Schedule BW-3

Public

2019 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
08/22/2019 v0.1	SPP Staff	Initial Draft Report	Posted for stakeholder review
09/17/2019 v0.2	SPP Staff	Full Draft Report	Posted for ESWG/TWG review
09/27/2019 v0.3	SPP Staff	Final Draft Report	Posted for ESWG/TWG approval
09/30/2019 v0.4	SPP Staff	Updated Final Draft Report: • Marginal energy losses zonal numbers updated (Table 8.9 updated) • ATRR number updated (Tables 8.5, 8.10, 8.11, 8.12 and 8.13 updated) • Infographic updated in Executive Summary	• Table 8.9: Marginal energy losses - zonal numbers updated to align correctly with each zone (regional numbers correct) • ATRR number updated; resulted in updates to the benefit summary tables 8.10, 8.11, 8.12 and 8.13. ATRR update impacted mandated reliability for the cost of reliability projects; resulted in update to Table 8.5

10/01/2019 v.0.5	SPP Staff	Updated Final Draft Report:
		• NTC Recommendations table corrected to match Section 9.1
		• ATRR number updated (Tables 8.12 and 8.13 updated)
			Updated Final Draft Report:
			• Added to NTC Recommendations in Executive Summary table:
			  ○ Replace 21 breakers at Riverside Station 138 kV
			  ○ Replace eight breakers at Southwestern Station 138 kV
			• ATRR number updated (Tables 8.12 and 8.13 updated)

10/01/2019 v0.5	SPP Staff	Final Report	Approved by ESWG/TWG
10/15/2019 v0.5	SPP Staff	Final Report	Approved by MOPC
10/29/2019 v1.0	SPP Staff	Final Report	Approved by SPP Board of Directors

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EXECUTIVE SUMMARY

2019 SPP Integrated Transmission Plan

COLLABORATION

- 8 groups; 100+ meetings
- 27-month schedule
- 1,600+ solutions reviewed
- 700+ inquiries processed

VALUE

- 4¢ - 23¢ Residential bill savings
- 3.5 - 5.8 to 1 Benefit-to-cost ratio

PROJECTS

- 44 projects
- 166 miles 345 kV transmission
- 28 miles transmission rebuild
- $336 million E&C costs

BENEFITS

- Solve 145 system needs
- Help levelize market prices
- Improve congestion hedging
- Access to low-cost energy

The 2019 Integrated Transmission Plan (ITP) looks ahead 10 years to ensure the SPP region can deliver energy reliably and economically, achieve public policy objectives 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. More than 1,600 solutions were evaluated. The analysis resulted in the recommendation to approve 44 transmission projects, including 166 miles of new extra-high-voltage transmission and 28 miles of rebuilt high-voltage infrastructure.

The consolidated portfolio is expected to provide a 40-year benefit-to-cost ratio ranging from 3.5 for Future 1 to 5.8 for Future 2. The net impact to ratepayers is a savings of $0.04 to $0.23 on the average retail residential monthly bill.

This portfolio will mitigate 145 system issues. Reliability projects allow the region to meet compliance requirements and keep the lights on through loading relief, voltage support and system protection. In addition to the reliability projects, the portfolio contains economic projects that help improve the locational marginal price (LMP) levelization, increase of auction revenue right (ARR) awards, and provides access to low-cost energy.

Enabling delivery of low cost renewable resources is a main driver of the EHV projects. Another project driver is reducing price separation in the SPP marketplace, which is caused by congestion on the transmission grid. 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 EHV 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 2019 economic needs assessment identified five of the ten highest congested flowgates from the 2018 Annual State of the Market Report. For the 2019 ITP assessment, more in-depth analysis was conducted 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.

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, generation retirements and electric vehicles.

The assessment focused on two target areas in southeast Kansas/southwest Missouri and central/eastern Oklahoma that experience economic congestion. The 2019 ITP consolidated portfolio will address this congestion in addition to improving these areas' steady-state reliability margins, transient stability concerns and unresolved transmission limits.

Project	Area	Type	Project Cost (2019$)	Miles	NTC/ NTC-C
Pryor Junction 138/115 kV transformer	AEPW	R	$9,155,167	-	NTC
Tulsa SE-21 St Tap 138 kV rebuild	AEPW	R	$1,307,802	1.48	NTC
Tulsa SE-S Hudson 138 kV rebuild	AEPW	R	$6,724,237	1.97	NTC
Firth 15MVAR 115 kV capacitor bank	NPPD	R	$3,370,000	-	NTC
Cleo Corner-Cleo Junction 69 kV terminal equipment	WFEC	R	$16,602	-	NTC
Rocky Point-Marietta 69 kV terminal equipment	OKGE/ WFEC	R	$100,000	-	NTC
Bushland-Deaf Smith 230 kV terminal equipment	SPS	R	$1,185,094	-	No
Carlisle-LP Doud Tap 115 kV terminal equipment	SPS	R	$88,924	-	No

Project	Area	Type	Project Cost (2019$)	Miles	NTC/ NTC-C
Deaf Smith-Plant X 230 kV terminal equipment	SPS	R	$1,185,094	-	No
Lubbock South-Jones 230 kV circuit 1 terminal equipment	SPS	R	$88,924	-	No
Lubbock South-Jones 230 kV circuit 2 terminal equipment	SPS	R	$88,924	-	No
Moore-RB-S&S 115 kV terminal equipment	SPS	R	$158,742	-	No
Plains Interchange-Yoakum 115 kV terminal equipment	SPS	R	$158,742	-	No
Potter Co-Newhart 230 kV terminal equipment	SPS	R	$1,185,094	-	No
Marshall County-Smittyville-Baileyville-South Seneca 115 kV rebuild	WERE	R	$17,636,022	16.19	NTC
Getty East-Skelly 69 kV terminal equipment	WERE	R	$114,821	-	NTC
Gypsum 12MVAR 69 kV capacitor bank	WFEC	R	$490,093	-	NTC
Replace 21 breakers at Riverside Station 138 kV	AEPW	R	$16,288,000	-	NTC
Replace eight breakers at Southwestern Station 138 kV	AEPW	R	$4,421,345	-	NTC
Replace one breaker at Craig 161 kV	KCPL	R	$254,000	-	NTC
Replace two breakers at Leeds 161 kV	KCPL	R	$440,000	-	NTC
Replace two breakers at Midtown 161 kV	KCPL	R	$440,000	-	NTC
Replace four breakers at Southtown 161 kV	KCPL	R	$880,000	-	NTC
Replace one breaker at Moore 13.8 kV tertiary bus	NPPD	R	$510,000	-	NTC
Replace two breakers at Hastings 115 kV	NPPD	R	$550,000	-	NTC
Replace five breakers at Canaday 115 kV	NPPD	R	$2,600,000	-	NTC
Replace two breakers at Westmoore 138 kV	NPPD	R	$271,289	-	NTC
Replace three breakers at Santa Fe 138 kV	NPPD	R	$406,935	-	NTC
Replace one breaker at Carlsbad Interchange 115 kV	SPS	R	$552,668	-	NTC
Replace three breakers at Denver City North and South 115 kV	SPS	R	$5,526,680	-	NTC
Replace three breakers at Hale County Interchange 115 kV	SPS	R	$1,658,004	-	NTC
Replace one breaker at Washita 69 kV	WFEC	R	$52,400	-	NTC
Replace 12 breakers at Mooreland 138/69 kV	WFEC	R	$835,850	-	NTC
Replace three breakers at Anadarko 138 kV	WFEC	R	$228,500	-	NTC
Gracemont-Anadarko 138 kV rebuild	WFEC	E	$2,850,000	5.09	NTC
Kingfisher-East Kingfisher Tap 138 kV rebuild	WFEC	E	$1,000,000	2.03	NTC

Project	Area	Type	Project Cost (2019$)	Miles	NTC/ NTC-C
Spearman-Hansford 115 kV terminal equipment	SPS	E	$828,359	1.2	NTC
Lawrence EC-Midland 115 kV terminal equipment	WERE	E	$30,939	-	NTC
New Wolf Creek-Blackberry 345 kV line, new Butler 138 kV phase-shifting transformer	WERE	E	$162,649,008	105.1	**Line**: NTC-C **PST**: No
New Sooner-Wekiwa 345 kV line, Sheffield Steel-Sand Springs 138 kV terminal equipment	AEPW/ OKGE	E	$85,948,123	60.6	NTC-C
Cimarron-Northwest-Matthewson 345 kV terminal equipment	OKGE	E	$369,869	-	NTC
Arnold-Ransom 115 kV terminal equipment, Pile-Scott City-Setab 115 kV terminal equipment	SUNC	E	$3,652,000	-	NTC
Sundown-Amoco Tap 115 kV terminal equipment	SPS	E	$358,281	-	NTC
		Total	**$336,656,532**[1]		

Table 0.1: 2019 ITP Consolidated Portfolio

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

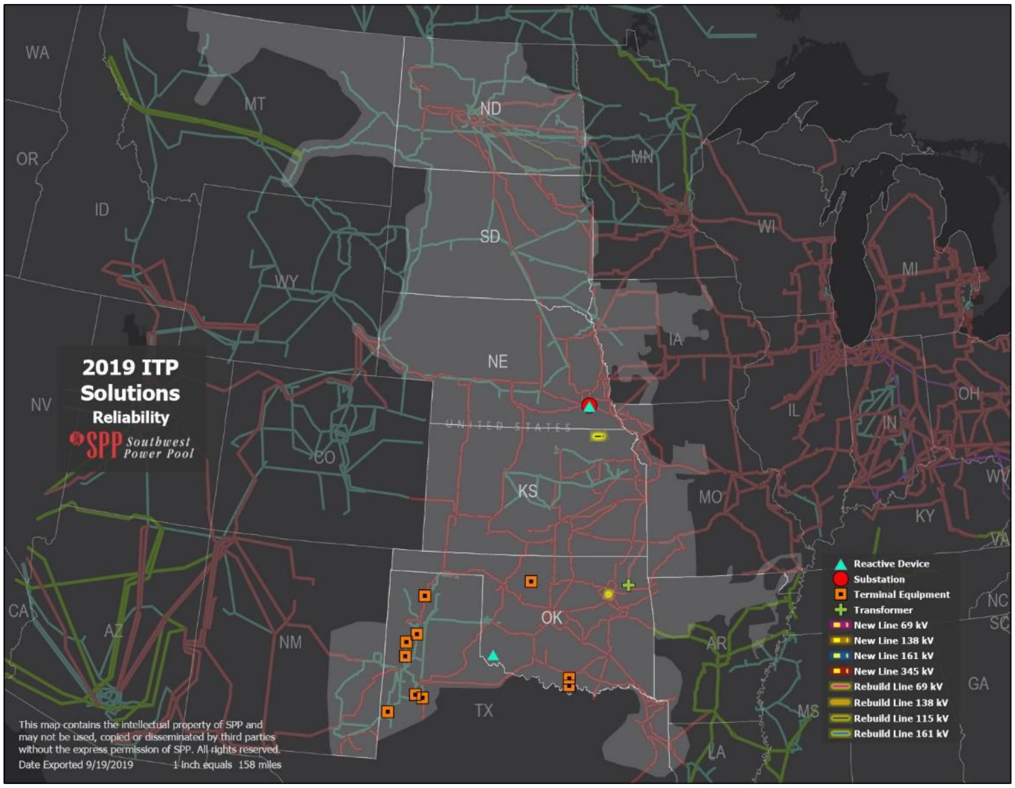


Figure 0.1: 2019 ITP Portfolio – Reliability

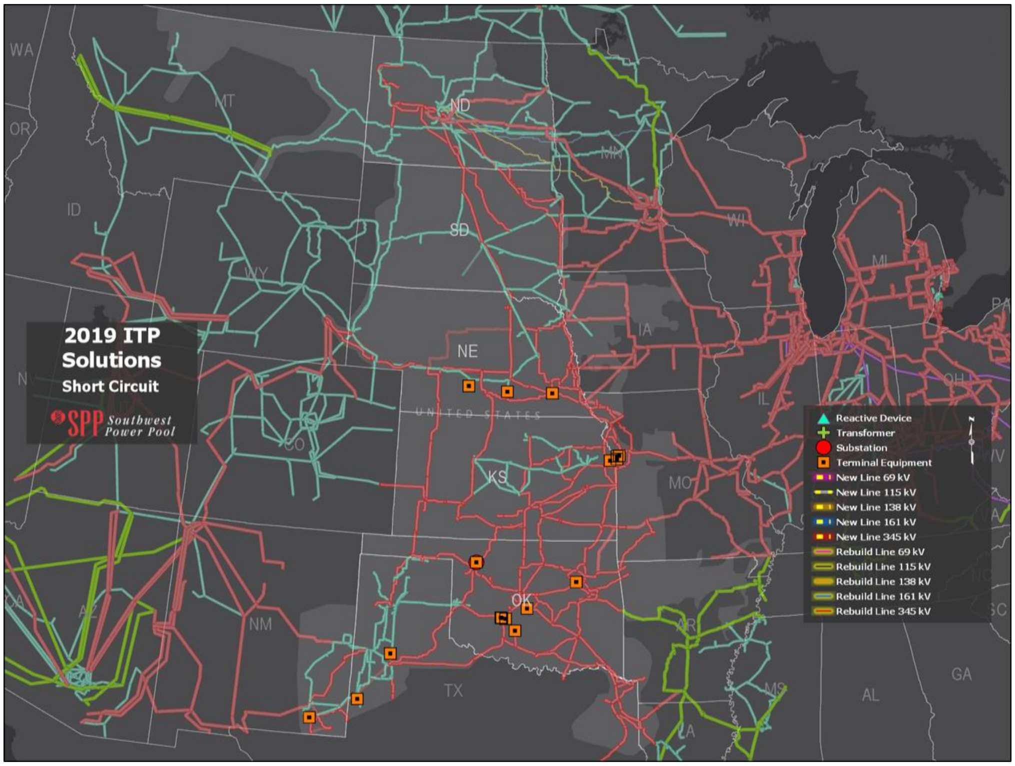


Figure 0.2: 2019 ITP Portfolio - Short Circuit

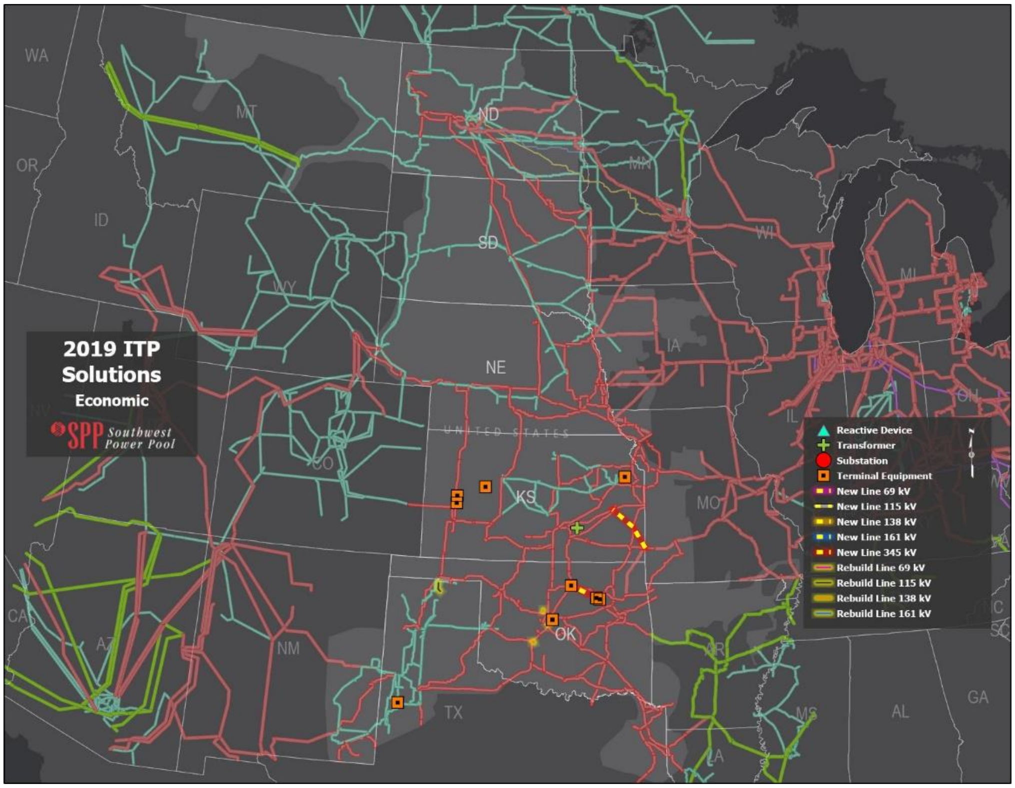


Figure 0.3: 2019 ITP Portfolio - Economic

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[2]. The ITP process coordinates solutions with ongoing compliance, local planning, interregional planning and tariff service[3] 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 2019 ITP assessment is guided by requirements defined in Attachment O to the SPP Open Access Transmission Tariff (tariff), the ITP Manual, and the 2019 ITP Scope. The 2019 ITP is the first completed assessment using the improved ITP process designed by the Transmission Planning Improvement Task Force.

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.

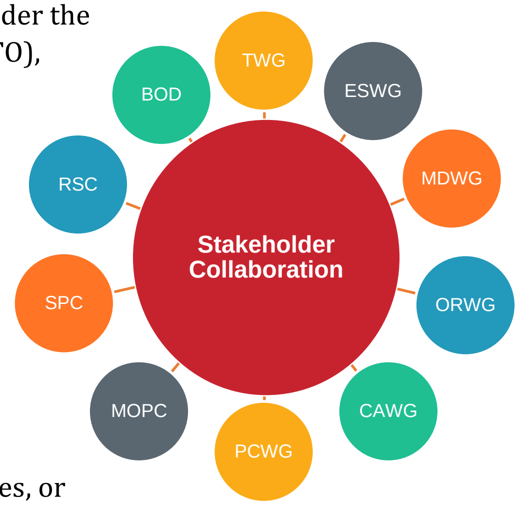
1.2 REPORT STRUCTURE

This report describes the ITP assessment of the SPP transmission system for a 10-year horizon, focusing on years 2021, 2024 and 2029. These years were evaluated with a baseline reliability scenario and two future market scenarios (futures). Sections Model Development and Benchmarking summarize modeling inputs and address the concepts behind this study's approach, key procedural steps in analysis development, and overarching study assumptions. Sections Needs Assessment through Project Recommendations address

[2] The highway/byway cost allocation approving order is Sw. Power Pool, Inc., 131 FERC ¶ 61,252 (2010). The approving order for ITP is Sw. Power Pool, Inc., 132 FERC ¶ 61,042 (2010).
[3] Tariff services include the SPP Aggregate Transmission Service Studies (ATSS) for long-term firm transmission service, Attachment AQ studies for delivery point changes (AQ), and Generator Interconnection (GI) studies for new generator interconnections.

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 set of legacy Balancing Authorities (BAs) and transmission owners (TOs) whose transmission facilities are under the functional control of the SPP regional transmission organization (RTO), unless otherwise noted.



The study was guided by the 2019 ITP Scope and SPP ITP Manual, version 2.4. All reports and documents referenced in this report are available on SPP.org. A mapping of supplemental documentation for each section is located in the Appendix of this report.

SPP 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 2019 ITP assessment assumptions and procedures in meetings throughout 2017, 2018, and 2019. 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)
- Operating Reliability Working Group (ORWG)
- 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 chairman 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 Strategic Planning Committee (SPC). Stakeholder feedback was instrumental in the refinement of the 2019 ITP.

1.3.1 PLANNING SUMMITS

In addition to the standard working group meetings and in accordance with Attachment O of the tariff, SPP held 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.

2 MODEL DEVELOPMENT

2.1 BASE RELIABILITY MODELS

2.1.1 GENERATION AND LOAD

Generation and load data in the 2019 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 MDWG Procedure Manual. Figure 2.1 and Figure 2.2 below provide a visual for the years two, five, and 10 summer peak and winter peak generation dispatch and load amounts. The generation dispatch amounts are provided by fuel type for all base reliability models that are part of the ITP assessment. 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, with remaining generation needs coming from conventional resources. In the base reliability models, all entities are required to meet their non-coincident peak demand with firm resources.

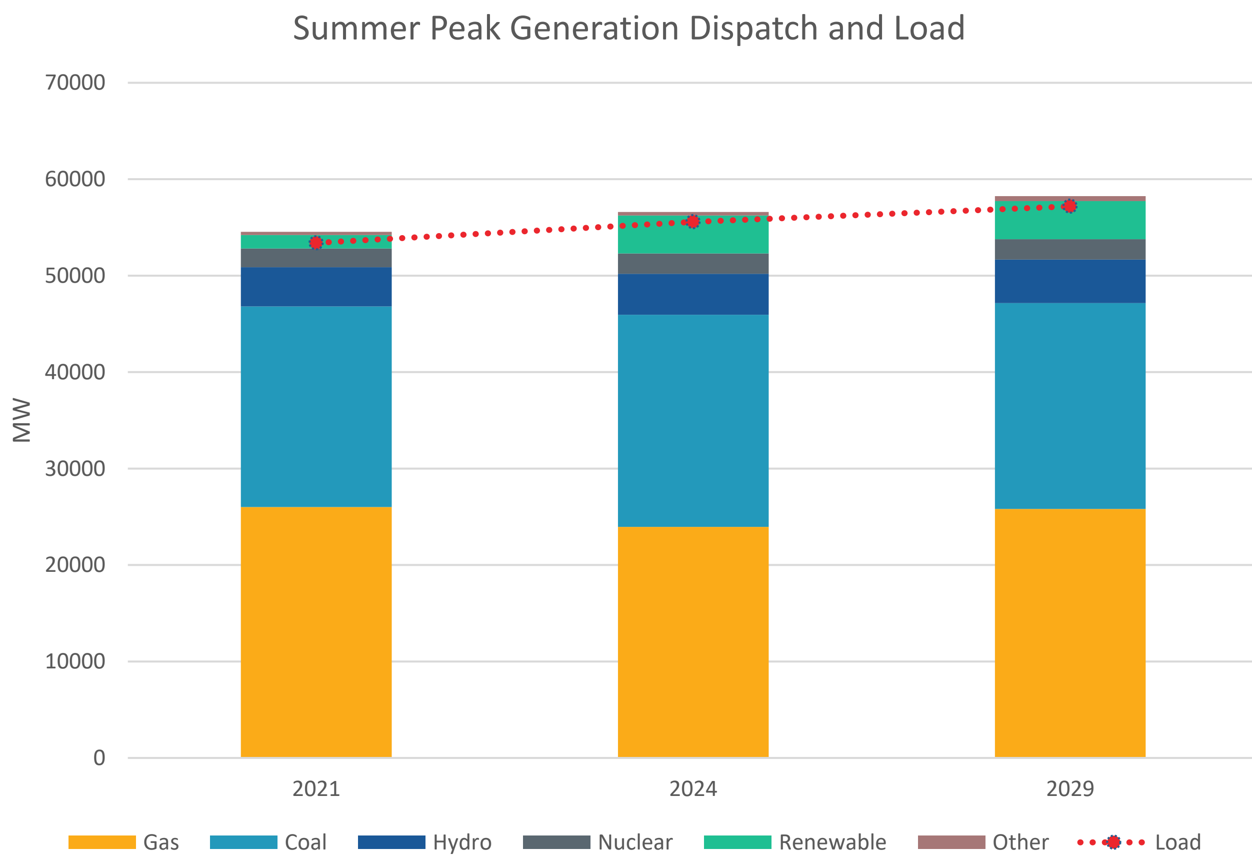


Figure 2.1: 2019 ITP Base Reliability Summer Generation Dispatch and Load

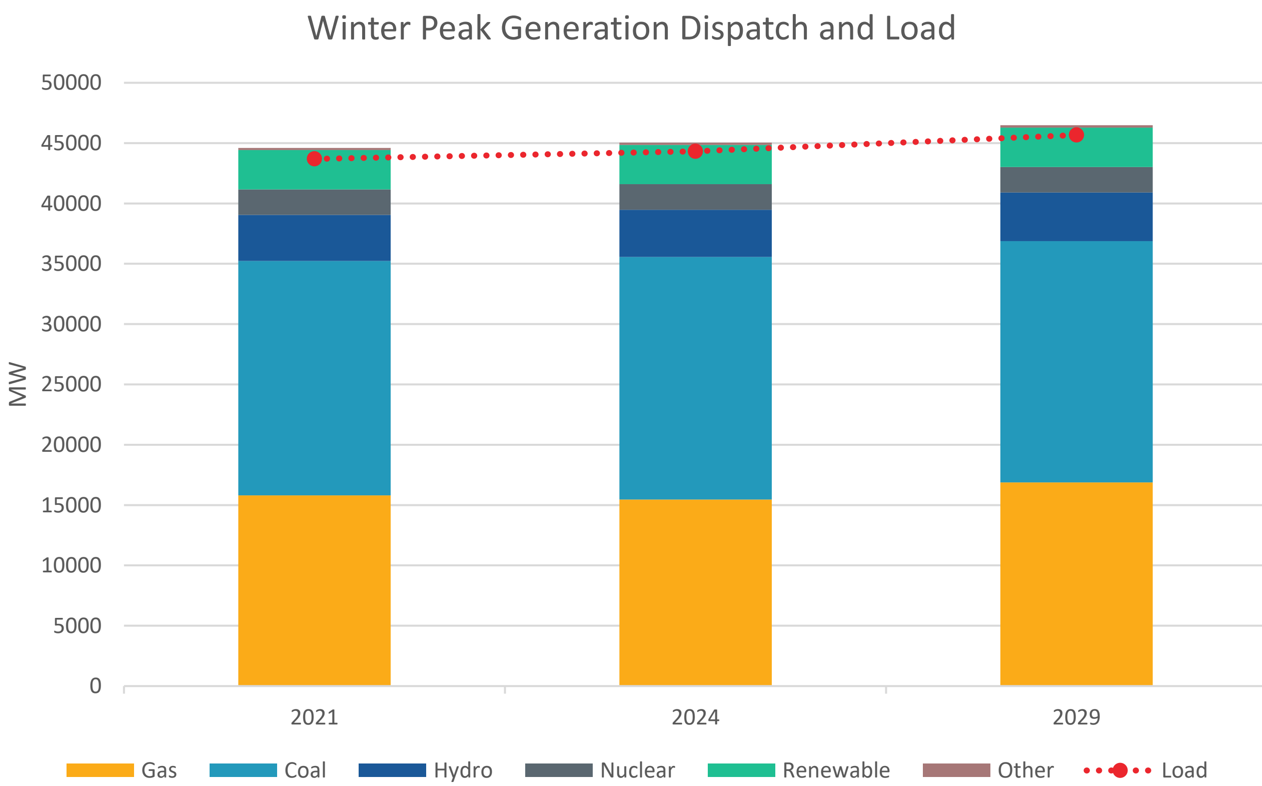


Figure 2.2: 2019 ITP Base Reliability Winter Generation Dispatch and Load

2.1.2 TOPOLOGY

Topology data in the 2019 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 MDWG Procedure Manual. The topology for areas external to SPP were consistent with the 2017 Eastern Interconnection Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG) model series.

2.1.3 SHORT-CIRCUIT MODEL

A year-two, summer peak, short-circuit model 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. 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

The SPC gave the ESWG policy-level direction on developing the ITP futures, which the ESWG incorporated into discussion of detailed drivers, forming the basis of the potential futures.

The ESWG and additional stakeholders developed a list of drivers and assumed the probability of each driver's occurrence. The list and probabilities were based on each participant's own expectation of future trends and their potential impact to the energy industry and transmission planning efforts. The initial drivers considered for this analysis were:

- Wind and solar capacity additions
- Peak and energy demand growth rates
- Natural gas prices
- Coal prices
- Emissions prices
- Generator retirements
- Environmental regulations
- Demand response
- Distributed generation
- Energy efficiency
- Renewable exports
- Increased renewable capacity factors
- Storage

This initial list of drivers was categorized by description and model implementation synergies to create six potential futures to be studied. SPP staff worked with the ESWG to build a proposal for the reference case and two additional candidate futures[4]: emerging technologies and renewables. These futures were further refined by the ESWG, with input from the SPC and TWG, into two futures to be assessed. The MOPC approved both futures in October 2017.

2.2.1.1.1 Future 1: Reference Case

The reference case future reflects the continuation of current industry trends and environmental regulations. Generally, coal and gas-fired generators over the age of 60 were assumed to be retired, but SPP stakeholders gave input on exceptions to that criteria. Long-term industry forecasts were used for natural gas and coal prices. Solar and wind additions exceeded renewable portfolio standards (RPS) due to economics, public appeal, and the anticipation of potential policy changes.

2.2.1.1.2 Future 2: Emerging Technologies

The assumptions that electric vehicles, distributed generation, demand response, and energy efficiency will impact energy growth rates drove the emerging technologies future. Coal and gas-fired generators over the age of 60 were assumed to be retired. As in the reference case future, this future assumed no changes to current environmental regulations and leveraged long-term industry forecasts for natural gas and coal prices. This future assumes higher solar and wind 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.

[4] Other futures discussed but not chosen: clean energy, robust economy, and low demand.

	Drivers				
Key Assumptions	**Reference Case**			**Emerging Technologies**	
	2021	**2024**	**2029**	**2024**	**2029**
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Age-based 60+, subject to stakeholder input	Age-based 60+, subject to stakeholder input		Age-based, 60+	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[5]	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	
Export Lines	No	No		No	
New/Re-Powered Renewables	Increased capacity factor	Increased capacity factor		Increased capacity factor	
Storage	None	None		None	
Total Renewable Capacity					
Solar (GW)	0.25	3	5	4	7
Wind (GW)	18.8	24.2	24.6	27	30

Table 2.1: Future Drivers

[5] As defined in the MDWG Model Development Procedure Manual

2.2.1.2 Load and Energy Forecasts

The 2019 ITP load review focused on load data through 2029. The load data was derived from the base reliability model set, and stakeholders were asked to identify/update the following parameters:

- Forecasted system peak load (MW)
- Annual energy (GWh) consumed[6]
- Loss factors
- Load factors
- Load demand group assignments

The ESWG- and TWG-approved load review was used to update the load information in the market economic models. Figure 2.3 shows the total coincident peak load for all study years. Figure 2.4 shows the monthly energy per future for all study years (2021, 2024, and 2029).

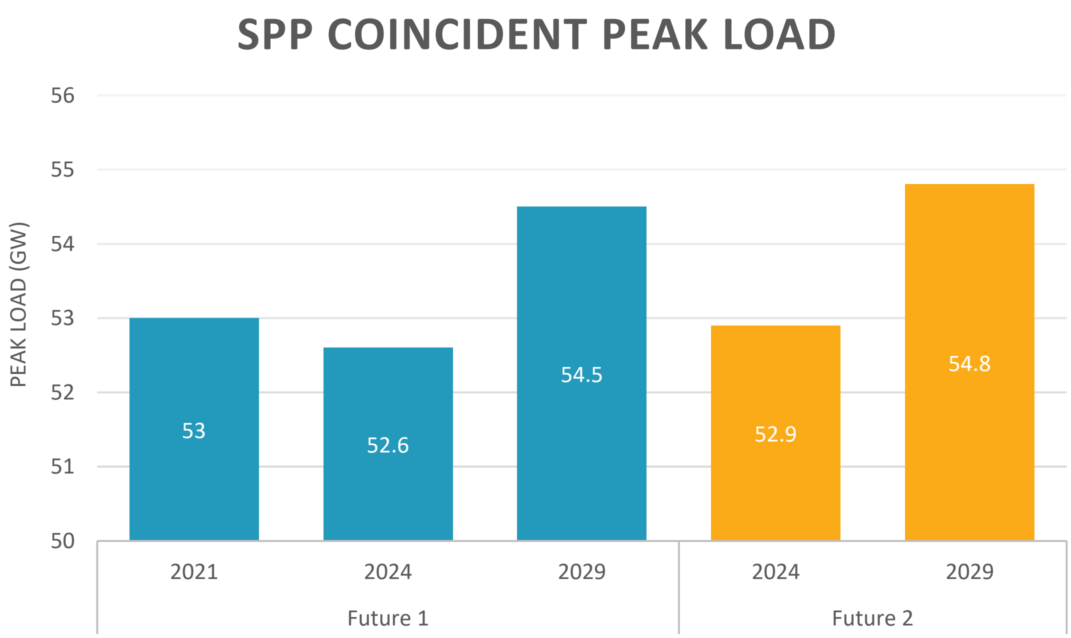


Figure 2.3: Coincident Peak Load

[6] Base annual energy requirements for both futures were reviewed via load factor percentages only. Additional annual energy amounts projected for Future 2 energy growth assumptions were reviewed by stakeholders.

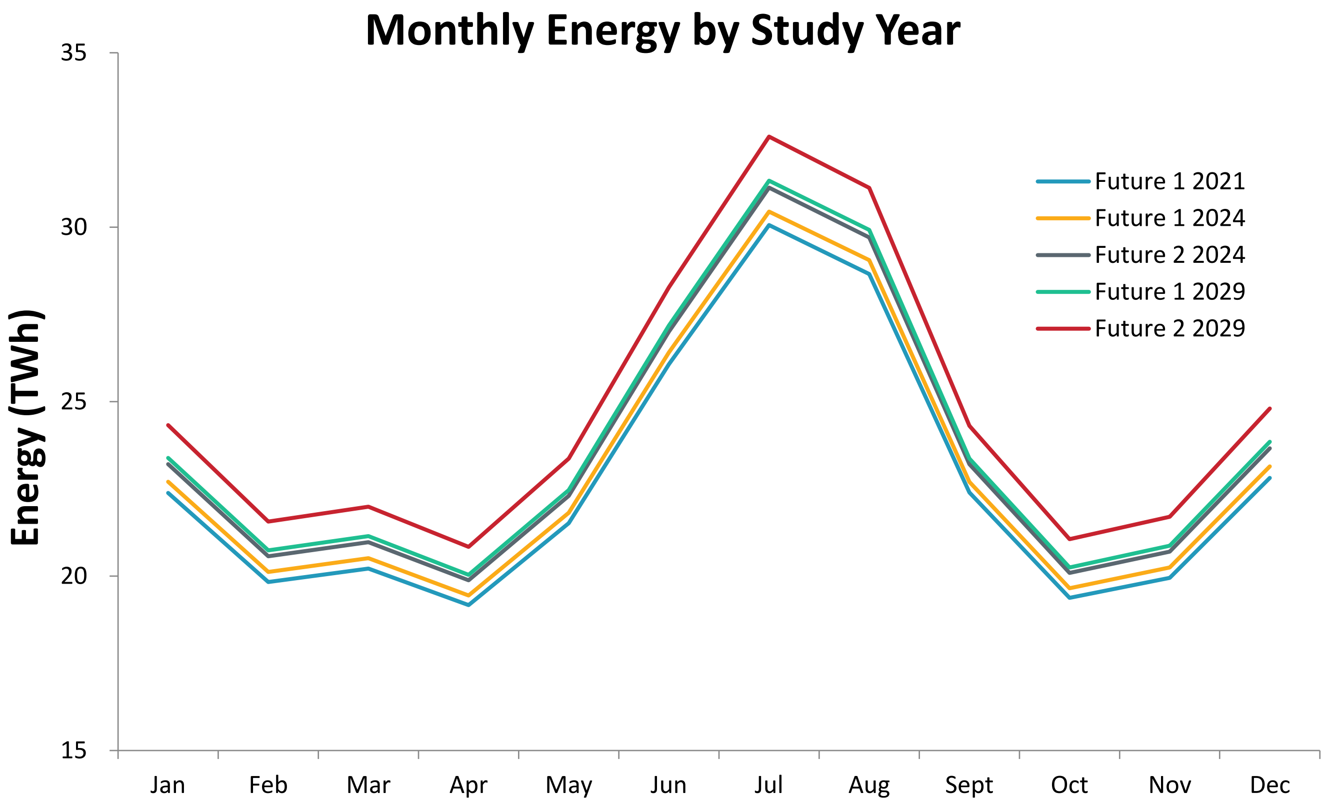


Figure 2.4: 2019 ITP Annual Energy

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 2019 ITP renewable policy review focused on renewable requirements through 2029.

2.2.1.4 Generation Resources

Existing generation data originated from the ABB Strategist (generation expansion software) fall 2016 reference case and was supplemented with SPP stakeholder information provided through the SPP Model on Demand (MOD) tool and the generation review.

Figure 2.5 and Figure 2.6 detail the annual energy and nameplate capacity by unit type for 2021.

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 Additional Request (RAR) process. As a result of the RAR process, 860 MW of wind generation was added to the market economic models; 660 MW of the additional wind 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.

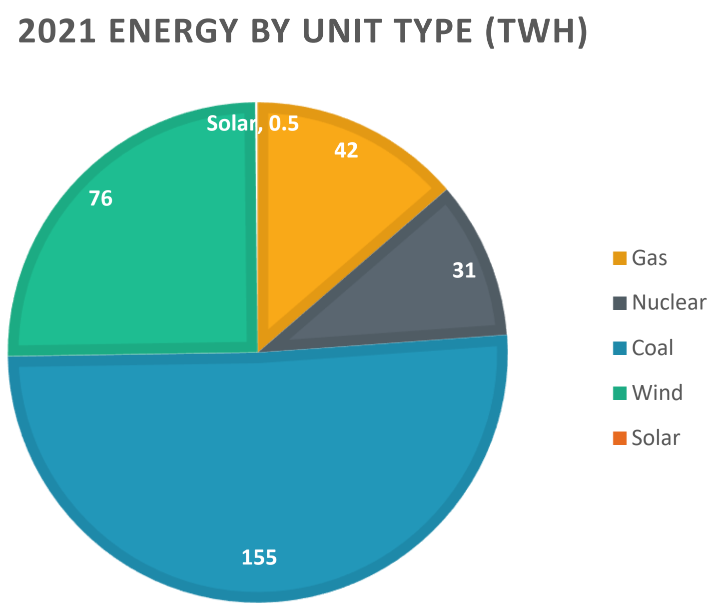


Figure 2.5: 2021 Energy by Unit Type

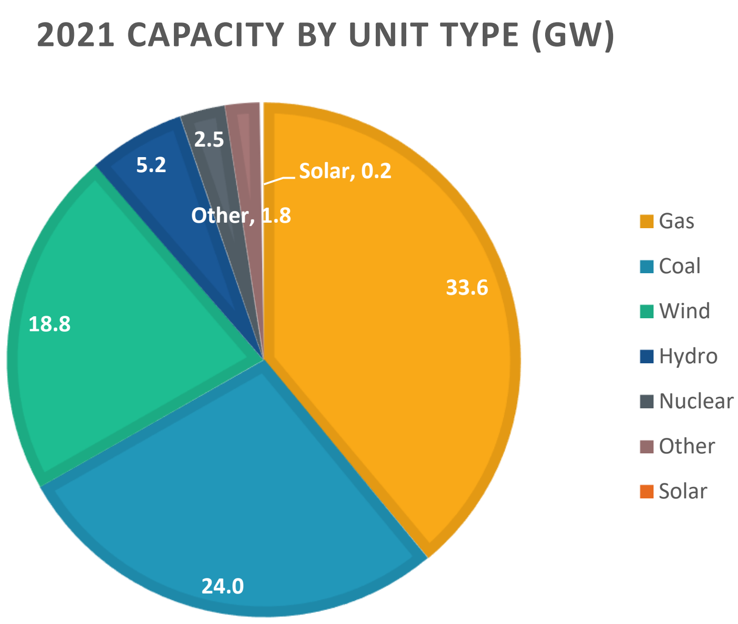


Figure 2.6: 2021 Capacity by Unit Type

Figure 2.7 identifies the amount of retired generation based upon the reference case provided by ABB. The figure reflects both real world retirement not yet included in in the ABB reference case as well as the retirements due to the assumptions within each future.

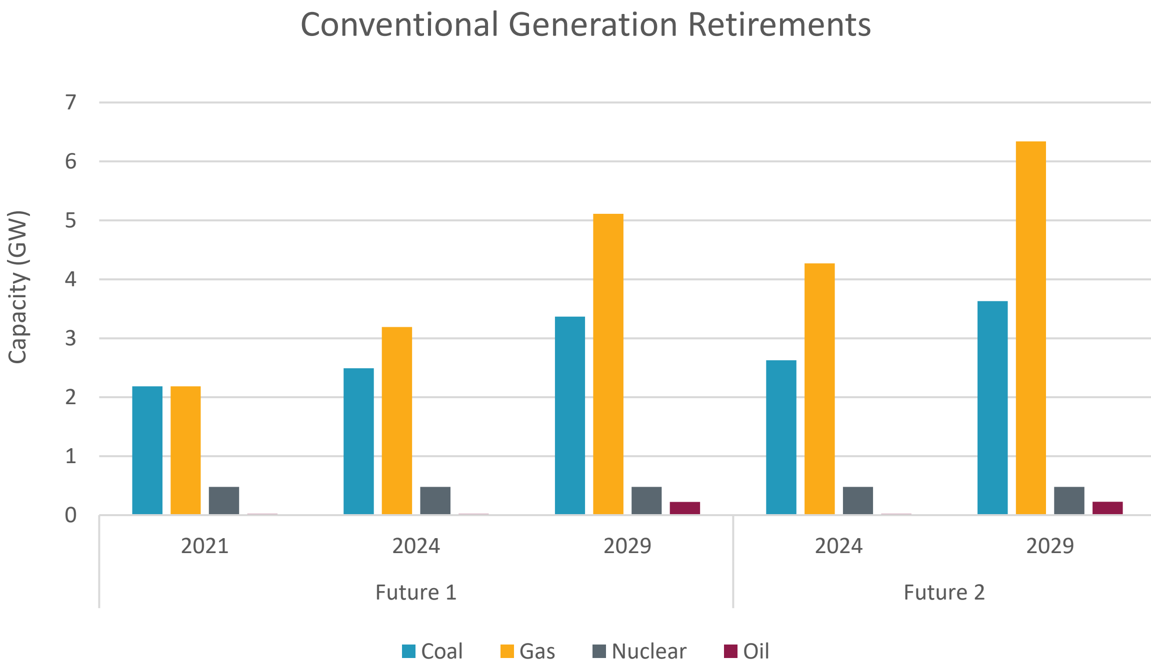


Figure 2.7: Conventional Generation Retirements

2.2.1.5 Fuel Prices

The ABB Strategist fall 2016 reference case and ABB Strategist natural gas fundamental forecast (for long-term price projections) were utilized for the fuel price forecasts. Figure 2.8 shows the annual average natural gas and coal prices for the study horizon. Between 2020 and 2029, these prices increase from \$3.14 to \$5.07 (~5.5% compound average escalation), \$2.20 to \$2.80 (~2.7% compound average escalation) and \$2.20 to \$2.80 (~2.7% compound average escalation) for natural gas and coal, respectively.

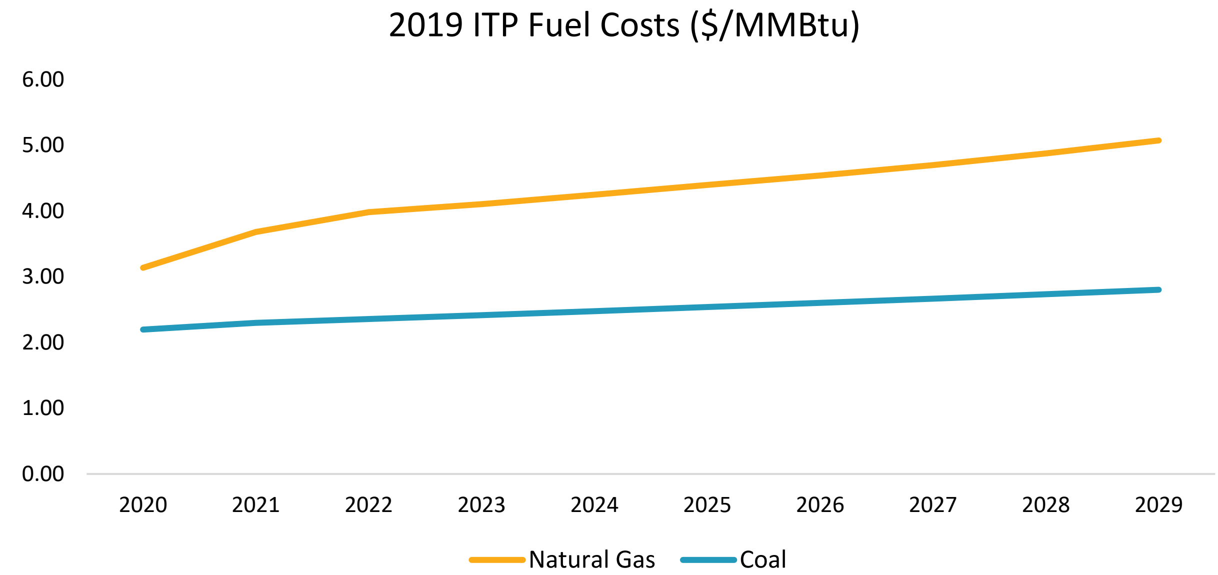


Figure 2.8: ABB Fuel Annual Average Fuel Price Forecast

2.2.2 RESOURCE PLAN

A key component of evaluating the transmission system for a 10-year horizon is to identify the resource outlook for each future. Due to changing load forecasts, resource retirements and a fast-changing mix of resource additions, the SPP generation portfolio will not be the same in 10 years as it is today. SPP staff developed renewable and conventional resource expansion plans for each future and study year to meet projected policy mandates and goals, expected renewable and emerging technology projections as approved in the 2019 ITP futures, and resource reserve margin requirements.

2.2.2.1 Renewable Resource Expansion Plan

The renewable resource expansion plan involves qualitatively forecasting the renewable levels to be included in the assessment; this was accomplished while developing the 2019 ITP scope with stakeholders. For utility-scale solar, the projections for the assessment are consistent with National Renewable Energy Laboratory's *2016 Annual Technology Baseline* standard scenario projections, specific member's integrated resource plan projections, SPP generation interconnection (GI) requests for utility-scale solar, and SPP stakeholder expectations that solar will be added in the future based on its accredited capacity value.

Wind projections in the near term are consistent with historic installation trends (when production tax credits are active), SPP's GI requests for wind, and specific member's public wind addition announcements. The wind projections after the expiration of production tax credits are consistent with wind development growth rates of 1% for Future 1, keeping pace with load growth rates. A wind development growth rate of 2% for Future 2Future 2 marginally outpaces load growth rates.

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 2024 and 2029. 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 the levels specified above. For states with an RPS that could be met by either wind or solar generation, a ratio of 80% wind additions to 20% solar additions was utilized. This split is 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 2029 were 212 MW in Future 1 and 222 MW in Future 2. Figure 2.9 shows renewable generation added in each future and study year.

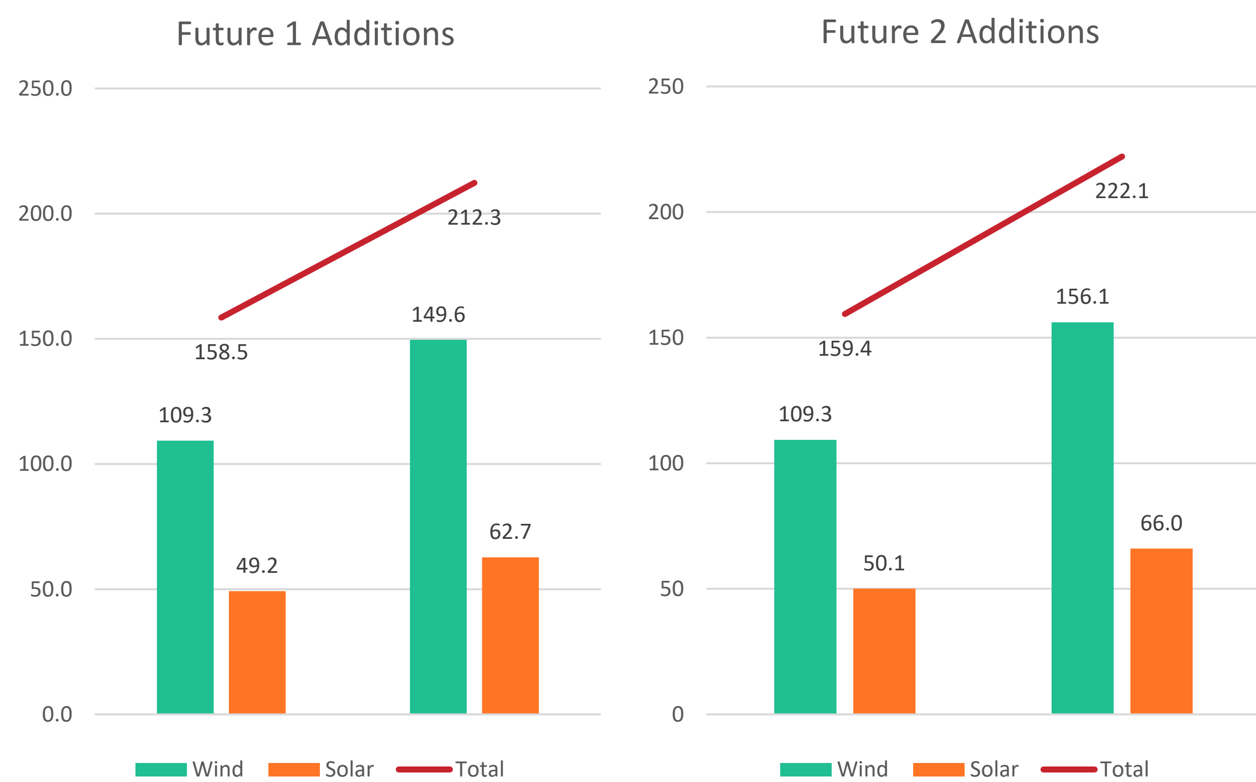


Figure 2.9: SPP Renewable Generation Assignments to meet Mandates and Goals

After ensuring mandates and goals are met by allocating renewables, SPP staff further assigned ownership and allocated the 2019 ITP projected renewable capacity to each pricing zone.

Projected solar additions were assigned based on the load-to-ratio share for each pricing zone. Projected wind additions were allocated to deficient zones to maximize the available accreditation of renewables for each zone, up to the zonal renewable cap defined in the study scope. The order in which resources were accredited was:

- Existing generation
- Policy wind and solar additions
- Projected solar 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.

After using expected renewables and emerging technologies, conventional resource expansion plans were developed to meet the 12% reserve margin requirement set by SPP Planning Criteria[7]. Projected reserve margins were calculated for each pricing zone using existing generation, projected renewable generation, and load projections through 2039. Resource expansion plans for capacity requirements aggregated to a pricing zone level achieves an appropriate level of assumed power purchase agreements (PPAs) and joint ownership of resources between load-serving entities. Each zone that was not yet meeting its minimum reserve requirement was assigned conventional resources in 2024 and 2029 of both futures.

Nameplate conventional generation capacity assigned to utilities is counted toward each zone's capacity margin requirement. 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 Lazard's Levelized Cost of Energy Analysis – Version 10.0[8] 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 primary technology selected in Futures 1 and 2 to meet capacity requirements. Future 1 included the addition of one reciprocating engine.

While both futures represent normal load growth, more resource additions are needed in future two due to the additional unit retirements and increased energy demand growth rates.

Table 2.2 shows the total nameplate generation additions by future and study year to meet futures definitions and resource adequacy requirements. Figure 2.10 shows the nameplate generation additions by future, study year, and capacity type for the SPP region.

	Future 1	Future 2
2024	9.5 GW	11.5 GW
2029	17.0 GW	22.7 GW

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

[7] SPP Planning Criteria
[8] Lazard's Levelized Cost of Energy Analysis - Version 10.0

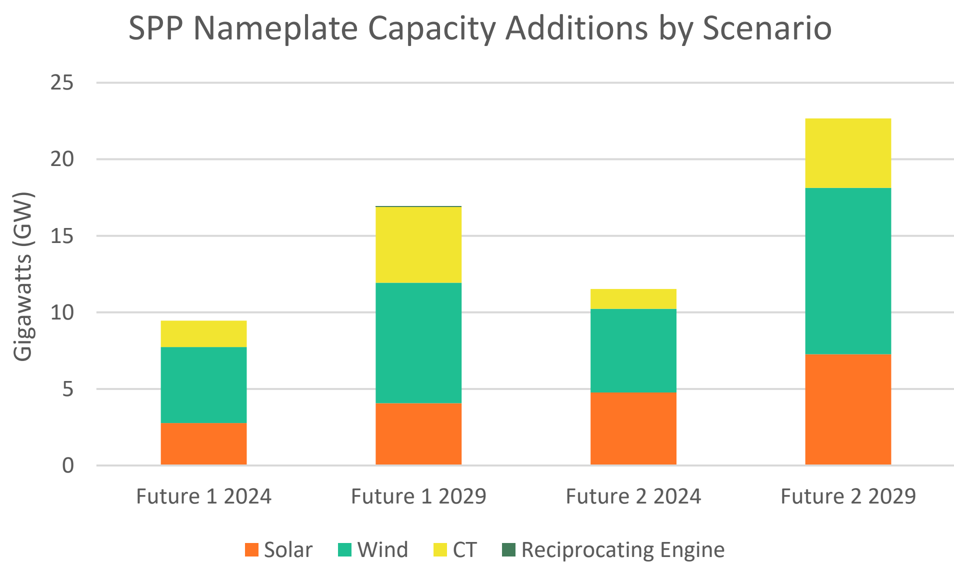


Figure 2.10: Nameplate Capacity Additions by Future and Year

Table 2.3 shows the total accredited generation additions by future and study year. Figure 2.11 shows accredited generation additions by future, study year, and technology for the SPP region.

	Future 1	Future 2
2024	4.7 GW	5.7 GW
2029	9.4 GW	11.3 GW

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

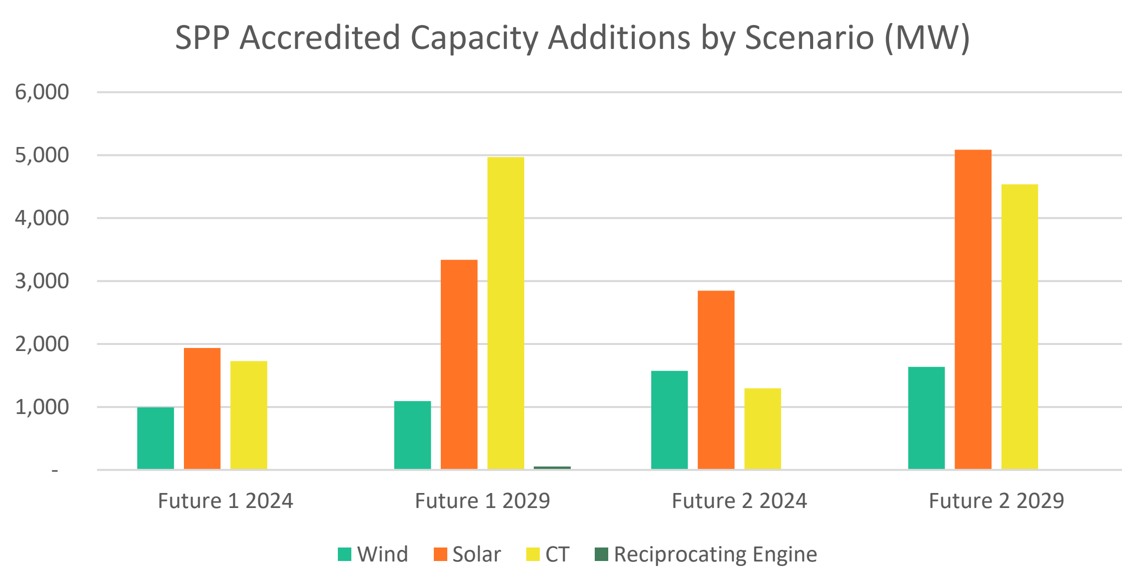


Figure 2.11: Accredited Capacity Additions by Scenario

2.2.2.3 Siting Plan

SPP sited projected renewable and conventional resources according to various site attributes for each technology[9].

Distributed solar generation, an assumption in Future 2 only, was allocated to the top 10% of load buses for each load area on a pro rata basis utilizing load review data. SPP stakeholder feedback was considered in the selection of sites for this technology. Figure 2.12 and Figure 2.13 show the selected sites and allocation of distributed solar capacity across the SPP footprint.

