Appendix I

Transmission Studies

Contain Confidential and Critical Energy Infrastructure information (CEII)

Do not Release

FINAL

Attachment Y2 Study Scope

Minnesota Power

Boswell Units 3 & 4: 959 MW

April 4, 2019

MISO

P.O. Box 4202

Carmel, IN 46082-4202

Tel.: 317-249-5400 Fax: 317-249-5703
http://www.misoenergy.org

CONFIDENTIAL

EXECUTIVE SUMMARY

On August 13, 2018, Minnesota Power submitted an Attachment Y-2 study request to MISO for the potential change of status of Boswell units 3&4 with the study effective date of January 1, 2030.

MISO performed a Transmission System reliability assessment of Boswell Units 3&4 set forth in the MISO Business Practices Manuals and was discussed and reviewed with the impacted Transmission Owners (TOs): Minnesota Power, Otter Tail Power, Great River Energy, Missouri River Energy Services, and Xcel Energy. This Attachment Y2 study focusses on studying various scenarios to identify reliability issues due to potential retirement of Boswell unit 3&4.

After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are reliability issues identified related to the potential change of status of Boswell Units 3 and 4, jointly or separately, that would likely require robust mitigating solutions to be built before the retirement of the unit(s) could be allowed. One or both units may need to be designated as System Support Resource ("SSR") units in the event the mitigating solution is not built prior to the retirement date indicated in the future Attachment Y study request. The issues are summarized below for each study case.

In Scenario 1 with **Boswell Unit 3 Offline**, there were very few issues identified in the Summer Peak and Shoulder cases. In the Winter Peak case with heavy northward flow toward Northern Minnesota and Manitoba, there appear to be transfer limitations related to the Chisago – Forbes 500 kV Line and parallel 230 kV lines that would result in voltage stability issues following loss of the [redacted]. Several related stability, voltage, and thermal violations were also observed in the Winter Peak case. These issues indicated a need for a robust mitigating solution prior to retirement of Boswell Unit 3. Absent such a solution it is likely that Boswell Unit 3 would be designated a System Support Resource if similar results were identified in an Attachment Y Study.

In Scenario 2 with **Boswell Unit 4 Offline**, similar to Scenario 1, there were very few issues identified in the Summer Peak and Shoulder cases. The same Winter Peak voltage stability and related issues were identified in Scenario 2 as in Scenario 1, and were observed to be worse when the larger Boswell unit is offline. If similar results were identified in an Attachment Y Study, it is likely that Boswell Unit 4 would be designated a System Support Resource and a robust mitigating solution would need to be developed.

In Sensitivity 1 with **Boswell Unit 3 & Boswell Unit 4 Offline**, there were also very few issues identified in the Summer Peak and Shoulder cases. The Winter Peak voltage stability and related issues identified with one of the two units offline were found to be worsened with both units offline. If Boswell Unit 3 and Boswell Unit 4 were evaluated under a single Attachment Y Notice and similar results were identified in that study as those found in this Attachment Y2 study, it is likely that both units would be designated a System Support Resource and a robust mitigating solution would need to be developed.

In Sensitivity 2 with **Boswell Unit 3 & Boswell Unit 4 [redacted] Generators Offline**, additional issues were identified in the Summer Peak, Shoulder, and Winter Peak cases. The Winter Peak voltage stability and related issues identified in the previous cases were found to be present, and some additional stability and voltage issues were also identified due to the [redacted] baseload generators also being offline. Since this sensitivity assumes the retirements of several units at several different sites across a relatively large geographic area and none of these units currently have Attachment Y notices in progress, it is difficult to say when or if these issues would show up in future Attachment Y studies. The main conclusion from Sensitivity 2 is that there are certain issues that do not show up in the cases involving only the Boswell units (Scenario 1, Scenario 2, and Sensitivity 1). These issues are therefore more strongly tied to the retirement of the [redacted] baseload generators and – at most – would be aggravated by the retirement of the Boswell units if some combination of [redacted] generators had already been retired.

The development of robust mitigating solution(s) which would enable the retirement scenarios contemplated in this report are outside the scope of this Attachment Y2 study. Due to the complex nature of the retirements contemplated, any such mitigation solution development would need detailed analysis and discussions. MISO and the Transmission Owner's involved with this study did not conduct an analysis of any potential mitigating solutions because the timeline for conducting the analysis is significantly outside the scope of an Attachment Y2 study.

An Attachment Y-2 study is a non-binding assessment of the Transmission System reliability for the potential suspension or retirement of a Generation Resource(s). The results of the study are not definitive and the analysis is to provide information to the Market Participant to assist them in evaluating their options. However, it does not commit the Market Participant to proceed with plans for suspension or retirement.

Furthermore, while the analysis conducted for the Attachment Y-2 study may be used in preparing a subsequent Attachment Y study, further study may be required to evaluate the impacts due to change in assumptions of system conditions when an Attachment Y Notice is submitted.

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1. INTRODUCTION

On August 13, 2018, Minnesota Power submitted an Attachment Y-2 study request to MISO for the potential change of status of Boswell units 3&4 with the study effective date of January 1, 2030.

The total capacity of Boswell units 3&4 is 959 MW. It is connected to the Minnesota Power transmission system, and is located in Minnesota.

1 Study Units

Power Flow Area	Unit Description	kV Network[1]	Total Net MW	GVTC Value MW	Start Date of Retirement
MP	Boswell Unit 3	20.9	390.9	366.5	1/1/2030
	Boswell Unit 4	22.8	630.0	592.5	
Total MW			1020.9	959	

[redacted]

Figure 1: General Location of Boswell Units 3 & 4

[1] In study models

2. STUDY OBJECTIVE

Under Section 38.2.7 of MISO's Tariff, SSR procedures maintain system reliability by providing a mechanism for MISO to enter into agreements with Market Participants (MP) that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that have requested to either Retire or Suspend, but are required to maintain system reliability.

The principal objective of an Attachment Y-2 study is to determine if the unit(s) for which a potential change in status requested is necessary for system reliability based on the criteria set forth in the MISO Business Practices Manuals. The study work included monitoring and identifying the steady state branch/voltage violations on transmission facilities due to the unavailability of the Generation Resource or SCU. The relevant MISO Transmission Owner(s) and/or regional reliability criteria are used for monitoring such violations.

An Attachment Y-2 study is a non-binding informational study intended to determine whether it is likely that the Generation Resource(s) would qualify as an SSR Unit(s). While the analysis conducted for the Attachment Y-2 study may be used in preparing a subsequent Attachment Y study, further study may be required to evaluate the impacts due to change in assumptions of system conditions when an Attachment Y Notice is submitted.

The purpose of this study is to assess the reliability impacts from the potential change of status of Boswell Units 3&4 located in Minnesota, effective January 1, 2030.

3. STUDY ASSUMPTIONS & INPUTS

3.1 Study Models

Studies were performed using the following power flow models:

- 2030 Summer Peak (Source: MISO17_2027_SUM_TA)
- 2030 Shoulder / Summer off peak (Source: MISO17_2027_SUM_TA)
- 2030 Winter Peak (Source: MMWG ERAG 2018 Series 2028-29 Winter Case)[2]

For the model, two scenarios were created which represented the "before" and "after" generator retirement/suspension states. In addition, two sensitivities were created which represented the unique situations of interest to the customer. The following is a brief summary of the four unique study cases:

- The purpose of Scenario 1 is to study the potential change in status of Boswell Unit 3 only
- The purpose of Scenario 2 is to study the potential change in status of Boswell Unit 4 only
- The purpose of Sensitivity 1 is to study the potential change in status of Boswell Unit 3 and Boswell Unit 4
- The purpose of Sensitivity 2 is to study the potential change in status of Boswell Unit 3 and Boswell Unit 4, in addition to several [redacted] generators

The scenarios and sensitivities are shown in the tables below.

2 Study Models

Scenario	Model Name	Loads	Topology	Boswell Unit 3 Generation	Boswell Unit 4 Generation	Sensitivity - Base Load Generation (Monticello Nuclear, Allen S King, Prairie Island Nuclear)	Dispatch[3] Type	Contingencies Category
Scenario1	2030SP_B3_OFF	Summer Peak	2030	*Off*	On	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030SP_B3_ON	Summer Peak	2030	*On*	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
	2030SH_B3_OFF	Shoulder off Peak	2030	*Off*	On	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030SH_B3_ON	Shoulder off Peak	2030	*On*	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6

[2] 2030Winter peak scenario was later added as per customer and impacted transmission owner request. The Manitoba Hydro (MH) interface in this study modeled at ~ 1400 MW import (instead of MH exporting 1000 MW as in the MMWG /ERAG 2028 Winter 2018 series).

[3] Dispatching according to procedure explained in BPM-020. "SCED + Scale" in the online cases means that all generators in the vicinity of the generator under study will remain dispatched at their SCED values identified in the corresponding offline case, and the rest of MISO scaled down to balance the overall generation in MISO after turning on Boswell 3 unit in Scenario1, Boswell 4 unit in Scenario2 and [redacted] units in Sensitivity scenario.

Scenario	Model Name	Loads	Topology	Boswell Unit 3 Generation	Boswell Unit 4 Generation	Sensitivity - Base Load Generation (Monticello Nuclear, Allen S King, Prairie Island Nuclear)	Dispatch[3] Type	Contingencies Category
	2030WP_B3_OFF	Winter Peak	2030	Off	On	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030WP_B3_ON	Winter Peak	2030	On	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
Scenario2	2030SP_B4_OFF	Summer Peak	2030	On	Off	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030SP_B4_ON	Summer Peak	2030	On	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
	2030SH_B4_OFF	Shoulder off Peak	2030	On	Off	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030SH_B4_ON	Shoulder off Peak	2030	On	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
	2030WP_B4_OFF	Winter Peak	2030	On	Off	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030WP_B4_ON	Winter Peak	2030	On	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
Sensitivity 1	2030SP_ Sens1_OFF	Summer Peak	2030	Off	Off	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030SP _Sens1_ON	Summer Peak	2030	On	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
	2030SH_ Sens1_OFF	Shoulder off Peak	2030	Off	Off	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030SH _Sens1_ON	Shoulder off Peak	2030	On	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
	2030WP_Sens1_OFF	Winter Peak	2030	Off	Off	On	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030WP_Sens1_ON	Winter Peak	2030	On	On	On	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
Sensitivity 2	2030SP_ Sens2_OFF	Summer Peak	2030	Off	Off	Off	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030SP _Sens2_ON	Summer Peak	2030	On	On	Off	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
	2030SH_ Sens2_OFF	Shoulder off Peak	2030	Off	Off	Off	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030SH _Sens2_ON	Shoulder off Peak	2030	On	On	Off	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6

Scenario	Model Name	Loads	Topology	Boswell Unit 3 Generation	Boswell Unit 4 Generation	Sensitivity - Base Load Generation (Monticello Nuclear, Allen S King, Prairie Island Nuclear)	Dispatch[3] Type	Contingencies Category
	2030WP_Sens2_OFF	Winter Peak	2030	*Off*	*Off*	*Off*	SCED	P1,P2,P4,P5,P7, Selected P3, P6
	2030WP_Sens2_ON	Winter Peak	2030	*On*	*On*	*Off*	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6

3.2 Study Assumptions

- **Generation**

Applicable approved Attachment Y (Retirement/Suspension) generation will be modelled offline

3 Generation Assumptions – Nearby Approved Attachment Y & Requested Scenarios

[redacted]

[redacted]

- **Transmission Projects**

Future Transmission Projects already included in study models are provided below:

4 MTEP Future Projects in 2030 Models

MOD Project Name	Project Type	Status	MOD Effective Date
GRE-2577-ColumbusTap69-R1	MTEP A	Planned	5/18/2021
GRE-2670-SCHUSTERLAKE_115_41_R1	MTEP A	Planned	8/28/2019
GRE-4380-Priam_115_69_R5	MTEP A	Planned	5/1/2019
GRE-BCC-ElkRiverToMMPA	Base Case Change	Correction	10/1/2018
GRE-7912-Lawndale2-115	MTEP A	Planned	5/1/2021
GRE-7884-Riverview345-115-69	MTEP A	Planned	12/10/2018
GRE-9200-TwoInlets115	MTEP B	Target MTEP A	10/1/2019
GRE-9201-BullMoose115	MTEP B	Target MTEP A	10/1/2019
GRE-9202-Swatara230	MTEP B	Target MTEP A	10/1/2019
GRE-9203-CromwellPump115	MTEP B	Target MTEP A	10/1/2019
GRE-8920-Elisha_115_34_R1	MTEP B	Target MTEP A	5/1/2021
GRE-12106-Scenic69	MTEP A	Planned	5/29/2020
GRE-12117-MoonLake69	MTEP A	Planned	9/1/2019
GRE-12104-Burnsville-RiverHills69	MTEP A	Planned	9/13/2019
GRE-12122-KnifeFalls115	MTEP A	Planned	9/28/2018
GRE-12165-Vermillion69	MTEP A	Planned	9/30/2019
GRE-10424-Zinran115	MTEP A	Planned	3/30/2018
GRE-12206-BensonCapBank115	MTEP C	Target MTEP A	1/8/2018
GRE-12211-LebanonHills115	MTEP C	Target MTEP A	4/30/2020
GRE-13464-BrooksLake115	MTEP C	Target MTEP A	10/30/2019
GRE-13851-HawickReroute69	MTEP C	Target MTEP A	6/1/2019
GRE-BCC-GardenCityMove	Base Case Change	Field Change	1/19/2018
GRE-BCC-XfmrUpdate20180130-R1	Base Case Change	Error Correction	1/30/2018
GRE-BCC-Update-20180131-01	Base Case Change	As Built	1/31/2018
GRE-9624-RemoveSandstoneTap69	MTEP A	Planned	6/1/2018
GRE-BCC-Update-20180227-01	Base Case Change	As Built	2/27/2018
GRE-BCC-VoltCriteria20180322	Base Case Change	Field Change	3/22/2018
GRE-BCC-Update-20180328-02	Base Case Change	As Built	3/28/2018

MOD Project Name	Project Type	Status	MOD Effective Date
GRE-BCC-HutchinsonUnit5	Base Case Change	As Built	4/1/2018
GRE-BCC-BrandonRoad	Base Case Change	Error Correction	4/6/2018
GRE-BCC-BlueberryDistName	Base Case Change	Error Correction	4/23/2018
GRE-BCC-Update-20180424-01	Base Case Change	As Built	4/24/2018
GRE-BCC-AreaZoneCorrections-20180515	Base Case Change	Error Correction	5/15/2018
GRE-BASECASE-REMOVE DODGE WIND	Base Case Change	Correction	5/21/2018
GRE-BCC-ND-FRM-Update-20180618-01	Base Case Change	As Built	11/1/2018
GRE-BCC-Update-20180626-01	Base Case Change	As Built	6/26/2018
GRE-9624-RemoveSandstoneTap69Part2	MTEP A	Planned	7/30/2018
GRE-BCC-Update-20180730-01	Base Case Change	As Built	7/30/2018
GRE-BCC-CoalCreekVS	Base Case Change	Field Change	7/30/2018
MP-2761-MISO-Dunka-Load	MTEP A	Planned	7/1/2020
MP-7910-5LUpgrade	MTEP A	Planned	11/1/2019
MP-3831-MISO-GNTL500kV-2015.04.16	MTEP A	Planned	6/1/2020
MP-MISO-Bison6	Generator	Planned	1/1/2018
MP-9625-Add_Nemadji	MTEP A	Planned	12/31/2018
MP-10383-LASTacHBRVolConv	MTEP A	Planned	12/31/2020
MP-12563-Bos230-115kVXfmr	MTEP A	Planned	12/31/2018
MP-12323-MISO-93Lupgrade	MTEP A	Planned	6/1/2020
MP-MISO-16LTapNormalOpen2018	Base Case Change	Correction	4/1/2018
MP-MISO-16LTapClosed2018	Base Case Change	Correction	10/1/2018
MP-MISO-16LTapNormalOpen2019	Base Case Change	Correction	4/1/2019
MP-MISO-16LTapClosed2019	Base Case Change	Correction	10/1/2019
MP-MISO-16LTapNormalOpen2020	Base Case Change	Correction	4/1/2020
MP-MISO-16LTapClosed2020	Base Case Change	Correction	10/1/2020
MP-MISO-16LTapNormalOpen2021	Base Case Change	Correction	4/1/2021
MP-MISO-16LTapClosed2021	Base Case Change	Correction	10/1/2021
MP-MISO-16LTapNormalOpen2022	Base Case Change	Correction	4/1/2022
MP-MISO-16LTapClosed2022	Base Case Change	Correction	10/1/2022

MOD Project Name	Project Type	Status	MOD Effective Date
MP-MISO-16LTapNormalOpen2023	Base Case Change	Correction	4/1/2023
MP-MISO-16LTapClosed2023	Base Case Change	Correction	10/1/2023
MP-MISO-16LTapNormalOpen2024	Base Case Change	Correction	4/1/2024
MP-MISO-16LTapClosed2024	Base Case Change	Correction	10/1/2024
MP-MISO-16LTapNormalOpen2025	Base Case Change	Correction	4/1/2025
MP-MISO-16LTapClosed2025	Base Case Change	Correction	10/1/2025
MP-MISO-16LTapNormalOpen2026	Base Case Change	Correction	4/1/2026
MP-MISO-16LTapClosed2026	Base Case Change	Correction	10/1/2026
MP-MISO-16LTapNormalOpen2027	Base Case Change	Correction	4/1/2027
MP-MISO-16LTapClosed2027	Base Case Change	Correction	10/1/2027
MP-13364-NorthShoreTransLineUpgradesProject	MTEP C	Target MTEP A	12/30/2019
MP-12583-MISO-76Lupgrade	MTEP A	Planned	5/1/2018
MP-7996-MISO-15LUpgrade	MTEP A	Planned	10/1/2019
MP-9646-MISO-NSWK_14LTapUpgrade	MTEP C	Target MTEP A	6/1/2020
MP-13504-MISO-LAS-TACHBRLUpgrades	MTEP C	Target MTEP A	12/31/2020
MP-13526-MISO-TiogaSub_MP	MTEP C	Target MTEP A	10/1/2018
MP-12644-MISO-NSS_STATCOM	MTEP A	Planned	9/1/2019
MP-9647-MISO-53LUpgrade	MTEP B	Target MTEP A	6/1/2020
MP-13484-MISO-TwoHarbors115kV	MTEP C	Target MTEP A	12/31/2019
MP-4294-18L Upratedatechng	MTEP A	Planned	3/1/2018
MP-MISO-16LTapClosed2028	Base Case Change	Correction	10/1/2028
MP-MISO-16LTapNormalOpen2028	Base Case Change	Correction	5/1/2028
MP-MISO-Nemadjitopofix	Base Case Change	Correction	12/31/2018
MP-12563-Boswell-Blackwater115kV	MTEP A	Planned	12/31/2018
MP-MISO-TacRidgecorrection	Base Case Change	Error Correction	1/8/2018
MP-13485-MISO-HoytLakes115kV	MTEP C	Target MTEP A	12/31/2020
MP-7997-MISO-15thAveModernization	MTEP A	Planned	12/31/2018
MP-MISO-NSSSLineImpUpdates	Base Case Change	As Built	1/15/2018

MOD Project Name	Project Type	Status	MOD Effective Date
MP-MISO-Reactivedeviceupdates	Base Case Change	Error Correction	1/17/2018
MP-MISO-BearCrk6946Kvupdates	Base Case Change	As Built	1/31/2018
MP-MISO-BBYXfmr2impfix	Base Case Change	Error Correction	1/31/2018
MP-MISO-PotlatchGenfix	Base Case Change	Error Correction	1/31/2018
MP-MISO-BoiseP2off	Base Case Change	Error Correction	1/31/2018
MP-MISO-BisonXfmrratiofix	Base Case Change	Field Change	2/6/2018
MP-MISO-RemoveHoytlakesCap	Base Case Change	Error Correction	2/6/2018
MP-MISO-16LTapClosed2028	Base Case Change	Correction	10/1/2028
MP-MISO-16LTapNormalOpen2028	Base Case Change	Correction	4/1/2028
MP-MISO-HibbardMbasefix	Base Case Change	Correction	2/6/2018
MP-MISO-37L_rtgupdate	Base Case Change	As Built	2/7/2018
18Series_ALL_MP	Base Case Change	Correction	6/20/2018
MP-MISO-95LImpchng	Base Case Change	Correction	6/30/2018
MP-MISO-20LImpchng	Base Case Change	Correction	6/30/2018
MP-MISO-71LImpchng	Base Case Change	Correction	2/20/2018
MP-MISO-18LImpchng	Base Case Change	Correction	3/7/2018
MP-MISO-21LImpchng	Base Case Change	Correction	2/20/2018
MP-MISO-6LImpchng	Base Case Change	Correction	4/9/2018
MP-MISO-10LImpchng	Base Case Change	Correction	4/9/2018
MP-MISO-37LImpchng	Base Case Change	Correction	6/4/2018
OTP_2220_BSS-Ellendale 345	MTEP A	Planned	6/30/2019
OTP_4232_TRF_Winger_230 [13-03-28 16:38]	MTEP B	Target MTEP A	11/15/2024
OTP_13344_RedLakeFallSWTap	MTEP A	Planned	1/27/2018
OTP_14056_Parkers_Prairie_115_tap	MTEP B	Target MTEP A	11/30/2020
OTP_Solway_Gen_RT_XT_Update	Base Case Change	Error Correction	1/5/2018
OTP_update_bus_voltage_limits	Base Case Change	Error Correction	1/9/2018

MOD Project Name	Project Type	Status	MOD Effective Date
OTP_re-add_Bottineau_TW	Base Case Change	Correction	1/12/2018
OTP_MTEP18_minor_load_fixes	Base Case Change	Error Correction	1/15/2018
OTP_13344_RedLkFallSWTap_add_branch	MTEP A	Planned	1/31/2018
OTP_Buffalo Xfmr2 Impedance fix	Base Case Change	Correction	2/7/2018
OTP-SHEYENNE-MAPLETON-RATING-CORRECTION	Base Case Change	Error Correction	3/29/2018
OTP_CassLk_115kV_Town-CasinoLd_Move	MTEP A	Planned	8/1/2018
OTP_Mapleton_115kV_Compressor & TownLd_Move	MTEP A	Planned	7/15/2018
OTP_15304_Twin Brooks 345 Sub	MTEP A	Planned	7/6/2020
XEL-4224-IRONWOOD-SW-REPLACEMENT_R3	MTEP A	Planned	12/1/2019
XEL-4696-PRENTICE-MEDFORD-REBUILD	MTEP A	Planned	5/30/2020
XEL-8079-LINE_0714_REBUILD	MTEP A	Planned	6/1/2021
XEL-3797-MAPLE_RIVER-RED_RIVER_2ND_CKT_R1	MTEP A	Planned	10/31/2018
XEL-4231-GALESVILLE_REBUILD_R3	MTEP A	Planned	5/31/2018
XEL-4314-ASHLAND-IRONWOOD-REBUILD_R2	MTEP A	Planned	12/1/2021
XEL-4695-WILSON-BUS-BKR-AND-HALF_R1	MTEP A	Planned	9/1/2019
XEL-4305-SW-MN-REACTOR_R2-P2	MTEP A	Planned	6/3/2019
XEL-10288-OSPREY-69KV-EXPANSION-R1	MTEP A	Planned	9/1/2018
XEL-3769-MANKATO_TC_THROUGHFLOW_R5	MTEP A	Planned	6/1/2019
XEL-10074-AIRPORT-ROGERS-LAKE-REBUILD	MTEP A	Planned	2/15/2019
XEL-10289-ELMWOOD-EAU-GALLE-REBUILD-P2	MTEP A	Planned	12/15/2019
XEL-10069-TWIN-CREEK-69KV	MTEP A	Planned	11/1/2019
XEL-10045-LAKE-HAZELTINE-115	MTEP A	Planned	1/31/2018
XEL-G261-11644 WILMARTH-SWAN LK UPRATE-R1	MTEP A	Planned	10/1/2018
XEL-10076-WEST_ST_CLOUD_TO_MILLWOOD-69-KV-REBUILD	MTEP A	Planned	5/1/2019
XEL-4697-SPK-LAJ-RECONDUCTOR_P2	MTEP A	Planned	11/30/2018
XEL-J426-EXPAND CHANARAMBIE-R1	MTEP A	Planned	12/15/2018
XEL-11993-BLACK-DOG-WILSON-1-AND-3-UPRATE	MTEP A	Planned	12/2/2019
XEL-8149-BAYFIELD_LOOP_34.5_KV_P1_R2	MTEP A	Planned	12/1/2019
XEL-8113-WARD_COUNTY_230kV-R3	MTEP A	Planned	11/30/2018
XEL-14035-14036-TC-Fault-Current	MTEP C	Target MTEP A	12/28/2018
XEL-BLACK-DOG-6-R2	Generator	Planned	6/1/2018
XEL-FORBES-SVC-RETIREMENT	MTEP C	Target MTEP A	6/1/2020
XEL-12011-BLUFF-SIDING-RECONFIGURATION	MTEP C	Target MTEP A	12/31/2019
XEL-14046-FALLS-CAPACITOR	MTEP C	Target MTEP A	6/1/2021
XEL-14047-LINCOLN-CO-CAPACITOR	MTEP C	Target MTEP A	6/1/2020

MOD Project Name	Project Type	Status	MOD Effective Date
XEL-3127-BRIGGS-ROAD-REACTOR	MTEP A	Planned	12/31/2018
XEL-14054-PLYMOUTH-AREA-UPGRADES-P2	MTEP C	Target MTEP A	6/1/2018
XEL-3473-SIOUX_FALLS_FINAL_PHASE	MTEP A	Planned	6/1/2018
XEL-WATERVILLE-AREA-RATINGS-CORRECTION	Base Case Change	Error Correction	1/3/2018
XEL-JANUARY-2018-IMPEDANCE-UPDATES	Base Case Change	Error Correction	1/4/2018
XEL-BROOKINGS-CO-TRANSFORMER-IMPEDANCE-CORRECTION	Base Case Change	Error Correction	1/11/2018
XEL-COLVILLE-RATING-CORRECTION	Base Case Change	Error Correction	1/25/2018
XEL-CARTWRIGHT-RATING-CORRECTION	Base Case Change	Error Correction	1/25/2018
XEL-WAVERLY-LOAD-CORRECTION	Base Case Change	Error Correction	1/25/2018
XEL-BAYFRONT-NORRIE-RATING-CORRECTION	Base Case Change	Error Correction	1/25/2018
XEL-RED-ROCK-TRANSFORMER-UPGRADE	MTEP C	Target MTEP A	6/1/2021
XEL-WILMARTH-SWAN-LAKE-RATINGS-CORRECTION	Base Case Change	Field Change	12/31/2018
XEL-CARVER-COUNTY-ARLINGTON-RATINGS-CORRECTION	Base Case Change	Field Change	12/31/2021
XEL-ST-CROIX-FALLS-IMPEDANCE-CORRECTION	Base Case Change	Error Correction	2/6/2018
XEL-WEST_ST_CLOUD_TO_WESTWOOD-69KV-EXISTING	Base Case Change	Error Correction	2/28/2018
XEL-MERRIAM-PARK-RATINGS-CORRECTION	Base Case Change	Error Correction	2/20/2018
XEL-14054-PLYMOUTH-AREA-UPGRADES-P3_R1	MTEP C	Target MTEP A	12/31/2018
XEL-CAPACITOR-BUS-CORRECTION	Base Case Change	Error Correction	2/28/2018
XEL-GLEASONLK-CAP-BUS-CORRECTION	Base Case Change	Error Correction	3/1/2018
XEL-BROOKINGS_CO-WHITE-RATING-CORRECTION	Base Case Change	Error Correction	3/27/2018
XEL-PRAIRIE-VOLTAGE-LIMIT-CORRECTION	Base Case Change	Error Correction	3/27/2018
XEL-MONTICELLO-LOAD-CORRECTION	Base Case Change	Error Correction	4/4/2018
XEL-MAIN_ST-TERMINAL-RATING-CORRECTIONS	Base Case Change	Error Correction	4/4/2018
XEL-TREMVAL-JACKSON_CO-IMPEDANCE-UPDATE	Base Case Change	Error Correction	4/9/2018
XEL-WABASHA-LAKE_CITY-RATING-UPDATE	Base Case Change	Error Correction	4/13/2018
XEL-REDWING-FRONTENAC_TAP-RATING-UPDATE	Base Case Change	Error Correction	4/13/2018

MOD Project Name	Project Type	Status	MOD Effective Date
XEL-RICE_LAKE-BARRON-RATING-UPDATE	Base Case Change	Error Correction	5/4/2018
XEL-KOHLMAN_LAKE-GOOSE_LAKE-RATING-UPDATE	Base Case Change	Error Correction	5/7/2018
XEL-SVEADHAL_TAP-BUTTERFIELD-RATING-UPDATE	Base Case Change	Error Correction	5/4/2018
XEL-APACHE-RATING-UPDATE	Base Case Change	Error Correction	5/30/2018
XEL-25301-FALLS-SPLIT_ROCK-RATING-UPDATE	Base Case Change	As Built	5/30/2018
XEL-BUTTERFIELD_TAP-SVEADAHL_TAP-RATING-UPDATE	Base Case Change	Error Correction	6/15/2018
XEL-GRAVEL_ISLAND-HALLIE-IMPEDANCE-UPDATE	Base Case Change	Error Correction	6/15/2018
XEL-JACKSON_CO-TREMVAL-IMPEDANCE-UPDATE	Base Case Change	Error Correction	6/13/2018
XEL-SIOUX_FALLS_TAP-LAWRENCE-RATING-UPDATE	Base Case Change	Error Correction	6/13/2018
XEL-THOMPSON-PRAIRIE-RATING-UPDATE	Base Case Change	Error Correction	6/15/2018
XEL-JUNE-2018-RATINGS-UPDATE	Base Case Change	Error Correction	6/21/2018
XEL-NROC-NO_HILLS-IMPEDANCE-UPDATE	Base Case Change	Error Correction	6/21/2018
XEL-THOMPSON-PRAIRIE-RATING-UPDATE	Base Case Change	Error Correction	6/15/2018
XEL-THOMPSON-HATTON-RATING-UPDATES	Base Case Change	Error Correction	7/2/2018
XEL-JULY-RATING-UPDATES	Base Case Change	Error Correction	7/3/2018
XEL-SEVEN-MILE-TRANSFORMER-UPDATES	Base Case Change	Error Correction	7/17/2018
XEL-AUG-RATING-UPDATES	Base Case Change	Error Correction	8/22/2018
MRES-GRE-OTP-15344-W MN Erie Jct to Frazee Project	MTEP A	Target A	1/1/2021

3.3 Monitoring and contingencies

- **Monitor**

Monitor all 69 kV and above facilities in areas MP (608), OTP (620), GRE (615), and XEL (600)

- **Contingencies**

NERC Category P1, P2, P4, P5, and P7 used in MTEP18 study of facilities within areas MP (608), OTP (620), GRE (615), and XEL (600)

Category P3 contingencies will be created using all single generator contingencies (P1-1), extracted from the P1 contingencies provided above, combined with all P1 contingencies provided above. To limit the number of possible P3 combinations:

- Only Category P1 events of facilities 100 kV or above within 6 Buses from the Study Unit(s) will be used in creating the required P3 combinations.
- Generator contingencies (Category P1-1) with aggregated generation above 50 MW will be used in creating the required P3 contingencies.

Similarly, Category P6 contingencies will be created using all non-generator contingencies (P1-2 to P1-5) of facilities 100 kV or above within 6 Buses from the Study Unit(s).

Specific NERC Category P3 and P6 contingencies requested by the customer were also included in the study. These contingencies include the following:

All P6 combinations of the following [redacted] kV [redacted] lines:

[redacted]

All P3 combinations for each of the tie lines listed above with each of the generators listed below:

[redacted]

4. STUDY CRITERIA

4.1 Applicable Reliability Criteria

- **Steady State Thermal Reliability Criteria**

Minnesota Power Transmission Planning Criteria applied for thermal analysis:

- For NERC Category P0 (System Intact), all thermal loadings exceeding 100% of the normal rating.
- For NERC Category P1 – P7 contingencies, all thermal loadings exceeding 100% of the emergency rating.

Otter Tail Power Transmission Planning Criteria applied for thermal analysis:

- For NERC Category P0 (System Intact), all thermal loadings exceeding 100% of the normal rating.
- For NERC Category P1 – P7 contingencies, all thermal loadings exceeding 100% of the emergency rating.

Great River Energy Transmission Planning Criteria applied for thermal analysis:

- For NERC Category P0 (System Intact), all thermal loadings exceeding 100% of the normal rating.
- For NERC Category P1 – P7 contingencies, all thermal loadings exceeding 100% of the emergency rating.

Xcel Energy Transmission Planning Criteria applied for thermal analysis:

- For NERC Category P0 (System Intact), all thermal loadings exceeding 100% of the normal rating.
- For NERC Category P1 – P7 contingencies, all thermal loadings exceeding 100% of the emergency rating.

- **Steady State Voltage Reliability Criteria**

Minnesota Power Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1 – P7 contingencies – Post Contingent

Rated Voltage / Facility	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
500 kV	1.00	1.05	0.95	1.10
230 kV	1.00	1.05	0.95	1.10
161 kV	1.00	1.05	0.95	1.10
138 kV	1.00	1.05	0.95	1.10
118 kV	1.00	1.05	0.95	1.10
115 kV	1.00	1.05	0.95	1.10
Warroad River SC 500 kV	0.90	1.20	0.90	1.20
Western MP 230 kV	0.97	1.05	0.92	1.10
North Dakota MP 230 kV	0.97	1.05	0.92	1.10
Western MP 115 kV	0.97	1.05	0.92	1.10

Otter Tail Power Transmission Planning Criteria applied for the voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1 – P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	**Max PU**	**Min PU**	**Max PU**
345 kV	0.97	1.05	0.92	1.10
230 kV	0.97	1.05	0.92	1.10
115 kV	0.97	1.07	0.92	1.10

Great River Energy Transmission Planning Criteria applied for the voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Voltage Ranges / Facility	Pre Contingent		Post Contingent	
	Min PU	**Max PU**	**Min PU**	**Max PU**
Ramsey 230 kV	0.95	1.05	0.90	1.10
Balta 230 kV	0.95	1.05	0.90	1.10
Coal Creek 230 kV6	0.95	1.05	0.90	1.10
Remaining ND Area	0.95	1.05	0.90	1.10
Dickinson 345 kV	0.95	1.05	0.90	1.10
Hubbard 230 & 115 kV 7	0.97	1.05	0.92	1.10
Wing River 230 & 115 kV 8	0.97	1.05	0.92	1.10
115 kV buses in OTP Operating area	0.95	1.07	0.90	1.10
All Load Serving Buses	0.95	1.05	0.92	1.10
Remaining Buses	0.95	1.05	0.90	1.10

Xcel Energy Transmission Planning Criteria applied for the voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Voltage Ranges / Facility	Pre Contingent		Post Contingent	
	Min PU	**Max PU**	**Min PU**	**Max PU**
Default for all buses > 100 kV	0.95	1.05	0.92	1.05
Default for all buses < 100 kV*	0.95	1.05	0.92	1.05
Default for all generator buses**	0.95	1.05	0.95	1.05

Voltage Ranges / Facility	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
Roseau 500 kV bus	0.95	1.10	0.92	1.10
Prairie 115 kV main bus	0.95	1.09	0.90	1.09
Prairie 115 kV capacitor bus	0.95	1.15	0.92	1.15
Sheyenne 115 kV capacitor bus	0.95	1.15	0.92	1.15
Running 230 kV capacitor bus	0.95	1.10	0.92	1.10
Roseau 230 kV capacitor bus	0.95	1.05	0.92	1.10
Chisago 500 kV bus	0.95	1.10	0.92	1.10
Forbes 500 kV bus	0.95	1.10	0.92	1.10
Bison 345 kV bus	0.95	1.05	0.92	1.10
Briggs Road 345 kV bus	0.95	1.05	0.92	1.10

*For 34.5 kV and below non-generation buses, pre and post contingent voltage of 0.9PU would be acceptable.
**For all Category P0, P1, P2, P4, P5, and P7 contingencies. [1] After a Category P3 or P6 contingency, generator bus voltage would be allowed to drop to 0.92 PU.

4.2 MISO Transmission Planning BPM SSR Criteria

-
- Per BPM-020 – R17, available mitigation may be applied for the valid NERC Category P1-P7 thermal and voltage violations as described by NERC Standards.
-

System Support Resource criteria for determining if an identified facility is impacted by the generator change of status will be:

- Under NERC Category P0 conditions and category P1-P7 contingencies, branch thermal violations are only valid if the flow increase on the element in the "after" retirement scenario is equal to or greater than:
  - a) 5% of the "to-be-retired" unit(s) MW amount (i.e. 5% PTDF) for a "base" (P0) violation compared with the "before" retirement scenario, or
  - b) 3% of the "to-be-retired" unit(s) amount (i.e. 3% OTDF) for a "contingency" (P1-P7) violation compared with the "before" retirement scenario.
- Under NERC category P0 conditions and category P1-P7 contingencies, high and low voltage violations are only valid if the change in voltage is greater than 1% as compared to the "before" retirement voltage calculation.
- Available mitigation may be applied for the valid NERC Category P1-P7 thermal and voltage violations as described by NERC Standards.
  - The need for the SSR is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available.
  - Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching, generator redispatch, and post-contingent Load Shedding plans allowed in the operating horizon.

5. STUDY METHODOLOGY

5.1 Steady-State Performance Analysis

- PTI – PSS/E version 33 and PowerGEM – TARA will be used to perform AC contingency analysis and SCED. Cases will be solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis will be performed on before and after cases. The results will be compared to find if there are any criteria violations due to the unit(s) change of status.

5.2 Voltage Stability Criteria

Voltage Stability Assessment (Power-Voltage Curve Analysis) will not be performed unless a specific concern is raised by the TO or MISO.

5.3 Dynamic Stability Criteria

Dynamic (Transient) Stability Assessment will not be performed unless a specific concern is raised by the TO or MISO.

6. STUDY RESULTS

Appendices of this report summarizes the results and analysis.

6.1 Scenario 1 (Boswell Unit 3) Analysis

The purpose of Scenario 1 was to evaluate the potential change in status of Boswell Unit 3 only.

No thermal violations were seen in the 2030 Summer Peak and Summer Shoulder Case. Thermal violations from the Winter Peak Case are discussed below.

No voltage violations were seen in the 2030 Summer Peak Case. Voltage violations which met the SSR voltage criteria were seen in 2030 Summer Shoulder Case and are shown in Appendix. All violations can be mitigated by Manitoba Hydro HVDC Run Back or Dorsey Synchronous Condensers operating guide. Voltage violations from the Winter Peak Case are discussed below.

There were numerous thermal and voltage violations in the Winter Peak Case, as well as several non-converged contingencies. A "non-converged" contingency is one that the power flow software program (PSS/E) was not able to solve. There could be a number of explanations for why a solution could not be reached, but in general non-converged contingencies are indicative of severe contingencies and in some cases potential voltage or transient stability problems. While most of the thermal violations identified in the Winter Peak Case could be addressed by redispatch or load shedding, the voltage violations and non-converged contingencies appear to require robust mitigating solution(s) for the Scenario 1 (Boswell Unit 3) Offline Case.

The thermal violations which could be addressed by redispatch are shown in Appendix. General observations about the underlying issues behind one of the thermal violations and some of the more severe voltage violations and non-converged contingencies are also discussed below. This is not meant to be an exhaustive discussion of all issues in the Scenario 1 (Boswell Unit 3) Offline Case, but rather to highlight what appear to be some of the more significant issues in the Winter Peak case.

Significant Overloads of Forbes 500/230 kV Transformers

There are two parallel 500/230 kV transformers at the Forbes Substation. For P6 events involving loss of [redacted], the remaining Forbes 500/230 kV transformer is loaded well beyond its emergency rating. In the study results, this flagged primarily for Category P6 events, but there are [redacted] failure events at Forbes that would produce similar results. Loss of the [redacted] leaves a single [redacted] as the sole outlet for all of the power flowing north on the Chisago – Forbes 500 kV Line. Post-contingent power flow on the remaining Forbes 500/230 kV transformer (normal capacity = 672 MVA) reaches 900 MVA in Scenario 1 (Boswell Unit 3 Offline); 1,000 MVA in Scenario 2 (Boswell Unit 4 Offline), and up to 1,200 MVA in Sensitivity 1 (Boswell Unit 3 & Boswell Unit 4 Offline). While these overloads were resolved in all study cases with redispatch and load shedding, they are driving a significant portion of the overall need for redispatch and load shedding due to their severity and would be worth addressing as part of a larger overall solution to the non-convergence issues described below.

Non-Convergence Due to Loss of* [redacted] *Line

The most prevalent and serious non-convergence issue identified in both Scenarios and both Sensitivities in the study is loss of the [redacted] Line. Across all contingency types (P1 – P7), most of the contingencies involving loss of the [redacted] Line result in non-convergence. The underlying issue appears to be regional voltage stability. There is a significant amount of power flowing north on the Chisago – Forbes 500 kV Line in the Winter Peak Case, and when it is lost there are no comparatively large (in terms of voltage and transfer capability) parallel transmission lines delivering power into Northeastern Minnesota. Without the [redacted] line, the majority of northward power flow gets rerouted onto five relatively long 230 kV transmission paths originating in the [redacted] and the Red River Valley. Based on the study results, these 230 kV lines do not appear to be capable of carrying the large amount of power flowing toward Northern Minnesota while maintaining adequate system voltage without the [redacted] line in service in any of the study scenarios. Given the confluence of circumstances contributing to this issue in the Winter Peak case (Boswell units offline, heavy northward MHEX flows, and heavy Northern Minnesota Winter Peak loading), further analysis would be necessary if a formal Attachment Y Notice was requested. In all likelihood, a robust mitigating solution would be necessary to address the voltage stability issues identified in this study.

Non-Convergence Due to Loss of Boswell Unit 4 + Riel – Forbes 500 kV

In the Scenario 1 Offline Case, non-convergence was observed for the [redacted] event involving loss of the [redacted] Line plus an unplanned outage of Boswell Unit 4. While it is not clear what the root cause of the non-convergence is, this contingency would result in significant additional power flow north on Chisago – Forbes 500 kV Line while simultaneously reducing outlet capability at Forbes without the [redacted] Line. This could be related to the Loss of [redacted] Line voltage stability issue described above and should be considered when developing a solution for it.

6.2 Scenario 2 (Boswell Unit 4) Analysis

The purpose of Scenario 2 was to evaluate the potential change in status of Boswell Unit 4 only.

No thermal violations were seen in the 2030 Summer Peak and Summer Shoulder Case. Thermal violations for the Winter Peak Case are discussed below.

No voltage violations were seen in the 2030 Summer Peak Case. Voltage violations which met the SSR voltage criteria were seen in the 2030 Summer Shoulder Case and are shown in Appendix. All violations can be mitigated by Manitoba Hydro HVDC Runback or Dorsey Synchronous Condensers operating guide. Voltage violations from the Winter Peak Case are discussed below.

There were numerous thermal and voltage violations in the Winter Peak Case, as well as several non-converged contingencies. A “non-converged” contingency is one that the power flow software program (PSS/E) was not able to solve. There could be a number of explanations for why a solution could not be reached, but in general non-converged contingencies are indicative of severe contingencies and in some cases potential voltage or transient stability problems. While most of the thermal violations identified in the Winter Peak Case could be addressed by redispatch or load shedding, the voltage violations and non-converged contingencies appear to require robust mitigating solution(s) for the Scenario 2 (Boswell Unit 4) Offline Case.

The thermal violations which could be addressed by redispatch are shown in Appendix. General observations about the underlying issues behind one of the thermal violations and some of the more severe voltage violations and non-converged contingencies are also discussed below. This is not meant to be an exhaustive discussion of all issues in the Scenario 2 (Boswell Unit 4) Offline Case, but rather to highlight what appear to be some of the more significant issues in the Winter Peak case.

