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SOAH DOCKET NO. 473-19-6862
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APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE ACQUISITION OF WIND GENERATION FACILITIES	§ § § § § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRD REQUEST FOR INFORMATION

SEPTEMBER 16, 2019

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRD REQUEST FOR INFORMATION

Question No. TIEC 3-1:

In reference to the Workpaper "Updated Torpey Errata Benefits Model Final.xslx," please provide all workpapers (in native format with formulas intact and provide all linked files) used to develop all inputs for all sensitivities studied.

Response No. TIEC 3-1:

See the Company's supplemental response to TIEC 1-19 for all of witness Torpey's workpapers and instructions including the PLEXOS output files. His source files weren't linked to the model due to the large number of them. The native format of the PLEXOS output files is all hard coded numbers.

Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: James F. Martin	Title: Regulatory Case Mgr
Sponsored By: John F. Torpey	Title: Mng Dir Res Plnning&Op Anlysis

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRD REQUEST FOR INFORMATION

Question No. TIEC 3-2:

Please provide the following PLEXOS model assumptions/outputs under the Base and Project cases (i.e., with and without the Wind Projects) for each year of the analysis for each scenario studied:

a. SWEPCO net energy for load.
b. Net generation by SWEPCO unit and energy purchased by PPA.
c. Heat rate and capacity factor for each generating unit.
d. Fuel and O&M expense for each generating unit.
e. Ancillary services (amount and costs).
f. Interchange purchases and sales (amounts and costs).
g. The assumed LMPs used in estimating off-system purchases/sales.
h. Escalation rates.
i. Discount rate.

Response No. TIEC 3-2:

A portion of the information responsive to this request is CONFIDENTIAL under the terms of the Protective Order. The Confidential information is available for review at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 1520, Austin, Texas, 78701, (512) 481-4562, during normal business hours.

a. In TIEC_3_2_ Attachment.zip provided on the attachment flash drive, see "TIEC_3_2_Attachment_10.csv" for annual SWEPCO load, same for all scenarios.
b. For net generation by SWEPCO unit, in TIEC_3_2_Confidential_Attachment.zip, go to desired scenario's folder and see "TIEC_3_2_Confidential_Attachment_2.csv". For energy purchased by PPA, go to TIEC_3_2_ Attachment.zip, go to desired scenario's folder and see "TIEC_3_2_Attachment_3.csv"
c. For Heat Rate by SWEPCO unit, in TIEC_3_2_Confidential_Attachment.zip, go to desired scenario's folder and see "TIEC_3_2_Confidential_Attachment_4.csv". For capacity factor by SWEPCO unit, in TIEC_3_2_Confidential_Attachment.zip, go to desired scenario's folder and see "TIEC_3_2_Confidential_Attachment_5.csv".
d. For Fuel by SWEPCO unit, in TIEC_3_2_Confidential_Attachment.zip, go to desired scenario's folder and see "TIEC_3_2_Confidential_Attachment_6.csv". For O&M by

SWEPCO unit, in TIEC_3_2_Confidential_Attachment.zip, go to desired scenario's folder and see "TIEC_3_2_Confidential_Attachment_7.csv".

e. The amount for ancillary services were deemed immaterial and were not included in the analysis.

f. For purchases and sales and their associated amounts and cost, in TIEC_3_2_ Attachment.zip, go to desired scenario's folder and see "TIEC_3_2_Attachment_1.csv".

g. For assumed LMPs in estimating off-systems purchases, in TIEC_3_2_ Attachment.zip, go to desired fundamental scenario's folder and see "TIEC_3_2_Attachment_8.csv". For assumed LMPs in estimating off-systems sales, in TIEC_3_2_ Attachment.zip, go to desired fundamental scenario's folder and see "TIEC_3_2_Attachment_9.csv".

h. In TIEC_3_2_ Attachment.zip, see "TIEC_3_2_Attachment_11.csv" for escalation rates, same for all scenarios.

i. 7.0854%

Prepared By: Paul N. Demmy	Title: Resource Planning Anlyst Sr
Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: William S. Robinson	Title: Resource Planning Anlyst Staff
Prepared By: James F. Martin	Title: Regulatory Case Mgr
Prepared By: Xuejin Zheng	Title: Resource Planning Anlyst Staff
Sponsored By: John F. Torpey	Title: Mng Dir Res Plnning&Op Anlysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRD REQUEST FOR INFORMATION

Question No. TIEC 3-3:

Please provide the following PROMOD model assumptions/outputs under the Base and Project cases (i.e., with and without the Wind Projects) for 2024 and 2029 for each scenario studied:

a. SPP system peak.

b. SPP net energy for load.

c. Each generation capacity addition/retirement.

d. Each transmission addition/upgrade/retirement.

e. Commodity prices and transportation prices (i.e, natural gas, coal).

f. Energy generated by resource.

Response No. TIEC 3-3:

A portion of the information responsive to this request is HIGHLY SENSITIVE under the terms of the Protective Order. The Highly Sensitive information is available for review at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 1520, Austin, Texas, 78701, (512) 481-4562, during normal business hours.

a. a. 2024 SPP Peak (Coincident) = 53.4 GW   2029 SPP Peak (Coincident) = 55.3 GW

b. b. 2024 SPP Energy = 280.5 TWh   2029 SPP Energy = 288.9 TWh

c. The Company relied on SPP's 2019 ITP PROMOD Reference Case (Future 1) developed through SPP's ongoing stakeholder-based 2019 ITP process. For generation-related assumptions made by SPP and its stakeholders in the developing the 2019 ITP PROMOD models, please refer to Sections 2.1.1 and 2.2.1.4 of SPP's 2019 ITP Draft Report, provided as TIEC_3_003_Attachment_1. Section 2.2.2.1 describes SPP's renewable additions for each future, while Section 2.2.1.2 describes the assumed conventional generation additions by technology type in 2024 and 2029. As described in this draft report, for Future 1, which is the future employed in the Company's customer benefits analysis, SPP projects total nameplate generation additions of 4.7 GW in 2024 and 9.4 GW in 2029. Further, as discussed in the Direct Testimony of SWEPCO witness Pfeifenberger, the Company only made minor modifications to SPP's 2019 ITP PROMOD Future 1 model to account for the Selected Wind Facilities that were not already included in SPP's model.

d. As described in Sections 2.1.4 (for reliability studies) and Section 2.2.1.6 (for economic studies) of SPP's ITP Manual (dated October 17, 2018), and provided as TIEC_3_003_Attachment 2, the transmission topology used in the SPP's PROMOD Future 1 Reference Case reflects SPP's existing transmission system and all transmission facilities or upgrades included in SPP's 2017 Transmission Expansion Plan (STEP) that have already been approved for construction. Additionally, SPP also included 2018 ITP Near-Term (ITP NT) transmission updates, which can be accessed through SPP's 2018 STEP listing. The 2017 and 2018 STEP Project Lists can be accessed on SPP website at:

   https://www.spp.org/spp-documents-filings/?document_name=SPP+Transmission+Expansion+Plan&docket=&start=&end=&filter_filetype=&search_type=filtered_search.

e. As explained on pp. 29-31 of the Direct Testimony of SWEPCO witness Pfeifenberger, the Company then only made minor transmission modeling refinements to the SPP's PROMOD Future 1 Reference Case.

f. e. See TIEC_3_003_Highly Sensitive Attachment 3 (Fuel Prices).

g. See TIEC_3_003_Highly Sensitive Attachment 4 (Energy Generated by Resource).

Prepared By: Anita A. Sharma	Title: Engineer Staff
Sponsored By:	Title:
Sponsored by: Akarsh Sheilendranath	Title: Senior Associate, The Brattle Group
Sponsored by: Johannes P. Pfeifenberger	Title: Principle, The Brattle Group

SPP Southwest Power Pool

DRAFT

2019 INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT

Published on DATE

By SPP Engineering

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
08/21/2019	SPP Staff	Initial Draft Report	

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EXECUTIVE SUMMARY

The 2019 ITP assessment began in July 2017 and will be completed in October 2019.

[Placeholder for Executive Summary]

1 INTRODUCTION

1.2 THE ITP ASSESSMENT

The SPP Integrated Transmission Planning (ITP) Assessment is a regional transmission plan that is designed to provide for the reliable and economic delivery of energy, facilitate achievement of public policy objectives and maximize benefits to end-use customers. The ITP assessment contains an evaluation of the SPP transmission system's reliability, public policy, operational, and economic needs and coordinates solutions with ongoing compliance, local planning, interregional planning, and tariff service[1] processes. The 2019 ITP assessment is guided by the requirements defined in the SPP Open Access Transmission Tariff (tariff) Attachment O, the ITP Manual, the 2019 ITP scope.

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, and
- Facilitate a cost-effective, responsive, and flexible transmission network

1.3 REPORT STRUCTURE

This report describes the 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 2 and 3 summarize modeling inputs and address the concepts behind this study's approach, key procedural steps in analysis development, and overarching study assumptions. Sections 4 through 7 address specific results, describe projects that merit consideration, and contain portfolio recommendations, benefits, and costs.

[1] 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.

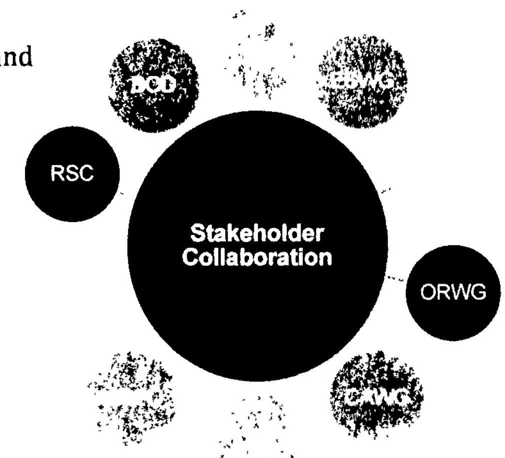
Within this study, any reference to the SPP footprint refers to the set of legacy Balancing Authorities (BAs) and transmission owners (TO) whose transmission facilities are under the functional control of the SPP RTO, unless otherwise noted.

The study was guided by the 2019 ITP Scope and SPP ITP Manual. 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.

1.4 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 assessment portfolio.

1.4.1 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 (BR) 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 1 and Figure 2 below provide a visual for the years 2, 5, and 10 Summer peak and Winter peak generation dispatch and load amounts. The generation dispatch amounts are provided by fuel type for all BR models that are part of the ITP assessment.

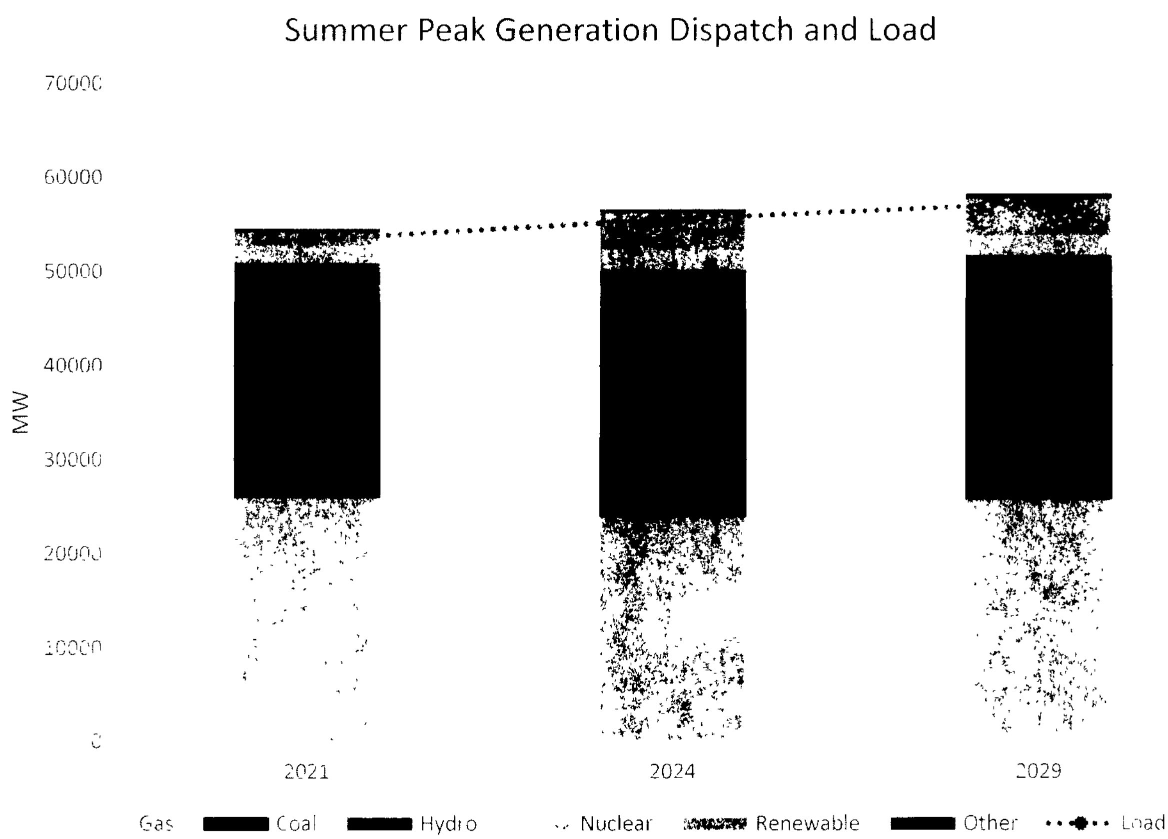


Figure 1 2019 ITP BR Summer Generation Dispatch and Load

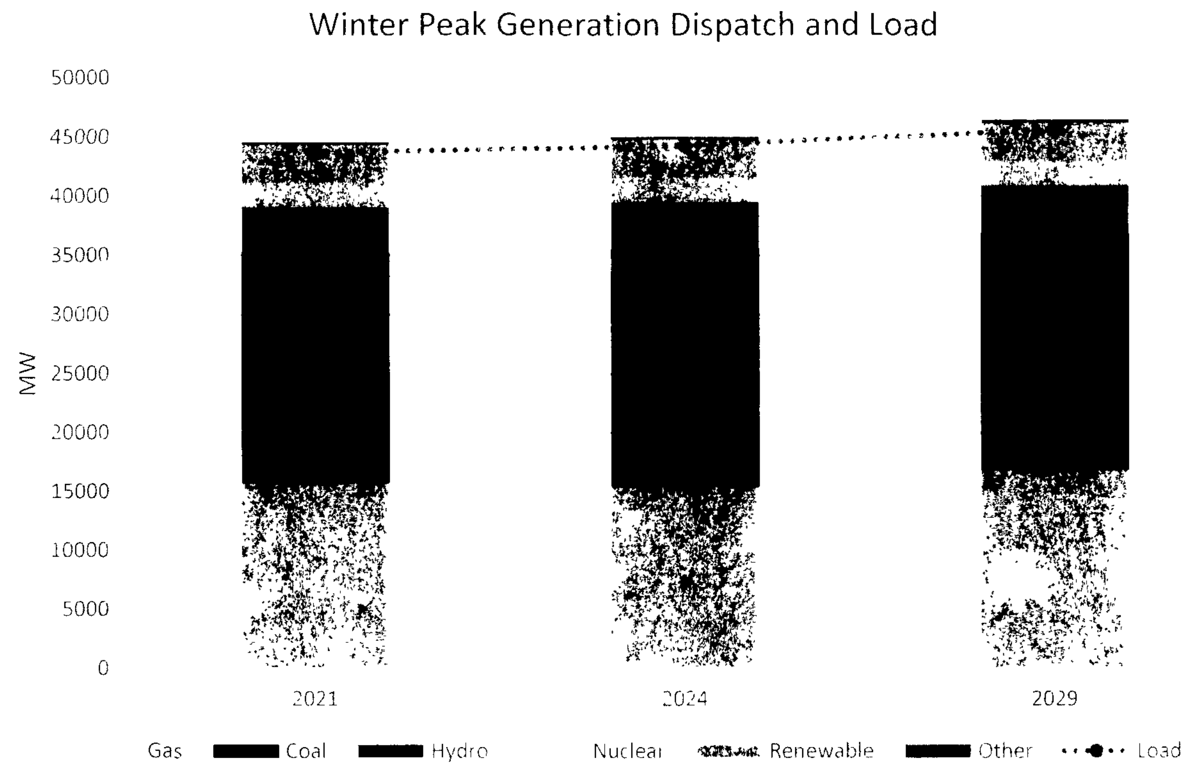


Figure 2: 2019 ITP BR Winter Generation Dispatch and Load

2.1.2 TOPOLOGY

Topology data in the 2019 ITP BR 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 2 summer peak short-circuit model was developed for short-circuit analysis. This short-circuit model modeled all generation and transmission equipment in service to simulate the maximum available fault current. This model was analyzed in consideration of the 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[2]: 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.

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.

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 1: Future Drivers defines the remaining drivers and how they were considered in each future.

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

Key Assumptions	Drivers: Reference Case 2021	Reference Case 2024	Reference Case 2029	Emerging Technologies 2024	Emerging Technologies 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[3]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)[8]	As submitted in load forecast	As submitted in load forecast		+300MW	+500MW
Energy Efficiency[8]	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 1: Future Drivers

[3] 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 BR model set, and stakeholders were asked to identify/update the following parameters:

- Forecasted system peak load (MW)
- Annual energy (GWh) consumed (Future 2 only)
- 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 3 shows the total non-coincident peak load for all study years. Figure 4 shows the monthly energy per future for all study years (2021, 2024, and 2029).

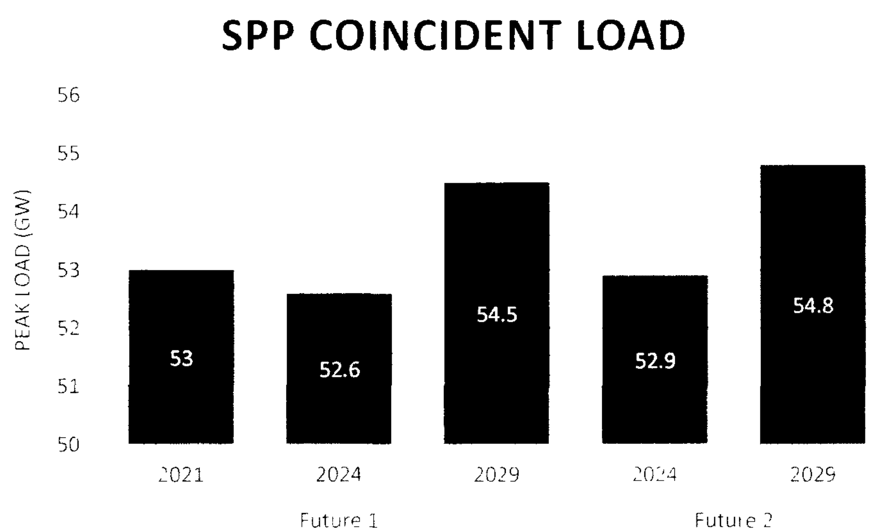


Figure 3 Coincident Peak Load

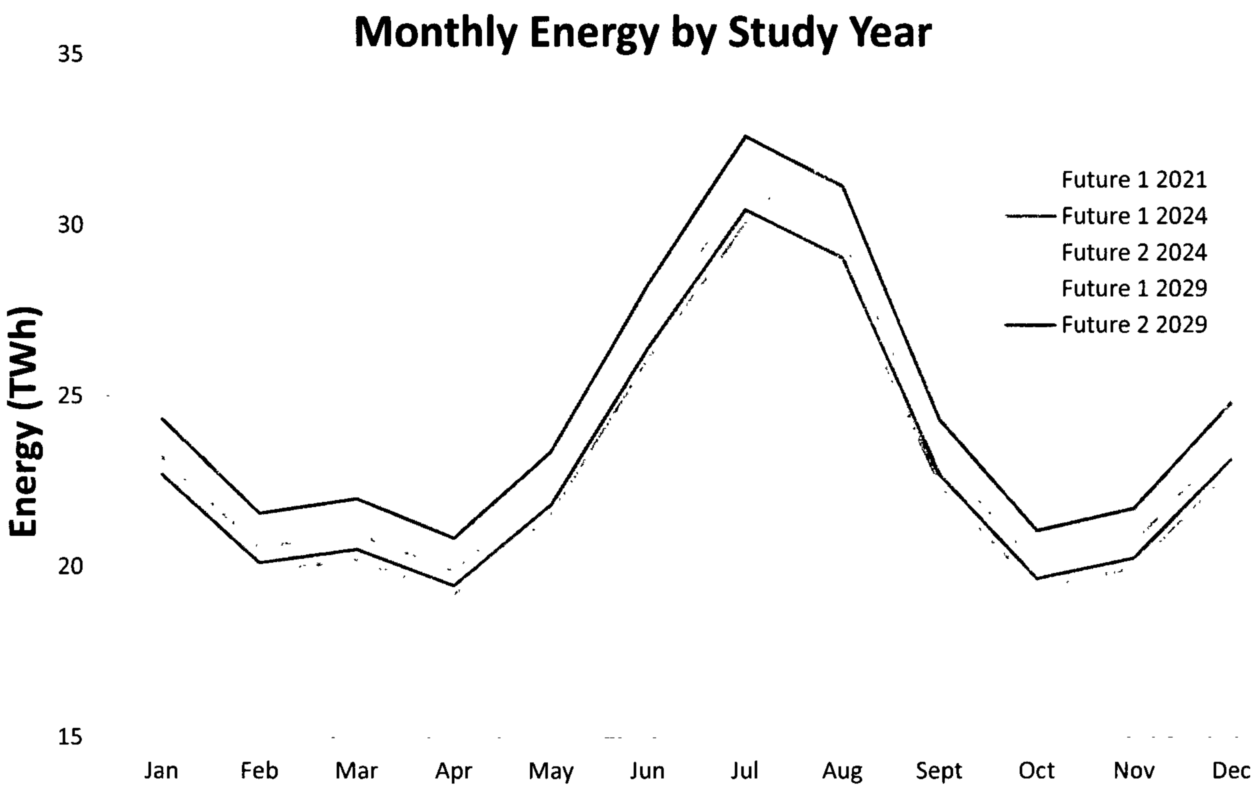


Figure 4 2019 ITP Annual Energy

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. 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 Fall 2016 Reference Case and is supplemented with SPP stakeholder information provided through the SPP Model on Demand (MOD) tool and the generation review.

Figure 5 and Figure 6 detail the annual energy and capacity by unit type for 2021. Figure 7 details the retirements of conventional generation for each future and study year.

In addition to resources accepted in the BR 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 were added to the economic models; 660 MW of the additional wind were included in the year 2 models.

