2012 Integrated Transmission Plan Near-Term Assessment Report

January 9, 2012

Engineering

Southwest Power Pool

Revision History

Date	Author	Change Description
10/3/2011	Staff	Initial Draft
11/28/2011	Staff	Changes after October MOPC
12/12/2011	Staff	Updates requested by TWG and updated SCERT estimates received through 12/7/2011
1/6/2012	Staff	Additional grammatical/editorial changes and updated with all SCERT estimates

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Executive Summary

This report documents analysis of the 2012 Integrated Transmission Planning Near-Term (ITPNT) Assessment. The ITPNT analyzes the SPP region's immediate transmission needs. The goals of the ITPNT are to not only preserve grid reliability, in compliance with NERC Reliability Standards and individual transmission owner planning requirements, but to also efficiently bridge SPP's 10-year and 20-year plans that meet public policy objectives and provide access to more economic energy sources. The ITPNT assesses: (a) regional upgrades required to maintain reliability in accordance with the NERC 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.

The 2012 ITPNT is one component of the newly-developed, three-year Integrated Transmission Planning (ITP) study process. The ITP assesses both near- and long-term transmission grid needs of the SPP region. The Federal Energy Regulatory Commission (FERC) approved this ITP process in July 2010 as defined in the SPP Attachment O. In conjunction with SPP's FERC-approved Highway/Byway cost allocation methodology[1], the ITP aims to meet reliability, economic, and public policy needs and improve access to the region's diverse generating resources by promoting investment in a cost-effective, flexible, and robust transmission network.

ITP development was driven by the Synergistic Planning Project Team (SPPT), which was created by the SPP Board of Directors (Board) to address gaps and conflicts in all of SPP's transmission planning processes including Generation Interconnection and Transmission Service; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities. The ITP is based on the SPPT's planning principles, which emphasize the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP's future needs. The first phase of the ITP process was completed with the Board's acceptance of the 2010 ITP20 Plan on January 25, 2011. The next phases of the ITP process were developed concurrently (ITP10 and ITPNT) as required by Open Access Transmission Tariff (OATT) Attachment O Section III.4 and III.5.

ITPNT projects are reviewed by SPP's Transmission Working Group (TWG), Markets and Operations Policy Committee (MOPC) and approved by the Board. Following Board approval, staff will issue Notification to Construct (NTC) letters for projects needed within the four-year financial commitment timeframe. Currently NTC letters direct the start of construction and qualify for full cost recovery of any costs expended for an upgrade.

In July 2011, the MOPC approved the concept of Conditional Notification to Construct (CNTC) letters as part of the Project Cost Task Force's whitepaper. CNTCs would initiate a refined cost estimate analysis for qualifying projects (above 100 kV and cost estimate over $20 million) before issuance of NTCs to direct the start of construction.

The Project Cost Working Group (PCWG) will be working with the Business Practice Working Group (BPWG) to develop the CNTC Business Practice. Until this business practice can be completed, SPP recommends an interim procedure for the 2012 ITPNT projects that qualify for CNTCs be to issue NTCs for these projects with language initiating a refined cost estimate analysis, but not allow the start of

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

construction or procurement of materials on these projects. SPP will send the NTCs to the incumbent Transmission Owner(s) for each project with an expected deadline for completion of refined cost estimates.

Projects which financial commitment is not required within the four-year window will receive an Authorization to Plan (ATP), which authorizes a TO to plan for a project but does not allow any cost recovery through the SPP OATT. A list of ATP projects will be posted on the SPP website contingent upon approval of the ATP Business Practice. Once the ATPs are posted, SPP will include them in future SPP Aggregate Study models in the appropriate model year.

SPP developed models for the 2012 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 – approved by the TWG in November 2010 –contains:

- The years and seasons to be modeled, including 2012-2017
- Treatment of upgrades in the models
- Scenario cases to be evaluated
- Description of the contingency analysis and monitored facilities
- Any new special conditions that are modeled or evaluated for the study

SPP performed reliability analyses identifying potential bulk power system problems. These findings were presented to Transmission Owners and stakeholders to solicit transmission solutions. Also considered were transmission options from other SPP studies, such as the Aggregate Study and Generation Interconnection processes. From the resulting list of potential solutions, staff identified the best regional solutions for potential reliability violations. Staff presented these solutions for member and stakeholder review at SPP's July and September 2011the planning summits. Through this process, SPP developed a final list of 69 kV and above solutions necessary to ensure the reliability in the SPP region in the near-term.

Figure 1 summarizes Engineering and Construction (E&C) cost estimates for new and modified reliability projects needed in the years 2012-2017, totaling $251 million. This is in addition to the upgrades previously approved by the Board and does not include $190 million in upgrades with active NTCs that need to be withdrawn.

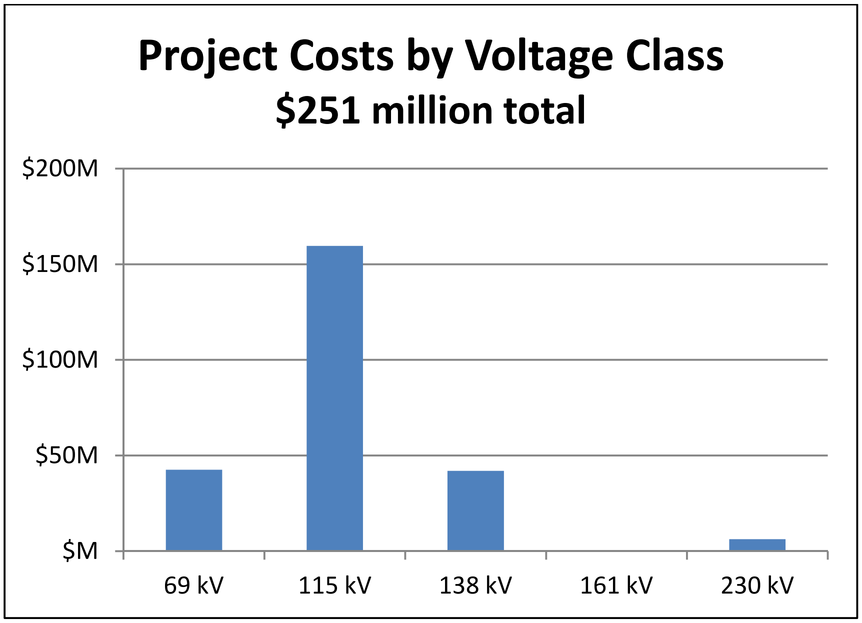

Figure 1: Cost summary of Upgrades by Voltage Class

PART I: STUDY SCOPE

Section 1: Introduction

1.1: What is ITPNT?

The ITPNT evaluates the near-term reliability and robustness of the SPP transmission system, identifying needed upgrades through stakeholder collaboration. The ITPNT focuses primarily on solutions required to meet the reliability criteria defined in OATT Attachment O Section III.6. However, it also considers policy components, economic components, and demand response. The ITPNT process coordinates the ITP20, ITP10, Aggregate Studies, and the Generation Interconnection transmission plans by communicating potential solutions between processes and using common solutions when appropriate.

The steady state assessment considers normal (non-contingency) and single contingency (N-1) outage condition scenarios using NERC Reliability Standards, SPP Criteria, and local planning criteria. It also coordinates appropriate mitigation plans to meet the SPP region's reliability needs. This effort considers the operating characteristics of the current EIS market using individual Balancing Authorities.

In addition to the steady state assessment, a stability analysis is performed on the SPP system, including the proposed 2012 ITPNT upgrades. This analysis determines if there are voltage stability issues within high load areas inside the SPP footprint.

The 2012 ITPNT assessment strives to meet the SPP RTO's requirements under Attachment O of the OATT for planning a reliable, robust transmission system rather than documenting compliance with NERC Reliability Standards which are enforced through the SPP Regional Entity. This process consists of the following steps:

- Identifying potential reliability-based problems (NERC Reliability, SPP and local criteria)
- Assessing known mitigation plans
- Developing additional mitigation plans to meet the region's needs and maintain SPP and local reliability/planning standards

The process is open and transparent, allowing for stakeholder input. SPP coordinates study results with other entities and regions responsible for transmission assessment and planning.

1.2: Study Planning Goals

The 2012 ITPNT assesses SPP's transmission system to ensure that:

- Mitigation plans exist for the following:
  - NERC Reliability Standards TPL-001 and TPL-002
  - SPP reliability criteria
  - Local planning criteria as submitted by Transmission Owners (TO)

Section 2: Assumptions

2.1: Modeling Assumptions

SPP built the 2012 ITPNT load flow cases based on the SPP MDWG 2011 Build 1 series. The study cases in this analysis were: 2012 Summer Peak, 2012/13 Winter Peak, 2013 Summer Peak, 2013/14 Winter Peak, 2017 Summer Peak, and 2017/18 Winter Peak. Updated construction plans from Associated Electric Cooperative Inc. (AECI) and Entergy were used for the contingency analysis.

The models' topology reflected the current transmission system and the following transmission upgrades: SPP approved for construction upgrades, SPP Transmission Owners' planned upgrades, upgrades from Entergy's 2011 Construction Plan, and AECI's planned upgrades. The model development processes for SPP MDWG and SERC account for long-term transmission line outages as forecasted by their respective member transmission owners.

The ITPNT models protected confirmed, long-term transmission service and based dispatch on each individual Balancing Authority's generation order of existing and planned generation that has or was seeking long-term transmission service. To account for the confirmed long-term transmission service SPP created two scenario models: one with projected transmission transfers and generation dispatch on the system and another with all confirmed long-term firm transmission service and its necessary generation dispatch. In the 2017 model, there may have been a lack of available generation for a Balancing Authority to serve its load, so existing generation in SPP, including IPPs, was dispatched to meet the shortfall.

In June, the Environmental Protection Agency approved the Cross-State Air Pollution Rule which imposes new restrictions on emissions. This ruling was well after the start of the 2012 ITPNT analysis and therefore, impacts of this ruling were not incorporated into this study. SPP is currently contemplating how to best assess the impact of this rule.

