

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE PETITION BY)
BRICKYARD SOLAR, LLC FOR CERTAIN)
DETERMINATIONS BY THE COMMISSION) CAUSE NO. 45424
WITH RESPECT TO ITS JURISDICTION)
OVER PETITIONER'S ACTIVITIES AS A)
GENERATOR OF ELECTRIC POWER)

BRICKYARD SOLAR, LLC'S QUARTERLY REPORT:
SECOND QUARTER 2022

This Quarterly Report ("Report") is filed as required by the Commission's Order in this Cause issued on May 5, 2021. This Report provides the required information to the extent such information is known and available. The requested information is as follows:

(1) Any changes to the information provided in the Initial Report.

The Initial Report is updated as follows:

(9) Current estimate of the engineering/construction timeline and critical milestones for the Facility.

Currently, the expected timeline for the Facility is as follows:

Sept. 2023: Start of Construction
Nov. 2024: Backfeed Available Date
Nov. 2024: Sync Date
Dec. 2024: Commercial Operation Date

(2) Any reports of Interconnection System Impact Studies not previously submitted to the Commission.

Final versions of the MISO Phase II and Phase III System Impact Studies are attached to this Report. All other interconnection studies have been provided.

(3) Copy of the GIA as filed with the FERC.

The GIA was executed January 27, 2022, and was provided with the Fourth Quarter 2021 Report.

- (4) Notice of the establishment of an independent financial instrument, including its form and amount.**

This has not yet been established.

- (5) Achievement of construction milestones described in the GIA and such events as the procurement of major equipment, the receipt of major permits material to the construction and operation of the Facility, construction start-up, initial energization, and commercial operation.**

Not applicable. Brickyard Solar has not yet commenced construction.

- (6) When commercial operation is achieved, the nameplate capacity, term, and identity of the purchaser(s) for contracts then existing for utility sales, contingency plans (if any) detailing response plans to emergency conditions as required by state or local units of government, the interconnecting transmission owner and/or MISO, and the Facility's certified (or accredited) dependable capacity rating.**

Not applicable.

VERIFICATION

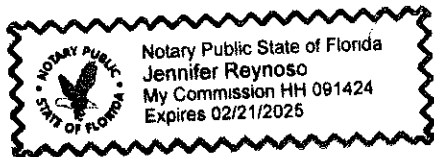
The undersigned, Anthony Pedroni, being first duly sworn upon his oath, states that he is the Vice President of Brickyard Solar, LLC; that he prepared or supervised the preparation of Brickyard Solar, LLC's Second Quarter 2022 Report; and that the statements contained therein are true to the best of his knowledge, information, and belief.

By: Anthony Pedroni

STATE OF FLORIDA)
)
COUNTY OF PALM BEACH)

SS:

Subscribed and sworn to before me, a Notary Public, in and for said State and County this 27 day of July, 2022.



Jennifer Reynoso
Signature
Jennifer Reynoso
Printed

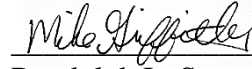
My Commission Expires:

2-21-25

My County of Residence:

Palm Beach

Respectfully submitted,



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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was electronically delivered this 29th day of July, 2022, to the following:

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An attorney for Petitioner,
Brickyard Solar, LLC



MISO DPP 2018 April Central Area Study Phase II Report

03/18/2021

Revision 5

MISO
720 City Center
Drive Carmel
Indiana 46032
<http://www.misoenergy.org>

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1. Executive Summary

This report presents the results of a System Impact Study (SIS) performed to evaluate the interconnection of the generators in the DPP 2018 April Central Area Phase II (Central Area DPP II). The study was performed under the direction of MISO and reviewed by an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren (AMIL, AMMO, ATXI), Duke Energy (DEI), Hoosier Energy (HE), Indianapolis Power & Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), Southern Illinois Power Cooperative (SIPC), and Southern Indiana Gas & Electric Company (SIGE).

1.1. Project List

The original interconnection requests for DPP 2018 April Central Area had a total of 61 generation projects.

- Projects J957, J973, J983, J1012, J1017, J1018, J1019, J1035, J1066, J1080, J1116, J1118, and J1150 withdrew prior to the Phase I study.
- 48 generation projects with a combined nameplate rating of 9348.23 MW (ERIS) & 9348.23 MW (NRIS) were studied in Phase I.
- Projects J980, J985, J995, J1016, J1021, J1031, J1059, J1123, J1148, J1161 withdrew during Decision Point 1 (Prior to Phase II Kickoff).
- 39 generation projects with a combined nameplate rating of 7888.95 MW (ERIS) & 7838.95 MW (NRIS) were studied in Phase II.

The Central Area DPP Phase II study was kicked off on January 8th 2020 and consisted of the projects shown below in Table 1.

Table 1: List of DPP April 2018 Central Area Phase II Projects

Project	Fuel Type	Transmission Owner	County	State	Service Requested	MW	POI
J955	Gas	Ameren Transmission Company of Illinois	Sangamon County	IL	NRIS	1165	Austin Substation 345kV Bus
J956	Solar	Ameren Missouri	Ralls County	MO	NRIS	200	Spencer Creek 345kV Substation
J968	Wind	Northern Indiana Public Service Company	Jasper County, White County	IN	NRIS	200	Reynolds 345kV Substation

J974	Wind	Ameren Illinois	Fulton County, Peoria County	IL	NRIS	250	Mapleridge 345kV Switching Station
J976	Solar	Ameren Missouri	Warren County	MO	NRIS	300	Montgomery - Enon 345kV Line Tap
J979	Wind	Ameren Transmission Company of Illinois	Christian County	IL	NRIS	170	Pana Substation 345kV Bus
J987	Solar	Ameren Missouri	Montgomery County	MO	NRIS	100	Montgomery 161kV Substation
J991	Solar	Ameren Illinois	Clay County	IL	NRIS	150	Xenia 345kV Switching Station
J992	Solar	Duke Energy Indiana	Cass County	IN	NRIS	200	Walton 230kV Substation
J993	Solar	Indianapolis Power & Light Company	Boone County	IN	NRIS	200	Hortonville - Whitestown 345kV Line Tap
J994	Solar	Ameren Missouri	Callaway County	MO	NRIS	100	Guthrie 161 kV Substation
J1022	Wind	Ameren Illinois	McLean County	IL	NRIS	150	Weedman Substation 138kV Bus
J1025	Wind	Ameren Transmission Company of Illinois	Knox County	MO	NRIS	300	Zachary - Maywood 345 kV Line Tap
J1026	Wind	Ameren Missouri	Audrain County, Ralls County	MO	NRIS	350	Maywood - Spencer Creek 345 kV Line Tap
J1027	Solar	Hoosier Energy	Pike County	IN	NRIS	150	Ratts 161 kV Substation
J1028	Solar	Hoosier Energy	Pike County	IN	NRIS	150	Ratts - Victory 161 kV Line Tap
J1033	Battery Storage	Ameren Missouri	Stoddard County	MO	NRIS	50	Stoddard - Morely 161 kV Line Tap
J1034	Solar	Ameren Missouri	Stoddard County	MO	NRIS	225	Stoddard - Morley 161kV Line Tap
J1039	Battery Storage	Ameren Missouri	Warren County	MO	NRIS	50	Enon - Montgomery 345kV Line Tap

J1055	Wind	Ameren Illinois	Mason County	IL	NRIS	144	Mason Substation 138 kV Bus
J1058	Solar	Northern Indiana Public Service Company	Lake County	IN	NRIS	200	Schahfer-St. John 345kV Line Tap
J1063	Solar	Duke Energy	Clinton County	IN	NRIS	195	New London - Frankfort 230kV Line Tap
J1067	Solar	Northern Indiana Public Service Company	Jasper County,Pulaski County	IN	NRIS	240	Reynolds - Burr Oak 345kV Line
J1069	Wind	Northern Indiana Public Service Company	Jasper County,Pulaski County	IN	NRIS	200	Reynolds 345kV Substation
J1074	Solar	Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.	Gibson County	IN	NRIS	200	Francisco 138 kV sub
J1087	Solar	Ameren Missouri	Scott County	MO	NRIS	200	Miner - Kelso 161 kV Line Tap
J1094	Solar	Ameren Illinois	Washington County	IL	NRIS	150	Prest 138kV Switching Station
J1096	Solar	Ameren Illinois	Saline County	IL	NRIS	150	Norris City North - Muddy 138 kV Line
J1102	Solar	Ameren Illinois	Logan County	IL	NRIS	70	Fogarty 138 kV Substation
J1107	Solar	Ameren Missouri	Cape Girardeau County	MO	NRIS	200	Kelso - Lutesville 345 kV Line Tap
J1111	Solar	Southern Illinois Power Cooperative	Jackson County	IL	NRIS	150	Campbell Hill - Jackson 161 kV Line Tap

J1112	Solar	Northern Indiana Public Service Company	Kosciusko County	IN	NRIS	150	Leesburg 138kV Substation
J1115	Wind	Ameren Illinois	Macon County	IL	NRIS	200	Latham - Oreana 345kV Line
J1139	Solar	Ameren Illinois	Champaign County	IL	NRIS	150	Sidney Substation 138 kV Bus
J1145	Solar	Ameren Missouri	Callaway County	MO	NRIS	250	Overton - (McCrede) - Montgomery 345 kV Line Tap
J1152	Solar	Indianapolis Power & Light Company	Hancock County, Shelby County	IN	NRIS	200	Gwynneville - Sunnyside 345 kV Line Tap
J1180	Solar	Ameren Illinois	Clark County	IL	NRIS	75	Casey West - Sullivan 345 kV Line
J1182	Solar	Ameren Transmission Company of Illinois	Adair County	MO	NRIS	250	Zachary Substation 345 kV Bus
J1189	Battery Storage	Duke Energy Indiana	Brown County, Martin County	IN	NRIS	4.95	Crane Solar 69kV Substation



1.2. Total Network Upgrades

The cost allocation of Network Upgrades for the projects in the DPP 2018 April Central Phase II reflects responsibilities for mitigating system impacts. The total cost of network upgrades is listed in Table 2 below. The costs for Network Upgrades are planning-level estimates and subject to revision in the facility studies.

Table 2: Total Cost of Network Upgrades for DPP 2018 April Central Phase II Projects

Project	ERIS Network Upgrades (\$)				NRIS Network Upgrades (\$)	Interconnection Facilities (\$)		Shared Network Upgrades (\$)	Total Network Upgrade Cost for Milestone Calculation (\$)	M2 (\$)	M3 (\$)	M4 (\$)
	Thermal	Stability	Short Circuit	Affected System	Deliverability	TO Network Upgrades	TO – Owned Direct Assigned					
a	b	c	d	e	f	g	h	i	j = b+c+d+f+g+i	\$4,000/MW	10% of (j) from Phase I-M2	(20% of (j) from Phase II)-M2-M3
J955	0	0	0	26,318,100	0	884,000	1,346,000	0	884,000	4,660,000	0	0.00
J956	0	0	0	0	8,734,641	1,170,000	1,626,000	0	9,904,641	800,000	9,725.10	1,171,203.10
J968	0	0	0	0	0	1,102,243	810,385	0	1,102,243	800,000	0	0.00
J974	0	0	0	4,777,168	0	1,596,000	1,092,000	0	1,596,000	1,000,000	0	0.00
J976	0	0	0	0	5,265,682	4,906,500	494,000	0	10,172,182	1,200,000	0	834,436.40
J979	0	0	0	3,275,500	0	4,042,000	1,519,000	0	4,042,000	800,000	0	8,400.00
J987	0	0	0	0	1,801,909	831,000	1,229,000	0	2,632,909	400,000	0	126,581.80
J991	0	0	0	298,000	0	2,391,000	1,199,000	0	2,391,000	800,000	0	0.00
J992	0	0	0	0	0	4,509,448	1,474,438	0	4,509,448	800,000	0	101,889.60
J993	0	0	0	0	0	16,350,303	569,301	0	16,350,303	800,000	242,500.00	2,227,560.60
J994	0	0	0	0	1,426,381	896,000	762,000	0	2,322,381	400,000	0	64,476.20
J1022	0	0	0	151,000	0	1,970,000	876,000	0	1,970,000	600,000	0	0.00
J1025	17,500,764	0	0	0	0	9,957,000	1,024,000	0	27,457,764	1,200,000	2,948,233.00	1,343,319.80
J1026	12,839,254	0	0	4,037,000	16,443,844	1,170,000	1,626,000	0	30,453,098	1,600,000	1,203,627.90	3,286,991.70
J1027	0	0	0	0	10,155,153	717,200	2,919,300	0	10,872,353	600,000	507,695.50	1,066,775.10
J1028	0	0	0	0	12,045,819	9,916,400	1,819,200	0	21,962,219	600,000	1,109,879.10	2,682,564.70
J1033	0	0	0	436,000	335,070	3,054,500	310,500	0	3,389,570	200,000	236,568.10	241,345.90
J1034	0	0	0	1,959,000	1,507,815	3,054,500	310,500	0	4,562,315	900,000	0	12,463.00
J1039	0	0	0	0	877,614	4,906,500	494,000	0	5,784,114	200,000	409,074.40	547,748.40
J1055	0	0	0	149,800	0	1,156,000	881,000	0	1,156,000	576,000	0	0.00
J1058	0	0	0	6,280,000	0	24,582,234	1,246,580	0	24,582,234	1,200,000	300,000.00	3,416,446.80
J1063	11,260,800	0	0	5,655,000	18,954,200	12,954,151	1,164,322	0	43,169,151	1,200,000	4,996,500.00	2,437,330.20
J1067	0	0	0	0	0	22,831,834	1,226,902	0	22,831,834	960,000	540,000.00	3,066,366.80
J1069	0	0	0	0	0	1,102,243	810,385	0	1,102,243	800,000	0	0.00
J1074	0	0	0	2,531,000	26,798,315	1,216,300	588,804	0	28,014,615	800,000	1,805,435.30	2,997,487.70

