AFFECTED SYSTEM ANALYSIS OF SPP DISIS-2019-001 PHASE 2

MINNKOTA POWER COOPERATIVE, INC.

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Document Revisions

Date	Revision	Description
8/18/2023	0	Initial Draft
8/23/2023	1	Addressed minor comments from MPC, expunged Redacted as the contingency was not valid.
9/8/2023	2	Final Report

1. Executive Summary

The purpose of this Affected System Analysis (ASA) is to determine the impacts of generators in the SPP DISIS-2019-001 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-2019-001 Phase 2 Projects

Project	POI	Summer MW	Fuel Type	Service Type
GEN-2019-037	Leland Olds 345 kV Substation	150	Solar	ER/NR

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.

The Hazel Creek to Scott County 345 kV line was included in the ASA SSH study case. A restudy will be required if the Hazel Creek to Scott County 345 kV line is not built by the DISIS-2019-001 Phase 2 project.

Table 2: Minnkota Network Upgrades Allocated to DISIS-2019-001 Phase 2 Project

Constraint	Owner	TSP	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Falconer-Oslo 115 kV	MPC	OTP	220.7	Rebuild line and terminal upgrade	$8,700,000	GEN-2019-037
Grand Forks-Falconer 115 kV	MPC / WAPA	OTP / WAPA	289.4	Rebuild line and terminal upgrade	$1,500,000	GEN-2019-037
Jamestown-Center 345 kV	MPC / OTP	OTP	850.8	Structure Raises, maximum conductor rating is 1595.4 MVA	$1,000,000	GEN-2019-037
Center 345/230 kV Autotransformers #1 and #2	MPC	OTP	795.9	Add third Center 345/230 kV autotransformer and terminal upgrades	$10,500,000	GEN-2019-037

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-2019-001 Phase 2 project.

Table 3: Minnkota Network Upgrades Allocated to Higher Queued Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Wilton-Winger 230 kV	MPC	406.8	Prior queued project expected to mitigate	GEN-2019-037
Prairie 345/230 kV Autotransformer	MPC	553.7	Prior queued project expected to mitigate	GEN-2019-037
Prairie-Walle 230 kV	MPC	416.1	Prior queued project expected to mitigate	GEN-2019-037
MPC03637POI-Wahpeton 230 kV	MPC	386.2	Prior queued project expected to mitigate	GEN-2019-037
Prairie-Lake Ardoch 230 kV	MPC	405.7	Prior queued project expected to mitigate	GEN-2019-037

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	543.6	Below minimum MPC equipment rating (876.4 MVA)	GEN-2019-037
J897POI-Prairie 230 kV	MPC / GRE	389.8	Below minimum MPC equipment rating	GEN-2019-037
Drayton-Lake Ardoch 230 kV	MPC / OTP	401.2	Below minimum MPC equipment rating	GEN-2019-037

1.2. DISIS-2019-001 Phase 2 Project Summary

The allocation of Minnkota NUs to the ASA project is summarized in the following table.

1.2.1. GEN-2019-037

Network Upgrade	Total Cost ($)	GEN-2019-037 Allocation
Falconer-Oslo 115 kV Line Rebuild and Terminal Upgrade	$8,700,000	$8,700,000
Grand Forks-Falconer 115 kV Line Rebuild and Terminal Upgrade	$1,500,000	$1,500,000
Jamestown-Center 345 kV Structure Raises	$1,000,000	$1,000,000
3rd Center 345/230 kV Autotransformer	$10,500,000	$10,500,000

Network Upgrade	Total Cost ($)	GEN-2019-037 Allocation
Total Cost	**$21,700,000**	**$21,700,000**

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-2019-001 Phase 2 project. Analyses were performed for summer peak and summer shoulder conditions.

MPC thermal constraints are summarized in Table 14. No MPC non converged or voltage constraints were identified.

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-2019-001 Phase 2 project. Transient stability analysis was performed for summer shoulder conditions.

Redacted

These violations were considered pre-existing and not due to the addition of the DISIS-2019-001 Phase 2 project. Transient stability results are summarized in Appendix C.

These issues will be monitored and evaluated further in the Phase 3 study.

1.5. Conclusion

Thermal constraints were identified on the MPC system for the DISIS-2019-001 Phase 2 ASA project. The required NUs to address the identified thermal issues are listed in Table 2, Table 3, and Table 4 above. Upgrade costs assigned to the DISIS-2019-001 Phase 2 project total to $21,700,000 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-2019-001 Phase projects under study.

