Gopher to Badger Link

Appendix E

Planning Analyses

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Appendix E.1

MTEP24 Chapter 2: Regional/Long Range Transmission Planning

MTEP24 Table of Contents

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.

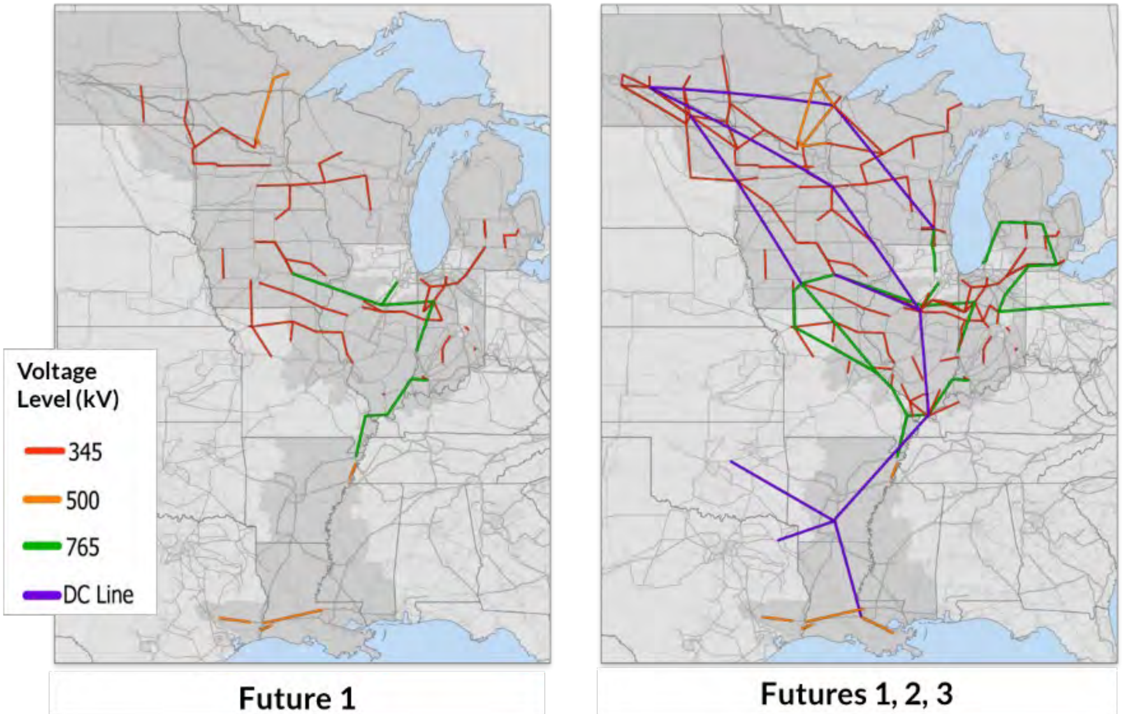


Figure 2.1: Indicative Roadmap

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 analyses[1] 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

[1]Consists 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.