J1087	0	0	0	656,000	1,319,532	8,322,000	621,000	0	9,641,532	800,000	935,301.00	193,005.40
J1094	0	0	0	0	1,227,725	7,653,000	867,000	0	8,880,725	600,000	27,877.50	1,148,267.50
J1096	0	0	0	0	0	6,422,000	621,000	0	6,422,000	600,000	200,000.00	484,400.00
J1102	0	0	0	0	0	1,031,000	517,000	0	1,031,000	280,000	0	0.00
J1107	0	0	0	447,000	1,358,952	9,813,000	1,024,000	0	11,171,952	800,000	704,358.70	730,031.70
J1111	12,677,000	0	0	0	1,028,551	7,550,000	377,000	0	21,255,551	600,000	824,911.60	2,826,198.60
J1112	0	0	0	0	0	4,326,378	1,166,956	0	4,326,378	800,000	0	65,275.60
J1115	0	0	0	9,681,700	0	9,847,000	1,024,000	0	9,847,000	800,000	280,000.00	889,400.00
J1139	0	0	0	41,861,500	0	290,000	1,017,000	0	290,000	600,000	0	0.00
J1145	0	0	0	1,865,000	3,672,284	9,855,000	1,024,000	0	13,527,284	1,000,000	388,122.80	1,317,334.00
J1152	0	0	0	3,909,000	2,181,818	0	0	0	2,181,818	800,000	242,500.00	0.00
J1180	0	0	0	0	0	15,006,000	1,024,000	0	15,006,000	300,000	880,000.00	1,821,200.00
J1182	3,659,982	0	0	2,098,000	0	1,367,000	1,227,000	0	5,026,982		390,083.40	615,313.00
J1189	0	0	0	0	284,936	0	0	0	284,936	20,000	8,493.60	28,493.60

Analyses performed demonstrate the following transmission facilities are required to reliably interconnect this group of generators to the transmission system. Energy Resource Interconnection Service (ERIS) Network Upgrades and Network Resource Interconnection Service (NRIS) Network Upgrades are shown in Table 3. Shared Network Upgrades are shown in Table 4.

Table 3: ERIS & NRIS Upgrades (Planning level cost estimates)

Network Upgrade	TO	GI projects requiring upgrade for ERIS	GI projects requiring upgrade for NRIS	Cost of solution (\$)	TO Self-fund
2nd Maywood - Herleman 345kV Line	AMMO	J1026, J1025		21,000,000	Yes
2nd Zachary 345kV Transformer and 2nd Zachary - Adair Line 161kV Line	AMMO	J1025, J1182		13,000,000	Yes
Campbell Hill - Bremen 69kV Rebuild	SIPC	J1111		3,868,000	No
Bremen - Evansville Tap 69kV Rebuild	SIPC	J1111		3,396,000	No
Evansville Tap - Sparta Tap 69kV Rebuild	SIPC	J1111		3,492,000	No
Campbell Hill 161kV : 69kV Transformer	SIPC	J1111		1,921,000	No
Coly - McKnight 500kV Terminal Upgrades	EES		J1028, J1074, J1152	6,000,000	No
Manson - Clarkhill 69kV Rebuild	DEI	J1063		7,101,700	No
Potato Creek - Manson 69kV Rebuild	DEI	J1063		4,159,100	No
Clarkhill - Thorntown 69kV Rebuild	DEI		J1063	18,954,200	No
2nd J829 - Dresser 345kV Circuit	DEI		J1189, J1027, J1028, J1074	45,500,000	No
J1026 - Maywood 345kV Rebuild	AMMO		J1094, J1111, J1107, J1087, J1033, J1034, J1026, J956, J994,	45,000,000	Yes

Network Upgrade	TO	GI projects requiring upgrade for ERIS	GI projects requiring upgrade for NRIS	Cost of solution (\$)	TO Self-fund
			J1145, J987, J976, J1039		

Table 4: Shared Network Upgrades (Planning level cost estimates)

Shared Network Upgrade	TO	Higher queued projects associated with SNU	Study projects associated with SNU	Cost of solution (\$)
No Projects Met Criteria – N/A				

Note:

- 1) Details pertaining to upgrades, costs, and the execution plan for interconnection of the generating facility at the POI will be documented in the Facility Study for Interconnecting Generator.
- 2) Facilities that have been included as base case assumptions and the level of interconnection service that would be conditional upon these facilities being in service will be documented in the GIA (Generator Interconnection Agreement) for each respective GI request successfully achieving GIA execution.
- 3) Analysis performed shows there are two DPP-2018-APR Central projects for Shared Network Upgrade cost allocation.

2. FERC Order 827 Compliance Review

The Final Rule of FERC Order 827 “Reactive Power Requirements for Non-Synchronous Generation”, which was issued June 16, 2016, stated that “Under this Final Rule, newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of this Final Rule will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.” As such, this Final Rule applies to all non-synchronous (wind, solar, and battery storage) projects included in the DPP 2018 April Central study cycle.

In this study, the power factor at the high-side of the generator substation for each inverter based project was calculated and reviewed. The study method is to set Qgen of each study project at its Qmax, solve the case, then record the P and Q injection on the high side of the generator substation to calculate the lagging power factor (injecting VAR to the system). The same process is then repeated by setting Qgen at Qmin to calculate the leading power factor (absorbing VAR from the system).

The results show that all projects meets the requirement to maintain 0.95 leading power factor, however, four projects do not meet the requirement to provide reactive power capability corresponding to 0.95 lagging power factor, as highlighted in red below in **Table 5**. Additional reactive support will be needed for these projects to meet the FERC requirement on reactive power capability prior to the completion of their GIA.

Table 5: FERC Order 827 Review Results

FERC Order 827				Steady State (At Generator Substation)							
Project	Pmax (MW)	Reactive Power Capability (MVar)	Proposed VAR Compensation	VAR Injection			VAR Absorption			Meet FERC Order 827 Requirement?	Add'l VAR Needed (MVar)
				P (MW)	Q (MVar)	p.f. (pu)	P (MW)	Q (MVar)	p.f. (pu)		
J1022	155.3	72.53 -66.14	2 x 10 MVar Cap	152.0	71.3	0.9053	150.3	-105.8	-0.8177	Yes	
J1025	319.0	±104.835	1 x 50 MVar Cap	306.0	134.9	0.9150	301.8	-149.9	-0.8956	Yes	
J1026	413.6	±135.924	1 x 65 MVar Cap	390.2	143.9	0.9382	379.0	-247.4	-0.8374	Yes	
J1027	150.0	±25.144	N/A	148.1	-4.6	0.9995	147.7	-61.3	-0.9236	No	53.3
J1028	150.0	±25.144	N/A	147.8	-4.8	0.9995	147.4	-62.2	-0.9213	No	53.4
J0133 & J1034	275.0	±84.5	1 x 4 MVar Cap	270.9	37.2	0.9907	268.8	-163.4	-0.8545	No	51.8
J1039	50.0	±30	1 x 4 MVar Cap	49.6	24.8	0.8944	49.3	-45.0	-0.7386	Yes	
J1055	144.0	67.68 -80	1 x 7.5 MVar Cap	132.8	55.6	0.9224	125.6	-128.5	-0.6990	Yes	
J1058	200.0	±97.6	1 x 4 MVar Cap	197.0	74.4	0.9355	195.6	-134.9	-0.8232	Yes	
J1063	195	±95.2	2 x 4 MVar Cap	192.3	80.2	0.9229	191.2	-129.4	-0.8282	Yes	

J1067	240.0	±97.9	2 x 17 MVar Cap	236.9	91.6	0.9327	235.4	-161.4	-0.8248	Yes	
J1069	200.0	±81.6	2 x 14 MVar Cap	196.6	80.8	0.9249	195.1	-130.3	-0.8316	Yes	
J1074	200.0	±36.925	N/A	197.2	-1.8	1.0000	196.6	-84.8	-0.9182	No	66.6
J1087	200.0	±36.925	N/A	197.2	1.6	1.0000	196.6	-84.7	-0.9184	No	63.2
J1094	150.0	±25.144	N/A	148.0	-3.0	0.9998	147.6	-58.5	-0.9296	No	51.6
J1096	150.0	±25.144	N/A	148.0	-2.9	0.9998	147.5	-59.7	-0.9270	No	51.5
J1102	70.0	±28.555	1 x 8 MVar Cap	68.7	27.5	0.9284	68.2	-43.9	-0.8409	Yes	
J1107	200.0	±87.7	2 x 14 MVar Cap	197.4	82.2	0.9232	196.2	-142.2	-0.8097	Yes	
J1111	150.0	±25.144	N/A	148.0	-2.4	0.9999	147.7	-57.6	-0.9317	No	51.0
J1112	153.3	±74.2	N/A	151.5	57.4	0.9351	150.8	-101.3	-0.8301	Yes	
J1115	200.0	±65.793	4 x 15 MVar Cap	195.8	112.5	0.8671	194.3	-106.3	-0.8773	Yes	
J1139	151.2	±95.3400	N/A	149.4	74.0	0.8961	148.6	-127.8	-0.7582	Yes	
J1145	250.0	±119.07	N/A	246.5	68.0	0.9640	244.4	-200.6	-0.7730	No	13.0
J1152	200.0	±94.3	N/A	196.6	52.1	0.9666	194.4	-163.8	-0.7647	No	12.5
J1180	75.0	±65.233	4 x 6 MVar Cap 1 x 6 MVar Inductor	73.8	86.8	0.6478	73.2	-86.9	-0.6442	Yes	
J1182	250.0	±82.1710	N/A	248.3	60.8	0.9713	248.1	-107.2	-0.9180	No	20.8
J1189	4.95	0.0	N/A	4.9	0.3	0.9948	4.9	0.5	-0.9948	No	1.3
J956	200.6	±97	N/A	197.9	68.1	0.9456	196.9	-141.3	-0.8124	Yes	
J968	200.0	66 -64	2 x 12 MVar Cap	196.7	62.6	0.9529	195.6	-105.1	-0.8809	No	2.1
J974	250.0	82.5 -80	2 x 9 MVar Cap	244.0	61.7	0.9695	241.9	-137.2	-0.8698	No	18.5
J976	300.0	±146.4	2 x 4 MVar Cap	293.7	98.3	0.9483	289.9	-238.9	-0.7717	Yes	
J979	170.0	±56.1	2 x 19 MVar Cap	167.4	75	0.9126	166.6	-91.7	-0.8761	Yes	
J987	100.0	±44.24	2 x 7 MVar Cap	98.8	42.2	0.9196	98.2	-70.1	-0.8139	Yes	

J991	150.0	±66.36	2 x 14 MVar Cap	148.5	78.4	0.8843	148.1	-92.7	-0.8476	Yes	
J992	200.0	±88.48	2 x 14 MVar Cap	197.5	82.7	0.9224	196.2	-146.3	-0.8017	Yes	
J993	200.0	±88.48	2 x 14 MVar Cap	197.3	81.1	0.9249	196.0	-145.3	-0.8033	Yes	
J994	100.0	±44.24	2 x 7 MVar Cap	98.8	40.8	0.9243	98.0	-73.5	-0.8000	Yes	

3. Model Development and Study Assumptions

3.1. Base Case Models

The origin of the DPP 2018 April Central models is the MTEP 18 models with the Bench Cases including all pre-queued projects and associated network upgrades, while the Study Cases contain all of the interconnection requests in DPP 2018 April Central Phase II, in addition to all the facilities in the Bench Cases.

