CRITICAL ENERGY/ELECTRIC INFRASTRUCTURE INFORMATION

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

MINNKOTA POWER COOPERATIVE, INC.

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Document Revisions

Date	Revision	Description
12/02/24	0	Initial Draft
12/06/24	1	Addressed comment from MPC
01/17/25	2	Final Release

1. Executive Summary

The purpose of this Affected System Analysis (ASA) is to determine the impacts of generators in the SPP DISIS-2019-001 study cycle on Minnkota Power Cooperative (MPC) facilities and any Network Upgrades (NUs) required to mitigate those impacts. This is a restudy for the previous ASA of DISIS-2019-001 Phase 2 study, triggered by the withdrawn units 2018-007, 2018-008, and 2018-039 of the 2018 study cluster.

Steady-state power flow, contingency analyses, and a dynamic stability analysis were performed for the DISIS generating facilities shown in Table 1. Mentions of the ASA project throughout this report will refer to the studied GEN-2019-037 project.

Table 1: ASA DISIS-2019-001 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 network upgrades required to mitigate constraints identified in the Minnkota ASA are listed in Table 2**Error! Reference source not found.**. The costs are planning level estimates and subject to revision in the facility studies.

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

Constraint	Owner	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Grand Forks – Falconer 115 kV	MPC / WAPA	266.5	Rebuild line and terminal upgrade	$1,500,000	GEN-2019-037
Center 345/230 kV Autotransformers #1 and #2	MPC	775.1	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 ASA project.

Table 3: Minnkota Network Upgrades Allocated to Higher Queued Projects for Thermal Violations

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Jamestown – Center 345 kV	MPC	822.4	Prior queued project expected to mitigate thermal violation	GEN-2019-037
Wilton – Winger 230 kV	MPC	371.7	Prior queued project expected to mitigate thermal violation	GEN-2019-037
Prairie 345/230 kV Autotransformer	MPC	549.5	Prior queued project expected to mitigate thermal violation	GEN-2019-037

Table 4 shows the MISO LRTP projects that are required to mitigate the identified stability constraints. If these projects are not built, then additional network upgrades described in Section 1.1.1 will be required.

Table 4: MISO LRTP Projects Required to Mitigate Stability Violations

Constraint	Owner	Mitigation	Generators
Transient Stability	MPC	Prior queued MISO projects LRTP-1 and LRTP-2 expected to mitigate stability violation	GEN-2019-037

Table 5 shows the Minnkota constraints that are alleviated by existing MPC equipment and do not require mitigation.

Table 5: Minnkota Constraints Mitigated by Existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Drayton – Letellier 230 kV	MPC / MH	485.2	Below minimum MPC equipment rating (876.4 MVA)	GEN-2019-037

1.1.1. Stability Network Upgrades without MISO LRTP Projects

If both MISO's LRTP-1 and LRTP-2 projects are not in-service, then additional network upgrades at Winger substation are required. Table 6**Error! Reference source not found.** shows the Minnkota network upgrade that is required to mitigate the identified stability constraints in the benchmark case if the MISO LRTP Projects are not in-service.

Table 6: Minnkota Network Upgrades to Mitigate Benchmark Case Violations in Stability Study without MISO's LRTP Projects

Constraint	Owner	Minimum Voltage (PU)	Network Upgrade to Address Benchmark Case Violations (not allocated)
Transient Stability	OTP / MPC	0.672	50 MVAR STATCOM + 1x 30 MVAR capacitor bank at Winger expected to mitigate stability violation in benchmark case

Table 7 shows the network upgrades that are cost allocated to the ASA project to mitigate the transient voltage drop violation.

Table 7: Minnkota Stability Network Upgrades Allocated to DISIS-2019-001 Phase 2 Project without MISO LRTP Projects

Constraint	Owner	Minimum Voltage (PU)	Mitigation	Cost ($)	Generators
Transient Stability	OTP / MPC	0.6719	3x 30 MVAR capacitor banks at Winger 4 230 kV substation (for a total of 4x 30 MVAR)	$3,000,000	GEN-2019-037

1.2. DISIS-2019-001 Project Summary

The allocation of Minnkota NUs to the ASA project are summarized below. Table 8 shows the cost allocation assuming both MISO LRTP-1 and LRTP-2 projects are in-service. If MISO's LRTP projects are not in-service, then additional network upgrades in Table 9 would be cost allocated to the ASA project in addition to the costs in Table 8.

Table 8: Cost Allocation of Minnkota Network Upgrades to GEN-2019-037

Network Upgrade	Total Cost ($)	GEN-2019-037 Allocation
Grand Forks – Falconer 115 kV Line Rebuild and Terminal Upgrade	$1,500,000	$1,500,000
3rd Center 345/230 kV Autotransformer and Terminal Upgrades	$10,500,000	$10,500,000
Total Cost	**$12,000,000**	**$12,000,000**

Table 9: Additional Cost Allocation of Minnkota Network Upgrades to GEN-2019-037 without MISO's LRTP Projects

Network Upgrade	Total Cost ($)	GEN-2019-037 Allocation
3x 30 MVAR capacitor banks at Winger 4 230 kV substation (for a total of 4x 30 MVAR)	$3,000,000	$3,000,000
Additional Cost to Table 8's Estimates	**$3,000,000**	**$3,000,000**

1.3. Steady State Power Flow Analysis

Power flow and contingency analyses were performed to identify and mitigate any non-converged, thermal, or voltage issues on the Minnkota system caused by the ASA project. Analyses were performed for summer peak and summer shoulder conditions.

