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MISO DPP 2016 August West Area Phase 3 Study

Prepared for

MISO

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Revision History

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Contents

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Executive Summary

This report presents results of a System Impact Study (SIS) performed to evaluate the interconnection of the DPP 2016 August Phase 3 West Area Group (DPP West Area) generating facilities. The results for 2022 scenario are summarized below.

1.1 Project List

The DPP West Area study group has thirteen (13) generation projects with a combined nameplate rating of 2302 MW. The DPP West Area generating facilities are listed in Table ES-1. The modeling details and projects' slider diagrams are shown in Appendix B.

Table ES-1: Generating Facilities in DPP 2016 August West Area Group

MISO Project #	Service Type	TO	County	State	Point Of Interconnection	Fuel Type	Max Output	SH MW	SPK MW	Stability MW
J302	NRIS	MDU	Emmons, Logan	ND	Heskett-Wishek 230 kV	Wind	101.2	101.2	15.79	101.2
J476	NRIS	MEC	Atchison	MO	Atchison Co-Orient 345 kV (1.7 mi from Atchison)	Wind	246	246	38.38	246
J503	NRIS	MDU	Emmons, Logan	ND	Heskett-Wishek 230 kV (20 miles NW of Wishek)	Wind	98.8	98.8	15.41	98.8
J512	NRIS	Xcel	Nobles	MN	Nobles-Fenton 115 kV	Wind	250	250	39.00	250
J541	NRIS	ATXI	Schuyler	MO	Zachary–Ottumwa 345 kV	Wind	400	400	62.40	400
J555	NRIS	MEC	Poweshiek	IA	Montezuma 345 kV	Wind	140	140	21.84	140
J569	NRIS	Xcel	Rock	MN	Rock County 161 kV	Wind	100	100	15.60	100
J583	NRIS	MEC	Audubon	IA	Fallow 345 kV	Wind	200	200	31.20	200
J587	NRIS	Xcel	Lincoln	MN	J460 Sub on the Brookings-H081 345 kV	Wind	200	200	31.20	200
J590	NRIS	MEC	Palo Alto	IA	J529 POI	Wind	90	90	14.04	90
J598	NRIS	ATXI	Adair, Schuyler	MO	Zachary–Ottumwa 345 kV	Wind	300	300	46.80	300
J611	NRIS	MEC	Nodaway	MO	Clarinda-Merryville 161 kV	Wind	110	110	17.16	110
J614	NRIS	SMMPA	Howard	IA	Rice 161 kV	Wind	66	66	10.30	66

1.2 Reactive Power Requirements for Non-Synchronous Generation (FERC Order 827)

For non-synchronous generation projects in the DPP 2016 August West Area study group, if they do not have signed Generator Interconnection Agreement (GIA) or Provisional GIA

(PGIA) by September 21, 2016, they are 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.

Except for generation project J590, all other non-synchronous generation projects in this study group are required to meet the reactive power requirements per FERC Order 827.

The reactive power requirement analysis results are summarized as following:

- J587 does not meet the reactive power requirements per FERC Order 827. This requirement can be met by installation of additional reactive power support at the project site.
- J590 is exempted from the FERC Order 827 reactive power requirements.
- All other non-synchronous generation projects can meet the reactive power requirements per FERC Order 827.

1.3 Total Network Upgrades for all Projects

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 System Impact Study report date. The total cost of network upgrades in the interconnection plan required for each generation project is listed in Table ES-2. The costs for Network Upgrades are planning level estimates and subject to be revised in the facility studies.

Table ES-2: Total Cost of Network Upgrades for DPP 2016 August West Area Generation Projects

Project Num	ERIS Network Upgrades ($)												NRIS Network Upgrades ($)	Interconnection Facilities ($)		SNU ($)	Total Cost (Exclude TOIF) ($)
	MISO Thermal & Voltage	Voltage Stability	Transient Stability	Short Circuit	DPC LPC	MDU LPC	Ameren LPC	CIPCO AFS	MPC AFS	PJM AFS	SPP AFS	AECI AFS		TO Network Upgrades	TO - Owned Direct assigned		
J302	$22,036,067	$0	$0	$0	$0	$6,881,600	$0	$0	$0	$0	$0	$0	$6,389,374	$3,250,000	NA	$0	$38,557,041
J476	$3,667,082	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,489	$11,440,000	$825,000	$0	$15,113,571
J503	$21,513,473	$0	$0	$0	$0	$6,718,400	$0	$0	$0	$0	$0	$0	$6,237,848	$3,250,000	NA	$0	$37,719,720
J512	$26,033,722	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,384	$7,490,000	$1,211,000	$0	$33,527,106
J541	$20,305,014	$0	$0	$0	$0	$0	$5,142,857	$0	$0	$0	$0	$3,380,000	$33,403	$8,500,000	$500,000	$56,466	$34,037,740
J555	$10,532,611	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,132	$0	NA	$53,463	$10,600,206
J569	$8,977,031	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,483	$0	$325,800	$0	$8,978,515
J583	$7,881,828	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,320	$3,267,000	$825,000	$0	$11,156,147
J587	$19,832,540	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,309	$2,149,000	$955,000	$0	$21,983,848
J590	$8,718,803	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,427	$0	NA	$0	$8,720,230
J598	$15,230,612	$0	$0	$0	$0	$0	$3,857,143	$0	$0	$0	$0	$0	$25,059	$8,500,000	$500,000	$54,429	$27,667,242
J611	$2,519,702	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$202,773	$7,000,000	NA	$70,650	$9,793,125
J614	$4,651,516	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,682,249	$852,822	$0	$8,333,765
Total ($)	**$171,900,000**	**$0**	**$0**	**$0**	**$0**	**$13,600,000**	**$9,000,000**	**$0**	**$0**	**$0**	**$0**	**$3,380,000**	**$12,925,000**	**$58,528,249**	**NA**	**$235,008**	**$266,188,257**

The study was performed under the direction of MISO by Siemens PTI and 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, American Transmission Company, Basin Electric Power, Cedar Falls Utilities, Central Iowa Power Cooperative, City of Springfield (IL) Water Light & Power, Columbia (MO) Water and Light, Commonwealth Edison, Corn Belt Power Cooperative, Dairyland Power, Great River Energy, ITC Midwest, Lincoln Electric System, Manitoba Hydro, MidAmerican Energy Company, MISO, Minnesota Power, Minnkota Power, Missouri River Energy Services, Montana-Dakota Utilities Co., Muscatine Power & Water, Nebraska Public Power District, Northwestern Public Service, Omaha Public Power District, Otter Tail Power, PJM, Southern Illinois Power Cooperative, Southern Minnesota Municipal Power Agency, SPP, Western Area Power Administration, and Xcel Energy.

1.4 Per Project Summary

This section provides estimated cost of Network Upgrades on a per project basis for the 2022 scenario. The shared cost of Network Upgrades for all the generation projects are listed below.

The Interconnection Customers are required to mitigate the constraints observed from the 2022 scenario.

1.4.1 J302 Summary

Network Upgrade	Cost	J302	NUs Type
J302&J503 POI-Heskett 230 kV	$9,000,000	$4,554,000	MISO SH & MDU LPC
Hankinson-Forman 230 kV	$650,000	$328,900	MISO SH
Oakes-Forman 230 kV	$19,950,000	$10,094,700	MISO SH
Oakes-Ellendale 230 kV	$20,500,000	$10,373,000	MISO SH
Merricourt-Ellendale 230 kV	$4,600,000	$2,327,600	MDU LPC
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$382,067	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$489,580	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$134,627	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$233,193	Reactive Power NU
Square Butte-Stanton 230 kV (NRIS)	$10,975,000	$5,553,350	NRIS
Merricourt-Ellendale 230 kV (NRIS)	$50,000	$25,300	NRIS
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$1,124	NRIS
J302 POI-J607 POI-Wishek 230 kV (NRIS)	$750,000	$379,500	NRIS

Network Upgrade	Cost	J302	NUs Type
Wishek-Merricourt 230 kV (NRIS)	$850,000	$430,100	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$35,307,041**	

1.4.2 J476 Summary

Network Upgrade	Cost	J476	NUs Type
J530 POI-Hills 345 kV	$27,000,000	$1,560,562	MISO SH
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$624,846	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$463,179	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$928,975	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$89,520	Reactive Power NU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$6,489	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$3,673,571**	

1.4.3 J503 Summary

Network Upgrade	Cost	J503	NUs Type
J302&J503 POI-Heskett 230 kV	$9,000,000	$4,446,000	MISO SH & MDU LPC
Hankinson-Forman 230 kV	$650,000	$321,100	MISO SH
Oakes-Forman 230 kV	$19,950,000	$9,855,300	MISO SH
Oakes-Ellendale 230 kV	$20,500,000	$10,127,000	MISO SH
Merricourt-Ellendale 230 kV	$4,600,000	$2,272,400	MDU LPC
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$373,007	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$477,969	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$131,434	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$227,663	Reactive Power NU
Square Butte-Stanton 230 kV (NRIS)	$10,975,000	$5,421,650	NRIS
Merricourt-Ellendale 230 kV (NRIS)	$50,000	$24,700	NRIS
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$1,098	NRIS
J302 POI-J607 POI-Wishek 230 kV (NRIS)	$750,000	$370,500	NRIS

Network Upgrade	Cost	J503	NUs Type
Wishek-Merricourt 230 kV (NRIS)	$850,000	$419,900	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$34,469,720**	

1.4.4 J512 Summary

Network Upgrade	Cost	J512	NUs Type
Helena-Scott Co 345 kV	$54,000,000	$22,404,560	MISO SH
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$1,457,618	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$1,354,958	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$430,170	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$386,416	Reactive Power NU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$3,384	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$26,037,106**	

1.4.5 J541 Summary

Network Upgrade	Cost	J541	NUs Type
J530 POI-Montezuma 345 kV	$350,000	$157,374	MISO SH
J530 POI-Hills 345 kV	$27,000,000	$10,342,658	MISO SH
Ottumwa 345-161 kV xfmr	$9,000,000	$4,639,994	MISO SH
Zachary 345/161 kV transformer	$7,000,000	$4,000,000	Ameren LPC
Zachary-Adair 161 kV line	$2,000,000	$1,142,857	Ameren LPC
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$5,164,988	Reactive Power NU
Novelty 161 -69 kV xfmr	$3,270,000	$3,270,000	AECI AFS
South River-Emerson 161 kV	$110,000	$110,000	AECI AFS
J530 POI-Hills 345 kV (SNU)	$300,000	$56,466	SNU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$33,403	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$28,917,740**	

1.4.6 J555 Summary

Network Upgrade	Cost	J555	NUs Type
J530 POI-Montezuma 345 kV	$350,000	$74,581	MISO SH
J530 POI-Hills 345 kV	$27,000,000	$4,915,735	MISO SH
Parnell-J438 POI 161 kV	$250,000	$250,000	MISO SH
Ottumwa 345-161 kV xfmr	$9,000,000	$879,896	MISO SH
Parnell-Hills 161 kV	$1,400,000	$1,400,000	MISO SH
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$442,848	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$371,523	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$2,198,028	Reactive Power NU
J530 POI-Hills 345 kV (SNU)	$300,000	$53,463	SNU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$14,132	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$10,600,206**	

1.4.7 J569 Summary

Network Upgrade	Cost	J569	NUs Type
Helena-Scott Co 345 kV	$54,000,000	$7,579,499	MISO SH
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$553,316	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$510,070	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$192,851	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$141,295	Reactive Power NU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$1,483	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$8,978,515**	

1.4.8 J583 Summary

Network Upgrade	Cost	J583	NUs Type
J530 POI-Hills 345 kV	$27,000,000	$1,755,753	MISO SH
Grimes-Sycamore 345 kV #2	$2,200,000	$2,200,000	MISO SH

Network Upgrade	Cost	J583	NUs Type
Bondurant-Sycamore 345 kV	$1,000,000	$1,000,000	MISO SH
Bondurant-Montezuma 345 kV	$200,000	$600,000	MISO SH
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$652,054	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$533,378	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$1,082,081	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$58,562	Reactive Power NU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$7,320	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$7,889,147**	

1.4.9 J587 Summary

Network Upgrade	Cost	J587	NUs Type
Helena-Scott Co 345 kV	$54,000,000	$16,799,157	MISO SH
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$886,888	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$1,047,667	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$280,020	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$818,808	Reactive Power NU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$2,309	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$19,834,848**	

1.4.10 J590 Summary

Network Upgrade	Cost	J590	NUs Type
Helena-Scott Co 345 kV	$54,000,000	$7,216,784	MISO SH
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$765,604	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$539,157	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$188,109	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$9,148	Reactive Power NU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$1,427	NRIS

Network Upgrade	Cost	J590	NUs Type
Total Cost Per Project for Actual NRIS Elections for each Project		**$8,720,230**	

1.4.11 J598 Summary

Network Upgrade	Cost	J598	NUs Type
J530 POI-Montezuma 345 kV	$350,000	$118,045	MISO SH
J530 POI-Hills 345 kV	$27,000,000	$7,758,196	MISO SH
Ottumwa 345-161 kV xfmr	$9,000,000	$3,480,110	MISO SH
Zachary 345/161 kV transformer	$7,000,000	$3,000,000	Ameren LPC
Zachary-Adair 161 kV line	$2,000,000	$857,143	Ameren LPC
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$3,874,260	Reactive Power NU
J530 POI-Hills 345 kV (SNU)	$300,000	$54,429	SNU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$25,059	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$19,167,242**	

1.4.12 J611 Summary

Network Upgrade	Cost	J611	NUs Type
J530 POI-Hills 345 kV	$27,000,000	$667,095	MISO SH
J611-Maryville 161 kV	$1,000,000	$1,000,000	MISO SH
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$247,461	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$175,293	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$394,458	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$35,395	Reactive Power NU
J274 POI-Creston 161 kV (SNU)	$160,000	$54,990	SNU
Clarinda-Brooks 161 kV (SNU)	$68,000	$15,660	SNU
Montezuma-J530 POI 345 kV (NRIS)	$100,000	$2,773	NRIS
MCKSBRG-Winterset 161 kV (NRIS)	$200,000	$200,000	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$2,793,125**	

1.4.13 J614 Summary

Network Upgrade	Cost	J614	NUs Type
Harmony-Cresco 69 kV	$4,000,000	$4,000,000	MISO SH & DPC LPC
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$114,291	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$537,225	Reactive Power NU
Total Cost Per Project for Actual NRIS Elections for each Project		**$4,651,516**	

Some generation projects are conditional on MTEP projects, these are:

Generator	Constraint	Type	Conditional on MTEP Appendix A Projects
J614	Rice 161-69 kV xfmr	ERIS	MOD project # 110359 to increase the Rice 161/69kV transformer to 190 MVA rating as per the GIA J614.
J302, J503	Low voltage in area of Donaldson 115 kV	ERIS	MTEP Project 13043 will add 2X15 Mvar at Donaldson 115 kV

If a MTEP transmission project(s) resolves the constraint, and that project(s) is approved by the Board within (1) calendar year of the Generator Interconnection Agreement (GIA) execution or execution of an amendment thereof, then the Interconnection Customer will not be responsible for transmission upgrade(s) that would resolve the constraint. If that MTEP project(s) is not approved within one (1) calendar year of the GIA execution or execution of an amendment thereof, the Interconnection Customer will be responsible for those transmission upgrade(s).

1.5 Study Compliance with NERC FAC-002-2 Standard

This DPP 2016 August West Area study was completed in compliance with NERC FAC-002-2:

R1.1: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s).

Section 3 covers summer peak steady-state analysis results which include thermal and voltage constraints impacted by the DPP West Area generating facilities.

Section 4 covers summer shoulder steady-state analysis results which include thermal and voltage constraints impacted by the DPP West Area generating facilities. Thermal and voltage upgrades required to interconnect the new generating facilities are also identified.

Section 5.1 covers reliability impact of the generating facilities per MDU Local planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

Section 5.2 covers reliability impact of the generating facilities per DPC Local planning Criteria (LPC).

Section 5.3 covers reliability impact of the generating facilities per Ameren Local planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

Section 6.1 covers reliability impact of the new generating facilities in the CIPCO affected systems.

Section 6.2 covers reliability impact of the new generating facilities in the MPC affected systems.

Section 6.3 covers reliability impact of the new generating facilities in the PJM affected systems.

Section 6.4 covers reliability impact of the new generating facilities in the SPP affected systems.

Section 6.5 covers reliability impact of the new generating facilities in the AECI affected systems. Network Upgrades required to interconnect the new generating facilities are also identified.

Section 7 covers transient stability analysis results.

Section 8 covers voltage stability (PV) analysis on the MWEX System Operating Limit (SOL).

Section 9 covers short circuit reliability impact of the new generating facilities.

Section 10 covers Deliverability reliability impact of the new NRIS generating facilities.

R1.2: Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements.

Sections 2.2-2.4, Section 5, Section 6, and Section 7 all cover NERC Reliability Standard TPL-001-4.

Section 5.1 covers MDU LPC.

Section 5.2 covers DPC LPC.

Section 5.3 covers Ameren LPC.

Section 6.1 covers CIPCO system planning criteria.

Section 6.2 covers MPC system planning criteria.

Section 6.3 covers PJM system planning criteria.

Section 6.4 covers SPP system planning criteria.

Section 6.5 covers AECI system planning criteria.

Section 8 (voltage stability analysis) covers individual system planning criteria (ATC).

Section 10 covers MISO system planning criteria.

R1.3: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions.

Section 3 and Section 4 cover MISO steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.1 covers MDU's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.2 covers DPC's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.3 covers Ameren's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.1 covers CIPCO steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.2 covers MPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.3 covers PJM assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.4 covers SPP steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.5 covers AECI steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 7 covers transient stability studies under NERC category P0 to P7 contingencies (TPL-001-4).

Section 8 covers steady-state voltage stability assessment.

Section 9 covers short-circuit assessment.

Section 10 covers MISO deliverability study (steady-state assessment) including NERC category P0 to P1 contingencies (TPL-001-4).

R1.4: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.

Section 2.1, Section 2.2, Section 2.3, Section 2.4, Section 7.2, Section 7.3, and Section 7.4 cover study assumptions and system performance criteria.

Jointly coordinated recommendations can be found in Section 5.1 (MISO and MDU), Section 5.2 (MISO and DPC), Section 5.3 (MISO and Ameren), Sections 6.1 (MISO and CIPCO), Section 6.2 (MISO and MPC), Section 6.3 (MISO and PJM), Section 6.4 (MISO and SPP), Section 6.5 (MISO and AECI), and Section 8 (MISO and ATC). Results in Section 3, 4, 5, 6, 7, 9, and 10 have also been reviewed by PJM, SPP, CIPCO, MPC, and AECI.

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Section
1

Introduction

Thirteen (13) generation projects, listed in Table A-1 (Appendix A.1), have requested to interconnect to the MISO transmission network in the West Area and have advanced to the Definitive Planning Phase (DPP) 2016 August Phase 3 study (DPP West Area). All generating facilities have requested both Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

This report presents the study results of a System Impact Study (SIS) performed to evaluate the interconnection of the generating facilities in the DPP West Area Phase 3 study.

The study was performed under the direction of MISO by Siemens PTI and 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, American Transmission Company, Basin Electric Power, Cedar Falls Utilities, Central Iowa Power Cooperative, City of Springfield (IL) Water Light & Power, Columbia (MO) Water and Light, Commonwealth Edison, Corn Belt Power Cooperative, Dairyland Power, Great River Energy, ITC Midwest, Lincoln Electric System, Manitoba Hydro, MidAmerican Energy Company, MISO, Minnesota Power, Minnkota Power, Missouri River Energy Services, Montana-Dakota Utilities Co., Muscatine Power & Water, Nebraska Public Power District, Northwestern Public Service, Omaha Public Power District, Otter Tail Power, PJM, Southern Illinois Power Cooperative, Southern Minnesota Municipal Power Agency, SPP, Western Area Power Administration, and Xcel Energy.

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Section

2

Model Development and Study Criteria

2.1 Model Development

2.1.1 Benchmark Cases

DPP 2016 August West area power flow benchmark cases representing 2022 summer shoulder and summer peak conditions were developed from the DPP 2016 February West Phase 3 steady state models, which were originally developed from MTEP17 models with LBA dispatch.

The benchmark cases for DPP 2016 August study were created as follows:

- MISO Prior queued generation projects and their associated Network Upgrades (NU) were modeled. Appendix A.2 lists all DPP 2016 February West Area Phase 3 Network Upgrades included in the models.
- DPP 2016 August generation projects in the West Area (DPP West Area, Table A-1) were modeled with offline status.
- DPP 2016 August generation projects in the Central Area (Table A-4), Michigan Area (Table A-5), and ATC Area (Table A-6) were modeled and dispatched.
- For MISO generation projects, their output was sunk to the MISO Classic (Appendix A.4, Table A-9), where generation was scaled uniformly;
- PJM generation projects were modeled and dispatched. The generation output was sunk to the PJM market (Appendix A.5, Table A-10), where generation was scaled uniformly.
- SPP generation projects were modeled and dispatched. MISO fuel type dispatch assumption was utilized to dispatch SPP queued generation to SPP footprint. The generation output was sunk to the SPP market (Appendix A.6, Table A-11), where generation was scaled uniformly. Cooper South flowgate was overloaded in the summer shoulder benchmark case but no Network Upgrade was required unless it was identified in the SPP affected system study. The following Network Upgrades identified in the SPP DIS2016-001 study were also modeled:
  - Advance Gentleman–Thedford–Holt 345 kV project
  - Build approximately 140 miles of new 345 kV from Banner County–Keystone
  - Build approximately 30 miles of second 345 kV circuit from Keystone–Gentleman
- The Hickory Creek–Cardinal 345 kV project (MVP project 3127) was included in the 2022 models; the Hickory Creek-Cardinal 345 kV project has an in-service date of 12/31/2023.
- Models were further reviewed by the Ad Hoc study members (transmission owners and customers). Model corrections and changes were made based on the comments and feedback. These modeling changes are listed in Appendix A.2.
- Adjusted Square Butte DC to match the total output of the Bison (Bison 1 to 5) and Oliver County (Oliver County 1 and 2) wind farms.

- Adjusted CU DC to match the total output of Coal Creek generation units #1 and #2.
- MHEX interface transfer level is at 492 MW in summer shoulder and 1406 MW in summer peak cases.

2.1.2 Study Cases

Summer peak study case was created by dispatching the DPP West Area generating facilities at the specified summer peak level (Table ES-1) from the benchmark cases.

Summer shoulder study case was created by dispatching the DPP West Area generating facilities at the specified summer shoulder level (Table ES-1) from the benchmark cases.

SPP generation projects were modeled and dispatched. MISO fuel type dispatch assumption was utilized to dispatch SPP queued generation to SPP footprint. Due to voltage collapse in SPP footprint under system intact condition, one (1) fictitious large size SVC (Table 2-1) in SPP was added to the summer shoulder study case to achieve converged power flow solutions.

Table 2-1: Fictitious SVCs in SPP Added Only in Summer Shoulder Case

Location	Bus #	SVC Output (Mvar)
Mingo 345 kV	531451	302

The MISO Classic was used for power balance, where generation was scaled uniformly.

Both study and benchmark power flow cases were solved with transformer tap adjustment enabled, area interchange disabled, phase shifter adjustment enabled, and switched shunt adjustment enabled.

The interface transfer levels in the 2022 study cases are summarized in Table 2-2.