- Bench Cases
 - APR18-2023SH-Bench_Discharging_Phase_2 Final 041720.raw
 - APR18-2023SUM-Bench_Discharging_Phase_2 Final 041720.raw
- Study Cases
 - APR18-2023SH-Study_Charging_Phase_2 Final 041720.raw
 - APR18-2023SUM-Study_Charging_Phase_2 Final 041720.raw
 - APR18-2023SH-Study_Discharging_Phase_2 Final 041720.raw
 - APR18-2023SUM-Study_Discharging_Phase_2 Final 041720.raw

3.2. Monitored Elements

Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal rating (PSS®E Rating A), and for NERC category P1-P7 conditions branches were monitored for emergency rating (PSS®E Rating B). Voltage limits were specified for system intact and contingent conditions as per applicable Transmission Owner Planning Criteria.

3.3. Contingencies

The following contingencies were considered in the steady state analysis:

- 1) NERC Category P0 (system intact -- no contingencies)
- 2) NERC Category P1 contingencies
 - a. Single element outages, at buses with a nominal voltage of 68 kV and above
 - b. Multiple element NERC Category P1 contingencies
- 3) NERC Category P2-P7 contingencies
- 4) For all the contingencies and post-disturbance analyses, cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment disabled (fixed) and switched shunt adjustment enabled.

3.4. Study Methodology

Non-linear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP 2018 April Central generating facilities was evaluated by comparing the steady state performance of the transmission system in the Bench and Study Cases. Analyses used PSS®E version 33.7.0 and TARA version 1902.

3.5. Performance Criteria

A branch is considered a thermal constraint if the following conditions are met:

- 1) The generator has a larger than twenty percent (20%) sensitivity factor on the overloaded facilities under post-contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system-intact condition, or
- 2) The overloaded facility or the overload-causing contingency is at generator's outlet, or
- 3) The megawatt impact due to the generator is greater than or equal to twenty percent (20%) of the applicable rating (normal or emergency) of the overloaded facility, or
- 4) For any other constrained facility, where none of the Study Generators meet one of the above criteria, however, the cumulative MW impact of the group of study generators is greater than twenty percent (20%) of the rating of the facility, then only those study generators whose individual MW impact is greater than five percent (5%) of the rating of the facility and has DF greater than five percent (5%) will be responsible for mitigating the cumulative MW impact constraint, or
- 5) Impacts on Affected Systems would be classified as Injection constraints based on the Affected Systems' criteria, or
- 6) Any other applicable Transmission Owner FERC filed Local Planning Criteria are met.

A bus is considered a voltage constraint if both of the following conditions are met:

- 1) The bus voltage is outside of the applicable normal or emergency limits for the post change case, and
- 2) The change in bus voltage is greater than 0.01 per unit

All generators must mitigate thermal injection constraints and voltage constraints in order to obtain any type of Interconnection Service. Further, all generators requesting Network Resource Interconnection Service (NRIS) must mitigate constraints found by using the Deliverability algorithm, to meet the system performance criteria for NERC category P1 events, if DFAX due to the study generator is equal to or greater than 5%.

4. Thermal Analysis

The thermal analysis results for 2018 April show generator projects J1025, J1026, J1063, J1111, and J1182 causing constraints. The details pertaining to the thermal analysis can be found in Appendix A – Ameren System Impact Study Report (CEII) and Appendix C – MISO ERIS Analysis (CEII).

5. Voltage Analysis

The voltage analysis results for 2018 April show that the study generators do not cause any voltage violations. The details pertaining to the voltage analysis can be found in Appendix C – MISO ERIS Analysis (CEII).

6. Stability Analysis

The MISO DPP Stability analysis shows that the study projects did not adversely impact the system.

An additional stability study capturing the Ameren Local Planning Criteria (LPC) for new generation interconnections was also performed by Ameren and also shows that study projects did not adversely impact the system under the Ameren LPC for new generation interconnections. The details pertaining to the stability analysis can be found in Appendix F – MISO Stability Analysis (CEII) and Appendix G – Ameren Stability Analysis (CEII).

6.1. Model Development

The following summer/shoulder discharging 2023 models were developed based on Phase II study models. The Ameren LPC stability models were also developed based on the Phase II stability study models and were adjusted in order to comply with Ameren's LPC by fully dispatching nearby local generation.

- Bench Cases:
 - APR18-2023SH-Bench_Discharging_Phase_2 Final 041720.raw
 - APR18-2023SUM-Bench_Discharging_Phase_2 Final 041720.raw
- Study Cases:
 - APR18-2023SH-Study_Discharging_Phase_2 Final 041720.raw
 - APR18-2023SUM-Study_Discharging_Phase_2 Final 041720.raw

6.2. Study Methodology

The purpose of the study is to identify potential angular instabilities, voltage dip violations, and damping violations, if any, due to the interconnection of the projects in the DPP 2018 April Central study cycle under disturbance conditions, and the impact of all study projects on the system stability performance.

The MISO fault scenarios simulated in this study cover faults simulated as part of the MTEP18 analysis as well as selected three-phase (3PH) faults with normal clearing and single line to ground (SLG) faults with delayed clearing. Dynamic simulations of fault scenarios were performed using the DSATools TSAT program (version 18.0.10).

The Ameren fault scenarios that were simulated in their LPC study were created by Ameren and are localized around each study projects POI. The fault said Ameren used were not based off of the MTEP18 stability package. Ameren also used PSS/E to run the stability analysis.

Fault scenarios were first simulated using the study case and the results were reviewed. For scenarios that exhibited instability, the bench case was simulated such that the stability performance with and without the proposed interconnection projects could be compared. Any new stability problems attributed to the proposed interconnection projects are flagged and reported.

For each fault, rotor angles, speed deviation, and electrical power outputs of the study generators and the generators in the proximity were monitored. Voltages at selected buses, including all POI buses of the study projects and all future buses, were also monitored.

Additional Ameren LPC criteria is listed in section 6.3 below.

A summary of the generation dispatch for the Entergy LPC analysis has been tabulated in Appendix E – Entergy Local Planning Criteria Stability Analysis (CEII).

The fault scenarios simulated in the Entergy LPC study cover selected 3PH and 3PH P3 contingency faults with normal clearing. In each fault scenario, a generator is disconnected at 0.5 seconds and the simulation continues to run until 5.0 seconds at which point the fault is initiated and the total simulation run time is 20.0 seconds.

6.3. Study Criteria

The transient stability study criteria that was used as part of this study is based upon 2 sets of guidelines:

Ameren's Transmission Planning Criteria and Guidelines



Ameren Transmission Planning Criteria and Guidelines prescribe the fault scenarios that should be evaluated in a transient stability and a small signal stability analysis. These criteria state that plant transmission outlet is considered adequate, from the standpoint of stability, if the following conditions are met:

1. With all lines in service, the plant and remainder of the system shall remain stable when a sustained three-phase fault on any outlet facility is cleared in primary clearing time.
2. With all lines in service, the plant and the remainder of the system shall remain stable when a sustained single-line-to-ground fault on any two circuits of a multiple circuit tower line is cleared in primary clearing time.
3. With one outlet facility out of service, the plant and the remainder of the system shall remain stable when a sustained three-phase fault on any of the remaining outlet facilities is cleared in primary clearing time.
4. With all lines in service, the system and the remainder of the plant units shall remain stable when a sustained double-line-to-ground (2-L-G) fault on any Ameren 345, 230, 161 or 138 kV plant bus section or outlet facility is cleared in breaker-failure back-up clearing time including tripping of a transmission facility and generating unit(s), if any, on the bus associated with the "stuck breaker".

Ameren's transient voltage recovery criteria states that "following clearing of a fault resulting from single or multiple contingency events (Planning Events P1- P7), transmission voltages should return to 85% of nominal or greater within fifteen seconds".

MISO's Transmission Planning Criteria and Guidelines:

All renewable study projects are subject to the voltage ride-through and frequency ride-through criteria specified in NERC PRC-024-2 ("Generator Frequency and Voltage Protective Relay Settings") to check if the projects remain connected during frequency and voltage excursions. Specifically, PRC-024-2 mandates that protective relaying should be set in such a way that:

- Voltage Ride-Through: a generator shall withstand zero voltage at the POI (typically the primary side of the station transformer) for up to 0.15 seconds (9 cycles) and the ensuing voltage recovery period for three phase faults.
- Frequency Ride-Through: a generator shall maintain continuous operation between 59.5 and 60.5 Hz.

6.4. Study Results

Ameren Stability Results:

Based on the simulations performed in this study, the performance of the MISO projects J955, J976, J979, J987, J991, J994, J1022, J1026, J1055, J1107 and J1115 were found to be acceptable under the fault scenarios prescribed by the Ameren Planning Criteria and Guidelines.

Projects J1087, J1094 and J1096 may also be deemed to have acceptable performance if the frequency relay protection settings can be adjusted to allow the generators to ride through the Ameren prescribed fault scenarios. J991 will be subject to the local Xenia operating guide and will not be allowed to operate when it is active.

Ameren was not able to evaluate the voltage and frequency ride-through capability of MISO projects J956, J1033, J1039 and J1139 because the generator customer did not provide data to model voltage and frequency relays.

MISO projects J974, J1102, J1145 and J1180 will be required to implement STATCOMs or similar



devices since they were not able to ride-through the fault scenarios evaluated or were not able to maintain acceptable voltage profiles after the fault was cleared.

MISO project J1025 performance was found to be acceptable with the withdrawal of projects J966 and J1177 and an election change to project J1182.

There were no violations of Ameren's transient voltage recovery criteria at transmission buses. A few violations occurred at distribution buses which do not require mitigation. No issues with nearby synchronous generators were observed. The complete list of 3PH and SLG faults simulated as well as their corresponding results and plots are included in Appendix G – Ameren Stability Analysis (CEII).

MISO Stability Results:

No network upgrades were identified or assigned to any study projects. Only some model tuning is needed for specific projects prior to moving onto Phase 3.

J1055 summer plots observed oscillation issues associated with the Torque control model. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

J1069's Generic Renewable Drive Train Model need tuning as would not run. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

Some of J1022 summer plots observed oscillation issues. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

J1055, J968, J974, and J1087 tripped offline for various fault simulations. Relay protection models may need to be tuned to prevent this occurrence. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

The complete list of 3PH and SLG faults simulated as well as their corresponding results and plots are included in Appendix F – MISO Stability Analysis (CEII).

7. Short Circuit Analysis

The short circuit analysis results for 2018 April show that the study generators do not cause any short circuit violations. The details pertaining to the short circuit analysis can be found in Appendix H – Short Circuit Study Analysis (CEII).

8. Affected System Impact Study

The details pertaining to the AECl, PJM, SPP, and TVA Affected Systems studies are in Appendix I – AECl Affected Systems Study Report (CEII), Appendix J – PJM Affected Systems Study Report (CEII), Appendix K – SPP Affected Systems Study Report (CEII), Appendix L – TVA Affected Systems Study Report (CEII).

8.1. J955

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 21.20% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (MISO End)



Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned MISO upgrade is to replace the limiting terminal equipment with a cost estimate of \$2.5 million. The project is allocated 89.84% of the cost.

3. AD1-133 - Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to perform sag mitigation, upgrade station conductor, upgrade 2 breakers, 2 disconnect switches, and CTs with a cost estimate of \$20.5 million. The project is allocated 100% of the cost.

4. Pontiac - Loretto 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the Pontiac 345 kV breaker and replace 345 kV disconnect switch with a cost estimate of \$5 million. The project is allocated 50.24% of the cost.

8.2. J956

No affected systems mitigations were found to be required for this generator.

8.3. J968

No affected systems mitigations were found to be required for this generator.

