

2016 STEP

2016 SPP Transmission Expansion Plan Report

January 5, 2016

Engineering

Revision History

Date	Author	Change Description
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01/25/2016	SPP Staff	Updated Multiple Table Headings and Updated Table in Section 15.2
01/26/2016	SPP Staff	Approved by SPP BOD
02/02/2016	SPP Staff	Project List Updated to Reflect Changes in Generator Interconnection Projects

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Section 1: Executive Summary

The 2016 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 Generation Interconnection;
- 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 2016 STEP consists of 480 upgrades with a total cost of \$6.1 billion. The chart below illustrates the cost distribution of the 2016 STEP based on project type. More detail on the total portfolio is listed in [Section 13](#).

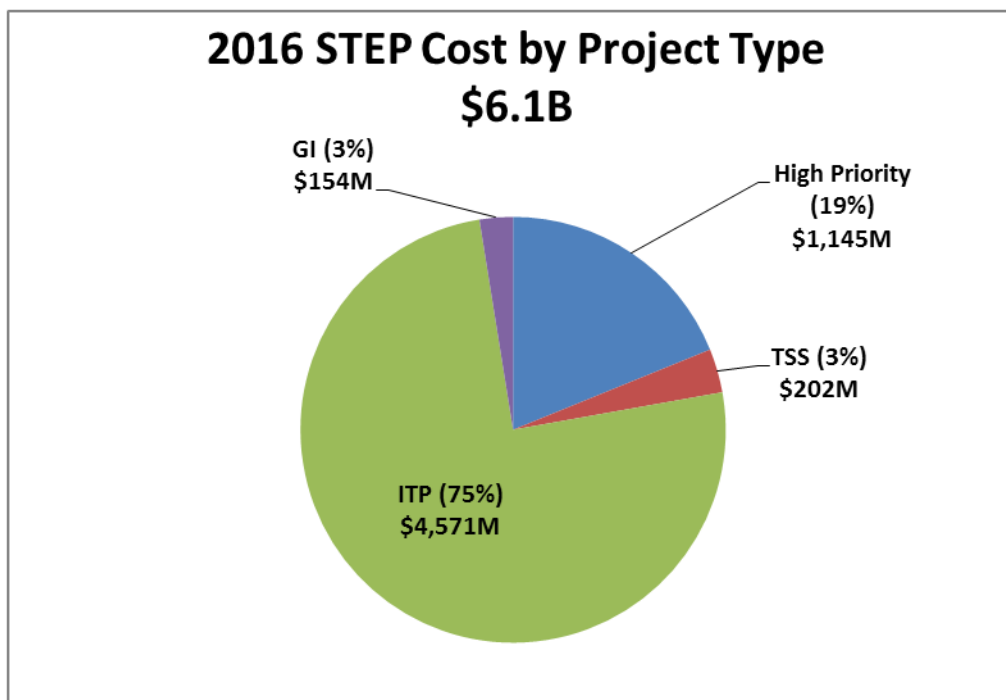


Figure 1.1: Cost by Project Type - 2016 STEP

After the SPP Board of Directors approves transmission expansion projects or once service agreements are filed with FERC, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners. A list of the NTCs issued in 2015 can be found in Section 14. A breakdown of the total list of NTCs issued in 2015 is shown below in Figure 1.2.

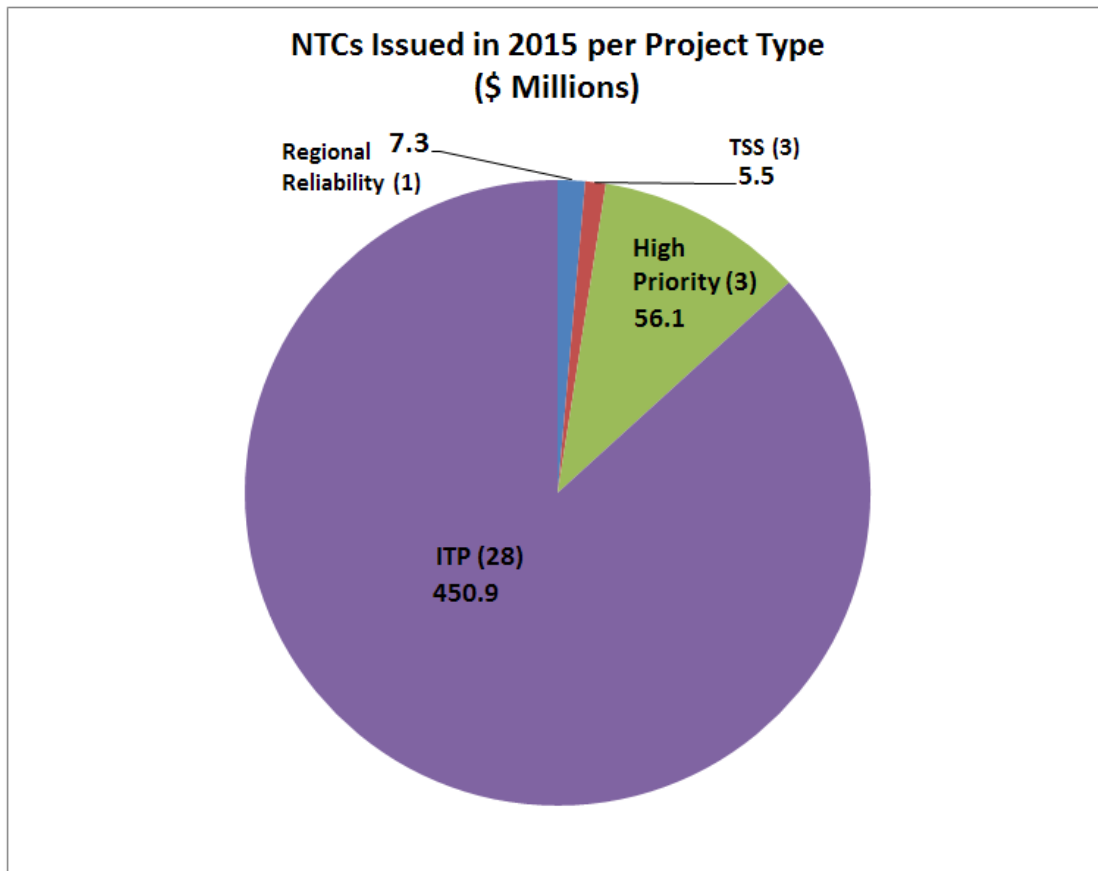


Figure 1.2: NTCs Issued in 2015 per Project Type

In 2015, SPP issued 35 NTC letters with estimated construction costs of \$519.9 million for 50 projects to be constructed over the next five years through 2020. Of this \$519.9 million, the project cost breakdown is as follows:

- \$7.3 million for Regional Reliability (RR);
- \$5.5 million for Transmission Service (TSS);
- \$56.1 million for High Priority (HP); and
- \$450.9 million for Integrated Transmission Planning (ITP) projects.

SPP actively monitors the progress of approved projects by soliciting feedback from project owners at least quarterly. As of December 31, 2015 ninety-three (93) upgrades were completed during the year. The breakdown includes:

- 45 Integrated Transmission Planning (ITP) - \$475.2 million
- 6 Transmission Service (TSS) - \$20.9 million
- 16 Generation Interconnection (GI) - \$100.2 million
- 18 Regional Reliability (RR) - \$90.3 million
- 7 High Priority (HP) - \$106.4 million
- 1 Balanced Portfolio (BP) - \$63 million

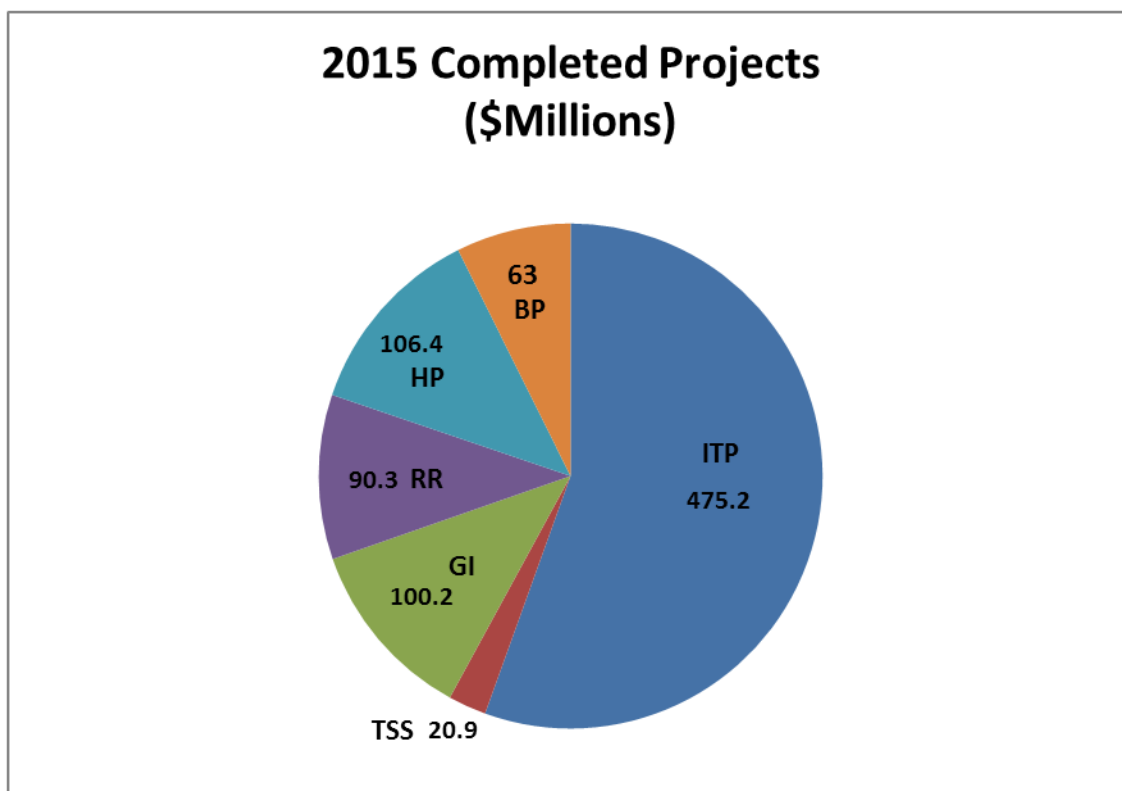


Figure 1.3: 2015 Completed Projects

Tables listing Extra-High Voltage (EHV) projects completed in 2015 as well as active EHV projects carrying forward into 2016 are located in [Section 15](#).

Section 2: Transmission Services

2.1: Transmission Service 2015 Overview

Studies are conducted as a result of customer-submitted requests for long-term firm transmission service to determine if the SPP transmission system and neighboring Transmission Providers can accommodate transmission service above what is currently in use. In October of 2013, SPP implemented a new process for evaluating transmission service requests, designed to expedite the evaluation of requests already in the queue (The “Backlog Clearing Process”). The Backlog Clearing Process¹ was intended to clear the queue of pending requests in anticipation of a new, more efficient and streamlined process that will permanently replace the existing. The Backlog Clearing Process will end with the conclusion of Study 2015-AG1. The successor process to the Backlog Clearing Process became effective with the closing of the open season on November 30, 2015 for Study 2015-AG2².

SPP will combine all long-term point-to-point and long-term designated network resource requests received during a specified period of time into a single Aggregate Transmission Service Study. Using this Aggregate Transmission Service Study process, the Transmission Provider will combine all requests received during an open season to develop a more efficient expansion of the transmission system that provides the necessary ATC to accommodate all such requests at the minimum total cost.

During 2015, SPP staff posted 11 Aggregate Facilities Studies, as compared to 22 in 2014, to meet 60-day study completion deadlines and FERC Order 890 requirements. Order 890 requires Transmission Providers to file notice with FERC if more than 20% of the Facilities Studies in any two (2) consecutive calendar quarters are not completed in the 60-day study window. In 2015, SPP was not required to file with FERC, as there were no two (2) 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 2015. 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.



¹ The SPP Tariff filing can be found at the following location: [2013-11-08 Ag Study Backlog Clearing Process Tariff Revisions ER13-2164-001](#)

² The SPP Tariff filing can be found at the following location: [2015-05-19 Order Ag Study Process Revisions ER15-1414](#)

	2013-AG2-AFS-1	2013-AG2-AFS-8
# of requests-beginning of study	31	
# of MW-beginning of study	15,161	
# of requests-end of study		16
#of MW-end of study		13,842

Table 2.1: Initial and Final Request and Capacity Amounts for 2013-AG2

	2013-AG3-AFS-1	2013-AG3-AFS-6
# of requests-beginning of study	33	
# of MW-beginning of study	2,889	
# of requests-end of study		13
#of MW-end of study		1,379

Table 2.2: Initial and Final Request and Capacity Amounts for 2012-AG2

	2014-AG1-AFS-1	2014-AG1-AFS-6
# of requests-beginning of study	45	
# of MW-beginning of study	5,853	
# of requests-end of study		14
#of MW-end of study		564

Table 2.3: Initial and Final Request and Capacity Amounts for 2013-AG3

The table below summarizes the Aggregate Studies for transmission service requests received in 2015.

Study	Currently Active Iteration	Due Date	Requests Currently in Study	MW Currently in Study
2015-AG1	AFS-6	1/27/2016	19	2,004
2015-AG2	AFS-1	5/13/2016 for study completion	30	2,334
Total			49	4,338

Table 2.4: Active 2015 Aggregate Studies

The graph below shows the total estimated cost of Transmission Service projects included in the 2016 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.

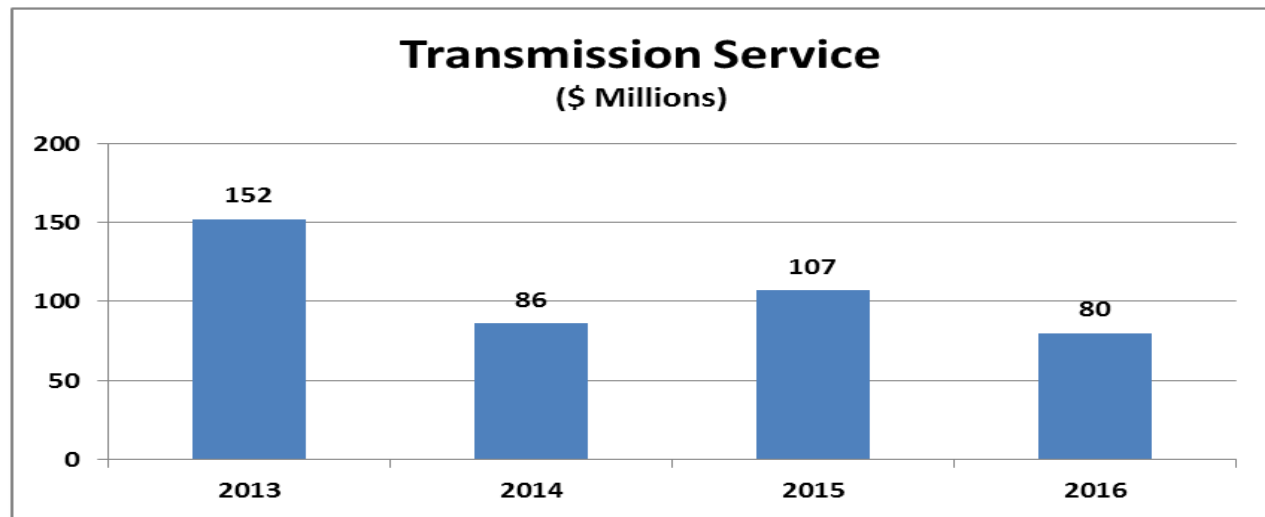


Figure 2.1: STEP Cost Estimate Comparison for Transmission Service Projects – 2013-2016

A list of Transmission Service projects completed in 2015 can be found in [Section 16](#).

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 was one (1) NTC issued in 2015 as a result of the AQ process.

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

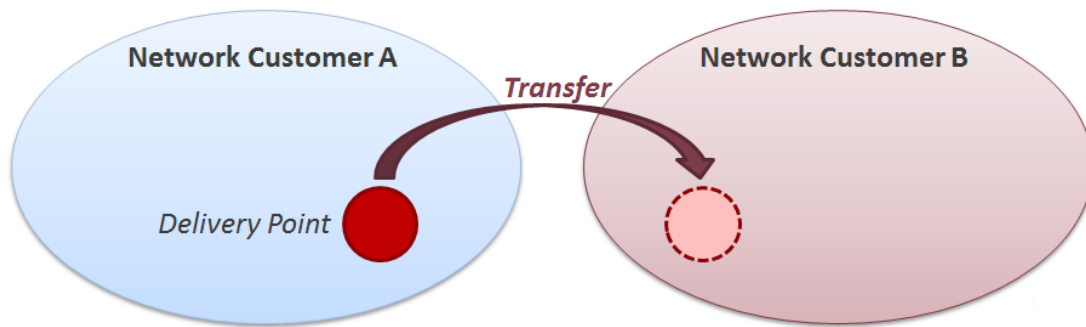
Study Year	Delivery Point Requests	Full Studies Required	Load Increase
2011	84	9	550 MW
2012	156	51	1,200 MW
2013	87	22	882 MW
2014	96	19	1,032 MW
2015	89	13	1,271 MW

Table 2.5: AQ Study Summary – 2011-2015

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 Aggregate Study process by reducing the number of requests in the studies.

