**BEFORE THE
STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Before Commissioners: Shari Feist Albrecht, Chair
Jay Scott Emler
Pat Apple

In the Matter of the Application of Westar Energy, Inc. for a Siting Permit for the Construction of a 345 kV Transmission Line in Riley and Pottawatomie Counties, Kansas.	)	Docket No. 15-WSEE-365-MIS

PETITION TO INTERVENE

COMES NOW, Southwest Power Pool, Inc. ("SPP") and pursuant to K.S.A. 77-521, petitions the State Corporation Commission of the State of Kansas ("the Commission") for an order granting SPP intervention in the above-captioned matter. In support of its Petition, SPP states the following:

1. On February 20, 2015, Westar Energy, Inc. ("Westar") submitted its *Application for a Siting Permit for the Construction of a 345 kV Transmission Line in Riley and Pottawatomie Counties, Kansas* ("Application for Siting Permit"), requesting the right to construct a new 345 kV transmission line from Westar's Jeffrey Energy Center Substation to Westar's East Manhattan Substation, located near Manhattan, Kansas, to replace the existing 230 kV line between those stations (the "Project").

2. SPP is a Regional Transmission Organization ("RTO") approved by the Federal Energy Regulatory Commission and is responsible for taking all reasonable steps, including planning and general oversight duties, necessary to maintain and enhance the reliability of the electric transmission network operated by its member companies in Kansas and adjacent states.

3. The Project's need was determined by SPP's Integrated Transmission Plan ("ITP"), an iterative three-year study process that assesses long and near-term infrastructure needs of the SPP Transmission System. The intent of the ITP is to bring about continued development of a cost-effective, flexible, and robust transmission network that will provide efficient, reliable access to the region's diverse generating resources.
4. SPP was responsible for conducting the studies related to the ITP, which include the Project. Accordingly, SPP intends to file testimony based on the studies demonstrating the need for and the benefit of the Project.
5. Because such testimony supports the need for and benefits of the Project, SPP respectfully requests permission to file its testimony promptly, which is attached hereto as Exhibit A, and ahead of any procedural schedule, so that other parties may consider such testimony when responding to Westar's Application for Siting Permit.
6. SPP's interests would, thus, be substantially affected by the outcome of this proceeding, and the interests of justice and the orderly and prompt conduct of the proceedings will not be impaired by allowing intervention.
7. Accordingly, SPP has an essential interest in the outcome of this proceeding which cannot be adequately represented by any other party.

WHEREFORE, SPP respectfully requests the Commission grant its Petition for Intervention in this matter.

Respectfully submitted,

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Petitioner

VERIFICATION
K.S.A. 53-601

STATE OF KANSAS)
) ss:
COUNTY OF SHAWNEE)

I verify under penalty of perjury that the foregoing is true and correct.

John R. Wine, Jr.

Executed on March 3, 2015.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the above Petition to Intervene was sent via email, this 3rd day of March, 2015, to the following:

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EXHIBIT A

DIRECT TESTIMONY
OF
ANTOINE LUCAS
DIRECTOR, PLANNING
SOUTHWEST POWER POOL, INC.

BEFORE THE
STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Before Commissioners:	Shari Feist Albrecht, Chair Jay Scott Emler Pat Apple

In the Matter of the Application of Westar Energy, Inc. for a Siting Permit for the Construction of a 345 kV Transmission Line in Riley and Pottawatomie Counties, Kansas.	))))	Docket No. 15-WSEE-365-MIS

DIRECT TESTIMONY

OF

ANTOINE LUCAS
DIRECTOR, PLANNING
SOUTHWEST POWER POOL, INC.

ON BEHALF OF SOUTHWEST POWER POOL, INC.

March 3, 2015

I. INTRODUCTION AND OVERVIEW

Q. Please state your name and business address.

A. My name is Antoine Lucas. My business address is 201 Worthen Drive, Little Rock, AR 72223.

Q. By whom and in what capacity are you employed?

A. I am employed by Southwest Power Pool, Inc. ("SPP") as Director, Planning.

Q. What are your duties and responsibilities in your current position?

A. I am responsible for the engineering and related activities insuring continued reliable development of the SPP transmission grid, including SPP approval, Federal Energy Regulatory Commission ("FERC") and state regulatory proceedings, and maintenance and operational policy decisions related to engineering planning processes and services. I also have responsibility for the design, management, development, implementation and monitoring of planning engineering activities to support reliable and economic transmission expansion plans to serve future needs in an economically efficient and effective manner. In addition, I manage and track all activities related to expansion planning in the SPP Regional Transmission Organization ("RTO") and coordinate with others as necessary to implement and administer regional planning analyses and project tracking/reporting. I provide engineering support as necessary for members, regulators and other departments, as well as coordinate with other departments to ensure regulatory compliance. These responsibilities also require that I interact with other external parties not otherwise identified in the list above.

Q. Please summarize your educational and professional background.

A. I earned a Bachelor's Degree in Industrial Engineering from Louisiana Tech University and a Master's Degree in Business Administration from the University of Arkansas-Little Rock. Prior to being named Director, Planning of SPP, I most recently served as

Manager of Economic Planning. I also served SPP as Manager, Special Studies and Engineering Support, Manager, Interregional Planning and Procurement, and Manager, Weekly Procurement Process. I formerly was employed with Entergy Services, Inc. in various engineering positions in real time system operations.

Q. Please give a brief summary of SPP's organization and operations.

A. SPP is a FERC-approved RTO. It is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP currently has 83 members in nine states and serves more than 6 million households in a 370,000 square-mile area. SPP's members include 14 investor-owned utilities, 11 municipal systems, 14 generation and transmission cooperatives, 8 state agencies, 12 independent power producers, 12 power marketers and 11 independent transmission companies, and 1 federal agency. SPP, in its role as an RTO, currently administers transmission service over 48,930 miles of transmission lines covering portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. These services include reliability coordination, tariff administration, regional scheduling, transmission expansion planning, market operations, compliance, and training.

SPP has a unique culture for an RTO, being member-driven and comprised of a large number of stakeholder-populated committees, working groups and task forces who develop, through achievement of consensus, policies to be implemented by SPP. These stakeholder meetings are open to the public, and agendas and materials are posted on the SPP website. In the SPP RTO, members have both the right and obligation to provide policy positions to the SPP Board of Directors ("SPP Board") and its Members Committee for consideration and approval. On all SPP committees other than the Oversight Committee, the SPP members hold the majority of the voting strength.

Included in these stakeholder groups is the SPP Regional State Committee ("RSC"), comprised of state regulators across the SPP footprint, and the Cost Allocation Working Group ("CAWG"), which is made up of staff members of the state regulatory authorities. The RSC plays more than just an advisory role in the policies and responsibilities of SPP;

the RSC actively engages in a broad range of issues where SPP has ceded authority, including transmission cost allocation, capacity adequacy, allocation of transmission rights, and market evolution issues.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information related to the development of the proposed project that is the subject of the Application filed in the above-styled docket by Westar Energy, Inc. ("Westar") on February 20, 2015 ("Application"), and to detail the need for the Project and explain the 2014 Integrated Transmission Plan ("ITP") Near Term Assessment ("ITPNT"). The proposed rebuild of the existing line to 345 kV standards, and operated at 230 kV, from East Manhattan to Jeffrey Energy Center (the "Project") in the Application was identified in the 2014 ITPNT as a reliability project that would increase the capacity of the East Manhattan - Jeffrey Energy Center 230 kV line so that the line would not exceed its capacity limit in the event the Geary - Jeffrey Energy Center 345 kV was taken out of service.

Q. Is the purpose of your testimony to offer an opinion on the route of the proposed Project?

A. No. SPP does not offer an opinion on the route of the Project nor is it SPP's responsibility to determine the route of the Project or any other transmission project within its region. In accordance with its FERC-approved planning processes, SPP determines the need for transmission expansion projects and directs construction of those projects as necessary to meet reliability, economic, and public policy needs in the region. Those projects are generally specified by SPP to be built at or from one point on the network to another but SPP does not specify the route a project will take. In other words, SPP will direct the utility to build transmission from point A to point B, but defers to the utility and the Commission to determine the appropriate route.

Q. How is your testimony organized?

A. Following this Introduction and Overview Section, my testimony is organized in the following sections:

II. ITP Planning Process

III. 2014 ITPNT Assumption Development, Stakeholder Review, and Portfolio Approval

IV. Project Portfolio Development and Need Determination

V. Conclusion

II. ITP PLANNING PROCESS

Q. What is ITP?

A. The Integrated Transmission Plan, or the ITP as it is commonly referred, is SPP's iterative three-year study process that assesses long and near-term infrastructure needs of the SPP Transmission System. The intent of the ITP is to bring about continued development of a cost-effective, flexible, and robust transmission network that will provide efficient, reliable access to the region's diverse generating resources. The ITP process as described in Attachment O of the SPP Open Access Transmission Tariff ("OATT") promotes transmission investment that will meet reliability, economic, and public policy needs.

The ITP process includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies transmission projects, generally above 300 kV, needed to provide a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year Assessment focuses on facilities 100 kV and above to meet system needs over a ten-year horizon. The Near Term Assessment is performed annually and assesses system upgrades, at all applicable voltage levels, required in the near term planning horizon to address reliability needs. The Project that is the subject of this Application was identified as a reliability project in the 2014 ITPNT.

Q. What was the intent of the 2014 ITPNT?

A. The goals of the 2014 ITPNT included focusing on local and regional needs, evaluating the compliance of the transmission system with the North American Electric Reliability Corporation's ("NERC") Transmission Planning Standards TPL-001 and TPL-002,[1] and utilizing a cost-effective approach to analyze transmission system needs up to six years into the future. The study process for this 2014 ITPNT evaluated the need for facilities at or above 69 kV that satisfy needs such as:

a) resolving potential criteria violations;

b) improving access to markets;

b) meeting expected load growth demands;

c) improving interconnections;

d) facilitating or responding to expected facility retirements; and

e) maintaining the feasibility of existing long term firm transmission service.

The 2014 ITPNT used three scenario models which included: (1) a Consolidated Balancing Authority ("CBA") scenario built across multiple years and seasons to evaluate power flows across the grid to account for various system conditions across the near-term horizon; (2) a Scenario 0 ("S0") models that evaluates all long term firm transmission service at expected levels; and (3) a Scenario 5 ("S5") model that evaluates all long term firm transmission service at full capacity. The 2014 ITPNT Report, dated January 28, 2014 ("2014 ITPNT Report"), which is attached hereto as Exhibit AOL-1.[2]

Q. DOES SPP PROPOSE TRANSMISSION PROJECTS FOR NEEDS THAT COULD BE SOLVED WITHOUT CONSTRUCTING UPGRADES?

A. No. Transmission Operating Guides are tools that are available to mitigate reliability needs identified in the planning and operation of the transmission grid. Transmission

[1] NERC's Reliability Standards are posted at: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.
[2] The 2014 ITPNT Report is also available at: http://www.spp.org/publications/2014_ITPNT_Report.pdf.

Operating Guides may be used as alternatives to planned projects and are tested annually to determine effectiveness in mitigating potential violations. The 2014 ITPNT identified solutions where the use of a known Transmission Operating Guide was not effective for solving the reliability needs.

III. 2014 ITPNT ASSUMPTION DEVELOPMENT, STAKEHOLDER REVIEW, AND PORTFOLIO APPROVAL

Q. How were the 2014 ITPNT study assumptions determined?

A. Assumptions and procedures for the 2014 ITPNT analysis were developed through SPP stakeholder meetings that took place in 2012 and 2013. The assumptions were presented and discussed through many meetings with members, liaison-members, industry specialists, and consultants to provide a thorough evaluation of those assumptions. Groups involved in assumptions development included the following: Transmission Working Group ("TWG"), Markets and Operations Policy Committee ("MOPC"), and the SPP Board.

The TWG provided technical guidance and review for inputs, assumptions, and findings. Policy level considerations were tendered to groups including the MOPC and SPP Board. Stakeholder feedback was integral to the development of assumptions to be used in the 2014 ITPNT.

Q. Were there meetings held in addition to the regular stakeholder meetings?

A. Yes. In addition to the standard working group meetings, two transmission planning workshops (often called summits) were conducted to elicit further input and provide stakeholders with an opportunity to interact with staff on all related planning topics.

In 2013, SPP held two transmission planning summits related to the 2014 ITPNT. The first was held on May 15, 2013. At this summit, SPP specifically discussed and solicited feedback on the approach adopted by the TWG to define a reliability need resulting from analysis of a CBA model. The CBA model assumes the economic commitment and dispatch of the generation resources of all SPP Balancing Authorities ("BA") as one single BA rather than individual BAs consistent with the design of the SPP Integrated Marketplace. The 2014 ITPNT was the first ITPNT process to assess the transmission system impacts of a CBA.

The second summit was held on November 20, 2013. At this summit SPP discussed the preliminary recommended solutions for the 2014 ITPNT and collected stakeholder feedback for further consideration prior to finalizing solutions.

Q. Please further describe the stakeholder review process related to the data that was relied upon in the ITPNT analysis and ITPNT Report.

A. As explained above, data and study approaches used in the 2014 ITPNT analysis went through an extensive review process. The TWG was responsible for technical oversight of the load forecasts, transmission topology inputs, reliability assessments, transmission project development, voltage studies, and the report. Study approaches, policies, and results were reviewed by the TWG, MOPC, and SPP Board.

The 2014 ITPNT Report was also reviewed by stakeholders. A draft 2014 ITPNT Report was provided to the MOPC and TWG for review and comment. The final version of the 2014 ITPNT Report was endorsed by the TWG at its December 18, 2013 meeting, and by MOPC at its January 15, 2014 meeting. The 2014 ITPNT was presented to the RSC on January 27, 2014. The 2014 ITPNT was approved by the SPP Board on January 28, 2014.

Q. Please describe the approval process for the 2014 ITPNT Projects.

A. At its January 15, 2014 meeting, the MOPC endorsed SPP staff's recommendation to approve the 2014 ITPNT project plan and issuance of Notifications to Construct ("NTC"). On January 28, 2014, the SPP Board approved the 2014 ITPNT project plan and the issuance of NTCs. On February 19, 2014, SPP issued an NTC with Conditions (NTC-C) to Westar for the Project.

Q. What is an NTC-C?

A. An NTC-C is a formal document directing a TO to further refine its study estimate for an applicable project. An NTC-C does not authorize the TO to start construction or to order materials for the project. The NTC-C will direct a TO to perform detailed engineering and cost studies within a stated timeframe in order to refine its Study Estimate and provide the refined Study Estimate to SPP for analysis. SPP will review the refined Study Estimate to determine if SPP should remove the conditions and issue an NTC for the construction of the project.

Q. When did Westar receive an NTC?

A. Westar's February 19, 2014 NTC-C was conditioned on Westar providing a refined estimate, which Westar provided to SPP on August 28, 2014. On September 2, 2014, SPP issued an NTC for the Project with the conditions removed.

IV. PROJECT DEVELOPMENT AND NEED DATE DETERMINATION

Q. What was the methodology used to determine the portfolio of transmission projects?

A. SPP performed a reliability assessment of transmission facilities in the SPP footprint to evaluate loadings and system voltages consistent with NERC Reliability Standards TPL-001 or TPL-002[3] and SPP Criteria[4] in order to determine the reliability needs of the system. These standards and criteria essentially require thermal loading of SPP facilities 69 kV and above to remain within 100% of rated capacity under system intact ("Base Case") and single outage ("N-1") conditions. The standards and criteria also require that system voltages remain between 105% and 95% of voltage ratings under Base Case conditions and between 105% and 90% of voltage ratings for N-1 conditions. SPP also monitored facilities 100 kV and above in neighboring first-tier control areas.

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[3] NERC's Reliability Standards are posted at: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.
[4] The SPP Criteria is posted at: http://www.spp.org/section.asp?group=215&pageID=27.

After performing the reliability assessment and identifying the bulk power system reliability needs, potential violations were presented and solutions requested to those reliability needs from Transmission Owners ("TOs") and other stakeholders. Utilizing stakeholder feedback and information from other SPP planning studies, regional solutions were developed and validated. This process repeated for several iterations as solutions were refined to determine the final portfolio.

Q. You mentioned that you conducted an analysis using N-1 conditions. Can you explain what that means?

A. An N-1 analysis means that single transmission elements were removed from service one at a time while monitoring the resulting effects on remaining facilities during each contingency.

Q. You stated that your analysis looks for thermal loading as well as voltage violations. Can you explain what each of those things is and why they are significant?

A. The flow of electrons ("electric current") through transmission system equipment creates heat and temperature increases. These temperature increases can become excessive and cause damage or failure of the equipment. As a result, all equipment that carries electric current has thermal restrictions that are commonly referred to as thermal limits or thermal ratings. SPP's planning analysis evaluates thermal loadings relative to these thermal limits for potential violations.

Voltage limits, which have both upper and lower values, represent the voltage levels necessary to avoid damage to or failure of transmission system equipment and to maintain transmission system stability. High voltage limits are intended to protect transmission system equipment while low voltage limits are intended to both protect transmission system equipment and transmission system voltage stability. SPP's planning analysis evaluates voltage levels relative to voltage limits for potential violations.

Q. What parameters were used to develop the final portfolio of projects?

A. The selection of projects included in the final portfolio followed these guidelines:

1) Projects that (i) relieved Base Case or N-1 thermal loading above 100% in either S0 or S5, or (ii) relieved voltage violations in S0 or S5 consistent with NERC Reliability Standards TPL-001, TPL-002, or SPP Criteria were classified as reliability projects.

2) Projects that (i) relieved Base Case or N-1 thermal loading above 100% in the CBA Scenario and 95% in either S0 or S5, or (ii) relieved voltage violations in the CBA Scenario consistent with NERC Reliability Standards TPL-001, TPL-002, or SPP Criteria and had voltage less than 92% of its nominal voltage rating in either S0 or S5 were classified as reliability projects.

Projects that were identified in the analysis, but did not meet these criteria were not included in the final portfolio.

Q. Why was the Project, which is the subject of the Application in this docket, selected as a 2014 ITPNT Project?

A. The Project was identified as a solution to address an overload of the existing East Manhattan - Jeffrey Energy Center 230 kV line for outage of Geary - Jeffrey Energy Center 345 kV Ckt 1. Two potential types of solutions were considered to mitigate this need: rebuild of the existing overloaded line to increase the capacity of the line, or construction of a new line to assume a portion of the power flows to reduce loading of the overloaded line. Rebuild of the East Manhattan – Jeffrey Energy Center 230 kV line to 345 kV standards and operated at 230 kV was proposed by Westar to address the potential violation.

SPP staff determined that this solution addressed the short term need and also was a viable long term solution in recognition of similar needs near the Jefferson Energy Center substation that were resolved in the 2013 ITP 20-Year Assessment ("ITP20") with a 345 kV solution. SPP also determined that the rebuild of the line would likely require mitigation of operational impacts due to outages to the line during construction. SPP Staff discussed this with Westar and it is SPP's understanding that Westar plans to avert the operational issues associated with construction so that the outage windows would be short and the outages would correspond with either non-peak periods or planned outages of a Jeffrey Energy Center unit. An alternative of building a new 345 kV line from Cooper to Jeffrey Energy Center was considered, but the analysis showed that such a line to Cooper would only reduce, but not fully relieve, the potential overload. As a result, rebuild of the existing East Manhattan – Jeffrey Energy Center 230 kV line was selected as the solution to address the reliability issue because it would fully relieve the potential overload.

Q. What was the overload and why is it important to prevent it?

A. The East Manhattan - Jeffrey Energy Center 230 kV line was loaded at 106% of its rated capacity following the loss of Geary - Jeffrey Energy Center 345 kV line. The thermal loading of the East Manhattan – Jeffrey Energy Center 230 kV line was in violation of NERC Category B Reliability Standard TPL-002 – "System Performance Following Loss of a Single Bulk Electric System Element,"[5] and SPP Criteria 3.4.[6] Mitigation of facility loadings beyond rated capacity under N-1 conditions is required for compliance with NERC Transmission Planning Standards and to meet the requirements of SPP Transmission Planning Criteria.

Q. How were the need dates for the projects in the 2014 ITPNT determined?

A. Once the final portfolio of 2014 ITPNT projects were selected, each project was timed using linear interpolation based on line loading between available model years of 2014, 2015, and 2019. For example, to time a project's need date due to a 2019 potential overload, SPP interpolated line loadings between the 2015 and 2019 models to determine when the loading exceeded 100%. The need date for each project selected to resolve a thermal overload was assigned based on this analysis.

[5] *See* NERC Reliability Standards at pg. 2620.
[6] *See* SPP Criteria at 3.4.

V. CONCLUSION

Q. Is it your opinion that the Project is needed to support the reliability of the transmission system?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF ARKANSAS)
COUNTY OF PULASKI)

I, **Antoine Lucas**, being duly sworn according to law, state under oath that the matters set forth in my Direct Testimony in this docket are true and correct to the best of my knowledge, information and belief.

Antoine Lucas

Subscribed and sworn to before me, a Notary Public, on this 3rd day of March, 2015.

Michelle Harris
Notary Public

My Commission Expires: 04·01·2018

SEAL

MICHELLE HARRIS
Notary Public-Arkansas
Pulaski County
My Commission Expires 04-01-2018
Commission # 12365480

Exhibit AOL-1

2014 Integrated Transmission Plan
Near-Term Assessment Report
January 28, 2014

ITPNT

2014 Integrated Transmission Plan Near-Term Assessment Report

Approved: January 28, 2014

Engineering

Revision History

Date	Author	Change Description
10/23/2013	SPP staff	Draft for TWG review
11/18/2013	SPP staff	2nd Draft for TWG review
12/09/2013	SPP staff	3rd Draft for TWG review
12/11/2013	SPP staff	4th Draft for TWG meeting
12/18/2013	SPP staff	TWG Approval
1/15/2013	SPP staff	MOPC approval
1/28/2013	SPP staff	BOD Approval

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Executive Summary

The Integrated Transmission Planning (ITP) process is Southwest Power Pool's iterative three-year study process that includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies transmission projects, generally above 300 kV, needed to provide a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year Assessment focuses on facilities 100 kV and above to meet system needs over a ten-year horizon. The Near Term Assessment is performed annually and assesses system upgrades, at all applicable voltage levels, required in the near term planning horizon to address reliability needs. Along with the Highway/Byway cost allocation methodology, the ITP process promotes transmission investment that will meet reliability, economic, and public policy needs[1] intended to create a cost-effective, flexible, and robust transmission network that will improve access to the region's diverse generating resources. This report documents the Near-Term Assessment that concludes in January 2014.

The 2014 ITPNT used two scenario models built across multiple years and seasons to evaluate power flows across the grid to account for various system conditions across the near-term horizon. The 2014 ITPNT draft project plan breakdown can be found in the tables below.

Voltage Class	New Line (miles)	Rebuild/Reconductor (miles)
345 kV	41	0
230 kV	40	27
161 kV	17	0
138 kV	28	37
115 kV	128	18
69 kV	3	92

Voltage Class	New XFMR	Modified XFMR
345/138	1	0
345/115	3	0
230/115	2	1
161/69	3	0
138/69	1	0
115/69	0	2

Voltage Conversion	Miles
69/138 kV	23
69/115 kV	13

Table 0.1: 2014 Project List Breakdown

[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).

The total cost of the 2014 ITPNT Project Plan is estimated to be $696 million for upgrades that will receive an NTC, NTC-C, or NTC Modify. Of that total, $486 million comes from new projects identified in the 2014 ITPNT Assessment. Upgrades recommended for an NTC Modify account for $210 million of the total project plan cost. $74 million of transmission upgrades are recommended for withdrawal.

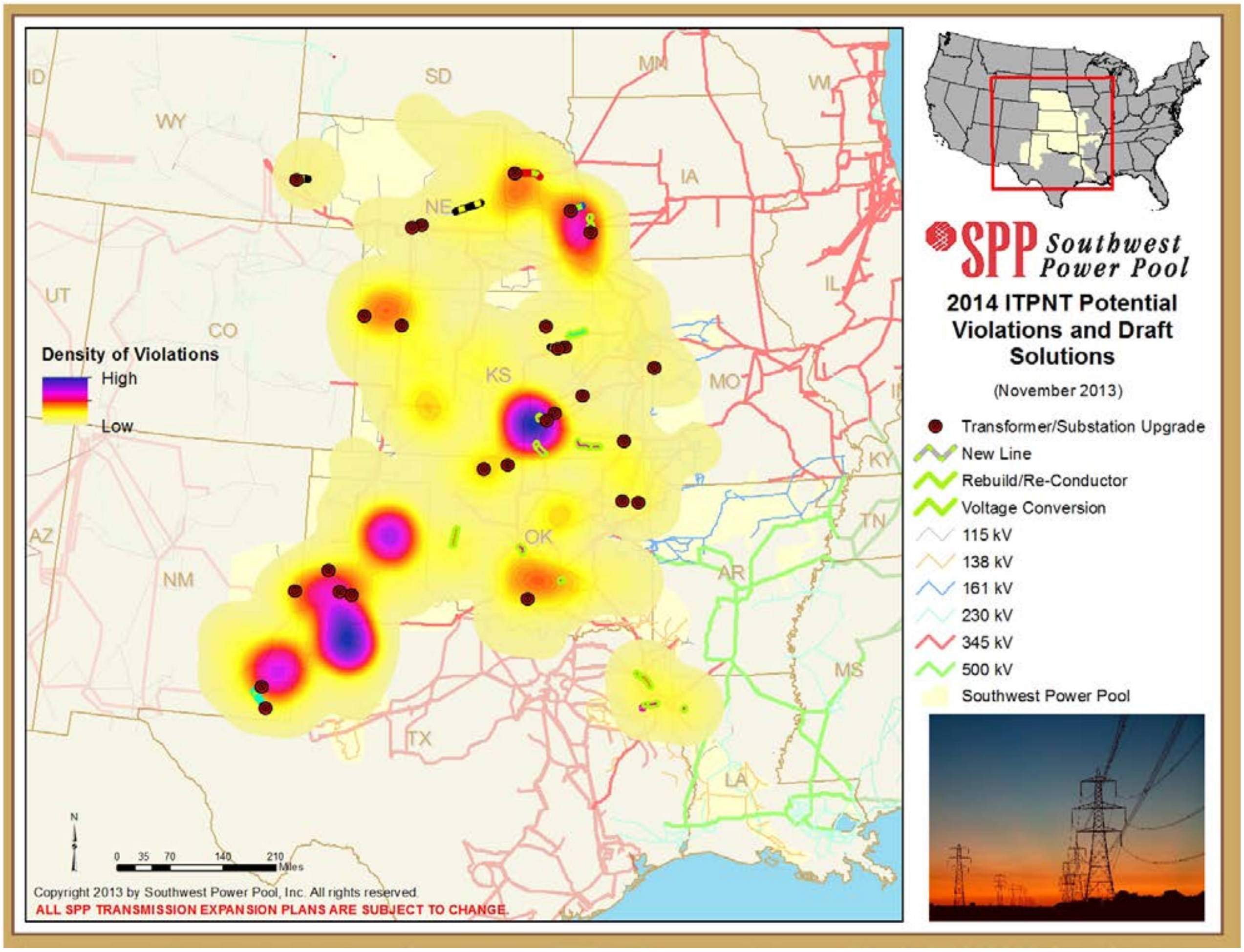


Figure 0.1: 2014 ITPNT Potential Violations and Solutions

PART I: STUDY PROCESS

Section 1: Introduction

1.1: The ITP Near-Term

The ITPNT is designed to evaluate 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. The 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. Unlike the ITP10 and ITP20, the ITPNT is not intended to focus on solutions based on a preferred voltage level, but to effectively solve all potential reliability needs in their entirety.

The 2014 ITPNT will create an effective near-term plan for the SPP footprint which identifies solutions to potential issues for system intact and single contingency (N-1) conditions using the following principles:

- Identifying potential reliability-based problems (NERC Reliability Standards TPL-001 and TPL-002, SPP and local criteria)
- Utilizing Transmission Operating Guides
- Developing additional mitigation plans including transmission upgrades to meet the region's needs and maintain SPP and local reliability/planning standards

Stability analysis is performed on the SPP system incorporating the proposed 100 kV and above 2014 ITPNT upgrades. This analysis determines if there are voltage stability issues within high load areas inside the SPP footprint. The areas studied this year are central Nebraska, south Oklahoma, south central Westar, northeast Westar, Oklahoma City, and Lincoln/Omaha.

The ITPNT process is open and transparent, allowing for stakeholder input throughout. Study results are coordinated with other entities, including embedded and Tier 1.

Goals

The goals of the ITPNT are to:

- Focus on local and regional needs
- Evaluate the response of the system on NERC TPL-001 and TPL-002 Standards
- Utilize a cost-effective approach to analyze six year out transmission system needs
- Identify 69 kV and above solutions stemming from such needs as:
    - Resolving potential reliability criteria violations
    - Improving access to markets
    - Improving interconnections with SPP's neighbors
    - Meeting expected load growth demands

  - Facilitating or responding to expected facility retirements
- Synergize the ITPNT with the GI process, ATSS process, and the ITP10 and ITP20 Assessments

The 2014 ITPNT is intended to provide solutions to ensure the reliability of the transmission system during the study horizon which includes modeling of the transmission system for six years (i.e. 2019). The specific near-term requirements of Attachment O are:

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

1.2: How to Read This Report

This report focuses on the years 2014-2019 and is divided into multiple sections.

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

SPP Footprint

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

Supporting Documents

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

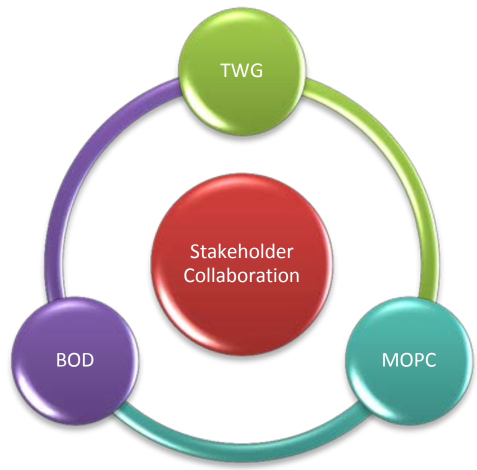
- SPP 2014 ITPNT Scope
- SPP ITP Manual

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

Confidentiality and Open Access

Proprietary information is frequently exchanged between SPP and its stakeholders in the course of any study and is extensively used during the ITP development process. This report does not contain confidential marketing data, pricing information, marketing strategies, or other data considered not acceptable for release into the public domain. This report does disclose planning and operational matters, including the outcome of certain contingencies, operating transfer capabilities, and plans for new facilities that are considered non-sensitive data.

Section 2: Stakeholder Collaboration



Assumptions and procedures for the 2014 ITPNT analysis were developed through SPP stakeholder meetings that took place in 2012 and 2013. The assumptions were presented and discussed through a series of meetings with members, liaison-members, industry specialists, and consultants to facilitate a thorough evaluation. Groups involved in this development included the following:

- Transmission Working Group (TWG)
- Markets and Operations Policy Committee (MOPC)
- SPP Board of Directors

SPP Staff served as facilitators for these groups and worked closely with the chairs to ensure all views were heard and that SPP's member-driven value proposition was followed.

The TWG provided technical guidance and review for inputs, assumptions, and findings. Policy level considerations were tendered to appropriate organizational groups including the MOPC. Stakeholder feedback was instrumental in the selection of the 2014 ITPNT projects.

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

Planning Summits

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

- Definition of a Reliability Need in a CBA Model was discussed at the planning summit on May 15, 2013[2].
- Recommended solutions for the 2014 ITPNT were discussed at the planning summit on November 20, 2013[3].

Project Cost Overview

Project costs utilized in the 2014 ITPNT were developed in accordance with the guidelines of the Project Cost Working Group (PCWG). Conceptual Estimates were prepared by SPP staff based on historical cost information in an SPP database and updated information provided by the TO.

[2] SPP.org > Engineering > Transmission Planning > 2013 May Planning Summit
[3] SPP.org > Engineering > Transmission Planning > 2013 November Planning Summit

Use of Transmission Operating Guides

TOGs 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. The 2014 ITPNT identifies all solutions where the use of a TOG is not effective.

Section 3: Study Drivers

3.1: Introduction

Drivers for the 2014 ITPNT were discussed and developed through the stakeholder process in accordance with the 2014 ITPNT Scope and involved stakeholders from several diverse groups. Stakeholder load, generation, and transmission were carefully considered in determining the need for, and design of, transmission solutions.

3.2: Load Outlook

Peak and Off-Peak Load

Future electricity usage was forecasted by utilities in the SPP footprint and collected and reviewed through the efforts of the MDWG. This assessment used both summer peak and light load scenarios to assess the performance of the grid in both peak and off-peak conditions.

Load Forecast

Load Serving Entities provided the load forecast used in the reliability analysis study models through the model building process. The 2014 loads are higher than previous forecasts. The figure below compares the current 2014 ITPNT load forecast with the previous STEP and ITPNT assessment forecasts.

