FINAL

MISO Project J255
Clean Line Energy Grain Belt Express

500 MW in Ralls County, MO

Optional Study Report

Prepared for the
Midcontinent Independent System Operator

by

Ameren Services Company
Transmission Planning

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DRAFT

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I. Executive Summary

This report presents the results of the optional System Impact Study for generation interconnection project J255. The project involves connecting an HVDC line originating in western Kansas to the MISO and PJM service territories. The interconnection customer's rectifier station (345 kV AC to 600 kV DC) will be located in Spearville, Kansas, with their 345 kV AC bus connected to wind farm feeds and also to ITC's 345 kV Clark Substation. A 600 kV DC line will be built from Spearville to a 500 MW inverter station (600 kV DC to 345 kV AC) in Ralls County, Missouri. The Ralls County inverter station will interconnect to a new Ameren 345 kV switching station to be built on Ameren's Maywood-Spencer Creek 345 kV transmission line approximately 24 miles south of Maywood. The 600 kV DC line will continue from the Ralls County inverter station to a 3500 MW inverter station (600 kV DC to 345 kV AC) in eastern Indiana that will interconnect to the 345kV bus at AEP's Breed Substation.

This study looked only at the 500 MW injection onto Ameren's Maywood-Spencer Creek 345 kV transmission line. PJM will study the 3500 MW injection at Breed.

The analyses were performed for two load levels, summer peak load and shoulder peak load, for the year 2021. The study models included MTEP Appendix A transmission projects that are scheduled to be in service by the summer of 2021. Generation dispatch in the study models was based on expected generator availability and seasonal dispatch patterns.

The study showed that J255 will cause a constraint on two transmission elements that will require Network Upgrades to accommodate the project.

A. *Thermal Analysis*

Thermal analysis was performed to determine if any transmission elements will be constrained by the addition of J255. No thermal constraints were identified.

B. *Reactive Power at Point of Interconnection*

J255 will be required to provide reactive support at the AC terminal of the inverter station to assist in controlling system voltage per applicable FERC/MISO/Local Planning Criteria requirements in place during the DPP study period.

C. Ameren Local Planning Criteria Analysis

Transfer Capability analysis was performed to determine whether J255 would reduce Ameren import capability. No constraints were identified due to Transfer Capability.

Line + Generator contingency analysis was performed for fifty-two (52) unique generation outage scenarios in both the summer peak and shoulder peak models. Two thermal constraints were identified based on this portion of the Local Planning Criteria. They are presented in the table below.

Line + Line contingency analysis was performed for all 345 kV lines on the Ameren system. No thermal constraints were identified based on this portion of the local Planning Criteria.

Table I.C.1 – Estimated Cost of Constraint Mitigation

Facility Owner	Local Planning Criterion	Constraint	Mitigation Suggested	Planning Level Cost Estimate
Ameren	Line + Generator	Rush Island Bus Tie 1-2	Upgrade bus with materials capable of > 3000 Amps continuous capability	$ 1,500,000
Ameren	Line + Generator	Fargo 345/138 kV Transformer	Add a second 560 MVA transformer at Fargo substation	$10,000,000
			Total Estimated Cost	**$11,500,000**

D. NIPSCO Local Planning Criteria Analysis

NIPSCO Local Planning Criteria requires that mitigation be performed for all constraints identified under system intact and N-1 contingency conditions where the study generation has a 3% distribution factor and a 3% MW impact of the facility rating is indicated on the constrained facility. No thermal constraints were identified based on the NIPSCO Local Planning Criteria.