During 2015, seven (7) DPT studies were posted. Service was granted for all seven DPT studies. One (1) LTSR study was requested and posted.



Section 3: Generation Interconnection

3.1: Generation Interconnection Overview

A Generation Interconnection (GI) 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.



As of October 30, 2015, SPP has received 103 SPP and 6 affected system GI requests, compared to the 81 SPP and 16 affected system study requests received through the same period in 2014. As of that date, there were 96 active queue requests for 15,387 MW under study, and 53 requests had been removed from “study” status either from being withdrawn by the Customer or SPP or by the Customer executing a Generation Interconnection Agreement (GIA). The 6 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 Generation Interconnection projects included in the 2016 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 Generation Interconnection Studies that have either been issued NTCs or are approved and are awaiting the issuance of an NTC, the completion of Generation Interconnection related projects, and the increase and decrease of Transmission Owner submitted project cost estimates within the applicable STEP timeframe.

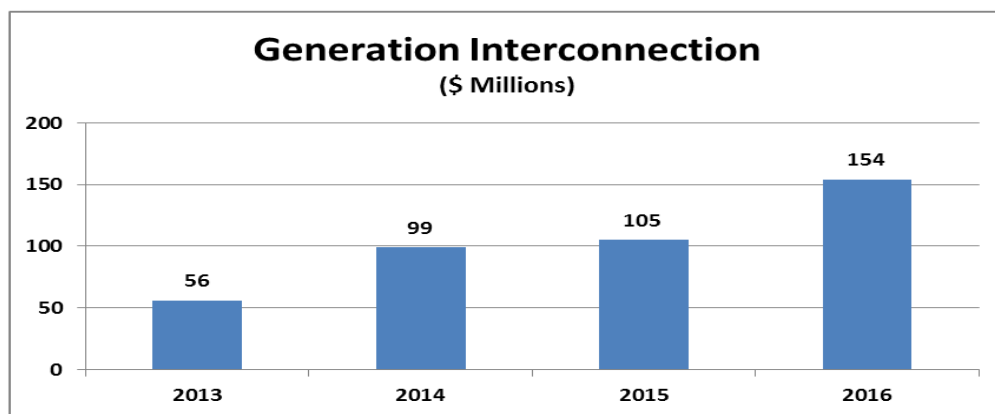


Figure 3.1: STEP Cost Estimate Comparison for Generation Interconnection Projects – 2013-2016

A list of Generation Interconnection projects completed in 2015 can be found in [Section 16](#).

Section 4: Integrated Transmission Planning

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 (ITP20), performed once every three (3) years, identifies transmission projects, generally above 300 kV, needed to develop a grid flexible enough to provide benefits to the region across multiple scenarios.

The 10-Year Assessment (ITP10), performed once every three (3) years, focuses on facilities 100 kV and above to meet system needs over a 10-year horizon.

The Near Term Assessment (ITPNT), performed annually, 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 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. A list of ITP projects completed in 2015 can be found in [Section 16](#).

4.1: ITP20

The first phase of the ITP process was completed with the Board of Directors' acceptance of the ITP20 Report on July 30, 2013. For more information on the 2013 ITP 20-Year Assessment, see the [full report](#) available on SPP's website (SPP.org > Engineering > Transmission Planning). A list of 2013 ITP20 projects can be found in Section 17.

During its July 29, 2014 meeting, the SPP BOD discussed the necessity of beginning the 2016 ITP20 in January 2015 as scheduled. The Board decided to defer work on the 20-Year Assessment for further consideration at the October 2014 Markets and Operations Policy Committee (MOPC) meeting.

At its October 25, 2014 meeting, the BOD approved the MOPC's recommendation regarding the timing of the ITP10 Assessment and recommended the submission of a deferral to the Federal Energy Regulatory Committee (FERC) seeking authorization to delay the performance of the ITP20 as prescribed by SPP's OATT.

The FERC granted SPP's ITP20 deferral request on April 20, 2015 per [Docket No. ER15-492-000](#) with the waiver effective January 1, 2015.

4.2: 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 OATT. 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.

During its September 2014 meeting, the Strategic Planning Committee (SPC), unanimously supported a proposal from SPP to delay the start of the Board-directed 2017 ITP10 by at least six (6) months while the EPA 111(d) Clean Power Plan Rule and the integration of the Integrated System (IS) facilities were finalized.

At its October 2014 meeting, the MOPC unanimously approved a recommendation from the Economic Studies Working Group (ESWG) per direction of the SPC to delay the start of the 2017 ITP10 by at least six (6) months.

At its October 25, 2014 meeting, the BOD approved the MOPC's recommendation regarding the timing requirements of the ITP10 Assessment and permitted SPP to commence the ITP10 Assessment in January 2015, to be completed no later than January 2017. The BOD recommended the submission of a timing change request to the Federal Energy Regulatory Committee (FERC) seeking authorization to for the performance of the ITP10 in lieu of an ITP20 Assessment as prescribed by SPP's OATT.

The FERC granted SPP's ITP10 request on April 20, 2015 per [Docket No. ER15-492-000](#) with the waiver effective January 1, 2015.

The 2017 ITP10 will be conducted based on three futures. These futures will consider evolving changes in technology, public policy, and the Clean Power Plan Rule that may influence the transmission system and energy industry as a whole. By accounting for multiple future scenarios, SPP staff will assess the transmission needs that arise for various uncertainties. In all futures, EPA environmental regulations, as known or anticipated at the time of the study, will be incorporated.

SPP staff intends to finalize the 2017 ITP10 Report and Portfolio in January 2017.

4.3: 2016 ITP Near-Term (ITPNT)

The third phase of the ITP study process includes the ITP Near-Term Assessment performed under the requirements of Attachment O, Section III of the SPP OATT.

The ITPNT analyzes the SPP region's immediate transmission needs over the near-term planning horizon. The ITPNT assesses: (a) regional upgrades required to maintain reliability in accordance with the NERC Reliability Standard TPL-001-4 P1 events 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 MOPC and subsequently recommended to the Board of Directors for approval. Following approval by the Board of Directors, staff will issue Notification to Construct (NTC) letters for upgrades that require a financial commitment within the next four-year timeframe.

During its August 2014 meeting, the Transmission Working Group (TWG), approved a shift of the ITP Near-Term Assessment by three (3) months. The MOPC during its October 2014 meeting unanimously approved the TWG recommendation to move the start of the 2016 ITPNT Assessment to May 1, 2015 and begin all future ITP Near-Term Assessments after the Board of Directors meeting in April of each year.

SPP staff intends to finalize the 2016 ITPNT Report and Portfolio in April 2016.

Section 5:Balanced Portfolio

The Balanced Portfolio was an initiative to develop a group of economic transmission upgrades benefitting the entire SPP region and to allocate those project costs regionally. The benefits of this group of 345 kV transmission upgrades have been demonstrated by model analysis to outweigh the costs, and the regional cost sharing creates balance across the SPP region. For more information on the Balanced Portfolio, see the [full report](#) (SPP.org > Engineering > Transmission Planning>Balanced Portfolio).

The SPP Board of Directors approved the Balanced Portfolio projects in April 2009 and directed staff to finalize the Balanced Portfolio Report in accordance with the SPP Tariff and then issue Notifications to Construct (NTC). NTCs for the approved Balance Portfolio projects were issued in June 2009.

The last Balanced Portfolio project still under construction was placed into service on April 30, 2015 when Transource Missouri energized the 30-mile 345 kV line from Iatan to Nashua in northwest Missouri.

Figure 5.1 below is a graph of the total estimated costs attributed to Balanced Portfolio projects for the 2016 STEP and previous years. The estimated project costs are affected by the completion of projects, as seen in Table 5.1, and adjustments in project cost estimates by project owners.

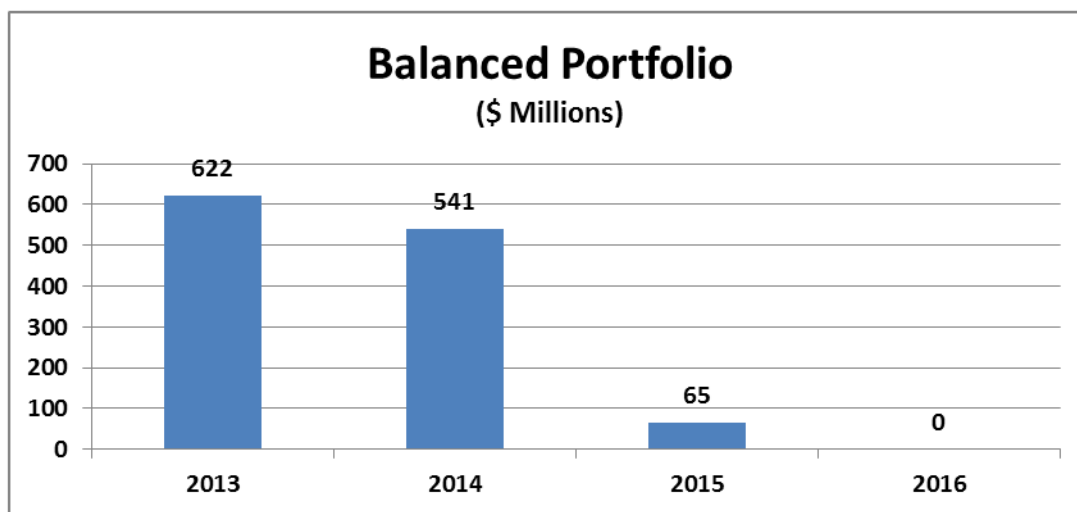


Figure 5.1: STEP Cost Estimate Comparison for Balanced Portfolio Projects – 2013-2016

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
200189	703	Transource Missouri	Multi - Iatan - Nashua 345 kV	\$62,949,252

Table 5.1: Balanced Portfolio Projects Completed in 2015



Figure 5.2: Approved Balanced Portfolio

Section 6: High Priority Studies

Attachment O, Section IV.2, of SPP's Open Access Transmission Tariff (OATT) 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 OATT.

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 2015 can be found in [Section 16](#). Study details follow in sections 6.1 and 6.2

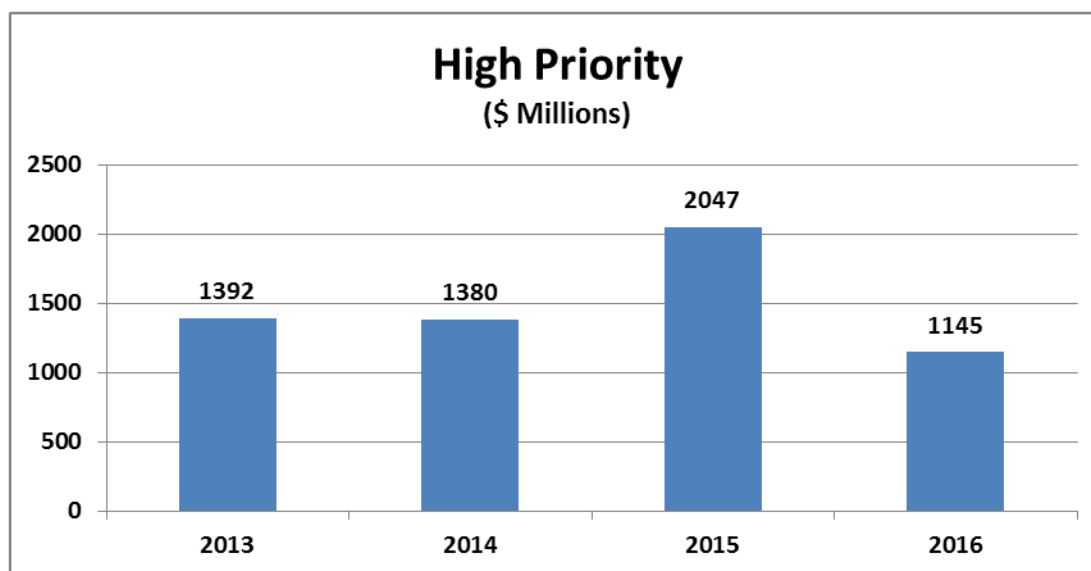


Figure 6.1: STEP Cost Estimate Comparison for High Priority Projects – 2013-2016

6.1: 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).

There were no Priority Projects completed in 2015, however, the last Priority Projects still under construction are projected to be in-service by the end of 2016 and are listed in Table 6.1 below.

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
20097	938	TSMO	Multi – Nebraska City – Mullin Creek – Sibley 345 kV (GMO)	\$226,072,098
20098	939	OPPD	Line – Nebraska City – Mullin Creek 345 kV (OPPD)	\$70,361,776

Table 6.1: Priority Projects

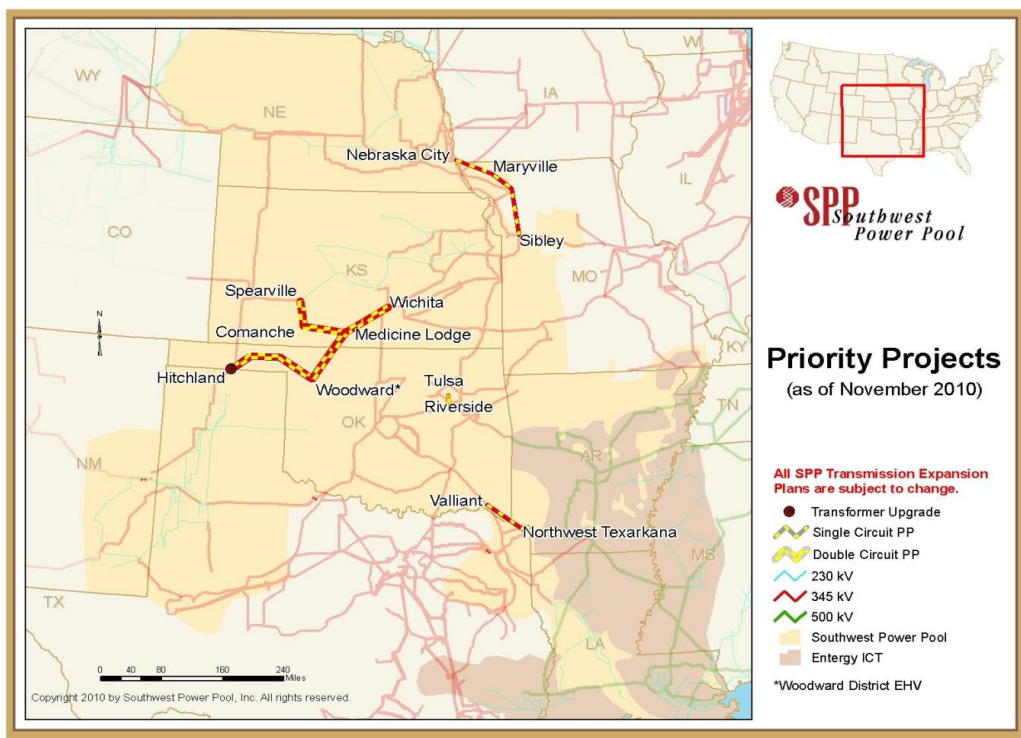


Figure 6.2: SPP Priority Projects

6.2: 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, SPP Board of Directors Chairman Jim Eckelberger directed the performance of a high priority study to evaluate transmission needs resulting from expected incremental loads that had not previously been studied. SPP staff began the HPILS after its scope was approved, with no opposition, by the MOPC at their July 16-17, 2013 meeting. Stakeholder oversight of the study was provided primarily by the High Priority Incremental Load Study Task Force (HPILSTF) established by the TWG.

HPILS was completed and a draft report issued in March of 2014. The HPILS report included an explanation of study processes and assumptions, an identification of projects needed over the 10-year study horizon to reliably meet load growth expectations, and a list of projects recommended for construction. Over a series of meetings in late March and early April of 2014, various SPP stakeholder groups reviewed the HPILS report. The report was unanimously approved by the HPILSTF. The TWG approved that the report indicated completion of the technical requirements of the HPILS scope. The MOPC reviewed the report at their April 15-16 meeting but, after a failed motion to “approve the HPILS report and Appendix C as submitted”, did not forward a recommendation to the BOD regarding the HPILS report and recommended projects.

Staff presented the HPILS report to the BOD and Members Committee for consideration at their April 29, 2014 meeting. Staff recommended that the BOD direct construction of those projects that meet near-term needs and as shown in Attachment C of the 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.

The BOD approval of the HPILS projects recommended for construction is supported by the statements shown below:

1. The projects were identified by a study performed in accordance with a stakeholder approved scope.
2. The projects were identified as cost effective solutions that met identified reliability needs associated with expected incremental load.
3. The projects approved for construction address the more urgent, near-term reliability needs such that risks associated with realization of incremental load in lower than expected amounts are minimized.
4. Concerns raised during MOPC discussion were sufficiently addressed with approval of the recommendations presented to the BOD.