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

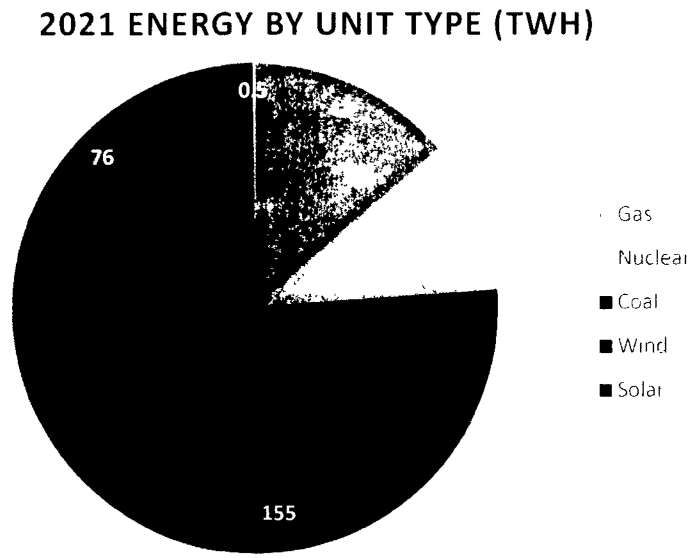


Figure 5: 2021 Energy by Unit Type

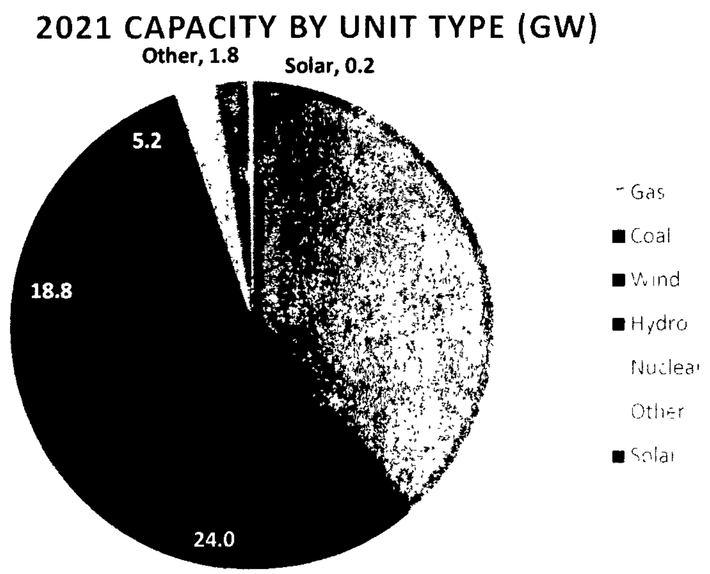


Figure 6 2021 Capacity by Unit Type

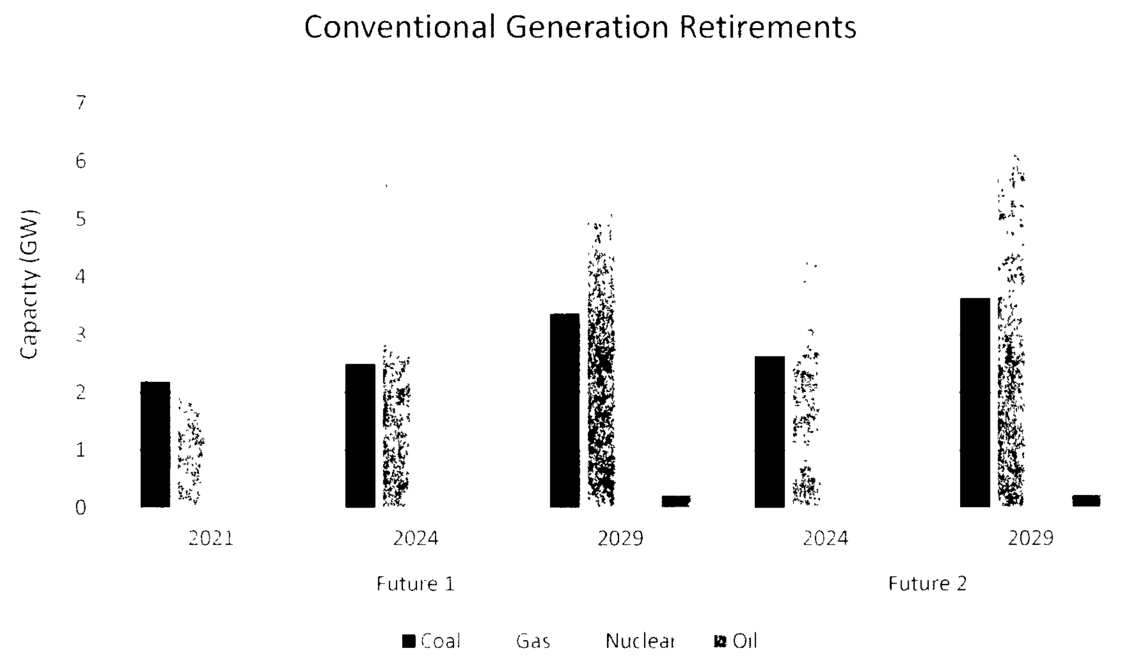


Figure 7 Conventional Generation Retirements

2.2.1.5 Fuel Prices

The ABB Fall 2016 Reference Case and ABB Natural Gas Fundamental Forecast (for long-term price projections) were utilized for the fuel price forecasts. Figure 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 and $2.20 to $2.80 for natural gas and coal, respectively.

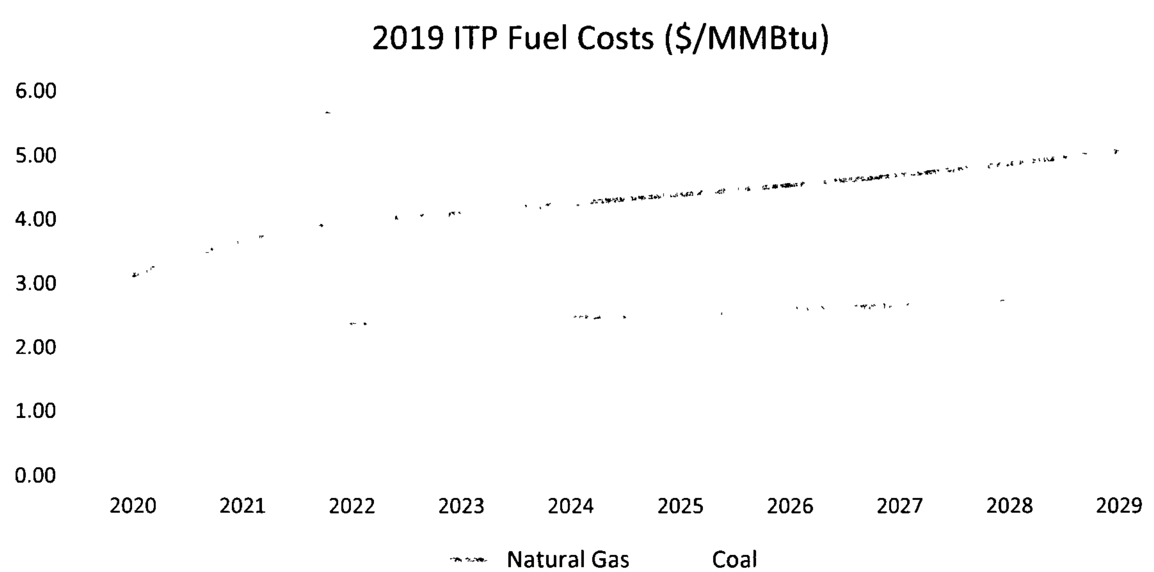


Figure 8 ABB Fuel Annual Average Fuel Price Forecast

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, and resource reserve margin requirements.

2.2.2.1 Renewable Resource Expansion Plan

After accounting for existing renewables, each utility was analyzed to determine if the assumed renewable mandates and goals identified by the renewable policy review could be met with initial resource projections for 2024 and 2029. If a utility was projected to be unable to meet requirements, additional resources were added to meet the levels specified above. For states with a RPS that could be met by either wind or solar generation, a ratio of 80 percent wind additions to 20 percent solar additions was utilized. This split is representative of the active GI queue requests for wind and solar resources.

The incremental renewables added 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 9 shows renewable generation added in each future and study year.

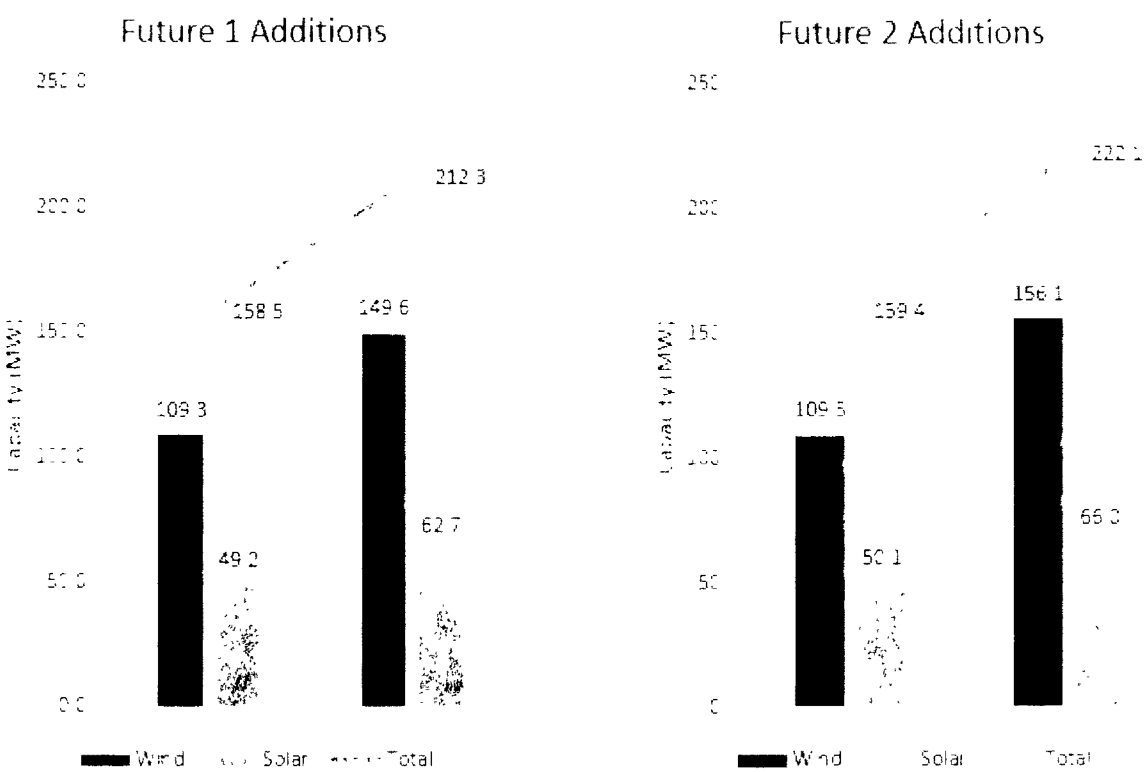


Figure 9 SPP Renewable Generation Additions to meet Mandates and Goals

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

Projected solar additions were assigned based on the load-ratio share of 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

2.2.1.2 Conventional Resource Expansion Plan

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

After utilization of expected renewables and emerging technologies, conventional resource expansion plans were developed to meet the 12 percent reserve margin requirement set by SPP Planning Criteria 4[4]. 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 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 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[5] were utilized. These resource prototypes define operating parameters of specific generation technologies to determine the optimal generation mix to add to the region.

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

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 2 due to the additional unit retirements and increased energy demand growth rates.

Table 2 shows the total nameplate generation additions by future and study year. Figure 10: Nameplate Capacity Additions by Future and Year 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: Total Nameplate Generation Additions by Future and Study Year

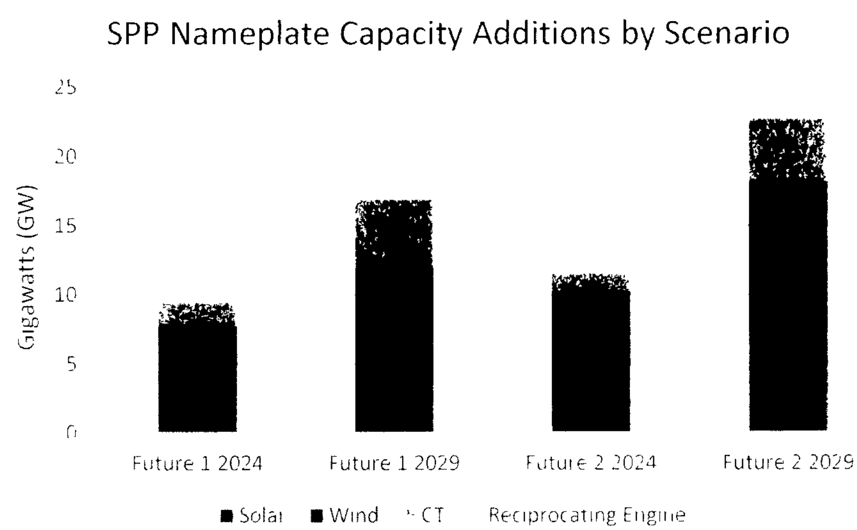

Figure 10: Nameplate Capacity Additions by Future and Year

Table 3 shows the total accredited generation additions by future and study year. Figure 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 3: Total Accredited Generation Additions by Future and Study Year

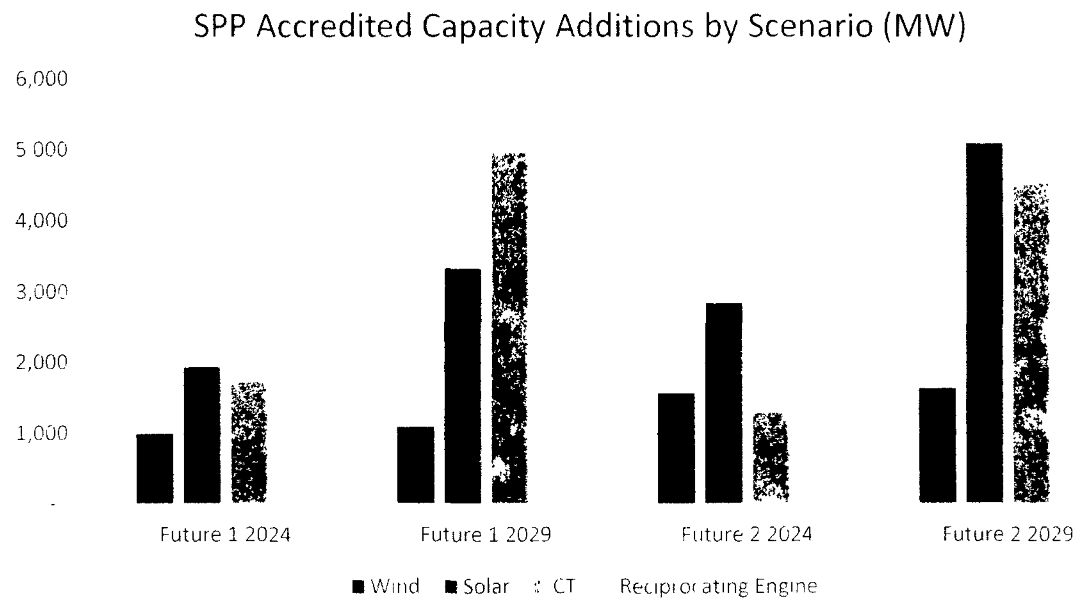

Figure 11 Accredited Capacity Additions by Scenario

2.2.1.3 Siting Plan

SPP sited projected renewable and conventional resources according to various site attributes for each technology[6].

Distributed solar generation, an assumption in Future 2 only, was allocated to the top 10 percent of load buses for each load area on a pro rata basis utilizing load review data. SPP stakeholder feedback was considered in the selection of sites for this technology. Figure 12 and Figure 13 show the selected sites and allocation of distributed solar capacity across the SPP footprint.

[6] Documented in the ITP Resource Siting Manual

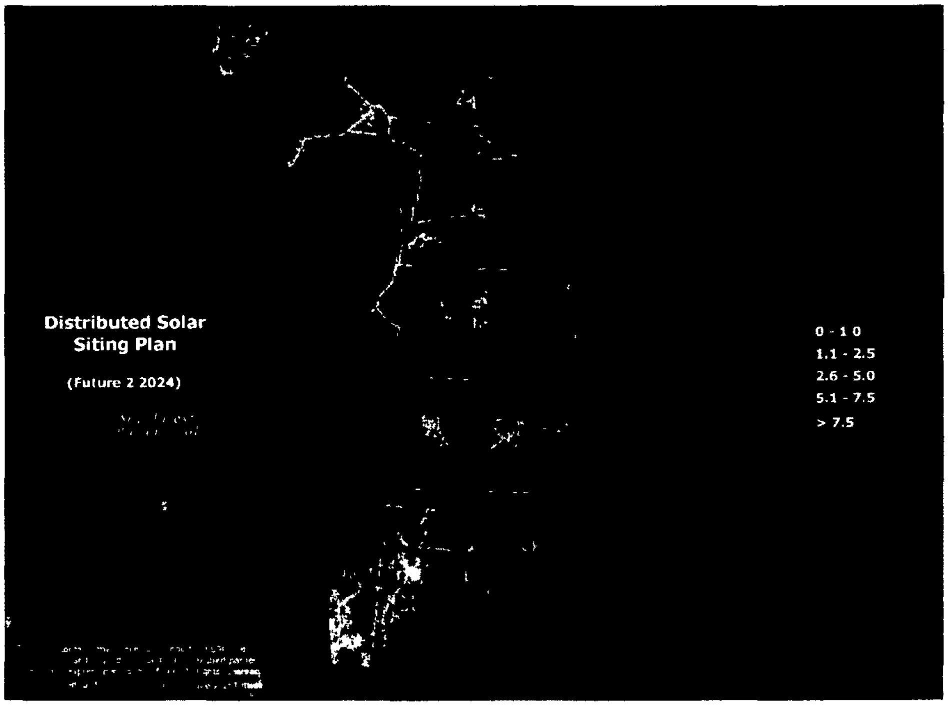

Figure 12 2024 Future 2 Distributed Solar Siting Plan

Figure 13: 2029 Future 2 Distributed Solar Siting Plan

Utility-scale solar was sited according to ownership (by zone or state), the data source of the site, capacity factor, and generator transfer capability of the potential sites. Sites from the following sources were given preference in the following order:

- SPP and Integrated System (IS) and GI queue requests
- Stakeholder-submitted sites
- Previous ITP sites
- Other NREL conceptual sites

In addition to this ranking criteria, stakeholders could request exceptions this approved methodology's results. The ESWG reviewed and approved the exceptions. Figure 14 through Figure 17 show the selected sited and allocation of utility solar capacity across the SPP footprint.

