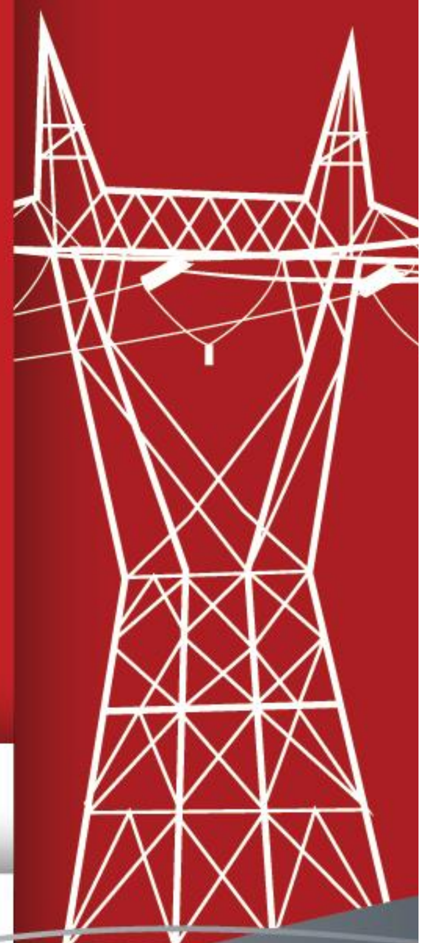
2017 INTEGRATED TRANSMISSION PLANNING NEAR-TERM ASSESSMENT



SPP Southwest Power Pool

March 28, 2017

ENGINEERING

REVISION HISTORY

Date	Author	Change Description
1/26/2017	SPP Staff	Initial Draft
4/3/2017	TWG	Incorporate Stakeholder Feedback
4/3/2017	TWG	TWG Approved
4/11/2017	No change	MOPC approved recommendation
4/25/2017	SPP Staff	SPP Board of Directors Approved

SOUTHWEST POWER POOL, INC.

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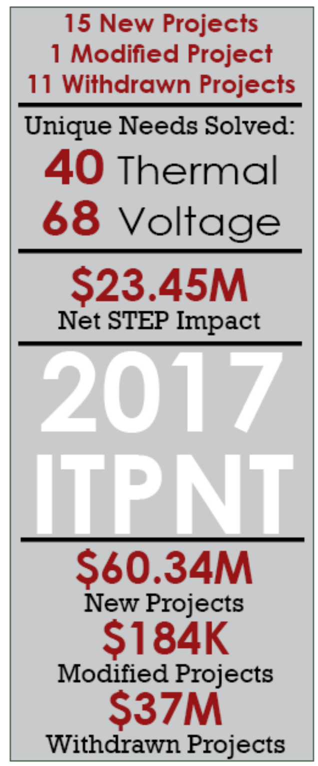
SECTION 1: EXECUTIVE SUMMARY

The Integrated Transmission Planning (ITP) process is Southwest Power Pool's iterative three-year study process that includes 20-Year, 10-Year and Near-Term assessments. The 20-Year assessment identifies transmission projects, generally above 300 kV, needed to provide a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year assessment focuses on facilities 100 kV and above to meet system needs over a 10-year horizon.

The ITP Near-Term assessment is performed annually and assesses system upgrades, at all applicable voltage levels, required in the near-term planning horizon to address reliability needs. Along with the Highway/Byway cost allocation methodology, the ITP process promotes transmission investment that will meet reliability, economic and public policy needs[1] intended to create a cost-effective, flexible and robust transmission network that will improve access to the region's diverse generating resources. This report documents the ITP Near-Term (ITPNT) assessment that will conclude in April 2017.



<u>1.1: The ITPNT Process</u>

The ITPNT assessment generates an effective near-term plan for the SPP Regional Transmission Organization (RTO) planning region by identifying solutions to reliability criteria exceedances for system intact and contingency conditions.

The ITPNT assesses:

- Regional upgrades required to maintain reliability in accordance with the North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4 NERC Reliability Standard TPL-001-4 Planning events that do not allow for Non-Consequential Load Loss (NCLL) or Interruption of Firm Transmission Service (IFTS) and SPP Criteria in the near-term horizon.
- Zonal upgrades required to maintain reliability in accordance with FERC filed company-specific local planning criteria in the near-term horizon.

[1] The Highway/Byway cost allocation approving order is *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010). The approving order for ITP is *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010).

- Coordinated projects with neighboring transmission providers.

ITPNT projects are reviewed and approved by SPP's Transmission Working Group (TWG) and the Markets and Operations Policy Committee (MOPC) and approved by the SPP board of directors (BOD). Upon BOD approval, staff will issue NTC letters for upgrades that require a financial commitment within the next four-year timeframe.

1.2: The 2017 ITPNT

The 2017 ITPNT included three separate scenario models — Scenarios 0, 5, and SPP Balancing Authority (BA) — built across multiple years and seasons to evaluate power flows across the grid and account for various system assumptions. The Scenario 0 and 5 models allow only resources with firm transmission service to be dispatched with the preferred order submitted by SPP members, while the BA model allows for resources without firm transmission service to be dispatched and is intended to mimic the SPP Integrated Marketplace by dispatching constraints on the system. The 2017 ITPNT assessment introduced key differences from previous assessments aimed at addressing recent stakeholder requests for process improvement.

These key differences include:

- Significant decrease in Scenario 5 only thermal and voltage needs due the utilization of a coupling criterion with the BA model violations. This criterion was implemented to address stakeholder concerns around needs driven by unusually high wind dispatch in the summer peak, typical of the Scenario 5 models.
- NERC Reliability Standard TPL-001-4 P2, P3, P4, and P5 events that do not allow for NCLL or IFTS (which were also analyzed in the 2017 ITPNT assessment for the year 5 Scenario 0, summer-peak (SP) and light-load (LL) models).
- Supplemental analysis was performed to help inform project recommendations due to schedule differences with the 2017 ITP10 study and other model updates received during the solution development phase. The development of updated models and additional analysis allowed SPP to determine if the chosen projects were sufficient to meet any change in transmission violations, as well as to avoid recommending projects for Notifications to Construct (NTCs) where a need was addressed.
- The 2017 ITPNT assessment was also impacted by an overall load reduction up to one gigawatt. Certain areas also experienced significant load reductions from the 2016 ITPNT assessment, due to removal of load from SPP to first-tier power providers, change in load forecasting methodology, more accurate modeling of loads, and reduction in oil field exploration.

SPP's transmission system performance was assessed from different perspectives designed to identify transmission expansion projects necessary to accomplish the reliability objectives of the SPP RTO:

- Avoid exposure to NERC Reliability Standard TPL-001-4 planning events that do not allow for NCLL or IFTS during the operation of the system under high stresses
- Contribute to the voltage stability of the system
- Reduce congestion and increase opportunities for competition within the SPP Integrated Marketplace

Voltage Class (kV)	New Line (miles)	Rebuild/Reconductor (miles)
345	0	0
230	0	0
161	0	0
138	0	9
115	24	11
69	2	15

Table 1: 2017 ITPNT Project List Breakdown – New Line Miles by Voltage Class

Voltage Class (kV)	New Transformer
345/230	0
345/138	0
345/115	0
230/115	0
138/69	0
115/69	1

Table 2: 2017 ITPNT Project List Breakdown – New Transformer by Voltage Class

New projects identified in the 2017 ITPNT assessment account for a total of $60.34 million. The net total study cost of the 2017 ITPNT project plan is estimated to be $23.45 million for upgrades that will receive an NTC, NTC-C or NTC Modify. Upgrades recommended for an NTC Modify account for a net change in cost of $184,000 of the total project plan cost. In addition, there was a total reduction of $37.07 million for withdrawn NTCs.

Reliability Project(s)	Project Area(s)	Cost	Need Date
Rebuild Broken Arrow – Lynn Lane East 7.2 mile 138 kV line	AEP	$ 5,714,095	6/1/2018
Rebuild Tulsa Southeast-East 61st 1.8 mile 138 kV (Addressing additional contingency)	AEP	$ 6,014,381	6/1/2021
New 28.8 MVAR 138 kV two-stage capacitor bank at IPC	AEP	$ 1,298,049	12/1/2018
New Ruthville – SW Minot 24 mile 115 kV line	BEPC	$ 21,780,000	6/1/2018
Reconductor Nichols – Republic North 9.7 mile 69 kV line Reconductor Republic North– Republic Hines Street 2 3.9 mile 69 kV line Reconductor Republic Hines Street – Republic East 1.3 mile 69 kV line	EMDE	$ 6,300,000	6/1/2018
Add redundant relaying at Stilwell (Addressing additional contingency)	KCPL	$ 147,500	6/1/2021
Two 69 kV line breakers at NIPCO L-10 New 69 kV Switching Station to replace existing K-116 line switch (J-16)	NIPCO	$ 1,406,577	6/1/2018
Upgrade terminal equipment at Coulter 115 kV bus	SPS	$ 268,490	6/1/2018
Upgrade terminal limitations on the 230kV circuit K62 at Nichols Substation	SPS	$ 490,000	12/1/2018
Upgrade terminal equipment at Hale 115 kV bus	SPS	$ 741,329	12/1/2018
New 230/115 kV transformer at Tuco Interchange (Modification of an existing NTC)	SPS	$ 183,814	6/1/2018

Upgrade terminal equipment at Plant X and Sundown 230 kV bus	SPS	$ 559,479	12/1/2020
Rebuild Etter - Moore 10.8 mile 115 kV line	SPS	$ 9,073,903	6/1/2018
Upgrade terminal equipment at Texas County 3 115 kV bus	SPS	$ 207,069	6/1/2018
New substation Roberts County 115 kV **New 115/69 kV transformer at Roberts County** **Tap Forman - Summit 115 kV line at Roberts County** **New Roberts County - Sisseton 2 mile 69 kV line**	WAPA/ EREC	$ 5,990,000	6/1/2018
Upgrade terminal equipment at Williston 115 kV bus	WAPA	$350,000	6/1/2018

* Monitored Element(s) is/are not the all-inclusive list of needs fixed by the project.

Table 3: 2017 ITPNT Projects

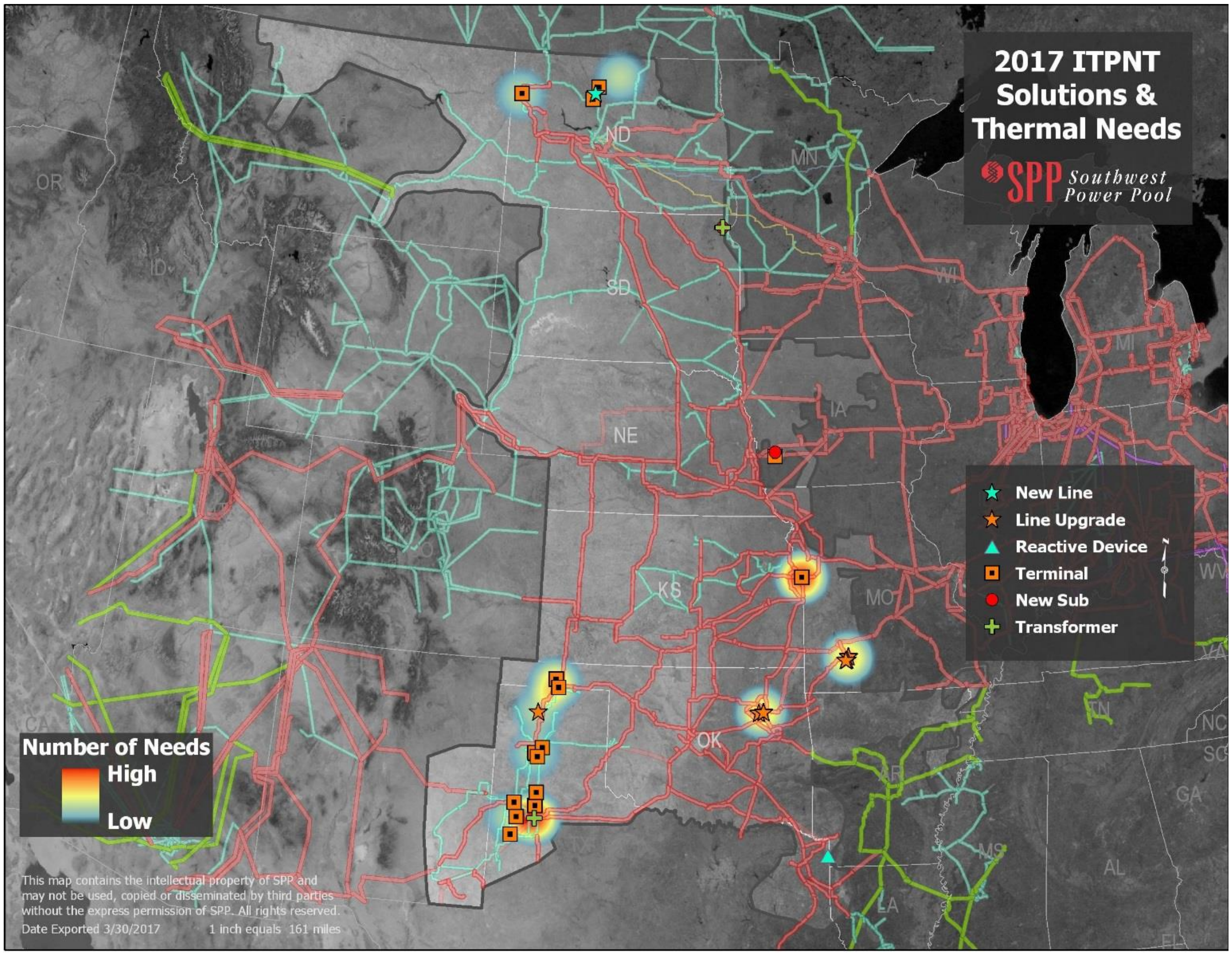


Figure 1.1: 2017 ITPNT Thermal Needs and Solutions

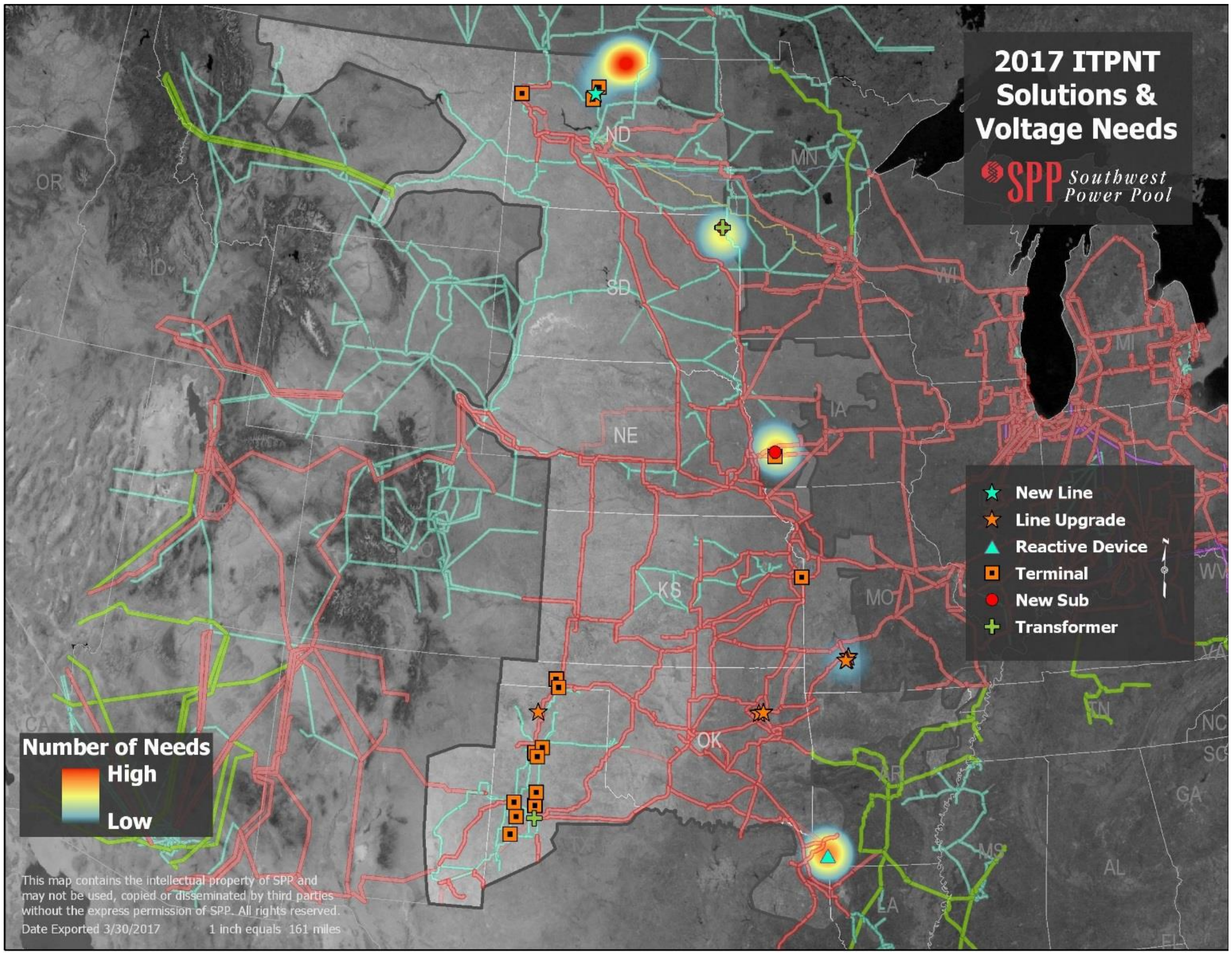


Figure 1.2: 2017 ITPNT Voltage Needs and Solutions

PART I: STUDY PROCESS

SECTION 2: INTRODUCTION

2.1: The ITP Near-Term

The ITPNT is designed to evaluate the near-term reliability of the SPP transmission system and identify needed upgrades through stakeholder collaboration. The ITPNT focuses primarily on solutions required to meet the reliability criteria defined in the SPP Open Access Transmission Tariff (tariff), Attachment O, Section III.6. The process coordinates the ITP 20-Year assessment (ITP20), 10-Year assessment (ITP10), Aggregate Transmission Service Studies (ATSS), Attachment AQ Studies (AQ) and the Generator Interconnection (GI) transmission plans by communicating potential solutions between processes and using common solutions when appropriate. Unlike the ITP10 and ITP20, the ITPNT is not intended to focus on economic or public policy solutions, or solutions based on a preferred voltage level, but to effectively resolve potential reliability needs observed in the near-term horizon.