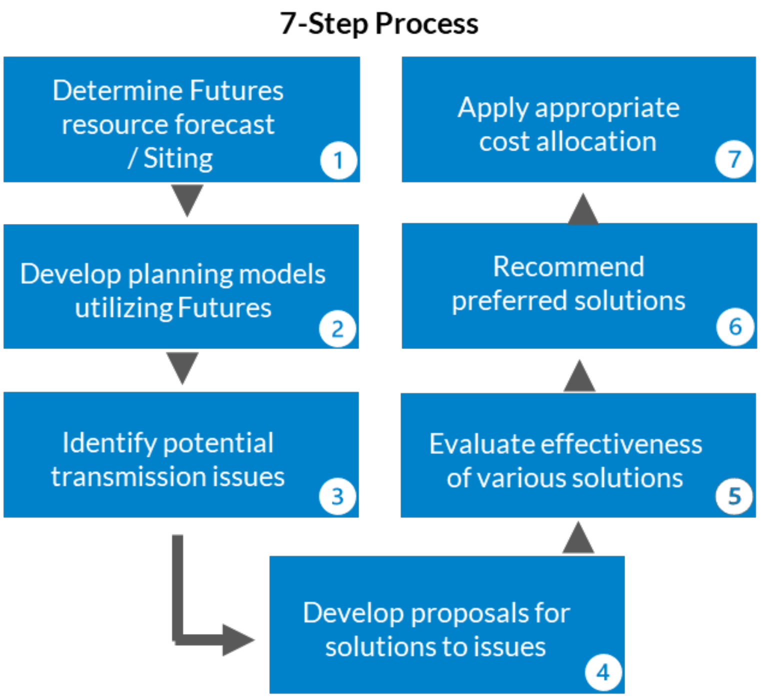


Figure 2.2: MISO's 7-Step Process

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 Panning 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.

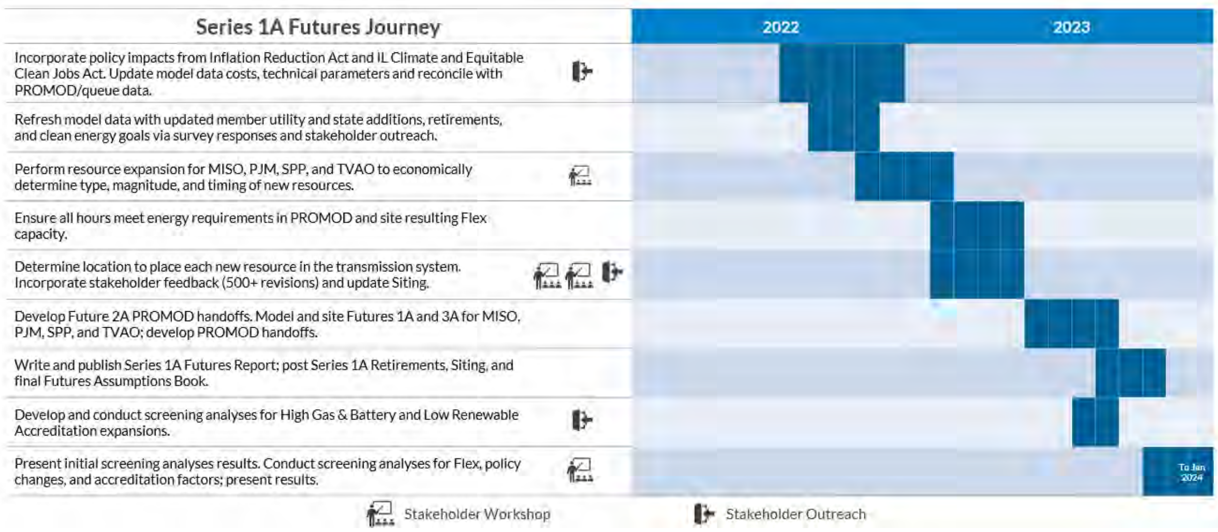


Figure 2.5: Series 1A Futures Journey

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.

