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MISO DPP August 2017 Wisconsin Area Phase 1

System Impact Study Report

J732, J798, J807, J818, J819, J821, J825, J831, J850, J855, J864, J870, J871, J878, J886, and J947

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1.0 EXECUTIVE SUMMARY

Sixteen (16) generation projects have requested to interconnect to the MISO transmission network in the Wisconsin Area and are included in the Definitive Planning Phase 2017 August Phase 1 study (Aug 17 DPP WI Phase 1). 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 generator interconnection requests in the Aug 17 DPP WI Phase 1 study. The study was performed under the direction of Midcontinent Independent System Operator (MISO) by ATC and an ad hoc study group. The results for 2022 scenario are summarized below.

1.1 Project List

The Aug 17 DPP WI Phase 1 has sixteen (16) generator interconnection requests with a combined nameplate rating of 2,466.38 MW. The Aug 17 DPP WI Phase 1 generator interconnection requests are listed in Table 1.1-1. The modeling details and one-line diagrams of the interconnection facilities are shown in Appendix C.

Table 1.1-1 – Generating Facilities in DPP August 2017 Phase 1 Wisconsin Area

MISO Queue #	Service Type	Control Area	County, State	Point of Interconnection	Fuel Type	Requested MW	Dispatch (MW) [1]		
							22SH	22SUM	Stability
J732	NRIS	WPS	Douglas, WI	Arrowhead – Stone Lake 345 kV	CC	561.5	280.75	561.5	561.5
J798	NRIS	WEC	Walworth, WI	University - Mukwonago 138 kV	Solar	124	62	124	124
J807	NRIS	ALTE	Lafayette, WI	Falcon 138 kV	Wind	41.4	41.4	6.46	41.4
J818	NRIS	WEC	Jefferson, WI	Jefferson 138 kV	Solar	149	74.5	149	149
J819	NRIS	ALTE	Lafayette, WI	Darlington 138 kV	Wind	99.9	99.9	15.6	99.9
J821	NRIS	WPS	Marathon, WI	Wien – Stratford 115 kV	Wind	99.9	99.9	15.6	99.9
J825	NRIS	ALTE	Green, WI	North Monroe – Albany 138 kV	Wind	99.9	99.9	15.6	99.9
J831[2]	NRIS	WEC	Ozaukee, WI	Port Washington 138 kV	CC	40	20	40	40
J850	NRIS	ALTE	Rock, WI	RCEC Bradford – RCEC LaPrairie 138 kV	Solar	250	125	250	250
J855	NRIS	ALTE	Grant, WI & Iowa, WI	Lancaster – Hill Valley 138 kV	Wind	100.8	100.8	15.72	100.8
J864	NRIS	ALTE	Richland, WI	Lone Rock 69 kV	Solar	49.98	25.38	49.98	49.98
J870	NRIS	ALTE	Grant, WI & Iowa, WI	Eden 138 kV	Solar	200	100	200	200
J871	NRIS	ALTE	Grant, WI & Iowa, WI	Eden 138 kV	Solar	100	50	100	100
J878	NRIS	WEC	Kenosha, WI	Paris 138 kV	Solar	200	100	200	200
J886	NRIS	WPS	Manitowoc, WI	Kewaunee 138 kV	Solar	150	75	150	150
J947	NRIS	ALTE	Grant, WI	Hillman – Potosi 138 kV	Solar	200	100	200	200

[1] Per MISO BPM 015-r18, the following dispatch assumptions are applied in the 2022 Shoulder (22SH), 2022 Summer Peak (22SUM), and 2022 Stability models for each Fuel Type.
a. Combined Cycle (CC) is dispatched to 50% of the Requested MW in the 22SH, 100% in the 22SUM, and 100% in the Stability model.
b. Solar is dispatched to 50% of the Requested MW in the 22SH, 100% in the 22SUM, and 100% in the Stability model.
c. Wind is dispatched to 100% of the Requested MW in the 22SH, 15.6% in the 22SUM, and 100% in the Stability model.

[2] J831 is an expansion of existing generating facilities.

1.2 Generating Facility Requirements

1.2.1 Voltage Schedule Requirement

ATC requires all generators in its territory to maintain a voltage schedule at the Point of Interconnection (POI). The standard voltage schedule is 1.02 per unit as measured at the POI. This schedule may be changed by the Transmission Operator for specific power plants or specific conditions.

1.2.2 Power Factor Range Requirement

FERC Order 827 and ATC Criteria require all newly interconnecting generators interconnecting to ATC-owned Facilities to provide a power factor range for synchronous and non-synchronous (e.g., wind turbines, solar) generation of 0.95 leading (when a Generating Facility is consuming reactive power from the Transmission System) to 0.90 lagging (when a Generating Facility is supplying reactive power to the Transmission System). The Generating Facility must be capable of maintaining ATC's standard power factor range at all power output levels by providing dynamic reactive power at the following locations:

A. The POI for all synchronous generators
B. The high-side of the generator substation for all non-synchronous generators

For synchronous machines, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of the POI. For non-synchronous machines, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of the generator substation. Dynamic reactive power provided by non-synchronous generators must meet the following requirement from FERC order 827 Item 35:

> "Non-synchronous generators may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the inverter, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses."

Therefore, static reactive power sources can only be used to make up for losses between the terminal of the machines and the high side of the generator substation for non-synchronous machines. All other reactive power to meet the power factor requirement must be provided by dynamic sources. Static sources can be switched on or off in the range of seconds and provide reactive power in large discrete blocks. Capacitor Banks are considered static sources of reactive power. Dynamic sources can provide variable amounts of reactive power in a few milliseconds. Static Var Compensators (SVCs), Static Synchronous Compensators (STATCOMs), Flexible AC Transmission Systems (FACTS), inverters and synchronous condensers are all considered dynamic sources or reactive power.

For non-synchronous generation projects in the DPP 2017 August Wisconsin Area study group, if they did not have a 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 0.90 lagging at the high-side of the generator substation.

Based on the reactive power requirement analysis, all of the synchronous and non-synchronous generation projects in this study group can meet the dynamic reactive power requirements per FERC Order 827 and ATC Criteria.

The generation requests shown in Table 1.2.2-1 did not meet the static reactive power requirements per ATC Criteria at the time of the model completion and are required to provide additional static reactive power sources. All other requests in this queue met FERC Order 827 and ATC Criteria.

Table 1.2.2-1 – Additional Static Mvar to meet ATC Capacitive Power Factor and FERC Order 827 Power Factor Requirements

MISO Queue #	Type	Additional Static Shunt Compensation [1] (Mvar)
J807	Asynchronous	5.6
J818	Asynchronous	13.3
J819	Asynchronous	15.2
J825	Asynchronous	15.1
J831	Synchronous	32.4
J850	Asynchronous	28.6
J855	Asynchronous	4.5
J870	Asynchronous	19.3
J871	Asynchronous	9.7
J878	Asynchronous	20.8
J947	Asynchronous	13.5

[1] Additional compensation is required to meet the criteria at the POI Bus for synchronous Generating Facilities or the high-side of the generator substation for asynchronous Generating Facilities.

1.2.3 Island Detection and Operation

In circumstances where the Generating Facility has no governor controls and the transmission system design could result in an islanding condition for the outage of two transmission elements, ATC requires the Customer to implement additional protection systems as mutually agreed by the Customer and ATC to prevent generation from being isolated or islanded with interconnected load. Alternatively, ATC will require the Customer to curtail their generation for circumstances that could result in an island condition with the next contingency.

This would apply to the following Generating Facilities from this DPP cycle that lack adequate governor controls to safely and reliably sustain an island with load.

- J821

- J825
- J850
- J855
- J947

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 SIS report date. The total cost of Network Upgrades required for each generator interconnection request is listed in Table 1.3-1. The costs for Network Upgrades are planning level estimates and subject to be revised in the facility studies. All Interconnection Facility Project Diagrams are documented in Appendix C and all Network Upgrade Project Diagrams are documented in Appendix D.

Overland_Public Comment 1_MISO GI DPP August 2017 Wisconsin Area Phase 1
See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

Table 1.3-1 – Total Cost of Network Upgrades for August 17 DPP Wisconsin Phase 1 Generator Interconnection Requests

MISO Queue #	Requested MW	ERIS Network Upgrades ($)				NRIS Network Upgrades ($)	Interconnection Facilities ($)		Shared Network Upgrade ($)	Total Cost of Network Upgrades (Exclude TOIF & Affected Systems) ($)	M2 Received ($)[1]	M3 Due ($)[2]
		Steady - State Thermal & Voltage	Transien t Stability	Short Circuit	Affected System		TO Network Upgrades	TO-Owned Direct Assigned (TOIF)				
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]=[c]+[d]+[e]+[g]+[h]	[l] = $4000 x [b]	[m]= (10%of [k])-[l]
J732	561.5	3,898,500	0	100,000	0	0	19,093,177	917,157	0	23,091,677	2,246,000	63,168
J798	124	24,266,033	0	0	0	16,281,245	8,582,303	131,773	0	49,129,581	496,000	4,416,958
J807	41.4	1,902,061	0	35,500	25,500	422,358	995,136	195,145	0	3,355,056	165,600	169,906
J818	149	0	0	100,000	100,000	0	2,014,700	358,000	0	2,114,700	596,000	0
J819	99.9	5,008,787	0	65,500	65,000	925,234	3,097,080	286,557	0	9,096,601	399,600	510,060
J821	99.9	0	0	0	0	0	8,479,530	370,095	0	8,479,530	399,600	448,353
J825	99.9	8,494,455	0	85,500	45,500	4,181,782	8,941,794	195,465	0	21,703,530	399,600	1,770,753
J831	40	0	0	0	0	167,337	0	0	0	167,337	160,000	0
J850	250	0	0	83,000	10,255,800	14,102,297	9,091,848	199,828	0	23,277,145	1,000,000	1,327,714
J855	100.8	0	0	22,500	18,500	13,299	8,704,428	190,871	0	8,740,227	403,200	470,823
J864	49.98	0	0	96,000	351,500	0	663,711	251,959	0	759,711	200,000	0
J870/J871	300	1,143,961	0	132,500	502,500	69,136	2,197,572	311,801	0	3,543,170	1,200,000	0
J878	200	0	0	150,000	0	23,538,683	2,177,000	377,192	0	25,865,683	800,000	1,786,568
J886	150	0	0	0	0	0	1,884,099	827,206	0	1,884,099	600,000	0
J947	200	6,405,827	0	129,500	80,500	2,252,390	8,728,445	191,368	0	17,516,163	800,000	951,616
Total ($)	-	51,119,625	0	1,000,000	11,444,800	61,953,761	84,650,823	4,804,417	0	198,724,209	9,865,600	11,915,919

[1] M2: Milestone Payment dollars received by MISO
[2] M3 = (10% of NU)-M2
[3] ATC projects are estimated in ISD dollars with a 2.5% annual escalation rate and include a 20% contingency.
[4] Pre-Certification costs are not included.
[5] Transmission Owner shall also collect from Interconnection Customer a tax gross-up amount on the payments made to Transmission Owner using the Transmission Owner rate in effect at the time the payment is received from Interconnection Customer. The current Transmission Owner tax gross-up rate is 12.848%.
[6] TOIF: Non-reimbursable Transmission Owner Interconnection Facilities to which tax gross-up amount must also be applied.

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1.4 In-Service Dates and Cost Estimates

ATC understands that the estimated in-service date may not align with the Interconnection Customer's Synchronization Date; however, negotiated and executed agreements, such as an Engineering and Procurement Agreement, can be used prior to the GIA execution date to expedite Network Upgrades. In absence of any special arrangement, typical times to develop a new Interconnection Facility is about 24-36 months after the GIA is executed, assuming no delays due to Interconnection Customer's permits, state processes, land acquisitions, deliverables (such as a finish graded substation site, etc. It also assumes that system outages required to construct facilities can be obtained timely. The cost estimates for Interconnection Facilities are based on the in-service date provided in the Interconnection Customer's application data. Therefore, any change in in-service date will have impact on the cost estimates. The requested dates for Interconnection Facility in-service, synchronization, and commercial operation are summarized in Table 1.4-1.

Table 1.4-1 – Requested Interconnection Facilities In-Service Dates, Synchronization Dates and Commercial Operation Dates

MISO Queue #	Requested Interconnection Facility In-service Date	Requested Synchronization Date	Requested Commercial Operation Date
J732	August 9, 2023	November 22, 2023	November 27, 2024
J798	September 1, 2019	October 1, 2019	December 1, 2019
J807	September 15, 2020	September 15, 2020	October 31, 2020
J818	September 1, 2019	October 1, 2019	December 1, 2019
J819	September 15, 2020	September 15, 2020	October 31, 2020
J821	September 15, 2020	September 15, 2020	October 31, 2020
J825	September 15, 2020	September 15, 2020	October 31, 2020
J831	June 3, 2018	June 3, 2018	June 3, 2018
J850	September 30, 2021	September 30, 2021	December 31, 2021
J855	August 1, 2019	October 1, 2019	December 1, 2019
J864	September 1, 2020	September 15, 2020	December 1, 2020
J870	September 10, 2020	September 10, 2020	December 31, 2020
J871	September 10, 2021	September 10, 2021	December 31, 2021
J878	September 10, 2021	September 10, 2021	December 31, 2021
J886	September 15, 2020	October 1, 2020	December 1, 2020
J947	September 15, 2019	October 1, 2019	December 1, 2019

1.5 MTEP Projects

If a MTEP transmission project(s) resolves the constraint, and that project(s) is approved by the Board within (1) calendar year of the 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).

1.6 Further Study

The next step in the MISO Generator Interconnection Procedures is to perform additional SISs (if needed), Interconnection Customer Interconnection Facility Studies, and Network Upgrade Facility Studies. Those Facilities Studies will specify in more detail the time and cost of the equipment, engineering, procurement, and construction of the Interconnection Facilities and Network Upgrades identified in this report.

1.7 Compliance Summary

This study report partially meets NERC TPL-001-4 standard, FAC-002-2 standard, and Local Planning Criteria. In ATC's annual Ten-Year Assessment (TYA) and MISO annual MTEP studies, additional compliance related studies will be performed for the generator interconnection requests with signed GIAs. Appendix J describes in detail the NERC and Local Criteria requirements met by this SIS report.

2.0 STEADY-STATE ANALYSIS

Steady-state analysis was performed to identify thermal and voltage upgrades required to interconnect the generator interconnection requests in the Aug 17 DPP WI Phase 1 to the transmission system. Detailed study assumptions, criteria, and methodology are documented in Appendix A.

2.1 Model Development

2.1.1 Study Cases

Two study cases for the steady-state thermal and voltage analysis were developed based upon the expected topology for the local area: 2022 summer peak (22SUM) and 2022 shoulder (22SH). The ATC system in these cases was updated with the most recent data available at the time of model construction. The Cardinal – Hickory Creek project was included in both study models, even though its in-service date is 12/31/2023, because it was defined as a required Network Upgrade in the DPP 2017 February Wisconsin Area Phase 1 SIS. The North Rochester – Rocky Run 345 kV line project was also included in both study models because it was a required Network Upgrade for DPP West Area Aug 2016 cycle. The cases were reviewed by ATC and the Interconnection Customers. Based on this review, the cases were further modified to account for model updates, changes, and competing generation requests that had dropped out of the MISO queue since the models were built.

The prior queued generator interconnection requests in the ATC system that are included in the study cases are listed in Table 2.1.1-1. Associated Network Upgrades were also included based on their expected in-service date.

Table 2.1.1-1 – Prior Queued Generator Interconnection Requests Not Yet In-Service

MISO Queue #	Type	Control Area	Requested MW	Requested In-Service Year
J390	CC	ALTE	702	2019
J505	Solar	WPS	99	2021
J584	Wind	ALTE	60	2019
J652	Wind	ALTE	98	2018
J703	RICE	MIUP	128.1	2019
J704	RICE	MIUP	54.9	2019
J711	Wind	MIUP	130	2020
J760	CC	ALTE	30	2019
J849	Solar	MIUP	125	2020
J928	Wind	MIUP	79.995	2019

Public information related to the MISO Generator Interconnection Request queue can be found at:

https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

The summer peak and shoulder cases dispatched generation within MISO according to section 6.1.1.1.2, Study Case Development, in the MISO BPM-015-r18.

All excess generation from this methodology is dispatched against all units in MISO Classic proportionally, excluding the units in the current DPP cycle. Scheduled firm transfers are ignored in this dispatch methodology.

2.1.2 Benchmark Cases

Two benchmark cases were used to benchmark system performance without the Aug 17 DPP WI Phase 1 generating facilities and were created by taking the Aug 17 DPP WI Phase 1 Generating Facilities offline from the corresponding two study cases. The MISO Classic was used for power balance, where generation was scaled in proportion to Pmax minus Pgen.