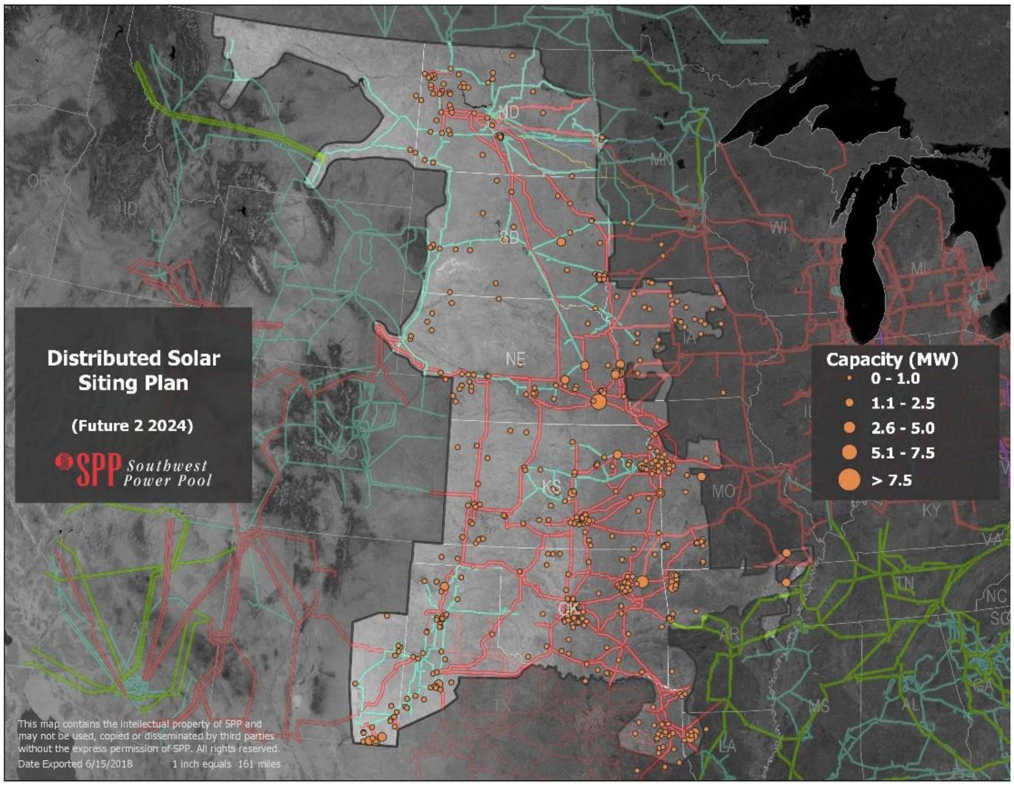


Figure 2.12: 2024 Future 2 Distributed Solar Siting Plan

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

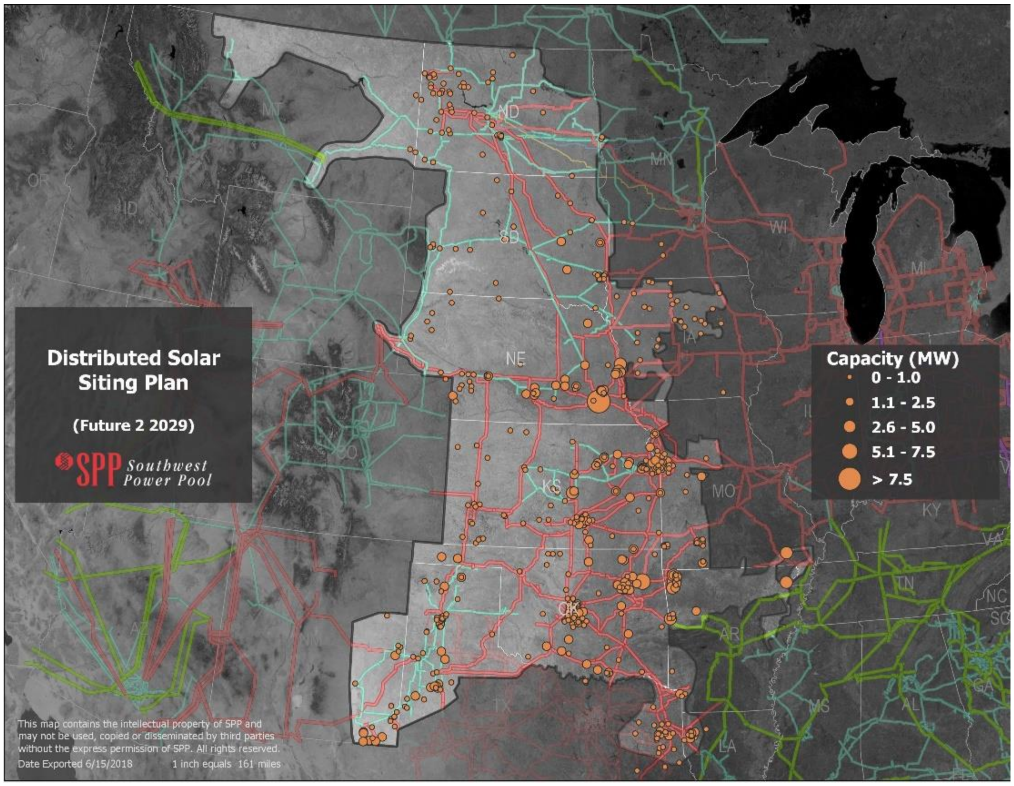


Figure 2.13: 2029 Future 2 Distributed Solar Siting Plan

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) and 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. The ESWG reviewed and approved the exceptions. Figure 2.14 through Figure 2.17 show the selected sited and allocation of utility solar capacity across the SPP footprint.

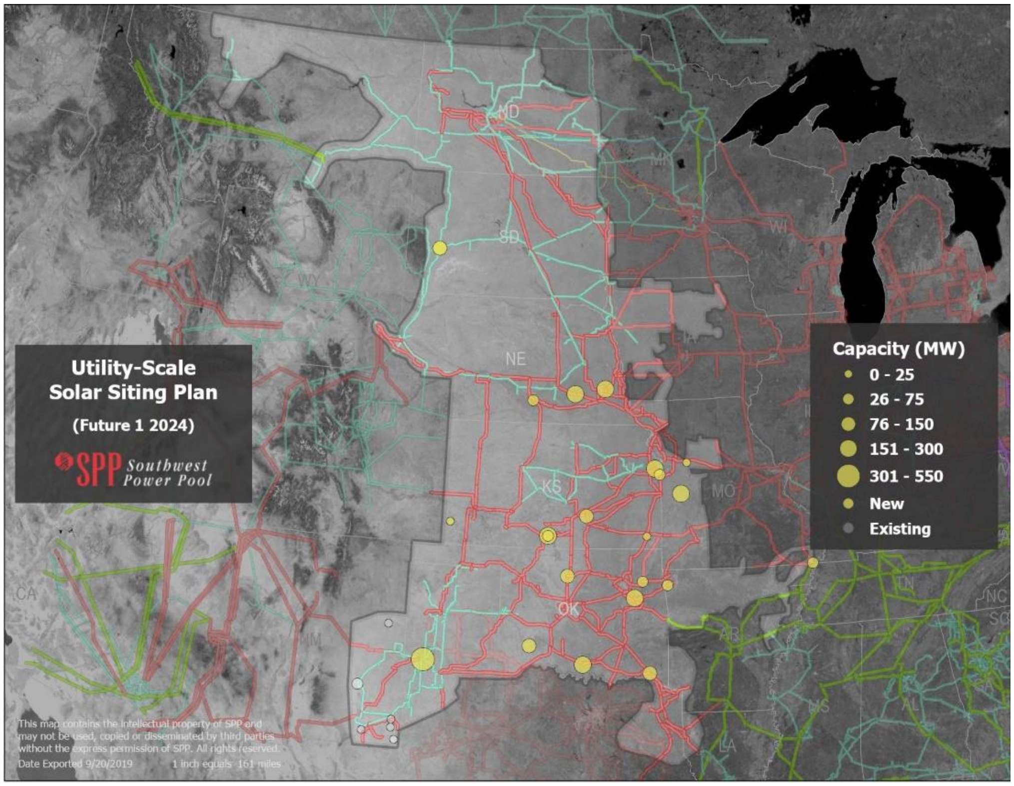


Figure 2.14: 2024 Future 1 Utility-Scale Solar Siting Plan

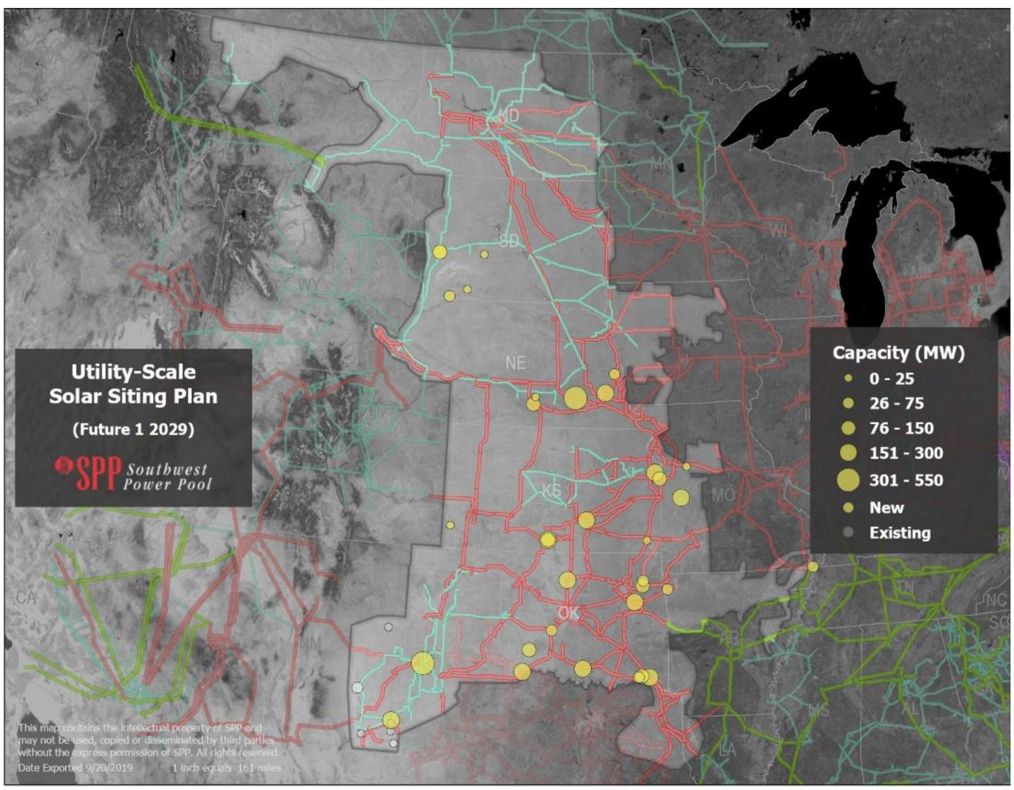


Figure 2.15: 2029 Future 1 Utility-Scale Solar Siting Plan

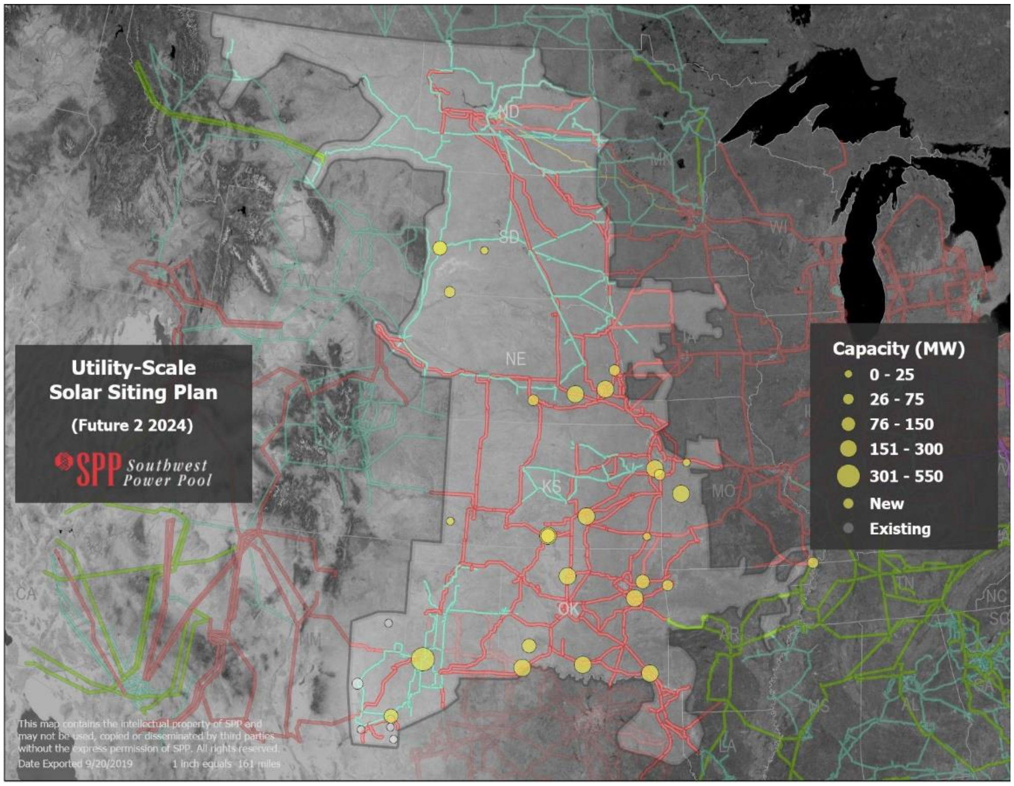


Figure 2.16: 2024 Future 2 Utility-Scale Solar Siting Plan

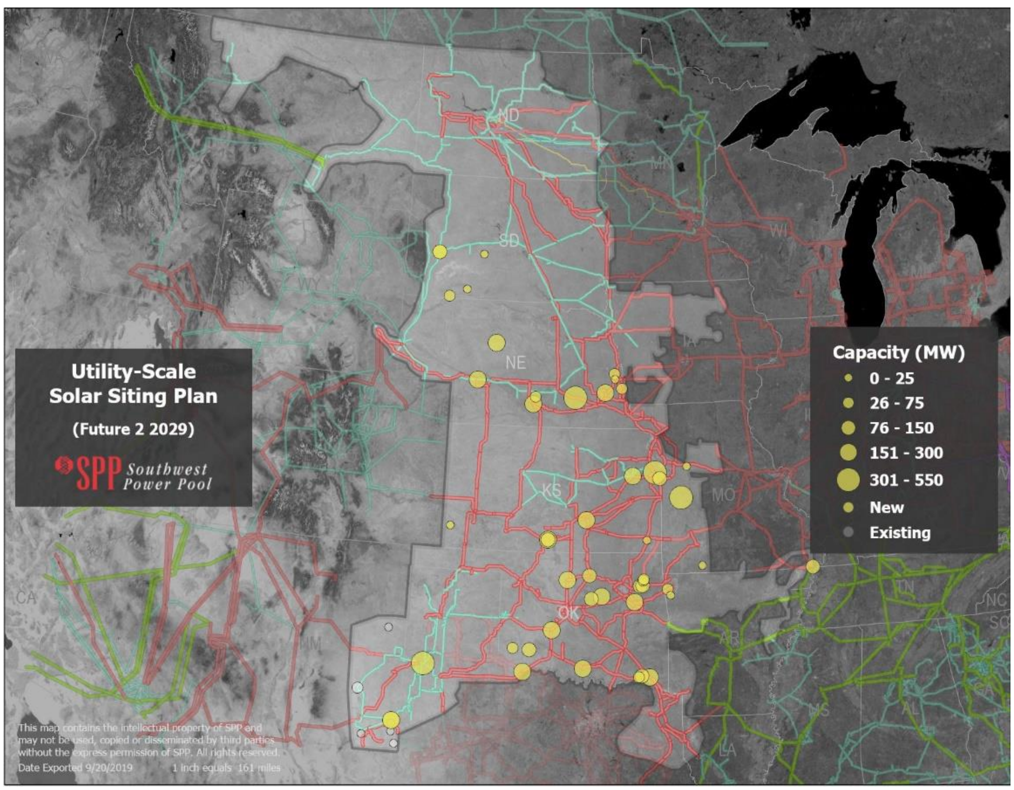


Figure 2.17: 2029 Future 2 Utility-Scale Solar Siting Plan

Wind sites were selected from GI queue requests that required the lowest total interconnection cost[10] per MW of capacity requested, taking into consideration the following:

- Potentially directly-assigned upgrade needed.
- Unknown third-party system impacts.
- Required generator outlet facilities (GOF).
- GI 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. The ESWG reviewed and approved exception requests. Figure 2.18 through Figure 2.21 show the selected siting and allocation of wind capacity across the SPP footprint.

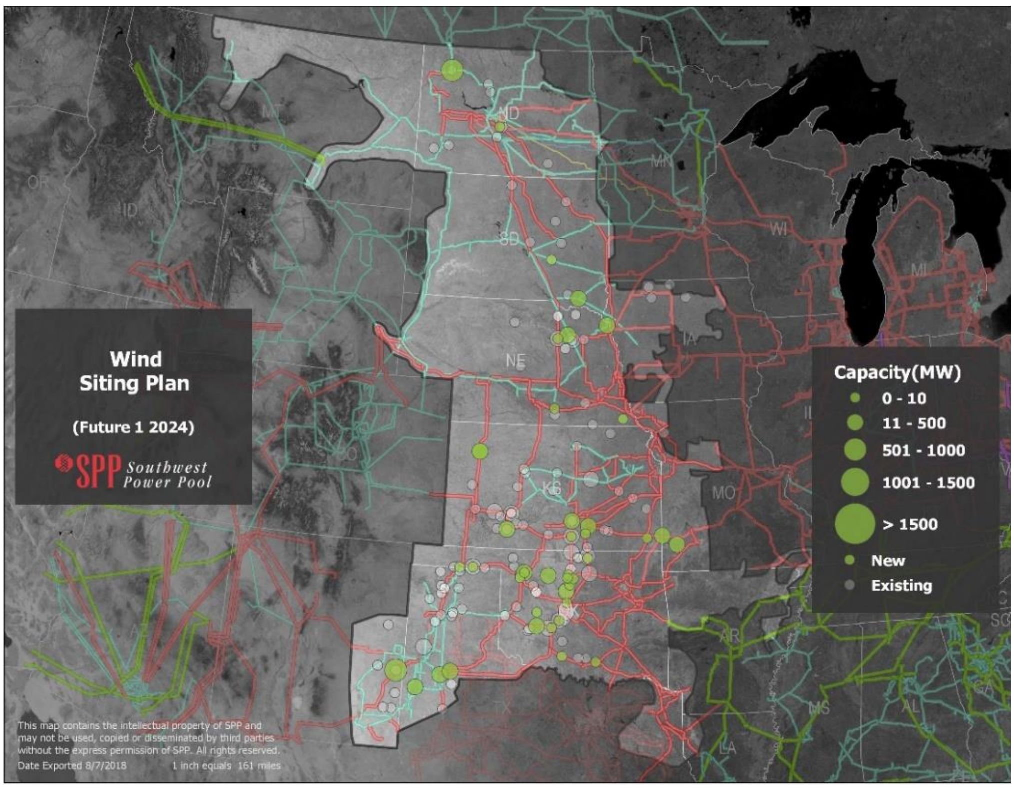


Figure 2.18: 2024 Future 1 Wind Siting Plan

[10] Includes assigned interconnection and network upgrade costs

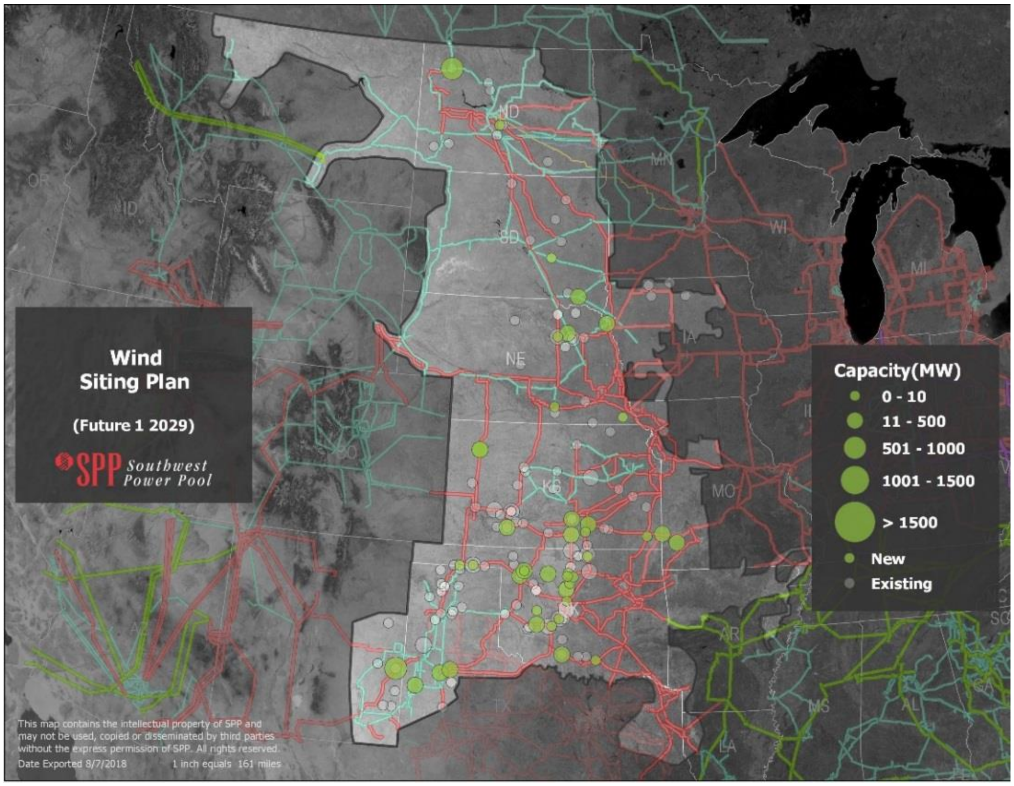


Figure 2.19: 2029 Future 1 Wind Siting Plan

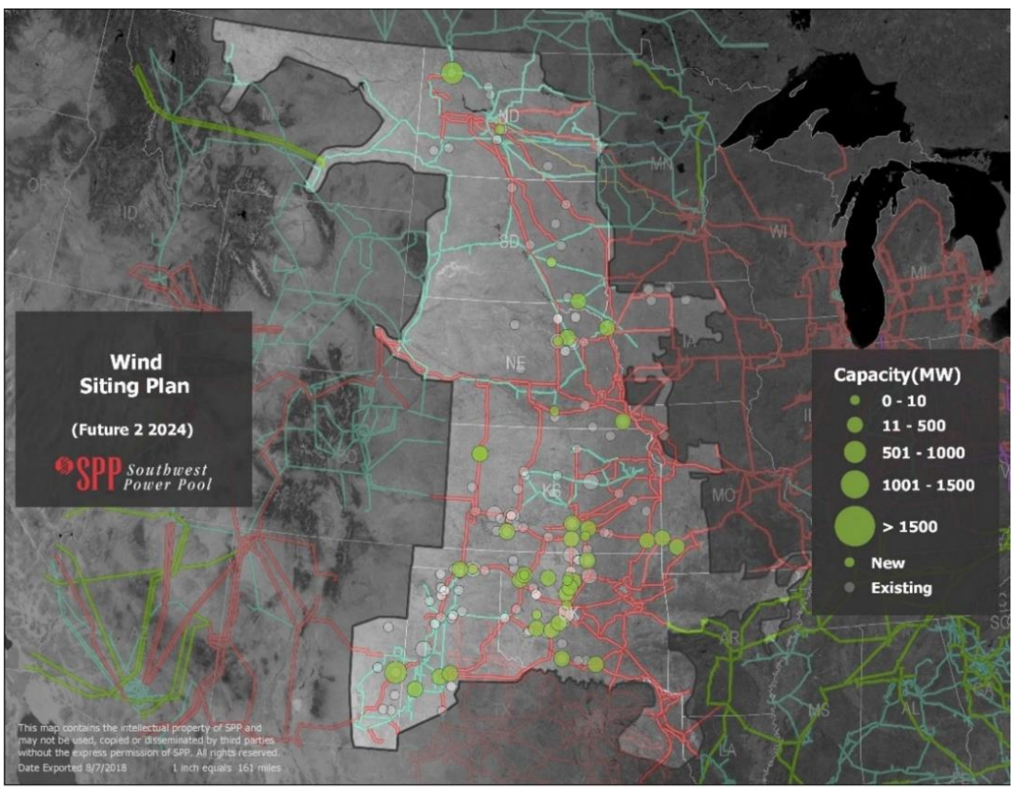


Figure 2.20: 2024 Future 2 Wind Siting Plan

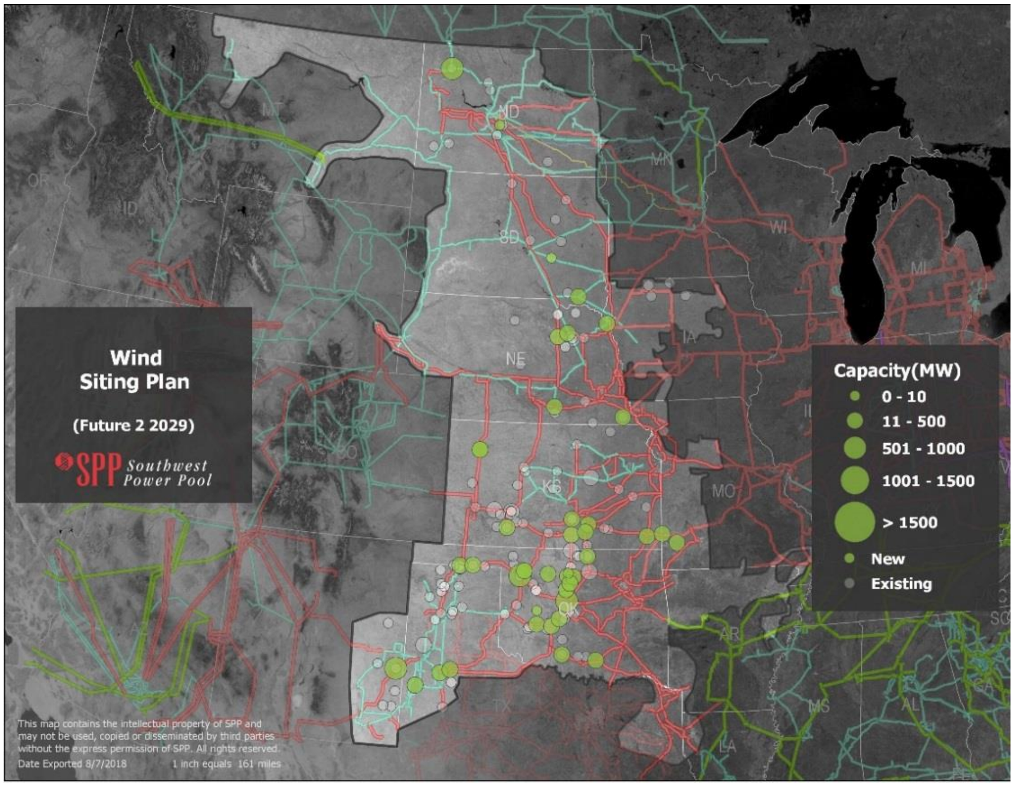


Figure 2.21: 2029 Future 2 Wind Siting Plan

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. The ESWG reviewed and approved exception requests. Figure 2.22 through Figure 2.25 show the selected sites for conventional generation across the SPP footprint.

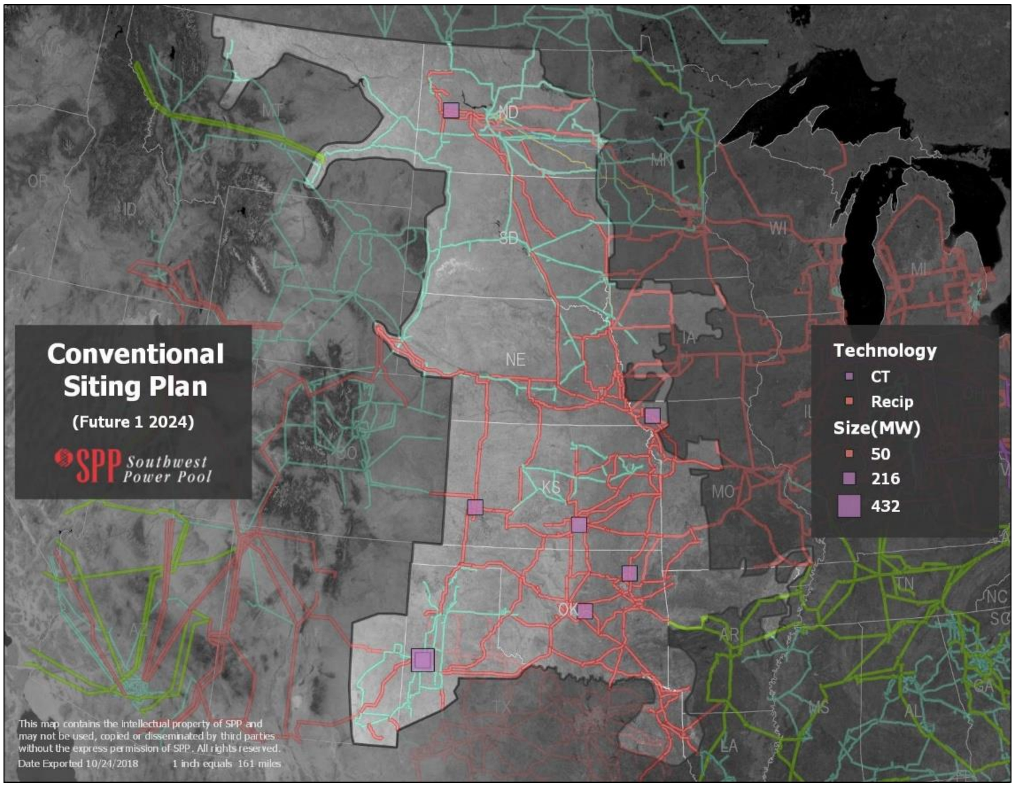


Figure 2.22: 2024 Future 1 Conventional Siting Plan

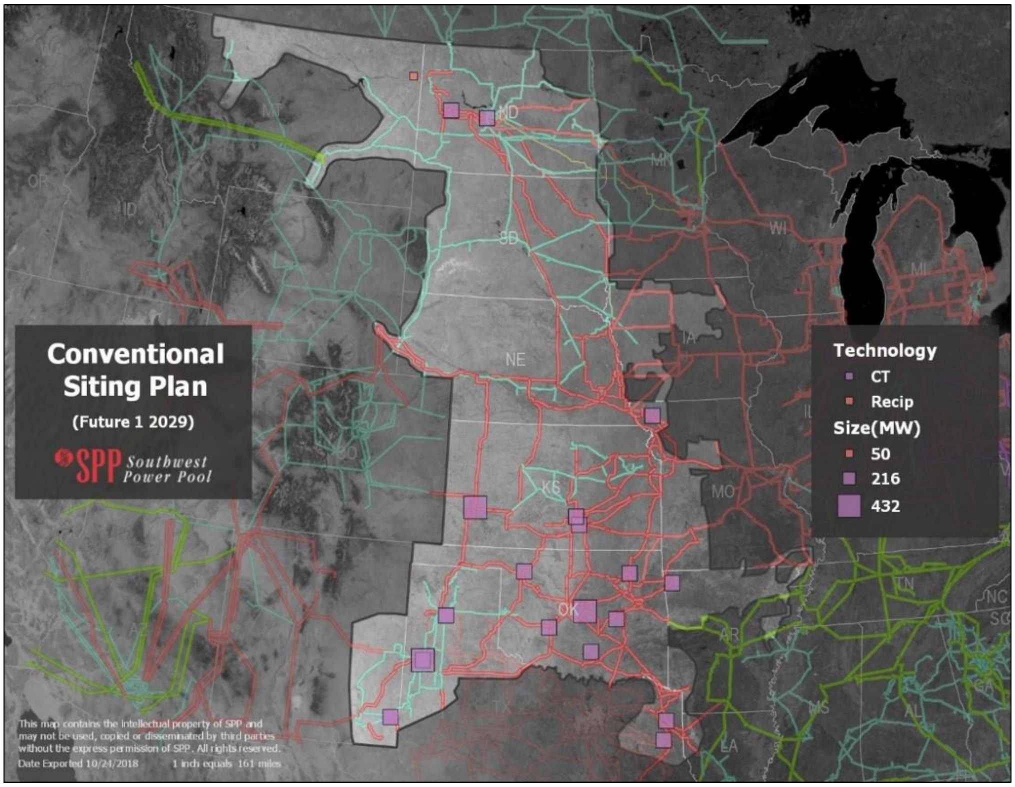


Figure 2.23: 2029 Future 1 Conventional Siting Plan

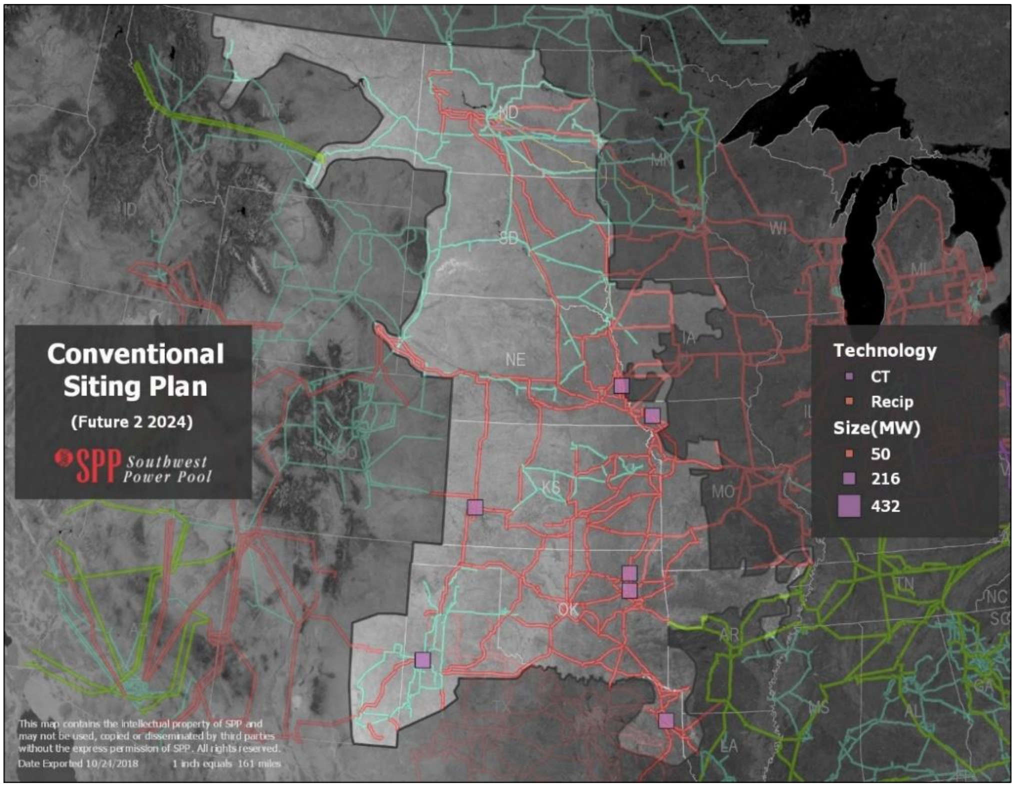


Figure 2.24: 2024 Future 2 Conventional Siting Plan

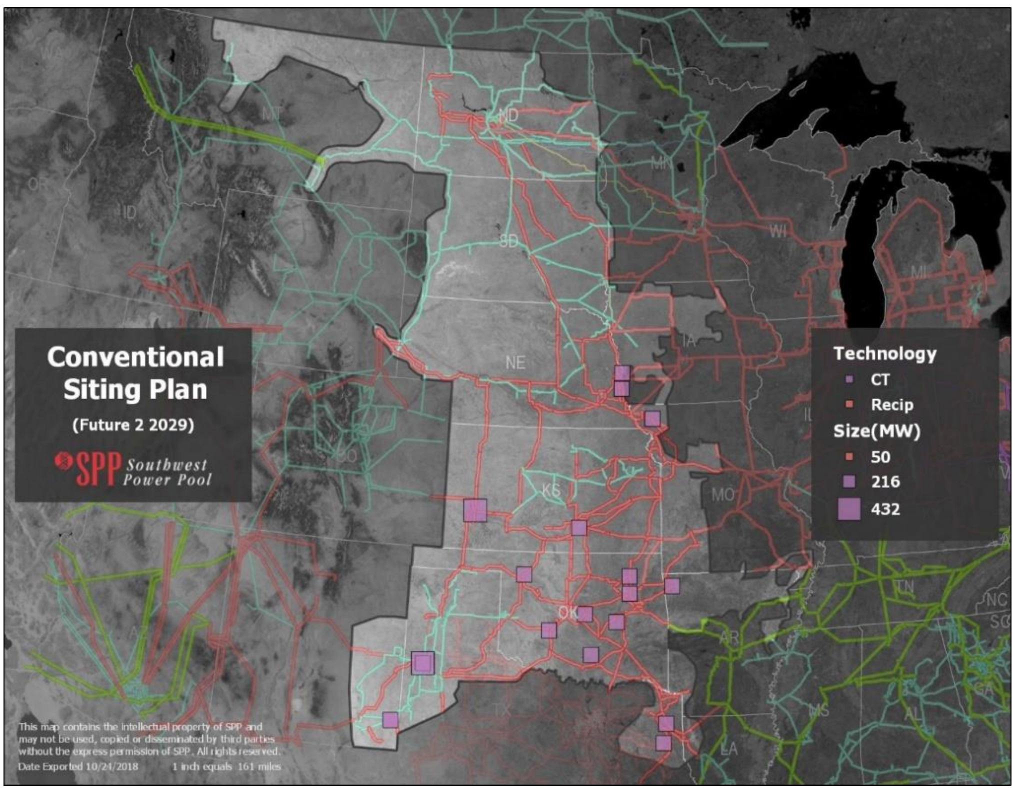


Figure 2.25: 2029 Future 2 Conventional Siting Plan

2.2.2.4 Generator Outlet Facilities (GOF)

The GOFs necessary to interconnect resources at individual sites were critical to the siting of resources. For sites with an executed GIA identifying a necessary upgrade, the upgrade included in the GIA was included as a GOF. For other instances, the site-specific results of a transfer analysis[11] conducted on all potential sites were assessed to determine if a site was capable of reliably allowing a resource to dispatch to the SPP system. The results of the GOF analysis determined the upgrades shown in Table 2.4.

GOF Description	Site	MW Sited	GOF Source
Second Tande-Neset 230 kV line	Tande 345 kV	604	Siting Availability
New Neset 230/115 kV transformer			
Cleo Corner-Cleo Tap 138 kV line terminal equipment	Cleo Corner 138 kV	200	GI Queue
Carl Junction-Asbury Plant-Purcell 161 kV line terminal equipment	Asbury Plant 161 kV	250	Siting Availability
Carthage SW-Carthage-La Russell-Monett 161 kV line terminal equipment	La Russell Energy Center 161 kV	250	Siting Availability
Second Tolk 345/230 kV transformer	Crossroads 345 kV	522	GI Queue
Eddy County-Crossroads 345 kV line terminal equipment	Crossroads 345 kV	522	Siting Availability
Eddy County-Tolk 345 kV line terminal equipment			

Table 2.4: GOFs

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 2018 MISO Transmission Expansion Planning (MTEP18) continued fleet change (CFC) and distributed and emerging technologies (DET) 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 MTEP18 CFC and DET futures, while AECI resource expansion and siting plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI. Figure 2.26 and Figure 2.27 show the cumulative capacity additions by unit type of these external regions for Futures 1 and 2.

[11] First-contingency incremental transfer capability (FCITC) analysis

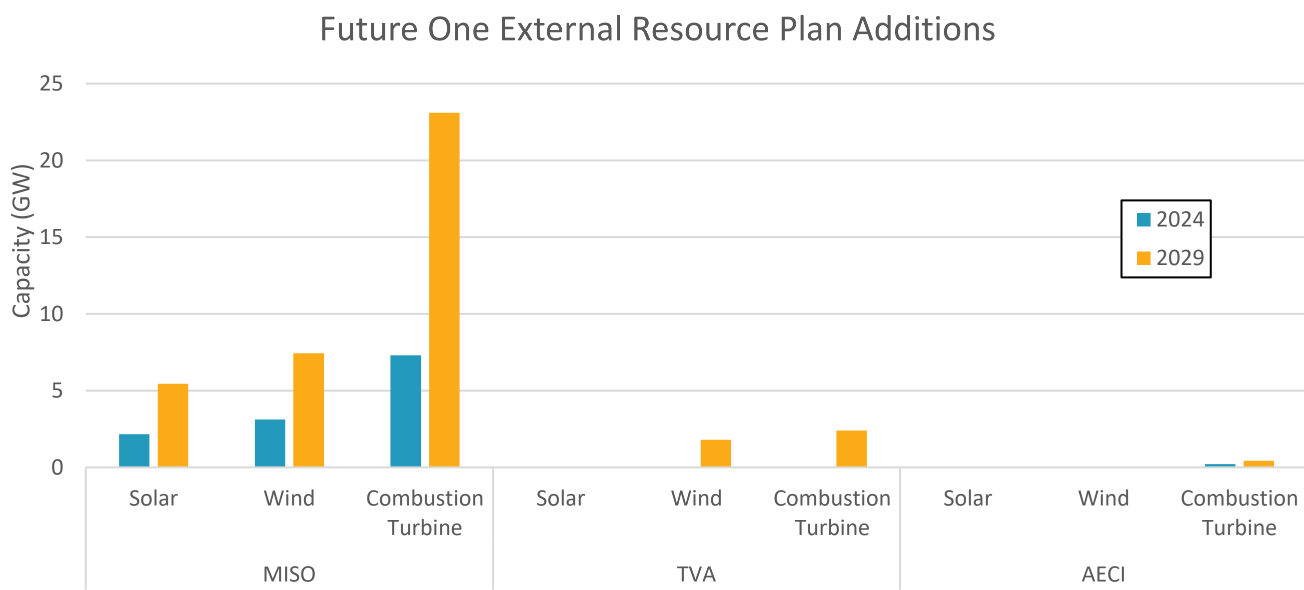


Figure 2.26: Capacity Additions by Unit Type – Future 1

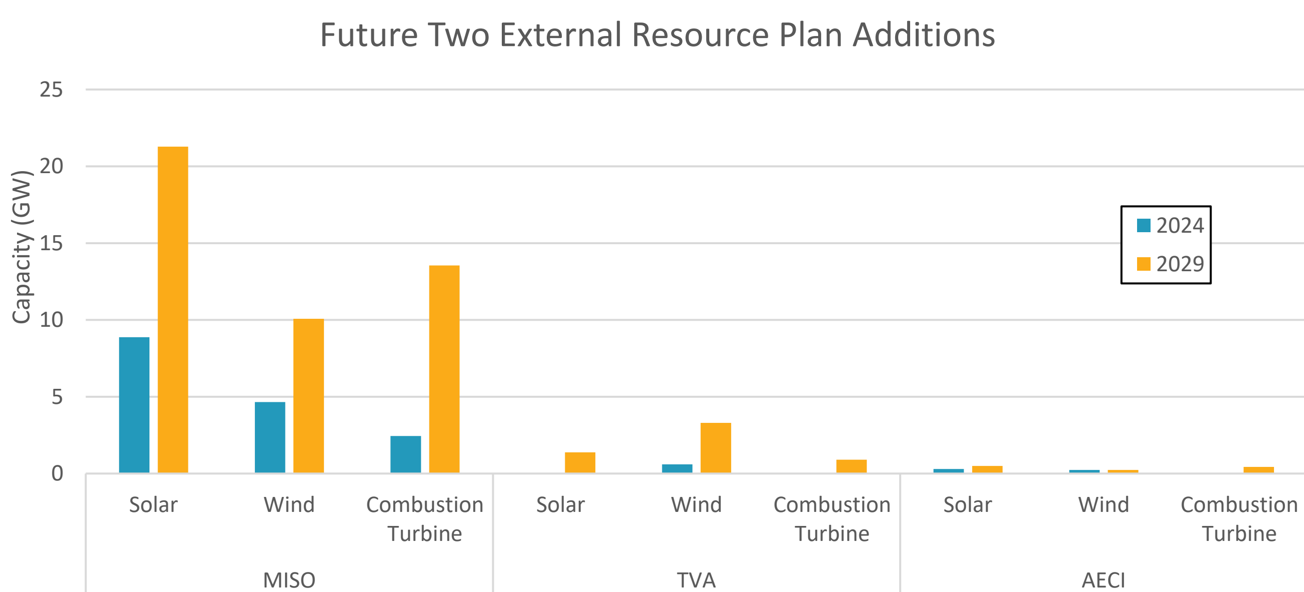


Figure 2.27: Capacity Additions by Unit Type – Future 2

2.2.3 CONSTRAINT ASSESSMENT

SPP considers transmission constraints when reliably managing, in the least-costly manner, the flow of energy across physical bottlenecks on the transmission system. 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[12], which consists of NERC-defined flowgates that are impactful to modeled regions and recent temporary flowgates identified by SPP in real-time.

MTEP18 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.

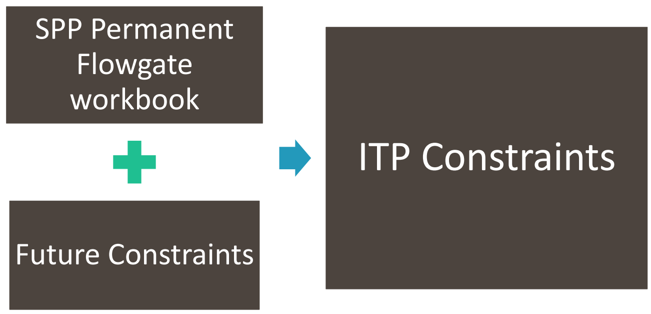


Figure 2.28: Constraint Assessment Process

2.3 MARKET POWERFLOW MODEL

The economic dispatch from each market economic model is used to develop market powerflow model snapshots representing stressed conditions on the SPP transmission system. Table 2.5 shows the SPP coincident peak (peak) and highest wind-to-load ratio (off-peak) reliability hours from each future and year of the market economic model simulations chosen for the market powerflow models.

	Off-Peak Hour	Wind Penetration[13]	Peak Hour	SPP Load (MW)
Future 1 2021	April 4 at 4:00 AM	79.5%	August 3 at 5:00 PM	52,958
Future 1 2024	April 1 at 3:00 AM	100.9%	July 30 at 4:00 PM	52,642
Future 1 2029	April 1 at 4:00 AM	100.9%	August 1 at 4:00 PM	54,470
Future 2 2024	April 1 at 3:00 AM	111.3%	July 16 at 4:00 PM	52,882
Future 2 2029	April 1at 4:00 AM	122.2%	July 17 at 4:00 PM	54,844

Table 2.5: Market Powerflow Reliability Hours

12 Posted on SPP OASIS
13 Does not include curtailments

3 BENCHMARKING

3.1 POWERFLOW MODEL

Powerflow model benchmarking for this assessment was performed on models from the 2018 ITP near-term (ITPNT) and 2019 ITP assessments. Model comparisons were conducted to ensure the accuracy of the powerflow model results, including:

- Comparison of the summer and winter year two load totals between the 2018 ITPNT scenario zero models and the 2019 ITP base reliability models. See Figure 3.1 and Figure 3.2.
- Comparison of the summer and winter years two, five, and 10 generation dispatch totals between the 2018 ITPNT scenario zero and base reliability models (summer only), and the 2019 ITP base reliability models. See Figure 3.3 and Figure 3.4.
- The summer and winter year 10 generator removals in the 2019 ITP base reliability models. See Figure 3.5.

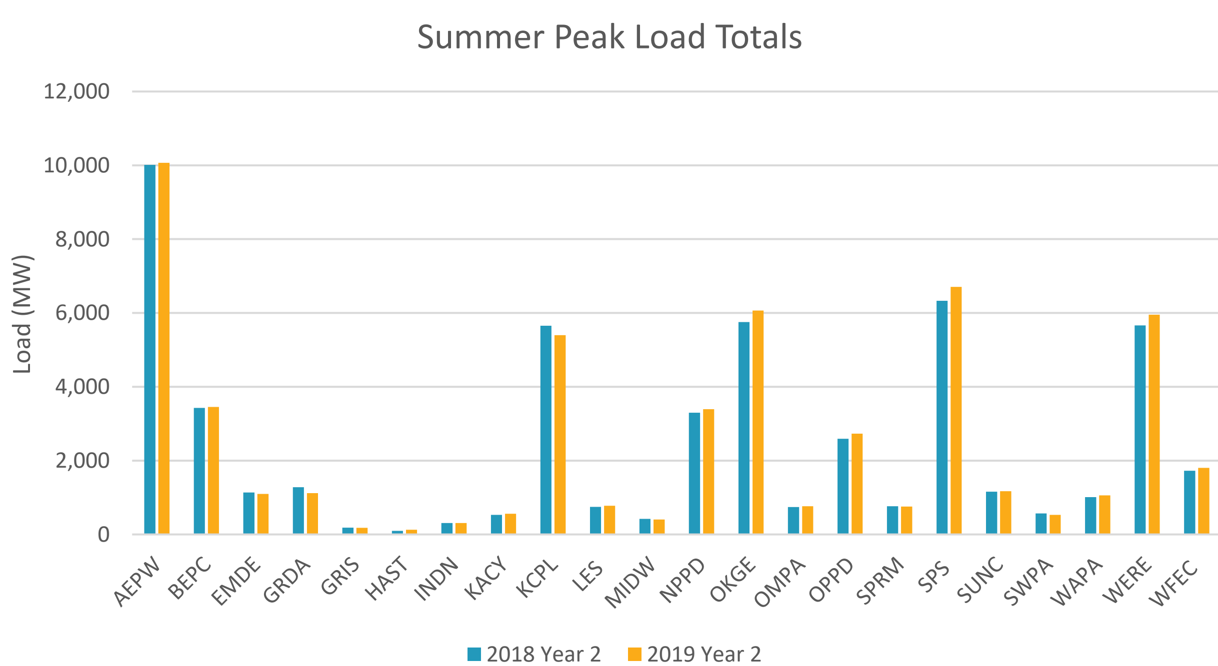


Figure 3.1: Summer Peak Year Two Load Totals Comparison

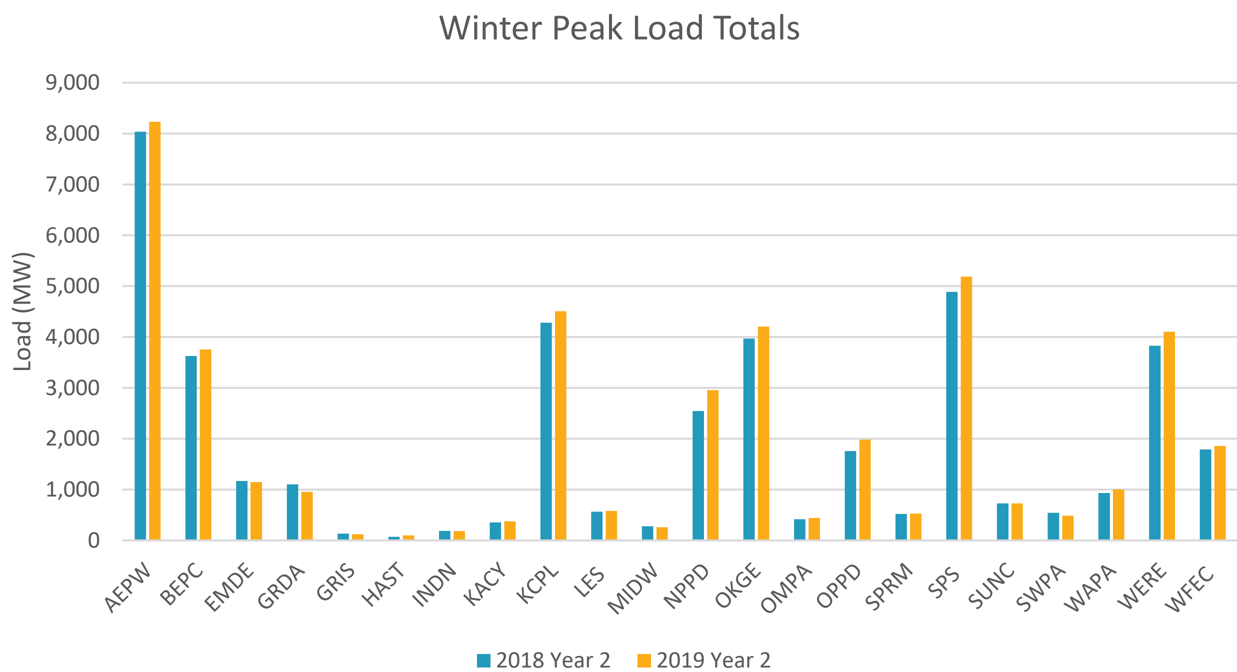


Figure 3.2: Winter Peak Year 2 Load Totals Comparison

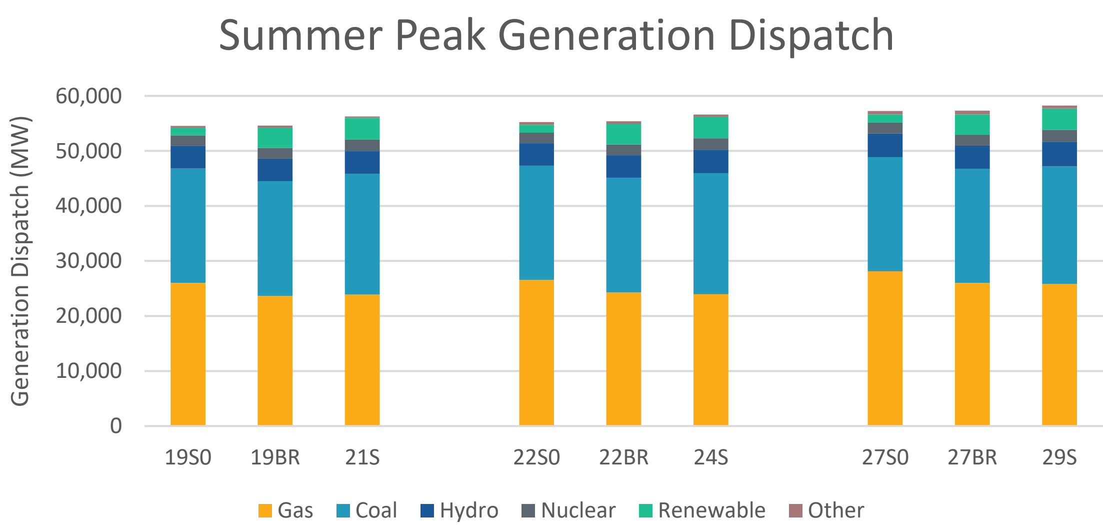


Figure 3.3: Summer Peak Years 2, 5, and 10 Generation Dispatch Comparison

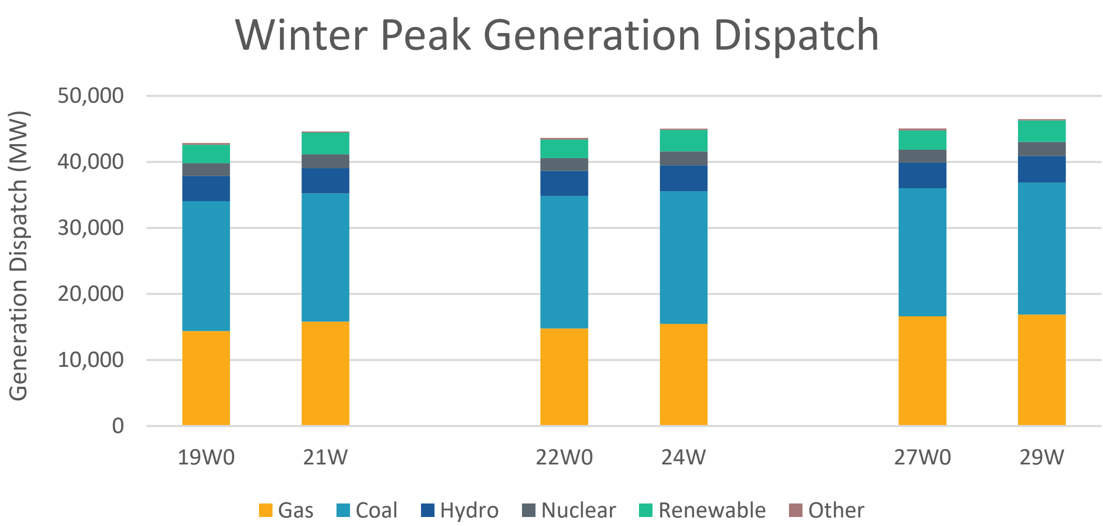


Figure 3.4: Winter Peak Years 2, 5, and 10 Generation Dispatch Comparison

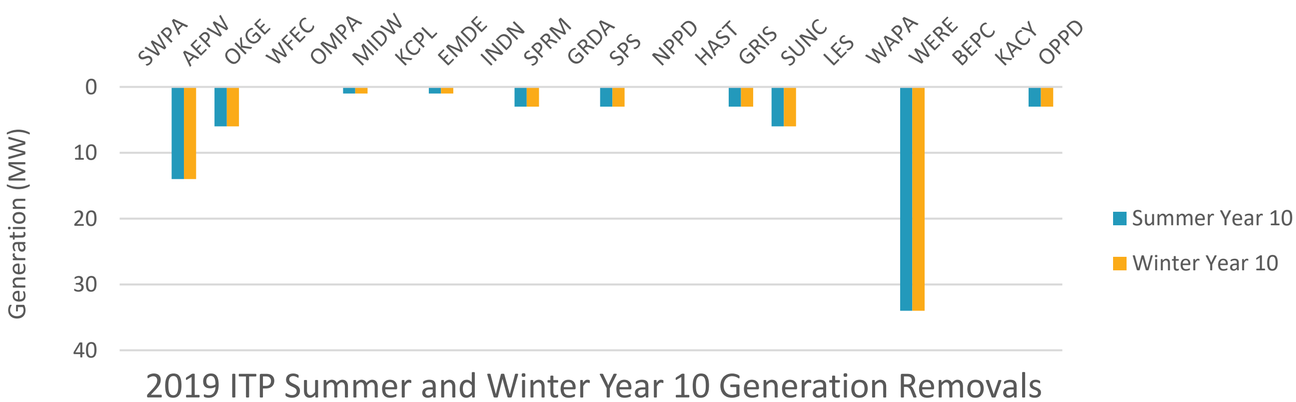


Figure 3.5: 2019 ITP Summer and Winter Year 10 Generation Removals

Operational model benchmarking for this assessment was performed on the year one model from the 2019 ITP base reliability models and August 2019 state estimator operational model (actual data). Model comparisons were conducted to ensure the accuracy of the powerflow model results, including:

- Comparison of the summer and winter load totals between the August 2019 state estimator operational model and 2019 ITP base reliability summer and winter year one model, as shown in Figure 3.6
- Comparison of the summer and winter generation dispatch totals between the August 2019 state estimator operational model and 2019 ITP base reliability summer and winter year one model, as shown in Figure 3.7 and Figure 3.8

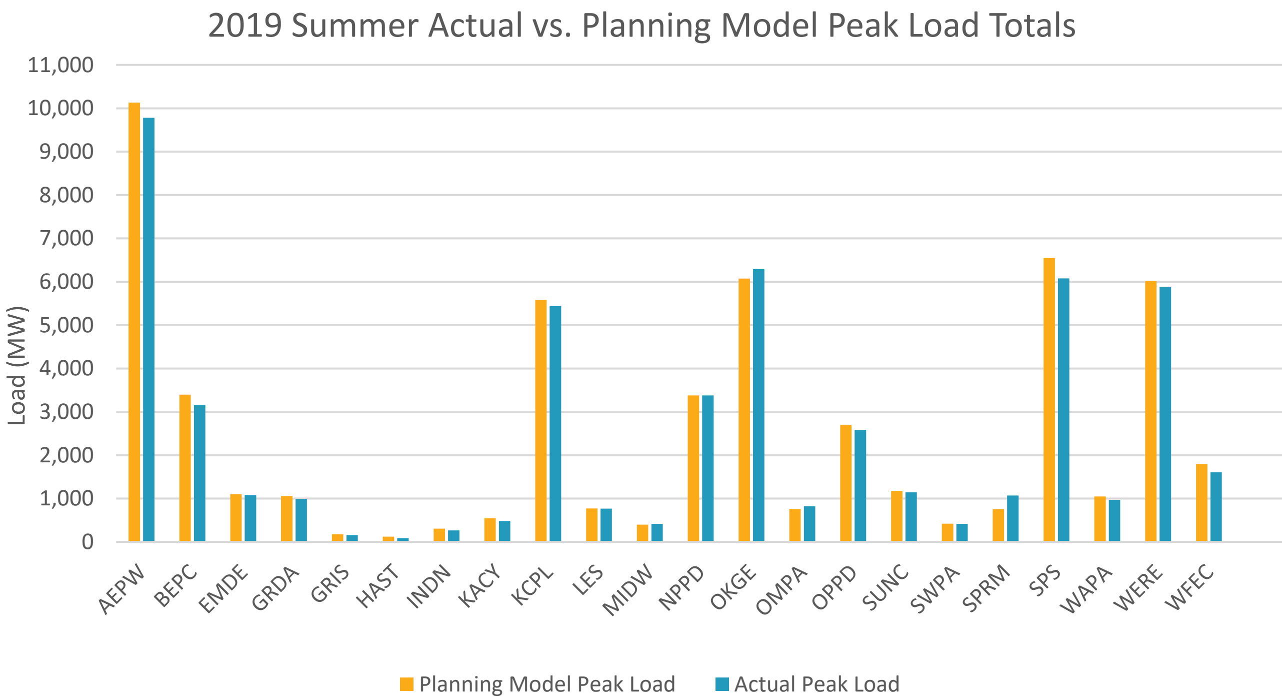


Figure 3.6: 2019 Summer Actual vs. Planning Model Peak Load Totals

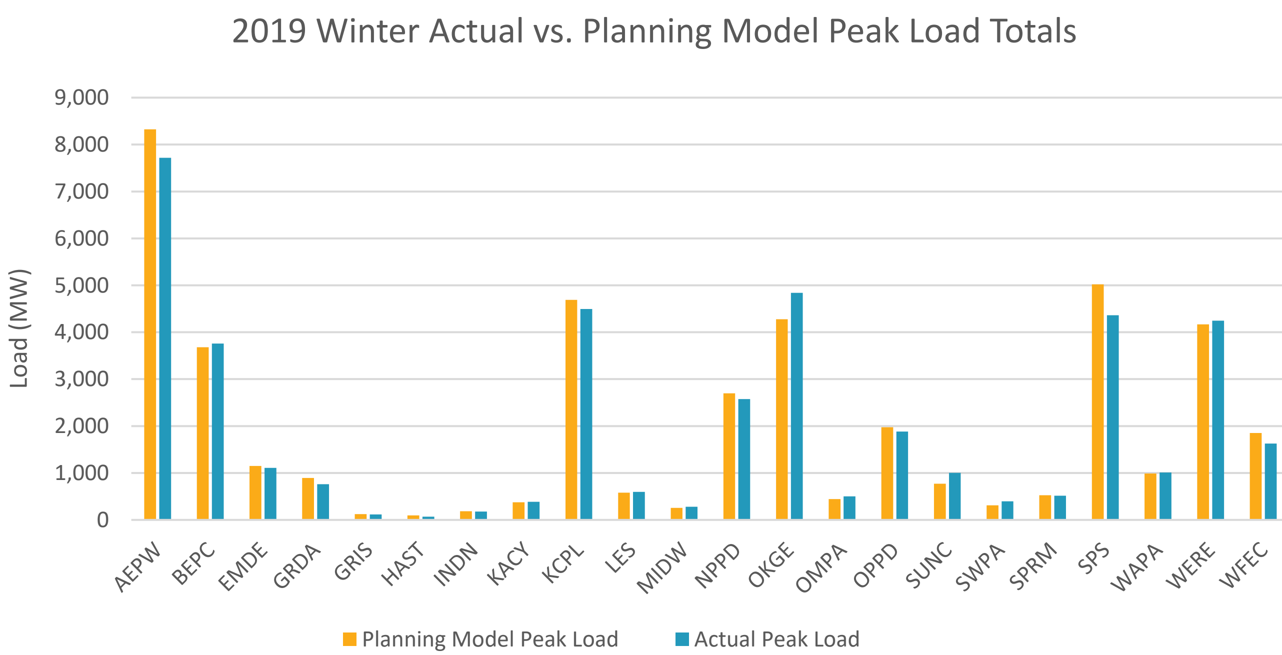


Figure 3.7: 2019 Winter Actual vs. Planning Model Peak Load Totals

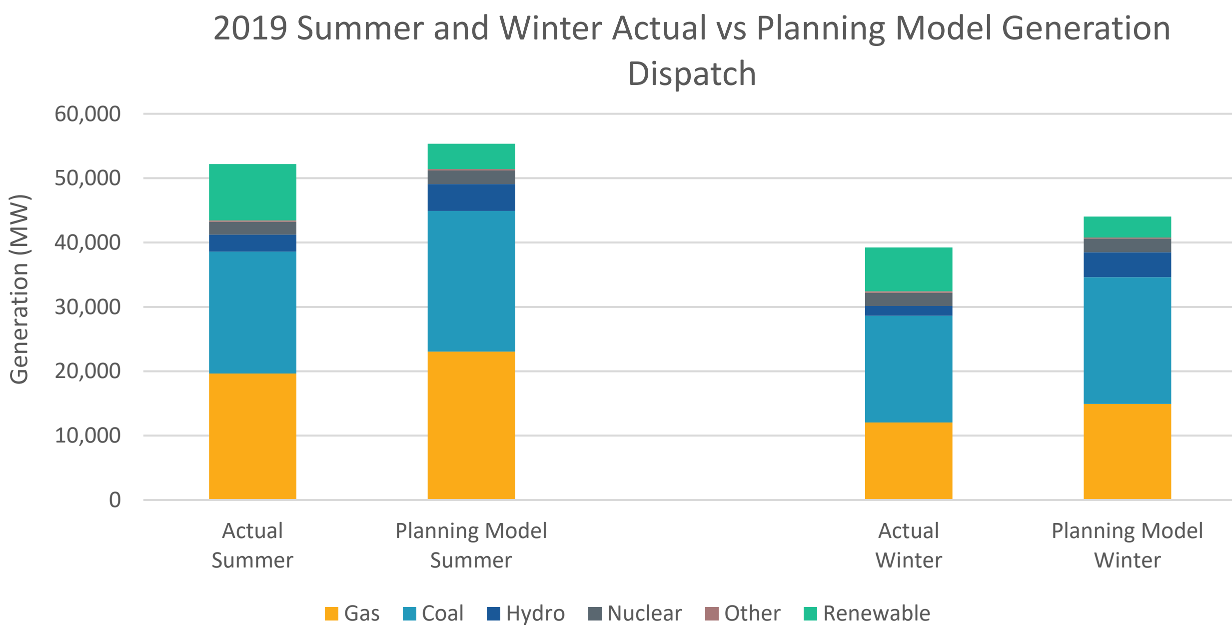


Figure 3.8: 2019 Actual vs. Planning Model Generation Dispatch Comparison

3.2 MARKET ECONOMIC MODEL

Market economic model benchmarking for this study was performed on the Year 2021 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 the 2019 ITP generation capacity factors with the U.S. Energy Information Administration (EIA) data, simulated maintenance outages to SPP real-time data, and operating and spinning reserve capacities to SPP Criteria; and
- Comparing the capacity factors, generating unit average cost, renewable generation profiles, system LMPs, APC, and interchange between the 2019 ITP and the 2017 ITP 10-year assessment (ITP10)[14].