Table 2-2: Interface Transfer Levels in 2022 Steady State Study Cases

Interface	2022 SH Case (MW)	2022 SPK Case (MW)
MHEX	492	1406
MWEX	1236	616
Arrowhead – Stone Lake 345 kV	455	222

2.2 Contingency Criteria

A variety of contingencies were considered for steady-state analysis:

- NERC Category P0 with system intact (no contingencies)
- NERC Category P1 contingencies

- NERC Category P1 contingencies, at buses with a nominal voltage of 69 kV and above, in the following areas: CWLD (area 333), AMMO (area 356), AMIL (area 357), CWLP (area 360), SIPC (area 361), WEC (area 295), WEC MI (area 296), XCEL (area 600), MP (area 608), SMMPA (area 613), GRE (area 615), OTP (area 620), ITCM (area 627), MPW (area 633), MEC (area 635), MDU (area 661), BEPC-MISO (area 663), MHEB (area 667), DPC (area 680), ALTE (area 694), WPS (area 696), MGE (area 697), UPPC (area 698), CE(area 222), NPPD (area 640), OPPD (area 645), LES (area 650), WAPA (area 652), BEPC-SPP (area 659), AECI (area 330), MIPU(area 540), KCPL (area 541), KACY (area 542), INDN (area 545).
- Multiple-element NERC Category P1 contingencies, in Dakotas, Illinois, Iowa, Minnesota, Missouri, and Wisconsin. These specified Category P1 contingencies are listed in Appendix A.7.

- NERC Category P2-P7 contingencies
  - Selected NERC Category P2-P7 contingencies provided by the Ad Hoc Study Group, in the study region of Dakotas, Illinois, Iowa, Minnesota, Missouri, and Wisconsin. These specified Category P2-P7 contingencies are listed in Appendix A.7.

For all contingency 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.

2.3 Monitored Elements

The study area is defined in Table 2-3. Facilities in the study area were monitored for system intact and contingency conditions. Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal (PSS®E rate A) rating. Under NERC category P1-P7 conditions, branches were monitored for loading as shown in the column labeled "Post-Disturbance Thermal Limits".

Table 2-3: Monitored Elements

Owner / Area	Monitored Facilities	Thermal Limits [1]		Voltage Limits [2]	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
AECI	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
AMIL	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.00	1.05/0.95
AMMO	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.00	1.05/0.95
ATCLLC	69 kV and above	95% of Rate A	95% of Rate B	1.05/0.95	1.10/0.90
BEPC-MISO	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
BEPC-SPP	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
CWLD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
CWLP	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.00	1.10/0.95
CE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
DPC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90

Owner / Area	Monitored Facilities	Thermal Limits [1]		Voltage Limits [2]	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
GMO	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
GRE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.92
INDN	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
ITCM	69 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.95	1.10/0.93
KACY	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
KCPL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
LES	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
MDU	57 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
MEC	69 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.96/0.95	1.05/0.96/0.95[3]
MHEB	69 kV and above	100% of Rate A	100% of Rate B	1.12/1.1/1.07/1.05/1.04/ 0.99/0.97/0.96/0.95	1.15/1.10/0.94/0.90
MP	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.00	1.10/0.95
MPW	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.06/0.92
NPPD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
OPPD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
OTP	40 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.97	1.10/0.92
PPI	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.05/0.95
SIPC	69 kV and above	100% of Rate A	100% of Rate B	1.07/0.95	1.09/0.91
SMMPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
WAPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
XEL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.05/0.92

Notes

1: PSS®E Rate A, Rate B or Rate C

2: Limits dependent on nominal bus voltage

3: For facilities in Cedar Falls Utilities or Ames Municipal Utilities, post-contingency voltage limits are 1.05/0.94 for >200 kV, and 1.05/0.93 for others.

2.4 Performance Criteria

A branch is considered as a thermal injection constraint if the branch is loaded above its applicable normal or emergency rating for the post-change case, and any of the following conditions are met:

1) the generator (NR/ER) has a larger than 20% DF on the overloaded facility under post contingent condition or 5% DF under system intact condition, or

2) the megawatt impact due to the generator is greater than or equal to 20% of the applicable rating (normal or emergency) of the overloaded facility, or
3) the overloaded facility or the overload-causing contingency is at generator's outlet, or
4) for any other constrained facility, where none of the study generators meet one of the above criteria in 1), 2), or 3), however, the cumulative megawatt impact of the group of study generators (NR/ER) is greater than 20% of the applicable rating, then only those study generators whose individual MW impact is greater than 5% of the applicable rating and has DF greater than 5% (OTDF or PTDF) will be responsible for mitigating the cumulative MW impact constraint.

A bus is considered a voltage constraint if both of the following conditions are met. All voltage constraints must be resolved before a project can receive interconnection service.

1) the bus voltage is outside of 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 DPP 2016 August West Area study generators must mitigate thermal injection constraints and voltage constraints in order to obtain unconditional 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 P0-P1 events, if the constraint demonstrates an incremental flow caused by the generator equal to or greater than 5% of the generator's maximum dispatch level in each case.

2.5 Reactive Power Requirements for Non-Synchronous Generation (FERC Order 827)

For non-synchronous generation projects in the DPP 2016 August West Area study group, if they do not have signed Generator Interconnection Agreement (GIA) or Provisional GIA (PGIA) by September 21, 2016, they are 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.

Except for generation project J590, all other non-synchronous generation projects in this study group are required to meet the reactive power requirements per FERC Order 827.

Collector system and shunt compensation of DPP West projects are modeled, which are listed in Appendix A.1, Table A-3. An analysis was performed to study the reactive power requirements (FERC Order 827) for the non-synchronous generation projects in the DPP 2016 August West study group. The analysis was performed as follows:

Step 1: Verify whether total dynamic reactive power (reactive power from generators and dynamic compensation devices) in the plant can meet the dynamic reactive power range of 0.95 leading to 0.95 lagging at the generator terminal bus. The verification in Step 1 was performed when generator data was submitted and modeled.

Step 2: Verify whether total reactive power (reactive power from generators, dynamic compensation devices, and static compensation devices) in the plant can meet the dynamic reactive power range of 0.95 leading to 0.95 lagging at the high-side of the generator substation. The testing procedure in Step 2 is described in the following:

- Lock the high-side of the generator substation at 1.0 per unit voltage by adding a fictitious SVC. This is to ensure that the test result is not affected by the system condition.
- Lock the reactive power output of the generator to the maximum limit (Qmax). Make sure all shunt compensation devices within the substation are at the maximum capacitive output. Adjust transformer tap to ensure bus voltages within the substation are within 0.95 – 1.05 p.u. range. Measure real power and reactive power from the generator plant to the high-side of the generator substation. Calculate the power factor to verify if it meets the 0.95 lagging requirement.
- Lock the reactive power output of the generator to the minimum limit (Qmin). Make sure all shunt compensation devices within the substation are at the maximum inductive output. Adjust transformer tap to ensure bus voltages within the substation are within 0.95 – 1.05 p.u. range. Measure real power and reactive power from the generator plant to the high-side of the generator substation. Calculate the power factor to verify if it meets the 0.95 leading requirement.

Appendix C lists reactive power requirement analysis results for the DPP West generation projects. The results are summarized as following:

- J587 does not meet the reactive power requirements per FERC Order 827. This requirement can be met by installation of additional reactive power support at the project site.
- J590 is exempted from the FERC Order 827 reactive power requirements.
- All other non-synchronous generation projects can meet the reactive power requirements per FERC Order 827.

Section

3

Summer Peak Steady-State Analysis

Summer peak steady-state analysis was performed in summer peak scenario to identify thermal and voltage upgrades required interconnecting the generating facilities in the DPP 2016 August West Area group to the transmission system.

3.1 Study Procedure

3.1.1 Computer Programs

Steady-state analyses were performed using PSS®E version 33.12 and PSS®MUST version 12.0.

3.1.2 Study Methodology

Summer peak power flow case was created in the procedure as described in Section 2.1. Nonlinear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP West Area generating facilities was evaluated by comparing the steady-state performance of the transmission system in the benchmark and study cases. Network upgrades were identified to mitigate any summer peak constraints.

3.2 Summer Peak Contingency Analysis Results

The incremental impact of the proposed interconnection on individual facilities was evaluated by comparing flows and voltages between benchmark case (without DPP West Area projects) and study case (with DPP West Area projects). Analysis was performed in the 2022 summer peak scenario using PSS®E and PSS®MUST.

3.2.1 System Intact Conditions

For NERC category P0 (system intact) conditions, no thermal or voltage constraints were identified (Table D-1, Table D-2).

3.2.2 Post Contingency Conditions

The results in this Section are for analysis of conditions following NERC Category P1-P7 contingencies. All category P1 contingencies were converged.

For P1 contingencies in the 2022 summer peak scenario, no thermal or voltage constraints were identified (Table D-3, Table D-4).

Two category P2-P7 contingencies (Table D-7) were not converged, and their dc thermal results are listed in Table D-8. The contingency was not converged in the benchmark or study cases. No mitigation plan is required for the study projects for this contingency.

For P2-P7 contingencies in the 2022 summer peak scenario, no thermal or voltage constraints were identified (Table D-5, Table D-6).

3.3 Network Upgrades Identified in MISO ERIS Analysis for 2022 Summer Peak Scenario

No Network Upgrades were identified in the 2022 summer peak scenario.

Section

4

Summer Shoulder Steady-State Analysis

Summer shoulder steady-state analysis was performed in summer shoulder scenario to identify thermal and voltage upgrades required interconnecting the generating facilities in the DPP 2016 August West Area group to the transmission system.

4.1 Study Procedure

4.1.1 Computer Programs

Steady-state analyses were performed using PSS®E version 33.12 and PSS®MUST version 12.0.

4.1.2 Study Methodology

Summer shoulder power flow case was created in the procedure as described in Section 2.1. Nonlinear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP West Area generating facilities was evaluated by comparing the steady-state performance of the transmission system in the benchmark and study cases. Network upgrades were identified to mitigate any summer shoulder constraints.

4.2 Summer Shoulder Contingency Analysis Results

The incremental impact of the proposed interconnection on individual facilities was evaluated by comparing flows and voltages between benchmark case (without DPP West Area projects) and study case (with DPP West Area projects). Analysis was performed in the 2022 summer shoulder scenario using PSS®E and PSS®MUST.

4.2.1 System Intact Conditions

For NERC category P0 (system intact) conditions, thermal constraints are listed in Table E-1. No voltage constraints were identified (Table E-2).

4.2.2 Post Contingency Conditions

The results in this Section are for analysis of conditions following NERC Category P1-P7 contingencies.

All category P1 contingencies were converged. For P1 contingencies in the 2022 summer shoulder scenario, thermal constraints are listed in Table E-3, and voltage constraints are listed in Table E-4.

One category P2-P7 contingency (Table E-7) was not converged in the benchmark or study cases. No mitigation plan is required for the study projects for this non-converged contingency. The dc thermal results for the non-converged contingency are listed in Table E-8.

For P2-P7 contingencies in the 2022 summer shoulder scenario, thermal constraints are listed in Table E-5, and voltage constraints are listed in Table E-6.

4.2.3 Worst Thermal Constraints in the 2022 Summer Shoulder ACCC

Table 4-1 lists worst thermal constraints identified in the 2022 summer shoulder scenario.

Table 4-1: 2022 Shoulder Thermal Constraints, Maximum Screened Loading

Constraint	Rating	Owner	Worst Loading (MVA)	Worst Loading (%)	Contingency	Cont Type	Generator
J530 POI-Montezuma 345 kV	1010.0	MEC	1228.9	121.7	CEII Redacted	P1	J541,J555,J598
J530 POI-Montezuma 345 kV	1010.0	MEC	1274.9	126.2	CEII Redacted	P2-P7	J541,J555,J598
J530 POI-Hills 345 kV	956.0	MEC	1108.7	116.0	CEII Redacted	P0	J476,J541,J555,J583,J598,J611
J530 POI-Hills 345 kV	1152.0	MEC	1470.7	127.7	CEII Redacted	P1	J541,J555,J598
J530 POI-Hills 345 kV	1152.0	MEC	1518.9	131.8	CEII Redacted	P2-P7	J541,J555,J598
J302&J503 POI-Heskett 230 kV	257.0	MDU	335.4	130.5	CEII Redacted	P1	J302,J503
J302&J503 POI-Heskett 230 kV	257.0	MDU	336.7	131.0	CEII Redacted	P2-P7	J302,J503
J611-Maryville 161 kV	199.0	MEC GMO	220.8	111.0	CEII Redacted	P1	J611
J611-Maryville 161 kV	199.0	MEC GMO	211.5	106.3	CEII Redacted	P2-P7	J611
Novelty 161 -69 kV xfmr	56.0	AECI	59.0	105.3	CEII Redacted	P1	J541

Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Generator
			(MVA)	(%)			
South River-Emerson 161 kV	167.0	AECI	169.6	101.6	CEII Redacted	P1	J541
St. Joseph-Cooper 345 kV	1195.0	NPPD GMO	1418.5	118.7	CEII Redacted	P1	J476
Adams 345-161-13.8 kV xfmr	334.6	XEL	361.6	108.1	CEII Redacted	P1	J614
Adams 345-161-13.8 kV xfmr	334.6	XEL	381.6	114.1	CEII Redacted	P2-P7	J614
Split Rock-White 345 kV	717.1	XEL WAPA	821.3	114.5	CEII Redacted	P1	J587
Split Rock-White 345 kV	717.1	XEL WAPA	820.5	114.4	CEII Redacted	P2-P7	J587
Helena-Scott Co 345 kV	1378.0	XEL WAPA	1445.4	104.9	CEII Redacted	P0	J512,J569,J587,J590
Rice 161-69 kV xfmr	106.0	SMMPA	142.9	134.8	CEII Redacted	P1	J614
Rice 161-69 kV xfmr	106.0	SMMPA	143.0	134.9	CEII Redacted	P2-P7	J614
Hankinson-Forman 230 kV	413.9	OTP	449.7	108.6	CEII Redacted	P1	J302,J503

Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Generator
			(MVA)	(%)			
Hankinson-Forman 230 kV	413.9	OTP	451.2	109.0	CEII Redacted	P2-P7	J302,J503
Oakes-Forman 230 kV	527.0	OTP	531.9	100.9	CEII Redacted	P1	J302,J503
Oakes-Forman 230 kV	527.0	OTP	532.8	101.1	CEII Redacted	P2-P7	J302,J503
Oakes-Ellendale 230 kV	527.0	OTP MDU	538.6	102.2	CEII Redacted	P1	J302,J503
Oakes-Ellendale 230 kV	527.0	OTP MDU	539.5	102.4	CEII Redacted	P2-P7	J302,J503
Parnell-J438 POI 161 kV	281.0	ITCM MEC	299.4	106.5	CEII Redacted	P1	J555
Henry Co-Jeff 161 kV	197.0	ITCM NEMO	198.2	100.6	CEII Redacted	P2-P7	J541,J598
Wapello-Jeff 161 kV	223.0	ITCM	240.8	108.0	CEII Redacted	P2-P7	J541,J598
Ottumwa 345-161 kV xfmr	400.0	ITCM	518.0	129.5	CEII Redacted	P1	J541,J555,J598
Ottumwa 345-161 kV xfmr	400.0	ITCM	506.4	126.6	CEII Redacted	P2-P7	J541,J555,J598

Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Generator
			(MVA)	(%)			
Grimes-Sycamore 345 kV #2	1319.0	MEC	1328.3	100.7	CEII Redacted	P2-P7	J583
Bondurant-Sycamore 345 kV	1152.0	MEC	1197.8	104.0	CEII Redacted	P2-P7	J583
Bondurant-Montezuma 345 kV	1083.0	MEC	1116.1	103.1	CEII Redacted	P1	J583
Bondurant-Montezuma 345 kV	1083.0	MEC	1170.9	108.1	CEII Redacted	P2-P7	J583
Blair-Granite Falls 230 kV	410.0	WAPA	452.0	110.2	CEII Redacted	P1	J587
Watertown 345-230-13.8 kV xfmr	500.0	WAPA	524.6	104.9	CEII Redacted	P1	J587
Watertown-Appledorn 230 kV	341.8	WAPA	353.4	103.4	CEII Redacted	P1	J587
Harmony-Cresco 69 kV	37.0	DPC	38.5	104.1	CEII Redacted	P1	J614
Parnell-Hills 161 kV	332.0	ITCM MEC	334.0	100.6	CEII Redacted	P1	J555

4.3 Network Upgrades Identified in MISO ERIS Analysis

Based on the MISO 2022 summer shoulder and summer peak steady state analyses, thermal NUs and cost are listed in Table 4-2, and reactive power NUs and cost are listed in Table 4-3.

Table 4-2: Thermal Network Upgrades and Cost Identified in MISO Steady State Analysis

Constraint	Owner	Mitigation	Cost ($)
J530 POI-Montezuma 345 kV	MEC	Structure Replacements	$350,000
J530 POI-Hills 345 kV	MEC	Reconductor / Terminal Equipment Upgrades.	$27,000,000
J302&J503 POI-Heskett 230 kV	MDU	Line Clearance Mitigation. New Rating: 343 MVA.	$750,000
J611-Maryville 161 kV	MEC GMO	MEC: Reconductor from POI substation to Missouri border point of ownership change with KCPL. GMO: NU is not required unless it is identified as constraint in affected system study.	$1,000,000
Novelty 161 -69 kV xfmr	AECI	NU is not required unless it is identified as constraint in affected system study.	$0
South River-Emerson 161 kV	AECI	NU is not required unless it is identified as constraint in affected system study.	$0
St. Joseph-Cooper 345 kV	NPPD GMO	NU is not required unless it is identified as constraint in affected system study.	$0
Adams 345-161-13.8 kV xfmr	XEL	Lock Adams xfmr tap at neutral position	$0
Split Rock-White 345 kV	XEL WAPA	Line is currently rated 1075 MVA for SN/SE no mitigation required	$0
Helena-Scott Co 345 kV	XEL WAPA	Rebuild Helana to Scott County (18 miles) with 2-0954 ACSS conductor	$54,000,000
Rice 161-69 kV xfmr	SMMPA	SMMPA: MOD project # 110359 to increase the Rice 161/69kV transformer to 190 MVA rating as per the GIA J614	$0
Hankinson-Forman 230 kV	OTP	Line clearance mitigations.	$650,000
Oakes-Forman 230 kV	OTP	Replacement of terminal equipment and complete rebuild of the 23.3 mile line.	$19,950,000
Oakes-Ellendale 230 kV	OTP MDU	MDU: MDU owns the Ellendale Terminal. It is rated for 776 MVA OTP: Complete rebuild of the 24 mile line.	$20,500,000
Parnell-J438 POI 161 kV	ITCM MEC	ITCM: ITCM terminal rated 335/335 MVA SN/SE. $0 MEC: Structure Replacements. $250,000	$250,000

Summer Shoulder Steady-State Analysis

Constraint	Owner	Mitigation	Cost ($)
Henry Co-Jeff 161 kV	ITCM NEMO	ITCM: ITCM line rating 229/229 MVA SN/SE. $0 NEMO: Per ITCM record NEMO terminal limit is 223 MVA which is sufficient. $0	$0
Wapello-Jeff 161 kV	ITCM	Line rated 251/251 MVA SN/SE	$0
Ottumwa 345-161 kV xfmr	ITCM	Add 2nd 450 MVA transformer.	$9,000,000
Grimes-Sycamore 345 kV #2	MEC	Add new 345 kV breaker at Grimes to eliminate this common breaker failure contingency.	$2,200,000
Bondurant-Sycamore 345 kV	MEC	Structure Replacements	$1,000,000
Bondurant-Montezuma 345 kV	MEC	Structure Replacements. $600,000. New rating is 1,189 MVA.	$600,000
Blair-Granite Falls 230 kV	WAPA	NU is not required unless it is identified as constraint in affected system study.	$0
Watertown 345-230-13.8 kV xfmr	WAPA	NU is not required unless it is identified as constraint in affected system study.	$0
Watertown-Appledorn 230 kV	WAPA	NU is not required unless it is identified as constraint in affected system study.	$0
Harmony-Cresco 69 kV	DPC	Rebuild line with 477 ACSR	$4,000,000
Parnell-Hills 161 kV	ITCM MEC	Add 1 stage of 36 MVAR nominal, 27.6 MVAR effective cap bank at Parnell 161 kV[1]	$1,400,000

Note 1: An alternative is to reconductor the line with substation terminal equipment upgrades. The estimated cost is $18,000,000. New line rating is 410 MVA.

Table 4-3: Reactive Power NUs and Cost Identified in MISO Steady State Analysis

Network Upgrades	Owner	Cost ($)
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	ITCM	$6,500,000
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	ITCM	$6,500,000
2x150 Mvar switched cap bank at Hills 345 kV (636400)	MEC	$15,000,000
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	MRES	$2,000,000

Section

5

Local Planning Criteria Analysis

Local Planning Criteria (LPC) analyses were performed to identify additional constraints per Transmission Owning Companies' LPC.

5.1 MDU Local Planning Criteria Analysis

Siemens PTI performed the local planning criteria analysis based on MDU's LPC. The MDU local planning criteria analysis details can be found in Appendix F.1.

5.1.1 Additional Network Upgrades Identified in MDU LPC Analysis

Besides the thermal constraints and NUs identified in the MISO ACCC analysis, there are several additional thermal constraints identified in the MDU LPC analysis.

No additional voltage constraints were identified in the MDU LPC analysis.

No additional stability Network Upgrades were identified in the MDU LPC analysis.

Additional Network Upgrades required in the MDU LPC study are listed in Table 5-1.

Table 5-1: Additional Network Upgrades for Constraints Identified in MDU LPC Analysis

Constraint	Owner	Mitigation	Cost ($)
J302&J503 POI-Heskett 230 kV	MDU	Line rebuild	$9,000,000[1]
Merricourt-Ellendale 230 kV	MDU	Rebuild line with high temp. conductor & upgrade Merricourt bus	$4,600,000[2]

Note 1: MISO ACCC only requires line clearance mitigation. Line rebuild is required in MDU LPC study.

Note 2: Additional NU cost required in the LPC analysis.

5.2 DPC Local Planning Criteria Analysis

Siemens PTI performed the local planning criteria analysis based on DPC's LPC. The DPC local planning criteria analysis details can be found in Appendix F.2.

5.2.1 Additional Network Upgrades Identified in DPC LPC Analysis

Except the thermal constraints or NUs identified in MISO ACCC analysis, no additional thermal constraints or NUs were identified in the DPC LPC analysis.

No voltage constraints were identified in the DPC LPC analysis.

No additional Network Upgrades are required in the DPC LPC study.

5.3 Ameren Local Planning Criteria Analysis

Ameren performed the local planning criteria analysis based on Ameren's LPC for generation projects J541 and J598. The Ameren local planning criteria analysis details can be found in Appendix F.3.

5.3.1 Steady-State Results Summary

The following constraints were identified under shoulder peak conditions for Line + Generator contingencies:

Monitored Element	Balancing Area	First Level Contingency Second Level Contingency	Summer Emergency Rating (MVA)	MVA Flow	%Load
Zachary 345/161 kV transformer	AMMO	CEII Redacted	560	580.2	103.6%
Zachary-Adair 161 kV line			557	571.3	102.6%

The following constraints were identified under shoulder peak conditions for 345 kV Line + Line contingencies:

Monitored Element	Area	First Level Contingency Second Level Contingency	Summer Emergency Rating (MVA)	MVA Flow	%Load
Zachary 345/161 kV transformer	AMMO	CEII Redacted	560	687.2	122.71
Adair 161 kV bus tie 2-3			335	354.9	105.95
Adair-Zachary 161 kV line			557	674.9	121.17

5.3.2 Stability Results Summary

The owner of the Ottumwa 345/161 kV transformer should be consulted to determine if mitigation is required for the scenario where a 3-phase fault occurs on the J541-Zachary 345 kV line with the Montezuma-Ottumwa 345 kV line out of service. In this scenario, all the J541 and J598 generation flows through the Ottumwa 345/161 kV transformer. During the simulation of this scenario, all the study generators exhibited undamped oscillations with real power swings that constituted eight percent of the maximum output.

5.3.3 Network Upgrades Identified in Ameren LPC Analysis

Additional Network Upgrades required in the Ameren LPC study is listed in Table 5-2.

Table 5-2: Additional Network Upgrades for Constraints Identified in Ameren LPC Analysis

Constraint	Mitigation	Cost ($)
Zackary 345/161 kV transformer	Add Second 560 MVA 345/161 kV transformer	$7,000,000
Adair-Zackary 161 kV	Add second 161 kV line between Adair and Zachary	$2,000,000
Adair 161 kV bus tie 2-3	Bus tie to be upgraded to 2000 A as part of the Zachary-Ottumwa MVP project	$0

Section
6

Affected System Steady-State Analysis

Steady state analyses were performed to identify constraints in affected systems.