2.2 Reactive Power Requirements (FERC Order 827)

All synchronous and non-synchronous generation in this queue were evaluated to determine if the requests meet FERC Order 827 and ATC Planning Criteria. Refer to PLG-METH-0005 in Appendix B for details on the methodology used to determine power factor compliance. All of the reactive resources modeled in the assessment are summarized in Table 2.2-1.

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See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

Table 2.2-1 – Reactive Resources Modeled in Generator Interconnection Power Factor Analysis

MISO Queue #	Machines				Dynamic Devices			Static Devices		
	Description	Real Power (MW)	Capacitive Reactive Power (Mvar)	Inductive Reactive Power (Mvar)	Description	Capacitive Reactive Power (Mvar)	Inductive Reactive Power (Mvar)	Description	Capacitive Reactive Power (Mvar)	Inductive Reactive Power (Mvar)
J732	CT CT AUX Load ST ST AUX Load	290.4 -7.6 252.7 -7.6	180.0 -4.7 156.6 -4.7	-95.4 -4.7 -83.6 -4.7	none	N/A	N/A	none	N/A	N/A
J798	Solar Machine	124	76.6	-76.6	none	N/A	N/A	9.32 Mvar cap bank	9.32	N/A
J807	Wind Machine	41.4	19.934	-18.009	none	N/A	N/A	none	N/A	N/A
J818	Solar Machine	149	89.6	-89.6	none	N/A	N/A	none	N/A	N/A
J819	Wind Machine	100.05	48.1	-43.456	none	N/A	N/A	none	N/A	N/A
J821	Wind Machine	99.9	48.1	-43.6	none	N/A	N/A	12.83 Mvar cap bank	12.83	N/A
J825	Wind Machine	100.05	48.1	-43.456	none	N/A	N/A	none	N/A	N/A
J831	CT G11 CT G12 ST G10 CT G21 CT G22 ST G20	207.0 207.0 257.1 207.0 207.0 257.1	121.0 121.0 184.0 121.0 121.0 184.0	-66 -66 -80 -66 -66 -80	none	N/A	N/A	none	N/A	N/A
J850	Solar Machine 1 Solar Machine 2	125.0 125.0	70.520 70.520	-70.52 -70.52	none	N/A	N/A	none	N/A	N/A
J855	Wind Machine	100.8	45.041	-39.839	DVAR	4.0	-4.0	3 * 6 Mvar cap banks	18.0	N/A
J864	Solar Machine	49.98	27.198	-27.198	none	N/A	N/A	6 * 1.2 Mvar cap banks	7.2	N/A
J870	Solar Machine 1 Solar Machine 2	100.0 100.0	57.67 57.67	-57.67 -57.67	none	N/A	N/A	none	N/A	N/A
J871	Solar Machine	100.0	57.67	-57.67	none	N/A	N/A	none	N/A	N/A
J878	Solar Machine 1 Solar Machine 2	100.0 100.0	57.73 57.73	-57.73 -57.73	none	N/A	N/A	none	N/A	N/A
J886	Solar Machine	150	73.1	-73.1	none	N/A	N/A	2 * 11 Mvar cap banks	22.0	N/A
J947	Solar Machine	200.572	97.365	-97.365	none	N/A	N/A	2 * 14 Mvar cap banks	28.0	N/A

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The dynamic capacitive power factor requirement analysis showed all requests meeting ATC Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-2.

Table 2.2-2 – Assessment of Dynamic Capacitive Power Factor Requirement

MISO Queue #	Machine Terminal Bus #	Capability at Machine Terminal		Additional Dynamic Capacitive Reactive Power [1] (Mvar)	Dynamic Power Factor Provided	Meets Requirement? [2]	Additional Requirement [3] (Mvar)
		Real Power (MW)	Capacitive Reactive Power (Mvar)				
J732	87322 87321	543.100	336.600	0.0	0.85	Yes	0.0
J798	87982	124.000	76.600	0.0	0.85	Yes	0.0
J807	88073	41.400	19.934	0.0	0.90	Yes	0.0
J818	88183	149.000	89.600	0.0	0.86	Yes	0.0
J819	88193	100.050	48.100	0.0	0.90	Yes	0.0
J821	821001	99.900	48.100	0.0	0.90	Yes	0.0
J825	88254	100.050	48.100	0.0	0.90	Yes	0.0
J831	699453 699454 699455 699457 699458 699459	1342.200	852.000	0.0	0.84	Yes	0.0
J850	88503 88506	250.000	141.040	0.0	0.87	Yes	0.0
J855	88553	100.800	45.041	4.0	0.90	Yes	0.0
J864	88643	49.980	27.198	0.0	0.88	Yes	0.0
J870	88703 88717	200.000	115.340	0.0	0.87	Yes	0.0
J871	88713	100.000	57.670	0.0	0.87	Yes	0.0
J878	88785 88784	200.000	115.460	0.0	0.87	Yes	0.0
J886	886001	150.000	73.100	0.0	0.90	Yes	0.0
J947	89474	200.527	97.365	0.0	0.90	Yes	0.0

[1] Dynamic capacitive reactive power provided by Interconnection Customer owned equipment in addition to the machine.
[2] ATC requires a 0.90 ATC Capacitive Dynamic Power Factor.
[3] Additional dynamic reactive power required to meet ATC Capacitive Dynamic Power Factor.

The static capacitive power factor requirement analysis showed 11 of the 16 requests do not meet the ATC Criteria or FERC Order 827 requirements. The results are summarized in Table 2.2-3.

Table 2.2-3 – Assessment of Static Capacitive Power Factor Requirement

MISO Queue #	Point of Measurement	Capability at Point of Measurement[1]		Power Factor	Meets Requirement?	Additional Requirement (Mvar)
		Real Power (MW)	Reactive Power (Mvar)			
J732	87323	525.8	260.8	0.90	Yes	0.0
J798	87980	121.5	58.1	0.90	Yes	0.0
J807	88075	40.3	13.9	0.95	No	5.6
J818	88180	146.6	57.7	0.93	No	13.3
J819	88190	97.8	32.2	0.95	No	15.2
J821	821004	97.3	47.7	0.90	Yes	0.0
J825	88251	97.9	32.3	0.95	No	15.1
J831	699443	1318.4	606.1	0.91	No	32.4
J850	88504	245.6	90.3	0.94	No	28.6
J855	88550	98.6	43.3	0.92	No	4.5
J864	88640	49.2	25.7	0.89	Yes	0.0
J870	88700	196.8	76.0	0.93	No	19.3
J871	88700	98.4	38.0	0.93	No	9.7
J878	88780	196.7	74.5	0.94	No	20.8
J886	886004	147.7	72.1	0.90	Yes	0.0
J947	89471	197.7	82.3	0.92	No	13.5

[1] Point of Measurement is the POI Bus for synchronous machines and high side of generator substation for asynchronous machines.

The dynamic inductive power factor requirement analysis showed all requests meeting ATC Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-4.

Table 2.2-4 – Assessment of Dynamic Inductive Power Factor Requirement

MISO Queue #	Machine Terminal Bus #	Capability at Machine Terminal		Additional Dynamic Inductive Reactive Power [1] (Mvar)	Dynamic Power Factor Provided	Meets Requirement? [2]	Additional Requirement [3] (Mvar)
		Real Power (MW)	Inductive Reactive Power (Mvar)				
J732	87322 87321	543.100	-179.000	0.0	0.95	Yes	0.0
J798	87983	124.000	-76.600	0.0	0.85	Yes	0.0
J807	88073	41.400	-18.009	0.0	0.92	Yes	0.0
J818	88183	149.000	-89.600	0.0	0.86	Yes	0.0
J819	88193	100.050	-43.456	0.0	0.92	Yes	0.0
J821	821001	99.900	-43.600	0.0	0.92	Yes	0.0
J825	88254	100.050	-43.456	0.0	0.92	Yes	0.0
J831	699453 699454 699455 699457 699458 699459	1342.200	-424.000	0.0	0.95	Yes	0.0
J850	88503 88506	250.000	-141.040	0.0	0.87	Yes	0.0
J855	88553	100.800	-39.839	-4.0	0.92	Yes	0.0
J864	88643	49.980	-27.198	0.0	0.88	Yes	0.0
J870	88703 88717	200.000	-115.340	0.0	0.87	Yes	0.0
J871	88713	100.000	-57.670	0.0	0.87	Yes	0.0
J878	88785 88784	200.000	-115.460	0.0	0.87	Yes	0.0
J886	886001	150.000	-73.100	0.0	0.90	Yes	0.0
J947	89474	200.527	-97.365	0.0	0.90	Yes	0.0

[1] Dynamic inductive reactive power provided by Interconnection Customer owned equipment in addition to the machine.
[2] ATC requires a 0.95 ATC Inductive Dynamic Power Factor.
[3] Additional dynamic reactive power required to meet ATC Inductive Dynamic Power Factor.

The static inductive power factor requirement analysis showed all requests meeting ATC Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-5.

Table 2.2-5 – Assessment of Static Inductive Power Factor Requirement

MISO Queue #	POI Bus (synchronous) or HV Bus (asynchronous)	MW at POI (synchronous) or HV Bus (asynchronous)	Mvar at POI (synchronous) or HV Bus (asynchronous)	POI (synchronous) or HV Bus (asynchronous) Power Factor	Meets 0.95 ATC Inductive Power Factor Requirement at POI Bus (synchronous) or HV Bus (asynchronous)?
J732	87323	526.7	-238.5	0.91	Yes
J798	87980	120.8	111.9	0.73	Yes
J807	88075	40.3	-24.3	0.86	Yes
J818	88180	146.0	-129.9	0.75	Yes
J819	88190	97.7	-60.0	0.85	Yes
J821	821004	97.2	-57.7	0.86	Yes
J825	88251	97.8	-60.0	0.85	Yes
J831	699443	1319.2	-629.5	0.90	Yes
J850	88504	244.6	-101.8	0.92	Yes
J855	88550	98.1	-72.3	0.80	Yes
J864	88640	49.1	-36.3	0.80	Yes
J870	88700	196.2	-163.8	0.77	Yes
J871	88700	98.1	-81.9	0.77	Yes
J878	88780	195.9	-167.0	0.76	Yes
J886	886004	150.0	-73.1	0.90	Yes
J947	89471	197.3	-146.3	0.80	Yes

The low output power factor requirement analysis showed all requests meeting ATC Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-6.

Table 2.2-6 – Assessment of Power Factor Requirements at Low Output Levels

MISO Queue #	P-Q Curve Type	Is Power Factor Evaluation Needed for Minimum Output Levels?	Additional Static Mvar required at POI Bus (synchronous) or HV Bus (asynchronous) to meet ATC Capacitive Power Factor Requirement
J732	D-shape	no	N/A
J798	D-shape	no	N/A
J807	D-shape	no	N/A
J818	D-shape	no	N/A
J819	D-shape	no	N/A
J821	D-shape	no	N/A
J825	D-shape	no	N/A
J831	D-shape	no	N/A
J850	D-shape	no	N/A
J855	D-shape	no	N/A
J864	V-shape at low output levels	yes	0.0
J870	D-shape	no	N/A
J871	D-shape	no	N/A
J878	D-shape	no	N/A
J886	D-shape	no	N/A
J947	D-shape	no	N/A

2.3 NERC TPL Contingency Analysis Results

The incremental impact of the proposed generator interconnection on transmission facilities was evaluated by comparing steady state power flows and voltages between benchmark cases (without Aug 17 DPP WI Phase 1 projects) and study cases (with Aug 17 DPP WI Phase 1 projects). Post-contingency cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment enabled, and switched shunt adjustment enabled. Detailed NERC TPL Category P contingencies that were studied are described in Table A.2.1-1 in Appendix A.

2.3.1 2022 Summer

The study identified the steady-state thermal and voltage constraints that qualified as MISO Injection Constraints in the 2022 Summer Peak study model under NERC Category P0-P7 Planning Events (except NERC Category P3 and P6). Detailed steady-state power flow results and Injection Constraint determination can be found in Appendix E. A summary of the 2022 Summer Peak MISO Injection Constraints that require Network Upgrades is presented in Table 2.3.1-1. No voltage constraints were identified in the steady-state analyses.

Table 2.3.1-1 – 2022 Summer Peak Steady-State Injection Constraints Requiring Network Upgrades

Study Case	Overloaded Facility	Facility Owner	Resulted by "No Load Loss Allowed"[1] NERC TPL Planning Events	Responsible Generator(s)
2022 Summer Peak	Eden – Wyoming Valley 138 kV line	ATC	P12	J870 J871 J947
	Wyoming Valley – Spring Green 138 kV line	ATC	P12	J870 J871 J947
	J798 POI – Mukwonago 138 kV line	ATC	P12	J798
	Whitewater – University 138 kV line	ATC	P12	J798
	Hillman 138/69 kV transformer	ATC	P12, P21	J947
	Stone Lake 345/161 kV transformer	XEL	P12, P13, P23	J732

[1] The “No Load Loss Allowed’ NERC TPL Planning Events refer to all the Planning Events in NERC TPL-001-4 Table 1 that the interruption of Firm Transmission Service and Non-Consequential Load Loss are not allowed.

2.3.2 2022 Shoulder

The study identified the steady-state thermal and voltage constraints that qualified as MISO Injection Constraints in the 2022 Shoulder study model under NERC Category P0-P7 Planning Events (except NERC Category P3 and P6). Detailed steady-state power flow results and Injection Constraint determination can be found in Appendix E. A summary of the 2022 Shoulder MISO Injection Constraints that require Network Upgrades is presented in Table 2.3.2-1. No voltage constraints were identified in the steady state analyses.

Table 2.3.2-1 – 2022 Shoulder Steady-State Injection Constraints Requiring Network Upgrades

Study Case	Overloaded Facility	Facility Owner	Resulted by "No Load Loss Allowed"[1] NERC TPL Planning Events	Responsible Generator(s)
2022 Shoulder	J825 POI - Albany 138 kV line	ATC	P0, P11, P12, P13, P21	J807 J819 J825 J947 J870/J871
	Albany – Bass Creek 138 kV line	ATC	P0, P11, P12, P13, P21	J807 J819 J825 J947 J870/J871
	Townline Road – Bass Creek 138 kV line	ATC	P0, P13	J807 J819 J825 J947
	North Monroe – Monticello 69 kV line	ATC	P12, P21	J807 J819 J825 J947
	North Monroe 138/69 kV transformer	ATC	P12, P21	J807 J819 J825 J947
	Eden – Wyoming Valley 138 kV line	ATC	P12, P23 EHV	J870/J871
	Wyoming Valley – Spring Green 138 kV line	ATC	P12, P23 EHV	J870/J871

[1] The "No Load Loss Allowed' NERC TPL Planning Events refer to all the Planning Events in NERC TPL-001-4 Table 1 that the interruption of Firm Transmission Service and Non-Consequential Load Loss are not allowed.

2.3.3 Network Upgrades Identified in ERIS Analysis

Based on the steady-state analyses, the worst loading of each facility under "No Load Loss Allowed" NERC TPL Planning Events that meets MISO Injection Constraint criteria is shown in Table 2.3.3-1. Potential Network Upgrades are also included. According to ATC's Transmission Planning Assessment Practices as listed in Appendix B, MISO generator interconnection studies shall utilize a five percent Transmission Reliability Margin (TRM) reduction in normal and emergency ratings for all facilities inside the ATC system. Good faith Cost Estimates of the ERIS Network Upgrades identified in the steady-state analysis for the 2022 scenarios are listed in Table 2.3.3-2. Detailed cost allocations are provided in Section 9.

Overland_Public Comment 1_MISO GI DPP August 2017 Wisconsin Area Phase 1
See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

Table 2.3.3-1 – ERIS Network Upgrades Identified to Address MISO Steady-State Injection Constraints

Steady-State Injection Constraint	Responsible Generator(s)	Facility Owner	Study Case	Applicable Rating (MVA) [1]	Worst Loading (%)	"No Load Loss Allowed" NERC TPL Planning Event	Network Upgrades
J825 POI – Albany 138 kV line	J807 J819 J825 J947 J870 J871	ATC	22SH	120.0	156.02	[redacted]	J825POI – Bass Creek 138 kV, reconductor
Albany – Bass Creek 138 kV line	J807 J819 J825 J947 J870 J871	ATC	22SH	120.0	153.50	[redacted]	
Townline Road – Bass Creek 138 kV line	J807 J819 J825 J947	ATC	22SH	161.0	97.26	[redacted]	Bass Creek – Townline Road 138 kV, reconductor
North Monroe – Monticello 69 kV line	J80 J819 J825 J947	ATC	22SH	63.0	107.81	[redacted]	North Monroe – Verona 69 kV, uprate
North Monroe 138/69 kV transformer	J807 J819 J825 J947	ATC	22SH	123.0	102.15	[redacted]	North Monroe SS, new transformer
Hillman 138/69 kV transformer	J947	ATC	22SUM	68.0	97.70	[redacted]	Hillman SS, upgrade transformer
Eden – Wyoming Valley 138 kV line	J870 J871 J947	ATC	22SH	202.0	104.72	[redacted]	Eden – Spring Green 138 kV, uprate
Wyoming Valley – Spring Green 138 kV line	J870 J871 J947	ATC	22SH	202.0	103.50	[redacted]	Eden –Spring Green 138 kV, uprate
J798 POI – Mukwonago 138 kV line	J798	ATC	22SUM	298.0	103.15	[redacted]	J798 POI – Mukwonago 138 kV, rebuild
Whitewater – University 138 kV line	J798	ATC	22SUM	304.0	99.51	[redacted]	Whitewater – University 138 kV, partial rebuild
Stone Lake 345/161 kV transformer	J732	XCEL	22SUM	386.4	103.38	[redacted]	Stone Lake SS, upgrade transformer

[1] The rating of the Injection Constraint without TRM.