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 2014 and 2016 and resulting from the 2017 ITP10 study, the capacity factors for conventional generation units fell near the expected values. The

[14] The 2019 ITP Future 1 (reference case) and 2021 market economic model outputs were compared to the 2017 ITP10, Future 3 (reference case), 2020 market economic model outputs.

difference in capacity factors between the datasets is attributed to the fuel and load forecasts and the difference in generation mix.

	Average Capacity Factor			
Unit Type	2014 EIA	2016 EIA	2017 ITP10 Future 3 2020	2019 ITP Future 1 2021
Nuclear	92%	92%	89%	93%
Combined Cycle	50%	55%	32%	41%
CT Gas	5%	8%	3%	3%
Coal	60%	53%	78%	61%
ST Gas	10%	12%	2%	3%
Wind	34%	35%	46%	46%
Solar	26%	25%	20%	23%

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 cost per MWh is lower in the 2019 ITP than in the 2017 ITP10 due to the fuel and load forecasts and the difference in generation mix.

	Average Energy Cost ($/MWh)	
Unit Type	2017 ITP10 Future 3 2020	2019 ITP Future 1 2021
Nuclear	$15	$15
Combined Cycle	$48	$31
CT Gas	$76	$44
Coal	$27	$24
ST Gas	$72	$41

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 curves from the historical data and the market economic model simulations complemented each other very well in shape. 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 2019 ITP are very similar to previous ITP assessments. The operations data includes outage types, such as "economic outages" that are difficult to exclude from the dataset and 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.

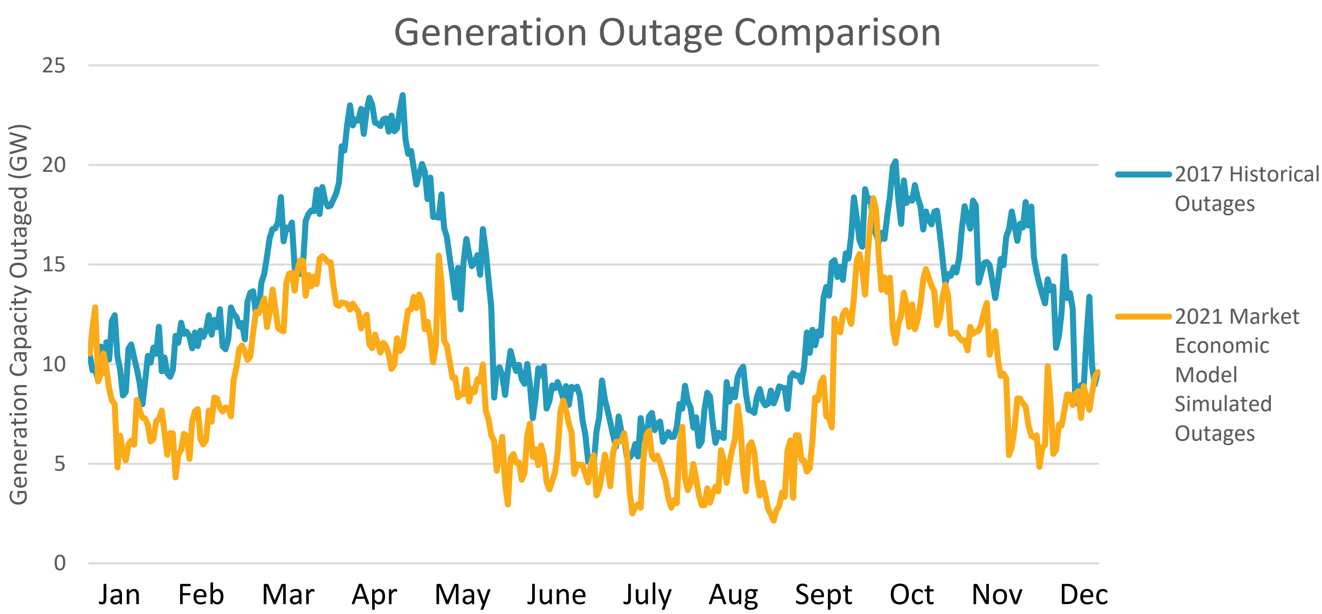


Figure 3.9: Generator Outage Comparison

3.2.1.4 Operating and Spinning Reserve Adequacy

Operational reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of 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 1,646 MW and spinning reserve capacity requirement was modeled at 823 MW. SPP met its reserve requirements in the market economic model.

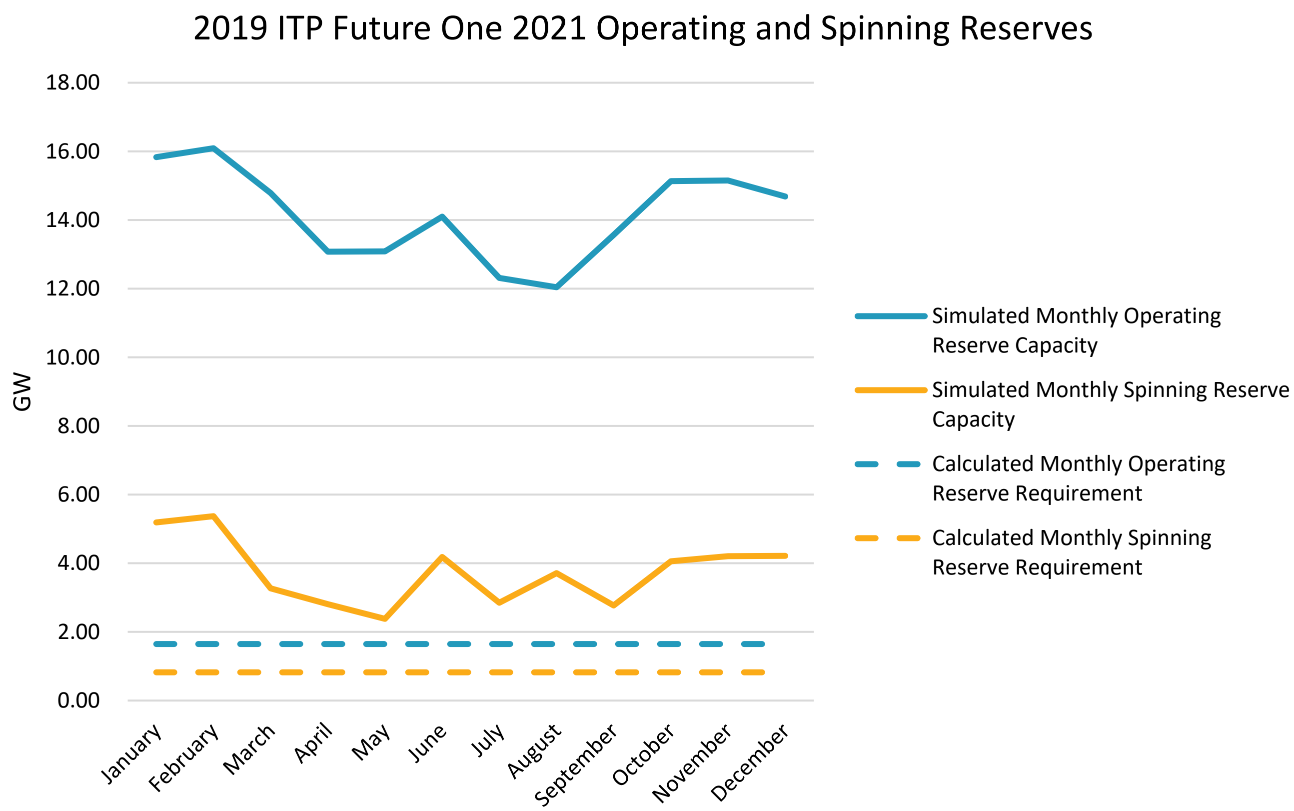


Figure 3.10: 2019 ITP Future 1 2021 Operating and Spinning Reserves

3.2.1.5 Renewable Generation

Wind energy output is overall greater in the 2019 ITP than the 2017 ITP10. In the 2017 ITP10, wind energy includes resource plan additions; however, a greater amount of wind is projected to be in-service by 2021 in the 2019 ITP model.

Solar energy is lower in the 2019 ITP than in the 2017 ITP10 because solar resource plan additions were modeled in the 2017 ITP10 model. The 2020 solar projection in the 2017 ITP10 is higher than solar in the 2019 ITP model for 2021. The solar energy for 2021 in the 2019 ITP model represents existing solar in the SPP footprint.

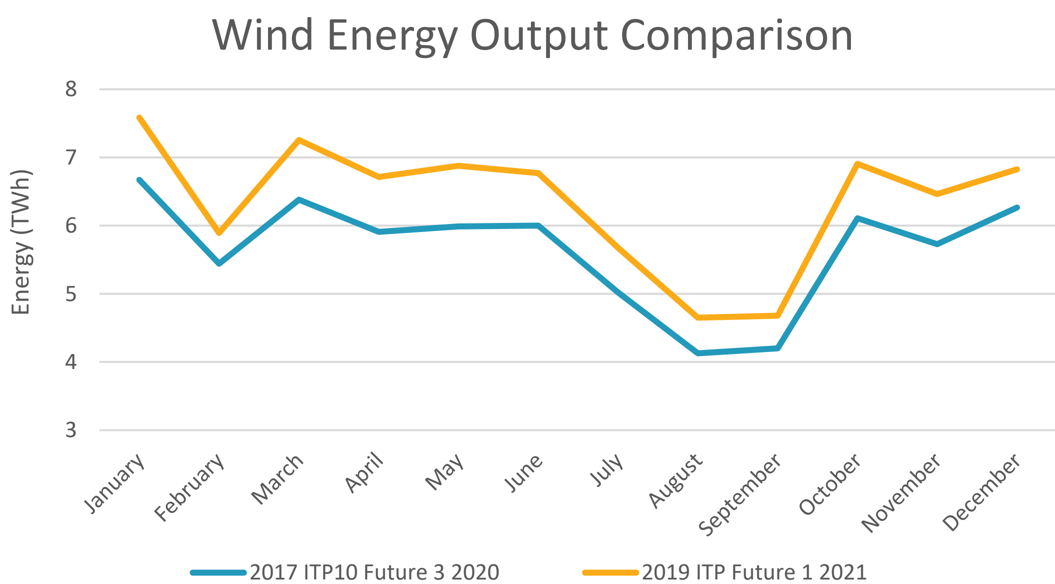


Figure 3.11: Wind Energy Output Comparison

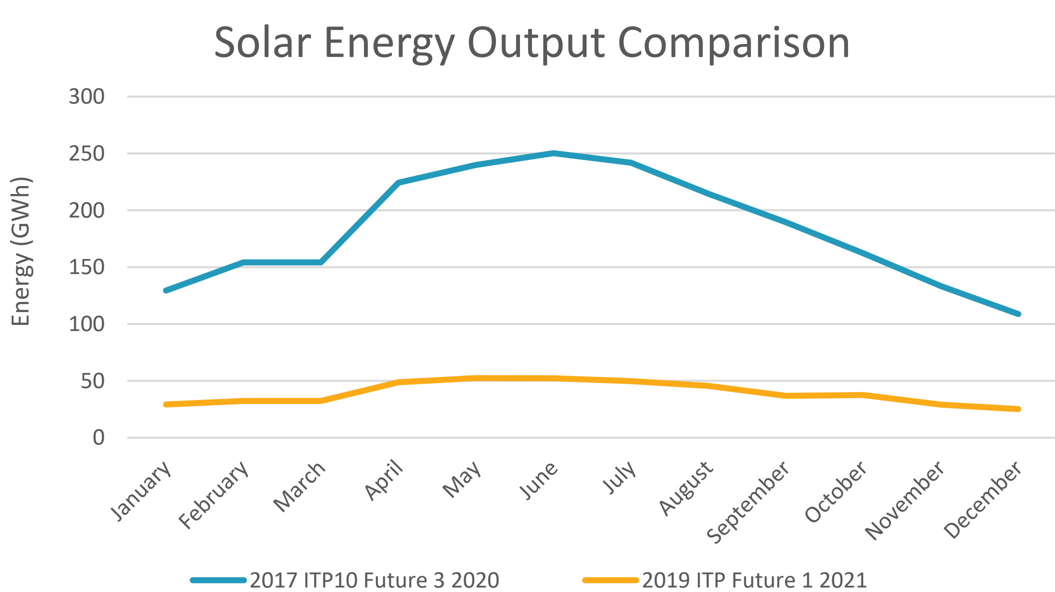


Figure 3.12: Solar Energy Output Comparison

When compared with capacity factors from the 2017 ITP10, the 2019 ITP capacity factors for renewable generation units fell near the expected values. The wind unit capacity factors in the 2017 ITP10 and 2019 ITP are very similar. The amount of wind energy is relatively similar between both models, and both models utilized the 2012 NREL dataset for hourly profile data. The solar capacity factors in the 2019 ITP are slightly higher than in the previous study due to utilizing the 2012 NREL dataset instead of the 2006 NREL dataset for hourly profile data.

	Average Capacity Factor			
Unit Type	**2014 EIA**	**2016 EIA**	**2017 ITP10 Future 3 2020**	**2019 ITP Future 1 2021**
Wind	34%	35%	46%	46%
Solar	26%	25%	20%	23%

Table 3.3: Renewable Generation Capacity Factor Comparison

3.2.2 SYSTEM LOCATIONAL MARGINAL PRICE (LMP)

Simulated LMPs were benchmarked against simulated LMPs from the 2017 ITP10. 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 and the difference in the two curves. The decrease in LMPs since the 2017 ITP10 is due to the change in fuel and load forecasts between studies.

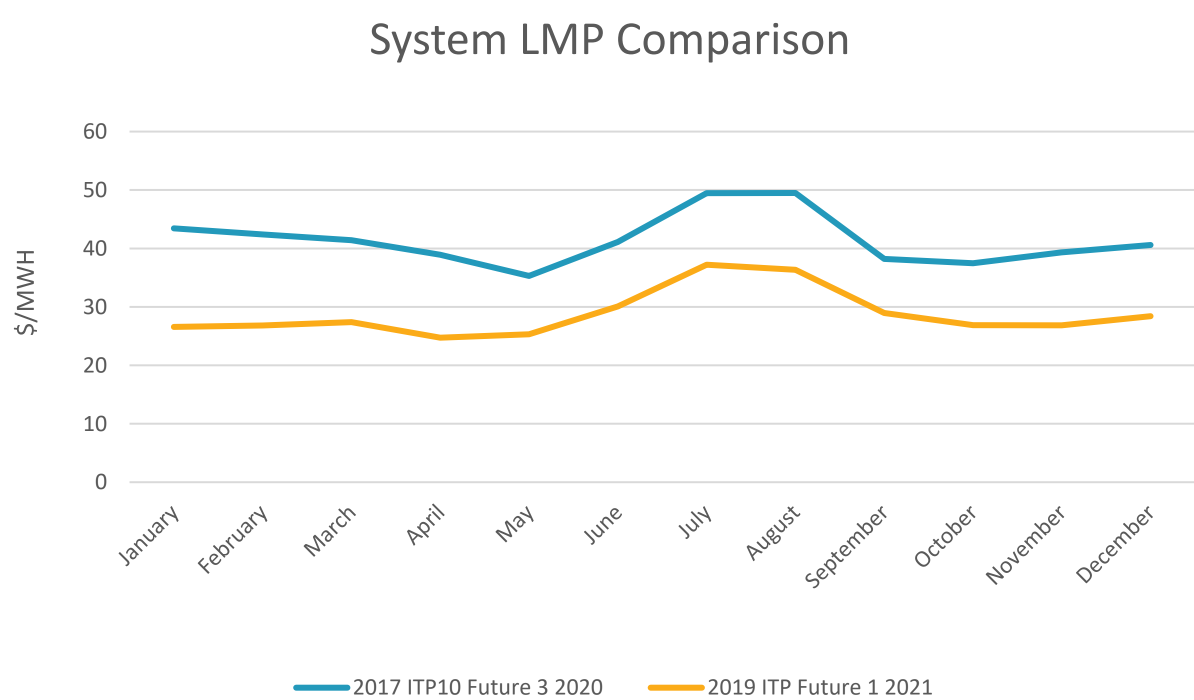


Figure 3.13: System LMP Comparison

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 lower in the 2019 ITP than in the 2017 ITP10 due to the change in fuel and load forecasts.

The APC for all zones in SPP decreased except for the Nebraska Public Power District (NPPD) and the Omaha Public Power District (OPPD). These anomalies are attributed to the retirement of the Fort Calhoun nuclear unit since the 2017 ITP10 model build and the different ownership assignment of wind in the 2019

ITP. Overall, each modeled region's APC results decreased between the two models, as expected from the increase in renewable forecasts. See Figure 3.14 and Figure 3.15 for a summary of regional APC results.

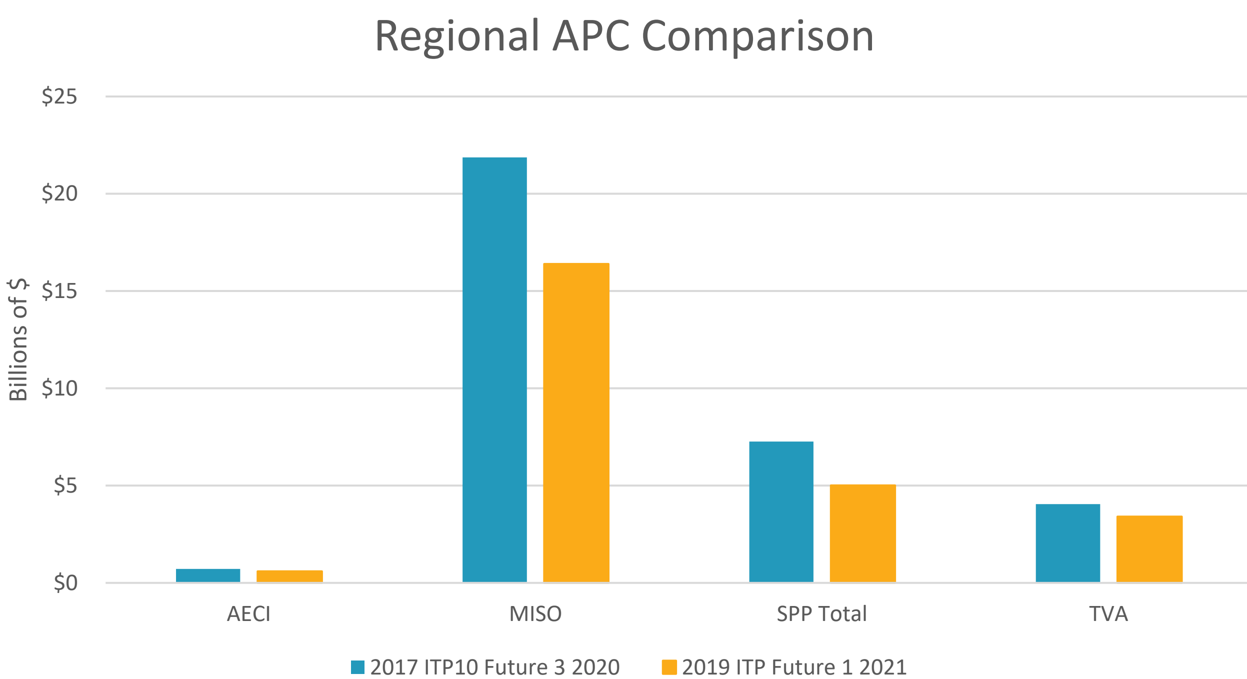


Figure 3.14: Regional APC Comparison

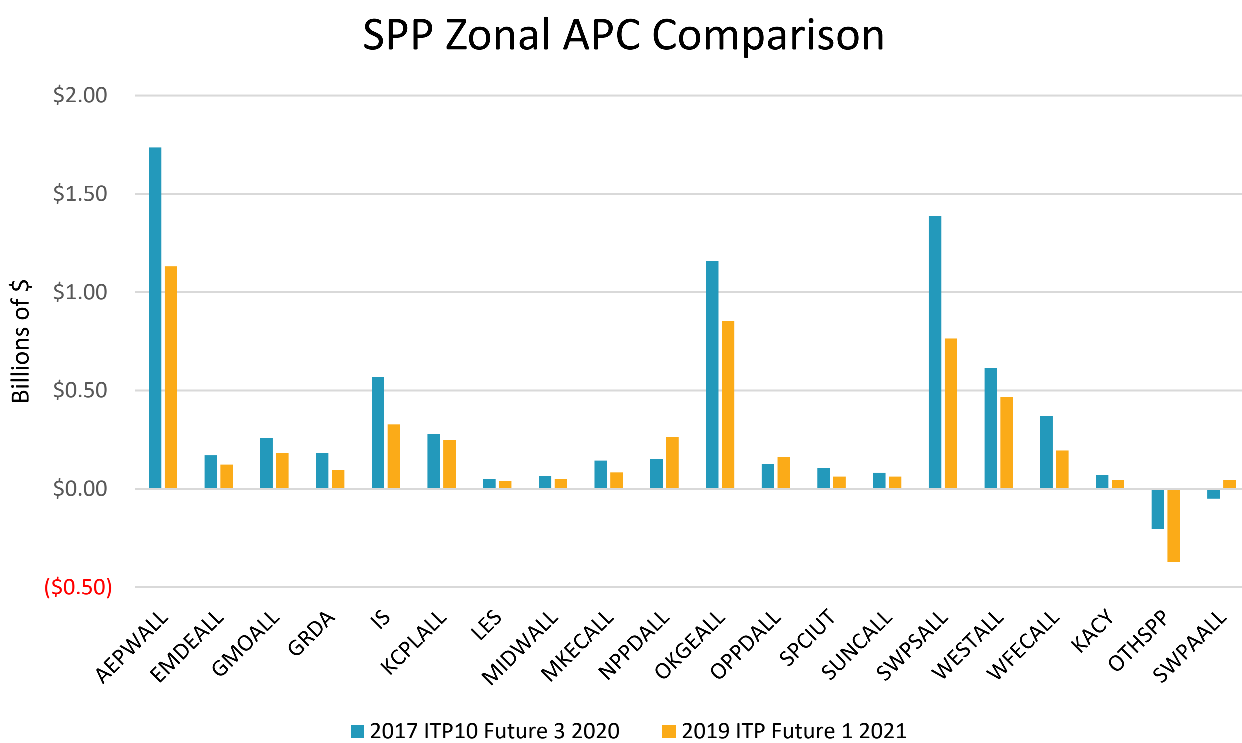


Figure 3.15: SPP Zonal APC Comparison

3.2.4 INTERCHANGE

Hurdle rate and interchange tests were implemented to validate the interchange in the 2019 ITP model. To test the behavior of both models with different hurdle rates, the previous study's hurdle rates were applied to the current study model and the current study hurdle rates were applied to the previous study model. The 2017 ITP10 hurdle rates increased overall exports in the 2019 ITP model. The 2019 ITP hurdle rates decreased overall exports in the 2017 ITP10 model. The 2019 ITP model interchange was validated against current SPP operations data. When compared to the SPP net scheduled interchange in 2017, the 2019 ITP model is similar in shape and magnitude. Overall, exports are lower in the 2019 ITP than in the 2017 ITP10.

Based on all interchange testing, the 2019 ITP model interchange is an acceptable representation of exports seen in the SPP Integrated Marketplace.

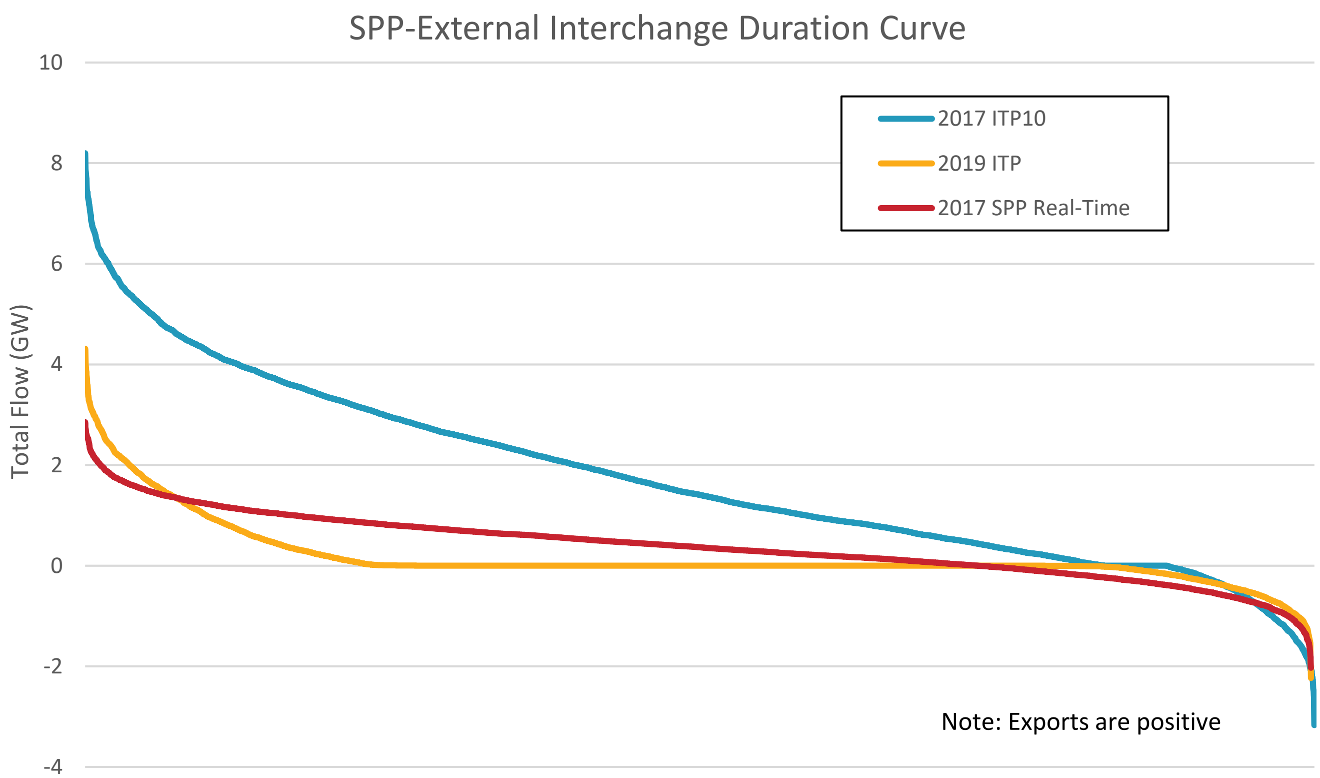


Figure 3.16: Interchange data comparison

4 NEEDS ASSESSMENT

4.1 ECONOMIC NEEDS

SPP determines its 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 heavily related to a previous constraint. The economic needs identified per future are shown in Figure 4.1 and Figure 4.2, and Table 4.1 and Table 4.2.

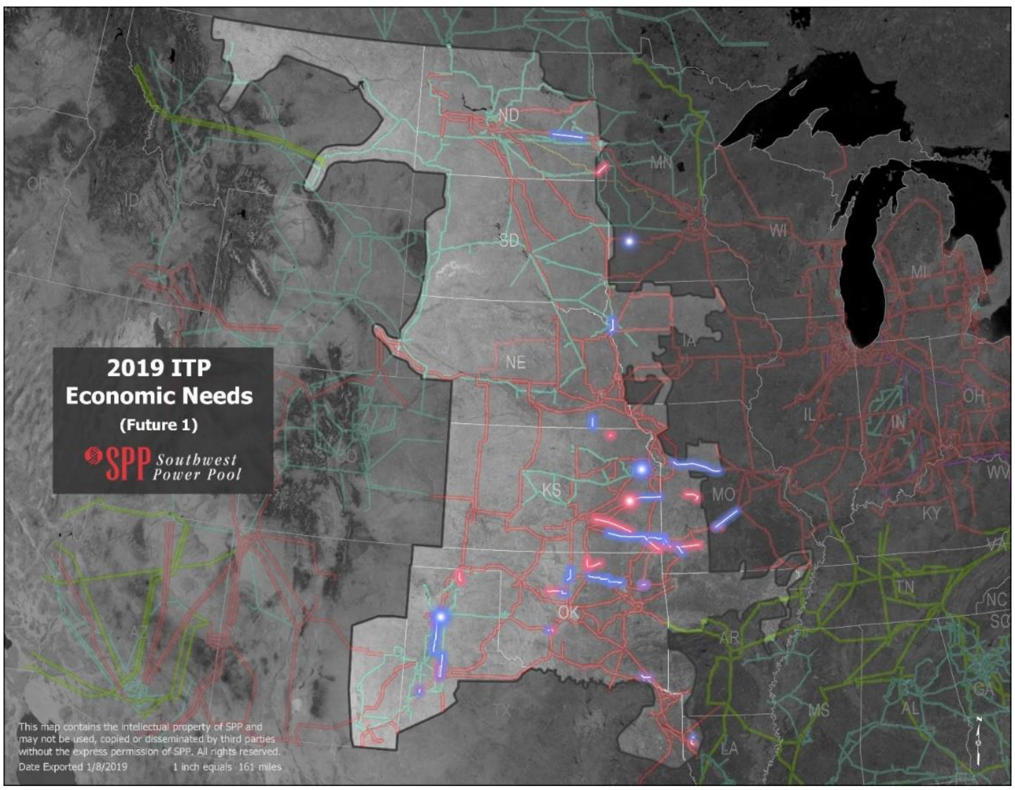


Figure 4.1: Future 1 Economic Needs

Rank	Constraint	2021 Congestion Score	2024 Congestion Score	2029 Congestion Score
1	Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV	258,542	434,827	1,034,322
2	Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	189,616	532,356	382,685
3	Lawrence Energy Center-Midland 115 kV for the loss of Lawrence Hill 230/115 kV transformer	95,537	195,517	384,195
4	Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1	285,494	190,263	183,892
5	Clinton-Trumann 161 kV for the loss of Overton-Sibley 345 kV	0	151,398	212,899
6	Hankinson-Wahpeton 230 kV for the loss of Buffalo-Jamestown 345 kV	100	64,893	171,568
7	Hale County-Tuco 115 kV for the loss of Swisher-Tuco 230 kV	158,719	19,394	21,718
8	Kingfisher-East Kingfisher Tap 138 kV for the loss of Dover-Dover Switchyard 138 kV	0	86,104	113,196
9	South Shreveport-Wallace Lake 138 kV for the loss of Fort Humbug-Trichel Street 138 kV	0	3,157	187,532
10	Kildare-White Eagle 138 kV for the loss of Woodring-Hunter 345 kV	99,902	41,743	40,217
11	La Russell-Springfield 161 kV for the loss of La Russell-Monett 161 kV	7	53,855	118,064
12	Marshall County-Smittyville 115 kV for the loss of Harbine-Steele City 115 kV	90,957	39,535	36,040
13	Sundown-Amoco Tap 115 kV for the loss of Sundown-Amoco S.S. 230 kV	513	71,766	93,533
14	Dover-Okeene 138 kV for the loss of Watonga Switch-Okeene 138 kV	85,312	26,835	49,230
15	Gracemont-Anadarko 138 kV for the loss of Washita-Southwestern Station 138 kV	12,144	54,147	91,421
16	Spearman County-Hansford 115 kV for the loss of Potter County 345/230 kV transformer	49,403	42,800	59,943
17	Carthage SW-Purcell SW 161 kV for the loss of Ashbury-Carl Junction 161 kV	0	67,898	75,884
18	Potter County-Bushland 230 kV for the loss of Potter County-Newhart 230 kV	48,635	34,040	55,451
19	Asbury-Carl Junction 161 kV for the loss of Asbury-Purcell SW 161 kV	6,708	60,301	62,562

Rank	Constraint	2021 Congestion Score	2024 Congestion Score	2029 Congestion Score
20	Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV	19,451	50,981	49,484
21	Neosho-Riverton 161 kV for the loss of Blackberry/RP2POI02-Neosho 345 kV	49,364	40,233	29,788
22	Sioux City SC2-Sioux City 230 kV for the loss of Raun-Sioux City 345 kV	-	26,403	20,521
23	Coffman-Huben 161 kV for the loss of Franks-Huben 345 kV	-	13,830	9,257
24	Granite Falls-Marshall Tap 115 kV for the loss of Lyon Co 345/115 kV transformer	13,656	45,034	59,782
25	Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	4,407	41,416	54,125
27	Northwest-Matthewson 345 kV for the loss of Cimarron-Northwest 345 kV	6,176	9,687	77,171
28	Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV	14,910	20,241	17,047

Table 4.1: Future 1 Economic Needs

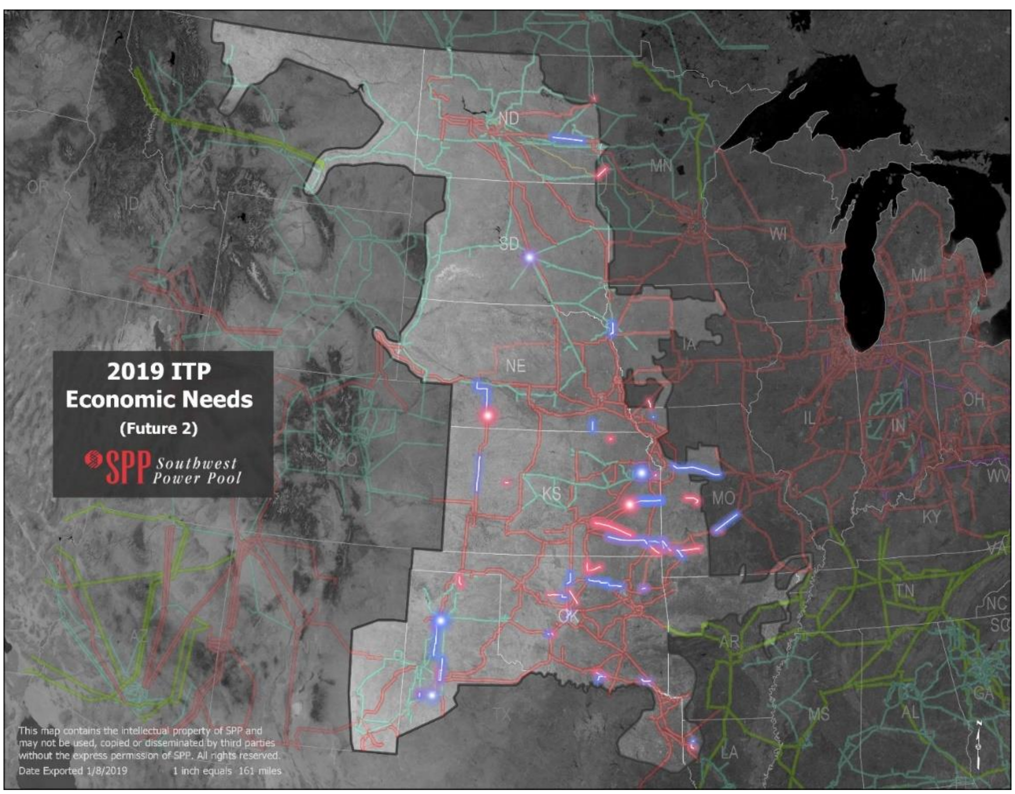


Figure 4.2: Future 2 Economic Needs

Rank	Constraint	2024 Congestion Score	2029 Congestion Score
1	Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV	704,406	1,188,264
2	Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	701,946	533,105
3	Lawrence Energy Center-Midland 115 kV for the loss of Lawrence Hill 230/115 kV transformer	234,634	622,429
4	Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1	229,440	302,129
5	Hankinson-Wahpeton 230 kV for the loss of Buffalo-Jamestown 345 kV	92,405	419,129
6	South Brown-Russett 138 kV for the loss of Caney Creek-Little City 138 kV	157,255	349,052
7	Clinton-Trumann 161 kV for the loss of Overton-Sibley 345 kV	126,369	154,273
8	South Shreveport-Wallace Lake 138 kV for the loss of Fort Humbug-Trichel Street 138 kV	5,334	256,002
9	Sundown-Amoco Tap 115 kV for the loss of Sundown-Amoco S.S. 230 kV	114,173	136,720
10	La Russell-Springfield 161 kV for the loss of La Russell-Monett 161 kV	76,292	143,344
11	Kingfisher-East Kingfisher Tap 138 kV for the loss of Dover-Dover Switchyard 138 kV	136,687	77,642
12	Gracemont-Anadarko 138 kV for the loss of Washita-Southwestern Station 138 kV	87,638	125,272
13	Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV	84,733	101,602
14	Sioux City SC2-Sioux City 230 kV for the loss of Raun-Sioux City 345 kV	57,710	107,454
15	Spearman County-Hansford 115 kV for the loss of Potter County 345/230 kV transformer	97,186	67,820
16	Hugo-Valliant 138 kV for the loss of Valliant-Hugo 345 kV	40,891	94,244
17	Neosho-RP2POI10 345 kV for the loss of Waverly-La Cygne 345 kV	46,601	71,507
17	Neosho-Riverton 161 kV for the loss of Blackberry/RP2OI02-Neosho 345 kV	43,235	43,677
18	Cottonwood Creek-RP2POI11 138 kV system intact	0	115,784
19	Coffman-Huben 161 kV for the loss of Franks-Huben 345 kV	66,999	47,148
20	Red Willow 345/115 kV transformer for the loss of Gerald Gentleman-Red Willow 345 kV	60,143	53,895

Rank	Constraint	2024 Congestion Score	2029 Congestion Score
21	Grand Forks-Falconer 115 kV for the loss of Drayton-Prairie 230 kV	7,259	105,277
22	Carthage SW-Purcell SW 161 kV for the loss of Ashbury-Carl Junction 161 kV	52,511	56,931
23	Arnold-Ransom 115 kV for the loss of Mingo-Setab 345 kV	43,993	59,143
24	Ft. Thompson 345/230 kV transformer #2 for the loss of Ft. Thompson 345/230 kV transformer #1	20,415	82,596
25	Dover-Okeene 138 kV for the loss of Watonga Switch-Okeene 138 kV	31,598	67,870
26	Northwest-Matthewson 345 kV for the loss of Cimarron-Northwest 345 kV	8,735	90,442
27	Potter County-Bushland 230 kV for the loss of Potter County-Newhart 230 kV	40,973	54,835
28	Asbury-Carl Junction 161 kV for the loss of Asbury-Purcell SW 161 kV	49,042	46,588
29	Carlisle-LP-Doud 115 kV for the loss of Wolfforth 230/115 kV transformer	19,067	68,274
30	Craig-Lenexa 161 kV circuit 2 for the loss of Craig-Lenexa 161 kV circuit 1	11,679	60,043
31	Maryville-Clarinda 161 kV for the loss of Maryville E-Maryville 161 kV	0	58,191
32	Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	16,574	24,090
33	Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV	12,412	6,813

Table 4.2: Future 2 Economic Needs

4.1.1 TARGET AREAS

As part of the economic needs assessment, two target areas were identified for the assessment to focus analysis efforts of staff and stakeholders. Drivers for these target 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 Southeast Kansas/Southwest Missouri Target Area (Target Area 1)

Southeast Kansas/southwest Missouri was identified as Target Area 1, requiring additional analysis for several reasons. The area has been the site of historic and projected congestion on the EHV system and has had unresolved transmission limits identified in multiple studies, most recently in the 2018 ITPNT. By defining this corridor as a target area in the 2019 ITP, SPP is able to address the TWG's direction to provide a path forward for the area to properly evaluate and resolve the issues present in day-to-day operations and in the planning horizon.

Continued integration of wind generation on the western side of the SPP system has contributed to diminishing transmission capacity capable of supporting bulk power transfers to the east. This has led to declining transient stability margins at the Wolf Creek nuclear plant. The Butler-Altoona 138 kV line in southeast Kansas, already known for its advanced age, was identified by NERC as having one of the highest outage rates for its voltage class. It regularly experiences high system flows during times of elevated wind output. The Neosho-Riverton 161 kV line to the south is also a common issue in real-time operations. The Wolf Creek 345/69 kV transformer, which supplies the 69 kV network of loads between Wolf Creek and Neosho, frequently experiences heavy congestion and loading when the Waverly-La Cygne line is outaged in both reliability and economic analyses.

Supplemental information posted in the needs assessment[15] outlined additional analysis needed to quantify the benefits of a comprehensive regional solution and to aid stakeholders in solution submittals.

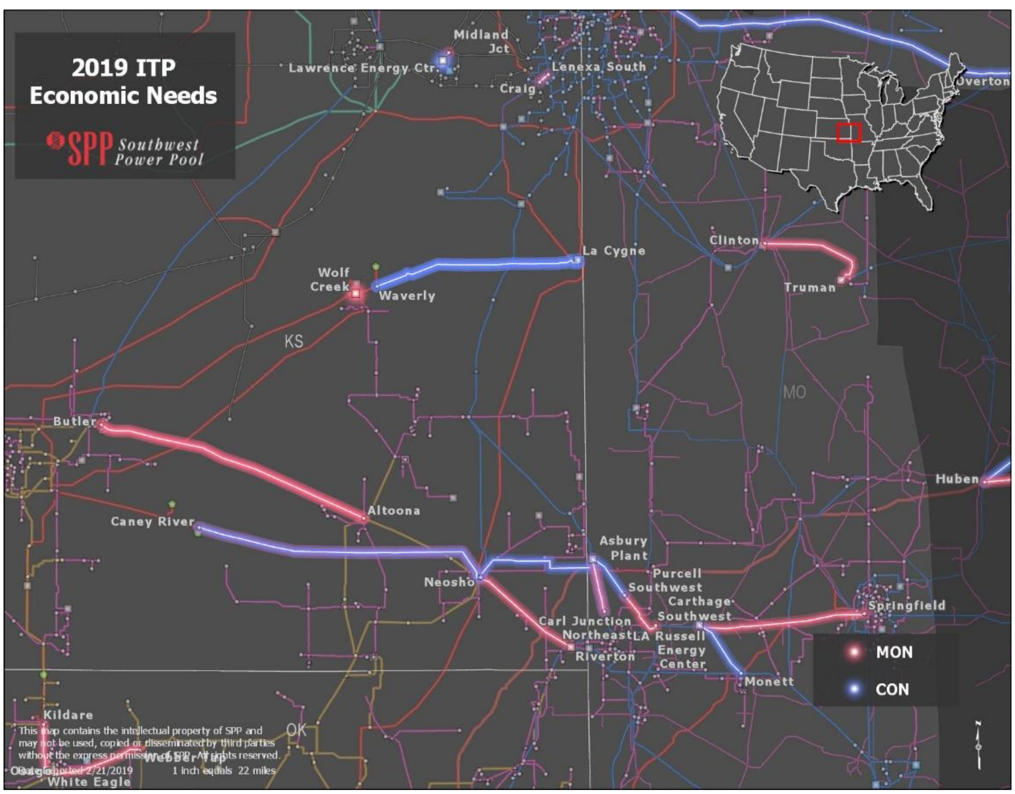


Figure 4.3: Southeast Kansas/Southwest Missouri Target Area Flowgates

[15] https://www.spp.org/documents/59347/2019_itp_needs_assessment_supplemental_information_(1.14.2019).pdf

Impactful Target Area 1 Constraints
Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV
LaRussell-Springfield 161 kV for the loss of LaRussell-Monett 161 kV
Carthage SW-Purcell SW 161 kV for the loss of Ashbury-Carl Junction 161 kV
Asbury-Carl Junction 161 kV for the loss of Asbury-Purcell SW 161 kV
Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV
Neosho-Riverton 161 kV for the loss of Blackberry/RP2POI02-Neosho 345 kV
Neosho-RP2POI10 345 kV for the loss of Waverly-La Cygne 345 kV
Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV

Table 4.3: Southeast Kansas/Southwest Missouri Target Area Flowgates

4.1.1.2 Central/Eastern Oklahoma Target Area (Target Area 2)

Central/eastern Oklahoma was identified as Target Area 2 due to heavy congestion and parallel system correlation with Target Area 1. Additional analysis was unnecessary for Target Area 2 because system issues in this area were only related to congestion and underlying voltage stability concerns. The main point of congestion in Target Area 2 is related to the Cleveland 345/138 kV station west of Tulsa, Oklahoma. The renewable forecast in the 2019 ITP drives increased bulk transfers across central Oklahoma. EHV contingencies in the area shift congestion mostly to the lower-voltage system.

Additional facilities that limit west-to-east transfers include the Webb Tap-Osage 138 kV path going west to east, north of the Tulsa area. The Northwest-Mathewson-Cimarron 345 kV line is also a limiting path. To achieve notable APC savings, bulk transfer paths must be improved in both target areas. To address congestion in this area, thermal limits need to be increased with rebuilds and terminal equipment or additional capacity to parallel to the most critical contingencies.

This target area was identified due to relationships with the transmission corridor east of Wichita, Kansas, connecting into Springfield, Missouri.

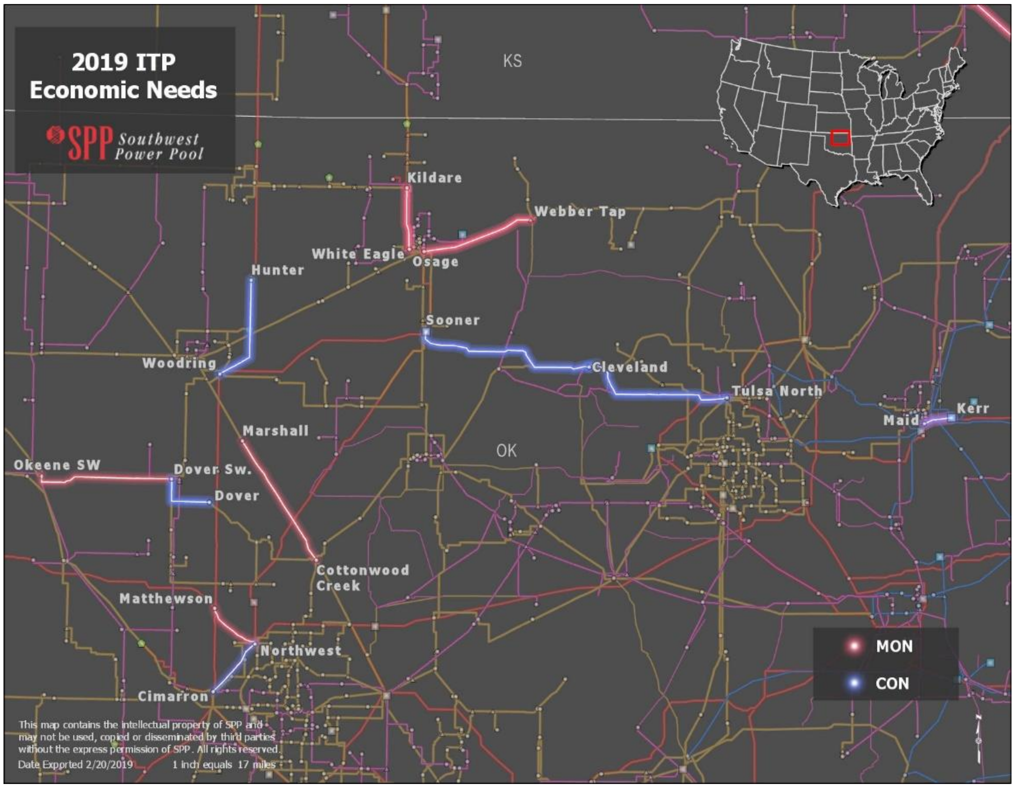


Figure 4.4: Central/Eastern Oklahoma Target Area Flowgates

Impactful Target Area 2 Constraints
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV
Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV
Northwest-Matthewson 345 kV for the loss of Cimarron-Northwest 345 kV

Table 4.4: Central/Eastern Oklahoma Target Area Flowgates

4.2 RELIABILITY NEEDS

4.2.1 BASE RELIABILITY ASSESSMENT

SPP evaluated nine base reliability models. Three separate seasons (summer, winter, light load) were developed for years two, five and 10. 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 (NCLL) or the interruption of firm transmission service (IFTS).

During the needs assessment, potential 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. Figure 4.5 and Figure 4.6 summarize the number of remaining thermal and voltage needs[16] that were unable to be mitigated during the screening process.

