DPA-2025-AUGUST-2166

Delivery Point Network Study

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By SPP Engineering, Transmission Services

REVISION HISTORY

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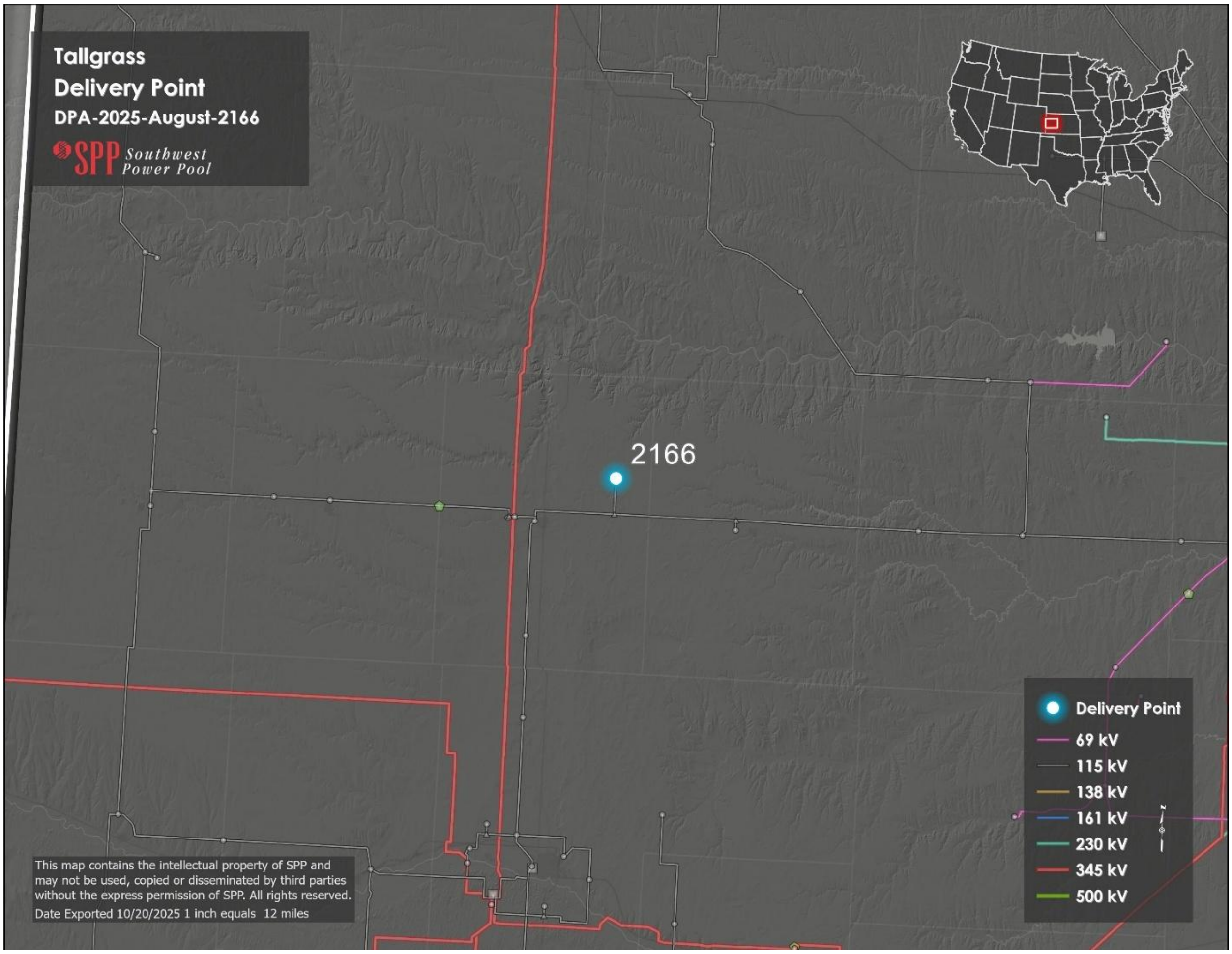
CONTENTS

