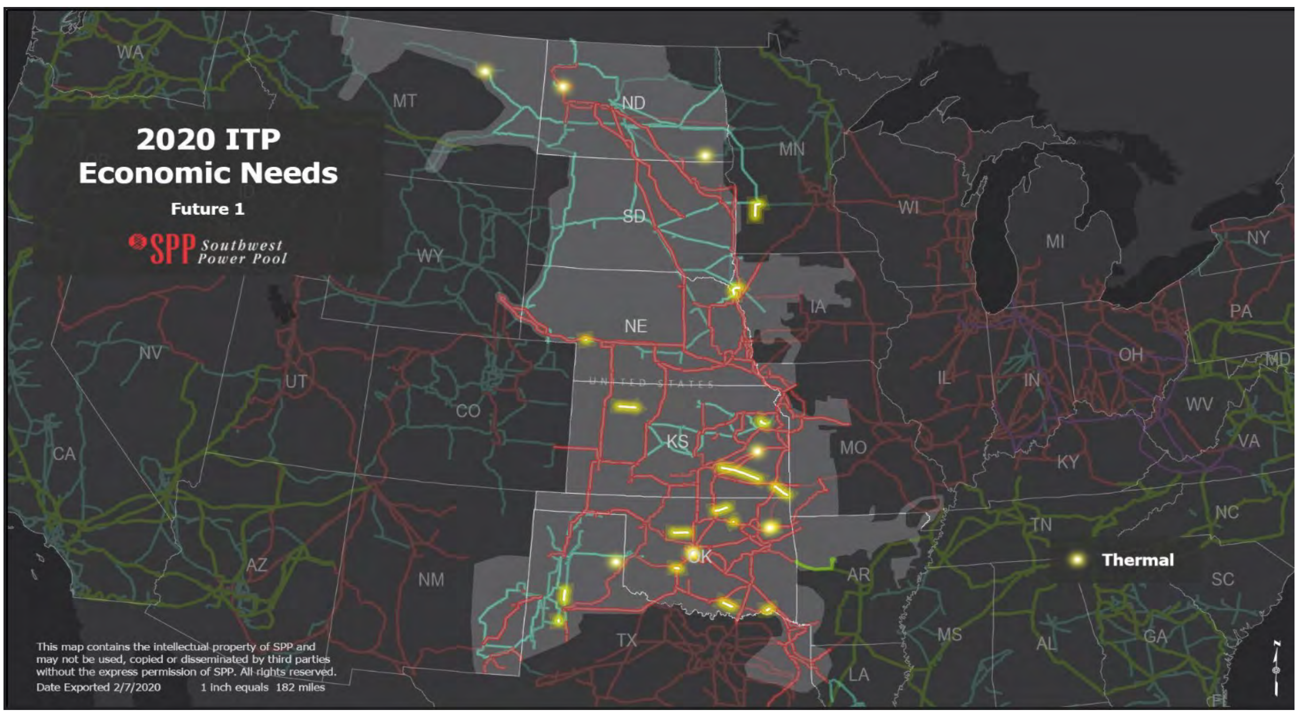

Figure 4.1: Future 1 Economic Needs

Constraint	2022 Congestion Score	2025 Congestion Score	2030 Congestion Score
Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV	471,640	742,822	1,104,558
Dover-Okeene 138 kV for the loss of Watonga Switch-Okeene 138 kV	249,849	273,418	878,571
Watford 230/115 kV transformer circuit 1 for the loss of Watford 230/115 kV circuit 2	129,827	160,785	368,343
SPSNMTIES	258,996	139,555	499,965
Neosho-Riverton 161 kV for the loss of Blackberry-Jasper 345 kV	2,112	2,362	204,967
Russett-South Brown 138 kV for the loss of Caney Creek-Little City 138 kV	-	73	198,136
Hugo-Valliant 138 kV for the loss of Valliant-Hugo 345 kV	24,557	50,251	188,163
Shamrock 115/69 kV transformer for the loss of Sweetwater-Chisholm 230 kV	44,005	93,937	179,494
Tecumseh Hill-Stull 115 kV for the loss of Lawrence Hill-Swissvale 230 kV	-	770	161,808
Ogallala (NPPD)-Ogallala (Tri-State)115 kV for the loss of Ogallala-Grant 115 kV	48,838	73,245	113,456
Kress-Hale 115 kV for the loss of Swisher-Tuco 230 kV	78,368	79,027	100,584
Hoxie-Beach 115 kV for the loss of Mingo-Setab 345 kV	-	49,405	98,913
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	279,083	190,546	98,374
Fort Peck 230/115 kV transformer for the loss of Fort Peck-Dawson County 230 kV	75,115	81,231	95,612
Franks-South Crocker 161 kV for the loss of Huben-Franks 345 kV	15,925	5,743	89,487
Cimarron 345/138 kV transformer circuit 1 for the loss of Cimarron 345/138 kV transformer circuit 2	12,499	47,521	86,676
Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1	64,087	67,792	74,697
Southwestern Station-Anadarko 138 kV for the loss of Anadarko-Gracemont 138 kV	417	17,625	57,225
Scottsbluff-Victory Hill 115 kV for the loss of Stegall-Stegall 230 kV	20,544	29,628	50,647

Constraint	2022 Congestion Score	2025 Congestion Score	2030 Congestion Score
GRDA 161/115 kV transformer circuit 2 for the loss of GRDA 345/161 kV transformer	10,033	19,668	50,109
Columbus East 230/115 kV transformer for the loss of Columbus East-Shell Creek 345 kV	2,288	34,138	49,182
Oahe-Sully Buttes 115 kV for the loss of Fort Thompson-Leland Olds 345 kV	-	35,036	48,119
Granite Falls-Marshall Tap 115 kV for the loss of Lyon Co. 345/115 kV transformer	24,845	29,070	47,526
Czech Hall-Cimarron 138 kV for the loss of Cimarron-Draper 345 kV	482	8,752	37,737
Sioux City-Twin Church 230 kV for the loss of Raun-Hoskins 345 kV	991	43,452	33,843
Kelly 161/115 kV for the loss of Kelly-Tecumseh Hill 161 kV	14,818	11,047	33,503
Skyline-Quail Creek 138 kV for the loss of Northwest-Arcadia	-	-	33,144
Warrensburg-Warrensburg Air Force Base 161 kV for the loss of Overton-Sibley 345 kV	9,803	9,806	29,644
MISO RDT	3,419	11,044	22,016
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	221,537	588,917	15,434
Webster-Wright 161 kV for the loss of Ledyard-Colby 345 kV	818	3,635	11,789
Kelly 161/115 kV for the loss of Tecumseh Hill 161/115 kV transformer	39	24	6,927
Fulton-Patmos 115 kV for the loss of Sarepta-Longwood 345 kV	10	383	5,752
Webster-Wright 161 kV for the loss of Grimes-Beaver Creek 345 kV	383	3,575	4,340
Raun-Tekamah 161 kV for the loss of Raun-S3451 345 kV	324	4,622	2,733
Split Rock 345/115 kV transformer circuit 10 for the loss of Split Rock 345/115 kV transformer circuit 11	81	620	2,712
Raun-S3451 115 kV for the loss of Grimes-Beaver Creek 345 kV	-	1,616	2,112
Fulton-Patmos 115 kV for the loss of Grimes-Crockett 345 kV	-	-	549

Constraint	2022 Congestion Score	2025 Congestion Score	2030 Congestion Score
Webster 161/115 kV transformer for the loss of Grimes-Beaver Creek 345 kV	-	26	324
Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV	71,873	125,031	-
Maryville (AECI)-Maryville 161 kV for the loss of Maryville-Nodway 161 kV	-	-	-
Fairbilt-Winn County 161 kV (Base Case)	-	-	-
Maryville (AECI)-Maryville 161 kV for the loss of Maryville-Creston 161 kV	-	-	-
Neosho-Riverton 161 kV for the loss of Blackberry-Blackberry North 345 kV	67,781	55,853	-
Blue River-Parkland 138 kV for the loss of Arbuckle-Arbuckle Blue River Tap 138 kV	-	-	-
Jameston-Valley 115 kV for the loss of Hankson-Wahpeton 230 kV	-	-	-
Maryville (AECI)-Maryville 161 kV for the loss of Gentry-Fairport 161 kV	-	-	-
Fairbilt-Winn County 161 kV for the loss of Huntley-Fairbilt 161 kV	-	-	-

Table 4.1: Future 1 Economic Needs

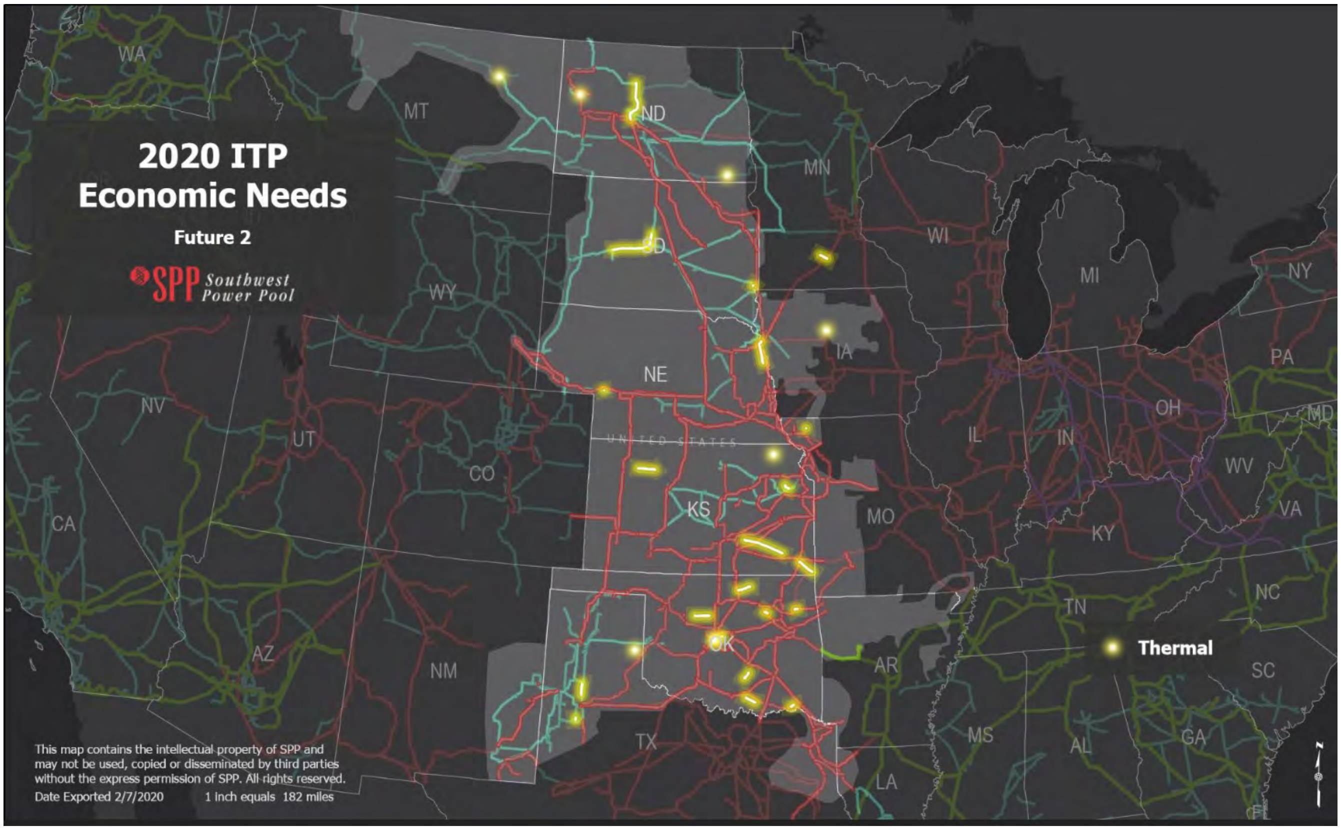

Figure 4.2: Future 2 Economic Needs

Constraint	2025 Congestion Score	2030 Congestion Score
Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV	1,037,096	985,274
Russett-South Brown 138 kV for the loss of Caney Creek-Little City 138 kV	224,826	522,446
Watford 230/115 kV transformer circuit 1 for the loss of Watford 230/115 kV circuit 2	188,501	356,741
SPSNMTIES	288,984	342,683
Dover-Okeene 138 kV for the loss of Watonga Switch-Okeene 138 kV	161,396	330,812
Neosho-Riverton 161 kV for the loss of Blackberry-Jasper 345 kV	5,406	294,608
Hugo-Valliant 138 kV for the loss of Valliant-Hugo 345 kV	134,545	274,983
Maryville (AECI)-Maryville 161 kV for the loss of Gentry-Fairport 161 kV	50,470	264,789
Fairbilt-Winn County 161 kV for the loss of Huntley-Fairbilt 161 kV	132,080	248,553
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	292,945	165,336
Shamrock 115/69 kV transformer for the loss of Sweetwater-Chisholm 230 kV	101,372	163,207
Raun-Tekamah 161 kV for the loss of Raun-S3451 345 kV	54,763	159,429

Constraint	2025 Congestion Score	2030 Congestion Score
Kress-Hale 115 kV for the loss of Swisher-Tuco 230 kV	69,276	146,036
Cimarron 345/138 kV transformer circuit 1 for the loss of Cimarron 345/138 kV transformer circuit 2	44,947	127,108
Oahe-Sully Buttes 115 kV for the loss of Fort Thompson-Leland Olds 345 kV	47,974	122,616
Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1	71,445	115,865
Split Rock 345/115 kV transformer circuit 10 for the loss of Split Rock 345/115 kV transformer circuit 11	21,941	104,407
Fort Peck 230/115 kV transformer for the loss of Fort Peck-Dawson County 230 kV	89,072	100,302
Czech Hall-Cimarron 138 kV for the loss of Cimarron-Draper 345 kV	20,066	91,094
Webster 161/115 kV transformer for the loss of Grimes-Beaver Creek 345 kV	64,431	87,329
Skyline-Quail Creek 138 kV for the loss of Northwest-Arcadia	181	86,046
Fairbilt-Winn County 161 kV (Base Case)	-	84,745
Tecumseh Hill-Stull 115 kV for the loss of Lawrence Hill-Swissvale 230 kV	8,535	80,935
Ogallala (NPPD)-Ogallala(Tri-State) 115 kV for the loss of Ogallala-Grant 115 kV	66,234	80,857
Hoxie-Beach 115 kV for the loss of Mingo-Setab 345 kV	35,723	76,020
Kelly 161/115 kV for the loss of Kelly-Tecumseh Hill 161 kV	39,759	73,301
Columbus East 230/115 kV transformer for the loss of Columbus East-Shell Creek 345 kV	41,254	71,847
MISO RDT	24,878	59,271
Blue River-Parkland 138 kV for the loss of Arbuckle-Arbuckle Blue River Tap 138 kV	-	58,860
Jameston-Valley 115 kV for the loss of Hankson-Wahpeton 230 kV	33,770	54,312
Maryville (AECI)-Maryville 161 kV for the loss of Maryville-Creston 161 kV	77,169	41,543
Franks-South Crocker 161 kV for the loss of Huben-Franks 345 kV	9,668	36,399
Scottsbluff-Victory Hill 115 kV for the loss of Stegall-Stegall 230 kV	17,080	34,387
Kelly 161/115 kV for the loss of Tecumseh Hill 161/115 kV transformer	227	25,582
Warrensburg-Warrensburg Air Force Base 161 kV for the loss of Overton-Sibley 345 kV	23,062	24,216
Webster-Wright 161 kV for the loss of Grimes-Beaver Creek 345 kV	13,979	20,086

Constraint	2025 Congestion Score	2030 Congestion Score
GRDA 161/115 kV transformer circuit 2 for the loss of GRDA 345/161 kV transformer	4,379	19,759
Southwestern Station-Anadarko 138 kV for the loss of Anadarko-Gracemont 138 kV	7,316	18,179
Granite Falls-Marshall Tap 115 kV for the loss of Lyon Co 345/115 kV transformer	17,005	17,400
Fulton-Patmos 115 kV for the loss of Sarepta-Longwood 345 kV	818	15,641
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	675,138	14,257
Sioux City-Twin Church 230 kV for the loss of Raun-Hoskins 345 kV	39,084	8,143
Webster-Wright 161 kV for the loss of Ledyard-Colby 345 kV	3,040	6,567
Fulton-Patmos 115 kV for the loss of Grimes-Crockett 345 kV	29	3,015
Raun-S3451 115 kV for the loss of Grimes-Beaver Creek 345 kV	6,005	2,192
Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV	162,158	-
Maryville (AECI)-Maryville 161 kV for the loss of Maryville-Nodway 161 kV	146,469	-
Neosho-Riverton 161 kV for the loss of Blackberry-Blackberry North 345 kV	73,449	-

Table 4.2: Future 2 Economic Needs

4.1.1 TARGET AREA

As part of the economic needs assessment, one target area was identified for the assessment to focus analysis efforts of SPP staff and stakeholders. After posting of the needs assessment, the need for additional analysis in another area of the system was identified by SPP staff. Drivers for these areas included:

- 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
- Impacted heavily by critical EHV contingencies
- Transient stability concerns for existing generators

4.1.1.1 MISO Regional Directional Transfer Target Area

The MISO Regional Directional Transfer (RDT) Target Area for the 2020 ITP aided SPP in regionally coordinated efforts to identify and evaluate potential transmission upgrades needed to mitigate impacts to the SPP transmission system due to transfers between the MISO Midwest and MISO South regions. SPP has historically seen congestion in the SPP footprint related to north-to-south flows within MISO. The flowgates that were identified as having the potential to meet these goals are shown in Figure 4.3 and listed in Table

4.3. SPP transmission facilities impacted by the exchange of power between MISO regions were evaluated as a target area with the potential for additional analysis in the 2020 ITP.

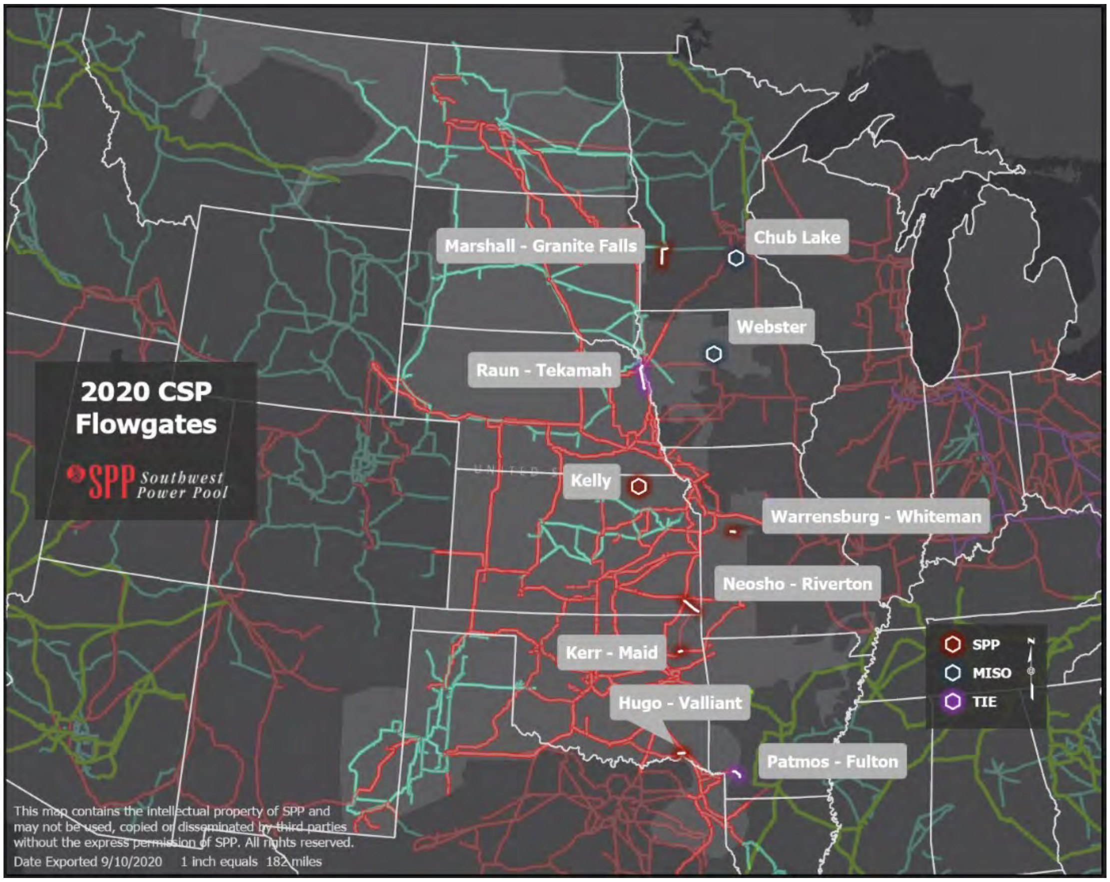

Figure 4.3: 2020 CSP Flowgates

CSP Target Flowgates
Raun-Tekamah 161 kV
Patmos-Fulton 115 kV
Chub Lake 345/115 kV transformer
Webster 345/115 kV transformer
Hugo-Valliant 138 kV
Kelly 161/115 kV transformer
Kerr-Maid 161 kV #2
Marshall-Granite Falls 115 kV
Neosho-Riverton 161 kV
Warrensburg-Whiteman AFB 161 kV

Table 4.3: MISO North CSP Interface Target Area Flowgates

4.1.2 SPS-NEW MEXICO TIES INTERFACE

The increased power flows into eastern New Mexico in SPS due to growing load and projected retirements has resulted in an increase in contingencies causing thermal and low voltage criteria and voltage collapse conditions in the initial and final base reliability and market power flow needs assessments. The SPS New Mexico Interface was added to the Market Economic Model post-constraint assessment to limit economic transfers and address voltage collapse observed in the development of the market economic model. This resulted in the SPSNMTIES interface being identified as a top congested economic need limiting economic transfer of energy into the area.

The 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. The intent of the interface is 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 (into southeastern New Mexico) to 765 MW for summer and winter seasons to 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 both system intact and loss of critical generation and 230 kV and 345 kV lines. SPS has three interfaces in the area to proxy non-thermal system limits and limit power transfer limits listed in Table 4.4 The interface congestion was identified as being related to:

- Base reliability powerflow models low voltage and voltage collapse needs in year-10 summer peak
- Market powerflow models Future 1 low voltage needs and voltage collapse needs in year-10 summer peak
- Market powerflow models Future 2 low voltage needs and voltage collapse needs in year-five summer peak

Supplemental information was posted with the needs assessment explaining the SPSNMTIES interface and outlined solution evaluation and additional analysis needed to aid stakeholders with their solution submittals. The New Mexico Ties Interface Guidelines and Study Scope 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.

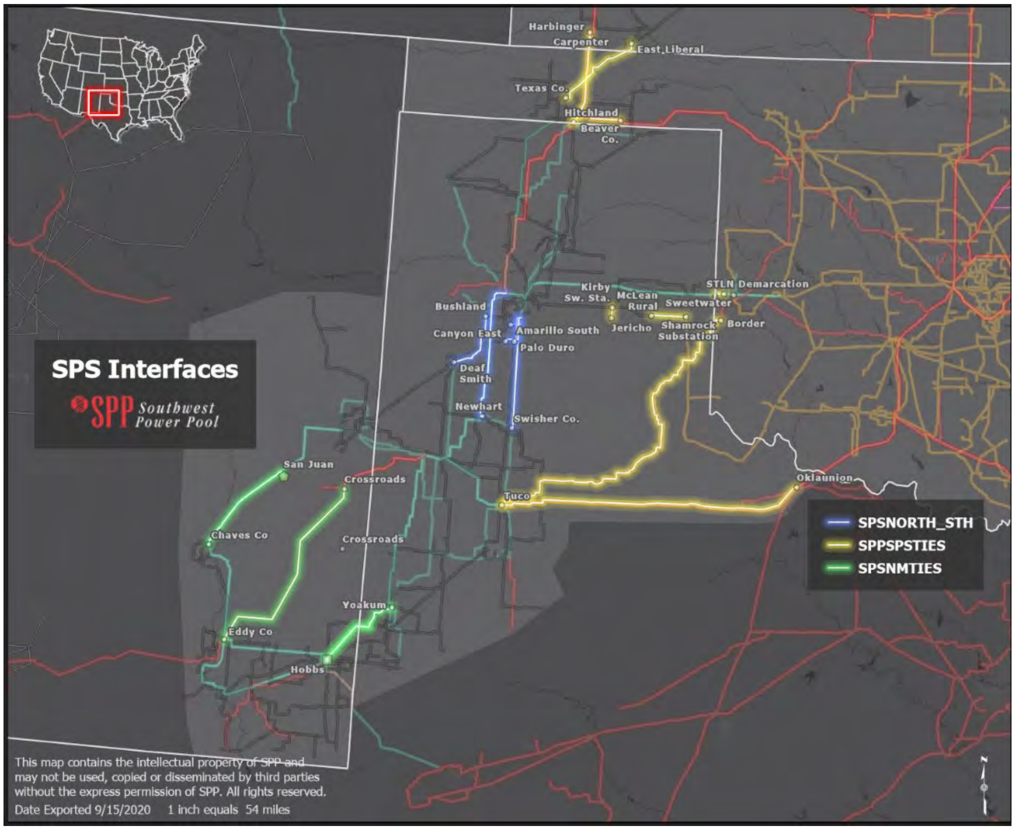

Figure 4.4: 2020 SPS New Mexico Ties Flowgates

Flowgate Interface		Limitation	
Name	**Definition**	**MW Flow**	**Directionality**
SPSNMTIES	San Juan Tap-Chaves County 230 kV	765	North-to-South
	Crossroads-Eddy County 345 kV		
	Ink Basin-Hobbs 230 kV		
	Yoakum-Hobbs 345 kV		
SPPSPSTIES	Border-Tuco 345 kV	1345	East-to-West
	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	1645	North-to-South
	Bushland-Deaf Smith 230 kV		
	Newhart-Potter County 230 kV		
	Randall-Canyon E Tap 115 kV		
	Randall-Palo Duro 115 kV		

Table 4.4: SPSNMTIES Interface Area Flowgates

4.2 RELIABILITY NEEDS

4.2.1 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, as well as remaining events that do not allow for non-consequential load loss or the interruption of firm transmission service.

During the needs assessment, potential violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, and identification of invalid contingencies, non-load-serving buses and facilities not under SPP's functional control. Figure 4.5 and Figure 4.6 summarize the number of remaining thermal and voltage needs[17] that were unable to be mitigated during the screening process.

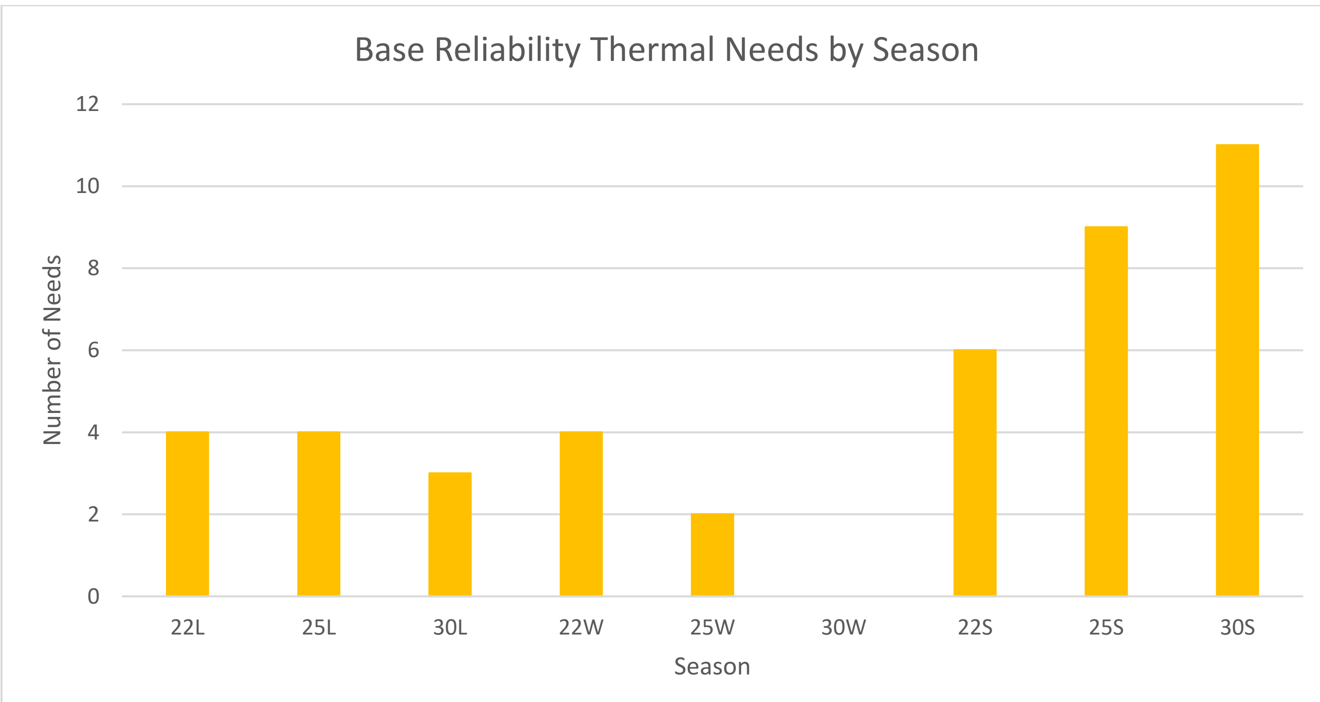

Figure 4.5: Unique Base Reliability Needs

[17] Figures summarize unique monitored elements.

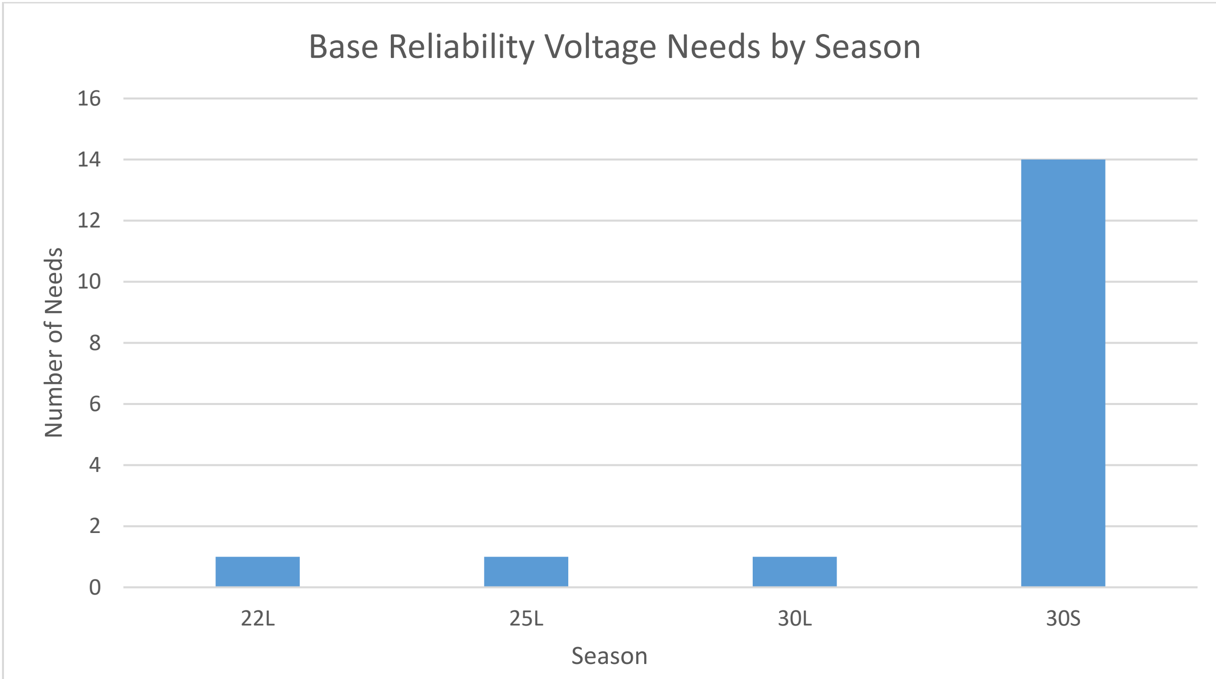

Figure 4.6: Unique Base Reliability Voltage Needs

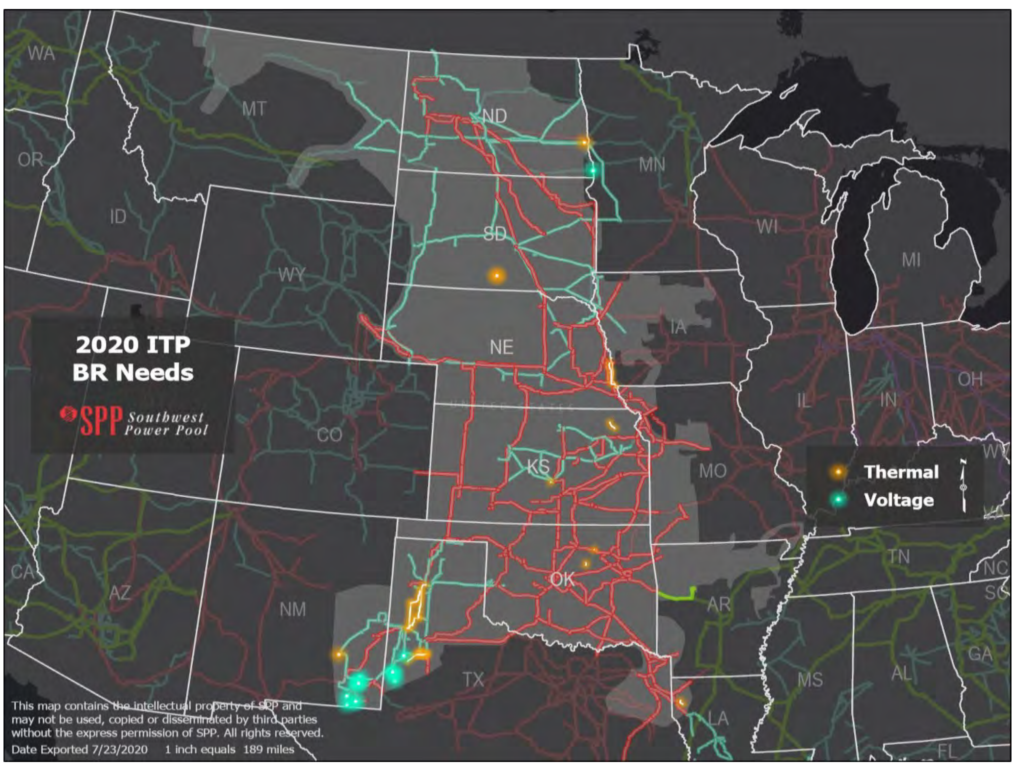

Figure 4.7: Base Reliability Needs

4.2.2 MARKET POWERFLOW ASSESSMENT

Contingency analysis for the market powerflow models was performed in accordance with the ITP Manual.

Figure 4.8 summarizes the number of remaining voltage needs[18] that were unable to be mitigated during the screening process. There were no thermal market powerflow model needs that were considered during the 2020 ITP.

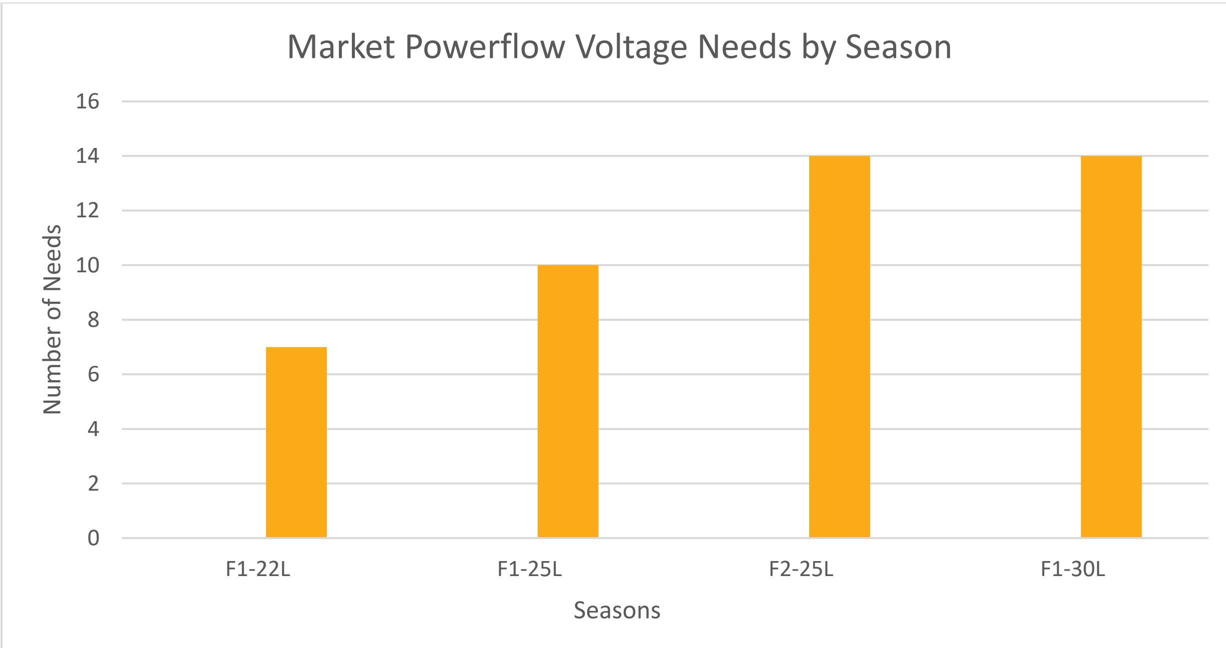

Figure 4.8: 2020 Market Powerflow Voltage Needs by Season

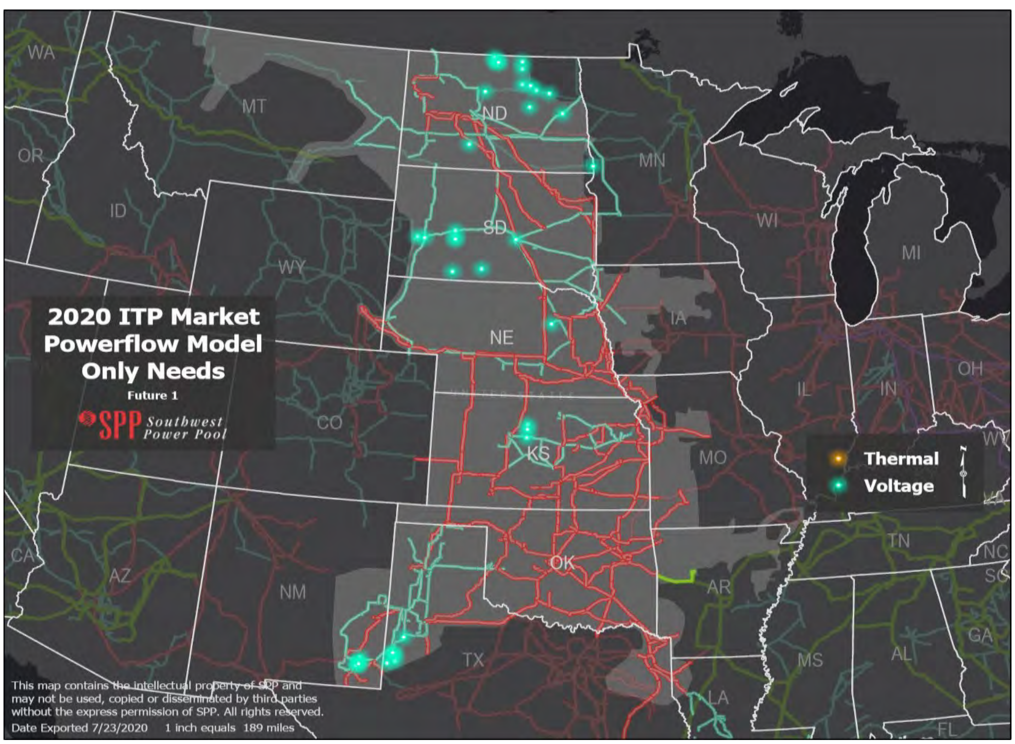

Figure 4.9: Future 1 Reliability Needs

[18] The figure summarizes the unique monitored elements per season.