2.2: Load Forecast

Load Serving Entities provided the load forecast used in the reliability analysis study models through the model building process. 2012 ITPNT analysis models showed a growth of 6.5% between summer 2011 through summer 2017, or approximately 1.1% per year. Overall forecasted growth rate for the 2012 ITPNT slowed compared to the 2009 and 2010 forecasts, as shown in Figure 2.

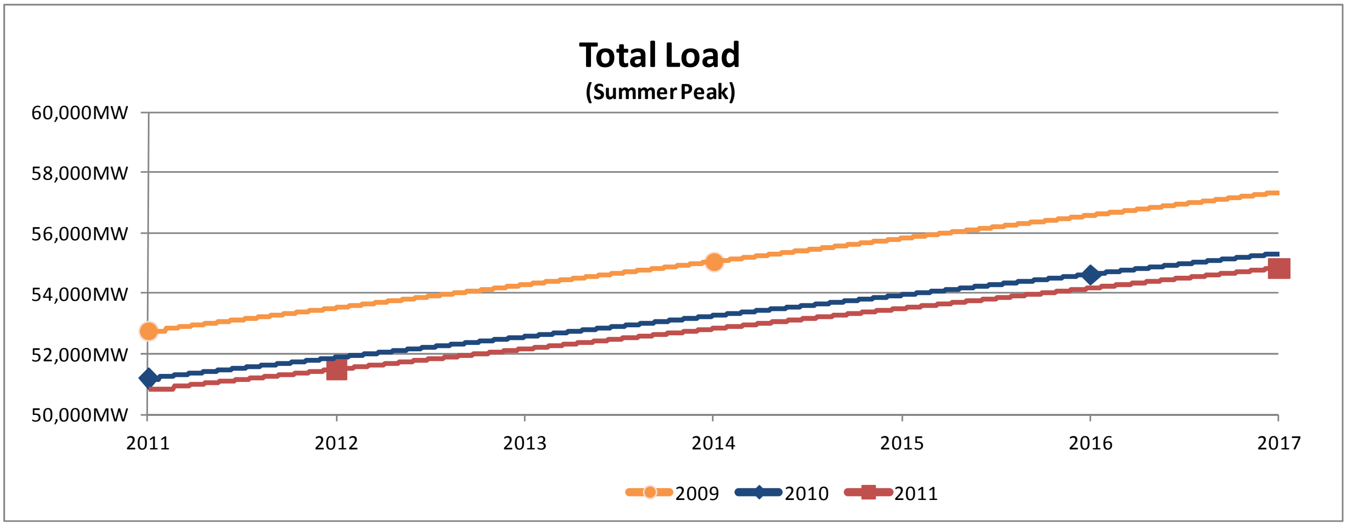

Figure 2: History of Load Forecasts

2.3: Criteria

SPP utilized NERC Reliability Standards, SPP Criteria, and local Transmission Owner planning criteria in this analysis, upholding the most stringent criteria. Projects needed for more stringent local Transmission Owner's planning criteria are identified as Zonal Reliability Upgrades.

SPP Criteria is available on SPP.org > Engineering > Transmission Planning.

Transmission Owners' planning criteria are available through SPP.org > Engineering > Transmission Planning > Local Area Planning and High Priority Studies.

2.4: Use of Transmission Operating Guides

Transmission Operating Guides (TOG) are tools used to mitigate violations in the daily management of the transmission grid. TOGs may be used as alternatives to planned projects and are tested annually to determine effectiveness in mitigating potential violations. For the purpose of this study, 2012 ITPNT identifies all solutions where the use of TOG is not effective.

Part II: Analysis

Section 3: Study Process

3.1: Steady State Analysis

Facilities in the SPP footprint 69 kV and above were monitored for 95% thermal loading. All facilities in first-tier control areas except Entergy's and AECI's were monitored at 230 kV and above. Based upon seams agreements, Entergy facilities are monitored 100 kV and above and AECI facilities at 69 kV and above.

SPP performed non-contingency (base case) and N-1 contingency analysis on the 2012 ITPNT models, and then verified and/or developed corrective plans exist for all potential violations.

After performing the reliability assessment identifying the bulk power problems, SPP presented and solicited Transmission Owners and stakeholders for transmission solutions to those reliability problems. SPP solicited stakeholders in several forums including the planning summits and working group meetings. Considering stakeholders' feedback and current Aggregate Studies and Generation Interconnection studies, SPP developed and validated proposed regional solutions. Then SPP shared and sought additional input from members and stakeholders.

This process repeated for several iterations as solutions were refined. SPP then timed upgrades using linear interpolation between available model years of 2012, 2013, and 2017. For example, to time a solution due to a 2017 potential overload, SPP interpolated loadings between the 2013 and 2017 models to determine when the loading exceeded 100%. SPP assigned this as the study need date. SPP used a similar process for timing potential voltage issues. Throughout the process, alternative solutions were proposed by stakeholders. SPP analyzed those alternatives in accordance with Section III.8 of Attachment O of the OATT and independently made recommendations for Network Upgrades.

3.2: Rate Impacts

The 2012 ITPNT's impact on end-use customers' rates is a valuable subject. The rate impact analysis accounted for the impacts of adding the proposed 2012 ITPNT upgrades. The impact of added transmission facilities on end-use customers' charges was driven by facilities' installed cost, estimated capital cost, and other components of ownership cost and timing of installation. The revenue requirement associated with each upgrade was determined and allocated to zones in accordance with applicable SPP OATT provisions. Then SPP determined the resulting increase on a typical residential monthly bill of 1,000 kWh per month.

3.3: Stability Analysis

With stakeholder input, staff selected eight load areas or "pockets" for the 2012 ITPNT voltage stability analysis:

- Area 1: Central Nebraska
- Area 2: South Oklahoma
- Area 3: West Arkansas
- Area 4: SPS – Amarillo
- Area 5: South Central Westar
- Area 6: Northeast Westar
- Area 7: Oklahoma City
- Area 8: Lincoln/Omaha

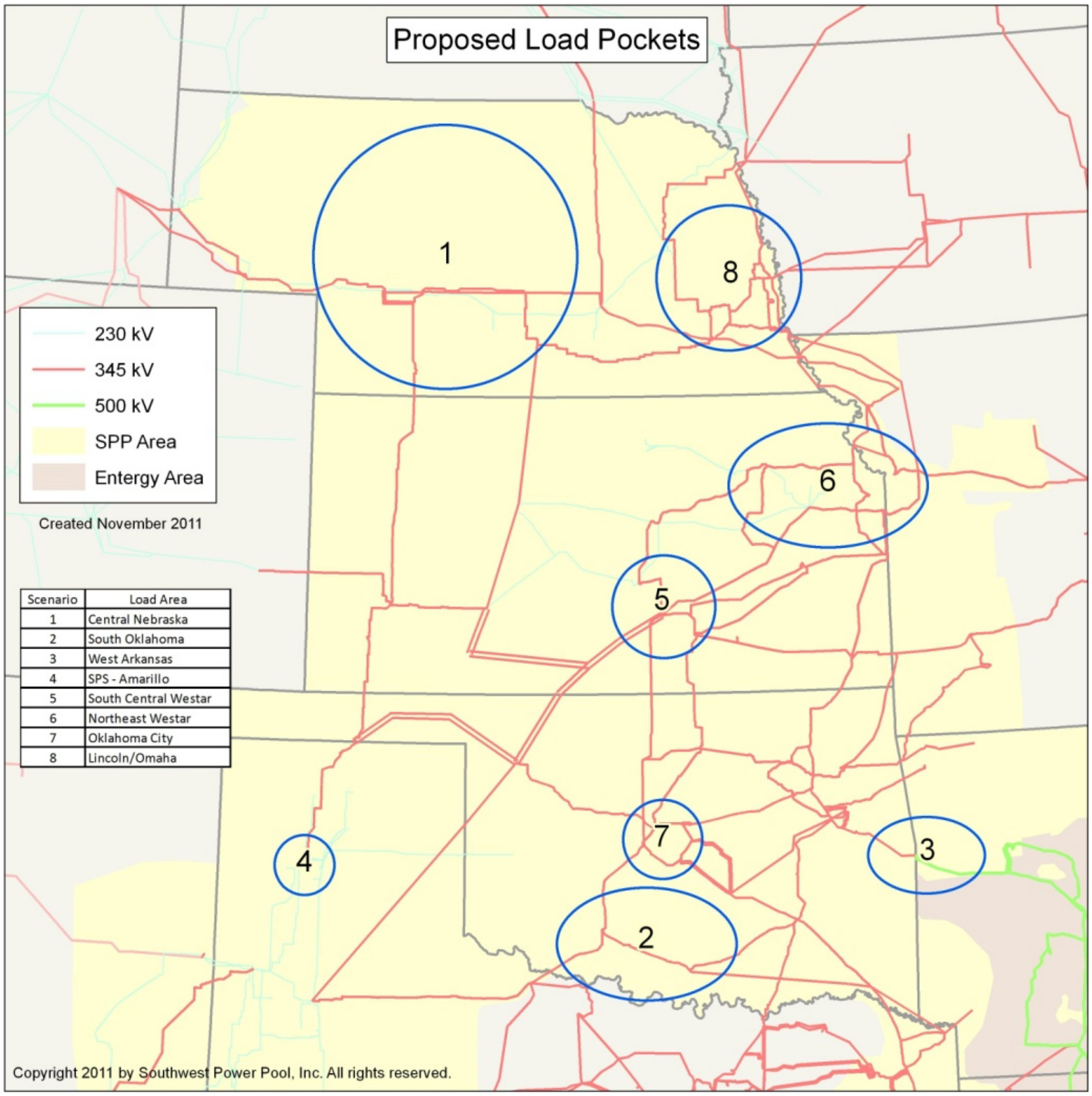

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Figure 3: Load Areas for ITPNT analysis

Staff determined contingencies for the stability analysis through the following process: (1) determined the single worst generator outage within the load area; (2) this identified generator outage was paired with all transmission line outages within the load area.

