

MTEP24

TRANSMISSION PORTFOLIO

Local

Regional

JTIQ

MTEP24 Report

Highlights

- The combination of local, Tranche 2.1 and JTIQ portfolios drove the largest investment in MISO history with 488 new projects totaling \$30 billion
- 24 Tranche 2.1 projects in the MISO Midwest provide a benefit-to-cost ratio between 1.8 and 3.5 and help ensure a reliable and resilient future grid
- The five-project JTIQ portfolio provides value to interconnection customers and load along the SPP-MISP seam, enabling approximately 28 GW of generation to interconnect



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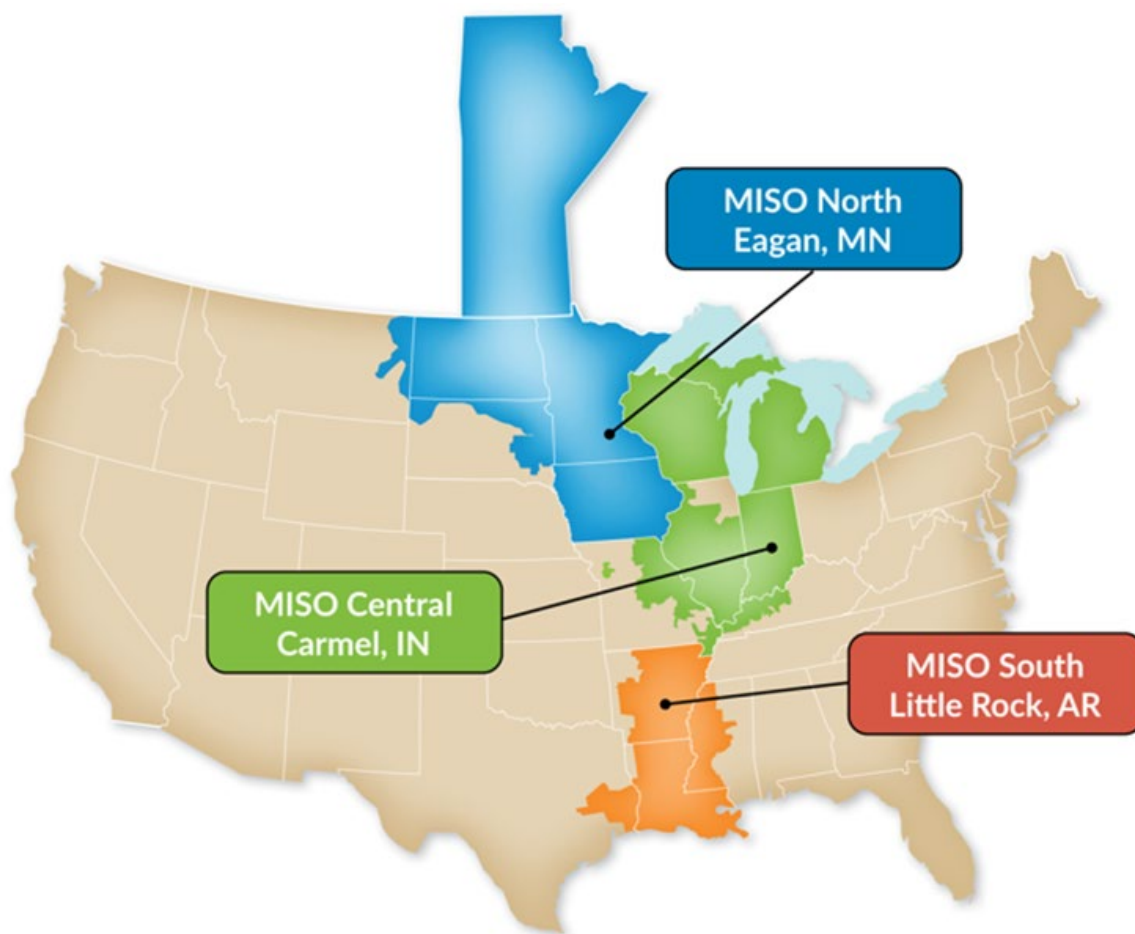
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About MISO

Midcontinent Independent System Operator (MISO) is an independent, 501(c)(4) not-for-profit, member-based organization, approved as a Regional Transmission Organization (RTO) by FERC in 2001, with responsibility for keeping the power flowing across its region reliably and cost effectively. The system MISO manages is the largest in North America based on geographical scope, with 471 market participants serving approximately 45 million people across all or part of 15 states and one Canadian province. The MISO energy markets are also among the largest in the world, with more than \$40 billion in annual gross market charges.

MISO Reliability Footprint and Regional Control Center Locations

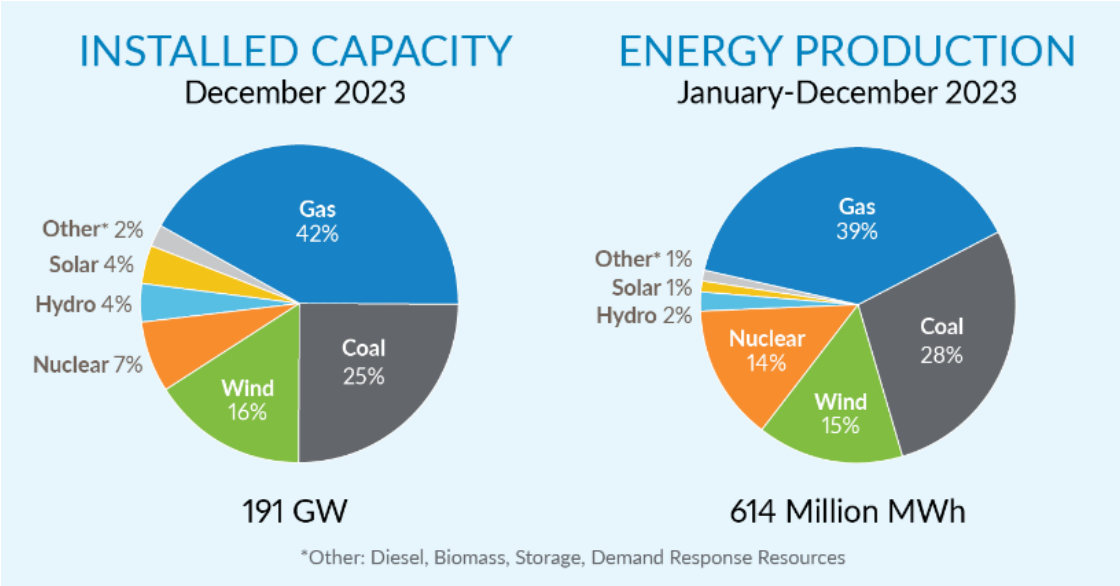




Currently, the MISO region contains nearly 77,000 miles of high-voltage transmission, as well as roughly 190,000 megawatts of electricity generating capacity. MISO does not own any of these assets. Instead, with the consent of our asset-owning members and in accordance with our FERC-approved tariff, MISO exercises functional control over the region’s transmission and generation resources with the aim of managing them in the most reliable and cost-effective manner possible. The MISO region is predominantly comprised of traditionally structured, state-regulated utilities.

KEY FACTS

Area Served	15 U.S. States and Manitoba, Canada
Population Served	45 Million
Transmission Line	77,000 Miles
Generating Units	2,956
Record Demand	127.1 GW 7/20/2011
Wind Peak	25.6 GW 1/12/2024
Solar Peak	6.2 GW 6/14/2024
Members	54 Transmission Owners 143 Non-transmission Owners
Market Participants	500+
Carbon Reduction	Approximately 32% since 2014



[Corporate data](#) as of September 2024



CHAPTER 1: TRANSMISSION PLANNING OVERVIEW

1.1 Transmission Evolution

The complex challenges of the electric system have been steadily materializing throughout the U.S. in recent years. Urgent and complex challenges in the MISO region and other areas of the country are driving the need for change in the way system operators plan and operate the grid. Widespread retirements of dispatchable resources, increasing load demand, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months and other times that rarely posed challenges in the past. This combination of economic, technological, policy-related and extreme weather factors are explained in MISO's Reliability Imperative Report. Drivers that significantly impact Transmission Evolution and Long Range Transmission Planning (LRTP) include the following:

Rapid and significant fleet change: Many utilities and states in the MISO region have adopted policies and goals to decarbonize their resource fleets and have made remarkable progress toward these efforts. Currently, about 75% of the region's total load is served by utilities that have ambitious decarbonization and/or renewable energy goals. Carbon emissions in MISO have already declined more than 32% since 2014, and far greater reductions are expected going forward.

Surging large load additions: Large spot power demand is growing rapidly because of significant growth in data centers and other energy-intensive facilities to support today's economy and the future of technologies like artificial intelligence, electrification and the resurgence of manufacturing in the United States. MISO has been calling these 'large load additions' in contrast to 'incremental load growth' as described below. The uncertainty about where and how many large load additions will be developed complicates MISO's ability to project long-term growth in planning.

Incremental load growth: While electricity demand has been flat for many years, it is expected to increase due to the electrification of other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial sectors are increasingly using electricity for heating and cooling. These trends will accelerate more due to the electrification tax credits in the 2022 Inflation Reduction Act for electric vehicles, rooftop solar systems and electric appliances. Electrification could transform the region's grid from a summer-peaking to a winter-peaking system and uncontrolled vehicle charging and daily heating and cooling load could result in two daily power peaks in nearly all months of the year.

Retirement of traditional resources: Economic conditions, state mandates and federal policies from authorities like the Environmental Protection Agency are quickly driving concerning amounts of dispatchable energy resources with critical reliability attributes into retirement, while also adding significant uncertainty to investment decisions in new resources — even when they're critically needed for reliability purposes.

Supply chain and permitting issues: Many projects that have been fully approved through MISO's Generator Interconnection Queue process are not going into service on schedule. The build out of renewable energy is being delayed and slowed due to supply chain (transmission and generation assets) and



permitting challenges that are global and outside of the control of MISO and utilities. A significant amount of approved resources signal delays to commercial operation as long as nearly two years.

Extreme weather events: While extreme weather has always been commonplace in the MISO region, severe weather events that impact electric reliability have been increasing. The Electric Power Research Institute (EPRI) found that hurricanes are increasing in intensity and duration, heat events are increasing in frequency and intensity and cold weather events are increasing in frequency.

Fuel assurance: The combination of declining dispatchable thermal resources, fuel insecurity, and growing intermittent resources create significant challenges to resource adequacy.

MISO, its members and states have a shared responsibility to address these challenges and ensure continued reliability. MISO is addressing this Reliability Imperative – the term it uses to describe this shared responsibility – through several interconnected and sequenced initiatives that are grouped into four key initiatives or pillars:

- **Market Redefinition:** Adapt our markets to ensure we are incenting the needed resources and attributes, appropriately valuing or accrediting those resources, and that prices reflect actual conditions at all times and incent availability.
- **System Enhancements:** The ongoing work to transform our Market System to meet increasingly complex requirements also falls under the Reliability Imperative.
- **Operations of the Future:** Examining needs across skills, processes, and technologies to ensure effective grid management in the face of that growing complexity.
- **Transmission Evolution:** Enhance planning process and identify solutions through long-term and interregional transmission planning that allow us to efficiently address both near and long-term system needs, including the optimal locations for generation to minimize the total cost between generation and transmission investment.

1.2 Planning Process

MISO as the FERC-approved regional transmission planner uses the MISO Transmission Expansion Plan (MTEP) to identify and support the development of cost-effective transmission infrastructure that is sufficiently robust to meet reliability needs, enable a competitive energy market, support policy goals and allow for competition among transmission developers in the assignment of transmission projects. MTEP is created through an inclusive, open process which provides opportunities for stakeholder participation and input. MISO also works with its stakeholders and Board of Directors to adopt MISO's Planning Guiding Principles (Figure 1.2-1), which are shaped by state and federal policy, stakeholder needs and cost efficiency goals.



Figure 1.2-1: MISO's Planning Guiding Principles.

Comprehensive Planning

These principles are enacted through MISO's value-based planning approach (Figure 1.2-2), which ensures local needs are integrated with regional requirements. Its processes consider a range of issues and viewpoints:

- For **local planning**, review and provide transparency on member plans, evaluate system against reliability standards, consider alternatives and verify needs as applicable.
- The long-term, broader system needs through MISO's **regional planning** processes, including its Long Range Transmission Planning efforts.
- The impact of policies on the transmission system and resource mix in **policy assessment**.
- System changes needed to accommodate new resources in **resource integration**.
- Planning issues shared with MISO neighbors in **interregional planning**.

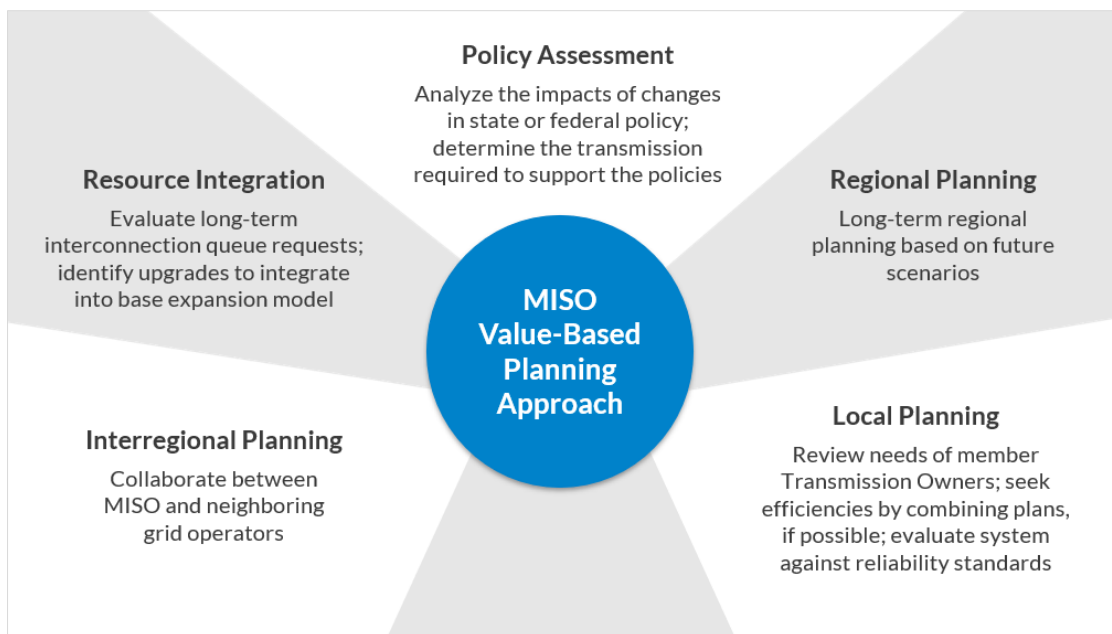


Figure 1.2-2: MISO's Value-Based Planning Approach.

MISO's various planning approaches cannot operate independently of each other. The goal of the transmission planning process is to identify a least-regrets outcome that meets its member plans, provides reliable power delivery, and appropriately balances local versus regional solutions to ensure a cost-effective outcome for customers. MISO's comprehensive planning process spans short- to long-term horizons depending on study objectives and need drivers. The process encompasses multiple planning functions that address different timelines and aspects of transmission and resource planning. Each process informs the others to cover the entire planning horizon.

Using this comprehensive planning approach, the MTEP Report is structured into three main planning areas: local, regional and interregional. Local reliability planning, sometimes referred to as near-term planning, is highlighted in Chapter 4. Regional, or long range transmission planning, is covered in Chapter 2 and primarily focuses on the Long Range Transmission Planning (LRTP) Tranche 2.1. Finally, interregional planning is highlighted in Chapter 3 and is mainly focused on the Joint Targeted Interconnection Queue (JTIQ) study.

Transmission Planning & Coordinated Process

MISO develops MTEP based on expected use patterns and analysis of the performance of the transmission system in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions. MISO uses both a near-term and long-term planning horizon in its processes with the near-term planning horizon (i.e., less than 10 years) mainly focused on local reliability planning, while the long-term planning horizon (i.e., up to 20 years) is focused on broader regional planning. This recommended plan is then subjected to stakeholder scrutiny and feedback to refine it further before it is eventually presented to the MISO Board of Directors ("MISO Board") for review and approval.

MISO strategically set up our local planning processes to assume FERC Order 890 transparency requirements for Transmission Owner submissions, with MISO's role ranging from alternative assessment, need validation, no-harm tests and/or transparency depending on the project submissions. MISO's



transmission planning rules are set forth in Attachment FF of the Tariff, which contains MISO’s transmission expansion planning protocol, and Appendix B of the MISO Agreement, which contains MISO’s planning framework. In addition, MISO maintains a Business Practices Manual (“BPM”) that covers the transmission expansion planning processes, which is known as BPM-020, including the study approaches applied by MISO. Finally, some of MISO’s local planning approach is driven by North American Electric Reliability Corporation (NERC) reliability standards and reliability standards adopted by Regional Reliability Organizations integrated as part of MISO’s role as a Planning Coordinator.

Project Input and Stakeholder Coordination

The planning process, in conjunction with an inclusive, transparent stakeholder process, must identify and support development of a sufficiently robust transmission infrastructure to meet local and regional reliability standards as well as enable competition among wholesale capacity and energy suppliers. Each planning cycle commences with developing models (see Figure 1.2-3 for MISO footprint planning regions) followed by identifying potential expansions from the local planning processes of the Transmission Owners; transmission issues driven by reliability (e.g., NERC criteria), economic, and public policy requirements; and potential expansions (from stakeholders or MISO) that address transmission issues. Each cycle concludes with recommendations of solutions to the MISO Board of Directors.

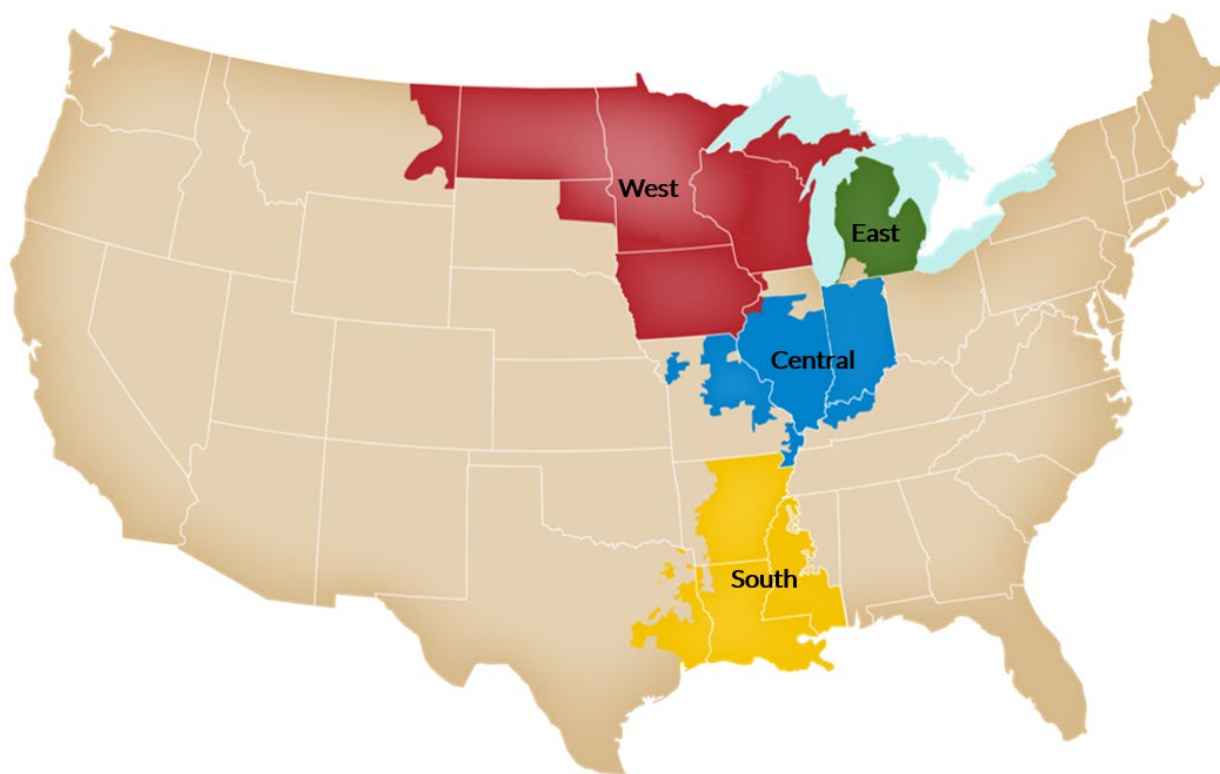


Figure 1.2-3: MISO footprint planning regions.

Transmission Owner plans developed through local planning processes are included in the beginning of each regional planning cycle as potential solutions to local transmission issues identified by the Transmission Owners to meet the FERC Order 890 transparency requirements.

MISO’s regional planning process makes evaluations – with stakeholder input from Subregional Planning Meetings, the Planning Subcommittee and the Planning Advisory Committee – throughout the cycle to



develop expansion plans to meet the needs of the system. This collaborative process allows analysis of all projects with regional and interregional impact for their combined effects on the Transmission System. Moreover, the design of this collaborative process ensures that the MTEP addresses transmission issues within the applicable planning horizon in an efficient and cost-effective manner, while considering the input of stakeholders.

These various planning functions occur at different times and begin the year before an MTEP report is finalized (see Figure 1.2-4). For example, assessments of generator interconnection and retirements occur on a continuous basis. Others repeat on a regular cycle, but the actual MTEP report is produced once every 12 months. Each MTEP cycle's scope definition actually begins in the summer of the prior year. The months of in-depth research and analysis, combined with many interactions between various work streams and stakeholders culminates in Appendix A.

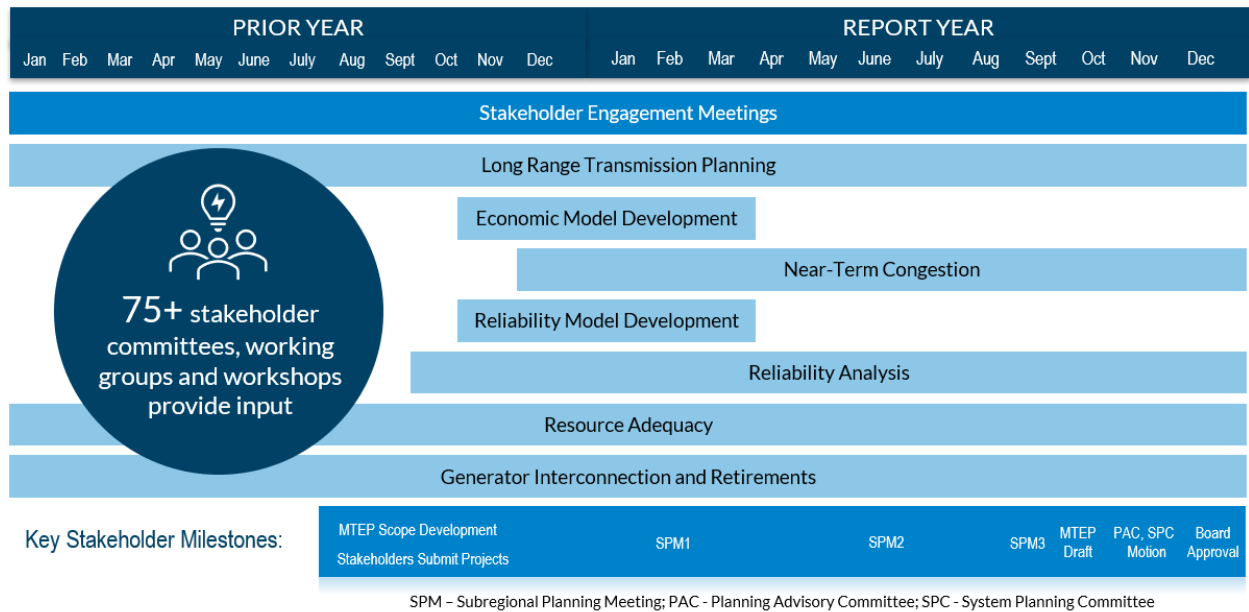


Figure 1.2-4: Typical MTEP cycle is developed in overlapping cycles and delivered annually.

Planning Analysis Methods

Planning analyses performed by MISO test the transmission system under a wide variety of conditions using standard industry applications to model key items, such as steady state power flow, voltage stability, and economic parameters, as determined appropriate by MISO to be compliant with applicable criteria and the Tariff. MISO collaborates with Transmission Owners, other transmission providers, transmission customers, and other stakeholders to develop appropriate planning models that reflect expected system conditions for the planning horizon. The local reliability planning process relies on known and committed inputs into the process, while the long-term planning process considers projected inputs (Figure 1.2-5).



Figure. 1.2-5: Summary of inputs into reliability and long-term planning processes.

[Models](#) are available to stakeholders with security measures as provided for in the Transmission Planning Business Practices Manual. MISO provides the opportunity for stakeholders to review and comment on the posted models before commencing planning studies.

MISO’s review of projects varies depending on project drivers, system needs, opportunities for alternatives, and other factors. Specific to local planning, MISO may verify the need, complete a no-harm analysis, or post information for stakeholders.

- **Verify need:** Confirmation of system need identified in project submission, including to meet compliance with applicable National Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. MISO must verify the need for alternatives to adequately examine their effectiveness.
- **No harm:** Ensure a submitted project does not create a system issue. Includes projects that create model changes like contingency definitions, line ratings, or line impedances.
- **Post only:** Provided for FERC Order 890 transparency provisions. May include controls equipment to communicate remotely with the facility. This information is not able to be represented with model changes.

Additionally, alternative assessments for projects may be completed by Transmission Owners prior to project submission to MISO, proposed by MISO, or proposed through stakeholder submissions. Some of the criteria to select an alternative considers cost comparisons, difficulty with local, state and federal permitting or challenges due to the terrain of the proposed transmission right of way and how reliability needs are resolved. Alternatives do not always result in one project replacing another, but instead tend to be additive to the original project, even when submitted with the thought that they would directly compete. MISO considers alternatives in multiple forms, including like-for-like replacement, regional reliability projects, the



combination of multiple local solutions, and other options identified through either MISO analysis or submitted by stakeholders.

Long Range Transmission Planning

Long Range Transmission Planning (LRTP) is an essential element of planning the regional grid to be reliable and efficient with a focus on the long-term (i.e., 20 years) planning horizon. LRTP efforts are launched periodically when needed to address significant changes to future conditions that the grid must be prepared to address. Long Range Transmission Planning results in projects that are regional backbone facilities needed to move bulk power between geographically dispersed areas within MISO. While they provide for a reliable and efficient grid based on forecasted resource developments, they are not intended to resolve all connection issues associated with precise siting of future generation or load.

Long Range Transmission Planning follows MISO's well-established seven-step value-based planning process and is part of MISO's overall MTEP process. Outlined below are the high-level descriptions of each step:

- 1 **Develop Future Scenarios** – develop scenario-based Futures with resource forecast and siting
- 2 **Develop Resource Plan and Site Future Resources** – development of planning models utilizing Futures
- 3 **Identify Transmission Issues** – identify potential transmission issues
- 4 **Integrated Transmission Development** – proposals for solutions to issues
- 5 **Transmission Solution Evaluation** – evaluate the effectiveness of various solutions
- 6 **Project Recommendation and Justification** – recommend preferred solutions for MTEP implementation
- 7 **Project Cost Allocation** – apply appropriate cost allocation

MISO is working to identify potential grid needs in support of the resource and load transformation underway and as contemplated under our members' resource plans and defined in the MISO Futures. This extensive stakeholder process includes regularly scheduled workshops and periodic discussions at the Planning Advisory Committee. Project recommendations resulting from this process will be presented for Board of Director review and approval over several MTEP cycles as analyses proceed and recommendations are developed.

Details of MISO's Long Range Transmission Planning Tranche 2.1 are summarized in Section 2.1.

Project Types and Approval

MTEP Appendix A projects are vetted by MISO through the planning process and project types are determined by criteria in MISO's Tariff. Below is an overview of Tariff-defined project types¹:

- **Baseline Reliability Project (BRP)** - Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable North American Electric

¹ Additional details on project types are in Section 2.3.1 of the Business Practice Manual.



Reliability Corporation reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. Baseline Reliability Project costs are allocated to the local Transmission Pricing Zone(s) and recovered through Attachment O by the Transmission Owner(s) developing the projects.

- **Generator Interconnection Project (GIP)** - Projects are New Transmission Access Projects that are associated with interconnection of new generation or the capacity modification of existing generation. Costs are primarily paid for by the interconnection customers with certain exceptions as specified in Attachment FF. Costs of network upgrades rated at 345 kV and above are eligible for 10 percent cost recovery from load on a system-wide basis.
- **Market Efficiency Project (MEP)** - Projects meet Attachment FF requirements for reduction in market congestion and are eligible for regional cost allocation. Projects qualify as Market Efficiency Projects based on cost and voltage thresholds and are developed to produce a benefit-to-cost ratio of 1.25 or greater. Costs are distributed to benefiting pricing zones, in accordance with Attachment FF of the Tariff.
- **Market Participant Funded Project (MPFP)** - Projects are defined as Network Upgrades fully funded by one or more market participants but owned and operated by a Transmission Owner.
- **Multi-Value Project (MVP)** - Projects meet Attachment FF requirements to provide regional or subregional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to energy withdrawals or export schedules. One example of this type of project is the LRTP Tranche 2.1 portfolio.
- **Other** - Projects to address local reliability issues and/or provide local economic benefit, which do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Multi-Value Projects. Project costs are allocated to the local Transmission Pricing Zone(s) and recovered through Attachment O by the Transmission Owner(s) developing the projects.
- **Targeted Market Efficiency Project (TMEP)** - Projects are designed to alleviate historical market-to-market congestion between MISO and PJM Interconnection, while meeting certain cost and construction requirements. The costs of Targeted Market Efficiency Projects are allocated first between MISO and PJM Interconnection by the ratio of each RTO's Day-Ahead and Excess Congestion Fund congestion, offset by historical market-to-market payments. The MISO share of costs for the project is then allocated to beneficiaries using historical nodal load congestion contribution data.
- **Transmission Delivery Service Project (TDSP)** - Projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.

MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval after all projects have been posted for transparency, MISO has completed its independent review of proposed projects for need or no-harm as applicable, and staff has addressed any stakeholder feedback received. These projects make up Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs of the MISO transmission planning process.



Interregional Coordination and Planning Studies

MISO works with the neighboring transmission planning regions, Southwest Power Pool (SPP) and PJM Interconnection (PJM), to identify issues on the seams, perform studies, and jointly evaluate transmission solutions that may be more efficient or cost effective than a corresponding regional solution. While MISO has a separate Joint Operating Agreement (JOA) with both SPP and PJM that details specific processes and criteria, the high-level interregional coordination activities are similar on each seam:

- 1) Exchange modeling data and other system information.
- 2) Review identified historic issues or propose reliability, economic, or transfers analysis to determine forward-looking issues on the seam.
- 3) Evaluate whether to perform an interregional study based on historic or forward-looking issues.

MISO performs joint studies with SPP and PJM on a regular basis, in accordance with the timelines and frequencies dictated in their respective JOAs, or as needed. Studies may have a targeted scope or a more complex scope requiring a longer study period, and can include reliability, economic and/or public policy issues along with analysis of interregional transfer capability and extreme weather events. Interregional issues and study efforts are coordinated through a public Interregional Planning Stakeholder Advisory Committee (IPSAC) consisting of representatives and interested parties from each RTO community.

In addition to the joint study efforts with SPP and PJM, MISO performs studies, as needed, with neighboring entities of the Southeastern Regional Transmission Planning (SERTP) group and the Independent Electricity System Operator of Ontario (IESO). While the study process is less formal, MISO and these entities still meet regularly to review interregional issues and possible areas of collaboration.

Details on planning procedures, on-going studies and stakeholder meetings can be found on the [Interregional Coordination](#) page of the MISO public website (misoenergy.org).

MTEP Portal

In late 2023, MISO launched a new MTEP Project Portal through the Help Center. The MTEP Portal provides a robust, user-friendly experience that supports the submission and management of MTEP projects throughout their lifecycle while enabling the integration capabilities for future MISO technologies. Within the MTEP Portal, users can use interactive dashboards to view projects based on various filters (Figure 1.2-6). Because this report is simply a snapshot of project information as of August 27, 2024 (or other date as listed), the [MTEP Portal](#) has the most up-to-date project information.

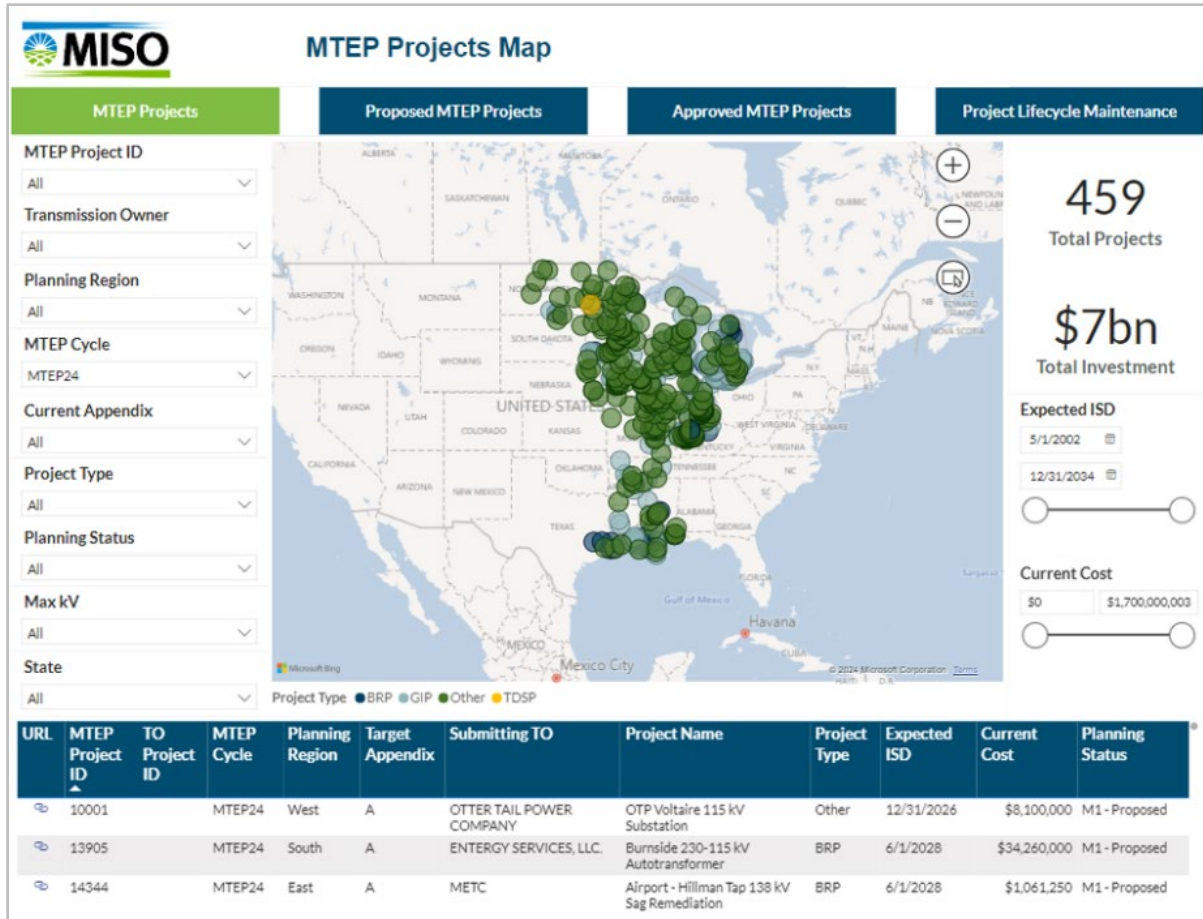


Figure. 1.2-6: Views within the MTEP Portal and the various dashboards reflecting project information.

1.3 Historical Background

MISO Transmission Infrastructure Investment

This iteration of the MTEP report highlights MISO’s transmission investment over a 20-year span totaling over \$67 billion in the United States (Figure 1.3-1). MISO’s proposed new projects for this MTEP cycle would add an additional estimated \$30 billion and are detailed in Chapters 2, 3 and 4 and included in Appendix A of this report.

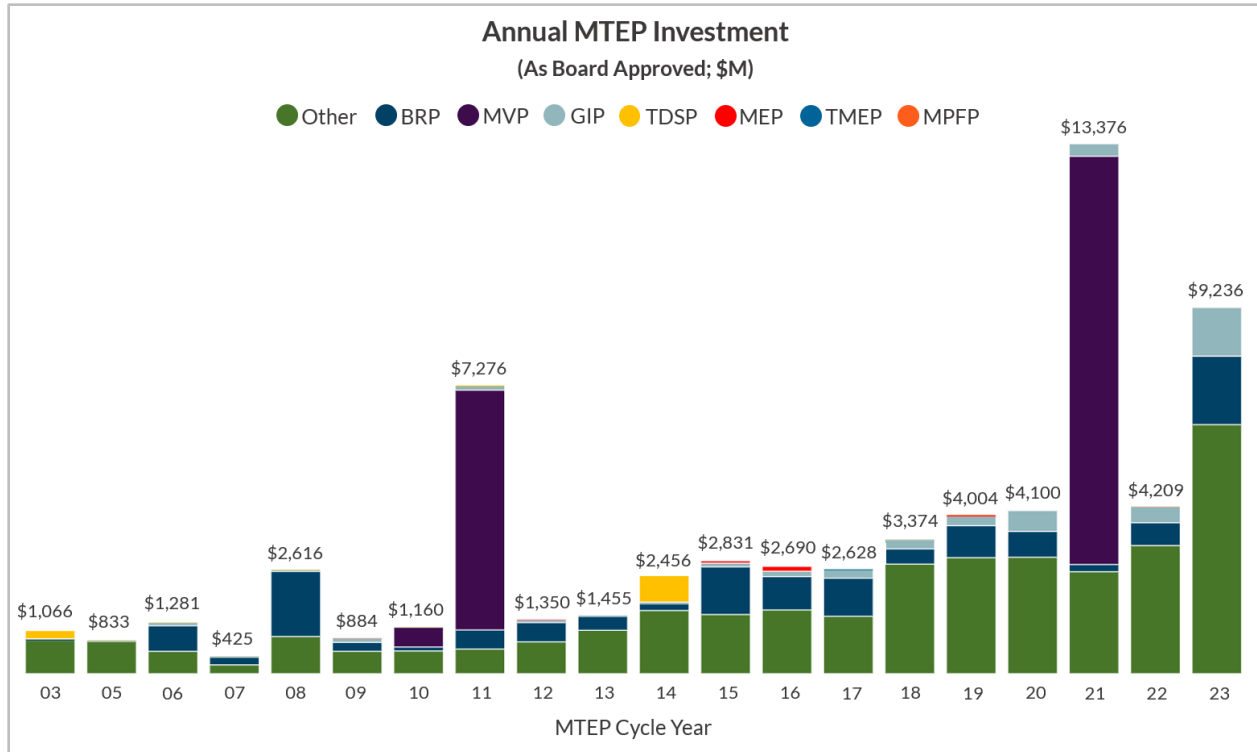


Figure 1.3-1: MTEP annual investment.

Highlights in prior MTEP cycles include:

- MTEP11 reflects the approval of the first Multi-Value Project portfolio
- MTEP14 reflects the addition of the MISO South region
- MTEP21 reflects the MTEP21 Addendum approval of the LRTP Tranche 1 portfolio, which accounts for \$10.3 billion of the total
- MTEP23 reflects the largest MTEP in MISO history by both project count and investment, excluding MTEP21 which included Multi-Value Projects/LRTP portfolio

MISO’s transmission planning responsibilities include the monitoring of previously approved Appendix A projects. MISO surveys all Transmission Owners and Selected Developers every quarter to determine the progress of each project. These [status updates](#) are reported to the MISO Board of Directors and posted quarterly to the public MISO Transmission Expansion Plan website.

Full archived files of [previous MTEP Reports](#) can be accessed via the public MISO Transmission Expansion Plan website.

MTEP Approved Projects Status

Since MTEP03, over \$39 billion of investment has gone into service and over \$28 billion of approved projects are yet to be fully placed into service (Figure 1.3-2). Most notably this includes the MTEP11 MVP project that recently went into service.

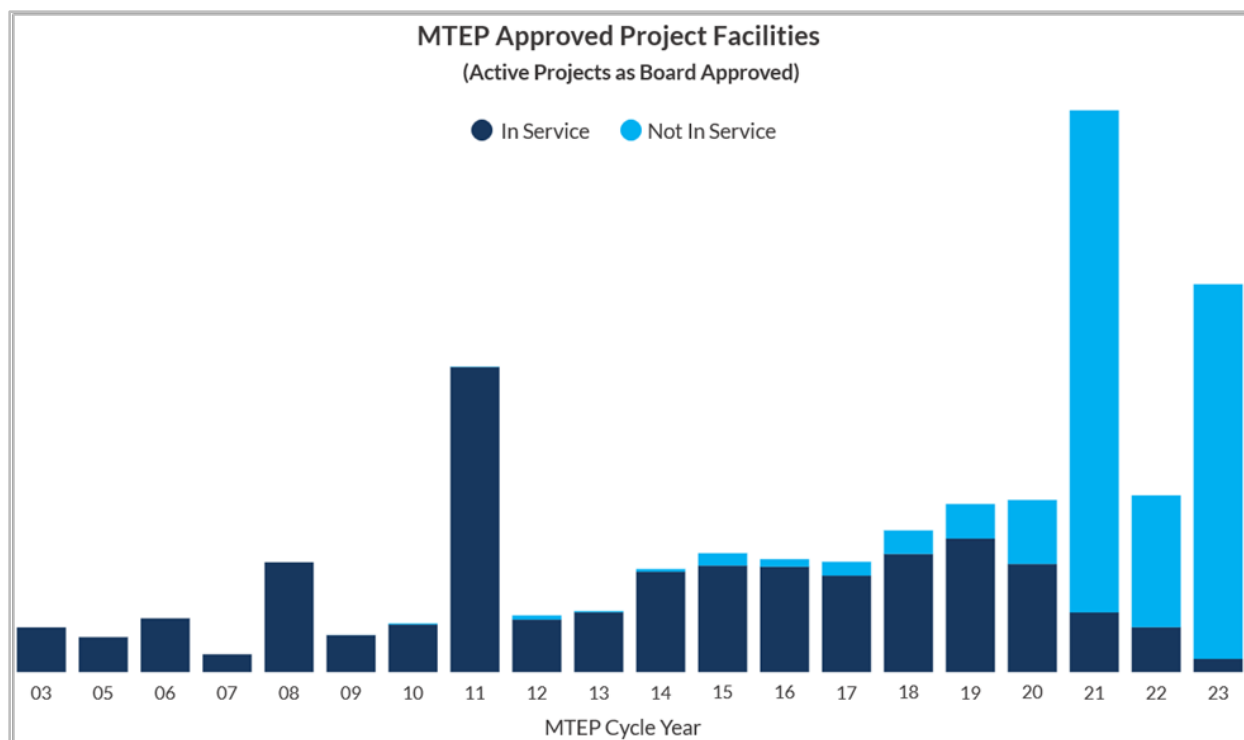


Figure 1.3-2: Appendix A project status .

L RTP Investment Update – Tranche 1

The \$13.4 billion investment in MTEP21 as shown above was the result of MISO’s approval of Tranche 1 of its Long Range Transmission Planning study. The Tranche 1 portfolio, approved in July 2022, consists of 18 projects totaling \$10.3 billion which are spread across the entire MISO Midwest Subregion and benefits multiple states, MISO members and customers. Table 1.3-1 reflects those 18 approved projects as of July 2024. Planning for Tranche 1 began in 2020 with the development of new Futures that reflected policy changes and the plans of states, utilities, and members. Tranche 1 solutions addressed approximately 30% of issues that were identified. Analysis was based on Future 1 and a Multi-Value Project (MVP) cost allocation approach will spread the costs of projects pro-rata to load across the MISO North and Central regions (Midwest Subregion). A wide range of value will be provided, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

The Tranche 1 projects are grouped by and located in five geographic focus areas: Dakotas and Western Minnesota, Minnesota – Wisconsin, Central Iowa, Northern Missouri Corridor and Central-East Corridor. With a Tariff requirement to provide benefits that are commensurate with costs, the full portfolio has a benefit-to-cost ratio of 2.6 - 3.8, which is well in excess of costs, and a benefit-to-cost ratio of at least 2.1 for every MISO zone. MISO’s planning maximized the use of existing rights-of-way, which helped reduce the typical challenges in the regulatory process stemming from siting and acquisition of new rights-of-way.

As of July 2024, all projects are well into regulatory approval processes with MISO supporting developers in these efforts. Going forward, as engineering and construction plans are finalized and applicable regulatory proceedings complete, MISO anticipates receiving more substantive quarterly project updates from the



constructing Transmission Owners, including updates on project cost and in-service dates. Transmission Owners will continue to provide quarterly project updates until the project is placed into service.

LRTP Eligible Project Status dashboard									
LRTP No.	Project Name	State	Estimated in Service Date (as of 6/30/2024)		Status (as of 10/3/2024)		Cost (as of 6/30/2024)		Explanation
			MTEP Approved	Current Date	State Regulatory Status*	Construction Status	MTEP Approved (\$M)	Current Cost (\$M)	
1	Jamestown – Ellendale	ND	2028	unchanged			\$439	\$439	
2	Big Stone South – Alexandria – Big Oaks (Cassie’s Crossing)	SD/MN	2030	unchanged			\$574	\$574	
3	Iron Range – Benton County – Big Oaks (Cassie’s Crossing)	MN	2030	unchanged			\$970	\$970	
4	Wilmarth – North Rochester – Tremval	MN/WI	2028	unchanged			\$689	\$685	
5	Tremval – Eau Claire – Jump River	WI	2028	unchanged			\$505	\$505	
6	Tremval – Rocky Run – Columbia	WI	2029	unchanged			\$1,050	\$1,050	
7	Webster – Franklin – Marshalltown – Morgan Valley	IA	2028	unchanged			\$755	\$755	
8	Beverly – Sub 92	IA	2028	unchanged			\$231	\$231	
9	Orient – Denny – Fairport	IA/MO	2030	unchanged			\$390	\$318	
10	Denny – Zachary – Thomas Hill – Maywood	MO	2030	unchanged			\$769	\$511	
11	Maywood – Meredosia	MO/IL	2028	unchanged			\$301	\$301	
12	Madison – Ottumwa – Skunk River	IA	2029	unchanged			\$673	\$673	
13	Skunk River – Ipava	IA/IL	2029	unchanged			\$594	\$592	
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	IL	2028	unchanged			\$572	\$572	
15	Sidney – Paxton East – Gilman South – Morrison Ditch	IL	2029	unchanged			\$454	\$516	
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	IL/IN	2029	unchanged			\$261	\$675	Cost change under review with Variance Analysis
17	Hiple – Duck Lake	IN/MI	2030	unchanged			\$696	\$520	
18	Oneida – Nelson Rd.	MI	2029	unchanged			\$403	\$403	
Total							\$10,324	\$10,288	

State Regulatory & Construction Status Indicator Scale	State Regulatory	Construction
	Pending <input type="checkbox"/>	Not <input type="checkbox"/>
	In regulatory process or partially complete <input type="checkbox"/>	Under construction <input type="checkbox"/>
Complete or no regulatory process requirements <input type="checkbox"/>	Completed <input type="checkbox"/>	

*State Regulatory Status is for Certificate of Need Approvals

Table 1.3-1: LRTP Tranche 1 approved project status dashboard as of July 2024.

Future Line Miles Appendix A Projects

Spanning from 2024-2031, there are approximately 6,230 circuit-miles of planned new or upgraded transmission lines projected in Appendix A (Figure 1.3-3).

- 3,790 circuit-miles of upgraded transmission line on existing corridors are planned of which 58% are ≤230 kV and 42% are ≥345 kV.
- 2,440 circuit-miles of new transmission line on new corridors are planned of which 40% are ≤230 kV and 60% are ≥345 kV.

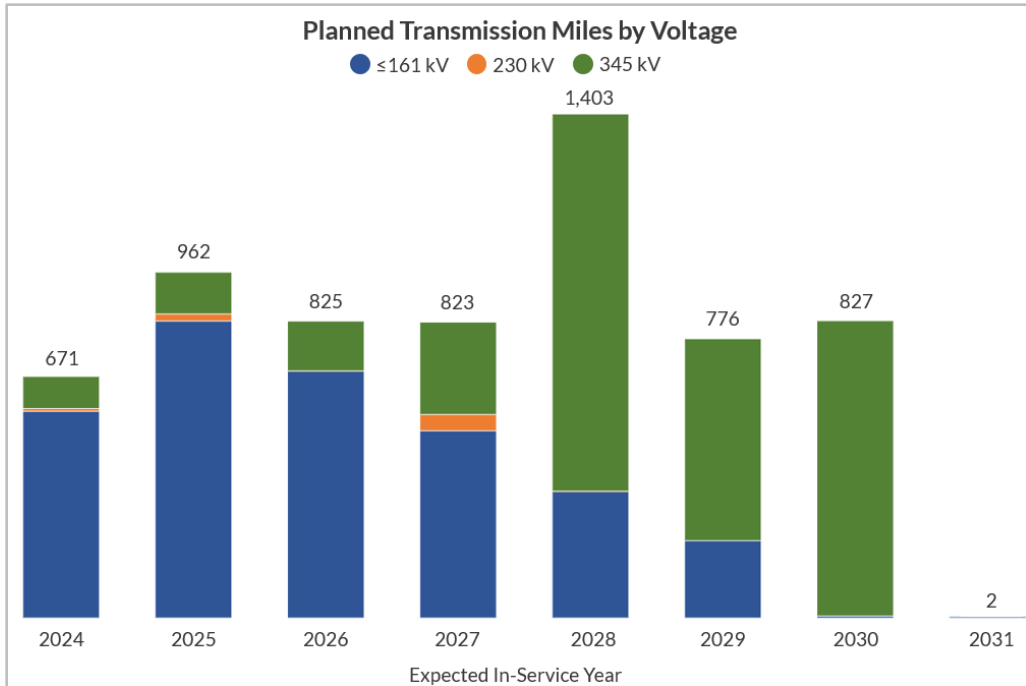


Figure 1.3-3: Active, not yet in-service, project circuit line miles by voltage and expected in-service year.

Existing Line Miles Summary

MISO has nearly 77,000 circuit-miles of transferred functional control transmission lines serving as the backbone of the footprint (Figure 1.3-4) in the United States. Currently, the West region holds 45% of total footprint line miles, the South region holds 22%, the Central region holds 21%, and the East holds 12%.

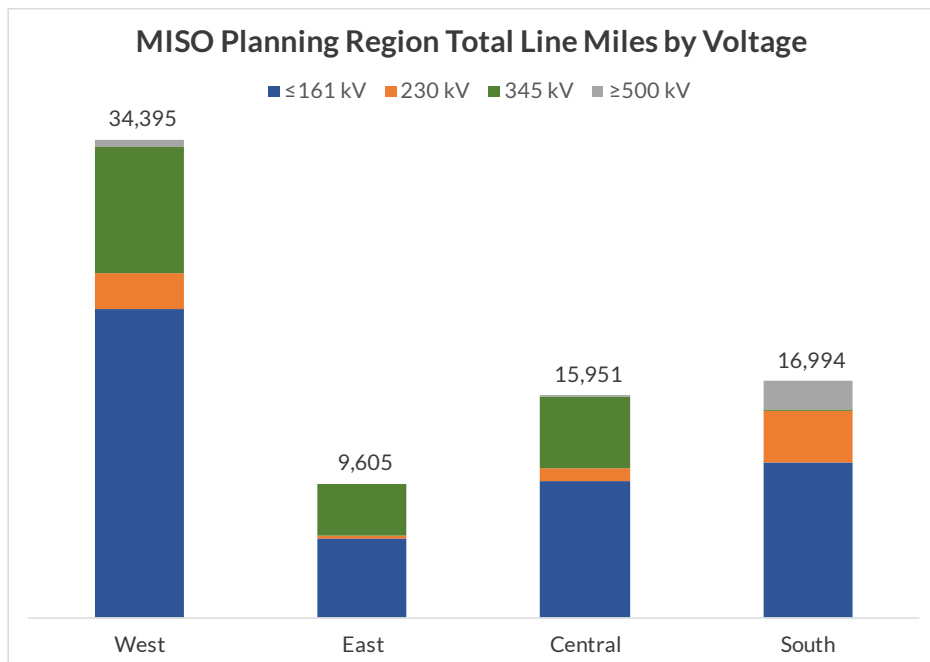


Figure 1.3-4: 2023 in-service transferred circuit miles by voltage class.



Transmission Facility Investment

In the early MTEP cycles, the predominant investment was in new line assets. There was a shift in investment in recent cycles with the leading investments being in substation. Looking back in total (MTEP03-MTEP23), Figure 1.3-5 below reflects the current asset investments with new lines at 43%, line upgrades at 29%, and substations representing 28% of the total investment.

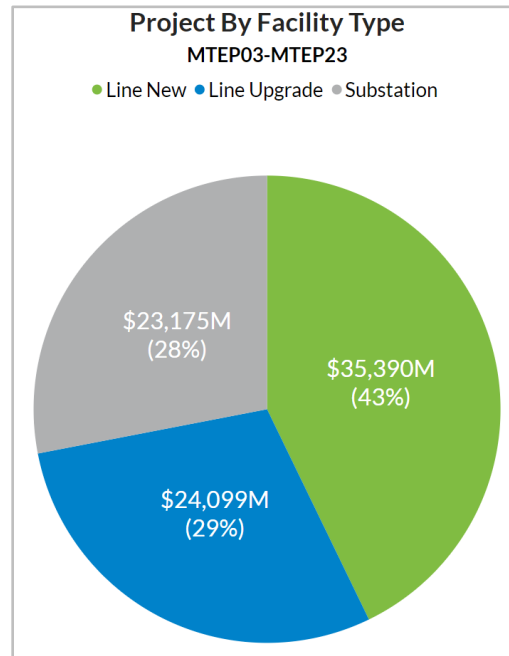


Figure 1.3-5: Appendix A project facility investment dollars in all MTEP historical cycles.

Historical MISO Queue Trend

The MISO Generator Interconnection (GI) queue provides an active and competitive mechanism to enable resource interconnections that will serve future energy and capacity needs. Projects submitted in the annual queue cycle are evaluated by MISO through an iterative study process to determine the reliability impacts and to identify transmission upgrades needed to support resource integration. Project viability is often tied to the costs of network upgrades, with the most viable candidates successfully executing a Generator Interconnection Agreement (GIA).

The Generator Interconnection queue has experienced extremely high volume over the last several years (see Figure 2.4-1). These high volumes create study cycles with more requests than MISO has load, resulting in significant delays in completing these cycles. As cycle sizes have increased, so has the time required to complete the studies. These delays can impact the ability of our utilities and states to meet their resource adequacy needs. In the 2023 Study Cycle, MISO received 600 individual project requests totaling roughly 124 GW. Solar, storage, and hybrid applications make up the bulk of the queue. Additionally, as of September 2024, the current state of the queue had 1,743 projects representing 317 GW of total capacity (see Figure 2.4-2). This rising volume of requests has resulted in MISO's need to implement a cap on the number of requests studied at one time and the need for new processes to study projects specifically identified to address resource adequacy. A cap will result in less overloads, which will result in faster processing, lower interconnection costs, and therefore less dropouts.

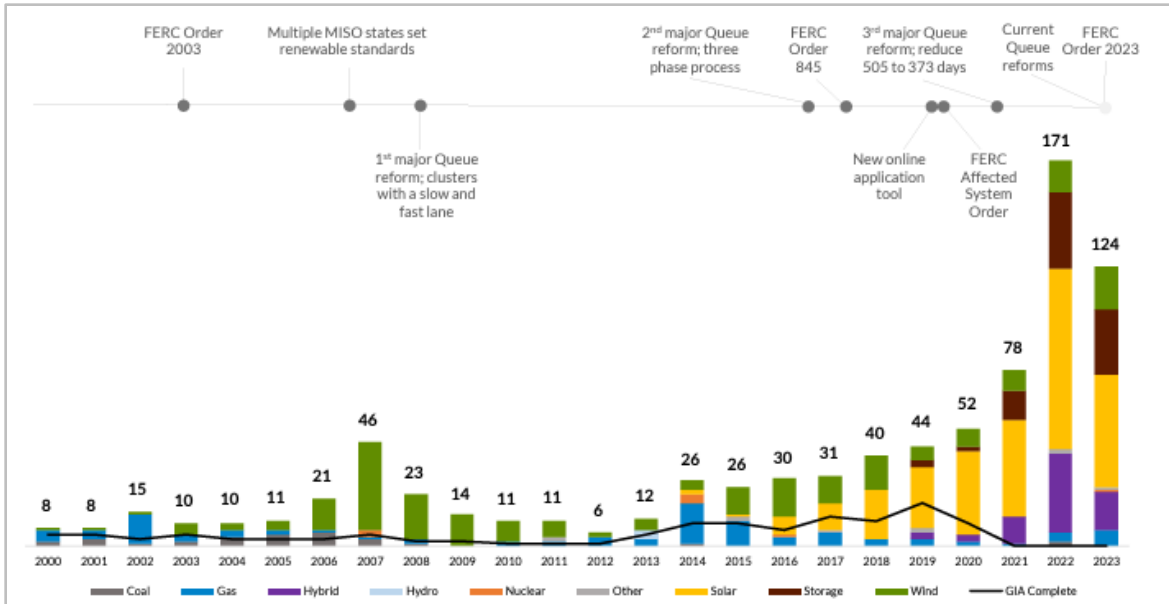


Figure 2.4-1: Historical view of MISO's Generator Interconnection Queue. Values are displayed in GW.

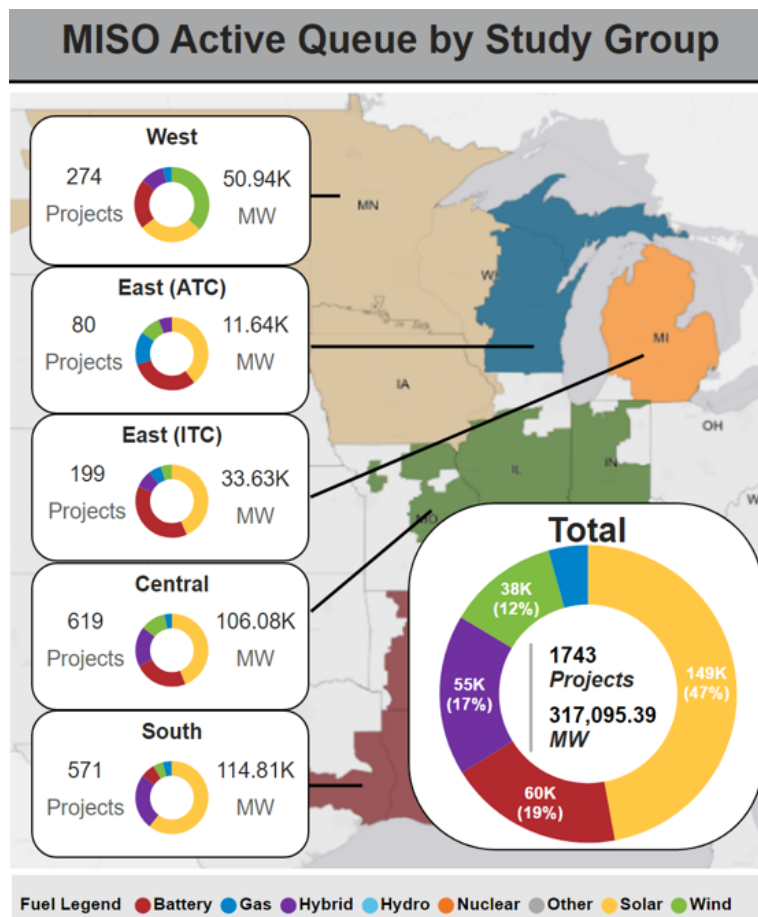


Figure 2.4-2: As of September 2024, the queue consists of 1,743 projects representing 317 GW of total capacity.



Chapter 2: Regional / Long Range Transmission Planning

2.1 Overview

Under the Reliability Imperative’s Transmission Evolution pillar, MISO is transforming how it plans for and manages the grid of the future, given all the complex changes underway. As part of this effort, Long Range Transmission Planning (LRTP) develops backbone regional projects to ensure the transmission system is reliable, economic and compliant in the future based on state and utility policy and goals, projected conditions and industry trends. This is accomplished while demonstrating the transmission portfolio provides benefits in excess of costs and value that is consistent with MISO’s Tariff criteria. LRTP tackles needs and issues that are not easily addressed in cyclical planning processes like MISO’s MTEP, which focuses on more near-term needs. Instead, it looks at a long-range (roughly 20- to 40-year) view of the system and provides a roadmap or vision to address those future issues, while also guiding near-term transmission planning.

From a transmission planning perspective, LRTP looks comprehensively at the MISO region in collaboration with stakeholders. While its resulting portfolios enable a reliable and efficient grid based on forecasted resources, they are not intended to resolve every issue associated with precise siting of future generation or load. As a result, LRTP portfolios are “least-regrets” to plan for an uncertain future based on the needs reflected in policy and member plans that are current at the time of modeling and analysis.

The overall LRTP effort is large and complex, unlike any effort MISO or any other organization has undertaken in the history of the grid. It takes a long time to plan for comprehensive regional solutions, especially when managing against a great deal of uncertainty. Additionally, LRTP has to be conducted over the course of rapid evolution as business plans, federal and state energy/environmental policies and other dynamic factors that affect the region’s transmission needs continually change.

Tariff Requirements

Categorized as Multi-Value Projects (MVPs) under MISO’s tariff, LRTP solutions must meet the following requirements: enable the transmission system to deliver energy reliably and economically, in support of documented energy policy mandates or laws; provide multiple types of economic value with a benefit-to-cost ratio of 1.0 or greater; or address at least one reliability issue and provide at least one type of transmission-based economic value. Additionally, an MVP cost allocation methodology must be applied—one that spreads costs footprint-wide on a load-ratio share basis, or spreads costs to a subregion only if benefits are primarily provided to that single subregion.



History

Long-term transmission planning was not new to MISO when LRTP launched in 2020. MISO's initial regional, long-term study began in 2008 to address the integration of renewable energy required by state Renewable Portfolio Standards. It resulted in the Multi-Value Project (MVP) portfolio of projects, which was approved in 2011 and fully constructed by 2024.

In 2019-2020, MISO began to formulate a strategy for LRTP. After cities, states, large commercial and industrial corporations and utilities started setting aggressive renewable and decarbonization goals, MISO members asked MISO to quickly move on long range transmission planning to align with their goals, preferences and investment decisions. In its own studies, like the Renewable Integration Impact Assessment (RIIA), MISO gained insight on significant system issues which would result from the continuing transition of the resource portfolio towards much higher weather-based renewable resources. Paramount to RIIA's findings was the fact that greater penetrations of renewable resources required new transmission to ensure system reliability. Additionally, the transfer capability realized because of this transmission buildout would provide better regional connectivity and thereby reduce the amount of generation capacity that would be needed to meet resource goals.

The job of LRTP is to enable a reliable generation fleet as planned by MISO Members and states. Based on RIIA and the Futures which had been recently updated, MISO knew the industry drivers and high level issues which informed the development of a conceptual, indicative roadmap (see Figure 2.1: Indicative Roadmap). Among other things, the roadmap is an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures. It was contemplated by MISO planning staff as an extension of the existing grid that could provide logical connections that increase connectivity, close gaps between subregions and support a more resilient grid by enabling more transfers of bulk power flows. The roadmap is not a plan, but provides a basis to guide conversations and consider solutions to expected transmission issues. Although solutions in the roadmap may not ultimately meet the necessary requirements to become projects in MTEP Appendix A, the roadmap provided and continues to provide a foundation from which to work.

Because of the magnitude of the needs and the study efforts required to determine solutions, MISO is approaching this large endeavor in tranches, beginning with a focus on the Midwest for Tranches 1, 2.1 and 2.2, moving later to the South region in Tranche 3 and the Midwest-South connection in Tranche 4. In its initial plan, MISO envisioned two tranches for the Midwest but during Tranche 2 planning, recognized the needs of the Midwest should be addressed in three phases. As a result, Tranche 2 was renamed 2.1 and Tranche 2.2 was added.

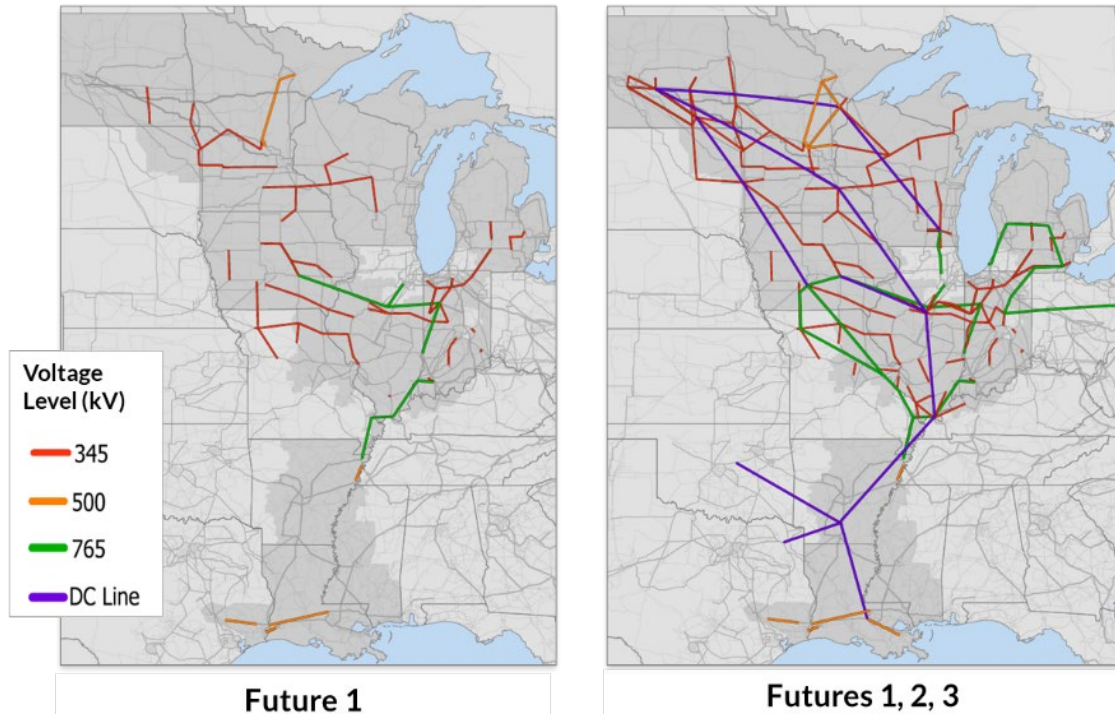


Figure 2.1: Indicative Roadmap

Tranche 1

Approved in July 2022 as part of MTEP21 Appendix A, the Tranche 1 portfolio totals \$10.3 billion, consists of 18 projects spread across the entire MISO Midwest subregion and benefits multiple states, MISO members and customers. Planning for Tranche 1 began in 2020 following the development of new Futures Series 1 that reflected policy changes and the plans of states, utilities, and members. Tranche 1 solutions addressed approximately 30% of issues that were identified. Analysis was based on Future 1 and a Multi-Value Project (MVP) cost allocation approach will spread the costs of projects pro-rata to load across the MISO West, Central and East regions (Midwest subregion). A wide range of value will be provided, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

With a Tariff requirement to provide benefits that are commensurate with costs, the full portfolio has a benefit-to-cost ratio of 2.6 - 3.8, which is well in excess of costs, and a benefit-to-cost ratio of at least 2.1 for every MISO zone. MISO's planning maximized the use of existing rights-of-way, which helped reduce the typical challenges in the regulatory process stemming from siting and acquisition of new rights-of-way.

As of July 2024, many projects are well into regulatory approval processes, with MISO supporting constructing Transmission Owners in these efforts. MISO will monitor the status of these projects through the build phase and utilize its variance analysis process to deal with any costs or schedule changes that exceed certain, established criteria, and other project scope or construction challenges that could put at risk getting the projects in service.



2.2 The Planning Process

The magnitude of change planned for the future is now more significant than it was just a few years ago when MISO developed Tranche 1. It requires prompt action to address the fast pace of transformation occurring in the industry. To ensure MISO identifies a robust set of projects that most effectively and efficiently resolve the identified issues and future system needs, a rigorous analysis by MISO with stakeholder engagement was conducted.

For Tranche 2.1, MISO followed its iterative seven-step process to build models, identify issues and test potential solutions, with over 40,000 staff hours invested in the study. Stakeholders were engaged in the process, with more than 300 meetings in various formats and forums, numerous one-on-one discussions, email exchanges and more. A reliability study whitepaper, economic study whitepaper, business case analysis whitepaper, models, scenarios and all key data inputs and analysis results were posted and reviewed by stakeholders. Additionally, formal and informal feedback was received and considered throughout the process, and appropriate updates were implemented based on feedback.

Models focused on Future 2A from the 1A series represented credible system conditions with likely and possible dispatch patterns determined following a data-driven process. Steady state, transfer and transient stability analyses were performed to ensure transmission system performance is reliable and adequate before and after contingencies (disturbances) occur. Economic analyses² were performed to evaluate congestion, generation curtailment, regional price separation and overall costs to serve load and to understand the impacts to overall Adjusted Production Cost savings.

To consider opportunities with existing and emerging technologies, MISO reviewed impacts of transmission technology concepts with stakeholders at the Planning Advisory Committee in 2023, discussing 345 kV, 765 kV, High Voltage Direct Current (HVDC) and Grid Enhancing Technologies (GETs). This presentation focused on high-level approaches with technology considerations and the potential impact of thermal and absolute limits, given factors like MW per mile cost and loading limits. For many of the new transmission line needs identified in LRTP Tranche 2.1, the necessary line mileages and power transfer requirements suggested that a 765 kV backbone would be the optimal choice at this stage. Grid Enhancing Technologies tend to work best when they are used to solve local issues, and were considered and selected for certain underbuild projects. Static synchronous series compensator technology was selected for one of the underbuild solutions as a flow control solution.

MISO also conducted robustness testing to determine the potential impact of key projects already approved or under consideration after LRTP power flow models were completed in October 2023. This assessment looked at select MTEP23 and MTEP24 projects, the JTIQ projects and the Grain Belt Express (GBX) Merchant High Voltage Direct Current project, and determined these projects do not negate the need for the Tranche 2.1 portfolio. Additionally, MISO received nearly 100 alternative solutions from stakeholders representing 47 solutions. After the evaluation process, some alternatives were incorporated into the portfolio.

In its final analysis and consideration of stakeholder feedback, MISO concluded the Tranche 2.1 portfolio boosts reliability and economic value, enabling member fleet transitions, load growth and regional power

²Consists of utilizing production cost models that simulate chronological dispatch for an entire year (8760 hours). For additional information please refer to [MISO Economic Planning Whitepaper](#).



transfer within MISO, when geographic diversity must be relied upon to help manage dispatch flexibility during a range of operating conditions.

Seven-Step Process

Through a seven-step iterative process (Figure 2.2: MISO's 7-Step Process), MISO plans, assesses, evaluates and repeats steps as necessary to ensure a least-regrets plan. It begins with development of the Futures with stakeholders, based on a minimum 20-year horizon because transmission can take 8 to 12 years to identify, site and develop. MISO forecasts and sites generation resources, as well as load and energy growth. MISO then analyzes the ability of the transmission system to perform reliably and safely in delivering resources economically to load, recognizing member and state goals across the entire footprint.

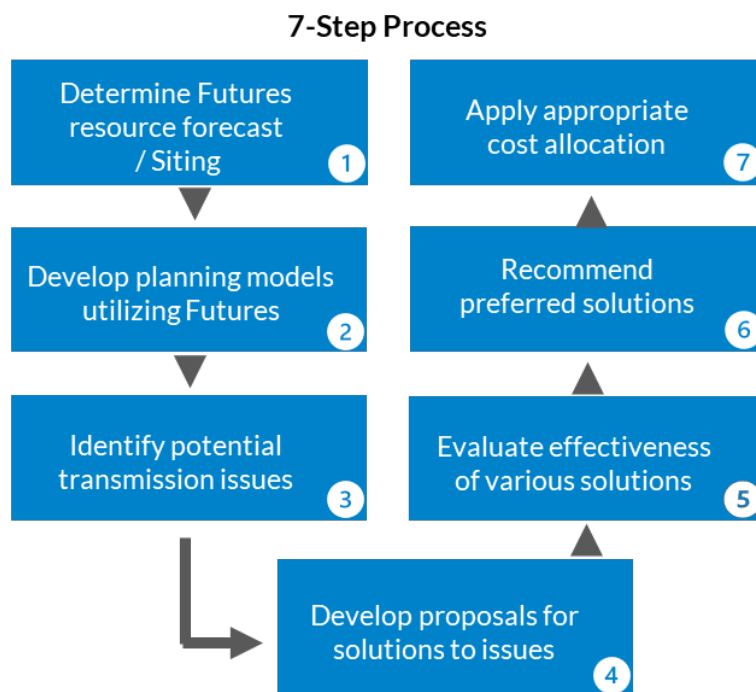


Figure 2.2: MISO's 7-Step Process

From there, MISO develops a conceptual long-range vision of the transmission system that could be needed to meet the Futures scenarios, with a focus on an incremental, subregional buildout based on the needs of each area. As solutions are identified, MISO considers the value of various transmission options in terms of reliability, economic and other factors.

Before choosing solutions to identified issues, guardrails are applied in several scenarios to show reliability and economic value considering how any subregional upgrades may fit into the conceptual long-term plan so MISO doesn't make shorter-term design decisions that would make the future development more costly – for example, effective use of right-of-way – constructing for higher voltages and operating at a lower voltage where that makes sense.

LRTP's focus is on regional transmission solutions, rather than resolving all localized issues. MISO recognizes some issues will be more appropriately addressed by annual MTEP reliability planning and



generator interconnection processes. The LRTP planning process and the reliability component of the NERC TPL annual reliability planning process have related, but distinct objectives. The NERC TPL annual reliability planning process is a compliance-based planning process that ensures the transmission system is planned to address reliability needs in the short-term (i.e., five-year planning horizon, etc.) and relies on known and committed inputs. LRTP is focused on regional and long-term issues that require regional and long-lead solutions. It is not designed to replace the shorter-term generator interconnection and annual reliability planning processes, but instead focuses on broad regional issues that are not sensitive to changes in input assumptions as well as long lead solutions that significantly reduce life cycle costs in the long-term costs and require advanced planning to implement.

Stakeholder Engagement

MISO could not complete this work without stakeholder input. Its transmission planning is conducted through a stakeholder process. In addition to regular stakeholder meetings, MISO provides other opportunities to encourage and ensure strong engagement, such as stakeholder feedback requests.

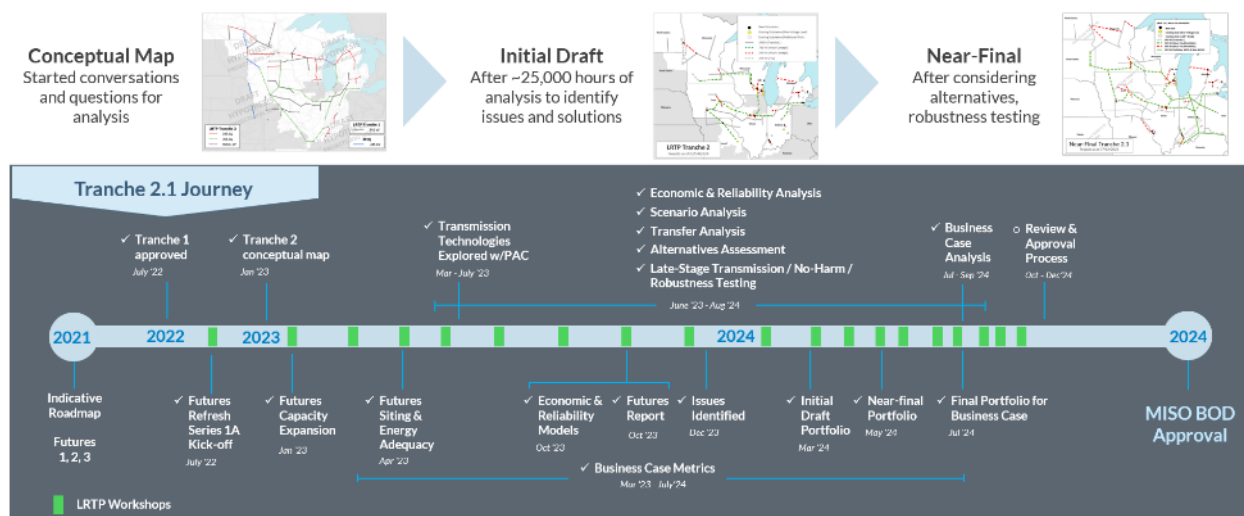


Figure 2.3: Tranche 2.1 Journey

From Planning Advisory Committee (PAC) meetings that analyze identified issues and proposed solutions, to deep dives in LRTP workshops, and so much more, there have been at least 300 meetings – both internal and external – to arrive at the Tranche 2.1 portfolio. With strong interest in LRTP, workshops averaged 275 participants and multiple other meetings and in-depth discussions were held. Among these various stakeholder meetings, MISO utilized both its public Stakeholder Feedback Tool and its LRTP email to elicit much of the feedback received and inform the inputs, scope and metrics for the Long Range Transmission Planning process. MISO reached out to Stakeholders 10 times across two years for Formal/Informal feedback thru the Feedback Tool; this combined with oral feedback received at LRTP workshops to shape the processes and portfolio. An example of feedback from the Feedback Tool and LRTP email includes:

- The Futures and Siting process was informed by 500+ stakeholder revisions impacting the inputs of the process



- MISO received significant stakeholder feedback and used that feedback to implement changes to the reliability and economic models throughout multiple months
- Stakeholder feedback informed the transfer scenarios selected as part of the scope
- Feedback was instrumental in informing the business case metrics

After sharing its rationale for planning approach, analysis and key decisions, MISO is confident it has developed a least-regrets, robust portfolio.

Step 1: Establish Futures and Siting

LRTP’s planning begins with forward-looking planning scenarios called Futures, which capture a range of economic, political, and technological possibilities over a twenty-year period, provide potential resource mixes, and appropriately bookend future uncertainty. The Futures are based on member data, stakeholder input, state and federal policy, and technical and economic data like the DOE’s National Renewable Energy Lab (NREL) Annual Technology Baseline. MISO defined three Futures which co-optimize several parameters to minimize total costs in achieving member goals, including peak demand plus reserve margin, annual energy, decarbonization goals and renewable portfolio standards/clean energy goals.



Figure 2.4: MISO Futures

MISO Futures

To develop Futures, MISO follows a rigorous, stakeholder-driven process to bridge the gap between what members plan for the future and the generation needed to get there. The original Futures are referenced as Series 1 (Futures 1, 2 and 3). The refreshed Futures, called Series 1A (Futures 1A, 2A and 3A) were initiated in July 2022. They provided the basis for the Future 2A resource expansion, which began in January 2023 with stakeholder engagement and included 500 siting changes based on feedback. Energy adequacy analysis was completed in April 2023 and was followed by capacity expansion modeling, siting, and production cost



modeling handoffs development for Futures 1A and 3A for MISO (and the three external areas modeled). Initial screening analyses was conducted in Summer 2023.

MISO posted the [Series 1A Futures Report](#) in Fall 2023 and then continued to conduct various screening analyses of the resource mix for the portfolio through January 2024. For Tranche 2.1, MISO determined Future 2A is most aligned with an optimized, least-cost expansion that meets member goals and Future 1A is an appropriate low-end bookend for the business case analysis.

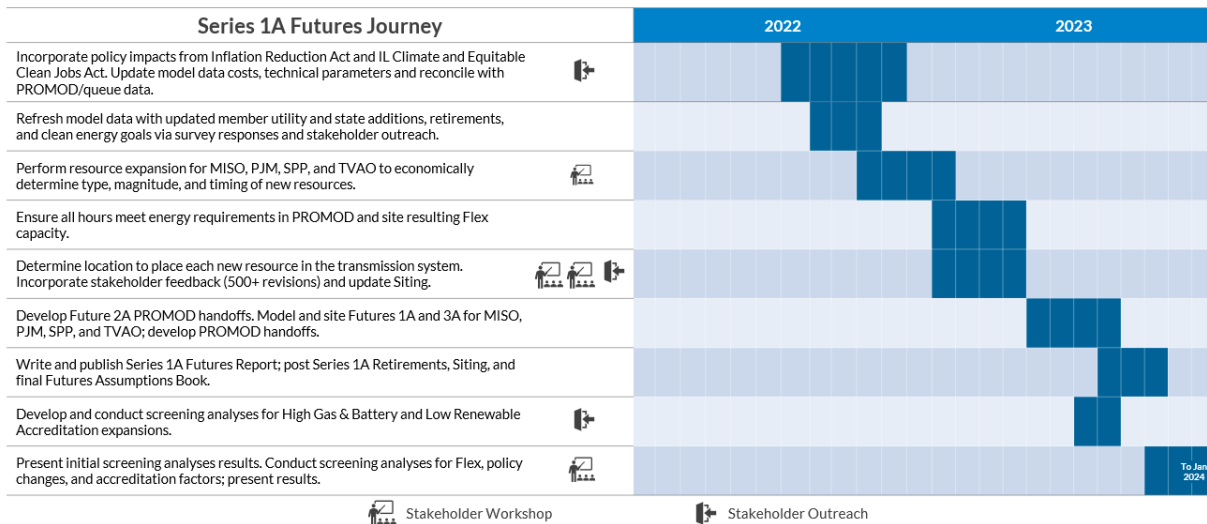


Figure 2.5: Series 1A Futures Journey

The Futures are periodically refreshed with key data inputs to help ensure the most accurate forecasts are used in planning. Subsequent refreshes will be driven by the timing and pace of planned new generation based on policy, load and other drivers of change.

Resource Expansion

Since MISO is not an integrated resource planner, MISO Futures reflect resource plans announced by member utilities and states. MISO is obligated to reflect and define a resource expansion that aligns with these plans. As such, transmission planning works to ensure the energy planned by members can be delivered to where it's needed. Additional future resources beyond member plans are required to meet projected load, policy objectives, and reserve margins. To bridge this gap, MISO performs an economic resource expansion analysis, which forecasts the additional resources to meet system needs at lowest cost.

For more than a decade, MISO has utilized a transmission-less, non-chronological resource modeling tool for transmission planning analysis. MISO develops a least-cost resource expansion with total costs linked to key assumptions, which grounded the Futures. Several notable outcomes from these key assumptions on Future 2A include:

- Generation Additions and Retirements:** For additions, 54% of the F2A expansion originates from member-planned resources. For retirements, MISO used member data and applied age-based retirement assumptions in cases for which no feedback was provided on generator retirement dates. For example, member data directly provided approximately 77% of coal retirements.



- **Load:** MISO benchmarked its load forecast with McKinsey & Company in 2022 and found load projections fell within Future 2A and Future 3A with annual energy similar to Future 3A.
- **Incentives:** The Inflation Reduction Act provides various incentives for battery, solar, hybrid and wind, which lower their respective overall costs through investment or production tax credits.
- **Resource Type Cost Modeling:** Resource operations and maintenance (O&M) costs are offset by incentives (Inflation Reduction Act), with wind costing the lowest and hybrid and battery the highest.
- **Decarbonization Goals:** 75% of MISO load is served by members with ambitious decarbonization and/or renewable energy goals.
- **Battery Storage Assumptions:** By utilizing excess energy for charging, battery storage plays an important role in the Futures expansion to minimize the overall resource fleet cost. Future 2A includes 11 GW of member-planned battery and 20 GW of model-built battery, for a total of 31 GW of 4-hour lithium-ion battery.
- **Accreditation:** Capacity accreditation was based on the approved 2022 Planning Resource Auction and shifts over time based on the Renewable Integration Impact Assessment (RIIA)

A full list of the Futures assumptions is included in the [Futures Refresh Assumptions Book](#).

Resource Siting

Futures development culminates in a siting process that maximizes resource availability and accommodates member goals. After the expansion, siting analysis ensures these resources can be built in needed areas. MISO followed a stakeholder-approved siting process which was covered in the [Series 1A Futures Report](#) and [Futures Refresh Assumptions Book](#). As part of this process, MISO sited model-built resources to address the following:

- Local/regional Renewable Portfolio Standards (RPS) and decarbonization goals
- 80/20 split between Generator Interconnection (GI) queue and Vibrant Clean Energy (VCE)/Greenfield Sites for renewable resources, with:
 - Up to 80% of Wind, Solar, or Hybrid sited at Active Definitive Planning Phase (DPP) 1, 2, or 3 Generator Interconnection (GI) Queue or Tranche 1-enabled sites
 - Remaining ~20% sited at VCE-identified areas with renewable potential
- Each Local Resource Zone (LRZ) meeting its Local Clearing Requirement (LCR) and Planning Reserve Margin Requirement (PRMR)
- Capacity sited at 5-year milestone intervals (2027, 2032, 2037, 2042)

Once the expansion was determined, MISO worked with stakeholders to determine appropriate resource sites, including over 500 revisions based on extensive stakeholder feedback:

- Made significant modifications to the sited wind across the MISO footprint, including:



- Moved all preliminary sited MISO South model-built onshore wind to MISO Midwest (primarily North Dakota and South Dakota)
- Moved ~60% of member-planned onshore wind in MISO South to SPP as a planned external resource
- Moved wind in Wisconsin and northern Minnesota to North Dakota and South Dakota
- Situationally re-sited capacity at provided/preferred buses:
 - Redistributed solar and solar hybrid to include more of these resources in MISO South and Wisconsin
 - Re-sited thermal capacity from MN and IL to locations provided by stakeholder feedback
- Redistributed Demand Response and distributed generation photovoltaic (DGPV) resources over additional sites
- Incorporated additional member-planned resources, primarily energy storage and Reciprocating Internal Combustion Engines (RICE)
- Reduced offshore wind due to a 54% reduction of the Wind Energy Area (WEA) affecting the size and availability of Bureau of Ocean Energy Management (BOEM) leasing sites near LA and TX.

Energy Adequacy and PROMOD Analysis

An example that demonstrates managing uncertainty through MISO’s comprehensive, iterative process is how MISO assessed energy adequacy during analysis to arrive at Future 2A. An energy adequacy analysis ensures the grid can be operated reliably, meeting energy needs during all hours with the forecasted resource mix—an important step given the increase in intermittent resources. Through planning, analysis revealed an energy shortfall during what MISO has called the twilight hours—at sunset and sunrise—when wind output is typically low and solar output is unavailable.

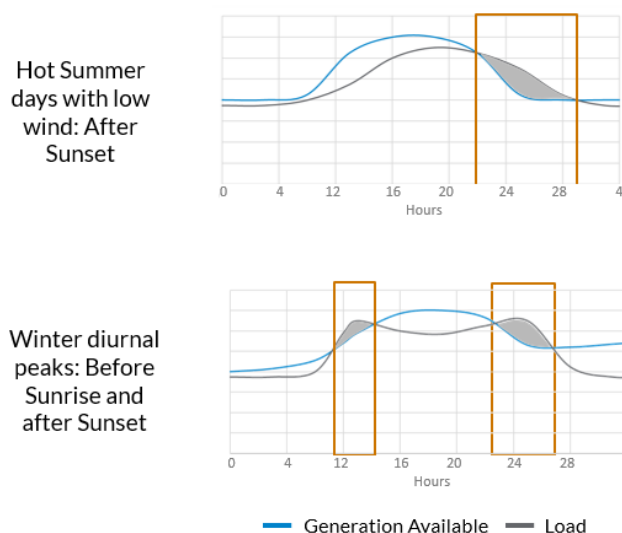


Figure 2.6: Energy Adequacy Analysis for Flexible Attribute Units



PROMOD, a production cost modeling tool providing hourly (annual) chronological security-constrained unit commitment and economic dispatch, identified generation shortfalls for three to four hours per day during twilight hours (before sunrise or at sunset) in up to 26 days of the modeled year, with a maximum shortfall of 29 GW in a single hour. To address this energy shortfall, 29 GW of supplemental low- or non-emitting, high availability resource additions, referred to as Flex for Flexible Attribute Units, were needed to ensure energy adequacy during these time periods. This is reflected in the shaded areas of both graphs in Figure 2.6: Energy Adequacy Analysis for Flexible Attribute Units.

These “Flex” units represent potential generation that is highly available, highly accredited, low- or non-carbon-emitting and long in duration. Flex resources could be, but are not limited to the following: Reciprocal Internal Combustion Engine (RICE) units, long-duration battery (>4 hours), traditional peaking resources, combined cycle with carbon capture and sequestration, nuclear Small Modular Reactors (SMRs), green hydrogen, enhanced geothermal systems, and other emerging technologies.

Low-End Bookend

MISO’s LRTP processes define a robust portfolio of transmission to achieve the energy goals of MISO states and members under a range of conditions. Part of this robustness is achieved through ensuring the models used in scenarios appropriately bookend future uncertainty and capture potential resource mixes. The Resource Expansion results drive the selection of transmission solutions.

As such, MISO conducted multiple screenings assessing the impact of different changes on the resource mix and validated Futures 2A and 1A as appropriate bookends. Many of the screens performed showed resource mixes similar to Future 2A; as a result, MISO proceeded with Future 1A as the low-end bookend.

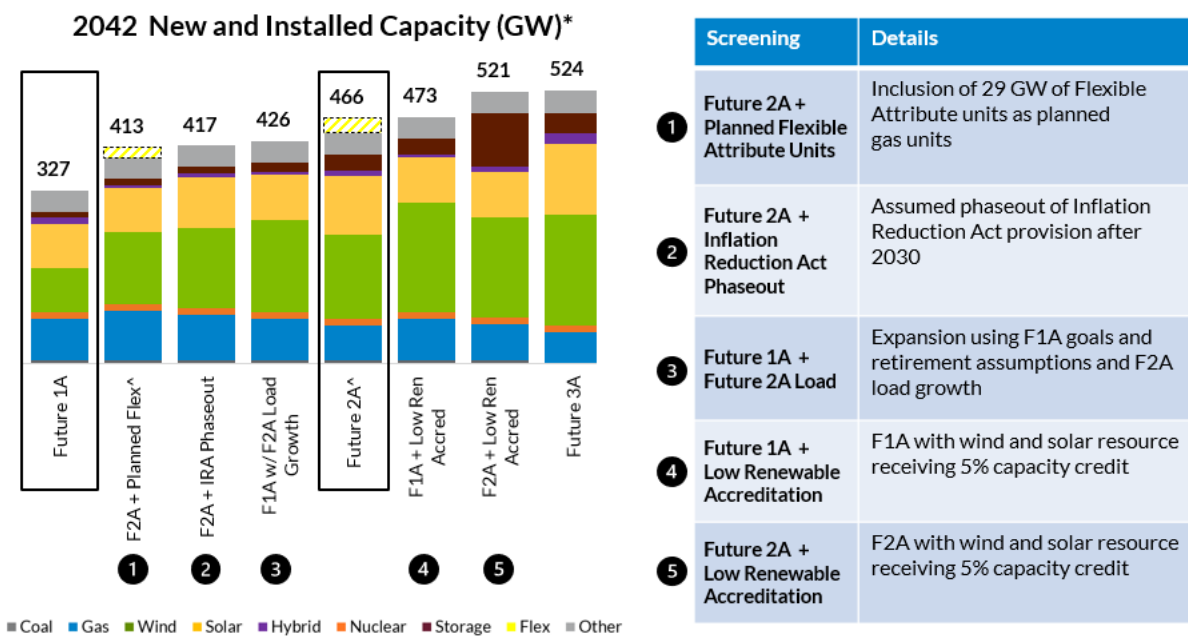


Figure 2.7: Futures Low-End Bookend



Step 2: Develop Planning Models Utilizing Futures

Reliability Models

MISO built 10-year, and 20-year reliability models based on Future 2A for LRTP reliability analysis. As part of this analysis, MISO tested transmission reliability under likely and possible dispatch with a focus on the worst credible conditions from the system point of view, while recognizing that local conditions may vary.

A set of base models were used to assess the impact of variable renewable and hybrid generation and other system conditions. These broad base models encompassed multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus providing the platform to perform a wide range of reliability studies.

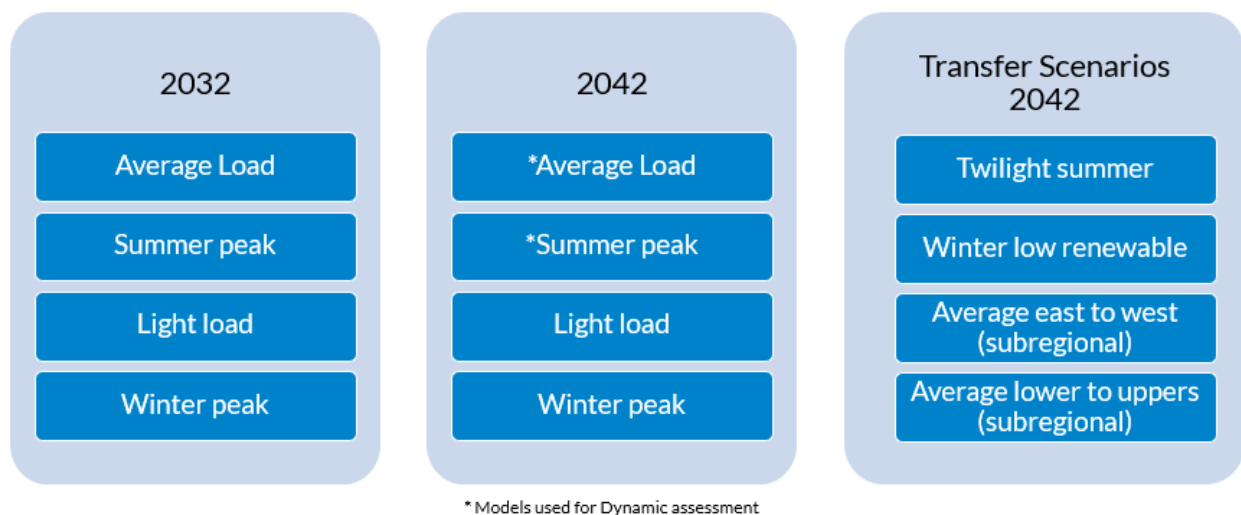


Figure 2.8: Core Models used in Reliability Assessment

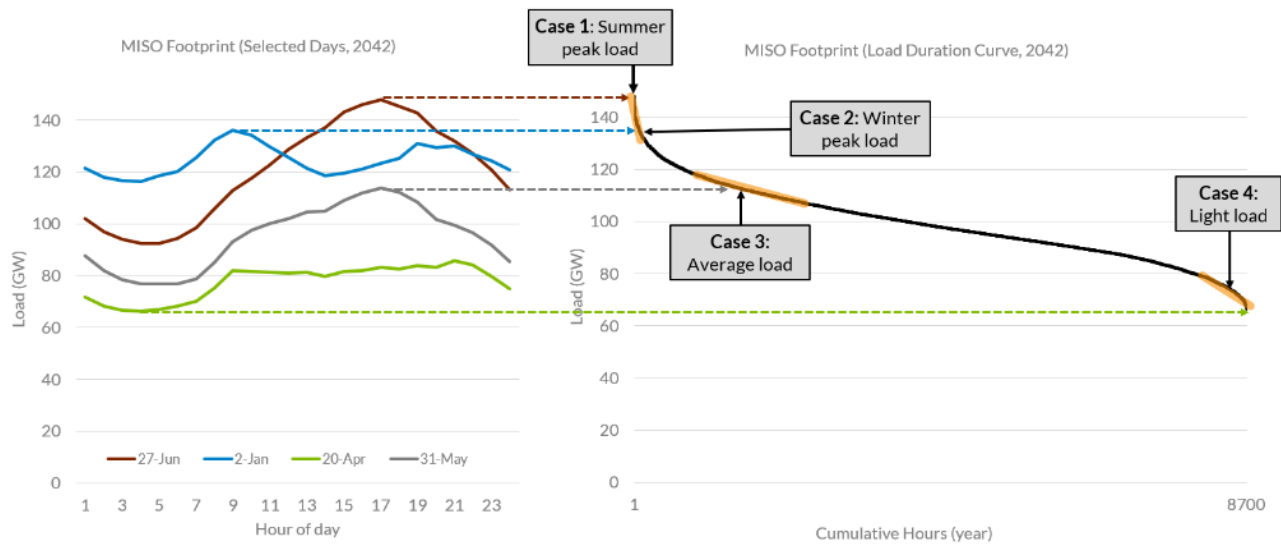
Core models were determined via load points on the MISO annual load duration curve (see Figure 2.9: Overview of load levels in Future 2A, Table 2.1). After selection of these load points, coincident output from wind and solar resource profiles were used to derive a credible dispatch for the given scenario. Figure 2.9 shows an overview of load levels in Future 2A, informing the selection of reliability models. To the right, the load duration curve is shown, highlighting the four desired load levels for the core models. The left shows a series of indicative daily load shapes and how they map to the load duration curve. These power flow models provided the basis for steady state, dynamic, voltage stability and additional scenarios. A more comprehensive explanation of reliability models and analysis is available in a [MISO Reliability Study Whitepaper](#).

Core cases	Renewable and storage dispatch methodology	Reason for inclusion
Case 1: Summer Peak Load	<ul style="list-style-type: none"> High coincident renewable output 	<ul style="list-style-type: none"> Test the ability to reliably serve load



Core cases	Renewable and storage dispatch methodology	Reason for inclusion
<ul style="list-style-type: none"> Represents summer peak demand which is the highest load on the annual load duration curve 	<ul style="list-style-type: none"> in the summer between 90% and 100% of the annual peak demand Storage off 	<ul style="list-style-type: none"> via variable renewable energy and conventional resources
Case 2: Winter Peak Load <ul style="list-style-type: none"> Represents winter peak demand 	<ul style="list-style-type: none"> High coincident renewable output in the winter between 90% and 100% of the annual winter peak demand Storage discharging at 50% nameplate 	<ul style="list-style-type: none"> Local/Regional/System load profile and peak is different from the summer case Test ability of renewables to reliably serve load considering load profile diversity Test system ability to export to Manitoba Hydro
Case 3: Average Load <ul style="list-style-type: none"> Represents typical system conditions within 70-80% on the load duration curve 	<ul style="list-style-type: none"> High coincident renewable output between 70% and 80% of the annual peak demand Storage charging at 60% nameplate 	<ul style="list-style-type: none"> Assess system ability to move power and reliably serve load during the annual maximum coincident wind/solar, which is likely to occur during this timeframe Peak variable renewable energy case is essential to evaluate dynamic performance
Case 4: Light Load <ul style="list-style-type: none"> Represents lowest 10% on the load duration curve 	<ul style="list-style-type: none"> High coincident renewable output to test ability of the system to absorb reactive power Storage charging at 60% nameplate 	<ul style="list-style-type: none"> Assess system conditions during low load, moderate wind, and zero solar output

Table 2.1: Core models



Indicative daily profiles and load duration curve developed from Future 2A load data, after accounting for energy efficiency.

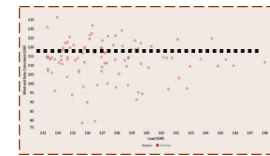
Figure 2.9: Overview of load levels in Future 2A



STEP 1: Select points meeting the load criteria. In this example: summer hours with load in the top 10% of peak.

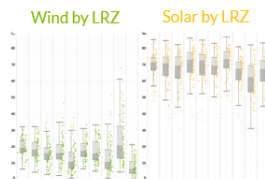


STEP 2: For the points meeting the load criteria, determine the target instantaneous penetration of renewables.



Target* is either average of 95th percentile of coincident renewables, or capped at 80% of highest load in points (dashed line)*

STEP 3: For all hours meeting the load criteria, examine the range of renewable outputs in each LRZ.



Different dispatch for each LRZ and renewable type, based on percent of nameplate

STEP 4: Select the average nameplate value in each LRZ and scale up until the target coincident penetration is reached. The upper and lower limits (whiskers) will be respected.

LRZ	Wind	Solar	Target
LRZ 1	100	0	100
LRZ 2	100	0	100
LRZ 3	100	0	100
LRZ 4	100	0	100
LRZ 5	100	0	100
LRZ 6	100	0	100
LRZ 7	100	0	100
LRZ 8	100	0	100
LRZ 9	100	0	100
LRZ 10	100	0	100
LRZ 11	100	0	100
LRZ 12	100	0	100
LRZ 13	100	0	100
LRZ 14	100	0	100
LRZ 15	100	0	100
LRZ 16	100	0	100
LRZ 17	100	0	100
LRZ 18	100	0	100
LRZ 19	100	0	100
LRZ 20	100	0	100
LRZ 21	100	0	100
LRZ 22	100	0	100
LRZ 23	100	0	100
LRZ 24	100	0	100
LRZ 25	100	0	100
LRZ 26	100	0	100
LRZ 27	100	0	100
LRZ 28	100	0	100
LRZ 29	100	0	100
LRZ 30	100	0	100
LRZ 31	100	0	100
LRZ 32	100	0	100
LRZ 33	100	0	100
LRZ 34	100	0	100
LRZ 35	100	0	100
LRZ 36	100	0	100
LRZ 37	100	0	100
LRZ 38	100	0	100
LRZ 39	100	0	100
LRZ 40	100	0	100
LRZ 41	100	0	100
LRZ 42	100	0	100
LRZ 43	100	0	100
LRZ 44	100	0	100
LRZ 45	100	0	100
LRZ 46	100	0	100
LRZ 47	100	0	100
LRZ 48	100	0	100
LRZ 49	100	0	100
LRZ 50	100	0	100

Figure 2.10: Overview of renewable dispatch methodology. This 4-step process provided a target variable dispatch for wind and solar resources specific to each LRZ. This served as a basis in the dispatch each of the core models.

Typically, powerflow models with high instantaneous penetration of renewable energy are challenging to solve. Furthermore, the retirements and additions from Future 2A represent a steep change from the starting models of MTEP22. Inverter Based Resources are modeled with a reactive power max (Qmax) and reactive power min (Qmin) at +/- 0.95 Power Factor based off the Power Generation (Pgen) of the unit. The units will adjust their reactive output within those limits to hold the scheduled voltage at the designated voltage-controlled bus Point of Interconnection (POI).

MISO has solved high renewable models through the Renewable Integration Impact Assessment (RIIA) and through building study models for the Definitive Planning Process (DPP) (i.e., interconnection queue). The goal of a power-flow model is to obtain a stable combination of voltages angle and magnitude information for each bus in a power system for specified load, generator, and topology conditions. Due to the nonlinear nature of this problem, to obtain a solution that is within an acceptable tolerance, the following issues may be experienced:

- The maximum real or reactive mismatch at any bus in the system exceeded
- The voltage magnitude and angle difference between buses too big or unknown
- The maximum number of iterations exceeded, etc.
- Voltage collapse and/or divergent solution

To solve the models, many methods may be required, such as:

- Additional fictitious reactive support devices
- Adjustment of model parameters including tap settings and voltage-controlled buses
- Localized generation curtailment if case approaches instability
- Model review to identify and rectify modeling issues



For each case MISO provided a summary of issues identified and methods (solutions) used to ensure modes are within acceptable tolerance. Once models were solved, the addition of fictitious resources, transmission lines, reactive resources or other model tweaks were re-examined for necessity and removed from the case to the extent possible.

Economic Models

MISO built 10-year, 15-year and 20-year economic models based on Future 2A for LRTP economic analysis. As part of this analysis, economic modeling utilizes PROMOD, a chronological security-constrained unit commitment and economic dispatch tool which applies a wide variety of operating constraints. Within the PROMOD model, Futures assumptions around load, generation, and fuel costs are incorporated up to a 20-year time horizon along with transmission grid topology and constraints to assess future transmission needs.

The economic model produces a unit commitment and security-constrained economic dispatch while optimizing production costs. The analysis allows simulation of all 8,760 hours in a year, not just the peak hour. The economic study model encompasses multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus allowing the model to perform a wide range of economic analysis.