HPILS was conducted in accordance with the high priority study provisions outlined in the OATT. In accordance with the HPILS scope, a cost-effective transmission plan was developed to address reliability needs over a 10-year period under updated load growth and corresponding generation expansion assumptions. The HPILS also reevaluated three projects previously approved in the 2012 Integrated Transmission Plan 10-Year Assessment (ITP10) for which Notifications to Construct with Conditions (NTC-Cs) had been suspended by the Board in April 2013, pending further evaluation. The study included an evaluation of project costs and economic benefits under selected scenarios and sensitivities. HPILS included the economic analysis of the total portfolio as well as the incremental benefit of the suspended NTC-C for the Tuco-Amoco-Hobbs or equivalent solutions.

The total cost³ of the projects for which new NTCs were recommended was estimated to be \$573 million. Regarding the three NTC-Cs that were re-evaluated as part of the study, it was determined that the Tuco – New Deal 345 kV and Grassland – Wolfforth 230 kV projects were no longer needed. As a result, the associated NTC-Cs were withdrawn, which removed \$114 M from the STEP.

HPILS identified the Tuco-Yoakum-Hobbs 345 kV project as a better performing and lower cost alternative to the Tuco-Amoco-Hobbs 345 kV project. The Tuco-Amoco-Hobbs NTC-C was modified to reflect the Tuco-Yoakum-Hobbs project with a 2020 in-service date at a cost savings of at least \$20 million.

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

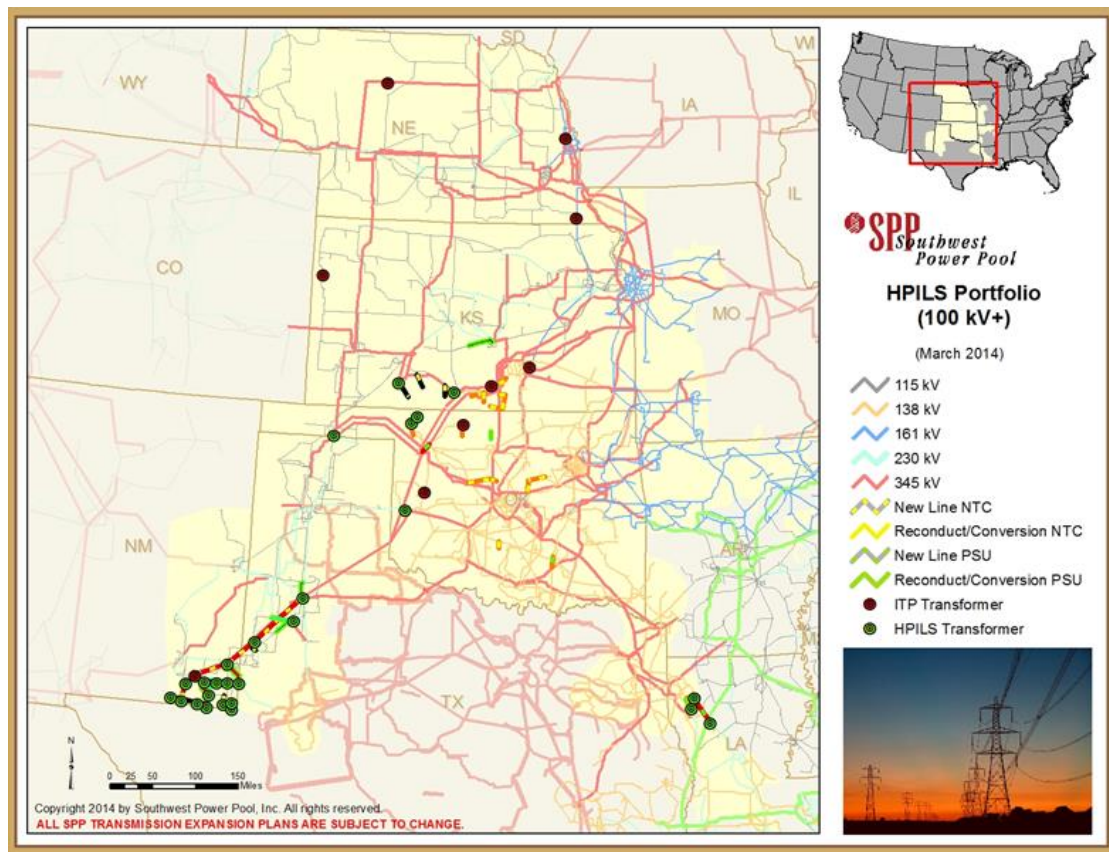


Figure 6.3: Finalized HPILS Portfolio (100 kV and above)

³ Unless otherwise specified, all costs are Engineering and Construction costs in 2014 dollars.

Section 7: Sponsored Upgrades

Sponsored upgrades are Network Upgrades requested by a Transmission Customer or other entity that have not been previously identified and 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 generation 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 their review as a part of the transmission planning process.

Two (2) Sponsored upgrades were completed in 2015 and are listed in the table below.

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
	30310	SPS	Device – Norton Reactor 115 kV	\$5,653,536
	30345	LES	Line – SW 7 & Bennet – 40 th & Rokeby 115 kV Ckt 1	\$7,531,000

Table 7.1: Completed Sponsored Upgrades

Section 8: Regional Cost Allocation Review (RCAR)

The Regional Cost Allocation Review (RCAR) is an analysis 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 Notifications to Construct (NTC) and funded through Highway/Byway are assessed for each zone. Any zone with benefits that are not roughly commensurate with their costs (defined as 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:

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

Upon conclusion of the RCAR Report in October 2013, SPP staff and the Regional Allocation Review Task Force (RARTF) recommended that a second RCAR process (RCAR II) be commenced in parallel with the 2015 ITP10 Assessment, and that it be completed shortly after the completion of the 2016 ITP10. The RCAR II analysis was originally scheduled for completion in July of 2015, however, on March 13, 2015, the 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 to be used in the RCAR II analysis have been developed in 2015 and will continue development in 2016. The RCAR II is currently scheduled for completion in July 2016.

For information on the October 2013 RCAR Report, see the full [report](#) (SPP.org > Org Group Documents>Regional Allocation Review Task Force>RARTF>Meeting Materials>Minutes & Materials>RCAR Final Report 10/10/13).

Section 9: Interregional Coordination

9.1: Interregional Planning

In 2015, SPP participated in two different joint planning processes with neighboring transmission providers. 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 and the resulting product of a Coordinated System Plan (CSP). SPP also performed a Regional Review of the potential interregional projects that resulted from the SPP-MISO CSP.

The SPP-AECI JOA requires a study be performed every other year to assure the reliable, efficient and effective operation of the transmission system. SPP completed the year-long effort of performing the 2014 SPP-AECI CSP by providing the results and final report from the study to the SPP MOPC and Board of Directors at their respective meetings in January 2015. The 2014 SPP-AECI CSP study did not result in any joint transmission solutions with AECI being recommended. At the conclusion of the study, SPP and AECI continued to coordinate planning issues and opportunities identified in both respective regional planning processes on several occasions throughout the rest of 2015. SPP staff participated in AECI's 2015 Long Range Plan stakeholder meetings, and AECI staff participated and provided input into the SPP ITP studies. SPP will work with AECI in 2016 to begin another joint planning effort to identify potential joint transmission projects that are mutually beneficial to both entities.

Also in 2015, SPP continued work on the SPP-MISO CSP study which began in early 2014 pursuant to the joint planning procedures contained in the SPP-MISO JOA. The purpose of the SPP-MISO CSP study was 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 incorporated an economic evaluation of seams transmission issues and an assessment of potential reliability violations. The 18 month joint study effort was concluded in June 2015 with a recommendation by the SPP-MISO Joint Planning Committee (JPC) to approve three (3) potential Interregional Projects for further evaluation in each party's respective Regional Review process. A high-level overview of the scope of the CSP study is shown in the table below:

MISO-SPP CSP Tasks	
Scope Development	
1. Develop and finalize scope document for CSP study	
2. Develop detailed schedule for CSP study	
3. Economic Evaluation and Reliability Assessment	
Economic Evaluation	Reliability Assessment
Future and Model Development	Perform steady-state reliability assessment using jointly developed power flow models
Historical and Projected Congestion Analysis	Test system stability using scenario(s) appropriate for studying dynamics.

MISO-SPP CSP Tasks	
• Solution Development	• Determine if there are interregional alternatives to proposed regional solutions
• Solution Evaluation and Robustness Testing	• Evaluate potential transmission solutions, as needed, based on identified issues.
• Reliability Analysis	
• Determine interregional cost allocation	
4. Draft Coordinated System Plan study report	
5. Regional Evaluation and Cost Allocation (if needed)	

Figure 9.1: MISO-SPP CSP Overview

MISO and SPP staff focused efforts on two primary sets of analyses - an economic evaluation and a reliability assessment. For the economic assessment, a 2024 joint transmission model was built specifically for the SPP-MISO CSP study. SPP and MISO staff evaluated the projected congestion resulting from the 2024 model to identify a list of economic needs impacting the SPP-MISO seam. Both staff and stakeholders collaborated to propose potential transmission projects to solve or alleviate the identified economic needs, which were then tested for APC and other benefits. Based on those results, SPP and MISO identified three projects for consideration as an Interregional Project:

Elm Creek to NSUB 345 kV

The proposed Interregional Project Elm Creek – NSUB 345 kV is a new transmission line heading north from the Elm Creek 345 kV substation in North-Central Kansas (Cloud County) to a new 345 kV substation that taps the existing Mark Moore – Pauline 345 kV line in Nebraska. The project was proposed to primarily relieve congestion on the Northeast to Charlotte 161 kV flowgate in the Kansas City area. MISO and SPP’s analysis showed that relieving the congestion on this flowgate provided benefit to both parties. In addition to the Northeast to Charlotte flowgate, other congestion was relieved or mitigated throughout the combined transmission system, primarily along the north-south corridor between SPP and MISO. Based on benefits estimated to be received by each party, the cost allocation proposed with this project was 80% to SPP and 20% to MISO. SPP estimated an engineering and construction (E&C) cost estimate of approximately \$140.6 million with an assumed in-service date of 2024. Since the proportion of cost paid by MISO and SPP is based on the proportion of estimated benefits, both MISO and SPP’s B/C ratio was projected to be 1.22.

Alto Series Reactor

The proposed Interregional Project New Series Reactor on Alto – Swartz 115 kV adds a 10% reactor on 100 MVA base in series with the Alto-Swartz 115 kV line. The Alto-Swartz 115 kV line with which the reactor would be placed in series is located in North Central - Northwest Louisiana. The project was proposed to relieve congestion on the Swartz – Alto 115 kV flowgate. MISO and SPP’s analysis showed that relieving the congestion on this flowgate provided benefit to both MISO and SPP. This project completely mitigates the

congestion on the Swartz – Alto 115 kV flowgate. While the primary value from this project is addressing the projected congestion on Swartz – Alto 115 kV, additional congestion is mitigated on other flowgates, though in a smaller magnitude. Based on benefits estimated to be received by each party, the cost allocation proposed with this project was 14% to SPP and 86% to MISO. MISO estimated an engineering and construction (E&C) cost estimate of approximately \$5.3 million with an assumed in-service date of 2024. Since the proportion of cost paid by MISO and SPP is based on the proportion of estimated benefits, both MISO and SPP's B/C ratio was projected to be 4.32.

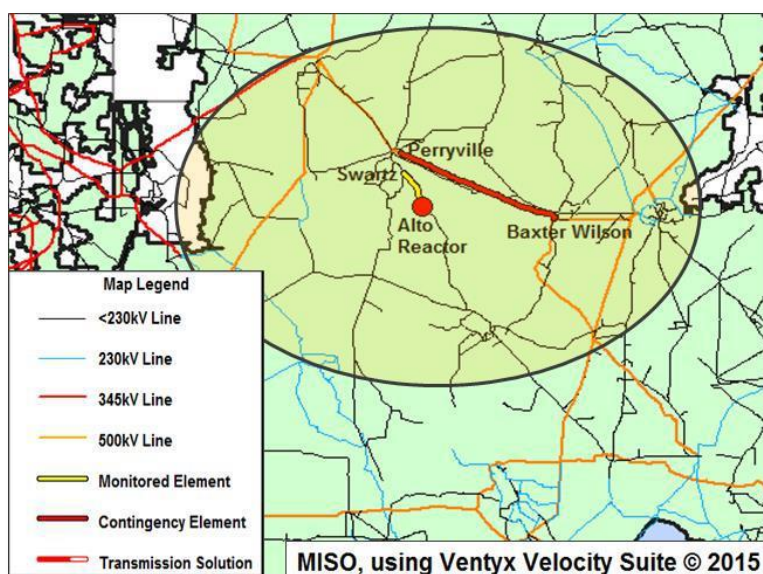


Figure 9.2: Alto Reactor

South Shreveport – Wallace Lake 138 kV Rebuild

The proposed Interregional Project South Shreveport – Wallace Lake 138 kV rebuild proposes rebuilding the existing 11 mile South Shreveport to Wallace Lake 138 kV line with upgrades at the South Shreveport and Wallace Lake substations. The project was proposed to primarily relieve congestion on the South Shreveport – Wallace Lake 138 kV flowgate. MISO and SPP's analysis showed that relieving the congestion on this flowgate provided benefit to both MISO and SPP. This project completely mitigates the projected congestion on the South Shreveport – Wallace Lake 138 kV flowgate. While the primary value from this project is addressing the congestion on the South Shreveport – Wallace Lake 138 kV, additional congestion is mitigated on other flowgates in the area, though in a smaller magnitude. Based on benefits estimated to be received by the parties, the cost allocation proposed with this project was 20% to SPP and 80% to MISO. SPP estimated an engineering and construction (E&C) cost estimate of approximately \$18.5 million with an assumed in-service date of 2024. Since the proportion of cost paid by MISO and SPP is based on the proportion of estimated benefits, both MISO and SPP's B/C ratio was projected to be 2.61.

Each of these projects individually demonstrated benefit to both SPP and MISO as well as APC benefit that exceed the cost of the project over the initial 20 years of the project life. These projects were recommended by MISO and SPP to the Interregional Planning

Stakeholder Advisory Committee (IPSAC) for endorsement to move from the interregional portion of the study onto the Regional Review process. Both the MISO and SPP portion of the IPSAC endorsed the projects with no opposition. Based on that recommendation the SPP-MISO JPC voted in favor for approving all three proposed Interregional Projects for review in both the MISO and SPP Regional Review processes.

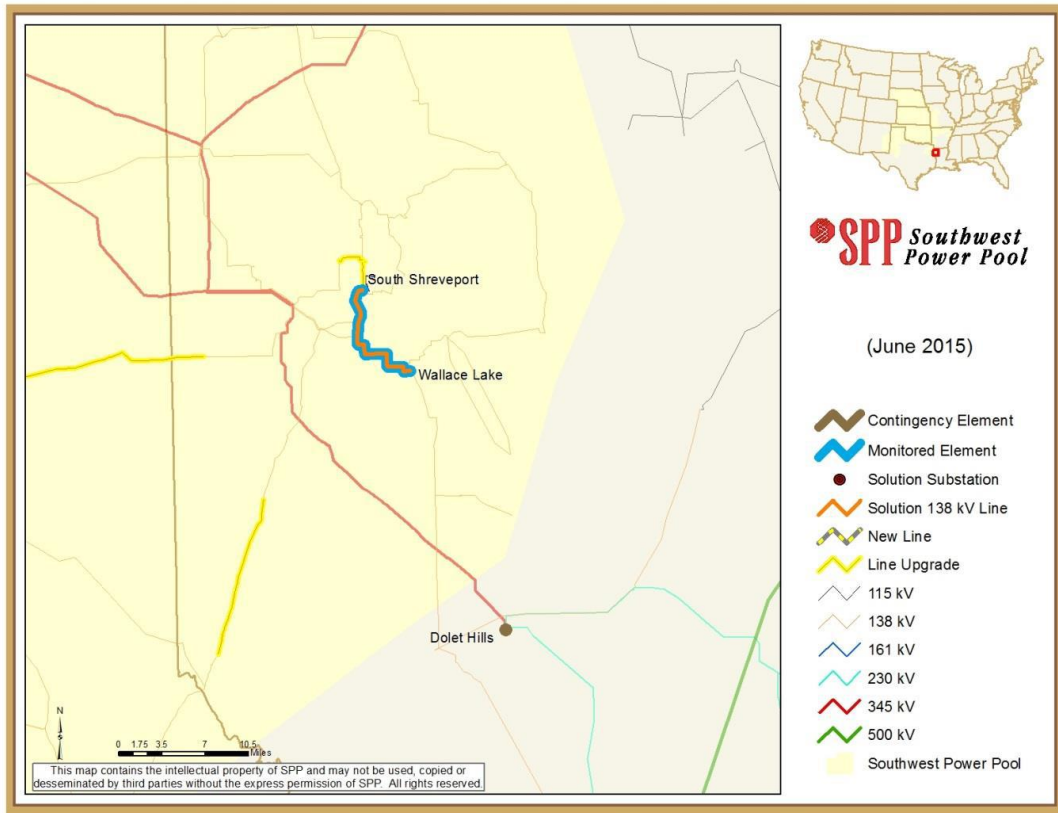


Figure 9.3: South Shreveport – Wallace Lake 138 kV Rebuild

To accomplish the reliability assessment, a joint power flow model for the year 2024 was built reflecting generation dispatch utilized in MISO and SPP’s respective regional planning processes specifically for the reliability portion of the SPP-MISO CSP. MISO and SPP staff also performed an ACCC assessment on the joint power flow model to determine a list of reliability needs along the SPP-MISO seam. Similar to the economic assessment, those needs were reviewed by staff and stakeholders to develop potential transmission projects addressing the issues. The projects that were tested were compared to MISO and SPP regional projects that also addressed the corresponding needs to determine if the potential Interregional Projects were more cost effective than the regional solutions. Based on the results of the study, SPP and MISO did not identify any Interregional Projects for the sole purpose of resolving reliability issues more cost effectively than MISO and SPP regional solutions. While no projects were identified from this portion of the SPP-MISO CSP to move through to the Regional Review process, the two projects below were highlighted throughout the process as being mutually beneficial to both MISO and SPP.