6.1 Affected System Analysis for CIPCO Company

Per CIPCO Affected System Planning Criteria, transmission facilities which meet all of the following three (3) conditions are considered as constraints:

1) the branch is loaded above its applicable normal or emergency rating for the post-change case, and
2) the generator has a larger than 3% DF on the overloaded facility under post contingent condition or 5% DF under system intact condition, and
3) the loading increase of the overloaded facility is greater than 1 MVA compared with that in the pre-change case under system intact or contingency conditions.

AC contingency analysis was performed for this CIPCO affected system analysis, using the following benchmark and study cases:

- Summer peak benchmark and study cases
- Summer shoulder benchmark and study cases

All NERC category P0-P7 contingencies described in Section 2.2 were simulated. The CIPCO affected system was monitored.

No additional thermal constraints in the affected systems were identified in this CIPCO affected system analysis (Appendix G.1).

6.2 MPC Affected System Analysis

MPC assumes MISO's mitigation will be sufficient to identify impact on MPC system and agree on MISO's study results on MPC facility. Therefore, no separate MPC Affected System Impact Study is performed.

6.3 PJM Affected System Analysis

The PJM affected system analysis details (dated on 2/12/2019) can be found in Appendix G.2.

6.3.1 Study Results

6.3.1.1 Overload on Twin Branch–Argenta 345 kV line

To relieve the Twin Branch–Argenta 345 kV line overload:

a. A sag check will be required for the ACSR ~ 954 ~ 45/7 ~ RAIL - Conductor Section 1 to determine if the line section can be operated above its emergency rating of 1409 MVA. Existing PJM Network Upgrade N5240. $208,000.

The following 2016 August DPP projects contribute loading to this flowgate: G359, J513, J614, J456, J474, J302, J503, J587, J512, J555, J569, J590, J541, J598, J583, J446, J476 and J611.

Per PJM cost allocation rules, the 2016 August DPP projects presently do not receive any cost allocation for this upgrade.

6.3.2 Study Summary

The projects in MISO DPP 2016 August West Area group are not responsible for the cost of Network Upgrades per PJM cost allocation rules.

6.4 SPP Affected System AC Contingency Analysis

Southwest Power Pool (SPP) conducted an Affected System Interconnection System Impact Study (ASISIS) to evaluate potential impacts to the SPP Transmission System related to the interconnection of generators on the Mid-Continent Independent System Operation (MISO) Transmission System.

A steady-state thermal and voltage analysis as well as Transfer Distribution Factor analysis was performed to determine the impact the MISO GIRs have on the SPP system. It was observed that the MISO GIRs resulted in no thermal constraints and no voltage constraints that are required to be mitigated.

The study results presented in this ASISIS are contingent upon completion of all SPP planned projects through 2017 ITPNT and DISIS-2016-001-1.

The SPP affected system analysis results (REP-0441, Rev #01) for this study are in Appendix G.3.

6.5 AECI Affected System Analysis

Associated Electric Cooperative Inc. (AECI) performed this affected system analysis.

6.5.1 Study Summary

The AECI affected system analysis details (dated on 08/27/2018) can be found in Appendix G.4. The results are summarized below:

1. Based on the information received from MISO and results reviewed, the following AECI facilities were impacted by project J541:
   - 300106 5NOVELY_SW 161 300364 2NOVLTY_SW 69.0 1
   - 300113 5SRIVER 161 300339 5EMERSN 161 1
2. The AECI analysis did not determine additional impacts to those identified by MISO on the AECI system due to J541 or other select Study Cycle projects.

6.5.2 Network Upgrades Cost

The table below provides a non-binding, good faith estimate of the timing and cost for upgrades needed as a result of J541.

Table 6-1: AECI Network Upgrades and Cost

Option / Description	Current Cost	Need Date	Year In Service
Replace Novelty 161/69 kV transformer to 84 MVA unit	$2,500,000	2020	2020
Upgrade 600A disconnect switches at South River	$100,000	2020	2020
Engineering	$520,000	2020	2020
Contingencies	$260,000	2020	2020
Total Cost	$3,380,000		

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Section

7

Stability Analysis

Stability analysis was performed to evaluate the transient stability and impact on the region of the generating facilities in the DPP 2016 August West Area group.

7.1 Procedure

7.1.1 Computer Programs

Stability analysis was performed using PSS®E revision 33.12.

7.1.2 Study Methodology

Study stability package representing 2022 summer shoulder (SH) conditions with generating facilities in the DPP 2016 August West Area group was created from the stability package used for the DPP 2016 February West Phase 3 study, which was originally developed from MTEP17 stability package. Benchmark case was created by removing the DPP West Area generating facilities from the study case. Disturbances were simulated to evaluate the transient stability and impact on the region of the generating facilities. If a simulation for the study case violates MISO transient stability criteria or local TOs' planning criteria, the simulation was repeated on the benchmark case to assess the impact of the generating facilities on the violation.

7.2 Case Development

7.2.1 Study Case

Study case representing 2022 shoulder (SH) condition was developed from the DPP 2016 February West Phase 3 stability package, which was originally developed from MTEP17 stability package.

The stability study case for DPP 2016 August study was created in the same procedure as the steady state models, as described in Section 2.1.1. The stability case includes reactive power Network Upgrades identified in the MISO steady state analysis.

The interface transfer levels are summarized in Table 7-1.

Table 7-1: Interface Transfer Levels in Phase-3 2022 Stability Study Case

Interface	2022 SH Case (MW)
MHEX	493
MWEX	1236
Arrowhead – Stone Lake 345 kV	453

7.2.2 Benchmark Case

The DPP West Area generating facilities as described in Table A-1 (Appendix A.1) were removed from the study case. MISO Classic was used for power balance, where generation was scaled uniformly.

7.3 Disturbance Criteria

The stability simulations performed as part of this study considered all the regional and local contingencies listed in Table 7-2. Regional contingencies with the pre-defined switching sequences were selected from the MISO MTEP17 study; switching sequences for local contingencies were developed based on the generic clearing times shown in Table 7-3. The admittance for local single line-to-ground (SLG) faults were estimated by assuming that the Thevenin impedance of the positive, negative and zero sequence networks at the fault point are equal.

Table 7-2: Regional and Local Disturbance Descriptions

CEII Redacted

Table 7-3: Generic Clearing Time Assumption

Voltage Level (kV)	Primary Clearing Time (cycle)	Backup Clearing Time (cycle)
345 kV	4	11
230 kV	5	13
161/138 kV	6	18
115 kV	6	20
69 kV	8	24

7.4 Performance Criteria

All generators must mitigate the stability constraints listed below in order to obtain any type of Interconnection Service:

- System instability
- Transient voltage constraint

- Damping violation

7.4.1 MISO Criteria

Stability simulation results are evaluated based on the following MISO criteria:

- All on-line generating units are stable
- No unexpected generator tripping
- Post-fault transient voltage limits: 1.2 per unit maximum, 0.7 per unit minimum.
- Per local TOs' planning criteria, specific transient voltage limits are applied to specific buses, areas or companies that have different requirements.
- All machine rotor angle oscillations must be positively damped with a minimum damping ratio of 3%.

A bus is considered a transient voltage constraint if both of the following conditions are met. All transient voltage constraints must be resolved before a project can receive interconnection service.

1. the bus transient voltage is outside of specified transient voltage limits during transient period, and
2. the bus voltage is at least 0.01 per unit worse than the benchmark case voltage for the same contingency.

7.4.2 Local Planning Criteria

7.4.2.1 ATC Local Planning Criteria

ATC has the following local transient voltage recovery criteria. For facilities in the ATC footprint, transient voltage recovery is evaluated based on ATC's local planning criteria.

- Voltage recovery within 80 percent and 120 percent of nominal for between 2 and 20 seconds following the clearing of a disturbance.

7.4.2.2 ITCM Local Planning Criteria

ITCM has the following local transient voltage and damping criteria. For facilities in the ITCM footprint, transient voltages and dampings are evaluated based on ITCM's local planning criteria.

- Voltages at all busses on the Transmission Systems should not drop below 0.70 per unit after the first swing for more than 5 cycles. The duration for the minimum voltage dip starts after the first swing post clearing of fault.

- Voltage at all Transmission System buses should recover to the applicable post-contingency steady-state voltage level (ITCM post-disturbance limits in Table 2-3), within 1.0 second of the clearing of the fault.

- Rotor angle oscillation damping ratios are not to be less than 0.03.

7.4.2.3 MEC Local Planning Criteria

MEC has the following local transient voltage and damping criteria. For facilities in the MEC footprint, transient voltages and dampings are evaluated based on MEC's local planning criteria.

- Generator bus transient voltage limits shall adhere to the high voltage duration and low voltage duration curve in Attachment 2 of NERC PRC-024, which is:
  - Generator bus transient over voltage limits (after fault clearing): 1.2 pu voltage from 0.0 to and including 0.2 s; 1.175 pu voltage from 0.2 to and including 0.5 s; 1.15 pu voltage from 0.5 to and including 1.0 s; 1.1 pu voltage for greater than 1.0 s.
  - Generator bus transient low voltage limits (after fault clearing): may be less than 0.45 pu voltage from 0 to 0.15 seconds; Voltage shall remain above 0.45 pu from 0.15 to 0.3 s; Voltage shall remain above 0.65 pu from 0.3 to 2.0 s; Voltage shall remain above 0.75 pu from 2.0 to 3.0 s; Voltage shall recover to 0.9 pu after 3 s.
- Load bus transient voltage limits:
  - Load bus transient over voltage limits (after fault clearing): 1.6 pu voltage from 0.01 to and including 0.04 s; 1.2 pu voltage from 0.04 to and including 0.5 s; 1.1 pu voltage from 0.5 to and including 5 s; and 1.05 pu voltage for greater than 5 s. These voltage limits also apply to buses without loads or generators.
  - Load bus transient low voltage limits (after fault clearing): may be less than 0.7 pu voltage from 0 to 2 s; Voltage shall remain above 0.7 pu from 2 to 20 s; Voltage shall recover to 0.9 pu after 20 s.
- Angular transient stability minimum damping ratio (ζ) should not be less than 0.03.

7.5 Stability Results

The contingencies listed in Table 7-2 were simulated using the 2022 summer shoulder Phase 3 study case. If a transient stability criteria violation was identified, the same disturbance was repeated in the benchmark case.

Appendix H.2 contains plots of generator rotor angles, generator power output, generator terminal voltages, bus voltages, and branch flows for each simulation. Simulations were performed with a 2.0 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 12-second duration.

Stability study results summary is in Appendix H, Table H-1. The following stability related issues were identified.

7.5.1 Out of Step (OOS) Relay at Forbes on M602F Tripping

The OOS relay at Forbes on M602F tripped for 3-phase fault '0890_w_xel_p12_pc3_at_king-eauclaire' (Table 7-4) in both study case and benchmark case. This OOS trip is initiated prior to fault clearing. During the fault OOS relay can operate if the apparent impedance initially remains between blinders long enough for the timer to time out and then moves into the trip area before the fault is cleared (Figure 7-1). M602F OOS relay settings may need to be adjusted when the GNTL 500 kV project goes into service.

The 3-phase fault '0890_w_xel_p12_pc3_at_king-eauclaire' was simulated again by blocking the OOS relay at Forbes on M602F to keep it from operating during the fault. No stability violations were identified.

Table 7-4: Disturbance Causing OOS Relay at Forbes on M602F Tripping

CEII Redacted

Figure 7-1: Forbes M602F OOS Relay Apparent Impedance under Disturbance "0890_w_xel_p12_pc3_at_king-eauclaire"

CEII Redacted

7.5.2 Tripping of Wind Farms by Low Voltage Protection

Under one disturbance listed in Table 7-5, Court wind farm was tripped by its low voltage protection (0.65 per unit voltage for 1.0167 s). The fault "1672_w_otp_p55_jamestown" is cleared after 3.1 second, which causes Court WTGs tripping by its low voltage protection 1.05 second after the fault. As defined in the fault file, the same WTGs will be tripped 3.1 s after the fault. The same tripping of the WTGs by low voltage protections also exists in the benchmark case. Network Upgrade is not required for DPP West project.

Table 7-5: Disturbances Causing Wind Farm Low Voltage Protection Tripping

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7.5.3 Transient High Voltage Violations

Under several disturbances listed in Table 7-6, voltage at buses listed in Table 7-6 exceeds 1.2 per unit for ¾ of a cycle (12 milliseconds) after faults are cleared. These transient high voltages have more than 0.01 per unit increase compared with those in the benchmark case, as shown in Figure 7-2 (transient high voltage at Merricourt 230 kV, 3PH fault at Merricourt to Wishek 230 kV line) and Figure 7-3 (transient high voltage at Rice 161 kV, 3PH fault at Rice to Beaver Creek 161 kV line). These voltage violations are outside of the 0 to 10 Hz frequency bandwidth covered by transient stability simulation tools such as PSS®E, so these results are not reliable, and the voltage spikes are not categorized as constraints.

Short Circuit Ratio (SCR) is a measure of system strength relative to the rating of the renewable plant and is used by manufacturers to screen for weak grid risks. Composite SCR (CSCR) considers the grid strength as seen by all electrically close converters and is used for renewable plants. CSCR is calculated as the ratio of the composite short-circuit MVA at the points of interconnection (POI) of all renewable plants in a given area to their combined MW rating.

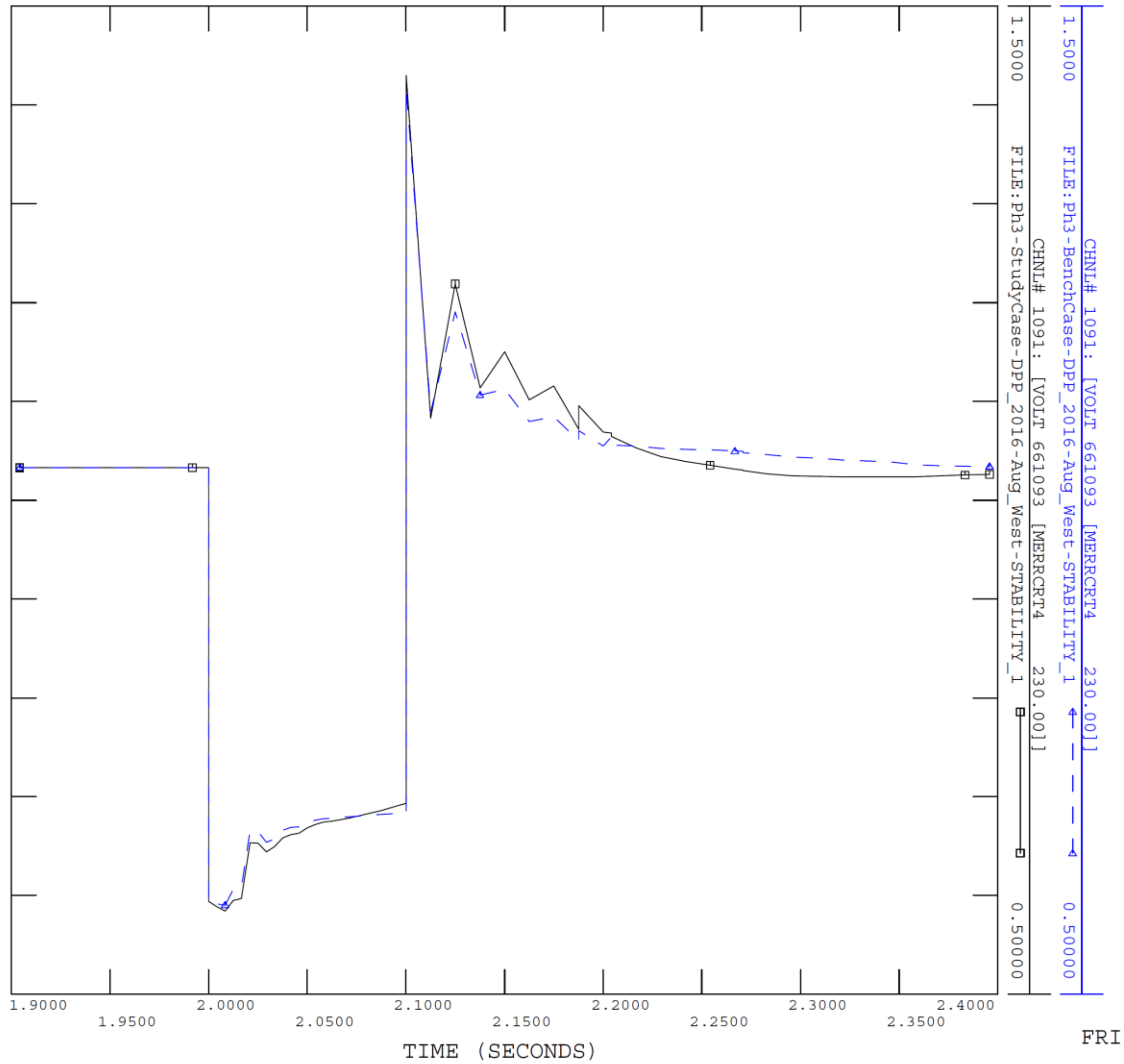
Further study is recommended using detailed EMT models to tune J302 and J503 controls and verify that J302, J503, Tatanka Wind, Foxtail Wind, J436, J437, J488, and G359 can operate at a Composite Short Circuit Ratio (CSCR) between 1.21 and 2.15.

Further study is also recommended using detailed EMT models to tune J614 controls and verify that G551 and J614 can operate at a CSCR around 1.50.

Table 7-6: Transient Voltage above 1.2 per unit

CEII Redacted

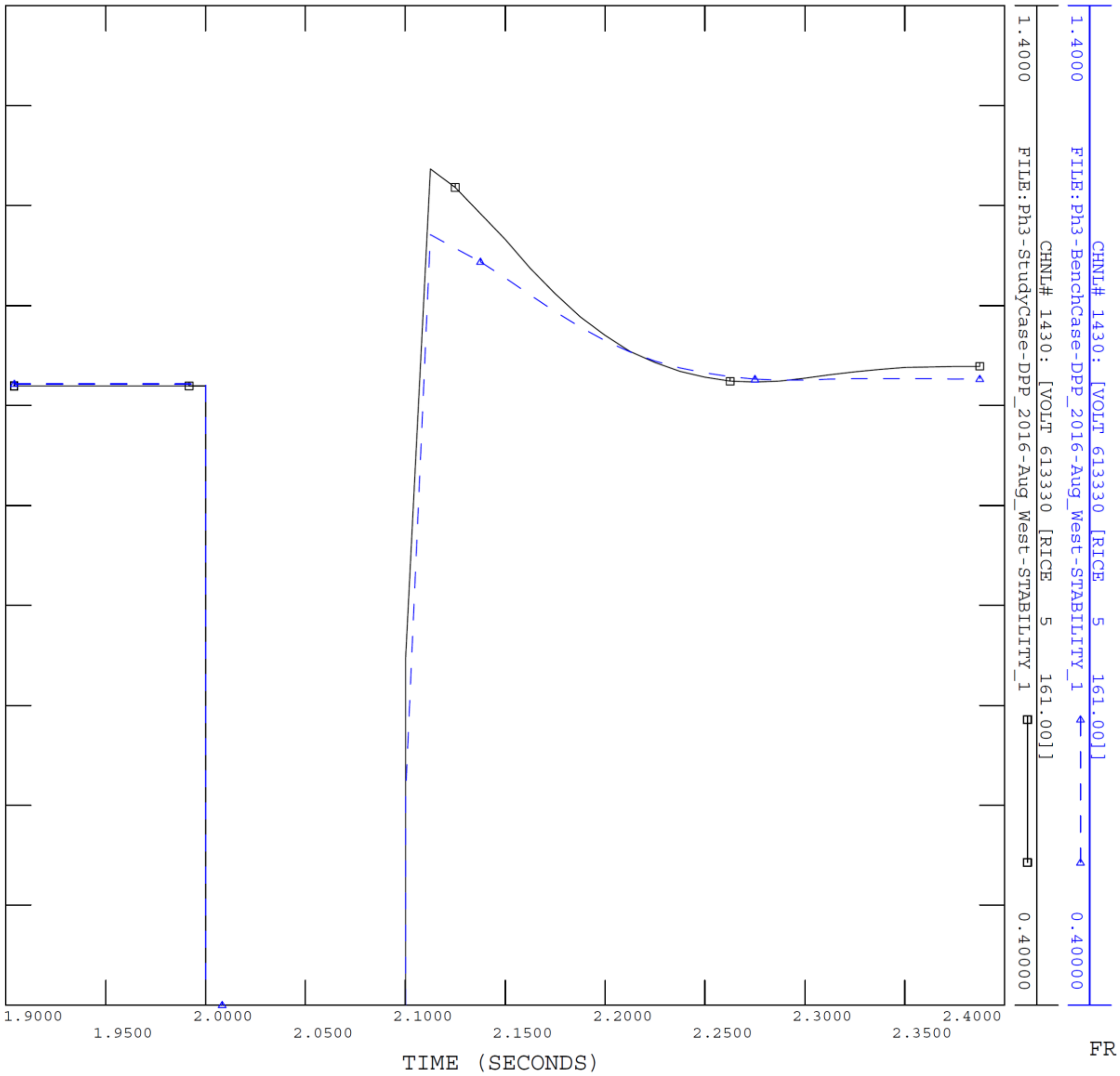
Figure 7-2: Merricourt 230 kV Transient High Voltage Comparison, Fault “1436_w_otp_p12_otp_p12_be3 _bigstonesouth”



Note 1: Blue curve represents transient voltage at Merricourt 230 kV bus in the benchmark case

Note 2: Black curve represents transient voltage at Merricourt 230 kV bus in the study case. The highest transient voltage is increased by 0.012 p.u.

Figure 7-3: Rice 161 kV Transient High Voltage Comparison, 3PH Fault at Rice to Beaver Creek 161 kV Line



Note 1: Blue curve represents transient voltage at Rice 161 kV bus in the benchmark case. The highest transient voltage is less than 1.2 p.u.

Note 2: Black curve represents transient voltage at Rice 161 kV bus in the study case The highest transient voltage is 1.24 p.u.

7.6 Network Upgrades Identified in Stability Analysis

No additional Network Upgrades are required in the stability analysis.

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Section

8

MWEX Voltage Stability Study

ATC performed steady state voltage stability analysis. Voltage stability analysis is required to determine if the initial conditions of the DPP system models under study are in a stable state as defined by Power-Voltage (PV) curves of the Minnesota Wisconsin Export Interface (MWEX) for the worst contingency.

The voltage stability analysis used 2022 shoulder load cases to compare the Pre-DPP and Post-DPP scenario.

As shown in Table 8-1, the Pre-DPP and Post-DPP scenarios in the 2022 shoulder load (2022 SH) case violates ATC Planning Criteria by the nose of the PV curve exceeding 0.95 p.u.. However, Post-DPP scenario does not aggravate the criteria violation and sufficient margin is maintained, Network Upgrades related to voltage stability will NOT be assigned to the Interconnection Customers, based on the assumptions used in this analysis.

Table 8-1: MWEX Margins to Collapse in the 2022SH Cases

	Real Power Flows (MW)						
	AHD-SLK[1]	MWEX			Margin to Nose[2,3]		
Case	N-0 Initial Condition	N-0 I.C.	N-1 I.C.	N-1 Nose	(MW)	(%)	Notes
Pre-DPP	427	1166	572	722	150	20.8	Voltage Stable Sufficient Margin [4] V(nose) > 0.95 p.u. [5]
Post-DPP	451	1238	602	712	110	15.4	Voltage Stable Sufficient Margin [4] V(nose) > 0.95 p.u. [5]

Notes:

1. As described in the active MWEX Operating Guide, the AHD-SLK interface is a single element PTDF interface measured at the Minnesota Power 230 kV side of the Arrowhead 230 kV phase shifter.

2. Margin to Nose (MW) is defined as the MWEX N-1 Nose minus the N-1 Initial Condition.

3. Initial Condition flows were measured in the base cases with the worst contingency plus operation of various control systems as needed with all transformer taps, switched shunts, and PARs locked.