Economic modeling and analysis rely on a 10-step process that starts with a core “No-Futures” model and ends with a “Final” economic model for portfolio development as shown in Figure 2.11. Throughout this process, MISO allows for touchpoints with stakeholders to incorporate feedback on models and flowgates, transmission issues and the portfolio, and to coordinate with the MISO reliability teams to sync issues and solutions across study work.

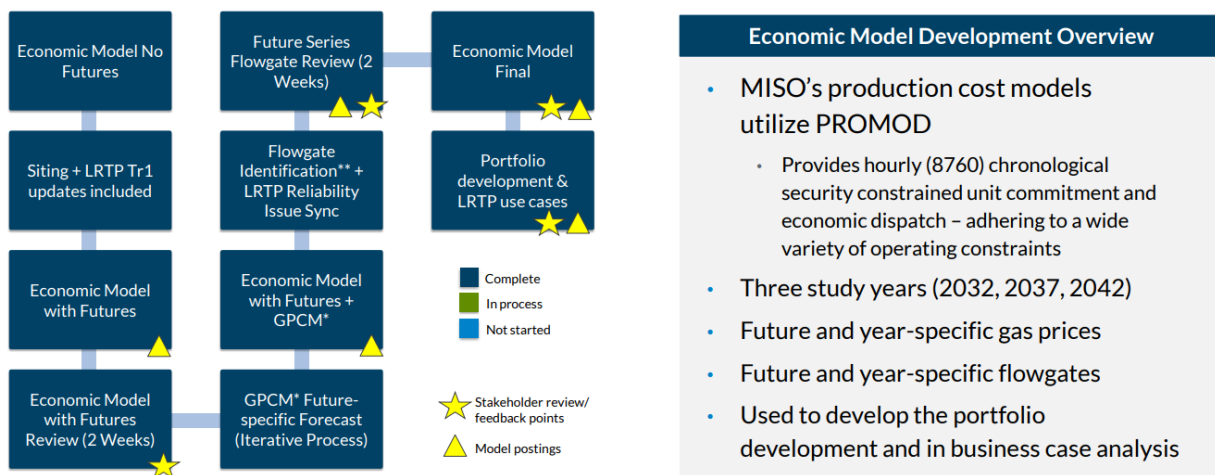
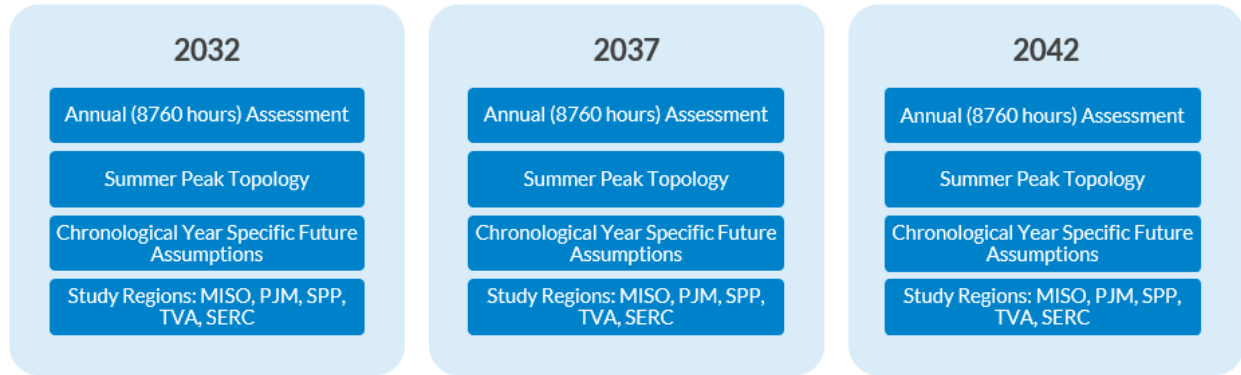


Figure 2.11: Economic Modeling 10-Step Process

Each of the economic production cost models include chronological Future- and year-specific assumptions for multiple regions to identify economic constraints and test potential solutions (See Figure 2.12: Economic Model Development Study Years).



Economic constraints included N-0 and N-1 constraints developed for each study year

Figure 2.12: Economic Model Development Study Years

Economic Model No Futures

The Economic model building process starts with developing the base economic model without any Futures assumptions. This requires compiling Hitachi-released generation and fuel data, resource utilization data, and transmission topology for the MISO footprint and neighboring entities. The Series 1A No Futures model includes:

Base Economic Data	What's included
Hitachi PROMOD Releases	<ul style="list-style-type: none"> o Fall 2021 – generator updates and economic data o Spring 2022 – coal price updates o 11.5.1 engine
Neighboring Entities Data	<ul style="list-style-type: none"> o SPP generator additions and economic data o PJM generator additions and economic data
Resource Utilization	<ul style="list-style-type: none"> o Generators with signed GIA additions o Attachment Y Retirement updates
Powerflow Model	<ul style="list-style-type: none"> o MTEP22 - 2032 Summer Peak Powerflow model with updates o LRTP Tranche 1 Projects o 2032 Winter Peak Powerflow model ratings
Natural Gas Price	<ul style="list-style-type: none"> o Q2 Henry Hub 2022 natural gas prices

Table 2.2: Economic Model No Futures Inputs

Economic Model with Futures

After finalizing a set of Futures with an energy adequacy validation process, that set is fully incorporated into the economic model, resulting in the Economic Model with Futures. Once an economic model with Futures is created, the database is made available to stakeholders who have completed the necessary non-disclosure documents with MISO. As part of this process, MISO looks to stakeholders to provide feedback on transmission ratings, generator attributes, and any other discrepancies identified within the database provided. Economic Planning works with stakeholders to update model data and address potential modeling concerns as needed.



Gas Price Forecasting

The Economic model includes estimated gas prices calculated using a Gas Pipeline Competition Model (GPCM) process. The GPCM models the physical and market systems of gas pipeline networks to forecast natural gas production, pipeline and storage utilization, deliveries, and prices at different locations across the North American gas market. By completing this process after the incorporation of Futures assumptions, the gas prices reflect the impact of changing gas demand levels. The 'Economic Model with Futures' is used in an iterative process to reach convergence between gas prices and gas burns within the associated PROMOD model as seen in Figure 2.13.



Figure 2.13: GPCM iterative process

Flowgate Identification

The MISO Flowgate Identification process has been developed and refined over time through multiple MTEP economic studies. Flowgate Identification requires multiple tools, including and not limited to PROMOD and PROMOD Analysis Tool (PAT), and requires multiple iterations to identify transmission constraints to construct the PROMOD event file (See Figure 2.14: Economic Flowgate Identification Process I). PROMOD utilizes an event file as instructions on what elements to monitor and what constraints to include in a run. Due to the size and complexity of a PROMOD model, not all transmission can be included in the event file. The Flowgate Identification process produces an event file that captures likely predicted binding flowgates for the economic analysis while still allowing the PROMOD model to solve. Additional criteria for flowgate identification is detailed in Figures 2.15, 2.16 and 2.17.

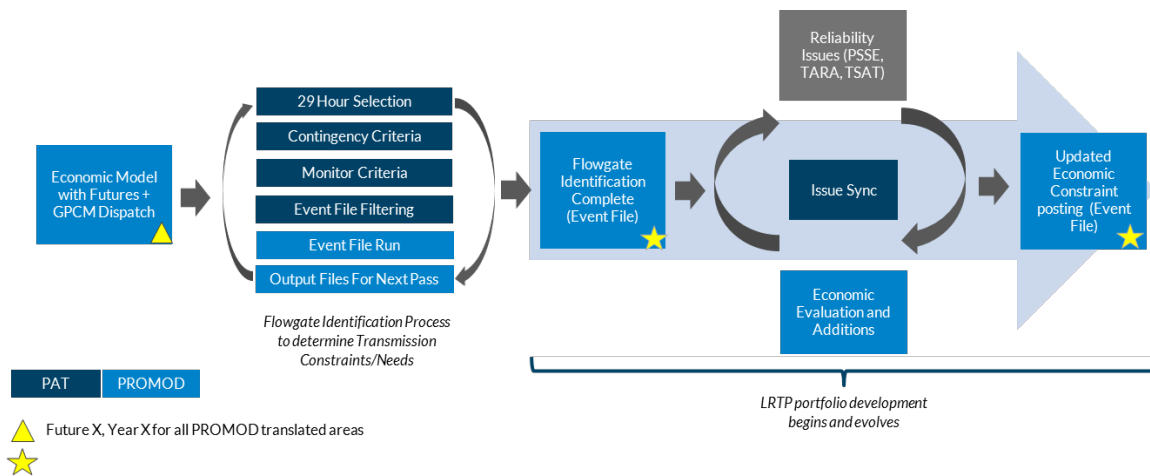


Figure 2.14: Economic Flowgate Identification Process I

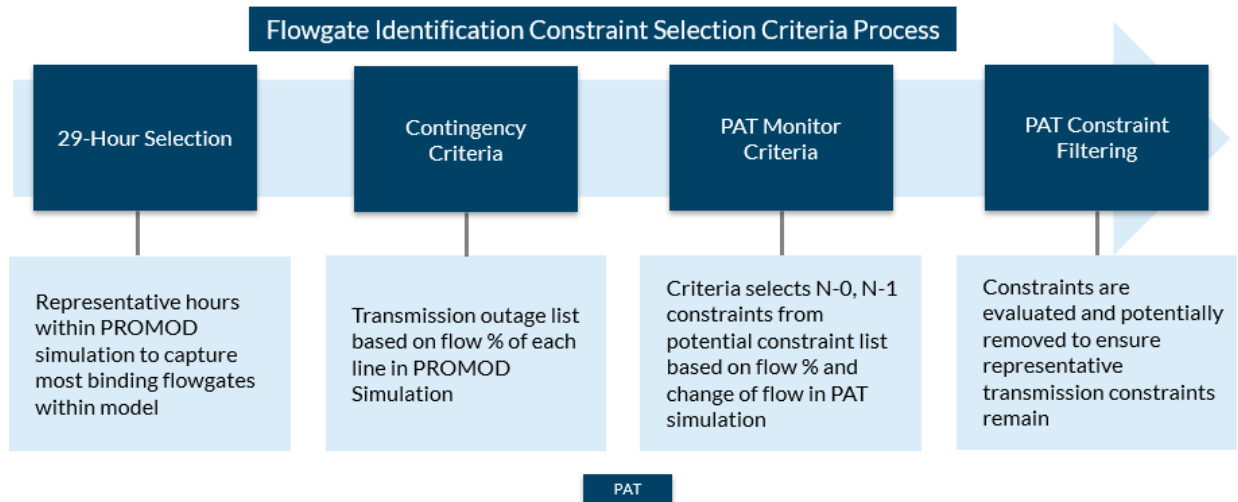


Figure 2.15: Flowgate Identification Constraint Selection Criteria Process II

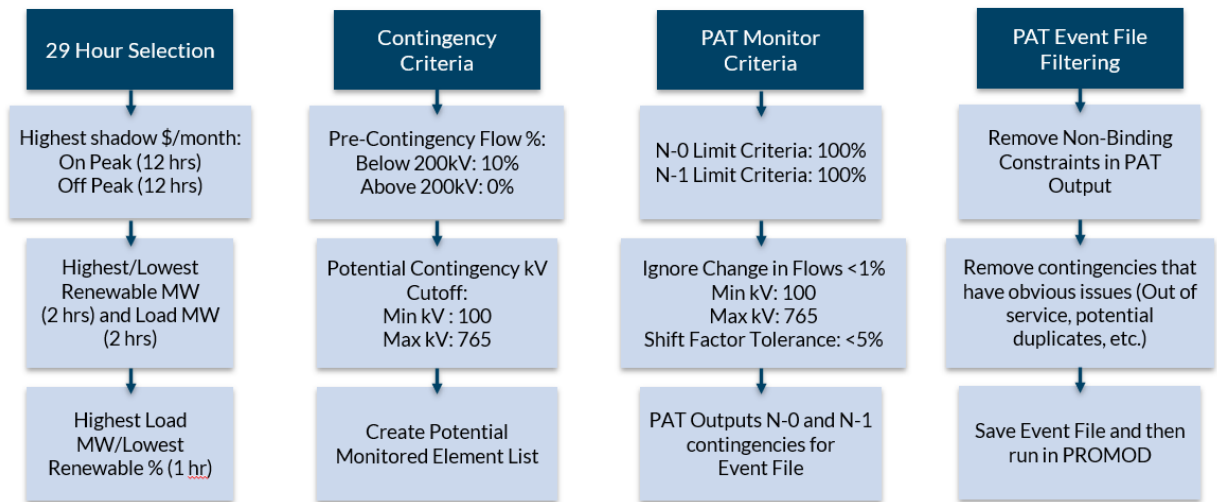


Figure 2.16: Flowgate Identification Constraint Selection Criteria Process III

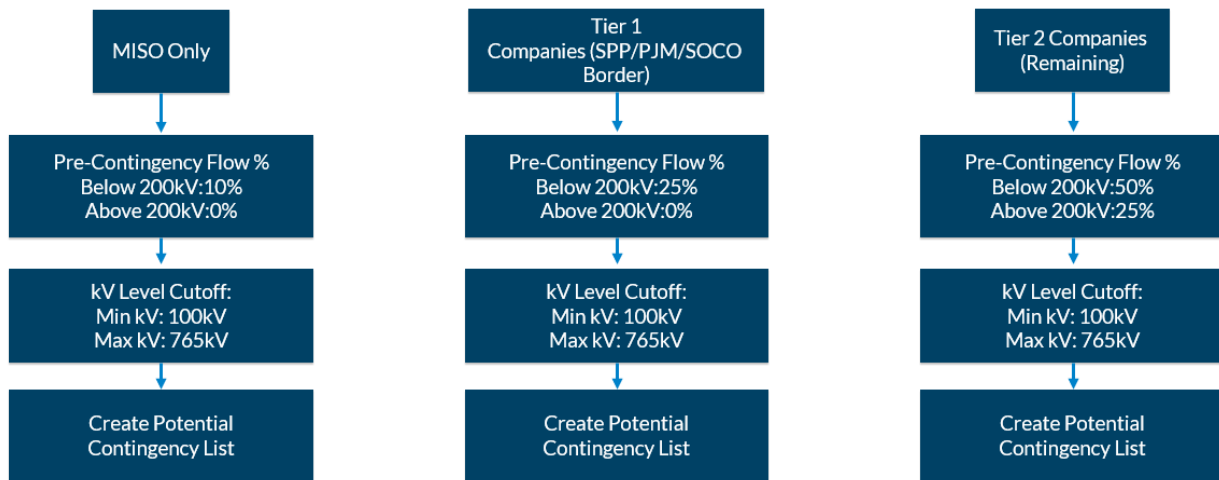


Figure 2.17: Flowgate Identification Constraint Selection Criteria Process IV

Step 3: Identify Transmission Issues

Step three involves performing reliability and economic analysis to identify transmission issues. The purpose of reliability analysis 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 2A scenario in the 10-year and 20-year time horizons. Economic analysis identifies issues like congestion, generation curtailment, widespread price separation, and price to serve load. The reliability analysis and economic analysis are iterative processes that are coordinated with each other to determine cost-effective and reliable solutions.

Tranche 2.1 work focused on resource changes contemplated by Future 2A. Key reliability and economic issues provided the foundation to develop Tranche 2.1 as a no-regrets and stand-alone first step towards the transmission required to enable Future 2A.

Economic and reliability analysis showed significant congestion across the Midwest, with widespread price separation and generation curtailment, along with significant levels of overload on lower and higher voltage equipment and decreased reactive support across the system. Also, the addition of generation located further away from load requires longer-distance transmission lines, and the lower stability limits of these lines increase stress on the system. Similar results were seen in the economic analysis with the widespread locational marginal price separation due to lack of a regional high-voltage backbone. Results also revealed opportunities to provide additional benefits by resolving energy losses from power transfers on existing transmission and by mitigating economic congestion.

Reliability Analysis

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. It is important to understand that the Tranche 2.1 portfolio was designed to enable the grid of the future and



was not designed to resolve all identified issues. Consequently, there remain unresolved overloads, voltage violations and non-converged contingencies in the Tranche 2.1 reliability models. To the extent an issue is local and caused by a specific driver, LRTP may not resolve it. The two most common examples of local issues from specific drivers would be local generator interconnection issues and local load growth issues. If the specific siting of a Futures resource causes an issue that would not exist if the siting was relocated to a different bus within the local area, that tends to suggest that the issue is local and specific to siting of the resource, and should be addressed by the generator interconnection process if and when that specific site is pursued by an interconnection customer. Likewise for local load growth, to the extent the load growth was relocated to another bus or set of buses within the local area, if the issue persists, this suggests it might be a regional issue. If the issue is resolved or changes, this would suggest it is an issue related to load growth that the annual MTEP reliability planning process has not yet detected based on a much shorter planning horizon, and is best addressed in the future via the annual reliability planning process. As part of the MISO reliability analysis process, engineers have conducted a thorough review of the study results to ascertain if specific issues tend to be more local in nature, as described above, or more regional in nature.

Furthermore, LRTP is not a NERC compliance study, whereby every issue identified must have an appropriate mitigation measure according to NERC standards and requirements. Some issues identified in the LRTP analysis were local in nature and will be addressed in other planning processes, such as the annual MTEP reliability planning and the generator interconnection processes, as specific load and generation locations are identified. 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.

Additionally, MISO conducted transient stability analysis to determine the degree to which the proposed LRTP portfolio improved system performance related to angular stability. MISO also utilized Safe Loading Limits (SLL) calculated based on the St. Clair methodology as an additional metric to assess the improvement in overall stability and voltage performance of the system. Unlike thermal limits, safe loading limits decrease as line length increases for Extra High Voltage transmission lines; thus, safe loading limits are a good general metric to assess the overall improvement in angular stability performance.

Reliability analysis ensures the transmission system can reliably serve load under various system conditions and dispatch patterns.

- Assess transmission line loading and voltages for a wide variety of system events called “contingencies”
 - Example of a contingency: a line trips offline to clear a fault
 - At a minimum, performance is evaluated against applicable contingency events and planning criteria
 - This study included 55k single initiating events and 100k multiple contingency events

Transmission projects may be identified to:

- Ensure transmission system performance is reliable and adequate before and after contingencies occur
- Enable high regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty



Reliability analysis included several different types of simulations, each targeting different information about performance. Multiple iterations were performed to build models, identify issues and test potential solutions.

Name	Description	Timeframe	Tools
Steady-state	Determines if transmission facilities remain within safe design limits (line loading and voltage) following disturbances	<ul style="list-style-type: none"> One operating point (instant) 5+ min after a system disturbance 	Powerflow (PSS/E, TARA)
Transient stability	Determines if the system will experience uncontrolled loss of load or generation following disturbances; focus on voltage and frequency performance	<ul style="list-style-type: none"> 0-30 seconds following a system disturbance 	Dynamics (PSS/E, DSA)
Transfer analysis	Assesses impact of various system conditions, dispatch patterns and intra-regional power transfer limits; focus on line loading and voltages	<ul style="list-style-type: none"> One operating point (instant) 5+ min after each change 	Transfer analysis (PSS/E, TARA)

Table 2.3: Description of reliability study components for LRTP 2.1 study

Steady-state contingency analysis is performed to identify any thermal and voltage violations that exist in the four base reliability cases for each of the 10-year and 20-year models. The analysis requires simulation of the MTEP single element (NERC Category P0, P1, P2, P4, P5, and P7) contingency events and selected multi-element (NERC Category P3, P6) events. Facilities in the Midwest subregion were monitored for steady state thermal loading in excess of 90% of applicable ratings and for voltage violations per the Transmission Owner voltage criteria. For Extra High Voltage lines that are longer than 50 miles, loading levels were also assessed utilizing the Safe Loading Limit (SLL) metric.

Transfer Analysis

MISO utilized core models and built another set of models called ‘transfer scenarios/models’ utilizing transfer techniques to test for robust performance under varying dispatch patterns. Once the appropriate transfers (MWs flow from one area to another and/or from one fuel type to another), these new models were created and added to the set of study models. These additional ‘transfer scenarios/models’ can be utilized for any further analysis like the core models. The LRTP transfer study includes four transfer scenarios (20-year models) to assess import requirements in situations where unexpected loss of renewable and thermal resources could occur due to changing weather conditions.

MISO leverages its extensive geographic footprint and diverse resources to ensure that the system remains reliable in the future. Transfer analysis helps assess system performance, particularly concerning subregional internal import and export capabilities during high regional power transfer scenarios. These scenarios arise when geographic diversity becomes crucial in managing dispatch volatility and resource uncertainty to serve anticipated load. Generation patterns are expected to significantly shift between day and night, as well as seasonally. Therefore, the ability of load in one area to be supported by generation from a remote area will become increasingly important for ensuring ongoing system reliability.

To better evaluate the need for system flexibility, assess project effectiveness under broader assumptions, and understand the impact of locational variability in resource profiles, additional transfer scenarios were developed. MISO utilized core models and built another set of models called ‘transfer scenarios/models’



utilizing transfer techniques. Once the appropriate transfers (MWs flow from one area to another and/or from one fuel type to another) are added to the core models, these new models were created and added to the set of study models. These additional 'transfer scenarios/models' can be utilized for full contingency analysis similar to the core models.

- East to West Transfer Scenario, derived from 2042 Average Model, highlights the bi-directional nature of the system with flows reversing as system conditions change. 18 GW of excess wind and solar in Local Resource Zones (LRZs) 4-7 is exported into LRZs 1-3 as they experience lower renewable output.
- Lovers to Uppers Scenario, derived from 2042 Average Model, highlights the importance of accessing resources in lower Central regions (hours where WI and MI will rely on imports). Additional excess wind from LRZs 4-6 exports into LRZ 2 (reached limit of 0.8 GW beyond the initial 4.2 GW import) and LRZ 7 (reached limit of 3.6 GW beyond the initial 5.8 GW import) as they experience lower renewable output.
- Winter Peak Low Renewable Scenario, derived from 2042 Winter Model, captures multi-day periods of low renewable output expected to occur during early morning hours and regional winter freeze. Winter low renewable scenario dispatches down solar, wind, and batteries. All conventional resources and demand response resources are dispatched to their maximum nameplate capacity. This scenario represents the lowest renewable scenario of all core models and additional scenarios with an objective to test reliance on conventional local resources to support load during winter freeze that historically occurred on MISO system.
- Twilight Summer Scenario, derived from 2042 Summer Model, captures the ability of conventional resources to meet demand during sunset. Twilight scenario dispatches down solar and wind resources to 10% of nameplate capacity. All conventional resources and demand response resources are dispatched up. Batteries are assumed unavailable since this scenario represents a multi-day low renewable scenario and batteries are not able to recharge.

Initially MISO scoped to build a fifth West to East Scenario, derived from 2042 Average Model, which highlights system limitations of output in the West. This scenario was removed from the final list as heavy West to East Bias was already present in core models and while attempting to further increase West to East flows only achieved a 2% increase in dispatch of wind nameplate percentage in LRZs 1 and 3 before voltage collapse i.e., 1.5 GW of excess wind in LRZs 1 and 3 exports into LRZs 2 and LRZs 4-7 as they experience lower renewable output.

The scope for transfer scenarios were initially presented at the [L RTP workshop in August 31, 2023](#) and needs or issues presented at [the L RTP workshop January 26, 2024](#). Each core model and additional transfer scenarios have supporting information such as imports/ exports from each zone with all material posted on MISO [Sharefile](#). In addition, all results and system performance under various contingencies are posted as well.

Dynamic Assessment

With the increasing integration of renewable energy sources, dynamic assessment is essential for managing the variability and uncertainty introduced into transmission systems. This assessment evaluates how the system performs under different system conditions and dispatch patterns, ensuring that transmission networks can meet future energy demands while maintaining stability and reliability.



In the LRTP Tranche 2.1 dynamics analysis, the focus was on comparing the dynamic performance of the system with the final portfolio against a base case scenario without the portfolio. The LRTP dynamic models were constructed from the steady-state power flow models, ensuring that the topology and dispatch align with these models.

For transient stability analysis in Tranche 2.1, MISO evaluated the system's performance using the 2042 Summer Peak and 2042 Average Load core models. The 2042 average load case represents a highly stressed scenario characterized by the highest angular separation across the system, lowest inertia (because of lowest conventional generation, both in absolute terms and by percentage), lowest short circuit current contribution, and 100% renewable penetration, meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. The 2042 summer peak model represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.

MISO monitored key factors such as Transient Stability Index (TSI), first swing transient stability, angular oscillations, damping characteristics, and voltage recovery for dynamic disturbances applied to the models, comparing the performance of scenarios with and without the portfolio.

Voltage and Reactive Support

As more renewable energy sources are integrated into the grid, reactive support becomes increasingly crucial for managing their variable output and maintaining system stability. Reactive power helps keep voltage levels within acceptable limits, which is vital for the stable operation of the power system. It improves efficiency, reduces losses, and enables transmission lines to carry more power without exceeding thermal limits, effectively increasing their transfer capability.

MISO has adopted a more conservative approach during model building and criteria selection for future Inverter-Based Resources (IBR), with their reactive capabilities determined by their output i.e. +/- .95 Power Factor based on output at the time and system needs. MISO used default acceptable steady-state thermal and voltage limits, as well as post-contingency voltage deviation and transient voltage response criteria established by each Transmission Owner (TO) or Transmission Planner (TP). For issues affecting multiple TO/TP footprints, the most conservative planning criteria among the relevant TOs/TPs will apply. If a TO/TP does not specify voltage criteria, the MISO criteria outlined in Appendix K of the BPM-020 Transmission Planning Business Practice Manual will be used by default.

Economic Analysis

Economic analysis requires a market-type dispatch reflective of [MISO Futures](#) modeling and planned topology set by the [MTEP powerflow model](#) in order to evaluate potential future transmission inefficiencies. MISO's economic analysis process relies on the production cost modeling software PROMOD to identify and address economic issues caused by these inefficiencies.

PROMOD dispatches generation to meet load for every hour over the course of the year based on the constraints and assumptions included in the model. Constraints like key flowgates identified in the Flowgate Identification process, and assumptions for battery dispatch, as detailed in MISO's [Series 1A Battery Modeling Whitepaper](#), increase the complexity of PROMOD runs and analysis.



To understand the impact of these constraints and assumptions, economic analysis occurs throughout the study process. MISO completes PROMOD runs and assesses outputs through each stage of the study process to review model accuracy, address dispatch assumptions, identify issues, and find transmission solutions. The [Economic Modeling](#), [Futures Energy Adequacy](#), and [Alternatives Analysis](#) sections provide details on how PROMOD was utilized in various stages of the Tranche 2.1 process. Additional critical components of the economic analysis process are detailed below.

Economic Metrics

The metrics in Table 2.4 are calculated from PROMOD outputs and used by MISO’s Economic Planning team to assess the economic impact of proposed projects.

Economic Metric Name	Description	Use
Congestion Measure (\$/MW)	An indication of the production cost savings opportunity from relieving transmission congestion	<ul style="list-style-type: none"> Identifying most constrained transmission elements A reduction in Congestion Measure for a constraint or group of constraints indicates a more optimal regional dispatch
Curtailment (MWh)	A measure of the total amount of energy from renewable sources which cannot be delivered economically	<ul style="list-style-type: none"> Reduction of curtailment at a single generator improves that unit’s financial viability Reduction of total curtailment in a region indicates that transmission investments enable additional renewable generation
Load LMP (\$/MWh)	The Locational Marginal Price (LMP) is the market price to purchase energy from a market. Load Weighted LMPs are expressed as an average price weighted by energy each hour and at each delivery point and are indicative of the price of energy in a region	<ul style="list-style-type: none"> A price separation in Load LMPs across a region indicates that transmission is limiting efficient dispatch, resulting in overall higher production costs
Adjusted Production Cost (APC) (\$)	A measure, by company, of the costs to serve demand, considering the effect of purchase and sales	<ul style="list-style-type: none"> Evaluating the combined measure of the operating cost of companies within MISO
Adjusted Production Cost Savings (\$)	APC Savings are seen when APC decreases from one model to another (i.e., Reference Case – Change Case). A company sees APC Savings when they dispatch lower cost generation, purchase power at a lower load LMP, or sell power at a higher Gen LMP	<ul style="list-style-type: none"> Evaluating portfolio benefits in the Business Case
Generation Enablement (MW)	A Distribution Factor (DFAX) based methodology to determine which Future Series Model Built resources are enabled by regional transmission to connect to the system	<ul style="list-style-type: none"> Future Series Model Built resources with $\geq 5\%$ DFAX are considered enabled

Table 2.4: Economic Metrics



Congestion Measure

Economic congestion is assessed using “Congestion Measure” (\$/MW), which is calculated by multiplying the annual Average Annual Shadow Price (\$/MW/hr) of a transmission constraint by the number of annual Binding Hours (hr/yr) in which congestion at that constraint is observed. Congestion Measure approximates the annual savings for the next additional MW that could flow if that constraint was relieved. It is used as an indicator of the magnitude of economic opportunity from relieving individual transmission constraints, and when summed over all the constraints in a region, it measures whether a project or set of projects has relieved congestion in that region.

Curtailement

Curtailement is a measure of the amount of energy (MWh) which is available from non-thermal generators (generally Wind, Solar, and Hydro), but cannot be dispatched and delivered economically primarily due to two reasons: transmission constraints and/or competition between abundant renewable resources to serve load, when available resources exceed load.

A reduction in Curtailement is generally seen when transmission constraints that limit the output of non-thermal generating resources are relieved by transmission investments. Curtailement may be caused by any constraint in a PROMOD case, and not all Curtailement will be caused by transmission congestion.

Load Weighted Locational Marginal Price (Load LMP)

Price to serve load is presented using Load-weighted Locational Marginal Prices (\$ / MWh) or Load LMPs. LMPs represent the marginal cost at a given location to deliver one additional MWh of energy in a given hour. A Load LMP represents the marginal cost to deliver one additional MWh of energy within a given region and over a given period of time. It is computed as the weighted average of LMPs using the hourly and locational distribution of demand energy as weighting factors.

Adjusted Production Cost

Adjusted Production Cost (APC) is a measure of the cost to serve load by company and is utilized to capture the differences in production costs between two models. This metric is used in portfolio development to identify and compare economic benefits across alternatives as well as in the Business Case to project 20-year APC savings.

Adjusted Production Cost Savings

Additional details on APC Savings can be found in [MISO’s Business Case Metrics Methodology Whitepaper](#) under the section on Congestion and Fuel Savings. MISO’s APC calculation methodology is described in detail the [MISO APC Methodology Whitepaper](#).

Generation Enablement

Distribution Factor (DFAX) analysis is 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, determining the amount of generator impact on facility loading. In this analysis, Future Series Model Built resources are considered enabled if they have a DFAX $\geq 5\%$ against reliability constraints that are addressed by regional transmission.



Reliability and Economic Analysis Results

The total resource expansion for Future 2A in the Midwest subregion provided the starting point in identifying transmission issues and anticipated Tranche 2.1 solutions. Regional analysis identified key system issues under Future 2A, providing a foundation from which to develop transmission concepts into a draft portfolio. As part of the 7-step process, the economic and reliability analysis identified potential transmission issues.

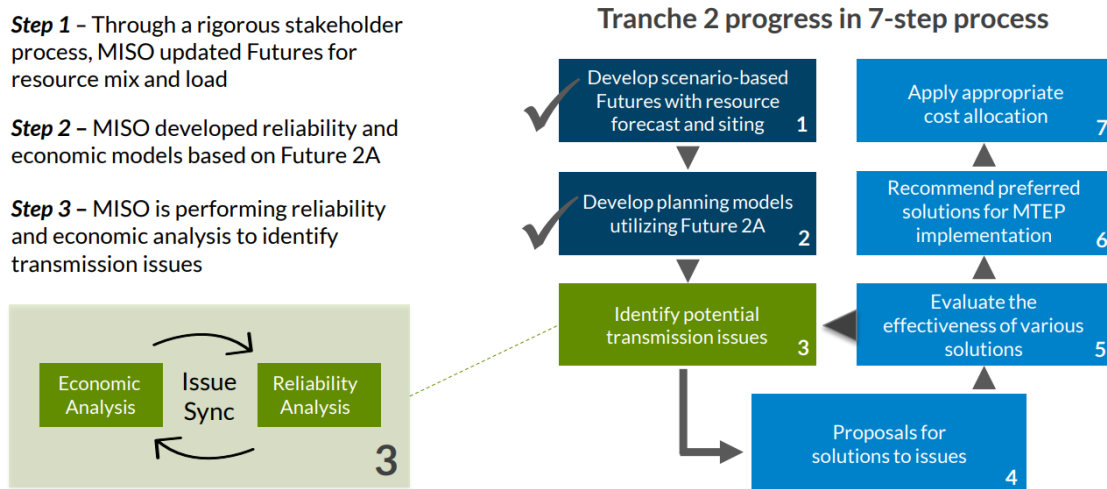


Figure 2.18: Economic and Reliability Transmission Issue Identification

The initial constraints discussed in the December 2023 LRTP workshop ([economic](#) and [reliability](#)) shaped the Tranche 2.1 portfolio. The economic analysis showed needs for MISO West, Central and East. Severe congestion was driven by high renewable penetration and load that lacked high-voltage regional transmission support to alleviate existing transmission. Similarly, the reliability analysis pointed to the need for significant transmission system enhancements. Both the economic and reliability analysis indicated significant transmission issues through the Midwest region (See Figure 2.19: Summary of Reliability and Economic Issues) and pointed to the need for a high voltage regional transmission backbone, including:

- Severe wide-area congestion across the MISO Midwest subregion
- Wide-area economic price separation between the West and East/Central regions
- Significant generation curtailment due to severe economic congestion on numerous lines
- Significant levels of overloads and voltage violations on High Voltage (HV) and Extra-High Voltage (EHV) equipment throughout the footprint
- With the changing resource fleet and decrease in reactive support, system is stressed with the expected results of lower stability limits of longer distance transmission lines
- Substantial increase in voltage angle difference between sending and receiving end as power is traveling a longer distance to reach load
- Multifold increase in system losses due to long-distance transfer and stressed transmission system



This analysis drove the development of transmission solutions for a draft portfolio.



WEST

- 20% of the facilities were found to be overloaded
- Annual curtailments exceeded 40%
- Energy losses over transmission lines increased from 2.5% to 11%

RELIABILITY ISSUES

ECONOMIC ISSUES

kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	66	206	28	1,000-4,000
230	41	208	17	150-4,100
<200	496	263	76	50-6,000

CENTRAL

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission enabled transfer of regional power
- Needs were refined through transfer sensitivities and multi-element contingencies

kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	21	171	23	11-2,500
230	13	142	5	25-960
<200	158	191	53	20-2,560

EAST

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission supported daily and nightly import / exports

kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	7	113	3	60-135
<200	159	223	42	10-2,400

Figure 2.19: Summary of Reliability and Economic Issues

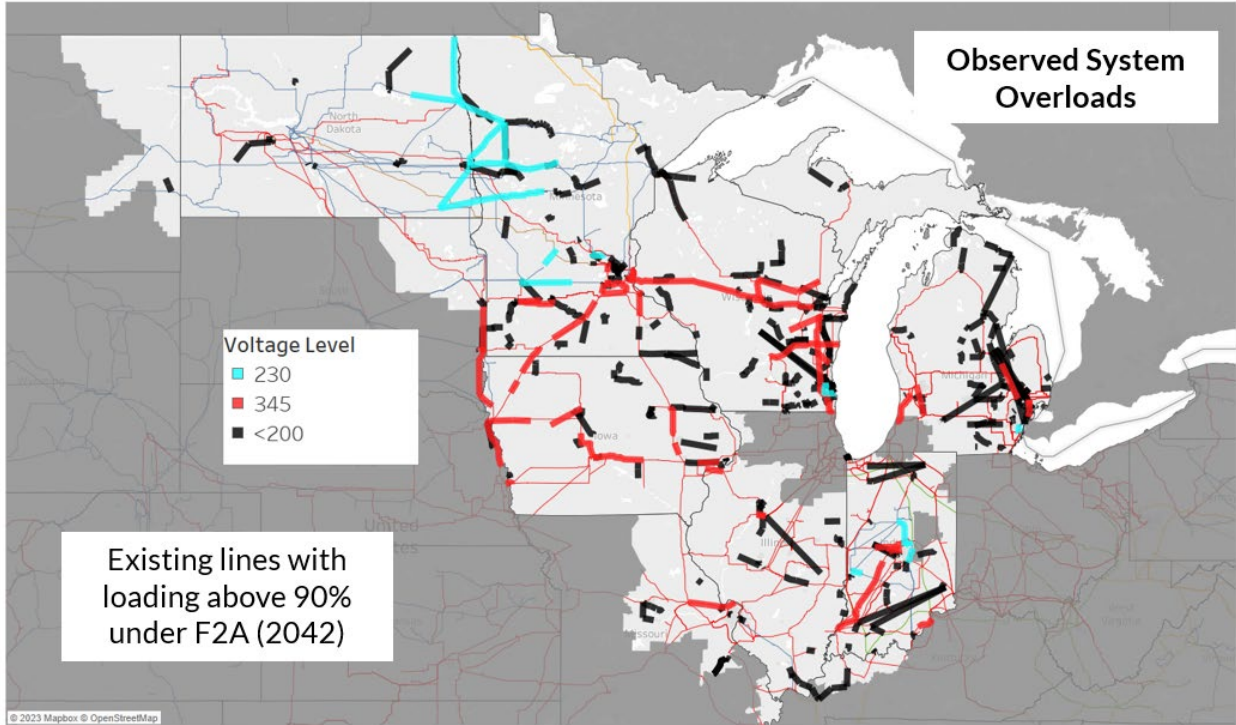


Figure 2.20: MISO Midwest subregion map showing thermal constraints observed by voltage level

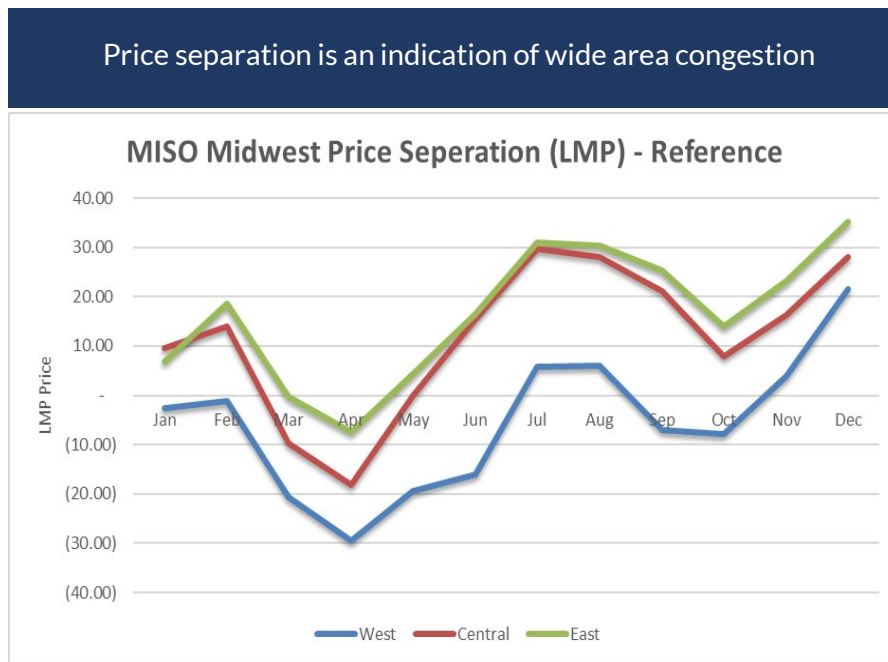


Figure 2.21: Figure 2.23: MISO Midwest Price Separation

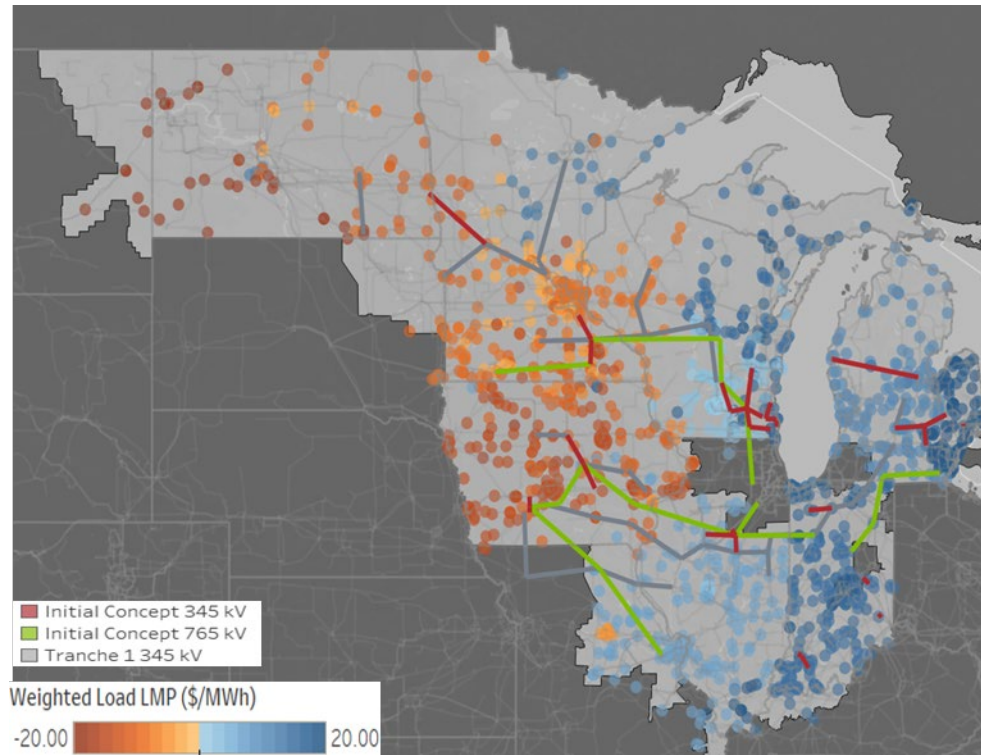


Figure 2.22: Pre-Portfolio LMP Map

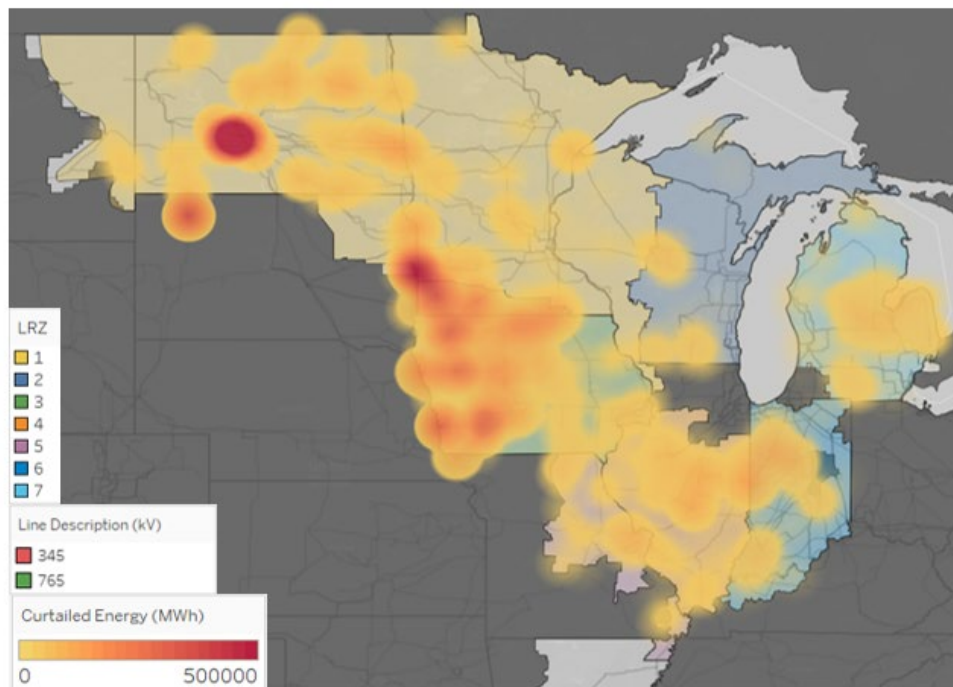


Figure 2.23: MISO Midwest Generation Curtailments Pre-Portfolio



West Region

The West region shows the need for higher voltage transmission facilities to support large power transfers and deliver generation from remote areas to load centers. MISO noted significant overloads and curtailments. Twenty percent of facilities are overloaded, curtailments exceed 15% and energy losses over transmission lines increase from 2.5% to 11%. This is also an area where line losses increase as the existing system attempts to deliver power from the Future 2A resource mix.

kV	RELIABILITY ISSUES		ECONOMIC ISSUES	
	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	66	206	28	1,000-4,000
230	41	208	17	150-4,100
<200	496	263	76	50-6,000

Table 2.5: West Region - Reliability and Economic Issues

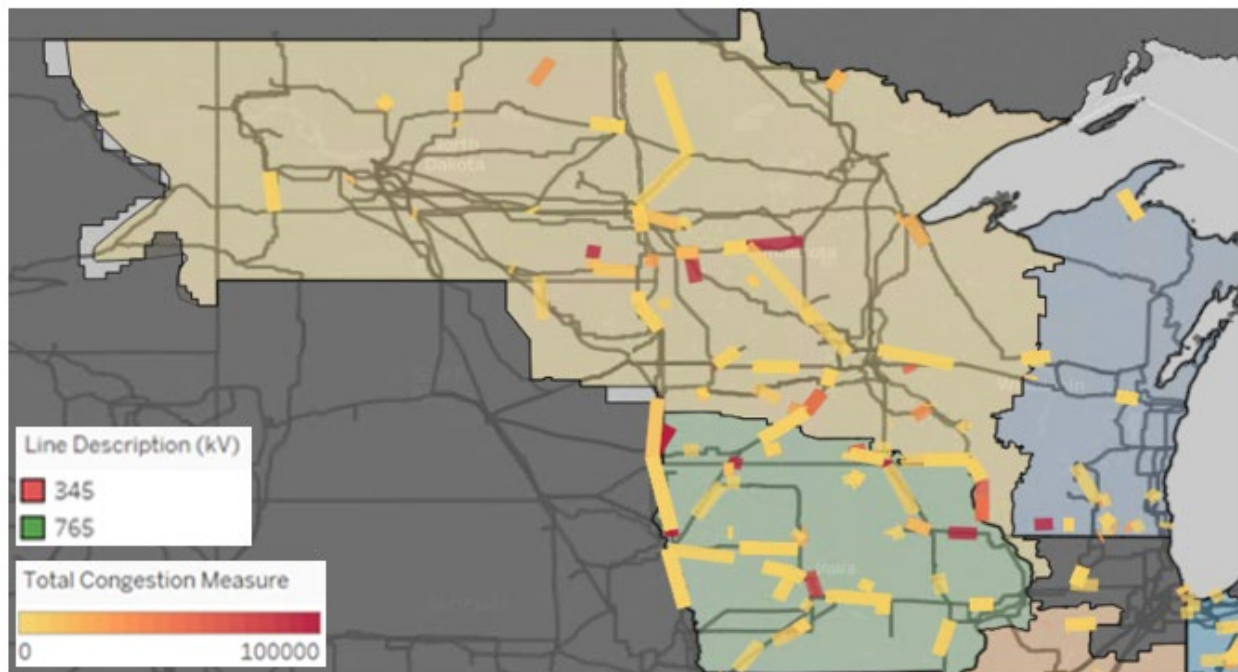


Figure 2.24: Reference Case: Economic Congestion (West)



Central Region

Transmission in the Central region will be key to enabling system transfers and supporting high transfer scenarios between the East and West regions. In the base Future 2A power flow cases, MISO sees 10% of facilities exhibiting overloads. In addition to these overloads, MISO expects that enabling resources in the West region will increase regional transfers into and through the Central region. MISO also has seen historically that the Central region is highly impacted by different transfers and weather patterns that it needs to consider. Multi-element contingencies will also have a large impact on this region and drive additional needs.

kV	RELIABILITY ISSUES		ECONOMIC ISSUES	
	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	21	171	23	11-2,500
230	13	142	5	25-960
<200	158	191	53	20-2,560

Table 2.6: Central Region – Reliability and Economic Issues

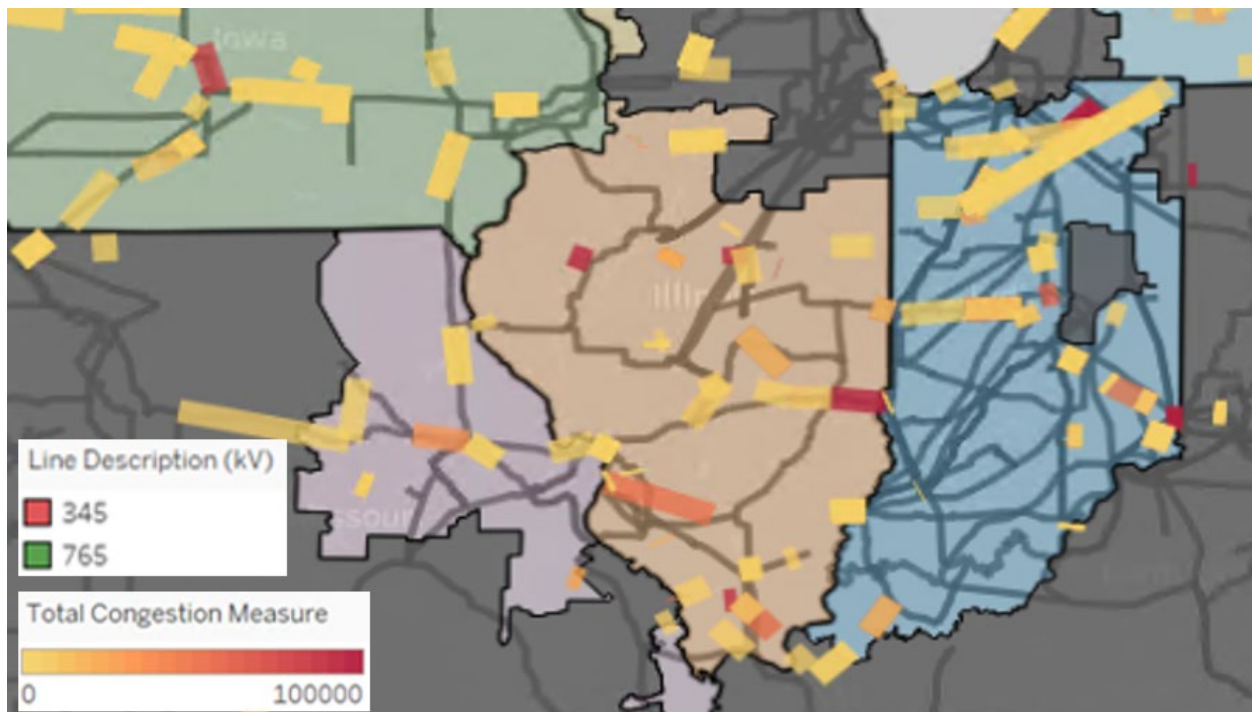


Figure 2.25: Reference Case: Economic Congestion (Central)



East Region

The East region's transmission solutions will need to consider transfer limits as changes to the resource mix create the need to enable increased imports and exports to and from the state. MISO sees more overloads (10% of facilities) and curtailment issues (annual curtailments exceed 15%), and especially the impacts of the resource fleet evolution in different import and export patterns between day and night. There is excess capacity during the day with solar resources, but imports will be needed during night hours.

kV	RELIABILITY ISSUES		ECONOMIC ISSUES	
	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	7	113	3	60-135
<200	159	223	42	10-2,400

Table 2.7: East Region - Reliability and Economic Issues

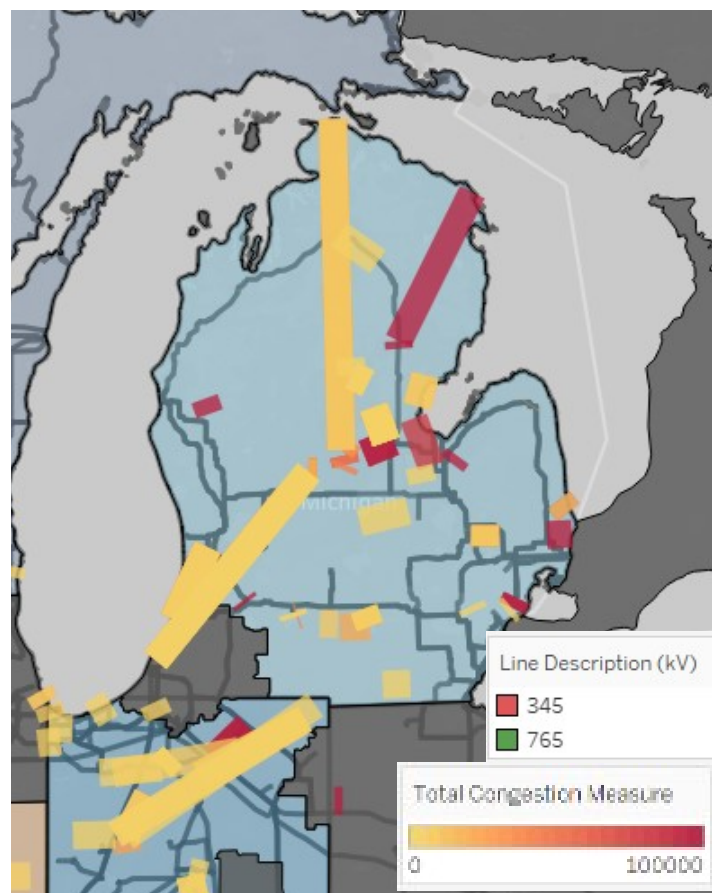


Figure 2.26: Reference Case: Economic Congestion (East)



Step 4: Propose Solutions

As MISO understood the impacts of member plans throughout the planning process, conceptual ideas were developed for what the potential transmission solutions may be. In January 2023, MISO shared a hypothetical roadmap taking concepts from its initial long-term roadmap shared in 2021. This map continued to be refined focusing on a 765 kV regional solution accounting for a future with more remote resources, and where safe loading limits and absolute limits will become more relevant. Absolute limits and Safe Loading Limits decrease as line length increases. As discussed in [March PAC material \(March 8, 2023\)](#), some considerations of the performance of 765 kV include:

- Transmission Limits including Safe Loading Limits and Absolute Limits,
- Cost per MW-Mile, and
- Land-Use per MW-Mile.

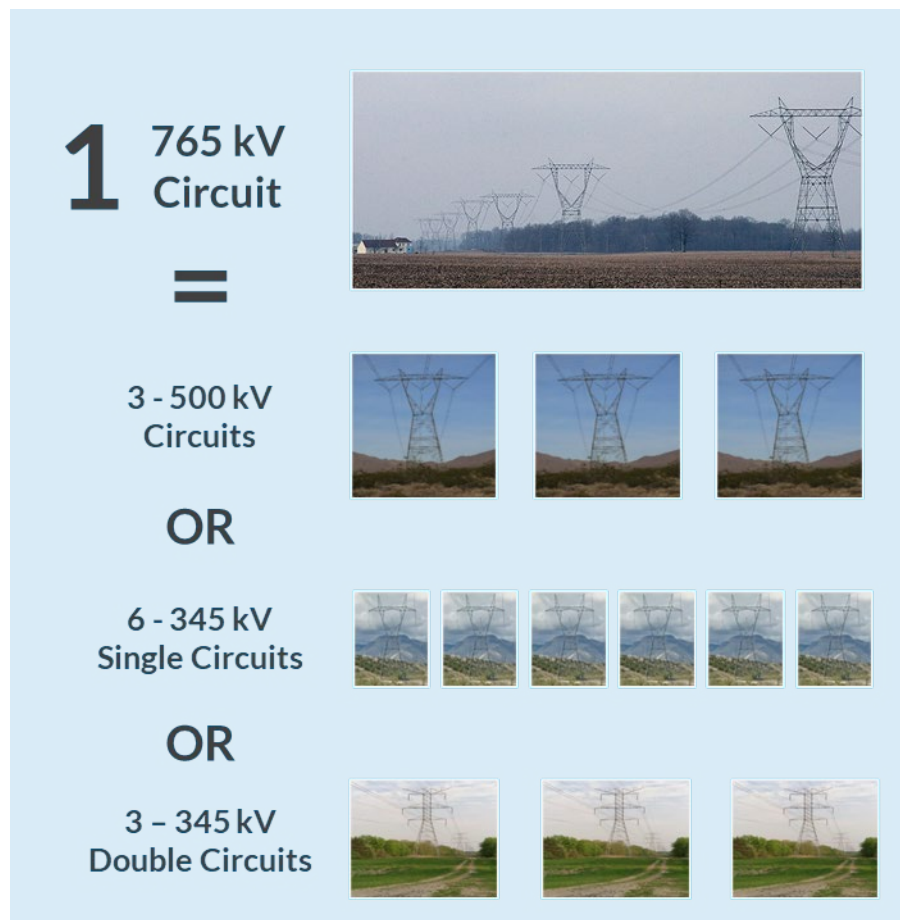


Figure 2.27: Land-Use Evaluation per Transmission Voltage



When considering the per MW-mile capability of 765 kV and 345 kV lines, 765 kV has much higher loading capability than 345 kV, particularly for longer distances. For Tranche 2.1, 50% of the proposed 765 kV facilities are more than 120 miles long. At 120 miles, the Safe Loading Limit of a 345 kV line is less than 1,000 MVA and 765 kV is 4,500 MVA. The loadings observed on the Tranche 2.1 765 kV facilities range between 2,000 and 4,000 MVA.

The cost per MW-mile of a 765 kV line is generally 33% to 50% of the cost per MW-mile of 345 kV or 500 kV lines. This implies a long distance, well utilized regional transmission system would cost much less if it incorporated a substantial amount of 765 kV transmission. Conversely, it would be much more costly to develop the required regional transmission system using only 345 kV transmission, and substantially even more cost to develop the system slowly and incrementally using sub-Extra High Voltage transmission only.

Given 345 kV is a legacy voltage, a hybrid regional solution making significant use of both 765 kV and 345 kV facilities is the optimal solution. If transmission upgrades were facilitated incrementally using 138 kV lines in place of 765 kV, the cost would be 12 to 18 times higher for 138 kV incremental transmission upgrades than it would be for 765 kV on a cost per MW-mile basis.

In addition to lower cost, a 765 kV line requires less land-use on a per MW-mile basis than 500 kV or 345 kV. The land use in acres per MW-mile required for 765 kV is less than 25% to 67% of the land use required in acres per MW-mile for the equivalent 345 kV alternative, and about 33% of the land use required in acres per mile for 500 kV.



Figure 2.28: Progress of Portfolio Development

Refining Solutions

Robustness Testing

A key objective of robustness testing is to identify key projects that were either approved or in the process of approval subsequent to the finalization of LRTP power flow models in October 2023, which may have a material impact on the anticipated Tranche 2 portfolio. The second main objective is to perform an assessment with and without key projects and identify areas that may result in MISO modifying, adding to, or removing transmission facilities in the LRTP portfolio.

- **Removals:** Tranche 2 projects or segments may be considered for removal and replacement by key projects. Evaluate areas where the reliability impact provided by key projects and Tranche 2.1 projects overlap or duplicate independently.
- **Modifications:** Tranche 2.1 projects or segments may be considered for modifications. Evaluate areas whether issues addressed by key projects and Tranche 2.1 projects are closely related and if modifying Tranche 2.1 transmission facilities could optimize the reliability impact of both.



- **Additions:** Consider potential adverse effects on the system resulting from the inclusion of key projects, while also considering constraints that may be local in nature that are better resolved in annual MTEP reliability planning and the generator interconnection processes.

If initial robustness testing results in a reliability impact such as need for removal, modification or addition, then further testing may be conducted utilizing some or all of the remaining core reliability cases and additional transfer scenarios that represent various system conditions and dispatch patterns to better understand the impacts of all projects and system changes.

Key Projects

Tranche 2 robustness testing refers to a process for reviewing the impact of system changes, specifically key projects, that were either approved or under consideration following the completion of LRTP power flow models in October 2023 which may affect the anticipated Tranche 2 portfolio. Each key project that is identified for robustness testing is analyzed in detail by looking at the relevant system conditions and contingencies with and without key projects. Performance of projects, effectiveness in resolving identified needs, or any new criteria violations is documented during the testing process.

MISO completed an assessment on the impact of select MTEP23 and MTEP24 projects, the JTIQ projects, and the Grain Belt Express (GBX) Merchant High Voltage Direct Current project. The MISO-SPP Joint Targeted Interconnection Queue Projects facilitate the integration of new resources by optimizing the transmission infrastructure required across regional boundaries. The JTIQ and Tranche 2.1 projects, being electrically close, complement each other. JTIQ projects do not negate the need for the Tranche 2.1 portfolio. The GBX project does not prompt any required modifications to the Tranche 2.1 portfolio located within its solution area. There is a noticeable reduction in overloads and lines loadings on monitored flowgates with addition of the Tranche 2.1 portfolio.

Eligible projects

In Tranche 2, the powerflow core models were built from the MTEP22 topology (including LRTP Tranche 1 approved projects) with load, generation, and siting information from Future 2A. After much collaboration and engagement with stakeholders, powerflow models were finalized in October 2023. These models used best-known information at the time of completion. Key projects were selected from the following categories for robustness testing:

- MTEP23 portfolio of projects approved by MISO's Board in December 2023
- The Transmission Connection Agreement (TCA) for the GBX Merchant HVDC project was accepted by FERC in February 2024
- JTIQ projects, subject to FERC approval and MISO Board approval
- MTEP24 portfolio of projects to be approved by MISO's Board in December 2024

Generally, projects on the 230 kV system and above that are electrically close to identified issues and transmission facilities shown on the March 4th portfolio map would qualify to be tested. It is important to highlight that if any of the key projects from MTEP23, MTEP24, JTIQ, or Grain Belt Express have a material impact on the anticipated Tranche 2.1 portfolio, that impact will be detected in the robustness testing. Based on the criteria described above, MISO identified several projects for Tranche 2.1 robustness testing, listed below:



Key projects eligible for robustness testing	Category	PSSE Area Number ³
P23026 – New South-Central Illinois Transmission Expansion	MTEP23	357, 361
P50106 – Big Cedar Interconnection	MTEP24	627, 635
Bison – Hankinson – Big Stone South 345	JTIQ	600, 608, 613, 615, 620, 627, 633, 635, 661
Lyon Co. – Lakefield 345		
Raun – S3452 345 kV		
Auburn – Hoyt 345 kV		
Grain Belt Express with projects as identified in Transmission Construction Agreement	MHVDC	356, 357, 330, 333

Table 2.8: Summary of Key projects eligible for robustness testing

MISO’s initial screening used the LRTP 20-year out average load model, developed for Tranche 2.1 reliability assessment with Future 2A assumptions. Models are described in detail in the [Reliability Study Whitepaper](#).

The 2042 LRTP Average Load Case represents typical system conditions within 70-80% on the load duration curve. This scenario is the most stressed case because it has 100% renewable penetration, meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. To better assess the impact of key projects, MISO ran all single initiating events, i.e., contingencies, on the following four scenarios first, then supplemented results with two additional scenarios incorporating the outcome of the alternative analysis (Key projects shared at the [May 13, 2024 LRTP workshop](#) and additional study material is posted on [MISO Sharefile](#)):

Models with March 2024 Initial Proposed Portfolio Results:

1. The 2042 LRTP Average load case (i.e., most stressed LRTP case)
2. The 2042 LRTP Average load case + LRTP T2.1 anticipated portfolio of projects
3. The 2042 LRTP Average load case + key projects
4. The 2042 LRTP Average load case + key projects¹ + LRTP T2.1 anticipated portfolio

Models with May 2024 Near-Final Proposed Portfolio Results:

1. The 2042 LRTP T2.1 Average load case with Alternatives Portfolio
2. The 2042 LRTP T2.1 Average load case with Alternatives Portfolio + key projects

At a high level, the process diagram below best illustrates robustness testing. The diagram refers to the models used for robustness testing and key projects were presented in May.

³ Key projects are electrically far away from each other and grouped by location (PSSE Areas #) to focus more closely on their impact.

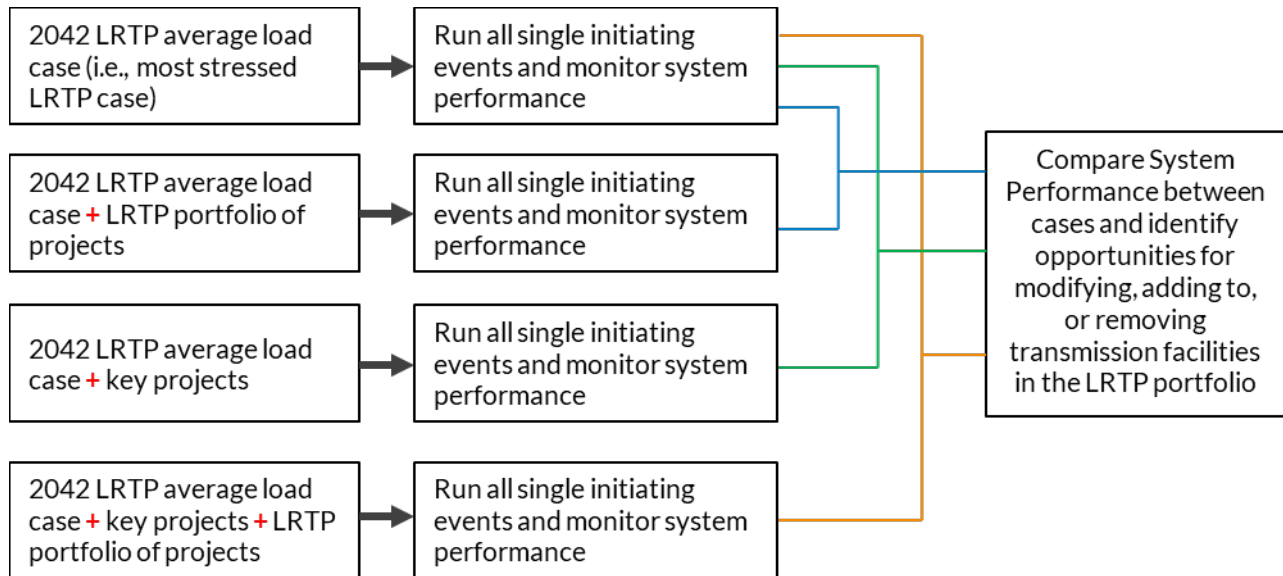


Figure 2.29: Models used in robustness testing

To gauge the impact of key projects more accurately, MISO first evaluated all single-initiating events using four scenarios from the March 2024 Initial Proposed Portfolio. Then this analysis was enhanced by incorporating two additional scenarios featuring alternative projects from the May 2024 Near-Final Proposed Portfolio. Key projects were shared at the [May 13, 2024, LRTP workshop](#).

Project P23026: New South-Central Illinois Transmission Expansion and Project P50106: Big Cedar Interconnection:

Robustness testing assessment reinforces the projects' alignment with local needs, consistent with their MTEP justification. No Tranche 2.1 project areas have been pinpointed for addition, removal, or modification. More information about the projects, local needs and robustness evaluation can be found at the [June 10, 2024, LRTP workshop](#).

JTIQ Projects

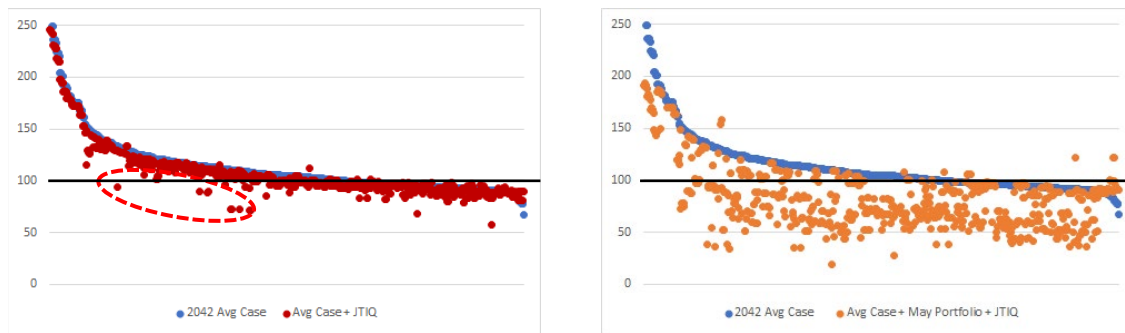
The MISO-SPP Joint Targeted Interconnection Queue Projects enable interconnection of new resources by optimizing transmission needed for interconnection across the seams. JTIQ projects have a positive impact on reducing overloads and loadings on monitored flowgates; consistent performance was observed with the March and May portfolios. JTIQ and LRTP Projects are electrically close, serving to complement rather than compete with one another. No Tranche 2.1 project areas have been pinpointed for addition, removal, or modification of projects required due to a very limited reach.

Models with May 2024 Near-Final Proposed Portfolio Results

Out of about 700 monitored flowgates, only a handful (highlighted in red circles in Figure 2.30) were considered for modification. The positive impact of JTIQ on monitored flowgates is noteworthy, yet it doesn't possess the comprehensive scope and robustness needed to entirely substitute or modify sections within the LRTP portfolio. There's a clear synergy among multiple local flowgates; JTIQ and LRTP portfolio



combined resolved non-converged events, enabled transfer of power, and bolstered the overall system strength.



- Flowgate loading in the Avg Case with and without JTIQ
- Red demonstrates JTIQ reduces loadings on some monitored flowgates versus the Avg Case without JTIQ
- Flowgate loading in the Avg Case with and without JTIQ + near-final proposed portfolio
- Orange demonstrates JTIQ and near-final proposed portfolio complements each other, further reducing flowgate loading

Figure 2.30: Flowgate loading in the Average Case with and without JTIQ vs Flowgate loading in the Average Case with and without JTIQ + near-final proposed portfolio

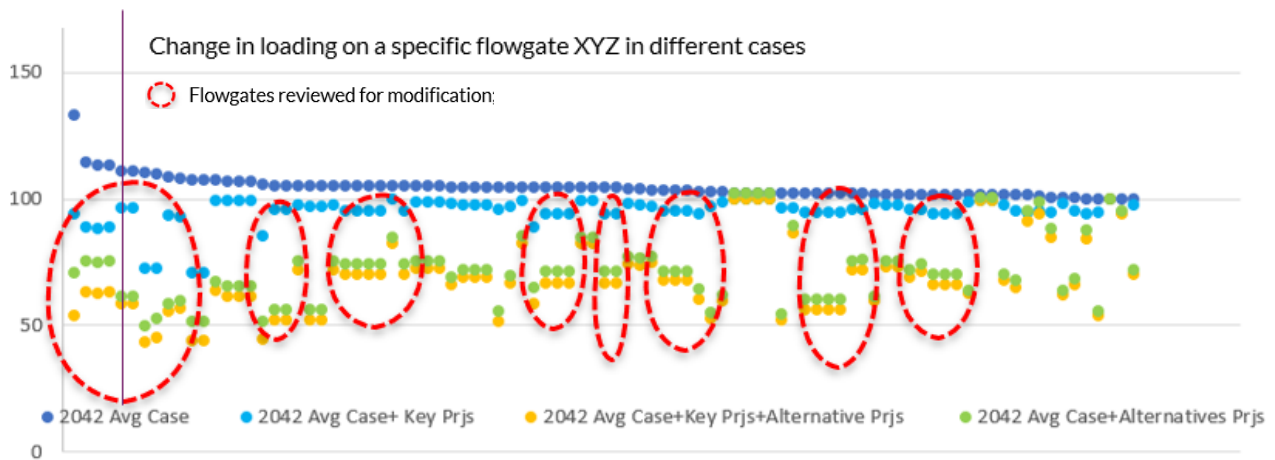


Figure 2.31: Flowgates considered for modification

Grain Belt Express (GBX)

Merchant HVDC Transmission Line with projects as identified in Transmission Connection Agreement (TCA). MISO appropriately modeled key transmission projects eligible for robustness testing to ensure a least-regrets, robust portfolio.

- Transmission line(s) modeled with appropriate characteristics.
- Grain Belt Express (GBX) modeled as a single 1.5 GW generator injection at the MISO Point of Interconnection (POI) and a single 1.0 GW generator injection at the AECI POI.



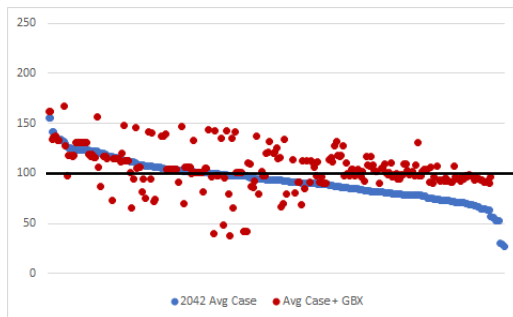
- Modeled MISO network upgrades associated with the injection.
- Dispatch:
 - Injection of 1.5 GW (GBX) into the MISO system was balanced with renewables across MISO Midwest system scaled down to balance load/losses with generation.
 - Injection of 1.0 GW (GBX) into the AECL system was balanced with output reduced by 1.0 GW from the oldest coal units.

All Network Upgrades identified in the Transmission Connection Agreement (TCA) were added ([Click here](#) for a detailed list of all connection facilities and necessary upgrades specified in the TCA):

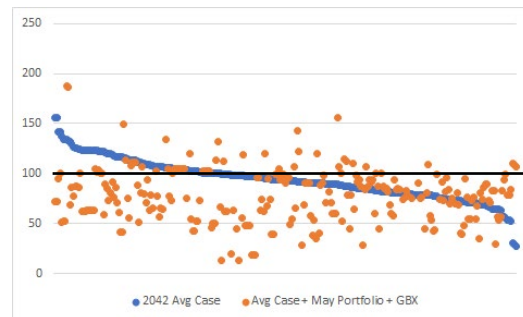
- New Burns-Montgomery 345 kV lines (2X)
- Rebuild Big Creek-Warrenton 161 kV line
- Rebuild Belle Tap Gasco Tap 138 kV line
- Rebuild Belle Tap-Meta Tap 138 kV line
- Rebuild Bland- Gasco Tap 138 kV line
- Rebuild Miller-Meta Tap 138 kV line
- Rebuild Warrenton-Montgomery-3 161 kV line

Models with May 2024 Near-Final Proposed Portfolio Results

Grain Belt Express (GBX) 1.5 GW injection further stressed the system; GBX 1.5 GW injection performance with the May portfolio still closely mirrors the March portfolio, no Tranche 2.1 project areas have been pinpointed for addition, removal, or modification. The near-final Tranche 2.1 projects strengthen the system and have a positive impact on reducing overloads and loadings on monitored flowgates.



- Flowgate loading in the Avg Case with and without GBX
- Red demonstrates GBX increases loadings on some monitored flowgates and reduces loadings on others versus the Avg Case without GBX



- Flowgate loading in the Avg Case with and without GBX + near-final proposed portfolio
- Orange demonstrates GBX + near-final proposed portfolio reduces stress for some flowgates

Figure 2.32: Flowgate loading in the Average Case with and without GBX vs Flowgate loading in the Average Case with and without GBX + near-final proposed portfolio



The near-final Tranche 2.1 proposed portfolio posted in May significantly reduces overloads/loadings on monitored flowgates when compared to the 2042 Avg Case + GBX without the near-final proposed portfolio demonstrating enhanced reliability for the MISO Midwest subregion, enabling member plans for fleet transition, load growth and regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty.

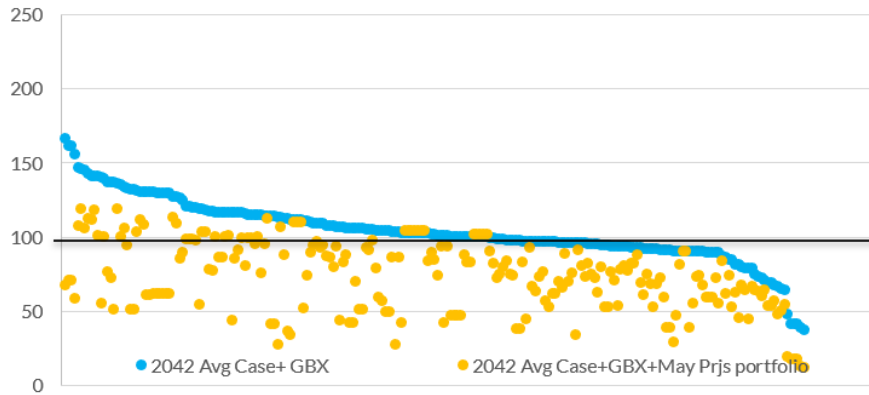


Figure 2.33: Flowgate loading in the Average Case with GBX vs. Flowgate loading in the Average Case with GBX + near-final proposed portfolio

Alternatives Analysis

Analysis of alternatives was performed and 97 projects representing 47 solutions were received from stakeholders. Not all these solutions were evaluated as MISO focused on alternatives that are more closely aligned with the same issues and needs that drove the solutions for this portfolio, various alternatives were similar in location and ones that are likely to be constructed in a timely manner. Additionally, some solutions were evaluated along with variations of alternatives developed by MISO staff, and some projects addressed more local versus regional needs and are more suited for the annual MTEP reliability planning and the generator interconnection processes. **Based on alternative analysis, MISO made additions to the portfolio in MN, IA, IN, ND, SD, MI and replacement in MO.**

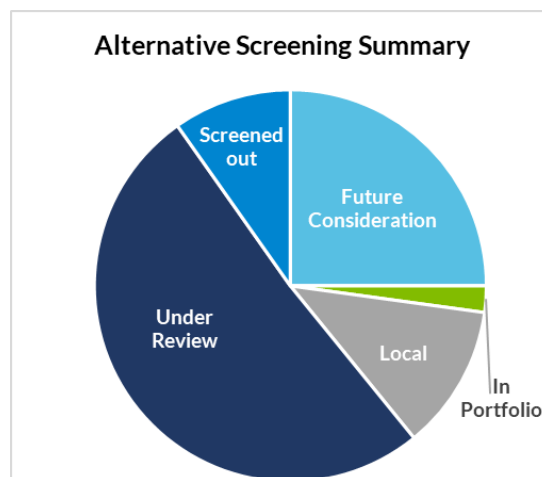


Figure 2.34: Alternative Screening Summary



Process

Alternative solutions were reviewed within key considerations.

- Does it align with the initial portfolio?
- Does it contribute to the objectives of Tranche 2.1?
- Is it focused on regional needs considering historic and new transfer patterns across the Midwest?
- Does it contribute to resolving and/or further mitigating identified issues in the subregion or region?
- Does it cause other potential issues?

Additionally, the following decision factors also guided analysis:

- If an alternative solution was identical or close to solutions already in the initial concept, there was no need to test the alternative solution. However, minor adjustments could be considered as appropriate.
- If an alternative solution was additive to the initial concept, MISO could recommend the project be resubmitted as an alternative in a future planning process.
- MISO could create a new alternative by combining components of one or more alternatives, and potentially combine them with initial solution concepts.
- Some alternative solutions could be screened out for several qualitative reasons, such as alignment with overall objectives and concept, constructability, permitting risk, local rather than regional focus, and other various reasons.

Of the 97 alternative solutions submitted, 47 passed the threshold for analysis.

- 97 alternative solutions were submitted by 32 entities
 - 21 Transmission Owners
 - 8 Transmission Developers
 - 3 Transmission Dependent Utilities
- Most included multiple facilities
- Alternatives recommended replacements and additions
- There were common facilities among multiple solutions

Analysis Decisions for Alternatives

- Under Review: Alternative or variations will be considered for Tranche 2.1
- Future Consideration: May be considered as possible solutions in future planning initiatives including, but not limited to, future LRTP initiatives



- In Portfolio: Represent proposed facilities already included in the March Tranche 2.1 initial proposed portfolio
- Local: Mainly resolving local issues
- Screened Out: Will not be considered in the current Tranche 2.1 based on initial screening

Alternative Analysis Results

MISO grouped the 47 alternatives into six studies for engineering analysis to understand system performance. Reliability analysis focused on the alternative performance compared to the March 4, 2024, draft portfolio (presented at March 15, 2024, LRTP workshop) with supplemental information from the base model (without portfolio) and transfer scenarios. Economic analysis focused on the alternative compared to the March 4th draft portfolio and reference case model (without portfolio). Details were provided via Sharefile.

No.	Alternative Description	Location	Recommendation
1	Maple River – Cuyuna 345	ND/MN	Add to portfolio
1	Big Stone South – Brookings – Lakefield 765	SD/MN	Add to portfolio
1	Lakefield – East Adair 765	MN/IA	Add to portfolio
1	Reynolds – Sullivan 765	IN	Do not add to portfolio
2	Denver – Nelson Road 345	MI	Add to portfolio
2	Goss – Sabine 345 Replaces: Oneida – Sabine Lake 345	MI	Do not add to portfolio
3	Brookings – Chisago Co. – Highway 22 – Paddock – Plano 765 Replaces: Lakefield – Pleasant Valley – North Rochester – Jefferson Co – Plano 765	SD/MN/ WI/IL	Do not replace project in portfolio, keep original
4	Milan – Sumpter 345	MI	Do not add to portfolio
4	Duff – Culley – Reid 345, AB Brown 2nd XF, Culley 2 XFs	IN/KY	Add to portfolio
4	Iron Range – St. Louis – Arrowhead 345	MN	Add to portfolio
4	Big Stone S – Hazel Creek – Blue Creek 345	SD/MN	Do not add to portfolio
5	Montgomery – Sioux – Stallings 345, Kingdom – Bland – Labadie 345	MO/IL	Do not add to portfolio
5	St. John – Burr Oak 345	IN	Do not add to portfolio
5	Lehigh – Twinkle 345	IA	Add to portfolio
6	Maywood – Belleau – MRPD- Sioux, MRPD – Bugle – Roxford/Gateway) 345 + XFs Replaces: East Adair – Timber Branch – Labadie 765	MO/IL	Replace project in portfolio

Table 2.9: Project grouping for alternative analysis



Alternative 1 - New 765kV from South Dakota through Minnesota into Iowa and North Dakota 345kV outlet into Northern Minnesota and evaluation of southern Indiana 765 kV

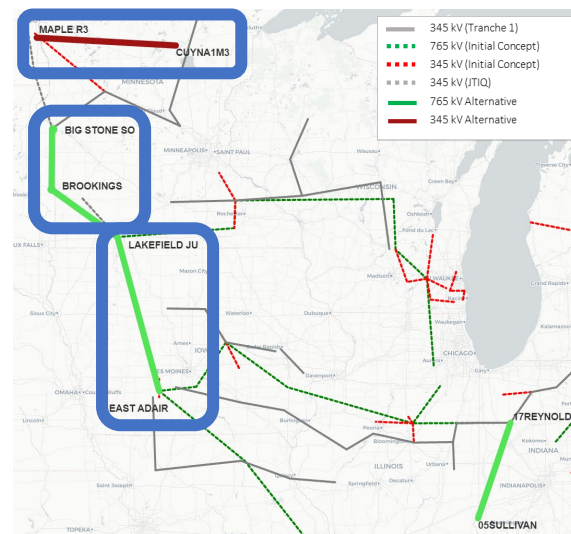


Figure 2.35: Map shows selected Alternative 1 projects in blue boxes

Alternative 1 adds four projects to the portfolio and unlocks generation in the West as a complement to existing and 765 kV paths in the initial draft portfolio.

- 3 project proposals to add in MN/SD/ND/IA
 - Maple River – Cuyuna 345
 - Big Stone South – Brookings County –Lakefield Junction 765
 - Lakefield – East Adair 765
- 1 project proposal to add in IN
 - Reynolds – Sullivan 765
- No projects from initial portfolio replaced or removed

Alternative 1 facilitates Future 2A fleet change by increasing the deliverability of renewable energy and providing more production cost savings for the MISO Midwest.

- 765 kV from South Dakota through Minnesota into Iowa increased delivered energy from North Dakota, South Dakota, Minnesota, Iowa and is added to the portfolio.
- 765 kV from Lakefield to Adair completed a redundant loop configuration for the 765 kV projects, allowing greater reliable use of other portions of the proposed 765 kV system and is added to the portfolio.
- 345 kV from North Dakota to Minnesota improved North Dakota exports and is added to the portfolio.



- Reynolds – Sullivan 765 did not result in significant congestion relief without additional support and therefore was not selected to be added to the portfolio.

Maple River – Cuyuna 345; Big Stone South – Brookings – Lakefield 765; Lakefield – East Adair 765

Overall, Alternative 1 curtails approximately 7.5 GWh less renewable energy than the Initial draft portfolio, reduces congestion on Iowa flowgates, improves North Dakota exports, and facilitates a more economical dispatch for MISO Midwest resulting in higher Adjusted Production Cost Saving over the initial portfolio. The projects resolve reliability constraints and reduce loading stress across all reliability models. Negative percentage indicates a decrease in curtailments.

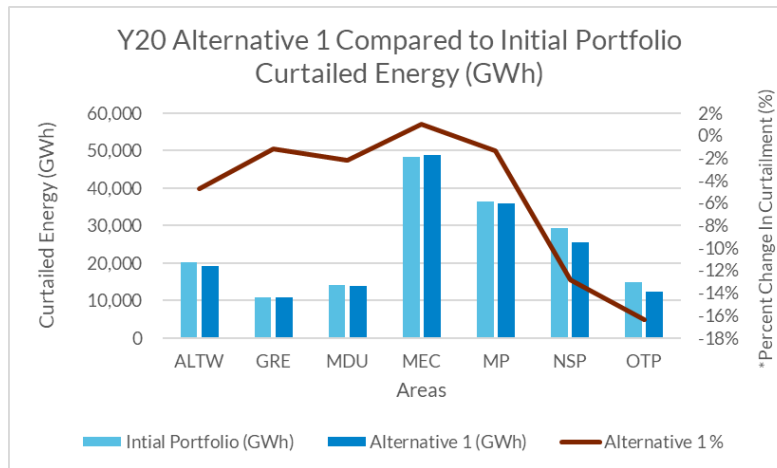


Figure 2.36: Year 20 Curtailed Energy for Initial Portfolio vs. Alternative 1

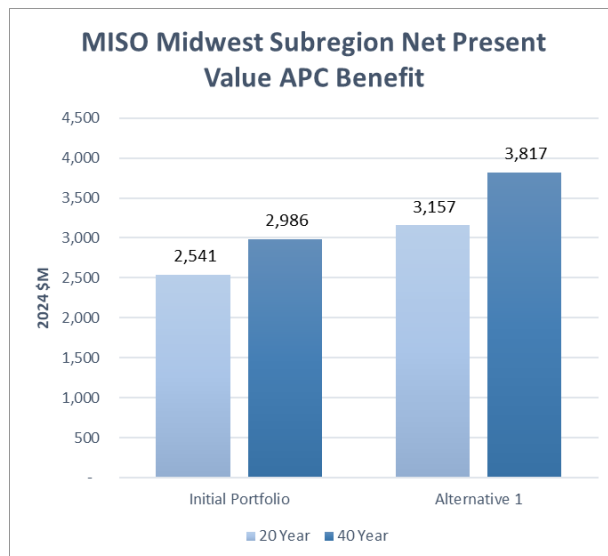


Figure 2.37: Midwest Subregion Net Present Value APC Benefit



Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Results based on analysis performed during portfolio definition. Results are not inclusive of all portfolio value and final results are expanded on by the business case analysis.

The new 765 kV from South Dakota through Minnesota into Iowa and North Dakota 345 kV outlet into Northern Minnesota unlock additional economic value by reducing renewable curtailment. The 765 kV extension into South Dakota provides greater transmission capacity and a direct regional outlet for strong wind resources in that area.

The 765 kV connection between Lakefield Junction and East Adair creates a redundant 765 kV loop between Minnesota, Wisconsin, Iowa, and Illinois, which allows the other portions of that loop to be reliably used at higher capacities. This increases the overall capacity of the 765 kV network to deliver renewable resources across the region. The redundant configuration is more successful at relieving congestion both near Lakefield Junction where the 765 kV station functions as an on-ramp for resources, and across central Wisconsin which would otherwise be sensitive to contingency flows for the loss of the 765 kV corridor between Rochester MN and Southern Wisconsin.

The 345 kV segment in Northern Minnesota improves the system's ability to move renewable resources from Western Minnesota and North Dakota towards load centers in Northern Minnesota and provides congestion relief for the line with the greatest Reference case Congestion Measure in Northern Minnesota.

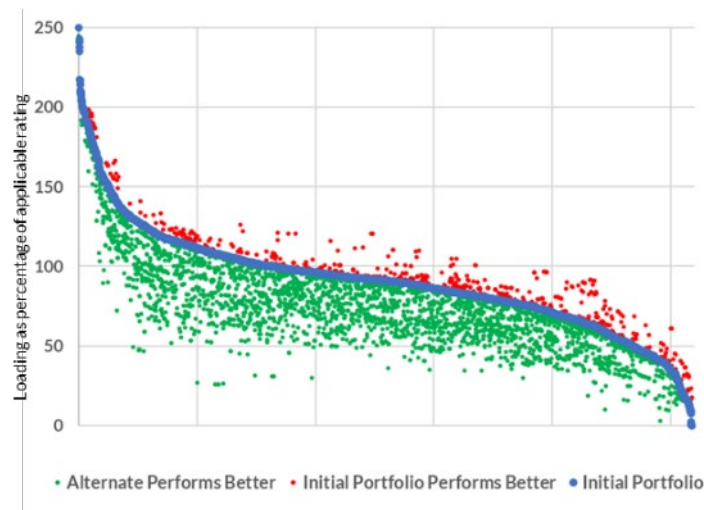


Figure 2.38: Scatter plot showing Alternative 1 performance as compared to Initial Portfolio

Each dot on this plot shows loadings observed from alternative projects for each monitor elements and contingency pair for all core models. Loadings observed in initial portfolio models are used as reference in blue font (blue dots make a smooth line as loadings are sorted in descending order). Loadings observed from alternative projects are shown in red (harming) and green (helping) fonts. More green dots suggest that alternative is helping in reducing the loading stress in the region, whereas redder means that alternative increased loading stress on the system. Blue line overlapping red and green dots means that alternative has little or no impact.

Additional data is provided in the [May 29, 2024, LRTP workshop](#) demonstrating other impactful considerations from alternative analysis. For the added projects there were a significant number of 138 and



230 kV facilities that were impacted, the primary voltages of facilities in the area. There were also some 161 and 345 kV facilities impacted.

Reynolds to Sullivan 765 kV

Reynolds – Sullivan 765 did not result in significant congestion relief without additional support and therefore was not selected to be added to the portfolio. Minimal constraints were resolved in the steady state analysis and in some situations additional constraints were created. Southern Indiana 765 may be reviewed further in later tranches with a continuous 765 kV path.

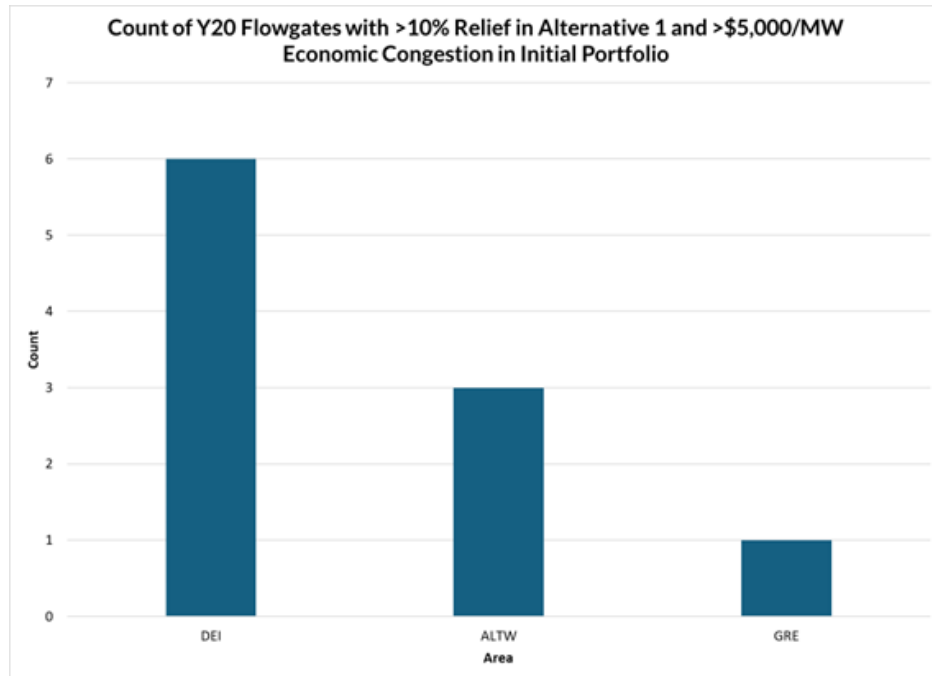


Figure 2.39: Count of Year 20 Flowgates with Congestion Relief for Alternative 1

This graph shows the number of Year 20 flowgates with greater than 10% congestion relief by Alternative 1 which had greater than \$5,000/MW congestion measure in the initial portfolio.

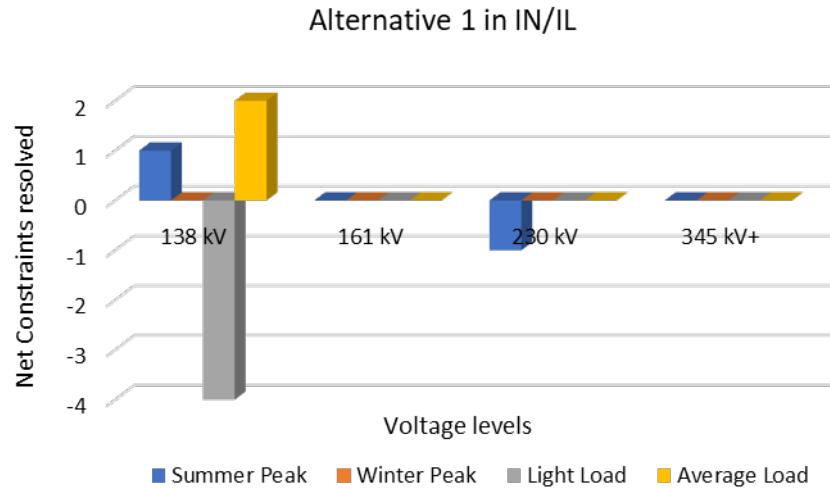


Figure 2.40: Figure: Indiana and Illinois Constraints resolved by Voltage level by Alternative 1 Indiana project

This graph shows the number of net constraints (monitor element and contingency pairs) resolved (= constraints resolved minus new constraints created) by Alternative 1 by voltage kV level and by core models. Additional explanation and detailed results are available at the [May 29, 2024, LRTP workshop](#).

Alternative 2 - New 345 kV in Michigan connecting proposed Tranche 2 facilities with Tranche 1

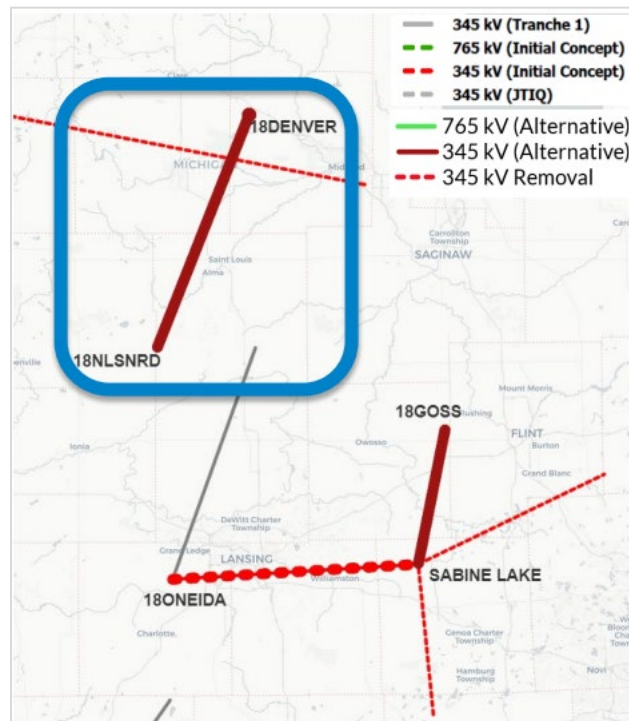


Figure 2.41: Map shows selected Alternative 2 projects in blue boxes



Alternative 2 adds four projects to the portfolio and unlocks generation in the West as a complement to existing and 765 kV paths in the initial draft portfolio.

- 2 project proposals to add in MI
 - Denver – Nelson Road 345
 - New Denver Substation
 - Two 345/138 transformers at Denver
 - Sabine Lake – Goss 345
- 1 project proposal to replace in MI
 - Oneida – Sabine Lake 345 (replaced by Sabine – Goss 345 in this Alternative)

Alternative 2 facilitates Future 2A fleet change by improving economic congestion relief, resolving constraints and reducing loading stress across all reliability models and providing more production cost savings for the MISO Midwest.

- 345 kV from Denver – Nelson Road resolves constraints and provides significant congestion relief on Michigan flowgates and is added to the portfolio.
- 345kV from Sabine Lake – Goss 345 did not show significant congestion relief over the initial portfolio and resolved a few constraints while stressing other system elements and therefore was not selected to be added to the portfolio as a replacement for Oneida – Sabine Lake 345 kV.

Denver – Nelson Road 345 kV

Alternative 2 Denver to Nelson Road resolves constraints (especially in Summer Peak models) and reduces loading stress across all models by increasing the connectivity of the proposed Tranche 2 Ludington to Tittabawassee 345 kV line. This alternative adds a tap to the proposed 345 kV line at Denver and adds a 345 kV line from Denver to the Tranche 1 Nelson Road substation.

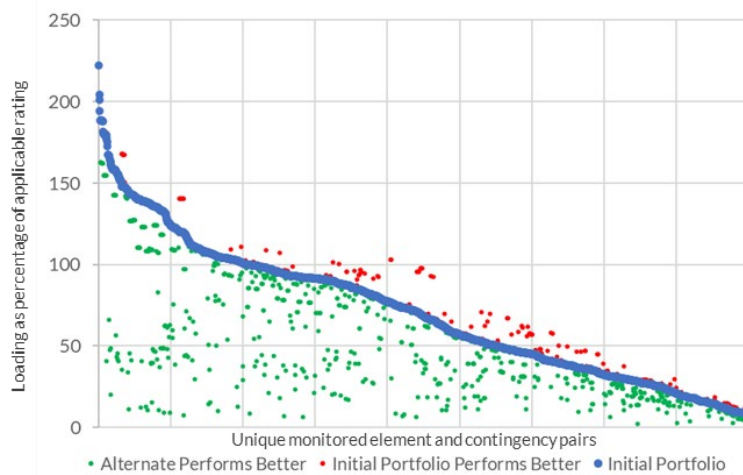


Figure 2.42: Scatter plot showing Denver-Nelson Road 345 kV performance as compared to Initial Portfolio

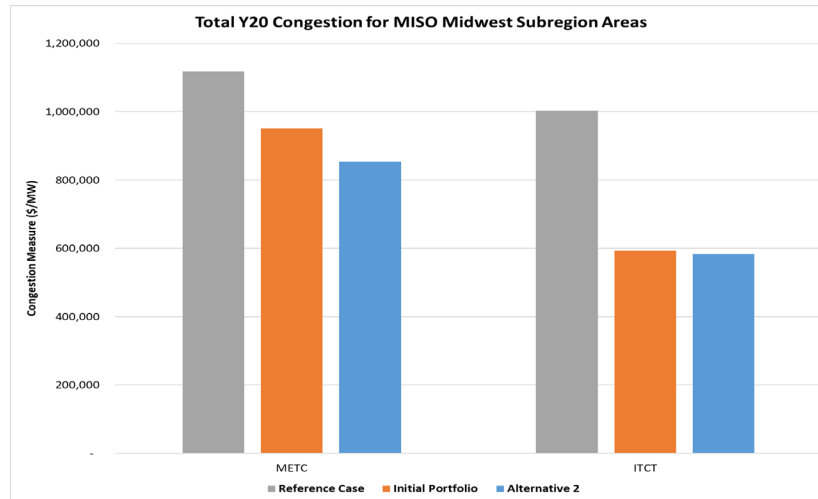


Figure 2.43: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 2

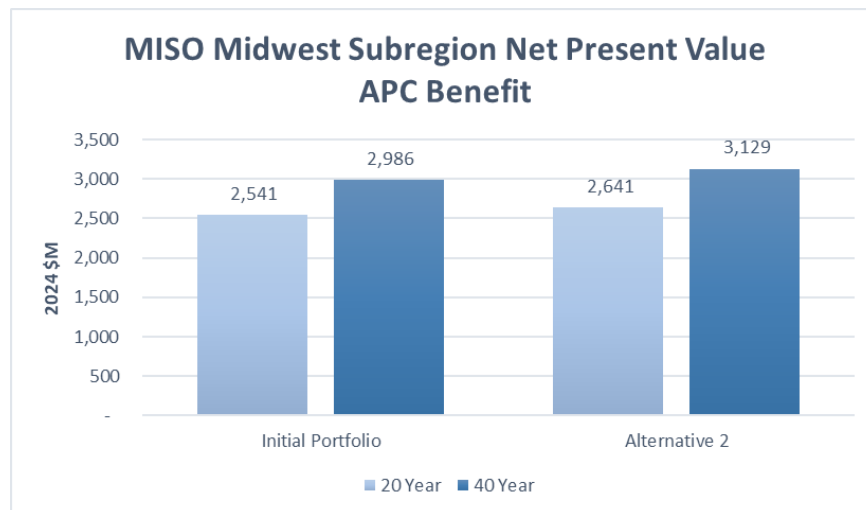


Figure 2.44: Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Results based on analysis performed during portfolio definition. Results are not inclusive of all portfolio value and final results are expanded on by the business case analysis.

Goss – Sabine Lake 345 kV

The Goss to Sabine Lake 345 kV replaced a proposed Tranche 2 Oneida to Sabine 345 kV facility. This facility resolved a few constraints while stressing other system elements in the reliability analysis. In the economic analysis, Goss – Sabine Lake 345 kV did not show significant congestion relief over the initial portfolio. Therefore, this alternative was not selected to be added to the portfolio as a replacement for Oneida – Sabine Lake 345 kV.

Additional explanation and detailed results are available at the [May 29, 2024, LRTP workshop](#).



Alternative 3 - Replacement of Lakefield Junction to Plano 765 kV projects in Minnesota and Wisconsin by moving the starting location to Brookings heading north of Twin Cities to Chisago onto Wisconsin Highway 22 to Paddock and retaining same end point at Plano 765

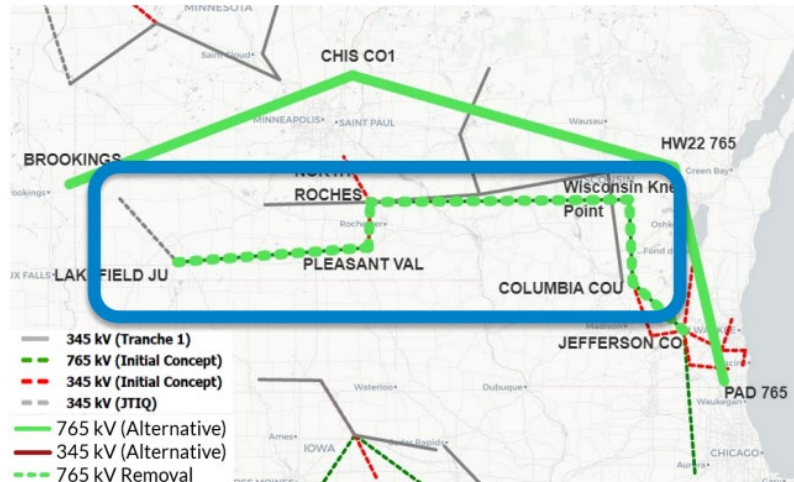


Figure 2.45: Map shows selected initial portfolio projects in blue boxes, Alternative 3 projects were not selected

Alternative 3 replaces the entire 765 kV project in MN/WI/IL with a configuration that is north of twin cities and is approximately 200 miles longer.