Fisher to Rodemacher 230 kV

Fisher to Rodemacher was a proposed new 50 mile 230 kV line addressing issues identified in the study located in west Louisiana. The project addressed projected thermal overloads in both MISO and SPP. The conceptual cost of the project was estimated to be approximately \$46M. MISO and SPP determined this project was not cost effective as both RTO's could address the projected overloads with regional projects for approximately \$10M each.

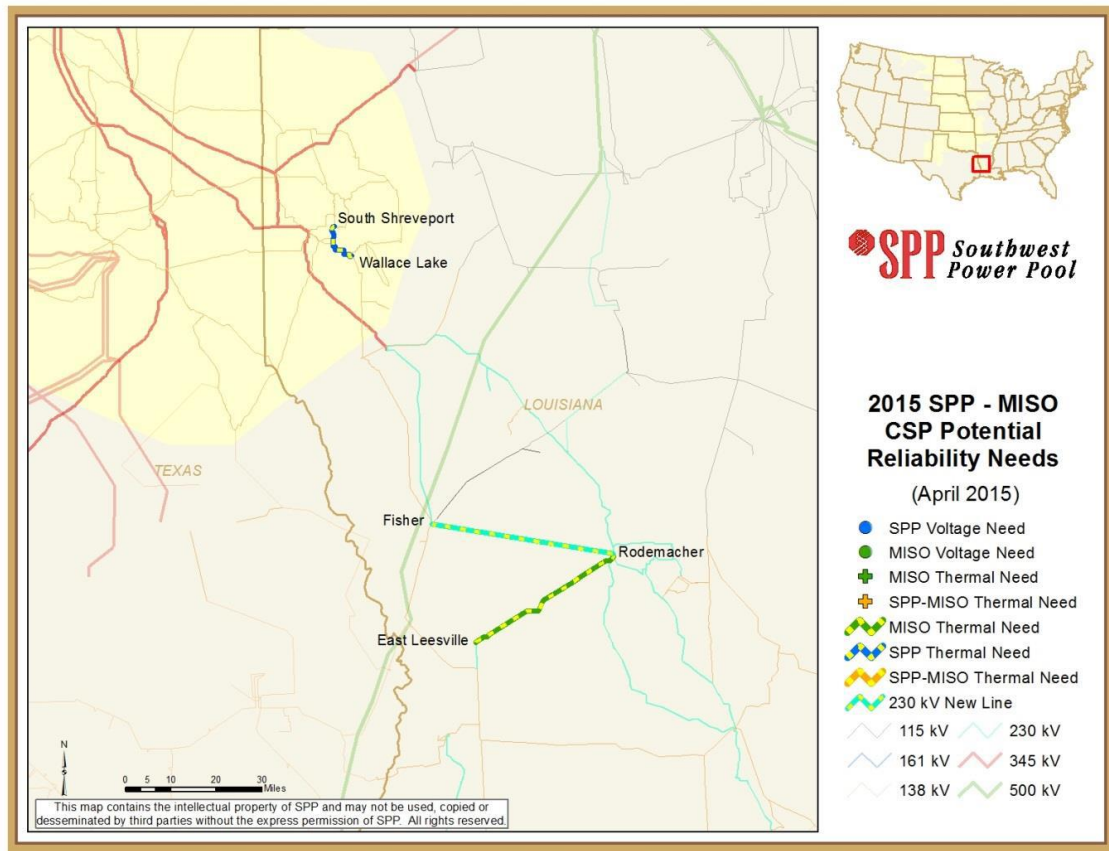


Figure 9.4: Fisher to Rodemacher 230 kV

Gobbler Knob to Datto 161 kV

Gobbler Knob to Datto was a proposed new 20 mile 161 kV line addressing issues identified in the study located in northeast Arkansas. The project addressed both thermal overloads and low voltages on the MISO system. The project also addressed low voltages on the SPP transmission system, specifically on portions of Southwestern Power Administration (SPA). The conceptual cost of the project was estimated to be approximately \$25M. The project potentially replaced \$44M of regional upgrades on the MISO system and \$3M of upgrades on the SPA system. MISO and SPP determined the project will not be recommended as a part of the MISO-SPP CSP due to the limited participation of SPA in SPP's planning region.

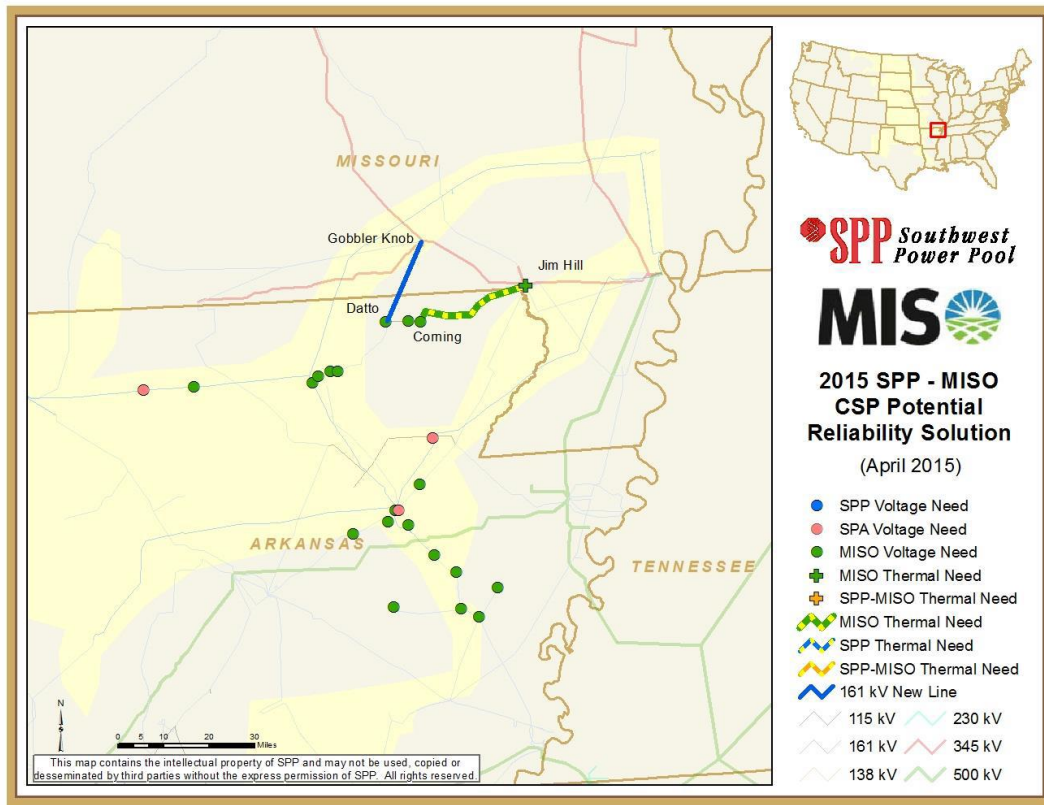


Figure 9.5: Gobbler Knob to Datto 161 kV

The conclusion of the 2014 SPP-MISO CSP was a significant milestone in SPP's efforts in interregional planning. In addition to the approval of three interregional projects into the Regional Review, the study resulted in a number of different benefits to both SPP and MISO. The completion of the study brought improved collaboration between SPP and MISO, increased model accuracy, enhanced regional models and processes, and improved understanding of each other's system and regional transmission planning processes. Another benefit of this study was that it tested the new Order 1000 Interregional Processes between SPP and MISO for the first time.

The 2014 SPP-MISO CSP study resulted in the identification of proposed Interregional Projects which, based on the analysis in the CSP, were expected to provide value to both SPP and MISO. The recommendation by the SPP-MISO JPC for these projects to continue from the CSP triggered the need for SPP staff to perform its Regional Review of the proposed Interregional Projects.

Regional Review

SPP evaluated three potential Interregional Projects in its Regional Review process which were recommended by the SPP-MISO JPC from the SPP-MISO CSP study. As described in the previous section of this STEP Report, these potential Interregional Projects were:

- Series Reactor on Alto-Swartz 115kV (Alto Series Reactor);
- Elm Creek – NSUB 345 kV (Elm Creek); and

- Rebuild South Shreveport – Wallace Lake 138 kV (South Shreveport).

The purpose of the Regional Review is to utilize SPP's own models and metrics to calculate the benefits to the SPP region from the potential Interregional Projects identified in the SPP-MISO CSP. The ESWG approved a study scope for the Regional Review for SPP staff to use a "Business-as-Usual" future. SPP utilized the 2015 ITP10 Future 1 model as the starting point for the Regional Review model. This model was then updated to include model enhancements that were identified in the latter stages of the 2015 ITP10, the CSP, and additional stakeholder review. The Regional Review scope described utilizing four benefit metrics to evaluate the potential Interregional Projects:

- Adjusted Production Cost;
- Avoided or Delayed Reliability Project Cost;
- Mitigation of Transmission Outage Cost; and
- Increased Wheeling Through and Out Revenue.

SPP performed a 40-year financial analysis of the potential Interregional Projects to determine the total present value of the benefits that could be attributed to SPP. The costs for the two potential Interregional Projects within SPP, South Shreveport to Wallace Lake and Elm Creek to NSUB, were estimated using SPP project cost estimation processes. These costs were study level estimates with a target level of accuracy of +/- 30%. The costs for the Alto Series Reactor was estimated using MISO's project cost estimation process with a target level of accuracy of +/- 30%.

SPP's evaluation of the Alto Series Reactor determined that this potential Interregional Project does not provide benefit to SPP. While SPP was only projected to be allocated 14% of the cost, which amounts to \$1.27 million over 40 years, SPP's 40-year APC benefit was estimated to be negative \$8.73 million based on the results of the Regional Review. Additionally this project does not provide benefits from the other three metrics: Increased Wheeling Through and Out Revenue, Mitigation of Transmission Outage Cost, and Avoided or Delayed Reliability Projects. SPP staff recommended that the Alto Series Reactor not be approved as an Interregional Project. In October 2015 the SPP Board of Directors voted to not approve this project as an Interregional Project.

SPP's evaluation of South Shreveport determined that this potential Interregional Project provided significant benefits to SPP. SPP was projected to be allocated 20% of the cost, which amounts to \$6.38 million over 40 years. SPP's 40-year APC benefit was \$39 million resulting in an APC-only B/C ratio of 6.2. This potential Interregional Project also was expected to provide Avoided or Delayed Reliability Project benefit of \$31.9 million and Mitigation of Transmission Outage Cost benefits of \$4.4 million, resulting in total 40-year benefits of \$75.7 million and a B/C ratio of 11.86.

Categories	Values
APC	\$ 39,328,392
Wheeling	\$ -
Trans Outages	\$ 4,444,108
Reliability	\$ 31,898,861
40-Yr PV Benefits	\$ 75,671,361
40-Yr PV Cost	\$ 6,379,772
NPC	\$ 69,291,589
B/C Ratio	11.86

Table 9.1: South Shreveport Evaluation Results

Even if SPP were responsible for a significantly higher percentage of the cost, this project would still be cost effective for SPP. Based on the results of the Regional Review, SPP staff recommended that this project be approved as an Interregional Project. In October 2015, the SPP Board of Directors voted to approve this project as an Interregional Project. If this project were to be approved by the MISO Board of Directors as well it would move forward as an Interregional Project.

SPP's evaluation of Elm Creek determined that this potential Interregional Project provided benefits to SPP. Benefits for this project are substantially less than what was calculated in the CSP. The primary driver for the benefit difference is the 2015 ITP10 approval of the voltage conversion for Iatan – Stranger 161 kV to 345 kV. This project was not included in the CSP study but was included in the Regional Review. SPP's 40-year APC benefit is \$190 million. This potential Interregional Project also provides Mitigation of Transmission Outage Cost benefits of \$21.4 million and Wheeling Through and Out Revenue benefit of \$8.3 million. The total 40-year benefit to SPP is \$219 million, resulting in a 40-year B/C ratio of 1.13.

Categories	Values
APC	\$ 189,646,497
Wheeling	\$ 8,335,167
Trans Outages	\$ 21,430,054
Reliability	\$ -
40-Yr PV Benefits	\$ 219,411,719
40-Yr PV Cost	\$ 193,479,100
NPC	\$ 25,932,619
B/C Ratio	1.13

Table 9.2: Elm Creek Evaluation Results

While the estimated B/C ratio of 1.13 is greater than 1, SPP staff recommended that Elm Creek not be approved as an Interregional Project. This recommendation is based on SPP staff's analysis that most of the estimated benefits of the Elm Creek project is

driven by an increase in coal generation, and given the uncertainty due to the Clean Power Plan SPP staff was not confident that the benefits would have a high likelihood of materializing under a carbon constrained future. Additionally, the Elm Creek project does not have an annual B/C ratio greater than 1.0 until 2034.

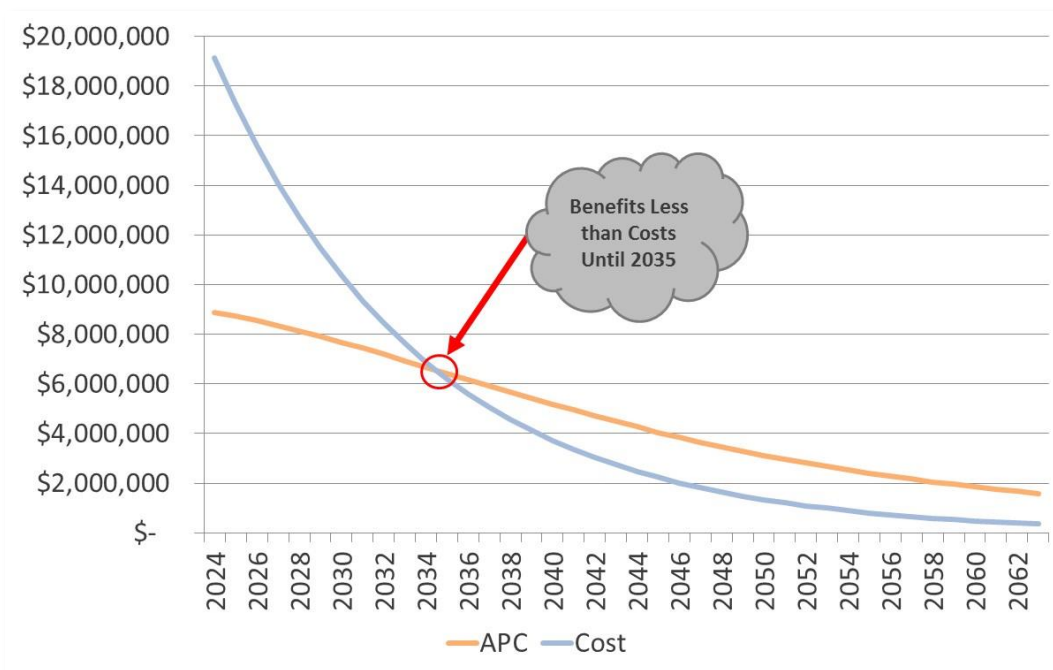


Figure 9.6: Elm Creek B/C Chart

SPP staff's conclusion to not recommend approval of the proposed Elm Creek Interregional Project because the majority of the benefits do not show up until later years and waiting to approve this project when there is more certainty represents a "no-regrets" approach. In October 2015 the SPP Board of Directors voted to not approve this project as an Interregional Project.

Of the three potential Interregional Projects resulting from the CSP, only South Shreveport was approved by the SPP Board of Directors as an Interregional Project.

In order for an Interregional Project to move forward it must also be approved by the MISO Board of Directors. MISO informed SPP staff that the MISO Board of Directors does not plan to take any action on these projects.

9.2: Interregional Requirements of Order 1000

SPP is currently waiting on a final response from FERC on its updated filings to satisfy the interregional requirements of Order 1000. SPP and MISO concluded a CSP in 2015 based on the pending SPP-MISO JOA. SPP also filed provisions to address the interregional requirements of Order 1000 with the Southeastern Regional Transmission Planning Region (SERTP). Most of the provisions were accepted by FERC in 2015 with only minor items outstanding. SPP and SERTP are fulfilling the filed provisions and most recently have set up the necessary logistical items needed to exchange planning data.

9.3: ITP Seams Coordination Enhancements

Similar to the enhancements documented in previous versions of this report, SPP continues to enhance and refine coordination with SPP's neighbors during SPP's regional planning studies. The goal of the enhanced coordination is to better ensure that the planning along the SPP seams is as robust as the transmission planning in the rest of the SPP footprint. To accomplish this, SPP's seams coordination objective is to coordinate with SPP's neighbors at every milestone of the regional planning process and on the same schedule as SPP staff coordinates with SPP stakeholders.

