2017 STEP

2017 SPP Transmission Expansion Plan Report

January 11, 2017

Engineering

Southwest Power Pool

Revision History

Date	Author	Change Description
01/06/2017	SPP	Initial Draft
01/11/2017	SPP	Final Draft
1/17/2017	SPP	Updated Section 9.2 to reflect 8 TSS projects
1/17/2017	SPP	Endorsed by MOPC
1/31/2017	SPP	Approved by the SPP BPD

Table of Contents

List of Figures

List of Tables

Section 1: Executive Summary

The 2017 SPP Transmission Expansion Plan (STEP) is a comprehensive listing of all transmission projects in SPP for the 20-year planning horizon. Projects included in the 2016 STEP are:

- Upgrades required to satisfy requests for Transmission Service;
- Upgrades required to satisfy requests for Generator Interconnection Service;
- Approved projects from the Integrated Transmission Planning (ITP) 20-Year,10-Year and Near-Term Assessments;
- Approved Balanced Portfolio Upgrades;
- Approved High Priority Upgrades;
- Endorsed Sponsored Upgrades; and
- Approved Interregional Projects.

The 2017 STEP consists of 474 upgrades with a total cost of $5.54 billion.

We invite stakeholders and all interested parties to submit any written comments on the projects included in the STEP via our Request Management System (RMS). SPP solicits feedback on proposed solutions to transmission needs through stakeholder working groups and planning summits as well as through meetings, teleconferences, web conferences, and via email or secure web-based workspace. These meetings provide an open forum where all stakeholders have an opportunity to provide advice and recommendations to SPP to aid in the development of the STEP. In addition to these opportunities, we also invite stakeholders to provide SPP with any transmission needs they deem to be beneficial to the transmission planning process through our website or RMS.

The chart below illustrates the cost distribution of the 2017 STEP based on project type. More detail on the total portfolio is listed in Section 10.

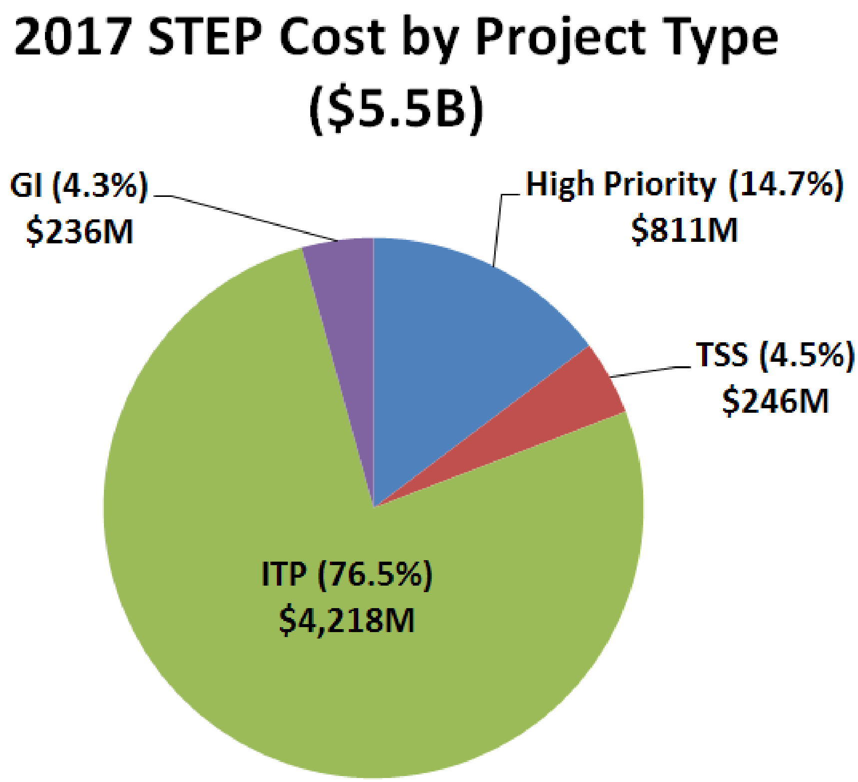


Figure 1.1: Cost by Project Type - 2017 STEP

After the SPP Board of Directors approves transmission expansion projects or once Service Agreements are executed, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners. A list of the NTCs issued in 2016 can be found in Section 11. A breakdown of the total list of NTCs issued in 2016 is shown below in Figure 1.2.

In 2016, SPP issued 47 NTC letters with estimated construction costs of $991.98 million for 138 projects to be constructed over the next five years through 2021. Of this $991.98 million, the upgrade cost breakdown is as follows:

- $7.3 million for Generator Interconnection (GI);
- $83.9 million for Transmission Service (TSS);
- $41.3 million for High Priority (HP); and
- $859.5 million for Integrated Transmission Planning (ITP) projects.

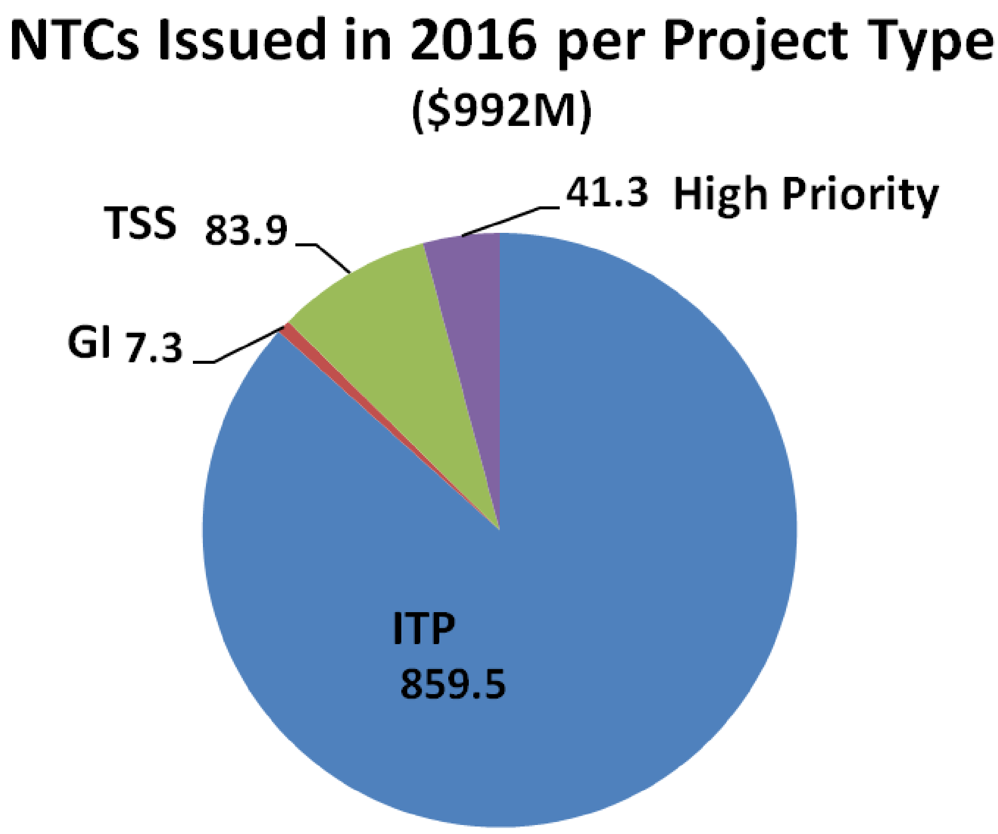


Figure 1.2: NTCs Issued in 2016 per Project Type

SPP actively monitors the progress of approved projects by soliciting feedback from project owners at least quarterly. As of December 31, 2016, 78 upgrades totaling approximately $939 million were completed during the year. The breakdown includes:

- 44 ITP - $582.3 million
- 8 TSS - $68 million
- 17 GI - $62.3 million
- 9 HP - $226.4 million

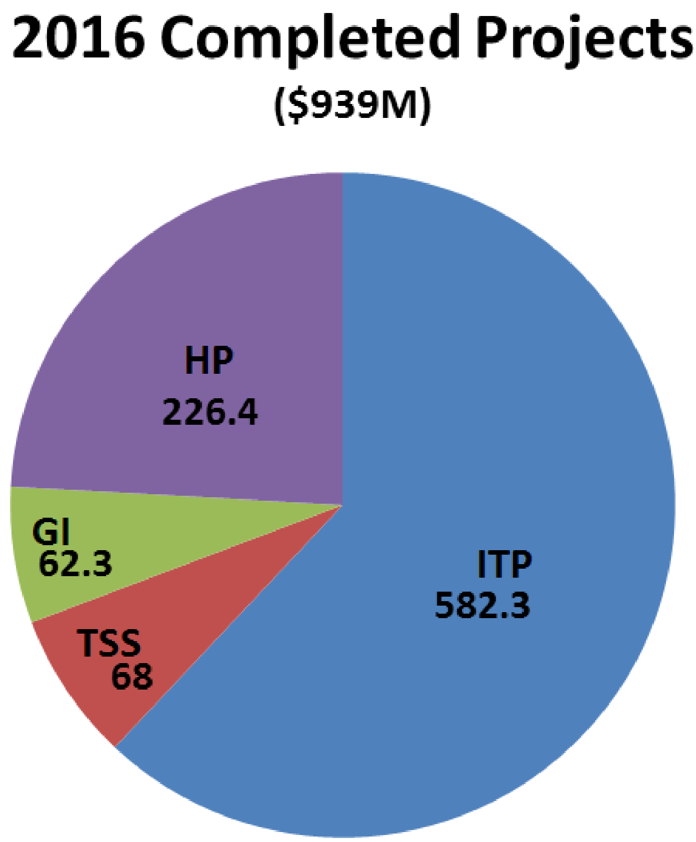
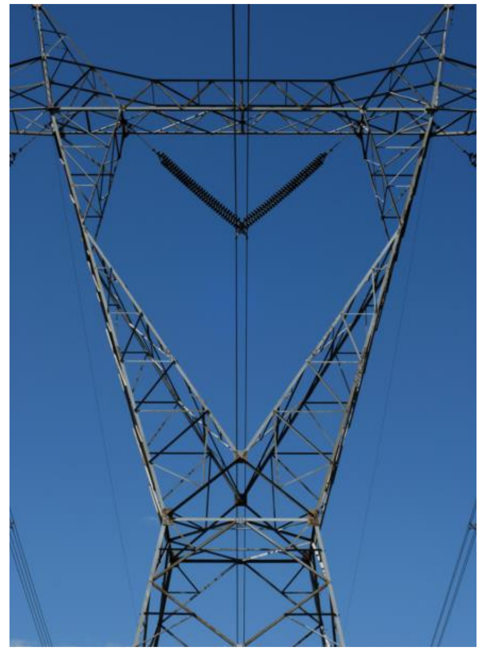


Figure 1.3: 2016 Completed Projects

Section 2: Transmission Services

2.1: Transmission Service 2016 Overview



SPP conducts the Aggregate Transmission Service Study (ATSS) process to determine if the SPP transmission system and neighboring Transmission Providers can accommodate requests for long-term firm Transmission Service. SPP combines all long-term point-to-point and long-term network integration transmission service requests received during a specified period of time into a single ATSS in order to develop a more efficient expansion of the transmission system that provides the necessary Available Transfer Capability (ATC) to accommodate all such requests at the minimum total cost.

In October of 2013, SPP implemented a new process for evaluating transmission service requests, designed to expedite the evaluation of transmission service requests already in the queue, known as the "Backlog Clearing Process." The Backlog Clearing Process was intended to clear the queue of pending transmission service requests in anticipation of a new, more efficient and streamlined ATSS process that was developed to replace the existing process. The Backlog Clearing Process ended with the conclusion of Study 2015-AG1 on January 5, 2016. The new, streamlined ATSS process in Attachment Z1 of the Tariff became effective with the closing of the open season on November 30, 2015 for Study 2015-AG2. The final iteration of 2015-AG2 was posted on April 25, 2016, completing transition of the aggregate study to a new process where the study is completed within 165 days.

During 2016, SPP completed three Aggregate Facilities Studies, as compared to two in 2015, two of which were completed to meet a new 165-day study completion deadline in Attachment Z1 of the SPP Tariff. The Tariff requires Transmission Providers to file notice with the Federal Energy Regulatory Commission (FERC) if more than 20% of the Facilities Studies in any two consecutive calendar quarters are not completed in the 60-day study window. In 2016, SPP was not required to file with FERC, as there were no two consecutive quarters in which more than 20% of the studies were late. This was due in large part to the timely submission of documentation by SPP Transmission Owners.

The tables below summarize the Aggregate Studies that were closed and resulted in Service Agreements during 2016. The tables show the number of requests and requested capacity (MW) for the initial study (AFS1) and the final number of requests and requested capacity (MW) for the last study iteration.

	2015-AG1-AFS-1	2015-AG1-AFS-6
# of requests-beginning of study	56	
# of MW-beginning of study	5,351	
# of requests-end of study		28
#of MW-end of study		2,425

Table 2.1: Initial and Final Request and Capacity Amounts for 2015-AG1

	2015-AG2-AFS-1	2015-AG1-AFS-3
# of requests-beginning of study	20	
# of MW-beginning of study	2,334	
# of requests-end of study		21
#of MW-end of study		1,405

Table 2.2: Initial and Final Request and Capacity Amounts for 2015-AG2

	2016-AG1-AFS-1	2016-AG1-AFS-3
# of requests-beginning of study	22	
# of MW-beginning of study	983	
# of requests-end of study		20
#of MW-end of study		673

Table 2.3: Initial and Final Request and Capacity Amounts for 2016-AG1

The table below summarizes long-term firm transmission service requests received in 2016 currently under review in the Aggregate Study process.

Study	Currently Active Iteration	Due Date	Requests Currently in Study	MW Currently in Study
2016-AG2	AFS-1	5/15/2017	32	963

Table 2.4: Active 2016 Aggregate Studies

The graph below shows the total estimated cost of Transmission Service projects included in the 2017 STEP as compared to previous STEP Reports. Fluctuations in the annual STEP estimates may be influenced by the number of new projects identified in completed Transmission Service Studies either having been issued NTCs or approved and awaiting the issuance of an NTC, the completion of Transmission Service related projects, and the increase and decrease of Transmission Owner submitted project cost estimates within the applicable STEP timeframe.

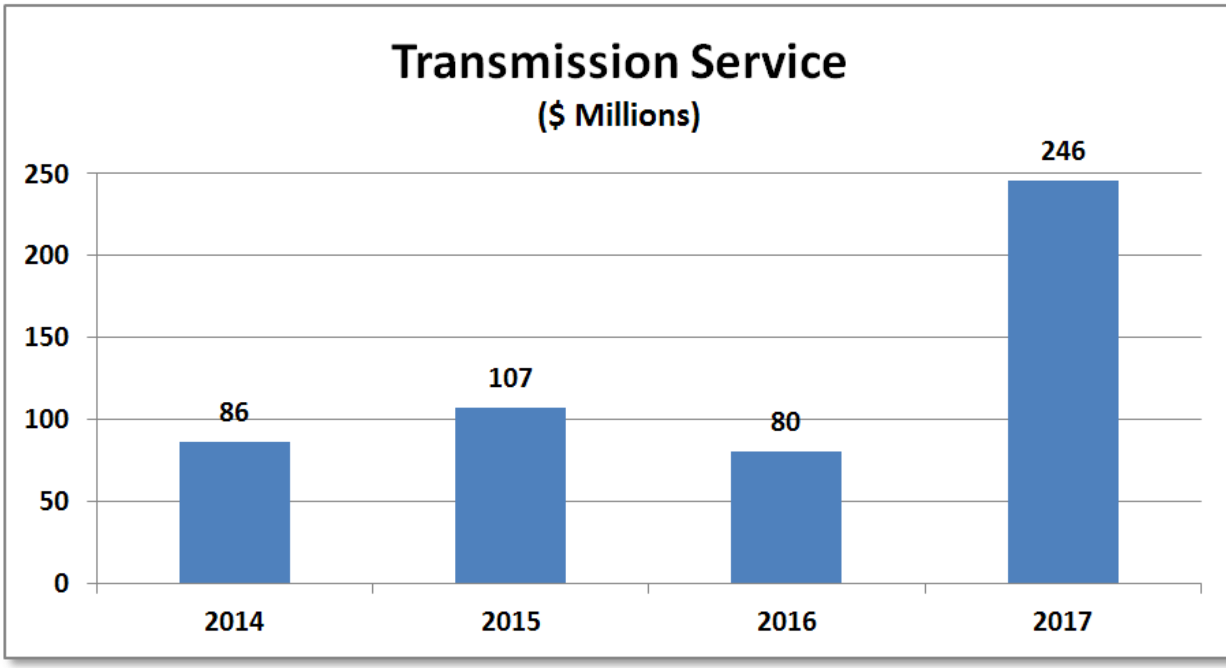


Figure 2.1: STEP Cost Estimate Comparison for Transmission Service Projects – 2014-2017

A list of Transmission Service projects completed in 2016 can be found in Section 12.