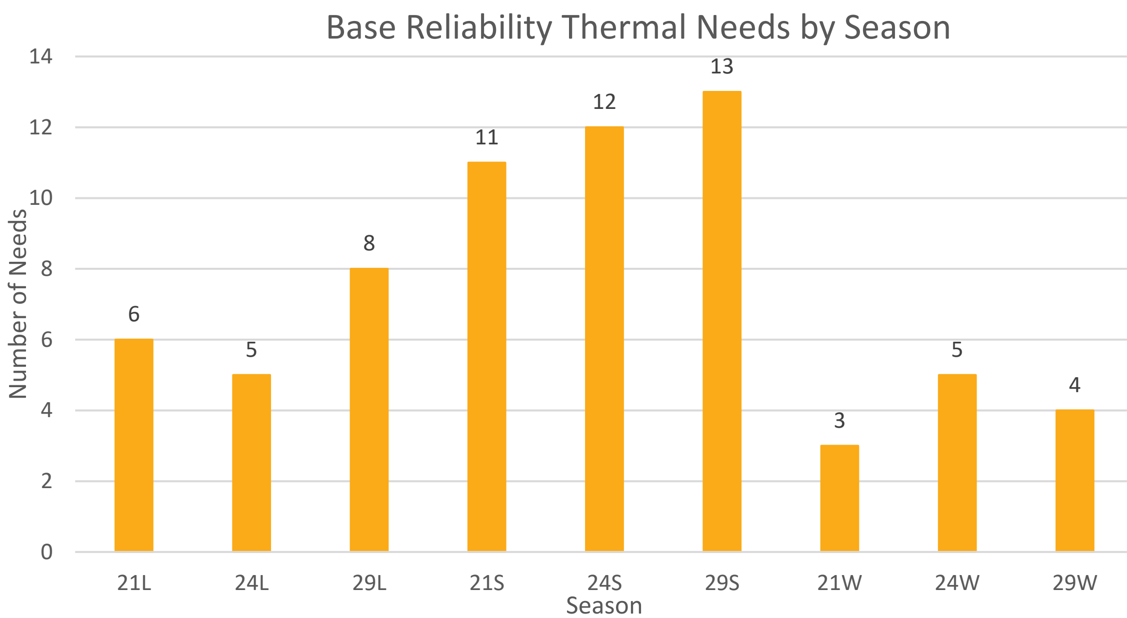


Figure 4.5: Unique Base Reliability Needs

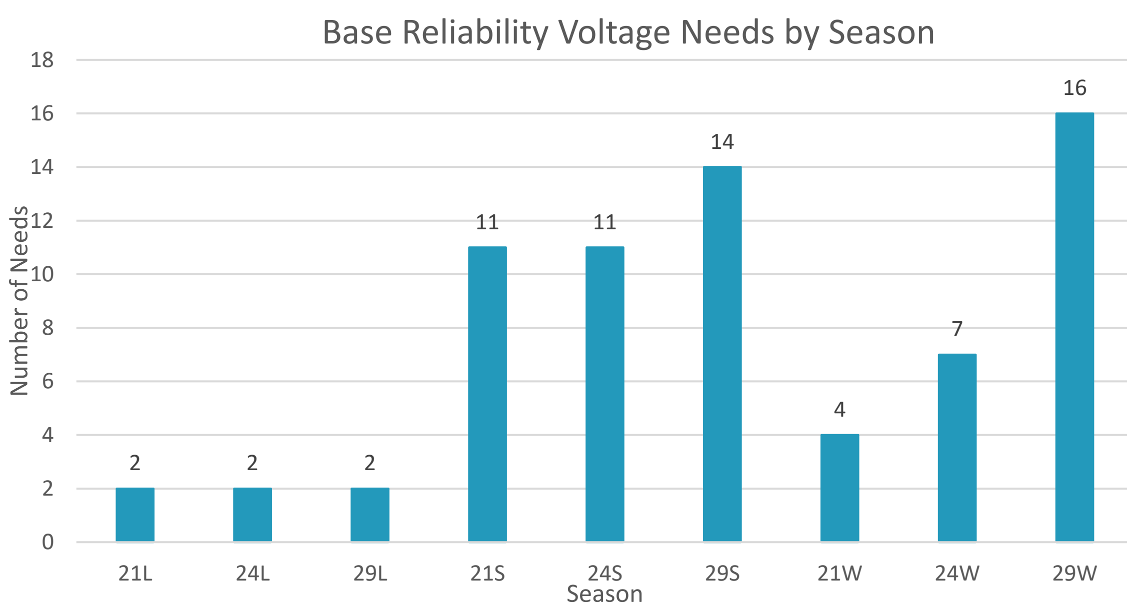


Figure 4.6: Unique Base Reliability Voltage Needs

[16] Figures summarize unique monitored elements.

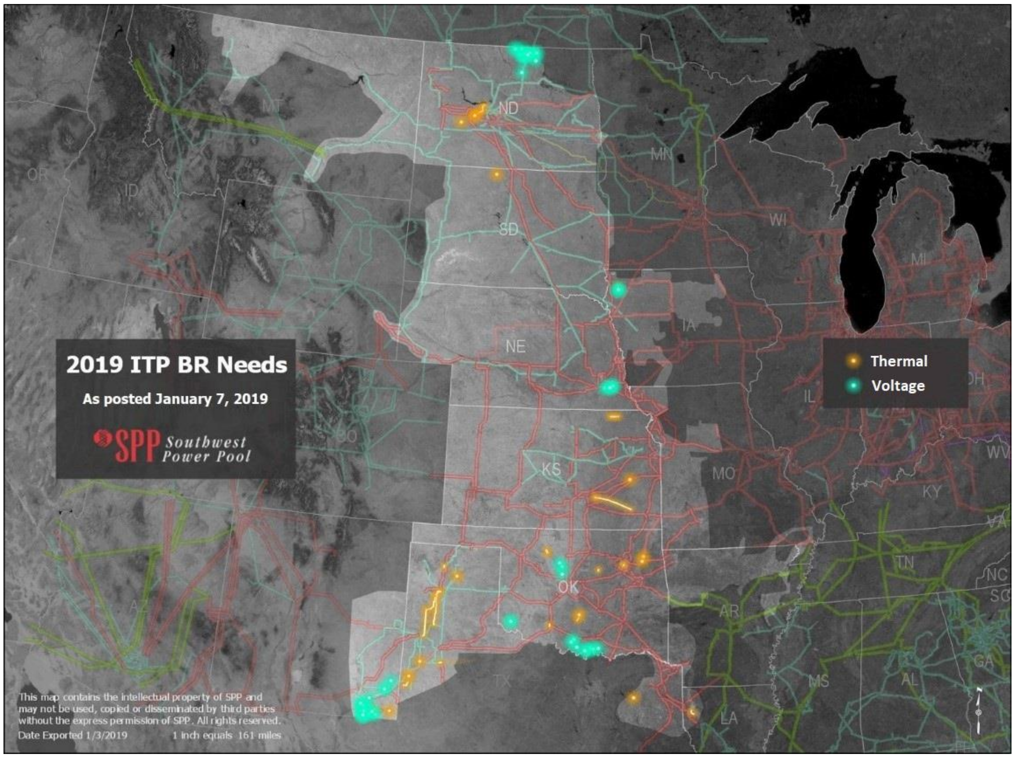


Figure 4.7: Base Reliability Needs

4.2.2 MARKET POWERFLOW ASSESSMENT

Contingency analysis for the market powerflow models consisted of analyzing P0, P1, and P2.1 planning events of varying voltage levels identified in NERC Standard TPL-001 Table 1 for each of the models. The 69 kV facilities that were selected for this portion of the study were identified in the constraint assessment.

The remaining contingencies in Table 1 of the NERC Standard TPL-001 that do not allow for NCLL or IFTS were analyzed only if a violation was observed in the same year and season of the base reliability models.

Figure 4.8 and Figure 4.9 summarize the number of remaining thermal and voltage needs[17] that were unable to be mitigated during the screening process.

[17] Figures summarize unique monitored elements

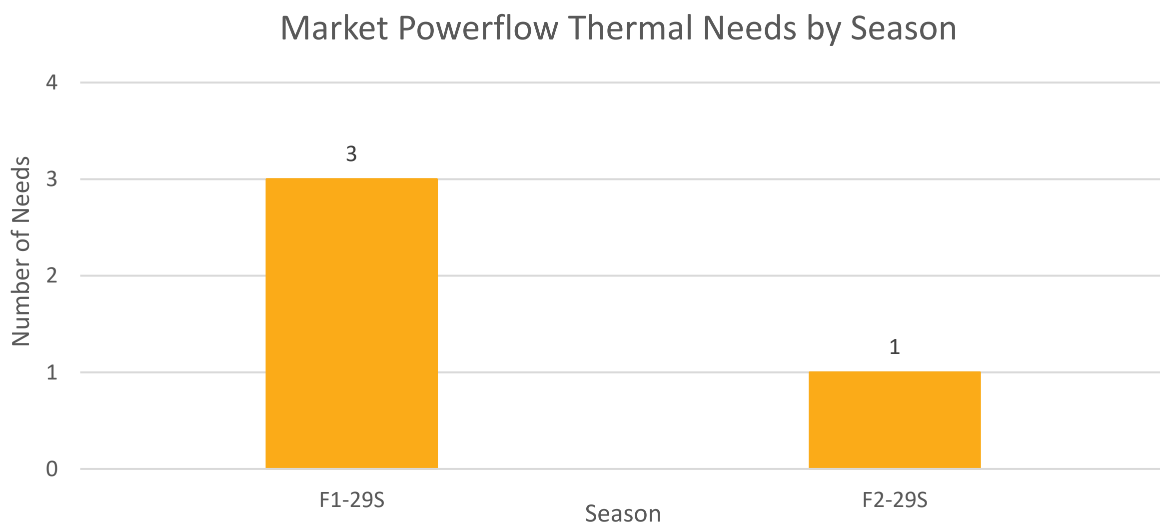


Figure 4.8: 2019 ITP Unique Market Powerflow Thermal Needs

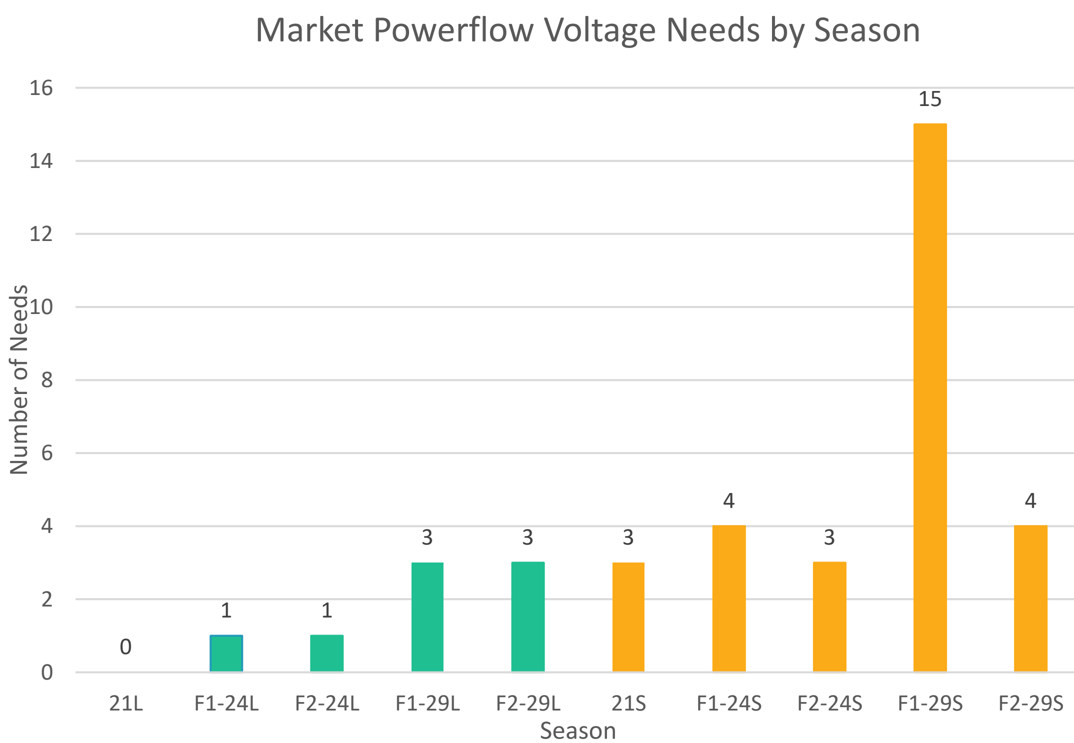


Figure 4.9: 2019 ITP Unique Market Powerflow Voltage Needs

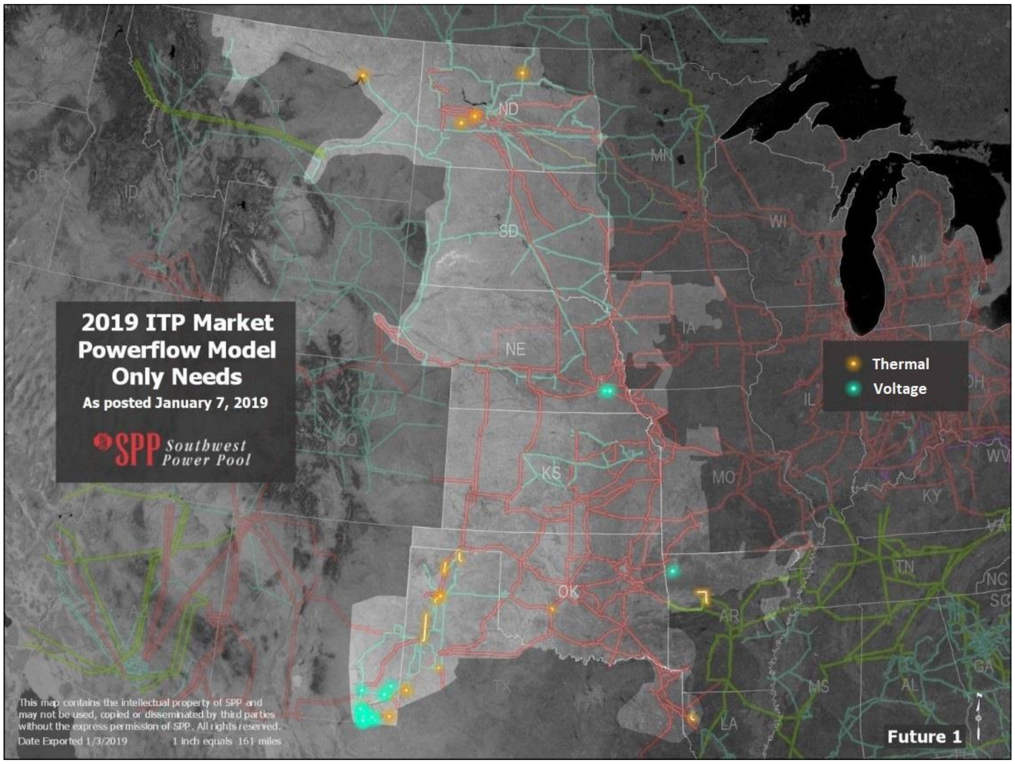


Figure 4.10: Future 1 Reliability Needs

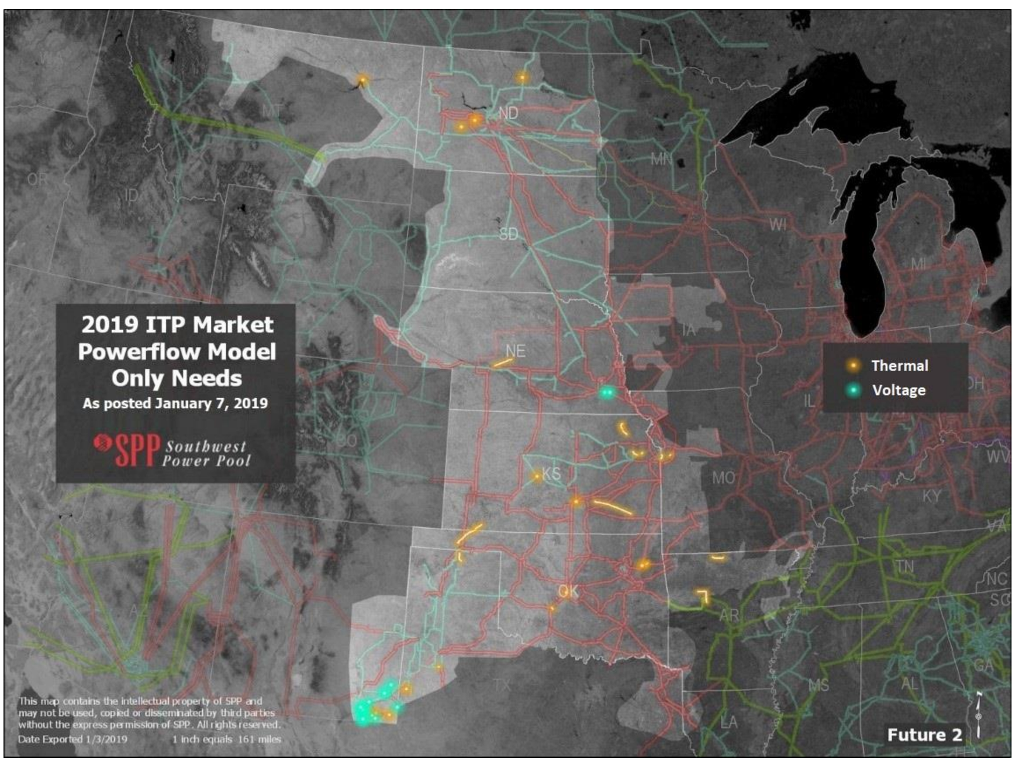


Figure 4.11: Future 2 Reliability Needs

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 2029 Summer Peak	Custer Mountain-Whitten 115 kV	Hobbs-Kiowa 345 kV	Thermal
Future 1 2024 Light Load	Eddy County 345 kV	Tolk-Crossroads 345 kV	Voltage
Future 2 2024 Light Load	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 1 2029 Light Load	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 2 2029 Light Load	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 1 2029 Summer Peak	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 2 2029 Summer Peak	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Base Reliability 2029 Summer Peak	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 2 2029 Summer Peak	North Loving 345 kV	Kiowa-North Loving 345 kV	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 Notification to Construct (NTC) are based on the SPP short-circuit analysis.

The short-circuit needs were comprised of 74 breakers housed in 18 substations across six SPP TP areas. They are depicted in Figure 4.12 below. The six TPs identifying short-circuit needs were American Electric Power (AEPW), Kansas City Power & Light Company (KCPL), Nebraska Public Power District (NPPD), Oklahoma Gas & Electric Company (OKGE), Southwestern Public Service Company (SPS), and Western Farmers Electric Cooperative (WFEC).

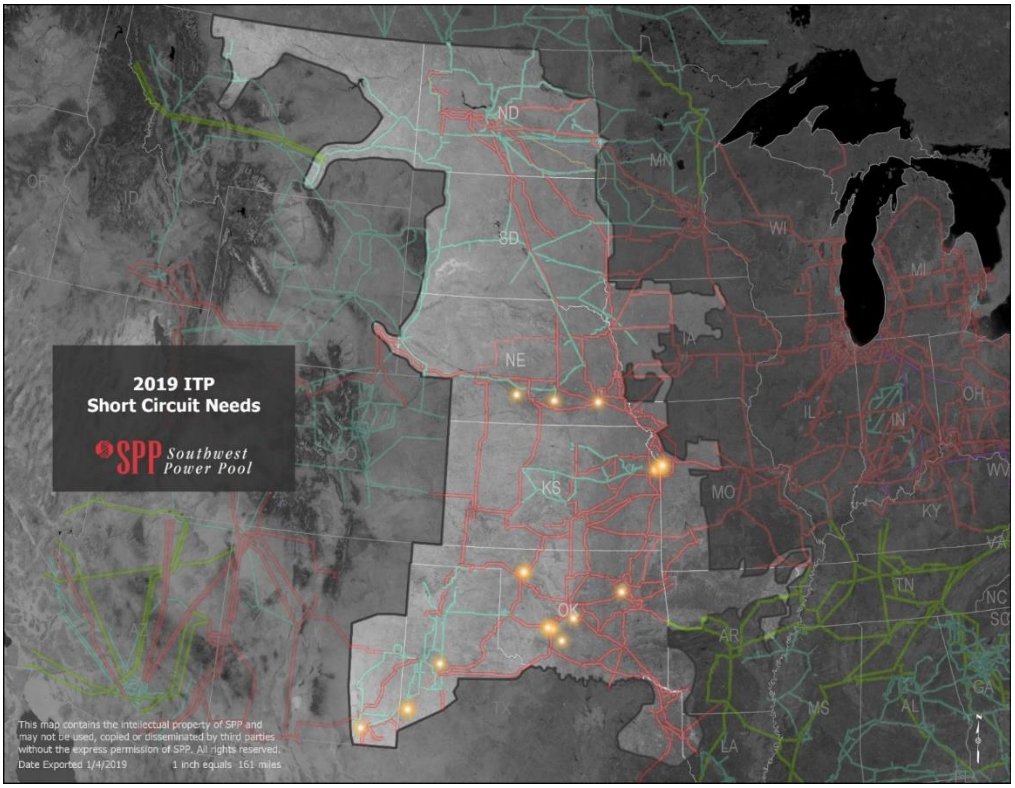


Figure 4.12: Short-Circuit Needs

4.3 PUBLIC POLICY NEEDS

Policy needs were analyzed based on the curtailment of renewable energy such that a Regulatory/Statutory Mandate or Goal identified in the renewable policy review is not able to be met. Policy needs are the result of the inability to dispatch renewable generation due to congestion, resulting in a utility-by-state not meeting its renewable Mandate or Goal. In spite of renewable curtailments, all utilities met their respective renewable Mandates and Goals, and thus there were no public policy needs..

4.3.1 METHODOLOGY

Policy needs were analyzed based on the curtailment of renewable energy such that a regulatory/statutory mandate or goal is not able to be met. Each zone with an energy mandate or goal was analyzed on a utility-by-state level (such as Basin Minnesota, Basin Montana, etc.) for renewable curtailments to determine if they met their mandate or goal. Policy needs are the result of an inability to dispatch renewable generation due to congestion, and any utility-by-state not meeting its renewable mandate or goal.

Renewable mandates and goals per utility were determined based on the renewable policy review. Mandates and goals for some states were based on installed capacity requirements only and were met by identifying capacity shortfalls and including the required capacity additions through phase one of the resource plan. It is not necessary to analyze curtailment to ensure capacity requirements are met. Therefore, they are not used to identify public policy needs.

4.3.2 POLICY NEEDS

Future 1, 2021						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	0.0	8.2	4.7	3.5
EMDE	MO	Wind, Solar	1.4	10.1	7.7	2.4
GMO	MO	Wind, Solar	0.4	16.0	12.6	3.4
KCPL	MO	Wind, Solar	0.0	1.0	0.5	0.6
NPPD	SD	Wind, Solar	0.0	14.3	12.3	2.1
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.1	7.0	3.5	3.5
SPS	NM	Wind	0.0	2.3	0.9	1.3
SPS	NM	Solar	0.1	18.9	13.3	5.6
BASIN	MN	Wind, Solar	0.0	4.0	3.6	0.4
BASIN	MT	Wind, Solar	0.0	1.6	1.1	0.5
BASIN	ND	Wind, Solar	0.0	1.7	1.1	0.6
BASIN	SD	Wind, Solar	0.3	35.6	11.4	24.2
HCPD	MN	Wind, Solar	0.3	14.4	6.1	8.3
CBPC	ND	Wind, Solar	0.0	0.8	0.5	0.4
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.4	2.5
MRES	ND	Wind, Solar	0.0	0.7	0.5	0.2
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.6: Policy Assessment Results: Future 1, 2021

Future 1, 2024						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	0.0	8.2	4.7	3.5
EMDE	MO	Wind, Solar	1.4	10.1	7.7	2.4
GMO	MO	Wind, Solar	0.4	16.0	12.6	3.4
KCPL	MO	Wind, Solar	0.0	1.0	0.5	0.6
NPPD	SD	Wind, Solar	0.0	14.3	12.3	2.1
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.1	7.0	3.5	3.5
SPS	NM	Wind	0.0	2.3	0.9	1.3
SPS	NM	Solar	0.1	18.9	13.3	5.6
BASIN	MN	Wind, Solar	0.0	4.0	3.6	0.4
BASIN	MT	Wind, Solar	0.0	1.6	1.1	0.5
BASIN	ND	Wind, Solar	0.0	1.7	1.1	0.6
BASIN	SD	Wind, Solar	0.3	35.6	11.4	24.2
HCPD	MN	Wind, Solar	0.3	14.4	6.1	8.3
CBPC	ND	Wind, Solar	0.0	0.8	0.5	0.4
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.4	2.5
MRES	ND	Wind, Solar	0.0	0.7	0.5	0.2
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.7: Policy Assessment Results: Future 1, 2024

Future 1, 2029						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	1.9	6.8	4.7	2.1

Future 1, 2029						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
EMDE	MO	Wind, Solar	1.1	8.7	7.8	0.9
GMO	MO	Wind, Solar	0.4	17.2	12.6	4.6
KCPL	MO	Wind, Solar	0.1	0.9	0.5	0.4
NPPD	SD	Wind, Solar	0.4	13.8	12.1	1.6
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.1	7.0	3.9	3.1
SPS	NM	Wind	0.0	2.3	1.0	1.2
SPS	NM	Solar	0.0	18.9	14.3	4.7
BASIN	MN	Wind, Solar	0.0	8.9	3.8	5.1
BASIN	MT	Wind, Solar	0.0	1.6	1.4	0.2
BASIN	ND	Wind, Solar	0.0	1.7	1.2	0.5
BASIN	SD	Wind, Solar	0.3	35.6	12.1	23.5
HCPD	MN	Wind, Solar	0.1	14.5	6.5	8.0
CBPC	ND	Wind, Solar	0.0	0.8	0.6	0.2
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.6	2.3
MRES	ND	Wind, Solar	0.0	0.7	0.7	0.1
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.8: Policy Assessment Results: Future 1, 2029

Future 2, 2024						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	0.0	8.4	4.8	3.6
EMDE	MO	Wind, Solar	2.8	9.1	7.9	1.2

Future 2, 2024						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
GMO	MO	Wind, Solar	1.1	15.0	12.9	2.2
KCPL	MO	Wind, Solar	0.0	0.8	0.5	0.4
NPPD	SD	Wind, Solar	0.0	14.3	12.5	1.8
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.3	6.8	3.7	3.0
SPS	NM	Wind	0.0	2.8	1.0	1.8
SPS	NM	Solar	0.6	18.4	14.0	4.5
BASIN	MN	Wind, Solar	0.0	4.0	3.7	0.2
BASIN	MT	Wind, Solar	0.0	1.6	1.1	0.5
BASIN	ND	Wind, Solar	0.0	1.7	1.1	0.5
BASIN	SD	Wind, Solar	0.2	35.6	11.6	24.1
HCPD	MN	Wind, Solar	0.3	14.3	6.2	8.1
CBPC	ND	Wind, Solar	0.0	0.8	0.5	0.3
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.5	2.4
MRES	ND	Wind, Solar	0.0	0.7	0.5	0.2
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.9: Policy Assessment Results: Future 2, 2024

Future 2, 2029						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	3.7	5.5	4.9	0.6
EMDE	MO	Wind, Solar	2.7	8.4	8.1	0.3
GMO	MO	Wind, Solar	0.5	17.4	13.1	4.3

Future 2, 2029						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
KCPL	MO	Wind, Solar	0.1	0.7	0.5	0.3
NPPD	SD	Wind, Solar	0.2	14.1	12.6	1.5
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.1	7.0	4.1	3.0
SPS	NM	Wind	0.0	2.8	1.1	1.7
SPS	NM	Solar	0.1	18.8	14.8	4.0
BASIN	MN	Wind, Solar	0.0	13.4	3.9	9.4
BASIN	MT	Wind, Solar	0.0	1.6	1.5	0.1
BASIN	ND	Wind, Solar	0.0	1.7	1.2	0.5
BASIN	SD	Wind, Solar	0.3	35.6	12.5	23.1
HCPD	MN	Wind, Solar	0.1	14.5	6.7	7.8
CBPC	ND	Wind, Solar	0.0	0.8	0.6	0.2
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.7	2.2
MRES	ND	Wind, Solar	0.0	0.7	0.7	0.0
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.10: Policy Assessment Results: Future 2, 2029

All utilities met their overall renewable mandates and goals. There were no public policy needs and thus no policy solutions identified in any of the futures.

4.4 PERSISTENT OPERATIONAL NEEDS

4.4.1 ECONOMIC OPERATIONAL NEEDS

In October 2018, the MOPC approved a waiver of the requirement to evaluate solutions against the economic operational needs in the 2019 ITP assessment due to identified software limitations. The economic operational needs identified for the 2019 ITP assessment in Table 4.11 through Table 4.14 were posted for informational purposes only.

Constraint	Monitored Element	Contingent Element	Congestion Cost
TMP270_23432	Cleveland 138 kV GRDA-AECI Bus Tie	Cleveland-Tulsa North 345 kV	$28,004,877
TMP228_22196 HALTUCSWITUC	Hale-Tuco 115 kV	Swisher-Tuco 230 kV	$19,687,942
TMP269_23661	Charlie Creek-Watford 230 kV	Charlie Creek-Patent Gate 345 kV	$17,724,562
TMP151_23193	Oakland North-Atlas Junction 161 kV	Asbury-Purcell 161 kV	$17,129,796
TMP103_22587	Kildare-White Eagle 138 kV	Hunter-Woodring 345 kV	$15,869,305
TMP192_21680	Smoky Hills-Summit 230 kV	Postrock-Axtell 345 kV	$13,006,107
TEMP39_23235	Waverly-La Cygne 345 kV	Caney River-Neosho 345 kV	$11,754,041
JECAUBHOYJEC	Jeffrey-Auburn 230 kV	Jeffrey-Hoyt 345 kV	$10,373,715
TEMP96_22409 HUGVALHUGVAL	Hugo-Valliant 138 kV	Hugo-Valliant 345 kV	$10,267,443

Table 4.11: Economic Operational Needs

The constraints in Table 4.12 have associated future upgrades which are expected to reduce some or all congestion associated with the constraint.

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
SUNAMOTOLYOA	Sundown-Amoco 230 kV	Tolk-Yoakum 230 kV	$22,121,967	NTC ID 200395, Issued 5/17/2016, 2016 ITPNT, Sundown-Amoco terminal equipment, Q1 2019 ISD
NEORIVNEOBLC	Neosho-Riverton 161 kV	Neosho-Blackberry 345 kV	$20,483,694	NTC ID 200430, Issued 2/21/2017, 2017 ITP10, Neosho and Riverton 161 kV terminal equipment, 12/2018 ISD

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
GGS	Gentleman-Red Willow 345 kV Gentleman-Sweetwater 345 kV circuit 1 Gentleman-Sweetwater 345 kV circuit 2 Gentleman-North Platte 230 kV circuit 1 Gentleman-North Platte 230 kV circuit 2 Gentleman-North Platte 230 kV circuit 3	System Intact	$15,769,205	NTC ID 200220, Issued 3/11/2013, 2012 ITP10, Gentleman-Cherry Co.-Holt 345 kV
HANMUSAGEPEC	Hancock-Muskogee 161 kV	Pecan-Agency 161 kV	$13,737,915	NTC ID 200423, Issued 1/12/2017, 2016-AG1, 6/1/2021 ISD, Hancock-Muskogee terminal equipment
TEMP60_22466	Tuco-Stanton 115 kV	Tuco-Carlisle 230 kV	$11,531,235	NTC ID 200444, Issued 2/22/2017, 2017 ITP10, 12/31/2018 ISD (Delay-Mitigation), Tuco-Stanton-Indiana-Erskine terminal equipment

Table 4.12: Economic Operational Needs

The constraints in Table 4.13 have associated upgrades currently in place which have reduced or eliminated loading of the associated constraint.

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
WDWFPLTATNOW	Woodward-Windfarm Switching Station 138 kV	Tatonga-Matthewson 345 kV circuit 1	$86,155,466	NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward-Tatonga-Matthewson 345 kV circuit 2, 2/15/2018 ISD, $665,000 congestion cost (outage related) since upgrade
PLXSUNTOLYOA	Plant X-Sundown 230 kV	Tolk-Yoakum 230 kV	$56,046,773	NTC ID 200455, Issued 5/12/2017, 2017 ITPNT, Plant X and

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
				Sundown 230 kV terminal equipment, 3/28/2018 ISD, $0 congestion cost since upgrade
TMP215_21787	Cimarron-Draper 345 kV	Terry Road-Sunnyside 345 kV	$41,040,182	NTC ID 200416, Issued 11/14/2016, 2015 ITP10, Cimarron-Draper terminal equipment, 11/28/2017 ISD, $0 congestion cost since upgrade
TMP118_22847	Southard-Roman Nose 138 kV	Tatonga-Matthewson 345 kV circuit 1	$34,561,487	NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward-Tatonga-Matthewson 345 kV circuit 2, 2/15/2018 ISD, $0 congestion cost since upgrade
VINHAYPOSKNO SHAHAYPOSKNO	Vine Tap-North Hays 115 kV	Post Rock-Knoll 230 kV	$30,519,207	NTC ID 200429, Issued 2/22/2017, 2017 ITP10, Post Rock-Knoll circuit 2, 12/2018 ISD
TMP171_22413	Mooreland-Cedardale 138 kV	Tatonga-Matthewson 345 kV circuit 1	$24,889,894	NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward-Tatonga-Matthewson 345 kV circuit 2, 2/15/2018 ISD, $0 congestion cost since upgrade
TMP113_22583	Cimarron-Draper 345 kV	Arcadia-Seminole 345 kV	$14,666,763	NTC ID 200416, Issued 11/14/2016, 2015 ITP10, terminal equipment, 11/28/2017 ISD, $0 congestion cost since upgrade

Table 4.13: Economic Operational Needs

4.4.2 RELIABILITY OPERATIONAL NEEDS

A reconfiguration for voltage mitigation in the southwest Missouri area was the single reliability operational need identified for the 2019 ITP assessment. This need was previously addressed in the 2018

ITPNT and is associated with a planned upgrade. As such, this need was posted for informational purposes only for the 2019 ITP planning cycle.

Reconfiguration	Type	Annual Reconfiguration (%)	Notes
Brookline-Flint Creek 345 kV opened for high voltage during light loading	Voltage	24.27%	NTC ID 210493, Issued 8/17/2018, 2018 ITPNT, 12/31/2019 ISD, New 50 MVAR reactor at Brookline 345 kV

Table 4.14: Reliability Operational Needs

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.

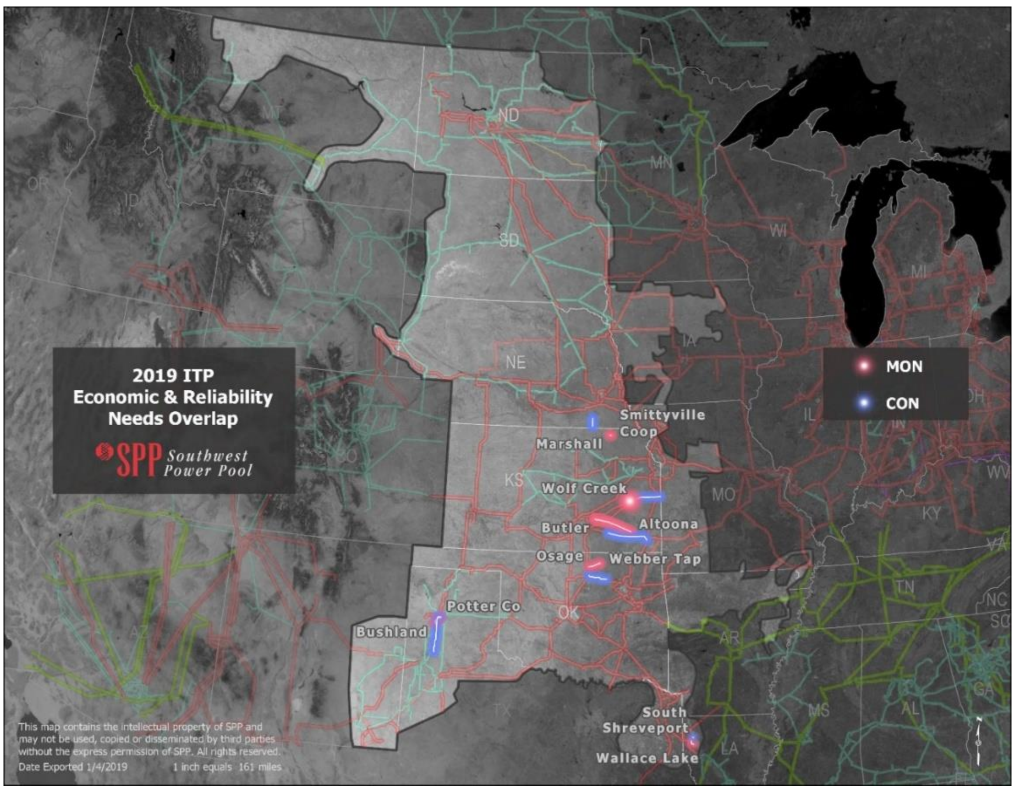


Figure 4.13: Base Reliability and Economic Need Overlap

Overlapping Reliability and Economic Needs
Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV
Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV
South Shreveport-Wallace Lake 138 kV for the loss of Ft. Humbug-Trichel 138 kV
Potter County-Bushland 230 kV for the loss of Potter County-Newhart 230 kV

Overlapping Reliability and Economic Needs
Marshall-Smittyville 115 kV for the loss of Harbine-Steele 115 kV
Carlisle-LP-Doud 115 kV for the loss of Wolfforth 230/115 kV transformer

Table 4.15: Overlapping Reliability and Economic Needs

Overlapping Informational Operational and Economic Needs
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
Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV
Hale County-Tuco 115 kV for the loss of Swisher-Tuco 230 kV
Kildare-White Eagle 138 kV for the loss of Woodring-Hunter 345 kV
Hugo-Valliant 138 kV for the loss of Valliant-Hugo 345 kV
Oakland North-Atlas Junction 161 kV for the loss of Asbury-Purcell 161 kV*

Table 4.16: 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 RAYBURN COUNTRY ELECTRIC COOPERATIVE

The Rayburn Country Electric Cooperative (Rayburn Country) transmission system and network load in the American Electric Power-West (AEPW) pricing zone that is involved in regulatory processes to move to the Electric Reliability Council of Texas (ERCOT) system was not included in the approved base models sets. While this is the future expectation, SPP has the obligation to protect long-term firm transmission service to serve the load until the delivery points are removed from the current network integration transmission service agreement (NITSA).

To satisfy this obligation, following the same analysis of the reliability needs assessment, an analysis was performed on the base reliability model set with the Rayburn Country system and network load included. This analysis identified no new potential transmission needs and therefore had no impact to the 2019 ITP assessment.

4.6.2 TRI-COUNTY ELECTRIC COOPERATIVE (TCEC)

The Tri-County Electric Cooperative (Tri-County) transmission system in the Oklahoma panhandle within the transmission SPS/Xcel Energy pricing zone came under SPP functional control via the requirements of Attachment AI of the tariff following the 2019 ITP model build. This system has been previously equivalenced prior to SPP model build that began in the fall of 2018. GridLiance High Plains (GLHP) performed its local planning process assessment in 2018 and identified three new transmission upgrades required to meet local planning process needs. To satisfy its own NERC and tariff requirements, GLHP requested SPP to expedite 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 2019 ITP assessment.

An analysis was performed to satisfy these obligations by determining the impact of including the explicitly modeled Tri-County system and proposed local planning process upgrades in the 2019 ITP base reliability and market economic model sets. Following the same analysis of the reliability and economic needs assessments, no new potential transmission needs were identified by including the existing system or the proposed local planning process upgrades. No regional transmission needs or projects identified in the 2019 ITP assessment were located geographically or electrically close to the Tri-County system.

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 2019 MTEP for evaluation in SPP models. Staff analyzed 1,073 Detailed Project Proposals (DPP) solutions received from stakeholders and approximately 560 staff solutions (including those provided by MISO and 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 a member's 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 cost. The second metric is cost per voltage relief (CVR) score, which relates the amount of voltage support a solution provides to its engineering and construction cost.

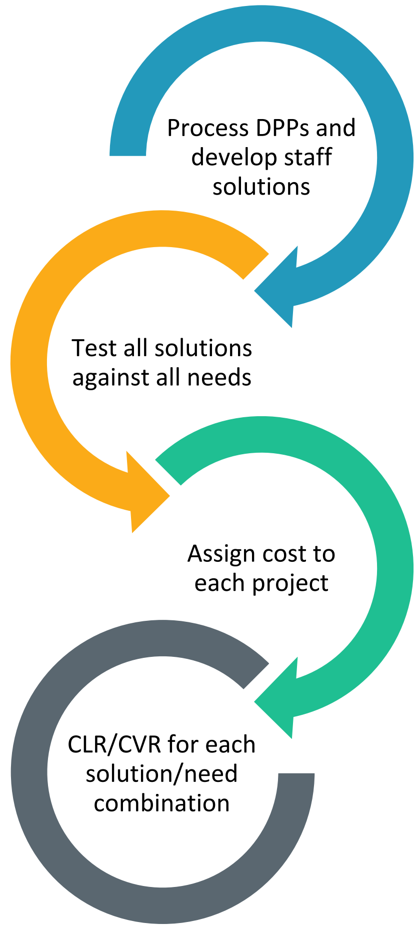


Figure 5.1: Reliability Screening Process

5.2 ECONOMIC PROJECT SCREENING

All solutions were tested in each market economic model 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) benefit-to-cost ratio were calculated for each project based on its projected APC savings in each future and study year (2021, 2024, and 2029).

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 benefit-to-cost 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 17.44%. The 40-year project cost is calculated using this NPCC, an 8% discount rate and a 2.5% 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 2019 ITP; therefore, no projects were analyzed during the public policy project screening.

5.5 PERSISTENT OPERATIONAL PROJECT SCREENING

Due to the MOPC-approved waiver described in section 4.4.1, 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.

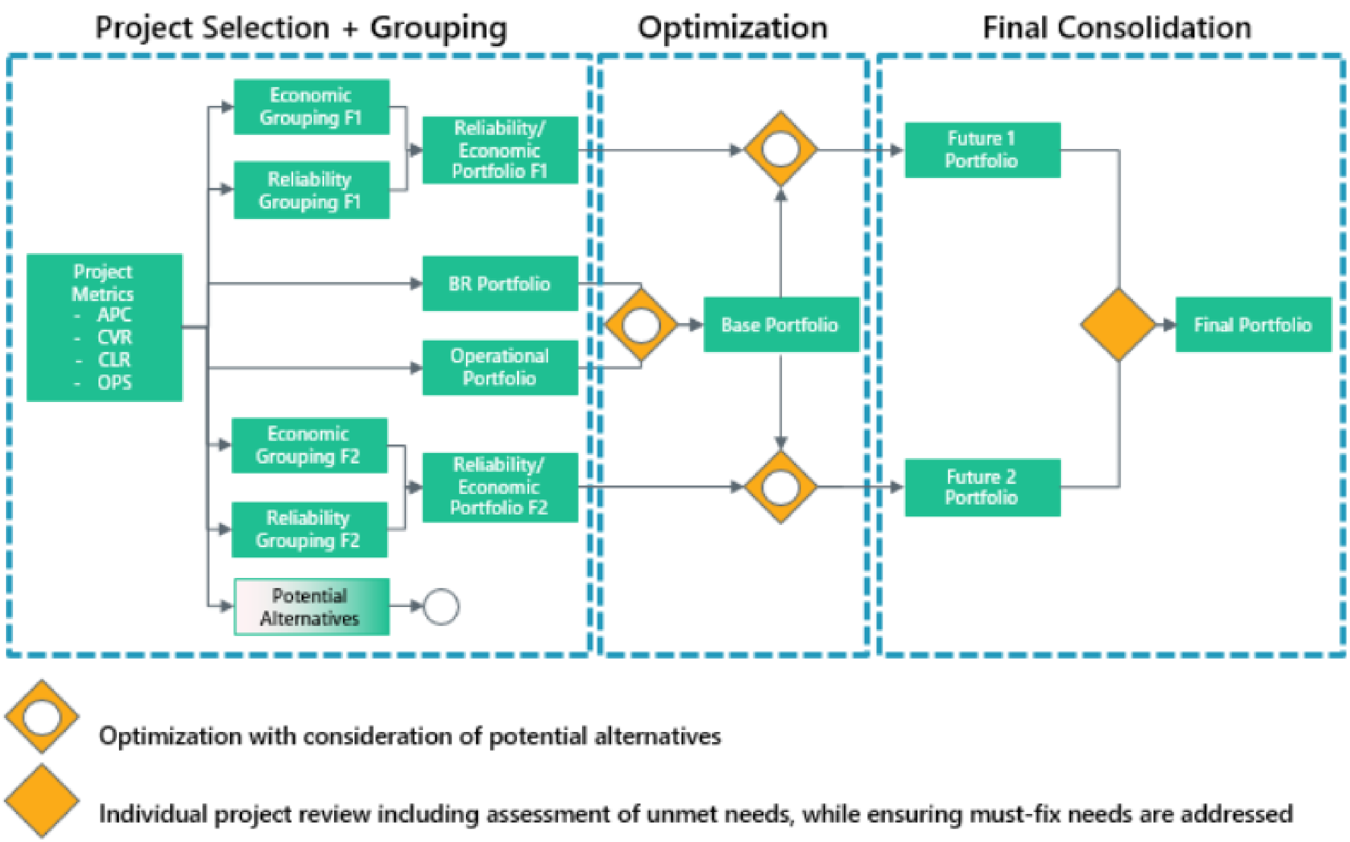


Figure 6.1: Portfolio Development Process

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 level cost estimates and stakeholder feedback from regularly scheduled working group meetings, the June 2019 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 Solution Development and Evaluation were sent out for the development of study cost estimates (±30% of final project cost). 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 member utility. SPP requested these study estimates before and after the June summit. 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. Using this solution selection software, a subset of solutions was generated by considering the metrics described in Section 5.1. During this iterative 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, Future 1, and Future 2 reliability needs.

While reviewing these results, it was determined there were no facilities unique to the futures scenarios that required solutions different from the base reliability results. Therefore, the iterative process was streamlined to consider all needs as a single grouping. The list of reliability solutions was continually refined through stakeholder feedback. Table 6.1 and Figure 6.2 below shows the final reliability grouping selected to address the valid list of reliability needs in the 2019 ITP.

Project	Area	Cost	Scenario[18]*
Pryor Junction 138/115 kV transformer	AEPW	$9,155,167	21S / BR,F1,F2
Tulsa SE-21 St Tap 138 kV rebuild	AEPW	$1,307,802	21S / BR
Tulsa SE-S Hudson 138 kV rebuild	AEPW	$6,724,237	21S / BR
Firth 15MVAR capacitor bank 115 kV	NPPD	$3,370,000	21S,W,L / BR,F1,F2
Cleo Corner-Cleo Junction 69 kV terminal equipment	OKGE	$16,602	24S / BR
Rocky Point-Marietta 69 kV terminal equipment	OKGE/ WFEC	$100,000	21W / BR
Bushland-Deaf Smith 230 kV terminal equipment	SPS	$1,185,094	29L / BR
Carlisle-LP Doud Tap 115 kV terminal equipment	SPS	$88,924	29S / BR
Deaf Smith-Plant X 230 kV terminal equipment	SPS	$1,185,094	29L / BR
Lubbock South-Jones 230 kV circuit 1 terminal equipment	SPS	$88,924	29S / BR
Lubbock South-Jones 230 kV circuit 2 terminal equipment	SPS	$88,924	29S / BR
Moore-RB-S&S 115 kV terminal equipment	SPS	$158,742	29S / BR,F1
Plains Interchange-Yoakum 115 kV terminal equipment	SPS	$158,742	29S / BR

[18] This is the first need date.

Project	Area	Cost	Scenario[18]*
Potter Co-Newhart 230 kV terminal equipment	SPS	$1,185,094	29L / BR
Marshall County-Smittyville-Baileyville-South Seneca 115 kV rebuild	WERE	$17,636,022	21L / BR
Getty East-Skelly 69 kV terminal equipment	WERE	$114,821	21S,W,L / BR
Gypsum 12 MVAR capacitor bank 69 kV	WFEC	$490,093	21S / BR

Table 6.1: Reliability Project Grouping

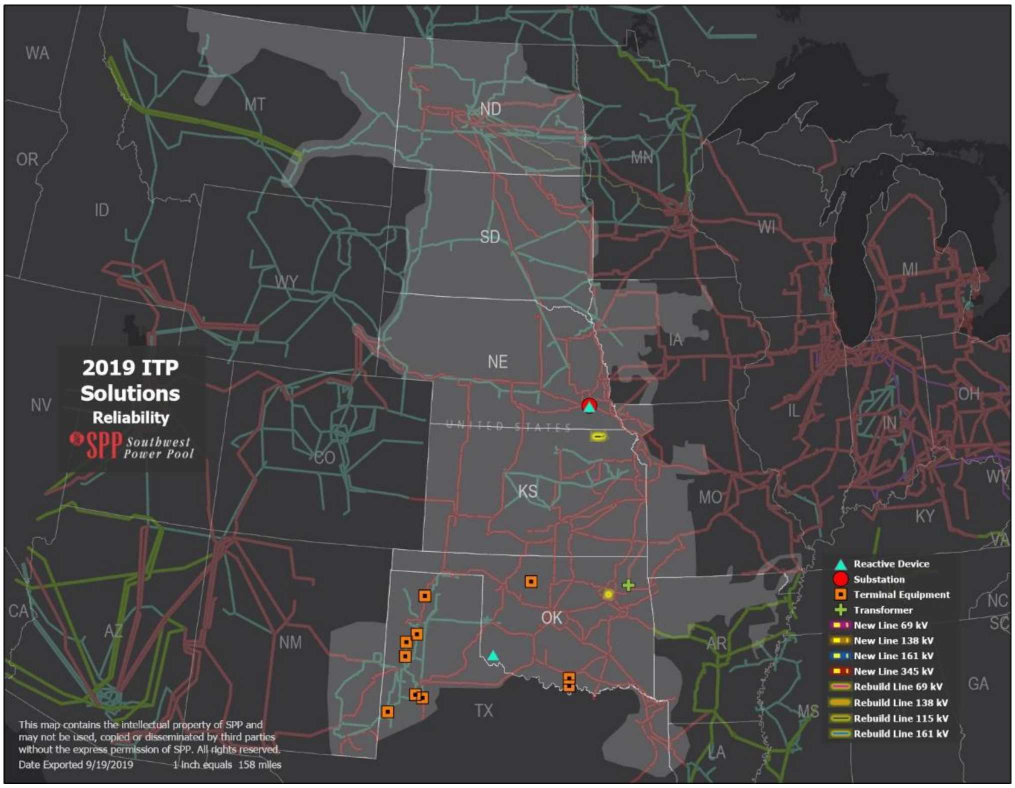


Figure 6.2: Reliability Project Grouping

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 21 breakers at Riverside Station 138 kV	AEPW	$16,288,000	21S / BR

Replace 8 breakers at Southwestern Station 138 kV	AEPW	$4,421,345	21S / BR
Replace 1 breaker at Craig 161 kV	KCPL	$254,000	21S / BR
Replace 2 breakers at Leeds 161 kV	KCPL	$440,000	21S / BR
Replace 2 breakers at Midtown 161 kV	KCPL	$440,000	21S / BR
Replace 4 breakers at Southtown 161 kV	KCPL	$880,000	21S / BR
Replace 1 breaker at Moore 13.8 kV tertiary bus	NPPD	$510,000	21S / BR
Replace 2 breakers at Hastings 115 kV	NPPD	$550,000	21S / BR
Replace 5 breakers at Canaday 115 kV	NPPD	$2,600,000	21S / BR
Replace 2 breakers at Westmoore 138 kV	OKGE	$271,289	21S / BR
Replace 3 breakers at Santa Fe 138 kV	OKGE	$406,935	21S / BR
Replace 1 breaker at Carlsbad Interchange 115 kV	SPS	$552,668	21S / BR
Replace 3 breakers at Denver City North and South 115 kV	SPS	$5,526,680	21S / BR
Replace 3 breakers at Hale County Interchange 115 kV	SPS	$1,658,004	21S / BR
Replace 1 breaker at Washita 69 kV	WFEC	$52,400	21S / BR
Replace 12 breakers at Mooreland 138/69 kV	WFEC	$835,850	21S / BR
Replace 3 breakers at Anadarko 138 kV	WFEC	$228,500	21S / BR

Table 6.2: Short-Circuit Project Grouping

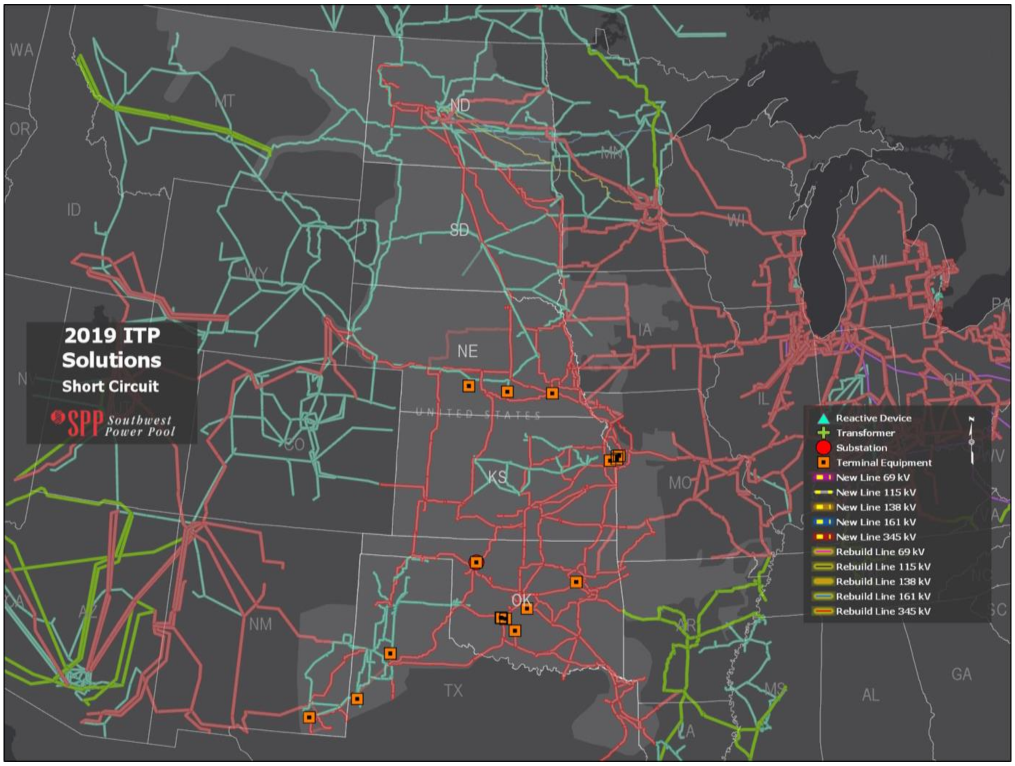


Figure 6.3: Short-Circuit Project Grouping

6.2.4 ECONOMIC GROUPING

All projects with a one-year benefit-to-cost ratio of at least 0.5 or a 40-year NPV benefit-to-cost 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 benefit-to-cost ratio, and congestion relief for the economic needs.

Three economic project groupings were developed for Futures 1 and 2, 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; includes the flexibility to use additional considerations.

The following factors were considered when developing and analyzing projects grouping per future:

- One-year project cost, APC benefit, and benefit-to-cost ratio.
- 40-year NPV cost, APC benefit, and the benefit-to-cost 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 six initial groupings. Some projects appeared in multiple groupings.

Economic Project	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Upgrade Wolf Creek 345/69 kV transformer	X	-	-	X	-	-
New Wolf Creek-Blackberry 345 kV line, new Butler 138 kV phase-shifting transformer	-	X	-	-	X	-
Tap Neosho-La Cygne and New Wolf Creek-New Tap-Blackberry 345 kV line, new Butler 138 kV phase-shifting transformer	-	-	X	-	-	X
New Butler 138 kV phase-shifting transformer	X	X	X	X	X	X
Neosho-Riverton 161 kV rebuild	X	X	X	X	X	X
Waverly-La Cygne 345 kV reconductor	X	-	-	X	-	-
Neosho-Caney River 345 kV terminal equipment	X	X	X	X	X	X
Springfield-La Russell 161 kV rebuild	X	X	X	X	X	X
Cleveland 138 kV bus tie terminal equipment	X	-	-	X	-	-
Kerr-Maid 161 kV double circuit rebuild	X	X	X	X	X	X
Osage-Webb Tap-Fairfax-Shidler 138 kV rebuild	X	-	-	X	-	-
Kinzie 138 kV bus tie terminal equipment	X	-	-	X	-	-
New Sooner-Wekiwa 345 kV line, Sand Springs-Sheffield Steel 138 kV terminal equipment	-	X	X	-	X	X
Cimarron-Northwest-Matthewson 345 kV terminal equipment	X	X	X	X	X	X
Hugo-Valliant 138 kV terminal equipment	-	-	-	X	X	X
South Brown-Russett 138 kV rebuild	-	-	-	X	X	X
Gracemont-Anadarko 138 kV rebuild	X	X	X	X	X	X
Cottonwood Creek-Cottonwood Creek-Marshall Tap 138 kV rebuild	-	-	-	X	X	X
Kingfisher Jct.-East Kingfisher Tap 138 kV rebuild	X	X	X	X	X	X
Dover Switch-Okeene 138 kV rebuild	X	X	X	X	X	X
Sundown-Amoco Tap 115 kV terminal equipment	X	X	X	X	X	X
Spearman-Hansford 115 kV rebuild	X	X	X	X	X	X
Carlisle-LP Doud 115 kV terminal equipment	-	-	-	X	X	X
Lawrence EC-Midland 115 kV terminal equipment	X	X	X	X	X	X
Craig-Lenexa 161 kV circuit 2 reconductor	-	-	-	X	X	X
Arnold-Ransom 115 kV terminal equipment, Pile-Scott City-Setab 115 kV terminal equipment	-	-	-	X	X	X
Upgrade Red Willow 345/115 kV transformer	-	-	-	X	X	X
Upgrade Fort Thompson 345/230 kV transformer circuits 1 and 2	-	-	-	X	X	X
Erie Road-Marshall re-termination and dynamically rate Granite Falls-Marshall 115 kV line	X	X	X	-	-	-

Table 6.3: Economic Project Grouping

Figure 6.4 provides a benefit-to-cost comparison (including a B/C ratio) of the six initial groupings. All costs and benefits are reported in 40-year NPVs. Based on these initial results, the highest net grouping was the best performing grouping for both futures 1 and 2. The calculated B/C ratios for each grouping are also shown in the figure.