- 1 project proposal to add SD/MN/WI/IL
 - Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV
- 1 project removed in MN/WI/IL
 - Lakefield Junction – Pleasant Valley – North Rochester – Jefferson Co – Plano 765 kV
 - electrically comparable to the final configuration of LRTP projects 24, 26, 30, and 31
- Multiple 345 kV changes (additions and removals) in Wisconsin were incorporated with this alternative (not shown on map)

Alternative 3 targeted the same constraints as Alternative 1, but Alternative 1 outperformed Alternative 3 on the loading stress reduction metric, curtailed energy, congestion relief, and production cost savings.

- 765 kV from Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 showed marginal or mixed results in improving congestion relief over Alternative 1 and resolved a few constraints while stressing other system elements and therefore was not selected to be added to the portfolio.

Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV

Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV, in Alternative 3, showed marginal improvements in economic congestion compared to Alternative 1, but did not facilitate Future 2A fleet



change as well as Alternative 1. Alternative 3 had mixed results on reducing congestion in Wisconsin; reducing congestion in some areas and aggravating it in others. Compared to Alternative 1 and the initial draft portfolio, Alternative 3 did not enable as much renewable generation in the area curtailing approximately 8 GWh more renewable energy than Alternative 1.

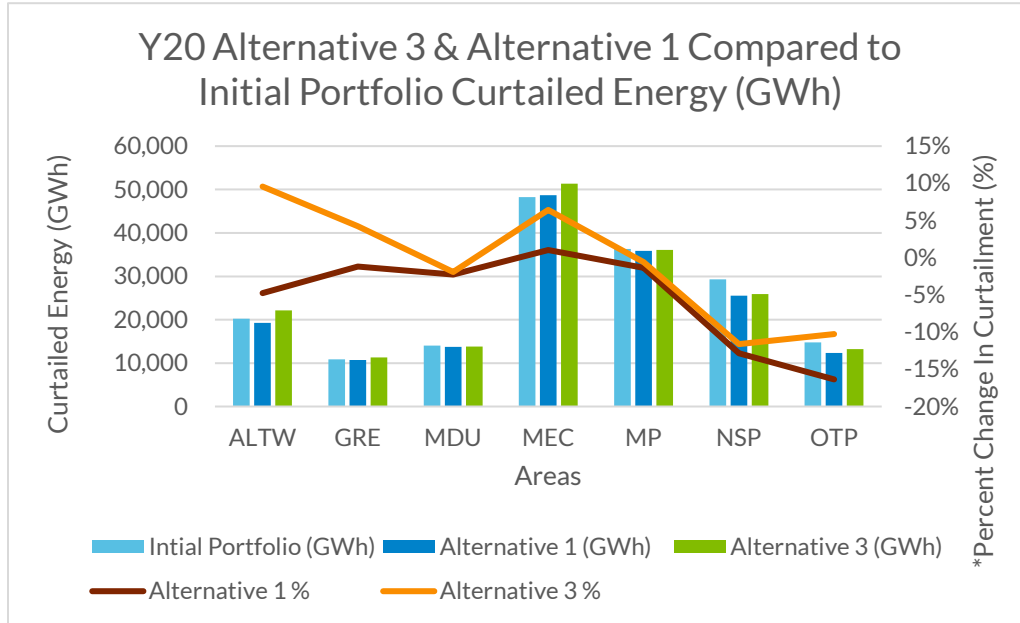


Figure 2.46: Year 20 Curtailed Energy for Initial Portfolio vs. Alternative 1 vs. Alternative 3

Alternative 3 had lower Adjusted Production Cost Savings as compared to Alternative 1 and the initial draft portfolio.

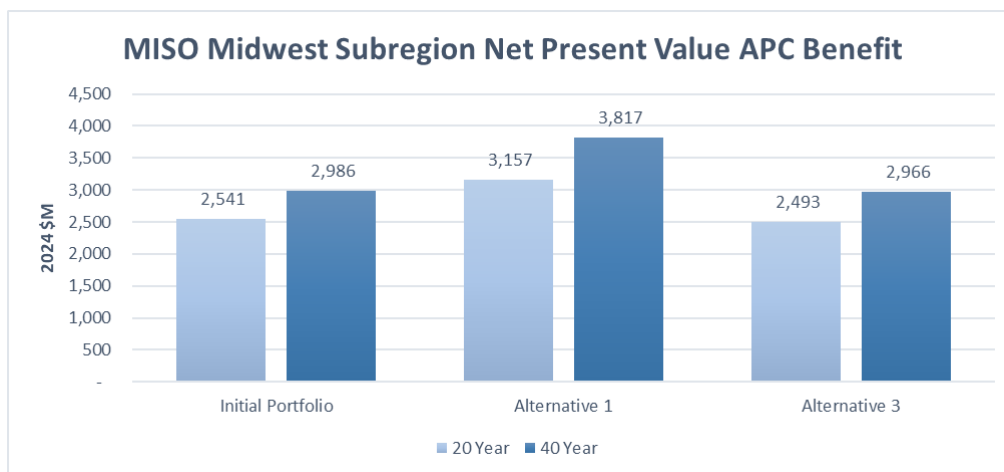


Figure 2.47: Initial Portfolio vs. Alternative 1 vs. Alternative 3 Adjusted Production Cost Savings

Alternative 3 was considered looking at the impacts of the MN area facilities and the WI area facilities considering the local areas that were impacted and comparing those reliability results.

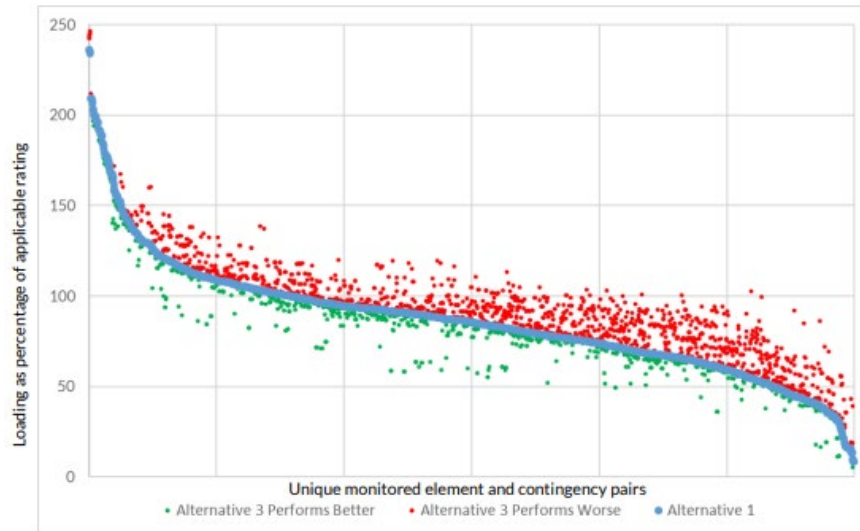


Figure 2.48: Scatter plot showing Alternative 3 performance as compared to Initial Portfolio with Alternative 1 in MN

Alternative 1 overall performed better for the Minnesota area than Alternative 3 due to better connecting the portfolio to the rest of the MISO region, allowing for more connections to Iowa since it traverses south of the Twin Cities. Alternative 1 also benefits more from Tranche 1 345 kV portfolio in the area as well.

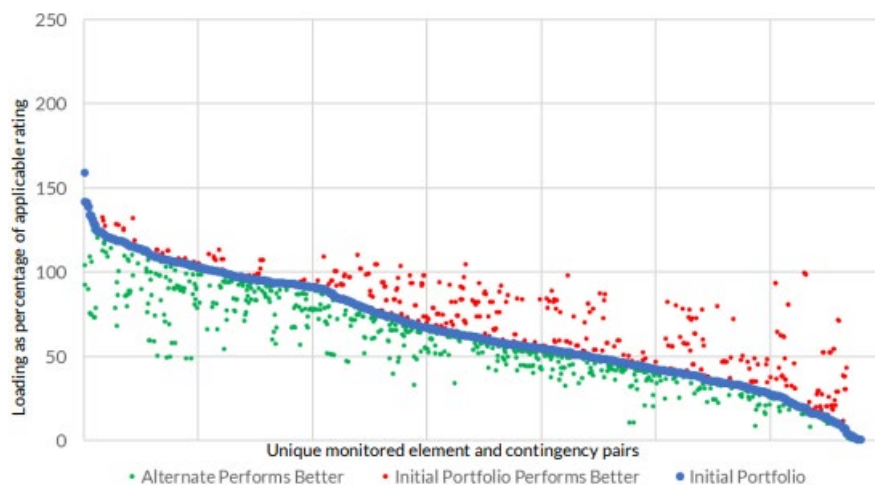


Figure 2.49: Scatter plot showing Alternative 3 performance as compared to Initial Portfolio in WI

For Wisconsin, the results were inconclusive whether incorporating the alternative resolved more violations, as both violations were created and resolved. The result was retaining the original Wisconsin portfolio in this area. Alternative 3 was not selected to move forward, instead a combination of the proposed facilities in this area with the Alternative 1 additions (Big Stone to Brookings County 765 kV and Lakefield Junction to East Adair 765 kV). Additional explanation and detailed results are available at the [May 29, 2024, LRTP workshop](#).



Alternative 4 - Add northern MN outlet from Tranche 1 facilities and add Southern IN reinforcements enabling interstate transfers. Evaluates Michigan 345 kV project proposal

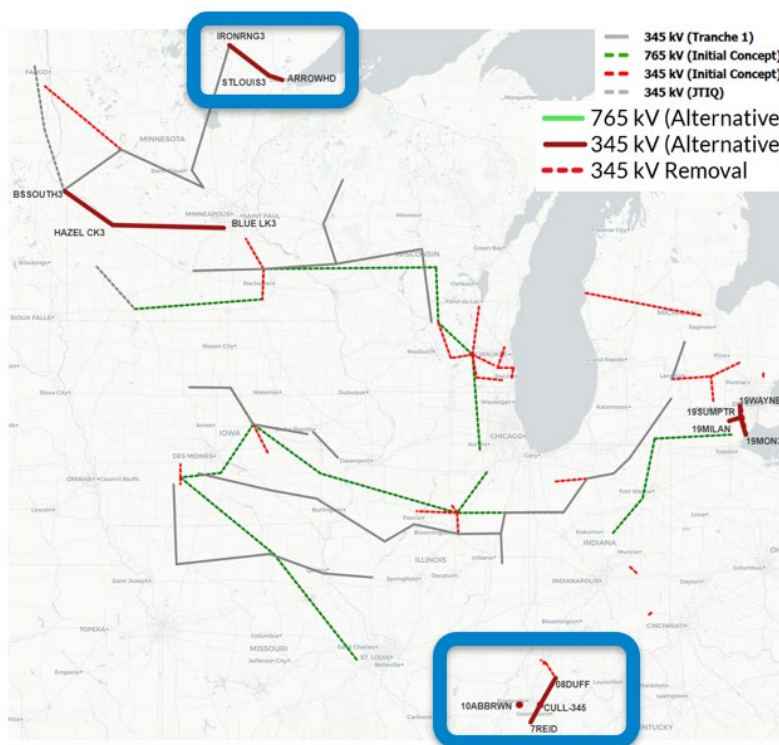


Figure 2.50: Map shows selected Alternative 4 projects in blue boxes

Alternative 4 adds four projects to the portfolio in Michigan, Indiana/Kentucky, Southern Minnesota and Northern Minnesota.

- 2 project proposals to add in MN
 - Iron Range – St Louis Co. – Arrowhead 345 kV (Northern MN)
 - Big Stone South – Hazel Creek – Blue Lake 345 kV (Southern MN)
- 1 project proposal to add in IN/KY
 - Duff – F. B. Culley – Reid EHV 345 +A. B. Brown 345/138 XF (1) and F. B. Culley 345/138 kV XFs (2)
- 1 project proposal to add in MI
 - Milan – Sumpter 345
- No projects from initial portfolio replaced or removed

Select projects within Alternative 4 facilitates Future 2A fleet change by increasing the deliverability of renewable energy and providing more production cost savings for the MISO Midwest.



- 345 kV in Northern Minnesota resolved constraints, reduced loading stress and improved economic congestion in Northern Minnesota and is added to the portfolio.
- 345 kV in Southern Indiana reduced loading in the area and supports interstate transfers and is added to the portfolio.
- 345 kV in Southern Minnesota resolved similar constraints in the region as Alternative 1 with mixed results observed on the loading reduction metric and was not selected to be added to the portfolio.
- Milan – Sumpter 345 kV had minimal economic impact in Michigan and had minimal impact on transmission facilities in the area therefore was not selected to be added to the portfolio.

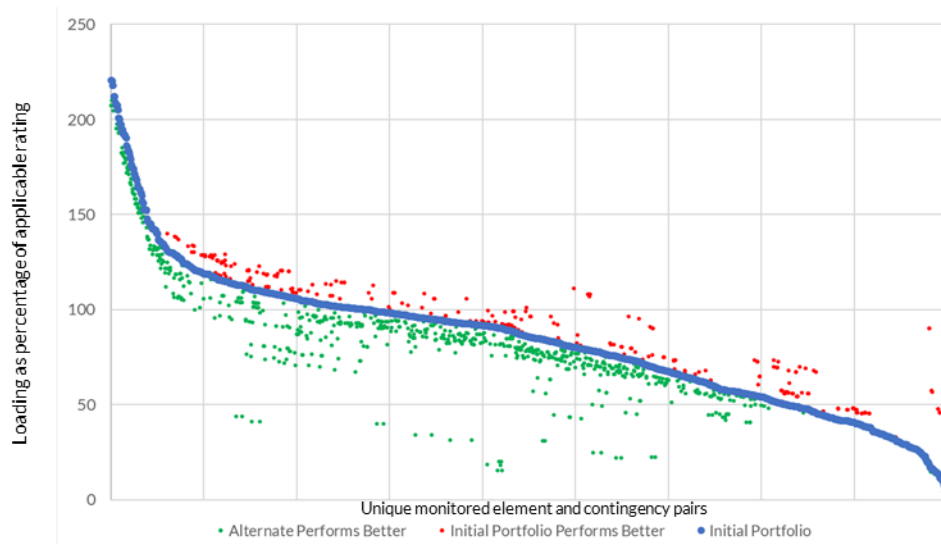


Figure 2.51: Scatter plot showing Iron Range- Arrowhead 345 kV performance as compared to Initial Portfolio

Alternative 4 in Northern Minnesota resolves constraints and reduces loading stress for the majority of impacted flowgates with healthy base case loading on the project in all models.

Iron Range – St Louis Co. – Arrowhead 345 kV provides additional congestion relief in Northern Minnesota in Iron Range and south of Duluth.

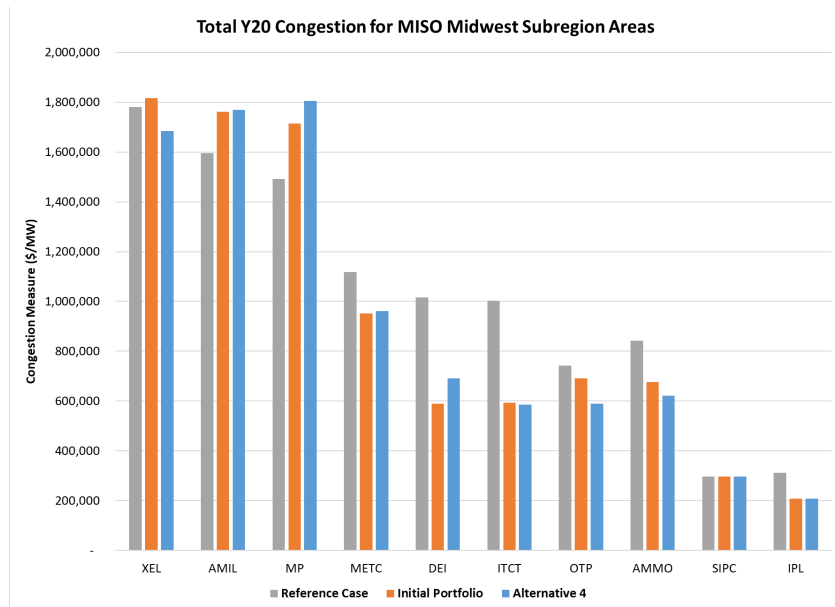


Figure 2.52: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 4 (MN)

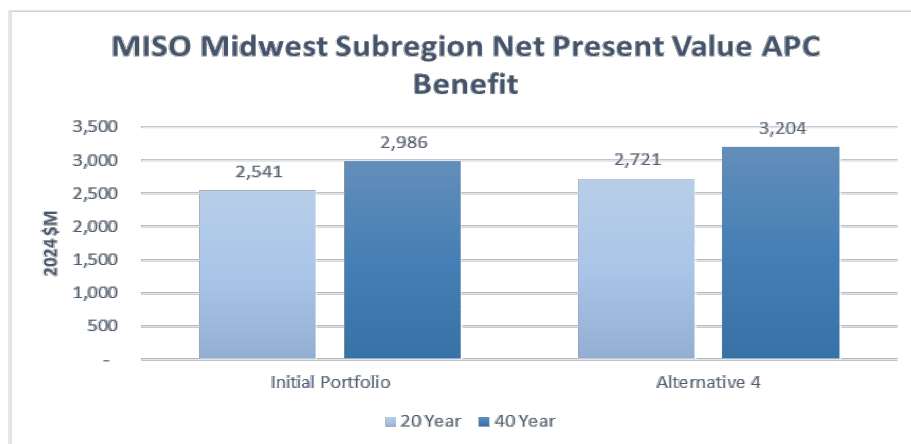


Figure 2.53: Initial Portfolio vs. Alternative 4 Adjusted Production Cost Savings

The Northern Minnesota 345 kV also shows economic value due to congestion relief and increases the Adjusted Production Cost Savings for the Midwest subregion as compared to the initial portfolio.

Duff – F. B. Culley – Reid EHV 345, A. B. Brown 2nd Transformer, F. B. Culley 2 Transformers

Alternative 4 project in Indiana resolves key constraints in the region and assists in reducing the loading on system elements in Southern Indiana. In addition, loading reductions occurred on constraints in additional transfer scenarios to enable regional flows.

Duff – F. B. Culley – Reid EHV 345 and A. B. Brown and Culley transformer alternative resulted in an overall downward trend in congestion in Indiana. Congestion reduction supports transfer capability in MISO Central and 345 kV facilities provided economic value for southern Indiana, Illinois and Kentucky.

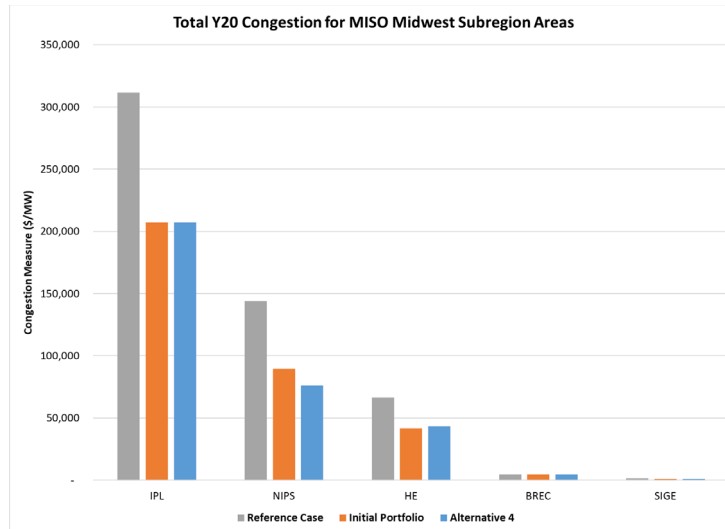


Figure 2.54: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 4 (IN)

Big Stone South – Hazel Creek – Blue Creek 345 kV

The Alternative 4 Southern Minnesota project resolves constraints in the region; however, these are similar constraints to those resolved by Alternative 1; mixed results were observed on the loading reduction metric. 345 kV Southern MN addresses similar constraints as Alternative 1, therefore was not selected for the final portfolio.

Milan – Sumpter 345 kV

Alternative 4 project in Michigan had minimal impact on transmission facilities in the area from a reliability analysis. In addition, the Milan – Sumpter 345 kV project had minimal economic impact for Michigan. Additional explanation and detailed results are available at the [May 29, 2024, LRTP workshop](#).

Alternative 5 - Central IA additional source to the proposed Twinkle 765 kV substation

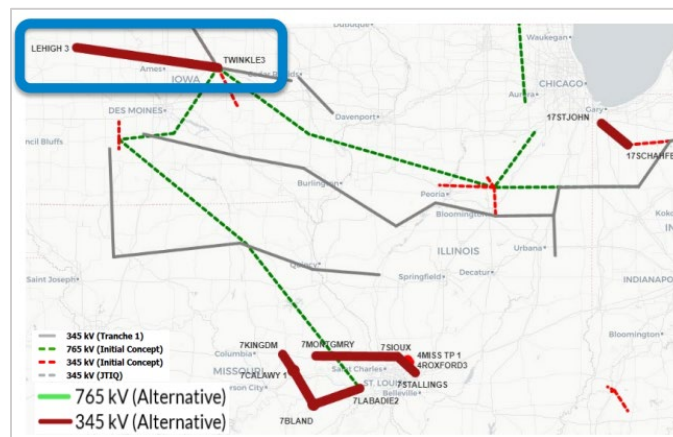


Figure 2.55: Map shows selected Alternative 5 projects in blue boxes



Alternative 5 adds three projects to the portfolio in Indiana, Missouri and Iowa

- 1 project proposal to add in Indiana
 - St. John – Burr Oak 345
- 2 project proposals to add in Missouri
 - Montgomery – Sioux – Stallings 345
 - Kingdom City – Bland – Labadie 345
- 1 project proposal to add in Iowa
 - Lehigh – Twinkle 345
- No projects from initial portfolio replaced or removed

Alternative 5 facilities build upon Tranche 1 and proposed Tranche 2 facilities in central Iowa further facilitating Future 2A and high voltages.

- 345 kV line from Lehigh to Twinkle further connected Tranche 1 Marshalltown 345 kV outlets (Marshalltown and Twinkle are same location) providing additional sources for the 765 kV outlet under contingency operation. This project was added to the portfolio.
- 345 kV facilities proposed in MO; Montgomery to Sioux to Stallings and Kingdom City to Bland to Labadie, resulted in minimal impact on transmission facilities in the area and was not selected to add or modify the portfolio.
- 345 kV line in northern Indiana St. John to Burr Oak 345 kV was considered and only impacted one constraint, resulting in no addition or modification to the portfolio.

Lehigh – Twinkle 345 kV

Alternative 5 in Iowa provides an additional source to the proposed Twinkle 765 kV substation, with healthy loadings confirming its utilization. The Lehigh -Twinkle 345 kV provided support to the 765 kV network and a marginal impact to the overall Adjusted Production Cost Savings as compared to the original portfolio.

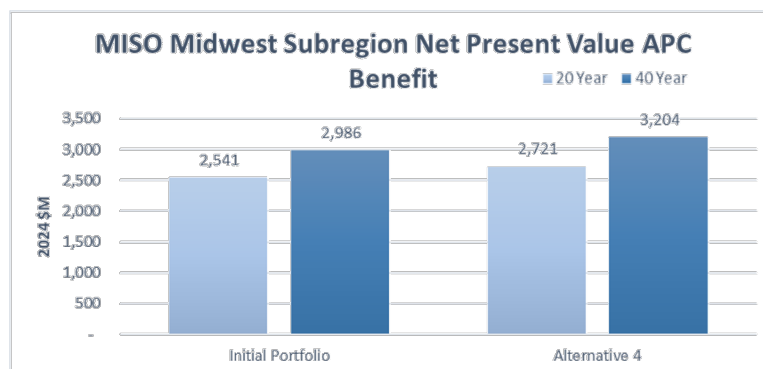


Figure 2.56: Initial Portfolio vs. Alternative 5 Adjusted Production Cost Savings



Montgomery – Sioux – Stallings 345, Kingdom City – Bland – Labadie 345 kV

Alternative 5 in Missouri has minimal impact on transmission facilities in the area. This project resolved high voltage constraints and assisted in reducing loading stress in the area. The Missouri area projects showed minimal congestion relief or economic value over the initial portfolio.

St. John – Burr Oak 345 kV

Alternative 5 in Indiana has minimal impact on transmission facilities in the area. The St. John – Burr Oak 345 kV project showed minimal congestion relief or economic value over the initial portfolio.

Additional explanation and detailed results are available at the [May 29, 2024, L RTP workshop](#).

Alternative 6 - Replace 765 kV proposed in MO with 345 kV projects connecting to Tranche 1 facilities

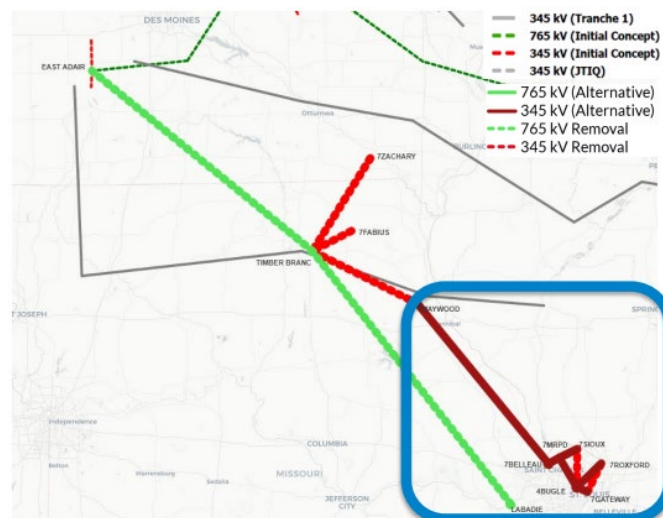


Figure 2.57: Map shows selected Alternative 6 projects in blue boxes

Alternative 6 replaces the 765 kV project in IA/MO with 345 kV projects in the St. Louis metropolitan area in Missouri.

- 1 project proposal to add in MO
 - Maywood – Belleau – MRPD- Sioux, MRPD – Bugle –Roxford /Gateway) 345
- 1 project removed in IA/MO
 - East Adair (IA) – Labadie 765 kV

Alternative 6 facilities build upon Tranche 1 and enables regional flows and removes 765 kV facilities into MO that may be reviewed further in later tranches with a continuous 765 kV path.

- 345 kV facilities in Missouri resolved constraints in MISO Central, reduced loadings in the Missouri area and provided economic value while enabling interstate transfers and was added to the portfolio.



- 765 kV from Iowa to Missouri did not result in significant congestion relief without additional support and was removed from the portfolio.

Maywood - Belleau - MRPD- Sioux, MRPD - Bugle -Roxford/Gateway) 345 kV + XFs

The 345 kV facilities reduced congestion supporting transfer capability in MISO Central.

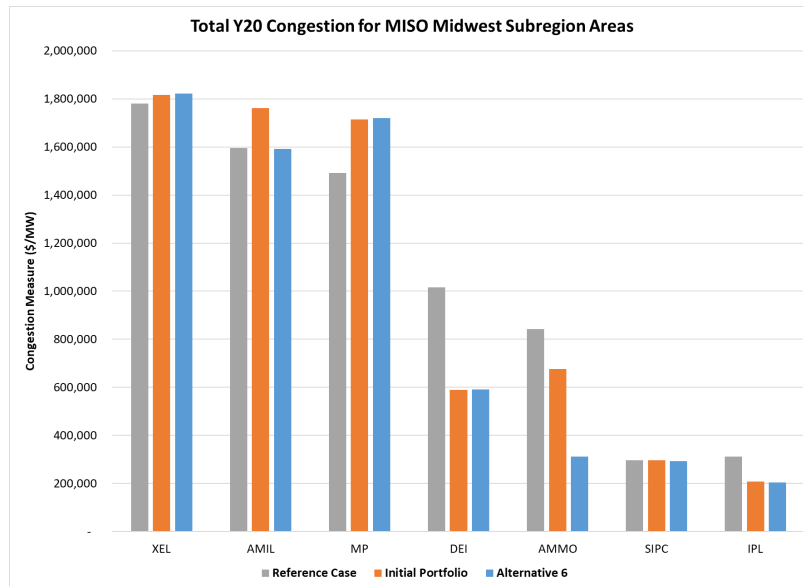


Figure 2.58: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 6

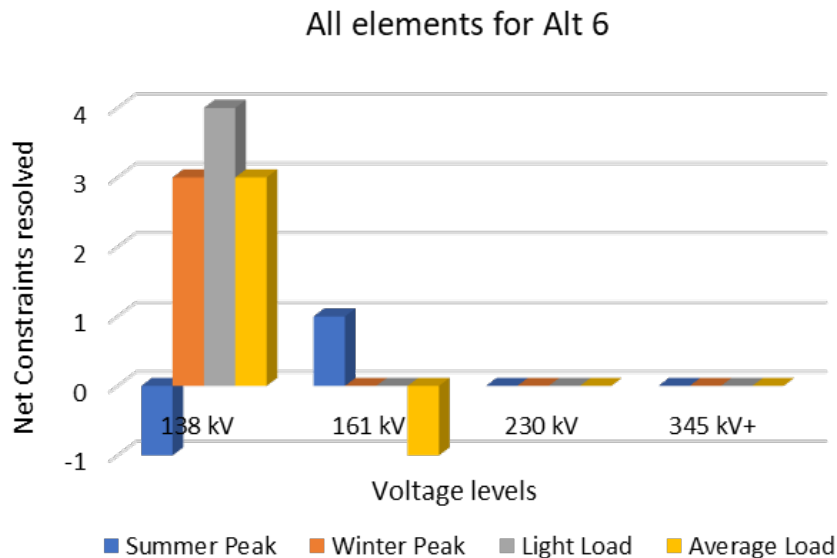


Figure 2.59: Constraints resolved by Voltage level by Alternative 6 project

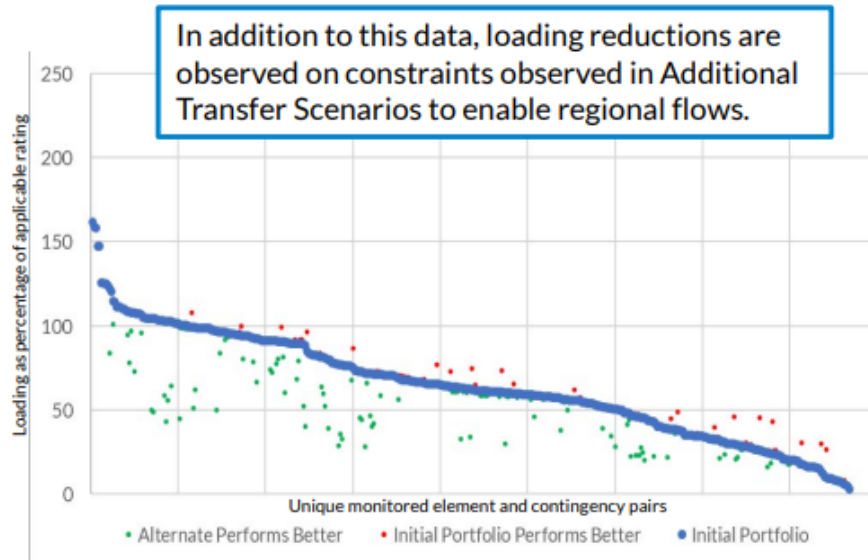


Figure 2.60: Scatter plot showing Alternative 6 performance as compared to Initial Portfolio

The Iowa - Missouri 765 kV line did provide economic value but did not result in significant congestion relief without additional support and may be reviewed further in later tranches with a continuous 765 kV path. Additional explanation and detailed results are available at the [May 29, 2024, LRTP workshop](#).

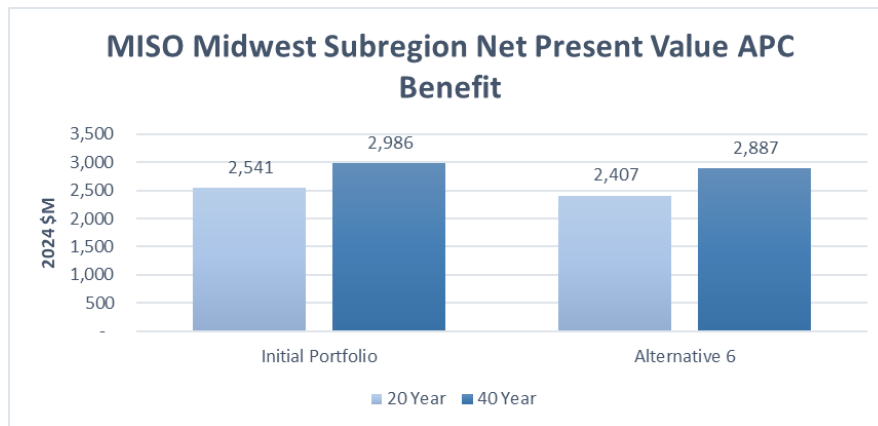


Figure 2.61: Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Refine Solutions

After identifying the issues that would be addressed in Tranche 2.1, and performing the above alternatives assessment, MISO developed a near-final portfolio of solutions to resolve those issues based on results from reliability and economic analysis using the criteria, data, tools and methodology described in the prior sections of this document and in the economic and reliability study whitepaper.

Tranche 2.1 portfolio includes 24 projects across the MISO Midwest subregion, estimated at \$21.8 billion. The projects are targeted to go in service from 2032 to 2034. The least-regrets, robust portfolio provides the following:



- Facilitates a more economical dispatch for MISO Midwest resulting in \$8.1B in Adjusted Production Cost (APC) savings
- Reduces economic congestion for MISO Midwest by 29.5%
- Reduces MISO Midwest curtailment by 11.2% (27.1M MWh)
- Decreases MISO Midwest load serving costs and reduces price separation
- Resolves more than 60% of >200 kV constraints for single initiating and multiple element contingency events
- Paired contingency (P3/P6) analysis shows on average more than 70% of thermal violations are resolved for all voltage levels
- Reduces the majority of the loadings below Safe Loading Limits
- Enables regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty

Step 5: Evaluate and Justify Solutions

Total Reliability Results

Analysis with twelve reliability models representing various system conditions and dispatch patterns helped MISO better understand system performance with and without LRTP portfolio of projects. MISO monitored flow on lines and voltage at substations with and without the LRTP portfolio of projects. To better assess the impact and severity of overloads and voltage violations across multiple lines and substations, MISO utilized industry-standard ranking criteria known as Severity Indices. The severity index formulation is a modified Contingency Severity Index (CSI) from Siemen PTI's PSS/MUST. This approach enables straightforward comparisons of overall system performance across various models, rather than focusing solely on specific monitored elements or contingency pairs.

The Thermal Severity Index provides an overview of the performance of the Tranche 2.1 portfolio taking into consideration the magnitude of thermal and voltage violations, respectively, from the contingency analysis. The Thermal and Voltage Severity Index values calculated for the Tranche 2.1 portfolio point to significant improvement in the overall system performance.



Figure 2.62: Thermal Severity Index and Voltage Severity Index with and without the Tranche 2.1 portfolio

Large Angular separation across the Midwest subregion was noticed while building models, as power was being transferred via longer, inefficient routes leading to increased risk of angular separation and instability, and increased losses. The Tranche 2.1 portfolio reduces angular separation across the MISO transmission system in the most stressed case by 47°, showing that power can take more direct paths from resources to load, enabling additional flexibility during outages.

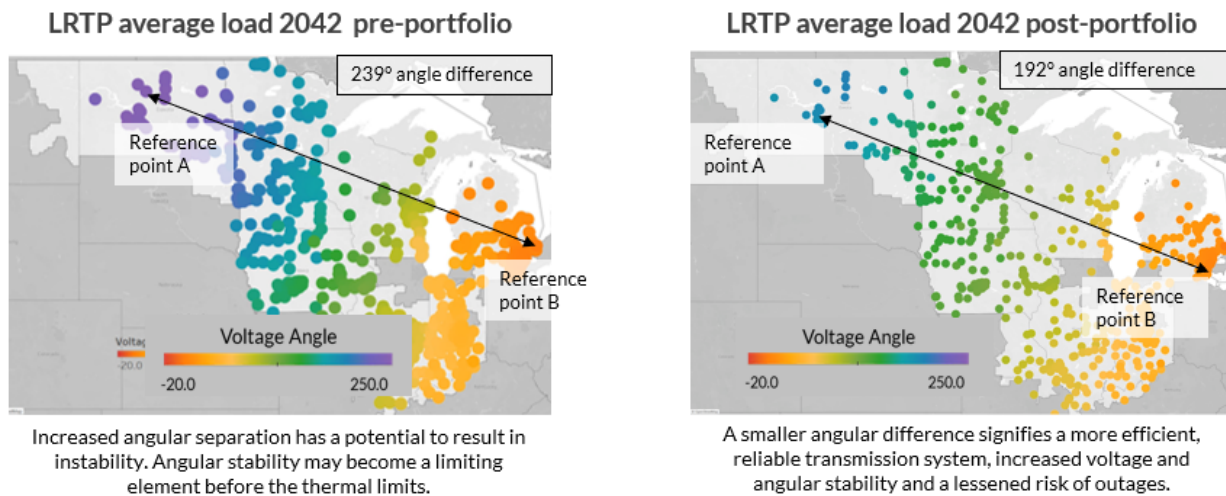


Figure 2.63: Angular separation with and without the Tranche 2.1 portfolio

Voltage and Reactive Support

Maintaining optimal loading levels is essential for reliable operation and effective voltage regulation in (Extra High Voltage) EHV transmission lines. When EHV lines operate below their Surge Impedance Loading (SIL), they generate reactive power, functioning as a source or reactive power that can alleviate voltage



issues elsewhere in the grid. To enhance system reactive support and reduce reliance on other voltage support devices, MISO intentionally planned the system to increase the SIL of regional lines when practical (e.g., use of 765 kV options and high-SIL 345 kV options for very long 345 kV lines), thus providing substantial reactive power capability from the regional transmission system under most conditions. Since regional flows are lower during summer peak conditions, which is the time when reactive power demand from loads tends to be highest, the lower regional flows that typically occur in the summer (because a much greater percentage of the generation output in summer is local) allow for even more reactive power capability from the regional lines, decreasing the need for local voltage support equipment during these conditions.

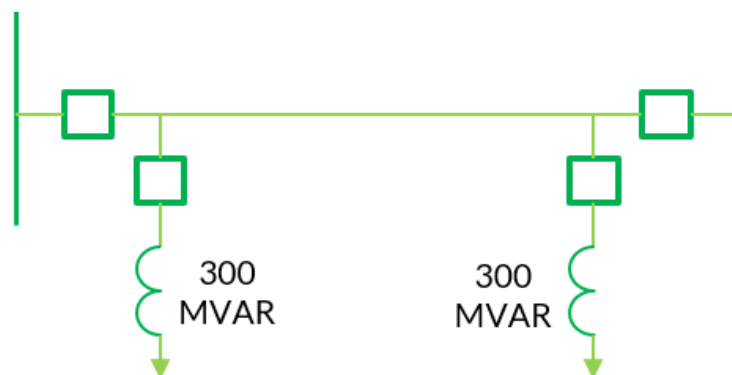


Figure 2.64: Default 765 kV line configuration includes line-side switchable shunt reactors to manage high voltages and mitigate Ferranti Effect during switching

To better manage high voltage issues and allow for greater flexibility, the default 765 kV line configuration includes line-side switchable 300MVAR shunt reactor banks at each terminal to control high voltages and mitigate the Ferranti Effect during switching. The reactor banks can also be switched off by operators when line flows exceed the SIL and it is necessary to maintain acceptable voltage levels in the area.

The LRTP Tranche 2.1 portfolio addressed most of the voltage violations. The average 765 kV N-0 loadings in the core cases are as follows:

- Summer Peak: 33.7% of Surge Impedance Loading
- Winter Peak: 50.1% of Surge Impedance Loading
- Average: 60.1% of Surge Impedance Loading
- Light Load: 58.7% of Surge Impedance Loading

Due to the Surge impedance loading of 2440 MW for 765 kV, the 765 kV system is providing substantial reactive power, particularly in the summer peak case where voltage support is most needed. This substantially reduces the need for other voltage support devices.

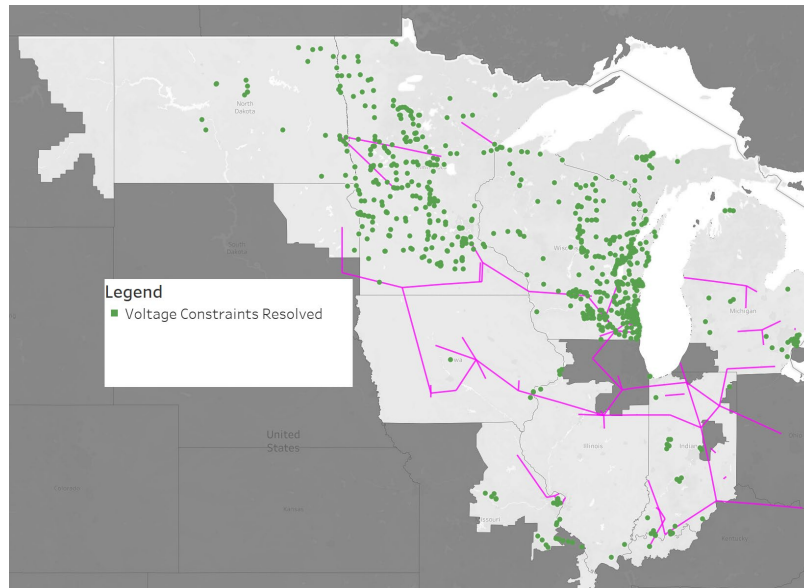


Figure 2.65: Green dots represent a voltage constraint observed in core models and is mitigated by the final portfolio

Since reactive support is inherently local—given that reactive power cannot be transferred over long distances—the remaining low and high voltage issues, along with overloaded transmission lines due to local load growth and specific generation interconnections, will be addressed through various shorter-term planning processes. These include the annual MTEP reliability planning and the generator interconnection processes, as specific load and generation locations are identified.

Dynamic Assessment

The portfolio enhances the overall stability of the system as demonstrated by a significant reduction in the number of transient voltage violations, low damping violations and relay trip violations. The 2042 average load case represents a highly stressed scenario characterized by the highest angular separation across the system, lowest inertia (because of lowest conventional generation, both in absolute terms and by percentage), lowest short circuit current contribution, and 100% renewable penetration meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. The 2042 summer peak model represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.

The Transient Stability Index (TSI) is an industry acceptable metric used in TSAT (Transient Security Assessment Tool) which assesses the severity of each disturbance. A higher TSI for a disturbance represents a more stable system response. The Tranche 2.1 portfolio resolved a vast majority of transient voltage violations for the 2042 AVG model and boosts the system performance in the 2042 SUM model.

Approximately 90% of transient voltage violations were resolved in the 2042 AVG stability model, and 30% of transient voltage violations were resolved in the 2042 SUM peak stability model.

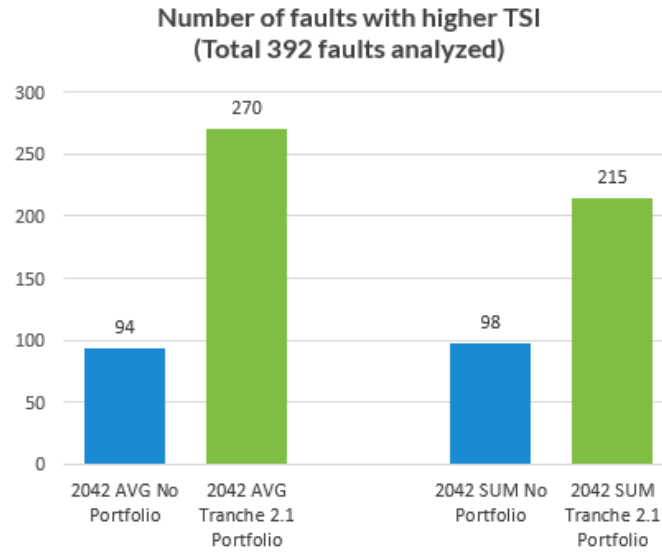


Figure 2.66: Transient Stability Index with and without the Tranche 2.1 portfolio

Many of the remaining transient voltage violations will have better resolution through site specific dynamic parameter tuning, and through the annual MTEP reliability planning and the generator interconnection planning processes. The portfolio resolved all the low damping violations and reduced the total number of relay violations.

Transfer Analysis

East to West Transfer Scenario underscores the portfolio's flexibility to accommodate significant shifts in generation during low renewable output in the West, while also highlighting the bi-directional nature of the system, with flows reversing as conditions change.

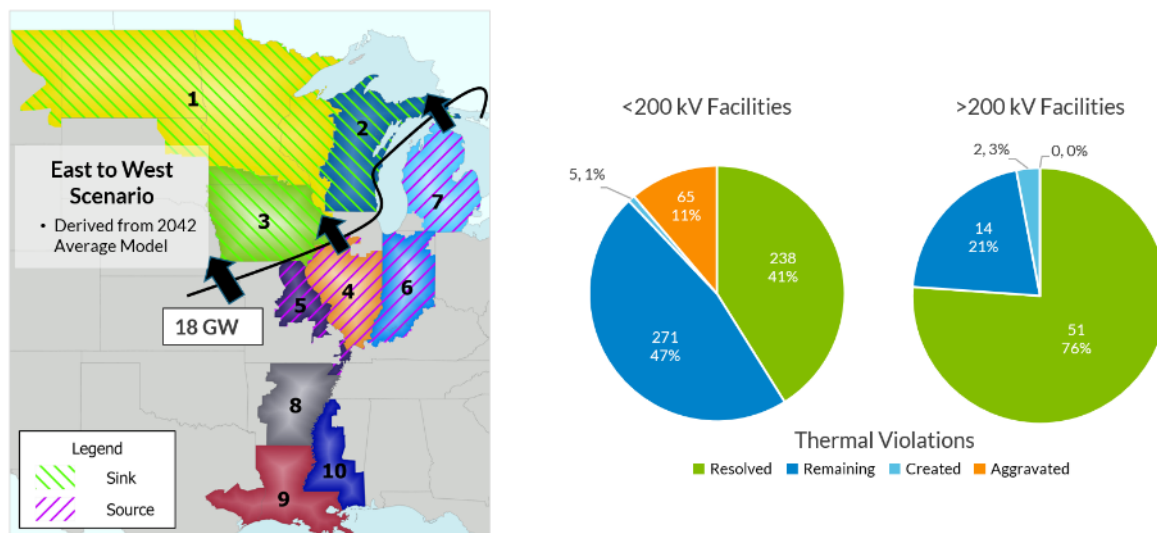


Figure 2.67: East to West Transfer results summary with the Tranche 2.1 portfolio

All reliability core models had natural direction of flows from West to East based on data from future hourly profiles; however, there were a number of hourly profiles where flow was in the East to West direction. To



cover this credible scenario, MISO utilized the data from Futures to build an East to West scenario. In the East to West transfer an additional 13% unique limiting elements were observed beyond the unique limiting elements in the core models (average load, summer peak, light load, and winter peak). The LRTP 2.1 portfolio resolves more than 75% of all 200 kV and above constraint violations observed in the East to West scenario.

The Lowers to Uppers Scenario highlights the flexibility of the portfolio to accommodate increased output in the Central Region and reliably deliver power to other MISO Regions.

Studying this scenario introduced an additional 6% unique limiting elements beyond the core models. The LRTP Tranche 2.1 portfolio resolves 70% of all 200 kV and above constraint violations observed in this scenario.

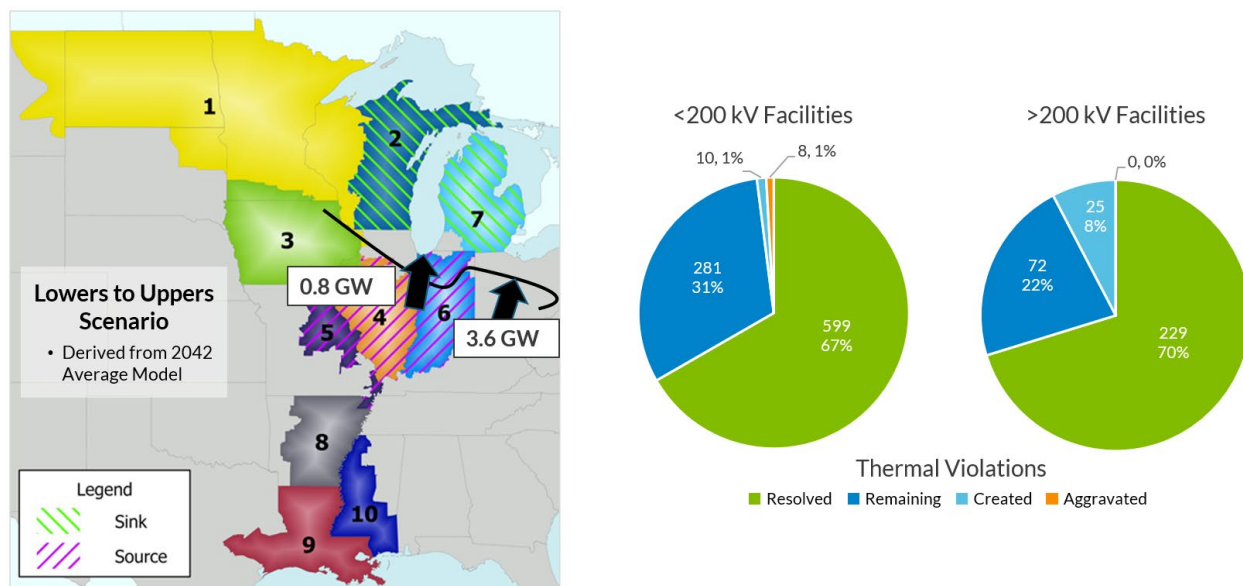


Figure 2.68: Lowers to Uppers Scenario results summary with the Tranche 2.1 portfolio

The Winter Peak Low Renewable scenario captures multi-day periods of low renewable output, particularly during early morning hours and regional winter freezes. The LRTP portfolio enables reliance on conventional local resources to reliably support load during winter events that have historically impacted the MISO system.

This scenario represents the lowest renewable scenario of all core models and additional scenarios. All conventional resources are dispatched to their maximum nameplate capacity. Studying this scenario introduced an additional 48% unique limiting elements beyond the unique limiting elements in the core models. LRTP Tranche 2.1 portfolio resolves 52% of all 200 kV and above constraint violations observed in this scenario.

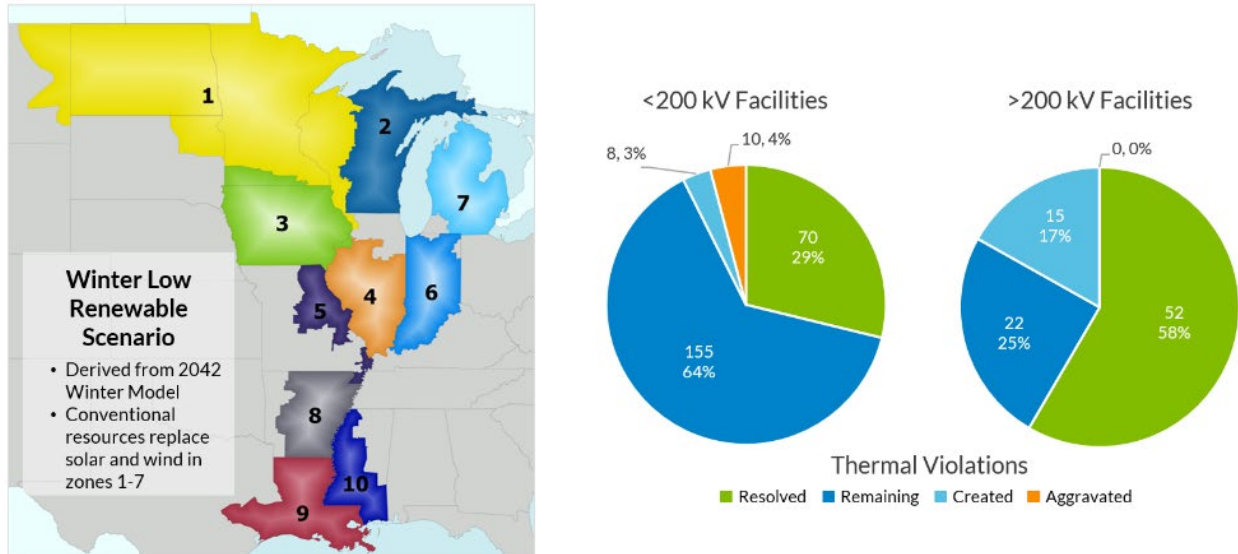


Figure 2.69: Winter Peak Low Renewable Scenario results summary with the Tranche 2.1 portfolio

The **Twilight Summer Scenario** demonstrates a large increase in reliability on the 200 kV and above system as the resource mix transitions during sunset at peak load.

The Twilight scenario dispatches down solar and wind resources to 10% of nameplate capacity. In this scenario, batteries are assumed unavailable. Studying this scenario introduced an additional 20% unique limiting elements beyond the unique limiting elements in the core models. The LRTP Tranche 2.1 portfolio resolves 72% of all 200 kV and above constraint violations observed in this scenario.

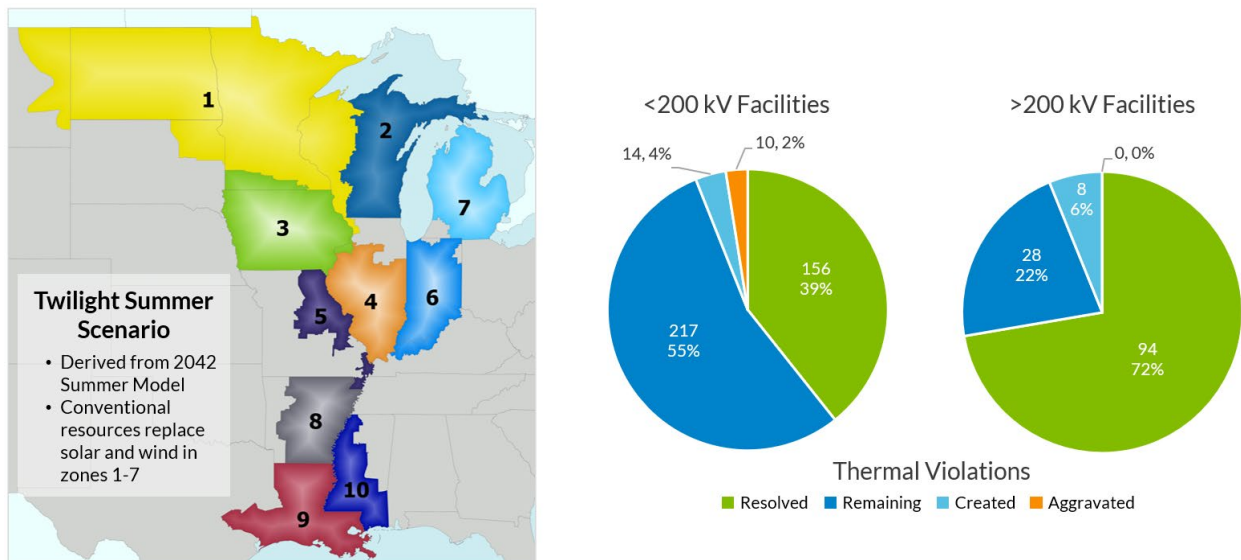


Figure 2.70: Twilight Summer Scenario results summary with the Tranche 2.1 portfolio



Total Economic Results

Analysis with annual economic models represent various system conditions and dispatch patterns helped MISO better understand system performance with and without the LRTP portfolio of projects. Unless otherwise indicated, the measures described in this section were derived from the 2042 Future 2A PROMOD models. The Tranche 2.1 portfolio enhances the economic value for the MISO Midwest subregion and enables member plans for fleet transition and load growth. The economic analysis revealed the Tranche 2.1 portfolio:

- Reduces economic congestion on existing transmission across the MISO Midwest subregion by 29.5%
- Reduces curtailment in the MISO Midwest subregion by 27.1M MWh (11.2%), improving access to more economic generation
- Supports the MISO Midwest subregion by reducing price separation across the subregions and decreasing system cost to serve load
- Facilitates a more economical dispatch for MISO Midwest resulting in \$8.1B in Adjusted Production Cost (APC) savings
- Provides a robust regional backbone supporting 115.7 GW of Future 2A resource enablement

Congestion Measure

Transmission congestion is quantified through “Congestion Measure” (\$/MW) and is calculated by multiplying annual Average Shadow Price (\$/MW/hr) by Binding Hours (hr/yr). A reduction in Congestion Measure demonstrates that the most congested transmission constraints in a region have been relieved, and that the effects of congestion throughout the region have been reduced.

The Tranche 2.1 portfolio reduces economic congestion on existing transmission across the MISO Midwest subregion by 29.5% including:

- West Region sees a 25.5% (\$2.0M/MW) reduction in economic congestion
- Central Region sees a 33.9% (\$2.0M/MW) reduction in economic congestion
- East Region sees a 31.7% (\$0.9M/MW) reduction in economic congestion

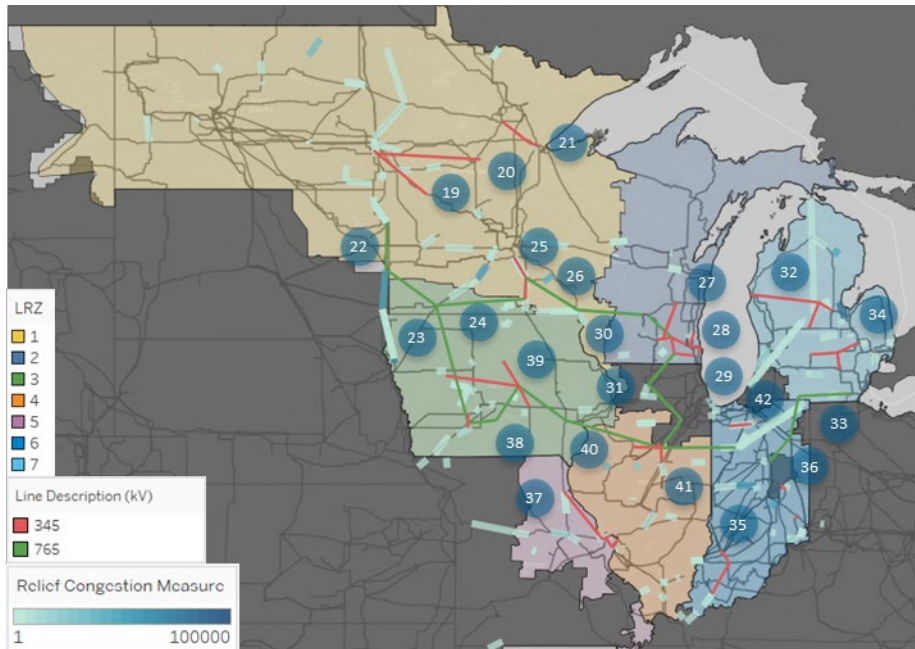


Figure 2.71: Change Case: Year 20 Economic Congestion Relief

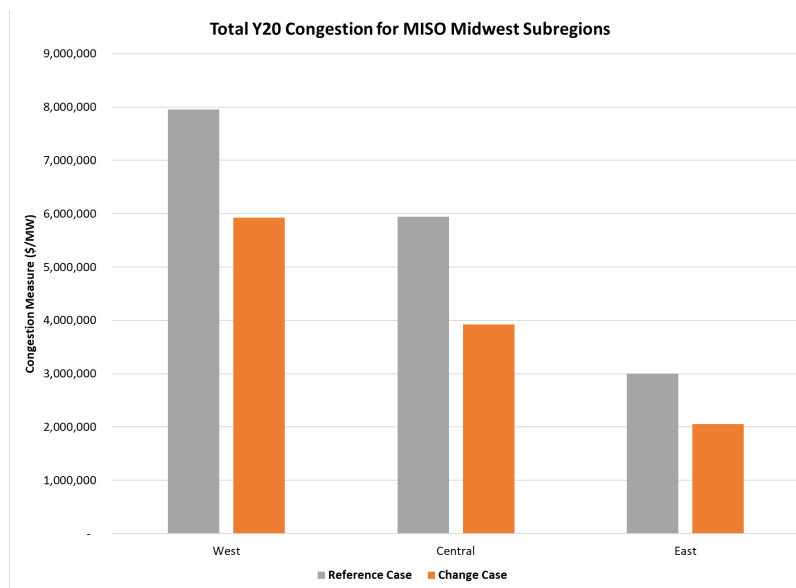


Figure 2.72: Reference and Change Case Year 20 Economic Congestion

MISO Subregion Y20 Congestion Measure by LRZ					
Region	LRZ	Reference Case (\$/MW)	Change Case (\$/MW)	Reduction (\$/MW)	Reduction (%)
West	LRZ1	6,032,037	5,054,985	977,052	16.2%
	LRZ2	1,109,215	345,145	764,070	68.9%
	LRZ3	811,109	526,642	284,467	35.1%
	West	7,952,361	5,926,772	2,025,589	25.5%



MISO Subregion Y20 Congestion Measure by LRZ					
Region	LRZ	Reference Case (\$/MW)	Change Case (\$/MW)	Reduction (\$/MW)	Reduction (%)
Central	LRZ4	1,972,466	1,698,381	274,085	13.9%
	LRZ5	1,277,548	563,671	713,877	55.9%
	LRZ6	2,688,959	1,661,564	1,027,395	38.2%
	Central	5,938,973	3,923,616	2,015,357	33.9%
East	LRZ7	3,000,363	2,050,593	949,770	31.7%
	East	3,000,363	2,050,593	949,770	31.7%
MISO Midwest	Total	16,891,697	11,900,981	4,990,716	29.5%

Table 2.10: Year 20 Congestion Reduction with LRTP Tranche 2.1 by Percentage

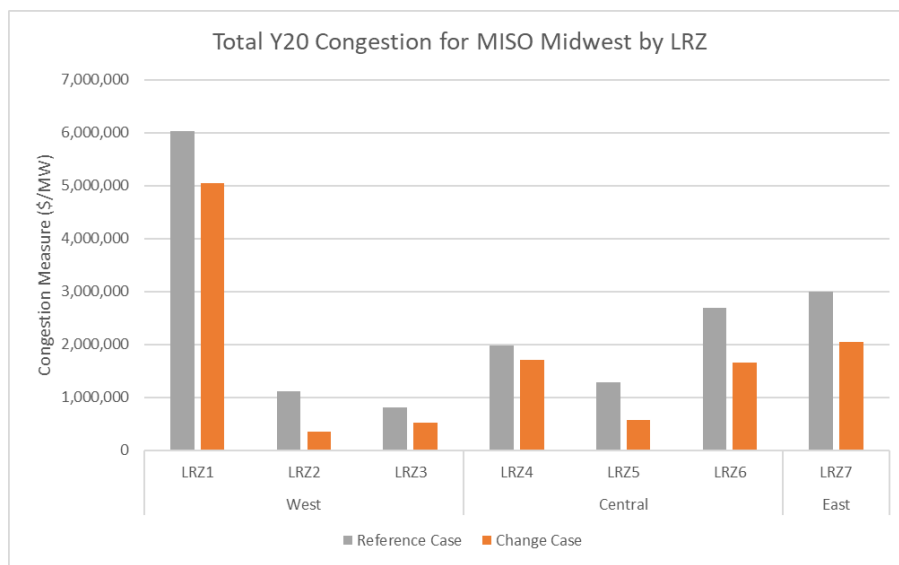


Figure 2.73: Year 20 Congestion with and without LRTP Tranche 2.1 by Local Resource Zone

Curtailement

Curtailement is due to many factors, including congestion and deliverability within MISO Midwest, which are substantially addressed with Tranche 2.1 transmission. Other curtailement is caused by competition and limited interregional export capacity and opportunity, which is outside the scope of this current effort to address.

Between the 2042 Reference case (without Tranche 2.1 transmission) and the 2042 Change case (with Tranche 2.1 transmission), the Tranche 2.1 portfolio reduces curtailement and improves access to more economic generation.

Curtailement in PROMOD is a measure of the available energy from renewable resources which are unable to deliver due to transmission constraints. Curtailement relief demonstrates the Tranche 2.1 portfolio will boost deliverability of additional generation, facilitate the Future 2A fleet change, and drive APC lower by reducing purchase and sales costs.

The Tranche 2.1 portfolio reduces generation curtailement across the MISO Midwest subregion 11.2% (27.1M MWh) including:



- West Region sees a 16.1% (31.6M MWh) reduction in curtailment
- Central Region sees marginal increase in curtailment, primarily due to increased competition from dispatch of more economical units within the Midwest subregion
- East Region sees marginal increase in curtailment, primarily due to increased competition from dispatch of more economical units within the Midwest subregion
- Overall, curtailment for the MISO Midwest subregion reduces from 33.7% to 29.9% in Year 20.

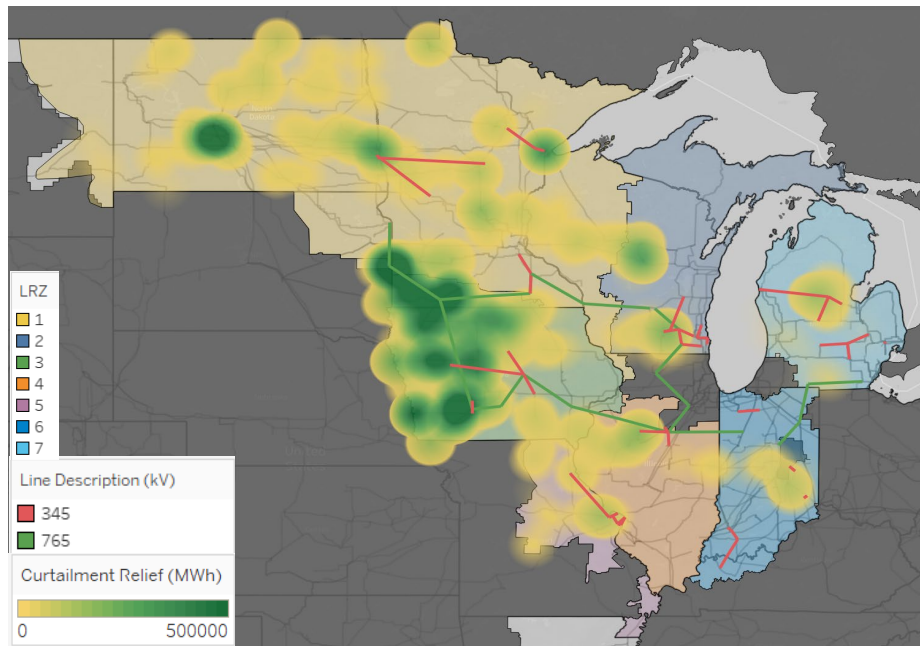


Figure 2.74: Change Case: Curtailment Energy Relief

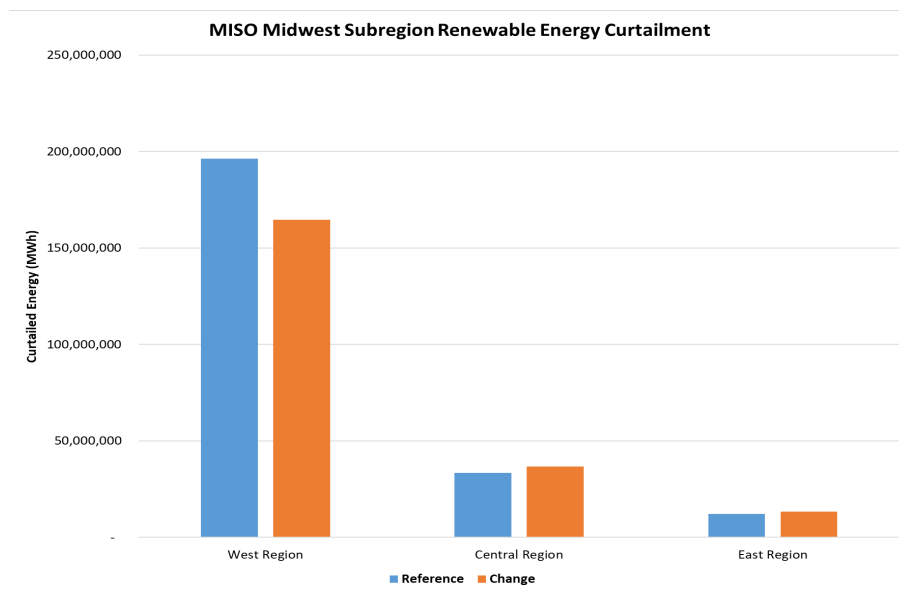


Figure 2.75: Reference and Change Case: Year 20 Curtailment Energy



Load Weighted Locational Marginal Price (Load LMP)

The portfolio supports the MISO Midwest subregion by reducing price separation across the subregion and decreasing system cost to serve load. Cost to serve load is represented by Load Weighted LMP (\$/MWh). The difference in prices between portions of the MISO Midwest subregion indicates that transmission constraints are limiting the efficient dispatch of lower cost resources. With Tranche 2.1 transmission included, the separation between these regions' prices decreases. Load Weighted LMPs decrease for each of the West, Central and East regions, with the greatest reductions seen in regions where Reference case prices are the highest.

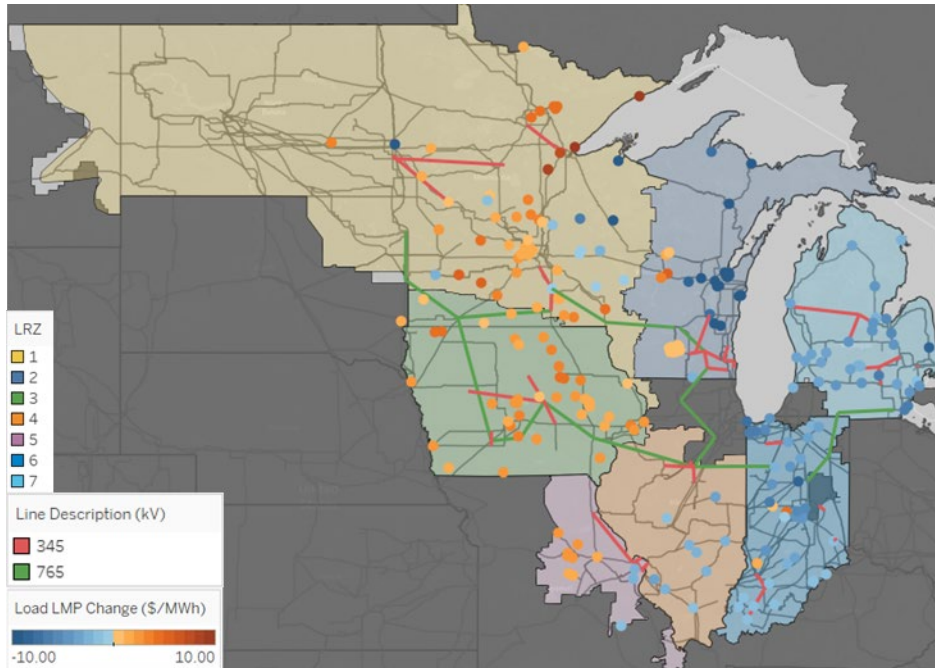


Figure 2.76: Change Case: Load LMP Price Reduction

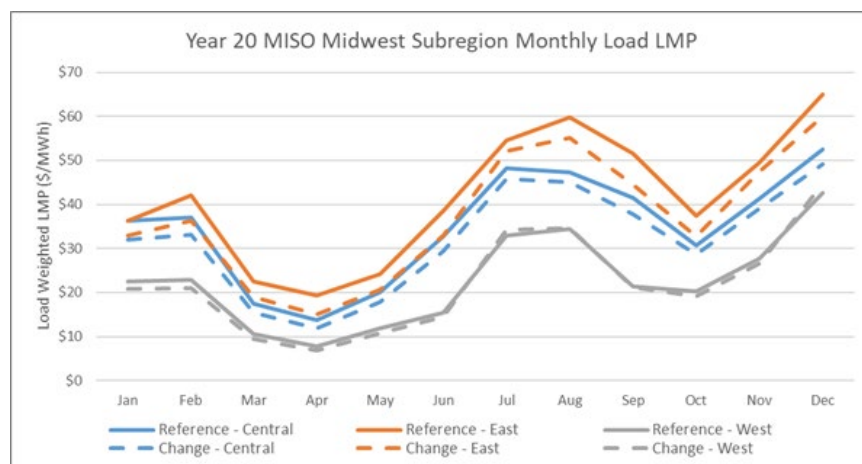
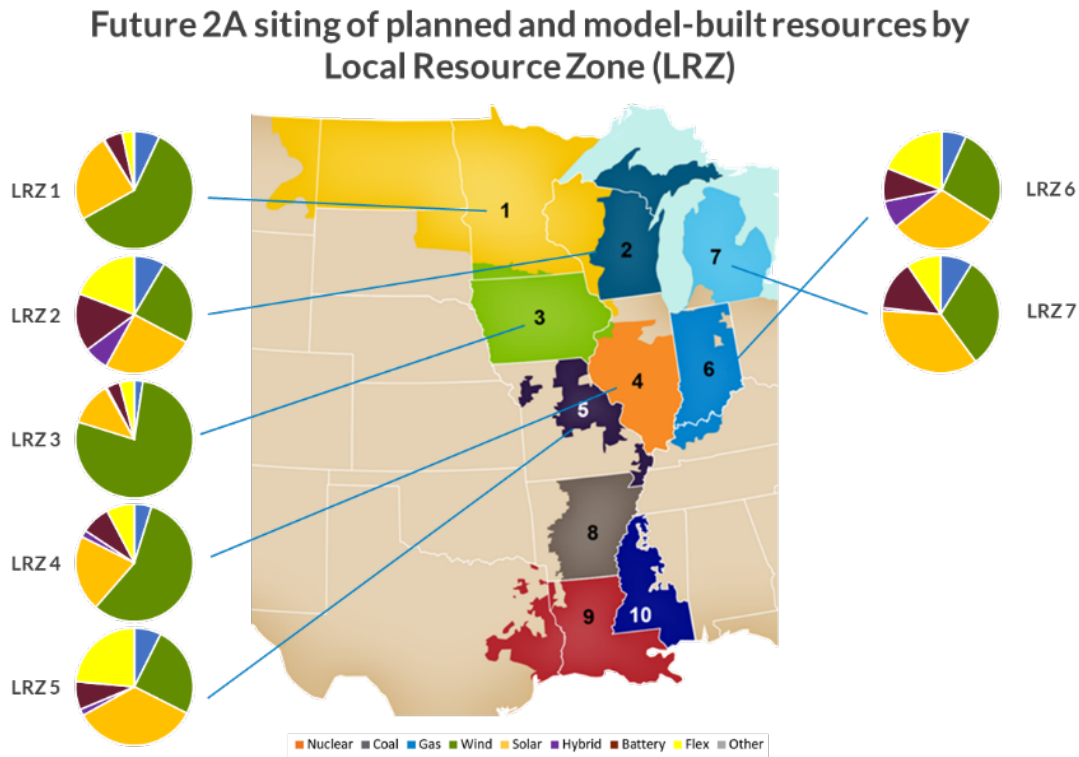


Figure 2.77: Reference & Change Case: Year 20 Load LMP Price



Generation Enablement

Tranche 2.1 provides a robust regional backbone supporting 115.7 GW of Future 2A resource enablement in addition to the 20.1 GW of generation previously enabled with Tranche 1 transmission. To date, the MISO Long Range Transmission Plan Tranche’s support 135.8 GW of resource enablement.



Generation Enabled by Resource Type (GW)		Generation Enabled by Local Resource Zone (GW)	
Storage	15.4	LRZ 1	32.1
Gas & Flex	16.9	LRZ 2	9.5
Solar	14.1	LRZ 3	27.4
Hybrid	1.2	LRZ 4	16.1
Wind	68.1	LRZ 5	2.8
Total	115.7	LRZ 6	16.6
		LRZ 7	11.2
		Total	115.7

Figure 2.78: LRTP Tranche 2.1 Future 2A Generation Enablement



West Region – Reliability and Economic Results

Results of transmission solutions in the West Region include the following:

- The Northern Minnesota group provides outlets to North Dakota generation, resolves constraints in this area and connects to Tranche 1 lines
- Congestion in Northern Minnesota is reduced
- Increased generation outlets in North Dakota, South Dakota and Minnesota shift congestion to new flowgates, which are addressed through underbuild
- The 765 kV project in northeastern South Dakota, Southwestern Minnesota and Western Iowa provides an outlet for generation in South Dakota and also connects both west-to-east 765 kV paths developed in the initial portfolio to provide contingency support
- The Minnesota-Wisconsin West – Wisconsin East project adds power transfer capability into load centers in Minnesota and Wisconsin
- Congestion in Eastern Wisconsin is reduced by moving regional flows onto the backbone network
- The Wisconsin-Illinois 765 kV project assists serving load centers in the region and provides contingency support by connecting to the West – East 765 kV path through Iowa and Illinois

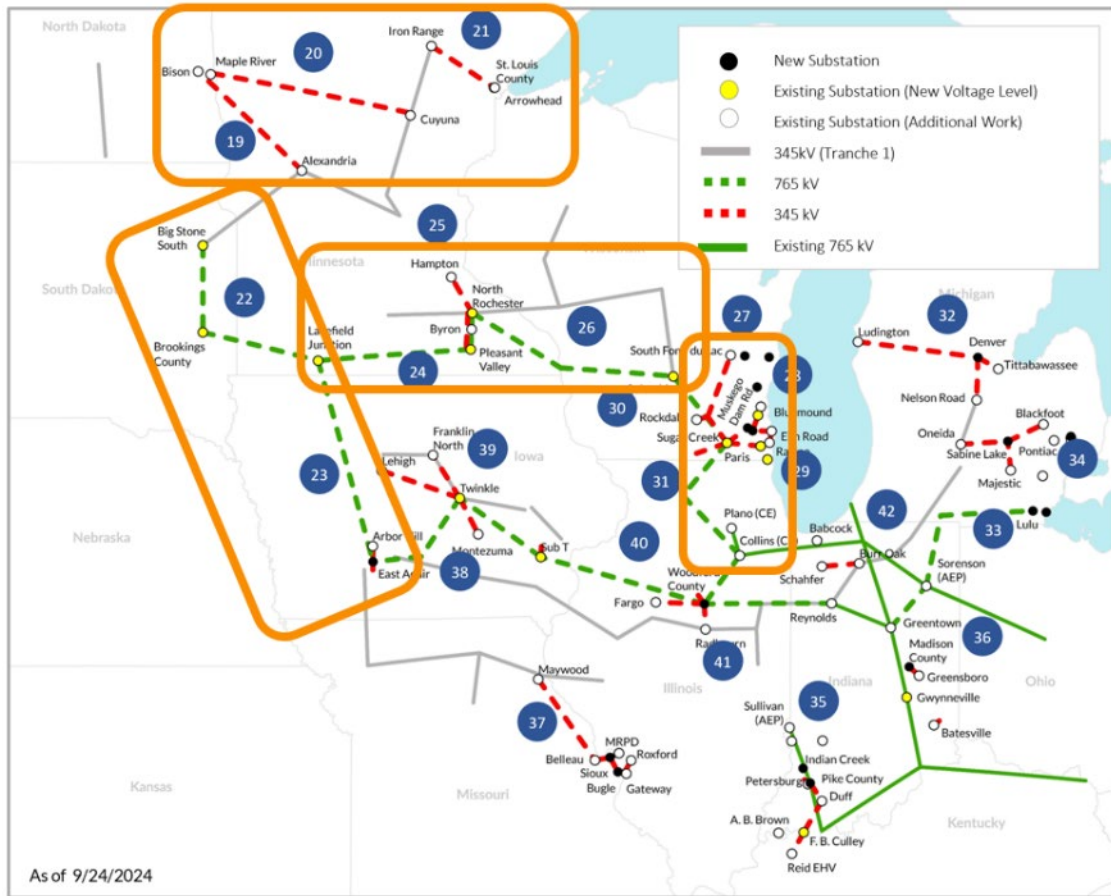


Figure 2.79: West Region Project Groups

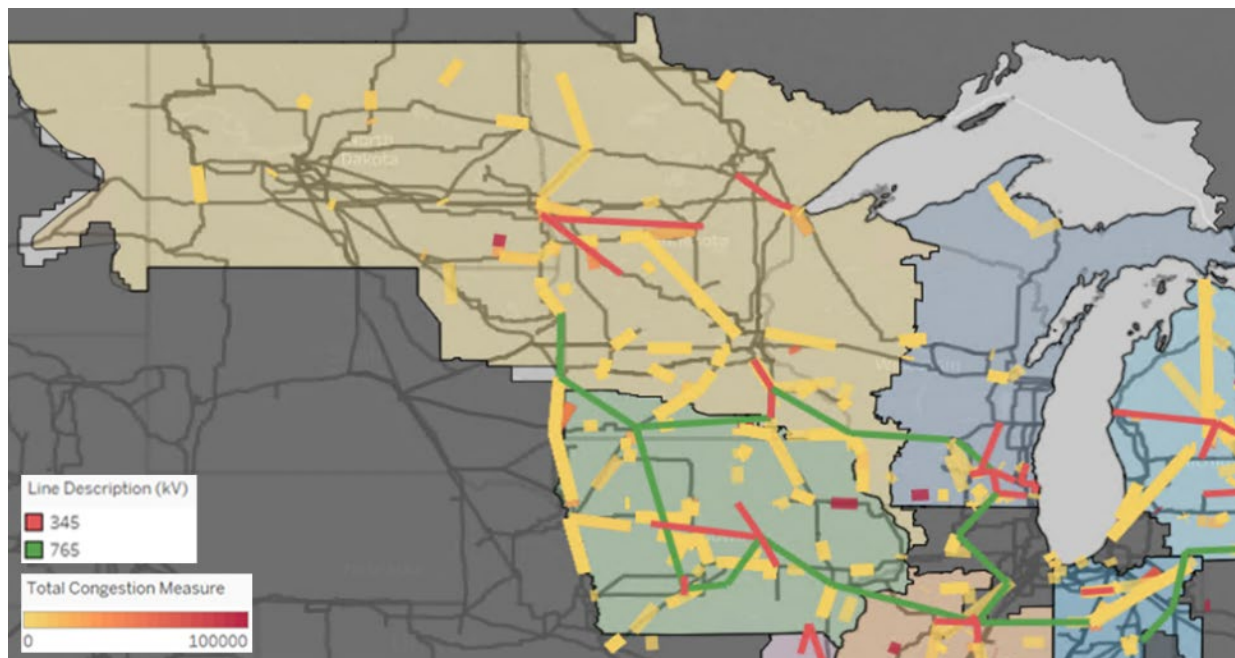


Figure 2.80: Change Case Economic Congestion - West



LRZ 1 – North Dakota and Minnesota

The LRTP Tranche 2.1 portfolio resolves most of the reliability violations on all voltage levels. The Tranche 2.1 portfolio reduces curtailments in LRZ1 by 13.2 % (15.5 M MWh) as illustrated in Figure 2.82 and reduces congestion throughout LRZ1 by 16.2% (977 k\$/MW). The curtailment reductions are seen in the areas of greatest base case curtailment, which can be seen in Figure 2.83. Based on the identification of relieved constraints, 32.1 GW of generation is enabled in LRZ 1.

The load serving costs annual Load LMP, moves towards a regional norm, as regional transmission better connecting west and east regions allows a more efficient dispatch of resources (cost to serve load is represented by Load Weighted LMP (\$/MWh)). This narrows the MISO Midwest subregion price disparity with a slight increase of \$1.87/MWh. Transmission enables greater access for generator exports, allowing renewable generation to offset higher cost generation in other regions. While overall congestion in LRZ1 decreases, generation enabled by new transmission shifts some congestion to new flowgates. The constraints that see increased congestion due to these shifts are associated with more localized issues, or with individual loads or generators and may be better resolved through annual MTEP reliability planning and the generator interconnection processes.

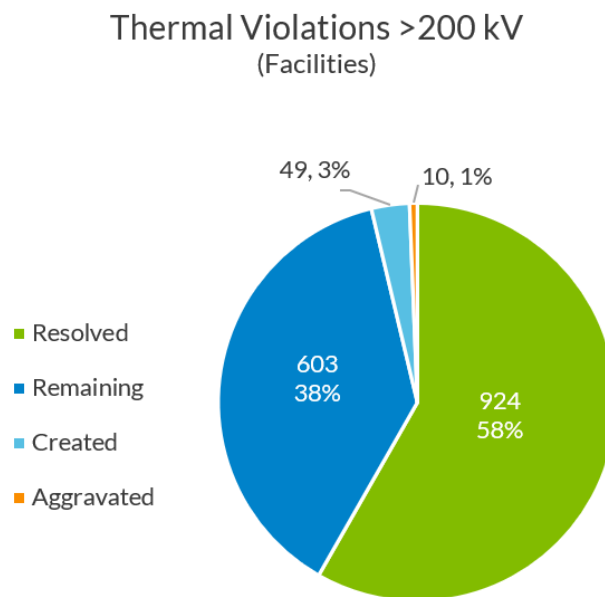


Figure 2.81: Thermal constraint resolution for LRZ1

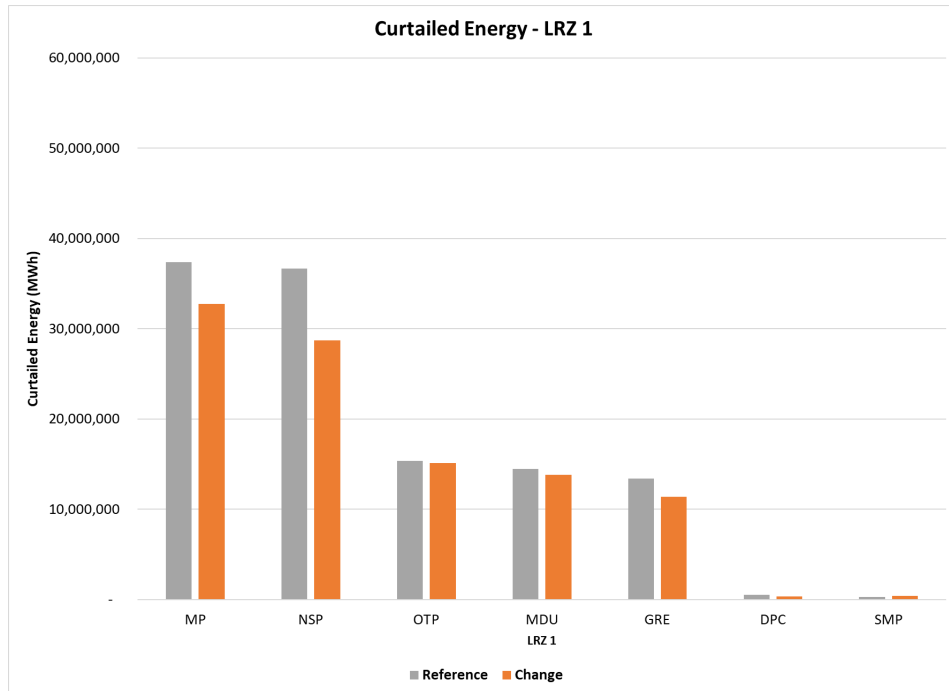


Figure 2.82: Curtailed Energy - LRZ 1

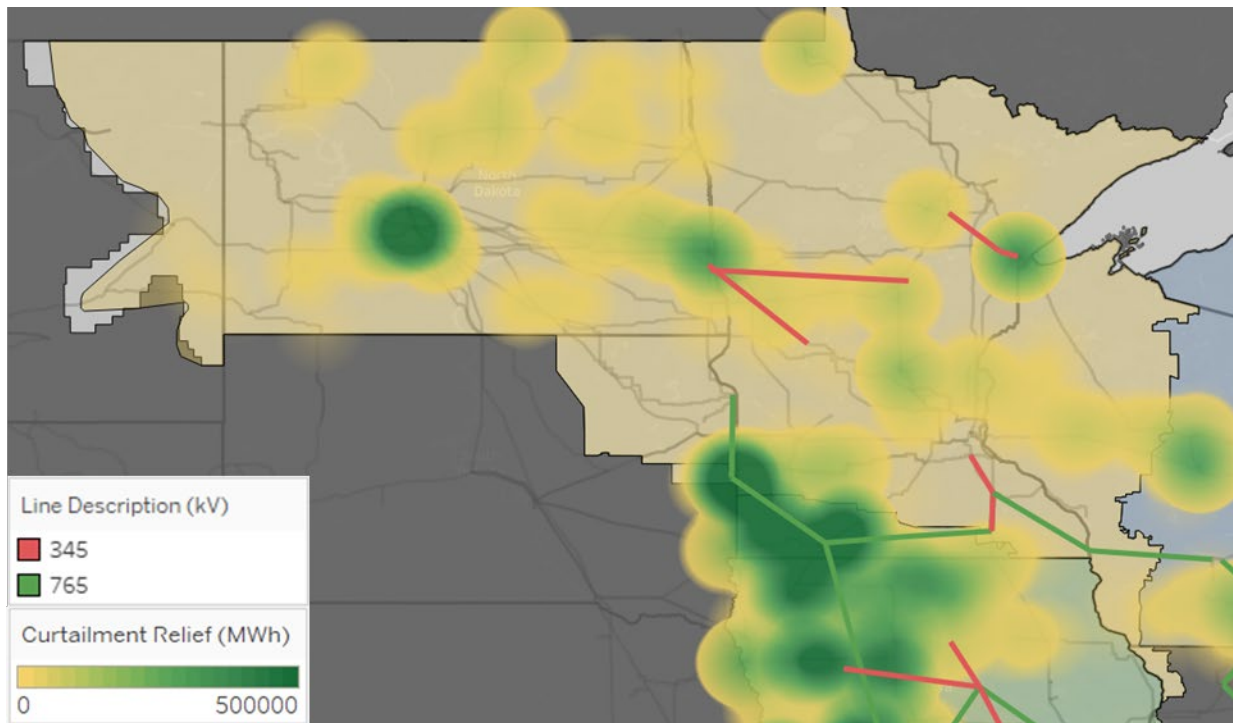


Figure 2.83: Change Case Curtailment Relief - LRZ 1



Bison - Alexandria 345 kV (Project 19), Maple River - Cuyuna 345 kV (Project 20), and Iron Range - St. Louis County - Arrowhead 345 kV (Project 21)

The 345 kV projects in Northern Minnesota (indicated by the dashed red lines in the map below) resolve more than 50% of the constraint violations for both the 200 kV above and below systems. The Northern Minnesota group provides outlets to North Dakota generation, resolves constraint violations in this area and connects to Tranche 1 lines. Congestion in Northern Minnesota is reduced and the increased generation outlet in North Dakota, South Dakota and Minnesota shifts congestion to new flowgates, which are addressed with the portfolio.



Figure 2.84: Northern Minnesota LRTP Tranche 2.1 projects

There is a significant reduction in the loadings in Northern Minnesota because of the portfolio. The top 20 lines with the most reduction in the loadings are shown in the table below. The criteria for selecting these lines was a combination of the number of violations resolved as well as the degree of reduction in loadings. The third column shows the highest loading for these elements in the models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The top resolved facilities are also displayed geographically in the figure below.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[MP] Badoura-[GRE] Hubbard 230 kV	138	84
2	[GRE] Hubbard-[OTP] Erie Jct 230 kV	121	78
3	[OTP] Erie Jct-[OTP] Audubon 230 kV	124	83
4	[OTP] Wahpeton-[MRES] Fergus Falls 230 kV	124	84
5	[GRE] Silver Lake-[MRES] Fergus Falls 230 kV	107	74
6	[MPC] Maple River-[MPC] Winger 230 kV	124	66
7	[OTP] Wahpeton-[MPC] Frontier 230 kV	110	51
8	[MP] Riverton-[GRE] Wing River 230 kV	123	74
9	[GRE] Silver Lake-[GRE] Henning 230 kV	104	68



#	Element	Initial Worst Loading %	Final Worst Loading %
10	[MP] Hibbard - [MP] Winter St. 115 kV	243	97
11	[MP] Dahlberg - [MP] Stinson 115 kV	211	Reconfigured
12	[XEL] Sheyenne - [WAPA] Fargo 230 kV	130	56
13	[XEL] Sheyenne - [OTP] Maple River 230 kV	114	51
14	[MP] Fairmount Park - [MP] Winter St. 115 kV	259	95
15	[MP] Fairmount Park - [MP] Stinson 115 kV	230	74
16	[OTP] Wilton - [OTP] Scribner 115 kV	126	86
17	[OTP] Wilton Tap - [OTP] Scribner 115 kV	123	86
18	[OTP] Solway - [OTP] Wilton Tap 115 kV	114	81
19	[XEL] Wakefield - [XEL] Stockade Tap 115 kV	111	90
20	[MP] Arrowhead - [MP] Gary 115 kV	123	74

Table 2.11: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Northern Minnesota



Figure 2.85: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Northern Minnesota

Projects in Northern Minnesota increase deliverability of resources from North Dakota, South Dakota and Western Minnesota towards load centers in Northern Minnesota and down towards the Twin Cities. These projects reduce congestion overall, and reduce congestion on the most heavily congested flowgate in LRZ1.



The increase in energy delivery shifts the dispatch throughout LRZ1, and some congestion shifts to different flowgates associated with more localized issues. Table 2.12 shows top relieved flowgates ranked by congestion measure relief for projects 19, 20, & 21. The combined congestion measure impact for flowgates assessed for projects 19, 20, & 21 is shown in Figure 2.86.

Y20 Top Relieved Flowgates - Projects 19, 20, & 21			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 1117: [MP] HIBBARD - [MP] WNTR ST 115 kV 1	1,621,984	876,000	745,984
Event 270: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	158,693	-	158,693
Event 192: [MP] LONG PR7 - [GRE] GRE-LTLSTKTP7 115 kV 1	454,591	329,864	124,727
Base Case: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	112,246	-	112,246
Event 1033: [MP] AITKNMN7 - [GRE] GRE-AITKIN 7 115 kV 1	47,573	-	47,573
Event 586: [GRE] GRE-INMAN 4 - [GRE] GRE-WINGRIV4 230 kV 1	64,442	24,550	39,892
Event 1355: [MP] CLOQUET7 - [MP] CANOSIA7 115 kV 1	58,902	19,317	39,585
Event 1391: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	38,318	-	38,318
Event 1045: [MP] FLDWDTP7 - [MP] MDWLND57 115 kV 1	31,812	-	31,812
Event 592: [NSP] SHEYNNE4 - [OTP] LAKE PARK T4 230 kV 1	40,486	11,028	29,457

Table 2.12: Top Relieved Flowgates – Projects 19, 20 & 21

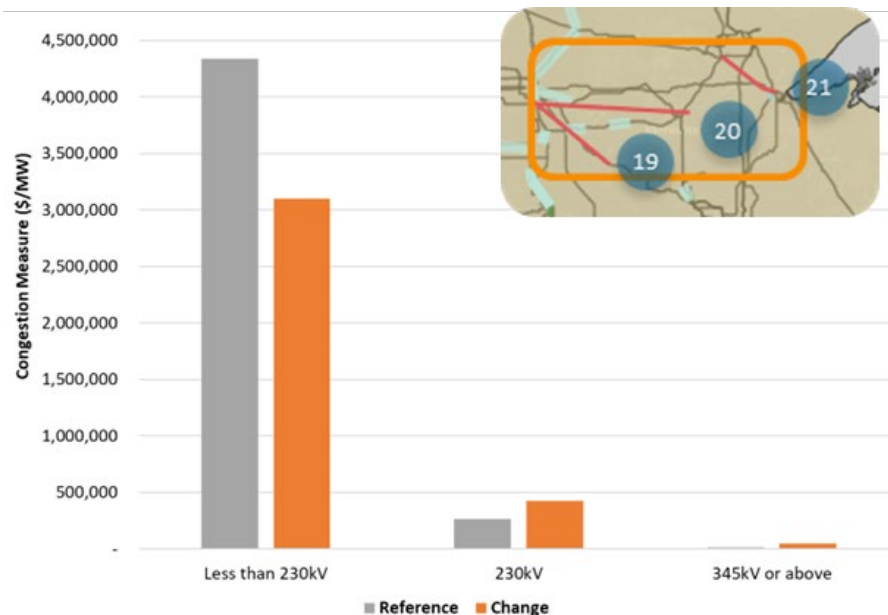


Figure 2.86: Congestion Measure for Projects 19, 20, and 21



Lakefield Junction - Pleasant Valley - North Rochester 765 kV (Project 24), Pleasant Valley - North Rochester - Hampton Corner 345 kV (Project 25), and North Rochester - Columbia 765 kV (Project 26)

The portfolio resolves most constraints in Southern Minnesota and Western Wisconsin, especially on 200 kV and above facilities. The Minnesota -Wisconsin West – Wisconsin East project assists transfer of power into load centers in Minnesota and Wisconsin.

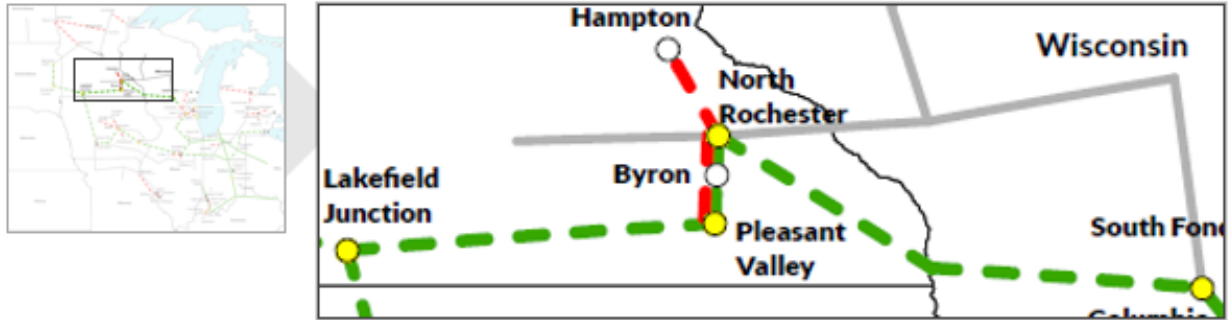


Figure 2.87: Southern Minnesota and Western Wisconsin L RTP Tranche 2.1 projects

**Thermal Violations >200 kV
(Facilities)**

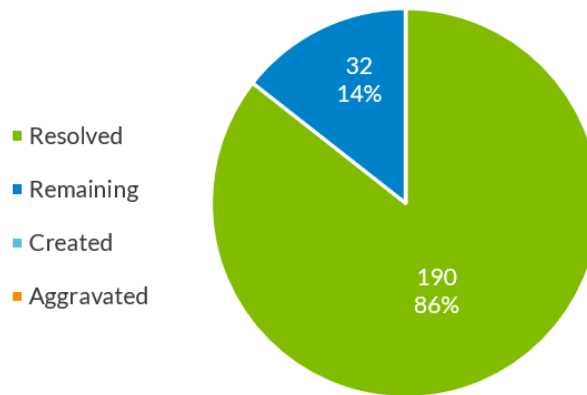


Figure 2.88: Thermal constraint resolution for Southern Minnesota and Western Wisconsin

There is a significant reduction in the loadings in Southern Minnesota and Western Wisconsin because of the portfolio. The top 20 lines with the most reduction in the loadings are shown in the table below. The third column shows the highest loading for these elements in the base models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The North Rochester-Byron and Byron-Pleasant Valley lines, which are labeled as reconfigured, still exist in the portfolio models and have been upgraded to higher ratings as part of a single-to-double circuit rebuild and are no longer overloaded anymore. The locations of the top 10 lines are shown on the map below.



#	Element	Initial Worst Loading %	Final Worst Loading %
1	[XEL] Helena-[XEL] Hampton Corner 345 kV	162	75
2	[XEL] AS King-[XEL] Eau Claire 345 kV	133	75
3	[XEL] Prairie Island-[XEL] N. Rochester 345 kV	123	90
4	[XEL] Helena-[XEL] Scott Co. 345 kV	127	98
5	[XEL] Wilmarth-[XEL] Crandall 345 kV	123	66
6	[XEL] Wilmarth-[XEL] Sheas Lake 345 kV	113	81
7	[XEL] N. Rochester-[XEL] Byron 345 kV	110	Reconfigured
8	[XEL] Helena-[XEL] Sheas Lake 345 kV	105	72
9	[XEL] Eau Claire-[ALTE] Arpin 345 kV	116	71
10	[XEL] Byron-[XEL] Pleasant Valley 345 kV	114	Reconfigured
11	[XEL] Wilmarth-[XEL] Huntley 345 kV	108	73
12	[XEL] Tremval - [MGE] North Madison 345 kV	112	67
13	[XEL] Jump River - [WPS] Gardner Park 345 kV	108	67
14	[ALTW] Emery - [MEC] Floyd 161 kV	120	83
15	[MP] Gordon - [MP] Hawthorne Tap 161 kV	135	22
16	[ALTW] Barton - [ALTW] Lime Creek 161 kV	121	91
17	[WPS] Cassel - [WPS] Wien 115 kV	130	79
18	[XEL] Minnesota Valley - [XEL] Redwood Falls 115 kV	125	82
19	[WPS] Sunnyvale - [WPS] Cassel 115 kV	134	79
20	[DPC] Wabaco - [DPC] Kellogg 161 kV	151	96

Table 2.13: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Minnesota and Western Wisconsin

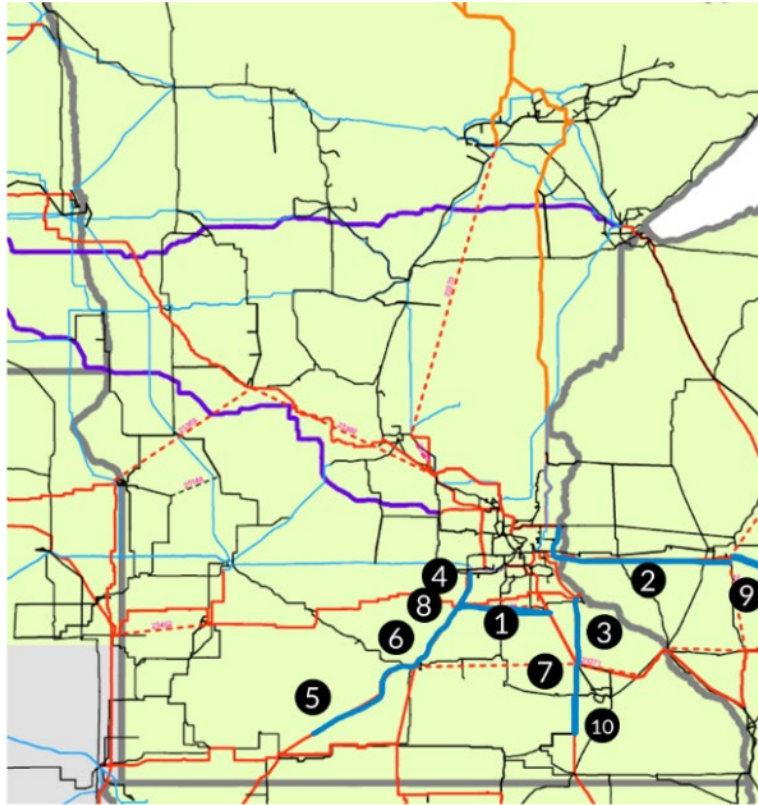


Figure 2.89: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Minnesota and Western Wisconsin

Projects in Southern Minnesota and Wisconsin enable substantially more renewable delivery, particularly from the Eastern Dakotas, Southwestern Minnesota, and Northern Iowa – locations with some of the strongest wind resources. This is aided through the loop configuration of the other Tranche 2.1 765 kV west-to-west path which increases the amount of power that can reliably flow over 765 kV facilities. Overall congestion in this area remains flat even as energy delivery increases. The additional enabled resources shift the patterns of congestion to new and different flowgates. Table 2.14 shows top relieved flowgates ranked by congestion measure relief for projects 24, 25, and 26. The combined congestion measure impact for flowgates assessed for projects 24, 25, and 26 is shown in Figure 2.90.