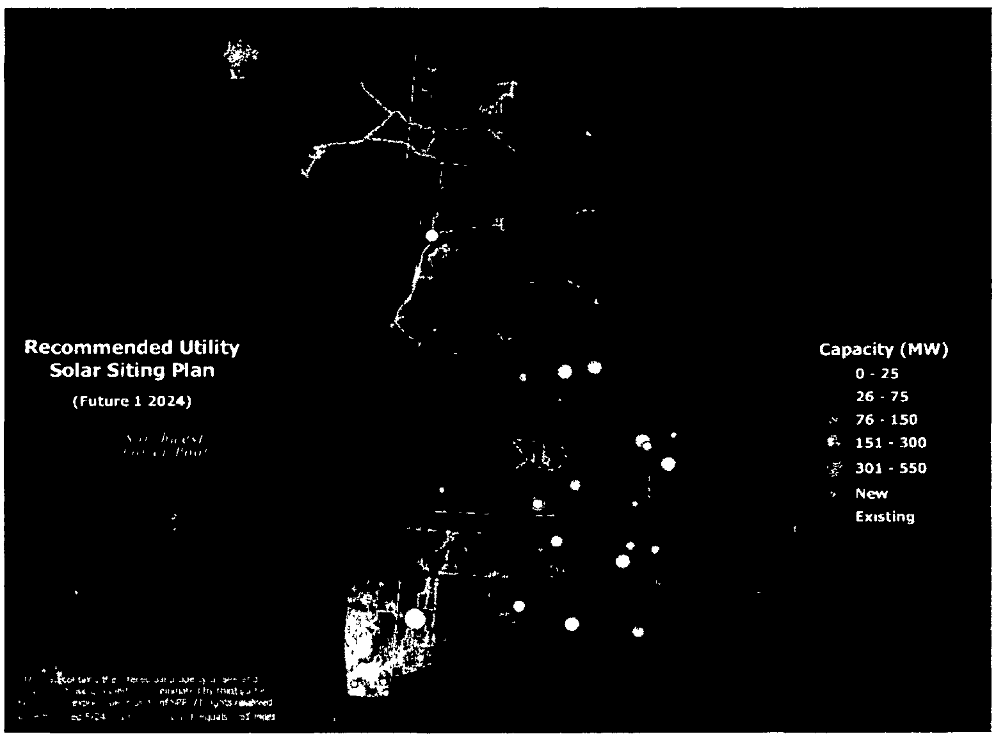

Figure 14: 2024 Future 1 Utility-Scale Solar Siting Plan

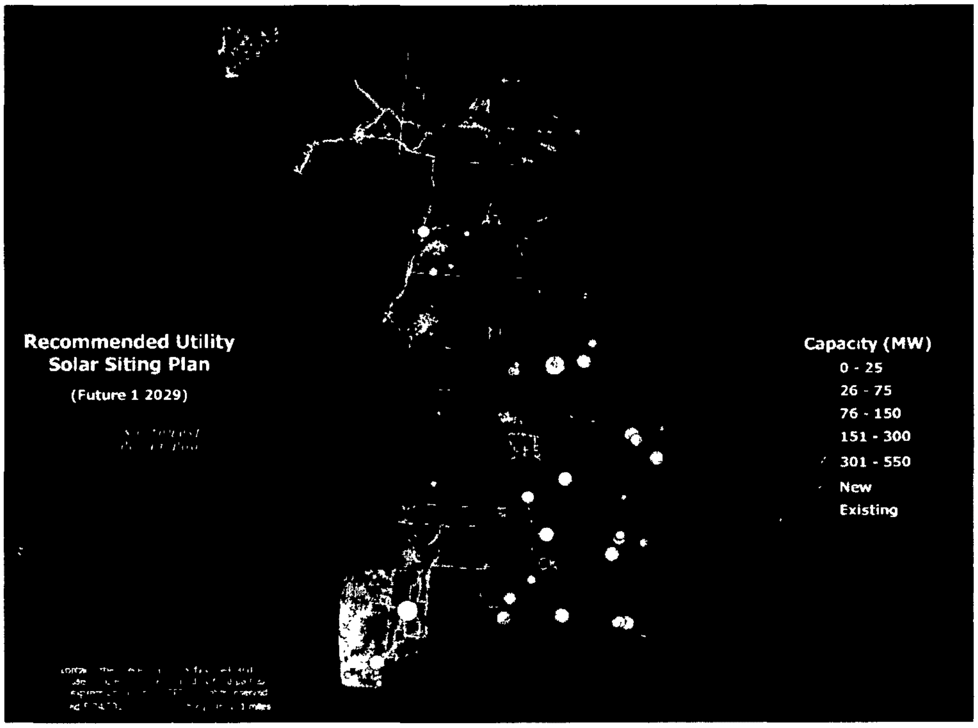

Figure 15: 2029 Future 1 Utility-Scale Solar Siting Plan

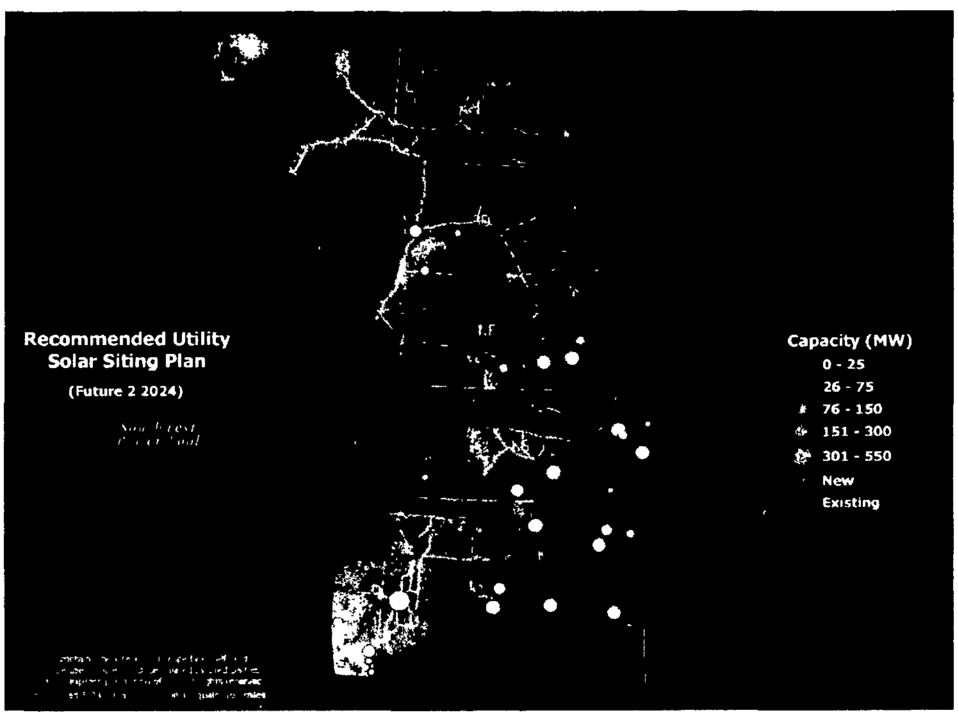

Figure 16: 2024 Future 2 Utility-Scale Solar Siting Plan

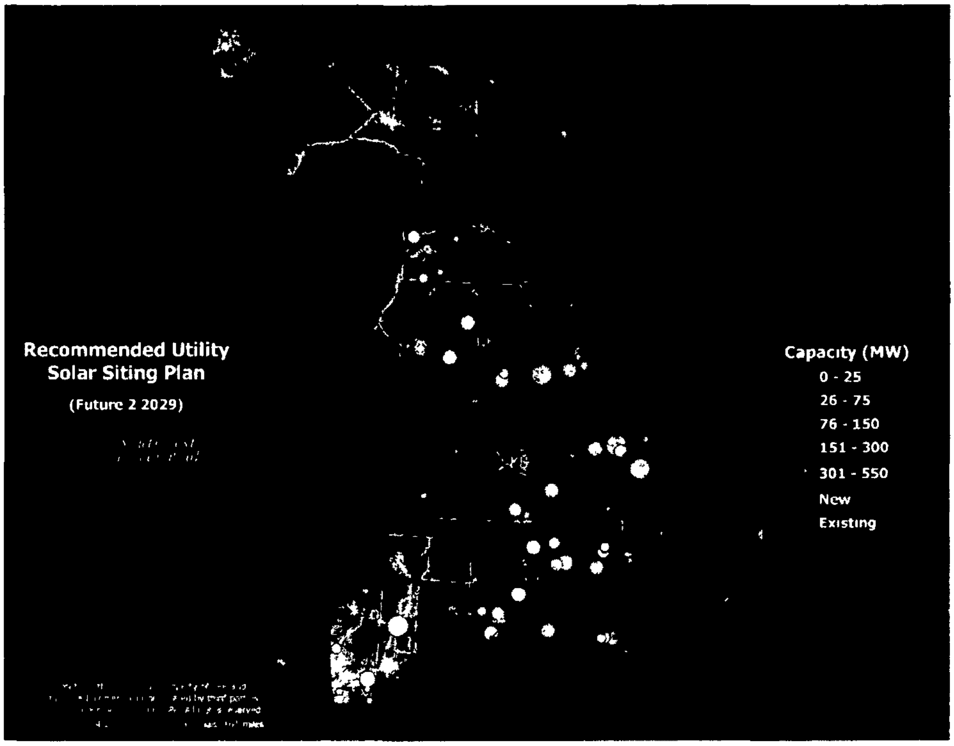

Figure 17: 2029 Future 2 Utility-Scale Solar Siting Plan

Wind sites were selected from GI queue requests that were assigned the lowest total cost[7] per MW of capacity requested, taking into consideration the following:

- Potentially directly-assigned upgrade needed
- Unknown third-party system impacts
- Required GOFs
- 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.

Stakeholders could request exceptions to the results of this standard methodology. The ESWG reviewed and approved exception requests. Figure 18 through Figure 21 show the selected siting and allocation of wind capacity across the SPP footprint.

[7] Includes assigned interconnection and network upgrade costs

Figure 18 2024 Future 1 Wind Solar Siting Plan

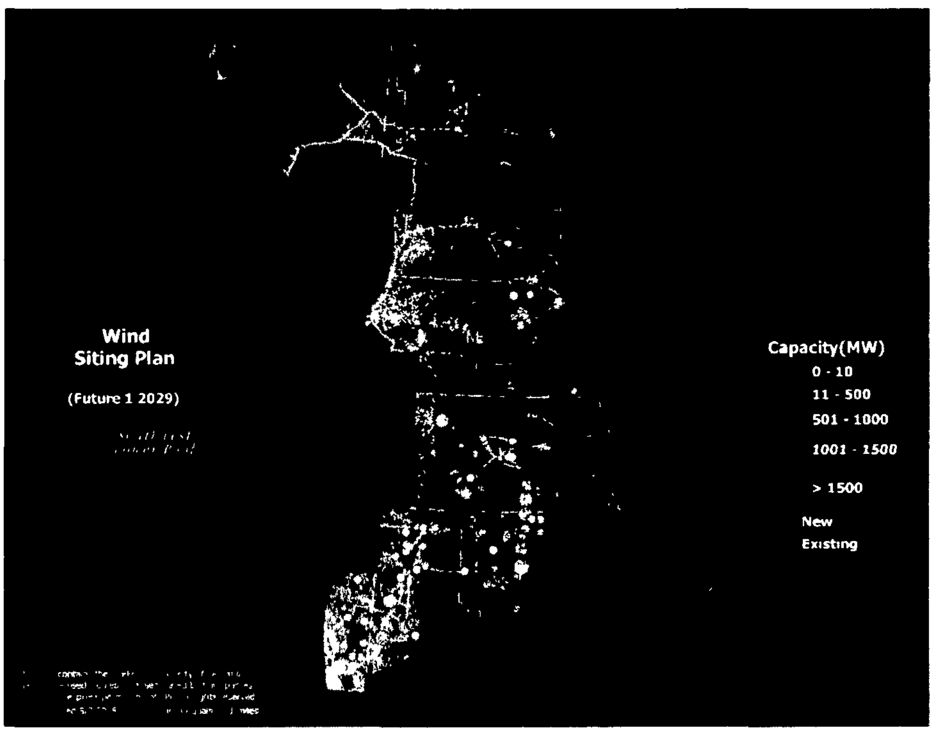

Figure 19 2029 Future 1 Wind Solar Siting Plan

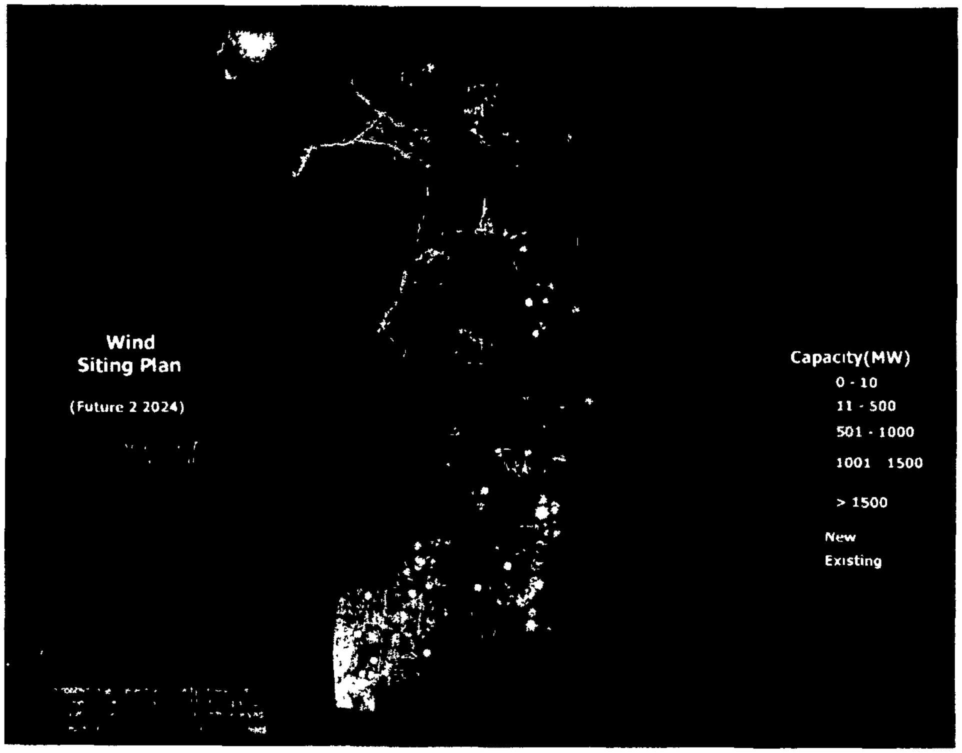

Figure 20 2024 Future 2 Wind Solar Siting Plan

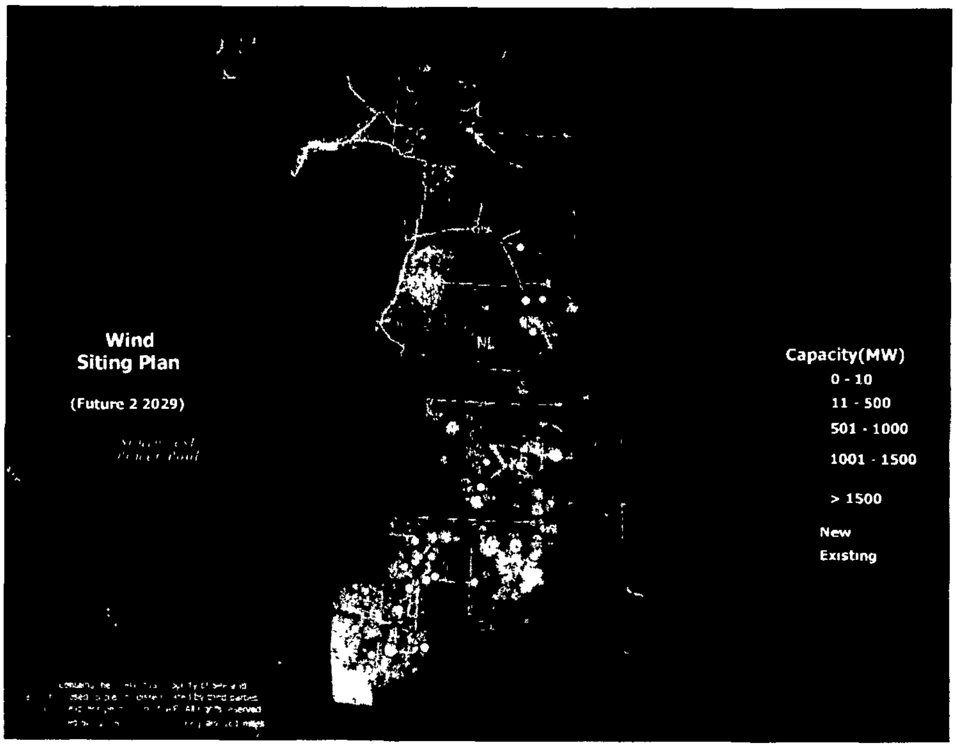

Figure 21 2029 Future 2 Wind Solar Siting Plan

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. In addition to this ranking criteria, stakeholders requested exceptions to the results of this approved methodology. The ESWG reviewed and approved exception requests. Figure 22 through Figure 25 show the selected sites for conventional generation across the SPP footprint.

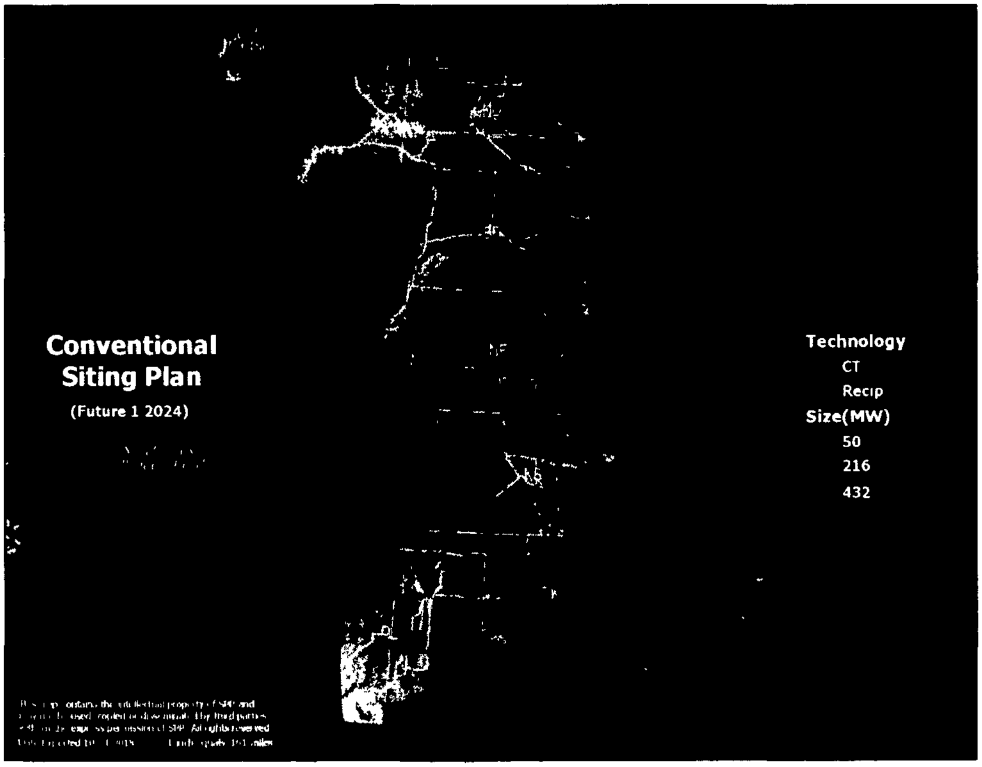

Figure 22 2024 Future 1 Conventional Siting Plan

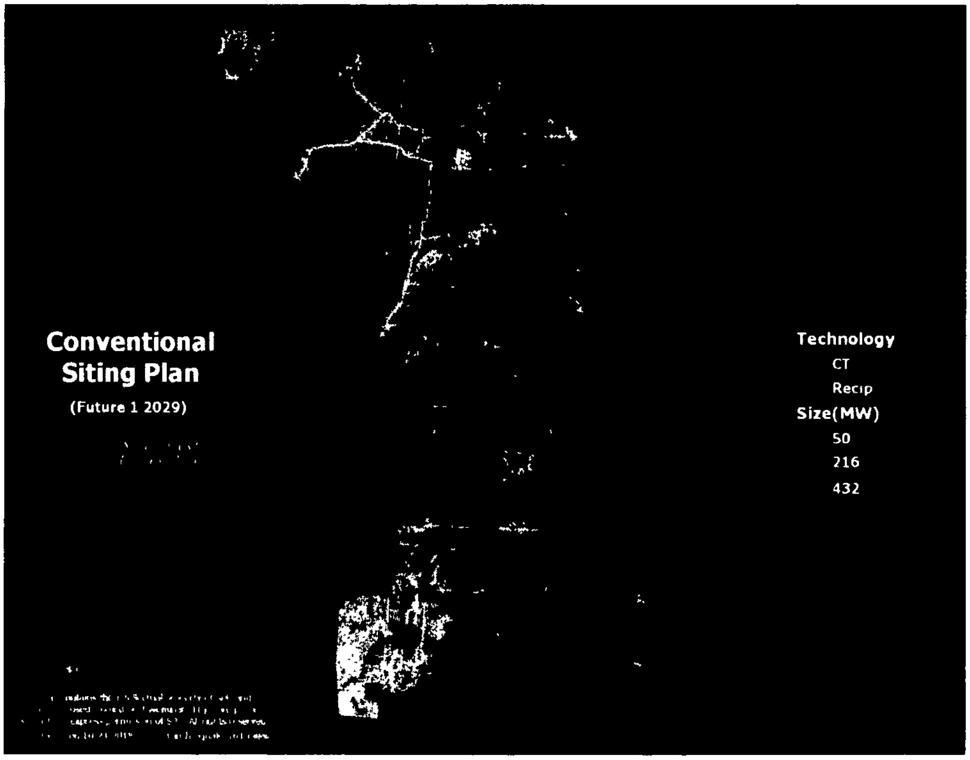

Figure 23 2029 Future 1 Conventional Siting Plan

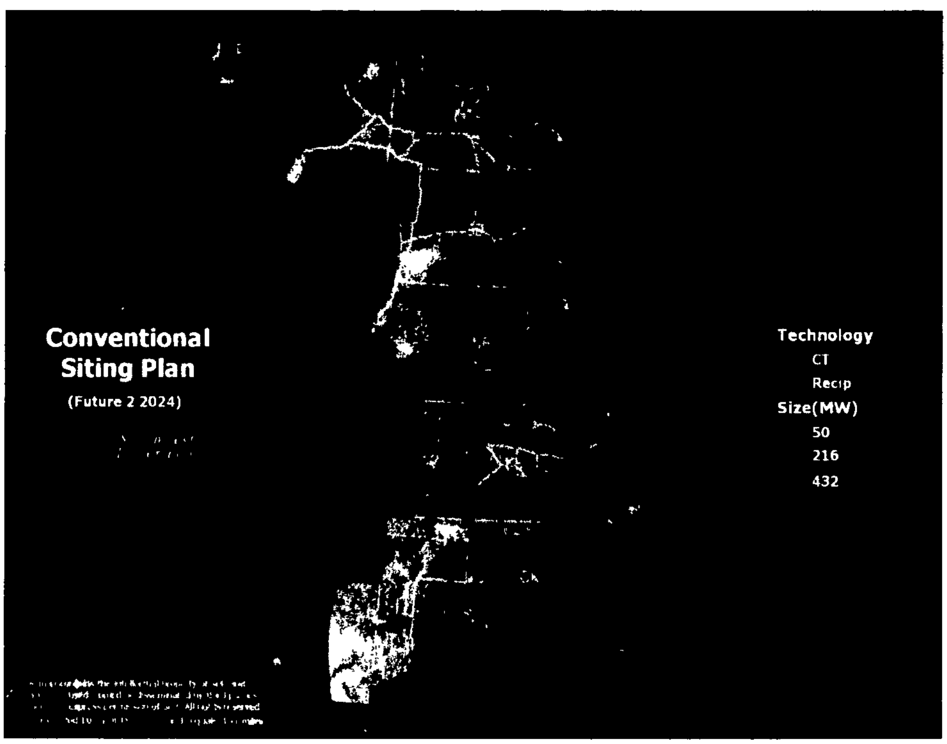

Figure 24 2024 Future 2 Conventional Siting Plan

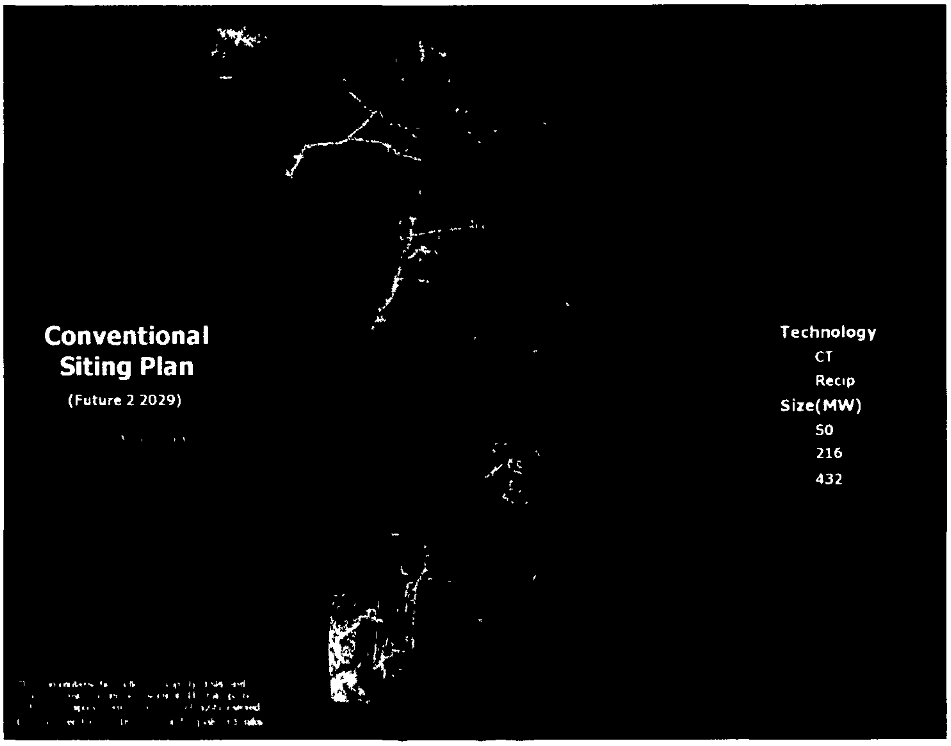

Figure 25 2029 Future 2 Conventional Siting Plan

2.2.1.4 Generator Outlet Facilities

The GOFs necessary to interconnect resources at individual sites were critical to the selection of sites. For sites with an executed GIA identifying a necessary upgrade, the upgrade included in the GIA was recommended and approved as a GOF. For other instances, the site-specific results of the transfer analysis[8] 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 4: Generator Outlet Facilities.

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

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

Table 4: Generator Outlet Facilities

2.2.1.5 External Regions

For the renewable resource plans, renewable policy requirements for external regions were not considered. However, the MISO and 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, while AECI renewable resource expansion plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI.

Conventional resource plans were also 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 26 and Figure 27 show the cumulative capacity additions by unit type of these external regions for Futures 1 and 2.