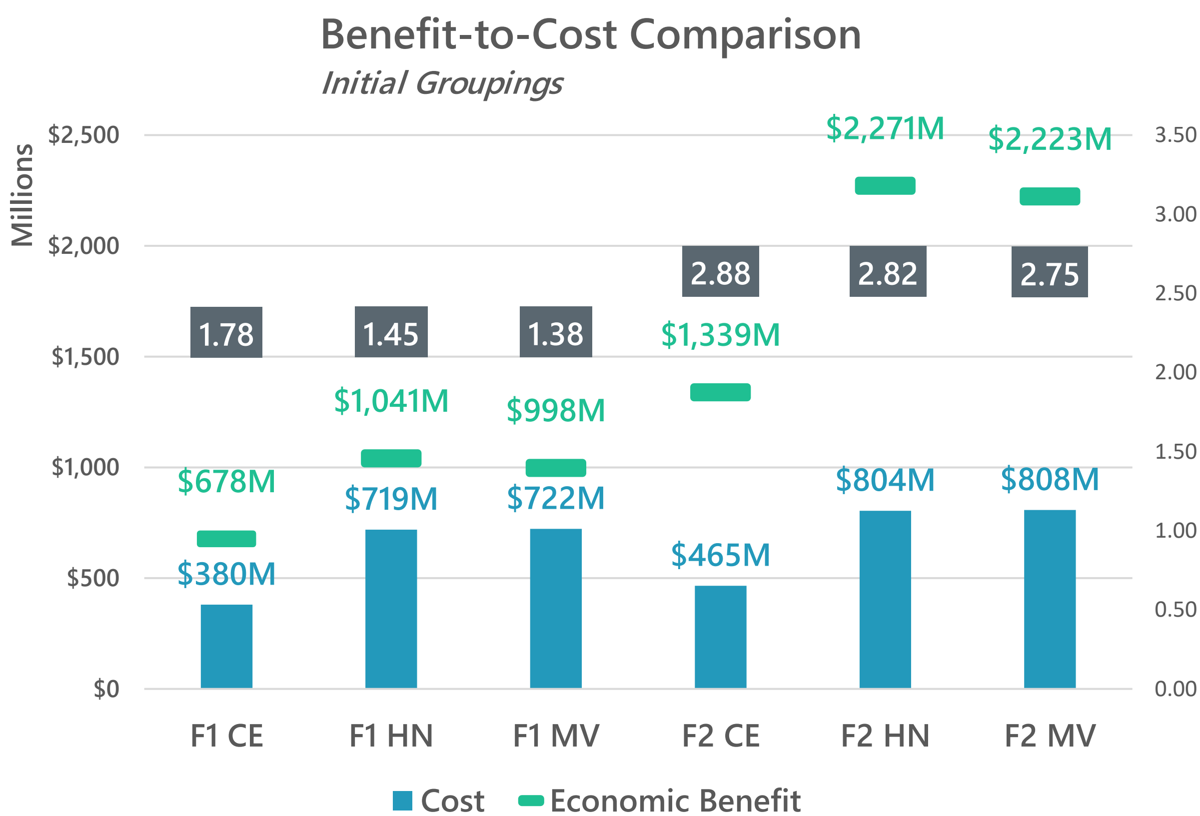


Figure 6.4: Benefit-to-Cost Comparison – Initial Groupings

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. "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. Six new sets of "base cases" were created by adding the solutions included in each grouping along with relevant model adjustments, corrections, and reliability 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 benefit-to-cost ratio from the subtraction evaluation were removed from the grouping. This subtraction evaluation was repeated for each grouping until all remaining projects maintained a benefit-to-cost ratio of 1.0 over 40 years.

The final result of the subtraction evaluation resulted in the selection of a future one and Future 2 groupings that provided the highest overall net benefit.

6.2.4.2 Final Economic Groupings

The selected grouping for each future was the grouping that provided the highest net benefit 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. Figure 6.5 and Figure 6.6 show the approximate location of identified projects within the SPP footprint.

	Future 1			Future 2		
Economic Project	**CE**	**HN**	**MV**	**CE**	**HN**	**MV**
Upgrade Wolf Creek 345/69 kV transformer	X	-	-	X	-	-
New Wolf Creek-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	-	X	-	-	X	-
Tap Neosho-La Cygne and New Wolf Creek-New Tap-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	-	-	X	-	-	X
New Butler 138 kV phase-shifting transformer	X	-	-	X	-	-
Neosho-Riverton 161 kV rebuild	-	X	X	-	X	-
Waverly-La Cygne 345 kV reconductor	-	-	-	X	-	-
Neosho-Caney River terminal equipment	-	X	-	X	X	X
Cleveland 138 kV bus tie terminal equipment	X	-	-	X	-	-
Osage-Webb Tap 138 kV rebuild	-	-	-	X	-	-
New Sooner-Wekiwa 345 kV line and Sand Springs-Sheffield Steel 138 kV terminal equipment	-	X	X	-	X	X
Cimarron-Northwest-Matthewson 345 kV terminal equipment	X	X	X	X	X	X
South Brown-Russett 138 kV rebuild	-	-	-	-	X	X
Gracemont-Anadarko 138 kV rebuild	X	X	X	X	X	X
Cottonwood Creek-Cottonwood Creek-Marshall Tap 138 kV rebuild	-	-	-	X	-	-
Kingfisher Jct.-East Kingfisher Tap 138 kV rebuild	X	X	X	X	X	X
Dover Switch-Okeene 138 kV rebuild	-	X	-	X	-	-
Sundown-Amoco Tap 115 kV terminal equipment	X	X	-	-	-	-
Spearman-Hansford 115 kV rebuild	X	X	X	X	X	X
Lawrence EC-Midland 115 kV terminal equipment	X	X	X	X	X	X
Craig-Lenexa 161 kV circuit 2 reconductor	-	-	-	X	-	-
Arnold-Ransom 115 kV terminal equipment and Pile-Scott City-Setab 115 kV terminal equipment	-	-	-	X	X	X
Upgrade Fort Thompson 345/230 kV transformer circuits 1 and 2	-	-	-	X	X	X
Erie Road-Marshall re-termination and dynamically rate Granite Falls-Marshall 115 kV line	-	-	-	X	X	X

Table 6.4: Final Economic Project Grouping

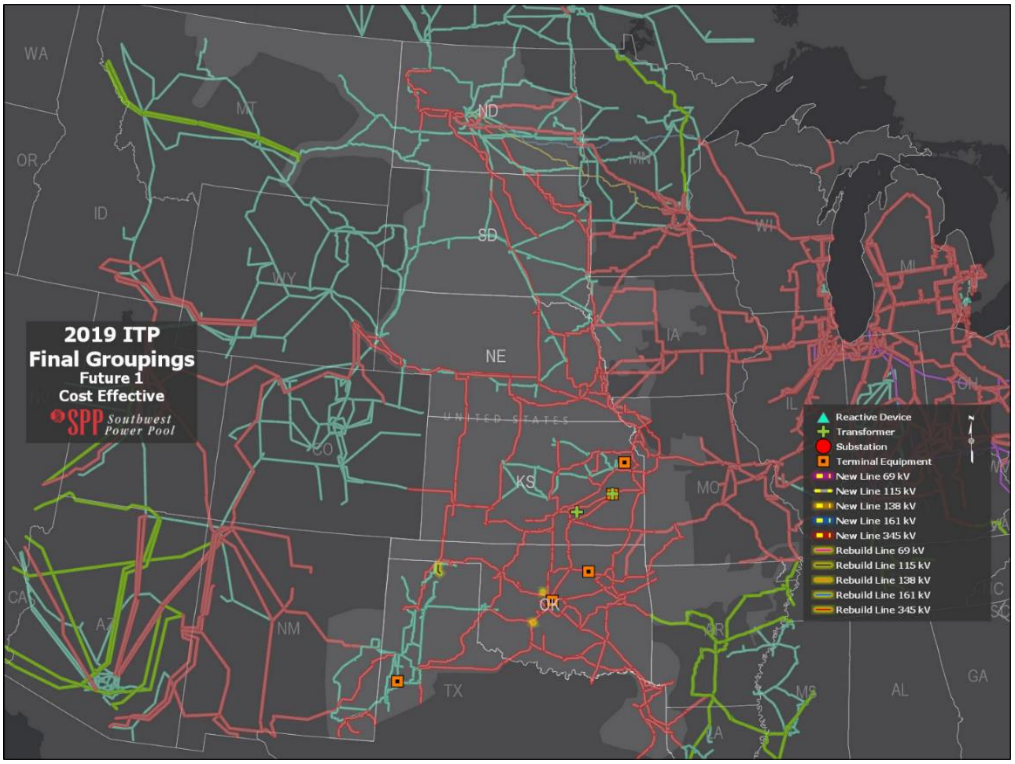


Figure 6.5: Final Project Groupings - Future 1 - Cost Effective

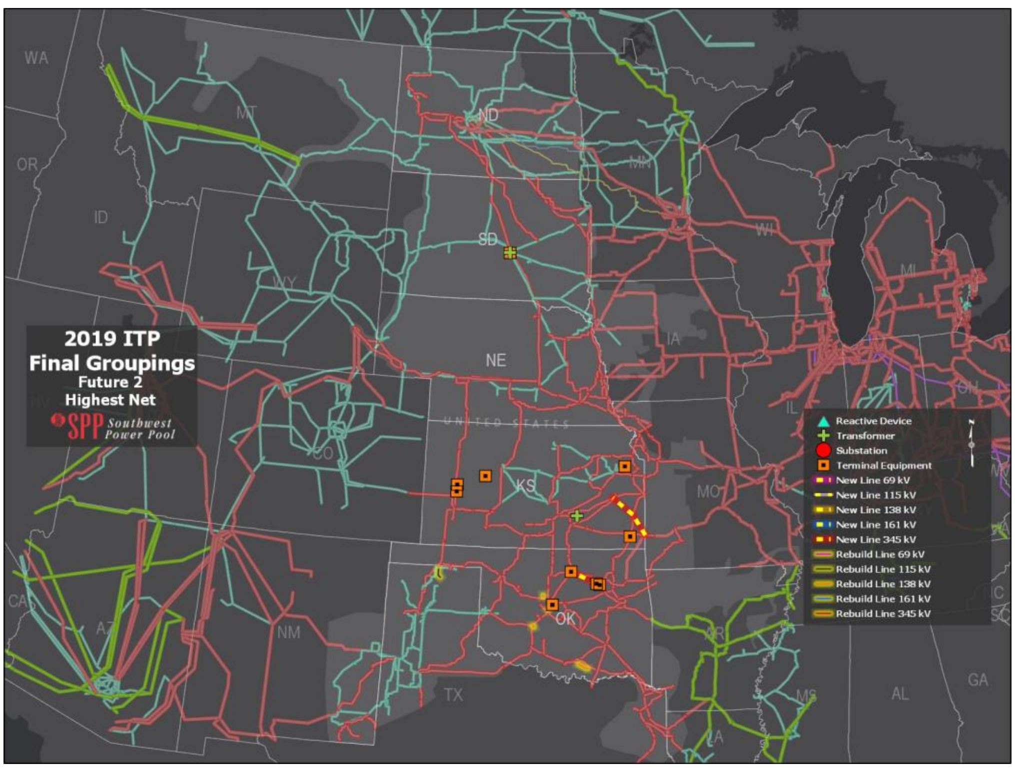


Figure 6.6: Final Groupings - Future 2 - Highest Net APC

Figure 6.7 is a benefit-to-cost comparison (including B/C ratio) of the final groupings. The cost-effective grouping for Future 1 provided a net benefit of $683 million, while the highest net grouping for Future 2 provided $1.891 billion in net benefit. The calculated B/C ratios for each grouping are also shown in the figure.

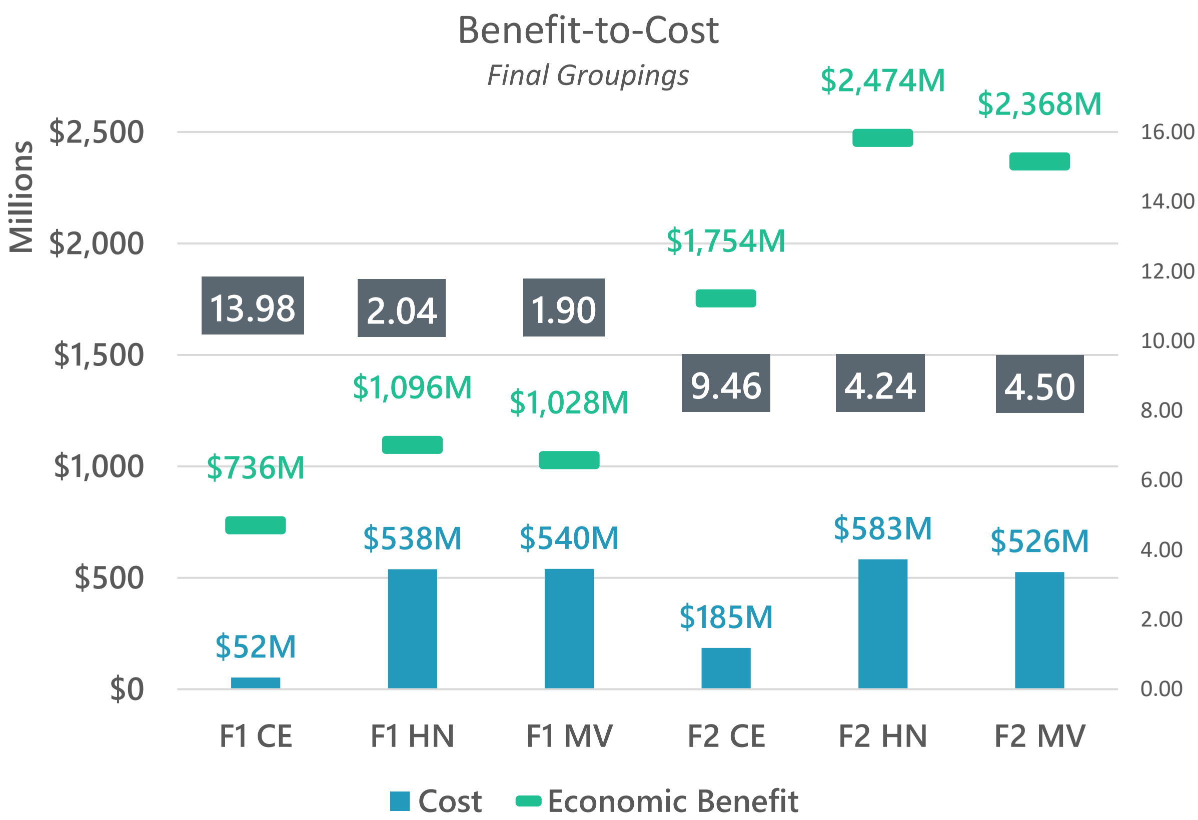


Figure 6.7: Final Groupings – Benefit-to-Cost Comparison

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. SPP observed overlap between the reliability and economic needs during the needs assessment milestone.

SPP originally identified overlap of reliability and economic needs, specifically in Target Area 1, and included those needs in its posted needs assessment. During the project grouping process the related reliability needs were invalidated due to model corrections. No additional overlap of economic and reliability needs were identified, therefore, all reliability (including those driven by short-circuit needs) and economic projects were included in the final optimized portfolio for each future.

6.4 PORTFOLIO CONSOLIDATION

Stakeholders determined the two futures assessed in the 2019 ITP would be treated equally to determine the consolidated portfolio. When determining whether a project 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 project was identified in only one future.

Stakeholders determined that 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 6.5 details the scoring rubric as well as some of the minimum criteria projects had to meet to receive points. 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 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 2019 ITP Scope.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC benefit-to-cost ratio in selected future	50	1.0 (0.9)
	40-year (1-year) APC benefit-to-cost 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 6.5: Consolidated Portfolio ScoringConsolidation Scenario One

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

- Gracemont-Anadarko 138 kV rebuild
- Kingfisher Junction-East Kingfisher Tap 138 kV rebuild
- Spearman-Hansford 115 kV rebuild
- Lawrence Energy Center-Midland 115 kV terminal equipment

6.4.1 CONSOLIDATION SCENARIO TWO

Consolidation Scenario Two occurred when two projects were identified to solve the same or similar economic needs for 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 6.5 was used to score the projects and determine which project should move forward into the consolidated portfolio.

6.4.1.1 Target Area 1

The cost-effective grouping in Future 1 included a 345/69 kV transformer at Wolf Creek paired with the phase-shifting transformer at the Butler 138 kV station. The highest net grouping in future two included a new 345 kV line from Wolf Creek-Blackberry, paired with the phase-shifting transformer at the Butler 138 kV station. As shown in Table 6.6, the new 345 kV line from Wolf Creek-Blackberry paired with the phase-shifting transformer at Butler scored higher using the consolidation rubric. The needs solved by these solutions include:

- Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV
- Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV
- Waverly-La Cygne 345 kV for the loss of Caney River/RP2POI10-Neosho 345 kV

No.	Consideration	Possible Points	F1 Project Score	F2 Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	39.6	50
	APC net benefit and benefit-to-cost ratio in opposite future			
2	Congestion relieved in selected future (by need(s), all years)	10	19.3	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	8	8
4	New EHV	7.5	0	7.5
5	Mitigate non-thermal issues	7.5	0	7.5
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	5	5
		Total Score	**71.9**	**97.9**

Table 6.6: Target Area 1 Consolidation Scoring

6.4.1.2 Target Area 2

The cost-effective grouping for Future 1 included a bus tie upgrade at the Cleveland 138 kV station. The highest net grouping for Future 2 identified a new 345 kV line from Sooner-Wekiwa, paired with terminal equipment on the Sheffield Steel-Sand Springs 138 kV line. As shown in Table 6.7, the Sooner-Wekiwa 345 kV new line paired with the 138 kV terminal equipment scored higher using the consolidation rubric. The needs solved by this project include:

- Cleveland 138 kV bus tie for the loss of Cleveland-Tulsa North 345 kV
- Webb Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV

No.	Consideration	Possible Points	F1 Project Score	F2 Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	48.6	50
	APC net benefit and benefit-to-cost ratio in opposite future			
2	Congestion relieved in selected future (by need(s), all years)	10	1.3	18
	Congestion relieved in opposite future (by need(s), all years)	10		
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	10	10
4	New EHV	7.5	0	7.5
5	Mitigate non-thermal issues	7.5	0	7.5
6	Long-term viability (e.g., 2013 ITP20) or improved ARR feasibility	5	0	0
		Total Score	**59.9**	**93**

Table 6.7: Target Area 1 Consolidation Scoring

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 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.

Neosho-Riverton 161 kV Rebuild

The Neosho-Riverton 161 kV rebuild was included in the Future 2 portfolio because it addressed some remaining congestion in Target Area 1. The 40-year benefit-to-cost ratio for this project was negative when included incrementally to the Future 1 portfolio, which led to a score of 0 out of a possible 50 points for the net benefit and benefit-to-cost criteria, causing it to score well below the minimum threshold.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	0
	APC net benefit and benefit-to-cost 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	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	5
	Total Score (minimum 70 threshold)		**35**

Table 6.8: Neosho-Riverton 161 kV Rebuild Consolidation Scoring

Neosho-Caney River 345 kV terminal equipment

The terminal equipment for the Neosho-Caney River 345 kV line were also included in the Future 2 portfolio. The project performed well using the net benefit, benefit-to-cost ratio, and congestion relieved metrics; however, it did not perform well enough with the other considerations to meet the minimum scoring threshold.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	42.6
	APC net benefit and benefit-to-cost 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	2
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)		**64.6**

Table 6.9: Neosho-Caney River 345 kV terminal equipment - Scoring

Cimarron-Northwest-Mathewson 345 kV terminal equipment

The project to upgrade terminal equipment on the Cimarron-Northwest-Mathewson 345 kV lines were only included in the Future 2 portfolio. However, it performed well in Future 1, which was why it was included in the initial round of each of the six groupings discussed earlier in this report. The project met the minimum scoring threshold for inclusion in the consolidated portfolio. The ability of this project to address operational congestion on these facilities was the deciding factor for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	45.5
	APC net benefit and benefit-to-cost 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	8
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)		**73.5**

Table 6.10: Cimarron-Northwest-Mathewson 345 kV terminal equipment

<u>South Brown-Russell 138 kV Rebuild</u>

The South Brown-Russett 138 kV rebuild project was found to have a negative benefit-to-cost ratio in Future 1, which led to the project receiving zero points for the net benefit and benefit-to-cost metric. Because of the low net benefit and benefit-to-cost score, this project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	0
	APC net benefit and benefit-to-cost 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	2
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)		**22**

Table 6.11: South Brown-Russell 138 kV Rebuild

<u>Sundown-Amoco Tap 115 kV terminal equipment</u>

The Sundown-Amoco Tap 115 kV terminal equipment project was included in the Future 1 portfolio. It received a near perfect score for APC/benefit-to-cost, and congestion relief considerations on the driving needs. Staff recommended the project move forward into the consolidated portfolio, even though it scored just below the minimum threshold, because needs were identified in both Future 1 and Future 2, projected wind modeled in the 2019 ITP is expected to be placed in-service, and continued load growth is expected in the area. Additionally, higher voltage facilities in the area have been issued NTCs, confirming the expected shift of congestion to the lower-voltage system.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future APC net benefit and benefit-to-cost ratio in opposite future	50	49.4
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)	**69.4**

Table 6.12: Sundown-Amoco Tap 115 kV terminal equipment – Scoring

Arnold-Ransom 115 kV terminal equipment and Pile-Scott City-Setab 115 kV terminal equipment

Terminal upgrades on these three lines were identified as a cost beneficial project in the Future 2 final portfolio. Although it was not a need in Future 1, when evaluated incrementally with the Future 1 final portfolio, it provided net APC benefits. This led to a perfect score for the net benefit and benefit-to-cost ratio, and congestion-relieved criteria. Additionally, it addresses operational congestion that the system currently experiences, leading to its inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future APC net benefit and benefit-to-cost ratio in opposite future	50	50
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 6.13: Arnold-Ransom 115 kV terminal equipment and

Pile-Scott City-Setab 115 kV terminal equipment – Scoring

Fort Thompson 230/115 kV Circuit 1 and Two (2) Transformer Replacements

The replacement of the Fort Thompson 230/115 kV transformers was included in the Future 2 final portfolio. When tested in Future 1, these transformer replacements did not meet the benefit-to-cost ratio criteria, resulting in a score of zero for the net benefit and benefit-to-cost ratio scoring criteria. With no points scored in the net benefit and the benefit-to-cost criteria this project did not meet the minimum threshold score and was not included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	0
	APC net benefit and benefit-to-cost 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	2
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)		**22**

Table 6.14: Fort Thompson 230/115 kV Circuits 1 and 2 Transformer Replacements – 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 $336.7M and is projected to create over $1B or $2B in APC savings under Future 1 or Future 2 assumptions, respectively. Benefit data reported in this section includes only APC savings.

Project	Classification	Project Cost (2019$)
Pryor Junction 138/115 kV transformer	Reliability	$9,155,167
Tulsa SE-21 St Tap 138 kV rebuild	Reliability	$1,307,802
Tulsa SE-S Hudson 138 kV rebuild	Reliability	$6,724,237
Firth 15 MVAR 115 kV capacitor bank	Reliability	$3,370,000
Cleo Corner-Cleo Junction 69 kV terminal equipment	Reliability	$16,602
Rocky Point-Marietta 69 kV terminal equipment	Reliability	$100,000
Bushland-Deaf Smith 230 kV terminal equipment	Reliability	$1,185,094
Carlisle-LP Doud Tap 115 kV terminal equipment	Reliability	$88,924
Deaf Smith-Plant X 230 kV terminal equipment	Reliability	$1,185,094

Project	Classification	Project Cost (2019$)
Lubbock South-Jones 230 kV circuit 1 terminal equipment	Reliability	$88,924
Lubbock South-Jones 230 kV circuit 2 terminal equipment	Reliability	$88,924
Moore-RB-S&S 115 kV terminal equipment	Reliability	$158,742
Plains Interchange-Yoakum 115 kV terminal equipment	Reliability	$158,742
Potter Co-Newhart 230 kV terminal equipment	Reliability	$1,185,094
Marshall County-Smittyville-Baileyville-South Seneca 115 kV rebuild	Reliability	$17,636,022
Getty East-Skelly 69 kV terminal equipment	Reliability	$114,821
Gypsum 12 MVAR 69 kV capacitor bank	Reliability	$490,093
Replace 21 breakers at Riverside Station 138 kV	Short-Circuit	$16,288,000
Replace 8 breakers at Southwestern Station 138 kV	Short-Circuit	$4,421,345
Replace 1 breaker at Craig 161 kV	Short-Circuit	$254,000
Replace 2 breakers at Leeds 161 kV	Short-Circuit	$440,000
Replace 2 breakers at Midtown 161 kV	Short-Circuit	$440,000
Replace 4 breakers at Southtown 161 kV	Short-Circuit	$880,000
Replace 1 breaker at Moore 13.8 kV tertiary bus	Short-Circuit	$510,000
Replace 2 breakers at Hastings 115 kV	Short-Circuit	$550,000
Replace 5 breakers at Canaday 115 kV	Short-Circuit	$2,600,000
Replace 2 breakers at Westmoore 138 kV	Short-Circuit	$271,289
Replace 3 breakers at Santa Fe 138 kV	Short-Circuit	$406,935
Replace 1 breaker at Carlsbad Interchange 115 kV	Short-Circuit	$552,668
Replace 3 breakers at Denver City North and South 115 kV	Short-Circuit	$5,526,680
Replace 3 breakers at Hale County Interchange 115 kV	Short-Circuit	$1,658,004
Replace 1 breaker at Washita 69 kV	Short-Circuit	$52,400
Replace 12 breakers at Mooreland 138/69 kV	Short-Circuit	$835,850
Replace 3 breakers at Anadarko 138 kV	Short-Circuit	$228,500
Gracemont-Anadarko 138 kV rebuild	Economic	$2,850,000
Kingfisher-East Kingfisher Tap 138 kV rebuild	Economic	$1,000,000
Spearman-Hansford 115 kV rebuild	Economic	$828,359
Lawrence EC-Midland 115 kV terminal equipment	Economic	$30,939
New Wolf Creek-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	Economic	$162,649,008
New Sooner-Wekiwa 345 kV line and Sheffield Steel-Sand Springs 138 kV terminal equipment	Economic	$85,948,123
Cimarron-Northwest-Matthewson 345 kV terminal equipment	Economic	$369,869

Project	Classification	Project Cost (2019$)
Arnold-Ransom 115 kV and Pile-Scott City-Setab 115 kV terminal equipment	Economic	$3,652,000
Sundown-Amoco Tap 115 kV terminal equipment	Economic	$358,281
	Total:	**$336,656,532**

Table 6.15: Final Consolidated Portfolio

Table 6.16 shows the Future 1 and Future 2 40-year benefit-to-cost ratio and net benefit of the economic projects 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 40-year B/C	F1 Net Benefit	F2 40-year B/C	F2 Net Benefit
New Wolf Creek-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	$162,409,008	1.33	$88,534,192	2.41	$377,012,612
New Sooner-Wekiwa 345 kV line and Sand Springs-Sheffield Steel 138 kV terminal equipment	$85,948,123	1.12	$16,809,011	4.29	$465,585,456
Cimarron-Northwest-Matthewson 345 kV terminal equipment	$369,869	3.01	$1,226,633	252.87	$153,608,902
Sundown-Amoco Tap 115 kV terminal equipment	$358,281	34.40	$19,730,784	93.65	$54,735,082
Gracemont-Anadarko 138 kV rebuild	$2,850,000	9.42	$39,545,505	27.14	$122,846,721
Kingfisher Jct.-East Kingfisher Tap 138 kV rebuild	$1,000,000	11.98	$18,104,474	26.58	$42,178,550
Arnold-Ransom 115 kV terminal equipment and Pile-Scott City-Setab 115 kV terminal equipment	$3,652,000	0.85	($878,692)	6.72	$34,472,576
Spearman-Hansford 115 kV rebuild	$828,359	23.70	$30,999,476	70.31	$94,673,161
Lawrence-Midland 115 kV terminal equipment	$30,939	2271.70	$115,835,862	4457.64	$227,348,348

Table 6.16: Consolidated Portfolio

Figure 6.8 below shows the benefit-to-cost ratio of the economic portfolio of projects included in the consolidated portfolio. Figure 6.9 shows benefit-to-cost ratio of the entire consolidated portfolio. As expected, the overall benefit-to-cost ratio is reduced within inclusion of the reliability projects, but the consolidated portfolio is still expected to produce benefits well over the cost of the projects.

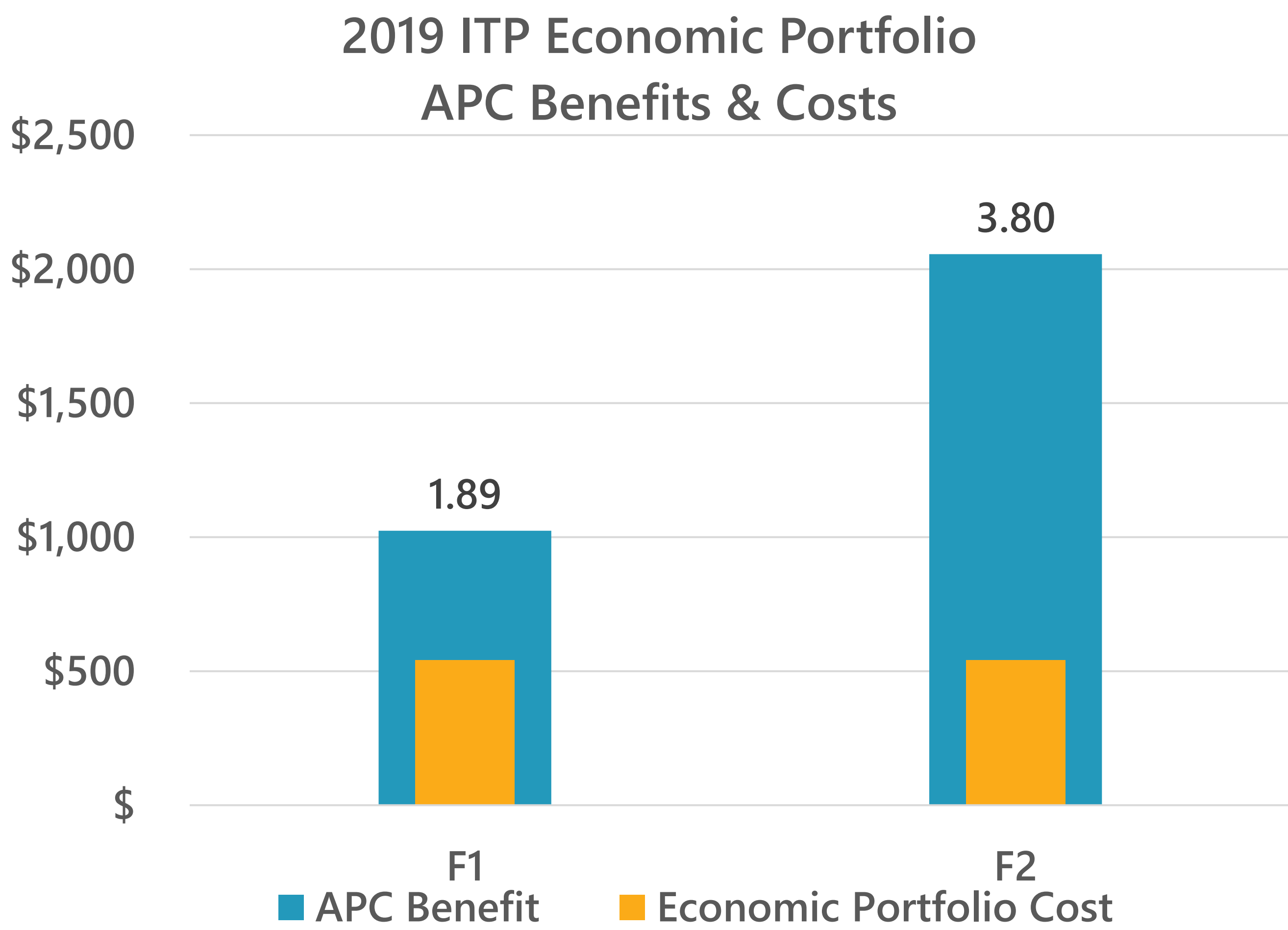


Figure 6.8: Economic Portfolio APC Benefits and Costs

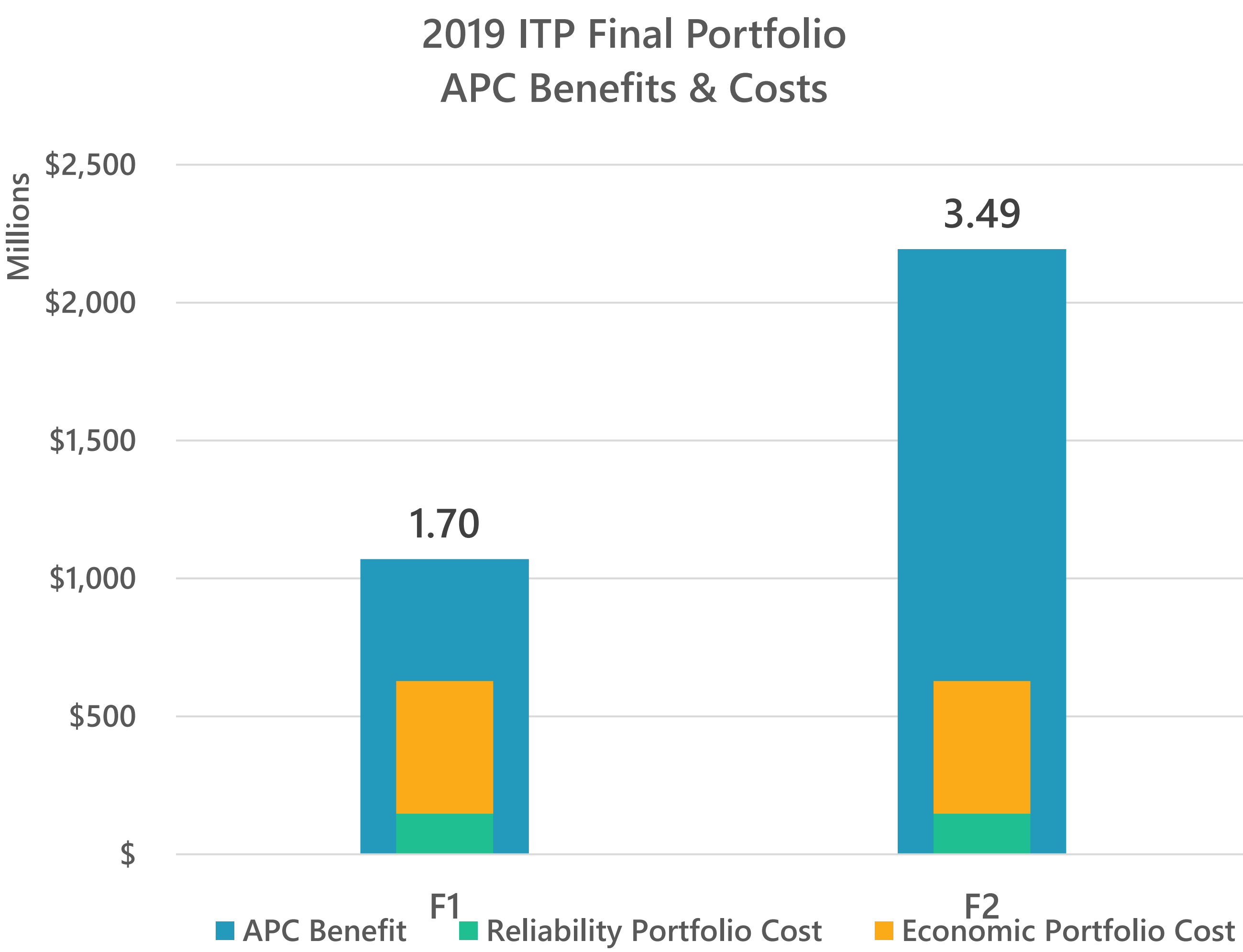


Figure 6.9: Final Consolidated Portfolio APC Benefits and Costs

6.6 STAGING

Staging is the process by which the need date for a project is determined. Unless the need exists in a year two model, an interpolation between model years is performed using different criteria depending on the category of the project. The interpolation methodology can be found in the ITP Manual.

6.6.1 ECONOMIC PROJECTS

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

Project Description	Need Date	Expected Lead Time
Lawrence-Midland 115 kV terminal equipment	1/1/2021	18 months
Sundown-Amoco 115 kV terminal equipment	1/1/2023	18 months

Project Description	Need Date	Expected Lead Time
Spearman-Hansford 115 kV terminal equipment	1/1/2021	18 months
Kingfisher Junction-East Kingfisher Tap 138 kV rebuild	1/1/2021	24 months
Matthewson-Northwest-Cimarron 345 kV terminal equipment	1/1/2021	18 months
New Sooner-Wekiwa 345 kV line and Sheffield-Sand Springs 138 kV terminal equipment	1/1/2026	48 months
Arnold-Ransom and Pile-Scott City-Setab 115 kV terminal equipment	1/1/2025	18 months
Gracemont-Anadarko 138 kV rebuild	1/1/2021	24 months
New Wolf Creek-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	1/1/2026	48 months

Table 6.17: Project Staging Results - Economic

6.6.2 POLICY PROJECTS

There were no policy-driven projects in the 2019 ITP.

6.6.3 RELIABILITY PROJECTS

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

Project Description	Need Date	Expected Lead Time
Cleo Corner-Cleo Switch 69 kV terminal equipment	6/1/2022	18 months
Deaf Smith-Plant X 230 kV terminal equipment	4/1/2029	18 months
Deaf Smith-Bushland 230 kV terminal equipment	4/1/2026	18 months
Potter-Newhart 230 kV terminal equipment	4/1/2028	18 months
Getty-Skelly 69 kV terminal equipment	4/1/2021	18 months
Marshall-Smittyville-Bailey-Seneca 115 kV rebuild	4/1/2021	30 months
Pryor Junction 138/115 kV transformer	6/1/2021	24 months
Tulsa SE-21st Street Tap 138 kV rebuild	6/1/2021	24 months
Tulsa SE-S. Hudson 138 kV rebuild	6/1/2021	24 months
Moore-RBSS 115 kV terminal equipment	6/1/2026	18 months
Carlisle-LP Doud 115 kV terminal equipment	6/1/2026	18 months
Lubbock-Jones 230 kV circuit 1 terminal equipment	6/1/2029	18 months

Project Description	Need Date	Expected Lead Time
Lubbock-Jones 230 kV circuit 2 terminal equipment	6/1/2029	18 months
Plains-Yoakum 115 kV terminal equipment	6/1/2029	18 months
Firth 115 kV capacitor bank	4/1/2021	24 months
Rocky Point-Marietta 69 kV terminal equipment	12/1/2021	18 months
Gypsum 69 kV capacitor bank	6/1/2021	24 months

Table 6.18: Project Staging Results - Reliability

6.6.4 SHORT-CIRCUIT PROJECTS

The short-circuit projects were all staged with a need date of 6/1/2021.

7 PROJECT RECOMMENDATIONS

7.1 TARGET AREA PROJECTS

The ITP Manual Section 4.1.2 describes potential additional analysis of target areas to address specific issues with considerations beyond the scope of a typical ITP assessment. In the 2019 ITP, two areas were identified as potential target areas: southern Kansas/southwest Missouri, and northern Oklahoma.

7.1.1 TARGET AREA 1: SOUTHEAST KANSAS/SOUTHWEST MISSOURI

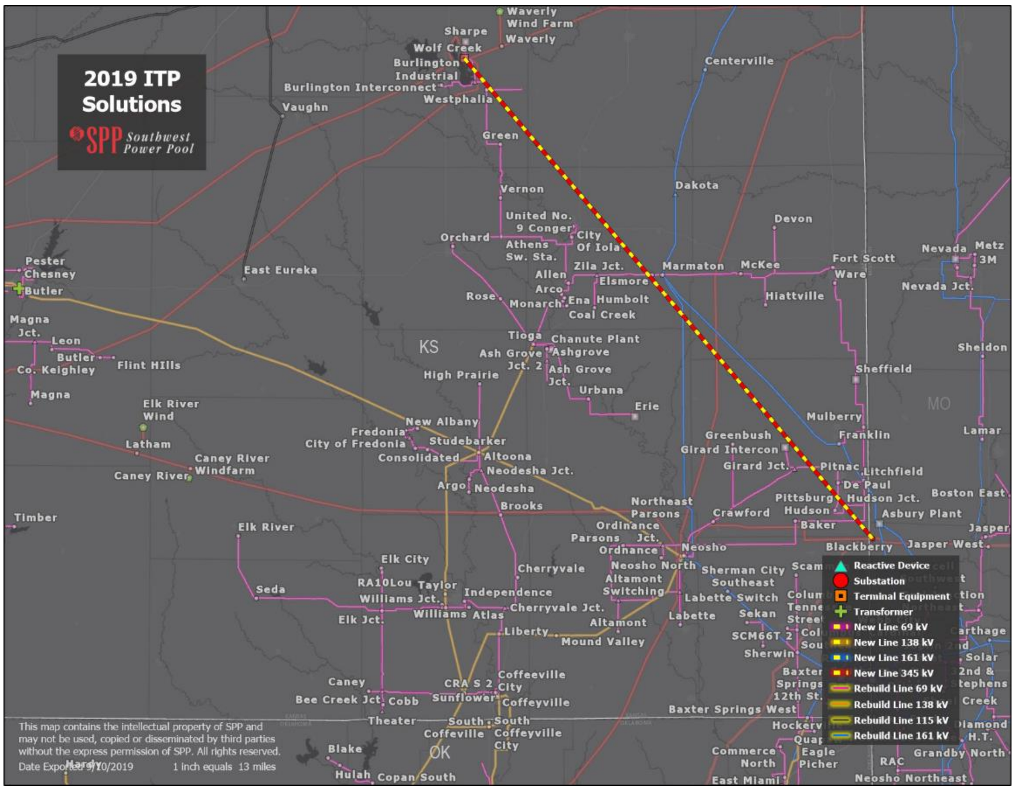


Figure 7.1: New Wolf Creek-Blackberry 345 kV Line and New Butler 138 kV Phase-Shifting Transformer

The new Wolf Creek-Blackberry 345 kV line, paired with the New Butler 138 kV phase-shifting transformer, resolves multiple 2019 ITP needs and additional issues identified for Target Area 1. The major study driver for the new Wolf Creek-Blackberry 345 kV line is its ability to relieve congestion and divert bulk power transfers away from the Wolf Creek-Waverly-La Cygne 345 kV line, Wolf Creek 345/69 kV transformer and downstream 69 kV lines, and allowing system bulk power transfers to continue to flow east to major SPP load centers. This will help to levelize system LMPs, low generator LMPs in the west and high load LMPs in the east, and overall system congestion while providing market efficiencies and benefits to ratepayers and transmission customers.

The new 345 kV line parallels three major contingencies in the area: Caney River-Neosho 345 kV line, Wolf Creek-Waverly-La Cygne 345 kV line, and Neosho-Blackberry 345 kV. Paralleling the Neosho-Blackberry

345 kV line relieves congestion on the Neosho-Riverton 161 kV for the Neosho-Blackberry 345 kV line outage and reduces congestion on Neosho-Riverton 161 kV line for the loss of Blackberry-Jasper 345 kV line outage.

In addition to the projected APC savings, the new Wolf Creek-Blackberry 345 kV line provides multiple reliability benefits. Primarily, it resolves declining transient stability margins at the Wolf Creek nuclear plant by adding a fourth 345 kV outlet that is expected to increase system resiliency and reduce system operation risks. Dynamic simulations show the performance of the Wolf Creek unit with the addition of the Wolf Creek-Blackberry 345 kV transmission line met the "SPP Disturbance Performance Requirements." This solution will address the transient stability limit discussed previously in Section 4.1.1.1.

The Wolf Creek-Blackberry 345 kV line adds transmission capacity that is expected to relieve system loading and increase available transfer capability (ATC) to local long-term transmission service customers. This should also improve positions of candidate ARR holders that would lead to improved TCR funding and reduce the need for counterflow optimization. This line would specifically help to mitigate the Neosho-Riverton 161 kV ARR constraints.

Although the new Wolf Creek-Blackberry 345 kV line is cost beneficial as a standalone project in the 2019 ITP, the new Butler phase-shifting transformer was paired with the 345 kV line to cost effectively mitigate remaining congestion on the Butler-Altoona 138 kV constraint. The congestion relieved by the new Wolf Creek-Blackberry 345 kV line and the new Butler 138 kV phase-shifting transformer is shown in Table 7.1.

The Wolf Creek transformer was identified as a need in the 2018 ITP near-term assessment, but was ultimately not addressed with new construction based upon the TWG's direction to determine a more holistic solution in the 2019 ITP. In addition the Butler-Altoona 138 kV line was loaded just below the SPP Planning Criteria reliability threshold. Continued analysis of reliability needs in the 2019 ITP revealed the Butler-Altoona 138 kV line and Wolf Creek 345/69 kV transformer reliability needs are minimally addressed by model corrections. However, thermal loading on both facilities remained just below the 100% threshold. The Wolf Creek-Blackberry 345 kV line achieves the TWG's goal of addressing thermal loading concerns associated with these facilities.

Alternative solutions were considered and selected in the final Future 1 portfolio – to replace Wolf Creek 345/69 kV transformer and rebuild a portion of the Waverly-La Cygne 345 kV line along with the Butler 138 kV phase-shifting transformer – but they did not perform well together and did not score as well during consolidation of the two futures. Considering that the market economic model represents a DC solution and the issues in the area are due to large power transfers, it is likely that benefits of smaller-scale solutions would not be fully realized due to angular stability limitations and known voltage stability limitations. These smaller-scale solutions could impose operational risks by allowing the system to operate at unstable operating points.[19]

[19] Generally, thermal limitations precede angular and voltage stability limitations of the BES and prevent the system from reaching unstable operating points. When thermal limitations are addressed by smaller-scale solutions that only address the thermal limitation, the thermal limitations may no longer precede angular and voltage stability limitations, and the system may be inadvertently operated at unstable operation points that are less recognizable.

The new Wolf Creek-Blackberry 345 KV line is the preferred alternative to the 2013 ITP 20-year assessment Wolf Creek-Neosho 345 kV line. The Wolf Creek-Blackberry line is considered to be a more diverse project than Wolf Creek-Neosho 345 kV. It performed better from an APC savings perspective, and it provides additional flexibility for future expansion options, including further expansion into eastern load centers and the opportunity for future seams projects with neighboring regions. At approximately 100 miles, it is short enough to not have surge-impedance-loading concerns.

Constraint	Base Congestion Score (k$/MWh)					Consolidated Portfolio Congestion Score (k$/MWh)				
	Future 1			Future 2		Future 1			Future 2	
	2021	2024	2029	2024	2029	2021	2024	2029	2024	2029
Butler-Altoona 138 kV for the loss of Caney River/RP2POI10-Neosho 345 kV	259	435	1,034	704	1,188	1	1	1	4	7
Wolf Creek 345/69 kV transformer for the loss of Waverly-LaCygne 345 kV	19	51	49	85	102	0	0	0	0	0
Neosho-RP2POI10 345 kV for the loss of Waverly-LaCygne 345 kV	0	0	0	47	72	0	0	0	0	0
Neosho-Riverton 161 kV for the loss of Blackberry/RP2POI02-Neosho 345 kV	49	40	30	43	44	0	0	0	0	0
Neosho-Riverton 161 kV for the loss of Blackberry-Jasper 345 kV	0	0	0	0	0	73	94	157	121	218
Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV	15	20	17	12	7	0	0	0	0	0

Table 7.1: Target Area 1 Congestion Relief

7.1.2 TARGET AREA 2: CENTRAL/SOUTHEAST OKLAHOMA

7.1.2.1 New Sooner-Wekiwa 345 kV Line and Sand Springs-Sheffield Steel 138 kV terminal equipment

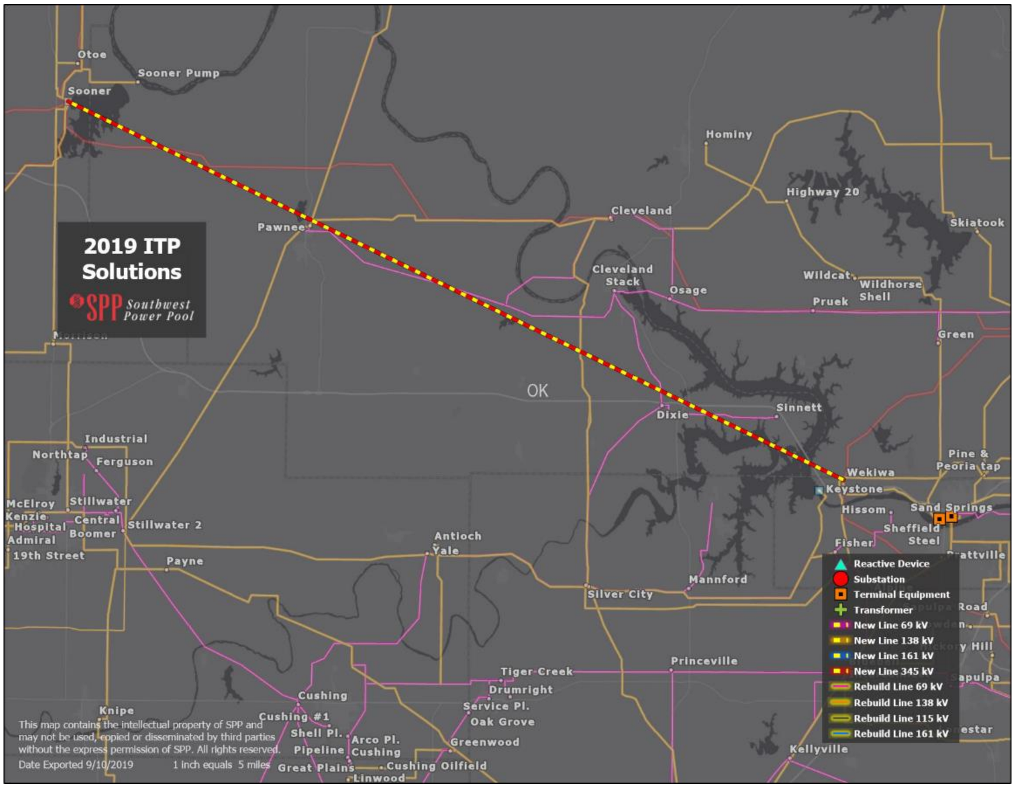


Figure 7.2: New Sooner-Wekiwa 345 kV Line and Sand Springs-Sheffield Steel 138 kV terminal equipment

The new Sooner-Wekiwa 345 kV line, paired with the Sheffield Steel-Sand Springs 138 kV terminal equipment, provides an alternate path for bulk power transfers to continue to flow east to major SPP load centers. This new 345 kV line keeps flows from being diverted to the 138 kV system at Cleveland, where they would continue to flow east toward Tulsa, Oklahoma. The inclusion of the terminal equipment on the 138 kV system in Tulsa is required to achieve the benefit of the EHV line, and it provides additional opportunity for transfers to serve load once the flow is stepped down on the system at the Wekiwa station. The new line parallels two major contingencies in the area: Cleveland-Tulsa North 345 kV line and the Sooner-Cleveland 345 kV line. It provides a new 345 kV source into the west side of Tulsa.

Alternative solutions were considered and ultimately selected in the final Future 1 portfolio – to replace terminal equipment and rebuild multiple sections of 138 kV in the area – but these did not score as well during consolidation of the two futures. Moving forward with these lower kV solutions likely would have driven the need to rebuild/rehabilitate additional 138 kV facilities, increasing overall costs to address congestion. Considering that the market economic model represents a DC solution, and issues in the area are due to large power transfers, it is likely the benefits of smaller-scale solutions would not be fully realized due to voltage stability limitations.

7.1.2.2 *Cimarron-Northwest-Matthewson 345 kV terminal equipment*

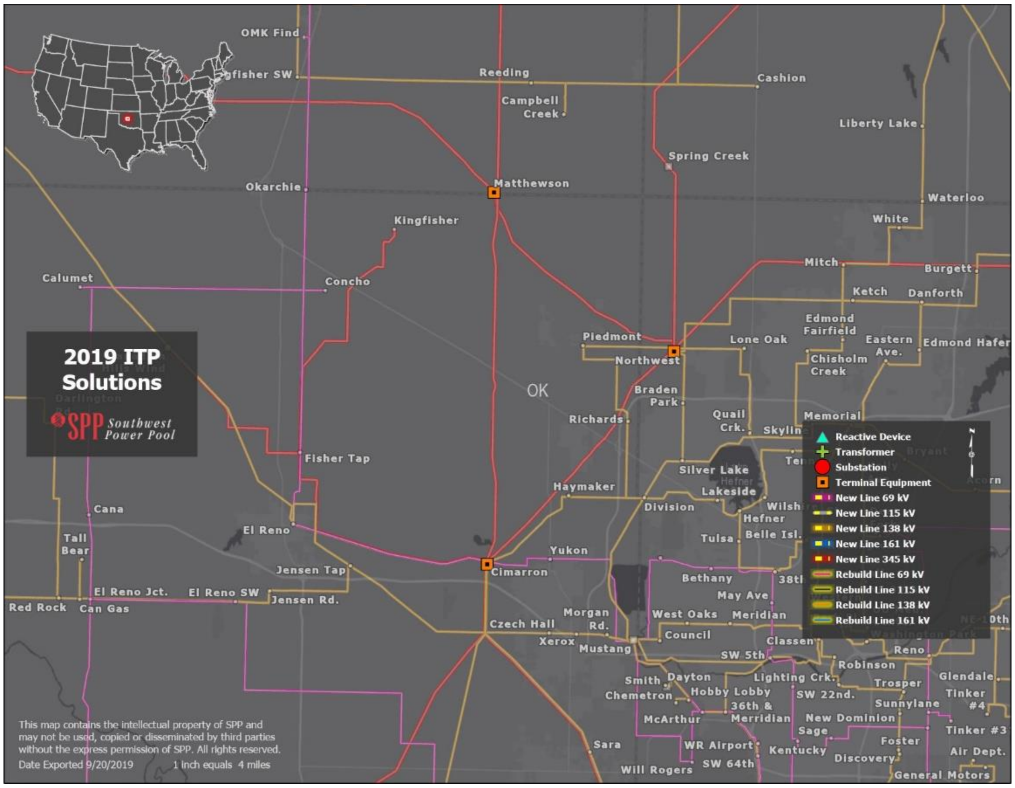


Figure 7.3: Cimarron-Northwest-Mathewson 345 kV terminal equipment

Similar to the Sooner-Wekiwa 345 kV line project, also located in Target Area 2, the Northwest-Mathewson-Cimarron 345 kV line is a thermally-limited path into the Oklahoma City area. Although congestion identified in the needs assessment milestone was only enough to warrant an identified need in Future 2-Year 10, addressing the target area one and Target Area 2 congestion west of Tulsa will create additional flows that move congestion to this area of Oklahoma. The terminal equipment identified for these facilities will continue to allow bulk transfers from the western part of the footprint to eastern load centers.

Constraint	Base Congestion Score (k$/MWh)					Consolidated Portfolio Congestion Score (k$/MWh)				
	Future 1			Future 2		Future 1			Future 2	
	2021	2024	2029	2024	2029	2021	2024	2029	2024	2029
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	190	532	383	702	533	0	0	1	5	33
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	15	20	17	17	24	0	5	26	54	80
Northwest-Matthewson 345 kV for the loss of Cimarron-Northwest 345 kV	0	7	36	9	90	0	0	0	0	0

Table 7.2: Target Area 2 Congestion Relief

7.2 RELIABILITY PROJECTS

7.2.1 PRYOR JUNCTION 138/115 KV TRANSFORMER

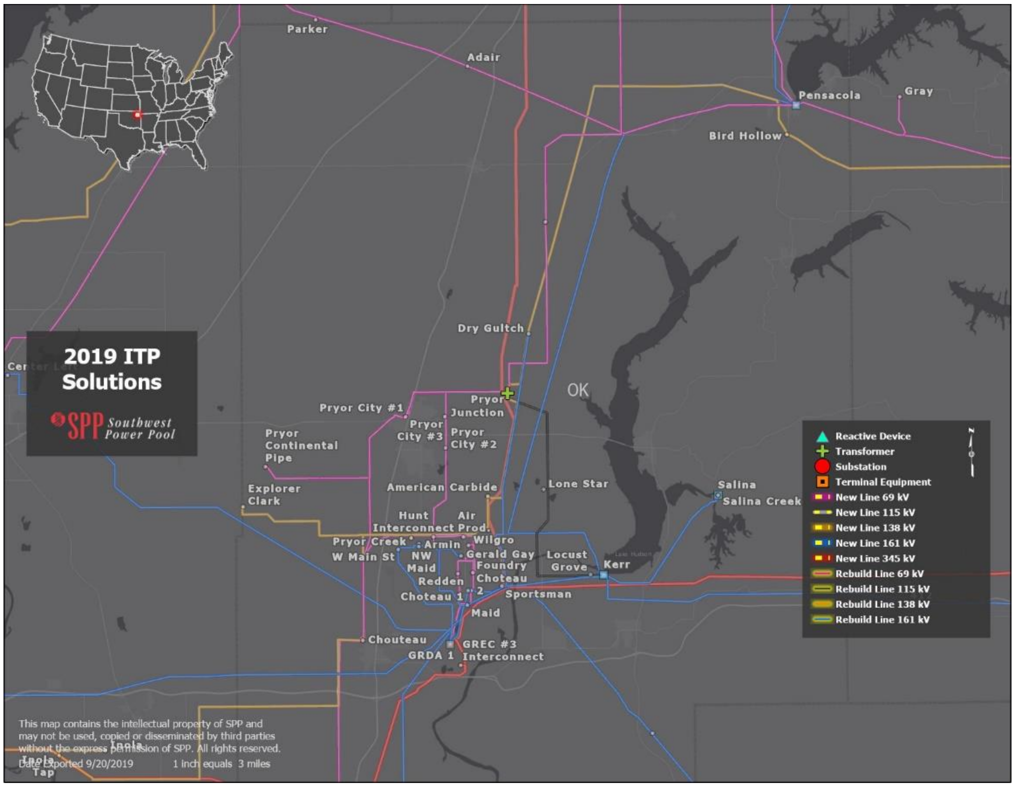


Figure 7.4: Pryor Junction 138/115 kV Transformer

East of Tulsa, near the town of Pryor, Oklahoma, the Pryor Junction 115/69 kV transformer overloads for the loss of the Inola Tap-Catoosa 138 kV line. Loss of this feed to west of Pryor increases flows from the 115 kV source in the east. These flows currently step down to the 69 kV bus at Pryor Junction and back up to the 138 kV bus at Pryor Junction to serve load on the 138 kV system that is no longer served from the western source. The project selected to mitigate this issue is to replace the 115/69 kV transformer with a 138/115 kV transformer to tie the 115 kV and 138 kV systems together and bypass the step-down to the 69 kV system.