4. ATC Planning Criteria requires a 10% voltage stability margin.

6. ATC Planning Criteria requires Vnose < Vmin. Vmin is 0.95 p.u. at the MP Arrowhead 230 kV.

The MWEX voltage stability study details can be found in Appendix I.

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Section

9

Short Circuit Analysis

9.1 Introduction

Siemens PTI and several transmission owning companies performed short circuit analysis for the DPP 2016 August West Area generation projects.

9.2 J302 Short Circuit Study Performed by Siemens PTI

The J302 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 6,492 A (increased by 469 A) and SLG fault current is 4,376 A (increased by 136 A) at the J302&503 POI 230 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J302 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.1.

9.3 J476 Short Circuit Study Performed by MEC

The J476 short circuit study was performed by MEC. The study results show that the changes in fault current at buses more than a couple of buses away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer's project.

Study details can be found in Appendix J.2.

9.4 J503 Short Circuit Study Performed by Siemens PTI

The J503 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 6,492 A (increased by 456 A) and SLG fault current is 4,376 A (increased by 132 A) at the J302&503 POI 230 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J503 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.3.

9.5 J512 Short Circuit Study Performed by Xcel

The J512 short circuit study was performed by Xcel. Based on the results of the study, the fault current ratings of the Transmission Owner's equipment in the area will not be exceeded. With the proposed J512 generation modeled the fault currents in the area are below 10 kA for 69 kV busses and approximately 12 kA for 115 kV and 345 kV busses. All of the Transmission Owner equipment is rated at 31.5 kA or greater. No short circuit upgrades are required in this area due to the proposed additional generation.

Study details can be found in Appendix J.4.

9.6 J541 Short Circuit Study Performed by Ameren

The J541 short circuit study was performed by Ameren. The study results show that no circuit breaker upgrades are required on the Ameren System based on the expected fault contribution of the J541 and J598 generation. Breaker ratings for MEC and AECI would be required in order to determine if ratings are exceeded for their facilities in this study. However, since the incremental increase in fault current is greater than 5% for only the Ottumwa 345 kV bus, this would be the only facility where the customers would be required to provide mitigation if necessary.

Study details can be found in Appendix J.5.

9.7 J555 Short Circuit Study Performed by MEC

The J555 short circuit study was performed by MEC. The study results show that the changes in fault current at buses more than a couple of buses away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer's project.

Study details can be found in Appendix J.6.

9.8 J569 Short Circuit Study Performed by Xcel

The J569 short circuit study was performed by Xcel. Based on the results of the study, the fault current ratings of the Transmission Owner's equipment in the area will not be exceeded. With the proposed J569 generation modeled the fault currents in the area are below 15 kA for 161 kV and 115 kV busses with the exception of the Anson 115 kV bus which was approximately 37 kA. All of the Transmission Owner equipment is rated at 40 kA or greater and the 115 kV equipment at Anson is rated at 63 kA. No short circuit upgrades are required in this area due to the proposed additional generation.

Study details can be found in Appendix J.4.

9.9 J583 Short Circuit Study Performed by MEC

The J583 short circuit facilities study was performed by MEC. The study results show that the changes in fault current at buses more than a couple of buses away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer's project.

Study details can be found in Appendix J.7.

9.10 J587 Short Circuit Study Performed by Xcel

The J587 (200 MW wind) short circuit study was performed by Xcel to determine the impact of the proposed 200 MW wind generation interconnecting on the 345 kV Transmission Line between Brookings County and Hawks Nest Lake substations. Based on the results of the study, the fault current ratings of the Transmission Owner's equipment in the area are below 30 kA for 115 kV and 345 kV busses. All of the Transmission Owner equipment is rated at 40 kA or greater. No short circuit upgrades are required in this area due to the proposed additional generation.

Study details can be found in Appendix J.4.

9.11 J590 Short Circuit Study Performed by MEC

The J590 short circuit facilities study was performed by MEC. The study results show that the changes in fault current at buses more than a couple of buses away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer's project.

Study details can be found in Appendix J.8.

9.12 J598 Short Circuit Study Performed by Ameren

The J598 short circuit facilities study was performed by Ameren. The study results show that no circuit breaker upgrades are required on the Ameren System based on the expected fault contribution of the J541 and J598 generation. Breaker ratings for MEC and AECI would be required in order to determine if ratings are exceeded for their facilities in this study. However, since the incremental increase in fault current is greater than 5% for only the Ottumwa 345 kV bus, this would be the only facility where the customers would be required to provide mitigation if necessary.

Study details can be found in Appendix J.5.

9.13 J611 Short Circuit Study Performed by MEC

The J611 short circuit facilities study was performed by MEC. The study results show that the changes in fault current at buses more than a couple of buses away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer's project.

Study details can be found in Appendix J.9.

9.14 J614 Short Circuit Study Performed by DPC

The J614 short circuit facilities study was performed by DPC. The short circuit study concludes the fault current rating of the existing Rice Substation equipment has the capabilities to withstand the additional generation.

Study details can be found in Appendix J.10.

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Section

10

Deliverability Study

10.1 Project Description

Interconnection requests requesting Network Resource Interconnection Services (NRIS) were considered for deliverability analysis.

10.2 Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted Network Resource Interconnection Services (NRIS).

If the generator is determined as not fully deliverable, the customer can choose either to change his project to an Energy Resource (ER) project or 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).

10.3 Study Methodology

MISO Generator Deliverability Study whitepaper describing the algorithm can be found at "https://cdn.misoenergy.org/Generator_Deliverability_Study_Methodology108139.pdf".

10.4 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 is in the "Top 30 DF List" (see white paper for detail), part or all of its output is not deliverable. The restricted MW is calculated as following:

(MW restricted) = (worst loading – MW rating) / (generator sensitivity factor)

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

The generator is also responsible for any NEW base case (pre-shift) overload or NEW "severe yet credible dispatch overload" where the generator is not in the "Top 30 DF List", if the generator's DF is greater than 5%. Please see white paper for detail. The formula above also applies to these situations.

10.5 2022 Deliverability Study Result

10.5.1 J302

J302 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades 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 Costs Allocated to Project	Total Cost of Upgrade
Square Butte-Stanton 230 kV	0.00	0.0669	No		J503, J302	$5,553,350	$10,975,000
Merricourt-Ellendale 230 kV	20.96	0.3892	Yes[2]	J503, J302	J503, J302	$25,300	$50,000
J530 POI-HILLS 345 kV	23.71	0.0510	Yes[1]	J476,J541,J555,J583,J598, J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	32.91	0.0513	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$1,124	$100,000
J302 POI-J607 POI-Wishek 230 kV	42.60	0.4311	No		J503, J302	$379,500	$750,000
Wishek-Merricourt 230 kV	101.20	0.4311	No		J503, J302	$430,100	$850,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.2 J476

J476 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	57.64 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	57.64	0.1216	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	246.00	0.1218	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$6,489	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.3 J503

J503 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades 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 Costs Allocated to Project	Total Cost of Upgrade
Square Butte-Stanton 230 kV	0.00	0.0669	No		J503, J302	$5,421,650	$10,975,000
Merricourt-Ellendale 230 kV	20.46	0.3892	Yes[2]	J503, J302	J503, J302	$24,700	$50,000
J530 POI-HILLS 345 kV	23.15	0.0510	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	32.13	0.0513	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$1,098	$100,000
J302 POI-J607 POI-Wishek 230 kV	41.58	0.4311	No		J503, J302	$370,500	$750,000
Wishek-Merricourt 230 kV	98.80	0.4311	No		J503, J302	$419,900	$850,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.4 J512

J512 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	58.58 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	58.58	0.0623	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	250.00	0.0625	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$3,384	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.5 J541

J541 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	93.72 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	93.72	0.3853	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	400.00	0.3856	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$33,403	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.6 J555

J555 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	32.8 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	32.80	0.4658	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	140.00	0.4661	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$14,132	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.7 J569

J569 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	23.43 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	23.43	0.0683	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	100.00	0.0685	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$1,483	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.8 J583

J583 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	46.86 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	46.86	0.1688	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	200.00	0.169	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$7,320	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.9 J587

J587 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	46.86 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	46.86	0.053	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	200	0.0533	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$2,309	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.10 J590

J590 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	21.09 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	21.09	0.0729	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	90.00	0.0732	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$1,427	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.11 J598

J598 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	70.3 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	70.30	0.3854	Yes[1]	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	300.00	0.3857	Yes[2]	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$25,059	$100,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.
Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.12 J611

J611 Deliverable (NRIS) Amount in 2022 case: (Conditional on ERIS and IC upgrades and case assumptions)	25.77 MW (23.43%)	

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 Costs Allocated to Project	Total Cost of Upgrade
J530 POI-HILLS 345 kV	25.77	0.1161	Yes1	J476,J541,J555,J583,J598,J611	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$0	$27,000,000
Montezuma-J530 POI 345 kV	61.12	0.1164	Yes2	J541,J555,J598	J555; J598; J583; J590; J541; J512; J569; J587; J476; J611; J503; J302	$2,773	$100,000
MCKSBRG-Winterset 161 kV	110.00	0.0754	No		J611	$200,000	$200,000

Note 1: ERIS constraint is greater in magnitude than NRIS constraint.

Note 2: ERIS solution is insufficient to solve NRIS constraint.

10.5.13 J614

J614 Deliverable (NRIS) Amount in 2022 Case: (Conditional on ERIS and IC upgrades and case assumptions)	66 MW (100%)

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Section

11

Shared Network Upgrades Analysis

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

The maximum MW impacts and Shared Network Upgrade (SNU) cost allocations are listed in Table 11-1.

Table 11-1: Maximum MW Impact and SNU Cost Allocations

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total NU Cost ($)	Cost Responsibility
J274 POI-Creston 161 kV	DPP-2013-AUG	J274	28.74	$160,000	$105,010
	DPP-2016-AUG	J611	15.05		$54,990
Clarinda-Brooks 161 kV	DPP-2014-AUG	J343	61.70	$68,000	$52,340
	DPP-2016-AUG	J611	18.46		$15,660
J530 POI-Hills 345 kV	DPP-2016-FEB	J475	66.60	$300,000	$63,708
	DPP-2016-FEB	J530	75.20		$71,934
	DPP-2016-AUG	J541	59.03		$56,466
	DPP-2016-AUG	J555	55.89		$53,463
	DPP-2016-AUG	J598	56.90		$54,429

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Section

12

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.

12.1 Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade was provided by the corresponding transmission owning company.

12.2 ERIS Network Upgrades Proposed for DPP West Area Projects

Network upgrades for Energy Resource Interconnection Service (ERIS) were identified in the MISO ERIS analysis and the affected system analysis. The ERIS network upgrades include reactive power network upgrades and thermal network upgrades identified in the MISO steady-state analysis, network upgrades identified in the Local Planning Criteria analysis and affected system analysis, reactive power network upgrades identified in the MWEX voltage stability analysis, stability network upgrades identified in the MISO transient stability analysis, and short circuit network upgrades identified in the MISO short circuit analysis. The total costs of ERIS network upgrades for the 2022 scenario are summarized in Table 12-1.

Table 12-1: Summary of ERIS Network Upgrades

Category of Network Upgrades	Cost ($)
Network Upgrades Identified in MISO Steady-State Analysis	$171,900,000
Network Upgrades Identified in MWEX Voltage Stability analysis	$0
Network Upgrades Identified in Transient Stability Analysis	$0
Network Upgrades Identified in Short Circuit Analysis	$0
Network Upgrades Identified in DPC LPC Analysis	$0
Network Upgrades Identified in MDU LPC Analysis	$13,600,000
Network Upgrades Identified in Ameren LPC Analysis	$9,000,000
Network Upgrades Identified in CIPCO Affected Systems	$0
Network Upgrades Identified in MPC Affected Systems	$0
Network Upgrades Identified in PJM Affected Systems	$0
Network Upgrades Identified in SPP Affected Systems	$0

Category of Network Upgrades	Cost ($)
Network Upgrades Identified in AECI Affected Systems	$3,380,000
Shared Network Upgrades	$235,008
Total	**$198,115,008**

ERIS network upgrades are listed below.

Table 12-2: Thermal Network Upgrades in MISO Steady-State Analysis

Constraint	Owner	Mitigation	Cost ($)
J530 POI-Montezuma 345 kV	MEC	Structure Replacements	$350,000
J530 POI-Hills 345 kV	MEC	Reconductor / Terminal Equipment Upgrades.	$27,000,000
J302&J503 POI-Heskett 230 kV	MDU	Line Clearance Mitigation. New Rating: 343 MVA.	$750,000[1]
J611-Maryville 161 kV	MEC GMO	MEC: Reconductor from POI substation to Missouri border point of ownership change with KCPL. GMO: NU is not required unless it is identified as constraint in affected system study.	$1,000,000
Adams 345-161-13.8 kV xfmr	XEL	Lock Adams xfmr tap at neutral position	$0
Helena-Scott Co 345 kV	XEL WAPA	Rebuild Helana to Scott County (18 miles) with 2-0954 ACSS conductor	$54,000,000
Rice 161-69 kV xfmr	SMMPA	SMMPA: MOD project # 110359 to increase the Rice 161/69kV transformer to 190 MVA rating as per the GIA J614	$0
Hankinson-Forman 230 kV	OTP	Line clearance mitigations.	$650,000
Oakes-Forman 230 kV	OTP	Replacement of terminal equipment and complete rebuild of the 23.3 mile line.	$19,950,000
Oakes-Ellendale 230 kV	OTP MDU	MDU: MDU owns the Ellendale Terminal. It is rated for 776 MVA OTP: Complete rebuild of the 24 mile line.	$20,500,000
Parnell-J438 POI 161 kV	ITCM MEC	ITCM: ITCM terminal rated 335/335 MVA SN/SE. $0 MEC: Structure Replacements. $250,000	$250,000
Ottumwa 345-161 kV xfmr	ITCM	Add 2nd 450 MVA transformer.	$9,000,000
Grimes-Sycamore 345 kV #2	MEC	Add new 345 kV breaker at Grimes to eliminate this common breaker failure contingency.	$2,200,000

Constraint	Owner	Mitigation	Cost ($)
Bondurant-Sycamore 345 kV	MEC	Structure Replacements	$1,000,000
Bondurant-Montezuma 345 kV	MEC	Structure Replacements. $600,000. New rating is 1,189 MVA.	$600,000
Harmony-Cresco 69 kV	DPC	Rebuild line with 477 ACSR	$4,000,000
Parnell-Hills 161 kV	ITCM MEC	Add 1 stage of 36 MVAR nominal, 27.6 MVAR effective cap bank at Parnell 161 kV[2]	$1,400,000

Note 1: MISO analysis requires $750,000 in mitigation. MDU LPC requires $9,000,000 in mitigation to rebuild the line. If the MDU LPC NU moves forward, this MISO NU is not required.

Note 2: An alternative is to reconductor the line with substation terminal equipment upgrades. The estimated cost is $18,000,000. New line rating is 410 MVA.

Table 12-3: Reactive Power NUs in MISO Steady-State Analysis

Network Upgrades	Owner	Cost ($)
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	ITCM	$6,500,000
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	ITCM	$6,500,000
2x150 Mvar switched cap bank at Hills 345 kV (636400)	MEC	$15,000,000
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	MRES	$2,000,000

Note 1: Ameren does not see the low voltage on the high side of the Lathrop transformer as a problem because the low-side voltage remains at an acceptable level. Therefore, switched cap bank at Lathrop is not required.

Note 2: MTEP Project 13043 will add 2X15 Mvar at Donaldson 115kV. Cost assigned to the study projects is $0.

Table 12-4: Network Upgrades in MWEX Voltage Stability

Constraint	Owner	Mitigation	Cost ($)
No Constraints			$0

Table 12-5: Network Upgrades Required for Transient Stability

Network Upgrades	Owner	Cost ($)
No additional Network Upgrades		$0

Table 12-6: Network Upgrades in Short Circuit Analysis

Constraint	Owner	Mitigation	Cost ($)
No Constraints			$0

Table 12-7: DPC Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
No additional NUs			$0

Table 12-8: MDU Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
J302&J503 POI-Heskett 230 kV	MDU	Line rebuild	$9,000,000[1]
Merricourt-Ellendale 230 kV	MDU	Rebuild Line with high temp. conductor New Rating: 440 MVA	$4,600,000

Note 1: MISO analysis requires $750,000 in mitigation. MDU LPC requires $9,000,000 in mitigation to rebuild the line. If the MDU LPC NU moves forward, this MISO NU is not required.

Table 12-9: Ameren Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Zackary 345/161 kV transformer	Ameren	Add Second 560 MVA 345/161 kV transformer	$7,000,000
Adair-Zackary 161 kV	Ameren	Add second 161 kV line between Adair and Zachary	$2,000,000
Adair 161 kV bus tie 2-3	Ameren	Bus tie to be upgraded to 2000 A as part of the Zachary-Ottumwa MVP project	$0

Table 12-10: CIPCO Affected System Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
No Constraints			$0

Table 12-11: MPC Affected System Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
No Constraints			$0

Table 12-12: PJM Affected System Network Upgrades

Constraint	Owner	Mitigation	Total Cost ($)
No Constraints			$0

Table 12-13: SPP Affected System Network Upgrades

Constraint	Owner	Mitigation	Total Cost ($)
No Constraints			$0

Table 12-14: AECI Affected System Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Novelty 161 -69 kV xfmr	AECI	Replace with 84 MVA.	$3,270,000
South River-Emerson 161 kV	AECI	Upgrade 600 A disconnect switches at South River.	$110,000

Table 12-15: Shared Network Upgrades

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total NU Cost ($)	Cost Responsibility
J274 POI-Creston 161 kV	DPP-2013-AUG	J274	28.74	$160,000	$105,010
	DPP-2016-AUG	J611	15.05		$54,990
Clarinda-Brooks 161 kV	DPP-2014-AUG	J343	61.70	$68,000	$52,340
	DPP-2016-AUG	J611	18.46		$15,660
J530 POI-Hills 345 kV	DPP-2016-FEB	J475	66.60	$300,000	$63,708
	DPP-2016-FEB	J530	75.20		$71,934
	DPP-2016-AUG	J541	59.03		$56,466
	DPP-2016-AUG	J555	55.89		$53,463
	DPP-2016-AUG	J598	56.90		$54,429

12.3 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 Post Case. For constraints identified in the shoulder peak scenario, the MW impact is calculated using the shoulder peak post-DPP case. The MW impact on constraints identified in the summer peak scenario is calculated using the summer peak post-DPP case. With all Group Study generation projects dispatched in the Post Case, all thermal and voltage constraints will be identified and a distribution factor from each project on each constraint will be obtained.

Constraints which are mitigated by one or a subset of NU are identified. The MW contribution on these constraints from each generating facility is calculated in the Post Case without any network upgrades. Then the cost of each NU is allocated based on the pro rata share of the

MW contribution from each generating facility on the constraints mitigated or partly mitigated by this NU. The methodology to determine the cost allocation of NU is:

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

12.4 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.

The Distribution Factor (DF) from each generating facility is calculated on the constraints identified in the steady-state analysis in the Post Case without any network upgrades. For a reactive power network upgrade required for mitigating voltage constraints identified in the steady-state AC contingency analysis and stability analysis, DFs are calculated under the most critical contingency on all branches (proxy branches for reactive power network upgrade) connecting at the constraint bus. For a reactive power network upgrade required for mitigating MWEX voltage stability constraints identified in the voltage stability analysis, DFs are calculated under the most critical contingency on all branches (proxy branches) connecting to the high voltage side of the transformer, where the voltage collapse occurs.

For each thermal constraint, the maximum MW contribution (increasing flow) from each generating facility is calculated. MW contribution from one generating facility is set as zero if the MW contribution is less than 1 MW, or the constraint is not categorized as MISO ERIS constraint or affected system constraint for that specific generating facility.

For reactive power network upgrades, or MWEX network upgrades and other voltage stability network upgrades, generators with positive net MW impact (harming the constraint) on all branches connected at the constraint bus will be responsible for mitigating these constraints.

Additional NRIS Network Upgrades are allocated to the impacting NRIS projects. ERIS Network Upgrades will be allocated to the impacting projects only based on the ERIS results.

Transient stability Network Upgrades are allocated based on projects causing instability. If multiple projects are causing instability, cost allocation will be based on pro rata share of total MW of all projects causing instability.

The calculated DF results and the MW contribution on each constraint are in Appendix K.1 for the 2022 scenario.

Finally, the cost allocation for each NU is calculated based on the MW contribution of each generating facility, as detailed in Appendix K.2 for the 2022 scenario.

Assuming all generating facilities in the DPP 2016 August West Area group advance, a summary of the costs for total NUs (NUs for ERIS, NRIS, and Interconnection Facilities) allocated to each generating facility is listed in Table 12-16.