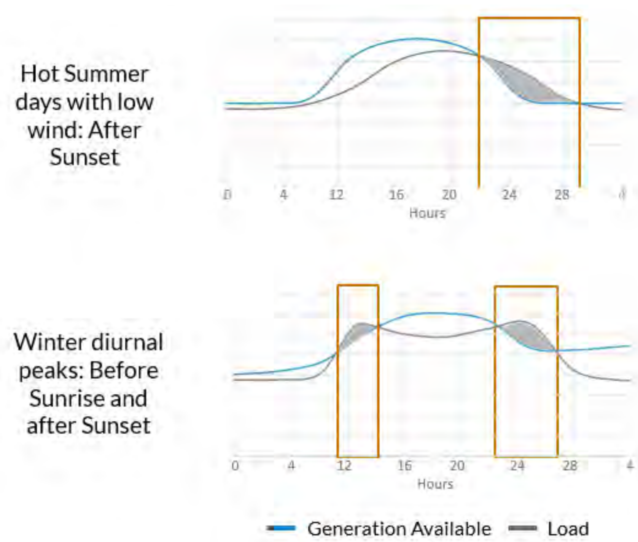


Figure 2.6: Energy Adequacy Analysis for Flexible Attribute Units

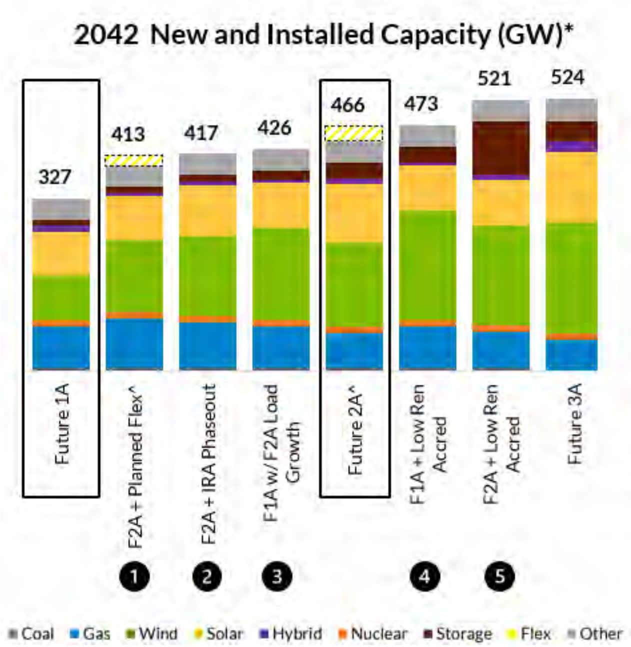
PROMOD, a production cost modeling tool providing hourly (annual) chronological security-constrained unit commitment and economic dispatch, identified generation shortfalls for three to four hours per day during twilight hours (before sunrise or at sunset) in up to 26 days of the modeled year, with a maximum shortfall of 29 GW in a single hour. To address this energy shortfall, 29 GW of supplemental low- or no-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.



	Screening	Details
1	Future 2A + Planned Flexible Attribute Units	Inclusion of 29 GW of Flexible Attribute units as planned gas units
2	Future 2A + Inflation Reduction Act Phaseout	Assumed phaseout of Inflation Reduction Act provision after 2030
3	Future 1A + Future 2A Load	Expansion using F1A goals and retirement assumptions and F2A load growth
4	Future 1A + Low Renewable Accreditation	F1A with wind and solar resource receiving 5% capacity credit
5	Future 2A + Low Renewable Accreditation	F2A with wind and solar resource receiving 5% capacity credit

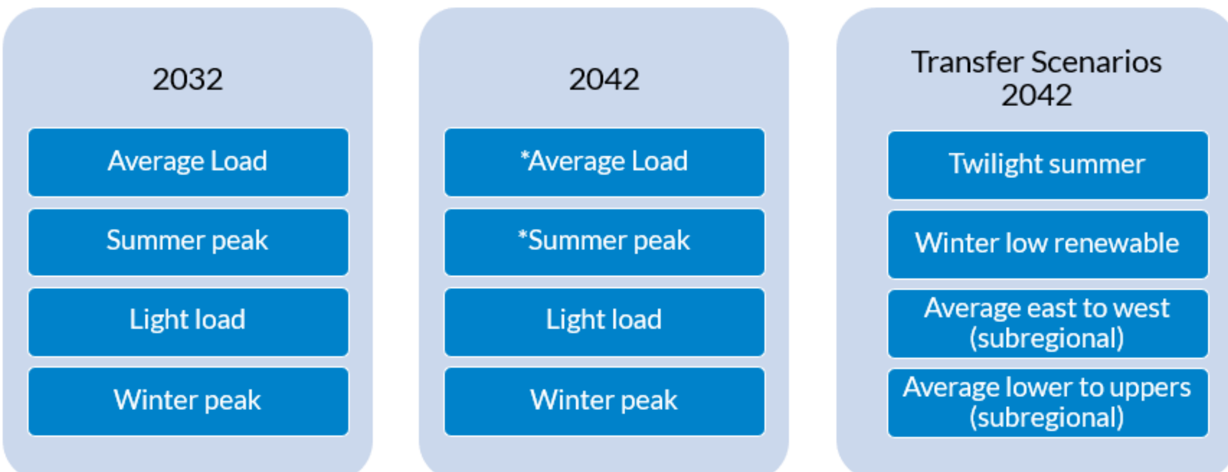
Figure 2.7: Futures Low-End Bookend

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.