Analysis was performed by increasing load within the load pocket while increasing transfer to the load area from adjacent areas until voltage collapse occurs. The system was tested under contingency and non-contingency conditions using the 2012 ITPNT 2017 summer peak models with and without the 2012 ITPNT proposed upgrades.

PART III: STUDY RESULTS

Section 4: Study Results

4.1: Summary of Potential Steady State Violations

SPP staff completed a contingency analysis for the years 2012-2017. This analysis evaluated non-contingency (base case) and N-1 contingencies. SPP shared these results with the stakeholders at the July 21 planning summit and requested that stakeholders provide solutions for the potential overload and potential voltage violations.

Figure 4 summarizes monitored facilities by element that had potential overloads, as identified by the 2012 ITPNT study for model years 2012, 2013, and 2017. There are a small number of potential violations under system intact conditions, but the majority of potential violations occur under contingency conditions. Some potential overloads were identified in multiple model years and were thus counted in multiple years in Figure 4. Therefore, the potential overloads between years are not additive.

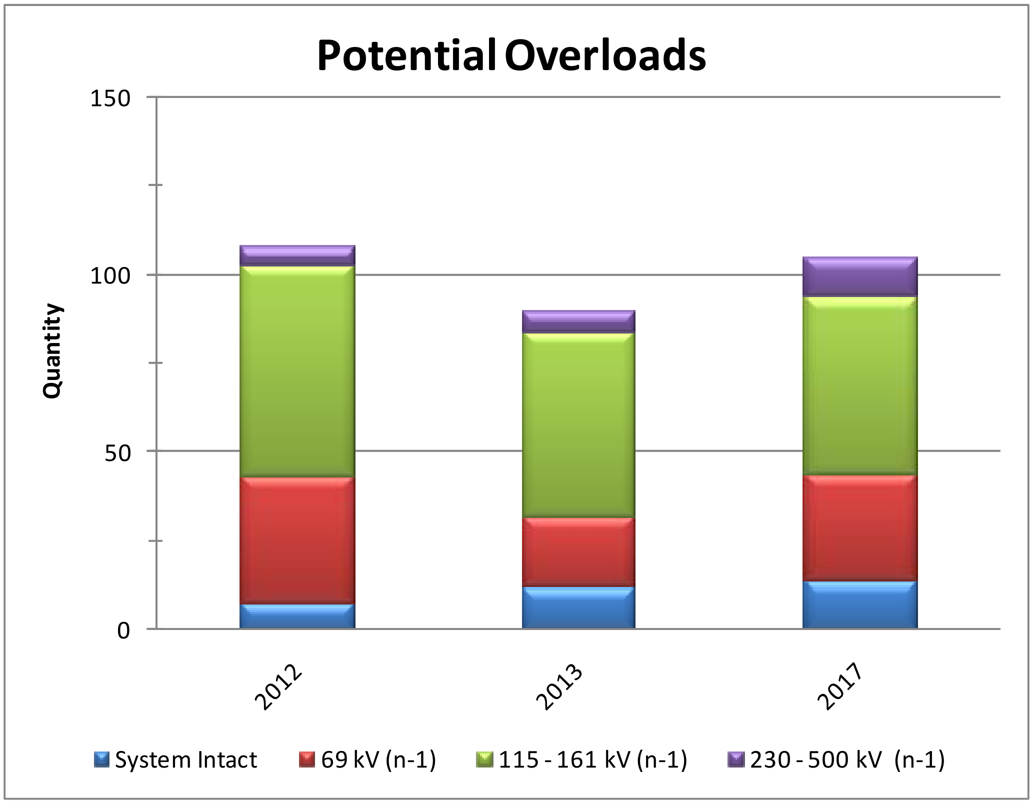

Figure 4: Potential Overloads

Figure 5 summarizes, by element, monitored facilities that had potential voltage violations, as identified by the 2012 ITPNT study for model years 2012, 2013, and 2017. Some potential voltage violations were identified in multiple model years and were thus counted in multiple years in Figure 4. Therefore, the potential voltage violations between years are not additive.

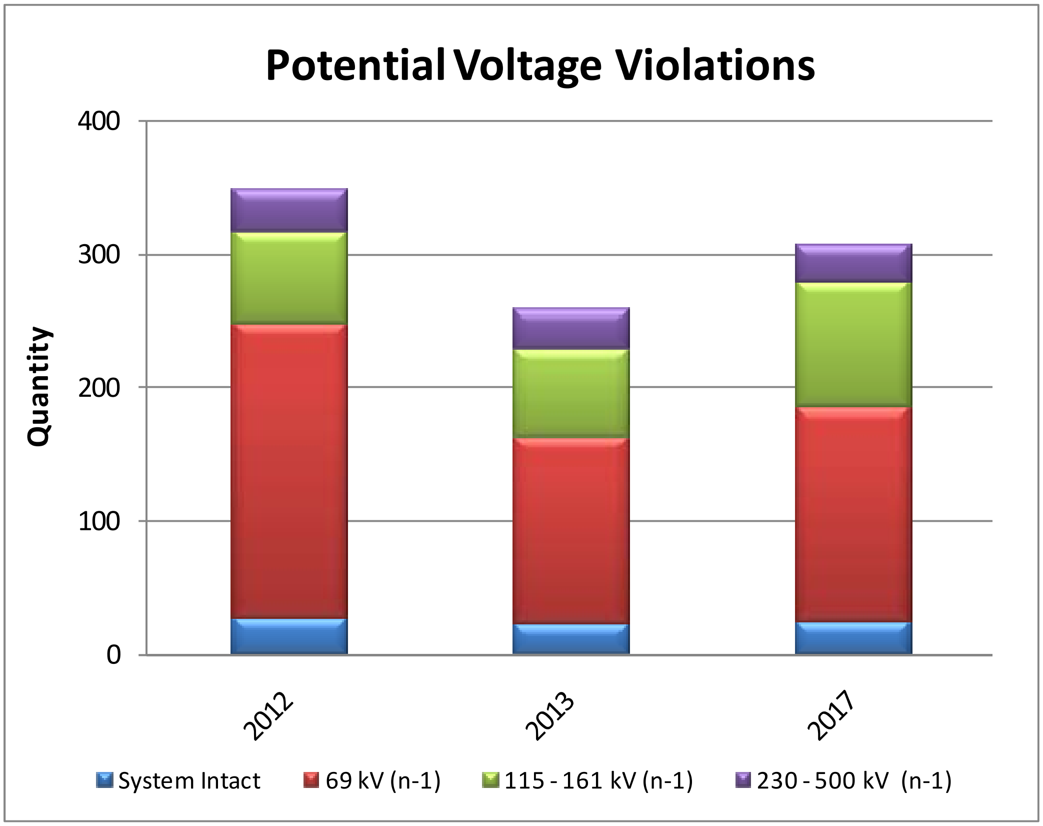

Figure 5: Potential Voltage Violations

4.2: Summary of Potential Stability Violations

Based on the projected 2017 load levels, no voltage instability in the eight load pockets was identified for the 2012 ITPNT upgrades.

4.3: Summary of Network Upgrades

Figures 6 through 11 summarize the 2012 ITPNT's 2012 –2017 newly identified Network Upgrades. Upgrades requiring Board action are shown in Appendix I – Upgrades for Board Approval. Appendix I contains $251 million E&C of new and modified upgrades and $190 million E&C of upgrade candidates to be withdrawn. The modified NTCs account for $35 million of the $251 million total. All upgrades identified in Appendix I are candidates for NTCs with the exception of one ATP candidate: a capacitor bank estimated at approximately $500,000.

These figures summarize the $251 million in new and modified upgrades, including: reconductoring/rebuilding 60 miles of transmission lines; adding 174 miles of new transmission lines; converting 4.8 miles of transmission lines; adding 164 Mvars of new capacitors; and adding/upgrading 10 transformers. Transmission Owners will work with staff to develop mitigation plans to address the reliability issues in cases where project construction cannot be completed before they are needed.