E. Cost Estimate of Interconnection Facilities and Network Upgrades at the POI

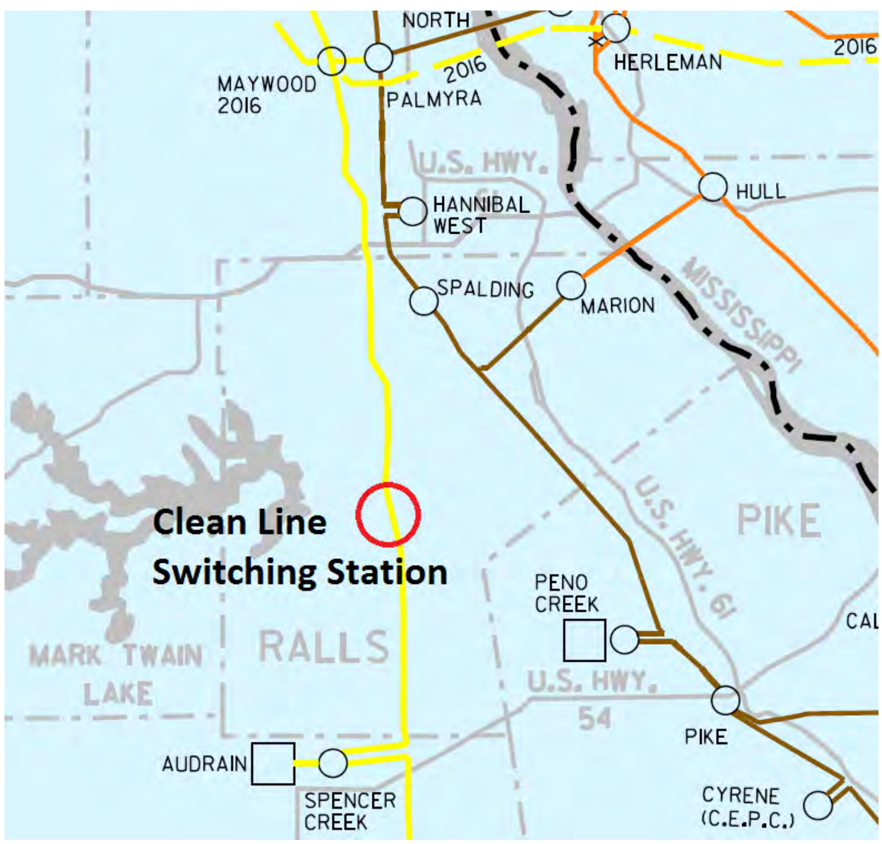
The planning-level cost estimate for the Transmission Owner Interconnection Facilities and Network Upgrades at the Point of Interconnection is approximately $9,500,000 based on a recent MISO Interconnection Facilities Study for similar interconnection. This is in addition to the $11,500,000 planning-level cost estimate for Network Upgrades to mitigate constraints caused by the study project. The total planning-level estimated cost for Transmission Owner Interconnection Facilities and Network Upgrades is **$21,000,000**.

II. Introduction

MISO project J255 involves connecting an HVDC line originating in western Kansas to the MISO and PJM service territories. The interconnection customer's rectifier station (345 kV AC to 600 kV DC) will be located in Spearville, Kansas, with their 345 kV AC bus connected to wind farm feeds and also to ITC's 345 kV Clark Substation. A 600 kV DC line will be built from Spearville to a 500 MW inverter station (600 kV DC to 345 kV AC) in Ralls County, Missouri. The Ralls County inverter station will interconnect to a new Ameren 345 kV switching station to be built on Ameren's Maywood-Spencer Creek 345 kV transmission line approximately 24 miles south of Maywood. The 600 kV DC line will continue from the Ralls County inverter station to a 3500 MW inverter station (600 kV DC to 345 kV AC) in eastern Indiana that will interconnect to the 345kV bus at AEP's Breed Substation.

This study looked only at the 500 MW injection onto Ameren's Maywood-Spencer Creek 345 kV transmission line. PJM will study the 3500 MW injection at Breed.

The study considered two load levels, summer peak and shoulder peak for the 2021 planning year. In the summer peak case J255 was dispatched at 100% of maximum output, 500 MW, and all wind generation in the study region was dispatched at 20% of its maximum output. In the shoulder peak case J255 and all wind generation in the study region was dispatched at 100% of maximum output.