1.4. Transient Stability Analysis

A transient stability analysis was performed to identify and mitigate any transient voltage, damping, or relay margin issues on the Minnkota system caused by the addition of the ASA project. The transient stability analysis was performed for summer shoulder conditions.

1.5. Conclusion

Thermal and stability constraints were identified on the MPC system for the ASA project, and there were no identified voltage constraints. The required network upgrades allocated to the ASA project to address the identified issues are listed in Table 2, which assumed that all contingent upgrades in Table 3 and Table 4 are in-service. The total upgrade costs assigned to the ASA project is $12,000,000 in planning level estimates as identified in Table 8, with an additional $3,000,000 in Table 9 if MISO's LRTP-1 and LRTP-2 projects are not both in-service.

2. Steady State Power Flow Analysis

Power flow and contingency analyses were performed to identify and mitigate any non-converged, thermal, or voltage issues on the MPC system caused by the ASA project under study.

2.1. Study Methodology

Study cases representing summer peak and summer shoulder system conditions were created with the ASA project dispatched at the GIA output, as applicable. System performance was benchmarked using cases without the studied ASA project.

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

Steady-state analyses were performed using TARA v2402.1 and cases were created using PSS®E version 34.

2.2. Case Development

Power flow cases were created from the MPC ASA of DISIS-2018-001 Ph2 Restudy summer peak base case (ASA-DIS1801-P2R1-25SUM-BASE) and summer shoulder base case (ASA-DIS1801-P2R1-25SSH-BASE).

ASA summer peak (SUM) and summer shoulder (SSH) study cases were created from the MPC DISIS-2018 ASA base cases by applying the model updates listed in Table 10 and dispatching MPC generators and MISO Generator Interconnection Projects as show in Table 11 and Table 12.

The dispatch of North Dakota and South Dakota generators in the ASA study cases can be found in Appendix A.

Table 10: ASA Model Updates

Model Update	SUM (MW)	SH (MW)
Dispatched Selected MISO DPP-2020-Cycle Study Units as PQ: - J1575 - J1588	 10.92 200	 70 0
Dispatched Selected SPP DISIS-2018-001 Study Units: - GEN-2018-010 (BESS)	 0	 0
Dispatched Selected SPP DISIS-2019-001 Study Units as CQ: - GEN-2019-037	 152.1	 152.1

Table 11: Minnkota Generator Dispatch

Generator	SUM (MW)	SH (MW)
Young 1	274	274
Young 2	493	493
Oliver County	99.3	99.3
Langdon	199.5	199.5
Ashtabula (GRE)	51	51
Ashtabula (OTP)	377.4	377.4
MPC03600	170	170
MPC03700	130	130
MPC03800	234	234
MPC03900	142	142
MPC04000	290	290

Table 12: ASA Study Project Dispatch

Project	Summer (MW)	Summer Shoulder (MW)	Fuel Type	Service Type
GEN-2019-037	152.1	152.1	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 and the MPC ASA of SPP DISIS-2018-001 Phase 2 Restudy; contingency files are shown below in Table 13.

Table 13: List of Contingency Files for Steady State Analysis

Contingency File Name	Summer	Shoulder
PY_WIN_MISO20_2025_SUM__TA_P1_MINN-DAKS.con	x	x
PY_WIN_MISO20_2025_SUM__TA_P1_P2_P4_P5_NoLoadLoss.con	x	x
PY_WIN_MISO20_2025_SUM__TA_P2_P4_P5_P6_P7_LoadLoss.con	x	x
cons_Auto_MPC.con	x	x
cons_Auto_DIS1801.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/TARA Rate A) rating; under NERC category P1-P7 (post-contingent) conditions, branches were monitored for loading above the emergency (PSS®E/TARA Rate B) rating. Bus voltages were monitored using the limits shown in Table 14.

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 TARA.

Table 14: 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.
- Thermal: Distribution Factor (DF) greater than 3%
- Voltage: impact greater than 0.01 p.u. (applies to all types of voltage analysis)

2.5.2. ERIS Maximum Impact Criteria

ERIS constraints are SAFs that meet the following criteria:

- Non-Converged
  - The study project has a larger than five percent (5%) distribution factor on the contingent elements pre-contingency.
- 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:

- Non-Converged
  - The study project has a larger than five percent (5%) distribution factor on the contingent elements pre-contingency.
- Thermal
  - System Intact (PTDF) greater than 5%
  - Under Contingency (OTDF) greater than 3%
- 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.

2.6. Thermal Constraints

MPC thermal constraints for the summer peak and summer shoulder cases are summarized in Table 15.

Thermal constraint details for NERC P0, P1, P2, P4, P5, and P7 (post-contingent) conditions are provided in Appendix B.

Table 15: Minnkota Worst Thermal Constraints

Facility	Owner	Rating MVA	Pre-Project Loading		Post-Project Loading		Contingency	Type	ERIS Constraint	NRIS Constraint
			MVA	%	MVA	%				
Jamestown – Center 345 kV	MPC/OTP	704.5	803.98	114.12	822.36	116.73	67020 MPC03839POI 345 657946 PRAIRIE3 345 1	P12		GEN-2019-037
Grand Forks – Falconer 115 kV	MPC / WAPA	232	258.19	111.29	266.50	114.87	LL_3882_P23:230:MPC:DRAYTON4:40	P23		GEN-2019-037
Wilton – Winger 230 kV	MPC	287.9	361.78	125.66	371.65	129.09	LL_5343_P23:230:MH:LETELLIER:R6	P23		GEN-2019-037
Drayton – Letellier 230 kV	MPC / MH	478	471.07	98.55	485.22	101.51	LL_2989_P23:230:MPC:WINGER 4:52FUT	P23		GEN-2019-037
3rd Center 345/230 kV Autotransformer #1	MPC	772.8	756.88	97.94	775.12	100.3	NLL_19132_P23:345:OTP:CENTER 3:3225	P23		GEN-2019-037
3rd Center 345/230 kV Autotransformer #2	MPC	772.8	755.80	97.8	774.04	100.16	NLL_19238_P23:345:OTP:CENTER 3:3215	P23		GEN-2019-037
Prairie 345/230 kV Autotransformer #1	MPC	386.4	539.22	139.55	549.46	142.2	NLL_13158_P13:230-345-13:OTP:PRAIRIE4:PRAIRIE3:PRAIR2TE:2:TR2	P13		GEN-2019-037