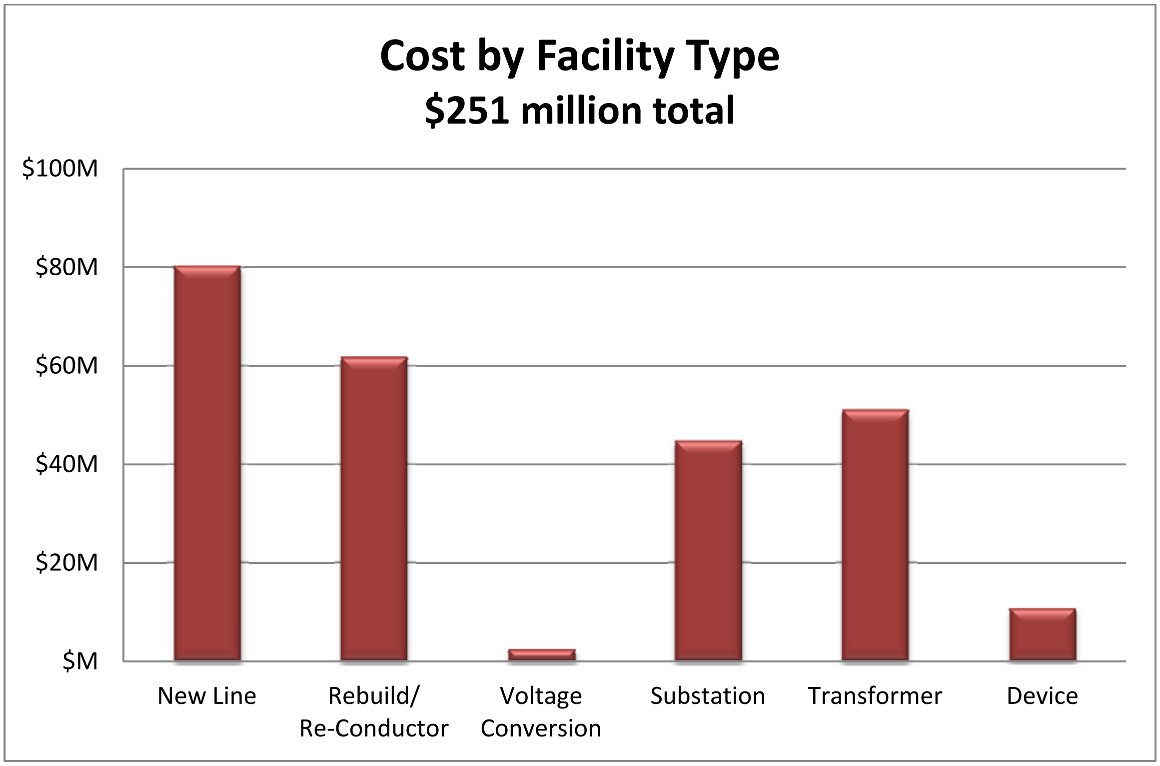

Figure 6: 2012 ITPNT Cost Summary

Table 1 below shows the cost impact of the addition of all the $251 million network upgrades on residential customers' monthly bills (1,000 kWh per month) from 2011, through the addition of the 2012 ITPNT upgrades in 2017. Cost impacts are expressed in nominal dollars, capturing an estimate of the bill impacts for 2017. Note these results are *rough estimates* of the expected impacts if 2012 ITPNT upgrades are installed.

The numbers below are reported as the Annual Transmission Revenue Requirement (ATRR) for the year 2017. In general, ATRRs are the amount of revenue necessary each year for transmission projects.

Three zones have the hightest impacts: Mid-Kansas, SPS, and Midwest Energy. Mid-Kansas' allocable portion of upgrades ($24 million) resulted in a $0.45/month rate impact. Midwest's allocable portion of upgrades ($8 million) resulted in a $0.30/month rate increase. SPS's sizeable allocable portion of upgrades ($107 million) caused its monthly rate impacts to increase by $0.43. These average monthly residential electric bill increases reflect the magnitude of zonal funding.

Average Monthly Residential Electric Bill Increase in $/Mo		
ZONE	***Additional ATRR ($/YR)***	***Residential Rate Impact ($/Mo)***
AEP	$6,421,148	$0.22
CUS	$114,744	$0.03
EDE	$198,260	$0.04
GRDA	$392,700	$0.01
KCPL	$613,728	$0.05
LES	$448,274	$0.13
MIDW	$487,200	$0.30
GMO	$316,636	$0.05
MKEC	$1,955,144	$0.45
NPPD	$919,821	$0.06
OGE	$1,343,856	$0.05
OPPD	$367,472	$0.04
SEPC	$76,254	$0.02
SPS	$9,244,213	$0.43
WFEC	$244,739	$0.04
WR	$3,684,964	$0.17

Table 1: Rate Impacts

Figure 6 represents the costs by year to rebuild and build new transmission in the 2012 ITPNT. The year 2014 contains the highest cost of line upgrades worth $49 million followed by $45 million worth of upgrades in 2012.

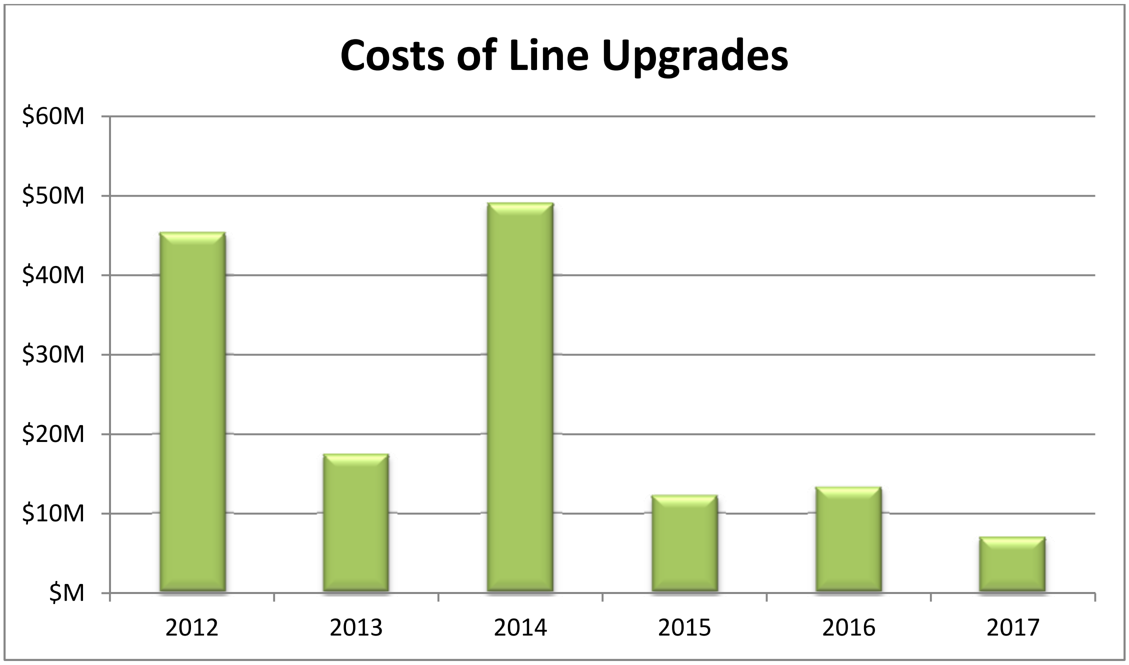

Figure 7: Cost summary of Line Upgrades by year

As seen in Figure 7, the majority of upgrades in the 2012 ITPNT are on the 115 kV system totaling $98 million, followed by the 138 kV and 69 kV system totaling $21 million and $20 million respectively.

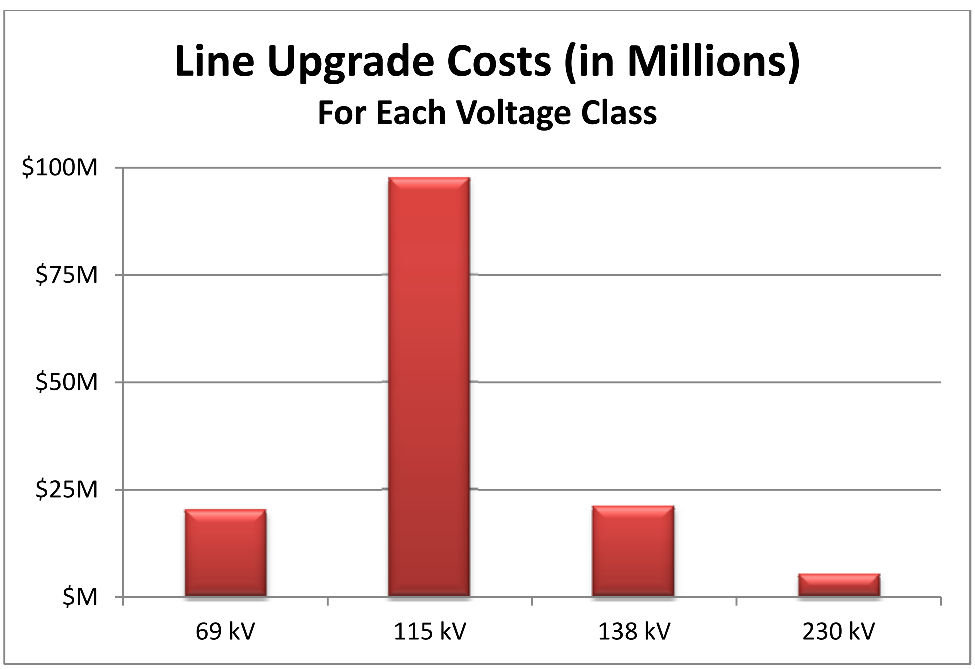

Figure 8: Cost summary of Line Upgrades by voltage class

Figure 8 represents the mileages to rebuild and build new transmission through 2017. The most miles of upgrades are in 2012.

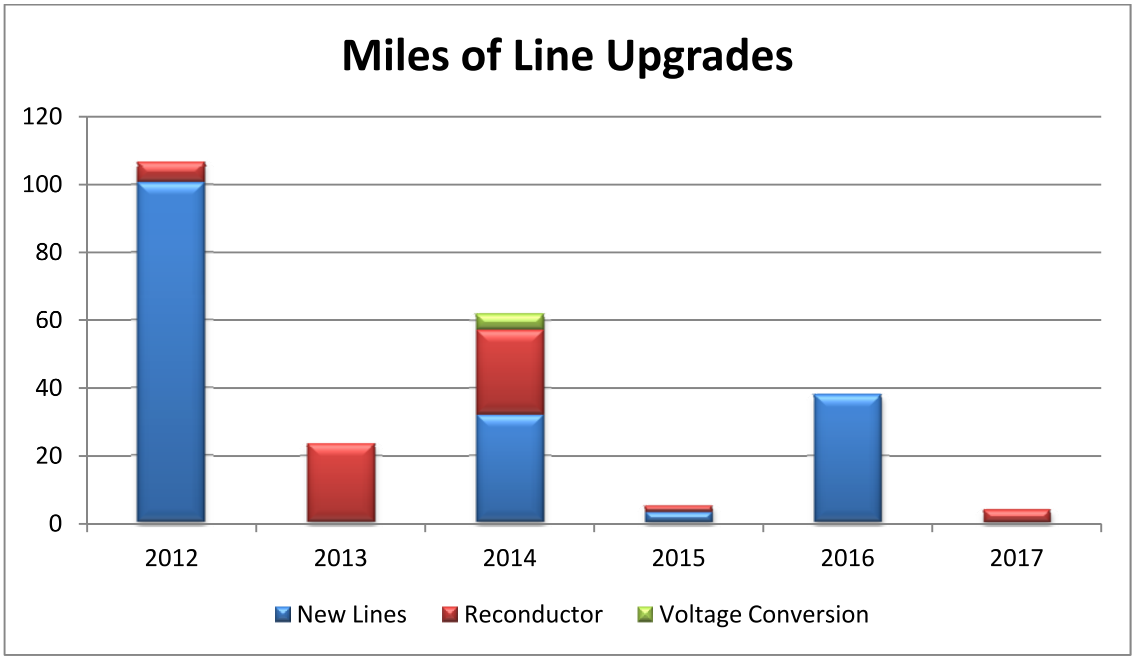

Figure 9: Mileage summary of Line Upgrades

In addition to rebuilding and building new transmission lines, the 2012 ITPNT contains $96 of substation and transformer upgrades to the system.