8.4. J974

The PJM Study identified that this generator contributes to the following constraints:

1. Goodings 3B – Goodings 4B 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the 345 kV circuit breaker and station conductor with a cost estimate of \$3.2 million. The project is allocated 100% of the cost.

2. AB-122 – Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of \$6.925 million. The project is allocated 5.98% of the cost.

3. Crete – St. John 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of \$11.2 million. The project is allocated 1.19% of the cost. The second portion of the upgrade will replace a 345 kV breaker and associated equipment at Crete with a cost of \$6 million. The project is allocated 2.22% of the cost.

4. Wilton R – Wilton 3M 765 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to build-out and relocate the Wilton 765 kV bus and install 2 new breakers with a cost estimate of \$12 million. The project is allocated 1.82% of the cost.

5. East Frankford – Crete 345 kV

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the 161 kV jumpers for the transformer with a cost estimate of \$10.3 million. The project is allocated 6.58% of the cost.

8.5. J976

No affected systems mitigations were found to be required for this generator.

8.6. J979

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 4.39% of the cost.

2. Z2-087 Tap – Pontiac R 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace 2-345kV circuit breakers, 5-345kV disconnect switches, mitigate line sag, station conductor with relay package with a cost estimate of \$18.5 million. The project is allocated 16.52% of the cost.

8.7. J987

No affected systems mitigations were found to be required for this generator.

8.8. J991

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 5.96% of the cost.

8.9. J992

No affected systems mitigations were found to be required for this generator.

8.10. J993

No affected systems mitigations were found to be required for this generator.

8.11. J994

No affected systems mitigations were found to be required for this generator.

8.12. J1022



The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 3.03% of the cost.

8.13. J1025

No affected systems mitigations were found to be required for this generator.

8.14. J1026

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of \$8 million. The project is allocated 50.5% of the cost.

8.15. J1027

No affected systems mitigations were found to be required for this generator.

8.16. J1028

No affected systems mitigations were found to be required for this generator.

8.17. J1033

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of \$2,895,000. The project is allocated 9.64% of the cost.

2. Essex – Stoddard 161 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Essex to Stoddard 161 kV line with a cost estimate of \$861,000. The project is allocated 18.23% of the cost.

8.18. J1034

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of \$2,895,000. The project is allocated 43.35% of the cost.

2. Essex – Stoddard 161 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Essex to Stoddard 161 kV line with a cost estimate of \$861,000. The project is allocated 81.77% of the cost.

8.19. J1039

No affected systems mitigations were found to be required for this generator.

8.20. J1055

The PJM Study identified that this generator contributes to the following constraints:

1. AB-122 – Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of \$6.925 million. The project is allocated 2.16% of the cost.

8.21. J1058

The PJM Study identified that this generator contributes to the following constraints:

1. St John – St John Tap 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate the sag on the ComEd portion of the line with a cost estimate of \$20.8 million. The project is allocated 17.55% of the cost.

2. St John Tap – Greenacre 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the ComEd portion of the line with a cost estimate of \$7.9 million. The project is allocated 17.55% of the cost.

3. Greenacre Tap – Olive 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate the sag on the ComEd portion of the line with a cost estimate of \$13.9 million. The project is allocated 8.96% of the cost.

8.22. J1063

The PJM Study identified that this generator contributes to the following constraints:

1. Cayuga – Eugene 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a new 345 kV circuit in parallel with a cost estimate of \$12.095 million. The project is allocated 47% of the cost.

8.23. J1067



No affected systems mitigations were found to be required for this generator.

8.24. J1069

No affected systems mitigations were found to be required for this generator.

8.25. J1074

The PJM Study identified that this generator contributes to the following constraints:

1. Cayuga – Eugene 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a new 345 kV circuit in parallel with a cost estimate of \$12.095 million. The project is allocated 21% of the cost.

8.26. J1087

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of \$2,895,000. The project is allocated 22.66% of the cost.

8.27. J1094

No affected systems mitigations were found to be required for this generator.

8.28. J1096

No affected systems mitigations were found to be required for this generator.

8.29. J1102

No affected systems mitigations were found to be required for this generator.

8.30. J1107

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of \$2,895,000. The project is allocated 15.44% of the cost.

8.31. J1111

No affected systems mitigations were found to be required for this generator.

8.32. J1112

No affected systems mitigations were found to be required for this generator.

8.33. J1115

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 3.57% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (ComEd End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned ComEd upgrade is to replace 2-345kV circuit breakers, mitigate line sag, station conductor with relay package with a cost estimate of \$16.7 million. The project is allocated 27% of the cost.

3. AB2-047 Tap – Z2-087 Tap 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace 2-345kV circuit breakers, 5-345kV disconnect switches, mitigate line sag, station conductor with relay package with a cost estimate of \$18.5 million. The project is allocated 27% of the cost.

8.34. J1139

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 4.31% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (MISO End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned MISO upgrade is to replace the limiting terminal equipment with a cost estimate of \$2.5 million. The project is allocated 10.16% of the cost.

3. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (ComEd End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned ComEd upgrade is to replace 2-345kV circuit breakers, mitigate line sag, station conductor with relay package with a cost estimate of \$16.7 million. The project is allocated 73% of the cost.

4. AB2-047 Tap – Z2-087 Tap 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace 2-345kV circuit breakers, 5-345kV disconnect switches, mitigate line sag, station conductor with relay package with a cost estimate of \$18.5 million. The project is allocated 73% of the cost.

5. Z2-087 Tap – Pontiac R 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace 2-345kV circuit breakers, 5-345kV disconnect switches,



mitigate line sag, station conductor with relay package with a cost estimate of \$18.5 million. The project is allocated 83.48% of the cost.

6. Pontiac - Loretto 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the Pontiac 345 kV breaker and replace 345 kV disconnect switch with a cost estimate of \$5 million. The project is allocated 5.03% of the cost.

8.35. J1145

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of \$8 million. The project is allocated 23.3% of the cost.

8.36. J1152

The PJM Study identified that this generator contributes to the following constraints:

1. Cayuga – Eugene 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a new 345 kV circuit in parallel with a cost estimate of \$12.095 million. The project is allocated 32% of the cost.

8.37. J1180

No affected systems mitigations were found to be required for this generator.

8.38. J1182

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of \$8 million. The project is allocated 26.2% of the cost.

8.39. J1189

No affected systems mitigations were found to be required for this generator.

9. Deliverability Analysis

9.1. Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted NRIS. If the generator is deemed not fully deliverable, the customer can choose either to change the project to an Energy Resource (ER) project or to proceed with the system upgrades that will make the generator fully

deliverable. Generator Deliverability Study ensures that the Network Resources, on an aggregate basis, can meet the MISO aggregate load requirements during system peak condition without getting bottled up. The wind generators are tested at 100% of their maximum output level which then can be used to meet Resource Adequacy obligations, under Module E, of the MISO Transmission and Energy Market Tariff (TEMT).

MISO Generator Deliverability Study whitepaper describing the algorithm can be found in BPM 015 – Generation Interconnection, Appendix C.

9.2. Determining the MW Restriction

If one facility is overloaded based on the assessed “severe yet credible dispatch” scenario described in the study methodology, and the generator under study has a DF greater than 5%, part or all of its output is not deliverable. The restricted MW is calculated as following:

$$(\text{MW restricted}) = (\text{worst loading} - \text{MW rating}) / (\text{generator sensitivity factor})$$

If the result is larger than the maximum output of the generator, 100% of this generator’s output is not deliverable.

9.3. Deliverability Study Results

The limiting constraints (mon-con pairs) seen in the deliverability analysis for the 2018 Summer case are summarized in Appendix D - Deliverability Analysis (CEII).

9.3.1. J955

This generator is found to be fully deliverable for 1165 MW without any network upgrades.

9.3.2. J956

This generator is determined to be fully deliverable for 188.10 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 6 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 6: NRIS Results for J956

J956 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIIS and case assumptions)				188.10 MW (94.05%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIIS Analysis?	Projects Associate d with ERIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	200	42.10%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	8,734,642	45,000,000

9.3.3. J968

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.4. J974

This generator is found to be fully deliverable for 250 MW without any network upgrades.

9.3.5. J976

This generator is determined to be fully deliverable for 282.16 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 7 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 7: NRIS Results for J976

J976 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)				282.16 MW (94.05%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribu tion Factor	Constrai nt in ERIS Analysis ?	Projects Associate d with ERIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	300	16.92%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	5,265,682	45,000,000

9.3.6. J979

This generator is found to be fully deliverable for 170 MW without any network upgrades.

9.3.7. J987

This generator is determined to be fully deliverable for 94.05 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 9 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 8: NRIS Results for J987

J987 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)				94.05 MW (94.05%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	100	17.37%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087,	1,801,909	45,000,000

					J1094, J1107, J1111, J1145		
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9.3.8. J991

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.9. J992

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.10. J993

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.11. J994

This generator is determined to be fully deliverable for 94.05 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 10 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 9: NRIS Results for J994

J994 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERS and case assumptions)				94.05 MW (94.05%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERS Analysis?	Projects Associated with ERS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	100	13.75%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	1,426,381	45,000,000

9.3.12. J1022

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.13. J1025

This generator is found to be fully deliverable for 300 MW without any network upgrades.

9.3.14. J1026

This generator is determined to be fully deliverable for 329.18 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 12 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 10: NRIS Results for J1026

J1026 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERS and case assumptions)		329.18 MW (94.05%)					
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERS Analysis?	Projects Associated with ERS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	350	45.29%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	16,443,844	45,000,000

9.3.15. J1027

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 13 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 11: NRIS Results for J1027

J1027 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERS and case assumptions)		0 MW (0%)					
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERS Analysis?	Projects Associated with ERS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J829 – Dresser 345kV Line	150	5.99%	No	-	J1027, J1028, J1074, J1189	10,155,153	45,500,000

9.3.16. J1028

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 14 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 12: NRIS Results for J1028

J1028 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERS and case assumptions)		0 MW (0%)					
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERS Analysis?	Projects Associated with ERS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)

McKnight – Coly 500kV Line	0	5.02%	No	-	J1028, J1074, J1152	1,636,364	6,000,000
J829 – Dresser 345kV Line	150	6.22%	No	-	J1016, J1074, J1028, J1027, J1189	9,198,791	45,500,000

9.3.17. J1033

This generator is determined to be fully deliverable for 47.03 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 15 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 13: NRIS Results for J1033

J1033 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERS and case assumptions)					47.03 MW (94.06%)		
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERS Analysis?	Projects Associated with ERS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	50	6.46%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	335,070	45,000,000

9.3.18. J1034

This generator is determined to be fully deliverable for 211.62 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 16 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 14: NRIS Results for J1034

J1034 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERS and case assumptions)					211.62 MW (94.05%)		
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERS Analysis?	Projects Associated with ERS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	225	6.46%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039,	1,507,815	45,000,000

					J1087, J1094, J1107, J1111, J1145		
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9.3.19. J1039

This generator is determined to be fully deliverable for 47.03 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 17 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 15: NRIS Results for J1039

J1039 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERS and case assumptions)					47.03 MW (94.06%)		
Next Upgrade for Higher NRIS Level (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERS Analysis?	Projects Associated with ERS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	50	16.92%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	877,614	45,000,000

9.3.20. J1055

This generator is found to be fully deliverable for 144 MW without any network upgrades.

9.3.21. J1058

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.22. J1063

This generator is determined to be fully deliverable for 134.42 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 17 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 16: NRIS Results for J1063

J1063 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERS and case assumptions)					134.42 MW (68.93%)		
Next Upgrade for Higher NRIS Level (cumulative)	Level of Service	Distribution Factor	Constraint in ERS	Projects Associated	Projects Associate	Upgrade Cost	Total Cost of

(i.e. All upgrades must be made for 100% NRIS)	Attainable (MW)		Analysis?	with ERIS Constraint	d with NRIS Constraint	Allocated to Project	Upgrade (\$)
Clarkhill – Thorntown 69 kV	195	9.97%	No	-	J1063	18,954,200	18,954,200

9.3.23. J1067

This generator is found to be fully deliverable for 240 MW without any network upgrades.