2.7. Voltage Significantly Affected Facilities

No voltage constraints were identified as a result of the ASA project.

2.8. Mitigation of Steady State Constraints

Network upgrades required to mitigate MPC NRIS thermal constraints are shown below in Table 16. There are no required network upgrades to mitigate MPC voltage constraints.

Table 16: Minnkota Thermal Constraint Mitigation

Facility	Owner	Rating MVA	Post-Project Loading		Mitigation	Cost	ERIS Constraint	NRIS Constraint
			MVA	%				
Grand Forks – Falconer 115 kV	MPC / WAPA	232	266.50	114.87	Rebuild line and terminal upgrades	$1,500,000		GEN-2019-037
3rd Center 345/230 kV Autotransformer #1	MPC	772.8	775.12	100.3	Add third Cetner 345 / 230 kV autotransformer and terminal upgrades	$10,500,000		GEN-2019-037
3rd Center 345/230 kV Autotransformer #2	MPC	772.8	774.04	100.16				

3. Transient Stability Analysis

A transient stability analysis was performed to identify and mitigate any transient voltage, damping, or relay margin issues on the MPC system caused by the ASA project under study.

3.1. Study Methodology

Transient stability analysis was performed using the MPC ASA of DISIS-2018-001 Ph2 Restudy summer shoulder case and making modifications as described in Table 17.

Table 17: Stability Model Updates

Model Update	Benchmark case	Study Case
Dispatched Selected MISO DPP-2020-Cycle Study Units as PQ: - J1575 - J1588	70 MW 0 MW	70 MW 0 MW
Dispatched Selected SPP DISIS-2018-001 Study Units: - GEN-2018-010 (BESS)	0 MW	0 MW
Dispatched Selected SPP DISIS-2019-001 Study Units as CQ: - GEN-2019-037	0 MW	152 MW

The mitigation measures from the steady-state analysis in Table 16 were also incorporated for the stability study, and the reactive support devices initially modeled in the benchmark case are shown in Table 18.

Table 18: Reactive Devices Modeled in Stability Analysis

Bus Num	Bus Name	Quantity	MVAR		Bus Num	Bus Name	Quantity	MVAR
658047	ALEXMRES3 345.00	1	75		657732	EDINTP 7 115.00		
658047	ALX STATCM				620239	BAGLEY 7 115.00	1	20
601067	BISON 3 345.00	3	75		615646	GRE-CDRMTH13	2	75
615529	GRE-PANTHER4230.00	3	50		615646	GRE-CDRMTH13	1	-50
658259	WMU-WILLMAR4				657752	DRAYTON4		
657758	WINGER 4 230.00	1	30		620369	JAMESTN3		
657758	WINGER 4 230.00 STATCOM				657754	MAPLE R4		
620329	WAHPETN4 230.00				657798	LKARDCH4		
620358	BUFFALO3 345.00	1	60		657946	PRAIRIE3		
620258	BUFFALO7 115.00				657946	PRAIRIE3		
620202	TORONTO N 7 115.00				67020	MPC3839 POI		
603251	FTRIDLY CAP7115.00	1	20		658276	HUC-MCLEOD 4		
603251	FTRIDLY CAP7115.00	1	21		620326	ERIEJCT		
620336	AUDUBON4 230.00				657733	EDNBURG7		

3.1.1. Sensitivity Analysis with MISO LRTP Projects

For the sensitivity analysis, Table 19 lists the MISO Long-Range Transmission Planning (LRTP) Projects that were considered for the worst-case contingency event.

Table 19: LRTP Project Description

Project Name	Description
LRTP-1	The Jamestown – Ellendale 345 kV transmission line.
LRTP-2	The Cassie's crossing substation and the Big Stone South – Alexandria – Cassie's Crossing 345 kV transmission line.

3.1.2. Stability Study Scenarios

Table 20 describes the high-level study scenarios used to identify the network upgrades that are required to address stability violations in the benchmark case and the violations as a result of the ASA project. Table 21 identifies the specific network upgrades included in each scenario.

Table 20: Stability Study Scenarios Description

Scenario	Description
Scenario 1	The summer shoulder case modeled with the steady-state network upgrades from Table 16 and reactive devices from Table 18. Only the benchmark case was simulated in TSAT.
Scenario 2	Scenario 1 modeled with the network upgrades to mitigate all stability concerns in Scenario 1's benchmark case. Both the benchmark and study cases were simulated in TSAT.
Scenario 3	Scenario 2 modeled with the network upgrades to mitigate all stability concerns in Scenario 2's study case. Both the benchmark and study cases were simulated in TSAT.
Scenario 4 Sensitivity LRTP-1	This is a sensitivity Scenario to assess the LRTP-1 project. Both the benchmark and study cases were simulated in TSAT.
Scenario 4 Sensitivity LRTP-1 and LRTP-2	This is a sensitivity Scenario to assess the LRTP-1 and LRTP-2 projects. Both the benchmark and study cases were simulated in TSAT.