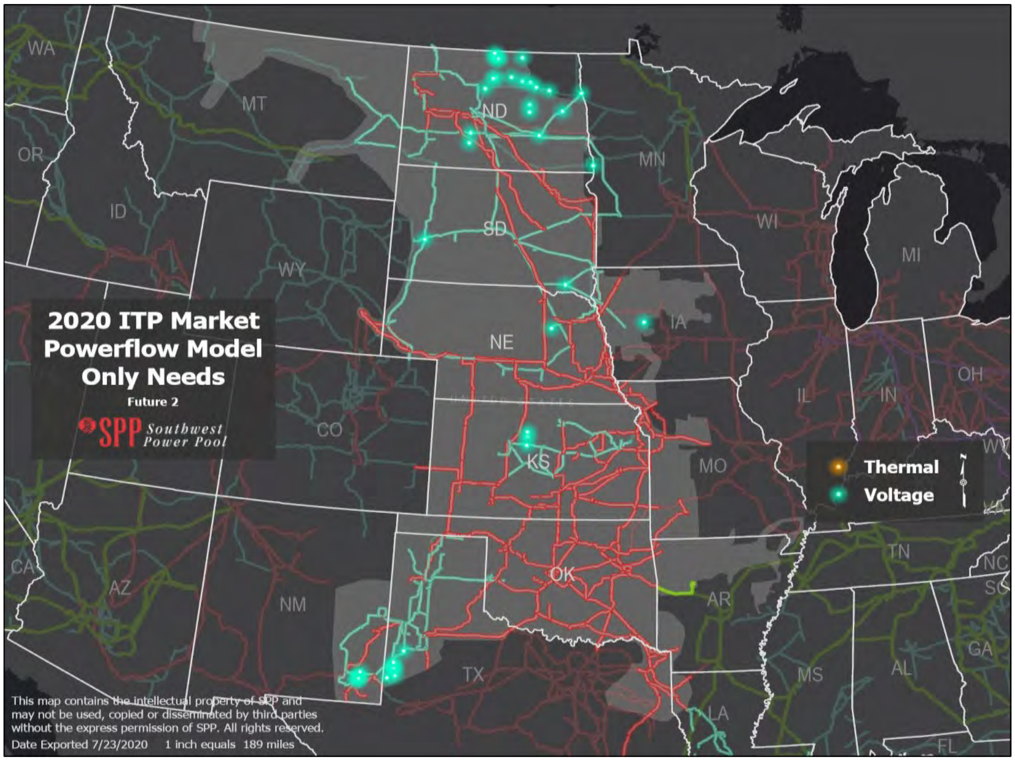

Figure 4.10: Future 2 Reliability Needs

4.2.3 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. Relative violations were identified as voltage collapse reliability needs in the applicable model and are listed in Table 4.5.

Model	Monitored Element	Contingent Element	Reliability Need
Base Reliability 2030 Summer Peak	Phantom 115 kV	Hobbs-Kiowa 345 kV	Voltage
Base Reliability 2030 Summer Peak	Phantom 115 kV	P53:345:SPS:EDDY-AT-FNC+	Voltage
Base Reliability 2030 Summer Peak	Phantom 115 kV	P42:345:SPS:KIOWA:J20####_SLG	Voltage
Future 2 2025 Summer Peak	Gaines 345 kV	Gaines Generator	Voltage
Future 1 2030 Summer Peak	Gaines 345 kV	Gaines Generator	Voltage
Future 2 2030 Summer Peak	Gaines 345 kV	Gaines Generator	Voltage

Table 4.5: Reliability Needs Resulting from Non-Converged Contingencies

4.2.4 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 Western Farmers Electric Cooperative (WFEC). The needs are depicted in Figure 4.11.

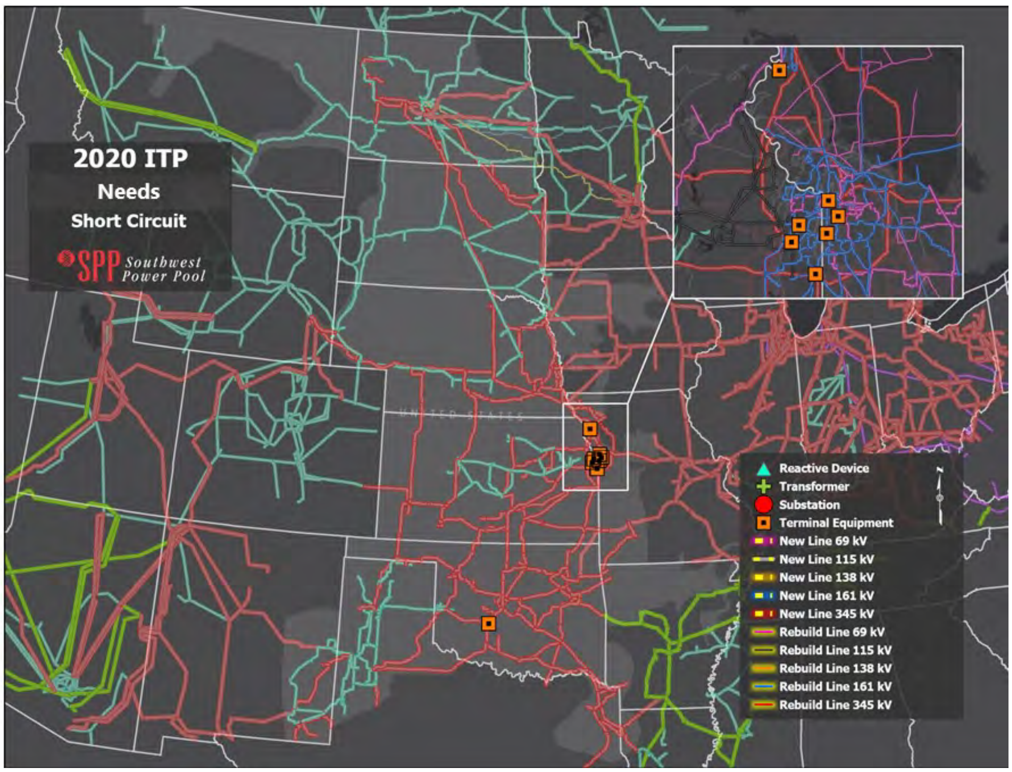

Figure 4.11: Short-Circuit Needs

4.3 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.

4.4 PERSISTENT OPERATIONAL NEEDS

4.4.1 ECONOMIC OPERATIONAL NEEDS

The economic operational needs identified for the 2020 ITP assessment in Table 4.6 through Table 4.8 were posted for informational purposes only.

Constraint	Monitored Element	Contingent Element	Congestion Cost
TMP421_24095	XF Cimarron 345/138 kV	XF Cimarron 345/138 kV	$52,090,959
FRAMIDCANCED	LN Midwest-Franklin 138 kV	LN Cedar Lane-Canadian 138 kV	$42,896,115
CHAWATCHAPAT TMP269_23661	LN Charlie Creek-Watford 230 kV	LN Charlie Creek-Patent Gate 345 kV	$24,968,600
SMOSUMMULCIR	LN Smoky Hills-Summit 230 kV	LN Great Bend-Circle 230 kV	$21,897,392
SCOVICSTESTG TMP127_23359	LN Scottsbluff-Victory Hill 115 kV	XF Stegall 345/230 kV	$18,063,559
TMP159_24149	LN Russett-South Brown 138 kV	LN Little City-Brown Tap 138 kV	$11,522,032

Table 4.6: Economic Operational Needs

The constraints in Table 4.7 had associated future upgrades which are expected to reduce some or all congestion associated with the constraint.

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
TMP142_25323 TMP39_23235	LN Waverly-La Cygne 345 kV	LN Caney River-Neosho 345 kV	$80,306,731	2019 ITP approved Wolf Creek-Blackberry 345 kV
TMP270_23432	Cleveland 138 kV GRDA-AECI Bus Tie	LN Cleveland-Tulsa North 345 kV	$53,229,005	ITP approved Sooner-Wekiwa 345 kV

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
GGS	LN Gentleman-Red Willow 345 kV LN Gentleman-Sweetwater 345 kV circuit 1 LN Gentleman-Sweetwater 345 kV circuit 2 LN Gentleman-North Platte 230 kV circuit 1 LN Gentleman-North Platte 230 kV circuit 2 LN Gentleman-North Platte 230 kV circuit 3	System Intact	$34,002,078	NTC for Gentleman-Cherry Co.-Holt 345 kV (2012 ITP10)
TMP109_22593	LN Stonewall-Tupelo 138 kV	LN Seminole-Pittsburg 345 kV	$31,746,284	NTC for Tupelo 138 kV terminal upgrades (July 2021, 2017 ITP10)
NEORIVNEOBLC	LN Neosho-Riverton 161 kV	LN Neosho-Blackberry 345 kV	$18,063,262	Neosho-Riverton 161kV rebuild (October 2023, ATSS SPP-2019-AG1-AFS-2)
TMP226_24352	LN Mathewson-Northwest 345 kV	LN Mathewson-Cimarron 345 kV	$14,806,741	2019 ITP approved terminal upgrades
TEMP89_22229	LN Anadarko-Gracemont 138 kV	LN Washita-Southwestern 138 kV	$14,786,648	2019 ITP approved Anadarko-Gracemont 138 kV circuit 1 Rebuild
WICXF2WICXF1	XF Wichita 345/138 kV circuit 2	XF Wichita 345/138 kV circuit 1	$13,212,822	2014 ITP Near-Term, Viola-Sumner County 138 kV
TEMP72_22893	LN Wolf Creek-Waverly 345 kV	XF Wolf Creek 345/69 kV	$11,353,483	2019 ITP approved Wolf Creek-Blackberry 345 kV

Table 4.7: Economic Operational Needs

The constraints in Table 4.8 had associated upgrades in place which have reduced or eliminated loading of the associated constraint.

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
SUNAMOTOLYOA	LN Sundown-Amoco 230 kV	LN Tolk-Yoakum 230 kV	$28,915,221	Terminal equipment upgrades (2016 ITPNT), has not loaded since ratings update on 12/19/19
VINHAYPOSKNO	LN Vine Tap-North Hays 115 kV	LN Postrock-Knoll 230 kV	$15,194,807	Parallel Postrock-Knoll 230 kV (2017 ITP10), has not loaded since completion of project Q4 2018
TMP151_23193	LN Oakland North-Atlas Junction 161 kV	LN Asbury-Purcell 161 kV	$13,426,140	Upgrade (Non-Public)

Table 4.8: Economic Operational Needs

4.4.2 RELIABILITY OPERATIONAL NEEDS

There were no reliability operational needs identified during the 2020 ITP assessment.

4.5 NEED OVERLAP

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

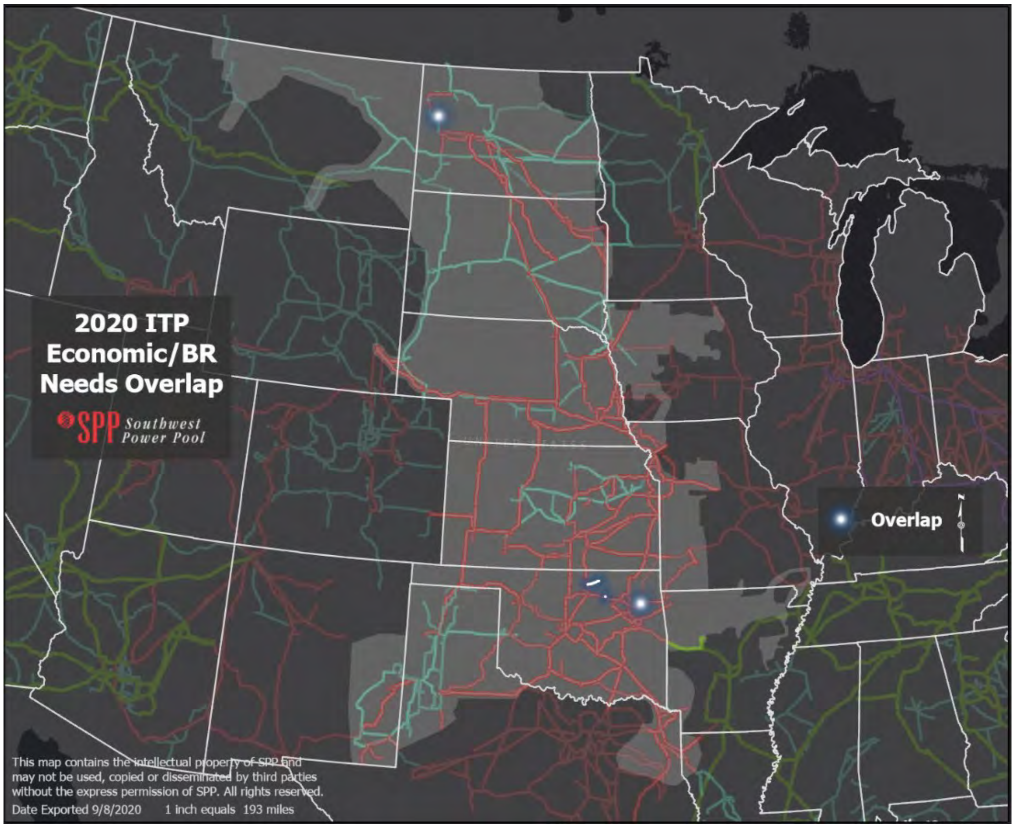

Figure 4.12: Base Reliability and Economic Need Overlap

Overlapping Reliability and Economic Needs
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV
Watford 230/115 kV transformer 1 for the loss of Watford 230/115 kV transformer 2
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV
GRDA 345/161 kV transformer 1 for the loss of GRDA 345/161 kV transformer 2

Table 4.9: Overlapping Reliability and Economic Needs

Overlapping Informational Operational and Economic Needs
Cimarron 345/138 kV transformer 1 for the loss of Cimarron 345/138 kV transformer 2
Scotts Bluff-Victory Hill 115 kV for the loss of Stegall 345/230 kV transformer
Russett-South Brown 138 kV for the loss of Little City-Brown Tap 138 kV
Neosho-Riverton 161 kV for the loss of Blackberry-Neosho 345 kV
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV

Table 4.10: Overlapping Informational Operational and Economic Needs

4.6 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.

4.6.1 GRIDLIANCE HIGH PLAINS

GridLiance High Plains (GLHP) performed its local planning process assessment in 2019 and identified two 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 2020 ITP assessment.

An analysis was performed to satisfy these obligations by determining the impact of including the proposed local planning process upgrades in the 2020 ITP base reliability and market powerflow model sets. After performing the no-harm study on the projects, two overload violations were identified as resultant of one the GLHP local planning projects. GridLiance then identified discrepancies between SPP's models and their internal models which had higher MVA capacity on the violated lines. The project in question was resubmitted with additional rating corrections and no further violations were discovered. Therefore, 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
Goodwell-Red Devil 115 kV line, Red Devil substation expansion, and Goodwell-Y-Road115 kV terminal equipment	16	Oklahoma Panhandle	2023
Winfield Tie 69 kV new substation,14.4 MVAR capacitor bank	8	Southern Kansas	2022

Table 4.11: Upgrades identified in GridLiance local planning assessment in 2019

5 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 staff, projects submitted in previous planning studies, and model adjustments/ corrections. MISO staff also provided a subset of solutions identified in the MTEP20 for evaluation in SPP models. SPP staff analyzed 1,577 Detailed Project Proposals (DPP) solutions received from stakeholders and approximately 626 SPP staff solutions (including those provided by MISO as well as additional solutions developed during portfolio development). SPP staff members developed a standardized conceptual cost template to calculate a conceptual cost estimate for each project to utilize during screening.

5.1 RELIABILITY PROJECT SCREENING

Solutions were tested in each powerflow model 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 Criteria and members' more stringent local planning criteria. Figure 5.1 illustrates the reliability project screening process.

Reliability metrics developed by SPP staff 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.

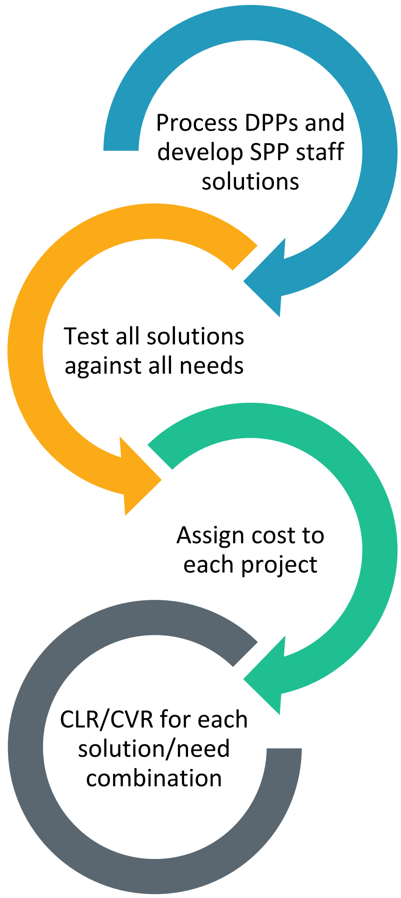

Figure 5.1: Reliability Screening Process

5.2 ECONOMIC PROJECT SCREENING

All solutions were evaluated for their economic performance to determine their effectiveness in mitigating transmission congestion in the study horizon. A one-year benefit-to-cost (B/C) ratio and a 40-year net present value (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 B/C ratio for each project. The one-year cost, or projected annual transmission revenue requirement (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 16.38 percent. The 40-year project cost is calculated using this NPCC, an eight percent discount rate and a 2.5 percent 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 under-stated.

5.3 SHORT-CIRCUIT PROJECT SCREENING

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

5.4 PUBLIC POLICY PROJECT SCREENING

No public policy needs were identified in the 2020 ITP; therefore, no projects were analyzed during the public policy project screening.

5.5 PERSISTENT OPERATIONAL PROJECT SCREENING

In October 2019, the MOPC approved a waiver of the requirement to evaluate solutions against the economic operational needs associated with flowgates in the 2020 ITP assessment due to identified software limitations. Due to this approved waiver, no projects were analyzed during persistent operational project screening.

6 PORTFOLIO DEVELOPMENT

6.1 PORTFOLIO DEVELOPMENT PROCESS

Figure 6.1 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.

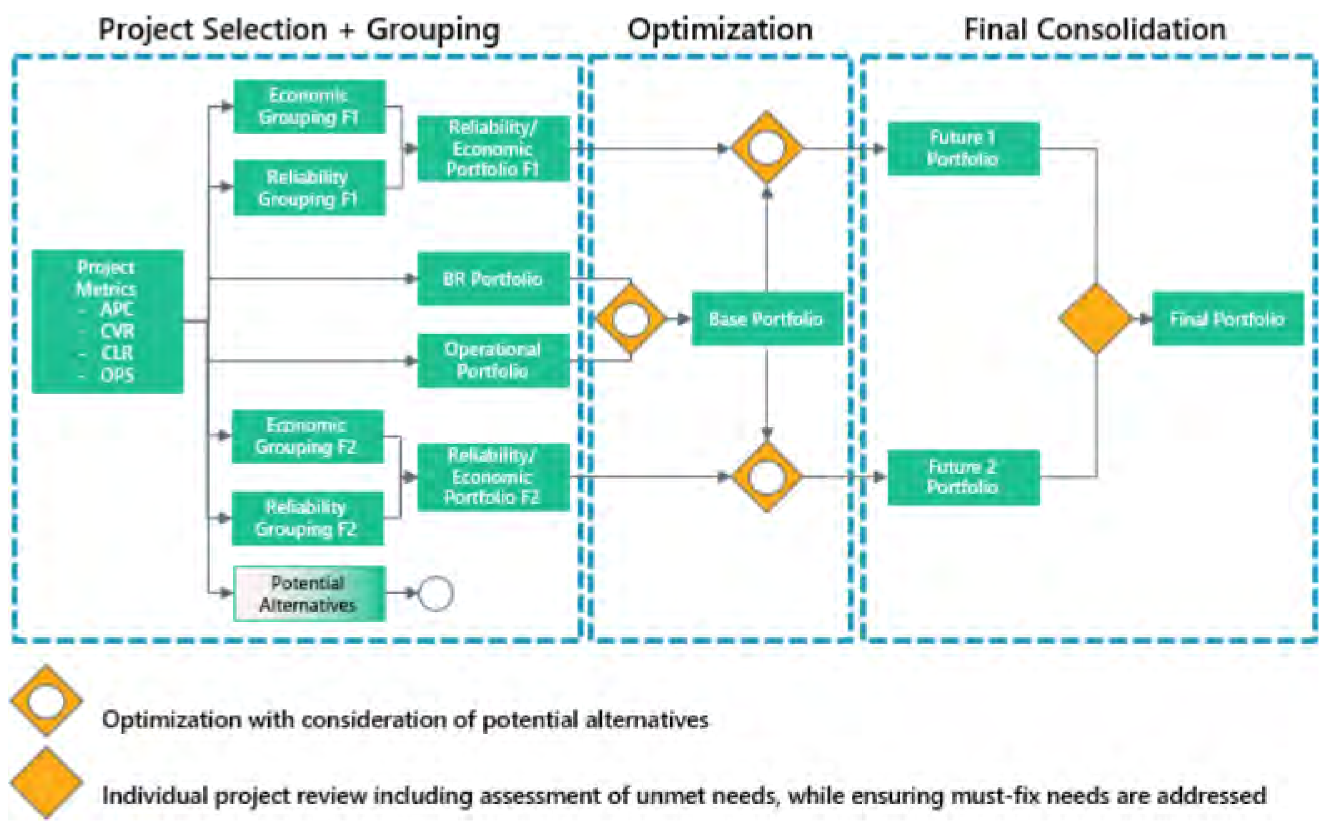

Figure 6.1: Portfolio Development Process

6.2 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 July 2020 SPP transmission planning summit, and SPP's Request Management System.

6.2.1 STUDY ESTIMATES

Solutions that performed well using the screening assessments described in section 5, Solution Development and Evaluation were sent out for the development of Study Estimates (final project cost within ±30 percent). In cases where the cost estimate was not received before the July 2020 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.

6.2.2 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 5.1. During this process, SPP staff 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. Figure 6.2 below shows the final reliability grouping selected to address the valid list of reliability needs in the 2020 ITP.

Project	Area	Cost	Scenario[19]
Grady 138 kV capacitor bank	AEPW	$688,781	22S / BR
South Shreveport-Wallace Lake 138 kV rebuild	AEPW	$23,622,577	25S / BR
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	OKGE	$5,362,799	25S / BR
S3456-S3458 345 kV terminal equipment	OPPD	$678,865	30S / BR
Allen-Lubbock South 115 kV rebuild	SPS	$6,817,226	22S / BR
Allen-Quaker 115 kV rebuild	SPS	$4,732,267	22S / BR
Bushland-Deaf Smith 230 kV terminal equipment	SPS	$923,938	22L / BR
Carlisle-Murphy 115 kV rebuild	SPS	$4,746,175	22S / BR
Deaf Smith-Plant X 230 kV terminal equipment	SPS	$2,100,196	22L / BR
Deaf Smith #6-Friona 115 kV rebuild	SPS	$12,626,190	22L / BR
Deaf Smith #6-Hereford 115 kV rebuild	SPS	$6,660,556	22L / BR
Eddy County-North Loving 345 kV new line	SPS	$64,422,600	30S / BR
Jones-Lubbock South 230 kV terminal equipment circuit 1	SPS	$666,728	30S / BR
Jones-Lubbock South 230 kV terminal equipment circuit 2	SPS	$397,668	30S / BR
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	SPS	$872,391	22S / BR
Maljamar 115 kV capacitor bank	SPS	$685,440	30S / F1
Newhart-Plant X 230 kV terminal equipment	SPS	$2,024,293	22L / BR
Newhart-Potter County 230 kV terminal equipment	SPS	$731,282	22L / BR
Replace Roswell 115/69 kV transformer #1	SPS	$2,777,743	22S / BR

[19] This is the earliest season.

Project	Area	Cost	Scenario[19]
Russell 115 kV capacitor bank	SUNC	$2,841,951	22S / F1,F2
Nixa-Nixa Espy 69 kV terminal equipment	SWPA	$91,147	25S / BR
Agate 115 kV reactor	WAPA	$571,200	22L / F1,F2
Bismarck 115 kV reactors	WAPA	$2,380,700	22L / BR,F2
Devil's Lake 115 kV reactor	WAPA	$1,190,000	22L / F1,F2
Moorehead 230 kV reactor	WAPA	$1,515,440	22S / F1,F2
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	WAPA	$11,394,000	22L / BR
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	WAPA	$3,562,780	22L / BR
Circleville-Goff 115 kV circuit 1 rebuild	WERE	$12,114,772	25S / BR
Goff-Kelly 115 kV rebuild	WERE	$7,108,395	25S / BR
Meadowlark-Tower 33 115 kV rebuild	WERE	$1,342,588	30S / BR

Table 6.1: Reliability Project Grouping

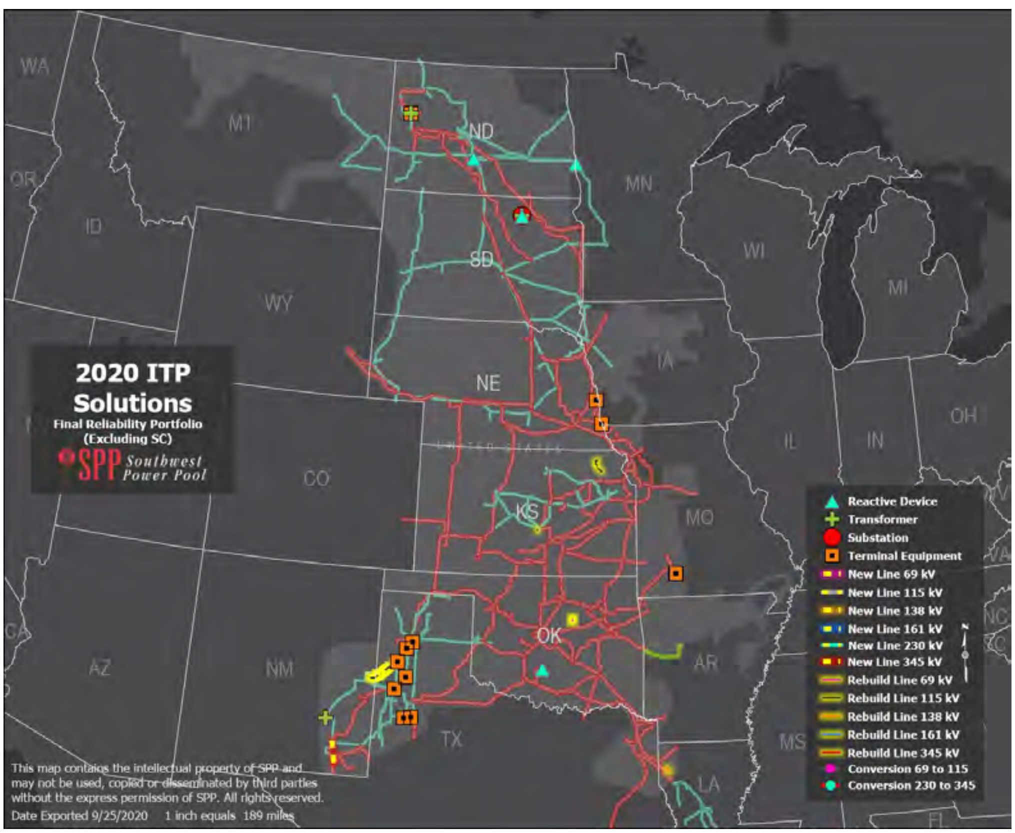

Figure 6.2: Reliability Project Grouping

6.2.3 SHORT-CIRCUIT GROUPING

The solutions submitted to address overdutied breakers 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 breaker upgrades only need to be rated higher than the maximum fault current identified in the needs assessment. Table 6.2 summarizes the final short-circuit grouping, while Figure 6.3 shows the approximate location of identified projects within the SPP footprint.

Reliability Project	Area	Cost	Scenario
Replace three breakers at Northeast 161 kV	KCPL	$887,479	22S / BR
Replace one breaker at Stilwell 161 kV	KCPL	$566,485	22S / BR
Replace one breaker at Leeds 161 kV	KCPL	$566,485	22S / BR
Replace one breaker at Shawnee Mission 161 kV	KCPL	$566,485	22S / BR
Replace one breaker at Southtown 161 kV	KCPL	$566,485	22S / BR
Replace two breakers at Lake Road 161 kV	KCPL	$1,132,970	22S / BR
Replace two breakers at Craig 161 kV	KCPL	$1,132,970	22S / BR
Replace four breakers at Anadarko 138 kV	WFEC	$850,000	22S / BR

Table 6.2: Short-Circuit Project Grouping

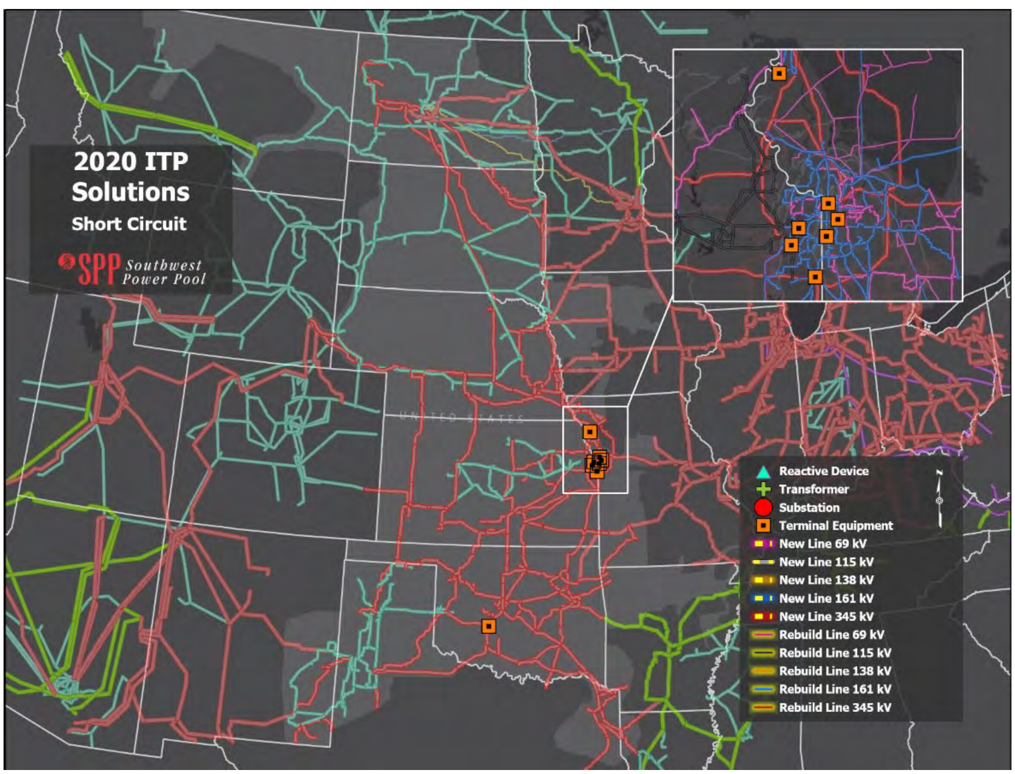

Figure 6.3: Short-Circuit Project Grouping

6.2.4 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 cost 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 6.3 identifies a comprehensive list of economic projects included in the four initial groupings. Some projects appeared in multiple groupings.

Project Description	F1		F2	
	CE	HN	CE	HN
Fort Peck 230/115 kV transformer replacement	X	X	X	X
Watford 230/115 kV transformer circuit 1 terminal equipment and circuit 2 replacement	X	X	X	X
Lyon 345/115 kV transformer replacement	X	X	X	X
Blue River-Parklane 138 kV terminal equipment	-	-	X	X
Russett-South Brown 138 kV rebuild	X	X	X	X
Kelly 161/115 kV terminal equipment	X	X	X	X
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	X	X	X	X

Project Description	F1 CE	F1 HN	F2 CE	F2 HN
Airport 115/69 kV substation and transformer, Airport-Sioux City 115 kV new line	-	-	X	X
Anadarko-Southwest Station 138 kV terminal equipment	X	X	-	-
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	X	X	-	-
Ogallala-Ogallala 115 kV terminal equipment	X	X	X	X
Hugo-Valliant 138 kV terminal equipment	X	X	X	X
Atwood-Colby 115 kV terminal equipment, Hoxie-Beach-Redline 115 kV terminal equipment	X	X	-	-
Columbus East 230/115 kV transformer replacement	X	X	X	X
Sioux City-Twin Church 230 kV terminal equipment	X	X	-	-
Franks-South Crocker-Lebanon 161 kV terminal equipment	X	X	X	X
Pleasant Valley 345/138 kV station, Pleasant Valley-Minco 345 kV new line	-	X	-	X
Cimarron South 345/138 kV station, Cimarron South-Minco 345 kV new line, Quail Creek-Skyline 138 kV rebuild, re-terminate nearby 345 and 138 kV lines into new station	X	-	X	-
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment	X	X	X	X
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal upgrades	X	X	X	X
Victory Hill-Scottsbluff 115 kV and Alliance-Snake Creek 115 kV rebuild	X	-	-	-
Second Stegall 345/230 kV transformer, Stegall-Stegall 230 kV new line, Alliance-Snake Creek 115 kV rebuild	-	X	-	-
Tecumseh Hill-Stull-Mockingbird 115 kV rebuild	X	X	X	X

Table 6.3: Economic Project Grouping

6.2.4.1 Project Subtraction Evaluation

Draft groupings were developed using project screening results, which tests projects by incrementally adding changes to the base market economic models. When assessing a group of economic solutions, it is necessary to re-evaluate project performance within the grouping to ensure the projected APC benefit of each project in the grouping remains supportive of the required B/C ratio thresholds. "Subtraction evaluation" is 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 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 was repeated for each grouping until all remaining projects maintained a minimum B/C ratio of 1.0 over 40 years.

6.2.4.2 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 grouping was selected for Future 1, while the highest net grouping was selected for Future 2. Table 6.4 shows the final list of projects included in each grouping.

Description	F1 CE	F1 HN	F2 CE	F2 HN
Arbuckle-Blue River 138 kV terminal equipment	-	-	X	-
Fort Peck 230/115 kV transformer replacement	-	X	-	-
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	X	X	X	X
Blue River-Parklane 138 kV terminal equipment	-	-	X	-
Anadarko-Gracemont 138 kV rebuild as double-circuit	X	X	X	-
Russett-South Brown 138 kV rebuild	X	X	X	X
Kelly 161/115 kV terminal equipment	-	-	X	-
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	X	X	X	X
GRDA 1 345/161 kV circuit 1 & circuit 2 terminal equipment	X	X	X	-
Hugo-Valliant 138 kV terminal equipment	-	-	X	-
Columbus East 230/115 kV transformer replacement	-	X	X	-
Split Rock 345/115 kV circuit 10 and 11 terminal equipment	-	-	X	X
Franks-South Crocker-Lebanon 161 kV terminal equipment	X	X	-	-
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	X	X	-	X
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	-	-	-	X
Oahe-Sully Buttes-Whitlock-Glenham-Campbell 230 kV terminal equipment	-	X	X	-
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal upgrades	X	X	X	X
Cimarron 345/138 kV circuit 3 Transformer, Cimarron-Czech Hall 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment	X	-	X	-
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	-	X	-	X
Anadarko-Gracemont 138 kV rebuild; Anadarko-Southwest Station 138 kV terminal equipment	-	-	-	X

Table 6.4: Final Economic Project Grouping

Figure 6.4 and Figure 6.5 show the approximate location of identified projects within the SPP footprint.

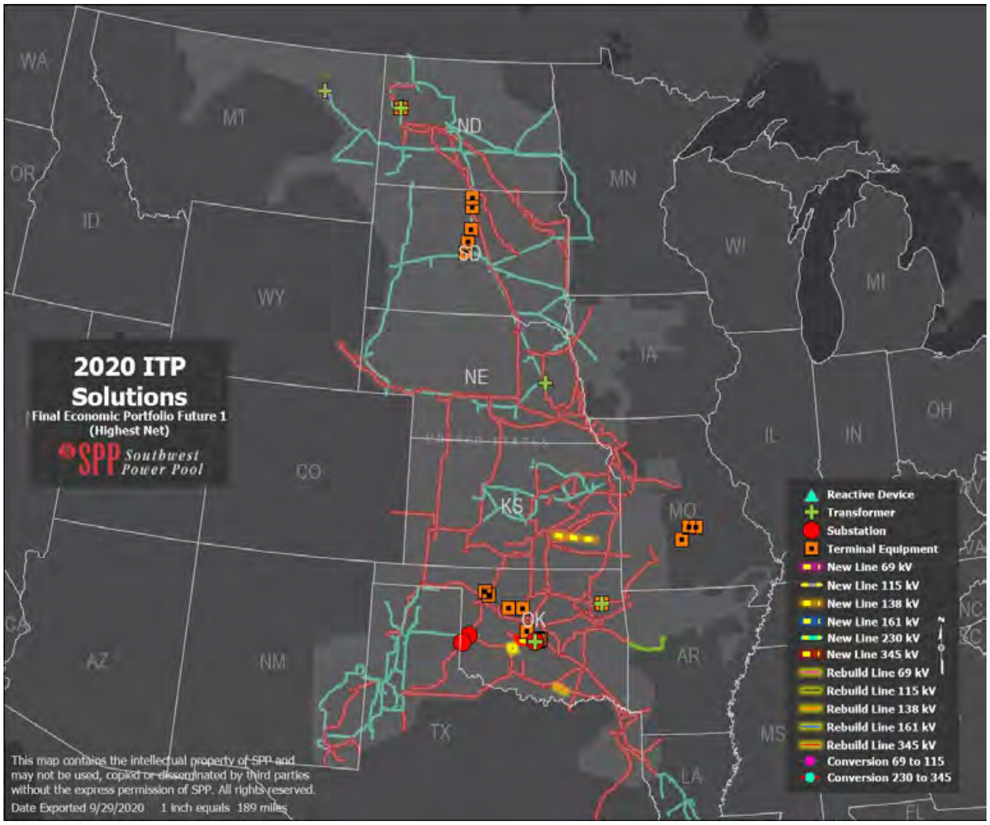

Figure 6.4: Final Project Groupings-Future 1-Highest Net

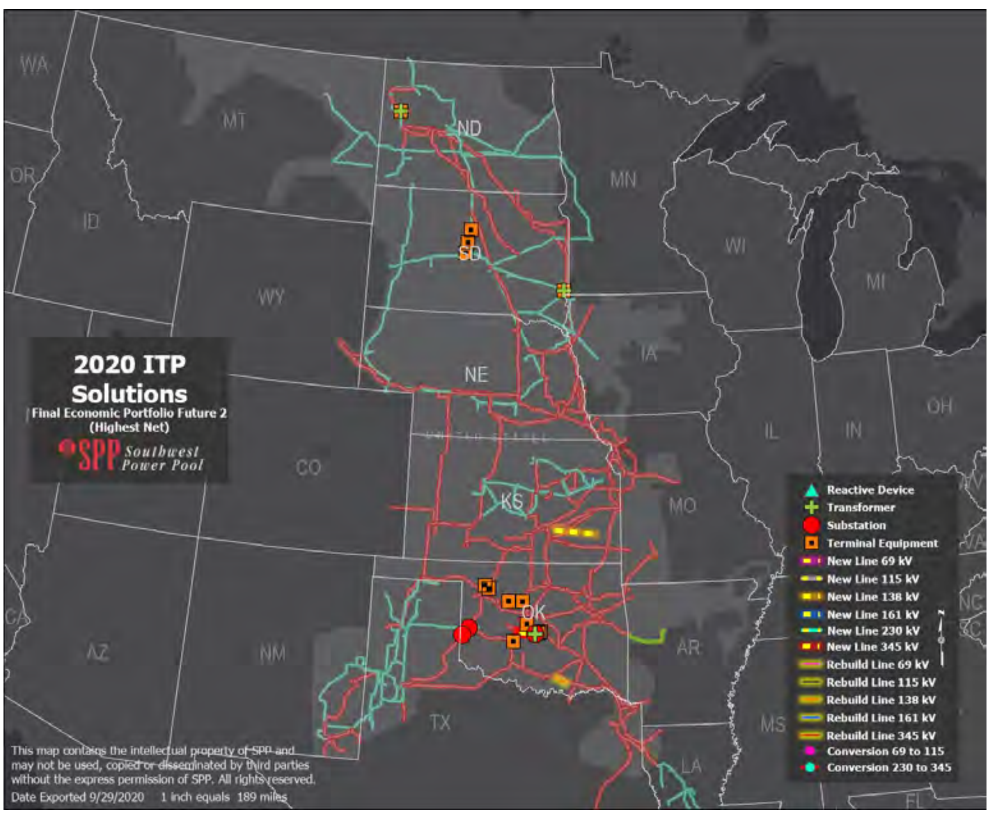

Figure 6.5: Final Groupings-Future 2-Highest Net APC

Table 6.5 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 in each future was selected as the future's final portfolio.