2.2: Tariff Attachments AQ and AR

Attachment AQ

SPP Tariff Attachment AQ defines a process through which delivery point additions, modifications, or abandonments can be studied without having to go through the Aggregate Study process. Delivery points submitted through the process are examined in an initial assessment to determine if a project is likely to have a significant effect on the transmission system. If necessary, a full study is then performed on the requested delivery points to determine any necessary upgrades. There were two NTCs issued in 2016 as a result of the Attachment AQ study process.

The number of requests and required studies are summarized in Table 2.5 below.

Study Year	Delivery Point Requests	Full Studies Required	Load Increase
2012	156	51	1,200 MW
2013	87	22	882 MW
2014	96	19	1,032 MW
2015	89	13	1,271 MW
2016	129	21	1,021 MW

Table 2.5: AQ Study Summary – 2012-2016

Attachment AR

Attachment AR defines a screening process used to evaluate potential Long-Term Service Request (LTSR) options or proposed Delivery Point Transfers (DPT). The LTSR option provides customers with a tool to assess possible availability of transmission service. The DPT screening study option enables customers to implement a DPT via issuance of a Service

Agreement, more expediently pending the results of the screening. Both of these screening tools allow for a more streamlined ATSS process by reducing the number of requests in the ATSS process.

During 2016, six DPT studies were posted and service was granted for all six studies. Twenty-One LTSR studies were requested and twelve studies were posted. The other nine LTSR studies will be posted in 2017.

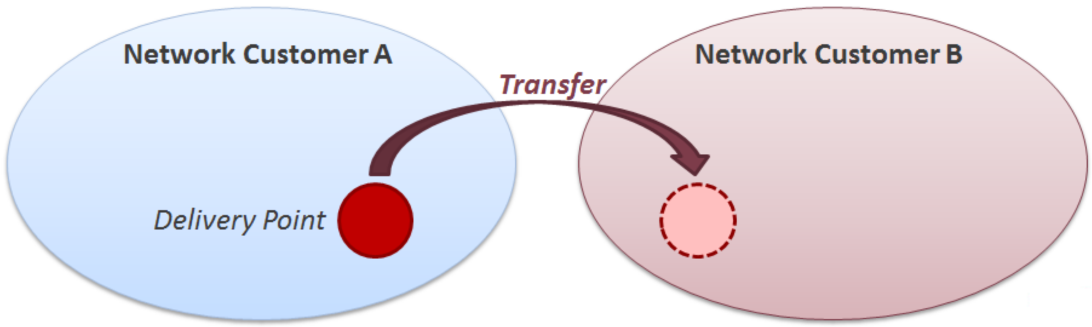


Figure 2.2 DPT Study Process

Section 3: Generator Interconnection

3.1: Generator Interconnection Overview

AGI study is conducted pursuant to Attachment V of the SPP Tariff whenever a request is made to connect new generation to the SPP transmission system. GI studies are conducted by SPP in collaboration with affected Transmission Owners and neighboring Transmission Providers to determine the required modifications to the transmission system, including cost and scheduled completion dates required to provide the service.

From January 1, 2016 to December 15, 2016 SPP received 184 GI requests and nine affected system GI requests, compared to the 103 GI requests and six affected system study requests received through the same period in 2015. As of December 15, 2016, there were 174 active GI queue requests under study for 29,814 MW, and 41 requests had been removed from "study" status either from being withdrawn by the Customer or SPP or by the Customer executing a Generator Interconnection Agreement (GIA). The affected system study requests were made by neighboring Transmission Providers requesting SPP's evaluation of the impact of the requests on SPP's transmission system.

The graph below shows the total estimated cost of GI projects included in the 2017 STEP as compared to previous STEP Reports. Fluctuations in the annual STEP estimates may be influenced by the number of new projects identified in completed Generator Interconnection Studies that have either been issued NTCs or are approved and are awaiting the issuance of an NTC, the completion of Generator Interconnection related projects, and the increase and decrease of Transmission Owner submitted project cost estimates within the applicable STEP timeframe.

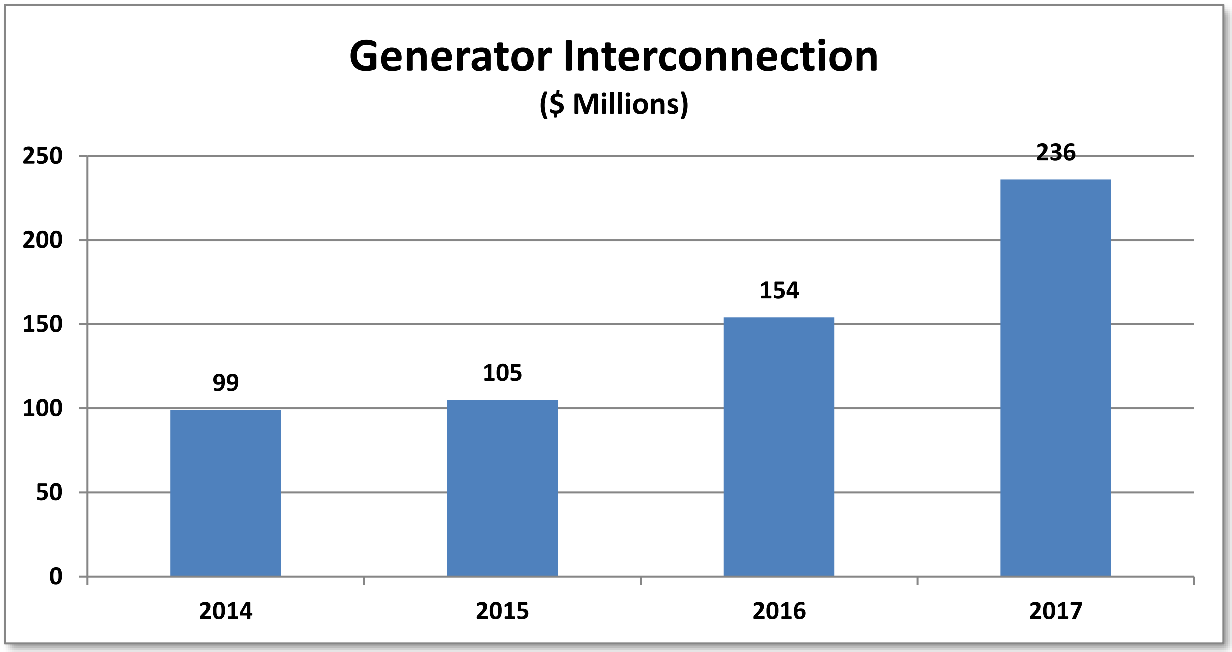


Figure 3.1: STEP Cost Estimate Comparison for Generator Interconnection Projects – 2014-2017

A list of GI projects completed in 2016 can be found in Section 12.

Section 4: Integrated Transmission Planning

4.1: Integrated Transmission Planning Overview

The ITP process is an iterative three-year process that includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies the transmission projects, generally above 300 kV, and provides 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 the system needs over a ten-year horizon. The Near Term Assessment is performed annually and assesses the system upgrades, at all applicable voltage levels, required in the near term planning horizon. The ITP process has helped to determine the transmission needs for the SPP region and has facilitated investment in over $5.5 Billion of cost effective transmission.

Along with the Highway/Byway cost allocation methodology, the ITP process promotes transmission investment that will meet reliability, economic, and public policy needs intended to create a cost-effective, flexible, and robust transmission network which will improve access to the region's diverse generating resources and facilitate efficient market processes.

During 2016, a 10-Year Assessment (2017 ITP10) was performed which focused on facilities 100 kV and above to meet system needs over a 10-year horizon. Results of the 2017 ITP10 assessment are recorded below in Section 4.3. The 2016 Near Term Assessment (2016 ITPNT) was completed and approved by the SPP Board Of Directors (BOD) in April of 2016. This annual study assesses system upgrades, at all applicable voltage levels, required in the near-term planning horizon to address reliability needs. Results of the 2016 ITPNT are recorded below in Section 4.4. A list of ITP projects completed in 2016 can be found in Section 12.

4.2: ITP20

The 20-Year Integrated Transmission Planning Assessment (ITP20) is designed to identify a transmission expansion portfolio containing primarily Extra High Voltage (EHV) projects needed to address reliability needs, support policy initiatives, and enable economic opportunities in the SPP transmission system within the studied twenty-year horizon. The portfolio will be used as a roadmap for the development of appropriate EHV projects in the coming years that would provide increased flexibility and value to SPP's members as those needs become better known through the performance of other planning assessments. The ITP20 is not intended to address lower voltage solutions that will be needed to integrate new EHV projects.

During 2016 the ITP process was engaged in the 2017 ITP10, the completion of the 2016 ITPNT, and the majority of the 2017 ITPNT. There was no 20-year assessment performed this year.

4.3: 2017 ITP10

The second phase of the ITP study process includes the ITP 10-Year Assessment performed under the requirements of Attachment O, Section III of the SPP Tariff. The approved portfolio includes projects ranging from comprehensive regional solutions to local reliability upgrades to address the expected reliability, economic, and policy needs of the studied 10-year planning horizon.

The development of the scenarios to be analyzed within each ITP assessment begins with policy-level direction from the Strategic Planning Committee (SPC). The Economic Studies Working Group (ESWG) incorporates that direction into discussion of detailed drivers that form the basis of potential Futures of the assessment.

The ESWG and stakeholders identified a list of drivers and determined each driver's probability of occurrence based on each participant's own expectation. The initial drivers considered for analysis are as follows:

- Environmental Protection Agency's (EPA) 111(d) (Clean Power Plan)
- Competitive wind
- High natural gas supply
- Low natural gas supply
- Severe weather (drought, extreme winter)
- Green future
- Technology advancement
- Changing renewable portfolio standards
- Cost of capital changes
- Solar development
- Reduced generation capacity availability
- Physical security concerns
- Extensive Western Electricity Coordinating Council (WECC) connectivity
- Load growth
- Smart grid technology
- Low risk operational guides
- Large increase in electric vehicles
- Financial expansion cap
- Significant deregulation
- Environmental regulations due to climate
- Economic collapse
- ERCOT becomes synchronous with the Eastern Interconnect

This initial list of drivers was reduced based on the probability ranking and combined similar drivers either by simple description or assumed modeling implementation. The reduced list was incorporated into a matrix of initial Future definitions considering the direction of the SPC to analyze different approaches to Clean Power Plan (CPP) compliance and the general implications of the remaining drivers. This initial list included four defined Futures: 1) a regional approach to CPP compliance; 2) a state approach to CPP compliance; 3) a reference case; and4) a worst-case scenario. These Futures were then further refined by determining whether each driver would be more appropriately considered in a longer-range assessment or sensitivity analysis.

Three distinct Futures were considered to account for possible variations in system conditions over the assessment's 10-year horizon. These Futures considered evolving changes in technology, public policy, and climate change that may influence the transmission system and energy industry as a whole. The Futures are as follows:

1. Regional Clean Power Plan Solution: Regional implementation of the proposed EPA Clean Power Plan.
2. State Level Clean Power Plan Solution: State by State implementation of the proposed EPA Clean Power Plan.
3. Reference Case: No implementation of the proposed EPA Clean Power Plan.

The recommended 2017 ITP10 portfolio is estimated at $201 million in engineering and construction costs and includes projects needed to meet potential reliability and economic requirements. The recommended portfolio consists of 14 projects. These projects will provide 93 miles of new transmission infrastructure.

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
6	Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line	KCPL	E	$512,500	-
7	Build a new second 230 kV line from Knoll to Post Rock.	MIDW	E	$3,389,019	1
8	Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138 kV line between the two substations to a summer emergency rating of 110 MVA.	WR	E	$244,606	-
9	Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161 kV line between the two substations to a summer emergency rating of 243 MVA.	WR/EDE	E	$114,154	-
12	Rebuild 2.1-mile 161 kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE)	AEP/GRDA	E	$5,185,885	2.1

Map Label	Project Description	Area(s)	Type	Study Cost Estimate	Mileage
13	Install 138 kV phase shifting transformer at Woodward EHV along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	OGE	E	$7,459,438	-
16	Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 138 kV line between the two substations to a summer and winter emergency rating of 169/201 MVA. Upgrade terminal equipment at Lula and/or Tupelo Tap to increase the rating of the line between the substations to 171/192 (SN/SE).	OGE/WFEC	E	$102,500	-
17	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations to a summer emergency rating of 175 MVA.	SPS	E	$969,942	-
18	Tap the intersection of the 230 kV line from Tolk to Yoakum and the 115 kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115 kV transformer at new substation.	SPS	E	$11,961,951	-
19	Tap the existing 230 kV line from Hobbs to Yoakum and the existing 115 kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115 kV transformer at new Hobbs - Yoakum Tap substation.	SPS	E/R	$9,953,077	-
20	Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	SPS	E	$7,423,880	-
25	Install a 345/161 kV transformer at Morgan substation and upgrade the Morgan - Brookline 161 kV line to summer emergency rating of 208 MVA and winter emergency rating of 232 MVA.	AECI	E	$9,481,250	-
26	Upgrade any necessary terminal equipment at Martin, Pantex North, Pantex South, and Highland tap to increase the rating of the 115 kV lines to 175/175 MVA (SN/SE).	SPS	R	$682,034	-
27	Build new 345 kV line from Potter to Tolk	SPS	E	$143,984,174	90

Table 4.1: 2017 ITP10 Project Portfolio

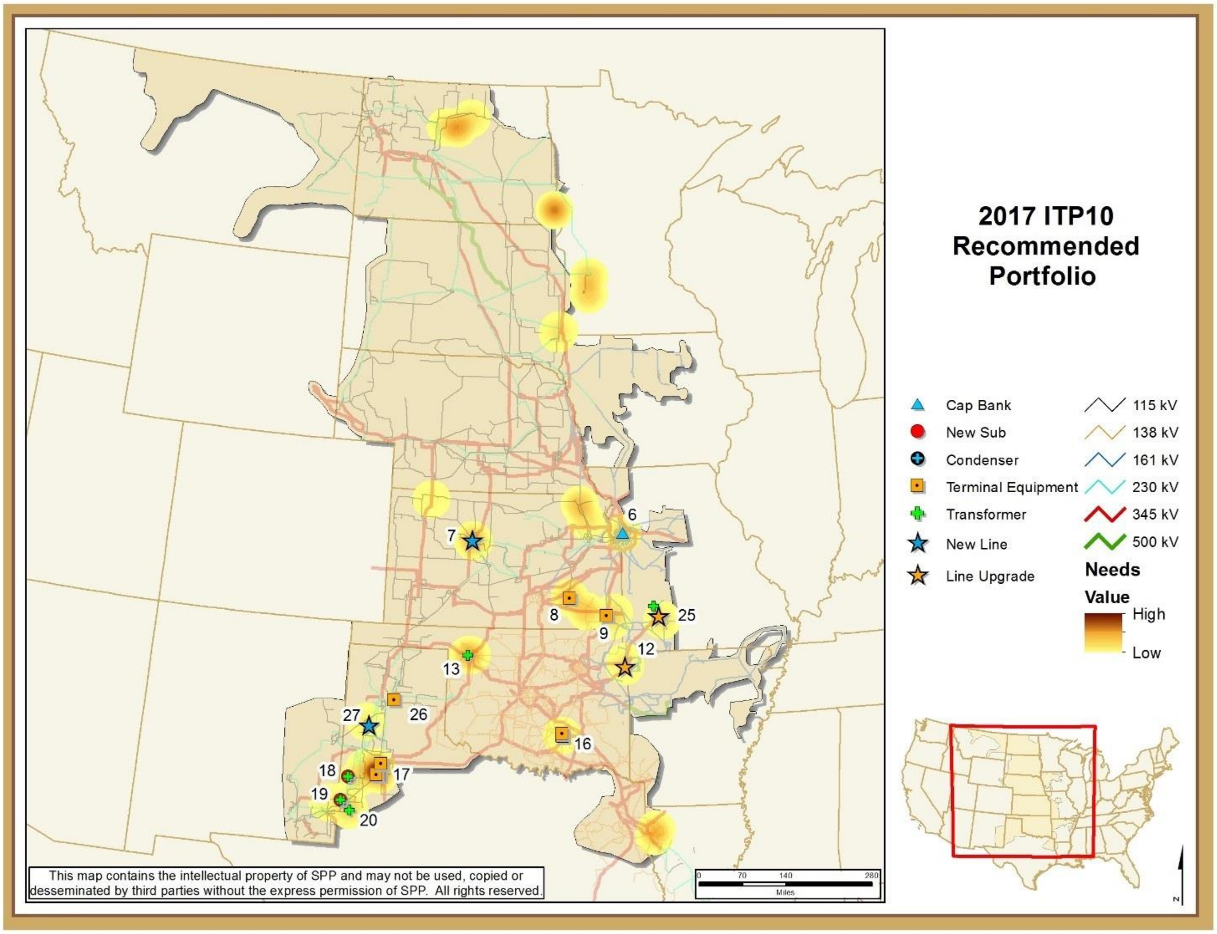


Figure 4.1: 2017 ITP10 Recommended Portfolio

4.4: 2016 ITP Near-Term (ITPNT)

The 2016 ITPNT analyzed the SPP region's immediate transmission needs over the near-term planning horizon. The ITPNT assessed: a) regional upgrades required to maintain reliability in accordance with the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards and SPP Criteria in the near-term horizon; b) zonal upgrades required to maintain reliability in accordance with more stringent individual Transmission Owner planning criteria in the near-term horizon; and c) coordinated projects with neighboring Transmission Providers. ITPNT projects are reviewed by SPP's Transmission Working Group (TWG) and Markets and Operations Policy Committee (MOPC) and approved by the SPP Board of Directors. Following Board of Directors' approval, SPP will issue NTC letters for upgrades that require a financial commitment within the next four-year timeframe.