Table 21: Stability Study Scenarios with Detailed Upgrades

Scenario	Base Case	Reactive Devices in Table 18	50 MVAR Winger STATCOM	3x 30 MVAR Winger Capacitors	LRTP-1	LRTP-2
Scenario 1	SH Case + Table 16's steady-state upgrades	Yes	No	No	No	No
Scenario 2	SH Case + Table 16's steady-state upgrades	Yes	Yes	No	No	No
Scenario 3	SH Case + Table 16's steady-state upgrades	Yes	Yes	Yes	No	No
Scenario 4 Sensitivity LRTP-1	SH Case + Table 16's steady-state upgrades	Yes, except the 30 MVAR Winger capacitor	No	No	Yes	No

Scenario	Base Case	Reactive Devices in Table 18	50 MVAR Winger STATCOM	3x 30 MVAR Winger Capacitors	LRTP-1	LRTP-2
Scenario 4 Sensitivity LRTP-1 and LRTP-2	SH Case + Table 16's steady-state upgrades	Yes, except the 30 MVAR Winger capacitor	No	No	Yes	Yes

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. The study project was represented with the following dynamic model:

- **GEN 2019-037**: Model consistent with DISIS 2019-001 representation

3.3. Contingency Criteria

The stability simulations performed as part of this study considered the MPC regional and local contingencies listed in Table 22. Simulations were performed with a 0.5-second steady-state run followed by the disturbance. Simulations were run for a 15-second duration.

Table 22: Disturbance Descriptions

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
Regional_1	Flat Run	No fault	P0	-
Regional_2	0690_w_gre_p23	SLG fault at GRE-STANTON4 with delayed clearing; clear by tripping GRE-COAL TP4 bus	P2-3	GRE
Regional_3	0800_w_mp_p12	3PH fault at SQBUTTE4 with normal clearing on SQBUTTE4 to GRE-STANTON4 line; clear SQBUTTE4 end at 6 cycles, GRE-STANTON4 end at 7 cycles	P1-2	GRE
Regional_4	0819_w_otp_p11	3ph fault at COYOTE1G with normal clearing; clear by tripping COYOTE1G gen	P1-1	OTP
Regional_5	0822_w_otp_p12	3PH fault at CENTER 3 with normal clearing on CENTER3-JAMESTN3 line	P1-2	OTP
Regional_6	0823_w_otp_p12	3PH fault at CENTER 4 with normal clearing on CENTER 4-ROUGHRIDER4 line	P1-2	OTP
Regional_7	0824_w_otp_p12	3PH fault at CENTER 4 with normal clearing on CENTER 4-SQBUTTE4 line	P1-2	OTP
Regional_8	0826_w_otp_p42	SLG fault at CENTER 3 with delayed clearing; clear by tripping CENTER 3-JAMESTN3 line and CENTER 3-SQBUTTE4 transformer	P4-2	OTP
Regional_9	0830_w_otp_p42	SLG fault at SQBUTTE4 with delayed clearing; clear by tripping SQBUTTE4-GRE-STANTON4 line at 12 cycles, both dc poles restart at 17 cycles	P4-2	OTP
Regional_10	0831_w_otp_p42	SLG fault at CENTER 4 with delayed clearing; clear by tripping CENTER4-ROUGHRIDER line at 12 cycles, both dc poles restart at 17 cycles	P4-2	OTP
Regional_11	0832_w_otp_p42	SLG fault at GRE-COAL CR4 with delayed clearing; clear by tripping GRE-COAL CR4-UNDERWD4 and GRE-STANTON4-GRE-COAL CR4 lines at 12 cycles	P4-2	GRE

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
Regional_12	1677_w_otp_p12	3PH fault at SQBUTTE4 with normal clearing; clear by tripping SQBUTTE4-GRE-STANTON line at 4 cycles	P1-2	GRE
Regional_13	1684_w_xel_p12.idv	3PH fault at BISON 3 with normal clearing; clear by tripping BISON 3 - ALXLNCRTRT line	P1-2	XEL
Regional_14	P7_GRE_CCK_BIPOLE_U1U2TRIP	Permanent bipole fault on the CUDC line; trip Coal Creek Units 1 and 2	P7	GRE
Regional_15	P15_GRE_CCK_MONOPOLE_U1TRIP	Monopole fault on the CUDC line; trip Coal Creek Unit 1	P1-5	GRE
G19_037_P1_1	P1_LELAND_ANTELOPE_345KV	3PH fault at LELAND 345 kV bus with normal fault clearing; clear by tripping LELAND-ANTELOPE line at 6 cycles	P1	G19-037
G19_037_P1_2	P1_LELAND_345_230_AUTO	3PH fault at LELAND 345 kV bus with normal fault clearing; clear by tripping LELAND 345/230 kV autotransformer at 6 cycles	P1	G19-037
G19_037_P1_3	P1_LELAND_GROTON_345KV	3PH fault at LELAND 345 kV bus with normal fault clearing; clear by tripping LELAND-GROTON line at 6 cycles	P1	G19-037
G19_037_P1_4	P1_LELAND_FT_THOM_345KV	3PH fault at LELAND 345 kV bus with normal fault clearing; clear by tripping LELAND-FT THOM line at 6 cycles	P1	G19-037
G19_037_P1_5	P1_G16-017-TAP_FT_THOM_345KV	3PH fault at G16-017-TAP with normal fault clearing; clear by tripping G16-017-TAP-FT THOM line at 6 cycles	P1	G19-037
G19_037_P1_6	P1_LELAND_GEN-2016-130345	3PH fault at LELAND 345 kV bus with normal fault clearing; clear by tripping GEN-2016-130345 bus at 6 cycles	P1	G19-037
G19_037_P1_7	P1_LELAND_LELAND_2-BEG	3PH fault at LELAND 345 kV bus with normal fault clearing; clear by tripping LELAND-LELAND_2-BEG2 transformer at 6 cycles	P1	G19-037
G19_037_P4_1	P4_LELAND_ANTELOPE_345KV_AND_LELAND_345_230_AUTO	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping LELAND-ANTELOPE line and LELAND 345/230 kV autotransformer at 17 cycles	P4	G19-037
G19_037_P4_2	P4_LELAND_ANTELOPE_345KV_AND_LELAND_FT_THOM_345KV	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping LELAND-ANTELOPE line and LELAND-FT THOM line at 17 cycles	P4	G19-037
G19_037_P4_3	P4_LELAND_ANTELOPE_345KV_AND_LELAND_GROTON_345KV	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping LELAND-ANTELOPE line and LELAND-GROTON line at 17 cycles	P4	G19-037
G19_037_P4_4	P4_LELAND_ANTELOPE_345KV_CKT_1_AND_2	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping both LELAND-ANTELOPE lines at 17 cycles	P4	G19-037
G19_037_P4_5	P4_LELAND_345_230_AUTO_AND_LELAND_FT_THOM_345KV	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping LELAND 345/230 kV autotransformer and LELAND-FT THOM line at 17 cycles	P4	G19-037
G19_037_P4_6	P4_LELAND_345_230_AUTO_AND_LELAND_GROTON_345KV	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping	P4	G19-037