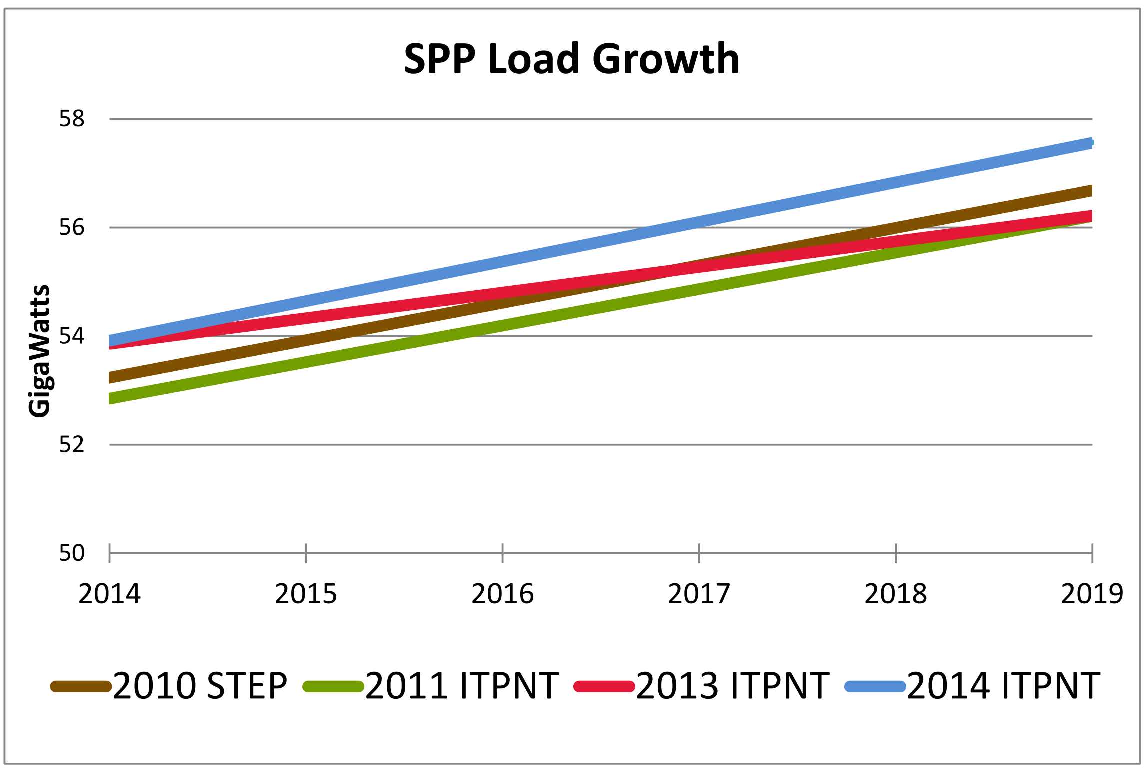


Figure 3.1: SPP Load Growth

3.3: Utilization of Different Voltage Levels

EHV Design Considerations

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

NERC N-1 Reliability Standards

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

Voltage Support

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

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

Construction Cost

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

Section 4: Analysis Methodology

4.1: 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 were monitored at 100 kV and above. System intact (base case) and N-1 contingency analysis on SPP facilities 69 kV and above and 100 kV and above for Tier 1 control areas were performed on the 2014 ITPNT models.

After performing the reliability assessment identifying the bulk power problems, potential violations were presented and solutions requested to those transmission reliability problems from TOs and stakeholders. Utilizing stakeholders' feedback and current ATSS and GI, proposed regional solutions were developed and validated.

This process repeated for several iterations as solutions were refined. The solutions were then timed using linear interpolation based on line loading between available model years of 2014, 2015, and 2019. For example, to time a solution due to a 2019 potential overload, SPP interpolated line loadings between the 2015 and 2019 models to determine when the loading exceeded 100%. The need date was assigned based on this analysis. A similar process for timing potential voltage issues was used. Throughout the process, alternative solutions were proposed by stakeholders, which were analyzed in accordance with Section III.8 of Attachment O of the OATT.

SPP transmission system performance was assessed from different perspectives designed to identify transmission expansion projects necessary to accomplish the reliability objectives of the SPP Regional Transmission Organization (RTO).

- Avoid exposure to Category A and B NERC Transmission Planning (TPL) standard criteria violations during the operation of the system under high stresses
- Contribute to the voltage stability of the system
- Reduce congestion and increase opportunities for competition within the SPP Integrated Marketplace.

Utilization of Past Studies & Stakeholder Expertise for Solutions

SPP shared potential violations with the stakeholders and posted them on the SPP password protected TrueShare site[4] for review. SPP Staff collected potential solutions from stakeholders throughout the footprint, as well as entities outside of the footprint. Additionally, solutions previously identified in the 2012 ITP10, 2013 ITP20, ATSS, and GI studies were also considered in this analysis. After assessment of the needs, SPP investigated mitigation of the overloads and congestion through individual projects by testing to ensure the project provided the expected result.

4.2: CBA Model Development

In order to account for the impacts of the Integrated Marketplace on the SPP footprint a CBA scenario model was developed as part of the 2014 ITPNT Assessment. The CBA scenario modeled SPP as a

[4] Send an email to questions@spp.org for access to the TrueShare site.

single BA and only modeled power transfers across the SPP seams. The CBA scenario utilized the SPP portion of the NERC Book of Flowgates updated with information from the 2013 Flowgate Assessment, 2014 ITPNT transmission topology, and 2013 ITP20 economic dispatch data. The goal was to attain a security-constrained unit commitment and economic dispatch (SCUC/SCED) for each year and season modeled in Scenario 0 and 5.

In order to simulate changes that will occur to the SPP portion of the NERC Book of Flowgates due to upgrades coming into service during the defined study period of the 2014 ITPNT Assessment, a constraint assessment was completed to determine if any system constraints should be added, removed, or modified before the SCUC/SCED was created. The constraint list was reviewed and approved by the TWG and other stakeholders before being applied to the models.

Making use of the economic data from the 2013 ITP20, an economic DC tool committed units, creating a dispatch to deliver the most economical power around the constraints approved by the TWG. This unit commitment and dispatch was the SCUC/SCED that was applied to the power flow model used to complete the N-1 contingency analysis described in Part A of the Analysis section. The security constrained economic dispatch in the CBA was applied to the SPP footprint only. The rest of the Eastern Interconnect remained unchanged.

4.3: Rate Impacts

The SPP Open Access Transmission Tariff (OATT) requires that a "Rate Impact Analysis" be performed for each Integrated Transmission Plan (ITP) per Attachment O: Transmission Planning Process, Section III: Integrated Transmission Planning Process, Sub-Section 8):

"8) Process to Analyze Transmission Alternatives for each Assessment:

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

The rate impact analysis process required to meet this 2014 ITPNT requirement was developed under the direction of the Regional State Committee in 2010-2011 by the Rate Impact Task Force (RITF). The RITF developed a methodology that allocated costs to specific rate classes in each SPP Pricing Zone (Zone).

The first step in this process is to estimate the zonal cost allocation of the Annual Transmission Revenue Requirement (ATRR). This cost allocated ATRR is calculated specifically for the ITPNT upgrades using the ATRR Forecast (Forecast). The Forecast allocated 2014 ITPNT upgrade costs to the Zones using the Highway/Byway ratemaking method. This method allocates costs to the individual Zones and to the Region based on the individual upgrade's voltage. Transformer costs were allocated based on the low side voltage. Regional ATRRs are summed and allocated to the Zones based on their individual Load Ratio Share percentages.

Highway Byway Ratemaking		
Voltage	Regional	Zonal
300 kV and Above	100%	0%
100 kV – 299 kV	33%	67%
Below 100 kV	0%	100%

Table 4.1: Highway Byway Ratemaking

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

- Initial investment of each upgrade
  - New 2014 ITPNT upgrade investments modeled were $486 million unadjusted dollars
- Transmission Owner's estimated individual annual carrying charge %
- Voltage level of each upgrade
- In-service year of each upgrade
- 2.5% annual straight line rate base depreciation
- 2.5% construction price inflation applied to 2013 base year estimates
- Mid-year in-service convention

4.4: Stability Analysis

Voltage stability was analyzed for six significant load areas or 'pockets' as part of the 2014 ITPNT Assessment. Contingencies used for the stability analysis were first created by determining the single worst generator unit outage within the load area. This identified generator outage was paired with all transmission line outages within the load area. Pairing the largest generator outage with each transmission line outage causes the largest amount of voltage instability in the load pocket.

Methodology to test the load pockets for voltage collapse began by increasing the amount of load within the load pocket. Simultaneously, a power transfer sending power from adjacent areas to the load pocket was simulated. The load and power transfer increased until voltage collapse occurs within the load pocket. This simulation was tested under system intact conditions as well as the previously identified contingency conditions on the 2014 ITPNT 2019 summer peak models. The simulation was run with the 2014 ITPNT proposed upgrades included in the models to determine the security limit and load margin for each load pocket.

Stakeholder input was crucial in the load pockets suggested for analysis. These areas included: 1) central Nebraska, 2) south Oklahoma, 3) south central Westar, 4) northeast Westar, 5) Oklahoma City, and 6) Lincoln/Omaha.

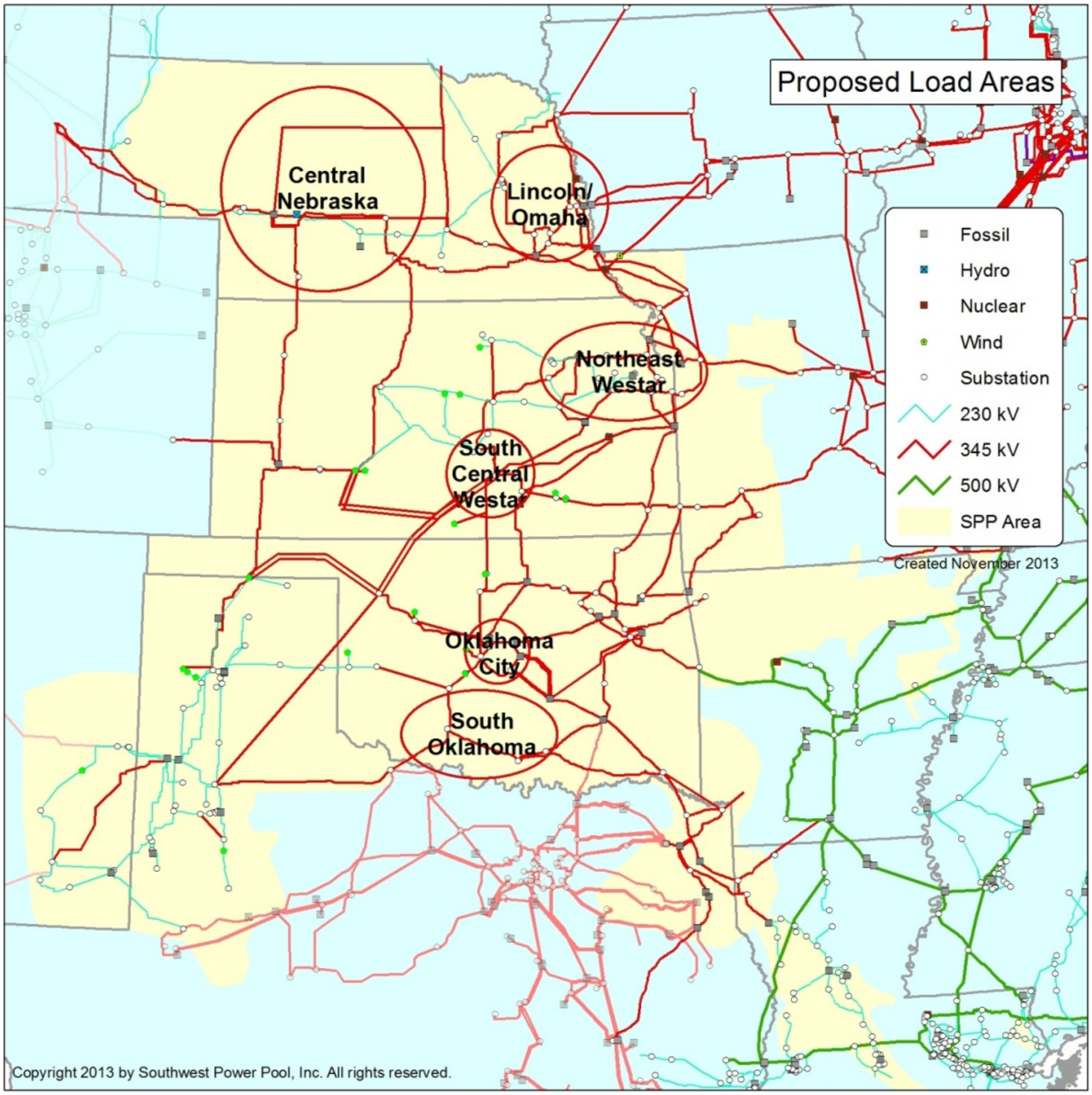


Figure 4.1: 2014 ITPNT Load Areas

PART II: STUDY FINDINGS

Section 5:Project Summary

5.1: Model Analysis and Results

The base case (N-0) and contingency (N-1) analysis that was completed provided SPP with a list of potential thermal and voltage limit violations. This list was provided to stakeholders to begin working with SPP staff to come up with the most effective solution the potential reliability needs identified. Table 5.1 below summarizes the all the observed thermal loading violations sorted by year and % loading. Violations observed in the following graphs

Potential Thermal Loading Violations			
% Overload	**2014**	**2015**	**2019**
100-105%	17	8	21
105-110%	6	13	16
110-120%	16	5	8
> 120%	9	8	8
Subtotals	**48**	**34**	**53**

Table 5.1: Potential Thermal Loading Violations

The table below shows all the observed voltage violations sorted by year and the per unit voltage value observed in the base case (N-0) and under contingency (N-1) conditions.

Potential Voltage Limit Violations			
Per Unit Voltage	**2014**	**2015**	**2019**
>.90 p.u.	22	21	23
.88-.90 p.u.	44	45	56
.85-.88 p.u.	18	20	54
< .85 p.u.	21	9	18
Subtotals	**105**	**95**	**151**

Table 5.2: Potential Voltage Limit Violations

5.2: Reliability Needs and Solution Development Summary

Based on the results of the contingency analysis, transmission upgrades were developed to mitigate potential reliability problems that were unable to be solved by mitigation plans or operating guides. A draft list of 100 kV + potential needs and draft solutions was presented to the Transmission Working Group at the August 14-15, 2013 meeting. A draft list of 69 kV+ was presented in September 2013. Below is the full list of projects in the ITPNT.

Reliability Project	Project Area(s)	Potential Violation	Miles Added/ Modified
XFR - Swisher 230/115 kV Transformer Ckt 1 Upgrade	SPS	Swisher 230/115 kV Transformer	0
Device - Vaughn Cap 115 kV	WR	Low voltage at East Eureka 115kV	0
Multi - Hoskins - Neligh 345 kV	NPPD	Overload of the Battle Creek - County Line 115 kV line	59.4
Multi - Geary County 345/115 kV and Geary - Chapman 115 kV	WR	Low voltages along the Abilene - Chapman 115 kV line	15.09
Multi - Stegall 345/115 kV and Stegall - Scottsbluff 115 kV	NPPD	Stegall 345/230 kV Transformer Ckt 2 and Stegall Tap 230 kV Ckt 2	23
XFR - Newhart 230/115 kV Ckt 2	SPS	Kress Interchange-Swisher County Interchange 115 kV Ckt 1 overload	0
Line - Welsh Reserve - Wilkes 138 kV reconductor	AEP	Line overload	23.74
Line - East Manhattan - JEC 230 kV	WR	East Manhattan - Jeffrey Energy Center 230kV line overload	27
SUB- Kerr - 412Sub 161kV Ckt 1	GRDA	Kerr to 412 Sub overload	0

Line - 412 Sub - Kansas Tap 161kV Ckt 1 Switch	GRDA	412 Sub to Kansas Tap Sub 161kV line overload	0
Multi-Bailey Co-Lamb County Conversion 115 KV	SPS	Lamb County 115/69 kV transformer overloads	38.6
Multi - Park Lane - Lula 69/138 kV voltage conversion	OGE	Park Lane - Ahloso Tap - Harden Tap,Valley View - Ada Industrial - Park Lane, and FRSCOTP – SOCPMT overloads and low voltages	22.8
Line - Wellington - Creswell 69 kV	WR	Creswell - Sumner County No.4 Rome 69 kV Ckt 1 facility overloads	18.5
Device - County Line 69 kV Cap	OGE	Mobil Oil 69 kV and Wildhorse 69 kV facilities voltage violations	0
XFR - Harrisonvile 161/69 kV	GMO	Harrisonville 161/69 kV Transformer Ckt 1 facility overloads	0
Line - Montgomery - Sedan 69kV	WR	Elk River 69 kV low voltages	28.5
Multi - Fremont 161/69 kV	OPPD	Fremont 115/69 kV transformer overloads; OPPD and NPPD area overloads;	20
Sub - Ruleton 115 kV	SEPC	Low voltages on multiple buses in Sunflower and Midwest	0
Multi-Broken Bow Wind-Ord 115 kV Ckt 1	NPPD	North loup 115 kV,Ord 115 kV and Spalding 115 kV low voltages	42
XFR - Knobhill 138/12.5 kV	OGE	ALVA,CZYCRVT2,HELENA TAP,KNOBHILL,SALINE low voltages	1.6
Line - Sub 907 - Sub 919	OPPD	Sub 907 - Sub 919 69 kV line overloads	3.3
Line - OXY Permian Sub - West Bender Sub 115 kV Ckt rebuild	SPS	OXY Permian Sub-West Bender Sub 115 kV Ckt 1 overload	.5
Sub - Butler - Weaver 138kV Terminal Equipment	WR	Butler - Weaver 138kV Ckt 1 overload	0
Quahada Switching Station 115 kV	SPS	Maljamr 115 kV system low voltage	.42
Sub - McDowell Creek Switching Station 115kV Terminal Upgrades	WR	Fort Junction Switching Station - McDowell Creek Switching Station 115kV Ckts 1 and 2 overload	0
XFR - Neosho 345/138kV	WR	Neosho 161/138/13.2kV Transformer Ckt 1 overload	.5
Line-Chapel Hill REC-Welsh Reserve 138 kV Ckt 1 rebuild	AEP	Chapel Hill Reserve - Welsh Reserve 138 kV Ckt1 overload	4.4
Line - Sumner County - Viola 138kV	WR	Creswell, Farber, Oxford, Sumner, Belle Plain, TC-Rock and Timber Junction low voltages	28
XFR - S1366 161/69kV	OPPD	Sub 1244 and S1366 voltage violations	0
Line - Elk City - Red Hills 138kV	WFEC	Elk City - Red Hills 138kV Ckt 1 base case overload	9
Sub - Sandy Corner 138kV	WFEC	Sand Ridge to Knob Hill138 kV low voltage	0
Sub - Keystone - Ogalala 115 kV Terminal Upgrades	NPPD	Keystone - Ogalala 115 kV line overloads	0

Sub - Maxwell - North Platt 115 kV Terminal Upgrades	NPPD	Maxwell - North Platte 115 kV overloads	0
Sub - Clay Center Switching Station 115kV	WR	Clay Center area low voltages	0
Multi-Potash Junction Interchange - Road Runner 230 kV line and 230/115 kV XF	SPS	Potash Junction Interchange 230/115 kV transformer overloads	40
Line - Battle Creek - North Norfolk 115 kV Ckt 1 Reconductor	NPPD	Accommodate new line rating of 193 MVA	3.5
Curry County 115 kV	SPS	Curry County Interchange 116/69 kV transformer Ckt 2 overloads	0
Multi - convert Centre St load and Hereford load from 69 to 115 kV	SPS	Hereford 115/69 kV transformers Ckt 1 and Ckt 2 for the outage of the parallel transformer	7.8
Sub - Mingo 115 kV	SEPC	Mingo xfrm low voltages	0
Multi-Chavis-Price-CV Pines-Capitan 69 kV to 115 kV	SPS	Chaves County Interchange 115/69 kV transformer base case overloads	13
Ellerbe Road - Forbing T 69 kV Ckt 1	AEP	Ellerbe Road - Forbing Road 69 kV Ckt 1 overloads	2
Mustang - Sunshine Canyon 69 kV Ckt 1	WFEC	Mustang - Sunshine Canyon 69kV Ckt 1 overloads	9.9
Broadmoor - Fort Humbug 69 kV Rebuild Ckt 1	AEP	Broadmoor-Fort Humbug 69 kV overloads	1.7
Dangerfield - Jenkins REC T 69 kV Rebuild Ckt 1	AEP	Daingerfield-Jenkins T 69 kV overload	1.3
Hallsville - Longview Heights 69 kV Rebuild Ckt 1	AEP	Hallsville-Longview Heights Ckt 1 69 kV overload	6.6
Hallsville-Marshall 69 kV Rebuild Ckt 1	AEP	Hallsville-Marshall 69 kV Ckt 1 overload	11.2
City of Wellington - Sumner County No.4 Rome 69 kV Rebuild Ckt 1	WR	City Of Wellington - Sumner County No.4 Rome 69 kV Ckt 1 overload	9.06
Kenmar - Northeast 69 kV Rebuild Ckt 1	WR	Ken mar - Northeast 69 kV Ckt 1 overload	1.7
Crestview - Northeast 69 kV Ckt 1	WR	Crestview - Northeast 69 kV Ckt 1 overload	5.6
Elk Junction - Montgomery 69kV Ckt 1	WR	Elk River 69 kV low voltage	9.7
S906 - S924 69kV Rebuild Ckt 1	OPPD	SUB 906 SOUTH - SUB 924 69KV CKT 1 overload	1.34
S924 - S912 69 kV Terminal Upgrades	OPPD	SUB 912 - SUB 924 69KV CKT 1 overloads	0
Letorneau - Air Liquide Tap 69 kV Ckt 1	AEP	Letorneau - Letourneau Tap 69 kV overloads	.3

Table 5.3: 2014 ITPNT Projects

5.3: Project Plan Breakdown

The figure below shows a breakdown of the 2014 ITPNT Project Plan. There are 75 proposed upgrades in the project plan and 12 that are requested for withdrawal. Of the 75 proposed upgrades 64 will be issued a new Notice to Construct (NTC/NTC-C). Eleven upgrades have been identified as needing a modified NTC (NTC Modify).

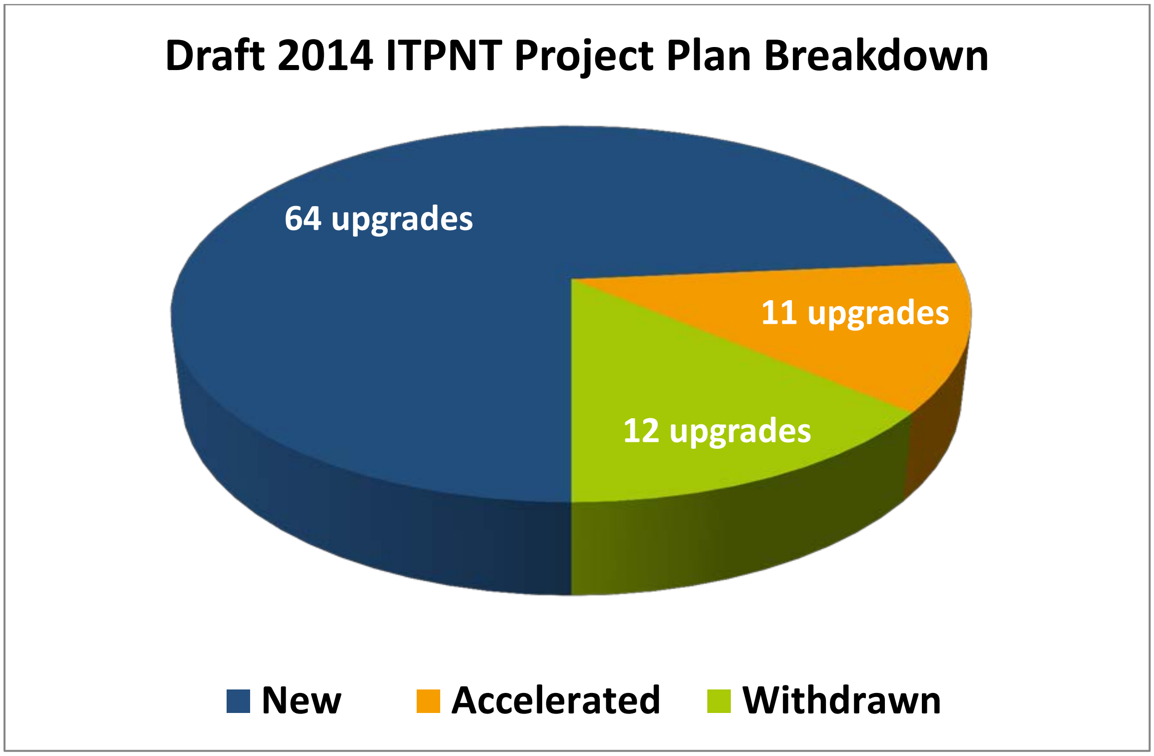


Figure 5.1: 2014 ITPNT Project Breakdown

The following figure illustrates the amount of new line needed based on each voltage class in the 2014 ITPNT Project Plan. There are 258 miles of new transmission line in the project plan.

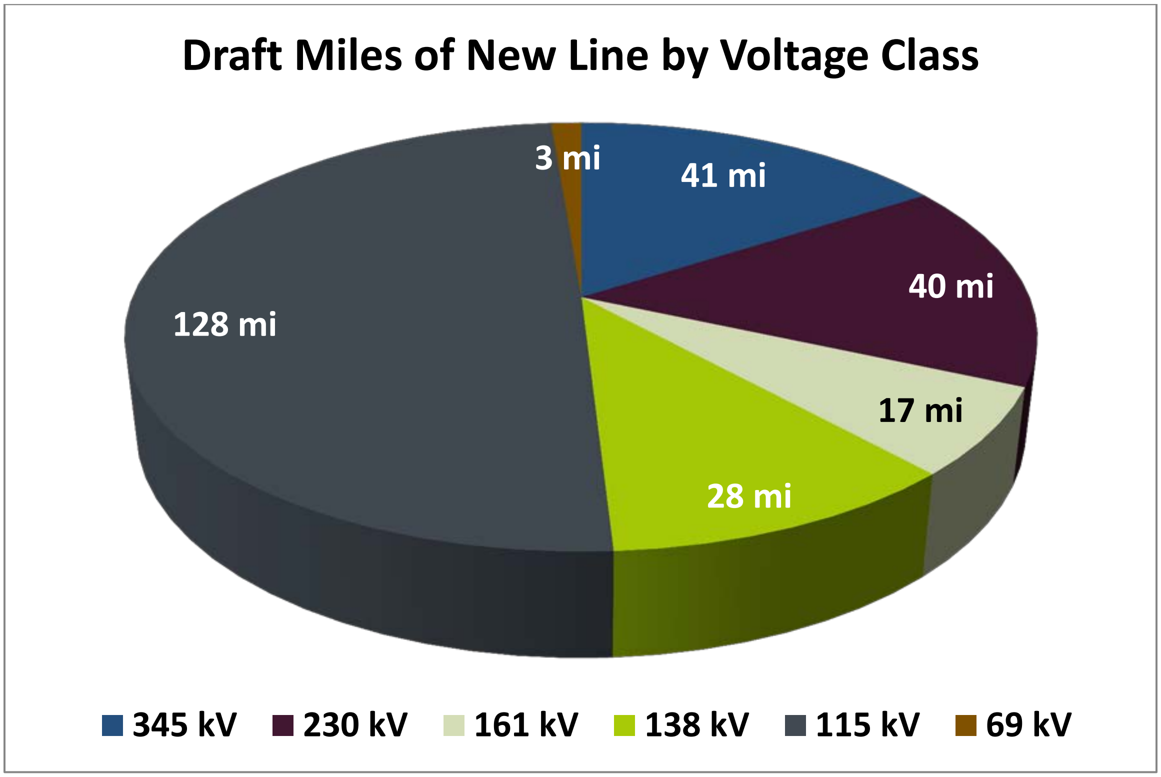


Figure 5.2: 2014 ITPNT New Line by Voltage Class

The figure below illustrates how many miles of transmission line that will require a rebuild or reconductor. There are 174 miles of rebuild/reconductor and approximately 36 miles of voltage conversion in the draft 2014 ITPNT Project Plan.

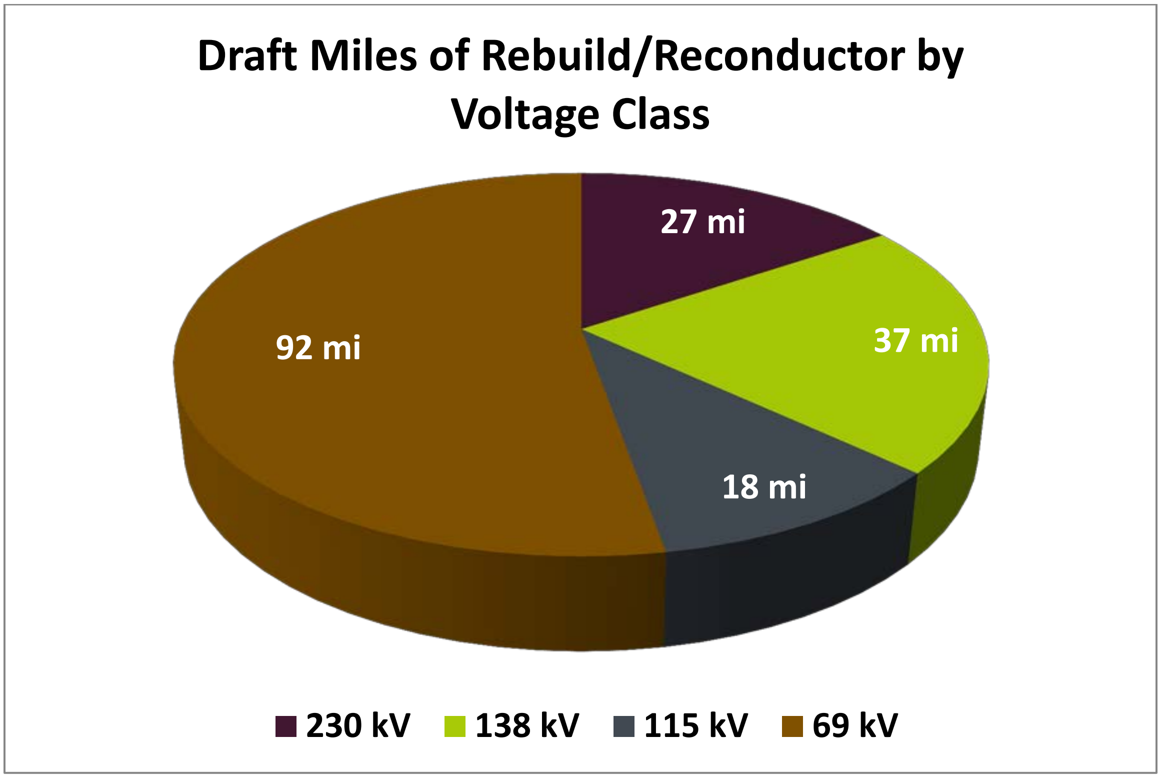


Figure 5.3: 2014 ITPNT Miles Rebuild by Voltage Class

Table 5.4 below shows the dollar amount of new, modified and withdrawn uprades of the 2014 ITPNT Appendix I identified in each state.

State	New NTC	Modified NTC	Withdrawn NTC
Arkansas	$0	$0	$0
Kansas	$194M	$65M	$27M
Louisiana	$6.7M	$8.2M	$0
Missouri	$3.8M	$0	$0
Nebraska	$77M	$133M	$0
New Mexico	$63M	$0	$0
Oklahoma	$36M	$0	$36M
Texas	$107M	$3.5M	$11M
Subtotals	**$486M**	**$210M**	**$74M**

Table 5.4: 2014 ITPNT Projects by State

Figure 5.4 is a representation of the 2014 ITPNT portfolio of new, modified, and withdrawn NTCs broken down by voltage level. For each column the cost of the new, modified, or withdrawn NTC is also displayed.

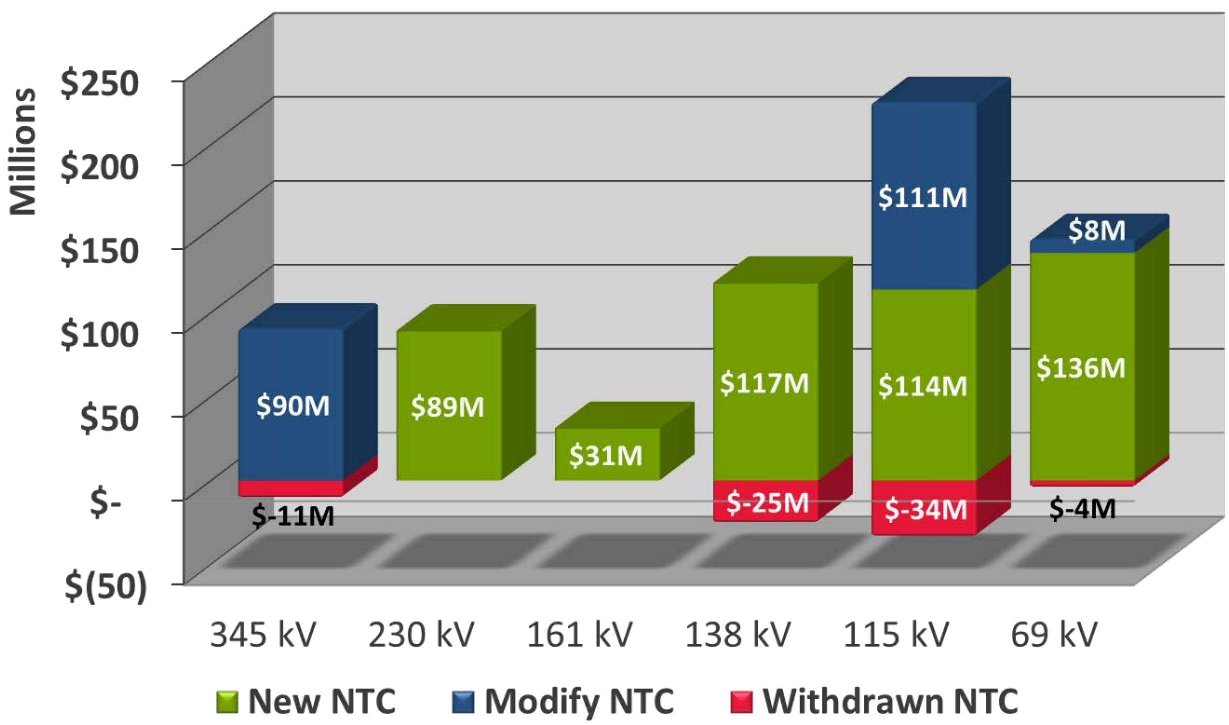


Figure 5.4: 2014 ITPNT Cost by Voltage Level

Figure 5.5 breaks down the mileage for new, rebuild/reconductor, or voltage conversion for the upgrades in the 2014 ITPNT by voltage level.