* Models used for Dynamic assessment

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 • Represents summer peak demand which is the highest load on the annual load duration curve	• High coincident renewable output in the summer between 90% and 100% of the annual peak demand • Storage off	• Test the ability to reliably serve load via variable renewable energy and conventional resources
Case 2: Winter Peak Load • Represents winter peak demand	• High coincident renewable output in the winter between 90% and 100% of the annual winter peak demand • Storage discharging at 50% nameplate	• 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 • Represents typical system conditions within 70-80% on the load duration curve	• High coincident renewable output between 70% and 80% of the annual peak demand • Storage charging at 60% nameplate	• 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 • Represents lowest 10% on the load duration curve	• High coincident renewable output to test ability of the system to absorb reactive power • Storage charging at 60% nameplate	• Assess system conditions during low load, moderate wind, and zero solar output

Table 2.1: Core models

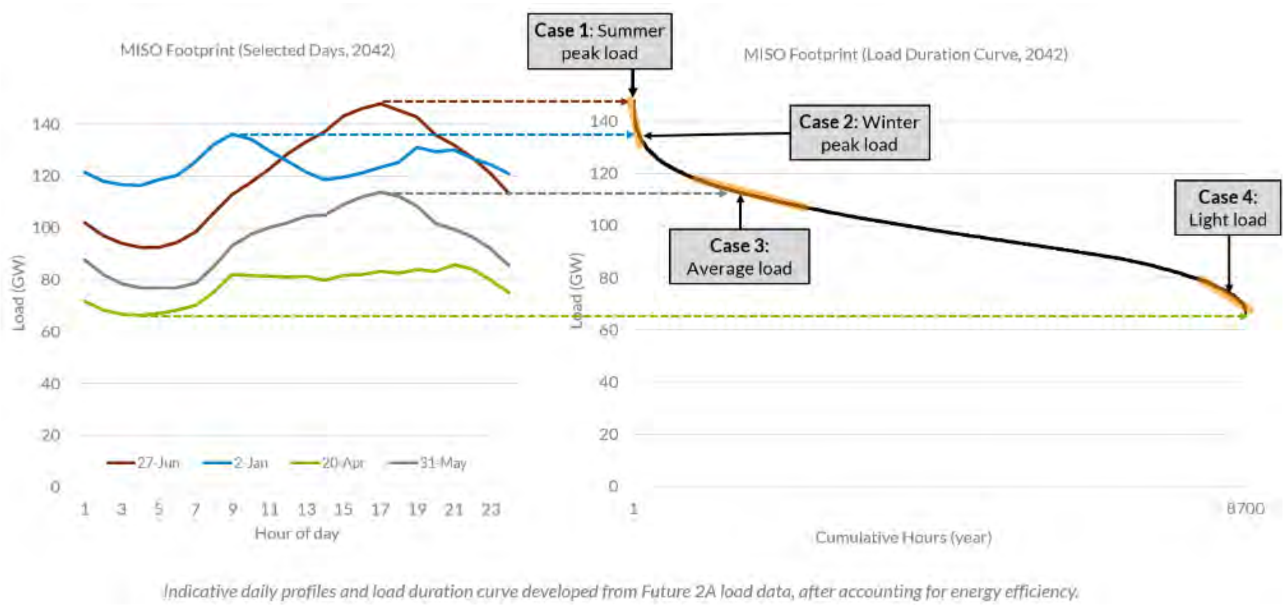


Figure 2.9: Overview of load levels in Future 2A

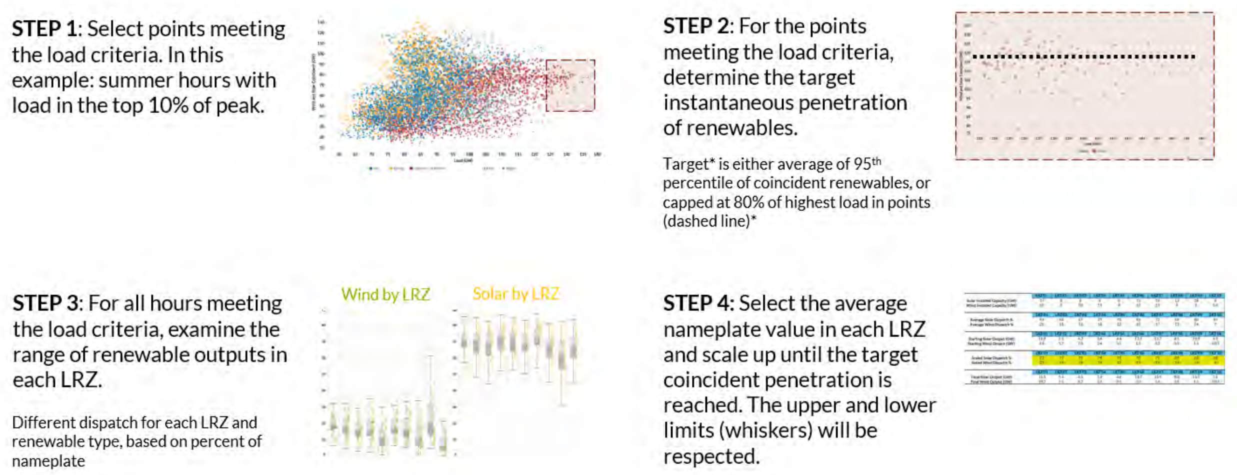


Figure 2.10: Overview of renewable dispatch methodology. This 4-step process provided a target variable dispatch for wind and solar resources specific to each LRZ. This served as a basis in the dispatch each of the core models.

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.

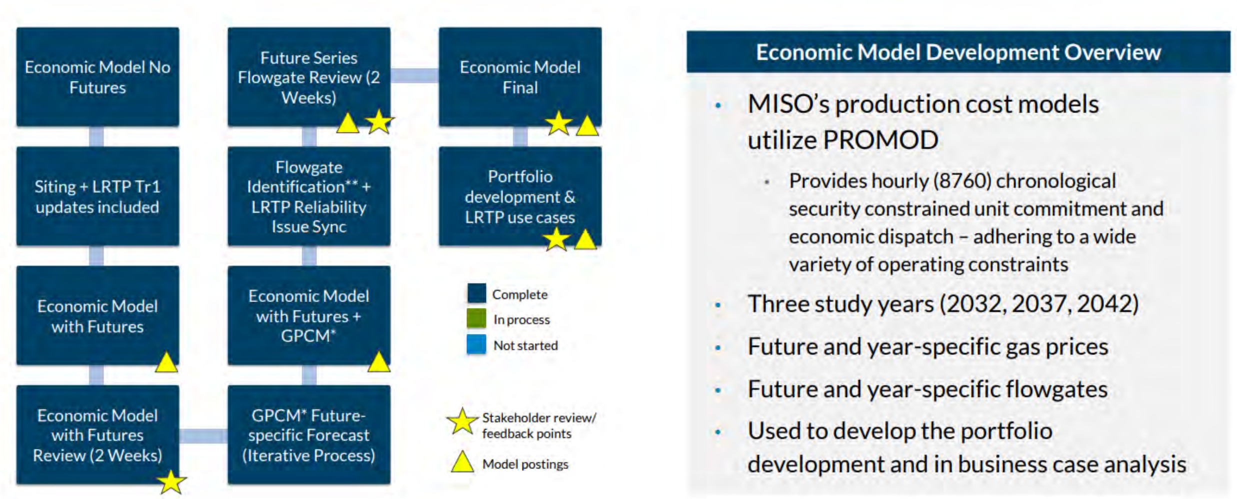
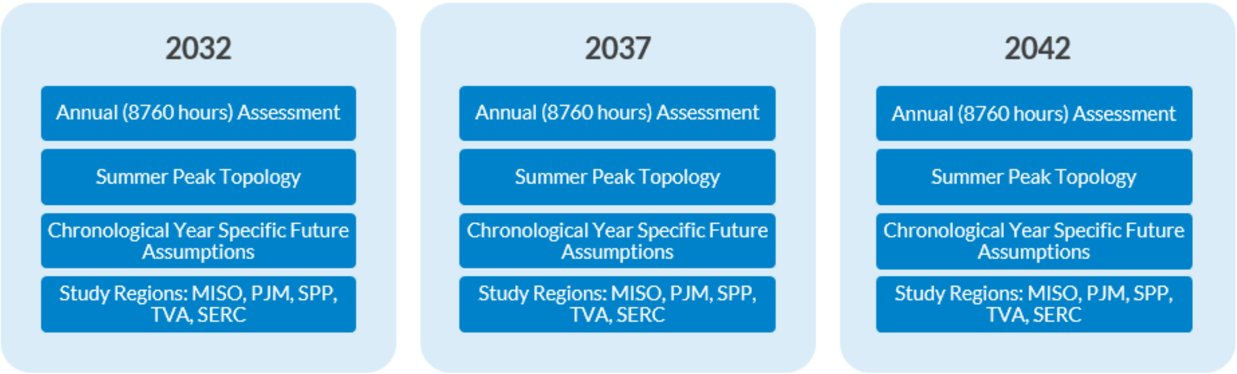