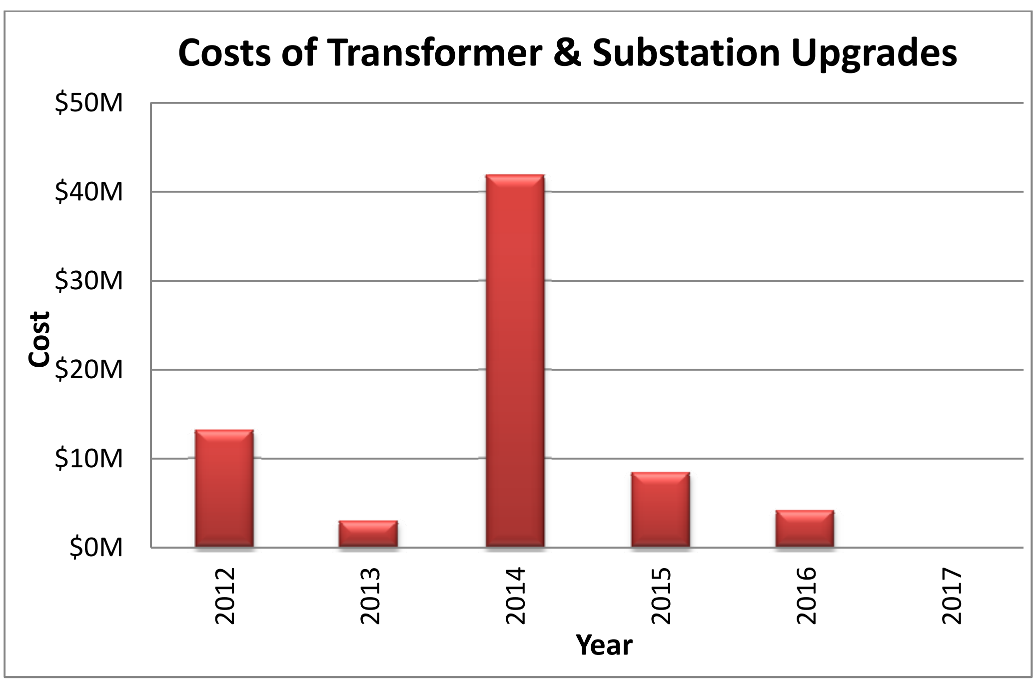

Figure 10: Cost summary of Transformer and Substation Upgrades

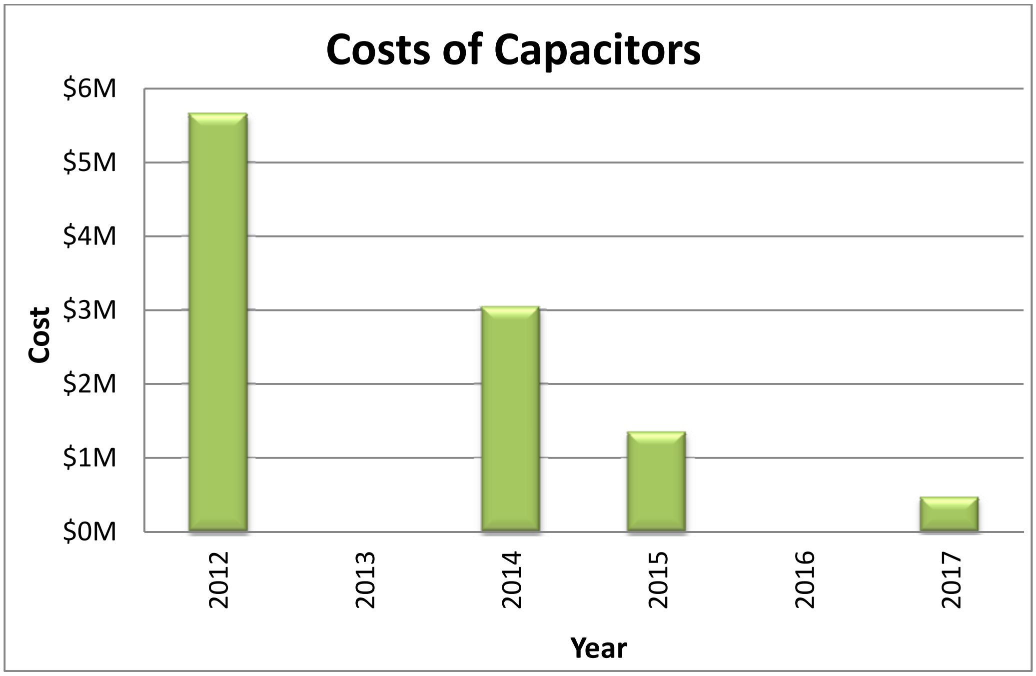

Figure 11: Cost summary of Capacitive Devices

Section 5: Recommendation

Staff recommends the Board approve Appendix I.