Grouping	Y5 Benefit ($M)	Y10 Benefit ($M)	40-Year Benefit ($M)	40-Year NPV Cost ($M)	40-Year Net Benefit ($M)	Y5 B/C	Y10 B/C	40-Year B/C	Selected Portfolio
F1 CE	$55.7	$82.6	$1,528	$352.3	$1,176	1.50	2.22	4.34	
F1 HN	$63.4	$97.8	$1,821	$514.7	$1,306	1.17	1.80	3.54	X
F2 CE	$60.7	$106.2	$2,012	$316.1	$1,696	1.82	3.19	6.36	
F2 HN	$83.5	$131.8	$2,462	$474.3	$1,987	1.67	2.64	5.19	X

Table 6.5: Final Groupings-Benefit Cost, Net Benefits, and B/C Ratios

Figure 6.6 shows a 40-year B/C comparison of all the final groupings.[20]

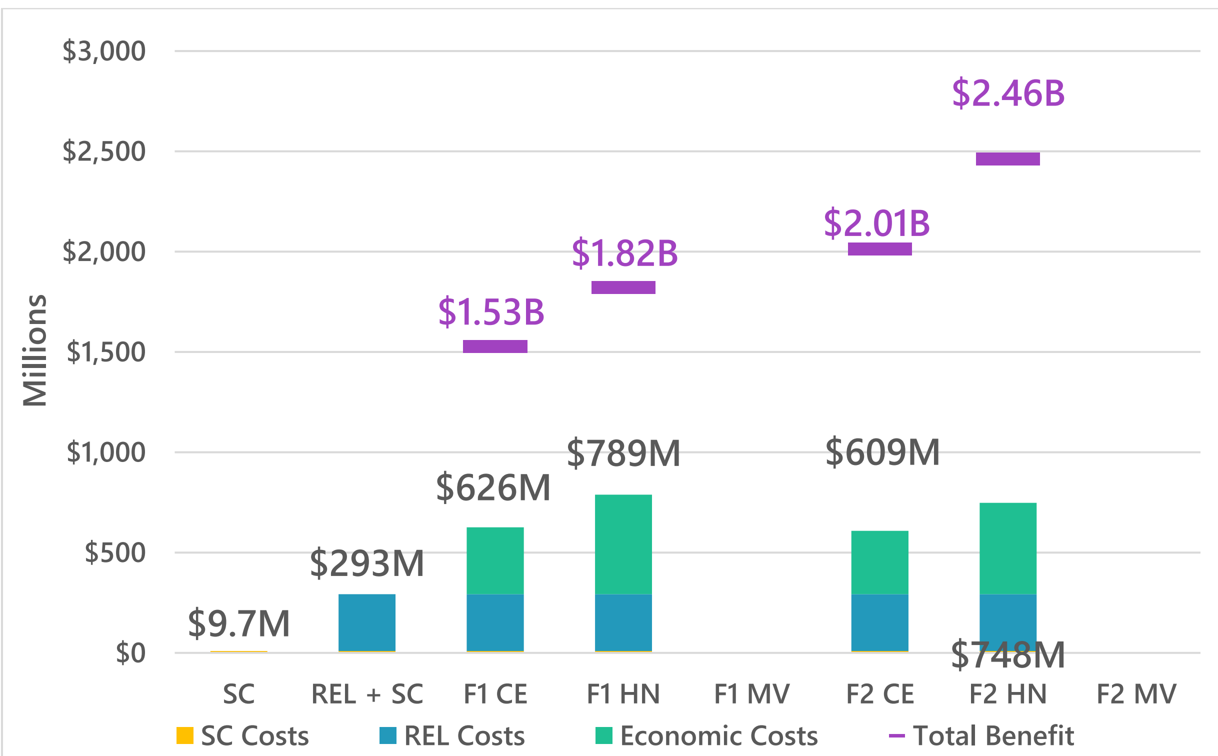

Figure 6.6: Final Groupings-Benefits and Costs Comparison

6.2.5 MISO RDT TARGET AREA

In order to mitigate impacts to the SPP transmission system due to transfers between the MISO Midwest and MISO South regions, a number of projects were considered. The flowgate that showed the greatest potential benefit to both MISO and SPP was the Raun-Tekamah 161 kV. Three of the foremost projects

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

during the analysis period were a new Raun-Council Bluffs 345 kV line, a new Raun-S3452 345 kV line, and a new Raun-S3451 345 kV line. These projects would create a strong corridor to alleviate constraints on the Raun-Tekamah flowgate. Figure 6.7 shows the approximate locations of identified projects.

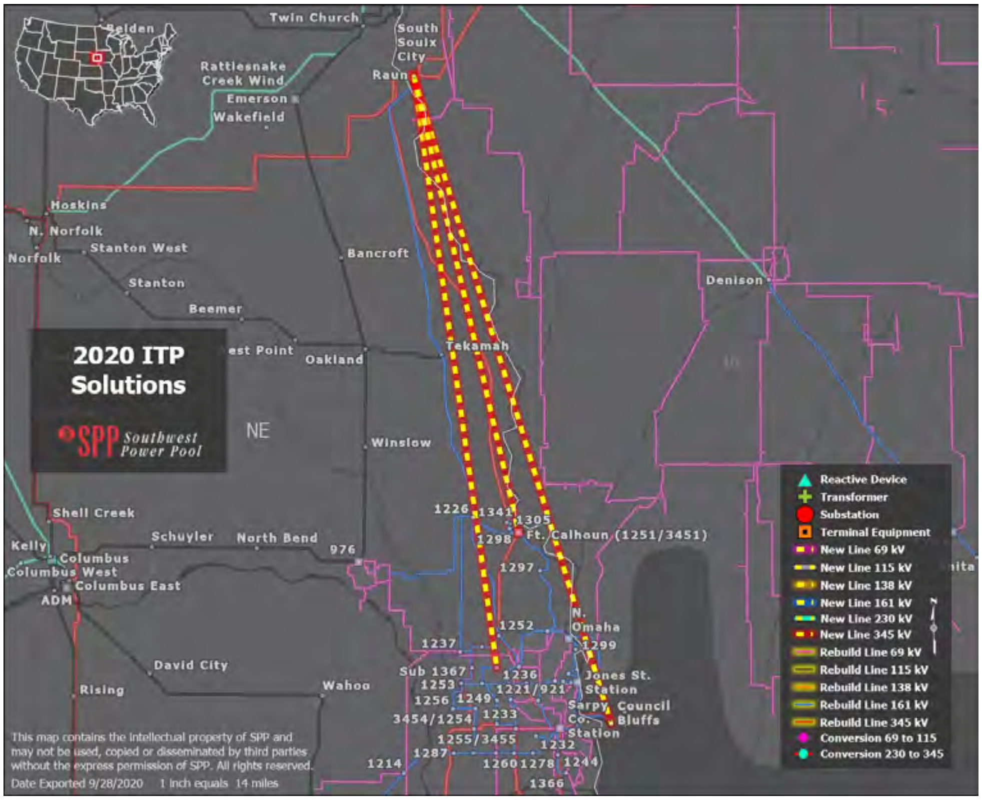

Figure 6.7: Potential SPP-MISO CSP Solutions

For a summary of SPP project cost, MISO and SPP benefits, and interregional cost sharing, see the information presented at the September 25, 2020 MISO-SPP IPSAC net conference.[21]

Due to differing methodologies between MISO and SPP when calculating benefits and project costs, the two RTOs decided not to pursue any projects in this area as part of the 2020 ITP. SPP is further investigating the differences in cost estimation, but did not have the time remaining in the schedule to address these differences in the 2020 ITP. These projects will continue to be investigated in future studies.

6.2.6 SPS-NEW MEXICO TIES INTERFACE

It was understood by SPP staff and communicated to stakeholders that the SPSNMTIES Interface would require a comprehensive solution to increase import capability into eastern New Mexico and sufficiently address system low voltage and voltage stability limits to support increased transfers of economic energy. Additional portfolio development considerations should also be given to the significant 702 MW combined

[21] CSP results for Raun-Council Bluffs and Raun-S3451 were presented at 09/25/2020 MISO-SPP IPSAC Net Conference (https://www.spp.org/Documents/63046/SPP-MISO%20IPSAC%20Meeting%20Materials%2020200925.zip)

cycle conventional resource plan unit and associated generator outlet facility[22] assumed in the eastern New Mexico area.

The transmission solutions screened included numerous combinations of existing reactive setting and configuration adjustments, new static and dynamic reactive devices, and additional HV and EHV facilities extending beyond the Eastern New Mexico area. Reliability project screening on AC power transfer models, results from the New Mexico Ties Interface Guidelines, and the study scope were used to identify top ranked solutions needing further review. Preliminary ranking results produced high-cost projects ranging from greater than $100 million to greater than $700 million to address system criteria violations for seven incremental transfer levels tested and resulting new interface ratings. Before further review of these preliminary results and additional solution evaluation, a relaxation run was performed on the SPSNMTIES interface by removing the constraint to determine potential APC Savings benefit and potential minimum project cost that would result in a 40-year NPV B/C ratio of at least 1.0.

	Y5 Benefit ($M)	Y10 Benefit ($M)	40-Year Benefit ($M)	40-Year B/C	Project Cost ($M)
F1	$57.6	$82.7	$1,317	1.00	$749.0
F2	$188.0	$120.9	$1,481	1.00	$842.7

Table 6.6: Potential APC Savings Benefit and Project Cost ($2025 Dollars)

The potential APC savings indicated that the high cost projects identified in the preliminary ranking results may prove to be economically justified and support further solution evaluation efforts. However, given ITP schedule, resource constraints and the complex nature of the solution evaluation needed by SPP staff and stakeholders to address the interface congestion, it was determined to delay any action on the congested interface to future ITP cycles and focus efforts on resolving the base reliability and market powerflow model reliability needs in eastern New Mexico.

Ultimately, no firm project selection was made for the economic issues.

6.3 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.

[22] The generator outlet facility identified for the 702 MW combined cycle conventional resource plan unit sited at the Sidewinder site can be found in Table 2.4. Both resource plan unit and generator outlet facility have load serving and economic energy delivery qualities and would be part of a comprehensive solution unless a transmission only solution proved overwhelmingly cost-beneficial without the combined cycle conventional resource plan unit assumed in the Eastern New Mexico Area.

One project, the upgrades of both Watford 230/115 kV transformers, was identified in both the reliability and economic portfolios. Additional economic project subtraction analysis performed to determine the impact of the base reliability portfolio identified the removal of the Fort Peck 230/115 kV transformer replacement from the Future 1 portfolio. No impact to the reliability portfolio was identified.

6.4 PORTFOLIO CONSOLIDATION

Stakeholders determined the two futures assessed in the 2020 ITP would be treated equally to determine the consolidated portfolio. When determining whether projects should move forward into the consolidated portfolio, three scenarios could occur:

1. The same project was identified in each future,
2. Two projects were competing against each other, or
3. A single project was identified in only one future.

If the same project was identified in both futures, that project would move forward into the consolidated portfolio. For the remaining scenarios, an independent method was necessary to assess each project and determine which, or if, those projects should move forward in the process.

To evaluate these scenarios, SPP and its stakeholders developed a comprehensive scoring rubric considering both quantitative and qualitative metrics. Quantitative metrics included APC and the percentage of congestion relieved. Qualitative metrics included giving credit to projects able to address operational congestion or non-thermal issues. Table 6.7 details the scoring rubric as well as some of the minimum criteria projects had to meet to receive points. SPP staff and stakeholders agreed that although this scoring methodology is a good way to measure a project's effectiveness, it should not be the only input to project selection. Stakeholders and SPP staff agreed a project narrative might be necessary when a preferred project is recommended against the results of the consolidation process.

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 2020 ITP Scope.

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 6.7: Consolidated Portfolio Scoring Consolidation Scenario One

Six 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:

- Russett-South Brown 138 kV rebuild
- Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV
- Franks-South Crocker-Lebanon 161 kV terminal equipment
- Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line
- Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment
- Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in

6.4.1 CONSOLIDATION SCENARIO TWO

Consolidation scenario two occurred when a different project was identified to solve the same or similar economic needs in each future. When this scenario occurred, it was clear a project was needed to address congestion in the models, but the consolidation methodology would be used to identify the better project. For this scenario, the scoring rubric identified in Table 6.7 was used to score the projects and determine which project should move forward into the consolidated portfolio.

In the 2020 ITP, two instances of scenario two occurred. These instances and their scoring are detailed in Table 6.8 and Table 6.9. Winning projects based on the consolidation scoring are shown in bold.

Project	Driving Future	APC Benefit	Congestion Relieved	Operational Congestion	New EHV	Non-Thermal	Long-term Viability	Total
Oahe-Sully Buttes-Whitlock-Glenham-Campbell 230 kV terminal equipment	1	0	20	0	0	0	0	20
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	**2**	**50**	**20**	**0**	**0**	**0**	**0**	**70**

Table 6.8: Consolidation Scenario Two Scoring

Project	Driving Future	APC Benefit	Congestion Relieved	Operational Congestion	New EHV	Non Thermal	Long-term Viability	Total
Anadarko-Gracemont 138 kV rebuild as double-circuit	1	46.2	20	10	0	0	0	76.2
Anadarko-Gracemont rebuild, Anadarko-Southwest Station terminal equipment 138 kV	**2**	**50**	**17.9**	**10**	**0**	**0**	**0**	**77.9**

Table 6.9: Consolidation Scenario Two Scoring

Although the Gracemont-Anadarko rebuild and Southwest Station-Anadarko terminal equipment scored higher, SPP staff recommended moving forward with the Gracemont-Anadarko double-circuit instead of the rebuild recommended by the scoring. The single circuit rebuild of Anadarko-Gracemont did not fully resolve the congestion in the area (hence the 17.9 vs. 20 score for that consideration), and SPP staff concluded that congestion in the area will continue to increase. The double circuit resolves the congestion fully, while also provides an additional path from the 345 kV hub at Gracemont. For these reasons, SPP staff recommended the double circuit instead.

6.4.2 CONSOLIDATION SCENARIO THREE

Consolidation scenario three occurred when a project was identified in only one of the two final future portfolios. When this situation occurred, the question remained whether a project driven by a single future should ultimately be recommended. For this scenario, the scoring rubric was used as a way to identify if a project should be included in the consolidated portfolio by achieving a minimum score of 70 points. Projects that did not meet the minimum scoring threshold but were recommended to be included have additional qualitative information justifying their inclusion.

GRDA 345/161 kV Transformer

The GRDA 345/161 kV transformer replacement originated from the Future 1 portfolio. The project performed well when compared to expected congestion in both futures, as well as resolved current operational needs. Therefore, the transformer replacement was added to the final portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	19.9
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	10
4	New EHV	7.5	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)		**79.9**

Table 6.10: GRDA 345/161 kV transformer Consolidation Scoring

Columbus East 230/115 kV transformer

The Columbus East transformer replacement also originated from the Future 1 portfolio. This project did well in both futures while also addressing current operational congestion, ultimately resulting in inclusion in the final portfolio.

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

No.	Consideration	Possible Points	Project Score
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	9
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)	**79**

Table 6.11: Columbus East 230/115 kV transformer Consolidation Scoring

Lebanon-Franks-Crocker 161 kV terminal equipment

The Lebanon-Franks-Crocker 161 kV terminal equipment upgrade also originated from the Future 1 portfolio. This project did well in both futures, but did not address any current operational needs. It also did not qualify for additional points via considerations 4 through 6. However, it did reach the minimum threshold of 70 points, resulting in final portfolio inclusion.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**70**

Table 6.12: Lebanon-Franks-Crocker 161 kV terminal equipment Consolidation Scoring

Split Rock 345/115 kV Transformer

The Split Rock 345/115 kV transformer originated from the Future 2 portfolio. This project did well in both futures. However, it did not qualify for any points from considerations 3 through 6 and did not reach the 70 point threshold. It did not resolve any operational congestion within the two-year span (6/1/2018-6/1/2020) considered for consolidation. However, the Split Rock transformer began experiencing congestion after that time period. Due to this fact, SPP staff chose to include that congestion in consideration 3.

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

No.	Consideration	Possible Points	Project Score
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	19.9
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0.1
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)		**70**

Table 6.13: Lebanon-Franks-Crocker 161 kV terminal equipment Consolidation Scoring

6.5 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 $500.2M and is projected to create $1B to $2B in APC savings under Future 1 or Future 2 assumptions, respectively. **Error! Reference source not found.** 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.

Project	Classification	Project Cost (2020$)
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	Reliability	$3,562,780
Circleville-Goff 115 kV circuit 1 rebuild	Reliability	$12,114,772
Goff-Kelly 115 kV rebuild	Reliability	$7,108,395
South Shreveport-Wallace Lake 138 kV rebuild	Reliability	$23,622,577
Grady 138 kV capacitor bank	Reliability	$688,781
Deaf Smith #6-Hereford 115 kV rebuild	Reliability	$6,660,556
Deaf Smith #6-Friona 115 kV rebuild	Reliability	$12,626,190
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	Reliability	$11,394,000
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	Reliability	$5,362,799
Bushland-Deaf Smith 230 kV terminal equipment	Reliability	$923,938
Newhart-Potter County 230 kV terminal equipment	Reliability	$731,282
Carlisle-Murphy 115 kV rebuild	Reliability	$4,746,175
Replace Roswell 115/69 kV transformer	Reliability	$2,777,743
S3456-S3458 345 kV terminal equipment	Reliability	$678,865
Meadowlark-Tower 33 115 kV rebuild	Reliability	$1,342,588
Jones-Lubbock South 230 kV terminal equipment circuit 1	Reliability	$666,728
Jones-Lubbock South 230 kV terminal equipment circuit 2	Reliability	$397,668

Project	Classification	Project Cost (2020$)
Deaf Smith-Plant X 230 kV terminal equipment	Reliability	$2,100,196
Newhart-Plant X 230 kV terminal equipment	Reliability	$2,024,293
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	Reliability	$872,391
Allen-Lubbock South 115 kV rebuild	Reliability	$6,817,226
Allen-Quaker 115 kV rebuild	Reliability	$4,732,267
Eddy County-North Loving 345 kV new line	Reliability	$64,422,600
Bismarck 115 kV reactors	Reliability	$2,380,700
Moorehead 230 kV reactor	Reliability	$1,515,440
Russell 115 kV capacitor bank	Reliability	$2,841,951
Maljamar 115 kV capacitor bank	Reliability	$685,440
Devil's Lake 115 kV reactor	Reliability	$1,190,000
Agate 115 kV reactor	Reliability	$571,200
Replace four breakers at Anadarko 138 kV	Short Circuit	$850,000
Replace three breakers at Northeast 161 kV	Short Circuit	$887,479
Replace one breaker at Stilwell 161 kV	Short Circuit	$566,485
Replace one breaker at Leeds 161 kV	Short Circuit	$566,485
Replace one breaker at Shawnee Mission 161 kV	Short Circuit	$566,485
Replace one breaker at Southtown 161 kV	Short Circuit	$566,485
Replace two breakers at Lake Road 161 kV	Short Circuit	$1,132,970
Replace two breakers at Craig 161 kV	Short Circuit	$1,132,970
Anadarko-Gracemont 138 kV rebuild as double-circuit	Economic	$8,297,502
Russett-South Brown 138 kV rebuild	Economic	$10,067,432
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	Economic	$135,720,424
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	Economic	$1,410,000
Columbus East 230/115 kV transformer replacement	Economic	$4,600,000
Franks-South Crocker-Lebanon 161 kV terminal equipment	Economic	$5,721,430
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	Economic	$31,686,685
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	Economic	$1,617,500
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	Economic	$113,620,907
Split Rock 345/115 kV circuit 10 & 11 terminal equipment	Economic	$4,577,336
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	Economic	$1,528,722[23]

Table 6.14: Final Consolidated Portfolio

[23] Estimated cost does not include the entire cost for this project.

Table 6.15 shows the Future 1 and Future 2 40-year B/C ratio and net benefit of the economic projects in 2020$ included in the consolidated portfolio using the same process described in the Section 6.2.4.1 for project subtraction evaluation.

Project	Project Cost (E&C)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit	F1 40-year Net Benefit	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit	F2 40-year Net Benefit
Anadarko-Gracemont 138 kV rebuild as Ckt	$8,297,502	2.88	4.28	8.35	$107,624,325	$94,731,224	5.35	3.09	4.56	$58,831,889	$45,938,788
Russett-South Brown 138 kV rebuild	$10,067,432	0.00	1.50	3.38	$52,833,714	$37,190,402	7.56	12.23	24.16	$377,875,070	$362,231,757
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	$135,720,424	0.75	1.00	1.91	$403,001,375	$192,111,748	1.06	1.37	2.62	$552,029,756	$341,140,129
GRDA 1 345/161 kV Ckt 1 and Ckt 2 terminal equipment	$1,410,000	13.98	20.09	38.98	$85,412,599	$83,221,666	7.15	5.38	8.90	$19,506,220	$17,315,287
Columbus East 230/115 kV transformer replacement	$4,600,000	0.20	0.50	1.05	$7,486,072	$338,347	2.02	3.27	6.46	$46,175,084	$39,027,359
Franks-South Crocker-Lebanon 161 kV terminal equipment	$5,721,430	(0.31)	2.04	4.74	$42,160,359	$33,270,096	0.01	0.90	2.02	$17,981,132	$9,090,869
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	$31,686,685	1.32	1.63	3.07	$151,237,189	$102,000,729	2.16	1.99	3.52	$173,144,070	$123,907,610
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	$1,617,500	51.34	82.75	163.37	$410,605,871	$408,092,513	13.52	21.06	41.36	$103,963,767	$101,450,410
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment, and Pleasant Valley cut-in	$113,620,907	0.81	1.33	2.62	$462,634,382	$286,084,161	1.28	2.72	5.56	$980,999,837	$804,449,617
Split Rock 345/115 kV Ckt 10 and 11 terminal equipment	$4,577,336	0.09	(0.06)	(0.16)	($1,171,751)	($8,284,260)	1.72	8.83	19.12	$136,025,615	$128,913,106
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	$1,528,722[24]	2.01	2.19	4.04	$9,593,533	$8,166,644	2.09	2.71	5.17	$12,275,136	$11,200,631

Table 6.15: Consolidated Portfolio – APC benefit only

[24] Estimated cost does not include the entire cost for this project.

Table 6.16 below shows the change in flowgate congestion scores due to the consolidated portfolio for the economic needs targeted by the portfolio.

	Base Congestion Score (k$/MWh)					Consolidated Portfolio Congestion Score (k$/MWh)				
	Future 1			Future 2		Future 1			Future 2	
Constraint	2022	2025	2030	2025	2030	2022	2025	2030	2025	2030
Russett-South Brown 138 kV FLO Caney Creek-Little City 138 kV	0	0	196	277	497	0	0	0	0	0
GRDA 345/161 kV circuit 1 FLO GRDA 345/161 kV circuit 2	11	39	49	16	19	0	0	0	0	0
Southwestern Station-Anadarko 138 kV FLO Gracemont-Anadarko 138 kV	0	0	1	0	1	0	0	0	0	0
Dover Switch-Okeene 138 kV FLO Watonga-Okeene 138 kV	238	503	885	213	334	0	0	0	0	0
Oahe-Sully Buttes 230 kV FLO Fort Thompson-Leland Olds 345 kV	0	33	48	45	118	0	0	0	0	0
Butler-Altoona 138 kV FLO Caney River-Neosho 345 kV	770	1,187	1,688	1,574	1,722	0	0	0	0	0
Columbus East 230/115 kV FLO Columbus East-Shell Creek 345 kV	2	41	50	51	79	0	0	0	0	0
Watford 230/115 kV circuit 1 FLO Watford 230/115 kV circuit 2	130	157	366	184	354	0	0	0	0	0
Shamrock 115/69 kV FLO Sweetwater-Chisholm 230 kV	5	7	20	9	24	0	1	3	2	5
Skyline-Quail Creek 138 kV FLO Northwest-Arcadia 345 kV	0	5	28	12	82	0	0	6	0	59
Czech Hall-Cimarron 138 kV FLO Cimarron-Draper 345 kV	1	10	30	41	88	0	0	0	0	0
Cimarron 345/138 kV circuit 1 FLO Cimarron 345/138 kV circuit 2	11	33	85	36	125	0	3	11	3	29
Franks-Crocker 161 kV FLO Huben-Franks 345 kV	18	5	99	8	41	0	0	0	0	0
Split Rock 345/115 kV circuit 10 FLO Split Rock 345/115 kV circuit 11	0	1	3	22	103	0	0	0	0	1

Table 6.16: Change in flowgate congestion scores

Figure 6.8 shows the B/C ratio of the economic portfolio of projects[25] included in the consolidated portfolio. Figure 6.9 shows B/C ratio of the entire consolidated portfolio. As expected, the overall B/C ratio is reduced with the inclusion of the reliability projects, but the consolidated portfolio is still expected to produce benefits well over the cost of the projects.

[25] Includes projects driven by market powerflow models not already identified in the base reliability portfolio.

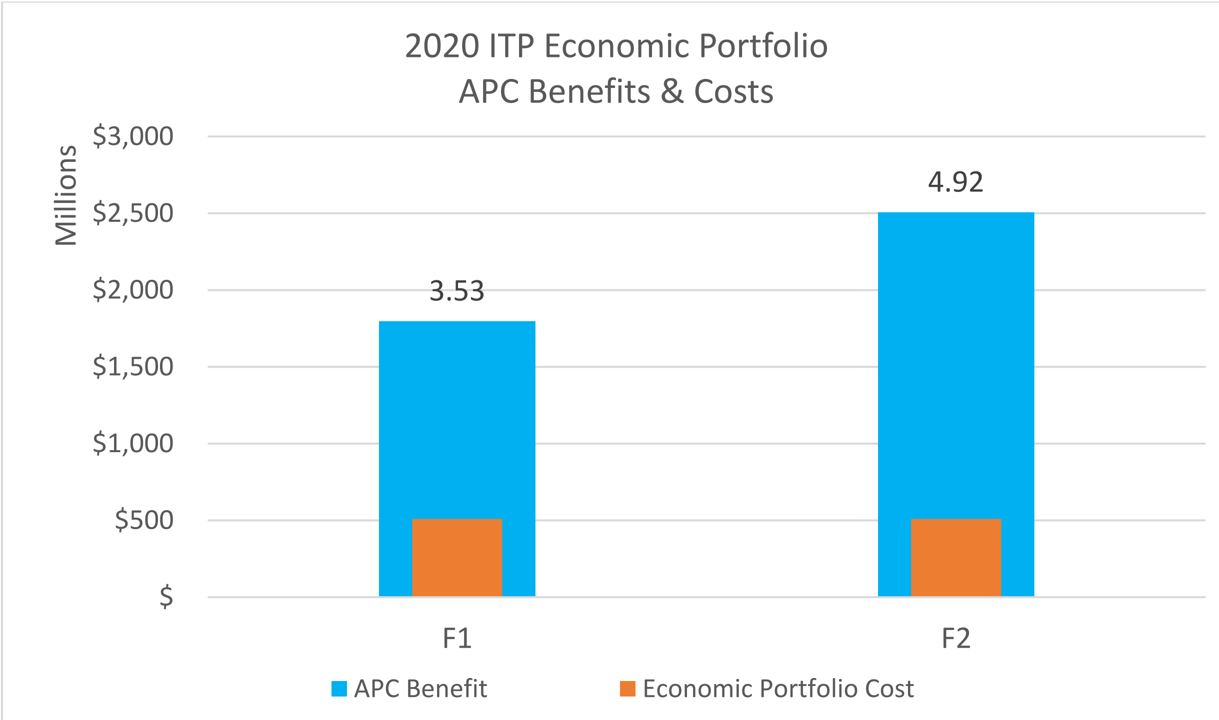

Figure 6.8: Economic Portfolio APC Benefits and Costs

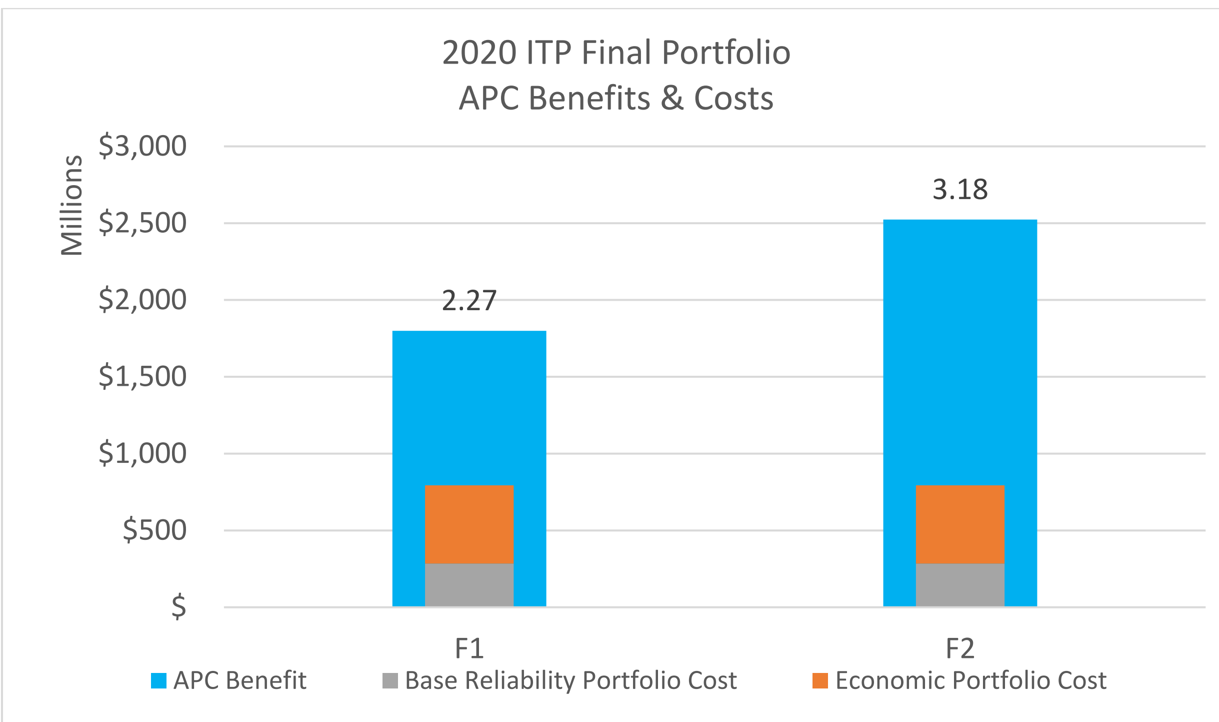

Figure 6.9: Final Consolidated Portfolio APC Benefits and Costs

Figure 6.10 below shows the break-even and payback dates of 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 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 expected to pay back total investment within the first 20 years.

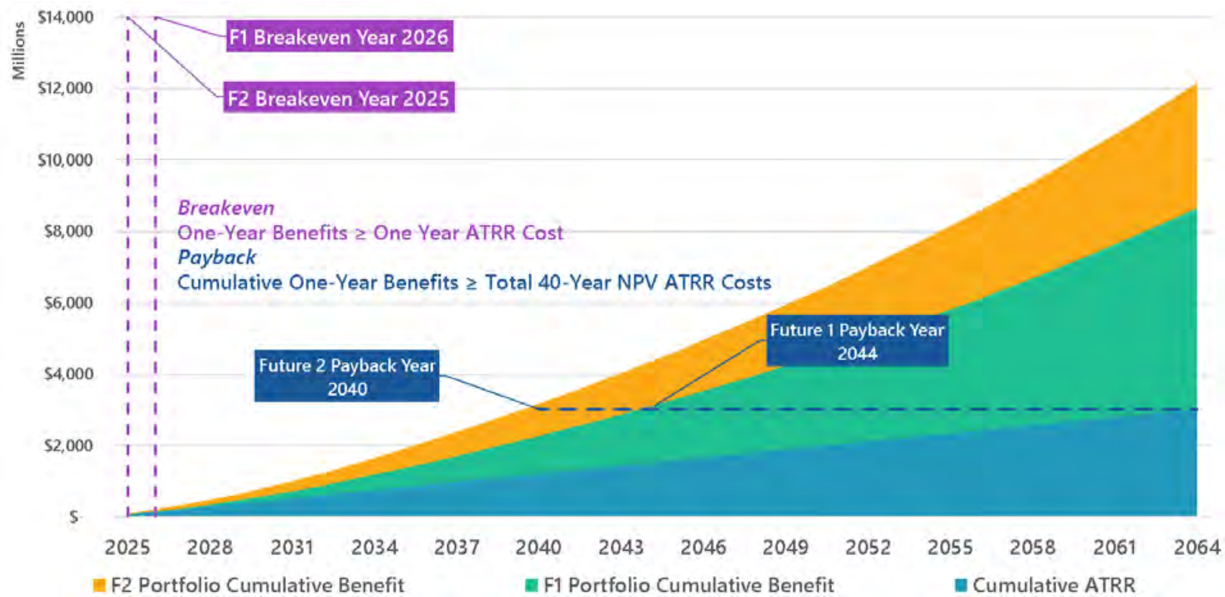

Figure 6.10: Portfolio Breakeven and Payback – APC benefit only

6.6 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.

6.6.1 ECONOMIC PROJECTS

The results of staging for the economic projects are shown in Table 6.17 below.

Economic Project	Need Date	Projected In-Service Date	Model
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	1/1/2022	11/17/2022	F1/F2
Anadarko-Gracemont 138 kV rebuild as double-circuit	1/1/2023	11/17/2023	F1
Russett-South Brown 138 kV rebuild	1/1/2022	5/17/2023	F1/F2
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	1/1/2024	1/1/2024	F1/F2
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	1/1/2022	5/17/2022	F1
Columbus East 230/115 kV transformer replacement	1/1/2039	1/1/2039	F1
Franks-South Crocker-Lebanon 161 kV terminal equipment	1/1/2028	1/1/2028	F1

Economic Project	Need Date	Projected In-Service Date	Model
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	1/1/2022	11/17/2024	F1/F2
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	1/1/2022	5/17/2022	F1/F2
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	1/1/2025	1/1/2025	F1/F2
Split Rock 345/115 kV circuit 10 & 11 terminal equipment	1/1/2025	1/1/2025	F2
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment[26]	1/1/2022	5/17/2022	F2

Table 6.17: Project Staging Results-Economic

6.6.2 POLICY PROJECTS

There were no policy-driven projects in the 2020 ITP.

6.6.3 RELIABILITY PROJECTS

The results of staging for the reliability projects are shown in Table 6.18 below. The Watford transformer upgrade will have a need date of January 1, 2022 because the economic staging need date is earlier than the reliability staging need date.

Reliability Project	Need Date	Projected In-Service Date	Model
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	6/1/2022	11/17/2022	BR
Circleville-Goff 115 kV circuit 1 rebuild	6/1/2025	6/1/2025	BR
Goff-Kelly 115 kV rebuild	6/1/2025	6/1/2025	BR
South Shreveport-Wallace Lake 138 kV rebuild	6/1/2024	6/1/2024	BR
Grady 138 kV capacitor bank	12/1/2022	12/1/2022	LPC
Deaf Smith #6-Hereford 115 kV rebuild	6/1/2022	5/17/2023	BR
Deaf Smith #6-Friona 115 kV rebuild	4/1/2022	11/17/2022	BR
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	12/1/2022	11/17/2023	BR

[26] The projected need date was calculated using an incomplete cost estimate. See Table 9.1 for accurate need and projected in-service dates.

Reliability Project	Need Date	Projected In-Service Date	Model
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	6/1/2023	6/1/2023	BR
Bushland-Deaf Smith 230 kV terminal equipment	4/1/2022	5/17/2022	BR
Newhart-Potter County 230 kV terminal equipment	4/1/2022	5/17/2022	BR
Carlisle-Murphy 115 kV rebuild	6/1/2022	11/17/2022	BR
Replace Roswell 115/69 kV transformer	6/1/2022	11/17/2022	BR
S3456-S3458 345 kV terminal equipment	6/1/2029	6/1/2029	BR
Meadowlark-Tower 33 115 kV rebuild	6/1/2023	11/17/2023	BR
Jones-Lubbock South 230 kV terminal equipment circuit 1	6/1/2028	6/1/2028	BR
Jones-Lubbock South 230 kV terminal equipment circuit 2	6/1/2028	6/1/2028	BR
Deaf Smith-Plant X 230 kV terminal equipment	4/1/2022	5/17/2022	BR
Newhart-Plant X 230 kV terminal equipment	4/1/2022	5/17/2022	BR
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	6/1/2022	6/1/2022	BR
Allen-Lubbock South 115 kV rebuild	6/1/2022	11/17/2022	BR
Allen-Quaker 115 kV rebuild	6/1/2022	11/17/2022	BR
Eddy County-North Loving 345 kV new line	6/1/2028	6/1/2028	BR
Bismarck 115 kV reactors	4/1/2022	11/17/2022	BR/MPM
Moorehead 230 kV reactor	4/1/2022	11/17/2022	BR/MPM
Russell 115 kV capacitor bank	6/1/2022	11/17/2022	MPM
Maljamar 115 kV capacitor bank	6/1/2028	6/1/2028	MPM
Devil's Lake 115 kV reactor	4/1/2022	11/17/2022	MPM
Agate 115 kV reactor	4/1/2022	11/17/2022	MPM
Nixa-Nixa Espy 69 kV terminal equipment	6/1/2022	6/1/2022	BR

Table 6.18: Project Staging Results-Reliability

6.6.4 SHORT-CIRCUIT PROJECTS

The short-circuit projects were all staged with need dates and projected in-service dates of June 1, 2022.