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
		LELAND 345/230 kV autotransformer and LELAND-GROTON line at 17 cycles		
G19_037_P4_7	P4_LELAND_345_230_AUTO_1_AND_2	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping both LELAND 345/230 kV autotransformers at 17 cycles	P4	G19-037
G19_037_P4_8	P4_LELAND_FT_THOM_345KV_AND_LELAND_GROTON_345KV	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping LELAND-FT THOM line and LELAND-GROTON line at 17 cycles	P4	G19-037
G19_037_P4_9	GROUP1_P4_LOCAL_FAULT_163	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping the following 230 kV lines: LELAND-GRE-STANTON4 , LELAND-GARRISN4, LELAND- WASHBRN4, LELAND- LOGAN___-BE4, LELAND-LELAND_1-BEG, LELAND- BASIN___-BE4, as well as both LELAND 345/230 kV autotransformers at 16 cycles	P4	G19-037
G19_037_P4_10	GROUP1_P4_LOCAL_FAULT_170	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping LELAND-ANTELOPE line and LELAND 345/230 kV autotransformer at 16 cycles	P4	G19-037
G19_037_P4_11	GROUP1_P4_LOCAL_FAULT_171	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping LELAND-GROTON line and LELAND 345/230 kV autotransformer at 16 cycles	P4	G19-037
G19_037_P4_12	GROUP1_P4_LOCAL_FAULT_201	SLG fault at LELAND 345 kV bus with delayed clearing; clear by tripping LELAND-ANTELOPE line and LELAND-GROTON line at 16 cycles	P4	G19-037
G19_037_P4_13	GROUP1_P4_LOCAL_FAULT_158	SLG fault at ANTELOPE 345 kV bus with delayed clearing; clear by tripping ANTELOPE-LELAND ckt 1 line and ANTELOPE-DGC_____-BE3 ckt 2 line at 16 cycles	P4	G19-037
G19_037_P4_14	GROUP1_P4_LOCAL_FAULT_173	SLG fault at ANTELOPE 345 kV bus with delayed clearing; clear by tripping ANTELOPE-ANTELP_2-BEG line and ANTELOPE-ROUNDUP_-BE3 line at 16 cycles	P4	G19-037
G19_037_P4_15	GROUP1_P4_LOCAL_FAULT_174	SLG fault at ANTELOPE 345 kV bus with delayed clearing; clear by tripping ANTELOPE- LELAND ckt 2 line and ANTELOPE-DGC_____-BE3345 ckt 1 line at 16 cycles	P4	G19-037

3.4. Performance Criteria

Regional and local disturbances were simulated using TSAT version 22.2.22. The results were screened to identify any violations of MPC transmission reliability criteria.

3.4.1. Transient Stability Period Voltage Limitations

MPC buses were monitored using the transient voltage limits summarized in Table 23. The voltage must return within applicable post-contingency voltage limits within ten seconds of fault clearing. The bus voltage on the MPC System is allowed to increase to 1.3 per unit for a duration of up to 200 milliseconds.

Table 23: Minnkota Transient Stability Period Voltage Limitations

Facility	Maximum Voltage (p.u.)	Minimum Voltage (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

The detailed transient stability results on the MPC facilities are found in Appendix C.

3.5.1. Scenario 1 Results

Scenario 1's benchmark case had transient voltage violations shown in Table 24 and Table 25. There were no violations related to damping or relay margin violations.