The 2017 ITPNT process produces a reliable, near-term plan for the SPP footprint, which identifies solutions to potential issues for system intact and single contingency (N-1) conditions using the following principles:

- Identifying potential, reliability-based problems (NERC Reliability Standard TPL-001-4 P0, P1, and P2.1 events respecting SPP and company-specific criteria)
- NERC Reliability Standard TPL-001-4 Planning events that do not allow for NCLL or IFTS
    - P2, P3, P4 and P5 events were evaluated in addition to the normal SPP contingency analysis process and are classified as NCLL and IFTS events. These incremental planning events were only analyzed on Year 5, Scenario 0 cases for the 2021 SP and 2021 LL models only.
- Utilizing Transmission Operating Guides (TOGs)
- Developing additional mitigation plans including transmission upgrades to meet the region's needs and maintain SPP and SPP member reliability/planning standards

The ITPNT 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.

Goals

The goals of the ITPNT are to:

- Focus on local, regional and interregional needs
- Evaluate the response of the system to NERC Reliability Standard TPL-001-4 planning events that do not allow for NCLL or IFTS, with respect to SPP and company-specific criteria
- Identify and analyze transmission-system needs over the five-year horizon
- Identify cost-effective 69 kV and above solutions that achieve, but are not limited to, the following:
    - Resolve reliability criteria needs
    - Improve access to markets
    - Improve interconnections with SPP's neighbors
    - Meet expected load-growth demands
    - Facilitate or respond to expected facility retirements
    - Synergize the ITPNT with the GI, ATSS and AQ processes and the ITP10 and ITP20 assessments

The 2017 ITPNT is intended to provide solutions to ensure the reliability of the transmission system during the study horizon, which includes modeling of the transmission system five years out (*i.e.*, 2021). The specific near-term requirements of Attachment O are:

- The transmission provider shall perform the Near-Term assessment on an annual basis
- The Near-Term assessment will be performed on a shorter planning horizon than the 10-Year assessment and shall focus primarily on identifying solutions required to meet the reliability criteria defined in Section III.6
- The assessment study scope shall specify the methodology, criteria, assumptions and data to be used to develop the list of proposed near-term upgrades
- The transmission provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope. The study scope shall take into consideration the input requirements described in Section III.6
- The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan (STEP) report
- In accordance with the assessment study scope, the transmission provider shall analyze potential solutions, including those upgrades approved by the BOD from the most recent 20-Year and 10-Year assessments, following the process set forth in Section III.8

2.2: How to Read This Report

This report focuses on the years 2018 and 2021 and is divided into multiple sections.

- Part I addresses the concepts behind this study's approach, key procedural steps in development of the analysis and overarching assumptions used in the study
- Part II addresses the specific results, describes the projects that merit consideration and contains recommendations and costs
- Part III contains detailed data and holds the report's appendix material

SPP Footprint

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

Supporting Documents

The development of this study was guided by the supporting documents noted below. These documents provide structure for this assessment:

- SPP 2017 ITPNT Scope
- SPP ITP Manual

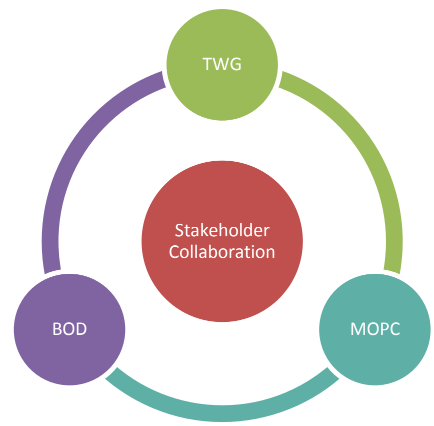
All referenced reports and documents contained in this report are available on SPP.org.

Confidentiality and Open Access

Proprietary information is frequently exchanged between SPP and its stakeholders in the course of any study and is extensively used during the ITP development process. 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.

SECTION 3: STAKEHOLDER COLLABORATION

Assumptions and procedures for the 2017 ITPNT analysis were developed through SPP stakeholder meetings that took place in 2015, 2016 and 2017. The assumptions were presented and discussed through a series of meetings with members, liaison members, industry specialists and consultants to facilitate a thorough evaluation. Groups involved in this development included the following:



- TWG
- MOPC
- BOD

SPP staff members served as facilitators for these groups and worked closely with each group's chairman to ensure all views were heard and SPP's member-driven value proposition was followed.

The TWG provided technical guidance and review for inputs, assumptions and findings. Policy-level considerations were tendered to appropriate organizational groups including the MOPC. Stakeholder feedback was instrumental in the selection of the 2017 ITPNT projects.

The TWG was responsible for technical oversight of the load forecasts, transmission-topology inputs, constraint-selection criteria, reliability assessments, transmission projects and the study report.

Planning Summits

In addition to the standard working group meetings, two transmission planning summits were conducted to elicit further input and provide stakeholders with a chance to interact with SPP staff members on all related planning topics.

Project Cost Overview

Conceptual estimates were prepared by SPP staff members and were based on historical cost information submitted by TOs through the project-tracking process. Refined cost estimates expected to be accurate within a ±30 percent bandwidth were prepared by a third party vendor and incumbent TOs. All cost estimates utilized in the 2017 ITPNT were developed in accordance with SPP Business Practice 7060, NTC and Project Cost Estimating Processes effective Jan. 1, 2012 and SPP Business Practice 7660, Upgrade Determination and Short-Term Reliability Project Process.

If a project meets the requirements in Attachment Y, Sections I and II to be a Competitive Upgrade, SPP will be responsible for providing the cost estimates for the project via a third party. If the project did not meet the requirements in Attachment Y, Sections I and II, SPP is requesting cost estimate information from the incumbent TO.

Use of TOGs

TOGs are tools used to mitigate issues in the daily management of the transmission grid. TOGs may be used as alternatives to planned projects. TOGs were submitted during the transmission planning response window and evaluated in the ITPNT process to determine effectiveness in addressing thermal and voltage needs.

SECTION 4: STUDY DRIVERS

4.1: Introduction

Drivers for the 2017 ITPNT were discussed and developed through the stakeholder process in accordance with the 2017 ITPNT Scope and involved stakeholders from several diverse groups. Stakeholder load, generation and transmission were carefully considered in determining the need for, and design of, transmission solutions.

4.2: Model Development

Scenario 0

Scenario 0 (S0) contains projected transmission service between SPP legacy BAs and generation dispatch on the system. S0 emphasizes high conventional generation commitment and dispatch. Wind generation is set to match the Model Development Working Group (MDWG) models.

Scenario 5

Scenario 5 (S5) maximizes all applicable, confirmed, long-term firm transmission service with its necessary generation dispatch. S5 emphasizes higher wind transfers. S5 sets all wind generation to maximum firm service, then all reservations between companies are set to maximum firm service as much as load will allow on a pro rata basis.

Balancing Authority

To account for the impacts of the Integrated Marketplace on the SPP footprint, a BA scenario model was developed as part of the 2017 ITPNT assessment. The BA scenario modeled SPP as a single BA and only modeled power transfers across the SPP seams.

To simulate changes that will occur to the SPP portion of the NERC Book of Flowgates due to upgrades coming into service during the defined study period of the 2017 ITPNT assessment, a constraint assessment was completed to determine if any system constraints should be added, removed or modified before the security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) cases were created.

Making use of the economic data from the 2017 ITP10, PowerGEM software, TARA, was used to perform an AC SCED on the SPP footprint to deliver the most economical power around SPP base case and N-1 constraints 69 kV and above excluding invalid constraints. An N-1 contingency analysis, described in subsection A (Steady State Assessment) of the Analysis section, was performed on each SPP BA power flow model. The Eastern Interconnect generation outside of SPP remained unchanged.

4.3: Load Outlook

Peak and Off-Peak Load

Future energy usage was forecasted by utilities in the SPP footprint and collected and reviewed through the efforts of the MDWG. This assessment used SP, winter-peak (WP), and LL scenarios to assess the performance of the grid in peak and off-peak conditions.

Load Forecast

Load serving entities (LSE) provided the load forecast used in the reliability analysis study models through the MDWG model building process.

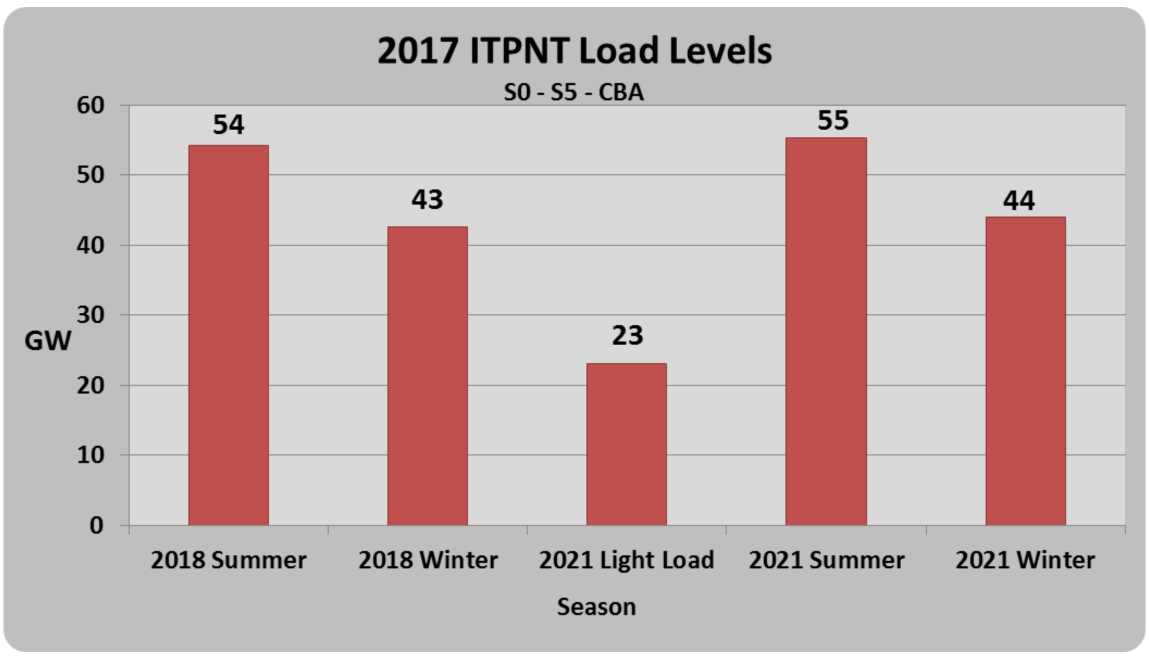


Figure 4.1: 2017 ITPNT Load Levels

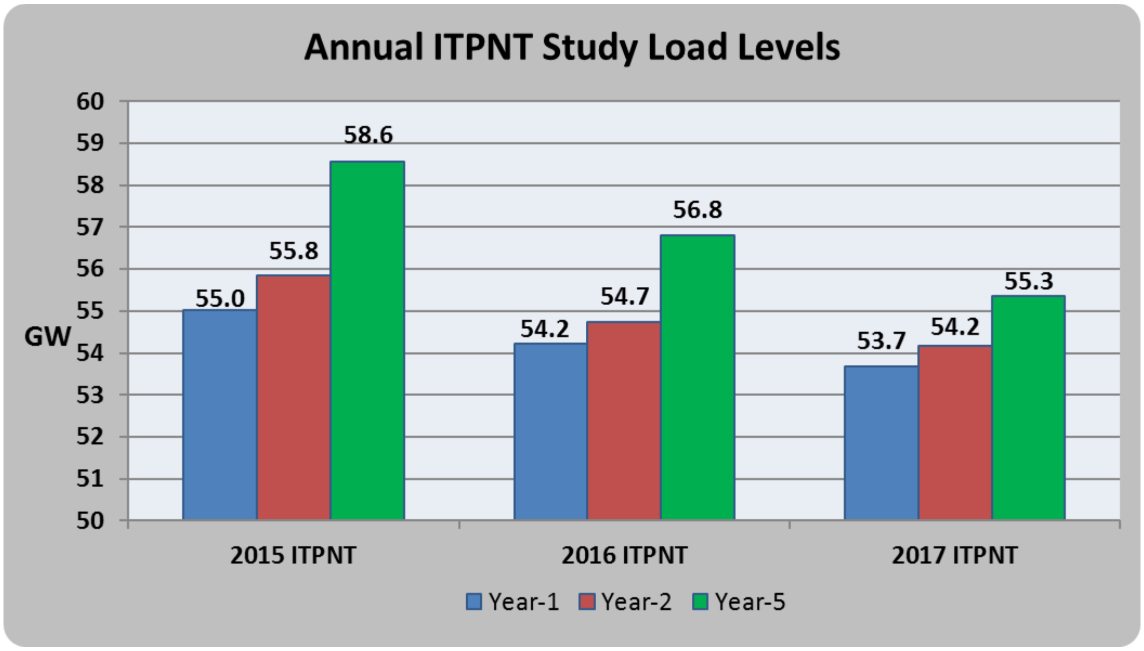


Figure 4.2: Annual ITPNT Study Load Levels (Each model series includes IS loads)

4.4: Generation

The three figures below show the difference in generation between the S0, S5 and BA scenario models for each season. Note the significant difference in the wind output for the S5 models. The BA Scenario dispatch methodology is discussed earlier in this report.