7 PROJECT RECOMMENDATIONS

7.1 RELIABILITY PROJECTS

7.1.1 WATFORD 230/115 KV TRANSFORMERS

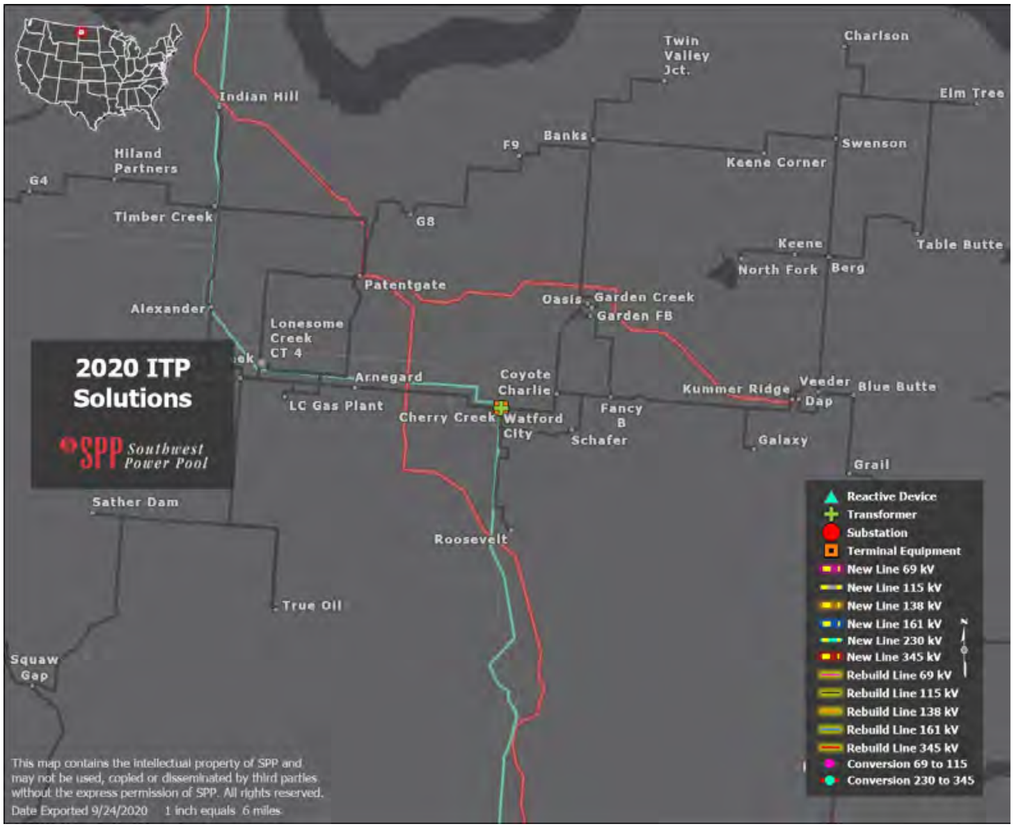

Figure 7.1: Watford 230/115 kV Transformers

In western North Dakota, the Watford City transformers that serve the 115 kV system experience both reliability violations and system congestion when one of the transformers is lost. The area around Watford has experienced expanded oil exploration and increasing load growth to support the shale play. Multiple solutions, including a new delivery point to support the increasing load, were analyzed but this area continues to grow and is expected to be of greater concern in future ITP assessments. The selected project is a no-regrets solution to strengthen the transformation at Watford by upgrading terminal equipment on one 230/115 kV transformer and replacing the other transformer to increase the capacity in cases where one is lost.

7.1.2 AMARILLO NORTH-SOUTH 230 KV CORRIDOR TERMINAL EQUIPMENT AND LINE CLEARANCES

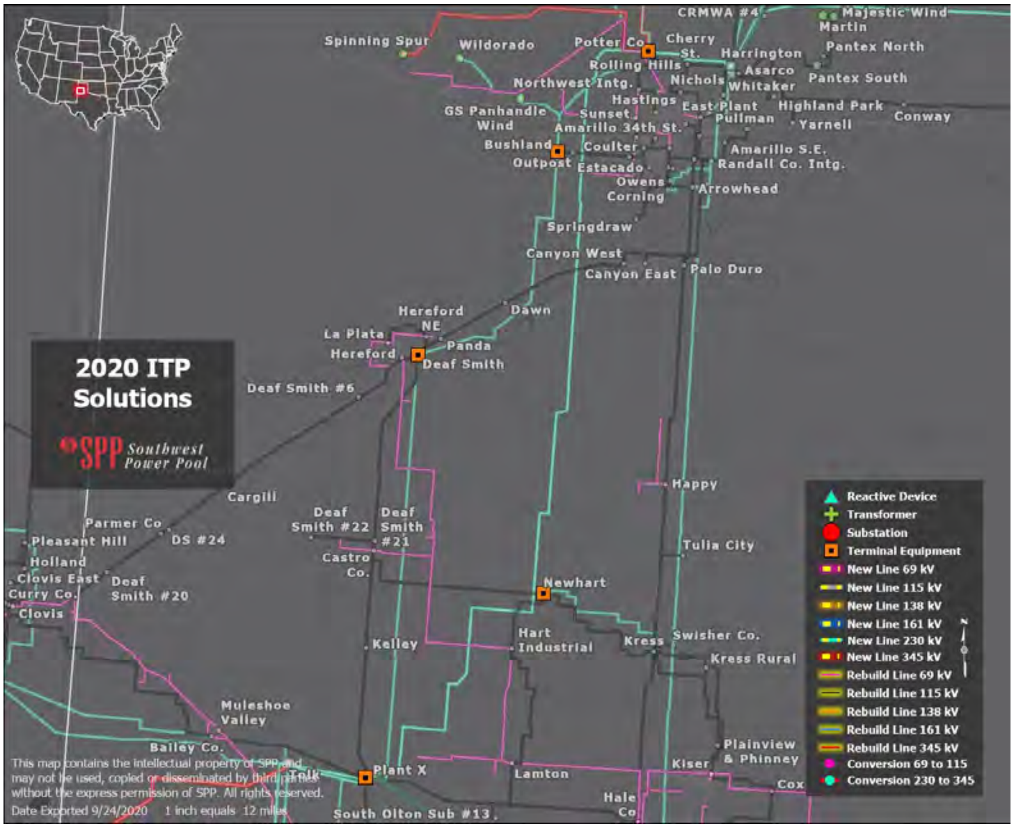

Figure 7.2: Amarillo North-South 230 kV Corridor Terminal Equipment

The Bushland-Deaf Smith 230 kV line and the Potter-Newhart-Plant X 230 kV line run parallel in a north-to-south direction near the city of Amarillo, Texas. When one of these 230 kV paths is out of service, an overload is observed on the parallel path. During light load conditions paired with a high wind output, generation in the south is no longer needed. This combination results in large north-to-south flows coming out of Amarillo. Given that each of these lines are terminally limited and the conductor can handle the observed post-contingency flows, the projects selected to mitigate these issues is to replace any terminal equipment that is limiting these three 230 kV line segments below their conductor rating, as well as increase the height of necessary structures to create appropriate line clearances.

7.1.3 HEREFORD-CURRY 115 KV CORRIDOR REBUILDS

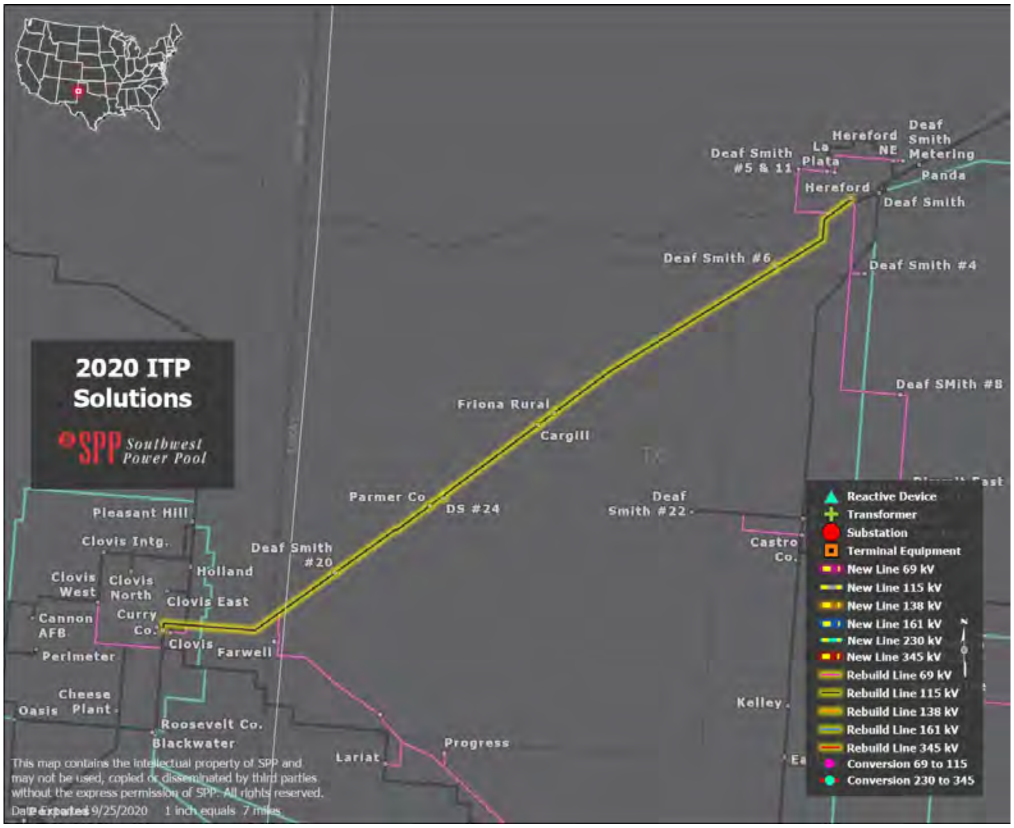

Figure 7.3: Hereford-Curry 115 kV Corridor Rebuild

Southwest of Amarillo, in a series corridor between Amarillo, Texas, and Clovis, New Mexico, seven 115 kV line segments overload for the loss of the Deaf Smith-Plant X 230 kV line. Similar to other needs in the Amarillo area, high wind output and less conventional generation south of Amarillo causes flows on the 115 kV corridor to overload upon loss of the 230 kV path. A rebuild of the Hereford-Deaf Smith #6-Friona-Cargill-Deaf Smith #24-Parmer-Deaf Smith #20-Curry 115 kV corridor is needed to bring these lines up to the same design standards of surrounding upgraded 115 kV lines and mitigate these issues. The Deaf Smith #20-Curry 115 kV portion of this corridor was identified as having been previously approved via a separate planning process with an expected in-service date prior to the ITP need date. Therefore, no NTC will be issued for this facility.

7.1.4 JONES-LUBBOCK SOUTH 230 KV TERMINAL EQUIPMENT

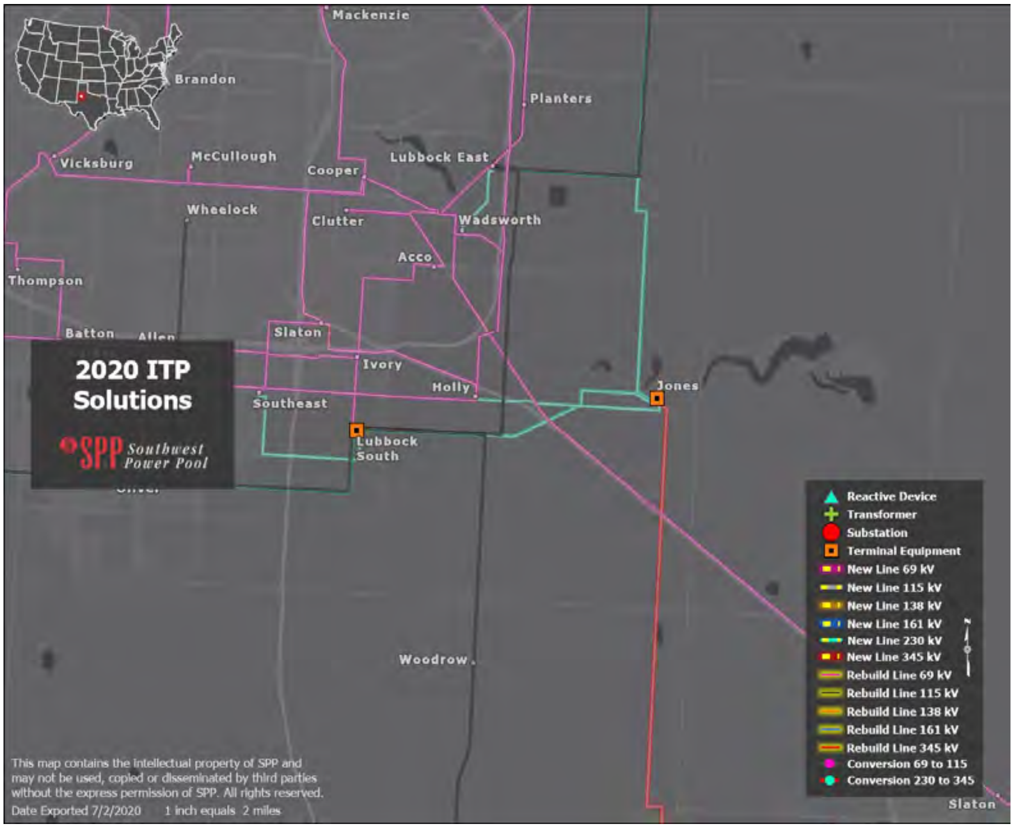

Figure 7.4: Jones-Lubbock South 230 kV Terminal Equipment

On the south end of Lubbock, Texas, in the Texas Panhandle, two parallel 230 kV circuits from Jones to Lubbock South each overload upon contingency of the other circuit. 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 in contingency conditions during the long-term summer peaks. Given that the ratings of these lines are driven by terminal equipment and the conductors can handle the post-contingency flows, the project selected to mitigate this issue is to upgrade the necessary terminal equipment at these substations and allow the conductors to become the most limiting element long each path.

7.1.5 LUBBOCK SOUTH-WOLFFORTH 230 KV TERMINAL EQUIPMENT AND LINE CLEARANCES

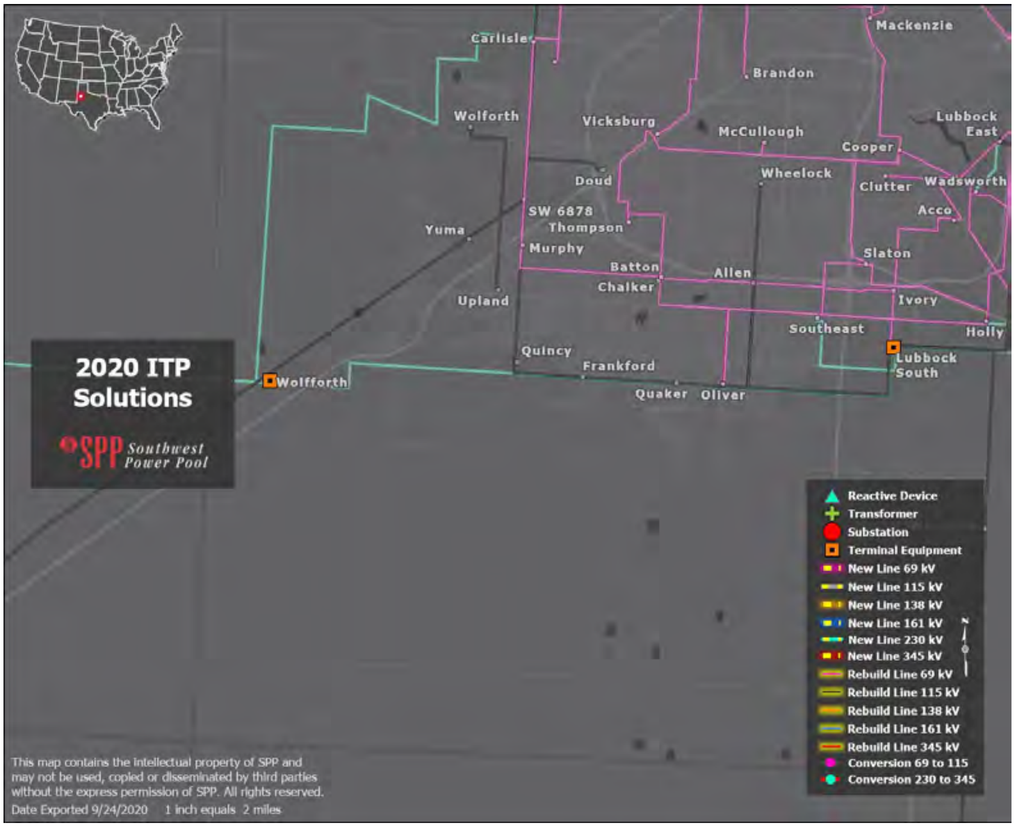

Figure 7.5: Lubbock South-Wolfforth 230 kV Terminal Equipment and Line Clearances

On the south end of Lubbock, Texas, in the Texas Panhandle, the Lubbock South-Wolfforth 230 kV line reaches near base-case overloads in the near-term winter peaks and the long-term summer peaks. The Lubbock South-Wolfforth line is a large feed to deliver energy in the SPS south area which contributes to this base-case flow. Since the flow is already approaching the line rating, many contingencies in the area can cause the line to overload. The project selected to mitigate this issue is to upgrade the terminal equipment limiting the line rating below the conductor rating, as well as increase the height of necessary structures to create appropriate line clearances.

7.1.6 CARLISLE-MURPHY 115 KV REBUILD

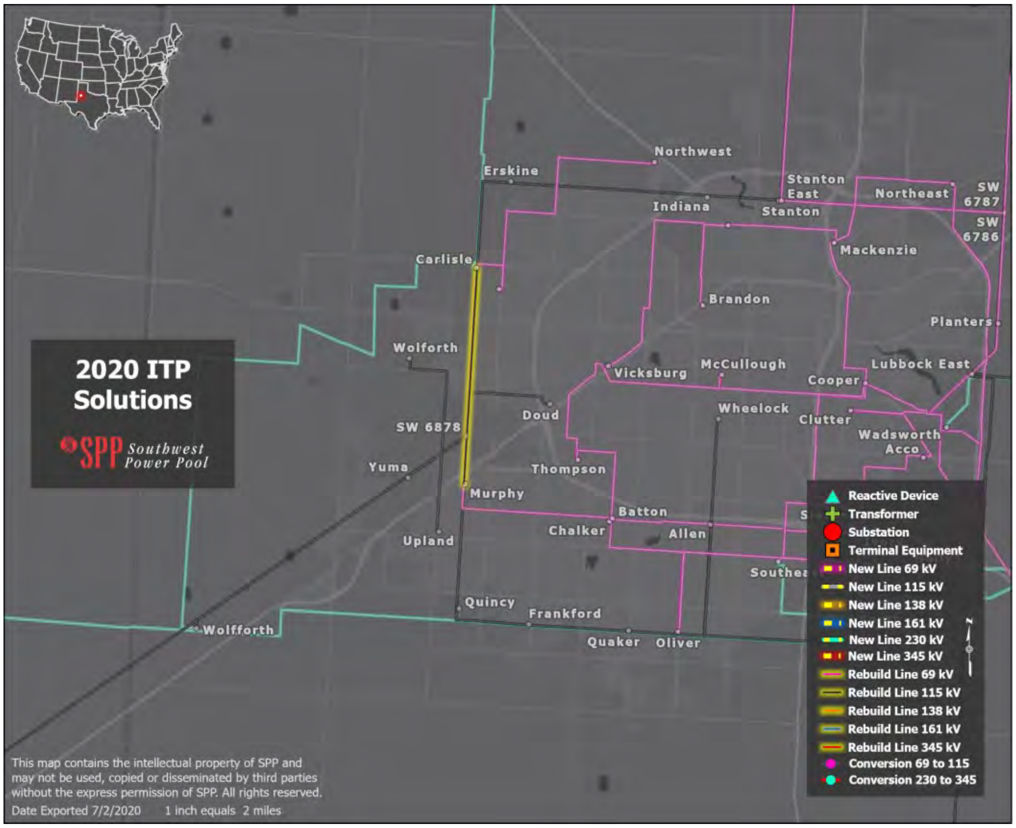

Figure 7.6: Carlisle-Murphy 115 kV

On the west side of Lubbock in the panhandle of Texas, the Carlisle-Murphy 115 kV line overloads for the loss of the Allen-Lubbock South 115 kV during the summer peaks. Loss of this 115 kV circuit forces flow to redirect around the city of Lubbock, overloading the Carlisle-Murphy 115 kV line which is serving radial load all the way through to Allen. A rebuild of the Carlisle-Murphy 115 kV line will mitigate the issue by increasing the transmission capability of that circuit.

7.1.7 EDDY COUNTY-NORTH LOVING 345 KV LINE

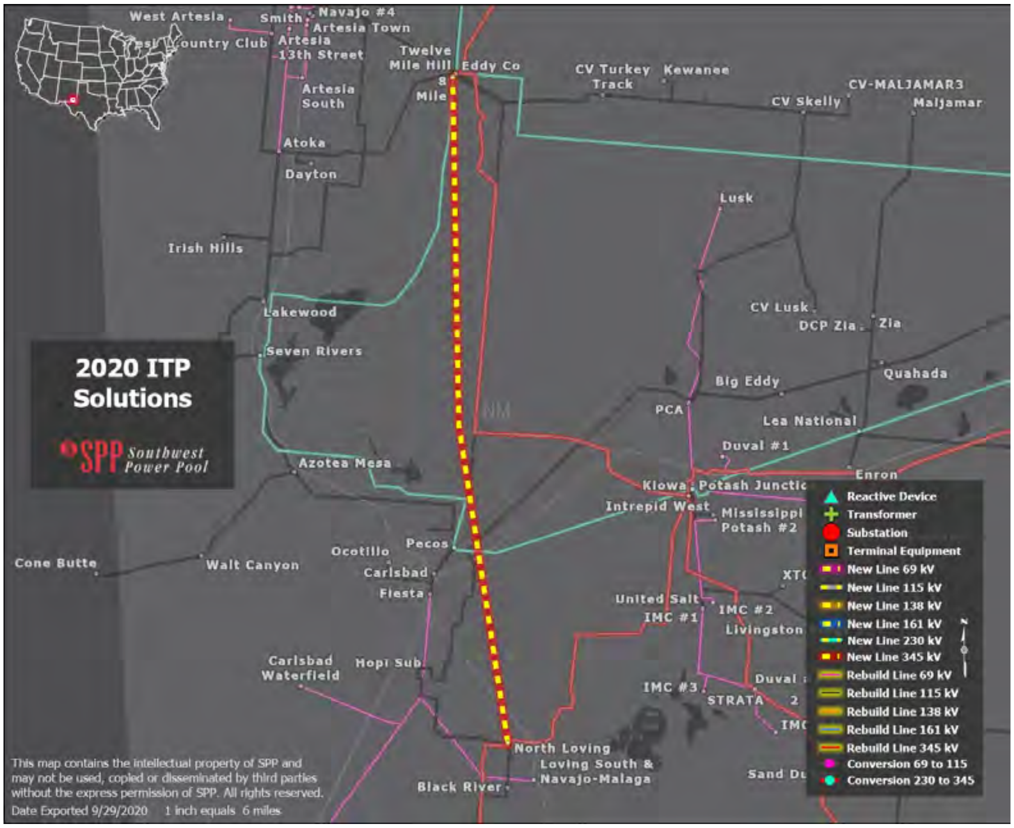

Figure 7.7: Eddy County-North Loving 345 kV

Southeast of Loving, New Mexico, the 115 kV system experiences low voltage for the loss of the Hobbs-Kiowa 345 kV line, including voltage collapse at the Phantom 115 kV bus. Increasing load, combined with a generator retirement in the south SPS area, has made this area less able to maintain minimal voltage in the long-term summer peaks upon the loss of a 345 kV feed into the area which carries critical real and reactive power support. The project selected to mitigate this issue is to construct a new 345 kV line from Eddy County-North Loving to deliver more real and reactive power support to this area.

Impactful out of scope NERC TPL-001-4 P3 planning events and SPSNMTIES interface violations in the base reliability model were identified late in the assessment and question the project's long-term viability. The NERC TPL-001-4 P3 planning events with limited system adjustment options cause voltage collapse in eastern New Mexico area in 2030 summer peak. These system conditions are related to the SPSNMTIES interface as described in section 4.1.2 and these violations were inadvertently not identified as part of the reliability needs assessment. Without these crucial system limits accounted for in reliability project screening and grouping introduces uncertainty in the large-scale project selection that has a June 2028 reliability need date.

For these reasons and consistent with delaying any action on the congested SPSNMTIES interface to future ITP cycles as described in section 6.2.6, it is recommended to not move forward with construction of this planned reliability project at this time and use the 2021 ITP to reassess this portion of the SPP system which allows for further stakeholder collaboration and opportunity to optimize base reliability solutions and potential economic solutions to identify a comprehensive solution in Eastern New Mexico area.

7.1.8 ROSWELL INTERCHANGE 115/69 KV TRANSFORMER #1 REPLACEMENT

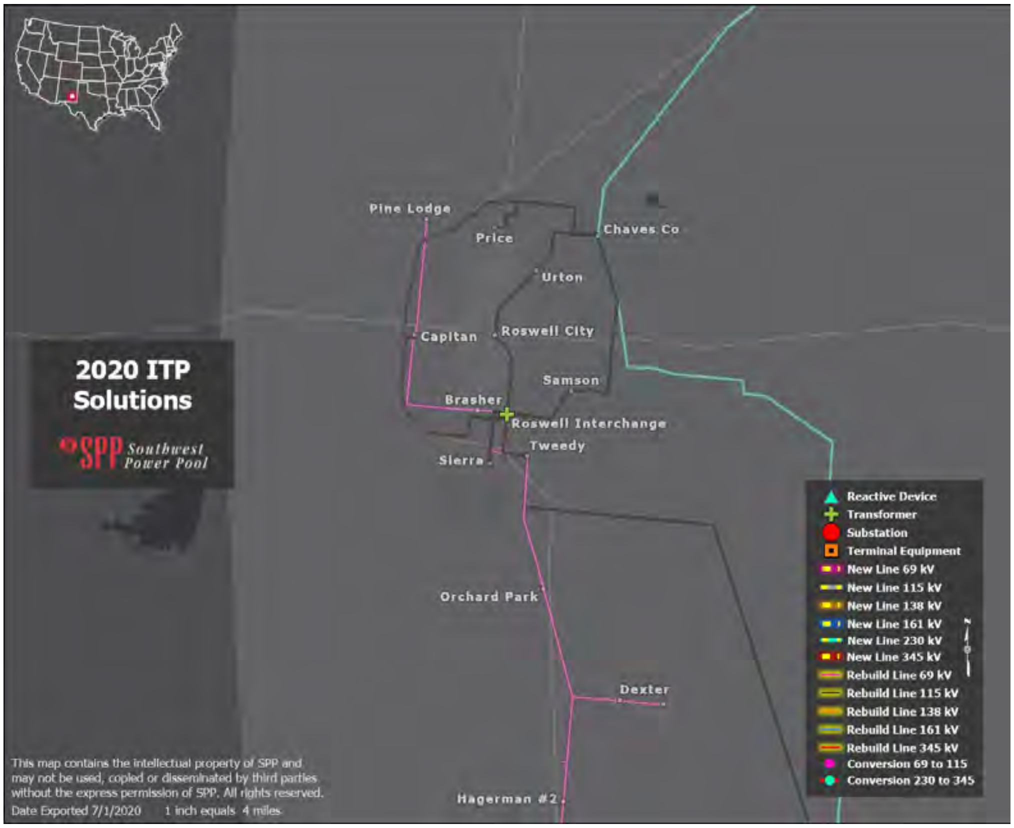

Figure 7.8: Roswell Interchange 115/69 kV Transformer #1

In the southeast corner of New Mexico in the city of Roswell, the 115/69 kV transformer #1 overloads for the loss of transformer #2. Summer peak loading conditions in Roswell, New Mexico, drives the load to levels that cannot be served through the single transformer after the contingency of transformer #2. Replacing transformer #1 with a transformer that meets the same standards as surrounding 115/69 kV transformers will mitigate this issue.

7.1.9 CUSHING TAP-SHELL CUSHING TAP-SHELL PIPELINE 69 KV REBUILD

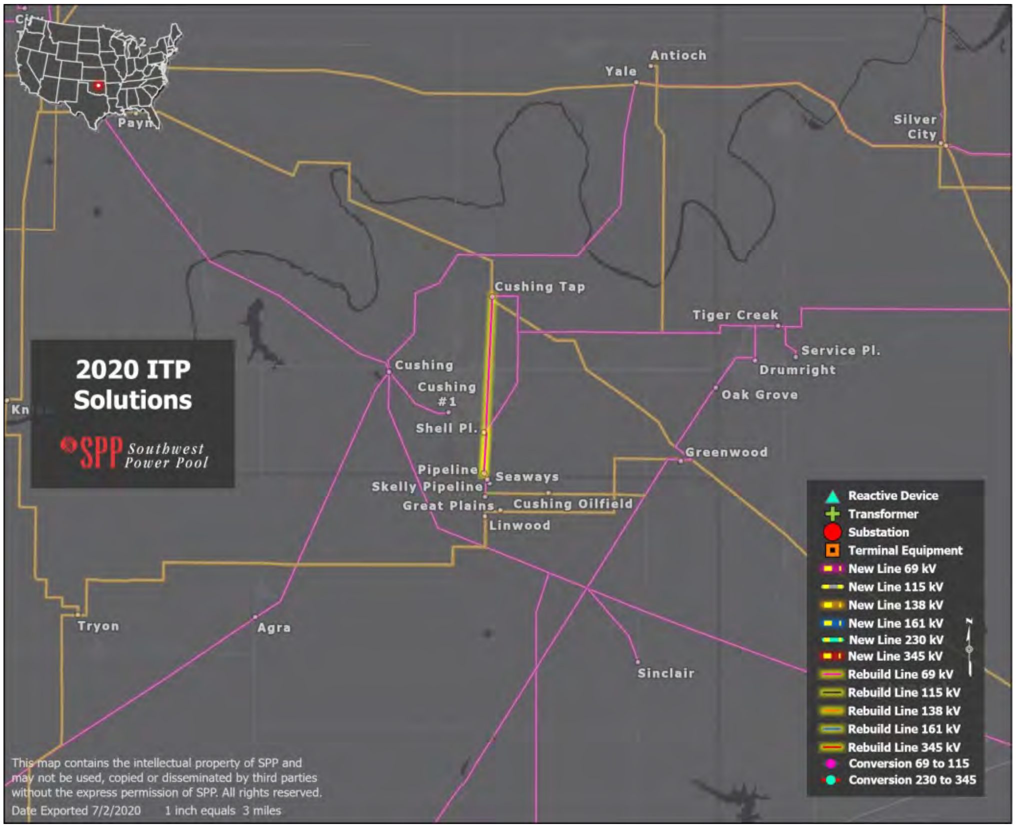

Figure 7.9: Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV

Northeast of Oklahoma City, near the town of Cushing, Oklahoma, the Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV series corridor overloads for the loss of the Highway 99 Tap-Cushing Oilfield 69 kV line. Loss of this feed places the load at Cushing Oilfield at a radial from the Cushing Tap substation, which overloads the Cushing Tap-Shell Cushing Tap 69 kV segment during the summer peaks and very nearly overloads the Shell Cushing Tap-Shell Pipeline segment. Rebuilding the Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV corridor will mitigate this issue by increasing the conductor ratings to tolerate the loss of the Highway 99 Tap-Cushing Oilfield 69 kV line.

7.1.10 SOUTH SHREVEPORT-WALLACE LAKE 138 KV REBUILD

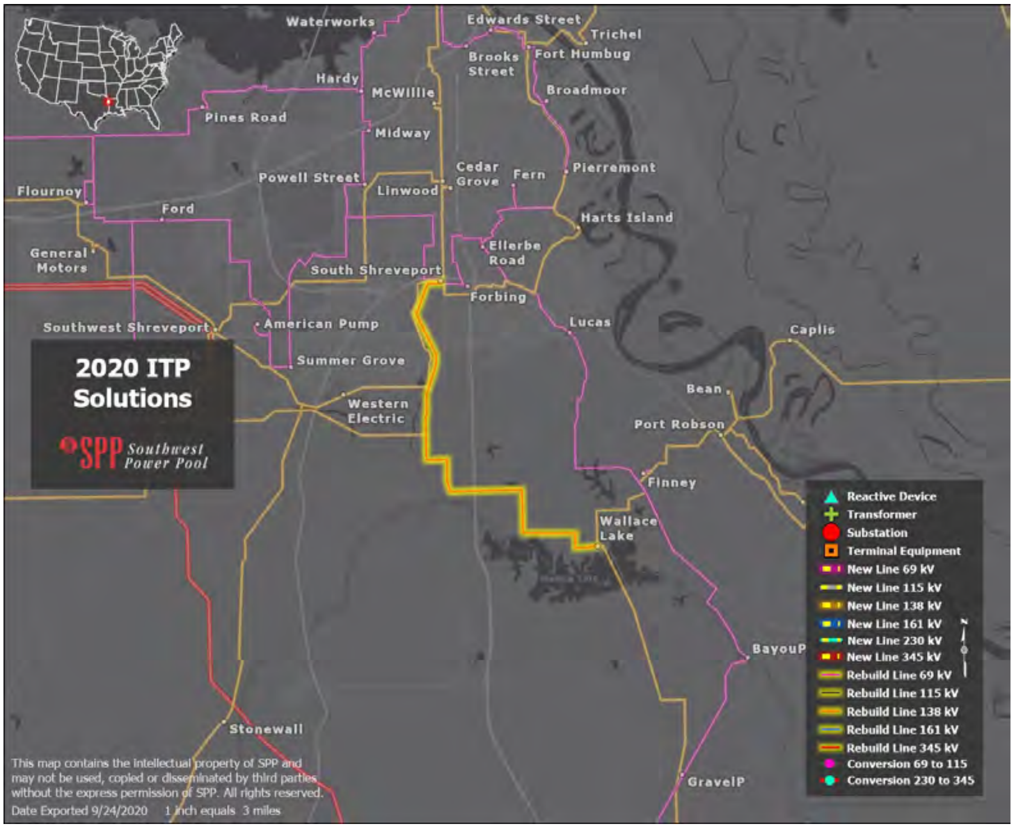

Figure 7.10: South Shreveport-Wallace Lake 138 kV

In northwest Louisiana in the city of Shreveport, the South Shreveport-Wallace Lake 138 kV line overloads for the loss of the Fort Humbug-Trichel 138 kV line. Loss of the 138 kV line which heads east out of the city causes the large amount of load across the Red River to be served out of South Shreveport. Rebuilding the South Shreveport-Wallace Lake 138 kV line will bring the facility up to the same design standards of surrounding upgraded 115 kV line and mitigate this issue.

7.1.11 GRADY 138 KV CAPACITOR BANK

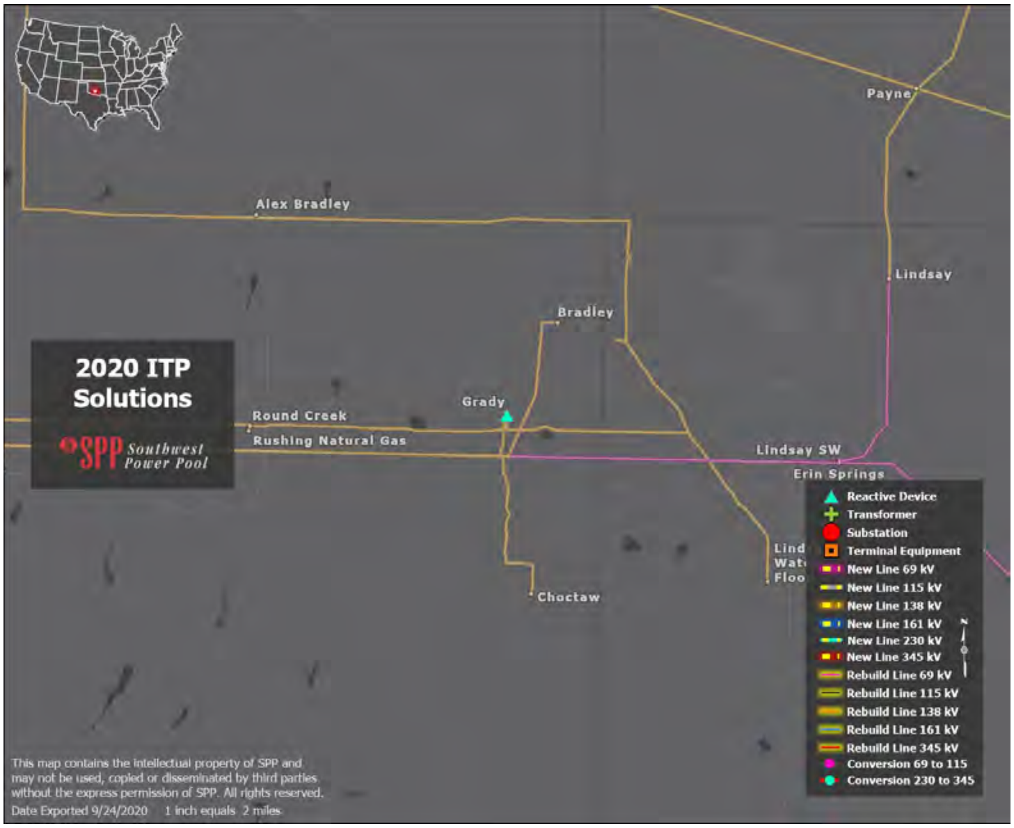

Figure 7.11: Grady 138 kV Capacitor Bank

South of Oklahoma City near the town of Lindsay, Oklahoma, the Choctaw and Grady 138 kV bus voltages dip below AEPW's minimum voltage criteria of 0.92pu for the loss of the Grady-Round Creek 138 kV line. Loss of this 138 kV feed places a large amount of load at Choctaw and Grady on a radial from the Cornville substation, bringing the voltage below acceptable levels during the summer peaks. The project selected to mitigate this issue is to place a capacitor bank capable of 23 MVAR at the Grady 138 kV substation.

7.1.12 NIXA-NIXA ESPY 69 KV TERMINAL EQUIPMENT

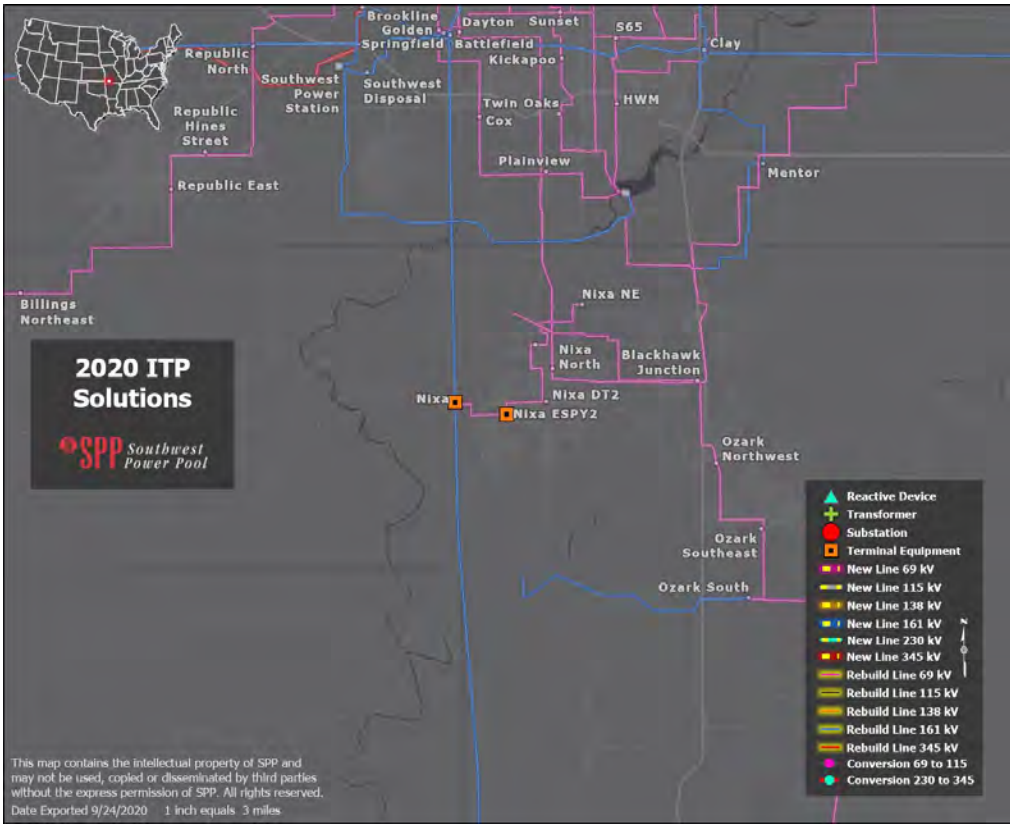

Figure 7.12: Nixa-Nixa Espy 69 kV Terminal Equipment

South of Springfield in the town of Nixa, Missouri, the Nixa-Nixa Espy 69 kV line overloads for the loss of the James River Power Station 161/69 kV transformer. Loss of the transformer causes energy to access the 69 kV system at Nixa and make its way north to serve load at Seminole and Twin Oaks, overloading the Nixa-Nixa Espy 69 kV circuit. The project selected to mitigate this issue is to upgrade the necessary 69 kV terminal equipment at Nixa and Nixa Espy which will increase the line rating up to the conductor capability.