Significant Overloads of Forbes 500/230 kV Transformers

Overloads were observed on the Forbes 500/230 kV transformers for contingencies resulting in loss of the [redacted]. Worst-case post-contingent loading on the 672 MVA-rated transformer in Scenario 2 was approximately 1,000 MVA. Further discussion of this issue is provided in Section 6.1.

Non-Convergence Due to [redacted] Line

Many contingencies resulting in loss of the [redacted] Line were non-converged in the Scenario 2 Offline study case. Further discussion of this issue is provided in Section 6.1.

Non-Convergence Due to Loss of [redacted]

In the Scenario 2 Offline Case, non-convergence was observed for the NERC Category P6 event involving loss of the [redacted] [redacted] plus loss of the [redacted] Line. While it is not clear what the root cause of the non-convergence is, this contingency would result in significant additional power flow north on Chisago – Forbes 500 kV Line while simultaneously reducing outlet capability at Forbes without the Riel – Forbes 500 kV Line. This could be related to the Loss of [redacted] voltage stability issue described above and should be considered when developing a solution for it.

Non-Convergence Due to Loss of [redacted] Transmission Outlets

In the Scenario 2 Offline Case, non-convergence was observed for NERC Category P7 events involving the [redacted] and the [redacted] Line. The same issue was also observed in the Sensitivity 1 and Sensitivity 2 Offline Cases. These contingencies likely weaken the source to the [redacted] in the Winter Peak case significantly enough to lead to a similar voltage stability issue as that described above for the [redacted] and should be considered when developing a solution for it.

6.3 Sensitivity 1 (Boswell Unit 3 & Boswell Unit 4) Analysis

The purpose of Sensitivity 1 was to evaluate the potential change in status of both Boswell Unit 3 and Boswell Unit 4 at the same time.

Several thermal violations that met the threshold of SSR criteria (3% OTDF of study units) were observed in the 2030 Summer Peak and Summer Shoulder Sensitivity 1 Case. These violations are shown in Appendix and can be mitigated by Manitoba Hydro HVDC Runback. Thermal violations for the Winter Peak Case are discussed below.

No voltage violations were seen in the 2030 Summer Peak Case. Voltage violations which met the SSR voltage criteria were seen in the 2030 Summer Shoulder Case and are shown in Appendix. As provided in Appendix all violations in the Sensitivity 1 Offline Case can be mitigated by load shed, Manitoba Hydro HVDC Runback, or Dorsey Synchronous Condensers operating guide. Voltage violations from the Winter Peak Case are discussed below.

There were numerous thermal and voltage violations in the Winter Peak Case, as well as several non-converged contingencies. A “non-converged” contingency is one that the power flow software program (PSS/E) was not able to solve. There could be a number of explanations for why a solution could not be reached, but in general non-converged contingencies are indicative of severe contingencies and in some cases potential voltage or transient stability problems. While most of the thermal violations identified in the Winter Peak Case could be addressed by redispatch or load shedding, the voltage violations and non-converged contingencies appear to require robust mitigating solution(s) for the Sensitivity 1 (Boswell Unit 3 & Boswell Unit 4) Offline Case.

The thermal violations which could be addressed by redispatch are shown in Appendix. General observations about the underlying issues behind one of the thermal violations and some of the more severe voltage violations and non-converged contingencies are also discussed below. This is not meant to be an exhaustive discussion of all issues in the Sensitivity 1 (Boswell Unit 3 & Boswell Unit 4) Offline Case, but rather to highlight what appear to be some of the more significant issues in the Winter Peak case.

Significant Overloads of Forbes 500/230 kV Transformers

Overloads were observed on the Forbes 500/230 kV transformers for contingencies resulting in loss of the [redacted]. Worst-case post-contingent loading on the 672 MVA-rated transformer in Sensitivity 1 was approximately 1,200 MVA. Further discussion of this issue is provided in Section 6.1.

Non-Convergence Due to Loss of [redacted] Line

Many contingencies resulting in loss of the [redacted] Line were non-converged in the Scenario 2 Offline study case. Further discussion of this issue is provided in Section 6.1.

Non-Convergence Due to Loss of [redacted]

Non-convergence was observed for the NERC Category P6 event involving [redacted]. Further discussion of this issue is provided in Section 6.2.

Non-Convergence Due to Loss of [redacted]

Non-convergence was observed for NERC Category P7 events involving the [redacted]. Further discussion of this issue is provided in Section 6.2.

6.4 Sensitivity 2 (Boswell Unit 3 & Boswell Unit 4 plus [redacted]) Analysis

The purpose of Sensitivity 2 was to evaluate the potential change in status of both Boswell Unit 3 and Boswell Unit 4 at the same time, in conjunction with the potential change in status of several other [redacted] generators in the region, including [redacted].

Several thermal violations that met the threshold of SSR criteria (3% OTDF of study units) were observed in the 2030 Summer Peak Sensitivity 2 Case. These violations are shown in Appendix and would be mitigated by Manitoba Hydro HVDC Runback. No thermal violations that met the threshold of SSR criteria were observed in the 2030 Summer Shoulder Sensitivity 2 Case. Thermal violations for the Winter Peak Case are discussed below.

Voltage violations which met the SSR voltage criteria were seen in the 2030 Summer Peak and Summer Shoulder Case and are shown in Appendix. As provided in Appendix many of the violations in the Sensitivity 2 Offline Case can be mitigated by load shed, Manitoba Hydro HVDC Runback, or Dorsey Synchronous Condensers operating guide.

However, load shedding is not allowed for the low voltage violations caused by NERC Category P1 contingencies in the Summer Peak Case, and therefore a mitigating solution would be required. It should be noted that this sensitivity assumes retirements of several units which are not yet approved or even in progress. Thus it is quite possible, depending on the order in which the units are retired (if they are retired at all) and the system conditions at the time, that an Attachment Y study for any of these units could produce similar low voltage results and thus cause these low voltage violations to be mitigated as a result of the study for that unit. Voltage violations from the Winter Peak Case are discussed below.

There were numerous thermal and voltage violations in the Winter Peak Case, as well as several non-converged contingencies. A "non-converged" contingency is one that the power flow software program (PSS/E) was not able to solve. There could be a number of explanations for why a solution could not be reached, but in general non-converged contingencies are indicative of severe contingencies and in some cases potential voltage or transient stability problems. While most of the thermal violations identified in the Winter Peak Case could be addressed by redispatch or load shedding, the voltage violations and non-converged contingencies appear to require robust mitigating solution(s) for the Sensitivity 2 (Boswell Unit 3 & Boswell Unit 4 plus [redacted]) Offline Case.

The thermal violations which could be addressed by redispatch are shown in Appendix. General observations about the underlying issues behind one of the thermal violations and some of the more severe voltage violations and non-converged contingencies are also discussed below. This is not meant to be an exhaustive discussion of all issues in the Sensitivity 2 (Boswell Unit 3 & Boswell Unit 4 plus [redacted]) Offline Case, but rather to highlight what appear to be some of the more significant issues in the Winter Peak case.

Significant Overloads of Forbes 500/230 kV Transformers

Overloads were observed on the Forbes 500/230 kV transformers for contingencies resulting in loss of the [redacted]. Further discussion of this issue is provided in Section 6.1.

Non-Convergence Due to Loss of [redacted] Line

Many contingencies resulting in loss of the [redacted] Line were non-converged in the Scenario 2 Offline study case. Further discussion of this issue is provided in Section 6.1.

Non-Convergence Due to Loss of [redacted]

Non-convergence was observed for the NERC Category P6 event involving loss of the [redacted]. Further discussion of this issue is provided in Section 6.2.

Non-Convergence Due to Loss of [redacted]

Non-convergence was observed for NERC Category P7 events involving the [redacted]. Further discussion of this issue is provided in Section 6.2.

Non-Convergence Due to [redacted]

In the Sensitivity 2 Offline Case, non-convergence was observed due to loss of the [redacted]. The "J732 POI" bus is the point of interconnection for Project #J732, the Nemadji Trail Energy Center combined cycle natural gas plant, which is currently in the MISO interconnection queue and has been included in all study cases. The underlying issue appears to be related to a system intact overload of the Arrowhead phase shifting transformer

(PST), which is the sole connection between the 345 kV line and the 230 kV system at Arrowhead. The Arrowhead PST has a normal rating of 800 MVA, and there is over 800 MVA flowing into the Arrowhead 230 kV bus from the 345 kV line in the Sensitivity 2 system intact model. This is likely due to the weakening of the [redacted] area source with multiple baseload units offline, which causes Northern Minnesota to lean more heavily in the Winter Peak case on its main tie line to Wisconsin. The related non-convergence following [redacted] Line seems to be a stability issue related either to the generator at J732 (angular instability) or to the remaining tie lines into Northern Minnesota (voltage stability). In any case, the Arrowhead PST would need to be adjusted in the system intact condition to limit the flow into Arrowhead and avoid overloading the Arrowhead PST. While it is possible that the PST could be used to reduce flow enough to eliminate the non-convergence issue for loss of [redacted], such action will likely only shift the problem and aggravate voltage stability issues associated with the other tie lines into Northern Minnesota (some of which have been described above).

<u>Non-Convergence Due to [redacted] Area Contingencies</u>

In the Sensitivity 2 Offline Case, there are many contingencies in the area around the [redacted] that do not converge or cause low post-contingent voltage violations. These appear to be voltage stability issues caused by loss of multiple transmission sources to the [redacted] during Winter Peak and heavy north flow conditions, similar to those described above for Northern Minnesota tie lines. Since this sensitivity assumes retirements of several units which are not yet approved or even in progress, it is difficult to say when or if these issues would show up in future Attachment Y studies. Given that these issues do not show up in the study cases involving only the Boswell units, the main conclusion from this study is that these low voltage and non-convergence issues are more strongly tied to the retirement of the [redacted] generators and – at most – would be aggravated by the retirement of the Boswell units if some combination of [redacted] area generators had already been retired.

7. CONCLUSION

After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are reliability issues identified related to the potential change of status of Boswell Units 3 and 4, jointly or separately, that would likely require robust mitigating solutions to be built before the retirement of the unit(s) could be allowed. One or both units may need to be designated as System Support Resource ("SSR") units in the event the mitigating solution is not built prior to the retirement date indicated in the future Attachment Y study request. The issues are summarized below for each study case.

In Scenario 1 with Boswell Unit 3 Offline, there were very few issues identified in the Summer Peak and Shoulder cases. In the Winter Peak case with heavy northward flow toward Northern Minnesota and Manitoba, there appear to be transfer limitations related to the [redacted] and parallel 230 kV lines that would result in voltage stability issues following loss of the Chisago – Forbes 500 kV Line. Several related stability, voltage, and thermal violations were also observed in the Winter Peak case. These issues indicated a need for a robust mitigating solution prior to retirement of Boswell Unit 3. Absent such a solution it is likely that Boswell Unit 3 would be designated a System Support Resource if similar results were identified in an Attachment Y Study.

In Scenario 2 with Boswell Unit 4 Offline, similar to Scenario 1, there were very few issues identified in the Summer Peak and Shoulder cases. The same Winter Peak voltage stability and related issues were identified in Scenario 2 as in Scenario 1, and were observed to be worse when the larger Boswell unit is offline. If similar results were identified in an Attachment Y Study, it is likely that Boswell Unit 4 would be designated a System Support Resource and a robust mitigating solution would need to be developed.

In Sensitivity 1 with Boswell Unit 3 & Boswell Unit 4 Offline, there were also very few issues identified in the Summer Peak and Shoulder cases. The Winter Peak voltage stability and related issues identified with one of the two units offline were found to be worsened with both units offline. If Boswell Unit 3 and Boswell Unit 4 were evaluated under a single Attachment Y Notice and similar results were identified in that study as those found in this Attachment Y2 study, it is likely that both units would be designated a System Support Resource and a robust mitigating solution would need to be developed.

In Sensitivity 2 with Boswell Unit 3 & Boswell Unit 4 plus Twin Cities Area Baseload Generators Offline, additional issues were identified in the Summer Peak, Shoulder, and Winter Peak cases. The Winter Peak voltage stability and related issues identified in the previous cases were found to be present, and some additional stability and voltage issues were also identified due to the [redacted] generators also being offline. Since this sensitivity assumes the retirements of several units at several different sites across a relatively large geographic area and none of these units currently have Attachment Y notices in progress, it is difficult to say when or if these issues would show up in future Attachment Y studies. The main conclusion from Sensitivity 2 is that there are certain issues that do not show up in the cases involving only the Boswell units (Scenario 1, Scenario 2, and Sensitivity 1). These issues are therefore more strongly tied to the retirement of the [redacted] baseload generators and – at most – would be aggravated by the retirement of the Boswell units if some combination of [redacted] generators had already been retired.

The development of robust mitigating solution(s) which would enable the retirement scenarios contemplated in this report are outside the scope of this Attachment Y2 study. Due to the complex nature of the retirements contemplated, any such mitigation solution development would need detailed analysis and discussions. MISO and the Transmission

Owner's involved with this study did not conduct an analysis of any potential mitigating solutions because the timeline for conducting the analysis is significantly outside the scope of an Attachment Y2 study.

An Attachment Y-2 study is a non-binding assessment of the Transmission System reliability for the potential suspension or retirement of a Generation Resource(s). The results of the study are not definitive and the analysis is to provide information to the Market Participant to assist them in evaluating their options. However, it does not commit the Market Participant to proceed with plans for suspension or retirement.

Furthermore, while the analysis conducted for the Attachment Y-2 study may be used in preparing a subsequent Attachment Y study, further study may be required to evaluate the impacts due to change in assumptions of system conditions when an Attachment Y Notice is submitted.

8. APPENDIX

Detailed thermal and voltage results are displayed in spreadsheets listed below:

1. Boswell_Y2_Thermal_results
2. Boswell_Y2_Voltage_results

[redacted]

Minnesota Power

LRTP Voltage Stability Analysis

Impact of MHEX Transfer Modeling on LRTP Winter Night Case

Christian Winter
February 2022

Revision History

Date	Rev	Description
October 22, 2021	1	Initial Release
February 23, 2022	2	Updated Report, Added Jamestown – Ellendale + Big Stone – Alexandria – Cassie's Corner Project Scenarios

Table of Contents

Section 1: Background & Purpose

The original overview issued by MISO for Base System Modeling for the MTEP21 LRTP Effort included the table on the next page, which provides an indication of the intended system conditions for various seasonal LRTP power flow cases. As shown in the table, the intent at the time was for the Winter Peak Night case to include "Typical wind with high Minnesota to Manitoba flow" – which is to say, the original intent was to model Manitoba Hydro import, commonly known as North Flow, in the Winter Peak Night case. However, when the LRTP Future 1 Year 10 and Year 20 (F1Y10 and F1Y20) power flow cases were finalized at a later date, all 14 power flow cases including both Winter cases were set up with moderate Manitoba to Minnesota flows (that is to say, South Flow). Without a Manitoba Hydro import case, the LRTP power flow case results do not adequately capture regional stressed cases that are of particular significance for the eastern Dakotas, the Northern half of Minnesota, and western Wisconsin.

Recent studies have identified that there is a severe voltage stability constraint that exists during Winter Peak North Flow conditions. Under heavy North Flow conditions with no or limited generation online in Northern Minnesota and peak or near-peak load levels, single contingency loss of the Forbes – Chisago 500 kV Line may result in a wide-ranging and severe voltage collapse stretching from the Red River Valley nearly to Wisconsin. Minnesota Power has done a significant amount of analysis on this issue over the last 3+ years, and the issue is discussed in Minnesota Power's 2021 Integrated Resource Plan (2021 IRP) as it relates to the significance of Boswell Units 3 & 4 for regional reliability. As discussed in the 2021 IRP, Boswell Units 3 & 4 are the only remaining baseload generators left in Northern Minnesota and among the last large dispatchable generators in Northern Minnesota. In February 2021, Minnesota Power announced that Boswell Unit 3 would be retired by 2030 and Boswell Unit 4 would be transitioned to a non-coal fuel supply by 2035. Prior to those changes, both Boswell units are likely to be placed on economic dispatch, meaning they will no longer be baseloaded and may not be online to provide essential reliability services to the Northern Minnesota transmission system during limiting system conditions. Both Boswell units are offline in the LRTP F1Y10 power flow cases.

The purpose of this study is to identify the extent to which the MHEX assumptions in the LRTP F1Y10 Winter Night case are masking known significant regional voltage stability issues, and to examine the effectiveness of the Iron Range – Benton County Project proposed by Minnesota Power and Great River Energy and certain other LRTP projects for resolving the issue in the LRTP power flow cases.

Reliability Base Models:

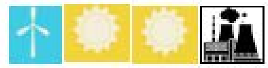
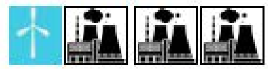
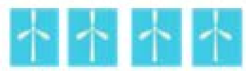
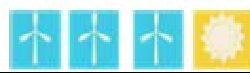
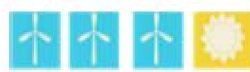
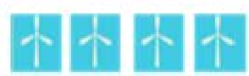
Base Model	Variation	Reasoning for inclusion	Wind/Solar Dispatch
Summer Peak	Day	-Typical system summer peak load -Low wind scenario -Represents MISO west import -S-N flows	Current MTEP planning assumptions based on Capacity Credit for wind and Solar 
	Night	-Typical system peak load level at night -No solar generation -Low wind -N-S Flows	Current MTEP planning assumptions based on Capacity Credit for wind and Solar 
Spring/Fall Light load	Day	-Explore voltage and dynamic stability concerns	High Solar output during low load conditions 
	Night	-Explore voltage and dynamic stability with minimal thermal units available for reactive support -N-S flows	High Wind output during low load conditions 
Fall/Spring shoulder load	Day	-Explore thermal, voltage and stability concerns with minimal thermal units available for reactive support	High renewable output during approximate shoulder load conditions 
Winter Peak	Day	-Typical system winter peak load -Represents high wind in North Observe different geographical loading pattern (Minnesota/Manitoba flow)	Typical wind with high Minnesota to Manitoba flow 
	Night	-Typical system winter peak load at night -N-S flow	Typical wind with high Minnesota to Manitoba flow 

Table 1: Original MISO Guidance on LRTP Power Flow Model Setup

Section 2: Modeling & Methodology

Figure 1 below illustrates the range of MHEX levels included in the 14 LRTP F1Y10 and F1Y20 power flow cases compared to 10 years of historical MHEX operational data. As shown in the figure, the 14 LRTP power flow cases only span the middle ~25 percent of potential MHEX operational conditions. This middle range is also the least-stressed range of MHEX operational conditions. Regional power flows and constraints vary significantly with MHEX dispatch in Minnesota, the eastern Dakotas, and western Wisconsin. As such, historical and typical modeling practice in the area has been to consider at least one power flow case on either end of the spectrum, to optimize regional transfers during high Manitoba exports and ensure that the system is stable and reliable during heavy Manitoba imports. As presently set up, the LRTP power flow base cases do not address either of these conditions and risk masking significant regional reliability issues in the Upper Midwest under operational conditions that have been experienced in the past and will continue in the future. The two ends of the MHEX load duration curve also correspond to firm Manitoba – United States transfer limits previously approved by MISO and maintained over the years by Manitoba Hydro, MISO, and the transmission owners in the area. The firm MHEX South Flow limit is 3,058 MW, and the firm MHEX North Flow limit is 1,398 MW.

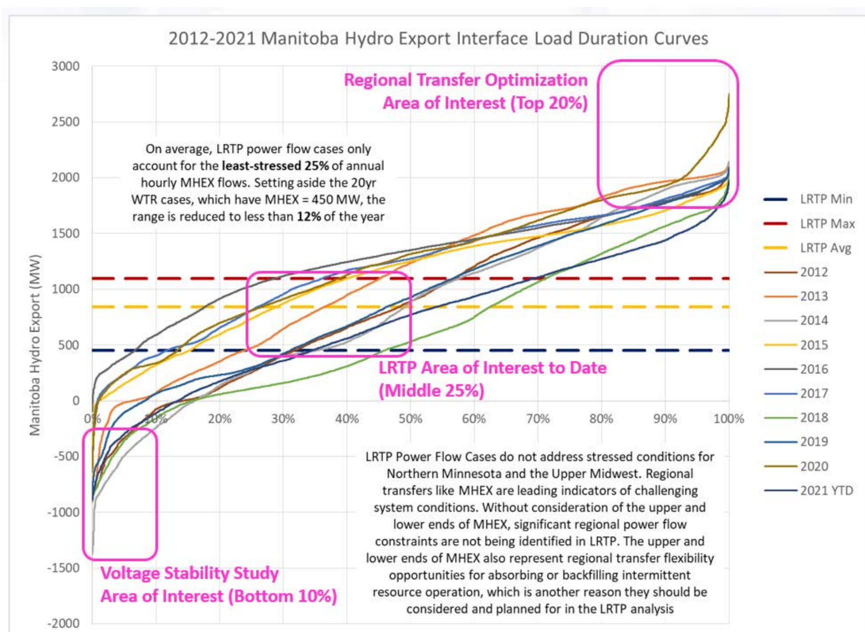


Figure 1: Historical Manitoba – United States (MHEX) Interface Flow v/ LRTP Power Flow Cases

This study will use the LRTP F1Y10 Winter Night case as a starting point. The base MHEX in that case is 811 MW export (South Flow). The MHEX export amount will be reduced and eventually reversed by turning off generation in Manitoba Hydro (Area 667) so that Manitoba is importing. The changes in Area 667 generation will be sunk to all online generators in a wide area generally corresponding to MISO Classic. Voltage stability analysis will be completed to develop PV Curves identifying the voltage stability operating limits for MHEX North Flow in the LRTP base case and with alternative transmission solutions. Voltage stability will consider only the Forbes – Chisago 500 kV line outage. The post-contingent case will be solved with transformer taps, switched shunts, and phase shifting transformers locked. Known fast-switched capacitors and static VAR compensators will be allowed to adjust. Per typical planning criteria, a 10 percent stability margin will be established from the nose of the voltage stability curve.

Detailed model changes implemented to adjust MHEX are recorded in Appendix: Model Change Log.

Section 3: Results

Figure 2 below shows voltage stability results for the LRTP F1Y10 WIN_NIGHT base case. While post-contingent voltages across Northern Minnesota and the Red River Valley are generally acceptable following loss of the Forbes – Chisago 500 kV Line in the base case with MHEX = 811 MW export, voltage rapidly degrades as soon as the MHEX interface flow flips from exporting to importing. Lowest voltages are seen at the Wahpeton, Fergus Falls, Erie Junction, and Mud Lake 230 kV buses, with low voltage violations beginning around 50 MW of MHEX import. The system is unstable for loss of the Forbes – Chisago 500 kV Line past approximately 225 MW of MHEX import. In order to maintain 10 percent stability margin, MHEX import would be limited to 202 MW in this case. This corresponds to a reduction of 1196 MW from the current firm MHEX import level of 1398 MW.

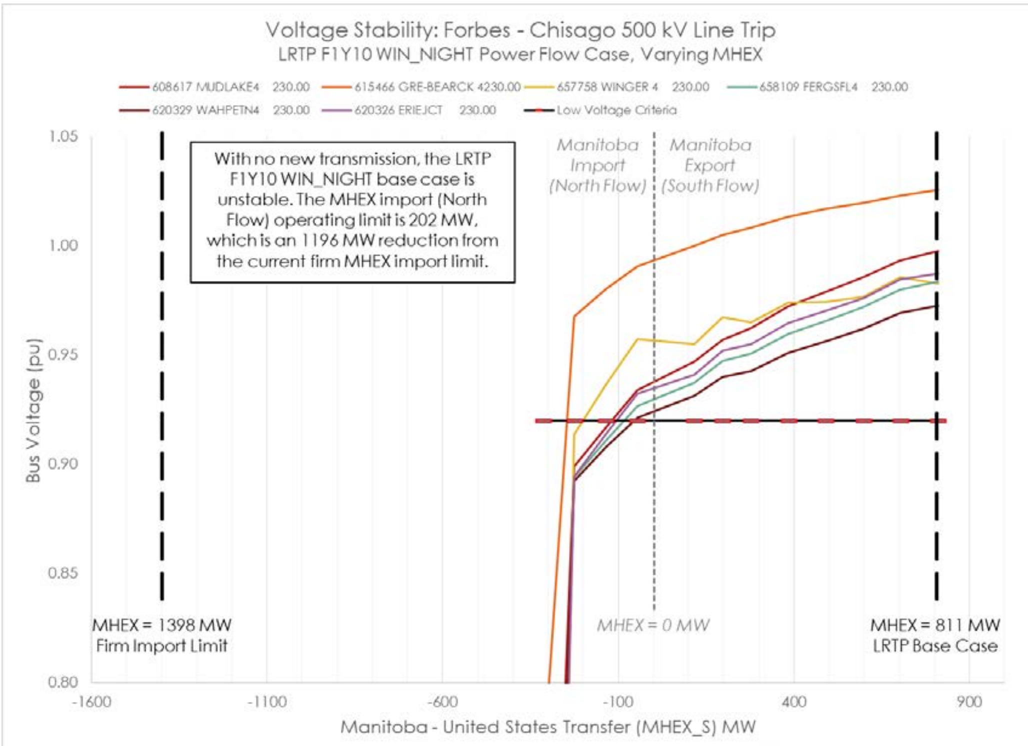


Figure 2: LRTP F1Y10 WIN_NIGHT Base Case PV Curve

One project MISO has previously considered for the LRTP Study is the Big Stone South – Bison – Hankinson 345 kV Line (Conceptual Project F1-8). Conceptual Project F1-8 was tested to determine the extent to which it might contribute to resolving the voltage stability issues associated with loss of the Forbes – Chisago 500 kV Line during North Flow conditions by supporting the Wahpeton/Fergus Falls area. Figure 3 below shows voltage stability results for the LRTP F1Y10 WIN_NIGHT case with Conceptual Project F1-8. The inclusion of the conceptual project shows some improvement at the Wahpeton and Fergus Falls buses, but the project is not sufficient to maintain a stable system at the current firm MHEX import level. Lowest voltages are seen at the Winger, Erie Junction, and Mud Lake 230 kV buses, with low voltage violations beginning around 350 MW MHEX import. The system is unstable for loss of the Forbes – Chisago 500 kV Line past approximately 634 MW of MHEX import. In order to maintain 10 percent stability margin, MHEX import would be limited to 570 MW in this case. This corresponds to a reduction of 828 MW from the current firm MHEX import level of 1398 MW. Conceptual Project F1-8 is not an acceptable solution for the identified voltage stability constraint.

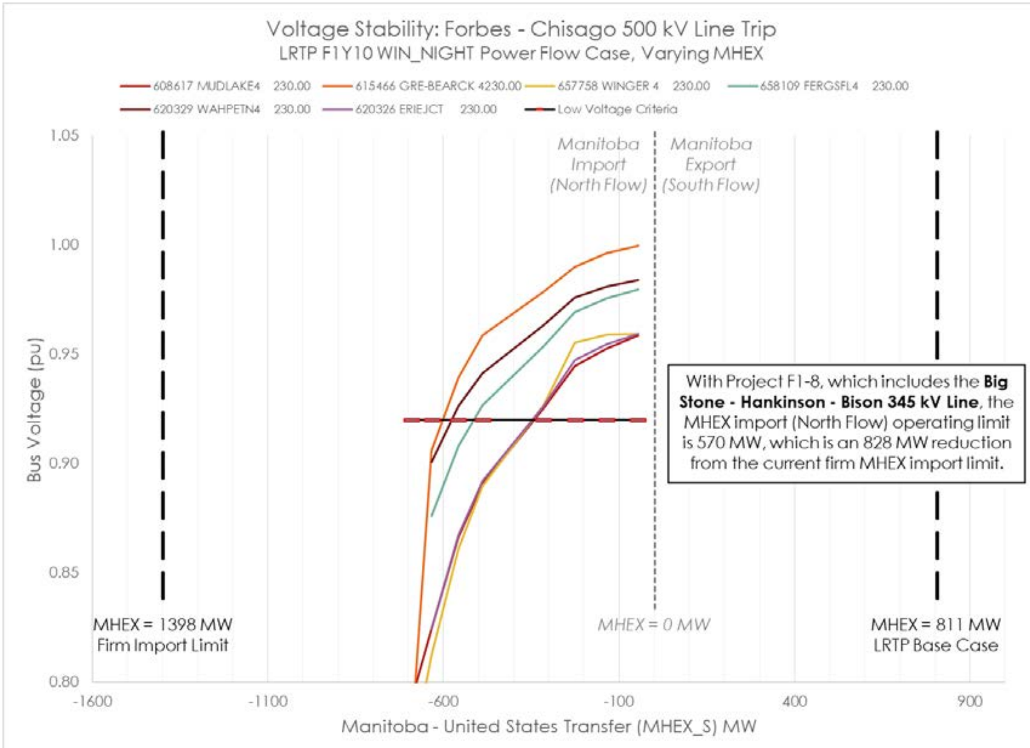


Figure 3: LRTP F1Y10 WIN_NIGHT Case PV Curve with Conceptual Project F1-8

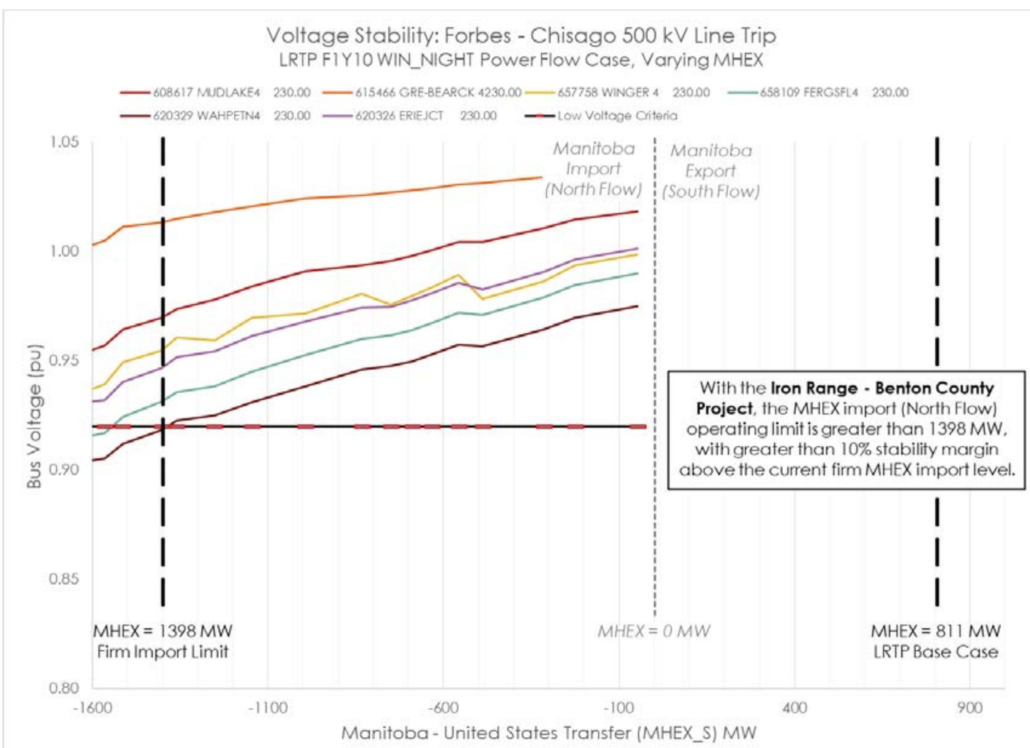


Figure 4: LRTP F1Y10 WIN_NIGHT Case PV Curve with Iron Range – Benton County Project

Minnesota Power and Great River Energy have proposed the Iron Range – Benton County 345 kV double circuit project as a priority Future 1 project for the MISO LRTP effort. Through several years of rigorous analysis, MP and GRE have determined that the Iron Range – Benton County Project is the optimal solution for the identified regional voltage stability constraint and that the project also provides many other benefits for the region. Figure 4 above shows voltage stability results for the LRTP F1Y10 WIN_NIGHT case with the Iron Range – Benton Project. Regional post-contingent voltages are very robust across Northern Minnesota and the Red River Valley, even for buses like Wahpeton, Fergus Falls, and Winger that are located far to the west of the Iron Range and Benton County substations. The system is stable for loss of the Forbes – Chisago 500 kV Line at the 1398 MW firm MHEX import level with more than 10 percent stability margin.[1] There are no post-contingent voltage violations for loss of the Forbes – Chisago 500 kV Line until MHEX import reaches the 1398 MW firm limit. Minnesota Power's internal analysis indicates that pre- and post-contingent low voltages in the Wahpeton area can be adequately resolved with targeted shunt capacitor additions in the Red River Valley (most likely starting at Wahpeton 230 kV).

More recently, MISO has moved away from Conceptual Project F1-8 in favor of a different set of projects for the first Tranche of LRTP project recommendations. The presently-preferred Red River Valley area project consists of a Jamestown – Ellendale 345 kV Line, a Big Stone South – Alexandria 345 kV Line, and an Alexandria – Cassie's Crossing (Monticello) 345 kV Line. The Jamestown – Ellendale + Big Stone South – Alexandria – Cassie's Crossing ("JBAC") Projects were tested to determine the extent to which they might contribute to resolving the voltage stability issues associated with loss of the Forbes – Chisago 500 kV Line during North Flow conditions by rerouting power flow away from the Big Stone – Hankinson – Wahepton 230 kV system. Figure 5 below shows voltage stability results for the LRTP F1Y10 WIN_NIGHT case with the JBAC Projects. The inclusion of the JBAC Projects shows some improvement at the Wahpeton and Fergus Falls buses, but the projects are less effective than the original Conceptual Project F1-8 for maintaining a stable system with significant North Flow at the current firm MHEX import level. Lowest voltages are again seen at the Winger, Erie Junction, and Mud Lake 230 kV buses, with low voltage violations beginning around 250 MW MHEX import. The system is unstable for loss of the Forbes – Chisago 500 kV Line past approximately 378 MW of MHEX import. In order to maintain 10 percent stability margin, MHEX import would be limited to 340 MW in this case. This corresponds to a reduction of 1058 MW from the current firm MHEX import level of 1398 MW. While the JBAC Projects may be an effective solution for other issues currently being considered in the LRTP Study, they are clearly not an acceptable solution for the identified Northern Minnesota voltage stability constraint.

Figure 6 below shows voltage stability results for the combination of the Iron Range – Benton Project and the JBAC Projects, if they were both to be advanced together in LRTP Tranche 1. As noted previously, the Iron Range – Benton Project is highly effective as a standalone project. When combined with the JBAC Projects, a considerable amount of complementarity is seen in the overall LRTP Tranche 1 portfolio for the Dakotas, Western Minnesota, and Northern Minnesota. Regional post-contingent voltages are very robust across Northern Minnesota and the Red River Valley, with notable improvements at Wahpeton and Fergus Falls due to the inclusion of the JBAC Projects. Interestingly, the combination of projects also contributes to significantly improved voltages in the Winger area, a finding that is discussed in greater detail below the figures. The system is stable for loss of the Forbes – Chisago 500 kV Line at the 1398 MW firm MHEX import level with more than 10 percent stability margin.[1] There are no post-contingent voltage violations for loss of the Forbes – Chisago 500 kV Line for MHEX import levels at least as high as 1684 MW.

[1] Voltage stability was not evaluated past 1684 MW MHEX import, which was a stable case and greater than 10 percent beyond the current 1398 MW firm import limit.

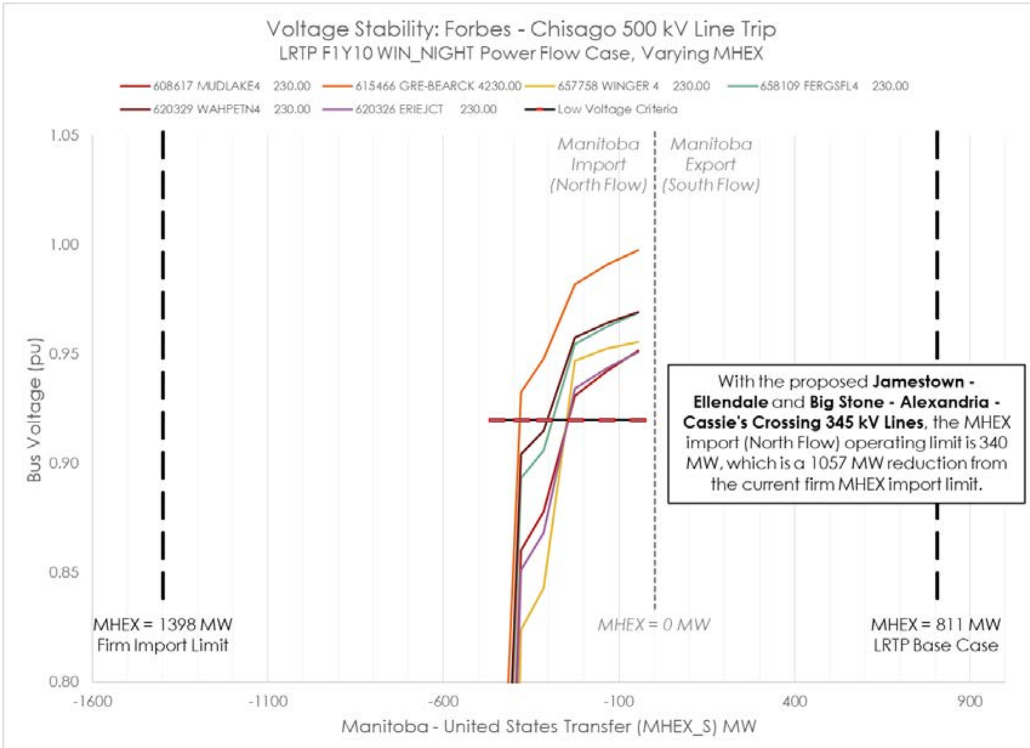


Figure 5: LRTP F1Y10 WIN_NIGHT Case PV Curve with Jamestown – Ellendale + Big Stone – Alexandria – Cassie's Project

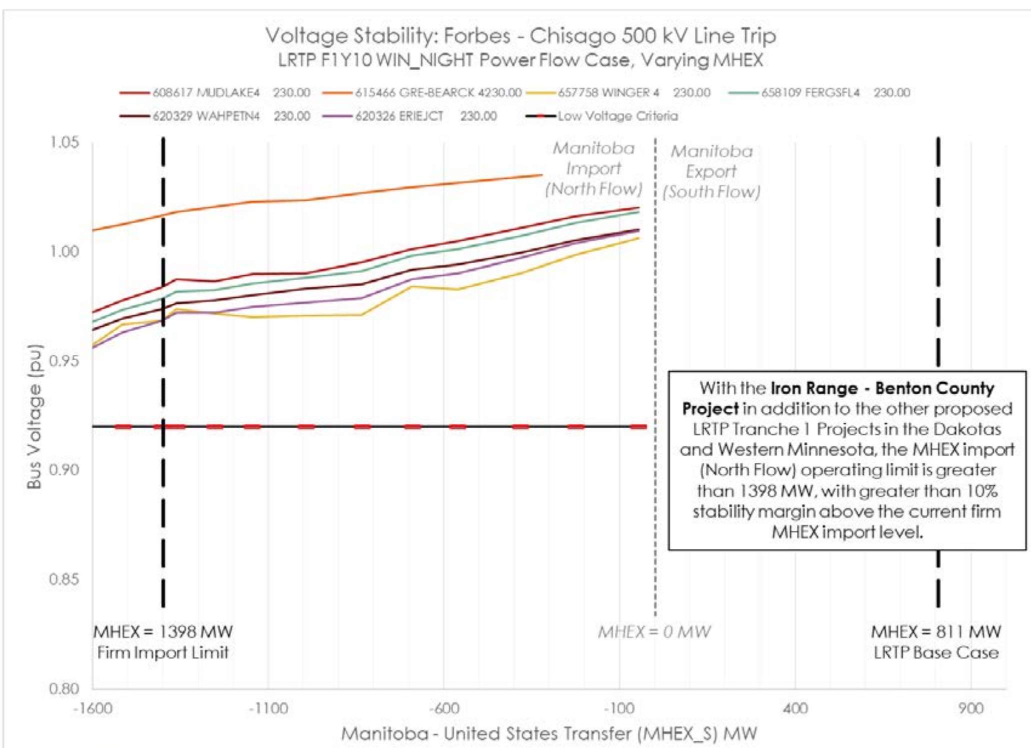


Figure 6: LRTP F1Y10 WIN_NIGHT Case PV Curve with LRTP Tranche 1 Projects in Dakotas + Western/Northern Minnesota

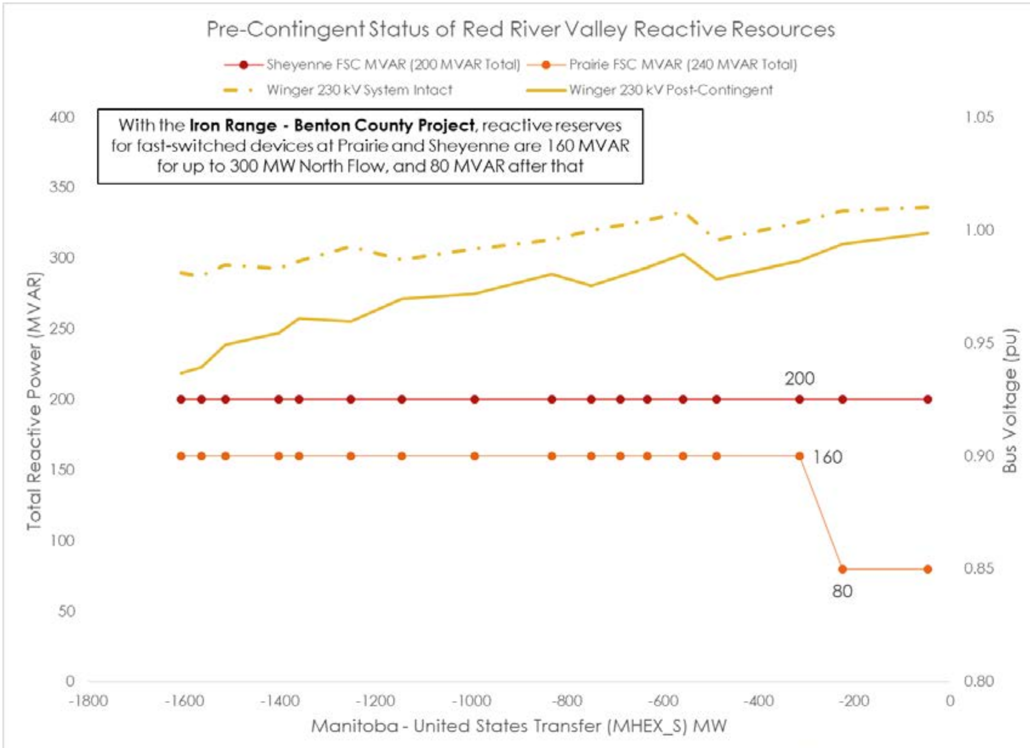


Figure 7: Red River Valley Fast-Switched Cap Banks with Iron Range – Benton County Project

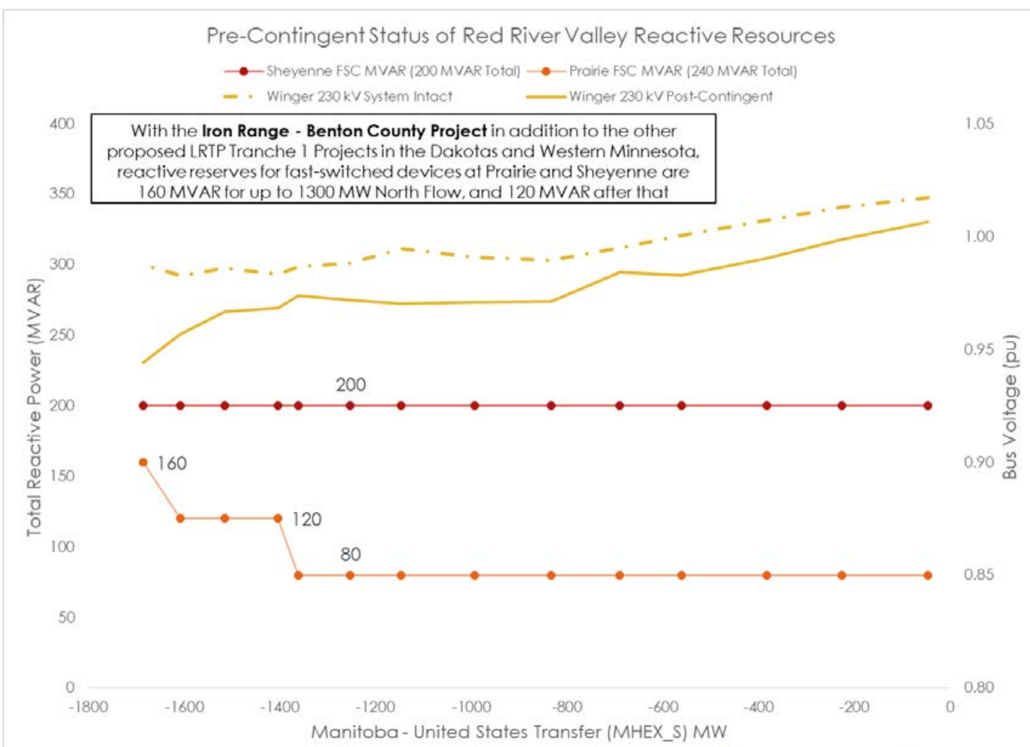


Figure 8: Red River Valley Fast-Switched Cap Banks with LRTP Tranche 1 Projects in Dakotas + Western/Northern Minnesota

As noted previously, very robust pre- and post-contingent voltages are observed in the Winger area when the Iron Range – Benton Project is combined with the JBAC Projects. To better understand this finding, the pre-contingent status of existing fast-switched capacitor banks at the Sheyenne and Prairie 115 kV buses was analyzed. The goal of this analysis was to determine how much dynamic reactive power is available in reserve for supporting post-contingent voltages in the area. Since the voltage stability analysis methodology employed for this study allows these fast-switched capacitors to operate for the post-contingent case,[2] additional dynamic reactive reserves at these Red River Valley locations will contribute to better voltage stability performance by propping up the nearby Winger, Erie Junction, Wahpeton, and Fergus Falls areas.