2.1. Study Methodology

Study cases representing summer peak and summer shoulder system conditions were created with the DISIS-2019-001 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 MPC ASA of MISO DPP-2020-Cycle Phase 3 ERIS summer peak study case (ASA_DPP20-Ph3_2025SUM_Study_230404) and ERIS summer shoulder study case (ASA_DPP20-Ph3_2025SH90_Study_230406).

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 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
Added 100 MVAR Statcom at ALX STATCM 345 kV	X	X
Added 250 MVAR Statcom at WINGR STATCM 230 kV	X	X
Removed Nearby Withdrawn Units	X	X
Dispatched Selected SPP DISIS-2018-001 Phase 2 Study Units - GEN-2018-008 - GEN-2018-010 - GEN-2018-039	X	X
Added Selected SPP DISIS-2019-001 Phase 2 Study Unit - GEN-2019-037	X	X
Hazel Creek-Scott County 345 kV line modeled in SSH study case		X

Table 6: Minnkota Generator Dispatch

Generator	Bus	Pgen	Pmax
Young 1	Redacted	274	274
Young 2		493	493
Oliver County		99.3	99.3
Langdon		40.5	40.5
Langdon		19.5	19.5
Langdon		99	99
Langdon		40.5	40.5
Ashtabula		51	51
Ashtabula		62.4	62.4
Ashtabula		118.5	118.5
Ashtabula		196.5	196.5

Table 7: Minnkota Generator Interconnection Project Dispatch

Project	SUM	SH
MPC03600	170	170
MPC03700	130	130
MPC03800	234	234
MPC03900	142	142
MPC04000	290	290

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	SPK Case Pgen (MW)	GEN Area	ERIS SP PMAX	NRIS SP PMAX	Service	Type
DPP-2017-AUG	West	MN	J803	22.1	XEL	32.5	0	ER	Solar
DPP-2017-AUG	West	ND	J897	95	GRE	190	0	ER	Wind
DPP-2017-AUG	West	ND	J897	95	GRE			ER	Wind
DPP-2020-Cycle	West	MN	J1800	6.1	XEL	25	25	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1767	7	ALTW	37	37	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1776	5.1	ALTW	34	34	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1776	3	ALTW			ER/NR	Wind
DPP-2020-Cycle	West	IA	J1729	12.8	ALTW	43	43	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1729	4.2	ALTW			ER/NR	Wind
DPP-2020-Cycle	West	IA	J1727	10.7	ALTW	33.75	33.75	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1728	11.6	ALTW	39	39	ER/NR	Wind

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

DPP Cluster	DPP Region	State	Generation Name	SSH Case Pgen (MW)	GEN Area	ERIS G PMAX	NRIS G PMAX	Service	Type
DPP-2017-AUG	West	ND	J897	95	GRE	190	0	ER	Wind
DPP-2017-AUG	West	ND	J897	95	GRE			ER	Wind
DPP-2020-Cycle	West	MN	J1800	68.7	XEL	25	25	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1767	66.6	ALTW	37	37	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1776	68.2	ALTW	34	34	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1776	34.1	ALTW			ER/NR	Wind
DPP-2020-Cycle	West	IA	J1729	136.5	ALTW	43	43	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1729	45	ALTW			ER/NR	Wind
DPP-2020-Cycle	West	IA	J1727	102.4	ALTW	33.75	33.75	ER/NR	Wind
DPP-2020-Cycle	West	IA	J1728	102.4	ALTW	39	39	ER/NR	Wind

The list of withdrawn generators that were taken out of service is shown in Table 10 for the summer and for the summer shoulder case. Power was balanced by scaling SPP generation outside of North Dakota for the withdrawn units.

Table 10: List of SPP Withdrawn Units Removed from the Summer Peak and Summer Shoulder Case

SPP Cluster	Group	State	Generation Name	SPK & SSH Case Pgen (MW)	GEN Area	ERIS PMAX	NRIS PMAX	Service	Type
DISIS-2017-002	01 NORTH	ND	GEN-2017-235	50	BEPC	50	50	ER/NR	Wind
DISIS-2017-002	01 NORTH	ND	GEN-2017-236	50	BEPC	50	50	ER/NR	Wind

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 11. 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 Generator Interconnection Projects.