7.1.13 MEADOWLARK-TOWER 33 115 KV REBUILD

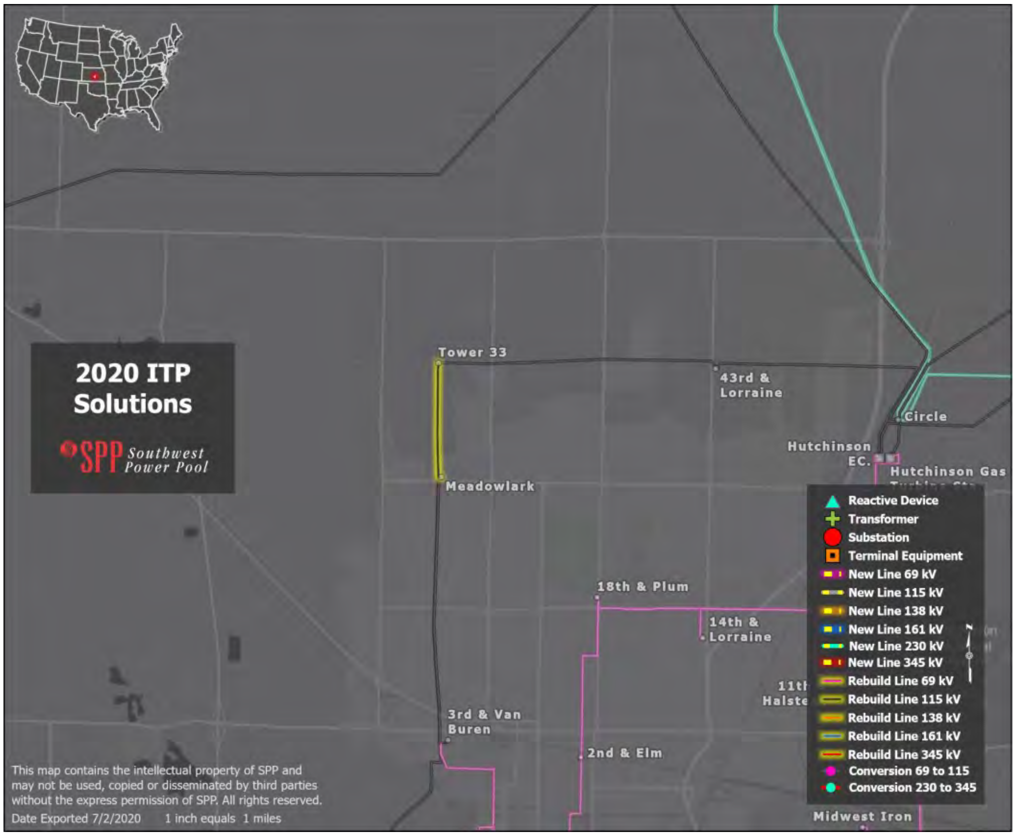

Figure 7.13: Meadowlark-Tower 33 115 kV

In the northwest corner of Hutchinson, Kansas, circuit 1 of Meadowlark-Tower 33 115 kV overloads for loss of the Davis-Reno County 115 kV line. Loss of the Davis-Reno County line causes all the load at Davis and South Hutchinson to be served radially through parallel Meadowlark-Tower 33 115 kV circuits, overloading the first circuit in the long-term summer peaks. The project selected to mitigate this issue is to rebuild the first circuit of Meadowlark-Tower 33 115 kV to increase the capacity up to the same design standards of surrounding upgraded 115 kV lines.

7.1.14 SUB 3458-SUB 3456 345 KV TERMINAL EQUIPMENT

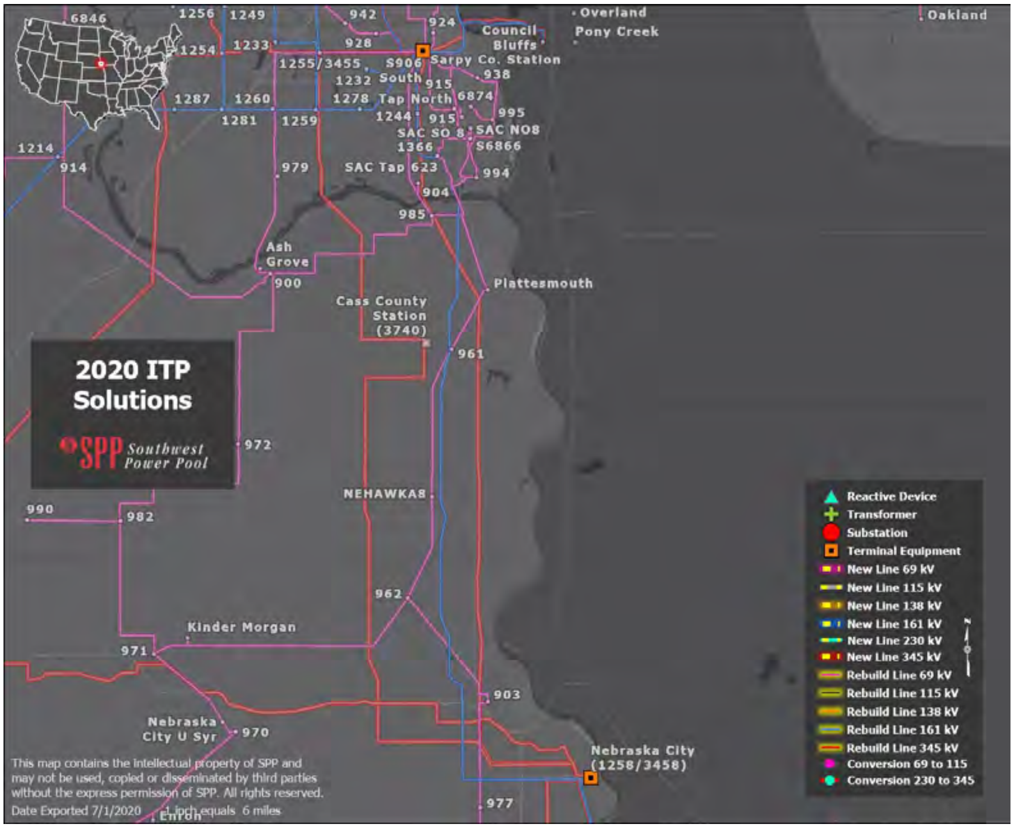

Figure 7.14: S3458-S3456 Terminal Equipment

Flowing south-to-north into the city of Omaha, Nebraska, the S3458-S3456 345 kV line overloads for the loss of the S3740-S3455 345 kV line. During the long-term summer peaks, Cass County and Nebraska City generating plants are operating at full output which overloads the northbound 345 kV line serving the city of Omaha when the parallel 345 kV line is lost. Upgrading the terminal equipment that is most limiting on the S3458-S3456 kV line will increase the rating of this line and mitigate this issue.

7.1.15 CIRCLEVILLE-GOFF-KELLY 115 KV REBUILD

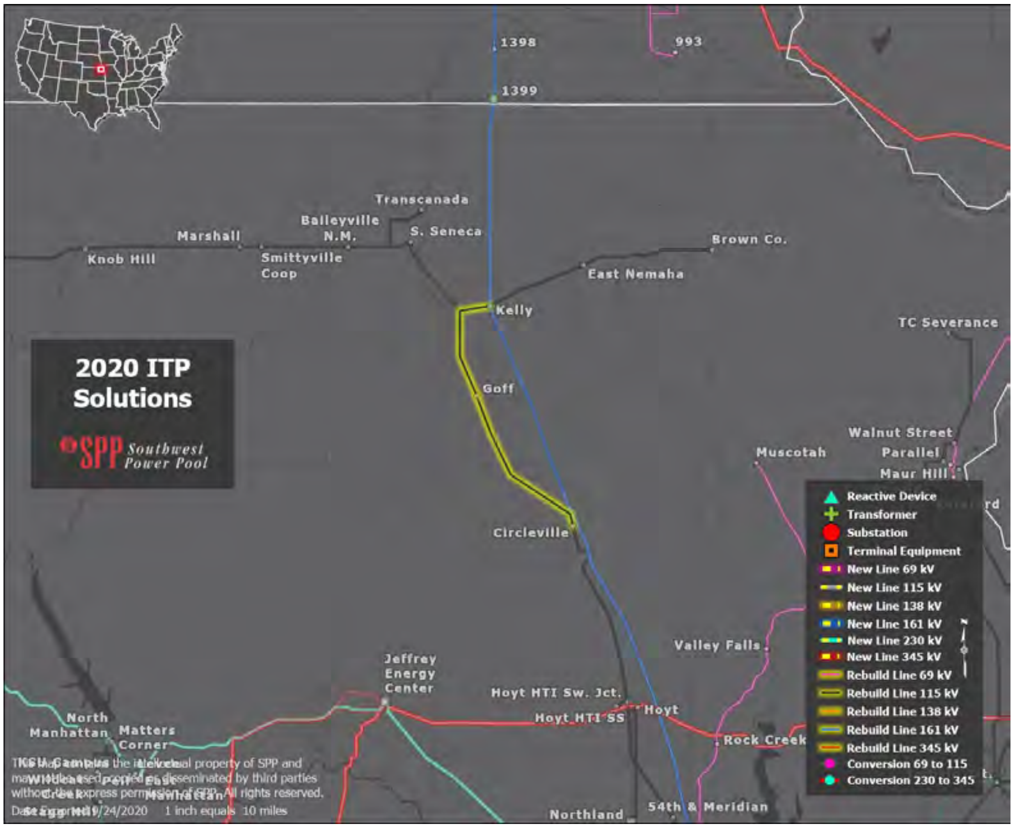

Figure 7.15: Circleville-Goff-Kelly 115 kV

North of Topeka, near the city of Circleville, Kansas, the Circleville-Goff-Kelly 115 kV lines overload for the loss of the Hoyt-Stranger Creek 345 kV line during summer peak of the Kansas City load center. Loss of the 345 kV line redirects flows down to the 115 kV system which then takes a northerly route through Circleville, east to Kelly, and back to the south again to reach Stranger Creek. The project selected to mitigate this issue is to rebuild the Circleville-Goff-Kelly 115 kV transmission lines which will bring those facilities up to the same design standards of surrounding upgraded 115 kV lines.

7.1.16 RICHMOND 115 KV SUBSTATION AND RICHMOND-ABERDEEN 115 KV

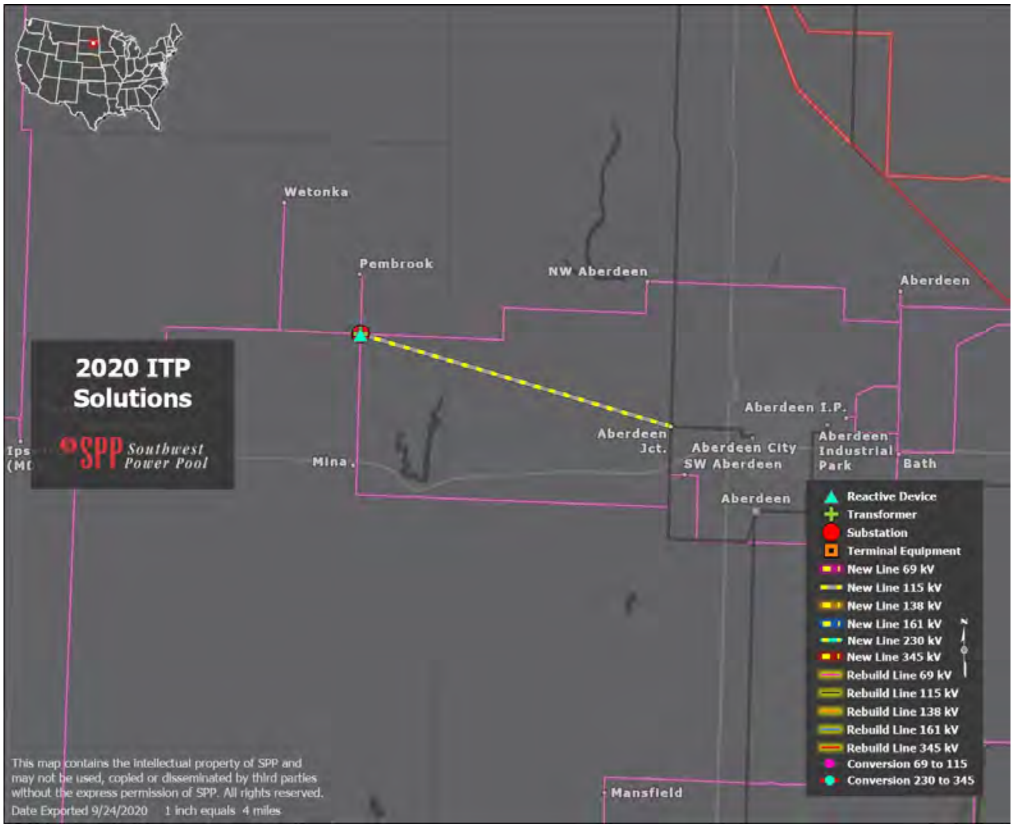

Figure 7.16: Richmond 115 kV Substation and Richmond-Aberdeen 115 kV

In the northeast corner of South Dakota near the town of Aberdeen, two parallel 115/69 kV transformers at Ordway overload, one for the loss of the other. Cold winters drive up energy consumption in North Dakota, which will overload each of these transformers if the parallel feed is lost. The project selected to mitigate this issue is to expand the Richmond substation to accommodate a 115 kV transmission line to Aberdeen as well as a 115/69 kV transformer. This will allow some of the 69 kV load west of Ordway to have an alternate source and take loading away from the Ordway transformers. Additionally, a capacitor needs to be installed at Richmond to provide voltage support in the area.

7.1.17 BISMARCK 115 KV REACTORS

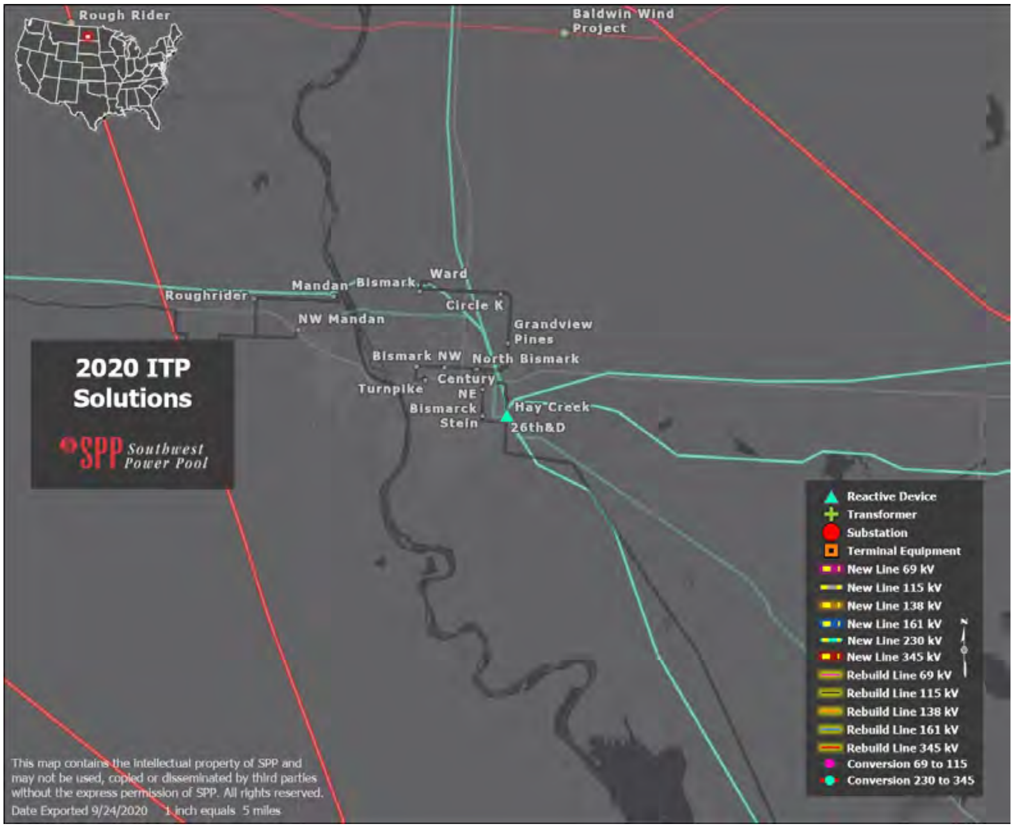

Figure 7.17: Bismarck 115 kV Reactors

Across the Missouri River from the city of Bismarck, North Dakota, light-load conditions cause base-case high voltage conditions at the Mandan 230 kV substation and surrounding 115 kV system. With limited reactive resources in the area to bring down the over-voltage condition, reactive consumption is needed near the 230 kV bus at Mandan. The project selected to mitigate this issue is to add 35 MVARs of reactive capability on two transformers at the Bismarck substation.

7.1.18 MOOREHEAD 230 KV REACTOR

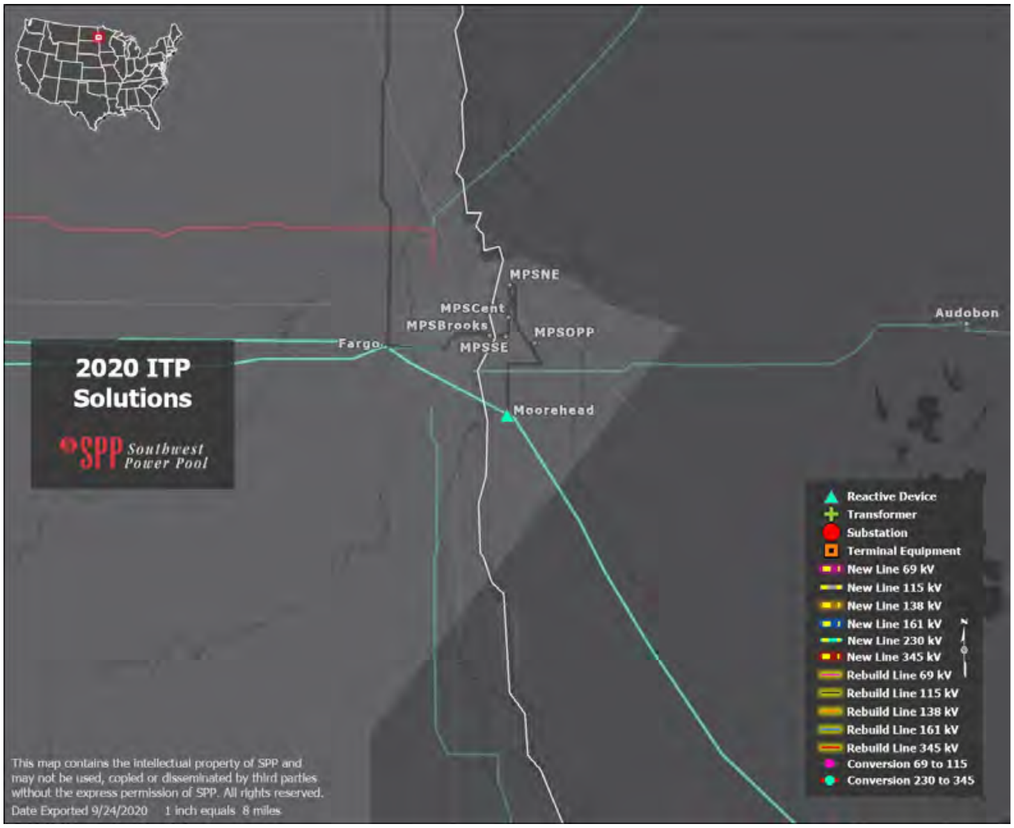

Figure 7.18: Moorehead 230 kV Reactor

Southeast of Fargo, North Dakota, across the border into Minnesota, the Moorehead 230 kV bus experiences base-case high voltage during light-load conditions and the near-term summer peak in the market powerflow models. With no reactive adjustments in the area available to help alleviate the base-case voltage issue, reactive capability must be installed to bring the voltage down to acceptable levels. Installing an 80 MVAR reactor bank at the Moorehead 230 kV bus will mitigate this issue.

7.2 SHORT-CIRCUIT PROJECTS

7.2.1 SHORT-CIRCUIT PROJECT PORTFOLIO

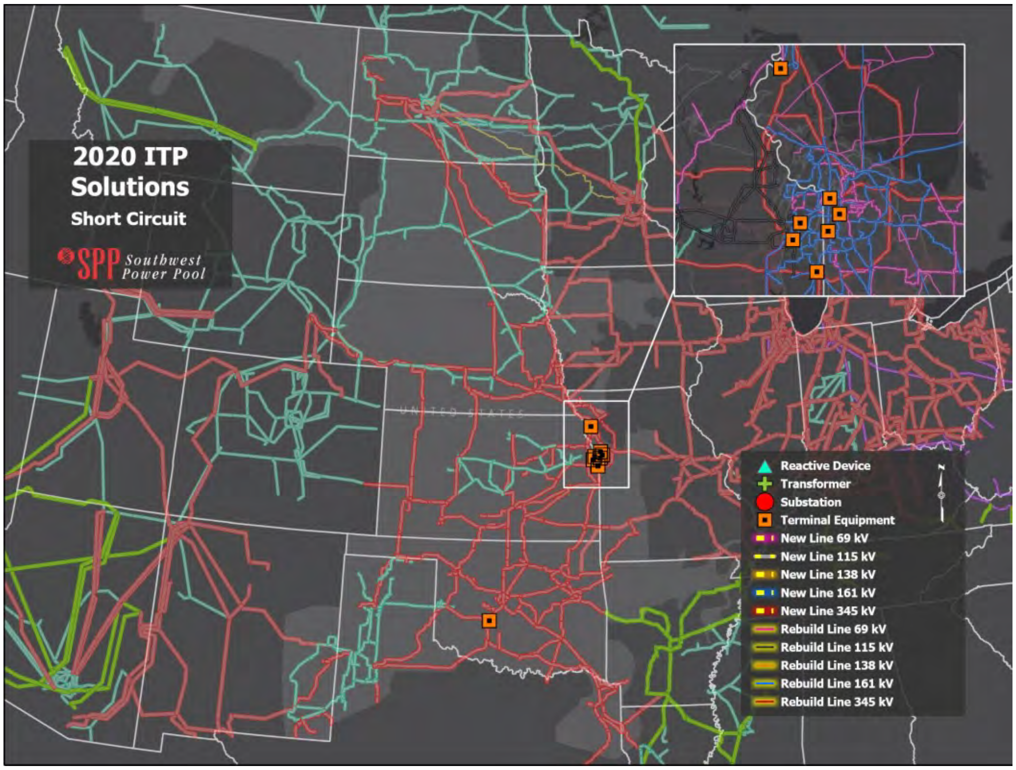

Figure 7.19: Short-Circuit Project portfolio

All short-circuit projects identified in the 2020 ITP were upgrades of overdutied breakers. 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 three breakers at Northeast 161 kV	KCPL	22S / BR
Replace one breaker at Stilwell 161 kV	KCPL	22S / BR
Replace one breaker at Leeds 161 kV	KCPL	22S / BR
Replace one breaker at Shawnee Mission 161 kV	KCPL	22S / BR
Replace one breaker at Southtown 161 kV	KCPL	22S / BR
Replace two breakers at Lake Road 161 kV	KCPL	22S / BR
Replace two breakers at Craig 161 kV	KCPL	22S / BR
Replace four breakers at Anadarko 138 kV	WFEC	22S / BR

Table 7.1: Short-Circuit Projects

7.3 ECONOMIC PROJECTS

7.3.1 BUTLER-TIOGA 138 KV

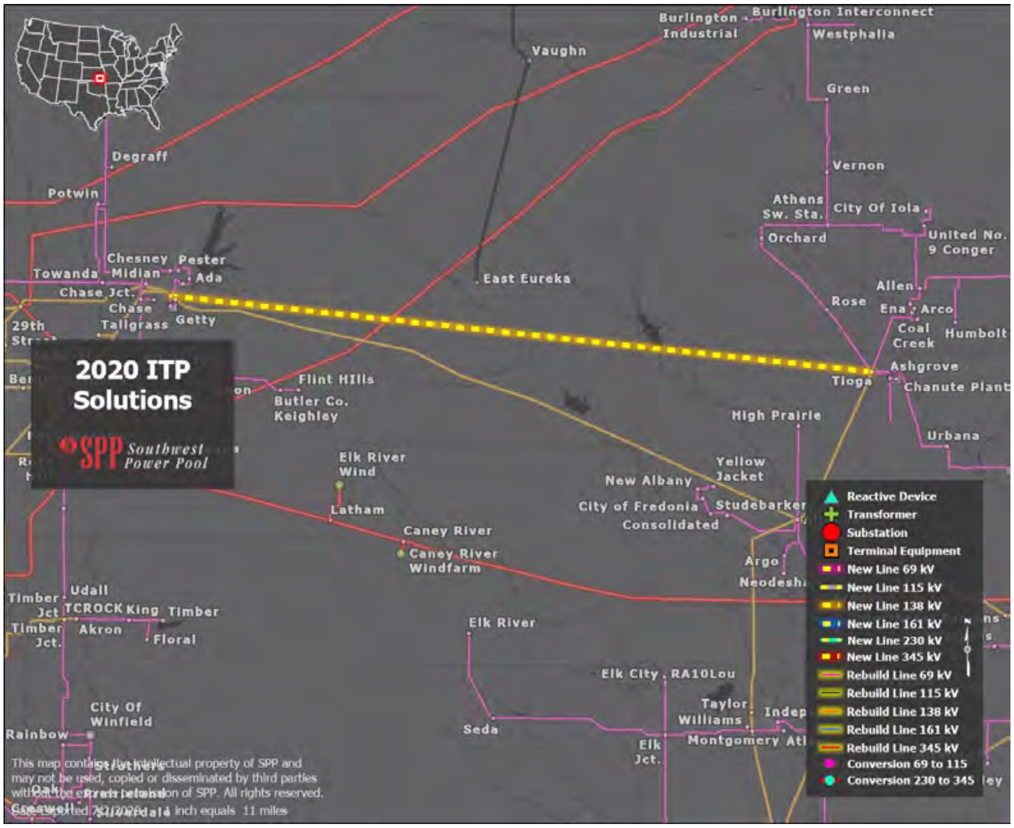

Figure 7.20: Butler-Tioga 138 kV

In southeast Kansas, the Butler-Altoona 138 kV line becomes congested for the loss of Caney River-Neosho 345 kV. The Butler-Altoona 138 kV constraint was identified as a part of Target Area 1 of the 2019 ITP assessment but was not addressed due to concerns with the final selected project, installing a phase-shifting transformer (PST) at the Butler 138 kV station. This PST project was originally selected and paired with the Wolf Creek-Blackberry 345 kV line to address residual congestion on Butler-Altoona 138 kV. Concerns were raised about the long-term viability of leaving the Butler-Altoona 138 kV in-service and installing a PST to divert system flows, primarily due to the age and condition of the facility. As discussed in the 2019 ITP, the Butler-Altoona 138 kV is known for its high outage rates during periods of high wind output or storm conditions and is nearing the level of becoming a persistent operational need for system reconfiguration, as defined in the ITP manual. The congestion in the 2020 ITP increased such that addressing the Butler-Altoona 138 kV directly was cost-beneficial to the SPP region. The preferred solution, given the benefit and the age and condition of the Butler-Altoona 138 kV line, is to wreck-out and rebuild a portion along existing right-of-way between Butler and Altoona, and re-route the termination point to Tioga, with the objective of minimizing transmission costs. This solution will provide a stronger source to an area of larger load.

7.3.2 ANADARKO-GRACEMONT 138 KV REBUILD AS DOUBLE-CIRCUIT

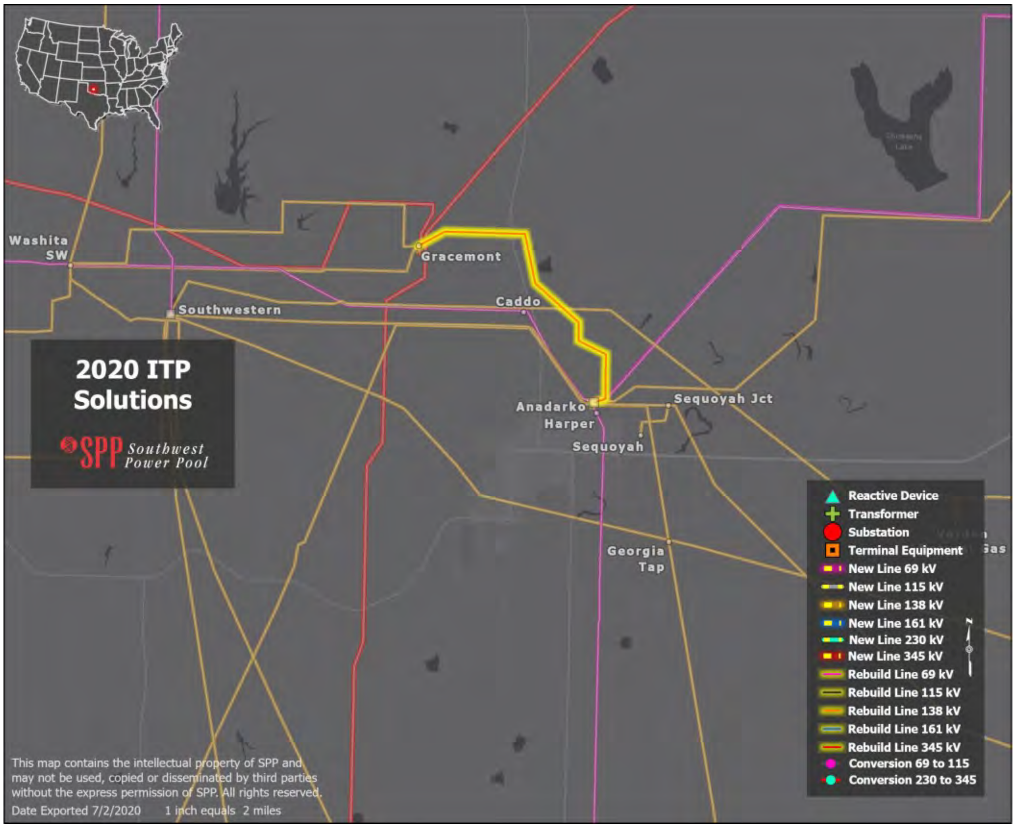

Figure 7.21: Anadarko-Gracemont 138 kV Rebuild as Double-Circuit

In southwest Oklahoma, the Southwestern Station-Anadarko 138 kV line becomes congested for loss of the Anadarko-Gracemont 138 kV line. This area is impacted by west-to-east system flows and existing renewable generation on the 138 kV system. This area was analyzed as part of the 2019 ITP assessment and a project to rebuild the Anadarko-Gracemont line was selected to address congestion when the Washita-Southwestern Station line is out of service. The Anadarko-Gracemont and Washita-Southwestern Station lines form a parallel transmission path east from Washita. This area has been identified in multiple ITP assessments and currently experiences operational congestion. The initial solutions evaluated included upgrading the Southwestern Station-Anadarko line, but given that the congestion is expected to increase, further analysis was performed to determine if a modification of the existing NTC would be prudent to strengthen the area and leverage the work that will be underway. The project selected to mitigate this issue is to modify the existing NTC and rebuild the Anadarko-Gracemont 138 kV line as a double circuit. This modified solution will increase the ability of the system to facilitate west-to-east flows and protect against the single circuit contingency that causes additional congestion in real-time and for the foreseeable future.

7.3.3 RUSSETT-SOUTH BROWN 138 KV REBUILD

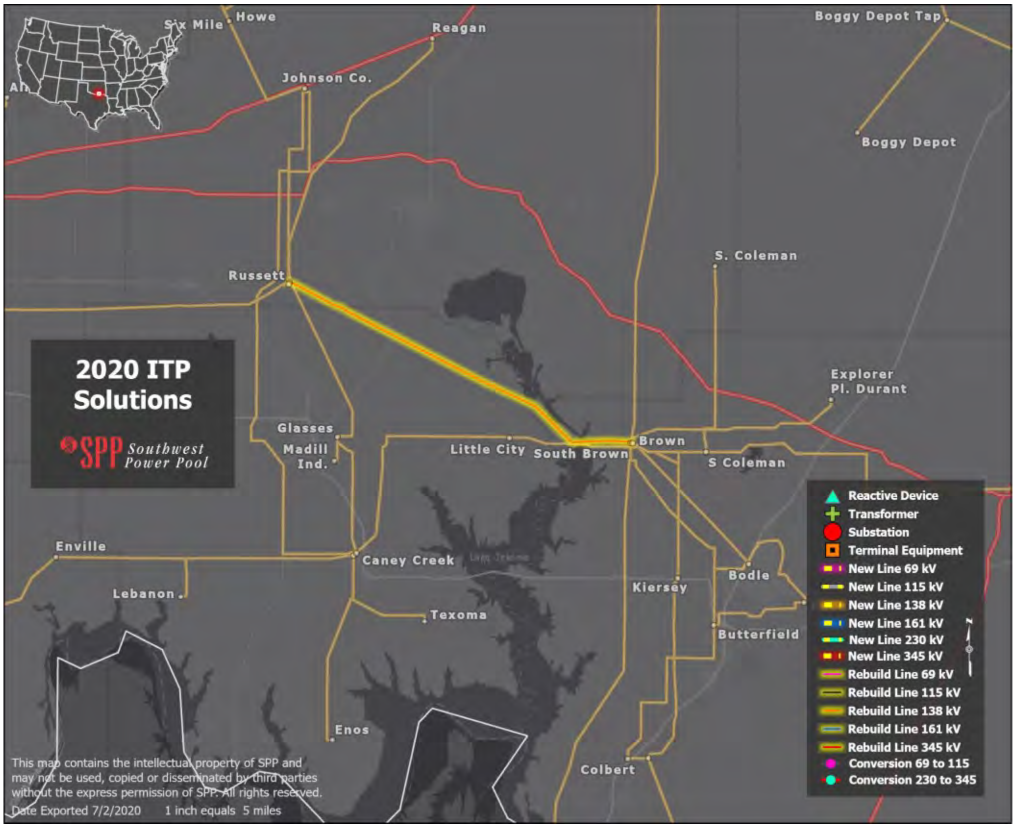

Figure 7.22: Russett-South Brown 138 kV Rebuild

In south-central Oklahoma, the Russett-South Brown 138 kV line becomes congested for the loss of the Caney Creek-Little City 138 kV line. This area is impacted by west-to-east system flows aggravated by existing and future renewable expansion. This flowgate was identified as a need in the 2019 ITP assessment but the project selected did not meet the consolidation criteria because it was identified in Future 2 and did not perform reasonably well in Future 1. With increasing bulk transfers in the area evaluated in the 2020 ITP assessment, congestion increased in both futures and a project became cost-beneficial to the region. The project selected to address the congestion is a rebuild of the Russett-South Brown 138 kV line, consistent with the top solution analyzed in the 2019 ITP.

7.3.4 GRDA 345/161 KV TRANSFORMERS

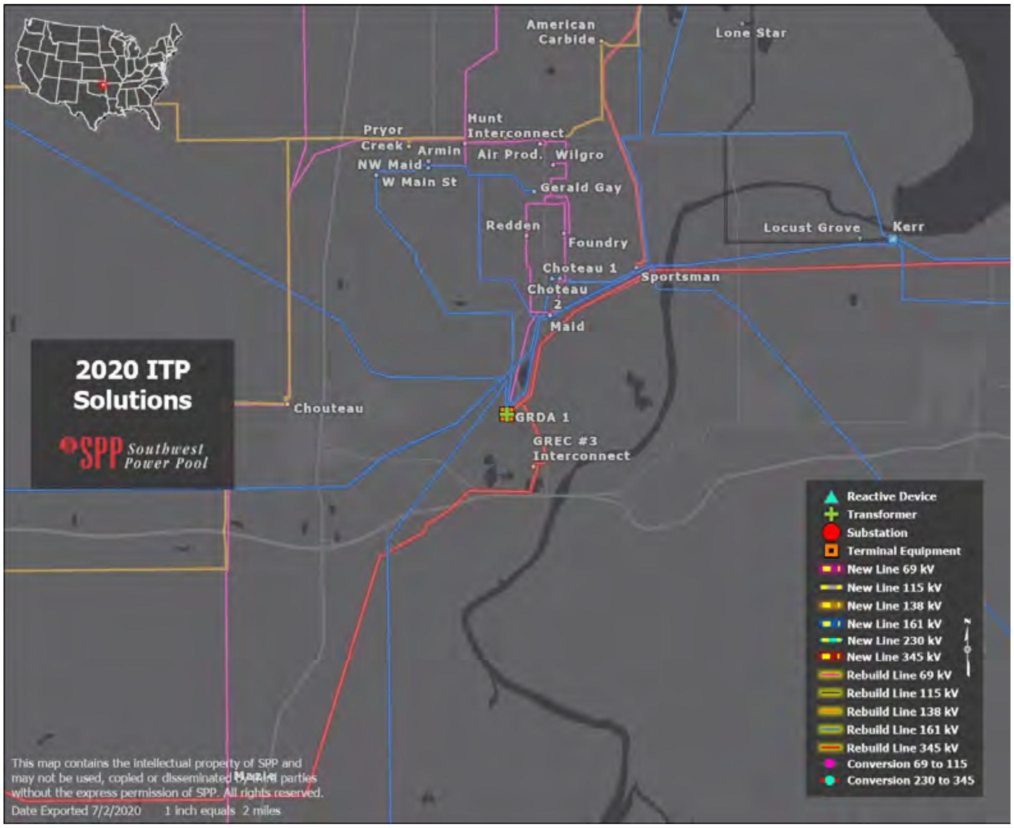

Figure 7.23: GRDA 345/161 kV Transformers

East of Tulsa, Oklahoma, at the GRDA plant substation, the second GRDA 345/161 kV transformer becomes congested for the loss of the first transformer. Both transformers are rated equally and are terminally limited, driving the need for the selected project to upgrade terminal equipment to increase the capacity of both transformers.