Revision History i
Section 1: Introduction 1
Section 2: Study Methodology 2
Objective 2
Study Process 2
Section 3: Results of Analysis 4
Potential Thermal and Voltage Violations 4
Short Circuit 5
Stability 6
Transmission Solutions 7
Section 4: Conclusion 9

SECTION 1: INTRODUCTION

This report outlines the results of an evaluation of regional transmission impacts from delivery point request DPA-2025-August-2166. The requesting entity plans to add new load to an existing delivery point called Manning with an in-service date of 7/1/2027. The Manning delivery point is in the Sunflower Electric Power Corporation (SEPC) Transmission System.



The load flow models used for the evaluation were 2025 Integrated Transmission Planning (ITP) base reliability models. Southwest Power Pool (SPP) performed an Alternating Current (AC) contingency analysis on these models using PSS®E.

SECTION 2: STUDY METHODOLOGY

OBJECTIVE

The purpose of this study was to determine the regional Transmission System impacts within the SPP footprint due to the new load served by SEPC. SPP performed a Delivery Point Network Study (DPNS) with the configurations shown in Table 2-1 below.

STUDY PROCESS

- Model Assumptions
    - DPA Requests Included
        - DPA-2024-July-1984 Scott Park
    - 2025 ITP Base Reliability Model Series
        - Model years 2029 and 2034
        - Summer Peak (2029S and 2034S), Winter Peak (2029W and 2034W), and Light Load (2029L and 2034L)
    - 2025 ITP Short Circuit Model Series
        - 2029 Summer Max Fault
    - 2025 Transmission System Planning (TPL) Dynamic Model Series
        - 2034 Summer Peak Base and Change Cases

Table 2-1: Study Cases

Case Name	Study Year	Season	Scenario	Load (MW/MVAR)
2025ITPFinal-29L.sav	2029	Light Load	Base Reliability	Base Case
2025ITPFinal-29S.sav	2029	Summer Peak	Base Reliability	Base Case
2025ITPFinal-29W.sav	2029	Winter Peak	Base Reliability	Base Case
2025ITPFinal-34L.sav	2034	Light Load	Base Reliability	Base Case
2025ITPFinal-34S.sav	2034	Summer Peak	Base Reliability	Base Case
2025ITPFinal-34W.sav	2034	Winter Peak	Base Reliability	Base Case
2025ITPFinal-29L_2166.sav	2029	Light Load	Base Reliability	Tallgrass = 14.25/4.684
2025ITPFinal-29S_2166.sav	2029	Summer Peak	Base Reliability	Tallgrass = 14.25/4.684
2025ITPFinal-29W_2166.sav	2029	Winter Peak	Base Reliability	Tallgrass = 14.25/4.684
2025ITPFinal-34L_2166.sav	2034	Light Load	Base Reliability	Tallgrass = 14.25/4.684
2025ITPFinal-34S_2166.sav	2034	Summer Peak	Base Reliability	Tallgrass = 14.25/4.684
2025ITPFinal-34W_2166.sav	2034	Winter Peak	Base Reliability	Tallgrass = 14.25/4.684

- Steady State Analysis
    - Assumptions (consistent with the ITP analysis)
        - AC contingency analysis on all load flow models using PSS®E
        - Monitored Elements
            - SPP facilities 69 kV and above
            - First-tier companies 100 kV and above
        - Contingencies (consistent with the ITP analysis)
            - Provided for the ITP by SPP members and first-tier companies
        - Apply SPP Criteria and National American Electric Reliability Corporation (NERC) reliability standards
    - Compare thermal and voltage violations that occur with and without the delivery point change to determine thermal and voltage violations resulting from the load addition to the Transmission System.
- Dynamics Analysis
    - Assumptions
        - 2025 TPL Dynamics Model Series
            - 2034 Summer Peak Base and Change Cases
    - Analyses
        - Fast Fault Screening using Physical and Operational Margins Studio
- Short Circuit Analysis
    - Assumptions
        - Used 2025 Final ITP Short Circuit models (Max Fault)
            - Placed all available facilities in service
                - Generation
                - Transmission lines
                - Transformers
                - Buses
            - Short Circuit Output
                - Physical
            - Short Circuit Coordinates
                - Polar
            - Short Circuit Parameters
                - 3 Phase
            - FLAT – classical fault analysis conditions
    - Analyses
        - Three-phase fault