7.2.2 TULSA SOUTHEAST-21ST ST. TAP 138 KV REBUILD

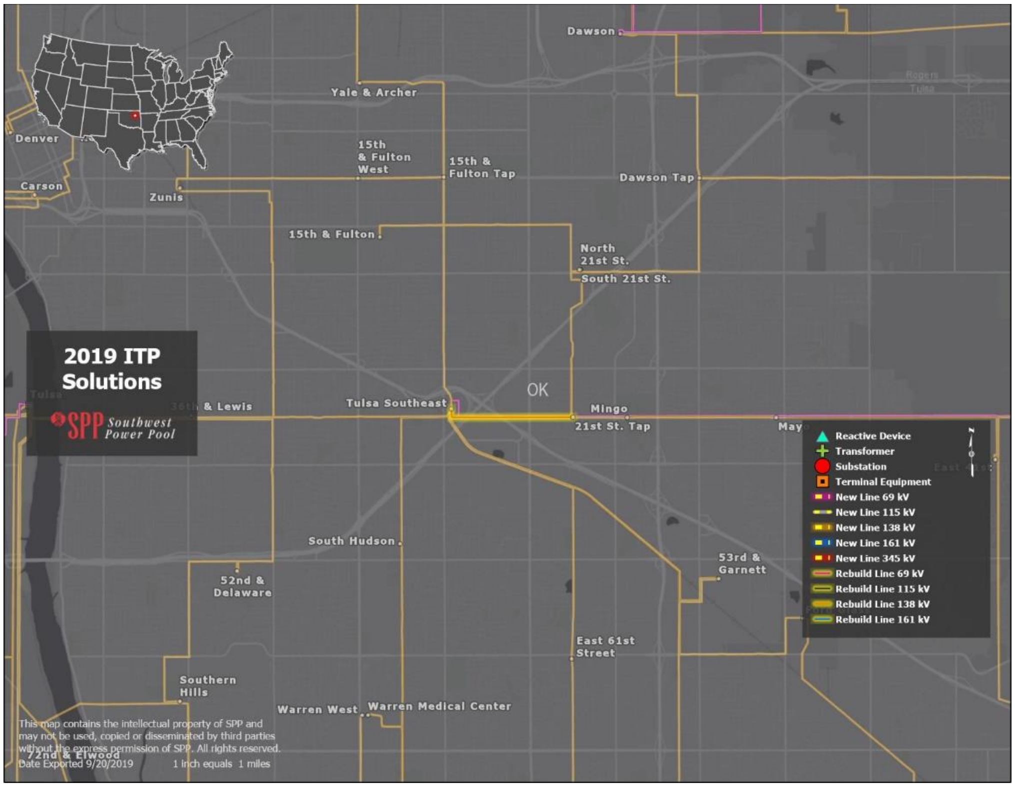


Figure 7.5: Tulsa Southeast-21st St. Tap 138 kV Rebuild

Southeast of downtown Tulsa, Oklahoma, the Tulsa Southeast-21st Street Tap 138 kV line overloads for the loss of the Broken Arrow North-Oneta 138 kV line. When the source from the Oneta generating plant on the east side of Tulsa is lost, west to east flows increase due to the loss of counterflows. The project selected to mitigate this issue is to rebuild the Tulsa Southeast-21st Street Tap 138 kV line to improve the rating closer to SPP minimum design guidelines.

7.2.3 TULSA SE-S. HUDSON 138 KV REBUILD

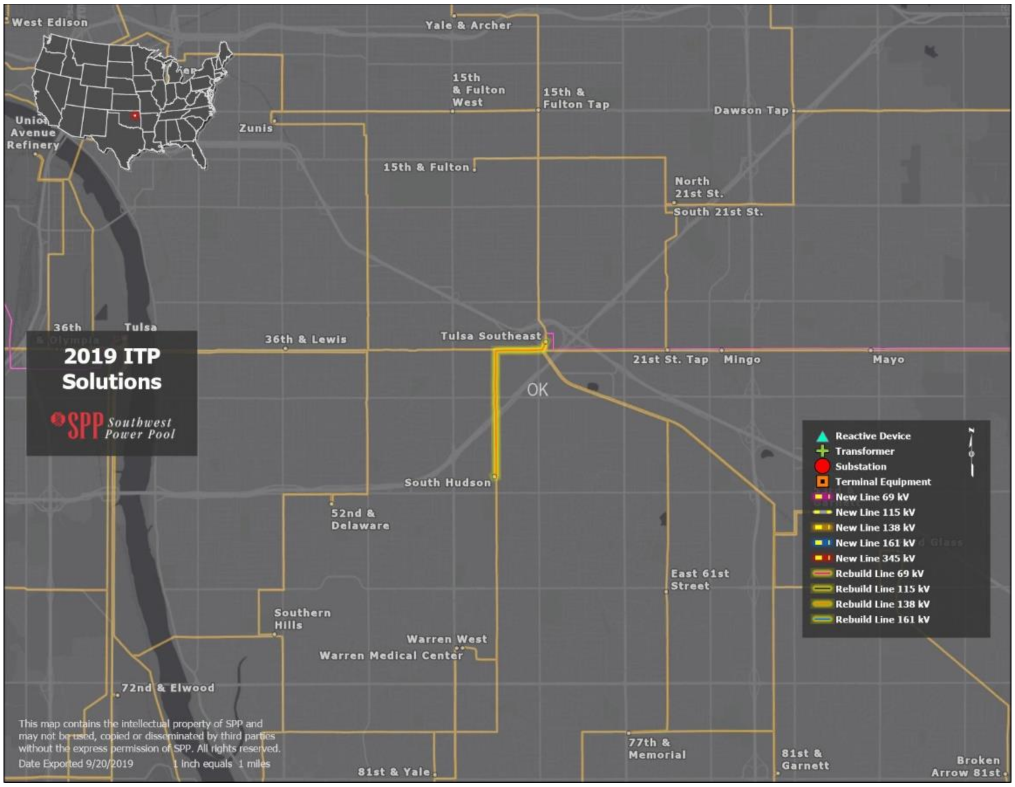


Figure 7.6: Tulsa Southeast-South Hudson 138 kV Rebuild

Southeast of downtown Tulsa, Oklahoma, the Tulsa Southeast-South Hudson 138 kV line overloads for the loss of the Riverside Station-Oral Roberts University (ORU) Tap 138 kV line. When one of the sources from the Riverside Station generating plant to the south is lost, north-to-south flows increase to serve load south of the Tulsa Southeast substation. The project selected to mitigate this issue is to rebuild the Tulsa Southeast-South Hudson 138 kV line to improve the rating closer to SPP minimum design guidelines.

7.2.4 CLEO CORNER-CLEO JUNCTION 69 KV TERMINAL EQUIPMENT

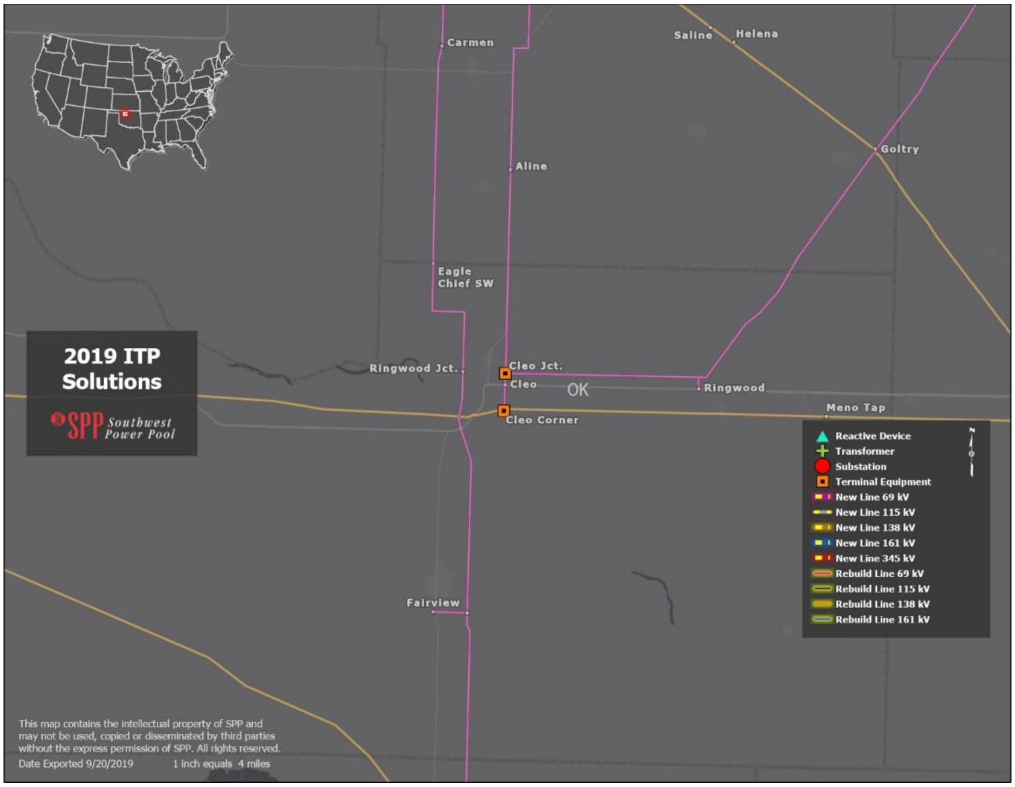


Figure 7.7: Cleo Corner-Cleo Junction 69 kV terminal equipment

In north-central Oklahoma, east of Enid, the Cleo Corner-Cleo Junction 69 kV line overloads for the loss of the 138 kV line connecting the OGE and Western Farmers' Renfrow substations. Losing this northern 138 kV source to the 69 kV system in the area forces more flow from the 138 kV system to step down at Cleo Corner, overloading the 69 kV line. The project selected to mitigate this issue is to replace any necessary terminal equipment at Cleo Corner and Cleo Junction to increase the line rating.

7.2.5 ROCKY POINT-MARIETTA 69 KV TERMINAL EQUIPMENT

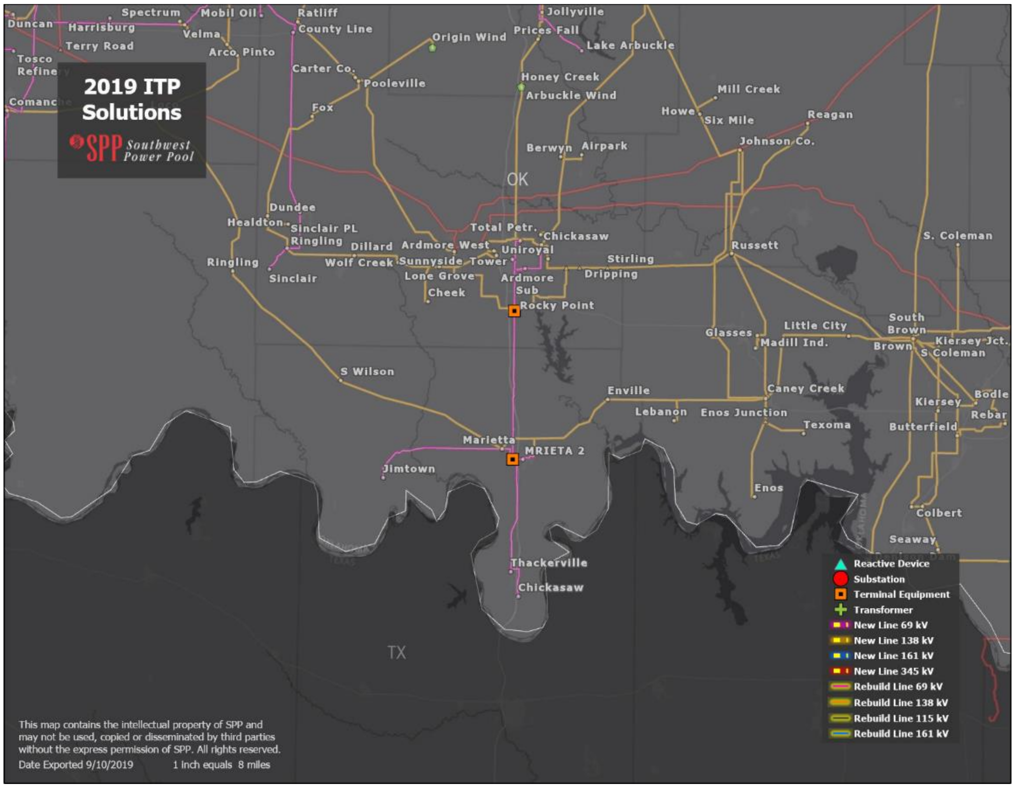


Figure 7.8: Rocky Point-Marietta 69 kV terminal equipment

In south-central Oklahoma near Marietta, the 138 kV system experiences low voltage for loss of the Caney Creek-Texoma Junction 138 kV line. This contingency creates a long radial system that serves nearly 100 MW of load at peak intervals. A capacitor bank at the Lebanon 138 kV station was analyzed and found to provide minimal voltage support. It was determined that a new source was needed to sufficiently raise voltage in the area. SPP analyzed multiple different 138 kV sources and, working with incumbent TOs, found the most cost-effective solution for the region was to close in an existing 69 kV line between OGE's Rocky Point substation and a switch near Marietta. The project selected to mitigate this issue is to install relay protection equipment to operate the existing line as a networked facility.

7.2.6 FIRTH 115 KV CAPACITOR BANK AND SUBSTATION EXPANSION

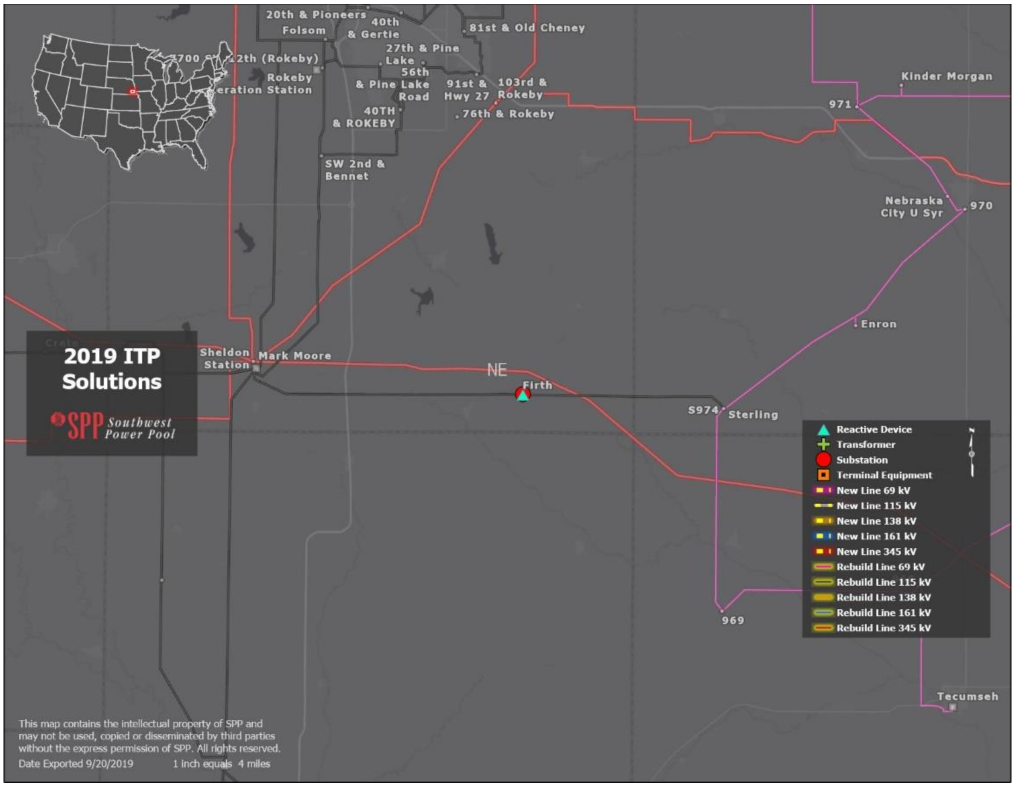


Figure 7.9: Firth 115 kV Capacitor Bank and Substation Expansion

SPP has persistently identified low-voltage issues on the 115 kV and 69 kV transmission system around the Firth and Sterling substations just south of Lincoln, Nebraska, during the summer, winter, as well as light load base reliability models. There was in increase in load at Firth, which decreases voltage below the acceptable range and makes the voltage unable to be mitigated through adjustments of transformer tap ratios. The same low-voltage issues were present in the 2018 ITPNT, but were able to be mitigated through reactive settings. The 15 MVAR capacitor bank, which will require substation expansion, proposed to address the low voltage was coordinated with Nebraska Public Power District and agreements on feasibility have been reached.

7.2.7 BUSHLAND-DEAF SMITH 230 KV TERMINAL EQUIPMENT

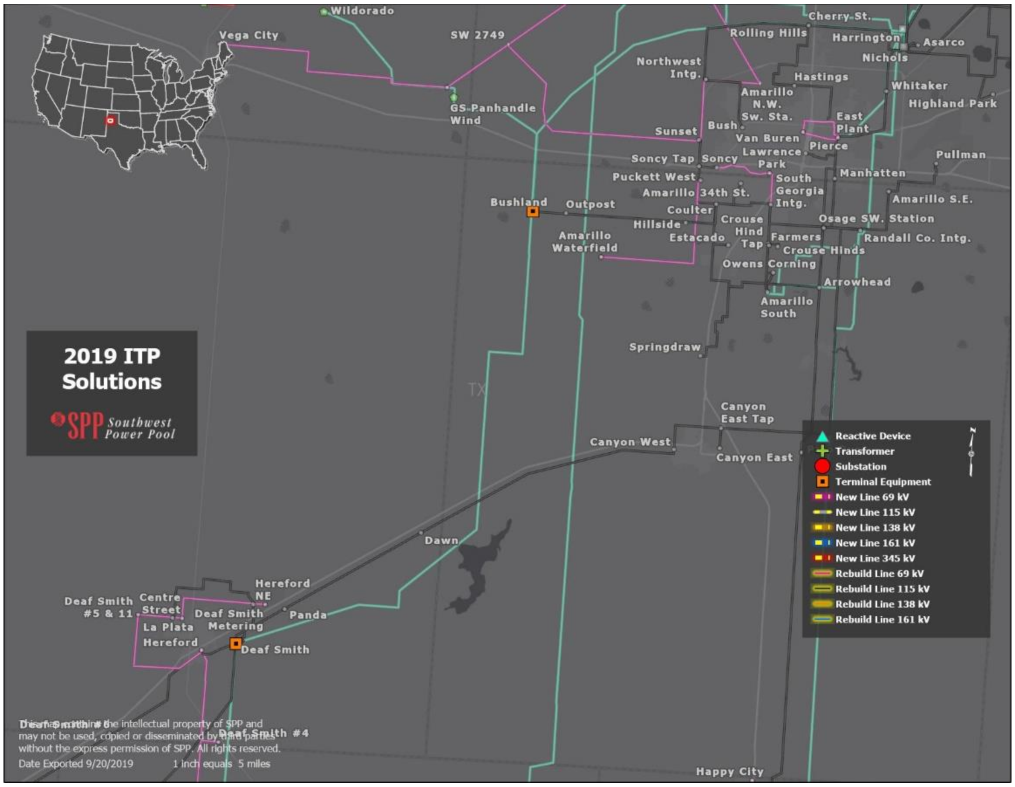


Figure 7.10: Bushland-Deaf Smith 230 kV terminal equipment

In the Texas Panhandle, east of Amarillo, the Bushland-Deaf Smith 230 kV line overloads for loss of the parallel Potter-Newhart 230 kV line. This line is part of a larger 230 kV corridor that aids in transferring power to the southern SPS load pockets. This corridor is heavily used in lighter load conditions when generation to the south is displaced by higher wind output levels. This transfer increases in the year-10 horizon, when additional generation to the south is decommitted due to projected retirements, causing the 230 kV line to overload. The project selected to mitigate this issue is to replace any necessary terminal equipment at Bushland and Deaf Smith to increase the line rating.

7.2.8 CARLISLE-LP DOUD TAP 115 KV TERMINAL EQUIPMENT

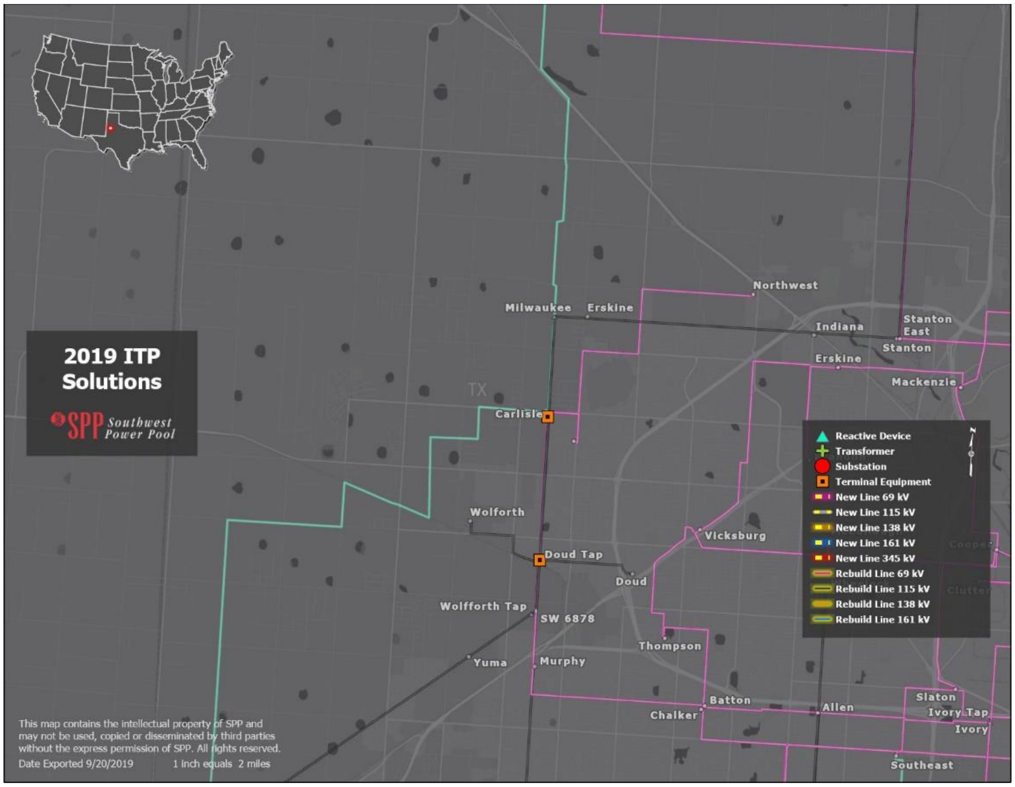


Figure 7.11: Carlisle-LP Doud Tap 115 kV terminal equipment

In the Texas Panhandle, east of Lubbock, the Carlisle-LP Doud Tap 115 kV line overloads for loss of the Wolfforth 230/115 kV transformer. The 230 kV system surrounding Lubbock is an off-ramp to serve load on the lower voltage system and part of the north-to-south highway for load pockets in the south SPS zone, which is continued by the 115 kV system to the southwest from the Wolfforth substation. When the Wolfforth transformer is lost, the counterflow provided on the 115 kV system to the north from Wolfforth into the city is lost. The flows in the area are aggravated by projected generator retirements southeast of Lubbock in the year-10 horizon, causing the line to overload. Due to the projected move of a portion of Lubbock load to the ERCOT system, a sensitivity was performed to remove the load and redispatch generation accordingly. The sensitivity showed that the thermal loading increased. This is consistent with the issues identified in SPP's Attachment AQ study. The project selected to mitigate this issue is to replace any necessary terminal equipment at Carlisle and LP Doud to increase the line rating.

7.2.9 DEAF SMITH-PLANT X 230 KV TERMINAL EQUIPMENT

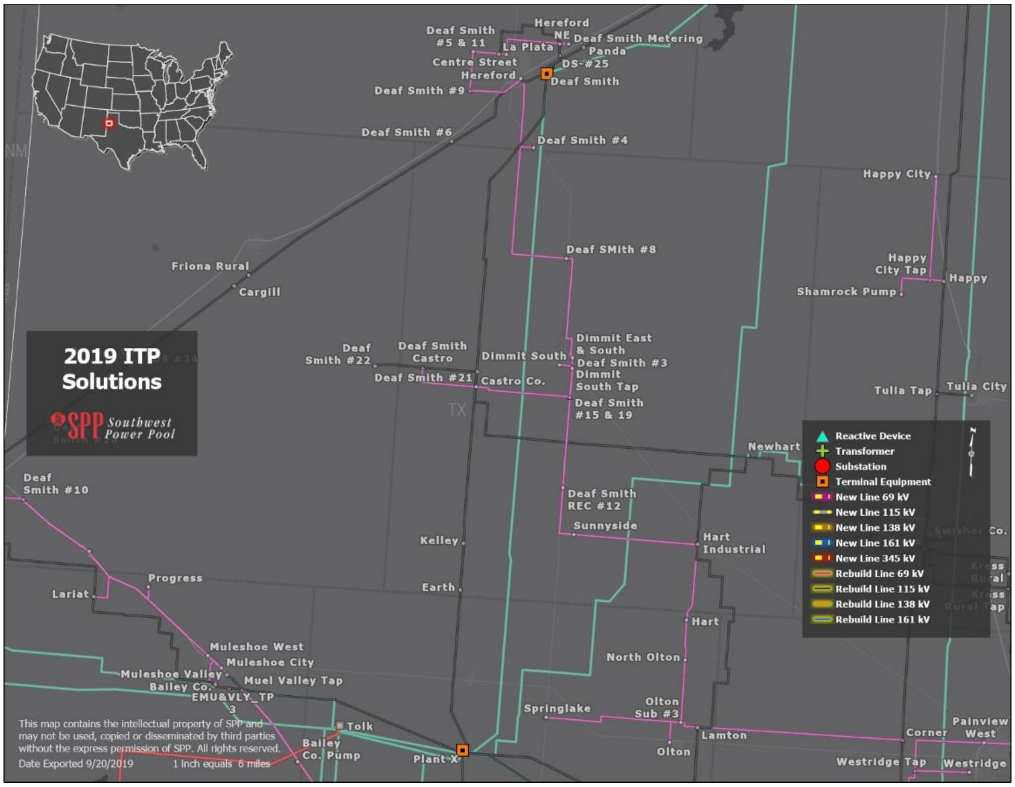


Figure 7.12: Deaf Smith-Plant X 230 kV terminal equipment

In the Texas Panhandle, east of Amarillo, the Deaf Smith-Plant X 230 kV line overloads for loss of the parallel Potter-Newhart 230 kV line. This line is part of a larger 230 kV corridor that aids in transferring power to the southern SPS load pockets. This corridor is heavily used in lighter load conditions when generation to the south is displaced by higher wind output levels. This transfer increases in the 10-year horizon when additional generation to the south is de-committed due to projected retirements, causing the 230 kV line to overload. The project selected to mitigate this issue is to replace any necessary terminal equipment at Deaf Smith and Plant X to increase the line rating.

7.2.10 LUBBOCK SOUTH-JONES 230 KV TERMINAL EQUIPMENT CIRCUITS 1 AND 2

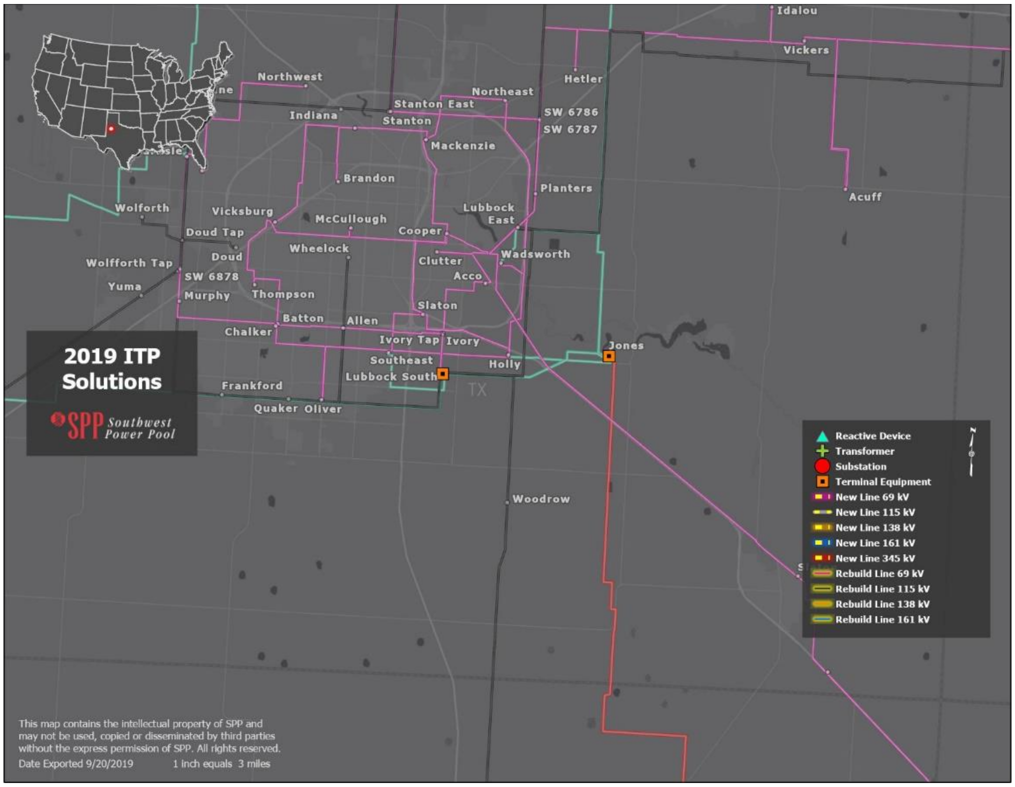


Figure 7.13: Lubbock South-Jones 230 kV terminal equipment Circuits 1 and 2

In the Texas Panhandle, southwest of Lubbock, both of the Lubbock South-Jones 230 kV lines overload for the loss of each other. The 230 kV system surrounding the city of Lubbock is an off-ramp to serve load on the lower voltage system and part of the north-to-south highway for load pockets in the south SPS zone. Flows in the area are aggravated by projected generator retirements southeast of Lubbock in the 10-year horizon, causing the line to overload. Due to the projected move of a portion of Lubbock load to the ERCOT system, a sensitivity was performed to remove the load and redispatch generation accordingly. The sensitivity showed that the thermal loading increased on these facilities. The projects selected to mitigate these issues are to replace any necessary terminal equipment at Lubbock South and Jones to increase the line rating.

7.2.11 MOORE-RB-S&S 115 KV TERMINAL EQUIPMENT

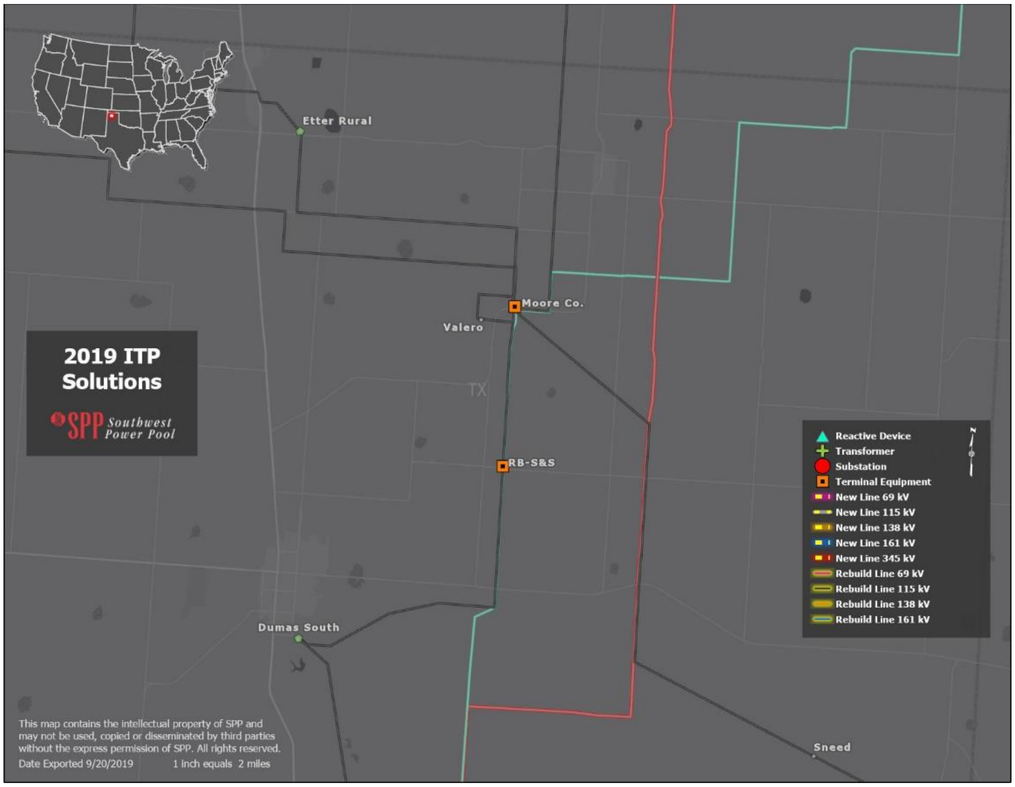


Figure 7.14: Moore-RB-S&S 115 kV terminal equipment

In the Texas Panhandle north of Amarillo, the Moore-RB-S&S (Rita Blanca's Stokes and Sheldon) 115 kV line overloads for loss of the McDowell-Exell Tap 115 kV line. The outage creates a radial 115 kV circuit out of the Moore substation that serves about 80 MW of load during peak conditions in the 10-year horizon. The Moore-RB-S&S segment is the lowest-rated section of the radial under contingent conditions. A large portion of the load is served at the RB-S&S substation, reducing flows on the rest of the line segments. The project selected to mitigate this issue is to replace any necessary terminal equipment at Moore and RB-S&S to increase the line rating.

7.2.12 PLAINS INTERCHANGE-YOAKUM 115 KV TERMINAL EQUIPMENT

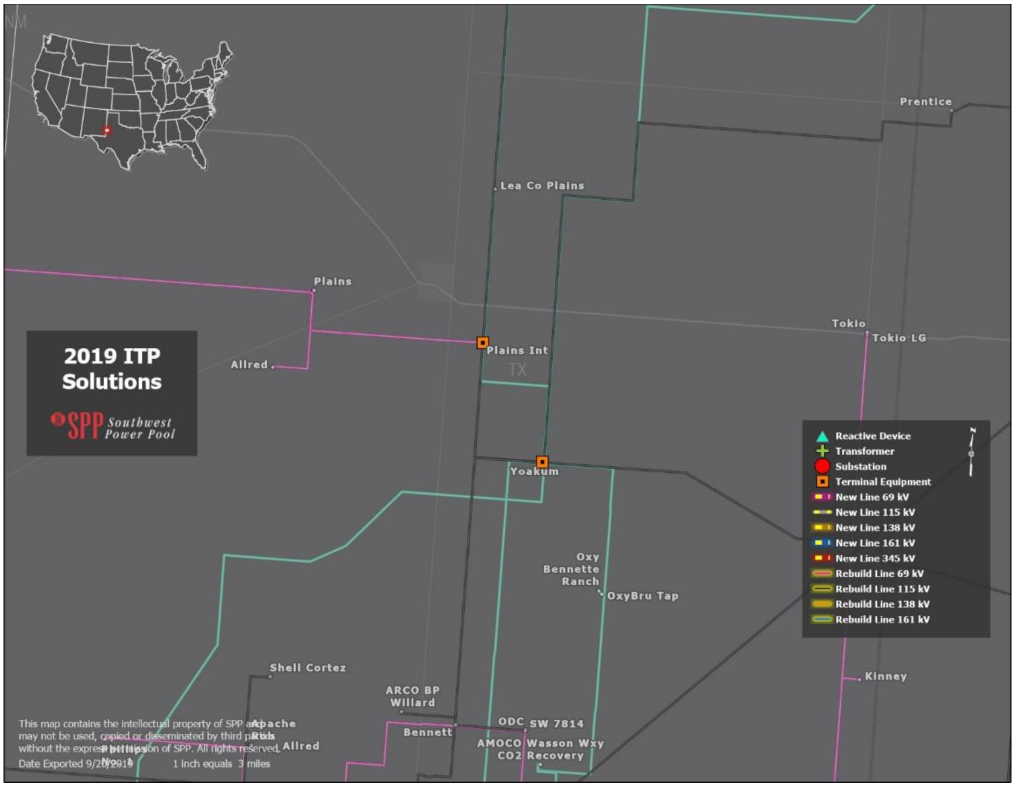


Figure 7.15: Plains Interchange-Yoakum 115 kV terminal equipment

In the Texas Panhandle, nearly equidistant between Levelland and Hobbs, the Plains Interchange-Yoakum 115 kV line overloads for loss of the Pacific-Sundown 115 kV line. When Pacific-Sundown is outaged, the source to the west side of the 115 kV system in the area is lost, forcing flows to increase to the east and loop back around to serve load on the west side. A previously-approved SPP project, Dean Interchange, tied the 230 and 115 kV systems together just north of Plains Interchange. This project would have provided an additional source to the area, but it was withdrawn in the 2018 ITPNT as not needed. This assessment confirms the decision to withdraw the project, as the issue was identified only in year 10 and can be resolved with a more cost-effective solution. The project selected to mitigate this issue is to replace any necessary terminal equipment at Plains Interchange and Yoakum to increase the line rating.

7.2.13 POTTER COUNTY-NEWHART 230 KV TERMINAL EQUIPMENT

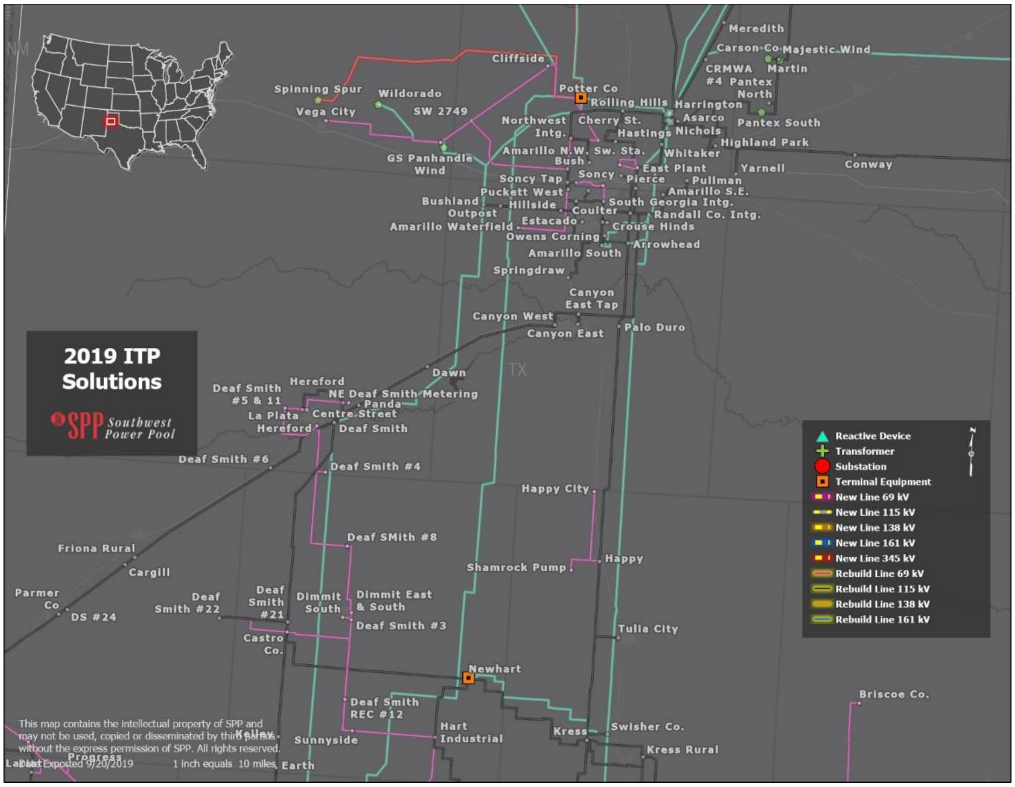


Figure 7.16: Potter County-Newhart 230 kV terminal equipment

In the Texas Panhandle east of Amarillo, the Potter County-Newhart 230 kV line overloads for loss of the parallel Bushland-Deaf Smith 230 kV line. This line is part of a larger 230 kV corridor that aids in transferring power to the southern SPS load pockets. This corridor is heavily used in lighter load conditions when generation to the south is displaced by higher wind output levels. This transfer increases in the 10-year horizon when additional generation to the south is decommitted due to projected retirements, causing the 230 kV line to overload. The project selected to mitigate this issue is to replace any necessary terminal equipment at Potter County and Newhart to increase the line rating.

7.2.14 GYPSUM 69 KV CAPACITOR BANK

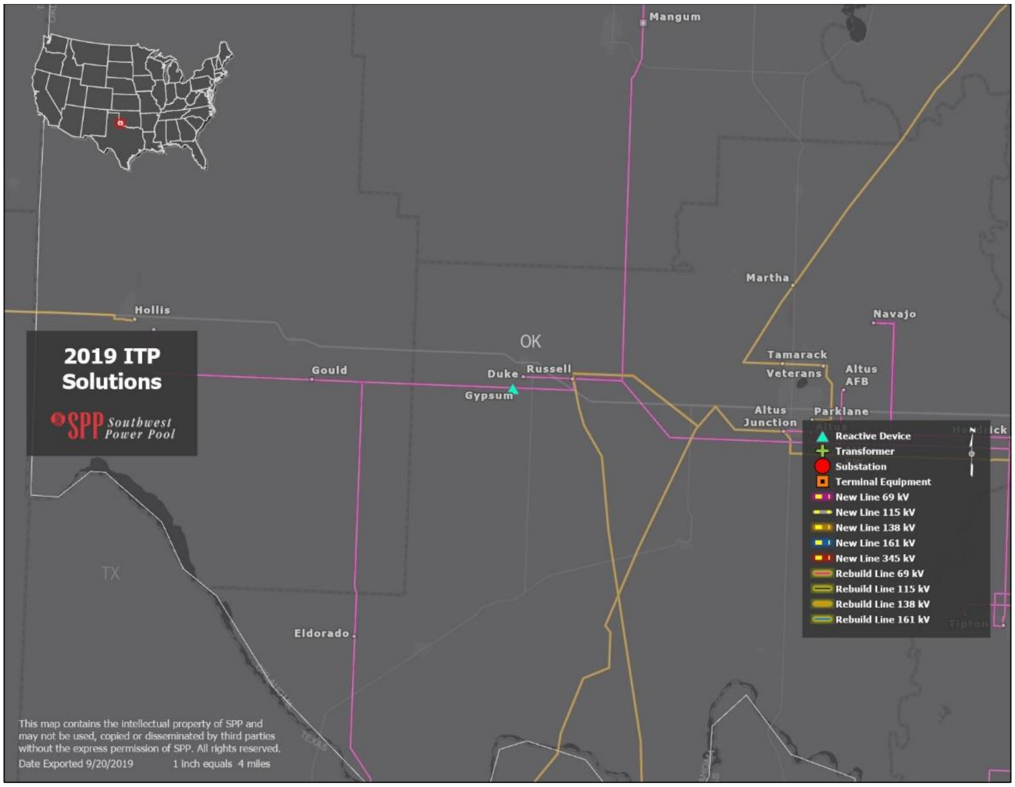


Figure 7.17: Gypsum 69 kV Capacitor Bank

In the southwest corner of Oklahoma, west of Altus near the Texas border, the 69 kV system out of Lake Pauline experiences low voltage for loss of the Duke-Russell 69 kV line. This outage creates a radial system from the Lake Pauline substation in Texas. The project selected to mitigate this issue is to install a 12 MVAR capacitor bank at Gypsum 69 kV.

7.2.15 MARSHALL COUNTY-SMITTYVILLE-BAILEYVILLE-SOUTH SENECA 115 KV REBUILD

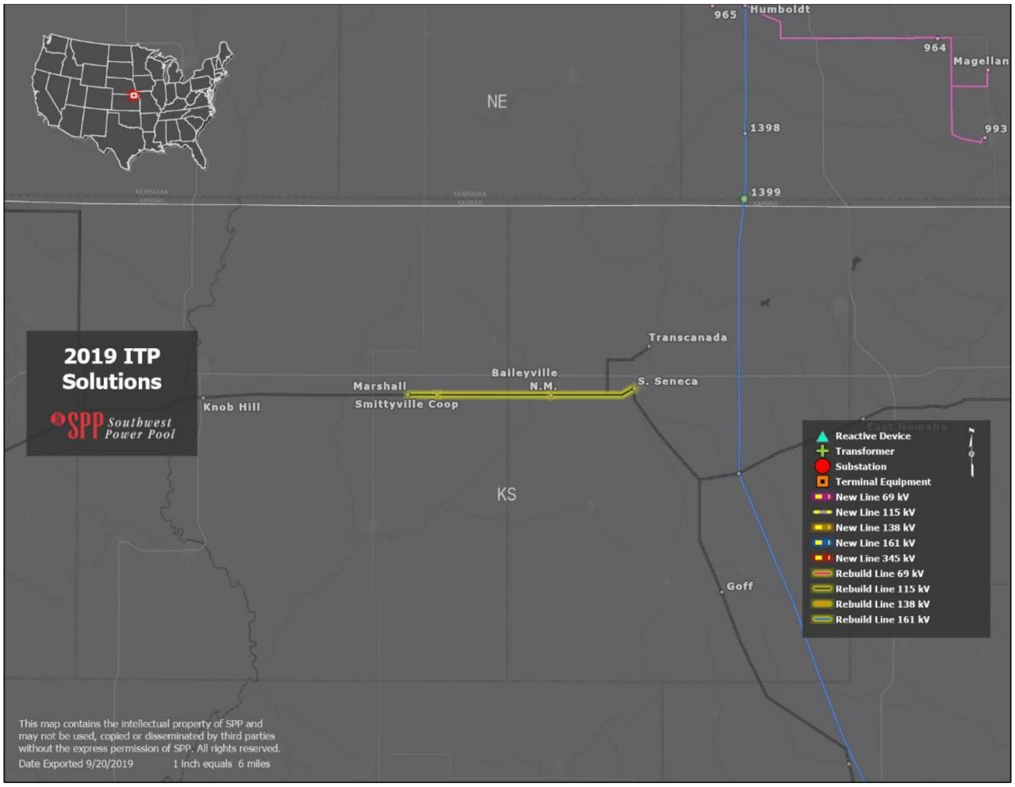


Figure 7.18: Marshall County-Smittyville-Baileyville-South Seneca 115 kV Rebuild

The 115 kV line sections between Marshall County and South Seneca in northeast Kansas overloads for loss of the Harbine-Steel City 115 kV line to the northwest. Losing this line directs the flow from the Steele Flats wind farm south. Incremental load increases between the previous ITP assessment models and the 2019 ITP models, contributing to the resulting overloads. The line is significantly below the nearby line ratings. The project selected to mitigate these overloads is to rebuild these sections of line.

7.2.16 GETTY-SKELLY 69 KV TERMINAL EQUIPMENT

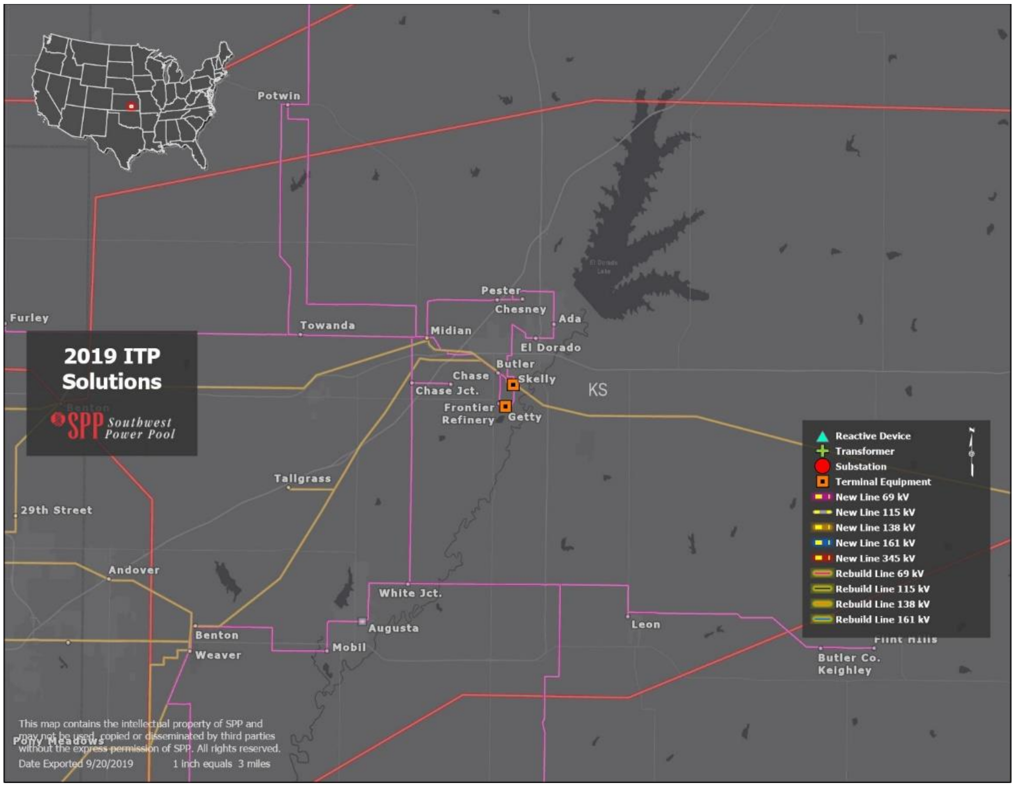


Figure 7.19: Getty-Skelly 69 kV terminal equipment

The Getty-Skelly 69 kV line is the eastern side of a loop serving the Frontier refinery. Losing the western side of the loop, Butler-Frontier 69 kV, radializes the refinery and causes the Getty-Skelly line to overload, as it serves the refinery's entire load. This line was loaded at 99% in previous studies for the same contingency. Minor load increases at the refinery caused the overload in the current models. The project recommended to address this issue is to replace any terminal equipment necessary to increase the line rating.

7.3 SHORT-CIRCUIT PROJECTS

7.3.1 SHORT-CIRCUIT PROJECT PORTFOLIO

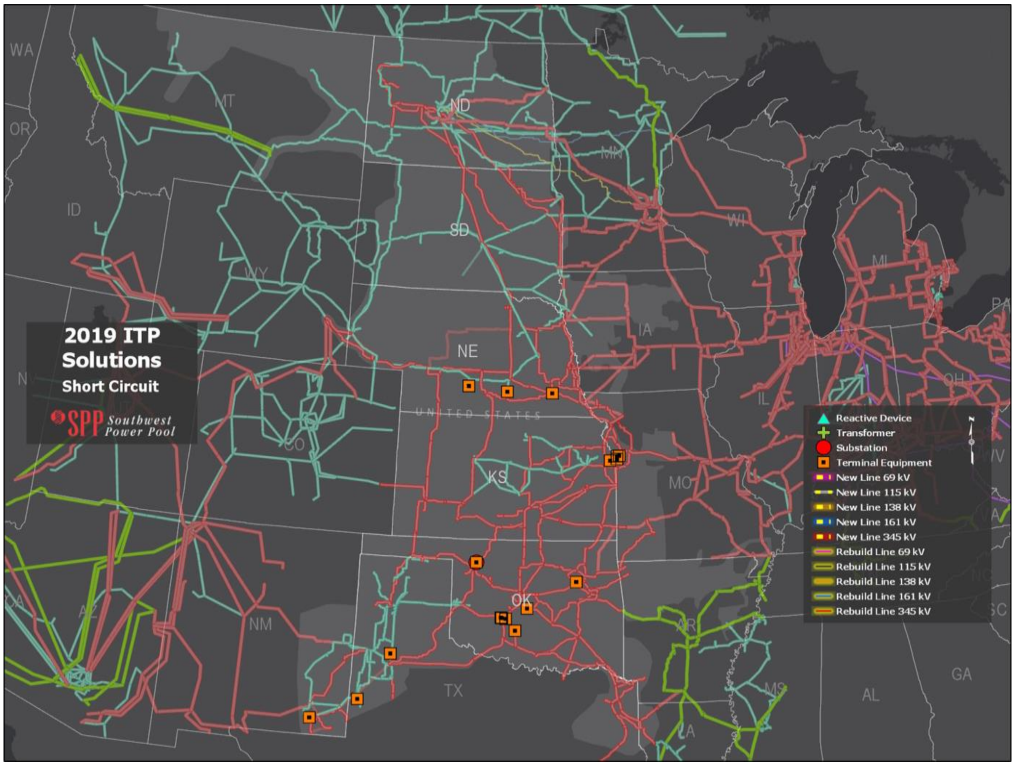


Figure 7.20: Short-Circuit Project portfolio

All short-circuit projects identified in the 2019 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.

Reliability Project	Area	Scenario*
Replace 21 breakers at Riverside Station 138 kV	AEPW	21S / BR
Replace eight breakers at Southwestern Station 138 kV	AEPW	21S / BR
Replace one breaker at Craig 161 kV	KCPL	21S / BR
Replace two breakers at Leeds 161 kV	KCPL	21S / BR
Replace two breakers at Midtown 161 kV	KCPL	21S / BR
Replace four breakers at Southtown 161 kV	KCPL	21S / BR
Replace one breaker at Moore 13.8 kV tertiary bus	NPPD	21S / BR
Replace two breakers at Hastings 115 kV	NPPD	21S / BR
Replace five breakers at Canaday 115 kV	NPPD	21S / BR

Reliability Project	Area	Scenario*
Replace two breakers at Westmoore 138 kV	OKGE	21S / BR
Replace three breakers at Santa Fe 138 kV	OKGE	21S / BR
Replace one breaker at Carlsbad Interchange 115 kV	SPS	21S / BR
Replace three breakers at Denver City North and South 115 kV	SPS	21S / BR
Replace three breakers at Hale County Interchange 115 kV	SPS	21S / BR
Replace one breaker at Washita 69 kV	WFEC	21S / BR
Replace 12 breakers at Mooreland 138/69 kV	WFEC	21S / BR
Replace three breakers at Anadarko 138 kV	WFEC	21S / BR

Table 7.3: Short-Circuit Projects

7.4 ECONOMIC PROJECTS

7.4.1 GRACEMONT-ANADARKO 138 KV REBUILD

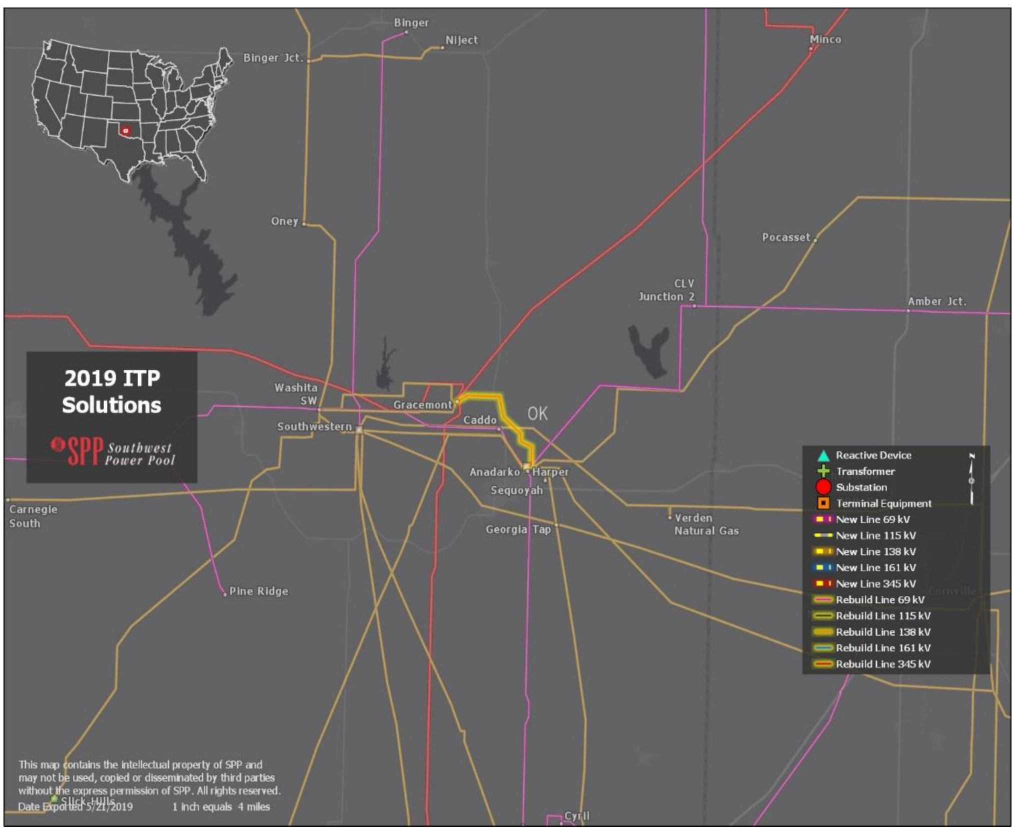


Figure 7.21: Gracemont-Anadarko 138 kV Rebuild

Southwest of Oklahoma City, near Anadarko, Oklahoma, the Gracemont-Anadarko 138 kV line becomes congested for loss of the Washita-Southwest Station 138 kV line. This area is impacted by west-to-east system flows and existing renewable generation on the 138 kV system. The Gracemont-Anadarko and Washita-Southwest Station lines form a parallel transmission path east from Washita, but the path to Anadarko has a lower capacity. This flowgate was identified in a previous ITP assessment and currently experiences operational congestion. The project selected to mitigate this issue was to leverage existing infrastructure and rebuild the Gracemont-Anadarko 138 kV line.