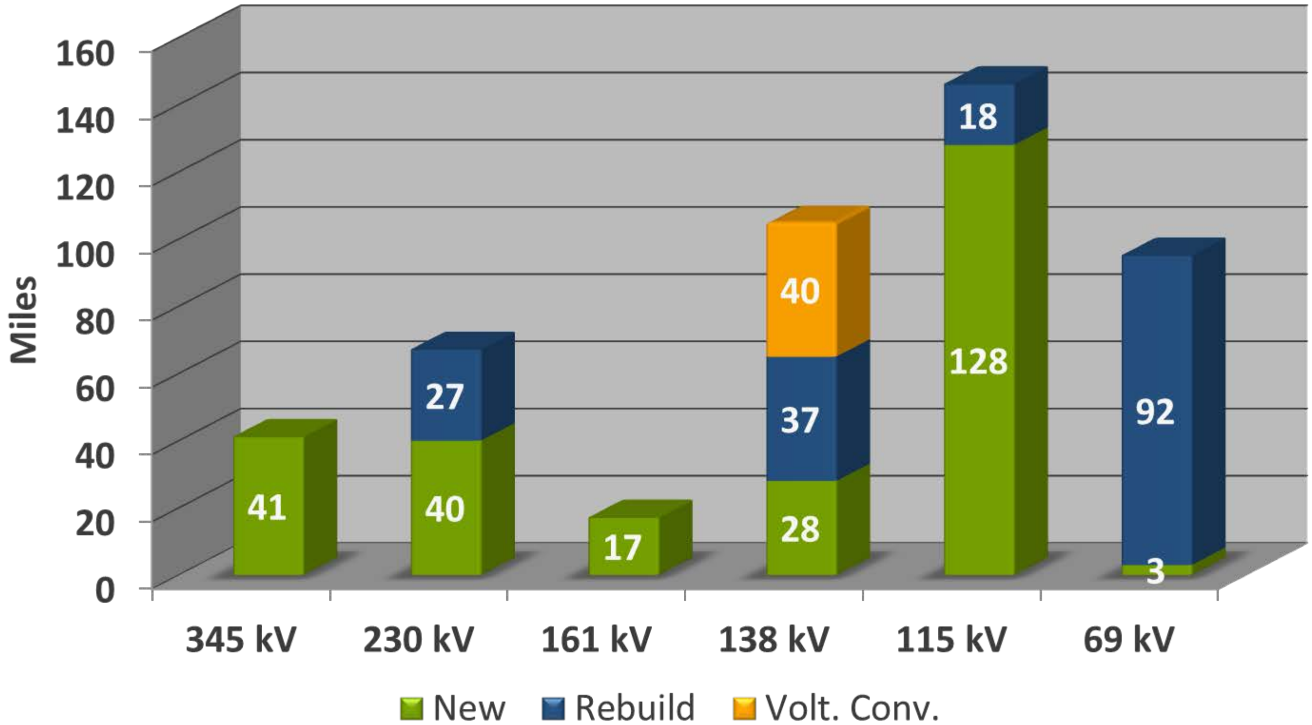


Figure 5.5: 2014 ITPNT Miles Rebuild by Voltage Level

The figure below shows the 2014 ITPNT projects broken down two ways. The green column represents the year that an upgrade is needed. The blue column represents the estimated in-service years of the upgrades and the dollars that will be invested to place the projects in service.

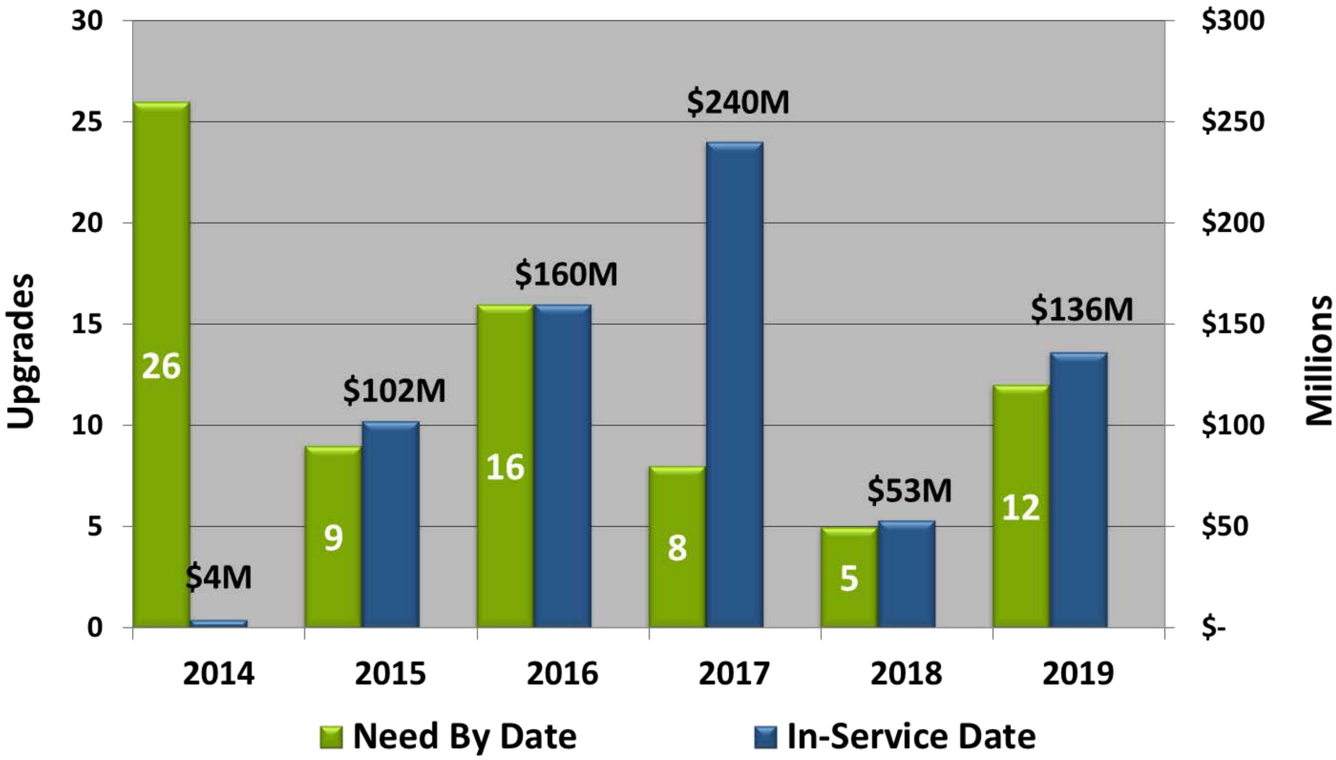


Figure 5.6: 2014 ITPNT Need Date by In-Serive Years and Dollars

Figure 5.7 below shows the allocation of upgrades with new NTCs, modified NTCs, and Withdrawn NTCs between upgrades needed for Regional Reliablity and Zonal Reliability. As previously mentioned upgrades classified as Zonal Reliability are required to meet local planning criteria which is more stringent than SPP Criteria.

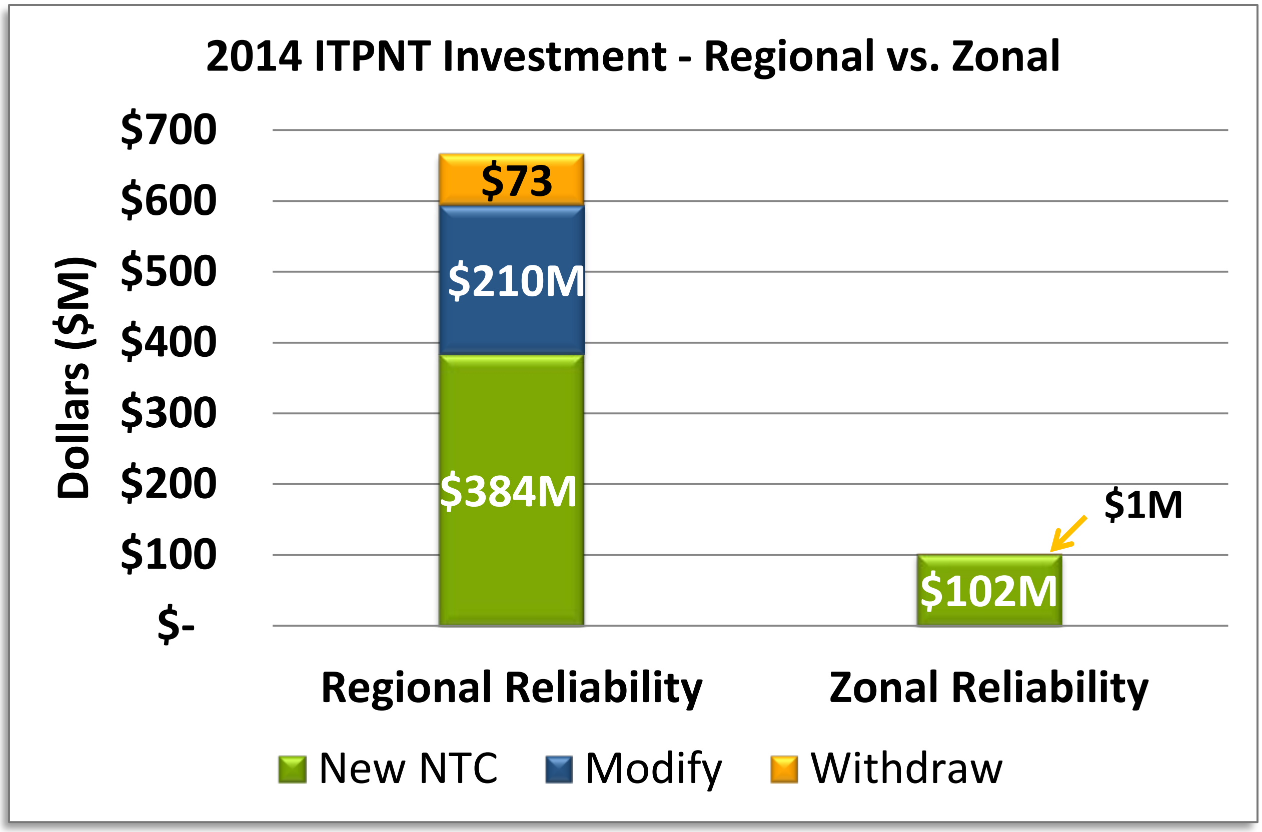


Figure 5.7: 2014 ITPNT Investment – Regional vs. Zonal

5.4: Project Details

This section details each of the major projects in the draft 2014 ITPNT Project Plan. Each of the projects discussed below have an SPP generated cost estimate greater than $20 million and are needed for Regional Reliability.

East Nebraska

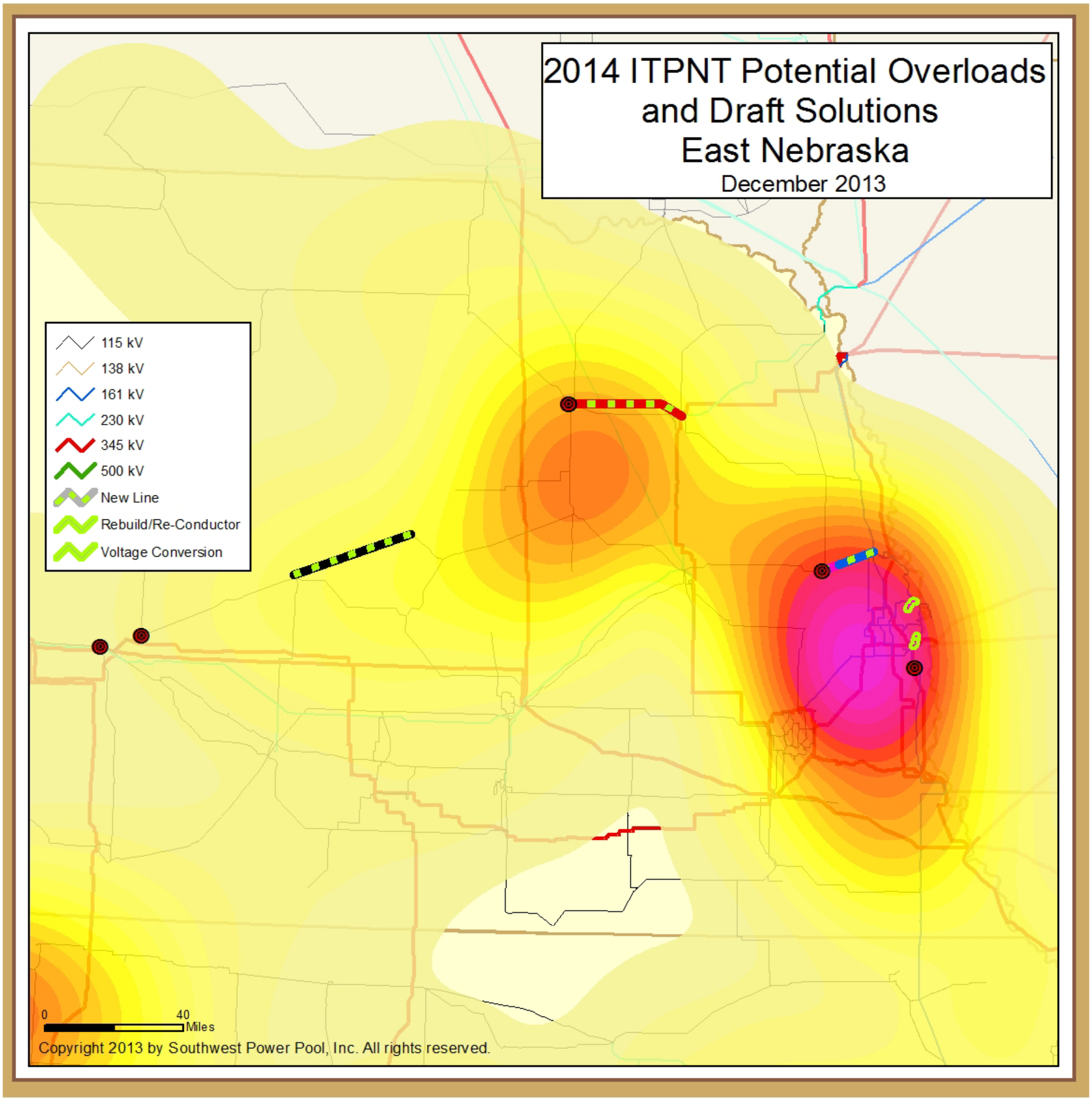


Figure 5.8: 2014 ITPNT East Nebraska

Hoskins – Neligh 345 kV

The Hoskins – Neligh 345 kV project was a previously approved Network Upgrade as part of the 2012 ITP10 Assessment. NTC's were issued by SPP with an identified need date of March of 2019. The results of the 2014 ITPNT Assessment support the acceleration of the need date for this previously approved project. This project includes a new 41 mile line from Hoskins to Neligh, and a new substation with 345/115 kV transformer. This project will addresses the overload of the Battle Creek - County Line 115 kV line for the outage of Albion - Petersburg 115 kV line. It also addresses overloads during contingencies in the Neligh area.

S1226 – S1301 161 kV and S6801 161/69 kV Transformer

Build 20 miles of 161 kV from S1226 to S1301 and five miles of 69 kV line from Fremont to new sub S6801. This project will address overloads in the OPPD and NPPD areas including Sub 902 - Sub 984 69 kV ckt 1 for the loss of Fremont Sub D - Sub 976 69 kV ckt 1.

East Kansas

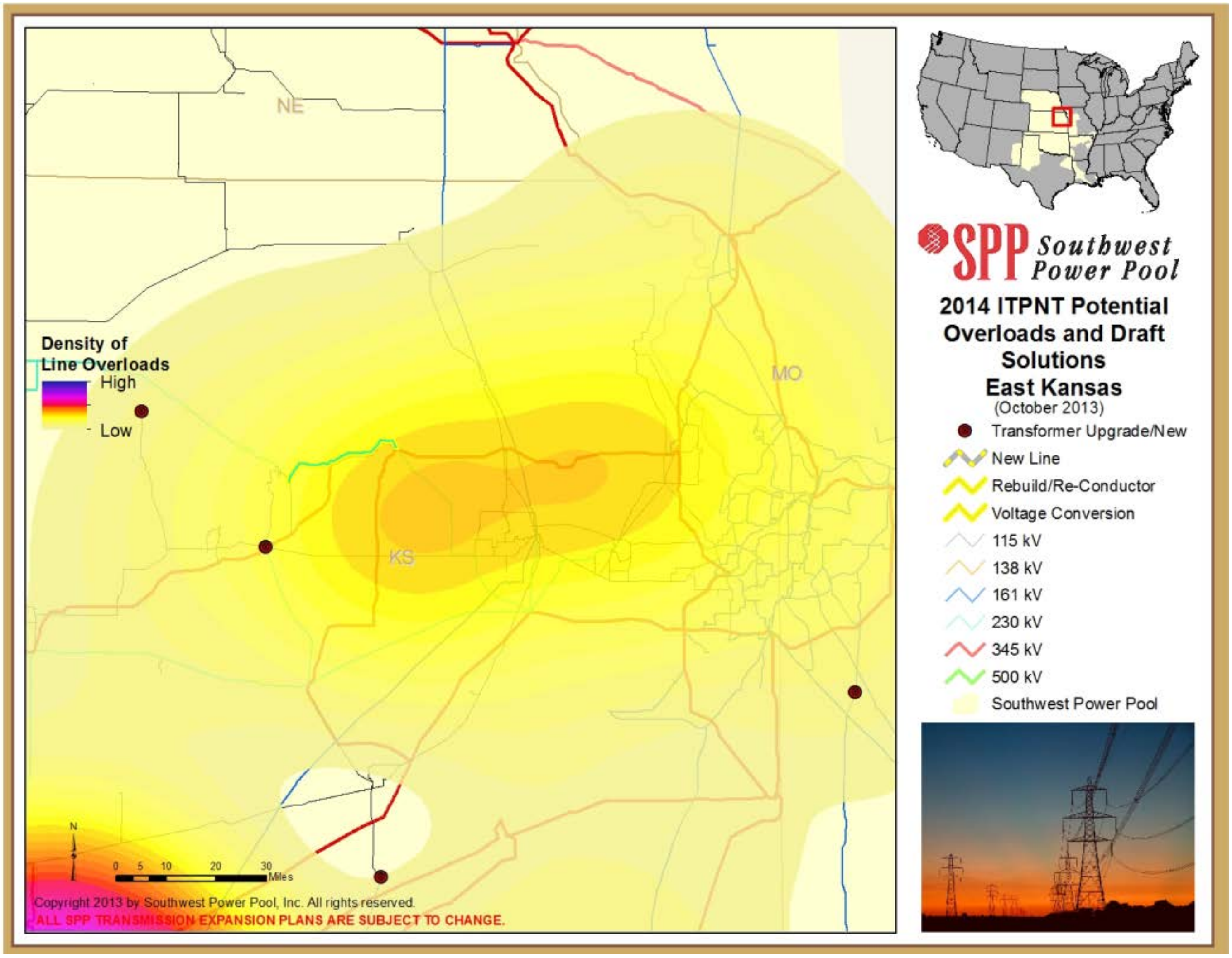


Figure 5.9: 2014 ITPNT East Kansas

Geary County 345/115 kV

This upgrade includes a new Geary County 345/115 kV substation and 345 kV ring bus south of Junction City where JEC - Summit 345 kV and McDowell Creek - Junction City #2 115 kV circuits separate.

Geary - Chapman 115 kV

Build a new 15.1-mile 115kV line between the new Geary County substation and Chapman Tap with 10.4 miles being built as a 2nd circuit to the existing Summit - McDowell Creek 345 kV line.

Geary County 345/115 kV and Geary – Chapman 115 kV address low voltages along the Abilene - Chapman 115 kV line for outages including:

- Abilene - Northview 115 kV Ckt 1 and Ckt 2
- East Manhattan - Jeffrey Energy Center 230 kV Ckt 1
- McDowell Creek - Morris County 230 kV Ckt 1
- McDowell Creek 230/115 kV transformer Ckt 1

East Manhattan - JEC 230 kV

Rebuild existing line to 345 kV standards and upgrade terminal equipment at JEC and East Manhattan. However, this line will still be operated at 230 kV. This will address the overload of the East Manhattan - Jeffrey Energy Center 230kV line for outage of Geary - Jeffrey Energy Center 345kV Ckt 1.

West Nebraska

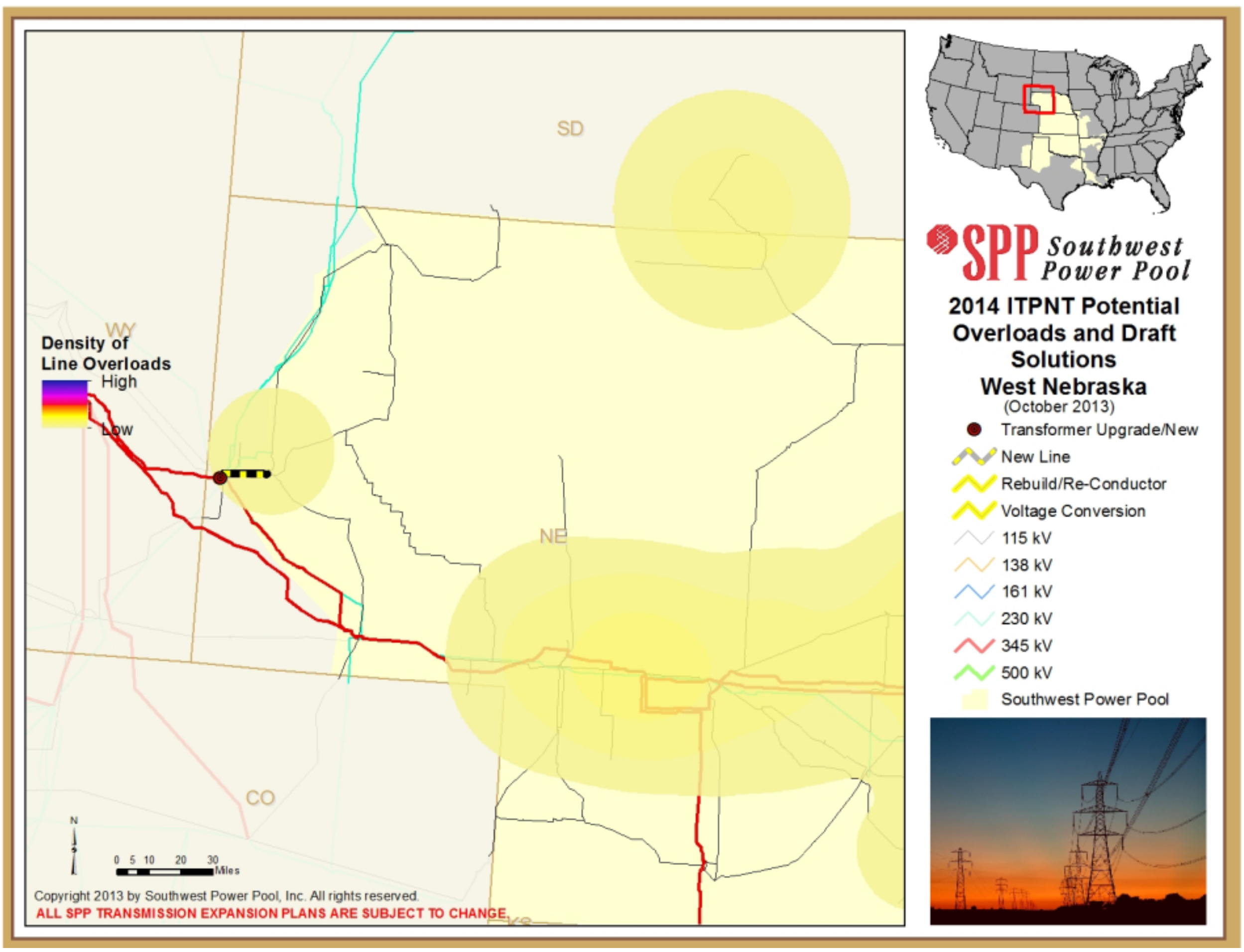


Figure 5.10: 2014 ITPNT West Nebraska

Stegall 345/115 kV

Install a new 345/115 kV 400 MVA transformer at Stegall substation and necessary terminal equipment at the 115 kV and 345 kV buses.

Stegall - Scottsbluff 115 kV

Install new 22-mile 115 kV line from Stegall to Scottsbluff and install any necessary terminal equipment.

These upgrades are needed to address low voltage at Victory Hill for the loss of Stegall 345/230 kV Transformer Ckt 1. The Stegall 345/115 kV Transformer and Stegall 115 kV Line project was a previously approved Network Upgrade as part of the 2013 ITPNT Assessment. NTC's were issued by SPP with an identified need date of June of 2015. The results of the 2014 ITPNT Assessment support the acceleration of the need date for this previously approved project.

East Texas

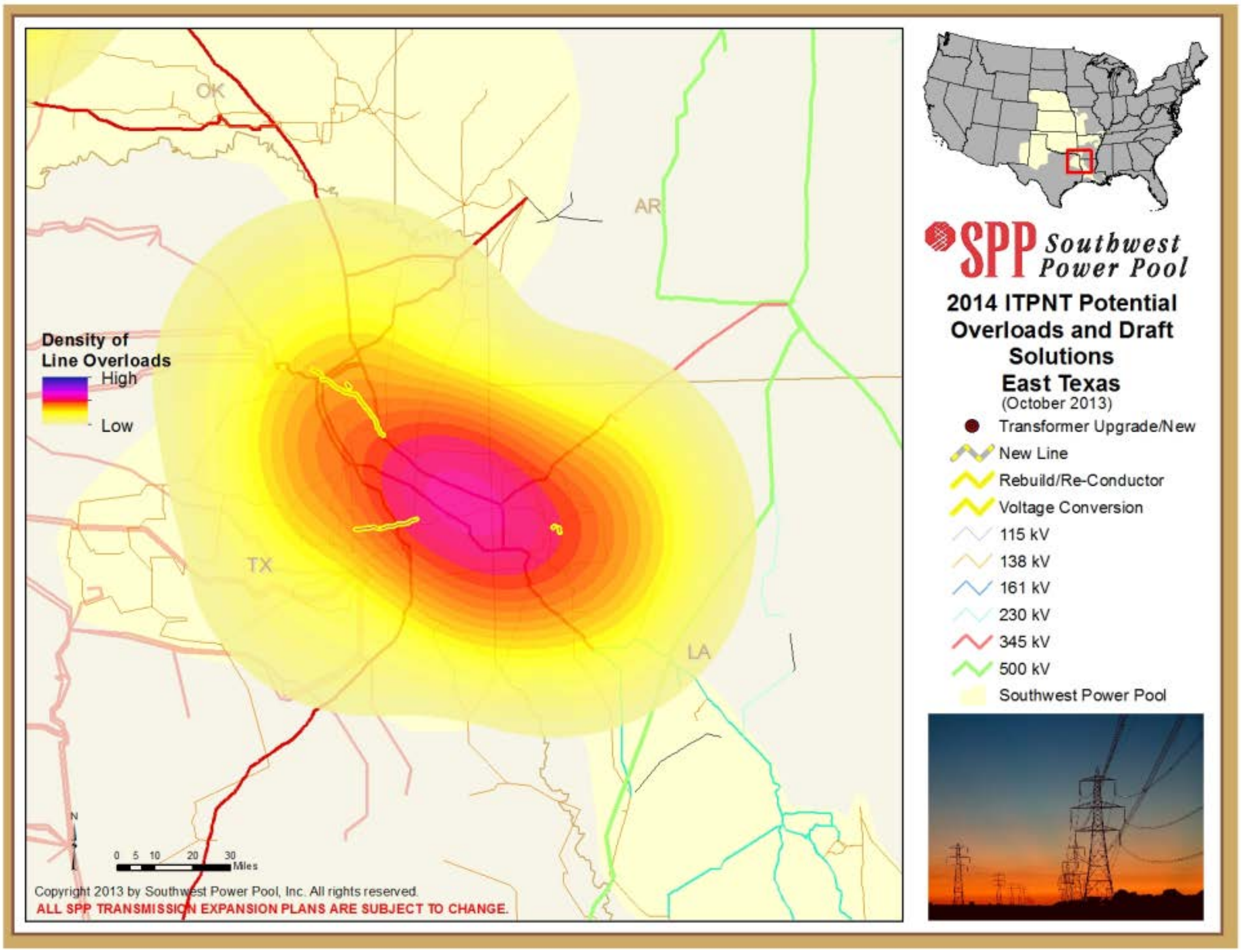


Figure 5.11: 2014 ITPNT East Texas

Welsh Reserve - Wilkes 138 kV Reconductor

Rebuild 23.7 miles of 138 kV line from Welsh REC – Wilkes and upgrade switches at both ends and wave traps, jumpers, CT ratios, and relay settings at Wilkes. This will address the overload of the line for the outage of Lone Star South-Pittsburg 138 kV line.

Texas

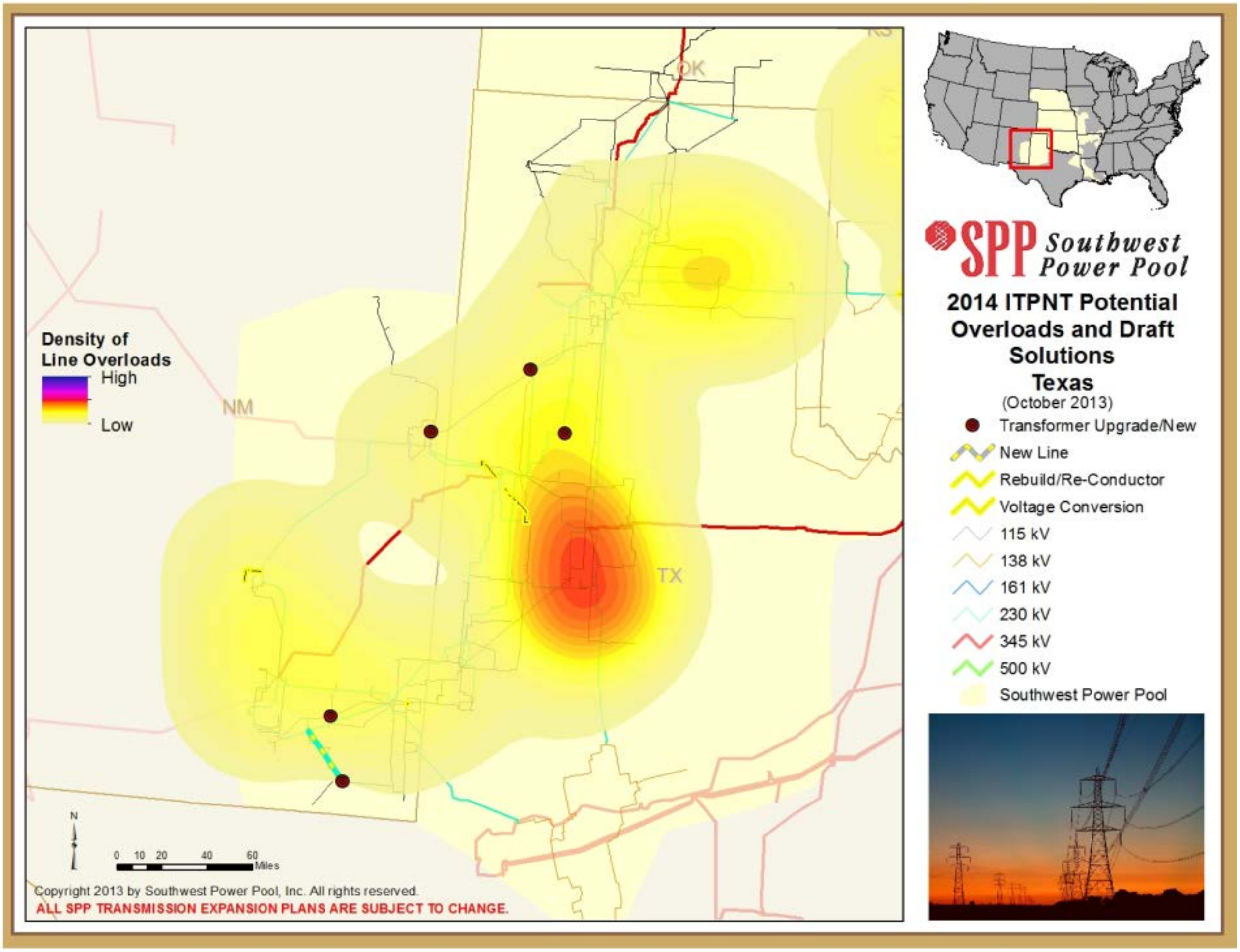


Figure 5.12: 2014 ITPNT Texas

Potash Junction Interchange - Road Runner 230 kV line and 230/115 kV XF

Build a new 40 mile 230 kV line from Potash Junction Interchange to a new 230/115 kV Road Runner Substation. Install the necessary 230 kV terminal equipment at Potash Junction and Road Runner substation with a 230/115 kV 250 Mva transformer and 115 kV terminal equipment. This will address the overload of Potash Junction Interchange 230/115 kV transformer for outages including:

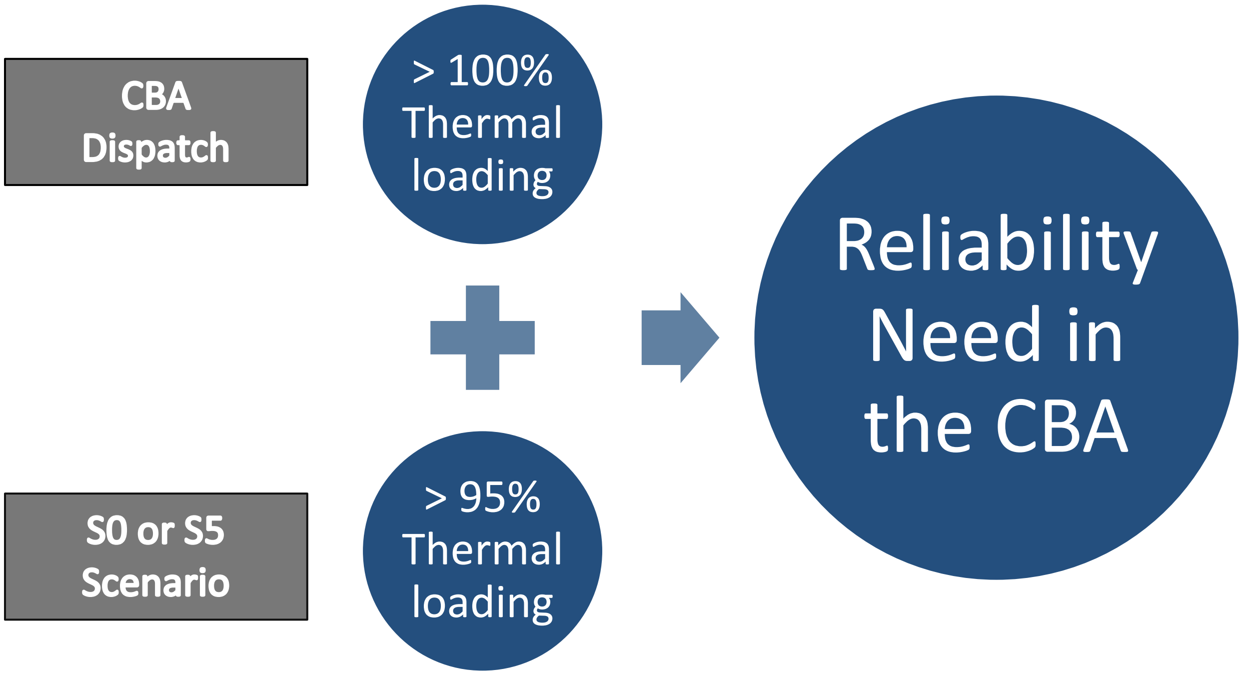
- Pecos Interchange-Potash Junction 230 kV Ckt 1
- Monument Sub-West Hobbs Switching station Ckt. 1
- Maddox Station-Sanger Switching station
- Oxy Permian Sub-Sanger Switching Station

This project also will mitigate low voltage at I.M.C. #1 Sub 115 kV bus for the outage of IMC # TP 1 115-Intepdw-TP3 115 kV.