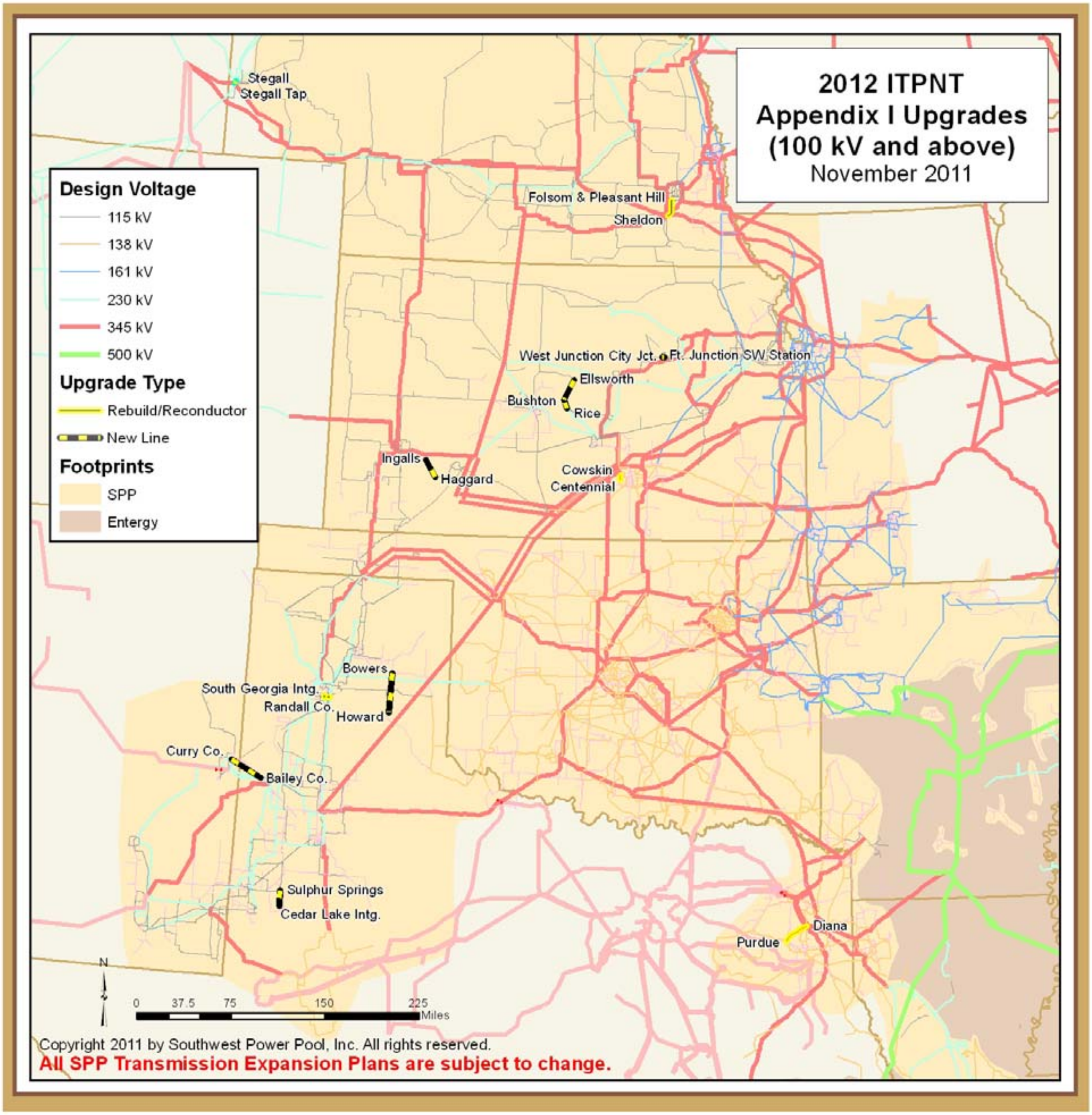

Figure 12: Map of 100 kV and above recommended upgrades

PART IV: APPENDICES

Section 6: Appendices

6.1: Appendix I - 2012 ITPNT Recommended Projects

2012 Requested Board Action	PID	UID	Facility Owner	Project Description/Comments	In-Service Date	2011 STEP DATE	Cost Estimate	Estimated Cost Source	2011 Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Circuit	Voltages (kV)	Miles of Re-conductor/ Rebuild	Miles of New	Miles of Voltage Conversion	Rating
				New and Modification															
NTC	30346	50438	AEP	Upgrade the Cornville 138 kV substation breaker scheme to breaker and half configuration in preparation for the 138 kV line conversion to Lindsay Water substation.		06/01/12	$19,998,928	AEP	regional reliability	511450	Cornville				138				
NTC - Modify	882	11171	AEP	Rebuild or reconductor 11.4-mile Rock Hill - Carthage line from 336 ACSR to 1272 ACSR and remove switches in middle of line. Upgrade breaker, switches, CT ratios, and relay settings at Carthage. Upgrade jumpers, switches, CT ratios, and relay settings at Rock Hill.		06/01/13	$10,920,454	AEP	regional reliability	509082	Rock Hill 69 kV	509056	Carthage 69 kV	1	69	11.4			123/143
NTC	503	10648	AEP	Replace two breakers and jumpers and wavetraps at Perdue. Replace wave traps at Diana.		06/01/13	$926,970	AEP	regional reliability	508351	Perdue 138 kV	508831	Diana 138 kV	1	138				261/303
NTC	1012	11331	AEP	Rebuild 21.85 mile Diana-Perdue 138 kV line. Replace switches, and jumpers, and upgrade CT ratios at Diana and Perdue. Upgrade relay settings at Diana.		06/01/14	$17,359,447	AEP	regional reliability	508351	Perdue 138 kV	508831	Diana 138 kV	1	138	21.85			455/478
NTC	502	10647	AEP	Reconductor 3.25 miles Northwest Henderson-Poynter 69 kV line with 1272 ACSR.		06/01/14	$7,214,837	AEP	regional reliability	509075	Northwest Henderson 69 kV	509081	Poynter 69 kV	1	69	3.25			143/143
NTC	30354	50405	AEP	Install 6 Mvar capacitor at Cowetta 69 kV.		06/01/14	$1,318,601	AEP	regional reliability	509719	Cowetta 69 kV								6 Mvar
NTC	549	10698	GRDA	Reconductor 69 kV Line to 795 ACSR and replace 600A switch with 1200A switch.		06/01/12	$1,064,300	GRDA	regional reliability	512626	Maid 69 kV	512681	Pryor Foundry South 69 kV	1	69	1.4			97/112
NTC	550	10699	GRDA	Reconductor 69 kV Line to 795 ACSR and replace 600A switch with 1200A switch.		06/01/12	$1,092,500	GRDA	regional reliability	512626	Maid 69 kV	512696	Redden 69 kV	1	69	1.3			97/112
NTC	1135	11498	KCPL	Loma Vista East limit is 600/5 CT ratio; reset to 1200/5		06/01/12	$190,860	KCPL	regional reliability	542998	Loma Vista East 161 kV	543009	Winchester Junction North 161 kV	1	161				224/224
NTC	30352	50403	LES	Rebuild 12 miles of 115 kV between Sheldon and Folsom/Pleasant Hill		01/01/12	$6,480,000	LES	regional reliability	640278	Sheldon	650242	Folsom & Pleasant Hill	2	115	12			240/240
NTC	30358	50411	MIDW	Install 8 miles of 115 kV from Rice to Bushton 115 kV. Install 115 kV breaker at Rice subastion and a terminal postion at Bushton Sub		06/01/12	$19,459,597	MIDW	regional reliability	530623	Rice	530681	Bushton	1	115		8		165/199
NTC	30358	50448	MIDW	Install 20 miles of 115 kV line from Bushton to Ellsworth and new 115 kV terminal at Midwest Bushton Substation		06/01/12		MKEC	regional reliability	530681	Bushton	539662	Ellsworth	1	115		10		165/199
NTC	30358	50409	MKEC	Install 20 miles of 115 kV line from Bushton to Ellsworth and new 115 kV terminal at Midwest Bushton Substation		06/01/12		MKEC	regional reliability	530681	Bushton	539662	Ellsworth	1	115		10		165/199
NTC	30358	50410	MKEC	Install three breaker ring bus at Ellsworth Tap		06/01/12		MKEC	regional reliability	539642	Ellsworth Tap				115				239/239
NTC	30358	50449	MKEC	Expand Ellsworth Substation to included two new 115 kV breakers		06/01/12		MKEC	regional reliability	539662	Ellsworth				115				
NTC	30347	50396	MKEC	Install 20.9 miles of 115 kV from Haggard to Ingalls 115 kV. Install two breakers at Haggard substation		06/01/12	$12,516,103	SEPC	regional reliability	539667	Haggard 115 kV	531407	Ingalls 115 kV	1	115		20.9		240/240
NTC	30237	50249	NPPD	Install a 18 Mvar capacitor bank at Holdrege substation 115 kV bus.	06/01/14	M	$1,193,000	NPPD	regional reliability	640224	Holdrege 115 kV				115				18 Mvar
NTC	816	11078	NPPD	Uprate conductor and substation equipment to 100 Degree rating.	06/01/14	M	$1,240,000	NPPD	regional reliability	640054	Albion 115 kV	640181	Genoa 115 kV	1	115				137/137
NTC	30286	50400	NPPD	Build 3 mile tie line between Stegall 230 kV and 345 kV substations		06/01/15	$5,239,000	NPPD	regional reliability	642573	Stegall 230 kV	659317	Stegall Tap 230 kV	2	230		3		
NTC	30302	50346	OGE	Increase size of Paoli 138/69 kV bus tie to full 50 MVA		06/01/12	$2,020,094	OGE	regional reliability	515100	Paoli 4 138kV	515099	PALIOGE 2 69kV	1	138/69				62/67
NTC	30092	50098	OGE	Add Mvar support at Kolache 69 kV substation to have a total of 9 Mvar at this location.		06/01/12	$440,081	OGE	regional reliability	515079	Kolache 69 kV				69				6 Mvar
NTC	30357	50408	OGE	Install 9 Mvar capacitor at Lula 69 kV.		06/01/12	$605,551	OGE	regional reliability	515191	Lula 69 kV				69				9 Mvar
NTC	30356	50406	SPS	Install new 115/69 kV transformer at new Cedar Lake Interchange		06/01/12	$3,914,970	SPS	regional reliability	527212	Cedar Lake Interchange	527211	Cedar Lake Interchange 69 kV	1	115/69				84/84
NTC	30356	50407	SPS	Build 12 miles of new 115 kV line from SulphurSprings to new Cedar Lake Interchange.		06/01/12	$6,112,772	SPS	regional reliability	527262	Sulphur Spring	527212	Cedar Lake Interchange	1	115		12		157/173
NTC	461	10597	SPS	Build 40 miles 115 kV between Bailey and Curry.		06/01/12	$9,132,270	SPS	regional reliability	524822	Curry County Interchange	525028	Bailey County Interchange	1	115		40		273/300
NTC	151	10195	SPS	Install 84MVA 3rd Transformer at Tuco Interchange		06/01/12	$1,984,500	SPP	regional reliability	525862	Tuco 69kv	525828	Tuco 115 kV	1	115/69				84/84
NTC	836	11104	SPS	Move load from Muleshoe 69 kV to Muleshoe 115 kV.		06/01/12	$1,634,119	SPS	regional reliability	524030	Muleshoe E 115 kV				115				120/120
NTC - Modify	1034	11359	SPS	Convert Hereford Interchange - NE-Hereford Interchange 69 kV line Z72 to 115 kV service	06/01/14	06/01/12	$2,362,500	SPP	regional reliability	524606	Hereford Interchange 115 kV	524567	Northeast Hereford Interchange	1	115			4.8	87/95
NTC	30351	50401	SPS	Install 14.4 Mvar capacitor at Crosby 115 kV		06/01/12	$1,336,466	SPS	regional reliability	525926	Crosby Sub 115KV				115				14.4 Mvar
NTC	30087	50093	SPS	Install two 50 Mvar capacitors at Bushland Interchange 230 kV.		06/01/12	$1,071,475	SPS	regional reliability	524267	Bushland Interchange				230				50 Mvar
NTC	1141	11505	SPS	Upgrade the Spearman transformer to 84/100 MVA		06/01/13	$2,394,495	SPS	regional reliability	523186	Spearman	523185	Spearman	1	115/69				84/105
NTC	884	11173	SPS	Add 2nd transformer Eddy Co 230-115 kV CKT 2		06/01/14	$6,761,086	SPS	regional reliability	527800	Eddy 230 kV	527798	Eddy 115 KV	2	230/115				168/168
NTC	30353	50402	SPS	Modify 230 kV bus to provide termination points for moving 230 kV lines from Lea County Sub to Hobbs. Retire Lea County 150 MVA 230/115 kV transformer. Install new 240 MVA 230/115 kV tranformer at Hobbs.		01/01/14	$8,270,297	SPS	regional reliability	527894	Hobbs Interchange 230 kV	527891	Hobbs Interchange 115 kV	1	230/115				240/240
NTC	1003	11317	SPS	Upgrade Grassland 230/ 115 kV XF #1 to 150.165 MVA XF		06/01/15	$3,961,322	SPS	regional reliability	526677	Grassland 230 kV	526676	Grassland 115 kV	2	230/115				150/165
NTC - Modify	839	11107	SPS	Build new 22.2 mile Kress Interchange - Kiser 115 kV.	06/01/15	M	$15,538,805	SPS	regional reliability	525192	Kress Int 115 kV	525271	Kiser 115 kV	1	115		20		157/173
NTC	839	50450	SPS	Build new Kiser substation. Install a 115/69 kV transformer and 69 kV terminal equipment to connect to the local 69 kV system.	06/01/15	06/01/14	$4,500,000	SPP	regional reliability	525271	Kiser 115 kV	525272	Kiser 69 kV	1	115/69				84/97
NTC - Modify	839	11109	SPS	Build new 9.8 mile Cox - Kiser 115 kV line unit.	06/01/15	M	$6,590,414	SPS	regional reliability	525326	Cox 115 kV	525271	Kiser 115 kV	1	115		10		157/173
NTC	30332	50379	SPS	Install 14.4 Mvar capacitor at Drinkard 115 kV		06/01/15	$1,349,807	SPS	regional reliability	528589	Drinkard Sub 115KV				115				14.4 Mvar
NTC	805	11067	SPS	Add 2nd 115/69 kV transformer at Bowers.		06/01/16	$4,120,585	SPS	regional reliability	523748	Bowers Interchange 115 kV	523747	Bowers Interchange 69kV	2	115/69				84/96
NTC	805	50453	SPS	Build new 33-mile 115 kV line from Bowers Interchange - Howard		06/01/16	$13,286,935	SPS	regional reliability	523748	Bowers Interchange 115 kV	523797	Howard	1	115		38		180/199
NTC	1033	11358	SPS	Reconductor 4.1 miles of 6.1 miles from Randall County to South Georgia 115 kV		06/01/17	$6,921,313	SPS	regional reliability	524364	Randall County Interchange 115 kV	524322	South Georgia Interchange 115 kV	1	115	4.1			246/270