SECTION 3: RESULTS OF ANALYSIS

POTENTIAL VOLTAGE VIOLATIONS

The analysis identified potential voltage violations resulting from the new load at the Manning delivery point. Table 3-1 details the potential voltage violations resulting from the load addition.

Table 3-1: Potential Voltage Violations

Year	Season	Facility Name	Facility Voltage (kV)	Contingency Name	Voltage Maximum (pu)	Voltage Minimum (pu)	Bus Voltage (pu)
2029	Summer	MANNGT 3	115	ONEOKTP3 - MANNGT 3 - 1	1.05	0.9	0.8946
2029	Summer	MANNING3	115	ONEOKTP3 - MANNGT 3 - 1	1.05	0.9	0.89097
2029	Summer	LS_ONEOK3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.8473
2029	Summer	ONEOKTP3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.84904
2029	Summer	JAGGER 3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.86214
2029	Summer	DIGHTON3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.8614
2029	Summer	MANNGT 3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.85083
2029	Summer	MANNING3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.84701
2034	Summer	JAGGER 3	115	ONEOKTP3 - MANNGT 3 - 1	1.05	0.9	0.89201
2034	Summer	DIGHTON3	115	ONEOKTP3 - MANNGT 3 - 1	1.05	0.9	0.89129
2034	Summer	MANNGT 3	115	ONEOKTP3 - MANNGT 3 - 1	1.05	0.9	0.88437
2034	Summer	MANNING3	115	ONEOKTP3 - MANNGT 3 - 1	1.05	0.9	0.88066
2034	Summer	LS_ONEOK3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.83495
2034	Summer	ONEOKTP3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.83671
2034	Summer	BEELER 3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.89394
2034	Summer	JAGGER 3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.85016
2034	Summer	DIGHTON3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.8494
2034	Summer	MANNGT 3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.83854
2034	Summer	MANNING3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.83462
2034	Summer	LS_ONEOK3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.89507
2034	Summer	ONEOKTP3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.8967
2034	Summer	MANNGT 3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.89837
2034	Summer	MANNING3	115	ONEOKTP3 - SCOTCTY3 - 1	1.05	0.9	0.89472

SHORT CIRCUIT

SPP performed short circuit analysis for the 2029 Summer Peak with the new load addition. The analysis identified the currents listed in Table 3-2.