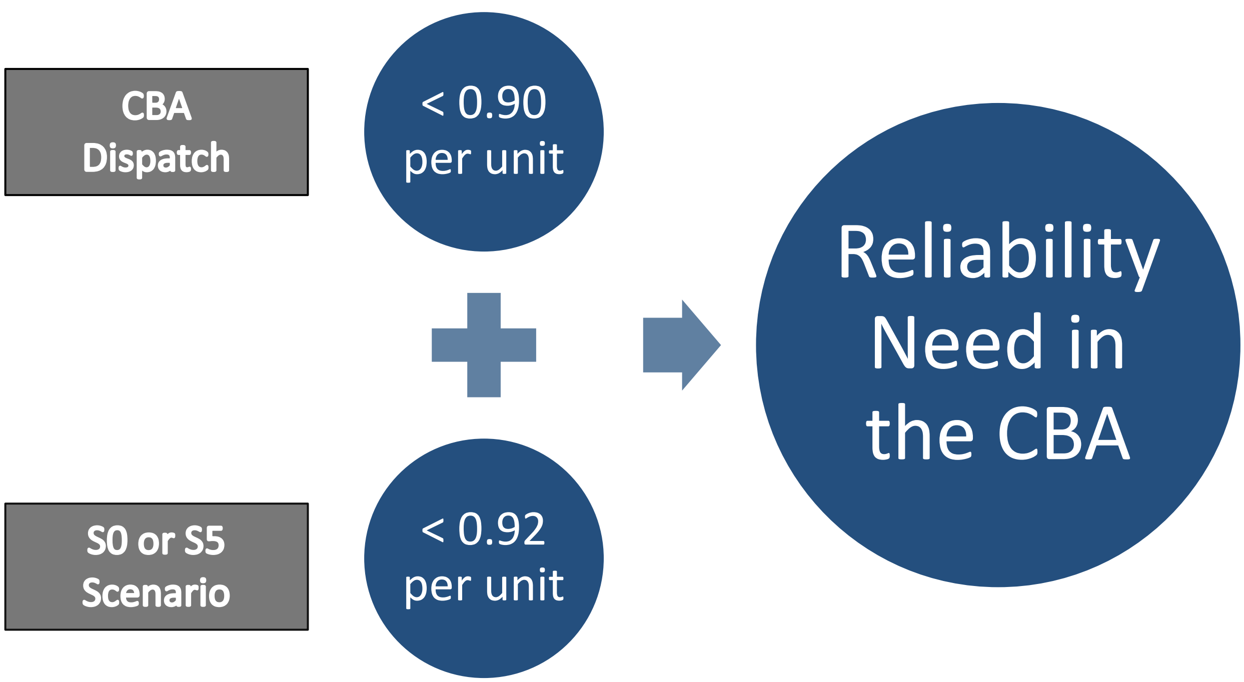
5.5: Reliability Upgrades from the CBA Model

This section details potential reliability issues from the CBA N-1 contingency analysis in the 2014 ITPNT. At the May 14, 2013 meeting the TWG approved the process by which a potential additional reliability issue would be identified. The methodology for determining reliability needs in the CBA scenario is found below.

For potential thermal violations:



For potential voltage violations:



Based on these criteria no upgrades were identified as potential advancement.

In addition, 24 facilities were identified in CBA as overloaded that were not overloaded in S0/S5. All were loaded below 95% in the S0/S5. These are documented in the table below.

Season	Facility	CBA % Loading	Near Term S0/S5 % Loading
14L	CANYON EAST SUB - OSAGE SWITCHING STATION 115KV CKT 1	102.2	46.9
14L	EAST LIBERAL - TEXAS COUNTY INTERCHANGE PHASE SHIFT TFMR 115KV CKT 1	106	8.5
14L	AMOCO SWITCHING STATION - SUNDOWN INTERCHANGE 230KV CKT 1	111.7	80.7
14L	MOUNDRIDGE (MOUND10X) 138/115/13.8KV TRANSFORMER CKT 1	112.2	19.9
14SP	AFTON (AFTAUTO1) 161/69/13.8KV TRANSFORMER CKT 1	100.1	92.4
14SP	HUMBOLDT (S975 T4) 161/69/13.8KV TRANSFORMER CKT 1	102.6	86.7
14SP	MILL STREET 2 - MUNCIE 2 69KV CKT 1	104.8	38.9
14SP	KAW 2 - SPEAKER 2 69KV CKT 1	106.7	33.4
14SP	COL PAL2 - KAW 2 69KV CKT 1	108.8	14.2
14SP	BARBER 2 - KAW 2 69KV CKT 1	116	21.7
14SP	AFTON - CLEORA TAP 69KV CKT 1	125.1	75.4
14SP	COL PAL2 - MUNCIE 2 69KV CKT 1	125.8	10.5
15SP	CIMARRON RIVER PLANT - SEWARD-3 115KV CKT 1	100.4	71.7
15SP	CROSSTOWN - NORTHEAST 161KV CKT 1	101.5	90.3
15SP	OMHUFFYT - OMPA-PONCA CITY 69KV CKT 1	103.1	13.3
15SP	AFTON - FAIRLAND EDE TAP 69KV CKT 1	104.7	51.1
15SP	FAIRLAND EDE TAP - FAIRLAND NEO 69KV CKT 1	106	52.9
15SP	HASKELL - SEWARD-3 115KV CKT 1	106	77.2
15SP	BROOKLINE (BRKLTX1) 345/161/13.2KV TRANSFORMER CKT 1	107.1	91.3
15SP	CLEORA TAP - PENSACOLA 69KV CKT 1	108.5	66.1
19SP	SUB 3456 (S3456 T4) 345/161/13.8KV TRANSFORMER CKT 1	100.7	79.7
19SP	SUB 1211 - SUB 1220 161KV CKT 1	102.3	83.9
19SP	WEST POINT 115/34.5KV TRANSFORMER CKT 1	104	70.7
19SP	PLATTESMOUTH - SUB 985 69KV CKT 1	107.5	94.4

Table 5.5: CBA Overloads not in S0/S5

One bus was identified in a CBA model with voltage below criteria that was not in the S0/S5 model. The Victory Hill 230 kV bus was identified with a 0.89666 p.u. voltage in the 14 Light Load case. A previously approved project is identified as the solution.

5.6: Rate Impacts on Transmission Customers

The 2014 ITPNT upgrades were run in the SPP Cost Allocation Forecast, the peak ATRR impact year was shown to be 2020.

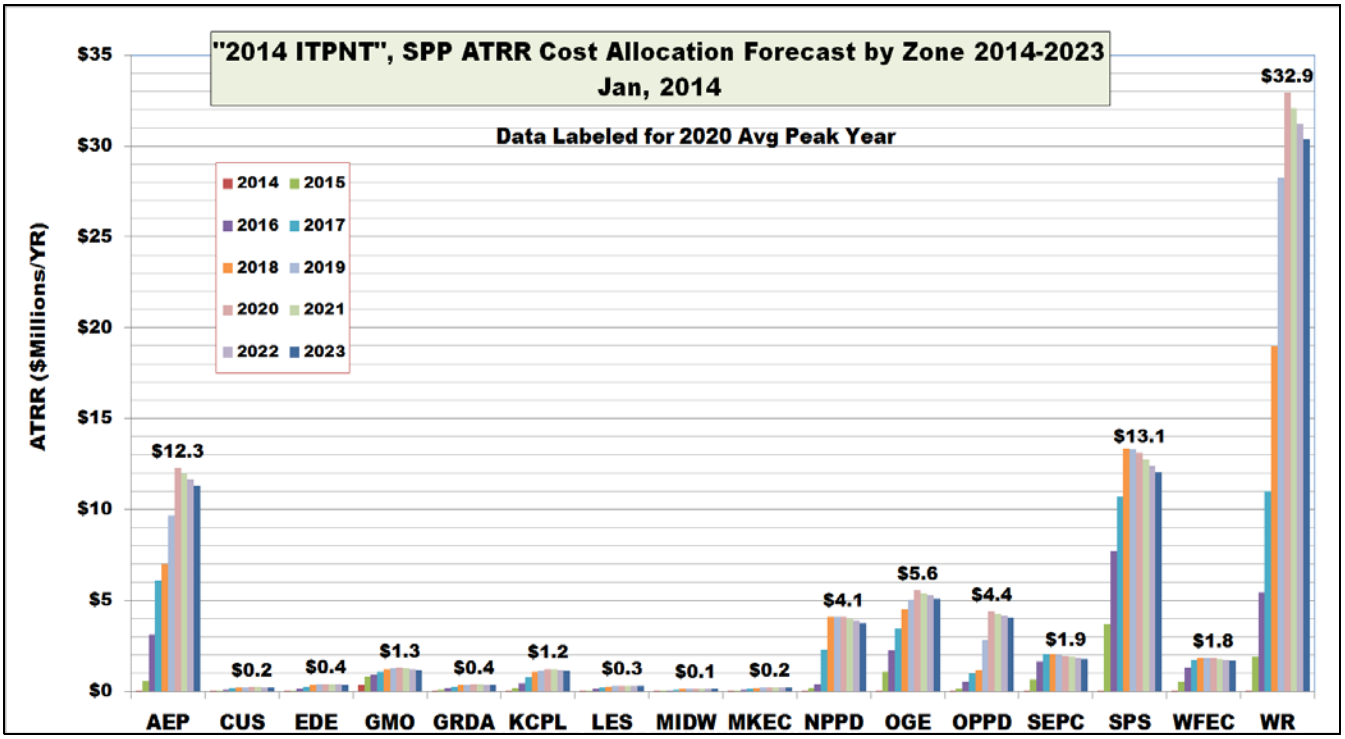


Figure 5.13: ATRR Cost Allocation Forecast by Zone of the 2014 ITPNT

As shown in the following chart, the majority of the 2014 ITPNT projects will be cost allocated to the Pricing Zone hosting the upgrade and a smaller amount will be cost allocated to the SPP region through the regional rate.

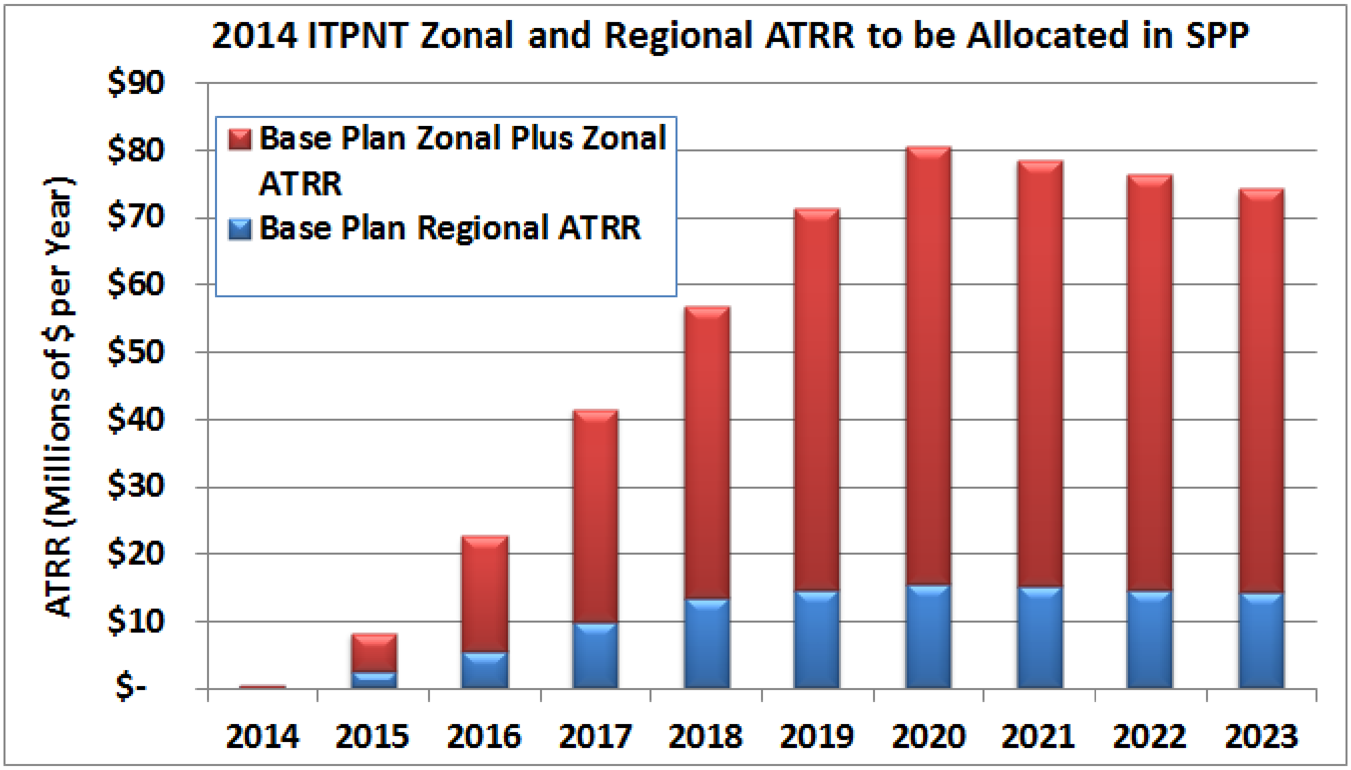


Figure 5.14: Zonal and Regional ATRR allocated in SPP

For additional information on estimating ATRR by Zone please see:

http://www.spp.org/publications/UPDATED%20July%2010%202012%20TEN%20YEARS%20ONLY.zip

The peak year ATRR is converted into a monthly impact on a typical 1000 kWh per month Retail Residential ratepayer. This conversion considers the individual Zone's ATRR allocation percentage by customer class and sales forecast in the peak year. This rate is then multiplied by a common SPP monthly Retail Residential consumption of 1000 kWh per month. The result is the monthly Rate Impact.

For additional information on how rate impacts are estimated please see:

http://www.spp.org/publications/RITF%20Output%20for%20RSC%20Jan%2024%202011%20REV%204.ppt

The SPP RSC has tasked the RITF to update key Zonal data such as allocation factors, sales forecasts, average monthly consumption by customer type, etc. Figure 5.15 below was calculated using 2013 Zonal data as reported by each Pricing Zone.

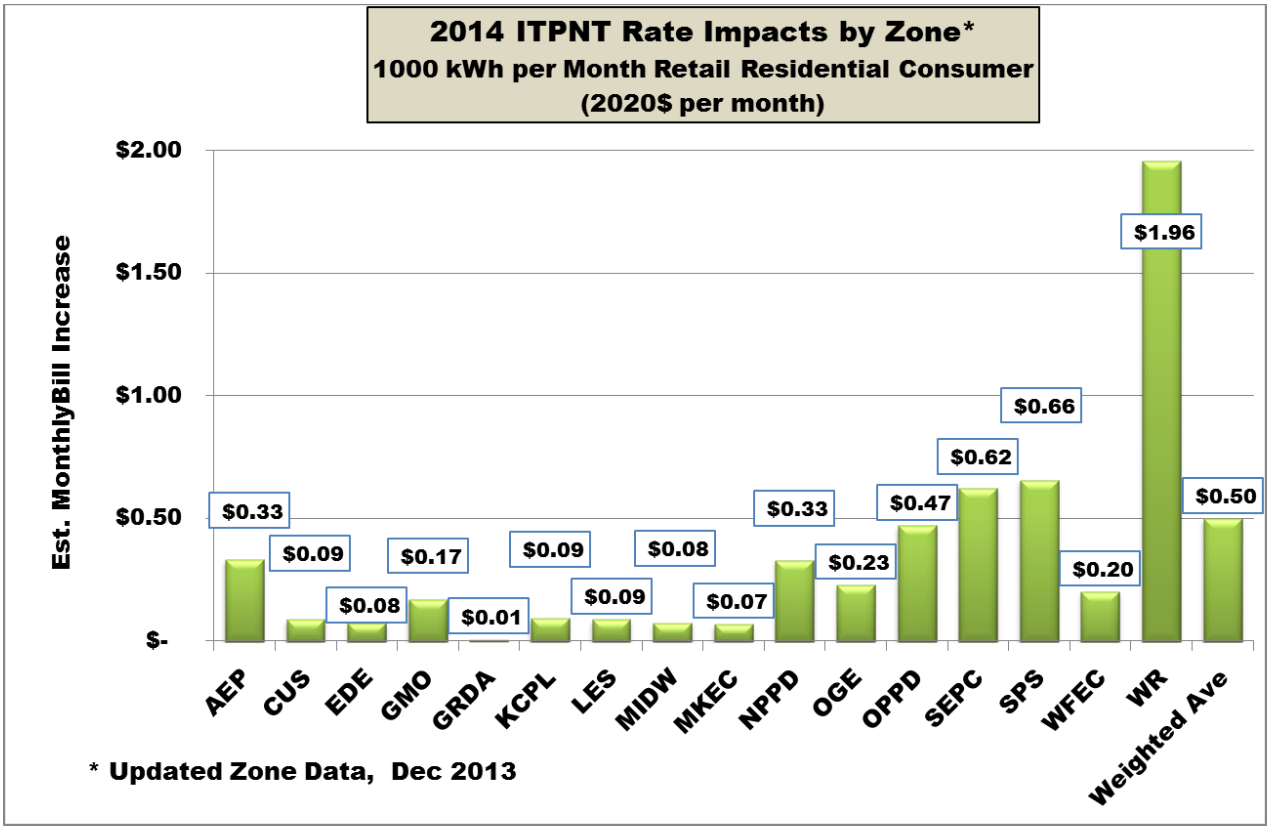


Figure 5.15: 2014 ITPNT Monthly Bill Impact 1000 kWh/Month Retail Residential

Zones providing information on more than one state were combined using a weighted average based on sales projections in each state in the peak ATRR year of 2020.

5.7: Summary of Potential Stability Violations

Based on the projected 2019 load levels, no voltage instability in the six load pockets was identified for the 2014 ITPNT upgrades. Results of the voltage stability analysis for the six load pockets can be found in Table 5.6.

	Central Nebraska	South Oklahoma	South Central Westar	Northeast Westar	Oklahoma City	Lincoln/Omaha
Initial Load (MW):	477	1712	2103	1507	3463	3728
Voltage Collapse Load (MW):	597	2473	4003	2707	5913	6168
Security Limit (MW):	587	2463	3993	2697	5903	6163
Load Margin (MW/%):	110/23%	751/44%	1890/90%	1190/80%	2440/70%	2435/65%

Table 5.6: Summary of Potential Stability Violations

**In the 2011 ITP Load Pocket analysis, the Central Nebraska load area was defined as area 640, NPPD. For this analysis, the Central Nebraska load area is defined as 29 selected buses provided by NPPD.*

PART III: APPENDICES

Section 6:Glossary of Terms

The following terms are referred to throughout the report.

Acronym	Description	Acronym	Description
ATRR	Annual Transmission Revenue Requirements	**MVA**	Mega Volt Ampere (10^6 Volt Ampere)
ATSS	Aggregate Transmission Service Studies	**MW**	Megawatt (10^6 Watts)
CBA	Consolidated Balancing Authority	**NERC**	North American Electric Reliability Corporation
BOD	SPP Board of Directors	**NTC**	Notification to Construct
EHV	Extra High Voltage	**NTC-C**	Notification to Construct with Conditions
FERC	Federal Energy Regulatory Commission	**OATT**	Open Access Transmission Tariff
GI	Generation Interconnection	**RITF**	Rate Impact Task Force
GW	Gigawatt (10^9 Watts)	**SPP**	Southwest Power Pool, Inc.
ITPNT	Integrated Transmission Plan Near-Term Assessment	**STEP**	SPP Transmission Expansion Plan
ITP10	Integrated Transmission Plan 10-Year Assessment	**TPL**	Transmission Planning NERC Standards
ITP20	Integrated Transmission Plan 20-Year Assessment	**TO**	Transmission Owner
MDWG	Model Development Working Group	**TOGs**	Transmission Operating Guides
MISO	Midcontinent Independent System Operator, Inc.	**TWG**	Transmission Working Group
MOPC	Markets and Operations Policy Committee		

Table 6.1: 2014 ITPNT Glossary of Terms

Section 7: Appendix I

2014 Requested Board Action	PID	UID	Facility Owner	Project Description/Comments	Project Justification	In-Service Date	2014 ITPNT Determined Need Date	Project Lead Time	Cost Estimate	Estimated Cost Source	2014 Project Type	From Bus Number	From Bus Name	To Bus Number	To Bus Name	Circuit	Voltages (kV)	Miles of Reconductor/Rebuild	Miles of New	Miles of Voltage Conversion	Rating
				New and Modification																	
NTC - Modify	512	10657	AEP	Rebuild 2.0-mile 69 kV line from Ellerbe Road to Forbing T with 1233.6 ACSR/TW.	To address the overload of Ellerbe Road - Forbing Road 69 kV Ckt 1 for the outage of Broadmoor - Fort Humbug 69 kV Ckt 1.	6/1/2018	6/1/2014	24 months	$8,174,689	AEP	Regional Reliability	507723	ELLERBE ROAD 69 kV	507728	FORBING TAP	1	69	2			90/121
NTC - Modify	1004	11318	SPS	Upgrade existing 230/115 kV transformer at Swisher to 250 MVA.	To address overload of the Swisher 230/115 kV Transformer for the outage of the New Hart 230/115 kV Transformer or the Outage of Happy Interchange-Palo Duro Sub 115 kV Ckt 1 or Randal-Pal Duro 115kV and Happy-Palo Duro Sub 115 kV (SPP-SWPS-Ta66).	6/30/2017	6/1/2014	24 months	$3,496,698	SPS	Regional Reliability	525213	Swisher County Interchange 230 kV	525212	Swisher County Interchange 115 kV	1	230/115				250/250
NTC - Modify	30374	50440	NPPD	Build a new 41-mile 345 kV line from Hoskins to Neligh.	To address the overload of the Battle Creek - County Line 115 kV line for the outage of Albion - Petersburg 115 kV line. To address overloads in the Neligh area during contingencies in the Neligh area.	6/1/2016	6/1/2016	39 months	$68,774,278	NPPD	Regional Reliability	640226	Hoskins 345 kV	750013	Neligh 345 kV	1	345		41		1792/1792
NTC - Modify	30374	50441	NPPD	Build new substation at Neligh. Install a new 345/115 kV transformer and all necessary 345 kV equipment at Neligh.	To address the overload of the Battle Creek - County Line 115 kV line for the outage of Albion - Petersburg 115 kV line. To address overloads in the Neligh area during contingencies in the Neligh area.	6/1/2016	6/1/2016	39 months	$12,118,564	NPPD	Regional Reliability	750013	Neligh 345 kV	640293	Neligh 115 kV	1	345/115				458/474
NTC - Modify	30374	50621	NPPD	Install necessary terminal equipment at the 115 kV bus in the new Neligh substation. Construct approximately 18 miles of new 115 kV transmission to tie Neligh East 345/115 kV into the existing 115 kV transmission system	To address the overload of the Battle Creek - County Line 115 kV line for the outage of Albion - Petersburg 115 kV line. To address overloads in the Neligh area during contingencies in the Neligh area. During review by the DTO, this Upgrade ID was created to separate the 115 kV terminal equipment from Upgrade ID No. 50441. The cost of this Network Upgrade was included in the original cost of Upgrade ID No. 50441.	6/1/2016	6/1/2016	39 months	$17,804,878	NPPD	Regional Reliability	640293	Neligh 115 kV			1	115	7	11.4		
NTC - Modify	30437	50532	WR	Build new Geary County 345/115 kV substation south of Junction City where JEC - Summit 345 kV and McDowell Creek - Junction City #2 115 kV circuits separate. Install 345/115 kV 440 MVA transformer and 115 kV terminal equipment.	To address low voltages along the Abilene - Chapman 115 kV line for the outages: Abilene - Northview 115 kV Ckt 1 and Ckt 2; East Manhattan - Jeffrey Energy Center 230 kV Ckt 1; McDowell Creek - Morris County 230 kV Ckt 1; McDowell Creek 230/115 kV transformer Ckt 1; or various other outages.	6/1/2017	6/1/2014	24 months	$20,530,196	WR	Regional Reliability	532767	Geary County 345 kV	533336	Geary County 115 kV	1	345/115				400/440
NTC - Modify	30437	50534	WR	Build new 15.1-mile 115kV line between the new Geary County substation and Chapman Tap. 10.4 miles of the line will be built as a 2nd circuit to the existing Summit - McDowell Creek 345 kV line.	To address low voltages along the Abilene - Chapman 115 kV line for the outages: Abilene - Northview 115 kV Ckt 1 and Ckt 2; East Manhattan - Jeffrey Energy Center 230 kV Ckt 1; McDowell Creek - Morris County 230 kV Ckt 1; McDowell Creek 230/115 kV transformer Ckt 1; or various other outages.	6/1/2017	6/1/2014	36 months	$27,938,225	WR	Regional Reliability	533336	Geary County 115 kV	533362	CHAPMAN 115 KV	1	115	10.42	4.67		218/262
NTC - Modify	30437	50605	WR	Install 345 kV ring bus at the new Geary County substation.	To address low voltages along the Abilene - Chapman 115 kV line for the outages: Abilene - Northview 115 kV Ckt 1 and Ckt 2; East Manhattan - Jeffrey Energy Center 230 kV Ckt 1; McDowell Creek - Morris County 230 kV Ckt 1; McDowell Creek 230/115 kV transformer Ckt 1; or various other outages.		6/1/2014	24 months	$16,190,561	WR	Regional Reliability	532767	Geary County 345 kV				345				1793/1793
NTC - Modify	30496	50608	NPPD	Install new 345/115 kV 400 MVA transformer at Stegall substation and necessary terminal equipment at the 115 kV bus. This upgrade is contingent upon approval from Basin Electric to connect to the Stegall 345 kV substation that they operate.	Identified in the 2013 ITP Near-Term Assessment as alternative solution for both Upgrade ID 50320, Stegall 345/230 kV Transformer Ckt 2 and Upgrade ID 50400, Stegall - Stegall Tap 230 kV Ckt 2. It also eliminates the potential need to upgrade the Victory Hill 230/115 kV transformer.		6/1/2014	48 months	$5,800,000	NPPD	Regional Reliability	659135	STEGALL 345 kV	640530	Stegall 115 kV	1	345/115				400/440

NTC - Modify	30496	50609	NPPD	Install new 22-mile 115 kV line from Stegall to Scottsbluff and install any necessary terminal equipment. This upgrade is contingent upon Basin Electric's approval noted in Upgrade ID 50608.	Identified in the 2013 ITP Near-Term Assessment as alternative solution for both Upgrade ID 50320, Stegall 345/230 kV Transformer Ckt 2 and Upgrade ID 50400, Stegall - Stegall Tap 230 kV Ckt 2. It also eliminates the potential need to upgrade the Victory Hill 230/115 kV transformer.		6/1/2014	48 months	$23,782,900	NPPD	Regional Reliability	640530	Stegall 115 kV	640338	Scottsbluff	1	115		23		400/440
NTC - Modify	30496	50616	NPPD	Install any necessary terminal equipment at the 345 kV bus in Stegall substation. This upgrade is contingent upon Basin Electric's approval noted in Upgrade ID 50608.	Identified in the 2013 ITP Near-Term Assessment as alternative solution for both Upgrade ID 50320, Stegall 345/230 kV Transformer Ckt 2 and Upgrade ID 50400, Stegall - Stegall Tap 230 kV Ckt 2. It also eliminates the potential need to upgrade the Victory Hill 230/115 kV transformer.		6/1/2014	48 months	$5,417,100	NPPD	Regional Reliability	659135	STEGALL 345 kV			1	345				
NTC	766	11010	SPS	Add second 230/115 kV 250 MVA transformer at Newhart substation.	To address the overload of Kress Interchange-Swisher County Interchange 115 kV Ckt 1 for the outage of Newhart 230/115 kV Ckt 1	6/1/2015	6/1/2015		$6,386,196	SPS	Regional Reliability	525461	Newhart Interchange 230 kV	525460	Newhart Interchange 115 kV	2	230/115				250/250
NTC	30616	50794	SPS	Install two 115 kV brakers at Curry Couty Interchange to covert the high side of the Curry Couty distibion transformer to 115 kV	To address the overload of Curry County Interchange 115/69 kV transformer Ckt 2 for outage of Curry County Interchange 115/69 kV transformer Ckt 1	6/1/2018	6/1/2018		$813,381	SPS	Regional Reliability	524822	Curry County Interchange 115 kV				115				
NTC	844	11113	WFEC	Upgrade 9.9 miles of 69 kV line from Mustang to Sunshine Canyon from 4/0 to 556.	To address the overload of Mustang - Sunshine Canyon 69kV Ckt 1 for the loss of Jensen Road - Jensen Tap 138kV Ckt 1	2/27/2015	6/1/2014	18 months	$4,725,000	WFEC	Regional Reliability	521005	MUSTANG	521058	SUNSHINE CANYON	1	69	9.9			72/89
NTC	856	11127	SPS	Build new 5.1-mile 115 kV line from Northeast Hereford to Centre Street. Convert Centre Steet distribution transformer high side from 69 kV to 115 kV. Install necessary terminal equipment at Northeast Hereford.	To address the overload of Hereford 115/69 kV transformers Ckt 1 and Ckt 2 for the outage of the parallel transformer	12/15/2015	6/1/2014		$9,754,258	SPS	Regional Reliability	524567	Northeast Hereford Interchange 115 kV	524555	Hereford Centre Street Sub	1	115		7.8		245/275
NTC	856	50754	SPS	Convert Hereford distribution transformer high side from 69 kV to 115 kV.	To address the overload of Hereford 115/69 kV transformer Ckt 1 and Ckt 2 for the outage of the parallel transformer.	12/15/2015	6/1/2014		$93,130	SPS	Regional Reliability	524606	Hereford Interchange 115 kV				115				
NTC	1083	11423	AEP	Rebuild 23.7 miles of 138 kV line from Wilkes to Welsh Reserve with 1926.9 ACSR/TW. Upgrade switches at both ends and wave traps, jumpers, CT ratios, and relay settings at Wilkes.	To address the overload of the line for the outage of Lone Star South-Pittsburg 138 kV line.	6/1/2019	6/1/2019		$24,880,495	AEP	Regional Reliability	508355	Welsh Reserve 138 kV	508840	WILKES 138KV	1	138	23.74			395/592
NTC	30097	50103	WR	Install 10.9-Mvar capacitor bank at 115 kV bus at Vaughn substation.	To address low voltage at East Eureka 115kV for the outage of Emporia Energy Center - Lang 345kV Ckt 1, Lang 345/115kV Transformer Ckt 1, or a transformer fault on the Lang 345/115kV.		6/1/2014	18 months	$1,198,694	WR	Zonal Reliability	533308	VAUGHN 115 KV				115				10.9 Mvar
NTC	30390	10600	WR	Rebuild 27-mile 230 kV line from East Manhattan to Jeffrey Energy Center to 345 kV construction but operate as 230 kV using bundled 1590 ACSR conductor. Upgrade terminal equipment at East Manhattan and Jeffrey Energy Center to a minimum emergency rating of 2000 Amps.	Manhattan - Jeffrey Energy Center 230kV line for the outage of Geary - Jeffrey Energy Center 345kV Ckt 1. Previously - To address the overload of the East Manhattan - Jeffrey Energy Center 230kV line for loss of a line from Jeffrey Energy Center to either Auburn Road, Hoyt, Morris County, or Summit		6/1/2017		$53,832,758	WR	Regional Reliability	532861	EAST MANHATTAN 230 KV	532852	JEFFREY ENERGY CENTER 230 KV	1	230	27			797/797
NTC	30438	50533	GRDA	Replace 161kV, 1200A switch with a 2000A Switch at Kerr substation bus.	To address the overload from Kerr to 412 Sub for outage from Flint Creek-Tonnece-GRDA1 345kV-Tonnece 345/161 XFR(GRDA-OPGD-05)		6/1/2017	12 months	$161,100	GRDA	Regional Reliability	512637	412SUB 161	512635	KERR 161	1	161				356/432
NTC	30440	50535	GRDA	Replace 161kV, 1200A switch with a 2000A switch at Kansas Tap substation.	To address the overload from 412Sub to Kansas Tap Sub 161kV line for the outage from Flint Creek-Tonnece-GRDA1 345kV-Tonnece 345/161 XFR(GRDA-OPGD-05)		6/1/2018	12 months	$161,100	GRDA	Regional Reliability	512637	412SUB 161	512714	KANSAS TAP 161	1	161				356/432
NTC	30552	50690	SPS	Rebuild 0.5 miles of 115 kV line from OXY Permian Sub to West Bender Sub.	To address the overload of OXY Permian Sub-West Bender Sub 115 kV Ckt 1 for the outage of Maddox Station-Monument Sub 115 kV Ckt 1.	6/1/2018	6/1/2018		$973,674	SPS	Regional Reliability	528575	OXY Permian Sub 115 kV	528449	West Bender Sub 115 kV	1	115	0.5			276/303
NTC	30553	50691	WR	Change CT setting from 600/5 to 1200/5 and upgrade relays at both Butler and Weaver to get to 160 MVA conductor limit.	To address the overload of Butler - Weaver 138kV Ckt 1 for the outage of Benton - Midian 138 kV Ckt 1.		6/1/2015		$200,046	WR	Regional Reliability	532991	WEAVER 138 KV	532989	Butler 138kV	1	138				143/160
NTC	30555	50693	SPS	Install 4-breaker ring bus to connect the Cunningham - PCA Interchange 115 kV line and the Lea National - Maljamar 115 kV line.	To address low voltage at Maljamr 115 kV system normal (no outages)	6/1/2015	6/1/2015		$2,593,936	SPS	Regional Reliability	528394	Quahada 115 kV				115		0.42		