SPP developed models for the 2016 ITPNT analysis based on the SPP Model Development Working Group (MDWG) models, for which Transmission Owners and

Balancing Authorities provided generation dispatch and load information. The study scope,[1] approved by the TWG on March 25, 2015, contains:

- The years and seasons to be modeled;
- Treatment of upgrades in the models;
- Scenario cases to be evaluated;
- Description of the contingency analysis and monitored facilities; and
- Any new special conditions that are modeled or evaluated for the study including the development of the model for SPP's Consolidated Balancing Authority (CBA) dispatch.

SPP performed analyses identifying potential bulk power system reliability needs. These findings were presented to Transmission Owners and the TWG to solicit transmission solutions to the potential issues identified. Also considered were transmission solutions from other SPP studies, such as the Aggregate Transmission Service Study and Generator Interconnection processes. From the resulting list of potential solutions, SPP identified the cost effective regional solutions for potential reliability needs. SPP presented these solutions for member and stakeholder review at SPP's March 2016 planning summit. Through this process, SPP developed a draft list of 69 kV and above solutions necessary to provide reliable service in the SPP region in the near-term planning horizon.

The maps in Figures 4.2 and 4.3 show the draft ITPNT thermal and voltage solutions in correlation to the areas identified with reliability criteria violations.

[1] 2016 ITPNT Scope

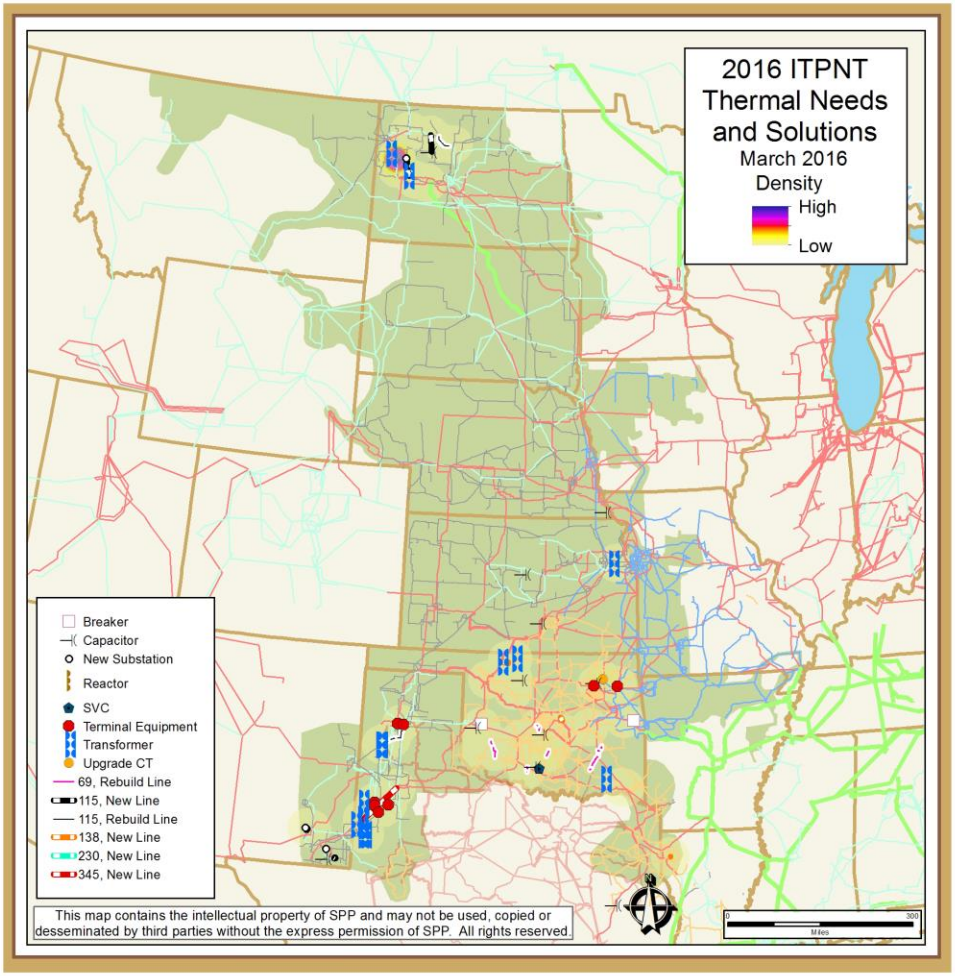


Figure 4.2: 2016 ITPNT Thermal Needs and Solutions

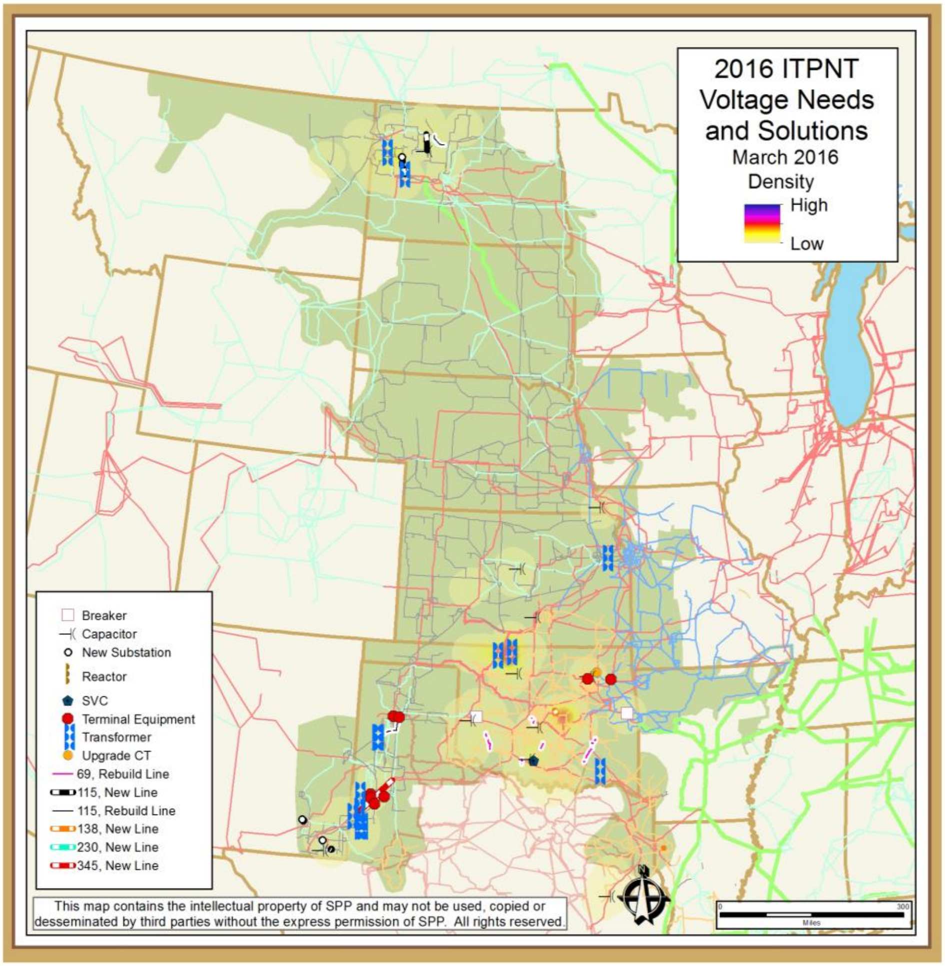


Figure 4.3: 2016 ITPNT Voltage Needs and Solutions

The net total study cost of the 2016 ITPNT project plan is estimated to be $229.2M for upgrades that received an NTC, NTC with Conditions (NTC-C) or Modified NTC. That total includes $362.6M for new projects, $6.8M in NTC Modify projects, and a reduction of $140.2M for withdrawn NTCs identified in the 2016 ITPNT Assessment. The 67 upgrades that received an NTC, NTC-C or NTC Modify solved 1,573 thermal and 2,982 voltage needs on the SPP transmission system. Project plan mileage consists of 225 miles of new transmission line and 173 miles of rebuild/reconductor line.

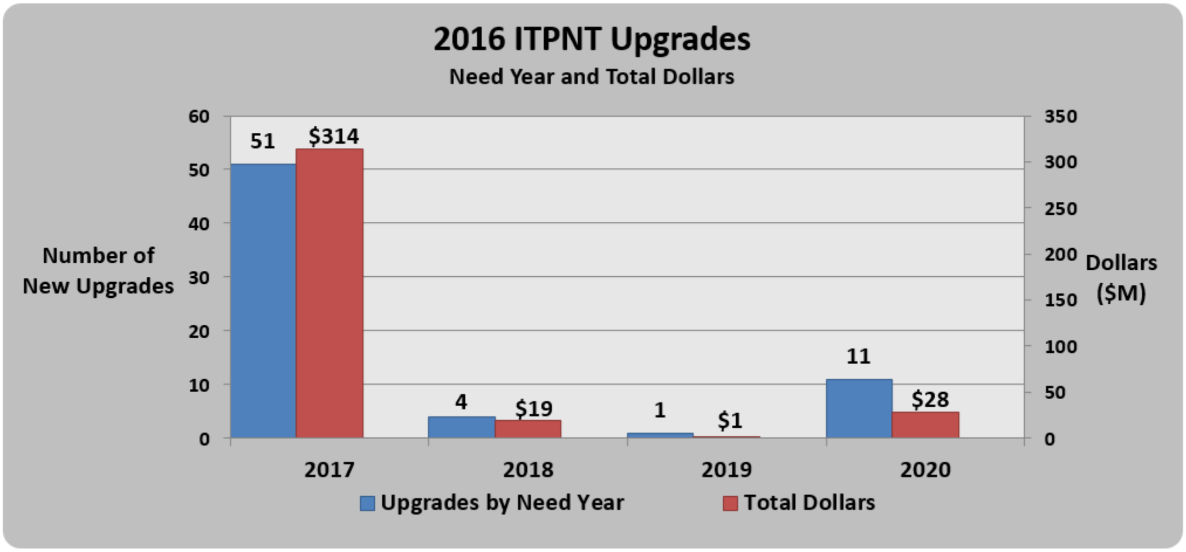


Figure 4.4: 2016 ITPNT Upgrades by Need Years and Dollars

Voltage Class	Total Line (miles)	Rebuild/Reconductor (miles)
345 kV	107	0
230 kV	0	0
161 kV	0	0
138 kV	24	0
115 kV	92	55
69 kV	2	118

Table 4.2: 2016 ITPNT Project Plan Mileages

The 2017 ITPNT assessment is currently in progress and SPP intends to finalize the Report and Portfolio in April 2017.

4.5: Transmission Planning Improvement Task Force

The experience of stakeholders and SPP has shed light on the strengths of the ITP process as well as potential improvements that could be made. The Transmission Planning Improvement Task Force (TPITF) was assembled by the SPP SPC and the MOPC and given the responsibility for developing recommendations that will improve the regional planning processes. The objective was to make the SPP transmission planning process more responsive to the effects of the continued growth of SPP's transmission system, changes in the SPP markets, challenges and opportunities presented by changing federal and state energy and environmental regulations, and an increase in NERC compliance requirements. The TPITF recommendations are intended to represent a consolidated and coordinated approach in planning, managing, and maintaining the SPP transmission system. The recommendations also intend to help improve the existing processes, with a particular emphasis on any progress that may be made to increase the availability of transmission service to SPP's customers without unduly compromising system reliability. The recommendations listed below are intended to enable the cost-effective use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint and to further develop and enhance policies, tools, and practices to optimize the use of the transmission system. The TPITF was tasked with reviewing, evaluating, and proposing recommendations on the following:

- The methodologies and modeling practices used in the GI Studies, Aggregate Transmission Service Studies, Integrated Transmission Planning (Near Term, 10, and 20), SPP TPL Compliance Assessments, and the MDWG model development process to ensure effectiveness, consistency, and to determine if any gaps exist between the various processes. Where appropriate, the TPITF will collaborate with the SPP committees and working groups involved in the development and approval process for SPP planning.
- The utilization of data, including data collected by operations that will benchmark the real-time and planning horizon assessments to ensure consistency in the planning process.
- The appropriateness of the planning cycle and assessments, including but not limited to, the effectiveness of using production cost modeling in more assessments; development, use, and weighting of Futures, scenarios and sensitivities; the metrics used to evaluate proposed projects, in particular those that evaluate the impact on rate payers; and planning the transmission system beyond the traditional planning criteria of first contingency ("N-1") in accordance with the approved NERC Standard TPL-001-4 .

The TPITF developed a set of five recommendations to accomplish this scope of work. The five recommendations are as follows:

1. Replace the current ITP schedules to produce an annual transmission expansion plan.
2. Create a standardized scope.
3. Establish a common planning model for use across the various SPP planning processes.
4. Utilize a holistic approach to planning.
5. Create a Staff/Stakeholder accountability program.

A copy of the MOPC approved SPP Planning Process Improvement Recommendations white paper can be found at the following location: *SPP Documents/Org Group*

Documents/Transmission Planning Improvement Task Force/TPITF Governing Documents[2].

The MOPC approved the whitepaper and directed the Regional Tariff Working Group (RTWG) to develop the Tariff language necessary to implement the recommendations. The recommended Tariff language is expected to be filed in May 2017. In addition, FERC approved SPP's request for Tariff waiver to not commence the ITP20 in January 2017 due to the expected Tariff changes. The TPITF recommended a transition to the new 2019 ITP planning process starting in September 2017 with the ITP model builds and assessment scope development leading to the initial ITP planning assessment that will be completed in October of 2019.

[2] TPITF: SPP Planning Process Improvement Recommendations White Paper

Section 5: High Priority Studies

Attachment O, Section IV.2, of SPP's Tariff describes the process for which High Priority Studies may be requested by stakeholders and performed by SPP as the Transmission Provider. Stakeholders may request High Priority Studies, including a request for the Transmission Provider to study potential upgrades or other investments necessary to integrate any combination of resources, whether demand resources, transmission, or generation, identified by the stakeholders. For each High Priority Study the Transmission Provider shall publish a report which will include, among other things, the Study input assumptions, the estimated cost of the upgrades, any third party impacts, the expected economic benefits of the upgrades, and identify reliability impacts, if any, of the upgrades. The Transmission Provider may recommend, based on the results of a High Priority Study, a High Priority Upgrade for inclusion in the SPP Transmission Expansion Plan in accordance with the approval process set forth in Section V of SPP's Tariff.

Figure 6.1 below is a comparison of the cost estimates for projects coming out of High Priority Studies. A list of High Priority Studies projects completed in 2016 can be found in Section 12. Study details follow in sections 5.1 and 5.2.

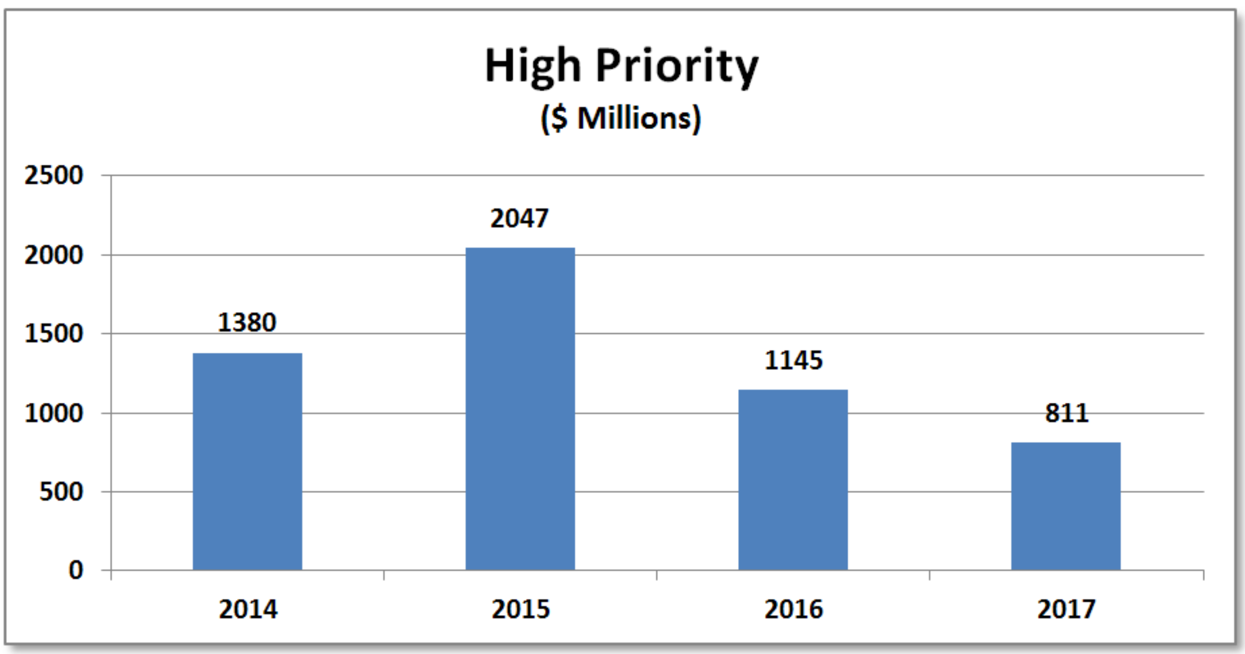


Figure 5.1: STEP Cost Estimate Comparison for High Priority Projects – 2014-2017

5.1: SPP Priority Projects

In 2010, the SPP Board of Directors and Members Committee approved for construction a group of "priority" high voltage electric transmission projects estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years. The projects will improve the regional electric grid by reducing congestion, better integrating SPP's east and west regions, improving SPP members' ability to deliver power to customers, and facilitating the addition of new renewable and non-renewable generation to the electric grid. For information on

Priority Projects, see the full report (SPP.org > Engineering > Transmission Planning>Local Area Planning and High Priority Studies).