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Table 2.3.3-2 – ERIS Network Upgrades and Cost Estimates

<table>
<tr><th>Steady-State Injection Constraint</th><th>Facility Owner</th><th>Network Upgrade</th><th>Cost ($)[1,2,3]</th></tr>
<tr><td>J825 POI – Albany 138 kV line</td><td>ATC</td><td rowspan="2">J825POI – Bass Creek 138 kV, reconductor</td><td rowspan="2">8,172,147</td></tr>
<tr><td>Albany – Bass Creek 138 kV line</td><td>ATC</td></tr>
<tr><td>Townline Road – Bass Creek 138 kV line</td><td>ATC</td><td>Bass Creek – Townline Road 138 kV, reconductor</td><td>4,596,833</td></tr>
<tr><td>North Monroe – Monticello 69 kV line</td><td>ATC</td><td>North Monroe – Verona 69 kV, uprate</td><td>762,980</td></tr>
<tr><td>North Monroe 138/69 kV transformer</td><td>ATC</td><td>North Monroe SS, new transformer</td><td>5,933,016</td></tr>
<tr><td>Hillman 138/69 kV transformer</td><td>ATC</td><td>Hillman SS, upgrade transformer</td><td>2,866,337</td></tr>
<tr><td>Eden – Wyoming Valley 138 kV line</td><td>ATC</td><td rowspan="2">Eden – Spring Green 138 kV, uprate</td><td rowspan="2">623,779</td></tr>
<tr><td>Wyoming Valley – Spring Green 138 kV line</td><td>ATC</td></tr>
<tr><td>J798 POI – Mukwonago 138 kV line</td><td>ATC</td><td>J798 POI – Mukwonago 138 kV, rebuild</td><td>22,289,710</td></tr>
<tr><td>Whitewater – University 138 kV line</td><td>ATC</td><td>Whitewater – University 138 kV, partial rebuild</td><td>1,976,323</td></tr>
<tr><td>Stone Lake 345/161 kV transformer</td><td>XCEL</td><td>Stone Lake SS, upgrade transformer</td><td>3,898,500</td></tr>
</table>

[1] All Network Upgrades were estimated on the generator ISD dollars.
[2] ATC Network Upgrades included a 20% contingency.
[3] No contingency was included for the Stone Lake transformer upgrade project according to Xcel Energy.

2.3.4 Network Upgrade Alternatives Considered

All of the ERIS network upgrades identified in Table 2.3.3-2 are direct upgrades of the ERIS thermal constraint facilities to ATC and XCEL design standards and considered as least-cost solutions. Therefore, no other alternatives were examined at this point.

2.3.5 Potential Operating Restriction

The purpose of the study is to identify potential operating restrictions for study generators under prior outage conditions and raise awareness of these potential operating restrictions to customers. Real-time thermal constraints due to NERC Category P6 events (N-1-1) will be mitigated in the day-ahead and real-time market through the MISO binding constraint and other operating procedures. The study was performed on study models with ERIS Network Upgrades included. Based on ATC generator operating restriction study methodology as described in Appendix A, the worst potential operating restrictions for study generators were identified and summarized in Table 2.3.5-1. If multiple P6 (N-1-1) events resulted in the same MW reduction requirement, only the worst N-1-1 event (highest loading % on the constraint) was listed. The full NERC Category P6 study results were documented in Appendix F. Operating restrictions could occur if either of the contingent elements are out of service.

Table 2.3.5-1 – Worst Operating Restrictions with ERIS Network Upgrades Included

Generator	Model	Worst NERC Category P6 (N-1-1) Event		Potential MW Reduction Required
		1st Contingency	2nd Contingency	
J732	22SUM	[redacted]	[redacted]	73.56
J798	22SUM	[redacted]	[redacted]	124.00
J807	22SH	[redacted]	[redacted]	41.40
J818	-	-	-	0.00
J819	22SH	[redacted]	[redacted]	99.90
J821	-	-	-	0.00
J825	22SH	[redacted]	[redacted]	99.90
J831	22SUM	[redacted]	[redacted]	40.00
J850	22SUM	[redacted]	[redacted]	10.56
J855	22SH	[redacted]	[redacted]	100.80
J864	22SUM	[redacted]	[redacted]	49.98
J870 /J871	22SUM	[redacted]	[redacted]	227.50
J878	22SUM	[redacted]	[redacted]	200.00
J886	22SUM	[redacted]	[redacted]	150.00
J947	22SUM	[redacted]	[redacted]	200.00

2.3.6 Additional Studies for J732

Due to unique concerns with the location of J732 POI, ATC performed the following additional studies. The three study reports were included in Appendix K.

1. Local Device Coordination Study

   This study reviewed coordination of J732 and local devices including Arrowhead 230 kV and 345 kV shunt capacitors, Stone Lake 345 kV shunt reactor and shunt capacitor, Arrowhead 345/230 kV LTC, Arrowhead 230 kV phase shifter (PAR) and Stinson 115 kV PAR.

   Study results indicated that all settings are acceptable except for the Vmin (MW) limit of the Arrowhead PAR. This limit will need to be increased from 200 MW (from Wisconsin to Minnesota) to greater than 560 MW.

2. Steady State Voltage Stability Study of MWEX

   This analysis was performed on the 2022 shoulder study case to determine if J732 could cause voltage stability violations on MWEX (Minnesota Wisconsin Export Interface).

   The study determined that the Post-DPP scenario is voltage stable but has a criteria violation related to the voltage at the nose of the PV curve. However, this criteria violation exists in the Pre-DPP scenario and is not aggravated by the Post-DPP scenario. Therefore, voltage stability related Network Upgrades will not be assigned to the Interconnection Customer.

3. Cross Tripping System at Arrowhead and Stone Lake 345 kV substations

   The existing Cross Tripping System (CTS) requirements at Arrowhead, Stone Lake, and Gardner Park were created to avoid over voltages with an open-ended 345 kV line. With the interconnection of J732, these CTSs were re-evaluated for possible modifications.

   The study concluded that the existing Arrowhead – Stone Lake CTS requires modification to avoid high voltage violations under different dispatch scenarios of J732. The new CTS requirements at Arrowhead, Superior (J732 POI), and Stone Lake can be found in the report in Appendix K. The costs to modify the CTS is included in the cost estimate for the Superior Substation.

3.0 STABILITY ANALYSIS

Stability analysis was performed to evaluate the transient stability and impact on the region of the generating facilities in the Aug 17 DPP WI Phase 1 group. Detailed study assumptions, criteria, and methodology are documented in Appendix B.

The stability faults were simulated using the 2022 summer shoulder study case. If a transient stability criteria constraint was identified, the same disturbance was repeated in the benchmark case.

Stability plots consist of generator rotor angles, generator real power output, generator reactive power output, generator terminal voltages, and transmission bus voltages for each simulation. Simulations were performed with a 9-cycle flat start followed by the appropriate disturbance. Simulations were run for a 20-second duration.

3.1 Model Development

3.1.1 Study Case

Stability study case representing 2022 shoulder of the summer peak load conditions was developed from the stability package used in the DPP 2017 August Central Area Phase 1 study stability package.

The stability study load flow case for DPP 2017 August Wisconsin study was created in the same procedure as described in Section 2.1.

3.1.2 Benchmark Case

The Aug 17 DPP WI Phase 1 generating facilities were removed from the study case. MISO Classic was used for power balance, where generation was scaled in proportion to Pmax minus Pgen.

3.2 J732 Stability Study

Siemens PTI performed the stability analysis for J732 and developed a study report which is listed in Appendix G - Dynamic Stability Results. The J732 stability study was performed with J732 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- Marshfield CT
- Weston G2, G3, G4, G31, and G32
- Rothschild Biomass
- J505 Solar
- Point Beach 1 and 2
- Lakefront 6 and 9

3.2.1 J732 Stability Results

Complete fault definitions and stability results for J732 can be found in the Siemens report in Appendix G. Table 3.2.1-1 summarizes the results with stability constraints.

Table 3.2.1-1 – Stability Constraints for J732

Event	Angular Stability	Transient Voltage Recovery
P6.1.9	J732 ST, CT Tripped	Numerous Voltage Violations
P6.1.13	OK	Voltage Dip: Bus Name Voltage MINONG 5 161 0.720 GORDON 5 161 0.730 HAWTHRN5 161 0.764 ST LAKE5 161 0.673 FRMSINN5 161 0.684 PIP61 ST LK5161 0.673 ST LK CAP5 161 0.673 STONELK8 69 0.690 FRMRSIN8 69 0.694 HAYWAR G 69 0.693 T RNDLK8 69 0.692 T SPRBR8 69 0.692 SANDLK 8 69 0.693 SLK PMP8 69 0.690 JOHNSON TIM 69 0.690 LOU PAC 69 0.690 SISTER B 69 0.683 ROUND_8 69 0.681 SPRNG BR 69 0.690 RADISSON 5 161 0.689
P6.1.19	J732 ST, CT Tripped	Voltage Dip: Bus Name Voltage J732POI 345 0.213 J732GENTIE 345 0.235 STONE LK B1 345 0.091

Under all other faults for J732, the simulations show the system meeting all transient stability criteria.

3.2.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J732 generating facility.

3.2.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. The maximum allowed real power outputs after prior outages were identified for the J732 generating facility to mitigate P6 stability constraints. See Table 3.2.3-1 below.

Table 3.2.2-1 – J732 Stability Operating Restrictions

Contingency	Units Restricted	Maximum Real Power Output (MW)
P6.1.9	J732 CT + J732 ST	463
P6.1.13	J732 CT + J732 ST	533
P6.1.19	J732 CT + J732 ST	523

3.3 J798 Stability Study

The J798 stability study was performed with J798 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- Concord 1, 2, 3, and 4
- Christiana 1, 2, and 3
- Edgewater 5
- Elm Road 1 and 2
- Germantown 1, 2, 3, 4, and 5
- Oak Creek 5H, 5L, 6H, 6L, 7H, 7L, and 8
- Paris 1, 2, 3, and 4
- University GT and ST

3.3.1 J798 Stability Results

Complete fault definitions and stability results for J798 can be found in Appendix G.

Under all faults for J798, the simulations show the system meeting all transient stability criteria.

3.3.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J798 generating facility.

3.3.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J798 generating facility.

3.4 J807, J819, J825, and J947 Stability Study

The J807, J819, J825, and J947 stability study was performed with J807, J819, J825, and J947 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- J390 CT1, CT2, and ST
- Riverside CT1, CT2, and ST
- Quilt Block Wind Farm
- Eden Wind Farm
- J584 Wind Farm

3.4.1 J807, J819, J825, and J947 Stability Results

Complete fault definitions and stability results for J807, J819, J825, and J947 can be found in Appendix G.

Under all faults for J807, J819, J825, and J947, the simulations show the system meeting all transient stability criteria.

3.4.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J807, J819, J825, or J947 generating facilities.

3.4.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J807, J819, J825, or J947 generating facilities.

3.4.4 LVRT Requirement for Wind Generators (FERC Order 661/661-A)

Per FERC orders 661/661-A all wind generating plants requesting to interconnect after January 1, 2007 must meet the following Low Voltage Ride Through (LVRT) requirement:

> Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

This standard applies to J807, J819, and J825, three wind generating plants. The 3PG portion of FERC Order 661/661-A is met by the customers provided LVRT durations as shown in Table 3.4.4-1. The SLG with delayed clearing portion of FERC Order 661/661-A is met because J807, J819, or J825 did not trip on the customer provided LVRT settings for any SLG plus delayed clearing faults (P4 and P5 events). All of the customer provided LVRT settings are shown in Appendix C.

Table 3.4.4-1: J807, J819, and J825 FERC Order 661/661-A 3PG LVRT Compliance Data

MISO Queue #	FERC Required LVRT Duration (sec)	Interconnection Customer Provided LVRT Duration (sec)
J807	0.15	0.45
J819	0.15	0.45
J825	0.15	0.45

3.5 J818 Stability Study

The J818 stability study was performed with J818 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- Concord 1, 2, 3, and 4
- Christiana 1, 2, and 3
- Edgewater 5
- Elm Road 1 and 2
- Germantown 1, 2, 3, 4, and 5
- Oak Creek 5H, 5L, 6H, 6L, 7H, 7L, and 8
- Paris 1, 2, 3, and 4
- University GT and ST

3.5.1 J818 Stability Results

Complete fault definitions and stability results for J818 can be found in Appendix G.

Under all faults for J818, the simulations show the system meeting all transient stability criteria.

3.5.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J818 generating facility.

3.5.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J818 generating facility.

3.6 J821 Stability Study

The J821 stability study was performed with J821 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- Marshfield CT
- Weston G2, G3, G4, G31, and G32
- Rothschild Biomass
- J505 Solar
- Point Beach 1 and 2
- Lakefront 6 and 9

3.6.1 J821 Stability Results

Complete fault definitions and stability results for J821 can be found in Appendix G.

Under all faults for J821, the simulations show the system meeting all transient stability criteria.

3.6.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J821 generating facility.

3.6.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J821 generating facility.

3.6.4 LVRT Requirement for Wind Generators (FERC Order 661/661-A)

FERC Order 661/661-A, as described in detail in Section 3.4.4, also applies to J821, a wind generating plant. The 3PG portion of FERC Order 661/661-A is met by the customer provided LVRT duration as shown in Table 3.6.4-1. The SLG with delayed clearing portion of FERC Order 661/661-A is met because J821 did not trip on the customer provided LVRT settings for any SLG plus delayed clearing faults (P4 and P5 events). All of the customer provided LVRT settings are shown in Appendix C.

Table 3.6.4-1: J821 FERC Order 661/661-A 3PG LVRT Compliance Data

MISO Queue #	FERC Required LVRT Duration (sec)	Interconnection Customer Provided LVRT Duration (sec)
J821	0.15	0.45

3.7 J831 Stability Study

The J831 stability study was performed with J831 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- Concord 1, 2, 3, and 4
- Christiana 1, 2, and 3
- Edgewater 5
- Elm Road 1 and 2
- Germantown 1, 2, 3, 4, and 5
- Oak Creek 5H, 5L, 6H, 6L, 7H, 7L, and 8
- Paris 1, 2, 3, and 4
- University GT and ST

3.7.1 J831 Stability Results

Complete fault definitions and stability results for J831 can be found in Appendix G.

Under all faults for J831, the simulations show the system meeting all transient stability criteria.

3.7.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J831 generating facility.

3.7.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J831 generating facility.

3.8 J850 Stability Study

The J850 stability study was performed with J850 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- J390 CT1, CT2, and ST
- Riverside CT1, CT2, and ST
- Quilt Block Wind Farm
- Eden Wind Farm
- J584 Wind Farm

3.8.1 J850 Stability Results

Complete fault definitions and stability results for J850 can be found in Appendix G.

Under all faults for J850, the simulations show the system meeting all transient stability criteria.

3.8.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J850 generating facility.

3.8.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J850 generating facility.

3.9 J855, J870, and J871 Stability Study

The J855, J870, and J871 stability study was performed with J855, J870, and J871 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- J390 CT1, CT2, and ST
- Riverside CT1, CT2, and ST
- Quilt Block Wind Farm
- Eden Wind Farm
- J584 Wind Farm

3.9.1 J855, J870, and J871 Stability Results

Complete fault definitions and stability results for J855, J870, and J871 can be found in Appendix G.

Under all faults for J855, J870, and J871, the simulations show the system meeting all transient stability criteria.

3.9.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J855, J870, or J871 generating facilities.

3.9.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J855, J870, or J871 generating facilities.

3.9.4 LVRT Requirement for Wind Generators (FERC Order 661/661-A)

FERC Order 661/661-A, as described in detail in Section 3.4.4, also applies to J855, a wind generating plant. The 3PG portion of FERC Order 661/661-A is met by the customer provided LVRT duration as shown in Table 3.6.4-1. The SLG with delayed clearing portion of FERC Order 661/661-A is met because J855 did not trip on the customer provided LVRT settings for any SLG plus delayed clearing faults (P4 and P5 events). All of the customer provided LVRT settings are shown in Appendix C.