The planning-level cost estimate for the Transmission Owner Interconnection Facilities and Network Upgrades at the POI, shown in Table III following, is approximately $9,500,000 based on a recent MISO Interconnection Facilities Study for a similar interconnection.

Table III – Planning Level Cost Estimate for Interconnection Facilities and Network Upgrades to Interconnect J255

Facility Type	Facilities to be Constructed by the Transmission Owner	Planning-Level Cost Estimate
Interconnection Facilities	Construct Transmission Owner Interconnection Facilities at the J255 Interconnection Switching Station	$ 800,000
Stand-Alone Network Upgrade	Construct the J255 Interconnection Switching Station	$ 8,150,000
Network Upgrade	Tap the Maywood-Spencer Creek 345 kV transmission line to connect the J255 Interconnection Switching Station	$ 550,000
TOTAL PLANNING-LEVEL ESTIMATED COST		**$ 9,500,000**

IV. Power Flow Analysis

A. Introduction

The steady-state power-flow analysis was performed using MISO Generator Interconnection Criteria and Ameren Transmission Planning Criteria. The study interconnection was dispatched at maximum output, and all wind generation in the area of study was dispatched at 20% of maximum output during summer peak conditions, and at 100% of maximum output during shoulder peak conditions. The analysis considered all Explicit P1 contingencies in the following control areas: AMMO, AMIL, AECI, CWLD, CLWP, ITC, and MEC. Numerous Explicit P2, P3, P4, P5, P6, and P7 contingencies were also simulated in these areas as provided by MISO.

The power flow analysis considered both MISO criteria and Ameren Transfer Capability (i.e., Import) criteria. MISO constraints are classified as either injection related or non-injection related.

For N-0 conditions, a constraint is identified as an injection related constraint if one or more of the following apply:

- The interconnection has a larger than 5% Distribution Factor on the overloaded facility.
- The overloaded facility is at the study interconnection's outlet.
- The megawatt impact due to the study interconnection is greater than or equal to 20% of the applicable (Normal) rating of the overloaded facility.

For N-1 and certain N-2 conditions, a constraint is identified as an injection related constraint if one or more of the following apply:

- The interconnection has a larger than 20% Distribution Factor on the overloaded facility under post contingency conditions.
- The overloaded facility or the overload-causing contingency is at the study interconnection's outlet.
- The megawatt impact due to the study interconnection is greater than or equal to 20% of the applicable (Emergency) rating of the overloaded facility.

The power flow analysis included the evaluation of all single contingencies in the study area.

Ameren's Local Planning Criteria considers the outage of a single generator combined with the loss of a single transmission element to be treated as single contingency (N-1 condition). Constraints were identified if the study interconnection had a distribution factor of 3% or higher on the overloaded facility or the addition of the interconnection increased the overload by 5% of the facility rating and the constraint did not previously appear as overloaded in the N-1 analysis.

The analysis also considered Ameren's import requirements for summer peak conditions. The import analysis tests the system for 2000 MW of simultaneous import capability. Any reduction in the First Contingency Incremental Transformer Capability (FCITC) of more than 200 MW and a distribution factor of 3% or higher from the study interconnection on a transmission facility will cause that facility to be considered an affected facility and will require mitigation.

Additionally, Ameren's Local Planning criterial considers the loss of any 345 kV line combined with the loss of a second 345 kV line to be treated as a violation if the study interconnection had a distribution factor of 3% or higher on any overloaded facility.

B. Ad-hoc Study Group Participation

MISO system impact studies are facilitated using ad-hoc study groups made up of affected transmission owners and regional transmission organizations. The participants in the ad-hoc study group formed for this study include representatives from Ameren; American Electric Power; Associated

Electric Cooperative Inc.; City Water, Light, and Power (Springfield, IL); Columbia Water and Light Department; International Transmission Company, and MidAmerican Energy Company. These companies participated in the study process, reviewed models and study results, and provided information related to their systems.

