AFFECTED SYSTEM ANALYSIS OF SPP DISIS-2018-001 PHASE 2

MINNKOTA POWER COOPERATIVE, INC.

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Document Revisions

Date	Revision	Description
3/14/2023	0	Initial Draft
3/16/2023	1	Final Report
1/16/2024	2	Final Report – Cost Allocation Corrections included.

1. Executive Summary

The purpose of this Affected System Analysis (ASA) is to determine the impacts of generators in the SPP DISIS-2018-001 Phase 2 study cycle on Minnkota Power Cooperative (MPC) facilities and any Network Updates (NUs) required to mitigate those impacts.

Steady-state power flow and contingency analyses and a dynamic stability analysis were performed for the DISIS generating facilities shown in Table 1.

Table 1: ASA DISIS-2018-001 Projects

Project	POI	Summer MW	Fuel Type	Service Type
GEN-2018-007	Summit 115 kV Substation	150	Solar	NRIS
GEN-2018-008	Tap Groton-Leland Olds 345 kV Line	252	Wind	NRIS
GEN-2018-010	Neset 230 kV Substation	74.1	Battery	NRIS
GEN-2018-039	Edgeley 115 kV Substation	72	Solar	NRIS

1.1. Network Upgrades Identified in ASA

The NUs required to mitigate constraints identified in the MPC ASA and allocated to the ASA projects are listed in Table 2. Costs are planning level estimates and subject to revision in the facility studies.

Table 2: Minnkota Network Upgrades Allocated to DISIS-2018-001 Projects

Constraint	Owner	TSP	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Wilton-Winger 230 kV	MPC	OTP	412.9	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
J897POI-Prairie 230 kV	MPC / GRE	GRE / OTP	484.2	Terminal Upgrade (478 MVA limit)	$500,000	GEN-2018-008
Jamestown-Center 345 kV	MPC / OTP	OTP	777.6	Structure Raises, Maximum conductor rating is 1595.4 MVA	$1,000,000	GEN-2018-008, GEN-2018-010
Prairie-Walle 230 kV	MPC	OTP	433.8	Structure Raises, Maximum conductor rating is 444 MVA	$500,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
Prairie-Lake Ardoch 230 kV	MPC	OTP	429.2	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
MPC03637POI-Wahpeton 230 kV	MPC / OTP	OTP	387.2	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-039

Constraint	Owner	TSP	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Winger-Walle 230 kV	MPC	OTP	410.8	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
Drayton-Lake Ardoch 230 kV	MPC	OTP	410.3	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
State-State Non-Convergence	OTP	OTP	N/A	Audubon 230 kV MSC: 1x50 MVAR	$1,000,000	GEN-2018-007, GEN-2018-008, GEN-2018-010, GEN-2018-039
Steady-State Voltage	XEL	XEL	N/A	Bison 345 kV MSC: Additional 1x75 MVAR	$1,500,000	GEN-2018-007, GEN-2018-008, GEN-2018-010, GEN-2018-039
Steady-State Voltage	OTP	OTP	N/A	Audubon 230 kV MSC: 2x50 MVAR	$2,000,000	GEN-2018-007, GEN-2018-008, GEN-2018-010, GEN-2018-039
Steady-State Voltage	MPC	MPC	N/A	Edinburg 115 kV MSC: 2x10 MVAR	$1,000,000	GEN-2018-008

Table 3 shows Minnkota network upgrades allocated to higher queued projects that are required to mitigate identified thermal constraints. If the upgrades are not built by the higher queued projects, they may be required to be built by the DISIS-2018-001 projects.

Table 3: Minnkota Network Upgrades Allocated to Higher Queued Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Falconer-Oslo 115 kV	MPC	224.9	Prior queued project expected to mitigate	GEN-2018-008, GEN-2018-039
Prairie 345/230 kV Autotransformer	MPC	504.3	Prior queued project expected to mitigate	GEN-2018-008
Grand Forks-Falconer 115 kV	MPC / WAPA	296.2	Prior queued project expected to mitigate	GEN-2018-008, GEN-2018-039
MPC03637POI-Fronter 230 kV	MPC	376.5	Prior queued project expected to mitigate	GEN-2018-007

Table 4 shows the Minnkota network upgrades that are alleviated by existing MPC equipment that do not require mitigation.

Table 4: Minnkota Network Upgrades Mitigated by Existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Drayton-Letellier 230 kV	MPC / MH	552.6	Below minimum MPC equipment rating (876.4 MVA)	GEN-2018-007, GEN-2018-008, GEN-2018-010, GEN-2018-039

1.2. DISIS-2018-001 Project Summary

The allocation of Minnkota NUs to the ASA projects is summarized in the following tables.

1.2.1. GEN-2018-007

Network Upgrade	Total Cost ($)	GEN-2018-007 Allocation
Audubon 230 kV MSC: 1x50 MVAR	$1,000,000	$201,774
Bison 345 kV MSC: Additional 1x75 MVAR	$1,500,000	$302,661
Audubon 230 kV MSC: 2x50 MVAR	$2,000,000	$403,548
Total Cost		**$907,982**

1.2.2. GEN -2018-008

Network Upgrade	Total Cost ($)	GEN-2018-008 Allocation
Wilton-Winger 230 kV	$1,000,000	$674,325
J897POI-Prairie 230 kV	$500,000	$500,000
Jamestown-Center 345 kV	$1,000,000	$862,994
Prairie-Walle 230 kV	$500,000	$361,620
Prairie-Lake Ardoch 230 kV	$1,000,000	$688,309
Winger-Walle 230 kV	$1,000,000	$719,964
Drayton-Lake Ardoch 230 kV	$1,000,000	$682,715
Audubon 230 kV MSC: 1x50 MVAR	$1,000,000	$419,069
Bison 345 kV MSC: Additional 1x75 MVAR	$1,500,000	$628,603
Audubon 230 kV MSC: 2x50 MVAR	$2,000,000	$838,137
Edinburg 115 kV MSC: 2x10 MVAR	$1,000,000	$1,000,000
Total Cost		**$7,375,737**