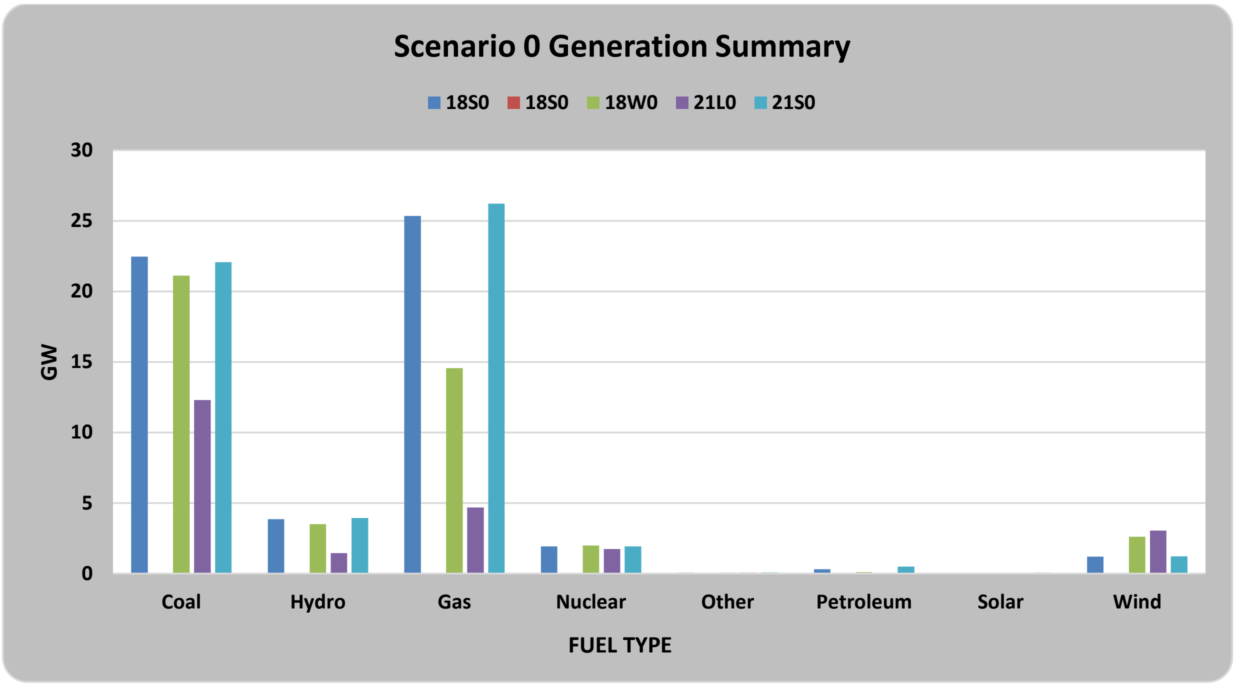


Figure 4.3: 2017 ITPNT S0 Generation Mix

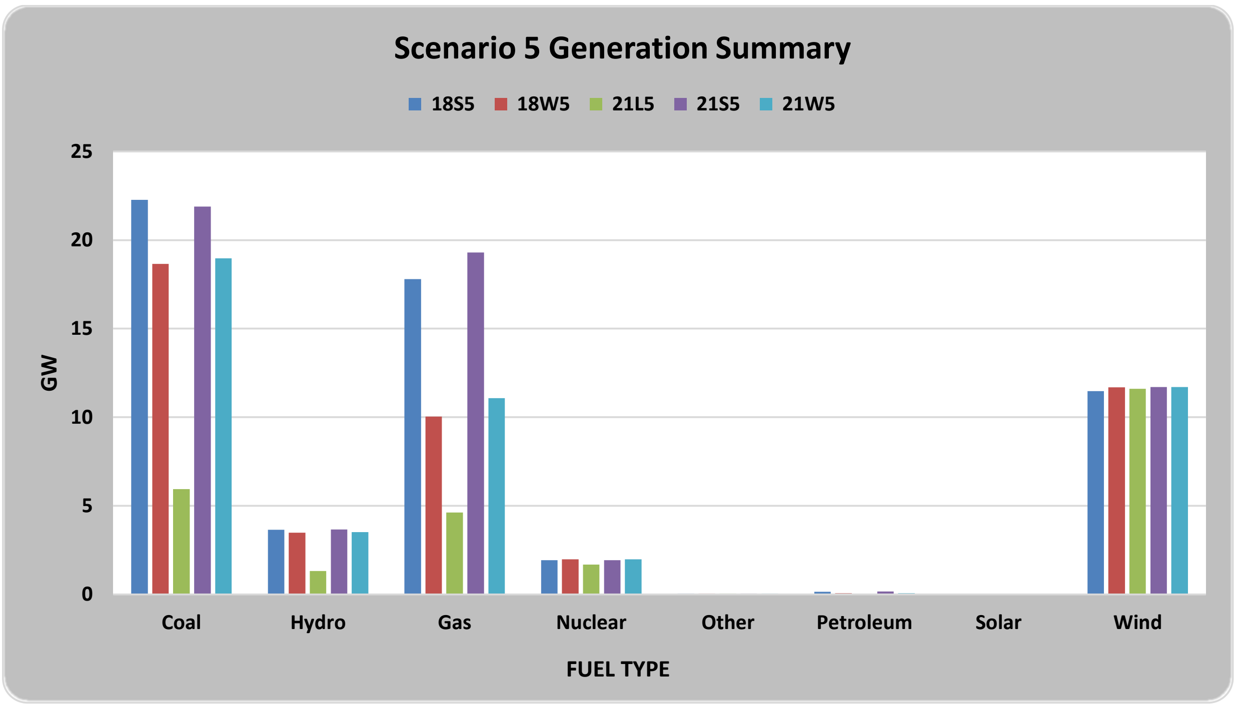


Figure 4.4: 2017 ITPNT S5 Generation Mix

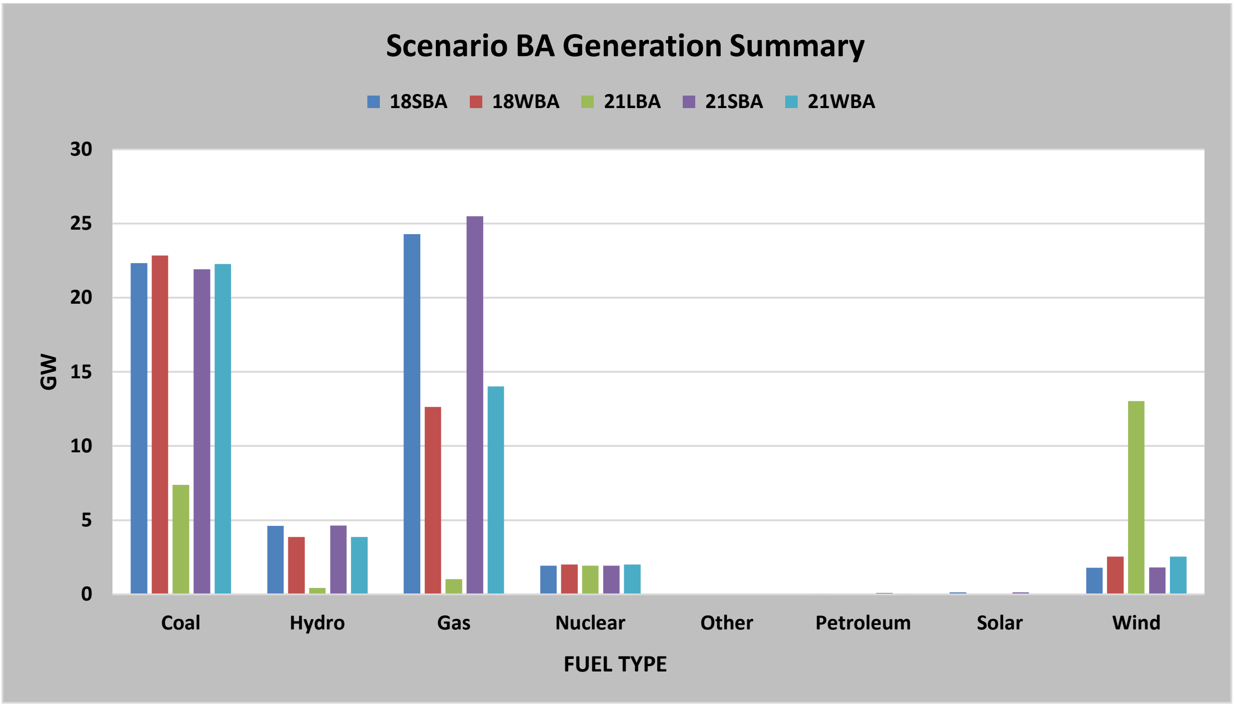


Figure 4.5: 2017 ITPNT BA Generation Mix

4.5: Utilization of Different Voltage Levels

EHV Design Considerations

When considering the design of an extra-high voltage (EHV) grid, many factors must be considered, such as contingency planning, typical line lengths, line load ability, capacity requirements, voltage, reliability, cost, asset life and operational issues.

NERC N-1 Reliability Standards

SPP designs and operates its transmission system to be capable of withstanding the next transmission outage that may occur; this is called N-1 planning and is in accordance with NERC planning standards. Due to N-1 planning, any EHV network must be looped in the event one element of the EHV grid is lost, a parallel path will exist to move that power across the grid and avoid overloading the underlying transmission lines.

Voltage Support

A transmission line can either support voltage by producing volt-ampere reactives (VARs) or require voltage support from other reactive devices (consume VARs), depending on its loading level. In either case, transmission system design should account for these factors. Under LL conditions, system voltages may rise due to VARs being produced from long EHV lines.

Shunt reactors would be necessary to help mitigate the rise in voltage. Some lines may need additional support to allow more power to flow through them. Series capacitors may be added to increase the load ability of a transmission line. However, the addition of series compensation can complicate operations and may lead to stability concerns.

Construction Cost

Cost plays a factor in EHV grid design. Lower-voltage designs cost less to construct initially. Higher-voltage lines have a larger initial investment but provide significantly higher capacity and more flexibility in bulk power transport. Lower-voltage lines offer more flexibility to act as a collector system for wind generation. Along with the initial cost, the lifetime of the asset needs to be considered. Transmission lines are generally assumed to have a 40-year life.

SECTION 5: ANALYSIS METHODOLOGY

5.1: Steady-State Analysis

Facilities in the SPP footprint 69 kV and greater were monitored for exceeding 90 percent thermal loading or voltage below 0.95 per unit. Needs are generated at 100 percent thermal loading or voltage below 0.9 or greater than 1.05 per unit for non-base-case conditions and voltage below 0.95 per unit for base-case conditions. All facilities in first-tier control areas were monitored at 100 kV and above. System intact and contingency analysis were performed on SPP facilities at 69 kV and greater and at 100 kV and greater for first-tier control areas in the 2017 ITPNT models.

After performing the initial reliability assessment identifying the bulk power problems, thermal and voltage needs were posted on the TrueShare site for stakeholder accessibility.

Order 1000

To comply with FERC's Order 1000, SPP developed the TO Selection Process (TOSP). In accordance with Attachment O, Section III.8.b, SPP shall notify stakeholders of identified transmission needs and provide a transmission planning response window of 30 days during which any stakeholder may propose a Detailed Project Proposal (DPP). SPP shall track each DPP and retain the information submitted pursuant to Attachment O, Section III.8.b(i). The initial 30-day window for proposals opened Oct. 4, 2016, for scenario 0/5/BA thermal and voltage needs.[2]

Project Screening

Stakeholders submitted 420 DPPs through the Order 1000 process, which included 131 modeling corrections, eight non-transmission solutions and 15 transmission operating guides. In addition to the DPPs and FERC Order 890 projects, 150 SPP staff solutions were considered to address the reliability needs. Altogether, 570 projects were evaluated.

To efficiently evaluate the high volume of submitted and created projects that would solve all identified reliability needs within the allotted schedule, an existing software solution was utilized by SPP. This comprehensive project-testing tool tested an individual project against each reliability need

[2] Information on the models, needs assessments and solutions used in the 2017 ITPNT can be found on the SPP website http://www.spp.org/engineering/transmission-planning

identified in the needs assessment using PSS®E. The output of the tool indicated if the project mitigated the reliability need according to SPP Criteria or a member's more stringent local planning criteria for either thermal-loading or per-unit voltage. Once a project was identified as solving a reliability need, a set of reliability metrics was calculated.

The reliability metrics (metrics) were developed by SPP staff members and stakeholders and were approved by the TWG for use as a tool for project selection. The metrics coincide with thermal and voltage reliability needs. The first metric is Cost per Loading Relief (CLR), which relates the amount of thermal loading relief for the cost of a project for a need. The second metric is Cost per Voltage Relief (CVR), which relates the amount of voltage support for the cost of a project for a need.

Metrics were calculated for each project's performance for each need. After the metrics were calculated, the projects were ranked per need and by the lowest CLR or CVR. The project with the highest ranking (lowest CLR or CVR) was identified as the most optimal project to address the particular need.

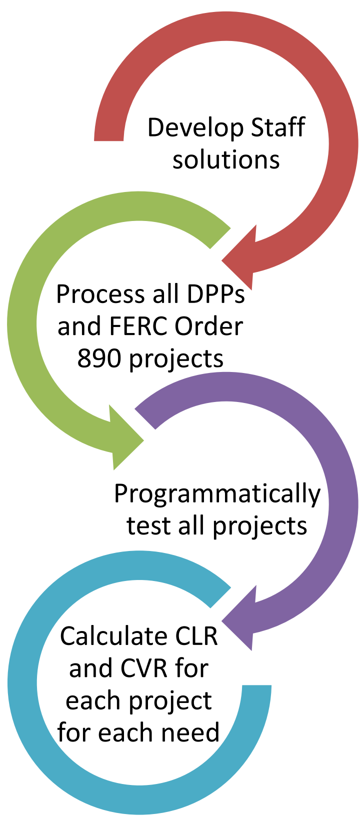


Figure 5.1: Project Processing Methodology Overview

Project Selection Methodology

SPP staff members developed a standardized conceptual cost template for assigning project costs to all stakeholder submitted and SPP staff members developed projects. After all projects were assigned a cost, each project was compared against all other projects using steady-state metrics. To perform a comparison of the extensive number of projects, a programmatic solution was utilized by SPP staff members. Using this project selection software, a subset of projects was generated by considering project cost as related to the amount of targeted relief the project could provide. Displacement of lower-voltage projects occurred by higher-voltage projects when a higher-voltage project solved needs at lower voltage level. SPP staff members applied engineering judgment to discern if a displaced project should remain in the portfolio. The subset of projects selected that solved all reliability needs was moved into the portfolio.

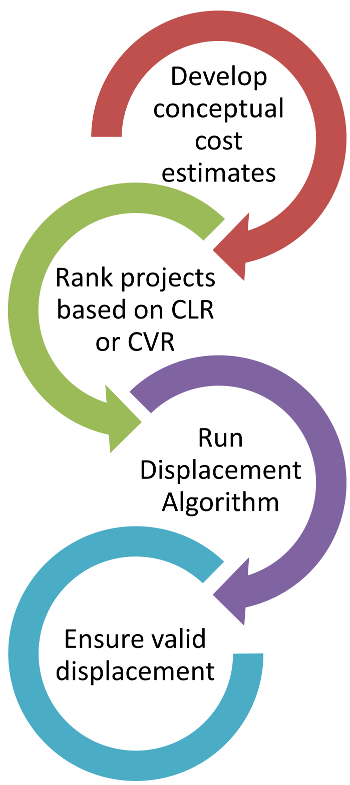


Figure 5.2: Project Selection

Staging

Selected projects were then timed using linear interpolation based on line loading between available model years of 2018 and 2021. For example, to time a solution due to a 2021 potential overload, SPP interpolated line loadings between the 2018 and 2021 models to determine when the loading exceeded 100 percent. The need date was assigned based on this analysis. A similar process for timing potential voltage issues was used to check for per unit under-voltage conditions below 0.90 and over-voltage conditions above 1.05. Projects only addressing needs resulting from the additional contingencies were given a need date of the season in which the violation was observed for the year 2021.

5.2: Rate Impacts

The SPP tariff requires that a rate impact analysis be performed for each ITP per Attachment O: Transmission Planning Process, Section III: Integrated Transmission Planning Process, Subsection 8:

> "8) Process to analyze transmission alternatives for each assessment:
>
> The following shall be performed, at the appropriate time in the respective planning cycle, for the 20-Year assessment, 10-Year assessment and Near-Term assessment studies: …
>
> f) The analysis described above shall take into consideration the following:
>
> vi) The analysis shall assess the net impact of the transmission plan, developed in accordance with this Attachment O, on a typical residential customer within the SPP Region and on a $/kWh basis."

The rate impact analysis process required to meet this requirement was developed under the direction of the Regional State Committee in 2010-2011 by the Rate Impact Task Force (RITF). The RITF developed a methodology that allocated costs to specific rate classes in each SPP pricing zone (zone).

The first step in this process is to estimate the zonal cost allocation of the Annual Transmission Revenue Requirement (ATRR). This cost-allocated ATRR is calculated specifically for the ITPNT upgrades using the ATRR forecast (forecast). The forecast allocated 2017 ITPNT upgrade costs to the zones using the highway/byway cost-allocation method. This method allocates costs to the individual zones and to the region based on the voltage level of the upgrade. Transformer costs were allocated based on the low-side voltage. Regional ATRRs are summed and allocated to the zones based on their individual load ratio share percentages.