C. Monitored Areas and Elements

The study area included the following Balancing Areas in Illinois, Missouri, and Indiana: AMMO, AMIL, EEI, AEP, OVEC, HE, DEI, SIGE, DEO&K, IPL, NIPS, BREC, CWLD, CWLP, SIPC, and LGEE. Monitored facilities included all branches and tie lines 100 kV and above in AMMO and AMIL, and all branches and tie lines 69 kV and above in all other Balancing Areas.

D. Contingencies

The study considered the following system conditions for evaluation of the transmission system:

- System performance under normal conditions (N-0)
- System performance under single contingency (N-1) conditions (P1), including the loss of a single section of a multi-terminal line (P2-1)
- System performance under bus fault (P2-2) and breaker failure (P2-3, P2-4) scenarios
- System performance under loss of line contingency conditions along with a loss of a nearby generator (Line + Generator) (P3-2)
- System performance under loss of Double Circuit Tower (P7)
- System performance with various Line + Line outage scenarios including all Ameren 345 kV pairs (P6)
- System performance with various Line + Transmission Facility outage scenarios including local transformers and shunts (P6)
- Ameren simultaneous and non–simultaneous import capability

The outage of generators, lines, and transformers were simulated explicitly as defined in the contingency files for AMMO, AMIL, AECI, CWLD, CLWP, ITCM, and MEC. MISO provided the contingency files for the non-Ameren portion of the study area. Typically these contingencies represent all elements removed from service during a fault condition with normal relay operation.

For Line + Generator analysis, all generating facilities within Ameren were chosen. For all contingencies that involve the loss of a generator, power was made up from MISO generators excluding Ameren.

F. Power Flow Base Case Impacts (N-0)

Transmission elements that were loaded above their summer normal ratings with J255 in service were flagged if J255 had at least a 5% distribution factor on that element. To qualify as an injection constraint, a flagged element must be at the study project's outlet or the study project must have a minimum of a 5% distribution factor on the flagged element. No transmission elements were identified as constraints under these criteria.

G. Power Flow Single Contingency (P1) Impacts (N-1)

Transmission elements that were over 100% of their summer emergency ratings under single contingency and have a distribution factor of 3% or higher from the study interconnection were flagged for review. For N-1 conditions, a constraint is identified as an injection-related constraint if one or more of the following apply:

- The interconnection has a larger than 20% Distribution Factor on the overloaded facilities under post contingent conditions
- The overloaded facility or the overload causing contingency is at the study interconnection's outlet
- The megawatt impact due to the study interconnection is greater than or equal to 20% of the applicable rating (normal or emergency) of the overloaded facility

No transmission elements were identified as constraints under these criteria.

H. Power Flow Contingency Impacts (P2-P7)

Transmission elements that were over 100% of their summer emergency ratings under P2-P7 contingency conditions and have a distribution factor of 3% or higher from the study interconnection were flagged for review. The same methodology was used to determine whether a constraint would be considered injection related as was used in the P1 analysis.

There were no P2-P7 injection-related constraint identified during shoulder peak or summer peak conditions. Table IV.H.1 details the non-injection related constraints identified during P2 - P7 contingency analysis.