Table 24: Scenario 1 – Summary of Violations for Benchmark Case

Cont. No.	Contingency Description	Damping Index (%)	Volt. Drop Duration Index (Sec)	Volt. Rise Duration Index (Sec)	Zone 1 Relay Margin Index (%)	Zone 2 Relay Margin Index (%)	Status
Regional_9	0830_w_otp_p42	99	0.3	0.392	51	41.3	Insecure

Table 25: Scenario 1 – Detailed Transient Voltage Violations for Benchmark Case

Cont. No.	Cont. Name	Bus Number	Bus Name	Violation Type	Minimum PU Voltage	Start Time	End Time	Voltage Threshold
Regional_9	0830_W_OTP_P42	657752	DRAYTON4 230.	Drop	0.7615	0.771	1.071	0.8
Regional_9	0830_W_OTP_P42	657754	MAPLE R4 230.	Drop	0.6925	0.85	0.975	0.7
Regional_9	0830_W_OTP_P42	657754	MAPLE R4 230.	Drop	0.6925	0.85	0.975	0.7
Regional_9	0830_W_OTP_P42	657946	PRAIRIE3 345.	Drop	0.6722	0.804	1.025	0.7
Regional_9	0830_W_OTP_P42	657946	PRAIRIE3 345.	Drop	0.6878	0.787	0.787	0.7
Regional_9	0830_W_OTP_P42	657946	PRAIRIE3 345.	Drop	0.6722	0.804	1.025	0.7
Regional_9	0830_W_OTP_P42	657758	WINGER 4 230.	Drop	0.6946	0.879	0.975	0.7
Regional_9	0830_W_OTP_P42	10000	WINGR STATCM230.	Drop	0.6946	0.879	0.975	0.7

To mitigate the transient low voltages in Scenario 1's benchmark case, Table 26 shows the network upgrade applied.

Table 26: Network Upgrade to Mitigate Scenario 1's Transient Voltage Violations

Constraint	Network Upgrade
Transient minimum voltage violation	50 MVAR STATCOM at Winger 4 230 kV substation (not allocated)

3.5.2. Scenario 2 Results

After applying the 50 MVAR STATCOM at Winger 4 substation to mitigate transient low voltages in Scenario 1's benchmark case, Table 27 and Table 28 show the transient voltage violation on MPC facilities for Scenario 2's study case. There were no concerns related to damping or relay margin violations.

Table 27: Scenario 2 – Summary of Violations for Study Case

Cont. No.	Contingency Description	Damping Index (%)	Volt. Drop Duration Index (Sec)	Volt. Rise Duration Index (Sec)	Zone 1 Relay Margin Index (%)	Zone 2 Relay Margin Index (%)	Status
Regional_9	0830_w_otp_p42	61.27	0.292	0.392	51.1	41.5	Insecure

Table 28: Scenario 2 – Detailed Transient Voltage Violations for Study Case

Cont. No.	Cont. Name	Bus Number	Bus Name	Violation Type	PU Voltage Minimum	Start Time	End Time	Voltage Threshold
Regional_9	0830_W_OTP_P42	657752	DRAYTON4 230.	Drop	0.7601	0.771	1.062	0.8
Regional_9	0830_W_OTP_P42	657419	GRAGER 7 115.	Drop	0.6977	0.883	0.958	0.7
Regional_9	0830_W_OTP_P42	657419	GRAGER 7 115.	Drop	0.6997	0.875	0.875	0.7
Regional_9	0830_W_OTP_P42	657754	MAPLE R4 230.	Drop	0.6913	0.846	0.983	0.7
Regional_9	0830_W_OTP_P42	657704	MODEROW7 115.	Drop	0.6956	0.879	0.967	0.7
Regional_9	0830_W_OTP_P42	657704	MODEROW7 115.	Drop	0.6977	0.867	0.875	0.7
Regional_9	0830_W_OTP_P42	657946	PRAIRIE3 345.	Drop	0.6719	0.8	1.025	0.7
Regional_9	0830_W_OTP_P42	657946	PRAIRIE3 345.	Drop	0.6819	0.783	0.792	0.7
Regional_9	0830_W_OTP_P42	657433	REED 7 115.	Drop	0.6968	0.883	0.962	0.7
Regional_9	0830_W_OTP_P42	657433	REED 7 115.	Drop	0.6988	0.867	0.875	0.7
Regional_9	0830_W_OTP_P42	657410	VETBLVD7 115.	Drop	0.7	0.95	0.95	0.7
Regional_9	0830_W_OTP_P42	657410	VETBLVD7 115.	Drop	0.699	0.908	0.933	0.7
Regional_9	0830_W_OTP_P42	657410	VETBLVD7 115.	Drop	0.699	0.887	0.892	0.7

To address the transient low voltage violations in Scenario 2's study case, the mitigation measures in Table 29 are required.

Table 29: Network Upgrade to Mitigate Scenario 2's Transient Voltage Violations

Cont. No.	Contingency Description	Violation Type	Mitigation Measure
Regional_9	0830_w_otp_p42	Voltage	3x 30 MVAR capacitor banks at Winger 4 230 kV substation (for a total of 4x 30 MVAR at Winger 4 substation)

3.5.3. Scenario 3 Results

With the network upgrades in Table 29 applied to Scenario 2, there were no transient voltage, damping, or relay margin violations in Scenario 3's benchmark and study cases.

3.5.4. Scenario 4 Sensitivity LRTP-1 Results

With only the LRTP-1 project, Table 30, Table 31, Table 32 and Table 33 show that there are transient low voltage violations in both the benchmark and study cases for the 0830_w_otp_p42 contingency event, which was the worst-case contingency identified in the previous scenarios.