Highway Byway Cost Allocation		
Voltage (kV)	Regional	Zonal
300 and above	100%	0%
100 – 299	33%	67%
Below 100	0%	100%

Table 4: Highway Byway Cost Allocation

The following inputs and assumptions were required to generate the forecast:

- Initial investment of each upgrade
- New 2017 ITPNT upgrade investments modeled were $60.52 million in 2017 dollars
- TO's estimated individual annual carrying charge percent
- Voltage level of each upgrade
- In-service year of each upgrade
- 2.5 percent annual straight-line rate-base depreciation
- 2.5 percent construction price inflation applied to 2017 base year estimates
- Mid-year in-service convention

PART II: STUDY FINDINGS

SECTION 6: PROJECT SUMMARY

6.1: Model Analysis and Reliability Needs

The analysis that was completed provided SPP with a list of thermal and voltage needs. The table below summarizes all the observed thermal needs sorted by year, season and scenario.

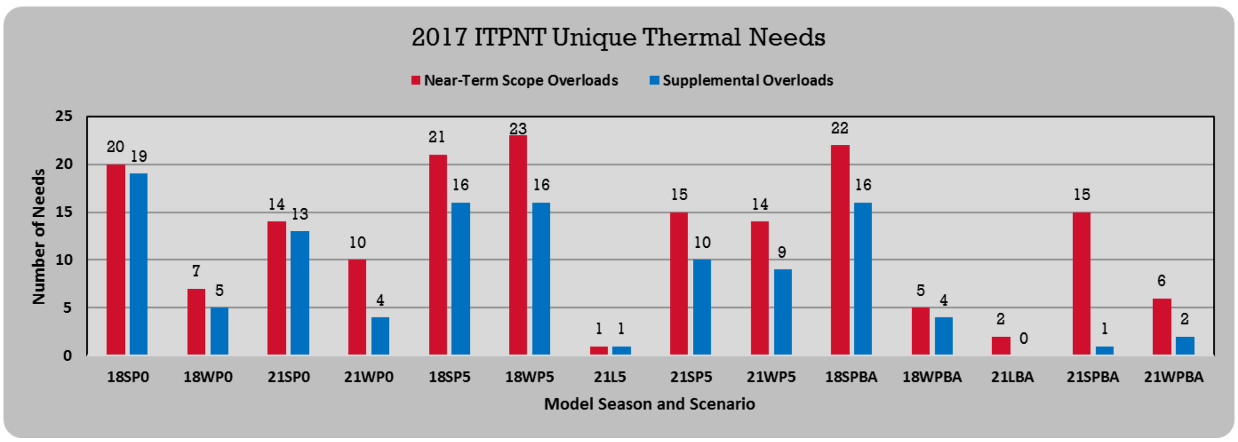


Figure 6.1: Unique Thermal Needs

The table below shows all the observed voltage needs sorted by year, season and scenario.

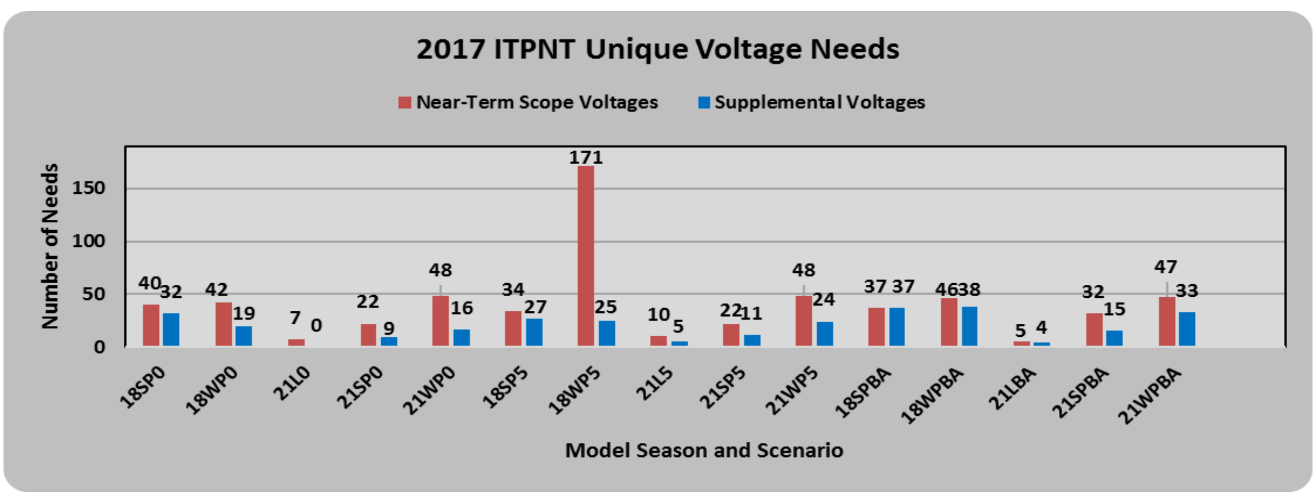


Figure 6.2: Unique Voltage Needs

6.2: Project Development Summary

Transmission upgrades submitted through the Order 890 and Order 1000 processes were analyzed, and SPP staff members developed projects to mitigate potential reliability problems that were unable to be solved by mitigation plans or operating guides. Below is the full list of projects in the ITPNT.

Reliability Project(s)	Project Area(s)	Cost	Need Date
Rebuild Broken Arrow – Lynn Lane East 7.2 mile 138 kV line	AEP	$ 5,714,095	6/1/2018
Rebuild Tulsa Southeast-East 61st 1.8 mile 138 kV (Addressing additional contingency)	AEP	$ 6,014,381	6/1/2021
New 28.8 MVAR 138 kV two-stage capacitor bank at IPC	AEP	$ 1,298,049	12/1/2018
New Ruthville – SW Minot 24 mile 115 kV line	BEPC	$ 21,780,000	6/1/2018
Reconductor Nichols – Republic North 9.7 mile 69 kV line **Reconductor Republic North– Republic Hines Street 2 3.9 mile 69 kV line** **Reconductor Republic Hines Street – Republic East 1.3 mile 69 kV line**	EMDE	$ 6,300,000	6/1/2018
Add redundant relaying at Stilwell **(Addressing additional contingency)**	KCPL	$ 147,500	6/1/2021
Two 69 kV line breakers at NIPCO L-10 **New 69 kV Switching Station to replace existing K-116 line switch (J-16)**	NIPCO	$ 1,406,577	6/1/2018
Upgrade terminal equipment at Coulter 115 kV bus	SPS	$ 268,490	6/1/2018
Upgrade terminal limitations on the 230kV circuit K62 at Nichols Substation	SPS	$ 490,000	12/1/2018
Upgrade terminal equipment at Hale 115 kV bus	SPS	$ 741,329	12/1/2018

Reliability Project(s)	Project Area(s)	Cost	Need Date
New 230/115 kV transformer at Tuco Interchange (Modification of an existing NTC)	SPS	$ 183,814	6/1/2018
Upgrade terminal equipment at Plant X and Sundown 230 kV bus	SPS	$ 559,479	12/1/2020
Rebuild Etter - Moore 10.8 mile 115 kV line	SPS	$ 9,073,903	6/1/2018
Upgrade terminal equipment at Texas County 3 115 kV bus	SPS	$ 207,069	6/1/2018
New substation Roberts County 115 kV **New 115/69 kV transformer at Roberts County** **Tap Forman - Summit 115 kV line at Roberts County** **New Roberts County - Sisseton 2 mile 69 kV line**	WAPA/EREC	$ 5,990,000	6/1/2018
Upgrade terminal equipment at Williston 115 kV bus	WAPA	$350,000	6/1/2018

* Monitored Element(s) is/are not the all-inclusive list of needs fixed by the project.

Table 5: 2017 ITPNT Projects

6.3: Project Plan Breakdown

The figures below show a breakdown of the 2017 ITPNT project plan. There are 25 proposed upgrades making up 16 projects in the project plan. Of the 16 proposed projects, 15 will be recommended for issuance of new NTCs. One project had been identified as needing a modified NTC (NTC modify).

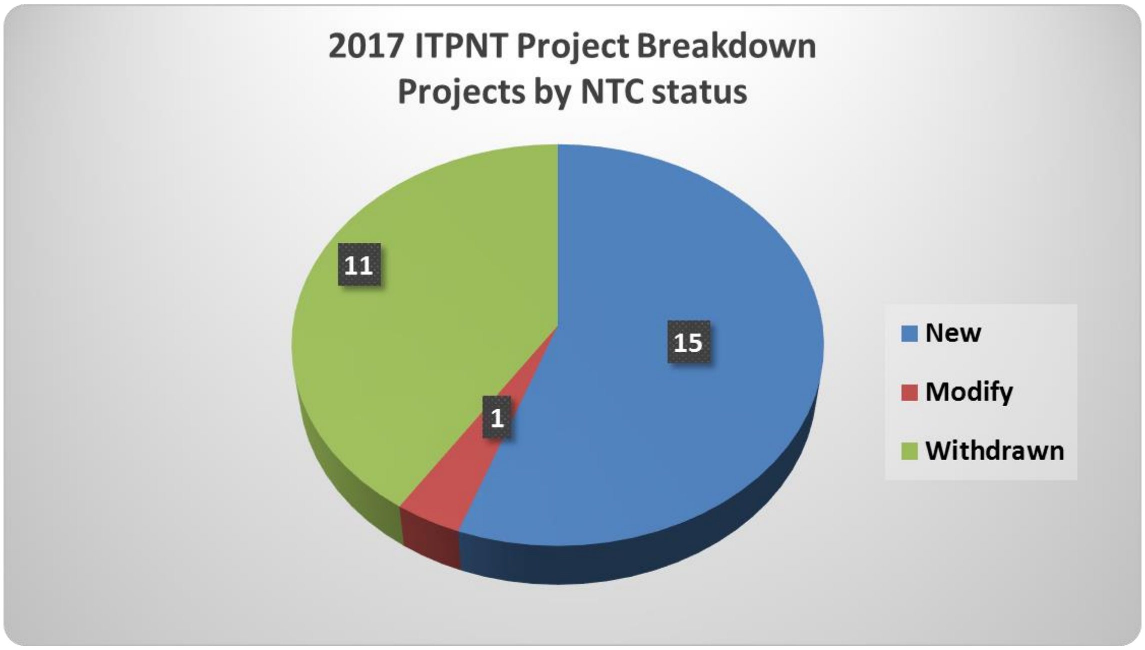


Figure 6.3: 2017 ITPNT Project Breakdown

The figure below shows the breakdown of new transmission by voltage class in the 2017 ITPNT project plan.

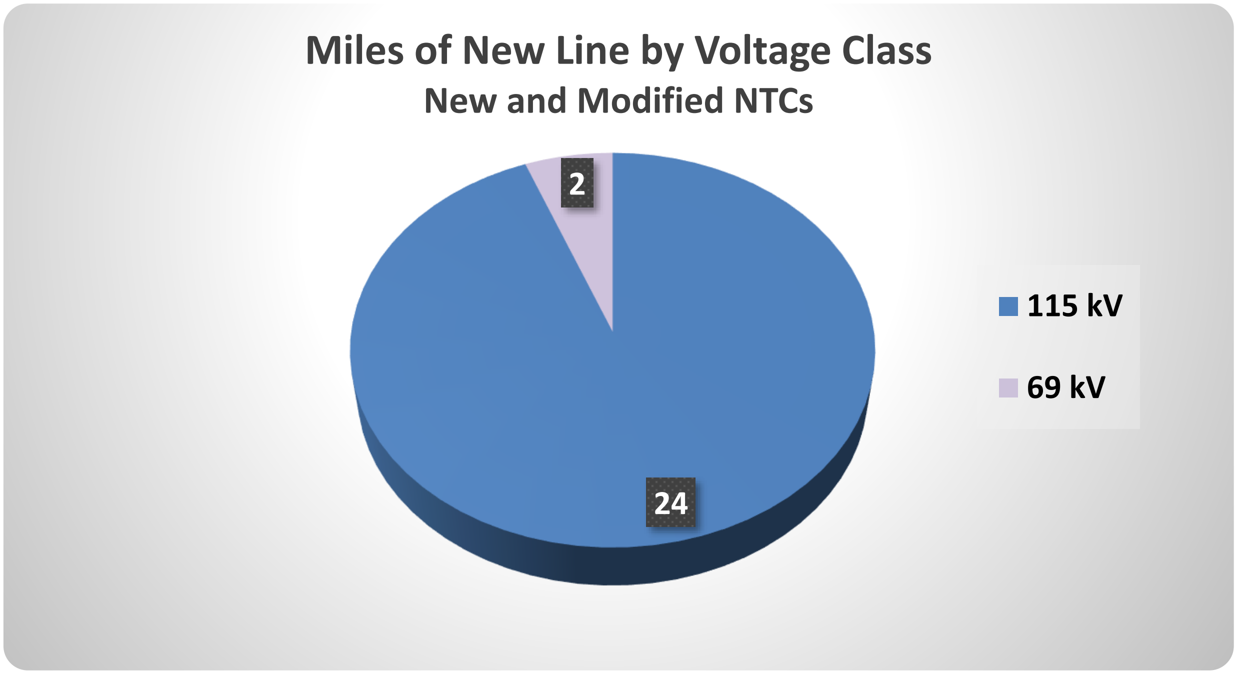


Figure 6.4: 2017 ITPNT New Line by Voltage Class

The figure below illustrates how many miles of existing transmission line that will require a rebuild or reconductor. There are 35 miles of rebuild/reconductor in the 2017 ITPNT project plan.

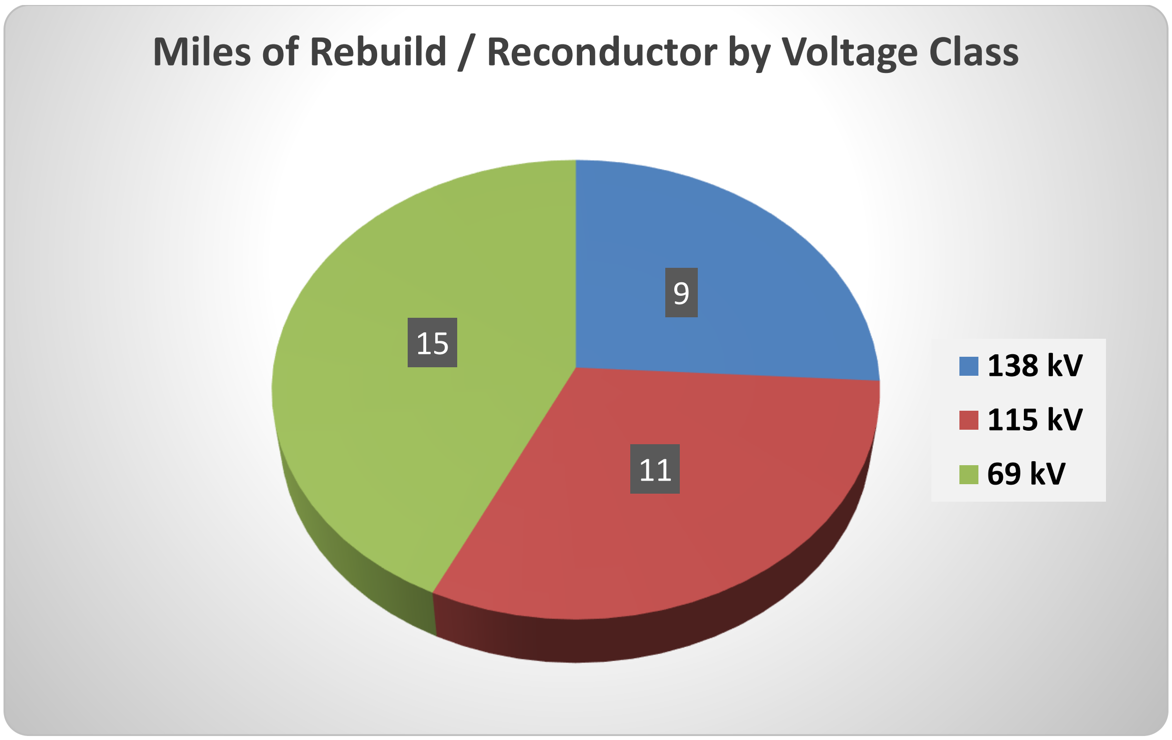


Figure 6.5: 2017 ITPNT Miles Rebuild/Reconductor by Voltage Class

Zonal Reliability projects are required to meet local planning criteria, which is more stringent than SPP criteria. There were no projects of this classification identified in this study.