Table 3.6.4-1: J855 FERC Order 661/661-A 3PG LVRT Compliance Data

MISO Queue #	FERC Required LVRT Duration (sec)	Interconnection Customer Provided LVRT Duration (sec)
J855	0.15	0.45

3.10 J864 Stability Study

The J864 stability study was performed with J864 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- J390 CT1, CT2, and ST
- Riverside CT1, CT2, and ST
- Quilt Block Wind Farm
- Eden Wind Farm
- J584 Wind Farm

3.10.1 J864 Stability Results

Complete fault definitions and stability results for J864 can be found in Appendix G.

Under all faults for J864, the simulations show the system meeting all transient stability criteria.

3.10.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J864 generating facility.

3.10.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J864 generating facility.

3.11 J878 Stability Study

The J878 stability study was performed with J878 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- Concord 1, 2, 3, and 4
- Christiana 1, 2, and 3
- Edgewater 5
- Elm Road 1 and 2
- Germantown 1, 2, 3, 4, and 5
- Oak Creek 5H, 5L, 6H, 6L, 7H, 7L, and 8
- Paris 1, 2, 3, and 4

- University GT and ST

3.11.1 J878 Stability Results

Complete fault definitions and stability results for J878 can be found in Appendix G.

Under all faults for J878, the simulations show the system meeting all transient stability criteria.

3.11.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J878 generating facility.

3.11.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J878 generating facility.

3.12 J886 Stability Study

The J886 stability study was performed with J886 dispatched at 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- Marshfield CT
- Weston G2, G3, G4, G31, and G32
- Rothschild Biomass
- J505 Solar
- Point Beach 1 and 2
- Lakefront 6 and 9

3.12.1 J886 Stability Results

Complete fault definitions and stability results for J886 can be found in Appendix G.

Under all faults for J886, the simulations show the system meeting all transient stability criteria.

3.12.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J886 generating facility.

3.12.3 Operating Restrictions Identified in the Stability Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. No stability operating restrictions were identified for the J886 generating facility.

3.13 Network Upgrades Identified in the Stability Analysis

Cost and cost allocation for Network Upgrades identified in the stability analysis are listed in Table 3.13-1.

Table 3.13-1 – Stability Network Upgrades Cost and Cost Allocation

Constraint	Owner	Mitigation	Total Cost ($)	Cost Allocation ($)
none	N/A	N/A	0	0

4.0 SHORT CIRCUIT ANALYSIS

4.1 ATC Short Circuit Analysis

4.1.1 ATC Short Circuit Study Results

Short Circuit analysis was performed for ATC owned facilities according to ATC short circuit analysis methodology as described in Appendix A. Short circuit analysis results for Non-ATC facilities are described in Section 7. Maximum and minimum fault duty was calculated at the POI for each generator request except for J831 and results are summarized in Table 4.1.1-1, Table 4.1.1-2, Table 4.1.1-3 and Table 4.1.1-4. J831 is only an NRIS increase request which will not increase short circuit values and so no analysis was performed.

Table 4.1.1-1 – Outage Assumptions for Minimum Fault Duty Calculations

MISO Queue #	Contingency
J732	[redacted]
J798	[redacted]
J807	[redacted]
J818	[redacted]
J819	[redacted]
J821	[redacted]
J825	[redacted]
J850	[redacted]
J855	[redacted]
J864	[redacted]

J870	
J871	
J878	
J886	
J947	

Table 4.1.1-2 – Maximum and Minimum Fault Duty at POIs

Location	Maximum Fault Duty (Amps)		Minimum Fault Duty (Amps)	
	Single-Phase	Three-Phase	Single-Phase	Three-Phase
J732 POI without J732	4,512	4,775	1,751	2,163
J732 POI with J732	9,748	8,693	2,926	2,157
J798 POI without J798	8,520	10,318	1,997	3,598
J798 POI with J798	10,712	10,983	4,521	4,260
J807 POI without J807	4,218	4,039	2,296	2,093
J807 POI with J807	4,640	4,225	2,674	2,281
J818 POI without J818	10,028	13,642	5,514	7,679
J818 POI with J818	12,657	14,076	7,896	8,112
J819 POI without J819	4,230	4,126	2,516	2,509
J819 POI with J819	5,043	4,571	2,832	2,506
J821 POI without J821	4,433	5,922	1,540	2,050
J821 POI with J821	4,590	6,360	1,696	2,503
J825 POI without J825	4,254	5,138	2,742	2,902
J825 POI with J825	5,654	5,584	3,321	2,901
J850 POI without J850	6,143	8,872	6,108	8,804
J850 POI with J850	9,215	9,932	8,109	8,722
J855 POI without J855	10,890	12,183	10,187	11,075
J855 POI with J855	11,356	12,677	10,238	11,108
J864 POI without J864	3,292	4,719	1,170	1,782
J864 POI with J864	6,046	5,163	2,377	1,782
J870 POI without J870	10,812	12,013	2,541	2,730
J870 POI with J870	13,021	12,928	3,286	2,729
J871 POI without J871	10,812	12,013	2,541	2,730
J871 POI with J871	11,970	12,470	3,037	2,729
J878 POI without J878	20,131	19,581	4,552	7,301
J878 POI with J878	22,726	21,222	8,262	8,918
J886 POI without J886	21,839	21,211	13,196	13,746
J886 POI with J886	23,872	23,232	13,955	13,743
J947 POI without J947	4,230	5,195	1,660	1,855
J947 POI with J947	6,855	5,360	2,335	1,845

Table 4.1.1-3 – Maximum Fault Thevenin Equivalent Data

Location	Positive Sequence	Negative Sequence	Zero Sequence
J732 POI without J732	3.32832 + j41.5816	3.34331 + j41.5818	6.44904 + j48.6297
J732 POI with J732	1.11637 + j22.8857	1.13130 + j23.0266	1.48883 + j15.2746
J798 POI without J798	1.06297+j764832	1.06739+j7.65610	2.39861+j12.3795
J798 POI with J798)	1.06300+j7.64843	1.06300+j7.65621	1.15677+j8.22286
J807 POI without J807	4.52445 + j19.1981	4.53755 + 19.1989	2.32475 + j17.1106
J807 POI with J807	4.52445 + j19.1981	4.53755 + j19.1989	1.63725 + j14.3945
J818 POI without J818	0.75323+j5.79133	0.76914+j5.82590	3.40472+j11.7031
J818 POI with J818	0.70918+j5.61552	0.72388+j5.64810	1.42676+j7.40310
J819 POI without J819	4.80947 + j18.7016	4.82499 + j18.7025	2.61786 + j17.7541
J819 POI with J819	4.81818 + j18.7174	4.83372 + j18.7183	2.09903 + j13.7566
J821 POI without J821	1.75364+j11.0729	1.77121+j11.1330	4.81419+j21.9429
J821 POI with J821	2.27468+j10.1884	2.29630+j10.2382	4.81419+j21.9429
J825 POI without J825	4.42054 + j14.8631	4.44605 + j14.8634	6.63268 + 24.2873
J825 POI with J825	4.42051 + j14.8581	4.44604 + j14.8585	2.34692 + j14.7870
J850 POI without J850	1.11955 + j8.90979	1.15867 + j8.91055	4.80295 + j20.4406
J850 POI with J850	1.13398 + j8.99401	1.17267 + j8.99495	1.46524 + j11.0814
J855 POI without J855	0.67211 + j6.50507	0.67840 + j6.50460	1.34446 + j8.77351
J855 POI with J855	0.66893 + j6.48794	0.67524 + j6.48747	1.32560 + j8.70475
J864 POI without J864	2.32818 + j8.11396	2.32994 + j8.11369	4.96504 + j18.7705
J864 POI with J864	2.32818 + j8.11396	2.32994 + j8.11369	0.53065 + j4.74970
J870 POI without J870	0.70326 + j6.59503	0.70987 + j6.59454	1.27024 + j8.75411
J870 POI with J870	0.70329 + j6.59516	0.70990 + j6.59466	0.73303 + j6.44966
J871 POI without J871	0.70326 + j6.59503	0.70987 + j6.59454	1.27024 + j8.75411
J871 POI with J871	0.70329 + j6.59516	0.70990 + j6.59466	0.93441 + j7.40690
J878 POI without J878	0.40358+j4.04891	0.42920+j4.27653	0.27617+j3.49606
J878 POI with J878	0.40322+j4.04598	0.42879+j4.27327	0.21878+j3.04830
J886 POI without J886	0.26837 + j3.80494	0.30927 + j3.80213	0.33582 + j3.52367
J886 POI with J886	0.22668 + j3.42129	0.24737 + j3.26099	0.30562 + j3.22923
J947 POI without J947	2.63622+ j15.1088	2.64022+ j15.1088	5.73950+ j25.1964
J947 POI with J947	2.63756+ j 15.1125	2.64156+ j 15.1125	1.56120+ j 11.9181

Table 4.1.1-4 – Minimum Fault Thevenin Equivalent Data

Location	Positive Sequence	Negative Sequence	Zero Sequence
J732 POI without J732	8.51407 + j91.6867	8.58710 + j91.6861	23.4832 + j155.469
J732 POI with J732	8.56013 + j91.9322	8.63355 + j91.9316	1.75557 + j19.4756
J798 POI without J798	3.90360+j21.7988	3.91217+j21.8239	16.2618+j73.5910
J798 POI with J798	3.90393+j21.7997	3.91250+j21.8248	1.53078+j18.2701
J807 POI without J807	6.27989 + j37.5475	6.28257 + j37.5482	3.04595 + j27.8177
J807 POI with J807	6.27989 + j37.5475	6.28257 + j37.5482	1.77145 + j21.2554
J818 POI without J818	1.43847+j10.2753	1.45307+j10.3982	6.36110+j21.6708
J818 POI with J818	1.29389+j9.73564	1.30542+j9.84584	1.62074+j10.3917
J819 POI without J819	9.81861 + j30.1934	9.85352 + j30.1918	4.14548 + j31.5907
J819 POI with J819	9.84732 + j30.2328	9.88233 + j30.2312	3.00895 + j20.8278
J821 POI without J821	4.63227+j32.0471	4.68160+j32.5281	13.5310+62.7559
J821 POI with J821	7.97715+j25.2969	8.11147+j25.5912	13.5310+j62.7559
J825 POI without J825	5.92014 + j26.8052	5.92763 + j26.8047	6.08665 + j31.6789
J825 POI with J825	5.92471 + j26.8153	5.93221 + 26.8148	1.71654 + j17.0451
J850 POI without J850	1.12642 + 8.97959	1.16501 + 8.98048	4.80826 + j20.5253
J850 POI with J850	1.14075 + j9.06282	1.17891 + j9.06389	1.46211 + j11.1041
J855 POI without J855	0.73259 + j7.15645	0.74065 + j7.15591	1.34140 + j8.98087
J855 POI with J855	0.72883 + j7.13544	0.73689 + j7.13491	1.32219 + j8.90853
J864 POI without J864	6.99060 + j21.2370	6.99081 + j21.2371	15.0826 + j55.4136
J864 POI with J864	6.99060 + j21.2370	6.99081 + j21.2371	0.47479 + j5.67607
J870 POI without J870	5.49393 + j28.6660	5.50933 + j28.6645	3.50448 + j35.6030
J870 POI with J870	5.49484 + j28.6683	5.51025 + j28.6668	0.81665 + j14.4442
J871 POI without J871	5.49393 + j28.6660	5.50933 + j28.6645	3.50448 + j35.6030
J871 POI with J871	5.49484 + j28.6683	5.51025 + j28.6668	1.36494 + j20.3854
J878 POI without J878	1.78588+j10.7653	1.79496+10.7731	7.51511+29.7862
J878 POI with J878	1.78588+j10.7653	1.79496+j10.7731	1.62925+j13.4175
J886 POI without J886	0.55971 + j5.90724	0.59763 + j5.90345	0.62315 + j6.79262
J886 POI with J886	0.55995 + j5.90848	0.59788 + j5.90469	0.52624 + j5.77715
J947 POI without J947	8.54812+ j42.3034	8.56555+ j42.3035	12.1157+ j56.7380
J947 POI with J947	8.56027+ j42.3322	8.57772+j42.3323	1.51699+j16.0865

Breaker duty analysis results are summarized in Table 4.1.1-5 and Table 4.1.1-6.

Table 4.1.1-5 – Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 4.1.1-6 – Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Ground fault analysis results are summarized in Table 4.1.1-7 and Table 4.1.1-8.

Table 4.1.1-7 – Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
BASS CREEK	BCK 138	138	7,021	7,764	10.59
BRISTOL	BOL 138 Bus1	138	6,109	6,984	14.33
BRISTOL	BOL 138 Bus2	138	6,109	6,984	14.33
CRAWFISH	937500	138	9,202	10,880	18.24
CRAWFISH	937501	138	9,202	10,880	18.24
DARLINGTON	DAR 138	138	4,431	6,183	39.55
DARLINGTON	DAR 69	69	6,719	7,881	17.29
DELAVAN	DEL 138	138	5,227	5,856	12.04
EDEN	EEN 138	138	10,812	14,701	35.97
FALCON	FLC	138	4,429	6,153	38.90
FALCON	QBW 34	34.5	9,164	11,237	22.62
Hill Valley	P310 HLV 138	138	12,155	15,567	28.07
Hill Valley	P310 HLV 345	345	6,470	7,449	15.14
HILLMAN	HLM 138	138	4,188	5,849	39.66
J850	J850_Bus	138	6,074	9,236	52.06
JEFFERSON	888400	138	10,028	12,658	26.23
JEFFERSON	934000	138	10,028	12,658	26.23
LONE ROCK	LOR 69	69	3,188	5,879	84.41
LONE ROCK	LORPS 69	69	2,376	3,414	43.67
NELSON DEWEY	NED 138 Bus1	138	7,915	9,282	17.26
NELSON DEWEY	NED 138 Bus2	138	7,915	9,282	17.26
NELSON DEWEY	NED 161	161	7,225	8,092	12.00
NORTH MONROE	NOM 138	138	4,323	5,775	33.59
NORTH MONROE	NOM 69	69	6,168	6,867	11.32
PARIS	940200	138	20,130	22,300	10.78
PARIS	940900	138	20,130	22,300	10.78
PARIS	941000	138	20,130	22,300	10.78
SPRING GREEN	SPG 69 Bus 1	69	6,496	7,292	12.24
SPRING GREEN	SPG 69 Bus 2	69	6,496	7,292	12.24
STONE LAKE	STLK_BUS	345	4,587	5,500	19.91

Table 4.1.1-8 – Buses with 10% or More Fault Current Increase in 3PG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
DARLINGTON	DAR 138	138	4,460	5,733	28.55
DARLINGTON	DAR 69	69	5,947	6,921	16.38
EDEN	EEN 138	138	12,013	14,171	17.97
FALCON	FLC	138	4,356	5,690	30.62
FALCON	QBW 34	34.5	8,971	10,836	20.79
FALCON	QBW 13.8	13.8	10,856	12,114	11.59
Hill Valley	P310 HLV 138	138	12,926	15,127	17.03
HILLMAN	HLM 138	138	4,665	6,179	32.45
LONE ROCK	LOR 69	69	4,486	4,984	11.10
NELSON DEWEY	NED 138 Bus1	138	8,682	10,283	18.44
NELSON DEWEY	NED 138 Bus2	138	8,682	10,283	18.44
NELSON DEWEY	NED 161	161	8,015	9,139	14.03
NORTH MONROE	NOM 138	138	5,004	5,925	18.41
STONE LAKE	STLK_BUS	345	5,239	6,518	24.41

4.1.2 Network Upgrades Identified in ATC Short Circuit Analysis

ATC short circuit Network Upgrades are summarized in Table 4.1.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 4.1.2-1 – Network Upgrade Required for ATC Facilities

Substation	Total Cost ($)
BASS CREEK	50,000
BRISTOL	50,000
CRAWFISH	50,000
DARLINGTON	50,000
DELAVAN	50,000
EDEN	50,000
FALCON	50,000
Hill Valley	50,000
HILLMAN	50,000
JEFFERSON	50,000
LONE ROCK	50,000
NELSON DEWEY	50,000
NORTH MONROE	50,000
PARIS	150,000
SPRING GREEN	50,000
STONE LAKE	50,000

4.2 Dairyland Power Cooperative Short Circuit Analysis

Some Dairyland Power Cooperative owned facilities under MISO functional control are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

4.2.1 Short Circuit Study Results

Dairyland Power Cooperative Breaker duty analysis results are summarized in Table 4.2.1-1 and Table 4.2.1-2.

Table 4.2.1-1 – Dairyland Power Cooperative Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 4.2.1-2 – Dairyland Power Cooperative Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Dairyland Power Cooperative ground fault analysis results are summarized in Table 4.2.1-3 and Table 4.2.1-4.