The last Priority Projects still under construction are projected to be in-service by the end of 2016 and are listed in Table 5.1 below. The 2017 STEP List will be updated once the projects are placed in-service to reflect the completion of the projects.

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
20096	936	AEP	Northwest Texarkana – Valliant 345 kV Ckt 1	$185,751,250
20097	938	TSMO	Multi – Nebraska City – Mullin Creek – Sibley 345 kV (GMO)	$81,407,015
20098	939	OPPD	Line – Nebraska City – Mullin Creek 345 kV (OPPD)	$70,361,776

Table 5.1: Priority Projects

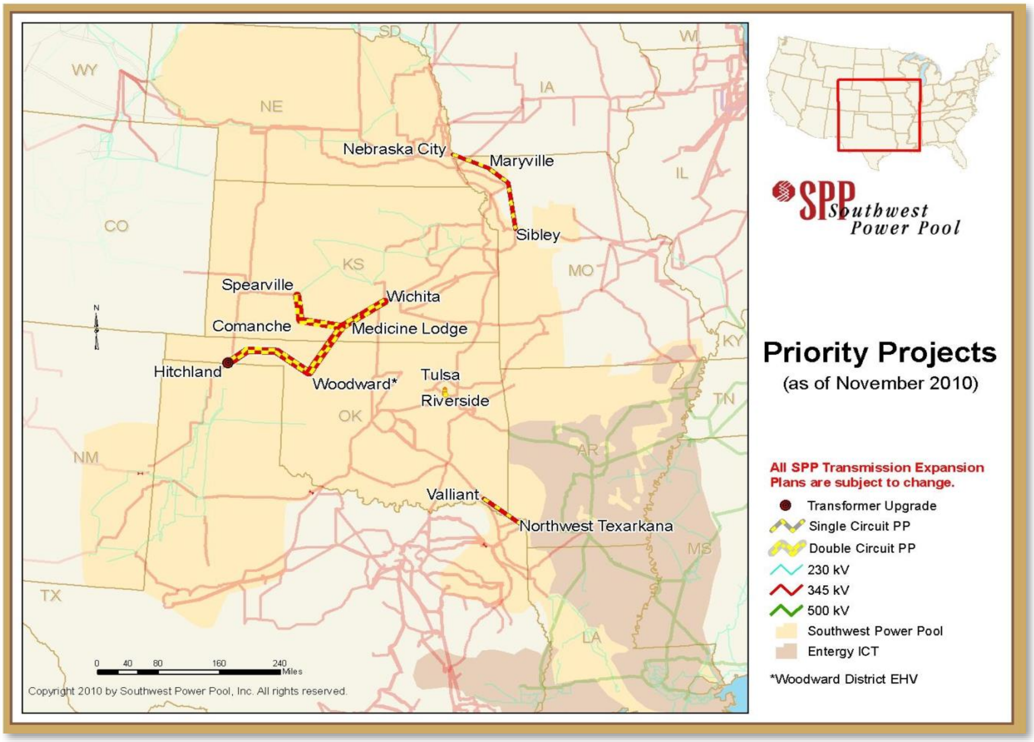


Figure 5.2: SPP Priority Projects

5.2: High Priority Incremental Load Study (HPILS)

The High Priority Incremental Load Study (HPILS) evaluated transmission needs resulting from significant incremental load growth expectations in certain parts of SPP. At its April 2013 meeting, the SPP BOD directed the performance of a High Priority Study to evaluate transmission needs resulting from expected incremental loads that had not previously been studied.

SPP presented the HPILS report to the BOD and Members Committee for consideration at their April 29, 2014 meeting. SPP recommended that the BOD direct construction of those projects that meet near-term needs and as shown in Attachment C of the HPILS report. Additional recommendations were also made to address concerns raised by stakeholders during the MOPC discussion. After considerable discussion with input from stakeholders in attendance, the BOD approved the recommendations, following a Members Committee vote that reflected eleven members supporting, two opposing, and one abstaining.

HPILS projects included in the 2017 STEP List are listed in Table 5.2 below.

For information on the HPILS assessment, see the full report (SPP.org > Engineering > Transmission Planning>Local Area Planning and High Priority Studies).

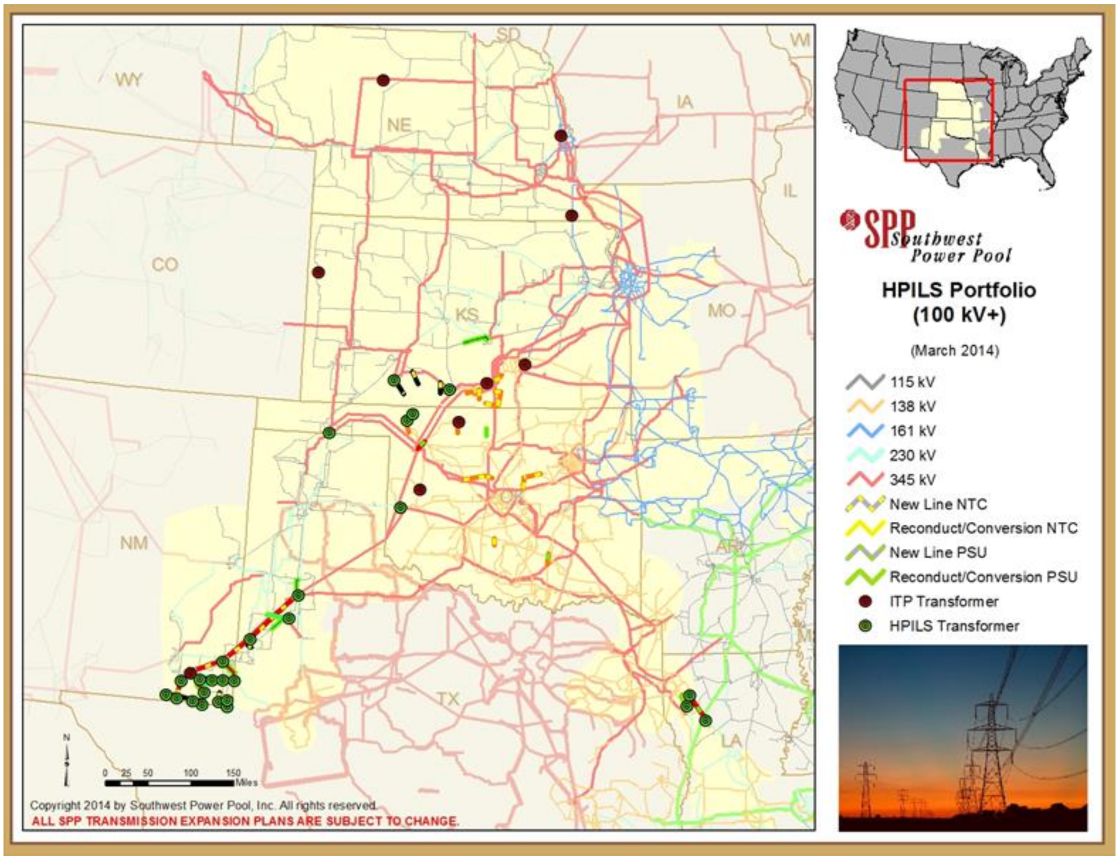


Figure 5.3: Finalized HPILS Portfolio (100 kV and above)

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
20096	936	AEP	Line - Valliant - NW Texarkana 345 kV	$185,751,250
20097	938	TSMO	Multi - Nebraska City - Mullin Creek - Sibley 345 kV (GMO)	$184,665,083
20097	938	TSMO	Multi - Nebraska City - Mullin Creek - Sibley 345 kV (GMO)	$81,407,015
20098	939	OPPD	Line - Nebraska City - Mullin Creek 345 kV (OPPD)	$70,361,776
200276	30645	MKEC	Line - Harper - Rago 138 kV Ckt 1	$11,475,555
200277	30678	NPPD	XFR - Thedford 345/115 kV	$9,306,000
200277	30678	NPPD	XFR - Thedford 345/115 kV	$930,800

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
200282	30675	SPS	Multi - China Draw - Yeso Hills 115 kV	$14,583,586
200282	30672	SPS	Multi - Dollarhide - Toboso Flats 115 kV	$822,700
200282	30672	SPS	Multi - Dollarhide - Toboso Flats 115 kV	$5,062,341
200282	30694	SPS	Multi - Ponderosa - Ponderosa Tap 115 kV	$996,485
200282	30694	SPS	Multi - Ponderosa - Ponderosa Tap 115 kV	$4,174,446
200282	30675	SPS	Multi - China Draw - Yeso Hills 115 kV	$1,046,485
200309	30376	SPS	Multi - Hobbs - Yoakum 345/230 kV Ckt 1	$16,204,449
200309	30376	SPS	Multi - Hobbs - Yoakum 345/230 kV Ckt 1	$90,628,750
200309	30638	SPS	Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	$19,255,234
200309	30638	SPS	Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	$25,716,516
200309	30638	SPS	Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	$4,649,045
200309	30638	SPS	Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	$4,172,734
200309	30637	SPS	Multi - Hobbs - Kiowa 345 kV Ckt 1	$11,249,526
200309	30638	SPS	Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	$5,950,217
200309	30638	SPS	Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	$7,873,653
200309	30639	SPS	Multi - Potash Junction - Road Runner 345 kV Conv. and Transformers at Kiowa and Road Runner	$5,443,140
200309	30639	SPS	Multi - Potash Junction - Road Runner 345 kV Conv. and Transformers at Kiowa and Road Runner	$2,176,451
200309	30637	SPS	Multi - Hobbs - Kiowa 345 kV Ckt 1	$59,808,956
200309	30695	SPS	Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$3,901,503
200309	30695	SPS	Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$1,200,057
200309	30695	SPS	Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$6,186,323
200309	30695	SPS	Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$5,304,552
200309	30695	SPS	Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$8,501,560
200310	30619	AEP	Line - Darlington - Roman Nose 138 kV Ckt 1	$11,652,107
200311	30619	OGE	Line - Darlington - Roman Nose 138 kV Ckt 1	$12,701,091
200311	30622	OGE	Multi - Knipe - SW Station - Linwood & Warwick Tap 138 kV Ckt 1	$12,767,120
200311	30622	OGE	Multi - Knipe - SW Station - Linwood & Warwick Tap 138 kV Ckt 1	$9,899,440
200311	30622	OGE	Multi - Knipe - SW Station - Linwood & Warwick Tap 138 kV Ckt 1	$8,218,020

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
200335	30644	MKEC	Line - Anthony - Harper 138 kV Ckt 1	$13,354,771
200362	30732	MKEC	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	$17,226,557
200362	30732	MKEC	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	$9,378,604
200362	30732	MKEC	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	$7,527,006
200362	30732	MKEC	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	$6,608,453
200362	30732	MKEC	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	$4,414,629
200363	30732	WR	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	$3,915,388
200411	30694	SPS	Multi - Ponderosa - Ponderosa Tap 115 kV	$5,404,344
200411	30695	SPS	Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$8,811,206
200411	30825	SPS	Line - China Draw - Wood Draw 115 kV Ckt 1	$15,200,000

Table 5.2: HPILS Projects

Section 6: Sponsored Upgrades

Sponsored Upgrades are Network Upgrades requested by a Transmission Customer or other entity that have not been previously identified and are included in the current SPP Transmission Expansion Plan as either 1) an upgrade required to satisfy requests for Transmission Service; 2) an upgrade required to satisfy requests for Generator Interconnection; 3) an approved ITP Upgrade; 4) an Upgrade within approved Balanced Portfolios; or 5) an approved High Priority Upgrade. Any entity may request the construction of a Sponsored Upgrade. However, the requesting entity must be willing to assume the cost of such Sponsored Upgrade, study costs, and any cost associated with any mitigation identified with SPP's evaluation of the impact of any Sponsored Upgrade on transmission system reliability. The proposed Sponsored Upgrade will be submitted to the proper stakeholder working group for its review as a part of the transmission planning process.

No Sponsored Upgrades were completed, and no new Sponsored Upgrades were approved in 2016.

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
NA	---	---	---	---

Table 6.1: 2016 Completed Sponsored Upgrades

Section 7: Regional Cost Allocation Review (RCAR)

The Regional Cost Allocation Review (RCAR) is an analysis pursuant to Attachment J, Section III.D of the SPP Tariff, to measure the cost allocation impacts of SPP's Highway/Byway methodology to each of SPP's transmission pricing zones. The costs and benefits of transmission projects with NTCs and funded through Highway/Byway are assessed for each zone. Any zone with benefits that are not roughly commensurate with their costs (defined as a benefit-to-cost (B/C) ratio less than 0.8) will be analyzed for potential remedies. Potential remedies, in order of most to least preferable, may include but are not limited to:

- Acceleration of planned upgrades;
- Issuance of NTCs for selected new upgrades;
- Apply Highway funding to one or more Byway projects;
- Apply Highway funding to one or more Seams projects;
- Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or a lack of benefits to a zone;
- Exemptions from cost associated with the next set of projects; or
- Change cost allocation percentages.

The RCAR I was completed in October 2013. The RCAR II analysis was originally scheduled for completion in July of 2015, however, on March 13, 2015, the Regional Allocation Review Task Force (RARTF) directed SPP to delay the RCAR II analysis in order to use the 2017 ITP10 model assumptions rather than the 2015 ITP10 model set. The updated models used in the RCAR II analysis were developed in 2015 and 2016 and the RCAR II analysis was completed in July 2016 after the vetting of results with the RARTF, MOPC, and Regional State Committee (RSC).

The RCAR II results indicated the Highway/Byway projects approved for construction since June 2010 provide a B/C ratio of 2.46 for the SPP region, based on the approved benefit metrics for transmission projects. This shows a strong increase from the RCAR I analysis, which showed a B/C ratio of 1.39 for projects issued an NTC since June 2010. In the RCAR II assessment:

- One zone (City Utilities of Springfield) was below the 0.8 threshold established by the RARTF
- Two additional zones were greater than the 0.8 threshold but below 1.0
- 14 zones were above a 1.0 B/C ratio

In order to provide a potential remedy to City Utilities of Springfield (CUS), SPP is assisting CUS in their efforts to participate in the current SPP planning processes, including the 2017 ITP10, the Seams Planning Study with Associated Electric Cooperative Inc. (AECI), and a Seams Planning Study with Midcontinent Independent System Operator (MISO). Should these planning processes not provide benefits to the CUS zone, SPP will work with the RARTF and the stakeholder process to request the SPP BOD to initiate a High Priority Study to evaluate the system needs and solutions for the Springfield zone.

For information on the July 2016 RCAR II Report, see the full report on SPP.org

Section 8: Interregional Coordination

8.1: Interregional Planning

Throughout 2016, SPP participated in joint planning and coordination processes with three different neighboring entities. SPP's respective Joint Operating Agreements (JOA) with Associated Electric Cooperative Inc. (AECI) and Midcontinent Independent System Operator (MISO) outline the requirements for joint and coordinated planning procedures, each of which result in the production of a Coordinated System Plan (CSP). Addendum 4 to Attachment O of the Tariff outlines the requirements of the joint coordination procedures with the Southeastern Regional Planning Transmission group (SERTP).

2016 SPP-AECI JCSP

The SPP-AECI Joint Operating Agreement (JOA) requires a Joint Coordinated System Plan (JCSP) study be performed every other year to assure the reliable, efficient and effective operation of the transmission system along the SPP-AECI seam. SPP and AECI, along with SPP stakeholders, collaborated throughout 2016 on the performance of a JCSP to identify potential joint transmission projects that are mutually beneficial to both entities.

The primary objectives of the study were to leverage SPP and AECI's respective planning and operational experiences to focus on specific target areas, and to collaborate on the development of mutually beneficial transmission projects for potential approval and construction.