NTC	30556	50694	WR	Upgrade terminal equipment including the wave trap at McDowell Creek Substation to a minimum of 1200 Amps.	To address the overload of Fort Junction Switching Station - McDowell Creek Switching Station 115kV Ckts 1 and 2 for various outages including Jeffrey Energy Center - Summit 345kVCkt 1, and, when built, Geary - Jeffrey Energy Center 345kV Ckt 1 and Geary 345/115kV Transformer 1.	6/1/2014	6/1/2014		$258,795	WR	Regional Reliability	533335	MCDOWELL CREEK SWITCHING STATION 115 KV				115				201/239
NTC	30558	50696	WR	transformers with a single transformer with a minimum emergency rating of 165 MVA. Then, re-terminate the Neosho 345/138 kV #1 transformer from 533020-532793-532824 to 533021-532793-532824. This will move the 138 kV connection of this transformer from the Neosho South 138 kV bus (533020) to the Neosho 138 kV center bus (533021).	To address the overload of Neosho(NEOSHO4X) 161/138/13.2kV Transformer Ckt 1 for the outage of Neosho - NEOSHOS4 138kV Ckt Z1	6/1/2016	6/1/2014		$8,878,557	WR	Regional Reliability	533021	NEOSHO 138 KV	533768	NEOSHO 69 KV	1	345/138	0.5			150/165
NTC	30559	50697	AEP	Rebuild 4.4 miles of 138 kV line from Chapel Hill REC to Welsh Reserve 138 kV.	To address the overload of the Chapel Hill REC - Welsh Reserve 138 kV Ckt1 for the outage of Lone Star South-Pittsburg 138 kV Ckt 1.	6/1/2019	6/1/2019		$6,651,694	AEP	Regional Reliability	508337	ChapelL Hill REC 138 kV	508355	Welsh Reserve 138 kV		138	4.39			395/592
NTC	30560	50698	WR	Build new 28-mile 138 kV line from Viola to Sumner County.	To address low voltages at Creswell, Farber, Oxford, Sumner, Belle Plain, TC-Rock and Timber Junction for the outage of El Paso - Farber 138kV, Farber - Sumner County No. 10 Belle Plain 138kV, and Kildare - Newkirk 138kV	6/1/2019	6/1/2019		$51,513,963	WR	Zonal Reliability	532984	SUMNER COUNTY 138 kV	533075	Viola 138kV	1	138		28		262/314
NTC	30561	50699	OPPD	Install new 161/69 kV auto transformer and 69kV terminal equipment.	To mitigate voltage violations at Sub 1244 and S1366 for the loss of Sub 1206 to Sub 1244.		6/1/2016		$4,426,730	OPPD	Zonal Reliability	646366	SUB 1366 161kV	647866			161/69				200/200
NTC	30561	50761	OPPD	Install 161 kV terminal equipment at S1366 for new 161/69 kV transformer.	To mitigate voltage violations at Sub 1244 and S1366 for the loss of Sub 1206 to Sub 1244.		6/1/2016		$422,270	OPPD	Zonal Reliability	646366	SUB 1366 161kV				161				
NTC	30562	50700	WFEC	Reconductor 9-mile 138 kV line from Red Hills to Elk City.	To address the base case overload of Elk City - Red Hills 138kV Ckt 1.		6/1/2015		$3,675,000	WFEC	Regional Reliability	521116	RED HILLS WIND FARM BUS 138 kV	511458	ELK CITY 138	1	138	9			183/228
NTC	30563	50702	WFEC	Add 20 Mvar of capacitors at Sandy Corner 138 kV.	To address low voltages along the 138kV line from Sand Ridge to Knob Hill for the outage of 138kV line sections from Renfrow to Sandy Corner.	5/1/2017	6/1/2017	18 months	$504,000	WFEC	Regional Reliability	520204	Sandy Corner 138 kV				138				20 Mvar
NTC	30565	50703	SEPC	Install 24-Mvar capacitor at Mingo substation.	To address low voltage in the area for the loss of Mingo xfrm. Upgrade solves low voltages for the loss of Mingo xfrm in SUNC and MIDW through 15 SP models.		6/1/2014	24 months	$4,812,363	SEPC	Regional Reliability	531429	MINGO			1	115				24 Mvar
NTC	30566	50704	NPPD	Upgrade substation equipment at Maxwell and North Platt substations to 1200 Amp to increase line rating to 215 MVA.	Required to address overloads of Maxwell - North Platte 115 kV for the loss of Broken Bow - Crooked Creek 115 kV or the Crooked Creek 230/115 kV transformer.	6/1/2014	6/1/2014	12 months	$30,000	NPPD	Regional Reliability	640287	North Platte 115 kV	640267	Maxwell 115 kV		115				215/215
NTC	30568	50706	WR	Install 10.8-Mvar capacitor bank at Clay Center Switching Station (bus# 533320).	To address low voltages in the Clay Center area for outage of the Geary County 345/115kV Transformer.	6/1/2016	6/1/2016		$1,390,166	WR	Zonal Reliability	533320	Clay Center Switching Station 115 kV				115				10.8 Mvar
NTC	30569	50708	SPS	Build new 40-mile 230 kV line from Potash Junction Interchange to new Road Runner substation. Install any necessary 230 kV terminal equipment at Potash Junction Interchange and Road Runner.	To address the overload of Potash Junction Interchange 230/115 kV transformer for the outage of Pecos Interchange-Potash Junction 230 kV Ckt 1; Overload of Monument Sub-West Hobbs Switching station Ckt. 1 for the outage of Maddox Station-Sanger Switching station or outage OXY Permian Sub-Sanger Switching Station. Also to address low voltage at I.M.C. #1 Sub 115 kV bus for the outage of IMC # TP 1 115-Intepdw-TP3 115 kV.	12/1/2015	6/1/2016		$35,007,385	SPS	Regional Reliability	527963	Potash Junction Interchange 230 kV	528027	Road Runner 230 kV	1	230		40.4		497/547
NTC	30569	50709	SPS	Install new Road Runner substation with a 230/115 kV 250 MVA transformer and 115 kV terminal equipment.	To address the overload of Potash Junction Interchange 230/115 kV transformer for the outage of Pecos Interchange-Potash Junction 230 kV Ckt 1; Overload of Monument Sub-West Hobbs Switching station Ckt. 1 for the outage of Maddox Station-Sanger Switching station or outage OXY Permian Sub-Sanger Switching Station. Also to address low voltage at I.M.C. #1 Sub 115 kV bus for the outage of IMC # TP 1 115-Intepdw-TP3 115 kV.	12/1/2015	6/1/2016		$8,989,747	SPS	Regional Reliability	528027	Road Runner 230 kV	528025	Road Runner 115 kV	1	230/115				250/250
NTC	30573	50718	AEP	Rebuild 1.7-mile 69 kV line from Fort Humbug to Broadmoor with 1233.6 ACSR/TW. Upgrade jumpers at Fort Humbug and jumpers and bus at Broadmoor.	To address overloads Broadmoor-Fort Humbug 69 kV for outage of Forbing Tap-South Shreveport 69 kV	6/1/2019	6/1/2019		$6,695,986	AEP	Regional Reliability	507716	BROADMOOR	507730	FORT HUMBUG 69KV	1	69	1.7			136/143

NTC	30574	50719	AEP	Rebuild 1.3-mile 69 kV line from Daingerfield to Jenkins REC T with 959.6 ACSR/TW.	To address the overload of overload of Daingerfield-Jenkins T 69 kV for the outage of Lone Star South - Pittsburg 138KV Ckt 1 or Welsh Reserve - Wilkes 138KV Ckt 1 or Chapel Hill REC - Welsh Reserve 138KV Ckt 1.	6/1/2019	6/1/2019		$2,819,806	AEP	Regional Reliability	508288	DAINGERFIELD	508293	JENKINS REC T		69	1.3			132/178
NTC	30575	50720	AEP	Rebuild 6.6-mile 69 kV line from Longview Heights to Hallsville with 1233.6 ACSR/TW. Upgrade jumpers, CT ratios, and relay settings at Longview Heights.	To address the overload of Hallsville-Longview Heights Ckt 1 69 kV for the outage of Marshall-Marshall Auto 69 kV Ckt 1	6/1/2017	6/1/2014		$8,851,677	AEP	Regional Reliability	508543	HALLSVILLE	508553	LONGVIEW HEIGHTS 69KV	1	69	6.6			68/89
NTC	30576	50721	AEP	Rebuild 11.2-mile 69 kV line from Hallsville to Marshall with 1233.6 ACSR/TW. Upgrade jumpers, CT ratios, and relay settings at Marshall.	Marshall 69 kV Ckt 1 for the outages of Pirkey- Whitney 138 kV; Lake Lamond-Spring Hill 138 kV Ckt 1; Easton Rec-Pirkey 138 kV Ckt 1; Easton Rec-Pirkey 138 kV; Easton Rec-Knox Lee 138 kV Ckt1; Diana-Spring Hill 138 kV; Blocker Tap-Marshall 69 kV Ckt 1; or Lake Lamond 138/69 kV transformer 1	6/1/2017	6/1/2014		$15,248,925	AEP	Regional Reliability	508556	MARSHALL 69KV	508543	HALLSVILLE	1	69	11.2			68/89
NTC	30577	50722	SPS	Rebuild 5-mile 69 kV line from Chaves to Price converting to 115 kV. Install necessary terminal equipment at Chaves.	To address the overload of the Chaves County Interchange 115/69 kV transformer in base case	12/30/2017	6/1/2017		$4,701,279	SPS	Regional Reliability	527482	Chaves County Interchange 115 kV	527543	PRICE 3 115 kV	1	115			5	250/250
NTC	30577	50723	SPS	Rebuild 3-mile 69 kV line from Price to CV Pines converting to 115 kV.	To address the overload of the Chaves County Interchange 115/69 kV transformer in base case	6/1/2017	6/1/2017		$4,158,668	SPS	Regional Reliability	527543	PRICE 3 115 kV	527542	CV-PINES 3 115 kV	1	115			3	245/245
NTC	30577	50724	SPS	Rebuild 5-mile 69 kV line from CV Pines to Capitan converting to 115 kV.	To address the overload of the Chaves County Interchange 115/69 kV transformer in base case	1/30/2016	6/1/2017		$5,415,053	SPS	Regional Reliability	527542	CV-PINES 3 115 kV	527541	Capitan 115 kV	1	115			5	245/265
NTC	30578	50725	SPS	Build 10-mile 115 kV line from Bailey County to Bailey Pump. Install necessary terminal equipment at Bailey County.	To address the overload of the Lamb County 115/69 kV transformer for the outage of the parallel 115/69 kV transformer and low voltage at East Muleshoe for the outage of East Muleshoe-Plant X 115 kV Ckt. 1		6/1/2016		$6,941,335	SPP	Regional Reliability	525028	Bailey County Interchange 115 kV	525040	Bailey Pump 115 KV	1	115		10		276/304
NTC	30578	50729	SPS	Build 10-mile 115 kV line from Bailey County Pump to Sundan Rural and covert Bailey Pumb and Sundan Rural distribution transformer high side from 69 to 115 kV.	To address the overload of the Lamb County 115/69 kV transformer for the outage of the parallel 115/69 kV transformer and low voltage at East Muleshoe for the outage of East Muleshoe-Plant X 115 kV Ckt. 1.		6/1/2016		$6,941,335	SPP	Regional Reliability	525040	Bailey Pump 115 KV	525594	Sundan Rural 115 kV	1	115		10		276/304
NTC	30578	50731	SPS	Install new 115/69 kV transformer 84 MVA. Install necessary 69 kV terminal equipment.	To address the overload of the Lamb County 115/69 kV transformer for the outage of the parallel 115/69 kV transformer and low voltage at East Muleshoe for the outage of East Muleshoe-Plant X 115 kV Ckt. 1.		6/1/2016		$3,000,000	SPP	Regional Reliability	525600	Lamb County Sandhill 115 kV	525599	Lamb County REC-Sandhill 115 kV	1	115/69				84/84
NTC	30578	50732	SPS	Build 4.1-mile 115 kV line from Sudan Rural to Lamb County REC Sandhill. Install 115 kV terminal equipment for new 115/69 kV transformer.	To address the overload of the Lamb County 115/69 kV transformer for the outage of the parallel 115/69 kV transformer and low voltage at East Muleshoe for the outage of East Muleshoe-Plant X 115 kV Ckt. 1.		6/1/2016		$2,845,947	SPP	Regional Reliability	525594	Sundan Rural 115 kV	525600	Lamb County Sandhill 115 kV	1	115		4.1		276/304
NTC	30578	50734	SPS	Build 2.6-mile 115 kV line from Lamb County REC Sandhill to Amherst. Convert Amherst distribution transformer high side from 69 kV to 115 kV.	To address the overload of the Lamb County 115/69 kV transformer for the outage of the parallel 115/69 kV transformer and low voltage at East Muleshoe for the outage of East Muleshoe-Plant X 115 kV Ckt. 1.		6/1/2016		$1,804,747	SPP	Regional Reliability	525600	Lamb County Sandhill 115 kV	525608	Amherst 115 kV		115		2.6		276/304
NTC	30578	50735	SPS	Build 4.9-mile 115 kV line from Amherst to West Littlefield. Convert West Littefield distribuition transformer high side from 69 kV to 115 kV.	To address the overload of the Lamb County 115/69 kV transformer for the outage of the parallel 115/69 kV transformer and low voltage at East Muleshoe for the outage of East Muleshoe-Plant X 115 kV Ckt. 1		6/1/2016		$3,401,254	SPP	Regional Reliability	525608	Amherst 115 kV	525615	West Littlefield 115 kV	1	115		4.9		276/304
NTC	30578	50736	SPS	Build 7-mile 115 kV line from West Littlefield to Lamb County converting. Install necessary terminal equipment at Lamb County.	To address the overload of the Lamb County 115/69 kV transformer for the outage of the parallel 115/69 kV transformer and low voltage at East Muleshoe for the outage of East Muleshoe-Plant X 115 kV Ckt. 1.		6/1/2016		$4,858,935	SPP	Regional Reliability	525615	West Littlefield 115 kV	525636	Lamb County Interchange 115 kV	1	115		7		276/304
NTC	30579	50726	WR	Rebuild 9.06-mile 69 kV line from Wellington to Sumner County No. 4 Rome with single 1192 ACSR conductor to achieve 1200 Amp minimum ampacity.	To address the overload of City Of Wellington - Sumner County No.4 Rome 69 kV Ckt 1 for the outage of Gill Energy Center West - Peck 69 kV Ckt 1.	6/1/2016	6/1/2014		$7,405,817	WR	Regional Reliability	533553	SUMNER COUNTY NO. 4 ROME 69 KV	533560	CITY OF WELLINGTON 69 KV		69	9			96/96
NTC	30579	50727	WR	Rebuild 9.43-mile 69 kV line from Creswell to Sumner County No. 4 Rome with single 1192 ACSR conductor to achieve 1200 Amp.	To address the overload of Creswell - Sumner County No.4 Rome 69 kV Ckt 1 facility for the outage of Gill Energy Center West - Peck 69 kV Ckt 1.	12/1/2015	6/1/2014		$7,988,648	WR	Regional Reliability	533543	CRESWELL 69 KV	533553	SUMNER COUNTY NO. 4 ROME 69 KV		69	9.5			96/96

NTC	30580	50730	WR	Rebuild 5.64-mile 69 kV line from Crestview to Northeast.	To address the overload of Crestview - Northeast 69 kV Ckt 1 facility for the outage of Renew 2 - Ripley 69 kV Ckt 1.	6/1/2015	6/1/2014		$7,752,352	WR	Regional Reliability	533822	NORTHEAST 69 KV	533789	CRESTVIEW 69 KV		69	5.59			131/143
NTC	30580	50733	WR	Rebuild 69 kV line from Kenmar to Northeast with single 1192 ACSR to achieve 1200 Amp minimum ampacity.	To address the overload of Kenmar - Northeast 69 kV Ckt 1 for a fault on the Seventeenth 138/69 kV Transformer (WR-B3-18), Evans Energy Center South - Lakeridge 138kV Ckt 1 or Hoover North - Lakeridge 138kV Ckt 1.	6/1/2016	6/1/2014		$2,829,128	WR	Regional Reliability	533822	NORTHEAST 69 KV	533811	KEN MAR 69 KV		69	1.74			131/143
NTC	30581	50763	OGE	Convert existing 4.32-mile 69 kV line from Ahloso to Park Lane to 138 kV.	To address overloads and low voltages in these 69 kV facilities: Park Lane - Ahloso Tap - Harden Tap,Valley View - Ada Industrial - Park Lane, and FRSCOTP - SOCPMT.	6/1/2017	6/1/2015	30 months	$4,634,000	OGE	Regional Reliability	515178	PARK LANE 138	515318	Ahloso 138KV	1	138			4.39	268/286
NTC	30581	50764	OGE	Convert existing 10.12-mile 69 kV line from Ahloso to Harden City to 138 kV.	To address overloads and low voltages in these 69 kV facilities: Park Lane - Ahloso Tap - Harden Tap,Valley View - Ada Industrial - Park Lane, and FRSCOTP - SOCPMT.	6/1/2015	6/1/2015	30 months	$5,566,000	OGE	Regional Reliability	515318	Ahloso 138KV	515362	Harden City 138KV	1	138			10.12	268/286
NTC	30581	50765	OGE	Convert existing 3.39-mile 69 kV line from Harden City to Frisco to 138 kV.	To address overloads and low voltages in these 69 kV facilities: Park Lane - Ahloso Tap - Harden Tap,Valley View - Ada Industrial - Park Lane, and FRSCOTP - SOCPMT.	6/1/2017	6/1/2015	30 months	$3,715,500	OGE	Regional Reliability	515500	Frisco 138 kV	515362	Harden City 138KV	1	138			3.39	268/286
NTC	30581	50766	OGE	Convert existing 3.39-mile 69 kV line from Frisco to Lula to 138 kV.	To address overloads and low voltages in these 69 kV facilities: Park Lane - Ahloso Tap - Harden Tap,Valley View - Ada Industrial - Park Lane, and FRSCOTP - SOCPMT.	6/1/2015	6/1/2015	30 months	$7,083,000	OGE	Regional Reliability	515192	LULA 138	515500	Frisco 138 kV	1	138			8.3	268/286
NTC	30582	50738	OGE	Install a 9-Mvar capacitor bank at either County Line or Wildhorse substation.	To address voltage violation issues at Mobil Oil 69 kV and Wildhorse 69 kV facilities for the loss of Ratliff - Wildhorse 69 kV Ckt 1 or Ratliff (Ratliff2) 138/69/13.2 kV transformer.	6/1/2017	6/1/2017	18 months	$740,254	OGE	Regional Reliability	515126	County Line 69 kV				69				9 Mvar
NTC	30583	50741	GMO	Install a second 50 MVA 161/69 kV transformer at Harrisonville including any 69 kV terminal equipment.	To address the overload of Harrisonville 161/69 kV Transformer Ckt 1 facility for the loss of Ralph Green - Pleasant Hill 69 kV Ckt and South Harper - Freeman 69 kV Ckt (SPP-MIPU-04).	1/30/2014	6/1/2014		$2,773,480	GMO	Regional Reliability	541239	Harrisonville 161 KV	541295	Harrisonville 69 KV	2	161/69				50/55
NTC	30583	50762	GMO	Install 161 kV terminal equipment for new second 161/69 kV transformer at Harrisonville.	To address the overload of Harrisonville 161/69 kV Transformer Ckt 1 facility for the loss of Ralph Green - Pleasant Hill 69 kV Ckt and South Harper - Freeman 69 kV Ckt (SPP-MIPU-04).	1/30/2014	6/1/2014		$1,005,220	GMO	Regional Reliability	541239	Harrisonville 161 KV				161				
NTC	30584	50739	WR	Rebuild 9.7-mile 69kV line from Elk Junction to Montgomery to 72 MVA.	To address low voltage at Elk River 69 kV for loss of existing Elk River 69 kV capacitor bank.	6/1/2018	6/1/2018		$10,537,806	WR	Zonal Reliability	533698	MONTGOMERY 69 KV	533690	ELK JUNCTION 69 KV	1	69	9.5			72/72
NTC	30584	50740	WR	Rebuild 18.8-mile 69kV line from Elk Junction to Sedan to 72 MVA.	To address low voltage at Elk River 69 kV for loss of existing Elk River 69 kV capacitor bank.	6/1/2018	6/1/2018		$32,548,502	WR	Zonal Reliability	533690	ELK JUNCTION 69 KV	533544	CANEY VALLEY NO. 5 SEDAN 69 KV	1	69	19			72/72
NTC	30588	50745	OPPD	New 161/69 kV transformer at Fremont to accommodate a new 161 kV interconnection.	This upgrade helps to relieve overloads of the Fremont 115/69 kV transformer as well as low voltage issues at the Fremont substation and surrounding areas.		6/1/2019		$5,601,611	OPPD	Regional Reliability	646301	S1301 161kV	647801	S6801 8 69kV		161/69				134.4/134.4
NTC	30588	50746	OPPD	Build new 3-mile 69 kV line from Fremont to new substation S6801.	To address overloads in the OPPD and NPPD areas. Including SUB 902 - SUB 984 69KV CKT 1 for the loss of FREMONT SUB D - SUB 976 69KV CKT 1.		6/1/2019				Regional Reliability	647422	Fremont Sub B	647801	S6801 8 69kV		161/69		3		144/144
NTC	30588	50747	OPPD	Build new 17-mile 161 kV line from S1226 to new substation S1301.	To address overloads in the OPPD and NPPD areas.		6/1/2019		$29,069,150	OPPD	Regional Reliability	646226	Sub 1226	646301	S1301 161kV		161		17		377/377
NTC	30589	50750	SEPC	Add an additional 12 Mvar of capacitance at Ruleton substation.	Add additional 12 mVAR of capacitance at Ruleton 115 kV substation to address low voltages on multiple buses in Sunflower and Midwest for the loss of the Mingo 345/115 kv transformer		6/1/2016	18 months	$2,791,167	SEPC	Regional Reliability	531357	RULETON			1	115				24 Mvar
NTC	30590	50748	OPPD	Rebuild 1.34-mile 69 kV line from S906 to S924 with a new rating of 143 MVA.	To adress overload of SUB 906 SOUTH - SUB 924 69KV CKT 1 for the loss of SUB 1201 (S1201 T1) 161/69/13.8KV TRANSFORMER CKT 1		6/1/2019		$1,360,327	OPPD	Regional Reliability	647906	Sub 906 South Bus	647924	Sub 924		69	1.34			143/143
NTC	30590	50749	OPPD	Substation improvements to increase S924 - S912 69 kV rating to 99 MVA.	To address the overload of SUB 912 - SUB 924 69KV CKT 1 for the loss of SUB 1201 (S1201 T1) 161/69/13.8KV TRANSFORMER CKT 1.		6/1/2019		$69,679	OPPD	Regional Reliability	647912	Sub 912	647924	Sub 924		69				99/99
NTC	30596	50757	NPPD	Build a new 35-mile 115 kV line from Ord to Broken Bow Wind and install necessary termal equipment.	To addres low voltage at North loup 115 kV,Ord 115 kV and Spalding 115 kV for the outage of Albion-Spalding 115 kV Ckt1 or low volate ot Ord 115 kV for the outage of North Loup-Spalding 115 kV Ckt1.		6/1/2014	36 months	$32,244,000	NPPD	Regional Reliability	640445	Broken Bow Wind	640308	Ord	1	115		42		160/176

NTC	30596	50760	NPPD	Increase line clearance on 115 kV line from North Loup to Ord to 100 degree C. Upgrade disconnect switches, CTs, and jumpers at North Loup.	To addres low voltage at North loup 115 kV,Ord 115 kV and Spalding 115 kV for the outage of Albion-Spalding 115 kV Ckt1 or low volate ot Ord 115 kV for the outage of North Loup-Spalding 115 kV Ckt1.		6/1/2014	24 months	$329,600	NPPD	Regional Reliability	640284	North Loup	640308	Ord	2	115				137/151
NTC	30597	50758	OGE	Install the new LANE 138-12.5 kV substation across the street from Knobhill sub. Install a new 138 kV terminal in Knobhill substation. Tie the new LANE substation and the existing Knobhill substations together with one span of 138 kV line. WFEC to eliminate the double circuit portion of the 138 kV Mooreland – Noel and the 138 kV Noel – Knobhill and return the 138 kV Mooreland – Knobhill to its original configuration. WFEC or OG&E to construct the new 1 ½ mile 138 kV Noel – LANE substation line.	To address low voltages in the following 69 kV facilities: ALVA,CZYCRVT2,HELENA TAP,KNOBHILL,SALINE for the loss of ALVA - KNOBHILL 69KV CKT 1 or RENFROW4 - SAND RDG_138KV CKT 1 or KNOBHILL (KNOBHIL4) 138/69/13.2KV XFR CKT 1.	6/1/2019	6/1/2019	30 months	$4,644,880	OGE	Regional Reliability	514795	KNOBHILL 138	514794	KNOBHILL 69		138/69		1.6		
NTC	30598	50759	AEP	Build new 0.3-mile 69 kV line from Letourneau to a tap point along the existing Air Liquide Tap line with 664.8 ACSR/TW. Make the existing Letourneau plant - Letourneau line section normally open.	To address the overload of Letorneau - Letourneau Tap 69 kV with no contingencies (base case).	6/1/2017	6/1/2017		$2,358,802	AEP	Regional Reliability	508536	LETOURNEAU STEEL	508594	Letouteau W tap 69 kV		69		0.3		150/150
NTC	30609	50783	OPPD	Rebuild 3.3-mile 69 kV line from S907 to S919 with a new rating of 143 MVA.	Upgrade is to resolve the overload of the line from Sub 907 - Sub 919 69 kV for the loss of the line from Sub 1250 - Sub 919 69 kV or for the loss of Sub 1250 161/69/13.8 kV Transformer.		6/1/2019		$3,141,600	OPPD	ITP Near Term	647907	Sub 907	647919	Sub 919		69	3.3			
				Withdrawn																	
NTC - Withdraw	534	10679	WR	Replace Halstead 138/69 kV transformer with 100/110 MVA unit.		6/1/2014		24 months	$3,205,323	WR	Regional Reliability	533012	HALSTEAD SOUTH BUS 138 KV	533736	HALSTEAD 69 KV	1	138/69				100/110
NTC - Withdraw	1085	11429	WFEC	Upgrade relaying at OU Switchyard and Lindsay Switchyard; close the normally open Criner - Lindsay 69 kV line	To address low voltages in the Cole area for the loss of the OU 138/69 kV Transformer	12/31/2013		6 months	$50,000	WFEC	Regional Reliability	520868	CRINER	520977	LINDSAY	1	69				72/89
NTC - Withdraw	1139	11501	SPS	Rebuild 6 miles of 115 kV line from Lubbock South Interchange to Allen Substation.	To address the overload of the Lubbock South Interchange - Allen Substation 115 kV Ckt 1 for the outage of Carlisle Interchange - Tuco Interchange 230 kV Ckt 1.	6/1/2017	6/1/2014	24 months	$10,946,449	SPS	Regional Reliability	526268	Lubbock South Interchange 115 kV	526213	Allen Sub 115 kV	1	115	6.1			273/300
NTC - Withdraw	30044	50050	WFEC	Install 3 Mvar 69 kV capacitor at Gypsum.		9/30/2013		12 months	$150,000		Regional Reliability	520929	GYPSUM				69				3 Mvar
NTC - Withdraw	30093	50099	WFEC	Install 12 Mvar capacitor at Latta Junction 138 kV.		1/1/2014		12 months	$324,000	SPP	Regional Reliability	520970	LATTA				138				12 Mvar
NTC - Withdraw	30350	50399	WR	Install second 6 Mvar capacitor at Elk River 69 kV.	To address low voltage at Elk River 69 kV for loss of existing Elk River 69 kV capacitor bank.	12/1/2015	6/1/2012	12 months	$1,007,160	WR	Zonal Reliability	533691	ELK RIVER 69 KV				69				6 Mvar
NTC - Withdraw	30427	50520	SEPC	Install second 345/115 kV transformer at Mingo.	To address low voltage at Colby 115 kV, Hoxie 115 kV, Goodland 115 kV, and other 115 kV buses in northwestern Kansas for the loss of Mingo 345/115/13.8 kV transformer Ckt 1.	6/1/2016	6/1/2013	36 months	$12,116,815	SEPC	Regional Reliability	531451	MINGO	531429	MINGO	2	345/115				280/280
NTC - Withdraw	30432	50527	AEP	Rebuild 5.4-mile 138 kV line from 52nd & Delaware West Tap to Riverside Station with 2-795 ACSR conductor. Upgrade relay settings at Riverside Station.	To address the overload of 52nd & Delaware West Tap - Riverside Station 138 kV Ckt 1 for the outage of SPP-AEPW-38 (72nd & Elwood - Tulsa Power 138 kV and Tulsa Power Station - Oaks East Tap - Riverside Station 138 kV).	6/1/2015	6/1/2014	18 months	$24,992,196	AEP	Regional Reliability	509814	52ND & DELAWARE WEST TAP	509783	RIVERSIDE STATION 138KV	1	138		5.4		280/331
NTC - Withdraw	30441	50536	OGE	Install a 50 Mvar reactor at Gracemont 345 kV bus.	To address high voltage at Gracemont 345 kV for the loss of Cimarron - Minco 345 kV Ckt 1 or Gracemont - Minco 345 kV Ckt 1.	4/1/2015	4/1/2015	12 months	$3,500,452	OGE	Regional Reliability	515800	Gracemont 345kv				345				50 Mvar
NTC - Withdraw	30442	50537	OGE	Install a 30 Mvar reactor at Hunter 345 kV bus for the Hunter - Wichita 345 kV line.	To address high voltage at Chisholm View Wind Farm 345 kV and Hunter 345 kV for the loss of Hunter - Woodring 345 kV Ckt 1.	4/1/2016	4/1/2016	24 months	$3,500,452	OGE	Regional Reliability	515476	Hunter 345 kV			1	345				30 Mvar
NTC - Withdraw	30445	50540	OGE	Install a 30 Mvar reactor at the Tatonga 345 kV bus on the Tatonga - Woodward District 345 kV line.	To address high voltage at Crossroads Wind 345 kV bus and Tatonga 345 kV bus for the loss of Northwest - Tatonga 345 kV Ckt 1.	5/30/2014	4/1/2013	24 months	$3,500,452	OGE	Regional Reliability	515407	Tatonga 345kv	515375	Woodward EHV 345kv	1	345				30 Mvar
NTC - Withdraw	30447	50543	MKEC	Rebuild 21-mile Haggard - Gray County Tap - West Dodge 115 kV line.	To address the overload of Gray County Tap - West Dodge 115 kV Ckt 1 for system intact conditions as well as for the outage of Gray County Tap - Haggard 115 kV Ckt 1 or various other outages.	6/1/2016	4/1/2013	0 months	$10,485,402	SEPC	Regional Reliability					1	115		21		202.2/248.8

Section 8: Appendix II

2014 ITPNT Scope

December 19, 2012

TWG Approved

Engineering

Southwest Power Pool

Revision History

Date	Author	Change Description
12/7/2012	Staff	Initial Draft
12/19/2012	Staff	TWG Approval
1/16/2013	Staff	MOPC Approval
5/28/2013	Staff	Updated based on feedback from MOPC and TWG
6/26/2013	TWG	Approved previous revisions and added Westar waivers and clarified language about NTCs from CBA model

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Overview

This document presents the scope and schedule of work for the 2014 Integrated Transmission Planning (ITP) Near-Term (NT) Assessment. This document was reviewed by the Transmission Working Group (TWG) in December 2012.

Objective

The third phase of the ITP process is the Near-Term Assessment (ITPNT). The main objectives of 2014 ITPNT are to evaluate the reliability of the SPP transmission system in the near-term planning horizon, collaborate on the development of improvements with stakeholders, and identify necessary upgrades for approval and construction. The 2014 ITPNT's primary focus is identifying solutions required to meet the reliability criteria defined in OATT Attachment O Section III.6. The process will also include coordination of transmission plans with the ITP20, ITP10, Aggregate Study, and Generation Interconnection processes.

The 2014 ITPNT will create an effective near-term plan for the SPP footprint which identifies solutions to potential issues for system intact and (N-1) conditions using the following principles:

- Identifying potential reliability-based problems (NERC Reliability Standards TPL-001 and TPL-002, SPP and local criteria)
- Utilizing Transmission Operating Guides
- Developing additional mitigation plans including transmission upgrades to meet the region's needs and maintain SPP and local reliability/planning standards

The 2014 ITPNT study horizon will include modeling of the transmission system for six years (i.e. 2019). This will provide enough lead time requirements such that NTC letters can be issued and project owners can begin work in a timely fashion to enable the completion of more complex projects by the identified need date.

The process is open and transparent, allowing for stakeholder input. Study results are coordinated with other entities and regions responsible for transmission assessment and planning. TWG will review and vet components of the 2014 ITPNT process, which includes but is not limited to the following items: model development, reliability analysis, stability analysis, transmission plan development, seams impacts, and 2014 ITPNT Report.

Data inputs

SPP will consider power flow models with individual Balancing Authorities (BA) as well as models with a Consolidated Balancing Authority (CBA Scenario). SPP will use 2014, 2015, and 2019 models in the 2014 ITPNT for the following seasons: 2014 light load, 2014 summer peak, 2015 summer peak, 2019 light load, and 2019 summer peak. Thus, 15 model scenarios will be analyzed as part of the 2014 ITPNT Assessment. The modeling assumptions are detailed in sections below.