Figure 7 shows the pre- and post-contingent bus voltages at the Winger 230 kV bus compared to the pre-contingent status of fast-switched capacitors at Sheyenne and Prairie for the LRTP F1Y10 WIN_NIGHT power flow case with the addition of the Iron Range – Benton Project. At Sheyenne, 200 MVAR of fast-switched capacitors (out of a total of 200 MVAR installed) are online pre-contingency for the entire range of studied transfers, leaving 0 MVAR reactive reserves. At Prairie, 80 MVAR of fast-switched capacitors (out of a total of 240 MVAR installed) are online pre-contingency at lower levels of Manitoba import, leaving 160 MVAR in reserve for post-contingent fast-switching. Above approximately 300 MW of Manitoba import, two additional 40 MVAR banks are switched in to support system intact voltage, reducing total reactive reserves to 80 MVAR. It can be seen from the steady decline in Winger 230 kV bus voltage that the effectiveness of the limited reactive reserves left available in the Red River Valley erodes as Manitoba import increases.

Figure 8 shows the pre- and post-contingent bus voltages at the Winger 230 kV bus compared to the pre-contingent status of fast-switched capacitors at Sheyenne and Prairie for the LRTP F1Y10 WIN_NIGHT power flow case with the addition of the Iron Range – Benton Project and the proposed JBAC Projects. At Sheyenne, 200 MVAR of fast-switched capacitors (out of a total of 200 MVAR installed) are online pre-contingency for the entire range of studied transfers, leaving 0 MVAR reactive reserves. At Prairie, 80 MVAR of fast-switched capacitors (out of a total of 240 MVAR installed) are online pre-contingency for most of the studied range of Manitoba import, leaving 160 MVAR in reserve for post-contingent fast-switching. Above approximately 1,300 MW of Manitoba import, one additional 40 MVAR banks are switched in to support system intact voltage, reducing total reactive reserves to 120 MVAR. The additional Prairie fast-switched capacitor bank reactive reserves that are enabled by the combination of LRTP Tranche 1 Projects (Iron Range – Benton and JBAC) explain why the Winger 230 kV bus voltage is strongly supported up to very high levels of Manitoba import in this study case. These findings further emphasize the complementary nature of the Iron Range – Benton Project and the JBAC Projects as part of the LRTP Tranche 1 Recommendations, as well as the importance of dynamic reactive support for the Red River Valley and Northern Minnesota.

[2] All switched shunts are locked for voltage stability analysis except known fast-switched capacitors and SVCs

Section 4: Conclusions

The results of this study demonstrate that the MHEX levels included in the original LRTP power flow base cases are not adequate to identify regional voltage stability issues that impact a broad area stretching from the eastern Dakotas through the Northern half of Minnesota to western Wisconsin. Voltage stability analysis demonstrates that the Iron Range – Benton County Project is the most optimal and robust long-term solution for the region, and therefore, that the Iron Range – Benton County Project should be considered a top-priority project for MISO's Tranche 1 LRTP recommendations. When the Iron Range – Benton County Project is combined with the other proposed LRTP Tranche 1 projects in the area, including the Jamestown – Ellendale 345 kV and Big Stone South – Alexandria – Cassie's Crossing 345 kV lines, notable complementarity between the projects contributes to a highly robust long-term solution for regional reliability in Northern Minnesota and the Red River Valley.

Appendix: Model Change Log

The tables below provide detailed documentation of the changes made to the base LRTP power flow case to adjust the MHEX interface flow from the original 811 MW export to the targeted import levels for the study. Steps ending in "+IRG" include the proposed Iron Range – Benton County Project. Steps ending in "+RRV" includes MISO's conceptual LRTP Project F1-8 which includes the Big Stone – Hankinson – Bison 345 kV Line. Steps ending in "+JBAC" include the proposed Jamestown – Ellendale and Big Stone South – Alexandria – Cassie's Crossing 345 kV lines. Steps ending in "+LRTP" include both Iron Range – Benton County and the JBAC Projects. The BP1 – BP3 columns shown the dispatch of the Manitoba HVDC bipoles. The MHEX and NOMN columns show the resulting Manitoba Hydro Export and Northern Minnesota Interface flows for each step.

Table 2: LRTP WIN_NIGHT Base Case Modifications

	Action	MH Gen Reduction	BP1	BP2	BP3	MHEX	NOMN	Comments
Step 0A	Initial Case	N/A	523.7	565	564.4	810.9	1450.9	
Step 0B	Unlocked MSC at 667679 (RIE-DCBUS) Unlocked MSC at 667669 (KEW-DCBUS) Unlocked MSC at 667001 (HENDAY 4) Unlocked MSC at 667231 (RADSNDC6) Disconnect 337074 (1J604GEN)	N/A	523.7	565	564.4	810.9	1450.9	All of these switched shunts were locked in their base case state, lead to extreme overvoltages as I adjusted MHEX transfer level; The PV generator at bus 337074 was dispatched at 0 MW but absorbing VARs and causing low voltage + non-convergence. I think its regulated bus (337090) is too far away
Step 1	Disconnect 669710 (LIMEST1G)	104.7 MW	488.6	527.2	526.5	704.2	1524.6	
Step 2	Disconnect 669711 (LIMEST2G)	104.7 MW	453.7	489.4	488.8	597.7	1599	
Step 3	Disconnect 669712 (LIMEST3G)	104.7 MW	418.8	451.8	451.1	491.1	1674.1	
Step 4	Disconnect 669712 (LIMEST4G)	104.7 MW	383.9	414.2	413.6	384.4	1749.5	
Step 5	Disconnect 669714 (LIMEST5S) Set 693970-693966 transformer to non-auto and winding ratio to 1.000	104.7 MW	349.2	376.7	376.0	277.6	1825.2	Straits transformer was regulating voltage causing toggling reactive resources, case was blowing up.
Step 6	Disconnect 669720 (LONGS_1G)	79.7	323	348.5	347.8	197	1880.2	
Step 7	Disconnect 669721 (LONGS_2G)	79.7	296.9	320.3	319.7	116.4	1937.9	
Step 8	Disconnect 669722 (LONGS_3G) Disconnect 669723 (LONGS_4G)	159.4 MW	244.5	263.8	263.2	-45.5	2055.7	
Step 9	Disconnect 669742 (KEEYAS1G) Disconnect 643253 (SHOLES.GEN.W)	89.9 MW	215.8	232.8	232.3	-134.6	2118.8	Sholes Gen W was contributing to blown up case. Unit was dispatched at 8 MW but absorbing VARs and causing low voltage in the surrounding area. I think its regulated bus (640226) is too far away
Step 10	Disconnect 669743 (KEEYAS2G)	89.9 MW	186.9	201.7	201.2	-224.3	2185.3	
Step 11	Disconnect 669744 (KEEYAS3G)	89.9 MW	158.1	170.6	170.2	-314.1	2246.1	
Step 12	Disconnect 669765 (WUSK 1G) Disconnect 669766 (WUSK 2G) Disconnect 669767 (WUSK 3G)	200.0 MW	158.1	170.6	170.2	-487.5	2372.1	Wuskwatim is outside the NCS, no impact to HVDC
Step 13	Disconnect 669768 (JENPEG1G) Disconnect 669769 (JENPEG2G) Disconnect 669770 (JENPEG3G)	76.18 MW	158.1	170.6	170.2	-556.6	2426.2	JenPeg is outside the NCS, no impact to HVDC
Step 14	Disconnect 669771 (JENPEG4G) Disconnect 669772 (JENPEG5G) Disconnect 669773 (JENPEG6G)	79.78 MW	158.1	170.6	170.2	-632.1	2481.5	JenPeg is outside the NCS, no impact to HVDC
Step 15	Disconnect 669784 (GRTFAL1G) Disconnect 669785 (GRTFAL2G) Disconnect 669786 (GRTFAL3G)	64.1 MW	158.1	170.6	170.2	-688.7	2523.7	Great Falls is outside the NCS, no impact to HVDC
Step 16	Disconnect 669787 (GRTFAL4G) Disconnect 669788 (GRTFAL5G) Disconnect 669789 (GRTFAL6G)	65.9 MW	158.1	170.6	170.2	-749.2	2569	Great Falls is outside the NCS, no impact to HVDC
Step 17	Disconnect 669778 (PINFLS1G) Disconnect 669779 (PINFLS2G) Disconnect 669780 (PINFLS3G) Disconnect 669781 (PINFLS4G) Disconnect 669782 (PINFLS5G) Disconnect 669783 (PINFLS6G)	88.2 MW	158.1	170.6	170.2	-831.9	2628.3	Pine Falls is outside the NCS, no impact to HVDC
Step 18	Disconnect 669808 (7SISTR1G) Disconnect 669809 (7SISTR2G) Disconnect 669810 (7SISTR3G) Disconnect 669811 (7SISTR4G) Disconnect 669812 (7SISTR5G) Disconnect 669813 (7SISTR6G)	166 MW	158.1	170.6	170.2	-991.9	2755.3	Seven Sisters is outside the NCS, no impact to HVDC
Step 19	Disconnect 669750 (KELSEY1G) Disconnect 669751 (KELSEY2G) Disconnect 669752 (KELSEY3G) Disconnect 669753 (KELSEY4G)	155.5 MW	158.1	170.6	170.2	-1144.7	2864.3	Kelsey is outside the NCS, no impact to HVDC
Step 20	Disconnect 669774 (GRSTCG#1)	104.8 MW	158.1	170.6	170.2	-1250.6	2940	Grand Rapids is outside the NCS, no impact to HVDC
Step 21	Disconnect 669775 (GRSTCG#2)	104.8 MW	158.1	170.6	170.2	-1358.6	3023.8	Grand Rapids is outside the NCS, no impact to HVDC
Step 22	Disconnect 669754 (KELSEY5G)	38.9 MW	158.1	170.6	170.2	-1401.5	3058.1	Kelsey is outside the NCS, no impact to HVDC

Table 3: LRTP WIN_NIGHT Case Modifications with Conceptual LRTP Project F1-8 (Red River Valley Project)

	Action	MH Gen Reduction	BP1	BP2	BP3	MHEX	NOMN	Comments
Step 11+RRV	Add LRTP F1-8 Project	N/A	158.1	170.6	170.2	-314	2255.2	Big Stone - Hankinson - Bison 345 kV + Jamestown - Bison 345 kV
Step 12+RRV	Disconnect 669765 (WUSK 1G) Disconnect 669766 (WUSK 2G) Disconnect 669767 (WUSK 3G)	200.0 MW	158.1	170.6	170.2	-487.4	2381.9	Wuskwatim is outside the NCS, no impact to HVDC
Step 13+RRV	Disconnect 669768 (JENPEG1G) Disconnect 669769 (JENPEG2G) Disconnect 669770 (JENPEG3G)	76.18 MW	158.1	170.6	170.2	-556.5	2433	JenPeg is outside the NCS, no impact to HVDC
Step 14+RRV	Disconnect 669771 (JENPEG4G) Disconnect 669772 (JENPEG5G) Disconnect 669773 (JENPEG6G)	79.78 MW	158.1	170.6	170.2	-632	2486.2	JenPeg is outside the NCS, no impact to HVDC
Step 15+RRV	Disconnect 669784 (GRTFAL1G) Disconnect 669785 (GRTFAL2G) Disconnect 669786 (GRTFAL3G)	64.1 MW	158.1	170.6	170.2	-688.6	2532.6	Great Falls is outside the NCS, no impact to HVDC

Table 4: LRTP WIN_NIGHT Case Modifications with Proposed LRTP "JBAC" Projects

	Action	MH Gen Reduction	BP1	BP2	BP3	MHEX	NOMN	Comments
Step 8+JBAC	Add LRTP JE+BSS-ALX-CASSIE Project	N/A	244.5	263.8	263.2	-45.4	2005.9	
Step 9	Disconnect 669742 (KEEYAS1G) Disconnect 643253 (SHOLES.GEN.W)	89.9 MW	215.8	232.8	232.3	-134.5	2069.8	Sholes Gen W was contributing to blown up case. Unit was dispatched at 8 MW but absorbing VARs and causing low voltage in the surrounding area. I think its regulated bus (640226) is too far away
Step 10	Disconnect 669743 (KEEYAS2G)	89.9 MW	186.9	201.7	201.2	-224.2	2134.9	
Step 11	Disconnect 669744 (KEEYAS3G)	89.9 MW	158.1	170.6	170.2	-314.1	2201.8	
Step 12	Disconnect 669768 (JENPEG1G) Disconnect 669769 (JENPEG2G) Disconnect 669770 (JENPEG3G)	76.18 MW	158.1	170.6	170.2	-378	2246.7	JenPeg is outside the NCS, no impact to HVDC
Step 13	Disconnect 669771 (JENPEG4G) Disconnect 669772 (JENPEG5G) Disconnect 669773 (JENPEG6G)	79.78 MW	158.1	170.6	170.2	-448	2295.4	JenPeg is outside the NCS, no impact to HVDC

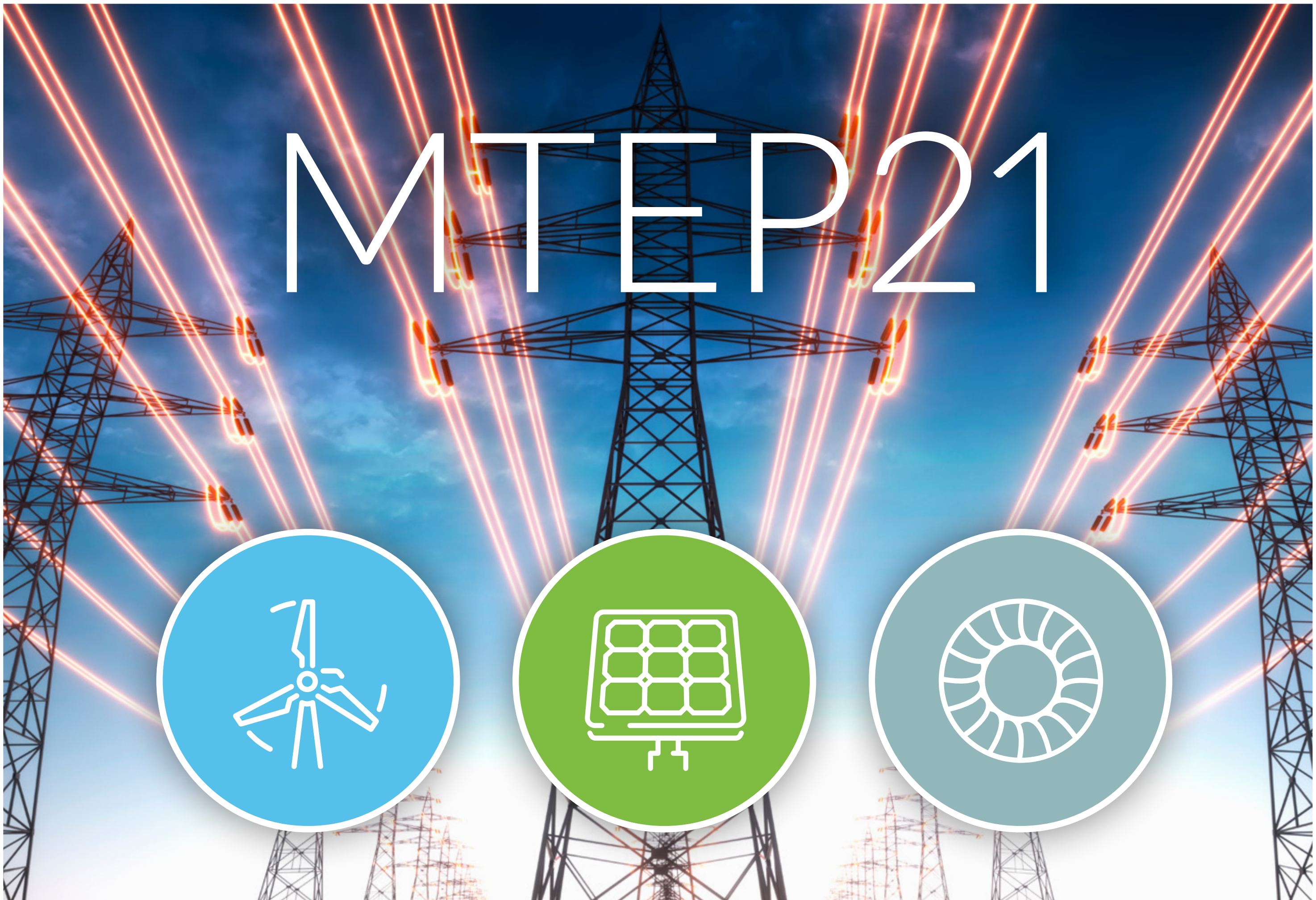
Table 5: LRTP WIN_NIGHT Case Modifications with Proposed Iron Range – Benton County Project

	Action	MH Gen Reduction	BP1	BP2	BP3	MHEX	NOMN	Comments
Step 8+IRG	Add IRG-BTN345d Project	N/A	244.5	263.8	263.2	-46.4	2261.3	NOMN now includes Benton - Iron Range 345 kV ckts
Step 10+IRG	Add IRG-BTN345d Project	N/A	186.9	201.7	201.2	-225	2402.3	NOMN now includes Benton - Iron Range 345 kV ckts
Step 11+IRG	Add IRG-BTN345d Project	N/A	158.1	170.6	170.2	-314.6	2475.6	NOMN now includes Benton - Iron Range 345 kV ckts
Step 12+IRG	Disconnect 669765 (WUSK 1G) Disconnect 669766 (WUSK 2G) Disconnect 669767 (WUSK 3G)	200.0 MW	158.1	170.6	170.2	-487.9	2614.9	Wuskwatim is outside the NCS, no impact to HVDC
Step 13+IRG	Disconnect 669768 (JENPEG1G) Disconnect 669769 (JENPEG2G) Disconnect 669770 (JENPEG3G)	76.18 MW	158.1	170.6	170.2	-556.9	2667.5	JenPeg is outside the NCS, no impact to HVDC
Step 14+IRG	Disconnect 669771 (JENPEG4G) Disconnect 669772 (JENPEG5G) Disconnect 669773 (JENPEG6G)	79.78 MW	158.1	170.6	170.2	-632.4	2728.7	JenPeg is outside the NCS, no impact to HVDC
Step 15+IRG	Disconnect 669784 (GRTFAL1G) Disconnect 669785 (GRTFAL2G) Disconnect 669786 (GRTFAL3G)	64.1 MW	158.1	170.6	170.2	-688.9	2774.5	Great Falls is outside the NCS, no impact to HVDC
Step 16+IRG	Disconnect 669787 (GRTFAL4G) Disconnect 669788 (GRTFAL5G) Disconnect 669789 (GRTFAL6G)	65.9 MW	158.1	170.6	170.2	-749.4	2823.6	Great Falls is outside the NCS, no impact to HVDC
Step 17+IRG	Disconnect 669778 (PINFLS1G) Disconnect 669779 (PINFLS2G) Disconnect 669780 (PINFLS3G) Disconnect 669781 (PINFLS4G) Disconnect 669782 (PINFLS5G) Disconnect 669783 (PINFLS6G)	88.2 MW	158.1	170.6	170.2	-831.8	2891.4	Pine Falls is outside the NCS, no impact to HVDC
Step 18+IRG	Disconnect 669808 (7SISTR1G) Disconnect 669809 (7SISTR2G) Disconnect 669810 (7SISTR3G) Disconnect 669811 (7SISTR4G) Disconnect 669812 (7SISTR5G) Disconnect 669813 (7SISTR6G)	166 MW	158.1	170.6	170.2	-992.1	3026.2	Seven Sisters is outside the NCS, no impact to HVDC
Step 19+IRG	Disconnect 669750 (KELSEY1G) Disconnect 669751 (KELSEY2G) Disconnect 669752 (KELSEY3G) Disconnect 669753 (KELSEY4G)	155.5 MW	158.1	170.6	170.2	-1144.6	3151	Kelsey is outside the NCS, no impact to HVDC
Step 20+IRG	Disconnect 669774 (GRSTCG#1)	104.8 MW	158.1	170.6	170.2	-1250.3	3235.4	Grand Rapids is outside the NCS, no impact to HVDC
Step 21+IRG	Disconnect 669775 (GRSTCG#2)	104.8 MW	158.1	170.6	170.2	-1358.1	3326	Grand Rapids is outside the NCS, no impact to HVDC
Step 22+IRG	Disconnect 669754 (KELSEY5G)	38.9 MW	158.1	170.6	170.2	-1400.9	3362.5	Kelsey is outside the NCS, no impact to HVDC
Step 23+IRG	Disconnect 669776 (GRAMPG#3)	104.2 MW	158.1	170.6	170.2	-1511.7	3453.8	Grand Rapids is outside the NCS, no impact to HVDC
Step 24+IRG	Disconnect 669755 (KELSEY6G) Disconnect 669241 (LAURRIV82)	43.9 MW	158.1	170.6	170.2	-1561.8	3497.1	Kelsey & Laurie River are outside the NCS, no impact on HVDC
Step 25+IRG	Disconnect 669814 (SELKRK1G) Disconnect 669804 (SLVFL12G)	48.3 MW	158.1	170.6	170.2	-1604	3532.5	Selkirk & Slave Falls are outside the NCS, no impact on HVDC

Table 6: LRTP WIN_NIGHT Case Modifications with Proposed Iron Range – Benton County Project & JBAC Projects

	Action	MH Gen Reduction	BP1	BP2	BP3	MHEX	NOMN	Comments
Step 8+LRTP	Add IRG-BTN345d Project Add LRTP JE+BSS-ALX-CASSIE Project	N/A	244.5	263.8	263.2	-46.3	2210.8	NOMN now includes Benton - Iron Range 345 kV ckts
Step 9+LRTP	Disconnect 669742 (KEEYAS1G) Disconnect 643253 (SHOLES.GEN.W) Disconnect 669743 (KEEYAS2G)	187.76 MW	186.7	201.5	200.9	-225.3	2353.3	Sholes Gen W was contributing to blown up case. Unit was dispatched at 8 MW but absorbing VARs and causing low voltage in the surrounding area. I think its regulated bus (640226) is too far away
Step10+LRTP	Disconnect 669744 (KEEYAS3G) Disconnect 669771 (JENPEG4G) Disconnect 669772 (JENPEG5G) Disconnect 669773 (JENPEG6G)	169.66 MW	157.9	170.4	169.9	-382.1	2478.9	JenPeg is outside the NCS, no impact to HVDC
Step 11+LRTP	Disconnect 669765 (WUSK 1G) Disconnect 669766 (WUSK 2G) Disconnect 669767 (WUSK 3G)	200.0 MW	157.9	170.4	169.9	-560.8	2622.7	Wuskwatim is outside the NCS, no impact to HVDC
Step 12+LRTP	Disconnect 669768 (JENPEG1G) Disconnect 669769 (JENPEG2G) Disconnect 669770 (JENPEG3G) Disconnect 669784 (GRTFAL1G) Disconnect 669785 (GRTFAL2G) Disconnect 669786 (GRTFAL3G)	140.28 MW	157.9	170.4	169.9	-689.6	2727.4	JenPeg is outside the NCS, no impact to HVDC JenPeg is outside the NCS, no impact to HVDC
Step 13+LRTP	Disconnect 669787 (GRTFAL4G) Disconnect 669788 (GRTFAL5G) Disconnect 669789 (GRTFAL6G) Disconnect 669778 (PINFLS1G) Disconnect 669779 (PINFLS2G) Disconnect 669780 (PINFLS3G) Disconnect 669781 (PINFLS4G) Disconnect 669782 (PINFLS5G) Disconnect 669783 (PINFLS6G)	154.1 MW	157.9	170.4	169.9	-832.5	2844.8	Great Falls is outside the NCS, no impact to HVDC Pine Falls is outside the NCS, no impact to HVDC
Step 14+LRTP	Disconnect 669808 (7SISTR1G) Disconnect 669809 (7SISTR2G) Disconnect 669810 (7SISTR3G) Disconnect 669811 (7SISTR4G) Disconnect 669812 (7SISTR5G) Disconnect 669813 (7SISTR6G)	166 MW	157.9	170.4	169.9	-992.7	2976	Seven Sisters is outside the NCS, no impact to HVDC
Step 15+LRTP	Disconnect 669750 (KELSEY1G) Disconnect 669751 (KELSEY2G) Disconnect 669752 (KELSEY3G) Disconnect 669753 (KELSEY4G)	155.5 MW	157.9	170.4	169.9	-1145.2	3102.1	Kelsey is outside the NCS, no impact to HVDC
Step16+LRTP	Disconnect 669774 (GRSTCG#1)	104.8 MW	157.9	170.4	169.9	-1250.9	3190.2	Grand Rapids is outside the NCS, no impact to HVDC
Step17+LRTP	Disconnect 669775 (GRSTCG#2)	104.8 MW	157.9	170.4	169.9	-1358.7	3279.9	Grand Rapids is outside the NCS, no impact to HVDC
Step18+LRTP	Disconnect 669754 (KELSEY5G)	38.9 MW	157.9	170.4	169.9	-1401.5	3316.3	Kelsey is outside the NCS, no impact to HVDC
Step19+LRTP	Disconnect 669776 (GRSTCG#2)	104.8 MW	157.9	170.4	169.9	-1512.3	3406.2	Grand Rapids is outside the NCS, no impact to HVDC
Step20+LRTP	Disconnect 669755 (KELSEY6G) Disconnect 669241 (LAURRIV82) Disconnect 669814 (SELKRK1G) Disconnect 669804 (SLVFL12G)	92.2 MW	157.9	170.4	169.9	-1604.7	3485.9	Kelsey, Laurie River, Selkirk, and Slave Falls are outside the NCS, no impact on HVDC
Step21+LRTP	Disconnect 669805 (SLVFL34G) Disconnect 669806 (SLVFL56G) Disconnect 669807 (SLVFL78G) Disconnect 669794 (PTDB1-4G) Disconnect 669795 (PTDB5-7G) Disconnect 669796 (PTDB8-10G) Disconnect 669798 (PTDB1314G)	80.5 MW	157.9	170.4	169.9	-1681.7	3547.7	Slave Falls & Point Du Bois are outside the NSC, no impact on HVDC

MTEP21



In this MISO Transmission Expansion Plan, MISO staff recommends $3 billion of new transmission enhancement projects for Board of Directors' approval.

Highlights

- 335 new projects for inclusion in Appendix A to address reliability and aging infrastructure
- $24 billion in projects constructed in the MISO region since 2003
- Generator Interconnection queue grew to a record 958 projects totaling 150.3 GW

misoenergy.org

Transmission Expansion for a Changing Industry

Fundamental changes in the electric industry landscape – such as shifts in generation resources, consumer demand for low-carbon resources, and decentralization of generation – require a planning process that can ensure the grid will be able to accommodate these changes in the years to come. Indicators predict as much industry change in the next 5 years as have happened in the past 35 years.

The 2021 MISO Transmission Expansion Plan (MTEP21) evaluates studies and planning initiatives that help MISO address future grid needs. Further, MISO's Long-Range Transmission Planning process, part of MISO's response to the shared Reliability Imperative, provides a holistic, systematic response in ensuring grid infrastructure is in place to realize the plans of member utilities, customer preferences, and state and federal policies.

As a deliverable, MTEP21 defines tangible, incremental improvements to address today's needs and tomorrow's direction as it proposes the approval of 335 new transmission projects, equaling $3 billion in investment. Investments identified address near-term reliability needs and aging infrastructure. Since 2003, $24 billion of MTEP transmission projects have been constructed in the region.

MTEP21 Snapshot

335 new projects representing $3 billion of investment

Proposed MTEP21 Appendix A projects go before the Board of Directors for approval in December 2021.

This includes the following project types:

GENERATOR INTERCONNECTION PROJECTS (GIP)

50 projects representing $345 million in investment

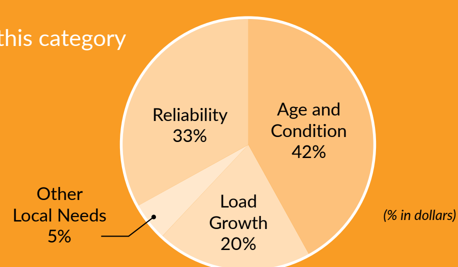
BASELINE RELIABILITY PROJECTS (BRP)

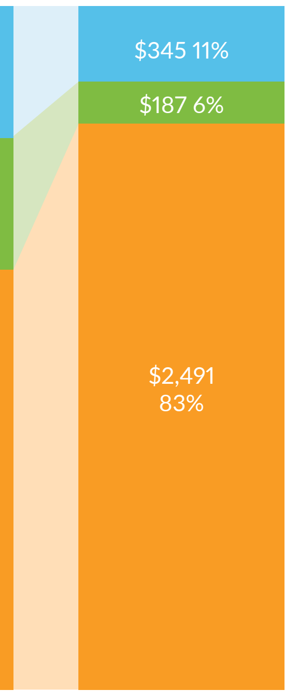
30 projects representing $187 million in investment

"OTHER" PROJECTS

255 projects representing $2,491 billion in investment

Drivers of this category





($ in Millions)

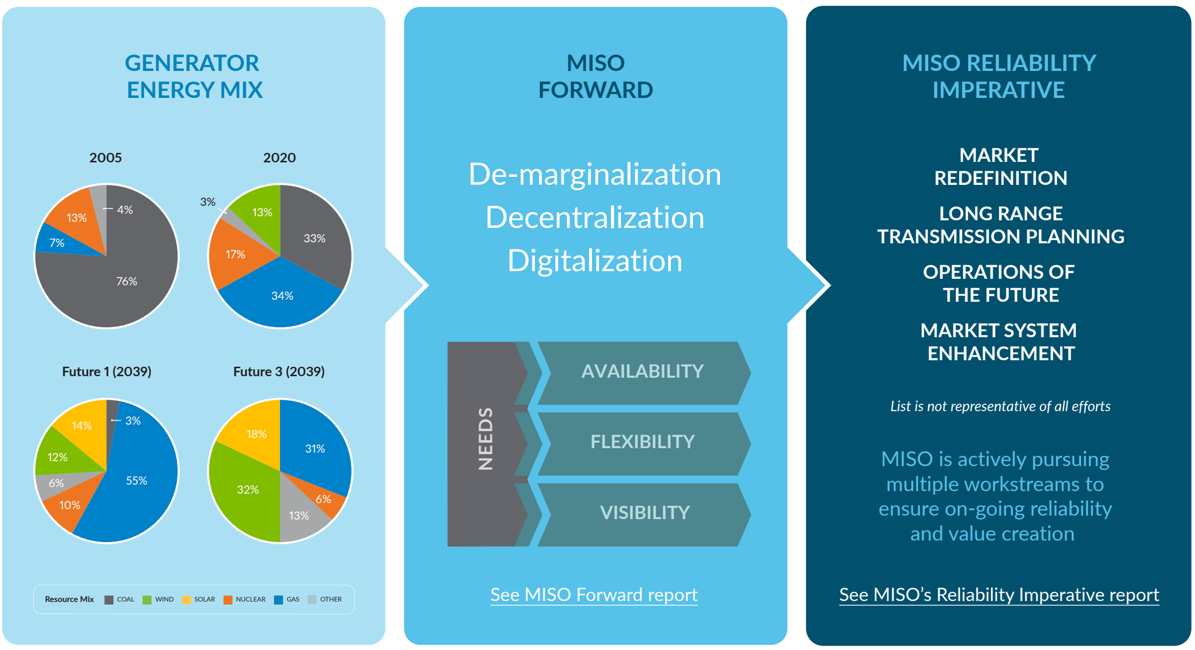
Planning Region	GIP	BRP	Other	Total
West	$137	$31	$931	**$1,100**
East	$125	$50	$331	**$506**
Central	$57	$43	$606	**$706**
South	$26	$62	$624	**$712**
Total	**$345**	**$187**	**$2,491**	**$3,023**

Dramatic Changes in the Fleet Require a Change in Direction

When MISO became a Regional Transmission Organization in 2001, generation was largely provided by coal plants and some gas, and customer demand was the largest source of day-to-day operating variation. Today, coal generation continues to retire; new gas generation in the queue is outpaced by wind and solar generators. And battery storage is gaining an increasing foothold in the region. This change is driven by customers, their member utilities, and state energy and environmental policy. It has challenged the assumptions of legacy planning processes, which were predicated on the idea that serving the hottest day of the year would also mean system and resource sufficiency for all other days of the year. It also supported the idea that a megawatt hour was inextricably bundled with other reliability attributes, such as flexibility, black start and frequency response characteristics.

As legacy units retire, they are replaced by wind and solar – whose best fuel sources are location-dependent. Older units are increasingly prone to outage, and load-modifying resources are an increasing proportion of available resources.

MISO's MTEP process iterates annually to provide a comprehensive grid expansion plan that meets reliability, policy and economic needs. It is in constant evolution and prioritizes transmission needs depending on system-wide needs (top down) and local service territory needs identified by local utilities (bottom up). The process is designed to ensure necessary grid infrastructure is in place to support the reliable operation of the transmission system; support achievement of state and federal energy policy requirements; and enable a competitive electricity market to benefit all customers. MISO's transmission planning processes uses Futures, which are meant to capture a range of possible outcomes over the next 20 years. It does this by incorporating a value-based process that integrates both top-down and bottom-up efforts, and integrates numerous, iterative opportunities for stakeholder feedback.



Members Active Throughout the MTEP Planning Process

Each cycle, MISO undergoes a rigorous stakeholder process that offers numerous opportunities over 18 months for advice and input from our diverse stakeholder community, which includes utilities, state regulators, and public interest organizations including environmental and consumer groups. Planning Advisory Committee (PAC) meetings are held monthly, and subregional planning meetings are interspersed on this timeline. Utilities submit bottom-up projects, and projects are identified by MISO for consideration through the MTEP process. Finally, in the fall, the System Planning Committee of the MISO Board of Directors recommend a slate of projects in MTEP to the full Board of Directors for consideration and approval in December.

Past MTEP cycles have ensured ongoing reliability and market efficiency as this evolution has occurred, including the execution of a long-range planning analysis spanning 2007-2011 to identify regional solutions needed to integrate a significant amount of wind resources to meet state policy goals. Known as the Multi-Value Projects, this portfolio has continued to generate reliability benefits and greater savings than costs by unlocking economical generation to the footprint.

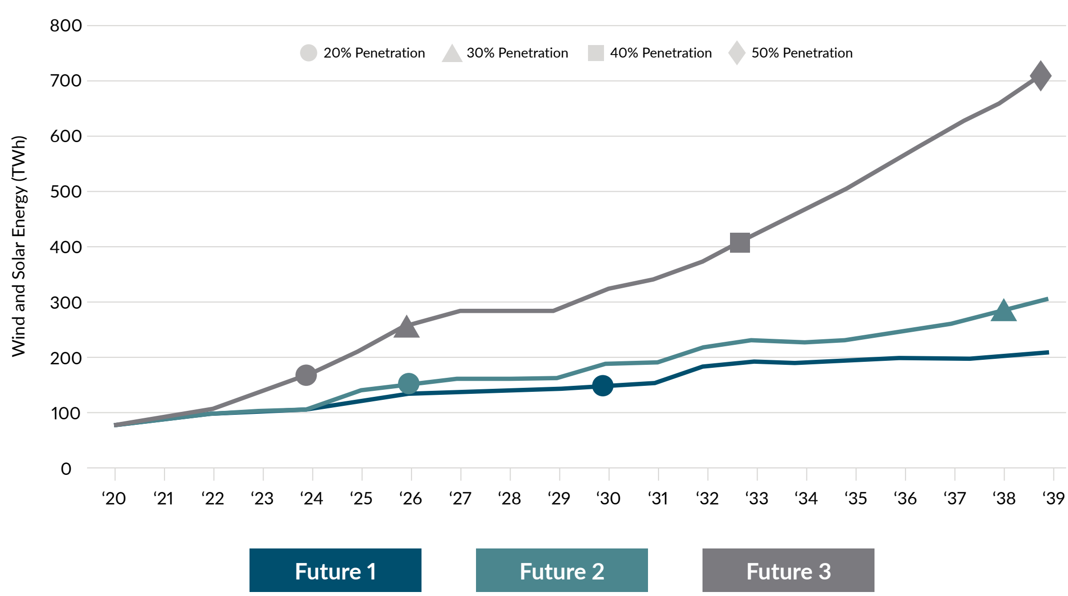
MISO's Planning Futures Show Further Resource Shift

The MISO region is at a point of significant resource and consumption change. Member resource plans, customer preferences and state policies are poised to reshape the industry landscape – and the grid needed to support this shift. The three forward-looking scenarios, or Futures, used in MTEP21 incorporate the increasing pace of fleet evolution that is urgently needed for states and their regulated utilities to meet their energy goals. These scenarios "bookend" plausible outcomes to plan no-regrets additions to the future grid. The Futures, which envision 20 years ahead, inform MTEP21 and the grid planning initiatives within the MTEP report, including Long-Range Transmission Planning and other MISO efforts that ensure continued reliable and economic energy delivery. MISO developed these Futures over the course of 18 months and incorporated numerous rounds of stakeholder feedback, policy assessments and industry trends.

MISO's three planning Futures incorporate varying assumptions about utility and state goals, retirements, Distributed Energy Resources (DER) adoption and electrification, among other factors. All Futures assume changes announced through September 2020 in utility Integrated Resource Plans (or IRPs, resource plans for 10-15 years into the future) are realized.

Further, the Futures model storage usage. The capacity expansion software used in Futures models four-hour duration lithium-ion batteries. In Future 1, 1 GW of storage is assumed; that figure rises to 2 GW in Future 2. Future 3 models 29 GW of storage.

MISO Futures' Wind and Solar Generation



Appendix I
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Docket No. E015,ET2/CN-22-416
Docket No. E015,ET2/TL-22-415

Future 1

Incorporates state and utility goals that are not reflected in enacted legislation at 85 percent of their goal.

Future 2

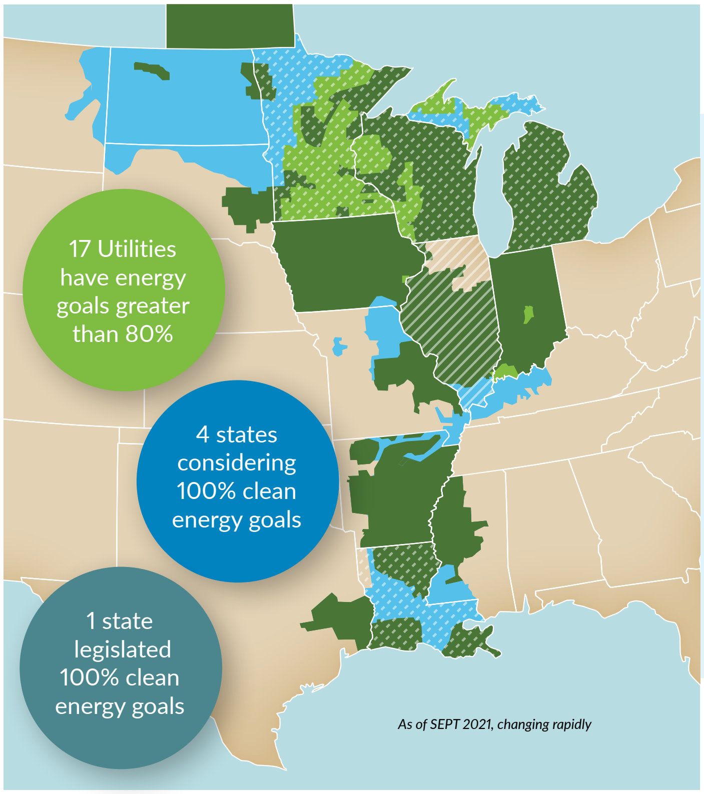
Incorporates announced state and utility goals by their respective timeframes.

Future 3

Incorporates 100 percent of announced state and utility goals within their respective timelines, while also including an 80 percent reduction in carbon dioxide emissions. Future 3 is especially notable for the quantity of resource additions – 330 GW, nearly 2.5 times that of Future 1 and twice that of Future 2.