SPP and AECI collaborated with stakeholders and determined five unique geographic areas in which to focus the study efforts. The areas were determined based upon historical analysis, operational experience, recent regional planning efforts, and stakeholder feedback. Shown below in figure 8.1, the five geographic target areas consisted of:

- Northeast Oklahoma Reliability Needs
- Brookline Overloads and High Voltage Issues
- Norton to Georgetown Low Voltage Issues
- Wheaton Area Potential Upgrades
- Mid-Missouri Robust Solutions

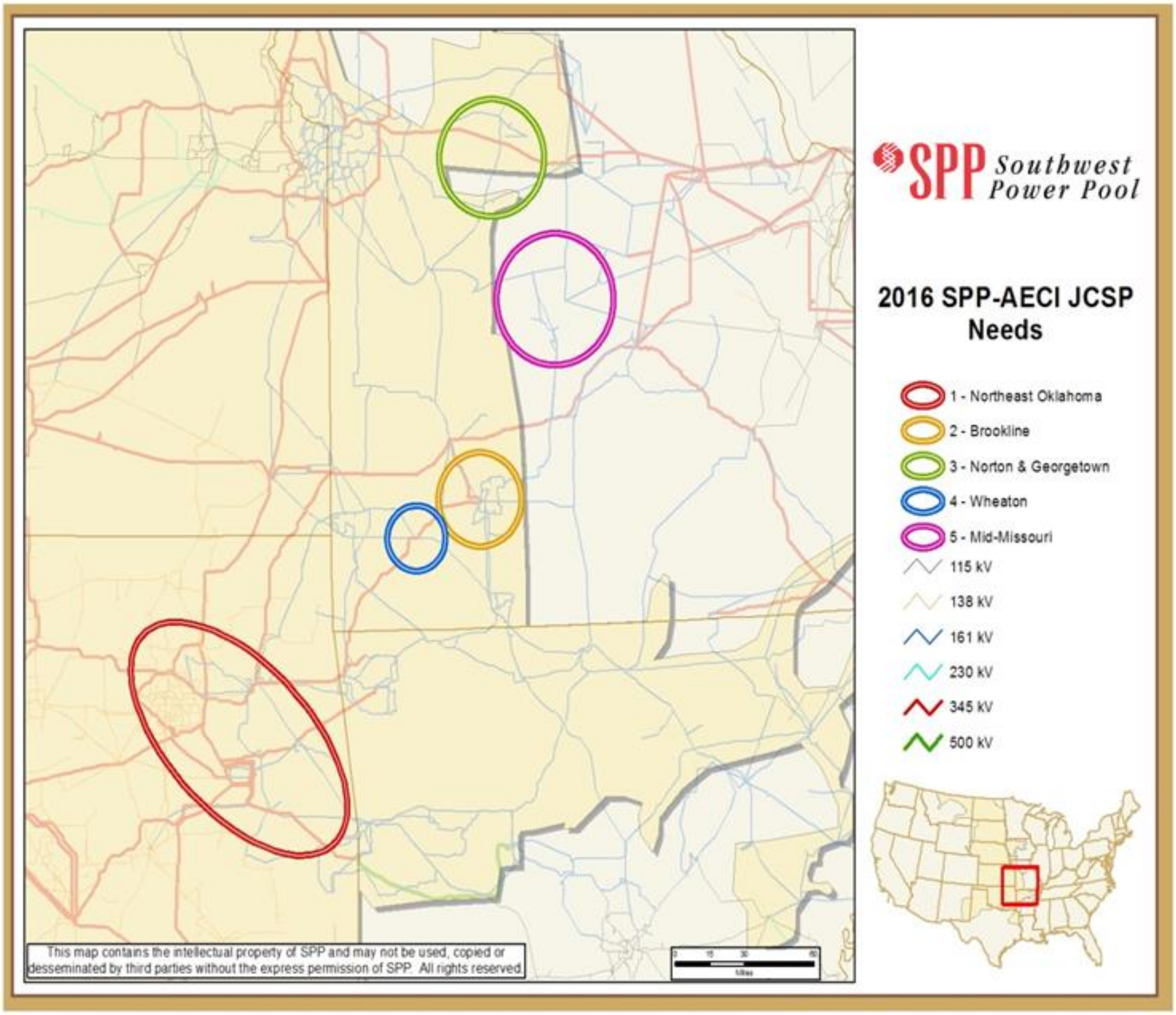


Figure 8.1: 2016 SPP-AECI JCSP Needs

The 2016 SPP-AECI JCSP did not identify any potential joint transmission expansion projects for the Northeast Oklahoma, Norton to Georgetown, Wheaton, or Mid-Missouri target areas. These areas will continue to be evaluated by SPP and AECI in our respective regional and future interregional processes. Potential mutually beneficial projects were identified to resolve the Brookline target area overloads and high voltage issues.

Morgan Transformer Project

This proposed seams project addresses the overloading issues evaluated around the Brookline area in Southern Missouri. The project includes the addition of a new 345/161 kV transformer at AECI's existing Morgan substation in addition to an uprate of the 161 kV line between Morgan and Brookline. The analysis performed in the 2016 SPP-AECI JCSP showed significant benefit across multiple models used for the study. SPP and AECI utilized real-time Emergency Management System (EMS) modeling data to mimic the known and chronic operational issues in a planning model. These models allowed SPP to test potential transmission solutions to address the overloading issues at Brookline. An adjusted 2017 ITPNT model was also used to recreate the problem using a No Hydro Scenario. By turning off all of Southwestern Power Administration's (SPA) hydro generation and CUS JTEC units, SPP was able to recreate the overloading issues in a severe planning case. Table 8.1 illustrates the results of the Brookline overloading issues.

2016 SPP-AECI JCSP	Brookline Transformer %Overloaded (EMS Model)	Brookline Transformer %Overloaded (No Hydro Model)
Base case	102.8%	129.4%
Morgan Transformer	84.2%	99.5%

Table 8.1: Brookline Overloading Issues

In addition to the benefit shown in the joint study with AECI, this project also was recommended as an economic solution to address congestion in the 2017 SPP ITP10 study. SPP and AECI will continue to work on finalizing the details around the recommendation of this SPP-AECI joint project, including the portion of the project's estimated $8.4M engineering and construction costs that would be allocated to SPP and AECI.

Brookline Reactor Project

This proposed seams project addresses the high voltage issues evaluated around the Brookline area in Southern Missouri. The project includes the addition of a 50 MVAR reactor at SPP's existing Brookline 345 kV substation. The analysis performed in the 2016 SPP-AECI JCSP showed significant benefit for the project by reducing the voltage levels to be under SPP's criteria of 1.05 per unit (pu). The analysis also demonstrated that voltage levels would be lower on two AECI buses located at Huben and Morgan. SPP and AECI utilized real-time EMS modeling data to mimic the known and chronic operational high voltage issues in a planning model. These models allowed SPP to test potential transmission solutions to address the issue. Table 8.2 illustrates the results of the Brookline high voltage issues.

2016 SPP-AECI JCSP	Brookline High Voltages (pu)	Huben High Voltages (pu)	Morgan High Voltages (pu)
Base case	1.051	1.057	1.053
Brookline Reactor	1.039	1.054	1.046

Table 8.2: Brookline High Voltage Issues

In addition to the joint study with AECI, SPP will also perform a regional review of this project in 2017. SPP and AECI will continue to work on finalizing the details around the recommendation of this SPP-AECI joint project, including the portion of the project's estimated $1.1 million engineering and construction costs that would be allocated to SPP and AECI.

2016 SPP-MISO CSP

SPP continued interregional planning activities with MISO in 2016. SPP and MISO commenced the 2016 CSP study which is being conducted pursuant to the joint planning procedures contained in Article 9 of the SPP-MISO JOA. The CSP was formally initiated on May 31, 2016 when the Joint Planning Commission (JPC) voted in favor of performing a 2016 CSP Study. The JPC's decision was based upon the recommendation of the SPP and MISO portions of the Interregional Planning Stakeholder Advisory Committee (IPSAC) which both voted to commence a joint study in 2016. While the SPP-MISO JOA allows for up to 18 months to complete the study, SPP and MISO have proposed to complete the 2016 CSP study in the 1st quarter of 2017.

The purpose of the 2016 CSP study is to jointly evaluate seams transmission issues and identify transmission solutions that efficiently address the identified issues to the benefit of both SPP and MISO. The study consists of an economic evaluation of seams transmission issues previously identified in SPP and MISO regional planning processes. This will be accomplished by leveraging transmission needs identified in the SPP Integrated Transmission Planning (ITP) studies (2017 ITP10) and the MISO Transmission Expansion Planning (MTEP) process (2016 MTEP). The goal of this approach is to determine if interregional transmission solutions exist that are more efficient and cost effective than what each Regional Transmission Organization (RTO) could do regionally to address these needs.

The set of needs being used for the 2016 CSP study was determined by SPP and MISO identifying the top needs from each of the respective regional planning studies relative to the entire seam between SPP and MISO. Once those lists were created, SPP and MISO further narrowed the list to only include needs likely to benefit from a potential interregional project. The seven needs included in the final scope of the 2016 CSP study are shown below in table 8.3 and figure 8.2.

2016 SPP-MISO CSP Joint Needs List		
Map Key	**RTO**	**Flowgate Name**
1	MISO	Rugby WAUE – Rugby OTP Tie
2	MISO	Hankinson - Wahpeton 230kV FLO Jamestown - Buffalo 345kV
3	TIE	Sub3 - Granite Falls 115kV Ckt1 FLO Lyon Co. 345kV Ckt1
4	TIE	Sioux Falls - Lawrence 115kV FLO Sioux Falls - Split Rock 230kV
5	SPP	Northeast - Charlotte 161kV FLO Northeast - Grand Ave West 161kV
6	SPP	Neosho - Riverton 161kV FLO Neosho - Blackberry 345kV
7	SPP	Brookline 345/161kV Ckt 1 Transformer FLO Brookline 345/161kV Ckt 2 Transformer

Table 8.3: 2016 SPP-MISO CSP Joint Needs List

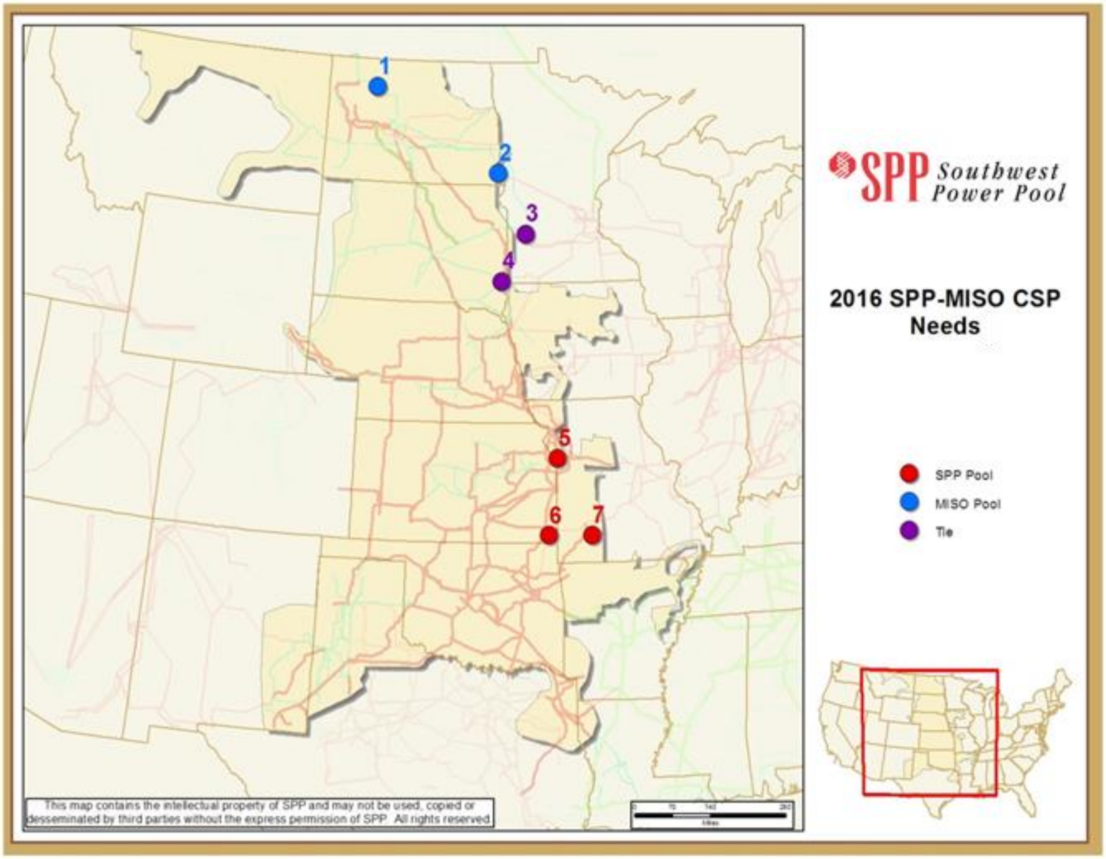


Figure 8.2: 2016 SPP-MISO CSP Needs

Table 8.4 below shows the different steps throughout the process and what has been completed to date.

SPP-MISO CSP Tasks
1. Develop and finalize scope document for CSP study – August 2016 ☑
2. Develop detailed schedule for CSP study – August 2016 ☑
3. Economic Evaluation
• Model Development – November 2016 ☑
• Determine needs list from regional studies – August 2016 ☑
• Solution Development – November 2016 ☑
• Solution Evaluation and Robustness Testing – February 2017
• Reliability No Harm Analysis – March 2017
• Determine interregional cost allocation - March 2017
4. Coordinated Reliability Assessment – March 2017
5. Draft Coordinated System Plan study report – April 2017
6. Regional Evaluation and Cost Allocation (if needed)

Table 8.4: SPP-MISO CSP Tasks

SPP-SERTP Interregional Coordination

Addendum 4 to Attachment O of the SPP Tariff outlines the interregional planning coordination procedures between SPP and Southeastern Regional Transmission Planning (SERTP). SPP and SERTP have both annual and biannual compliance requirements regarding interregional planning coordination and data sharing. Both the annual and biannual requirements were due to be completed in 2016. To meet these requirements, SPP and SERTP met in the months of June and December 2016 to discuss the following planning-related items:

- Planning Process Overviews of each region
- Review of SPP and SERTP regional plans for 2016
- Review of projects and needs near the SPP-SERTP seam
- Planning related data and information exchanges

8.2: Interregional Requirements of Order 1000

In 2016, SPP received final orders from the FERC approving the interregional coordination procedures between SPP-MISO and SPP-SERTP as being compliant with the interregional requirements of Order 1000.

8.3: Interregional Planning Coordination Improvements

In addition to the joint planning efforts conducted in 2016, SPP worked to further improve its planning coordination with all of its neighbors. SPP and MISO worked together to develop revised procedures targeting the improvement of the coordination of third party impacts in the GI and Transmission Service Request processes. The new coordination language between SPP and MISO relating specifically to GI coordination resulted in a JPC-approved document outlining procedures each party will follow when it receives a request to interconnect a new generator that may impact the other party. The new coordination language regarding Transmission Service Request coordination will be incorporated into the SPP-MISO JOA. The new JOA language is expected to be filed at FERC in early 2017. Both these efforts to improve coordination were at the request of stakeholders who were also involved throughout the process to develop the enhanced procedures.

SPP also focused on improving the coordination of its regional planning processes with neighboring entities. In 2016, SPP worked through several different issues with neighboring entities related to regional planning upgrades made by SPP or the neighbor. These instances brought awareness to the need for improved coordination of transmission impacts on all of SPP's seams. SPP will continue working on this issue with MISO and its other seams neighbors in 2017.

Section 9: Project Tracking

9.1: NTC Letters Issued in 2016

After the SPP Board of Directors approves transmission expansion projects or once Service Agreements are executed, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners.

In 2016, SPP issued 47 NTC letters with estimated construction costs of $991.98 million for 138 projects to be constructed over the next five years through 2021. Of this $991.98 million, the project cost breakdown is as follows:

- $7.3 million for GI;
- $83.9 million for TSS;
- $41.3 million for HP; and
- $859.5 million for ITP projects.

A list of the NTCs issued in 2016 can be found in Section 11.