Y20 Top Relieved Flowgates Ranked by Cong, and 26estion Measure Relief - Projects 24, 25, & 26			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 130: [SMP] RUTLAND5 - [ALTW] FOX LK 5 161 kV 1	85,064	720	84,343
Event 146: [NSP] BLUE LK3 - [NSP] SCOTTCO3 345 kV 1	49,404	13,732	35,672
Event 32: [NSP] BLUE LK3 - [NSP] HMPT CNR3 345 kV 1	55,518	26,597	28,922
Event 587: [ALTW] BARTON5 - [ALTW] LIME CK L2 5 161 kV 1	34,899	15,532	19,367
Event 143: [NSP] ADAMS 3 345kV - [ALTW] ADAMS 5 161 kV 9	26,860	8,666	18,194
Base Case: [DPC] ALMA 5 - [DPC] KELLOGG 5 161 kV 1	18,347	1,254	17,093
Event 1443: [NSP] WILMART3 - [ALTW] HUNTLEY3 345 kV 1	10,423	50	10,372



Y20 Top Relieved Flowgates Ranked by Cong, and 26estion Measure Relief - Projects 24, 25, & 26			
Event 255: [NSP] BRIGGS RD 5 - [NSP] TREMVAL5 161 kV 1	5,248	210	5,038
Event 250: [MEC] WEBSTER5 - [MEC] SUB T FD 5 161 kV 1	4,729	0	4,729
Event 78: [NSP] WILMART3 - [NSP] SHEAS LK3 345 kV 1	4,807	188	4,619

Table 2.14: Top Relieved Flowgates – Projects 24, 25, & 26

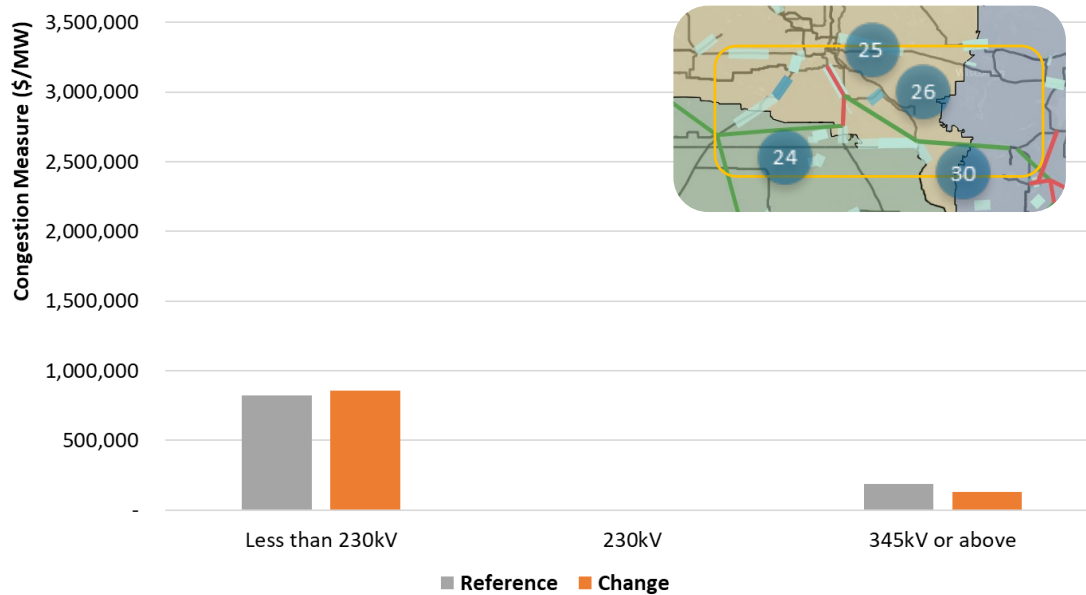


Figure 2.90: Congestion Measure for Projects 24, 25, and 26

LRZ 2 – Wisconsin

The LRTP Tranche 2.1 portfolio resolves a vast majority of the thermal violations across all voltage levels in LRZ2. The Tranche 2.1 portfolio reduces congestion throughout LRZ2 by 68.9% (764 k\$/MW) and reduces curtailments in LRZ2 by 26.9% (1.4M MWh) enabling 9.5 GW of generation. Load serving costs decrease year-round and throughout LRZ2, by an average of \$7.67 / MWh as shown in Figure 2.93.

Reductions in curtailment follow the geographic pattern of initial curtailment and are observed in corridors relieved by the 765 kV regional path, seen in Figure 2.92. The 765 kV pathway moves regional flows off lower voltage facilities, supports economic congestion reduction and significantly relieves top binding constraints. Congestion in LRZ2 is driven by regional loop flow, which is more easily relieved through 765 kV paths. The Tranche 2.1 facilities reduce congestion due to loop flow and access to additional lower cost renewables in the West. Increased access to low-cost resources from neighboring LRZs significantly reduces Load LMPs.

Thermal violations remaining on >200 kV facilities are a result of splitting of the existing lines, and their overloads are less severe than the original overloads. For example, some of the new violations are attributed to the splitting of two lines. The highest loading on one of the lines was 156% in the core models and decreased to 109% in the portfolio models. Similarly, the other facility was loaded at 119% in the core models and decreased to 102% in the portfolio models. The 345/230 kV transformers are fully relieved in the core models, and the new violations are limited to the transfer scenarios specific to new resource units



to load and it is more appropriate for these issues to be addressed by the annual MTEP reliability planning and the generator interconnection processes.

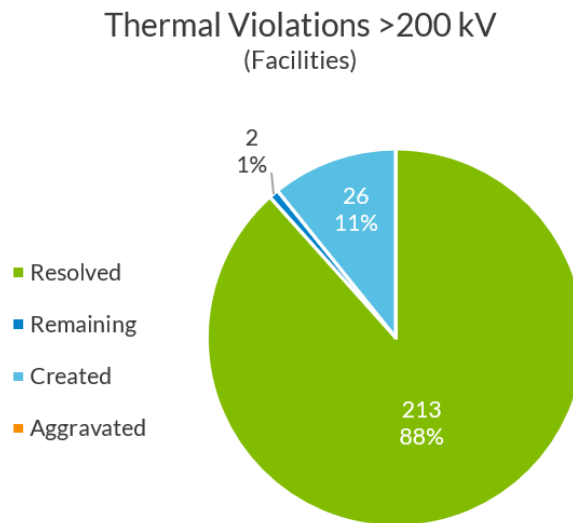


Figure 2.91: Thermal constraint resolution for LRZ2

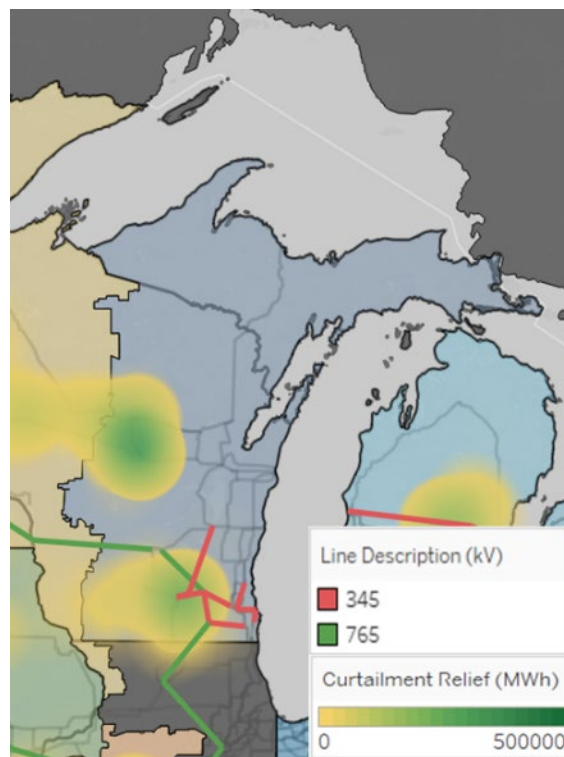


Figure 2.92: Change Case: Curtailment Relief for LRZ 2

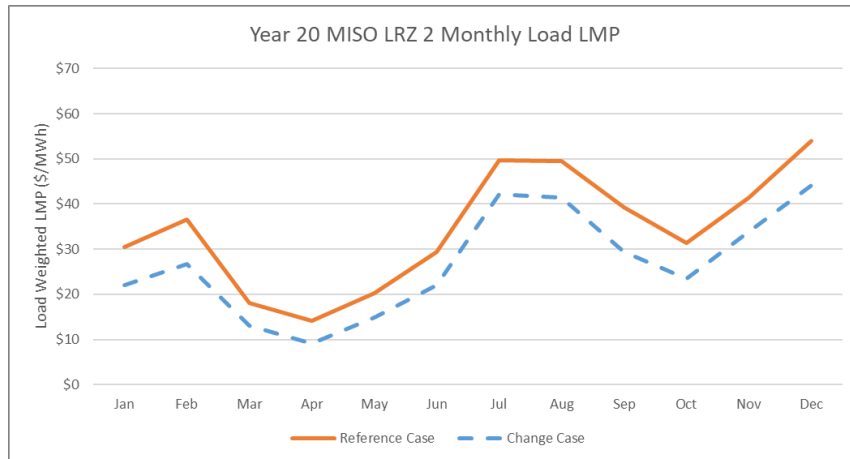


Figure 2.93: Comparison: Monthly Load LMP for LRZ 2

Rocky Run – Werner West - North Appleton 345 kV (Project 27), South Fond du Lac – Jefferson - Rockdale and Big Bend - Sugar Creek - Kitty Hawk 345 kV (Project 28), Bluemound - Arcadian -- Muskego Dam Road - Elm Road - Racine 345 kV and Arcadian – Waukesha 138 kV uprate (Project 29), Columbia - Sugar Creek 765 kV (Project 30), and Sugar Creek - Collins 765 kV (Project 31)

The Tranche 2.1 portfolio resolves a majority of the thermal violations across all voltage levels in Southeastern Wisconsin. Congestion in Eastern Wisconsin is reduced by moving regional flows onto the backbone network. Sugar Creek – Collins 765 kV project in Wisconsin and Illinois assists in serving load centers in the region and provides contingency support by connecting the northern 765 kV path to the West – East 765 kV corridors through Iowa and Illinois.

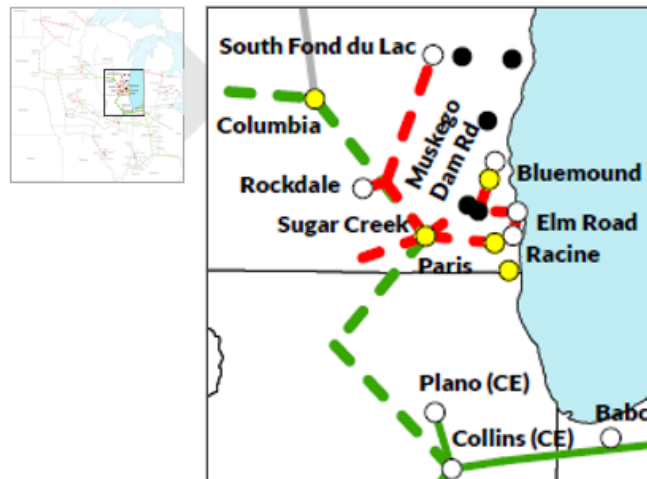


Figure 2.94: Southeastern Wisconsin LRTP Tranche 2.1 projects

Loading stress on several elements across various voltage levels in this region is relieved by the Tranche 2.1 portfolio. The elements with the most reduction in the loadings are shown in the table below.

“Reconfigured” means that the circuits have been cut into two or more segments, because of new stations added in between, and thus such circuits no longer exist in the cases with the portfolio.



- The Cypress – Arcadian 345 kV line is now the Cypress - Sheboygan River - Cedar Creek Junction – Arcadian 345 kV line
- The Edgewater - S Fond du Lac 345 kV line is now the Edgewater - Mullet River Junction - Sheboygan River - S Fond du Lac 345 kV line
- The Zion Station - Pleasant Prairie 345 kV line is now Zion Station - Lakeview - Pleasant Prairie 345 kV line
- The Arcadian – Paris – Zion Station e 345 kV line is now Arcadian – Big Bend - Muskego Dam Rd - Elm Rd - Racine - Mt Pleasant - Pleasant Prairie 345 kV line
- The Arcadian – Pleasant Prairie 345 kV line is now the Arcadian – Big Bend – Muskego Dam Road – Paris – Lakeview – Pleasant Prairie 345 kV line.

The map below depicts the top relieved facilities from the table.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[WPS] Rocky Run-[WEC] Werner W. 345 kV	201	56
2	[WEC] Werner W.-[WEC] N. Appleton 345 kV	192	48
3	[WEC] Cypress-[WEC] Arcadian 345 kV	156	Reconfigured
4	[ALTE] Edgewater-[ALTE] S. Fond du Lac 345 kV	119	Reconfigured
5	[WEC] Cypress-[WEC] Forest Jn. 345 kV	138	77
6	[WEC] Cedar Sauk-[ALTE] Edgewater 345 kV	121	56
7	[WPS] Rocky Run-[WPS] Gardner Park 345 kV	113	86
8	[CE] Wempletown-[ALTE] Paddock 345 kV	105	75
9	[CE] Zion Station-[WEC] Pleasant Prairie 345 kV	103	Reconfigured
10	[WEC] Arcadian-[WEC] Pleasant Prairie 345 kV	112	Reconfigured
11	[CE] Zion Energy Center-[WEC] Pleasant Prairie 345 kV	117	52
12	[WEC] Elk Lake Reactor - [WEC] Elkhart Lake 138 kV	148	92
13	[ALTE] N. Lake Geneva - [ALTE] Elkhorn 138 kV	115	93
14	[WEC] Auburn - [WEC] Butternut 138 kV	121	87
15	[ALTE] Sunrise - [WEC] Lakehead 138 kV	117	74
16	[ALTE] Nelson Dewey 161/138 kV Transformer	134	97
17	[WEC] Elkhart Lake - [WEC] Sauville 138 kV	148	80
18	[WEC] Forest Junction - [WPS] Tecumseh Rd 138 kV	122	77
19	[WEC] Esker View - [WPS] Tecumseh Rd 138 kV	122	70
20	[WEC] PM - [WEC] Esker View 138 kV	119	66

Table 2.15: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Eastern Wisconsin

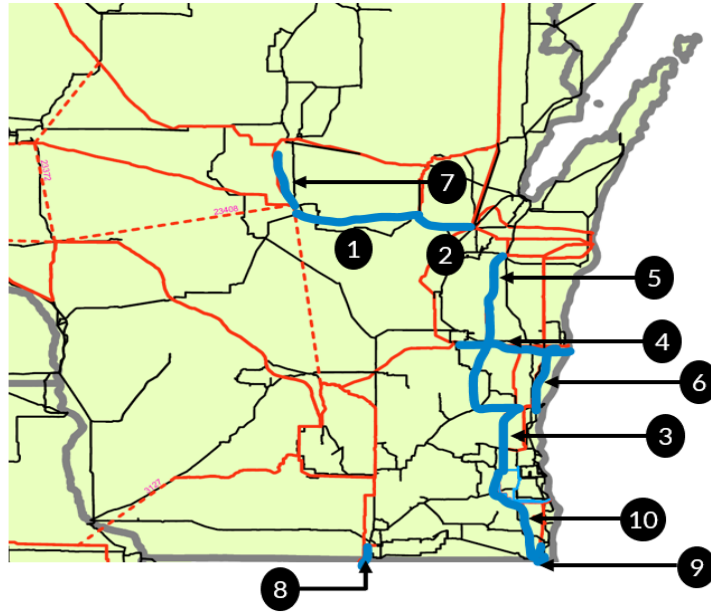


Figure 2.95: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southeastern Wisconsin

The regional backbone projects in and through Wisconsin are successful in moving regional flows off of the local system and onto the backbone transmission, which results in the relief of the majority of congestion seen in LRZ2. The most congested flowgate in LRZ2 is fully relieved by these projects. This congestion relief also allows LRZ2 resources to dispatch more efficiently, reducing curtailment in the zone. Table 2.16 lists the top flowgates relieved by projects 27, 28, 29, 30, and 31 in LRZ 2. Figure 2.96 shows the combined impact for all flowgates assessed with projects 27, 28, 29, 30, and 31.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 27, 28, 29, 30, & 31			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 1463: [WPS] ROCKY RUN - [WEC] WERNER W B4 345 kV 1	292,658	-	292,658
Event 94: [ALTE] NLG 138 - [ALTE] ELK 138 138 kV 1	123,330	790	122,541
Base Case: [WEC] JEFRSN5 - [WEC] CRWFSH R 138 kV 1	142,777	29,873	112,904
Event 47: [WEC] BRLGTN1 - [WEC] NLK GV T 138 kV 1	48,790	211	48,579
Base Case: [ALTE] ROE 138 - [WEC] LKHD_CAM_TP 138 kV 1	36,426	-	36,426
Event 22: [UPPC] SILVER RIVER - [UPPC] GREENSTN TAP 138 kV 1	89,452	58,211	31,241
Event 75: [ALTE] NLG 138 - [ALTE] ELK 138 138 kV 1	20,300	398	19,902
Event 361: [UPPC] SILVER RIVER - [UPPC] GREENSTN TAP 138 kV 1	43,144	24,512	18,632
Event 615: [UPPC] PERCH LK - [MIUP] PRESQ IS4567 138 kV 1	36,357	19,733	16,624
Event 92: [WEC] BCR_LNG_TAP - [WEC] BLUFFCRK 138 kV 1	14,126	-	14,126

Table 2.16: Top Relieved Economic Flowgates – Projects 27, 28, 29, 30, & 31

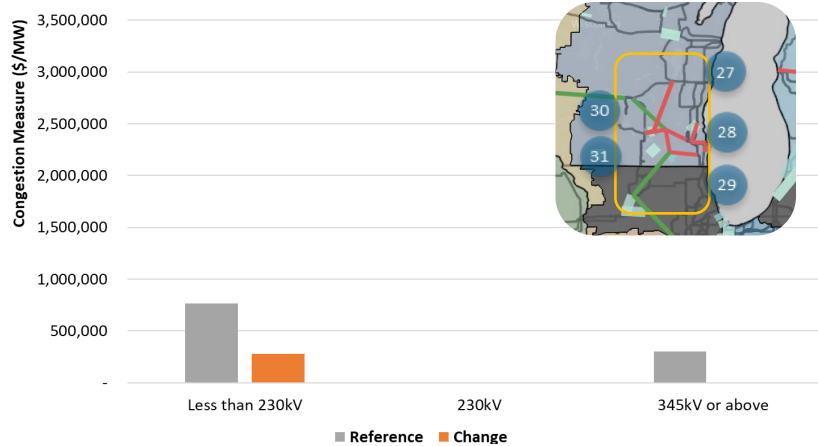


Figure 2.96: Congestion Measure for Projects 27, 28, 29, 30, & 31

LRZ 3 – Iowa

The LRTP Tranche 2.1 portfolio resolves a vast majority of the thermal violations in LRZ 3. For the <200 kV system, 92% of the violations have been resolved with 80% of the violations resolved on the >200 kV system as shown in the two pie charts below. Congestion shown in the reference case is reduced by the LRTP Tranche 2.1 portfolio by 35.1% (284 k\$/MWh). The strongest economic congestion relief is observed in the West to East oriented elements in Central Iowa and Southern Minnesota. Smaller increases in economic congestion are in Western Iowa, and numerous smaller shifts of congestion are seen as transmission enables Future 2A generation.

The LRTP Tranche 2.1 portfolio reduces curtailments by 20.0% (14.6M MWh) which is demonstrated in Figure 2.99 and enables 27.4 GW of generation. Reduced curtailment generally matches the geography of reference case curtailment, with the largest concentration in Northern and Western Iowa as can be observed from Figure 2.98. Transmission enables greater access for generator exports, reducing costs for purchasing companies. Load LMPs increase slightly by \$2.52/MWh, moving towards a regional norm, while narrowing the MISO Midwest subregion price disparity. Overall congestion in LRZ is reduced, as backbone transmission picks up more regional flows.

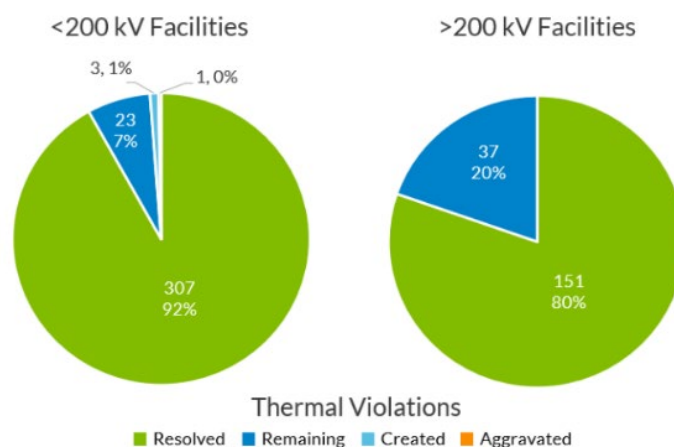


Figure 2.97: Pie- charts showing LRTP Tranche 2.1 resolving a vast majority of thermal violations in LRZ 3

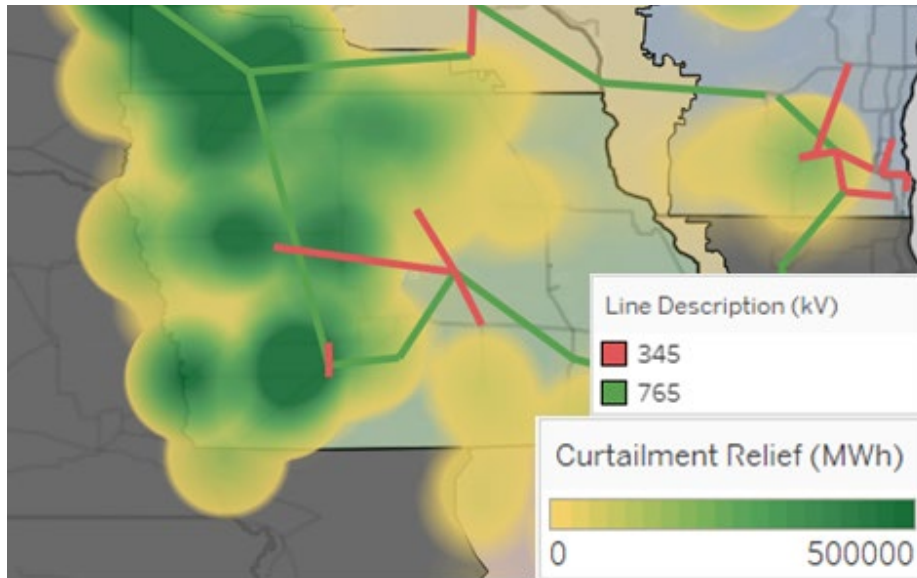


Figure 2.98: Change Case Curtailment Relief - LRZ 3

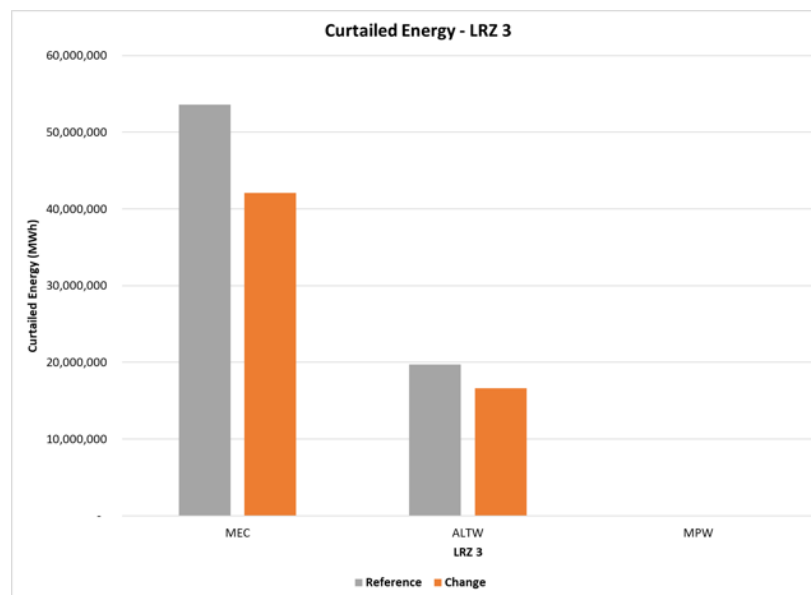


Figure 2.99: Curtailed Energy - LRZ 3

Big Stone South - Brookings County - Lakefield Junction 765 kV (Project 22) & Lakefield Junction - East Adair 765 kV (Project 23)

The 765 kV project in northeastern South Dakota, Southwestern Minnesota and Western Iowa provides outlet for generation in South Dakota and also connects both 765 kV west-to-east paths together at the western end to provide contingency support. The reliability impacts of LRTP Tranche 2.1 portfolio, and the Big Stone South- Brookings County- Lakefield Junction -East Adair 765 kV projects have been studied in this section.

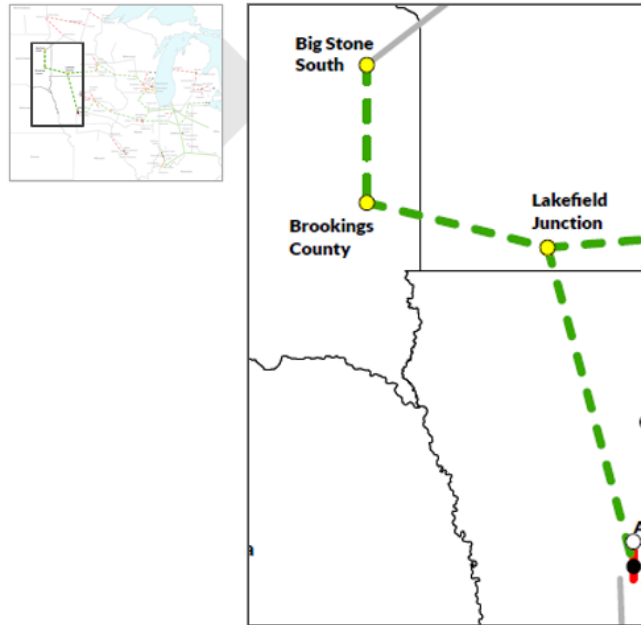


Figure 2.100: South Dakota, Southwestern Minnesota, and Western Iowa L RTP Tranche 2.1 projects

The L RTP Tranche 2.1 portfolio solved the majority of the thermal violations (82%) for the 200 kV+ system as shown below in the pie-chart below. A large number of the unresolved thermal violations for the 200 kV and below facilities are due to local generation siting, and can be better addressed through the annual MTEP reliability planning and the generator interconnection processes.

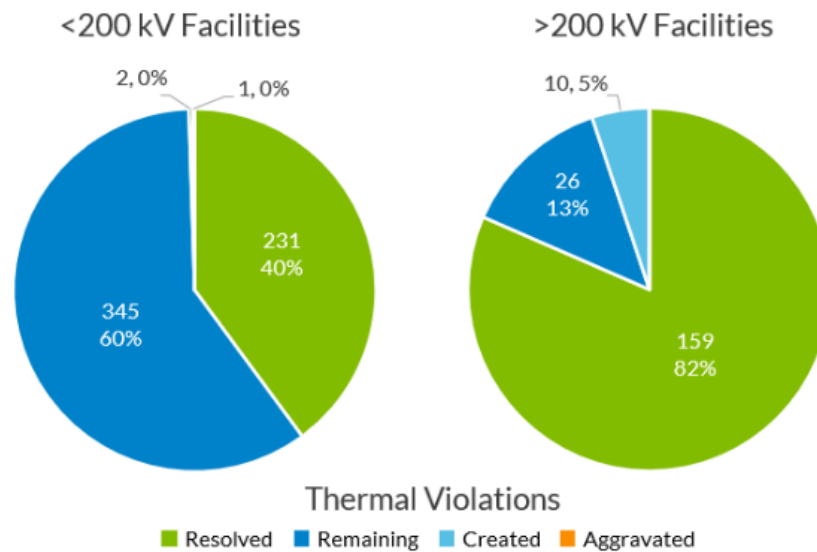


Figure 2.101: Pie-charts showing majority of thermal violations on the 200 kV and above facilities in South Dakota, Southwestern Minnesota, and Western Iowa being resolved by the L RTP Tranche 2.1 portfolio

The table below shows the top twenty limiting elements in the area that had the most impactful resolution in their thermal violations upon portfolio application, the map shows the geographic location of the top



facilities. The elements with overloading as high as 150% across all models and all seasons/scenarios in the pre-portfolio had loading level drop to less than 100% upon application of the portfolio. Notably among them is the Raun- Ida County West 345 kV line which was loaded at 142% of its rated capacity in the Light Load 2042 case. The same element had loading drop to 48% for the Light Load 2042 case upon application of the Tranche 2.1 portfolio.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[GRE] Panther-[XEL] McLeod 230 kV	121	81
2	[XEL] Minnesota Valley-[GRE] Panther 230 kV	114	76
3	[XEL] Minnesota Valley-[WAPA] Granite Falls 230 kV	116	75
4	[XEL] Hazel Creek 345/230 kV transformer	112	74
5	[XEL] Split Rock-[WAPA] White 345 kV	122	92
6	[MEC] Raun-[MEC] Ida County West 345 kV	142	48
7	[NPPD] Tekamah -[MEC] Raun 161 kV	147	83
8	[MEC] Raun-[OPPD] Sub 3451 345 kV	114	46
9	[MEC] Ida County West-[MEC] Ida County 345 kV	123	24
10	[AEPW] Southern Hills-[MEC] Booneville 345 kV	109	74
11	[XEL] Swan Lake-[XEL] Stockade Tap 115 kV	108	77
12	[XEL] Split Rock 230/115 kV transformer	119	53
13	[GRE] Kerkhoven Tap-[GRE] Kerkhoven 115 kV	117	77
14	[XEL] Split Rock- [WAPA] Sioux Falls 230kV	143	63
15	[XEL] McLeod 230/115 kV transformer	120	98
16	[XEL] Coon Creek- [XEL] Moore Lake 115 kV	100	97
17	[OTP] Benson-[OTP] Danvers 115 kV	106	77
18	[XEL] Monticello-[GRE] Oakwood 115 kV	103	99
19	[XEL] Brookings County 345/115 kV transformer	113	92
20	[OTP] Formal 230/115 kV transformer	107	99

Figure 2.102: Top reliability constraints resolved by LRTP Tranche 2.1 projects in South Dakota, Southwestern Minnesota, and Western Iowa

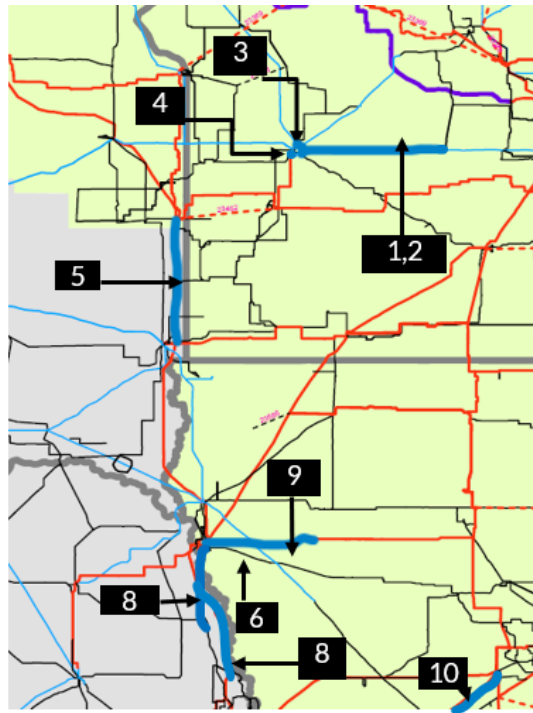


Figure 2.103: Top reliability constraints resolved by L RTP Tranche 2.1 projects in South Dakota, Southwestern Minnesota, and Western Iowa

The L RTP Tranche 2.1 portfolio significantly reduces curtailment and increases energy delivery from LRZ3. The increase in energy delivery shifts the dispatch, with relieved congestion in the western portion of LRZ3 being offset by congestion from new flowgates, many of which represent more localized issues. While the total congestion in the western portion of Iowa slightly increases, congestion throughout LRZ3 decreases, due to the combined contribution of the other transmission backbone system elements. Table 2.17 shows top relieved flowgates ranked by congestion measure relief for projects 22 and 23. The combined congestion measure impact for flowgates assessed for projects 22 and 23 is shown in Figure 2.104.

Y20 Top Relieved Flowgates - Projects 22 & 23			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 42: [NSP] HUC-MCLEOD 4 230 kV - [OTP] HUC-MCLEOD 7 115 kV 1	239,742	114,971	124,771
Base Case: [OTP] BIGSTON4 230kV - [OTP] YBUS770 100 kV 2	15,099	0	15,099
Event 43: [NSP] HUC-MCLEOD 4 230kV - [OTP] HUC-MCLEOD 7 115 kV 1	8,200	-	8,200
Event 392: [OTP] HANKSON4 - [OTP] FORMAN 4 230 kV 1	5,781	-	5,781
Event 53: [OTP] BIGSTON4 - [OTP] BROWNSV4 230 kV 1	6,444	2,873	3,570
Event 375: [MEC] RAUN 3 - [OPPD] S3451 3 345 kV 1	7,970	4,681	3,289
Event 171: [MEC] RAUN 3 - [OPPD] S3451 3 345 kV 1	4,817	2,877	1,940
Base Case: [NSP] BRKNGCO3 345kV - [NSP] BRKNGCO7 115 kV 9	2,068	329	1,739



Y20 Top Relieved Flowgates - Projects 22 & 23			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 45: [OTP] BIGSTON4 230kV - [OTP] BROWNSV4 230 kV 1	2,767	1,404	1,363
Event 70: [NSP] SPLT RK4 - [WAUE] SIOUXFL4 230 kV 1	2,753	1,499	1,253

Table 2.17: Top Relieved Economic Flowgates – Projects 22 & 23

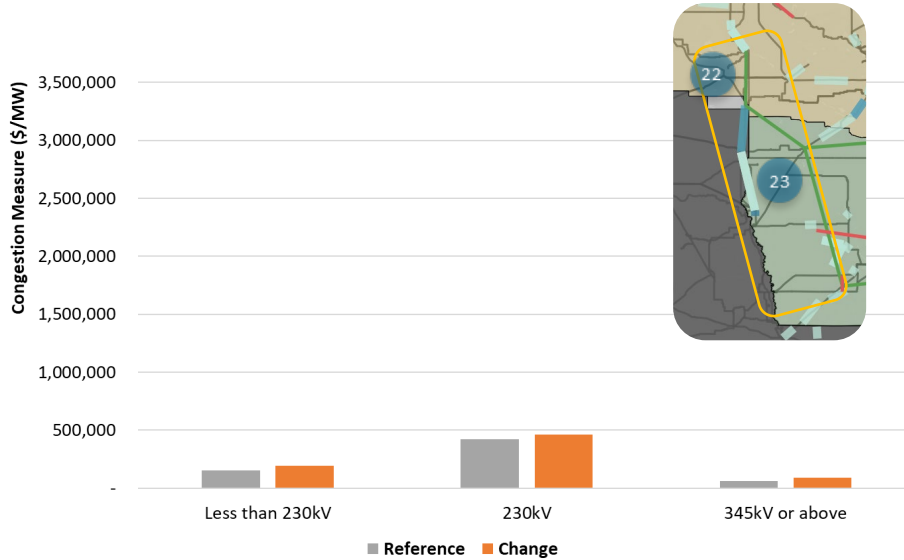


Figure 2.104: Congestion Measure for Projects 22, 23

Central Region – Reliability and Economic Results

- Both 765 & 345 kV level projects going West – East from Iowa through Illinois into Indiana provide a regional transfer path that enables generation in LRZ 1, 3, and 4 and supports strong East – West transfers to and from LRZ 6 and 7
- Transmission relieves congestion across Central and Eastern Iowa and throughout Illinois, Missouri, and Indiana. The 345 kV project in Missouri resolves numerous constraints in the St. Louis Metro region and enables increased intraregional transfers across the Central Region
- The Southern Indiana/Western Kentucky 345 kV project resolves constraints in the region and enhances West – East transfer capacity across the Central Region
- East Central Indiana upgrades more than double the 345 kV outlet and allows both 765 & 345 kV connections to adequately and reliably transfer remote generation to the Indiana load centers in Central and Southeastern Indiana

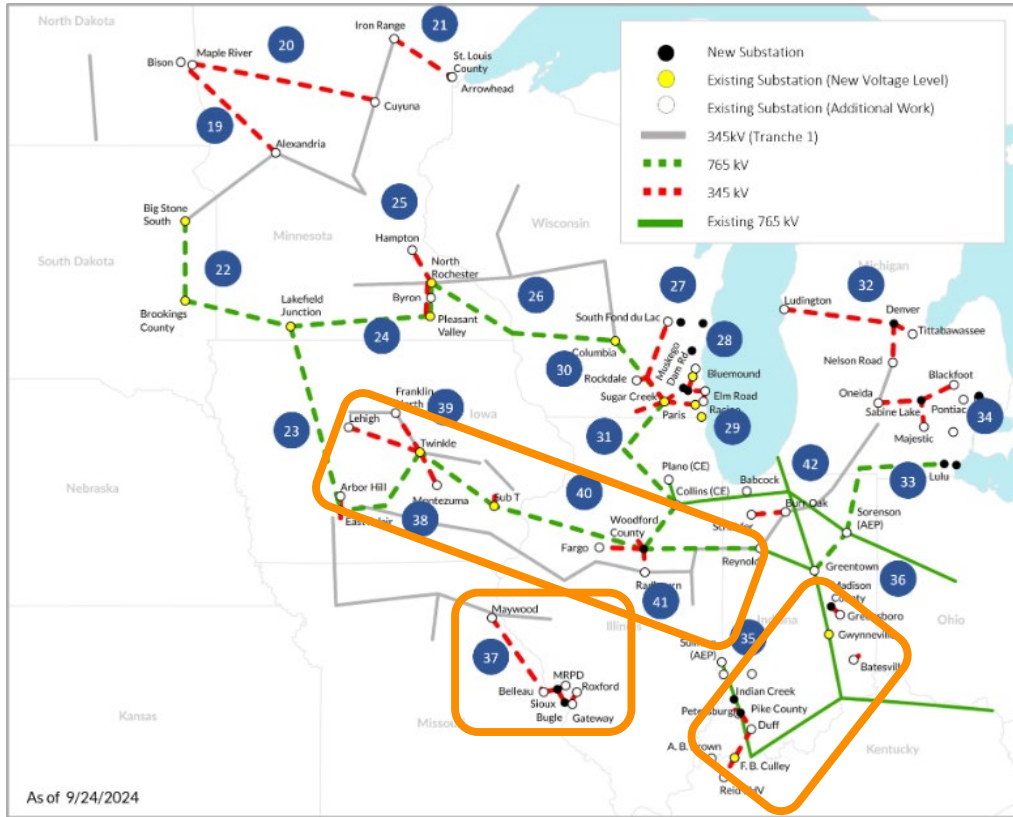


Figure 2.105: Central Region Project Groups

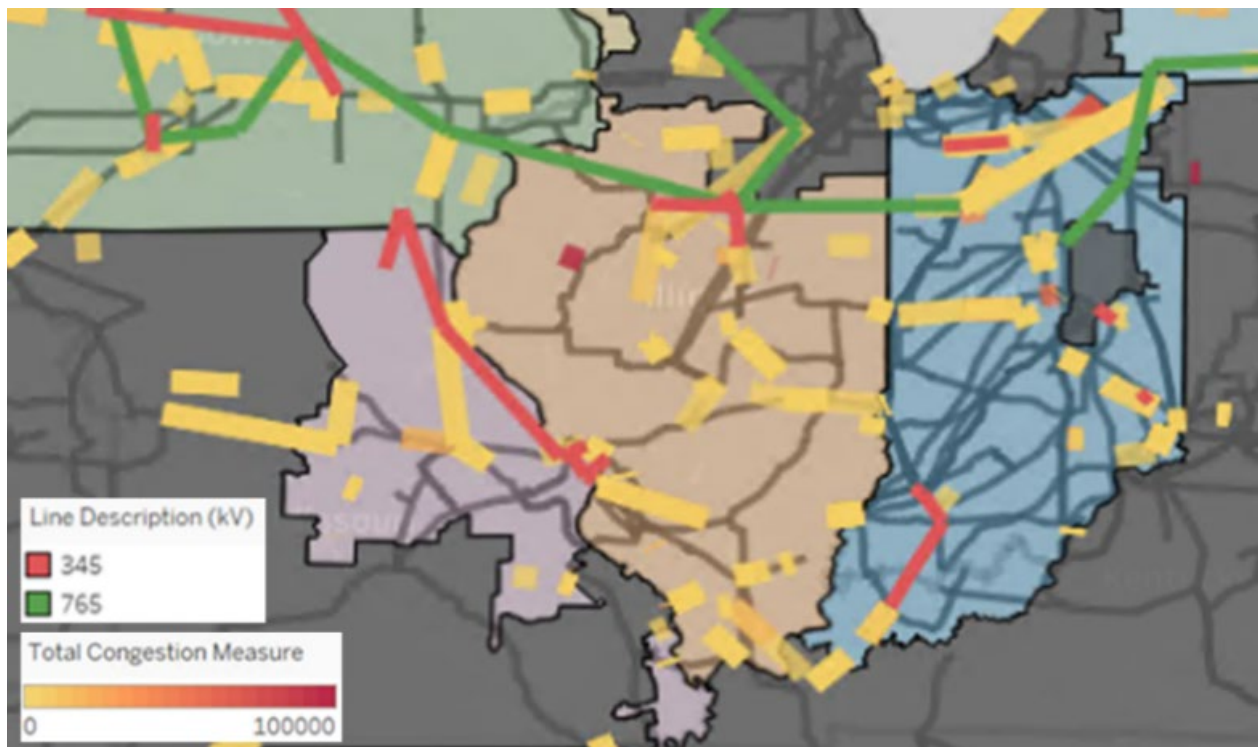


Figure 2.106: Change Case Economic Congestion - Central



LRZ 4 - Illinois

The Tranche 2.1 portfolio resolves most thermal violations on 200 kV and above facilities in LRZ4. For the <200 kV system, more than 50% of thermal violations are resolved. The Tranche 2.1 portfolio reduces congestion in LRZ4 by 13.9% (274 k\$/MW) – shown in Figure 2.109 – and enables 16.1 GW of generation in LRZ 4. Load serving costs decrease year-round and throughout LRZ4, by an average of \$1.90 / MWh, which is demonstrated in Figure 2.109. Increased exports through transmission expansion allows renewable generation to offset higher cost generation in LRZ4.

Increased access to low cost resources enabled throughout the MISO Midwest subregion drives down Load LMPs in LRZ4 . Curtailment, increased by 1.5M MWh. Change is mainly driven by increased competition with lower cost enabled generation throughout the region. Relief of regional constraints shifts congestion to more localized constraints, resulting in overall reduction in congestion. The remaining under 200 kV reliability issues are specific to local generation or load and may be better resolved through annual MTEP reliability planning and the generator interconnection processes.

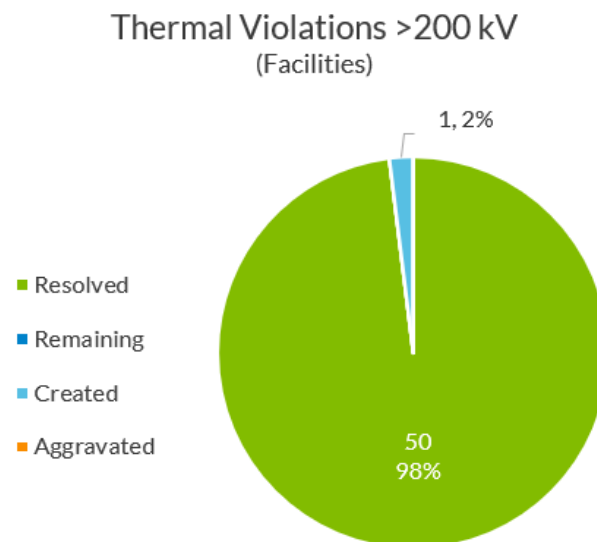


Figure 2.107: Thermal constraint resolution for LRZ4

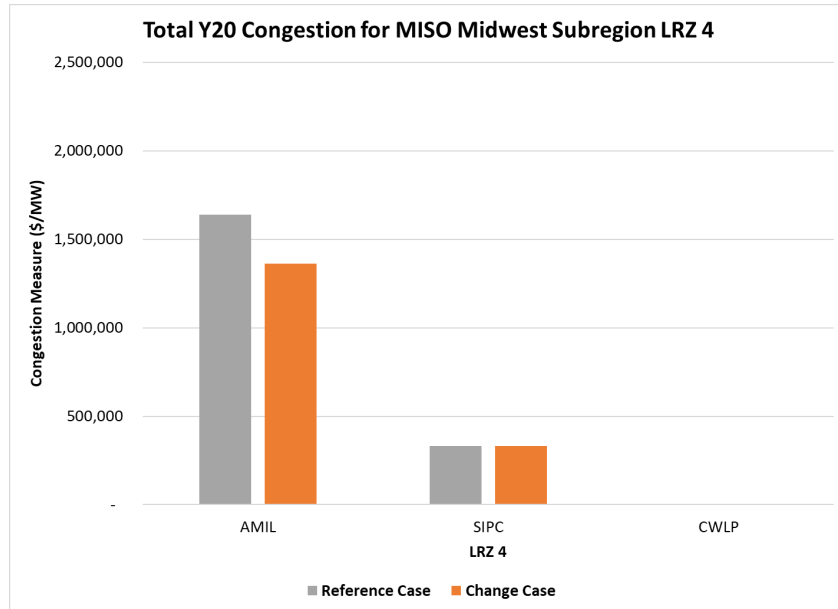


Figure 2.108: Congestion Measure - LRZ 4

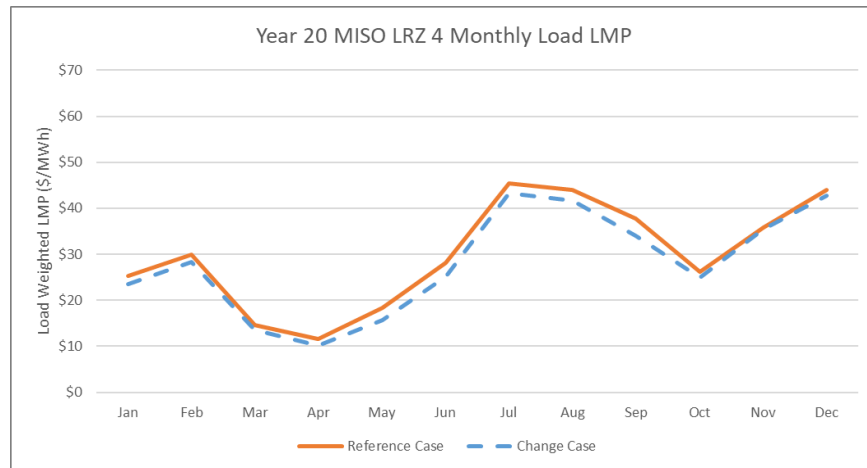


Figure 2.109: Comparison: Monthly Load LMP - LRZ 4



East Adair - Marshalltown - Sub T 765 kV (Project 38), Lehigh - Marshalltown - Franklin North & Montezuma - Marshalltown 345 kV (Project 39), Sub T - Woodford County - Collins & Woodford County - Reynolds 765 kV (Project 40), and Woodford County - Fargo & Woodford County - Radbourn 345 kV (Project 41)

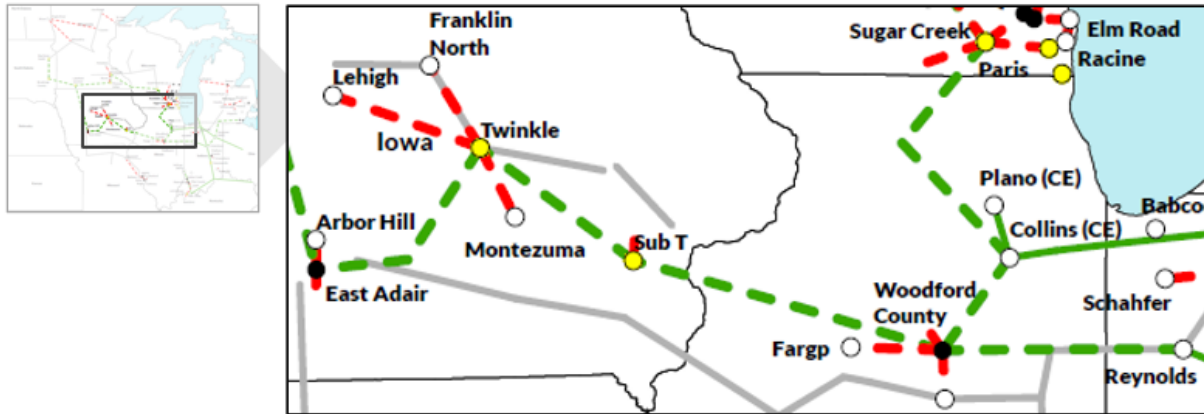


Figure 2.110: Central Iowa and, Illinois and Northern Indiana L RTP Tranche 2.1 projects

Both 765 & 345 kV level projects going West – East from Iowa through Illinois into Indiana provide a regional transfer path that enables generation in LRZ 1, 3, and 4 and supports strong East – West transfers to and from LRZ 6 and 7. Transmission relieves congestion across Central and Eastern Iowa and throughout Illinois, Missouri, and Indiana. Various violations in Central IA and IL are alleviated with the 765 kV facility connecting the western IA 765 to the Indiana 765 kV system. The regional backbone significantly relieves multiple 345 kV facilities while providing transfer capability to various load centers. The top alleviated facilities are in the table and the map shows the top 10 from the list.



#	Element	Initial Worst Loading %	Final Worst Loading %
1	[ALTW] Hazleton - [ALTW] Arnold 1 345 kV	125	69
2	[MEC] Bondurant- [MEC] Montezuma 1 345 kV	110	56
3	[MEC] Grimes - [MEC] Beaver Crk 1 345 kV	115	60
4	[MEC] Oak Grove - [AMMO] Sub 93 1 345 kV	108	58
5	[MEC] Webster - [MEC] LeHigh 1 345kV	144	62
6	MEC] Morgan Valley - [MEC] Tiffin 1 345 kV	103	56
7	[AMIL] Tazewell-[AMIL] Maple Ridge 345 kV Ckt 1	143	65
8	[AEP] Eugene – [AMIL] Bunsonville 345 kV	101	81
9	[AMIL] Tazewell-[AMIL] Maple Ridge 345 kV Ckt 2	141	65
10	[AMIL] Sandburg-[AMIL] Mercer 161 kV	115	69
11	[ALTW] Lasalle – [ALTW] Mitchell County 345 kV	105	57
12	[ALTW] Lasalle – [ALTW] Hazelton 345kV	110	60
13	[MEC] Walcott - [MEC] Sub 92 345kV	105	48
14	[MEC] Hills - [MEC] Sub T 345kV	112	32
15	[AMIL] Hines – [AMIL] Pioneer 138 kV	165	73
16	[ALTW] Hazelton – [ALTW] Dundee 138 kV	124	72
17	[ALTW] Liberty – [ALTW] Dundee 138 kV	115	67
18	[AMIL] Fargo 345 kV - [AMIL] Fargo 138 kV Xfmr 1	134	36
19	[AMIL] Fargo 345 kV - [AMIL] Fargo 138 kV Xfmr 2	134	36
20	[NIPSCO] Sheffield – [NIPSCO] Wolf Lake	107	97

Figure 2.111: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Central Iowa and Illinois

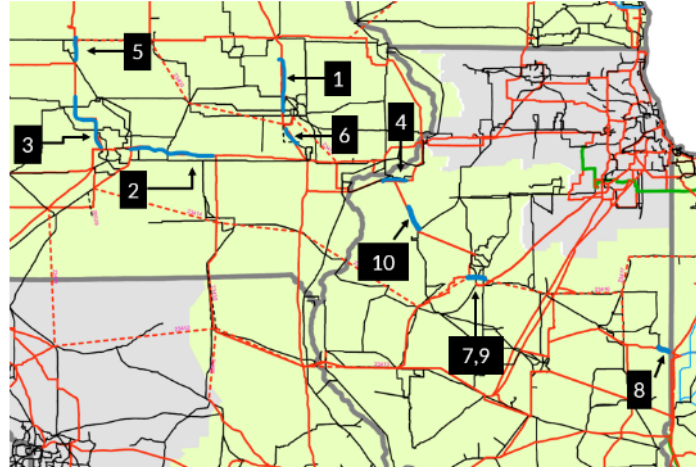


Figure 2.112: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Iowa and Illinois

The corridor of projects between Central Iowa and Northern Indiana supports a more robust exchange of low-cost resources across this region, and from net exporting regions like LRZ3. This results in lower prices in LRZ4. Overall congestion measure is seen to decrease in LRZ4 and along this corridor, with reductions on West/East oriented elements at a wide range of voltage levels. Figure 2.18 shows top relieved flowgates ranked by congestion measure relief for projects 38, 39, 40, and 41. The combined congestion measure impact for flowgates assessed for projects 38, 39, 40, and 41 is shown in Figure 2.113.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 38, 39, 40 & 41			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Base Case: [AEP] 05ALBION - [NIPS] 17NORTHPORT 138 kV 1	908,179	633,175	275,004
Event 660: [AMIL] 7TAZEWELL - [AMIL] 7MAPLE RIDGE 345 kV 2	216,702	13,734	202,968
Event 3: [DUK-IN] 08WABASH_RIV 345kV - [DUK-IN] 08WAB R 230 kV 1	173,755	11,961	161,794
Event 62: [ALTW] HAZLTON L2 5 - [ALTW] DUNDEE 5 161 kV 1	273,853	148,901	124,952
Event 395: [DUK-IN] 08CHRYS3 - [DUK-IN] 08KOKOMO 138 kV 1	220,813	123,911	96,902
Event 62: [ALTW] LIBERTY5 - [ALTW] DUNDEE 5 161 kV 1	86,730	40,931	45,798
Event 1301: [AMIL] 7TAZEWELL - [AMIL] 7MAPLE RIDGE 345 kV 1	46,211	2,008	44,203
Event 63: [MEC] BONDURANT3 - [MEC] MONTEZUMA 3 345 kV 1	34,589	-	34,589
Base Case: [COMED] MAZON; R - [AMIL] 4CORBIN 138 kV 1	30,507	2,956	27,551
Event 108: [DUK-IN] 08CUYSUB - [DUK-IN] 08CUYUGA 345 kV 1	42,624	18,530	24,094

Table 2.18: Top Relieved Economic Flowgates – Projects 38, 39, 40, & 41

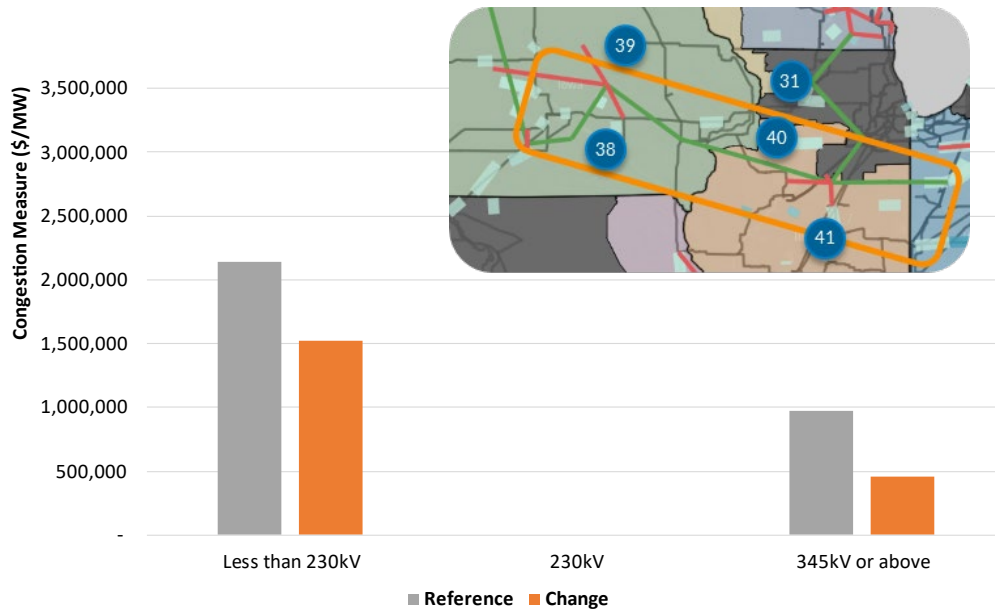


Figure 2.113: Congestion Measure - Projects 38, 39, 40, & 41

LRZ 5 – Missouri

The Tranche 2.1 portfolio resolves all thermal violations for 200 kV and above in LRZ 5. The final portfolio provides relief to the <200 kV system across multiple scenarios. The final portfolio reduces congestion in LRZ 5 by 55.9% (714 k\$/MW), shown below in Figure 2.114, by adding another path directly north of congested facilities. The majority of relief comes from the congested [AMMO] Ft Zumwalt-[AMMO] Huster 138 kV line. The new 345 kV line also provides relief to transmission lines facilitating west to east flows.

Load serving costs decrease year-round and throughout LRZ 5, by an average of \$2.08 / MWh, as seen in Figure 2.115. Transmission enables greater access to cheaper generation from other parts of the MISO Midwest subregion, and with that increased access and competition, curtailments see minimal change in LRZ 5 (-0.02M MWh). Resolved transmission constraints enable 2.8 GW of generation in LRZ 5.

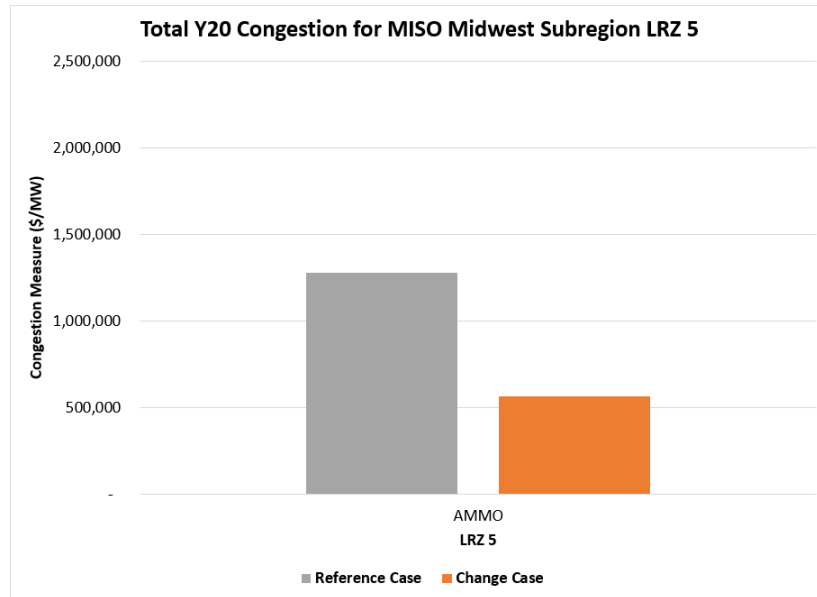


Figure 2.114: Congestion Measure – LRZ 5

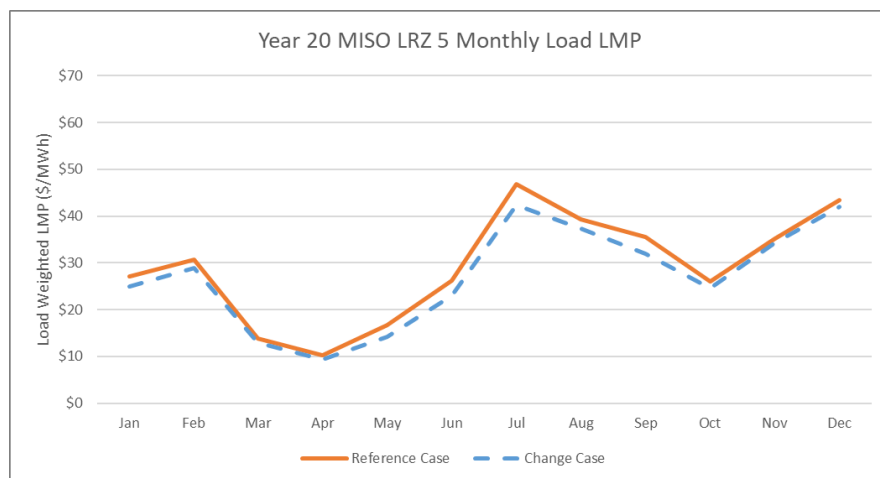


Figure 2.115: Comparison: Monthly Load LMP – LRZ 5



Maywood - Belleau - MRPD - Sioux - Bugle 345 kV (Project 37)

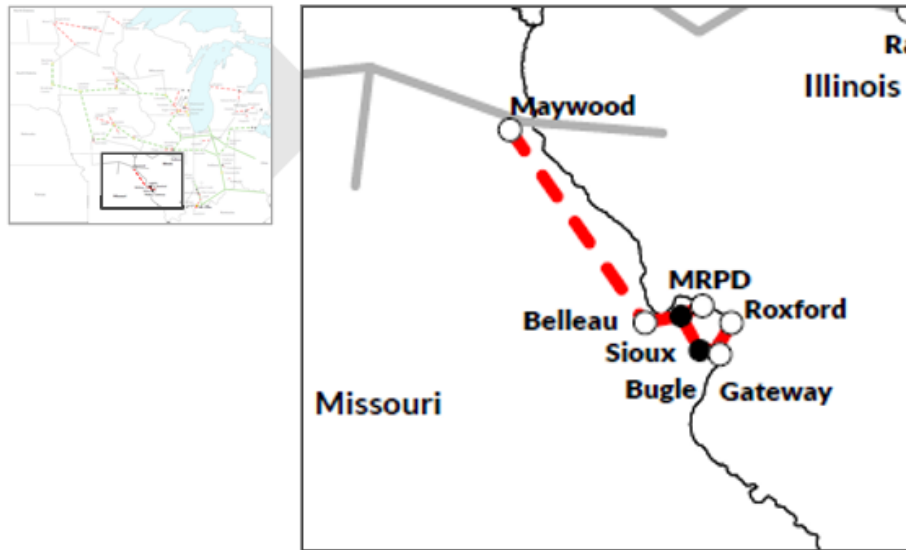


Figure 2.116: Missouri LRTP Tranche 2.1 projects

The 345 kV project in Missouri resolves numerous constraints in St. Louis Metro region and enables increased intraregional transfers across the Central Region. There are five limiting elements <200 kV that were not completely addressed with the addition of the portfolio, see table below. Worth noting, the loading of the elements are relatively the same with and without the portfolio and may be resolved in the annual MTEP reliability planning and generator interconnection processes. The geographically distant constraint, the [AMMO] Overton 345/161 kV transformer loading percent is greatly reduced with the addition of the portfolio.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[AECI] Essex - [AMMO] Richland 161 kV	124	124
2	[AMMO] Joachim 345/138 kV transformer	118	114
3	[AMMO] Overton 345/161 kV transformer	128	108
4	[AECI] Big Creek - [AMMO] Warrenton 161 kV	115	112
5	[AMMO] Ester - [AMMO] Rivermines 138 kV	110	109

Figure 2.117: Unresolved constraints in Missouri better suited for resolution in MTEP or queue processes

There were zero areas of LRZ 5 where new system constraints are being introduced. The top 20 facilities mitigated are provided in the table, the portfolio resolved all thermal violations on 200 kV and above facilities in Missouri and nearby Illinois area. The top 10 facilities resolved are geographically represented on the map.



#	Element	Initial Worst Loading %	Final Worst Loading %
1	[AMMO] Mason 345/138 kV Transformer	114	92
2	[AECI] McCredie-[AMMO] Montgomery 345 kV	108	65
3	[AMMO] Scarlett-[AMMO] Montgomery 345 kV	103	76
4	[AMMO] Belleau 345/138 kV Transformer	108	49
5	[AMMO] Enon-[AMMO] Montgomery 345 kV	105	71
6	[AMMO] Loy Martin-[AMMO] McBain 161 kV	124	70
7	[AMMO] Apache-[AMMO] California 161 kV	124	71
8	[AECI] Cyrene-[AMMO] Pike 161 kV	128	66
9	[AMMO] Franklin-[AECI] Clover Bottom-[AMMO] Tegeler - [AMMO] Bland 138 kV	110	73
10	[AMMO] Moberly-[KCPL] Salsbury 161 kV	101	99
11	[AMMO] Mason-[AMMO] Schuetz 138 kV	104	69
12	[AMMO] Dorsett-[AMMO] Schuetz 138 kV	105	67
13	[AMMO] Dorsett-[AMMO] Warson 138 kV	100	62
14	[AMMO] Loy Martin-[AMMO] Guthrie 161 kV	112	62
15	[AMMO] Belleau-[AMMO] Fort Zumwalt 138 kV	131	62
16	[AMMO] Fort Zumwalt-[AMMO] McClay 138 kV	121	53
17	[AMMO] Fort Zumwalt-[AMMO] Huster 138 kV	106	48
18	[AECI] Palmyra-[AMMO] Hannibal West 161 kV	105	61
19	[AMMO] Overton 1-[AMMO] Overton 2 161 kV bus tie	111	83
20	[AMMO] McBain-[AMMO] Overton 161 kV	127	97

Table 2.19: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Missouri

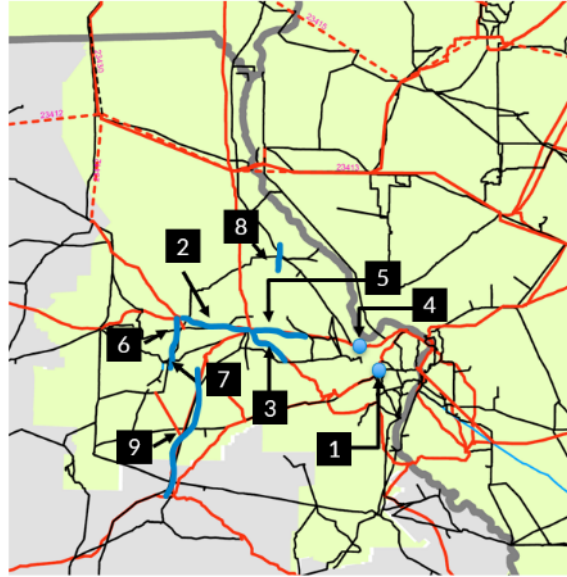


Figure 2.118: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Missouri

Project 37 is located within LRZ 5 and is responsible for the majority of the congestion relief seen in the LRZ. Project 37 reduces congestion in LRZ 5 by adding another path directly north of congested facilities and providing west to east relief. Table 2.20 and Figure 2.119 illustrate this further.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Project 37			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 539: [AMMO] 4FTZUM_TP 1 - [AMMO] 4HUSTER 3 138 kV 1	697,486	-	697,486
Event 355: [AMMO] 7ENON_TP - [AMMO] 7MONTGMRY 345 kV 1	41,533	12,601	28,932
Event 21: [AMIL] 4MORO - [AMIL] 4LACLEDE NTP 138 kV 1	224,528	196,378	28,150
Event 680: [AMMO] 4ESTHER TP2 - [AMMO] 4RIVMIN 2 138 kV 1	112,531	88,873	23,658
Event 420: [AECIZ] 5FLETCH - [AMMO] 5BR CREEK 161 kV 1	130,809	110,260	20,549
Event 1350: [AMMO] 4WITTNBURG - [AMIL] 4JENKINS 138 kV 1	26,138	12,925	13,213
Event 539: [AMMO] 7BELLEAU 345 kV - [AMMO] 4BELLEAU 1 138 kV 1	10,665	-	10,665
Event 1152: [AMIL] 4CAHOK 1 - [AMIL] 4RIDGE 2 138 kV 1	45,847	37,078	8,769
Event 582: [AMMO] 7MONTGMRY - [AMMO] 7SPENCER 345 kV 1	8,595	-	8,595
Event 324: [AECIZ] 5ESSEX - [AMMO] 5RICHLAND_TP 161 kV 1	16,661	14,253	2,408

Table 2.20: Top Relieved Economic Flowgates - Project 37

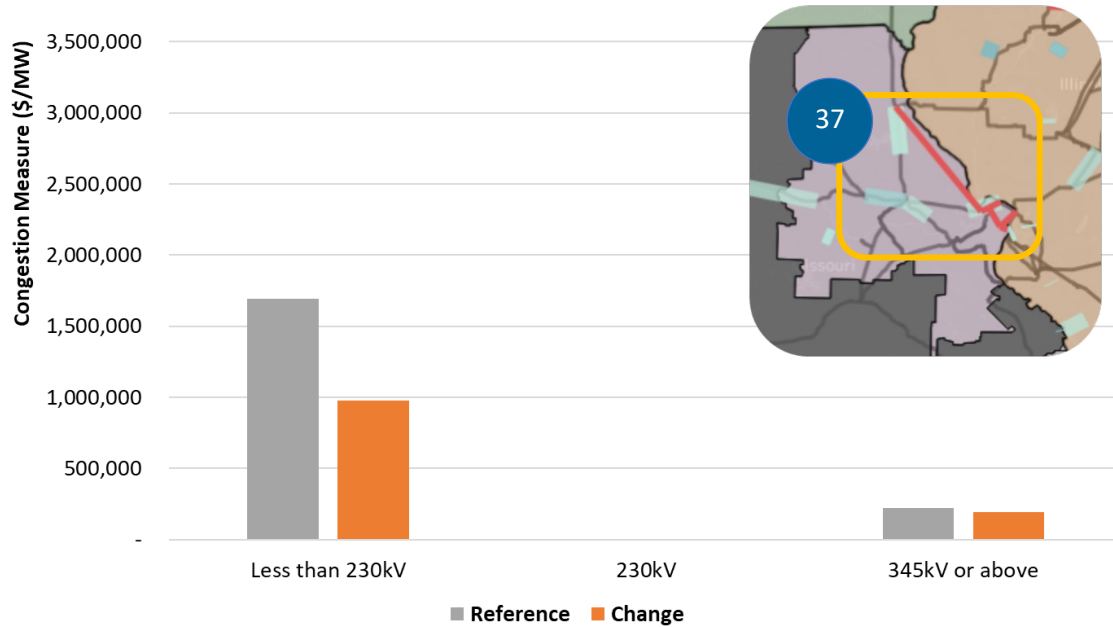


Figure 2.119: Congestion Measure - Project 37

LRZ 6 - Indiana

The Tranche 2.1 portfolio resolves most of the thermal violations in LRZ 6 for 200 kV and above facilities. The Tranche 2.1 portfolio improves transfer capability in Central/Southern Indiana by enabling more power to reach large load centers reliably.

The Tranche 2.1 portfolio reduces congestion evenly across LRZ 6, with all companies seeing congestion relief as shown in Figure 2.120. The portfolio also demonstrates relief throughout LRZ 6 footprint at multiple kV levels. Total congestion in LRZ 6 is reduced by 38.2% (1027 k\$/MW). Load serving costs decrease year-round and throughout LRZ 6, as shown in Figure 2.121, by an average of \$3.61 / MWh. Increased exports through transmission boost energy transfers while reducing costs for purchasing companies. With increased access to low-cost resources from the larger region, the Tranche 2.1 portfolio sees curtailments in LRZ 6 increase by 0.9M MWh. Relief of transmission constraints enables 16.6 GW of generation.



Thermal Violations >200 kV (Facilities)

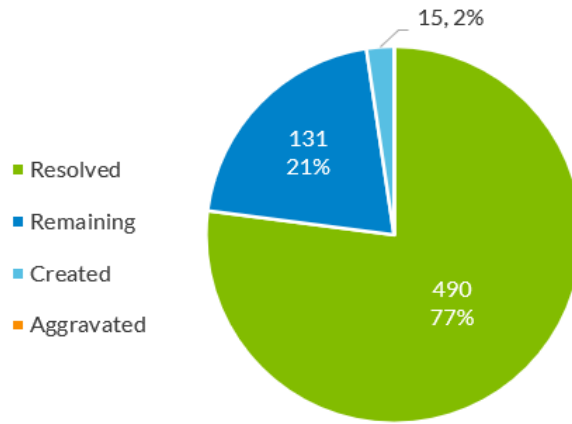


Figure 2.120: Thermal constraint resolution for LRZ6

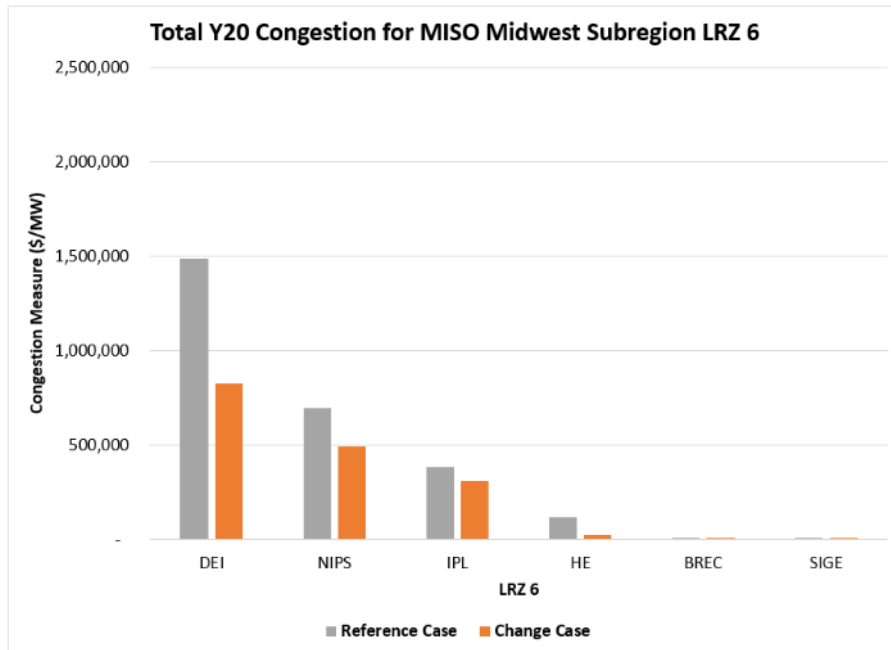


Figure 2.121: Congestion Measure - LRZ 6

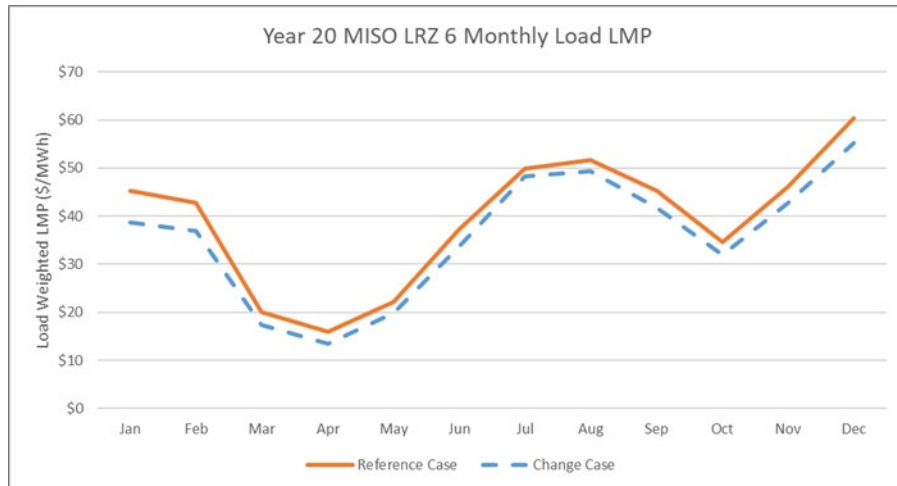


Figure 2.122: Comparison: Monthly Load LMP - LRZ 6

Southwest Indiana - Kentucky (Project 35) and Southeast Indiana (Project 36)

Southern IN/KY 345 kV project resolves constraints in the region and promotes West - East transfers across the central region. Southeast IN upgrades more than double the 345 kV outlet and allows both 765 & 345 kV connections to adequately and reliably transfer remote generation to the IN load centers in Central IN and Southeastern IN.

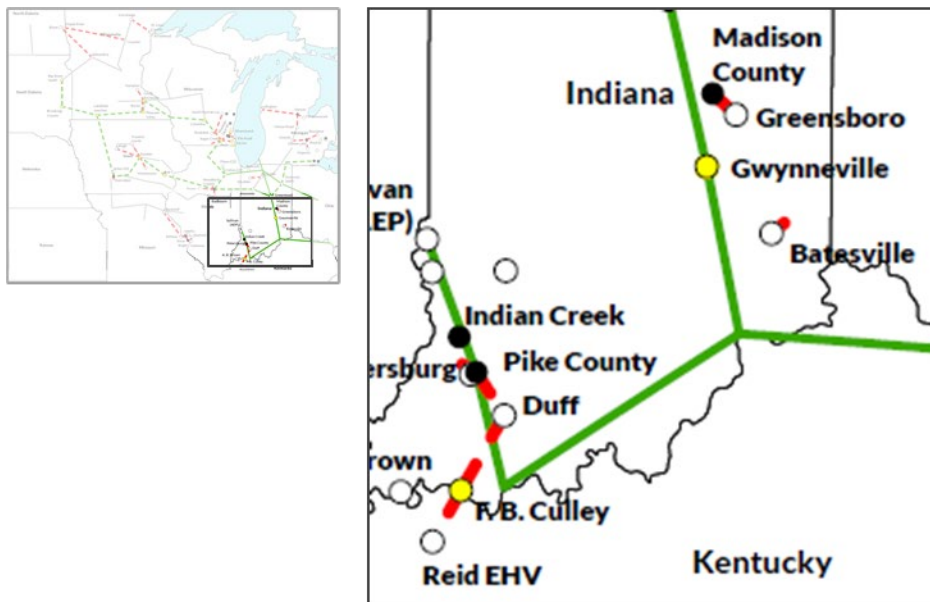


Figure 2.123: Southwest Indiana - Kentucky and Southeast Indiana L RTP Tranche 2.1 projects

There are two main areas of LRZ6 where system constraints were not completely addressed and these areas fall both in Central Indiana, as noted below in tables. The [DEI] Qualitech-[DEI] Whitestown-[IPL] Guion 345 kV and the [DEI] Kokomo-[DEI] Tipton-[DEI]-Carmel 230 kV transmission corridors are both overloaded with the portfolio, though the loading percents have been greatly reduced. The [DEI] Noblesville-[DEI] Madison County-[AEP] Fall Creek 345 kV transmission corridors are showing overloads



with the addition of the portfolio, though the loading percentages have been greatly reduced. Other facilities experienced aggravated loadings and all of the facilities referred to here are attributed to local drivers and better resolved in the annual MTEP reliability planning and the generator interconnection processes.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[DEI] Qualitech –[DEI] Whitestown –[IPL]Guion 345 kV	168	140
2	[DEI] Kokomo –[DEI] Tipton –[DEI] Carmel 230 kV	143	118
3	[DEI] Noblesville - [DEI] Madison County [AEP] Fall Creek 345 kV	121	107

Table 2.21: Loadings significantly relieved, full resolution better suited for MTEP and queue processes in LRZ6

The top 20 lines with the most reduction in the loadings are shown in the table below. The third column shows the highest loading for these elements in the base models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The Fall Creek – Noblesville 345 kV line listed below as 15 is reconfigured to the Fall Creek to Madison County to Noblesville 345 kV line to accommodate the new 345 kV circuit from Greensboro to Madison County in the Tranche 2.1 portfolio. The locations of the top 10 lines are shown on the map below.



#	Element	Initial Worst Loading %	Final Worst Loading %
1	[DEI] Noblesville - [DEI] Durbin 230 kV	105	81
2	[DEI] Hortonville - [DEI] Whitestown 230 kV	106	88
3	[DEI] Nucor - [DEI] Whitestown 230 kV	111	89
4	[DEI] Staunton - [DEI] Wabash River 230	117	79
5	[DEI] Wheatland - [DEI] Edwardsport 345 kV	126	Reconfig
6	[DEI] Gibson- [LGEE] Wheatland 345 kV	107	11
7	[DEI] Speed - [LGEE] Trimble County 345 kV	107	94
8	[DEI] Batesville - [DEI] Hubble - [DEI] Weisburg - [DEI] Wilmington - [HE] Hidden Valley - [DEI] Greendale - [DEO&K] Miami Fort 138 kV	145	55
9	[SIGE] Newtonville - [SIGE] Grandview - [SIGE] Rockville Tap 138 kV	118	69
10	[BREC] Reid - [BREC] Hopkins County - [BREC] Caldwell - [BREC] Barkley HP 161kV - [BREC] Henderson County 161/138 kV transformer	113	79
11	[HE] Decatur - [DEI] Greensburg 138 kV	132	47
12	[DEI] Plainfield - [WVPA] Airport West 138 kV	107	81
13	[DEI] Wabash River 230/138 kV transformer 1B	110	56
14	[DEI] Lapel - [DEI] Noblesville 230	101	82
15	[AEP] Fall Creek - [DEI] Noblesville 345 kV	121	Reconfig
16	[IPL] Guion - [IPL] Pike 138 kV	108	96
17	[IPL] Guion - [IPL] Westlane 138 kV	102	94
18	[IPL] Guion - [IPL] Mill Street 138 kV	108	90
19	[IPL] Guion - [IPL] Tremont 138 kV	103	90
20	[DEI] Vincennes - [DEI] Lawrenceville 138 kV	105	68

Table 2.22: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central and Southern Indiana

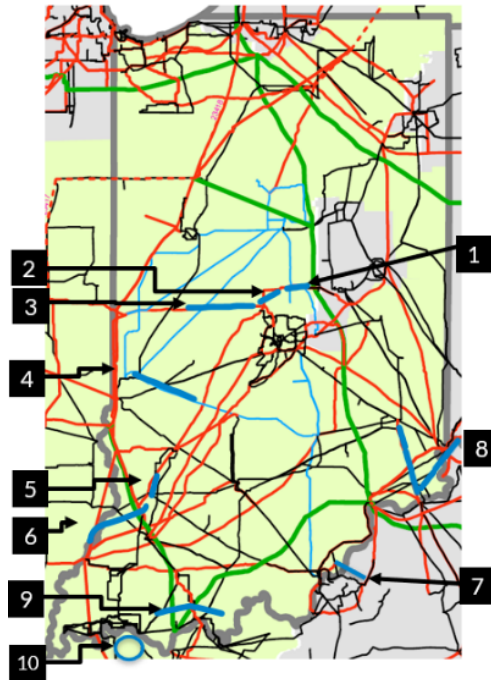


Figure 2.124: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central and Southern Indiana

Projects 35 and 36 provide relief for many lower kV constraints in the mid-southern area of the LRZ, shown below in Table 2.9 and Figure 2.123. They enable more generation to reach the load centers in Central and Southeastern Indiana.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 35 & 36			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 154: [DUK-IN] 08WILM J - [DUK-IN] 08WEISBG 138 kV 1	72,018	-	72,018
Event 246: [DUK-IN] 08WILM J - [DUK-IN] 08WEISBG 138 kV 1	70,780	-	70,780
Event 153: [HE] 07DCTRSS - [DUK-IN] 08GRNSBR 138 kV 1	70,391	-	70,391
Event 36: [HE] 07DCTRSS - [DUK-IN] 08GRNSBR 138 kV 1	61,494	-	61,494
Event 2: [DUK-IN] 08KOK HP - [DUK-IN] 08TIPTN 230 kV 1	58,806	-	58,806
Event 572: [DUK-IN] 08KOK HP - [DUK-IN] 08TIPTN 230 kV 1	55,899	3,382	52,517
Event 167: [IPL] 16GUION - [IPL] 16WSTLAN 138 kV 40	238,760	186,961	51,799
Event 243: [HE] 07HUBBL8 - [DUK-IN] 08BATESV 138 kV 1	39,313	-	39,313
Event 2: [DUK-IN] 08WHITST - [IPL] 16GUION 345 kV 1	142,080	112,538	29,542
Event 1025: [DUK-IN] 08LAFAYE 230kV - [DUK-IN] 99494 YBUS504 100 kV 1	50,262	28,268	21,995

Table 2.23: Top Relieved Flowgates – Projects 35 & 36

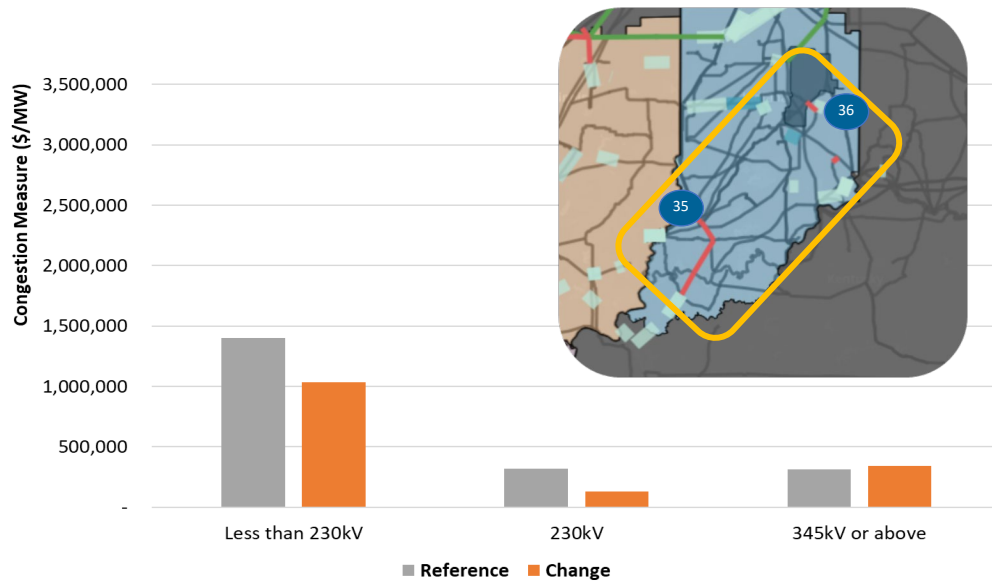


Figure 2.125: Congestion Measure - Project 35 & 36

East Region – Reliability and Economic Results

- Central MI project assists in unlocking generation in Western and Central MI and connects to Tranche 1 project to allow greater transfer capability
- Transmission connects resources from Western MI to load centers in the East, relieving congestion especially near the Eastern load centers
- MI to Northeast IN project supplement the existing connections into Michigan and provide the transfer capability in and out of MI

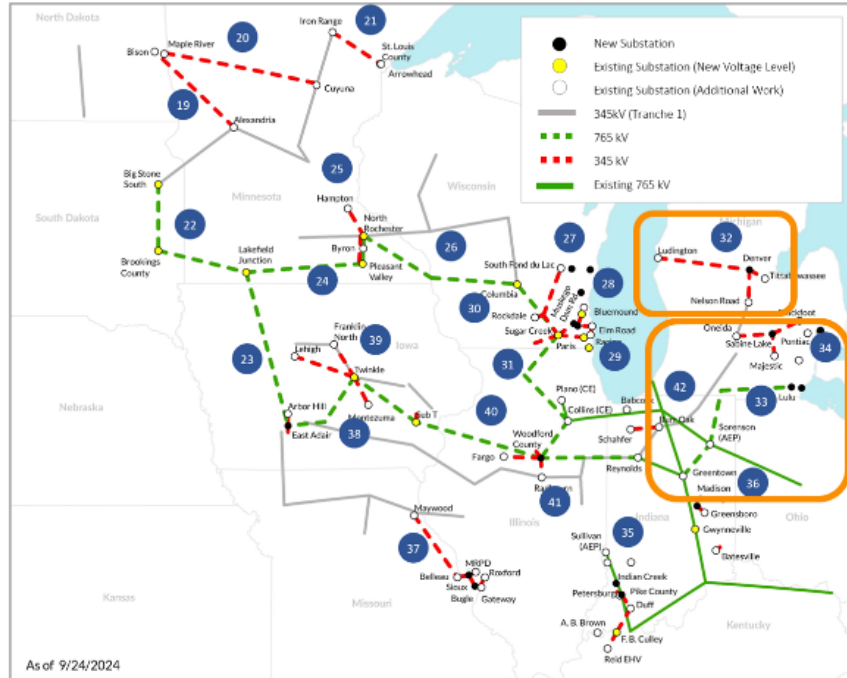


Figure 2.126: East Region Project Groups

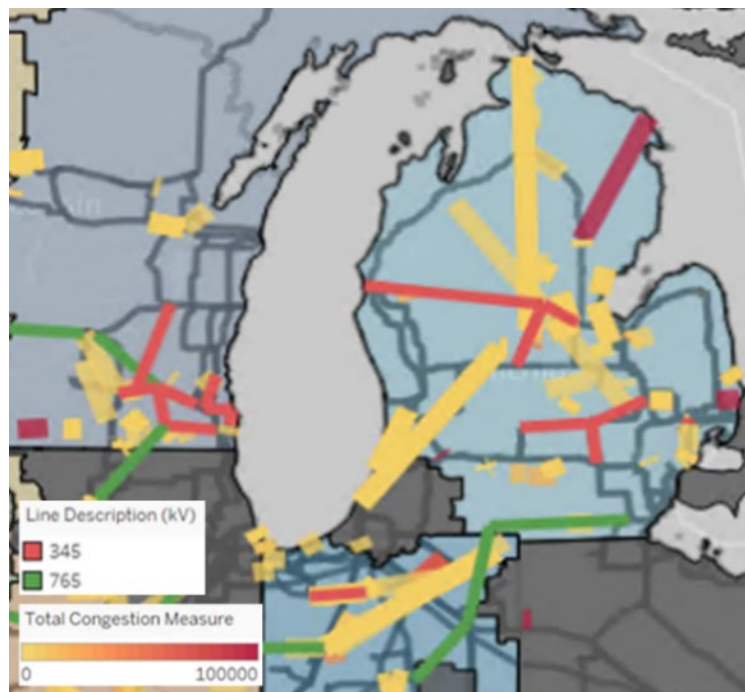


Figure 2.127: Change Case Economic Congestion - East

LRZ 7 – Michigan

For the <200 kV system, 31% of the violations have been resolved. For the >200 kV system, stronger East to West ties are established in the MI footprint. These ties shift flow patterns in the region by allowing access to remote resources and provide high utilization of new Tranche 2 lines. For the >200 kV system, a majority



of the remaining and created violations occur in the twilight, low winter renewable, and lower-upper transfers, where the system is stressed. The remaining reliability issues are specific to local generation sited or load which has better resolution through annual MTEP reliability planning and the generator interconnection processes.

Tranche 2.1 portfolio reduces congestion in LRZ 7 by using regional facilities to relieve local congested areas. Congestion is reduced in LRZ7 by 31.7% (950 k\$/MW), and most of the relief is on local constraints near 345 kV additions. Few constraints see increased economic congestion. Both companies see notable congestion relief, as shown in Figure 2.128. Load serving costs decrease year-round and throughout LRZ7 by an average of \$3.70 / MWh, generally lowering LMPs in higher cost areas of the state. This is detailed in Figure 2.129. Curtailment reductions are seen in the central part of the LRZ near new transmission, and relief of transmission constraints enables 11.2 GW of generation in LRZ 7. Tranche 2.1 portfolio maintained the relatively low curtailments in LRZ 7, only increasing them by 1.1M MWh. Curtailments, shown in Figure 2.130, improved near the eastern terminus of Project 32. Relief of transmission constraints enables 11.2 GW of generation.

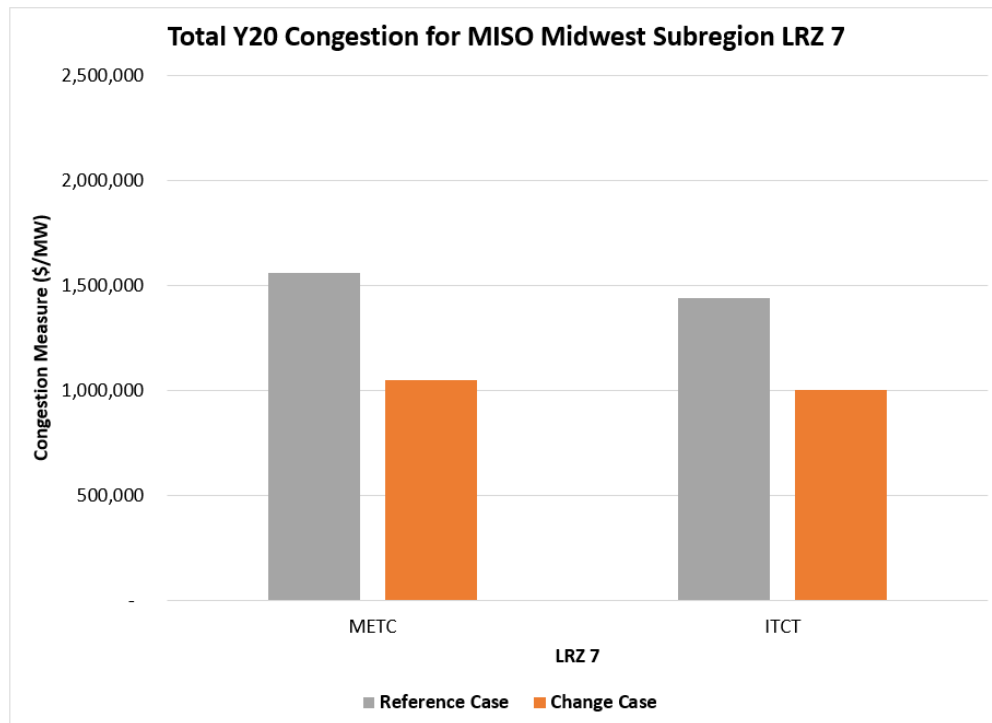


Figure 2.128: Congestion Measure - Project 37

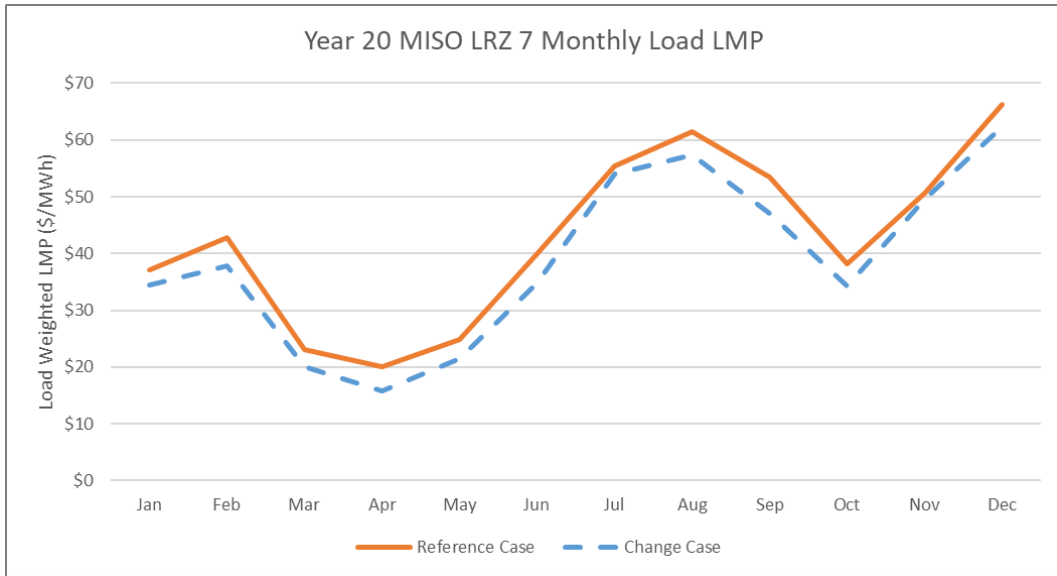


Figure 2.129: Comparison: Load LMP - Project 37

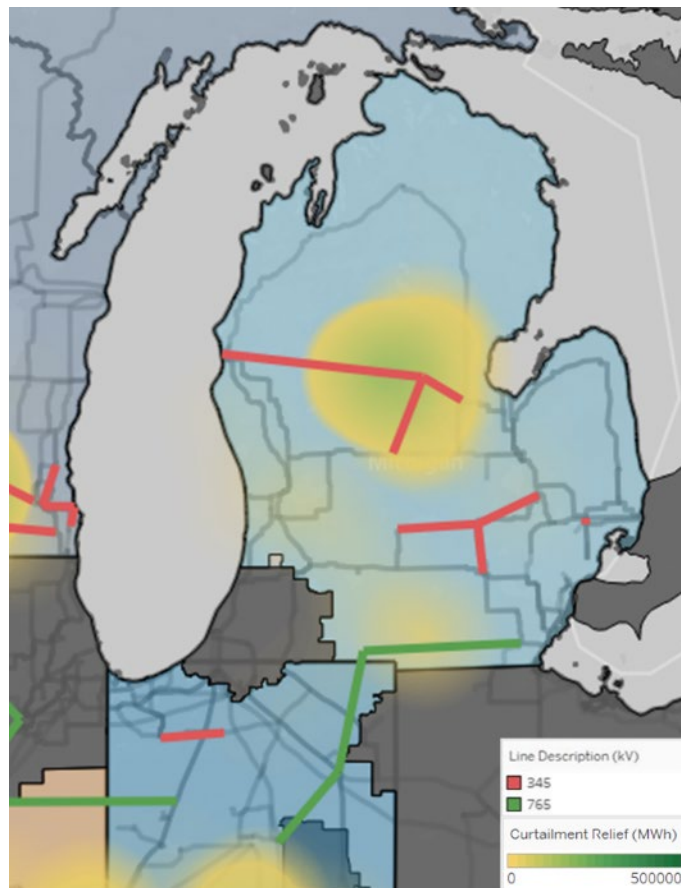


Figure 2.130: Change Case Curtailment Relief - LRZ 7



Ludington - Denver - Tittabawassee & Nelson Road 345 kV (Project 32)



Figure 2.131: Central Michigan LRTP Tranche 2.1 projects

Central MI project assists in unlocking generation in Western and Central MI and connects to Tranche 1 project to allow greater transfer capability. Transmission connects resources from Western MI to load centers in the East, relieving congestion especially near the eastern load centers. The bulk of the identified constraints in Central MI were on the 138 kV line, as this is the predominant voltage in the area. Tranche 2.1 portfolio resolves 37% of thermal violations on 200 kV and below facilities in Central Michigan.

Another key benefit of Central MI projects is aiding the bi-directional nature within the MI system. Ludington Pumped Storage Plant functions as either a significant source of generation, or a significant load to the MI system. This is exhibited by both West to East and East to West flows on the added facilities, respectively. The table shows the most reduction in loadings, while the figure shows the first eight elements.



#	Element	Initial Worst Loading %	Final Worst Loading %
1	[METC] Bullock-[METC] Edenville Junction 138 kV	175	34
2	[METC] Bullock-[METC] Salt River Junction 138 kV	193	27
3	[METC] Regal -[METC] Luce 138 kV	186	53
4	[METC] Tittabawassee -[METC] Redstone 138 kV	135	58
5	[METC] Summerton-[METC] Camelot Lake 138 kV	159	9
6	[METC] Camelot Lake Jct -[METC] Salt River 138 kV	160	10
7	[METC] Lewiston-[METC] Plywood Jct 138 kV	115	91
8	[METC] Plywood Jct-[METC] Bagley 138 kV	115	90
9	[METC] Chase -[METC] Mecosta 138 kV	108	93
10	[METC] Hillman -[METC] Airport 138 kV	112	87
11	[METC] Bluegrass Jct -[METC] Summerton 138 kV	131	22
12	[METC] Edenville Junction 138 kV-[METC] Salt River 138 kV	111	13

Table 2.24: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Michigan

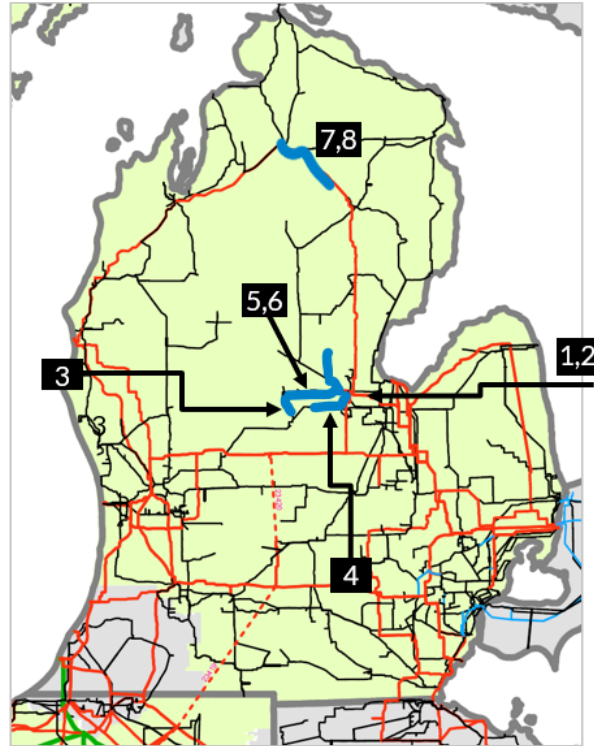


Figure 2.132: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Michigan

Project 32 provides congestion relief to lower kV local constraints located in the central part of the LRZ near the project. It does so by pulling flows off of the local system and distributing them more evenly towards surrounding load centers. Table 2.24 and Figure 2.134 illustrate this.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Project 32			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 627: [CONS] 18BULLOCKW - [CONS] 18SALTRIV 138 kV 1	107,294	-	107,294
Event 791: [CONS] 18ALMDAJ - [CONS] DUQUITE 138 kV 1	65,165	247	64,918
Base Case: [CONS] 18DEJAJ - [CONS] 18VESTABURG 138 kV 1	55,520	61	55,460
Event 826: [CONS] 18ALMA - [CONS] 18REGAL 138 kV 2	52,867	163	52,704
Event 227: [CONS] 18BULLOCKB - [CONS] 18EDNV LJ 138 kV 1	39,857	-	39,857
Event 9: [CONS] 18HLLMNJ - [CONS] 18AIRPORTW 138 kV 1	28,106	7,124	20,982
Event 529: [CONS] 18CORWTJ - [CONS] 18RONDO 138 kV 1	56,298	36,235	20,063
Event 163: [CONS] 18GALAGR - [CONS] 18GRNWDJ 138 kV 1	15,857	0	15,857
Event 627: [CONS] 18CAML TJ - [CONS] 18SALTRIV 138 kV 1	13,502	-	13,502
Event 150: [CONS] 18CAML TJ - [CONS] 18SALTRIV 138 kV 1	11,583	0	11,583

Table 2.25: Top Relieved Economic Flowgates – Projects 32

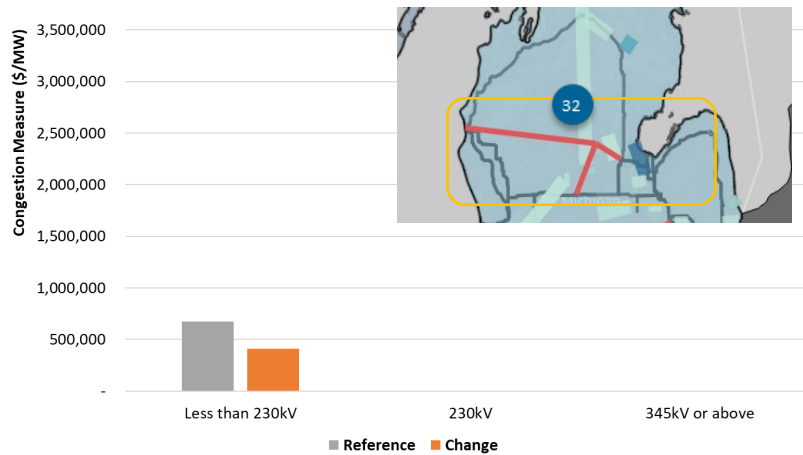


Figure 2.133: Congestion Measure - Project 32

Greentown - Sorenson - Lulu 765 kV (Project 33), Oneida - Sabine Lake - Blackfoot & Majestic 345 kV (Project 34), and Burr Oak - Schafer 345 kV (Project 42)

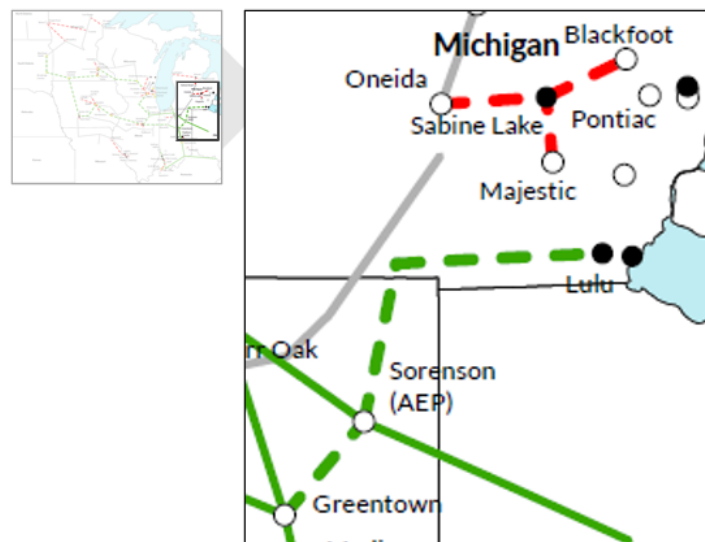


Figure 2.134: Southern Michigan and Northeastern Indiana LRTP Tranche 2.1 projects

The MI to Northeast IN project supplements the existing connections into Michigan and provides the transfer capability in and out of MI. Additionally, the re-configuration near existing Babcock and Burr Oak substations in Northwestern IN strengthen a load pocket that will increasingly rely on support from the rest of the MISO system as local generation retires.