Table 3-2: Short Circuit Results

Season	Model	Fault	Bus	Current (Amps)
29S	Max Fault	Three Phase	NESCTY 3 115.00	3,600
29S	Max Fault	Three Phase	SETAB 1 13.800	26,894
29S	Max Fault	Three Phase	CNTRLPL1 13.800	30,009
29S	Max Fault	Three Phase	BEELER 3 115.00	3,241
29S	Max Fault	Three Phase	JAGGER 3 115.00	3,694
29S	Max Fault	Three Phase	DIGHTON3 115.00	3,507
29S	Max Fault	Three Phase	MANNGT 3 115.00	5,348
29S	Max Fault	Three Phase	MANNING3 115.00	4,210
29S	Max Fault	Three Phase	RANSOM 3 115.00	2,841
29S	Max Fault	Three Phase	DOBSON 3 115.00	12,434
29S	Max Fault	Three Phase	LEOTI 3 115.00	4,112
29S	Max Fault	Three Phase	PILE 3 115.00	6,576
29S	Max Fault	Three Phase	SCOTCTY3 115.00	9,127
29S	Max Fault	Three Phase	HOLCOMB7 345.00	10,429
29S	Max Fault	Three Phase	MINGO 7 345.00	6,154
29S	Max Fault	Three Phase	NESSCTY3 115.00	3,602
29S	Max Fault	Three Phase	SETAB 3 115.00	10,449
29S	Max Fault	Three Phase	SETAB 7 345.00	7,074
29S	Max Fault	Three Phase	CNTRLPL3 115.00	6,080
29S	Max Fault	Three Phase	CNTRLPL2 34.500	9,698
29S	Max Fault	Three Phase	GANO 3 115.00	6,921
29S	Max Fault	Three Phase	7BLACKBERRY 345.00	15,470
29S	Max Fault	Three Phase	7SPORTSMAN 345.00	25,308
29S	Max Fault	Three Phase	5SPORTSMAN 161.00	41,348
29S	Max Fault	Three Phase	1SPORTT1 13.200	30,581
29S	Max Fault	Three Phase	1SPORTT2 13.200	30,688
29S	Max Fault	Three Phase	KEYSTON4 138.00	22,449
29S	Max Fault	Three Phase	CHAMSPR1 13.800	33,058
29S	Max Fault	Three Phase	FLINTCR7 345.00	16,105
29S	Max Fault	Three Phase	CHAMSPR5 161.00	24,842
29S	Max Fault	Three Phase	CHAMSPR7 345.00	10,777
29S	Max Fault	Three Phase	TONTITN7 345.00	9,740
29S	Max Fault	Three Phase	BA.NO-S4 138.00	12,319
29S	Max Fault	Three Phase	BA101 S4 138.00	18,238
29S	Max Fault	Three Phase	CLARKSV7 345.00	21,595
29S	Max Fault	Three Phase	DENVTAP4 138.00	9,803
29S	Max Fault	Three Phase	BA81---4 138.00	18,228
29S	Max Fault	Three Phase	WEKIWA-7 345.00	21,504

Season	Model	Fault	Bus	Current (Amps)
29S	Max Fault	Three Phase	WEKIWA-4 138.00	32,382
29S	Max Fault	Three Phase	B111---4 138.00	15,993
29S	Max Fault	Three Phase	BA101ST4 138.00	18,939
29S	Max Fault	Three Phase	BA101-N4 138.00	19,845
29S	Max Fault	Three Phase	RSS T1 4 138.00	52,194
29S	Max Fault	Three Phase	R.S.S.-7 345.00	32,873
29S	Max Fault	Three Phase	R.S.S.-4 138.00	63,152
29S	Max Fault	Three Phase	BANNTAP4 138.00	18,710
29S	Max Fault	Three Phase	BA.N-ST4 138.00	24,430
29S	Max Fault	Three Phase	E 11TH ST 4 138.00	29,537
29S	Max Fault	Three Phase	ONETA--4 138.00	52,866
29S	Max Fault	Three Phase	ONETA--7 345.00	33,375
29S	Max Fault	Three Phase	SHEFFD-4 138.00	25,617
29S	Max Fault	Three Phase	T.NO.--4 138.00	42,690
29S	Max Fault	Three Phase	WED-TAP4 138.00	18,988
29S	Max Fault	Three Phase	COGENT 7 345.00	30,822
29S	Max Fault	Three Phase	OEC 7 345.00	33,246
29S	Max Fault	Three Phase	CDC-ET 4 138.00	24,806
29S	Max Fault	Three Phase	CDC-WT 4 138.00	26,206
29S	Max Fault	Three Phase	OWASOTP4 138.00	15,208
29S	Max Fault	Three Phase	P&P WTP4 138.00	15,362
29S	Max Fault	Three Phase	T.NO.--7 345.00	24,254
29S	Max Fault	Three Phase	ONETA2-1 34.500	16,175
29S	Max Fault	Three Phase	121LYNN4 138.00	17,832
29S	Max Fault	Three Phase	SAPLPRD7 345.00	22,587
29S	Max Fault	Three Phase	SAPLPRD4 138.00	32,718
29S	Max Fault	Three Phase	SAPLPRD1 13.800	24,235
29S	Max Fault	Three Phase	ONETA5-1 34.500	8,206
29S	Max Fault	Three Phase	RSS T2 4 138.00	53,136
29S	Max Fault	Three Phase	RSST2 T1 13.800	41,948

STABILITY

SPP performed a Fast Fault Screening (FFS) using the 2034 Summer Peak for the base case and change case models. The change case models include the Manning delivery point changes. SPP determined no significant differences in the critical clearing times between the base and change cases. Therefore, a transient stability analysis is not required.