9.3.24. J1069

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.25. J1074

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 19 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 17: NRIS Results for J1074

J1074 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)				0 MW (0%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
McKnight – Coly 500kV Line	0	5.02%	No	-	J1028, J1074, J1152	2,181,818	6,000,000
J829 – Dresser 345kV Line	200	10.89%	No	-	J1027, J1028, J1074, J1189	24,616,497	45,500,000

9.3.26. J1087

This generator is determined to be fully deliverable for 188.10 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 20 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 18: NRIS Results for J1087

J1087 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)				188.10 MW (94.05%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	200	6.36%	No	-	J956, J976, J987, J994, J1026, J1033,	1,319,532	45,000,000

					J1034, J1039, J1087, J1094, J1107, J1111, J1145		
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9.3.27. J1094

This generator is determined to be fully deliverable for 141.08 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 21 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 19: NRIS Results for J1094

J1094 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)					141.08 MW (94.05%)		
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	150	7.89%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	1,227,725	45,000,000

9.3.28. J1096

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.29. J1102

This generator is found to be fully deliverable for 70 MW without any network upgrades.

9.3.30. J1107

This generator is determined to be fully deliverable for 188.10 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 22 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 20: NRIS Results for J1107

J1107 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)					188.10 MW (94.05%)		
Next Upgrade for Higher NRIS Level (cumulative)	Level of Service	Distribution Factor	Constraint in ERIS	Projects Associated	Projects Associated	Upgrade Cost	Total Cost of

(i.e. All upgrades must be made for 100% NRIS)	Attainable (MW)		Analysis?	with ERI Constraint	with NRIS Constraint	Allocated to Project	Upgrade (\$)
J1026 – Maywood 345kV Rebuild	200	6.55%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	1,358,952	45,000,000

9.3.31. J1111

This generator is determined to be fully deliverable for 141.08 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 23 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 21: NRIS Results for J1111

J1111 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERI and case assumptions)				141.08 MW (94.05%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERI Analysis?	Projects Associated with ERI Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	150	6.61%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	1,028,551	45,000,000

9.3.32. J1112

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.33. J1115

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.34. J1139

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.35. J1145

This generator is determined to be fully deliverable for 235.13 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 25 shows the NRIS results

and cost estimates determined in the NRIS analysis.

Table 22: NRIS Results for J1145

J1145 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIIS and case assumptions)					235.13 MW (94.05%)		
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIIS Analysis?	Projects Associated with ERIIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J1026 – Maywood 345kV Rebuild	250	14.16%	No	-	J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145	3,672,284	45,000,000

9.3.36. J1152

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 19 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 23: NRIS Results for J1152

J1145 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIIS and case assumptions)					0 MW (0%)		
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIIS Analysis?	Projects Associated with ERIIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
McKnight – Coly 500kV Line	200	5.02%	No	-	J1028, J1074, J1152	2,181,818	6,000,000

9.3.37. J1180

This generator is found to be fully deliverable for 75 MW without any network upgrades.

9.3.38. J1182

This generator is found to be fully deliverable for 250 MW without any network upgrades.

9.3.39. J1189

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 27 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 24: NRIS Results for J1189

J1189 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)				0 MW (0%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J829 – Dresser 345kV Line	4.95	5.70%	No	-	J1027, J1028, J1074, J1189	318,896	45,500,000

10. Shared Network Upgrades Analysis

Shared Network Upgrade (SNU) Analysis tests for Network Upgrades driven by higher queued interconnection projects was performed for this System Impact Study.

The maximum MW impacts and Shared Network Upgrade (SNU) cost allocations appear in Table 28.

Table 25: Maximum MW Impact and SNU Cost Allocations

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total NU Cost (\$)	Cost Responsibility (\$)
N/A	N/A	N/A	N/A	N/A	N/A

11. Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the draft System Impact Study report date.

11.1. Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade identified in System Impact Study was provided by the corresponding transmission owning company.

11.2. Cost Allocation Methodology

The costs of Network Upgrades (NU) for a set of generation projects (one or more sub-groups or entire group with identified NU) are allocated based on the MW impact from each project on the constrained facilities in the Study Case.

Cost Allocation Methodology for Thermal Constraints

1. With all Study Group generation projects dispatched in the Post Case, all thermal constraints are identified.
2. Distribution factor from each project on each constraint is obtained.
3. For each thermal constraint, the maximum MW contribution (increasing flow) from each project is then calculated in the Post Case without any network upgrades.
4. For each thermal constraint, the cost estimates for one or a subset of NU are provided by the corresponding Transmission Owner.
5. Then the cost of each NU is allocated based on the pro rata share of the MW contribution from each project on the constraints mitigated or partly mitigated by this NU. The methodology to determine



the cost allocation of one NU is:

$$\text{Cost of NU} = \frac{\text{Project A cost portion of NU} \times \text{Max(Proj. A MW contribution on constraint)}}{\sum_i \text{Max(Proj. i MW contrution on constraint)}}$$

6. The total NU costs for each project are calculated if more than one NU is required.



Appendix A – Ameren System Impact Study Report (CEII)

Appendix B – Cost Allocation Summary (CEII)

Appendix C – MISO ERIS Analysis (CEII)

Appendix D – MISO Deliverability Analysis (CEII)

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Appendix I – AECI Affected Systems Study Report (CEII)

Appendix J – PJM Affected Systems Study Report (CEII)

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Appendix L – TVA Affected Systems Study Report (CEII)

Appendix M – MISO A10 Results (CEII)



MISO DPP 2018 April Central Area Study Phase III Report

10/12/2021

Revision 2

**MISO
720 City Center
Drive Carmel
Indiana 46032**
<http://www.misoenergy.org>

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1. Executive Summary

This report presents the results of a System Impact Study (SIS) performed to evaluate the interconnection of the generators in the DPP 2018 April Central Area Phase III (Central Area DPP III). The study was performed under the direction of MISO and reviewed by an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren (AMIL, AMMO, ATXI), Duke Energy (DEI), Hoosier Energy (HE), Indianapolis Power & Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), Southern Illinois Power Cooperative (SIPC), and Southern Indiana Gas & Electric Company (SIGE).

1.1. Project List

The original interconnection requests for DPP 2018 April Central Area had a total of 61 generation projects.

- Projects J957, J973, J983, J1012, J1017, J1018, J1019, J1035, J1066, J1080, J1116, J1118, and J1150 withdrew prior to the Phase I study.
- 48 generation projects with a combined nameplate rating of 9348.23 MW (ERIS) & 9348.23 MW (NRIS) were studied in Phase I.
- Projects J980, J985, J995, J1016, J1021, J1031, J1059, J1123, J1148, J1161 withdrew during Decision Point 1 (Prior to Phase II Kickoff).
- 39 generation projects with a combined nameplate rating of 7888.95 MW (ERIS) & 7838.95 MW (NRIS) were studied in Phase II.
- Projects J1033, J1039, J1111, J1112 withdrew during Decision Point 2 (Prior to Phase III Kickoff).
- 35 generation projects with a combined nameplate rating of 7,300 MW (ERIS) & 7,150 MW (NRIS) were studied in Phase III.

The Central Area DPP Phase III study was kicked off on March 16th, 2021 and consisted of the projects shown below in Table 1.

Table 1: List of DPP April 2018 Central Area Phase III Projects

Project	Fuel Type	Transmission Owner	County	State	Service Requested	MW	POI
J955	Gas	Ameren Transmission Company of Illinois	Sangamon County	IL	NRIS	1165	Austin Substation 345kV Bus
J956	Solar	Ameren Missouri	Ralls County	MO	NRIS	200	Spencer Creek 345kV Substation
J968	Wind	Northern Indiana Public Service Company	Jasper County, White County	IN	NRIS	200	Reynolds 345kV Substation

J974	Wind	Ameren Illinois	Fulton County, Peoria County	IL	NRIS	225	Mapleridge 345kV Switching Station
J976	Solar	Ameren Missouri	Warren County	MO	NRIS	300	Montgomery - Enon 345kV Line Tap
J979	Wind	Ameren Transmission Company of Illinois	Christian County	IL	NRIS	170	Pana Substation 345kV Bus
J987	Solar	Ameren Missouri	Montgomery County	MO	NRIS	100	Montgomery 161kV Substation
J991	Solar	Ameren Illinois	Clay County	IL	NRIS	150	Xenia 345kV Switching Station
J992	Solar	Duke Energy Indiana	Cass County	IN	NRIS	200	Walton 230kV Substation
J993	Solar	Indianapolis Power & Light Company	Boone County	IN	NRIS	200	Hortonville - Whitestown 345kV Line Tap
J994	Solar	Ameren Missouri	Callaway County	MO	NRIS	100	Guthrie 161 kV Substation
J1022	Wind	Ameren Illinois	McLean County	IL	ERIS	150	Weedman Substation 138kV Bus
J1025	Wind	Ameren Transmission Company of Illinois	Knox County	MO	NRIS	290	Zachary - Maywood 345 kV Line Tap
J1026	Wind	Ameren Missouri	Audrain County, Ralls County	MO	ERIS/NRIS	380/265	Maywood - Spencer Creek 345 kV Line Tap
J1027	Solar	Hoosier Energy	Pike County	IN	NRIS	150	Ratts 161 kV Substation
J1028	Solar	Hoosier Energy	Pike County	IN	NRIS	150	Ratts - Victory 161 kV Line Tap
J1034	Solar	Ameren Missouri	Stoddard County	MO	NRIS	225	Stoddard - Morley 161kV Line Tap
J1055	Wind	Ameren Illinois	Mason County	IL	NRIS	144	Mason Substation 138 kV Bus

J1058	Solar	Northern Indiana Public Service Company	Lake County	IN	NRIS	200	Schahfer-St. John 345kV Line Tap
J1063	Solar	Duke Energy	Clinton County	IN	NRIS	195	New London - Frankfort 230kV Line Tap
J1067	Solar	Northern Indiana Public Service Company	Jasper County,Pulaski County	IN	NRIS	240	Reynolds - Burr Oak 345kV Line
J1069	Wind	Northern Indiana Public Service Company	Jasper County,Pulaski County	IN	NRIS	200	Reynolds 345kV Substation
J1074	Solar	Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.	Gibson County	IN	NRIS	200	Francisco 138 kV sub
J1087	Solar	Ameren Missouri	Scott County	MO	NRIS	200	Miner - Kelso 161 kV Line Tap
J1094	Solar	Ameren Illinois	Washington County	IL	NRIS	150	Prest 138kV Switching Station
J1096	Solar	Ameren Illinois	Saline County	IL	NRIS	150	Norris City North - Muddy 138 kV Line
J1102	Solar	Ameren Illinois	Logan County	IL	NRIS	70	Fogarty 138 kV Substation
J1107	Solar	Ameren Missouri	Cape Girardeau County	MO	NRIS	200	Kelso - Lutesville 345 kV Line Tap
J1115	Wind	Ameren Illinois	Macon County	IL	NRIS	200	Latham - Oreana 345kV Line
J1139	Solar	Ameren Illinois	Champaign County	IL	NRIS	135	Sidney Substation 138 kV Bus

J1145	Solar	Ameren Missouri	Callaway County	MO	NRIS	250	Overton - (McCrede) - Montgomery 345 kV Line Tap
J1152	Solar	Duke Energy	Shelby County	IN	NRIS	200	Gwynneville 345kV Substation
J1180	Solar	Ameren Illinois	Clark County	IL	NRIS	75	Casey West - Sullivan 345 kV Line
J1182	Solar	Ameren Transmission Company of Illinois	Adair County	MO	NRIS	250	Zachary Substation 345 kV Bus
J1189	Battery Storage	Duke Energy Indiana	Brown County, Martin County	IN	NRIS	4.95	Crane Solar 69kV Substation

1.2. Total Network Upgrades

The cost allocation of Network Upgrades for the projects in the DPP 2018 April Central Phase III reflects responsibilities for mitigating system impacts. The total cost of network upgrades is listed in Table 2 below. The costs for Network Upgrades are planning-level estimates and subject to revision in the facility studies.