1.2.3. GEN -2018-010

Network Upgrade	Total Cost ($)	GEN-2018-010 Allocation
Wilton-Winger 230 kV	$1,000,000	$133,087
Jamestown-Center 345 kV	$1,000,000	$137,006
Prairie-Walle 230 kV	$500,000	$60,560
Prairie-Lake Ardoch 230 kV	$1,000,000	$130,179
Winger-Walle 230 kV	$1,000,000	$121,282
Drayton-Lake Ardoch 230 kV	$1,000,000	$131,083
Audubon 230 kV MSC: 1x50 MVAR	$1,000,000	$166,297
Bison 345 kV MSC: Additional 1x75 MVAR	$1,500,000	$249,446
Audubon 230 kV MSC: 2x50 MVAR	$2,000,000	$332,594
Total Cost		**$1,461,535**

1.2.4. GEN -2018-039

Network Upgrade	Total Cost ($)	DISIS-2018-039 Allocation
Wilton-Winger 230 kV	$1,000,000	$192,587
Prairie-Walle 230 kV	$500,000	$77,819
Prairie-Lake Ardoch 230 kV	$1,000,000	$181,512
MPC03637POI-Wahpeton 230 kV	$1,000,000	$1,000,000
Winger-Walle 230 kV	$1,000,000	$158,754
Drayton-Lake Ardoch 230 kV	$1,000,000	$186,202
Audubon 230 kV MSC: 1x50 MVAR	$1,000,000	$212,860
Bison 345 kV MSC: Additional 1x75 MVAR	$1,500,000	$319,290
Audubon 230 kV MSC: 2x50 MVAR	$2,000,000	$425,721
Total Cost		**$2,754,746**

1.3. Steady State Power Flow Analysis

Power flow and contingency analyses were performed to identify and mitigate any thermal or voltage issues on the Minnkota system caused by the DISIS-2018-001 projects. Analyses were performed for summer peak and summer shoulder conditions.

MPC non-converged voltage violations are summarized in Table 13. Thermal constraints are summarized in Table 14, and voltage constraints are summarized in Table 15.

1.4. Transient Stability Analysis

Transient stability analysis was performed to identify and mitigate any transient stability issues on the MPC system caused by the addition of the DISIS-2018-001 projects. Transient stability analysis was performed for summer shoulder conditions.

Redacted

These violations are shown across both the benchmark and study cases with little to no difference between the two cases. The identified violations were considered pre-existing and not due to the addition of the DISIS-2018-001 Phase 2 projects. Details on the MPC facilities which show violations are found in Appendix C.

The identified violations will be monitored and further evaluated in the Phase 3 study for further impact.

1.5. Conclusion

Thermal, voltage, and transient stability constraints were identified on the MPC system for the DISIS-2018-001 ASA projects. The stability constraints were determined to be pre-existing and not attributable to the DISIS-2018-001 projects. The required Nus to address the identified thermal and voltage issues are listed in Table 2, Table 3, and Table 4 above. Upgrade costs assigned to the DISIS-2018-001 projects total to $12,500,000 in planning level estimates.

2. Steady State Power Flow Analysis

Power flow and contingency analyses were performed to identify and mitigate any thermal or voltage issues on the MPC system caused by the DISIS-2018-001 projects under study.

2.1. Study Methodology

Study cases representing summer peak and summer shoulder system conditions were created with the DISIS-2018-001 Phase 2 projects dispatched at rated output. System performance was benchmarked using cases without the DISIS projects.

Power flow and nonlinear (AC) contingency analyses were performed on the benchmark and study cases, and the incremental impacts of the DISIS projects were evaluated by comparing the steady-state performance of the MPC system.

Steady-state analyses were performed using TARA v2301.1 and cases were created using PSS®E version 34.

2.2. Case Development

Power flow cases representing summer peak and summer shoulder system conditions were created from the MPC04200 Phase 1 ERIS summer peak study case (MPC04200-PH1-SUM-BASE) and ERIS summer shoulder study case (MPC04200-PH1-SH90-BASE).

ASA summer peak and summer shoulder study cases were created from the MPC study cases by applying the model updates listed in Table 5, removing withdrawn units near North Dakota, and dispatching MPC generators as shown in Table 6. Minnkota Generator Interconnection Projects (GIPs) were dispatched as shown in Table 7. The dispatch of North Dakota and South Dakota generators in the ASA study cases can be found in Appendix A.