Future I	Future 2	Future 3
• The footprint develops in line with 100% of utility IRPs and 85% of utility announcements, state mandates, goals, or preferences • Emissions decline as an outcome of utility plans • Load growth consistent with current loads	• Companies/states meet their goals, mandates and announcements • Changing federal and state policies support footprint-wide carbon emissions reduction of 60% by 2040 • Energy increases 30% footprint-wide by 2040 driven by electrification	• Changing federal and state policies support footprint-wide carbon emissions reduction of 80% by 2040 • Increased electrification drives a footprint-wide 50% increase in energy by 2040
	ADDITIONS	
121 GW	160 GW	330 GW
	RETIREMENTS	
77 GW	80 GW	112 GW
	NET PEAK LOAD	
136 GW - July	148 GW - July	164 GW - Jan
	CO_2 EMISSIONS	
↓63% 199 MMT CO_2	↓64% 195 MMT CO_2	↓81% 104 MMT CO_2

MMT CO_2 (million metric tons of carbon dioxide)



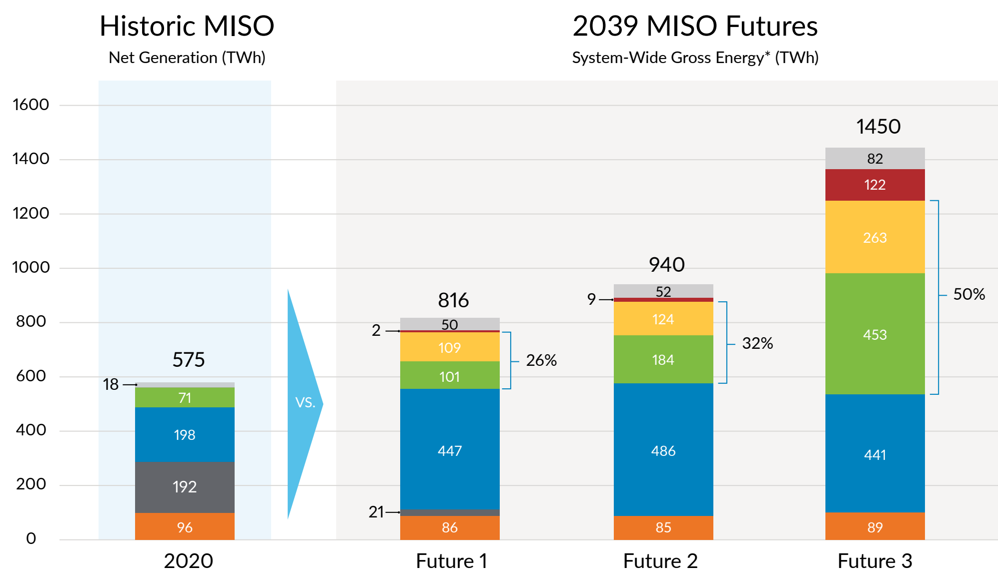
MISO States and Utilities with Decarbonization or Clean Energy Goals

The planning Futures also model different rates of decarbonization. Decarbonization goals are becoming more widespread among states, municipalities, utilities and companies, and those goals are becoming increasingly aggressive, with greater emissions reductions on a shorter timeframe. While the entire footprint does not share these goals, this fleet transition will still have implications regarding what resources are needed regionally to ensure grid reliability. At their apex, goals include reaching 100 percent renewable energy supply or zero net carbon by 2050. Today, carbon emissions in the MISO footprint have reduced 29 percent since 2005. Future 1 and Future 2 both have similar carbon reductions – 65 percent and 64 percent, respectively. Future 3 features reductions of 81 percent. All reductions are from 2005 levels.

Relatedly, the Futures also model load growth, and specifically anticipate electrification of significant portions of the economy. After years of negligible load growth, electrification presents a unique challenge for electric utilities that could potentially transform the electric power system. Electrification —the conversion of equipment to utilize electricity as its energy source — is of special importance as states, municipalities, utilities and companies pursue decarbonization, strategies that depend on a decarbonized electricity system.

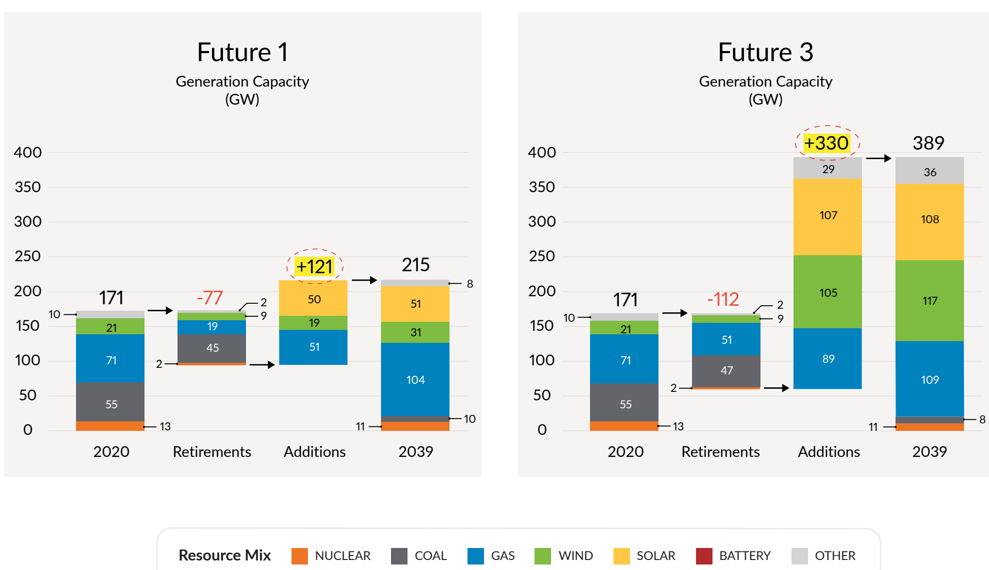
Future 1 assumes that demand and energy growth are driven by existing economic factors, with small increases in electric vehicle adoption, for an annual energy growth rate of 0.5 percent. Future 2 assumes an increase in electrification, with a resulting 1.1 percent annual energy growth rate. Future 3 includes a larger electrification scenario for a 1.7 percent annual energy growth rate.

The Futures incorporate and build upon member plans to reflect the resource transition and changing demand patterns, including dramatic energy increases with electrification...



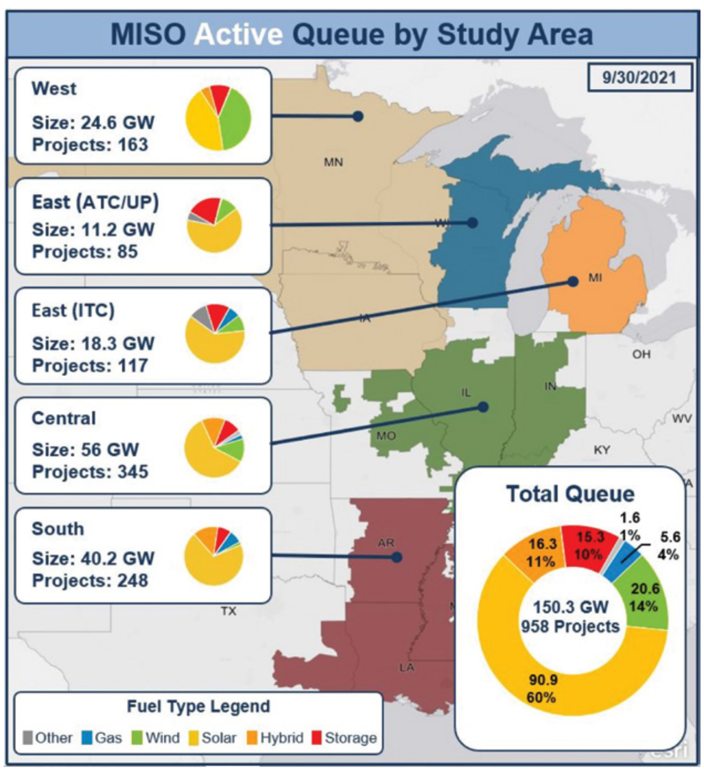
*System-Wide Gross Energy includes increasing amounts of dumped (or curtailed) renewable energy and storage fill;
New Generation does not include dumped energy, storage fill or DERs.

...and substantial capacity requirements and additions



Finally, resource additions are only half the picture. The other half are the number of conventional generators that are retiring, resulting in the overall resource shift in the fleet to intermittent, renewable resources. Age-based retirements of coal units gradually decrease with each Future, with 46 years assumed in Future 1, 36 years in Future 2 and 30 years in Future 3. Gas generation follows a similar pattern of 50, 45 and 35 years at retirement, respectively. Retirements are similar between Future 1 (77 GW) and Future 2 (80 GW). Retirements increase substantially in Future 3 (112 GW).

Change is also occurring on the demand side, both in terms of load growth and how customers interact with the grid. Consumers are increasingly siting solar generation and storage near homes and businesses. Further, customer, utility and state efforts to decarbonize will employ increasing electrification of the economy as an important tool to meeting those goals. All of this will require a very different grid to support these new technologies and uses. To meet these needs, the Futures model different penetrations of DERs. These resources are broken up into three subcategories: Demand Resources (programs in which customers reduce their energy use at times of greatest system need); energy efficiency (using energy more efficiently, for example, through more efficient lighting); and distributed generation (such as customer-sited solar generation). While Demand Resources maintain a consistent addition of 118 GWh of generation across each of the three Futures, both Energy Efficiency and distributed generation increase (from 7.8 GW to 11.7 GW for energy efficiency, and almost 3.5 GW to 6.2 GW, respectively, for Distributed Generation).



In 2021, MISO's interconnection queue process received record generation capacity requests to connect to the transmission system.

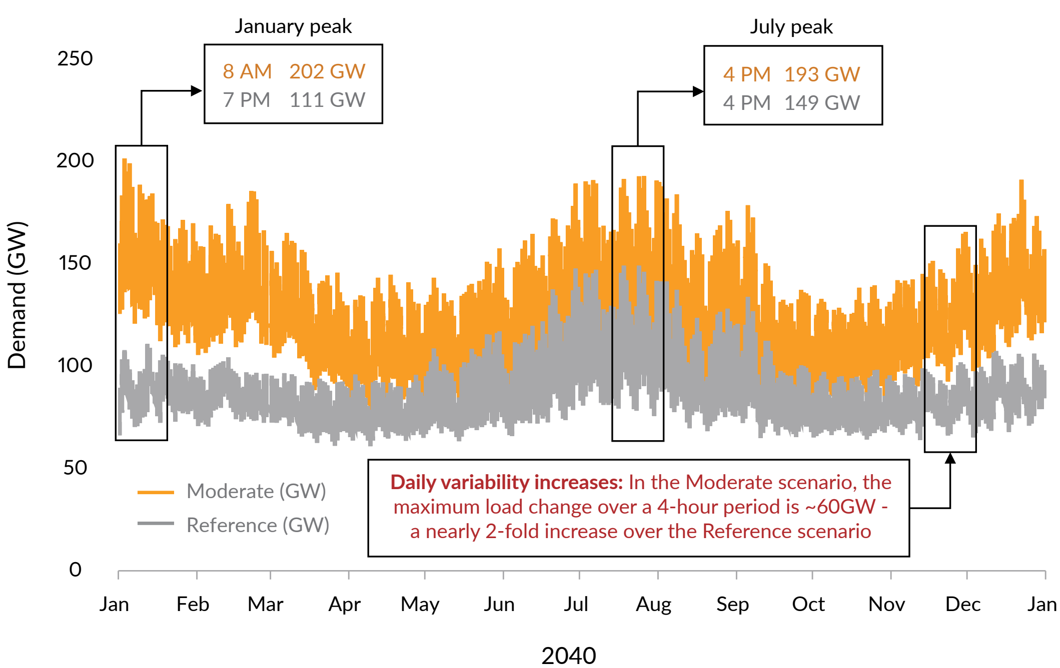
Risks and Mitigations

Recent and ongoing MISO studies offer unique perspectives of what issues different planning futures might require of planning efforts. These studies form a knowledge base and put a lens on possible future risks and how they could be mitigated through transmission expansion planning.

The Renewable Integration Impact Assessment (RIIA), a multi-year study published in 2021, shows that as renewable penetrations increase, so do the variety and magnitude of bulk electric system needs and risks. Up to 30 percent renewable penetration seems manageable with incremental transmission. Managing the system beyond 30 percent of system-wide renewable penetrations will require transformational change in planning, markets and operations.

Additionally, the multi-year Resource Availability and Need (RAN) effort is based on increasing the availability of resources when they are needed, in response to an increasing number of operating emergencies. The ability to

Moderate scenarios of electrification could change MISO to a winter-peaking system, and require greater flexibility and ramp to meet two seasonal peaks in summer and winter



See MISO's Electification Insights study transfer power across the footprint, and across the North-South interface, has been an important factor in mitigating operating emergencies.

The 2021 MISO Electrification Insights study finds that increases in electrification will change load profiles. Electrification requires an increase in ramping services, as the average annual load increases and becomes more variable. It also has the potential to change MISO from a summer-peaking system to one with a winter peak. Research suggests that flexible loads have potential to offset extreme ramps.

MISO's Regional Resource Assessment, scheduled for publication in late 2021, provides visibility into long-range utility resource planning across the region to inform state regulators and utilities as they make their long-term resource plans. As the region evolves, more coordination will be needed between utilities, state regulators and MISO to ensure a reliable system. The Regional Resource Assessment will use MISO's system-wide vantage point to compile resource plans and assumptions to develop zonal models and analysis.

Future Reliability: A Shared Responsibility

As work continues during this resource evolution, it becomes clear that MISO, its members, state regulators and other entities responsible for system reliability all have an obligation to work together to address the challenges posed by a dramatically changing fleet. MISO calls this shared responsibility the Reliability Imperative because the reliability-enhancing work it requires cannot be delayed. This work will also enable utilities and states in the MISO region to invest in the type of infrastructure that is needed to meet energy needs and policy objectives going forward.

Renewable resources account for about 13 percent of today's energy in the MISO footprint. Even at this level, the areas within the region already experience challenges in congestion, trapped generation, pockets of curtailments and negative pricing. The initiatives identified in MISO's response to the Reliability Imperative anticipates future needs in system planning, markets and operations.

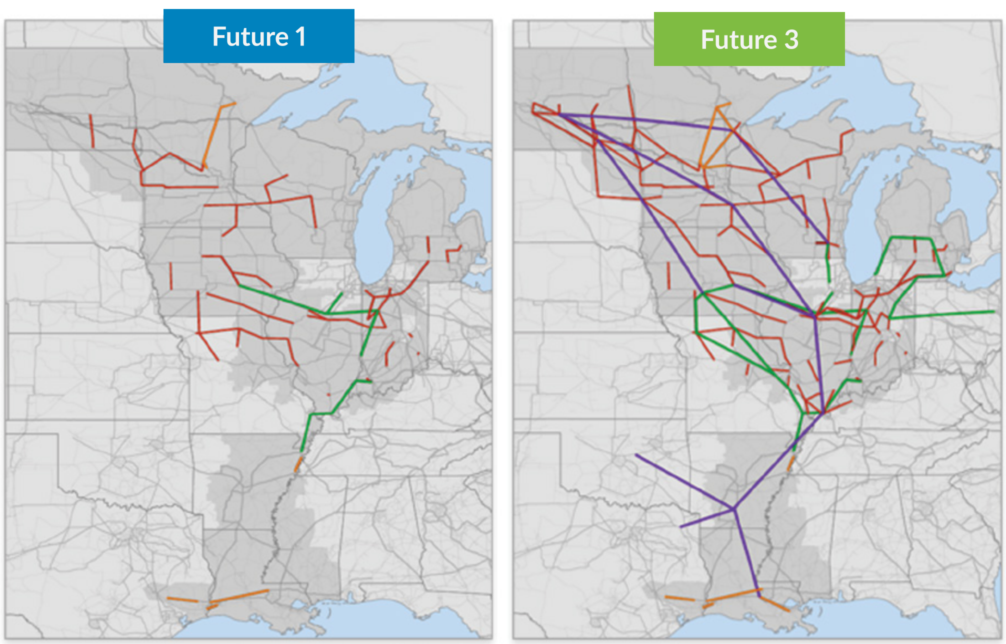
"MISO calls this shared responsibility the Reliability Imperative because the reliability-enhancing work it requires cannot be delayed."

Long-Range Transmission Planning

Changes in transmission planning, markets and operations are needed to enable the future grid infrastructure to align with the ambitious decarbonization goals in a reliable manner. Transmission facilities take an average of 10 years to go from planning to in-service. Further, areas of MISO are already experiencing periods of more than 40 percent of its energy from wind, creating operating challenges. To ensure the necessary infrastructure is in place, planning processes must proceed — with the input of our diverse stakeholder community — as efficiently as possible.

MISO's transmission planning scenarios reflect significant capacity requirements and additions. Future 1 alone — which reflects member plans as they look to adjust their fleets to achieve clean energy goals — anticipates 121 GW of resource additions to meet those goals. MISO's current

Indicative 'Roadmaps' (as of June 2021)



*Indicative 'Cost to Achieve'** *($billion)*	Future 1	Future 3
New Generation/Resources	+/- 135	+/- 430
New Transmission Solutions	+/- 30	+/- 100
Total New Investment	**+/- 165**	**+/- 530**

* Initial 'indicative' investment cost estimates expressed in 2020 dollars; generation additions thru 2039 are 121 GW in Future 1, 330 GW in Future 3; generation costs from EGEAS modeling; transmission solutions cost from MISO transmission cost estimating tools.

Voltage Level (kV)
- 345
- 500
- 765
- DC Line

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system capacity today is 184 GW. The indicative "cost to achieve" this transformation in Future 1 is estimated at $165 billion in investment. A relatively small portion of that total — $30 billion — would be transmission infrastructure necessary to support this transition.

For decades, grid operators have managed variability and uncertainty in the system. MISO expects this variability and uncertainty to become more profound, making it more challenging to manage supply, load, and reserves.

Unlike annual processes that identify Baseline Reliability Projects, Market Efficiency Projects and generator interconnection network upgrades, MISO periodically identifies regional needs through a regional overlay process. Like other transmission project types, conditions for successful planning include a consensus that transmission is required, a deeper analysis of those issues and solutions, and ensuring allocation of cost is roughly commensurate with benefits received by each area. Long-Range Transmission Planning uses a process that is iterative to ensure the system is planned to be reliable, resilient and efficient in the near term and out to 20 years and beyond. MISO continuously plans, assesses, evaluates and repeats as necessary to ensure a least-regrets plan. In such an approach, MISO seeks to identify transmission that will be used and useful across a variety of scenarios as utility, customer and state plans continue to shift over time.

A strong regional backbone enables the movement of power across the footprint, from where it is generated to where it's needed most. This further unlocks economic generation across the footprint. The ability to move power around the footprint is also an important benefit during periods of grid stress, such as extreme weather events like the 2021 Arctic storm that crippled Texas.

In this event, extreme low temperatures impeded operation of many generators, especially in the South region. As temperatures plummeted, a number of generators went offline. At that time, it became critical to move power to where it was needed. The MISO system was able to move large amounts of power from north to south across the MISO grid, and import power from the east for use by MISO and its neighboring RTO, Southwest Power Pool (SPP.)
If the trend of severe weather events continue, regional transmission will become even more important for the resiliency of the electric system, providing needed power to homes and businesses as they navigate temperature extremes. Long-Range Transmission Planning projects will promote regional bulk transfer, interzonal support, resource integration and resource retirement.

Long-Range Transmission Planning will facilitate increased regional energy transfer that, in turn, will support and allow for increased interregional energy transfer that results in market efficiencies as well as emergency and reliability support. MISO will identify these projects, along with appropriate cost allocation, through an extensive stakeholder process that includes monthly workshops, periodic discussions at the Planning Advisory Committee, plus additional stakeholder meetings through the Regional Expansion Criteria and Benefits Working Group.

MISO-SPP Joint Transmission Interconnection Queue Study

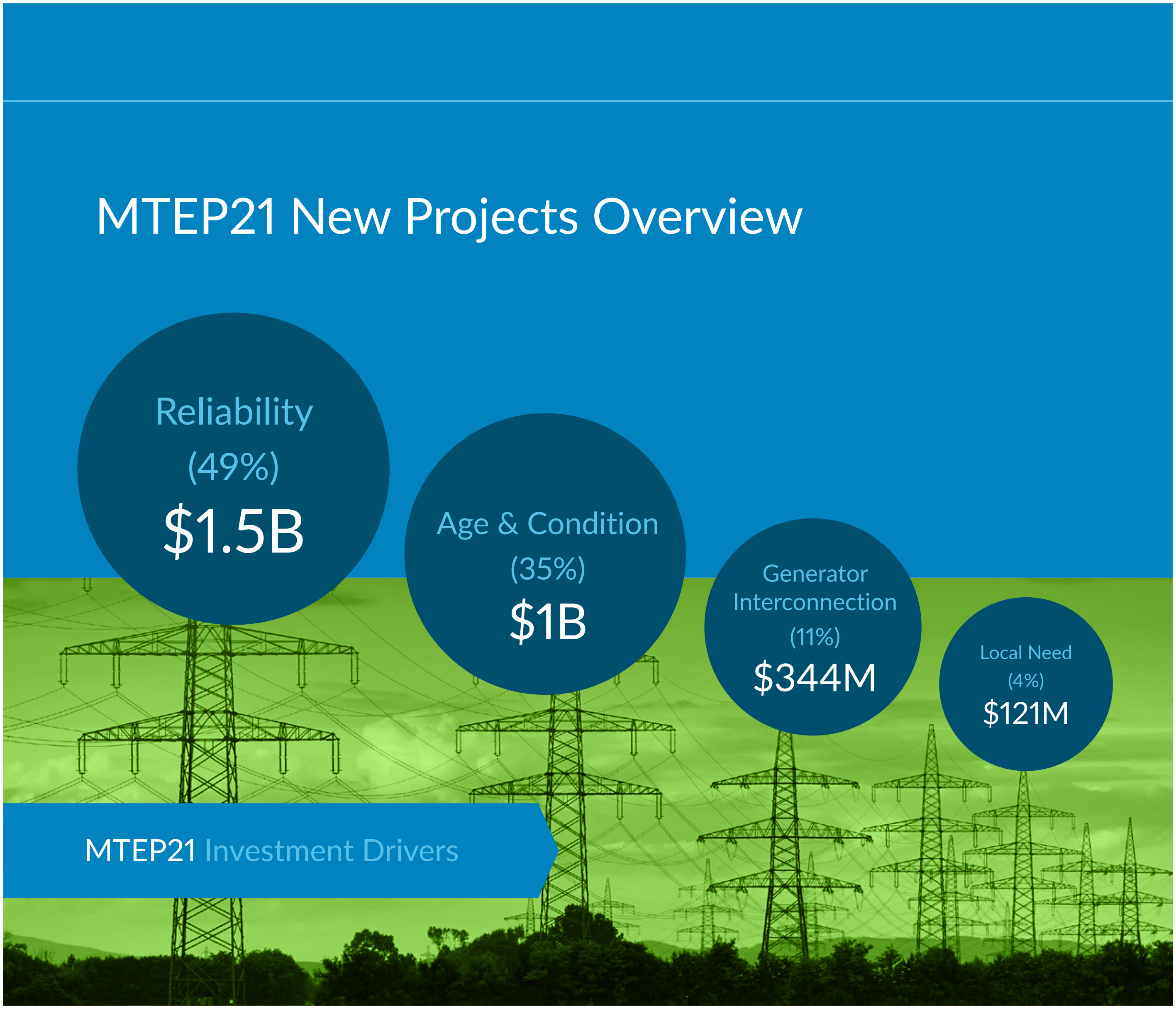
As both MISO and SPP face large interconnection queues with overwhelming quantities of wind and solar resources, the transmission system is at its capacity on the MISO-SPP seam. Renewable resources and additional transmission at the borders benefit markets as a whole, but network upgrades are too costly for individual interconnection projects to proceed and current cost allocation methodologies do not provide sufficient cost-sharing to facilitate interconnection of new generators. Collaboration between MISO and SPP is important in bringing resources online.

Further, robust interconnection capabilities during severe weather events may avert catastrophe. At one point during the Arctic Event, MISO's RTO neighbor to the east, PJM, exported 13,000 MW into MISO for use in the affected areas. However, ERCOT could only import 800 MW due to its limited interconnections to other regions.

Solutions coming from this effort, and the Long-Range Transmission Planning initiative, will feed into upcoming MTEP cycles.

MISO

SPP Southwest Power Pool



MTEP21 Appendix A projects are vetted by MISO through the planning process and are ready for execution.

The 335 new Appendix A projects in MISO's 2021 Transmission Expansion Plan (MTEP21) represents over **$3 billion in transmission infrastructure**

Top 10 proposed MTEP21 projects

(In descending order of cost)

Rank	Project Name	Project Driver	Estimated Cost ($M)
1	Golden Meadow to Clovelly 115 kV: Line Rebuild	Other – Reliability	$86
2	Southern Iowa New 161 kV Line and Breaker Stations	Other – Reliability	$71
3	Northline 230 kV: New Substation	Other – Load Growth	$43
4	Cato – Corktown 120 kV	Other – Reliability	$40
5	J875 Generator Interconnection	Generator Interconnection	$37
6	Lincoln - 43rd Street Terminal 138 kV: Line Rebuild	Other – Age and Condition	$36
7	Southline 138 kV: New Substation	Other – Load Growth	$35
8	Appleton – Benson (AG-AB) 115 kV Line	Other – Reliability	$35
9	Panther – Big Swan Rebuild	Other – Age and Condition	$33
10	Bullock Shale 138 kV - Rebuild	Baseline Reliability	$33

The 10 largest projects represent 15 percent of the total cost and are distributed across the MISO region. These projects support safe, reliable transmission to enable load and generation interconnection, NERC reliability compliance and other local needs.

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MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report

MISO

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1 Introduction

MISO's multi-year Long Range Transmission Planning (LRTP) initiative assesses reliability risks looking 10-20 years into the future to identify the transmission investments needed to enable regional delivery of energy. Projections show a drastically different resource fleet, along with other influences such as electrification, that is driving a need for the bulk electric system to be better prepared for these massive shifts. MISO proposes a Tranche 1 Portfolio of 18 transmission projects, equaling approximately $10 billion of investment, to enhance connectivity and maintain adequate reliability for the Midwest Subregion by 2030 and beyond (Figure 1-1, Table 1-1).

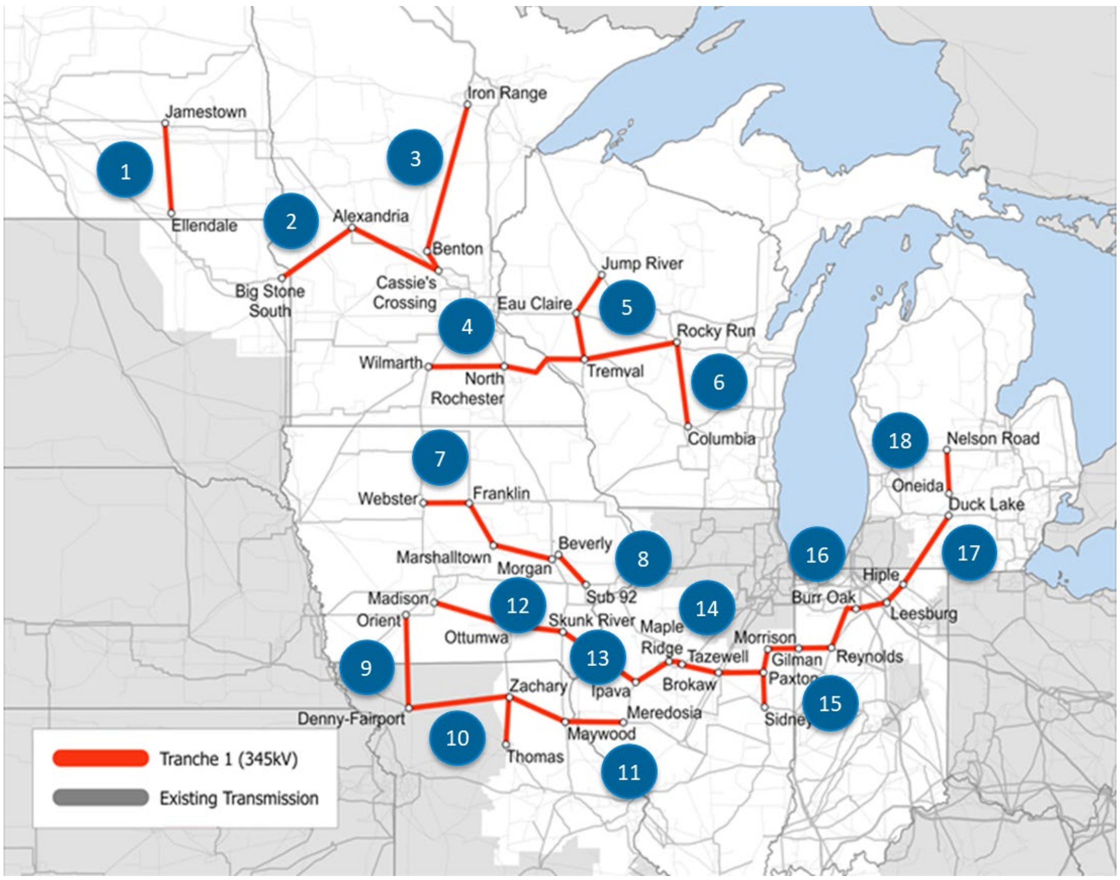


Figure 1-1: LRTP Tranche 1 Transmission Portfolio

LRTP Tranche 1 Portfolio of Projects

ID	Description	Expected ISD	Estimated Cost ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439M
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574M
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970M
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689M
5	Tremval – Eau Claire – Jump River	6/1/2028	$505M
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050M
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755M
8	Beverly – Sub 92	12/31/2028	$231M
9	Orient – Denny - Fairport	6/1/2030	$390M
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769M
11	Maywood – Meredosia	6/1/2028	$301M
12	Madison – Ottumwa – Skunk River	6/1/2029	$673M
13	Skunk River – Ipava	12/31/2029	$594M
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572M
15	Sidney – Paxson East – Gilman South – Morrison Ditch	6/1/2029	$454M
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261M
17	Hiple – Duck Lake	6/1/2030	$696M
18	Oneida – Nelson Rd.	12/29/2029	$403M
	Total Project Portfolio Cost:		$10,324M

Table 1-1: Proposed Tranche 1 Portfolio of Projects
(Costs as of June 1, 2022 and are subject to change. Costs represent "overnight" costs)

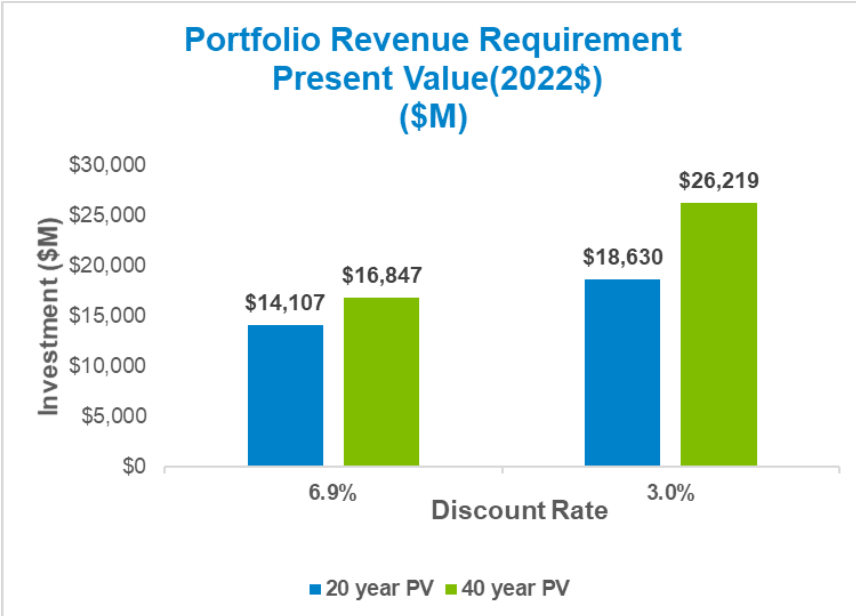
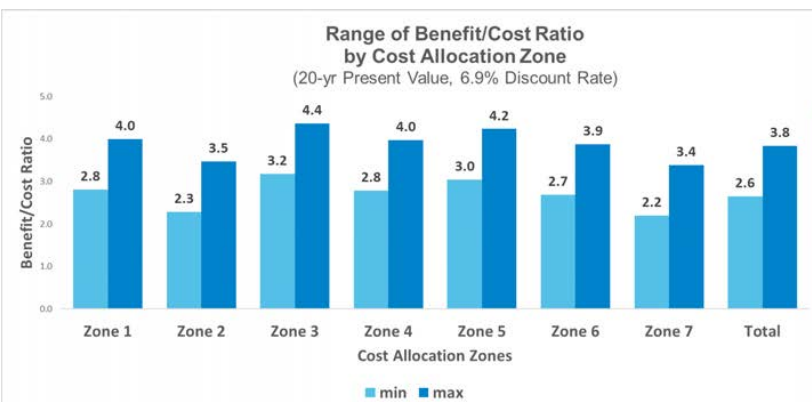


Figure 1-2: Present Value of LRTP Tranche 1 Portfolio (values as of 6/1/2022)

The Tranche 1 Portfolio has a benefit to cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit to cost ratio of at least 2.2 for every Cost Allocation Zone, well in excess of the LRTP Tranche 1 Portfolio costs (Figure 1-2 and 1-3). The proposed projects and costs are spread across the entire MISO Midwest Subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.



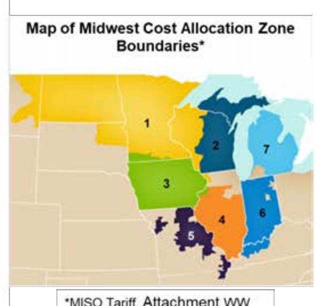


Figure 1-3: Distribution of benefits to Cost Allocation Zones in Midwest (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP study was initiated in 2020, and the LRTP Tranche 1 Portfolio Report is the first iteration of MISO's findings and recommendations. This report identifies reliability challenges in the Midwest Subregion associated with MISO's Future 1.

Efforts on Tranche 2 will be underway in the second half of 2022 and will continue to focus on the Midwest Subregion and addressing the needs identified in MISO's Futures. Tranche 3 of the LRTP study will focus on identifying system needs in the MISO South Subregion, and Tranche 4 will look at the part of the system connecting the Midwest and South Subregions.

While the Tranche 1 Portfolio is the result of MISO's long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward.

2 History of MISO's Innovative Long Range Transmission Planning Process

The transmission grid, while not top of mind for many people, is a critical component of ensuring the lights come on when a switch is flipped, our favorite devices can be charged, and life-saving machines can operate. But even with that level of importance, transmission investments, especially on a large scale, are very difficult to undertake and are not very common in the United States currently. However, the clear direction of the industry, towards a cleaner energy future, requires investments of this nature. Fortunately, MISO has a proven process, experience, and an engaged stakeholder community to draw upon as we embark on this very difficult journey. This is not the first time we have been here, or successfully facilitated significant grid investment.

As a Regional Transmission Organization/Independent System Operator, MISO coordinates with its members to facilitate transmission system investments needed to ensure continued reliable and efficient delivery of least-cost electricity across the MISO region. This requires a continuous execution of MISO's recurring transmission planning process. The culmination of the extensive work executed during each 18-month planning cycle, including proposed new projects, are codified annually in a MISO Transmission Expansion Plan (MTEP). These plans have put in motion approximately $42 billion in transmission investments going back to 2003.

Section 1.2 of MTEP21 provides an overview of MISO's overall transmission planning process, so only the primary aspects are described here to provide high-level context. The process involves both top-down and bottom-up identification of issues and potential solutions associated with transmission system maintenance and enhancement. There are also several aspects, or objectives of different components of MISO's transmission planning process, including resolving grid reliability issues, transmission expansion needed to connect new generation resources to the grid, and reducing congestion on the system. Assessing these types of needs can occur as often as annually and involves looking out 5-15 years to identify near- and mid-term needs.

The overall process also includes a component that has been exercised less frequently, the long-range transmission planning (LRTP) process, which considers challenges projected in the 20 year and beyond timeframe. Given the extensive lead time associated with large-scale transmission investment, this process is designed to be responsive to situational grid needs and utilized when incremental transmission system fixes, upgrades, and/or additions will not be sufficient to effectively or efficiently address those needs. These situations require that MISO consider the range of potential future states, the implications of those outcomes for the industry, and the transmission system needs this will create. Those potential future scenarios serve to provide bookends for the uncertainty that exists when planning this far out.

The inaugural iteration of MISO's long range planning process culminated in the first-of-its-kind portfolio of projects being approved by the MISO Board of Directors in 2011. Beginning in 2007, in response to an increase of individual Renewable Portfolio Standards within MISO states, MISO began the initial execution of the LRTP process to mitigate the significant impact on the future generation mix and the reliability of the system. During this multi-year effort, a new project type — Multi-Value Project (MVP) — was developed. As codified in the MISO Tariff, a project must meet one or more of the following criteria to be included in an MVP portfolio:

> *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.*
>
> *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*
>
> *Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.*

As the criteria demonstrate, economic benefits are a significant part of the requirements for these types of projects. Given the regional scope of these projects, the level of investment, and the uncertainty associated with the time horizon, a strong business case is paramount. The types of economic benefits that could be used to meet these criteria were defined through collaboration with stakeholders. Those benefits are:

- *Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be* *realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements.*

- *Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*
- *Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*
- *Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*
- *Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and related to the provisions of Transmission Service.*

The ground-breaking work executed during this process culminated in a nearly $6 billion portfolio, with a projected 1.8-3.1 benefit-to-cost ratio, being approved by the MISO Board of Directors in 2011. MISO was required to periodically reassess the projected benefits to determine if modifications to the MVP criteria were necessary. Each of those analyses found that the projected benefits remained consistent with, and were sometimes greater than, initially estimated, as shown in Figure 2-1. This, along with the fact that all but one of the 17 MVP projects are currently (as of June 2022) in service and fully utilized, demonstrates the effectiveness of MISO's value-based planning process and the use of future scenarios to bookend uncertainty and identify robust solutions, and to project benefits.

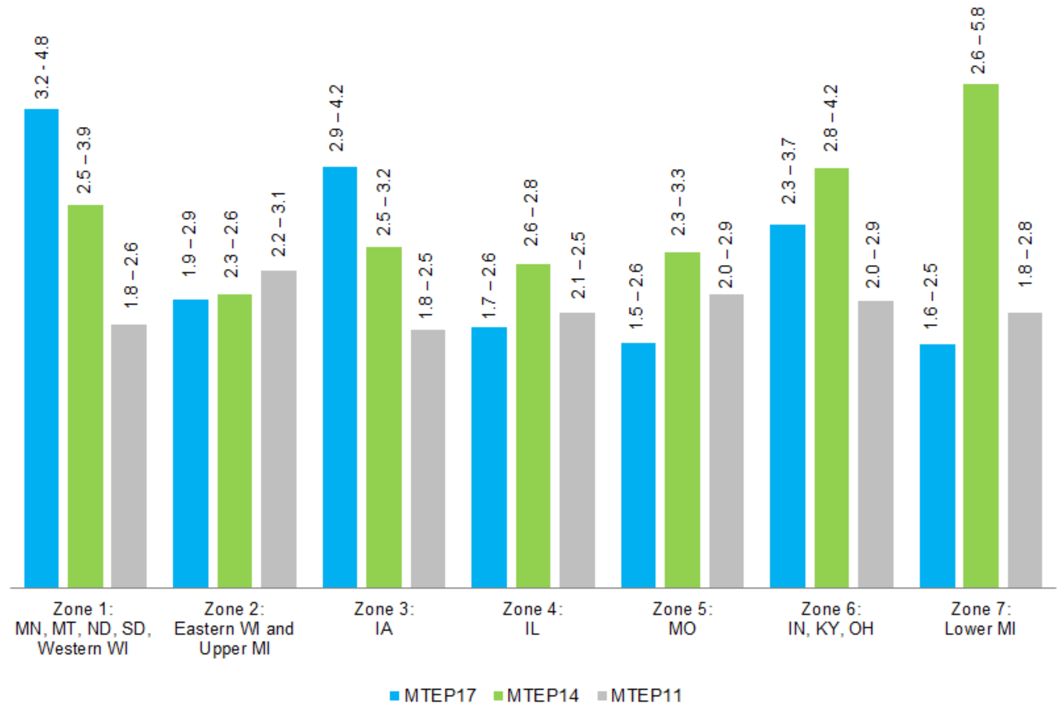


Figure 2-1: Zonal benefit to cost ratios for the original MTEP11 MVP Analysis and subsequent MTEP14 and MTEP17 Triennial Reviews

In the years immediately following the approval of the MVP portfolio, the level of annual investment put forward in MTEP reports returned to historical levels of approximately $1.5 billion annually. Upgrades or replacements of aging assets, and the added investment associated with the integration of the South Subregion have contributed to the annual average investment rising to $3.4 billion over the last five years, but still well below the level approved in 2011 with the MVPs. While this increased rate of investment is strengthening the grid in the MISO Region, it is not reflective of the magnitude of change that has been occurring across the landscape during this time.

3 The Long Range Transmission Planning Component of MISO's Broad-Based Response to Current Industry Change

The generation mix evolution in the MISO Region that drove the need for the MVP portfolio didn't end with that portfolio's approval. In fact, the pace towards more renewables has increased since that time. Progressively increased carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery storage and hybrid projects. MISO made a number of incremental changes to its markets, tools, and processes along the way to mitigate the early impacts of this change. However, beginning in 2016, the challenge was becoming obvious and more difficult to mitigate.

Change Drivers and Implications Contributing to Aligning Interests

Over the last several years, MISO began to experience operational situations that required the use of emergency procedures, even outside of the summer period when demand peaks occur, and supply becomes strained. In the real time horizon, when resource margins are projected to be significantly low, MISO will begin to implement the steps in its emergency procedures in an attempt to gain access to additional resources. While not having to make a single emergency declaration in the two years preceding 2016, 41 such emergency declarations have been required since 2016. These events are largely the result of reduced generation capacity due to the retirement of conventional generation as the fleet has transitioned toward more renewable resources and greater reliance on Load Modifying Resources for meeting capacity requirements.

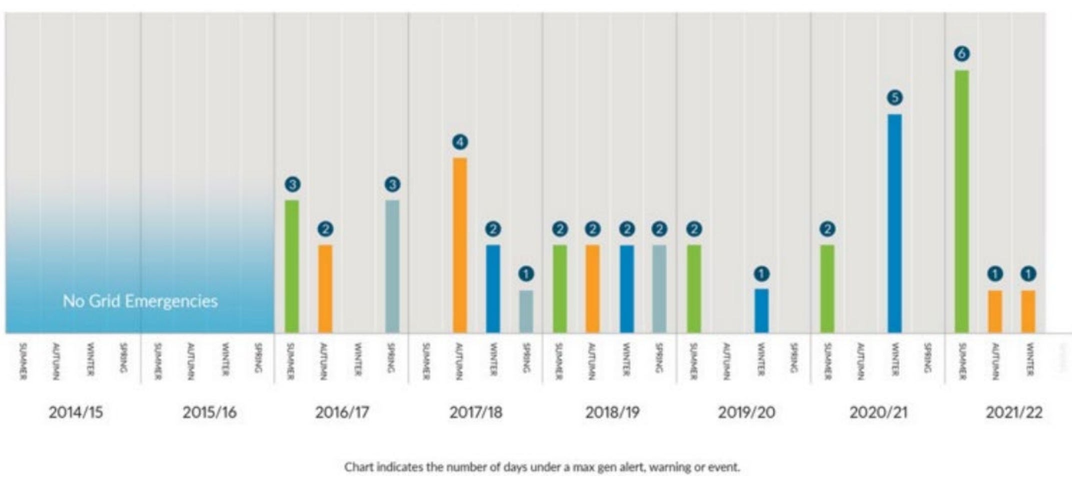


Figure 3-1: Historical MISO MaxGen Alerts, Warnings, and Events

In response to this growing challenge, MISO launched the Resource Availability and Need (RAN) initiative to understand the drivers and identify a variety of changes to markets and resource adequacy process solutions to generation availability issues.

At the same time, and driven by the ongoing fleet shift, MISO executed a multiple-year study called the Renewable Integration Impact Assessment (RIIA) to deepen its understanding of the implications of more renewable generation on the system. This assessment identified inflection points, or renewable energy penetration levels where challenges would get increasingly more complex. It also identified key risks that would result, including insufficient transmission infrastructure.

- ***Stability Risk*** requires multiple transmission technologies, operating and market tools to incentivize availability of grid services
- ***Shifting periods of grid stress*** requires flexibility and innovation in transmission planning processes
- ***Shifting periods of energy shortage risk*** requires new unit commitment tools, revised resource adequacy mechanisms
- ***Shifting flexibility risk*** requires market products to incentivize flexible resources
- ***Insufficient transmission*** requires proactive regional transmission planning

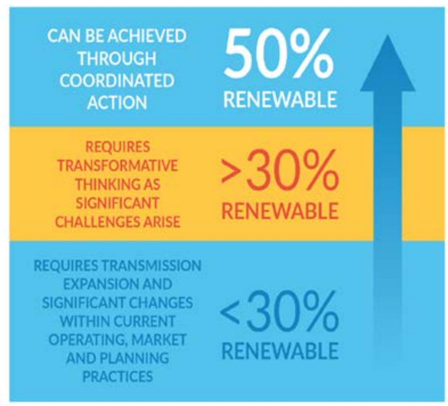


Figure 3-2: RIIA Study Identified Key Risks with increasing levels of Renewable Energy

The timing of when the region would reach these inflection points was then uncertain. However, an additional driver emerged that accelerated the pace towards more renewables: a growing customer preference for clean energy. MISO began to see a growing number of member utilities and state policies incorporating decarbonization goals into their resource fleet strategies. Around this same time another trend was emerging on the demand side as well. The movement towards electrification will have a significant impact on electricity demand, which has in recent years been relatively stable.