Table 11: ASA Study Project Dispatch

Project	Summer (MW)	Summer Shoulder (MW)	Fuel Type	Service Type
GEN-2019-037	150	150	Solar	ER/NR

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 MPC ASA of MISO DPP-2020-Cycle Phase 3 study; contingency files are shown below in Table 12.

Table 12: 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
ASA DPP20 Ph3_HVDC_SPK.con	X	
ASA DPP20 Ph3_HVDC_SH.con		X
Monopole_Bipole_Update_20220125.con	X	X
ASA DPP20 Ph3_P1.con	X	X
ASA DPP20 Ph3_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.

Redacted

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 13.

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 13: List Monitored Elements

Area	Monitored Elements	Voltage Limits (High/Low)[1]	
		System intact	Post-Contingency
BEPC (659,663)	69 kV and above	1.05/0.95	1.1/0.90

Area	Monitored Elements	Voltage Limits (High/Low)[1]	
		System intact	Post-Contingency
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)	100 kV and above	1.05/1.00	1.1/0.95
MRES (owner 608)	69 kV and above	1.05/0.97	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)	69 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 Generator Interconnection Projects 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

There are no MPC non converged constraints in the summer peak or summer shoulder cases. Additionally, there are no MPC voltage constraints in the summer peak or summer shoulder cases.

2.8. Mitigation of Steady State Constraints

Network Upgrades required to mitigate MPC NRIS thermal constraints are shown in Table 15.

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 Summer Peak and Summer Shoulder Thermal Constraint Mitigation

Facility	Owner	Rating MVA	Post-Project Loading		Mitigation	Cost	ERIS Constraint	NRIS Constraint
			MVA	%				
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-2019-001 Phase 2 projects under study.

3.1. Study Methodology

Transient stability analysis was performed using the MPC ASA of MISO DPP-2020-Cycle Phase 3 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 21.0.63 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 MPC 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 2019-037**: WECC Generic Models consistent with DISIS 1901 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 16. Redacted

Table 16: Disturbance Descriptions

Cont. No.	Disturbance Name	Description	NERC Cat.	Area
1	Flat Run	Redacted	P0	
2	0690_w_gre_p23		P2-3	GRE
3	0800_w_mp_p12		P1-2	GRE
4	0819_w_otp_p11		P1-1	OTP
5	0822_w_otp_p12		P1-2	OTP
6	0823_w_otp_p12		P1-2	OTP
7	0824_w_otp_p12		P1-2	OTP
8	0826_w_otp_p42		P4-2	OTP
9	0830_w_otp_p42		P4-2	OTP
10	0831_w_otp_p42		P4-2	AEPW
11	0832_w_otp_p42		P4-2	GRE

Cont. No.	Disturbance Name	Description	NERC Cat.	Area
12	1677_w_otp_p12	Redacted	P1-2	GRE
13	1684_w_xel_p12.idv		P1-2	XEL
14	P7_GRE_CCK_BIPOLE_U1U2TRIP		P7	GRE
15	P15_GRE_CCK_MONOPOLE_U1TRIP		P1-5	GRE
16	1681_w_otp_p42		P4-2	OTP
17	BISON-ALEX__BISON_BUFFALO		P4	XEL
18	BISON-BUFFALO__BISON-MAPLE		P4	XEL
19	BISON-MAPLE__BISON-J1588		P4	XEL
20	BISON-J1588__BISON_ALEX		P4	XEL
21	P23:345:XEL:LYONCO3:8N64_17		P2-3	XEL
22	BISON-ALEX		P1-2	XEL
23	BISON-MAPLE		P1-2	XEL
24	BISON-BUFFALO		P1-2	XEL
25	BISON-J1588		P1-2	XEL
26	P1_G19-037_LELAND_O_AUTO1		P1-2	G19-037
27	P1_G19-037_LELAND_O-ANTELOPE_1_345		P1-2	G19-037
28	P1_G19-037_LELAND_O-GEN-2016-130_345		P1-2	G19-037
29	P1_G19-037_LELAND_O-LELAND_2-BE_345		P1-2	G19-037
30	P1_G19-037_LELAND_O-LO.LS-FT-BE_345		P1-2	G19-037
31	P1_G19-037_LELAND_O-LO.LS-GR-BE_345		P1-2	G19-037
32	P4_86704		P4	G19-037
33	P4_116072		P4	G19-037
34	P4_G19-037_LELAND_O_AUTOS_1-2		P4	G19-037
35	P4_G19-037_LELAND_O-ANTELOPE_DCT_345		P4	G19-037