A. Load

The load density and distribution for the steady state analysis will be provided through the MDWG model building process[1]. The load will represent each individual BA's coincident conditions per season (i.e. non-coincident conditions for the SPP region). Resource obligations will be determined for the footprint taking into consideration what load is industrial, non-scalable type loads and which load grows over time.

B. *Generation Resources*

Existing generating resources will be represented in the power flow models taking into account planned retirements and retirements. New generating resources included in the power flow models will be limited to resources with a FERC filed Interconnection Agreement not on suspension or resources with an executed Service Agreement. Exceptions to these qualifications are addressed in the ITP Manual.

Mid-Kansas Electric Company requested a waiver for its Rubart generation station to be included in the 2014 ITPNT models through the process outlined in the ITP Manual and MDWG manual. That request was approved by the TWG in May 2013. Golden Spread Electric Cooperative requested a waiver for its Antelope Station generation to be included in the 2014 ITPNT models. That request was approved by the TWG in June 2013.

Westar Energy, Inc. requested a waiver for Post Rock wind generation to be included in the 2014 ITPNT models. That request was approved by the TWG in June 2013. Westar Energy, Inc. also requested a waiver for Flat Ridge wind generation to be included in the 2014 ITPNT models. In June 2013, TWG approved 300 MW of the request be included in the models.

All generation with waivers was placed in the necessary models based on the estimated in-service dates.

C. Model Topology

The topology used to account for the transmission system excluding generation will be the current transmission system and the following transmission upgrades: SPP approved for construction upgrades, SPP Transmission Owners' planned (zonal sponsored) upgrades, and first tier entities' planned upgrades (AECI, Entergy, MEC, and WAPA). The model development processes for SPP

[1] SPP MDWG Powerflow Procedure Manual

MDWG and SERC account for long-term transmission line outages as forecasted by each process's member transmission owners.

D. *Transmission Service*

To account for the confirmed long-term transmission service SPP will create two scenario models representing individual BAs. The first scenario (S0) contains projected transmission transfers between individual BA's and generation dispatch on the system. The second scenario (S5) contains all confirmed long-term firm transmission service with its necessary generation dispatch.

E. *Consolidated Balancing Authority*

In order to account for the impacts of the Integrated Marketplace on the SPP footprint a Consolidated Balancing Authority (CBA) scenario model will be developed as part of the 2014 ITPNT Assessment. The CBA scenario will model SPP as a single Balancing Authority and will only model transmission transfers across the SPP seams. The CBA scenario will utilize the SPP portion of the NERC Book of Flowgates updated with information from the 2013 Flowgate Assessment, 2014 ITPNT transmission topology, and 2013 ITP20 economic dispatch data. The goal will be to attain a security-constrained unit commitment and economic dispatch (SCUC/SCED) for each year and season identified as part of the 2014 ITPNT Assessment. In order to simulate changes that will occur to the SPP portion of the NERC Book of Flowgates due to upgrades coming into service during the defined study period of the 2014 ITPNT Assessment, a constraint assessment will be completed to determine if any constraints should be added, removed, or modified before the SCUC/SCED have been created. The constraint list will be reviewed and approved by the TWG before being applied to the models. Making use of the economic data from the 2013 ITP20, an economic DC tool will commit units and create a dispatch to deliver the most economical power around the constraints approved by the TWG. This unit commitment and dispatch will be the SCUC/SCED that will be applied to the power flow model which will be used to complete the N-1 contingency analysis described in Part A of the Analysis section. The security constrained economic dispatch in the CBA will be applied to the SPP footprint only. The rest of the Eastern Interconnect remained unchanged.

F. *Demand Response*

Demand response will be incorporated into the models through lower load and capacity forecasts, which is developed in Subsection A above.

Analysis

A. Steady state assessment

The steady state assessment will use the following models: 2014 light load and summer peak, 2015 summer peak, 2019 summer peak and light load using individual BA dispatch. Staff will also use consolidated Balancing Authority models of these same seasons. An N-1 contingency analysis will be conducted for the peak and off-peak cases for facilities 60 kV and above in SPP and facilities 100 kV above in first-tier. All facilities 60 kV and above in SPP and 100 kV and above in first-tier will be monitored for this analysis in consideration of 60 kV and above solutions to the problems identified.

B. Solution development

SPP will use a pool of possible solutions to evaluate upgrades used to create the 2014 ITPNT plan. This pool of solutions will come from SPP transmission service studies, generation interconnection studies, previous ITP studies, local reliability planning studies by TOs, Attachment AQ studies, stakeholder input and staff evaluation.

C. Shunt reactive requirements assessment

If any 300 kV and above upgrades are identified as solutions and presented in the 2014 ITPNT Project Plan, line-end reactive requirements analysis will be performed for the new transmission lines greater than 300 kV system. This analysis will be performed on the 2019 light load models by opening each end of the new line to identify preliminary shunt reactive needs. The analysis will provide the amount of MVAR needed to maintain both 1.05 and 1.1 p.u. voltage at both ends of each new line identified. After performing the light load analysis, the reactor will be studied under steady state summer peak conditions to determine if switched capability is needed. This analysis will provide an indicative amount of reactor needs before design level studies are completed. This analysis will be completed with the entire 2014 ITPNT Project Plan included in the model.

D. Load pocket analysis

SPP will perform voltage stability analysis for 6 load pockets as part of the 2014 ITPNT Assessment. These areas include: Central Nebraska, South Oklahoma, South Central Westar, Northeast Westar, Oklahoma City, and Lincoln/Omaha.

Contingencies used for the stability analysis will be developed by determining the single worst generator unit outage within the load area. This identified generator outage will paired with all transmission line outages within the load area. By pairing the largest generator outage with each transmission line outage, the largest amount of voltage instability will occur in the load pocket.

Methodology to test the load pockets for voltage collapse will begin by increasing the amount of load within the load pocket. Simultaneously, a power transfer sending power from adjacent areas to the load pocket will be simulated. The load and power transfer will increase until voltage collapse occurs within the load pocket. This simulation will be tested under system intact conditions as well as the previously identified contingency conditions on the 2014 ITPNT 2019 summer peak models. The simulation will be run with the 2014 ITPNT proposed upgrades included in the models to determine voltage stability of each load pocket with the 2014 ITPNT portfolio.

E. Final reliability assessment

After all upgrades have been identified and incorporated into the power flow models, a steady state N-1 contingency analysis will be conducted to identify any new issues.

Seams

In the development of 2014 ITPNT, Staff will review expansion plans of neighboring utilities and Regional Transmission Organizations (RTOs) and include first-tier party's planned projects in the 2014 ITPNT models. Based upon that review, Staff may take into account other external plans. The models used in the 2014 ITPNT incorporate the latest data from the neighboring utilities and RTOs through the MMWG model development process.

Potential impacts of the 2014 ITPNT on neighboring systems will be considered. Coordination is done in accordance with existing Seams agreements. For those without an explicit agreement, those neighbors will be contacted in order to discuss the potential impacts of the ITP on their systems.

Study Process

1. The resource additions and retirements, load profiles, and transmission service inclusion processes will be developed through stakeholder reviews.

2. The TWG/MDWG will oversee the development of the models that incorporate the assumptions developed in step #1 above, including review of data and results. A model review will be conducted by MDWG to verify the models before analysis proceeds.

3. An initial steady state analysis will be performed using applicable planning standards on power flow models that represent the applicable load profiles and generation dispatch per year and season. The assessment will be for the horizon years 1-6. Within SPP all facilities 60 kV and above in the models will be monitored and within the first-tier for all facilities 100 kV and above will be monitored in this analysis as a means to determine 60 kV and above solutions in the SPP footprint.

4. With input from stakeholders, 60 kV and above solutions will be developed to mitigate potential criteria violations. Solutions will be coordinated with the Aggregate (AG) and Generation Interconnection (GI) Study processes for the SPP transmission system footprint. An NTC will not be automatically issued for a potential violation identified in the CBA scenario models.

    a. Since 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 violations. For the purpose of this study, the 2014 ITPNT will identify all solutions where the use of TOGs is deemed not effective.

    b. A check will be performed to determine if projects identified in the ITP20 or ITP10 assessments will eliminate or defer any projects identified in the 2014 ITPNT.

5. A follow-up analysis will be performed repeating the steps above on the identified solutions to validate the solutions and check for potential violations that may have been created.

6. Load pocket analysis will be performed on the final portfolio of upgrades for the specified load pockets.

7. Stability analysis will be performed on the final portfolio of upgrades.

Timeline

The study will begin in January 2013 with final results complete by January 2014. The estimated study timeline is as follows:

	Group to review/endorse	Start Date	Completion Date
Scoping	TWG	November 2012	January 2013
Model Development (S0, S5)	TWG	February 2013	May 2013
Model Development (CBA)*	TWG	April 2013	August 2013
Reliability Assessment (S0, S5)	TWG	June 2013	
Reliability Assessment (CBA)	TWG	September 2013	
Solution Development	TWG	June 2013	December 2013
Load Pocket Assessment	TWG	August 2013	December 2013
Stability Assessment	TWG	August 2013	December 2013
Final Reliability Assessment	TWG	December 2013	
Review report	TWG	November 2013	November 2013
Final report with recommended plan	TWG	December2013	January2014
	MOPC/BOD	January 2014	

*Note: Model Development for the CBA Scenario includes TWG review of constraints to be used in the models

Staff plans to hold stakeholder planning summits at least twice during the 2013 calendar but may hold more as appropriate.

Deliverables

The results from the 2014 ITPNT, which define a set of transmission upgrades needed to meet the near-term needs of the system, will be compiled into a report detailing the findings and recommendations of SPP Staff.

Changes in Process and Assumptions

In order to protect against changes in process and assumptions that could present a significant risk to the completion of the ITPNT, any such changes must be vetted. If TWG votes on any process steps or assumptions to be used in the study, those assumptions will be used for the 2014 ITPNT. Changes to process or assumptions recommended by stakeholders must be approved by the TWG. This process will allow for changes if they are deemed necessary and critical to the ITP, while also ensuring that changes, and the risks and benefits of those changes, will be fully vetted and discussed.

Section 9: Appendix III

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 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**
Southwestern Public Service Company	Buffalo Dunes 2 Wind	101	1/1/2014
Southwestern Public Service Company	DeWind Little Pringle I	10	In-Service
Southwestern Public Service Company	DeWind Little Pringle II	10	In-Service
Southwestern Public Service Company	Channing Wind	4.2	In-Service
Southwestern Public Service Company	High Majestic II Wind	79.5	In-Service
Southwestern Public Service Company	GSEC Mustang Unit #6	165	In-Service
Southwestern Public Service Company	Wildcat Wind	27.3	In-Service
Sunflower Electric Power Corporation	Rubart	108	In-Service
Sunflower Electric Power Corporation	Greenburg WF	21.9	6/1/2014

Table 1

In the ITPNT 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 2.

Generation Capacity without an Executed Transmission Service Agreement			
Model Area	**Plant Name**	**Net Summer Capacity (MW)**	**In-Service Date**
Southwestern Public Service Company	Antelope CT	180	6/1/2012
Southwestern Public Service Company	Jones #4	180	6/1/2013
Westar Energy	Flat Ridge II Wind	300	6/1/2013
Midwest	Post Rock Wind	201	6/1/2013

Table 2

To address the generation deficiencies, existing IPP generation was also modeled and dispatched to serve load as represented in Table 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	Oneta Energy Center	310
American Electric Power	Eastman Cogeneration Facility	485
American Electric Power	Harrison County Power Project	262
KCP&L Greater Missouri Operations Company	Dogwood	430

Table 3

*Based on available capacity less confirmed long-term firm transmission service.

Section 10: Appendix IV

ITPNT

2014 Integrated Transmission Plan Near-Term Stability Analysis

December 18, 2013

SPP Engineering

Southwest Power Pool

Revision History

Date	Author	Change Description
12/10/2013	SPP Staff	Initial Draft
12/18/2013	SPP Staff	TWG Approval

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Section 1: **Overview**

1.1: Introduction

ITPNT solutions will be assessed for reliability by examining thermal and voltage performance. Thermal and voltage performance are normally assessed through the tools of steady state contingency analysis; however, this analysis does not determine the distance to and location of voltage collapse or voltage instability. This must be determined by examining voltage performance during power transfer into a load area or across an interface. This document provides the methods of study as well as the results of these assessments for the ITPNT upgrade case.

1.2: Background

Voltage stability is defined as a power system's ability to control voltages following a large disturbance such as a fault or contingency. Voltage stability requires that system voltage characteristics be maintained during periods of high load, large power transfers, or sudden disturbances such as a loss of a generator and/or transmission line.

Voltage stability analysis was performed using Voltage Security Assessment Tool (VSAT). This tool is part of Powertech Labs, Inc.'s Dynamic Security Assessment (DSA) Tools.

1.3: Objective

The objective of the ITP Near-Term Stability Analysis is to determine voltage stability limitations and reactive reserve within high load areas in the SPP footprint. This analysis will be assessed using the ITPNT Upgrade 2019 Summer Peak Cases.

1.4: Load Area Analysis

A total of six load areas, or "pockets" were selected and prioritized for the ITPNT voltage stability analysis. These load areas are listed below. Analysis was performed by increasing load within the load pocket while increasing transfer to the load area from adjacent areas. The transfer was increased while under contingency until voltage collapse occurred on the transmission system inside the load area. This provides a load area increase limit as well as the amount of reactive reserve available at the collapse point.

Priority	Load Area
1	Central Nebraska
2	Lincoln/Omaha
3	South Oklahoma
4	Oklahoma City
5	South Central Westar
6	North East Westar

Table 1.1: Prioritized Load Areas

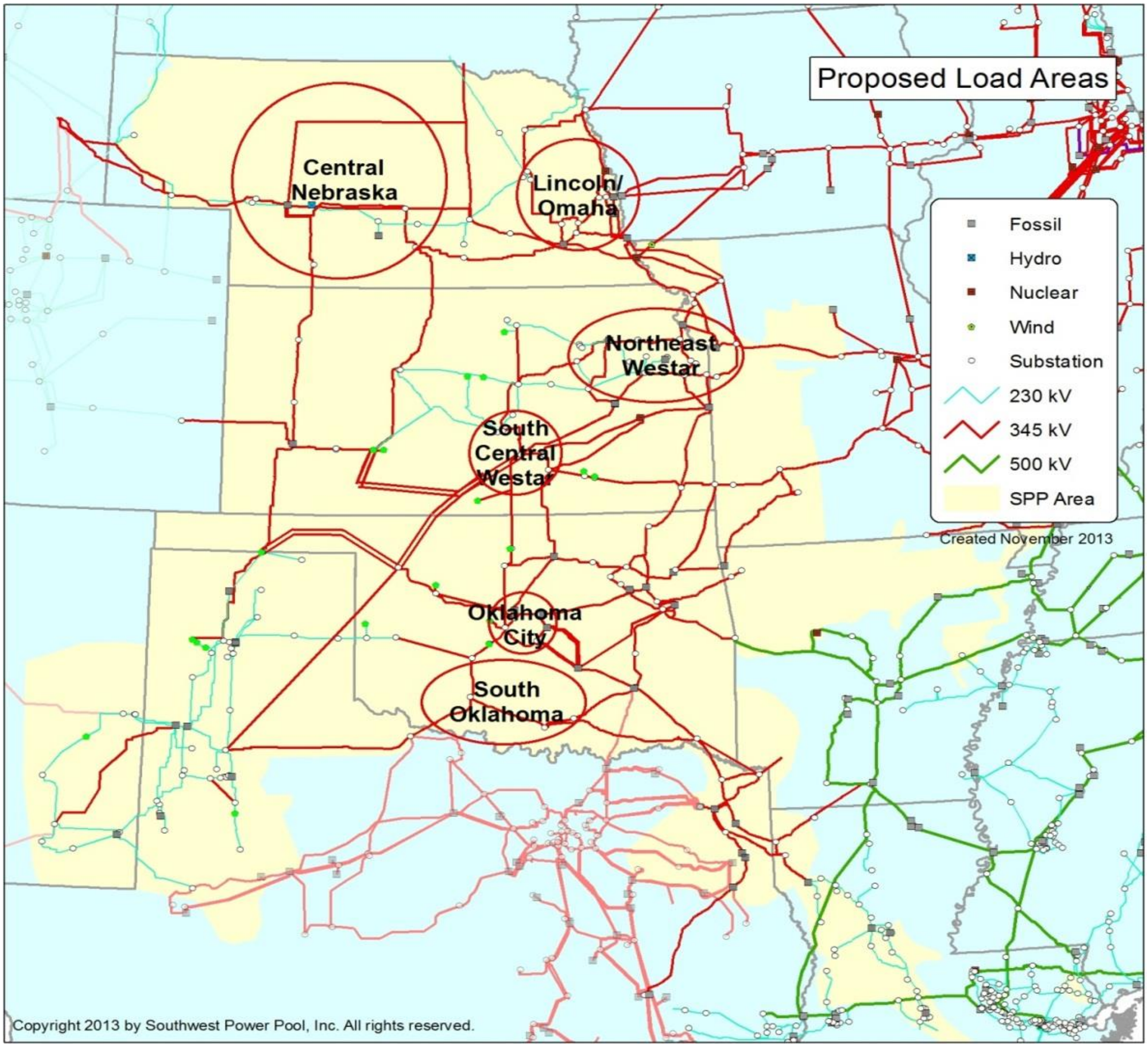

Figure 1.1: Load Areas for Analysis

The contingencies consist of a selected single generation outage (G-1) with all branch outages (T-1), or one generator and one transmission branch within the load area removed from service. More specifically:

The selected G-1 outage is the generator within the load area that, when compared to others within the load area, causes the highest degree of voltage instability stress during the transfer. This generator was paired with all T-1 contingencies, which consisted of all branches greater than 100 kV within the load area.

Section 2: **South Oklahoma**

2.1: Load Area

The South Oklahoma load area under this study is defined by the following zones:

Area	Zone
520 AEPW	533 WTU
	549 PSO Western
525 WFEC	589 AEP CS
	590 AEP KP
	591 FLA
	592 AEP IM-I

Table 2.1: South Oklahoma Load Area

2.2: Summary

Load area analysis was performed by importing generation into the South Oklahoma load area and increasing both real and reactive load in proportion to the initial MW output of each source generator for the Upgrade Case. The 69 kV loads were equivalenced to the 138 kV system buses in the load zones.

Table 2.2 provides the simulation results. These results indicate that voltage instability occurs on the 138kV transmission system subsequent to a load increase of 761 MW.

Load Margin: 751 MW

Case Used	**2019S ITPNT Upgrade Case**
Generation Source	Areas 351,502,503,523,526,531, 534,541,542,640,645,650,652
Initial Source (MW)	47278
Load Area	Zones 533,549,589,590,591,592
Initial Load Area (MW)	1,712
Load at Voltage Collapse (MW)	2,473
Limiting Contingency	A101: G-1: SWS3 24.0 1 out T-1: Anadarko -Georgia 138 out
MVar Reserve at Voltage Collapse	Zone PSO: 58 MVar Zone FLA: 206 MVar Zone AEP-CS: 141 MVar

Table 2.2: South Oklahoma Load Area Results

2.3: Voltage Instability

The table and figure below show the 138kV buses that have the highest participation in the collapse.

	2019 NT Upgrade Case			
	Bus No.	**Bus Name**	**kV**	**Zone**
1	520923	GEORGIA4	138	525
2	520912	FLETCH-4	138	525
3	520900	EMPIRE-4	138	525
4	520864	COMANCH4	138	525

Table 2.3: South Oklahoma Load Area Buses Experiencing Voltage Collapse

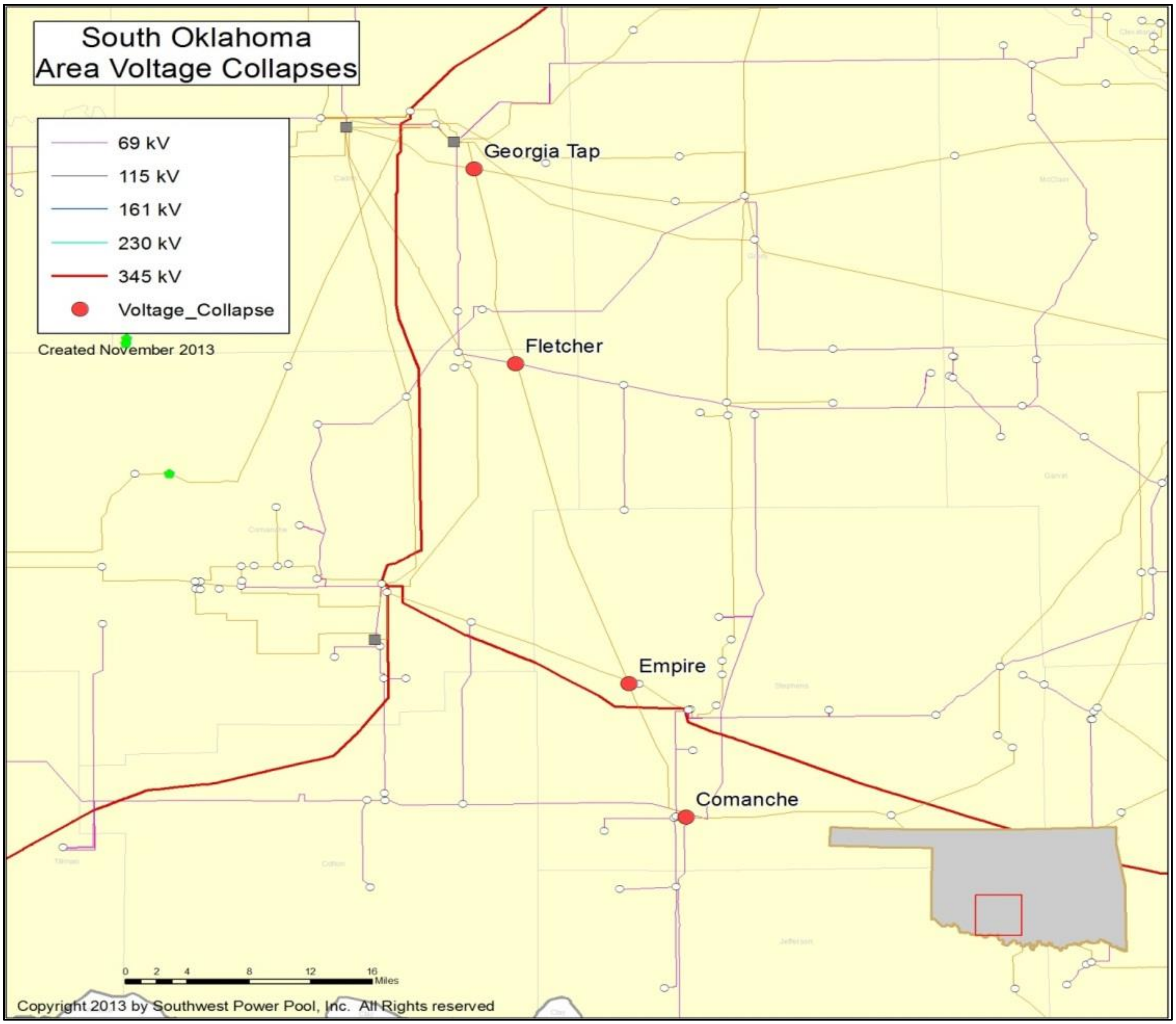

Figure 2.1: South Oklahoma Load Area Buses Experiencing Voltage Collapse

The P-V curves below are provided for the 138kV buses in table 2.3 above for the limiting contingency shown in table 2.2. These curves indicate that when the load is proportionally increased in the South Oklahoma area, voltage collapses occur. The last point shown is the point of voltage collapse.

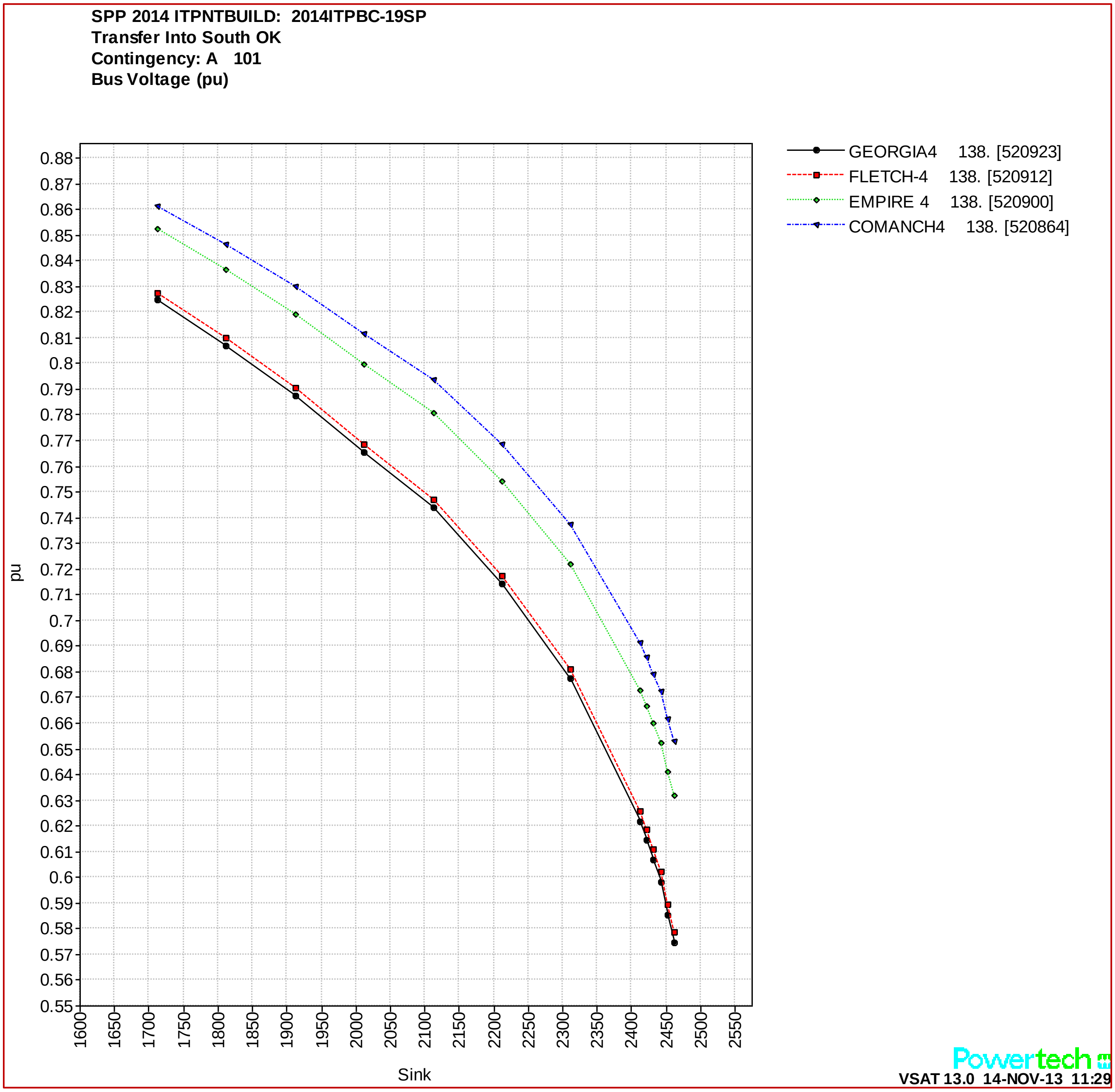

Figure 2.2: South Oklahoma Load Area PV Curves for Upgrade Case

2.4: MVar Reserve

The figure below shows the MVar reserve remaining in each zone of the load pocket at the collapse point for the limiting contingency for the Upgrade Case. The remaining three zones have no generation.

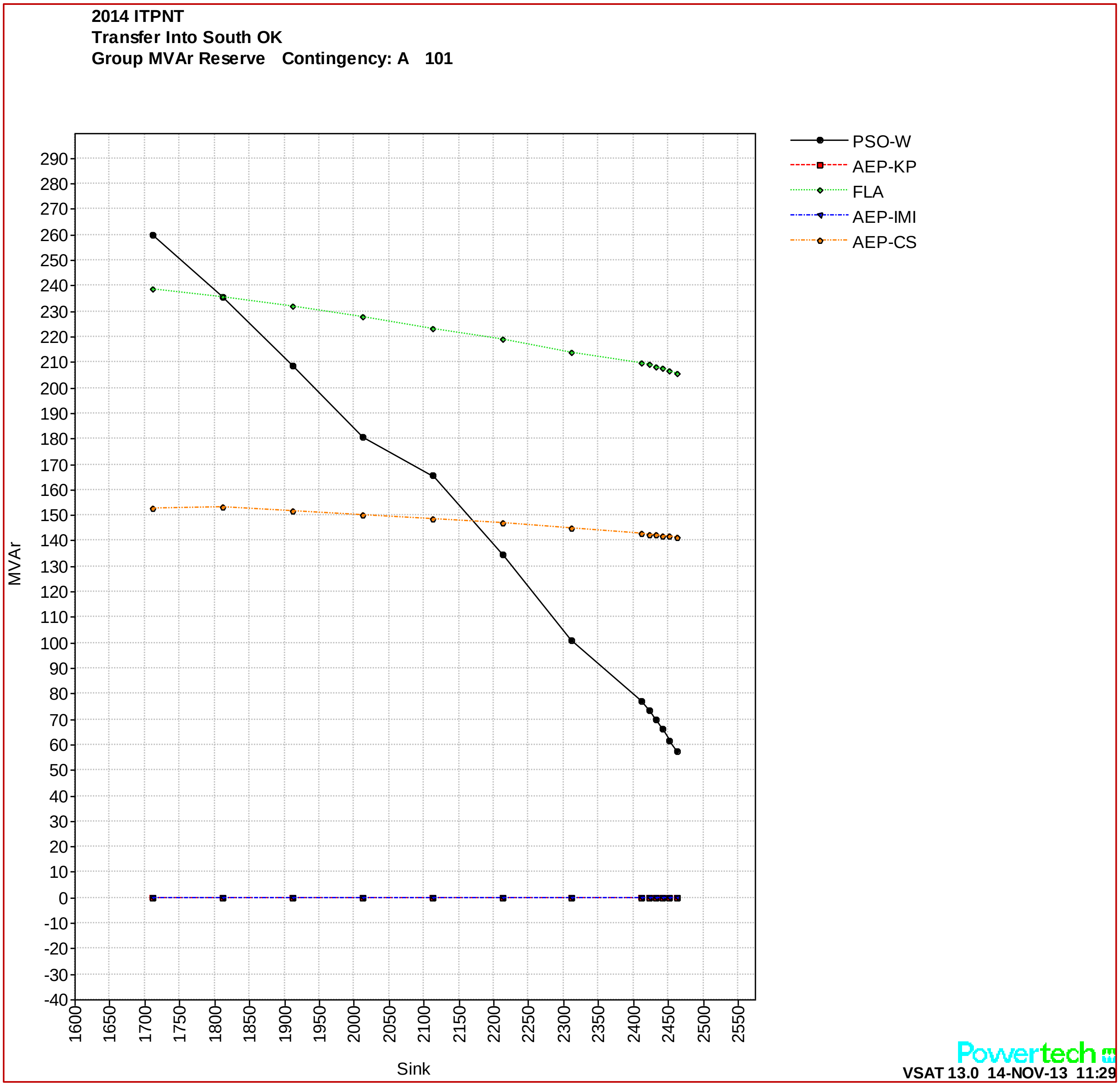

Figure 2.3: South Oklahoma Load Area MVar Reserve

Section 3: **Oklahoma City**

3.1: Load Area

The Oklahoma City, OK load area under this study is defined by the following zones:

Area	Zone
524 OKGE	569
	572

Table 3.1: Oklahoma City Load Area

3.2: Summary

Load area analysis was performed by importing generation into Oklahoma City in OKGE while increasing both real and reactive load in proportion to the initial MW output of each source generator for the Upgrade Case. The 69 kV load in zones 569 and 572 were equivalenced to the 138 kV system buses.

Table 3.2 provides the simulation results. These results indicate that voltage instability occurs on the 138kV transmission system subsequent to a load increase of 2,450 MW.

Load Margin: 2,440 MW

Case Used	**2019 ITPNT Upgrade Case**
Generation Source	536, 541, 635, 640 (exclude Wolf Creek)
Initial Source (MW)	19,271
Load Area	Zone 569, and 572
Initial Reduced Load Area (MW)	3,463
Load at Voltage Collapse (MW)	5,913
Limiting Contingencies	A 6: G-1: HSL 8G T-1: NORTWST7 - SPRNGCK7 Ckt. 1, 345 kV
MVar Reserve at Voltage Collapse	Zone 569: 434 MVar Area 524: 74 MVar

Table 3.2: Oklahoma City Load Area Results

3.3: Voltage Instability

The table and figure below show the 138kV buses that have the highest participation in the collapse.