This level of uncertainty makes it very difficult to plan for the future with confidence. However, as demonstrated with the development of the 2011 MVP portfolio, MISO has an existing process to effectively manage these types of risks. MISO, in collaboration with stakeholders, establishes future planning scenarios to understand the economic, policy and technological impacts on future resource needs. Starting in 2019, MISO examined three future scenarios to define and bookend regional resource expectations over the next 20 years (MISO Futures Report[1]). These Futures recognize the widespread clean energy goals of states and utilities within the region, as well as the associated rapid pace of regional resource transformation.

[1] MISO Futures Report

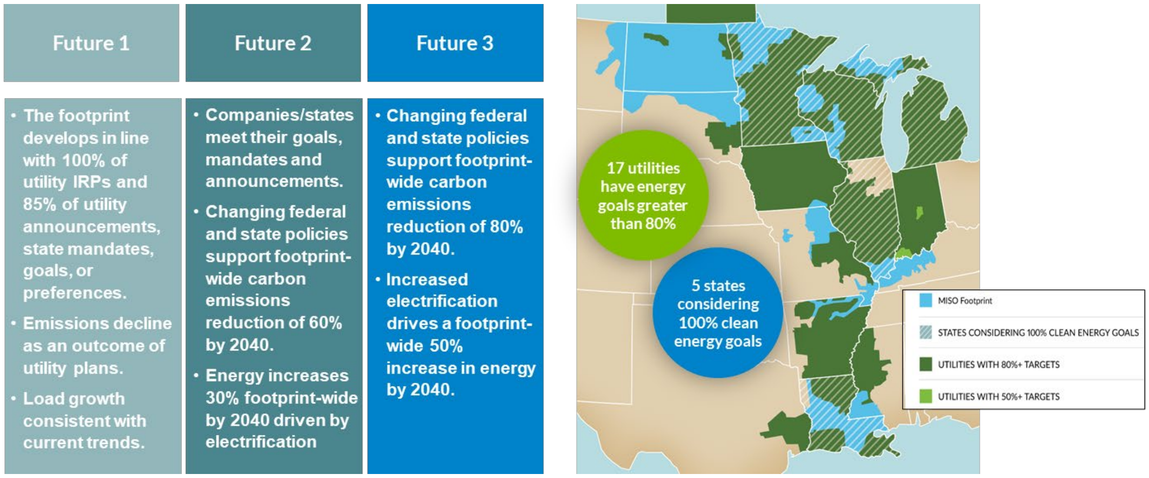


Figure 3-3: MISO Futures Key Drivers

MISO's Reliability Imperative Response: The Long Range Transmission Planning Initiative

These future scenarios reflect the significance of the changes the region must prepare for, and similar to the situation facing the region back in 2007, incremental changes will no longer be adequate. The magnitude of landscape changes has created an imperative for transformational changes across MISO's markets, planning, operations, and technology. The Reliability Imperative Report[2] documents the collection of related initiatives that address the growing risks and that are required to enable member resource plans and strategies. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges.

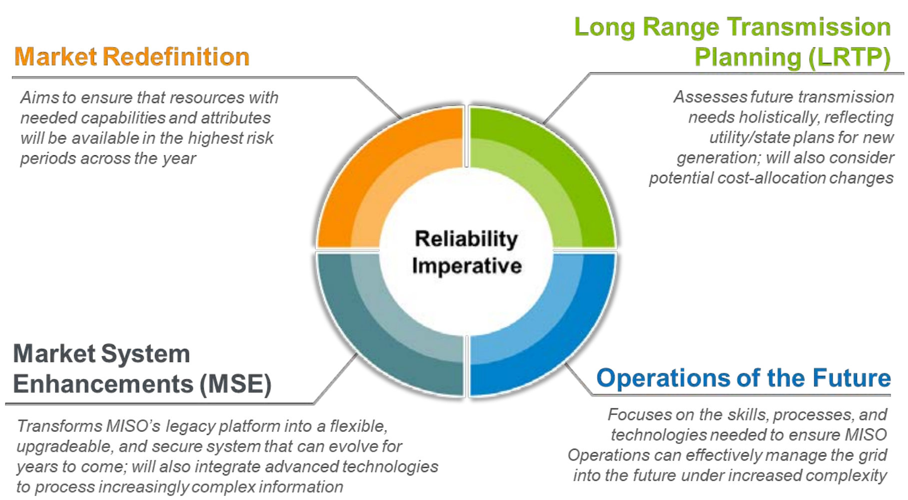


Figure 3-4: MISO's Reliability Imperative Key Initiatives

[2] MISO'S Response to the Reliability Imperative

As work has been underway, an additional risk emerged that has increased the urgency associated with progressing these initiatives. An increase in the frequency of extreme weather events is exacerbating the risks and challenges that originally drove the need for the Reliability Imperative. These types of scenarios can force a large number of generators out of service in a local area, putting reliability at risk. This has contributed to the emergency procedure declarations over the last several years (Figure 3.1).

Robust Business Case for Long-Range Transmission Plan

As the region faces both a changing resource fleet and increased prevalence of extreme weather events, the ability to move electricity from where it is generated to where it is needed most becomes paramount. One needs only to consider the need for increased power flow within and between regions during Winter Storm Uri in February 2021 to understand the importance of transfer capability. MISO can leverage its large geographic footprint and diversity of resources to ease some of these challenges. However, adequate transmission infrastructure is key.

With the landscape once again shifting and expected to do so even more dramatically in the future, the transmission planning aspect of the Reliability Imperative includes the second execution of MISO's long-range transmission planning process. The MISO LRTP initiative, introduced to stakeholders in August 2020 to invite their collaboration, provides a regional approach to transmission planning that addresses future challenges of the resource fleet evolution and electrification. The transformational changes occurring in the industry necessitate the identification of transmission solutions to ensure continued grid reliability and cost-effective transmission investments that will serve future needs.

The objective of LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
- **Cost Efficient** – enable access to lower-cost energy production
- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice

LRTP is designed to assess the region's future transmission needs in concert with utility and state plans for future generation resources.

LRTP is a multi-year effort to address the myriad and complex issues associated with the significant resource transformation underway. Because there is urgency to keep pace with this rapid evolution, MISO is seeking to recommend projects identified in the LRTP effort over several MTEP cycles as work progresses. While it is important to move quickly, MISO must ensure reliable power delivery for customers with investment decisions that appropriately balance generation and transmission solutions on a regional scale to ensure the best cost outcomes for customers.

LRTP continues the MISO Value-Based Planning approach to extend value beyond the traditional planning processes to achieve a more efficient comprehensive long-term system plan.

Tariff Requirements

The needs driving the LRTP portfolio, the scope of the projects and types of benefits they enable aligns relatively well with those of the MVP portfolio and the associated MVP tariff requirements are being applied for the LRTP. The criteria to meet the project definition are listed in their entirety in Section 2, and in summary are: 1) enable the transmission system to reliably and economically deliver energy in support of documented energy policy mandates or laws, 2) provide multiple types of economic value, with a benefit-to-cost of 1.0 or greater, or 3) address at least one reliability issue and provide at least one type of transmission-based economic value.

LRTP Cost Allocation Aligned with Beneficiaries

A condition that must be met prior to any transmission investment being approved is to determine how the costs will be allocated. The original MVP ruleset established a cost allocation methodology of spreading costs footprint-wide on a load-ratio share basis. With the initial Tranche of LRTP projects identified to address reliability issues in MISO's Midwest Subregion only, this approach was not going to meet FERC's requirement of costs spread roughly commensurate with benefits.

To address this risk, MISO proposed a modified MVP methodology where costs could be spread to a subregion only, if the projects within the portfolio primarily provide benefits to a single subregion. This proposal was approved by FERC on May 18, 2022 with a May 19, 2022 effective date. With FERC's approval the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion.

4 Rigorous, Collaborative Approach Ensures Robust LRTP Solutions

With this being the second execution of MISO's long-range transmission planning process, it was not groundbreaking, but it is no less significant than the first execution that developed the 2011 MVP portfolio. In fact, the landscape changes being planned for are much more significant now and require prompt action to address the fast pace of transformational changes occurring in the industry. The initial tranche of LRTP projects was developed in a focused effort to deliver a set of least regrets solutions that would be ready to address needs in the next 10 years.

While the process was executed in significantly less time, the quality of the analysis and commitment to identifying robust solutions was not sacrificed. This portfolio of projects represents over 2,000 miles of transmission, a significant level of investment unprecedented in the industry and will have its benefits and costs shared broadly. Given this backdrop, it is incumbent on MISO to perform a rigorous analysis to ensure we identify a robust set of projects that most effectively and efficiently resolve the identified issues and future system needs.

The process MISO follows to identify projects and create a portfolio is designed to result in a business case that justifies the investments. As described in Section 3 of this report, the first step in this process is to create potential future scenarios, or Futures, to essentially establish a target for our planning efforts. In some situations, the Futures could bookend very different directions for the region's generation fleet due to uncertainty around energy policy and other factors. However, given the current clear trends that include Members and States increasingly establishing clean energy goals, the continued retirement of fossil fueled resources from the system, and a growing trend toward electrification, the current set of futures reflect different progressions or the velocity of change in that singular direction.

MISO developed a long range conceptual regional transmission plan to explore and further study possible solutions needed to address future transmission needs. The conceptual plan serves as a set of solution ideas that guide the development of candidate transmission projects that meet the objective of long range planning to achieve reliable and economic delivery of energy in a range of future scenarios. Reliability analysis is conducted on a series of study models that represent various system conditions and dispatch patterns to identify issues. MISO then evaluates the candidate projects and potential alternative solutions developed by MISO and stakeholders to identify the most effective transmission investments to address the issues and performs an economic analysis that factors into selecting the best of the options. Section 5 of this report is a detailed walk-through of the reliability analysis that was undertaken, with the results provided in Section 6.

Once the portfolio of projects is identified, MISO then calculates the economic benefits created by the portfolio. The primary objective of the LRTP projects was to address reliability issues identified in the planning studies that considered a range of system conditions. However, while transmission investments are usually built for a specific purpose, the value that any particular investment brings can extend well beyond addressing the singular issue driving it. That is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant economic benefits as well.

While the objective of LRTP is primarily focused on the need for reliable energy delivery, the analysis of economic benefits is essential to the demonstration of value of the portfolio as required by the Tariff for eligibility as regionally cost shared projects. The economic benefit types that can be assessed were identified in Section 2 of this report in the discussion on Multi-Value Projects, which the LRTP will be categorized as. The specific metrics that were used to determine the economic benefits of the LRTP portfolio are:

- Congestion and fuel savings – LRTP projects will allow more low-cost renewables to be integrated, which will replace higher-cost resources and lower the overall production cost to serve load.
- Avoided local resource capital costs – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local resource build out.
- Avoided future transmission investment – LRTP projects will reduce loading on other transmission lines, in some cases preventing lines from becoming overloaded in the future and thus avoiding the need to upgrade those lines.
- Reduced resource adequacy requirement – LRTP projects will expand transfer capability, which will in certain situations increase the ability for a utility to use a new or existing resource from another part of the MISO region, rather than construct one locally, to meet its resource adequacy obligation.
- Avoided risk of load shed – the LRTP portfolio will increase the resilience of the grid and lower the probability that a major service interruption occurs.
- Decarbonization – the higher penetration of renewable resources that the LRTP portfolio will enable will result in less CO_2 emissions.

The methodology used to calculate each of these economic benefits and the results are the focus of Section 7.

As described in Section 8 of this report, the allocation of LRTP portfolio costs is spread broadly to the entire Midwest Subregion. The Federal Energy Regulatory Commission requires that transmission costs associated with investments of this nature be allocated roughly commensurate with how the benefits are realized. Given the large-scale of the LRTP projects and the fact that they span the Midwest Subregion, benefits flow to the entire subregion. To illustrate this and demonstrate support of FERC's guidance, Section 8 shows the benefits by MISO Cost Allocation Zone.

Given the expected continued key role of natural gas generation, volatility in the price of natural gas can have a significant impact on the cost of producing electricity. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than natural gas. Chapter 8 includes a sensitivity analysis performed using a range of natural gas prices to demonstrate the robustness of the LRTP Tranche 1 Portfolio across a range of scenarios.

5 LRTP Tranche 1 Portfolio Development and Scope

Most good plans result not from a single work effort, but rather develop from refinements to an effective starting point. The latter characterizes the path to the LRTP Tranche 1 Portfolio. In anticipation of reliability needs in a future with growing renewable penetration and load consumption, MISO developed an indicative transmission roadmap of potential transmission expansions throughout the region for both Future 1 and a combined Future 1, 2, and 3. The roadmap provides an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures and candidate transmission solutions to be used as a starting point in determining potential projects. This roadmap was developed by MISO planning staff as extensions of the existing grid that would provide for logical connections that could increase connectivity, close gaps between subregions, and support a more robust and resilient grid by enabling the delivery of energy from future resources to future loads and increasing the reliance on geographic diversity to manage the increased dispatch volatility and uncertainty associated with the future resource fleet. The indicative roadmap is not a final plan but instead a starting point for considering solutions to transmission issues expected.

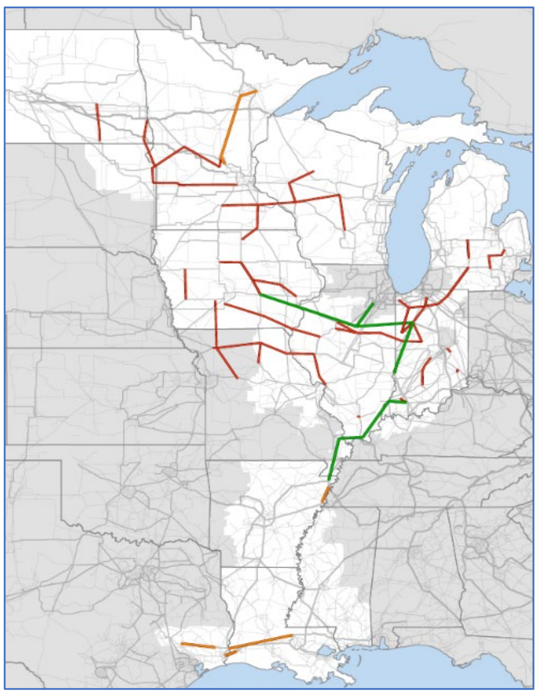


Figure 5-1: Future 1 Indicative Roadmap

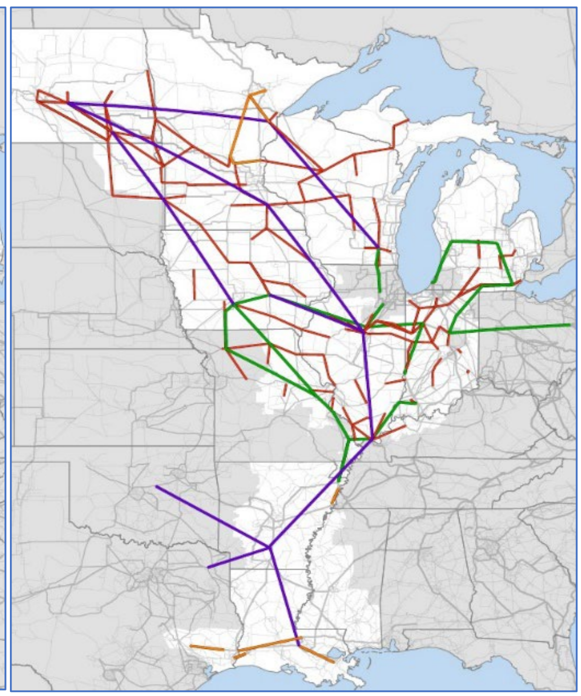


Figure 5-2: Futures 1, 2, & 3 Indicative Roadmap

The initial tranche of the LRTP is focused primarily on enabling the resource expansion and load forecasts associated with the 10- and 20-year timeframe under Future 1 in the Midwest

Subregion. In Future 1, the most significant aspects are resource retirements and increased renewable penetration.

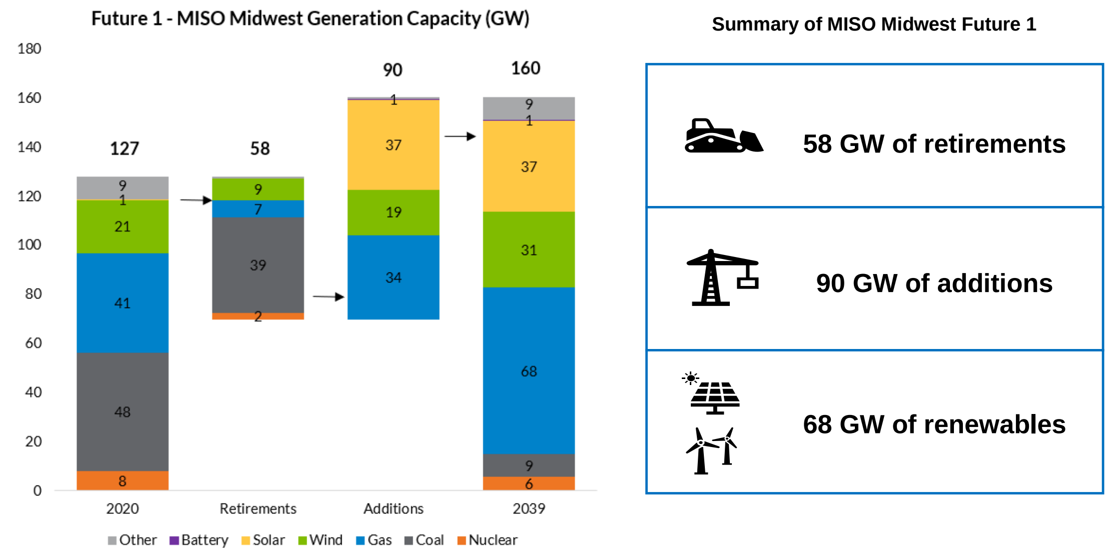


Figure 5-3: Future 1 changes in Generation Capacity for Midwest Subregion

In Futures 2 and 3, higher levels of resource retirements and renewable resource penetration coupled with higher levels of electrification will be significant. Later tranches of LRTP will focus more on Future 2 and Future 3 scenarios.

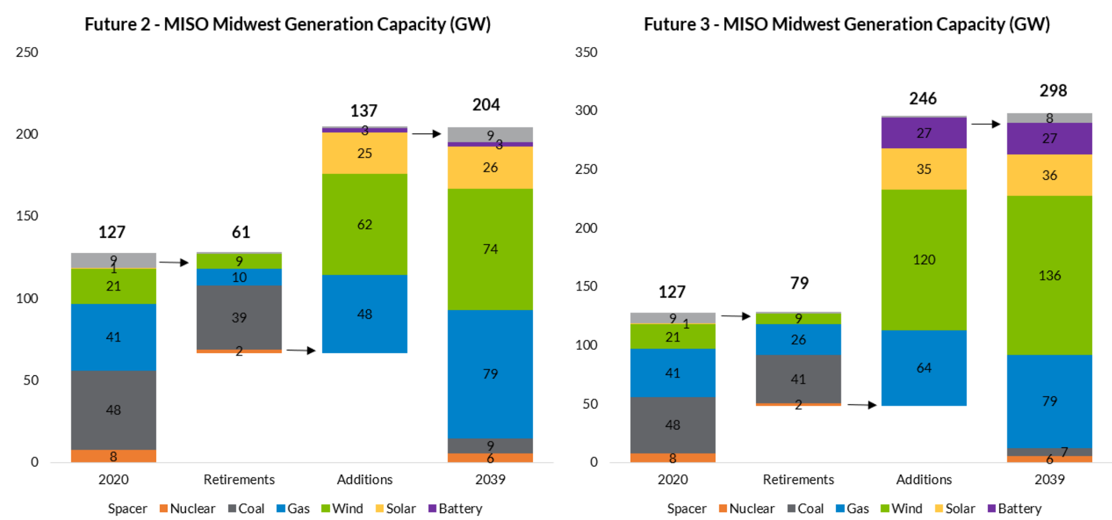


Figure 5-4: Future 2 & 3 changes in Generation Capacity for Midwest Subregion

Reliability Study Scope

MISO developed snapshots of system stress under a Future 1 resource expansion in the 10-year and 20-year timeframe. These scenarios, or base cases, vary based on season of the year, time of the day, load level, and coincident availability of renewable resources. MISO then used the scenarios to test the impact of the LRTP Tranche 1 Portfolio.

Model	Season	Hours	Range of dates and hours used to characterize the model	LRTP modeling definition of load level
1	Summer Peak	Day	Summer :6/21 to 9/20 Hours ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served. (system load >=90 percentile during day)
2	Summer Peak	Night	Summer: 6/21 to 9/20 Hours NOT ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served (system load >=90 percentile during night)
3	Fall/Spring Light load	Day	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Day)
4	Fall/Spring Light load	Night	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours NOT ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Night)
5	Fall/Spring shoulder load	Day	Fall: 9/21 to 12/20 Spring à 3/21 to 6/20	70% to 80% of the Summer Peak Load (Day)
6	Winter Peak	Day	Winter: 12/21 - 3/20 Hours ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during day)
7	Winter Peak	Night	Winter: 12/21 - 3/20 Hours NOT ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during night)

Table 5-1: Temporal and load parameters for defining base models

The purpose of the reliability study is to ensure the MISO Transmission System can reliably deliver energy from future resources to future loads under a range of projected load and dispatch patterns associated with the Future 1 scenario in the 10-year and 20-year time horizon. The analysis includes ensuring transmission system performance is reliable and adequate with both an intact system and one where contingencies have occurred, and high regional power transfer scenarios that result when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty. Techniques used to analyze projected performance with and without the proposed transmission solutions included steady state contingency analysis to identify thermal loading and voltage issues under normal and contingency conditions, transfer analysis to ensure MISO can rely upon geographic diversity to manage renewable dispatch volatility and uncertainty and voltage stability analysis to ensure voltage stability in the Midwest subregion.

Steady-state contingency analysis is performed to identify any thermal and voltage violations that exist in the seven base reliability cases for each of the 10-year and 20-year models. The analysis requires simulation of the MTEP20 NERC Category P0, P1, P2, P4, P5, and P7 contingency events and selected NERC Category P3, P6 events. Facilities in the Midwest Subregion were monitored for steady state thermal loading in excess of 80% of applicable ratings and for voltage violations per the Transmission Owner voltage criteria.

Transfer analysis is performed to test for robust performance under varying dispatch patterns. The LRTP transfer study includes eight transfer scenarios to assess import requirements in situations where unexpected loss of renewable and thermal resources could occur due to changing weather conditions.

Scenario	Description	Objective	Resource	Sink
1	Central to Iowa	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	All Gen. Local Resource Zones (LRZ) 4-6	Wind in LRZs 1&3
2	MISO to Michigan	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	Renewables in LRZs 1-6	Renewable in LRZ 7
3	Michigan to MISO	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZ 7	Renewables in LRZs 1-6
4	Iowa/MN to MH	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Manitoba Hydro load
5	MISO West to Wisconsin	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Renewables in LRZ 2
6	Central Renewables to rest of MISO Midwest	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZs 4-6	Gen. in LRZs 1,2,3,7
7	MISO Midwest to Central Region	Ensure reciprocal export capability to MISO Subregions in high resource deficiencies	Gen. in LRZs 1,2,3,7	Gen. in LRZs 4-6
8	MISO West to East across the Mississippi	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	MISO West of the Mississippi River Renewables in LRZs 1,2,3,5	MISO East of the Mississippi river Gen. in LRZs 4,6,7

Table 5-2: Transfer Scenarios

Economic analysis supports reliability analysis evaluation of project candidates as needed for selecting the preferred solutions. Production cost simulations analyze the impact of the proposed project on production costs to assess how the economic performance of a project compares to other alternatives that have been proposed. These results are used to supplement the reliability analysis results and provide an additional measure of economic performance to aid in selecting the preferred solution.

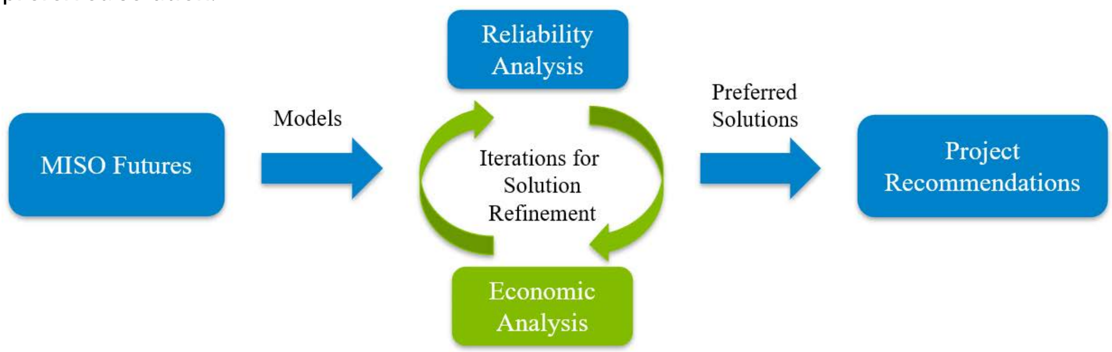


Figure 5-5: Iterative Solution Refinement

The results of the reliability analysis contained in Section 6 of this report discusses the detailed results from this iterative selection process and explains the reasons for selecting the preferred solution, including a summary of any significant economic analysis findings, for projects to be included in the LRTP Tranche 1 Portfolio.

6 LRTP Tranche 1 Projects and Reliability Issues Addressed

The reliability studies were performed on the Future 1 power flow models to assess the system performance and identify any necessary upgrades to ensure reliable energy delivery under different load and dispatch patterns. Analysis of the Future 1 10-year and 20-year base case models without the LRTP Tranche 1 Portfolio indicated numerous thermal and voltage violations throughout the Midwest Subregion. Additionally, transfer analysis was performed to assess transfer capability and identify limiting constraints to be addressed to assess effectiveness of projects under broader future assumptions. Variations of candidate projects identified in the LRTP indicative roadmap were studied to determine areas of focus for project development.

It is important to understand that LRTP is not a NERC compliance study whereby every issue identified must be resolved according to NERC standards and requirements. A NERC compliance study, which is more local in nature in terms of modeling assumptions, is different than the approach taken in a long-range transmission planning study. From that perspective, the LRTP reliability solution testing sought to find solutions that provided a balance between issues resolved and cost to mitigate. This included discounting some issues, for example, as more local in nature or others that will be dealt with in the generator interconnection process. It is also related to the fact that more study work will be done in the next tranches using other Futures and additional needs will be dealt with at that time.

In doing so, MISO used the roadmap as a starting point for testing system solutions but also looked to alternative solutions either from MISO or submitted by stakeholders. Several alternatives have been considered for the Tranche 1 effort. The final portfolio represents those solutions that provided the best fit solution. It is also important to note that the ability to efficiently use existing corridors in developing transmission is a key element. As final solutions were developed, the ability of those solutions to use existing system right of way was a key consideration. Ultimately though final routing will be determined by the applicable state and/or local authorities.

Project selection involved detailed analysis in five geographic focus areas:

- Dakotas and Western Minnesota
- Minnesota – Wisconsin
- Central Iowa
- Northern Missouri Corridor
- Central-East Corridor

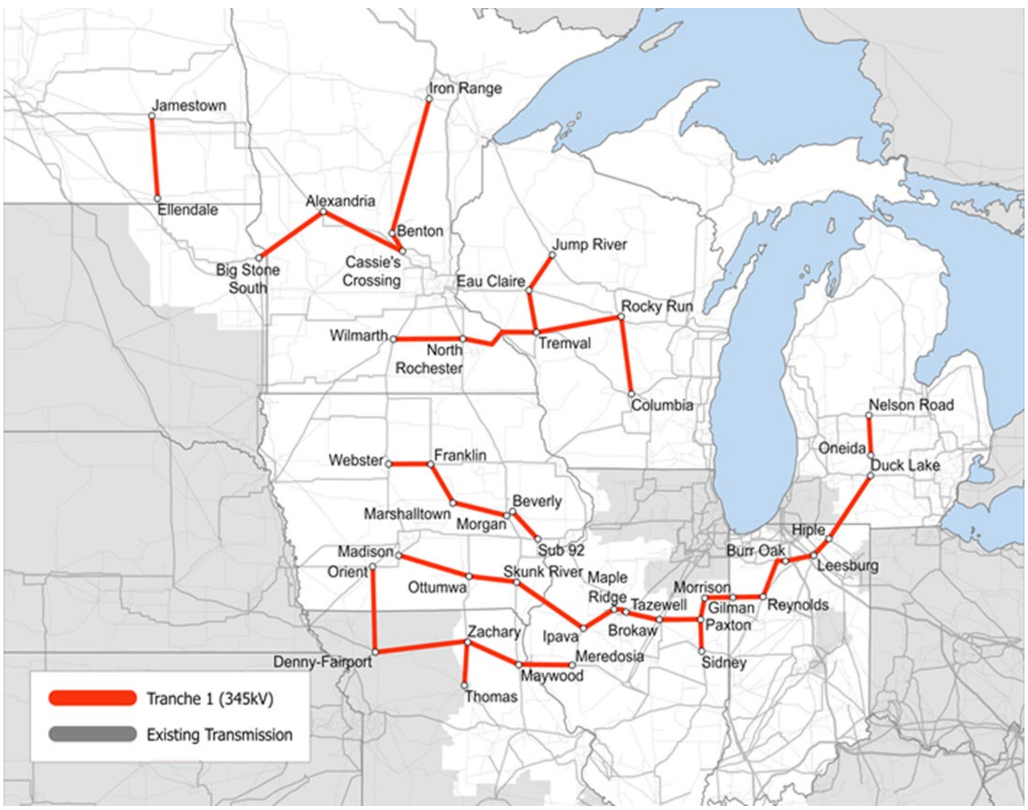


Figure 6-1: LRTP Tranche 1 Transmission Portfolio

Dakotas and Western Minnesota

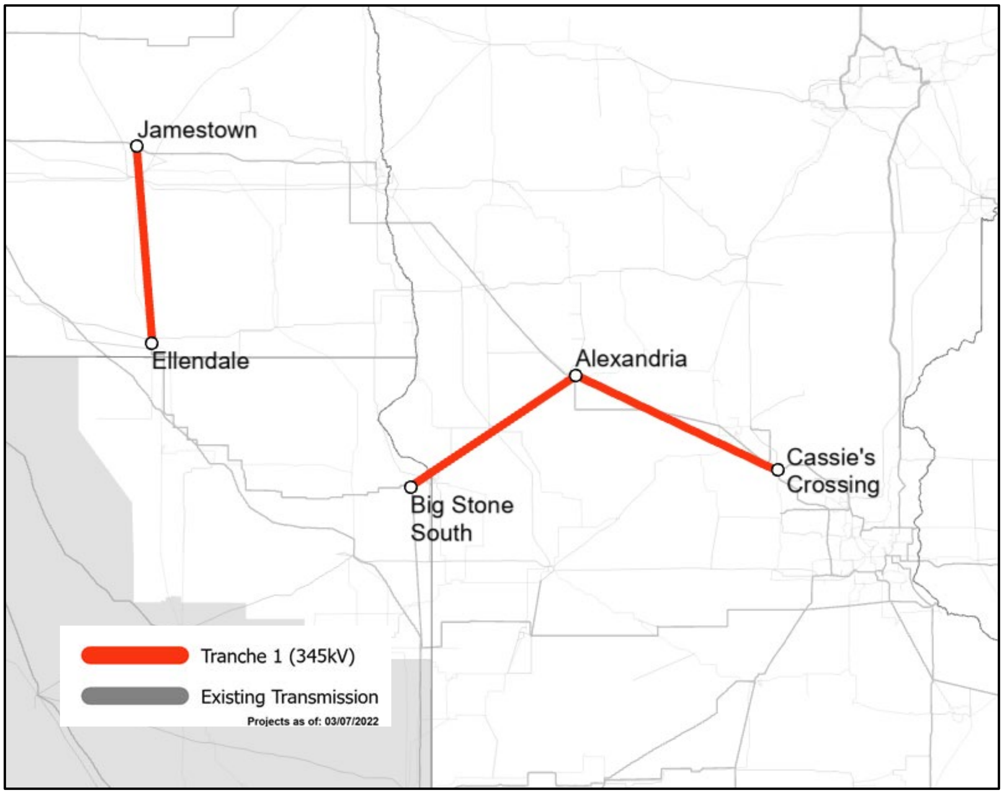


Figure 6-2: Dakotas and Western Minnesota Final Solution

Projects:
Jamestown - Ellendale 345 kV
Bigstone – Alexandria – Cassie's Crossing 345 kV

Rationale:
The Eastern Dakotas and Western/Central Minnesota 230 kV system is heavily constrained for many different seasons through the year. This 230 kV system has been playing a key role in transporting energy across a large geographical area as generation is needing to be transported out of the Dakotas and into Minnesota. Under shoulder load levels and high renewable output, this energy has a bias towards the Southeast into the Twin Cities load center. During peak load, particularly in Winter, this system is a key link for serving load in central and northern Minnesota. The 230 kV system is at capacity and shows many reliability concerns not only for N-1 outages in Future 1, but also for system intact situations. The 345 kV lines in the area provide additional outlets for the Dakotas by tying two existing 345 kV systems together. These lines unload the 230 kV system of concern and improve reliability across the greater Eastern Dakotas and Minnesota.

Issues Addressed:

The Dakotas and Western Minnesota project addresses many thermal and voltage issues for Western Minnesota and Eastern Dakotas. Most notable, the 230 kV system from Ellendale and Big Stone South to Fergus Falls is relieved for all N-1 and N-1-1 outages, as you can see in Figure 6-3 geographically. The solid green lines in Figure 6-3 depict Transmission Lines which no longer have overloads because of the project with circles depicting transformers that are relieved. Voltage depression was seen for a wide geographical area along the South Dakota, North Dakota, and Minnesota border typically described as the Red River Valley Area. Table 6-1 describes overloads seen in Future 1 for the Dakotas and Western Minnesota area which are relieved by the Big Stone South – Alexandria – Cassie's Crossing & Jamestown – Ellendale project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

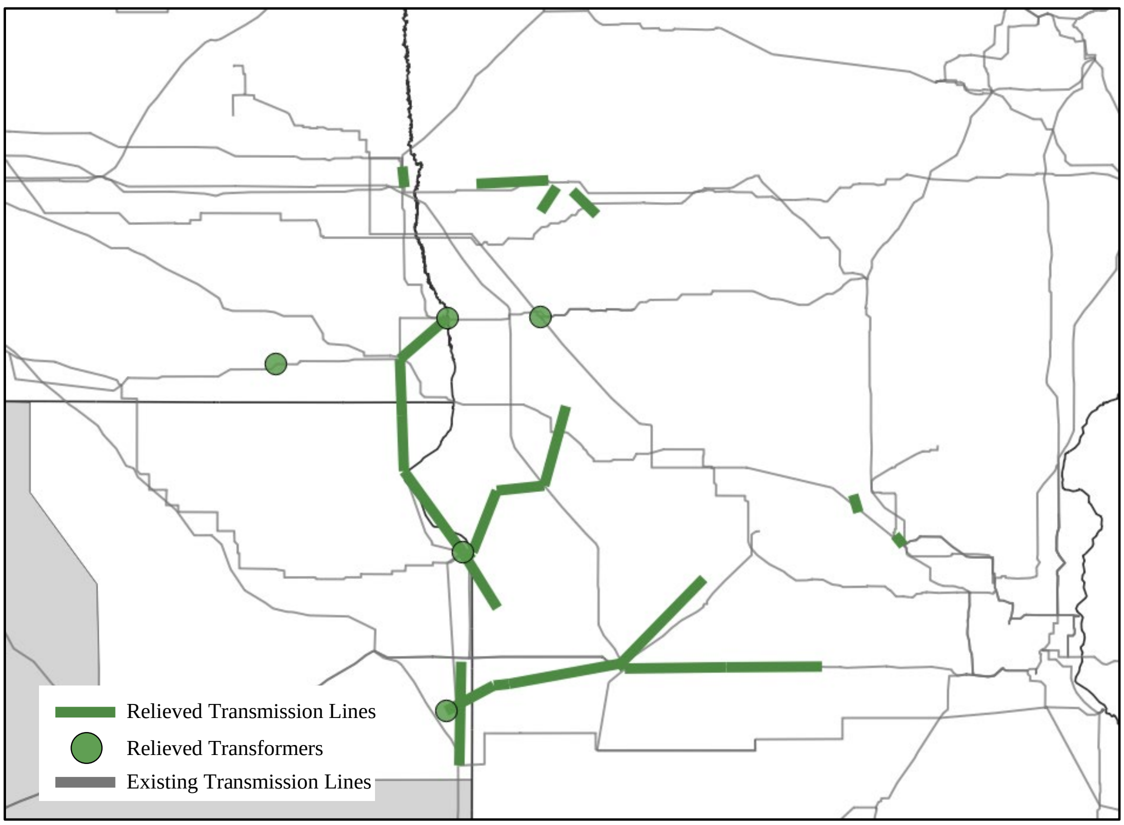


Figure 6-3: Dakotas and Western Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	40	214	70	209
230 kV Lines	18	157	25	153

Table 6-1: Elements with thermal issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	97	0.80	91	0.81
345 & 230 kV Buses	23	0.80	30	0.81

Table 6-2: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the OTP area (620)

Alternatives Considered:

Big Stone South – Alexandria 345 kV & Jamestown – Ellendale 345 kV
Without double circuit to Cassie's Crossing there are new N-1 issues around Alexandria.

Big Stone South – Hankinson – Fergus Falls 345 kV & Jamestown – Ellendale 345 kV
Solves overloads of concern on 230 kV system around Wahpeton but creates new issues on the 230 kV and 115 kV system around Fergus Falls.

Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV
Reduces nearly all overloads of concern but not to the extent of the preferred project.

Big South – Alexandria 345 kV & Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV.
Combination of alternative 1 and 3. This alternative creates new overloads on the 115 kV system around Alexandria but fully relieves reliability issues of concern as the preferred project. However, as this is a combination of alternatives, the southern circuit to Blue Lake (Alternative 3) does not add enough additional value over the preferred project.

Big Stone South – Breckenridge – Barnesville 345 kV & Jamestown – Ellendale 345 kV
Solves many issues in the area of concern without any new issues. However, there are still a few key overloads on the key 230 kV system around Wahpeton which are not solved by this alternative.

Western Minnesota - Dakota

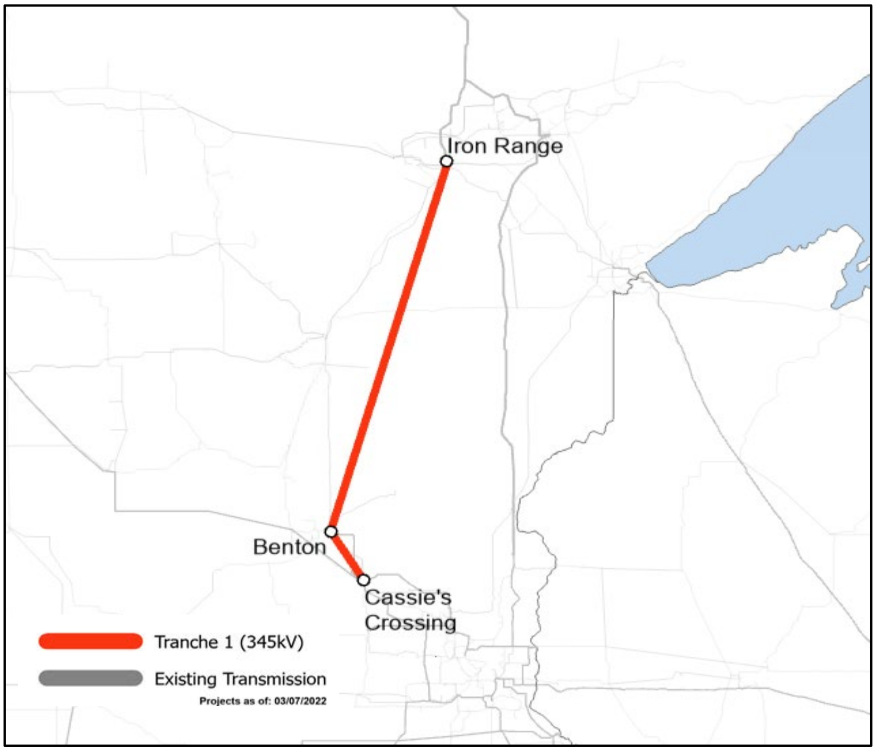


Figure 6-4: Western Minnesota - Dakota Final Solution

Project:
Iron Range – Benton - Cassie's Crossing 345 kV

Rationale:
Minnesota has and is projected to continue to undergo fleet change. This generation shift has resulted in central and northern Minnesota to have a drastic decrease in generation resources creating a large geographical area to be served by only 115 kV and 230 kV transmission. Central to northern Minnesota has moderate load, with heavy load being further north relating to iron mining operations. During the winter, Minnesota load increases significantly. This causes strain on the widespread 115 kV and 230 kV system as power is needing to get from the twin cities to the north to serve load. This large geographical disparity in generation and weak transmission causes voltage stability concerns for a majority of the Minnesota system north of the Twin Cities. The Iron Range – Benton – Cassie's Crossing 345 kV line provides a second low impedance path for power flow from southern Minnesota to the north. This unloads and relieves the 115 kV and 230 kV issues seen and relieves voltage stability concerns.

Issues Addressed:

Iron Range – Benton – Cassie's Crossing 345 kV prevents many thermal and voltage issues on the lower voltage system in central and northern Minnesota, especially for situations where the single 500 kV line heading north from the Twin Cities is lost. Under heavy winter loading situations central and northern Minnesota suffer from voltage collapse issues during transfer scenarios.

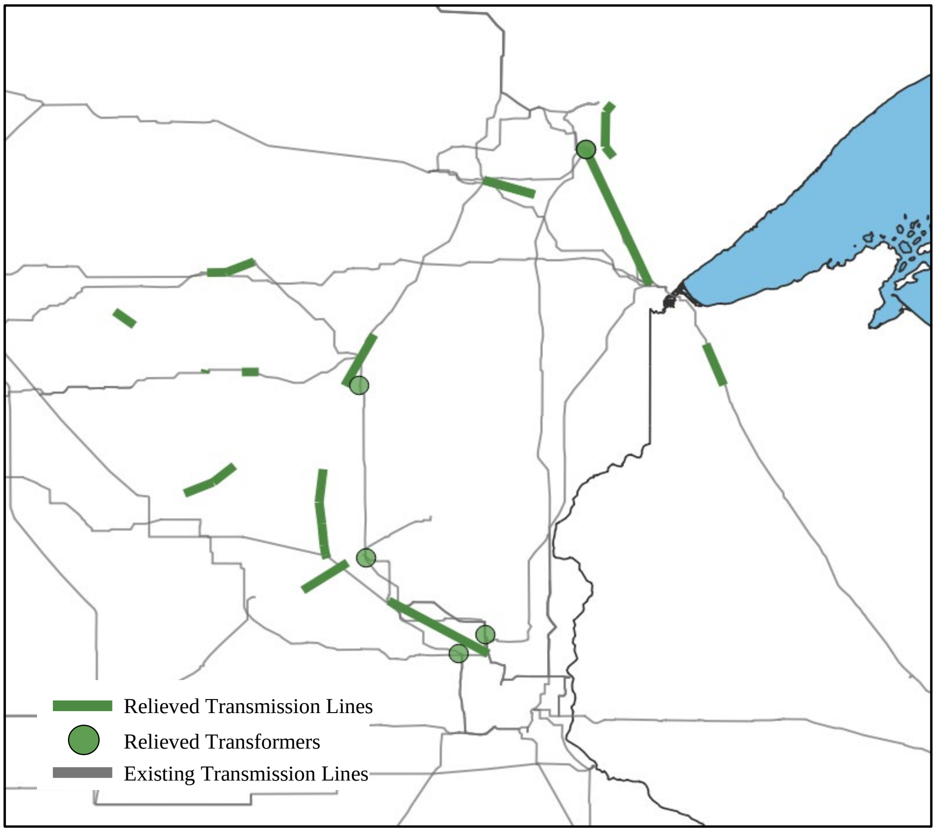


Figure 6-5: Central and Northern Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

The chart below is a graph of the Red River Valley area (northwestern Minnesota) voltage after loss of the 500 kV line from Chisago to Forbes for varying levels of transfer to the north through Minnesota. Without Iron Range – Benton – Cassie's Crossing voltage collapses for transfers less than 500 MW. Post project, transfers through Minnesota can be greater than 2000 MW without voltage collapse.