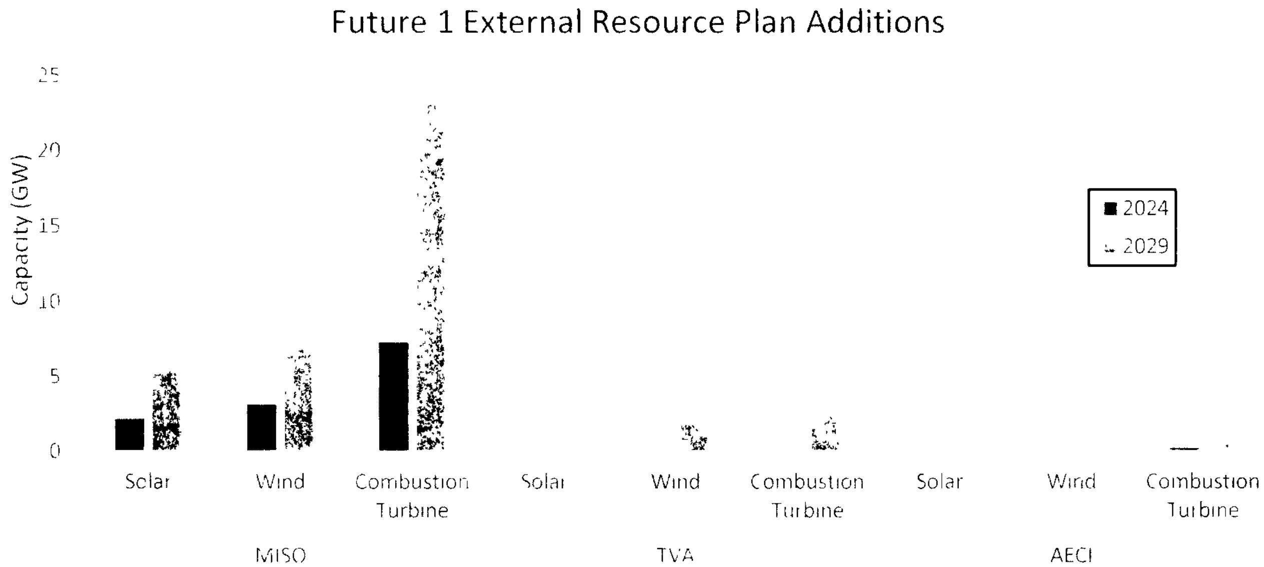

Figure 26 Capacity Additions by Unit Type – Future 1

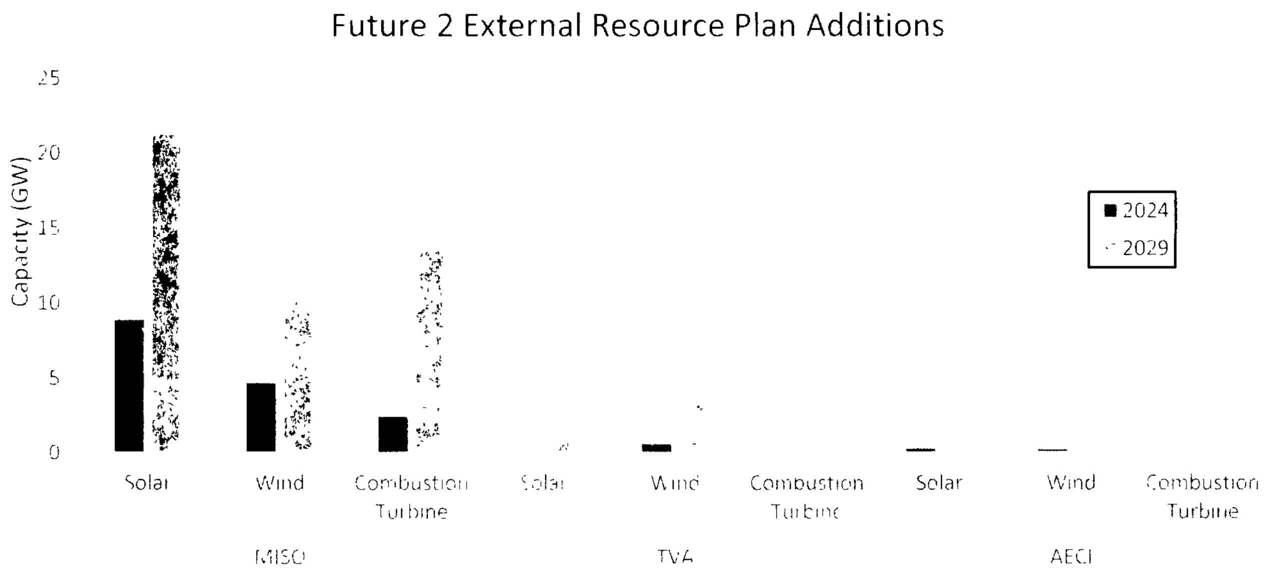

Figure 27 Capacity Additions by Unit Type - Future 2

2.2.3 CONSTRAINT ASSESSMENT

SPP utilizes transmission constraints to reliably manage the flow of energy across the physical bottlenecks of the transmission system in the least costly manner. Developing these study-specific constraints plays a critical part in determining transmission needs, as the constraint assessment identifies future bottlenecks as well as fine-tunes the market economic models.

SPP conducted an assessment to develop a list of transmission constraints for use in the security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) analysis for all futures and study years. Elements that were identified in this assessment as limiting the incremental transfer of power throughout the transmission system, both under system intact and contingency situations, were reviewed and approved by the TWG. SPP staff defined the initial list of constraints leveraging the SPP Permanent Flowgate List[9], 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 neighboring areas constraints identified in this constraint assessment process to be considered for inclusion in the study-specific constraint list.

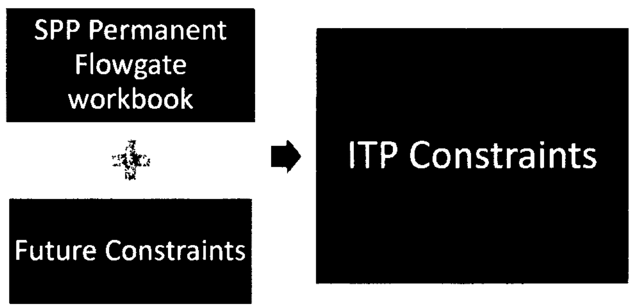

Figure 28: Constraint Assessment Process

2.3 MARKET POWERFLOW MODEL

The economic dispatch from each market economic model is used to develop market powerflow snapshots representing stressed conditions of the SPP transmission system.

Table 5 shows the peak and off-peak reliability hours from each future and year of the market economic model simulations chosen for the development of market powerflow models.

[9] Posted on SPP OASIS

	Off-Peak Hour	Wind Penetration[10]	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 5 Market Powerflow Reliability Hours

3 BENCHMARKING

3.1 POWERFLOW MODEL

Powerflow model benchmarking for this assessment was performed on the year 2 models from the 2018 ITP Near-Term (ITPNT) and 2019 ITP assessments. Model comparisons were conducted to ensure the accuracy of the powerflow modeling data, including:

- Comparision of the load totals between the 2018 ITPNT and 2019 ITP models
- Comparision of the generation dispatch totals between the 2018 ITPNT and 2019 ITP models
- Comparision of the generator retirements between the 2018 ITPNT and 2019 ITP models

[10] Does not include curtailments

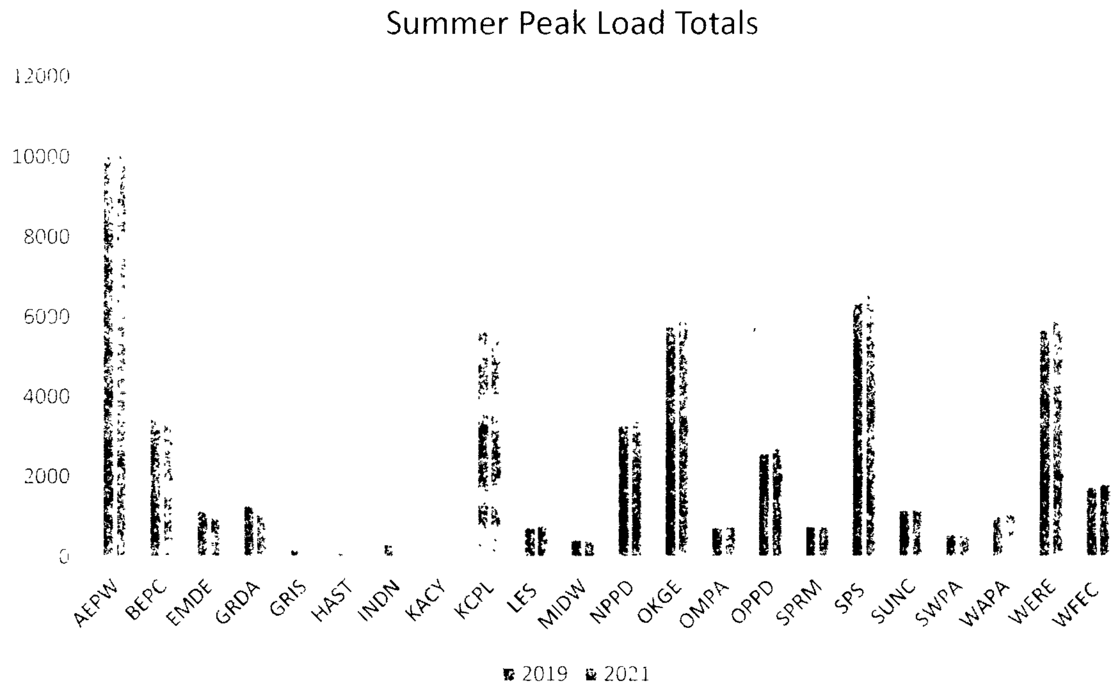

Figure 29: Summer Peak Load Comparison

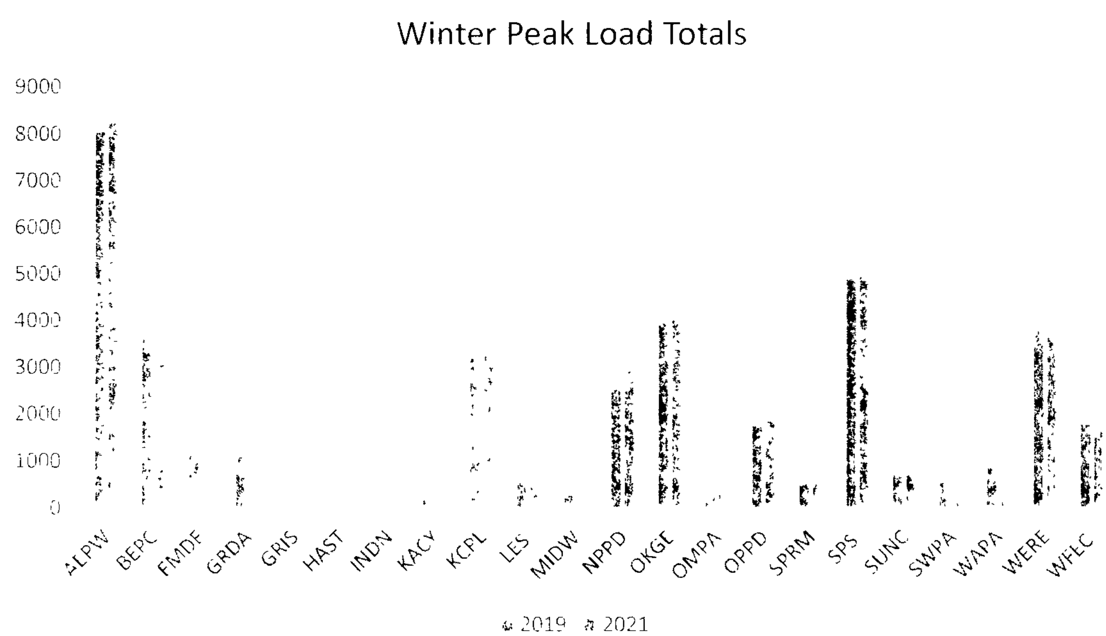

Figure 30: Winter Peak Load Comparison

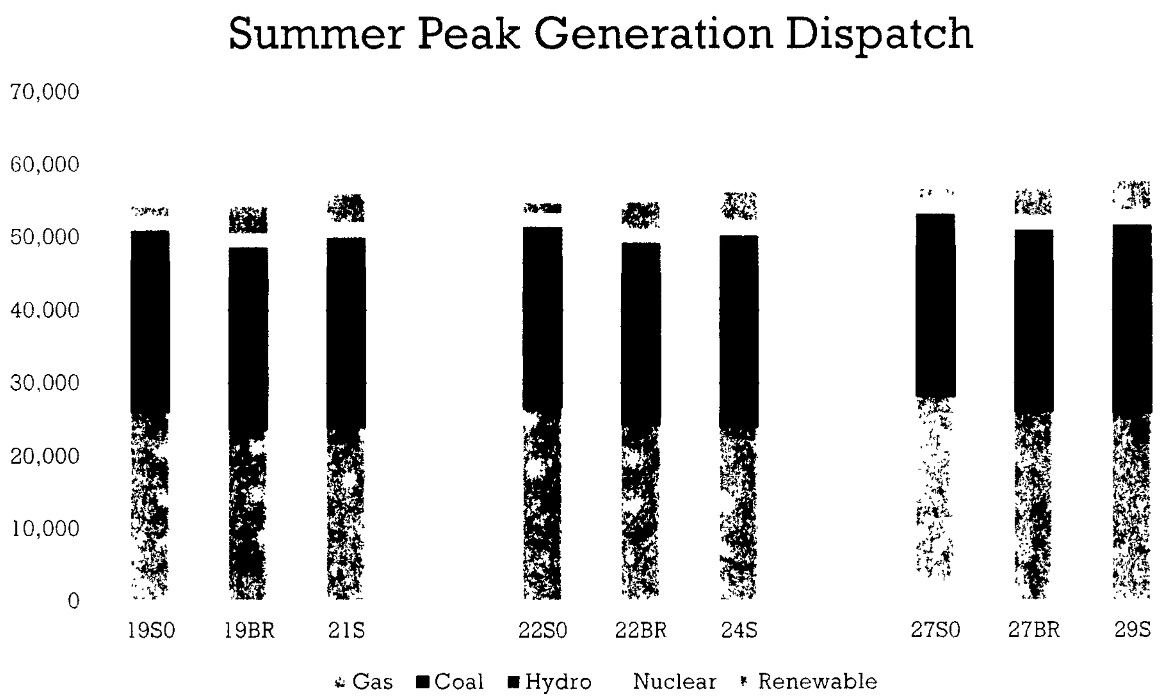

Figure 31 Summer Peak Generation Dispatch Comparison

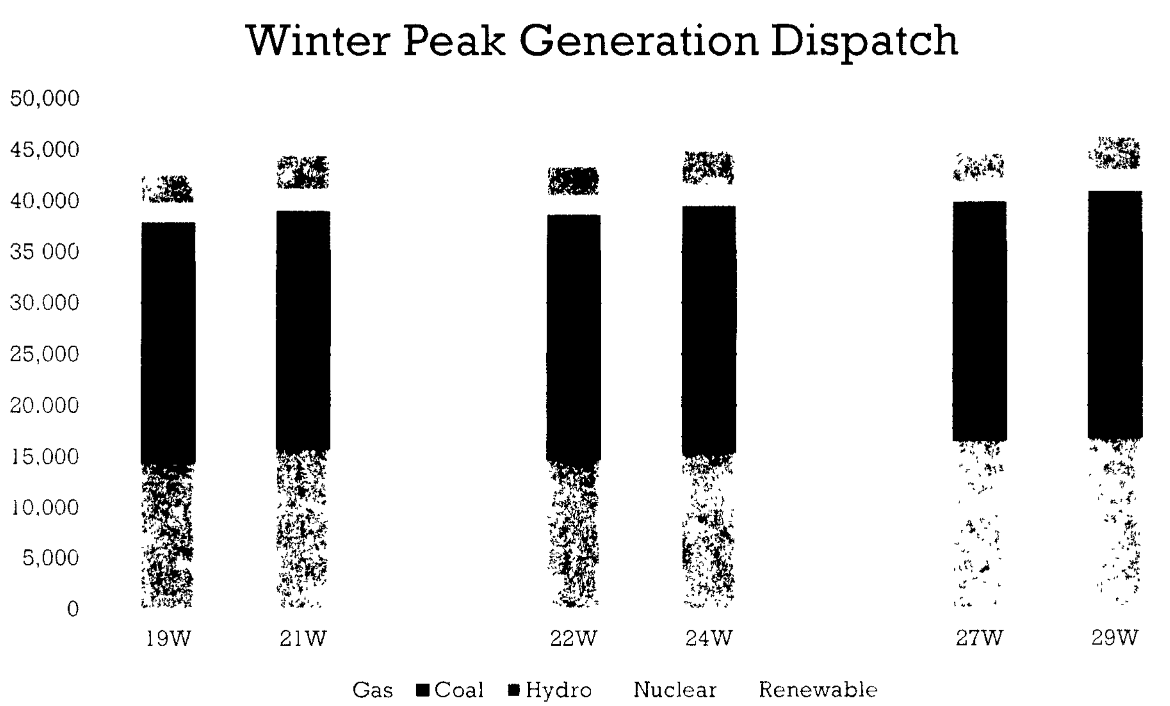

Figure 32 Winter Peak Generation Disptach Comparison

Placeholder for Generator Retirement Charts

Placeholder for Operational Benchmark

3.2 ECONOMIC MODEL

Economic model benchmarking for this study was performed on the Future 1 2021 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:

- Comparisons of 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
- Comparisons of the capacity factors, generating unit average cost, renewable generation profiles, system locational marginal prices (LMPs), adjusted production cost (APC), and interchange between the 2019 ITP and the 2017 ITP10[11].

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 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%

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

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

Table 6 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 consideration of 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 7 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 omit 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 difference in the content with each dataset.

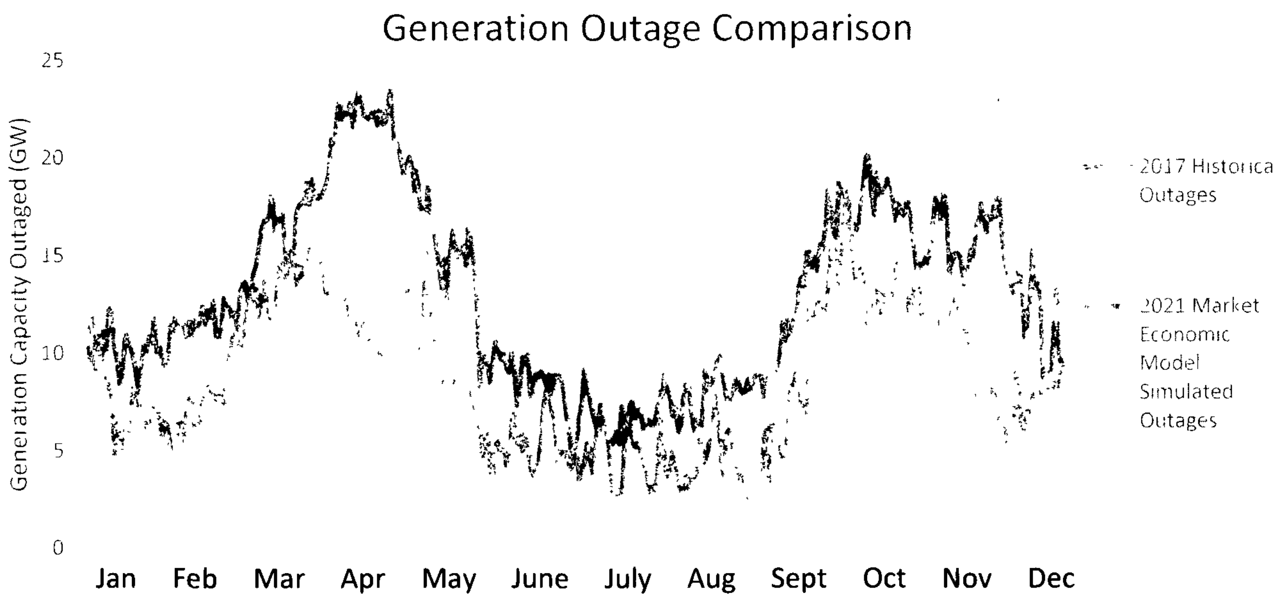

Figure 33 Generator Outage Comparison

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 a unit failure. 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 1,646 MW and spinning reserve capacity requirement was 823 MW. SPP met its reserve requirements in the market economic model.

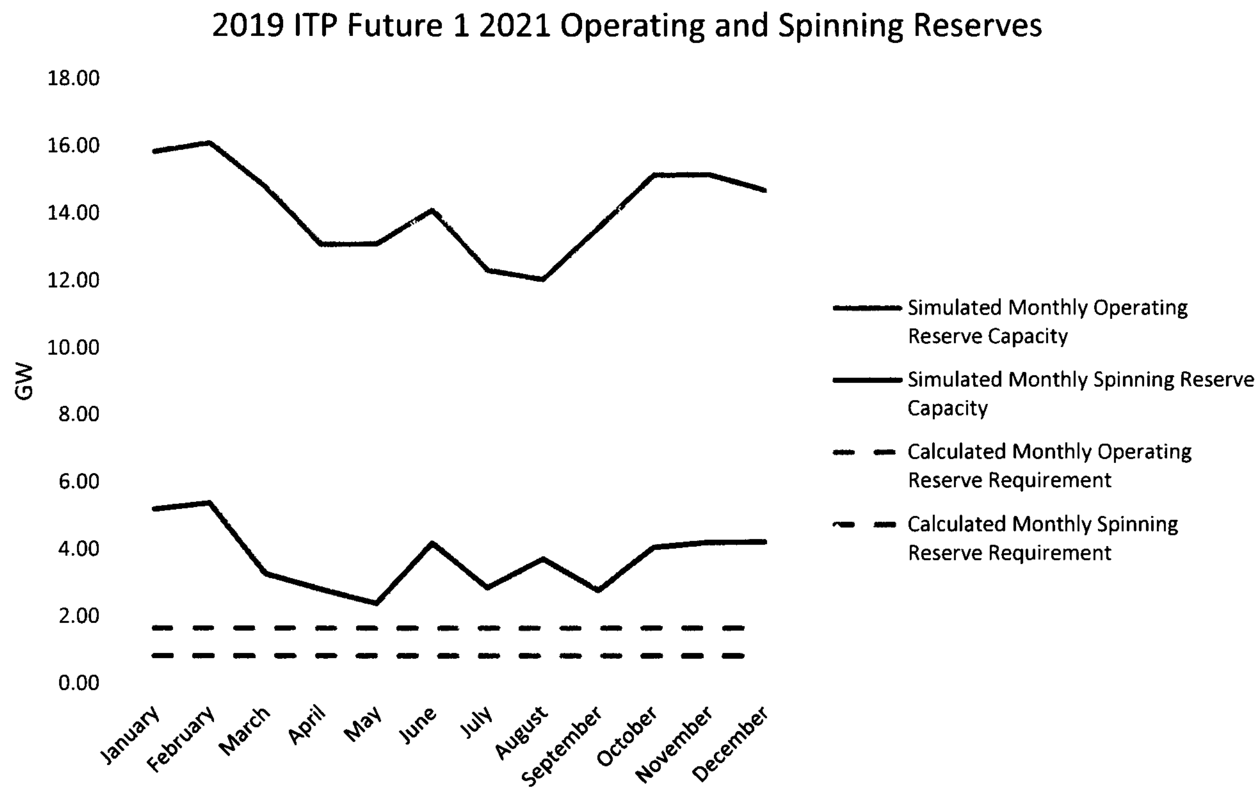

Figure 34 2019 ITP Future 1 2021 Operating and Spinning Reserves

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.