2012 Requested Board Action	PID	UID	Facility Owner	Project Description/Comments	In-Service Date	2011 STEP DATE	Cost Estimate	Estimated Cost Source	2011 Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Circuit	Voltages (kV)	Miles of Re-conductor/ Rebuild	Miles of New	Miles of Voltage Conversion	Rating
ATP	30330	50377	SPS	Install 2nd stage 14.4 MVAR at Etter Rural Sub 115 kV		06/01/17	$466,889	SPS	regional reliability	523256	Etter Rural Sub 115 kV				115				14.4 Mvar
NTC	30339	50386	WR	Replace terminal equipment on Pentagon Substation to increase Mund - Pentagon 115 kV ckt 1 to 1200A	12/31/12	12/01/12	$278,300	WR	regional reliability	533282	Mund	533261	Pentagon	1	115				179/194
NTC	30348	50397	WR	Rebuild Cowskin to Centennial 138 kV line		06/01/12	$3,676,071	WR	regional reliability	533038	Cowskin	533034	Centennial	1	138	3.4			287/287
CNTC	30349	50398	WR	Replace Auburn 230/115 kV transformer with 400/440MVA unit.		06/01/14	$25,845,600	WR	regional reliability	533151	Auburn Road	532851	Auburn Road		230/115				400/440
NTC	30350	50399	WR	Install 2nd 6 Mvar capacitor at Elk River 69 kV		06/01/12	$1,007,160	WR	Zonal Reliability	533691	Elk River 69 kV				69				6 Mvar
NTC	30335	50382	WR	Install 1 stage of 10.8 MVAR		06/01/12	$957,660	WR	Zonal Reliability	533439	Wheatland				115				10.8 Mvar
NTC	30336	50383	WR	Install 1 stage of 15 Mvar at Northwest Manhattan 115kV		06/01/14	$957,660	WR	Zonal Reliability	533347	Northwest Manhattan 115kV				115				15 Mvar
NTC	624	10812	WR	Rebuild 1.7 mile Fort Junction - West Junction City 115 kV line with 1192.5 ACSR. Remove old double circuit and West Junction City Junction (East) - West Junction City 115 kV line.		06/01/15	$6,969,136	WR	regional reliability	533328	Fort Junction Switching Station 115 kV	533342	West Junction City 115 kV	1	115	1.7			240/240
				Withdrawal															
NTC - Withdraw	546	10695	AEP	Rebuild the 26.2-mile Carnegie - Hobart Jct. 138 kV line from 397 ACSR to 1272 ACSR. Replace 3 switches, wavetraps and jumpers. Reset CTs and relays.		D	$28,500,000	AEP		511463	Hobart Junction 138 kV	511445	Carnegie South 138 kV	1	138	26.15			280/287
NTC - Withdraw	546	10696	AEP	Reconductor the 14.37-mile Southwest Station - Carnegie 138 kV line from 397 ACSR to 1272 ACSR. Replace wavetraps and jumpers.		D	$16,000,000	AEP		511445	Carnegie South 138 kV	511477	Southwestern Station 138 kV	1	138	14.37			202/235
NTC - Withdraw	30072	50078	GRDA	Install (3) 7.2 Mvar capacitors for a total of 21.6 Mvar at Afton 69 kV bus.		D	$800,000	GRDA		512633	Afton 69 kV				69				21.6 Mvar
NTC - Withdraw	30090	50096	MKEC	Add 9.6 Mvar capacitor at Russell 115 kV.		R	$1,200,000	MKEC		539701	Russell 115 kV				115				9.6 Mvar
NTC - Withdraw	858	11129	OGE	Convert 14-mile Mehan - Cushing 69 kV line to 138 kV		D	$18,000,000	OGE		515513	Mehan 138 kV	515033	Cushing 138 kV	1	138			14	194/222
NTC - Withdraw	858	11130	OGE	Convert 6-mile Stillwater - Spring Valley 69 kV line to 138 kV		D		OGE		515011	Stillwater 138 kV	515512	Spring Valley 138kV	1	138			5.98	194/222
NTC - Withdraw	858	11131	OGE	Convert 3-mile Spring Valley - Mehan 69 kV line to 138 kV		D		OGE		515512	Spring Valley 138kV	515513	Mehan 138 kV	1	138			3	72/72
NTC - Withdraw	858	11132	OGE	Convert 8.7-mile Spring Valley - Knipe 69 kV line to 138 kV		D		OGE		515512	Spring Valley 138kV	515514	Knipe 138 kV	1	138			8.69	268/286
NTC - Withdraw	858	11133	OGE	Tap existing Cushing - Bristow 138 kV line into new Greenwood substation. Build new Greenwood substation with 138/69 kV transformer.		D		OGE		515033	Cushing 138 kV	515035	Bristow 138 kV	1	138				120/120
NTC - Withdraw	858	11134	OGE	Tap existing Oak Grove - Hwy 99 Tap 69 kV circuit into new Greenwood substation		D		OGE		515021	OakGrove 69 kV	515019	Hwy 99 Tap 69 kV	1	69				52/66
NTC - Withdraw	30303	50345	OGE	Install 6 Mvar capacitor bank at Wells 69 kV		D	$352,350	SPP		515202	Wells 69 kV				69				6 Mvar
NTC - Withdraw	621	10809	WR	Uprate JEC- E. Manhattan 230 kV line to 100 deg C operation by raising structures.		R	$19,307,000	SPP		532861	E. Manhattan 230 kV	532852	JEC 230 kV	1	230				446/490
NTC - Withdraw	1030	11354	SPS	Construct approximately 6 miles of 115 kV line from Tuco Interchange to SP-Abernathy Substation. Convert SP-Abernathy Substation to 115 kV service.		R	$2,126,250	SPP		525828	Tuco 115 kV	525732	SP- Abernathy 115 kV	1	115		6		157/173
NTC - Withdraw	839	11108	SPS	Add new Plainview County 115/69 kV transformer with 44/50.6 MVA ratings.		R	$5,278,922	SPS		525271	Plainview CTY 115 kV	525270	Planiview Co 69 kV	1	115/69				44/50.6
NTC - Withdraw	645	10846	WR	Add second transformer in 17th Street substation.		D	$8,300,000	WR		533064	17TH Street 4 138 kV	533840	17TH Street 2 69 kV	1	138/69				150/165
NTC - Withdraw	533	10678	WR	Install second Auburn Road 230/115 kV transformer.		R	$23,818,000	WR		532851	Auburn 230kV	533151	Auburn 115kV	2	230/115				280/308
NTC - Withdraw	643	10844	WR	Tap the Neosho - Twin Valley line into Altamont.		D	$4,650,000	WR		533008	Twin Valley No. 1 Valley 138 kV	533021	Neosho 138 kV	1	138				191/210
NTC - Withdraw	463	10600	WR	Rebuild existing line to 345kV operated as 230 kV		D	$46,682,401	WR		532861	East Manhattan 230kV	532852	JEC 230kV	1	230	27			892/892
NTC - Withdraw	463	10602	WR	The East Manhattan-McDowell 115 kV is built as a 230 kV line but is operated at 115 kV. Substation work will have to be performed in order to convert this line to 230 kV operation.		D	$14,716,000	WR		532862	East Manhattan 230kV	532861	McDowell 230kV	1	230			15.65	358/358
NTC - Withdraw	30128	50134	WR	Install 10.8 Mvar capacitor at Rock Creek 69 kV bus.		D	$427,000	WR		533458	Rock Creek				69				10.8 Mvar

6.2: Appendix II - 2012 ITPNT Scope

TWG Approved: 11-4-10

Introduction

The main objective of the Integrated Transmission Planning (ITP) Near-Term Assessment is to evaluate the reliability of the SPP transmission system in the near-term planning horizon, collaborate on the development of mitigations with stakeholders and identify necessary reliability upgrades for approval and construction. The process will also include coordination of transmission plans with the ITP20, ITP10, Aggregate Study, and Generation Interconnection processes.

The Near-Term Assessment will create an effective near-term plan for the SPP footprint which identifies problems for normal conditions (no contingency) and (N-1) scenarios using NERC Reliability Standards, SPP Criteria, and local planning criteria, The process will coordinate the development of appropriate mitigation plans to meet the reliability needs of the SPP region. This analysis is not for NERC compliance reporting (NERC compliance will be facilitated through a different SPP process), but rather to meet SPP OATT, Attachment 'O' requirements to plan a reliable transmission system for the near-term transmission service needs of the SPP system.

The ITP Near-Term study horizon will include modeling of the transmission system for loads out for six years. This will provide enough project planning margin such that NTC letters can be issued and project owners can begin work in a timely fashion to enable the completion of the more complex projects by the identified need date. The process will be conducted in an open and transparent manner allowing for stakeholder input and feedback on all scope and timing needs. All study results from the planning process will be coordinated with other entities/regions responsible for transmission planning needs and assessment/planning.