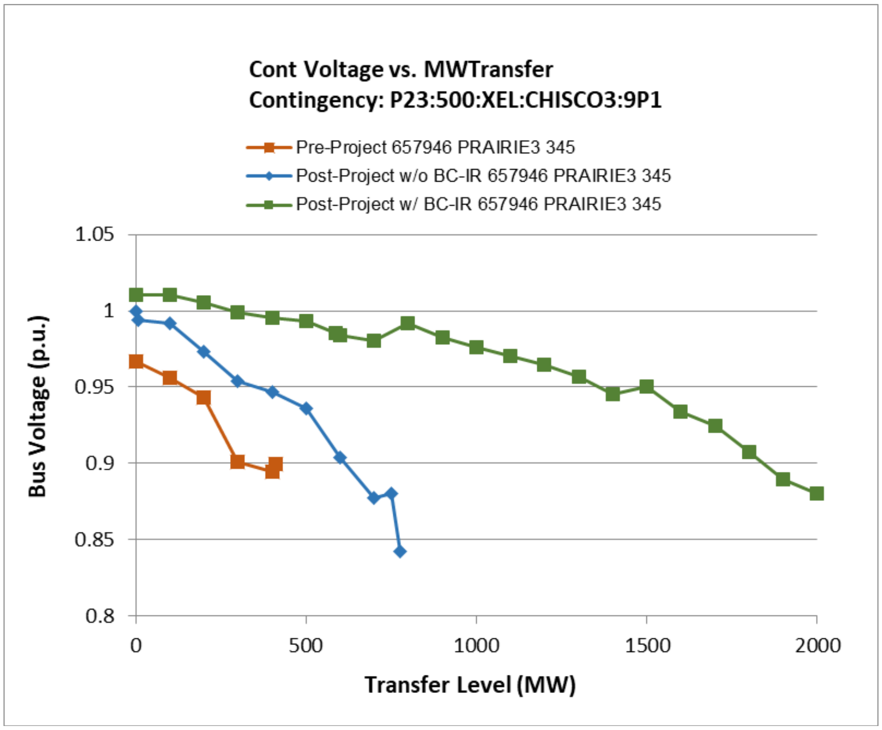


Figure 6-6: Voltage Stability Analysis P-V curve for Minnesota transfers after losing the 500 kV lines from Chisago to Forbes

The tables below describe thermal and voltage issues relieved by the Iron Range to Benton to Cassie's Crossing 345 kV line. Figure 6-5 shows geographically lines and transformers relieved by the project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
		Max % Loading		Max % Loading
	Count Elements	Pre-Project	Count Elements	Pre-Project
All	15	110	25	165

Table 6-3: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
		Minimum p.u. voltage		Minimum p.u. voltage
	Count Elements	Pre-Project	Count Elements	Pre-Project
All	23	<0.80	105	0.80
230 kV Buses	3	0.93	18	0.85

Table 6-4: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the MP area (608).

Alternatives Considered:

1. Iron Range – Alexandria 500 kV
2. Iron Range – Arrowhead 500 kV
3. Iron Range – Bison 500 kV
4. Iron Range – Benton 500 kV

A study interface was created to analyze alternatives to the Iron Range – Benton – Cassie's Crossing line. This interface is defined as the northern Minnesota interface (NOMN) which includes the Forbes – Chisago 500 kV line and six underlying 230 kV lines which connect central and northern Minnesota to the Twin cities and North Dakota. This interface was determined to study the system's ability to meet two primary goals.

1. Understand an operating limit for central and northern Minnesota to ensure the ability to serve peak load with a 10% or greater stability margin.
2. Maintain the ability to serve the existing 1400 MW Manitoba Import Limit while also achieving goal 1.

The proposed project, Iron Range – Benton County – Cassie's Crossing double circuit 345 kV meets both goals. Alternatives 1 (Iron Range – Alexandria 500 kV), 2 (Iron Range – Arrowhead 500 kV), and 3 (Iron Range – Bison 500 kV) do not achieve the above goals. Alternative 4 (Iron Range – Benton 500 kV) achieves both goals, however the double circuit 345kV was chosen for many reasons over the 500 kV as described below:

a. Double circuit 345 kV has a higher capacity
    i. 500 kV: 1732 MVA
    ii. 345 kV: 1195 MVA per circuit (2390 MVA Total)
b. Double circuit 345 kV is cheaper per mile compared to 500 kV
    i. 500 kV: $3,036,384 per mile
    ii. 345 kV: $2,829,742 per mile
c. A double circuit creates two lines for N-1 protection
d. Series compensation near Riverton would allow for easier 345/230 kV conversion for future expansion and support for central Minnesota as 345 kV to lower kV is more standard in the Minnesota area than 500 kV to lower kV transformation

Minnesota – Wisconsin

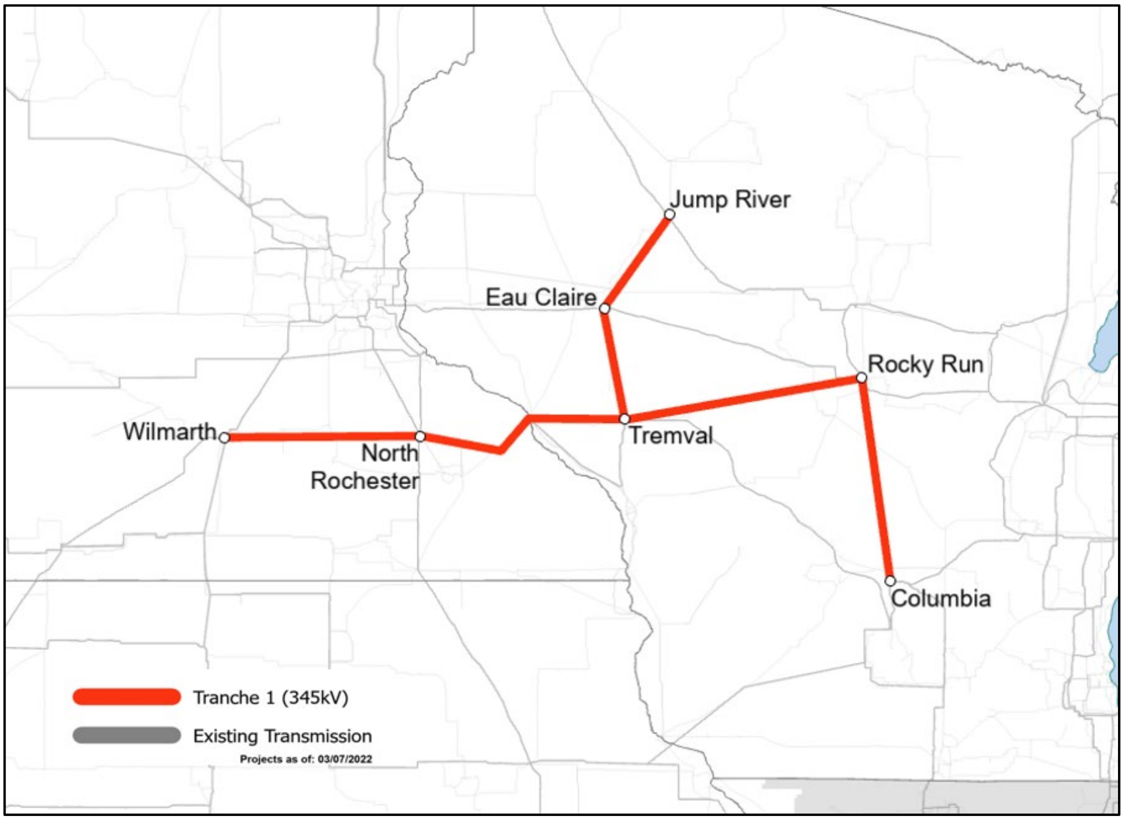


Figure 6-7: Minnesota-Wisconsin Final Solution

Projects:
Wilmarth – North Rochester – Tremval – Eau Claire – Jump River 345 kV
Tremval – Rocky Run – Columbia 345 kV

Rationale:
The transmission system in southern Minnesota is a nexus between significant wind and renewable resources in Minnesota and North and South Dakota, the regional load center of the Twin Cities, and transmission outlets to the East and South. In a future with significant renewable energy growth, MISO sees strong flows West to East across Minnesota to Wisconsin and a need for outlet for those renewables in times of high availability to deliver that energy to load centers in MISO. The Minnesota to Wisconsin projects relieve constraints in the Twin Cities metro area due to high renewable flow towards and past the Twin Cities load center. The projects also reinforce the outlet towards load centers in Wisconsin, providing relief of congestion as well as easing both thermal loading and transfer voltage stability.

Issues Addressed:
The Minnesota – Wisconsin series of projects work together to relieve a number of related issues. Table 6-5 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 Portfolio attributed to the Minnesota – Wisconsin set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-8.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	39	95-132%	96	95-151%
345 kV Lines	6	98-119%	9	97-120%
345/xx kV Transformers	9	97-132%	12	95-132%

Table 6-5: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases

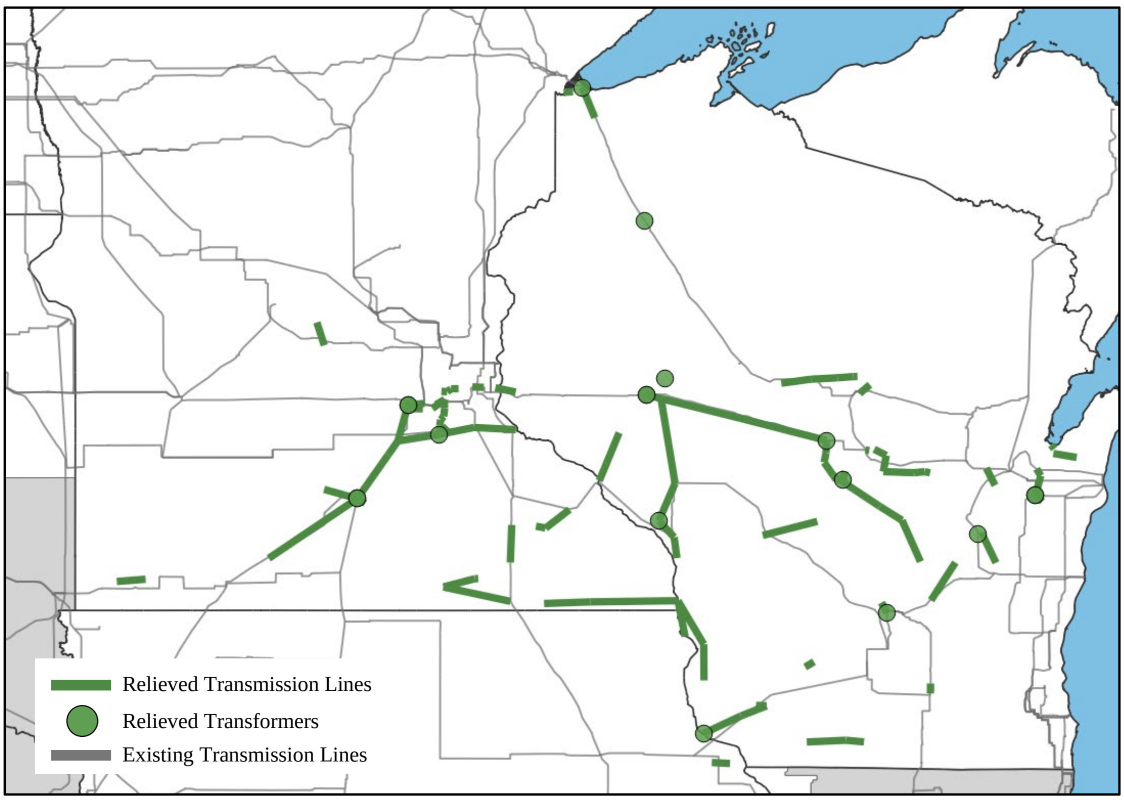


Figure 6-8: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Wilmarth to North Rochester parallels a number of 345 kV lines across the Southern Twin Cities that are heavily loaded under high renewable output from southwestern Minnesota and northwestern Iowa. In doing so, it relieves several 345 kV lines and 345/115 kV transformers in the region including Wilmarth – Shea's Lake – Helena – Chub Lake 345 kV and 345/115 kV transformers at Wilmarth and Scott County. These increased flows cause new congestion and overloads on the existing Crandall – Wilmarth 345 kV line. This project includes the rebuild of that line. If uprated, the congestion savings associated with the Wilmarth – North Rochester circuit specifically, and the rest of the Minnesota – Wisconsin project generally, increase significantly.

The connection out of North Rochester towards Tremval and east creates a lower impedance path that pulls power across Wilmarth – North Rochester and diverts power from other heavily loaded Twin Cities facilities, increasing the efficacy of that line. The sections from Tremval to Eau Claire and Jump River relieve loading on a handful of 161 kV and 115 kV facilities in Northwest Wisconsin. Those facilities increase the redundancy of the two Northern 345 kV circuits across Wisconsin and relieve overloads seen on one of the Eau Claire 345/161 kV transformers.

The new path from Tremval to Rocky Run to Columbia completes an outlet for renewable power flow across Wisconsin to the Madison and Milwaukee area load centers. These circuits also bolster voltage stability limited transfer capability across and into Wisconsin. It also relieves overloads on a variety of 345 kV and 138 kV facilities throughout central Wisconsin.

The traditional analysis of voltage stability for the voltage stability interface across Western Wisconsin uses a load to load transfer. MISO performed this analysis for a transfer using Local Resource Zone 2 (LRZ2, roughly comprised of ATC member companies in eastern and central Wisconsin) as the destination subsystem, to capture the impact of directly serving LRZ2 load. MISO measured the impact to voltage stability both with and without Tremval – Rocky Run and Rocky Run – Columbia segments are included in this project. The addition of these facilities adds 250 MW to the transfer capability. Figure 5-9 shows the post-contingent bus voltage for the most limiting bus and outage for either the pre-project or post-project case. Those buses and outages are:

Eau Claire 345 kV for loss of King – Eau Claire 345 kV
Eau Claire 345 kV for loss of Stone Lk. – Gardner Pk 345 kV
Briggs Rd. 345 kV for loss of Stone Lk. – Gardner Pk 345 kV

Both the steady state voltages and the final nose of the stability curve can be seen to improve, with the increase measured from either point being approximately 250 MW. MISO also reviewed this analysis for scenarios using a wide area load subsystem consisting of both Wisconsin load and loads further East in MISO's system. Those cases also showed an approximate increase of 250 MW in the low voltage and voltage stability limits of the system.

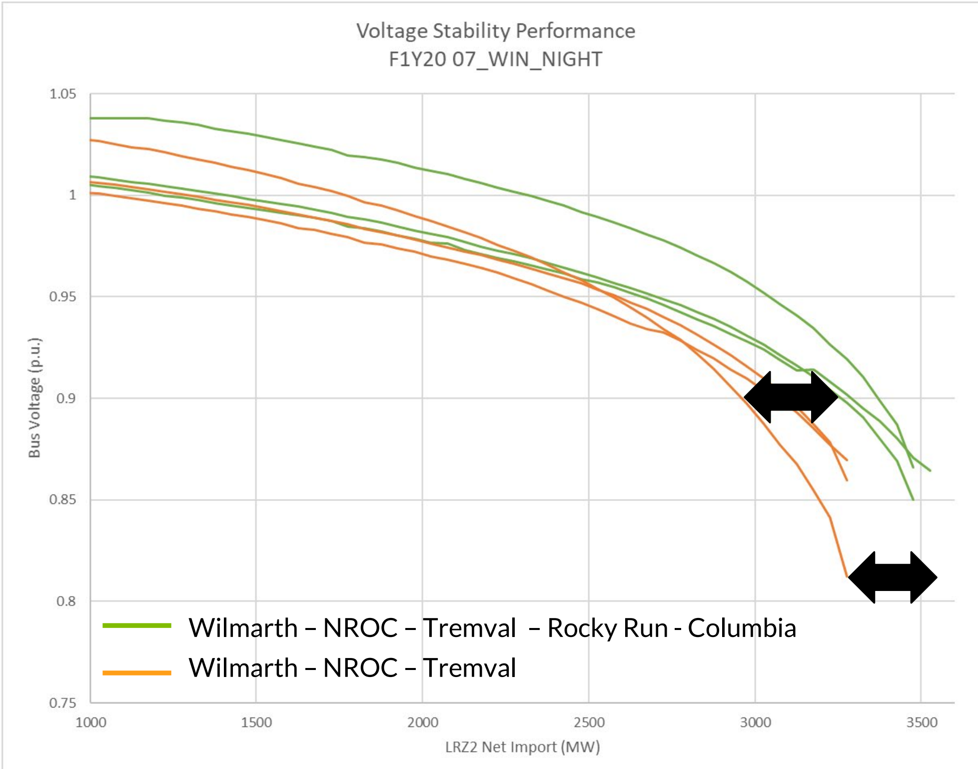


Figure 6-9: Voltage performance for key buses and outages for transfers into LRZ2. Orange lines indicate buses and outages with just Wilmarth – North Rochester – Tremval 345 kV, while green lines indicate performance with Tremval – Rocky Run – Columbia 345 kV included as well

System Design Benefits of Tremval – Eau Claire – Jump River

To date there are three 345 kV lines that connect Minnesota to Wisconsin. The lines and their lengths are listed below:

Arrowhead – Stone Lake - Gardner Park:	220 Miles
King – Eau Claire – Arpin - Rocky Run:	183 Miles
North Rochester – Briggs Road – North Madison:	250 Miles

Assuming an average Surge Impedance Loading (SIL) value of approximately 400 MW for legacy 345 kV lines such as the ones above, the Safe Loading Limits on these three 345 kV long lines based on the St. Clair curve would be as follows:

Arrowhead – Stone Lake - Gardner Park:	460 MW
King – Eau Claire – Arpin - Rocky Run:	560 MW
North Rochester – Briggs Road – North Madison:	440 MW

Safe Loading Limits[3] were proposed to avoid or mitigate excessive operating risks by limiting the voltage drop along a transmission circuit to 5% or less while maintaining a Steady State Stability Margin of 30% or greater along the transmission circuit. The excessive 345 kV line lengths between Minnesota and Wisconsin result in safe loading limits for these 345 kV lines well below the thermal limits of the lines. Even more alarming is the fact that under an N-1 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall from 1,460 MW to 900 MW, and for an N-2 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall to 440 MW.

The addition of the fourth 345 kV circuit from Minnesota – Wisconsin will significantly improve the situation above by adding additional transmission capacity across MWEX. In the case of a North Rochester – Rocky Run line, the length and Safe Loading Limit of this additional 345 kV line would be as follows:

North Rochester – Rocky Run 345 kV Mileage:	162 – 187 Miles
North Rochester – Rocky Run Safe Loading Limit:	540 MW – 600 MW

While the fourth 345 kV circuit adds considerable benefit, for an N-2 contingency with the fourth 345 kV circuit added, the combined safe loading limit of the 345 kV circuits falls to about 900 MW.

An effective method to strengthen the four parallel 345 kV circuit is to add an intermediate connection between the four 345 kV circuits as close to the midpoint as possible. A major benefit of the Tremval 345 kV Substation and the Tremval – Eau Claire – Jump River 345 kV line is that under contingency conditions, the overall reduction in the combined Safe Loading Limit of the parallel 345 kV circuits is minimized. For example, for a loss of the Eau Claire – Arpin 345 kV circuit, a 345 kV connection remains between the King - Eau Claire 345 kV circuit, and the other three 345 kV lines across the MWEX interface. This not only mitigates loading issues on the transformers at Eau Claire, but also reduces the effective 345 kV impedance across the MWEX interface, which in turn increases the capacity and combined safe loading limit of the MWEX interface. In addition, because the King – Eau Claire 345 kV circuit is still connected at the midpoint of the MWEX interface, the distributed line capacitance associated with the King – Eau Claire 345 kV circuit is available to support voltages in western Wisconsin. Lower overall impedance coupled with higher distributed capacitance means a higher effective SIL for the MWEX interface under contingency conditions.

In summary, there are desirable benefits of tying together long lines at an intermediate point, and there are examples of this technique throughout North America. These types of system design benefits will be crucial to the success of the future transmission system to operate with reliability,

[3] Dunlop, R.D., Gutman, R., Marchenko, P.P., *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.

robustness, and resilience under a future with higher renewable generation penetration and electrification.

Alternatives Considered:

MISO reviewed a wide variety of project alternatives in the project focus area between Minnesota and Wisconsin – many of them submitted by stakeholders.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included Wilmarth – North Rochester – Tremval – Eau Claire – Jump River as well as a double circuit rebuild between Adams and North Rochester, and a new 345 kV line from Colby to Adams. MISO found that the Wilmarth – North Rochester segment was important for resolving Twin Cities area loading, and that the river crossing from North Rochester to Tremval and then Tremval to elsewhere in Northern Wisconsin was effective at both relieving loading across Western Wisconsin and boosting the effectiveness of Wilmarth – North Rochester by providing an outlet and a shorter electrical path towards load centers. The double circuit from North Rochester to Adams directly relieved loading on parallel facilities. Colby – Adams relieved some loading associated with a large amount of future generation sited at Adams, but the effects were very localized.

Several stakeholders submitted alternative projects along the "Southern Corridor". These included a line from Huntley to Pleasant Valley (between Adams and North Rochester), and from Adams to Genoa and Hill Valley. One stakeholder also submitted Colby – Adams as an alternative. MISO reviewed the performance of Huntley – Pleasant Valley and Colby – Adams as alternatives to the Wilmarth – North Rochester line. Colby – Adams by itself is not effective at reducing the West to East loading across Southern Twin Cities 345 kV facilities and shows little reliability value on its own. Huntley – Pleasant Valley, when combined with a double circuit rebuild between Pleasant Valley and North Rochester, resolved many but not all of the same 345 kV and 345 stepdown transformer overloads as Wilmarth – North Rochester. It also showed higher adjusted production cost savings when included in PROMOD simulations. However, the difference in production cost savings was less than the difference in increased cost of Huntley-Pleasant Valley to North Rochester. MISO sees Huntley – Pleasant Valley as a valuable project that may be helpful in reinforcing this region in future cycles of the LRTP study.

Another proposed stakeholder alternative was a line from Adams to Genoa and Hill Valley. MISO initially viewed this project as an alternative to North Rochester – Tremval – Jump River – Eau Claire. However, analysis showed these paths address different sets of reliability concerns, with the Adams – Genoa – Hill Valley project better addressing constraints across northeast Iowa and southern Wisconsin. When tied into Hill Valley, once the Hickory Creek – Hill Valley line is in service, this would effectively form an additional path parallel to Adams – Hazleton 345 kV, and relieve flows being pushed south across eastern Iowa. MISO is prioritizing a northern path (North Rochester – Tremval) in order to address the voltage stability interface and tie into load centers. For that reason, MISO does not propose pursuing Adams – Genoa Hill Valley at this time, but

MISO understands the project's value, especially when paired with Huntley-Pleasant Valley, to potentially reinforcing the region in future cycles of the LRTP study.

MISO initially viewed Tremval – Eau Claire – Jump River and Tremval – Rocky Run – Columbia as alternatives to each other, specifically due to their relationship to the existing voltage stability interface. After some review, though, MISO found them to be addressing separate but complementary sets of issues. Tremval – Eau Claire -Jump River has only a minor impact to the voltage stability performance but relieves a variety of constraints across northern Wisconsin, including several sub-345 kV facilities and some high loading on one of the 345/161 kV transformers at Eau Claire. Tremval – Rocky Run – Columbia has a more significant impact on the voltage stability performance and resolves a number of thermal constraints East of Tremval and Eau Claire. That complimentary performance is what prompted MISO's recommendation of both project segments. MISO also reviewed several variations on the Tremval – Eau Claire – Jump River segment, which proposed different endpoints along either North Rochester – Briggs Rd – North Madison 345 kV or Stone Lake – Gardner Park. MISO found that a line from Alma to Eau Claire would have very similar cost and perform just as well electrically, when compared to Tremval – Eau Claire. MISO sees Tremval as a better tie-in point, due to its more easterly location with better accessibility, which would position it as a better long term hub. A line from Eau Claire to Stone Lake, in comparison to Eau Claire – Jump River, would be significantly more expensive and MISO's screening showed that it was less effective at relieving thermal loading on lines that Eau Claire – Jump River successfully unloaded.

Central Iowa

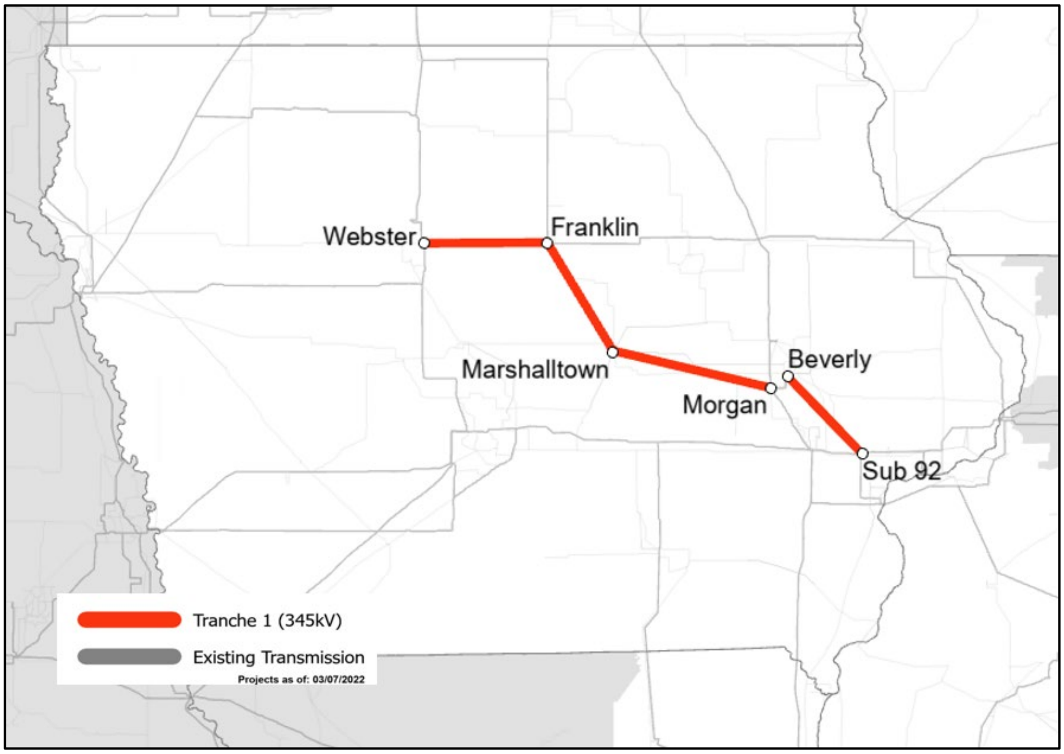


Figure 6-10: Central Iowa Final Solution

Projects:
Webster – Franklin – Morgan Valley 345 kV
Beverly – Sub 92 345 kV

Rationale:
Within MISO's system, the state of Iowa acts as both a major source of renewable energy and a gateway between MISO's members in the upper Midwest and MISO's Central planning region – Missouri, Illinois, and Indiana. Wind resources sited in Iowa are located primarily in the north and west parts of the state, and a large amount of wind resources are also located in western Minnesota and the Dakotas. During hours with high renewable output levels, power must flow southeast across and out of this region towards MISO load centers. In the LRTP models as well as in previous MISO planning studies, we have seen overloads and congestion across Iowa's central corridor. This project is intended to provide an additional 345 kV path southeast across the state, linking the high renewable region in the west with the Quad Cities load center and 345 kV outlets towards the rest of MISO. In doing so, we form a corridor both west-east and north-south across central Iowa.

Issues Addressed:

The Central Iowa projects between Webster and Sub 92 relieve a number of related issues. Table 6-6 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 projects and attributed to the Central Iowa set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-11.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	21	95-128%	34	96-132%
345 kV Lines	6	96-128%	7	97-128%
345/xx kV Transformers			4	96-127%

Table 6-6: Elements relieved by the Central Iowa projects in Future 1 power flow cases

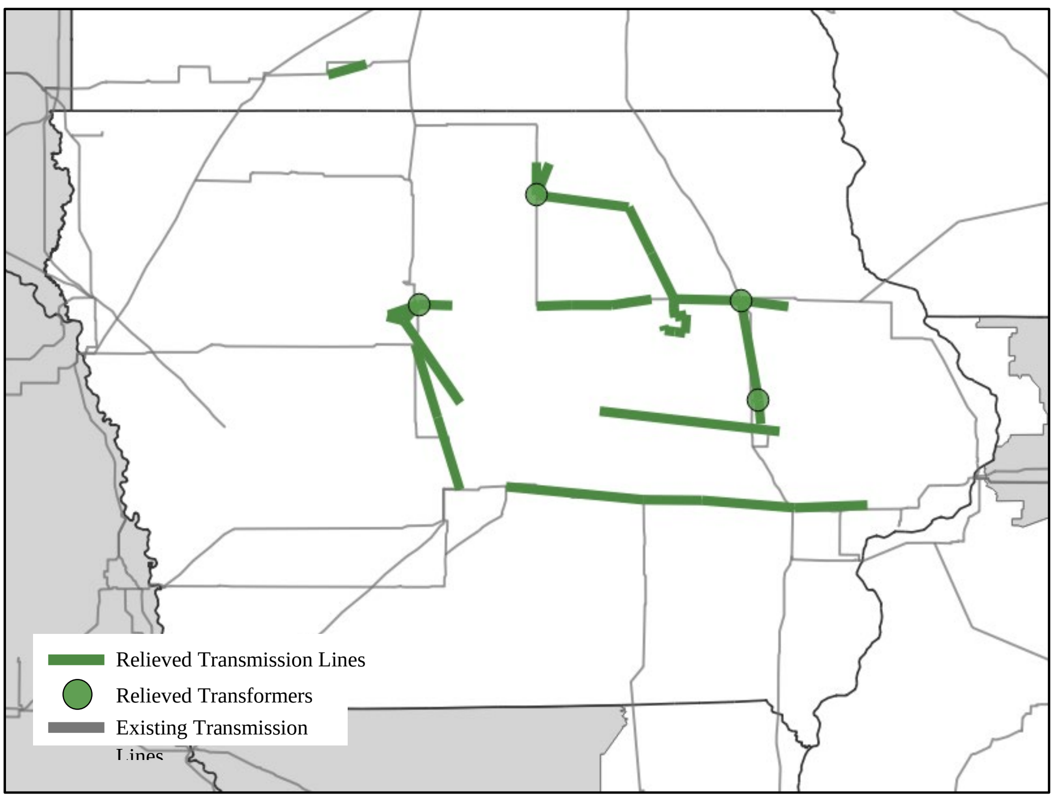


Figure 6-11: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Webster – Franklin – Marshalltown – Morgan Valley 345 kV forms a new connection from the 345 kV network in northwest Iowa (roughly west and north of Lehigh) to the north-south corridor across eastern Iowa (Adams – Hazleton – Hills – Maywood 345 kV). A previously approved line from Morgan Valley to Beverly stretches a few miles to the east, from which a new line can connect south from Beverly to Sub 92 345 kV. With that added segment, the overall path also completes a link from the northern 345 kV across central Iowa (Ledyard – Colby – Killdeer – Blackhawk – Hazleton 345 kV) down to a southern corridor (Bondurant – Montezuma – Hills – Sub 92 345 kV). By reinforcing the system in both directions, the project relieves loading on both west-east and north-south transmission facilities paralleling it. This loading is primarily seen in high renewable output cases, when renewable resources across western Iowa and southern Minnesota are producing high output. Lines seeing the greatest relief include Hazleton – Arnold 345 kV, Lehigh – Beaver Creek – Grimes 345 kV, and Montezuma – Diamond Trail – Hills 345 kV.

Alternatives Considered:

MISO reviewed several project alternatives and variations of the proposed central Iowa project set.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included the proposed version of this project (Webster – Franklin – Marshalltown – Morgan Valley 345 kV and Beverly – Sub 92 345 kV), as well as some additional facilities. These included a new line between Marshalltown and Montezuma, with both the Franklin – Marshalltown and Marshalltown – Montezuma lines built as double circuit 345 kV. Two transformers were also sited at Franklin and Marshalltown. MISO found that the double circuit line sections did not relieve an appreciable number of additional facility overloads. MISO saw that the inclusion of a line from Marshalltown to Montezuma contributed minimal reliability benefit. Of the proposed transformers, MISO found no clear benefit to including 345/161 kV transformers at Franklin. At Marshalltown, a single 345/161 kV transformer can relieve some local loading on the lower kV system, but a second 345/161 kV transformer did not appear necessary.

MISO also reviewed a roadmap project in western Iowa that was submitted as a stakeholder alternative as well. Ida County – Avoca 345 kV would create a new line between Ida County in NW IA and a new 345 kV substation in SW Iowa adjacent to the existing Avoca 161 kV station. In comparison to the proposed project, this project was similarly successful at relieving loading on Lehigh – Beaver Creek – Grimes 345 kV and parallel facilities, but ineffective at relieving constraints east of that corridor, or generally east of the Des Moines metro area.

MISO reviewed portions of the Iowa – Michigan corridor project and the Iowa – Missouri project, in comparison to the proposed project. These facilities were not effective at relieving most of the facilities north and east of Des Moines that are relieved by the proposed project. They did relieve overloads in the Des Moines metro area and in southeastern Iowa and reduced some of the loading that the proposed project moved into southeastern Iowa. Within Iowa, MISO sees the reliability benefit of these two additional project groups as additive, in addition to the benefits of the central Iowa project.

East-Central Corridor

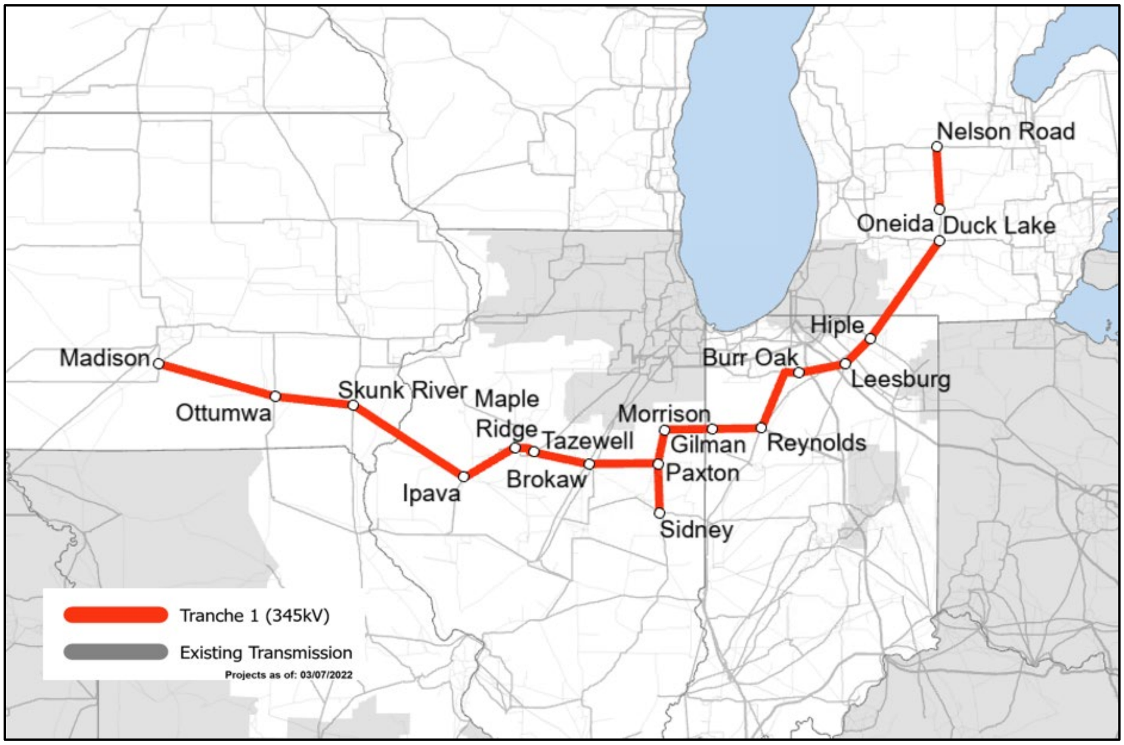


Figure 6-12: East-Central Corridor (Iowa to Michigan) Final Solution

Projects:

Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345 kV
Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345 kV
Paxton – Sidney 345 kV
Oneida – Nelson Road 345 kV

Rationale:

MISO performed steady-state and voltage stability analyses on the proposed Iowa to Michigan LRTP projects. The steady-state results show the projects can mitigate severe thermal issues in Michigan, Indiana, Illinois, Missouri, and Iowa, with 77 monitored facilities addressed. The top 20 monitored facilities with worst-case contingencies are shown in Table 6-7.

The voltage stability results further demonstrate the effectiveness of the projects in improving voltage profiles and increasing transfer levels from West-East/East-West (Figures 6-14, 6-15, 6-16).

Issues Addressed:

The Iowa to Michigan projects addresses 600 thermal violations associated with 77 unique monitored facilities (Figure 6-13). For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the projects.

- 28 issues resolved in Michigan
- 16 issues resolved in Indiana
- 19 issues resolved in Missouri and Illinois
- 14 issues resolved in Iowa

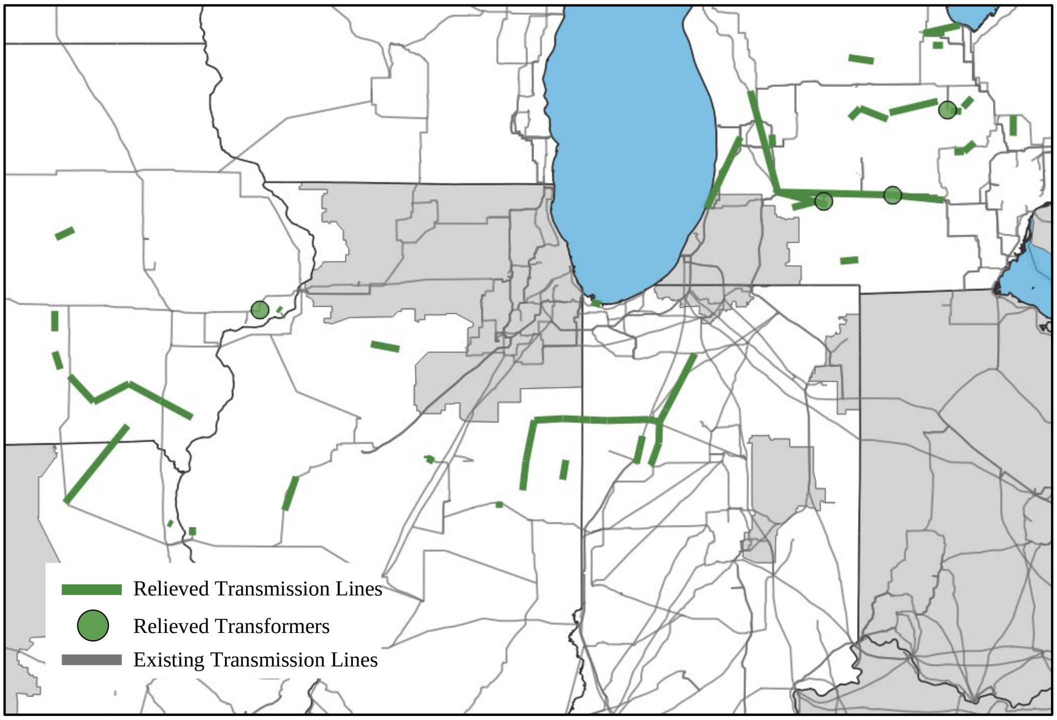


Figure 6-13: East-Central Corridor (Iowa to Michigan Line) map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

		% Loading	
Monitored Facility	Area	Base + West LRTP*	+ IA to MI Projects
Goodland – Reynolds 138 kV Ckt. 1	NIPS	383	< 65
Reynolds 345/138 kV Transformer	NIPS	278	86
Reynolds – Magnetation 138 kV Ckt. 1	NIPS	264	67
Monticello – Magnetation 138 kV Ckt. 1	NIPS	263	67
Springboro – Monticello 138 kV Ckt. 1	DEI/NIPS	230	72
Lafayette 2 – Springboro 138 kV Ckt. 1	DEI	186	< 65
Morrison Ditch – Sheldon South 138 kV Ckt. 1	NIPS/AMIL	181	< 65
Gilman – Paxton East 138 kV Ckt. 1	AMIL	171	< 65
East Winamac – Headlee 138 kV Ckt. 1	NIPS	163	79

Westwood – South Prairie 138 kV Ckt. 1	DEI/NIPS	163	<65
Sheldon South – Watseka 138 kV Ckt. 1	AMIL	157	< 65
Burr Oak – East Winamac 138 kV Ckt. 1	NIPS	155	72
Island Rd 138 kV Bus	METC	155	67
Ottumwa 345/161 kV Transformer	ALTW	150	96
Poweshiek – Irvine 161 kV Ckt. 1	ALTW	144	98
Monticello – Headlee 138 kV Ckt. 1	NIPS	144	< 65
Gilman – Watseka 138 kV Ckt. 1	AMIL	136	< 65
Goodland – Morrison Ditch 138 kV Ckt. 1	NIPS	135	< 65
Tompkin – Majestic 345 kV Ckt. 1	METC/ITCT	133	82
Mahomet 138 kV Bus	AMIL	127	93

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-7: Top 20 thermal issues addressed by East-Central Corridor

Transfer levels increase and voltage profiles improve in Indiana, Missouri, and Michigan with the IA – MI projects (Figures 6-14, 6-15, and 6-16).