TRANSMISSION SOLUTIONS

The addition of the load at the Manning delivery point caused potential voltage issues on the 115 kV system for the loss of the ONEOK – Manning Tap and ONEOK – Scott City 115kV lines. SPP worked with SEPC to determine the location and the size of the reactive support needed to mitigate the potential voltage violations in Table 3-1. Some of the solutions are listed below.

Solution #1: Total cost $15.6 M

- Add 24 MVAR (2x12) capacitor bank at Manning Tap 115kV substation
- Convert Manning Tap 115kV into switching station

Solution #2: Total cost $26.9 M

- New Scott City – Manning Tap 115kV line (10 miles)
- Convert Manning Tap 115kV into switching station

SPP chose to move forward with Solution #1. This solution solves all issues identified in Table 3-1 in the most cost-effective manner.

Table 3-3: Recommended Upgrade Solution 1

New Upgrade Description*	Mileage	MVA (Rate B)	Date Needed**	Host Transmission Owner	Estimated Cost***
Add 24 MVAR (2x12) capacitor bank at Manning Tap 115kV substation	-	-	7/1/2027	SEPC	$2,700,000
Convert Manning Tap 115kV into switching station	-	-	7/1/2027	SEPC	$12,900,000
TOTAL NEW UPGRADE COST					**$15,600,000**

*All requests with a Network Upgrade(s) identified in the DPNS will be subject to further evaluation in the soonest available Integrated Transmission Planning Assessment that is able to include the load changes, if it is determined that the Network Upgrade(s) will be able to meet the study timeframe requirements pursuant to the standardized project timelines in SPP Business Practices, based on the SPP determined Network Upgrade(s) need date. If it is determined that a Network Upgrade(s) identified from a DPNS is unable to be further evaluated pursuant to the Integrated Transmission Planning Assessment, the DPNS report will be posted on the SPP website once SPP is notified by the Transmission Customer to update the applicable Network Integration Transmission Service Agreement to reflect the changes in delivery points and the Network Upgrade(s).

Pursuant to Attachment AQ of the Tariff, the Transmission provider is responsible for assessing the impacts on the Transmission System caused by modifying an existing delivery point or establishing the new delivery point through the Delivery Point Network Study ("DPNS"). The DPNS may determine the need for a Network Upgrade(s) necessary for the modification of an existing delivery point or the establishment of a new delivery point. A Network Upgrade(s) that the Transmission Customer or Host Transmission Owner desires that exceeds the needed Network Upgrade(s) identified in the DPNS will need to be studied through the Transmission Provider's Sponsored Upgrade study process to evaluate the impacts of the desired changes on the Transmission System.

**If the project need date specified in this study cannot be met, the Transmission Owner will be required to submit mitigations pursuant to the SPP Project Tracking process. All upgrades or mitigations must be in place prior to the dates shown in Table 3-3.

***Note that the estimated new upgrade cost provided in this report is an SPP Conceptual Cost Estimate only; this is preliminary, and a more refined Study Cost Estimate will be developed after issuance of this report through a Standardized Cost Estimate Reporting Template (SCERT).

SECTION 4: CONCLUSION

The AC analysis revealed potential voltage violations associated with the load addition at the Manning delivery point. The study shows that the following upgrades are required to reliably serve the load addition:

- Add 24 MVAR capacitor bank at Manning Tap 115kV substation
- Convert Manning Tap 115kV into switching station

The transmission upgrades in Table 3-3 are recommended to mitigate the potential voltage violations.