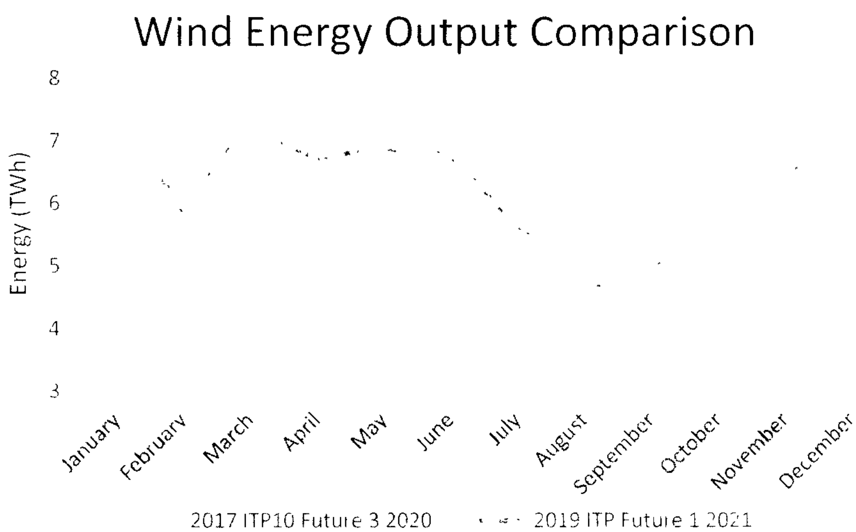

Figure 35 Wind Energy Output Comparison

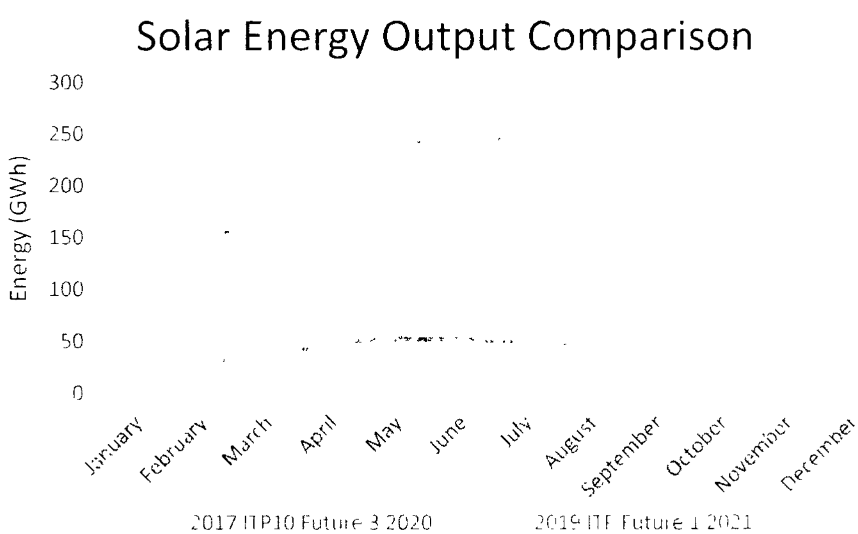

Figure 36 Solar Energy Output Comparison

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 8 Renewable Generation Capacity Factor Comparison

3.2.2 SYSTEM LOCATIONAL MARGINAL PRICE

Simulated LMPs were benchmarked against simulated LMPs from the ITP10. This data was compared on an average monthly value-by-area basis. Figure 37 portrays the results of the benchmarking model for the SPP system and the difference in the two curves. The increase in LMPs since the 2017 ITP10 is due to the change in fuel and load forecasts between studies.

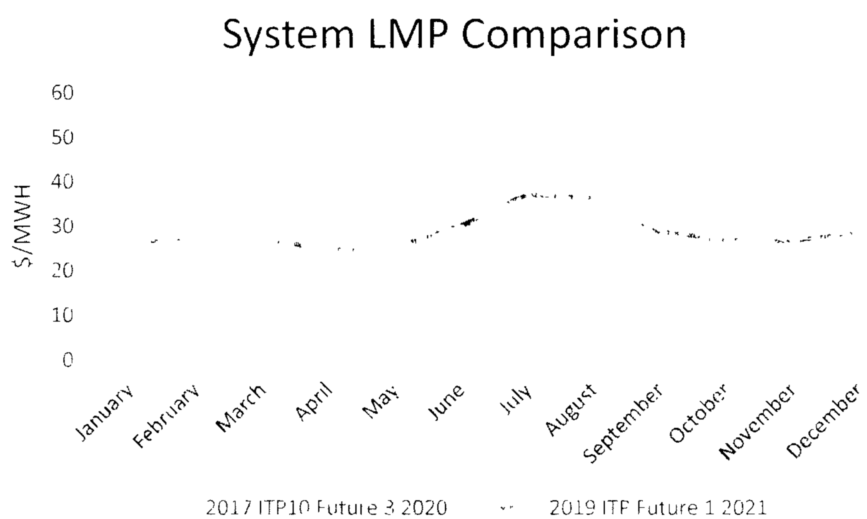

Figure 37 System LMP Comparison

3.2.3 ADJUSTED PRODUCTION COST

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 LMPs for all zones in SPP decreased except for Nebraska Public Power District (NPPD) and 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 38 and Figure 39 for a summary of regional APC results.

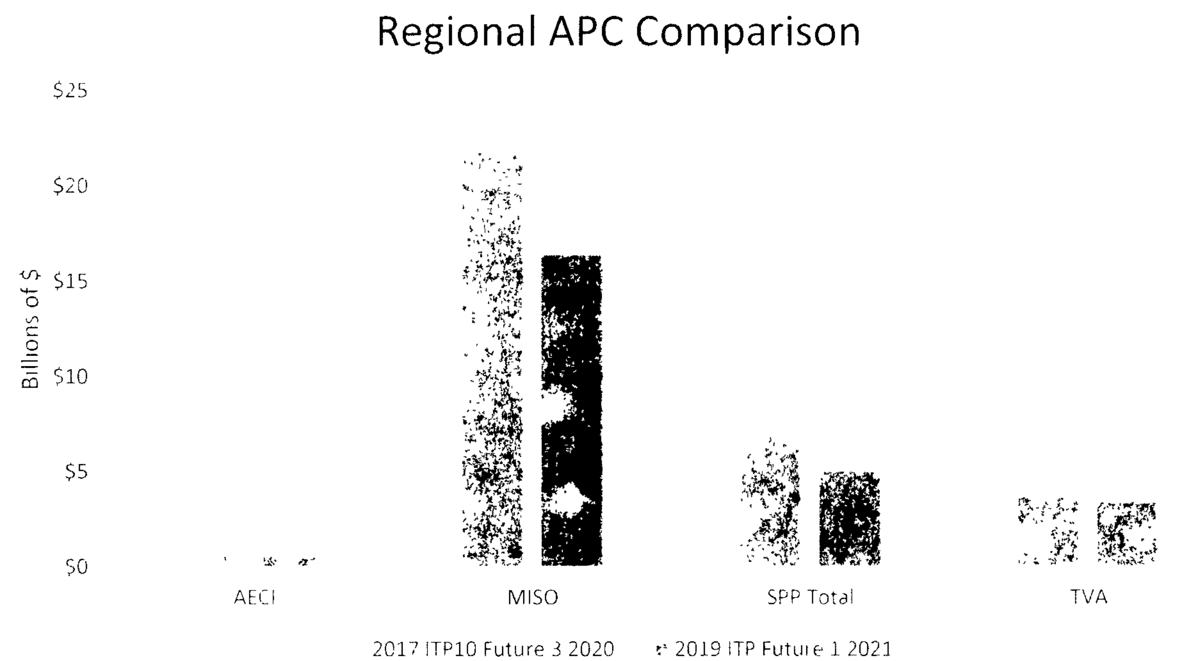

Figure 38. Regional APC Comparison

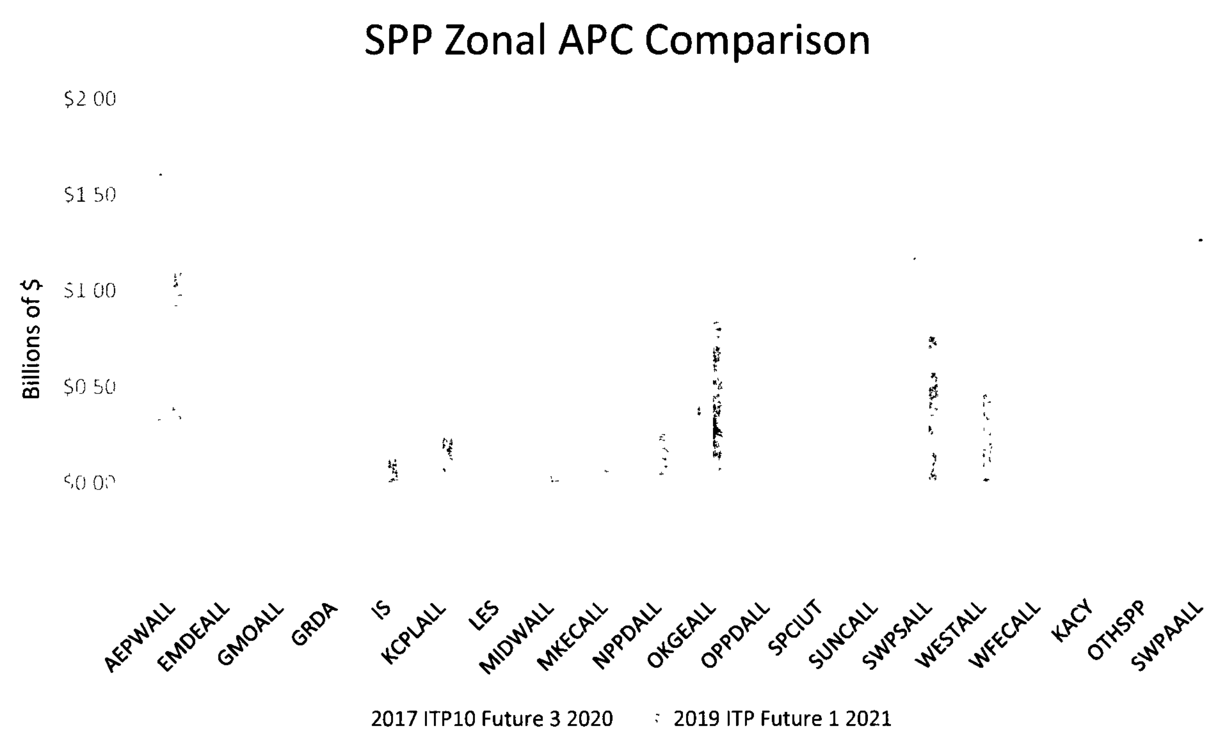

Figure 39 SPP Zonal APC Comparison

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.

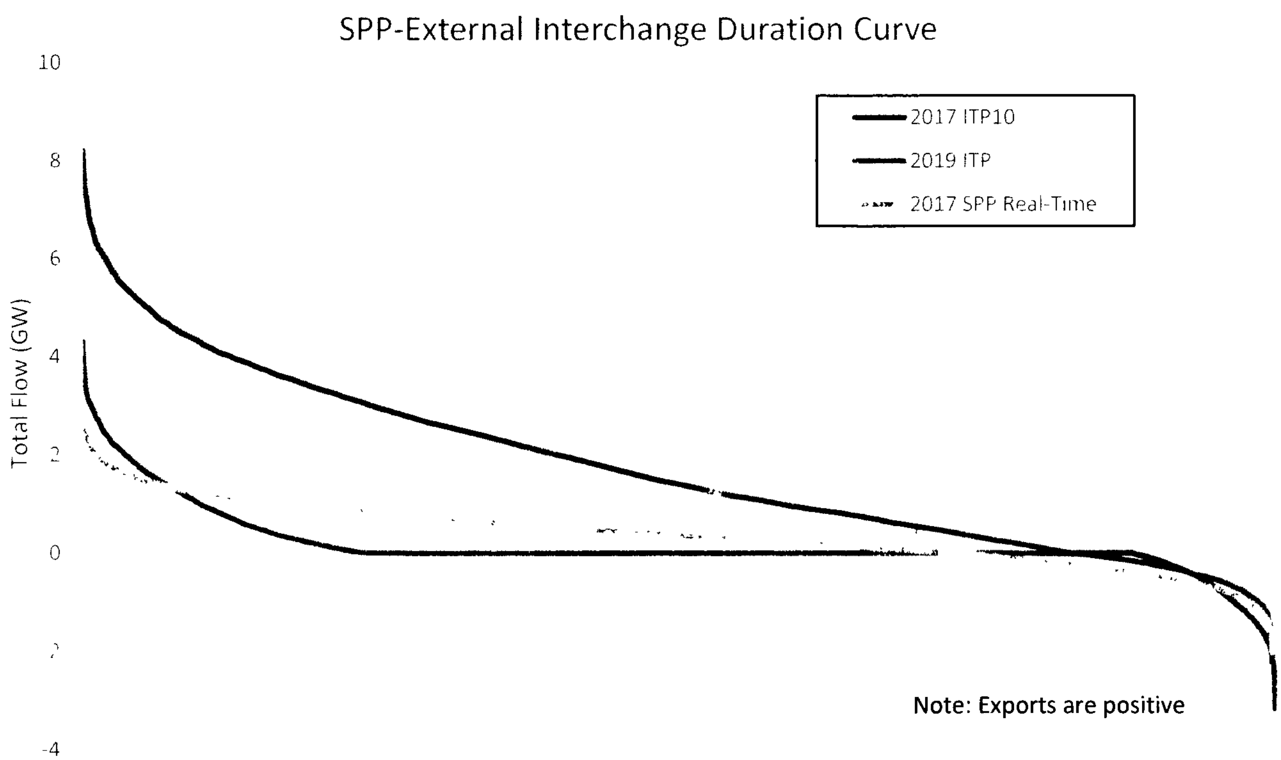

Figure 40 Interchange data comparison

4 NEEDS ASSESSMENT

4.1 ECONOMIC NEEDS

The economic needs identified per future are shown in Figure 41: Future 1 Economic NeedsFigure 41 and Figure 42 and Table 9 and Table 10.

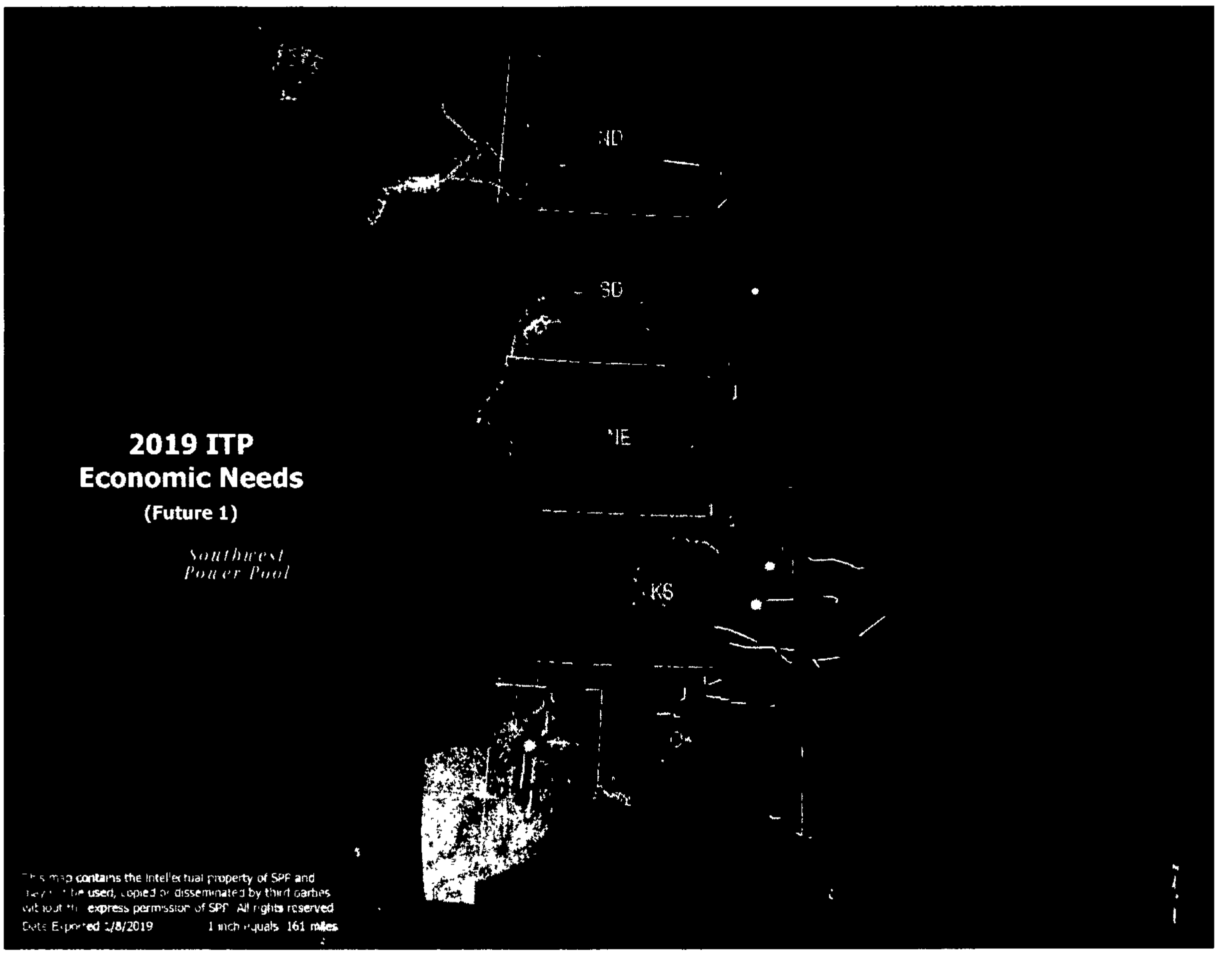

Figure 41 Future 1 Economic Needs

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

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

Table 9. Future 1 Economic Needs

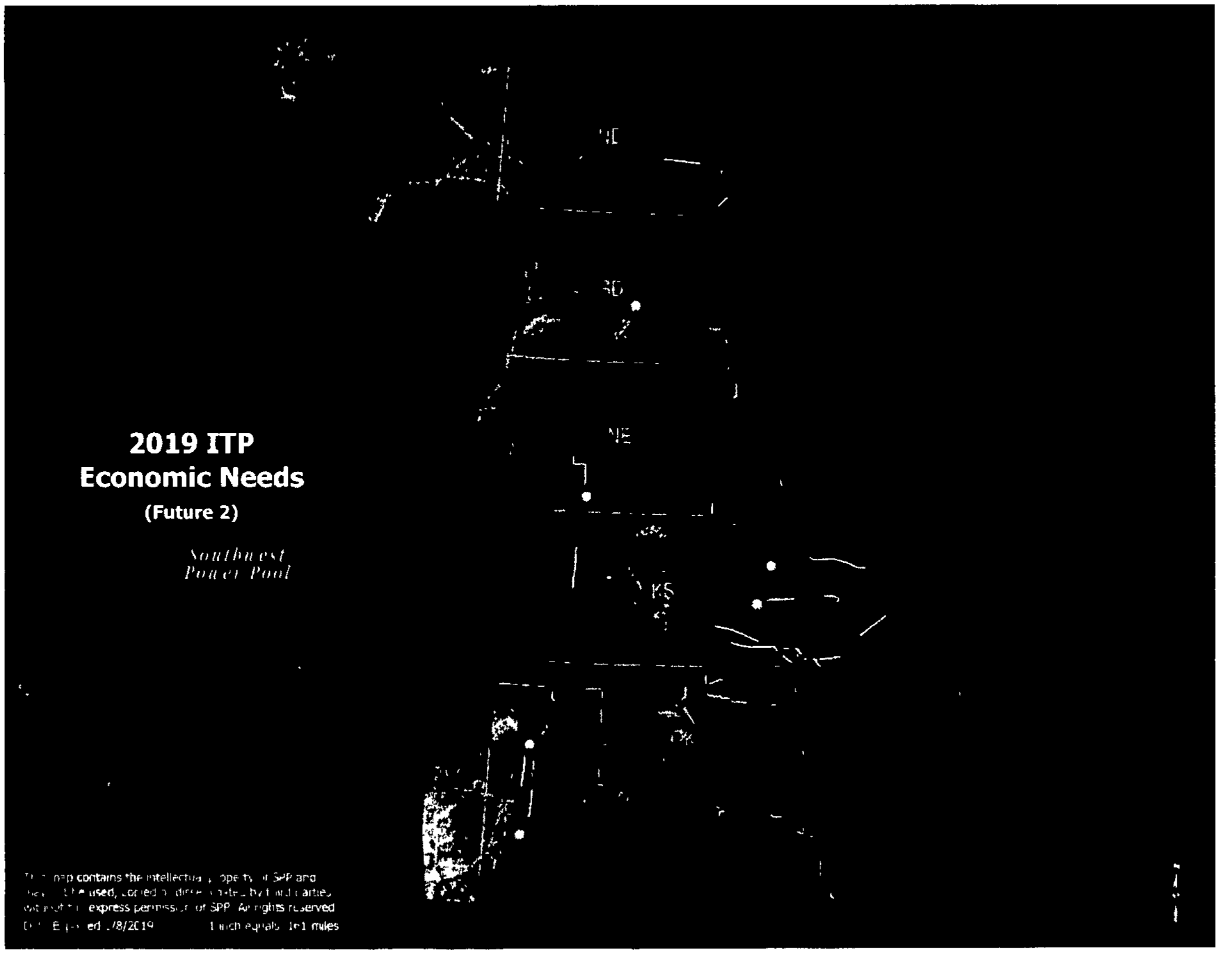

Figure 42: Future 2 Economic Needs

Rank	Constraint	2024 Congestion Score	2029 Congestion Score
1	Butler - Altoona 138kV FLO Caney River - Neosho 345kV	704,406	1,188,264
2	Cleveland AECI - Cleveland GRDA 138kV FLO Cleveland - Tulsa North 345kV	701,946	533,105
3	Lawrence Energy Center - Midland 115kV FLO Lawrence Hill 230/115kV Transformer	234,634	622,429
4	Kerr to Maid 161kV Circuit #2 FLO Kerr to Maid 161kV Circuit #1	229,440	302,129
5	Hankinson - Wahpeton 230kV FLO Buffalo - Jamestown 345kV	92,405	419,129
6	South Brown - Russett 138kV FLO Caney Creek - Little City 138kV	157,255	349,052
7	Clinton - Trumann 161kV FLO Overton - Sibley 345kV	126,369	154,273
8	South Shreveport - Wallace Lake 138kV FLO Fort Humbug to Trichel Street 138kV	5,334	256,002
9	Sundown - Amoco Tap 115kV FLO Sundown - Amoco S.S. 230kV	114,173	136,720
10	La Russell - Springfield 161kV FLO La Russell - Monett 161kV	76,292	143,344
11	Kingfisher - East Kingfisher Tap 138kV FLO Dover to Dover Switchyard 138kV	136,687	77,642
12	Gracemont - Anadarko 138kV FLO Washita to Southwestern Station 138kV	87,638	125,272

13	Wolf Creek 345/69kV Transformer FLO Waverly to La Cygne 345kV	84,733	101,602
14	Sioux City SC2 - Sioux City 230kV FLO Raun - Sioux City 345kV	57,710	107,454
15	Spearman County - Hansford 115kV FLO Potter County 345/230kV Transformer	97,186	67,820
16	Hugo - Valliant 138kV FLO Valliant - Hugo 345kV	40,891	94,244
17	Neosho - RP2POI10 345kV FLO Waverly - La Cygne 345kV	46,601	71,507
17	Neosho - Riverton 161kV FLO Blackberry/RP2OI02 - Neosho 345kV	43,235	43,677
18	Cottonwood Creek - RP2POI11 138kV System Intact	0	115,784
19	Coffman - Huben 161kV FLO Franks - Huben 345kV	66,999	47,148
20	Red Willow 345/115kV Transformer FLO Gerald Gentleman - Red Willow 345kV	60,143	53,895
21	Grand Forks - Falconer 115kV FLO Drayton - Prairie 230kV	7,259	105,277
22	Carthage SW - Purcell SW 161kV FLO Ashbury - Carl Junction 161kV	52,511	56,931
23	Arnold - Ransom 115kV FLO Mingo - Setab 345kV	43,993	59,143
24	Ft Thompson 345/230kV Transformer #2 FLO Ft Thompson 345/230kV Transformer #1	20,415	82,596
25	Dover - Okeene 138kV FLO Watonga Switch - Okeene 138kV	31,598	67,870
26	Northwest - Matthewson 345kV FLO Cimarron - Northwest 345kV	8,735	90,442
27	Potter County - Bushland 230kV FLO Potter County to Newhart 230kV	40,973	54,835
28	Asbury - Carl Junction 161kV FLO Asbury - Purcell SW 161kV	49,042	46,588
29	Carlisle - LP-Doud 115kV FLO Wolfforth 230/115kV Transformer	19,067	68,274
30	Craig - Lenexa 151kV Circuit #2 FLO Craig - Lenexa 161kV Circuit #1	11,679	60,043
31	Maryville - Clarinda 161kV FLO Maryville E - Maryville 161kV	0	58,191
32	Webb City Tap - Osage 138kV FLO Sooner - Cleveland 345kV	16,574	24,090
33	Waverly - La Cygne 345kV FLO Caney River to Neosho 345kV	12,412	6,813

Table 10 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.