Table 5: ASA Model Updates

Update	SUM	SH
Removed 2x75 MVAR at ALEXMRES 345 kV	X	X
Removed 2x40 MVAR at Audubon 230 kV	X	X
Removed 1x75 MVAR at Bison 345 kV	X	X
Removed 1x10 MVAR at EDINTP 7 115 kV	X	X
Removed 3x50 MVAR at GRE-INMAN4 230 kV	X	X
Removed 1x10 MVAR at RICELKT7 115 kV	X	X
Removed 1x30 MVAR at Winger 230 kV	X	X
Added STATCOM: ±50 MVAR at Winger 230 kV	X	X
Removed Nearby Withdrawn Units	X	X
Added SPP DISIS-2018-001 Study Units	X	X

Table 6: Minnkota Generator Dispatch

Generator	Bus	Pgen	Pmax
Young 1	657749	274	274
Young 2	657748	493	493
Oliver County	657745	99.3	99.3
Langdon	620412	40.5	40.5
Langdon	620413	19.5	19.5
Langdon	657600	99	99
Langdon	657601	40.5	40.5
Ashtabula	615124	51	51
Ashtabula	657737	62.4	62.4
Ashtabula	657964	118.5	118.5
Ashtabula	657985	196.5	196.5

Table 7: Minnkota GIP Dispatch

Project	SUM	SH
MPC03600	170	170
MPC03700	130	130
MPC03800	234	234
MPC03900	142	142
MPC04000	300	300

The list of withdrawn generators that were taken out of service is shown in Table 8 for the summer and Table 9 for the summer shoulder case. Power was balanced by scaling MISO generation outside of North Dakota for the withdrawn units.

Table 8: List of Withdrawn Units Removed from the Summer Peak Case

DPP Cluster	DPP Region	State	Generation Name	SUM Case Pgen (MW)	GEN Area	ERIS SP PMAX	NRIS SP PMAX	Service	Type
DPP-2019-Cycle	West	IA	J1321	43.9	MEC	65	65	ER/NR	Battery
DPP-2019-Cycle	West	SD	J1328	67.5	OTP	100	100	ER/NR	Solar
DPP-2019-Cycle	West	MN	J1349	40.5	XEL	60	60	ER/NR	Hybrid
DPP-2019-Cycle	West	MN	J1349	14.8	XEL	135	135	ER/NR	Hybrid
DPP-2019-Cycle	West	MN	J1349	14.9	XEL	140	140	ER/NR	Hybrid
DPP-2019-Cycle	West	MN	J1371	16.4	OTP	150	150	ER/NR	Wind
DPP-2019-Cycle	West	IA	J1416	100.6	ALTW	149	149	ER/NR	Solar
DPP-2019-Cycle	West	IA	J1417	50.6	ALTW	75	75	ER/NR	Battery
DPP-2019-Cycle	West	MN	J1446	101.2	XEL	150	150	ER/NR	Battery
DPP-2019-Cycle	West	MN	J1468	67.5	XEL	100	100	ER/NR	Battery
DPP-2019-Cycle	West	IA	J1471	135.0	ALTW	200	200	ER/NR	Solar
DPP-2019-Cycle	West	IA	J1478	16.9	ALTW	25	25	ER/NR	Battery
DPP-2019-Cycle	West	IA	J1479	67.5	ALTW	100	100	ER/NR	Battery
DPP-2019-Cycle	West	MN	J1487	13.0	ALTW	120	120	ER/NR	Wind

DPP Cluster	DPP Region	State	Generation Name	SUM Case Pgen (MW)	GEN Area	ERIS SP PMAX	NRIS SP PMAX	Service	Type
DPP-2019-Cycle	West	MN	J1315	10.5	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	10.5	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	10.5	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	10.5	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	10.5	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	10.5	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1395	68.2	XEL	100	100	ER/NR	Solar
DPP-2019-Cycle	West	MN	J1395	68.2	XEL	100	100	ER/NR	Solar
DPP-2019-Cycle	West	IA	J1413	101.2	ALTW	118	94	ER/NR	Solar
DPP-2019-Cycle	West	IA	J1413	101.2	ALTW	117	94	ER/NR	Solar
DPP-2019-Cycle	West	IA	J1438	67.5	ALTW	100	100	ER/NR	Solar
DPP-2019-Cycle	West	ND	J1456	100.0	OTP	100	100	ER/NR	Wind
DPP-2019-Cycle	West	ND	J1456	100.0	OTP	100	100	ER/NR	Wind
DPP-2019-Cycle	West	ND	J1456	100.0	OTP	100	100	ER/NR	Wind
DPP-2020-Cycle	West	MN	J1498	52.8	XEL	50	50	ER/NR	Battery
DPP-2020-Cycle	West	WI	J1582	32.5	XEL	160	160	ER/NR	Solar
DPP-2020-Cycle	West	ND	J1622	102.0	OTP	100	100	ER/NR	Solar
DPP-2020-Cycle	West	ND	J1754	208.0	GRE	200	200	ER/NR	Wind
DPP-2020-Cycle	West	WI	J1804	40.8	XEL	0	0	ER/NR	Battery
DPP-2020-Cycle	West	MN	J1494	52.8	XEL	50	50	ER/NR	Battery
DPP-2020-Cycle	West	MN	J1495	52.8	XEL	50	50	ER/NR	Battery

Table 9: List of Withdrawn Units Removed from the Summer Shoulder Case

DPP Cluster	DPP Region	State	Generation Name	SH Case Pgen (MW)	GEN Area	ERIS G PMAX	NRIS G PMAX	Service	Type
DPP-2019-Cycle	West	IA	J1321	64.7	MEC	65	65	ER/NR	Battery
DPP-2019-Cycle	West	MN	J1349	134.8	XEL	135	135	ER/NR	Hybrid
DPP-2019-Cycle	West	MN	J1349	140.4	XEL	140	140	ER/NR	Hybrid
DPP-2019-Cycle	West	MN	J1371	154.7	OTP	150	150	ER/NR	Wind
DPP-2019-Cycle	West	IA	J1417	74.7	ALTW	75	75	ER/NR	Battery
DPP-2019-Cycle	West	MN	J1468	99.6	XEL	100	100	ER/NR	Battery
DPP-2019-Cycle	West	IA	J1478	24.9	ALTW	25	25	ER/NR	Battery
DPP-2019-Cycle	West	IA	J1479	99.6	ALTW	100	100	ER/NR	Battery
DPP-2019-Cycle	West	MN	J1487	123.2	ALTW	120	120	ER/NR	Wind
DPP-2019-Cycle	West	MN	J1315	99.6	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	99.6	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	99.6	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	99.6	XEL	100	0	ER	Wind