In the average and light load core models, where batteries are charging and solar output is modest to non-existent, MI is importing approximately 5.7 GW. During peak summer and winter cases, MI is exporting approximately 3 GW and 1.6 GW, respectively. Drivers for these large swings can be attributed to a heavy concentration of solar and battery resources in the MI footprint in F2A, coupled with Ludington Pumped Storage Hydro.



The Sorenson to Lulu 765 kV line maintains system reliability as Michigan experiences increasingly large swings in imports and exports. From the constraints resolved map, thermal violations are resolved on the Argenta lines (Western MI) as MWs transfer into or out of the Detroit area (load center) or thumb of MI (generation center) via the Sorenson to Lulu 765 kV line. Additionally, the Oneida - Sabine Lake - Blackfoot & Majestic 345 kV strengthens the pathways into the Detroit area by interconnecting with Tranche 1 facilities. Ultimately these new 345 and 765 kV lines increase the ability of the MI system to handle large generation swings throughout the year. The table shows the most reduction in loadings, while the figure shows the first nine elements.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[ITCT] Jewell -[ITCT] Bismarck 345 kV	115	54
2	[ATSI] Lallendorf-[ITCT] Monroe 345 kV	117	Reconfigured
3	[AEP] Lemoyne-[ITCT] Maple 345 kV	122	Reconfigured
4	[METC] Oneida 345/138 kV transformer	111	82
5	[METC] Delhi-[METC] Green 138 kV	149	83
6	[METC] College-[METC] Green 138 kV	139	76
7	[METC] Argenta-[METC] Palisades 345 kV 1	108	93
8	[METC] Argenta-[METC] Palisades 345 kV 2	115	99
9	[METC] Argenta-[METC] Meyer 345 kV	102	87
10	[METC] Hagadorn Junction-[METC] Tihart 138 kV	129	68
11	[METC] Hagadorn Junction-[METC] College 138 kV	106	57

Table 2.26: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Michigan and Northeastern Indiana

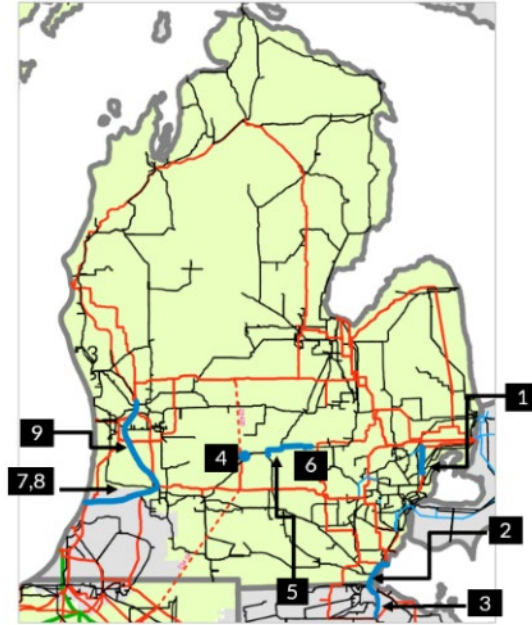


Figure 2.135: Top reliability constraints resolved by L RTP Tranche 2.1 projects in Southern Michigan

Projects 33, 34, and 42 provide relief to lower kV local constraints in the southern and southeastern portions of the LRZ, illustrated in Figure 2.135. Table 2.27 shows the relieved flowgates ranked by congestion measure relief for projects 33, 34, and 42.

Y20 Top Relieved Flowgates - Projects 33, 34 & 42			
Top Relieved Flowgates	Congestion Measure (\$/MW)		
	Reference	Change Case	Total Relief
Event 126: [DECO] 19CANIF7 - [DECO] 19HAMTRAMCK6 120 kV 1	281,619	166,593	115,026
Event 1156: [DECO] 19BUNCE1 - [DECO] 19FITZ 120 kV 1	131,271	25,320	105,951
Event 1018: [DECO] 19LEE1 - [DECO] 19LHPMPT 120 kV 1	102,215	22,023	80,192
Event 136: [DECO] 19CANIF7 - [DECO] 19HAMTRAMCK6 120 kV 1	315,538	244,547	70,991
Event 1004: [CONS] 18HALSEY - [CONS] GRAND BOC 2 138 kV 1	89,505	24,908	64,596
Event 1124: [CONS] DEAN RD - [CONS] OAKLAND 138 kV 1	41,314	11,652	29,662
Base Case: [NIPS] 17STJOHN - [COMED] CRETE EC ;BP 345 kV 1	30,400	800	29,600
Base Case: [CONS] PLYMOUTH 1 138kV - [CONS] YBUS536 100 kV 12	411,950	382,553	29,397
Event 1114: [DECO] 19CLRDT1 - [DECO] 19PONTC2 120 kV 1	107,992	79,373	28,619
Event 55: [CONS] 18LEONI - [CONS] 18WSHTNJ 138 kV 1	36,842	11,248	25,594

Table 2.27: Top Relieved Economic Flowgates – Projects 33, 34, & 42

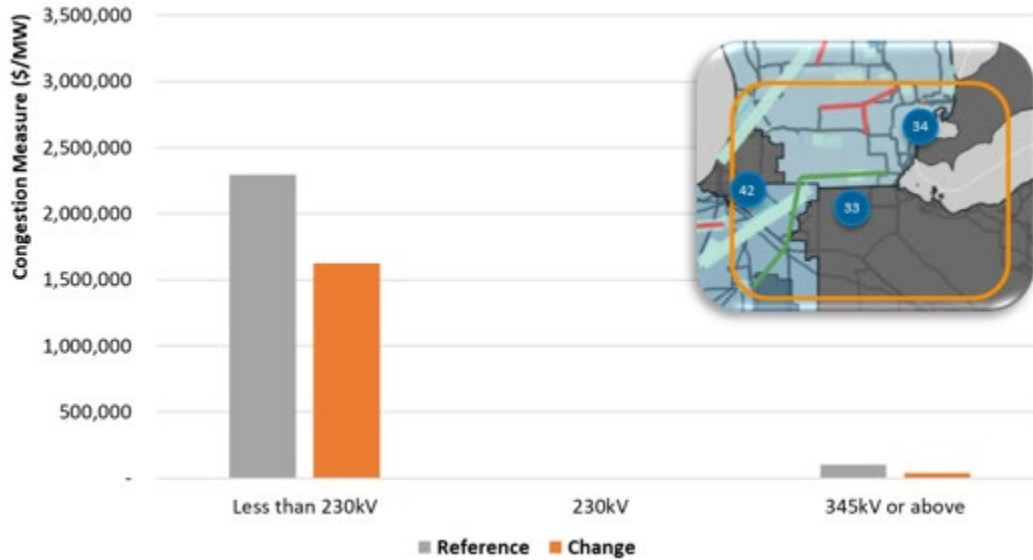


Figure 2.136: Congestion Measure - Project 33, 34 & 36

Business Case Analysis

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

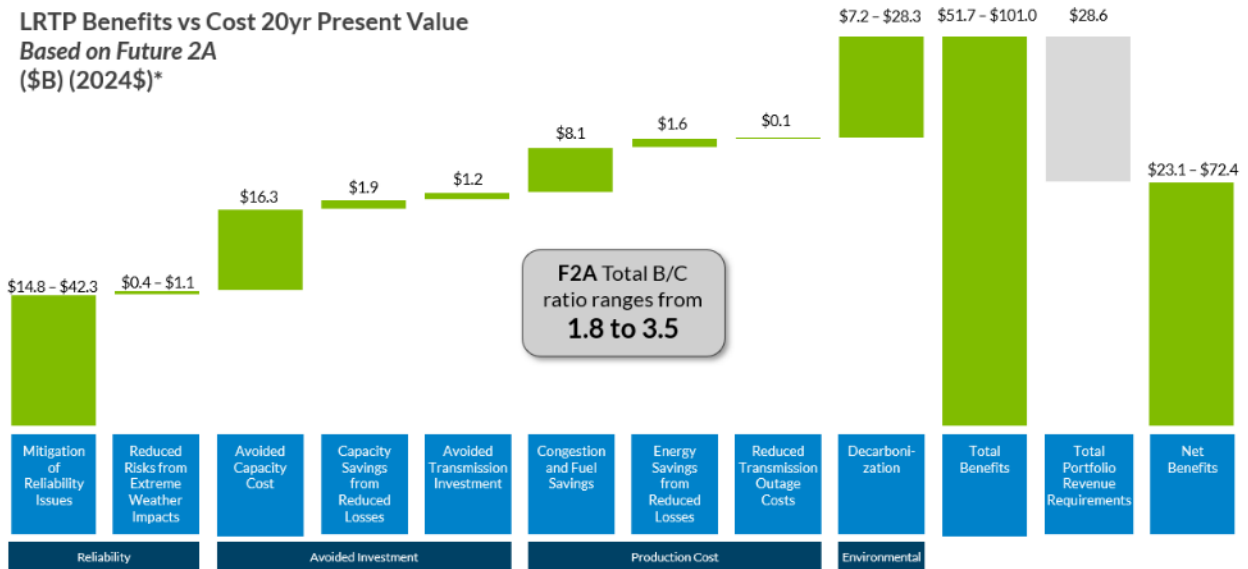


Figure 2.137: Financially Quantifiable Benefits of Tranche 2.1 Portfolio (values as of 11/1/2024).

Guided by the financially quantifiable benefits defined in the tariff for MVP projects, the following benefit metrics were evaluated to determine the amount of value delivered by the Tranche 2.1 Portfolio:



Reliability Benefits	1. Mitigation of reliability issues	Value of alleviating reliability issues which, if unresolved, introduce a risk of unserved load
	2. Reduced risks from extreme weather events	Increases grid resilience and decreases the probability of major service interruptions
Avoided Investment Benefits	3. Avoided capacity costs	Avoids capital costs for local resource builds versus regional expansions defined in Futures
	4. Capacity Savings from Reduced Losses	Value of reducing transmission losses during peak capacity periods
	5. Avoided transmission investments	Avoids the need for facility replacement due to age and condition
Production Cost Benefits	6. Congestion and fuel savings	Enhances market efficiency and provides access to low-cost generation
	7. Energy Savings from Reduced Losses	Lower production costs to serve load with transmission facilities that reduce system losses
	8. Reduced transmission outage costs	Reduced transmission congestion during forced and planned transmission outages
Environmental Benefits	9. Decarbonization	Enables the economical dispatch of renewable resources to help reduce the carbon footprint

Table 2.28: Nine Benefit Metrics used for Tranche 2.1.

Each benefit metric represents a distinct piece of the overall value resulting from the transmission investments. The nine benefit metrics can be grouped into four categories of benefits – reliability (1 and 2), avoided investment (3, 4 and 5), production costs (6, 7 and 8), and environmental (9). The methodologies were developed to define the calculations used to assess the impact of LRTP Tranche 2.1 projects on specific financially quantifiable measures that reflect the value of the investment and are summarized in this report. The details of the methodologies are more fully discussed within the [LRTP Tranche 2 Business Case Metrics Methodology Whitepaper](#).

For consistency and comparability, a general set of assumptions and variables was applied in the analysis of benefits. Benefits were calculated over a 20-year period as required for MVPs in accordance with the MISO Tariff, starting from the assumed in-service year of 2032, and over a 40-year period to demonstrate the additional value provided by the portfolio over the many decades beyond 20-years the portfolio is expected to be in-service. All benefit values are expressed in 2024 dollars. A discount rate of 7.1 percent is used to calculate the minimum value used to assess the benefit-to-cost ratio and is based on the gross-plant weighted average of the Transmission Owners’ cost of capital and represents the minimum return required on their transmission investments. Benefits are also assessed using a rate of three percent to show how assets perform with a social discount rate that reflects the return a ratepayer would typically receive on a risk-adjusted investment.

While the LRTP Tranche 2.1 Portfolio study has focused on Future 2A, the benefits analysis has also been performed using Future 1A to provide a lower-bookend representation of the value the portfolio provides.



Future 2A Benefit Metric Analysis

Mitigation of Reliability Issues

High-Level Methodology Overview

Traditionally, the NERC TPL standard has been used to ensure the transmission system is planned to be reliable. The NERC TPL standards articulate a minimum level of reliability with which the transmission system must support.

With regard to long-range transmission planning, the objective is to ensure the regional system is reliable and cost effective in the long-term given the many changes that are expected to the resource fleet and load characteristics. In that respect, long-range transmission planning is not TPL compliance-focused, but instead value-focused. LRTP seeks to determine the benefits of reliability improvements associated with long-term projects.

The reliability benefit metric captures where LRTP resolves reliability issues, as defined by instances where the post contingent load under steady state conditions would exceed applicable facility limits after redispatch. The benefit of remediating reliability issues is determined by quantifying the avoided risk of load shedding that would be needed to return the facility within applicable limits and monetizing the value. This load shedding is used as a measure of reliability risk rather than an operating action taken to resolve issues.

Analysis of benefits is performed in a two-step process which applies preventive generation re-dispatch in the first step to mitigate initial overloads followed by a corrective load re-dispatch process to calculate the minimum load shedding to address the contingency violations. This analysis uses the TARA software application to perform an optimal security constrained reliability dispatch for NERC Category P1, P2, and P7 contingencies associated with the LRTP resolved issues.

Thermal overloads identified in each of the core (seasonal) study scenarios for the 2032 and 2042 study years that are relieved by the addition of the LRTP Tranche 2 portfolio, and their associated contingencies are compiled and monitored in the first pass generation re-dispatch step. Since seasonal study models are snapshots that reflect a wide range of load and generation dispatch conditions, two dispatch scenarios are created for each of the core study scenarios. The first scenario represents hours with excess renewable availability where renewables are allowed to dispatch in the upward direction. The second scenario represents hours with less renewable availability than modeled where renewables are limited in dispatch to the downward direction.

The unresolved overloads from the generation redispatch step are compiled and monitored in the second pass load redispatch step to calculate load shedding needed to mitigate the remaining thermal overloading. The reduction in load at each bus is calculated and the maximum value for each bus for all contingencies is summed to determine quantity of load shedding needed in each dispatch scenario. The value of this load shedding amount is multiplied by the hours represented by the dispatch scenario and summed to quantify the total risk of unserved energy (in MWh). This value is then multiplied by the Value of Lost Load (VOLL) to monetize the benefit.



$$\text{Benefit} = \sum_1^n \text{LoadShedMW} * \text{VOLL}$$

Where

$n = \text{dispatch scenario/season}$

$\text{LoadShedMW} = \text{amount of load redispatch for each study scenario}$

$\text{VOLL} = \text{Value of Lost Load } (\$3,500/\text{MWh} - \$10,000/\text{MWh})$

Benefits are accrued on a one-time basis for each of the study years (2032 and 2042) and issues identified in the earlier 2032 study year are excluded from consideration in the later 2042 study year. Any reliability issues that are identified are assumed to be mitigated and pose no further risk in the later years to provide a more conservative estimate.

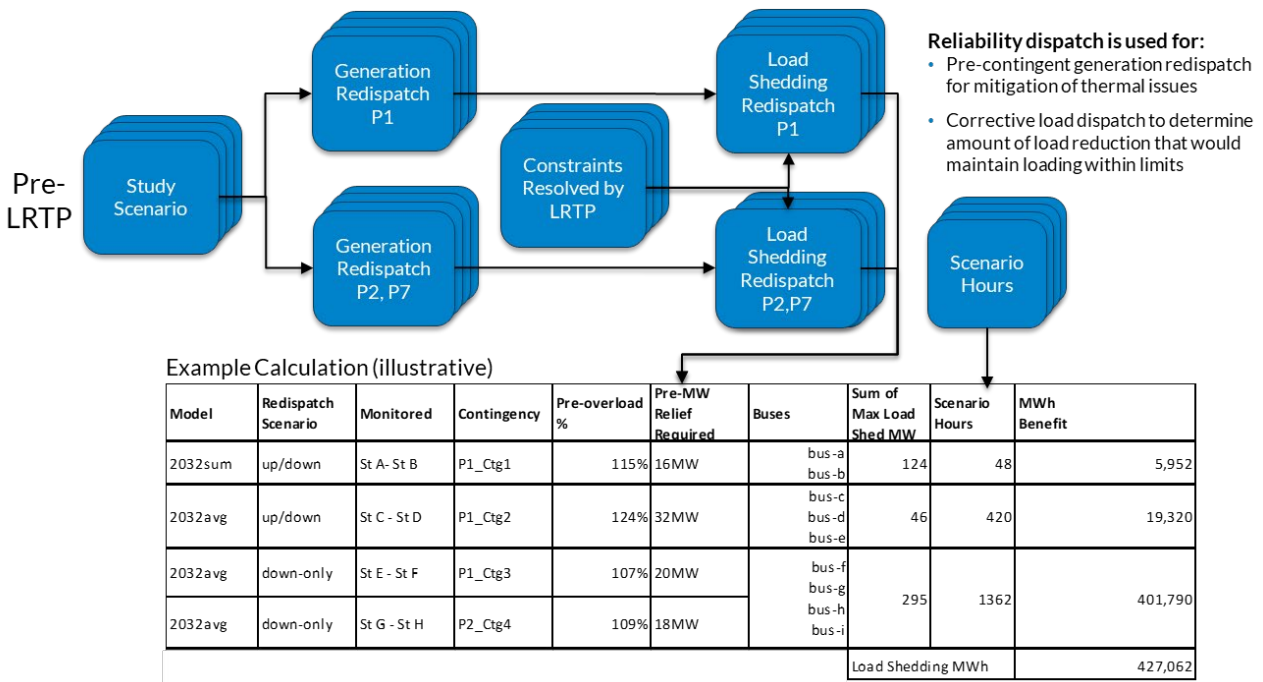


Figure 2.138: Process for Identifying Load Shedding Risk

Results

LRTP Tranche 2.1 projects provide value by proactively addressing numerous thermal overloads that reduces risk of unserved load as indicated in table below and yields \$14.8B benefits over a 20- to 40-year period.

Total Unserved Energy Risk by Season (GWh)				
Year	Summer	Winter	Average	Light Load
2032	449	58	2971	278
2042	149	80	400	115

Table 2.29: Avoided by Mitigation of Reliability Issues Benefits Summary of Avoided Unserved Energy

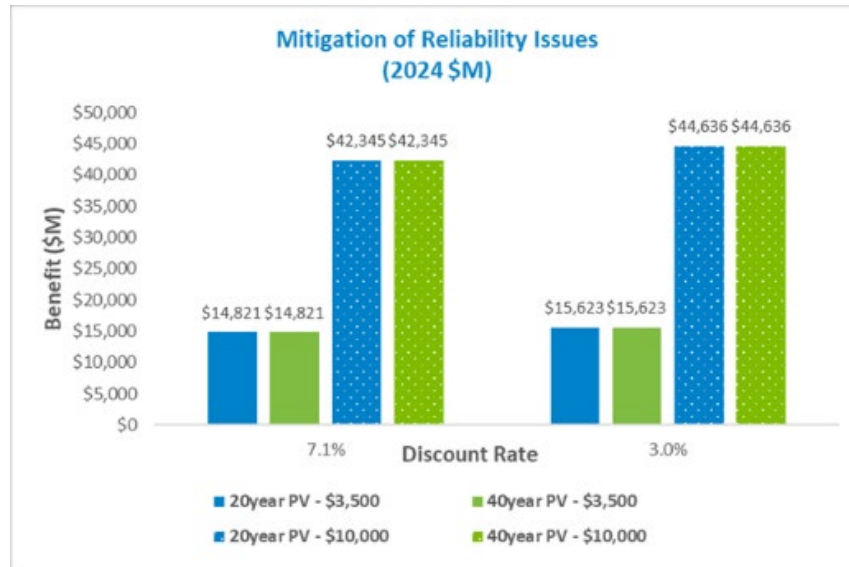


Figure 2.139: Mitigation of Reliability Issues Benefit Value

Reduced Risks from Extreme Weather Impacts

High-Level Methodology Overview

Reduced risks from extreme weather impacts reflects the value of reducing the risk of unserved energy during periods of expected supply deficiency attributed to extreme weather conditions. The increased penetration of variable resources that are reflected in the Futures scenarios, in combination with correlated outages of thermal resources and higher than expected load levels, will increase the risk of supply disruptions due to extreme weather and resulting in more unserved energy. Limited transmission capacity restricts access to resources that are needed to cover capacity shortfalls that can result in greater unserved energy. The addition of the Tranche 2.1 portfolio increases transfer capability to enhance capacity deliverability that reduces the amount of unserved energy.

The analysis uses PLEXOS software to perform probabilistic Loss of Load Expectation (LOLE) simulations using a simplified zonal transmission constraint model to assess the amount of expected unserved energy (EUE) observed in the worst intervals with and without the LRTP Tranche 2.1 portfolio. Hourly simulations are run using 14 weather years of load and renewable generation profiles with 150 samples to reflect the probabilities of forced outages including temperature-dependent correlated outages. Planned maintenance is also accounted for using maintenance outage rates and maintenance frequency. This analysis examines the Conditional Value at Risk (CVaR) to focus on the tails of the risk distribution (i.e. intervals with the highest EUE) which captures the benefits of addressing more extreme risks in a future with high levels of uncertainty and variability in the generation resources. The expected unserved energy metric is used to capture both the duration and magnitude of the loss of load events as a measure of the benefit. A threshold for CVaR is established from the event duration and magnitude and applied to the dataset to select the subset of events in the tail of the risk distribution that are used in the analysis and reflect the top percentage of EUE hours. The benefit metric applies a CVaR(80) target that is used to capture the top 20% of the worst events with greater than 2000 MWh unserved and 4 hour duration.

The reduced risk from extreme weather impacts measures the change in the expected unserved energy (EUE) during the most severe events and uses a VOLL equal to 3,500 \$/MWh to monetize the lower end of



this benefit and 10,000 \$/MWh on the upper end. The economic value, which is applied from year 10, when LRTP transmission is enabled in the planning horizon and accrued every 5 years in accordance with CVaR(80) target,⁴ is calculated by the following equation:

$$\text{Economic Value} = \left(\sum_{n=1}^H EUE \right) * VOLL$$

Where

EUE is Expected Unserved Energy (MW) in hour n

H is total hourly intervals

VOLL is the Value of Lost Load (\$3,500 - \$10,000/MW/hr)

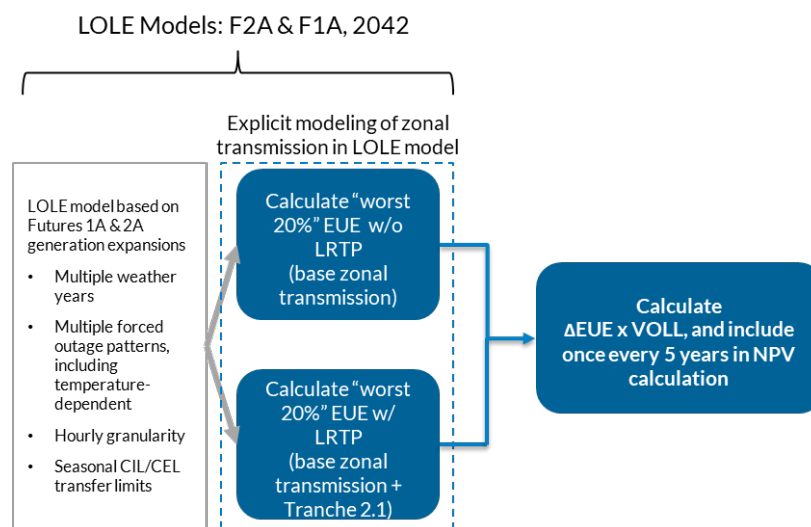


Figure 2.140: Reduced risk from extreme weather Calculation Process

Results

Analysis of the Reduced Risk from Extreme Weather Events benefit indicates that the increased transfer capability provided by the LRTP Tranche 2.1 portfolio improves system performance during extreme weather events. The portfolio provides reduction in Expected Unserved Energy of 37.9 GWh in the top 20% of event hours with the highest Expected Unserved Energy. The Tranche 2.1 portfolio delivers benefits of \$394M - \$557M over a 20- to 40-year period.

⁴ For a CVaR(80), the benefit is applied to year 0, 5, 10, 15, 20 in the 20-yr NPV calculation.

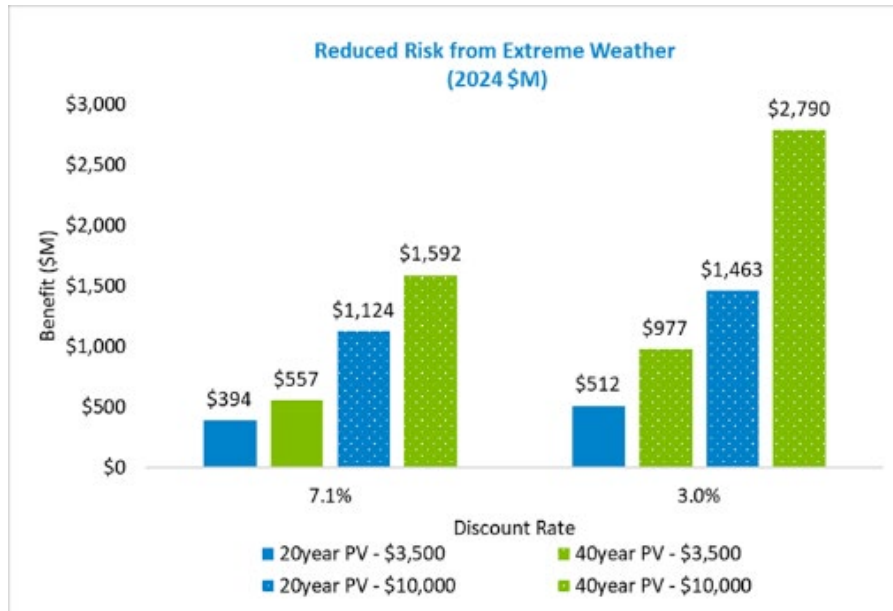


Figure 2.141: Reduced Risk from Extreme Weather Benefit Value

Avoided Capacity Cost

High-Level Methodology Overview

Avoided Capacity Cost (ACC) benefits capture savings in resource investment that result from the increased transfer capability to enable access to a more geographically diverse pool of resources. Transmission constraints limit access to resources elsewhere in the region, requiring more resource investment to meet future capacity needs. The addition of Tranche 2.1 projects alleviates the constraint violations and avoids the need for more capacity above what is included in the Future 2A scenario.

The analysis method first identifies the additional reserve requirement by using a simplified transmission constraint model that represents a change in zonal transmission limits and applies probabilistic Loss of Load Expectation (LOLE) analysis. This determines the additional reserves needed to achieve the same level of LOLE with and without LRTP using a 1-day-in-10-year criterion (0.1 d/y). The probabilistic LOLE analysis is performed with the PLEXOS software and includes the evaluation of 14 weather years of load and renewable generation profiles. Hourly simulations are run with 150 samples to reflect the probabilities of forced outages, including temperature-dependent correlated outages. Planned maintenance is also accounted for, using maintenance outage rates and maintenance frequency.

The LOLE analysis is performed using the 2042 seasonal capacity import/export limits (CIL/CEL) values without the portfolio to compute the LOLE for the modeled resources, and an incremental amount of perfect capacity (or load) is then added until the 0.1 d/y annual LOLE is reached (Seasonal LOLE targets are also applied to the cases). The same analysis is repeated using the seasonal CIL/CEL values with the LRTP portfolio to determine the incremental amount of capacity needed to reach the 0.1 d/y annual LOLE. The difference is calculated as the additional reserves that would be needed without the portfolio, reflecting the impact of the LRTP transmission.

This additional reserve value is then applied as an adjustment to the planning reserve margin (PRM) requirement in an incremental EGEAS resource expansion analysis that determines the amount and types of



resources that are built to meet the added requirements. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the base model as committed capacity. The PRM adjustment is phased in, starting with the assumed portfolio in-service year and increased to the full value in the 2042 study year. The EGEAS expansion for this metric is performed in combination with the Capacity Savings from Reduced Losses (CSRL) metric to reflect the total impact of the LRTP Tranche 2.1 portfolio. The ACC and CSRL components are split out after modeling completes, in proportion to their contribution to the total reserve requirement adjustment in 2042.

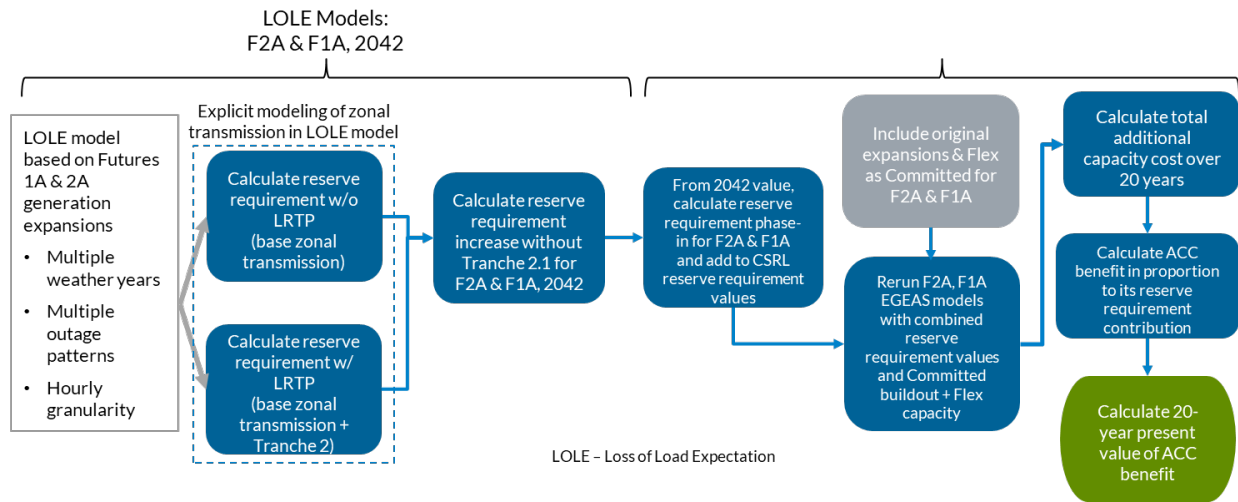


Figure 2.142: Avoided Capacity Costs Calculation Process

Results

Analysis of the Avoided Capacity Costs benefit indicate that the LRTP Tranche 2.1 portfolio increases transfer capability, which enhances resource diversity by allowing access to resources across the region. This provides for a more cost-effective buildout of regional resources and avoids the need for 20.5 GW of capacity that would otherwise be needed in addition to the buildout reflected in Future 2A. The ACC metric delivers benefits of \$16.3B – \$19.2B over a 20- to 40-year period.

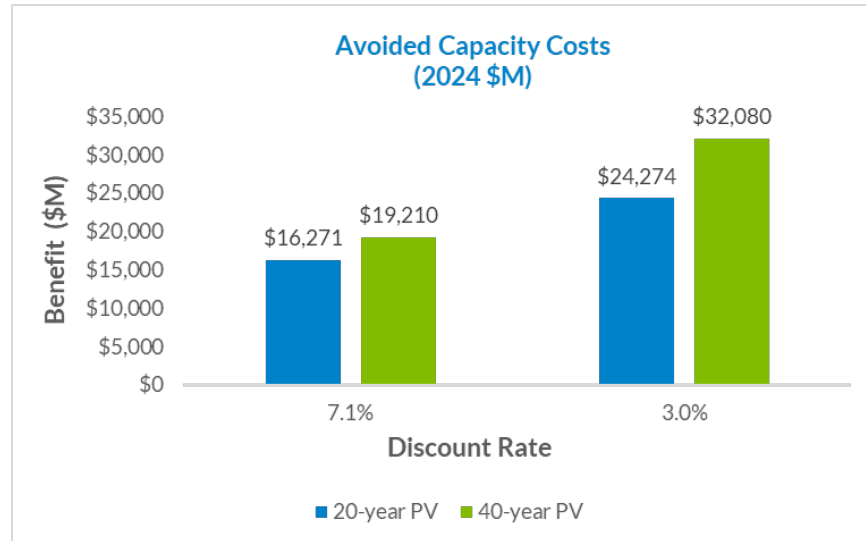


Figure 2.143: Avoided Capacity Costs Benefit Value

Capacity Savings from Reduced Losses

High-Level Methodology Overview

The Capacity Savings from Reduced Losses (CSRL) benefit reflects the capacity savings associated with the reduced losses resulting from the addition of LRTP Tranche 2.1. These projects lower the effective system impedance and redistribute flows to decrease system losses. The adoption of more widely dispersed and remote resources in the future will cause power to flow extensively and over longer distances on the transmission network, producing significant power losses. These losses, occurring during the period with highest capacity requirements, contribute to the need for additional capacity investment. In modeling system requirements for capacity expansion modeling, losses are included in the load forecast data and are held constant when evaluating Avoided Capacity Cost benefits (i.e., the benefit metric does not account for the change in losses with and without LRTP transmission). Capacity Savings from Reduced Losses (CSRL) captures an incremental benefit where LRTP transmission reduces losses in the peak capacity period.

The methodology applied in the calculation of CSRL examines change in losses observed in the reliability power flow models that reflect the various seasonal loading conditions. These reliability power flow cases model both without-LRTP topology (higher losses) and with-LRTP topology (lower losses). The change in losses is calculated using the power flow models that correspond to the season with the peak capacity requirements that determine the capacity investment needed to meet Future 2A needs. For Future 2A expansion, the winter season was determined to have the highest capacity requirements.

The modeling of incremental losses in the EGEAS expansion is reflected as a reserve requirement adjustment to introduce the additional requirements in the resource expansion. While reserve requirement itself is not a function of system losses, it simply serves as mechanism to capture the effects of losses by introducing additional requirements for capacity. The additional reserve requirements for Capacity Savings from Reduced Losses are added to the reserve requirements from the Avoided Capacity Cost metric and applied as a PRM adjustment in an incremental EGEAS expansion. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the base model as committed capacity. The PRM adjustment is phased in starting in the assumed portfolio in service year and increased to the full value in the



2042 study year. The EGEAS expansion results reflect the total impact of the LRTP Tranche 2.1 portfolio and the components for each metric are split out after the fact in proportion to their contribution to the total reserve requirement adjustment in 2042.

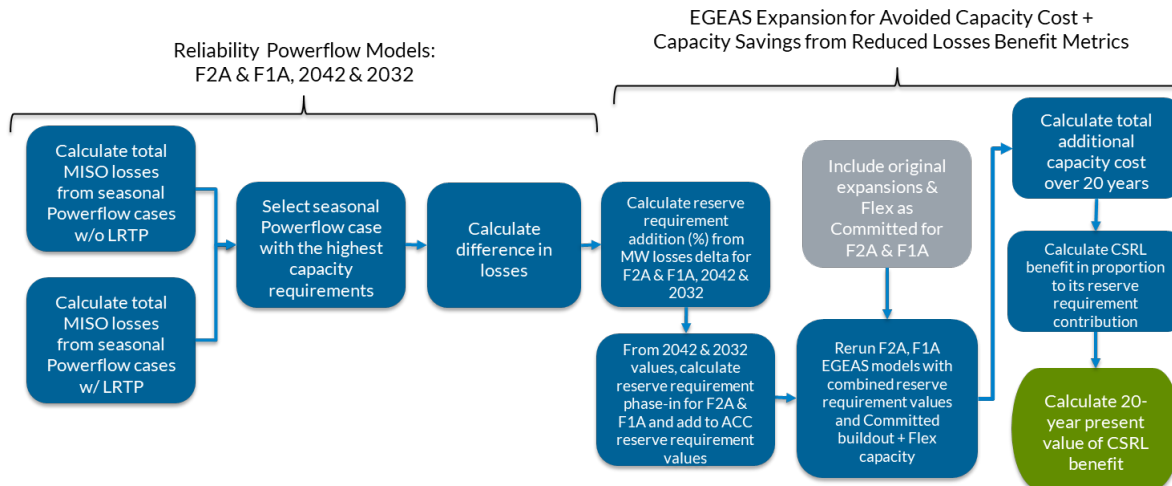


Figure 2.144: Capacity Savings from Reduced Losses Calculation Process.

Results

The lower capacity requirements resulting from the decrease in transmission system losses with the LRTP Tranche 2.1 portfolio avoids the need for 2.3 GW more capacity investment which yields benefits of \$1.9B - \$2.2B over a 20- to 40-year period.

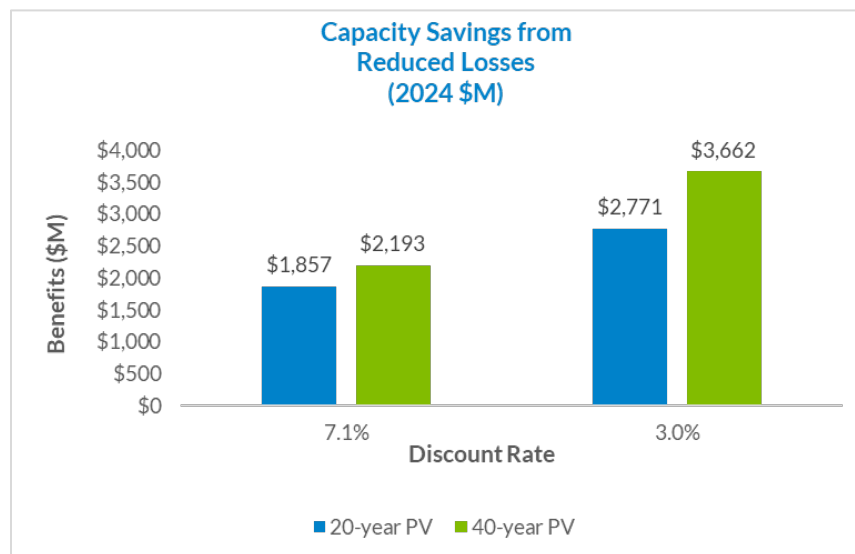


Figure 2.145: Capacity Savings from Reduced Losses Benefit Value.



Avoided Transmission Investment

High-Level Methodology Overview

Avoided Transmission Investment benefits reflect the capital cost savings from eliminating the need for age and condition replacement of existing facilities where LRTP projects reuse existing transmission infrastructure. LRTP projects that require rebuild of existing facilities or co-location of new transmission circuits along the same route as the existing facilities would require installation of new structures and hardware to support both the new circuit as well as the existing circuit and eliminates the need to replace the aging facility later resulting in avoided costs. Candidate facilities for age and condition replacement are identified in the LRTP project scoping effort. These selections are then evaluated for replacement cost except where Transmission Owners have determined that the facilities are ineligible for age and condition replacement due to recent construction or rebuild. Costs are estimated using high level cost estimates derived from the current MISO Transmission Cost Estimation Guide.

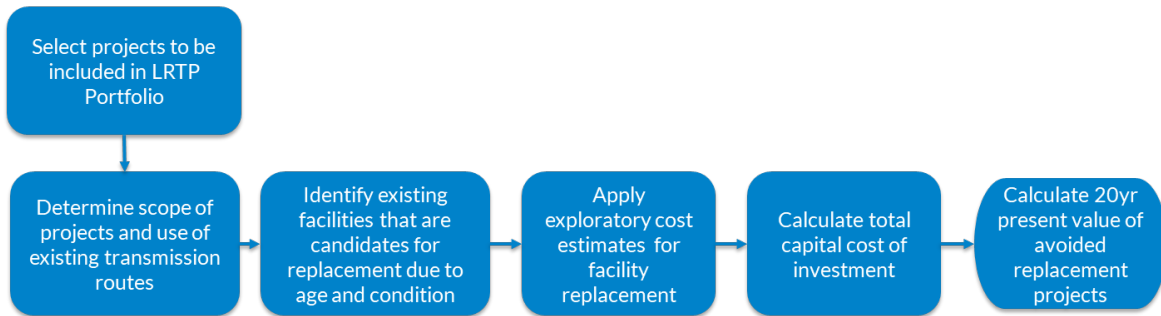


Figure 2.146: Avoided Transmission Investment Calculation Process.

Results

LRTP Tranche 2.1 portfolio avoids the need for replacement of over 700 miles of existing transmission and delivers benefits of \$1.2B - \$1.8B over a 20- to 40-year period.

Equipment and Upgrade Type	Unit Cost (\$M)	Quantity /Miles	Cost (\$M)
Transformer Replacement =345	\$12.00	0	\$0.0
Transformer Replacement <345	\$8.40	0	\$0.0
Transmission line Replacement =345kV (per mile)	\$3.20	178	\$569.6
Transmission line Replacement <345kV (per mile)	\$1.90	424	\$805.6
Transmission double-ckt line replacement = 345 (per mile)	\$3.24	30	\$97.2
Transmission double-ckt line replacement <345 (per mile)	\$2.60	75	\$195.0
Transmission triple-ckt line replacement <345 (per mile)	\$2.64	1	\$1.9
		Total (2024\$)	\$1,669.3

Table 2.30: Summary of Avoided Transmission Investment Benefits

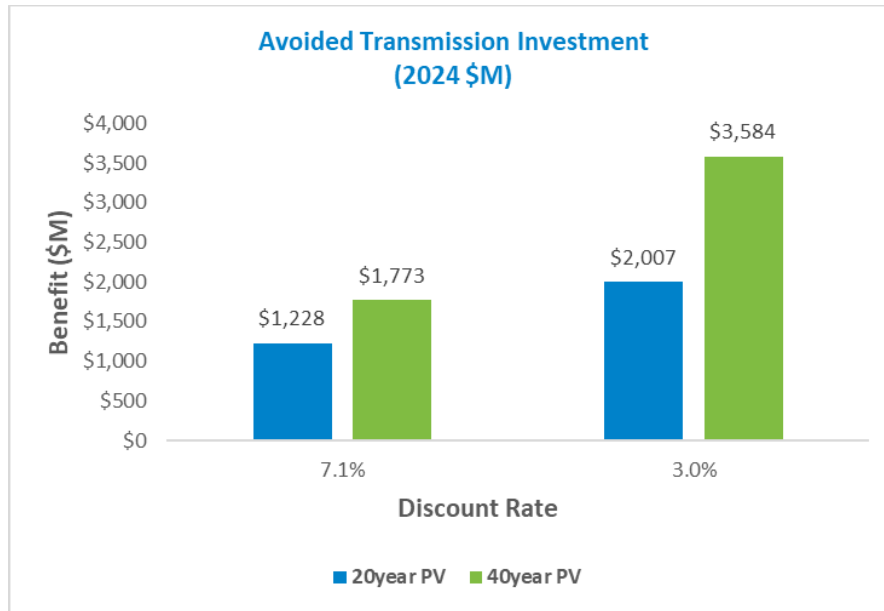


Figure 2.147: Avoided Transmission Investment Benefit Value.

Congestion and Fuel Savings

High-Level Methodology Overview

The congestion and fuel savings benefit reflects production cost savings that are achieved through a more economically efficient dispatch enabled by regional transmission, which reduces congestion and provides access to lower-cost generation. Production cost analysis uses hourly (8760) chronological security constrained unit commitment and economic dispatch, adhering to a wide variety of operating constraints and respecting N-1 contingency conditions. Production cost savings calculations compare the reference case dispatch using a model without the LRTP transmission portfolio to a change case dispatch that incorporates the LRTP transmission portfolio. The addition of LRTP transmission decreases the loading (congestion) on the pre-existing network, alleviating several thermal constraint violations that would otherwise necessitate dispatch of higher-cost resources and facilitates access to lower-cost generation. The difference in production costs between the reference case and change case is thus captured as a benefit provided by the LRTP portfolio.

MISO's production cost models do incorporate Production Tax Credits (PTC) (See [MISO Series 1A Futures Report - Inflation Reduction Act](#)) for applicable resources into the security constrained unit commitment and economic dispatch; however, the PTC value is removed from the final congestion and fuel savings value shown for the transmission portfolio.

Production cost simulations are run using the 2032, 2037 and 2042 reference case economic models and to produce annual values of adjusted production costs (by zone) without LRTP transmission for the three study years. The production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of adjusted production costs (by Cost Allocation Zone) with LRTP transmission for the three study years.



For the three study years, the difference in Adjusted Production Costs with and without LRTP transmission is calculated to produce an annual savings. These yearly values are then used to interpolate or extrapolate annual values for the remaining years within the benefit period.

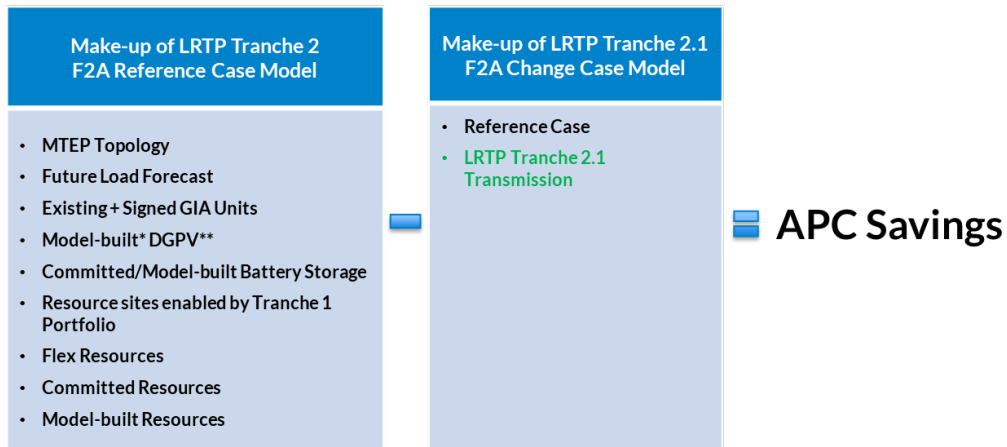


Figure 2.148: APC Savings

Results

The LRTP Tranche 2.1 Portfolio alleviates transmission constraint violations and reduces congestion to allow more efficient dispatch of lower cost resources which provides benefits of congestion and fuel savings benefits of \$8.1B - \$11.3B over a 20- to 40-year period.

Discount Rate	20 Year Present Value (2024\$)		40 Year Present Value (2024\$)	
	7.1%	3.0%	7.1%	3.0%
CAZ				
1	\$1,366	\$2,236	\$2,856	\$6,876
2	\$2,546	\$3,698	\$3,888	\$7,809
3	\$1,689	\$1,932	\$1,000	-\$326
4	-\$341	-\$407	-\$255	-\$121
5	\$232	\$433	\$645	\$1,727
6	\$1,847	\$2,612	\$2,607	\$4,922
7	\$808	\$940	\$531	\$31
Total	\$8,148	\$11,443	\$11,272	\$20,916

Table 2.31: Distribution of Congestion and Fuel Savings Benefits

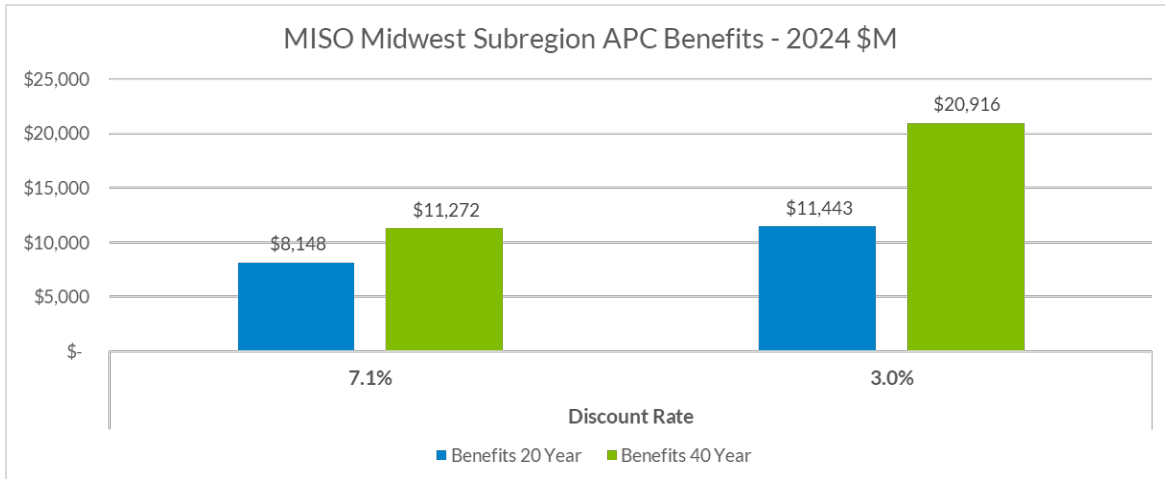


Figure 2.149: Congestion and Fuel Savings Benefit Value

Energy Savings from Reduced Losses

High-Level Methodology Overview

Energy Savings from Reduced Losses captures the lower production costs that result from the addition of transmission facilities that reduces the overall system losses. Transmission losses that are produced by flow of power across the transmission network contribute to the energy requirements and increase the overall costs of energy to customers. As the resource fleet transitions to utilize more dispersed generation in remote areas of the footprint, losses increase with the more extensive use of the transmission network and transport of power over longer distances further increasing energy costs.

The addition of new transmission facilities provides additional transmission capacity and lowers the effective system impedance which will result in a decrease in real system losses. These real losses are modeled as constant values within the load profiles used in the standard production cost simulations. Thus, production cost savings generally do not capture the incremental benefits of reduced losses provided by the addition of new transmission elements. The production cost model case can be modified to reflect the reduction in losses, estimated from the power flow cases and applied to the demand in the change case which includes the new transmission. The Adjusted Production Costs (APC) savings are calculated using a reference and change case model pair with base case losses in the reference case and the change case reflecting the estimated reduction in losses. The difference between those two APC values is the APC savings from reduced losses resulting from the transmission expansion.

The differences in losses are calculated with and without the LRTP Tranche 2.1 portfolio for the four 2032 and four 2042 core power flow models. Loss reduction values are averaged across all core models for each study year and compared to the average demand in the MISO Midwest subregion to determine an average percentage of load as a scaling factor. This scaling factor is used to adjust the load profiles in the change case economic models to reflect the reduced loss component.

Production cost simulations are run using the 2032, 2037 and 2042 reference case economic models and to produce annual values of Adjusted Production Costs (by zone) without LRTP transmission for the three study years. The production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of Adjusted Production Costs (by Cost Allocation Zone)



with LRTP transmission for the three study years. The difference in APC between the change case containing the additional loss component and the reference case without the reduced losses provides the total APC savings when reduced loss energy is applied. The APC savings attributable to reduced loss energy is determined by netting out the value of the base Congestion and Fuel Savings metric.

APC Savings from Reduced Loss Energy

$$= (\text{Baseline Reference Case APC} - \text{Reduced Loss Energy Change Case APC}) - (\text{Baseline Reference Case APC} - \text{Baseline Change Case APC})$$

For the three study years (2032, 2037, and 2042), the annual production cost savings from reduced losses are used to interpolate or extrapolate annual values for the remaining years within the benefit period.

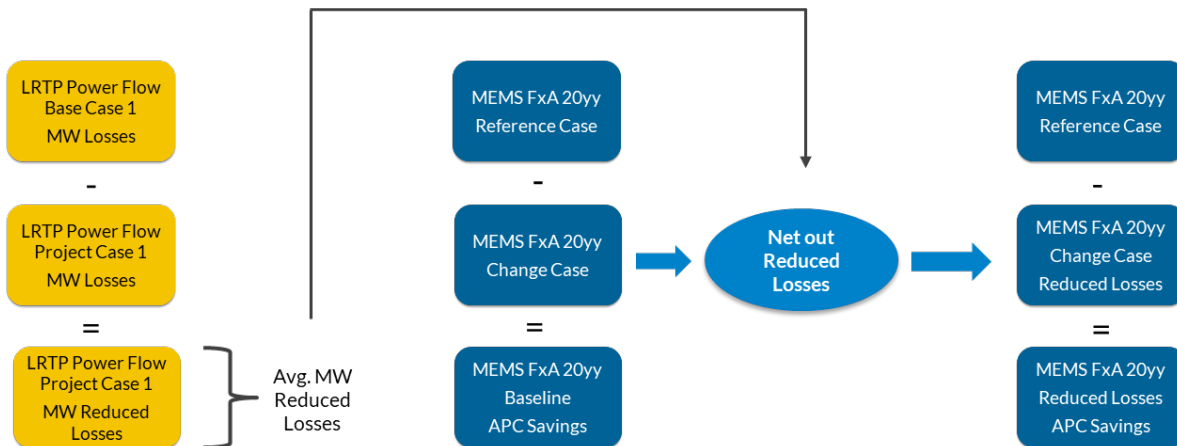


Figure 2.150: Energy Savings from Reduced Losses Calculation Process.

Results

The LRTP Tranche 2.1 Portfolio provides additional transmission capacity and redistributes flows to reduce system losses which delivers energy savings from reduced losses benefits of \$1.6B - \$2.4B over a 20- to 40-year period.

Discount Rate	20 Year Present Value (2024\$)		40 Year Present Value (2024\$)	
	7.1%	3.0%	7.1%	3.0%
CAZ				
1	\$246	\$361	\$388	\$799
2	\$273	\$376	\$356	\$626
3	\$54	\$102	\$153	\$413
4	\$92	\$143	\$168	\$379
5	\$129	\$180	\$176	\$323
6	\$428	\$598	\$584	\$1,069
7	\$411	\$571	\$551	\$993
Total	\$1,632	\$2,332	\$2,376	\$4,602

Table 2.32: Distribution of Energy Savings from Reduced Losses Benefits

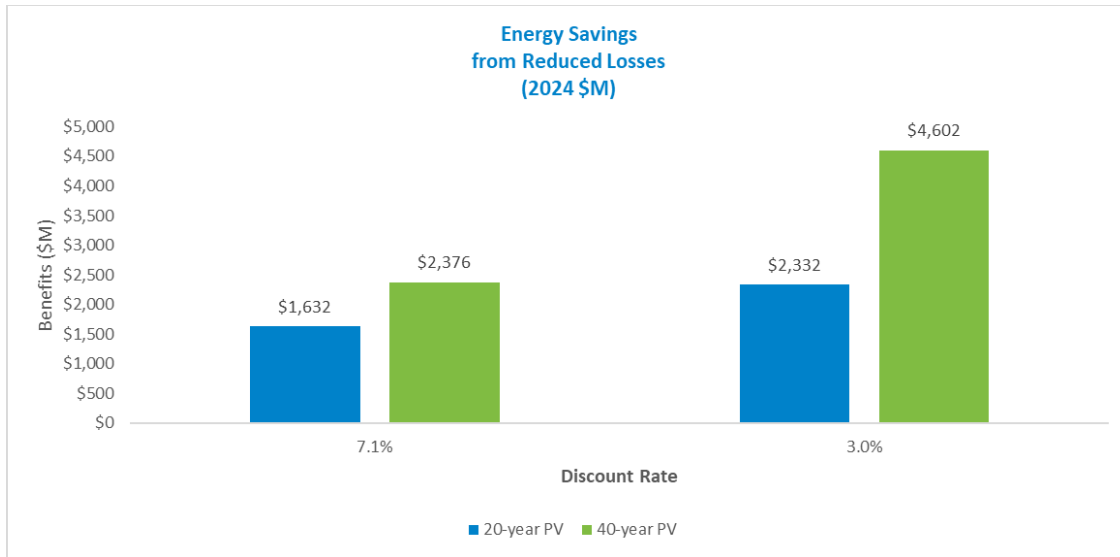


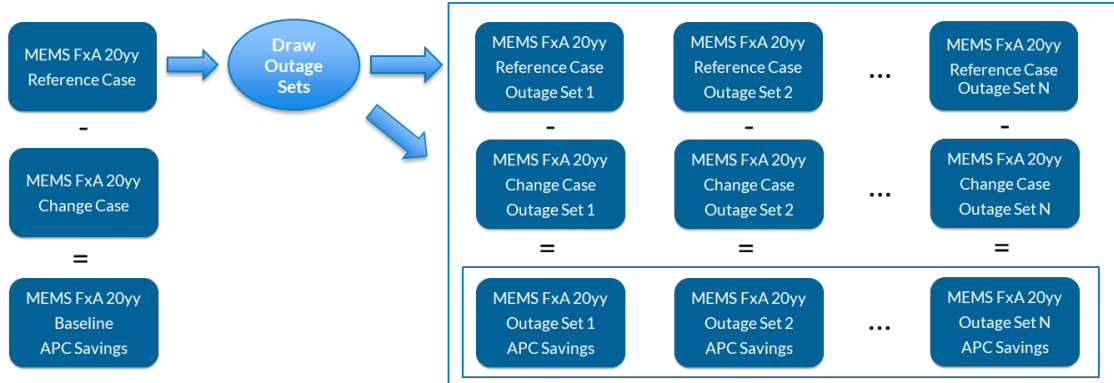
Figure 2.151: Energy Savings from Reduced Losses Benefit Value.

Reduced Transmission Outage Costs

High-Level Methodology Overview

Reduced Transmission Outage Costs captures incremental savings that more fully reflect the effects of congestion under actual operating conditions. Congestion and fuel savings benefits apply conservative modeling of system conditions that reflect an intact transmission network. Throughout the year there are typically numerous planned and forced transmission outages that occur with varying degrees of overlap. These facility outages remove available transmission capacity from the system, increase the loading on remaining in-service facilities, and contribute to congestion. The addition of LRTP transmission unlocks additional value by relieving the additional congestion attributed to typical planned and forced outage schedules.

Outage sets are created by applying outage probabilities established from historical transmission outage records to prepare annual profiles of random outage draws for modeled transmission elements on a daily basis for forced outages and on a monthly basis for planned outages. Ten outage sets are developed to reflect a range of different outage schedules. For each of the three study years (2032, 2037, and 2042), the difference in APC with and without LRTP is calculated to produce an annual savings that captures the effects of the randomized sets of planned and forced outages. For each of the three study years, the production cost savings are averaged across the 10 outage simulation runs to reflect annual savings for a typical year of outages. The APC savings attributed to the outage impact is determined by netting out the base Congestion and Fuel Savings, and the values for the three study years are used to interpolate or extrapolate the annual values for the remaining years within the benefit period.



$$\text{Reduced Transmission Outage Costs} = \frac{\sum_n \text{Outage Set } n \text{ APC Savings}}{N} - \text{Baseline APC Savings}$$

Figure 2.152: Reduced Transmission Outage Costs Calculation Process

Results

The LRTP Tranche 2.1 Portfolio provides additional transmission capacity that helps to enhance operational flexibility and reduce congestion that occurs from typical outage schedules which provides Reduced Transmission Outage Costs benefits of \$76M - \$110M over a 20- to 40-year period.

Discount Rate	20 Year Present Value (2024\$)		40 Year Present Value (2024\$)	
	7.1%	3.0%	7.1%	3.0%
CAZ				
1	\$31	\$46	\$49	\$100
2	\$14	\$16	\$8	-\$2
3	-\$34	-\$40	-\$26	-\$15
4	-\$3	-\$9	-\$18	-\$56
5	\$69	\$90	\$75	\$106
6	\$22	\$34	\$40	\$91
7	-\$22	-\$27	-\$18	-\$12
Total	\$76	\$108	\$110	\$211

Table 2.33: Distribution of Benefits for Reduced Transmission Outage Costs

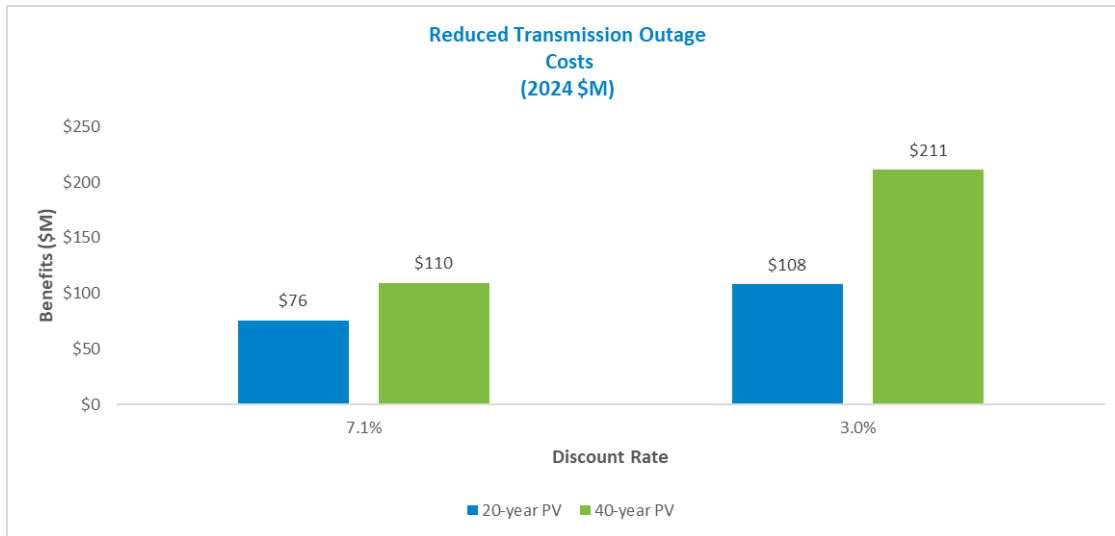


Figure 2.153: Reduced Transmission Outage Costs Benefit Value

Decarbonization

High-Level Methodology Overview

Decarbonization benefits are associated with avoided CO₂ emissions that result from the more efficient dispatch of lower-cost resources. Production cost simulations are used to economically dispatch resources with respect to availability and subject to transmission constraints and establish the hourly dispatch of resources over 8760 annual hours. The dispatch of lower-cost, non-emitting renewable resources avoids CO₂ emissions for the generation fleet. As transmission congestion occurs on the system, dispatchable carbon-emitting resources are needed to manage system flows and can displace carbon-free renewable energy, leading to higher levels of CO₂ emissions. The addition of LRTP transmission alleviates congestion, allowing dispatch of more renewable energy that provides benefits through avoided carbon emissions.

Analysis of Decarbonization benefits uses the emissions data from the Adjusted Production Cost (APC) analysis used for the base Congestion and Fuel Savings benefit metric and compares the change in CO₂ emissions between the reference case without LRTP and the change case with LRTP. Values are computed for years 2032, 2037 and 2042; and are interpolated for years in between and extrapolated for years beyond 2042. The reductions in annual CO₂ emissions are converted to metric tons and monetized by applying a range of carbon prices that reflect the value of decarbonization.

	Federal	MN PUC
2024\$/metric ton	\$85	\$248.67

Table 2.34: Carbon Costs for Monetization of Benefits

Results

The LRTP Tranche 2.1 portfolio alleviates congestion, allowing for more efficient dispatch of non-emitting resources to reduce CO₂ emissions by 127-199M metric tons over 20 to 40 years. This provides Decarbonization benefits of \$7.2B - \$9.0B over a 20- to 40-year period.

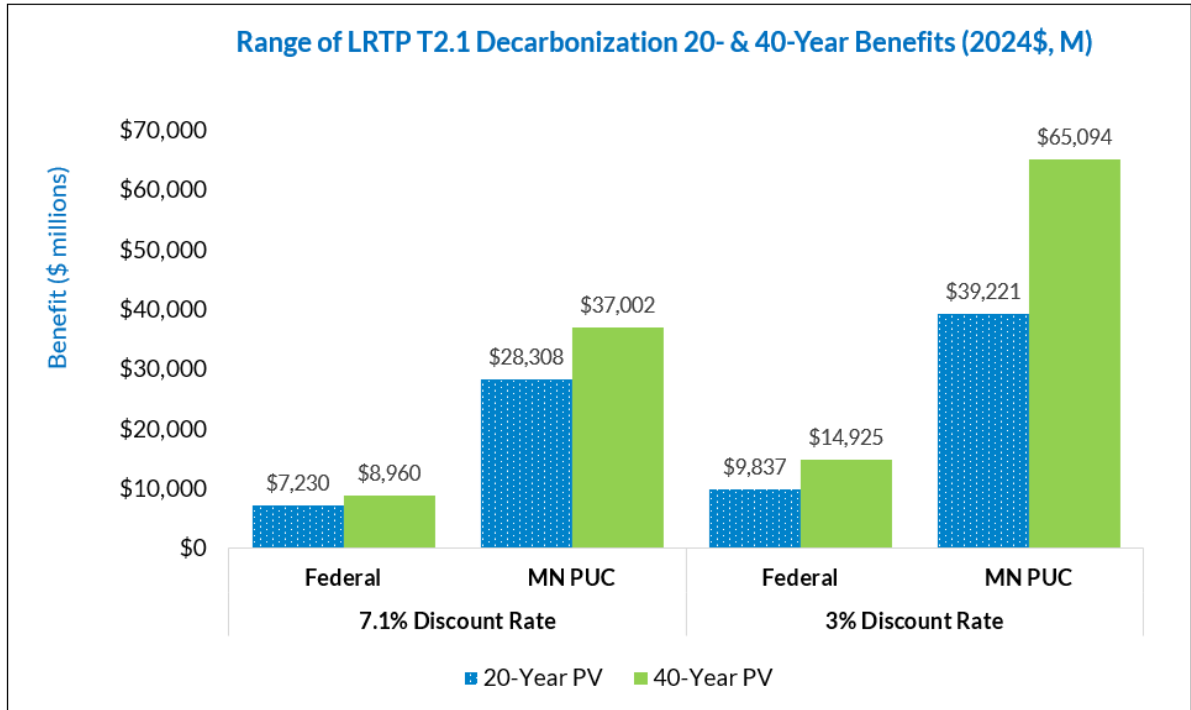


Figure 2.154: Decarbonization Benefit Value.

Future 1A Benefit Metric Analysis

The benefits metrics for the LRTP Tranche 2.1 portfolio were evaluated with Future 1A assumptions to assess value in a lower-bookend scenario applying the same methodologies used for Future F2A. The analysis demonstrates that under the Future 1A scenario, the LRTP Tranche 2.1 portfolio delivers benefits in excess of costs, totaling \$34.2B - \$61.9B over a 20-year period with an overall benefit-to-cost ratio ranging from 1.2 to 2.2.

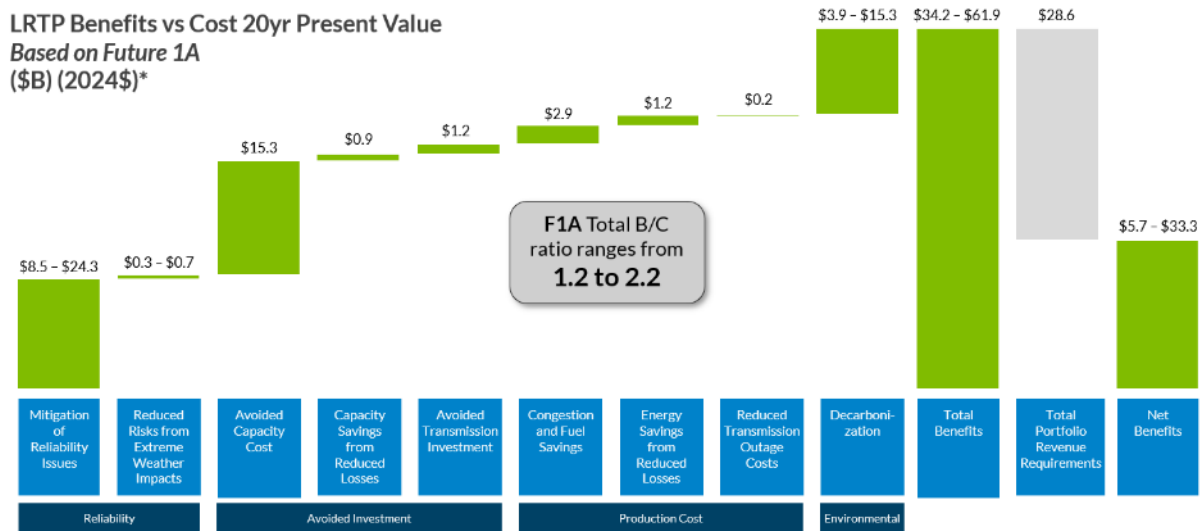


Figure 2.155: Tranche 2.1 Benefits based on Future 1A.



Step 6: Recommend Preferred Solutions

Tranche 2.1 portfolio includes 24 projects and 323 facilities across the MISO Midwest subregion estimated at \$21.8 billion and targeted to go in service from 2032 to 2034.

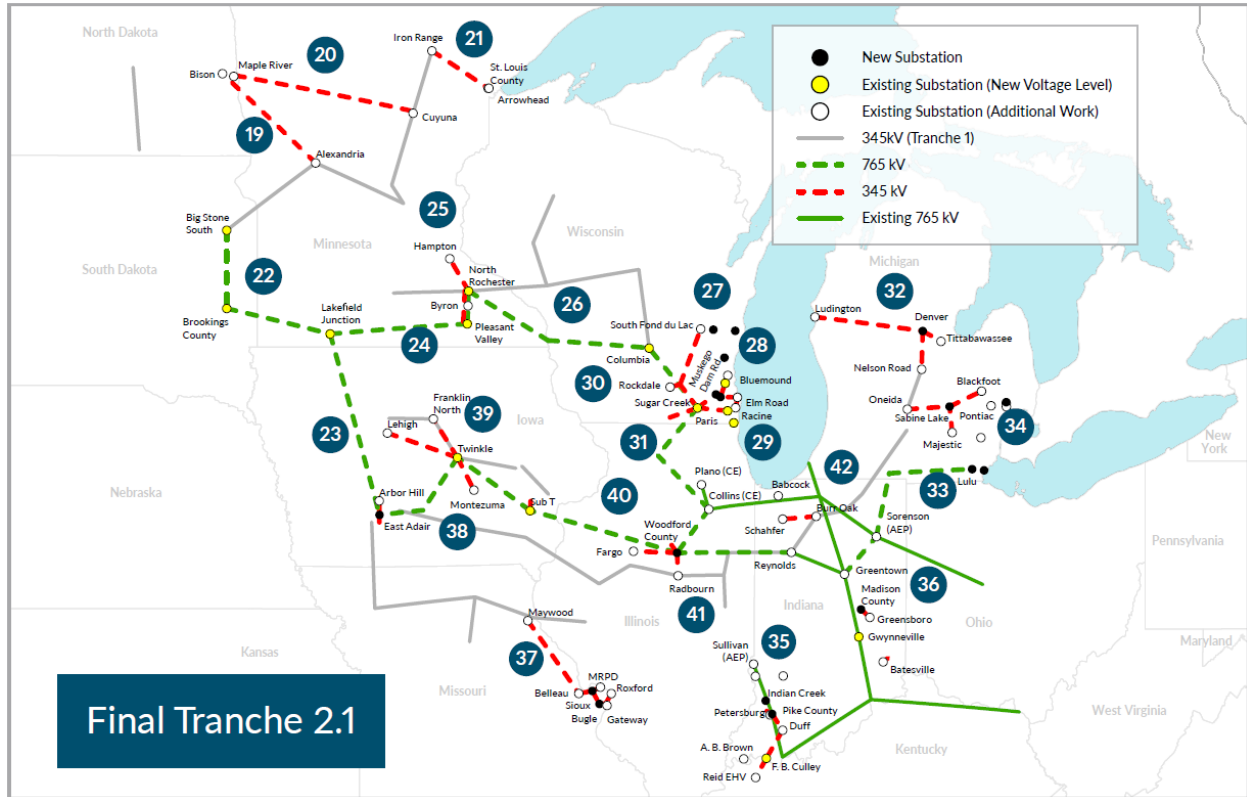


Figure 2.156: Tranche 2.1 Portfolio Map



ID	Project Name	Predominate kV	Targeted ISD	Est. Cost (\$M, 2024)
19	Bison- Alexandria	345	2032	\$216
20	Maple River- Cuyuna	345	2033	\$908
21	Iron Range - Arrowhead	345	2032	\$428
22	Big Stone South- Brookings County- Lakefield Junction	765	2034	\$1,459
23	Lakefield Junction- East Adair	765	2034	\$1,375
24	Lakefield Junction- Pleasant Valley- North Rochester	765	2034	\$1,195
25	Pleasant Valley- North Rochester - Hampton Corner	345	2032	\$222
26	North Rochester - Columbia	765	2034	\$1,924
27	Rocky Run- Werner - North Appleton	345	2032	\$212
28	South Fond du Lac- Rockdale- Big Bend- Sugar Creek - Kitty Hawk	345	2033	\$1,102
29	Bluemond- Arcadian- Waukesha- Muskego- Elm Road- Racine	345	2032	\$731
30	Columbia- Sugar Creek	765	2034	\$743
31	Sugar Creek- Collins	765	2034	\$733
32	Ludington- Denver- Tittabawassee & Nelson Road	345	2032	\$1,553
33	Greentown- Sorenson - Lulu	765	2033	\$1,310
34	Oneida- Sabine Lake- Blackfoot & Majestic	345	2032	\$600
35	Southwest Indiana-Kentucky	345	2032	\$743
36	Southeast Indiana	345	2032	\$578
37	Maywood- Belleau- MRPD- Sioux - Bugle	345	2032	\$881
38	East Adair- Marshalltown- Sub T	765	2034	\$1,583
39	Lehigh- Marshalltown- Franklin North & Montezuma	345	2032	\$588
40	Sub T - Woodford County- Collins & Reynolds	765	2034	\$2,298
41	Woodford County- Fargo & Radbourn	345	2032	\$422
42	Burr Oak - Schahfer	345	2032	\$68
Total Portfolio Cost			Total	\$21,868

Table 2.35: Tranche 2.1 Portfolio Projects



Step 7: Apply Appropriate Cost Allocation

Distribution of Benefits and Portfolio Costs

Benefits are spread across the Midwest subregion. The LRTP Tranche 2.1 Portfolio of projects was developed for the MISO Midwest subregion to ensure transmission is reliable, economic, and compliant in the future, given state and utility policy and goals, projected conditions and industry trends. Analysis of the nine benefit metrics included identifying the distribution of each benefit across the Cost Allocation Zones in the Midwest subregion. The distribution of benefits of the LRTP Tranche 2.1 Portfolio is shown to provide benefits in excess of costs for each Cost Allocation Zone (CAZ) under Future 1A and 2A.

Benefit Metric	CAZ Allocation Method
Mitigation of Reliability Issues	Based on location of reliability issues
Reduced Risks from Extreme Weather Impacts	Based on load ratio share
Avoided Capacity Costs	Based on load ratio share
Capacity Savings from Reduced Losses	Based on load ratio share
Avoided Transmission Investment	Based on the zonal location of upgrade
Congestion and Fuel Savings	Derived directly from PROMOD results
Energy Savings from Reduced Losses	Derived directly from PROMOD results
Reduced Transmission Outage Costs	Derived directly from PROMOD results
Decarbonization	Based on load ratio share

Table 2.36: Benefit Metric Method to Distribute Benefits to Cost Allocation Zones

Future 2A

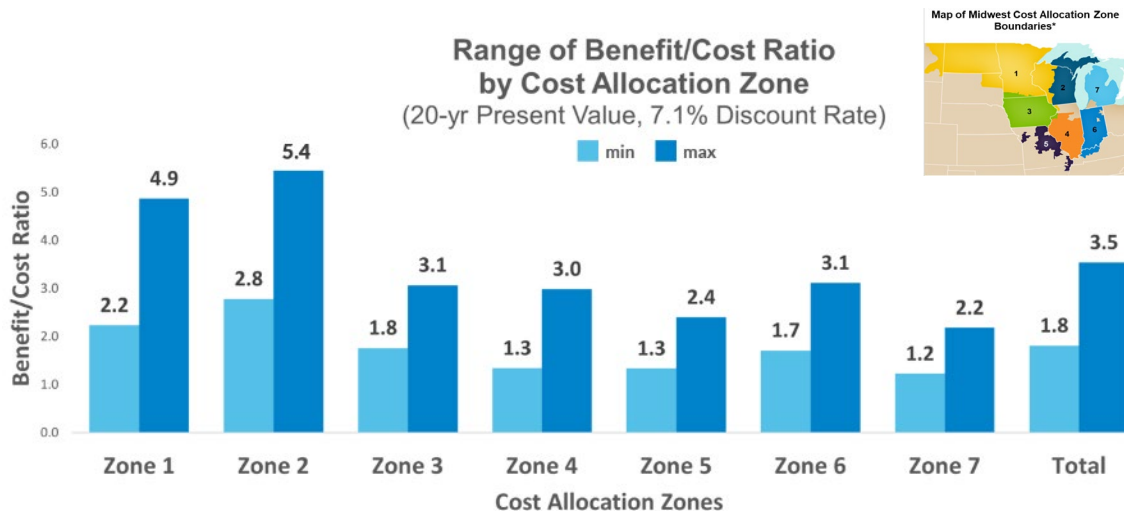


Figure 2.157: Tranche 2.1 Distribution of Benefits – Future 2A



Future 1A

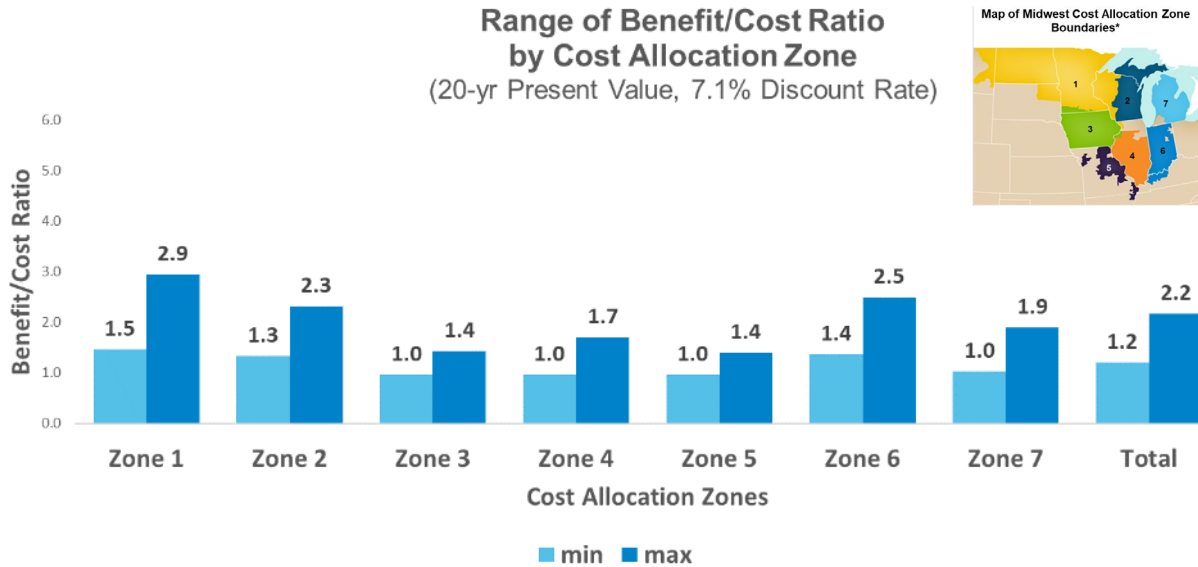


Figure 2.158: Tranche 2.1 Distribution of Benefits - Future 1A⁵

Estimates of MVP Usage Rates for Tranche 2.1 Portfolio

As Multi-Value-Projects, the costs of the LRTP Tranche 2.1 Portfolio will be recovered from MISO load and exports associated with the MISO Midwest subregion through the energy-based MVP Usage Rate (\$/MWh). Additionally, indicative annual MVP usage rates for the LRTP Tranche 2.1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. The MVP Usage Rate for Tranche 2.1 is estimated to peak at \$6.44 per MWh of energy usage and average \$4.76 per MWh over a 40-year period. While the Tranche 2.1 portfolio is estimated to cost MISO members about \$5 per 1 MWh or 1,000 kWh of energy used, that investment will provide \$10 to \$18 of value over that same amount of usage, based on Future 2A analysis.

⁵ Min and Max range reflect changes in the assumptions for the value of lost load (Mitigation of Reliability Issues/Reduced Risks from Extreme Weather Impacts) and avoided CO₂ emissions values (Decarbonization).

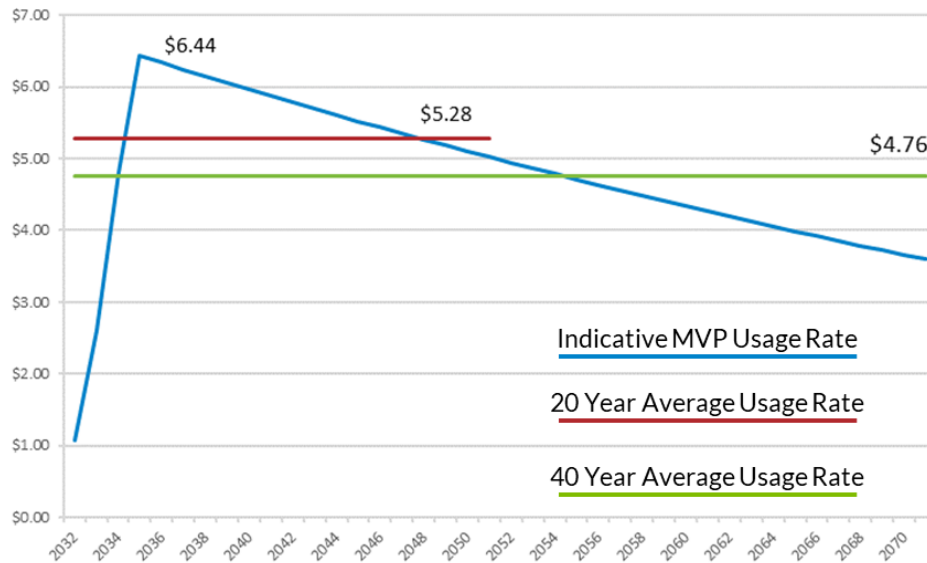


Figure 2.159: Tranche 2.1 Estimated MVP Usage Rate (\$/MWh)⁶

Other Benefits

Natural Gas Price Sensitivity

MISO Futures used for the LRTP T2.1 study utilized a new natural gas price forecast methodology. Previous MISO methodologies had used a blend of fixed forecasts, anchored to Henry Hub (HH) price. In the new methodology Gas Pipeline Competition Model (GPCM) was used to develop forecasts that incorporate gas usage from the production cost model runs, to iteratively match both gas usage and price. In this way, gas prices can be calibrated to different Futures assumptions. Gas price base forecasts, used in the EGEAS Futures expansion, were fed into PROMOD, and the gas usage observed in those models was fed into GPCM to create updated price forecasts. This was repeated iteratively until prices between the two models converged, and those converged prices were used in the base PROMOD models. To gain further insight into the impact of gas prices on benefits, an analysis was performed where Future 2A natural gas prices were increased by 20 – 60% above those in the base model, testing both the LRTP reference and change case models. This range corresponds to a range of historical prices seen between 2012 and 2022.

⁶ MISO's Schedule 26-A indicative MVP Usage Rate is reflective of rates applied to wholesale electricity transactions and not intended to be used for impacts to retail electricity rates.

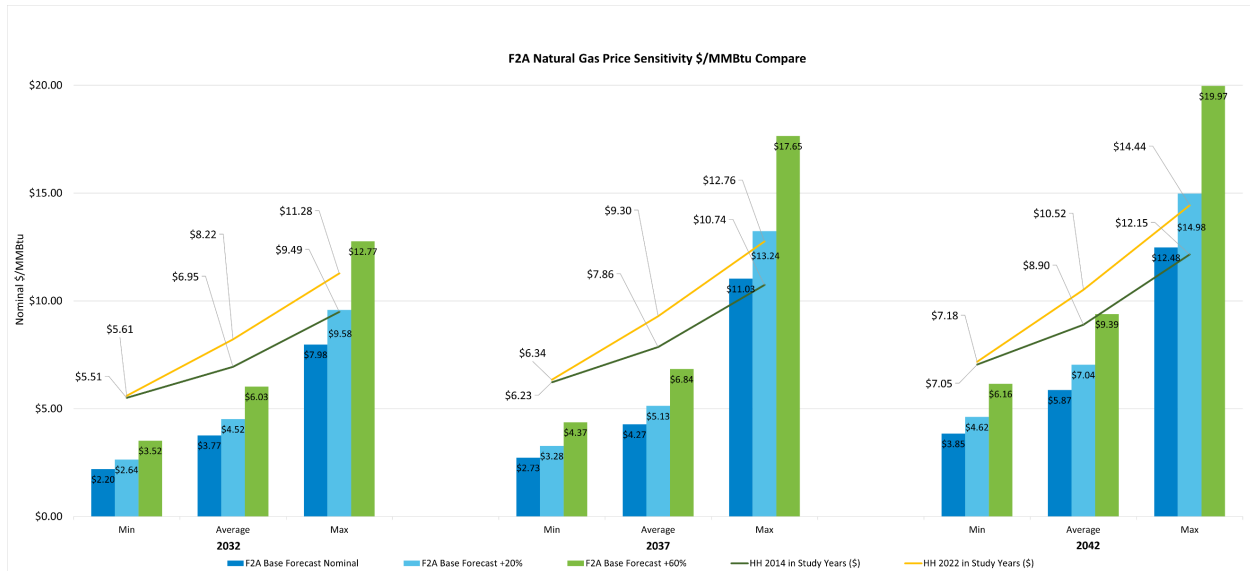


Figure 2.160: Future 2A Natural Gas Price Sensitivity Results

The 20% gas price increase generates a \$9.1B congestion and fuel savings, approximately \$1B increase in savings, while a 60% gas price increase generates a \$10.8B congestion and fuel savings increase, approximately \$2.6B increase in savings.

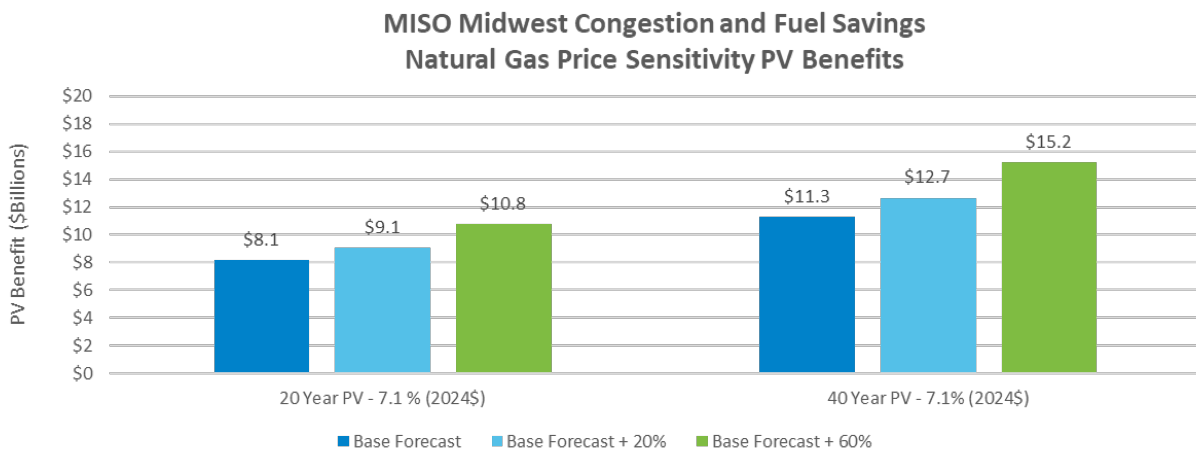


Figure 2.161: Natural Gas Price Sensitivity Congestion and Fuel Savings

Economic Development Benefits

In addition to the direct benefits calculated in the Business Case, Tranche 2.1 transmission investments will also deliver significant economic development benefits to local economies in the MISO region.

Some of these economic development benefits, such as the impact on long-run economic growth, are difficult to quantify. However, as electricity serves as a key input into business production processes, the access to lower and more efficient energy prices provided by transmission investments will support higher



productivity and long-run economic growth. Further, transmission has the potential to attract new businesses and support connections to burgeoning high-growth industries, such as data centers.

Other economic development benefits, such as the short-run impacts on employment and economic output in local economies can be quantified.

Local Investment and Job Creation

Economists typically place the impacts of investments on jobs and economic output into three groupings: direct, indirect, and induced economic activity.

Direct economic impacts refer to impacts in industries directly benefiting from transmission investment, such as construction companies and manufacturers of transmission materials. Indirect economic impacts refer to changes in industries further down the supply chain, such as the suppliers to transmission material manufacturers. Induced impacts refer to changes in the local economy from increased spending on housing, food, and other services by those directly or indirectly employed by the transmission investments.

To arrive at estimates for the potential economic development impacts of Tranche 2.1 investments, MISO surveyed the literature on the impacts of transmission investment on direct jobs, total jobs, and total economic output. MISO's literature survey found that \$1 million in transmission investments powers between 1 and 3 direct local jobs, between 2 and 6 total local jobs (including direct, indirect, and induced effects), and between \$0.2 and \$1.1 million in total local economic output. Ranges were chosen to cover roughly 90% of study estimates found in the MISO literature review.

Using these multipliers, Tranche 2.1 investments are estimated to power roughly 22,000 to 65,000 direct jobs in the MISO region. Direct jobs stemming from Tranche 2.1 investments are also high-quality jobs, with wages estimated to be about 30% higher than a typical worker's wages. Adding in the effects of supply chains and further induced demand and Tranche 2.1 investments are estimated to power between 44,000 and 131,000 total jobs in the MISO region and between \$4 and \$24 billion in total economic output.

	Tranche 2.1 Investment (\$Mns)	Direct Local Jobs		Total Local Jobs		Local Investment/Total Economic Output (\$Mns)	
		Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Central							
MO	\$872	872	2,616	1,744	5,231	\$ 174	\$ 959
IL	\$2,886	2,886	8,659	5,772	17,317	\$ 577	\$ 3,175
IN	\$2,378	2,378	7,135	4,757	14,270	\$ 476	\$ 2,616
KY	\$77	77	230	153	459	\$ 15	\$ 84
East							
MI	\$2,672	2,672	8,015	5,344	16,031	\$ 534	\$ 2,939
West							
IA	\$3,606	3,606	10,817	7,212	21,635	\$ 721	\$ 3,966
MN	\$4,342	4,342	13,026	8,684	26,051	\$ 868	\$ 4,776
ND	\$188	188	564	376	1,129	\$ 38	\$ 207
SD	\$724	724	2,171	1,447	4,341	\$ 145	\$ 796
WI	\$4,086	4,086	12,257	8,171	24,514	\$ 817	\$ 4,494
Total	\$21,830	21,830	65,489	43,659	130,978	\$ 4,366	\$ 24,013

Table 2.37: Tranche 2.1 Investment by State and Jobs and Economic Impact.



2.3 Near Term Congestion Study Update

Introduction and Background

The first Near-Term Congestion Study was completed in 2023 in response to PAC-2021-1: Address Congestion at Existing Resources. The 2023 study focused on recreating and assessing historically congested flowgates in a near-term PROMOD model. In 2024 this issue was delegated to the Planning Subcommittee (PSC) for further stakeholder technical discussion. Information on stakeholder discussions and presentations on this issue can be found on the MISO website at [PAC-2021-1 Address Congestion At Existing Resources](#).

The 2024 Near-Term Congestion Study provided stakeholders the opportunity to submit feedback on various near-term study approaches. The study options presented to stakeholders included:

- Year 5 Economic Model Refinement and Study
- LRTP Tranche 1 Construction Outages Assessment
- Year 2 Economic Model Development and Study

Based on stakeholder feedback and internal MISO interest, MISO moved forward with an LRTP Tranche 1 Construction Outages Assessment for the 2024 Near-Term Congestion Study. This study utilized the Year 5 PROMOD model from the 2023 Near-Term Congestion Study to test and analyze LRTP Tranche 1 construction outages. By partnering with Operations Planning and Competitive Transmission teams internally, and working with our Transmission Owners, outage sequence issues were identified, GETs solutions were requested, and general outage sequence recommendations were developed.

Study Objectives and Scope

The primary objective of this study was to provide insight into the impact of the LRTP Tranche 1 construction outages. Given the magnitude and siting of the LRTP Tranche 1 projects we anticipate temporary increases in congestion and the need for additional coordination with Transmission Owners to identify conflicting outages that could result in reliability issues. By collecting data on these construction outages early and studying them in PROMOD we can provide recommendations on outage sequences.

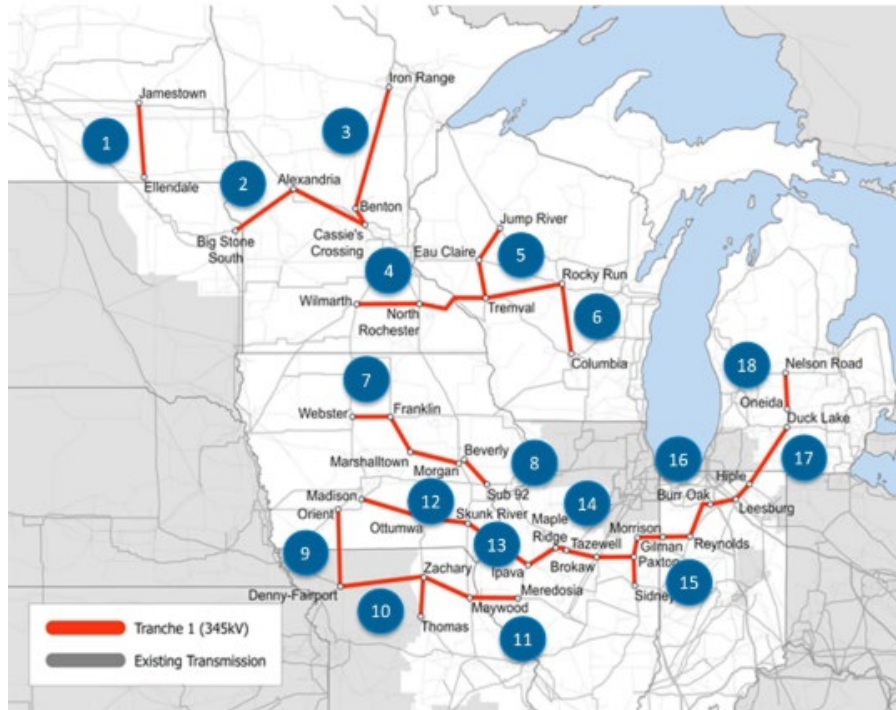


Figure 2.162: L RTP Tranche 1 Portfolio

The 2023 Near-Term Congestion Study model was utilized for this study with adjustments made to reflect random planned and forced, and construction outages.

Model assumptions include:

- Hitachi PROMOD⁷ releases
 - Fall 2021 gen updates and economic data
 - Spring 2022 coal prices
 - PROMOD 11.5 engine
- MTEP23 No Futures Assumptions model
 - Hartburg – Sabine was removed
 - Out of cycle projects were added if in-service date was before study window
- MTEP22 Year 2027 Summer Peak TA powerflow
- Resource utilization – generators with signed GIA additions and finalized retirement studies were included.

Operations Planning and Competitive Transmission teams supported the collection of outage information from Transmission Owners required for the study. Outage data was submitted directly to MISO teams through the MTEP Quarterly Update report and CROW. Operations Planning teams provided general guidelines and helped review potential reliability issues in outage information submitted.

General guidelines that have been used to develop and assess outage sequences include:

- Evaluate outages to minimize concurrent outages likely to strand or limit generation outlets.

⁷ PROMOD, Hitachi Energy owned, is a chronological security constrained unit commitment and economic dispatch tool that adheres to a wide variety of operating constraints.



- Evaluate outages to ensure that multiple outages do not impact the same interface and interchange as it would create a significant challenge to the system's reliability.
- Review and compare against historical outages that have been challenging for our system.

PROMOD studies are typically conducted with transmission system intact assumptions, excluding the contingencies included in the event file. The Near-Term Congestion Study used a similar methodology to the LRTP Tranche 2.1 Transmission Outages business case metric to create a base random planned and forced outages scenario. This allows us to compare the impact of LRTP Tranche 1 construction outages against more simulated “real-world” conditions. Approximately 2,450 random planned and forced outages were included in all runs with about 250 planned and 2,200 forced outages.

The construction outage scenarios studied include LRTP Tranche 1 construction outage sequences combined with random planned and forced outages. The scenarios studied range from currently planned sequences to worst case scenarios that would present more severe impacts on the system.

Outage sequences from Transmission Owners were incorporated in the testing and study work as they were received. For LRTP Tranche 1 projects where outages were not submitted, Economic Planning estimated outages by utilizing powerflow models and input from Operations Planning and Competitive Transmission teams. Approximately 220 Tranche 1 construction outages were submitted and estimated based on in-service date expectations with about half of those outages occurring in 2027. Figure 2.163 outlines how outages were incorporated to build the scenarios studied.

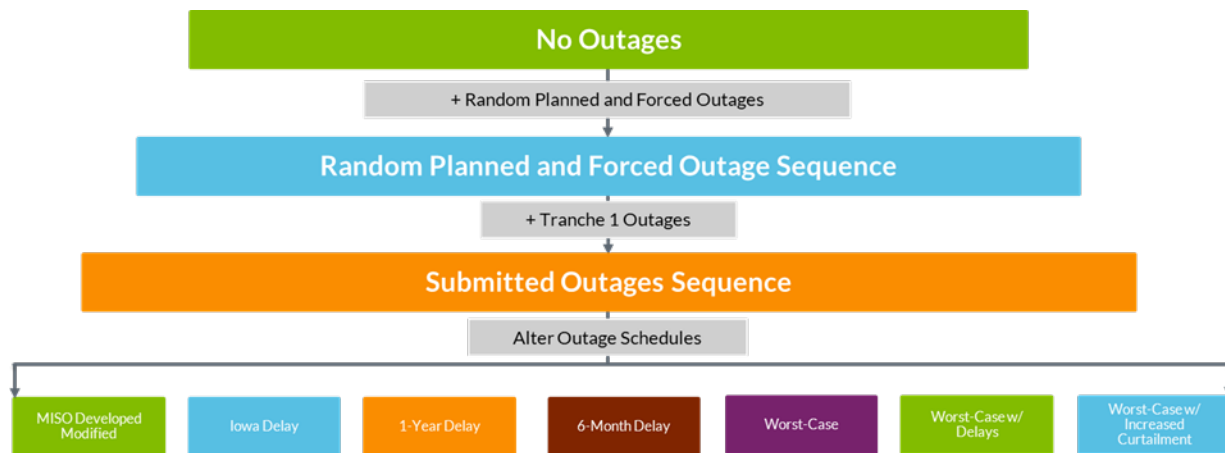


Figure 2.163: Process for Adding Outages and Building Scenarios

Study

Initial Testing

Testing for this study followed a path of simple to complex when it came to identifying outages and how they are included in the model. Initially, specific outages were entered into PROMOD. This worked for small amounts of outages but was not ideal for larger sequences of outages. By utilizing the PDTR (Power Dated Transmission Record) Tool in PAT (PROMOD Analysis Tool) and incorporating the LRTP Tranche 2.1 Transmission Outage business case outage methodology, we were able to come up with a more efficient process for incorporating outages.



Additional testing included comparing runs by Local Resource Zone (LRZ) versus region, and the impact of a larger number of outages within a year timeframe. Much of this testing was done to assess any impacts on runtime. Because PROMOD can only study one year at a time, we started by putting all outages in 2027 to test its capabilities. We then sequenced them between 2025-2030, with consistent lengths, followed by the same test with more realistic lengths. We also split the MISO footprint into multiple areas for these runs to analyze outages at a more localized level. Since we did not encounter any hurdles related to PROMOD run-times or processing, our study remained focused on the full MISO footprint.

Scenarios Studied

All sequences studied included random planned and forced outages and started with the Submitted Outages sequence. Adjustments or alterations were made to specific information in the Submitted Outages sequence relative to that scenario. Scenario descriptions and assumptions are listed below:

Submitted Outages (Base Outages)

Description

- Around 77% of all construction outage data was submitted by Transmission Owners and included in the sequence. The remaining 23% was estimated by the MISO Economic Planning Team with assistance from MISO Operations Planning and Competitive Transmission teams.
- All Iowa outages are estimated due to continued discussions around project ownership.

Assumptions

- Outages not submitted by Transmission Owners were estimated based off Tranche 1 line connection points. Start and end dates for outages were estimated by using in service dates and working with Competitive Transmission group to estimate outage durations.

6-Month Delay

Description

- Construction outages in the Submitted Outages sequence were pushed out by 6 months.

Assumptions

- Start dates were moved to the closest Monday and end dates were moved to the closest Sunday for PROMOD efficiency.

1-Year Delay

Description

- Construction outages in the Submitted Outages sequence were pushed out by 1 year.

Assumptions

- Start dates were moved to the closest Monday and end dates were moved to the closest Sunday for PROMOD efficiency.

MISO Developed Modified

Description

- All submitted outage information and estimated outages that were not related to Iowa projects.
- Outages for estimated construction outages were adjusted due to various combinations of outages possible using engineering judgement.

Assumptions

- Adjustments were developed by taking the initial outage schedule and flipping it. The right pieces would still connect by making sure that certain outages followed one another while still ensuring that dates would be changed. Projects remained the same length of time.



- For example: Outage A to B is from January to June and Outage C to D is from July to December. After making the adjustments, Project A to B is now from July to December and Project C to D is now from January to June. This ensures that outages are left in the same time frame but mixes up concurrent outages.

Iowa Delay

Description

- Outages related to Iowa projects were pushed out beyond the 2027 study year.

Assumptions

- Construction was assumed to be delayed due to ongoing discussions around Iowa project ownership. Outages were pushed out to 2028 and beyond.

Worst-Case

Description

- Outages are sourced from the Submitted Outages scenario but adjusted to all occur in 2027.

Assumptions

- Outages originally scheduled for 2027: These dates remain unchanged.
- Multi-year outages (e.g., Nov 2025–Feb 2026): These start on a comparable Monday in 2027 and conclude on the last Sunday of 2027.
- Outages originally scheduled outside of 2027: For outages scheduled in other years, we identified the same calendar date in 2027 and determined the corresponding day of the week. Based on this, we adjusted the start or end dates using the guidelines below:
 - Start date adjustments:
 - Outages that originally began on a Tuesday through Thursday were moved to the preceding Monday.
 - Outages that originally began on a Friday through Sunday were moved to the following Monday.
 - If the Monday is a national holiday, the outage is scheduled for the following Monday.
 - End date adjustments:
 - Outages that originally ended on a Monday through Wednesday are moved to the preceding Sunday.
 - Outages that originally ended on a Thursday through Saturday are moved to the following Sunday.
 - If the Sunday is a national holiday, the outage is scheduled for the following Sunday.

Worst-Case w/ Delays

Description

- Outages are pulled from the Submitted Outages scenario but adjusted to all occur in 2027 but with additional 1 to 2 month delays.

Assumptions

- Similar to the original Worst Case sequence, we assumed that all outages will occur in the year 2027, but with an additional 1 to 2 month delay to the original end dates. To complete this delayed scenario, the end dates for the outages were adjusted as follows:
 - Outages set to end between January and October: A 2-month delay was added to the original end date.
 - Outages set to end in November: A 1-month delay was applied.
 - Outages set to end in December: These were extended to the last Sunday of 2027.
- For the new end dates, we located the same day of the month in the adjusted period. If the corresponding day fell on a Monday through Wednesday, the outage was set to end on the



preceding Sunday. If it fell on a Thursday through Saturday, the outage was set to end on the following Sunday.