Table 12-16: Summary of Total NU Costs Allocated to Each Generation Project

Project	Max Output (MW)	Total Cost of NU per Project ($)	$/MW	Share %
J302	101.2	$38,557,041	$380,998	14.30%
J476	246	$15,113,571	$61,437	5.61%
J503	98.8	$37,719,720	$381,779	13.99%
J512	250	$33,527,106	$134,108	12.44%
J541	400	$37,417,740	$93,544	13.88%
J555	140	$10,600,206	$75,716	3.93%
J569	100	$8,978,515	$89,785	3.33%
J583	200	$11,156,147	$55,781	4.14%
J587	200	$21,983,848	$109,919	8.16%
J590	90	$8,720,230	$96,891	3.23%
J598	300	$27,667,242	$92,224	10.26%
J611	110	$9,793,125	$89,028	3.63%
J614	66	$8,333,765	$126,269	3.09%
Total/Average	**2550.0**	**$269,568,257**	**$137,499**	**100.00%**

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Appendix

A

Model Development for Steady-State and Stability Analysis

A.1 DPP 2016 August Generation Projects

Table A-1: DPP 2016 August West Area Projects

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J302	ND	Emmons, Logan	MDU	Heskett-Wishek 230 kV	101.2	Wind	NRIS
J476	MO	Atchison	MEC	Atchison Co-Orient 345 kV (1.7 mi from Atchison)	246	Wind	NRIS
J503	ND	Emmons, Logan	MDU	Heskett-Wishek 230 kV (20 miles NW of Wishek)	98.8	Wind	NRIS
J512	MN	Nobles	Xcel	Nobles-Fenton 115 kV	250	Wind	NRIS
J541	MO	Schuyler	ATXI	Zachary–Ottumwa 345 kV	400	Wind	NRIS
J555	IA	Poweshiek	MEC	Montezuma 345 kV	140	Wind	NRIS
J569	MN	Rock	Xcel	Rock County 161 kV	100	Wind	NRIS
J583	IA	Audubon	MEC	Fallow 345 kV	200	Wind	NRIS
J587	MN	Lincoln	Xcel	J460 Sub on the Brookings-H081 345 kV	200	Wind	NRIS
J590	IA	Palo Alto	MEC	J529 POI	90	Wind	NRIS
J598	MO	Adair, Schuyler	ATXI	Zachary–Ottumwa 345 kV	300	Wind	NRIS
J611	MO	Nodaway	MEC	Clarinda-Merryville 161 kV	110	Wind	NRIS
J614	IA	Howard	SMMPA	Rice 161 kV	66	Wind	NRIS

Table A-2: Dynamic Modeling for DPP West Area Projects

MISO Project #	Dynamic Modeling	Generator Reactive Power Capability (power factor)
J302	44 GE 2.3 MW (GEWTG2)	± 0.9
J476	123 Vestas V110 2.0MW (VS3103)	± 0.95
J503	43 GE 2.3MW (GEWTG2)	± 0.9
J512	10 Vestas V110 2.0 MW (VS3103) & 64 Vestas V136 3.6MW (CP17083200)	V136 3.6 MW: '-0.93 (leading), 0.913 (lagging) V110 2.0 MW: ± 0.95
J541	163 Vestas V120 2.2 MW, 12 Vestas V112 3.45 MW	V120 2.2 MW: ± 0.95 V112 3.45 MW: ± 0.95
J555	70 Vestas V110 2.0 MW (VS3103)	± 0.95
J569	42 Siemens SWT 2.5-120 2.5 MW (SWTGU2)	± 0.9
J583	80 GE 2.5 MW (GEWTG2)	± 0.9

MISO Project #	Dynamic Modeling	Generator Reactive Power Capability (power factor)
J587	101 Vestas V110 2.0 MW (VS3103)	0.98 lagging 0.96 leading
J590	45 Vestas V110 2.0 MW (VS3103)	± 0.95
J598	150 Vestas V110 2.0 MW (VS3103)	± 0.95
J611	55 Vestas V110 2.0 MW (VS3103)	± 0.95
J614	33 Vestas V116 2.0 MW (VCS218)	± 0.95

Table A-3: Collector System and Shunt Compensation Modeling for DPP West Area Non-Synchronous Projects

MISO Project #	Generator Modeling	Collector System Modeling	Shunt Compensation
J302	One 101.2 MW unit	Req = 0.00387 pu Xeq = 0.00639 pu Beq = 0.0 pu	3×8 MVAR capacitor bank on 34.5kV system
J476	One 246 MW unit	R=0.0062 pu X=0.0099 pu B=0.25631 pu	3×15 Mvar capacitor bank and 1×5 Mvar reactor bank on 34.5 kV system
J503	One 98.9 MW unit	R=0.003865 pu X=0.006385 pu B=0.0 pu	1×24 Mvar capacitor bank on 34.5 kV system
J512	One 20 MW unit and one 230 MW unit	Circuit #1: R=0.00665 pu X=0.01062 B=0.012 Circuit #2: R=0.00409 X=0.00653 B=0.10606	16 Mvar capacitor bank on 34.5 kV collector system
J541	One 400 MW unit	Circuit #1: R=0.00184 pu X=0.000831 pu B=0.002317 pu Circuit #2: R=0.002427 pu X=0.001096 pu B=0.002241 pu	3×18 Mvar capacitor bank on each of 34.5 kV collector system
J555	One 140 MW unit	R=0.00716 pu X=0.01143 pu B=0.1694 pu	1×5, 1×10, and 2×15 Mvar capacitor banks on 34.5 kV collector system

MISO Project #	Generator Modeling	Collector System Modeling	Shunt Compensation
J569	One 100 MW unit	R=0.002352 pu X=0.003697 pu B=0.03911 pu	None
J583	One 200 MW unit	R=0.00267 pu X=0.00863 pu B=0.0 pu	3×8 MVAR capacitor bank on 34.5 kV system
J587	One 99 MW unit and one 101 MW unit	Circuit #1: R=0.0136 pu X=0.0448 pu B=0.0061 pu Circuit #2: R=0.0136 pu X=0.0448 pu B=0.0061 pu	20 Mvar capacitor bank on each 34.5 kV collector system
J590	Two 45 MW units	None	None
J598	Two 150 MW units	Circuit #1: R=0.00486 pu X=0.00776 pu B=0.08187 pu Circuit #2: R=0.00481 pu X=0.00769 pu B=0.09973 pu	2x20 Mvar capacitor bank on one 34.5 kV collector system, and 1x20 Mvar capacitor bank on another 34.5 kV collector system
J611	One 110 MW unit	R=0.00416 pu X=0.00664 pu B=0.05313 pu	2x10 Mvar capacitor bank on 34.5 kV system
J614	One 66 MW unit	R=0.02227 pu X=0.127 pu B=0.00182 pu	2x6.3 and 1x6.3 Mvar capacitor bank on 34.5 kV system

Table A-4: DPP 2016 August Central Area Projects

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J446	IN	Clinton	DEI	Frankfort-New London 230 kV	200	Wind	NRIS
J456	IL	McDonough	AMIL	Niota-Macomb 138 kV	150	Wind	NRIS
J474	IL	DeWitt	AMIL	North Clinton 138 kV	144	Wind	NRIS
J513	IN	Jasper	NIPS	Reynolds 138 kV	100.05	Wind	NRIS
J641	IL	Morgan, Scott	AMIL	Meredosia East-Jacksonville Industrial Park 138 kV	140	Solar	NRIS
J643	IL	Jasper	NIPS	RM Schahfer-Starke 138 kV	175	Solar	NRIS
J644	IL	Greene, Scott	AMIL	Jerseyville 138 kV	110	Solar	NRIS
J648	IL	Cook	ComEd	SCEP switchyard 138 kV	296	Gas	External NRIS

Table A-5: DPP 2016 August Michigan Area Projects

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J571	MI	Kalamazoo	METC	Morrow 138 kV	6.4	CT	NRIS
J572	MI	Manistee	METC	Filler City JCT 138 kV	150	CC	NRIS
J589	MI	Gratiot	METC	Regal-Summerton 138 kV	148.8	Wind	NRIS
J602	MI	Shiawassee	METC	Goss 138 kV	200	Wind	NRIS

Table A-6: DPP 2016 August ATC Area Projects

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J652	WI	Lafayette	ATC	Darlington-Hillman 138 kV	98	Wind	NRIS Only

A.2 DPP 2016 February West Area Phase 3 Network Upgrades

Table A-7: DPP 2016 February West Phase 3 NUs

Constraint	Owner	Mitigation
J530 POI-Hills 345 kV	MEC	MEC: Structure replacements
Adams 345-161-13.8 kV xfmr	XEL	Upgrade Transformer Nameplate to 336 MVA and terminal equipment
Hazel Creek 345-230-13.8 kV xfmr #6	XEL	Upgrade Hazel Creek TR9 to 672 MVA
Panther-McLeod 230 kV	GRE	Remediate 4 Structures
Johnson Jct-Ortonville 115 kV	MRES GRE OTP	OTP: Ortonville terminal equipment requires replacement. OTP's portion of the 0.56 mile line will be required to be fully rebuilt with a larger conductor. GRE: GRE owned switch at Johnson Jct needs to be replaced. MRES: The MRES owned section (majority of the line) will have to be rebuilt for rating increases.
Johnson Jct-Morris 115 kV	GRE WAPA OTP	GRE: Rebuild 15 miles of 115 kV line from Johnson Junction to Morris. OTP: OTP's 1 mile portion will be required to be fully rebuilt. WAPA: NU is not required unless it is identified as constraint in affected system study.
Big Stone 115-230-13.8 kV xfmr	OTP	Big Stone terminal equipment requires replacement. The Big Stone 230/115/13.8 kV transformer requires replacement.
Big Stone-Browns Valley 230 kV	OTP MDU	OTP: owns Big Stone and Browns Valley terminal equipment which is sufficient to handle the flow seen in the study. $0 MDU: Conductor clearance mitigation.
Big Stone-Blair 230 kV	OTP BEPC	OTP: Big Stone terminal equipment requires replacement. BEPC: NU is not required unless it is identified as constraint in affected system study.
Hankinson-Wahpeton 230 kV	OTP	Line clearance mitigation is required. Hankinson and Wahpeton substation terminal equipment requires replacement.
Hankinson-Forman 230 kV	OTP	Line clearance mitigation is required. Forman substation terminal equipment requires replacement.

Constraint	Owner	Mitigation
Wahpeton-Fergus Falls 230 kV	OTP MRES	Line clearance mitigation is required. Wahpeton substation terminal equipment requires replacement.
Oakes-Forman 230 kV	OTP	Line clearance mitigation is required. Oakes and Forman substation terminal equipment requires replacement.
Oakes-Ellendale 230 kV	OTP MDU	OTP: Line clearance mitigation is required. Oakes substation terminal equipment requires replacement. MDU: The Ellendale MVP 230 kV bus will be built to 796 MVA. $0
Marshalltown-Blairstown 115 kV	ITCM	Sag limit at 162F. Replace 4 structures and replace bus conductor at Blairstown. New rating of 120 MVA.
Blairstown-Prairie Crk 115 kV	CIPCO ITCM	CIPCO: No Mitigation Needed. $0 ITCM: Clearance limit at 153F. Replace 14 structures to reach a minimum rating of 114 MVA
Hazleton-Washburn 161 kV	ITCM MEC	MEC: Reconductor with structure replacements as appropriate and substation terminal equipment upgrades. ITCM: Terminal limit is 325 MVA.
Boone Jct-Sub T Fort Dodge 161 kV	MEC CIPCO	CIPCO: No Mitigation Needed. $0 MEC: Reconductor with structure replacements as appropriate and substation terminal equipment upgrades.
Parnell-J438 POI 161 kV	MEC ITCM	MEC: Structure replacements. ITCM: ITCM Limit is 335 MVA at Parnell
Poweshiek-Reasnor 161 kV	ITCM	Line is sag-limited. Structure replacements are required.
Morgan Valley-Tiffin 345 kV	ITCM MEC	MEC: No Mitigation Required. Existing MEC rating is 961 MVA. $0 ITCM: ITCM future facilities at Morgan Valley will be constructed to a rating greater than what is required for the constaint. $0
Raun-S3451 345 kV	MEC OPPD	MEC: No mitigation required. Existing MEC emergency rating is 1152 MVA. $0 OPPD: NU is not required unless it is identified as constraint in affected system study.
Grimes-Sycamore 345 kV #2	MEC	Sycamore substation terminal equipment upgrades.
Grimes-Beaver Creek 345 kV	MEC	Structure replacements.

Constraint	Owner	Mitigation
Granger Tap-108th & 54th 161 kV	MEC	MEC: Reconductor with structure replacements as appropriate and substation terminal equipment upgrades.
Bondurant-Montezuma 345 kV	MEC	Structure replacements
Webster-Sub T Ft Dodge 161 kV	MEC	Reconductor with structure replacements as appropriate.
Lundquist-Deere Northeast 161 kV	MEC	MEC: Replace limiting substation terminal equipment at both ends of line.
Deere Northeast-Washburn 161 kV	MEC	MEC: Replace limiting substation terminal equipment at both ends of line.
Franklin-Wall Lake 161 kV	MEC	Structure replacements
Blair-Granite Falls 230 kV	WAPA	NU is not required unless it is identified as constraint in affected system study.
Voltage constraints in the areas of Hickory Creek, Salem, and Rock Creek	ITCM	Hickory Creek-Cardinal 345 kV project (MVP project 3127); XFMR tap should be locked at neutral position for the two 345-161 kV xfmrs at Salem (631140)
Voltage constraint in the area of Blackhawk	MEC	150 Mvar switched cap bank at Blackhawk 345 kV (636199) and 1×50 Mvar switched cap bank at Midport 161 kV (636202)
Voltage constraint in the area of Montezuma, J530 POI	MEC	100 Mvar switched cap bank at Montezuma 345 kV (635730)
Voltage constraint in the area of J438 POI	MEC	1×25 Mvar switched cap bank at J438 POI 161 kV (51113)
Mqoketa-Wyoming 161 kV	CIPCO	CIPCO: Rebuild 20.3 miles of 161 kV line to T2-477 ACSR conductor. Replace 2 161 kV switches and jumpers. Change 3 CT ratios to minimum 800 amps.
Liberty-Dundee 161 kV	CIPCO ITCM	CIPCO: If feasible, Reconductor line with high temp conductor. ITCM: CIPCO LPC

A.3 Model Review Comments

Table A-8: Model Review Comments

Company	Python/ Idev File Name	2022 SH	2022 SPK	2022 Stability
ATC	20210917_StoneLake_345kV_STATCOM.idv	x	x	x
ATC	Increase NED xfmr Rate B to 334 MVA.py	x	x	x
ATC	20231231_Z3_SB_EEN_345-138kV.IDV	x	x	x
ATC	20231231_Z3_SB_HCK-EEN_345kV.idv	x	x	x
ATC	20231231_Z3_SB_EEN-CDL_345kV.idv	x	x	x
ATC	20170808_CHC-NLL_Eden2.con	x	x	
BEPC	BEPC_MISO_2016_FEB_West_Phase2_Modelupdate_R1.idv	x	x	x
BEPC	BEPC_MISO_2016_FEB_West_Phase2_Gen_update_SH22-SPTI.idv	x		x
BEPC	BEPC_MISO_2016_FEB_West_Phase2_Gen_update_SP22-SPTI.idv		x	
CIPCO	CIPCO_Gen_SH.idv	x		x
CIPCO	CIPCO_Gen_PK.idv		x	
CIPCO	CIPCO DPP-2016-FEB Phase 2 Additional P6.con	x	x	
DPC	Update DPC Ratings.py	x	x	x
GRE	py-GRE-add-G667-at-RoundLakeTap.py	x	x	x
GRE	py-GRE-add-G549-at-Williams.py	x	x	x
GRE	py-open4X55atRockRiver.py	x	x	x
GRE	GRE_CCR-DKN.CON	x	x	
GRE	Adding H081 Info.idv	x	x	x
ITCM	ITCM DPP 16 Feb Phase 2 Comments.idv	x	x	x
MDU	MDU_Updates-MISO17_2022SUM_TA_SPTI.idv		x	
MDU	MDU_Updates-MISO17_2022SH90_TA_SPTI.idv	x		x
MEC	Adjust MEC Wind output_SH.idv	x		x
MEC	DPP2016FEB Ph2 MEC SH Updates 09.15.2017.py	x		x
MEC	DPP2016FEB Ph2 MEC SUM Updates 09.15.2017.py		x	
MEC	Turn off MEC Reactors.py	x		x
MEC	Adjust J416 SH output.py	x		x
MRES	MRES Summer Model Updates.idv	x	x	x
OTP	1) OTP_Buffalo_disconnect_xfmr2_416.idv	x	x	x
OTP	2) Jamestown345Transformers_10-25-16.idv	x	x	x
OTP	3) BSS XFMR updates.idv	x	x	x

Company	Python/ Idev File Name	2022 SH	2022 SPK	2022 Stability
OTP	4) OTP_unlock_BSS_reactors.idv	x	x	x
OTP	5) BigStone-BigStoneSouth230kV_LineImedanceUpdates_9-13-17.idv	x	x	x
OTP	6) SummerRatingUpdates_9-13-17.idv	x	x	x
OTP	7) BigStoneSouth-Brookings345kV_LineImedanceUpdates_9-13-17.idv	x	x	x
OTP	8) BigStoneSouth-Ellendale345kV_LineImedanceUpdates_9-13-17.idv	x	x	x
SPP	Turn off Ft Calhoon.py	x	x	x
MISO	Adjust J171 Gen output.py	x	x	x
MISO	Update MDU WTG outputs.py	x		x
MISO	Update J320 Pmax.py	x	x	x
MISO	Turn off J391_SH.py	x		x
IC	Address J493 Comments.idv	x	x	x
MISO	SystemModelingShoulderFinalPython.py	x		x
MISO	SystemModelingSummerFinalPython.py		x	
SPTI	Update Area Numbers.idv	x	x	x
GRE	Adjust J171 Gen output.py	x	x	x
MISO	Update MDU WTG outputs.py	x		x
MISO	Update J320 Pmax.py	x	x	x
MISO	Remove Duplicated DPP Projects.idv	x	x	x
MISO	Remove retired gens.idv	x	x	x
IC	J475_SH.idv	x		x
IC	J475_PK.idv		x	
IC	J493&J510_SH.idv	x		x
IC	J493&J510_PK.idv		x	
IC	J514_SH.idv	x		x
BEPC	SH-Turn Off BSS SSL.py	x		x
MISO	RMV_J264.py	x	x	x
MISO	RMV_J298.py	x	x	x
MEC	Cap_ShaulisRd 161.py	x	x	x
MISO	J514_SH.idv	x		x
MISO	J514_PK.idv		x	
MEC	Correct_J475_SH.idv	x		x

Company	Python/ Idev File Name	2022 SH	2022 SPK	2022 Stability
MEC	Correct_J475_PK.idv		x	
MISO	Adjust length of J436 J437 POI line.py	x	x	x
MISO	Turn off BSSE Reactor.py	x	x	x
SPTI	Update DPP Caps.py	x	x	x
OTP	OTPSummerRatingUpdates_10-24-17.idv	x	x	x
MDU	MDU_Updates-Bench_MISO17_2022SH90_NetInt.idv	x		x
MDU	MDU_Updates-MISO17_2022SH90.idv	x		x
MDU	MDU_Updates-MISO17_2022SUM.idv		x	
SPP	RMV_SPP-531449.py	x	x	x
IC	Update J525 GSU.idv	x	x	x
MISO	Correct J442-G736.py	x	x	x
MISO	Add 2015AugDPP changes_171031.py	x	x	x
MEC	MEC Stability Updates.py			x
MDU	MDU-ModelUpdates_StudyCase-2022_SH90_DS_171020.idv			x
MDU	MDU-OtherUpdates_StudyCase-2022_SH90_DS_171020.idv	x	x	x
AMRN	Gateway.idv	x	x	x
AMRN	Beehive.idv	x	x	x
AMRN	Watson Area.idv	x	x	x
AMRN	Tabor.idv	x	x	x
AMRN	AMRN_VSchedule.py	x	x	x
AMRN	AMRN_Rating Chng.py	x	x	x
AMRN	AMRN_Impedance Chng.py	x	x	x
BEPC	BEPC_Proj-Area Chng.py	x	x	x
MEC	MEC DPP2016AUG West Ph1 SH90 Updates 10.12.2017.py	x		x
MEC	MEC DPP2016AUG West Ph1 SUM Updates 10.12.2017.py		x	
J414	J414_DPP1_SH.py	x		x
J414	J414_DPP1_SPK.py		x	
J415	J415_DPP1_SH.py	x		x
J415	J415_DPP1_SPK.py		x	
SPP	RMV_GEN-2016-034.py	x	x	x
SPP	RMV_GEN-2016-055.py	x	x	x
SPP	RMV_GEN-2016-064.py	x	x	x

Company	Python/ Idev File Name	2022 SH	2022 SPK	2022 Stability
J457	J457_Xfmr_Rating.py	x	x	x
J457	Correct_Modeling errors.py	x	x	x
J459	Correct J459.py	x	x	x
J511	Correct_J511_Cap.py	x	x	x
J512	Correct_J512_SH.py	x		x
J512	Correct_J512_PK.py		x	
J569	J569_SH.idv	x		x
J569	J569_PK.idv		x	
J587	Correct_J587.py	x	x	x
J590	Correct_J590_SH.py	x		x
J590	Correct_J590_PK.py		x	
J613	Correct_J613_SH.py	x		x
J613	Correct_J613_PK.py		x	
J614	J614_Caps.py	x	x	x
J614	Correct_J614_0.95_SH.idv	x		x
J614	Correct_J614_0.95_PK.idv		x	
J615	J615_Caps.py	x	x	x
J637, J638	Correct_J637-J638.py	x	x	x
J439	J439.idv	x	x	x
J476	J476.idv	x	x	x
J555	J555.idv	x	x	x
J598	J598.idv	x	x	x
J599	J599.idv	x	x	x
MISO	Remove the original NUs required for DPP 2015 Aug West group	x	x	x
ITCM	Aug_15_DPP_RestudyMitigation_ITCM.idv	x	x	x
OTP	OTP_Mitigations_11-22-17.idv	x	x	x
MEC	M Ave-New Sharon 69 kV Reconductor.py	x	x	x
MEC	Poweshiek-New Sharon 69 kV Reconductor.py	x	x	x
J493	Add-J493-Cap.py	x	x	x
MISO	RMV_J601.py	x	x	x
MISO	RMV_J608.py	x	x	x
MISO	Order827_Updates.py	x	x	x

Company	Python/ Idev File Name	2022 SH	2022 SPK	2022 Stability
SPP	15.DIS1502PQ_ERIS_BUILD_RPLAN-PROJECT[16WP-17WP].idv	x	x	x
SPP	16.DIS1601_ERIS_BUILD_KEYSTONE-GGS-345kV-CKT2.idv	x	x	x
SPP	BANNERCO-KEYSTONE-345kV-CKT1.idv	x	x	x
MISO	correct J503 collector system.py	x	x	x
Xcel	G621_SH.py	x		x
Xcel	G621_PK.py		x	
J475	J475_update.py	x	x	x
MISO	Order827_Updates.py	x		x
MISO	Order827_Updates_SPK.py		x	
MDU	remove duplicate Ellendale shunt reactor.py	x	x	x
Comments on DPP 2016 Aug Ph2 models				
MISO	RMV_Retired Gen.py	x	x	x
MISO	RMV J489.py	x	x	x
MISO	RMV J525.py	x	x	x
MISO	RMV J414.py	x	x	x
MISO	RMV J415.py	x	x	x
MISO	RMV J439.py	x	x	x
MISO	RMV J459.py	x	x	x
MISO	RMV J511.py	x	x	x
MISO	RMV J575.py	x	x	x
MISO	RMV J577.py	x	x	x
MISO	RMV J593.py	x	x	x
MISO	RMV J594.py	x	x	x
MISO	RMV J596.py	x	x	x
MISO	RMV J597.py	x	x	x
MISO	RMV J599.py	x	x	x
MISO	RMV J607.py	x	x	x
MISO	RMV J613.py	x	x	x
MISO	RMV J615.py	x	x	x
MISO	RMV J638.py	x	x	x
SPTI	RMV_DPP 2016 Feb_Stage-2_NUs.py	x	x	x
SPTI	Add-DPP 2016Feb Ph3 NUs.py	x	x	x

Company	Python/ Idev File Name	2022 SH	2022 SPK	2022 Stability
SPTI	RMV_Backbone-NUs.py	x		x
SPTI	RMV MWEX-NUs.py	x		x
J476	J476_POI-Chng.py	x	x	x
MH	MH-BP3-DCTxf-raito-2017on.py	x		x
MH	MH-BP3-DCTxf-raito-2017on_PK.py		x	
Ameren	RMV-Lathrop-Cap.py	x	x	x
Ameren	AMRN_Rating-Chng.py	x	x	x
Ameren	MISO_DPP_AUG16W_Ameren_Updates.idv	x	x	x
Ameren	Euclid.idv	x	x	x
Ameren	Pike.idv	x	x	x
Ameren	Jarvis.idv	x	x	x
Ameren	Kren.idv	x	x	x
Ameren	Redhawk.idv	x	x	x
Ameren	Otto.idv	x	x	x
Ameren	LaFarg.idv	x	x	x
Ameren	Blue Mound.idv	x	x	x
Ameren	Prest-Coulterville.idv	x	x	x
Ameren	Corbin.idv	x	x	x
Ameren	Stallings.idv	x	x	x
Ameren	Towerline.idv	x	x	x
Ameren	Shockey.idv	x	x	x
Ameren	Greenback.idv	x	x	x
Ameren	Ruby-J468 Bus change.idv	x	x	x
Ameren	Tabor.idv	x	x	x
ITCM	ITCM DPP Aug 16 Ph 2 Mtown - Praire Creek.idv	x	x	x
MDU	MDU-Lewis&ClarkUpdate_PK.idv		x	
MDU	MDU-ThunderSpiritWind2Update	x	x	x
MDU	MDU-RatingsUpdate.idv	x	x	x
MEC	MEC_Units.sub	x	x	
MEC	MEC-DPP2016AUG West Ph2 2022 Cat P1 10.26.2018.con	x	x	
MEC	MEC-DPP2016AUG West Ph2 2022 Cat P2 10.26.2018.con	x	x	
MEC	MEC-DPP2016AUG West Ph2 2022 Cat P5 10.26.2018.con	x	x	
MEC	MEC-DPP2016AUG West Ph2 2022 Cat P7 10.26.2018.con	x	x	