DPP Cluster	DPP Region	State	Generation Name	SH Case Pgen (MW)	GEN Area	ERIS G PMAX	NRIS G PMAX	Service	Type
DPP-2019-Cycle	West	MN	J1315	99.6	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	MN	J1315	99.6	XEL	100	0	ER	Wind
DPP-2019-Cycle	West	ND	J1456	100.0	OTP	100	100	ER/NR	Wind
DPP-2019-Cycle	West	ND	J1456	100.0	OTP	100	100	ER/NR	Wind
DPP-2019-Cycle	West	ND	J1456	100.0	OTP	100	100	ER/NR	Wind
DPP-2020-Cycle	West	MN	J1498	-52.8	XEL	50	50	ER/NR	Battery
DPP-2020-Cycle	West	ND	J1622	102.0	OTP	100	100	ER/NR	Solar
DPP-2020-Cycle	West	ND	J1754	208.0	GRE	200	200	ER/NR	Wind
DPP-2020-Cycle	West	WI	J1804	-40.8	XEL	0	0	ER/NR	Battery
DPP-2020-Cycle	West	MN	J1494	-52.8	XEL	50	50	ER/NR	Battery
DPP-2020-Cycle	West	MN	J1495	-52.8	XEL	50	50	ER/NR	Battery

The study cases were created from the ASA benchmark cases by adding and dispatching the DISIS study projects. DISIS generators were dispatched at the rated output as shown in Table 10. Power was balanced by scaling SPP generation for the DISIS generators. The ASA benchmark and study cases included reactive power network upgrades associated with prior queued MISO and MPC GIPs.

Table 10: ASA Study Project Dispatch

Project	Summer (MW)	Summer Shoulder (MW)	Fuel Type	Service Type
GEN-2018-007	150	150	Solar	NRIS
GEN-2018-008	252	252	Wind	NRIS
GEN-2018-010	74.1	74.1	Battery	NRIS
GEN-2018-039	72	72	Solar	NRIS

The power flow cases were solved with transformer tap adjustments enabled, area interchange adjustments disabled, phase shifter adjustments enabled, and switched shunt adjustments enabled.

2.3. Contingencies

The study area was defined as transmission facilities rated 69 kV and above in the BEPC (areas 663 and 659), GRE (area 615), MDU (area 661), MH (area 667), MP (area 608), OTP (area 620), WAPA (area 652) and XEL (area 600) areas. The contingency set included contingencies in the study area from the MPC4200 Phase 1 study; contingency files are shown below in Table 11.

Table 11: List of Contingency Files for Steady State Analysis

Contingency File Name	Summer	Shoulder
MISO20_2025_SUM__TA_P2_P4_P5_P6_P7_LoadLoss.con	X	X
MISO20_2025_SUM__TA_P1_MINN-DAKS.con	X	X
MISO20_2025_SUM__TA_P1_P2_P4_P5_NoLoadLoss.con	X	X
MPC20ASA_Ph2_HVDC_SPK.con	X	

Contingency File Name	Summer	Shoulder
MPC20ASA_Ph2_HVDC_SH.con		X
Monopole_Bipole_Update_20220125.con	X	X
MPC20ASA_Ph2_P1.con	X	X
MPC20ASA_Ph2_Outlet_Contingency.con	X	X

Post-contingent cases were solved with transformer tap adjustments enabled, area interchange adjustments disabled, phase shifter adjustments disabled, and switched shunt adjustments enabled.

2.4. Monitored Elements

Facilities in the study area were monitored for system intact and post-contingency conditions. Under NERC category P0 conditions (system intact), branches were monitored for loading above the normal (PSS®E Rate A) rating; under NERC category P1-P7 (post-contingent) conditions, branches were monitored for loading above the emergency (PSS®E Rate B) rating. Bus voltages were monitored using the limits shown in Table 12.

Facility loadings were calculated based on MVA at the actual voltage by setting both transformer and non-transformer units to "Current expressed as MVA" in PSS®E.

Table 12: List Monitored Elements

Area	Monitored Elements	Voltage Limits (High/Low)[1]	
		System intact	Post-Contingency
BEPC (659	69 kV and above	1.05/0.95	1.1/0.90
GRE (615)	Load buses 69 kV and above	1.05/0.95	1.1/0.92
	No load buses 69 kV and above	1.05/0.95	1.1/0.90
MDU (661)	100 kV and above	1.05/0.95	1.1/0.90
MH (667)	100 kV and 119 kV	1.1/0.99	1.15/0.94
	120 kV and 129 kV	1.1/0.95	1.1/0.90
	130 kV and 199 kV	1.05/0.96	1.1/0.90
	200 kV and 228 kV	1.12/0.97	1.15/0.94
	229 kV and 499 kV	1.05/0.97	1.1/0.90
	500 kV and 800 kV	1.07/1.04	1.1/0.90
MPC (owner 657)	69 kV and above	1.07/0.97	1.1/0.92
MP (owner 608)	69 kV and above	1.05/1.00	1.1/0.95
MRES (owner 608)	69 kV and above	1.05/1.00	1.1/0.95
OTP (owner 620)	69 kV and above	1.07/0.97	1.1/0.92
	200 kV and 800 kV	1.05/0.97	1.1/0.92
WAPA (652)	100 kV and above	1.05/0.95	1.1/0.92
XEL (owner 600)	69 kV and above	1.05/0.95	1.05/0.92

Notes:

1. Default voltage limits are shown in the table; some buses were monitored using specific limits provided in Transmission Owner Planning Criteria.