Table 4.2.1-3 – Dairyland Power Cooperative Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
None	N/A	N/A	N/A	N/A	N/A

Table 4.2.1-4 – Dairyland Power Cooperative Buses with 10% or More Fault Current Increase in 3PG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
STONEMAN	SMN 161	161	7,894	8,813	11.65

4.2.2 Network Upgrades Identified in the Short Circuit Analysis

Dairyland Power Cooperative short circuit Network Upgrades are summarized in Table 4.2.2-1 below. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9

Table 4.2.2-1 – Network Upgrade Required for Dairyland Power Cooperative Facilities

Substation	Total Cost ($)
STONEMAN	50,000

4.3 Minnesota Power Affected System Short Circuit Analysis

Some Minnesota Power owned facilities under MISO functional control are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

4.3.1 Short Circuit Study Results

Minnesota Power Breaker duty analysis results are summarized in Table 4.3.1-1 and Table 4.3.1-2.

Table 4.3.1-1 – Minnesota Power Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 4.3.1-2 – Minnesota Power Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Minnesota Power ground fault analysis results are summarized in Table 4.3.1-3 and Table 4.3.1-4.

Table 4.3.1-3 – Minnesota Power Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
ARROWHEAD MP	AWHD_Bus	345	5,528	8,167	47.75
ARROWHEAD MP	AWHD ATC BUS	230	10,534	12,740	20.95
ARROWHEAD MP	AWHD MP BUS	230	12,623	14,341	13.61

Table 4.3.1-4 – Minnesota Power Buses with 10% or More Fault Current Increase in 3PG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
ARROWHEAD MP	AWHD MP BUS	230	11,140	12,867	15.50
ARROWHEAD MP	AWHD_Bus	345	5,003	7,569	51.29
ARROWHEAD MP	AWHD ATC BUS	230	9,286	11,438	23.18

4.3.2 Network Upgrades Identified in the Short Circuit Analysis

Minnesota Power short circuit Network Upgrades are summarized in Table 4.3.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 4.3.2-1 – Network Upgrade Required for Minnesota Power Facilities

Substation	Total Cost ($)
ARROWHEAD MP	50,000

5.0 TRANSFORMER ENERGIZATION ANALYSIS

5.1 Transformer Energization Study Results

Transformer Energization Analysis were performed based on ATC transformer initial energization criteria as described in Appendix A. The results are summarized in Table 5.1-1. No constraints were found.

Table 5.1-1 – Inrush Calculations Using Shoulder Model

Generation Project	Transformer(s)		PSSE POI	Fault	Vmin Inrush (pu)	
	Number	Windings	Bus #	Current (A)	Raw	Multiplier
J732	2[1]	2	87323	4,448	0.6756	0.7770
J798	1	2	87985	9,557	0.8482	0.9754
J807	1	3	693405	5,586	0.8742	1.0053
J818	1	2	699340	11,728	0.8506	0.9782
J819	1	3	699033	5,247	0.7571	0.8706
J821	1	3	821006	5,533	0.7057	0.8116
J825	1	3	88250	4,986	0.7259	0.8348
J850	2	3	88500	7,523	0.8150	0.9372
J855	1	3	88554	12,413	0.9376	1.0782
J864	1	2	698123	4,321	0.6827	0.7851
J870/871	3	3	699034	12,298	0.9005	1.0355
J878	2	3	699409	12,040	0.9000	1.0350
J886	1	3	699620	19,849	0.9165	1.0540
J947	1	3	890475	5,357	0.6739	0.7750

[1] Inrush current and Vmin calculated for combustion turbine transformer as the worst-case scenario

5.2 Network Upgrades Identified in the Transformer Energization Analysis

Cost and cost allocation for Network Upgrades identified in the transformer energization analysis are listed in Table 5.2-1.

Table 5.2-1 – Transformer Energization Network Upgrades Cost and Cost Allocation

Generation Project	Mitigation	Total Cost	Cost Allocation
N/A	none	$ -	$ -

6.0 WEAK GRID CONDITION ANALYSIS

ATC performed a weak-grid Screening analysis for all inverter-based generation in the DPP-2017-August Wisconsin Area Phase 1. The methodology for the weak-grid screening analysis is detailed in Appendix A.

6.1 Weak Grid Screening Results

The weak grid screening analysis included classic Short Circuit Ratio (SCR) analysis with results shown in Tables 6.1-1 and 6.1-2. For the requests in southwest Wisconsin this analysis was also repeated for a case without the Cardinal-Hickory Creek 345-kV MVP project included since the in-service dates of all of these requests are prior to the expected in-service date of Cardinal-Hickory Creek 345-kV. These results are shown in Tables 6.1-3 and 6.1-4.

Table 6.1-1: SCR Analysis Results for System Intact

MISO Queue #	POI Bus #	Capacity (MW)	Short Circuit Capacity (MVA)	Short Circuit Ratio
J798	87980	124	2,695.00	21.73
J807	693406	41.4	1,268.49	30.64
J818	88180	149	2,729.00	18.32
J819	699033	99.9	1,223.49	12.25
J821	821006	99.9	1,111.00	11.12
J825	88250	99.9	1,203.76	12.05
J850	88500	250	1,788.35	7.15
J855	693668	100	3,258.12	32.58
J864	88640	49.98	488.88	9.78
J870	693668	200	3,258.12	16.29
J871	693668	100	3,258.12	32.58
J878	88780	200	2,862.00	14.31
J886	699620	150	4,753.33	31.69
J947	89475	200	1,246.10	6.23

Table 6.1-2: SCR Analysis Results for Worst N-1 Contingency

MISO Queue #	POI Bus #	Capacity (MW)	Short Circuit Capacity (MVA)	Short Circuit Ratio
J798	87980	124	1,532.00	12.35
J807	693406	41.4	780.00	18.84
J818	88180	149	1,544.00	10.36
J819	699033	99.9	859.79	8.61
J821	821006	99.9	337.00	3.37
J825	88250	99.9	572.97	5.74
J850	88500	250	766.85	3.07
J855	693668	100	2,716.86	27.17
J864	88640	49.98	201.35	4.03
J870	693668	200	2,716.86	13.58
J871	693668	100	2,716.86	27.17
J878	88780	200	1,659.00	8.30
J886	699620	150	3,091.22	20.61
J947	89475	200	694.35	3.47

Table 6.1-3: Southwest Wisconsin SCR Analysis Results for System Intact without Cardinal-Hickory Creek 345-kV MVP Project

MISO Queue #	POI Bus #	Capacity (MW)	Short Circuit Capacity (MVA)	Short Circuit Ratio
J807	693406	41.4	1,233.88	29.80
J819	699033	99.9	1,194.62	11.96
J825	88250	99.9	1,197.29	11.98
J850	88500	250	1,786.96	7.15
J855	693668	100	1,257.95	12.58
J864	88640	49.98	477.63	9.56
J870	693668	200	1,257.95	6.29
J871	693668	100	1,257.95	12.58
J947	89475	200	1,184.26	5.92

Table 6.1-4: Southwest Wisconsin SCR Analysis Results for Worst N-1 Contingency without Cardinal-Hickory Creek 345-kV MVP Project

MISO Queue #	POI Bus #	Capacity (MW)	Short Circuit Capacity (MVA)	Short Circuit Ratio
J807	693406	41.4	778.14	18.80
J819	699033	99.9	828.24	8.29
J825	88250	99.9	566.80	5.67
J850	88500	250	767.15	3.07
J855	693668	100	674.36	6.74
J864	88640	49.98	200.66	4.01
J870	693668	200	674.36	3.37
J871	693668	100	674.36	6.74
J947	89475	200	652.58	3.26

It was determined that three groups of inverter-based generation were placed sufficiently close together to require Weighted Short Circuit Ration (WSCR) analysis. The first group included J855, J870, J871, and the existing Montfort Windfarm. The second group included J807, J819, J825, and the existing Quilt Block windfarm. The third group included the J886 and J505 (DPP Feb 16) solar plants. The results for these WSCR analyses are shown in Tables 6.1-5 and 6.1-6. For the groups in southwest Wisconsin this analysis was also repeated for a case without the Cardinal-Hickory Creek 345-kV MVP project included since the in-service dates of all of these requests are prior to the expected in-service date of Cardinal-Hickory Creek 345-kV. These results are shown in Tables 6.1-7 and 6.1-8.

Table 6.1-5: WSCR Analysis Results for System Intact

Generator Group	Cumulative Capacity (MW)	Cumulative MW * MVA	Weighted SCR
J855+J870+J871 (Group 1) + Montfort Wind (Existing)	430	1,329,673.50	7.19
J947+J807+J819+J825 (Group 2) + J395 (Existing)	539.2	544,217.76	1.87
J886 + J505 (DPP Feb 16)	249	690,476.16	11.14

Table 6.1-6: WSCR Analysis Results for Worst N-1 Contingency

Generator Group	Cumulative Capacity (MW)	Cumulative MW * MVA	Weighted SCR
J855+J870+J871 (Group 1) + Montfort Wind (Existing)	430	1,098,040.80	5.94
J947+J807+J819+J825 (Group 2) + J395 (Existing)	539.2	314,294.72	1.08
J886 + J505 (DPP Feb 16)	249	346,598.40	5.59

Table 6.1-7: Southwest Wisconsin WSCR Analysis Results for System Intact without Cardinal-Hickory Creek 345-kV MVP Project

Generator Group	Cumulative Capacity (MW)	Cumulative MW * MVA	Weighted SCR
J855+J870+J871 (Group 1) + Montfort Wind (Existing)	430	525,329.30	2.84
J947+J807+J819+J825 (Group 2) + J395 (Existing)	539.2	526,886.44	1.81

Table 6.1-8: Southwest Wisconsin WSCR Analysis Results for Worst n-1 Contingency without Cardinal-Hickory Creek 345-kV MVP Project

Generator Group	Cumulative Capacity (MW)	Cumulative MW * MVA	Weighted SCR
J855+J870+J871 (Group 1) + Montfort Wind (Existing)	430	280,748.00	1.52
J947+J807+J819+J825 (Group 2) + J395 (Existing)	539.2	302,095.49	1.04

Given the low SCR and WSCR values found in southwest Wisconsin and the number of individual inverter-based generators in the area it was determined that the system could become sufficiently weak to require further study in PSCAD.

6.2 PSCAD Analysis Results

The PSCAD analysis found that for [redacted] J864, J870, and J871 repeatedly fail to recover but do not trip. J870 and J871 show oscillations in P and Q during recovery, while J864 appears to be very sensitive to ride-through re-entry.

The PSCAD analysis found that for [redacted] J864 blocks P and Q for over 2 seconds after the fault (momentary cessation). This is likely a result of prolonged exposure to a three-phase fault.

Full PSCAD results can be found in Appendix L.

6.3 Network Upgrades Identified in the PSCAD Analysis

The results listed in section 6.2 will need to be mitigated in Phase 2 by the interconnection customers through model/design tuning or transmission network upgrades will need to be assigned to mitigate those results.

7.0 AFFECTED SYSTEM ANALYSIS

Analyses were performed to identify constraints on affected systems.

7.1 Alliant Affected System Short Circuit Analysis

Some Alliant owned facilities are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

7.1.1 Short Circuit Study Results

Alliant breaker duty analysis results are summarized in Table 7.1.1-1 and Table 7.1.1-2.

Table 7.1.1-1 – Alliant Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 7.1.1-2 – Alliant Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Alliant ground fault analysis results are summarized in Table 7.1.1-3 and Table 7.1.1-4.

Table 7.1.1-3 – Alliant Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
ALBANY	ALB 138	138	4,418	5,734	29.78
BLUE RIVER	BRR 69	69	1,867	2,126	13.82
PINE RIVER (ALTE)	PIR 69	69	2,057	2,313	12.44
POTOSI	POT 138	138	4,208	7,365	75.02
RED BIRD	RDBT 69	69	5,303	6,027	13.66
RED BIRD	RDB 69	69	5,188	5,882	13.38
RICHLAND	RIN 69	69	2,033	2,344	15.29
SOUTHWEST DELAVAN	SOD 138	138	5,621	6,916	23.03
WEST DARIEN	WDN 138	138	5,510	7,274	32.01

Table 7.1.1-4 – Alliant Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
ALBANY	ALB 138	138	5,484	6,303	14.93
LANCASTER	LAN 138	138	7,043	8,134	15.49
POTOSI	POT 138	138	5,167	6,887	33.29
RED BIRD	RDBT 69	69	5,336	6,165	15.55
RED BIRD	RDB 69	69	5,273	6,089	15.47
WEST DARIEN	WDN 138	138	8,161	9,091	11.39
WYOMING VALLEY	WYV 138	138	6,205	6,914	11.42

7.1.2 Network Upgrades Identified in the Short Circuit Analysis

Alliant short circuit Network Upgrades are summarized in Table 7.1.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 7.1.2-1 – Network Upgrade Required for Alliant Facilities

Substation	Total Cost ($)
Albany	50,000
Blue River	50,000
Lancaster	50,000
Pine River (ALTE)	50,000
Potosi	50,000
Red Bird	50,000
Richland	50,000
Southwest Delavan	50,000
West Darien	50,000
Wyoming Valley	50,000

7.2 Dairyland Power Cooperative Affected System Short Circuit Analysis

Some Dairyland Power Cooperative owned facilities that are not under MISO functional control are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

7.2.1 Short Circuit Study Results

Dairyland Power Cooperative Breaker duty analysis results are summarized in Table 7.2.1-1 and Table 7.2.1-2.

Table 7.2.1-1 – Dairyland Power Cooperative Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 7.2.1-2 – Dairyland Power Cooperative Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Dairyland Power Cooperative ground fault analysis results are summarized in Table 7.2.1-3 and Table 7.2.1-4.

Table 7.2.1-3 – Dairyland Power Cooperative Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
None	N/A	N/A	N/A	N/A	N/A

Table 7.2.1-4 – Dairyland Power Cooperative Buses with 10% or More Fault Current Increase in 3PG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
GRATIOT	GET 69	69	4,260	4,746	11.41

7.2.2 Network Upgrades Identified in the Short Circuit Analysis

Dairyland Power Cooperative short circuit Network Upgrades are summarized in Table 7.2.2-1 below. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9

Table 7.2.2-1 – Network Upgrade Required for Dairyland Power Cooperative Facilities

Substation	Total Cost ($)
GRATIOT	50,000

7.3 Muscoda Municipal Affected System Short Circuit Analysis

Some Muscoda Municipal owned facilities are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

7.3.1 Short Circuit Study Results

Muscoda Municipal Breaker duty analysis results are summarized in Table 7.3.1-1 and Table 7.3.1-2.

Table 7.3.1-1 – Muscoda Municipal Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 7.3.1-2 – Muscoda Municipal Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Muscoda Municipal ground fault analysis results are summarized in Table 7.3.1-3 and Table 7.3.1-4.

Table 7.3.1-3 – Muscoda Municipal Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
MUSCODA	MUS 69	69	2,012	2,534	25.92
MUSCODA IND PK	MUIT 69	69	2,023	2,560	26.54

Table 7.3.1-4 – Muscoda Municipal Buses with 10% or More Fault Current Increase in 3PG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
none	N/A	N/A	N/A	N/A	N/A

7.3.2 Network Upgrades Identified in the Short Circuit Analysis

Muscoda Municipal short circuit Network Upgrades are summarized in Table 7.3.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 7.3.2-1 – Network Upgrade Required for Muscoda Municipal Facilities

Substation	Total Cost ($)
MUSCODA	50,000
MUSCODA IND PK	50,000

7.4 Rock Energy Cooperative Affected System Short Circuit Analysis

Some Rock Energy Cooperative owned facilities are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

7.4.1 Short Circuit Study Results

Rock Energy Cooperative Breaker duty analysis results are summarized in Table 7.4.1-1 and Table 7.4.1-2.

Table 7.4.1-1 – Rock Energy Cooperative Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 7.4.1-2 – Rock Energy Cooperative Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Rock Energy Cooperative ground fault analysis results are summarized in Table 7.4.1-3 and Table 7.4.1-4.

Table 7.4.1-3 – Rock Energy Cooperative Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
BRADFORD	RC2 138	138	6,058	9,178	51.51
LA PRAIRIE	RC9 138	138	9,367	10,925	16.64

Table 7.4.1-4 – Rock Energy Cooperative Buses with 10% or More Fault Current Increase in 3PG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
BRADFORD	RC2 138	138	8,769	9,946	13.42

7.4.2 Network Upgrades Identified in the Short Circuit Analysis

Rock Energy Cooperative short circuit Network Upgrades are summarized in Table 7.4.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 7.4.2-1– Network Upgrade Required for Rock Energy Cooperative Facilities

Substation	Total Cost ($)
BRADFORD	50,000
LA PRAIRIE	50,000

7.5 Richland Center Municipal Affected System Short Circuit Analysis

Some Richland Center Municipal owned facilities are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

7.5.1 Short Circuit Study Results

Richland Center Municipal Breaker duty analysis results are summarized in Table 7.5.1-1 and Table 7.5.1-2.

Table 7.5.1-1 – Richland Center Municipal Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 7.5.1-2 – Richland Center Municipal Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Richland Center Municipal ground fault analysis results are summarized in Table 7.5.1-3 and Table 7.5.1-4.