7.4.2 KINGFISHER JUNCTION-EAST KINGFISHER TAP 138 KV REBUILD

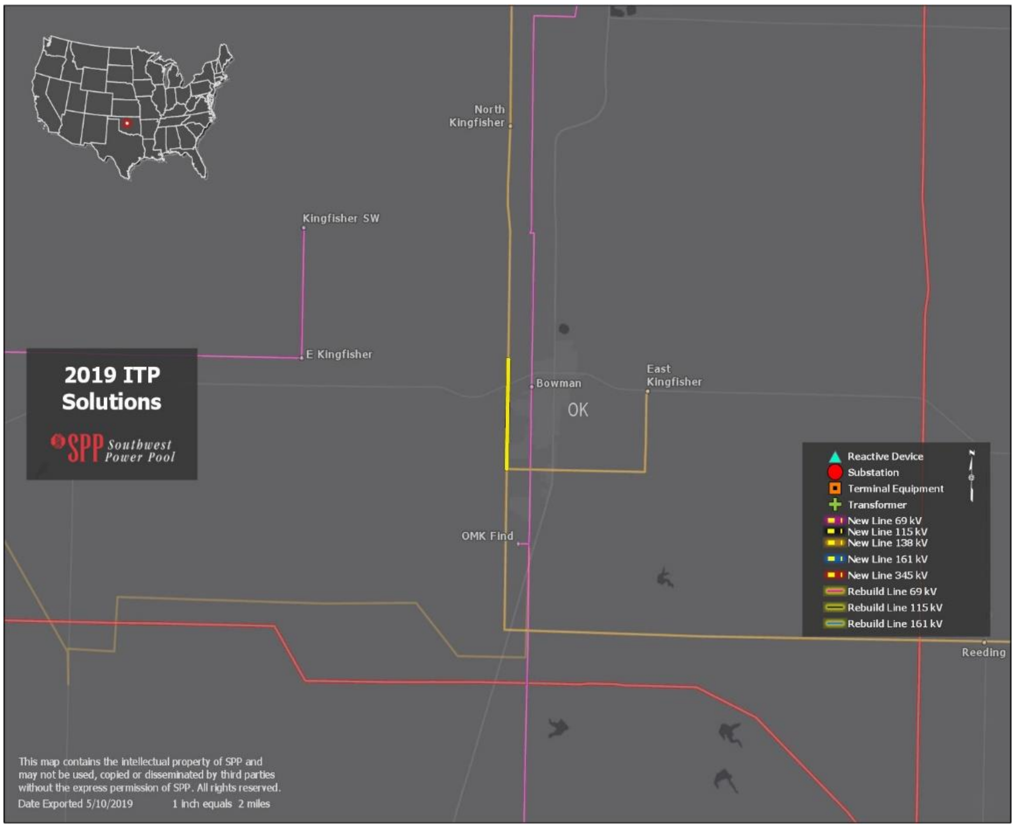


Figure 7.22: Kingfisher Junction-East Kingfisher Tap 138 kV Rebuild

Northwest of Oklahoma City, near Kingfisher, Oklahoma, the Kingfisher Junction-East Kingfisher Tap 138 kV line becomes congested for loss of the Dover-Dover Switch 138 kV line. This area is impacted by west-to-east and north-to-south bulk system flows. The Kingfisher Junction-East Kingfisher Tap and Dover-Dover Switch lines are part of a parallel transmission path east from Dover switch to Twin Lakes, but the path Kingfisher Junction-East Kingfisher Tap segment has a much lower capacity than the rest of the paths. The project selected to mitigate this issue was to leverage existing infrastructure and rebuild the Kingfisher Junction-East Kingfisher Tap 138 kV line.

7.4.3 SUNDOWN-AMOCO TAP 115 KV TERMINAL EQUIPMENT

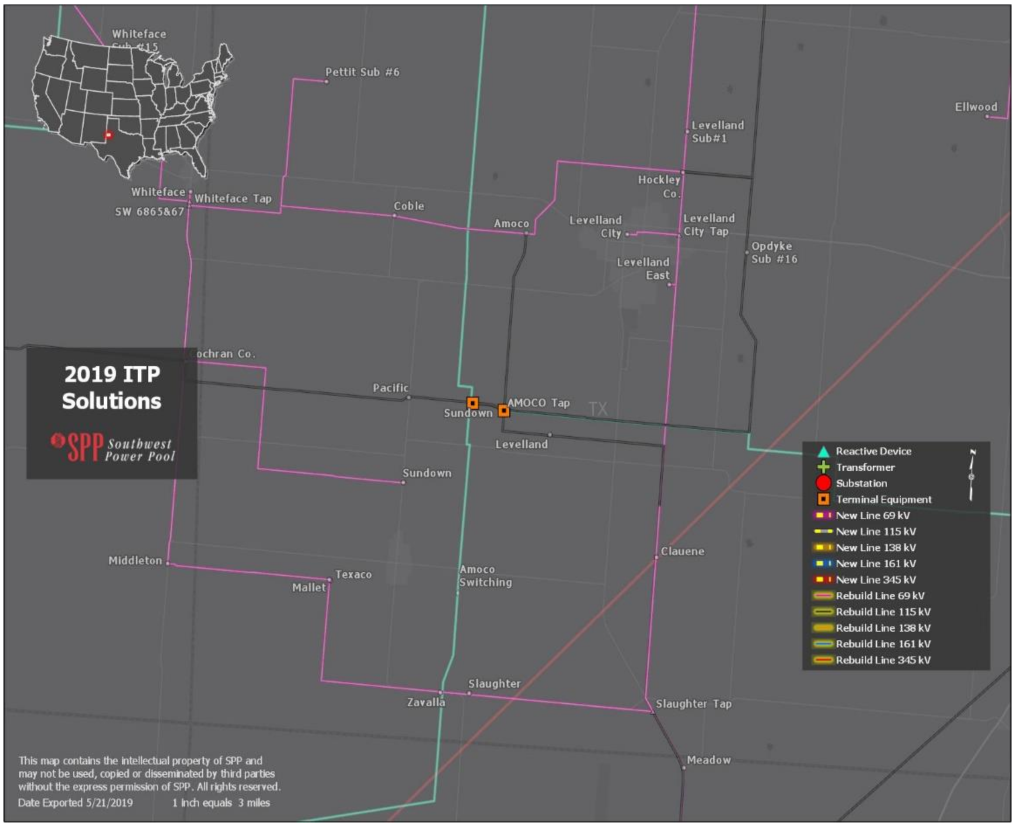


Figure 7.23: Sundown-Amoco Tap 115 kV terminal equipment

West of Lubbock, Texas, near Levelland, the Sundown-Amoco Tap 115 kV line becomes congested for loss of the Sundown-Amoco Switching Station 230 kV line. This area experiences north-to-south bulk system transfers to serve the New Mexico load pocket. It becomes especially congested during off-peak hours when conventional generation is offset by wind. In the 2015 ITP10 assessment, SPP issued an NTC resulting in a capacity increase on the Sundown-Amoco 230 kV line. This caused increasing flows that become more impactful to the underlying system when the line is outaged. The 230 kV flowgate currently experiences operational congestion. Once the upgrade is in service, it could be expected that congestion would move to the underlying system. Congestion is further increased by projected retirements in the southern SPS zone. The project selected to mitigate this issue is to replace any necessary terminal equipment at the Sundown and Amoco Tap 115 kV substations to increase the line rating.

7.4.4 SPEARMAN-HANSFORD 115 KV REBUILD

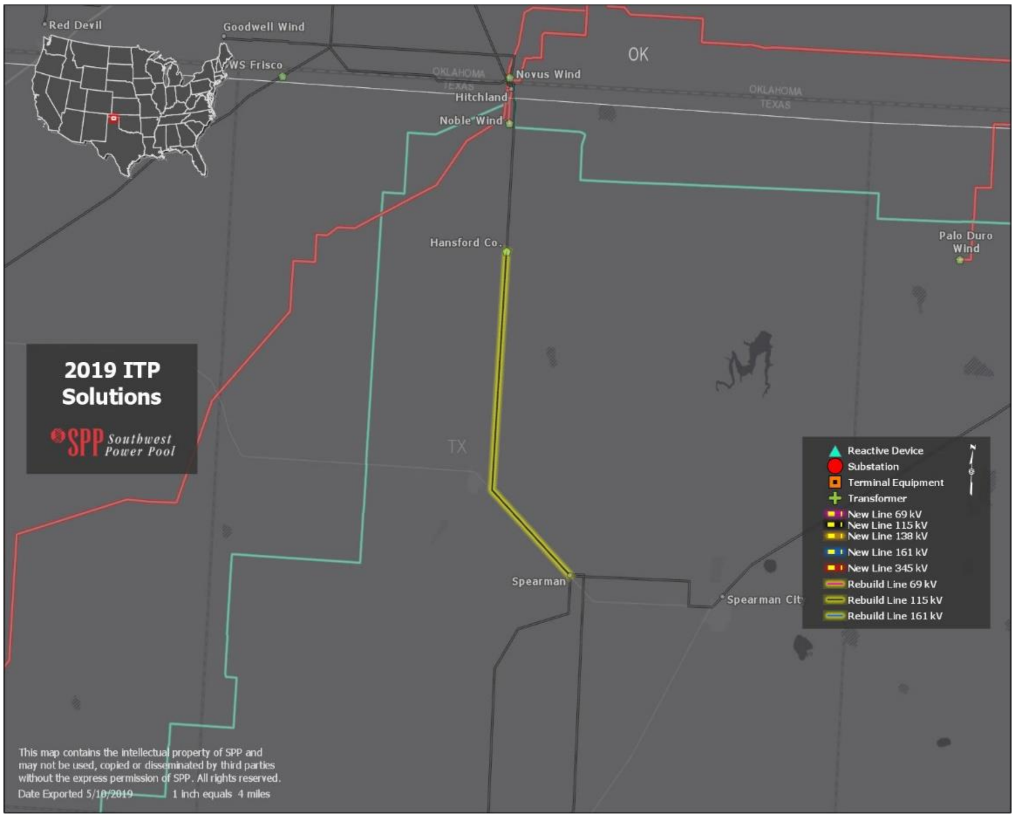


Figure 7.24: Spearman-Hansford 115 kV Rebuild

Northeast of Amarillo, Texas, near the Oklahoma border, the Spearman-Hansford 115 kV line becomes congested for loss of the Potter County 345/230 kV transformer. The 345 kV line north from the Potter substation is the only EHV transmission connecting the northern SPS system to the rest of SPP. The loss of this feed via the outage of the step-down transformer at Potter forces using the underlying HV system to support the typical north-to-south bulk system transfers into the SPS system. This line currently experiences operational congestion for multiple outages. The project selected to mitigate the issue is to rebuild the Spearman-Hansford 115 kV line.

7.4.5 LAWRENCE ENERGY CENTER-MIDLAND JUNCTION 115 KV TERMINAL EQUIPMENT

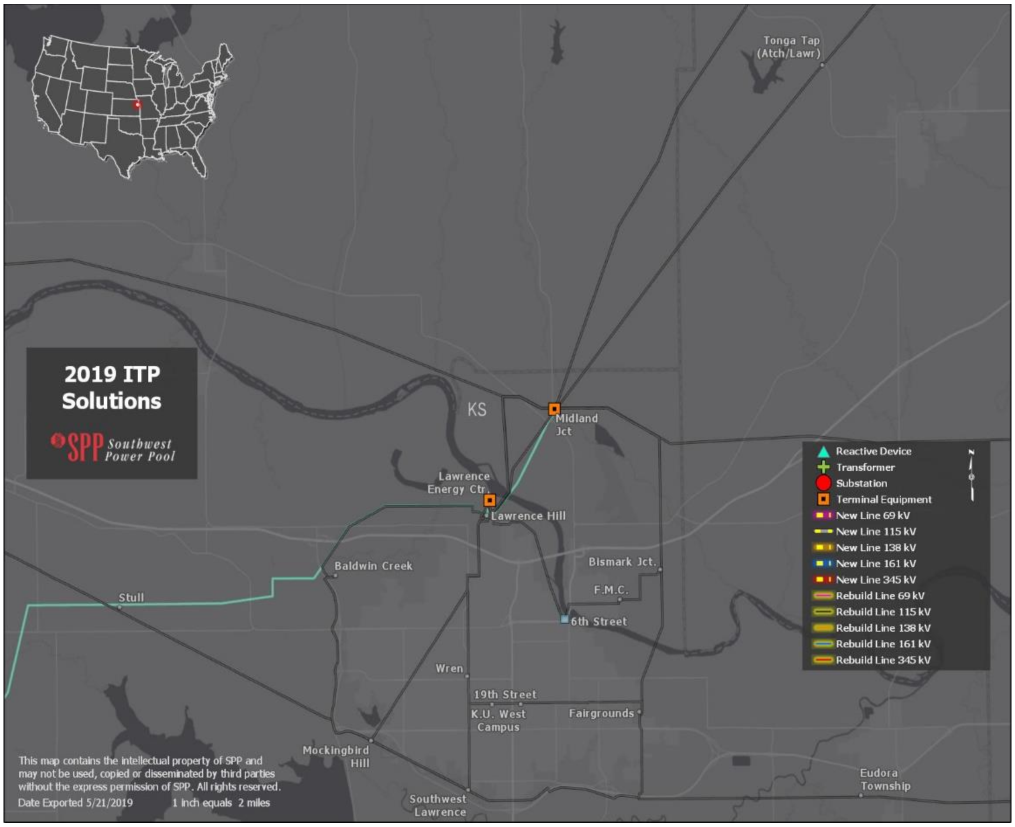


Figure 7.25: Lawrence Energy Center-Midland Junction 115 kV terminal equipment

On the north end of Lawrence, Kansas, the Lawrence Energy Center-Midland 115 kV line experiences congestion for loss of the Lawrence Hill 230/115 kV transformer. The 230 kV and 115 kV network serve to bring power from the Lawrence Energy Center to the area. When the 230 kV path from the plant to Midland Junction is lost, flows on the 115 kV system increase, creating congestion on the low capacity line. The project selected to mitigate this issue is to replace any necessary terminal equipment at Lawrence Energy Center and Midland Junction to increase the 115 kV line rating.

7.4.6 ARNOLD-RANSOM AND PILE-SCOTT CITY-SETAB 115 KV TERMINAL EQUIPMENT

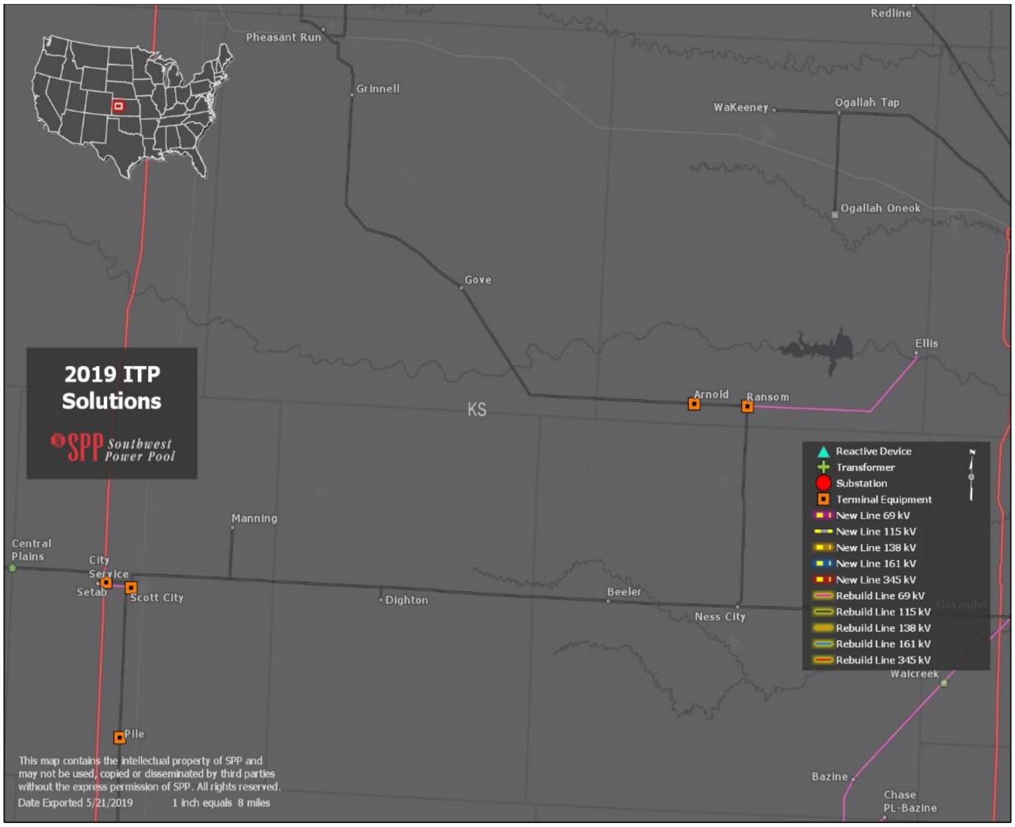


Figure 7.26: Arnold-Ransom and Pile-Scott City-Setab 115 kV terminal equipment

In central western Kansas, the Arnold-Ransom 115 kV line experiences congestion for loss of the Mingo-Setab 345 kV line. The Mingo-Setab 345 kV line supports north-to-south bulk system transfers from SPP north into Kansas. When the path is outaged, the flows transfer to the 115 kV system in northwest Kansas to continue the journey southeast. This line currently experiences operational congestion for outages of either 345 kV line making up the EHV corridor between Nebraska and western Kansas.

While developing solutions for this flowgate, it was observed that congestion moved to similar flowgates in the area: the Pile-Scott City and Scott City-Setab for loss of the Setab-Holcomb 345 kV line. To adequately address the area and allow bulk flows to continue southeast, all three flowgates need to be addressed. The project selected to mitigate these issue is to replace any necessary terminal equipment at Arnold, Ransom, Pile, Scott City, and Setab to increase the rating of the lines.

7.5 POLICY PROJECTS

No policy projects are required for the 2019 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[20] provides the definitions, concepts, calculations, and allocation methodologies for all approved metrics. The ESWG directed that the 2019 ITP benefit-to-cost ratios be calculated for the final portfolio using the Future 1 and Future 2 models. The benefit analysis is performed on all reliability and economic projects passed through the consolidation process. The benefit structure shown in Table 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

[20] Benefit Metrics Manual

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

To calculate benefits over the expected 40-year life of the projects[21], two years were analyzed, 2024 and 2029. APC savings were calculated accordingly for these years. The benefits are extrapolated for the initial five-year period based on the slope between the two points. After that, they are assumed to grow at an inflation rate of 2.5% per year. Each year's benefit was then discounted to 2024 using an 8% discount rate, and a 2.5% inflation rate from 2024 back to 2019. 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, and 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.

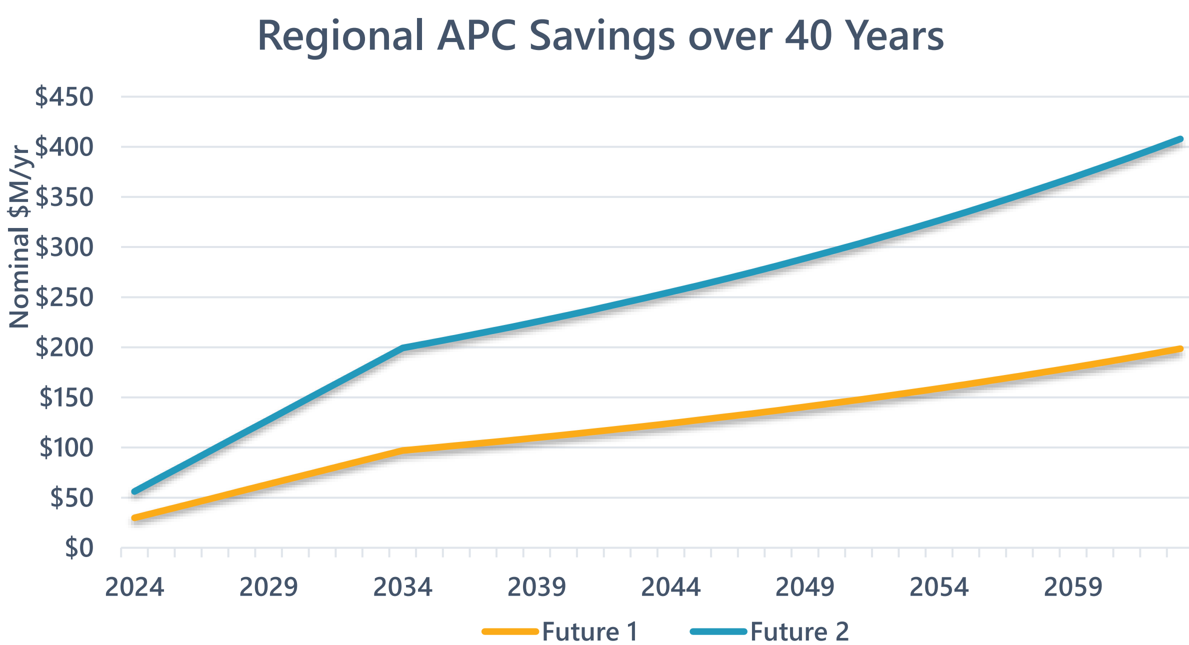


Figure 8.1: Regional APC Savings Estimated for the 40-year Study Period

	Future 1			Future 2		
Zone	**2024 ($M)**	**2029 ($M)**	**40-yr NPV ($2019M)**	**2024 ($M)**	**2029 ($M)**	**40-yr NPV ($2019M)**
AEPW	$14.2	$22.2	$322.8	$25.8	$37.3	$532.3
EMDE	$2.6	$4.8	$72.7	$3.3	$4.2	$57.6
GMO	$0.2	$0.6	$10.2	$2.2	$2.3	$30.7

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

	Future 1			Future 2		
Zone	2024 ($M)	2029 ($M)	40-yr NPV ($2019M)	2024 ($M)	2029 ($M)	40-yr NPV ($2019M)
GRDA	$10.2	$13.1	$182.2	$14.9	$25.5	$377.2
KCPL	$9.6	$11.4	$154.5	$10.3	$6.9	$70.7
LES	$0.5	$0.5	$6.0	$0.2	($0.5)	($10.5)
MIDW	($1.6)	($2.2)	($30.1)	($2.3)	($2.8)	($37.7)
MKEC	($4.3)	($5.4)	($75.0)	($5.4)	($6.0)	($79.3)
NPPD	$0.1	($0.2)	($3.8)	$0.3	$0.2	$1.5
OKGE	($4.7)	$0.5	$32.4	$5.5	$24.6	$407.7
OPPD	$0.1	$0.6	$10.1	$0.1	($0.0)	($1.4)
SPRM	$3.2	$4.7	$68.0	$3.3	$9.0	$142.0
SPS	($9.6)	($8.2)	($98.3)	($8.7)	$0.9	$58.4
SUNC	($1.6)	($1.8)	($23.5)	($2.0)	($1.9)	($23.9)
SWPA	$1.1	$0.1	($3.2)	($0.1)	$0.7	$12.8
UMZ	$0.0	($0.4)	($6.9)	($0.4)	($1.6)	($25.8)
WERE	$8.3	$18.6	$288.9	$7.2	$21.4	$343.0
WFEC	$1.5	$4.3	$68.4	$2.0	$7.8	$127.6
TOTAL	**$29.8**	**$63.4**	**$975.3**	**$56.1**	**$127.7**	**$1,982.8**

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% production cost minus sales to other zones (revenue).

	Future 1			Future 2		
Zone	2024 ($M)	2029 ($M)	40-yr NPV ($2019M)	2024 ($M)	2029 ($M)	40-yr NPV ($2019M)
OTHSPP	$100.9	$121.0	$1,643.1	$143.0	$143.0	$1,824.9

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 SO_2, NOX, and CO_2 emissions. Such a reduction in emissions is a benefit that is already monetized through the APC savings metric, based on the assumed allowance prices for these effluents. Note that neither ITP future assumes any allowance prices for CO_2.

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

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% to estimate the reduction in installed capacity requirements. The value of capacity savings is monetized by applying a net cost of new entry (net CONE) of $85.61/kW-yr in 2018 dollars. The net CONE value was obtained from Attachment AA Resource Adequacy–Attachment AA Section 14 of the tariff. The net cone was assumed to grow at an inflation rate of 2.5% for each study year, $99.2 for 2024, and $112.3 for 2029. Table 8.4 displays the associated capacity savings for each zone in each study year and the 40-year NPV.

Base Reliability			
Zone	**2024 ($M)**	**2029 ($M)**	**40-yr NPV (2019 $M)**
AEPW	$0.10	$0.07	$0.82
EMDE	$0.03	$0.05	$0.69
GMO	$0.06	$0.07	$0.88
GRDA	$0.01	$0.01	$0.14
KCPL	$0.36	$0.40	$5.25
LES	$0.01	$0.01	$0.07
MIDW	$0.00	$0.00	$0.01
MKEC	($0.00)	$0.00	$0.02
NPPD	$0.07	$0.10	$1.46
OKGE	($0.16)	($0.20)	($2.70)
OPPD	$0.02	$0.02	$0.27
SPRM	($0.00)	($0.00)	($0.05)
SPS	$0.01	$0.02	$0.31
SUNC	($0.02)	($0.02)	($0.21)
SWPA	$0.02	$0.04	$0.65
UMZ	$0.01	$0.01	$0.10
WERE	$0.39	$0.42	$5.59
WFEC	$0.07	$0.08	$0.00
Total	**$1.0**	**$1.1**	**$13.3**

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 required to meet compliance and mitigate SPP Criteria violations. The regional benefits are assumed to be equal to the 40-year NPV of ATRRs of the projects, totaling **$100.8 million** in 2019 dollars.

The system reconfiguration approach to allocate zonal benefits utilizes the powerflow models to measure incremental flows shifted onto the existing system during outage of the proposed reliability upgrade. This is used as a proxy for how much each upgrade reduces 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 system reconfiguration analysis results and the benefit allocation factors for different voltage levels. The table shows the overall zonal benefits calculated by applying these allocation factors.

Mandated Reliability Benefits Base Reliability and Short-Circuit									
< 100 kV		100–300 kV			> 300 kV			All Projects	
SPP-wide Benefit	$2.84	$98			$0			$101	
Zone	100% SR	67% SR	33% LRS	Wtd. Avg	33% SR	67% LRS	Wtd. Avg	Allocation	Benefit 2019 $M
AEPW	14.2%	14.7%	20.6%	16.7%	0.0%	20.6%	13.7%	16.6%	$16.7
EMDE	0.3%	0.6%	2.4%	1.2%	0.0%	2.4%	1.6%	1.2%	$1.2
GMO	0.9%	5.6%	3.8%	5.0%	0.0%	3.8%	2.6%	4.9%	$5.0
GRDA	0.1%	4.3%	1.7%	3.4%	0.0%	1.7%	1.1%	3.3%	$3.4
KCPL	1.0%	3.1%	7.6%	4.6%	0.0%	7.6%	5.0%	4.5%	$4.5
LES	10.2%	0.4%	1.5%	0.8%	0.0%	1.5%	1.0%	1.1%	$1.1
MIDW	0.3%	0.4%	0.8%	0.5%	0.0%	0.8%	0.5%	0.5%	$0.5
MKEC	0.9%	0.8%	1.3%	1.0%	0.0%	1.3%	0.8%	1.0%	$1.0
NPPD	2.5%	3.2%	6.0%	4.2%	0.0%	6.0%	4.0%	4.1%	$4.2
OKGE	3.6%	19.4%	13.1%	17.3%	0.0%	13.1%	8.7%	16.9%	$17.1
OPPD	4.5%	4.8%	4.8%	4.8%	0.0%	4.8%	3.2%	4.8%	$4.8
SPRM	0.1%	0.3%	1.3%	0.6%	0.0%	1.3%	0.9%	0.6%	$0.6
SPS	6.6%	19.8%	11.6%	17.1%	0.0%	11.6%	7.8%	16.8%	$16.9
SUNC	0.4%	3.9%	0.9%	2.9%	0.0%	0.9%	0.6%	2.9%	$2.9
SWPA	0.8%	1.8%	0.5%	1.4%	0.0%	0.5%	0.4%	1.4%	$1.4
UMZ	0.1%	1.1%	8.8%	3.7%	0.0%	8.8%	5.9%	3.6%	$3.6
WERE	35.5%	8.6%	3.3%	6.8%	0.0%	3.3%	2.2%	7.7%	$7.7
WFEC	17.9%	6.8%	10.1%	7.9%	0.0%	10.1%	6.7%	8.2%	$8.2
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**0.0%**	**100.0%**	**66.7%**	**100.0%**	**$100.8**

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 estimated 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%.[22,23] Applying this ratio to the APC savings estimated for the recommended portfolio translates to a 40-year NPV of benefits of **$110 million** for Future 1 and **$223 million** for Future 2 in 2019 dollars. These benefits are allocated based upon the load ratio share of the region. Table 8.6 shows the outage mitigation benefits allocated to each SPP zone.

Zone	Future 1 (2019 $M)	Future 2 (2019 $M)
AEPW	$22.6	$45.9
EMDE	$2.6	$5.3
GMO	$4.2	$8.6
GRDA	$1.8	$3.7
KCPL	$8.3	$16.8
LES	$1.6	$3.3
MIDW	$0.8	$1.7
MKEC	$1.4	$2.8
NPPD	$6.6	$13.5
OKGE	$14.4	$29.3
OPPD	$5.2	$10.7

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

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

Zone	Future 1	Future 2
	(2019 $M)	(2019 $M)
SPRM	$1.5	$3.0
SPS	$12.8	$26.0
SUNC	$1.0	$2.1
SWPA	$0.6	$1.2
UMZ	$9.7	$19.7
WERE	$11.1	$22.5
WFEC	$3.6	$7.3
TOTAL	**$109.8**	**$223.1**

Table 8.6: Transmission Outage Cost Mitigation Benefits by Zone

8.1.10 INCREASED WHEELING THROUGH AND OUT REVENUES

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

To estimate how increased ATC could affect the wheeling services sold, the historical long-term firm transmission service request (TSR) allowed by the historical NTC projects are analyzed and compared against the ATC increase in the 2014 powerflow models estimated based on a FCITC analysis. As summarized in Table 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 2019. The amount of capacity granted for these TSRs add up to 1,402 MW. The associated wheeling revenues are estimated to be $45 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 2019.

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	$7.9	$9.6	$3.5	**$20.9**
KACY	1	100	$1.1	$1.3	$0.5	**$2.9**
Entergy	6	586	$10.3	$7.8	$2.8	**$21.0**
TOTAL	**13**	**1,402**	**$19.3**	**$18.8**	**$6.8**	**$44.9**

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 2024 and 2029 base reliability powerflow models were utilized for the FCITC analysis on the consolidated portfolio. The ratio of TSRs sold as a percent of increase in export ATC is capped at 100%, as incremental TSR sales would not be expected to exceed the amount of increase in export ATC. The recommended portfolio increased the export ATC by 109 MW in 2024 and 159 MW in 2029. Applying the historical ratio suggests the recommended portfolio could enable incremental TSRs by the same amount, generating additional wheeling revenues of $4-7 million annually.

The 40-year NPV of benefits is estimated to be **$119 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 for each SPP zone.

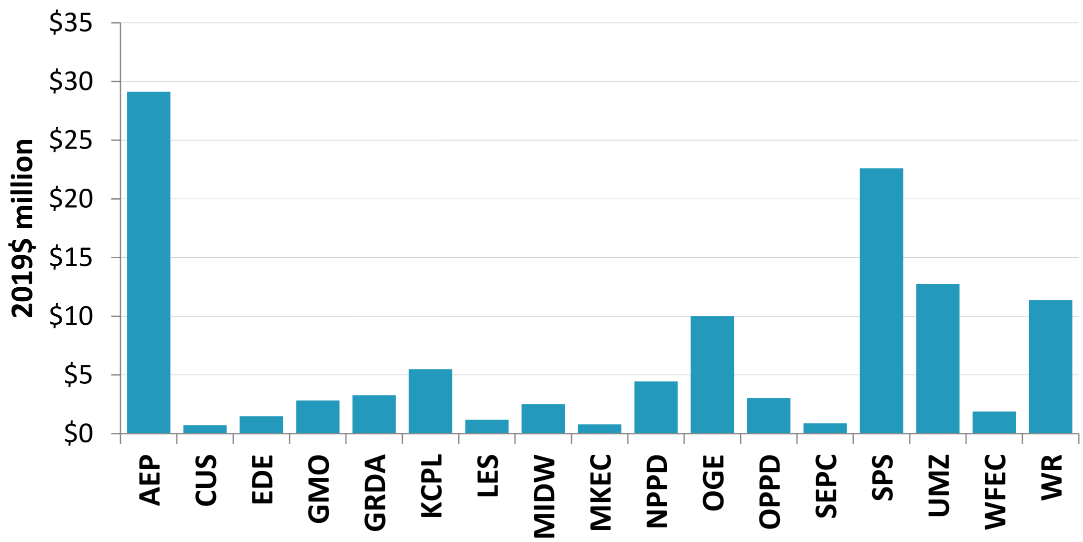


Figure 8.2: Increased Wheeling Revenue Benefits by Zone (40-year NPV)

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[24] for marginal energy losses, which accounts for losses on generation and market imports. The 40-year NPV of benefits is estimated to be $168.7 million in future 1 and $34.9 million in future 2, as shown in Table 8.9 below.

Zone	Future 1 40-yr NPV (2019 $M)	Future 2 40-yr NPV (2019 $M)
AEPW	$19.0	($0.6)
EMDE	$15.6	$4.0
GMO	$7.0	$2.7
GRDA	($5.2)	($22.1)
KCPL	$31.5	$29.43
LES	$2.1	$1.13
MIDW	($0.6)	($0.34)
MKEC	$5.7	$4.66
NPPD	$12.7	$16.54
OKGE	$15.3	($26.74)
OPPD	$3.3	$4.49
SPRM	$1.5	($4.76)
SPS	$44.1	$10.22
SUNC	($0.1)	($0.81)
SWPA	$3.0	$0.89
UMZ	$15.2	$12.76
WERE	$6.4	$11.31
WFEC	($7.7)	($7.94)
TOTAL	**$168.7**	**$34.9**

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 benefit-to-cost ratios for each SPP zone.

For the region, the benefit-to-cost ratio is estimated to be 3.5 in Future 1 and 5.8 in Future 2. The higher benefit-to-cost ratio in Future 2 is driven by the APC savings due to higher congestion relief.

[24] As described in the Benefit Metric Manual

Future 1 Present Value of 40-yr Benefits for the 2024-2063 Period (in 2019 $million)										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 2019 $million)	Benefit/ Cost Ratio
AEPW	$323	$0	$1	$17	$0	$23	$29	$19	$409	$105	3.9
EMDE	$73	$0	$1	$1	$0	$3	$1	$16	$94	$8	11.6
GMO	$10	$0	$1	$5	$0	$4	$3	$7	$30	$13	2.3
GRDA	$182	$0	$0	$3	$0	$2	$3	($5)	$185	$6	32.8
KCPL	$155	$0	$5	$5	$0	$8	$6	$15	$193	$28	6.9
LES	$6	$0	$0	$1	$0	$2	$1	$32	$41	$5	8.3
MIDW	($30)	$0	$0	$1	$0	$1	$3	$2	($24)	$3	(9.4)
MKEC	($75)	$0	$0	$1	$0	$1	$1	($1)	($73)	$4	(16.9)
NPPD	($4)	$0	$1	$4	$0	$7	$4	$6	$18	$27	0.7
OKGE	$32	$0	($3)	$17	$0	$14	$10	$13	$82	$46	1.8
OPPD	$10	$0	$0	$5	$0	$5	$3	$15	$38	$16	2.4
SPRM	$68	$0	($0)	$1	$0	$1	$1	$3	$74	$5	16.1
SPS	($98)	$0	$0	$17	$0	$13	$23	$1	($46)	$49	(0.9)
SUNC	($24)	$0	($0)	$3	$0	$1	$1	($0)	($19)	$7	(2.6)
SWPA	($3)	$0	$1	$1	$0	$1	$4	$3	$7	$2	3.7
UMZ	($7)	$0	$0	$4	$0	$10	$13	$44	$63	$30	2.1
WERE	$289	$0	$6	$8	$0	$11	$11	$6	$330	$57	5.9
WFEC	$68	$0	$0	$8	$0	$4	$2	($8)	$73	$17	4.3
Total	**$975**	**$0**	**$13**	**$101**	**$0**	**$110**	**$119**	**$169**	**$1,475**	**$427**	**3.5**

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

	Future 2 Present Value of 40-yr Benefits for the 2024-2063 Period (in 2019 $million)									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 2019 $million)	Benefit/ Cost Ratio
AEPW	$532	$0	$1	$17	$0	$46	$29	($1)	$622	$105	6.0
EMDE	$58	$0	$1	$1	$0	$5	$1	$4	$70	$8	8.6
GMO	$31	$0	$1	$5	$0	$9	$3	$3	$50	$13	3.8
GRDA	$377	$0	$0	$3	$0	$4	$3	($22)	$365	$6	64.5
KCPL	$71	$0	$5	$5	$0	$17	$6	$13	$115	$28	4.1
LES	($11)	$0	$0	$1	$0	$3	$1	$29	$24	$5	4.9
MIDW	($38)	$0	$0	$1	$0	$2	$3	$1	($32)	$3	(12.4)
MKEC	($79)	$0	$0	$1	$0	$3	$1	($0)	($75)	$4	(17.5)
NPPD	$2	$0	$1	$4	$0	$13	$4	$5	$29	$27	1.1
OKGE	$408	$0	($3)	$17	$0	$29	$10	$17	$476	$46	10.5
OPPD	($1)	$0	$0	$5	$0	$11	$3	($27)	($10)	$16	(0.6)
SPRM	$142	$0	($0)	$1	$0	$3	$1	$4	$151	$5	32.8
SPS	$58	$0	$0	$17	$0	$26	$23	($5)	$117	$49	2.4
SUNC	($24)	$0	($0)	$3	$0	$2	$1	($1)	($19)	$7	(2.6)
SWPA	$13	$0	$1	$1	$0	$1	$4	$1	$21	$2	11.6
UMZ	($26)	$0	$0	$4	$0	$20	$13	$10	$20	$30	0.7
WERE	$343	$0	$6	$8	$0	$22	$11	$11	$401	$57	7.1
WFEC	$128	$0	$0	$8	$0	$7	$2	($8)	$136	$17	7.9
Total	**$1,983**	**$0**	**$13**	**$101**	**$0**	**$223**	**$119**	**$35**	**$2,462**	**$427**	**5.8**

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

Future 1 Present Value of 40-yr Benefits for the 2024-2063 Period (in 2019 $million)										Present	Est.
State	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 2019 $million)	Benefit/ Cost Ratio
Arkansas	$107	$0	($0)	$10	$0	$8	$8	$2	$135	$51	2.6
Iowa	($1)	$0	$0	$0	$0	$0	$1	$1	$1	$0	3.7
Kansas	($55)	$0	$3	$10	$0	$17	$20	$54	$48	$97	0.5
Louisiana	$43	$0	$0	$2	$0	$3	$4	$3	$55	$14	3.9
Minnesota	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	3.7
Missouri	$249	$0	$4	$12	$0	$14	$8	$29	$316	$109	2.9
Montana	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	3.7
Oklahoma	$633	$0	$4	$34	$0	$35	$36	$20	$763	$77	9.9
Nebraska	$12	$0	$2	$10	$0	$14	$9	$53	$99	$35	2.8
New Mexico	($27)	$0	$0	$5	$0	$4	$6	$0	($12)	$5	(2.7)
North Dakota	($1)	$0	$0	$1	$0	$0	$2	$1	$3	$1	3.7
South Dakota	($1)	$0	$0	$0	$0	$0	$1	$1	$2	$0	3.7
Texas	$16	$0	$0	$16	$0	$15	$23	$6	$77	$38	2.0
Wyoming	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	3.7
TOTAL	**$975**	**$0**	**$13**	**$101**	**$0**	**$110**	**$119**	**$169**	**$1,475**	**$427**	**3.5**

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

Future 2 Present Value of 40-yr Benefits for the 2024-2063 Period (in 2019 $million)										Present	Est.
State	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 2019 $million)	Benefit/ Cost Ratio
Arkansas	$174	$0	$0	$8	$0	$15	$7	($8)	$196	$32	6.1
Iowa	$2	$0	$0	$0	$0	$0	$1	$0	$4	$0	11.5
Kansas	$320	$0	$7	$31	$0	$67	$40	$25	$488	$140	3.5
Louisiana	$71	$0	$0	$2	$0	$6	$4	($0)	$83	$14	6.0
Minnesota	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	11.6
Missouri	$507	$0	$2	$13	$0	$21	$9	($4)	$546	$35	15.7
Montana	$1	$0	$0	$0	$0	$0	$0	$0	$1	$0	11.6
Oklahoma	$275	$0	$6	$20	$0	$65	$33	($1)	$396	$117	3.4
Nebraska	$513	$0	($3)	$18	$0	$34	$14	$22	$596	$53	11.3
New Mexico	($7)	$0	($0)	$1	$0	$1	$0	($0)	($5)	$2	(2.6)
North Dakota	$5	$0	$0	$1	$0	$0	$2	$0	$8	$1	11.6
South Dakota	$4	$0	$0	$0	$0	$0	$1	$0	$6	$0	11.5
Texas	$116	$0	$0	$6	$0	$13	$8	($1)	$143	$32	4.5
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	11.6
TOTAL	**$1,983**	**$0**	**$13**	**$101**	**$0**	**$223**	**$119**	**$35**	**$2,462**	**$427**	**5.8**

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

8.2 RATE IMPACTS

The rate impact to the average retail residential ratepayer in SPP was computed for the recommended portfolio. Rate impact costs and benefits[25] 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 2029 study year were used to calculate rate impacts. All 2029 benefits and costs are shown in 2019 dollars, discounting at a 2.5% 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 4 cents for Future 1. There is a monthly net benefit for the average SPP residential ratepayer of 23 cents for Future 2.

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact-Cost	Rate Impact Benefit	Net Impact
AEPW	$9,079	$17,334	$0.17	$0.32	($0.15)
EMDE	$760	$3,770	$0.12	$0.59	($0.47)
GMO	$1,231	$491	$0.13	$0.05	$0.08
GRDA	$528	$10,268	$0.09	$1.72	($1.63)
KCPL	$2,575	$8,908	$0.18	$0.62	($0.44)
LES	$466	$364	$0.11	$0.09	$0.02
MIDW	$240	($1,689)	$0.09	($0.62)	$0.71
MKEC	$400	($4,245)	$0.12	($1.24)	$1.36
NPPD	$2,367	($146)	$0.10	($0.01)	$0.10
OKGE	$4,234	$420	$0.17	$0.02	$0.15
OPPD	$1,528	$473	$0.12	$0.04	$0.08
SPRM	$428	$3,694	$0.13	$1.12	($0.99)
SPS	$4,448	($6,421)	$0.14	($0.20)	$0.33
SUNC	$675	($1,376)	$0.24	($0.50)	$0.74
SWPA	$171	$108	$0.17	$0.11	$0.06
UMZ	$2,822	($297)	$0.12	($0.01)	$0.14
WERE	$5,028	$14,558	$0.16	$0.46	($0.30)
WFEC	$1,486	$3,344	$0.12	$0.26	($0.14)
TOTAL	**$38,468**	**$49,558**	**$0.14**	**$0.18**	**($0.04)**

Table 8.14: Future 1 2029 Retail Residential Rate Impacts by Zone (2019 $)

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

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact-Cost	Rate Impact Benefit	Net Impact
AEPW	$9,079	$29,110	$0.17	$0.54	($0.37)
EMDE	$760	$3,255	$0.12	$0.51	($0.39)
GMO	$1,231	$1,827	$0.13	$0.19	($0.06)
GRDA	$528	$19,905	$0.09	$3.34	($3.25)
KCPL	$2,575	$5,357	$0.18	$0.37	($0.19)
LES	$466	($422)	$0.11	($0.10)	$0.21
MIDW	$240	($2,176)	$0.09	($0.80)	$0.88
MKEC	$400	($4,683)	$0.12	($1.37)	$1.48
NPPD	$2,367	$130	$0.10	$0.01	$0.09
OKGE	$4,234	$19,213	$0.17	$0.76	($0.59)
OPPD	$1,528	($34)	$0.12	($0.00)	$0.12
SPRM	$428	$7,001	$0.13	$2.12	($1.99)
SPS	$4,448	$680	$0.14	$0.02	$0.12
SUNC	$675	($1,499)	$0.24	($0.54)	$0.79
SWPA	$171	$546	$0.17	$0.55	($0.37)
UMZ	$2,822	($1,231)	$0.12	($0.05)	$0.18
WERE	$5,028	$16,715	$0.16	$0.52	($0.37)
WFEC	$1,486	$6,077	$0.12	$0.47	($0.36)
TOTAL	**$38,468**	**$99,772**	**$0.14**	**$0.37**	**($0.23)**

Table 8.15: Future 2 2029 Retail Residential Rate Impacts by Zone (2019 $)

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact-Cost	Rate Impact Benefit	Net Impact[26]
Arkansas	$2,474	$3,683	$0.17	$0.25	($0.08)
Iowa	$485	($51)	$0.12	($0.01)	$0.14
Kansas	$7,655	$11,828	$0.16	$0.24	($0.09)
Louisiana	$1,217	$2,324	$0.17	$0.32	($0.15)
Minnesota	$34	($4)	$0.12	($0.01)	$0.14
Missouri	$3,719	$12,129	$0.14	$0.46	($0.32)
Montana	$139	($15)	$0.12	($0.01)	$0.14
Nebraska	$4,677	$658	$0.11	$0.02	$0.09
New Mexico	$1,223	($1,765)	$0.14	($0.20)	$0.33
North Dakota	$1,121	($118)	$0.12	($0.01)	$0.14
Oklahoma	$9,590	$21,065	$0.15	$0.33	($0.18)
South Dakota	$703	($74)	$0.12	($0.01)	$0.14
Texas	$5,407	($99)	$0.15	($0.00)	$0.15
Wyoming	$25	($3)	$0.12	($0.01)	$0.14
TOTAL	**$38,468**	**$49,558**	**$0.14**	**$0.18**	**($0.04)**

Table 8.16: Future 1 2029 Retail Residential Rate Impacts by State (2019 $)

[26] State level results are based on load allocations by zone, by state. For example, 11% of Upper Missouri Zone (UMZ) load is in Nebraska, so 11% of UMZ benefits are attributed to Nebraska.

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact-Cost	Rate Impact Benefit	Net Impact[27]
Arkansas	$2,474	$8,683	$0.17	$0.58	($0.42)
Iowa	$485	($211)	$0.12	($0.05)	$0.18
Kansas	$7,655	$11,184	$0.16	$0.23	($0.07)
Louisiana	$1,217	$3,902	$0.17	$0.54	($0.37)
Minnesota	$34	($15)	$0.12	($0.05)	$0.18
Missouri	$3,719	$14,673	$0.14	$0.56	($0.42)
Montana	$139	($61)	$0.12	($0.05)	$0.18
Nebraska	$4,677	($464)	$0.11	($0.01)	$0.12
New Mexico	$1,223	$187	$0.14	$0.02	$0.12
North Dakota	$1,121	($489)	$0.12	($0.05)	$0.18
Oklahoma	$9,590	$54,845	$0.15	$0.85	($0.70)
South Dakota	$703	($305)	$0.12	($0.05)	$0.18
Texas	$5,407	$7,855	$0.15	$0.21	($0.07)
Wyoming	$25	($11)	$0.12	($0.05)	$0.18
TOTAL	**$38,468**	**$99,772**	**$0.14**	**$0.37**	**($0.23)**

Table 8.17: Future 2 2029 Retail Residential Rate Impacts by State (2019 $)

8.3 SENSITIVITY ANALYSIS

8.3.1 METHODOLOGY

The recommended portfolio was tested under select sensitivities to understand the economic impacts associated with variations in certain model inputs. These sensitivities were not used to develop transmission projects nor filter out projects, but rather to measure the flexibility of the final consolidated portfolio in both futures (including economic, reliability and short-circuit projects) under different uncertainties. The following sensitivities were performed:

- Scoped sensitivities
    - High natural gas price
    - Low natural gas price
    - High demand
    - Low demand

[27] State level results are based on load allocations by zone, by state. For example, 11% of Upper Missouri Zone (UMZ) load is in Nebraska, so 11% of UMZ benefits are attributed to Nebraska.

- Supplemental sensitivities
    - Increased wind and solar (Future 2 only)
    - Decreased wind and solar (Future 1 only)

The demand and natural gas price sensitivities were included in the 2019 ITP Scope, however, throughout the study there have been questions about how the wind and solar assumptions would impact the potential benefit of the different portfolio. Staff performed additional sensitivities on the consolidated portfolio to provide insight into these questions.

The consolidated portfolio was tested in both futures. The economic impacts of variations in the model inputs were calculated for the simulations. One-year benefit-to-cost ratios are shown in **Error! Reference source not found.** and Figure 8.4, while 40-year benefit-to-cost ratios are shown in Figure 8.5 and Figure 8.6. The benefit-to-cost ratios are shown for all sensitivity and non-sensitivity runs. APC savings is the only benefit considered in these results. The red dashed bar in the figures represents the expected case benefit-to-cost ratio for comparison to the sensitivity case benefit-to-cost ratios.

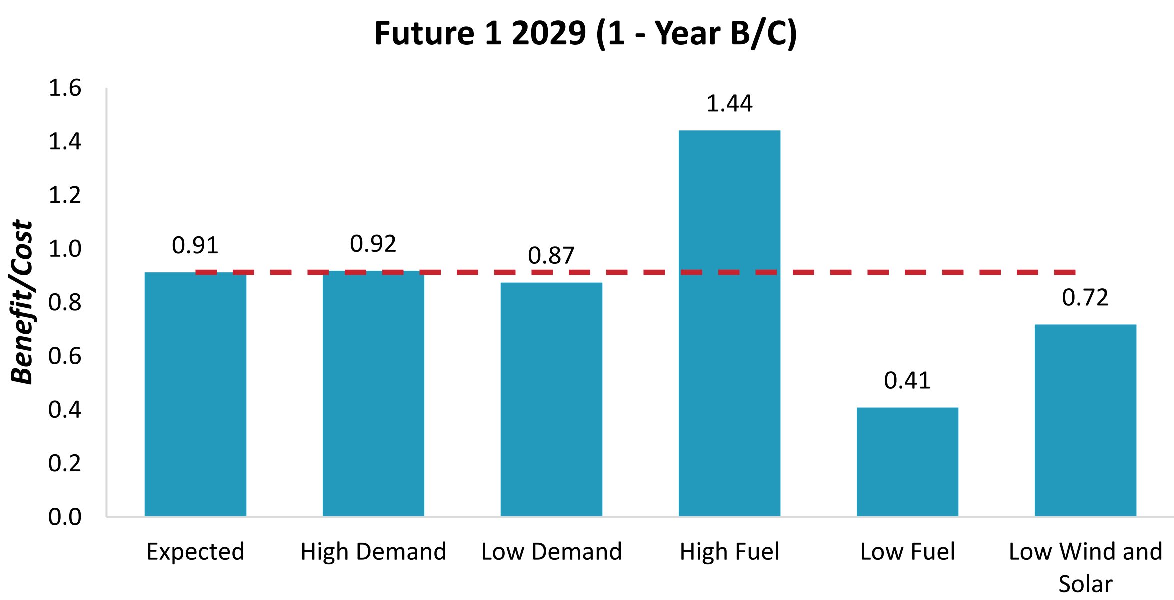


Figure 8.3: *1-Year Benefit-to-Cost Ratios for Sensitivities*

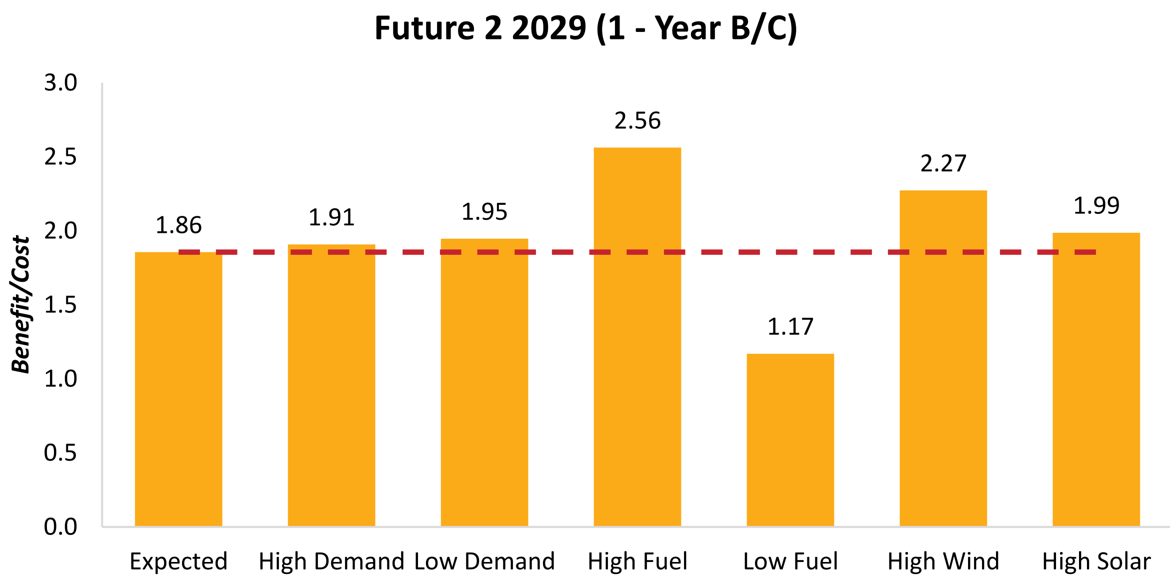


Figure 8.4: *1-Year Benefit-to-Cost Ratios for Sensitivities*

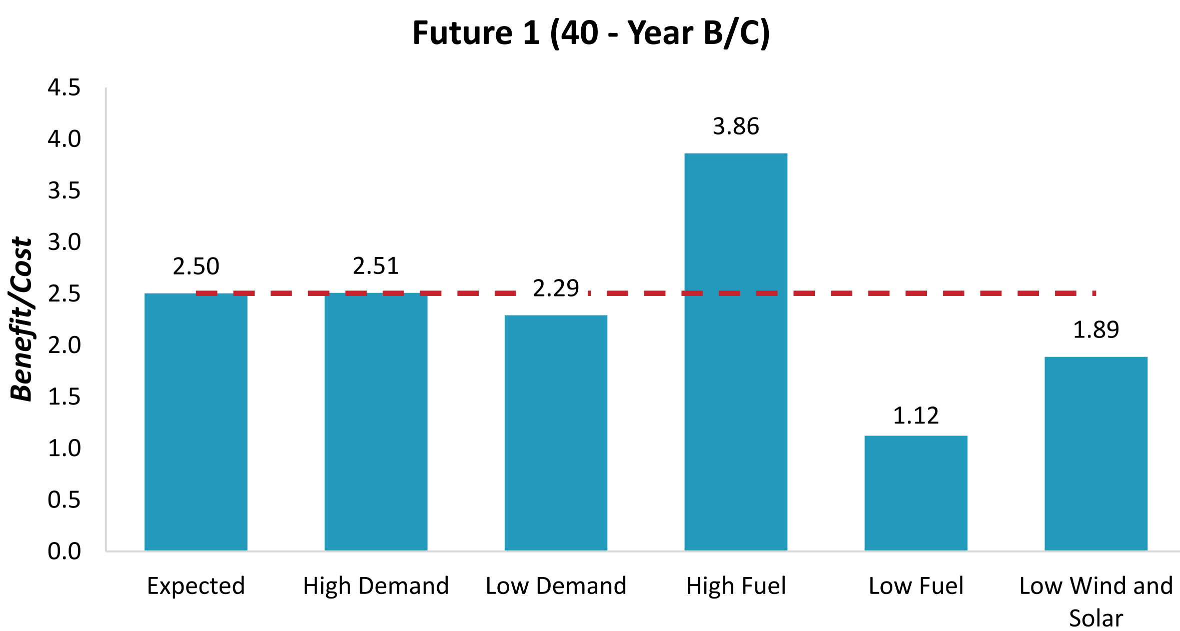


Figure 8.5*: 40-Year Benefit-to-Cost Ratios for Sensitivities*

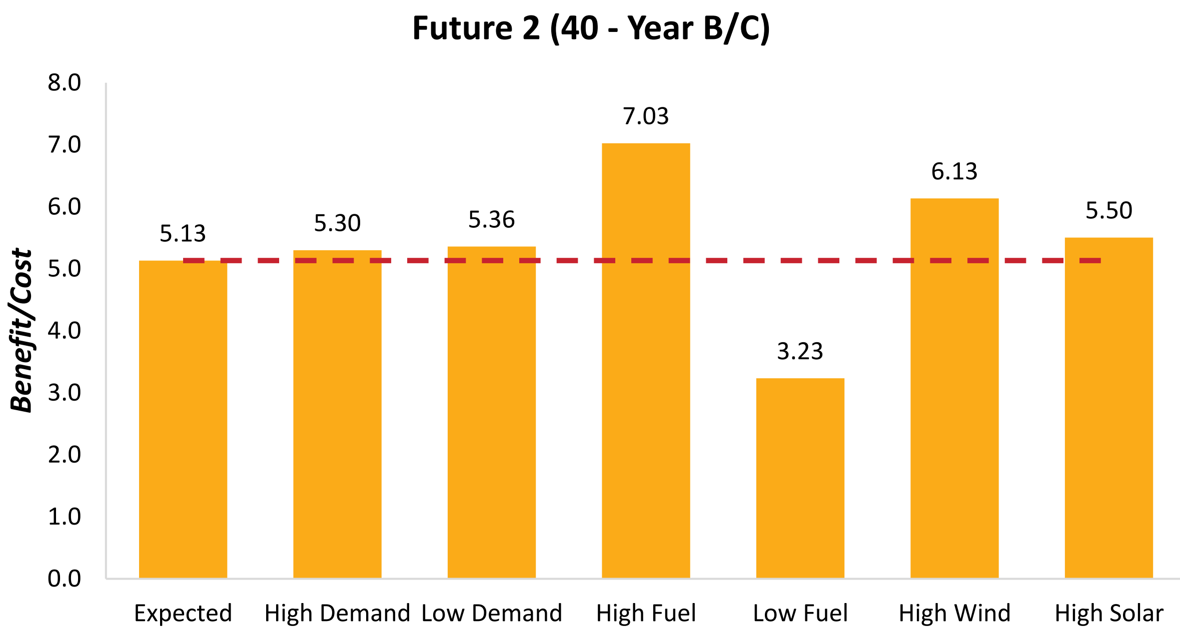


Figure 8.6*: 40-Year Benefit-to-Cost Ratios for Sensitivities*

The sensitivity results show one-year benefits and costs as well as 40-year benefits and costs. The highest benefit-to-cost ratios resulted from the high gas price and increased renewable assumptions. For detailed discussion on these results, see the following sections.