Table IV.H.1 –P2-P7 Non-Injection Related Constraints

Transmission Owner	Overloaded Facility	Contingency	Model	Emerg. Rating (MVA)	POST Project Loading (MVA)	PRE Project Loading (MVA)	DF*
AECI	300103 5NEWMAD 345 - 300046 7NEWMAD 161: 2	P6: New Madrid – Dell 500 & New Madrid 345 / 161 # 1	2021 Shoulder	424	676.5	661.1	3.08%
AECI	345436 7PALMYRA 345 - 345437 5PALMYRA 161: 1	P6: Herleman – Maywood 345 & Zachary 345 / 161	2021 Shoulder	336	371.6	304.7	13.4%
AECI	345436 7PALMYRA 345 - 345437 5PALMYRA 161: 1	P6: Herleman – Maywood 345 & Clean Line – Spencer Ck. 345	2021 Shoulder	336	533.7	387.1	29.3%
AECI	345436 7PALMYRA 345 - 345437 5PALMYRA 161: 1	P6: Herleman – Maywood 345 & Montgomery – Spencer Ck. 345	2021 Shoulder	336	533.6	388.2	29.1%
AECI	345436 7PALMYRA 345 - 345437 5PALMYRA 161: 1	P6: Herleman – Maywood 345 & Audrain SPS 345	2021 Shoulder	336	533.6	388.2	29.1%
AECI	345436 7PALMYRA 345 - 345437 5PALMYRA 161: 1	P6: Montgomery– Spencer Cr. 345 & Herleman 345 / 161	2021 Peak	336	382.4	304.9	15.5%
AECI	345436 7PALMYRA 345 - 345437 5PALMYRA 161: 1	P6: Herleman 345 / 161 & Meredosia 345 / 138	2021 Peak	336	306.5	339.5	6.6%

*DF = Distribution Factor

(Note): These constraints would not be considered injection related and would not require mitigation by the customer. They have been included in the table for informational purposes to indicate possible areas of congestion once the study interconnection has been placed in service.

I. *Local Planning Criteria (Line + Generator Analysis)*

Ameren's Local Planning Criteria considers the outage of a transmission element with the simultaneous outage of a large generator, peaking plant, or wind farm as a single contingency event. The analysis considered all Ameren generation. Single contingency analysis was performed on the powerflow cases with the generation switched offline in N-1-1 contingency analysis and dispatched to MISO areas excluding Ameren. Ameren facilities were monitored for thermal overloads during this analysis. There were two constraints identified under shoulder peak conditions. These constraints are listed below.

Table IV.I.1 – Injection Related Constraints for Line + Generator Analysis

Transmission Owner	Overloaded Facility	Contingency	Model	Emerg. Rating (MVA)	POST Project Loading (MVA)	PRE Project Loading (MVA)	DF*
Ameren	345667 7RUSH 1 345 - 345668 7RUSH 2 345 BUS TIE	P3: RUSH UNIT 2 & PRARIE STATE – MT. VERNON 4541 345 kV	2021 Shoulder	1494	1508.4	1484.5	4.78%
Ameren	349730 7FARGO 345 - 349650 4FARGO 138 1 XFMR	P3: EDWARDS U 3 & TAZEWELL – MAPLERIDGE 345 kV	2021 Shoulder	560	563.2	544.4	3.76%

J. Local Planning Criteria (Transfer Capability Analysis)

All study projects are required to meet Ameren's local planning criteria for import capability. This criteria states that a minimum simultaneous import capability of 2,000 MW, which is measured by the first contingency incremental transfer capability (FCITC) as limited by an Ameren transmission facility, should be used as a proxy to maintain transmission capability related to generation reserves in the Ameren Missouri (AMMO) or Ameren Illinois (AMIL) footprint. Table IV.J.1 summarizes the simulations of simultaneous imports to various subsystems in the AMMO and AMIL areas from non-Ameren areas inside and outside the MISO footprint using the 2021 Summer Peak case. Various combinations of generators located in the Ameren control areas and dispatched in the power flow case, excluding study generation, served as sinks for these imports. The analysis included simulations with and without the study generators dispatched. A distribution factor of 3% or greater and a decrease of 200 MW of first contingency incremental transfer capability (FCITC) for the simulated import served as the basis for determining if an Ameren facility was limiting.