Table 7.5.1-3 – Richland Center Municipal Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
BREWER	BRW 69	69	2,058	2,313	12.41
RICHLAND CENTER	RIC 69	69	2,080	2,316	11.32

Table 7.5.1-4 – Richland Center Municipal Buses with 10% or More Fault Current Increase in 3PG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
none	N/A	N/A	N/A	N/A	N/A

7.5.2 Network Upgrades Identified in the Short Circuit Analysis

Richland Center Municipal short circuit Network Upgrades are summarized in Table 7.5.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 7.5.2-1 – Network Upgrade Required for Richland Center Municipal Facilities

Substation	Total Cost ($)
BREWER	50,000
RICHLAND CENTER	50,000

7.6 We Energies Affected System Short Circuit Analysis

Some We Energies owned facilities are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

7.6.1 Short Circuit Study Results

We Energies Breaker duty analysis results are summarized in Table 7.6.1-1 and Table 7.6.1-2.

Table 7.6.1-1 – We Energies Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 7.6.1-2 – We Energies Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

We Energies ground fault analysis results are summarized in Table 7.6.1-3 and Table 7.6.1-4.

Table 7.6.1-3 – We Energies Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
FORT_ATKINSON	930500	138	5,848	6,665	13.97
FORT_ATKINSON	929800	138	5,656	6,419	13.49
LAKEHEAD CAMBRIDGE	934900	138	11,044	12,277	11.17

Table 7.6.1-4 – We Energies Buses with 10% or More Fault Current Increase in 3PG Analysis

Substation	Bus Name	Bus Voltage (kV)	3PG Fault Current Before (Amps)	3PG Fault Current After (Amps)	Change (%)
none	N/A	N/A	N/A	N/A	N/A

7.6.2 Network Upgrades Identified in the Short Circuit Analysis

We Energies short circuit Network Upgrades are summarized in Table 7.6.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 7.6.2-1 – Network Upgrade Required for We Energies Facilities

Substation	Total Cost ($)
FORT_ATKINSON	50,000
LAKEHEAD CAMBRIDGE	50,000

7.7 PJM Affected System AC Contingency Analysis

PJM performed the PJM affected system analysis and the report can be found in Appendix H. A summary of PJM constraints and required Network Upgrades identified by PJM is provided in Section 9 when there are cost allocations to one or more study generators in Aug 17 DPP WI Phase 1 group. Detailed cost allocations are also provided in Section 9.

8.0 DELIVERABILITY STUDY

Generator interconnection requests 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 either choose to elect the amount of NRIS available without upgrades or build 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.

MISO Generator Deliverability Study whitepaper describing the algorithm can be found at

https://cdn.misoenergy.org/Generator_Deliverability_Study_Methodology108139.pdf

8.1 Study Summary

The summary of MISO deliverability results based on the 2022 summer peak study model is shown in the following tables.

Table 8.1-1 below lists the deliverability results with ERIS upgrades included in the NRIS analysis. Minimum NR Deliverable is the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew. Maximum NR Deliverable is the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction.

Table 8.1-1 – NRIS Analysis Summary

MISO Queue #	Area	NR Tested	Minimum NR Deliverable (MW)	Maximum NR Deliverable (MW)
J732	ATC	527.8	527.8	527.8
J798	ATC	124	0	42.8
J807	ATC	41.4	0	16.31
J818	ATC	149	149	149
J819	ATC	99.9	0	39.35
J821	ATC	99.9	99.9	99.9
J825	ATC	99.9	0	15.69
J831	ATC	40	0	0
J850	ATC	250	0	39.26
J855	ATC	100	65.17	93.1
J864	ATC	49.98	49.98	49.98
J870	ATC	200	159.85	182.225
J871	ATC	100	59.85	82.225
J878	ATC	200	84.35	102.44
J886	ATC	150	150	150
J947	ATC	200	0	176.29

Table 8.1-2 below lists all of the NRIS constraints from the deliverability study and the identified NRIS Network Upgrades. Both ERIS Network Upgrades and NRIS Network Upgrades must be made for 100% NRIS, i.e. fully deliverable. Please note, if a NRIS Network Upgrade entirely or partially changes the scope of an ERIS Network Upgrade, only the cost difference between the NRIS upgrade and the ERIS upgrade will be eligible for NRIS Network Upgrade cost allocation. Detailed NRIS Network Upgrade cost allocation calculations are provided in Section 9.

Table 8.1-2 – Network Upgrades Needed to Address MISO Identified NRIS Steady-State Injection Constraints

NRIS Thermal Constraints	Required NRIS Network Upgrades	Mitigation Type	Responsible Generators	NRIS Network Upgrade Cost Estimates ($) [a]	ERIS Network Upgrade (Required for Same Constraint) Cost Estimate ($) [b]	Cost Used for NRIS Network Upgrade Allocation ($) [c] = [a] - [b]
699409 PARIS B5 138 693647 BERRYVILLE 138 1 699410 PARIS WE 138 699982 RAYMOND 138 1 699982 RAYMOND 138 699442 ST MARTIN B3 138 1	Paris SS, new 345/138 kV transformer	NR	J798, J850, J878	$29,773,189	$0	$29,773,189
	Paris – Burlington 138 kV line, rebuild (MTEP18 Target A : MTEP ID - 13732)	NR	No Allocation	A10	$0	No Allocation
698879 SGR CK4 138 699360 NLK GV T 138 1 698883 WHTWTR5 138 699516 BLUFFCRK 138 1 699512 UNVRSTY 138 698883 WHTWTR5 138 1 87985 J798TAP 138 699357 MUKWONGO 138 1	J798 - Mukwonago 138 kV, construct new line	ER & NR	J798, J825, J850	$41,544,935	$24,266,033[1]	$17,278,902
	Mukwonago – Merrill Hills 138 kV, uprate	NR	J798, J825, J850	$207,627	$0	$207,627
699512 UNVRSTY 138 87985 J798TAP 138 1	University to J798 138 kV, rebuild	NR	J825, J850	$7,947,630	$0	$7,947,630
698090 BOL 138 138 699086 ELK 138 138 1	X81 Bristol - Elkhorn 138 kV, uprate	NR	J825, J850	$373,789	$0	$373,789
698028 NOM 69 69.0 698036 MAP 69 69.0 1 698036 MAP 69 69.0 698038 NEG 69 69.0 1 698038 NEG 69 69.0 698039 BEE 69 69.0 1	North Monroe – Verona 69 kV, uprate	ER & NR	J807, J819, J825, J947	$793,169	$762,980	$30,189
88250 J825POI 138 699036 NOM 138 138 1 C	North Monroe - J825 138 kV, reconductor	NR	J798, J825, J850	$2,062,598	$0	$2,062,598
699141 TOWNLINE 138 699897 BASSCRK 138 1	Bass Creek - Town Line Rd 138 kV, reconductor	ER & NR	J850	$4,596,833	$4,596,833	$0
698007 DAR 69 69.0 698018 ROB 69 69.0 1	Y109 Darlington – Rock Branch 69 kV, uprate	NR	J807, J819, J825, J947	$1,050,528	$0	$1,050,528
699034 EEN 138 138 699115 WYV 138 138 1 699115 WYV 138 138 699114 SPG 138 138 1	Eden – Spring Green 138 kV, uprate	ER & NR	J807, J819, J855 J870/J871, J947	$715,120	$623,779	$91,341
694022 FOXRIVER B1 345 699359 N APPLETON 345 1	North Appleton - Fox River 345 kV, uprate	NR	J831	$167,337	$0	$167,337
699030 POT 138 138 699020 NED 138 138 1 699031 HLM 138 138 698003 HLM 69 69.0 1 89475 J947_POI 138 699030 POT 138 138 1 C	Hillman SS, new 138/69 kV transformer	ER & NR	J807, J819, J825, J947	$5,836,969	$2,866,337[2]	$2,970,632

[1] This is the sum of the ERIS Network Upgrade cost for J798 POI – Mukwonago 138 kV, rebuild and the ERIS Network Upgrade cost for Whitewater – University 138 kV, partial rebuild.

[2] This is the ERIS Network Upgrade cost for Hillman SS, upgrade transformer.

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See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

8.2 Per Project Summary

8.2.1 J732

J732 Deliverable (NRIS) Amount in 2022 Case: 527.8 MW (Conditional on ERIS upgrades and case assumptions)	527.8 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes

8.2.2 J798

J798 Deliverable (NRIS) Amount in 2022 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	124 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
88250 J825POI 138 699036 NOM 138 138 1 C	750.01	0	73.79	50.21	0.051	J798, J825, J850	$207,085	$2,062,598	North Monroe - J825 138 kV, reconductor
699409 PARIS B5 138 693647 BERRYVILLE 138 1	353.16	0	21.56	102.44	0.0855	J798, J850, J878	$1,819,142	$29,773,189	Paris SS, new 345/138 kV transformer Paris – Burlington 138 kV line, rebuild
699512 UNVRSTY 138 698883 WHTWTR5 138 1	81.18	42.82	81.18	42.82	0.9981	J798	$14,255,018	$41,752,562	J798 - Mukwonago 138 kV, construct new line Mukwonago – Merrill Hills 138 kV, uprate
87985 J798TAP 138 699357 MUKWONGO 138 1	40.51	83.49	27.82	96.18	0.496	J798, J825, J850	$14,255,018	$41,752,562	J798 - Mukwonago 138 kV, construct new line Mukwonago – Merrill Hills 138 kV, uprate
698883 WHTWTR5 138 699516 BLUFFCRK 138 1	34.34	89.66	34.34	89.66	0.4339	J798	$14,255,018	$41,752,562	J798 - Mukwonago 138 kV, construct new line Mukwonago – Merrill Hills 138 kV, uprate
698879 SGR CK4 138 699360 NLK GV T 138 1	32.28	91.72	32.28	91.72	0.4339	J798	$14,255,018	$41,752,562	J798 - Mukwonago 138 kV, construct new line Mukwonago – Merrill Hills 138 kV, uprate
		124		124					

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See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

8.2.3 J807

J807 Deliverable (NRIS) Amount in 2022 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	41.4 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
699034 EEN 138 138 699115 WYV 138 138 1	319.17	0	4.91	36.49	0.0822	J807, J819, J855, J870, J871, J947	$1,197	$715,120	Eden – Spring Green 138 kV, uprate
699115 WYV 138 138 699114 SPG 138 138 1	277.65	0	4.27	37.13	0.0822	J807, J819, J855, J870, J871, J947	$1,197	$715,120	Eden – Spring Green 138 kV, uprate
698007 DAR 69 69.0 698018 ROB 69 69.0 1	116.08	0	25.09	16.31	0.2414	J807, J819, J825, J947	$145,288	$1,050,528	Y109 Darlington – Rock Branch 69 kV, uprate
698028 NOM 69 69.0 698036 MAP 69 69.0 1	67.42	0	6.3	35.1	0.0968	J807, J819, J825, J947	$3,170	$793,169	North Monroe – Verona 69 kV, uprate
698036 MAP 69 69.0 698038 NEG 69 69.0 1	38.45	2.95	3.59	37.81	0.0968	J807, J819, J825, J947	$3,170	$793,169	North Monroe – Verona 69 kV, uprate
699031 HLM 138 138 698003 HLM 69 69.0 1	26.98	14.42	2.62	38.78	0.2461	J807, J819, J825, J947	$272,704	$5,836,969	Hillman SS, new 138/69 kV transformer
698038 NEG 69 69.0 698039 BEE 69 69.0 1	20.07	21.33	1.87	39.53	0.0968	J807, J819, J825, J947	$3,170	$793,169	North Monroe – Verona 69 kV, uprate
89475 J947_POI 138 699030 POT 138 138 1 C	1.6	39.8	0.15	41.25	0.4534	J807, J819, J825, J947	$272,704	$5,836,969	Hillman SS, new 138/69 kV transformer
699030 POT 138 138 699020 NED 138 138 1	0.67	40.73	0.06	41.34	0.4534	J807, J819, J825, J947	$272,704	$5,836,969	Hillman SS, new 138/69 kV transformer
		41.4		41.4					

8.2.4 J818

J818 Deliverable (NRIS) Amount in 2022 Case: 149 MW (Conditional on ERIS upgrades and case assumptions)	149 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		149		149					

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8.2.5 J819

J819 Deliverable (NRIS) Amount in 2022 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	99.9 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
698007 DAR 69 69.0 698018 ROB 69 69.0 1	116.08	0	60.55	39.35	0.2414	J807, J819, J825, J947	$350,666	$1,050,528	Y109 Darlington – Rock Branch 69 kV, uprate
699034 EEN 138 138 699115 WYV 138 138 1	314.9	0	11.84	88.06	0.0833	J807, J819, J855, J870, J871, J947	$2,932	$715,120	Eden – Spring Green 138 kV, uprate
699115 WYV 138 138 699114 SPG 138 138 1	273.93	0	10.3	89.6	0.0833	J807, J819, J855, J870, J871, J947	$2,932	$715,120	Eden – Spring Green 138 kV, uprate
698028 NOM 69 69.0 698036 MAP 69 69.0 1	64.39	35.51	15.19	84.71	0.1014	J807, J819, J825, J947	$8,700	$793,169	North Monroe – Verona 69 kV, uprate
698036 MAP 69 69.0 698038 NEG 69 69.0 1	36.72	63.18	8.66	91.24	0.1014	J807, J819, J825, J947	$8,700	$793,169	North Monroe – Verona 69 kV, uprate
699031 HLM 138 138 698003 HLM 69 69.0 1	32.1	67.8	6.32	93.58	0.2069	J807, J819, J825, J947	$562,935	$5,836,969	Hillman SS, new 138/69 kV transformer
698038 NEG 69 69.0 698039 BEE 69 69.0 1	19.17	80.73	4.52	95.38	0.1014	J807, J819, J825, J947	$8,700	$793,169	North Monroe – Verona 69 kV, uprate
89475 J947_POI 138 699030 POT 138 138 1 C	1.87	98.03	0.35	99.55	0.3879	J807, J819, J825, J947	$562,935	$5,836,969	Hillman SS, new 138/69 kV transformer
699030 POT 138 138 699020 NED 138 138 1	0.79	99.11	0.15	99.75	0.3879	J807, J819, J825, J947	$562,935	$5,836,969	Hillman SS, new 138/69 kV transformer
		99.9		99.9					

8.2.6 J821

J821 Deliverable (NRIS) Amount in 2022 Case: 99.9 MW (Conditional on ERIS upgrades and case assumptions)	99.9 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes

8.2.7 J825

J825 Deliverable (NRIS) Amount in 2022 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	99.9 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
88250 J825POI 138 699036 NOM 138 138 1 C	112.35	0	84.21	15.69	0.4254	J798, J825, J850	$1,390,810	$2,062,598	North Monroe - J825 138 kV, recondu
698007 DAR 69 69.0 698018 ROB 69 69.0 1	230.87	0	60.55	39.35	0.1214	J807, J819, J825, J947	$178,800	$1,050,528	Y109 Darlington – Rock Branch 69 kV, u ate
87985 J798TAP 138 699357 MUKWONGO 138 1	346.64	0	22.41	77.49	0.058	J798, J825, J850	$666,237	$41,752,562	J798 - Mukwonago 138 kV, construct ne line Mukwonago – Merrill Hills 138 kV, upr e
698090 BOL 138 138 699086 ELK 138 138 1	118.66	0	7.65	92.25	0.0601	J825, J850	$24,072	$373,789	X81 Bristol - Elkhorn 138 kV, uprat
699512 UNVRSTY 138 87985 J798TAP 138 1	75.66	24.24	15.62	84.28	0.058	J825, J850	$1,640,391	$7,947,630	University to J798 138 kV, rebuild
699031 HLM 138 138 698003 HLM 69 69.0 1	68.71	31.19	6.32	93.58	0.0967	J807, J819, J825, J947	$267,951	$5,836,969	Hillman SS, new 138/69 kV transform
698028 NOM 69 69.0 698036 MAP 69 69.0 1	58.26	41.64	15.19	84.71	0.112	J807, J819, J825, J947	$13,522	$793,169	North Monroe – Verona 69 kV, upra
698036 MAP 69 69.0 698038 NEG 69 69.0 1	33.23	66.67	8.66	91.24	0.112	J807, J819, J825, J947	$13,522	$793,169	North Monroe – Verona 69 kV, upra
698038 NEG 69 69.0 698039 BEE 69 69.0 1	17.34	82.56	4.52	95.38	0.112	J807, J819, J825, J947	$13,522	$793,169	North Monroe – Verona 69 kV, upra
89475 J947_POI 138 699030 POT 138 138 1 C	3.93	95.97	0.35	99.55	0.1847	J807, J819, J825, J947	$267,951	$5,836,969	Hillman SS, new 138/69 kV transformer
699030 POT 138 138 699020 NED 138 138 1	1.65	98.25	0.15	99.75	0.1847	J807, J819, J825, J947	$267,951	$5,836,969	Hillman SS, new 138/69 kV transformer
		99.9		99.9					

8.2.8 J831

J831 Deliverable (NRIS) Amount in 2022 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	40 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
694022 FOXRIVER B1 345 699359 N APPLETON 345 1	595.74	0	595.74	0	0.0781	J831	$167,337	$167,337	North Appleton - Fox River 345 kV, u ate
		40		40					