	2019 NT Upgrade Case			
	Bus No.	**Bus Name**	**kV**	**Area**
1	514871	PARKPL 4	138	524
2	515156	WASHPRK4	138	524
3	514875	OUMED 4	138	524
4	514870	STNWAL 4	138	524

	2019 NT Upgrade Case			
5	514874	REMNGPK4	138	524
6	514872	REMPKTP4	138	524
7	514869	WESTERN4	138	524
8	514844	BELISLE4	138	524

Table 3.3: Oklahoma City Load Area Buses Experiencing Voltage Collapse

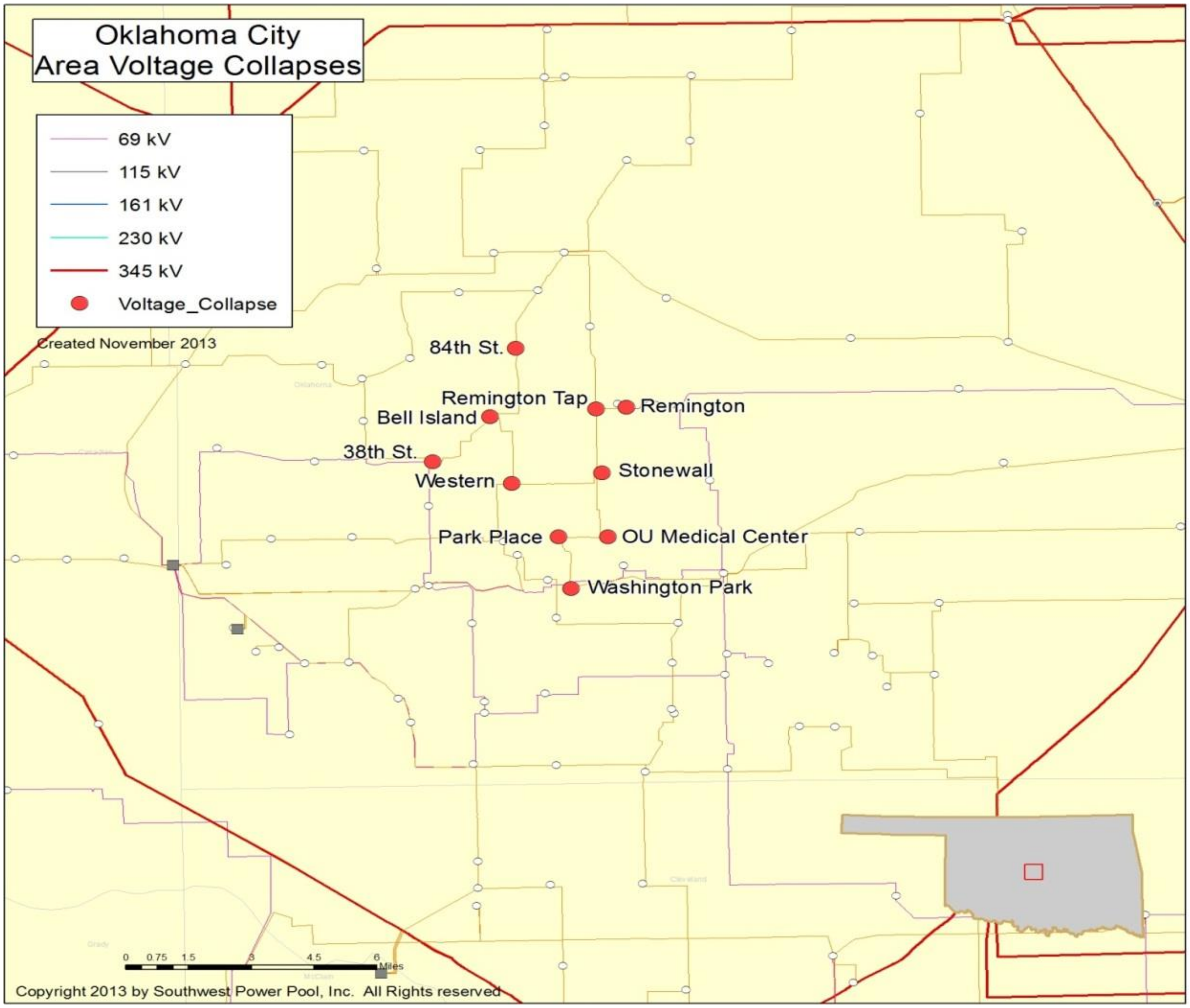

Figure 3.1: Oklahoma City Load Area Buses Experiencing Voltage Collapse

The P-V curves below are provided for the 138kV buses in table 3.3 above for the limiting contingency shown in table 3.2. These curves indicate that when the load is proportionally increased in the Oklahoma City area, voltage collapses occur. The last point shown is the point of the voltage collapse.

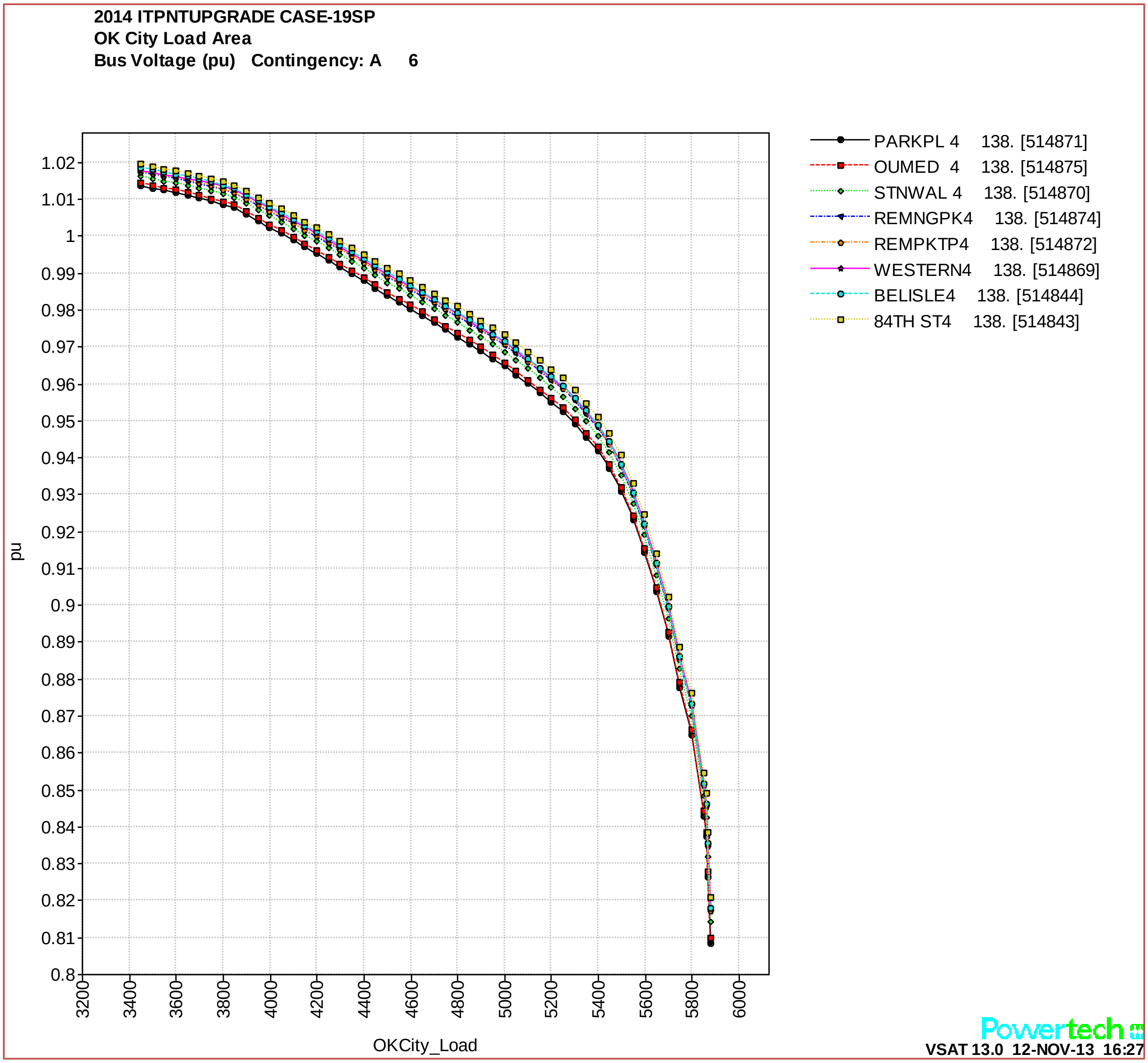

Figure 3.2: Oklahoma City Load Area PV Curves for Upgrade Case

3.4: MVar Reserve

The figure below shows the MVar reserve remaining in the load pocket at the collapse point for the limiting contingency in the Upgrade Case.

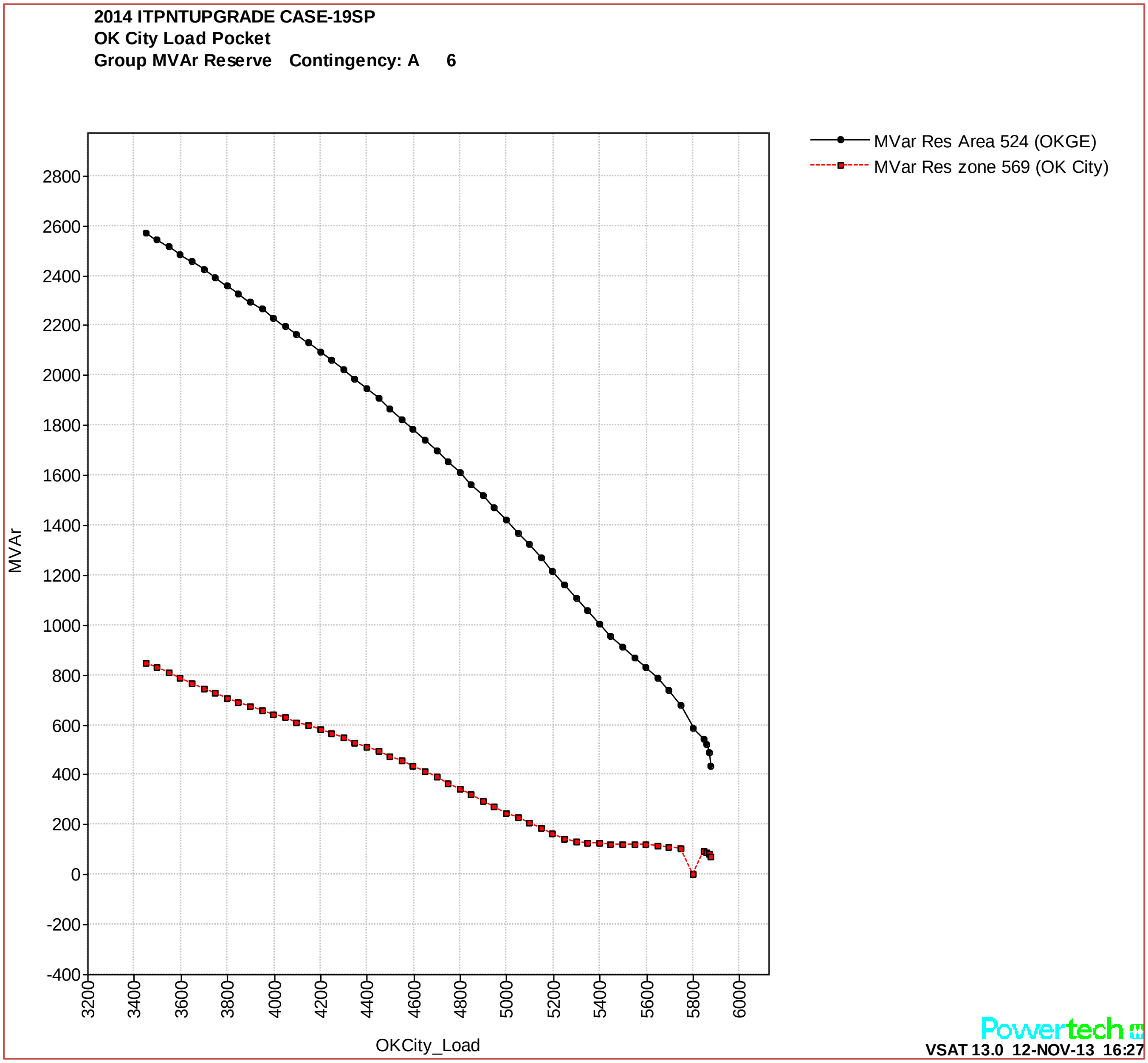

Figure 3.3: Oklahoma City Load Area MVar Reserve Upgrade Case

Section 4: **South Central Westar**

4.1: Load Area

The South Central Westar Wichita, KS load area under this study is defined by the following zone:

Area	Zone
536 WERE	1537 South Central

Table 4.1: Wichita Load Area

4.2: Summary

Load area analysis was performed by importing generation into the Wichita area in South Central Westar while increasing both real and reactive load in proportion to the initial MW output of each source generator in the Upgrade Case.

Table 4.2 provides the simulation results. The 69 kV load in zone 1537 is equivalenced to the 138 kV system buses. These results indicate that voltage instability occurs on the 138kV transmission system subsequent to a load increase of 1,900 MW.

Load Margin: 1,890 MW

Case Used	**2019 ITPNT Upgrade Case**
Generation Source	524, 534, 536, 541 (Excluding Zone 1537 and Wolf Creek)
Initial Source (MW)	17,341
Load Area	Zone 1537 (Wichita)
Initial Reduced Load Area (MW)	2,103
Load at Voltage Collapse (MW)	4003
Limiting Contingencies	B 1 : G-1: Gordon Evans U2 (367 MW) T-2: Rose Hill – Wolf Creek 345 kV Benton – Wolf Creek 345 kV
MVar Reserve at Voltage Collapse for Zone 1537	0 MVar

Table 4.2: Wichita Load Area Results

4.3: Voltage Instability

The table and figure below show the 138kV buses that have the highest participation in the collapse.

	2019 ITPNT Upgrade Case			
	Bus No.	**Bus Name**	**kV**	**Zone**
1	533069	TCBURNS4	138	1537
2	533031	BURNSTP4	138	1537
3	533048	HARRY 4	138	1537

	2019 ITPNT Upgrade Case			
4	533027	BEECH 4	138	1537
5	533028	BEECHTP4	138	1537
6	533066	64TH 4	138	1537
7	533030	BOEING 4	138	1537
8	532987	BUTLER 4	138	1537
9	533067	SPRNGDL4	138	1537

Table 4.3: Wichita Load Area Buses Experiencing Voltage Collapse

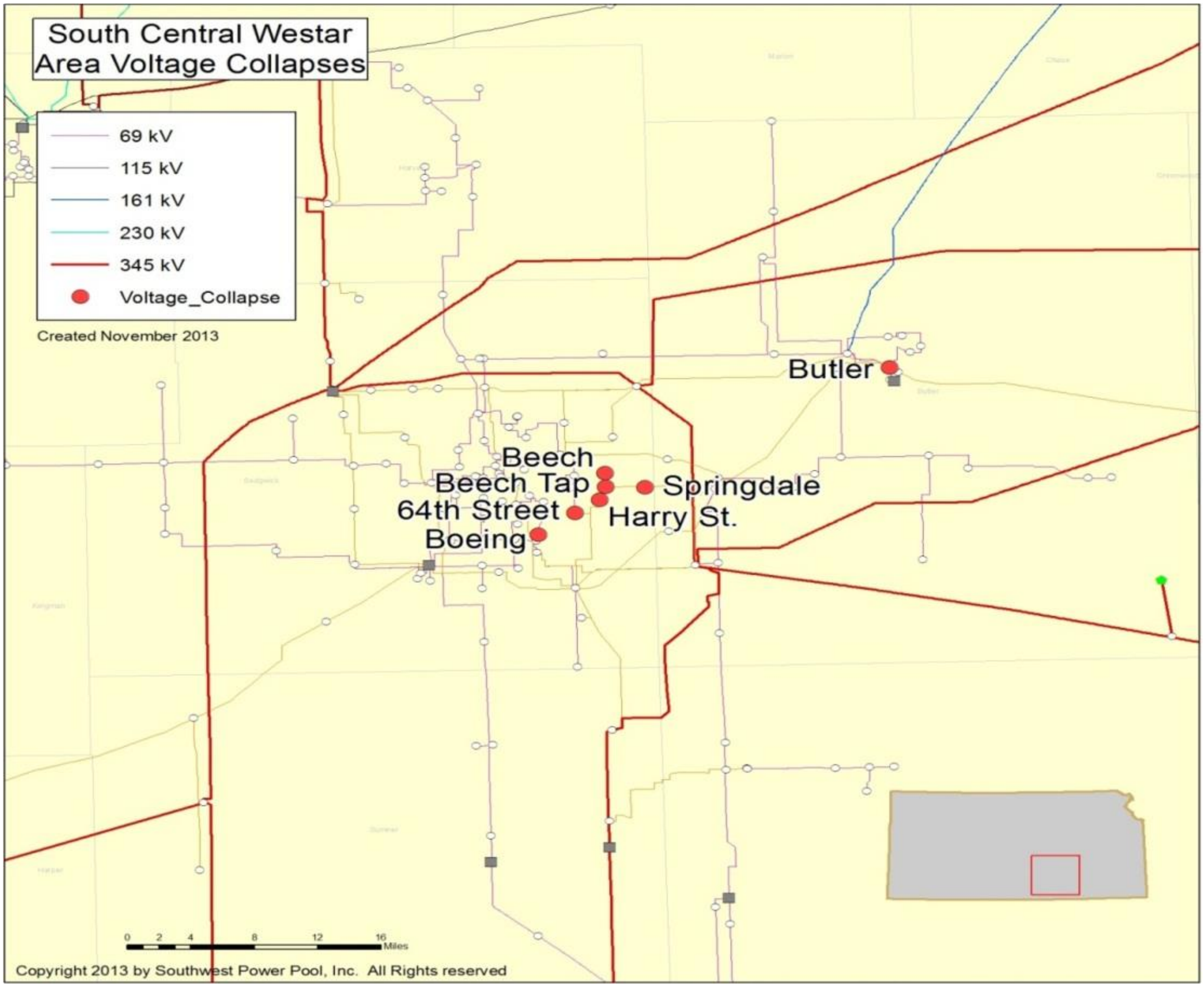

Figure 4.1: Wichita Load Area Buses Experiencing Voltage Collapse

The P-V curves are provided for the 138kV buses in table 4.3 above for the limiting contingency shown in table 4.2. These curves indicate that when the load is proportionally increased in the Wichita area, voltage collapses occur. The last point shown is the point of the voltage collapse.

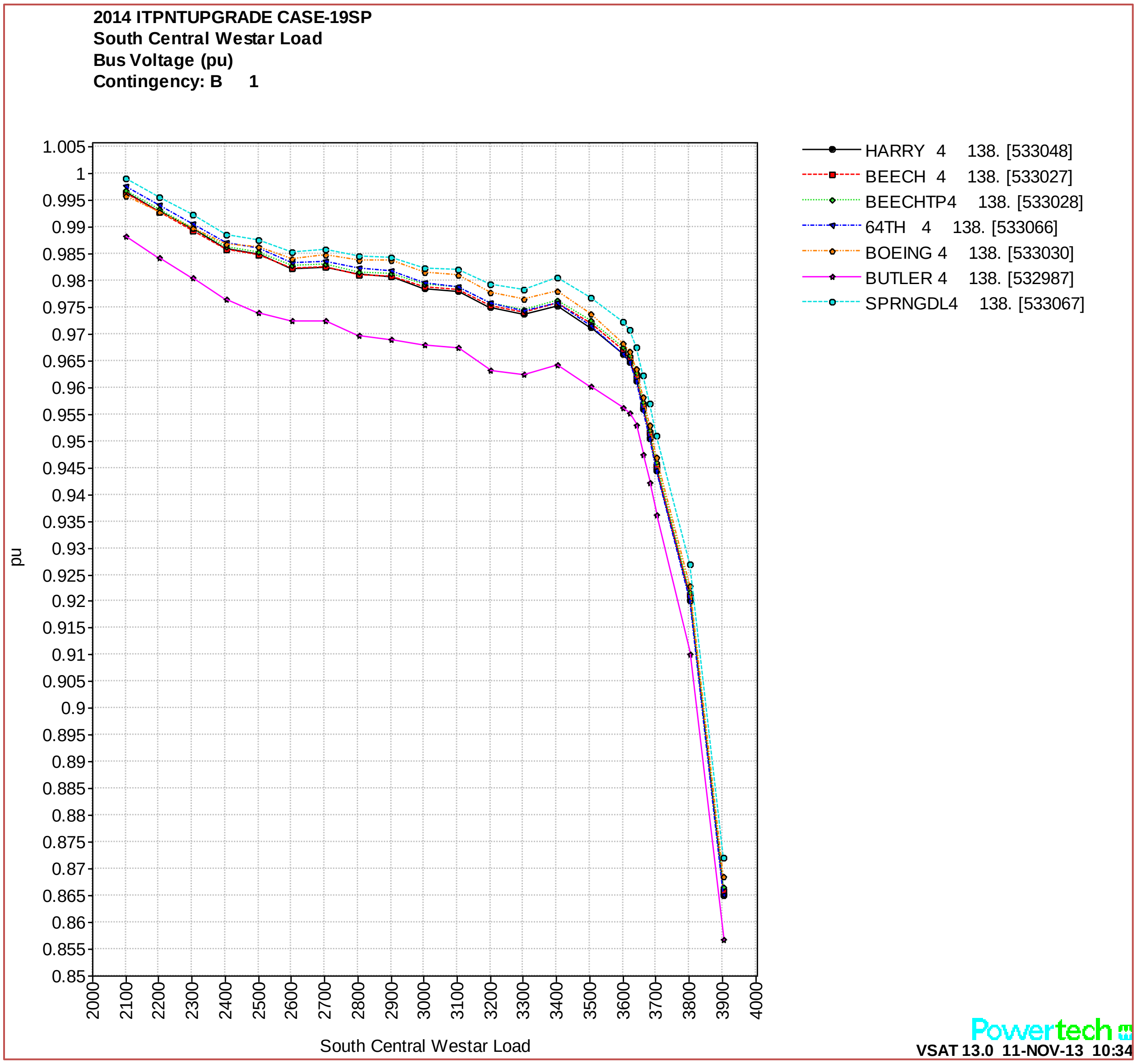

Figure 4.2: Wichita Load Area PV Curves for Upgrade Case

4.4: MVar Reserve

The figure below shows the MVar reserve remaining in the load pocket at the collapse point for the limiting contingency in the Upgrade Case.

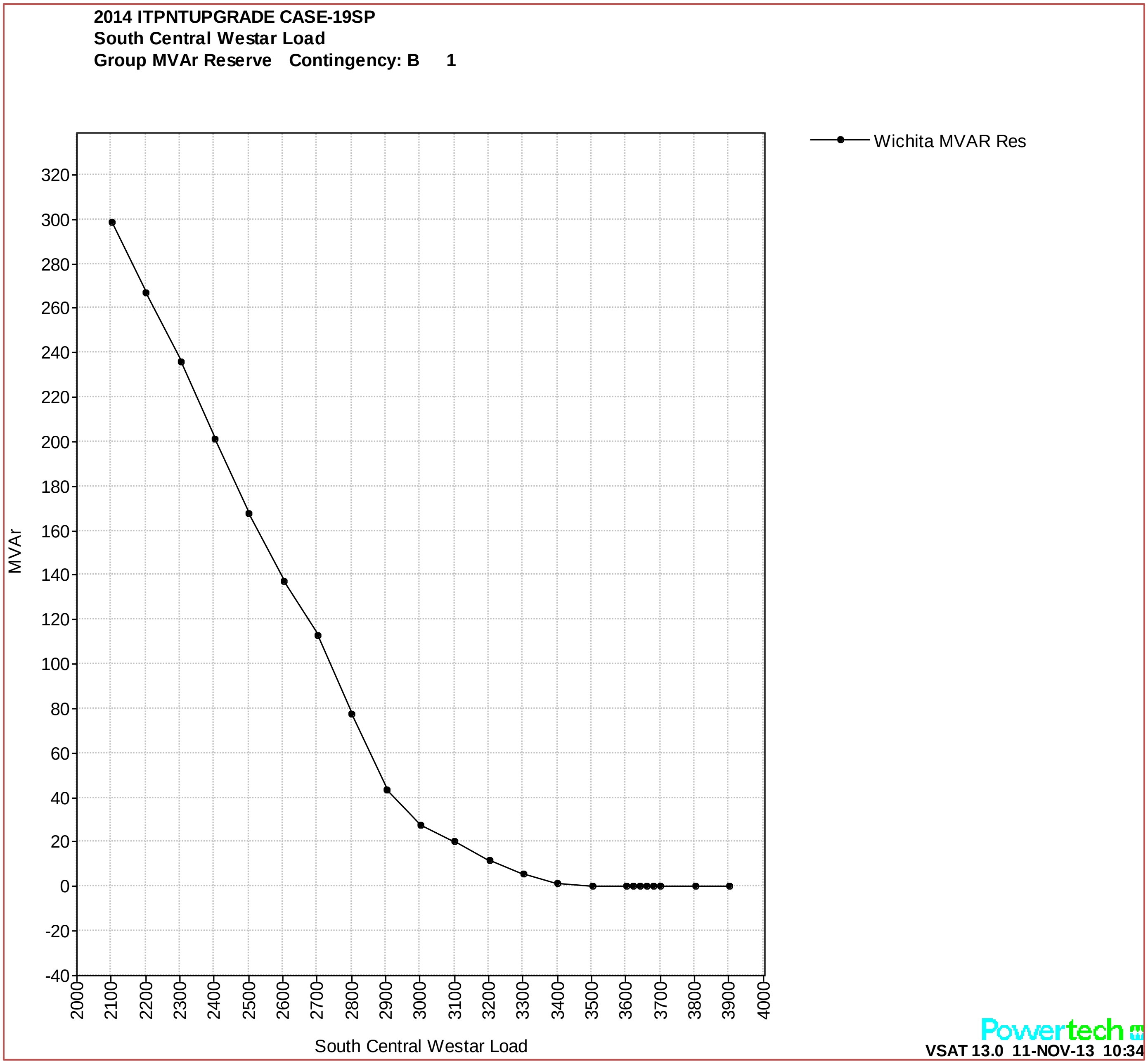

Figure 4.3: Wichita Load Area MVar Reserve

Section 5: **North East Westar**

5.1: Load Area

The North East Westar Topeka, KS load area under this study is defined by the following zone:

Area	Zone
536 WERE	1533 Topeka

Table 5.1: Topeka Load Area

5.2: Summary

Load area analysis was performed by importing generation into the into North East Westar area in Topeka, KS while increasing both real and reactive load in proportion to the initial MW output of each source generator for the Upgrade Case. The 69 kV load in zone 1533 is equivalenced to the 115 kV system buses. The 69 kV load from Rock Creek to Wathena is not scaled in this analysis.

Table 5.2 provides the simulation results. These results indicate that voltage instability occurs on the 115 kV transmission system subsequent to a load increase of 1,200 MW.

Load Margin: 1,190 MW

Case Used	**2019 ITPNT Upgrade Case**
Generation Source	524, 534, 536, 541 (Excluding Zone 1533 and Wolf Creek)
Initial Source (MW)	**15,553**
Load Area	**Zone 1533 (Topeka)**
Initial Reduced Load Area (MW)	1,507
Load at Voltage Collapse (MW)	2,707
Limiting Contingencies	A7: G-1: 1 LEC U5 T-1: HOYT 7/3 Transformer 345 kV
MVar Reserve at Voltage Collapse for Zone 1533	0 MVar

Table 5.2: Topeka Load Area Results

5.3: Voltage Instability

The table and figure below show the buses that have the highest participation in the collapse.

	2019 ITPNT Upgrade Case			
	Bus No.	**Bus Name**	**kV**	**Zone**
1	533159	4VANBUR3	115	1533
2	533175	17&FAIR3	115	1533
3	533166	INDIANH3	115	1533
4	533196	EDUCATE3	115	1533

	2019 ITPNT Upgrade Case			
5	533174	2MADISN3	115	1533
6	533168	N TYLER3	115	1533
7	533184	12&CLAY3	115	1533
8	533186	29 GAGE3	115	1533
9	533185	29EVENG3	115	1533
10	533172	QUINTON3	115	1533

Table 5.3: Topeka Load Area Buses Experiencing Voltage Collapse

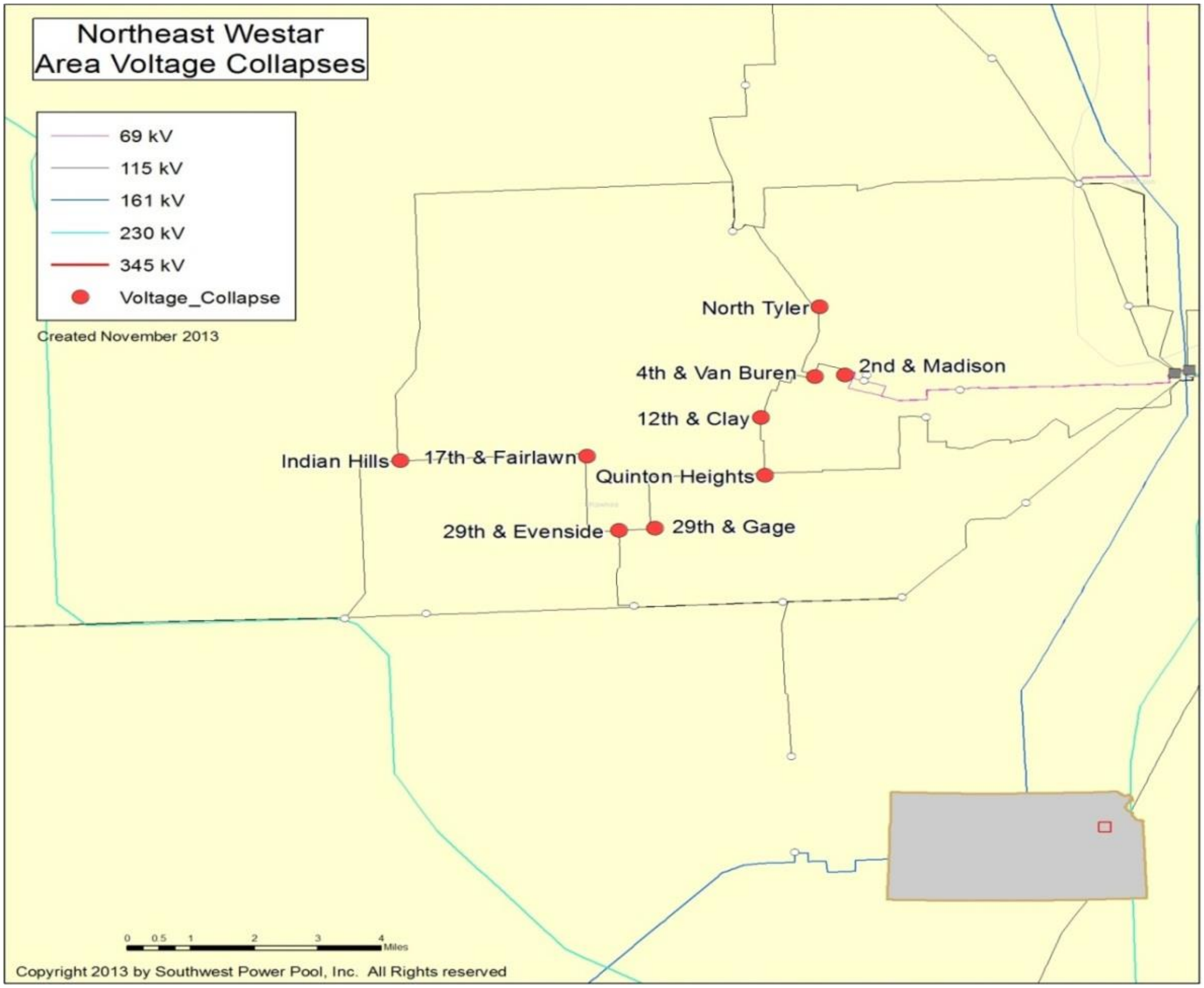

Figure 5.1: Topeka Load Area Buses Experiencing Voltage Collapse

The P-V curves are provided for the 115kV and 69kV buses in table 5.3 above for the limiting contingency shown in table 5.2. These curves indicate that when the load is proportionally increased in the Topeka area, voltage collapses occur. The last point shown is the point of the voltage collapse.

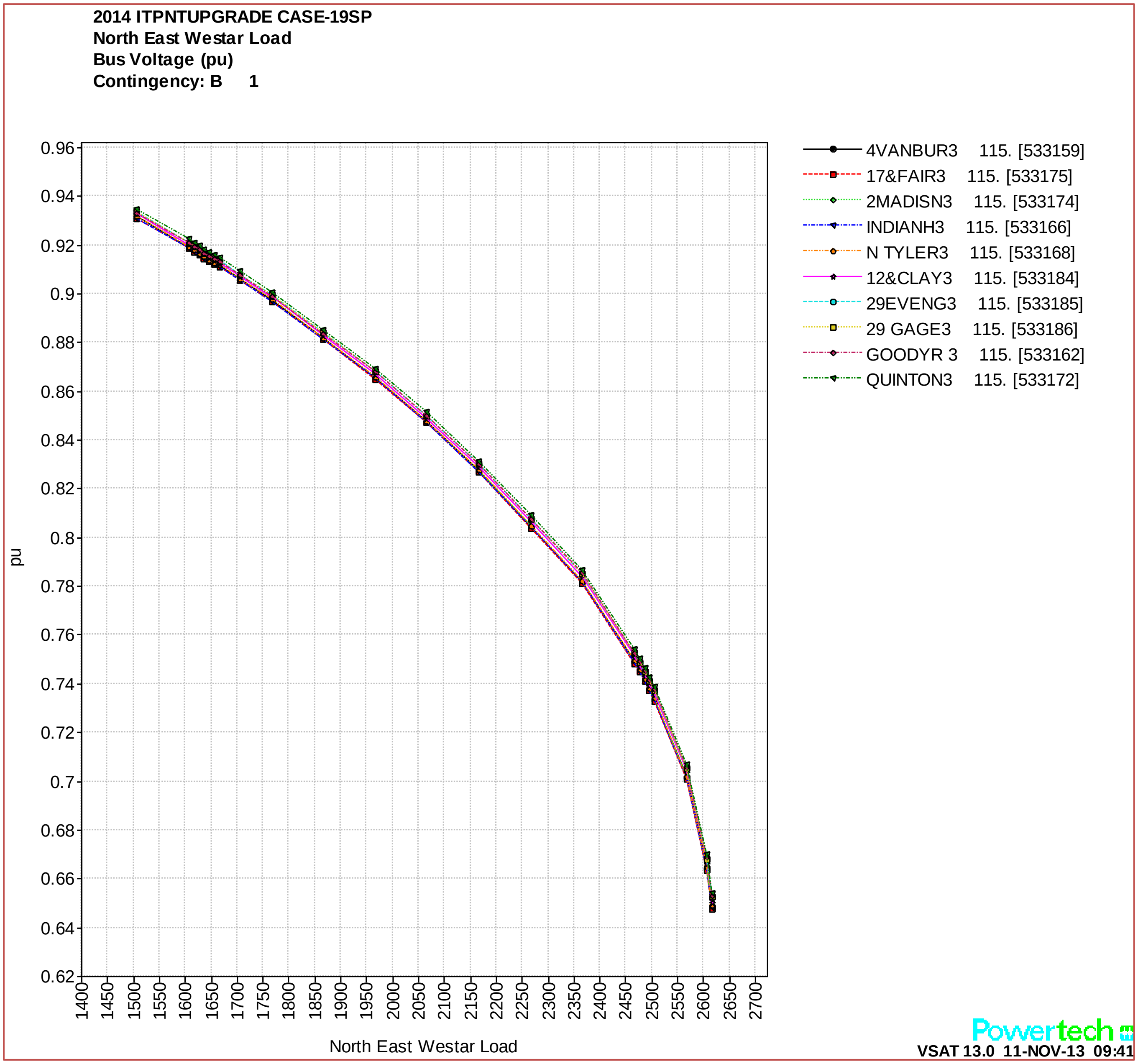

Figure 5.2: Topeka Load Area PV Curves for Upgrade Cases

5.4: MVar Reserve

The figure below shows the MVar reserve remaining in the load pocket at the collapse point for the limiting contingency for the Upgrade Case.