Near-Term Study Objectives

The study will assess the SPP transmission system to ensure that SPP has mitigation plans to the following:

- NERC Reliability Standards TPL-001 and TPL-002
- SPP reliability criteria
- Local planning criteria as submitted by Transmission Owners (TO)
-

The study will coordinate the results of the ITP-10 and ITP-20 as they correlate with the Near-Term study horizon. The study will assess mitigation plans proposed by TOs (operating guides and/or new facilities). SPP will incorporate approved and planned system upgrades into the quarterly project tracking process to ensure reliability projects are built or mitigations plans are in place in time to meet the needs of the system. SPP will coordinate all regional transmission plans with neighboring entities, regions and RTO's.

ITP Near-Term Study Assumptions

Study Models

The Near-Term Assessment will use the 2012 summer peak and 2012/13 winter peak models and the 2013 summer peak, 2013/14 winter peak, 2017 summer peak, and 2017/18 winter peak ITP reliability study models. The models will be built using the 2011 series MDWG, Models On Demand (MOD) process. The 2010 spring MDWG models will be used for the basic starting topology and the MOD process will be used to determine load and which MOD projects to include in the ITP Reliability models. The load and capacity forecast for the models have included the impact on load of the existing and planned demand response resources.

The models will incorporate the following aspects:

- All MOD projects that have been energized. MOD Type – Network, MOD Status – Energized
- All MOD projects that update network data. MOD Type – Network, MOD Status – Update
- All MOD projects that change network topology status; constructed facilities that are out-of-service or normally open; MOD Type – Outage, MOD Status – Outage
- The latest SERC model data, which includes the AECI and EES systems, in the base model
- All projects in AECI's Construction Plan
- All projects in Entergy's Construction Plan
- Transmission Owner-Initiated Projects
    - Transmission Owner-Initiated Projects will be included as determined by the Transmission Owner. MOD Type – Reliability, MOD Status – STEP (w/NTC) or Planned
- Previously identified SPP Transmission Expansion Plan Projects
    - All regional reliability upgrades with an LOA/NTC will be included in the model except for those that have been requested to be removed and have been through stakeholder review. MOD Type – Reliability, MOD Status – STEP (w/NTC) or TO Planned
    - Balanced Portfolio projects
    - High priority projects
- SPP Aggregate Study (Attachment Z) Projects
    - All projects that have either an LOA/NTC will be included in the model except for those that have been requested to be removed and have been through stakeholder review. MOD Type – TSR, MOD Status – w/NTC (Approved)
- Confirmed Long Term Firm transmission service
    - In addition to Confirmed Firm service mentioned above, other service will be included as defined in the ITP Manual section V.E.1.

    - Exception has been identified for SPS generation deficiency:
        - Add the Antelope 170 MW unit and Jones 190 MW gas turbine unit in the SPS area to the models

- When a deficiency between interchange, generation, and load is identified, the following process will be used:
    1) Exhaust the customer's dispatchable designated network resources until the network resources are sufficient to meet network load.

   a. Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.
   b. Add generation from behind the meter generating units. This generation consists of dispatchable behind the meter generation that may not already included in the SPP MDWG models.

2) If the customer's dispatchable designated load cannot be served after Step One, then exhaust the customer's other dispatchable, operational generation that is not designated.
   a. Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.
   b. Add generation from behind the meter generating units. This generation consists of behind the meter generation that may not already included in the SPP MDWG models.

3) If the customer's designated load cannot be served after Step One and Step Two, exhaust the Host Transmission Owner's existing dispatchable generation.
   a. Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.

4) If the customer's network load cannot be served after the above steps, exhaust Independent Power Producer's ("IPP") existing dispatchable generation in the Host Transmission Owner's modeling area.
   a. Exhaust IPP generation on a pro rata, as available basis accounting for firm transmission commitments. In other words, Use power from each IPP to meet the customer's designated load. The amount of power from each IPP will be determined using the total amounts available based on the IPP's historical generating levels minus the amount of power to model existing transmission service from the IPP.

5) Finally, if a customer's network load cannot be served after applying the above steps, exhaust dispatchable IPP generation and remaining unused generation in SPP (from these modeling areas: AEPW, GRDA, OKGE, WFEC, SPS, MIDW, SUNC/MKEC, WERE, GMO, KCPL, EMDE, SPRM, NPPD, OPPD, and LES) on a pro rata basis.
   a. Similar to Step Four, exhaust this generation on a pro rata, as available basis for firm transmission commitments. The amount of power from each IPP and from each modeling area generation will be determined using the total amounts available based on the maximum generating levels minus the amount of power to model existing transmission service from the IPP and modeling area generation.

Scenarios To Be Developed

SPP will develop two scenario models for each season for the steady state evaluation

- The “Scenario Zero” model has the same dispatch as the MDWG models with the exception that generation that does not have a signed interconnection agreement and generation that does not have transmission service is also removed. The exception to this is in later years when generation load and interchange does not match the shortfall is made up of units that are in-service.
- The “All transactions” (“Scenario 5”) model is the same as the “Scenario Zero” model with the dispatch changed to include all transmission service sold with ERCOTN North to South, ERCOTE East to West, SPS importing and SPS exporting to the Lamar HVDC tie

Methodology for the Reliability Assessment

Steady State Analysis

- Monitoring of Facilities
  - SPP staff will monitor all facilities in the SPP footprint 69 kV and above at 95% thermal loading. With the exception of Entergy (EES) and Associated Electric (AECI), staff will monitor all facilities in first-tier control areas 230 kV and above. Within EES and AECI, facilities will be monitored at 100 kV and above.
- Normal conditions and contingency analysis will be performed on the Near-Term models including the “Scenario Zero” and “Scenario 5” transaction models.
  - Normal conditions
  - All N-1 single-element contingencies 69 kV and above in SPP will be evaluated. These contingencies do not include manual transfer of load or manual switching.
  - All N-1 single-element contingencies 100 kV and above in EES, AECI, and in all other first-tier companies, 230 kV and above N-1contingencies will be evaluated.
- SPP will verify that all normal conditions and N-1 violations identified have corrective plans

Use of Transmission Operating Guides (TOG)

- The Steady State analysis will identify all violations without the use of TOGs.
- TOGs may be used as alternatives to planned projects. Load flow analysis will be performed to determine the effectiveness of the TOG in alleviating the violation(s).

System Stability Analysis

SPP will conduct a stability analysis as part of the 2011 ITP 10-Year Assessment.

Demand Response

The load and capacity forecast for the models have included the impact on load of the existing and planned demand response resources as provided through the MDWG modeling process.

Study Timeline

Finalize Scope ---– November 2010
Build Models ---– Feb – March 2011
Distribute Results of Contingency Analysis ------------------------- April 2011
Present Preliminary Findings and Proposed Improvements----- Late May 2011
Refine regional solutions and collaborate reliability needs
with ITP findings --– June – August 2011
Fall Joint Planning Summit to share solutions --------------------- September 2011
Draft STEP Report Sections --– October 2011
TWG Approve STEP Report Sections-------------------------------- November 2011

6.3: Appendix III - Generation Details

Appendix III exhibits the details of new generation that was captured in the ITPNT models along with the existing generation used to help serve a Balancing Authorities load if lacking sufficient generation.

Table 6.1 shows new generation in SPP that was included in the ITPNT models. This generation has both executed Generation Interconnection and transmission service agreements.

Generation Capacity with an Executed Transmission Service Agreement			
Model Area	**Plant Name**	**Net Capacity (MW)**	**In-Service Date**
American Electric Power	Turk	618	Late 2012
American Electric Power	Elk City Wind	99	In-Service
City Utilities, Springfield Missouri	Southwest 2	275	In-Service
Mid-Kansas Electric Company	Greensburg Wind	12.5	In-Service
Nebraska Public Power District	Petersburg Wind Farm	41	12/31/2011
Nebraska Public Power District	Broken Bow Wind Farm	80	12/31/2012
Nebraska Public Power District	Whelan Energy Center 2	220	In-Service
Nebraska Public Power District	Crofton Bluffs Wind Farm	42	12/31/2012
Oklahoma Gas and Electric Company	OU Spirit Wind	80	In-Service
Oklahoma Gas and Electric Company	Keenan Wind	152	In-Service
Oklahoma Gas and Electric Company	Taloga Wind	130	In-Service
Oklahoma Gas and Electric Company	Minco Wind	99	In-Service
Oklahoma Gas and Electric Company	Redbud	130	In-Service
Omaha Public Power District	Flatwater Wind	60	In-Service
Southwestern Public Service Company	Antelope	170	In-Service
Southwestern Public Service Company	Majestic Wind	80	In-Service
Westar Energy	Caney River Wind	201	1/1/2012
Westar Energy	Wolfcreek	42	In-Service
Westar Energy	Sheffield	2	In-Service
Western Farmers Electric Cooperative	Red Hills Wind	123	In-Service*

For wind farms, nameplate capacity is shown; for other generation, net summer capacity is shown.
*Start of long-term firm service: 1/1/2015

Table 6.1

In the IPTNT models additional generation was included and dispatched that has an executed FERC-filed Generation Interconnection Agreement not on suspension even though it does not have an executed transmission service agreement. This is shown in Table 6.2.

Generation Capacity without an Executed Transmission Service Agreement			
Model Area	**Plant Name**	**Net Summer Capacity (MW)**	**In-Service Date**
Southwestern Public Service Company	Jones #3	180	6/1/2012
Southwestern Public Service Company	LCEC Lovington	42	3/1/2012

Table 6.2

To address the generation deficiencies in 2017, existing IPP generation was also modeled and dispatched to serve load as represented in Table 6.3.

IPP Generation Capacity Used to Meet Shortfall of Generation and Interchange		
Model Area	**Units used for shortfall**	**MW available for Shortfall**
American Electric Power	Green Country Energy LLC	778
American Electric Power	Oneta Energy Center	1077
American Electric Power	Eastman Cogeneration Facility	402
American Electric Power	Harrison County Power Project	570
KCP&L Greater Missouri Operations Company	Dogwood	481

Table 6.3