Worst-Case w/ Increased Curtailment

Description

- Outages are pulled from the Submitted Outages scenario but adjusted to all occur in 2027 but with additional 1 to 2 month delays.
- Additional outages are added intended to stress the system and increase curtailment.

Assumptions

- Utilizes assumptions from the Worst Case scenario.
- Additional outages added include:
 - MN & ND:
 - Loss of HVDC lines between Square Butte - Arrowhead
 - Loss of HVDC lines between Coal Creek - Dickinson
 - Loss of MWEX Lines (King - Eau Claire 345 kV, Arrowhead - Stone Lake 345 kV are main two)
 - Loss of lines parallel to MWEX (North Rochester - Briggs Road 345 kV or Hazelton - Hickory Creek 345 kV)
 - AMEREN:
 - Sibley - Overton 345 kV, Zachary - Hughes 345 kV
 - Lutesville - Essex 345 kV
 - Sidney - Rising 345 kV
 - Sub T - Maywood 345 kV
 - McCredie - Burns 345 kV
 - NIPS:
 - Wilton Center - Dumont 765 kV
 - Reynolds - Olive 345 kV
 - Reynolds - Meadow Lake 345 kV ckt 1
- Reynolds - Meadow Lake 345 kV ckt 2

2024 Near-Term Congestion Study Report

All information included in the Near-Term Congestion Study section of this chapter along with final study results and takeaways can be found in the 2024 Near-Term Congestion Study Report on the [MISO MTEP website](#) under the Related Documents section.



CHAPTER 3: INTERREGIONAL PLANNING

3.1 MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study

JTIQ Overview

Transmission has been at capacity along the MISO and Southwest Power Pool (SPP) seams, and both RTOs are undergoing a grid evolution that is driving the need for MISO's Reliability Imperative. Additional renewable resources and transmission capacity along the seams would benefit MISO and SPP markets as a whole but require costly network upgrades. Current study approaches have, historically, meant the needed network upgrade costs have been too costly for the small groups of interconnection customers to fund.

For several years, MISO and SPP have been coordinating to understand and address these transmission needs along the seams to meet FERC's Affected Systems Study (AFS) requirements. Both RTOs found that the AFS process limits our ability to appropriately address needs. Each RTO separately studies interconnection projects within its own cycles and the cycle of projects of its neighbors to determine their impact on their own system, with a focus only on issues caused by the projects in each individual cycle while impacts and potential benefits to subsequent queue cycles are out of study scope. The process is also subject to extensive delays because exact upgrades often change or get assigned to later cycles as customers exit the queue. Additionally, process, criteria and schedule differences between RTOs causes study delays and drives questions about the certainty of study results.

To tackle these challenges, MISO and SPP collaborated to initiate a new study process which reduces RTO differences and identifies more comprehensive, cost-effective and efficient upgrades that can meet the needs of multiple clusters of interconnection projects in both SPP and MISO. The JTIQ study kicked off in late 2020 with three key objectives.

1. Identify transmission constraints that limit or inhibit new generator interconnections in key locations along the MISO-SPP seams for which large transmission projects can lower the cost and improve the certainty of generator interconnections for multiple queue cycles.
2. Identify more comprehensive transmission projects to allow interconnection requests spanning multiple MISO and SPP queue cycles to connect at lower costs than what would be determined through an individual queue cycle. In doing so, the joint study identified projects that will better prepare both systems for future portfolio change.
3. Address barriers to study processes which negatively impacted customers by reducing the need for interconnection request-specific analysis.

JTIQ Portfolio and Benefits

Through collaboration between MISO and SPP, the JTIQ study identified five-transmission-projects. Those projects are noted in Table 3.2.1-1, with a projected cost of approximately \$1.65 billion.

The recommended JTIQ Portfolio is expected to fully address the set of transmission constraints evaluated in the JTIQ Study as being significant barriers to the development of new generation along the MISO-SPP



seam. In addition to these substantial reliability benefits, an estimated 28.6 GW of interregional generation enablement would be available to new generator interconnection projects near the seam. Additional benefits of the JTIQ framework include but are not limited to:

- Streamlined GI queue process to help ensure the timely build of projects and system reliability.
- Optimized network upgrades that enable more customers and reduce overall affected system costs.
- Greater cost certainty because the JTIQ Portfolio of projects is known, the amount of enablement (28GW) is known, and customers will pay their pro rata share of the JTIQ Portfolio.
- Greater timing certainty of projects as the unknown network upgrades, study costs and timing delays that are prevalent in the standard affected system study process are mitigated or are eliminated.
- Fewer delays because transmission construction can start before the portfolio is fully subscribed.
- Availability of U.S. Department of Energy (DOE) funding to reduce the overall costs of the projects in the portfolio (see below).



Figure 3.2.1-1: JTIQ Portfolio Map

JTIQ Portfolio	Location by RTO
Bison – Hankinson – Big Stone South 345 kV	MISO
Lyons Co.- Lakefield 345 kV	MISO
Raun – S3452 345 kV	MISO - SPP
Auburn – Hoyt 345 kV	SPP
Sibley - 345 kV Bus Reconfiguration	SPP
Total Cost of Portfolio of Projects	\$1.65B

Table 3.2.1-1: List of projects comprising the JTIQ Portfolio



DOE Grid Resilience and Innovation Partnership Grant

In collaboration with SPP, Minnesota Department of Commerce, Minnesota Commission, Transmission Owners and Great Plains Institute, MISO supported the application for partial funding of the JTIQ projects through the DOE Grid Innovation Program. On October 18th, 2023, the DOE announced approval of \$464 million in Grid Resilience and Innovation Partnerships (GRIP) program funds for the portfolio. This historic opportunity significantly reduces the estimated \$1.6 billion investment for the JTIQ projects and further enhances the value presented by completion of this portfolio.

Cost Allocation and Cost Sharing

Projects in the JTIQ Portfolio are Generator Interconnection Projects (GIP), as their sole purpose is to support the connection of interconnection projects. SPP's existing cost allocation method for Generator Interconnection Projects allocates 100% of the capital costs to the interconnection customers. MISO's methodology is the same for GIPs less than 345 kV, and those 345 kV or greater utilizing a 90% allocation to interconnection customers and 10% to load. Through negotiations with all parties and given the novel and innovative approach of JTIQ, it was determined that SPP's methodology would apply to this specific set of projects. This cost allocation methodology reflects the balancing of load and generation interests and accounts for the availability of DOE funding. Each generator interconnection customer included in the group and allocated costs of the JTIQ Portfolio will pay their share of capital costs based on the size of their facility in proportion to the total enabled MWs of the portfolio. Non-capital costs associated with the generator interconnection customer's share will be allocated consistent with each RTO's current regional Tariff.

Joint Operating Agreement (JOA) and Tariff updates

The proposed MISO-SPP JOA captures changes in the planning processes, Affected System Study process, and allocation of costs between the two RTOs. MISO and SPP, in collaboration with their stakeholders, have filed a number of changes to the JOA and respective regional tariffs. Once these changes are approved by FERC, the RTOs will seek approval by their respective Board of Directors.

Summary of MISO JOA/Tariff Changes:

- Joint Operating Agreement (JOA) revisions to establish the overall framework.
- Modifications to Attachment X and related Appendices Business Practice Manuals, and Generator Interconnection Agreement (GIA) have been or will be made.
- New agreements for JTIQ participation have been added as part of the pro forma GIA. Module A and Attachment FF are clarified and augmented to capture that the existing Generator Interconnection Project category and cost allocation applies to this JTIQ Portfolio.
- New Attachments and Schedules detail how costs will be charged to generator interconnection customers and MISO load.



3.2 MISO-PJM Interregional Transfer Capability Study

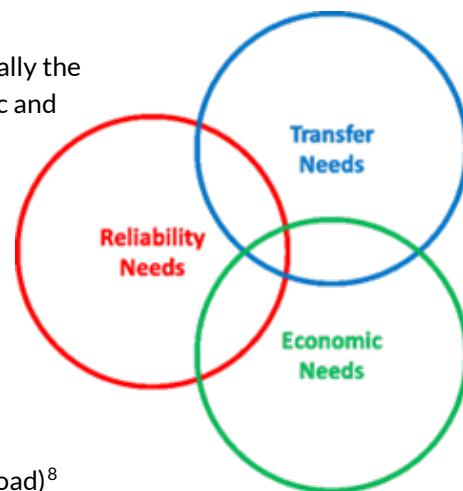
PJM and MISO have a long history of performing coordinated interregional transmission planning. Interregional planning helps identify transmission projects that improve the system's ability to mitigate constraints, respond to extreme weather, and increase interregional transfer capability. This study was devised outside of pre-existing Joint Operating Agreement (JOA) procedures in order to evaluate a holistic set of future system needs along the seam. Study work began mid-2024 and the RTOs anticipate sharing results and discussing next steps with stakeholders in the first half of 2025.

Study Highlights:

- PJM and MISO designed a study to identify near-term upgrades that incrementally enhance transfer capability between the two RTOs, with a focus on both addressing near-term needs and building a framework for future long-term planning efforts along the PJM-MISO seam with Order 1920
- The study includes reliability, economic, and transfer analysis using forward-looking models and assumptions (2032 Models)
- Following the study, MISO and PJM will partner with states and stakeholders to identify and pursue JOA/Tariff adjustments as needed to bring solutions forward for implementation

Study scope and approach:

The analysis will focus on the transmission system along the RTO seams, specifically the MISO Classic and PJM West regions. The RTOs will evaluate reliability, economic and transfer-capability needs. No common model will be used; instead, consistent scenarios will be designed for each RTO's models. The RTOs will analyze the scenarios using both PJM and MISO models. MISO and PJM are exploring the options of a blended model for joint modeling.



Models:

- MISO 2032 LRTP F2A Reliability Core Model set (summer, winter, light load, and average load)
- MISO 2032 LRTP F2A Economic (PROMOD Model)
- PJM 2032 LTRTP Blended Reliability Model (summer, winter, and light load)⁸
- PJM 2032 LTRTP Blended Economic Model (PROMOD Model)¹

⁸ PJM developed a blended reliability and economic model consisting of MISO footprint F2A and PJM footprint Long-Term Regional Transmission Planning (LTRTP) Assumptions



Scenarios/Analysis:

- Economic/PROMOD: Congestion analysis
- Reliability Analysis: Steady state reliability analysis
- Informational Transfer Analysis: Reliability Base Case to improve incremental transfer capability
- Informational Extreme Weather Analysis: scenario in the winter, for example Winter Storms Uri and Elliott including high RTO-RTO transfers, storm load levels, and generation outages

Solutions Guidance:

PJM and MISO will share summarized results and issues with stakeholders. Potential solutions will address needs using existing right-of-way, terminal equipment or transformers. This study, along with Order 1920, will pave the way for future studies focused on longer-term needs and greenfield solutions.⁹



Interfaces considered for transfer analysis

3.3 MISO-SPP Interregional Study

SPP and MISO have a long history of performing coordinated interregional transmission planning. Interregional planning helps identify transmission projects that improve the system's ability to mitigate constraints, respond to extreme weather, and increase interregional transfer capability. This study was devised similar to the PJM study effort in order to evaluate a holistic set of future system needs along the seam. To pursue this study in place of a Coordinated System Plan (CSP) as defined in the MISO-SPP Joint Operating Agreement (JOA), MISO and SPP must seek relief from FERC from their interregional planning requirements to conduct a CSP every two years. Scope revisions and study work will continue thru 2025, and the RTOs will share progress and discussing next steps with stakeholders throughout the process.

Study Highlights:

- SPP and MISO designed a study to identify near-term upgrades that incrementally enhance transfer capability and yield multiple benefits across the two RTOs
- The study includes reliability, economic, and transfer analysis using forward-looking models and assumptions
- SPP and MISO will partner with states and stakeholders to identify and pursue JOA/Tariff adjustments as needed to bring solutions forward for recommendation and approval
- The RTO's study work will continue through 2025

⁹ The RTOs are also monitoring pending industry interregional transfer capability studies including the NERC ITCS



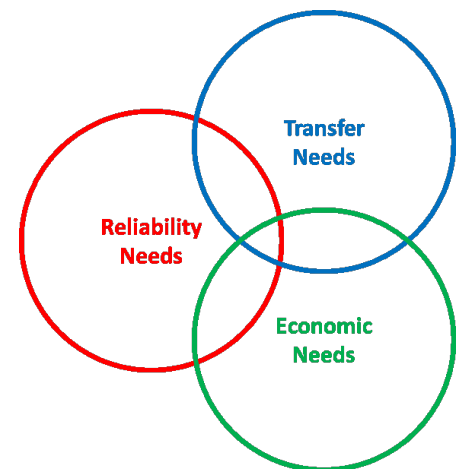
Solutions Guidance:

- Solutions will increase transfer capability incrementally by a range of future determined GWs
- Seek a balance of investment in each RTO
- Priority will be immediately actionable enhancements such as upgrades that use existing right-of-way, terminal equipment, or transformers
- Greenfield transmission development may be considered as appropriate

Planning Models:

RTOs will pursue use of blended models in parallel with existing SPP and MISO regional models for Economic (PROMOD) and Reliability models. Three to four Reliability Base Case Models (e.g. winter, summer, average load, and light load) will be targeted:

- MISO 2032 LRTP F2A Reliability Core Model set
- SPP 2025 ITP Model set (2029; 2034)
- MISO 2032 LRTP F2A Economic (PROMOD Model)
- SPP 2025 ITP Model set (2029; 2034)



Scenarios/Analysis:

- Economic/PROMOD: Congestion analysis
- Reliability Analysis: Steady state reliability analysis
- Transfer Analysis: Study to improve first contingency incremental transfer capability (FCITC)
- Extreme Weather Analysis: scenario in the winter, for example Winter Storms Uri and Elliott including high RTO-RTO transfers, storm load levels, and generation outages
- Others to be determined, if/as needed, for final scope direction

JOA and Cost Allocation Considerations:

- The RTOs will pursue JOA revisions regarding project types and cost allocation in parallel with study work
- A multi-benefit style project type and cost allocation is desired by both RTOs to draw on a broader set of benefits for project recommendations
 - Utilizing guidance/direction from FERC Order 1920



CHAPTER 4: LOCAL RELIABILITY PLANNING

4.1 Local MTEP24 Investment Summary

The local MTEP24 portfolio consists of 459 new Appendix A projects (Figure 4.1-1) and represents over \$6.7 billion in transmission infrastructure investment for the MISO region. Of these projects, 310 are classified as Other projects, 111 Generator Interconnection Projects, 36 Baseline Reliability Projects, and two Transmission Delivery Service Projects. The two large Transmission Delivery Service Projects are aimed at modernizing HVDC converter stations and upgrading the capacity of a HVDC transmission line within Minnesota Power territory.

Of the over \$4.0 billion investment in Other projects, 39% are driven by age and condition issues, 37% by load growth, and 20% by local reliability issues. The majority of Other projects address localized reliability issues that are due to load serving needs and aging transmission infrastructure.

Local MTEP24 Appendix A Project Investment Summary (Data as of August 27, 2024; \$M, % of total investment dollars)

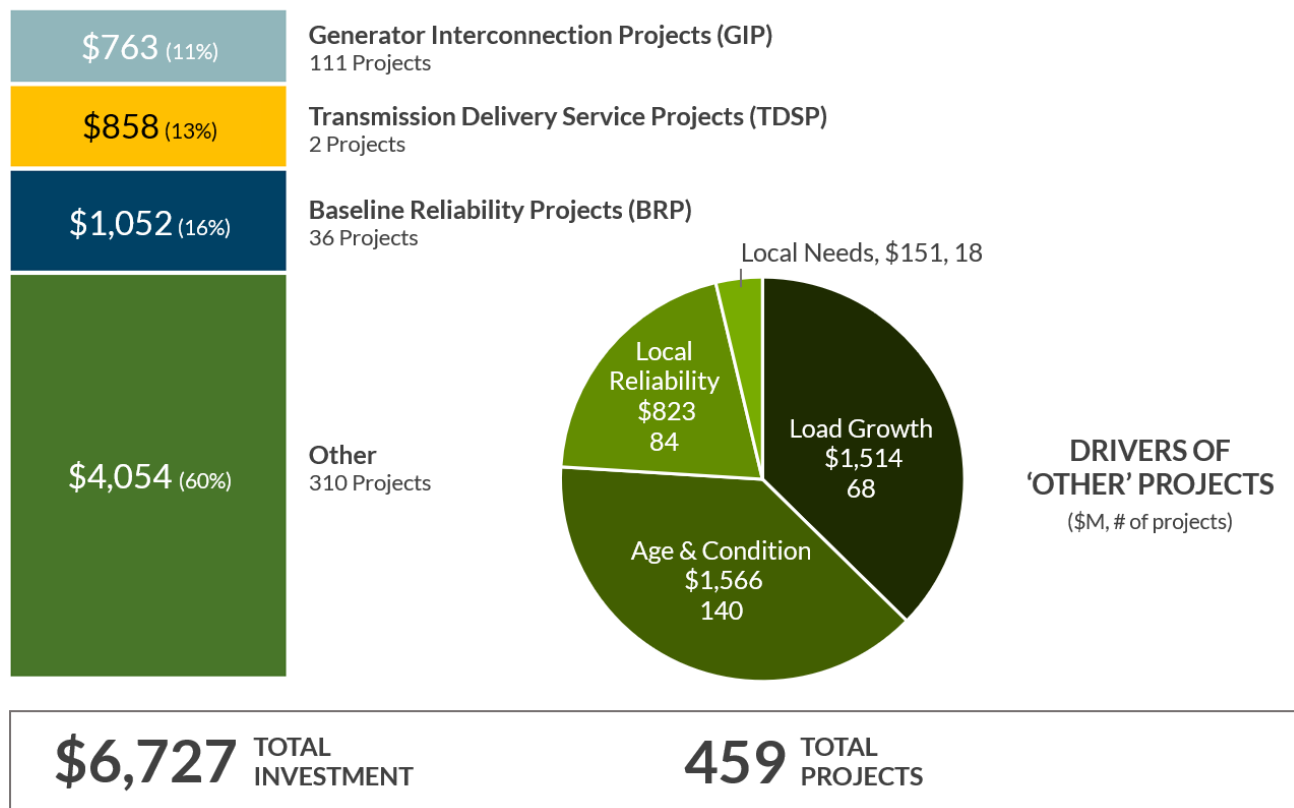


Figure 4.1-1: Local Appendix A project investment summary (data as of 8-27-2024).



Table 4.1-1 summarizes local MTEP24 projects by planning regions, project categories, and number of projects within each region.

Local MTEP24 Appendix A Project Investment Summary

(Data as of August 27, 2024; \$M, number of projects, and % of total investment dollars)

Planning Region	Baseline Reliability Project (BRP)	Generator Interconnection Project (GIP)	Other Project	Transmission Delivery Service Project (TDSP)	Total	# of Projects
Central	\$77	\$190	\$1,149		\$1,416	127
East	\$155	\$178	\$438		\$771	77
South	\$737	\$232	\$903		\$1,872	63
West	\$83	\$162	\$1,563	\$858	\$2,667	192
Total	\$1,052	\$763	\$4,054	\$858	\$6,727	459

Table 4.1-1: Local Appendix A project investment summary (data as of 8-27-2024).

The local MTEP24 projects are distributed across MISO’s entire footprint (Figure 4.1-2). Because of the two large Transmission Delivery Service Projects, 40% of the total investment is dedicated to projects in the West subregion. The rest of the total investment is shared between the remaining three subregions: 28% for the South, 21% for the Central and 11% for the East.

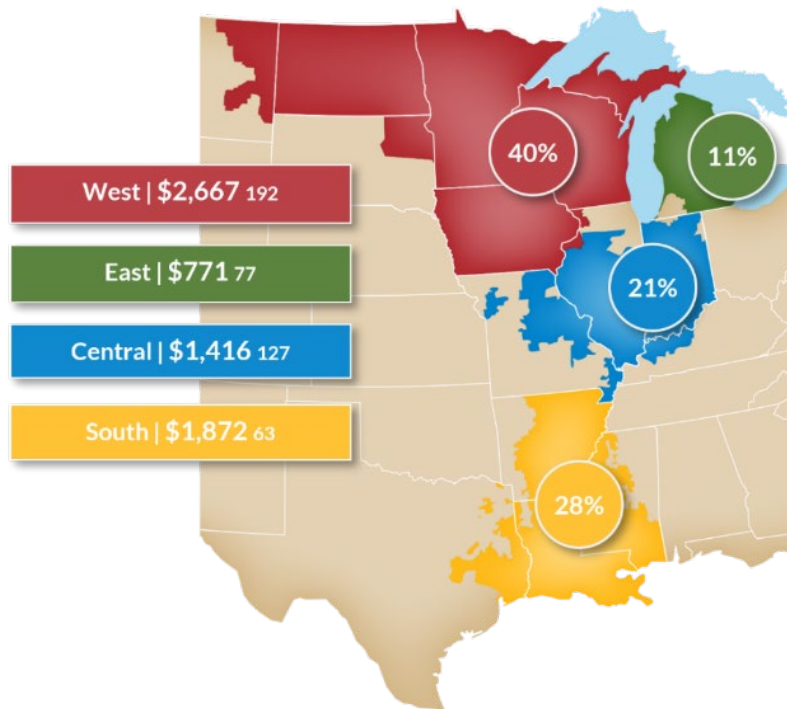


Figure 4.1-2: Local Appendix A project investment summary (data as of 8-27-2024).



Within the local MTEP24 projects, the top ten projects represent roughly 31%, or \$2.1 billion of the total \$6.7 billion investment and are in three of the four planning regions (Figure 4.1-3). Out of the top ten projects, 60% are Other – Load Growth projects, 60% were submitted through the Expedited Project Review process and 60% are in the South.

Top 10 Local MTEP24 Appendix A Projects

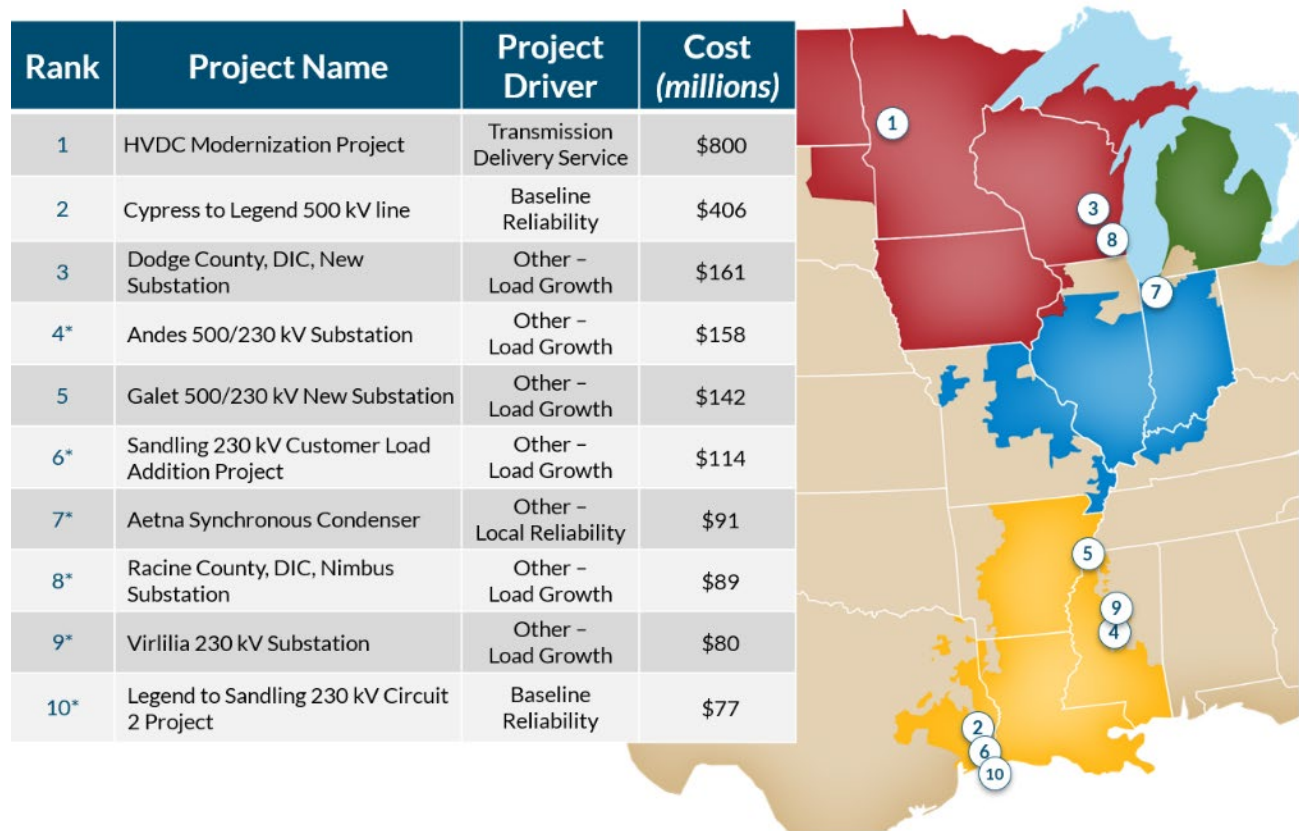


Figure 4.1-3: List of top ten local MTEP24 projects as of August 27, 2024, blanket renewal projects excluded from ranking, and * represents projects studied through Expedited Project Review (EPR) process.

Of the total projects for the local component of MTEP24, 83% percent are projected to go into service within the next three years (Figure 4.1-4).



Local MTEP24 Projects by Estimated In-Service Year

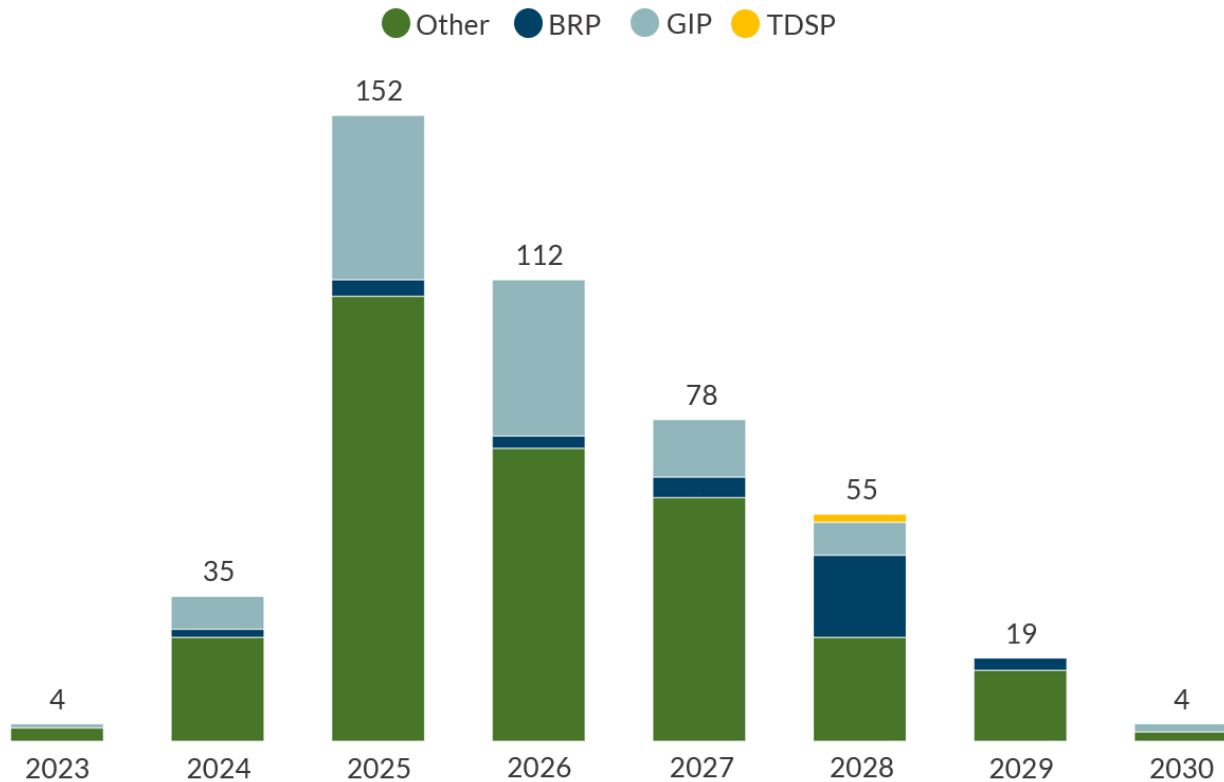


Figure 4.1-4: Number of local MTEP24 Projects by In-Service Year (data as of 8-27-24).

Facility Type

Each MTEP project is composed of one or more facilities, where each facility represents an individual element of the project. Examples of facilities include substations, transformers, voltage devices, circuit breakers or various types of transmission lines (Figure 4.1-5).

The largest share (43%) of facility investment in the local MTEP24 cycle is dedicated to substation or switching station related construction and maintenance. This includes completely new substations as well as terminal equipment work, circuit breaker additions and replacements. Twenty-four percent is dedicated to line upgrades which includes rebuilds, conversions, and relocations. Fourteen percent is dedicated to new lines on new right-of-way in MISO. The remaining 19% of facility costs are dedicated between voltage devices, transformers, and miscellaneous categories.



Local MTEP24 Transmission Investment by Facility Type

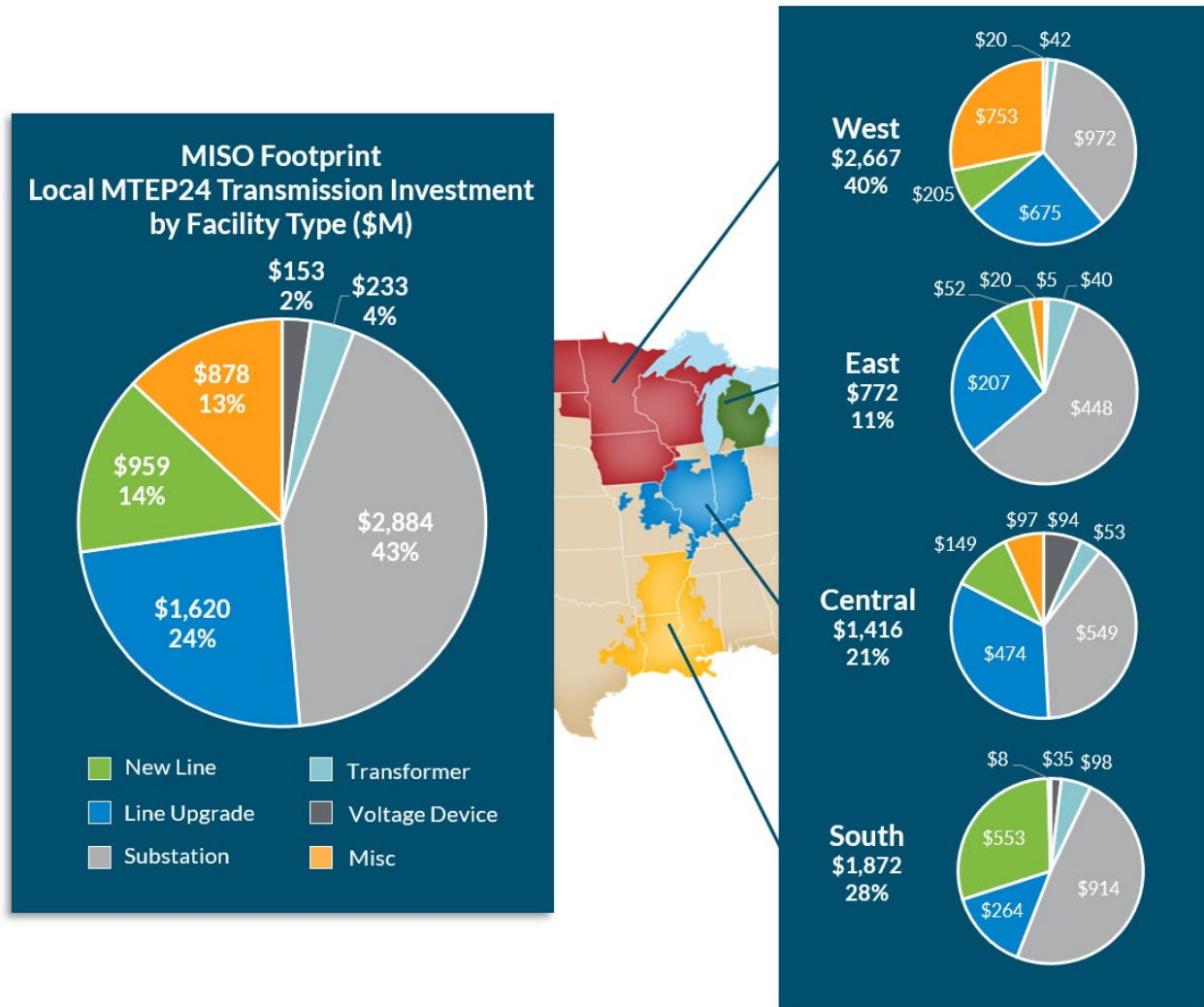


Figure 4.1-5: Facility type investment for new local MTEP24 Appendix A projects by planning region (as of 8-27-24).



New local Appendix A projects can be broken down at a facility level and are spread over 14 states (Figure 4.1-6). These geographic trends vary greatly year to year depending on local needs due to varying asset renewal programs or as existing transmission capacity is consumed and new build becomes necessary. This year truly shows the investment at a facility level spanning between all subregions.

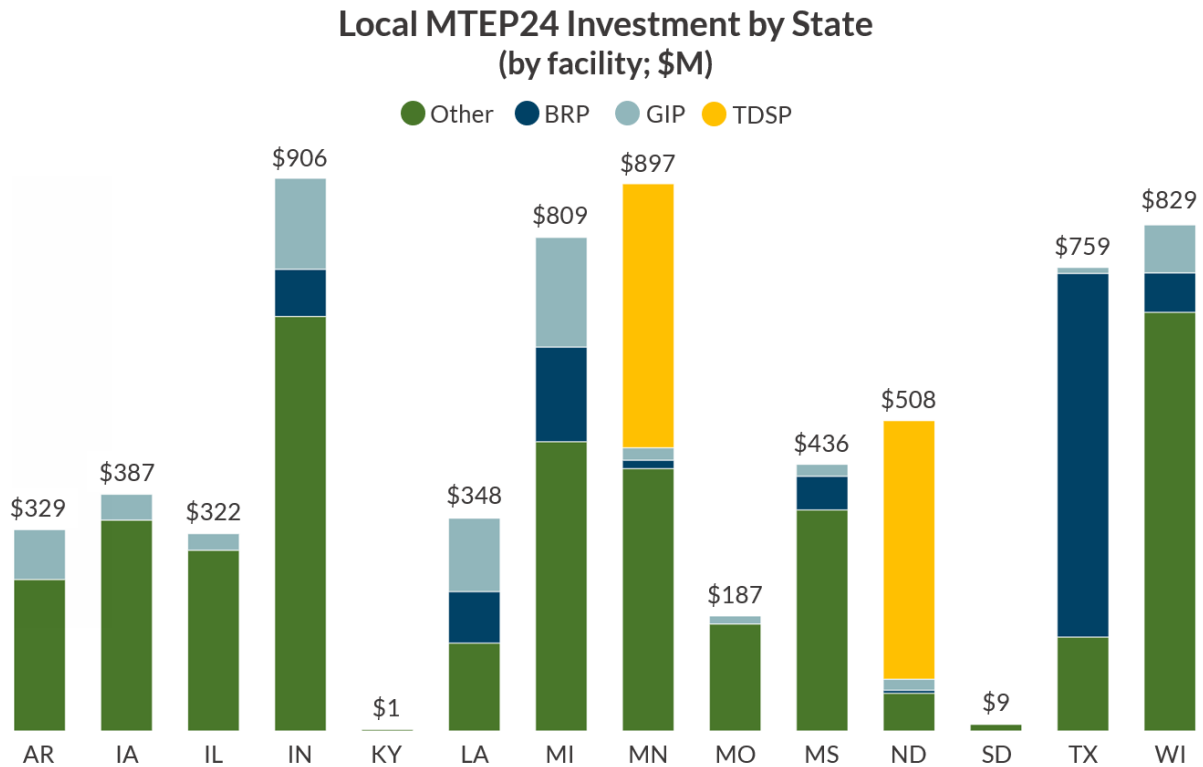
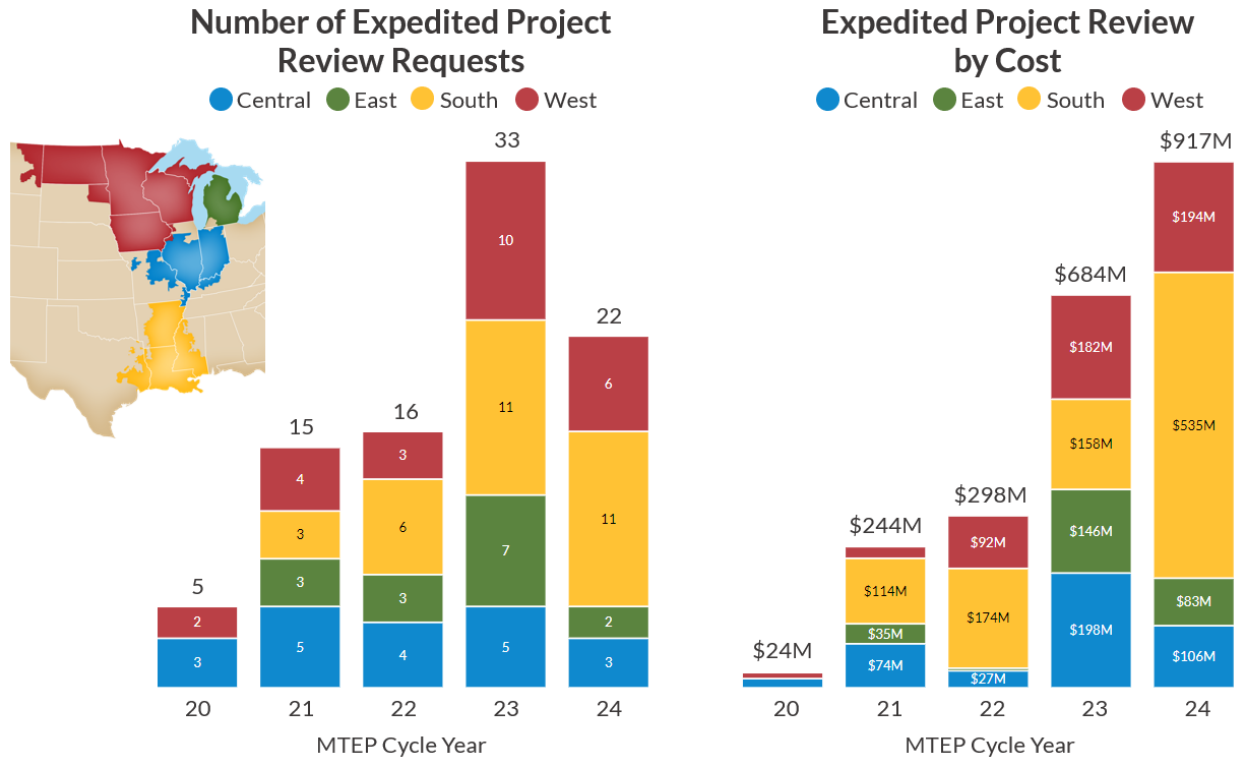


Figure 4.1-6: Local MTEP24 Appendix A investment categorized at a facility-level by state (as of 8-27-24).

Out of the 459 local MTEP24 projects submitted in this cycle, MISO Planning Engineers received and evaluated 22 Expedited Project Review (EPR) requests (Figure 4.1-7). These projects are approved in a quicker approval process because of immediate system needs. More information on these projects is included in Section 4.2. The volume of EPRs continue to be driven by the accelerating new load growth trends seen in previous MTEP cycles.



Expedited Project Review Drivers

DOT Project (Department of Transportation) Load Reliability Retirement

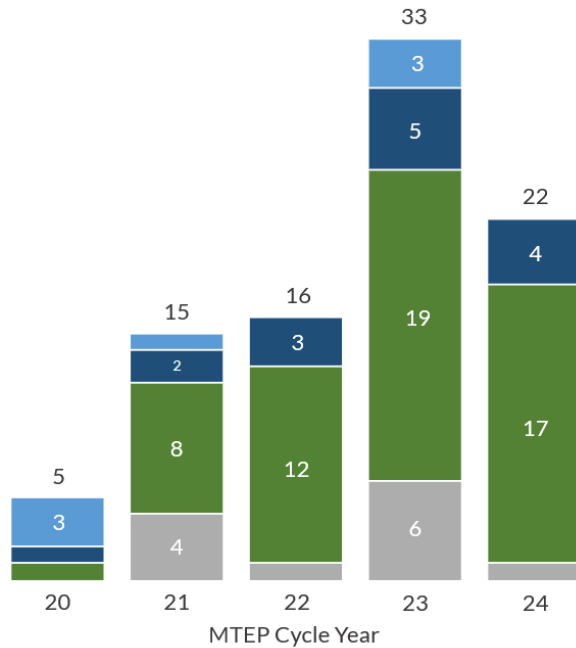


Figure 4.1-7: History on projects studied through the Expedited Project Review (EPR) process.



Local MTEP24 New and Upgraded Line Miles

The local MTEP24 Appendix A projects total approximately 932 miles of new or upgraded lines (shown in Figure 4.1-8). Of the total, forty-two percent of new or upgraded line miles will go into service within the next three years, or 90% within five years. There are 775 line miles, or 83% of the total line miles, that are 161 kV or below. There are 157 line miles are projected at 230 kV or above.

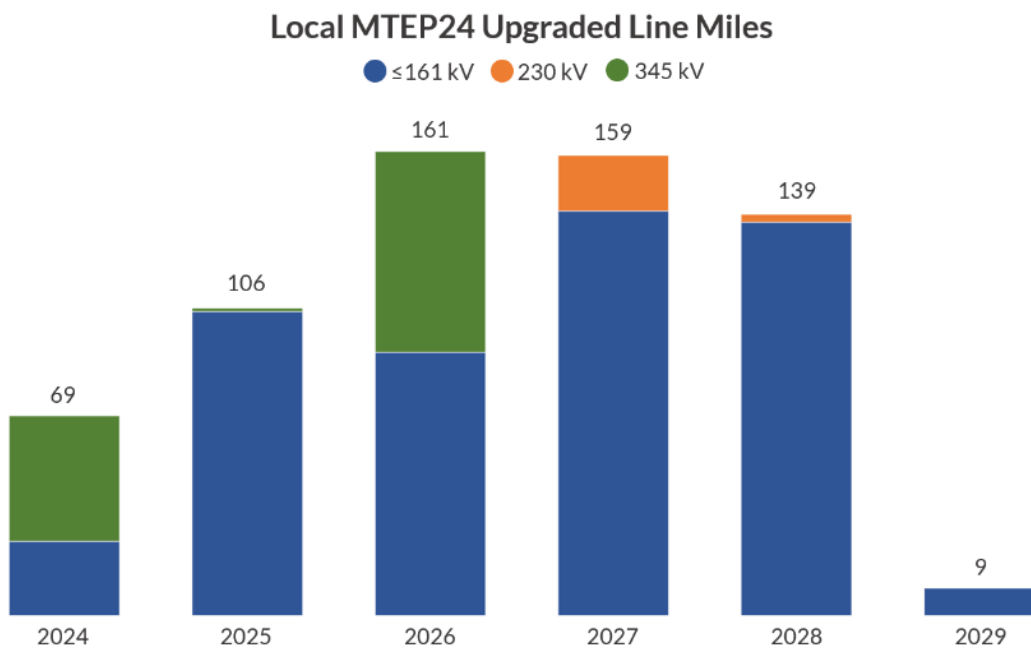
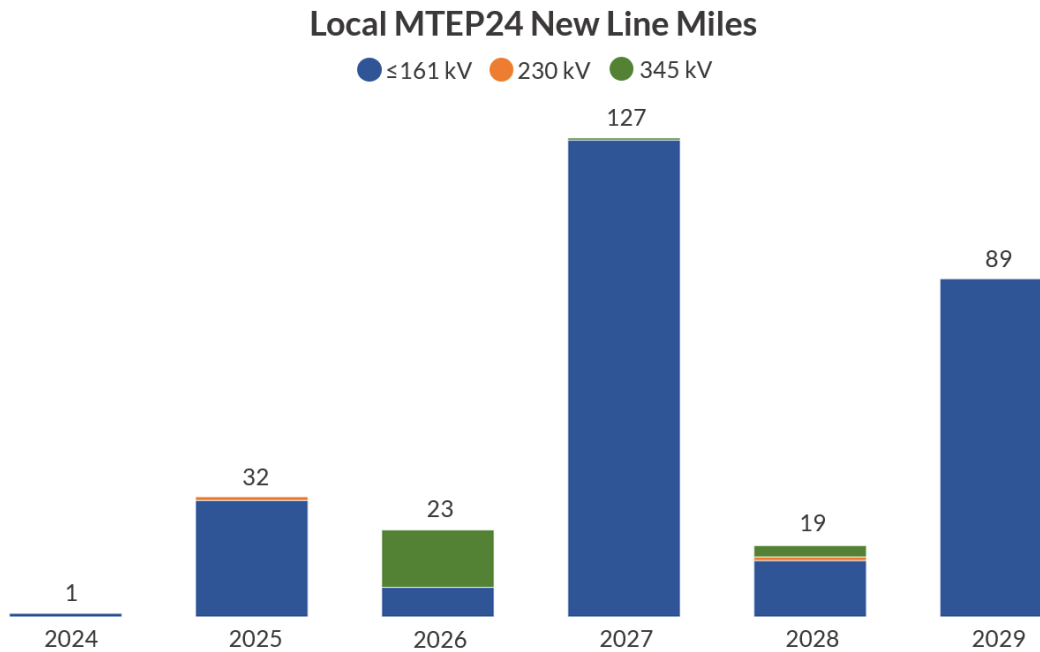


Figure 4.1-8: New and upgraded line miles proposed in local MTEP24 Appendix A projects (as of 8-27-24).



Allocation of Costs

The local MTEP24 projects includes a total of 35 new cost-share eligible Generator Interconnection Projects (GIPs) for Appendix A. GIP costs are primarily paid for by the interconnecting customer (generator), however, a portion of the costs for certain network upgrades are eligible for regional cost allocation under Attachment FF of the MISO Tariff. Detailed allocations by pricing zone are provided in Appendix A1.

Indicative rates related to past MTEP cost-shared projects are calculated on an annual basis. Please refer to the reports ([indicative forecasts of annual charges](#)) posted on the MISO public website¹⁰.

MTEP Appendix B

MTEP Appendix B contains all projects that have been validated by MISO as the preferred solution to address an identified system need based on current information and forecasts, but where it is prudent to defer the final recommendation of a solution to a subsequent MTEP cycle.

This generally occurs when the preferred project does not yet need a commitment based on anticipated lead-time and there is still some uncertainty as to the prudence of selecting this project over an alternative project given potential changes in projected future conditions. MTEP Appendix B is limited to Baseline Reliability Projects and Other Projects and will be reviewed by MISO in subsequent cycles.

4.2 Reliability Assessment and Compliance

MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure the continued system reliability in compliance with applicable local and regional reliability standards. The reliability assessment process for local MTEP24 projects (shown in Figure 4.1-1) began with a roll-up of issues and potential solutions from the NERC assessment of the prior MTEP cycle and from the local planning processes of Transmission Owners (TOs). Following this step, MISO conducted an independent reliability assessment to evaluate and integrate the TO local planning information into the development of the overall MTEP.

MISO closely coordinates the annual reliability assessment with other planning efforts to ensure the transmission expansion plan is identified in an efficient and cost-effective manner. A variety of factors are considered as part of MISO's transmission expansion plan development, including but not limited to, urgency of needs, cost effectiveness of solutions, system performance of solution alternatives to address identified transmission issues, and other considerations such as lead time to develop a project, right-of-way (ROW) or substation impacts, expandability, operational flexibility, etc.

¹⁰ Cost Allocation updates web address: <https://www.misoenergy.org/planning/planning/schedule-26-and-26a-indicative-reports/>

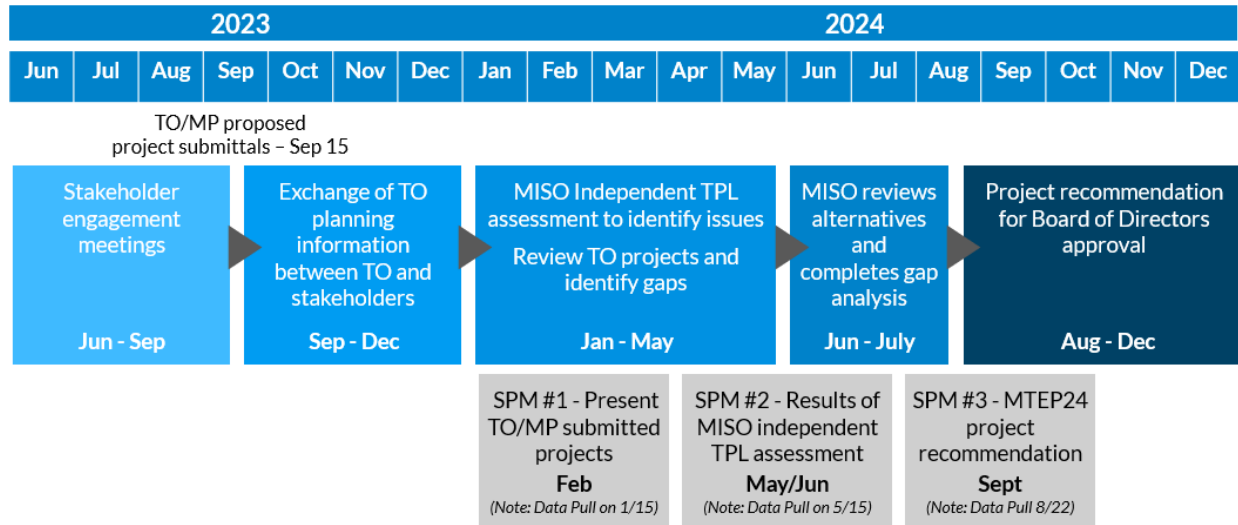


Figure 4.2-1: Local MTEP24 reliability assessment process.

In conjunction with the MTEP planning process, an inclusive, transparent stakeholder process is utilized to facilitate open discussions and allow stakeholders to provide early and meaningful inputs into the development of transmission solutions in each planning cycle. The results of MISO’s independent reliability assessments, along with proposed solution alternatives, are presented to stakeholders through a series of public Sub-regional Planning Meetings (SPM), and additional Technical Study Task Force (TSTF) meetings as needed, for each of the four MISO planning sub-regions: Central, East, South, and West.

MISO strategically set up our local planning processes to assume FERC Order 890 transparency requirements for Transmission Owner submissions resulting in different study approaches based on the types of projects submitted by Transmission Owners.

- **Verify need:** Confirmation of system need identified in project submission including to meet compliance with applicable National Electric Reliability Organization (NERC) reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. MISO must verify the need for alternatives to adequately examine their effectiveness.
- **No harm:** Ensure a submitted project does not create a system issue. Includes projects that create model changes like contingency definitions, line ratings, or line impedances.
- **Post only:** Provided for FERC Order 890 transparency provisions. May include controls equipment to communicate remotely with the facility. This information is not able to be represented with model changes.

Alternatives for projects may be completed prior to submission to MISO by the Transmission Owners, proposed by MISO, or proposed by stakeholders. Alternative criteria considers cost comparisons, feasibility to construct and how reliability needs are resolved. Alternatives do not always result in one project replacing another, instead they tend to be additive to the original project, even when submitted with the thought that they would directly compete. MISO considers alternatives in multiple forms, including like-for-like replacement, regional reliability projects, the combination of multiple local solutions, and other options identified through either MISO analysis or submitted by stakeholders.



After MISO completes its independent review of all proposed projects and associated alternatives and addresses stakeholder feedback received through SPM discussions, MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval. These projects make up Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs of the MISO reliability assessments. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

The complete results of local MTEP24 reliability assessments are detailed in Appendices D3-D10 of the MTEP24 report, which are available on the [MISO ShareFile site](#) and subject to Critical Energy Infrastructure Information (CEII) and non-disclosure agreements. These results serve as compliance evidence for a variety of NERC planning standards listed on the [MISO public website](#).

As appropriate, an executive summary of results for the appendix will be available on the MISO website.

Appendix	Title	Insights
D3	Steady State CEII	MISO ran N-1, N-1-1, spare equipment, planned outages, adjacent, and extreme event contingency analysis to identify any voltage and thermal violations in the MISO area. For local MTEP24 projects, over 400,000 issues were identified, and all valid results contain a corrective action plan to mitigate the violation.
D4	Voltage Stability CEII	MISO studied seven interfaces for voltage stability. The results have been reviewed with impacted parties.
D5	Transient Stability CEII	MISO is currently running over 4,000 dynamic disturbances to identify any violations on the system and will post issues for stakeholder comments after MISO reviews the results.
D6	Generator Deliverability CEII	MISO conducts the Annual MTEP Deliverability Analysis to ensure the ongoing deliverability of existing Network Resources (NRs). Affected stakeholders have reviewed the preliminary results for MTEP24, which are currently in progress.
D7	Contingency Coverage CEII	MISO received 247,718 steady state contingencies from 39 Transmission Owners to be used in MTEP24 contingency analysis. There were an additional 11,951 contingencies added by MISO to ensure full coverage.
D8	Nuclear Plant Interface Coordination CEII	MISO incorporated NPIRs into the MTEP24 analyses, adhering to Nuclear Plant Operating Agreements. MISO monitored steady state analysis, transient stability, and extreme events for nuclear plants in the MISO footprint and addressed any constraints by implementing mitigations necessary to adhere to NPIRs.
D9	Planning Horizon Transfer Capability CEII	MISO performed an Interregional Transfer Capability Study in collaboration with NERC ITCSI. In the MTEP24 Transfer Capability study the transfer limit of Illinois import interface has been identified.
D10	Short Circuit Analysis CEII	For local MTEP24, TO transmission planners have performed a short-circuit analysis to determine whether their circuit breakers have the expected interrupting capability for faults. If the short-circuit current interrupting duty on a circuit breaker exceeds the equipment rating, the TO transmission planner has provided MISO a corrective action plan to mitigate the violation.



Local MTEP24 project recommendations

The local MTEP24 portfolio consists of 459 proposed projects totaling over \$6.7 billion in investment from 37 Transmission Owners across MISO’s footprint. Table 4.2-1 provides a quick glance into local MTEP24 Appendix A project investment summarized by category and planning region. Table 4.2-2 provides a quick summary of each Transmission Owner’s number of projects and estimated investment totals being considered. Project justification details of the recommended local Appendix A projects are summarized in the following subsections for each of the four MISO planning subregions. All project details are available on the [MTEP Portal](#) on MISO’s public website and were pulled as of August 27, 2024.

Local MTEP24 Appendix A Project Investment Summary

(Data as of August 27, 2024; \$M, number of projects, and % of total investment dollars)

Planning Region	Baseline Reliability Project (BRP)	Generator Interconnection Project (GIP)	Other Project	Transmission Delivery Service Project (TDSP)	Total	# of Projects
Central	\$77	\$190	\$1,149		\$1,416	127
East	\$155	\$178	\$438		\$771	77
South	\$737	\$232	\$903		\$1,872	63
West	\$83	\$162	\$1,563	\$858	\$2,667	192
Total	\$1,052	\$763	\$4,054	\$858	\$6,727	459

Table 4.2-1: Local MTEP24 Appendix A new project investment summary (as of 8-27-2024).



Transmission Owners	Baseline Reliability Projects		Generator Interconnection Projects		Other		Transmission Delivery Service Projects		Grand Total	
	#	\$M	#	\$M	#	\$M	#	\$M	#	\$M
Ameren Illinois			5	\$41	18	\$197			23	\$238
Ameren Missouri			1	\$0	10	\$105			11	\$105
Ameren Transmission Company of Illinois					2	\$5			2	\$5
American Transmission Company	1	\$65	10	\$80	31	\$650			42	\$794
Arkansas Electric Cooperative Corporation					4	\$24			4	\$24
Big Rivers Electric Corporation			2	\$0					2	\$0
Henderson, KY, Municipal Power & Light					1	\$1			1	\$1
City Water & Light Plant of Jonesboro, AR					1	\$1			1	\$1
Cleco Power LLC			5	\$65	1	\$21			6	\$86
Dairyland Power Cooperative			2	\$21					2	\$21
Duke Energy Indiana	2	\$65	7	\$96	11	\$154			20	\$316
Entergy Arkansas			7	\$82	6	\$222			13	\$304
Entergy Louisiana	6	\$85	4	\$55	5	\$121			15	\$261
Entergy Mississippi	1	\$55	1	\$20	4	\$330			6	\$405
Entergy Texas, Inc	6	\$597	1	\$10	2	\$153			9	\$759
Great River Energy					24	\$189			24	\$189
Hoosier Energy			4	\$18	2	\$93			6	\$111
Indianapolis Power & Light Company	1	\$12	1	\$3	18	\$159			20	\$174
ITC	2	\$23	14	\$57	8	\$155			24	\$235
ITC Midwest			12	\$20	16	\$198			28	\$218
Lafayette Utilities System			1	\$1					1	\$1
Michigan Electric Transmission Co.	12	\$114	27	\$121	11	\$223			50	\$459
MidAmerican Energy Co.			2	\$24	23	\$177			25	\$200
Minnesota Power Inc.	2	\$0.5			4	\$39	2	\$858	8	\$897
Minnkota Power Cooperative, Inc					3	\$15			3	\$15
Missouri River Energy Services					1	\$2			1	\$2
Montana-Dakota Utilities Co.	1	\$5	1	\$18	3	\$33			5	\$56
Northern Indiana Public Service Company			3	\$12	2	\$103			5	\$115
Northern States Power Company	1	\$13			40	\$225			41	\$238
Northwestern Wisconsin Electric Co.					1	\$1			1	\$1
Otter Tail Power Company					10	\$32			10	\$32
Prairie Power, Inc.					8	\$101			8	\$101
South Mississippi Electric Power Association					8	\$31			8	\$31
Southern Indiana Gas & Electric Co.			1	\$20	26	\$169			27	\$189
Southern Minnesota Municipal Power Agency					2	\$4			2	\$4
Wabash Valley Power Association, Inc					2	\$61			2	\$61
Wolverine Power Supply Cooperative, Inc	1	\$18			2	\$60			3	\$77
	36	\$1,052	111	\$763	310	\$4,054	2	\$858	459	\$6,727

Table 4.2-2: Local MTEP24 Appendix A new project investment and totals by Transmission Owners (as of 8-27-2024).



MISO also considered alternatives for two projects in the East region and one project in the South. As a result of the alternative analysis, MISO selected two of the original projects and one alternative. Below are the projects that were submitted and evaluated as alternatives. More details are shared about these alternatives in the following sub-sections.

	Project Name	Planning Region	MISO Recommendation
1	Rebuild Benson to Stephens 120 kV Line	East	Not selected due to not meeting Local Planning Criteria
2	Iosco-Karn 138 kV Relocation	East	Recommended for approval in MTEP24 due to cost savings
3	Hartburg to Sabine 500 kV Line (as submitted and approved in MTEP17)	South	Not selected due to better reliability performance by original project

In accordance with Attachment FF of the tariff, in the event a Transmission Owner determines that system conditions warrant the urgent development of system enhancements, an expedited review of the impacts of the project can be requested. MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) and decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. Out of the 459 local MTEP24 projects submitted in this cycle, MISO Planning Engineers received and evaluated 22 Expedited Project Review (EPR) requests. New load interconnections account for over 77% of the EPR requests submitted, and 50% are located in the South planning region. The following local MTEP24 projects were submitted through the Expedited Project Review (EPR) process:

	Project ID	Project Name	Planning Region	Current Cost (\$M)
1	24958	Sandling 230 kV Customer Load Addition Project	South	\$114
2	24959	Kolbs to Port Acres 230 kV upgrade project	South	\$17
3	24960	Legend to Sandling 230 kV Circuit 2 Project	South	\$77
4	25214	Virililia 230 kV Substation	South	\$80
5	25215	Andes 500/230 kV Substation	South	\$158
6	25229	Costas 230 kV Substation	South	\$45
7	25299	Racine County, DIC, Nimbus Substation	West	\$89
8	25301	Leola load addition	West	\$4
9	25321	Winnebago City Substation Interconnection	West	\$8
10	25544	JCWL - Commerce to Ringier 69kV Rebuild	South	\$1
11	50011	Weeks Island Sub	South	\$21
12	50037	Ellendale load 2 addition	West	\$17



	Project ID	Project Name	Planning Region	Current Cost (\$M)
13	50038	Project Phoenix-Husky Substation	East	\$50
14	50086	Load addition at Montgomery 161 kV Substation	Central	\$3
15	50089	Aetna Synchronous Condenser	Central	\$91
16	50094	Northstar	South	\$7
17	50099	Lewisville West Capacity Increase	South	\$5
18	50106	Big Cedar Interconnection	West	\$64
19	50151	Sphinx 138 kV Station	East	\$33
20	50152	Ellendale load 3 addition	West	\$13
21	50164	Woodberry Load Addition	South	\$10
22	50174	New Customer X 138kV Substation	Central	\$12



4.3 Project Justifications – Central Region

Central Region Overview

The MISO Central planning region spans four states (Missouri, Illinois, Indiana, and Kentucky) and consists of the following Transmission-Owning members:

American Electric Power Service Corporation (AEP)	Hoosier Energy REC Inc. (HE)
Ameren Illinois (AMIL)	Indianapolis Power & Light (IPL)
Ameren Missouri (AMMO)	Northern Indiana Public Service Co. (NIPSCO)
Ameren Transmission Company of Illinois (ATXI)	Pioneer Transmission (PTx)
Big Rivers Electric Corp. (BREC)	Prairie Power Inc. (PPI)
City of Columbia, Mo. (CWLD)	Republic Transmission (RTx)
City of Springfield, Ill. (CWLP)	Southern Indiana Gas & Electric (SIGE)
Duke Energy Corp. (DEI)	Southern Illinois Power Cooperative (SIPC)
GridLiance Heartland LLC (GLH)	Wabash Valley Power Association Inc. (WVPA)
Henderson Municipal Power & Light (HMPL)	

The Bulk Power System (BPS) within these states consists of an extensive 765 kV, 345 kV, 230 kV, 161 kV, and 138 kV networked transmission system. The 345 kV network spans Missouri, Illinois, and Indiana, both north to south and east to west. The 230 kV network spans through Indiana, both north to south and east to west. The 161 kV network spans north to south and east to west in Missouri, Illinois, and Kentucky. The 138 kV network spans both north and south, and east to west in Illinois, Indiana, and Kentucky and east in Missouri. All of Ameren, BREC, CWLD, CWLP, GLH, HMPL, PPI, and SIPC belong entirely in the SERC Region for reliability administration. All of DEI, HE, IPL, NIPSCO, PTx, RTx and SIGE belong entirely in the ReliabilityFirst Region. Wabash Valley is split between both ReliabilityFirst and SERC Regions.

Major load pockets in the MISO Central planning region are St. Louis, MO; Peoria, IL; Springfield, IL; Evansville, IN; Gary, IN; and Indianapolis, IN (shown in Figure 4.3-1).

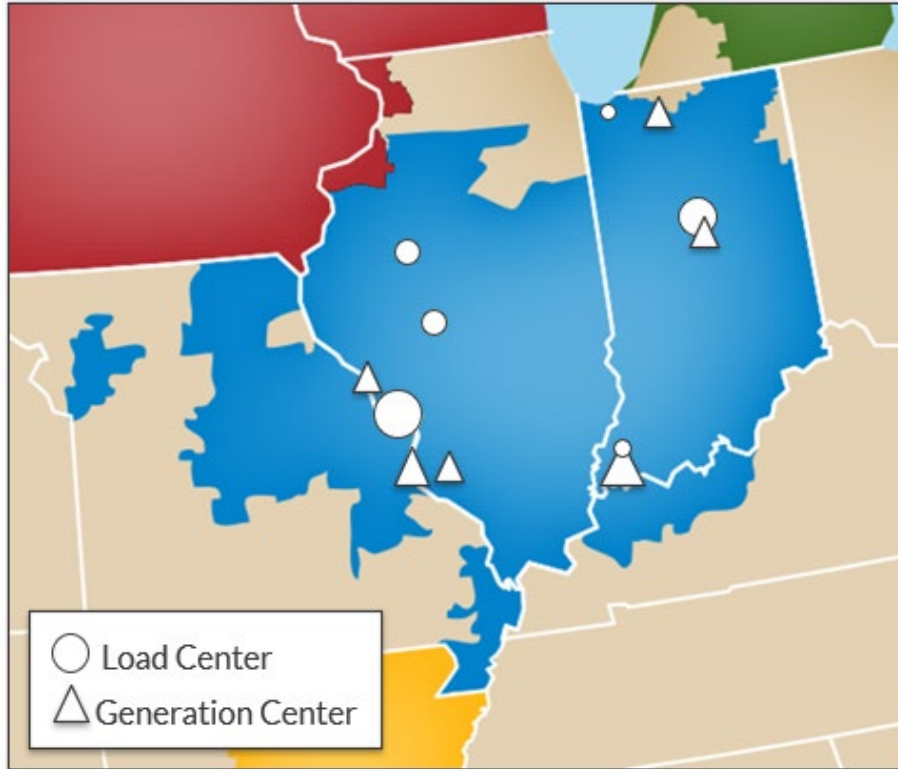
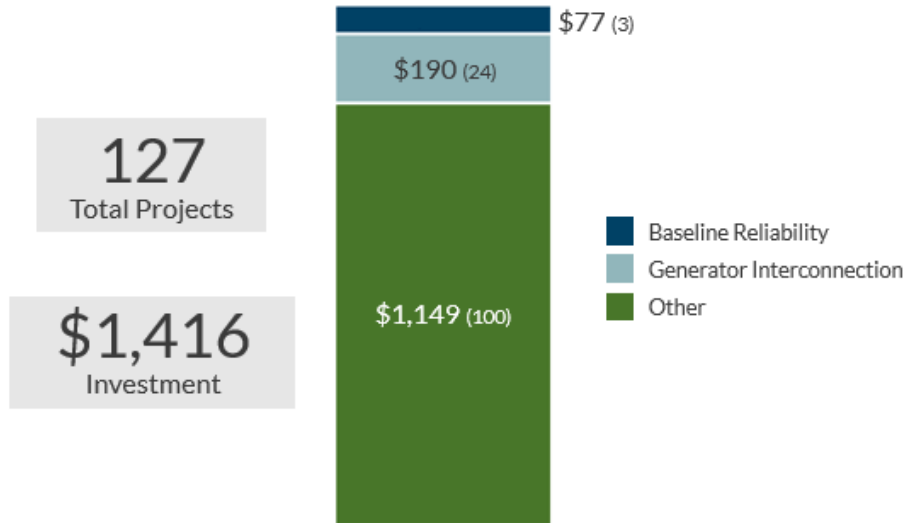


Figure 4.3-1: Generation and load centers in the Central planning region.

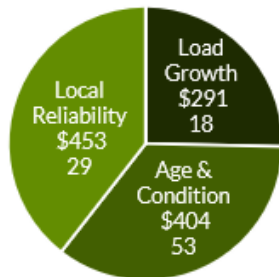


Central Planning Region Local MTEP24 Summary

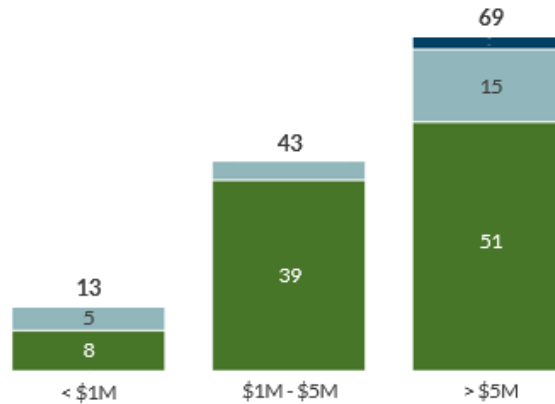
(Data as of August 27, 2024; \$M, # project count)



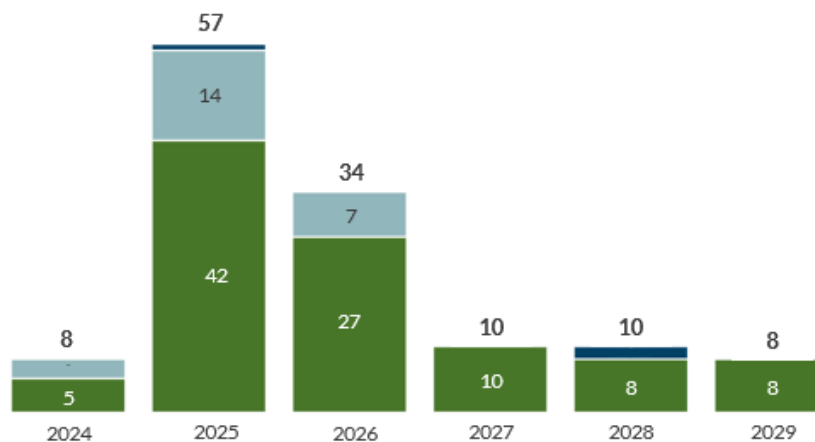
BREAKDOWN OF OTHER PROJECTS BY COST



PROJECT COUNT BY COST CATEGORY



PROJECTS BY IN-SERVICE DATE





The ten largest project investments in the MISO Central region represent \$540 million (38%) of the \$1.4 billion total recommended projects for the Central region in the local MTEP24 portfolio, or 8% of the \$6.7 billion total recommended in the MISO footprint. The locations of these projects are shown in Figure 4.3-2 and the investment is spread across the Central planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

Central Region Top 10 Local MTEP24 Projects

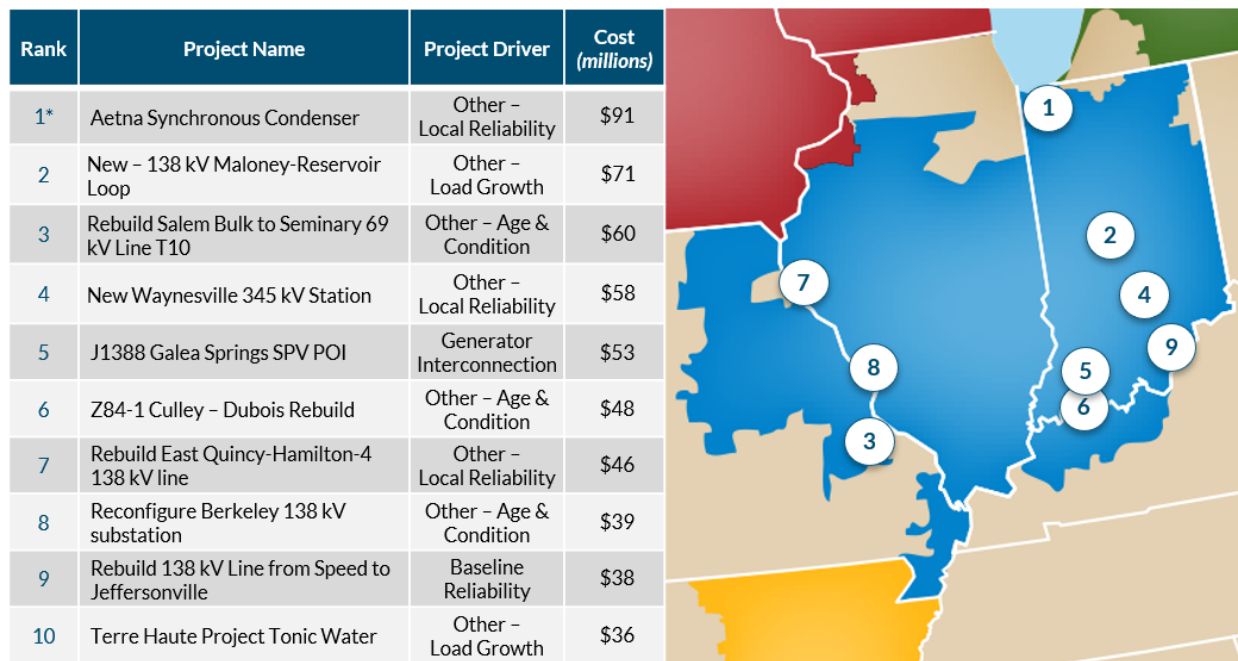


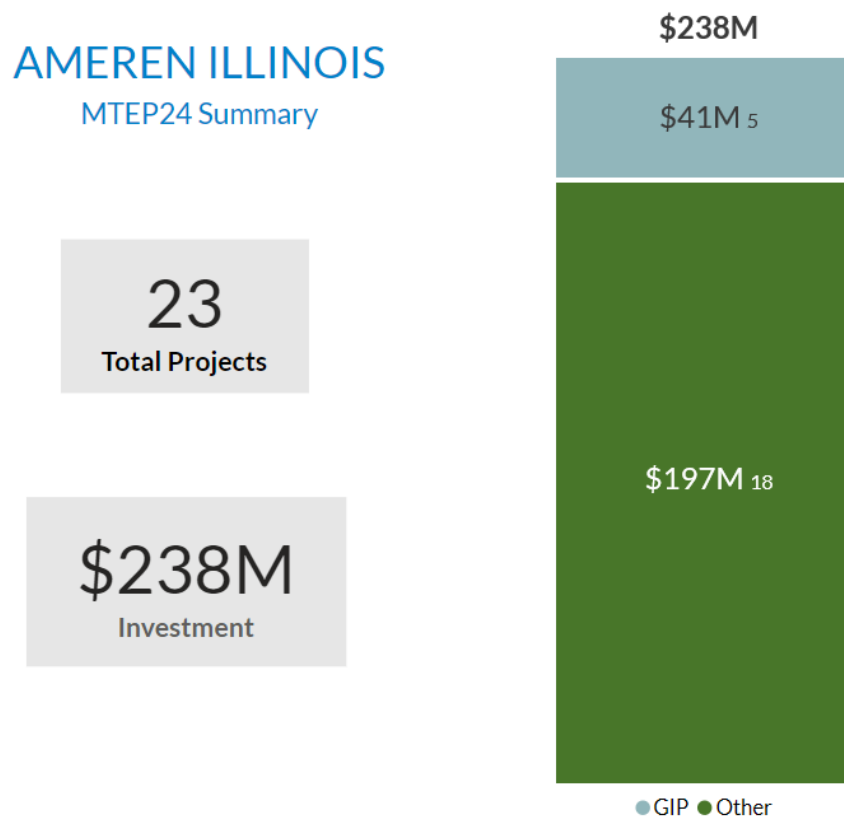
Figure 4.3-2: Central region top ten projects by cost; * represents project studied through Expedited Project Review (EPR) process (as of 8-27-2024).

4.3.1 American Electric Power Service Corporation (AEP)

American Electric Power Service Corporation and MISO are not recommending any new projects for MTEP24.



4.3.2 Ameren Illinois (AMIL)



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
22872	Upgrade Macomb NE 138 kV substation	Age and Condition	12/1/2027	\$1.8
22878	Upgrade Cat Mapleton 138 kV substation	Age and Condition	6/1/2026	\$8.7
22951	Upgrade Rantoul 138 kV substation	Age and Condition	12/1/2025	\$7.1
22969	Upgrade Decatur East Main St. 138 kV substation	Age and Condition	6/1/2026	\$2.3
23151	Rebuild East Quincy-Hamilton-4 138 kV line	Local Reliability	12/1/2025	\$46.0
24034	Coffeen N. XFMR 2 Replacement	Load Growth	12/1/2026	\$6.0
24717	Rebuild Edwards-Keystone-1397 138 kV Transmission Line	Local Reliability	12/1/2025	\$5.5
24737	Rebuild Woodhall-Hallock-1570 138 kV Transmission Line	Local Reliability	12/1/2025	\$16.0
24738	Rebuild Hull-Herleman-1682 138 kV Transmission Line	Local Reliability	12/1/2025	\$24



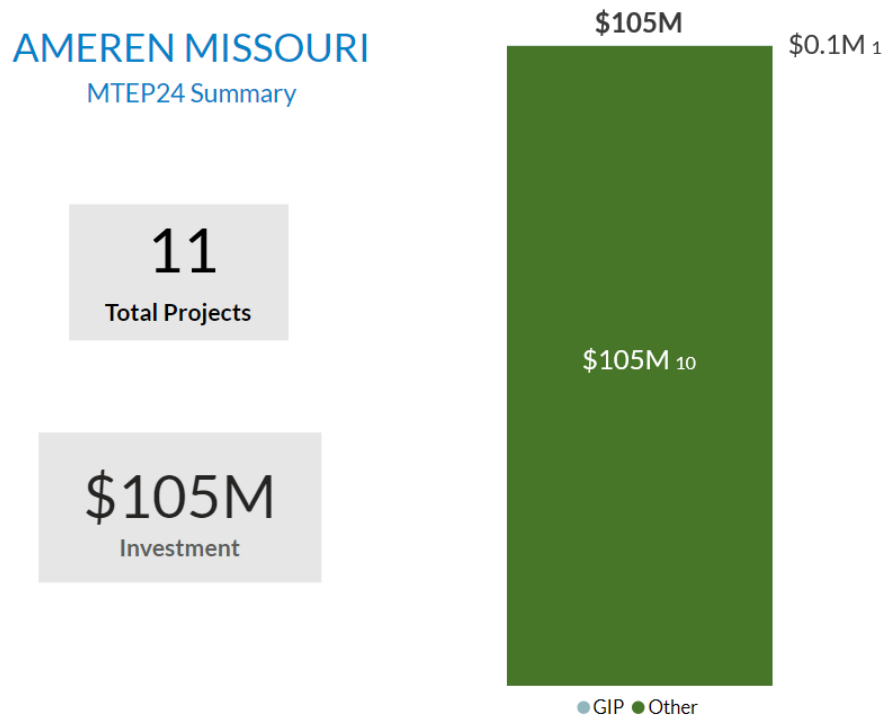
Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
24739	Rebuild Greenback-Lanesville 138 kV Line	Local Reliability	12/1/2025	\$2.2
24921	New Steamboat 138 kV Ringbus for Babylon 138 kV Sub for PPI Connection	Local Reliability	6/1/2026	\$9.7
25091	Replace 345/138 kV Transformer 2 at Norris City North	Age and Condition	12/1/2025	\$7.0
25153	New Moyer 138 kV Ring Bus for One Earth Energy Interconnection	Load Growth	6/1/2025	\$16.7
25193	Turkey Hill - Transformer 1 Replacement	Age and Condition	12/1/2025	\$6.7
25279	Replace Pole and Insulator Program - MTEP24	Age and Condition	12/31/2026	\$20.0
25362	Replace Breakers and Relays Program - MTEP24	Age and Condition	12/31/2026	\$5.0
50044	Hull-Marion-7324 Rebuild	Age and Condition	12/1/2026	\$5.5
50045	Austin Transformer 3 Replacement	Age and Condition	12/1/2027	\$6.8

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
24987	Mason-IL 138 kV Upgrade for Glacier Sands Wind II (J1454)	12/1/2025	\$0.1
25041	Virden 138 kV Substation for Virden Wind (J1408)	7/1/2026	\$8.0
25042	Supernova 345 kV Substation for Perry County Solar (J1306)	12/1/2026	\$11.0
25043	Moose 138 kV Substation for Albion PV1 (J1422)	12/1/2025	\$8.4
50148	Havana-Puro 138 kV1422 MPFCA	12/1/2025	\$13.2



4.3.3 Ameren Missouri (AMMO)



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
22880	Zion 161 kV Substation Add High Side Interrupter	Local Reliability	6/1/2026	\$2.0
22886	Reconfigure Berkeley 138 kV substation	Age and Condition	12/1/2026	\$39.2
22949	Rebuild Stoddard 161 kV substation	Local Reliability	6/1/2026	\$15.9
22950	Upgrade Watson 161 kV substation	Age and Condition	6/1/2026	\$6.2
25225	Maurer Lake 161 Aging Infrastructure	Local Reliability	6/1/2025	\$4.0
25243	Rockwood 138 kV Aging Infrastructure and Line Breaker Addition	Local Reliability	12/1/2026	\$3.5
25276	Conway 138 kV Add Breakers and Aging Infrastructure	Local Reliability	12/1/2027	\$17.5
25349	Labadie-Montgomery 345 kV Aging Infrastructure	Local Reliability	12/1/2025	\$10.5
50057	Vessel Bulk Sub - Add 2nd 138/34 kV Transformer	Load Growth	1/1/2026	\$4.0
*50086	Load addition at Montgomery 161 kV Substation	Load Growth	3/1/2026	\$2.5

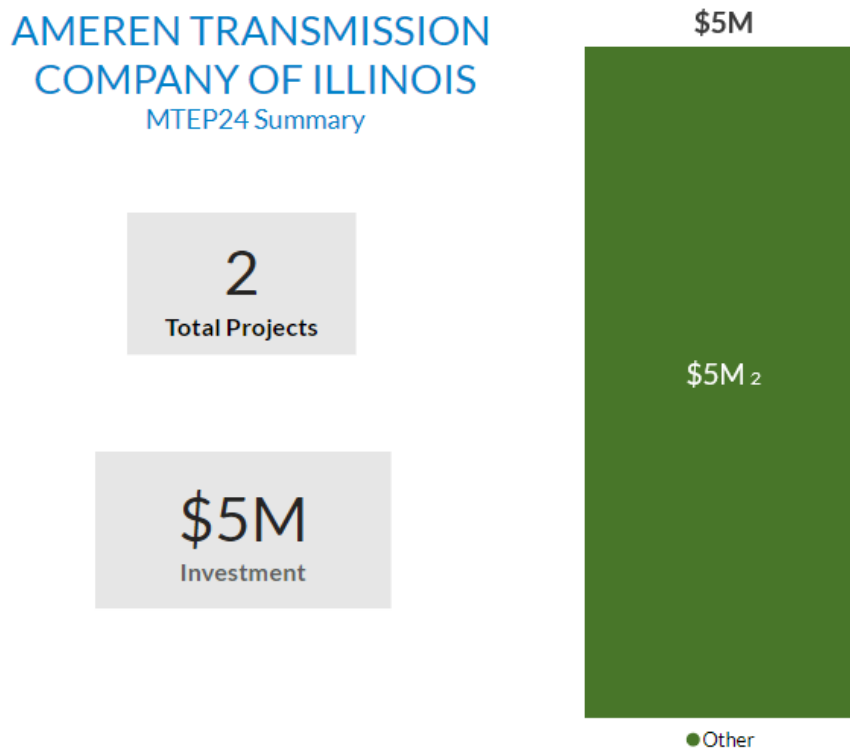
* Project studied through Expedited Project Review (EPR) process.



Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25039	Taum Sauk 138 kV Upgrade for 60MW Hydro (J1213)	12/1/2025	\$0.1

4.3.4 Ameren Transmission Company of Illinois (ATXI)



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25092	Zachary 161 kV BAAH Addition	Local Reliability	12/1/2025	\$3.0
25093	Zachary 161 kV Terminal Addition	Local Reliability	12/1/2025	\$1.5



4.3.5 Big Rivers Electric Corporation (BREC)

BIG RIVERS ELECTRIC CORPORATION

MTEP24 Summary

2
Total Projects

\$0M
Investment

● GIP — \$0M₂

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25081	J1450 Webster County Switching Station for POI	12/1/2025	\$0.0
25120	J1466 Reid EHV 161 kV Terminal Addition	12/1/2025	\$0.0

4.3.6 City of Columbia, MO (CWLD)

City of Columbia, MO, and MISO are not recommending any new projects for MTEP24.

4.3.7 City of Springfield, IL (CWLP)

City of Springfield, IL, and MISO are not recommending any new projects for MTEP24.



4.3.8 Duke Energy Corporation (DEI)

DUKE ENERGY INDIANA, LLC

MTEP24 Summary

20

Total Projects

\$316M

Investment

\$316M

\$65M₂

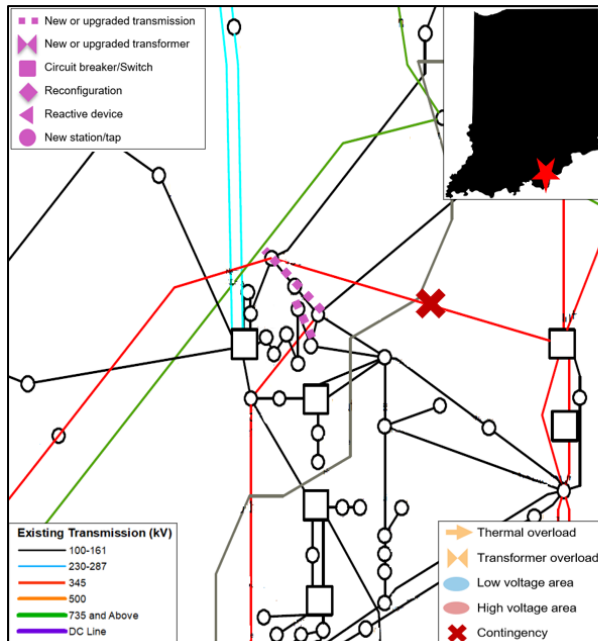
\$96M₇

\$154M₁₁

● BRP ● GIP ● Other

Baseline Reliability Projects

P25414 – Rebuild 138 kV Line from Speed to Jeffersonville



Project #	25414
Project Name	Rebuild 138kV Line from Speed to Jeffersonville
Project Type	BRP
Project Description	(1) Rebuild entire 13898 ckt from Speed to Jeffersonville with 954ACSS@200C; (2) upgrade very short 13882 tie with LGE at Jeffersonville to 954ACSS@200C and have LGE add ATO switches at the junction just outside Jeffersonville sub; (3) rebuild 6955 ckt where double circuited with 13898 ckt; (4) upgrade line terminals and substation buses as needed
System Needs	Fixes overload issues related to local load growth (Sluggar, Gateway, etc.); OL's seen in MTEP23 - P2, P4, P5, P7, P6
Estimated Cost	\$38,300,000
Expected ISD	12/31/25
Target Appendix	A

Figure 4.3.8-1: P25414 Geographic transmission map of project area and MTEP Portal project details.

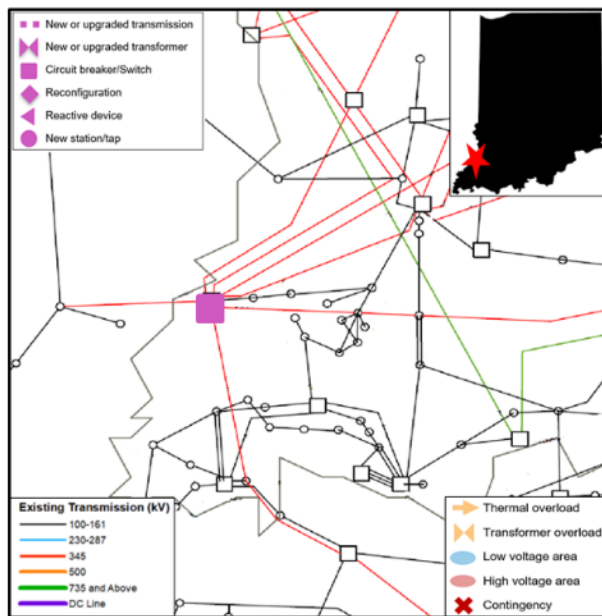


Project Justification: The [DEI] Clark Martime - [DEI] Jeffersonville 138 kV line becomes overloaded to one hundred eighteen (118%) percent in year 2025 for a NERC defined category P2-3 contingency event. The Rebuild [DEI] Speed – [DEI] Jeffersonville 138 kV line project will modify several ratings including an increase in the summer emergency rating of [DEI] Clark Martime - [DEI] Jeffersonville 138 kV line from 161 MVA to 480 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P2	[DEI] Clark Martime – [DEI] Jeffersonville 138 kV line	480	136	46

Table 4.3.8-1: P25414 Thermal loading drivers.

P25458 – Gibson 345 kV Ckt Brkr Upgrades



Project #	25458
Project Name	Gibson 345kV Ckt Brkr Upgrades
Project Type	BRP
Project Description	Gibson 345 CB upgrades - TPL-001 short ckt overduty - replace (18) 345kV-63kA interrupting rated CBs with 80kA; replace breaker disconnect switches and upgrade bus conductor as needed. ALTERNATIVE: add neutral to ground fault current limiting reactors on Gibson Units 1 and 2 GSUs (6 ohms) currently under consideration.
System Needs	These CBs were identified in the 2023 short circuit study as being over-dutied during certain fault conditions. This is a NERC TPL 001 compliance requirement.
Estimated Cost	\$27,000,000
Expected ISD	12/31/28
Target Appendix	A

Figure 4.3.8-2: P25458 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: Need for project determined through short circuit analysis.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25331	WVPA Blacketor 69/12 kV Sub	Load Growth	12/31/2025	\$8.8



Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25332	WVPA Pike 69 kV Line Rebuild	Load Growth	12/31/2028	\$15.0
25333	Westfield 156th St 69/12 kV Sub	Load Growth	12/31/2026	\$3.4
25334	Kokomo Webster St Ckt Brkr Replacements	Local Reliability	12/22/2025	\$6.3
25335	Add new Thorntown 69 kV ckt and rebuild 6943 ckt	Load Growth	9/4/2025	\$31.2
25336	Greensburg Washington St. 69 kV Breaker upgrades	Local Reliability	7/24/2025	\$2.1
25347	WVPA Lebanon Industrial 69/12 kV Sub	Load Growth	10/1/2025	\$12.2
25463	Glenwood to Rushville 69 kV Line Rebuild	Age and Condition	10/31/2025	\$24.7
25525	Kokomo Project Fusion Phase 2 - 230/69 kV Sub	Load Growth	6/30/2026	\$14.0
25526	Terre Haute Project Tonic Water	Load Growth	3/1/2027	\$35.8
50068	HE Taylorsville 69/12 kV Sub	Load Growth	10/17/2025	\$0.9

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25504	J1481 Emerald Green Solar POI	4/1/2026	\$8.5
25521	J992 Appleseed Solar POI	8/15/2025	\$7.3
25523	J1348 Brouilletts Creek Solar POI	6/1/2026	\$8.4
25542	J1357 Williams Power POI	9/30/2025	\$5.7
25543	J1381 Locomotive Solar POI	10/1/2026	\$6.7
25545	J1390 Lowland Solar Park POI	12/1/2025	\$6.8
25546	J1388 Galea Springs SPV POI	6/1/2026	\$52.9

4.3.9 GridLiance Heartland LLC (GLH)

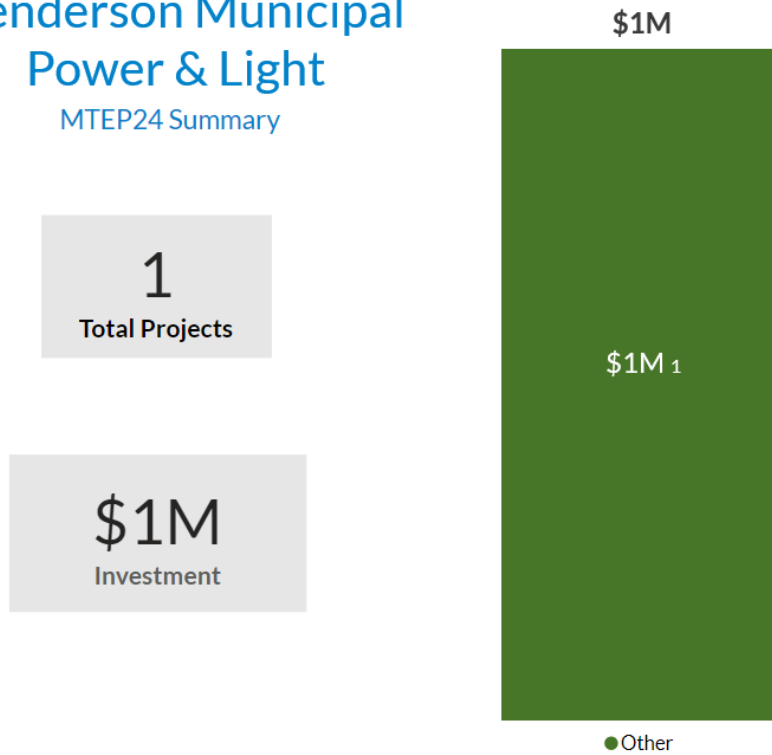
GridLiance Heartland LLC and MISO are not recommending any new projects for MTEP24.



4.3.10 Henderson Municipal Power & Light (HMPL)

Henderson Municipal Power & Light

MTEP24 Summary



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25499	Reconductor HMPL Sub 2 to HMPL Sub 5 69 kV line	Age and Condition	12/1/2025	\$1.0



4.3.11 Hoosier Energy REC, Inc. (HE)

HOOSIER ENERGY

MTEP24 Summary



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25350	New Waynesville 345 kV Station	Local Reliability	5/31/2028	\$58.2
25560	Centerton-Wilbur New 69 kV Line and Upgrades	Local Reliability	12/31/2027	\$34.7

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25261	HE_J1028_Ratts1_Solar	9/6/2024	\$11.4
25280	HE_J1354_Decatur_Battery	11/15/2025	\$3.2
25303	HE_J1027_Ratts2_Solar	10/1/2025	\$3.6
25304	HE_J1396_Ratts_3_Solar	8/20/2024	\$0.01

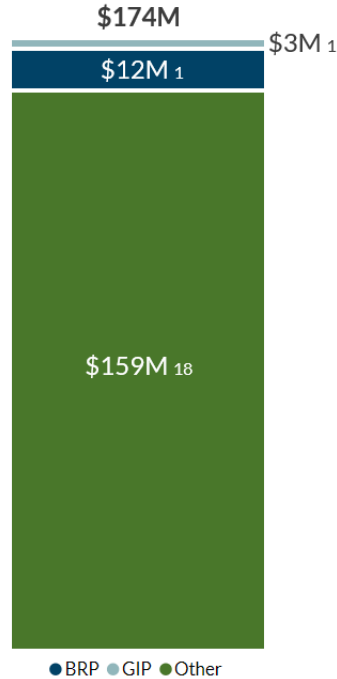


4.3.12 Indianapolis Power & Light Company (IPL)

INDIANAPOLIS POWER & LIGHT COMPANY MTEP24 Summary

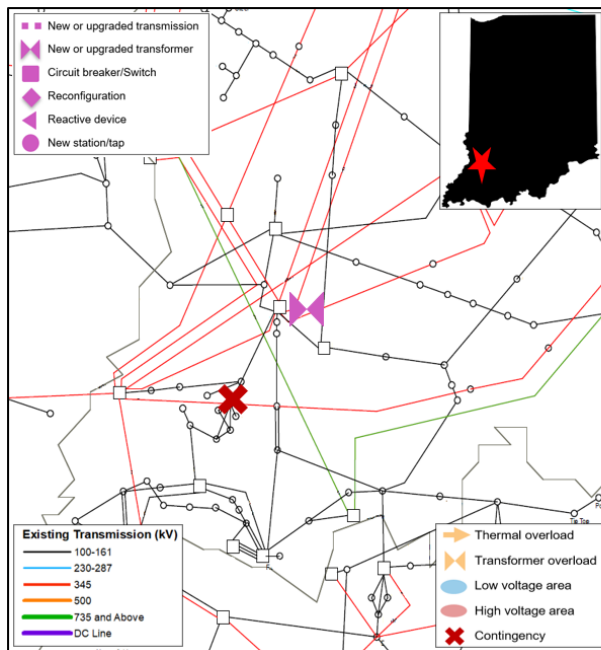
20
Total Projects

\$174M
Investment



Baseline Reliability Projects

P25268 – Replace 345-138 kV Petersburg East & West Autos



Project #	25268
Project Name	Replace 345-138 kV Petersburg East & West Autos
Project Type	BRP
Project Description	Replacement of the Petersburg 345/138 kV 300 MVA autotransformers with 500 MVA autotransformers. Project scope includes adding redundant relaying to each autotransformer.
System Needs	Reliability need resulting from the annual steady-state analysis for spare equipment as required by NERC TPL-001-5 R2.1.5 & R2.7. Outage of either autotransformer in conjunction with P23:345:DEI:GIBSON 34516, results in >120% thermal overload, violating AES Indiana's 2-hour short term emergency rating.
Estimated Cost	\$12,000,000
Expected ISD	12/31/28
Target Appendix	A

Figure 4.3.12-1: P25268 Geographic transmission map of project area and MTEP Portal project details.



Project Justification: The [IPL] Petersburg 345/138/34.5 kV East and West Auto transformers become overloaded to one hundred twenty-eight (128%) percent in year 2025 for a NERC defined category Spare Equipment contingency event. Replacing the [IPL] Petersburg 345/138/34.5 kV Auto transformers will increase the summer emergency rating of the transformers from 300 MVA to 500 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
Spare	[IPL] Petersburg 345/138/34.5 kV East	500	152	91
Spare	[IPL] Petersburg 345/138/34.5 kV West	500	152	91

Table 4.3.12-1: P25268 Thermal loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
24274	New - 138 kV Maloney-Reservoir Loop	Load Growth	12/31/2029	\$71.4
24555	New - Waverly - 138 kV Substation	Load Growth	12/1/2029	\$6.0
25353	Replace Southwest 138 kV #1 Breaker	Age and Condition	12/5/2024	\$0.9
25354	Replace Parker 138 kV Breakers	Age and Condition	5/21/2025	\$2.7
25355	Replace Northwest 138 kV Breakers	Age and Condition	5/21/2025	\$3.6
25367	New 138 kV Hawthorne Substation	Load Growth	6/25/2025	\$15.0
25372	New 345-138 kV Monrovia Substation	Load Growth	6/30/2029	\$35.3
25383	Replace South 138 kV Breakers	Age and Condition	4/28/2025	\$2.7
25384	Replace East 138 kV Breakers	Age and Condition	4/29/2025	\$4.5
25385	Replace Petersburg 345 kV Breakers	Age and Condition	9/11/2025	\$5.4
25386	Replace North 138 kV Breakers	Age and Condition	12/22/2025	\$1.8
25387	Replace Prospect 138 kV #2 Breaker	Age and Condition	12/22/2025	\$0.9
25389	Replace Northeast 138 kV Breakers	Age and Condition	12/22/2025	\$1.8
25390	Replace Brookwood 138 kV Breakers	Age and Condition	12/22/2025	\$1.8
25401	New 138-34.5 kV Northwest Transformer	Local Reliability	6/30/2025	\$4.0
25402	Replace Petersburg 138 kV #4 Breaker	Age and Condition	5/28/2025	\$0.9



Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
50095	Upgrade Stout CT - CT 4 and 5 Relaying	Local Reliability	9/30/2026	\$0.3
50096	Upgrade Stout CT - CT Bus Relaying	Local Reliability	9/30/2026	\$0.2

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
50032	New Pike County Energy Storage 345 kV (R1021 & R1022)	1/15/2026	\$3.0

4.3.13 Northern Indiana Public Service Company (NIPSCO)

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC MTEP24 Summary



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
*50089	Aetna Synchronous Condenser	Local Reliability	5/1/2024	\$91.0
*50174	New Customer X 138 kV Substation	Load Growth	12/31/2026	\$12.0



* Project studied through Expedited Project Review (EPR) process.

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
24939	J1407 Network Upgrades	8/1/2025	\$5.4
25021	J1387 Network Upgrades	10/16/2025	\$1.1
25080	J1323 J1392 Network Upgrades	6/1/2025	\$5.4

4.3.14 Pioneer Transmission, LLC (PTx)

Pioneer Transmission, LLC and MISO are not recommending any new projects for MTEP24.

4.3.15 Prairie Power, Inc. (PPI)

PRAIRIE POWER, INC. MTEP24 Summary

8
Total Projects

\$101M
Investment





Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
23373	New Industry-Ipava 69 kV Line	Local Reliability	12/31/2027	\$15.7
23374	New Babylon 138/69 kV Substation and Lines	Local Reliability	12/31/2027	\$18.3
23375	Replace Babylon 138/69 kV XFMR	Local Reliability	12/31/2029	\$2.6
23426	New Rushville-Ipava 69 kV Line	Local Reliability	12/31/2029	\$16.2
25315	New Forest City-St. David 69 kV Line	Local Reliability	12/31/2029	\$20.1
25316	New Plymouth-Macomb 69 kV Line	Local Reliability	12/31/2029	\$19.1
25318	Upgrade Winchester 138/69 kV Transformer	Age and Condition	12/31/2029	\$3.5
25450	Rebuild Breiner-Spring Lake Jct. 69 kV Line	Age and Condition	12/31/2027	\$5.5

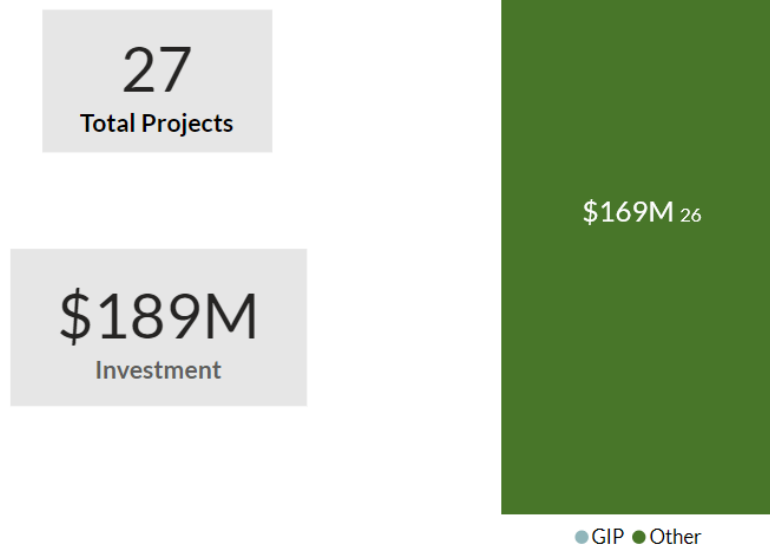
4.3.16 Republic Transmission, LLC (RTx)

Republic Transmission and MISO are not recommending any new projects for MTEP24.

4.3.17 Southern Indiana Gas & Electric Company (SIGE)

Southern Indiana Gas & Electric Company

MTEP24 Summary





Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25088	Givens 69/12 kV T1 Replacement	Age and Condition	4/1/2025	\$3.5
25089	New Harmony 69/12 kV T2 and CB's Replacement	Age and Condition	10/1/2025	\$5.3
25090	Northwest CB's Replacement	Age and Condition	10/17/2025	\$5.0
25144	Y52-3 Oakland City - Duke Oakland City Rebuild	Age and Condition	8/1/2024	\$3.9
25145	Lynnville 69 kV OCB Replacement	Age and Condition	11/1/2024	\$0.9
25146	Fairlawn 69 kV Switch Replacement	Age and Condition	12/1/2024	\$1.0
25147	Mead Johnson 69/12 kV Transformer Replacement	Age and Condition	12/31/2028	\$3.8
25149	County Line 69/12 kV T1 Replacement	Age and Condition	12/31/2025	\$3.0
25150	Y52-2 Mackey - Oakland City Rebuild	Age and Condition	12/31/2025	\$8.0
25151	Y67/Z78 Junction - Jasper South Rebuild	Age and Condition	12/31/2025	\$10.0
25152	Z99 AB Brown - Wolf Road Rebuild	Age and Condition	12/31/2025	\$8.5
25359	Louis Allis Switch Replacement	Age and Condition	12/31/2028	\$2.3
25393	Chrisney 69/12 kV T1 Replacement	Age and Condition	12/31/2026	\$4.0
25394	Midway 69/2.4 kV Transformer Replacement	Age and Condition	12/31/2028	\$2.0
25395	Oakland City 69/15 kV Xformer and CB Replacement	Age and Condition	12/31/2026	\$2.7
25397	Tepe Park 138/15 kV Transformer Addition	Age and Condition	12/31/2026	\$4.0
25403	Newtonville T3, T2 and CB's Replacement	Age and Condition	12/31/2026	\$18.5
25404	Winslow 69 kV CB Replacement	Age and Condition	12/31/2026	\$1.5
25406	Santa Claus Switch Replacement	Age and Condition	12/31/2028	\$1.5
25407	Angel Mounds CB and Switch Replacement	Age and Condition	12/31/2026	\$3.0
25408	Fort Branch 69 kV Capacitor Bank	Local Reliability	12/31/2025	\$3.0
25440	Vigo Coal 69/12 kV Xformer and CB Replacement	Age and Condition	12/31/2028	\$6.0
25441	Z91-2 Pigeon Creek - Heidelberg Rebuild	Age and Condition	12/31/2025	\$5.5
25442	Z91-1 NW - Pigeon Creek Rebuild	Age and Condition	12/31/2026	\$11.0
25443	Z84-1 Culley - Dubois Rebuild	Age and Condition	12/31/2027	\$47.5
25444	Y74 Azteca - VIP Pole Replacement	Age and Condition	12/31/2026	\$4.0



Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25148	Posey Solar Gen Interconnection (J1308)	10/1/2024	\$20.0

4.3.18 Southern Illinois Power Cooperative (SIPC)

Southern Illinois Power Cooperative and MISO are not recommending any new projects for MTEP24.