Cont. No.	Disturbance Name	Description	NERC Cat.	Area
36	P4_G19-037_LELAND_O_AUTO1__LELAND_O-ANTELOPE_1_345	Redacted	P4	G19-037
37	P4_G19-037_LELAND_O_AUTO1__LELAND_O-LO.LS-FT-BE_345		P4	G19-037
38	P4_G19-037_LELAND_O_AUTO1__LO.LS-GR-BE3345._LELAND_O-BE3345		P4	G19-037
39	P4_G19-037_G19-037_LELAND_O-ANTELOPE_1_345__LELAND_O-LO.LS-FT-BE_345		P4	G19-037
40	P4_G19-037_G19-037_LELAND_O-ANTELOPE_1_345__LO.LS-GR-BE3345._LELAND_O-BE3345		P4	G19-037
41	P4_G19-037_LELAND_O-LO.LS-FT-BE_345__LO.LS-GR-BE3345._LELAND_O-BE3345		P4	G19-037

3.4. Performance Criteria

3.4.1. Transient Stability Period Voltage Limitations

MPC buses were monitored using the transient voltage limits summarized in Table 17. 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 17: 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

Redacted

These violations were considered pre-existing and not due to the addition of the DISIS-2019-001 Phase 2 project. These issues will be monitored and evaluated further in the Phase 3 study.

Detailed transient stability results are summarized in Appendix C.

Table 18. Benchmark Case Violations

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

Table 19. Study Case Violations

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

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

Redacted

3.6. Conclusion

Redacted These violations were considered pre-existing and not due to the addition of the DISIS-2019-001 Phase 2 project. These issues will be monitored and evaluated further in the Phase 3 study.

Transient stability results are summarized in Appendix C.

GEN-2019-037 will be evaluated in the Phase 3 study for further impact.

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 20 through Table 22. Costs are planning level estimates and subject to revision in the facility studies.

Table 20 shows Minnkota NUs allocated to the DISIS-2019-001 Phase 2 project.

Table 20: Minnkota Network Upgrades Allocated to DISIS-2019-001 Phase 2 Project

Constraint	Owner	TSP	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Falconer-Oslo 115 kV	MPC	OTP	220.7	Rebuild line and terminal upgrade	$8,700,000	GEN-2019-037
Grand Forks-Falconer 115 kV	MPC / WAPA	OTP / WAPA	289.4	Rebuild line and terminal upgrade	$1,500,000	GEN-2019-037
Jamestown-Center 345 kV	MPC / OTP	OTP	850.8	Structure Raises, maximum conductor rating is 1595.4 MVA	$1,000,000	GEN-2019-037
Center 345/230 kV Autotransformer #1 and #2	MPC	OTP	795.9	Add third Center 345/230 kV autotransformer and terminal upgrades	$10,500,000	GEN-2019-037
				Total Cost	**$21,700,000**	

Table 21 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-2019-001 projects.

Table 21: Minnkota Network Upgrades Allocated to Higher Queued Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Wilton-Winger 230 kV	MPC	406.8	Prior queued project expected to mitigate	GEN-2019-037
Prairie 345/230 kV Autotransformer	MPC	553.7	Prior queued project expected to mitigate	GEN-2019-037
Prairie-Walle 230 kV	MPC	416.1	Prior queued project expected to mitigate	GEN-2019-037
MPC03637POI-Wahpeton 230 kV	MPC	386.2	Prior queued project expected to mitigate	GEN-2019-037

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Prairie-Lake Ardoch 230 kV	MPC	405.7	Prior queued project expected to mitigate	GEN-2019-037

Table 22 shows the Minnkota network upgrades that are alleviated by existing MPC equipment that do not require mitigation.

Table 22: Minnkota Network Upgrades Mitigated by Existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Drayton-Letellier 230 kV	MPC / MH	543.6	Below minimum MPC equipment rating (876.4 MVA)	GEN-2019-037
J897POI-Prairie 230 kV	MPC	389.8	Below minimum MPC equipment rating	GEN-2019-037
Drayton-Lake Ardoch 230 kV	MPC	401.2	Below minimum MPC equipment rating	GEN-2019-037

4.2. Cost Allocation Methodology

A generator in the DISIS-2019-001 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 23.

Table 23: Summary of NU Costs Allocated to each Generation Project

Project	Cost of NUs ($)
GEN-2019-037	$21,700,000
Total Cost	**$21,700,000**

Redacted

Redacted

Redacted

Redacted