8.2.9 J850

J850 Deliverable (NRIS) Amount in 2022 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	250 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
88250 J825POI 138 699036 NOM 138 138 1 C	841.4	0	210.74	39.26	0.0568	J798, J825, J850	$464,703	$2,062,598	North Monroe - J825 138 kV, reconductor
699410 PARIS WE 138 699982 RAYMOND 138 1	779.38	0	121.94	128.06	0.092	J850, J878	$4,415,364	$29,773,189	Paris SS, new 345/138 kV transformer Paris – Burlington 138 kV line, rebuild
699982 RAYMOND 138 699442 ST MARTIN B3 138 1	504.59	0	78.94	171.06	0.092	J850, J878	$4,415,364	$29,773,189	Paris SS, new 345/138 kV transformer Paris – Burlington 138 kV line, rebuild
699409 PARIS B5 138 693647 BERRYVILLE 138 1	293.01	0	43.46	206.54	0.103	J798, J850, J878	$4,415,364	$29,773,189	Paris SS, new 345/138 kV transformer Paris – Burlington 138 kV line, rebuild
87985 J798TAP 138 699357 MUKWONGO 138 1	225.6	24.4	56.08	193.92	0.0891	J798, J825, J850	$2,565,274	$41,752,562	J798 - Mukwonago 138 kV, construct new line Mukwonago – Merrill Hills 138 kV, uprate
699512 UNVRSTY 138 87985 J798TAP 138 1	49.24	200.76	39.08	210.92	0.0891	J825, J850	$6,307,239	$7,947,630	University to J798 138 kV, rebuild
699141 TOWNLINE 138 699897 BASSCRK 138 1	35.67	214.33	35.68	214.32	0.0704	J850	$0	$4,596,833	Bass Creek - Town Line Rd 138 kV, reconductor
698090 BOL 138 138 699086 ELK 138 138 1	20.46	229.54	19.14	230.86	0.3485	J825, J850	$349,717	$373,789	X81 Bristol - Elkhorn 138 kV, uprate
		250		250					

8.2.10 J855

J855 Deliverable (NRIS) Amount in 2022 Case: 65.17 MW (Conditional on ERIS upgrades and case assumptions)	100 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
699034 EEN 138 138 699115 WYV 138 138 1	34.83	65.17	6.9	93.1	0.3773	J807, J819, J855, J870, J871, J947	$13,299	$715,120	Eden – Spring Green 138 kV, uprate
699115 WYV 138 138 699114 SPG 138 138 1	28.06	71.94	5.56	94.44	0.3773	J807, J819, J855, J870, J871, J947	$13,299	$715,120	Eden – Spring Green 138 kV, uprate
		100		100					

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See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

8.2.11 J864

J864 Deliverable (NRIS) Amount in 2022 Case: 49.98 MW (Conditional on ERIS upgrades and case assumptions)	49.98 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes

8.2.12 J870 and J871

J870_871 Deliverable (NRIS) Amount in 2022 Case: 259.85 MW (Conditional on ERIS upgrades and case assumptions)	300 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
699034 EEN 138 138 699115 WYV 138 138 1	40.15	259.85	35.55	264.45	0.6537	J807, J819, J855, J870, J871, J947	$69,136	$715,120	Eden – Spring Green 138 kV, uprate
699115 WYV 138 138 699114 SPG 138 138 1	34.92	265.08	30.93	269.07	0.6537	J807, J819, J855, J870, J871, J947	$69,136	$715,120	Eden – Spring Green 138 kV, uprate
		300		300					

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8.2.13 J878

J878 Deliverable (NRIS) Amount in 2022 Case: 84.35 MW (Conditional on ERIS upgrades and case assumptions)	200 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
699410 PARIS WE 138 699982 RAYMOND 138 1	115.65	84.35	97.56	102.44	0.6203	J850, J878	$23,538,683	$29,773,189	Paris SS, new 345/138 kV transformer Paris – Burlington 138 kV line, rebuild
699982 RAYMOND 138 699442 ST MARTIN B3 138 1	74.87	125.13	63.16	136.84	0.6203	J850, J878	$23,538,683	$29,773,189	Paris SS, new 345/138 kV transformer Paris – Burlington 138 kV line, rebuild
699409 PARIS B5 138 693647 BERRYVILLE 138 1	43.98	156.02	34.78	165.22	0.6862	J798, J850, J878	$23,538,683	$29,773,189	Paris SS, new 345/138 kV transformer Paris – Burlington 138 kV line, rebuild
		200		200					

8.2.14 J886

J886 Deliverable (NRIS) Amount in 2022 Case: 150 MW (Conditional on ERIS upgrades and case assumptions)	150 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes

8.2.15 J947

J947 Deliverable (NRIS) Amount in 2022 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	200 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
699034 EEN 138 138 699115 WYV 138 138 1	387.45	0	23.71	176.29	0.0677	J807, J819, J855, J870, J871, J947	$4,777	$715,120	Eden – Spring Green 138 kV, upr[illegible]
699115 WYV 138 138 699114 SPG 138 138 1	337.04	0	20.62	179.38	0.0677	J807, J819, J855, J870, J871, J947	$4,777	$715,120	Eden – Spring Green 138 kV, upr[illegible]
698007 DAR 69 69.0 698018 ROB 69 69.0 1	187.08	12.92	83.64	116.36	0.1292	J807, J819, J825, J947	$375,774	$1,050,528	Y109 Darlington – Rock Branch 69 kV, uprate
698028 NOM 69 69.0 698036 MAP 69 69.0 1	74.18	125.82	30.41	169.59	0.088	J807, J819, J825, J947	$4,797	$793,169	North Monroe – Verona 69 kV, uprate
698036 MAP 69 69.0 698038 NEG 69 69.0 1	42.3	157.7	17.34	182.66	0.088	J807, J819, J825, J947	$4,797	$793,169	North Monroe – Verona 69 kV, uprate
698038 NEG 69 69.0 698039 BEE 69 69.0 1	22.08	177.92	9.05	190.95	0.088	J807, J819, J825, J947	$4,797	$793,169	North Monroe – Verona 69 kV, uprate
699031 HLM 138 138 698003 HLM 69 69.0 1	20.61	179.39	12.66	187.34	0.3222	J807, J819, J825, J947	$1,867,042	$5,836,969	Hillman SS, new 138/69 kV transformer
89475 J947_POI 138 699030 POT 138 138 1 C	1.13	198.87	0.71	199.29	0.6425	J807, J819, J825, J947	$1,867,042	$5,836,969	Hillman SS, new 138/69 kV transformer
699030 POT 138 138 699020 NED 138 138 1	0.48	199.52	0.3	199.7	0.6425	J807, J819, J825, J947	$1,867,042	$5,836,969	Hillman SS, new 138/69 kV transformer
		200		200					

8.3 Network Upgrade Alternatives Considered

Except for the Paris SS, new 345/138 kV transformer project, all other NRIS network upgrades identified in Table 8.1-2 are direct upgrades of the constraint facilities to ATC design standards and considered as least-cost solutions at this point. Therefore, no other alternatives were examined.

As a network upgrade alternative to the Paris SS, new 345/138 kV transformer project, a new 138 kV line between Paris and Albers substation on existing right-of-way was considered which are expected to address the NRIS thermal constraints and have similar costs based a high-level review. At this point, the Paris transformer project is considered as a more robust alternative with less environmental /community impact.

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

9.1 ERIS Network Upgrades Proposed for Aug 17 DPP WI Phase 1 Projects

Network upgrades for Energy Resource Interconnection Service (ERIS) were identified in the ERIS analysis and the affected system analysis. The ERIS network upgrades include thermal network upgrades and voltage support network upgrades identified in the steady-state analysis, stability network upgrades identified in the transient stability analysis, short circuit network upgrades identified in the short circuit analysis and network upgrades identified in the affected system analysis. For DPP 2017 August Wisconsin Area Phase 1 group, the total costs of ERIS network upgrades for the 2022 scenario are summarized in Tables 9.1-1, 9.1-2, 9.1-3, 9.1-4, 9.1-5 and 9.1-6.

Table 9.1-1 – ERIS Network Upgrades Identified

Steady-State Injection Constraint	Facility Owner	Network Upgrade	ISD (For Cost Estimate Only)	Cost ($)[1,2,3]
J825 POI – Albany 138 kV line	ATC	J825POI – Bass Creek 138 kV, reconductor	09/15/2019	8,172,147
Albany – Bass Creek 138 kV line	ATC			
Townline Road – Bass Creek 138 kV line	ATC	Bass Creek – Townline Road 138 kV, reconductor	09/15/2019	4,596,833
North Monroe – Monticello 69 kV line	ATC	North Monroe – Verona 69 kV, uprate	09/15/2019	762,980
North Monroe 138/69 kV transformer	ATC	North Monroe SS, new transformer	09/15/2019	5,933,016
Hillman 138/69 kV transformer	ATC	Hillman SS, upgrade transformer	09/15/2019	2,866,337
Eden – Wyoming Valley 138 kV line	ATC	Eden – Spring Green 138 kV, uprate	09/15/2019	623,779
Wyoming Valley – Spring Green 138 kV line	ATC			
J798 POI – Mukwonago 138 kV line	ATC	J798 POI – Mukwonago 138 kV, rebuild	09/01/2019	22,289,710
Whitewater – University 138 kV line	ATC	Whitewater – University 138 kV, partial rebuild	09/01/2019	1,976,323
Stone Lake 345/161 kV transformer	XCEL	Stone Lake SS, upgrade transformer	08/09/2023	3,898,500

[1] All Network Upgrades were estimated on the earliest ISD dollars of responsible generator.
[2] ATC Network Upgrades included a 20% contingency.
[3] No contingency was included for the Stone Lake transformer upgrade project according to Xcel Energy.

Table 9.1-2 – ERIS Transient Stability Network Upgrades

Constraint	Facility Owner	Network Upgrade	Cost ($)
None	-	-	-

Table 9.1-3 – ERIS Network Upgrades in Short Circuit Analysis

Constraint	Facility Owner	Network Upgrade	Cost ($)
BASS CREEK	ATC	Grounding Upgrades	50,000
BRISTOL	ATC	Grounding Upgrades	50,000
CRAWFISH	ATC	Grounding Upgrades	50,000
DARLINGTON	ATC	Grounding Upgrades	50,000
DELAVAN	ATC	Grounding Upgrades	50,000
EDEN	ATC	Grounding Upgrades	50,000
FALCON	ATC	Grounding Upgrades	50,000
Hill Valley	ATC	Grounding Upgrades	50,000
HILLMAN	ATC	Grounding Upgrades	50,000
JEFFERSON	ATC	Grounding Upgrades	50,000
LONE ROCK	ATC	Grounding Upgrades	50,000
NELSON DEWEY	ATC	Grounding Upgrades	50,000
NORTH MONROE	ATC	Grounding Upgrades	50,000
PARIS	ATC	Substation and Grounding Upgrades	150,000
SPRING GREEN	ATC	Grounding Upgrades	50,000
STONE LAKE	ATC	Grounding Upgrades	50,000
STONEMAN	DPC	Grounding Upgrades	50,000
ARROWHEAD MP	MP	Grounding Upgrades	50,000

Table 9.1-4 – ERIS Affected System Network Upgrades

Constraint	Facility Owner	Network Upgrade	Cost ($)
ALBANY	ALTE	Grounding Upgrades	50,000
BLUE RIVER	ALTE	Grounding Upgrades	50,000
LANCASTER	ALTE	Grounding Upgrades	50,000
PINE RIVER (ALTE)	ALTE	Grounding Upgrades	50,000
POTOSI	ALTE	Grounding Upgrades	50,000
RED BIRD	ALTE	Grounding Upgrades	50,000
RICHLAND	ALTE	Grounding Upgrades	50,000
SOUTHWEST DELAVAN	ALTE	Grounding Upgrades	50,000
WEST DARIEN	ALTE	Grounding Upgrades	50,000
WYOMING VALLEY	ALTE	Grounding Upgrades	50,000
GRATIOT	DPC	Grounding Upgrades	50,000
MUSCODA	MUSCODA MUNI	Grounding Upgrades	50,000
MUSCODA IND PK	MUSCODA MUNI	Grounding Upgrades	50,000
BRADFORD	REC	Grounding Upgrades	50,000
LA PRAIRIE	REC	Grounding Upgrades	50,000
BREWER	RICHLAND CENTER	Grounding Upgrades	50,000
RICHLAND CENTER	RICHLAND CENTER	Grounding Upgrades	50,000
FORT_ATKINSON	WEC	Grounding Upgrades	50,000
LAKEHEAD CAMBRIDGE	WEC	Grounding Upgrades	50,000

Table 9.1-5 – ERIS PJM Affected System Network Upgrades

Constraint	Facility Owner	Network Upgrade	Cost ($)
GARDEN PR;R –SILVER LK;R 345 kV Ckt 1	ComEd	re-conductor the existing line and upgrade station conductor at both terminals	50,000,000
Cherry Valley;B-GARDEN PR;R 345 kV Ckt 1	ComEd	re-conductor the existing line and upgrade terminal equipment at both ends	50,000,000
Rock CK3 –Quad 1 3-11 345 Ckt 1	ITCM	6 wiring the line	6,600,000

Table 9.1-6 – ERIS Shared Network Upgrades

Constraint	Facility Owner	Network Upgrade	Cost ($)
None	-	-	-

9.2 NRIS Network Upgrades Proposed for Aug 17 DPP WI Phase 1 Projects

Network upgrades for Network Resource Interconnection Service (NRIS) were identified in the MISO's deliverability analysis and listed in the Table 9.2-1 below.

Table 9.2-1 – NRIS Network Upgrades Identified

Network Upgrade	Facility Owner	ISD (For Cost Estimate Only)	Cost Used for NRIS Cost Allocation ($)
Paris SS, new 345/138 kV transformer	ATC	09/10/2021	$29,773,189
Paris – Burlington 138 kV line, rebuild (MTEP18 Target A MTEP ID - 13732)	ATC	12/31/2021	A10, No Allocation
J798 - Mukwonago 138 kV, construct new line	ATC	09/01/2019	$41,544,935
Mukwonago – Merrill Hills 138 kV, uprate	ATC	09/01/2019	$207,627
University to J798 138 kV, rebuild	ATC	09/01/2019	$7,947,630
X81 Bristol - Elkhorn 138 kV, uprate	ATC	09/15/2020	$373,789
North Monroe – Verona 69 kV, uprate	ATC	09/15/2019	$30,189
North Monroe - J825 138 kV, reconductor	ATC	09/15/2019	$2,062,598
Bass Creek - Town Line Rd 138 kV, reconductor	ATC	09/15/2019	$0
Y109 Darlington – Rock Branch 69 kV, uprate	ATC	09/15/2019	$1,050,528
Eden – Spring Green 138 kV, uprate	ATC	09/15/2019	$91,341
North Appleton - Fox River 345 kV, uprate	ATC	06/03/2018	$167,337
Hillman SS, new transformer	ATC	09/15/2019	$2,970,632

[1] All Network Upgrades were estimated on the earliest ISD dollars of responsible generators.
[2] ATC Network Upgrades included a 20% contingency.

9.3 Cost Allocation Methodology for Thermal Network Upgrades

The costs of Network Upgrades (NU) for a set of generation projects (one or more subgroups or entire group with identified NU) are based off the MW impact of the worst-case scenario for each specific generator project. Basically, whatever the highest MW impact (increasing flow) is for that particular generator where the constraint is identified and requires NU is how it should be calculated.

Constraints which are mitigated by one or a subset of NU are identified. The highest MW contribution on these constraints from each generating facility is calculated in the MISO DPP study models 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:

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

9.4 Cost Estimating and Allocation Methodology for Short Circuit Upgrades

For each breaker shown to be loaded above 100% of rating a new breaker will be scoped and the cost of that upgrade will be assigned by to generators based on the MW impact provided from each generator for the worst case loading of the breaker.

For each substation that shows a bus having fault current (SLG or 3PG) increased by 10% or more costs are assigned for ground grid upgrades at that substation. Only one cost estimate is scoped per substation regardless of the number of buses at that substation that show a 10% or greater increase in fault current. The largest MW fault current value at a substation will determine the ground grid upgrade costs. If the highest fault current is above 20 kA, the upgrades are assigned a planning level estimate of $100,000 for equipment upgrades and $50,000 is assigned for ground grid upgrades. If the highest fault current is below 20 kA, the upgrades are assigned a planning level estimate of $50,000 for ground grid upgrades only. These are placeholder costs until further studies are performed during the facility studies. Based on those results, costs are adjusted. This methodology is applied to both ATC and non-ATC facilities. For non-ATC facilities, it is interconnection customer’s responsibility to work with facility owners to further refine costs, and implementation of the mitigation projects (if needed).

Once costs are determined, they are allocated to each generator based on the percentage MW contribution to an overload facility, requiring mitigation.