The table below shows the dollar amount of new and modified projects of the 2017 ITPNT identified by state.

State	New NTC	Modified NTC
Kansas	**$ 147,500**	**$ 0**
South Dakota	$ 5,990,000	$ 0
Missouri	$ 6,300,000	$ 0
North Dakota	$ 22,130,000	$ 0
Oklahoma	$ 11,935,545	$ 0
Texas	$ 12,431,249	$ 183,814
Iowa	$ 1,406,577	$ 0
Subtotals:	**$ 60,340,871**	**$ 183,814**

Table 6: 2017 ITPNT Projects by State

The table below shows the net investment amount of new, modified and withdrawn projects of the 2017 ITPNT identified by state.

State	New NTC	Modified NTC (Net Change)	Withdrawn NTC	Net Investment
KS	$147,500	0	($2,521,411)	($2,373,911)
IA	$1,406,577	0	0	$1,406,577
MO	$6,300,000	0	0	$6,300,000
ND	$22,130,000	0	0	$22,130,000
NE	0	0	($3,141,600)	($3,141,600)
NM	0	0	($3,700,000)	($3,700,000)
OK	$11,935,545	0	($20,795,000)	($8,859,455)
SD	$5,990,000	0	0	$5,990,000
TX	$12,431,249	$183,814	($6,915,750)	$5,699,313
Total	**$60,340,871**	**$183,814**	**($37,073,761)**	**$23,450,924**

Table 7: 2017 ITPNT Net Investment by State

The figure below is a representation of the 2017 ITPNT portfolio of new, modified and withdrawn NTCs by voltage class. For each column, the cost of the new, modified or withdrawn NTC is also displayed.

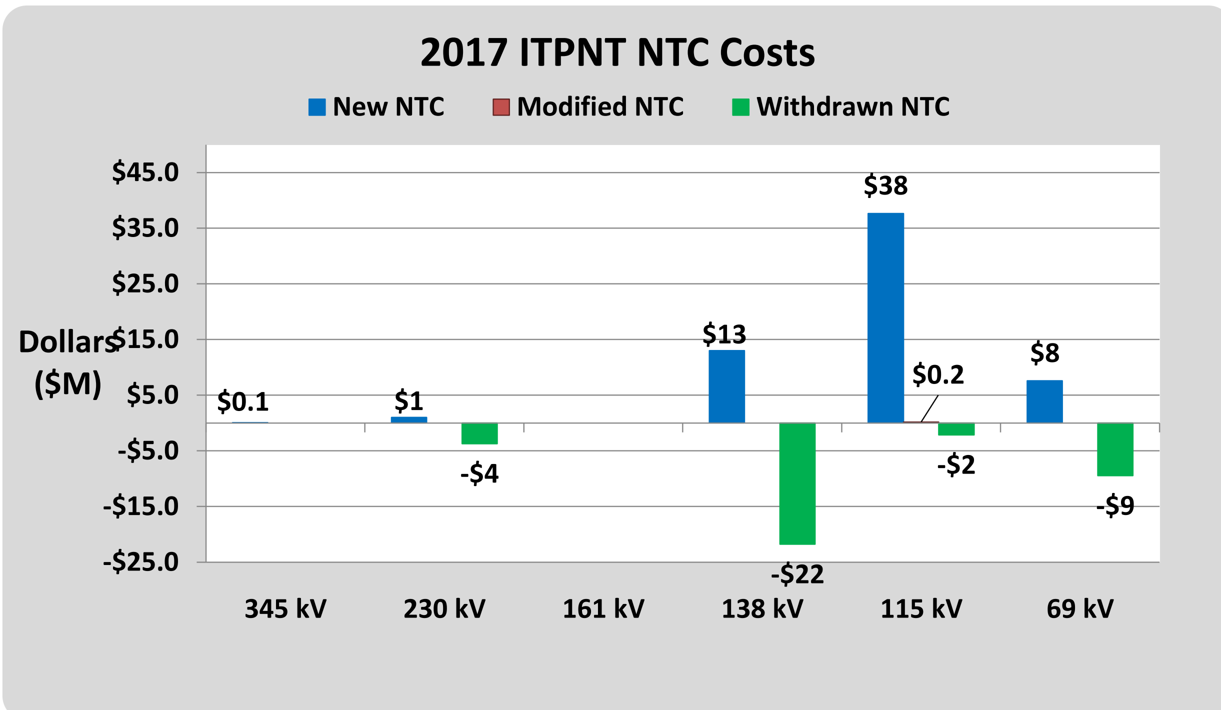


Figure 6.6: 2017 ITPNT NTC Costs by Voltage Class

The figure below shows the 2017 ITPNT projects represented two ways. The blue column represents the number of upgrades by year. The red column represents the dollars that will be invested to place the projects in service.

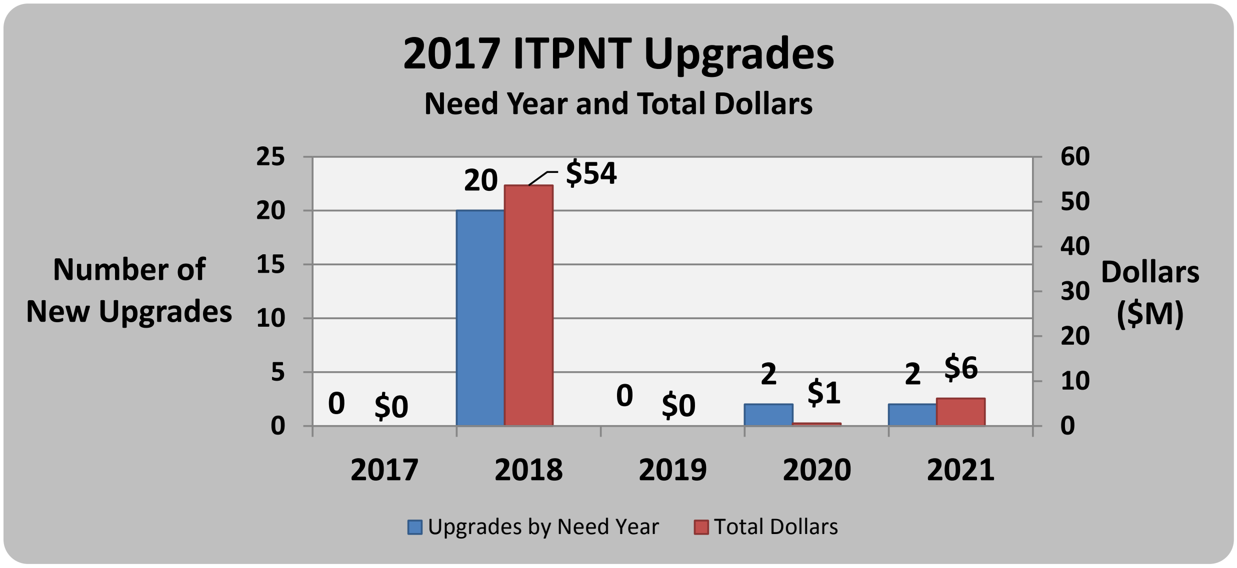


Figure 6.7: 2017 ITPNT Upgrades by Need Year and Total Dollars

The figure below shows the cost allocation of upgrades with new NTCs and modified NTCs between upgrades needed for regional reliability and zonal reliability.

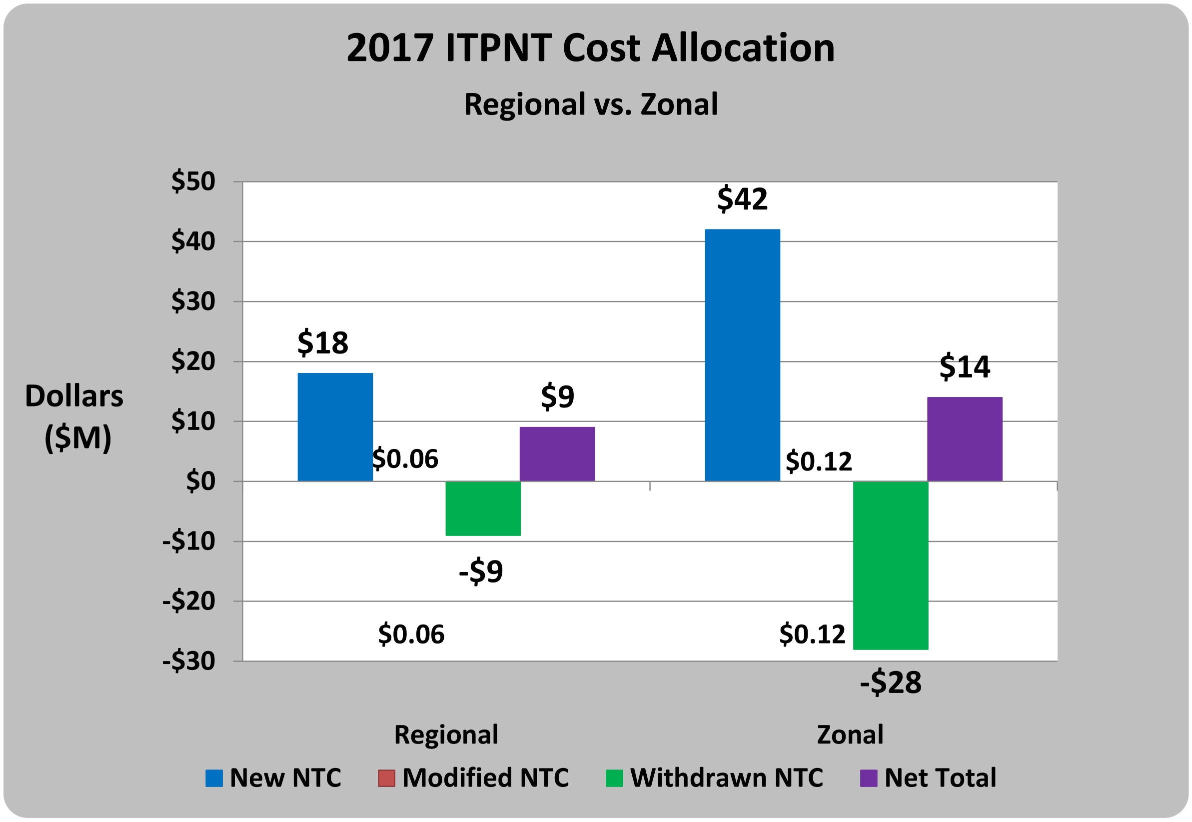


Figure 6.8: 2017 ITPNT Cost Allocation – Regional vs. Zonal

6.4: Project Details

This section details each of the major projects in the 2017 ITPNT project plan. Each of the projects discussed below have an SPP generated cost estimate greater than $20 million and are needed for Regional Reliability.

North Dakota Area

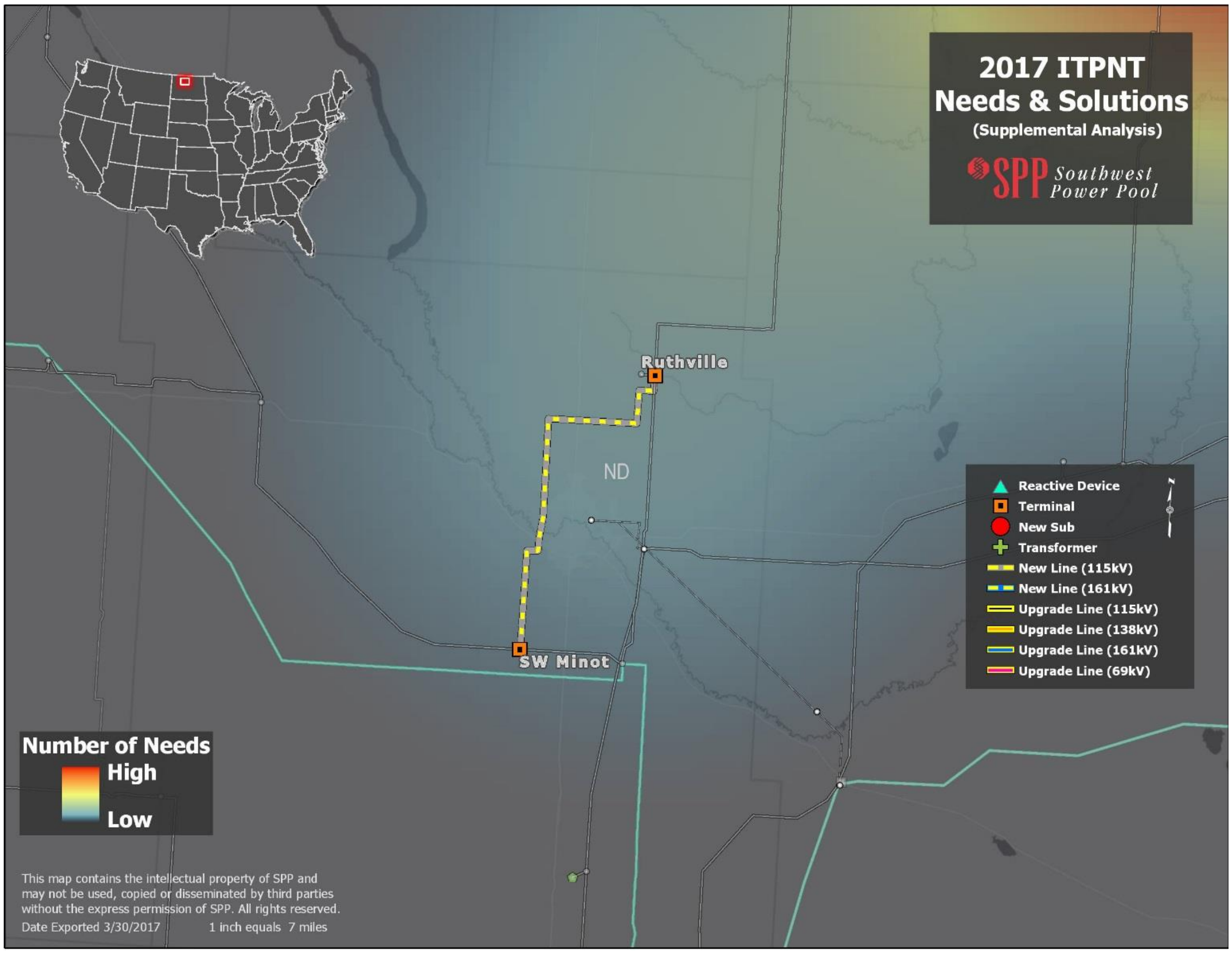


Figure 6.9: 2017 ITPNT North Dakota Solutions

New Ruthville – SW Minot 115 kV line

This project is a new 24-mile 115 kV line from east Ruthville to southwest Minot. This project will address the overload of Botno southeast to Towner 115 kV line for the loss of the east Ruthville to Mallard 115 kV line. It will also address 115 kV and 69 kV needs at Ruthville, Thorne, Dunning, Kelvin and Haram.

6.5: Rate Impacts on Transmission Customers

The 2017 ITPNT upgrades were run in the SPP Cost Allocation Forecast and the peak ATRR impact year was shown to be 2022.