2.5. Performance Criteria

MPC Significantly Affected Facilities (SAF), ERIS constraints, and NRIS constraints were identified in accordance with the MPC Transmission Planning BPM and MPC Planning Criteria.

2.5.1. Significantly Affected Facilities

SAF are identified as any transmission facility, 69 kV and above, for which all the following conditions exist:

- In the post-project case, the facility exceeds its applicable thermal or voltage rating.
- The increase in the loading of the facility from the pre-project to the post-project case is greater than 1 MVA.
- The project has greater than 3% TDF or 0.01 p.u. change in voltage.

2.5.2. ERIS Maximum Impact Criteria

ERIS constraints are SAF that meet the following criteria.

- Thermal
  - The study project has a larger than twenty percent (20%) distribution factor on the overloaded facilities under post-contingent conditions or five percent (5%) distribution factor under system intact conditions, or
  - The overloaded facility or the overload-causing contingency is at the study project's POI, or
  - The impact due to the new facility is greater than or equal to twenty percent (20%) of the applicable facility rating of the overloaded facility.
  - The cumulative impact of the group of study generators is greater than twenty percent (20%) of the rating of the facility and the impact of the study generator is greater than five percent (5%) of the rating of the facility.
- Voltage
  - The voltage change due to the study project is greater than 0.01 per unit of the nominal system voltage.
  - The cumulative impact of the group of study generators is greater than 0.01 per unit of the nominal system voltage and the impact of the study generator is greater than 0.003 per unit.

2.5.3. NRIS Maximum Impact Criteria

When performing affected system analysis to determine the impacts of neighboring providers' queued generation interconnection requests on the Minnkota system, standard transmission service impact criteria are applied for NRIS requests. NRIS thermal constraints are SAF that meet the following criteria.

- The study project has a larger than three percent (3%) distribution factor on the overloaded facilities under post-contingent conditions or five percent (5%) distribution factor under system intact conditions.

2.6. Thermal Constraints

MPC thermal constraints for the summer peak and summer shoulder cases are summarized in Table 14. Each facility in the table is a constraint for the GIPs listed in the "ERIS Constraint" and "NRIS Constraint" columns. Note that all projects under study only flagged on the NRIS criteria.

There are no MPC thermal constraints for NERC P0 (system intact) conditions in the summer peak or summer shoulder cases. Thermal constraint details for NERC P1, P2, P4, P5, and P7 (post-contingent) conditions are provided in Appendix B.

2.7. Voltage Significantly Affected Facilities

The Minnkota non-converged voltage constraint identified for the summer shoulder study case is summarized in Table 13.

Table 13: Minnkota Non-Converged Voltage Constraints

Contingency	Type	Bench Status	Study Status
Redacted			

After mitigating the identified non-converged voltage constraint, additional voltage constraints were identified for the summer shoulder case as summarized in Table 15.

There are no MPC voltage constraints in the summer peak case.

Minnkota voltage constraints for system intact and post-contingent conditions in the summer shoulder case are provided in Appendix B.

2.8. Mitigation of Steady State Constraints

Network Upgrades required to mitigate MPC ERIS and NRIS thermal constraints are shown in Table 16.

Network Upgrades required to mitigate MPC steady-state voltage constraints are shown in Table 17.

Table 14: Minnkota Summer Peak and Summer Shoulder Thermal Constraints

Facility	Owner	Rating MVA	Pre-Project Loading		Post-Project Loading		Contingency	Type	ERIS Constraint	NRIS Constraint
			MVA	%	MVA	%				
										Redacted

Table 15: Minnkota Voltage Constraints

Facility	Owner	Vlow	Vhigh	Bench Vcont	Study Vcont	Impact	Contingency	Type
Redacted								

Facility	Owner	Vlow	Vhigh	Bench Vcont	Study Vcont	Impact	Contingency	Type
Redacted								

Table 16: Minnkota Summer Peak and Summer Shoulder Thermal Constraint Mitigation

Facility	Owner	Rating MVA	Post-Project Loading		Mitigation	Cost	ERIS Constraint	NRIS Constraint
			MVA	%				
								Redacted

Table 17: Minnkota Voltage Constraint Mitigation

Constraint	Mitigation	Cost	Generators
Redacted			

3. Transient Stability Analysis

Transient stability analysis was performed to identify and mitigate any transient stability issues on the MPC system caused by the DISIS-2018-001 projects under study.

3.1. Study Methodology

Transient stability analysis was performed using the ASA summer shoulder benchmark case and study case and making modifications similar to those described in Section 2.2. Regional and local disturbances were simulated using TSAT version 21.0.0 and results were screened to identify any violations of MPC transmission reliability criteria.