Table 2: Total Cost of Network Upgrades for DPP 2018 April Central Phase III Projects

Project	ERIS Network Upgrades (\$)				NRIS Network Upgrades (\$)	Interconnection Facilities (\$)		Shared Network Upgrades (\$)	Total Network Upgrade Cost (\$)	M2 (\$)	M3 (\$)	M4 (\$)
	Thermal	Stability	Short Circuit	Affected System	Deliverability	TO Network Upgrades	TO – Owned Direct Assigned					
a	b	c	d	e	f	g	h	i	j = b+c+d+f+g+i	\$4,000/MW	10% of (j) from Phase I-M2	(20% of (j) from Phase II)-M2-M3
J955	2,730,900	0	0	24,072,200	0	884,000	1,346,000	0	3,614,900	4,660,000	0	0.00
J956	0	0	0	0	0	1,170,000	1,626,000	0	1,170,000	800,000	9,725.10	1,171,203.10
J968	0	0	0	0	0	1,102,243	810,385	0	1,102,243	800,000	0	0.00
J974	0	0	0	4,777,168	0	1,596,000	1,092,000	0	1,596,000	1,000,000	0	0.00
J976	0	0	0	0	0	4,906,500	494,000	0	4,906,500	1,200,000	0	834,436.40
J979	15,000	0	0	1,953,800	0	4,042,000	1,519,000	0	4,057,000	800,000	0	8,400.00
J987	0	0	0	0	0	831,000	1,229,000	0	831,000	400,000	0	126,581.80
J991	0	0	0	298,000	0	2,391,000	1,199,000	0	2,391,000	800,000	0	0.00
J992	0	0	0	0	0	4,509,448	1,474,438	0	4,509,448	800,000	0	101,889.60
J993	0	0	0	0	0	16,350,303	569,301	0	16,350,303	800,000	242,500.00	2,227,560.60
J994	0	0	0	0	0	896,000	762,000	0	896,000	400,000	0	64,476.20
J1022	0	0	0	151,000	0	1,970,000	876,000	0	1,970,000	600,000	0	0.00
J1025	9,084,000	0	0	0	0	9,957,000	1,024,000	0	19,041,000	1,200,000	2,948,233.00	1,343,319.80
J1026	0	0	0	4,037,000	0	1,170,000	1,626,000	0	1,170,000	1,600,000	1,203,627.90	3,286,991.70
J1027	0	0	0	0	11,442,836	717,200	2,919,300	0	12,160,036	600,000	507,695.50	1,066,775.10
J1028	0	0	0	0	11,694,804	9,916,400	1,819,200	0	21,611,204	600,000	1,109,879.10	2,682,564.70
J1034	0	0	0	1,403,981	0	3,054,500	310,500	0	3,054,500	900,000	0	12,463.00
J1055	0	0	0	149,800	0	1,156,000	881,000	0	1,156,000	576,000	0	0.00
J1058	0	0	0	6,280,000	0	24,582,234	1,246,580	0	24,582,234	1,200,000	300,000.00	3,416,446.80
J1063	11,260,800	0	0	0	18,954,200	12,954,151	1,164,322	0	43,169,151	1,200,000	4,996,500.00	2,437,330.20
J1067	0	0	0	0	0	22,831,834	1,226,902	0	22,831,834	960,000	540,000.00	3,066,366.80
J1069	0	0	0	0	0	1,102,243	810,385	0	1,102,243	800,000	0	0.00
J1074	0	0	0	0	26,333,709	1,216,300	588,804	0	27,550,009	800,000	1,805,435.30	2,997,487.70
J1087	0	0	0	725,369	0	8,322,000	621,000	0	8,322,000	800,000	935,301.00	193,005.40
J1094	0	0	0	0	0	7,653,000	867,000	0	7,653,000	600,000	27,877.50	1,148,267.50

J1096	0	0	0	0	0	6,422,000	621,000	0	6,422,000	600,000	200,000.00	484,400.00
J1102	0	0	0	0	0	1,031,000	517,000	0	1,031,000	280,000	0	0.00
J1107	0	0	0	494,252	0	9,813,000	1,024,000	0	9,813,000	800,000	704,358.70	730,031.70
J1115	0	0	0	2,635,700	0	9,847,000	1,024,000	0	9,847,000	800,000	280,000.00	889,400.00
J1139	254,100	0	0	15,875,100	0	290,000	1,017,000	0	544,100	600,000	0	0.00
J1145	0	0	0	1,865,000	0	9,855,000	1,024,000	0	9,855,000	1,000,000	388,122.80	1,317,334.00
J1152	0	0	0	0	1,717,212	0	0	0	1,717,212	800,000	242,500.00	0.00
J1180	0	0	0	0	0	15,006,000	1,024,000	0	15,006,000	300,000	880,000.00	1,821,200.00
J1182	3,916,000	0	0	2,098,000	0	1,367,000	1,227,000	0	5,283,000		390,083.40	615,313.00
J1189	0	0	0	0	318,896	0	0	0	318,896	20,000	8,493.60	28,493.60

Analyses performed demonstrate the following transmission facilities are required to reliably interconnect this group of generators to the transmission system. Energy Resource Interconnection Service (ERIS) Network Upgrades and Network Resource Interconnection Service (NRIS) Network Upgrades are shown in Table 3. Shared Network Upgrades are shown in Table 4.

Table 3: ERIS & NRIS Upgrades (Planning level cost estimates)

Network Upgrade	TO	GI projects requiring upgrade for ERIS	GI projects requiring upgrade for NRIS	Cost of solution (\$)	TO Self-fund
2nd Zachary 345kV Transformer and 2nd Zachary - Adair Line 161kV Line	AMMO	J1025, J1182		13,000,000	Yes
Coly - McKnight 500kV Terminal Upgrades	EES		J1028, J1074, J1152, J1027	6,000,000	No
Manson – Clarkhill 69kV Rebuild	DEI	J1063		7,101,700	No
Potato Creek – Manson 69kV Rebuild	DEI	J1063		4,159,100	No
Clarkhill – Thorntown 69kV Rebuild	DEI		J1063	18,954,200	No
Decatur – Main St. 138 kV Structures	AMIL	J955, J979		500,000	Yes
2nd J829 - Dresser 345kV Circuit	DEI		J1189, J1027, J1028, J1074	45,500,000	No
Decatur – Main St. 138 kV Structures Rebuild	AMIL	J955, J979		500,000	Yes
Terminal Equipment replacement at Brokaw end of Brokaw - Z2-087 Tap line (MISO End)	AMIL	J955, J1139		2,500,000	Yes

Table 4: Shared Network Upgrades (Planning level cost estimates)

Shared Network Upgrade	TO	Higher queued projects associated with SNU	Study projects associated with SNU	Cost of solution (\$)
No Projects Met Criteria – N/A				

Note:

- 1) Details pertaining to upgrades, costs, and the execution plan for interconnection of the generating facility at the POI will be documented in the Facility Study for Interconnecting Generator.
- 2) Facilities that have been included as base case assumptions and the level of interconnection service that would be conditional upon these facilities being in service will be documented in the GIA (Generator Interconnection Agreement) for each respective GI request successfully achieving GIA execution.
- 3) Analysis performed shows there are two DPP-2018-APR Central projects for Shared Network Upgrade cost allocation.

2. FERC Order 827 Compliance Review

The Final Rule of FERC Order 827 “Reactive Power Requirements for Non-Synchronous Generation”, which was issued June 16, 2016, stated that “Under this Final Rule, newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of this Final Rule will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.” As such, this Final Rule applies to all non-synchronous (wind, solar, and battery storage) projects included in the DPP 2018 April Central study cycle.

In this study, the power factor at the high-side of the generator substation for each inverter based project was calculated and reviewed. The study method is to set Qgen of each study project at its Qmax, solve the case, then record the P and Q injection on the high side of the generator substation to calculate the lagging power factor (injecting VAR to the system). The same process is then repeated by setting Qgen at Qmin to calculate the leading power factor (absorbing VAR from the system).

The results show that all projects meets the requirement to maintain 0.95 leading power factor, however, four projects do not meet the requirement to provide reactive power capability corresponding to 0.95 lagging power factor, as highlighted in red below in **Table 5**. Additional reactive support will be needed for these projects to meet the FERC requirement on reactive power capability prior to the completion of their GIA.

Table 5: FERC Order 827 Review Results

FERC Order 827				Steady State (At Generator Substation)							
Project	Pmax (MW)	Reactive Power Capability (MVar)	Proposed VAR Compensation	VAR Injection			VAR Absorption			Meet FERC Order 827 Requirement?	Add'l VAR Needed (MVar)
				P (MW)	Q (MVar)	p.f. (pu)	P (MW)	Q (MVar)	p.f. (pu)		
J1022	155.3	72.53 -66.14	2 x 10 MVar Cap	152.0	71.3	0.9053	150.3	-105.8	-0.8177	Yes	
J1025	319.0	±104.835	1 x 50 MVar Cap	306.0	134.9	0.9150	301.8	-149.9	-0.8956	Yes	
J1026	413.6	±135.924	1 x 65 MVar Cap	390.2	143.9	0.9382	379.0	-247.4	-0.8374	Yes	
J1027	150.0	±25.144	N/A	148.1	-4.6	0.9995	147.7	-61.3	-0.9236	No	53.3
J1028	150.0	±25.144	N/A	147.8	-4.8	0.9995	147.4	-62.2	-0.9213	No	53.4
J1034	225	±109	1 x 4 MVar Cap	221.1	74.7	0.9474	218.5	-175.3	-0.78	Yes	
J1055	144.0	67.68 -80	1 x 7.5 MVar Cap	132.8	55.6	0.9224	125.6	-128.5	-0.6990	Yes	
J1058	200.0	±97.6	1 x 4 MVar Cap	197.0	74.4	0.9355	195.6	-134.9	-0.8232	Yes	
J1063	195	±95.2	2 x 4 MVar Cap	192.3	80.2	0.9229	191.2	-129.4	-0.8282	Yes	
J1067	240.0	±97.9	2 x 17 MVar Cap	236.9	91.6	0.9327	235.4	-161.4	-0.8248	Yes	
J1069	200.0	±81.6	2 x 14 MVar Cap	196.6	80.8	0.9249	195.1	-130.3	-0.8316	Yes	

J1074	200	±36.925	3 x 23 MVar Cap	197.4	78.4	0.9294	196.6	-84.8	-0.9182	Yes	
J1087	200	±36.925	N/A	197.2	1.6	1	196.6	-84.7	-0.9184	No	63.2
J1094	150	±25.144	N/A	148	-3	0.9998	147.6	-58.5	-0.9296	No	51.6
J1096	150	±25.144	N/A	148	-2.9	0.9998	147.5	-59.7	-0.927	No	51.5
J1102	70.0	±28.555	1 x 8 MVar Cap	68.7	27.5	0.9284	68.2	-43.9	-0.8409	Yes	
J1107	200.0	±87.7	2 x 14 MVar Cap	197.4	82.2	0.9232	196.2	-142.2	-0.8097	Yes	
J1115	200.0	±65.793	4 x 15 MVar Cap	195.8	112.5	0.8671	194.3	-106.3	-0.8773	Yes	
J1139	151.2	±95.3400	N/A	149.4	74.0	0.8961	148.6	-127.8	-0.7582	Yes	
J1145	250.0	±119.07	N/A	246.5	68.0	0.9640	244.4	-200.6	-0.7730	No	13.0
J1152	200.0	±94.3	N/A	196.6	52.1	0.9666	194.4	-163.8	-0.7647	No	12.5
J1180	75.0	±65.233	4 x 6 MVar Cap 1 x 6 MVar Inductor	73.8	86.8	0.6478	73.2	-86.9	-0.6442	Yes	
J1182	250.0	±82.1710	N/A	248.3	60.8	0.9713	248.1	-107.2	-0.9180	No	20.8
J1189	4.95	0.0	N/A	4.9	0.3	0.9948	4.9	0.5	-0.9948	No	1.3
J956	200.6	±97	N/A	197.9	68.1	0.9456	196.9	-141.3	-0.8124	Yes	
J968	200	66	2 x 14 MVar Cap	196.7	66.5	0.9473	195.6	-105.1	-0.8809	Yes	
J974	225	82.5	1 x 14 MVar Cap	225	63.1	0.9629	223.7	-129.4	-0.8656	No	10.9
J976	300.0	±146.4	2 x 4 MVar Cap	293.7	98.3	0.9483	289.9	-238.9	-0.7717	Yes	
J979	170.0	±56.1	2 x 19 MVar Cap	167.4	75	0.9126	166.6	-91.7	-0.8761	Yes	
J987	100.0	±44.24	2 x 7 MVar Cap	98.8	42.2	0.9196	98.2	-70.1	-0.8139	Yes	
J991	150.0	±66.36	2 x 14 MVar Cap	148.5	78.4	0.8843	148.1	-92.7	-0.8476	Yes	
J992	200.0	±88.48	2 x 14 MVar Cap	197.5	82.7	0.9224	196.2	-146.3	-0.8017	Yes	
J993	200.0	±88.48	2 x 14 MVar Cap	197.3	81.1	0.9249	196.0	-145.3	-0.8033	Yes	
J994	100.0	±44.24	2 x 7 MVar Cap	98.8	40.8	0.9243	98.0	-73.5	-0.8000	Yes	

3. Model Development and Study Assumptions

3.1. Base Case Models

The origin of the DPP 2018 April Central models is the MTEP 18 models with the Bench Cases including all pre-queued projects and associated network upgrades, while the Study Cases contain all of the interconnection requests in DPP 2018 April Central Phase III, in addition to all the facilities in the Bench Cases.