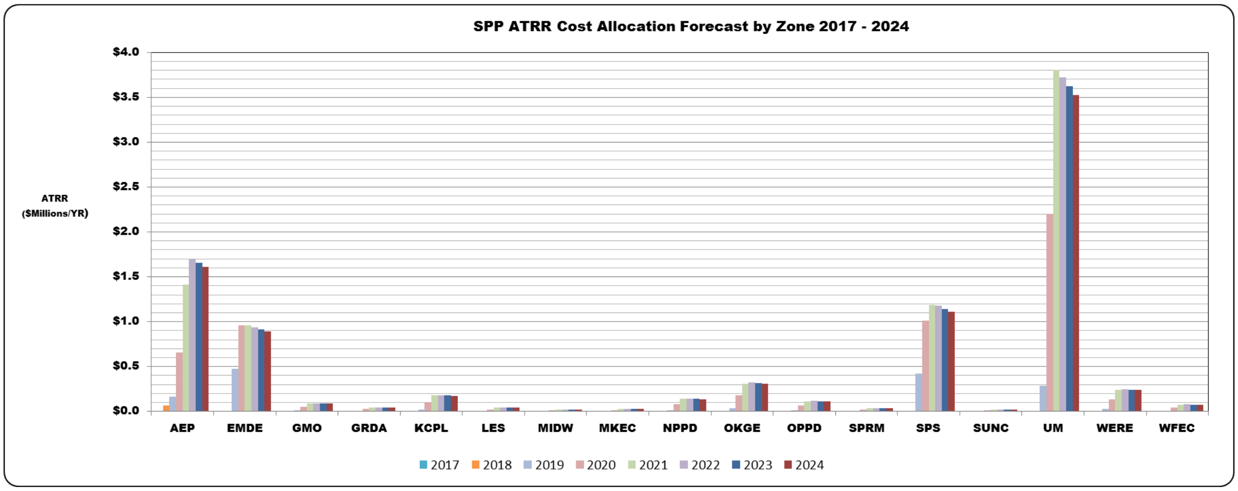


Figure 6.10: ATRR Cost Allocation Forecast by Zone of the 2017 ITPNT

As shown in the following chart, the majority of the 2017 ITPNT projects will be cost allocated to the zone hosting the upgrade with a smaller amount being cost allocated to the SPP region through the regional rate for all years, 2018-2024:

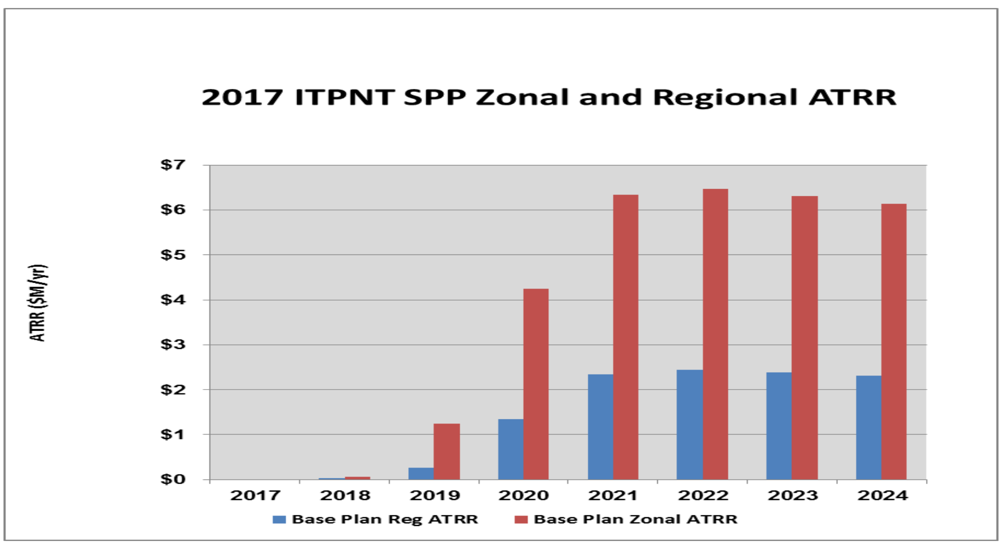


Figure 6.11: Zonal and Regional ATRR allocated in SPP

The peak-year ATRR is converted into a monthly impact on a typical 1000 kWh per month retail residential ratepayer. This is done by dividing the ATRR zonal impact by the zonal energy usage as adjusted for typical losses.

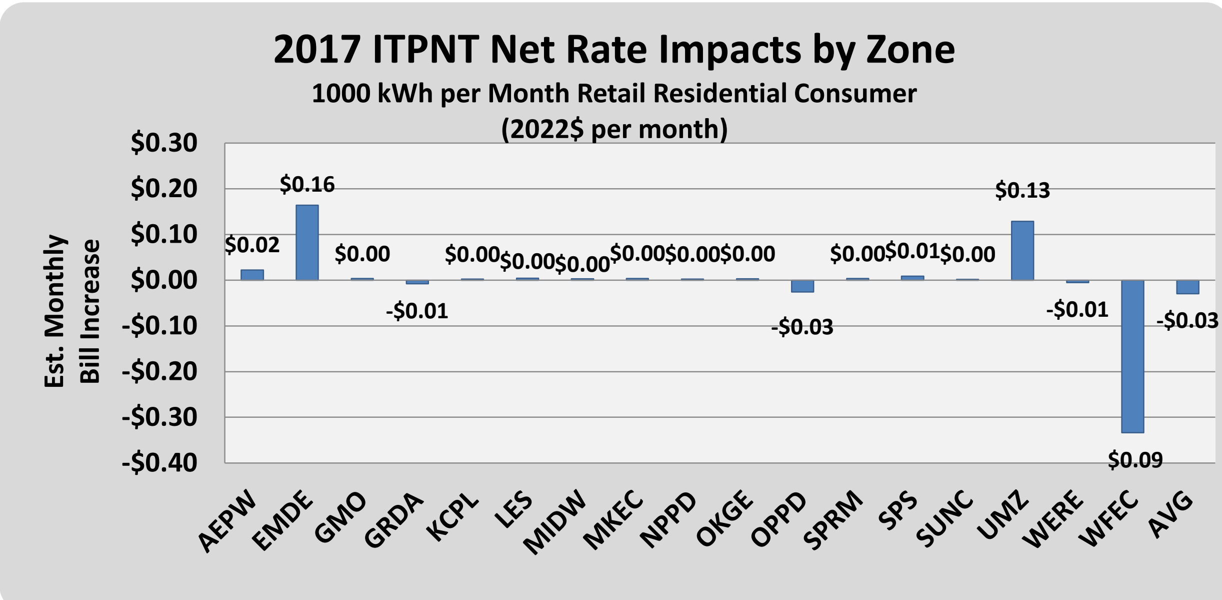


Figure 6.12: 2017 ITPNT Net Rate Impacts by Zone

PART III: APPENDICES

SECTION 7: PROJECT MAPS

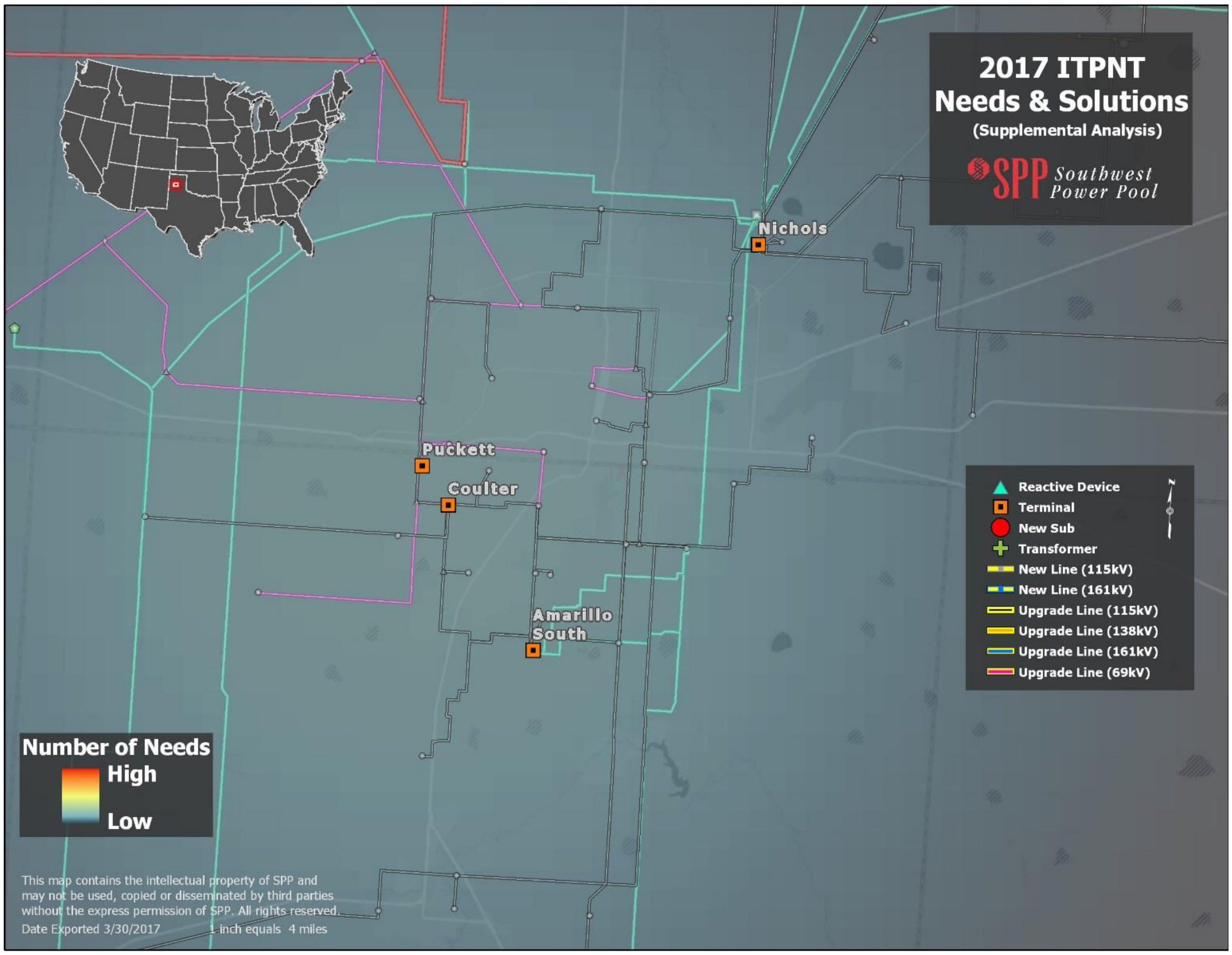


Figure 7.1: Upgrade terminal equipment at Coulter 115 kV bus
Upgrade terminal limitations on the 230kV circuit K62 at Nichols Substation

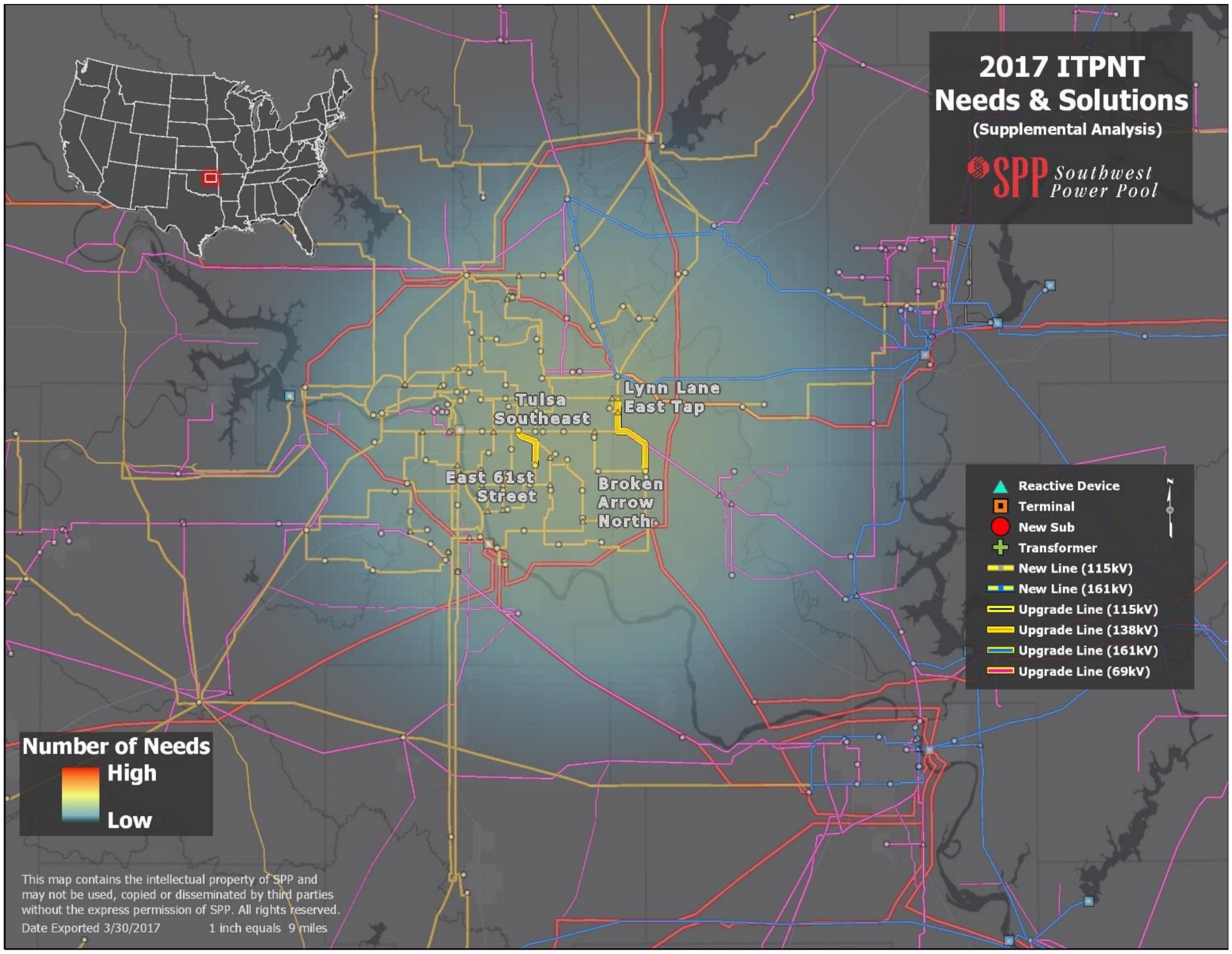


Figure 7.2: Rebuild Broken Arrow – Lynn Lane East 7.2 mile 138 kV line
Rebuild Tulsa Southeast-East 61st 1.8 mile 138 kV (Addressing additional contingency)