9.2: Projects Completed in 2016

After the SPP Board of Directors approves transmission expansion projects, SPP issues NTC letters to appropriate Transmission Owners. SPP actively monitors the progress of approved projects by soliciting feedback from project owners at least quarterly. As of December 31, 2016, 78 upgrades were completed during the year. The breakdown includes:

- 44 ITP - $582.3 million
- 8 TSS - $68 million
- 17 GI - $62.3 million
- 9 HP - $226.4 million

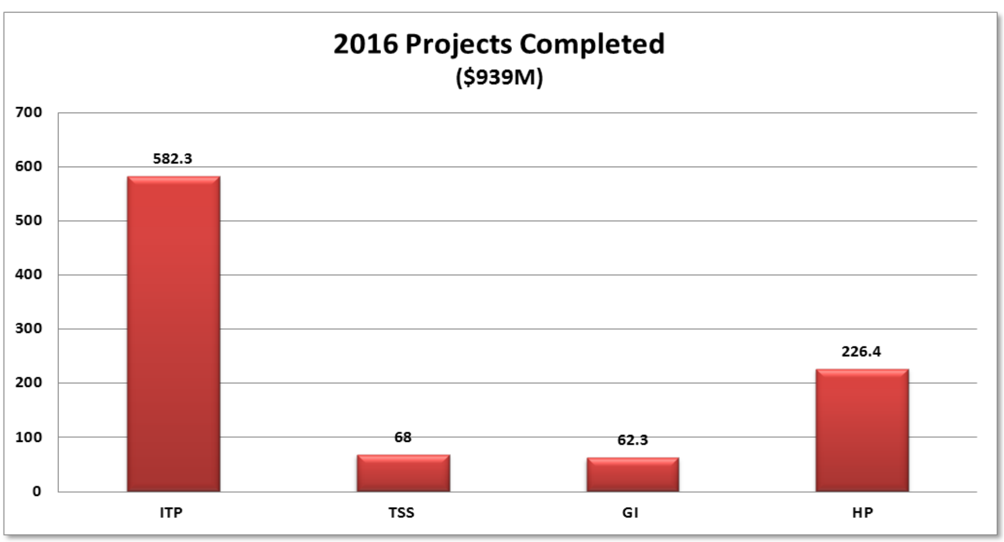


Figure 9.1: Projects Completed in 2016

9.3: ITP20 Projects

ITP20 assessments were performed in 2010 and 2013. While the projects proposed by those studies are incorporated into the STEP Project List, they are not included in SPP's project tracking effort as part of the Quarterly Tracking Report. A list of active ITP20 projects will be maintained in the STEP Report and Project List. The current ITP20 projects are listed in the table below.

Name	Type	Size	Cost Estimate	Source Study
Post Rock 345/230 kV transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Mingo-Post Rock 345 kV	New Line	345	$121,500,000	2010 ITP20
Iatan-Jeffery Energy Center 345 kV	New Line	345	$79,875,000	2010 ITP20
Spearville - Mullergren 345 kV	New Line	345	$85,840,000	2010 ITP20
Mullergren - Circle 345 kV	New Line	345	$85,840,000	2010 ITP20
Circle - Reno 345 kV	New Line	345	$6,519,500	2010 ITP20
Keystone - Ogallala 345 kV	New Line	345	$5,625,000	2010 ITP20
Ogallala Transformer 345/230 kV	Transformer	345	$6,000,000	2010 ITP20
Mullergren 345/230 kV Transformer	Transformer	345	$6,000,000	2010 ITP20
Circle 345/230 kV transformer	Transformer	345	$6,000,000	2010 ITP20
Grand Island - Holt Co 345 kV	Rebuild/Re-Conductor	345	$64,125,000	2010 ITP20
Holt Co. - Shell Creek 345 kV	New Line	345	$69,750,000	2010 ITP20
Shell Creek 345/230 kV Transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Holt - Neligh 345 kV	New Line	345	$30,656,000	2010 ITP20
Columbus East 345/115 kV Transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Hoskins 345/230 kV Transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Hoskins 345/115 kV Transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Hoskins - Ft. Calhoun 345 kV	New Line	345	$193,380,000	2010 ITP20
Ft Calhoun - S3454 345 kV	New Line	345	$46,875,000	2010 ITP20
Cass Co. - S.W. Omaha (aka S3454) 345 kV Ckt1	New Line	345	$33,126,800	2010 ITP20
S3459 345/161 kV Transformer Ckt 2	Transformer	345	$12,600,000	2010 ITP20
Hitchland-Potter 345 kV Ckt 2	New Line	345	$133,875,000	2010 ITP20
Wichita-Viola 345 kV	New Line	345	$54,000,000	2010 ITP20
Viola-Rose Hill 345 kV Ckt 1	New Line	345	$54,000,000	2010 ITP20
South Fayetteville 345/161 kV Transformer Ckt1	Transformer	345	$12,600,000	2013 ITP20
Chamber Springs - South Fayetteville 345 kV Ckt1	New Line	345	$21,295,800	2013 ITP20

Name	Type	Size	Cost Estimate	Source Study
Maryville 345/161 kV Transformer Ckt1	Transformer	345	$12,600,000	2013 ITP20
Nashua 345/161 kV Transformer Upgrade Ckt11	Transformer	345	$12,600,000	2013 ITP20
Keystone - Red Willow 345 kV Ckt1	New Line	345	$130,141,000	2013 ITP20
Tolk - Tuco 345 kV Ckt1	New Line	345	$75,718,400	2013 ITP20
Holcomb 345/115 kV Transformer Ckt2	Transformer	345	$12,600,000	2013 ITP20
Neosho - Wolf Creek 345 kV Ckt1	New Line	345	$117,126,900	2013 ITP20
Clinton - Truman 161 kV Ckt1 Reconductor	Rebuild/Re-Conductor	161	$15,701,325	2013 ITP20
North Warsaw - Truman 161 kV Ckt1 Reconductor	Rebuild/Re-Conductor	161	$1,082,850	2013 ITP20
Auburn 345/115 kV Transformer Ckt2	Transformer	345	$12,600,000	2013 ITP20
Auburn - Swissvale 345 kV Ckt1 Voltage Conversion	Voltage Conversion	345	$20,112,700	2013 ITP20
Auburn - Jeffrey EC 345 kV Ckt1 Voltage Conversion	Voltage Conversion	345	$35,493,000	2013 ITP20
Muskogee/Pecan Creek 345 kV Terminal Upgrades	Substation	345	$34,605,675	2013 ITP20

Table 9.1: ITP20 Projects

Section 10: STEP Project List

The 2016 STEP Project List includes a comprehensive listing of transmission projects identified by the SPP RTO. All SPP BOD-approved projects are included in the 2016 STEP Project List. The list also includes SPP Tariff study projects, economic projects, and zonal projects.

Projects in the list are categorized in the column labeled “Project Type” by the following designations:

- Balanced Portfolio – Projects identified through the Balanced Portfolio process
- Generator Interconnection – Projects associated with a FERC-filed Generator Interconnection Agreement
- High Priority – Projects identified in the high priority process
- ITP – Projects needed to meet regional reliability, economic, or policy needs in the ITP study processes
- Transmission Service – Projects associated with a FERC-filed Service Agreement
- Interregional – Projected identified in SPP’s joint planning and coordination processes
- Sponsored – Entity requested and funded project reviewed and approved by SPP

The complete Network Upgrade list includes two dates.

1. In-service: Date Transmission Owner has identified as the date the upgrade is planned to be in-service.
2. SPP Need Date: Date upgrade was identified as needed by SPP.

A copy of the *2017 SPP Transmission Expansion Plan Report Project List* can be found at the following location: spp.org>engineering>transmission-planning>documents

10.1: Facility owner abbreviations used in the STEP List

Abbreviation and Identification	
AEP	American Electric Power
BEPC	Basin Electric Power Cooperative
ETEC	East Texas Electric Cooperative
GRDA	Grand River Dam Authority
ITCGP	ITC Great Plains
KCPL	Kansas City Power and Light Company
GMO	KCP&L Greater Missouri Operations Company
LEA	Lea County Cooperative
LES	Lincoln Electric System
MKEC	Mid-Kansas Electric Company
MIDW	Midwest Energy, Incorporated
NPPD	Nebraska Public Power District
OGE	Oklahoma Gas and Electric Company
OPPD	Omaha Public Power District
SWPA	Southwestern Power Administration
SPS	Southwestern Public Service Company
SEPC	Sunflower Electric Power Corporation
TSMO	Transource Energy
WFEC	Western Farmers Electric Cooperative
WR	Westar Energy

10.2: Upgrades: Information breakdown

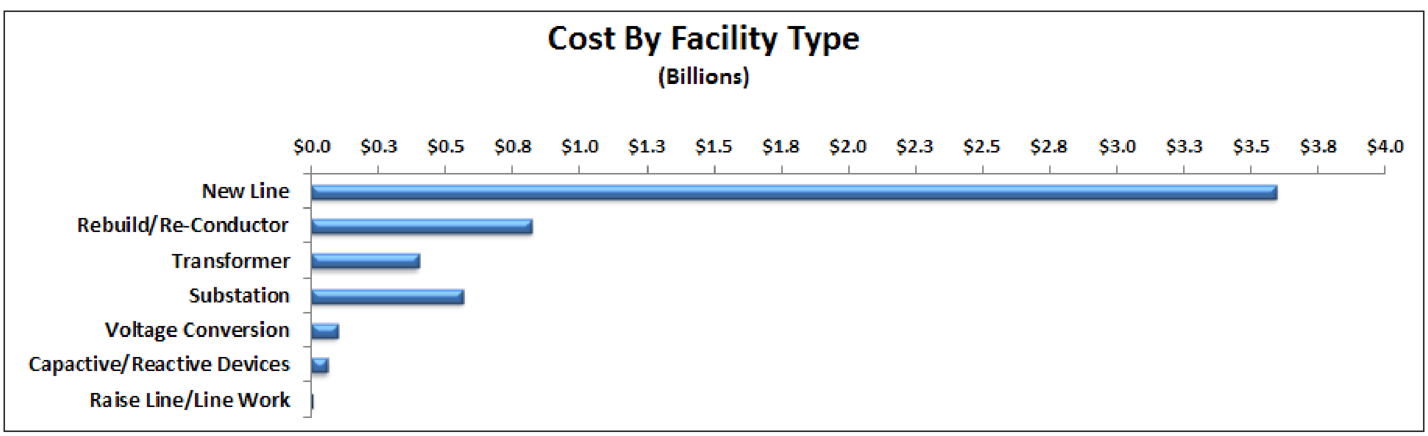


Figure 10.1: Total Cost by Facility Type (Dollars)

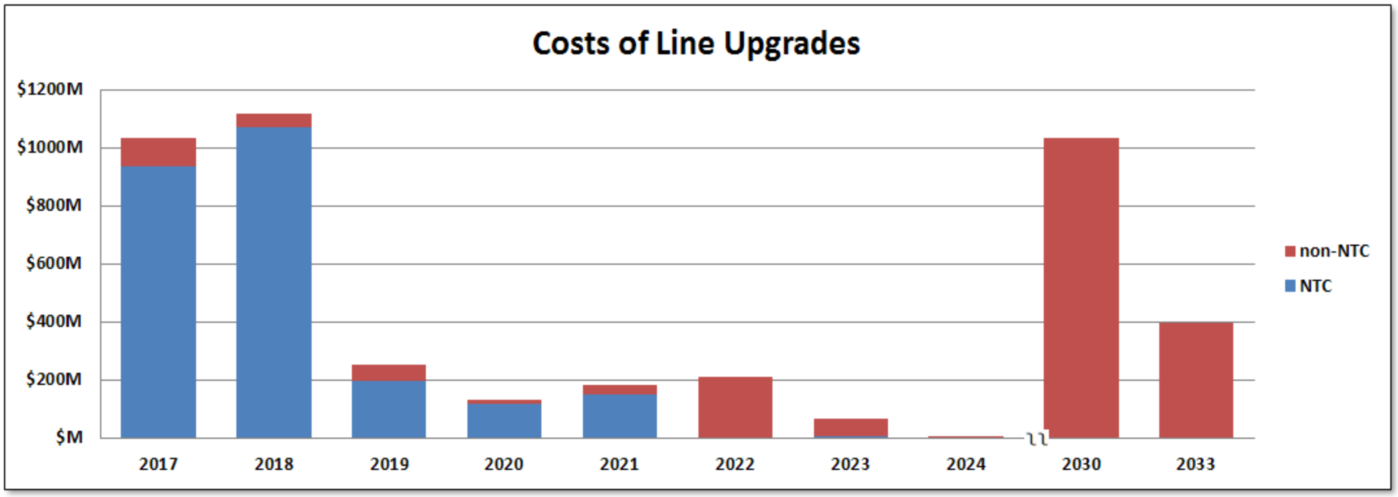


Figure 10.2: Total Cost of Line Upgrades

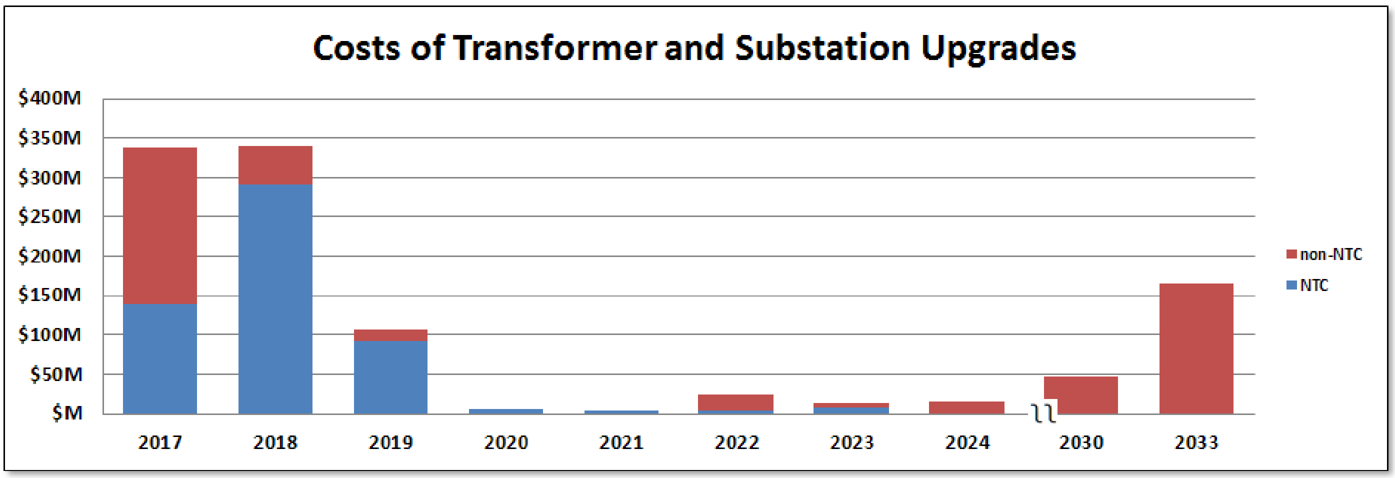
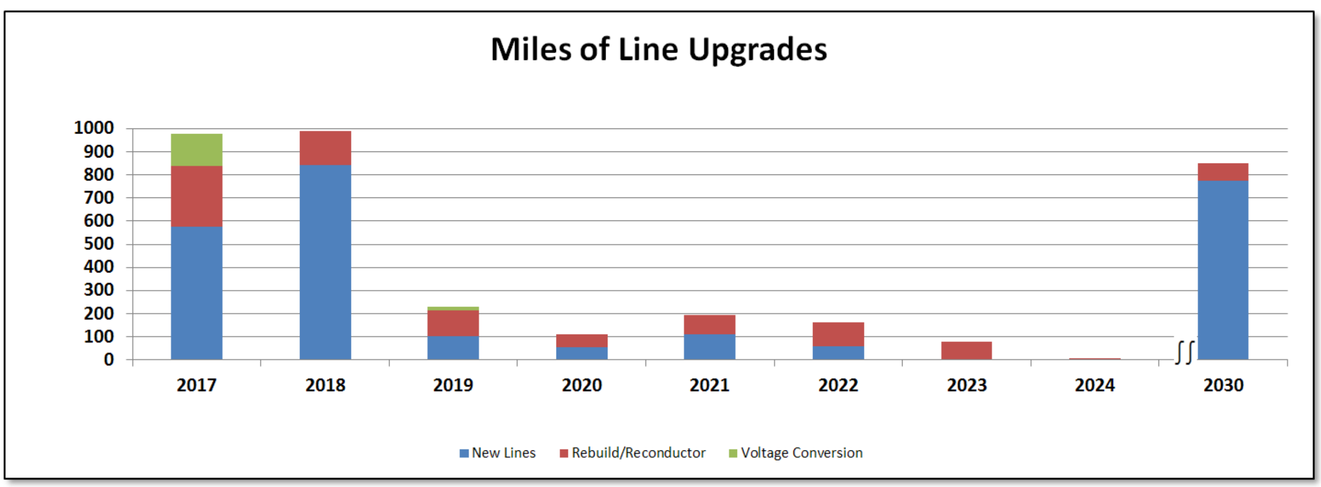