- Bench Cases
 - APR18-2023SH-Bench_Discharging_Phase_3 Final 041421.raw
 - APR18-2023SUM-Bench_Discharging_Phase_3 Final 041421.raw
- Study Cases
 - APR18-2023SH-Study_Charging_Phase_3 Final 041421.raw
 - APR18-2023SUM-Study_Charging_Phase_3 Final 041421.raw
 - APR18-2023SH-Study_Discharging_Phase_3 Final 041421.raw
 - APR18-2023SUM-Study_Discharging_Phase_3 Final 041421.raw

3.2. Monitored Elements

Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal rating (PSS®E Rating A), and for NERC category P1-P7 conditions branches were monitored for emergency rating (PSS®E Rating B). Voltage limits were specified for system intact and contingent conditions as per applicable Transmission Owner Planning Criteria.

3.3. Contingencies

The following contingencies were considered in the steady state analysis:

- 1) NERC Category P0 (system intact -- no contingencies)
- 2) NERC Category P1 contingencies
 - a. Single element outages, at buses with a nominal voltage of 68 kV and above
 - b. Multiple element NERC Category P1 contingencies
- 3) NERC Category P2-P7 contingencies
- 4) For all the contingencies and post-disturbance analyses, cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment disabled (fixed) and switched shunt adjustment enabled.

3.4. Study Methodology

Non-linear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP 2018 April Central generating facilities was evaluated by comparing the steady state performance of the transmission system in the Bench and Study Cases. Analyses used PSS®E version 33.7.0 and TARA version 1902.

3.5. Performance Criteria

A branch is considered a thermal constraint if the following conditions are met:

- 1) The generator has a larger than twenty percent (20%) sensitivity factor on the overloaded facilities under post-contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system-intact condition, or
- 2) The overloaded facility or the overload-causing contingency is at generator's outlet, or
- 3) The megawatt impact due to the generator is greater than or equal to twenty percent (20%) of the

- applicable rating (normal or emergency) of the overloaded facility, or
- 4) For any other constrained facility, where none of the Study Generators meet one of the above criteria, however, the cumulative MW impact of the group of study generators is greater than twenty percent (20%) of the rating of the facility, then only those study generators whose individual MW impact is greater than five percent (5%) of the rating of the facility and has DF greater than five percent (5%) will be responsible for mitigating the cumulative MW impact constraint, or
 - 5) Impacts on Affected Systems would be classified as Injection constraints based on the Affected Systems' criteria, or
 - 6) Any other applicable Transmission Owner FERC filed Local Planning Criteria are met.

A bus is considered a voltage constraint if both of the following conditions are met:

- 1) The bus voltage is outside of the applicable normal or emergency limits for the post change case, and
- 2) The change in bus voltage is greater than 0.01 per unit

All generators must mitigate thermal injection constraints and voltage constraints in order to obtain any type of Interconnection Service. Further, all generators requesting Network Resource Interconnection Service (NRIS) must mitigate constraints found by using the Deliverability algorithm, to meet the system performance criteria for NERC category P1 events, if DFAX due to the study generator is equal to or greater than 5%.

4. Thermal Analysis

The thermal analysis results for 2018 April show generator projects J955, J979, J1025, J1063, and J1182 causing constraints. The details pertaining to the thermal analysis can be found in Appendix A – Ameren System Impact Study Report (CEII) and Appendix C – MISO ERS Analysis (CEII).

NIPSCO LPC criteria was screened for in MISO's ERS analysis and did not yield any actionable constraints.

5. Voltage Analysis

The voltage analysis results for 2018 April show that the study generators do not cause any voltage violations. The details pertaining to the voltage analysis can be found in Appendix C – MISO ERS Analysis (CEII).

6. Stability Analysis

The MISO DPP Stability analysis shows that the study projects did not adversely impact the system.

An additional stability study capturing the Ameren Local Planning Criteria (LPC) for new generation interconnections was also performed by Ameren and also shows that study projects did not adversely impact the system under the Ameren LPC for new generation interconnections. The details pertaining to the stability analysis can be found in Appendix F – MISO Stability Analysis (CEII) and Appendix G – Ameren Stability Analysis (CEII).

6.1. Model Development

The following summer/shoulder discharging 2023 models were developed based on Phase III study models. The Ameren LPC stability models were also developed based on the Phase III stability study models and were adjusted in order to comply with Ameren's LPC by fully dispatching nearby local generation.

- Bench Cases:
 - APR18-2023SH-Bench_Discharging_Phase_3 Final 041421.raw
 - APR18-2023SUM-Bench_Discharging_Phase_3 Final 041421.raw
- Study Cases:
 - APR18-2023SH-Study_Discharging_Phase_3 Final 041421.raw
 - APR18-2023SUM-Study_Discharging_Phase_3 Final 041421.raw

6.2. Study Methodology

The purpose of the study is to identify potential angular instabilities, voltage dip violations, and damping violations, if any, due to the interconnection of the projects in the DPP 2018 April Central study cycle under disturbance conditions, and the impact of all study projects on the system stability performance.

The MISO fault scenarios simulated in this study cover faults simulated as part of the MTEP18 analysis as well as selected three-phase (3PH) faults with normal clearing and single line to ground (SLG) faults with delayed clearing. Dynamic simulations of fault scenarios were performed using the DSATools TSAT program (version 18.0.10).

The Ameren fault scenarios that were simulated in their LPC study were created by Ameren and are localized around each study projects POI. The fault said Ameren used were not based off of the MTEP18 stability package. Ameren also used PSS/E to run the stability analysis.

Fault scenarios were first simulated using the study case and the results were reviewed. For scenarios that exhibited instability, the bench case was simulated such that the stability performance with and without the proposed interconnection projects could be compared. Any new stability problems attributed to the proposed interconnection projects are flagged and reported.

For each fault, rotor angles, speed deviation, and electrical power outputs of the study generators and the generators in the proximity were monitored. Voltages at selected buses, including all POI buses of the study projects and all future buses, were also monitored.

Additional Ameren LPC criteria is listed in section 6.3 below.

NIPSCO LPC criteria studying in MISO's ERS analysis includes a 3% DF cutoff, or MW Impact from study generator greater to 3% of facility rating in GI studies for elements the NIPSCO TO area.

6.3. Study Criteria

The transient stability study criteria that was used as part of this study is based upon 2 sets of guidelines:

Ameren's Transmission Planning Criteria and Guidelines

Ameren Transmission Planning Criteria and Guidelines prescribe the fault scenarios that should be evaluated in a transient stability and a small signal stability analysis. These criteria state that plant transmission outlet is considered adequate, from the standpoint of stability, if the following conditions are met:

1. With all lines in service, the plant and remainder of the system shall remain stable when a sustained three-phase fault on any outlet facility is cleared in primary clearing time.
2. With all lines in service, the plant and the remainder of the system shall remain stable when a

sustained single-line-to-ground fault on any two circuits of a multiple circuit tower line is cleared in primary clearing time.

3. With one outlet facility out of service, the plant and the remainder of the system shall remain stable when a sustained three-phase fault on any of the remaining outlet facilities is cleared in primary clearing time.

4. With all lines in service, the system and the remainder of the plant units shall remain stable when a sustained double-line-to-ground (2-L-G) fault on any Ameren 345, 230, 161 or 138 kV plant bus section or outlet facility is cleared in breaker-failure back-up clearing time including tripping of a transmission facility and generating unit(s), if any, on the bus associated with the "stuck breaker".

Ameren's transient voltage recovery criteria states that "following clearing of a fault resulting from single or multiple contingency events (Planning Events P1- P7), transmission voltages should return to 85% of nominal or greater within fifteen seconds".

MISO's Transmission Planning Criteria and Guidelines:

All renewable study projects are subject to the voltage ride-through and frequency ride-through criteria specified in NERC PRC-024-2 ("Generator Frequency and Voltage Protective Relay Settings") to check if the projects remain connected during frequency and voltage excursions. Specifically, PRC-024-2 mandates that protective relaying should be set in such a way that:

- Voltage Ride-Through: a generator shall withstand zero voltage at the POI (typically the primary side of the station transformer) for up to 0.15 seconds (9 cycles) and the ensuing voltage recovery period for three phase faults.
- Frequency Ride-Through: a generator shall maintain continuous operation between 59.5 and 60.5 Hz.

6.4. Study Results

Ameren Stability Results:

Based on the simulations performed in this study, the performance of the MISO projects J955, J976, J979, J987, J991, J994, J1022, J1026, J1055, J1107 and J1115 were found to be acceptable under the fault scenarios prescribed by the Ameren Planning Criteria and Guidelines.

Projects J1087, J1094 and J1096 may also be deemed to have acceptable performance if the frequency relay protection settings can be adjusted to allow the generators to ride through the Ameren prescribed fault scenarios. J991 will be subject to the local Xenia operating guide and will not be allowed to operate when it is active.

Ameren was not able to evaluate the voltage and frequency ride-through capability of MISO projects J956, J1033, J1039 and J1139 because the generator customer did not provide data to model voltage and frequency relays.

MISO projects J974, J1102, J1145 and J1180 will be required to implement STATCOMs or similar devices since they were not able to ride-through the fault scenarios evaluated or were not able to maintain acceptable voltage profiles after the fault was cleared.

MISO project J1025 performance was found to be acceptable with the withdrawal of projects J966 and J1177 and an election change to project J1182.

There were no violations of Ameren's transient voltage recovery criteria at transmission buses. A few violations occurred at distribution buses which do not require mitigation. No issues with nearby



synchronous generators were observed. The complete list of 3PH and SLG faults simulated as well as their corresponding results and plots are included in Appendix G – Ameren Stability Analysis (CEII).

MISO Stability Results:

No network upgrades were identified or assigned to any study projects. Only some model tuning is needed for specific projects prior to moving onto Phase 3.

J1055 summer plots observed oscillation issues associated with the Torque control model. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

J1069's Generic Renewable Drive Train Model need tuning as would not run. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

Some of J1022 summer plots observed oscillation issues. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

J1055, J968, J974, and J1087 tripped offline for various fault simulations. Relay protection models may need to be tuned to prevent this occurrence. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

The complete list of 3PH and SLG faults simulated as well as their corresponding results and plots are included in Appendix F – MISO Stability Analysis (CEII).

7. Short Circuit Analysis

The short circuit analysis results for 2018 April show that the study generators do not cause any short circuit violations. The details pertaining to the short circuit analysis can be found in Appendix H – Short Circuit Study Analysis (CEII).

8. Affected System Impact Study

The details pertaining to the AECI, PJM, SPP, and TVA Affected Systems studies are in Appendix I – AECI Affected Systems Study Report (CEII), Appendix J – PJM Affected Systems Study Report (CEII), Appendix K – SPP Affected Systems Study Report (CEII), Appendix L – TVA Affected Systems Study Report (CEII).

8.1. J955

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 21.20% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (MISO End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned MISO upgrade is to replace the limiting terminal equipment with a cost estimate of \$2.5 million. The project is allocated 89.84% of the cost. The MISO portion of this upgrade has been classified as an ERIS upgrade and costs assigned reflect this, and the MISO TO for the NU is AMIL.

3. AD1-133 - Dresden 345 kV Overload



Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to perform sag mitigation, upgrade station conductor, upgrade 2 breakers, 2 disconnect switches, and CTs with a cost estimate of \$20.5 million. The project is allocated 100% of the cost.

4. Pontiac - Loretto 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the Pontiac 345 kV breaker and replace 345 kV disconnect switch with a cost estimate of \$5 million. The project is allocated 50.24% of the cost.

8.2. J956

No affected systems mitigations were found to be required for this generator.

8.3. J968

No affected systems mitigations were found to be required for this generator.

8.4. J974

The PJM Study identified that this generator contributes to the following constraints:

1. Goodings 3B – Goodings 4B 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the 345 kV circuit breaker and station conductor with a cost estimate of \$3.2 million. The project is allocated 100% of the cost.