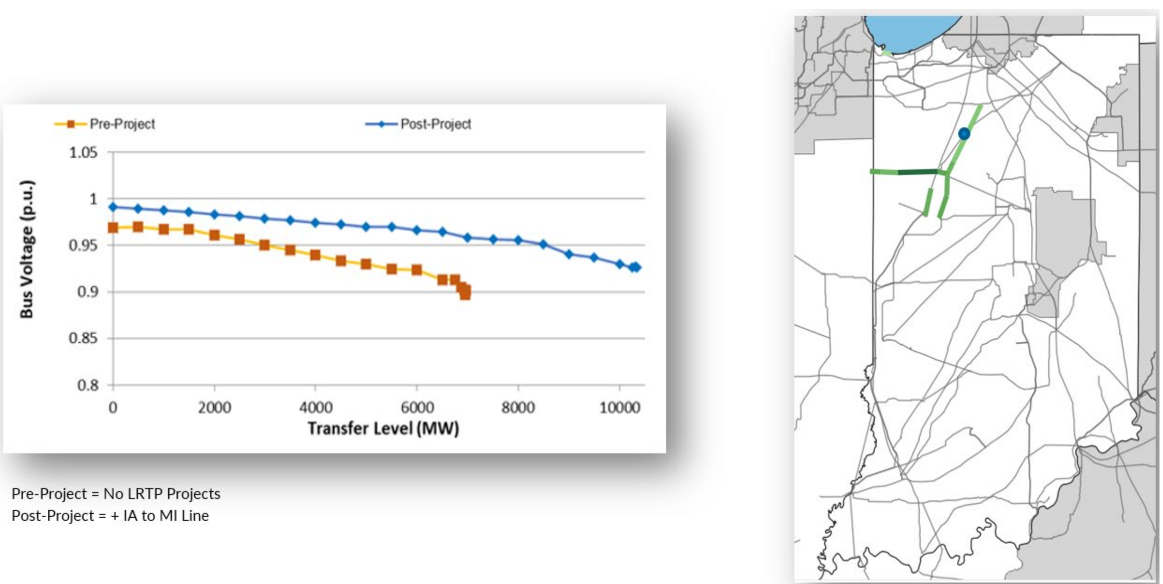


Figure 6-14: Improved voltage profiles in Indiana and Increased transfer levels with the Iowa to Michigan Projects

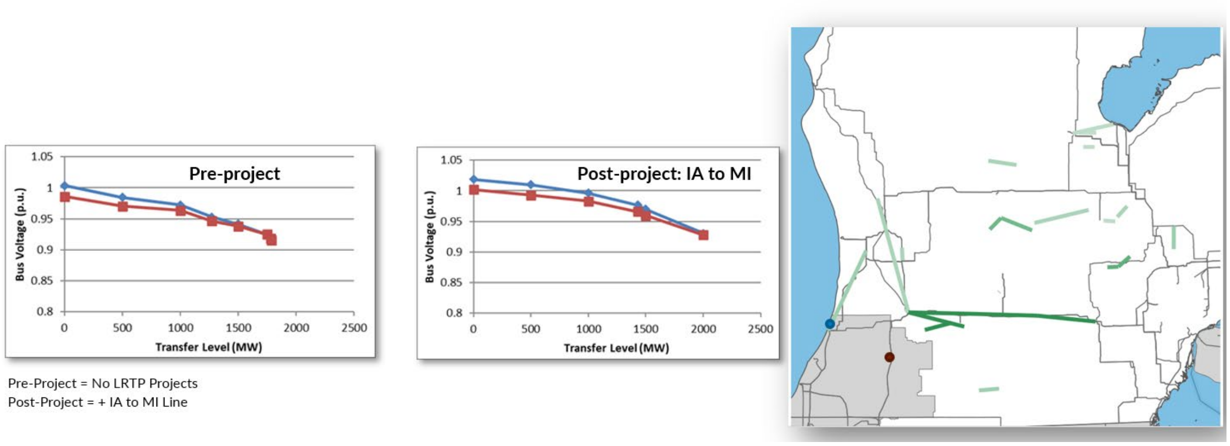


Figure 6-15: Improved voltage profiles in Michigan and Increased transfer levels with the Iowa to Michigan Projects

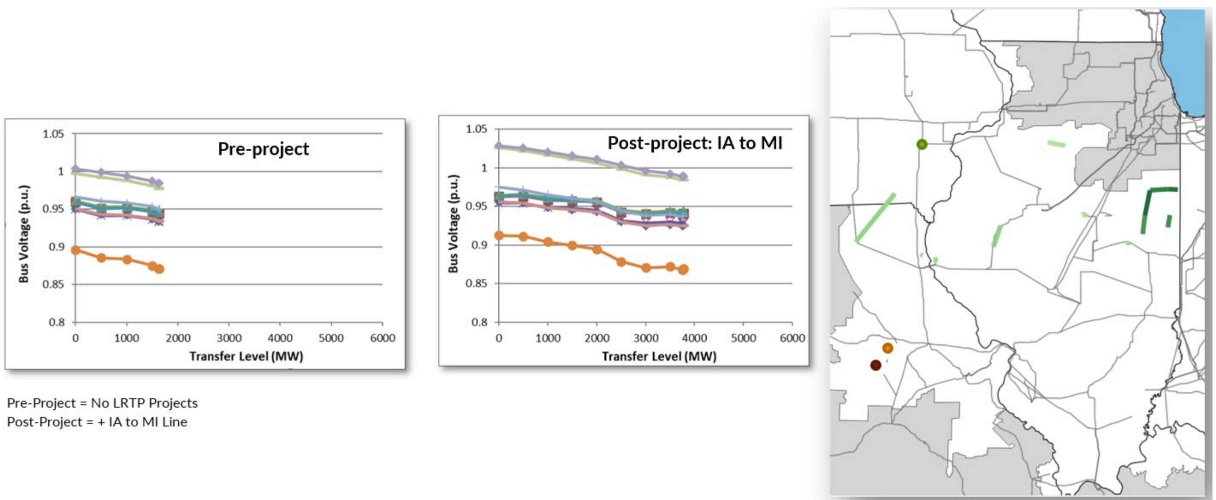


Figure 6-16: Improved voltage profiles in Missouri and Increased transfer levels with the Iowa to Michigan Projects

Alternatives Considered:

Two alternative solutions were received during the alternative submittal period, Duck Lake to Weeds Lake and Hiple to Duck Lake (MISO Main Proposal). Four additional alternatives were also evaluated. The alternative solutions resolve issues in Michigan, but fewer unsolved contingencies are associated with the road map project or MISO Main Proposal.

- Duck Lake to Weeds Lake, resolves 28 thermal issues:
- Hiple to Duck Lake (MISO main proposal), resolves 28 thermal issues
- Tie One Circuit in Argenta (resolves 28 thermal issues)
  - Argenta – Hiple
  - Argenta – Duck-Lake
- Oneida to Madrid (double-circuit), resolves 36 thermal issues
- Iowa to Indiana with Duck Lake Configuration, resolves 15 thermal issues

Northern Missouri Corridor

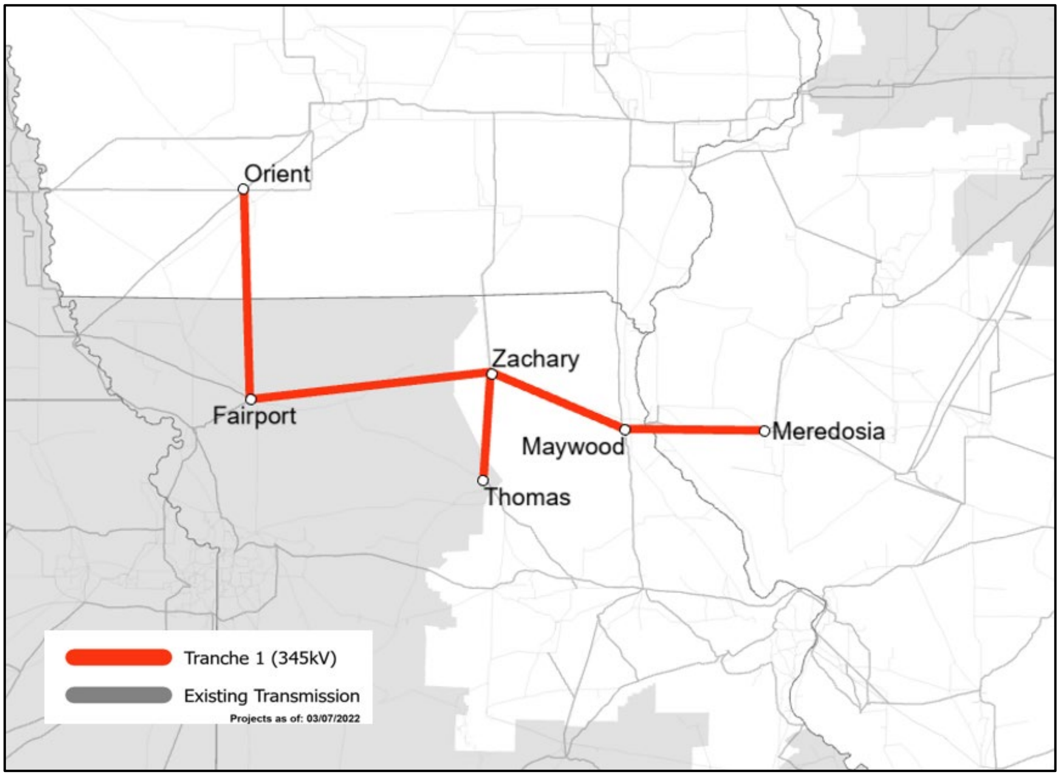


Figure 6-17: Northern Missouri Corridor Final Solution

Projects:
Orient – Fairport – Zachary – Maywood – Meredosia 345 kV
Zachary – Thomas 345 kV

Rationale:
The northern Missouri Corridor relieves loading on transmission elements in Iowa, Missouri, and Illinois. Increased transfer levels and improved voltage profiles are associated with the Missouri projects (Figure 6-17).

Issues Addressed:
The Missouri Corridor addressed thermal issues (Figure 6-18). Facilities mitigated by the Missouri Corridor are listed in Table 6-8. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

- 14 issues resolved in Missouri and Illinois
- 5 issues resolved in Iowa

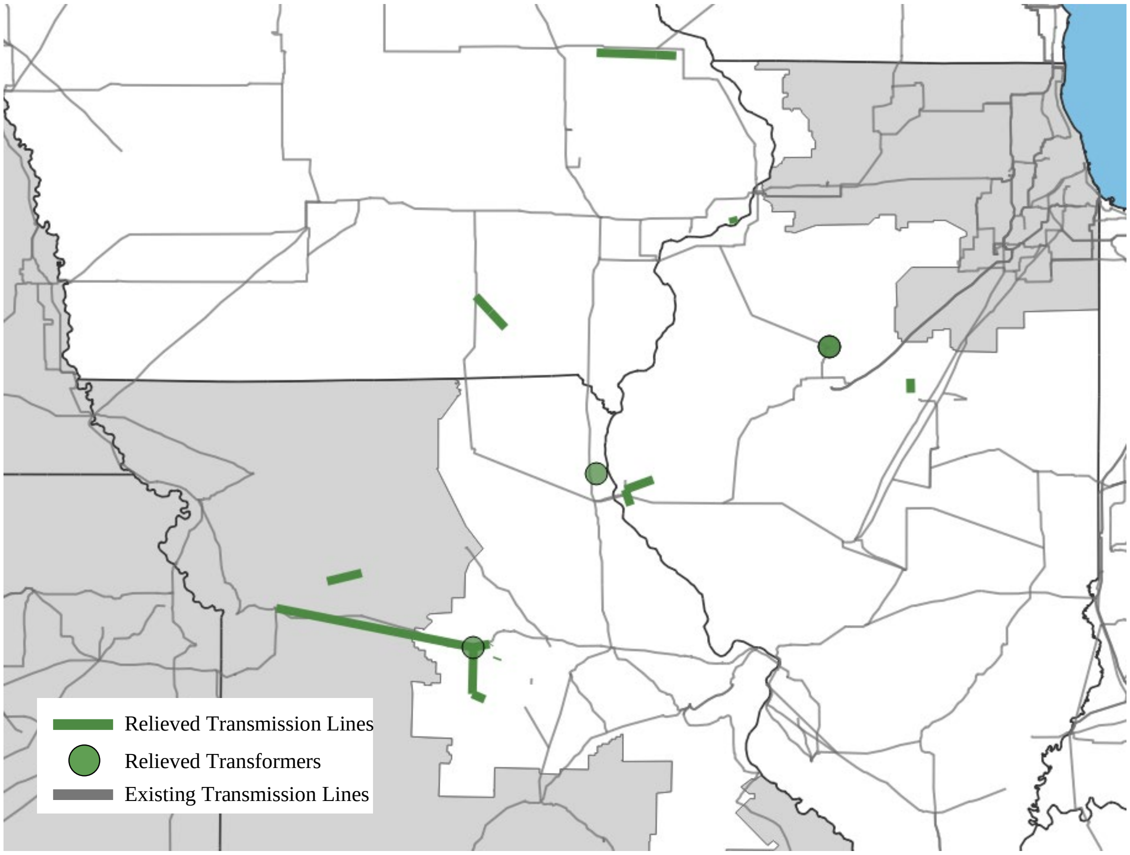


Figure 6-18: Northern Missouri Corridor map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Monitored Facility	Area	% Loading: Base + West LRTP*	% Loading: + IA to MI Project + MO Projects
Marblehead 161/138 kV Transformer	AMIL	137	85
Fargo 345/138 kV Transformer 1	AMIL	122	98
Fargo 345/138 kV Transformer 2	AMIL	122	98
Herleman 3 – Quincy S. 138 kV Ckt. 73	AMIL	120	79
Herleman 1 – Quincy N. 138 kV Ckt. 50	AMIL	120	79
Diamond Start Tap – White Oak Wind Bus 138kV Ckt. 1	AMIL	114	100
Overton 345/161 kV Transformer	AMMO	109	97
Overton – Sibley 345 kV Ckt. 1	AMMO	102	88
Huntsdale – Overton 1 161 kV Ckt. 1	AMMO	101	91
California 161 kV Bus 1 – Overton 2 161 kV Ckt. 1	AMMO	98	88
Huntsdale – Perche Creek 161 kV Ckt. 1	CWLD	97	87
McBaine Bus #2 – McBaine Tap 161 kV Ckt. 1	AMMO	97	85

Maurer Lake 161 kV Bus 1 – Carrollton 161 kV Ckt. 1	AMMO	96	70
California 161 kV Bus	AMMO	95	85
Sub 71 – Sub 88 161 kV Ckt. 1	MEC	109	98
Heights – Ottumwa 161 kV Ckt. 1	ALTW	103	95
Heights – Woody 161 kV Ckt. 1	ALTW	101	93
Liberty – Hickory Creek 161 kV Ckt. 1	ALTW	98	91
Liberty – Dundee 161 kV Ckt. 1	ALTW	98	91

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-8: Facilities mitigated by the Missouri Corridor

The Missouri projects can help power delivery, in addition to increasing transfer levels from East-West/West-East. Moreover, the projects address voltage instability in Missouri (Figure 6-19).

- In the Pre-project case (without LRTP projects), with the transfer level reaching 1640 MW, one 345 kV bus in Missouri shows voltage dropping to 0.87 p.u. following loss of a large generating plant, which demonstrates voltage instability in this source area
- With the proposed IA – MI 345 kV line, the transfer level is increased to 3773 MW
- With the addition of the MO Project, the transfer level is further increased to 6000 MW

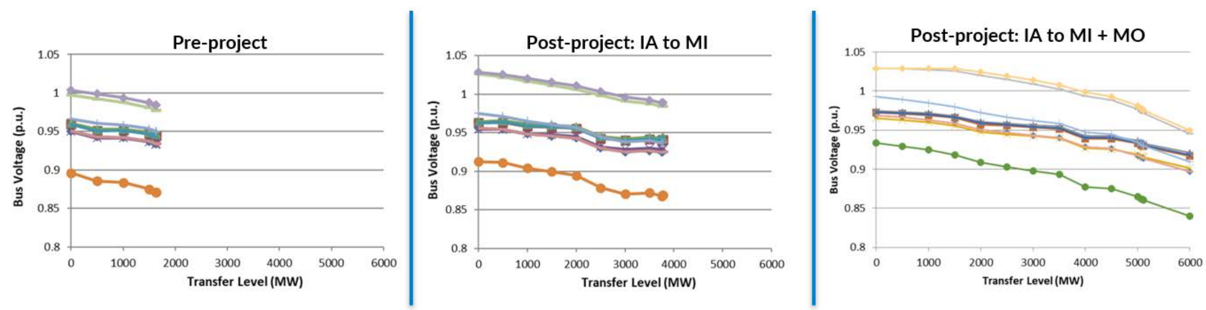


Figure 6-19: Bus Voltage Profiles

Alternatives Considered:
Segments of the Missouri corridor were considered separately, the full Missouri path (Orient – Fairport – Zachary – Maywood – Meredosia 345 kV / Zachary – Thomas 345 kV) is a better solution, with 19 issues addressed by the full path compared to:

- Zachary – Thomas – Maywood – Meredosia, resolves 11 issues
- Thomas – Zachary, resolves 4 issues
- Zachary – Maywood, resolves 6 issues
- Zachary – Maywood – Meredosia, resolves 9 issues
- Zachary – Maywood – Thomas, resolves 5 issues

7 LRTP Tranche 1 Portfolio Benefits

In accordance with the guiding principles of the MISO planning process, the allocation of costs for the transmission investment must be roughly commensurate with the expected benefits. As Multi-Value Projects, the eligibility of LRTP projects is established by Tariff requirements that define the need to demonstrate financially quantifiable benefits in excess of costs.

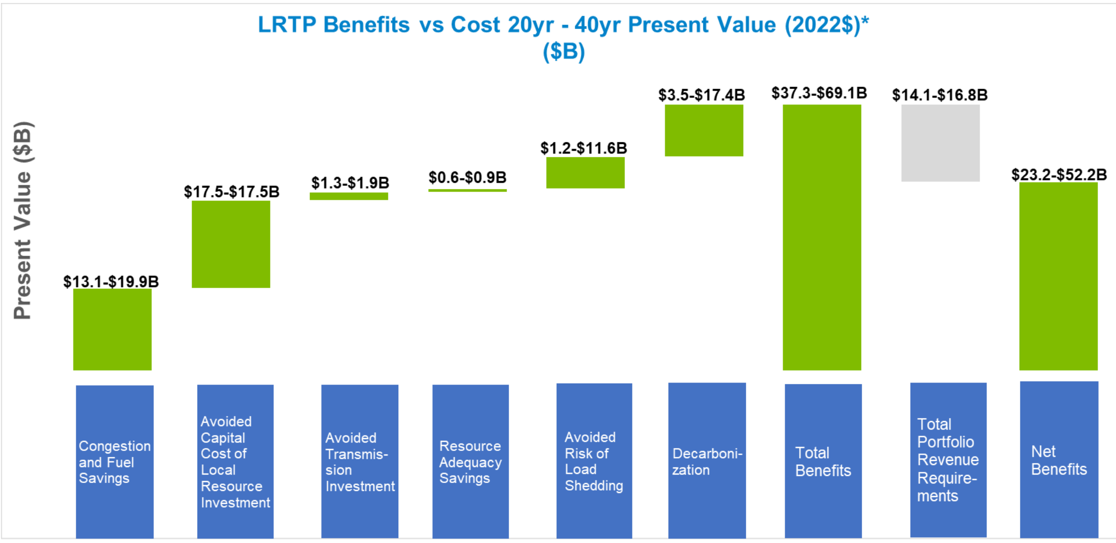


Figure 7-1: Financially Quantifiable Benefits of LRTP Tranche 1 Portfolio (values as of 6/1/22)

Guided by the allowable economic benefits defined in the tariff for MVP projects, the following benefit components were evaluated to determine the amount of value delivered by the LRTP Tranche 1 Portfolio:

- Congestion and fuel cost savings
- Avoided capital costs of local resource investment
- Avoided future transmission investment
- Reduced resource adequacy requirements
- Avoided risk of load shedding
- Decarbonization

Each benefit metric represents a distinct piece of the overall value resulting from either the transmission investments or the generation changes enabled by the transmission projects. Each benefit component is discussed in more detail, explaining what is captured in the metric, how LRTP projects impact the value being measured, and the methodology used to calculate the benefit. Starting from their assumed in-service year of 2030, benefits were calculated over a twenty-year horizon to evaluate eligibility as a multi-value project, and over a forty-year period to demonstrate the additional value provided over the expected useful life of the assets.

For consistency and comparability, a general set of assumptions and variables was applied in the analysis of benefits. All benefit values are expressed in 2022 dollars. An inflation rate of 2.5% is assumed when adjusting for the benefit period. A rate of 3 percent is used to represent the value a ratepayer would typically receive on a risk-adjusted investment. A discount rate of 6.9 percent is used to calculate the minimum value used to assess the benefit to cost ratio and based on the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments. The benefits analysis also includes evaluation of a natural gas price sensitivity to determine how benefits change with respect to swings in natural gas prices. While the benefits of the LRTP Tranche 1 Portfolio business case are analyzed for a Future 1 resource expansion scenario based on a specific gas price assumption, the sensitivity analysis offers additional insights into the value of LRTP under a broader set of assumptions.

Congestion and Fuel Cost Savings

In the MISO Futures[4], transmission limitations require robust solutions that not only reduce system congestion but also facilitate access to the diverse, ever-changing resource mix. The LRTP Tranche 1 Portfolio helps deliver economic benefits by providing more transmission infrastructure to distribute loading on other facilities and by enabling the connection of more low-cost resources.

Congestion and Fuel Savings benefit analysis is determined by calculating Adjusted Production Cost (APC[5]) savings between a reference case and a change case production cost model. The makeup of the reference case includes sufficient resources to meet Future 1 energy requirements, without applying the limitations of the transmission system, as well as Future 1 Regional Resource Forecast (RRF) resources that do not require the LRTP Tranche 1 Portfolio to connect to the system. The change case includes the LRTP Tranche 1 Portfolio and Future 1 RRF resources enabled by regional transmission to connect to the system. To determine which RRF resources are included in the reference and change case models, MISO performed a distribution factor (DFAX[6]) analysis on reliability constraints addressed by the LRTP Tranche 1 Portfolio. Only renewable RRF resources with ≥ 5% DFAX are included in the change case and renewable RRF resources with < 5% DFAX will be included in both the reference and change cases (Figure 7-2).

[4] MISO Futures Report
[5] MISO APC White Paper
[6] The DFAX analysis utilized LRTP Powerflow models and identified LRTP reliability issues addressed by the LRTP Tranche 1 Portfolio and involves the computation of change in flow on a network branch in the transmission model to the injection of power at a bus where generation is located which determines the amount of generator impact on facility loading.

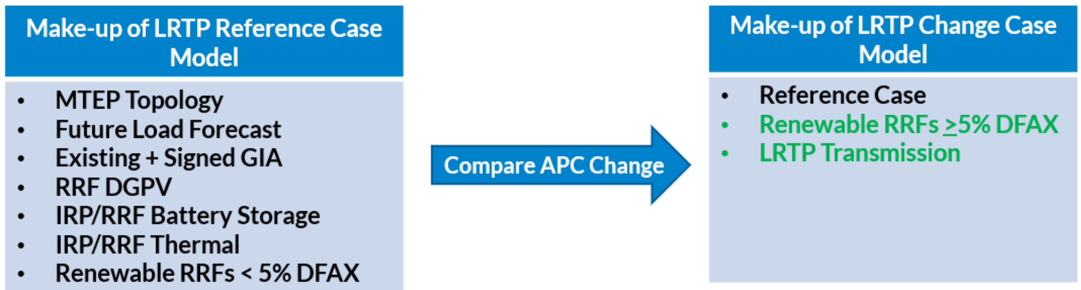


Figure 7-2: LRTP Reference and Change Case Criteria

As seen in Figure 7-3, application of this criteria resulted in 136.6 GW of resources being added to the LRTP Reference Case to meet Future 1 energy requirements and left 20.4 GW of renewable RRF resources available for DFAX analysis. This assessment resulted in the enablement of 20.1 GW of renewable RRF resources being added to the change case. Reference Figure 7-4 for geographical representation of the enabled renewable RRF resources in relation to the LRTP Tranche 1 portfolio.

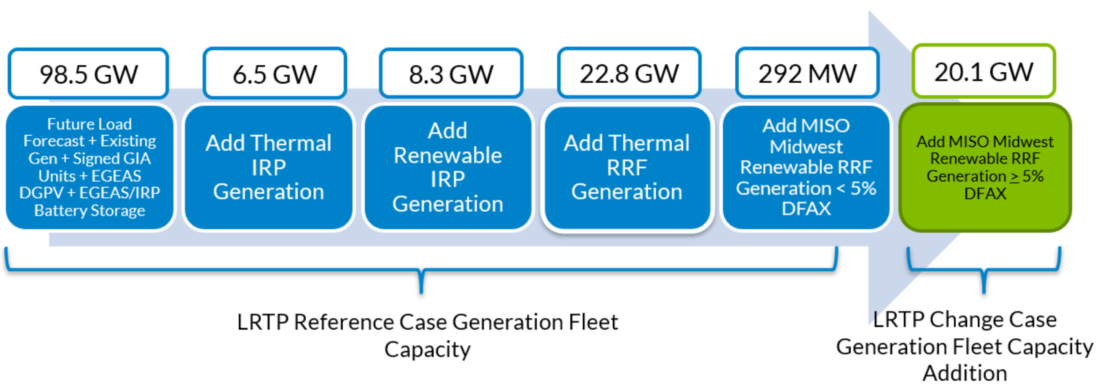


Figure 7-3: LRTP Reference and Change Case Criteria Capacity Result

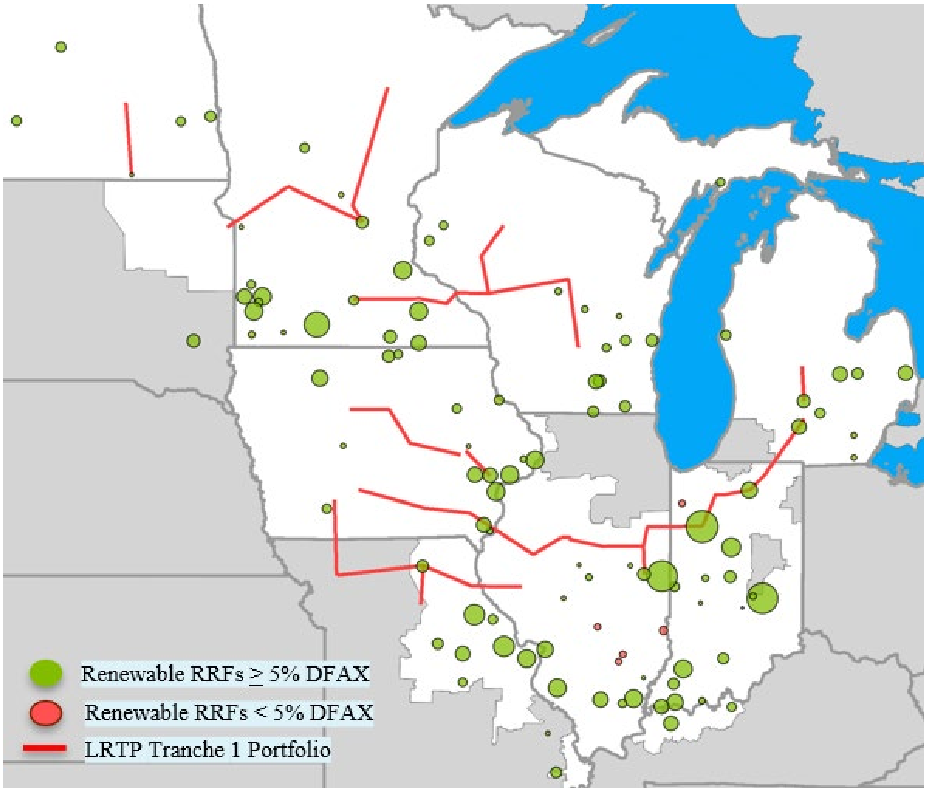


Figure 7-4: Geographic Map of RRF Resources Enabled by LRTP Tranche 1 Portfolio

The APC savings created by the LRTP Tranche 1 Portfolio generated $13.1 billion in congestion and fuel savings benefits over a 20-year period at a 6.9% discount rate. See Table 7-1 for additional benefit details on a Cost Allocation Zone (CAZ) granularity.

Present Value		20-year PV (Millions-2022$)		40-year PV (Millions-2022$)	
Discount Rate		6.9%	3.0%	6.9%	3.0%
CAZ	1	$3,169	$4,455	$4,668	$8,797
	2	$1,049	$1,511	$1,667	$3,313
	3	$2,195	$3,060	$3,151	$5,823
	4	$1,352	$1,934	$2,107	$4,133
	5	$1,471	$2,078	$2,205	$4,210
	6	$2,884	$4,133	$4,517	$8,890
	7	$1,006	$1,432	$1,543	$2,993
		$13,125	**$18,603**	**$19,858**	**$38,160**

Table 7-1: LRTP Tranche 1 Portfolio Congestion and Fuel Savings Benefits

Avoided Capital Costs of Local Resource Investments

The Avoided Capital Costs of Local Resource Investments metric captures the cost savings realized from a more cost-effective regional resource buildout that is enabled by regional transmission investment instead of depending on a more costly local resource buildout that is required due to local transmission limitations. In this specific case, the cost savings created by the LRTP Tranche 1 Portfolio will be determined by calculating an increase in costs for the resources enabled by the LRTP Tranche 1 Portfolio using a local versus regional capacity ratio.

To determine what the local resource investments would be, MISO had to first build local resource expansion models in EGEAS utilizing the same Future 1 assumptions[7] used in the regional expansion plan.

The local expansion plan EGEAS model assumptions are as follows:

- Local representation would be represented by Local Balancing Authority (LBA) granularity.
- Each LBA is treated as its own pool, self-constructing resources necessary to meet simulation constraints such as Planning Reserve Margin (PRM) and emissions.
- MISO PRM value of 18% was scaled for each LBA based upon its alignment to the MISO coincident peak.
- Utilizes the same assumptions as the regional Future 1 analysis and resources are attributed to LBAs based on resource ownership.
- Capacity purchases are enabled for the first year to meet each LBA's PRM due to limitations driven by the construction lead time for new resource alternatives.
- LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.

[7] MISO Futures Report

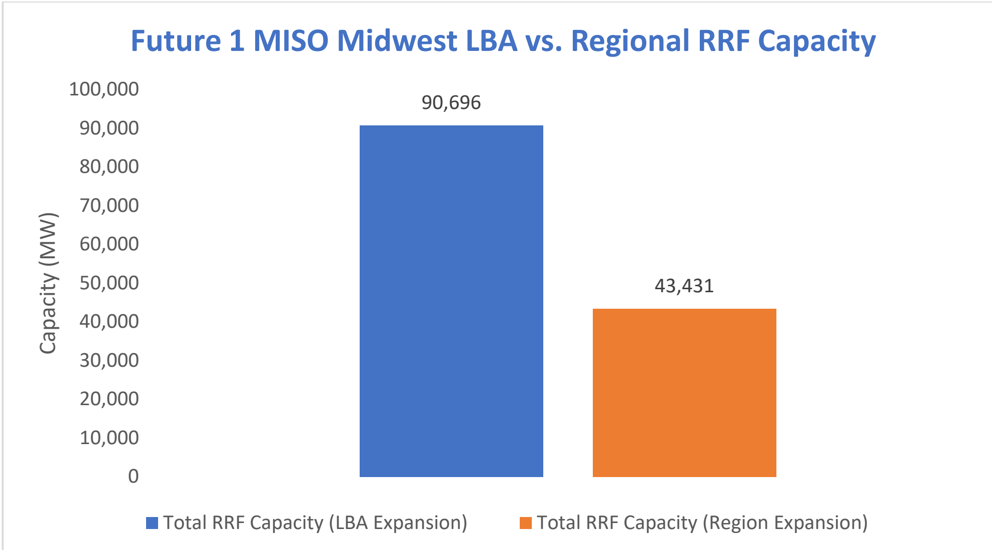


Figure 7-5: Future 1 LBA vs. Regional RRF Expansion Plan

As indicated in Figure 7-5, the LBA-specific scenario requires a much greater amount of localized resource expansion due to limited transmission capability, which is represented by isolating each LBA into its own EGEAS (transmission-less) model, compared to the equivalent regional expansion.

While Future 1 assumptions[8] were modeled consistently between the regional and LBA EGEAS models, the avoided capital cost benefit cannot be calculated by directly subtracting the regional expansion capital costs from local LBA expansion capital costs, as this would over-state the benefit created directly by regional transmission. To avoid this situation MISO had to consider what cost savings the Tranche 1 Portfolio would create. After evaluating several different options[9] with stakeholders to link the LRTP Tranche 1 Portfolio to the regional and local expansion, MISO proposed revised calculations and reviewed the details of the changes with stakeholders in the LRTP workshop discussions.[10] The ultimately decided on calculations are shown in equations (1) and (2) below:

$$Adjusted\ Capital\ Cost_{LBA\ Expansion} = \sum_{Year\ 2020}^{Year\ 2040} Enabled\ RRF\ Capital\ Cost_{Region\ Expansion} \times \frac{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{LBA\ Expansion})}{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{Regional\ Expansion})} \quad (1)$$

[8] MISO Futures Report
[9] January 21, 2022, LRTP Workshop
[10] February 25, 2022 LRTP Workshop

$$Avoided\ Capital\ Cost\ of\ Local\ Resource\ Investments\ = Adjusted\ Capital\ Cost_{LBA\ Expansion} - Enabled\ RRF\ Capital\ Cost_{Region\ Expansion} \quad (2)$$

Equation (1) is used to determine what the assumed local resource expansion cost would be by increasing the cost of the enabled resources by a ratio set by the LBA and regional EGEAS expansion results.

- $Adjusted\ Capital\ Cost_{LBA\ Expansion}$ represents the assumed capital cost of a local (LBA) resource expansion for MISO Midwest
- $Enabled\ RRF\ Capital\ Cost_{Regional\ Expansion}$ is the capital cost associated with the enabled[11] Regional Resource Forecasting (RRF) units determined by EGEAS using Future 1 assumptions[12], reduced to MISO Midwest
- $Total\ RRF\ Capacity_{LBA\ Expansion}$ is a summation of MISO Midwest's LBA RRF capacity determined through EGEAS by applying Future 1 assumptions on a LBA level
- $Total\ RRF\ Capacity_{Regional\ Expansion}$ is a summation of MISO Midwest's regional RRF capacity determined through EGEAS by applying Future 1 assumptions on a regional level

Equation (2) is used to determine what the Avoided Capital Costs of Local Resource Investments would be by subtracting the $Enabled\ RRF\ Capital\ Cost_{Regional\ Expansion}$, that is already accounted for, from the assumed LBA expansion capital cost calculated in equation (1).

As a result of being able to utilize the regional transmission buildout of the LRTP Tranche 1 Portfolio, approximately $17.5 billion of savings can be realized through the avoidance of local resource investment (Figure 7-6).

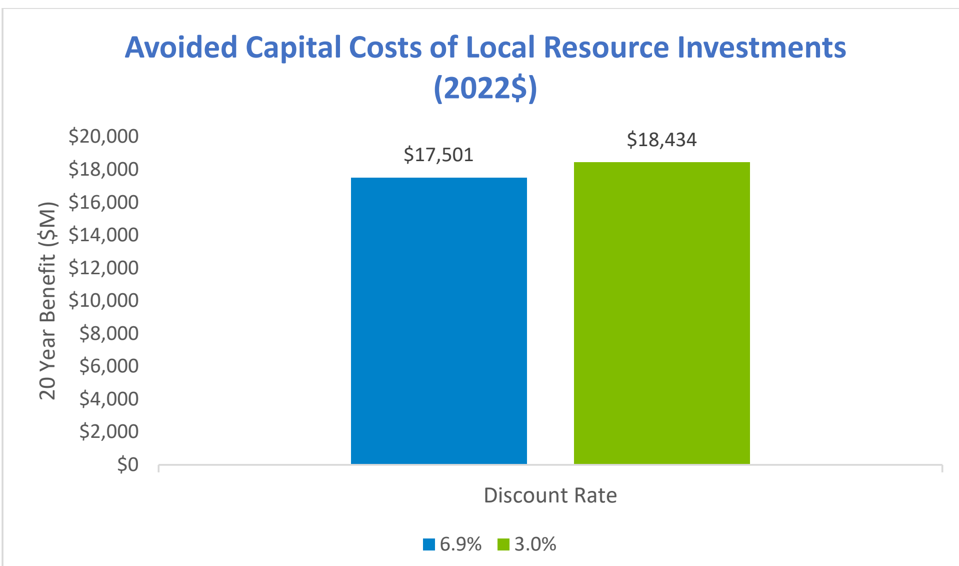


Figure 7-6: Avoided Capital Cost of Local Resource Investments Created by LRTP Tranche 1 Portfolio

[11] Renewable RRFs located in MISO Midwest Subregion which have ≥5% DFAX on reliability constraints addressed by LRTP Projects
[12] MISO Futures Report

Avoided Transmission Investment

The development of the LRTP Tranche 1 Portfolio provides a regional solution to addressing the future energy needs rather than an incremental approach to reliability planning. Avoided Transmission Investment captures the benefit provided by LRTP regional projects that address both avoided reliability projects and avoided age and condition replacement projects on right-of-way shared by LRTP projects.

LRTP projects deliver benefits by addressing future reliability issues and avoiding the costs of future upgrades that would have been required absent the LRTP Tranche 1 Portfolio. Benefits of avoided future reliability upgrades are based on potential overloads in the future rather than issues observed within the LRTP study period, in order to avoid double counting of benefits.

Identification of future upgrades considers facilities with high thermal loading but not overloaded in the 20-year reference case without LRTP reinforcements, and uses the thermal loading observed in the 10-year reference case to calculate the projected overload (equation below).

$$Flow_{proj} = Flow_{20} + (Flow_{20} - Flow_{10})$$

These projected overloads are analyzed in the LRTP case to determine if the LRTP Tranche 1 Portfolio mitigates the overload condition and are included as candidates for avoided future upgrades.

For future avoided transmission facilities >=345 kV a cost adjustment is applied to reduce the value by 50% to offset future production cost benefits that may be realized. These upgraded extra high voltage (EHV) facilities will reduce future congestion and offset production cost savings in the long term and discounting reduces potential for double counting of benefits. EHV facilities support regional energy delivery and generally have greater influence on production cost than lower voltage facilities that provide local reliability.

LRTP solutions in some cases make use of existing transmission corridors to reduce the need for new right-of-way and often the existing facilities have long been in service and in need of replacement. The avoided transmission investment benefit component also includes the avoided cost of upgrades where LRTP Tranche 1 projects are constructed on existing right-of-way with facilities that would have required upgrades as a result of facility age and condition. Where LRTP Tranche1 projects require rebuilding the structures and facilities of the aging circuits to accommodate the new transmission line, the future cost of the replacement is eliminated.

Facilities included in the Avoided Transmission Investment metric were verified with Transmission Owners to determine if facility upgrades are already planned or existing circuits on shared right-of-way are not candidates for age and condition replacement and were excluded from further consideration. Costs for avoided transmission investment use exploratory cost estimates that are based on the type of upgrade or replacement required. MISO estimated costs are derived from the MISO *Transmission Cost Estimation Guide for MTEP21* and are show in Table 7-2 below.

Upgrades are assumed to be needed prior to the end of the LRTP 20-year study period, and capital investment is assumed to be spread equally over the 5-year period prior to the in-service date of 2040.

Facility Improvement Type	Unit Cost($M)	Quantity/Miles	Cost ($M)
Bus-tie Replacement	$1.50	2	$3
Transformer Replacement =345	$5.00	4	$20
Transformer Replacement <345	$3.00	5	$15
Transmission line Replacement =345kV (per mile)	$2.65	21	$56
Transmission line Replacement <345kV (per mile)	$1.60	1012	$1,617
Transmission line upgrade=345kV (per mile)	$0.56	230	$64
Transmission line upgrade <345kV (per mile)	$0.34	124	$43
		Total	**$1,819**

Table 7-2: Estimated Costs of Avoided Transmission Investment (values as of 6/1/22)

Analysis Results
Cost savings associated with avoided future upgrades and future facility replacement for age and condition yields 20-40 year present value benefits from $1.3B to $1.9B (2022$).

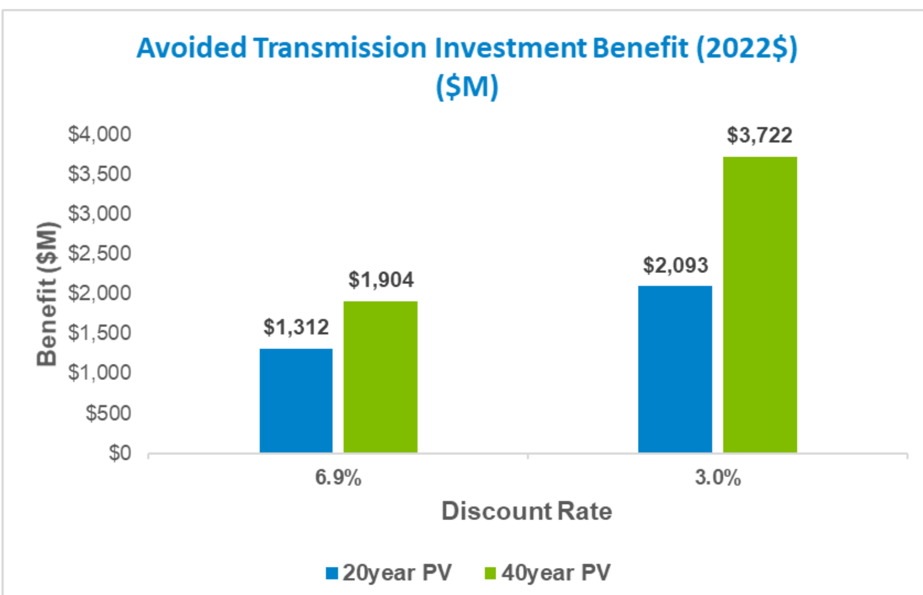


Figure 7-7: Avoided Transmission Investment Benefit (values as of 6/1/22)

Reduced Resource Adequacy Needs

The Reduced Resource Adequacy benefit metric represents a deferral of capacity that would be needed to address resource adequacy requirements due to increased zonal import limits. The transmission enhancements provided by the LRTP Tranche 1 Portfolio increases import capability and enables access to resources across the subregion. This decreases the need to procure capacity locally to meet resource adequacy needs.

The load serving entities (LSEs) that are located within the Local Resource Zones (LRZ) in MISO are required to meet two planning reserve margins in the Planning Resource Auction (PRA): the zonal planning reserve margin requirement (PRMR), which is based on the MISO-wide coincident peak load and MISO-wide PRM, and the local clearing requirement (LCR), which is based on each zone's non-coincident peak load and the local reliability requirement (LRR). The resource adequacy benefits presented in this section are related to the LCR.

Modeling and Assumptions

The modeling includes two parts; the first one involves a transfer analysis and the second one includes the monetization of the benefit.

1. Transfer Study: The CIL analysis generally aligns with the study methodology used in the Planning Resource Auction (PRA). The transfer analysis starts with the Future 1-2040 "peak load day" power flow model and associated input files (monitored elements and contingencies and sub-systems). These are then used in the TARA simulation tool to determine the incremental amount of power that can be transferred from source to sink. The First Contingency Incremental Transfer Capability (FCITC) is determined and the CIL is calculated for a base case (without LRTP Tranche 1 Portfolio) and change case (including LRTP Tranche 1 Portfolio). The definition of each case, in terms of the resource dispatch and demand levels, is consistent with the LRTP Future 1 reliability models.

2. Economic value of LCR reductions: The economic value of the LCR reduction is estimated as a function of the total unforced capacity (UCAP), CIL, and the LRR. The 2040 unforced capacity for each LRZ is determined using forced outage rates for thermal resources and the effective load carrying capability for non-thermal resources.

   The excess capacity within each LRZ is calculated as follows:

   Excess Capacity (LRZ_i) = 2040 UCAP (LRZ_i) – 2040 LCR (LRZ_i; without LRTP),
   where "i" represents the LRZ number (from 1-7).

   The RA benefits are estimated as follows:

   If Excess Capacity < 0 → Benefit = (Cost of new entry) x (-Excess Capacity)
   If Excess Capacity > 0 → Benefit = $0/year

   The LRR-UCAP percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ. The cost of new entry (CONE) assumptions is also consistent with the PY22-23 MISO LOLE study.

Analysis Results

The resulting CIL, with and without the LRTP Tranche 1 Portfolio, are shown in Table 7-3. The CIL values include the net-area interchange (e.g., the base transfer) gathered from the power flow model. Although their impact on the LCR benefit is negligible, the other components used in the CIL equation, e.g., border external resources (BER), coordinated owner (CO), and exports are kept unchanged in the base and reference cases.