4.3.19 Wabash Valley Power Association, Inc. (WVPA)

WABASH VALLEY POWER ASSOCIATION, INC. MTEP24 Summary



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25284	Rebuild Salem Bulk to Seminary 69 kV Line T10	Age and Condition	12/31/2028	\$60.0
25290	Sprott 69/12 kV Substation	Load Growth	12/31/2027	\$1.2



4.4 Project Justifications – East Region

East Region Overview

The MISO East Planning Region consists of six Transmission-Owners within Michigan. These Transmission Owners are:

ITC Transmission (ITCT)	Michigan Public Power Agency (MPPA)
Michigan Electric Transmission Co. (METC)	Michigan South Central Power Agency (MSCPA)
Wolverine Power Supply Cooperative Inc. (WPSC)	Lansing Board of Water & Light (LBWL)

The region contains 9710 circuit miles of transmission lines ranging from 120 kV to 345 kV. It also contains 1227 circuit miles of 69 kV sub-transmission system. The MISO East Region is interconnected with non-MISO systems: Hydro One Networks Inc. and American Electric Power to the east.

The 2024 Summer Peak planning model indicates the region contains 34 GW of generation. Installed generation capacity in the region consists mostly of coal, gas, and solar. Figure 4.4-1 shows the major load centers and generation pockets within the East Region. The load centers are typically found around larger cities in the region, i.e., Detroit, Lansing, and Grand Rapids. According to the 2024 Summer Peak planning model, the region's load is 22 GW.

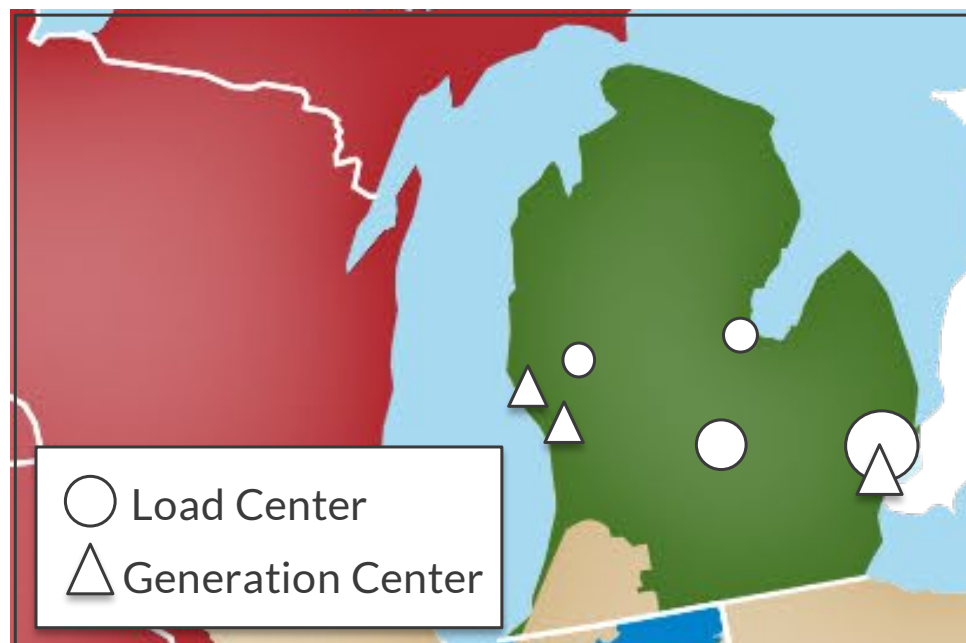
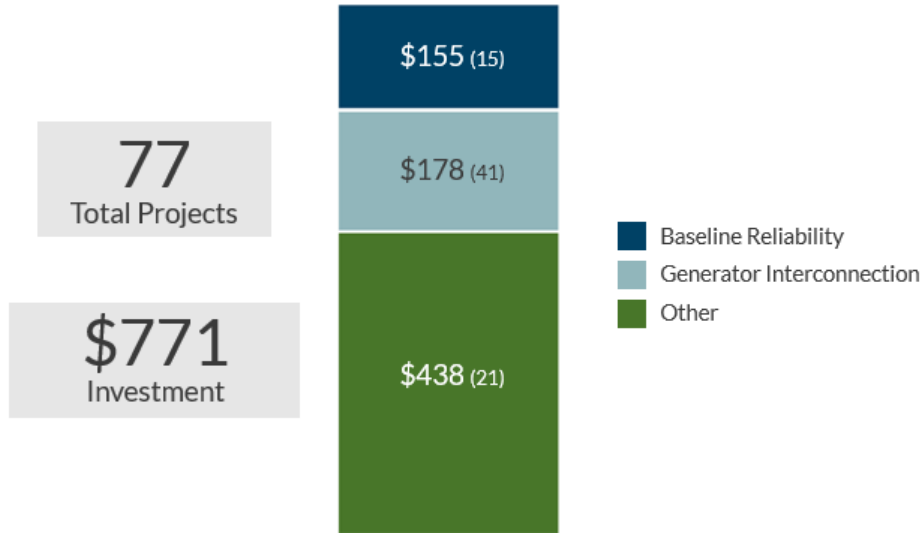


Figure 4.4-1: Generation and load centers in the East planning region.

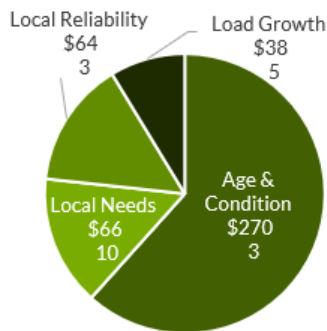


East Planning Region Local MTEP24 Summary

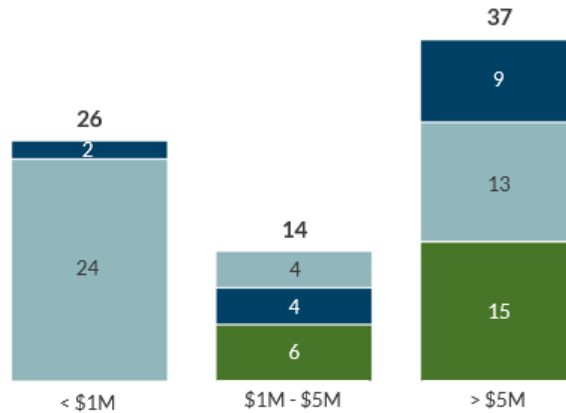
(Data as of August 27, 2024; \$M, # project count)



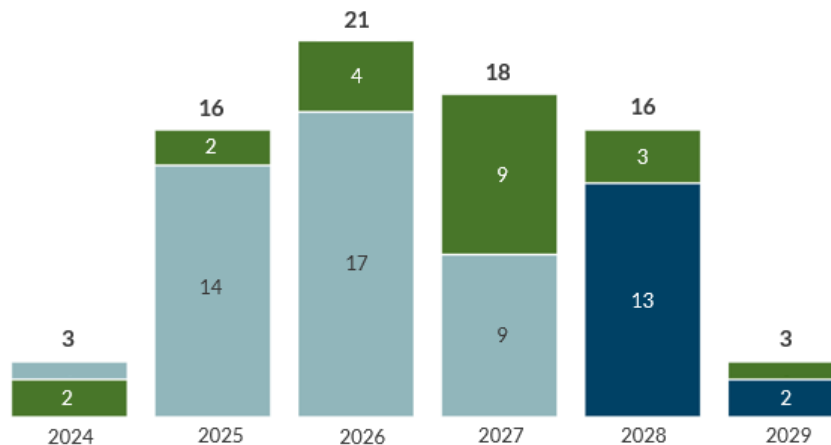
BREAKDOWN OF OTHER PROJECTS BY COST



PROJECT COUNT BY COST CATEGORY



PROJECTS BY IN-SERVICE DATE





The ten largest project investments in the MISO East region represent \$367 million (48%) of the \$771 million total recommended projects for the East region in the local MTEP24 portfolio, or 5% of the \$6.7 billion total recommended in the MISO footprint. The locations of these projects are shown in Figure 4.4-2. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

East Region Top 10 Local MTEP24 Projects

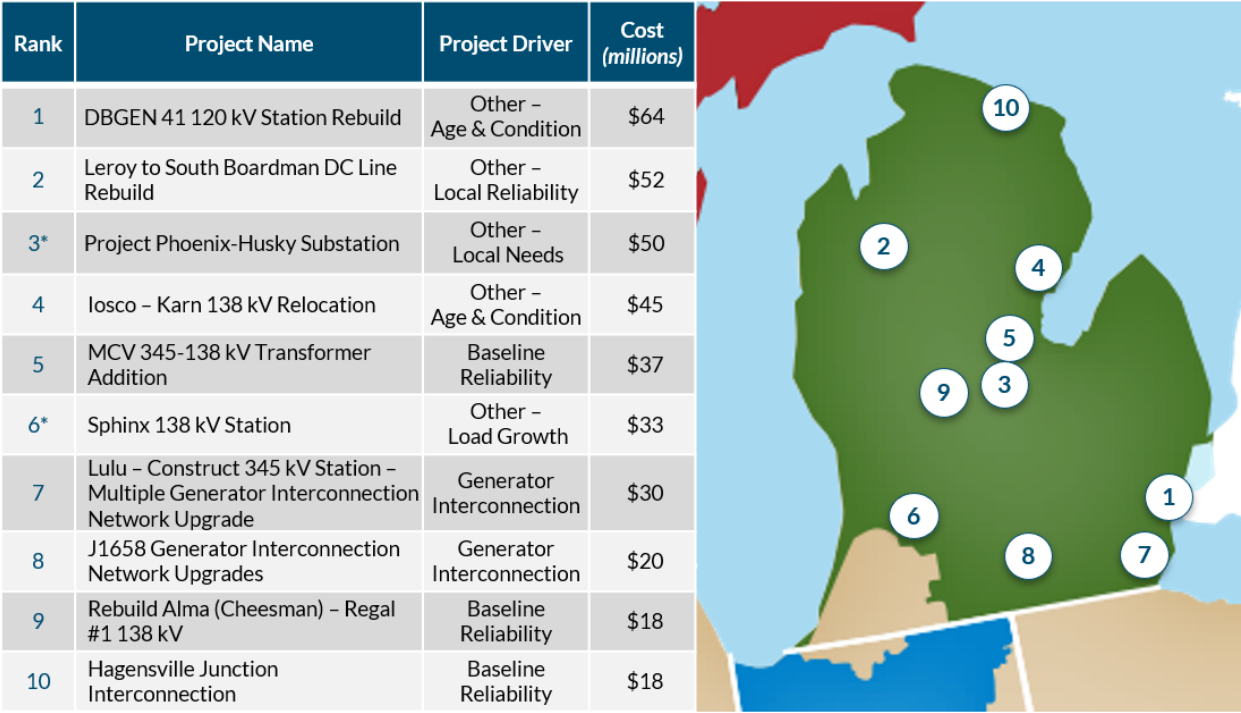
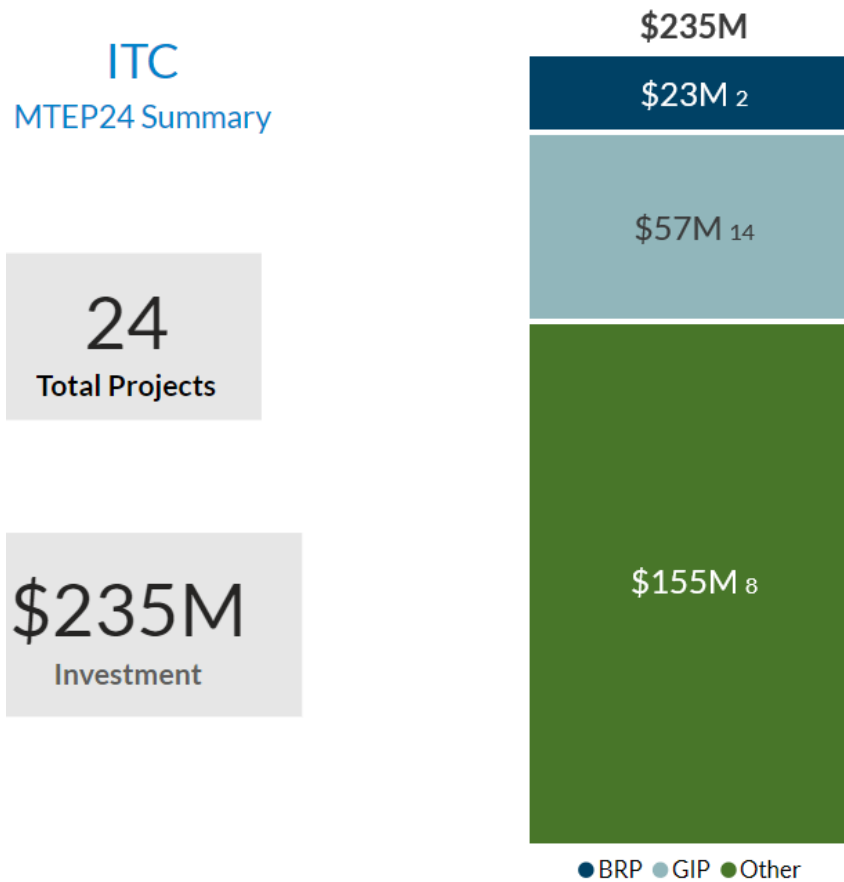


Figure 4.4-2: East region top ten projects by cost; * represents project studied through Expedited Project Review (EPR) process (as of 8-27-2024).

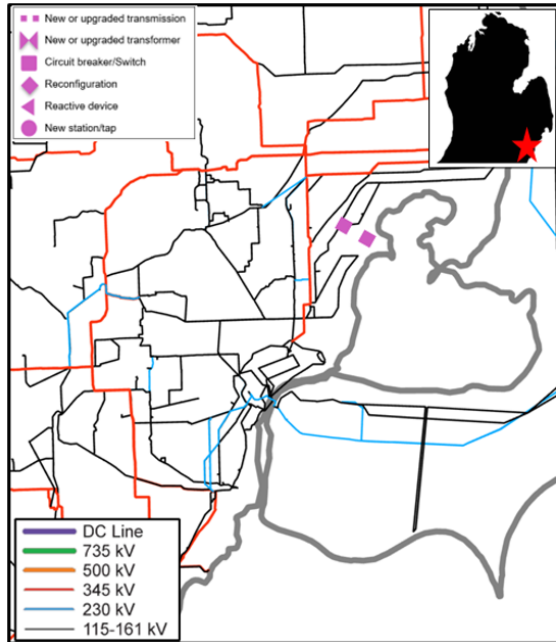


4.4.1 ITC Transmission (ITCT)



Baseline Reliability Projects

ITCT 50060 – Bismarck – Macomb 120 kV Line



Project #	50060
Project Name	Bismarck - Macomb 120 kV Line
Project Type	BRP
Project Description	Construct a new 120 kV line (~6.7 miles) from Bismarck to Macomb. Approximately 3.9 miles of this new circuit will be using new 954 ACSR conductor, 2.7 miles of which will be strung on the vacant side of existing Lenox - Stephens 120 kV structures and the other 1.2 miles will be on new ROW. The remaining section from the west-to-east crossover point toward Macomb (2.8 miles) will utilize existing 795 ACSR conductor through undoing 6-wire on the Macomb - Stephens 120 kV circuit. This new 120 kV line will require installations of a new 120 kV breaker at Bismarck and Macomb stations.
System Needs	MISO identified various voltage and thermal violations around the Golf and Macomb areas in the MTEP23 study .
Estimated Cost	\$11,160,000
Expected ISD	6/1/28
Target Appendix	A

Figure 4.4.1-1: P50060 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The Benson – Stephens #1 120 kV line is overloaded for NERC defined P6 contingencies. Voltage results are also found in the Golf area buses for a P6 contingency. Post project values are within limits.

Alternatives Considered: An alternative project was studied but did not resolve all issues to the standards of Local Planning Criteria, therefore MISO recommends the original version.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P2	[ITCT] Benson – [ITCT] Stephens #1 120 kV line	249	103	61
P6	[ITCT] Benson – [ITCT] Stephens #1 120 kV line	249	110	55
P6	[ITCT] Houston Tap 2 – [ITCT] St. Clair 120 kV line	204	99	32

Table 4.4.1-1: P50060 Thermal loading drivers.

Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P6	[ITCT] Golf Station	0.97	0.90	0.99

Table 4.4.1-2: P50060 Voltage loading drivers.



ITCT 25363 – ITCT SPOF Blanket

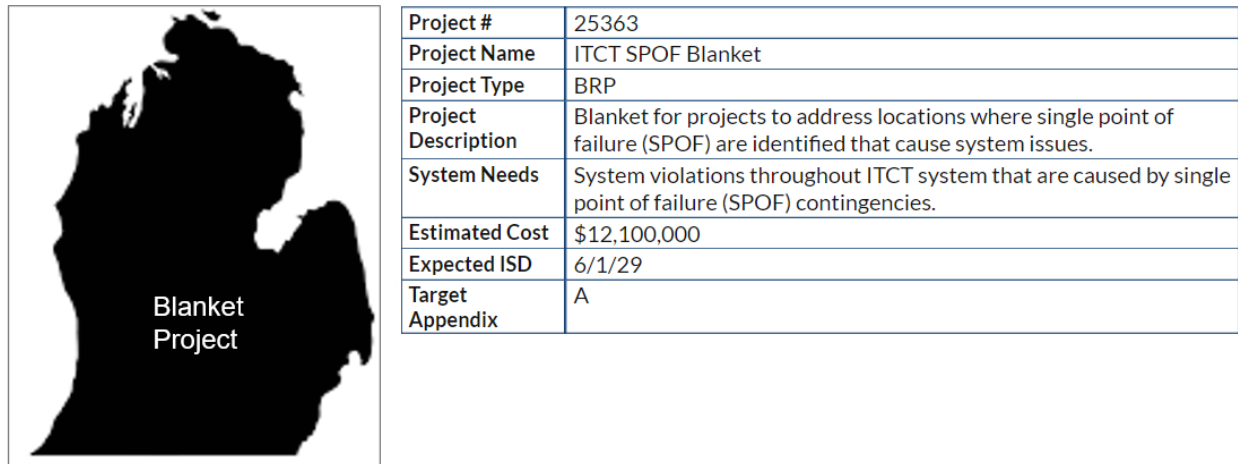


Figure 4.4.1-2: P25363 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: Since the implementation of TPL-001-5.1, many ITCT BES substations have been identified as having single points of failure (SPOF) violations in MISO steady-state and dynamic analysis and ITCT short-circuit analysis. This blanket project addresses 29 facilities with these SPOFs prior to the implementation deadline of the standard. The highest observed thermal and voltage violations are listed below.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P5	[ITCT] Scott - [ITCT] B3N 120 kV	456	146	Project upgrade invalidates the single point of failure contingency impact on this line

Table 4.4.1-3: P25363 Thermal loading drivers.



Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P5	[ITCT] State 1 120 kV – [ITCT] State 2 120 kV	0.92	0.89	Project upgrade invalidates the single point of failure contingency impact on this line

Table 4.4.1-4: P25363 Voltage loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
24998	Pontiac 345 kV Station - Extend Buses and Add A Row	Local Needs	6/1/2027	\$8.3
25208	Brownstown #304 345-120 kV Transformer Replacement	Age and Condition	12/31/2027	\$6.6
25218	Sterling #201 230-120 kV Transformer Replacement	Age and Condition	12/31/2027	\$8.0
25228	DBGEN 41 120 kV Station Rebuild	Age and Condition	3/31/2029	\$64.2
25364	ITCT Customer Interconnections - 2027	Load Growth	12/31/2027	\$2.5
25365	ITCT Line Relocation - 2024	Local Needs	12/31/2024	\$2.5
25366	ITCTransmission Asset Replacement Program - 2026	Age and Condition	12/31/2026	\$60.7
25478	ITCT Line Relocation - 2025	Local Needs	12/31/2025	\$2.5

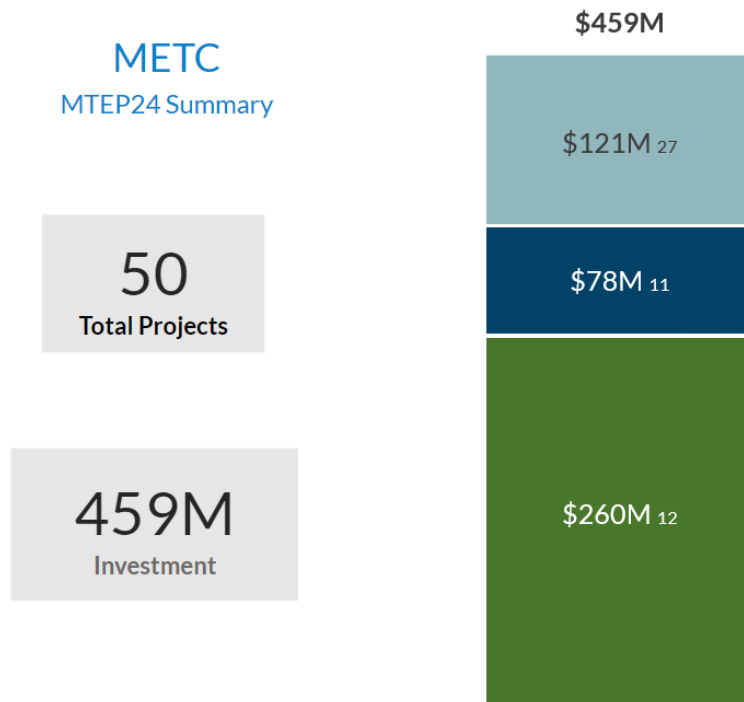
Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
24450	J1516 Generator Interconnection Network Upgrades	8/3/2026	\$0.9
24451	J1516 Generator Interconnection TOIF	8/3/2026	\$0.0
24461	Grassmere - J1525 Gen Network Upgrade	11/17/2025	\$7.6
24462	Grassmere - J1525 TOIF - Install Position CQ and switch CQA	11/17/2025	\$0.0
24463	Greenwood-Rapson#1 - J1557 Generator Interconnection (Cribbins) - Network Upgrade	7/1/2027	\$14.0
24494	Cribbins-J1557 TOIF- Install position CQ and switch CQA	7/1/2027	\$0.0



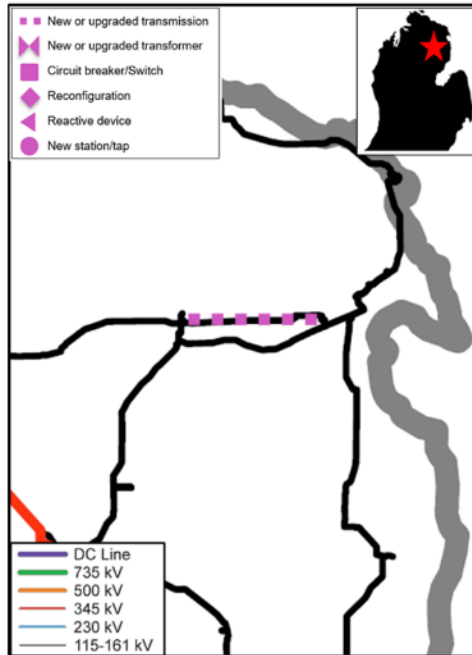
Project ID	Project Name	ISD	Estimated Cost (\$M)
24533	J1526 Generator Interconnection Network Upgrades	5/13/2026	\$1.4
24534	J1526 Generator Interconnection TOIF	5/13/2026	\$0.0
24553	J1659 Generator Interconnection Network Upgrades	4/1/2026	\$0.9
24554	J1659 Generator Interconnection TOIF	4/1/2026	\$0.0
24574	J1664 Generator Interconnection Network Upgrades	1/1/2027	\$2.0
24693	Milan - J799 Amended Generation Interconnection - TOIF	12/31/2024	\$0.0
25082	J1664 Generator Interconnection TOIF	1/1/2027	\$0.0
25223	Lulu - Construct 345 kV Station - Multiple Generator Interconnect Network Upgrade	6/11/2027	\$29.9

4.4.2 Michigan Electric Transmission Co. (METC)



Baseline Reliability Projects

METC 14344 – Airport – Hillman Tap 138 kV Sag Remediation



Project #	14344
Project Name	Airport - Hillman Tap 138 kV Sag Remediation
Project Type	BRP
Project Description	Remediate the sag limit on ~17.0 miles of 266 ACSR conductor of the ~21.3 mile-long Airport - Hillman Tap 138 kV section of the Airport - Mio 138 kV line to at least the planned target summer normal/summer emergency rating of 133 MVA/556 Amps.
System Needs	The Airport - Hillman Tap 138 kV section of the Airport - Mio 138 kV line is projected to become overloaded for P6 contingencies.
Estimated Cost	\$1,061,250
Expected ISD	6/1/28
Target Appendix	A

Figure 4.4.2-1: P14344 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [METC] Hillman Junction - [WPSC] Airport section #1 138 kV line is approaching overload to ninety-six (96%) percent in year 2029 for a NERC defined category P5 contingency event. It becomes overloaded to one hundred twenty-seven (127%) percent in year 2029 for NERC defined category P6 contingency events. Upgrading [METC] Hillman Junction - [WPSC] Airport section #1 138 kV line will increase the summer emergency rating of the line from 76 MVA to 133 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P5	[METC] Hillman Jct. - [WPSC] Airport 1 138 kV line	76	96	22
P6	[METC] Hillman Jct. - [WPSC] Airport 1 138 kV line	76	127	61

Table 4.4.2-1: P14344 Thermal loading drivers.



METC 15831 – Alma – Regal #2 138 kV Rebuild

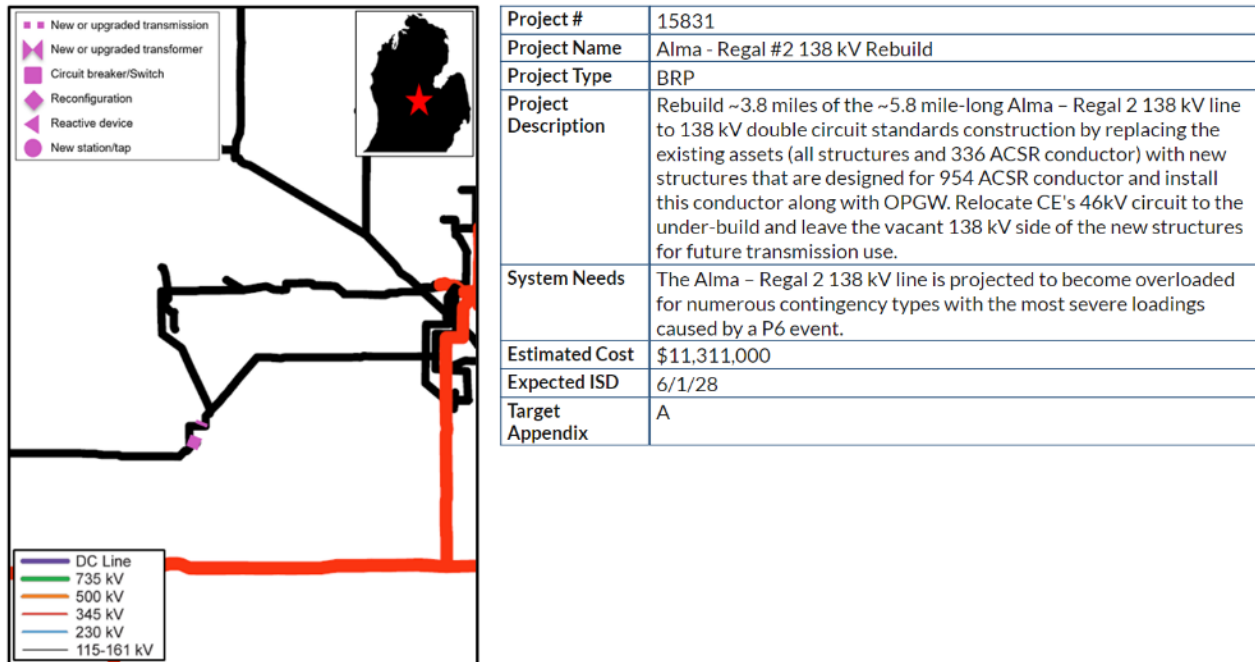


Figure 4.4.2-2: P15831 Geographic transmission map of project area and MTEP Portal project details.

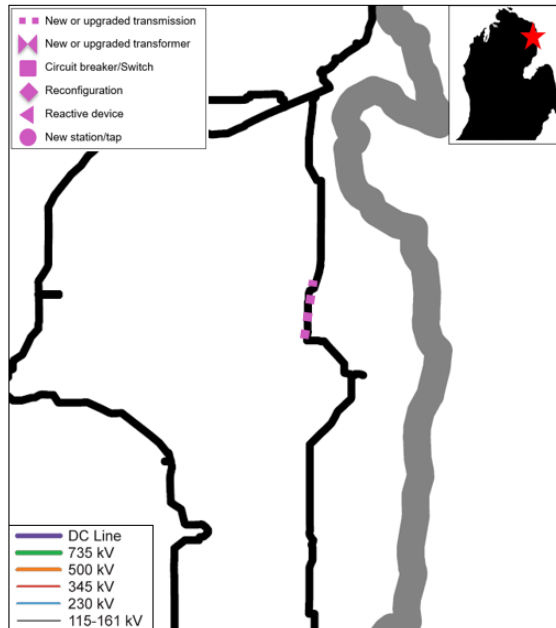
Project Justification: The [METC] Alma – [METC] Regal bus section #2 138 kV line becomes nearly overloaded to ninety-eight (98%) percent in year 2029 for a NERC defined category P2 contingency event. It becomes overloaded to one hundred twelve (112%) percent in year 2029 for NERC defined category P6 events. Upgrading [METC] Alma – [METC] Regal bus section #2 138 kV line will increase the summer emergency rating of the line from 171 MVA to 234 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P2	[METC] Alma – [METC] Regal 2 138 kV line	171	98	73
P6	[METC] Alma – [METC] Regal 2 138 kV line	171	112	83

Table 4.4.2-2: P15831 Thermal loading drivers.



METC 18072 – Sag Remediation Hubbard Lake – Spruce Road 138 kV



Project #	18072
Project Name	Sag Remediation Hubbard Lake – Spruce Road 138 kV
Project Type	BRP
Project Description	Remediate the sag on the Hubbard Lake – Spruce Road section of the Alpena – Iosco 138kV line to at least 124 MVA for summer emergency rating.
System Needs	The Hubbard Lake – Spruce Road section of the Alpena – Iosco 138kV circuit is projected to overload for P6 contingency.
Estimated Cost	\$700,000
Expected ISD	6/1/28
Target Appendix	A

Figure 4.4.2-3: P18072 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [METC] Spruce Road – [METC] Hubbard Lake Junction 138 kV line becomes overloaded to one hundred six (106%) percent in year 2029 for NERC defined category P6 contingency events. Upgrading [METC] Spruce Road – [METC] Hubbard Lake Junction 138 kV line will increase the summer emergency rating of the line from 100 MVA to 124 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P6	[METC] Spruce Road – [METC] Hubbard Lake Jct. #1 138 kV line	100	106	68

Table 4.4.2-3: P18072 Thermal loading drivers.



METC 20017 – Rebuild Alma (Cheesman) – Regal #1 138 kV

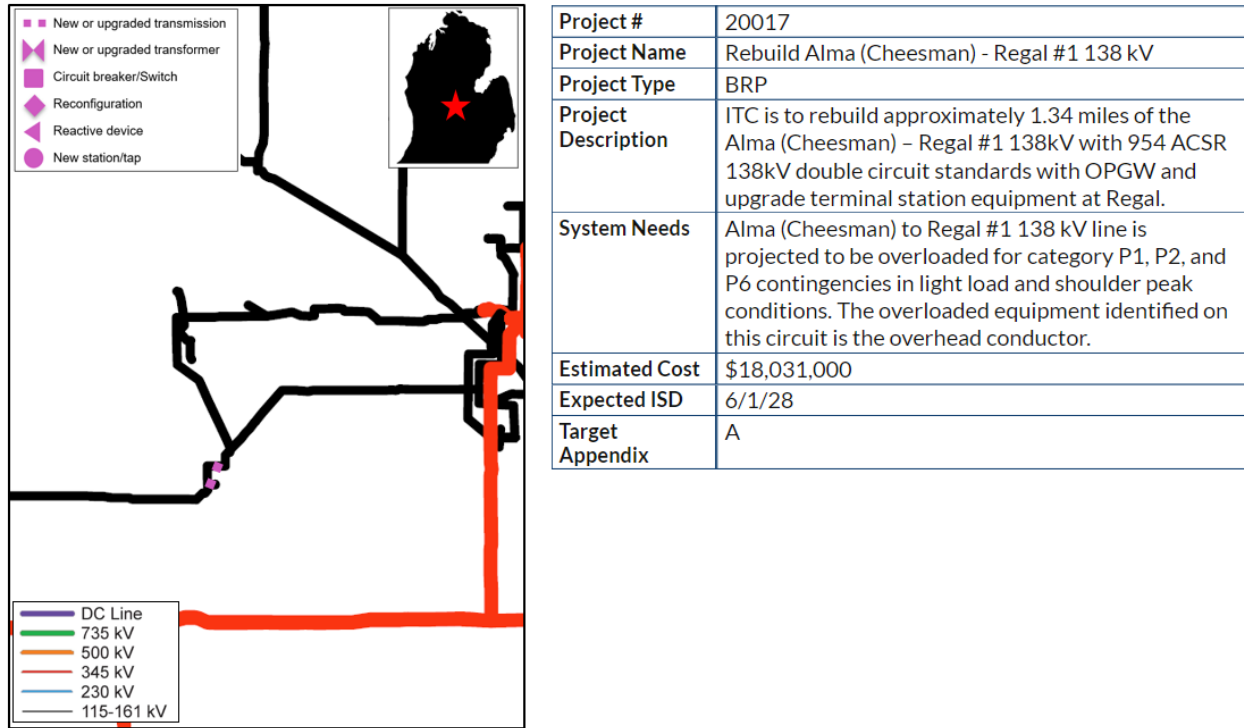


Figure 4.4.2-4: P20017 Geographic transmission map of project area and MTEP Portal project details.

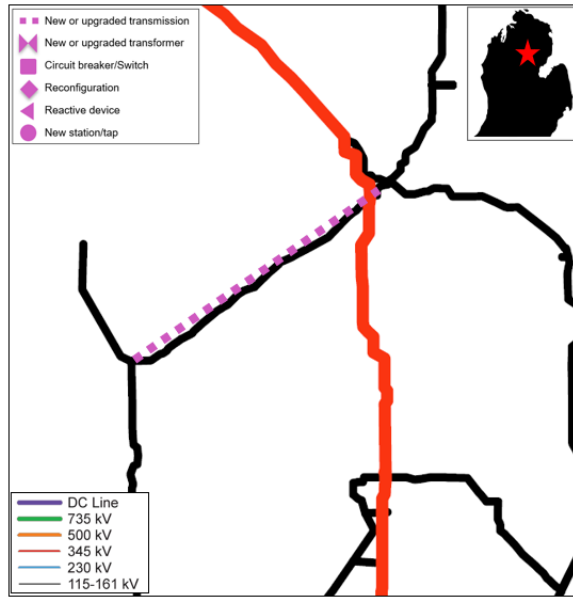
Project Justification: The [METC] Regal – [METC] Cheesman Junction #1 138 kV line becomes overloaded to one hundred two (102%) percent in year 2029 for a NERC defined category P2 contingency event. It also becomes overloaded to one hundred eleven (111%) percent in year 2029 for NERC defined category P6 contingency events. Upgrading [METC] Regal – [METC] Cheesman Junction #1 138 kV line will increase the summer emergency rating of the line from 171 MVA to 332 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P2	[METC] Regal – [METC] Cheesman Jct. 138 kV line	76	102	54
P6	[METC] Regal – [METC] Cheesman Jct. 138 kV line	76	111	58

Table 4.4.2-4: P20017 Thermal loading drivers.



METC 20034 – Sag Remediate Higgins – Mio Dam 138 kV



Project #	20034
Project Name	Sag Remediate Higgins - Mio Dam 138 kV
Project Type	BRP
Project Description	The proposed solution is to remediate sag limit on the 266.8 ACSR on the Higgins – Mio Dam 138kV line up to the conductor’s limit.
System Needs	Higgins to Mio Dam 138 kV line is projected to be overloaded for category P3 and P6 contingencies in the light load case.
Estimated Cost	\$2,800,000
Expected ISD	6/1/28
Target Appendix	A

Figure 4.4.2-5: P20034 Geographic transmission map of project area and MTEP Portal project details.

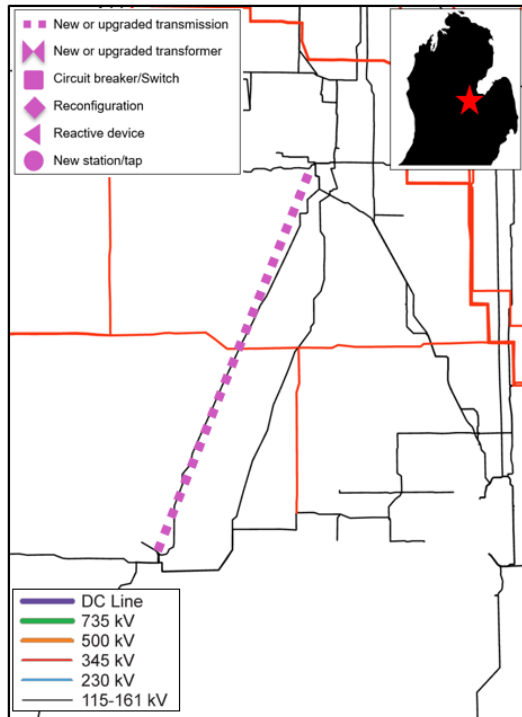
Project Justification: The [METC] Ryno Junction – [METC] Higgins #1 138 kV line becomes overloaded to one hundred six (106%) percent in year 2034 for NERC defined category P6 contingency events. Upgrading [METC] Ryno Junction – [METC] Higgins #1 138 kV line will increase the summer emergency rating of the line from 109 MVA to 147 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P6	[METC] Ryno Jct. – [METC] Higgins 2 138 kV line	109	106	74

Table 4.4.2-5: P20034 Thermal loading drivers.



METC 20119 – Sag Remediate Claremont – Cornell #2 138 kV



Project #	20119
Project Name	Sag Remediate Claremont - Cornell #2 138 kV
Project Type	BRP
Project Description	METC is to raise the sag limit on the 477 ACSR to 257F and 795 ACSR to 178F on the Bell Road - Cornell section of the Claremont - Cornell #2 138 kV Line
System Needs	Claremont to Cornell #2 138 kV line is projected to be overloaded for category P6 contingencies in the light load, off-peak cases, and peak cases.
Estimated Cost	\$1,263,000
Expected ISD	6/1/28
Target Appendix	A

Figure 4.4.2-6: P20119 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [METC] North Corunna Junction – [METC] Cornell 138 kV line 2 becomes overloaded to one hundred twenty-four (124%) percent in year 2029 for a NERC defined category P7 contingency event. It also becomes overloaded to one hundred twenty-seven (127%) percent in year 2029 for NERC defined category P6 contingency events. Upgrading [METC] North Corunna Junction – [METC] Cornell 138 kV line 2 will increase the summer emergency rating of the line from 152 MVA to 217 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P7	[METC] North Corunna Jct. - [METC] Cornell 2 138 kV line	152	124	88
P6	[METC] North Corunna Jct. - [METC] Cornell 2 138 kV line	152	127	91

Table 4.4.2-6: P20119 Thermal loading drivers.



METC 22015 – Blackstone – Leoni #1 and #2 138 kV Rebuild

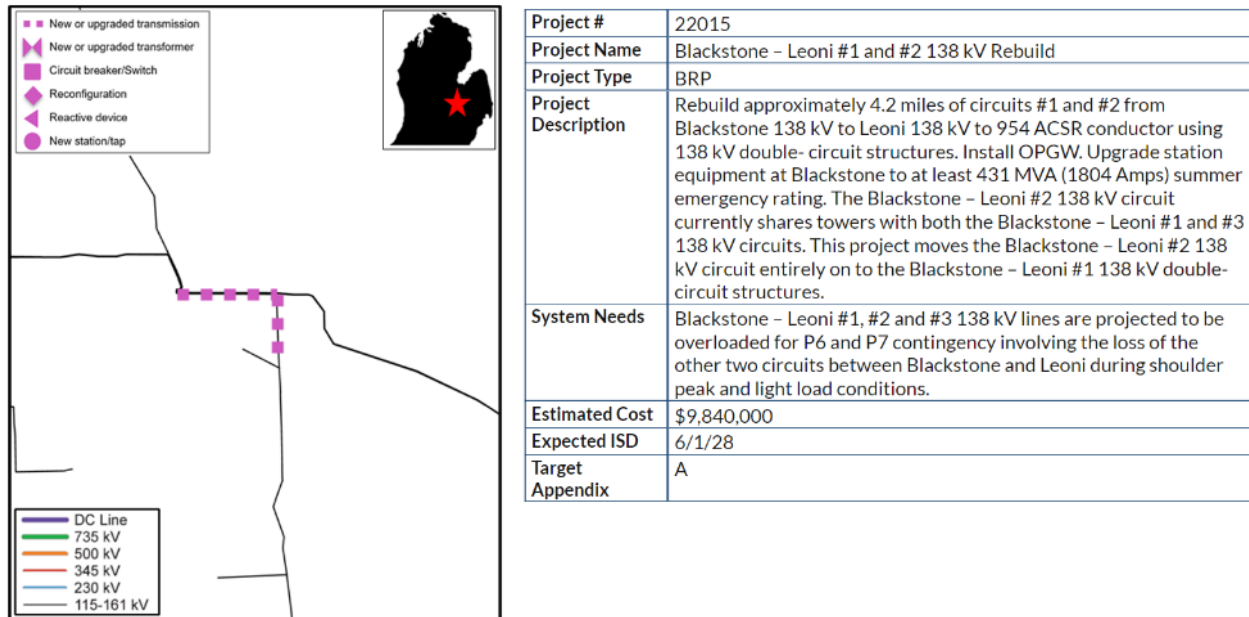


Figure 4.4.2-7: P22015 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [METC] Blackstone – [METC] Leoni 138 kV line 1 becomes overloaded to one hundred twenty-five (125%) percent in year 2029 for both NERC defined category P7 and P6 contingency events. Upgrading [METC] Blackstone – [METC] Leoni 138 kV line 1 will increase the summer emergency rating of the line from 263 MVA to 332 MVA.

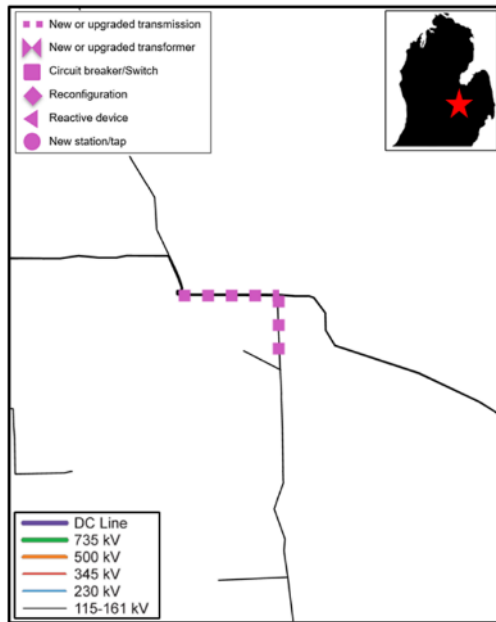
The [METC] Leoni – [METC] Blackstone 138 kV line 2 becomes overloaded to one hundred twenty (120%) percent in year 2029 for NERC defined category P6 contingency events. Upgrading [METC] Leoni – [METC] Blackstone 138 kV line 2 will increase the summer emergency rating of the line from 263 MVA to 332 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P7	[METC] Blackstone – [METC] Leoni 1 138 kV line	263	125	99
P6	[METC] Blackstone – [METC] Leoni 1 138 kV line	263	125	97
P6	[METC] Blackstone – [METC] Leoni 2 138 kV line	263	120	97

Table 4.4.2-7: P22015 Thermal loading drivers.



METC 22018 – Blackstone – Leoni #3 138 kV Rebuild



Project #	22018
Project Name	Blackstone – Leoni #3 138 kV Rebuild
Project Type	BRP
Project Description	The proposed solution is to rebuild approximately 4.2 miles of the Blackstone – Leoni #3 138 kV line using 954 ACSR on double circuit structures constructed at 138kV Standards, with future double circuit on the northeast side of the towers. Install OPGW along the entire length from Blackstone to Leoni.
System Needs	Blackstone – Leoni #1, #2 and #3 138 kV lines are projected to be overloaded for P6 and P7 contingency involving the loss of the other two circuits between Blackstone and Leoni during shoulder peak and light load conditions.
Estimated Cost	\$8,405,000
Expected ISD	6/1/28
Target Appendix	A

Figure 4.4.2-8: P22018 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [METC] Leoni – [METC] Blackstone 138 kV line 3 becomes overloaded to one hundred twenty-three (123%) percent in year 2029 for NERC defined P7 and P6 contingency events. Rebuilding [METC] Leoni – [METC] Blackstone 138 kV line 3 will increase the summer emergency ratings of the line from 263 MVA to 332 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P7	[METC] Leoni – [METC] Blackstone 138 kV line 3	236	123	97
P6	[METC] Leoni – [METC] Blackstone 138 kV line 3	263	123	97

Table 4.4.2-8: P22018 Thermal loading drivers.



METC 25195 – MCV 345-138 kV Transformer Addition

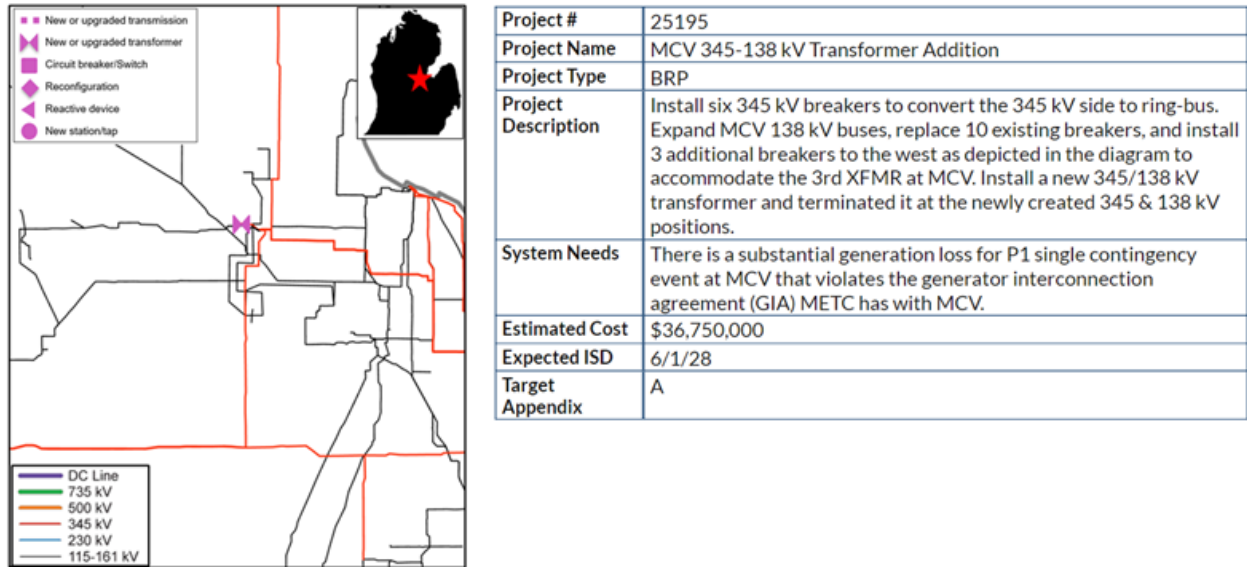


Figure 4.4.2-9: P25195 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [METC] MCV Transformer #1 and #2 show angular instability for NERC defined category P1 contingency events in MISO’s dynamic analysis. Adding a third transformer and reconfiguring the station mitigates these violations.



METC 25216 – Gaines – Caledonia Jct. 138 kV Sag Remediation

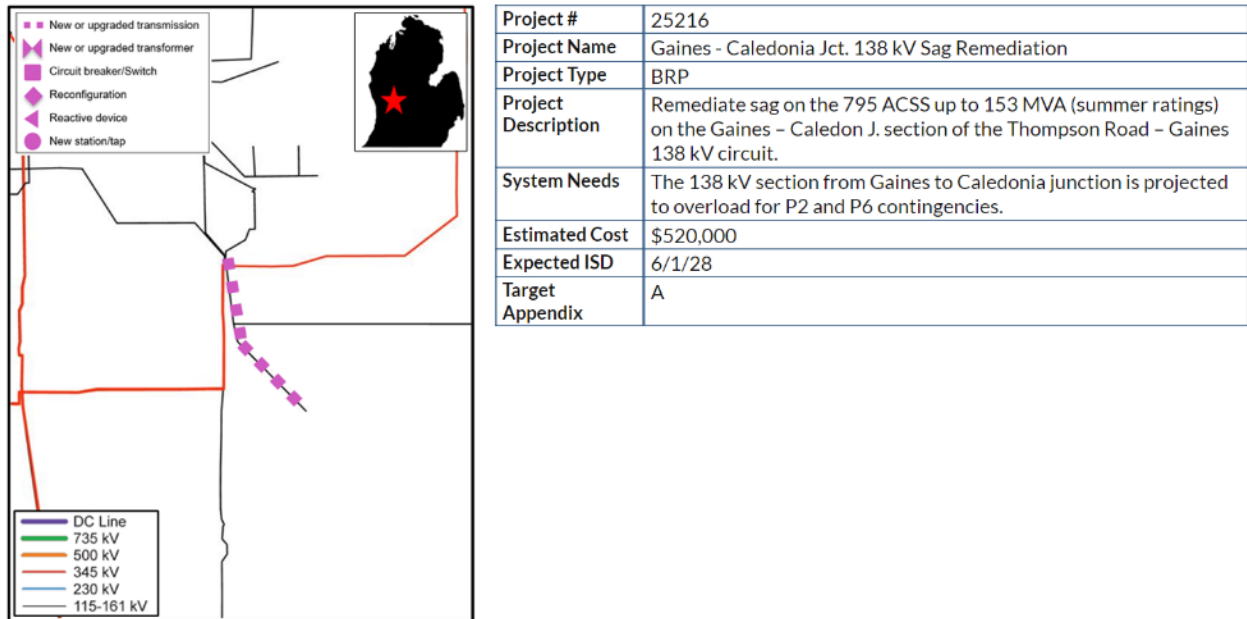


Figure 4.4.2-10: P25216 Geographic transmission map of project area and MTEP Portal project details.

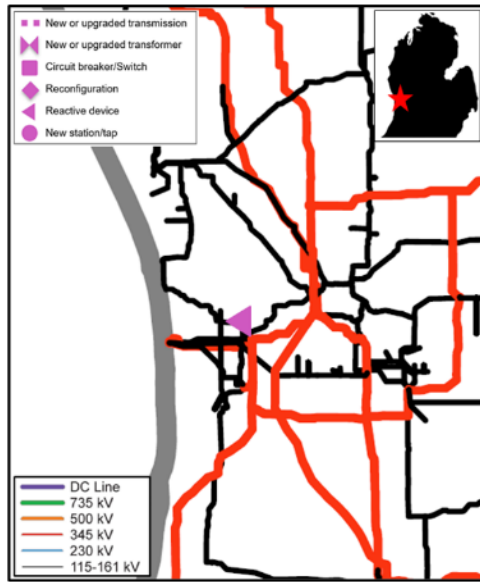
Project Justification: The [METC] Gaines – [METC] Caledonia Junction 138 kV line becomes overloaded to one hundred six (106%) percent in year 2029 for NERC defined category P7 and P6 contingency events. Upgrading [METC] Gaines – [METC] Caledonia Junction 138 kV line will increase the summer emergency rating from 107 MVA to 153 MVA.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P7	[METC] Gaines – [METC] Caledonia Jct. 138 kV line	107	106	76
P6	[METC] Gaines – [METC] Caledonia Jct. 138 kV line	107	106	76

Table 4.4.2-9: P25216 Thermal loading drivers.



METC 25217 – Blendon 138 kV Capacitor



Project #	25217
Project Name	Blendon 138 KV Capacitor
Project Type	BRP
Project Description	Install (1) 33.33 MVAR capacitor bank with associated 138kV, 40 kA synchronous breakers and disconnect switch at the Blendon 138kV substation. The proposed capacitor will be connected to bus 40 and Transformer 1 will be moved to Bus 50. Relocate the existing Blendon-Campbell 138kV line termination from bus 30 to the bus 60. Also, Relocate the existing Blendon-Fairview 138kV line termination from bus 60 to the section 30 bus.
System Needs	Low voltage is projected to occur at Blendon 138kV buses for P6 or P23 contingencies. The low voltage violations were identified in the 2025, 2028 and 2033, peak and off-peak load models.
Estimated Cost	\$4,260,000
Expected ISD	6/1/28
Target Appendix	A

Figure 4.4.2-11: P25217 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The Blendon 138 kV bus has undervoltage issues of 0.90 p.u. in year 2034 for both NERC defined category P2 and P6 contingency events. Adding a capacitor at the Blendon 138 kV bus will provide voltage support.

Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P2	[METC] Blendon 138 kV bus	0.92	0.90	0.99
P6	[METC] Blendon 138 kV bus	0.92	0.90	0.94

Table 4.4.2-10: P25217 Voltage loading drivers.



METC 25275 – METC SPOF Blanket



Project #	25275
Project Name	METC SPOF Blanket
Project Type	BRP
Project Description	Blanket for projects to address locations where single point of failure (SPOF) are identified that cause system issues.
System Needs	System violations throughout METC system that are caused by single point of failure (SPOF) contingencies.
Estimated Cost	\$19,500,000
Expected ISD	6/1/29
Target Appendix	A

Figure 4.4.2-12: 25275 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: Since the implementation of TPL-001-5.1, many METC BES substations have been identified as having single points of failure (SPOF) violations in MISO steady-state and dynamic analysis and METC short-circuit analysis. This blanket project addresses 35 facilities with these SPOFs prior to the implementation deadline of the standard. The highest observed thermal and voltage violations are listed below.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P5	[METC] Long Rapids - [METC] Rockport 138 kV line	92	132	Project upgrade invalidates the single point of failure contingency impact on this line

Table 4.4.2-11: P25275 Thermal loading drivers.



Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P5	[METC] Ellis Jct. 138 kV bus	0.92	0.90	Project upgrade invalidates the single point of failure contingency impact on this bus

Table 4.4.2-12: P25275 Voltage loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
21968	Delaney 138 kV Station Rebuild	Age and Condition	6/1/2027	\$8.6
25198	Port Calcite 138 kV Station Rebuild	Local Reliability	6/1/2028	\$9.8
25230	Manning #2 345-138 kV Transformer Replacement	Age and Condition	12/31/2027	\$7.1
25277	METC Customer Interconnections - 2027	Load Growth	12/31/2027	\$2.5
25278	METC Line Relocation - 2024	Local Reliability	12/31/2024	\$2.5
25327	METC Asset Replacement Program - 2026	Age and Condition	12/31/2026	\$54.0
25500	METC Line Relocation - 2025	Local Needs	12/31/2025	\$2.5
25522	Oakland 138 kV Station Rebuild	Age and Condition	6/1/2027	\$8.3
*50038	Project Phoenix-Husky Substation	Local Needs	8/19/2026	\$50.3
**50121	Iosco - Karn 138 kV Relocation (Alternative)	Age and Condition	6/1/2028	\$45.1
*50151	Sphinx 138 kV Station	Load Growth	9/1/2027	\$32.8

* Project studied through Expedited Project Review (EPR) process; ** Project included an original project (50064 Iosco-Karn 138 kV Rebuild) which was evaluated and not selected due to cost, therefore MISO recommends the alternative project as listed in the table above.

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
24440	Van Tyle - J1603 NU - Install breaker 4B7 and switches 4M5 and 4B3	8/1/2025	\$1.1
24442	Van Tyle-J1603 TOIF-Install position BM4 and switch 177	8/1/2025	\$0.0

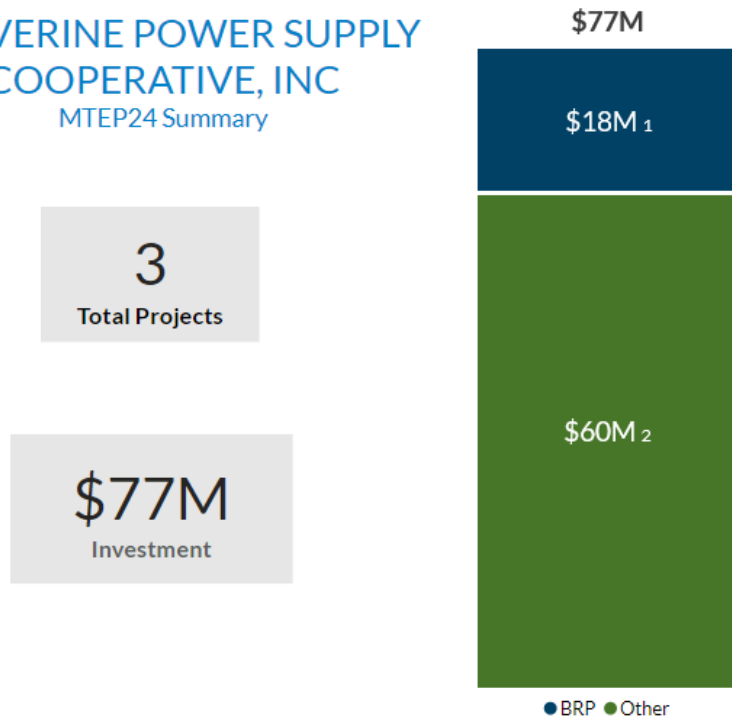


Project ID	Project Name	ISD	Estimated Cost (\$M)
24443	Tallmadge-Argenta - J1663 Generator Interconnection (Gordon) - Network Upgrade	5/1/2026	\$14.8
24444	Barton Lake-Batavia - J1550 Generator Interconnection (Dorrance) TOIF	5/1/2025	\$0.0
24458	Kenowa - J1527 TOIF - Install position FH35 and switch 177	12/31/2026	\$0.0
24477	Gaines - Thompson Road 138 kV - J1292 GIA (Peddler) TOIF	9/29/2027	\$0.0
24478	Kenowa - J1527 Gen Network Upgrade	4/1/2026	\$5.6
24479	Gordon-J1663 TOIF-Install position RH29 and switch 177	5/1/2026	\$0.0
24515	J1553 Generator Interconnection TOIF	5/30/2025	\$0.0
24516	J1571 Generator Interconnection Network Upgrades	12/31/2026	\$8.6
24535	J1553 Generator Interconnection Network Upgrades	5/30/2025	\$6.2
24536	J1571 Generator Interconnection TOIF	12/31/2026	\$0.0
24537	J1635 Generator Interconnection Network Upgrades	4/3/2025	\$9.6
24538	J1635 Generator Interconnection TOIF	4/1/2025	\$0.0
24556	J1586 Generator Interconnection Network Upgrades	1/21/2027	\$14.5
24557	J1586 Generator Interconnection TOIF	12/31/2026	\$0.0
24558	J1658 Generator Interconnection Network Upgrades	2/2/2026	\$19.7
24559	J1658 Generator Interconnection TOIF	12/31/2025	\$0.0
24560	J1614 Generator Interconnection Network Upgrades	3/3/2026	\$11.8
24561	J1614 Generator Interconnection TOIF	12/31/2025	\$0.0
25194	Cronk-Moore Road Rebuild & Station Equipment Upgrades (J1550, J1635, J1658) - Network Upgrade	2/2/2026	\$11.3
25196	Beecher-Dowling Junction Sag Remediation (J1550, J1635, J1658) - Network Upgrade	9/30/2025	\$0.3
25209	Battle Creek-Oneida and Argenta-Tompkins Line Upgrades (J1586) - Network Upgrade	2/1/2027	\$16.2
25210	Replace Moore Road WM33 Trainer (J1658) - Network Upgrade	1/30/2026	\$0.0
25227	Dowling Junction-Knowles Sag Remediation (J1658) - Network Upgrade	3/3/2025	\$1.1
25244	Morocco - Replace RH34 Relaying - Multiple Generator Network Upgrade	6/11/2027	\$0.3
25245	Coldwater-Ash Road Junction Sag Remediation (J1550) - Network Upgrade	10/31/2025	\$0.3



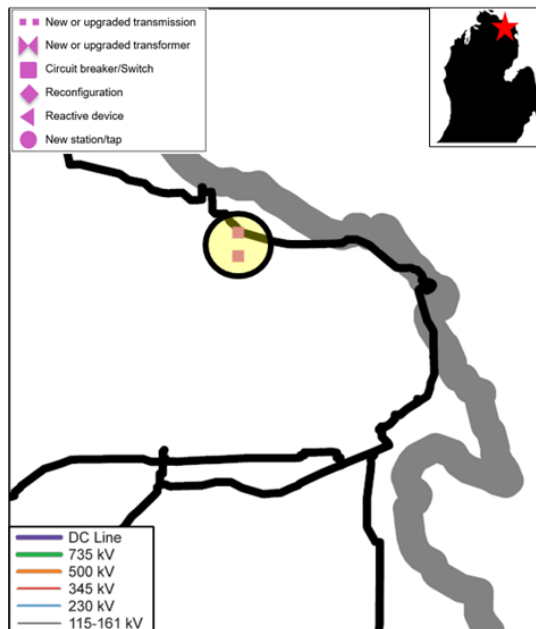
4.4.3 Wolverine Power Supply Cooperative Inc. (WPSC)

WOLVERINE POWER SUPPLY COOPERATIVE, INC MTEP24 Summary



Baseline Reliability Projects

WPSC 50098 – Hagensville Junction Interconnection



Project #	50098
Project Name	Hagensville Junction Interconnection
Project Type	BRP
Project Description	Interconnect Wolverine's Hagensville Junction with METC's Rockport to Port Calcite line.
System Needs	Voltage support of Northeast Michigan for P6 contingencies as observed in MTEP23 with further integration of Wolverine's system to METC's system.
Estimated Cost	\$17,550,000
Expected ISD	12/31/28
Target Appendix	A

Figure 4.4.3-1: P50098 Geographic transmission map of project area and MTEP Portal project details.



Project Justification: The [METC] Long Rapids – [METC] Rockport 138 kV line becomes overloaded to one hundred eighteen (118%) percent in year 2029 for a NERC defined category P6 contingency event. This project will provide an additional path for power flow and reduce loading on the nearby lines.

The [METC] Grand Lake 138 kV bus is projected to have an under-voltage level of 0.90 p.u. in year 2029 for NERC defined category P6-contingencies. The [METC] Rockport 138 kV bus is projected to have an under-voltage level of 0.91 p.u. in year 2029 for NERC defined category P6-contingencies. The [METC] Hagensville Junction 138 kV bus is projected to have an under-voltage level of 0.91 p.u. in year 2029 for NERC defined category P6 contingency events. The additional Hagensville Junction 138 kV line will provide voltage support.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P6	[METC] Long Rapids – [METC] Rockport 138 kV	133	118	78

Table 4.4.3-1: P50098 Thermal loading drivers.

Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P6	[METC] Grand Lake 138 kV	0.92	0.90	0.94
P6	[METC] Rockport 138 kV	0.92	0.91	0.94
P6	[METC] Hagensville Jct. 138 kV	0.92	0.91	0.94

Table 4.4.3-2: P50098 Voltage loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
21786	Vestaburg 69 kV Relocation	Age and Condition	12/31/2026	\$7.5
25191	Leroy to South Boardman DC Line Rebuild	Local Reliability	12/31/2028	\$52.1

4.4.4 Michigan Public Power Agency (MPPA)

Michigan Public Power Agency and MISO are not recommending any new projects for MTEP24.



4.4.5 Lansing Board of Water and Light (LBWL)

Lansing Board of Water and Light and MISO are not recommending any new projects for MTEP24.

4.4.6 Michigan South Central Power Agency (MSCPA)

Michigan South Central Power Agency and MISO are not recommending any new projects for MTEP24.



4.5 Project Justifications – South Region

South Region Overview

The MISO South Planning Region consists of eleven Transmission-Owning members spanning four states, Arkansas, Louisiana, Mississippi, and parts of Texas. These Transmission Owners are:

Arkansas Electric Cooperative Corporation (AECC)	Entergy Louisiana LLC (ELL)
City of Alexandria (AXLA)	Entergy Mississippi LLC (EML)
CLECO Power LLC (CLEC)	Entergy Texas Incorporated (ETI)
Cooperative Energy (SMEPA)	Lafayette Utilities Systems (LAFA)
East Texas Electric Cooperative (ETEC)	City Water and Light Jonesboro (CWLT)
Entergy Arkansas LLC (EAL)	

The region contains approximately 17,800 circuit miles of transmission lines ranging from 115 kV to 500 kV. There is also a significant 69 kV sub-transmission network interspersed across the footprint.

In the 2024 series of planning models, the south region contains more than 54.7 GW of generation. The MISO South generation profile consists of mostly combined cycle, nuclear, gas, coal fuel types, and solar serving major load centers such as Little Rock, New Orleans, etc. Approximately 40% (21.9 GW) of the South region's generation capacity is made up of combined cycle (CC) units. Major generation centers are in central Arkansas, lower Louisiana, and western Mississippi (Figure 4.5-1).

Major load centers are typically found around larger cities in the region such as Little Rock, Jonesboro, and Pine Bluff in Arkansas; Monroe, Alexandria, Lake Charles, Lafayette, New Orleans, and Baton Rouge in Louisiana; Jackson, Hattiesburg, Natchez, Vicksburg, and Greenville in Mississippi. Texas major load centers in the Western load pocket include Bryan and the Woodlands area. The major load center in the West of the Atchafalaya Basin (WOTAB) load pocket portion of Texas is in South Beaumont and the Port Arthur Area (Figure 4.5-1). According to the 2026 Summer Peak planning model, the regional load is over 39.8 GW.

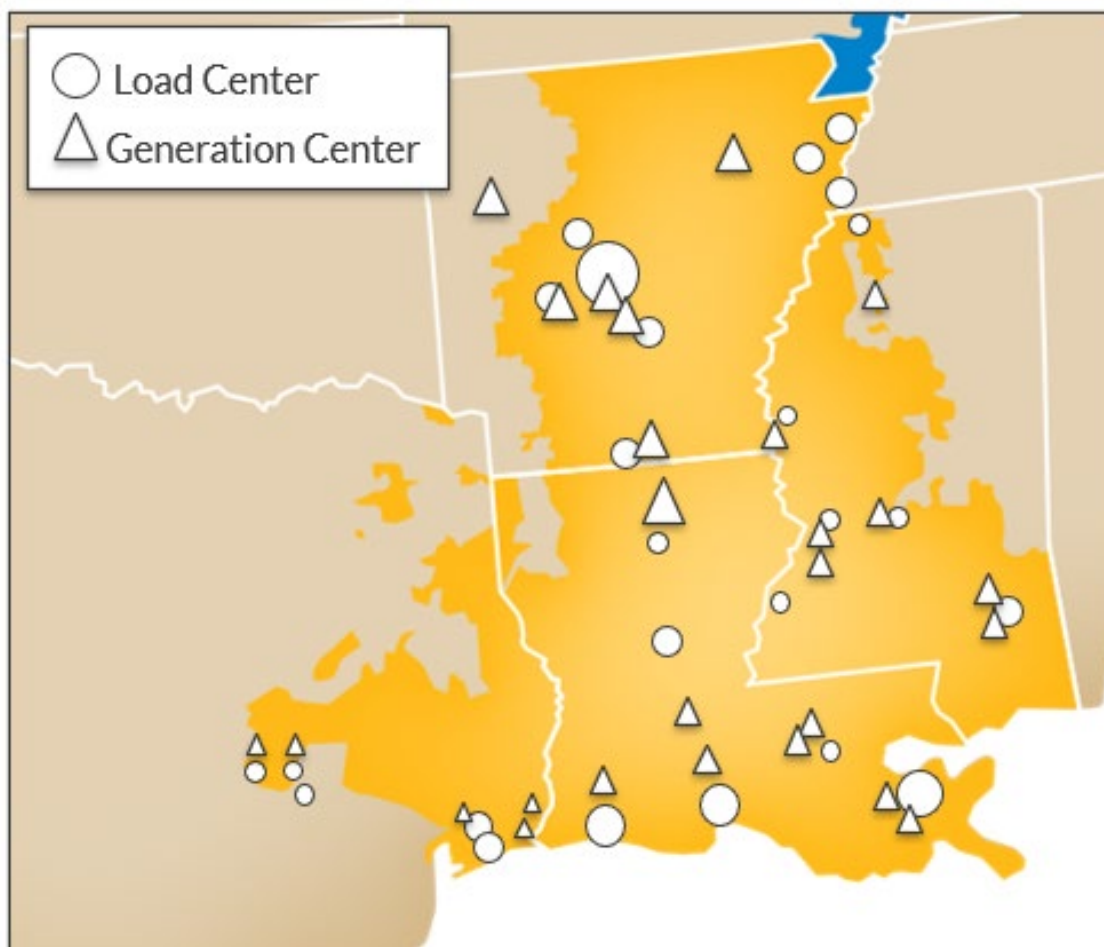
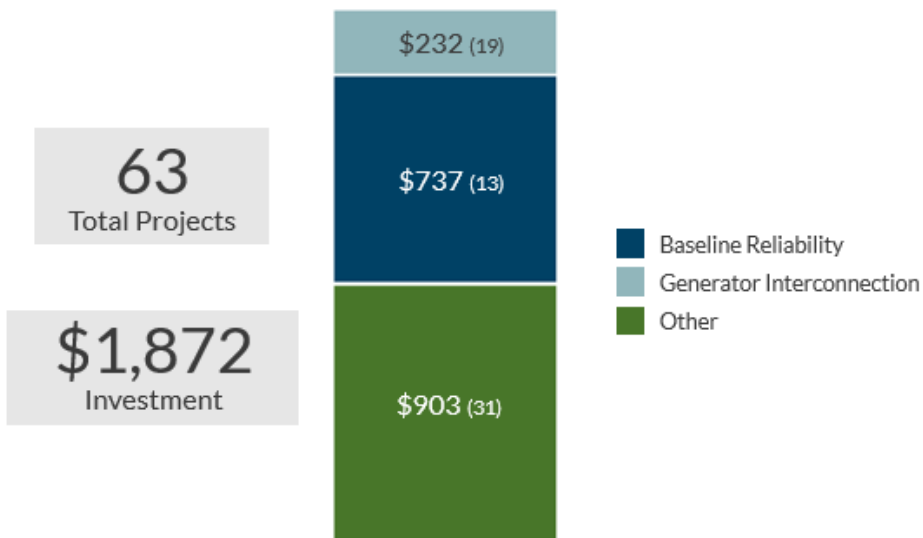


Figure 4.5-1: Generation and load centers in the South planning region.

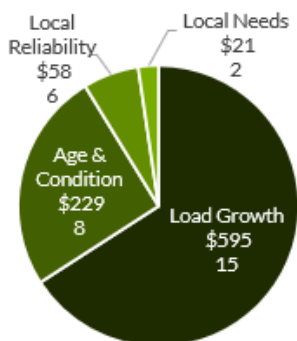


South Planning Region Local MTEP24 Summary

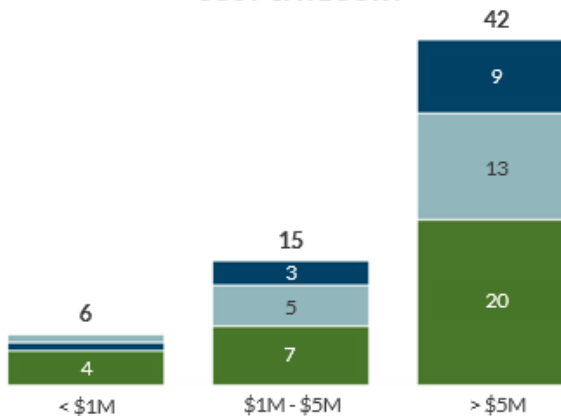
(Data as of August 27, 2024; \$M, # project count)



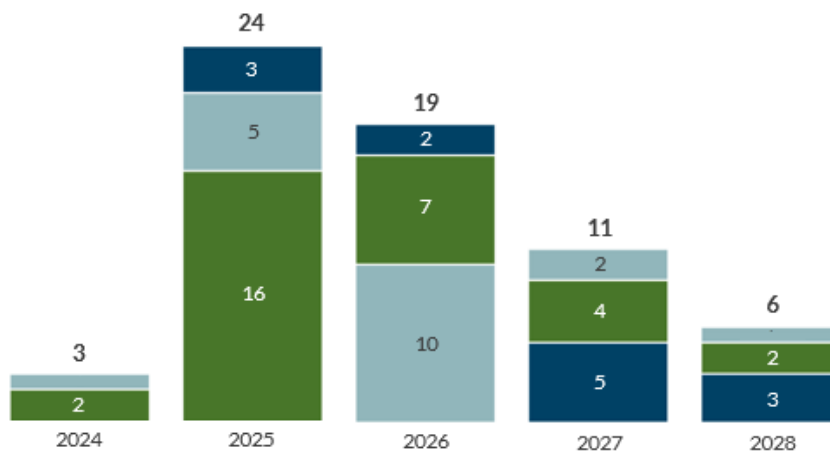
BREAKDOWN OF OTHER PROJECTS BY COST



PROJECT COUNT BY COST CATEGORY



PROJECTS BY IN-SERVICE DATE





The ten largest project investments in the MISO South region represent an estimated \$1.2 billion (62%) of the \$1.9 billion total recommended projects for the South region in the local MTEP24 portfolio, or 17% of the \$6.7 billion total recommended in the MISO footprint. The locations of these projects are shown in Figure 4.5-2. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

South Region Top 10 Local MTEP24 Projects

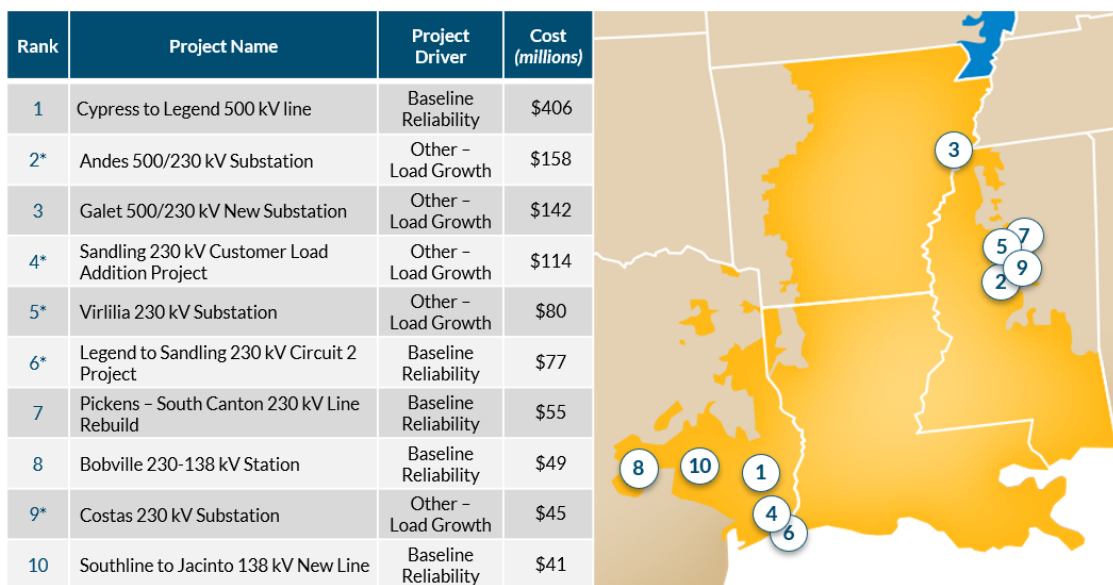
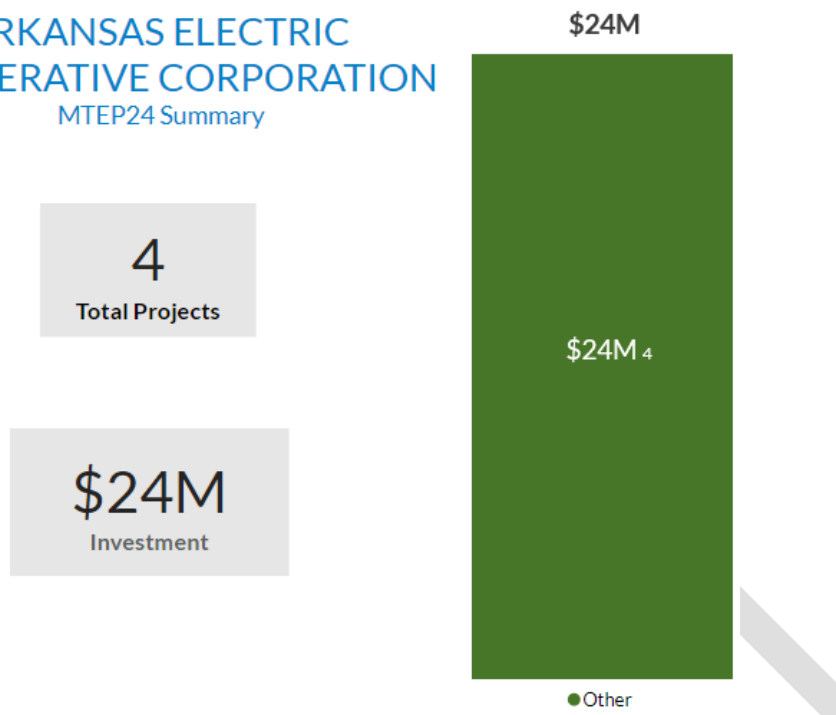


Figure 4.5-2: South region top ten projects by cost; * represents project studied through Expedited Project Review (EPR) process (data as of 8-27-2024).



4.5.1 Arkansas Electric Cooperative Corporation (AECC)

ARKANSAS ELECTRIC COOPERATIVE CORPORATION MTEP24 Summary



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
24694	Coop Office Breaker Addition	Local Reliability	12/31/2026	\$2.5
*50094	Northstar	Load Growth	4/1/2026	\$7.0
*50099	Lewisville West Capacity Increase	Load Growth	10/1/2025	\$4.5
*50164	Woodberry Load Addition	Load Growth	12/1/2025	\$10.2

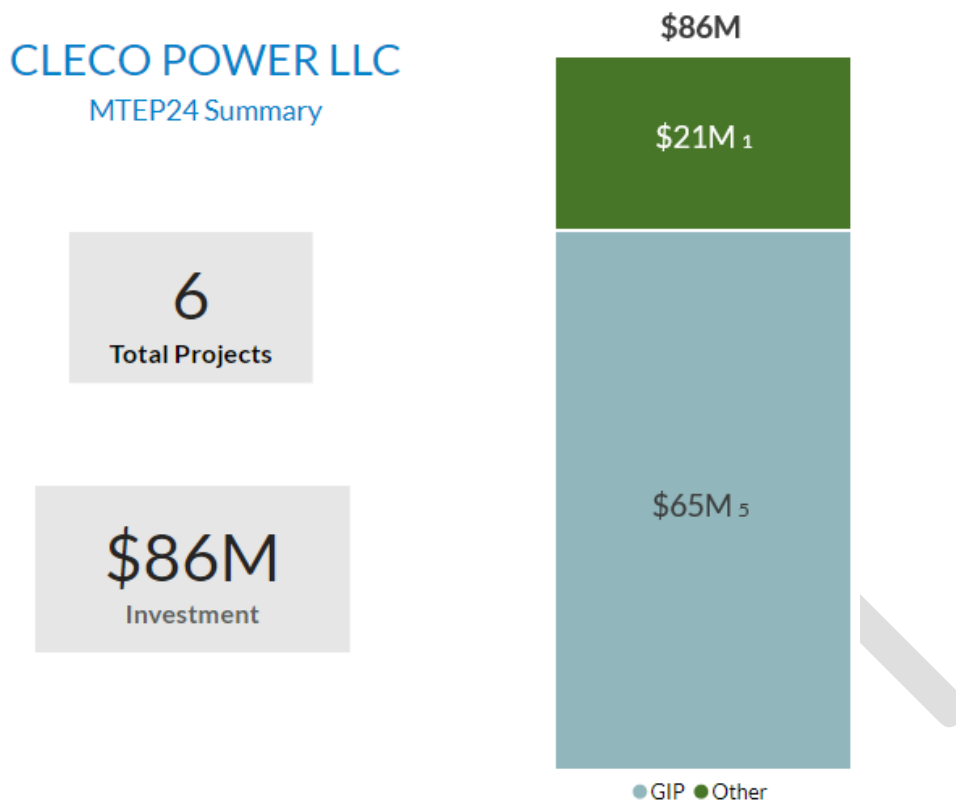
* Project studied through Expedited Project Review (EPR) process.

4.5.2 City of Alexandria (AXLA)

City of Alexandria and MISO are not recommending any new projects for MTEP24.



4.5.3 CLECO Power LLC (CLEC)



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
*50011	Weeks Island Sub	Local Reliability	5/16/2025	\$21.2

* Project studied through Expedited Project Review (EPR) process.

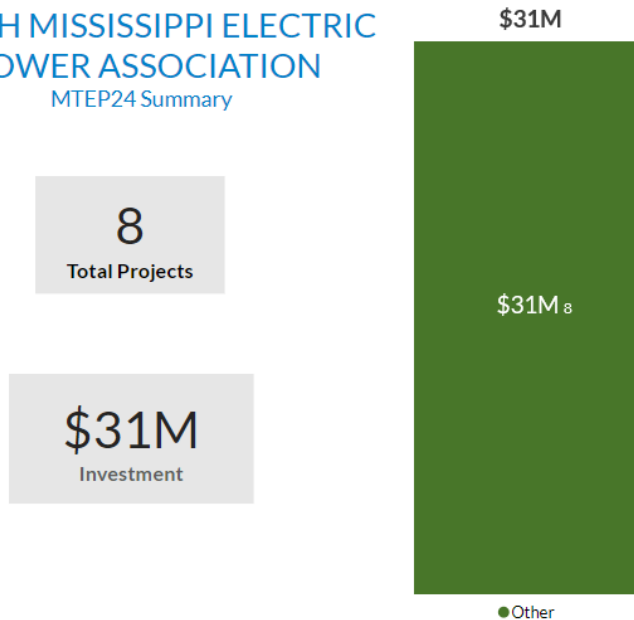
Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25283	Dolet Solar Replacement R1004	12/15/2026	\$19.7
25312	J1832 Plaisance Expansion	7/15/2024	\$6.5
25313	J1599 Daspit Substation	9/1/2025	\$16.2
50067	J1686 Generator Interconnection on Coughlin - Plaisance 138 kV	9/1/2026	\$18.2
50087	J1673 & J1759 Ft. Jessup Substation	7/1/2025	\$4.1



4.5.4 Cooperative Energy (formerly SMEPA)

SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION MTEP24 Summary



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25416	Lucedale 69 kV Switching Station	Load Growth	10/1/2025	\$2.9
25417	Line 34 Rebuild	Age and Condition	12/1/2025	\$5.0
25419	Hermanville 115 kV Delivery Point	Load Growth	11/1/2028	\$0.7
25459	Line 35 Rebuild	Age and Condition	6/1/2026	\$7.1
25489	North Lucedale 69 kV Delivery Point	Load Growth	12/1/2027	\$6.4
25501	County Line 115 kV Delivery Point	Load Growth	12/1/2026	\$2.2
25520	South Lucedale 69 kV Delivery Point	Load Growth	3/1/2028	\$6.5
25540	State Line 69 kV Delivery Point	Load Growth	12/1/2025	\$0.7

4.5.5 East Texas Electric Cooperative (ETEC)

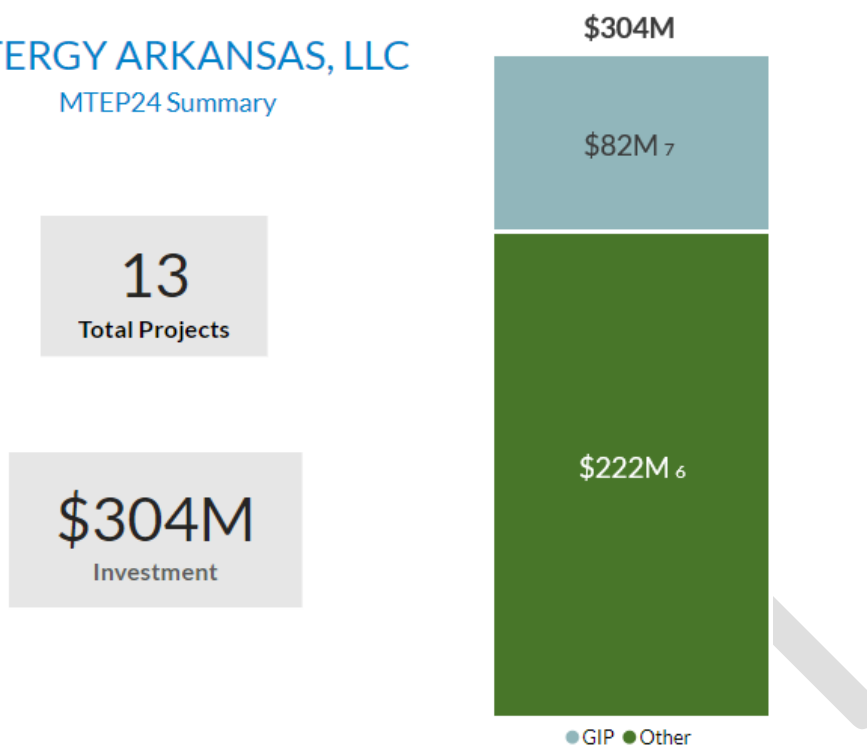
East Texas Electric Cooperative and MISO are not recommending any new projects for MTEP24.



4.5.6 Entergy Arkansas LLC (EAL)

ENTERGY ARKANSAS, LLC

MTEP24 Summary



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25472	2025 EAL Asset Renewal Program	Age and Condition	12/1/2025	\$32.9
25481	Arklahoma 115 kV Bus Relay Improvement SPOF	Local Reliability	12/1/2025	\$2.5
25485	Champs 115 kV: New Substation Phase 1	Local Reliability	12/1/2025	\$10.8
25487	Frazier Pike 115 kV: New Substation	Local Reliability	12/1/2025	\$18.0
50013	Grand Prairie 115 kV: New substation	Load Growth	4/1/2025	\$15.6
50093	Galet 500/230 kV New Substation	Load Growth	9/30/2026	\$142.0

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
50004	J1670 Crooked Lake 2 GIA upgrades	4/3/2026	\$1.3
50034	J1437 Nimbus Wind FCA	4/30/2025	\$1.9

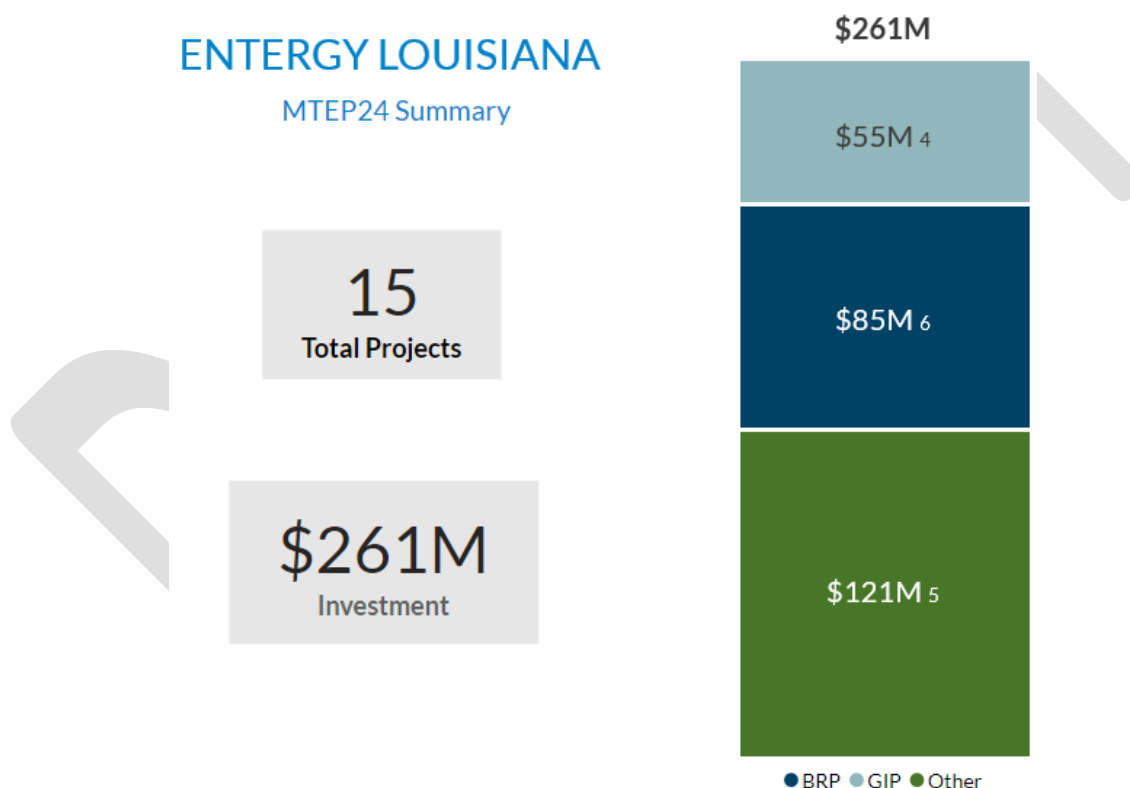


Project ID	Project Name	ISD	Estimated Cost (\$M)
50035	Doylestown 115 kV: Cut in Switching Station (J1577 & J1607)	5/1/2025	\$3.8
50040	Morrilton East 161 kV: POI for J1559	4/1/2026	\$3.2
50059	Kinder 161 kV: New POI J1558	10/1/2026	\$14.0
50090	Wheatley 500 kV: New POI J1710 J1819 J1820 J1821	9/13/2026	\$32.4
50197	West Memphis 500/161 kV Auto Replacement MPFCA	12/5/2026	\$25.5

4.5.7 Entergy Louisiana LLC (ELL)

ENTERGY LOUISIANA

MTEP24 Summary





Baseline Reliability Projects:

Project 13905 – Burnside 230-115 kV Autotransformer

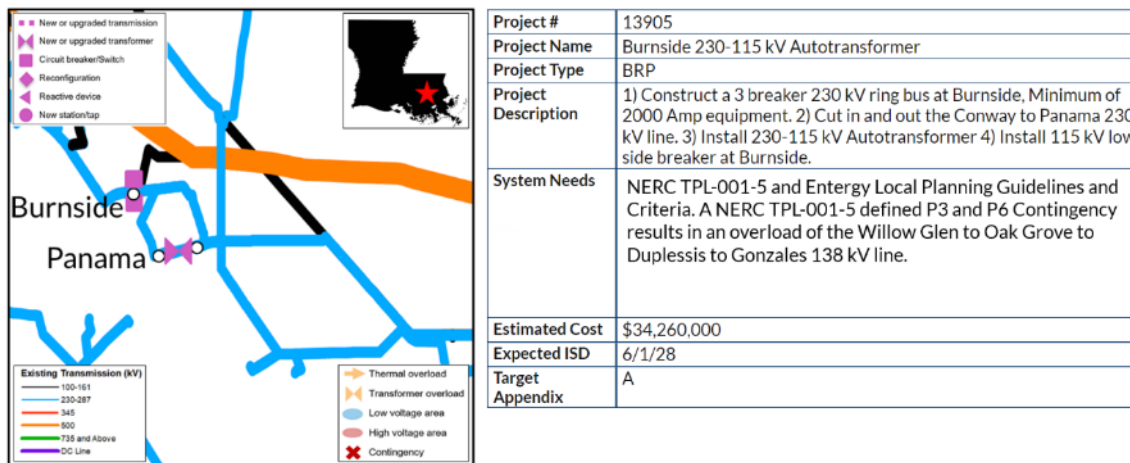


Figure 4.5.7-1: P13905 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: A NERC TPL-001-5 defined P3 and P6 contingency results in an overload of the Willow Glen to Oak Grove to Duplessis to Gonzales 138 kV line.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P6	[EES] Willow Glen to Oak Grove 138 kV	309	143	50
P6	[EES] Oak Grove to Duplessis 138 kV	232	112	31

Table 4.5.7-1: P13905 Thermal loading drivers.



Project 25430 – Fairview to Madisonville 230 kV Upgrades

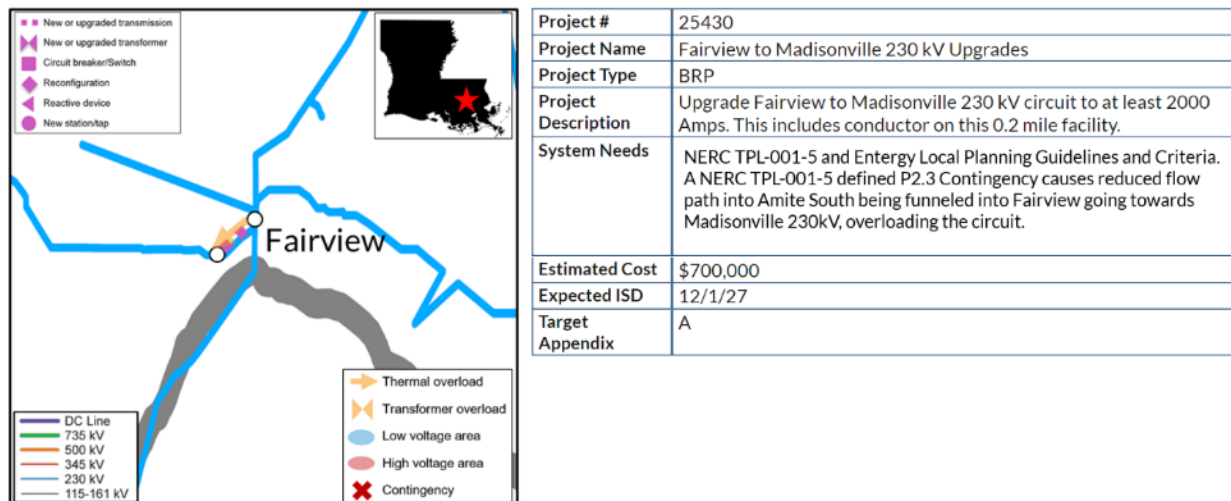


Figure 4.5.7-2: P25430 Geographic transmission map of project area and MTEP Portal project details.

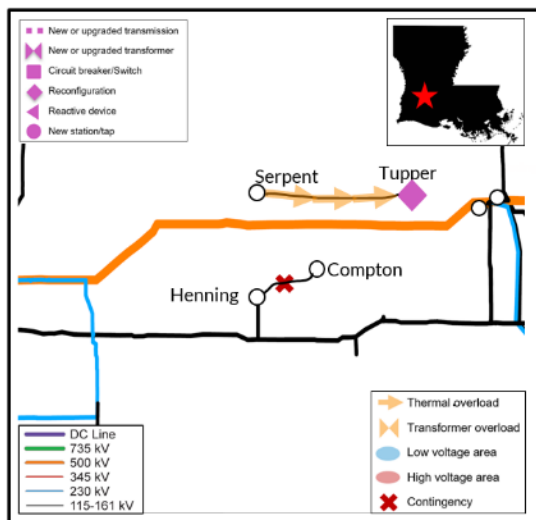
Project Justification: A NERC TPL-001-5 defined P2.3 contingency causes reduced flowpath into Amite South being funneled into Fairview going towards Madisonville 230 kV, overloading the circuit.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P2.3	[EES] Fairview to Madisonville 230 kV	467	102	67

Table 4.5.7-2: P25430 Thermal loading drivers.



Project 25435 – Serpent to Tupper 69 kV Upgrade



Project #	25435
Project Name	Serpent to Tupper 69 kV Upgrade
Project Type	BRP
Project Description	Upgrade 69 kV bus at Tupper.
System Needs	NERC TPL-001-5 and Entergy Local Planning Guidelines and Criteria. A NERC TPL-001-5 defined P1.2 Contingency causes an overload on the Serpent to Tupper 69kV line.
Estimated Cost	\$1,200,000
Expected ISD	12/1/28
Target Appendix	A

Figure 4.5.7-3: P25435 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: A NERC TPL-001-5 defined P1.2 contingency causes an overload on the Serpent to Tupper 69 kV line.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
N-1	[EES] Serpent to Tupper 69 kV line	105	111	50

Table 4.5.7-3: P25435 Thermal loading drivers.



Project 25465 – Paincourtville 115 kV Capacitor Bank Split

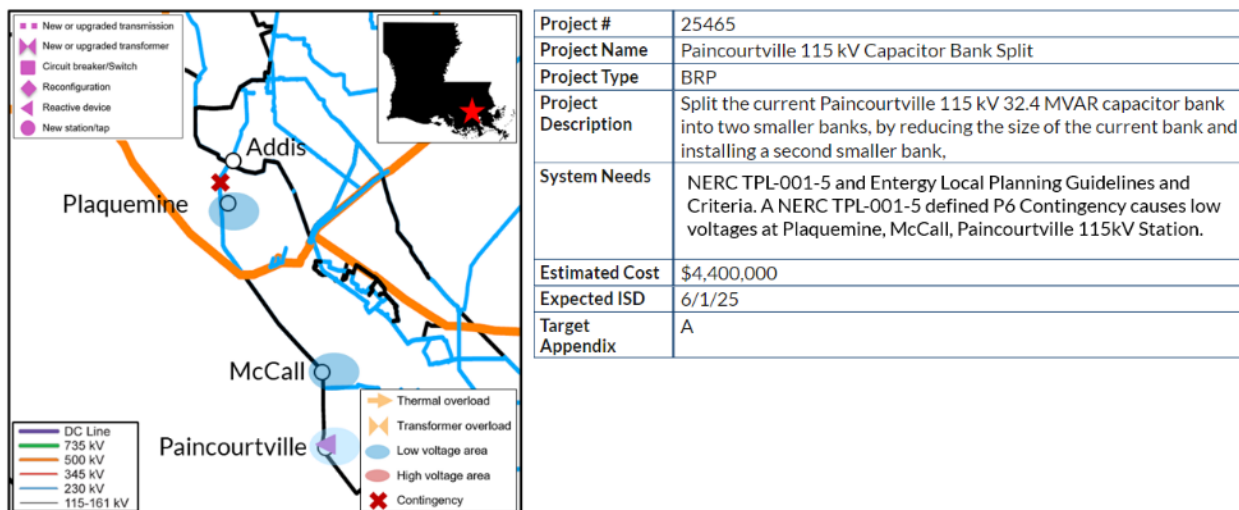


Figure 4.5.7-4: P25465 Geographic transmission map of project area and MTEP Portal project details.

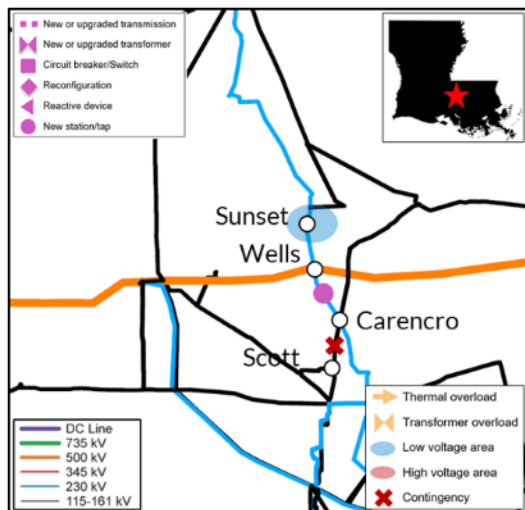
Project Justification: A NERC TPL-001-5 defined P6 contingency causes low voltages at Plaquemine, McCall, Paincourtville 115 kV Station.

Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
N-1-1	[EES] McCall 115 kV	0.92 - 1.05	0.91	0.96
N-1-1	[EES] Plaquemine 115 kV	0.92 - 1.05	0.90	0.95
N-1-1	[EES] Paincourtville 115 kV	0.92 - 1.05	0.91	0.95

Table 4.5.7-4: P25465 Voltage loading drivers.



Project 25470 – Sunrise 230 kV New Station



Project #	25470
Project Name	Sunrise 230 kV New Station
Project Type	BRP
Project Description	Cut a new 230 kV station named Sunrise on the Wells to Labbe 230 kV line. Install distribution facilities to serve load currently served from the existing Sunset 69 kV station.
System Needs	Entergy Local Planning Guidelines and Criteria. A NERC TPL-001-5 defined P1.2 Contingency causes and overload on the Champagne to Sunset 69 kV Line and low voltage at the Sunset and International Pipeline 69kV stations.
Estimated Cost	\$39,600,000
Expected ISD	6/1/27
Target Appendix	A

Figure 4.5.7-5: P25470 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: A NERC TPL-001-5 defined P1.2 contingency causes an overload on the Champagne to Sunset 69 kV Line and low voltage at the Sunset and International Pipeline 69 kV stations.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
N-1	[EES] Champagne to Sunset 69 kV line	56	110	38

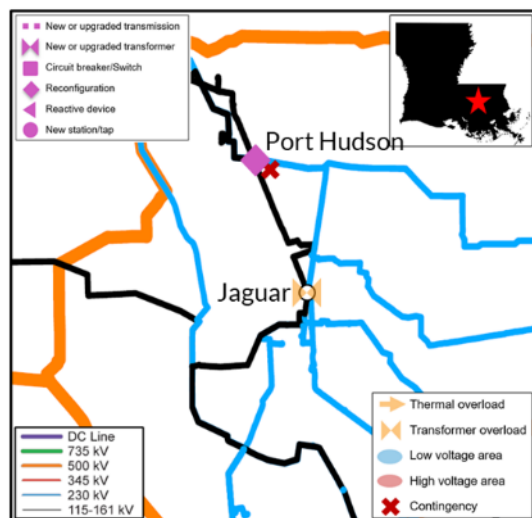
Table 4.5.7-5: P25470 Thermal loading drivers

Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
N-1	[EES] Sunset 69 kV	0.90 - 1.05	0.89	0.99
N-1	[EES] International Pipeline 69 kV	0.90 - 1.05	0.88	0.99

Table 4.5.7-6: P25470 Voltage loading drivers.