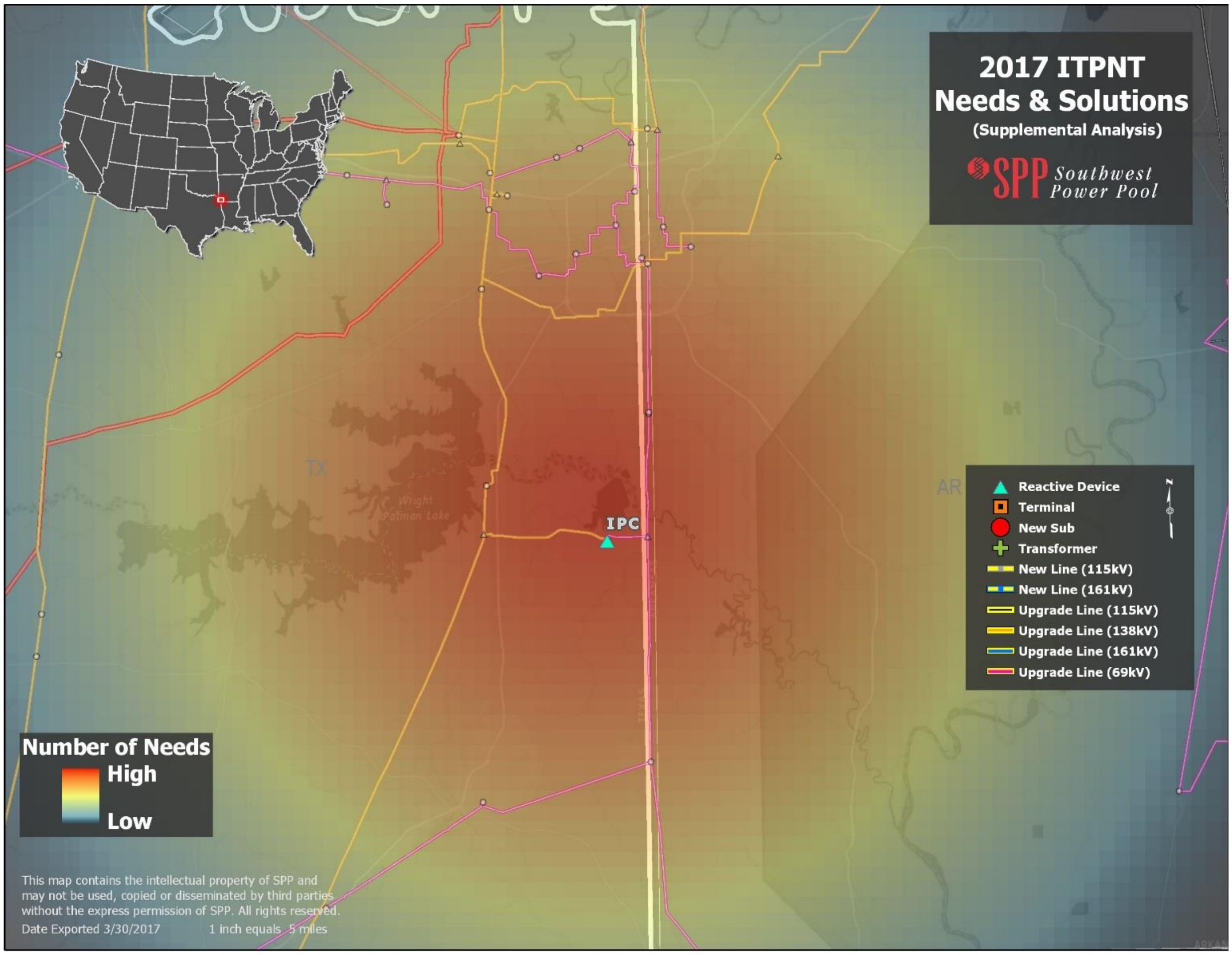


Figure 7.3: New 28.8 MVAR 138 kV two-stage capacitor bank at IPC

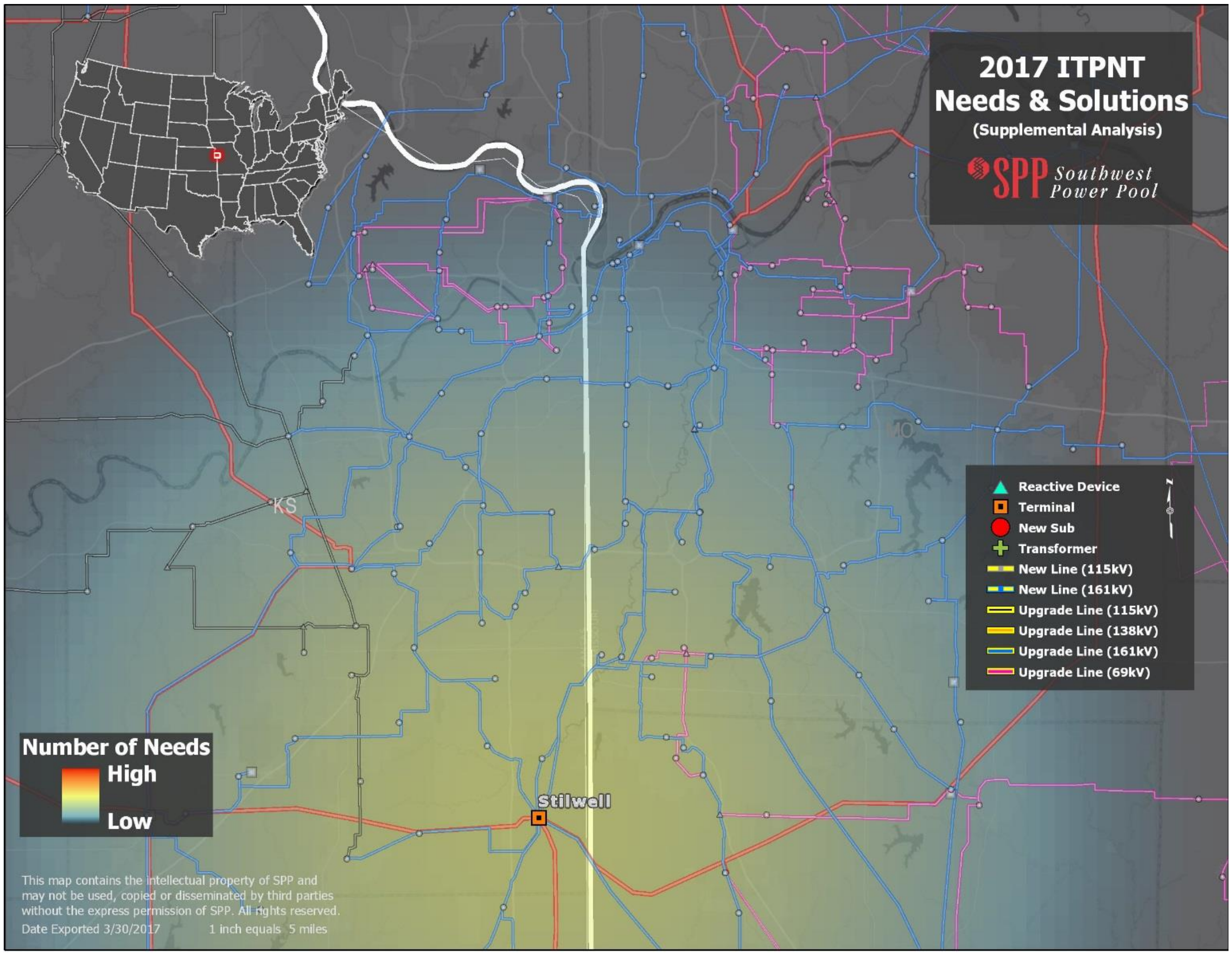


Figure 7.4: Add redundant relaying at Stilwell

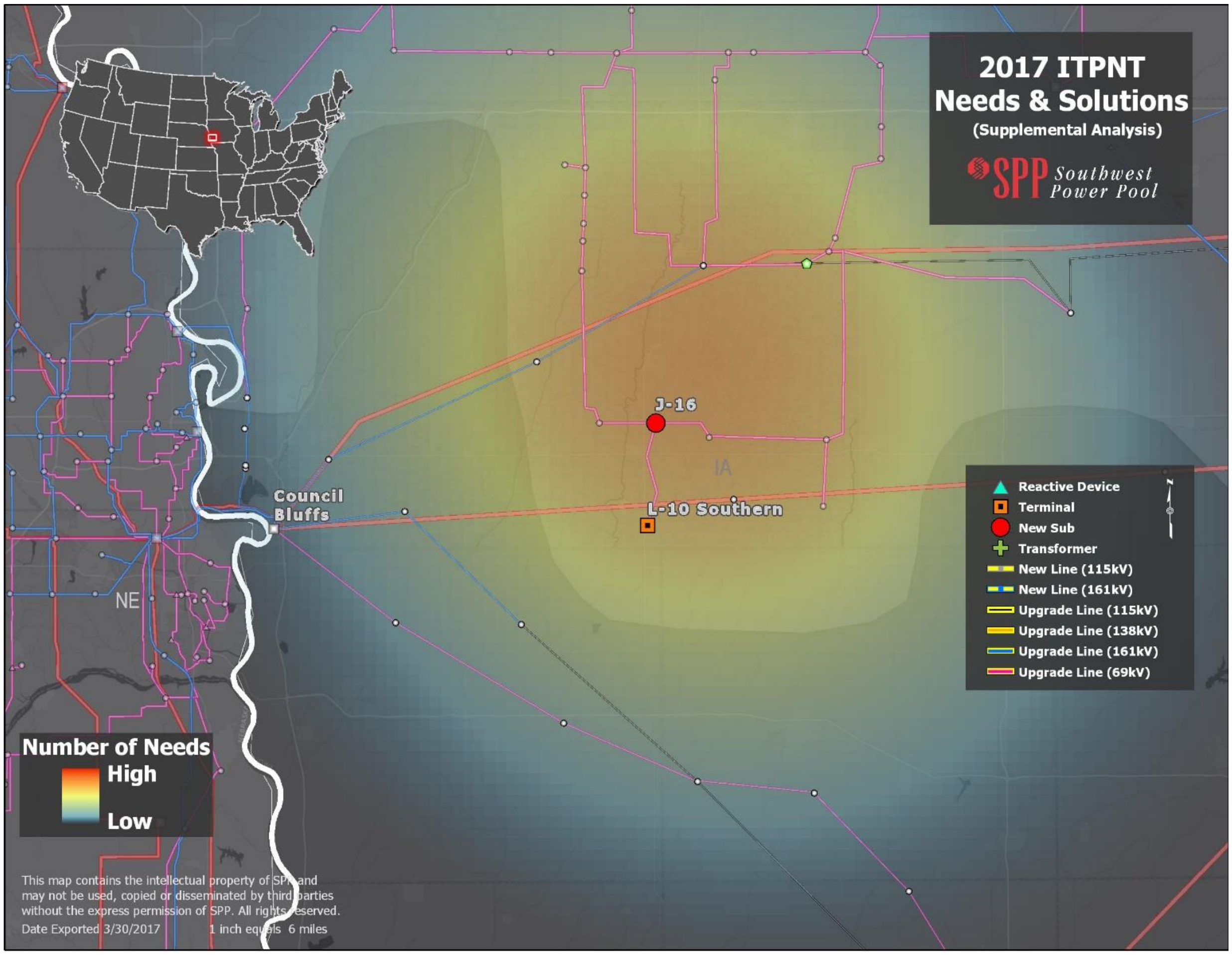


Figure 7.5: Two 69 kV line breakers at NIPCO L-10
New 69 kV Switching Station to replace existing K-116 line switch (J-16)

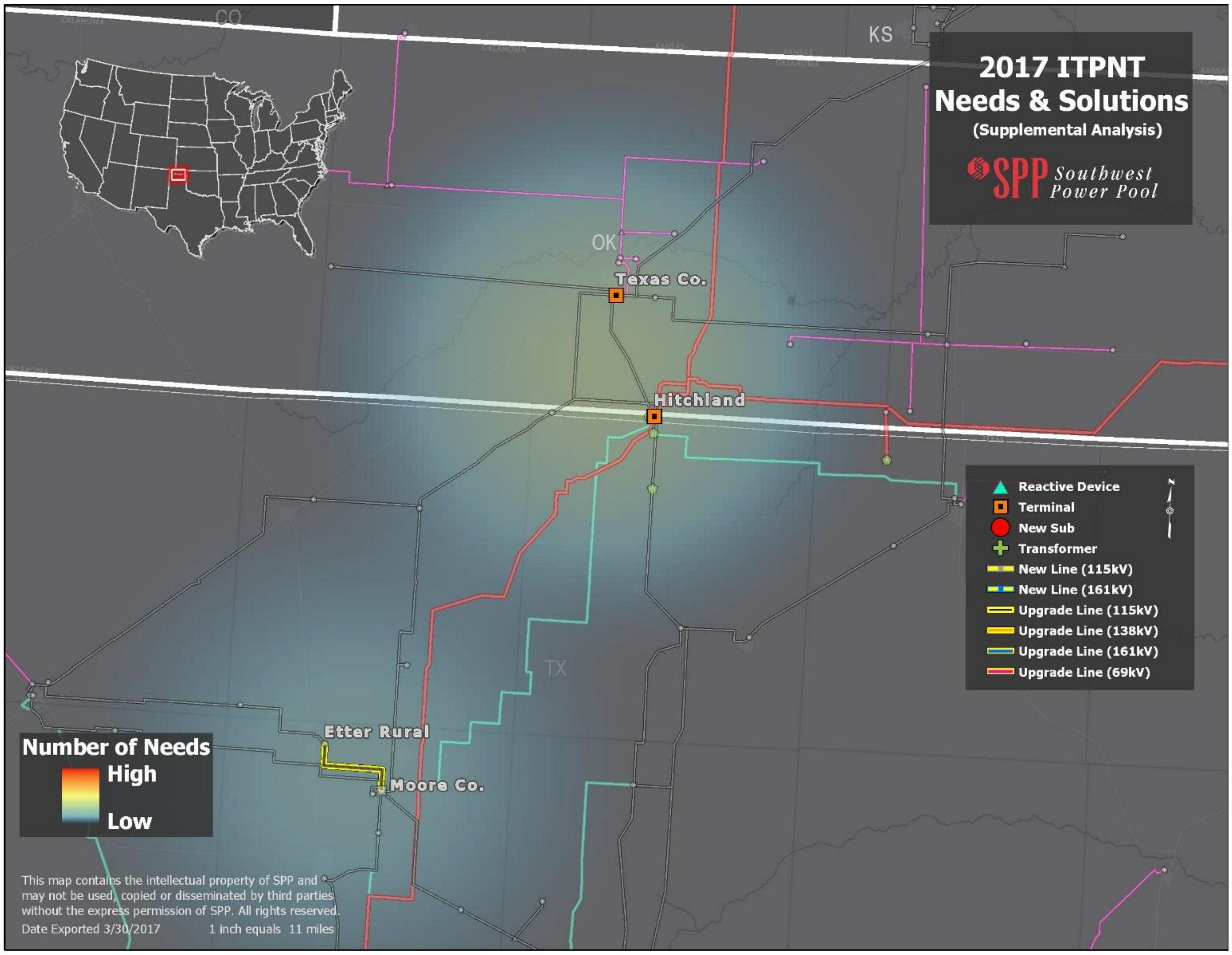


Figure 7.6: Rebuild Etter - Moore 10.8 mile 115 kV line
Upgrade terminal equipment at Texas County 3 115 kV bus

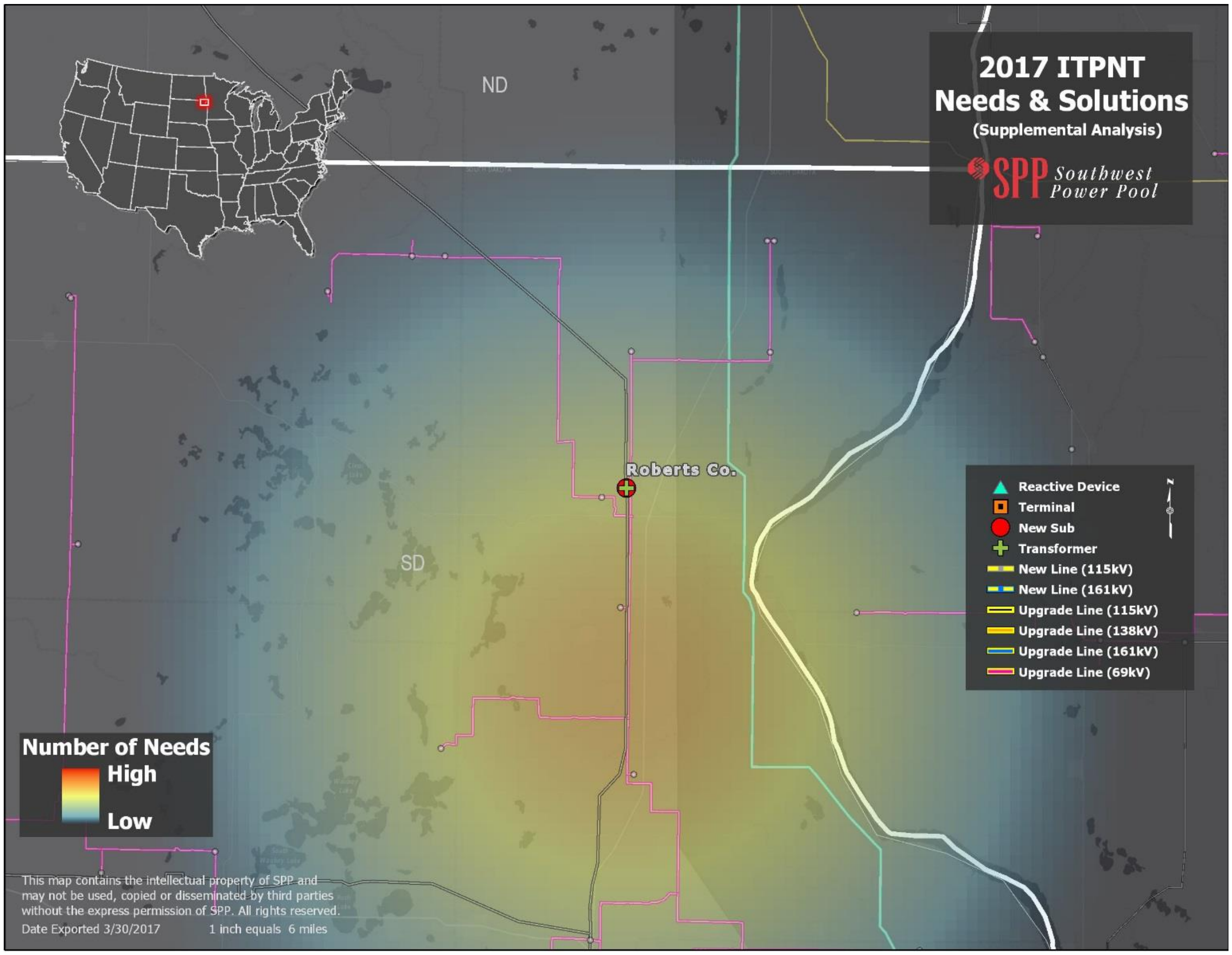


Figure 7.7: New substation Roberts County 115 kV
New 115/69 kV transformer at Roberts County
Tap Forman - Summit 115 kV line at Roberts County
New Roberts County - Sisseton 2 mile 69 kV line