7.3.5 COLUMBUS EAST 230/115 KV TRANSFORMER

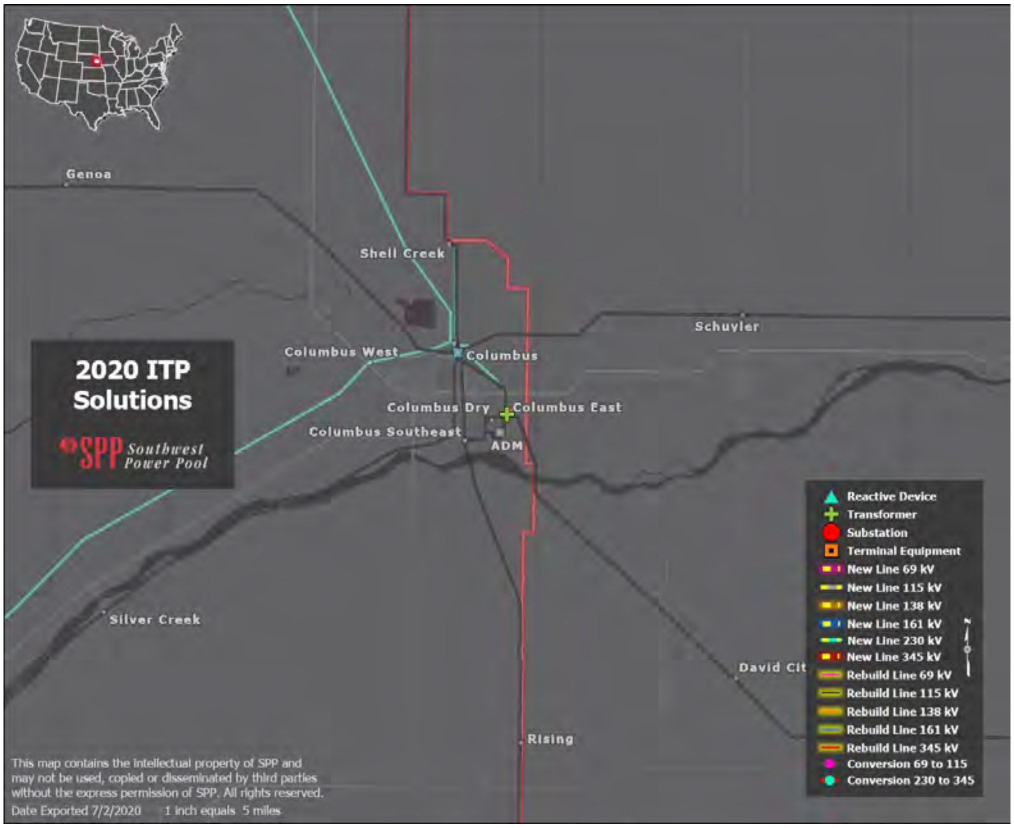

Figure 7.24: Columbus East 230/115 kV Transformer

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 today. The project selected to address the congestion is to replace the Columbus East transformer in order to better utilize the HV system that feeds into Columbus, Lincoln, and Omaha, NE load centers.

7.3.6 FRANKS-SOUTH CROCKER-LEBANON 161 KV

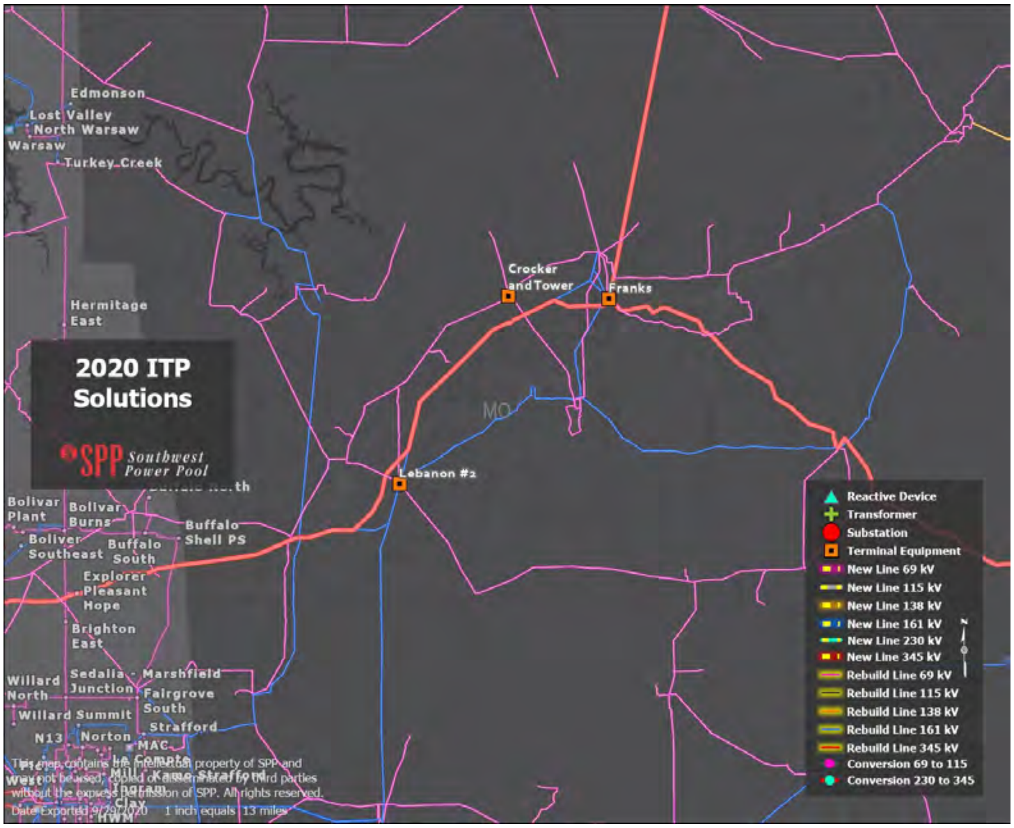

Figure 7.25: Franks-South Crocker-Lebanon 161 kV

In south-central Missouri, northeast of Springfield, the Franks-Crocker 161 kV line becomes congested for the loss of the Huben-Franks 345 kV line. The 161 kV path parallels the 345 kV path and carries the power when the EHV line is out of service. The 161 kV path is terminally limited so upgrading the terminal equipment at the Franks, South Crocker, and Lebanon substations relieves the congestion by allowing for increased flows in the area.

7.3.7 CHISHOLM-WOODWARD/BORDER TAP 345 KV

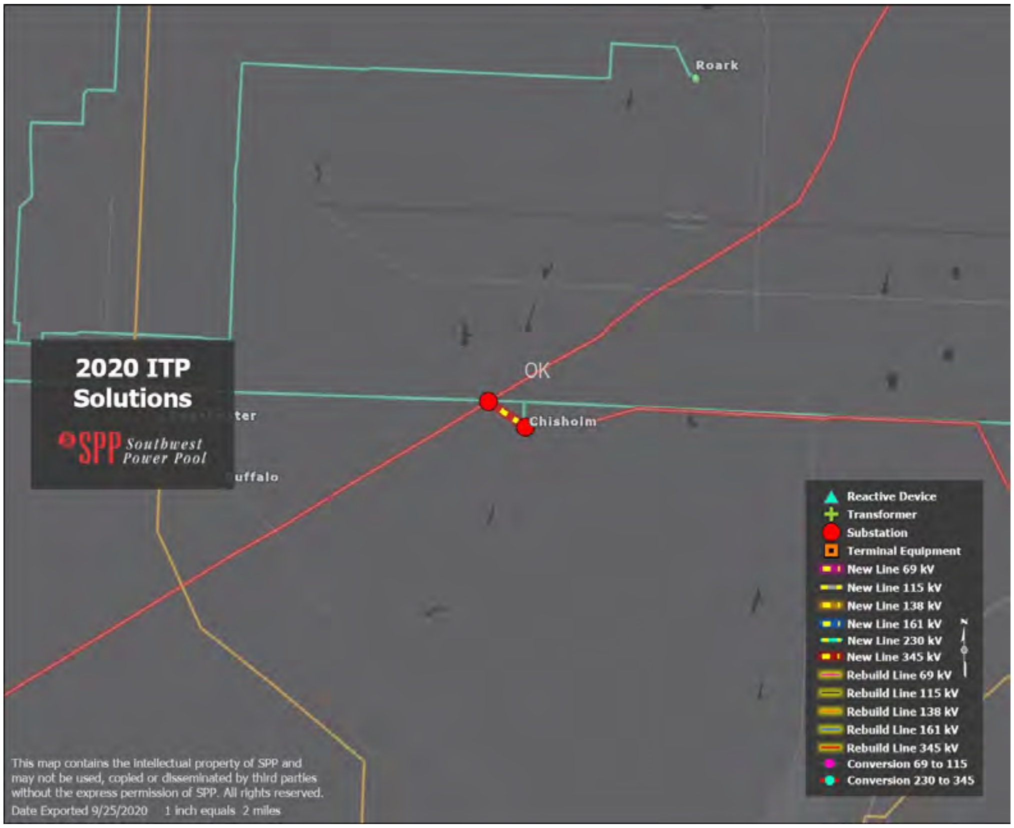

Figure 7.26: Chisholm-Woodward/Border Tap 345 kV

In western Oklahoma, just east of the Texas border, the 345 kV system out of Gracemont to the west is built out but not connected. The top congested flowgate in the area is the Shamrock 115/69 kV transformer for the loss of the Sweetwater-Chisholm 230 kV line. The project selected for the area is to tap the Border-Tuco 345 kV line and connect to the Chisholm 345 kV station less than a mile away. This project connects the 345 kV radial from Gracemont to the rest of the 345 kV system and allows more bulk transfers across the east Texas/west Oklahoma system. The Sweetwater-Chisholm outage has also been identified as a limiting constraint in the assessment of resource adequacy.

7.3.8 DOVER SWITCH-OKEENE AND ASPEN-MOORELAND-PIC 138 KV

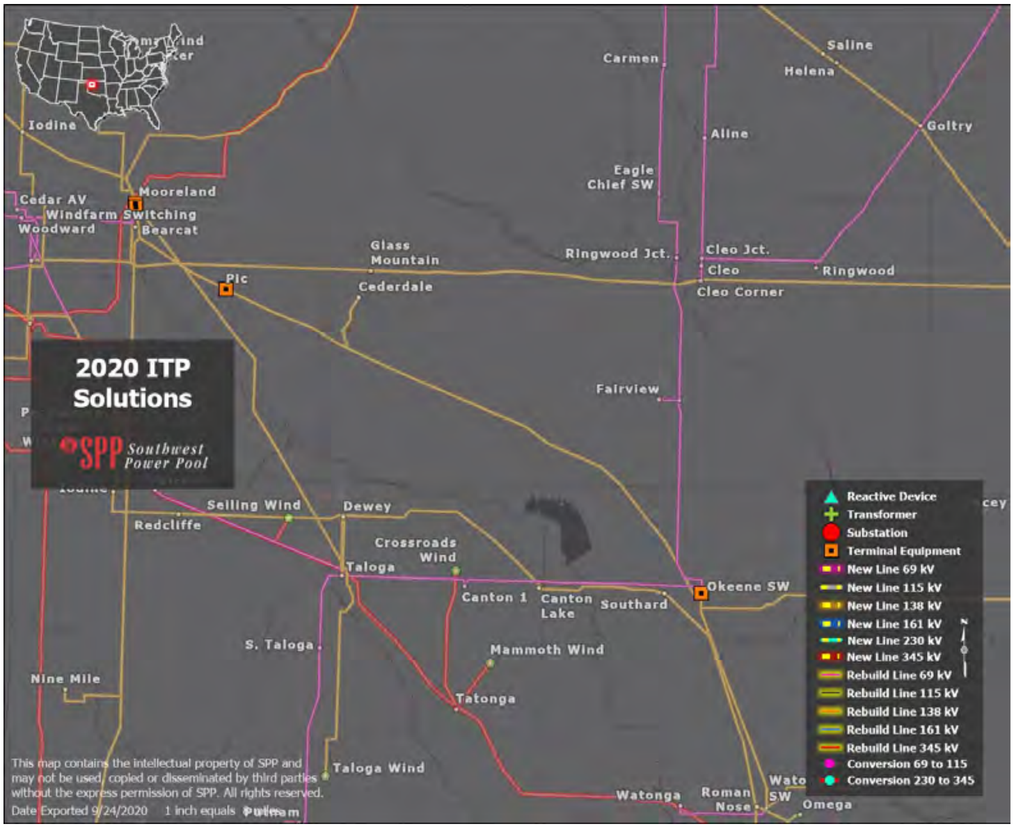

Figure 7.27: Dover Switch-Okeene and Aspen-Mooreland-Pic 138 kV

Northwest of Oklahoma City towards Woodward, the Dover-Okeene 138 kV line becomes congested for the loss of the Watonga-Okeene 138 kV line. The line to Watonga is a parallel 138 kV path to the south while the line to Dover is to the east out of the Okeene substation. This 138 kV network supports west-to-east bulk power transfers to bring low cost generation to the central and eastern load centers. The Dover-Okeene line is terminally limited, and when those limitations are eliminated, congestion increases on the 138 kV system to the north. The project selected to address the congestion is to upgrade terminal equipment on the Dover Switch-Okeene 138 kV line. To realize the benefits of increased transfers on the Dover-Okeene line, terminal equipment on the upstream elements of Aspen-Mooreland-Pic 138 kV must also be upgraded.

7.3.9 MINCO-PLEASANT VALLEY-DRAPER 345 KV

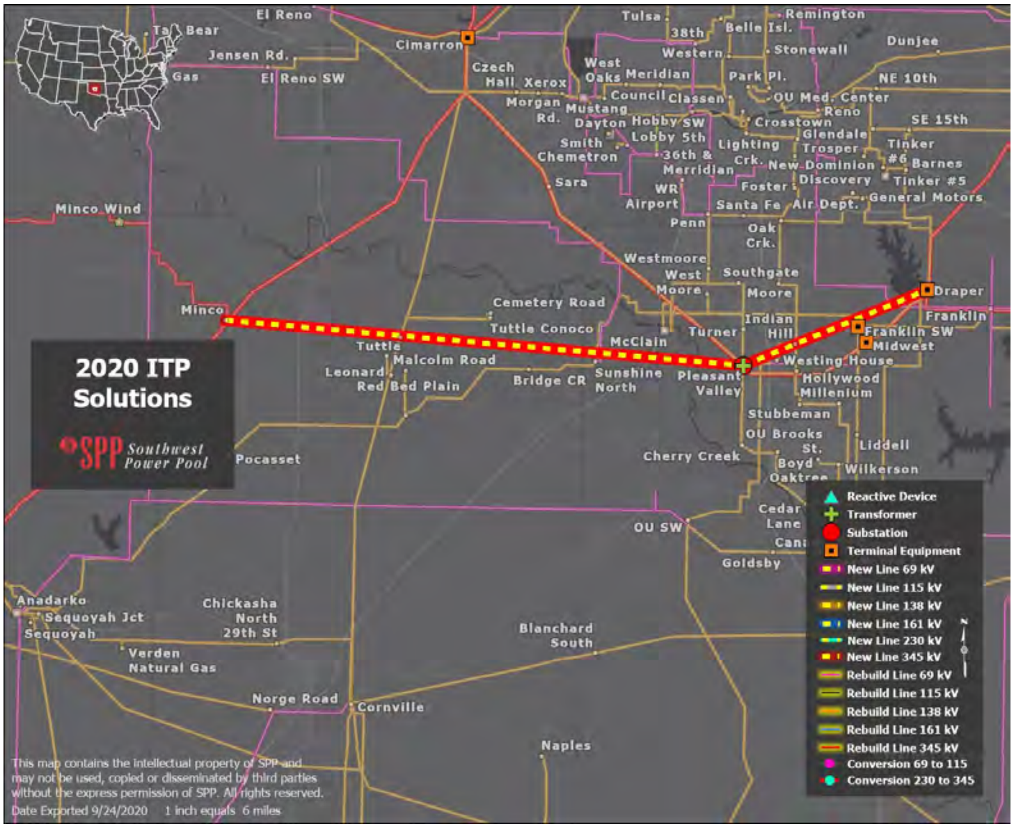

Figure 7.28: Minco-Pleasant Valley-Draper 345 kV

Several different needs were identified in and around the Oklahoma City (OKC) area. The first of two 345/138 kV transformers at Cimarron experiences congestion for the loss of the second. Just south of the Cimarron station, the Czech Hall-Cimarron 138 kV line, which feeds the west side of the city, experiences congestion for the loss of the Cimarron-Draper 345 kV line. The Skyline-Quail Creek 138 kV line to the north of the city experiences congestion for the loss of the Northwest-Arcadia 345 kV line. These issues show the impact of west-to-east power flows across the EHV loop around OKC as well as the need for additional sources into OKC to serve local load.

Multiple solutions to address congestion in the area were analyzed, from new EHV on both the north and south sides of OKC, to HV solutions attempting to address the congestion directly. The project selected is:

- A new Minco-Pleasant Valley-Draper 345 kV line on the south side of OKC;
- A tie-in of the existing Cimarron-Draper 345 kV line to the Pleasant Valley substation;
- Terminal upgrades at Cimarron and Draper to increase the line rating to a 3.000 amp standard that the new facilities will be built at; and
- Terminal upgrades on the Midwest-Franklin 138 kV line to address downstream congestion on the HV system that exists today.

7.3.10 SPLIT ROCK 345/115 KV TRANSFORMERS

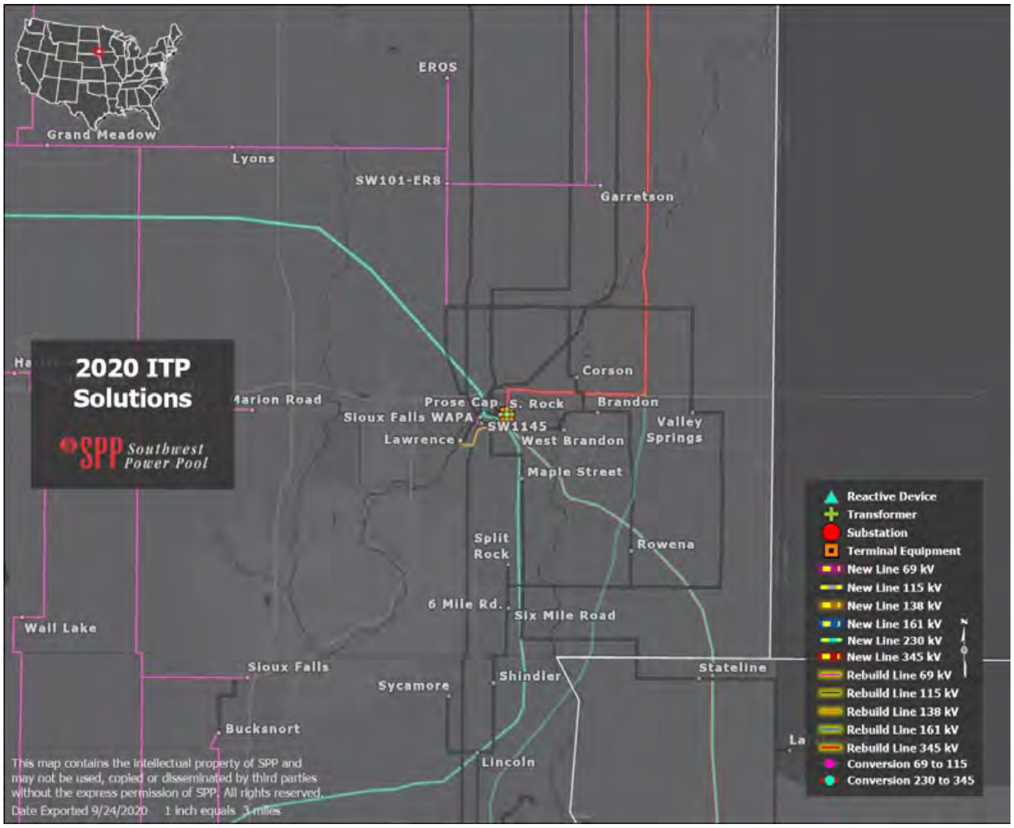

Figure 7.29: Split Rock 345/115 kV Transformers

On the northeast side of Sioux Falls, South Dakota, the Split Rock substation helps to serve as a transmission hub for power transfers, mostly in support of north-to-south flows. The first Split Rock 345/115 kV transformer becomes congested for the loss of the second. This issue was also analyzed in the CSP study with MISO but did not produce a solution beneficial to both regions because SPP generation is largely redispatching to resolve the congestion. These transformers are terminally limited and by upgrading this equipment, the SPP region still sees benefit even though this facility is not under the SPP tariff, but rather a Northern States Power facility in MISO. The selected solution is to upgrade terminal equipment on both Split Rock 345/115 kV transformers.

An upgrade of a Non-SPP facility in MISO would require additional coordination with Northern States Power (NSPP) and MISO, and a FERC filing to support SPP regional highway/byway cost allocation. The project benefits are primarily driven by Future 2 and marginally passed consolidation by including a small amount of real-time operational congestion. Additionally, there are stakeholder concerns around the benefits and staff concerns that the upgrade may reflect the need for a generator outlet facility for a MISO-projected resource and siting plan assumed in Future 2.

For these reasons, there is not strong enough justification for SPP to pursue this upgrade at this time and is recommending to defer addressing this system limit to future ITP/CSP cycles.

7.3.11 OAHE-SULLY BUTTES-WHITLOCK 230 KV

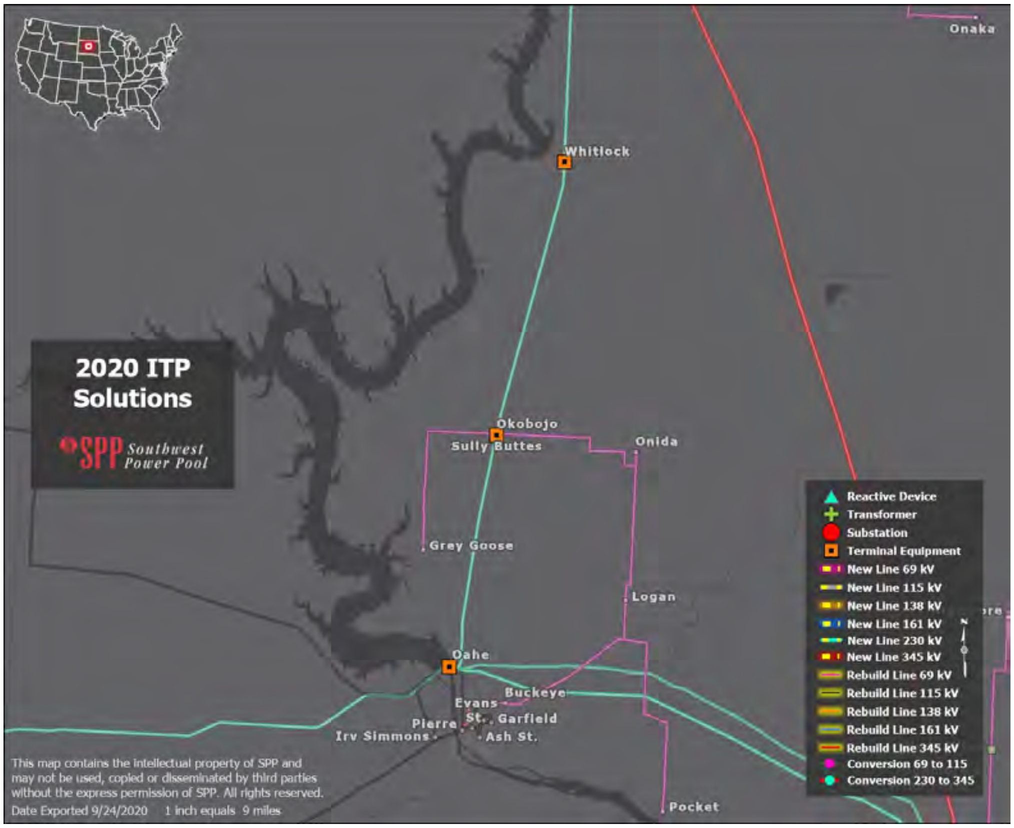

Figure 7.30: Oahe-Sully Buttes-Whitlock 230 kV

To the north of Pierre, South Dakota, multiple transmission paths help to serve load centers to the north towards Bismarck, North Dakota. The Oahe-Sully Buttes 230 kV line becomes congested for the loss of the Fort Thompson-Leland Olds 345 kV line. The 230 kV segments from Oahe moving north are all terminally limited. 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 was to replace terminal equipment and increase line clearances for the Oahe-Sully Buttes-Whitlock 230 kV lines.

However, estimated cost did not include additional expenses for transmission line clearance mitigations which, when considered, do not make this project cost beneficial enough to receive an NTC at this time. SPP recommends that this project be reconsidered in future ITP cycles.

7.3.12 MALJAMAR 115 KV CAPACITOR BANK

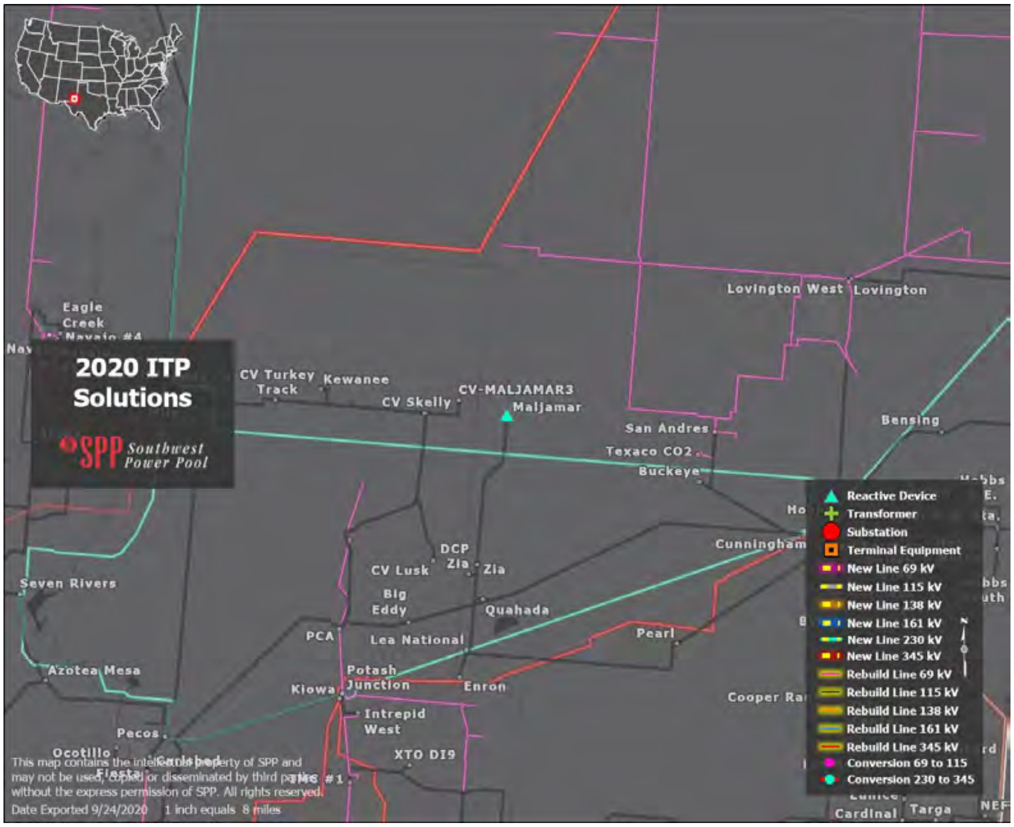

Figure 7.31: Maljamar 115 kV Capacitor Bank

West of Hobbs near the community of Maljamar, New Mexico, the Maljamar 115 kV bus experiences both base-case low voltage and low voltage for the loss of the PCA-Big Eddy 115 kV line. These low voltages are present only in the long-term summer peaks of the market powerflow models. The Maljamar bus serves load at the end of a radial feed, making it susceptible to lower voltages. The PCA-Big Eddy 115 kV line is a connector to the 230 kV bus at Potash Junction, which causes the Maljamar 115 kV bus to lose voltage support once the contingency occurs. Adding a capacitor capable of producing 14.4 MVAR at the Maljamar 115 kV bus will mitigate this issue.

7.3.13 RUSSELL 115 KV CAPACITOR BANK

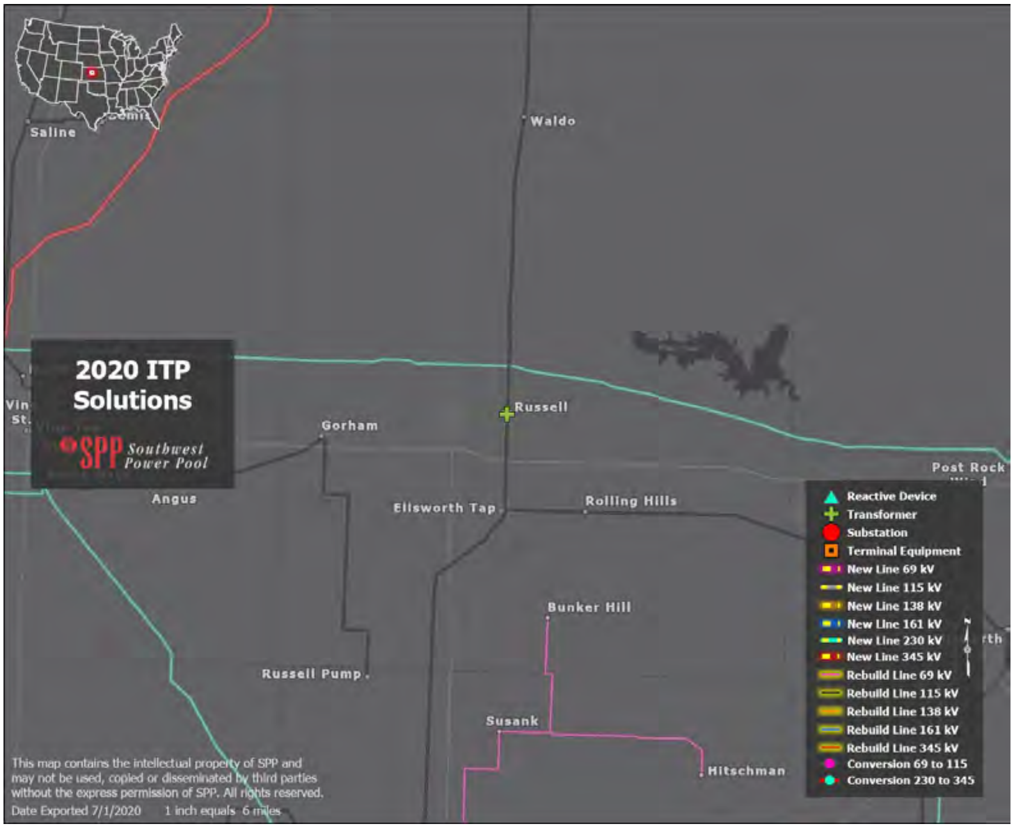

Figure 7.32: Russell 115 kV Capacitor Bank

West of Salina near the town of Russell, Kansas, the Russell substation experiences low voltage for the loss of the Ellsworth Tap-Russell 115 kV transmission line. Upon contingency, the Russell load is fed at the end of a long radial 115 kV line, which causes voltage drop below criteria when load is high in the summer in the market powerflow models. The project selected to mitigate this issue is to add a 24 MVAR capacitor at the Russell substation to bring the voltage back up to acceptable levels.

7.3.14 AGATE 115 KV REACTOR

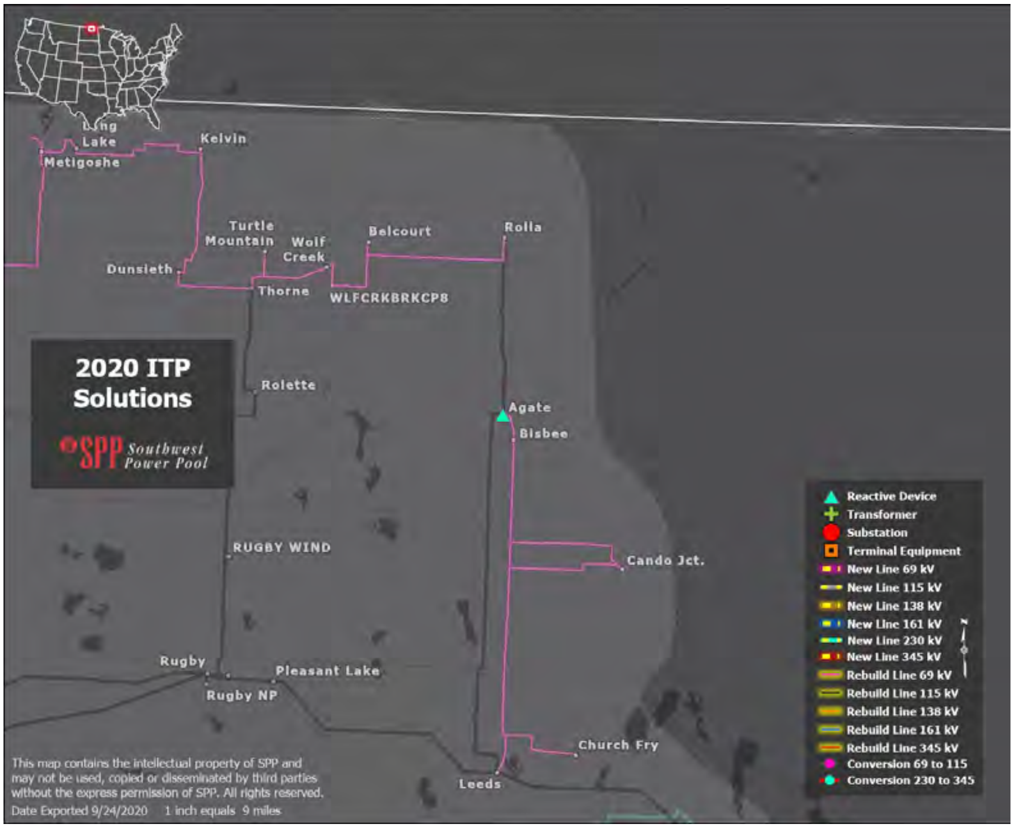

Figure 7.33: Agate 138 kV Reactor

Northwest of Grand Forks, near the town of Rolla, North Dakota, light-load conditions in the market powerflow models cause the 69 kV system to experience base-case high voltages coming off the 115/69 kV transformers at Agate and Leeds. Tap adjustments on the Agate 115/69 kV transformer shift the over-voltage to the high side of the transformer, making this an infeasible mitigation. With no other reactive resources in the area to bring down the over-voltage condition, reactive consumption needs to be installed near the 69 kV loads in this region. The project selected to mitigate this issue is to add a 12 MVAR reactor at the Agate 115 kV bus.

7.3.15 DEVIL'S LAKE 115 KV REACTOR

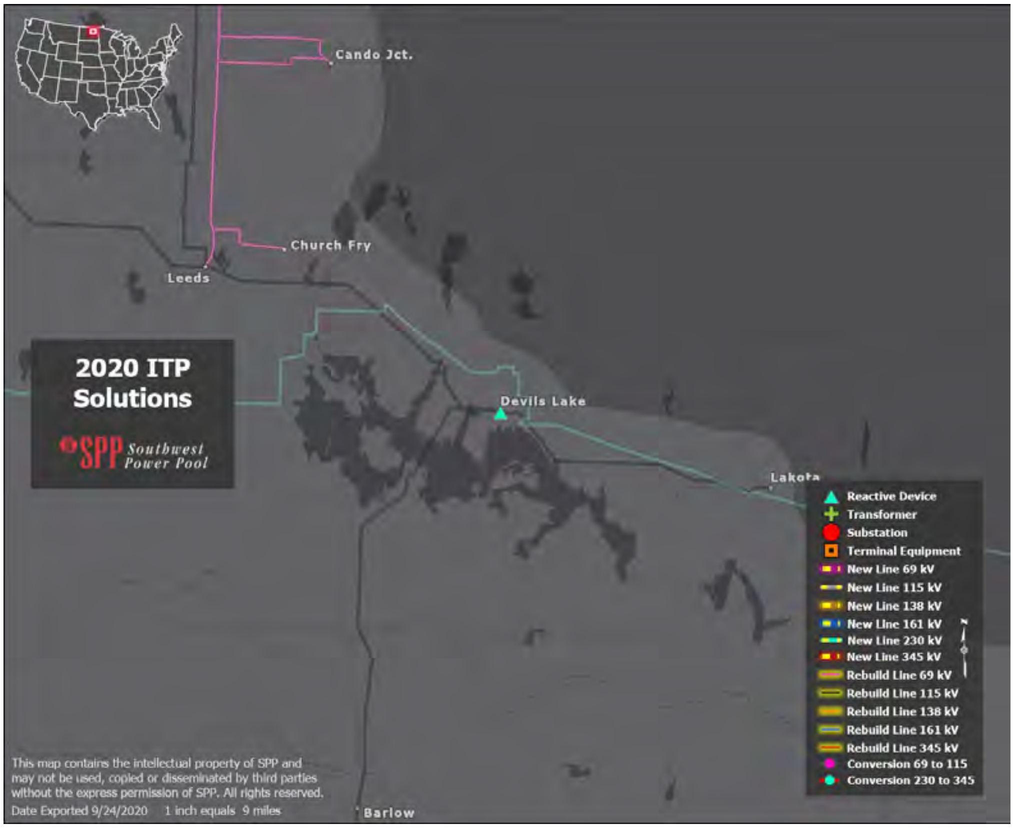

Figure 7.34: Devil's Lake 115 kV Reactor

West of Grand Forks, near the town of Devil's Lake, North Dakota, the 115 kV bus at Devil's Lake and surrounding area experiences high base-case voltages during light-load conditions in the market powerflow models. Without any reactive consumption devices or tap changing transformers nearby, no reactive adjustments are available to bring the voltage back to acceptable levels. The project selected to mitigate this issue is to install a 25 MVAR capable reactor bank at the Devil's Lake 115 kV substation.

7.4 POLICY PROJECTS

No policy projects are required for the 2020 ITP assessment.

8 INFORMATIONAL PORTFOLIO ANALYSIS

8.1 BENEFITS

8.1.1 METHODOLOGY

Benefit metrics were used to measure the value and economic impacts of the final portfolio. The Benefit Metrics Manual[27] provides the definitions, concepts, calculations, and allocation methodologies for all approved metrics. The ESWG directed that the 2020 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 shown in Table 9.1 (regardless of NTC recommendation). The benefit structure shown in Table 8.1 illustrates the metrics calculated as the incremental benefit of the projects included in the portfolios.

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

Table 8.1: Benefit Metrics

8.1.2 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

[27] Benefit Metrics Manual

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[28], two years were analyzed, 2025 and 2030. APC savings were calculated accordingly for these years. The benefits are extrapolated to the fifteenth year based on the slope between the two points. After that, they are assumed to grow at an inflation rate of 2.5 percent per year. Each year's benefit was then discounted to 2025 using an eight percent discount rate, and a 2.5 percent inflation rate from 2025 back to 2020. The sum of all discounted benefits was presented as the NPV benefit. This calculation was performed for every zone.

Figure 8.1 shows the regional APC savings for the recommended portfolio over 40 years.

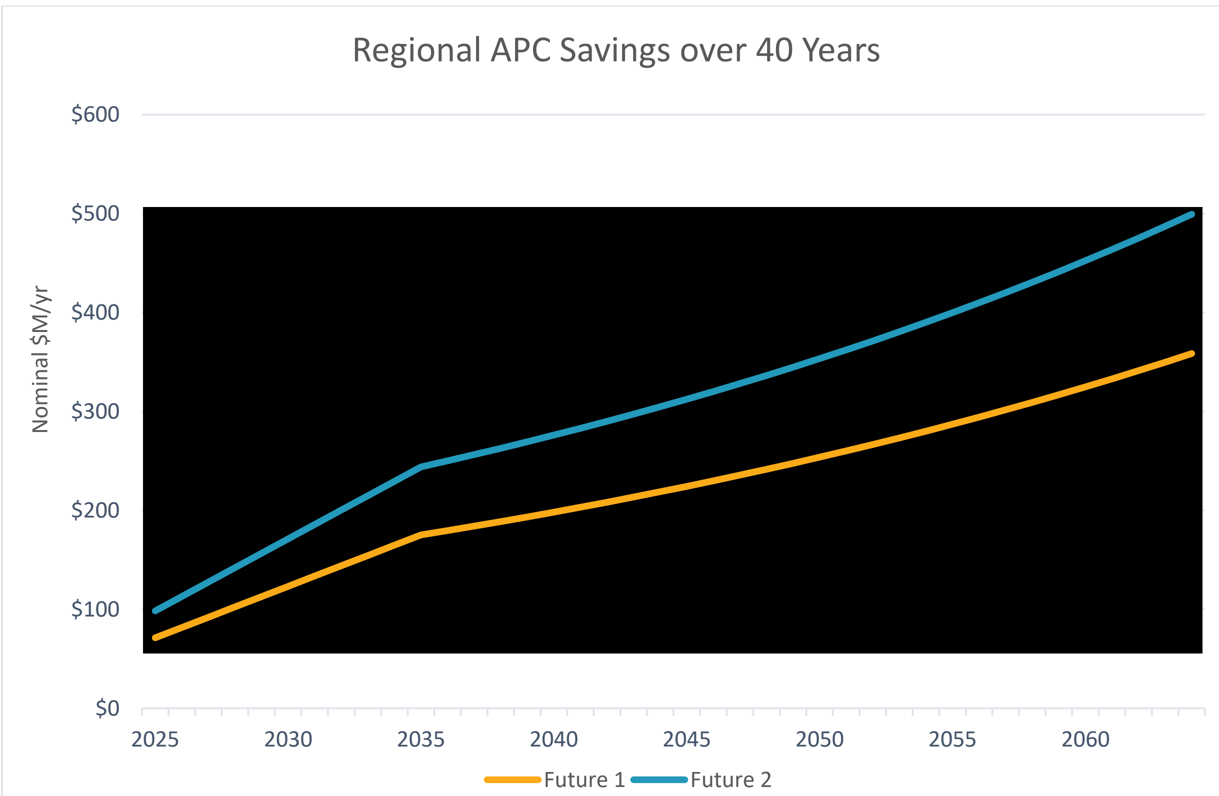

Figure 8.1: Regional APC Savings for the 40-Year Study Period

Table 8.2 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.