Coordination Activities

Seams coordination in the ITP studies focused on SPP's Tier 1 neighbors. Throughout the previous sections of this report, coordination with SPP's Tier 1 neighbors is discussed as it pertains to each specific section. The subsections below provide additional information regarding that coordination.

Model Development & Resource Plan

In addition to using the Multi-regional Modeling Working Group (MMWG) models as a starting point for SPP's model development, SPP also provided SPP's Tier 1 neighbors with an opportunity to review and provide edits to the ITP10 model. AECI and MISO each provided specific feedback on the modeling for their respective footprints. This review was similar to reviews performed by SPP stakeholders as the Tier 1 neighbors had the opportunity to review load, generation, topology, and other modeling inputs. Additionally, SPP's neighbors provided feedback on the resource plan that SPP used to model the retirements and generation expansion for 2024 in the ITP10. Since SPP and MISO have a process in place to share their regional planning models, SPP was able to utilize the resource expansion plan MISO used in the MISO Transmission Expansion Plan (MTEP) 2013. The MISO expansion plan was supplemented by incorporating additional resources, as needed, for Entergy and Cleco as these areas were not included in the MTEP 2013.

Tier 1 Needs Visibility

SPP worked with MISO prior to the 2016 ITPNT needs assessment to discuss the possibility of posting MISO's needs identified in the study along with SPP's regional needs. MISO agreed to allow SPP to post MISO's needs for informational purposes. The goal in doing this was to provide additional information to stakeholders proposing solutions and to facilitate evaluation of potential seams projects. By posting MISO's needs alongside the SPP needs we hoped to paint a clearer picture of the needs on both sides of the seam for study participants. Posting these needs provided stakeholders an opportunity to propose transmission solutions that address issues on both sides of the seam. SPP provided MISO the list of needs it planned to post prior to sharing the information with stakeholders.

Model Development & Resource Plan

In addition to using the Multi-Regional Modeling Working Group (MMWG) models as a starting point for SPP's model development, SPP also continued to provide SPP's Tier 1 neighbors with an opportunity to review and provide edits to the ITP models. This review was similar to reviews performed by SPP stakeholders as the Tier 1 neighbors are given the opportunity to review load, generation, topology, and other modeling inputs. Since

SPP and MISO have a process in place to share their regional planning models, SPP will continue to utilize the resource expansion plan MISO used in the MISO regional planning processes.

Leveraging Seams Assessments

The joint planning efforts that took place in 2015 provided an abundance of data and information from our neighbors that SPP did not previously have. This data was used to enhance SPP's regional planning efforts, specifically by updating SPP's regional planning models to increase model accuracy.

9.4: Eastern Interconnection Planning Collaborative

SPP is a participating Planning Authority ("PA") in the Eastern Interconnection Planning Collaborative (EIPC). A significant amount of time and effort has been expended by the EIPC to facilitate an improved understanding regarding the interdependencies between the bulk power electric system and the natural gas supply and delivery network.

In 2015, EIPC created two scenarios, updated base cases for 2025 Summer and 2025 Winter, that were used to perform two types of analyses. The two analyses were an interregional transmission "gap" analysis and a linear transfer analysis. In 2016, EIPC will be initiating the development of an EIPC Eastern Interconnection-wide production cost database with input from all EIPC members that SPP ought to consider leveraging to facilitate effective regional and interregional planning efforts.

The activities of the EIPC can be found on the EIPC website at www.eipconline.com.

Section 10: Sub-Regional Planning

Based on FERC Order 890 and Section III.2.b of Attachment O of the OATT, sub-regional areas were defined and local area planning meetings were held during 2015 in conjunction with the SPP planning summits.

The purpose of local area planning meetings is to identify unresolved local issues and transmission solutions at a more granular level than are accomplished at general regional planning meetings. Local area planning meetings provide stakeholders with local needs the opportunity to give advice and recommendations to the Transmission Provider and Transmission Owners. Local area planning meetings are open, coordinated, and transparent, providing a forum to review local area planning criteria as specified in Section II of the OATT, Attachment O. Feedback offered at each sub-regional meeting is taken into consideration by SPP staff when developing the regional reliability plan.

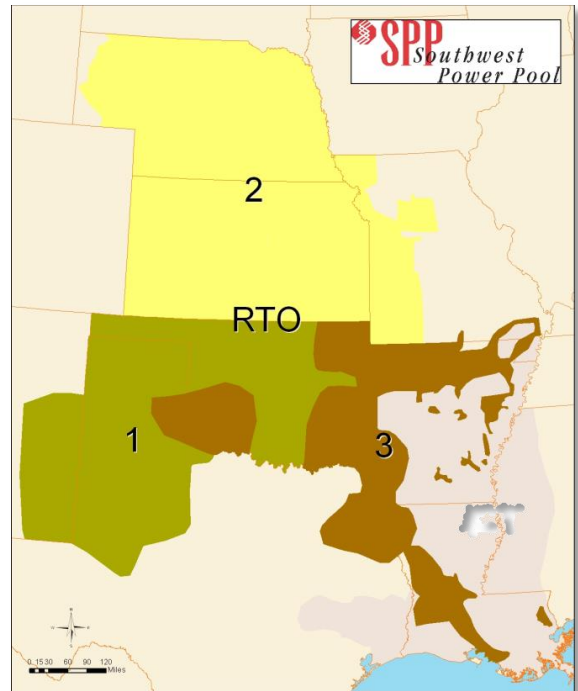


Figure 10.1: SPP Sub-Regional Map

10.1: Stakeholder Process and Forums

Notices for the sub-regional planning meetings are posted on SPP.org and distributed to the appropriate email distribution lists. Sub-regional planning meetings are open to all entities. Any regulatory agency is invited and encouraged to participate. The map above represents the three SPP local areas.

2015 Sub-Regional Meetings

SPP held a sub-regional planning meeting in conjunction with its Planning Summit at a face-to-face meeting on August 25, 2015 held in Little Rock at SPP's corporate headquarters. A joint sub-regional planning and Planning Summit teleconference was held on December 28, 2015. Subject matter experts from SPP staff were present at all of the meetings to receive suggestions, answer questions, and discuss any concerns that stakeholders had about the transmission needs in their respective region. Minutes for each sub-regional/Planning Summit meeting can be found on SPP's [website](http://www.spp.org) (SPP.org>Engineering>Transmission Planning).

Section 11: Integrated System

On October 1, 2015, the Integrated System (IS) was incorporated into SPP's footprint. The IS consists of the following entities:

- Western Area Power Administration – Upper Great Plains Region
- Basin Electric Power Cooperative
- Heartland Consumers Power District

The IS added approximately 5,000 MW of load and nearly 10,000 miles of high-voltage transmission lines increasing the number of SPP-managed transmission lines by 18% to more than 58,000 miles. The addition of the Integrated System into SPP has also opened opportunities to expand SPP's services to affiliated entities in the western interconnect. Any future additions, either through membership or contracted services, will have a visible impact on SPP's operation

On October 16, 2013, SPP published a report outlining the evaluation of the IS transmission grid by the SPP Engineering department. The purpose of this report was to aid in the decision-making process of both the IS and SPP members in the event that the IS decided to join the SPP RTO. The two main goals of this report were to;

- Evaluate the IS transmission system to determine whether it satisfies SPP's Planning Criteria and NERC TPL Standards
- Identify the SPP "need-by" dates of the transmission projects provided by the IS in relation to the assumed October 2015 integration date

The results of the analysis identified 24 potential reliability issues that needed to be mitigated by the IS in order to meet SPP's criteria. Of the 9 projects (9 principal with 21 sub-projects) currently planned by the IS to address Category A or B issues, 4 are needed before the assumed integration date of October 2015 and 5 (5 principal with 17 sub-projects) are needed after the assumed integration date of October 2015.

For information on the Integration Study Report, see the full [report](#) (SPP.org > SPP Documents>Org Group Documents/Transmission Working Group>TWG Meeting Materials>TWG 10/23/13 Agenda & Background Materials).

The projects associated with the integration of IS entities listed above and the cost impact to the STEP are captured in Table 11.1 below.

PID	Facility Owner	Project Name	Cost Estimate
30943	BEPC	Multi - AVS - Charlie Creek 345 kV	\$108,000,000
30944	BEPC	Multi - Charlie Creek - Judson - Williston 345/230 kV	\$126,400,000
30945	BEPC	Multi - Judson - Tande - Neset 345/230 kV	\$111,000,000
30946	BEPC	Multi - Lower Brule - Witten 230 kV	\$38,000,000

Table 11.1: Integrated System Projects

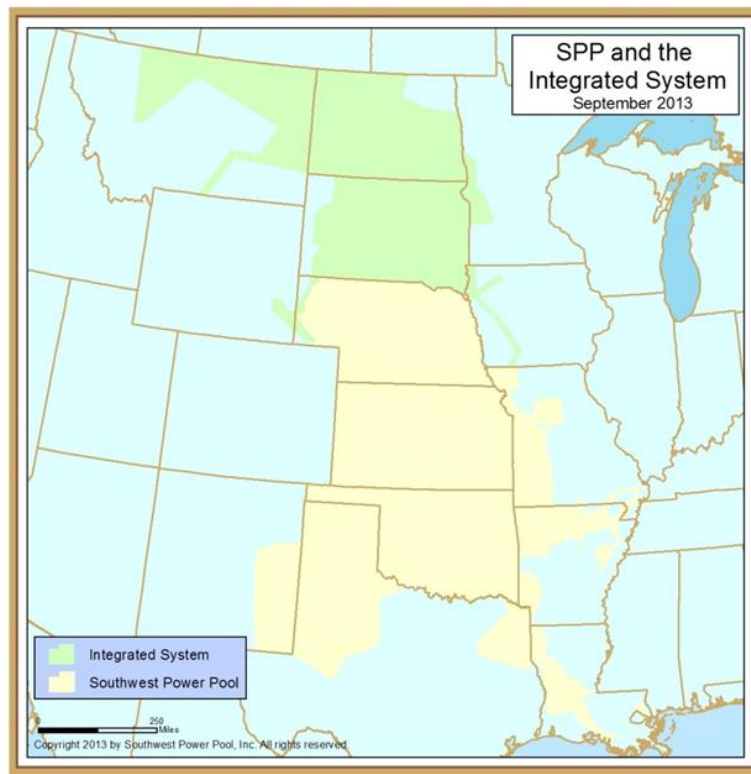


Figure 11.1: SPP and the Integrated System

Section 12: Project Tracking

12.1: NTC Letters Issued in 2015

After the SPP Board of Directors approves transmission expansion projects or once service agreements are filed with FERC, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners.

In 2015, SPP issued 35 NTC letters with estimated construction costs of \$519.9 million for 50 projects to be constructed over the next five years through 2020. Of this \$519.9 million, the project cost breakdown is as follows:

- \$7.3 million for Regional Reliability;
- \$5.5 million for Transmission Service;
- \$56.1 million for High Priority; and
- \$450.9 million for ITP projects.

A list of the NTCs issued in 2015 can be found in [Section 14](#).

12.2: Projects Completed in 2015

After the SPP Board of Directors approves transmission expansion projects or once Interconnection or Network Integrated Transmission Services Agreements are filed with FERC, SPP issues NTC letters to appropriate Transmission Owners. SPP actively monitors the progress of approved projects by soliciting feedback from project owners. Ninety-three (93) upgrades were completed as of December 31, 2015. The breakdown includes:

- 45 Integrated Transmission Planning (ITP) - \$475.2 million
- 6 Transmission Service (TSS) - \$20.9 million
- 16 Generation Interconnection (GI) - \$100.2 million
- 18 Regional Reliability (RR) - \$90.3 million
- 7 High Priority (HP) - \$106.4 million
- 1 Balanced Portfolio (BP) - \$63 million

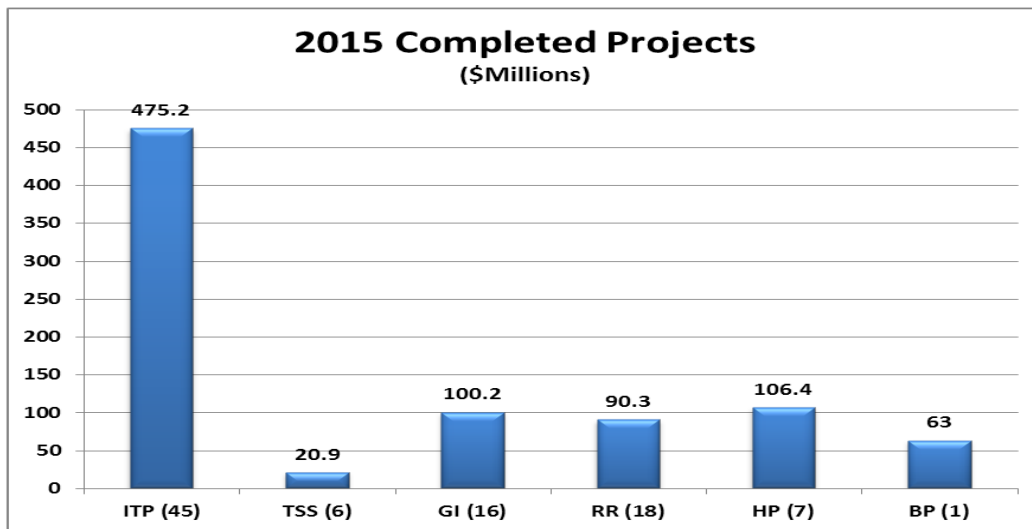


Figure 12.1: Projects Completed in 2015

Section 13: STEP List

The 2016 STEP List includes a comprehensive listing of transmission projects identified by the SPP RTO. Not all projects in the 2016 STEP List have been approved by the BOD, but all BOD-approved projects are included in the list. The 2016 STEP List also includes Tariff study projects, economic projects, and zonal projects.

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

- Balanced Portfolio – Projects identified through the Balanced Portfolio process
- Generation Interconnection – Projects associated with a FERC-filed Generation 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
- Zonal Reliability – Projects identified to meet more stringent local Transmission Owner criteria
- Regional Reliability – Projects identified in the Aggregate Study and Delivery Point Study processes to meet SPP Criteria

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 the RTO.

A copy of the 2016 STEP project list can be found at the following location:

http://www.spp.org/Documents/34210/2016%20SPP%20Transmission%20Expansion%20Plan%20Project%20List_01-05-2016.xlsx

Facility owner abbreviations used in the STEP List:

Abbreviation and Identification	
	Alliant Energy Corporation
AEP	American Electric Power
AECC	Arkansas Electric Cooperatives
AECI	Associated Electric Cooperative, Incorporated
BEPC	Basin Electric Power Cooperative
INDN	City Power & Light, Independence, Missouri
CUS	City Utilities, Springfield Missouri
DETEC	Deep East Texas Electric Cooperative
EDE	Empire District Electric Company
GRIS	Grand Island Electric Department (GRIS)
GRDA	Grand River Dam Authority
HCPD	Heartland Consumers Power District
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
MMPA	Minnesota Municipal Power Agency
Minnkota	Minnkota Power Cooperatives
MRES	Missouri River Energy Services
MDU	Montana-Dakota Utilities
NPPD	Nebraska Public Power District
NSP	Northern States Power Company
NWE	NorthWestern Energy (formerly Montana Power Company)
NWPS	NorthWestern Energy (formerly Northwestern Public Service)
OGE	Oklahoma Gas and Electric Company
OMPA	Oklahoma Municipal Power Authority
OPPD	Omaha Public Power District
PW	Prairie Wind Transmission
RCEC	Rayburn Electric Cooperative
SMGT	Southern Montana Electric Generation and Transmission Cooperative
SWPA	Southwestern Power Administration
SPS	Southwestern Public Service Company

SEPC	Sunflower Electric Power Corporation
WAPA / UGP	Western Area Power Administration/Upper Great Plains Region
WFEC	Western Farmers Electric Cooperative

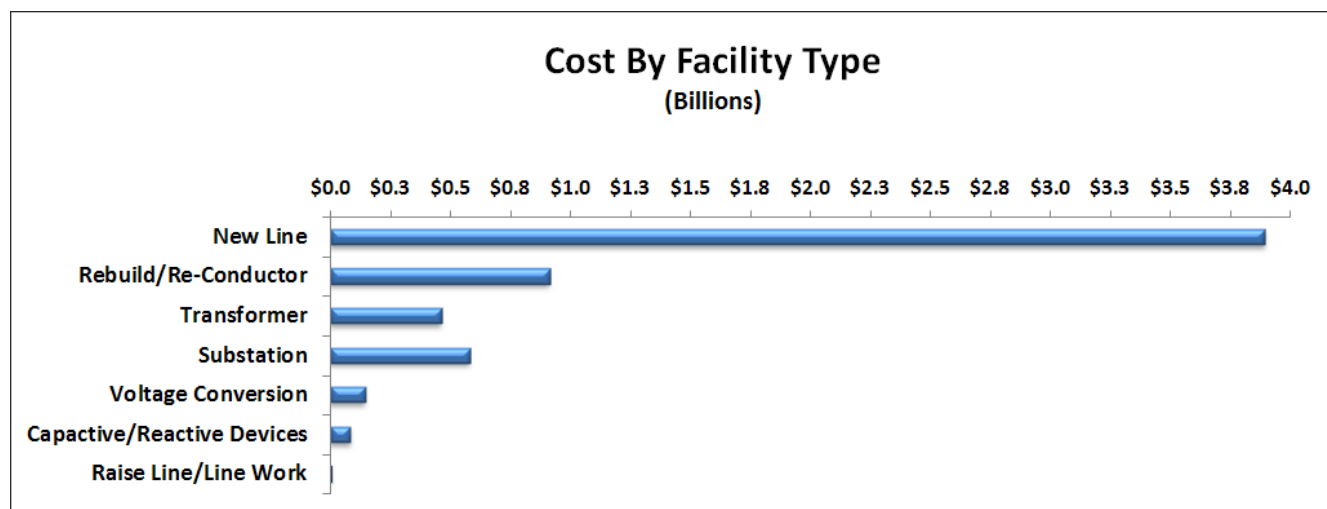


Figure 13.1: Total Cost by Facility Type (Dollars)