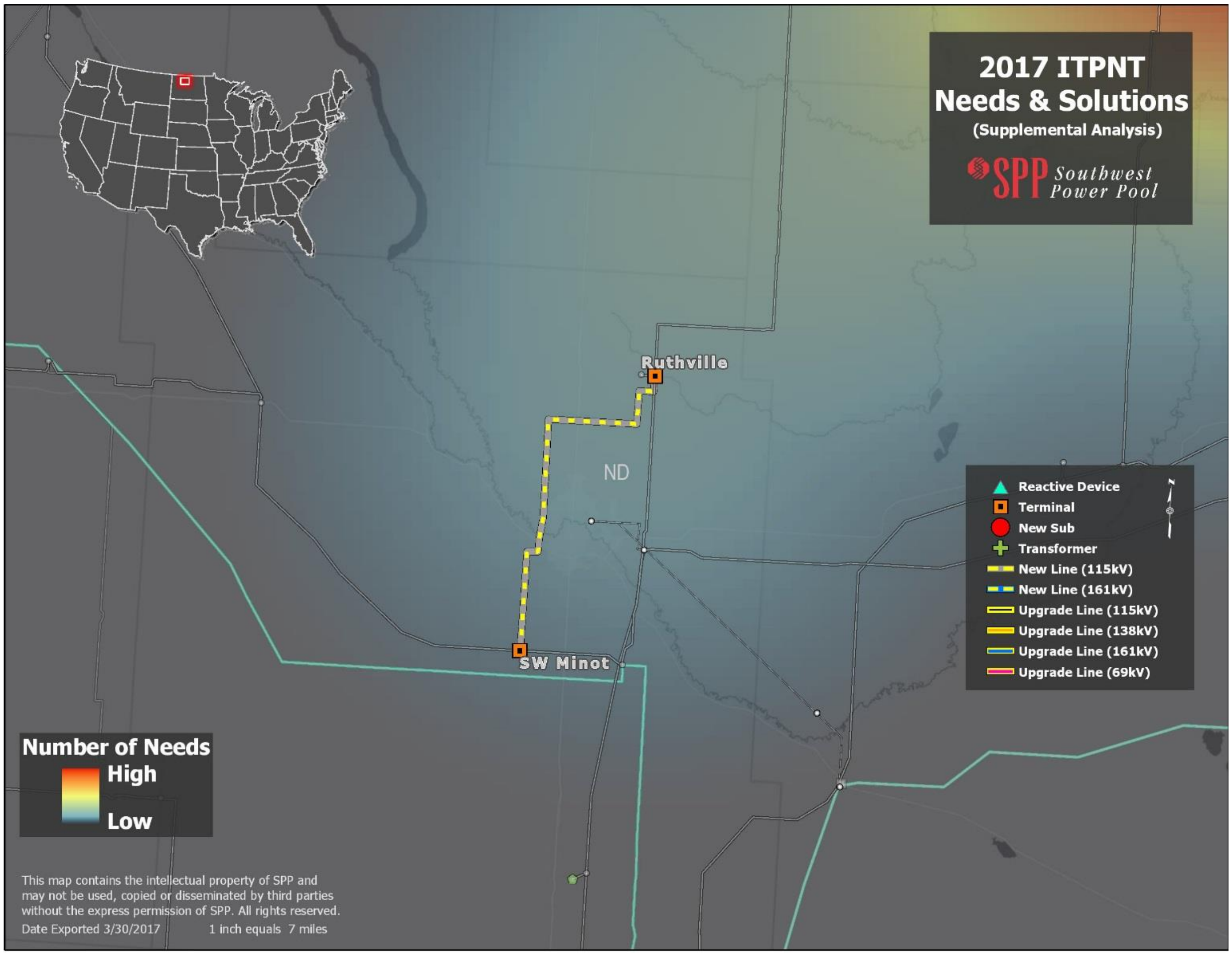


Figure 7.8: New Ruthville – SW Minot 24 mile 115 kV line

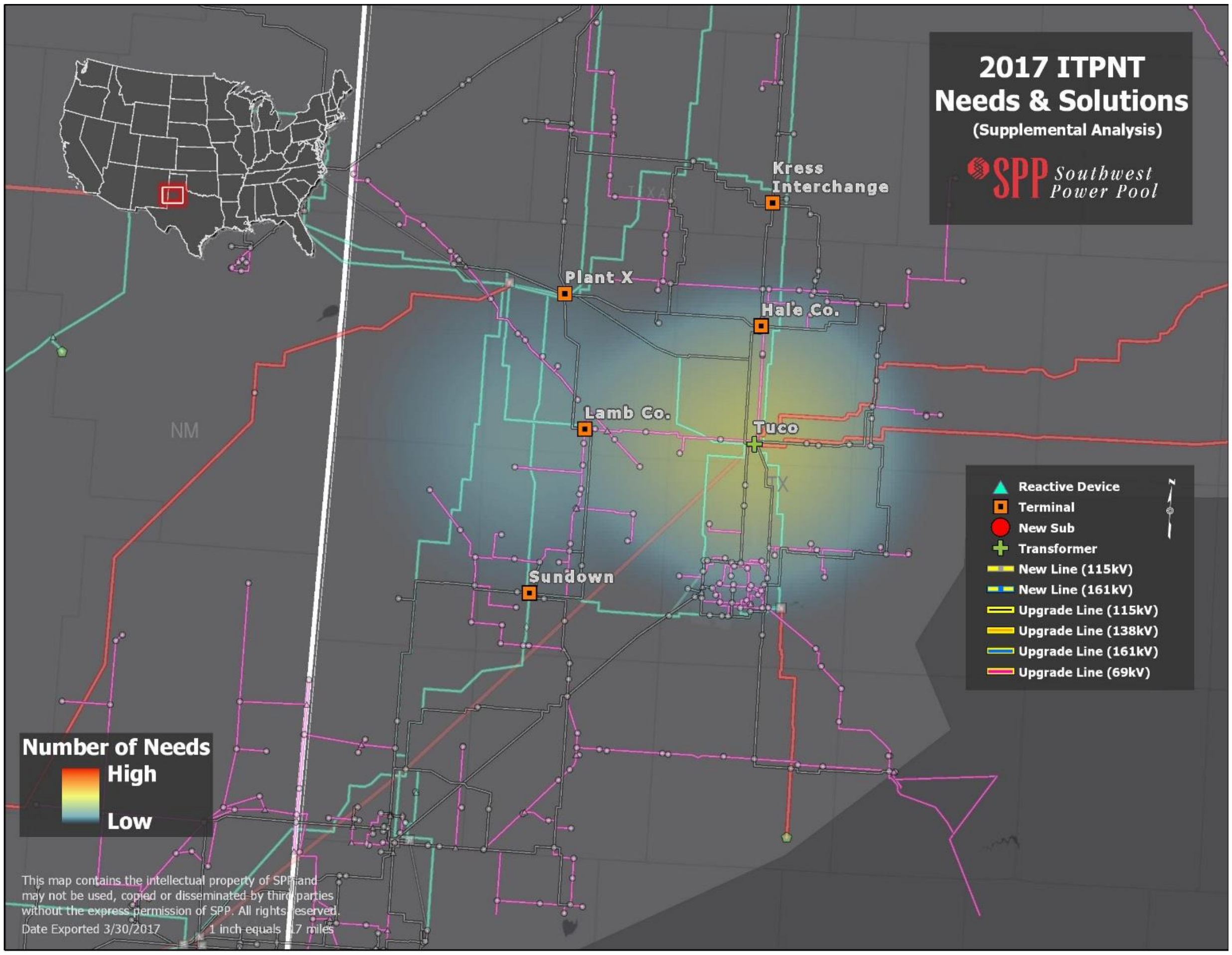


Figure 7.9: Upgrade terminal equipment at Hale 115 kV bus
New 230/115 kV transformer at Tuco Interchange
Upgrade terminal equipment at Plant X and Sundown 230 kV bus

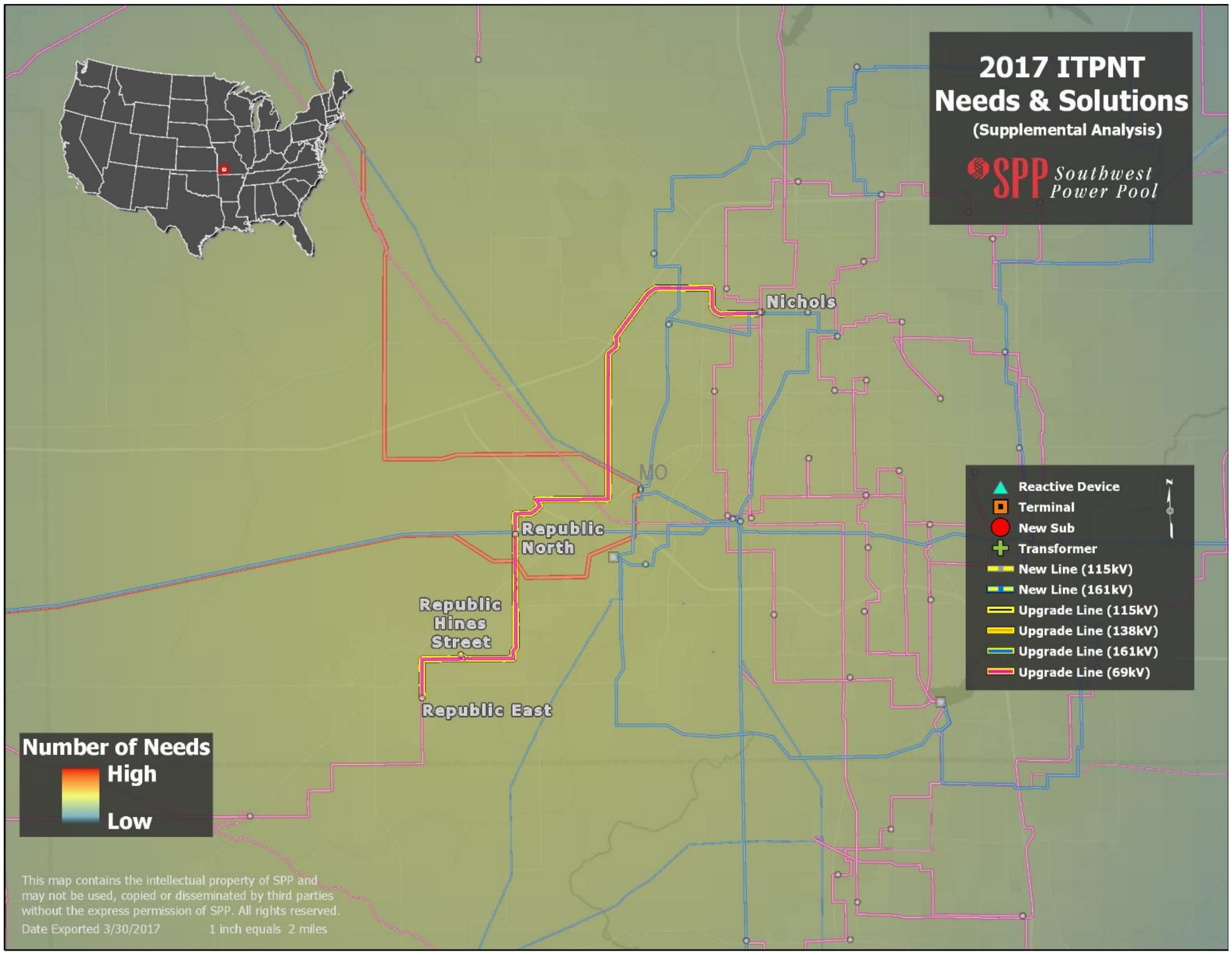


Figure 7.10: Reconductor Nichols – Republic North 9.7 mile 69 kV line
Reconductor Republic North– Republic Hines Street 2 3.9 mile 69 kV line
Reconductor Republic Hines Street – Republic East 1.3 mile 69 kV line

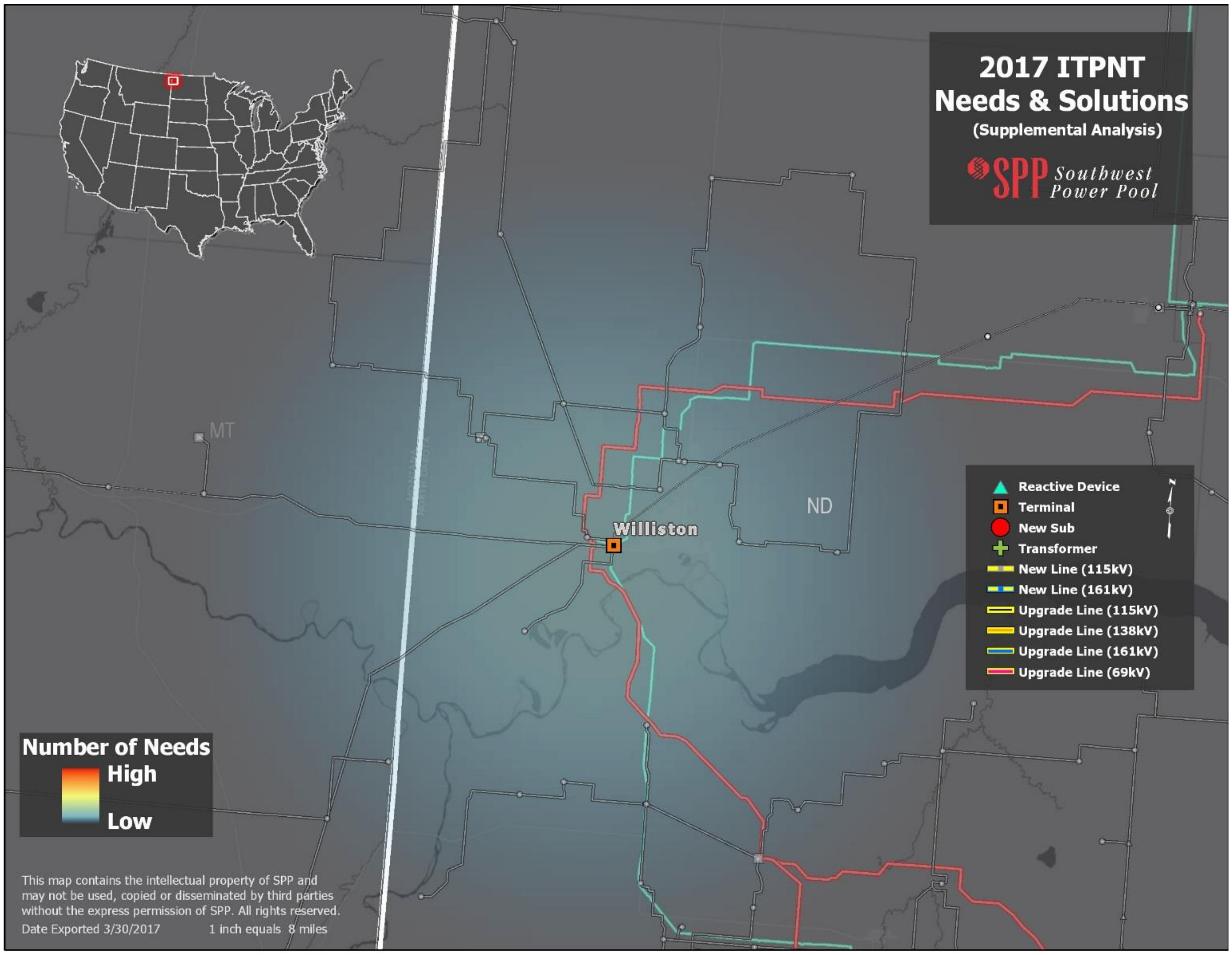


Figure 7.11: Upgrade terminal equipment at Williston 115 kV bus

SECTION 8: 2017 ITPNT PROJECT LIST

The 2017 ITPNT project list is posted as a separate document at the following location: https://www.spp.org/engineering/transmission-planning/.

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