Company	Python/ Idev File Name	2022 SH	2022 SPK	2022 Stability
MEC	2016AUGPH2 MEC SH90 Updates.py	x		x
MEC	2016AUGPH2 MEC SUM Updates.py		x	
MPC	MPC-fixrtngs-DPP2016AUG-Ph2.idv	x	x	x
MPC	MPC-retire-6Prairie115Caps.idv	x	x	x
MRES	JohnsonJct-Ortonville_Rebuild.idv	x	x	x
Xcel	contingencies-MEC RAS Retirement.con	x	x	
Xcel	contingencies-Nobles RAS Retirement.con	x	x	
ICs	J476_Correction.py	x	x	x
ICs	J598_Correction.py	x	x	x
ICs	J611_Correction.py	x	x	x
ICs	J541 Correction_SH.py	x		x
ICs	J541 Correction_PK.py		x	
SPP	RMV_SPP-2007-023IS.py	x	x	x
SPP	RMV_SPP-2013-001IS.py	x	x	x
SPP	RMV_SPP-2014-013.py	x	x	x
SPP	RMV_SPP-Withdrawn.py	x	x	x
MRES	MRES Fergus Falls to Silver Lake_Rateing-Correction	x	x	x
OTP	Feb16DPP3_NetworkUpgrades_6-11-18.idv	x	x	x
ITCM	ITCM Rating Corrections.py	x	x	x
MISO	RMV G549.py	x	x	x
MISO	Correct J637 POI.py	x	x	x
Comments on DPP 2016 Aug Ph3 models				
IC	J541_Update.py	x	x	x
IC	J569_Update.idv	x		x
IC	J569_Update_PK.idv		x	
OTP	OTP_G359SISMitigations_1-14-19.idv	x	x	x
MDU	Ellendale SW Reactor LPC.IDV	x	x	x
MDU	Ellendale FSC LPC.IDV	x	x	x
MDU	Ellendale345_FSC_BSSE_20190115.dyr			x
MISO	RMV_J457.py	x	x	x
MISO	RMV_J637.py	x	x	x
MISO	RMV J637 Dynamics Model.py			x
MISO	RMV Ph2 Shunt Caps.py	x		

Company	Python/ Idev File Name	2022 SH	2022 SPK	2022 Stability
MISO	RMV Forman Shunt Cap.py			x
MISO	change Wind Code.py	x	x	x
MISO	2016 Aug DPP Standard Models.dyr			x
Ameren	AMRN_Rating Chngs.py	x	x	x
Ameren	DPP_AUG16W_Ameren_Updates.idv	x	x	x
ATC	ATC_Model_Updates_Aug16_Ph3_SH.idv	x		x
ATC	ATC_Model_Updates_Aug16_Ph3_PK.idv		x	
MEC	MEC_DPP2016AUGPh3_updates.py	x	x	x
MPC	MPC-fixrtngs-Ph3-DPP2016AUG-SH22.idv	x	x	x
IC	J476_J598_J611_MBase-Zsorce.py	x	x	x
IC	Change Khv for Vestas.idv			x
MISO	RMV_PJM-Withdrawn_Prjs.py	x	x	x
MISO	RMV_PJM-NUs.py	x	x	x
MISO	RMV GEN-2015-096.py	x	x	x

A.4 MISO Classic as the Study Sink

Table A-9: MISO Classic as the Study Sink

Area #	Area Name	Area #	Area Name
207	HE	600	Xcel
208	DEI	608	MP
210	SIGE	613	SMMPA
216	IPL	615	GRE
217	NIPS	620	OTP
218	METC	627	ALTW
219	ITC	633	MPW
295	WEC	635	MEC
296	MIUP	661	MDU
314	BREC	663	BEPC-MISO
333	CWLD	680	DPC
356	AMMO	694	ALTE
357	AMIL	696	WPS
360	CWLP	697	MGE
361	SIPC	698	UPPC

A.5 PJM Market as PJM Projects Sink

Table A-10: PJM Market as PJM Projects Sink

Area #	Area Name	Area #	Area Name
201	AP	229	PPL
202	ATSI	230	PECO
205	AEP	231	PSE&G
209	DAY	232	BGE
212	DEO&K	233	PEPCO
215	DLCO	234	AE
222	CE	235	DP&L
225	PJM	236	UGI
226	PENELEC	237	RECO
227	METED	320	EKPC
228	JCP&L	345	DVP

A.6 SPP Market as SPP Projects Sink

Table A-11: SPP Market as SPP Projects Sink

Area #	Area Name
515	SWPA
520	AEPW
523	GRDA
524	OKGE
525	WFEC
526	SPS
527	OMPA
531	MIDW
534	SUNC
536	WERE
540	GMO

Area #	Area Name
541	KCPL
542	KACY
544	EMDE
545	INDN
546	SPRM
640	NPPD
645	OPPD
650	LES
652	WAPA
659	BEPC-SPP

A.7 Contingency Files used in Steady-State Analysis

Table A-12: List of Contingencies used in Steady-State Analysis

Contingency File Name	Description	2022
Automatic single element contingencies	Single element outages at buses 60 kV and above in the study region	x
20170808_CHC-NLL_Eden2.con	Specified category P1, P2 contingencies in ATC, ITCM	x
CIPCO DPP-2016-AUG-P6.con	Specified category P6 contingencies in CIPCO	x
HVDC_con.con	Specified category P1-P7 HVDC contingencies	x
MEC-DPP2016AUG West Ph2 2022 Cat P1 10.26.2018.con	Specified category P1 contingencies in MEC	x
MEC-DPP2016AUG West Ph2 2022 Cat P2 10.26.2018.con	Specified category P2 contingencies in MEC	x
MEC-DPP2016AUG West Ph2 2022 Cat P5 10.26.2018.con	Specified category P5 contingencies in MEC	x
MEC-DPP2016AUG West Ph2 2022 Cat P7 10.26.2018.con	Specified category P7 contingencies in MEC	x
P1_AMES_MTEP17-2022TA.CON	Specified category P1 contingencies in AMES	x
P2-P7_AMES_MTEP17-2022TA.con	Specified category P2-P7 contingencies in AMES	x
P1_ATC_MTEP17-2022TA.con	Specified category P1 contingencies in ATC	x
P2-P7_ATC_MTEP17-2022TA.con	Specified category P2-P7 contingencies in ATC	x
P1_BEPC_MTEP17-2022TA.con	Specified category P1 contingencies in BEPC	x
P2-P7_BEPC_MTEP17-2022TA.con	Specified category P2-P7 contingencies in BEPC	x
P1_CBPC_MTEP17-2022TA.con	Specified category P1 contingencies in CBPC	x
P2-P7_CBPC_MTEP17-2022TA.con	Specified category P2-P7 contingencies in CBPC	x
P1_CFU_MTEP17-2022TA.con	Specified category P1 contingencies in CFU	x
P2-P7_CFU_MTEP17-2022TA.con	Specified category P2-P7 contingencies in CFU	x
P1_CIPCO_MTEP17-2022TA.con	Specified category P1 contingencies in CIPCO	x
P2-P7_CIPCO_MTEP17-2022TA.con	Specified category P2-P7 contingencies in CIPCO	x
P1_DPC_MTEP17-2022TA.con	Specified category P1 contingencies in DPC	x
P2-P7_DPC_MTEP17-2022TA.con	Specified category P2-P7 contingencies in DPC	x
P1_GRE_MTEP17-2022TA.con	Specified category P1 contingencies in GRE	x
P2-P7_GRE_MTEP17-2022TA.con	Specified category P2-P7 contingencies in GRE	x

Contingency File Name	Description	2022
P1_ITCM_MTEP17-2022TA.con	Specified category P1 contingencies in ITCM	x
P2-P7_ITCM_MTEP17-2022TA.con	Specified category P2-P7 contingencies in ITCM	x
P1_MDU_MTEP17-2022TA.con	Specified category P1 contingencies in MDU	x
P2-P7_MDU_MTEP17-2022TA.con	Specified category P2-P7 contingencies in MDU	x
P1_MP_MTEP17-2022TA.con	Specified category P1 contingencies in MP	x
P2-P7_MP_MTEP17-2022TA.CON	Specified category P2-P7 contingencies in MP	x
P1_MPC_MTEP17-2022TA.con	Specified category P1 contingencies in MPC	x
P2-P7_MPC_MTEP17-2022TA.con	Specified category P2-P7 contingencies in MPC	x
P1_MPW_MTEP17-2022TA.con	Specified category P1 contingencies in MPW	x
P2-P7_MPW_MTEP17-2022TA.CON	Specified category P2-P7 contingencies in MPW	x
P1_MRES_MTEP17-2022TA.con	Specified category P1 contingencies in MRES	x
P2-P7_MRES_MTEP17-2022TA.CON	Specified category P2-P7 contingencies in MRES	x
P1_OTP_MTEP17-2022TA.con	Specified category P1 contingencies in OTP	x
P2-P7_OTP_MTEP17-2022TA.con	Specified category P2-P7 contingencies in OTP	x
P1_RPU_MTEP17-2022TA.con	Specified category P1 contingencies in RPU	x
P2-P7_RPU_MTEP17-2022TA.con	Specified category P2-P7 contingencies in RPU	x
P1_SMMPA_MTEP17-2022TA.con	Specified category P1 contingencies in SMMPA	x
P2-P7_SMMPA_MTEP17-2022TA.con	Specified category P2-P7 contingencies in SMMPA	x
P1_XEL_MTEP17-2022TA.con	Specified category P1 contingencies in XEL	x
P2-P7_XEL_MTEP17-2022TA.con	Specified category P2-P7 contingencies in XEL	x
P1-4_ATC_MTEP17-2022TA.con	Specified category P1-4 contingencies in ATC	x
P1-4_DPC_MTEP17-2022TA.con	Specified category P1-4 contingencies in DPC	x
P1-4_GRE_MTEP17-2022TA.con	Specified category P1-4 contingencies in GRE	x
P1-4_ITCM_MTEP17-2022TA.con	Specified category P1-4 contingencies in ITCM	x
P1-4_MDU_MTEP17-2022TA.con	Specified category P1-4 contingencies in MDU	x
P1-4_MP_MTEP17-2022TA.con	Specified category P1-4 contingencies in MP	x
P1-4_MPC_MTEP17-2022TA.con	Specified category P1-4 contingencies in MPC	x
P1-4_OTP_MTEP17-2022TA.con	Specified category P1-4 contingencies in OTP	x
P1-4_SMMPA_MTEP17-2022TA.con	Specified category P1-4 contingencies in SMMPA	x

Contingency File Name	Description	2022
P1-4_XEL_MTEP17-2022TA.con	Specified category P1-4 contingencies in XEL	x
P1_AMRN_MTEP17-2022TA.con	Specified category P1 contingencies in Ameren	x
P2-P7_AMRN_MTEP17-2022TA.con	Specified category P2-P7 contingencies in Ameren	x
P1_CWLD_MTEP17-2022TA.con	Specified category P1 contingencies in CWLD	x
P2-P7_CWLD_MTEP17-2022TA.con	Specified category P2-P7 contingencies in CWLD	x
P1_CWLP_MTEP17-2022TA.con	Specified category P1 contingencies in CWLP	x
P2-P7_CWLP_MTEP17-2022TA.con	Specified category P2-P7 contingencies in CWLP	x
P1_PPI_MTEP17-2022TA.con	Specified category P1 contingencies in PPI	x
P2-P7_PPI_MTEP17-2022TA.con	Specified category P2-P7 contingencies in PPI	x
P1_SIPC_MTEP17-2022TA.con	Specified category P1 contingencies in SIPC	x
P2-P7_SIPC_MTEP17-2022TA.con	Specified category P2-P7 contingencies in SIPC	x
ComEd_RTEP_Cat_P1.con	Specified category P1 contingencies in ComEd	x
ComEd_RTEP_Cat_P2-P7.con	Specified category P2-P7 contingencies in ComEd	x
P1_AECI_MTEP17-2022TA.con	Specified category P1 contingencies in AECI	x
P2-P7_AECI_MTEP17-2022TA.con	Specified category P2-P7 contingencies in AECI	x
P1_CE_MTEP17-2022TA.con	Specified category P1 contingencies in ComEd	x
P2-P7_CE_MTEP17-2022TA.con	Specified category P2-P7 contingencies in ComEd	x
P1_WAPA_MTEP17-2022TA.con	Specified category P1 contingencies in WAPA	x
P2-P7_WAPA_MTEP17-2022TA.con	Specified category P2-P7 contingencies in WAPA	x
P1-4_AMRN_MTEP17-2022TA.con	Specified category P1-4 contingencies in Ameren	x
P1-4_CWLP_MTEP17-2022TA.con	Specified category P1-4 contingencies in CWLP	x
P1-4_SIPC_MTEP17-2022TA.con	Specified category P1-4 contingencies in SIPC	x
P1-4_WAPA_MTEP17-2022TA.con	Specified category P1-4 contingencies in WAPA	x

Appendix

B

Model Data

B.1 Power Flow Model Data

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B.2 Dynamic Model Data

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B.3 2022 Slider Diagrams

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Appendix C

Reactive Power Requirement Analysis Results (FERC Order 827)

Table C-1: Reactive Power Requirement Analysis Results

		Lagging Power Factor Results				Leading Power Factor Results					
Project #	**HV Side Bus #**	**MW from plant to HV side (P)**	**MVAR from plant to HV side (Q)**	**Lagging Power Factor at HV Side**	**Meet Lagging Power Factor Req.?**	**MW from plant to HV side (P)**	**MVAR from plant to HV side (Q)**	**Leading Power Factor at HV Side**	**Meet Leading Power Factor Req.?**	**Turbine Inherent Power Factor**	**Shunt Compensation**
J302	83024	99.71	59.62	0.858	Yes	99.51	-65.48	-0.835	Yes	± 0.9	3×8 MVAR capacitor bank on 34.5kV system
J476	84761	239.26	88.17	0.938	Yes	239.02	-123.14	-0.889	Yes	± 0.95	3×15 Mvar capacitor bank and 1×5 Mvar reactor bank on 34.5 kV system
J503	83024	97.47	59.65	0.853	Yes	97.29	-64.14	-0.835	Yes	± 0.9	1×24 Mvar capacitor bank on 34.5 kV system
J512	85122	245.48	82.54	0.948	Yes	244.70	-153.30	-0.847	Yes	V136 3.6 MW: '-0.93 (leading), 0.913 (lagging) V110 2.0 MW: ± 0.95	16 Mvar capacitor bank on 34.5 kV collector system
J541	85412 854121	392.90	137.20	0.944	Yes	392.00	-244.10	-0.849	Yes	± 0.95	6×18 Mvar capacitor bank on 34.5 kV collector system
J555	65730	166.73	59.65	0.942	Yes	166.87	-86.12	-0.889	Yes	± 0.95	1×5, 1×10, and 2×15 Mvar capacitor banks on 34.5 kV collector system
J569	85691	98.9	40.6	0.925	Yes	98.7	-76.7	-0.790	Yes	± 0.9	None
J583	85831	197.10	76.80	0.932	Yes	196.60	-150.20	-0.795	Yes	± 0.9	3×8 MVAR capacitor bank on 34.5 kV system
J587	85873	196.70	46.20	0.974	No	195.90	-101.40	-0.888	Yes	0.98 lagging 0.96 leading	20 Mvar capacitor bank on each 34.5 kV collector system
J598	85982	294.40	115.90	0.930	Yes	294.20	-140.30	-0.903	Yes	± 0.95	2x20 Mvar capacitor bank on one 34.5 kV collector system, and 1x20 Mvar capacitor bank on another 34.5 kV collector system
J611	86112	108.20	39.60	0.939	Yes	108.00	-55.90	-0.888	Yes	± 0.95	2x20 Mvar capacitor bank on 34.5 kV system
J614	86141	64.20	21.30	0.949	Yes	63.90	-44.10	-0.823	Yes	± 0.95	2x6.3 and 1x6.3 Mvar capacitor bank on 34.5 kV system

Appendix

D

2022 Summer Peak Contingency Analysis Results

D.1 2022 Summer Peak (SPK) Constraints

Table D-1: 2022 SPK System Intact Thermal Constraints

Table D-2: 2022 SPK System Intact Voltage Constraints

Table D-3: 2022 SPK Category P1 Thermal Constraints

Table D-4: 2022 SPK Category P1 Voltage Constraints

Table D-5: 2022 SPK Category P2-P7 Thermal Constraints

Table D-6: 2022 SPK Category P2-P7 Voltage Constraints

Table D-7: 2022 SPK Non-Converged Contingencies

Table D-8: 2022 SPK Non-Converged Contingencies DCCC Results

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Appendix

E

2022 Summer Shoulder Contingency Analysis Results

E.1 2022 Summer Shoulder (SH) Constraints

Table E-1: 2022 SH System Intact Thermal Constraints

Table E-2: 2022 SH System Intact Voltage Constraints

Table E-3: 2022 SH Category P1 Thermal Constraints

Table E-4: 2022 SH Category P1 Voltage Constraints

Table E-5: 2022 SH Category P2-P7 Thermal Constraints

Table E-6: 2022 SH Category P2-P7 Voltage Constraints

Table E-7: 2022 SH Non-Converged Contingencies

Table E-8: 2022 SH Non-Converged Contingencies DCCC Results

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Appendix F

Local Planning Criteria Analysis Results

F.1 MDU LPC Analysis

Below is the MDU local planning criteria analysis report.

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F.2 DPC LPC Analysis

Below is the DPC local planning criteria analysis report.

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F.3 Ameren LPC Analysis

Below is the Ameren local planning criteria analysis report.

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Appendix

G

Affected System Contingency Analysis Results

G.1 CIPCO Company Affected System Analysis Results

Table G-1: 2022 SH CIPCO Affected System Analysis Results

Table G-2: 2022 SPK CIPCO Affected System Analysis Results

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G.2 PJM Affected System Study Results

Below is the PJM affected system study report provided by PJM.

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G.3 SPP Affected System Study Results

Below is the SPP affected system study report provided by SPP.

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G.4 AECI Affected System Study Results

Below is the AECI affected system study report provided by AECI.

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Appendix
H

Transient Stability Results

H.1 2022 Summer Shoulder Stability Results Summary

Stability simulation was performed in the 2022 summer shoulder Phase 3 case with reactive power Network Upgrades identified in the MISO steady state analysis.

Stability study results summary is in Table H-1.

Table H-1: 2022 Summer Shoulder Phase 3 Stability Analysis Results Summary

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H.2 2022 Summer Shoulder Stability Plots

Plots of stability simulations for 2022 summer shoulder Phase 3 study case are in separate files which are listed below:

AppendixH2_2022SH_DPP 2016Aug-West_Ph3_Study_Plots.zip

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Appendix

I

MWEX Voltage Study Details

Below is the MWEX voltage stability study report provided by ATC.

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Appendix

J

Short Circuit Analysis

J.1 J302 Short Circuit Study Performed by Siemens PTI

J.2 J476 Short Circuit Study Performed by MEC

J.3 J503 Short Circuit Study Performed by Siemens PTI

J.4 J512, J569, and J587 Short Circuit Studies Performed by Xcel

J.5 J541 and J598 Short Circuit Study Performed by Ameren

J.6 J555 Short Circuit Study Performed by MEC

J.7 J583 Short Circuit Study Performed by MEC

J.8 J590 Short Circuit Study Performed by MEC

J.9 J611 Short Circuit Study Performed by MEC

J.10 J614 Short Circuit Study Performed by SMMPA

Short Circuit Analysis

1.1 Introduction

A short circuit analysis was performed by Siemens PTI to assess the impact of the J302 generating facility (44 GE 2.3 MW wind turbine generators) on the adequacy of existing circuit breakers and related equipment in the study area.

1.2 Short Circuit Model

An ASPEN short circuit database including positive, negative and zero sequence parameters of the MDU system and its neighboring systems was provided by the MDU. This starting short circuit model is listed below:

- Short Circuit Model: “MDU 02012018.olr”

The J302 short circuit study model was developed as follows:

- Turned on generators which were nearby the POI but were off line in the starting short circuit model (Table 1-1).
- The J302 generating facility with its sequence parameters was added at the tap bus on Heskett to Wishek 230 kV line. J302 WTGs were aggregated and modeled as one induction generator with impedances set as follows:
    - o Positive sequence impedances (i.e. subtransient, transient and synchronous) (Z_1): 0.0+j0.2 pu on 106.52 MVA base with the current limit A set to 445,647 A (five times of rated current)
    - o Zero sequence impedance (Z_0) is set to 0+j9999 pu, and Negative sequence impedance (Z_2) is set to be the same as the Positive sequence impedance.
- The impedance and data for the J302 collection system was modeled as following:
    - o The positive and zero sequence impedance of the 34.5-0.69 kV GSU transformer impedance: 0.00759+j0.05699 pu and 0.00687+j0.05154 pu on 110 MVA base, respectively. Connection is Delta/Wye-ground.
    - o The 34.5 kV collection systems were modeled as a equivalent 34.5 kV line with the positive and zero sequence impedance at 0.00387+j0.00639pu on 100 MVA base.
    - o The main transformer is modeled as one 230-34.5 kV transformer. Positive and zero sequence impedances: 0.00242+j0.08496 pu and 0.00228+j0.07996 pu on 135 MVA base. Connection is Wye-ground/Wye-ground.
    - o Positive sequence impedance for the 230 kV Gentie: 0.0017+j0.01011 pu; Zero sequence impedance: 0.0017+j0.01011 pu.

Table 1-1: Generators Which Were Turn On

ASPEN Bus Name	ID	Starting Case Status	J302 Case Status
WATFORD-S 4.16kV	1	Offline	Online
CAPITOL G2 4.16kV	2	Offline	Online

ASPEN Bus Name	ID	Starting Case Status	J302 Case Status
LINTON GEN 3 13.8kV	1	Offline	Online
DICK DSU GEN 0.48kV	1	Offline	Online
GascWF singl 0.675kV	1	Offline	Online
LINTON GEN 2 13.8kV	1	Offline	Online
LINTON GEN 1 13.8kV	1	Offline	Online
St A-Hosp 12.5kV	1	Offline	Online
CAPITOL G4 4.16kV	1	Offline	Online
EDG-WF singl 0.675kV	1	Offline	Online
ST.JOE GEN 0.48kV	1	Offline	Online
Ellen WF gen 0.675kV	1	Offline	Online
SPROLE Gen 0.48kV	1	Offline	Online
GascWF gen 0.675kV	1	Offline	Online
TESORO G4 4.16kV	1	Offline	Online
BisWP Gen 4.16kV	1	Offline	Online
Ell WF singl 0.675kV	1	Offline	Online
CAPITOL G3 4.16kV	2	Offline	Online
Bowdle WF G 0.675kV	1	Offline	Online
HESKET 3G 0.48kV	1	Offline	Online
CAPITOL G1 4.16kV	2	Offline	Online
RAY D 4.16kV	1	Offline	Online
ST.JOE GEN 0.48kV	2	Offline	Online
Bow WF singl 0.675kV	1	Offline	Online
MILCYCT9 13.8kV	1	Offline	Online
WILLCT 9 12.5kV	1	Offline	Online
COY MDU9 24.kV	1	Offline	Online
WILL DT9 12.5kV	1	Offline	Online
PARSHAL6 69.kV	1	Offline	Online

The following DPP queue projects are also added to the case:

- J457
- J503
- J593
- J599
- J607

1.3 Short Circuit Analysis

Short circuit analysis was performed on the study case (with the J302 project) and benchmark case (without the J302 project). The following fault simulation options were used in the short circuit analysis:

- The prefault voltage was set to “from a linear network solution”
- Current limited generator was set to “Enforce current limit A”

Three-phase (3PH) and Single Line to Ground (SLG) faults were simulated on buses within the Study Project area. The short circuit results are summarized in Table 1.

The results of the short circuit analysis showed that the 3PH fault current at the J302&503 POI 230 kV bus to be 6,492 Amps with J302 (study case) and 6,023 Amps without J302 (benchmark case), and the SLG fault current at the J302&503 POI 230 kV bus to be 4,376 Amps with J302 and 4,241 Amps without J302.

1.4 Summary of Short Circuit Analysis

The study results show that the 3PH fault current is 6,492 A (increased by 469 A) and SLG fault current is 4,376 A (increased by 136 A) at the J302&503 POI 230 kV bus. Based on the Transmission Owner’s short circuit criteria, interconnection of the J302 generation project does not cause any Transmission Owner short circuit constraints.