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

Zone	Reference Case (Future 1)			Emerging Technologies (Future 2)		
	2025 ($M)	2030 ($M)	40-yr NPV ($2020M)	2025 ($M)	2030 ($M)	40-yr NPV ($2020M)
AEPW	$9.2	$22.4	$350.0	$15.9	$37.7	$587.8
EMDE	$5.2	$3.7	$39.4	$8.3	$5.1	$50.2
GMO	$0.2	$1.2	$20.5	$1.8	$3.7	$56.7
GRDA	$8.7	$12.9	$186.3	$6.9	$10.5	$152.3
KCBPU	($0.1)	$0.6	$11.5	$0.0	$2.1	$37.5
KCPL	$1.9	$3.8	$57.2	($0.3)	$1.6	$30.4
LES	$0.2	$0.3	$4.2	$0.3	$1.6	$26.2
MIDW	($1.1)	($1.5)	($20.7)	($1.2)	($1.3)	($16.8)
NPPD	$0.2	$0.7	$12.1	($0.1)	$0.9	$16.8
OKGE	$31.4	$57.0	$854.4	$33.5	$64.7	$979.5
OPPD	$0.3	($0.4)	($8.0)	$0.8	$1.4	$21.0
SPRM	$1.1	$0.7	$5.9	$1.1	$0.4	$2.0
SPS	($0.4)	($0.1)	$0.7	$9.4	$2.0	($11.7)
SUNC	($3.5)	($4.8)	($67.1)	($3.4)	($3.9)	($52.2)
SWPA	$0.3	$0.7	$11.6	$1.6	$2.4	$34.2
UMZ	$5.8	$9.2	$134.1	$9.6	$23.1	$361.1
WERE	$4.6	$6.0	$83.1	$4.7	$4.6	$58.3
WFEC	$7.0	$11.3	$165.4	$9.3	$16.6	$248.0
TOTAL:	**$71.2**	**$123.8**	**$1,840.4**	**$98.4**	**$173.3**	**$2,581.3**

Table 8.2: APC Savings by Zone

Table 8.3 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 percent production cost minus sales to other zones (revenue).

Zone	Reference Case (F1)			Emerging Technologies (F2)		
	2025 ($M)	2030 ($M)	40-yr NPV ($2020M)	2025 ($M)	2030 ($M)	40-yr NPV ($2020M)
OTHSPP	$38.8	$85.3	$1,317.2	$54.8	$69.6	$960.9

Table 8.3: Other SPP APC Benefit

8.1.3 REDUCTION OF EMISSION RATES AND VALUES

Additional transmission may result in a lower fossil-fuel burn (for example, less coal-intensive generation), resulting in less SO2, NOX, and CO2 emissions. Such a reduction in emissions is a benefit that is already monetized through the APC savings metric, based on the assumed allowance prices for these effluents. Note that neither ITP future assumes any allowance prices for CO2.

8.1.4 SAVINGS DUE TO LOWER ANCILLARY SERVICE NEEDS AND PRODUCTION COSTS

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

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

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

8.1.5 AVOIDED OR DELAYED RELIABILITY PROJECTS

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

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

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

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes an inefficiency inherent to all standard conductors. Line losses across the SPP system are directly related to system impedance. Transmission projects often reduce losses during peak load conditions, which lowers the costs associated with additional generation capacity needed to meet the capacity requirements.

The capacity cost savings for the recommended portfolio are calculated based on the on-peak losses estimated in the base reliability powerflow model. The loss reductions are then multiplied by 112 percent to estimate the reduction in installed capacity requirements. The value of capacity savings is monetized by applying a net cost of new entry (CONE) of $85.61/kW-yr in 2018 dollars. The net CONE value was obtained from Attachment AA Resource Adequacy-Attachment AA Section 14 of the tariff. The net CONE was assumed to grow at an inflation rate of 2.5 percent for each study year, $2M for 2025, and $2.7M for 2030. Table 8.4 displays the associated capacity savings for each zone in each study year and the 40-year NPV.

Base Reliability			
Zone	2025 ($M)	2030 ($M)	40-yr NPV (2020$M)
AEPW	$0.08	$0.11	$1.46
EMDE	($0.00)	($0.00)	($0.01)
GMO	$0.00	$0.00	$0.04
GRDA	$0.00	$0.00	$0.01
KCBPU	$0.00	$0.00	($0.00)
KCPL	$0.01	$0.00	$0.03
LES	$0.00	$0.00	$0.03
MIDW	$0.00	$0.00	$0.02
NPPD	$0.02	$0.01	$0.08
OKGE	$0.38	$0.47	$6.46
OPPD	($0.00)	($0.00)	($0.01)
SPRM	($0.00)	($0.00)	($0.00)
SPS	$0.73	$1.20	$17.63
SUNC	$0.01	$0.01	$0.10
SWPA	$0.04	$0.04	$0.50
UMZ	$0.38	$0.52	$7.42
WFEC	$0.11	$0.11	$1.36
WERE	$0.22	$0.25	$3.36
Total:	**$2.0**	**$2.7**	**$38.5**

Table 8.4: On-Peak Loss Reduction and Associated Capacity Cost Savings

8.1.7 ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

This metric monetizes the benefits of reliability projects built to meet compliance requirements and mitigate SPP Criteria violations. The regional benefits are assumed to be equal to the 40-year NPV of ATRRs of the projects, totaling $217 million in 2020 dollars.

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

Table 8.5 summarize the SR analysis results, load-ratio shares (LRS), and the benefit allocation factors for different voltage levels. The table shows the overall zonal benefits calculated by applying these allocation factors.

Mandated Reliability Benefits Base Reliability and Short-Circuit									
	< 100 kV	100-300 kV			> 300 kV			All Projects	
SPP-wide Benefit	**$22.86**	**$130**			**$64**			**$217**	
Zone	**100% SR**	**67% SR**	**33% LRS**	**Wtd. Avg**	**33% SR**	**67% LRS**	**Wtd. Avg**	**Allocation**	**Benefit 2020$M**
AEPW	6.8%	10.4%	20.3%	13.7%	0.5%	20.3%	13.7%	13.0%	$28.1
EMDE	3.2%	1.5%	2.3%	1.8%	0.6%	2.3%	1.7%	1.9%	$4.2
GMO	2.9%	7.2%	3.7%	6.1%	24.9%	3.7%	10.8%	7.1%	$15.5
GRDA	1.1%	0.6%	1.6%	1.0%	0.4%	1.6%	1.2%	1.1%	$2.3
KCBPU	0.1%	1.9%	0.9%	1.5%	0.2%	0.9%	0.7%	1.1%	$2.5
KCPL	4.5%	7.0%	7.4%	7.2%	20.5%	7.4%	11.8%	8.2%	$17.9
LES	0.3%	0.2%	1.4%	0.6%	17.0%	1.4%	6.6%	2.4%	$5.1
MIDW	4.9%	2.8%	0.7%	2.1%	0.3%	0.7%	0.6%	2.0%	$4.3
NPPD	6.9%	4.0%	6.0%	4.7%	7.4%	6.0%	6.5%	5.4%	$11.8
OKGE	17.3%	13.0%	12.9%	13.0%	1.3%	12.9%	9.1%	12.3%	$26.7
OPPD	4.0%	2.5%	4.6%	3.2%	0.4%	4.6%	3.2%	3.3%	$7.1
SPRM	4.6%	3.2%	2.1%	2.9%	0.0%	2.1%	1.4%	2.6%	$5.7
SPS	3.2%	2.8%	0.7%	2.1%	0.3%	0.7%	0.6%	1.8%	$3.9
SUNC	7.3%	1.2%	1.3%	1.3%	0.3%	1.3%	1.0%	1.8%	$3.9
SWPA	23.2%	29.3%	11.4%	23.3%	23.0%	11.4%	15.3%	20.9%	$45.4
UMZ	4.4%	2.7%	9.4%	4.9%	0.0%	9.4%	6.3%	5.3%	$11.5
WERE	3.5%	5.3%	9.8%	6.8%	2.9%	9.8%	7.5%	6.7%	$14.5
WFEC	1.7%	4.1%	3.2%	3.8%	0.2%	3.2%	2.2%	3.1%	$6.8
Total:	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**$216.9**

Table 8.5: Mandated Reliability Benefits

8.1.8 BENEFIT FROM MEETING PUBLIC POLICY GOALS

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

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

8.1.9 MITIGATION OF TRANSMISSION OUTAGE COSTS

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

To estimate the incremental savings associated with the mitigation of transmission outage costs, the production cost simulations can be augmented for a realistic level of transmission outages. Due to the significant effort needed to develop these augmented models for each case, the findings from the RCAR II study were used to calculate this benefit metric for the consolidated portfolio as a part of this ITP assessment.

In the RCAR analysis, adding a subset of historical transmission outage events to the production cost simulations increased the APC savings by 11.3 percent.[29] Applying this ratio to the APC savings estimated for the recommended portfolio translates to a 40-year NPV benefit of $1,840 million for Future 1 and $2,581 million for Future 2 in 2020 dollars. These benefits are allocated to zones based upon their LRS within the region. Table 8.6 shows the outage mitigation benefits allocated to each SPP zone.

Zone	Future 1 (2020$M)	Future 2 (2020$M)
AEPW	$43.2	$59.9
EMDE	$4.9	$6.8
GMO	$7.9	$11.0
GRDA	$3.5	$4.9
KCBPU	$1.9	$2.7
KCPL	$15.8	$21.9
LES	$3.0	$4.2
MIDW	$1.6	$2.2
NPPD	$12.7	$17.6
OKGE	$27.5	$38.2
OPPD	$9.7	$13.5
SPRM	$2.8	$3.9
SPS	$24.3	$33.7
SUNC	$4.6	$6.3
SWPA	$1.5	$2.1

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

Zone	Future 1 (2020$M)	Future 2 (2020$M)
UMZ	$20.0	$27.8
WERE	$20.8	$28.9
WFEC	$6.9	$9.6
Total:	**$212.7**	**295.0**

Table 8.6: Transmission Outage Cost Mitigation Benefits by Zone

8.1.10 INCREASED WHEELING THROUGH AND OUT REVENUES

Increasing available transfer capacity (ATC) with a neighboring region improves import and export opportunities for the SPP footprint. Increased interregional transmission capacity that allows for increased through and out transactions will also increase SPP wheeling revenues.

To estimate how increased ATC could affect the wheeling services sold, the historical long-term firm transmission service request (TSR) allowed by the historical NTC projects are analyzed and compared against the ATC increase in the 2014 powerflow models estimated based on a First-Contingency Incremental Transfer Capability (FCITC) analysis. As summarized in Table 8.7, the NTC projects that have been put in-service under SPP's highway/byway cost allocation methodology enabled 13 long-term TSRs to be sold between 2010 and 2014. The TSRs remain active for 2020. The amount of capacity granted for these TSRs add up to 1,402 MW. The associated wheeling revenues are estimated to be $50.4 million annually based on current SPP tariff rates. The results of the FCITC analysis are summarized in Table 8.8. The export ATC increase in the 2014 powerflow models is calculated to be 1,142 MW, which is comparable to the amount of firm capacity granted for the incremental TSRs sold historically for 2020.

Point of Delivery	Number of Firm PtP Service Requests	MW Capacity Granted	2014 Wheeling Revenues in $million			
			Sch 7 Zonal	Sch 11 Reg-Wide	Sch 11 Thru & Out Zonal	TOTAL
AECI	6	716	$8.3	$11.8	$5.4	**$25.6**
KACY	1	100	$1.4	$1.7	$0.8	**$3.9**
Entergy	6	586	$6.8	$9.7	$4.4	**$20.9**
Total:	**13**	**1,402**	**$16.5**	**$23.2**	**$10.6**	**$50.4**

Table 8.7: Estimated Wheeling Revenues from Incremental Long-Term TSRs Sold (2010-2014)

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

Table 8.8: Historical Ratio of TSRs Sold against Increase in Export ATC

The 2025 and 2030 base reliability powerflow models were utilized for the FCITC analysis on the final consolidated portfolio. The ratio of TSRs sold as a percent of increase in export ATC is capped at 100 percent, as incremental TSR sales would not be expected to exceed the amount of increase in export ATC. The recommended portfolio increased the export ATC by 104 MW in 2025 and 234 MW in 2030. Applying the historical ratio suggests the recommended portfolio could enable incremental TSRs by the same amount, generating additional wheeling revenues of $5-12 million annually.

The 40-year NPV of benefits is estimated to be $226 million. These benefits are allocated based on the current revenue sharing method in the tariff. Figure 8.2 shows the distribution of wheeling revenue benefits in each SPP zone.

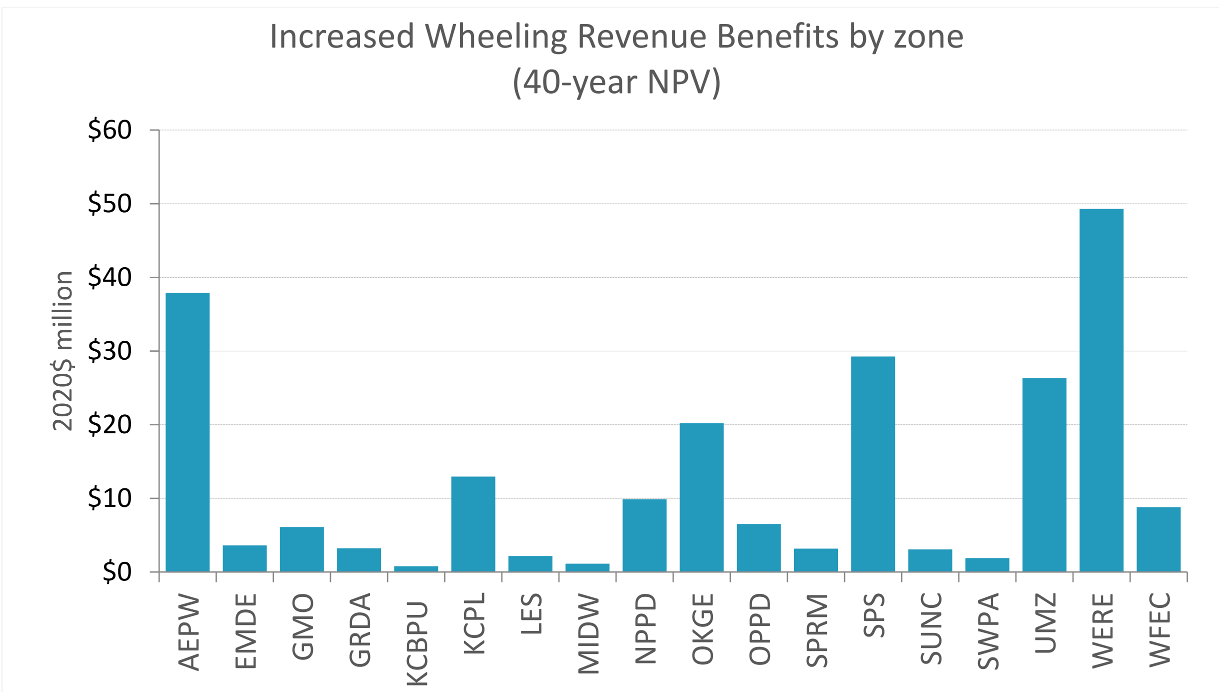

Figure 8.2: Increased Wheeling Revenue Benefits by Zone (40-year NPV)

8.1.11 MARGINAL ENERGY LOSSES BENEFIT

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

APC savings due to such energy loss reductions can be estimated by post-processing the marginal loss component (MLC) of the LMPs from simulation results and applying a methodology[30] for marginal energy losses, which accounts for losses on generation and market imports. The 40-year NPV of benefits is estimated to be $10.97 million in Future 1 and $14.7 million in Future 2, as shown in Table 8.9.

	Reference Case (F1)			Emerging Technologies (F2)		
Zone	2025 ($M)	2030 ($M)	40-yr NPV (2020$M)	2025 ($M)	2030 ($M)	40-yr NPV (2020$M)
AEPW	($0.09)	($1.3)	($22.6)	($1.16)	($1.19)	($15.37)
EMDE	($0.2)	($0.3)	($4.3)	($0.30)	$0.01	$1.73
GMO	$0.34	$0.4	$5.9	$0.71	$0.22	$0.30
GRDA	($0.3)	($0.5)	($7.3)	($0.30)	($0.27)	($3.37)
KCBPU	$0.27	$0.4	$5.2	($0.33)	$0.14	$4.15
KCPL	$0.4	$0.5	$7.3	$0.25	$0.09	$0.30
LES	$0.03	$0.2	$2.7	$0.02	$0.07	$1.12
MIDW	($0.0)	($0.1)	($1.1)	($0.02)	($0.02)	($0.34)
NPPD	$0.06	$0.5	$7.9	$0.22	$0.23	$2.95
OKGE	($0.2)	($1.2)	($19.8)	$0.44	$0.14	$0.31
OPPD	$0.15	$1.4	$23.5	$0.31	$0.18	$1.61
SPRM	$0.0	$0.1	$2.0	$0.24	$0.25	$3.19
SPS	$1.91	$2.0	$25.8	$1.61	$2.07	$28.69
SUNC	$0.1	$0.1	$1.8	$0.18	$0.02	($0.59)
SWPA	($0.03)	($0.0)	($0.3)	($0.03)	$0.06	$1.26
UMZ	$0.2	$0.1	$1.3	$0.21	($0.73)	($14.04)
WERE	$0.64	($0.1)	($4.4)	($0.03)	($0.23)	($3.92)
WFEC	$0.2	($0.6)	($12.5)	($4.93)	($0.99)	$6.76
Total:	**$3.56**	**$1.61**	**$10.97**	**($2.89)**	**$0.03**	**$14.75**

Table 8.9: Energy Losses Benefit by Zone

8.1.12 SUMMARY

Table 8.10 through Table 8.13 summarize the 40-year NPV of the estimated benefit metrics and costs and the resulting B/C ratios for each SPP zone.

For the region, the B/C ratio is estimated to be 4.0 in Future 1 and 5.2 in Future 2. The higher B/C ratio in Future 2 is driven by the APC savings due to higher congestion relief.

[30] As described in the Benefit Metric Manual

Reference Case (Future 1)											
Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)										Present Value of 40-yr ATRRs (in 2020$M)	Est. Benefit/ Cost Ratio
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits		
AEPW	$350	$0	$1	$28	$0	$43	$23	($23)	$423	$93	4.6
EMDE	$39	$0	($0)	$4	$0	$5	$2	($4)	$46	$8	5.5
GMO	$20	$0	$0	$15	$0	$8	$4	$6	$53	$13	4.0
GRDA	$186	$0	$0	$2	$0	$4	$2	($7)	$187	$7	27.1
KCBPU	$12	$0	($0)	$3	$0	$2	$0	$5	$22	$3	6.6
KCPL	$57	$0	$0	$18	$0	$16	$8	$7	$106	$32	3.3
LES	$4	$0	$0	$5	$0	$3	$1	$3	$16	$5	3.2
MIDW	($21)	$0	$0	$4	$0	$2	$1	($1)	($15)	$3	(5.8)
NPPD	$12	$0	$0	$12	$0	$13	$6	$8	$51	$25	2.0
OKGE	$854	$0	$6	$27	$0	$28	$12	($20)	$907	$61	14.9
OPPD	($8)	$0	($0)	$7	$0	$10	$4	$23	$36	$16	2.2
SPRM	$6	$0	($0)	$6	$0	$3	$2	$2	$18	$5	3.9
SPS	$1	$0	$1	$4	$0	$24	$18	$26	$73	$92	0.8
SUNC	($67)	$0	$0	$4	$0	$5	$2	$2	($55)	$11	(4.9)
SWPA	$12	$0	$18	$45	$0	$2	$1	($0)	$77	$3	27.9
UMZ	$134	$0	$7	$11	$0	$20	$16	$1	$190	$65	2.9
WERE	$83	$0	$1	$14	$0	$21	$30	($4)	$145	$159	0.9
WFEC	$165	$0	$3	$7	$0	$7	$5	($12)	$175	$31	5.6
Total:	**$1,840**	**$0**	**$38**	**$217**	**$0**	**$213**	**$137**	**$11**	**$2,456**	**$634**	**3.9**

Table 8.10: Estimated 40-year NPV of Benefit Metrics and Costs-Zonal

Emerging Technologies (Future 2)											
Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)										Present	Est.
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
AEPW	$588	$0	$1	$28	$0	$60	$23	($15)	$685	$93	7.4
EMDE	$50	$0	($0)	$4	$0	$7	$2	$2	$65	$8	7.8
GMO	$57	$0	$0	$15	$0	$11	$4	$0	$87	$13	6.5
GRDA	$152	$0	$0	$2	$0	$5	$2	($3)	$158	$7	22.9
KCBPU	$38	$0	($0)	$3	$0	$3	$0	$4	$47	$3	14.4
KCPL	$30	$0	$0	$18	$0	$22	$8	$0	$78	$32	2.4
LES	$26	$0	$0	$5	$0	$4	$1	$1	$38	$5	7.4
MIDW	($17)	$0	$0	$4	$0	$2	$1	($0)	($10)	$3	(3.8)
NPPD	$17	$0	$0	$12	$0	$18	$6	$3	$55	$25	2.2
OKGE	$980	$0	$6	$27	$0	$38	$12	$0	$1,063	$61	17.4
OPPD	$21	$0	($0)	$7	$0	$13	$4	$2	$47	$16	2.9
SPRM	$2	$0	($0)	$6	$0	$4	$2	$3	$17	$5	3.5
SPS	($12)	$0	$1	$4	$0	$34	$18	$29	$73	$92	0.8
SUNC	($52)	$0	$0	$4	$0	$6	$2	($1)	($41)	$11	(3.7)
SWPA	$34	$0	$18	$45	$0	$2	$1	$1	$102	$3	36.9
UMZ	$361	$0	$7	$11	$0	$28	$16	($14)	$410	$65	6.3
WERE	$58	$0	$1	$14	$0	$29	$30	($4)	$129	$159	0.8
WFEC	$248	$0	$3	$7	$0	$10	$5	$7	$280	$31	8.9
Total:	**$2,581**	**$0**	**$38**	**$217**	**$0**	**$295**	**$137**	**$15**	**$3,283**	**$634**	**5.2**

Table 8.11: Estimated 40-year NPV of Benefit Metrics and Costs-Zonal

Reference Case (Future 1)[31]											
	Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)									Present	Est.
States	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
Arkansas	$85	$0	$0	$12	$0	$13	$6	($3)	$114	$26	4.5
Iowa	$28	$0	$0	$0	$0	$1	$0	($1)	$28	$1	21.4
Kansas	$83	$0	$26	$75	$0	$59	$41	$41	$324	$185	1.7
Louisiana	$51	$0	$0	$4	$0	$6	$3	($3)	$62	$14	4.6
Minnesota	$5	$0	$0	$0	$0	$0	$0	($0)	$5	$0	27.1
Missouri	$923	$0	$7	$62	$0	$56	$26	$7	$1,079	$115	9.4
Montana	$3	$0	$0	$0	$0	$0	$0	($0)	$3	$0	27.1
Oklahoma	$193	$0	$1	$27	$0	$34	$17	($6)	$267	$70	3.8
Nebraska	$266	$0	$5	$24	$0	$30	$36	($12)	$348	$194	1.8
New Mexico	($7)	$0	$0	$2	$0	$1	$0	($0)	($5)	$1	(5.8)
North Dakota	$83	$0	$0	$1	$0	$2	$1	($3)	$83	$3	27.1
South Dakota	$60	$0	$0	$1	$0	$1	$1	($2)	$60	$2	27.0
Texas	$67	$0	$0	$9	$0	$11	$6	($6)	$88	$23	3.8
Wyoming	$1	$0	$0	$0	$0	$0	$0	($0)	$1	$0	27.1
Total:	**$1,840**	**$0**	**$38**	**$217**	**$0**	**$213**	**$137**	**$11**	**$2,456**	**$634**	**3.9**

Table 8.12: Estimated 40-year NPV of Benefit Metrics and Costs-State

[31] State level numbers are representative of load and generation in the SPP region, not the entire state.

Emerging Technologies (Future 2)[32]											
	Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)									Present Value of 40-yr ATRRs (in 2020$M)	Est. Benefit/ Cost Ratio
States	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits		
Arkansas	$150	$0	$0	$12	$0	$18	$6	($3)	$184	$26	7.2
Iowa	$24	$0	$0	$0	$0	$1	$0	($0)	$25	$1	19.2
Kansas	$346	$0	$26	$74	$0	$81	$41	$20	$587	$185	3.2
Louisiana	$86	$0	$0	$4	$0	$9	$3	($2)	$100	$14	7.4
Minnesota	$4	$0	$0	$0	$0	$0	$0	($0)	$4	$0	22.9
(Missouri	$1,078	$0	$7	$62	$0	$78	$26	$3	$1,252	$115	10.9
Montana	$2	$0	$0	$0	$0	$0	$0	($0)	$2	$0	22.9
Oklahoma	$307	$0	$1	$27	$0	$48	$17	($2)	$398	$70	5.7
Nebraska	$347	$0	$5	$24	$0	$41	$36	$7	$460	$194	2.4
New Mexico	($6)	$0	$0	$2	$0	$1	$0	($0)	($4)	$1	(3.8)
North Dakota	$67	$0	$0	$1	$0	$2	$1	($1)	$70	$3	22.9
South Dakota	$49	$0	$0	$1	$0	$2	$1	($1)	$51	$2	22.9
Texas	$125	$0	$0	$9	$0	$15	$6	($4)	$151	$23	6.6
Wyoming	$1	$0	$0	$0	$0	$0	$0	($0)	$1	$0	22.9
Total:	**$2,581**	**$0**	**$38**	**$217**	**$0**	**$295**	**$137**	**$15**	**$3,283**	**$634**	**5.2**

Table 8.13: Estimated 40-year NPV of Benefit Metrics and Costs-State

[32] State level numbers are representative of load and generation in the SPP region, not the entire state.

8.2 RATE IMPACTS

The rate impact to an average retail residential ratepayer in SPP was computed for the recommended portfolio. Rate impact costs and benefits[33] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kWh per month. Benefits and costs for the 2030 study year were used to calculate rate impacts. All 2030 benefits and costs are shown in 2020 dollars, discounting at a 2.5 percent inflation rate.

The retail residential rate impact benefit is subtracted from the retail residential rate impact cost to obtain a net rate impact cost by zone. If the net rate impact cost is negative, it indicates a net benefit to the zone. The rate impact costs and benefits are shown in Table 8.14 through Table 8.17. There is a monthly net benefit for the average SPP residential ratepayer of 16 cents for Future 1. There is a monthly net benefit for the average SPP residential ratepayer of 30 cents for Future 2.

Zone	One-Year ATRR Costs 2030 ($thousands)	One-Year Benefit 2030 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2020$)
AEPW	$7,896	$17,468	$0.15	$0.34	($0.19)
EMDE	$719	$2,859	$0.14	$0.56	($0.42)
GMO	$1,156	$950	$0.12	$0.10	$0.02
GRDA	$581	$10,114	$0.06	$1.05	($0.99)
KCBPU	$283	$496	$0.10	$0.18	($0.08)
KCPL	$2,688	$2,940	$0.18	$0.20	($0.02)
LES	$443	$230	$0.13	$0.07	$0.06
MIDW	$227	($1,145)	$0.10	($0.50)	$0.60
NPPD	$1,854	$577	$0.11	$0.03	$0.07
OKGE	$5,184	$44,561	$0.16	$1.33	($1.18)
OPPD	$1,417	($281)	$0.10	($0.02)	$0.12
SPRM	$408	$509	$0.14	$0.18	($0.04)
SPS	$7,336	($63)	$0.25	$0.00	$0.25
SUNC	$910	($3,729)	$0.14	($0.56)	$0.70
SWPA	$235	$583	$0.43	$1.07	($0.64)
UMZ	$5,297	$7,186	$0.17	$0.23	($0.06)
WERE	$13,179	$4,675	$0.49	$0.17	$0.31
WFEC	$2,521	$8,817	$0.16	$0.56	$0.40
Total:	**$52,334**	**$96,748**	**$0.19**	**$0.35**	**($0.16)**

Table 8.14: Future 1 2030 Retail Residential Rate Impacts by Zone (2020$)

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

Zone	One-Year ATRR Costs 2030 ($thousands)	One-Year Benefit 2030 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2020$)
AEPW	$7,896	$29,423	$0.15	$0.57	($0.42)
EMDE	$719	$4,016	$0.14	$0.79	($0.65)
GMO	$1,156	$2,901	$0.12	$0.31	($0.19)
GRDA	$581	$8,221	$0.06	$0.86	($0.80)
KCBPU	$283	$1,665	$0.10	$0.60	($0.50)
KCPL	$2,688	$1,269	$0.18	$0.09	$0.10
LES	$443	$1,230	$0.12	$0.35	($0.22)
MIDW	$227	($1,009)	$0.10	($0.44)	$0.54
NPPD	$1,854	$732	$0.11	$0.04	$0.06
OKGE	$5,184	$50,551	$0.15	$1.51	($1.35)
OPPD	$1,417	$1,110	$0.10	$0.08	$0.02
SPRM	$408	$327	$0.14	$0.11	$0.03
SPS	$7,336	$1,530	$0.25	$0.05	$0.20
SUNC	$910	($3,052)	$0.14	($0.46)	$0.60
SWPA	$235	$1,853	$0.43	$3.41	($2.98)
UMZ	$5,297	$18,039	$0.17	$0.08	($0.40)
WERE	$13,179	$3,594	$0.49	$0.13	$0.35
WFEC	$2,521	$12,985	$0.16	$0.82	$0.60
Total:	**$52,334**	**$135,386**	**$0.19**	**$0.49**	**($0.30)**

Table 8.15: Future 2 2030 Retail Residential Rate Impacts by Zone (2020$)

State[34]	One-Year ATRR Costs 2030 ($thousands)	One-Year Benefit 2030 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact[35] (2020$)
Arkansas	$1,972	$4,773	$0.15	$0.36	($0.21)
Iowa	$84	$1,415	$0.06	$1.08	($1.02)
Kansas	$18,815	$9,380	$0.17	$0.09	$0.09
Louisiana	$1,155	$2,556	$0.15	$0.34	($0.19)
Minnesota	$16	$278	$0.06	$1.09	($1.02)
Missouri	$8,148	$46,549	$0.14	$0.81	($0.67)
Montana	$9	$151	$0.06	$1.09	($1.02)
Nebraska	$8,234	$11,123	$0.20	$0.26	($0.07)
New Mexico	$411	$338	$0.50	$0.41	$0.09
North Dakota	$257	$4,481	$0.06	$1.09	($1.02)
Oklahoma	$10,488	$7,735	$0.39	$0.29	$0.10
South Dakota	$195	$3,276	$0.06	$1.08	($1.01)
Texas	$2,545	$4,616	$0.19	$0.35	($0.16)
Wyoming	$4	$77	$0.06	$1.09	($1.02)
Total:	**$52,334**	**$96,748**	**$0.19**	**$0.35**	**($0.16)**

Table 8.16: Future 1 2030 Retail Residential Rate Impacts by State (2020$)

[34] State level numbers are representative of load and generation in the SPP region, not the entire state.
[35] State level results are based on load allocations by zone, by state. For example, 4.2 percent of Upper Missouri Zone (UMZ) load is in Nebraska, so 4.2 percent of UMZ benefits are attributed to Nebraska.

State[36]	One-Year ATRR Costs 2030 ($thousands)	One-Year Benefit 2030 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact[37] (2020$)
Arkansas	$1,972	$7,700	$0.15	$0.59	($0.44)
Iowa	$84	$1,164	$0.06	$0.89	($0.83)
Kansas	$18,815	$13,928	$0.17	$0.13	$0.05
Louisiana	$1,155	$4,305	$0.15	$0.57	($0.42)
Minnesota	$16	$226	$0.06	$0.88	($0.82)
Missouri	$8,148	$56,385	$0.14	$0.98	($0.84)
Montana	$9	$123	$0.06	$0.88	($0.82)
Nebraska	$8,234	$21,487	$0.20	$0.51	($0.31)
New Mexico	$411	$1,031	$0.50	$1.26	($0.76)
North Dakota	$257	$3,642	$0.06	$0.88	($0.82)
Oklahoma	$10,488	$14,078	$0.39	$0.52	($0.13)
South Dakota	$195	$2,660	$0.06	$0.88	($0.81)
Texas	$2,545	$8,596	$0.19	$0.64	($0.45)
Wyoming	$4	$62	$0.06	$0.88	($0.82)
Total:	**$52,334**	**$135,386**	**$0.19**	**$0.49**	**($0.30)**

Table 8.17: Future 2 2030 Retail Residential Rate Impacts by State (2020$)

8.3 SENSITIVITY ANALYSIS

The recommended portfolio was tested under select sensitivities to understand the economic impacts associated with variations in certain model assumptions. These sensitivities were not used to develop transmission projects nor filter out projects, but rather to measure the flexibility of the final consolidated portfolio in both futures under different uncertainties. The demand and natural gas price sensitivities were included in the 2020 ITP Scope, however, SPP staff performed additional sensitivities to further explore the performance of the portfolio.

The following sensitivities were conducted:

- Scoped sensitivities
    - High/low natural gas price
    - High/low demand

[36] State level numbers are representative of load and generation in the SPP region, not the entire state.
[37] State level results are based on load allocations by zone, by state. For example, 4.2 percent of Upper Missouri Zone (UMZ) load is in Nebraska, so 4.2 percent of UMZ benefits are attributed to Nebraska.

- Supplemental sensitivities
    - High/low wind[38]
    - High/low solar
    - High/low energy storage
    - High/low unit retirements

The consolidated portfolio was tested in both futures. The APC savings impacts of variations in the model inputs were calculated for the simulations. Figure 8.3 illustrates the expected range of APC savings benefit in comparison to the range of portfolio cost and the impacts of varying sensitivity assumptions on that range of benefits. The cost ranges represent the ±30 percent Study Estimate requirement. The dashed bar in subsequent figures represents the expected case B/C ratio for comparison to the sensitivity case B/C ratios.

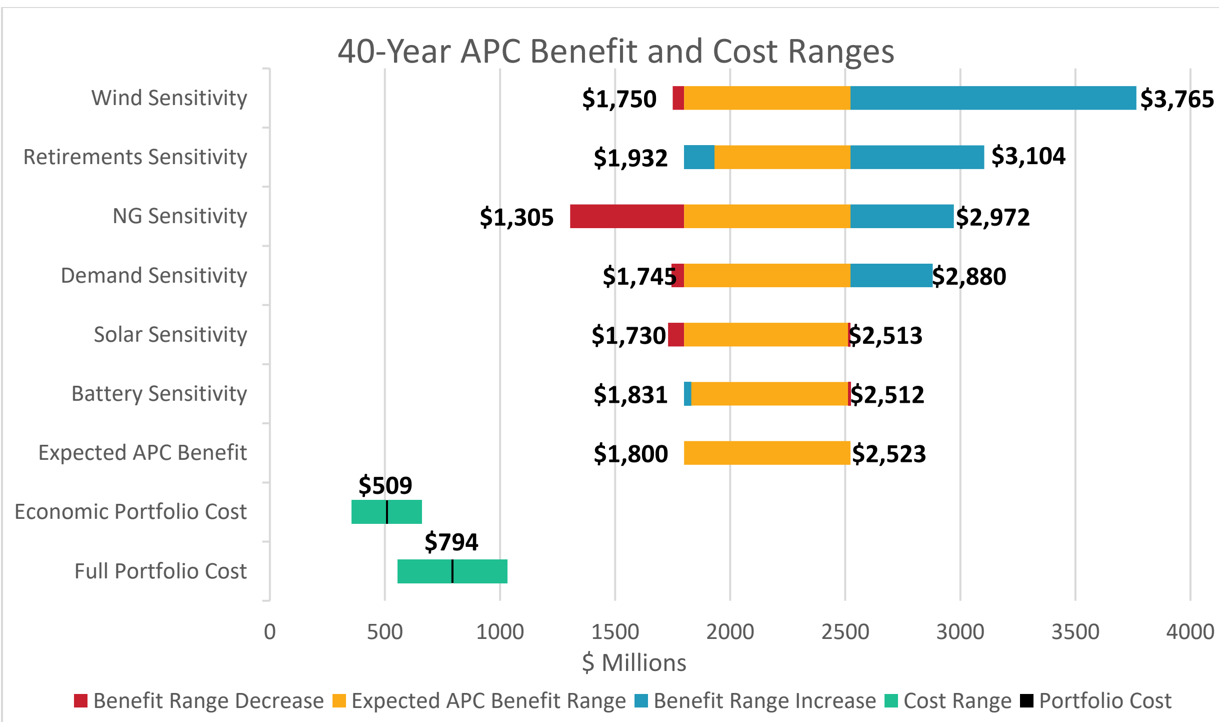

Figure 8.3: 40-Year APC Benefit and Cost Ranges

8.3.1 PEAK DEMAND SENSITIVITY

A single confidence interval for demand levels was developed from FERC Form No. 714. The demand sensitivities had a 67 percent confidence interval (1 standard deviation) in positive and negative directions.

The change in peak demand and energy reflects the SPP regional average volatility based on historical data. The average deviation from the projected 2030 load forecasts developed by the MDWG and

[38] Low wind sensitivity was only assessed in Future 2.

reviewed by the ESWG results in a ±7.5 percent change. This change was implemented on the load at a company level. For companies without available data, the SPP regional average confidence interval was used.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Peak Demand (GW)	Low	53	55	53	55
	Expected	58	59	58	59
	High	62	64	62	64

Table 8.18: Peak Demand Sensitivity

These high and low values were included as inputs to the base models of each future with and without the recommended portfolio. The results of the 40-year APC benefit for this sensitivity are reflected in Figure 8.4. An increase in demand creates an increase in congestion on the SPP system, resulting in higher congestion costs for the portfolios to mitigate, thus increasing the benefit. The opposite is true for the low demand case, which decreases the opportunity for the portfolio to mitigate congestion.