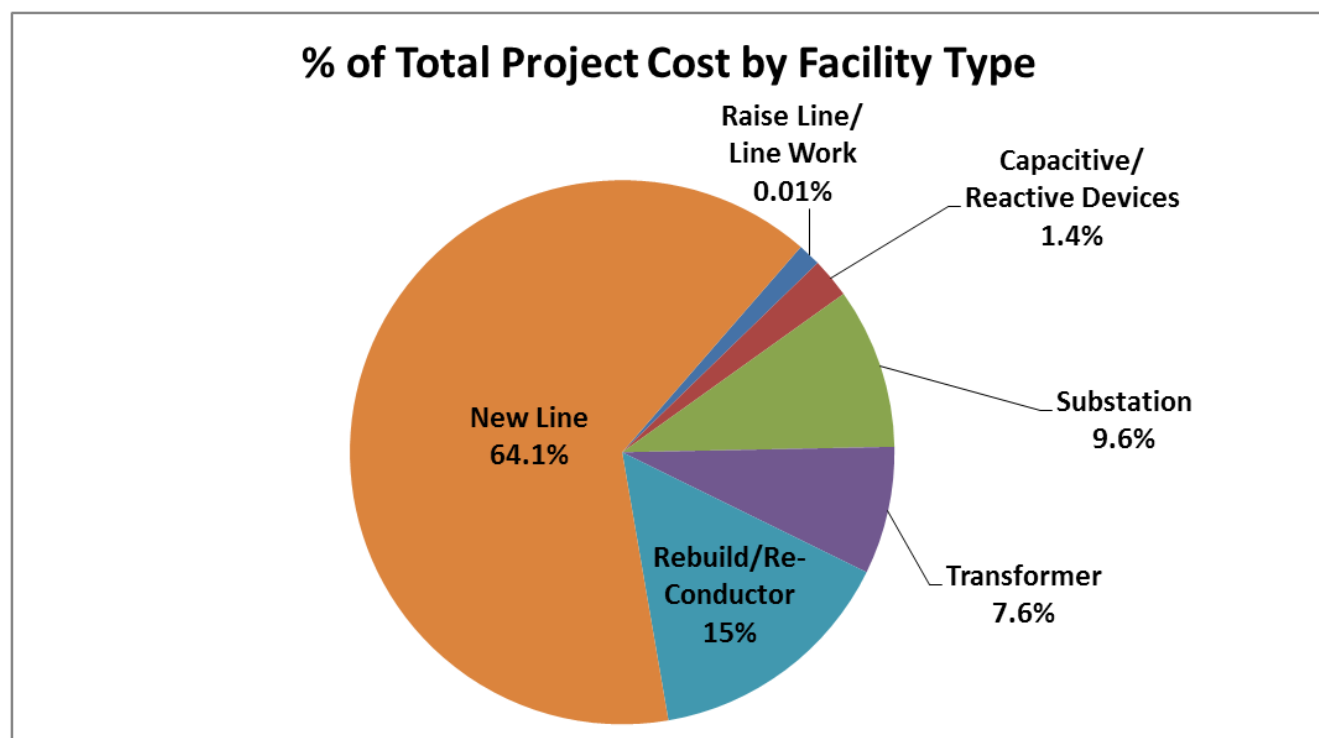


Figure 13.2: Percentage of Total Cost of Facility Type

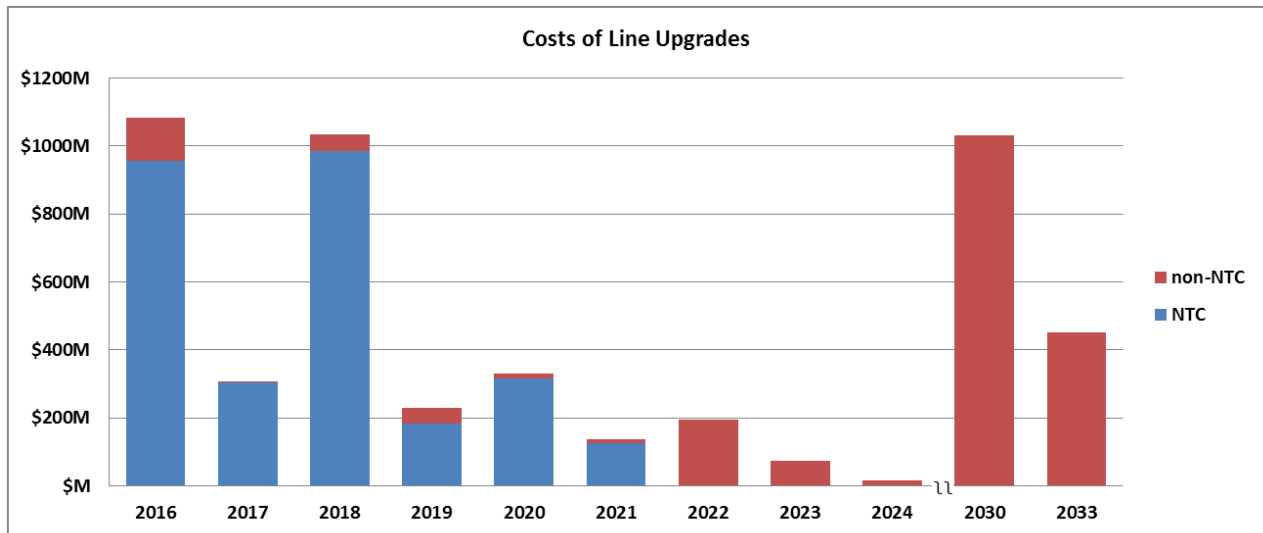
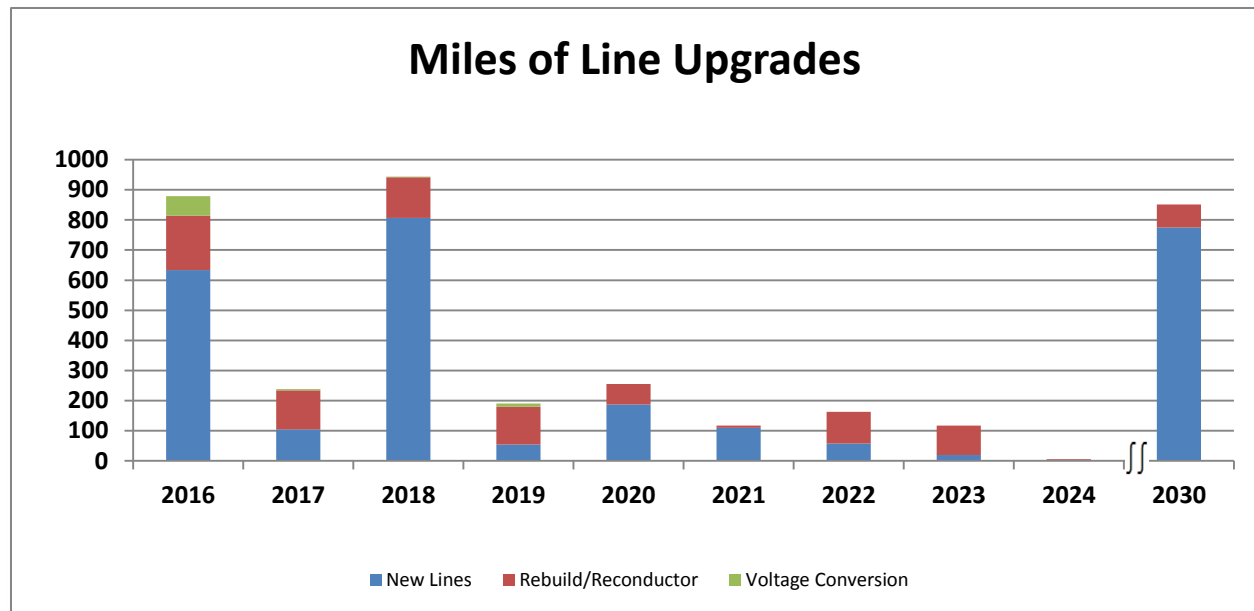