Figure 10.3: Total Cost of Transformer and Substation Upgrades



***2024 has 6 miles of Rebuild/Reconductor line**

Figure 10.4: Total Miles of Line Upgrades by Project Type

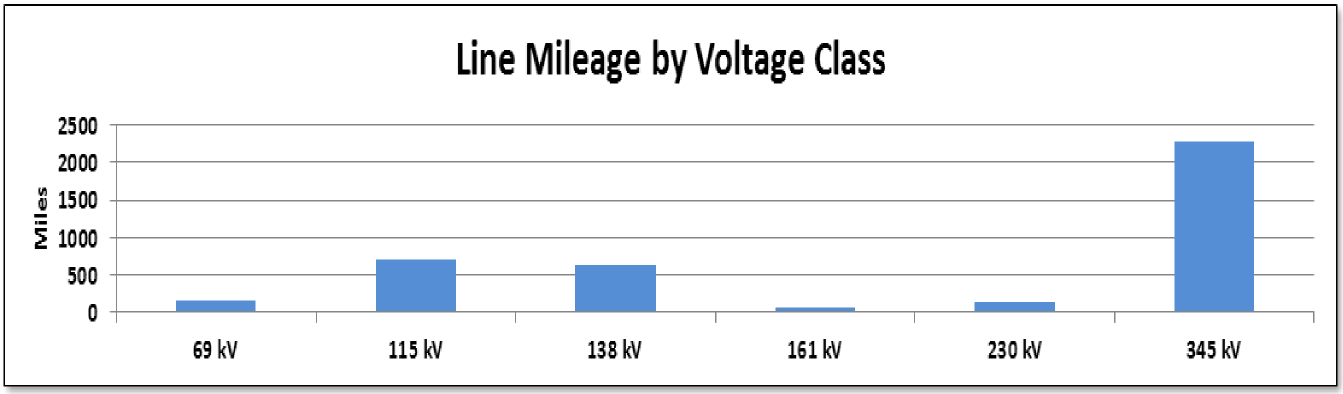


Figure 10.5: Total Line Mileage by Voltage Class

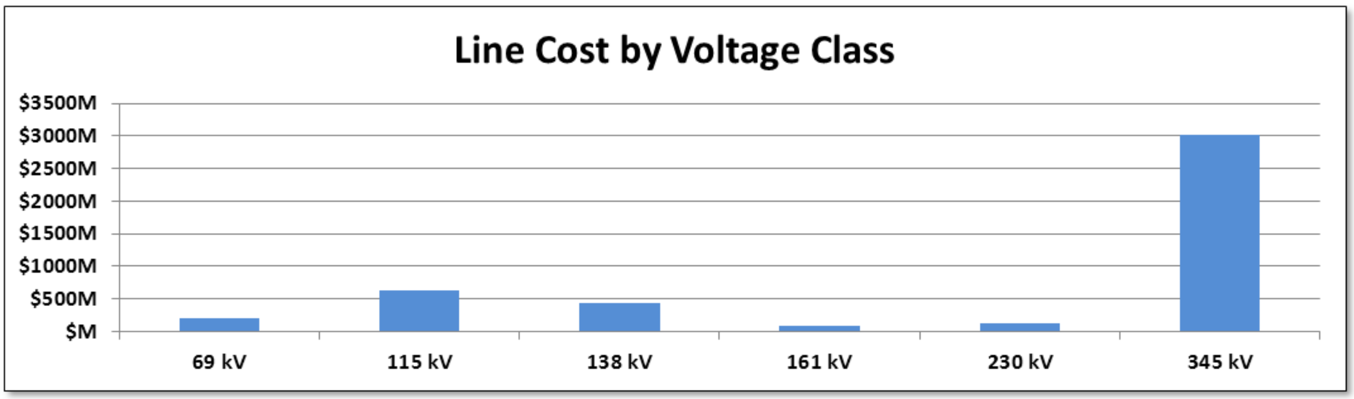


Figure 10.6: Total Line Cost by Voltage Class

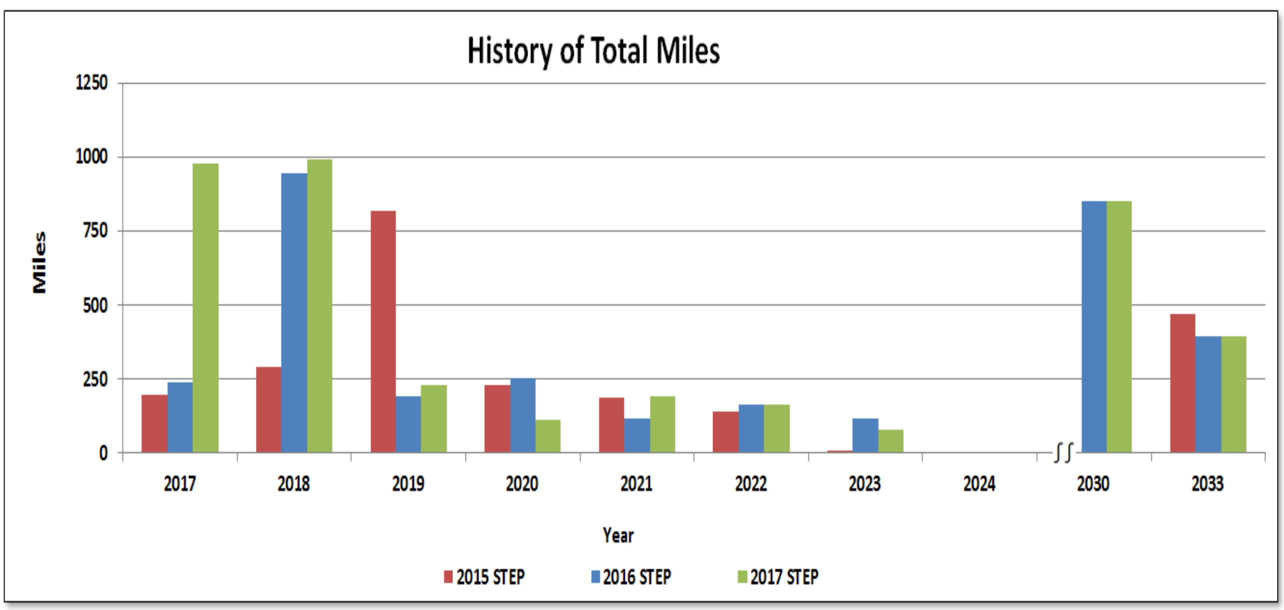


Figure 10.7: History of Total Miles 2015-2033

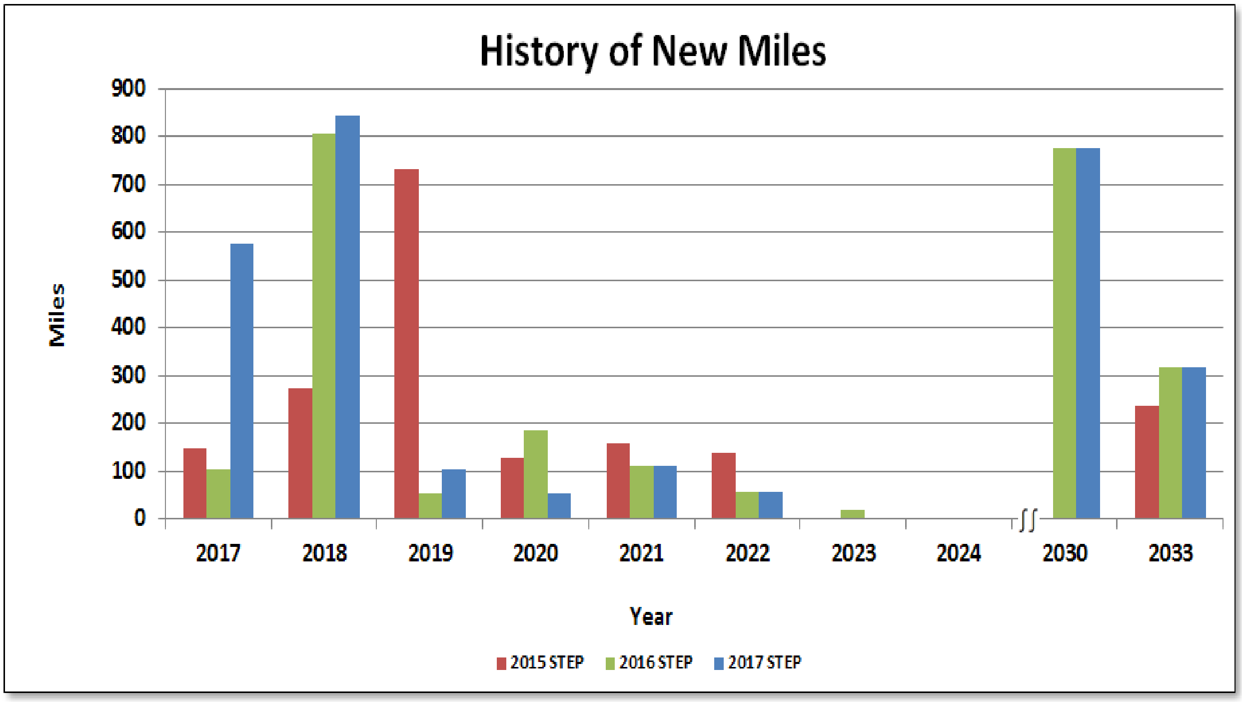


Figure 10.8: History of New Line Miles 2015-2033

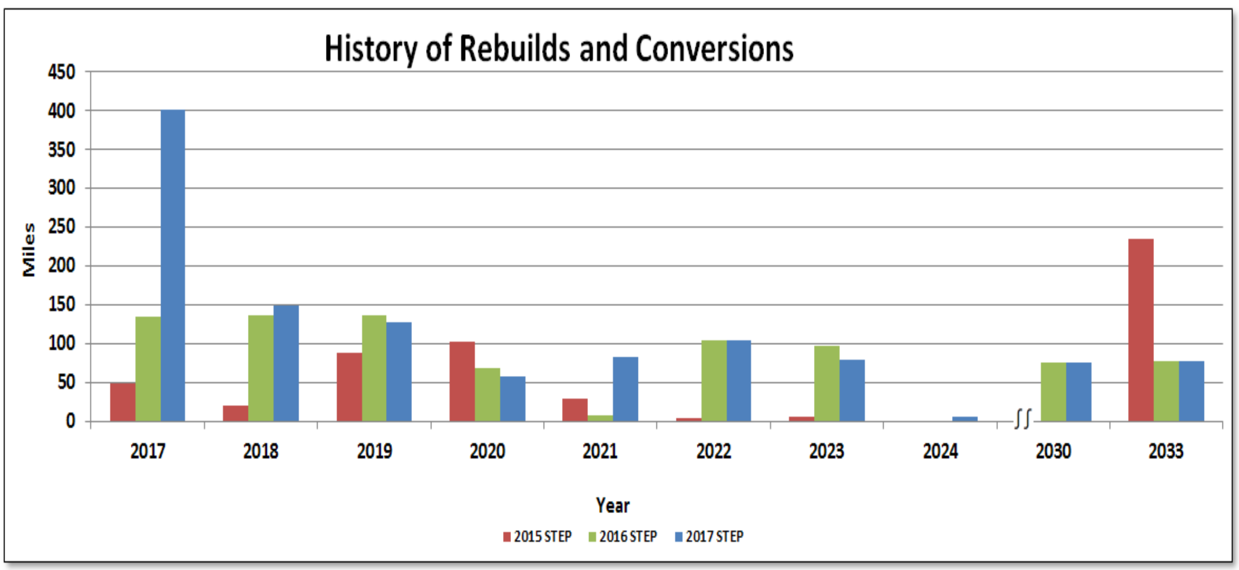


Figure 10.9: History of Line Rebuilds and Conversions 2015-2033

Section 11: NTCs Issued in 2016

NTC ID	Project ID	Facility Owner	Project Name	Current Cost Estimate
200365	30708	SPS	Line - Ochoa - Ponderosa Tap 115 kV Ckt 1 Rebuild	$4,161,825
	30918		Line - Byrd Tap - Cooper Ranch - Oil Center - Lea Road 115 kV Ckt 1 Rebuild	$2,597,868
	30918		Line - Byrd Tap - Cooper Ranch - Oil Center - Lea Road 115 kV Ckt 1 Rebuild	$3,566,564
	30987		Line - Cunningham - Monument Tap 115 kV Ckt 1 Rebuild	$4,770,097
	30918		Line - Byrd Tap - Cooper Ranch - Oil Center - Lea Road 115 kV Ckt 1 Rebuild	$2,282,308
	30989		Sub - Potash Junction 230 kV Terminal Upgrade	$63,251
	30990		Line - Jal - Teague 115 kV Ckt 1 Rebuild	$7,544,091
	30991		Line - National Enrichment Plant - Teague 115 kV Ckt 1 Rebuild	$4,990,255
200366	30988	SPS	Sub - Eddy Co. 230 kV Bus Tie	$9,485,379
200367	30986	OPPD	Sub - Tap Nebraska City - Mullin Creek 345kV (Holt County) POI for GEN-2014-021	$122,455
200368	1001	SPS	Line - Randall - South Georgia and Osage Station 115 kV Line Re-termination	$10,316,217
200369	1142	SPS	Line - Canyon East - Randall 115 kV Ckt 1 Rebuild	$12,806,065
	30509		Line - Canyon East Sub - Canyon West Sub 115 kV Ckt 1	$2,694,811
200370	30649	SPS	Multi - Andrews 230/115 kV Transformer and Andrews - NEF 115 kV Ckt 1	$10,671,660
200371	30666	SPS	Device - China Draw and Road Runner 115 kV SVC	$25,925,187
	30666		Device - China Draw and Road Runner 115 kV SVC	$28,918,070
200375	30992	OGE	XFR - Woodward EHV 138kV Phase Shifting Transformer	$7,099,999
200376	30952	SEPC	Device - Ingalls 115 kV Cap Bank	$2,955,010
	30953		Device - Lane Scott 115 kV Cap Bank	$2,093,739
200377	31050	WR	Sub - Summit 115 kV Terminal Upgrades	$200,000
200378	458	OGE	Line - Franklin SW - Midwest TP 138 kV	$500,000
200379	468	WR	Line - Arkansas City - Paris	$500,000
	31059		Crawford - Neosho	$145,773
200380	30984	OGE	Sub - Claremore 69 kV Terminal Upgrades	$335,000
	30984		Sub - Claremore 69 kV Terminal Upgrades	$340,000
200381	777	SPS	Sub - East Plant 115 kV Terminal Upgrade	$5,000
200382	30809	AEP	Line - Keystone Dam - Wekiwa 138 kV Ckt 1 Rebuild	$4,319,501
200384	30444	SPS	Device - Cochran 115 kV Cap Bank	$1,833,655
	30971		Multi - Cochran - Whiteface 115 kV	$2,721,459
200385	30922	MKEC	Line - North Liberal - Walkemeyer 115 kV Ckt 1	$8,325,610
200386	30997	AEP	Device - Sayre 138 kV Cap Bank	$758,441
	31003		Sub - Northeastern Station 138 kV Terminal Upgrades	$518,011
	31005		Sub - Elk City 138 kV Move Load	$2,904,911
	31049		Device - Cedar Grove - Linwood 138 kV Reactor	$3,534,979
	31057		Line - Atoka - Atoka Pump - Pittsburg - Savanna - Army Ammo - McAlester City 69 kV Ckt 1 Rebuild	$7,458,042
	31057		Line - Atoka - Atoka Pump - Pittsburg - Savanna - Army Ammo - McAlester City 69 kV Ckt 1 Rebuild	$7,232,496
	31057		Line - Atoka - Atoka Pump - Pittsburg - Savanna - Army Ammo - McAlester City 69 kV Ckt 1 Rebuild	$20,404,361
	31058		Line - Fort Towson - Kiamichi Pump Tap - Valliant 69 kV Ckt 1 Rebuild	$8,119,642

	31058		Line - Fort Towson - Kiamichi Pump Tap - Valliant 69 kV Ckt 1 Rebuild	$4,330,476
200387	31031	BEPC	Multi - Kummer Ridge - Roundup 115 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$49,589,600
	31031		Multi - Kummer Ridge - Roundup 115 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$6,662,000
	31031		Multi - Kummer Ridge - Roundup 115 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$6,122,000
	31031		Multi - Kummer Ridge - Roundup 115 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$30,000,000
	31031		Multi - Kummer Ridge - Roundup 115 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$27,100,000
	31031		Multi - Kummer Ridge - Roundup 115 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$3,918,000
200388	31032	BEPC	Multi - Plaza 115 kV Substation and Blaisdell - Plaza 115 kV New Line	$3,918,000
	31032		Multi - Plaza 115 kV Substation and Blaisdell - Plaza 115 kV New Line	$14,841,308
	31032		Multi - Plaza 115 kV Substation and Blaisdell - Plaza 115 kV New Line	$283,000
	31033		Line - Berthold - Southwest Minot 115 kV Ckt 1 Reconductor	$2,876,720
200389	31030	ETEC	Device - Latexo 138 kV Cap Bank	$1,712,000
200390	30892	GRDA	Sub - CPPXF#22 69 kV Terminal Upgrades	$134,800
	30909		Sub - Collinsville - Skiatook 69 kV Terminal Upgrades	$160,200
	31024		Device - Skiatook 69 kV Cap Bank	$1,134,600
	31025		Sub - Sallisaw 161 kV Terminal Upgrades	$2,266,000
200391	31042	OGE	Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$15,000,000
	31042		Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$6,000,000
	31042		Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$8,300,000
	31042		Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$0.00
200392	30597	OGE	Multi - Knob Hill - Lane - Noel 138 kV Ckt 1	$4,009,000
	31002		Line - Lincoln - Meeker 138 kV Ckt 1 New Line	$750,000
200393	31038	OPPD	Device - S964 69 kV Cap Bank	$619,277
200394	30917	SEPC	Device - Ellsworth 115 kV Cap Bank	$1,909,424
200395	409	SPS	XFR - Hereford Interchange 115/69 kV #1 and #2	$2,468,463
	409		XFR - Hereford Interchange 115/69 kV #1 and #2	$2,437,078
	31068		Multi - Tuco - Yoakum 345/230 kV Ckt 1	$128,473,352
	31068		Multi - Tuco - Yoakum 345/230 kV Ckt 1	$5,138,920
	30692		XFR - Seminole 230/115 kV #1 and #2	$3,890,904
	30692		XFR - Seminole 230/115 kV #1 and #2	$3,890,904
	31067		Sub - Livingston Ridge 115 kV Substation Conversion	$5,283,323
	30817		Line - Canyon West - Dawn - Panda - Deaf Smith 115 kV Ckt 1 Rebuild	$9,006,562
	30817		Line - Canyon West - Dawn - Panda - Deaf Smith 115 kV Ckt 1 Rebuild	$5,447,497
	30817		Line - Canyon West - Dawn - Panda - Deaf Smith 115 kV Ckt 1 Rebuild	$3,232,285
	30844		Sub - Amoco - Sundown 230 kV Terminal Upgrades	$2,200,956
	30996		Sub - Hobbs - Yoakum Tap 230 kV Substation and Transformer	$9,441,616