3.2. Dynamic Data

The transient stability analysis was performed using the MCP042000 summer shoulder stability package. The stability package was updated by applying the model updates listed in Appendix A, removing withdrawn units near North Dakota in Table 9. The study projects were represented with the following dynamic models:

- **GEN 2018-007**: WECC Generic Models consistent with DISIS 1801 P2 representation (REGCAU1 inverter)
- **GEN 2018-008**: GE Wind Turbine Models consistent with DISIS 1801 P2 representation (GEWTG0705 inverter)
- **GEN 2018-010**: PE Models updated from DISIS 1801 P2 representation (PEGEN_HM1007 inverter) to WECC Generic Models due to TSAT incompatible PE models available at study
- **GEN 2018-039**: WECC Generic Models consistent with DISIS 1801 P2 representation (REGCAU1 inverter)

3.3. Contingency Criteria

The stability simulations performed as part of this study considered the MPC regional and local contingencies listed in Table 18. Redacted

Table 18: Disturbance Descriptions

Disturbance Name	Description	NERC Cat.	Area
Flat Run	Redacted	P0	N/A
0690_w_gre_p23	Redacted	P2-3	GRE
0800_w_mp_p12	Redacted	P1-2	GRE
0819_w_otp_p11	Redacted	P1-1	OTP
0822_w_otp_p12	Redacted	P1-2	OTP
0823_w_otp_p12	Redacted	P1-2	OTP
0824_w_otp_p12	Redacted	P1-2	OTP
0826_w_otp_p42	Redacted	P4-2	OTP
0830_w_otp_p42	Redacted	P4-2	OTP

Disturbance Name	Description	NERC Cat.	Area
0831_w_otp_p42	Redacted	P4-2	OTP
0832_w_otp_p42	Redacted	P4-2	GRE
1677_w_otp_p12	Redacted	P1-2	GRE
1681_w_otp_p42	Redacted	P4-2	OTP
1682_w_xel_p12	Redacted	P1-2	XEL
P15_GRE_CCK_MONOPOLE_U1TRIP	Redacted	P1-5	GRE
P7_GRE_CCK_BIPOLE_U1U2TRIP	Redacted	P7	GRE
1684_W_XEL_P12	Redacted	P1-2	XEL
BISON-ALEX__BISON_BUFFALO	Redacted	P4	XEL
BISON-BUFFALO__BISON-MAPLE	Redacted	P4	XEL
BISON-MAPLE__BISON-J1588	Redacted	P4	XEL
BISON-J1588__BISON_ALEX	Redacted	P4	XEL
P23:345:XEL:LYONCO3:8N64	Redacted	P2-3	XEL
P1_G18-007_SUMMIT7-WATERTN7_115	Redacted	P1-2	G18-007
P1_G18-007_SUMMIT7-ROVERTSCTY7_115	Redacted	P1-2	G18-007
P1_G18-007_SUMMIT7-BRISTOLER7_115	Redacted	P1-2	G18-007
P1_G18-007_SUMMIT7-SUMMIT9_115/69KV	Redacted	P1-2	G18-007
P1_G18-007_SUMMIT7-SUMMIT8_115/69KV	Redacted	P1-2	G18-007
P4_116325	Redacted	P4	G18-007
P4_116327	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-WATERTN7_115_G18-007_SUMMIT7-ROVERTSCTY7_115	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-WATERTN7_115_G18-007_SUMMIT7-BRISTOLER7_115	Redacted	P4	G18-007

Disturbance Name	Description	NERC Cat.	Area
P4_G18-007_SUMMIT7-WATERTN7_115_G18-007_SUMMIT7-SUMMIT9_115/69KV	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-WATERTN7_115_G18-007_SUMMIT7-SUMMIT8_115/69KV	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-ROVERTSCTY7_115_G18-007_SUMMIT7-BRISTOLER7_115	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-ROVERTSCTY7_115_G18-007_SUMMIT7-SUMMIT9_115/69KV	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-ROVERTSCTY7_115_G18-007_SUMMIT7-SUMMIT8_115/69KV	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-BRISTOLER7_115_G18-007_SUMMIT7-SUMMIT9_115/69KV	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-BRISTOLER7_115_G18-007_SUMMIT7-SUMMIT8_115/69KV	Redacted	P4	G18-007
P4_G18-007_SUMMIT7-SUMMIT9_115/69KV_G18-007_SUMMIT7-SUMMIT8_115/69KV	Redacted	P4	G18-007
P1_G18-008_G18-008-TAP-GR.LS-LO-BE3345	Redacted	P1-2	G18-008
P1_G18-008_G18-008-TAP-LO.LS-GR-BE3345	Redacted	P1-2	G18-008
P1_G18-008_GROTON__-BE3-CROCKER_-BE3345	Redacted	P1-2	G18-008
P1_G18-008_GROTON__345KV_AUTO	Redacted	P1-2	G18-008
P1_G18-008_LELAND_O_AUTO1	Redacted	P1-2	G18-008
P1_G18-008_LELAND_O-ANTELOPE_1_345	Redacted	P1-2	G18-008
P1_G18-008_LELAND_O-GEN-2016-130_345	Redacted	P1-2	G18-008
P1_G18-008_LELAND_O-LELAND_2-BE_345/20KV	Redacted	P1-2	G18-008
P1_G18-008_LELAND_O-LO.LS-FT-BE_345	Redacted	P1-2	G18-008
P4_86704	Redacted	P4	G18-008
P4_116083	Redacted	P4	G18-008
P4_114892	Redacted	P4	G18-008
P4_G18-008_LELAND_O_AUTOS_1-2	Redacted	P4	G18-008
P4_G18-008_LELAND_O-ANTELOPE_DCT_345	Redacted	P4	G18-008