Table 1: Three Phase (3PH) and Single-Line-to-Ground (SLG) Fault Currents with and without J302

ASPEN Bus Number	ASPEN Bus Name	ASPEN Base kV	LOCATION	AREA	ZONE	Benchmark Case without J302		Study Case with J302		Amps Change with J302 vs Benchmark		% Change with J302 vs Benchmark	
						3PH Fault Current (A)	SLG Fault Current (A)	3PH Fault Current (A)	SLG Fault Current (A)	3PH Fault (A)	SLG Fault (A)	3PH Fault	SLG Fault
0	J302&503	230		2	1	5128.9	3721.4	5643.7	3881.4	514.8	160.0	10.0%	4.3%
0	J302&503 POI	230		2	1	6023.3	4240.5	6491.9	4376.2	468.6	135.7	7.8%	3.2%
0	J607 POI	230		2	1	6332.2	5999.1	6542.8	6114.0	210.6	114.9	3.3%	1.9%
1551	WISHEK 4	230	WISHEK 4	7	1	6309.7	5931.3	6491.2	6028.0	181.5	96.7	2.9%	1.6%
0	J607	230		2	1	5255.8	5428.1	5380.0	5508.4	124.2	80.3	2.4%	1.5%

CRITICAL ENERGY INFRASTRUCTURE INFORMATION NOTICE

The materials contained in this document include Critical Energy Infrastructure Information (CEII). All materials designated as CEII must be handled and protected per the requirements in FERC CEII Policy. There may be additional requirements for CEII materials in the future.

J476 Short Circuit Study Performed by MEC

The scope of this DPP short circuit facilities study is a review of the available fault current at the proposed 345 kV interconnection substation for MISO generation queue request J476, a proposed 246 MW wind farm, and nearby substations both with and without the Interconnection Customer interconnected. J476 was assumed to interconnect off the Atchison County-Orient 345 kV line. Orient is the assumed interconnection point of a higher queued generator. The fault currents were used to identify if any existing MidAmerican circuit breakers become overdutied because of the proposed Interconnection Customer based on the system configuration. The study reviewed single-line-to-ground (SLG) fault current levels and three phase (3PH) fault current levels.

The Interconnection Customer is in an ongoing DPP study cycle of the MISO generation interconnection process where the system impact study is not complete. As a result, the short circuit study is preliminary and does not include changes to the transmission system and/or the generators in the area that may be required when the DPP study results are known. The results of the short circuit analysis are summarized in Table 1.

The results of the short circuit analysis showed the three phase fault current at the 345 kV interconnection substation bus to be 13,807 Amps without the Interconnection Customer included and 14,136 Amps with the Interconnection Customer included (based upon the assumed modeling information for the generator step-up transformer, wind turbines, grounding transformers, and other collector system assumptions). These assumptions affect the results. For example, the preliminary generator step-up transformer information may be different from the impedances from the transformer test report. In specifying equipment or completing equipment settings such as voltage control systems, the Interconnection Customer should be aware that fault currents are subject to change and may increase or decrease at the interconnection point because of additions and/or retirements of the transmission system and/or area generation as well as for system contingencies.

As shown in the table, the changes in fault current at buses more than a couple buses away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer's project. The study results are subject to change based on the outcome of the DPP study or if project design considerations change from those that were studied.

A protective relay coordination review will be required if the Interconnection Customer's project proceeds, and the Interconnection Customer will be required to provide relay settings to MidAmerican. In addition, continued communication and coordination will be required for the parties to meet NERC Standard PRC-001 and PRC-005 and/or future standards.

Table 1. Single-Line-to-Ground (SLG) and Three Phase (3PH) Fault Currents with and without J476

						SLG Fault Current Comparison				3 Ph Fault Current Comparison		
Bus Number	Bus Name	English Name	Base kV	Area Num	Owner	Base SLG w/o new wind farm	SLG with new wind farm	SLG Difference w/ wind farm vs Base		Base 3PH w/o new wind farm	3PH with new wind farm	3PH Difference w/ wind farm vs Base
84760	J476 POI	J476 POI	345	635	MEC	9,817	11,576	1,759		13,807	14,136	329
635017	ATCHSN 3	Atchison	345	635	MEC	9,881	11,623	1,742		13,145	14,187	1,042
635570	ORIENT 3	Orient	345	635	MEC	13,355	13,457	102		16,962	17,096	134
640139	COOPER 3	Cooper	345	640	NPPD	21,796	22,468	672		21,232	21,908	676
635100	RLHILLS3	Rolling Hills	345	635	MEC	10,116	10,145	29		12,883	12,935	52
645458	S3458 3	Sub 3458	345	645	OPPD	17,249	17,349	100		18,134	18,292	158
640277	MOORE 3	Moore	345	640	NPPD	11,162	11,187	25		12,216	12,261	45
300039	7FAIRPT	Fairport	345	330	AECI	8,826	8,851	26		10,493	10,544	51
541199	ST JOE 3	St Joseph	345	540	GMO	12,089	12,124	35		14,500	14,570	70
640140	COOPER 5	Cooper	161	640	NPPD	11,164	11,217	53		9,887	9,939	53
635013	PNYCRK 3	Pony Creek	345	635	MEC	26,914	26,962	48		25,842	25,906	64
635630	BOONVIL3	Booneville	345	635	MEC	15,475	15,505	30		18,196	18,246	50
635635	MADISON3	Madison County	345	635	MEC	13,278	13,303	25		16,367	16,412	45

Short Circuit Analysis

1.1 Introduction

A short circuit analysis was performed by Siemens PTI to assess the impact of the J503 generating facility (43 GE 2.3 MW wind turbine generators) on the adequacy of existing circuit breakers and related equipment in the study area.

1.2 Short Circuit Model

An ASPEN short circuit database including positive, negative and zero sequence parameters of the MDU system and its neighboring systems was provided by the MDU. This starting short circuit model is listed below:

- Short Circuit Model: “MDU 02012018.olr”

The J503 short circuit study model was developed as follows:

- Turned on generators which were nearby the POI but were off line in the starting short circuit model (Table 1-1).
- The J503 generating facility with its sequence parameters was added at the tap bus on Heskett to Wishek 230 kV line. J503 WTGs were aggregated and modeled as one induction generator with impedances set as follows:
    - Positive sequence impedances (i.e. subtransient, transient and synchronous) (Z_1): 0.0+j0.2 pu on 104.1 MVA base with the current limit A set to 435,523 A (five times of rated current)
    - Zero sequence impedance (Z_0) is set to 0+j9999 pu, and Negative sequence impedance (Z_2) is set to be the same as the Positive sequence impedance.
- The impedance and data for the J503 collection system was modeled as following:
    - The positive and zero sequence impedance of the 34.5-0.69 kV GSU transformer impedance: 0.00759+j0.05699 pu on 107.5 MVA base. Connection is Delta/Wye-ground.
    - The 34.5 kV collection systems were modeled as an equivalent 34.5 kV line with the positive and zero sequence impedance at 0.00386+j0.00638 pu on 100 MVA base.
    - The main transformer is modeled as one 230-34.5 kV transformer. Positive and zero sequence impedances: 0.00242+j0.08496 pu and 0.00228+j0.07996 pu on 135 MVA base. Connection is Wye-ground/Wye-ground.
    - Positive sequence impedance for the 230 kV Gentie: 0.0017+j0.01011 pu; Zero sequence impedance: 0.0017+j0.01011 pu.

Table 1-1: Generators Which Were Turn On

ASPEN Bus Name	ID	Starting Case Status	J503 Case Status
WATFORD-S 4.16kV	1	Offline	Online
CAPITOL G2 4.16kV	2	Offline	Online

ASPEN Bus Name	ID	Starting Case Status	J503 Case Status
LINTON GEN 3 13.8kV	1	Offline	Online
DICK DSU GEN 0.48kV	1	Offline	Online
GascWF singl 0.675kV	1	Offline	Online
LINTON GEN 2 13.8kV	1	Offline	Online
LINTON GEN 1 13.8kV	1	Offline	Online
St A-Hosp 12.5kV	1	Offline	Online
CAPITOL G4 4.16kV	1	Offline	Online
EDG-WF singl 0.675kV	1	Offline	Online
ST.JOE GEN 0.48kV	1	Offline	Online
Ellen WF gen 0.675kV	1	Offline	Online
SPROLE Gen 0.48kV	1	Offline	Online
GascWF gen 0.675kV	1	Offline	Online
TESORO G4 4.16kV	1	Offline	Online
BisWP Gen 4.16kV	1	Offline	Online
Ell WF singl 0.675kV	1	Offline	Online
CAPITOL G3 4.16kV	2	Offline	Online
Bowdle WF G 0.675kV	1	Offline	Online
HESKET 3G 0.48kV	1	Offline	Online
CAPITOL G1 4.16kV	2	Offline	Online
RAY D 4.16kV	1	Offline	Online
ST.JOE GEN 0.48kV	2	Offline	Online
Bow WF singl 0.675kV	1	Offline	Online
MILCYCT9 13.8kV	1	Offline	Online
WILLCT 9 12.5kV	1	Offline	Online
COY MDU9 24.kV	1	Offline	Online
WILL DT9 12.5kV	1	Offline	Online
PARSHAL6 69.kV	1	Offline	Online

The following DPP queue projects are also added to the case:

- J302
- J457
- J593
- J599
- J607

1.3 Short Circuit Analysis

Short circuit analysis was performed on the study case (with the J503 project) and benchmark case (without the J503 project). The following fault simulation options were used in the short circuit analysis:

- The prefault voltage was set to “from a linear network solution”
- Current limited generator was set to “Enforce current limit A”

Three-phase (3PH) and Single Line to Ground (SLG) faults were simulated on buses within the Study Project area. The short circuit results are summarized in Table 1.

The results of short circuit analysis showed that the 3PH fault current at the J302&503 POI 230 kV bus to be 6,492 Amps with J503 (study case) and 6,036 Amps without J503 (benchmark case), and the SLG fault current at the J302&503 POI 230 kV bus to be 4,376 Amps with J503 and 4,244 Amps without J503.

1.4 Summary of Short Circuit Analysis

The study results show that the 3PH fault current is 6,492 A (increased by 456 A) and SLG fault current is 4,376 A (increased by 132 A) at the J302&503 POI 230 kV bus. Based on the Transmission Owner’s short circuit criteria, interconnection of the J503 generation project does not cause any Transmission Owner short circuit constraints.

Table 1: Three Phase (3PH) and Single-Line-to-Ground (SLG) Fault Currents with and without J503

ASPEN Bus Number	ASPEN Bus Name	ASPEN Base kV	LOCATION	AREA	ZONE	Benchmark Case without J503		Study Case with J503		Amps Change with J503 vs Benchmark		% Change with J503 vs Benchmark	
						3PH Fault Current (A)	SLG Fault Current (A)	3PH Fault Current (A)	SLG Fault Current (A)	3PH Fault (A)	SLG Fault (A)	3PH Fault	SLG Fault
0	J302&503	230		2	1	5142.6	3725.8	5643.7	3881.4	501.1	155.6	9.7%	4.2%
0	J302&503 POI	230		2	1	6036.0	4244.3	6491.9	4376.2	455.9	131.9	7.6%	3.1%
0	J607 POI	230		2	1	6338.2	6002.4	6542.8	6114.0	204.6	111.6	3.2%	1.9%
1551	WISHEK 4	230	WISHEK 4	7	1	6314.9	5934.0	6491.2	6028.0	176.3	94.0	2.8%	1.6%
0	J607	230		2	1	5259.3	5430.4	5380.0	5508.4	120.7	78.0	2.3%	1.4%

Interconnection Facility Study Report

Generation Interconnection MISO projects J512, J569, and J587

March 15, 2018

Submitted by Tim Bickford, PE

Xcel Energy Services, Inc.

1.0 J512

A short circuit analysis was performed to determine the impact of the proposed 250MW wind generation MISO project J512 interconnecting on the 115 kV Transmission Line between Nobles County and Fenton substations. The proposed generation was added to the existing Transmission Owner’s CAPE model and faults were studied on all busses within four busses from the point of interconnection.

Based on the results of the study, the fault current ratings of the Transmission Owner’s equipment in the area will not be exceeded. With the proposed J512 generation modeled the fault currents in the area are below 10 kA for 69 kV busses and approximately 12 kA for 115 kV and 345 kV busses. All of the Transmission Owner equipment is rated at 31.5kA or greater.

There are no short circuit upgrades required in this area due to the proposed additional generation.

2.0 J569

A short circuit analysis was performed to determine the impact of the proposed 100MW wind generation MISO project J569 interconnecting at the 161 kV Rock County substation. The proposed generation was added to the existing Transmission Owner’s CAPE model and faults were studied on all busses within four busses from the point of interconnection.

Based on the results of the study, the fault current ratings of the Transmission Owner’s equipment in the area will not be exceeded. With the proposed J569 generation modeled the fault currents in the area are below 15 kA for 161 kV and 115 kV busses with the exception of the Anson 115 kV bus which was approximately 37 kA. All of the Transmission Owner equipment is rated at 40 kA or greater and the 115 kV equipment at Anson is rated at 63 kA.

There are no short circuit upgrades required in this area due to the proposed additional generation.

3.0 J587

The short circuit analysis for J587 (200 MW wind) was performed to determine the impact of the proposed 200 MW wind generation interconnecting on the 345 kV Transmission Line between Brookings County and Hawks Nest Lake substations. The proposed generation was added to the existing Transmission Owner’s CAPE model and faults were studied on all busses within four busses from the point of interconnection.

Based on the results of the study, the fault current ratings of the Transmission Owner's equipment in the area will not be exceeded. With the proposed J587 generation modeled the fault currents in the area are below 30 kA for 115 kV and 345 kV busses. All of the Transmission Owner equipment is rated at 40 kA or greater.

There are no short circuit upgrades required in this area due to the proposed additional generation.

C. Short Circuit Analysis

Short circuit analysis was performed with and without the study generation in service using Aspen on a model maintained by Ameren specifically for calculating fault current. A comparison of fault current calculations provided the necessary information to determine if the interrupting capability of existing circuit breakers at substations within three buses of the J541 and J598 interconnections would be exceeded. Per MISO criteria, the study generation is not responsible for circuit breaker interrupting capability upgrades if the incremental increase is less than 5.0%. Results of the short circuit analysis are shown in tables IV-N-1 and IV-N-2below:

J541 & J598 Short Circuit Results

			Without Projects		With Projects		Delta	
Substation	**Voltage**	**T.O.**	**3-Phase amps**	**L-G amps**	**3-Phase amps**	**L-G amps**	**3-Phase amps**	**L-G amps**
J598 POI	345 kV	Ameren	8,055	6,075	9,944	9,542	1,889	3,467
J541 POI	345 KV	Ameren	8,120	5,924	10,406	9,946	2,286	4,022
Zachary	345 KV	Ameren	8,770	6,468	10,393	8,701	1,623	2,233
Zachary	161 kV	Ameren	13,305	9,976	14,254	11,673	949	1,697
Adair	161 kV	Ameren	12,952	9,484	13,698	10,706	746	1,222
Maywood	345 kV	Ameren	15,722	11,906	16,210	12,293	488	387
Ottumwa	345 KV	MEC	11,257	12,309	12,146	13,232	889	923
Ottumwa	161 kV	MEC	34,542	36,514	35,486	37,736	944	1,222
Bridgeport	161 kV	MEC	20,613	16,831	20,903	17,031	290	200
Wapello	161 kV	MEC	13,885	12,502	14,033	12,597	148	95
Appanoose	161 kV	AECI	6,469	4,978	6,530	5,021	61	43
Novelty	161 kV	AECI	6,252	4,732	6,337	4,810	85	78

No circuit breaker upgrades are required on the Ameren System based on the expected fault contribution of the J541 and J598 generation. Breaker ratings for MEC and AECI would be required in order to determine if ratings are exceed for their facilities in this study. However, since the incremental increase in fault current is greater than 5% for only the Ottumwa 345 kV bus, this would be the only facility where the customers would be required to provide mitigation if necessary.

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J475 and J555 Short Circuit Study Performed by MEC

The scope of this DPP Optional Study facilities study is a review of the available fault current at the proposed 345 kV interconnection substation for MISO generation queue request J475, a proposed 200 MW wind farm, and J555, a proposed 140 MW expansion, and nearby substations both with and without the Interconnection Customer interconnected. J475 and J555 were assumed to interconnect at the MidAmerican and ITC Midwest jointly-owned Montezuma Substation. The fault currents were used to identify if any existing MidAmerican circuit breakers become overdutied because of the proposed Interconnection Customer based on the system configuration. The study reviewed single-line-to-ground (SLG) fault current levels and three phase (3PH) fault current levels.

The Interconnection Customer is in DPP study cycles of the MISO generation interconnection process, where the system impact studies are not complete. As a result, the short circuit study is preliminary and does not include changes to the transmission system and/or the generators in the area that may be required when the DPP study results are known. The results of the short circuit analysis are summarized in Table 1.

The results of the short circuit analysis showed the three phase fault current at the 345 kV interconnection substation bus to be 13,008 Amps without the Interconnection Customer included and 14,334 Amps with the full 340 MW from the Interconnection Customer included (based upon the assumed modeling information for the generator step-up transformer, wind turbines, grounding transformers, and other collector system assumptions). These assumptions affect the results, especially the 34.5 kV results that should be calculated by the Interconnection Customer. For example, generator step-up transformer information may be different from the impedances from the transformer test report. In specifying equipment or completing equipment settings such as voltage control systems, the Interconnection Customer should be aware that fault currents are subject to change and may increase or decrease at the interconnection point because of additions and/or retirements of the transmission system and/or area generation or system contingencies.

As shown in the table, the changes in fault current at buses more than one bus away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican breakers become overdutied as a result of the Interconnection Customer's project. The study results are subject to change based on the outcome of the DPP study or if project design considerations change from those that were studied.

A protective relay coordination review will be required if the Interconnection Customer's project proceeds, and the Interconnection Customer will be required to provide relay settings to MidAmerican. In addition, continued communication and coordination will be required for the parties to meet NERC Standard PRC-001 and PRC-005 and/or future standards.

Table 1. Single-Line-to-Ground (SLG) and Three Phase (3PH) Fault Currents
with and without J475 and J555

						SLG Fault Current Comparison					**3 Ph Fault Current Comparison**				
Bus Number	Bus Name	English Name	Base kV	Area Num	Owner	Base SLG w/o wind farms J475/J555	SLG with new J475 wind farm	SLG Difference w/ J475 wind farm vs Base	SLG with J475 & J555 wind farm	SLG Difference w/ J475 & J555 wind farm vs Base	Base 3PH w/o wind farms J475/J555	3PH with new J475 wind farm	3PH Difference w/ J475 wind farm vs Base	3PH with J475 & J555 wind farm	3PH Difference w/ J475 & J555 wind farm vs Base
635730	MNTZUMA3	Montezuma	345	635	MEC	9,020	10,083	1,063	11,078	2,058	13,008	13,705	697	14,334	1,326
		J475 Collector Bus	34.5			19,371	32,795	13,424	32,856	13,485	16,744	27,713	10,969	27,756	11,012
		J555 Collector Bus	34.5			19,371	19,371	-	29,325	9,954	16,744	16,744	-	24,307	7,563
635680	BONDRNT3	Bondurant	345	635	MEC	17,016	17,131	115	17,223	207	19,055	19,188	133	19,299	244
631143	OTTUMWA3	Ottumwa	345	627	ITCM	9,031	9,193	162	9,322	291	10,891	11,055	164	11,194	303
	J530 POI	J530 POI	345	635	MEC	10,293	10,542	249	10,742	449	12,902	13,146	244	13,354	452
635700	SYCAMOR3	Sycamore	345	635	MEC	19,005	19,070	65	19,122	117	20,106	20,193	87	20,265	159
635690	GDMEC	GDMEC	345	635	MEC	18,566	18,638	72	18,697	131	18,624	18,711	87	18,783	159
344000	7ADAIR	Adair/Zachary 345	345	356	AMMO	8,920	8,934	15	8,946	26	12,465	12,494	29	12,517	52
631115	OTTUMWA5	Ottumwa	161	627	ITCM	27,848	27,929	81	27,993	145	23,967	24,035	68	24,091	124
636400	HILLS 3	Hills	345	635	MEC	16,822	16,902	80	16,966	144	19,937	20,054	117	20,151	214
		J530 Collector Bus	34.5			30,409	30,480	71	30,537	128	26,522	26,574	52	26,617	95
635600	GRIMES 3	Grimes	345	635	MEC	18,245	18,292	47	18,330	85	20,460	20,535	75	20,597	137
635701	SYCAMOR5	Sycamore	161	635	MEC	33,003	33,067	64	33,119	116	32,925	33,003	78	33,068	143
635650	SE POLK3	SE Polk	345	635	MEC	17,992	18,057	65	18,110	118	18,356	18,438	82	18,505	149
345435	7MAYWOOD	Maywood	345	356	AMMO	8,222	8,226	4	8,228	6	11,420	11,429	9	11,436	16
344006	5ADAIR3	Adair/Zachary 161	161	356	AMMO	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
631110	WAPELLO5	Wapello	161	627	ITCM	10,727	10,735	8	10,741	14	11,096	11,108	12	11,117	21
631118	LUCAS 5	Lucas Co	161	627	ITCM	3,221	3,222	1	3,222	1	3,339	3,340	1	3,341	2
631116	BRDGPRT5	Bridgeport	161	627	ITCM	15,772	15,794	22	15,811	39	17,111	17,144	33	17,170	59
631134	TRICNTY5	Tri County	161	627	ITCM	15,937	15,960	23	15,978	41	17,358	17,391	33	17,418	60
635880	PLSNT CRNR 5	Pleasant Corner	161	635	MEC	9,837	9,846	9	9,853	15	12,403	12,420	17	12,434	31
636420	TIFFIN 3	Tiffin	345	635	MEC	11,251	11,275	24	11,295	44	14,815	14,864	49	14,905	90
636620	WALCOTT3	Walcott	345	635	MEC	11,076	11,083	7	11,088	12	15,648	15,667	19	15,682	34
636640	LOUISA 3	Louisa	345	635	MEC	19,061	19,085	24	19,105	44	19,077	19,111	34	19,139	62
636645	SUB T 3	Sub T Haskins	345	635	MEC	11,232	11,252	20	11,269	37	15,712	15,759	47	15,797	85
636401	HILLS 5	Hills	161	635	MEC	19,245	19,278	33	19,304	59	19,685	19,723	38	19,755	70
631034	ROSEHLW5	Rose Hollow	161	627	ITCM	5,802	5,803	2	5,804	3	6,551	6,554	3	6,556	5

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J583 Short Circuit Study Performed by MEC

The scope of this DPP short circuit facilities study is a review of the available fault current at the proposed 345 kV interconnection substation for MISO generation queue request J583, a proposed 200 MW wind farm, and nearby substations both with and without the Interconnection Customer interconnected. J583 was assumed to interconnect at an expanded Fallow Ave Substation. The fault currents were used to identify if any existing MidAmerican circuit breakers become overdutied because of the proposed Interconnection Customer based on the system configuration. The study reviewed single-line-to-ground (SLG) fault current levels and three phase (3PH) fault current levels.

The Interconnection Customer is in an ongoing DPP study cycle of the MISO generation interconnection process where the system impact study is not complete. As a result, the short circuit study is preliminary and does not include changes to the transmission system and/or the generators in the area that may be required when the DPP study results are known. The results of the short circuit analysis are summarized in Table 1.

The results of the short circuit analysis showed the three phase fault current at the 345 kV interconnection substation bus to be 10,216 Amps without the Interconnection Customer included and 10,844 Amps with the Interconnection Customer included (based upon the assumed modeling information for the generator step-up transformer, wind turbines, grounding transformers, and other collector system assumptions). These assumptions affect the results. For example, the preliminary generator step-up transformer information may be different from the impedances from the transformer test report. In specifying equipment or completing equipment settings such as voltage control systems, the Interconnection Customer should be aware that fault currents are subject to change and may increase or decrease at the interconnection point because of additions and/or retirements of the transmission system and/or area generation as well as for system contingencies.

As shown in the table, the changes in fault current at buses more than a couple buses away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer's project. The study results are subject to change based on the outcome of the DPP study or if project design considerations change from those that were studied.

A protective relay coordination review will be required if the Interconnection Customer's project proceeds, and the Interconnection Customer will be required to provide relay settings to MidAmerican. In addition, continued communication and coordination will be required for the parties to meet NERC Standard PRC-001 and PRC-005 and/or future standards.