Figure 13.3: Total Cost of Line Upgrades



*2024 has 6 miles of Rebuild/Reconductor line

Figure 13.4: Total Miles of Line Upgrades by Project Type

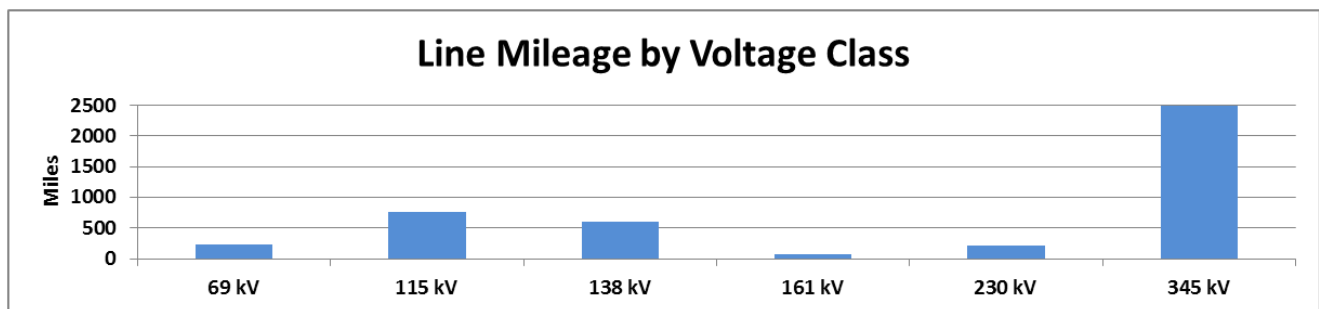


Figure 13.5: Total Line Mileage by Voltage Class

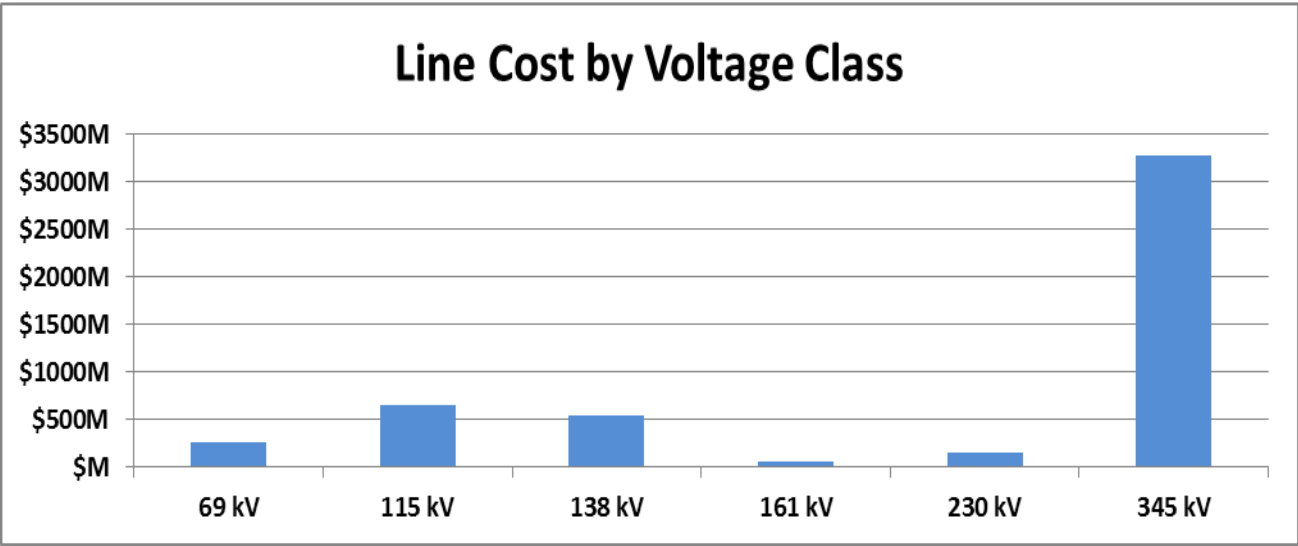


Figure 13.6: Total Line Cost by Voltage Class

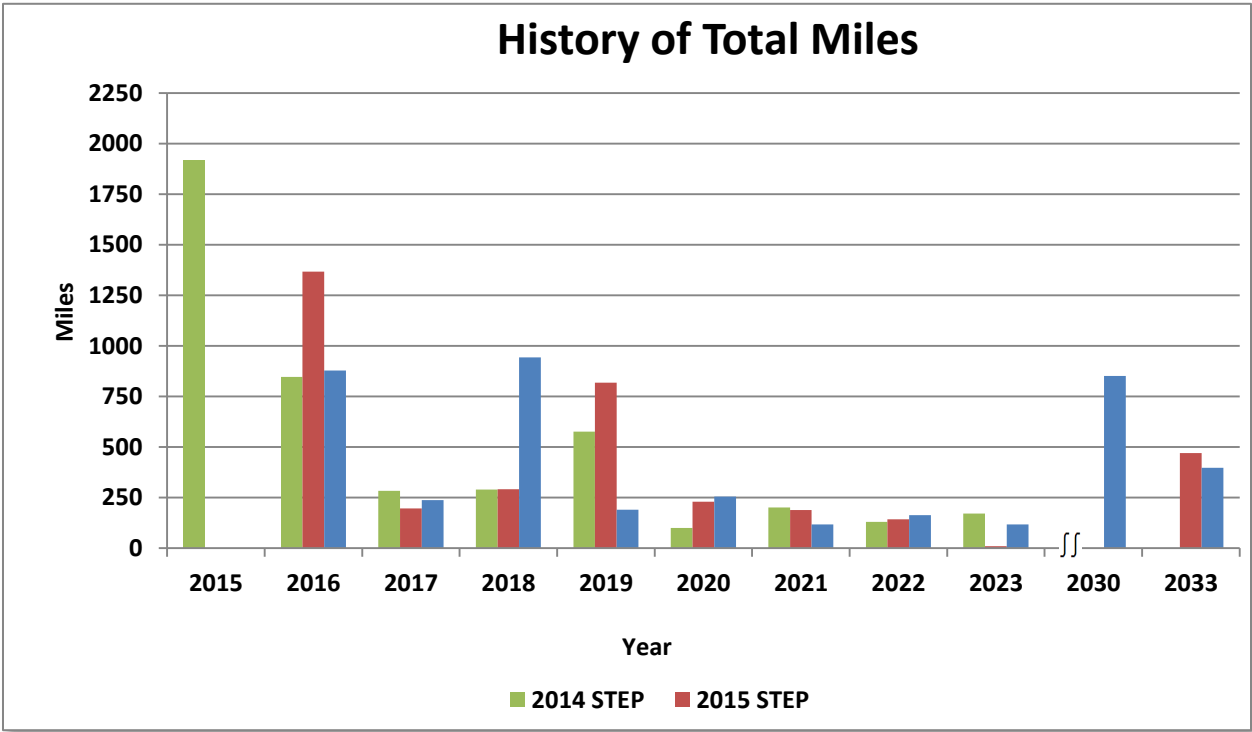


Figure 13.7: History of Total Miles 2015-2033

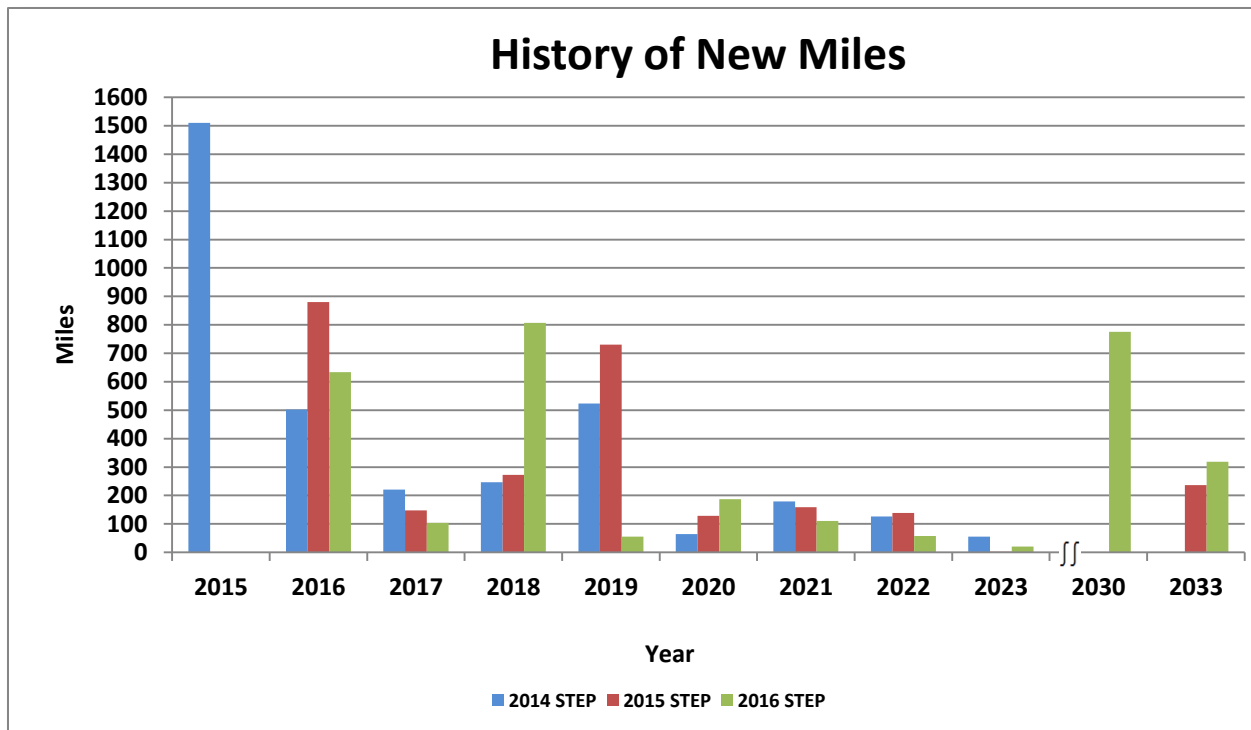


Figure 13.8: History of New Line Miles 2015-2033

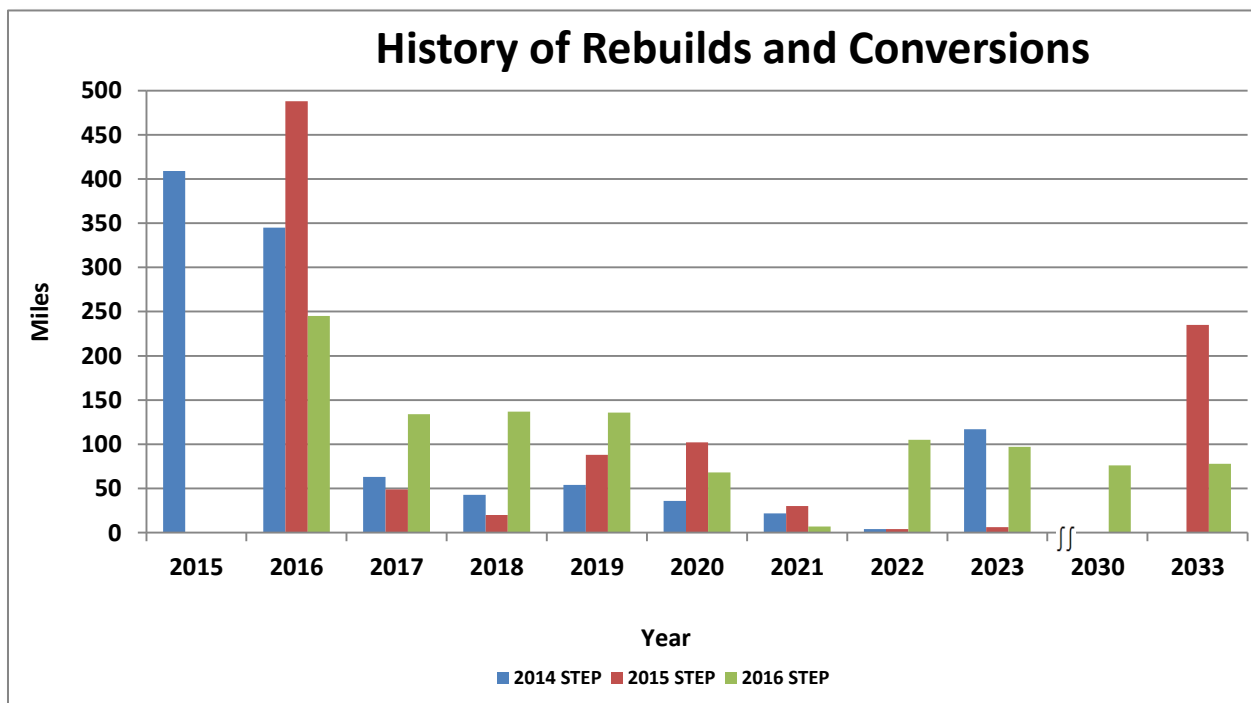


Figure 13.9: History of Line Rebuilds and Conversions 2015-2033

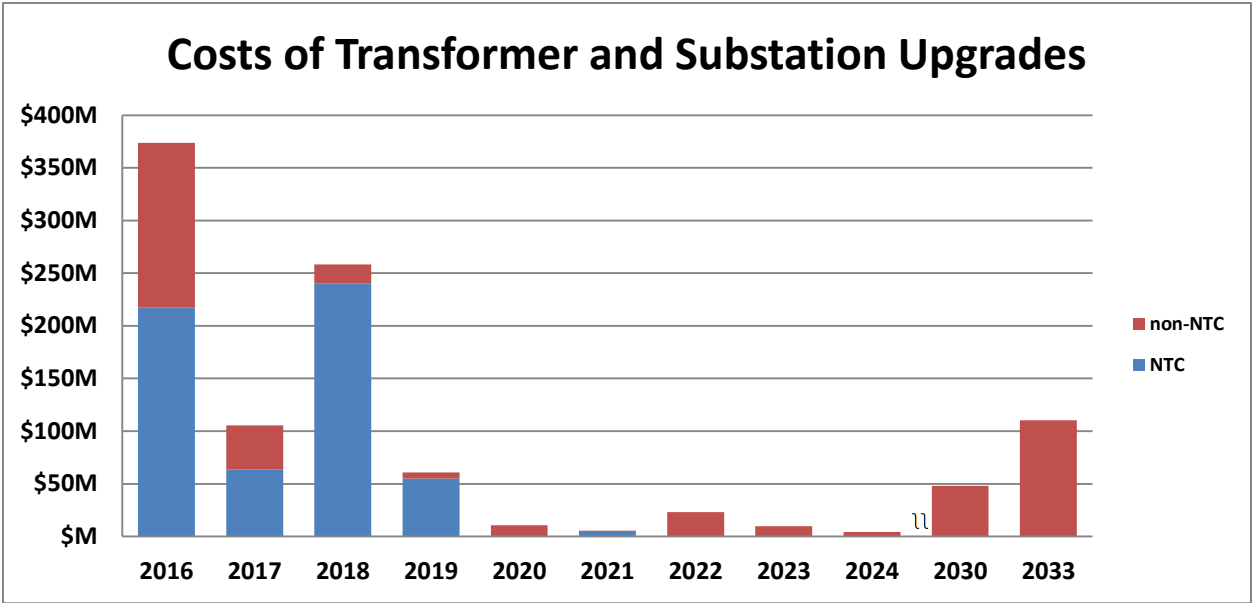


Figure 13.10: Costs of Transformer and Substation Upgrades

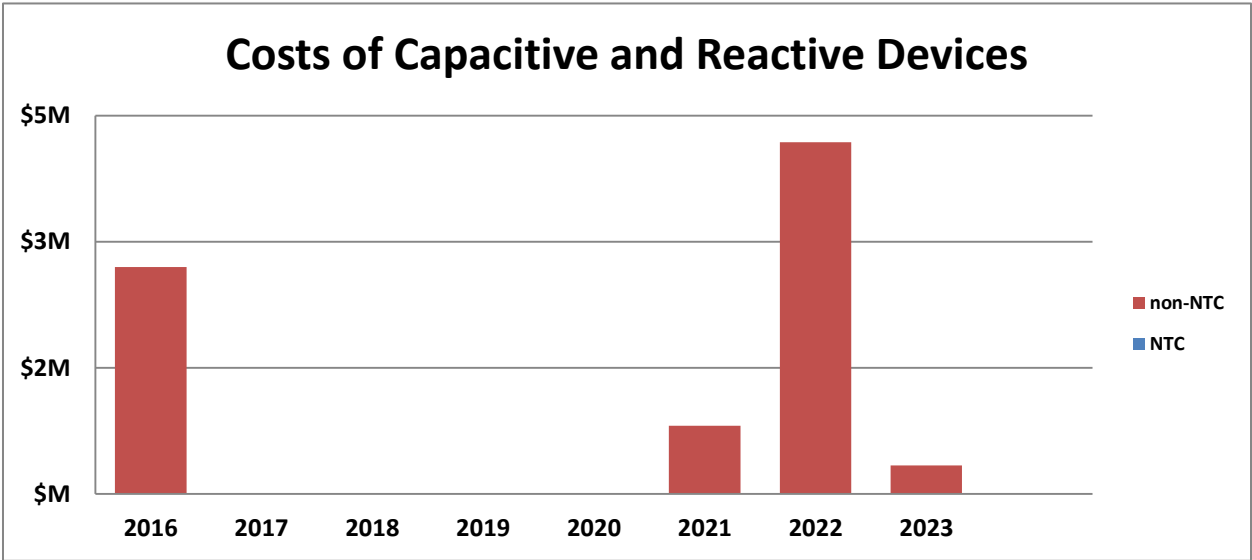


Figure 13.11: Costs of Capacitive and Reactive Devices

Section 14: NTCs Issued in 2015

NTC ID	Project ID	Facility Owner	Project Name	Current Cost Estimate
200297	1139 30755 30820	SPS	Line - Allen Sub - Lubbock South Interchange 115 kV Ckt 1 XFR - Tuco 230/115 kV Ckt 1 Carlisle Interchange - Tuco Interchange 230 kV Ckt 1	\$1,164,782 \$3,927,000 \$362,250
200307	30839	OPPD	Multi - S906 - S912 69 kV Accelerate	\$0
200313	30688	OGE	Line - Park Lane - Seminole 138 kV Terminal Upgrades	\$89,100
200314	30526 30803 30873 30889 30895	AEP	Line - Hobart - Roosevelt Tap - Snyder 69 kV Ckt 1 Rebuild Line - Mineola - Grand Saline 69 kV Ckt 1 Rebuild Line - Southwestern Station - Carnegie 138kV Ckt 1 Rebuild Line - Linwood - South Shreveport 138kV Ckt 1 Rebuild Line - Brooks Street - Edwards Street 69kV Ckt 1 Rebuild	\$36,017,091 \$22,967,874 \$15,821,763 \$7,062,332 \$4,294,228
200316	30848 30892 30909	GRDA	Sub - Claremore 161 kV Terminal Upgrades Sub - CPPXF#22 69 kV Terminal Upgrades Sub - Collinsville - Skiatook 69 kV Terminal Upgrades	\$11,200 \$134,800 \$160,200
200317	30881	KCPL	XFR - South Waverly - 161/69 kV Ckt 1 Transformer	\$2,280,000
200318	30883 30921	NPPD	Multi - Bassett 115 kV Line - Ainsworth - Ainsworth Wind 115 kV Ckt 1 Rebuild	\$6,065,000 \$200,000
200319	30876 30884 30900	OGE	Line - Little River - Maud 69 kV Ckt 1 Rebuild XFR - Stillwater 138/69 kV Ckt 1 Transformer Sub - Warner Tap 69 kV Terminal Upgrades	\$387,722 \$3,398,023 \$3,404,703
200320	30588	OPPD	Multi - Fremont - S6801 161/69 kV Ckt 1	\$35,091,946
200322	30903 30905	WFEC	Device - Winchester 69 kV Cap Bank Device - Thackerville 69 kV Cap Bank	\$224,900 \$160,241
200323	30891	WR	Sub - Benton 138 kV Terminal Upgrades	\$734,229
200324	30666	SPS	Device - China Draw and Road Runner 115 kV SVC	\$54,843,257
200325	30427 30916	SEPC	XFR - Mingo 345/115 kV Ckt 2 Transformer Sub - Buckner - Spearville 345 kV Terminal Upgrades	\$10,696,692 \$2,437,937
200326	30817 30866 30875 30888 30894	SPS	Line - Canyon West - Dawn - Panda - Deaf Smith 115 kV Ckt 1 Rebuild Sub - Amarillo South 230 kV Terminal Upgrades Line - PCA Interchange - Quahada 115 kV Ckt 1 Rebuild XFR - Lynn County 115/69 kV Ckt 1 Transformer Device - Cargill 115 kV Cap Bank	\$17,895,569 \$31,198 \$7,264,308 \$1,699,629 \$1,262,485
200327	30847	AEP	Line - South Shreveport - Wallace Lake 138 kV Ckt 1 Rebuild	\$18,553,018
200328 200337 200338	30850	KCPL/GMO/WR	Line - Iatan - Stranger 345 kV Ckt 1 Voltage Conversion	\$37,510,000
200329	30841 30843	OGE	Line - Gracemont - Anadarko 138 kV Ckt 1 Reconnector Sub - Cimarron - Draper 345 kV Terminal Upgrades	\$0 \$1,500,000
200330	30838	OPPD	XFR - Sub 3459 345/161 kV Ckt 1 Transformer	\$10,193,697
200331	30917	SEPC	Device - Ellsworth 115 kV Cap Bank	\$1,909,424
200332	30844	SPS	Sub - Amoco - Sundown 230 kV Terminal Upgrades	\$404,101
200333	30578	SPS	Multi - Bailey Co. - Lamb Co. 115 kV	\$49,643,005
200335	30644	MKEC	Line - Anthony - Harper 138 kV Ckt 1	\$12,838,896
200336	30859	SPS	Device - Plains Interchange 115 kV Cap Bank	\$1,217,275
200339	30762	AEP	Multi - Ellerbe Road - Lucas 69 kV	\$7,282,123
200340	879	OGE	Line - Bluebell - Prattville 138 kV	\$0
200342	30922	MKEC	Line - North Liberal - Walkemeyer 115 kV Ckt 1	\$17,502,514

Southwest Power Pool, Inc.

NTC ID	Project ID	Facility Owner	Project Name	Current Cost Estimate
200343	30913	SPS	Multi - RIAC 115 kV Voltage Conversion	\$4,811,635
200343 200344	30912	SPS/SEPC	Multi - Walkemeyer Tap - Walkemeyer 345/115 kV	\$31,963,968
200345	756	WR	XFR - Baldwin Creek 230/115 kV Ckt 1 Transformer	\$9,536,211
200360	30914	SPS	Multi - Road Runner 115 kV Loop Rebuild	\$30,027,505
200361	30598	AEP	Device - Letourneau 69 kV Cap Bank	\$1,600,349
200362 200363	30732	MKEC/WR	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	\$43,265,193

Section 15: 345 kV Projects

15.1 345 kV Projects Completed in 2015

Facility Owner	Upgrade Name	Network Upgrade Type
TSMO	Multi - Iatan - Nashua 345 kV	Balanced Portfolio
OGE	XFR - Northwest 345/138 kV Ckt 3	Transmission Service
MKEC	XFR - Spearville 345/115kV Ckt 1	Generation Interconnection
SPS	SUB - Eddy County - Tolk 345kV Ckt 1	Generation Interconnection
OGE	Sub - Beaver County 345kV Substation GEN-2010-001 Addition	Generation Interconnection
WR	Sub - LaCygne - Wolf Creek 345kV Ckt 1	Generation Interconnection
BEPC	Multi - AVS - Charlie Creek 345 kV	Regional Reliability
BEPC	Multi - Charlie Creek - Judson - Williston 345/230 kV	Regional Reliability
OGE	SUB - Renfrow 345kV - add terminal for GEN-2013-029	Generation Interconnection
OGE	SUB - Open Sky 345kV Substation	Generation Interconnection

15.2 345 kV Projects in the 2016 STEP

Facility Owner	Upgrade Name	Network Upgrade Type
AEP	Northwest Texarkana - Valliant 345kV Ckt 1	High Priority
AEP	Chisholm - Gracemont 345kV Ckt 1 (AEP)	ITP10
AEP	Chisholm 345/230 kV Substation	ITP10
AEP	South Fayetteville 345/161 kV Transformer Ckt1	ITP20
AEP	Lake Hawkins - Welsh 345 kV Ckt 1	ITP10
AEP	Lake Hawkins 345/138 kV Transformer Ckt 1	ITP10
AEP	Terry Road 345kV Station (TOIF)	Generation Interconnection
AEP	Terry Road 345kV Station (NU)	Generation Interconnection
BEPC	AVS - Charlie Creek 345 kV Ckt 1	Regional Reliability
BEPC	Charlie Creek 345 kV Substation	Regional Reliability
BEPC	Judson 345/230 kV Substation	Regional Reliability
BEPC	Judson - Tande 345 kV Ckt 1	Regional Reliability
BEPC	Tande 345/230 kV Substation	Regional Reliability
GMO	Maryville 345/161 kV Transformer Ckt1	ITP20
GMO	Iatan - Stranger Creek 345 kV Ckt 1 Voltage Conversion (GMO)	ITP10
GRDA	GRDA3 345kV - Interconnection Substation for GEN-2013-028	Generation Interconnection
ITCGP	Elm Creek - Summit 345 kV Ckt 1 (ITCGP)	ITP10
ITCGP	Elm Creek 345/230 kV Transformer	ITP10
ITCGP	Elm Creek 345 kV Terminal Upgrades	ITP10
ITCGP	Post Rock 345/230 kV transformer Ckt 2	ITP20
ITCGP	Clark County 345kV Switching Station GEN-2011-008 Addition	Generation Interconnection
ITCGP	Clark County 345kV Switching Station GEN-2012-024 Addition	Generation Interconnection
KCPL	Iatan - Stranger 345 kV Voltage Conversion Ckt 1	ITP10
KCPL	Nashua 345/161 kV Transformer Upgrade Ckt 1	ITP20
MIDW	Mullergren 345/230 kV Transformer	ITP20
NPPD	Hoskins - Neligh 345 kV Ckt 1	Regional Reliability