Project 25480 – Port Hudson 230-138 kV AT4 & 5 SPOF



Project #	25480
Project Name	Port Hudson 230-138 kV AT4 & 5 SPOF
Project Type	BRP
Project Description	Ensure Port Hudson 230/138 kV AT4 and AT5 both have redundant high-speed protection.
System Needs	NERC TPL-001-5 and Entergy Local Planning Guidelines and Criteria. A NERC TPL-001-5 defined P5 Contingency will overload the Jaguar 230-69 kV AT, Jaguar to Blount 69 kV line and Swan to Grace 69 kV.
Estimated Cost	\$4,400,000
Expected ISD	6/1/25
Target Appendix	A

Figure 4.5.7-6: P25480 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: A NERC TPL-001-5 defined P5 contingency will overload the Jaguar 230-69 kV AT, Jaguar to Blount 69 kV line and Swan to Grace 69 kV.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P5	[EES] Jaguar to Blount 69 kV	148	122	44
P5	[EES] Swan to Grace 69 kV	101	109	35

Table 4.5.7-7: P25480 Thermal loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25413	Retirement of Golden Meadow to Barataria 115 kV line	Local Needs	12/31/2024	\$0.0
25455	Amite South/DSG Reactive Support Project	Local Needs	6/1/2027	\$21.0
25457	PCI 69 kV Breaker Upgrades	Local Reliability	6/1/2027	\$2.7
25482	2025 ELL Asset Renewal Program	Age and Condition	12/31/2025	\$87.9
25483	2025 ENOL Asset Renewal Program	Age and Condition	12/31/2025	\$9.6



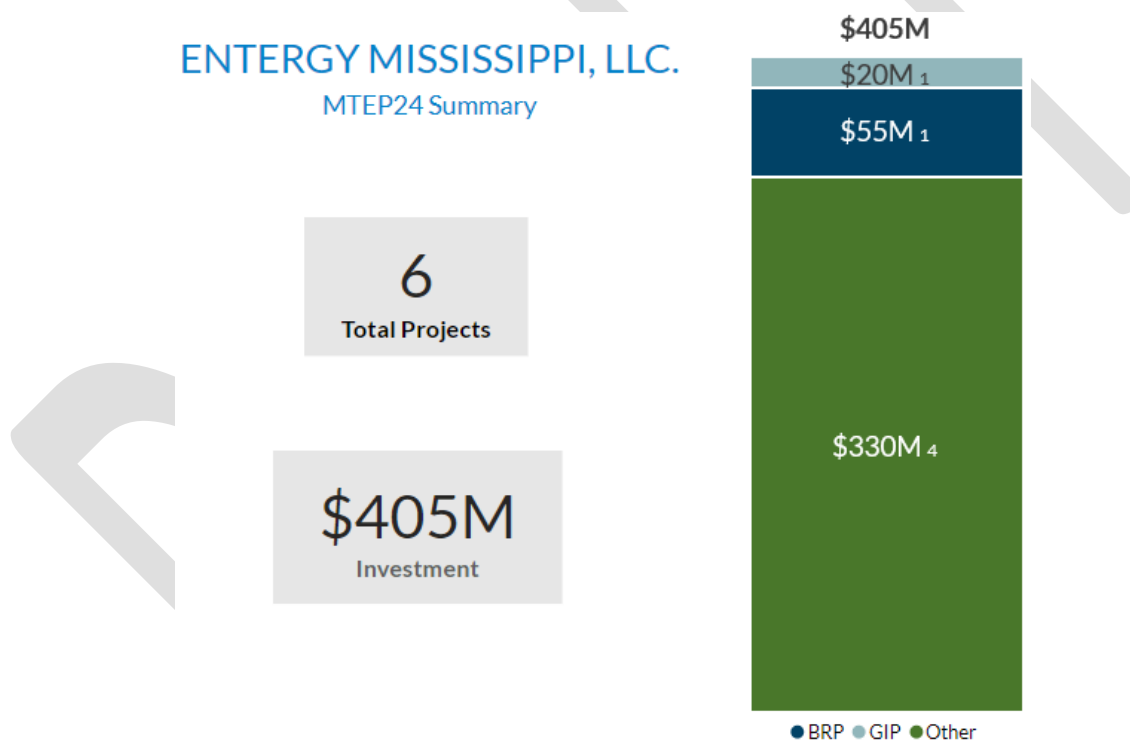
Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25352	J1833 Generator Interconnection	4/1/2027	\$17.8
50039	J1561 Generator Interconnection at Richard 138 kV	4/1/2026	\$8.3
50048	MPFCA J1644, J1686, J1832: Upgrade of Champagne – East Opelousas – Colton 138 kV line	6/9/2026	\$9.1
50065	J1576 Generator Interconnection on the Adams Creek - Angie 230 kV	11/15/2026	\$19.7

4.5.8 Entergy Mississippi LLC (EML)

ENTERGY MISSISSIPPI, LLC.

MTEP24 Summary





Baseline Reliability Projects:

Project 25438 – Pickens – South Canton 230 kV Line Rebuild

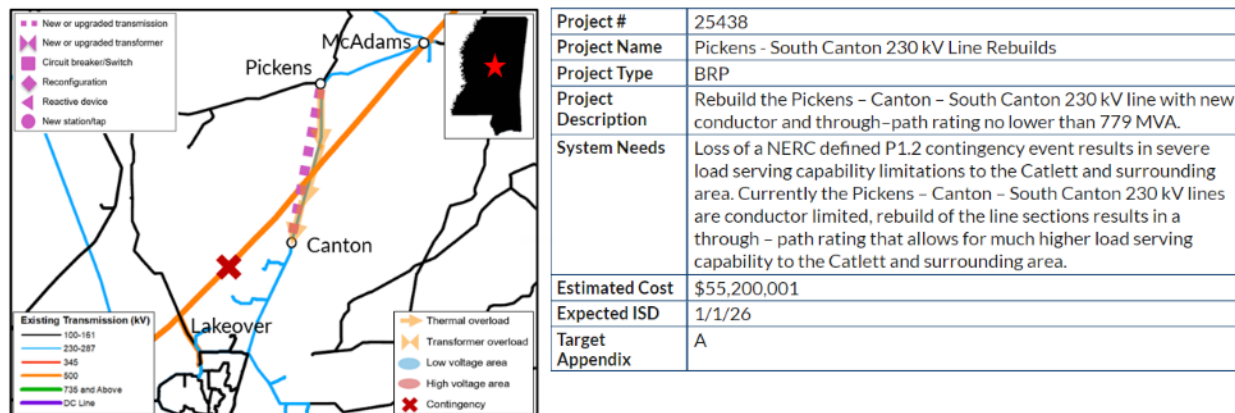


Figure 4.5.8-1: P25438 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [EML] Pickens – [EML] Canton 230 kV & [EML] Canton – [EML] South Canton 230 kV line sections become overloaded in year 2023 for a NERC defined category P1-2 contingency event. Reconductoring [EML] Pickens – [EML] Canton – [EML] South Canton 230 kV to a minimum summer emergency rating of 779 MVA will decrease post-contingent Loading and resolve thermal violations.

Cont. Type	MTEP Cycle	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P1-2	24	[EML] Pickens – [EML] Canton 230 kV	462	88	53
P1-2	24	[EML] Canton – [EML] South Canton 230 kV	462	80	48
P1-2	23 EPR	[EML] Pickens – [EML] Canton 230 kV	462	102	48
P1-2	23 EPR	[EML] Canton – [EML] South Canton 230 kV	462	95	41

Table 4.5.8-1: P25438 Thermal loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
*25214	Virililia 230 kV Substation	Load Growth	1/1/2025	\$79.5
*25215	Andes 500/230 kV Substation	Load Growth	6/1/2027	\$158.0



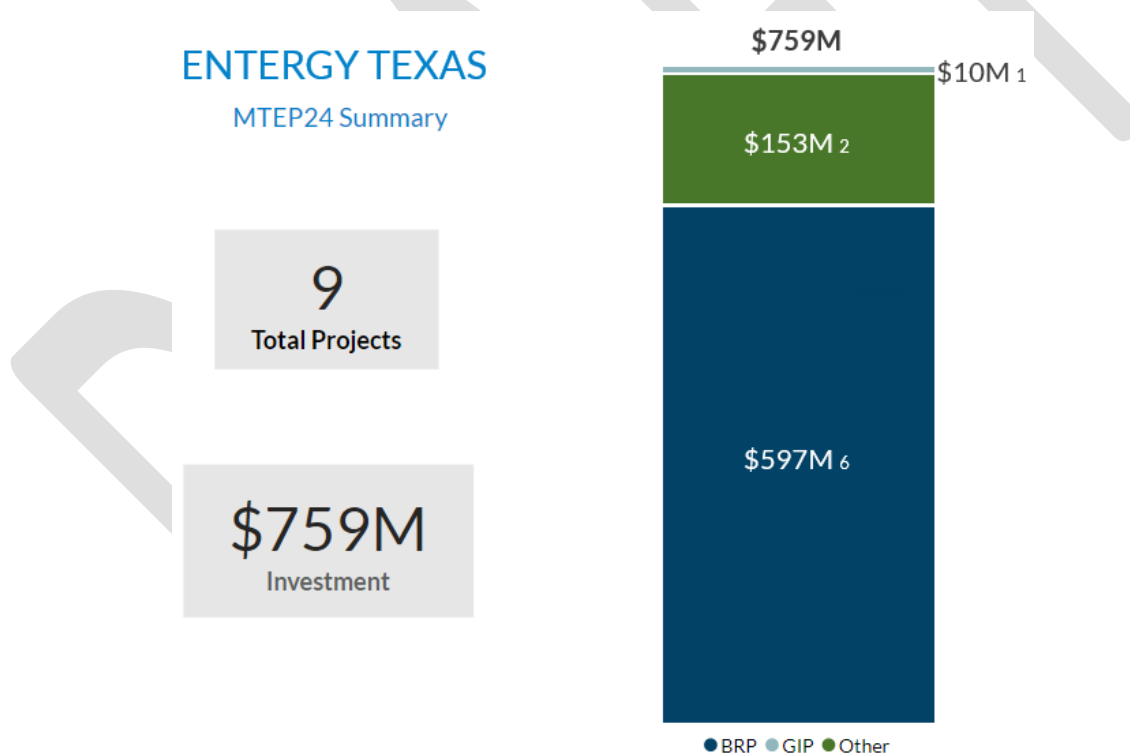
Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
*25229	Costas 230 kV Substation	Load Growth	1/1/2026	\$44.5
25486	2025 EML Asset Renewal Program	Age and Condition	12/31/2025	\$47.8

* Project studied through Expedited Project Review (EPR) process.

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
50160	J1672 Network Upgrades: Gerald Andrus 230 kV Auto	12/15/2027	\$19.8

4.5.9 Entergy Texas, Inc. (ETI)





Baseline Reliability Projects:

Project 24959 – Kolbs to Port Acres 230 kV Upgrade Project

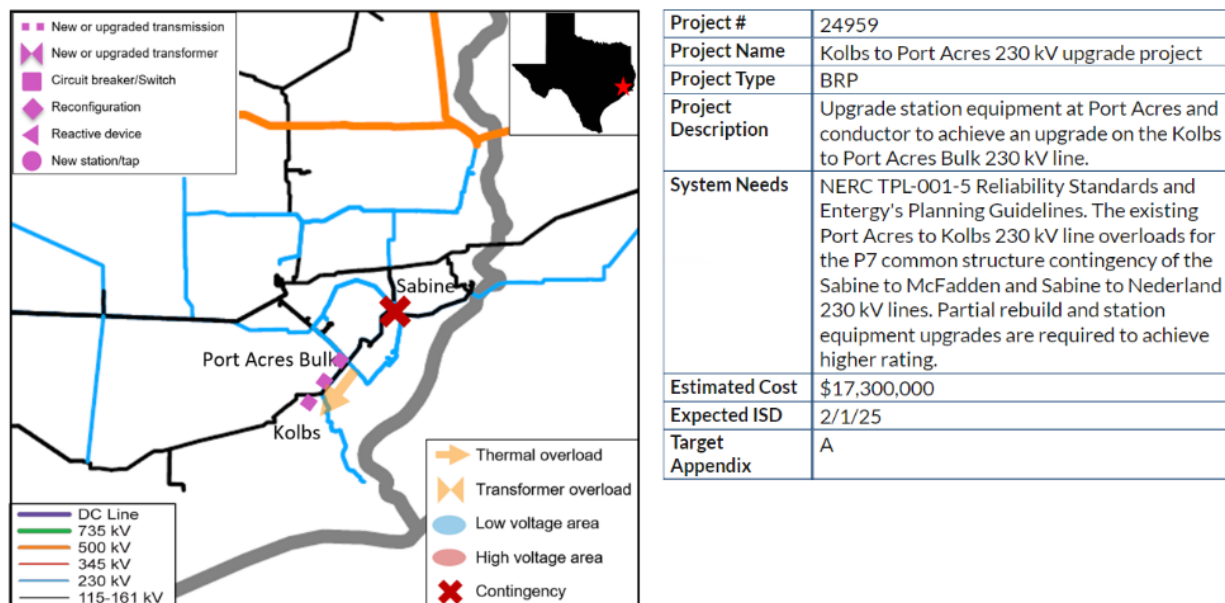


Figure 4.5.9-1: P24959 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [EES] Port Acres Bulk – [EES] Kolbs 230 kV line becomes overloaded to one hundred nineteen (119%) percent in year 2029 for a NERC defined category P7 contingency event. Partial rebuild and station equipment upgrades will decrease post-contingent loading to fifty-seven (57%) percent and resolve thermal violations.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P7	[EES] Port Acres Bulk – [EES] Kolbs 230 kV	502	119	57

Table 4.5.9-1: P24959 Thermal loading drivers.



Project 24960 – Legend to Sandling 230 kV Circuit 2 Project

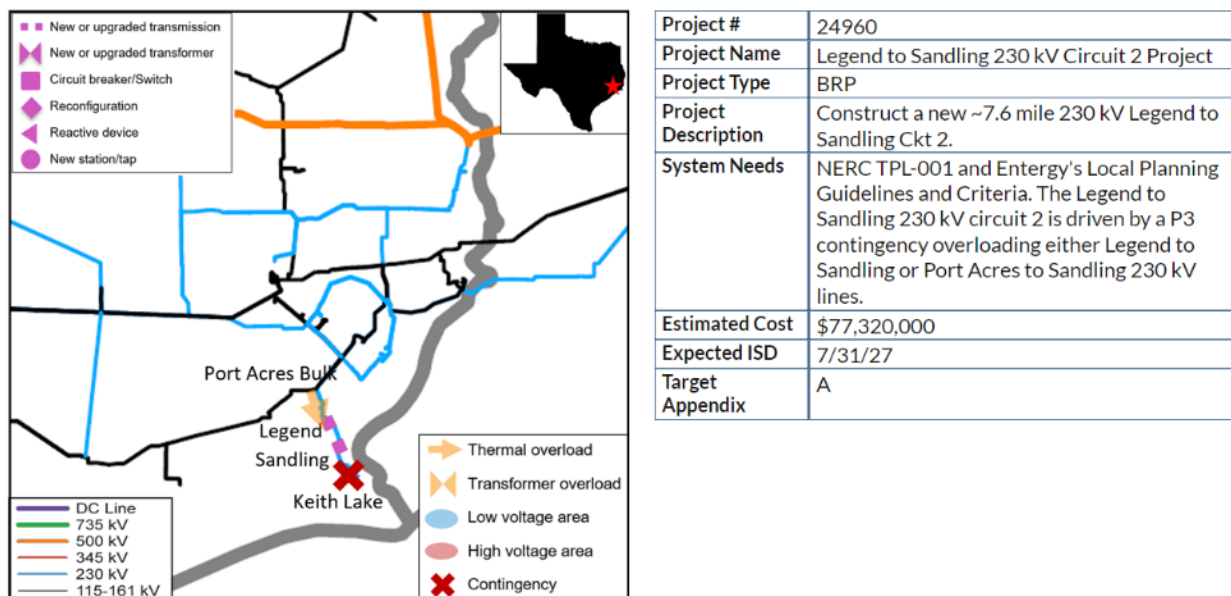


Figure 4.5.9-2: P24960 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [EES] Port Acres Bulk – [EES] Legend 230 kV & [EES] Port Acres Bulk – [EES] Sandling 230 kV line sections become overloaded to one hundred twenty-three (123%) percent and one hundred eight (108%) percent, respectively in year 2029 for a NERC defined category P3 contingency. Building a new Legend to Sandling 230 kV Ckt 2 will decrease post-contingent loading and resolve thermal violations.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P3	[EES] Port Acres Bulk – [EES] Legend 230 kV	351	123	65
P3	[EES] Port Acres Bulk – [EES] Sandling 230 kV	352	108	46

Table 4.5.9-2: P24960 Thermal loading drivers.



Project 25410 – Winshire 69 kV Capacitor Banks

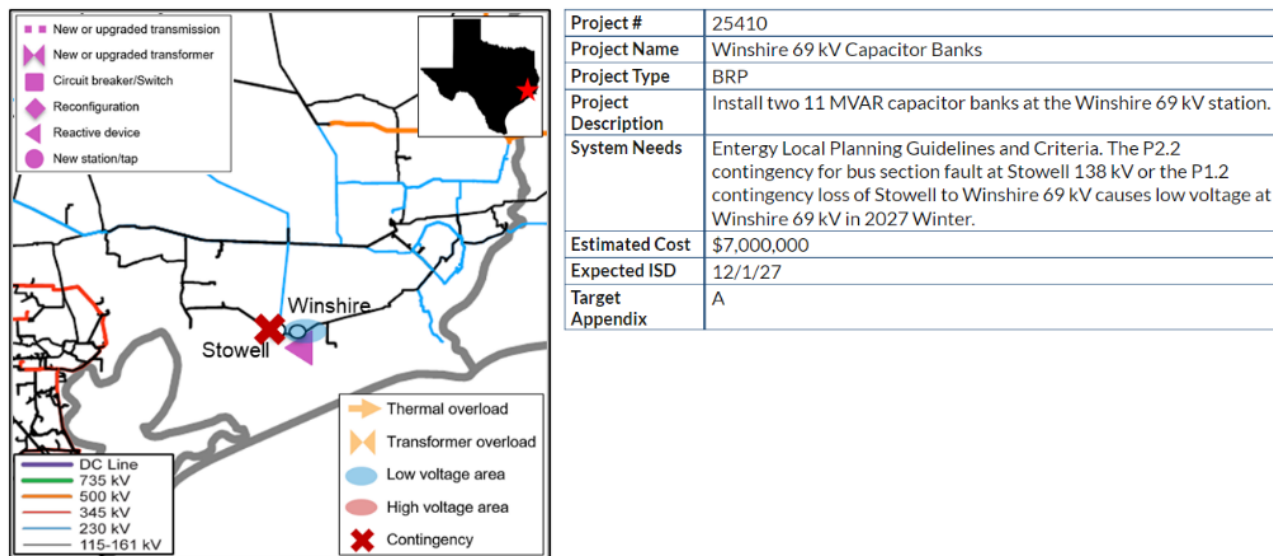


Figure 4.5.9-3: P25410 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [EES] Winshire 69 kV substation’s voltage drops to 0.87 pu in year 2029 for a NERC defined category P1 contingency event. Adding a 11MVAR capacitor bank at [EES] Winshire substation will increase the post-contingency voltage to 0.98 pu.

Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P1	[EES] Winshire 69 kV	0.9	0.87	0.98

Table 4.5.9-3: P25410 Voltage loading drivers.



Project 25432 – Cypress to Legend 500 kV Line

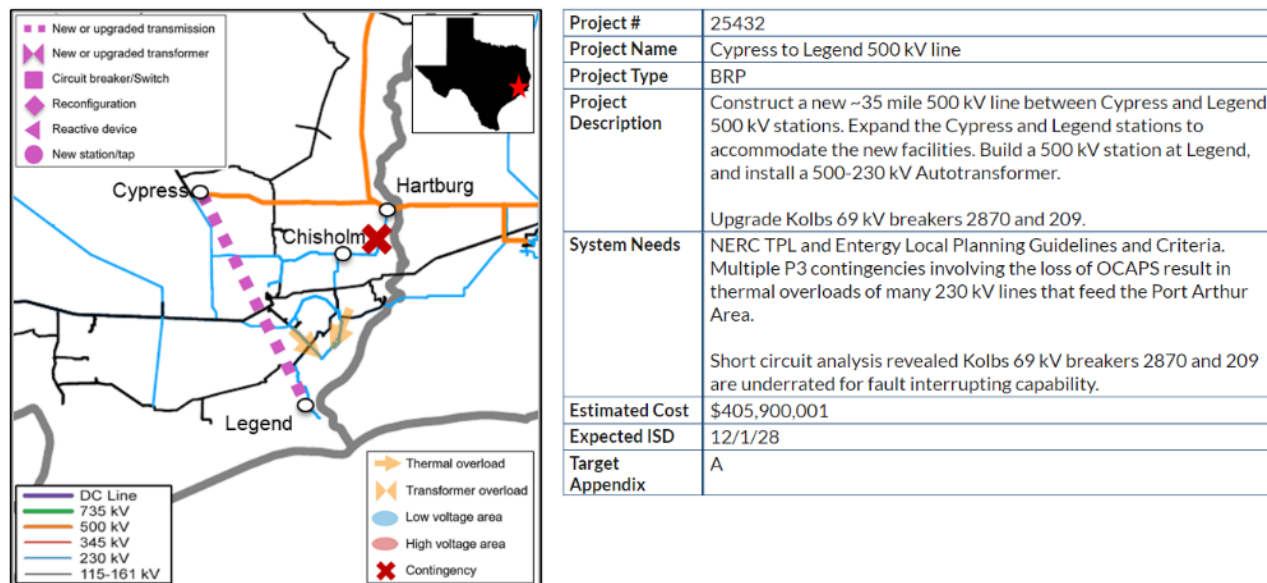


Figure 4.5.9-4: P22432 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [EES] McLewis – [EES] Inland, [EES] McLewis – [EES] Chisholm, [EES] Inland – [EES] Hartburg 230 kV lines become overloaded in year 2028 for a NERC defined category P3 contingency event. The Cypress to Legend 500 kV line will mitigate these overloads.

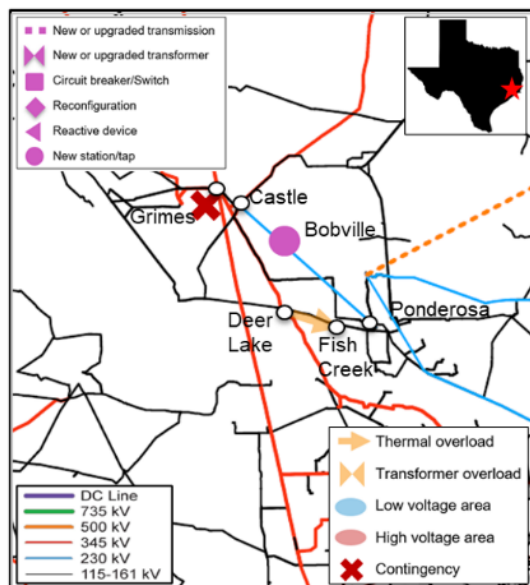
Alternatives Considered: An alternative project, Hartburg to Sabine 500 kV Line, was submitted and studied. Both projects were studied on MTEP24 base case planning models and load growth sensitivities. Both projects showed similar performance for the base case planning models, however the original project showed superior performance when taking future load growth into account represented in the sensitivity. Therefore, MISO is recommending the original project, Cypress to Legend 500 kV.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P3	[EES] McLewis – [EES] Inland 230 kV	681	115	89
P3	[EES] McLewis – [EES] Chisholm 230 kV	681	111	86
P3	[EES] Inland – [EES] Hartburg 230 kV	797	104	81

Table 4.5.9-4: P25432 Thermal loading drivers.



Project 25436 – Bobville 230-138 kV Station



Project #	25436
Project Name	Bobville 230-138 kV Station
Project Type	BRP
Project Description	Cut a new 230 kV station called Bobville into the Castle to Ponderosa 230 kV line. Install a 230-138 kV Autotransformer. Cut Bobville 138 kV station into the Dobbin to Spring Branch 138 kV line. Bobville 230 kV and 138 kV stations will both be three breaker ring. Upgrade the short section between the Dobbin and Bobville 138 kV stations.
System Needs	NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. The P2-1 contingency of the Ponderosa to Fish Creek 138 kV line section results in low voltage at Fish Creek, Dobbin, Spring Branch, and Deer Lake 138 kV and a thermal overload on the Tubular to Dobbin 138 kV line. The P2-3 contingency of a Grimes 345 kV breaker results in a thermal overload of the Deer Lake to Fish Creek 138 kV line section. A P5 at Grimes overloads Fish Creek to Deer Lake to Spring Branch.
Estimated Cost	\$48,600,001
Expected ISD	6/1/26
Target Appendix	A

Figure 4.5.9-5: P25436 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [EES] Dobbin–[EES] Tubular 138 kV line becomes overloaded and causes low voltage in its adjacent buses in year 2034 for a NERC defined category P2 contingency event. Adding the Bobville station will reduce the loading and mitigate low voltage issues.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P2	[EES] Dobbin - [EES] Tubular 138 kV	112	113	13

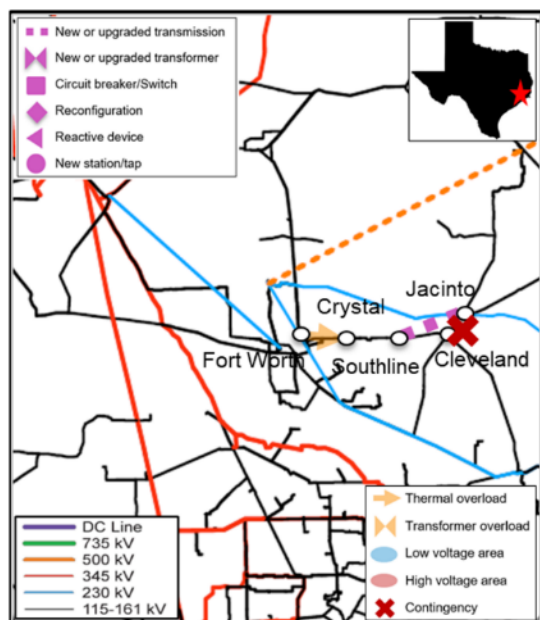
Table 4.5.9-5: P25436 Thermal loading drivers.

Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P2	[EES] Fish Creek	0.92	0.88	0.96
P2	[EES] Deer Lake 138 kV	0.92	0.88	0.96
P2	[EES] Spring Branch 138 kV	0.92	0.89	0.97
P2	[EES] Dobbin 138 kV	0.92	0.90	0.98

Table 4.5.9-6: P25436 Voltage loading drivers.



Project 25468 – Southline to Jacinto 138 kV New Line



Project #	25468
Project Name	Southline to Jacinto 138 kV New Line
Project Type	BRP
Project Description	Construct a new ~6 mile 138 kV line between Jacinto and Southline 138 kV stations.
System Needs	NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. P1 contingencies cause low voltage near Cleveland and thermal overloads on Fort Worth Pipe to Crystal 138 kV line. N-1-1 contingencies cause low voltages due to the amount of load being served radially back out of Dayton 138 kV.
Estimated Cost	\$40,700,000
Expected ISD	6/1/27
Target Appendix	A

Figure 4.5.9-6: P25468 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [EES] Fort Worth Pipe—[EES] Crystal 138 kV line becomes overloaded in year 2034 for a NERC defined category P1 contingency event. Adding a new 138 kV line from Southline to Jacinto will reduce the loading.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P1	[EES] Fort Worth Pipe - [EES] Crystal	206	102	46

Table 4.5.9-7: P25468 Thermal loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
*24958	Sandling 230 kV Customer Load Addition Project	Load Growth	1/30/2026	\$114.2
25484	2025 ETI Asset Renewal Program	Age and Condition	12/31/2025	\$38.3

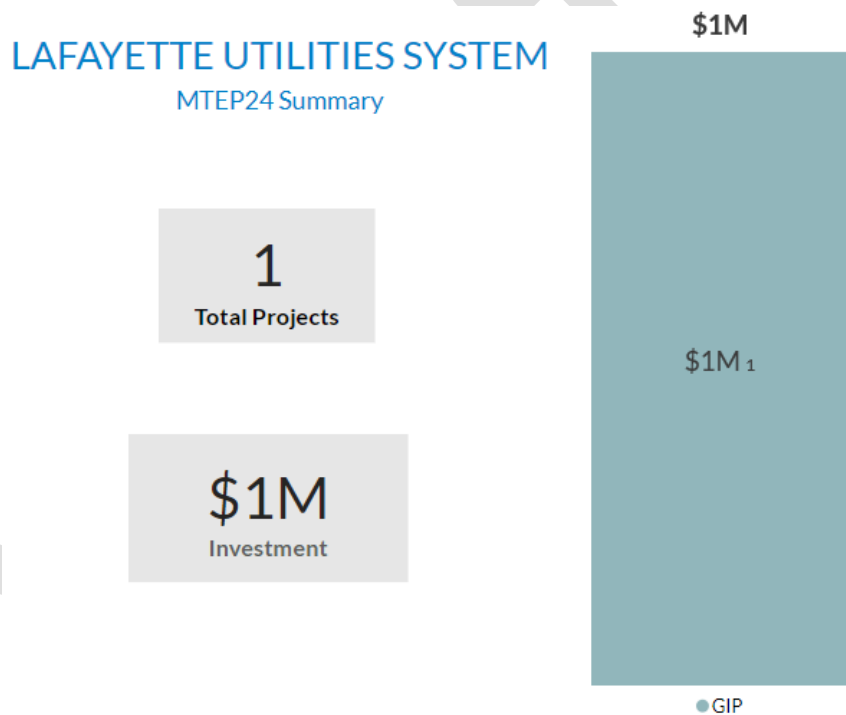
* Project studied through Expedited Project Review (EPR) process.



Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
50043	J1834 NRIS/ERIS Sabine to Neches L5 & L-172 upgrade to Double Bus Double Breaker	9/30/2025	\$10.0

4.5.10 Lafayette Utilities System (LAFA)



Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
50139	J1818 Generator Interconnection at Moss 69 kV Station	6/30/2028	\$1.0



4.5.11 City Water and Light Jonesboro (CWLT)

CITY WATER AND LIGHT PLANT OF JONESBORO ARK... MTEP24 Summary

1
Total Projects

\$1M
Investment



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
*25544	JCWL - Commerce to Ringier 69 kV Rebuild	Age and Condition	7/1/2024	\$0.9

* Project studied through Expedited Project Review (EPR) process.



4.6 Project Justifications – West Region

West Region Overview

The MISO West Planning Region consists of 21 Transmission-Owning members spanning eight states in the upper Midwest. It includes Iowa, Minnesota, Wisconsin, and parts of North Dakota, South Dakota, Montana, Michigan, and Illinois. These Transmission Owners are:

American Transmission Company (ATC)	Missouri River Energy Services (MRES)
Cedar Falls Utilities (CFU)	Montana-Dakota Utilities Co. (MDU)
Central Minnesota Municipal Power Agency (CMMPA)	Muscatine Power and Water (MPW)
City of Ames, IA (COA)	Northwestern Wisconsin Electric (NVEC)
Dairyland Power Cooperative (DPC)	Otter Tail Power Company (OTP)
Great River Energy (GRE)	Rochester Public Utilities (RPU)
ITC Midwest (ITCM)	Southern Minnesota Municipal Power Agency (SMMPA)
MidAmerican Energy Company (MEC)	Wilmar Municipal Utilities (WMU)
Minnesota Municipal Power Agency (MMPA)	WPPI Energy (WPPI)
Minnesota Power (MP)	Xcel Energy (Northern States Power, XEL/NSP)
Minnkota Power Cooperative	

The West planning region contains approximately 27,300 miles of transmission ranging from 57 kV to 500 kV. In the 2026 Summer Peak planning model, the region contains more than 75.5 GW of generation, around 20.6 GW of that being wind. Installed generation capacity in the region consists mostly of coal, gas and wind.

Major generation centers are located in central North Dakota; the Twin Cities in Minnesota; and the Quad Cities in Iowa and Illinois, with wind generation located in the eastern Dakotas and western Iowa and Minnesota (Figure 4.6-1). Major load centers are typically found around larger cities in the region: Minneapolis/Saint Paul, Milwaukee, and Des Moines. In the 2026 Summer Peak planning model, the regional load exceeds 43.7 GW. Power generally flows from generation-rich areas in the western portion of the region through Minnesota, Iowa, and Wisconsin, toward large load centers in the east. This is especially prevalent in times of high wind output.

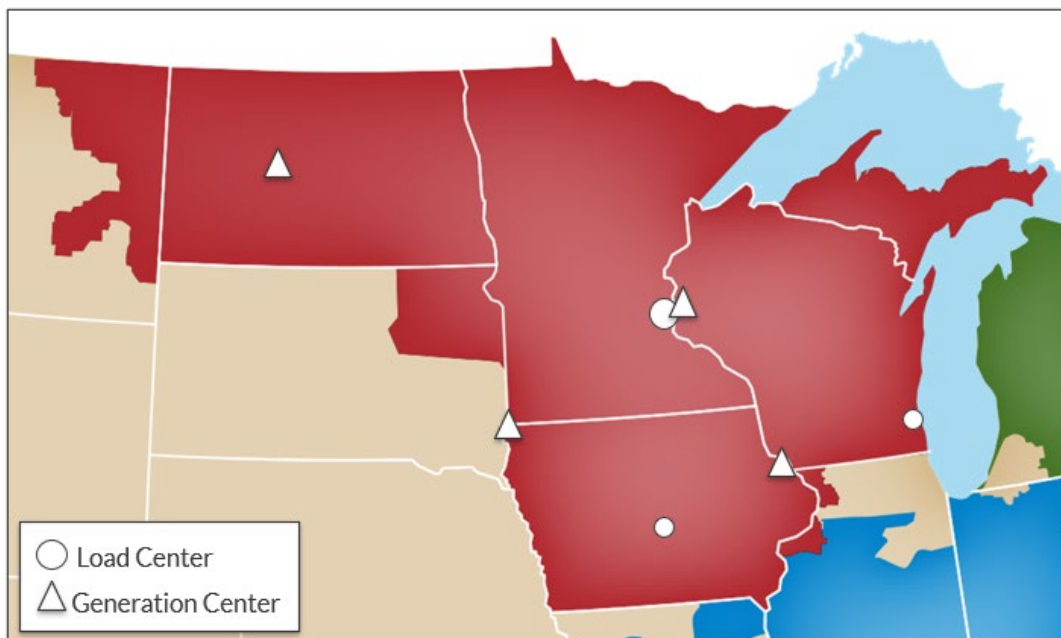
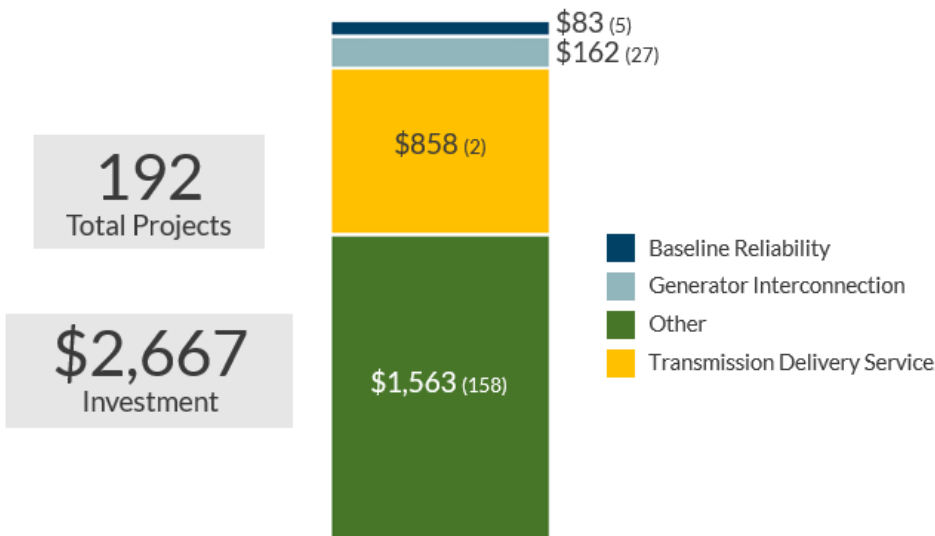


Figure 4.6-1: Generation and load centers in the West Planning Region.

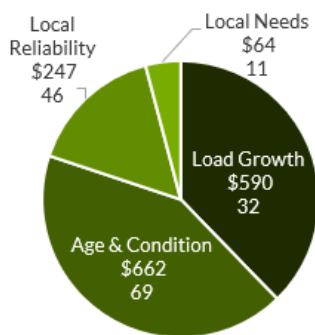


West Planning Region Local MTEP24 Summary

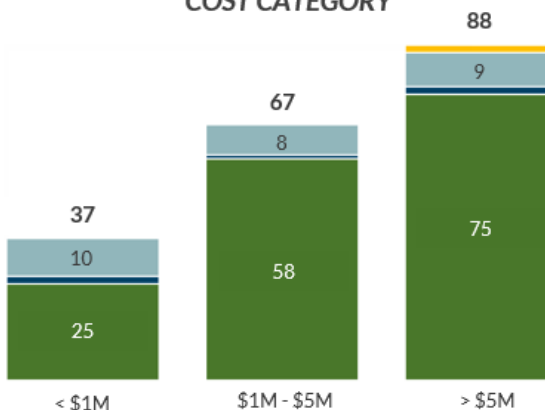
(Data as of August 27, 2024; \$M, # project count)



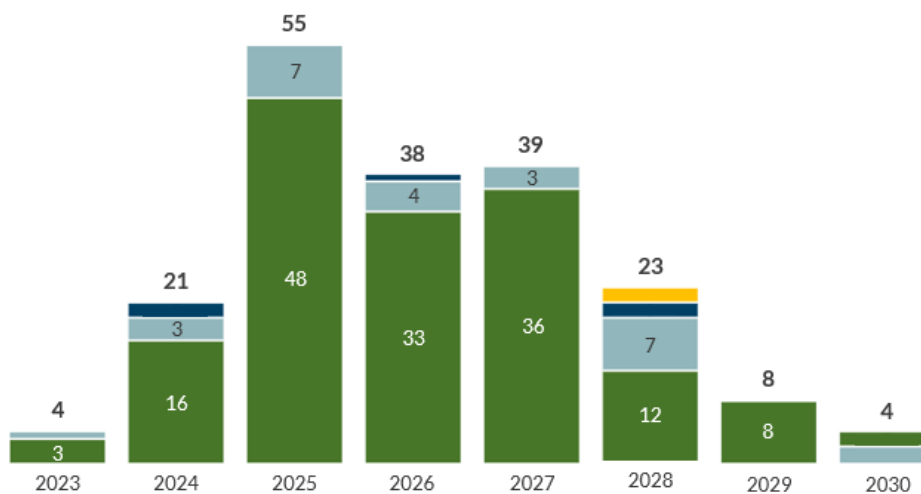
BREAKDOWN OF OTHER PROJECTS BY COST



PROJECT COUNT BY COST CATEGORY



PROJECTS BY IN-SERVICE DATE





The ten largest project investments in the MISO West region represent nearly \$1.5 billion (55%) of the \$2.7 billion total recommended projects for the West region in the local MTEP24 portfolio, or 22% of the \$6.7 billion total recommended in the MISO footprint. The locations of these projects are shown in Figure 4.6-2 and the investment is spread across the West planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

West Region Top 10 Local MTEP24 Projects

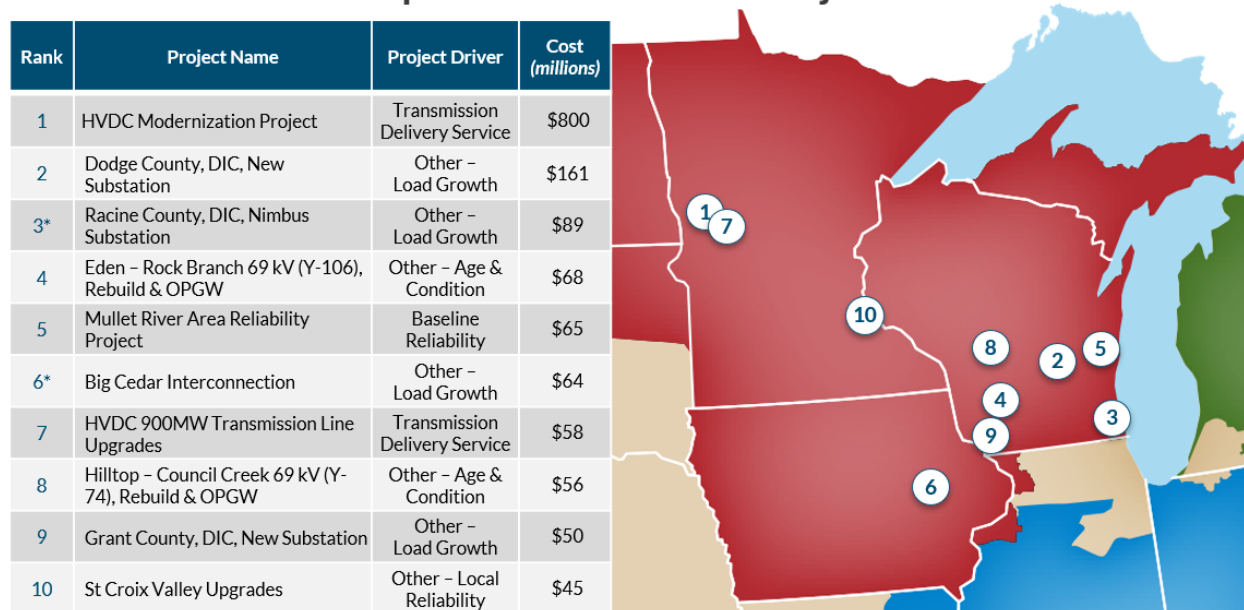


Figure 4.6-2: West region top ten projects by cost; * represents project studied through Expedited Project Review (EPR) process (data as of 8-27-2024).



4.6.1 American Transmission Company (ATC)

AMERICAN TRANSMISSION COMPANY MTEP24 Summary

42
Total Projects

\$794M
Investment





Baseline Reliability Projects

ATC 21900 – Mullet River Area Reliability Project

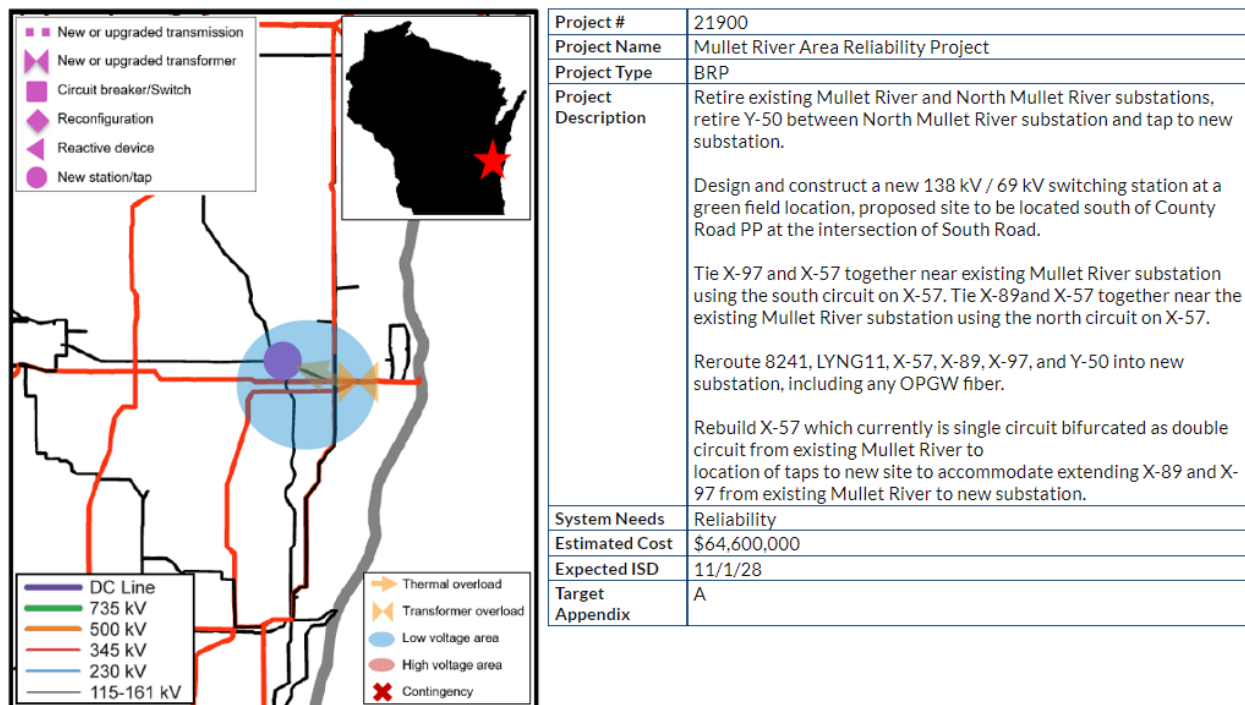


Figure 4.6.1-1: P21900 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: For NERC defined category P6 contingency events, multiple buses experience voltages below their emergency limits. Additionally, six unique non-BES elements experience thermal violations beyond their emergency limits. The new Mullet River Substation will provide the area multiple additional connections to enhance reliability under P6 events. All thermal/voltage issues are resolved, and the existing corrective action plan resulting in non-consequential load loss is no longer needed. This project will also address ATC’s asset renewal needs by retiring both the existing Mullet River and North Mullet River substations, which are space-constraint for modernization or expansion.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P6	Multiple non-BES elements	56-75	106-141	50

Table 4.6.1-1: P25300 Thermal loading drivers.



Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P6	Multiple 138 and 69 kV buses	0.90	0.60-0.89	~1.01

Table 4.6.1-2: P14344 Voltage loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
22798	Small Capital Project and Asset Renewal Program 2025	Age and Condition	6/30/2027	\$45.0
22911	Load Interconnection Program 2025	Load Growth	6/30/2027	\$19.0
23910	Eden - Rock Branch 69 kV (Y-106), Rebuild & OPGW	Age and Condition	12/31/2030	\$67.9
23951	Line Clearance Mitigation Program 2025	Local Reliability	6/30/2027	\$5.4
24778	Grant County, DIC, New Substation	Load Growth	1/1/2028	\$50.1
24842	Atlantic - Osceola 69 kV (Laurium2), Re-insulate	Age and Condition	12/31/2025	\$8.1
24922	Forest Junction SS and Remote End Relay Asset Renewal	Age and Condition	12/1/2027	\$6.5
24980	Pioneer SS Breaker Relay and Remote Ends Asset Renewal	Age and Condition	12/31/2027	\$3.8
24983	Hilltop - Council Creek 69 kV (Y-74), Rebuild & OPGW	Age and Condition	10/31/2026	\$56.0
25000	Lakefront SW YD - Revere Dr 69 kV (D-104), Partial Rebuild	Age and Condition	10/1/2028	\$9.0
25104	2nd St. Tap - 30th Ave. 69 kV (N-14), Partial Rebuild	Age and Condition	11/1/2027	\$7.5
25160	Weston - Morrison Ave 115 kV (Z-52), Reconductor	Local Reliability	6/1/2026	\$3.8
25162	Milwaukee Leased Dark Fiber Retirement Plan	Local Needs	12/31/2027	\$6.0
25163	Freeman - Presque Isle (X-118), OPGW Addition	Local Needs	12/31/2026	\$7.0
25164	Menominee - 30th Ave. 69 kV (Y-199), Rebuild	Age and Condition	6/1/2028	\$8.4
25165	Glory Road - Oak St. 69 kV (GLNY41), Partial Rebuild	Age and Condition	6/1/2028	\$6.0
25190	Badger SS Control House, Breaker, and Relay Asset Renewal	Age and Condition	6/1/2026	\$5.9
25220	Cuba City South, DIC, Sub Expansion	Load Growth	12/31/2027	\$11.0
25226	Union Townline, DIC, Sub Expansion	Load Growth	11/1/2026	\$11.6
*25299	Racine County, DIC, Nimbus Substation	Load Growth	4/1/2025	\$89.0
25309	Substation Technology Package #2 - 2024	Local Needs	12/31/2024	\$3.6



Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25348	Saratoga – 7 Mile Creek 138 kV, Construct New Line	Local Reliability	12/31/2027	\$10.3
50017	West Middleton - Str 36 69 kV (6967/6963), Rebuild Green Poles (CAC/CCA/SX) Replacements	Age and Condition	10/1/2026	\$7.2
50026	Kaukauna Central Tap - Melissa 138 kV (971K11), Rerate	Local Reliability	5/1/2025	\$7.0
50041	West Junction SS 138 kV Sectionalizing	Local Reliability	12/31/2026	\$8.7
50042	Substation Technology Package #2 - 2025	Local Needs	12/31/2025	\$10.5
50091	Milwaukee County, New DIC	Load Growth	6/1/2027	\$2.6
50102	University – Whitewater 138 kV (UNIG51), Partial Reconductor & OPGW	Local Reliability	12/31/2025	\$4.8
50136	Baraboo SS, DIC, Substation Relocation	Load Growth	6/1/2027	\$3.0
50137	Line ILKY31 and 6912 Grounding Improvement	Age and Condition	12/1/2025	\$4.0
50138	Dodge County, DIC, New Substation	Load Growth	6/1/2027	\$161.0

* Project studied through Expedited Project Review (EPR) process.

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
50036	J1304 Big Hill Park SS Network Upgrades and Interconnection Facilities	7/31/2023	\$9.1
50107	J1513 Clintonville Swt St Network Upgrades and Interconnection Facilities	9/10/2028	\$3.2
50108	J1573 Plover SS Network Upgrades and Interconnection Facilities	9/10/2028	\$2.6
50109	J1814 Nordic SS Network Upgrades and Interconnection Facilities	9/10/2028	\$2.2
50110	J1751 Young St SS Network Upgrades and Interconnection Facilities	9/10/2028	\$9.7
50111	J1773 Edmund Swt St Network Upgrades and Interconnection Facilities	3/10/2030	\$19.7
50112	J1781 Hill Valley SS Network Upgrades and Interconnection Facilities	3/10/2030	\$7.2
50113	J1716 Eldorado SS Network Upgrades	3/19/2027	\$0.2
50120	J1615 Morgan SS Network Upgrades and Interconnection Facilities	9/10/2028	\$3.3
50184	Elm Road Generation POI Relocation Project	6/30/2026	\$22.6

4.6.2 Cedar Falls Utilities (CFU)

Cedar Falls Utilities and MISO are not recommending any new projects for MTEP24.



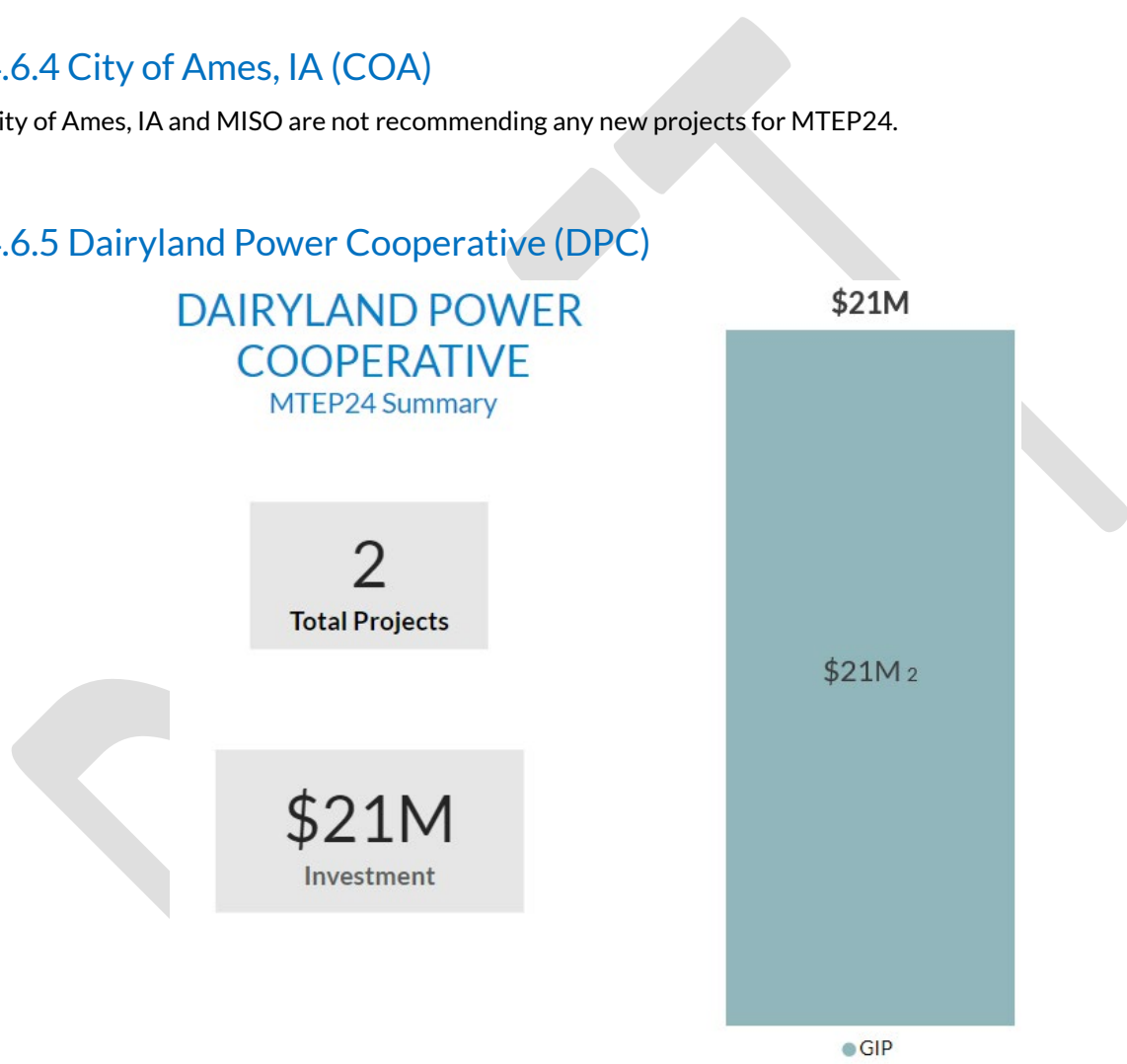
4.6.3 Central Minnesota Municipal Power Agency (CMMMPA)

Central Minnesota Municipal Power Agency and MISO are not recommending any new projects for MTEP24.

4.6.4 City of Ames, IA (COA)

City of Ames, IA and MISO are not recommending any new projects for MTEP24.

4.6.5 Dairyland Power Cooperative (DPC)



Generator Interconnection Projects

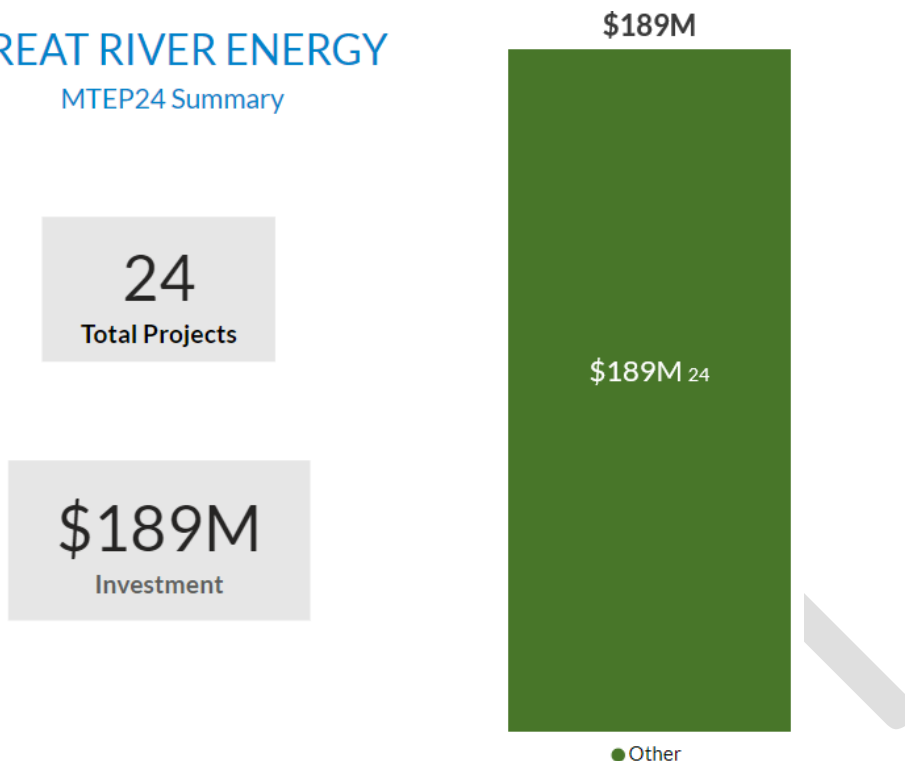
Project ID	Project Name	ISD	Estimated Cost (\$M)
25498	J898 Generation Interconnection Network Upgrades	9/1/2027	\$19.6
25505	J1314/S1039 Generation Interconnection Upgrades	6/30/2025	\$1.3



4.6.6 Great River Energy (GRE)

GREAT RIVER ENERGY

MTEP24 Summary



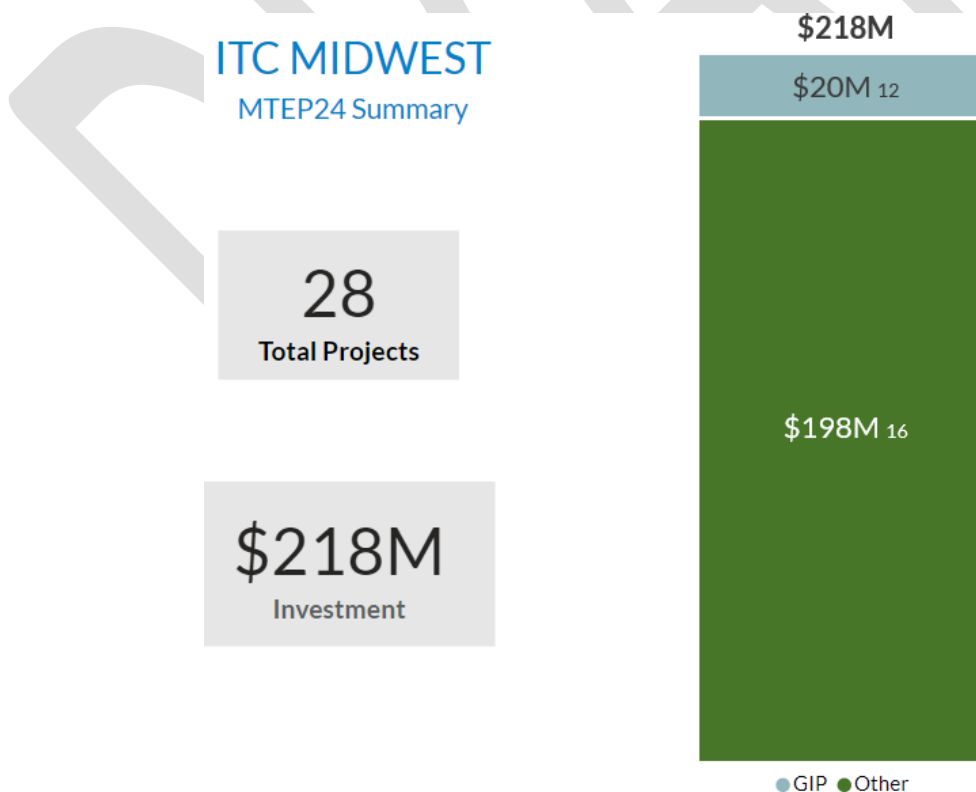
Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
23851	Stanton Breaker Replacement	Age and Condition	11/5/2026	\$2.2
25337	Meadowbrook to Side Lake Area Projects	Age and Condition	12/1/2027	\$12.1
25338	Victor to Woodland Rebuild Projects	Local Reliability	12/1/2027	\$9.3
25358	Burnsville Area Projects	Local Needs	5/31/2028	\$4.0
25373	Salem Breaker Station	Local Reliability	10/17/2025	\$1.3
25374	Blackberry Area Rebuild Projects	Local Reliability	12/10/2027	\$14.3
25381	Long Siding - Princeton Area Projects	Local Reliability	12/19/2027	\$5.7
25388	Cleveland Breaker Replacement	Local Reliability	10/1/2025	\$1.3
25391	Mud Lake to Riverton 230 kV Upgrade	Local Reliability	6/1/2027	\$1.1
25396	Otsego Area Rebuilds	Age and Condition	2/28/2029	\$40.1
25399	Congestion Mitigation Projects	Local Reliability	2/1/2028	\$23.5
25405	Lakeville Area Projects	Local Reliability	9/30/2025	\$1.2



Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25421	Sand Lake Area Projects	Age and Condition	11/20/2024	\$1.6
25422	Airport Substation Breaker Addition	Local Reliability	6/30/2026	\$5.7
25423	Fox Lake Area Upgrades	Age and Condition	9/30/2027	\$12.5
25445	Prairie Woods to Sunburg Rebuild	Age and Condition	12/31/2027	\$7.6
25452	Dickinson Breaker Replacement	Age and Condition	6/1/2027	\$1.8
25453	Medina Breaker Addition and Replacement	Age and Condition	11/30/2026	\$1.4
25454	East Chain Tie Line Projects	Local Reliability	10/6/2028	\$3.0
25456	Spring Creek Upgrade Projects	Age and Condition	12/31/2029	\$20.0
25469	Silver Lake Transformer Replacement	Age and Condition	12/31/2027	\$4.6
25471	St. Clair Tap Rebuild	Age and Condition	12/30/2027	\$4.7
25547	Blind Lake Breaker Addition	Local Reliability	12/30/2027	\$8.8
50101	Hodges Substation Tap	Load Growth	7/31/2025	\$0.8

4.6.7 ITC Midwest (ITCM)





Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25188	ITCM Boone South 69 kV Substation Interconnection	Load Growth	12/1/2025	\$4.4
25205	ITCM Meservey 69 kV Tap Rebuild	Age and Condition	12/31/2027	\$4.8
25206	ITCM Lime Creek 161/69 kV Transformer Replacement	Age and Condition	12/31/2026	\$5.7
25211	ITCM Customer Interconnects with short lead time 2026	Load Growth	12/31/2026	\$3.8
25212	ITC Midwest Asset Replacement Program 2026	Age and Condition	12/31/2026	\$52.6
25213	ITC Midwest SCADA Controlled Motor Operated Switch Addition Program 2025	Local Needs	12/31/2025	\$3.1
25241	ITCM Newton 8th St Control Enclosure, Relay, and SCADA Replacement	Age and Condition	12/31/2026	\$2.7
25247	ITCM Abbott - Marshalltown 161 kV Rebuild	Age and Condition	12/31/2028	\$10.8
25253	ITCM Flint Ridge Control Enclosure & 69 kV Tie Breaker Addition	Load Growth	12/31/2026	\$2.2
25306	ITCM Burlington 4th Street Control Enclosure & 69 kV Tie Breaker Addition	Load Growth	12/31/2026	\$2.0
25307	ITCM State Center Rural 69 kV Interconnection	Load Growth	12/15/2026	\$2.9
25308	ITCM Leon Rodeo 69 kV Substation Interconnection	Load Growth	12/31/2028	\$4.9
*25321	Winnebago City Substation Interconnection	Local Needs	10/31/2025	\$7.9
25345	ITCM Cleveland to Sheas Lake Rebuild	Age and Condition	12/30/2029	\$22.3
25346	ITCM Walcott 80 Substation Interconnection	Local Needs	12/30/2029	\$4.5
*50106	Big Cedar Interconnection	Load Growth	3/31/2026	\$63.7

* Project studied through Expedited Project Review (EPR) process.

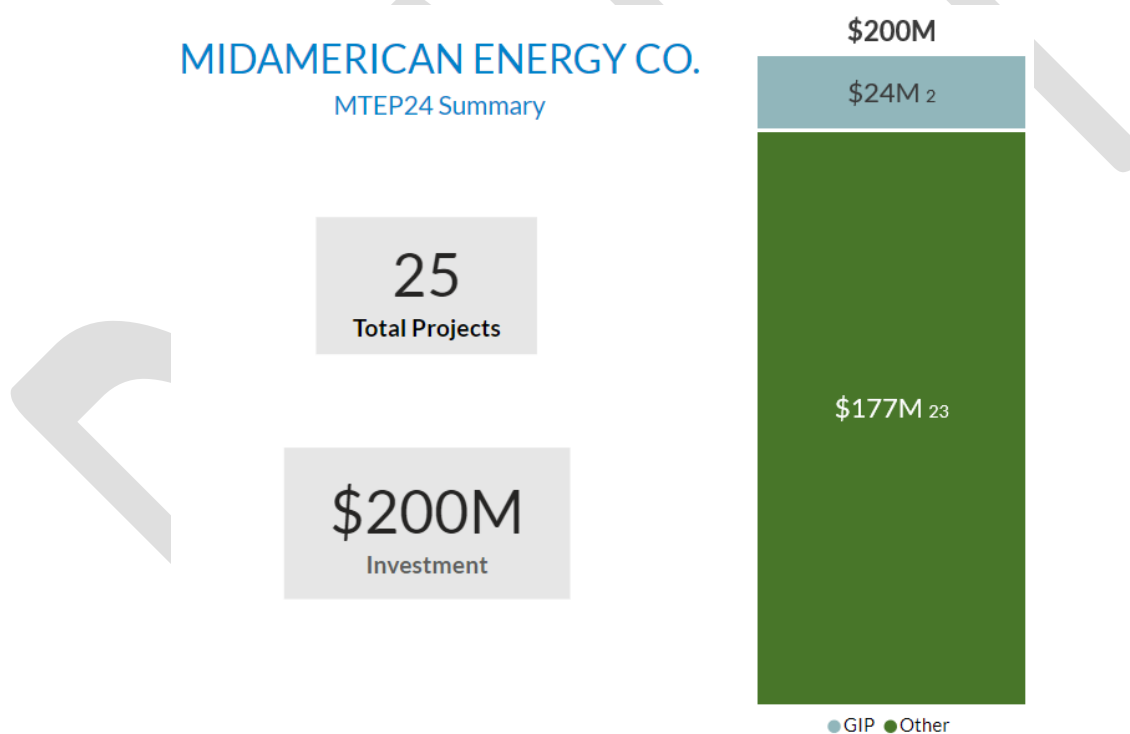
Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25181	J1190 GIA TOIF Calamus East 161 kV Terminal Addition	10/1/2026	\$0.8
25182	J1313 GIA TOIF Karma 161 kV Terminal Addition	6/30/2025	\$0.4
25183	J1313 GIA NU Karma 161 kV Ring Bus Expansion	6/30/2025	\$0.6
25184	J1365 GIA TOIF Traer 161 kV Terminal Addition	9/6/2024	\$0.5
25197	J1734 GIA TOIF New Wever 161 kV Terminal	6/1/2024	\$0.6



Project ID	Project Name	ISD	Estimated Cost (\$M)
25200	J1190 GIA NU Calamus East 161 kV Bus Expansion	10/1/2026	\$0.2
25201	J1325 GIA TOIF Magnolia 161 kV Terminal Addition	6/30/2025	\$0.4
25202	J1325 GIA NU Magnolia 161 kV Bus Expansion	6/30/2025	\$0.5
25204	J1365 GIA NU Traer 161 kV Ring Bus Expansion	7/26/2024	\$1.6
25221	J1432 GIA TOIF New Bryant 345 kV Terminal	9/1/2028	\$0.7
25222	J1432 GIA NU New Bryant 345 kV Switch Station	9/1/2028	\$12.8
25251	J1734 GIA NU Wever 161 kV Bus Expansion	7/31/2025	\$1.1

4.6.8 MidAmerican Energy Company (MEC)



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25302	Hills 69 kV Breaker Replacement	Local Reliability	12/1/2025	\$0.5
25411	Second 69 kV Line into Rock Valley Town Substation	Load Growth	12/1/2027	\$1.6
25412	Line Rebuilds Blanket 2025 - 2027	Age and Condition	12/1/2029	\$45



Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25424	NE 6th St Substation and 161 kV line taps	Load Growth	6/1/2027	\$6.5
25425	Metro East Substation 161 kV line breakers	Local Reliability	12/1/2027	\$3.0
25428	New Shenandoah Substation and 69 kV lines	Load Growth	12/31/2027	\$19.1
25429	Liberty Substation 161-69 kV Expansion and Associated Lines	Local Reliability	12/1/2027	\$12.5
25431	Dakota Dunes: Install 69 kV Capacitor Bank	Local Reliability	6/1/2026	\$2.8
25437	Substation 85: Convert to Ring Bus	Local Reliability	12/31/2027	\$7.0
25439	Sub G 69 kV Line Taps	Local Reliability	12/31/2030	\$0.6
25447	Forest & Vermont Breaker Replacements	Local Reliability	12/1/2025	\$2.4
25448	Browns Woods Substation and 161 kV lines	Load Growth	12/1/2026	\$13.4
25449	Norwoodville Substation and 69 kV lines	Local Reliability	12/31/2027	\$16.9
25460	Southridge Substation and 161 kV line taps	Load Growth	6/1/2027	\$6.5
25461	Johnson Creek - Maffitt Lake 161 kV line	Load Growth	8/1/2027	\$15.3
25464	CBEC Upgrade Sync Check Relaying	Local Reliability	12/1/2025	\$1.2
25466	Maynard Substation: Replace Three 69 kV Breakers and Relaying	Age and Condition	12/31/2029	\$1.6
25467	Substation P Iowa City Transformer Breakers	Local Reliability	12/1/2025	\$0.9
50014	West Grand Add 161 kV Line Breakers	Load Growth	6/30/2025	\$3.0
50029	SE Soteria Add 161 kV Breakers	Load Growth	6/1/2026	\$6.0
50030	Johnson Creek Add 161 kV Breakers	Load Growth	6/1/2026	\$6.0
50031	Maffitt Lake Add 161 kV Breakers	Load Growth	6/1/2025	\$4.0
50075	Raun-Remsen 345 kV Structure Replacement	Local Needs	6/1/2025	\$0.7

Generator Interconnection Projects

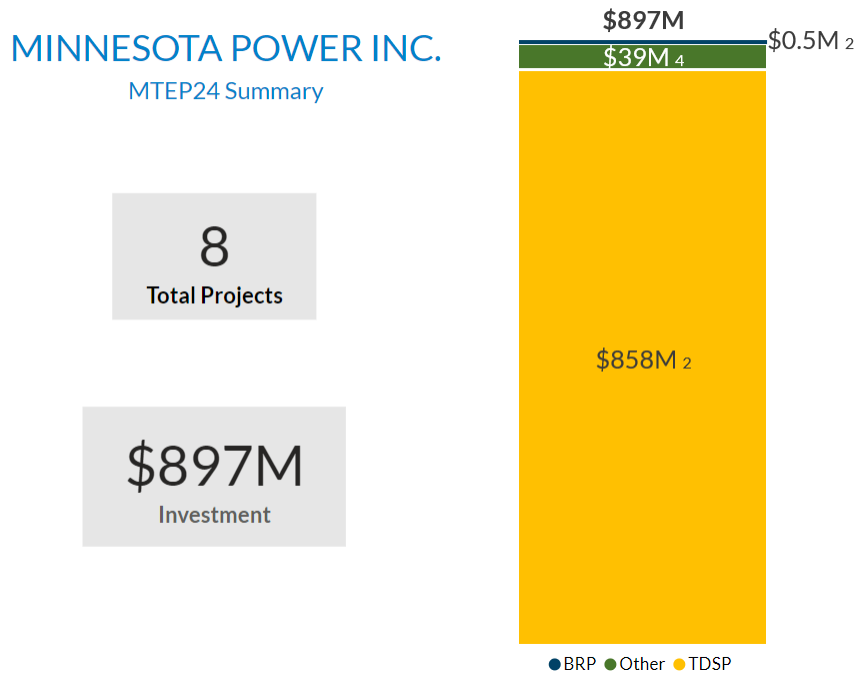
Project ID	Project Name	ISD	Estimated Cost (\$M)
25433	J1270 POI New 345 kV Interconnection Substation and 345 kV Line Taps	9/18/2025	\$19.5
25434	J1218/J1229 Network Upgrades at Sub 92	6/30/2027	\$4.0



4.6.9 Minnesota Municipal Power Agency (MMPA)

Minnesota Municipal Power Agency and MISO are not recommending any new projects for MTEP24.

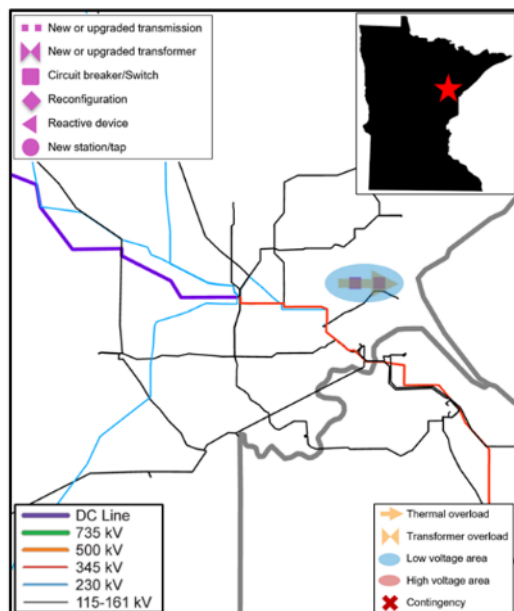
4.6.10 Minnesota Power (MP)





Baseline Reliability Projects

P25141 – Arrowhead 115 kV SPF Upgrade



Project #	25141
Project Name	Arrowhead 115kV SPF Upgrade
Project Type	BRP
Project Description	Add redundancy or monitoring to the single point of failures to mitigate P5 contingences associated with the Arrowhead 115kV buses.
System Needs	MTEP23 results shows multiple thermal and voltage violation in the Duluth area caused by multiple NERC defined P5 contingencies.
Estimated Cost	\$250,000
Expected ISD	12/31/24
Target Appendix	A

Figure 4.6.10-1: P25141 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [MP] Thomson7—[MP] Fondulac 115kV line becomes overloaded to one hundred twenty-one (121%) percent and has several low voltage issues in year 2025 for a NERC defined category P5 contingency event. The reconfiguration of the Arrowhead substation area changes the P5 contingency that is created on this line and the overload and voltage impact no longer exists.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P5	[MP] Thomson7 - [MP] Fondulac	115	122	Project upgrade invalidates the single point of failure contingency impact on this line.

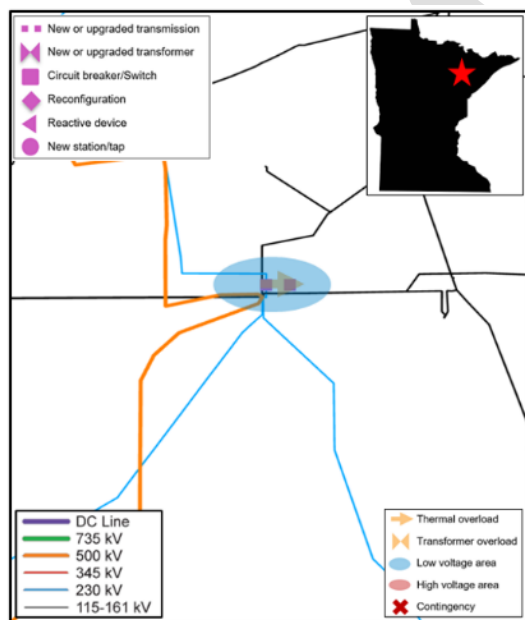
Table 4.6.10-1: P25141 Thermal loading drivers.



Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P5	[MP] Hanes Road7	0.9	0.89	Project upgrade invalidates the single point of failure contingency impact at this bus.

Table 4.6.10-2: P25141 Voltage loading drivers.

P25142 – Forbes 115 kV SPF Upgrade



Project #	25142
Project Name	Forbes 115kV SPF Upgrade
Project Type	BRP
Project Description	Add redundancy or monitoring to the single point of failures to mitigate P5 contingences associated with the Forbes 115kV buses.
System Needs	MTEP23 results shows multiple thermal and voltage violation in the Northern MN area caused by multiple NERC defined P5 contingencies.
Estimated Cost	\$250,000
Expected ISD	12/31/24
Target Appendix	A

Figure 4.6.10-2: P25142 Geographic transmission map of project area and MTEP Portal project details.

Project Justification: The [MP] Kewntnp7–[MP] Hibbing7 115kV line becomes overloaded to one hundred forty (140%) percent in year 2025 for a NERC defined category P5 contingency events. The reconfiguration of the Forbes substation area changes the P5 contingency that is created on this line and the overload issue is resolved.



Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P5	[MP] Kewtnp7 - [MP] Hibbing	115	141	Project upgrade invalidates the single point of failure contingency impact on this line.

Table 4.6.10-3: P25142 Thermal loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
20030	LSPI Cap Bank Asset Renewal	Age and Condition	12/31/2024	\$0.8
21767	13 Line Rebuild	Age and Condition	3/31/2027	\$12.0
23706	158 Line Rebuild	Age and Condition	3/31/2027	\$25.0
25311	Stinson PST Retirement	Age and Condition	12/31/2028	\$1.0

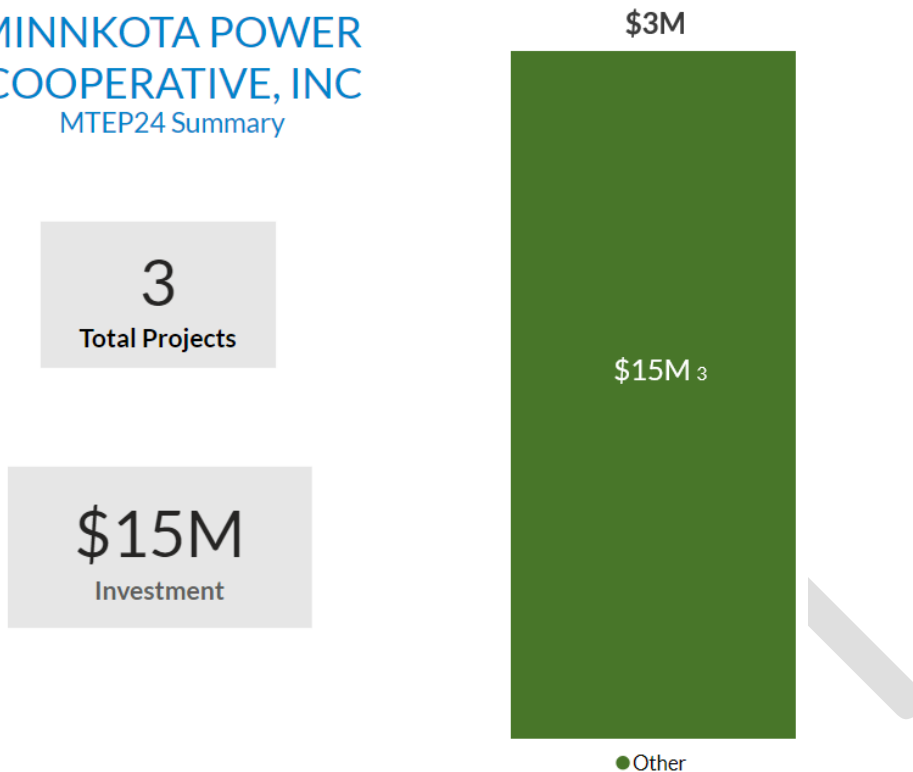
Transmission Delivery Service Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
3856	HVDC 900MW Transmission Line Upgrades	12/31/2028	\$58.0
4295	HVDC Modernization Project	12/31/2028	\$800.0



4.6.11 Minnkota Power Cooperative (MPC)

MINNKOTA POWER COOPERATIVE, INC MTEP24 Summary



Other Projects

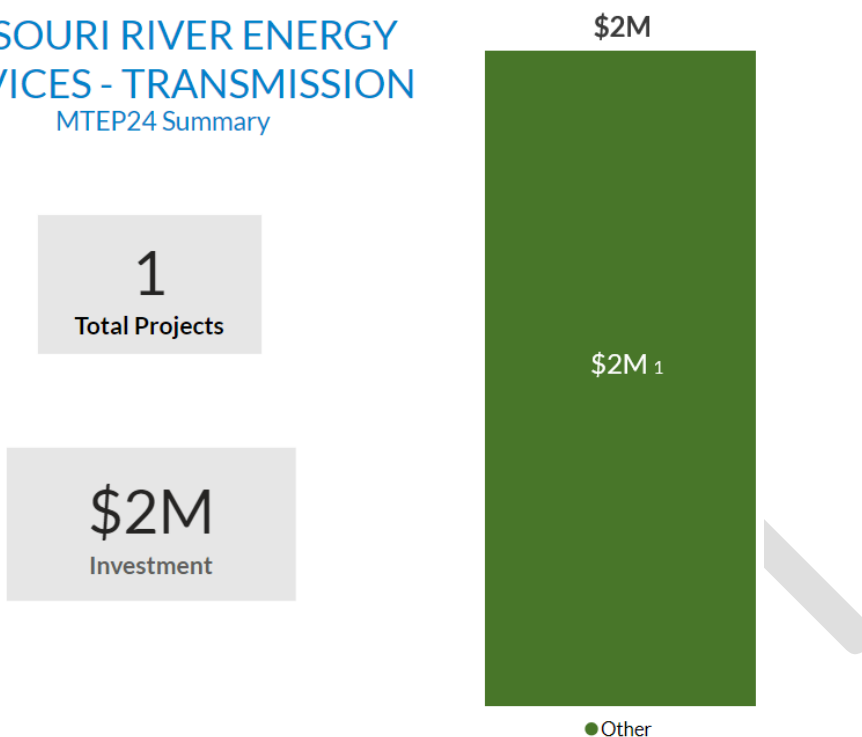
Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
24375	Center-Maple River 345 kV Foundation Restoration	Age and Condition	12/31/2028	\$7.6
24394	Maple River-Buffalo River 69 kV Line Rebuild	Age and Condition	12/31/2024	\$6.1
24413	Richer-Littlefork 230 kV Line Rebuild	Age and Condition	2/28/2025	\$1.6



4.6.12 Missouri River Energy Services (MRES)

MISSOURI RIVER ENERGY SERVICES - TRANSMISSION

MTEP24 Summary



Other Projects

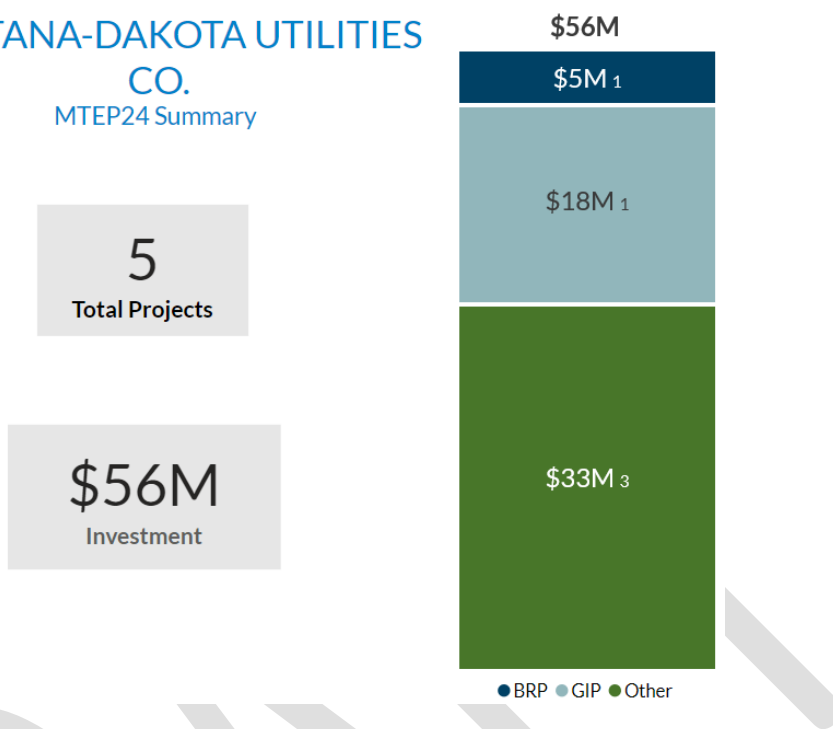
Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25446	Willmar System Upgrades	Age and Condition	12/05/2025	\$2.0



4.6.13 Montana-Dakota Utilities Co. (MDU)

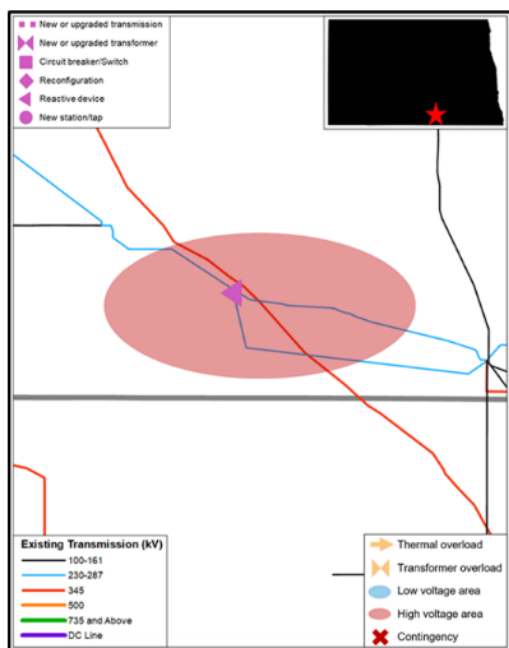
MONTANA-DAKOTA UTILITIES

CO.
MTEP24 Summary



Baseline Reliability Projects

P25475 – Merricourt Reactor



Project #	25475
Project Name	Merricourt Reactor
Project Type	BRP
Project Description	Adding a 50 MVar reactor at Merricourt to support high voltages on the 230 kV when wind and load are low.
System Needs	To support high voltages on the 230 kV path when wind and load are low.
Estimated Cost	\$5,000,000
Expected ISD	12/31/26
Target Appendix	A

Figure 4.6.13-1: P25475 Geographic transmission map of project area and MTEP Portal project details.



Project Justification: The area around Merricourt, ND experiences high voltage violations on the 230 kV path when wind and load are low. Buses in the Merricourt area exceed their transient voltage threshold value of 1.20 pu due to NERC defined category P1 contingency events. Installing the 50 MVar reactor at Merricourt will remove these voltage violations in the area.

Cont. Type	Limiting Element	Summer Emergency Rating (pu)	Pre-Project (pre-cont.) Voltage (pu)	Post-Project (post-cont.) Voltage (pu)
P1	Merricourt 230 kV	1.20	1.21	1.22
P1	Tatanka North 230 kV	1.20	1.20	1.22
P1	Foxtail 230 kV	1.20	1.21	1.22

Table 4.6.13-1: P25475 Voltage loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
*25301	Leola load addition	Load Growth	9/1/2024	\$3.6
*50037	Ellendale load 2 addition	Load Growth	9/1/2024	\$16.8
*50152	Ellendale load 3 addition	Load Growth	9/1/2025	\$12.6

* Project studied through Expedited Project Review (EPR) process.

Generator Interconnection Projects

Project ID	Project Name	ISD	Estimated Cost (\$M)
25503	MDU Network and Interconnection Upgrades - J1040	10/1/2026	\$18.1

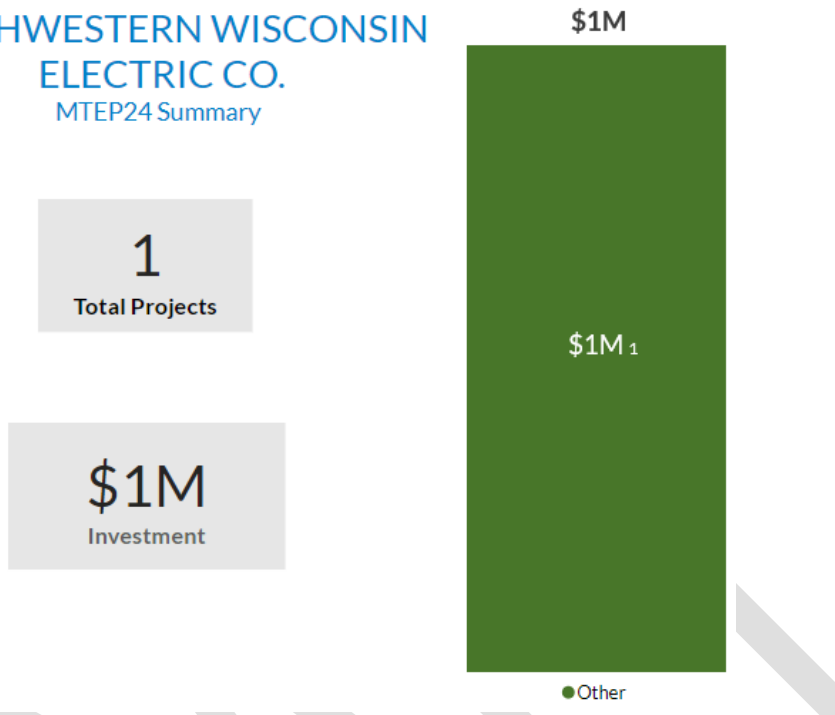
4.6.14 Muscatine Power and Water (MPW)

Muscatine Power and Water and MISO are not recommending any new projects for MTEP24.



4.6.15 Northwestern Wisconsin Electric (NWECC)

NORTHWESTERN WISCONSIN ELECTRIC CO. MTEP24 Summary



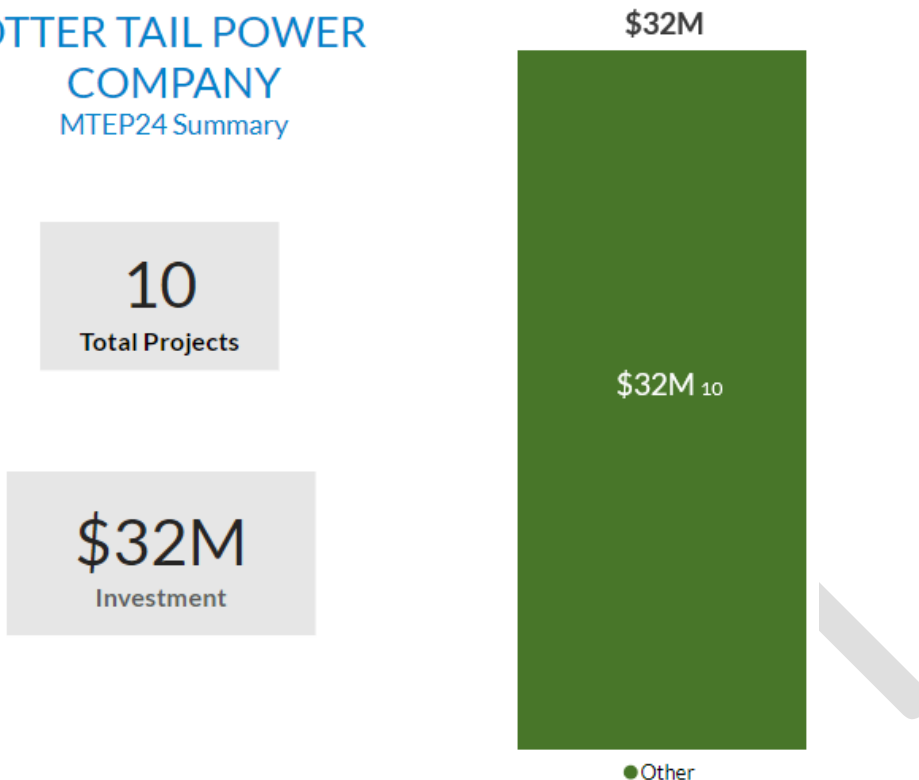
Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
50147	Frederic To Lewis - 69 kV - Clam Falls Drive Section	Local Reliability	5/1/2027	\$0.7



4.6.16 Otter Tail Power Company (OTP)

OTTER TAIL POWER COMPANY MTEP24 Summary



Other Projects

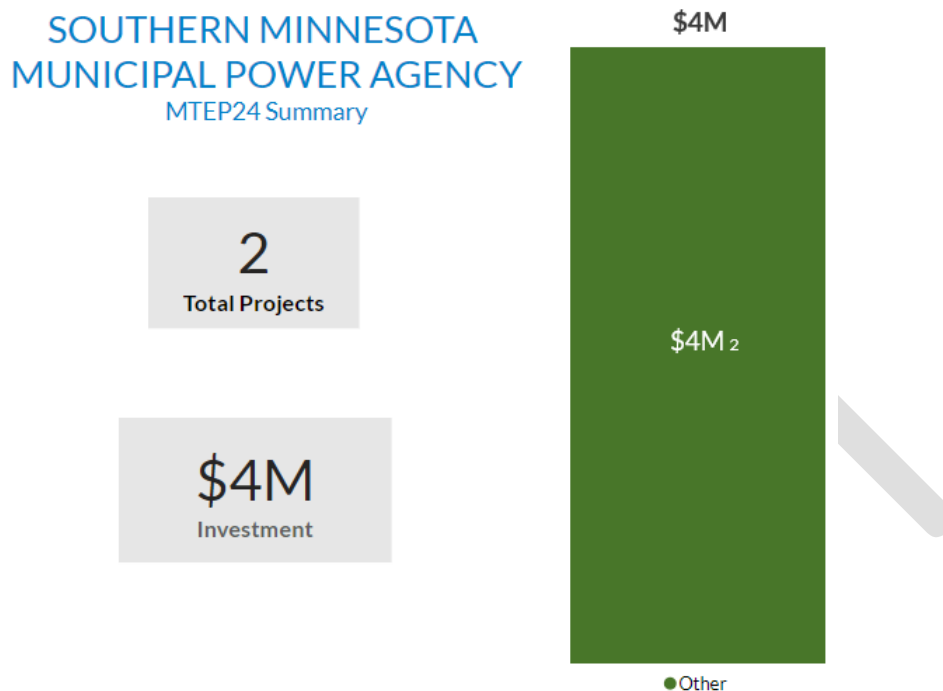
Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
10001	OTP Voltaire 115 kV Substation	Local Needs	12/31/2026	\$8.1
16289	Bemidji 115/12.5 kV Substation	Load Growth	12/31/2025	\$8.0
22487	OTP Audubon and Erie 230/115 kV Transformer Tap Adjustments	Local Reliability	11/30/2025	\$0.0
50005	OTP Donaldson 41.6 kV CB 215 Reconductor	Age and Condition	12/31/2025	\$0.8
50006	OTP Marvin - Corona Area 41.6 kV Rebuild	Local Reliability	12/31/2025	\$1.5
50007	OTP Omemee Rebuild 41.6 kV Line	Local Reliability	11/1/2025	\$0.8
50008	OTP Oklee Rebuild 41.6 kV Tap	Local Reliability	12/31/2025	\$0.5
50009	OTP Winger 41.6 kV Line Reroute	Local Reliability	12/31/2025	\$0.1
50012	OTP Buffalo Area 41.6 kV Rebuild	Age and Condition	12/31/2028	\$3.8
9997	OTP Rolette 230 kV Substation	Local Needs	12/31/2026	\$8.7



4.6.17 Rochester Public Utilities (RPU)

Rochester Public Utilities and MISO are not recommending any new projects for MTEP24.

4.6.18 Southern Minnesota Municipal Power Agency (SMMPA)



Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25199	Fairmont 10th St 69 kV Substation Modernization	Age and Condition	2/1/2025	\$1.8
25260	Loon Lake 69 kV Substation Modernization	Age and Condition	2/1/2025	\$1.8

4.6.19 Wilmar Municipal Utilities (WMU)

Wilmar Municipal Utilities and MISO are not recommending any new projects for MTEP24.

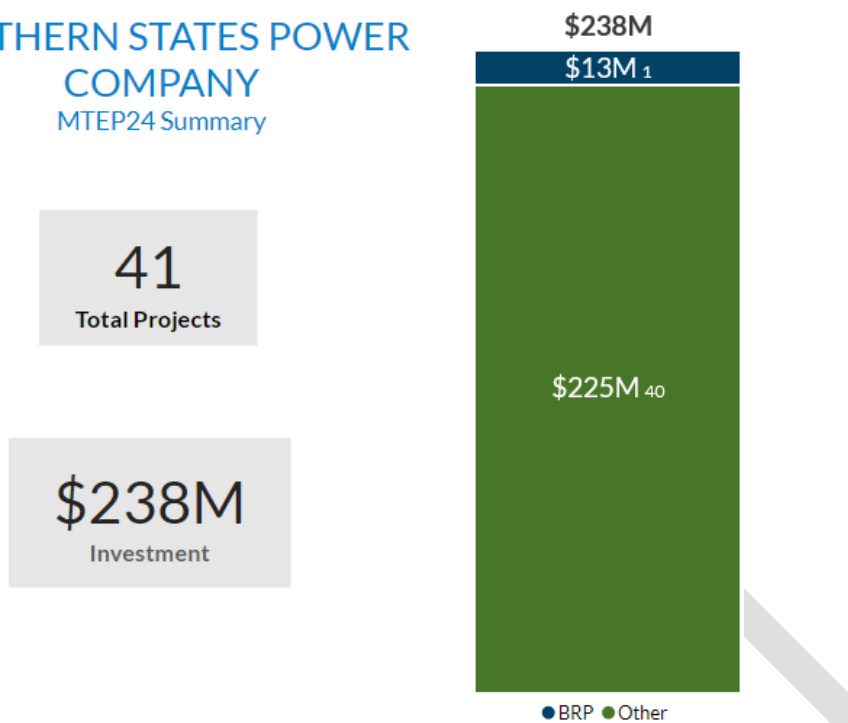
4.6.20 WPPI Energy (WPPI)

WPPI Energy and MISO are not recommending any new projects for MTEP24.



4.6.21 Xcel Energy (Northern States Power)

NORTHERN STATES POWER COMPANY MTEP24 Summary



Baseline Reliability Projects

P25300 – Nobles County Third Transformer

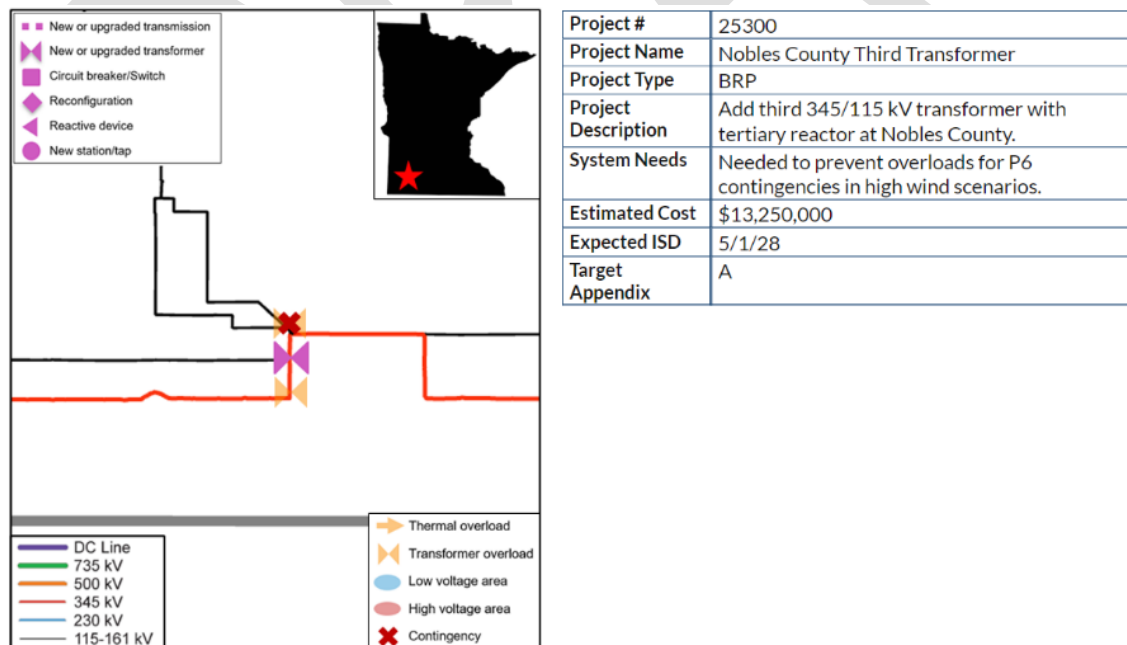


Figure 4.6.21-1: P25300 Geographic transmission map of project area and MTEP Portal project details.



Project Justification: The transformers at Nobles County substation become overloaded for several NERC defined P6 contingency events in high wind conditions. Adding a third transformer at the substation relieves these overloads to well below emergency limits.

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project (pre-cont.) Loading (%)	Post-Project (post-cont.) Loading (%)
P6	Nobles Transformer #9	598	111	56
P6	Nobles Transformer #10	598	111	56

Table 4.6.21-1: P25300 Thermal loading drivers.

Other Projects

Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25257	W3419 Str 162 Switch Replacement	Age and Condition	12/31/2024	\$0.7
25258	Prior TR02 And Feeder	Local Reliability	6/15/2026	\$7.3
25270	0760 Redwing - Lake City - Str 217 Rebuild	Age and Condition	12/31/2026	\$10.0
25272	MNN MOD Installation	Local Reliability	6/13/2025	\$3.6
25273	Bateman Substation Breaker Upgrade	Local Reliability	12/31/2025	\$1.0
25285	0891 West St Cloud - Crossroads Rebuild	Age and Condition	12/15/2025	\$3.5
25286	0754 Buffalo - Maple Lake Rebuild	Age and Condition	12/15/2025	\$6.0
25287	W3402 Loyal - Spokesville Rebuild	Age and Condition	12/31/2025	\$6.0
25288	0774 Goodview - Str 444 Rebuild	Age and Condition	12/31/2025	\$6.0
25289	0821 Highbridge - Miriam Park Refurb	Age and Condition	12/31/2025	\$4.0
25293	0725 Tracy Switching Station to 5535 Str 191 Rebuild	Age and Condition	12/31/2024	\$0.8
25294	Reinforce Tracy Switching Station TR01	Local Reliability	10/15/2025	\$2.2
25295	2023 Line Clearance Mitigations	Local Reliability	9/30/2023	\$0.6
25296	Install Lawrence LAW TR02	Local Reliability	6/15/2025	\$4.2
25297	Blue Heron Second Transformer	Local Reliability	10/15/2025	\$5.8
25317	Wakefield Protection Upgrade	Local Reliability	9/30/2024	\$0.5
25319	Sheas Lake Pilot Channel Replacement	Age and Condition	4/1/2024	\$0.3
25322	0890 Granite City - Crossroads Rebuild	Age and Condition	12/15/2025	\$4.0



Project ID	Project Name	Other Breakdown	ISD	Estimated Cost (\$M)
25323	St Croix Valley Upgrades	Local Reliability	9/30/2029	\$45.0
25324	Downing Substation	Local Reliability	10/15/2025	\$4.0
25325	0986 K Frame Replacement	Age and Condition	12/31/2026	\$15.0
25340	Albany Second Transformer	Local Reliability	10/15/2025	\$5.5
25341	0987 K Frame Replacement	Age and Condition	12/31/2026	\$15.0
25342	Missouri Creek Substation	Age and Condition	6/1/2029	\$9.0
25356	CNC-BUL-SHC Pilot Channel Replacement	Age and Condition	1/15/2024	\$0.3
25357	BYN-NRH Pilot Channel Replacement	Age and Condition	12/15/2023	\$0.2
25368	W3418 Insulator Replacement and Refurb	Age and Condition	12/31/2024	\$0.5
25369	W3410 Ellsworth Switch Replacement	Local Reliability	12/31/2024	\$0.5
25370	W3401 Insulator Replacement and Refurb	Age and Condition	12/31/2024	\$1.0
25375	W3415 EGA-DUR-ARK Insulator Replacement and Refurbishment	Age and Condition	12/1/2025	\$1.0
25376	Line 0876 Redwood Falls Tap Switch Replacement	Age and Condition	12/1/2024	\$0.4
25377	DPC North Wal Interconnection	Load Growth	12/1/2024	\$0.5
25378	Gaylord Substation Rebuild	Age and Condition	10/15/2026	\$5.1
25379	Rebuild Wabasha Substation	Age and Condition	12/31/2026	\$3.0
25380	OTP Erie Junction Interconnection	Local Reliability	11/1/2023	\$0.7
25506	Inver Grove - Inver Hills 115 kV Rebuild to Double Circuit 115 kV	Age and Condition	12/31/2025	\$10.0
25507	Umore Park 115 kV Substation	Load Growth	12/31/2025	\$35.0
50002	Overstress Breaker Replacement	Age and Condition	5/1/2026	\$0.8
50020	0711 Redwing - Str 11 Rebuild	Age and Condition	12/31/2026	\$2.0
50061	CAPX Fargo-TC OPWG Replacement	Age and Condition	12/15/2026	\$4.3

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