Table 1. Single-Line-to-Ground (SLG) and Three Phase (3PH) Fault Currents with and without J583

						SLG Fault Current Comparison				3 Ph Fault Current Comparison		
Bus Number	Bus Name	English Name	Base kV	Area Num	Owner	Base SLG w/o new wind farm	SLG with new wind farm	SLG Difference w/ wind farm vs Base		Base 3PH w/o new wind farm	3PH with with new wind farm	3PH Difference w/ wind farm vs Base
635590	FALLOW 3	Fallow Ave	345	635	MEC	8,704	9,323	619		10,216	10,844	628
85831	J583	J583 Sub	345	635	IC	8,344	8,980	636		9,927	10,556	629
635580	ARBR HL 3	Arbor Hill	345	635	MEC	9,239	9,501	263		11,441	11,827	386
635014	OVRLND 3	Overland Trail	345	635	MEC	23,173	23,244	71		24,238	24,378	140
635589	ECLIPSE3	Eclipse	345	635	MEC	7,028	7,410	382		8,409	8,818	409
635600	GRIMES 3	Grimes	345	635	MEC	19,284	19,361	77		21,843	22,015	172
635000	CBLUFFS3	CBEC	345	635	MEC	30,982	31,058	76		28,226	28,363	137
635015	OVRLND 5	Overland Trail	161	635	MEC	24,540	24,558	18		26,188	26,236	48
636003	BVR CRK 3	Beaver Creek	345	635	MEC	9,622	9,626	4		12,476	12,492	16
635700	SYCAMOR3	Sycamore	345	635	MEC	19,678	19,734	56		21,259	21,393	134
635630	BOONVIL3	Booneville	345	635	MEC	15,478	15,505	27		18,170	18,246	76
635601	GRIMES 5	Grimes	161	635	MEC	22,606	22,636	30		24,177	24,239	62
635599	GRIM1XT9	Grimes 9T1 Tertiary	13.8	635	MEC	-	-	-		32,723	32,731	8
635013	PNYCRK 3	Pony Creek	345	635	MEC	26,905	26,962	57		25,792	25,906	114
635016	STHLND 3	Southland	345	635	MEC	26,877	26,933	56		25,775	25,889	114
645456	S3456 3	Sub 3456	345	645	OPPD	26,457	26,485	28		27,851	27,924	73
635001	CBLUFFS5	CBEC	161	635	MEC	37,185	37,220	35		35,674	35,750	76
635026	CBLF2XT9	CBEC 9T2 Tertiary	13.8	635	MEC	-	-	-		35,119	35,125	6

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J529 Short Circuit Study Performed by MEC

The scope of this DPP Optional Study facilities study is a review of the available fault current at the proposed 345 kV interconnection substation for MISO generation queue request J529, a proposed 250 MW wind farm along with J590, a proposed 90 MW expansion at the same interconnection point, and nearby substations both with and without the Interconnection Customer interconnected. J529/J590 was assumed to interconnect off the Obrien County-Kossuth County 345 kV line. The fault currents were used to identify if any existing MidAmerican circuit breakers become overdutied because of the proposed Interconnection Customer based on the system configuration. The study reviewed single-line-to-ground (SLG) fault current levels and three phase (3PH) fault current levels.

The Interconnection Customer is in a DPP study cycle of the MISO generation interconnection process where the system impact study is not complete. As a result, the short circuit study is preliminary and does not include changes to the transmission system and/or the generators in the area that may be required when the DPP study results are known. The results of the short circuit analysis are summarized in Table 1.

The results of the short circuit analysis showed the three phase fault current at the 345 kV interconnection substation bus to be 10,000 Amps without the Interconnection Customer included and 11,705 Amps with the Interconnection Customer included (based upon the assumed modeling information for the generator step-up transformer, wind turbines, grounding transformers, and other collector system assumptions). These assumptions affect the results. For example, generator step-up transformer information may be different from the impedances from the transformer test report. In specifying equipment or completing equipment settings such as voltage control systems, the Interconnection Customer should be aware that fault currents are subject to change and may increase or decrease at the interconnection point because of additions and/or retirements of the transmission system and/or area generation or system contingencies.

As shown in the table, the changes in fault current at buses more than a couple buses away from the point of interconnection are comparatively small. Based on MidAmerican's short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer's project. The study results are subject to change based on the outcome of the DPP study or if project design considerations change from those that were studied.

A protective relay coordination review will be required if the Interconnection Customer's project proceeds, and the Interconnection Customer will be required to provide relay settings to MidAmerican. In addition, continued communication and coordination will be required for the parties to meet NERC Standard PRC-001 and PRC-005 and/or future standards.

Table 1. Single-Line-to-Ground (SLG) and Three Phase (3PH) Fault Currents
with and without J529/J590

					SLG Fault Current Comparison				3 Ph Fault Current Comparison		
Bus Number	Bus Name	English Name	Base kV	Owner	Base SLG w/o new wind farm	SLG with new wind farm	SLG Difference w/ wind farm vs Base		Base 3PH w/o new wind farm	3PH with new wind farm	3PH Difference w/ wind farm vs Base
		J529J590 POI	345		7,660	9,703	2,043		10,000	11,705	1,705
		J529J590 Collector	34.5		23,730	37,957	14,227		20,331	32,060	11,730
55368	J455 POI	J455 POI	345	MEC	9,827	10,320	493		11,388	11,993	606
635369	KOSSUTH 3	Kossuth Co	345	MEC	8,502	9,587	1,085		11,804	12,852	1,048
635368	OBRIEN 3	O'Brien Co	345	MEC	11,489	11,804	315		13,740	14,192	452
631197	LEDYARD3	Ledyard	345	ITCM	8,258	8,705	448		11,552	12,112	560
636000	WEBSTER3	Webster	345	MEC	9,825	10,033	208		11,901	12,150	249
631138	LAKEFLD3	ITCM Lakefield	345	ITCM	15,041	15,234	192		16,469	16,736	267
635400	HIGHLND 3	Highland	345	MEC	10,112	10,283	171		12,330	12,588	258
631193	HUNTLEY3	Huntley	345	ITCM	7,823	8,019	196		10,432	10,725	293
631198	COLBY3	Colby	345	ITCM	7,974	8,039	65		9,386	9,484	98
636010	LEHIGH 3	Lehigh	345	MEC	9,802	9,910	109		12,385	12,541	156
636001	WEBSTER5	Webster	161	MEC	17,205	17,352	147		17,701	17,831	130
601034	NOBLES 3	Nobles Co	345	XCEL	5,670	5,687	16		8,543	8,587	43
601029	LKFLDXL3	Xcel Lakefield	345	XCEL	20,018	20,173	156		14,337	14,438	101
631041	LAKEFLD5	ITCM Lakefield	161	ITCM	17,185	17,286	101		18,941	19,081	140
635200	RAUN 3	Raun	345	MEC	27,244	27,345	101		25,743	25,839	95

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J611 Short Circuit Study Performed by MEC

The scope of this DPP short circuit facilities study is a review of the available fault current at the proposed 161 kV interconnection substation for MISO generation queue request J611, a proposed 110 MW wind farm, and nearby substations both with and without the Interconnection Customer interconnected. J611 was assumed to interconnect off the Clarinda-Maryville 161 kV line. Maryville Substation and additional buses in Missouri are not owned by MidAmerican and are not evaluated here. The fault currents were used to identify if any existing MidAmerican circuit breakers become overdutied because of the proposed Interconnection Customer based on the system configuration. The study reviewed single-line-to-ground (SLG) fault current levels and three phase (3PH) fault current levels.

The Interconnection Customer is in an ongoing DPP study cycle of the MISO generation interconnection process where the system impact study is not complete. As a result, the short circuit study is preliminary and does not include changes to the transmission system and/or the generators in the area that may be required when the DPP study results are known. The results of the short circuit analysis are summarized in Table 1.

The results of the short circuit analysis showed the three phase fault current at the 161 kV interconnection substation bus to be 5,338 Amps without the Interconnection Customer included and 6,207 Amps with the Interconnection Customer included (based upon the assumed modeling information for the generator step-up transformer, wind turbines, grounding transformers, and other collector system assumptions). These assumptions affect the results. For example, the preliminary generator step-up transformer information may be different from the impedances from the transformer test report. In specifying equipment or completing equipment settings such as voltage control systems, the Interconnection Customer should be aware that fault currents are subject to change and may increase or decrease at the interconnection point because of additions and/or retirements of the transmission system and/or area generation as well as for system contingencies.

As shown in the table, the changes in fault current at buses more than a couple buses away from the point of interconnection are comparatively small. Based on MidAmerican’s short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer’s project. The study results are subject to change based on the outcome of the DPP study or if project design considerations change from those that were studied.

A protective relay coordination review will be required if the Interconnection Customer’s project proceeds, and the Interconnection Customer will be required to provide relay settings to MidAmerican. In addition, continued communication and coordination will be required for the parties to meet NERC Standard PRC-001 and PRC-005 and/or future standards.

Table 1. Single-Line-to-Ground (SLG) and Three Phase (3PH) Fault Currents
with and without J611

						SLG Fault Current Comparison			3 Ph Fault Current Comparison		
Bus Number	Bus Name	English Name	Base kV	Area Num	Owner	Base SLG w/o new wind farm	SLG with new wind farm	SLG Difference w/ wind farm vs Base	Base 3PH w/o new wind farm	3PH with with new wind farm	3PH Difference w/ wind farm vs Base
86111	J611 POI	J611 POI	161	635	MEC	4,107	5,040	933	5,338	6,207	869
86112	J611	J611 IC Sub	161	635	IC	3,154	4,268	1,115	4,381	5,289	909
635034	CLARINDA 5	Clarinda	161	635	MEC	5,678	6,046	368	6,144	6,647	503
541251	MARYVLE5	Maryville (GMO)	161	540	GMO	4,642	4,945	303	6,171	6,585	414
635037	BROOKS 5	Brooks	161	635	MEC	4,236	4,300	64	5,321	5,478	157
635032	HASTING5	Hastings	161	635	MEC	5,898	5,954	56	6,963	7,091	128
635035	CLARINDA 8	Clarinda	69	635	MEC	9,565	9,809	244	7,707	7,960	253
635056	ADAMS 5	Adams County	161	635	MEC	4,948	4,999	51	5,870	5,999	129
635031	BUNGE 5	Bunge	161	635	MEC	19,104	19,129	25	22,761	22,838	77
635033	HASTING8	Hastings	69	635	MEC	9,510	9,561	51	9,177	9,272	95
635065	REDOAK 8	Red Oak	69	635	MEC	2,420	2,427	7	3,736	3,766	30
635050	SHENAND8	Shenandoah	69	635	MEC	2,502	2,509	7	3,873	3,901	28
629170	VILISCAJCT8	Villisca Jct	69	627	CIPCO	2,116	2,124	8	2,001	2,018	17
652560	CRESTON5	Creston	161	652	WAPA	9,378	9,431	54	9,825	9,949	124

Short Circuit Study for J614

66 MW Wind Generation Interconnection

Rice Substation

Howard County, Iowa

MISO# J614

March 9, 2017

Prepared by:
Dairyland Power Cooperative

1. Overview of the Project

J614 is a proposed 66 MW wind generation interconnection to Southern Minnesota Municipal Power's (SMP) Rice substation. A circuit position will need to be added at Rice Substation to accommodate this proposed interconnection. In addition to the circuit position being required, the additional generation may require a capacity increase to the 161/69 kV transformer.

2. Short-Circuit Fault Study

The purpose of the short circuit study is to review the short circuit withstand capabilities of the equipment at Rice Substation. The customer requested two separate scenarios be studied. The first scenario was to include the interconnection at Rice Substation with the existing 161/69 kV transformer, no increase in transformer capacity. The second scenario was to replace the existing 161/69 kV transformer with a larger capacity (200 MVA) transformer. The customer intends to install wind machines per documentation received by Dairyland Power Cooperative (DPC) on January 23, 2017. DPC used the information contained in file "GI_J614_Attachment A Revised 20161011" titled "Large Generating Facility Data" supplied by SMP. A summary of the short circuit impacts to the Rice Substation is attached.

In summary, the short circuit study concludes the fault current rating of the existing Rice Substation equipment has the capabilities to withstand the additional generation. Due to the increased short circuit current, it is recommended that a protection coordination review be performed on all 161 kV and 69 kV terminals in the Rice Substation and on any other affected stations remote to Rice Substation. The scope and cost associated with this protection coordination review is captured in a facility study being performed by others.

Short Circuit Study - Rice Substation

Scenerio 1: Rice Substation with Exising Transformer

						Fault on Line (kA)			Fault on Bus (kA)			Int. Capability (kA)	
Bkr Owner	Bus Name	BKR 1 Name	Remote End	Line	Base kV	SLG	TPH	DLG	SLG	TPH	DLG	BKR	Over Rating?
SMMPA	Rice	6670	Saratoga Tap	Q-30	161	1.9	1.6	1.8	4.5	5.0	4.7	40	No
SMMPA	Rice	6680	JADE AVE	SMMPA	161	5.4	5.8	5.5	1.3	1.0	1.3	40	No
SMMPA	Rice	0507	Rice 69	AT1	161	5.7	5.7	5.6	1.0	1.0	1.0	40	No
SMMPA	Rice	050	Rice 161	AT1	69	2.0	3.6	3.1	5.0	4.4	4.7	31.5	No
SMMPA	Rice	051	Saratoga Tap	N-81	69	6.4	6.0	6.0	1.0	1.9	1.6	31.5	No
SMMPA	Rice	052	Riceville	SMMPA	69	7.2	7.0	6.8	0.5	0.8	0.7	31.5	No
SMMPA	Rice	053	Cresco IPW	SMMPA	69	6.9	6.6	6.5	0.6	1.1	1.0	31.5	No

Scenario 2: Rice Substation with Increased Capacity Transformer (200 MVA)

						Fault on Line (kA)			Fault on Bus (kA)			Int. Capability (kA)	
Bkr Owner	Bus Name	BKR 1 Name	Remote End	Line	Base kV	SLG	TPH	DLG	SLG	TPH	DLG	BKR	Over Rating?
SMMPA	Rice	6670	Saratoga Tap	Q-30	161	2.4	1.9	2.2	4.5	5.0	4.7	40	No
SMMPA	Rice	6680	JADE AVE	SMMPA	161	6.1	6.0	5.9	1.3	1.0	1.3	40	No
SMMPA	Rice	0507	Rice 69	AT1	161	5.7	5.7	5.6	1.6	1.3	1.4	40	No
SMMPA	Rice	050	Rice 161	AT1	69	2.0	3.6	3.1	9.2	7.9	8.8	31.5	No
SMMPA	Rice	051	Saratoga Tap	N-81	69	10.6	9.4	10.0	1.0	1.9	1.6	31.5	No
SMMPA	Rice	052	Riceville	SMMPA	69	11.5	10.4	10.8	0.5	0.8	0.7	31.5	No
SMMPA	Rice	053	Cresco IPW	SMMPA	69	11.2	10.0	10.5	0.6	1.1	1.0	31.5	No

Values current as of 1-25-17

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Appendix

K

2022 Cost Allocation Results

K.1 Distribution Factor (DF) and MW Contribution Results for Cost Allocation in 2022

Table K-1: Distribution Factor and MW Contribution on Constraints for Thermal NU Cost Allocation in 2022

Table K-2: Distribution Factor and MW Contribution on Voltage Constraints for NU Cost Allocation

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K.2 Cost Allocation Details

Table K-3: Network Upgrades Cost Allocation in 2022

Table K-3: Network Upgrades Cost Allocation in 2022

Monitored Element	English Name	Cost	J302	J476	J503	J512	J541	J555	J569	J583	J587	J590	J598	J611	J614	Upgrade for
75730 J530 POI 345 635730 MNTZUMA3 345 1	J530 POI-Montezuma 345 kV	$350,000	$0	$0	$0	$0	$157,374	$74,581	$0	$0	$0	$0	$118,045	$0	$0	MISO SH
75730 J530 POI 345 636400 HILLS 3 345 1	J530 POI-Hills 345 kV	$27,000,000	$0	$1,560,562	$0	$0	$10,342,658	$4,915,735	$0	$1,755,753	$0	$0	$7,758,196	$667,095	$0	MISO SH
83021 J302&503 POI 230 661042 HESKETT4 230 1	J302&J503 POI-Heskett 230 kV	$9,000,000	$4,554,000	$0	$4,446,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH & MDU LPC
86111 J611 161 541251 MARYVLE5 161 1	J611-Maryville 161 kV	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,000,000	$0	MISO SH
541199 ST JOE 3 345 640139 COOPER 3 345 1	St. Joseph-Cooper 345 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601002 ADAMS 3 345 631046 ADAMS 5 161 605739 ADAMS1 9 13.8 9	Adams 345-161-13.8 kV xfmr	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601006 SPLT RK3 345 652537 WHITE 3 345 1	Split Rock-White 345 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601050 HELENA 3 345 601055 SCOTTCO3 345 1	Helena-Scott Co 345 kV	$54,000,000	$0	$0	$0	$22,404,560	$0	$0	$7,579,499	$0	$16,799,157	$7,216,784	$0	$0	$0	MISO SH
613330 RICE 5 161 630189 RICE 8 69.0 1	Rice 161-69 kV xfmr	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620327 HANKSON4 230 620363 FORMAN 4 230 1	Hankinson-Forman 230 kV	$650,000	$328,900	$0	$321,100	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620362 OAKES 4 230 620363 FORMAN 4 230 1	Oakes-Forman 230 kV	$19,950,000	$10,094,700	$0	$9,855,300	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620362 OAKES 4 230 661098 ELLENDLMVP4 230 1	Oakes-Ellendale 230 kV	$20,500,000	$10,373,000	$0	$10,127,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
631085 PARNEL 5 161 51113 J438 POI 161 1	Parnell-J438 POI 161 kV	$250,000	$0	$0	$0	$0	$0	$250,000	$0	$0	$0	$0	$0	$0	$0	MISO SH
631106 HENRYCO5 161 631111 JEFF 5 161 1	Henry Co-Jeff 161 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
631110 WAPELLO5 161 631111 JEFF 5 161 1	Wapello-Jeff 161 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
631115 OTTUMWA5 161 631143 OTTUMWA3 345 1	Ottumwa 345-161 kV xfmr	$9,000,000	$0	$0	$0	$0	$4,639,994	$879,896	$0	$0	$0	$0	$3,480,110	$0	$0	MISO SH
635600 GRIMES 3 345 635700 SYCAMOR3 345 2	Grimes-Sycamore 345 kV #2	$2,200,000	$0	$0	$0	$0	$0	$0	$0	$2,200,000	$0	$0	$0	$0	$0	MISO SH
635680 BONDRNT3 345 635700 SYCAMOR3 345 1	Bondurant-Sycamore 345 kV	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$1,000,000	$0	$0	$0	$0	$0	MISO SH
635680 BONDRNT3 345 635730 MNTZUMA3 345 1	Bondurant-Montezuma 345 kV	$600,000	$0	$0	$0	$0	$0	$0	$0	$600,000	$0	$0	$0	$0	$0	MISO SH
652503 BLAIR 4 230 652550 GRANITF4 230 1	Blair-Granite Falls 230 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
652530 WATERTN4 230 652529 WATERTN3 345 652237 WATERT19 13.8 1	Watertown 345-230-13.8 kV xfmr	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
652530 WATERTN4 230 652582 APPLEDORN 4 230 1	Watertown-Appledorn 230 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
631085 PARNEL 5 161 636401 HILLS 5 161 1	Parnell-Hills 161 kV	$1,400,000	$0	$0	$0	$0	$0	$1,400,000	$0	$0	$0	$0	$0	$0	$0	MISO SH
661093 MERRCRT4 230 661098 ELLENDLMVP4 230 1	Merricourt-Ellendale 230 kV	$4,600,000	$2,327,600	$0	$2,272,400	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MDU LPC
661098 ELLENDLMVP4 230 620362 OAKES 4 230 1	Oakes-Ellendale 230 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MDU LPC
680026 HARMNY 69.0 680175 CRESCO 69.0 1	Harmony-Cresco 69 kV	$4,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,000,000	MISO SH & DPC LPC
Zachary 345/161 kV transformer	Zachary 345/161 kV transformer	$7,000,000	$0	$0	$0	$0	$4,000,000	$0	$0	$0	$0	$0	$3,000,000	$0	$0	Ameren LPC
Zachary-Adair 161 kV line	Zachary-Adair 161 kV line	$2,000,000	$0	$0	$0	$0	$1,142,857	$0	$0	$0	$0	$0	$857,143	$0	$0	Ameren LPC
Adair 161 kV bus tie 2-3	Adair 161 kV bus tie 2-3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Ameren LPC
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	$6,500,000	$382,067	$624,846	$373,007	$1,457,618	$0	$442,848	$553,316	$652,054	$886,888	$765,604	$0	$247,461	$114,291	Reactive Power NU
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	$6,500,000	$489,580	$463,179	$477,969	$1,354,958	$0	$371,523	$510,070	$533,378	$1,047,667	$539,157	$0	$175,293	$537,225	Reactive Power NU
2x150 Mvar switched cap bank at Hills 345 kV (636400)	2x150 Mvar switched cap bank at Hills 345 kV (636400)	$15,000,000	$134,627	$928,975	$131,434	$430,170	$5,164,988	$2,198,028	$192,851	$1,082,081	$280,020	$188,109	$3,874,260	$394,458	$0	Reactive Power NU
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	1×50 Mvar switched cap bank at McLeod 230 kV (619940)	$2,000,000	$233,193	$89,520	$227,663	$386,416	$0	$0	$141,295	$58,562	$818,808	$9,148	$0	$35,395	$0	Reactive Power NU
300106 5NOVELY_SW 161 300364 2NOVLTY_SW 69.0 1	Novelty 161 -69 kV xfmr	$3,270,000	$0	$0	$0	$0	$3,270,000	$0	$0	$0	$0	$0	$0	$0	$0	AECI AFS
300113 5SRIVER 161 300339 5EMERSN 161 1	South River-Emerson 161 kV	$110,000	$0	$0	$0	$0	$110,000	$0	$0	$0	$0	$0	$0	$0	$0	AECI AFS
J274 POI-Creston 161 kV (SNU)	J274 POI-Creston 161 kV (SNU)	$160,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$54,990	$0	SNU
Clarinda-Brooks 161 kV (SNU)	Clarinda-Brooks 161 kV (SNU)	$68,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,660	$0	SNU
J530 POI-Hills 345 kV (SNU)	J530 POI-Hills 345 kV (SNU)	$300,000	$0	$0	$0	$0	$56,466	$53,463	$0	$0	$0	$0	$54,429	$0	$0	SNU
Square Butte-Stanton 230 kV (NRIS)	Square Butte-Stanton 230 kV (NRIS)	$10,975,000	$5,553,350	$0	$5,421,650	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
Merricourt-Ellendale 230 kV (NRIS)	Merricourt-Ellendale 230 kV (NRIS)	$50,000	$25,300	$0	$24,700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
Montezuma-J530 POI 345 kV (NRIS)	Montezuma-J530 POI 345 kV (NRIS)	$100,000	$1,124	$6,489	$1,098	$3,384	$33,403	$14,132	$1,483	$7,320	$2,309	$1,427	$25,059	$2,773	$0	NRIS
J302 POI-J607 POI-Wishek 230 kV (NRIS)	J302 POI-J607 POI-Wishek 230 kV	$750,000	$379,500	$0	$370,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
Wishek-Merricourt 230 kV (NRIS)	Wishek-Merricourt 230 kV (NRIS)	$850,000	$430,100	$0	$419,900	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
MCKSBRG-Winterset 161 kV (NRIS)	MCKSBRG-Winterset 161 kV (NRIS)	$200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$200,000	$0	NRIS
Total Cost Per Project for Actual NRIS Elections for each Project		**$211,040,008**	**$35,307,041**	**$3,673,571**	**$34,469,720**	**$26,037,106**	**$28,917,740**	**$10,600,206**	**$8,978,515**	**$7,889,147**	**$19,834,848**	**$8,720,230**	**$19,167,242**	**$2,793,125**	**$4,651,516**	

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