Table 30: Scenario 4 Sensitivity LRTP-1 – Summary of Violations for Benchmark Case

Contingency Description	Damping Index (%)	Volt. Drop Duration Index (Sec)	Volt. Rise Duration Index (Sec)	Zone 1 Relay Margin Index (%)	Zone 2 Relay Margin Index (%)	Status
0830_w_otp_p42	99	0.217	0.363	51.200	41.600	Insecure

Table 31: Scenario 4 Sensitivity LRTP-1 – Detailed Transient Voltage Violations for Benchmark Case

Cont. Name	Bus Number	Bus Name	Violation Type	PU Voltage Minimum	Start Time	End Time	Voltage Threshold
0830_W_OTP_P42	657752	DRAYTON4 230.	Drop	0.783	0.779	0.983	0.8

Table 32: Scenario 4 Sensitivity LRTP-1 – Summary of Violations for Study Case

Contingency Description	Damping Index (%)	Volt. Drop Duration Index (Sec)	Volt. Rise Duration Index (Sec)	Zone 1 Relay Margin Index (%)	Zone 2 Relay Margin Index (%)	Status
0830_w_otp_p42	99	0.296	0.396	51.600	42.000	Insecure

Table 33: Scenario 4 Sensitivity LRTP-1 – Detailed Transient Voltage Violations for Study Case

Cont. Name	Bus Number	Bus Name	Violation Type	PU Voltage Minimum	Start Time	End Time	Voltage Threshold
0830_W_OTP_P42	657726	ANDERNW7 115.	Drop	0.699	0.937	0.942	0.700
0830_W_OTP_P42	657726	ANDERNW7 115.	Drop	0.699	0.887	0.892	0.700
0830_W_OTP_P42	657726	ANDERNW7 115.	Drop	0.700	0.871	0.875	0.700
0830_W_OTP_P42	657752	DRAYTON4 230.	Drop	0.755	0.767	1.062	0.800
0830_W_OTP_P42	657723	GREENWD7 115.	Drop	0.699	0.937	0.942	0.700
0830_W_OTP_P42	657723	GREENWD7 115.	Drop	0.699	0.887	0.892	0.700
0830_W_OTP_P42	657723	GREENWD7 115.	Drop	0.700	0.871	0.875	0.700
0830_W_OTP_P42	657754	MAPLE R4 230.	Drop	0.700	0.962	0.962	0.700
0830_W_OTP_P42	657754	MAPLE R4 230.	Drop	0.697	0.937	0.942	0.700
0830_W_OTP_P42	657754	MAPLE R4 230.	Drop	0.699	0.908	0.921	0.700

Cont. Name	Bus Number	Bus Name	Violation Type	PU Voltage Minimum	Start Time	End Time	Voltage Threshold
0830_W_OTP_P42	657754	MAPLE R4 230.	Drop	0.698	0.883	0.892	0.700
0830_W_OTP_P42	657754	MAPLE R4 230.	Drop	0.700	0.875	0.875	0.700
0830_W_OTP_P42	657946	PRAIRIE3 345.	Drop	0.672	0.779	1.021	0.700
0830_W_OTP_P42	657946	PRAIRIE3 345.	Drop	0.672	0.779	1.021	0.700
0830_W_OTP_P42	657758	WINGER 4 230.	Drop	0.681	0.804	1.017	0.700
0830_W_OTP_P42	657758	WINGER 4 230.	Drop	0.691	0.783	0.787	0.700
0830_W_OTP_P42	657758	WINGER 4 230.	Drop	0.681	0.804	1.017	0.700
0830_W_OTP_P42	10000	WINGR STATCM230.	Drop	0.681	0.804	1.017	0.700
0830_W_OTP_P42	10000	WINGR STATCM230.	Drop	0.691	0.783	0.787	0.700
0830_W_OTP_P42	10000	WINGR STATCM230.	Drop	0.681	0.804	1.017	0.700

Due to transient low voltages in the benchmark case, this result demonstrates that MISO's LRTP-1 project by itself is not sufficient to replace network upgrades at identified at Winger from the previous scenarios.

3.5.5. Scenario 4 Sensitivity LRTP-1 and LRTP-2 Results

With both MISO LRTP-1 and LRTP-2 projects in-service, there were no transient voltage, damping, or relay margin violations from the 0830_w_otp_p42 contingency event in both the benchmark and study cases. This sensitivity study demonstrates that with both MISO LRTP-1 and LRTP-2 projects, no additional network upgrades are required at Winger substation.

3.6. Conclusion

The transient stability study assessed regional and local contingencies across three scenarios without MISO's LRTP projects and two sensitivity scenarios with the LRTP projects in-service.

There were no damping or relay margin violations in any of the scenarios. However, transient voltage drop violations were initially identified on MPC facilities on the benchmark case. If both of MISO's LRTP-1 and LRTP-2 projects were in-service, then the transient voltage violations would be mitigated, and no stability network upgrades would be allocated to the ASA project.

If both MISO LRTP-1 and LRTP-2 projects were not in-service, then a 50 MVAR STATCOM contingent upgrade at Winger 4 substation would be required to mitigate the voltage drop violation. Additionally, three 30 MVAR capacitor banks (for a total of 4x 30 MVAR capacitor banks) would be required at Winger 4 substation and cost allocated to the ASA project.

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 Minnkota ASA are listed in Table 34 through Table 39. Costs are planning level estimates and subject to revision in the facility studies.

Table 34 shows Minnkota network upgrades allocated to the ASA project assuming both MISO's LRTP-1 and LRTP-2 projects are in-service. Otherwise, additional costs in Table 35 will be cost allocated to the ASA project as well.