8.3.2 DEMAND AND NATURAL GAS

Two confidence intervals were developed using historical market prices and demand levels from the NYMEX and FERC Form No. 714. The standard deviation of the log difference from the normal within the pricing datasets was used to provide a confidence interval. The natural gas price sensitivities had a 95% confidence interval (1.96 standard deviations) in positive and negative directions, while the demand sensitivities had a 67% confidence interval (1 standard deviation) in positive and negative directions.

The resulting assumptions are shown in Figure 8.7 and Table 8.18.

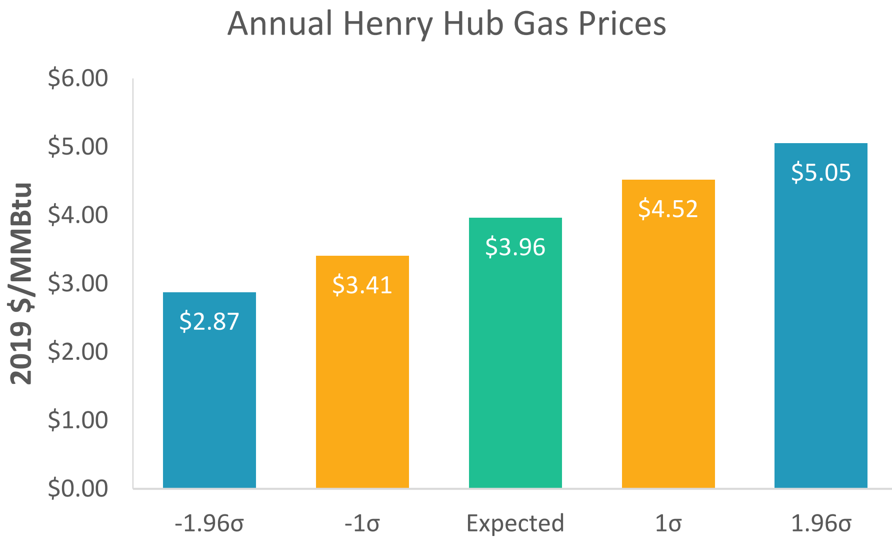


Figure 8.7: *Annual Henry Hub Natural Gas Price Values*

Sensitivity	2029 Annual Energy[28]	2029 Natural Gas Price ($/MMBtu)[29]
Expected Case	No change	No change
High Demand	7.4% Increase	No change
Low Demand	7.4% Decrease	No change
High Natural Gas	No change	$1.39 Increase
Low Natural Gas	No change	$1.39 Decrease

Table 8.18: Natural Gas and Demand Changes (2029)

The change in peak demand and energy shown in Table 8.18 reflects the SPP regional average volatility based on historical data. The 7.4% increase and decrease is the average deviation from the projected 2029 load forecasts developed by the MDWG and reviewed by the ESWG. They were implemented on the load company level. For companies without available data, the SPP regional average confidence interval was used.

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 demand and natural gas sensitivities for one-year APC benefit are reflected in Figure 8.8 and Figure 8.9. The 40-year APC benefit for these sensitivities are reflected in Figure 8.10 and Figure 8.11.

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 in Future 1. However, the low demand in Future 2 shows higher benefit than the expected case. The fundamental driver of the higher APC benefit observed under low demand in Future 2 is increased congestion on flowgates driven by wind generators; as wind production remains constant while

[28] SPP Regional
[29] Henry Hub 2029 average annual data

demand decreases, the congestion costs are spread over less load. This means in certain cases there is a greater economic opportunity under low demand for transmission projects targeting congestion caused by wind generation.

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

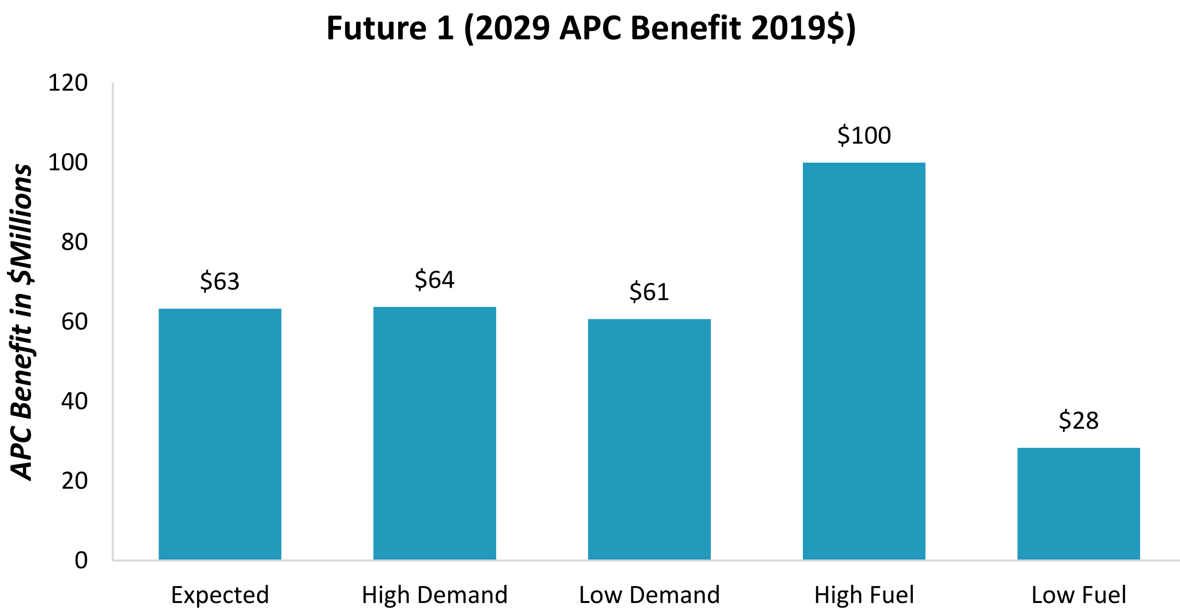


Figure 8.8: *1-Year Benefits of Future 1 Portfolio for Demand and Natural Gas Sensitivities*

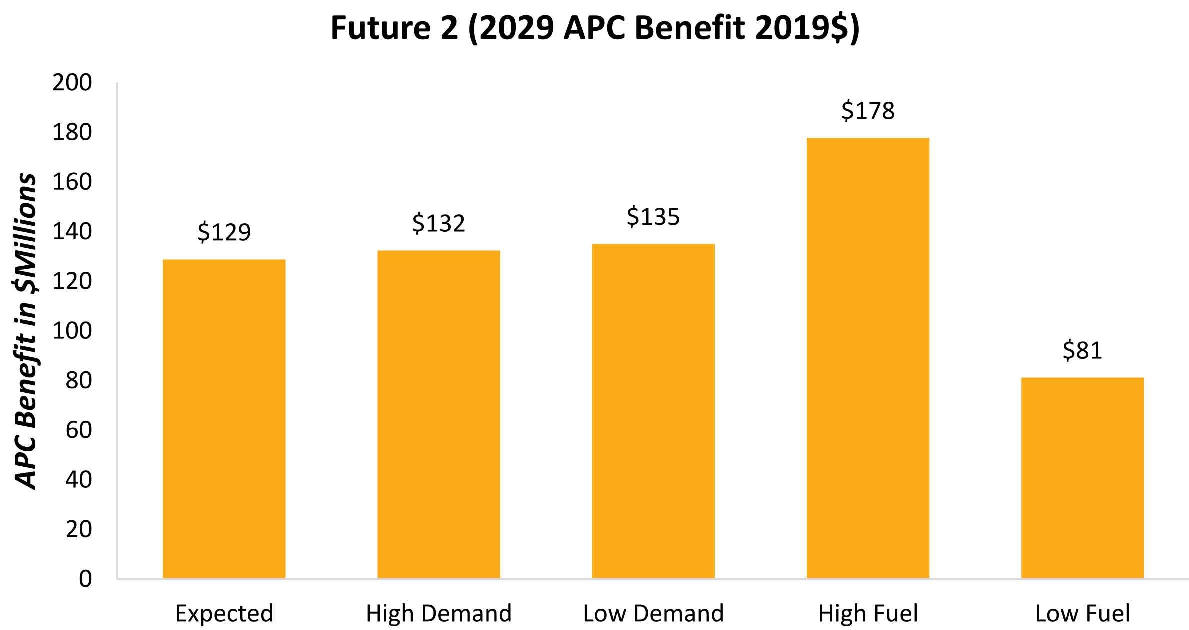


Figure 8.9: 1-Year Benefits of Future 2 Portfolio for Demand and Natural Gas Sensitivities

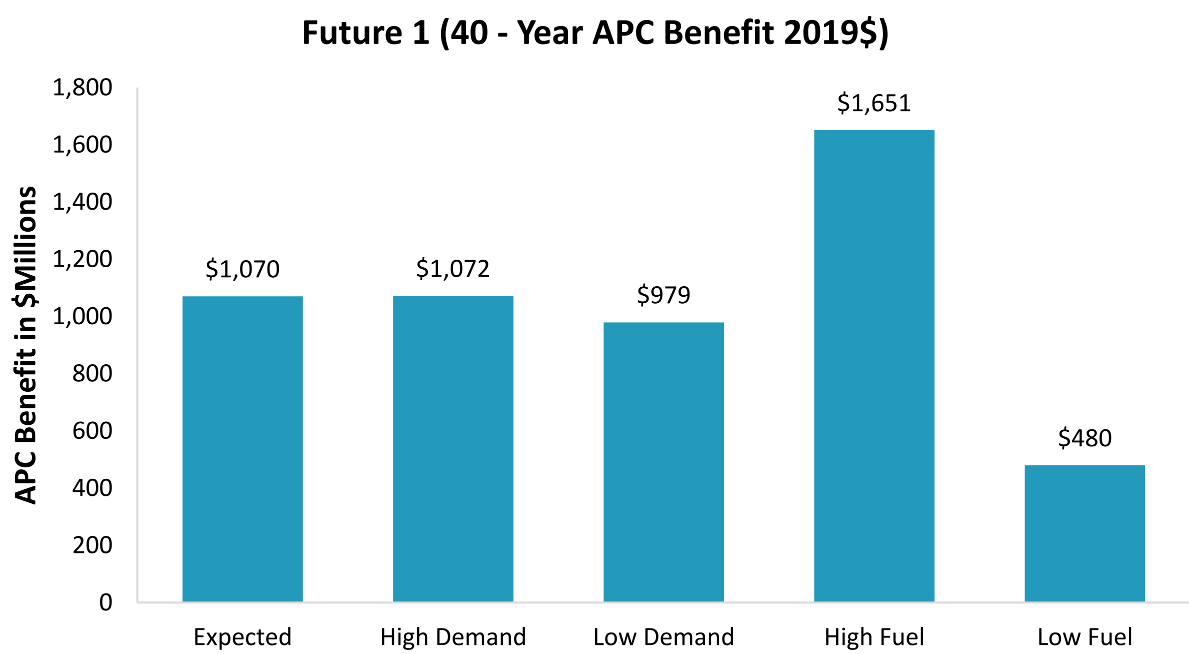


Figure 8.10*: 40-Year Benefits of Future 1 Portfolio for Demand and Natural Gas Sensitivities*

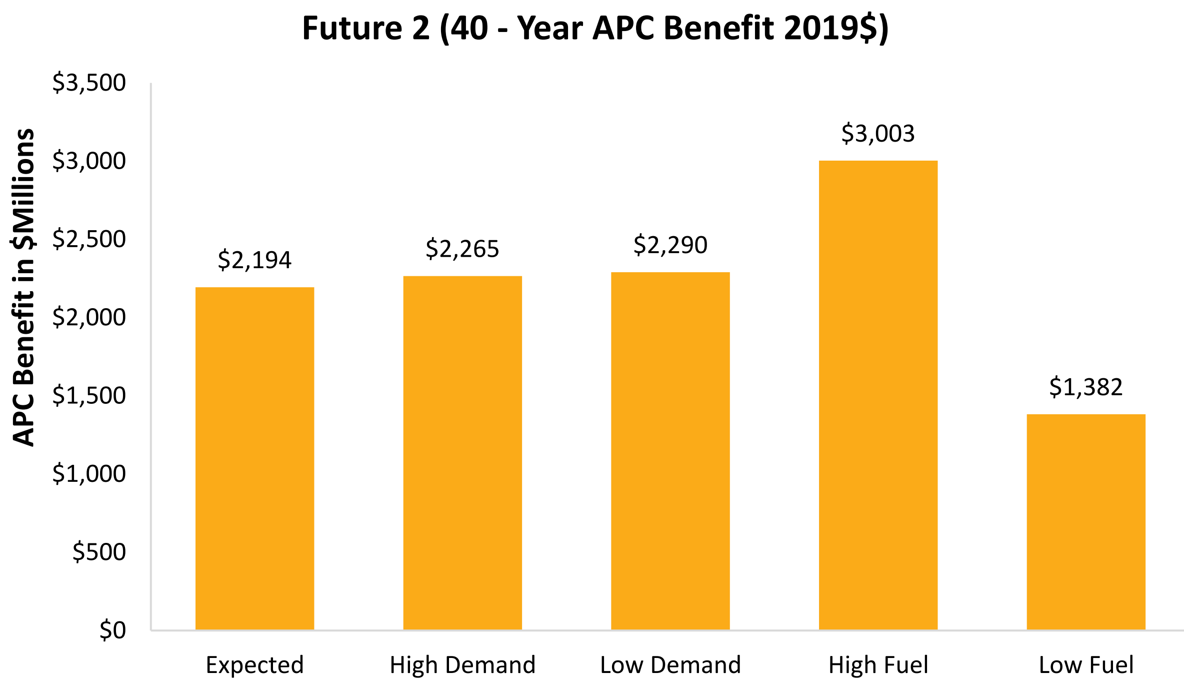


Figure 8.11*: 40-Year Benefits of Future 2 Portfolio for Demand and Natural Gas Sensitivities*

8.3.3 INCREASED RENEWABLES

The 2019 ITP renewable energy forecast in Future 2 projects an increase in wind and solar additions on the SPP system over the next 10 years. During the course of the ITP assessment, discussions occurred which questioned if the renewable amounts were conservative. As a result, a wind and solar sensitivity was conducted to test the portfolio's performance under higher wind and solar conditions. In this sensitivity (Future 2 only), wind and solar were scaled up an additional 3 GW from projected amounts. This additional wind and solar was added to each existing capacity site in the base case assumptions on a pro rata basis. APC results of this increased wind are shown in Figure 8.12 and Figure 8.13.

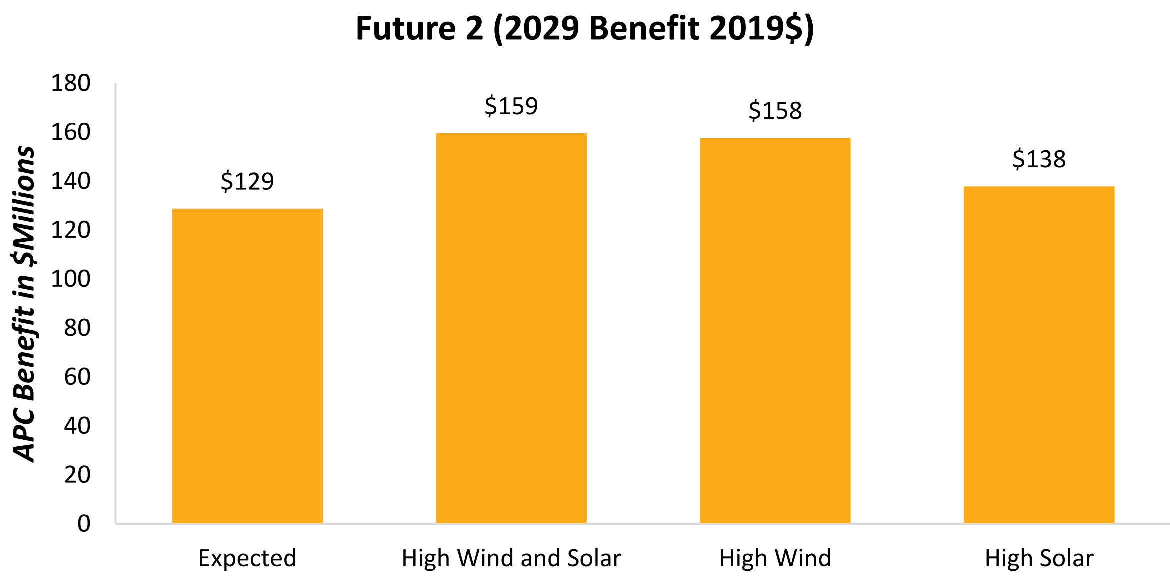


Figure 8.12: 1-Year Benefits of Future 2 Portfolio for Increased Renewables Sensitivity

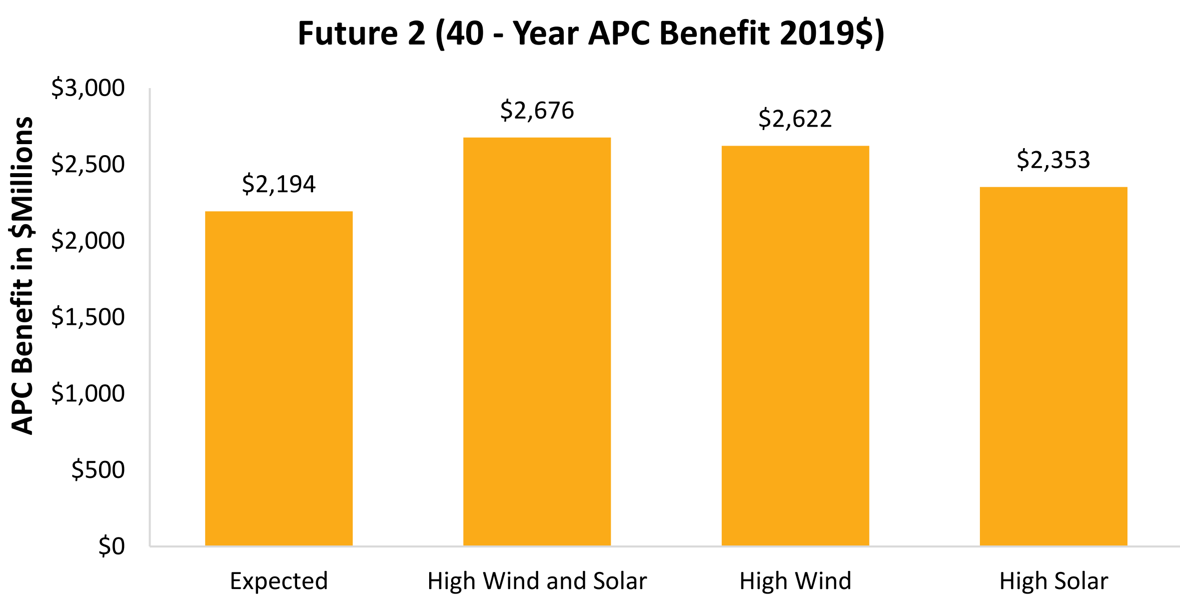


Figure 8.13: 40-Year Benefits of Future 2 Portfolio for Increased Renewables Sensitivity

Testing the portfolio against additional renewables in Future 2 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 renewables would be facilitated by these specific sets of projects. See Table 8.14 and Table 8.15 for the total wind and solar delivered and curtailed under the additional wind and solar scenarios compared to the base scenarios.

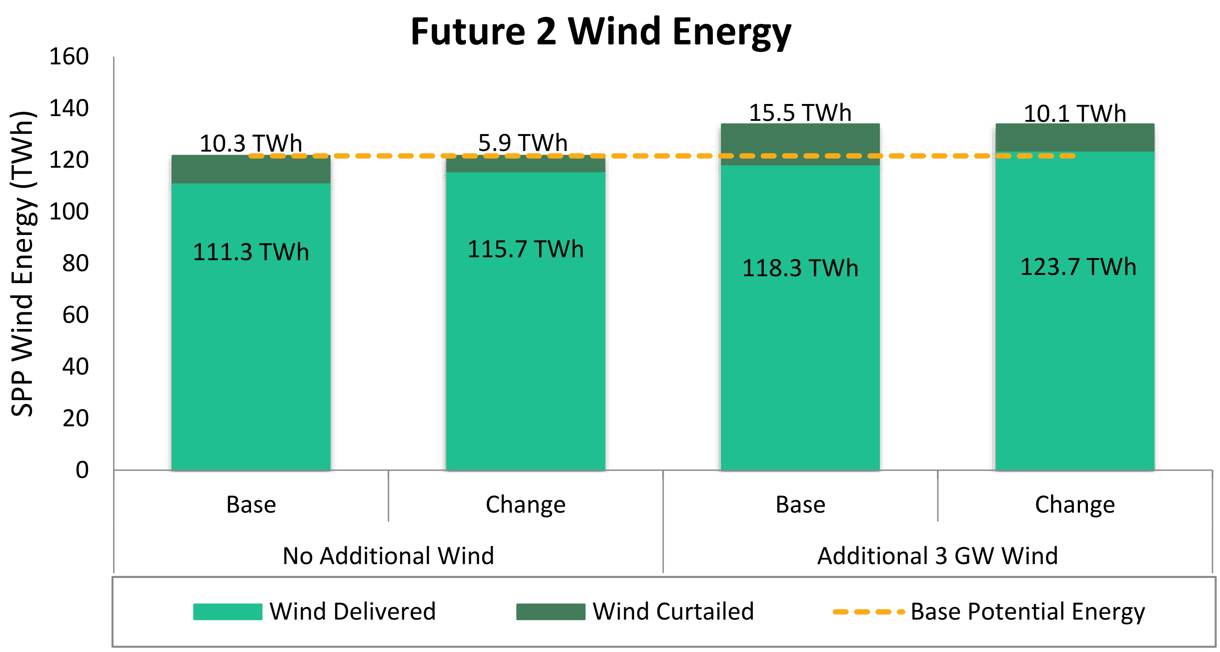


Figure 8.14: SPP Annual Wind Energy for Future 2 Portfolio (2029)

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

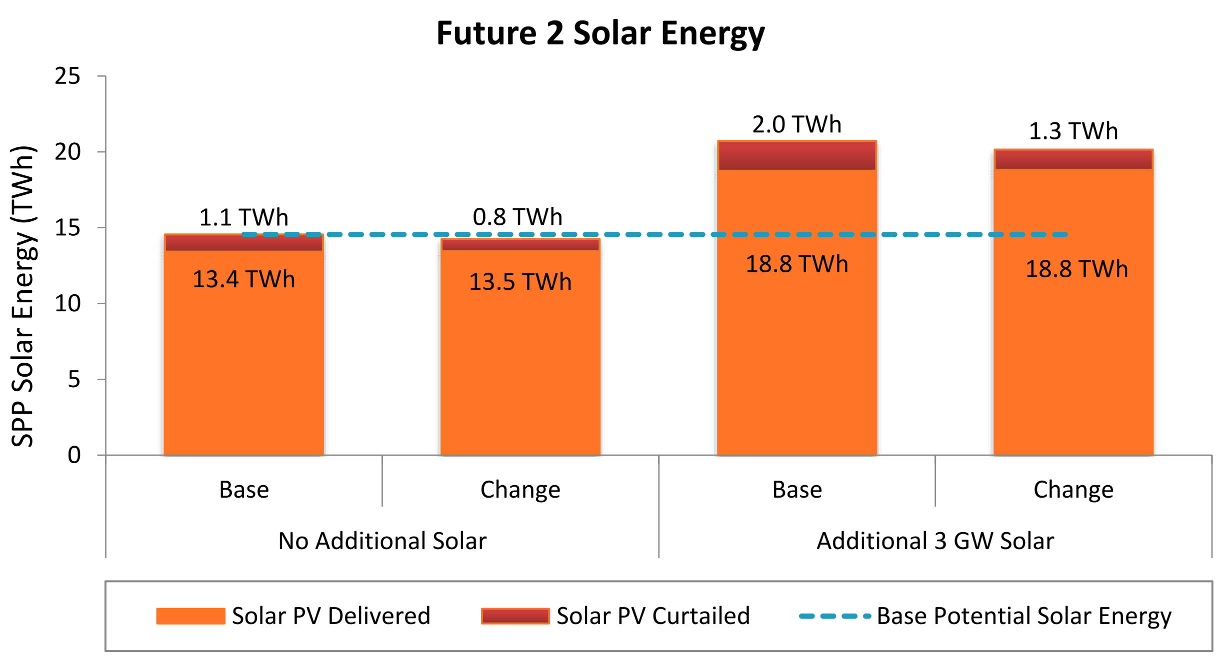


Figure 8.15: Future 2 Portfolio Solar Energy (2029)

8.3.4 DECREASED RENEWABLES

The 2019 ITP renewable energy forecast in Future 1 projects a modest increase in wind additions on the SPP system over the next 10 years. In order to understand the performance of the portfolio under the currently installed renewables, a low wind and solar sensitivity was conducted to test the portfolio's performance. In this sensitivity (Future 1 only), wind and solar are scaled down at projected sites using currently installed amounts on the SPP system of 21.5 GW of wind and 232.9 MW of solar. Wind and solar was decreased at each projected capacity site in the expected case assumptions on a pro rata basis. APC results of the decreased wind and solar are shown in Figure 8.16 and Figure 8.17.

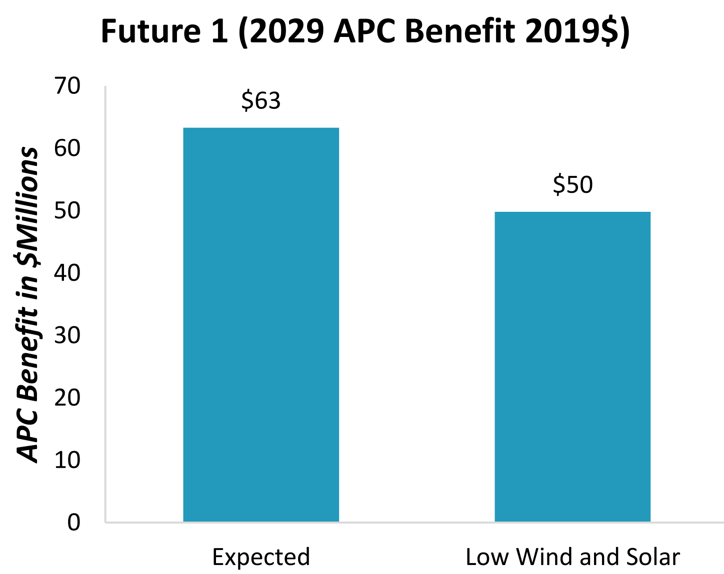


Figure 8.16: 1-Year Benefits of Future 1 Portfolio for Decreased Wind & Solar Sensitivity

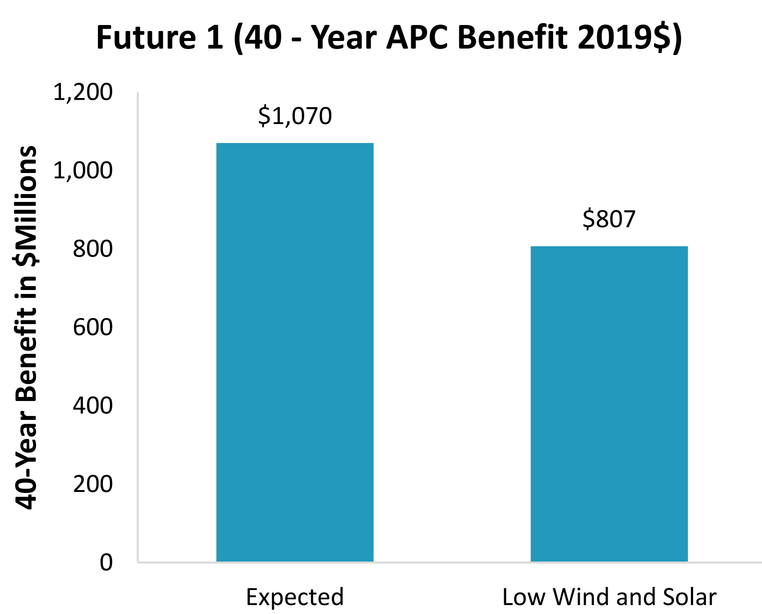


Figure 8.17: 40-Year Benefits of Future 1 Portfolio for Decreased Wind & Solar Sensitivity

Testing the scaled down renewables on Future 1 showed a decrease in APC benefit. The reduction of energy decreases congestion in the base cases leaving less congestion to be addressed by the portfolio of projects. See Figure 8.18 for the total wind and solar reduced and curtailed under the decreased wind and solar scenarios compared to the base scenarios. There was no curtailment for solar in the low renewables case; thus, Figure 8.18 does not show data for curtailed energy.

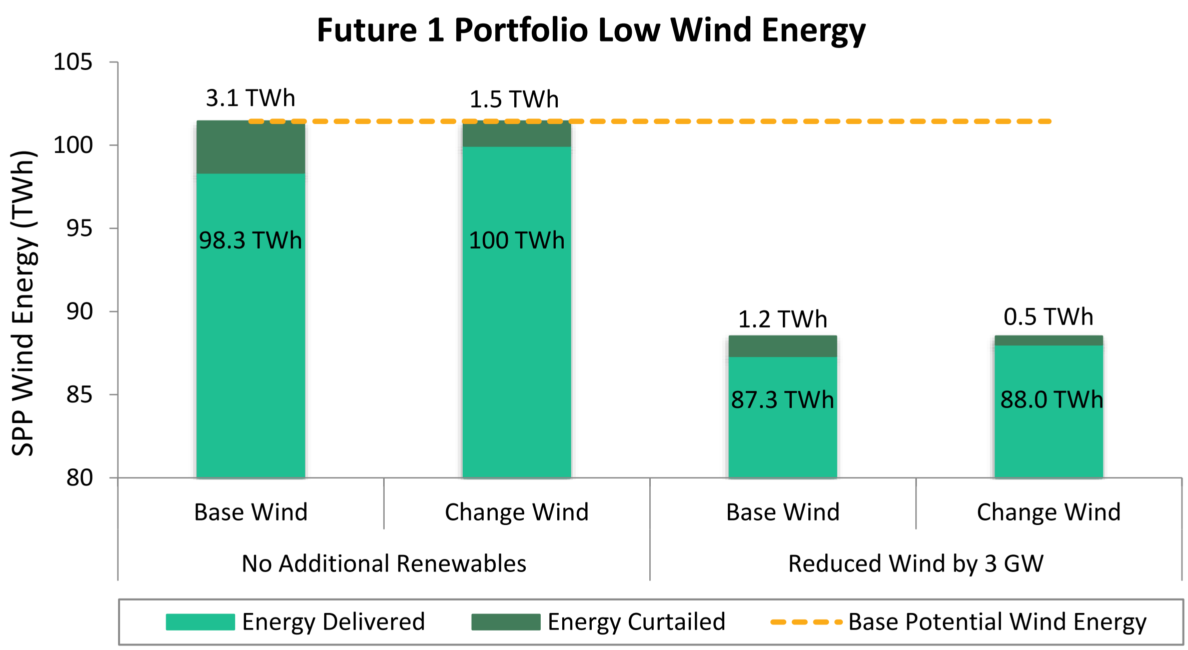


Figure 8.18: SPP Annual Wind Energy for Future 1 Portfolio (2029)

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.[30] 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 2019 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. However, the results illustrate previously known limits of the planned system that will need to be considered further in future planning assessments when making project recommendation decisions. [31]

[30] See TWG 11/30/2017 meeting minutes and attachments for the TWG-approved 2019 ITP Voltage Stability Scope:
[31] Specifically, 345 kV contingencies in southwestern, south-central, and southeastern Oklahoma

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 8.19 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 8.19: Generation Zones

Table 8.20 shows the transfers that were performed on the 2029 light load and 2029 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 2029 light load model due to the reliability hour being identified as 4 a.m.

Model	Source Zone	Sink Zone
2029 Light Load	SPP renewables (Wind)	SPP conventional thermal generation
2029 Light Load	SPP renewables (Wind)	SPP conventional thermal generation
2029 Summer	SPP renewables (Wind and Utility Scale Solar)	First Tier and Second Tier conventional thermal generation
2029 Summer	SPP renewables (Wind and Utility Scale Solar)	First Tier and Second Tier conventional thermal generation

Table 8.20: Transfers by Model

Single contingencies (N-1) for all SPP branches, transformers, and ties equal to or greater than 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. The last stable transfer was then continued in increments of 10 MW to the VSL. 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 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

Table 8.21 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: 2029 Light Load							
Wind -->Internal	15.7	6.8	Reached Minimum Sink	16.5	6.1	0.8	N/A
Wind -->External Thermal	15.7	19.1	Terry Road-Sunnyside 345 kV	17.4	17.7	1.7	Yes
"	15.7	19.1	Chisholm-Gracemont 345 kV (Tap at RP2POI06)	17.8	17.5	2.1	Yes
"	15.7	19.1	Cimarron-Draper 345 kV	18.8	16.7	3.1	Yes
"	15.7	19.1	Sunnyside-Hugo 345 kV	18.8	16.7	3.1	Yes
"	15.7	19.1	Minco-Cimarron 345 kV	18.8	16.7	3.1	Yes
Future 1: 2029 Summer Peak							
Solar & Wind -->Internal	5.5	42.0	Reached Maximum Source	30.1	18.5	24.5	Yes
Solar & Wind -->External	5.5	87.2	Oklaunion-Lawton Eastside 345 kV	16.8	77.6	11.2	Yes
"	5.5	87.2	Mount Olive-Layfield 500kV	17.4	77.2	11.8	Yes
"	5.5	87.2	Holt-S3458 345 kV	17.6	77.0	12.0	Yes
"	5.5	87.2	Tuco-Oklaunion 345 kV	17.8	76.9	12.2	Yes
"	5.5	87.2	Muskogee-Fort Smith 345 kV	17.8	76.9	12.2	Yes
Future 2: 2029 Light Load							
Wind -->Internal	18.2	5.7	Reached Minimum Sink	18.9	5.1	0.7	N/A
Wind -->External	18.2	21.1	Crossroads-Eddy County 345 kV	20.6	19.4	2.4	Yes
"	18.2	21.1	Terry Road-Sunnyside 345 kV	21.0	19.1	2.8	Yes
"	18.2	21.1	Pittsburg-Valliant 345 kV	21.0	19.1	2.8	Yes
"	18.2	21.1	Sunnyside-Hugo 345 kV	21.6	18.7	3.4	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
"	18.2	21.1	Fort Smith-ANO 500kV	21.6	18.7	3.4	Yes
Future 2: 2029 Summer Peak							
Solar & Wind -->Internal	16.1	33.7	Mingo-Red Willow 345 kV	28.7	21.9	12.6	Yes
"	16.1	33.7	Setab-Mingo 345 kV	28.7	21.9	12.6	Yes
"	16.1	33.7	La Cygne-Stillwell 345 kV	28.7	21.9	12.6	Yes
Future 2: 2029 Summer Peak *(continued)*							
"	16.1	33.7	Wichita-Reno 345 kV	28.9	21.7	12.8	Yes
"	16.1	33.7	JEC-Hoyt 345 kV	28.9	21.7	12.8	Yes
Solar & Wind -->External	16.1	82.7	JEC-Hoyt 345 kV	20.3	78.9	4.2	Yes
"	16.1	82.7	La Cygne-Stillwell 345 kV	21.1	78.3	5.0	Yes
"	16.1	82.7	Hoyt-Stranger 345 kV	21.5	77.9	5.4	Yes
"	16.1	82.7	Jasper-Morgan 345 kV	21.5	77.9	5.4	Yes
"	16.1	82.7	La Cygne-West Gardner 345 kV	21.7	77.8	5.6	Yes

Table 8.21: Post-Contingency Voltage Stability Transfer Limit Summary

Table 8.22 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: 2029 Light Load				
Wind-->Internal	**24.6**	N/A	N/A	Reached Sink Minimum
Wind-->External	**24.6**	17.4	16.9	Thermal Issues prior to Voltage Collapse
Future 1: 2029 Summer Peak				
Solar & Wind -->Internal	**29.6**	30.1	7.3	No Voltage Collapse
Solar & Wind -->External	**29.6**	16.8	9.0	Thermal Issues prior to Voltage Collapse
Future 2: 2029 Light Load				
Wind-->Internal	**30**	N/A	N/A	Reached Sink Minimum

Transfer Source-->Sink	Total Renewable Capacity (GW)	VSL Limit (GW)	Thermal Limit (GW)	Comment
Wind-->External	**30**	20.6	20.4	Thermal Issues prior to Voltage Collapse
Future 2: 2029 Summer Peak				
Solar & Wind -->Internal	**37**	28.7	16.1	Thermal Issues prior to Voltage Collapse
Solar & Wind -->External	**37**	20.3	16.1	Thermal Issues prior to Voltage Collapse

Table 8.22: 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 model 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 market economic model reliability hours after modeling the consolidated portfolio.

8.5 FINAL RELIABILITY ASSESSMENT

8.5.1 METHODOLOGY

All projects in the 2019 ITP recommended portfolio and model adjustments identified during solution development were incorporated into the base reliability, short-circuit, and select seasons of the market powerflow models (year 10 peak and off-peak, Futures 1 and 2). The market powerflow models were rebuilt following the DC-to-AC conversion process described in Section 2.3.1 of the ITP Manual. A contingency analysis of equivalent scope to the analysis described in Sections 4.2.1 and 4.2.2 of the ITP Manual was performed to determine if the selected projects caused any new reliability violations.

8.5.1.1 Short-Circuit Model

A proxy automatic sequencing fault calculation (ASCC) short-circuit analysis was performed on the 2019 ITP Year 2 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 58 of the 9,610 buses monitored experienced a 5% increase in fault current. Only three of the 58 buses appeared to exceed common breaker duty ratings of 20kA and 40kA. 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 Powerflow 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.

8.5.2.2 Market Powerflow Models

A portion of the resulting thermal and voltage violations caused by the 2019 ITP consolidated portfolio were solved or marked invalid through the same methods utilized for the base reliability powerflow models. The remaining thermal overload violations were given additional review and not considered to be new reliability violations based on ITP Manual Section 4.2.5 violation filtering criteria. New voltage violations were observed at several monitored facilities in the south SPS area for loss of the Crossroads-Eddy County 345 kV line; no solutions will be developed for these violations. These facilities will be monitored in the initial assessments of the 2020 ITP for continued 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

The final reliability assessment showed no new reliability violations caused by the 2019 ITP recommended portfolio that require additional project recommendations in this ITP assessment.

9 NTC RECOMMENDATIONS

SPP staff makes Notification to Consruct (NTC) recommendations for projects included in the consolidated portfolio based upon 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). 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 cost estimate greater than $20 million.

One exception to this process for the 2019 ITP is the Butler 138 kV phase-shifting transformer. Although this upgrade proved to be cost-effective during the analysis, no NTC is recommended. A qualitative assessment of the Butler 138 kV phase-shifting transformer revealed it may not be the optimal long-term solution.

The Butler-Altoona 138 kV line is 70 miles, spanning from northeast Wichita to a rural area north of Independence, Kansas. This line is one of the oldest and lowest rated in SPP, as compared to other 138 kV facilities. The Butler 138 kV phase-shifting transformer was expected to redirect flows on the Butler-Altoona 138 kV line to other higher capacity facilities. However, definitive long-term plans for rehabilitation of the facility have yet to be determined, suggesting additional analysis is necessary in future planning studies.

Table 9.1 below shows SPP's NTC recommendations when considering staging results, expected lead times, and the resulting financial commitment date. For the reasons indicated above, the Butler 138 kV phase-shifting is not recommended to receive an NTC.

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Replace one breaker at Craig 161 kV	6/1/2021	18	12/1/2019	NTC
Replace two breakers at Leeds 161 kV	6/1/2021	18	12/1/2019	NTC
Replace two breakers at Midtown 161 kV	6/1/2021	18	12/1/2019	NTC
Replace four breakers at Southtown 161 kV	6/1/2021	18	12/1/2019	NTC
Replace one breaker at Moore 13.8 kV tertiary bus	6/1/2021	18	12/1/2019	NTC
Replace two breakers at Hastings 115 kV	6/1/2021	18	12/1/2019	NTC
Replace five breakers at Canaday 115 kV	6/1/2021	18	12/1/2019	NTC
Replace two breakers at Westmoore 138 kV	6/1/2021	18	12/1/2019	NTC
Replace three breakers at Santa Fe 138 kV	6/1/2021	18	12/1/2019	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Replace one breaker at Carlsbad Interchange 115 kV	6/1/2021	18	12/1/2019	NTC
Replace three breakers at Denver City North and South 115 kV	6/1/2021	18	12/1/2019	NTC
Replace three breakers at Hale County Interchange 115 kV	6/1/2021	18	12/1/2019	NTC
Replace one breaker at Washita 69 kV	6/1/2021	18	12/1/2019	NTC
Replace 12 breakers at Mooreland 138/69 kV	6/1/2021	18	12/1/2019	NTC
Replace 21 breakers at Riverside Station 138 kV	6/1/2021	18	12/1/2019	NTC
Replace eight breakers at Southwestern Station 138 kV	6/1/2021	18	12/1/2019	NTC
Replace three breakers at Anadarko 138 kV	6/1/2021	18	12/1/2019	NTC
Cleo Corner-Cleo Switch 69 kV terminal equipment	6/1/2022	18	12/1/2020	NTC
Deaf Smith-Plant X 230 kV terminal equipment	4/1/2029	18	10/1/2027	No
Bushland-Deaf Smith 230 kV terminal equipment	4/1/2026	18	10/1/2024	No
Potter-Newhart 230 kV terminal equipment	4/1/2028	18	10/1/2026	No
Getty-Skelly 69 kV terminal equipment	4/1/2021	18	10/1/2019	NTC
Marshall-Smittyville-Bailey-Seneca 115 kV rebuild	4/1/2021	30	10/1/2018	NTC
Pryor Junction 138/115 kV transformer	6/1/2021	24	6/1/2019	NTC
Tulsa SE-21st Street Tap 138 kV rebuild	6/1/2021	24	6/1/2019	NTC
Tulsa SE-S. Hudson 138 kV rebuild	6/1/2021	24	6/1/2019	NTC
Moore-RB–S&S 115 kV terminal equipment	6/1/2026	18	12/1/2024	No
Carlisle-LP Doud 115 kV terminal equipment	6/1/2026	18	12/1/2024	No
Lubbock-Jones 230 kV circuit 1 terminal equipment	6/1/2029	18	12/1/2027	No
Lubbock-Jones 230 kV circuit 2 terminal equipment	6/1/2029	18	12/1/2027	No
Plains-Yoakum 115 kV terminal equipment	6/1/2029	18	12/1/2027	NO
Firth 15 MVAR 115 kV capacitor bank	4/1/2021	24	4/1/2019	NTC
Rocky Point-Marietta 69 kV terminal equipment	12/1/2021	18	6/1/2020	NTC
Gypsum 12 MVAR 69 kV capacitor bank	6/1/2021	24	6/1/2019	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Lawrence EC-Midland 115 kV terminal equipment	1/1/2021	18	7/1/2019	NTC
Sundown-Amoco 115 kV terminal equipment	1/1/2023	18	7/1/2021	NTC
Spearman-Hansford 115 kV rebuild	1/1/2021	18	7/1/2019	NTC
Kingfisher-East Kingfisher Tap 138 kV rebuild	1/1/2021	24	1/1/2019	NTC
Cimarron-Northwest-Mathewson 345 kV terminal equipment	1/1/2021	18	7/1/2019	NTC
New Sooner-Wekiwa 345 kV line, Sheffield Steel-Sand Springs 138 kV terminal equipment	1/1/2026	48	1/1/2022	NTC-C
Arnold-Ransom 115 kV terminal equipment, Pile-Scott City-Setab 115 kV terminal equipment	1/1/2025	18	7/1/2023	NTC
Gracemont-Anadarko 138 kV rebuild	1/1/2021	24	1/1/2019	NTC
New Wolf Creek-Blackberry 345 kV line, new Butler 138 kV phase shifting transformer	1/1/2026	48	1/1/2022	**Line**: NTC-C **PST**: No

Table 9.1: NTC Recommendations

10 APPENDIX

10.1 FINAL RELIABILITY ASSESSMENT – NEW VIOLATIONS

Table 10.1 lists the new voltage violations observed in the market powerflow models after performing the final reliability assessment.

Scenario	Contingency Name	Bus Number	Post-Contingent Voltage
F2 2029 LL	Crossroads-Eddy County 345 kV	AMOCO_SS 6	0.8889
F2 2029 LL	Crossroads-Eddy County 345 kV	AMOCOWASSON6	0.8365
F2 2029 LL	Crossroads-Eddy County 345 kV	YOAKUM 6	0.8414
F2 2029 LL	Crossroads-Eddy County 345 kV	YOAKUM_345	0.85
F2 2029 LL	Crossroads-Eddy County 345 kV	BRU_SUB 6	0.8386
F2 2029 LL	Crossroads-Eddy County 345 kV	OXYBRU 6	0.8386
F2 2029 LL	Crossroads-Eddy County 345 kV	XTO_MAHONEY6	0.8377
F2 2029 LL	Crossroads-Eddy County 345 kV	BENNETT 3	0.8742
F2 2029 LL	Crossroads-Eddy County 345 kV	CORTEZ 3	0.8788
F2 2029 LL	Crossroads-Eddy County 345 kV	APACHE_ROB 3	0.8788
F2 2029 LL	Crossroads-Eddy County 345 kV	ALLRED_SUB 3	0.879
F2 2029 LL	Crossroads-Eddy County 345 kV	INK_BASIN 3	0.89
F2 2029 LL	Crossroads-Eddy County 345 kV	INK_BASIN 6	0.8362
F2 2029 LL	Crossroads-Eddy County 345 kV	ALRDCRTZ_TP3	0.8801
F2 2029 LL	Crossroads-Eddy County 345 kV	XTO_CORNEL+3	0.8774
F2 2029 LL	Crossroads-Eddy County 345 kV	SHELL_C2 3	0.8723
F2 2029 LL	Crossroads-Eddy County 345 kV	ARCO_TP 3	0.8748
F2 2029 LL	Crossroads-Eddy County 345 kV	OXY_WILRD1 3	0.8736
F2 2029 LL	Crossroads-Eddy County 345 kV	ODC_TP 3	0.8741
F2 2029 LL	Crossroads-Eddy County 345 kV	ODC 3	0.872
F2 2029 LL	Crossroads-Eddy County 345 kV	SHELL_CO2 3	0.8687
F2 2029 LL	Crossroads-Eddy County 345 kV	SHELLC3_TP 3	0.8749
F2 2029 LL	Crossroads-Eddy County 345 kV	SHELLC3 3	0.8747
F2 2029 LL	Crossroads-Eddy County 345 kV	EL_PASO 3	0.8684
F2 2029 LL	Crossroads-Eddy County 345 kV	SAN_ANDS_TP3	0.8677
F2 2029 LL	Crossroads-Eddy County 345 kV	SAN_ANDRES 3	0.8651
F2 2029 LL	Crossroads-Eddy County 345 kV	DENVER_N 3	0.8687
F2 2029 LL	Crossroads-Eddy County 345 kV	DENVER_S 3	0.8687
F2 2029 LL	Crossroads-Eddy County 345 kV	MUSTANG 3	0.8673

Scenario	Contingency Name	Bus Number	Post-Contingent Voltage
F2 2029 LL	Crossroads-Eddy County 345 kV	MUSTANG 6	0.8357
F2 2029 LL	Crossroads-Eddy County 345 kV	GS-MUSTANG 6	0.8357
F2 2029 LL	Crossroads-Eddy County 345 kV	LG-PLSHILL 3	0.8895
F2 2029 LL	Crossroads-Eddy County 345 kV	SEAGRAVES 3	0.8853
F2 2029 LL	Crossroads-Eddy County 345 kV	DIAMONDBACK3	0.8816
F2 2029 LL	Crossroads-Eddy County 345 kV	ROZ 3	0.8757
F2 2029 LL	Crossroads-Eddy County 345 kV	AMERADA 3	0.8755
F2 2029 LL	Crossroads-Eddy County 345 kV	SULPHUR 3	0.8877
F2 2029 LL	Crossroads-Eddy County 345 kV	SEMINOLE 3	0.8768
F2 2029 LL	Crossroads-Eddy County 345 kV	SEMINOLE 6	0.8157
F2 2029 LL	Crossroads-Eddy County 345 kV	RUSSELL 3	0.8611
F2 2029 LL	Crossroads-Eddy County 345 kV	HIGGEAST 3	0.862
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-KCM 2	0.8534
F2 2029 LL	Crossroads-Eddy County 345 kV	AM_FRAC 3	0.8597
F2 2029 LL	Crossroads-Eddy County 345 kV	GAINES 3	0.8644
F2 2029 LL	Crossroads-Eddy County 345 kV	OXY_WSTSEM 3	0.8634
F2 2029 LL	Crossroads-Eddy County 345 kV	OXY_WSEM_TP3	0.8639
F2 2029 LL	Crossroads-Eddy County 345 kV	DOSS 3	0.8675
F2 2029 LL	Crossroads-Eddy County 345 kV	LEGACY 3	0.8627
F2 2029 LL	Crossroads-Eddy County 345 kV	MAPCO 3	0.8597
F2 2029 LL	Crossroads-Eddy County 345 kV	JOHNSON_DRW3	0.86
F2 2029 LL	Crossroads-Eddy County 345 kV	HIGG 3	0.862
F2 2029 LL	Crossroads-Eddy County 345 kV	FLANNAGAN 2	0.8998
F2 2029 LL	Crossroads-Eddy County 345 kV	LG-FLOREY +2	0.8998
F2 2029 LL	Crossroads-Eddy County 345 kV	CUNNINHAM 3	0.8836
F2 2029 LL	Crossroads-Eddy County 345 kV	CUNNIGHM_N 6	0.8727
F2 2029 LL	Crossroads-Eddy County 345 kV	CUNNIGHM_S 6	0.8727
F2 2029 LL	Crossroads-Eddy County 345 kV	HOBBS_INT 3	0.8871
F2 2029 LL	Crossroads-Eddy County 345 kV	HOBBS_INT 6	0.8652
F2 2029 LL	Crossroads-Eddy County 345 kV	HOBBS_INT 7	0.8696
F2 2029 LL	Crossroads-Eddy County 345 kV	POTASH_JCT 6	0.8908
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-WAITS 3	0.8877
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-WEST_SUB3	0.8894
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-NRTH_INT3	0.8892
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-SANANDRS3	0.8809
F2 2029 LL	Crossroads-Eddy County 345 kV	BUCKEYE_TP 3	0.8814
F2 2029 LL	Crossroads-Eddy County 345 kV	MADDOXG23 3	0.8839

Scenario	Contingency Name	Bus Number	Post-Contingent Voltage
F2 2029 LL	Crossroads-Eddy County 345 kV	MADDOX 3	0.8839
F2 2029 LL	Crossroads-Eddy County 345 kV	BUCKEYE 3	0.8813
F2 2029 LL	Crossroads-Eddy County 345 kV	PEARLE 3	0.8928
F2 2029 LL	Crossroads-Eddy County 345 kV	TAYLOR 3	0.8741
F2 2029 LL	Crossroads-Eddy County 345 kV	BENSING 3	0.8727
F2 2029 LL	Crossroads-Eddy County 345 kV	MILLEN 3	0.8771
F2 2029 LL	Crossroads-Eddy County 345 kV	NE_HOBBS 3	0.8757
F2 2029 LL	Crossroads-Eddy County 345 kV	W_BENDER 3	0.8708
F2 2029 LL	Crossroads-Eddy County 345 kV	N_HOBBS 3	0.8682
F2 2029 LL	Crossroads-Eddy County 345 kV	SANGER_SW 3	0.8728
F2 2029 LL	Crossroads-Eddy County 345 kV	E_SANGER 3	0.8762
F2 2029 LL	Crossroads-Eddy County 345 kV	S_HOBBS 3	0.8858
F2 2029 LL	Crossroads-Eddy County 345 kV	OXY_S_HOBBS3	0.888
F2 2029 LL	Crossroads-Eddy County 345 kV	SW_4J44 3	0.892
F2 2029 LL	Crossroads-Eddy County 345 kV	MONUMENT 3	0.8869
F2 2029 LL	Crossroads-Eddy County 345 kV	W_HOBBS 3	0.8941
F2 2029 LL	Crossroads-Eddy County 345 kV	LEA_ROAD 3	0.897
F2 2029 LL	Crossroads-Eddy County 345 kV	OIL_CENTER 3	0.8921
F2 2029 LL	Crossroads-Eddy County 345 kV	COOPER_RNCH3	0.8868
F2 2029 LL	Crossroads-Eddy County 345 kV	MONUMNT_TP 3	0.8809
F2 2029 LL	Crossroads-Eddy County 345 kV	OXYPERMIAN 3	0.8711
F2 2029 LL	Crossroads-Eddy County 345 kV	BYRD_TP 3	0.8797
F2 2029 LL	Crossroads-Eddy County 345 kV	BYRD 3	0.878
F2 2029 LL	Crossroads-Eddy County 345 kV	ANDREWS 6	0.8634
F2 2029 LL	Crossroads-Eddy County 345 kV	GAINESGENTP6	0.8645
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-TXACO_TP3	0.8811
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-SW91 2	0.8558
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ANCELL 2	0.8558
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ANCEL_TP2	0.8567
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ERF 2	0.8573
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ERF 3	0.86
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-GAINES 2	0.8533
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ROZ 2	0.8544
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-TEXACO 3	0.8809
F2 2029 LL	Crossroads-Eddy County 345 kV	RP2POI12	0.8441

Table 10.1: Market Powerflow Model – New Voltage Violations

10.2 ITP MANUAL AND 2019 ITP SCOPE REFERENCES

Section	Description	ITP Manual Section(s)	ITP Scope Section(s)
1	**Introduction**	**1**	**1**
1.1	The ITP Assessment	1.1, 1.2, 1.6	
1.2	Report Structure	8.1	
1.3	Stakeholder Collaboration	1.3.1, 1.4	
1.3.1	Planning Summits	6.1	
2	**Model Development**	**2**	**2**
2.1	Base Reliability Model	2.1	
2.2	Market Economic Model	2.2	
2.3	Market Powerflow Model	2.3	
3	**Benchmarking**	**3**	
3.1	Powerflow Model	3.1	
3.2	Economic Model	3.2	
4	**Needs Assessment**	**4**	
4.1	Economic Needs	4.1	
4.1.1	Target Areas	4.1.2	
4.2	Reliability Needs	4.2	
4.2.1	Base Reliability Assessment	4.2.1	
4.2.2	Market Powerflow Assessment	4.2.2	
4.2.3	Non-Converged Contingencies	4.2.3	
4.2.4	Short-Circuit Assessment	4.2.7	
4.3	Policy Needs	4.3	
4.4	Persistent Operational Needs	4.4	
4.5	Need Overlap	6.1.5	
5	**Solution Development and Evaluation**	**5**	**3**
5.1	Reliability Project Screening	5.3.2	
5.2	Economic Project Screening	5.3.1	
5.3	Short-Circuit Project Screening	4.2.7	
5.4	Public Policy Project Screening	5.3.3	
5.5	Persistent Operational Project Screening	5.3.4	**3**
6	**Portfolio Development**	**6**	
6.1	Portfolio Development Process	6.1	
6.2	Project Selection and Grouping	6.1.1-6.1.4	
6.2.1	Study Estimates	5.2	
6.2.2	Reliability Grouping	6.1.2	
6.2.3	Short-Circuit Grouping	4.2.7	
6.2.4	Economic Grouping	6.1.1	
6.3	Optimization	4.2.7	

Section	Description	ITP Manual Section(s)	ITP Scope Section(s)
6.4	Portfolio Consolidation	6.2	**3**
6.5	Final Consolidated Portfolio	6.2	**3**
6.6	Staging	6.3	
6.6.1	Economic Projects	6.3.1	
6.6.2	Policy Projects	6.3.3	
6.6.3	Reliability Projects	6.3.2	
6.6.4	Short-Circuit Projects	4.2.7	
7	**Project Recommendations**	**6.2**	**3**
8	**Informational Portfolio Analyses**	**7**	**4**
8.1	Benefits	7.1	
8.2	Rate Impacts	6.3	
8.3	Sensitivity Analysis	7.2	**4**
8.4	Voltage Stability Assessment	--	**4**
8.5	Final Reliability Assessment	6.4	

Table 10.2: ITP Manual and 2019 ITP Scope References

11 GLOSSARY

Acronym	Name
ABB	ABB Group licenses the PROMOD enterprise software SPP uses for economic simulations
APC	Adjusted production cost = Production Cost $ + Purchases $ - Sales $
ARR	Auction Revenue Rights
ATC	Available transfer capacity
BA	Balancing Authority
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
MTEP16	2016 MISO Transmission Expansion Plan
MTEP18	2018 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 11.1: Glossary