Local Resource Zone	CIL (Base)	CIL (Change-With LRTP)	Delta CIL(MW)
1	5412	6070	658
2	4188	5223	1035
3	5062	6453	1391
4	7117	7609	492
5	6131	6183	52
6	6005	6171	166
7	3367	4659	1292

Table 7-3: Change in Capacity Import Limits (CIL)

A summary of the UCAP, LCR, LRR, and the Excess Capacity calculated for each LRZ is included in Table 7-4. The excess capacity shown in row 7 reflects the pre-LRTP scenario and a negative value represents a potential shortfall situation. The excess capacity shown in row 8 reflects the case with LRTP and confirms the ability of Tranche 1 projects to hedge against potential shortfall situations. The total 20-year and 40-year net present values are shown in Figure 7-8.

Row Number	Summary of resource adequacy benefits								
	LRZ	1	2	3	4	5	6	7	Formula Key
1	2040 Unforced Capacity (MW)	22,981	15,458	12,079	11,111	8,274	20,659	23,982	A
2	2040 Local Reliability Requirement Unforced Capacity (MW)	23,672	16,431	12,405	14,230	12,391	24,196	27,814	B
3	Without LRTP CIL (MW)	5,412	4,188	5,062	7,117	6,131	6,005	3,368	C
4	With LRTP CIL (MW)	6,070	5,223	6,453	7,609	6,183	6,171	4,659	D
5	Without LRTP LCR (MW)	18,260	12,243	7,343	7,113	6,260	18,191	24,446	E=B-C
6	With LRTP LCR (MW)	17,602	11,208	5,952	6,621	6,208	18,025	23,155	F=B-D
7	Excess capacity after LCR	4,721	3,216	4,737	3,998	2,014	2,468	-465	G=A-E

	without LRTP (MW)								
8	Excess capacity after LCR with LRTP (MW)	5,379	4,251	6,128	4,490	2,066	2,634	827	H=A-F
9	Deferred capacity value (M$)	0	0	0	0	0	0	-44	I=G*CONE

Table 7-4: Summary of resource adequacy benefits

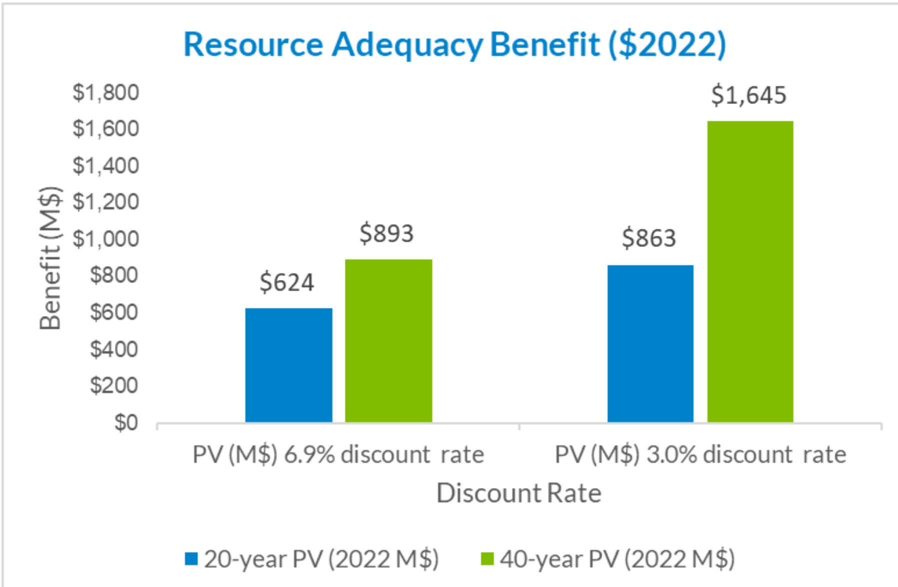


Figure 7-8: Resource Adequacy Benefit Total 20-year and 40-year Present Value

Avoided Risk of Load Shedding

Avoided Risk of Load Shedding is one of several metrics that is used to quantify the benefits provided by the LRTP Tranche 1 Portfolio. The method for determining this resiliency value considers high impact events with an expectation of a significant amount of controlled load shedding to ensure reliable system performance and/or prevent system collapse. While smaller, more common contingencies can result in the need for load shedding actions to maintain reliability, these events are often local in nature and beyond the scope of this analysis, which examines the impact of large-scale generation loss events caused by changing weather conditions or under extreme weather events. In a future with extensive penetration of renewable resources, the variability in weather introduces the potential for loss of renewable production. Additionally, extreme winter weather patterns can cause fuel supply disruptions that may result in extensive thermal generation outages. LRTP projects help to enable regional transfers mitigating the risk associated with these high impact generation outage events.

Analysis of load shedding risk was performed using 2040 winter peak reliability powerflow models, which represent system conditions under which the severe winter weather generation loss event is expected to occur. Weather events may be limited in scale to smaller areas that can affect a single resource zone or may be extreme in nature and have widespread impacts across the footprint. Study scenarios are defined for zonal and system-wide events that specify the generation outages resulting from severe winter weather impacts. Analysis of severe winter weather impacts on generation performance is generally straightforward but captures only one area of the risk associated with loss of load. This narrow focus results in a conservative estimate of the value of avoided risk of load shedding.

Historical weather event data is used to understand and develop assumptions about the frequency of significant winter weather events that could lead to large scale generation loss. MISO analyzed information on significant freeze and storm events over the past 40 years that have resulted in significant economic impact in order to establish the frequency of occurrence for evaluating risk (Figure 7-9).

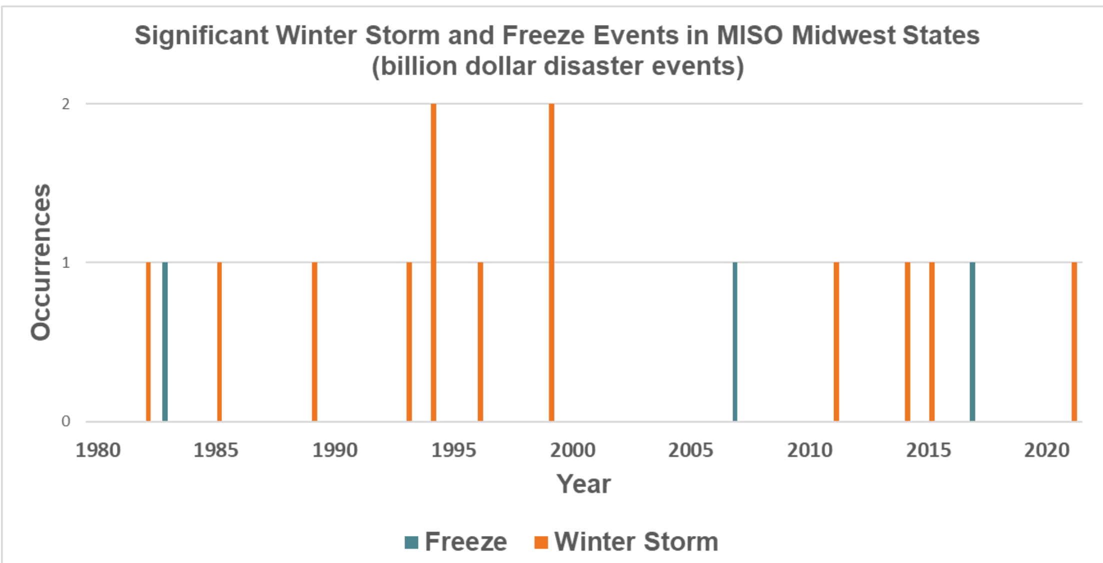
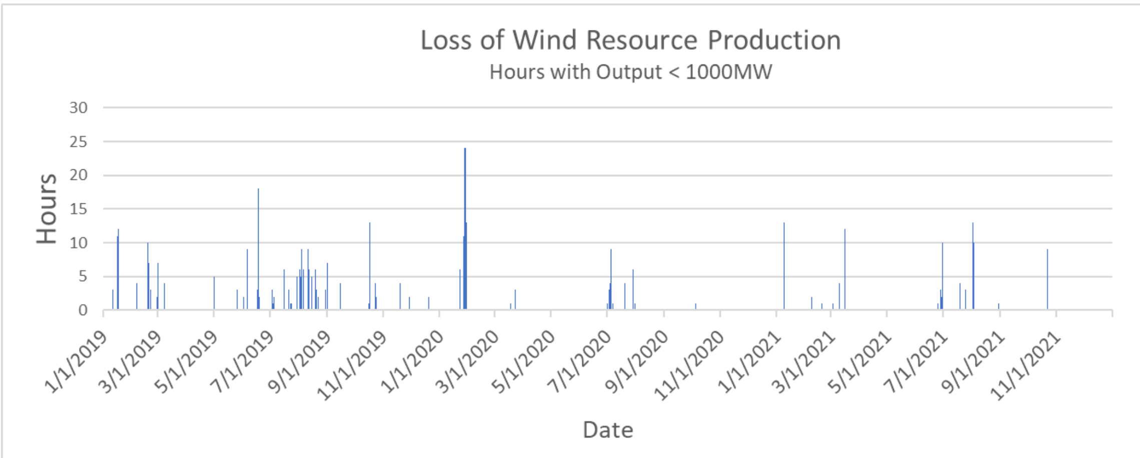


Figure 7-9: Winter storm and freeze events have been occurring every three years on average

Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/, DOI: 10.25921/stkw-7w73

Additionally, operational event data was analyzed to examine trends in resource availability events over time when severe winter weather conditions occur, which provides insights into how fleet composition affects the risk of generation deficiency. While many of these weather events have not caused major disruption of generation supply in the past, recently there have been a growing number of instances where weather conditions caused the need to implement emergency measures to maintain adequate supply. In the last five years, tight generation supply during winter conditions presented operational challenges that will continue with growing dependency on renewable resources and gas-fired generation. The MISO response to the Reliability Imperative report[13] notes a key indicator of the change in risk profile for the region is seen in the 41 MaxGen emergencies that have been declared since 2016.

Historical generation output data highlights recurring risks associated with periods of low renewable production which can occur during any season and any time of the day (Figure 7-10). Such events can leave a significant amount of generation capacity unavailable to meet load requirements and where the duration of generation shortfall can last several hours.



Data Source: MISO Historical Hourly Wind, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

Figure 7-10: Periods of low wind production may last several hours

The interruption of load may have far reaching impacts that include risk to public health and safety, financial loss, and regulatory/legal burdens, which are difficult to accurately quantify. The monetization of value of lost load is often considered in the context of customer willingness to pay to avoid interruption. While the application of the MISO Tariff defined Value of Lost Load (VOLL) in the LRTP business case does not suggest that VOLL represents the full value of risk, it does provide a reasonable measure that is indicative of the LRTP benefits and closely aligns with other business processes. The value of avoided risk of load loss of the LRTP Tranche 1 Portfolio considers a range of VOLL from $3,500/MWh to $23,000/MWh. The $3,500/MWh is currently defined by the MISO Tariff for use in market pricing while $23,000/MWh is a value recommended by the MISO Independent Market Monitor to be more representative of the value. This value of VOLL is applied to the calculated MW value of load loss determined by the zonal and system-wide studies in order to capture the benefits associated with the LRTP Tranche 1 Portfolio.

[13] MISO's Response to the Reliability Imperative

Method for Calculating Value of Avoided Risk of Load Shedding

Scenario Development

Analysis of historical winter storm and freeze event data from the past 20 years and recent extreme winter weather events indicates that significant winter storms are recurring every three years on average with extreme winter storms and temperature conditions observed periodically (polar vortex, Uri). The increased influence of weather due to the variability of renewable resources and impact of cold temperatures on fuel supply and availability of gas-fired generation will result in more periods of risk for load loss. Thus, each occurrence of a severe winter event every one out of three years represents a risk of load shedding due to the widespread generation outages. This risk persists beyond a single day since winter storms often occur over multiple days.

Duration of the load loss was derived using hourly wind production data to examine periods of low wind output since variability in wind output will have a large influence on the risk of an event. While the duration of low wind output events can range from 1 hour to 24 hours for a given day (Figure 7-10), approximately half of the events occurring in winter season are greater than 10 hours and period of risk for load loss is assumed to be eight hours per day over a two-day period for the purpose of assessing the risk of load shedding caused by a severe winter weather event.

A series of event scenarios were developed to represent significant generation loss due to weather related conditions. Events were created to reasonably reflect the loss of future renewable and thermal resources within defined zones or groups of zones. Loss of wind resources was modeled to represent a 90% drop in output from the maximum capacity and loss of solar output was modeled as a 50% reduction from maximum capacity. For regional and zonal event analysis, loss of thermal generation was derived by using outage information from the recent extreme winter storm event to establish a 50% outage rate in regional scenarios and 40% outage rate in zonal scenarios to capture the higher impact from future growth in gas-fired resources. Where modeled wind output is less than 10% of maximum capacity or solar output less than 50% in either zonal or regional scenarios, no adjustment is applied to the wind or solar output.

Load Loss Analysis

In zonal load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given local resource zone. Load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis. Reliability analysis models normally apply a 50/50 load forecast, which reflects the normal peak load expected in the planning horizon. However, during extreme weather conditions, the peak load is expected to reach a 90/10 peak load forecast level, which is typically 5% higher. Resources were grouped within a single zone and event generation outage scenario applied to determine the amount of generation remaining. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total zone load and losses and adding any net imports into the zone. The future CIL calculated in the resource adequacy analysis is used to determine if sufficient import capability exists to support any shortfall and any change in CIL due to the addition of the

LRTP projects is used to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Area/Zonal Event Scenario

Generation Loss:
Thermal: 40% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Capacity Import Limit (CIL)

For all LRZ 1-7

$$\textbf{LoadLossMW} = GenMW_{net} - 1.05 * LoadMW - TxLossMW + \text{Capacity Import Limit (MW)}$$
$$\text{where } GenMW_{net} = GenMW_{cap} - GenMW_{loss}$$

In regional load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given group of local resource zones. Similar to zonal analysis, the load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis due to the extreme weather. Resources were grouped within a set of zones and event generation outage scenario applied to determine the amount of generation remaining. In the regional analysis scenarios, the amount of thermal generation loss is escalated to 50% of capacity to represent a more extreme condition with regional scale impacts. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total load and losses and adding any net imports into the study group. The incremental transfer capability is calculated using the power flow model and added to the existing group net imports to determine the total transfer capability to support any shortfall and the change in total transfer capability due to the LRTP projects is calculated to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Two scenarios are included for evaluating risk of load loss for regional scale events:

Scenario 1 assesses the impact of an extreme winter storm primarily on the western part of the MISO footprint causing large scale loss of generation in MISO upper Midwest areas and Southwest Power Pool (SPP) with SPP imports assumed to be 7,500 MW.

Scenario 2 assesses the impact of extreme winter storm activity in the MISO central areas and Ohio Valley with PJM exports curtailed to 0 MW.

Regional Event Scenario

Generation Loss:
Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
Sink: MISO Zones 4-7

$$\textbf{LoadLossMW} = GenMW_{net} - 1.05 * LoadMW - TxLossMW + \text{Total Transfer Capability (MW)}$$
$$\text{where } GenMW_{net} = GenMW_{cap} - GenMW_{loss}$$

The value of avoided risk of load shedding is monetized by the use of the Value of Lost Load (VOLL) to represent a portion of the outage costs associated with load curtailment during generation deficiency events. While VOLL is based on outage costs, it is a market pricing mechanism that considers a customer's willingness to pay for energy to avoid load curtailment under emergency conditions and does not fully consider the related impacts or the effects of extended outages in more extreme scenarios. Furthermore, there is a wide range of opinion concerning the appropriate value that should be used with $3,500/MWh currently being used in the MISO market pricing structure while MISO's Independent Market Monitor has recommended a value of $23,000/MWh to be used in the MISO market. Thus the $3,500/MWh figure is a conservative estimate for capturing the benefit of avoided risk of load loss with the $23,000/MWh value used to establish the upper bound of the value.

The load loss hours are summed for all scenarios to obtain the load risk of load loss in MWhr and the range of values for VOLL is applied to obtain the monetary value.

Avoided Load Loss Value ($) = VOLL * LoadLossMW * duration(hrs.)
where VOLL – Value of Lost Load: $3,500- $23,000[14]

[14] IMM Quarterly Report: Summer 2020,

Analysis Results

The additional transfer capability provided by the LRTP Tranche 1 Portfolio enables power transfers to address supply deficiency caused by weather related generation outages and delivers 20- to 40-year present value benefits of $1.2 billion to $11.6 billion (2022$).

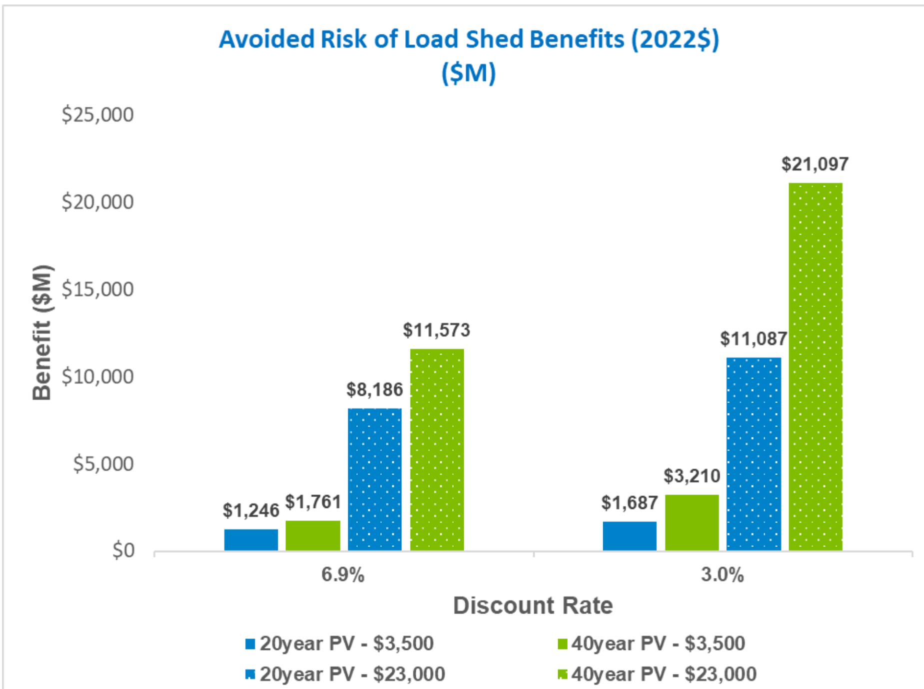


Figure 7-11: Benefits of Avoided Risk of Load Shedding (values as of 6/1/2022)

Decarbonization

MISO continues to explore how the rapid growth of members' decarbonization goals creates additional needs and opportunities to provide value. The robust transmission planning embodied by the LRTP initiative can signal better locations that deliver decarbonization, among other benefits. This item captures a range of potential cost savings from LTRP-enabled Decarbonization.

MISO acknowledges there is no cost of carbon applicable to the entire footprint currently. However, with the energy transition and changing landscape, it is possible that additional emissions standards may be placed on the electric industry. Since the 1990s, sulfur dioxide has decreased by 94%, nitrogen oxides by 88% and mercury emissions by 95% across the U.S. electric power sector.[15] Many of the benefits associated with these emission reductions have already been captured throughout the footprint.

[15] Edison Electric Institute: Climate and Clean Air

Over the past several years, MISO members have announced large carbon emission reduction goals that will rely on intermittent low-cost energy. The LRTP initiative aims to help ensure an efficient dispatch of energy across MISO during this fleet transition. With the rationale above, MISO conducted research to develop a price range to express Decarbonization's value. MISO chose sources within the U.S., at state and federal levels, within and outside of the MISO footprint. The range in prices draws from regulatory and market-based approaches, both of which are influenced by policy. From MISO's PROMOD analysis, carbon emissions are reduced by 399 million metric tons over 20 years and 677 million metric tons over 40 years of LRTP Tranche 1 project life (Figure 7-11).[16]

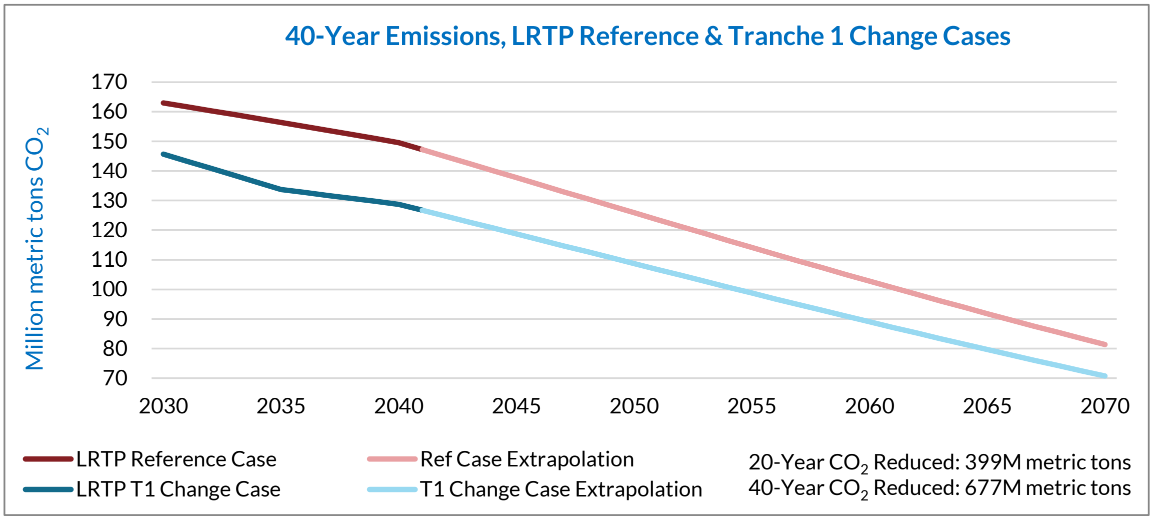


Figure 7-12: 40-Year CO_2 Emissions of LRTP Reference and Tranche 1 Change Cases

MISO took two steps to standardize price terms. First, as applicable, MISO converted source price data to dollars per metric ton, using a conversion factor of one U.S. (short) ton = 0.9071847 metric tons.[17] Second, MISO converted prices from nominal dollar-years of origin into 2022 dollars using the Consumer Price Index Inflation Calculator.[18] For consistency, the month of January was used for dollar-year conversions except in cases related to market prices, which used the month of auction settlement as the origin date. A range of CO_2 emission prices were identified to estimate a benefit value, and are summarized below:

- The Minnesota Public Utility Commission (MN PUC) price began with the 2022 Low[19] price of $9.46 per short ton in 2015 dollars and yielded $10.43 per metric ton; $12.55 per metric ton in 2022 dollars.

[16] MISO interpolated emissions data among PROMOD model years 2030, 2035, and 2040 and used linear extrapolation for post-2040 emissions reductions. 20-year and 40-year benefits refer to projects' in-service value to 2050 and 2070, respectively.
[17] U.S. Energy Information Administration
[18] U.S. Bureau of Labor Statistics Consumer Price Index Inflation Calculator
[19] Minnesota Public Utility Commission

- The Regional Greenhouse Gas Initiative (RGGI) Q4 2021 Auction average (mean)[20] price of $12.47/short ton yielded $13.75/metric ton; $13.87 in 2022 dollars.
- The California and Quebec (CA-QC) Cap-and-Trade Program Q4 2021 Auction settlement[21] price of $28.26/metric ton is $28.59 in 2022 dollars.
- The Federal price is the average of two price data inputs: the 45Q Tax Credit and the Social Cost of Carbon.[22] The 45Q Tax Credit follows a prescribed price schedule; starting with $31.77/metric ton in 2020, increasing to $50 by 2026, and inflation-adjusted afterwards by 2.5% annually. This interpolation yields a 2022 value of $37.85. The Social Cost of Carbon (SCC) follows a similar schedule, but in 2020 dollars. Converting the SCC schedule in 2020 dollars from $51/metric ton (2020) yields $55.58 and $85 (2050) yields $92.64 for those price-years, in 2022 dollars. The SCC's 2022 value in 2022 dollars is $57.76. Beyond 2050, annual inflation of 2.5% is applied. To produce the Federal price, the annual values of 45Q and SCC through 2069 are averaged, beginning in 2022 at $47.80/metric ton in 2022 dollars.

The Decarbonization assessment employs the following overall methodology:

- From the Congestion and Fuel Cost Savings analysis, calculate the difference in CO_2 emissions between the LRTP Reference case and LRTP Change case
- Convert the reduced emissions to metric tons
- Use range of carbon prices to produce yearly values at 2.5% inflation as applicable
- Multiply yearly values by annual reduced emissions and discount rates to produce discounted annual benefits
- Sum discounted annual benefits to yield net present values for 20- and 40-year emission reduction benefits along the price range (Figure 7-12, Table 7-4, Table 7-5)

Detailed assumptions, calculations and formulas are found in the supplementary LRTP Business Case Analysis workbook.

	MN PUC	RGGI Q4 2021	CA-QC Q4 2021	Federal
2022$/metric ton	$12.55	$13.87	$28.59	$47.80
20-Year Benefit (2022$, M):	$3,473	$3,839	$7,913	$13,438
40-Year Benefit (2022$, M):	$4,548	$5,026	$10,361	$17,364

Table 7-4: Full Range of Carbon Prices and Tranche 1 Decarbonization Benefits at 6.9% Discount Rate

[20] Regional Greenhouse Gas Initiative (Q4 2021 average [mean] price)
[21] California-Quebec Carbon Allowance Price (November 2021)
[22] Federal: 45Q Tax Credit, Social Cost of Carbon

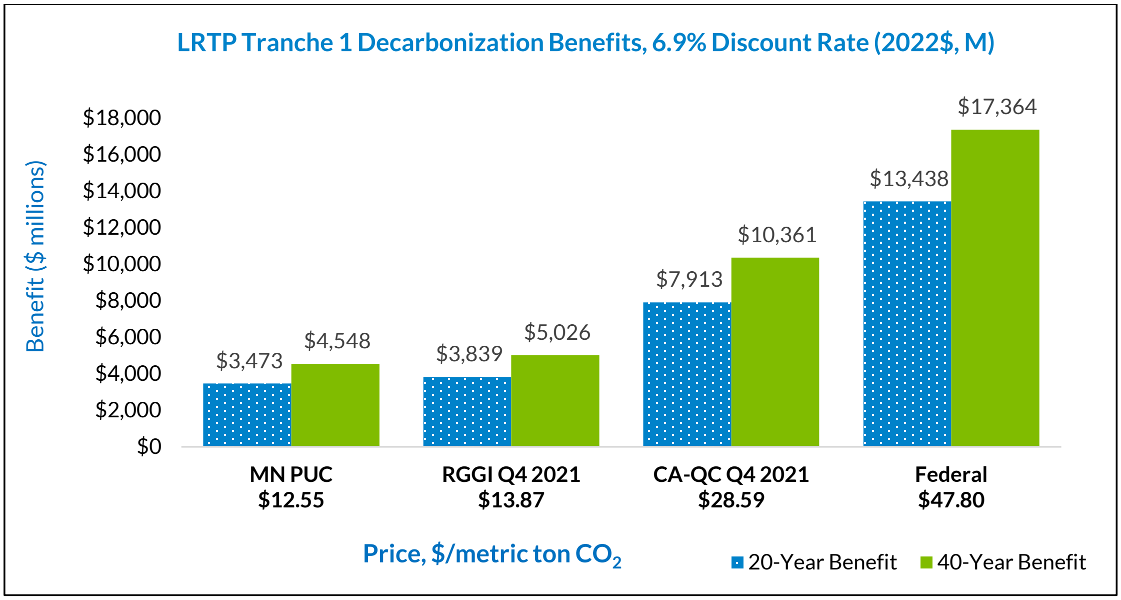


Figure 7-13: LRTP Tranche 1 Decarbonization 20- and 40-Year Benefits Using Full Carbon Price Range, Applying 6.9% Discount Rate (2022$, M)

	6.9% Discount Rate		3% Discount Rate	
	MN PUC (Min)	Federal (Max)	MN PUC (Min)	Federal (Max)
2022$/metric ton	$12.55	$47.80	$12.55	$47.80
20-Year Benefit (2022$, M):	$3,473	$13,438	$4,781	$18,404
40-Year Benefit (2022$, M):	$4,548	$17,364	$7,818	$29,498

Table 7-5: Min/Max Carbon Prices and Tranche 1 Decarbonization Benefits at Two Discount Rates

8 Benefits Are Spread Across the Midwest Subregion

The LRTP Tranche 1 Portfolio of projects was developed to address regional energy delivery needs for the MISO Midwest subregion. As Multi-Value-Projects, the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion. Analysis of benefits examined how much each benefit accrued to the Midwest Subregion Cost Allocation Zones in order to compare the relative impacts between zones and the relationship with cost allocation. The distribution of benefits of the LRTP Tranche 1 Portfolio is shown to yield significant benefits for all Cost Allocation Zones (CAZs) well in excess of the share of portfolio costs.

Distribution of Benefits

Congestion and fuel savings are distributed to CAZs based on the production cost simulations used to calculate the savings and aggregated to the CAZs.

Avoided capital cost of local resource investment benefits are assigned based on load ratio share of each CAZ and aligns with the goal of the resource expansion to meet the future energy needs of the Midwest Subregion.

Avoided transmission investment benefits are allocated to the CAZ in which the baseline transmission upgrades, and age and condition replacement facilities are located. Costs for these avoided projects would otherwise be borne by the local pricing zone which yields a benefit to those specific CAZs.

Reduced Resource Adequacy savings are assigned directly to the CAZs in which the cost savings are realized since each CAZ has a responsibility for their own resource adequacy needs, and the CAZs in the Midwest Subregion align with the Local Resource Zones used for resource adequacy.

Avoided Risk of Load Shedding benefits are distributed to CAZs based on load ratio share to reflect the widespread protection against load loss in the interconnected electric system.

Decarbonization captures the benefits of reduced carbon emissions in energy production that is used to serve load across the Midwest subregion and is allocated by load ratio share to CAZs.

Distribution of LRTP Tranche 1 Portfolio Costs

The cost for Multi-Value Projects are allocated to load in the Midwest Subregion according to load ratio share of energy withdrawals. To determine the benefit/cost ratios by Cost Allocation Zone the energy withdrawals by the applicable LBAs included in each zone have been aggregated for Figure 8-1. Additionally, indicative annual MVP usage rates for the LRTP Tranche 1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. This information on the estimated MVP usage rates is provided in Appendix A-3.

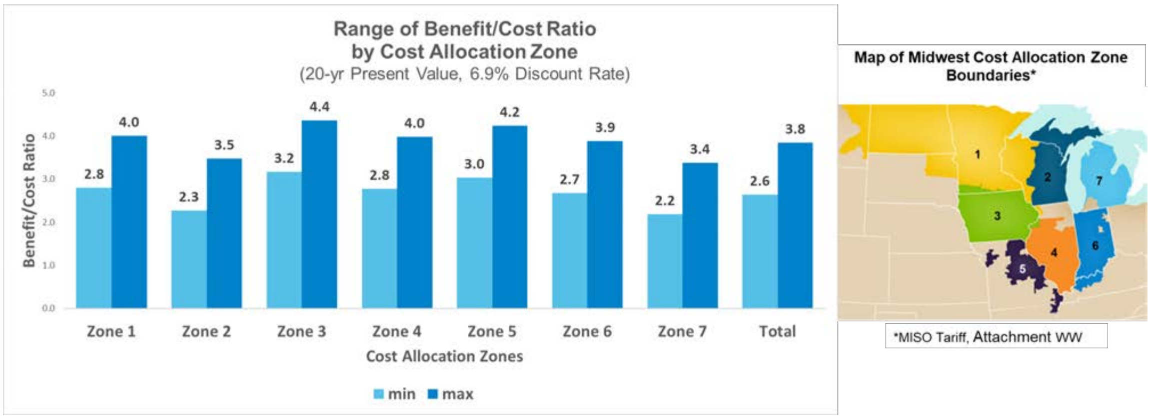


Figure 8-1: Distribution of benefits to Cost Allocation Zones in Midwest Subregion (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP Tranche 1 Portfolio provides broad distribution of benefits across the Midwest subregion zones and delivers a benefit to cost ratio of at least 2.2 for every CAZ. Analysis of the zonal benefit distribution indicates that the spread of benefits is roughly commensurate with the allocation of portfolio costs.

9 Natural Gas Price Sensitivity

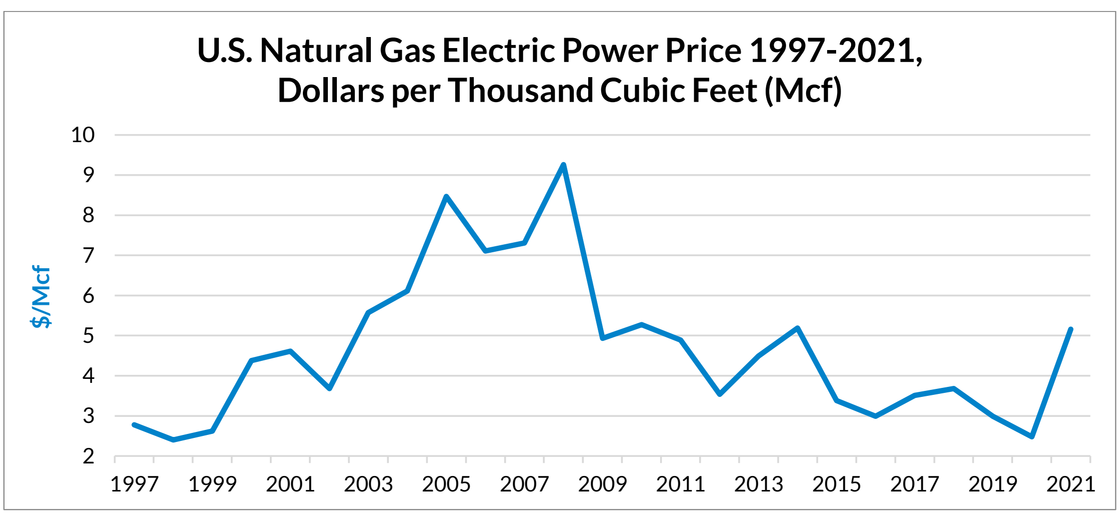


Figure 9-1: Historic U.S. Natural Gas Electric Power Prices

Beginning in 2021, natural gas prices increased sharply, reversing the general price decline seen over the last decade as production grew dramatically from the shale revolution (Figure 9-1).

U.S. export capacity of liquefied natural gas (LNG) has grown rapidly since beginning in 2016, from 0.55 billion cubic feet per day (Bcf/d) to an estimated peak of 11.6 Bcf/d as of November 2021. The U.S. Energy Information Administration estimates U.S. LNG peak export capacity will reach 16.3 Bcf/d by the end of 2024.[23]

Considering the expansion of LNG exports along with the growing prevalence of extreme weather events and current geopolitical developments, U.S. gas price exposure to the global market has increased as well. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than gas.

Two sensitivity analyses were performed on the LRTP Tranche 1 Congestion and Fuel Savings Reference and Change Case PROMOD models to quantify the impact of changes in gas prices. The sensitivity cases maintained the same production cost modeling assumptions from the business case analysis, except for the gas prices. The sensitivity assumed gas price increases of 20 and 60 percent, respectively. For both analyses, the prices increased starting in the year 2030 and escalated by inflation thereafter.

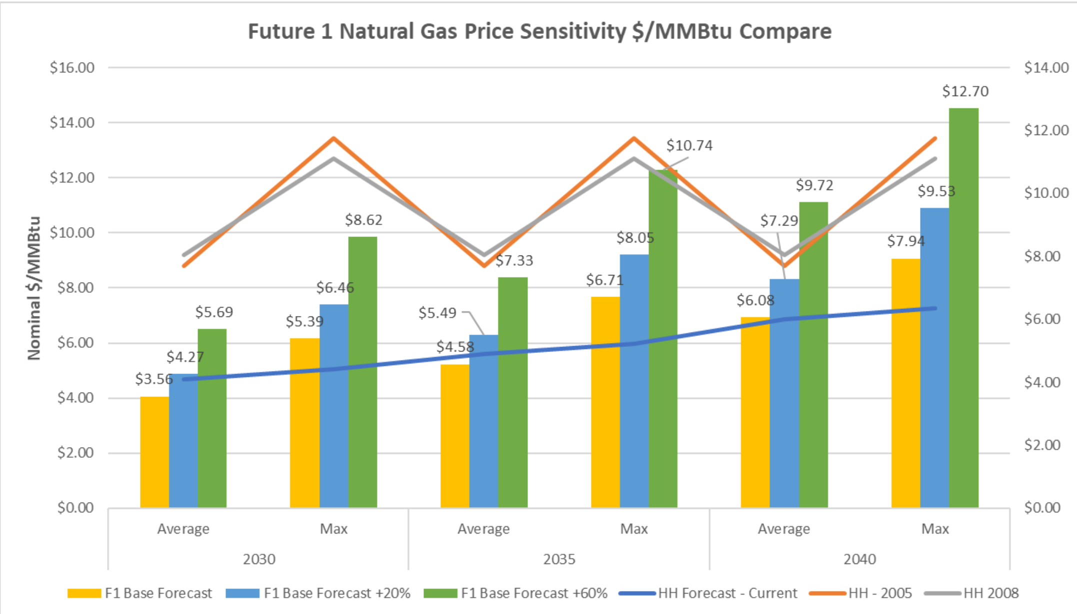


Figure 9-2: Future 1 Natural Gas Price Sensitivity $/MMBtu per LRTP PROMOD Study Year

The resulting natural gas price increases achieved (Figure 9-2) created a gas price increase that ensures each study year's average fuel cost is greater than current Henry Hub (HH) projections as

[23] https://www.eia.gov/todayinenergy/detail.php?id=50598

well as representing HH highest historical sale prices from 2005 and 2008. This sensitivity concluded that the LRTP Tranche 1 Portfolio offsets gas price volatility by providing additional Congestion and Fuel Savings benefits by enabling access to renewable energy, as shown in Figure 9-3.

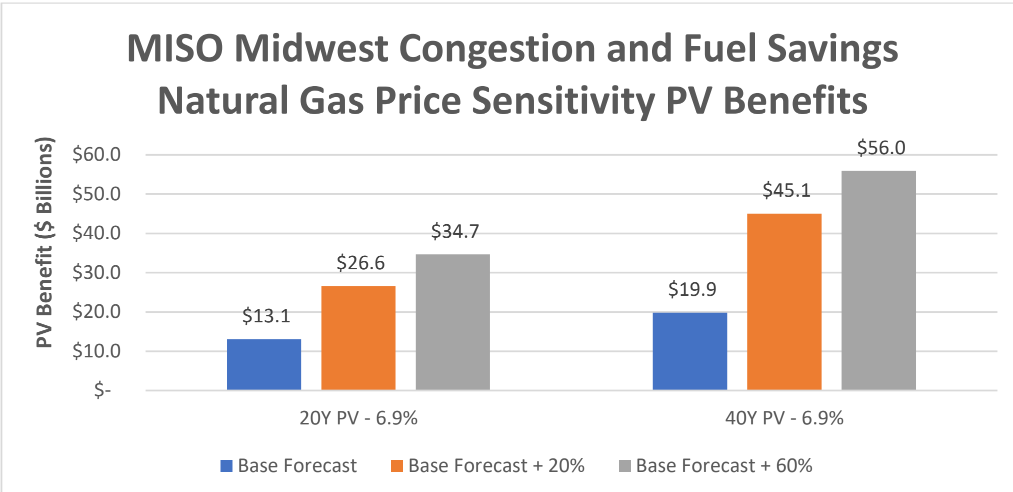


Figure 9-3: Natural Gas Price Sensitivity Results

10 Other Qualitative and Indirect Benefits

In addition to the quantifiable economic and reliability benefits, the LRTP Tranche 1 Portfolio enables other value streams that are reflected qualitatively.

Transmission reinforcements strengthen the grid to support the stability of the larger interconnection and provide greater resilience to recover from unexpected system events without adverse impacts. The interconnected nature of the power system provides support between neighboring systems during severe system disturbances. Regional transmission projects bolster the network, enabling greater bulk power transfers to address the developing conditions and avoid further degradation of the system performance.

Investment in regional transmission projects expand access to a greater diversity of lower-cost resources across the footprint, allowing more options for customer choice of fuel mix. Transmission allows for leveraging of the wide geographic and fuel diversity offered by the MISO region. The stronger regional ties offer more flexibility to handle the variability of renewable output caused by differences in weather patterns across different areas of the MISO footprint. This capability offers greater protection against both market price risk and possible load curtailment measures.

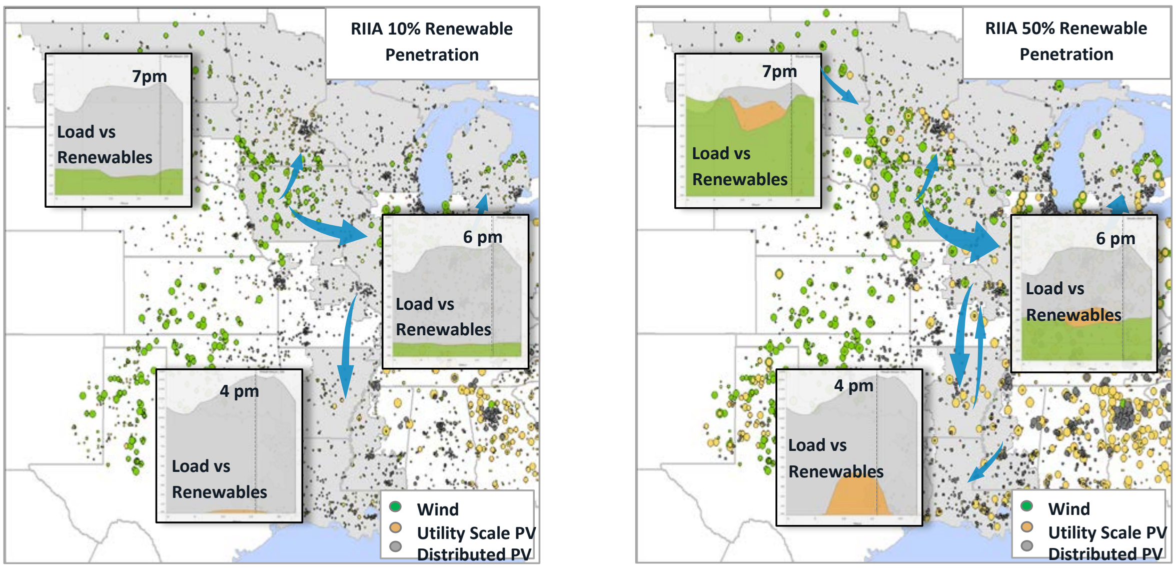


Figure 10-1: Illustration of flow changes with increasing renewable penetration spread throughout the MISO footprint (MISO Renewable Integration Impact Assessment (RIIA) Summary Report, February 2021 https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

The addition of transmission facilities allows greater operational flexibility related to unplanned and planned transmission facility outages. While the Congestion and Fuel Savings metric described earlier captures economic value related to reduced congestion, it represents value under normal system intact conditions. In practice, numerous outages occur throughout the year which introduce additional congestion which is not reflected in the calculation of the economic benefits. Furthermore, as the grid moves to a higher penetration of renewables and seasonal load curve flattens, outage scheduling becomes more challenging. Additional transmission improves system utilization and allows more opportunity for scheduling transmission outages with less risk of causing operational issues or rescheduling of outages.

The LRTP Tranche 1 Portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environment and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

The LRTP Tranche 1 Portfolio gives more flexibility to better support diverse policy needs. The proactive long-range approach to planning of regional transmission provides regulators greater confidence in achieving their policy goals by reducing uncertainty around the future resource expansion plans. Elimination of much of the high transmission cost barriers allows resource planners to assume less risk in making resource investment decisions.