Table 34: Minnkota Network Upgrades Allocated to DISIS-2019-001 Phase 2 Project

Constraint	Owner	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Grand Forks – Falconer 115 kV	MPC / WAPA	266.50	Rebuild line and terminal upgrades	$1,500,0000	GEN-2019-037
3rd Center 345/230 kV Autotransformer #1	MPC / OTP	775.12	Add third Center 345 / 230 kV autotransformer and terminal upgrades	$10,500,000	GEN-2019-037
3rd Center 345/230 kV Autotransformer #2		774.04			
			Total Cost	$12,000,000	GEN-2019-037

Table 35: Additional Minnkota Network Upgrades Allocated to DISIS-2019-001 Phase 2 Project without MISO LRTP-1 and LRTP-2

Constraint	Owner	Minimum Voltage (PU)	Mitigation	Cost ($)	Generators
Transient Stability	MPC / OTP	0.6719	3x 30 MVAR capacitor bank at Winger 4 230 kV substation (for a total of 4x 30 MVAR)	$3,000,000	GEN-2019-037
			Additional Costs to Table 34's Estimate	$3,000,000	GEN-2019-037

Table 36 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 ASA project.

Table 36: Minnkota Network Upgrades Allocated to Higher Queued Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Jamestown – Center 345 kV	MPC / OTP	822.4	Prior queued project expected to mitigate thermal violation	GEN-2019-037
Wilton – Winger 230 kV	MPC	371.7	Prior queued project expected to mitigate thermal violation	GEN-2019-037
Prairie 345/230 kV Autotransformer	MPC	549.5	Prior queued project expected to mitigate thermal violation	GEN-2019-037

Table 37 shows the MISO LRTP Projects that are required to mitigate the identified stability constraints. If these upgrades are not built, then the contingent upgrades in Table 38 are required as well as the network upgrades that will be cost allocated to the ASA project as shown in Table 35.

Table 37: MISO Network Upgrades Required to Mitigate Stability Violations

Constraint	Owner	Mitigation	Generators
Transient Stability	MPC	MISO LRTP-1 and LRTP-2 projects expected to mitigate stability violation	GEN-2019-037

Table 38 shows the Minnkota contingent network upgrade that is required to mitigate the identified stability constraints in the benchmark case if both MISO LRTP-1 and LRTP-2 projects are not in-service.

Table 38: Minnkota Network Upgrades to Mitigate Benchmark Case Violations in Stability Study without MISO's LRTP-1 and LRTP-2 Projects

Constraint	Owner	Minimum Voltage (PU)	Network Upgrade to Address Benchmark Case Violations (not allocated)
Transient Stability	OTP / MPC	0.672	50 MVAR STATCOM + 1x 30 MVAR capacitor bank at Winger expected to mitigate stability violation in benchmark case

Table 39 shows the Minnkota network upgrades that are alleviated by existing MPC equipment that do not require mitigation.

Table 39: Minnkota Network Upgrades Mitigated by Existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Drayton – Letellier 230 kV	MPC / MH	485.2	Below minimum MPC equipment rating (876.4 MVA)	GEN-2019-037

4.2. Cost Allocation Methodology

A generator in the DISIS-2019-001 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 a steady-state or a transient stability voltage constraint driven NUs was determined from the voltage impact each project has on the most constrained bus under the most constraining contingency[1]. 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.

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 40.

Table 40: Summary of NU Costs Allocated to each Generation Project

Project	Cost of NUs ($)	Additional Costs of NUs without MISO LRTP Projects
GEN-2019-037	$12,000,000	$3,000,000
Total Cost	**$12,000,000**	**$3,000,000**

[1]In the stability analysis, for contingencies that resulted in non-convergence in power flow, the voltage impact was taken from the stability models at system intact condition.

Appendix A
Case Development

ND and SD Generator Dispatch

Appendix A - ND
and SD Generator D

Appendix B
ACCC Analysis Results

Thermal Constraints

Appendix B -
Thermal Constraints

Non-Converged Contingencies

Appendix B -
Non-Converged Cor

Voltage Constraints

Appendix B -
Voltage Constraints

Appendix C
Transient Stability Results

Scenario 1 Benchmark Case – Transient Stability Analysis Results

Appendix C.1 -
Scenario 1 TSAT Res

Scenario 2 Benchmark Case – Transient Stability Analysis Results

Appendix C.2 -
Scenario 2 TSAT Res

Scenario 2 Study Case – Transient Stability Analysis Results

Appendix C.2 -
Scenario 2 TSAT Res

Scenario 3 Benchmark Case – Transient Stability Analysis Results

Appendix C.3 -
Scenario 3 TSAT Res

Scenario 3 Study Case – Transient Stability Analysis Results

Appendix C.3 -
Scenario 3 TSAT Res

Scenario 4 Sensitivity LRTP-1 Benchmark Case – Transient Stability Analysis Results

Appendix C.4 -
Scenario 4 LRTP-1 TS

Scenario 4 Sensitivity LRTP-1 Study Case – Transient Stability Analysis Results

Appendix C.4 -
Scenario 4 LRTP-1 TS

Scenario 4 Sensitivity LRTP-1 and LRTP-2 Benchmark Case – Transient Stability Analysis Results

Appendix C.4 -
Scenario 4 LRTP-1 ar

Scenario 4 Sensitivity LRTP-1 and LRTP-2 Study Case – Transient Stability Analysis Results

Appendix C.4 -
Scenario 4 LRTP-1 ar

Appendix D
Cost Allocation

Maximum MW Impacts

Appendix D -
Maximum MW Impa

MW Contribution to Constraints

Appendix D - MW
Contribution to Cor

Voltage Impacts on Steady-State Constraints

Appendix D -
Voltage Impact on S

Network Upgrades Cost Allocation

Appendix D -
Network Upgrade C