Importing scenarios simulated in this study are shown in Table IV.J.1 below:

Table IV.J.1 – Summary of Import Simulations

Source	Sink	Comments
WORLD_NOAMRN_E	AMIL_IMA	Imports to all on-line AMIL generators
WORLD_NOAMRN_E	AMMO_IMA	Imports to all on-line AMMO generators
WORLD_NOAMRN_E	IL_138	Imports to on-line generators in Illinois connected to 138 kV
WORLD_NOAMRN_E	IL_345	Imports to on-line generators in Illinois connected to 345 kV
WORLD_NOAMRN_E	IL_COAL	Imports to on-line coal plants in Illinois
WORLD_NOAMRN_E	MO_138	Imports to on-line generators in Missouri connected to 138 kV
WORLD_NOAMRN_E	MO_345	Imports to on-line generators in Missouri connected to 345 kV
WORLD_NOAMRN_E	MO_COAL	Imports to on-line coal plants in Missouri
WORLD_NOAMRN_E	AMIL_BASE	Imports to on-line AMIL base-load generators
WORLD_NOAMRN_E	AMMO_BASE	Imports to on-line AMMO base-load generators

There were no constraints related to transfer capability identified due to the addition of J255 in this portion of the local planning criteria analysis.

K. Local Planning Criteria (345 kV Line + Line Analysis)

A line + line outage analysis was performed for all Ameren 345 kV lines to determine whether the addition of the J255 generation would cause additional constraints with the combination of two 345 kV lines out of service. There were no additional constraints identified under shoulder peak or summer peak conditions beyond those injection-related constraints previously described in Sections IV.I.

L. NIPSCO Local Planning Criteria

NIPSCO Local Planning Criteria requires that mitigation be performed for all constraints identified under system intact and N-1 contingency conditions where the study interconnection has a 3% distribution factor and a 3% MW impact of the facility rating is indicated on the constrained facility. There were no constraints that met these criteria for this study.

M. Voltage Analysis and Reactive Power Requirements

The analysis evaluated the impact of the addition of J255 on voltages under single contingency conditions. To be identified as a voltage constraint, the voltage at the transmission bus should degrade by 1% with the addition of the study interconnection. The study did not identify any voltage degradation during single contingencies with the addition of study interconnection.

Non-synchronous generators (like wind farms) are required to operate across the power factor range of 0.95 lagging to 0.95 leading at the Point of Interconnection (POI).

N. Mitigation of Constraints

The mitigation of thermal constraints was provided by the Transmission Owners of each constraint. Table IV.N.1 below provides additional details and a planning-level cost estimate for the mitigation of each injection-related constraint.

Table IV.N.1 Mitigation of Injection-Related Constraints

Facility Owner	Local Criteria	Constraint	Mitigation Suggested	Planning-Level Cost Estimate
Ameren	Line + Generator	Rush Island Bus Tie 1- 2	Upgrade bus with materials capable of > 3000 Amps continuous capability	$ 1,500,000
Ameren	Line + Generator	Fargo 345 / 138 kV Transformer	Add second 560 MVA transformer at Fargo substation	$10,000,000
			Total Planning Level Estimated Cost	**$11,500,000**

O. Summary of Cost Estimates

The planning-level cost estimates to mitigate injection-related constraints and to construct the Transmission Owner Interconnection Facilities and Network Upgrades at the POI are shown below in Table IV.N.1.

Table IV.O.1 Summary of Cost Estimates

Facility Type	Facilities to be Constructed by the Transmission Owner	Planning-Level Cost Estimate
Interconnection Facilities	Construct Transmission Owner Interconnection Facilities at the J255 Interconnection Switching Station	$ 800,000
Stand-Alone Network Upgrade	Construct the J255 Interconnection Switching Station	$ 8,150,000
Network Upgrade	Tap the Maywood-Spencer Creek 345 kV transmission line to connect the J255 Interconnection Switching Station	$ 550,000
Network Upgrade	Upgrade the Rush Island bus tie with materials capable of > 3000 Amps continuous capability	$ 1,500,000
Network Upgrade	Add a second 560 MVA transformer at Fargo substation	$ 10,000,000
TOTAL PLANNING-LEVEL ESTIMATED COST		**$ 21,000,000**

V. Conclusion

The results of the optional System Impact study indicate that the addition of J255 will cause constraints on the transmission system that will require mitigation. Ameren has provided mitigation for these constraints. The mitigation was generally the re-building of existing facilities.