Disturbance Name	Description	NERC Cat.	Area
P4_G18-008_LELAND_O_AUTO1_G18-008_LELAND_O-ANTELOPE_1_345	Redacted	P4	G18-008
P4_G18-008_LELAND_O_AUTO1_G18-008_LELAND_O-LO.LS-FT-BE_345	Redacted	P4	G18-008
P4_G18-008_LELAND_O_AUTO1_G18-008_LO.LS-GR-BE3345._LELAND_O-BE3345	Redacted	P4	G18-008
P4_G18-008_G18-008_LELAND_O-ANTELOPE_1_345_G18-008_LELAND_O-LO.LS-FT-BE_345	Redacted	P4	G18-008
P4_G18-008_G18-008_LELAND_O-ANTELOPE_1_345_G18-008_LO.LS-GR-BE3345._LELAND_O-BE3345	Redacted	P4	G18-008
P4_G18-008_LELAND_O-LO.LS-FT-BE_345_G18-008_LO.LS-GR-BE3345._LELAND_O-BE3345	Redacted	P4	G18-008
P1_G18-010_NESET-TANDE_230	Redacted	P1	G18-010
P1_G18-010_NESET-TIOGA_230	Redacted	P1	G18-010
P1_G18-010_NESET_AUTO	Redacted	P1	G18-010
P4_116758	Redacted	P4	G18-010
P4_69310	Redacted	P4	G18-010
P4_G18-010_NESET-TANDE_230_G18-010_NESET-TIOGA_230	Redacted	P4	G18-010
P4_G18-010_NESET-TANDE_230_G18-010_NESET_AUTO	Redacted	P4	G18-010
P4_G18-010_NESET-TIOGA_230_G18-010_NESET_AUTO	Redacted	P4	G18-010
P1_G18-039_EDGELEY-115/69KV_1	Redacted	P1	G18-039
P1_G18-039_EDGELEY-ORDWAY_115	Redacted	P1	G18-039
P1_G18-039_EDGELEY-JAMESTN_115	Redacted	P1	G18-039
P1_G18-039_EDGELEY-POMONA_115	Redacted	P1	G18-039
P1_G18-039_EDGELEY_115/69KV_2	Redacted	P1	G18-039
P4_G18-039_EDGELEY-JAMESTN_115_G18-039_EDGELEY-ORDWAY_115	Redacted	P4	G18-039
P4_G18-039_EDGELEY-JAMESTN_115_G18-039_EDGELEY_115/69KV_2	Redacted	P4	G18-039
P4_G18-039_EDGELEY-ORDWAY_115_G18-039_EDGELEY_115/69KV_2	Redacted	P4	G18-039
BISON-ALEX	Redacted	P1-2	XEL
BISON-MAPLE	Redacted	P1-2	XEL
BISON-BUFFALO	Redacted	P1-2	XEL

Disturbance Name	Description	NERC Cat.	Area
BISON-J1588	Redacted	P1-2	XEL

3.4. Performance Criteria

3.4.1. Transient Stability Period Voltage Limitations

MPC buses were monitored using the transient voltage limits summarized in Table 19. Voltage must return within applicable post-contingency voltage limits within ten seconds of fault clearing; bus voltage on the MPC System is allowed to increase to 1.3 per unit for a duration of up to two hundred milliseconds.

Table 19: Minnkota Transient Stability Period Voltage Limitations

Facility	Maximum kV (p.u.)	Minimum kV (p.u.)
All buses	1.2	0.7
Drayton 230 kV	1.15	0.8

3.4.2. Transient-Period Damping Criteria

Machine rotor-angle oscillations were monitored using the criteria below, which does not apply to bus voltages.

- For disturbances (with faults): SPPR (maximum) = 0.95; Damping Factor (minimum) = 5%
- For line trips: SPPR (maximum) = 0.90; Damping Factor (minimum) = 10%

The Damping Factor is calculated from the Successive Positive Peak Ratio (SPPR) of the peak-to-peak amplitude of the rotor oscillation. SPPR and the associated Damping Factor will be calculated as:

- SPPR = Successive swing amplitude / previous swing amplitude, and
- Damping Factor = (1 - SPPR) * 100 (in %)

3.4.3. Distance Relaying – Apparent Impedance Transient Criteria

Apparent impedance swings on all lines were monitored, after fault clearing, against a three-zone ohm (or offset impedance) circle characteristic. Apparent impedance transient swings into the inner zones (Circles A or B) are considered unacceptable unless documentation is provided showing the actual relays will not trip for the event.

3.5. Transient Stability Analysis Results

3.5.1. Results with Steady State Reactive Power NUs

Redacted

These violations are shown across both the benchmark and study cases with little to no difference between the two cases. These violations are considered pre-existing and not due to the addition of the DISIS-2018-001 Phase 2 projects. These issues will be monitored and further evaluated in the Phase 3 study. Details on the MPC facilities which show violations are found in Appendix C.

Table 20: Benchmark Case Redacted Violations

Cont. No.	Contingency Description	MPC Violations	Violation Type	Volt. Drop Duration Index (Sec)	Volt. Rise Duration Index (Sec)	Zone 1 Relay Margin Index (%)	Zone 2 Relay Margin Index (%)	Status
Redacted								

Table 21: Study Case Redacted Violations

Cont. No.	Contingency Description	MPC Violations	Violation Type	Volt. Drop Duration Index (Sec)	Volt. Rise Duration Index (Sec)	Zone 1 Relay Margin Index (%)	Zone 2 Relay Margin Index (%)	Status
Redacted								

3.6. Conclusion

Transient stability violations were found for MPC facilities; however, these were found to exist in both the benchmark and study cases. These violations were not noticeably degraded due to the DISIS-2018-001 Phase 2 projects and are considered to be pre-existing issues. These issues will be monitored and further evaluated in the Phase 3 study. Details on the MPC facilities which show violations are found in Appendix C.

4. Cost Allocation

The cost allocation of Network Upgrades reflects responsibilities for mitigating system impacts.

4.1. Required Network Upgrades

The network upgrades required to mitigate constraints identified in the Minnkota ASA are listed in Table 22 through Table 24. Costs are planning level estimates and subject to revision in the facility studies.