Southeast Kansas/Southwest Missouri Target Area

The transmission corridor east of Wichita, Kansas connecting into Springfield, Missouri was identified as a target area for the 2019 ITP assessment. Drivers for this target area include:

- Unresolved transmission limits identified in previous ITP assessments and operational evaluation(s)
- Historical and projected congested flowgates in area
- Parallel and in-series relationships between flowgates within Southeast Kansas/Southwest Missouri target area
- Parallel and in-series relationships with flowgates located in Central/Eastern Oklahoma
- Steady-state reliability violations
- Stability concerns at Wolf Creek nuclear unit

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

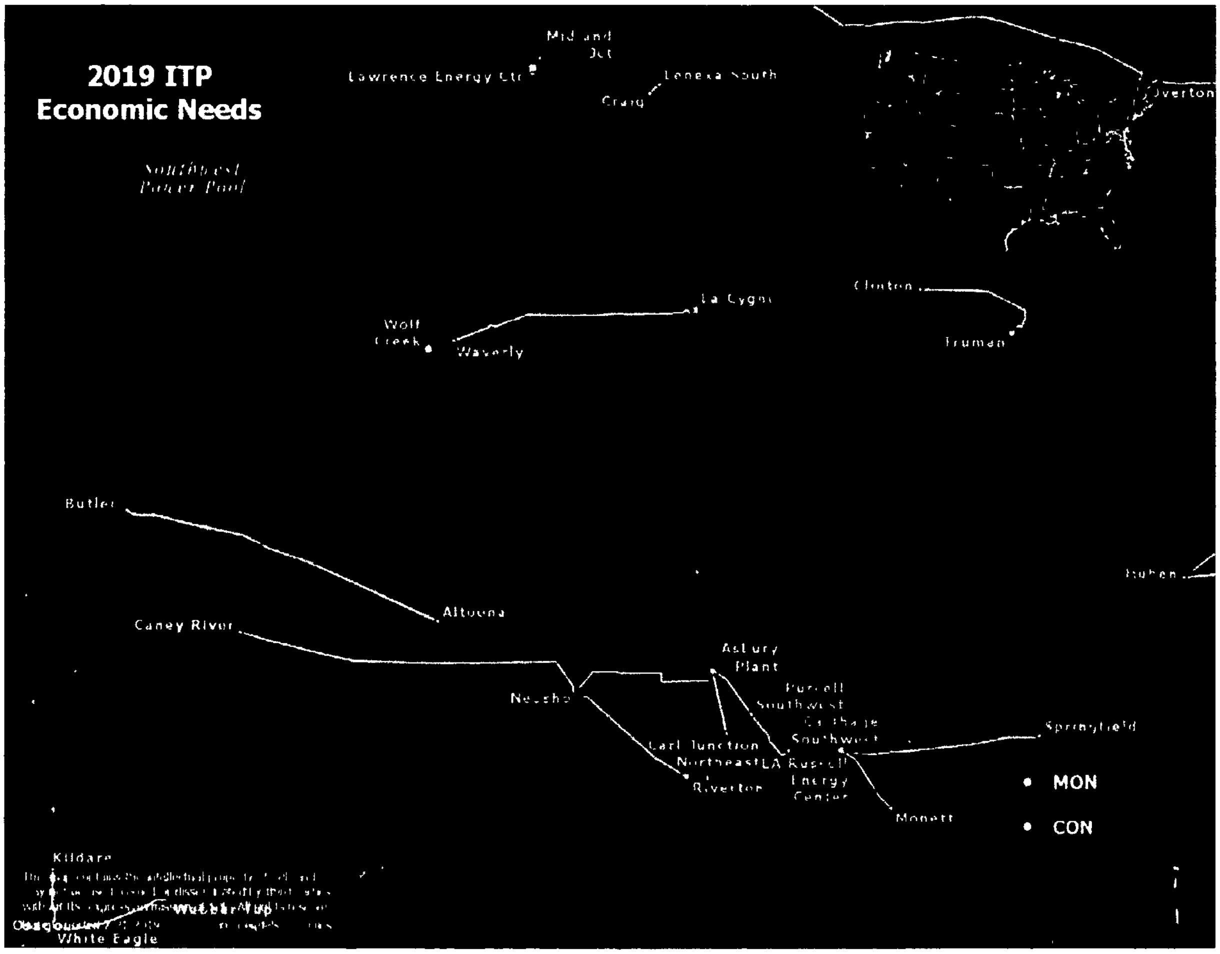

Figure 43. Southeast Kansas/Southwest Missouri Target Area Flowgates

Constraint
Butler – Altoona 138kV FLO Caney River – Neosho 345kV
LaRussell – Springfield 161kV FLO LaRussell – Monett 161kV
Carthage SW – Purcell SW 161kV FLO Ashbury – Carl Junction 161kV
Asbury – Carl Junction 161kV FLO Asbury – Purcell SW 161kV
Wolf Creek 345/69kV Transformer FLO Waverly to La Cygne 345kV
Neosho – Riverton 161kV FLO Blackberry/RP2POI02 – Neosho 345kV
Neosho – RP2POI10 345kV FLO Waverly – La Cygne 345kV
Waverly – La Cygne 345kV FLO Caney River to Neosho 345kV

Table 11: Southeast Kansas/Southwest Missouri Target Area Flowgates

Central/Eastern Oklahoma Target Area

The transmission corridor from Stillwater, Oklahoma connecting into Tulsa, Oklahoma was identified as an additional target area for the 2019 ITP assessment. Drivers for this target area include:

- Historical and projected congested flowgates in area

- Parallel and in-series relationships between flowgates within Central/Eastern Oklahoma target area
- Parallel and in-series relationships with Southeast Kansas/Southwest Missouri target area
- Impacted by "critical contingencies" in transmission corridor
    - Sooner to Cleveland 345 kV
    - Cleveland to Tulsa North 345 kV

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

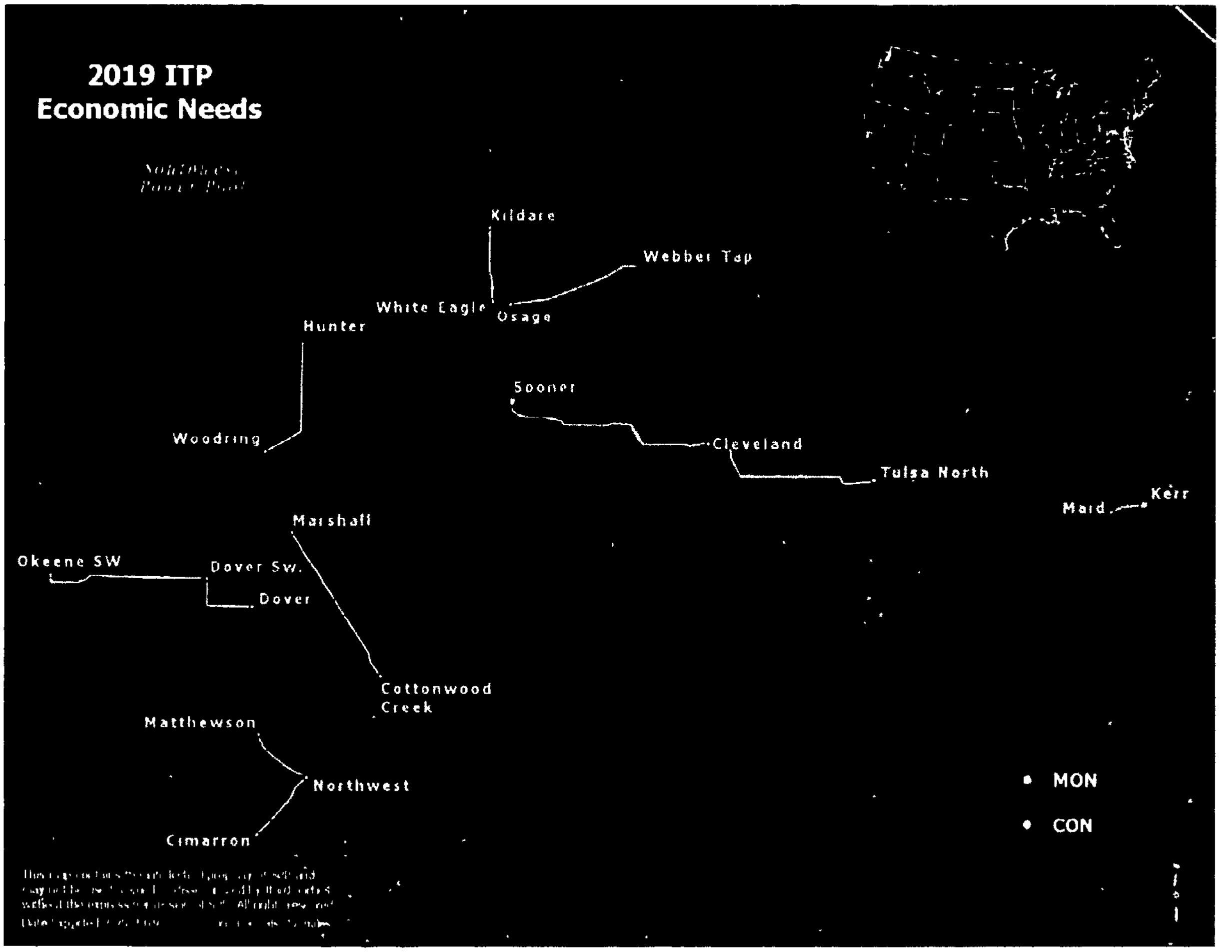

Figure 44 Central/Eastern Oklahoma Target Area Flowgates

Constraint
Cleveland AECI – Cleveland GRDA 138kV FLO Cleveland – Tulsa North 345kV
Kerr to Maid 161kV Circuit #2 FLO Kerr to Maid 161kV Circuit #1
Webb City Tap – Osage 138kV FLO Sooner – Cleveland 345kV
Northwest – Matthewson 345kV FLO Cimarron – Northwest 345kV

Table 12 Central/Eastern Oklahoma Target Area Flowgates

4.2 RELIABILITY NEEDS

4.2.1 BASE RELIABILITY ASSESSMENT

Contingency analysis for the BR models consisted of analyzing P0, P1, and P2.1 planning events as well as the remaining contingencies from Table 1 in the NERC TPL-001 Standard that do not allow for non-consequential load loss (NCLL) or the interruption of firm transmission service (IFTS).

During the course of the needs assessment, potential violations were solved or marked invalid through methods such as reactive device setting adjustments; model updates; and identification of invalid contingencies, non-load-serving buses, and facilities not under functional control of SPP. Figure 45 and Figure 46 summarize the number of remaining thermal and voltage needs[12] that were unable to be mitigated during the screening process.

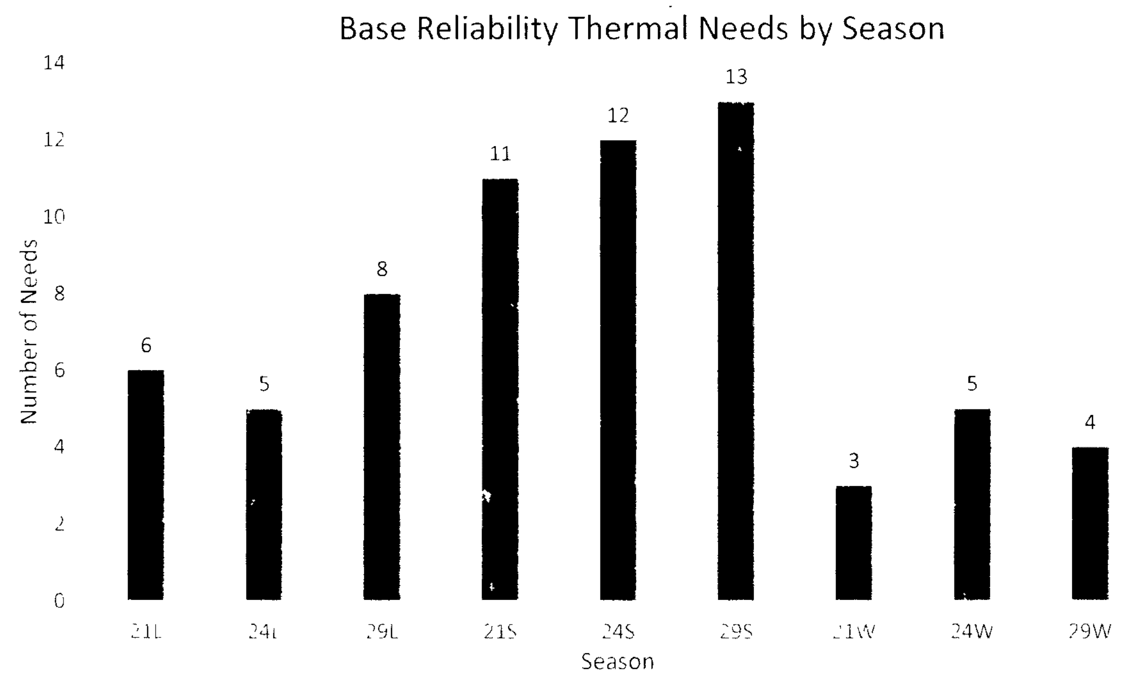

Figure 45 Unique Base Reliability Needs

[12] Figures summarize unique monitored elements

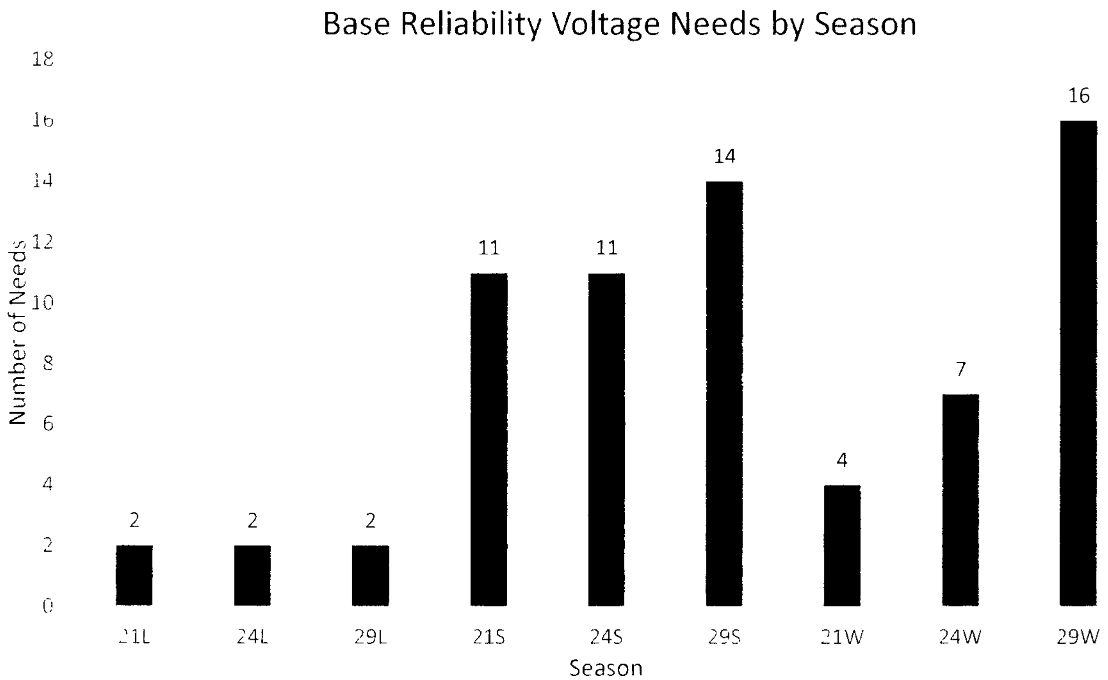

Figure 46 Unique Base Reliability Voltage Needs

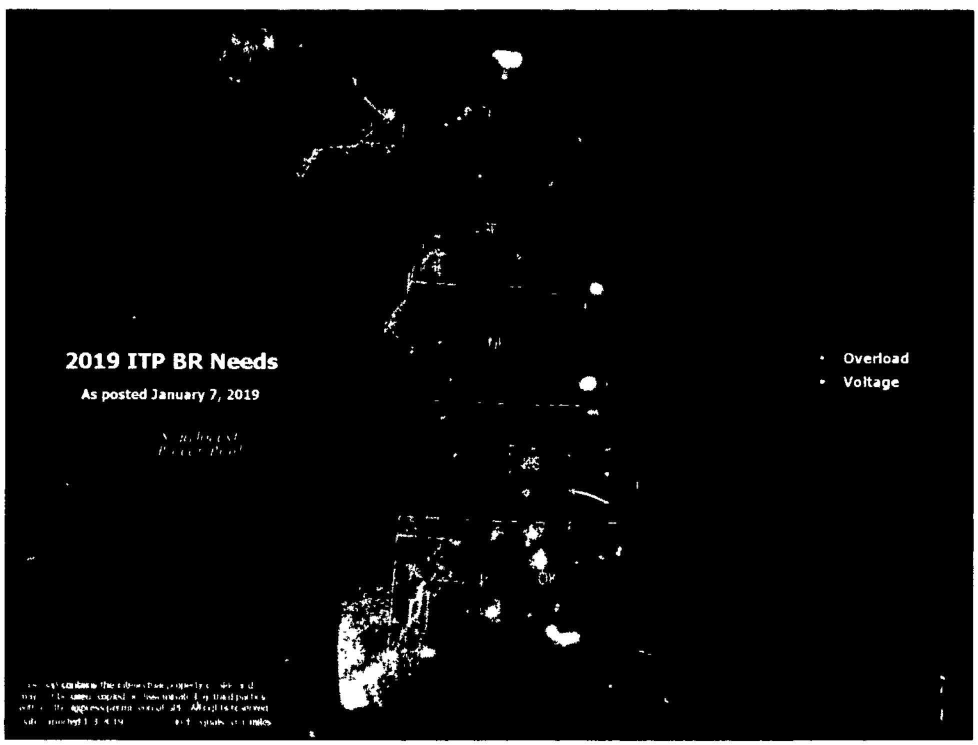

Figure 47 Base Reliability Needs

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 to be a part of 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 BR model

Figure 48 and Figure 49 summarize the number of remaining thermal and voltage needs[13] that were unable to be mitigated during the screening process.