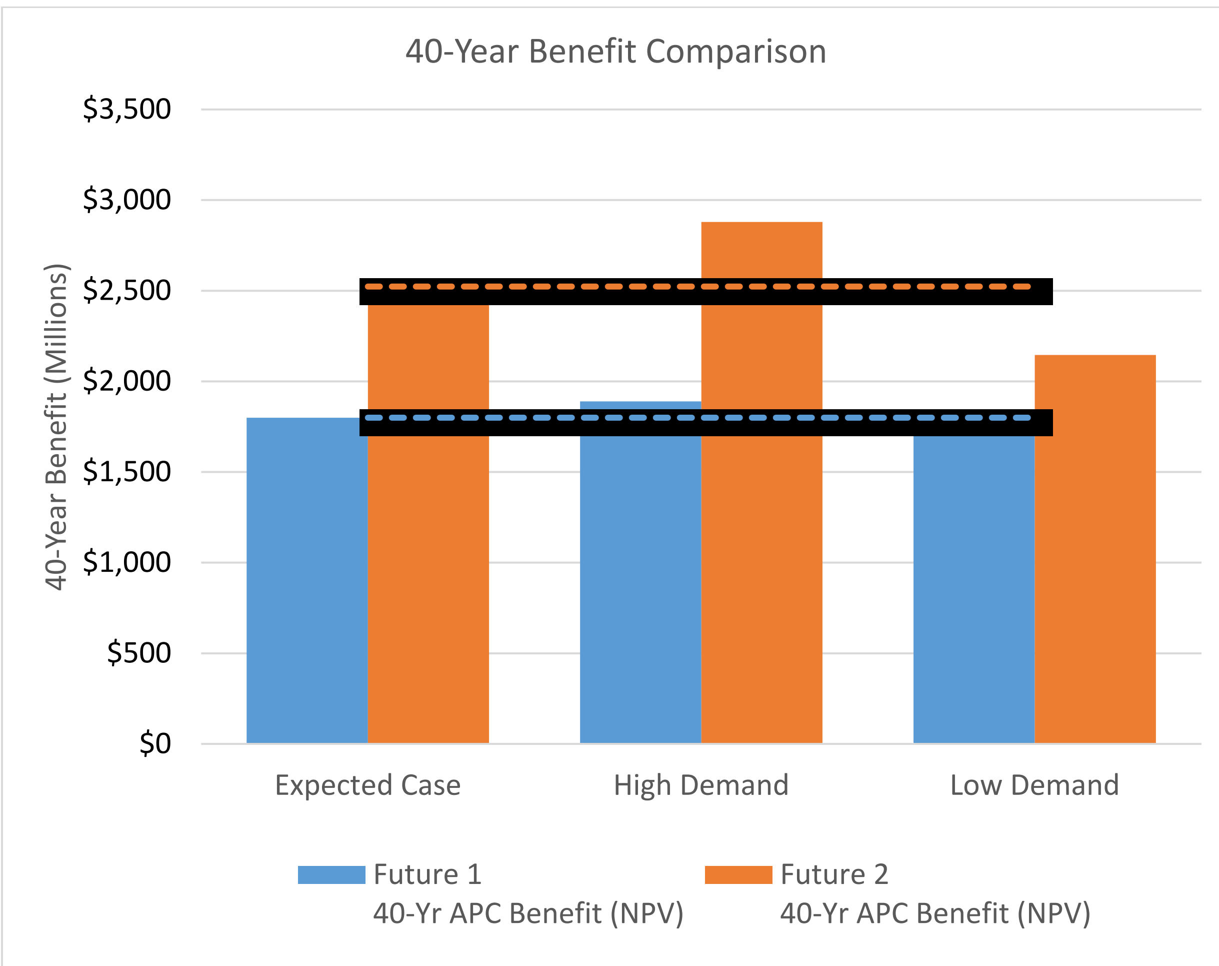

Figure 8.4: 40-Year Benefit Comparison (Peak Demand Sensitivity)

8.3.2 NATURAL GAS SENSITIVITY

A single confidence interval for natural gas prices was developed from the ABB fundamental forecast. The natural gas sensitivity had a 95 percent confidence interval (1.96 standard deviations) in positive and negative directions.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Natural Gas (2020$)	Low	2.72	2.95	2.72	2.95
	Expected	3.75	4.07	3.75	4.07
	High	4.79	5.19	4.79	5.19

Table 8.19: Natural Gas Sensitivity

A change in gas price is reflected by a corresponding change in the overall price of energy. The high natural gas sensitivity shows the portfolio's ability to reduce overall energy costs by allowing for a more economical generation dispatch. The low natural gas sensitivity shows a reduced benefit caused by lessened economic opportunity of resources with similar energy costs.

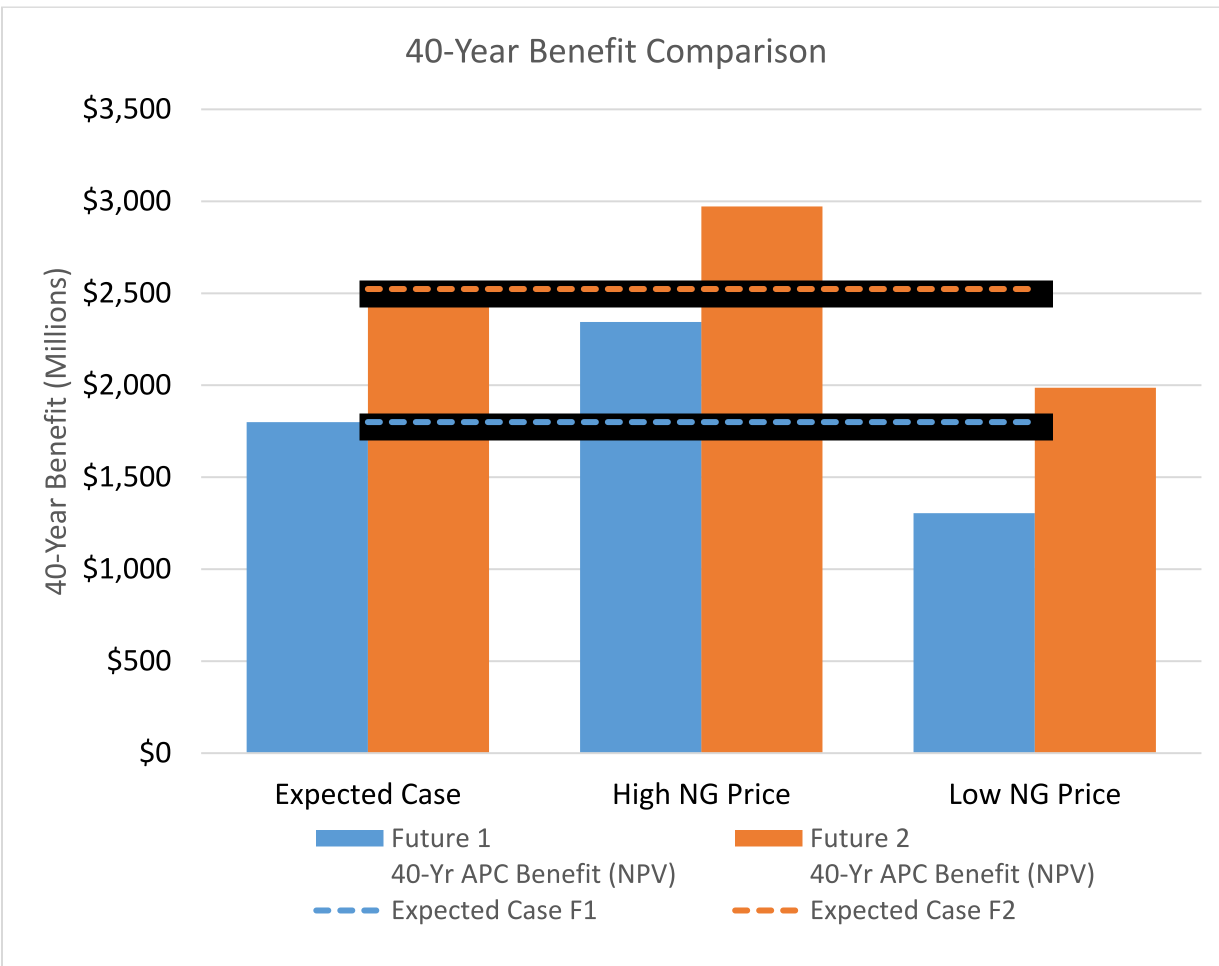

Figure 8.5: 40-Year Benefit Comparison (Natural Gas Sensitivity)

8.3.3 WIND CAPACITY SENSITIVITY

A wind sensitivity was conducted to test the portfolio's performance under alternative wind conditions. For this sensitivity, wind capacity and energy were scaled to the projected amounts shown in Table 8.20. For Future 1 only an increase in the wind capacity and energy was assessed due to the current growth of wind installation in real-time since scope development. For the high wind sensitivity, wind capacity and energy was added to existing and resource plan sites in the base case assumptions on a pro rata basis. For the low wind sensitivity, wind capacity and energy was reduced at only the resource plan sites.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Wind (GW)	**Low**	N/A	N/A	25	28
	Expected	26	28	30	33
	High	34	38	38	44

Table 8.20: Wind Capacity Sensitivity

Testing the portfolio against increased wind showed an increase in APC benefit. This influx of additional energy increases congestion in the base cases, leaving more congestion to be addressed by the project portfolio. The increase in benefit for both portfolios confirms that additional renewables would be facilitated by these specific sets of projects. For the reduced wind Future 2 sensitivity, the opposite occurs. A reduction in wind capacity and energy reduces the benefits the portfolio can realize.

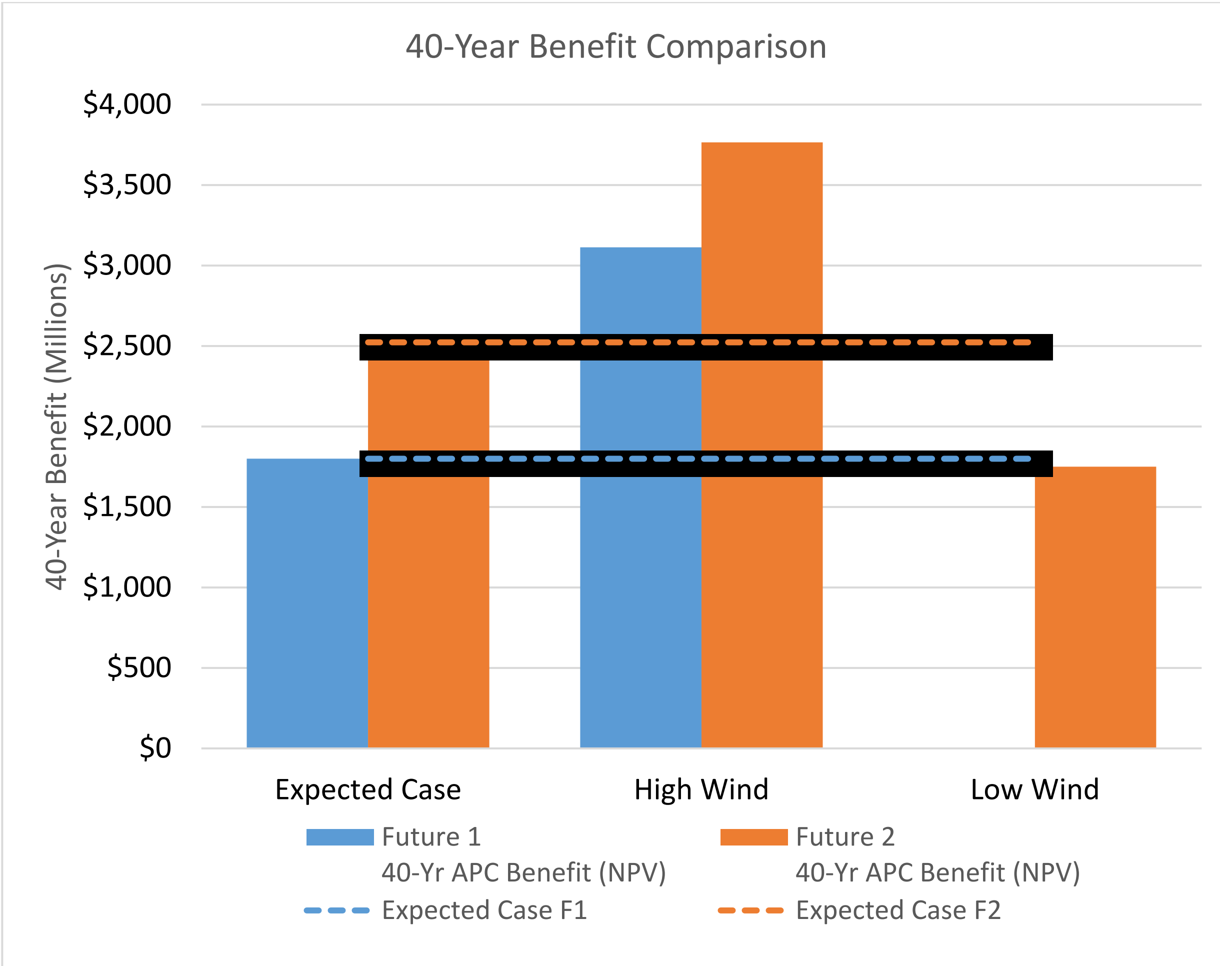

Figure 8.6: 40-Year Benefit Comparison (Wind Capacity Sensitivity)

8.3.4 SOLAR CAPACITY SENSITIVITY

Performance of the portfolio was assessed under varying solar capacity and energy assumptions. In this sensitivity, solar capacity and energy was scaled to the projected amounts shown in Table 8.21.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Solar (GW)	Low	0	0	0	0
	Expected	4	7	5	9
	High	9	11	10	13

Table 8.21: Solar Capacity Sensitivity

Like the wind sensitivity, increased solar capacity and energy reduces the overall cost of energy available to the system. This leads to similar changes in portfolio performance as those seen in the wind sensitivity, except for the high solar sensitivity in Future 2. The increased solar capacity and energy is competing with higher amounts of energy from wind resources with a lower cost of energy, which results in a negligible change due to the increase solar in Future 2.

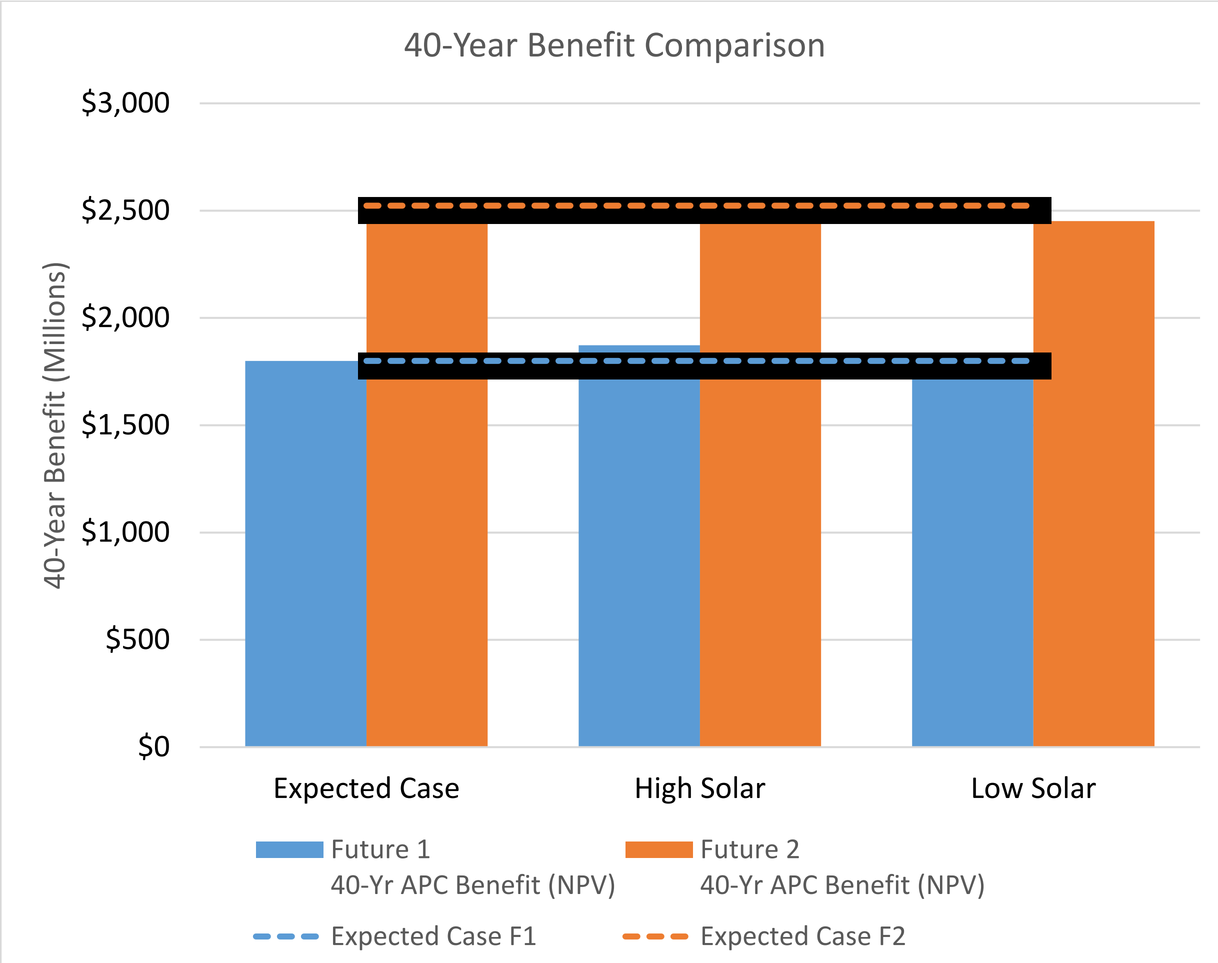

Figure 8.7: 40-Year Benefit Comparison (Solar Capacity Sensitivity)

8.3.5 ENERGY STORAGE SENSITIVITY

The 2020 ITP was the first study to incorporate the development of energy storage resources. To understand the impacts of energy storage on the portfolio a sensitivity was conducted. Energy storage amounts were scaled to the amounts shown in Table 8.22.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Energy Storage (GW)	**Low**	0.0	0.0	0.0	0.0
	Expected	0.8	1.4	1.7	3.1
	High	1.5	2.7	3.3	6.1

Table 8.22: Energy Storage Sensitivity

As illustrated in Figure 8.8 below, modifying the amounts of energy storage caused negligible effect on the benefits observed by the portfolio in an hourly simulation. More impacts would generally be expected in a sub-hourly simulation due to increased volatility.

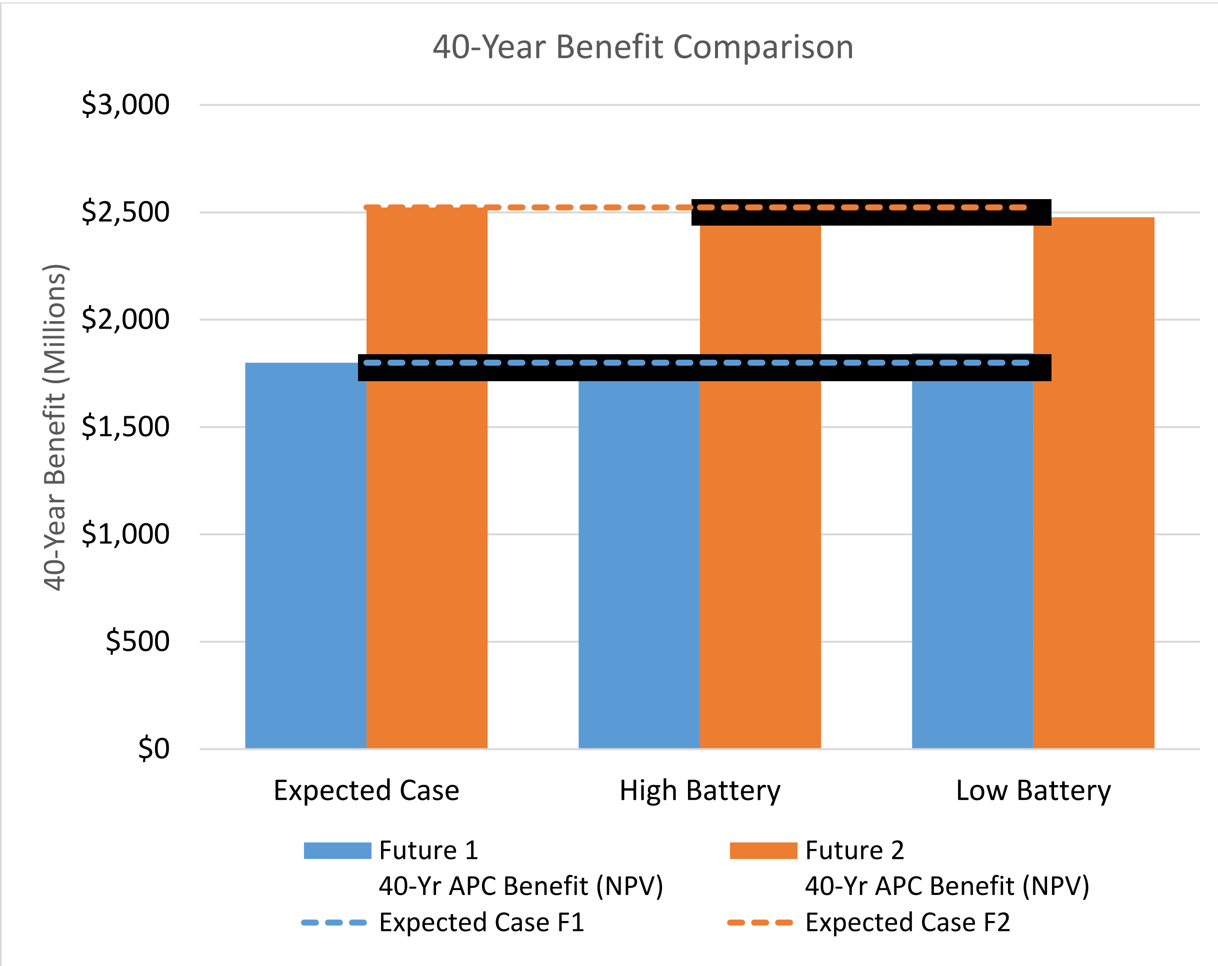

Figure 8.8: 40-Year Benefit Comparison (Energy Storage Sensitivity)

8.3.6 UNIT RETIREMENTS SENSITVITY

Retirement assumptions for the 2020 ITP resulted in additional capacity retirements compared to the 2019 ITP. As a result of stakeholders' concerns related to this assumption a sensitivity was conducted to understand the effect of varying this assumption. Table 8.23 shows the change in the amount of retirements, in gigawatts, for the low, expected, and high retirement amounts. For the low retirement sensitivity, the conventional resource plan units were deactivated from the simulation and the previously retired units were placed back in service. The high retirements sensitivity targeted coal facilities from the 2017 ITP10 with a lower than average capacity factor under emission restrictions, which were replaced by combustion turbines primarily at the same locations to maintain zonal reserve margins.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Unit Retirements (GW)	Low	0	0	0	0
	Expected	6	11	13	17
	High	17	20	23	25

Table 8.23: Unit Retirements Sensitivity

All four scenarios of this sensitivity experienced increased congestion for the portfolio to address, which was somewhat unexpected. This can be explained by the wide range of variables as it relates to the SPP fleet. Locations of added/removed retirements, the large change in resource mix, and system congestion patterns all play a significant role in the APC of the system.

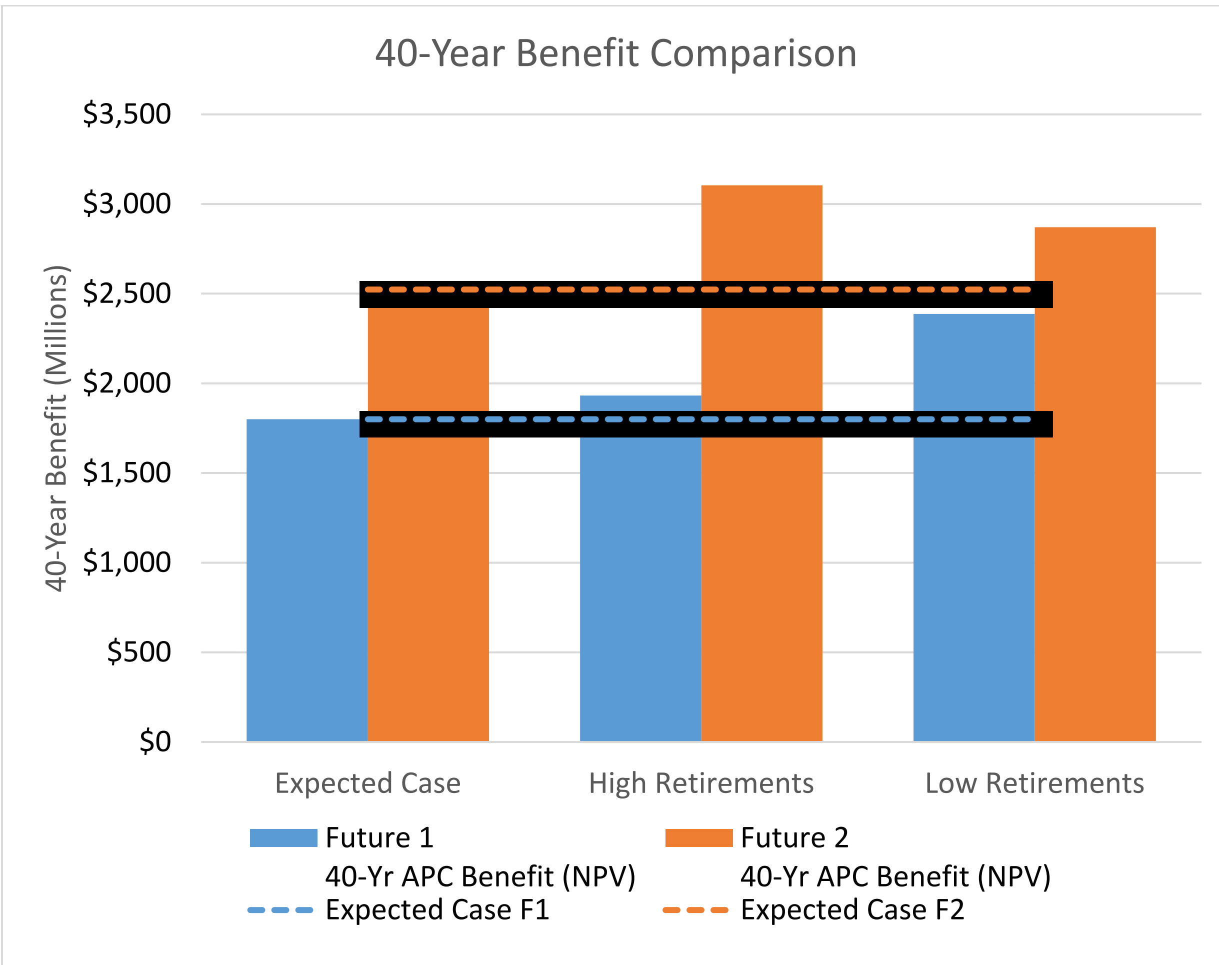

Figure 8.9: 40-Year Benefit Comparison (Unit Retirements Sensitivity)

8.4 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.[39] 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 2020 ITP assessment.

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 prior to reaching voltage stability limits.

8.4.1 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 8.24 identifies the transfer zones and boundaries.

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

Table 8.24: Generation Zones

Table 8.25 shows the transfers that were performed on the 2030 light load and 2030 summer models by scaling both on-line and off-line renewables from the source zone and scaling down the sink zone. Utility scale solar was not included in the source zone for the 2030 light for the 2029 light load model due to the reliability hour being identified as 4 a.m.

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

Model	Source Zone	Sink Zone
2030 Light Load	SPP renewables (Wind)	SPP conventional thermal generation
2030 Light Load	SPP renewables (Wind)	First-Tier and Second-Tier conventional thermal generation
2030 Summer	SPP renewables (Wind and Utility Scale Solar)	First-Tier and Second-Tier conventional thermal generation
2030 Summer	SPP renewables (Wind and Utility Scale Solar)	SPP conventional thermal generation

Table 8.25: Transfers by Model

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

8.4.2 SUMMARY

Figure 8.2 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 minimum internal conventional thermal generation levels or when a thermal limit is reached prior to 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: 2030 Light Load							
Wind -->Internal			Reached Minimum Sink				N/A
Wind -->External Thermal	19.7	18.3	Blackberry-Wolf Creek	21.5	17.0	1.8	Yes
"	19.7	18.3	Sooner-Wekiwa	21.5	17.0	1.8	Yes

Transfer Source -->Sink	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
"	19.7	18.3	Terry Road-Sunnyside	21.5	17.0	1.8	Yes
Future 1: 2030 Summer Peak							
Solar & Wind -->Internal	21.1	28.7	Crossroad-Eddy County	26.2	23.8	5.2	Yes
"	21.1	28.7	Holt-S3458	26.2	23.8	5.2	Yes
Solar & Wind -->External	21.1	72.1	Ketchem-Sibley	26.7	67.5	5.4	Yes
"	21.1	72.1	La Cygne-Stillwell	26.6	67.5	5.4	Yes
"	21.1	72.1	JEC-Hoyt	26.8	67.3	5.7	Yes
Future 2: 2030 Light Load							
Wind -->Internal			Reached Minimum Sink				N/A
Wind -->External	18.8	17.9	Hugo-Sunnyside	21.0	16.1	1.8	Yes
"	18.8	17.9	Blackberry-Wolf Creek	21.6	15.7	2.2	Yes
"	18.8	17.9	Fort Smith-ANO	21.6	15.7	2.2	Yes
Future 2: 2030 Summer Peak							
Solar & Wind -->Internal	25.2	24.6	Crossroad-Eddy County	29.6	20.4	4.1	Yes
"	25.2	24.6	Terry Road-Sunnyside	39.0	11.6	13.0	Yes
"	25.2	24.6	Mathewson-Northwest	39.8	10.9	13.7	Yes
Solar & Wind -->External	25.2	70.5	Ketchem-Sibley	30.4	66.2	4.4	Yes
"	25.2	70.5	La Cygne-Stilwell	30.6	66.0	4.5	Yes
"	25.2	70.5	Blackberry-Wolf Creek	31.0	65.7	4.6	Yes

Table 8.26: Post-Contingency Voltage Stability Transfer Limit Summary

Table 8.27 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: 2030 Light Load				
Wind-->Internal	**25.6**	N/A	N/A	
Wind-->External	**26.9**	21.5	20.2	
Future 1: 2030 Summer Peak				
Solar & Wind -->Internal	**33.1**	26.2	23.4	
Solar & Wind -->External	**33.1**	26.7	23.8	
Future 2: 2030 Light Load				
Wind-->Internal	**30.1**	N/A	N/A	
Wind-->External	**30.8**	21.0	20.2	
Future 2: 2030 Summer Peak				
Solar & Wind -->Internal	**40.2**	29.6	28.0	
Solar & Wind -->External	**41.2**	30.4	28.2	

Table 8.27: Voltage Stability Results Summary

8.4.3 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.*, causing 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 generally derives 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.

8.5 FINAL RELIABILITY ASSESSMENT

8.5.1 METHODOLOGY

Thermal and voltage violations were identified in the market powerflow portfolio rebuilt models following the same methods in the base reliability powerflow assessment. There were three thermal violations identified a result of the new market dispatch and portfolio additions, although they were reclassified and invalidated as reliability violations per section 4.2.5 of the ITP Manual. No additional voltage violations were observed and no supplementary solutions were developed to accommodate the market powerflow models.

8.5.1.1 Short-Circuit Model

A proxy automatic sequencing fault calculation (ASCC) short-circuit analysis was performed on the 2020 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, it was found that 113 of the 9,888 buses monitored experienced a 5 percent increase in fault current. Only nine of the 113 buses appeared to exceed common breaker duty ratings of 20kA. The subsequent short-circuit analysis performed next cycle will confirm whether or not the duty ratings are exceeded given the latest modeling assumptions.

8.5.2 SUMMARY

8.5.2.1 Base Reliability Models

The resulting thermal and voltage violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, identification of invalid contingencies, non-load-serving buses, and facilities not under SPP's functional control. Additional rebuilds were identified as needed for portfolio inclusion based on downstream overloads resulting from rebuilds already selected in the proposed portfolio. Due to the fact that these sections of the Deaf Smith 115kV corridor were not up to minimum design standard, they have all been identified as rebuild projects. Per the ITP manual, base reliability projects driving additional needs require portfolio project adjustment or additions in order to fully mitigate the resulting needs. The details of the additional rebuilds are listed below.

Rebuild Projects	Portfolio Need Identification
Deaf Smith #6-Hereford 115 kV rebuild	Base Reliability
Deaf Smith #6-Friona 115 kV rebuild	Base Reliability
Cargill-Friona 115 kV rebuild	Final Reliability Assessment
Cargill-Deaf Smith #24 115 kV rebuild	Final Reliability Assessment
Parmer-Deaf Smith #24 115 kV rebuild	Final Reliability Assessment
Parmer-Deaf Smith #20 115 kV rebuild	Final Reliability Assessment
Curry-Deaf Smith #20 115 kV rebuild	Final Reliability Assessment

Table 8.28: Additional Identified Reliability Rebuilds

8.5.2.2 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. There were three thermal violations identified as resultant of the new market dispatch and portfolio additions, although they were reclassified and invalidated as reliability violations per Section 4.2.5 of the ITP Manual. Of the fifteen voltage violations identified, thirteen were related to local planning more stringent monitoring criteria and only two were low voltage per the SPP Planning Criteria. Per the ITP manual, no new solutions were developed for these identified violations, and the facilities will be monitored in the 2021 ITP for any further issues.

8.5.2.3 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.

8.5.3 CONCLUSION

Overall, only the Base Reliability assessment yielded any additional needs which were addressed by portfolio project additions per the direction provided in the ITP Manual.

9 NTC RECOMMENDATIONS

SPP staff 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.

Two exceptions to this process for the 2020 ITP are the Eddy County-North Loving 345 kV line identified as a reliability project with a June 2028 need date and the Split Rock 345/115 kV terminal equipment identified as an economic project with a January 2025 need date for the reasons discussed in section 7.1.7 and 7.3.10, warranting additional analysis necessary in future planning studies before move forwarded with the planned projects.

As discussed throughout the report the eastern New Mexico area is extremely complex. Both economic and reliability issues are present and a comprehensive solution is necessary to address the thermal loading, low voltage, and voltage collapse conditions. The Eddy County-North Loving 345 kV line does not address some of these conditions as it is not a comprehensive solution. Additionally, there are some out of scope compliance events NERC TPL 001-4 P3 planning events that are also known to cause concerns in the area. SPP Operations staff is also currently working to update interface ratings due to transmission topology being placed in service in the near future. SPP expects to continue studying this in the 2021 ITP assessment with the goal of utilizing information gathered in the 2020 ITP along with new analysis to provide a comprehensive solution to address the system conditions in the area.

The terminal equipment that would require replacement to increase the rating of the Split Rock 345/115 kV transformers, which is not an SPP tariff facility and would require FERC filings to support SPP regionally beneficial seams project cost allocation. The project was also identified and assessed during the 2020 MISO-SPP CSP, but was not found to be jointly beneficial. Additionally, the project marginally passed SPP's consolidation criteria.

For the reasons listed above the Eddy County-North Loving 345 kV line and the Split Rock 345/115 kV terminal equipment upgrades are not recommended for an NTC.

Table 9.1 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?
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	6/1/2022	24	11/17/2020	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Circleville-Goff 115 kV circuit 1 rebuild	6/1/2025	24	6/1/2023	NTC
Goff-Kelly 115 kV rebuild	6/1/2025	24	6/1/2023	NTC
South Shreveport-Wallace Lake 138 kV rebuild	6/1/2024	24	6/1/2022	NTC-C
Grady 138 kV capacitor bank	12/1/2022	24	12/1/2020	NTC
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	12/1/2022	36	11/17/2020	NTC
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	6/1/2023	24	6/1/2021	NTC
Bushland-Deaf Smith 230 kV terminal equipment	4/1/2022	18	11/17/2020	NTC
Newhart-Potter County 230 kV terminal equipment	4/1/2022	18	11/17/2020	NTC
Carlisle-Murphy 115 kV rebuild	6/1/2022	24	11/17/2020	NTC
Roswell 115/69 kV replace transformer #1	6/1/2022	24	11/17/2020	NTC
S3456-S3458 345 kV terminal equipment	6/1/2029	18	12/1/2027	No
Meadowlark-Tower 33 115 kV rebuild	6/1/2023	36	11/17/2020	NTC
Jones-Lubbock South 230 kV terminal equipment circuit 1	6/1/2028	18	12/1/2026	No
Jones-Lubbock South 230 kV terminal equipment circuit 2	6/1/2028	18	12/1/2026	No
Deaf Smith-Plant X 230 kV terminal equipment	4/1/2022	18	11/17/2020	NTC
Newhart-Plant X230 kV terminal equipment	4/1/2022	18	5/17/2022	NTC
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	6/1/2022	18	12/1/2020	NTC
Allen-Lubbock South 115 kV rebuild	6/1/2022	24	11/17/2020	NTC
Allen-Quaker 115 kV rebuild	6/1/2022	24	11/17/2020	NTC
Eddy County-North Loving 345 kV new line	6/1/2028	48	6/1/2024	No
Bismarck 115 kV reactors	4/1/2022	24	11/17/2020	NTC
Moorehead 230 kV reactor	4/1/2022	24	11/17/2020	NTC
Russell 115 kV capacitor bank	6/1/2022	24	11/17/2020	NTC
Maljamar 115 kV capacitor bank	6/1/2028	24	6/1/2026	No
Devil's Lake 115 kV reactor	4/1/2022	24	11/17/2020	NTC
Agate 115 kV reactor	4/1/2022	24	11/17/2020	NTC
Nixa-Nixa Espy 69 kV terminal equipment	6/1/2022	18	12/1/2020	No
Replace four breakers at Anadarko 138 kV	6/1/2022	18	12/1/2020	NTC
Replace three breakers at Northeast 161 kV	6/1/2022	18	12/1/2020	NTC
Replace one breaker at Stilwell 161 kV	6/1/2022	18	12/1/2020	NTC
Replace one breaker at Leeds 161 kV	6/1/2022	18	12/1/2020	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Replace one breaker at Shawnee Mission 161 kV	6/1/2022	18	12/1/2020	NTC
Replace one breaker at Southtown 161 kV	6/1/2022	18	12/1/2020	NTC
Replace two breakers at Lake Road 161 kV	6/1/2022	18	12/1/2020	NTC
Replace two breakers at Craig 161 kV	6/1/2022	18	12/1/2020	NTC
Anadarko-Gracemont 138 kV rebuild as double-circuit	1/1/2023	36	11/17/2020	NTC-Modify
Russett-South Brown 138 kV rebuild	1/1/2022	30	11/17/2020	NTC
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	1/1/2024	36	1/1/2021	NTC-C
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	1/1/2022	18	11/17/2020	NTC
Columbus East 230/115 kV transformer replacement	1/1/2039	24	1/1/2037	No
Franks-South Crocker-Lebanon 161 kV terminal equipment	1/1/2028	18	7/1/2026	No
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	1/1/2022	48	11/17/2020	NTC-C
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	1/1/2022	18	11/17/2020	NTC
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	1/1/2025	48	1/1/2021	NTC-C
Split Rock 345/115 kV circuit 10 and 11 terminal equipment	1/1/2025	18	7/1/2023	No
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment[40]	1/1/2028	18	7/1/2026	No
Deaf Smith #6-Hereford 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Deaf Smith #6-Friona 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Cargill-Friona 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Cargill-Deaf Smith #24 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Parmer-Deaf Smith #24 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Parmer-Deaf Smith #20 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Curry-Deaf Smith #20 115 kV rebuild	4/1/2022	24	11/17/2020	No

Table 9.1: NTC Recommendations

[40] Information in this table includes considerations of the updated cost estimate.

10 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
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GOF	Generator outlet facilities
GW	Gigawatt
GWh	Gigawatt hour
HV	High voltage
IFTS	Interruption of firm transmission service
IRP	Integrated resource plan

Acronym	Name
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
MDWG	Model Development Working 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
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

Acronym	Name
TVA	Tennessee Valley Authority
TWG	Transmission Working Group
US EIA	United States Energy Information Administration
VSL	Voltage stability limit

Table 10.1: Glossary