Table 22 shows Minnkota NUs allocated to the DISIS-2018-001 projects.

Table 22: Minnkota Network Upgrades Allocated to DISIS-2018-001 Projects

Constraint	Owner	TSP	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Wilton-Winger 230 kV	MPC	OTP	412.9	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
J897POI-Prairie 230 kV	MPC / GRE	GRE / OTP	484.2	Terminal Upgrade (478 MVA limit)	$500,000	GEN-2018-008
Jamestown-Center 345 kV	MPC / OTP	OTP	777.6	Structure Raises, Maximum conductor rating is 1595.4 MVA	$1,000,000	GEN-2018-008, GEN-2018-010
Prairie-Walle 230 kV	MPC	OTP	433.8	Structure Raises, Maximum conductor rating is 444 MVA	$500,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
Prairie-Lake Ardoch 230 kV	MPC	OTP	429.2	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
MPC03637POI-Wahpeton 230 kV	MPC / OTP	OTP	387.2	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-039
Winger-Walle 230 kV	MPC	OTP	410.8	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
Drayton-Lake Ardoch 230 kV	MPC	OTP	410.3	Structure Raises, Maximum conductor rating is 444 MVA	$1,000,000	GEN-2018-008, GEN-2018-010, GEN-2018-039
Steady-State Non-Convergence	OTP	OTP	N/A	Audubon 230 kV MSC: 1x50 MVAR	$1,000,000	GEN-2018-007, GEN-2018-008, GEN-2018-010, GEN-2018-039
Steady-State Voltage	XEL	XEL	N/A	Bison 345 kV MSC: Additional 1x75 MVAR	$1,500,000	GEN-2018-007, GEN-2018-008, GEN-2018-010, GEN-2018-039

Constraint	Owner	TSP	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Steady-State Voltage	OTP	OTP	N/A	Audubon 230 kV MSC: 2x50 MVAR	$2,000,000	GEN-2018-007, GEN-2018-008, GEN-2018-010, GEN-2018-039
Steady-State Voltage	MPC	MPC	N/A	Edinburg 115 kV MSC: 2x10 MVAR	$1,000,000	GEN-2018-008
				Total Cost	**$12,500,000**	

Table 23 shows Minnkota network upgrades allocated to higher queued projects that are required to mitigate identified thermal constraints. If the upgrades are not built by the higher queued projects, they may be required to be built by the DISIS-2018-001 projects.

Table 23: Minnkota Network Upgrades Allocated to Higher Queued Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Falconer-Oslo 115 kV	MPC	224.9	Prior queued project expected to mitigate	GEN-2018-008, GEN-2018-039
Prairie 345/230 kV Autotransformer	MPC	504.3	Prior queued project expected to mitigate	GEN-2018-008
Grand Forks-Falconer 115 kV	MPC / WAPA	296.2	Prior queued project expected to mitigate	GEN-2018-008, GEN-2018-039
MPC03637POI-Fronter 230 kV	MPC	376.5	Prior queued project expected to mitigate	GEN-2018-007

Table 24 shows the Minnkota network upgrades that are alleviated by existing MPC equipment that do not require mitigation.

Table 24: Minnkota Network Upgrades Mitigated by Existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Drayton-Letellier 230 kV	MPC / MH	552.6	Below minimum MPC equipment rating (876.4 MVA)	GEN-2018-007, GEN-2018-008, GEN-2018-010, GEN-2018-039

4.2. Cost Allocation Methodology

A generator in the DISIS-2018-001 Phase 2 ASA will participate in mitigating a thermal constraint if the constrained facility is identified as an ERIS or NRIS constraint for that generator. Costs are allocated based on a pro-rata share of the MW impact of each impacting generator.

The MW impact of each ASA study generator is calculated using the distribution factor of each generator. 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 by the NU. The methodology to determine the cost allocation of NU is:

$$Project\ A\ Cost\ Portion\ of\ NU = Cost\ of\ NU \times \frac{Max(Project\ A\ MW\ Contribution\ on\ Constraint)}{\sum_i Max(Project\ i\ MW\ Contribution\ on\ Constraint)}$$

A generator will participate in mitigating a voltage constraint if the generator has an impact greater than 0.003 per unit of the nominal bus voltage. Costs are allocated based on a pro-rata share of the voltage impact of each impacting generator.

4.2.1. Cost Allocation

The Distribution Factor (DF) from each generating facility was calculated on the thermal constraints identified in the steady-state analysis. For each thermal constraint, the maximum MW contribution (increasing flow) from each generating facility was calculated. The MW contribution of a generating facility was set as zero if the constraint is not categorized as a constraint for that specific generating facility. The maximum MW contribution on each constraint is provided in Appendix D.

Cost allocation of voltage constraint driven NUs was determined from the voltage impact each project has on the most constrained bus under the most constraining contingency. The voltage impact of each project was calculated by locking all voltage-regulating equipment in the model and backing out each project one at a time to identify each project's impact on the constraint. The impact of each project on each voltage constraint is provided in Appendix D.

The cost allocation for each NU is calculated based on the MW or voltage impact of each generating facility. Details are provided in Appendix D.

A summary of the costs allocated to each generating facility is shown in Table 25.

Table 25: Summary of NU Costs Allocated to each Generation Project

Project	Cost of NUs ($)
GEN-2018-007	$907,982
GEN-2018-008	$7,375,737
GEN-2018-010	$1,461,535
GEN-2018-039	$2,754,746
Total Cost	**$12,500,000**

Redacted

Redacted

Redacted

Redacted