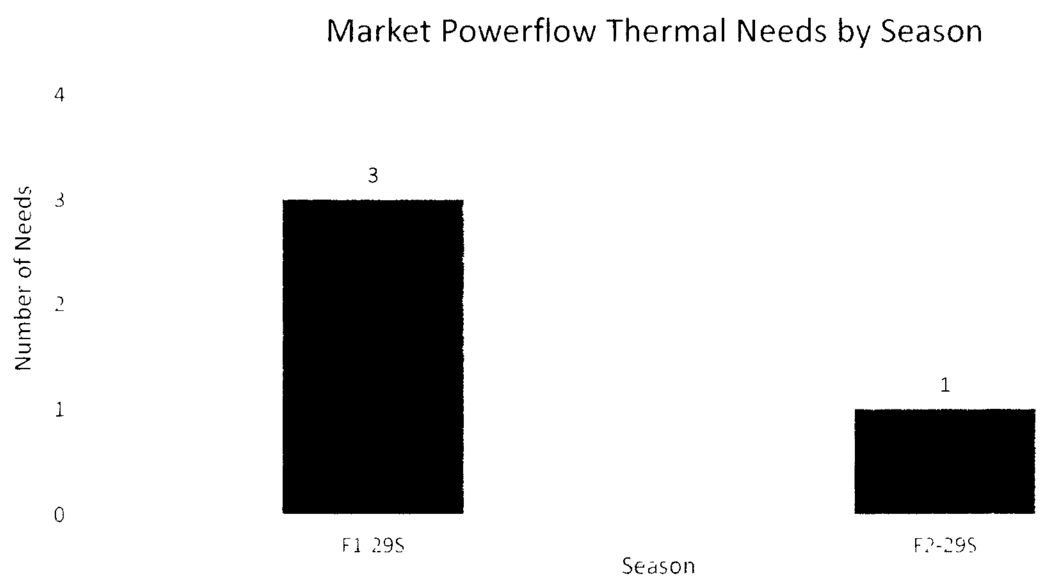

Figure 48 2019 ITP Unique Market Powerflow Thermal Needs

[13] Figures summarize unique monitored elements

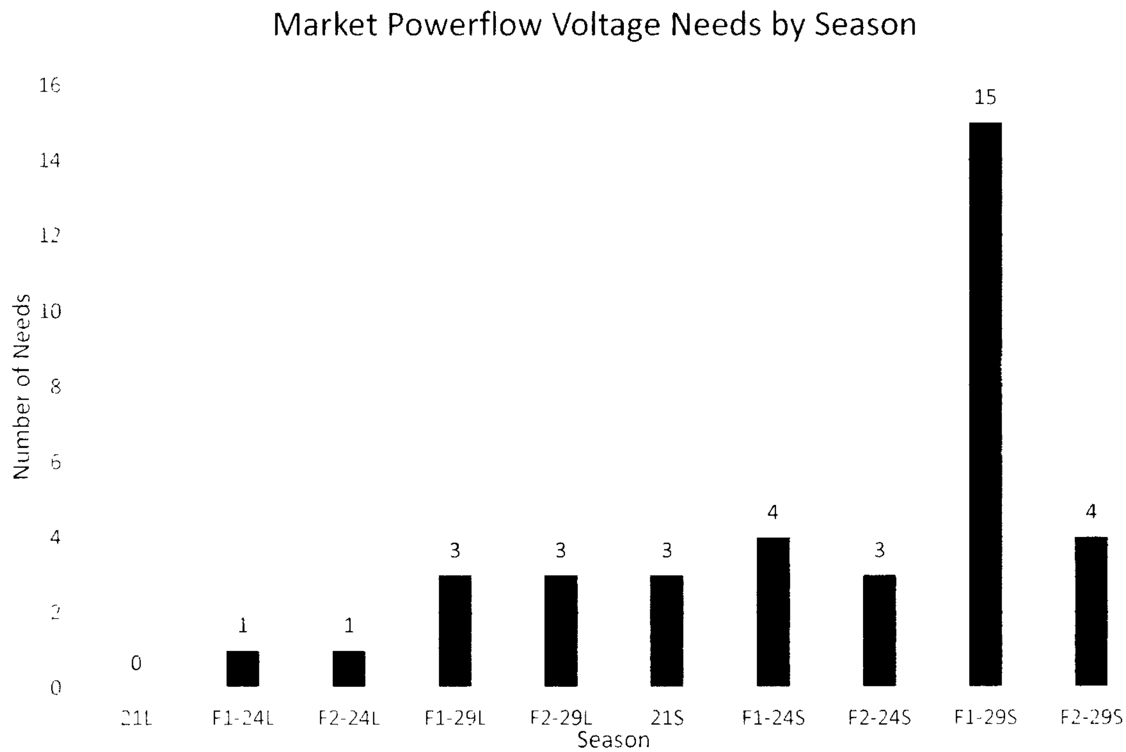

Figure 49 2019 ITP Unique Market Powerflow Voltage Needs

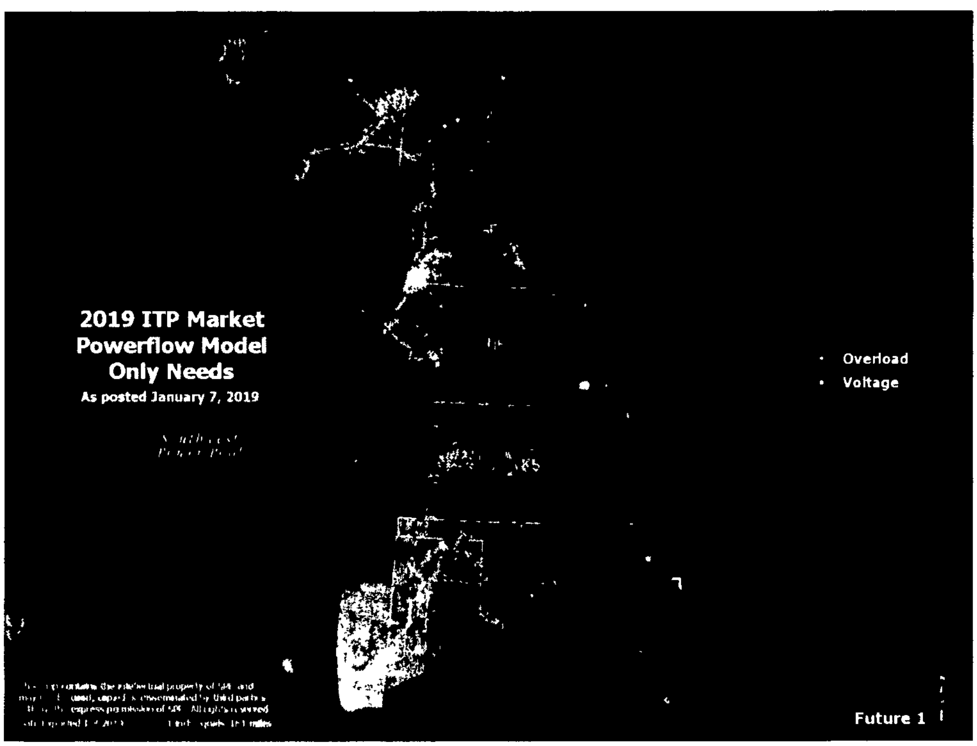

Figure 50: Future 1 Reliability Needs

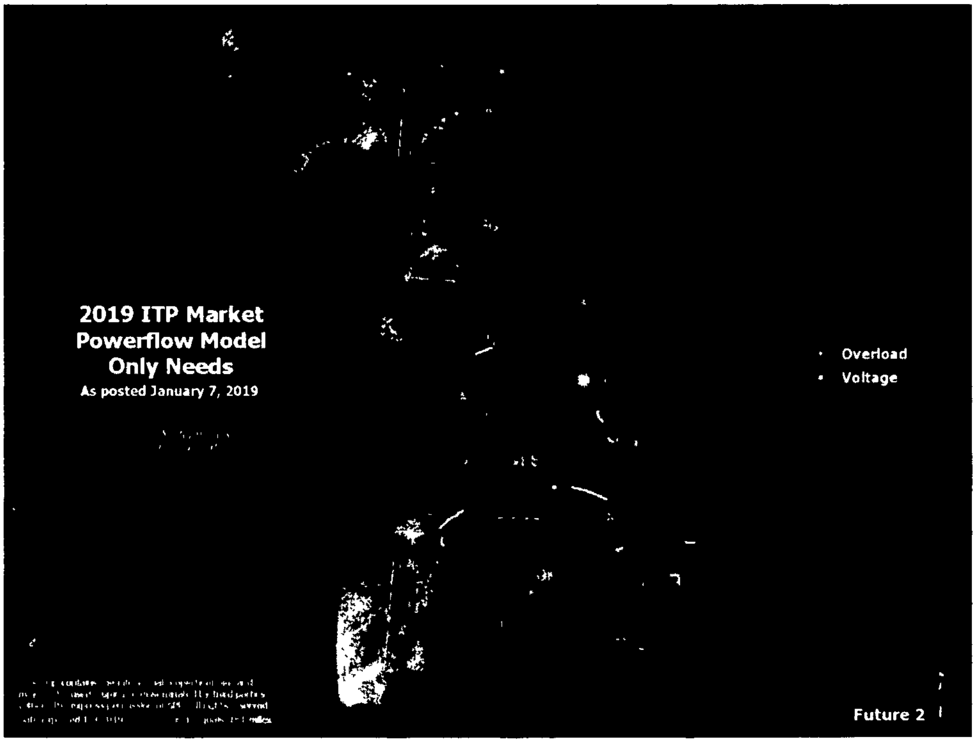

Figure 51: Future 2 Reliability Needs

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, so relative violations were identified as voltage collapse reliability needs in the applicable model and are listed in Table 13.

Model	Monitored Element	Contingent Element	Reliability Need
Base Reliability 2029 Summer Peak	Custer Mountain – Whitten 115kV	Hobbs – Kiowa 345kV	Thermal
Future 1 2024 Light Load	Eddy County 345kV	Tolk – Crossroads 345kV	Voltage
Future 2 2024 Light Load	Battle Axe 115kV	Hobbs – Kiowa 345kV	Voltage
Future 1 2029 Light Load	Battle Axe 115kV	Hobbs – Kiowa 345kV	Voltage
Future 2 2029 Light Load	Battle Axe 115kV	Hobbs – Kiowa 345kV	Voltage
Future 1 2029 Summer Peak	Battle Axe 115kV	Hobbs – Kiowa 345kV	Voltage
Future 2 2029 Summer Peak	Battle Axe 115kV	Hobbs – Kiowa 345kV	Voltage
Base Reliability 2029 Summer Peak	Battle Axe 115kV	Hobbs – Kiowa 345kV	Voltage
Future 2 2029 Summer Peak	North Loving 345kV	Kiowa – North Loving 345kV	Voltage

Table 13 Reliability Needs Resulting from Non-Converged Contingencies

4.2.4 SHORT-CIRCUIT ASSESSMENT

SPP sent out 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 (CAPs) 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 6 SPP TP areas and can be seen depicted in Figure 52: Short-Circuit Needs below. The six TPs 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 52 Short-Circuit Needs

4.3 POLICY NEEDS

All utilities were assessed to determine if they would be able to meet their future renewable mandates and goals identified during the renewable policy review. All utilities met their respective renewable mandates and goals, thus there were no 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 1 of the resource plan. It is not necessary to analyze capacity requirements for curtailment and thus they were not used to identify policy needs.

4.3.2 POLICY NEEDS AND SOLUTIONS

Future 1, 2020

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 14 Policy Assessment Results Future 1 2020

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 15 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
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

Future 1, 2029

Utility	State	Renewable Type	Curtailed Energy (TWh)	Energy Mandate Contribution (TWh)	Energy Mandate Requirement (TWh)	Surplus (TWh)
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 16: 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
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

Future 2, 2024

Utility	State	Renewable Type	Curtailed Energy (TWh)	Energy Mandate Contribution (TWh)	Energy Mandate Requirement (TWh)	Surplus (TWh)
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 17 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
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

Future 2, 2029

Utility	State	Renewable Type	Curtailed Energy (TWh)	Energy Mandate Contribution (TWh)	Energy Mandate Requirement (TWh)	Surplus (TWh)
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 18. Policy Assessment Results. Future 2, 2029

All utilities met their overall renewable Mandates and Goals. There were no policy needs and thus no policy projects identified in any of the Futures.

4.4 PERSISTENT OPERATIONAL NEEDS

4.4.1 ECONOMIC OPERATIONAL NEEDS

In October 2018, the MOPC approved a waiver of the requirements of the Operational Model Development and Economic Operational Needs sections of the ITP Manual for the 2019 ITP planning cycle. The economic operational needs identified for the 2019 ITP planning cycle in Tables 19-21 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 19 Economic Operational Needs

The constraints in Table 20 have associated future upgrades which reduce loading of the associated 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 upgrades, 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 161kV Terminal Upgrades, 12/2018 ISD
GGS	**Gentleman - Red Willow 345 kV Gentleman - Sweetwater 345 kV Ckt 1 Gentleman - Sweetwater 345 kV Ckt 2 Gentleman - North Platte 230 kV Ckt 1 Gentleman - North Platte 230 kV Ckt 2 Gentleman - North Platte 230 kV Ckt 3**	**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 upgrades
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 upgrades**

Table 20: Economic Operational Needs

The constraints in Table 21 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 Ckt 1**	**$86,155,466**	**NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward - Tatonga - Matthewson 345 kV Ckt 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 Sundown 230 kV terminal upgrades, 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 upgrades, 11/28/2017 ISD, $0 congestion cost since upgrade**
TMP118_22847	Southard - Roman Nose 138 kV	Tatonga - Matthewson 345 kV Ckt 1	$34,561,487	NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward - Tatonga - Matthewson 345 kV Ckt 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 ckt 2, 12/2018 ISD**
TMP171_22413	Mooreland - Cedardale 138 kV	Tatonga - Matthewson 345 kV Ckt 1	$24,889,894	NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward - Tatonga - Matthewson 345 kV Ckt 2, 2/15/2018 ISD, $0 congestion cost since upgrade

CONSTRAINT	MONITORED ELEMENT	CONTINGENT ELEMENT	CONGESTION COST	NOTES
TMP113_22583	Cimarron - Draper 345 kV	Arcadia - Seminole 345 kV	$14,666,763	NTC ID 200416, Issued 11/14/2016, 2015 ITP10, terminal upgrades, 11/28/2017 ISD, $0 congestion cost since upgrade

Table 21: 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 planning cycle. 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 345kV

Table 22. Reliability Operational Needs

4.5 NEED OVERLAP

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

Figure 53: Base Reliability and Economic Need Overlap

Constraint
Wolf Creek 345/69kV Transformer FLO Waverly – La Cygne 345kV
Butler – Altoona 138kV FLO Caney River – Neosho 345kV
Webb City Tap – Osage 138kV FLO Sooner – Cleveland 345kV
South Shreveport – Wallace Lake 138kV FLO Ft. Humbug – Trichel 138kV
Potter County – Bushland 230kV FLO Potter County to Newhart 230kV
Marshall – Smittyville 115kV FLO Harbine – Steele 115kV
Carlisle – LP-Doud 115kV FLO Wolfforth 230/115kV Transformer

Table 23 Overlapping Reliability and Economic Needs

MAP PLACEHOLDER

Figure 54 Informational Operational and Economic Needs Overlap

Constraint
Neosho - Riverton 161kV FLO Blackberry - Neosho 345kV
Cleveland AECI - Cleveland GRDA 138kV FLO Cleveland - Tulsa North 345kV
Waverly - La Cygne 345kV FLO Caney River to Neosho 345kV
Hale County - Tuco 115kV FLO Swisher - Tuco 230kV
Kildare - White Eagle 138kV FLO Woodring - Hunter 345kV
Hugo - Valliant 138kV FLO Valliant - Hugo 345kV
Oakland North - Atlas Junction 161kV FLO Asbury - Purcell 161kV*

Table 24 Overlapping Informational Operational and Economic Needs

4.6 ADDITIONAL ASSESSMENTS

Additional assessments were performed in order 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

The Rayburn Country transmission system and network load in the American Electric Power - West (AEPW) zone that is in the process of moving 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).

In order to satisfy this obligation, following the same analysis of the reliability needs assessment, an analysis was performed on the BR 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

The Tri-County transmission system in the Oklahoma panhandle of the Southwestern Public Service (SPS) zone came under SPP functional control via the requirements of SPP tariff attachment AI since the 2019 ITP model build. This system has been previously equivalenced on tariff facilities prior to the fall of 2018. GridLiance High Plains (GLHP) performed a local planning process assessment in 2018 and identified three new transmission upgrades required to meet local planning process needs. In order to satisfy its own NERC and tariff requirements, GLHP requested SPP expedite the requirements under FAC-002 and SPP tariff Attachment O, Section II.1)e) to perform a no-harm analysis on the proposed upgrades and coordinate the upgrades with the potential solutions of the regional planning process, the 2019 ITP assessment.

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

GLOSSARY

Acronym	Name
APC	Adjusted Production Cost = Production Cost \$ + Purchases \$ - Sales \$
BA	Balancing Authority
BAU	Business as Usual
CC	Combined Cycle
CPP	Clean Power Plan
CT	Combustion Turbine
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GOF	Generator Outlet Facilities
GW	Gigawatt
GWh	Gigawatt hour
IRP	Integrated resource plan
IS	Integrated System, which includes the Western Area Power Administration's Upper Great Plains Region (Western-UGP), Basin Electric Power Cooperative, and the Heartland Consumers Power District
ITP 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
MTEP16	2016 MISO Transmission Expansion Planning
MW	Megawatt
NREL	National Renewable Energy Laboratory
PPA	Power Purchase Agreement
RPS	Renewable portfolio standards
SASK	Saskatchewan Power

SPC	Strategic Planning Committee
SPP OATT	SPP Open Access Transmission Tariff
TO	Transmission Owner
US EIA	United States Energy Information Administration

SPP Southwest Power Pool

INTEGRATED TRANSMISSION PLANNING MANUAL

Published on October 17, 2018

By SPP staff

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
10/13/2010	**SPP Staff**	**Initial Draft approved by the MOPC.**	
1/7/2011	SPP Staff	Incorporated TWG and ESWG edits to the ITPNT and ITP20 sections.	
7/13/2011	**SPP Staff**	**Revised Draft approved by the MOPC.**	
12/15/2014	ESWG	Accepted Task Force Edits	
06/22/2017	**SPP Staff**	**Implementation of TPITF recommendations**	
04/19/2018	SPP Staff	Incorporate RR276, renewable VOM Pricing	
9/7/2018	**SPP Staff**	**Incorporate RR 314: ITP Manual Model Build Updates**	
9/27/2018	SPP Staff	Incorporate RR 321: Clean up Items	MOPC approval 10/16/2018

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1 INTRODUCTION

1.1 PURPOSE

The SPP Open Access Transmission Tariff (OATT or SPP tariff) Attachment O requires Southwest Power Pool, Inc. (SPP) to conduct the Integrated Transmission Planning (ITP) Assessment in accordance with this Integrated Transmission Planning Manual. This manual will outline the methodology, criteria, assumptions, and data necessary for the for the ITP assessment.

The ITP assessment is a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, operational, and economic needs, as well as compliance, generator interconnection, and transmission service request impacts to develop a cost-effective transmission portfolio over a 10-year planning horizon. A common set of foundational modeling assumptions will be utilized as the starting point for all planning studies. System needs resulting from generator interconnection and transmission service requests will be identified within the currently established timelines for those processes. However, the evaluation of transmission service needs and associated projects will be coordinated with those identified in the ITP assessment to facilitate continuity in the overall transmission expansion plan. This targeted approach is both forward-looking and proactive, designed to facilitate a cost-effective and responsive transmission network that adheres to the ITP principles (listed in History of the ITP Assessment), while following the Federal Energy Regulatory Commission (FERC) "Nine Transmission Principles".[1]

Analyses will be performed following the adoption of the study assumptions and will focus on cost-effectiveness and flexibility, while taking into account reliability, public policy, operational, and economic considerations in project or portfolio recommendations. The assessment of a project or group of projects' performance may include:

- Performance across multiple futures
- Ability to solve multiple need types
- Reliability impacts related to compliance with North American Electric Reliability Council (NERC) Standard TPL-001[2]
- Operational impacts

Cost-effective analysis is a form of economic analysis that allows for the most effective planning over a longer- versus shorter-term period. The objective is to produce the most economical project planning over the longer-term horizon.

This manual includes standardized language detailing ITP assessment items that were reviewed by the appropriate SPP stakeholder groups and approved by the Markets and Operations Policy Committee (MOPC). This standardization will provide specific details on each scope item and eliminate the need for repetitive reviews and approvals to help facilitate the performance of a planning cycle that produces an annual report. An ITP assessment scope will be developed for each

[1] These FERC principles are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning (congestion) studies, and cost allocation for new projects, as described more fully in Order 890, Final Rule, pages 245 - 323.

[2] NERC TPL-001

ITP assessment for items that will require SPP stakeholder review and approval with each new study. This process is described further in the Study Scope Document section of this manual.

1.2 REVISION REQUEST PROCESS

A request to make additions, deletions, revisions, or clarifications to this ITP Manual shall be made in accordance with the SPP revision request process.[3]

1.3 OVERVIEW OF THE SPP ITP ASSESSMENT

The ITP assessment is SPP's approach to planning transmission upgrades needed to maintain reliability, provide economic benefits, and achieve public policy goals for the SPP region in the near- and long-term horizons. The ITP assessment enables SPP and stakeholders to facilitate the development of a reliable and flexible transmission grid that provides regional customers improved access to the region's diverse resources.

The ITP assessment assesses transmission needs over a 10-year horizon and is intended to produce an annual report. It is designed to create synergies by integrating SPP transmission planning activities that incorporate reliability, economic, policy, and operational components in the overall assessment of the transmission grid. The ITP assessment works in concert with SPP's existing subregional planning stakeholder process and parallels the NERC transmission planning reliability standards compliance process.

1.3.1 ORGANIZATIONAL GROUP SUPPORT

The Economic Studies Working Group (ESWG) identifies and maintains the economic data, data sources, models, economic planning methodology and processes, and benefit metrics to be used in the evaluation of economic expansion needs in the SPP region.

The Transmission Working Group (TWG) oversees and maintains the study processes for reliability and compliance to be used in the evaluation of reliability expansion needs in the SPP region.

The Operating Reliability Working Group (ORWG) identifies and maintains operational data, data sources, and models to be used in the evaluation of persistent operational expansion needs in the SPP region.

The ORWG, TWG, and ESWG are responsible for identifying needs associated with persistent operational issues.

The ITP recommended plan will be reviewed and may be endorsed by ESWG, TWG and MOPC.

1.4 WORKING GROUP OWNERSHIP

ECONOMIC STUDIES WORKING GROUP

Generally, the ESWG will be responsible for review of data and results for the following items:

[3] SPP Revision Requests

- Scope
- Scenarios development
- Load forecasts
- Existing and planned generation
- Renewable policy requirements
- Resource plan
- Market Economic model
- Economic analysis
- Recommended plan
- Benefit metrics
- Sensitivities
- Assessment report

TRANSMISSION WORKING GROUP

Generally, the TWG will be responsible for review of the data and results for the following items:

- Scope
- Transmission topology
- Load forecasts
- Existing and planned generation
- Base reliability models
- Market Powerflow models
- Constraint assessment
- Reliability analysis
- Recommended plan
- Assessment report

MODEL DEVELOPMENT WORKING GROUP

Generally, the MDWG will be responsible for review of the data for the following item:

- Load forecasts
- Existing and planned generation
- Transmission topology

SEAMS STEERING COMMITTEE

The Seams Steering Committee (SSC) will be responsible for the review of the following:

- Seams impacts

STRATEGIC PLANNING COMMITTEE

The Strategic Planning Committee (SPC) will provide input for the following items:

- Scenarios development
- Policy decisions

MARKETS AND OPERATIONS POLICY COMMITTEE

MOPC will make a recommendation to the SPP Board regarding approval decisions of the following items:

- Assessment report

REGIONAL STATE COMMITTEE

The RSC will review the following items:

- Assessment report

SPP BOARD OF DIRECTORS

The Board will make approval decisions for the following items:

- Assessment report
- Recommended plan

1.5 ITP ASSESSMENT SCHEDULE

The planning cycle, as illustrated in Figure 1, will consist of scope development and model development for approximately 12 months and a planning assessment period of approximately 12 months. The scope and model development for the succeeding cycle will begin concurrently with the planning assessment period of the preceding study resulting in a 12-month overlap. This planning cycle will result in an annual assessment report with a set of recommended projects.

The assessment will also satisfy the NERC Standard TPL-001 short-circuit and portions of the NERC Standard TPL-001 steady-state assessment requirements. The ITP assessment will assess years 2, 5, and 10 for reliability, public policy, operational, and economic needs.