	30996		Sub - Hobbs - Yoakum Tap 230 kV Substation and Transformer	$2,966,656
	30999		Sub - Potter Co. - Harrington 230 kV Terminal Upgrades	$1,033,584
	31001		Line - Road Runner - Agave Red Hills/Ochoa/Custer Mountain 115 kV New Line	$443,866
	31001		Line - Road Runner - Agave Red Hills/Ochoa/Custer Mountain 115 kV New Line	$519,061
	31001		Line - Road Runner - Agave Red Hills/Ochoa/Custer Mountain 115 kV New Line	$759,610
	31001		Line - Road Runner - Agave Red Hills/Ochoa/Custer Mountain 115 kV New Line	$4,580,864
	31001		Line - Road Runner - Agave Red Hills/Ochoa/Custer Mountain 115 kV New Line	$25,280
	31001		Line - Road Runner - Agave Red Hills/Ochoa/Custer Mountain 115 kV New Line	$25,280
	31008		Multi - Artesia County 115 kV	$5,201,175
	31008		Multi - Artesia County 115 kV	$336,134
	31008		Multi - Artesia County 115 kV	$2,814,758
	409		XFR - Hereford Interchange 115/69 kV #1 and #2	$457,209
	409		XFR - Hereford Interchange 115/69 kV #1 and #2	$457,209
	31022		Line - Canyon East Tap - Randall 115 kV Ckt 1 Rebuild	$4,960,481
	31051		Sub - Terry Co. - Wolfforth 115 kV Terminal Upgrades	$1,700,000
	31054		Device - Bopco 115 kV Cap Bank	$273,060
200396	31006	WFEC	Device - Arco 138 kV SVC	$20,500,000
	31042		Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$1,200,000
200397	242	WFEC	Line - Elmore - Paoli 69 kV Rebuild	$3,240,000
	844		Line - Sara Road - Sunshine Canyon 69 kV Ckt 1 Rebuild	$4,725,000
	30628		Device - Freedom 69 kV Cap Bank	$237,000
	30597		Multi - Knob Hill - Lane - Noel 138 kV Ckt 1	$450,000
	30995		Device - Harrisburg 69 kV Cap Bank	$450,000
	31002		Line - Lincoln - Meeker 138 kV Ckt 1 New Line	$6,000,000
	31010		Device - Blanchard 69 kV Cap Bank	$341,325
	31065		Sub - Cleo Junction 138 kV Terminal Upgrades	$4,000,000
	31066		Sub - Ringwood 138 kV Terminal Upgrades	$4,000,000
	31040		Device - Ringwood 138 kV Cap Bank	$450,000
	31041		Multi - Driftwood 138/69 kV Substation and Transformer	$550,000
	31041		Multi - Driftwood 138/69 kV Substation and Transformer	$3,000,000
200398	31056	WR	Device - Sunset 69 kV Cap Bank	$364,080
200399	30496	BEPC	Multi - Bobcat Canyon 345/115 kV and Bobcat Canyon - Scottsbluff 115 kV	$0
200400	30496	NPPD	Multi - Bobcat Canyon 345/115 kV and Bobcat Canyon - Scottsbluff 115 kV	$5,928,479
	30496		Multi - Bobcat Canyon 345/115 kV and Bobcat Canyon - Scottsbluff 115 kV	$26,027,015
	30496		Multi - Bobcat Canyon 345/115 kV and Bobcat Canyon - Scottsbluff 115 kV	$4,749,663
200401	30578	SPS	Multi - Bailey Co. - Lamb Co. 115 kV	$3,187,532
200402	30973	OGE	Sub - Terry Road 345kV (Tap Lawton Eastside - Sunnyside 345kV)	$20,000
200403	31073	MIDW	XFR - Heizer 115/69 kV Ckt 4 Transformer	$2,663,963
200404	1001	SPS	Line - Randall - South Georgia and Osage Station 115 kV Line Re-termination	$10,316,217

200406	30889	AEP	Line - Linwood - South Shreveport 138kV Ckt 1 Rebuild	$4,202,042
	31009		Line - Duncan - Tosco 69 kV Ckt 1 Rebuild	$5,974,766
	31039		Line - Comanche Tap - Tosco 69 kV Ckt 1 Rebuild	$4,365,864
200407	31021	SPS	Line - Mustang - Seminole 115 kV Ckt 1 New Line	$10,715,275
	31021		Line - Mustang - Seminole 115 kV Ckt 1 New Line	$1,591,690
	31021		Line - Mustang - Seminole 115 kV Ckt 1 New Line	$2,016,340
	31052		Multi - Tolk Yoakum Tap 230/115 kV Substation and Transformer	$11,670,196
200409	31031	BEPC	Multi - Kummer Ridge - Roundup 115 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$52,312,877
200410	30552	SPS	Line - Oxy Permian Sub - West Bender Sub 115 kV Ckt 1	$668,829
200411	30694	SPS	Multi - Ponderosa - Ponderosa Tap 115 kV	$5,404,344
	30695		Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$8,811,206
	30825		Line - China Draw - Wood Draw 115 kV Ckt 1	$16,425,742
200412	30985	OGE	Sub - Leonard 138kV Switching Station (GEN-2014-020 POI)	$20,000
200413	31087	GMO	Sub - Ketchem 345kV Interconnection Switching Station GEN-2015-005 Addition	$30,000
200416	30843	OGE	Sub - Cimarron - Draper 345 kV Terminal Upgrades	$1,500,000
200417	31031	BEPC	Multi - Kummer Ridge - Roundup 345 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$52,312,877
	31031		Multi - Kummer Ridge - Roundup 345 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$6,662,000
	31031		Multi - Kummer Ridge - Roundup 345 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$6,662,000
	31031		Multi - Kummer Ridge - Roundup 345 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$30,000,000
	31031		Multi - Kummer Ridge - Roundup 345 kV New Line and Patent Gate and Roundup 345/115 kV Substations	$27,100,000
200418	31042	OGE	Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$7,700,661
	31042		Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$3,600,000
	31042		Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$8,383,000
	31042		Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$7,723,383
200419	31042	WFEC	Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	$1,400,000

Table 11.1: NTCs Issued in 2016

Section 12: Projects Completed in 2016

12.1 ITP Projects Completed in 2016

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
20003	402	WFEC	GRANDFIELD 138/69KV TRANSFORMER CKT 1	$5,000,000
200166	461	SPS	Bailey County Interchange - Curry County Interchange 115 kV Ckt 1	$37,938,898
200216	478	AEP	Forbing Tap - South Shreveport 69 kV Ckt 1	$1,221,505
200246	512	AEP	Ellerbe Road - Forbing T 69 kV Ckt 1	$8,174,689
20130	764	SPS	HAPPY INTERCHANGE 115/69KV TRANSFORMER CKT 1	$1,518,414
20130	764	SPS	HAPPY INTERCHANGE 115/69KV TRANSFORMER CKT 2	$1,565,056
200208	909	WFEC	Cole - OU Switchyard 138 kV Ckt 1	$1,705,000
200214	1003	SPS	Grassland Interchange 230/115 kV Transformer Ckt 1	$3,868,000
200208	909	WFEC	Cole - Criner 138 kV Ckt 1	$1,400,000
20122	30296	AEP	WINNSBORO 138KV	$1,166,400
20122	30298	AEP	LOGANSPORT 138KV	$1,731,419
200221	30367	WR	Elm Creek - Summit 345 kV Ckt 1 (WR)	$57,092,480
200253	30374	NPPD	Hoskins - Neligh 345 kV Ckt 1	$53,741,554
200223	30364	OGE	Cimarron - Matthewson 345 kV Ckt 2	$32,936,400
200223	30364	OGE	Matthewson 345 kV	$19,967,850
200214	30423	SPS	Deaf Smith County Interchange 230/115 kV Transformer Ckt 2	$4,225,233
200231	30449	AEP	Rock Hill - Springridge Pan-Harr REC 138 kV Ckt 1	$25,060,655
200210	30494	MIDW	Hays Plant - South Hays 115 kV Ckt 1 #2	$8,922,219
200231	30495	AEP	Layfield 500/230 kV Transformer Ckt 1	$30,369,537
200231	30495	AEP	Layfield 500 kV Terminal Upgrades	$21,508,234
200253	30374	NPPD	Neligh 115 kV Terminal Upgrades	$20,378,603
200242	30553	WR	Butler - Weaver 138 kV Terminal Upgrades Ckt 1	$0
200242	30558	WR	Neosho 138/69 kV Ckt 1 Transformer	$8,814,650
200258	30561	OPPD	S1366 161/69 kV Ckt 1 Transformer	$4,426,730
200242	30579	WR	City of Wellington - Sumner County No.4 Rome 69 kV Ckt 1 Rebuild	$4,450,370
200258	30561	OPPD	S1366 161 kV Ckt 1 Terminal Upgrades	$422,270
200299	30581	OGE	Ahloso - Park Lane 138 kV Ckt 1 Voltage Conversion	$5,693,264
200299	30581	OGE	Ahloso - Harden City 138 kV Ckt 1 Voltage Conversion	$6,929,179

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
200299	30581	OGE	Frisco - Harden City 138 kV Ckt 1 Voltage Conversion	$2,121,320
200299	30581	OGE	Frisco - Lula 138 kV Ckt 1 Voltage Conversion	$6,749,202
200371	30666	SPS	China Draw 115 kV SVC	$25,925,187
200371	30666	SPS	Road Runner 115 kV SVC	$28,918,070
200319	30876	OGE	Little River - Maud 69 kV Ckt 1 Rebuild	$387,722
200317	30881	KCPL	South Waverly 161/69 kV Ckt 1 Transformer	$2,000,000
200323	30891	WR	Benton 138 kV Terminal Upgrades	$893,730
200319	30900	OGE	Warner Tap 69 kV Terminal Upgrades	$3,404,703
200317	30881	KCPL	South Waverly 161 kV Terminal Upgrades	$280,000
200340	879	OGE	Bluebell 138 kV Terminal Upgrades	$0
	30943	BEPC	AVS - Charlie Creek 345 kV Ckt 2	$78,000,000
	30943	BEPC	AVS 345 kV Substation	$5,800,000
200386	31003	AEP	Northeastern Station 138 kV Terminal Upgrades	$518,011
200387	31031	BEPC	Patent Gate 345 kV Substation	$30,000,000
200387	31031	BEPC	Roundup 345 kV Substation	$27,100,000

12.2 Transmission Service Projects Completed in 2016

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
20104	947	AEP	BROKEN ARROW NORTH - SOUTH TAP - ONETA 138KV CKT 1 #2	$6,072,000
20108	30290	WR	HALSTEAD SOUTH BUS - SEDGWICK COUNTY NO. 12 COLWICH 138KV CKT 1	$136,806
200190	805	SPS	Bowers - Howard 115 kV	$21,906,370
200190	30410	SPS	Bowers - Canadian 69 kV Rebuild	$31,779,309
200193	30422	SPS	Deaf Smith County Interchange 230/115 kV Transformer Ckt 1 #2	$4,236,816
200234	30501	WFEC	Medford Tap - Pond Creek 138 kV (WFEC)	$3,540,000
200313	30688	OGE	Park Lane 138 kV Terminal Upgrades	$89,100
200377	31050	WR	Summit 115 kV Terminal Upgrades	$261,758

12.3 Generator Interconnection Projects Completed in 2016

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
	30763	OGE	Woodward District EHV 345kV Substation	$2,707,042

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
	30962	GRDA	GRDA3 345kV - Interconnection Substation for GEN-2013-028	$17,847,821
	30962	GRDA	GRDA3 345kV - GRDA1 Relays	$0
	30962	GRDA	GRDA3 345kV - Tonnece Relays	$0
	30972	NPPD	Meadow Grove 230kV (GEN-2014-031 TOIF)	$100,000
	30978	OGE	Tap Beaver County - Woodward District EHV 345kV DBL CKT (GEN-2011-014 POI) (TOIF)	$1,099,958
	30978	OGE	Tap Beaver County - Woodward District EHV 345kV DBL CKT (GEN-2011-014 POI) (NU)	$15,744,936
	30932	MIDW	Nekoma 115/69 kV Substation GEN-2014-025 Addition to Walnut Creek 69kV	$231,564
	31015	SPS	Chaves County Interchange 115kV Substation GEN-2014-033 Addition (TOIF)	$260,000
	31015	SPS	Chaves County Interchange 115kV Substation GEN-2014-033 Addition	$1,830,343
	31018	OGE	Minco 345kV Substation GEN-2014-056 Addition (TOIF)	$40,000
	31019	OGE	Ranch Road 345kV Substation GEN-2015-001 Addition (TOIF)	$1,099,958
	31019	OGE	Ranch Road 345kV Substation GEN-2015-001 Addition	$1,150,142
	30763	OGE	Woodward District EHV 345kV Substation GEN-2007-062 (TOIF)	$1,099,958
	30937	SPS	TUCO 230kV Switching Station GEN-2012-020 Addition (TOIF)	$260,000
	31087	TSMO	Ketchem 345kV Interconnection Switching Station GEN-2015-005 Addition (TOIF)	$1,000,000
	31087	TSMO	Ketchem 345kV Interconnection Switching Station GEN-2015-005 Addition (NU)	$17,830,000

12.4 High Priority Projects Completed in 2016

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
20097	938	TSMO	Sibley - Mullin Creek 345 kV	$184,665,083
200282	30331	SPS	Eagle Creek 115 kV Cap Bank	$1,370,000
200282	30824	SPS	Potash Junction 230/115 kV Ckt 1	$3,687,581
200309	30639	SPS	Road Runner 345/115 kV Ckt 1 Transformer	$3,989,689
200309	30639	SPS	Road Runner 345 kV Substation Conversion	$11,569,711
200370	30649	SPS	Andrews 230/115 kV Ckt 1 Transformer	$10,671,660
200282	30649	SPS	Andrews - NEF 115 kV Ckt 1	$3,523,472
200286	30771	MIDW	Midwest Pump Tap 115 kV Substation	$4,477,251
200286	30771	MIDW	Midwest Pump - Midwest Pump Tap 115 kV Ckt 1	$2,443,469

12.5 Sponsored Projects Completed in 2016

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
NA	---	---	---	---

Section 13: Glossary of Terms

Abbreviation and Identification	
AECI	Associated Electric Cooperative Inc.
ATC	Available Transfer Capability
ATSS	Aggregate Transmission Service Study
B/C	Benefit-to-Cost
BOD	Board of Directors
CBA	Consolidated Balancing Authority
CPP	Clean Power Plan
CUS	City Utilities of Springfield
DPT	Delivery Point Transfers
EHV	Extra High Voltage
EMS	Emergency Management System
EPA	Environmental Protection Agency
ESWG	Economic Studies Working Group
FERC	Federal Energy Regulatory Committee
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
HP	High Priority
HPILS	High Priority Incremental Load Study
IPSAC	Interregional Planning Stakeholder Advisory Committee
ITP	Integrated Transmission Planning
ITP10	10-Year Integrated Transmission Planning Assessment
ITP20	20-Year Integrated Transmission Planning Assessment
ITPNT	Near-Term Integrated Transmission Planning Assessment
JCSP	Joint Coordinated System Plan
JOA	Joint Operating Agreement
LTSR	Long-Term Service Request
MDWG	Model Development Working Group
MISO	Midcontinent Independent System Operator
MOPC	Markets and Operations Policy Committee

Abbreviation and Identification	
MTEP	MISO Transmission Expansion Planning
NERC	North American Electric Reliability Corporation
NTC	Notifications to Construct
OATT	Open Access Transmission Tariff
RARTF	Regional Allocation Review Task Force
RCAR	Regional Cost Allocation Review
RMS	Request Management System
RSC	Regional State Committee
RTO	Regional Transmission Organization
RTWG	Regional Tariff Working Group
SERTP	Southeastern Regional Transmission Planning
SPA	Southwestern Power Administration
SPC	Strategic Planning Committee
STEP	SPP Transmission Expansion Plan
TPITF	Transmission Planning Improvement Task Force
TPL	Transmission Planning
TSS	Transmission Service
TWG	Transmission Working Group
WECC	Western Electricity Coordinating Council