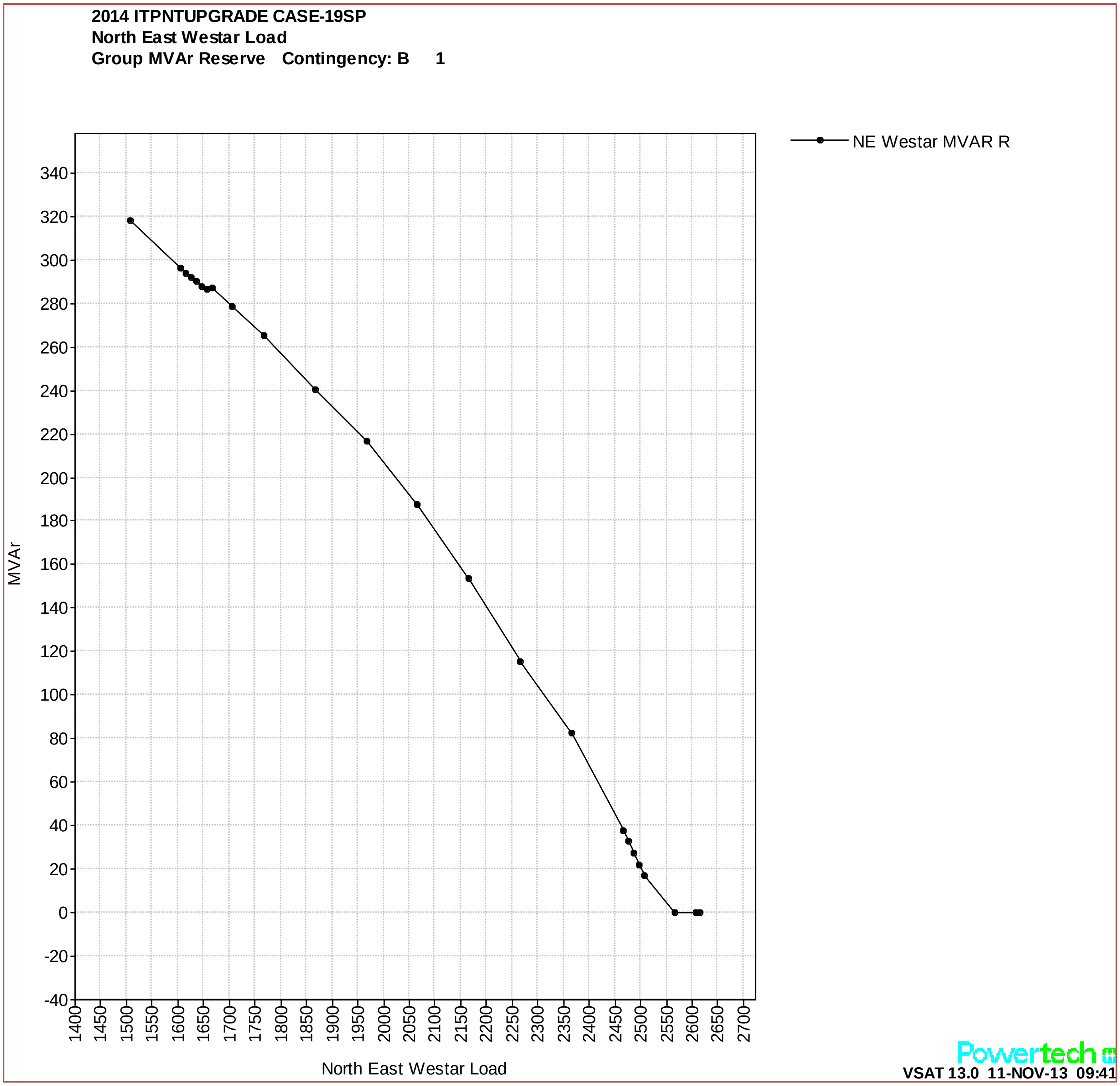

Figure 5.3: Topeka Load Area MVar Reserve

Section 6: **Lincoln/Omaha Nebraska**

6.1: Load Area

The Lincoln/Omaha, NE load area under this study is defined by the following zones:

Area	Zone
645 OPPD	All
650 LES	All

Table 6.1: Lincoln/Omaha, NE Load Area

6.2: Summary

Load area analysis was performed by importing generation into the Lincoln/Omaha, NE while increasing both real and reactive load in this load area for the Upgrade Case. The initial 2019 Summer Peak Lincoln/Omaha, NE area load is 3,728 MW. The load buses below 100 kV in areas 645 and 650 were equivalenced to the 115 kV and 161 kV system buses.

Table 6.2 provides the simulation results. These results indicate that voltage instability occurs on the 161 kV transmission system subsequent to a load pocket increase of 2,435 MW.

Load Margin: 2,435

Case Used	**2019 ITPNT Upgrade Case**
Generation Source	524, 534, 536, 541
Initial Source (MW)	**19,187**
Load Area	**645 (OPPD), 650 (LES)**
Initial Reduced Load Area (MW)	3,728
Load at Voltage Collapse (MW)	6168
Limiting Contingencies	A841: G-1: FT CAL1G T-1: S1281 5 161kV – S1287 5 161kV
MVar Reserve at Voltage Collapse for Lincoln/Omaha	18 MVar

Table 6.2: Lincoln/Omaha, NE Load Area Results

6.3: Voltage Instability

The table and figure below show the 115 kV and 161 kV that have the highest participation in the collapse for the upgrade case.

	2019 ITPNT Upgrade Case			
	Bus No.	**Bus Name**	**kV**	**Area**
1	646287	S1287 5	161	645

	2019 ITPNT Upgrade Case			
2	646214	S1214 5	161	645
3	650169	70&BLUFF 5	161	650
4	650269	70&BLUFF 7	115	650
5	650284	84FLETCHER	115	650
6	650275	84&BLUFF 7	115	650

Table 6.3: Lincoln/Omaha, NE Load Buses Experiencing Voltage Collapse

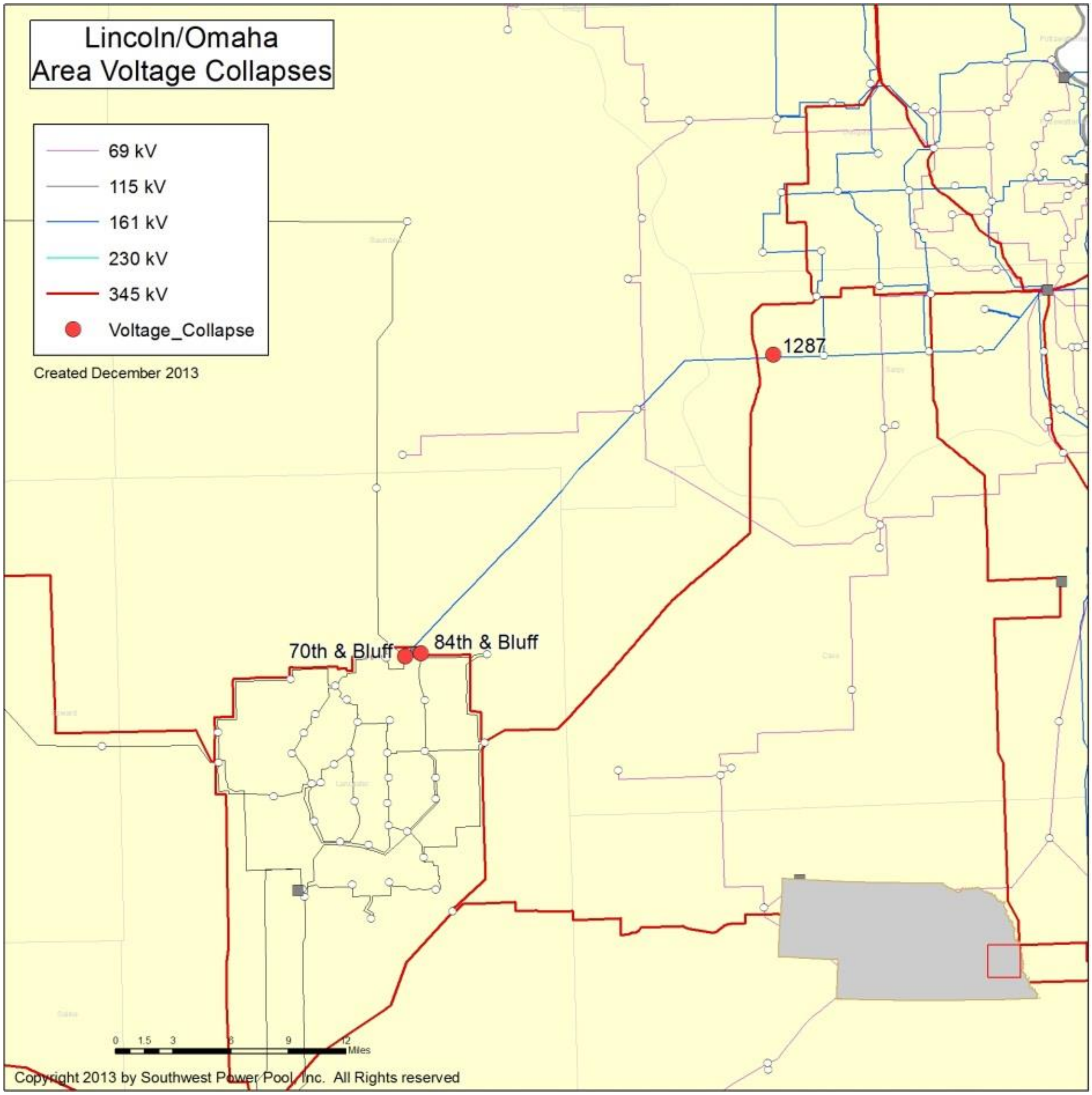

Figure 6.1: Lincoln/Omaha Load Area Buses Experiencing Voltage Collapse

The P-V curves below are provided for the 161kV & 115kV buses in table 6.3 above for the limiting contingency shown in table 6.2. These curves indicate that when the load is proportionally increased in the Lincoln – Omaha Nebraska area, voltage collapses occur. The last point shown is the point of voltage collapse.

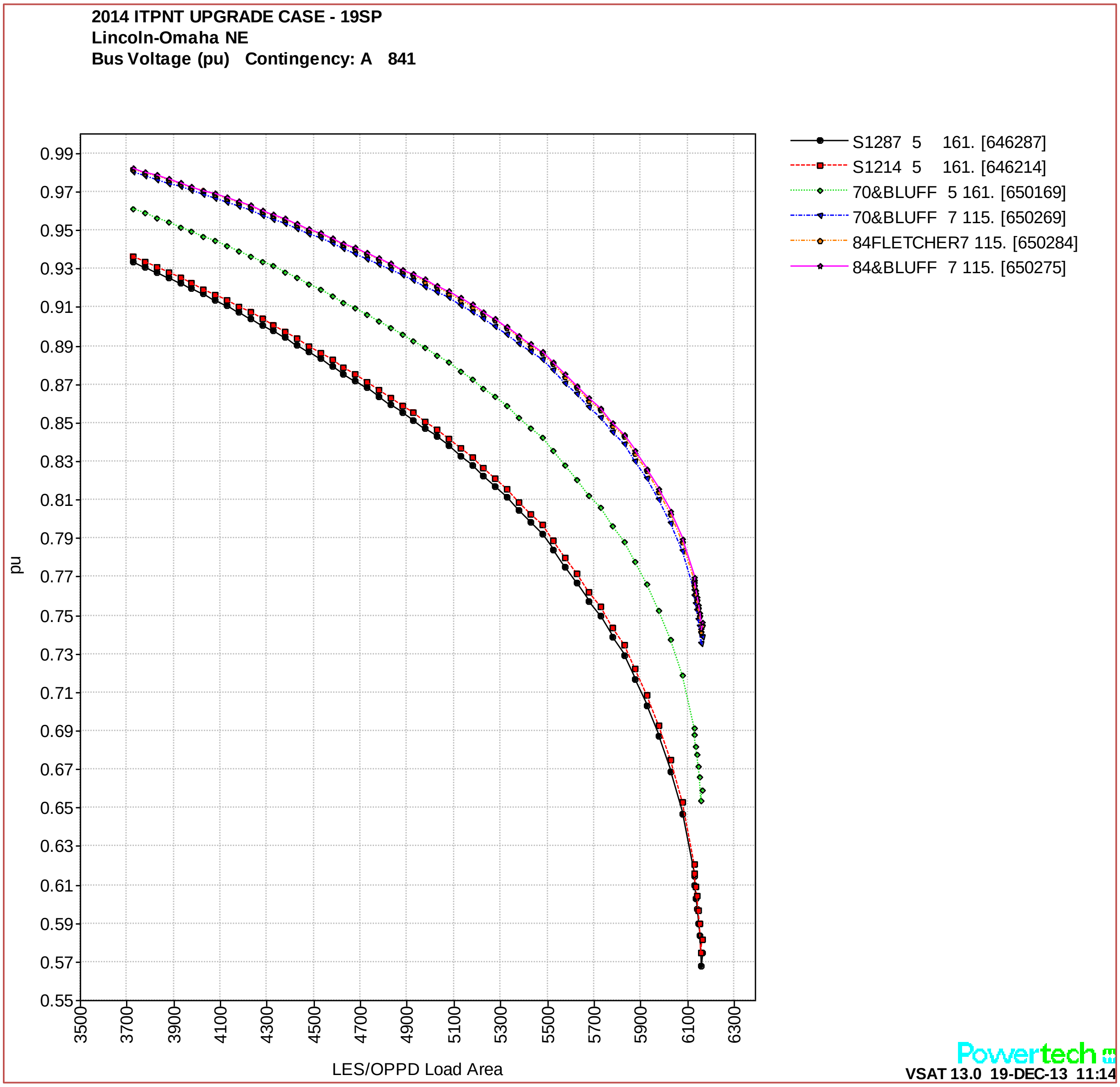

Figure 6.2: Lincoln-Omaha Load Area PV Curves for Upgrade Case (G-1, T-1 Contingency: Ft. Calhoun 1G and S1281 to S1287 161 kV)

6.4: MVar Reserve

The figure below shows the MVar reserve remaining in each zone of the load pocket at the collapse point for the limiting contingency for the Upgrade Case.

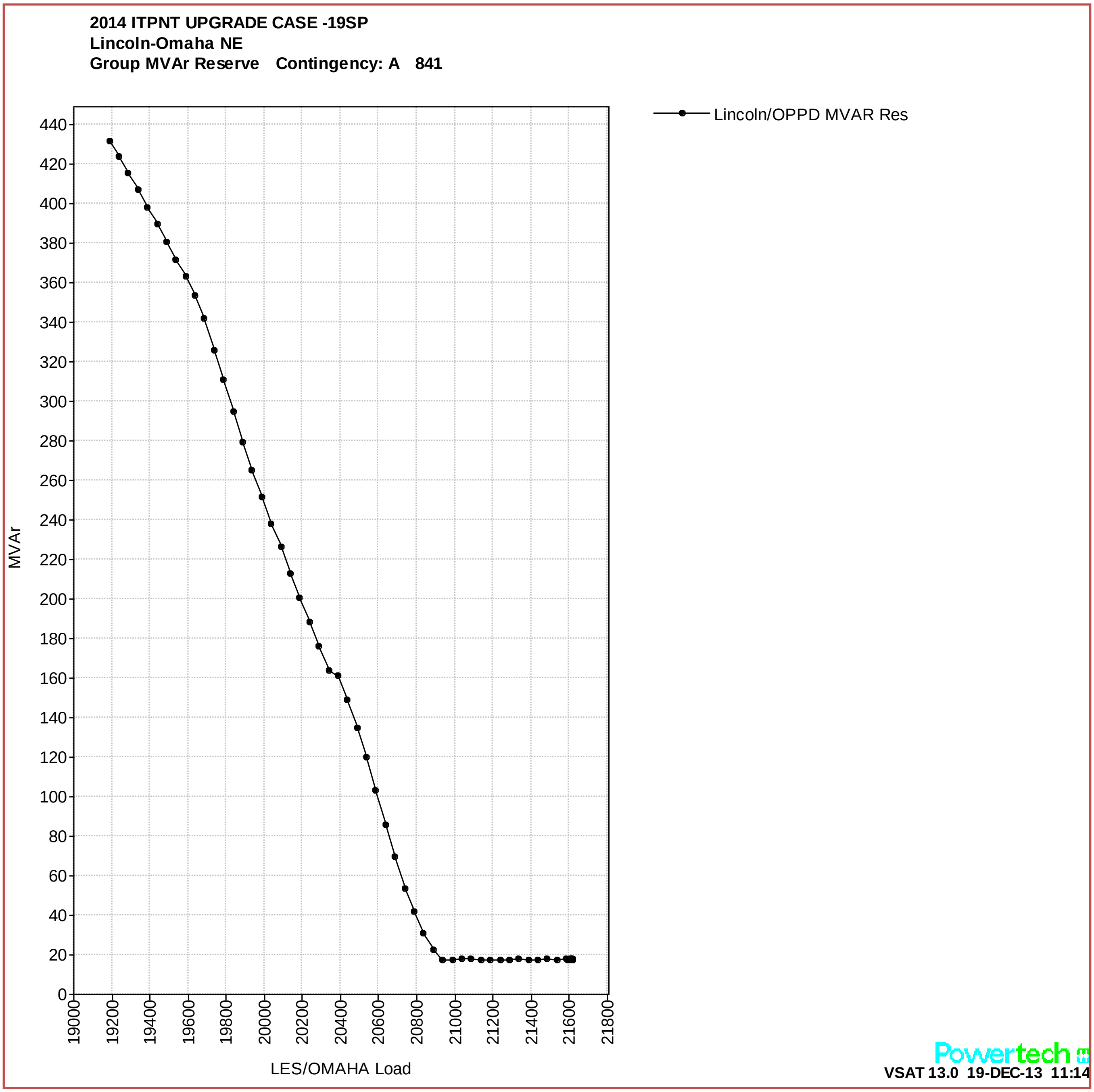

Figure 6.3: Lincoln-Omaha Load Area MVar Reserve

Section 7: **Central Nebraska**

7.1: Load Area

The Central Nebraska load area under this study is defined by the following zones:

Area	Selected Buses
640 NPPD	640052,640053,640055,640058,640073,640085,640090,640096,640099, 640113,640115,640150,640165,640177,640182,640260,640285,640294, 640295,640306,640309,640319,640348,640350,640356,640367,640382, 640393,640395,640050,640051,640054,640355,640392,640381,640349, 640318,640305,640284,640259,640181,640176

Table 7.1: Central Nebraska Load Area

7.2: Summary

Load area analysis was performed by importing generation into the Central Nebraska area while increasing both real and reactive load in this load area for both the Upgrade Case. The initial 2019 Summer Peak Central Nebraska area load is 477 MW. Voltage instability occurs on the 115kV transmission system subsequent to a load pocket increase of 120 MW.

Load Margin: 110 MW

Case Used	**2019 ITPNT Upgrade Case**
Generation Source	534,536,541,635,645,650,652
Initial Source (MW)	**27,041**
Load Area	**640052, 640053, 640055, 640058, 640073, 640085, 640090, 640096, 640099, 640113, 640115, 640150, 640165, 640177, 640182, 640260, 640285, 640294, 640295, 640306, 640309, 640319, 640348, 640350, 640356, 640367, 640382, 640393, 640395, 640050, 640051, 640054, 640355, 640392, 640381, 640349, 640318, 640305, 640284, 640259, 640181, 640176**
Initial Reduced Load Area (MW)	477
Load at Voltage Collapse (MW)	597
Limiting Contingencies	A234: G-1: GENTLM1G T-1: Fort Randall – Spencer 115 kV
MVar Reserve at Voltage Collapse for Select Buses in Area 640	0 MVar

Table 7.2: Central Nebraska Load Area Results

7.3: Voltage Instability

The table and figure below shows the 115kV buses that have the highest participation in the collapse.

	2019 ITPNT Upgrade Case			
	Bus No.	**Bus Name**	**kV**	**Area**
1	640466	EMMETE.P22	115	640
2	640058	ATKINSN7	115	640
3	640165	EMMET 7	115	640
4	640465	EMMETE.TAP 7	115	640
5	640367	STUART 7	115	640
6	640349	SPENCER7	115	640
7	640305	ONEILL 7	115	640
8	640051	AINSWRT7	115	640
9	640050	AINSWND7	115	640
10	640117	CODY 7	115	640

Table 7.3: Central Nebraska Load Area Buses Experiencing Voltage Collapse

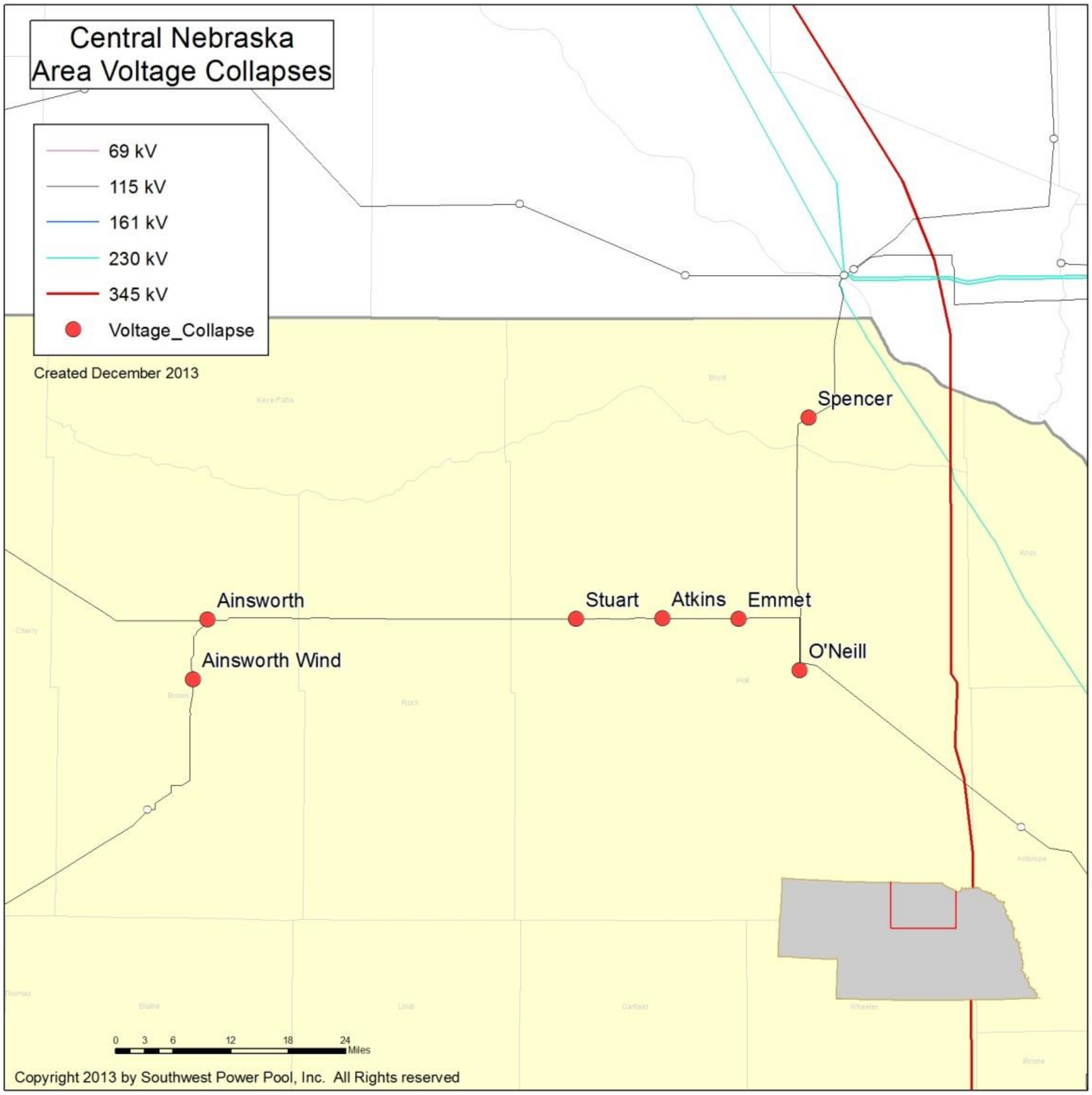

Figure 7.1: Central Nebraska Load Area Buses Experiencing Voltage Collapse

The P-V curves shown below are provided for the 115kV buses in table 7.3 above for the limiting contingency shown in table 7.2. These curves indicate that when the load is proportionally increased in the Central Nebraska area, voltage collapses occur. The last point shown is the point of the voltage collapse.

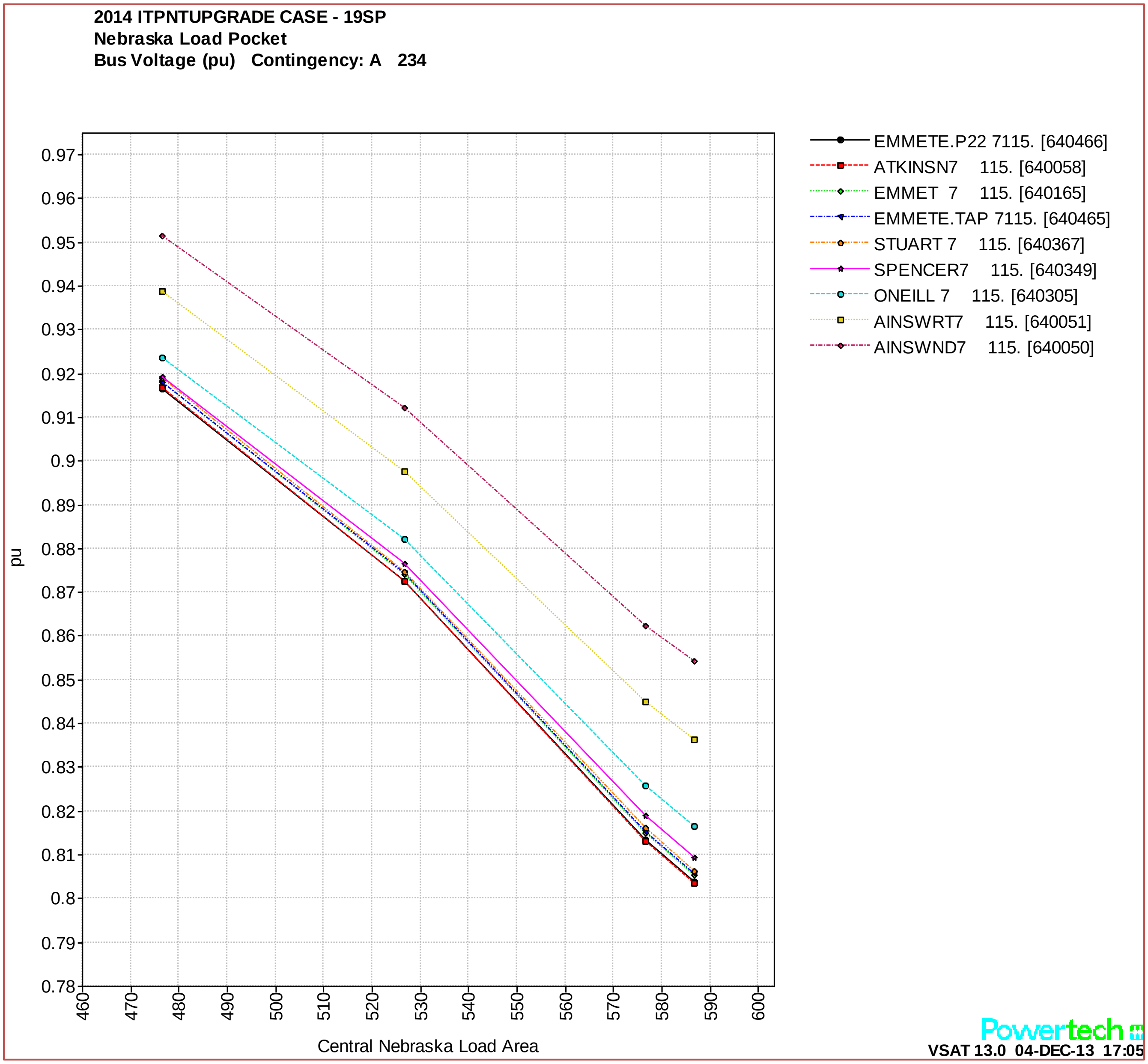

Figure 7.2: Central Nebraska Load Area PV Curves Upgrade Case
(G-1, T-1 Contingency: Gentleman 1 and Spencer to Fort Randall 115 kV)

7.4: MVar Reserve

The figure below shows the MVar reserve remaining in the load pocket at the collapse point for the limiting contingency in the Upgrade Case.

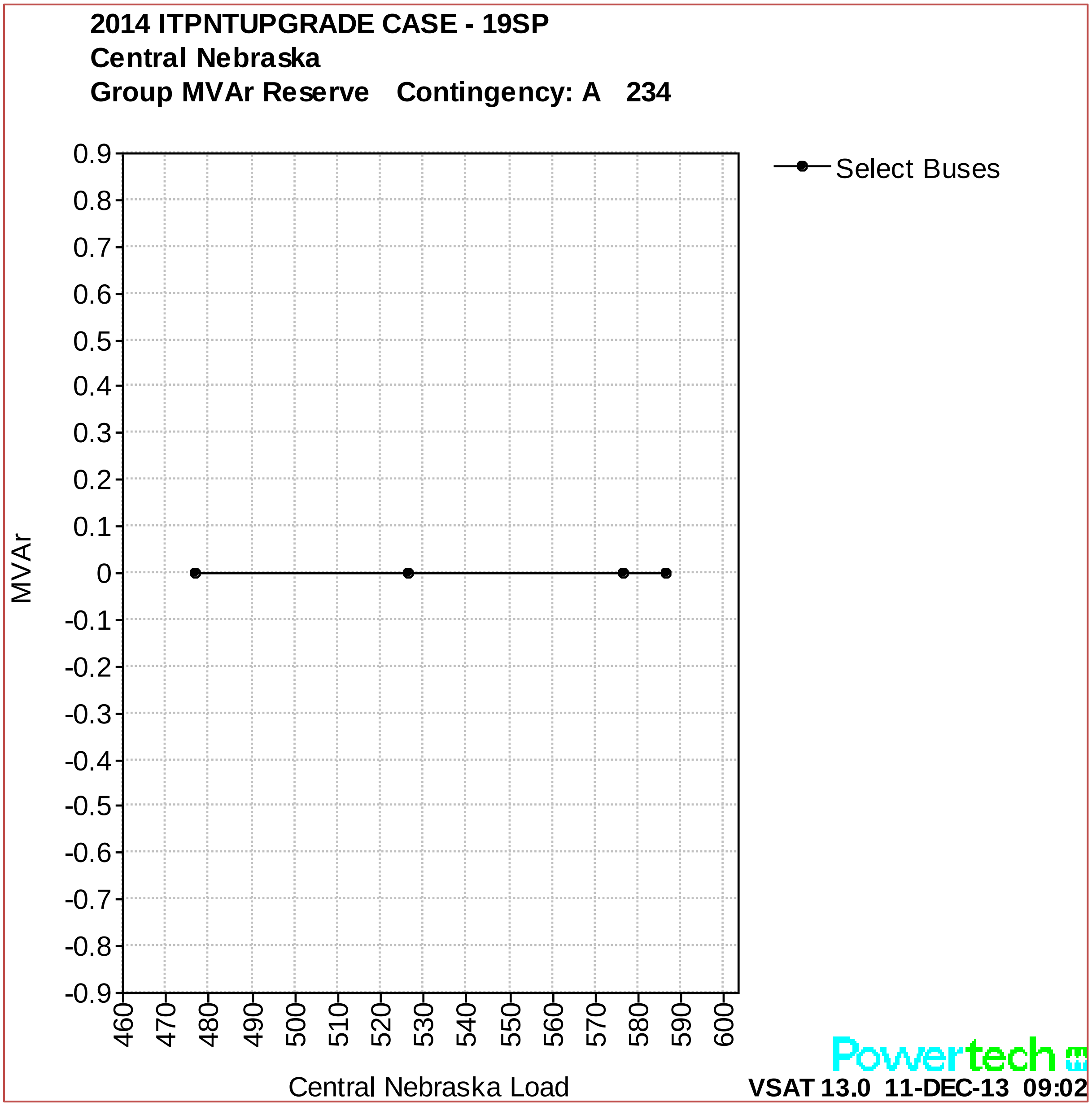

Figure 7.3: Central Nebraska Load Area MVar Reserve

Section 8: **Summary of Results**

8.1: Load Area Voltage Stability Analysis Summary

Load Area	Vicinity of Voltage Instability Upgrade	Load Increase at Voltage Stability Limit Upgrade (MW)	Reactive Reserve at Voltage Stability Limit Upgrade (MVar)	Limiting Contingency Upgrade
South Oklahoma	Georgia 138kV	751	275	SWS3 24 Anadarko – Georgia 138kV
Oklahoma City	PARKPL 4 138kV	2440	508	HSL 8G and Northwest – Spring Creek 345kV
South Central Westar	TCBURNS4 138kV	1890	0	Gordon Evans U2 Rose Hill – Wolf Creek 345kV Benton – Wolf Creek 345 kV
North East Westar	4VANBUR3 115kV	1190	0	1 LEC U5 HOYT 7/3 Transformer 345kV
Lincoln/Omaha Nebraska	S1287 5 161kV	2520	18	S1281 – S1287 161kV
Central Nebraska	EMMETE.P22 7 115kV	110	0 (for the select buses)	Spencer – Ft. Randall 7 115kV
Oklahoma City	PARKPL 4 138 kV	2440	508	HSL 8G and Northwest – Spring Creek 345kV

Table 8.1: Summary of Results

Summary

Voltage instability due to transfers into load areas within SPP has been studied and results are provided in this report. Reactive reserve for these load areas are shown at the transfer levels that cause instability.