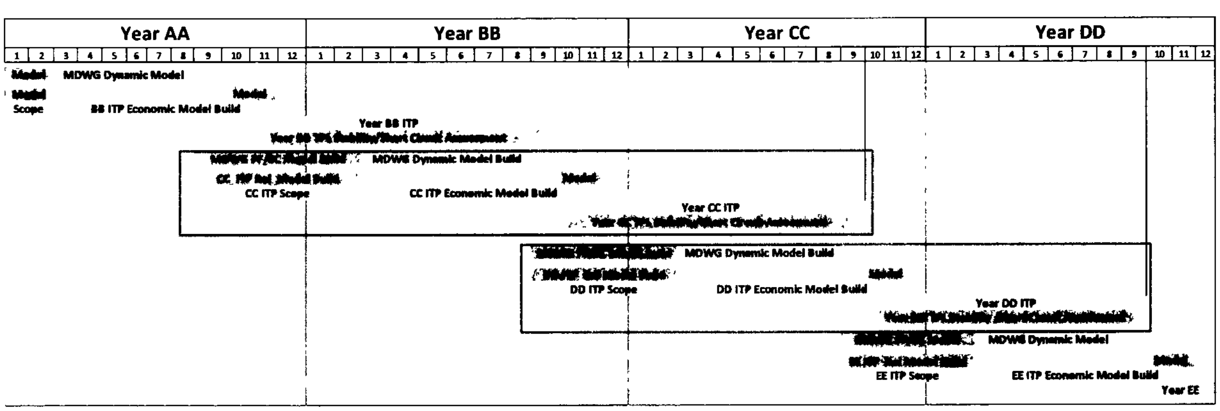

Figure 1 ITP Cycle

1.6 STUDY SCOPE DOCUMENT

To provide context under which to assess the future performance of the existing transmission system and any needed improvements, certain assumptions and methodologies may change with each study cycle. Maintaining the ability to update these assumptions from study to study will provide the flexibility needed for the transmission planning process. The study scope document describes those items that will require SPP stakeholder review and approval with each new study. Those study scope items will be approved by the appropriate working groups during the scope development phase at the beginning of each planning cycle.

1.7 CONSIDERATION OF NERC STANDARD TPL-001

The analyses performed for the holistic planning assessment described in this manual allow SPP to meet the requirements of the SPP tariff, as well as a portion of the NERC standards for transmission planning requirements detailed in NERC Standard TPL-001. This allows for a consistent approach in the planning processes while allowing SPP to issue NTCs to transmission owners (TOs) to construct upgrades needed to meet certain NERC Standard TPL-001 Table 1 requirements.

The Reliability Needs Assessment section detailed in this manual will describe the assessment of transmission system planning events in NERC Standard TPL-001 Table 1 for which non-consequential load loss or the interruption of firm transmission service is not allowed. A common powerflow analysis for the ITP assessment and NERC Standard TPL-001 will be performed for these planning events. Additionally, the short-circuit analysis required by NERC Standard TPL-001 will be performed and a subset of those needs will be considered as ITP needs.

While these analyses will be common to both the ITP assessment and the requirements of the NERC Standard TPL-001, SPP will continue to compile and issue a separate annual report (SPP Compliance Assessment) to fully document SPP's compliance with all NERC Standard TPL-001 requirements.

2 MODEL DEVELOPMENT

Table 1 lists the model sets for the ITP assessment cycle. After the model sets are finalized, no topology changes will be accepted to update the model. Any identified model changes will be required to be submitted during the detailed project proposal (DPP) window as detailed in the Model Adjustments section.

Description	Year 2	Year 5	Year 10	Total
Base Reliability	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	9
Market Economic Model	One Future (1)	Each Future (1-3)	Each Future (1-3)	3-7
Market Powerflow Model	One Future's Peak and Off-Peak (2)	Each Futures' Peak and Off-Peak (2-6)	Each Futures' Peak and Off-Peak (2-6)	6-14

Table 1 ITP Model Sets

2.1 BASE RELIABILITY MODEL OVERVIEW

The base reliability model set will be the base model set for all of SPP's planning processes including transmission service, generator interconnection, and compliance studies. Each of the base reliability models will be an indicative representation of how entities within SPP responsible for serving network load would do so utilizing network resources only. These models will consist of non-coincident peak load forecasts, assumed long-term firm transmission service usage levels, and expected conventional and renewable resource output levels.

Information needed to develop the models will be provided by SPP TOs and stakeholders with appropriate review opportunities by SPP and stakeholders, prior to receiving final approval. These inputs, described in the following sections, include but are not limited to:

- Generation resources
- Load forecasts
- Definition of the SPP footprint
- Topology
- Modeling of firm transmission service
- DC tie modeling
- DC line modeling
- Phase-shifting transformers (PSTs)
- NTC re-evaluation requests

All data requests and review opportunities for the base reliability model set will be administered through the MDWG and TWG, and the TWG will approve the base reliability models.

Additionally, a short-circuit model will be developed for a short-circuit assessment in consideration of NERC Standard TPL-001. This short-circuit model will be developed under the guidance of the MDWG.

2.1.1 GENERATION RESOURCES

Resource Inclusion and Availability

Generation resources[4] shall be included in the base reliability model if any of the following requirements are met:

1. The resource is existing and in service.
2. The resource has both of the following:
    a. An effective Generator Interconnection Agreement (GIA), not on suspension
    b. Approved long-term firm transmission service with an effective transmission service agreement.
3. The resource is approved by the TWG as meeting the requirements detailed in the Waiver Requests section of this manual.
4. The resource has been identified by SPP as necessary[5] to solve a model and is approved for inclusion by the TWG[6] with considerations such as:
    a. Resources in the generator interconnection queue.
    b. Resources have been included in an approved SPP-developed resource plan.

Seasonal resource availability (not outage related) may be modified per request of SPP stakeholders and applied if there is no shortfall. If the resource being requested to be made unavailable is the area slack machine, SPP stakeholder(s) will identify another resource as the new area slack machine, but coordinate with SPP. In the cases where violations appear in the ITP models that can be mitigated by turning on a resource that was requested to be made unavailable, SPP may turn on the resource to mitigate the violations. Notification of these requests should be made through SPP's Model On Demand (MOD) application and the SPP Request Management System (RMS) for the base reliability model.

Resource Dispatch

Generation resources will be available for dispatch in the base reliability model if either of the following criteria are met:

1. The resource has approved long-term transmission service with an effective transmission service agreement, or
2. SPP has identified the resource as necessary to solve a model.

[4] Associated transmission upgrades will be modeled in accordance with the SPP tariff

[5] Reactive resources or previously approved transmission upgrades will also be considered as potential solutions.

[6] Resources added for this criteria will not be included in the Market Economic model and Market Powerflow unless they are also identified in the resource planning process

If a generation resource is utilized solely for reactive support, it will be dispatched to its P_{Min} value in the appropriate model(s). TWG approval will include the specific models for which the generation resource, reactive resource, or transmission upgrade will be included.

Dispatch will not surpass the lesser of gross P_{max} or net designated resource amount plus the station service load.

Generation resources that have been mothballed or are planned for retirement must be submitted to SPP through SPP's MOD Application and the SPP RMS for the base reliability model. Upon receiving this information, these resources will remain in the models until such time they are officially decommissioned. Until this decommission occurs, the resources will be given a P_{Min}, P_{Max}, Q_{Min}, and Q_{Max} value of zero within the models to ensure that the units are not dispatched.

Resources considered required to be online may be modified in order to displace renewable generation in the planning models. These resource types include, but are not limited to: area slack machines, hydroelectric, cogen, landfill gas, and nuclear.

Shortfall Process[7]

Shortfall occurs when an entity does not have enough dispatchable generation to serve the entity's load. When a shortfall scenario appears in the models, the following actions will be taking in this order until the load is served:

1. Exhaust the dispatchable generation of the network customer.
2. Exhaust the independent power producers (IPP) dispatchable generation in the same model area.
3. Dispatch the remaining unused, dispatchable generation on a pro rata basis within SPP footprint.
4. When all other options have been exhausted, including the waiver process, include generation resources [8]from the most recently approved ITP resource plan.

2.1.1.1 Waiver Requests

Certain generation resources and associated transmission service requests that have not fully completed the processes defined in Attachment V and Z1 of the SPP tariff but have a high probability of going into service or obtaining an effective transmission service agreement can be included in the base reliability model. Generation resources that meet all of the following requirements will be included:

1. A formal request has been sent to SPP requesting the generation resource be included in the base reliability model.
2. The generation resource has an effective interim GIA.
3. The generation resource has entered the aggregate transmission service study or equivalent transmission service study publicly posted on OASIS and has a completed facility study that is awaiting final results without unmitigated third-party impacts.
4. The generation resource has acquired air and environmental permits where applicable.
5. The generation resource has started construction with major equipment funding and procurement contracts awarded.

[7] Renewable generation or other generation with operating restrictions shall not be used.

[8] Study needs generated by the addition of these generation resources will not automatically generate NTCs.

If a generation resource does not meet all of the above requirements, a formal request for resource inclusion in the base reliability model can be submitted to the TWG for approval. The TWG will take the following information into account in deciding whether to approve the waiver:

1. A formal request has been sent to SPP requesting the generation resource be included in the base reliability model, including any additional information deemed relevant by the requesting entity. The request should identify which transmission upgrades will be deferred, if applicable.
2. The generation resource has a mitigation plan for the deferred transmission upgrades until it makes a financial commitment to complete the required upgrades.
3. A Definitive Interconnection System Impact Study (DISIS) agreement for the generation resource has been executed, an interim GIA has been requested, and a GIA will be entered into when applicable.
4. An RFP for the generation resource has been awarded, if applicable.

2.1.2 LONG-TERM FIRM TRANSMISSION SERVICE

SPP long-term Point-To-Point and Network Integration Transmission Service commitments are generally modeled at expected usage of firm transmission service reservations in each year and season, as supplied by SPP stakeholders during the SPP modeling process. Commitments with external entities are coordinated with those entities through the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG).

The modeling of long-term firm transmission service in the base reliability models will result in a change in generation dispatch for the defined source and sink of the service and will vary by season, year and generation type.9 All DC tie set points will be modeled with expected usage for the season as submitted by stakeholders, not exceeding long-term firm transmission service. Resources related to a long-term firm transmission service reservation with a single plant as the source will be dispatched to meet the modeled usage. Conventional resources related to long-term firm transmission service reservations with a fleet of resources as the source will be dispatched based on economic merit order within each resource fleet, as needed to serve the service commitments and applicable load. The fleet of conventional resources will be dispatched after renewable resources. Renewable resources will be dispatched based upon the following seasonal methodologies[10]:

- Light load models: Output of wind resources will be modeled at 100 percent of each facility's long-term firm transmission service amount in the light load base reliability model. Solar resources will be modeled at zero MW in the light load base reliability model regardless of the facility's long-term firm transmission service amount.
- Peak models: Output of renewable resources with long-term firm transmission service will be modeled in the base reliability model at each facility's latest five-year average (or replacement data if unavailable) for the applicable seasonal SPP coincident[11] peak, not to exceed each facility's firm service amount.

[9] Resources may be added to a source or sink definition if the requirements of the **Error! Reference source not found.** section are met.
[10] The renewable dispatch methodology may necessitate a change to the modeled expected usage of firm transmission service.
[11] SPP coincident peak equals the highest demand including transmission losses for energy measured over a one clock hour period during the defined season.

Replacement data may be necessary to determine the dispatch amount for each renewable resource type if the resources have less than five years of data available. SPP will calculate the replacement data for use in the methodology for the peak models.

To calculate the replacement data, SPP will determine for each renewable type the amount of renewables being dispatched in each SPP coincident peak hour located within each state, then divide by the total amount of long-term firm transmission service sold on those renewable resources. This will provide a percentage of MW within each state dispatched during the SPP coincident peak hour. This calculation will be done for the five previous years. SPP will average the data together to develop a flat percentage value for each state. These state average values for each renewable type will be the replacement value for each renewable resource requiring replacement data located within that state to give each renewable resource five years of data.

For load pseudo-tied into the SPP BA, SPP will coordinate with the external entity and the owner of the load to model the long-term firm transmission service in the planning models as follows:

- Firm Point-To-Point Transmission Service: Model up to the long-term firm transmission service amount
- Network Integration Transmission Service: Model up to the firm load amount

2.1.3 LOAD FORECASTS

The ITP assessment will require load forecasts for SPP TOs and stakeholders within the SPP footprint, as well as areas outside of the SPP footprint, for the corresponding study years. The load forecast will be submitted to SPP using the process described in the Model Development Procedure Manual[12]. The load will represent each individual load-serving entity's peak conditions without losses per season (*i.e.*, non-coincident conditions for the SPP region).

2.1.4 TOPOLOGY

The topology used to account for the SPP transmission system, excluding future generation resources and associated interconnection facilities, will be the existing transmission system and any upgrades or facilities that are included in the SPP Transmission Expansion Plan (STEP) and have been approved for construction.[13] In-service dates of upgrades with NTC/NTC-C should be consistent with the latest information supplied by the transmission owner in the project tracking process. Upgrades that have met the requirements for NTC withdrawal or reevaluation will be excluded from the base reliability model as specified in SPP business practices.

The base reliability models will be developed to reflect the expected state of the transmission system over the long-term horizon. The model development process accounts for long-term transmission line outages as forecasted by the data submitting entity per the applicable NERC MOD standards. Temporary facilities shall not be modeled and transmission lines operated in real-time as normally open shall be modeled as normally open.

For topology updates outside the SPP footprint, the Eastern Interconnection model areas will be obtained from the latest ERAG MMWG model set. SPP will coordinate with the appropriate external entities and request first-tier planned upgrades that should be included in the models.

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[12] MDWG Model Development Procedure Manual

[13] This includes upgrades identified through the generator interconnection process and those approved by Southwestern Power Administration.

2.1.4.1 *Phase-Shifting Transformers*
PSTs will be modeled in accordance with the guidelines documented in the MDWG Manual[14].

2.1.5 EXTERNAL TRANSACTIONS
Transaction data between entities external to the SPP footprint, not including those with transmission service with SPP, will be obtained directly from the external entity, if available, or from the latest ERAG MMWG models that most closely align with the corresponding study year models.

2.2 *MARKET ECONOMIC MODEL OVERVIEW*
Each Market Economic model simulation is an hourly security-constrained unit commitment and economic dispatch utilizing a DC representation of the transmission system.

The assumptions for each of the economic models are detailed later in this section.

2.2.1 MODEL ASSUMPTIONS AND DATA
2.2.1.1 *Future Development*
Due to the uncertainties involved in forecasting future system conditions, a number of diverse futures will be considered that take different assumptions into account. Consideration of multiple futures allows for a transmission expansion plan that is sufficiently flexible to meet a variety of needs that may develop as economic, environmental, regulatory, public policy, and technological changes arise that affect the industry. The futures will be developed by the ESWG with input from the SPC and the TWG and will be subject to the approval of MOPC.

Economic models will be developed for three study years (years 2, 5, and 10). A single future will be developed for year 2, due to the limited uncertainty in policy or other factors impacting the system that could occur in such a short time frame. Up to three futures will be developed for years 5 and 10, during the scoping of each successive annual assessment. The futures will consist of a reference case, as determined by the ITP study scope, and up to two additional futures designed to assimilate expected or plausible future scenarios. Details about the reference case and any other future case(s) will be included in the ITP study scope document. As a result, up to seven total economic models may be developed to support economic assessments.

During the development of the futures, SPP will solicit stakeholders for potential public policy drivers to be considered in the study through a survey within the SPP annual data request. Timing for the submission of public policy drivers that SPP stakeholders request to be considered shall be included in the study schedule. Any drivers requested to be considered by SPP stakeholders that are excluded from the study, as well as an explanation for the exclusion, shall be detailed in the ITP assessment report.

2.2.1.2 *Load and Energy Forecasts*
The ITP assessment will require load forecasts for areas within and outside the SPP footprint for each of the study years. The load will represent each individual load-serving entity's peak conditions without losses per season (*i.e.*, non-coincident peak conditions for the SPP region).

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[14] MDWG Model Development Procedure Manual

Resource obligations will be determined for the footprint taking into consideration non-scalable and scalable loads.

For the economic model development process, SPP will obtain load data to utilize in the ITP assessment by the following unless directed otherwise by the ESWG:

- Peak load: The source shall be the no-loss aggregated bus load totals (MW) based on the current base reliability models.
- Hourly load shape: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP will create a synthetic load shape based on historical data points and FERC Form 714 information.
- Monthly peak and energy percentages: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP will calculate the monthly peak and energy percentages by using hourly load shape data.
- Load factor: As a primary source, annual load factors shall be provided by SPP stakeholders. If the primary source is not available or is not appropriate, SPP will calculate load factors by utilizing hourly load shapes.
- Transmission loss factor: As a primary source annual loss factors shall be provided by SPP stakeholders. If the primary source is not available or is not appropriate, SPP will utilize previous ITP study values.
- Demand mapping: The primary source shall be the economic load ownership legend[15] reviewed as part of the SPP annual data request. If the primary source is not available or is not appropriate, SPP stakeholders will provide load bus and ID mappings to demand groups.

External region load forecasts will be taken from the base reliability model set and each region will be allowed to review load forecast data prior to use in the ITP assessment. If readily available and appropriate, load forecasts from the most current neighboring entity's study will be used for their region in the ITP assessment in place of the base reliability model data. The use of their load forecast will be future specific. If there is not a future comparable to the ITP future, as determined by SPP and the ESWG, the load forecast would be determined utilizing base reliability model data. The data sources approved by the ESWG to be used will be documented in the study report.

2.2.1.3 Renewable Policy Review

After the forecasted load is finalized, renewable policy standards (RPS) will be assessed for utilities within the SPP footprint. The percentages in Table 2 will be used to calculate the mandate or goal for each utility residing in the listed states with respect to the load submitted as part of the SPP annual data request. For those utilities that span multiple states, the approved powerflow models and geographical information system (GIS) data will be used to calculate each utility's load obligation in the corresponding state for purposes of calculating mandates and goals.

The values in Table 2 consider forward-looking legislation set by the states that either should be or must be met, depending on the state, in each of the study years. A generation type of "both" indicates the mandate or goal can be met by either wind or solar generation in the study. Both capacity- and energy-based mandates and goals will be assessed for fulfillment during development

[15] Table within the SPP annual data request that maps loads according to their attributes to groups of demands for the economic model

of the resource plan. Those that are energy-based also will be assessed during the policy needs assessment. States within the SPP footprint that are not included in Table 2 do not have RPS requirement for the purposes of this renewable policy review.

State	RPS Type	Generation Type	Capacity- or Energy- Based	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	20	20
Minnesota	Mandate	Both	Energy	20	25
Missouri	Mandate	Both	Energy	15	15
Montana	Mandate	Both	Energy	15	15
North Dakota	Goal	Both	Energy	10	10
New Mexico	Mandate	Wind	Energy	15	15
New Mexico	Mandate	Solar	Energy	4	4
South Dakota	Goal	Both	Energy	10	10
Texas	Mandate	Both	Capacity	5	5

Table 2 ITP RPS by State

Renewable energy credits will be accommodated appropriately as provided to SPP.

If any significant changes to renewable mandates or goals occur during an ITP assessment, SPP stakeholders can bring them to the ESWG for review and potential approval for use in the ITP assessment. If exemptions to the mandates or goals are allowed (e.g. the applicable technology is cost prohibitive or municipals are exempt), those exemptions will be considered as SPP is notified during the renewable policy review.

Any resulting deviations from the standard values in Table 2 will be noted in the study report.

2.2.1.4 Generation Resource Inclusion

Generation resources included in the base reliability model will be incorporated into the economic model, as appropriate.[16] Resources identified by SPP as necessary to solve the base reliability model shall not be included in the economic and powerflow models, unless the resources meet the requirements of adding generation described in this section.

[16] Generally, smaller resources that are not included in the economic data supplied by the vendor but are modeled in the powerflow are not included in the economic model for consideration in the production cost simulation. Examples are units reported publically as behind-the-meter or small municipal generation.

Incremental to the resources included in the base reliability models, a generator interconnection resource and its associated network upgrades will be included in the economic models if they meet all of the following requirements:

1. A formal request has been sent to SPP[17] requesting the generation capacity be included.
2. The generating resource has an effective GIA that is not on suspension or an effective interim GIA.
3. The generating resource will have a firm contract for delivery through ownership and operation of the resource or procurement of a purchase power agreement (PPA) from the generation owner.

If a generating resource does not meet all the above requirements, a request for generation capacity to be included in the economic models can be made to ESWG and TWG on a case-by-case basis. ESWG and TWG will, at a minimum, consider the following points:

1. A DISIS agreement for the generating resource has been executed, an interim GIA has been requested, and a GIA will be entered into, when applicable.
2. An RFP for the generating resource has been awarded, if applicable.

All other resource expansion needs will be determined through the SPP resource expansion planning process as detailed in the Resource Expansion Plan section.

2.2.1.5 Generation Resources

Third-party vendor data will be used as the starting point for generation parameters needed for the economic model set. Data related to the physical characteristics of generators will be reviewed and updated as needed by the SPP stakeholders to provide company-specific values through the SPP annual data request.

The third-party vendor data to be utilized as a starting point may include:

- Generator name
- Category type
- Conventional variable operation & maintenance (VOM)
- Conventional fixed operation & maintenance (FOM)
- Heat rate
- Heat rate profile
- Physical state location
- Annual maintenance hours
- Forced outage rate
- Effluents (percentage removed)
- Emission rates
- Fuel forecast
- Hydro energy limits
- Seasonal max capacity by year

[17] Submitted through SPP RMS

- Retirement date
- Commission date
- Must-run designation

2.2.1.6 Topology

The topology used in the economic models to account for the transmission system of SPP and external entities will follow the same guidelines detailed in the Base Reliability Model Overview section with the following exceptions:

- The topology utilized for each study year's annual simulation will be based on the summer-peak base reliability model developed for that year.
- Long-term transmission outages as forecasted by the data submitting entity will not be included.

2.2.1.6.1 DC Lines

DC lines are included in the economic model through an import of the base reliability powerflow data. The range of allowable hourly operation will be based on:

- Operational practice (current or future expected), and
- Expected flows from the SPP powerflow models.

2.2.1.6.2 Phase-Shifting Transformers

Modeling parameters for PSTs will be determined leveraging data from:

- Historical and/or current operating practices, and
- Powerflow modeling.

The specific modeling of the PSTs will be detailed in the study scope.

2.2.1.6.3 DC Ties

For direct current (DC) ties that connect SPP to the Texas and western interconnections, hourly profiles will be developed based on at least three years of historical flows across each DC tie and will be capped at long-term firm transmission service amounts. These transactions will be modeled as fixed with no assumed curtailment price.

2.2.1.7 Fuel Prices

Fuel price forecasts for the reference case future, including natural gas, oil, uranium, coal, and associated transportation costs, will be based upon the latest vendor data set.

Potential adjustments to the fuel prices for the non-reference case future(s) will be determined by the ESWG to appropriately reflect each future and will be described in the ITP study scope document.

2.2.1.8 Emission Prices

Emission price forecasts for the reference case future, including CO_2, SO_2 and NO_X, will be based upon the latest vendor data set.