9.5 Cost Allocation Tables

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 issued date of the System Impact Study report.

Assuming all generating facilities in the DPP 2017August Wisconsin group advance, Table 9.5-1, Table 9.5-2, Table 9.5-3, Table 9.5-4 show how the costs for ERIS Network Upgrades, short-circuit Network Upgrades, PJM affected system Network Upgrades and NRIS Network Upgrades) allocated to responsible generating facilities.

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See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

Table 9.5-1 – ERIS Steady-State Thermal Network Upgrade Costs Allocated to Each Generation Project

Steady-State Injection Constraints	Required ERIS Network Upgrades	Cost Estimates ($)	Worst MW Impact							Total MW Impact	% of Network Upgrade Cost Allocaiton							ERIS Steady State Thermal Network Upgrade Cost ($) Allocated to Each Generation Project						
			J732	J798	J807	J819	J825	J870 /J871	J947		J732	J798	J807	J819	J825	J870 /J871	J947	J732	J798	J807	J819	J825	J870 /J871	J947
J825POI - Albany 138 kV line	J825POI – Bass Creek 138 kV, reconductor	8,172,147	-	-	17.98	44.79	65.83	12.36	40.71	181.67	-	-	9.9%	24.7%	36.2%	6.8%	22.4%	-	-	808,786	2,014,594	2,961,358	556,131	1,831,278
Albany – Bass Creek 138 kV line			-	-	17.98	44.79	65.83	12.36	40.71	181.67	-	-	9.9%	24.7%	36.2%	6.8%	22.4%	-	-	0	0	0	0	0
Townline Road – Bass Creek 138 kV line	Bass Creek – Townline Road 138 kV, reconductor	4,596,833	-	-	10.61	28.98	51.58	-	16.44	107.61	-	-	9.9%	26.9%	47.9%	-	15.3%	-	-	453,415	1,238,005	2,203,113	-	702,300
North Monroe – Monticello 69 kV line	North Monroe – Verona 69 kV, uprate	762,980	-	-	4.64	12.73	19.79	-	7.02	44.18	-	-	10.5%	28.8%	44.8%	-	15.9%	-	-	80,127	219,900	341,728	-	121,224
North Monroe 138/69 kV transformer	North Monroe SS, new transformer	5,933,016	-	-	7.27	19.97	38.84	-	11.03	77.11	-	-	9.4%	25.9%	50.4%	-	14.3%	-	-	559,733	1,536,288	2,988,256	-	848,739
Hillman 138/69 kV transformer	Hillman SS, upgrade transformer	2,866,337	-	-	-	-	-	-	51.24	51.24	-	-	-	-	-	-	100.0%	-	-	-	-	-	-	2,866,337
Eden – Wyoming Valley 138 kV line	Eden – Spring Green 138 kV, uprate	623,779	-	-	-	-	-	198.19	12.12	210.31	-	-	-	-	-	94.2%	5.8%	-	-	-	-	-	587,830	35,949
Spring Green – Wyoming Valley 138 kV line			-	-	-	-	-	198.19	12.12	210.31	-	-	-	-	-	94.2%	5.8%	-	-	-	-	-	0	0
J798TAP – Mukwonago 138 kV line	J798 POI – Mukwonago 138 kV, rebuild	22,289,710	-	123.87	-	-	-	-	-	123.87	-	100.0%	-	-	-	-	-	-	22,289,710	-	-	-	-	-
White water – University 138 kV line	Whitewater – University 138 kV, partial rebuild	1,976,323	-	123.87	-	-	-	-	-	123.87	-	100.0%	-	-	-	-	-	-	1,976,323	-	-	-	-	-
Stone Lake 345/161 kV transformer	Stone Lake SS, upgrade transformer	3,898,500	228.87	-	-	-	-	-	-	228.87	100.0%	-	-	-	-	-	-	3,898,500	-	-	-	-	-	-
Total ERIS Steady State Thermal Network Uprade Cost($) Allocated To Each Generator																		3,898,500	24,266,033	1,902,061	5,008,787	8,494,455	1,143,961	6,405,827

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See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

Table 9.5-2 – ERIS Short-Circuit Network Upgrade Costs Allocated to Each Generation Project

Substation	Facility Owner	Total Cost ($)	ERIS Short Circuit Network Upgrade Cost ($) Allocated to Each Generation Project														
			J732	J798	J807	J818	J819	J821	J825	J831	J850	J855	J864	J870/J871	J878	J886	J947
BASS CREEK	ATC	50,000	0	0	3,500	0	6,500	0	34,500	0	3,000	0	0	0	0	0	2,500
BRISTOL	ATC	50,000	0	0	0	0	0	0	0	0	29,500	0	0	0	0	0	20,500
CRAWFISH	ATC	50,000	0	0	0	50,000	0	0	0	0	0	0	0	0	0	0	0
DARLINGTON	ATC	50,000	0	0	2,500	0	6,500	0	2,000	0	0	0	0	36,500	0	0	2,500
DELAVAN	ATC	50,000	0	0	0	0	0	0	0	0	50,000	0	0	0	0	0	0
EDEN	ATC	50,000	0	0	500	0	500	0	0	0	0	4,500	1,000	42,000	0	0	1,500
FALCON	ATC	50,000	0	0	13,000	0	16,500	0	6,000	0	0	500	0	1,000	0	0	13,000
Hill Valley	ATC	50,000	0	0	1,000	0	2,500	0	1,000	0	0	10,000	2,000	29,000	0	0	4,500
HILLMAN	ATC	50,000	0	0	5,000	0	10,000	0	5,000	0	0	500	0	2,500	0	0	27,000
JEFFERSON	ATC	50,000	0	0	0	50,000	0	0	0	0	0	0	0	0	0	0	0
LONE ROCK	ATC	50,000	0	0	0	0	0	0	0	0	0	0	50,000	0	0	0	0
NELSON DEWEY	ATC	50,000	0	0	3,000	0	6,000	0	2,000	0	0	3,000	1,000	8,000	0	0	27,000
NORTH MONROE	ATC	50,000	0	0	3,500	0	10,000	0	33,000	0	500	0	0	0	0	0	3,000
PARIS	ATC	150,000	0	0	0	0	0	0	0	0	0	0	0	0	150,000	0	0
SPRING GREEN	ATC	50,000	0	0	500	0	500	0	0	0	0	1,500	40,500	6,500	0	0	500
STONE LAKE	ATC	50,000	50,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ALBANY	ALTE	50,000	0	0	4,500	0	13,000	0	23,500	0	1,500	500	0	1,000	0	0	6,000
BLUE RIVER	ALTE	50,000	0	0	0	0	0	0	0	0	0	0	48,500	1,000	0	0	500
LANCASTER	ALTE	50,000	0	0	2,000	0	3,500	0	1,000	0	0	8,000	1,000	23,000	0	0	11,500
PINE RIVER (ALTE)	ALTE	50,000	0	0	0	0	0	0	0	0	0	0	49,000	500	0	0	500
POTOSI	ALTE	50,000	0	0	2,000	0	3,500	0	1,000	0	0	0	0	500	0	0	43,000
RED BIRD	ALTE	50,000	0	0	7,500	0	21,000	0	9,500	0	0	500	0	2,500	0	0	9,000
RICHLAND	ALTE	50,000	0	0	0	0	0	0	0	0	0	0	49,500	500	0	0	0
SOUTHWEST DELAVAN	ALTE	50,000	0	0	0	0	0	0	0	0	50,000	0	0	0	0	0	0
WEST DARIEN	ALTE	50,000	0	0	0	0	0	0	0	0	50,000	0	0	0	0	0	0
WYOMING VALLEY	ALTE	50,000	0	0	1,000	0	1,000	0	500	0	0	9,000	6,500	30,000	0	0	2,000
GRATIOT	DPC	50,000	0	0	8,500	0	23,000	0	9,500	0	0	500	0	1,500	0	0	7,000
STONEMAN	DPC	50,000	0	0	3,000	0	6,500	0	2,000	0	0	2,500	1,500	7,000	0	0	27,500
ARROWHEAD MP	MP	50,000	50,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MUSCODA	MUSCODA MUNI	50,000	0	0	0	0	0	0	0	0	0	0	49,500	500	0	0	0
MUSCODA IND PK	MUSCODA MUNI	50,000	0	0	0	0	0	0	0	0	0	0	49,500	500	0	0	0
BRADFORD	REC	50,000	0	0	0	0	0	0	0	0	50,000	0	0	0	0	0	0
LA PRAIRIE	REC	50,000	0	0	0	0	0	0	500	0	49,500	0	0	0	0	0	0
BREWER	RICHLAND CENTER	50,000	0	0	0	0	0	0	0	0	0	0	49,000	500	0	0	500
RICHLAND CENTER	RICHLAND CENTER	50,000	0	0	0	0	0	0	0	0	0	0	49,000	500	0	0	500
FORT_ATKINSON	WEC	50,000	0	0	0	50,000	0	0	0	0	0	0	0	0	0	0	0
LAKEHEAD CAMBRIDGE	WEC	50,000	0	0	0	50,000	0	0	0	0	0	0	0	0	0	0	0
Total ERIS Short Circuit NU Cost ($) Allocated to Each Generator			100,000	0	61,000	200,000	130,500	0	131,000	0	284,000	41,000	447,500	195,000	150,000	0	210,000

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See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

Table 9.5-3 – PJM Affected System Costs Allocated to Each Generation Project

PJM Steady-State Injection Constraint	Required PJM Affected Systems Network Upgrades	Cost Estimate ($)	PJM Affected Systems Network Upgrade Cost ($) Allocated to Each Generation Project	
			J850	J870
GARDEN PR;R –SILVER LK;R 345 kV Ckt 1	re-conductor the existing line and upgrade station conductor at both terminals	50,000,000	3,747,100	0
Cherry Valley;B- GARDEN PR;R 345 kV Ckt 1	re-conductor the existing line and upgrade terminal equipment at both ends	50,000,000	6,307,700	0
Rock CK3 –Quad 1 3-11 345 Ckt 1	6 wiring the line	6,600,000	0	440,000
Total Affected Systems Network Upgrade Cost (S) Allocated to Each Generation Project			**10,054,800**	**440,000**

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Table 9.5-4 – NRIS Network Upgrade Costs Allocated to Each Generation Project (Part 1)

Required NRIS Network Upgrades	Responsible Generators	Cost Used for NRIS Network Upgrade Allocation ($)	MW Impact and % Cost Allocation Details Provided by MISO					
Paris SS, new 345/138 kV transformer	J798, J850, J878	$29,773,189	J798, 10.602 MW impact, 6.11%	J850, 25.75 MW impact, 14.83%	J878, 137.24 MW impact, 79.06%	173.592 total MW impact	-	-
Paris – Burlington 138 kV line, rebuild (MTEP18 Target A : MTEP ID - 13732)	No Allocation	No Allocation	-	-	-	-	-	-
J798 - Mukwonago 138 kV, construct new line	J798, J825, J850	$17,278,902	J798, 123.7644 MW impact, 81.52%	J825, 5.79 MW impact, 3.81%	J850, 22.27 MW impact, 14.67%	151.8244 total MW impact	-	-
Mukwonago – Merrill Hills 138 kV, uprate	J798, J825, J850	$207,627	J798, 123.7644 MW impact, 81.52%	J825, 5.79 MW impact, 3.81%	J850, 22.27 MW impact, 14.67%	151.8244 total MW impact	-	-
University to J798 138 kV, rebuild	J825, J850	$7,947,630	J825, 5.7942 MW impact, 20.64%	J850, 22.275 MW impact, 79.36%	28.0692 total MW impact	-	-	-
X81 Bristol - Elkhorn 138 kV, uprate	J825, J850	$373,789	J825, 6 MW impact, 6.44%	J850, 87.14 MW impact, 93.56%	93.14 total MW impact	-	-	-
North Monroe – Verona 69 kV, uprate	J807, J819, J825, J947	$30,189	J807, 4.64 MW impact, 10.5%	J819, 12.734 MW impact, 28.82%	J825, 19.789 MW impact, 44.79%	J947, 7.02 MW impact, 15.89%	44.183 total MW impact	-
North Monroe - J825 138 kV, reconductor	J798, J825, J850	$2,062,598	J798, 6.324 MW impact, 10.04%	J825, 42.49746 MW impact, 67.43%	J850, 14.2 MW impact, 22.53%	63.02146 total MW impact	-	-
Bass Creek - Town Line Rd 138 kV, reconductor	J850	$0	100% J850	-	-	-	-	-
Y109 Darlington – Rock Branch 69 kV, uprate	J807, J819, J825, J947	$1,050,528	J807, 9.99 MW impact, 13.83%	J819, 24.12 MW impact, 33.38%	J825, 12.3 MW impact, 17.02%	J947, 25.84 MW impact, 35.77%	72.25 total MW impact	-
Eden – Spring Green 138 kV, uprate	J807, J819, J855 J870/J871, J947	$91,341	J807, 3.40308 MW impact, 1.31%	J819, 8.32167 MW impact, 3.21%	J855, 37.73 MW impact, 14.56%	J870/871, 196.11 MW impact, 75.69%	J947, 13.54 MW impact, 5.23%	259.10475 total MW impact
North Appleton - Fox River 345 kV, uprate	J831	$167,337	100% J831	-	-	-	-	-
Hillman SS, new 138/69 kV transformer	J807, J819, J825, J947	$2,970,632	J807, 18.77 MW impact, 9.18%	J819, 38.75 MW impact, 18.95%	J825, 18.45 MW impact, 9.02%	J947, 128.5 MW impact, 62.85%	204.47 total MW impact	-

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See e.g. ATC Dagenais Direct p. 31, fn 26; MP Winter Direct Schedule 29, p.2

Table 9.5-5 – NRIS Network Upgrade Costs Allocated to Each Generation Project (Part 2)

Required NRIS Network Upgrades	Responsible Generators	Cost Used for NRIS Network Upgrade Allocation ($)	J798	J807	J819	J825	J831	J850	J855	J870/J871	J878	J947
Paris SS, new 345/138 kV transformer	J798, J850, J878	$29,773,189	$1,819,142	-	-	-	-	$4,415,364	-	-	$23,538,683	-
Paris – Burlington 138 kV line, rebuild (MTEP18 Target A : MTEP ID - 13732)	No Allocation	No Allocation	-	-	-	-	-	-	-	-	-	-
J798 - Mukwonago 138 kV, construct new line	J798, J825, J850	$17,278,902	$14,085,761	-	-	$658,326	-	$2,534,815	-	-	-	-
Mukwonago – Merrill Hills 138 kV, uprate	J798, J825, J850	$207,627	$169,258	-	-	$7,911	-	$30,459	-	-	-	-
University to J798 138 kV, rebuild	J825, J850	$7,947,630	-	-	-	$1,640,391	-	$6,307,239	-	-	-	-
X81 Bristol - Elkhorn 138 kV, uprate	J825, J850	$373,789	-	-	-	$24,072	-	$349,717	-	-	-	-
North Monroe – Verona 69 kV, uprate	J807, J819, J825, J947	$30,189	-	$3,170	$8,700	$13,522	-	-	-	-	-	$4,797
North Monroe - J825 138 kV, reconductor	J798, J825, J850	$2,062,598	$207,085	-	-	$1,390,810	-	$464,703	-	-	-	-
Bass Creek - Town Line Rd 138 kV, reconductor	J850	$0	-	-	-	-	-	$0	-	-	-	-
Y109 Darlington – Rock Branch 69 kV, uprate	J807, J819, J825, J947	$1,050,528	-	$145,288	$350,666	$178,800	-	-	-	-	-	$375,774
Eden – Spring Green 138 kV, uprate	J807, J819, J855 J870/J871, J947	$91,341	-	$1,197	$2,932	-	-	-	$13,299	$69,136	-	$4,777
North Appleton - Fox River 345 kV, uprate	J831	$167,337	-	-	-	-	$167,337	-	-	-	-	-
Hillman SS, new 138/69 kV transformer	J807, J819, J825, J947	$2,970,632	-	$272,704	$562,935	$267,951	-	-	-	-	-	$1,867,042
Total NRIS Network Uprade Cost($) Allocated To Each Generator			$16,281,245	$422,358	$925,234	$4,181,782	$167,337	$14,102,297	$13,299	$69,136	$23,538,683	$2,252,390

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10.0 AVAILABLE APPENDIX DOCUMENTS (NOT ATTACHED)

Appendix A – Study Criteria, Methodology, and Assumptions

Appendix B – ATC Planning Criteria and Generation Facility Interconnection Guide

Appendix C – Interconnection Facility Project Diagrams and Modeling Details

Appendix D – Network Upgrade Project Diagrams

Appendix E – Steady State Power Flow Results

Appendix F – Operating Restriction Study Results

Appendix G – Dynamic Stability Results

Appendix H – Affected System Study Results

Appendix I – MISO Deliverability Study Results

Appendix J – Assessed System Performance Reference

Appendix K – J732 Additional Studies

Appendix L – PSCAD Study Report