Facility Owner	Upgrade Name	Network Upgrade Type
NPPD	Neligh 345/115 kV Substation	Regional Reliability
NPPD	Cherry Co. - Gentleman 345 kV Ckt 1	ITP10
NPPD	Cherry Co. Substation 345 kV	ITP10
NPPD	Cherry Co. - Holt Co. 345 kV Ckt 1	ITP10
NPPD	Holt Co. Substation 345 kV	ITP10
NPPD	Stegall 345/115 kV Transformer Ckt 1	Regional Reliability
NPPD	Stegall 345 kV Terminal Upgrades	Regional Reliability
NPPD	Thedford 345/115 kV Transformer	High Priority
NPPD	Thedford 345 kV Terminal Upgrades	High Priority
NPPD	Keystone – Ogallala 345 kV	ITP20
NPPD	Ogallala Transformer 345/230 kV	ITP20
NPPD	Holt Co. - Shell Creek 345 kV	ITP20
NPPD	Shell Creek 345/230 kV Transformer Ckt 2	ITP20
NPPD	Holt - Neligh 345 kV	ITP20
NPPD	Columbus East 345/115 kV Transformer Ckt 2	ITP20
NPPD	Hoskins 345/230 kV Transformer Ckt 2	ITP20
NPPD	Hoskins 345/115 kV Transformer Ckt 2	ITP20
OGE	Arcadia - Redbud 345kV Ckt 3	Transmission Service
OGE	Chisholm - Gracemont 345 kV Ckt 1 (OGE)	ITP10
OGE	Tatonga - Woodward District EHV 345 kV Ckt 2	ITP10
OGE	Matthewson - Tatonga 345 kV Ckt 2	ITP10
OGE	Cimarron - Matthewson 345 kV Ckt 2	ITP10
OGE	Matthewson 345 kV	ITP10
OGE	Woodward District EHV 345kV Substation	Generation Interconnection
OGE	Muskogee/Pecan Creek 345 kV Terminal Upgrades	ITP20
OGE	Cimarron - Draper 345 kV Terminal Upgrades	ITP10
OGE	Beaver County Substation - Add 345kV terminal for GEN-2013-030	Generation Interconnection
OGE	Border 345kV Substation - GEN-2011-049 Addition	Generation Interconnection
OGE	Terry Road 345kV Station (NU) (OKGE)	Generation Interconnection
OGE	Tap Beaver County - Woodward District EHV 345kV DBL CKT (GEN-2011-014 POI) (TOIF)	Generation Interconnection
OGE	Tap Beaver County - Woodward District EHV 345kV DBL CKT (GEN-2011-014 POI) (NU)	Generation Interconnection
OGE	Tap Tatonga - Woodward District EHV 345kV (GEN-2011-051 POI) (TOIF)	Generation Interconnection
OGE	Tap Tatonga - Woodward District EHV 345kV (GEN-2011-051 POI) (NU)	Generation Interconnection
OPPD	Nebraska City - Mullin Creek 345 kV (OPPD)	High Priority
OPPD	S3459 345/161 kV Transformer	ITP10
OPPD	S3459 345 kV Terminal Upgrades	ITP10
OPPD	S3459 345/161 kV Transformer Ckt 2	ITP20
TBD	Ft Calhoun - S3454 345 kV	ITP20
SEPC	Mingo 345/115 kV Ckt 2 Transformer	Regional Reliability
SEPC	Mingo 345 kV Terminal Upgrades	Regional Reliability
SEPC	Buckner - Spearville 345 kV Ckt 1 Terminal Upgrades	Regional Reliability
SEPC	Holcomb 345/115 kV Transformer Ckt2	ITP20
SEPC	Buckner 345kV Substation GEN-2010-045 Addition (TOIF)	Generation Interconnection

Facility Owner	Upgrade Name	Network Upgrade Type
SEPC	Buckner 345kV Substation GEN-2010-045 Addition (NU)	Generation Interconnection
SEPC	Stevens Co. 345/115 kV Transformer	Regional Reliability
SPS	Tuco - Yoakum 345 kV Ckt 1	High Priority
SPS	Yoakum 345/230 kV Ckt 1 Transformer	High Priority
SPS	Hobbs 345/230 kV Ckt 1 Transformer	High Priority
SPS	Hobbs - Yoakum 345 kV Ckt 1	High Priority
SPS	China Draw - North Loving 345 kV Ckt 1	High Priority
SPS	Kiowa - North Loving 345 kV Ckt 1	High Priority
SPS	China Draw 345/115 kV Ckt 1 Transformer	High Priority
SPS	China Draw 345 kV Ckt 1 Terminal Upgrades	High Priority
SPS	Kiowa 345 kV Substation	High Priority
SPS	North Loving 345/115 kV Ckt 1 Transformer	High Priority
SPS	North Loving 345 kV Terminal Upgrades	High Priority
SPS	Road Runner 345/115 kV Ckt 1 Transformer	High Priority
SPS	Road Runner 345 kV Substation Conversion	High Priority
SPS	Kiowa 345/115 kV Ckt 1 Transformer	High Priority
SPS	Kiowa - Potash Junction 345/115 kV Ckt 1	High Priority
SPS	Hobbs - Kiowa 345 kV Ckt 1	High Priority
TBD	Hitchland-Potter 345 kV Ckt 2	ITP20
SPS	Tuco 345/230 kV Ckt 3 Transformer	Regional Reliability
SPS	Road Runner 345/115 kV Ckt 2 Transformer	Regional Reliability
SPS	Road Runner 345 kV Terminal Upgrades	Regional Reliability
SPS	Stevens Co. 345 kV Substation	ITP10
TBD	Cass Co. - S.W. Omaha (aka S3454) 345 kV Ckt1	ITP20
TBD	Chamber Springs - South Fayetteville 345 kV Ckt1	ITP20
TBD	Keystone - Red Willow 345 kV Ckt1	ITP20
TBD	Tolk - Tuco 345 kV Ckt1	ITP20
TBD	Neosho - Wolf Creek 345 kV Ckt1	ITP20
TBD	Auburn - Swissvale 345 kV Ckt1 Voltage Conversion	ITP20
TBD	Auburn - Jeffrey EC 345 kV Ckt1 Voltage Conversion	ITP20
TBD	Mingo-Post Rock 345 kV	ITP20
TBD	Iatan-Jeffery Energy Center 345 kV	ITP20
TBD	Spearville - Mullergren 345 kV	ITP20
TBD	Mullergren - Circle 345 kV	ITP20
TBD	Grand Island - Holt Co 345 kV	ITP20
TBD	Hoskins - Ft. Calhoun 345 kV	ITP20
TSMO	Sibley - Mullin Creek 345 kV	High Priority
TSMO	Nebraska City - Mullin Creek 345 kV (GMO)	High Priority
WR	Auburn 345/115 kV Transformer Ckt2	ITP20
WR	Elm Creek - Summit 345 kV Ckt 1	ITP10
WR	Geary County 345/115 kV Substation	Regional Reliability
WR	Viola 345/138 kV Transformer Ckt 1	Regional Reliability
WR	Geary County 345 kV	Regional Reliability
WR	Viola 345 kV Terminal Equipment	Regional Reliability

Southwest Power Pool, Inc.

Facility Owner	Upgrade Name	Network Upgrade Type
WR	Moundridge 345 kV Terminal Upgrades	Regional Reliability
WR	Moundridge 345/138 kV Ckt 1 Transformer	Regional Reliability
WR	Moundridge - Wichita 345kV Ckt1	Regional Reliability
TBD	Circle - Reno 345 kV	ITP20
TBD	Circle 345/230 kV transformer	ITP20
TBD	Wichita-Viola 345 kV	ITP20
TBD	Viola-Rose Hill 345 kV Ckt 1	ITP20
WR	Moundridge - Reno County 345kV Ckt1	Regional Reliability
WR	Iatan - Stranger Creek 345 kV Ckt 1 Voltage Conversion (WR)	ITP10
WR	Moundridge 345/115kV Transformer	Regional Reliability

Section 16: Projects Completed in 2015

16.1 ITP Projects Completed in 2015

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
20003	311	WFEC	Multi - Franklin SW - Acme - Norman - OU SW Conversion 138 kV	\$5,243,000
20003	361	WFEC	Line - Fletcher - Marlow Jct 69 kV	\$2,000,000
20003	399	WFEC	Line - Lindsay - Wallville 69 kV	\$1,347,000
20003	402	WFEC	Multi - Granfield - Cache SW 138 kV	\$8,431,000
200212	412	WR	Line - 64th - Eastborough 69 kV Rebuild	\$4,915,569
200214	486	SPS	XFR - Chaves 230/115 kV Transformer Ckt 2	\$2,749,216
20031	633	SPS	Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new lines	\$3,300,000
20130	764	SPS	XFR - Happy County 115/69 kV Transformers	\$1,518,414
20084	774	SPS	Multi - Cherry Sub add 230kV source and 115 kV Hastings Conversion	\$5,374,736
20086	819	WR	Line - Gill Energy Center East - MacArthur 69 kV	\$7,149,555
20084	834	SPS	Line - Portales - Zodiac 69 kV to 115 kV Conversion	\$6,500,000
200166	836	SPS	Sub - Convert Muleshoe East 69 kV to 115 kV	\$3,000,000
200216	879	AEP	Line - Bluebell - Prattville 138 kV	\$10,241,314
200208	909	WFEC	Multi - Payne Switching Station - OU 138 kV conversion	\$3,250,000
200256	1004	SPS	XFR - Swisher 230/115 kV Ckt 1	\$3,183,028
20130	1029	SPS	Convert Lynn load to 115 kV	\$8,027,718
20130	1042	SPS	Line - North Plainview line tap 115 kV	\$287,099
200214	1031	SPS	XFR - Crosby Co. 115/69 kV Transformers Ckt 1 and Ckt 2	\$4,240,572
200214	1143	SPS	XFR - Lubbock South 230/115/13.2 kV Ckt 2	\$4,628,416
200214	1147	SPS	Multi - Potter - Channing - Dallam 230 kV Conversion	\$12,901,626
20003	30079	WFEC	Device - Carter Cap 69 kV	\$324,000
200242	30097	WR	Device - Vaughn Cap 115 kV	\$961,853
200166	30332	SPS	Device - Drinkard 115 kV Capacitor	\$1,458,467
200166	30351	SPS	Device - Crosby 115 kV Capacitor	\$1,265,432
200166	30356	SPS	Multi - Cedar Lake Interchange 115 kV	\$13,400,001
200172	30358	MIDW/MKEC	Multi - Ellsworth - Bushton - Rice 115 kV	\$23,247,935
200173				
200212	30369	WR	XFR - Moundridge 138/115 kV	\$13,540,579
200214	30424	SPS	Line - Ochiltree - Tri-County Cole 115 kV Ckt 1	\$12,470,000
200214	30430	SPS	Device - Floyd 115 kV Capacitor	\$1,705,681
200214	30466	SPS	XFR - Potash Junction 115/69 kV Ckt 1	\$2,500,000
200216	30471	AEP	Line - Dekalb - New Boston 69 kV	\$16,548,317
200216	30472	AEP	Line - Hardy Street - Waterworks 69 kV	\$7,519,658
200216	30473	AEP	Line - Midland REC - North Huntington 69 kV	\$1,829,026
200216	30474	AEP	Line - Midland - Midland REC 69 kV	\$5,653,353
200216	30475	AEP	Line - Howe Interchange - Midland 69 kV	\$9,145,130
200202	30476	GRDA	Line - Chelsea - Childers 69 kV	\$355,000
200207	30478	OPPD	Line - 915 Tap South in Ckt 623 - Sub 915 T2 69 kV Ckt 1	\$260,590
200212	30483	WR	XFR - Gill 138/69 kV Ckt 3	\$5,803,853
200242	30553	WR	Line - Butler - Weaver 138 kV Ckt 1	\$0
200256	30555	SPS	Quahada Switching Station 115 kV	\$8,250,000

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
200242	30579	WR	Line - Wellington - Creswell 69 kV	\$4,259,395
200242	30580	WR	Line - Crestview - Kenmar 69 kV	\$8,968,153
	30943	BEPC	Multi - AVS - Charlie Creek 345 kV	\$108,000,000
	30944	BEPC	Multi - Charlie Creek - Judson - Williston 345/230 kV	\$126,400,000

16.2 Transmission Service Projects Completed in 2015

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
200193	1000	SPS	Line - Jones Station Bus#2 - Lubbock South Interchange 230 kV CKT 2 terminal upgrade	\$204,158
20137 200194	1134	OGE	XFR - Northwest 345/138 kV Ckt 3	\$12,655,506
20059	30226	WR	Device - Altoona East 69 kV Capacitor	\$2,166,509
20107	30299	MKEC	Line - Jewell - Smith Center 115kV Ckt 1	\$124,144
20136	30320	WFEC	Line - Canton - Taloga 69 kV ckt 1	\$4,800,000
20136	30321	WFEC	XFR - Taloga 138/69 kV ckt 1	\$837,746

16.3 Generation Interconnection Projects Completed in 2015

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
	30416	MKEC	Line - Ft Dodge - N Ft. Dodge - Spearville CKT 2	\$30,496,745
	30417	MKEC	XFR - Spearville 345/115kV CKT 1	\$18,276,977
	30592	SPS	SUB - Eddy County - Tolk 345kV Ckt 1	\$13,224,349
	30753	SPS	Sub - Hitchland 115kV Interchange GEN-2007-046 Addition	\$990,329
	30768	MIDW	Sub - Post Rock 230kV Substation GEN-2008-092 Addition	\$599,380
	30782	OGE	Sub - Beaver County 345kV Substation GEN-2010-001 Addition	\$2,466,719
	30783	WR	Sub - LaCygne - Wolf Creek 345kV Ckt 1	\$13,322,627
	30931	MIDW	Sub - South Hays 230kV Substation GEN-2009-008 Addition	\$2,949,038
	30932	MIDW	Sub - Walnut Creek 69kV Substation	\$3,691,270
	30936	WR	Sub - Cresswell 138 kV GEN-2011-057 Addition	\$1,258,420
	30939	WFEC	Line - Lake Creek - Lone Wolf 69kV Ckt 1	\$197,972
	30961	OGE	SUB - Renfrow 345kV - add terminal for GEN-2013-029	\$0
	30964	OGE	SUB - Interconnection Substation for GEN-2013-007	\$2,779,863
	30966	OGE	SUB - Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033-Tap) 138kV	\$2,223,890
	30967	OGE	SUB - Open Sky 345kV Substation	\$7,584,395
	30972	NPPD	Sub - Meadow Grove 230kV (GEN-2014-031)	\$100,000

16.4 High Priority Projects Completed in 2015

NTC ID	PID	Facility Owner	Project Name	Cost Estimate
200309	30569	SPS	Multi - Potash Junction - Road Runner 230/115 kV Ckt 1	\$58,507,773
200279	30624	OGE	Sub - Alva OGE 69 kV	\$72,851
200284	30635	WFEC	Device - Eagle Chief 69 kV	\$237,000
200309	30717	SPS	Line - Hopi Sub - North Loving - China Draw 115 kV Ckt 1	\$21,320,588
200272	30747	AEP	Line - Grady - Round Creek 138 kV Ckt 1	\$12,132,497
200282	30756	SPS	Multi - Battle Axe - Road Runner 115 kV	\$13,800,000
200282	30777	SPS	Sub - Oxy South Hobbs 115 kV	\$327,861

Section 17: 2013 ITP20 Project List

Name	Type	Size	Focus
Keystone – Red Willow	New Branch	345 kV	Reliability
Tolk – Tuco	New Branch	345 kV	Reliability
S3459	2nd Transformer	345/161 kV	Economic
Holcomb	2nd Transformer	345/115 kV	Reliability
Maryville	New Transformer	345/161 kV	Reliability
Pecan Creek – Muskogee	Upgrade 2 circuits	345 kV	Reliability
Nashua	Upgrade Transformer	345/161 kV	Reliability
JEC – Auburn Hills – Swissvale	Rebuild (New Auburn Hills transformer)	345 kV, 345/115 kV	Reliability
Clinton – Truman – N Warsaw	Upgrade Branch	161 kV	Reliability
S3740 - S3454	New Branch	345 kV	Reliability
Chamber Springs – S Fayetteville	New Branch & Transformer	345 KV, 345/161 kV	Economic
Wolf Creek - Neosho	New Branch	345 kV	Economic