2. AB-122 – Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of \$6.925 million. The project is allocated 5.98% of the cost.

3. Crete – St. John 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of \$11.2 million. The project is allocated 1.19% of the cost. The second portion of the upgrade will replace a 345 kV breaker and associated equipment at Crete with a cost of \$6 million. The project is allocated 2.22% of the cost.

4. Wilton R – Wilton 3M 765 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to build-out and relocate the Wilton 765 kV bus and install 2 new breakers with a cost estimate of \$12 million. The project is allocated 1.82% of the cost.

5. East Frankford – Crete 345 kV

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the 161 kV jumpers for the transformer with a cost estimate of \$10.3 million. The project is allocated 6.58% of the cost.

8.5. J976

No affected systems mitigations were found to be required for this generator.

8.6. J979

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 4.39% of the cost.

2. Z2-087 Tap – Pontiac R 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate line sag with a cost estimate of \$10.5 million. The project is allocated 16.52% of the cost.

8.7. J987

No affected systems mitigations were found to be required for this generator.

8.8. J991

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 5.96% of the cost.

8.9. J992

No affected systems mitigations were found to be required for this generator.

8.10. J993

No affected systems mitigations were found to be required for this generator.

8.11. J994

No affected systems mitigations were found to be required for this generator.

8.12. J1022

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 3.03% of the cost.

8.13. J1025

No affected systems mitigations were found to be required for this generator.

8.14. J1026

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of \$8 million. The project is allocated 50.5% of the cost.

8.15. J1027

No affected systems mitigations were found to be required for this generator.

8.16. J1028

No affected systems mitigations were found to be required for this generator.

8.17. J1034

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of \$2,895,000. The project is allocated 48.5% of the cost.

8.18. J1055

The PJM Study identified that this generator contributes to the following constraints:

1. AB-122 – Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of \$6.925 million. The project is allocated 2.16% of the cost.

8.19. J1058

The PJM Study identified that this generator contributes to the following constraints:

1. St John – St John Tap 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate the sag on the ComEd portion of the line with a cost estimate of \$20.8 million. The project is allocated 17.55% of the cost.

2. St John Tap – Greenacre 345 kV Overload



Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the ComEd portion of the line with a cost estimate of \$7.9 million. The project is allocated 17.55% of the cost.

3. Greenacre Tap – Olive 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate the sag on the ComEd portion of the line with a cost estimate of \$13.9 million. The project is allocated 8.96% of the cost.

8.20. J1067

No affected systems mitigations were found to be required for this generator.

8.21. J1069

No affected systems mitigations were found to be required for this generator.

8.22. J1087

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of \$2,895,000. The project is allocated 25.05% of the cost.

8.23. J1094

No affected systems mitigations were found to be required for this generator.

8.24. J1096

No affected systems mitigations were found to be required for this generator.

8.25. J1102

No affected systems mitigations were found to be required for this generator.

8.26. J1107

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of \$2,895,000. The project is allocated 17.07% of the cost.

8.27. J1115

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed



constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 3.57% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (ComEd End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned ComEd upgrade is to replace 2-345kV circuit breakers, mitigate line sag, station conductor with relay package with a cost estimate of \$9.1 million. The project is allocated 27% of the cost.

8.28. J1139

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of \$5 million. The project is allocated 4.31% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (MISO End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned MISO upgrade is to replace the limiting terminal equipment with a cost estimate of \$2.5 million. The project is allocated 10.16% of the cost. The MISO portion of this upgrade has been classified as an ERIS upgrade and costs assigned reflect this, and the MISO TO for the NU is AMIL

3. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (ComEd End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned ComEd upgrade is to replace 2-345kV circuit breakers, mitigate line sag, station conductor with relay package with a cost estimate of \$9.1 million. The project is allocated 73% of the cost.

4. Z2-087 Tap – Pontiac R 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate line sag with a cost estimate of \$10.5 million. The project is allocated 83.48% of the cost.

5. Pontiac - Loretto 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the Pontiac 345 kV breaker and replace 345 kV disconnect switch with a cost estimate of \$5 million. The project is allocated 5.03% of the cost.

8.29. J1145

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of \$8 million. The project is allocated 23.3% of the cost.



8.30. J1180

No affected systems mitigations were found to be required for this generator.

8.31. J1182

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of \$8 million. The project is allocated 26.2% of the cost.

8.32. J1189

No affected systems mitigations were found to be required for this generator.

9. Deliverability Analysis

9.1. Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted NRIS. If the generator is deemed not fully deliverable, the customer can choose either to change the project to an Energy Resource (ER) project or to proceed with the system upgrades that will make the generator fully deliverable. Generator Deliverability Study ensures that the Network Resources, on an aggregate basis, can meet the MISO aggregate load requirements during system peak condition without getting bottled up. The wind generators are tested at 100% of their maximum output level which then can be used to meet Resource Adequacy obligations, under Module E, of the MISO Transmission and Energy Market Tariff (TEMT).

MISO Generator Deliverability Study whitepaper describing the algorithm can be found in BPM 015 – Generation Interconnection, Appendix C.

9.2. Determining the MW Restriction

If one facility is overloaded based on the assessed “severe yet credible dispatch” scenario described in the study methodology, and the generator under study has a DF greater than 5%, part or all of its output is not deliverable. The restricted MW is calculated as following:

$$(\text{MW restricted}) = (\text{worst loading} - \text{MW rating}) / (\text{generator sensitivity factor})$$

If the result is larger than the maximum output of the generator, 100% of this generator's output is not deliverable.

9.3. Deliverability Study Results

The limiting constraints (mon-con pairs) seen in the deliverability analysis for the 2018 Summer case are summarized in Appendix D - Deliverability Analysis (CEII).

9.3.1. J955

This generator is found to be fully deliverable for 1165 MW without any network upgrades.

9.3.2. J956

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.3. J968

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.4. J974

This generator is found to be fully deliverable for 250 MW without any network upgrades.

9.3.5. J976

This generator is found to be fully deliverable for 300 MW without any network upgrades.

9.3.6. J979

This generator is found to be fully deliverable for 170 MW without any network upgrades.

9.3.7. J987

This generator is found to be fully deliverable for 170 MW without any network upgrades.

9.3.8. J991

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.9. J992

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.10. J993

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.11. J994

This generator is found to be fully deliverable for 100 MW without any network upgrades.

9.3.12. J1022

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.13. J1025

This generator is found to be fully deliverable for 290 MW without any network upgrades.

9.3.14. J1026

This generator is found to be fully deliverable for 170 MW without any network upgrades.

9.3.15. J1027

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 6 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 6: NRIS Results for J1027

J1027 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIIS and case assumptions)				0 MW (0%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIIS Analysis?	Projects Associated with ERIIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
McKnight – Coly 500kV Line	0	5.00%	No	-	J1027, J1028, J1074, J1152	1,280,228	6,000,000
J829 – Dresser 345kV Line	150	5.99%	No	-	J1027, J1028, J1074, J1189	10,155,153	45,500,000

9.3.16. J1028

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 7 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 7: NRIS Results for J1028

J1028 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIIS and case assumptions)				0 MW (0%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIIS Analysis?	Projects Associated with ERIIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
McKnight – Coly 500kV Line	0	6.14%	No	-	J1028, J1074, J1152	1,285,349	6,000,000
J829 – Dresser 345kV Line	150	6.22%	No	-	J1016, J1074, J1028, J1027, J1189	9,198,791	45,500,000

9.3.17. J1034

This generator is found to be fully deliverable for 225 MW without any network upgrades.

9.3.18. J1055

This generator is found to be fully deliverable for 144 MW without any network upgrades.

9.3.19. J1058

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.20. J1063

This generator is determined to be fully deliverable for 134.42 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 8 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 8: NRIS Results for J1063

J1063 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)		140.18 MW (71.89%)					
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associate d with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
Clarkhill – Thorntown 69 kV	195	9.97%	No	-	J1063	18,954,200	18,954,200

9.3.21. J1067

This generator is found to be fully deliverable for 240 MW without any network upgrades.

9.3.22. J1069

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.23. J1074

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 9 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 9: NRIS Results for J1074

J1074 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions)		0 MW (0%)					
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
McKnight – Coly 500kV Line	0	5.03%	No	-	J1028, J1074, J1152	1,717,212	6,000,000
J829 – Dresser 345kV Line	200	10.89%	No	-	J1027, J1028, J1074, J1189	24,616,497	45,500,000

9.3.24. J1087

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.25. J1094

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.26. J1096

This generator is found to be fully deliverable for 150 MW without any network upgrades.

9.3.27. J1102

This generator is found to be fully deliverable for 70 MW without any network upgrades.

9.3.28. J1107

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.29. J1115

This generator is found to be fully deliverable for 200 MW without any network upgrades.

9.3.30. J1139

This generator is found to be fully deliverable for 135 MW without any network upgrades.

9.3.31. J1145

This generator is found to be fully deliverable for 250 MW without any network upgrades.

9.3.32. J1152

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 10 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 10: NRIS Results for J1152

J1145 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIIS and case assumptions)				0 MW (0%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIIS Analysis?	Projects Associated with ERIIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
McKnight – Coly 500kV Line	200	5.03%	No	-	J1028, J1074, J1152	1,717,212	6,000,000

9.3.33. J1180

This generator is found to be fully deliverable for 75 MW without any network upgrades.

9.3.34. J1182

This generator is found to be fully deliverable for 250 MW without any network upgrades.

9.3.35. J1189

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 11 shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 11: NRIS Results for J1189

J1189 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIIS and case assumptions)				0 MW (0%)			
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIIS Analysis?	Projects Associated with ERIIS Constraint	Projects Associated with NRIS Constraint	Upgrade Cost Allocated to Project	Total Cost of Upgrade (\$)
J829 – Dresser 345kV Line	4.95	5.70%	No	-	J1027, J1028, J1074, J1189	318,896	45,500,000

10. Shared Network Upgrades Analysis

Shared Network Upgrade (SNU) Analysis tests for Network Upgrades driven by higher queued interconnection projects was performed for this System Impact Study.

The maximum MW impacts and Shared Network Upgrade (SNU) cost allocations appear in Table 12.

Table 12: Maximum MW Impact and SNU Cost Allocations

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total NU Cost (\$)	Cost Responsibility (\$)
N/A	N/A	N/A	N/A	N/A	N/A

11. Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the draft System Impact Study report date.

11.1. Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade identified in System Impact Study was provided by the corresponding transmission owning company.

11.2. Cost Allocation Methodology

The costs of Network Upgrades (NU) for a set of generation projects (one or more sub-groups or entire

group with identified NU) are allocated based on the MW impact from each project on the constrained facilities in the Study Case.

Cost Allocation Methodology for Thermal Constraints

1. With all Study Group generation projects dispatched in the Post Case, all thermal constraints are identified.
2. Distribution factor from each project on each constraint is obtained.
3. For each thermal constraint, the maximum MW contribution (increasing flow) from each project is then calculated in the Post Case without any network upgrades.
4. For each thermal constraint, the cost estimates for one or a subset of NU are provided by the corresponding Transmission Owner.
5. Then the cost of each NU is allocated based on the pro rata share of the MW contribution from each project on the constraints mitigated or partly mitigated by this NU. The methodology to determine the cost allocation of one NU is:

$$\text{Cost of NU} = \frac{\text{Project A cost portion of NU} \times \text{Max(Proj. A MW contribution on constraint)}}{\sum_i \text{Max(Proj. i MW contrution on constraint)}}$$

6. The total NU costs for each project are calculated if more than one NU is required.



Appendix A – Ameren System Impact Study Report (CEII)

Appendix B – Cost Allocation Summary (CEII)

Appendix C – MISO ERIS Analysis (CEII)

Appendix D – MISO Deliverability Analysis (CEII)

Appendix E – Network Upgrades Per Project (CEII)

Appendix F – MISO Stability Analysis (CEII)

Appendix G – Ameren Stability Analysis (CEII)

Appendix H – Short Circuit Study Analysis (CEII)

Appendix I – AECI Affected Systems Study Report (CEII)

Appendix J – PJM Affected Systems Study Report (CEII)

Appendix K – SPP Affected Systems Study Report (CEII)

Appendix L – TVA Affected Systems Study Report (CEII)

Appendix M – MISO A10 Results (CEII)