Figure 2.11: Economic Modeling 10-Step Process

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	○ Fall 2021 – generator updates and economic data ○ Spring 2022 – coal price updates ○ 11.5.1 engine
Neighboring Entities Data	○ SPP generator additions and economic data ○ PJM generator additions and economic data
Resource Utilization	○ Generators with signed GIA additions ○ Attachment Y Retirement updates
Powerflow Model	○ MTEP22 - 2032 Summer Peak Powerflow model with updates ○ LRTP Tranche 1 Projects ○ 2032 Winter Peak Powerflow model ratings
Natural Gas Price	○ 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.

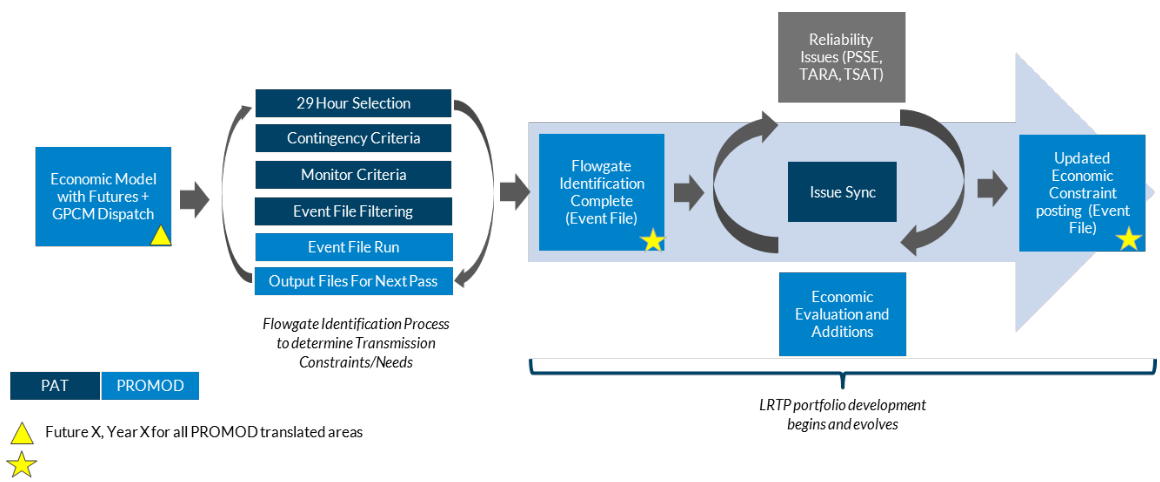


Figure 2.14: Economic Flowgate Identification Process I

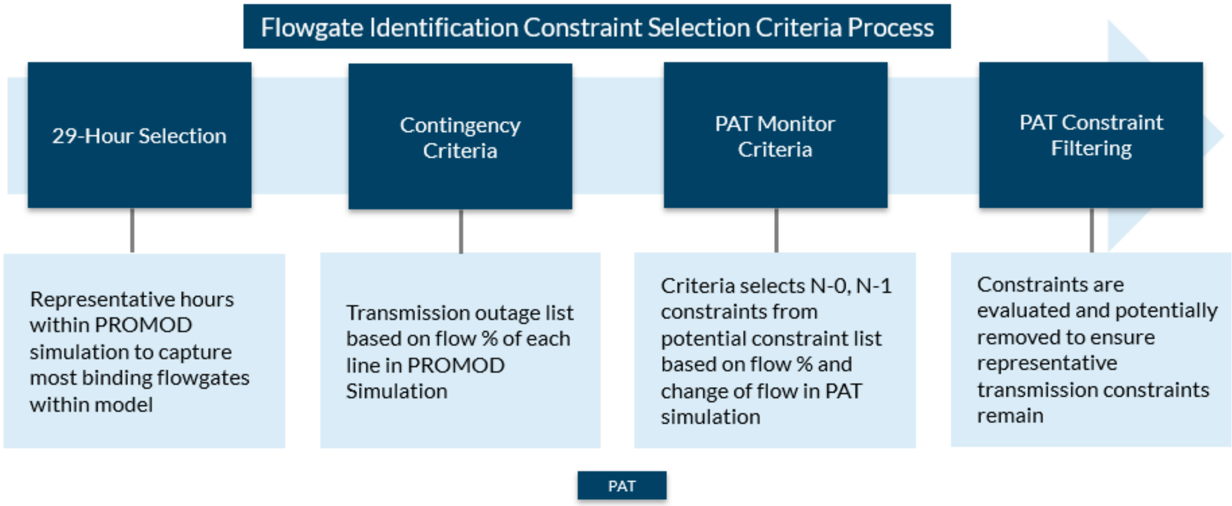


Figure 2.15: Flowgate Identification Constraint Selection Criteria Process II

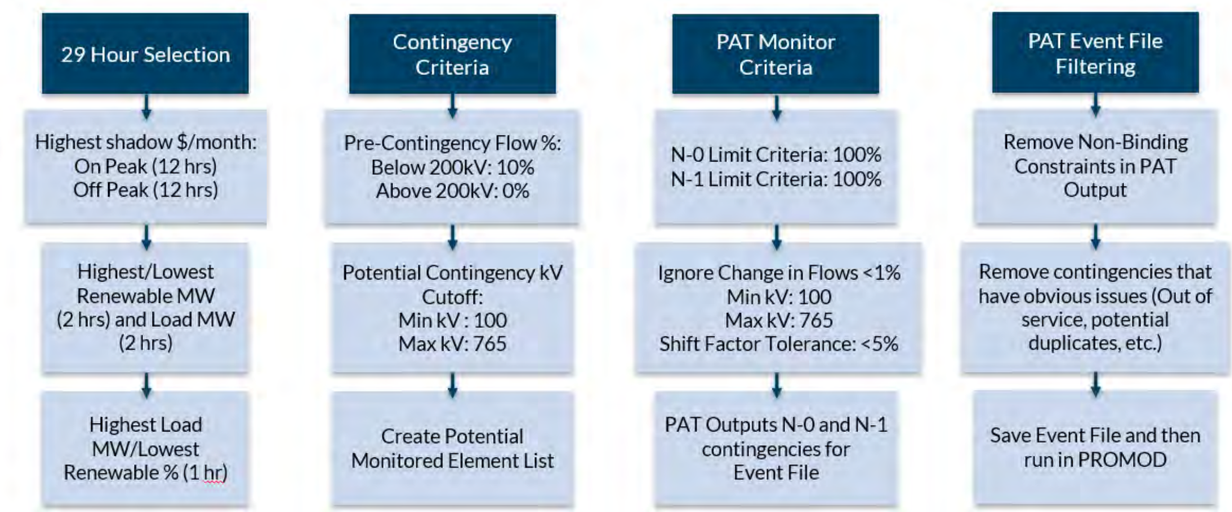


Figure 2.16: Flowgate Identification Constraint Selection Criteria Process III

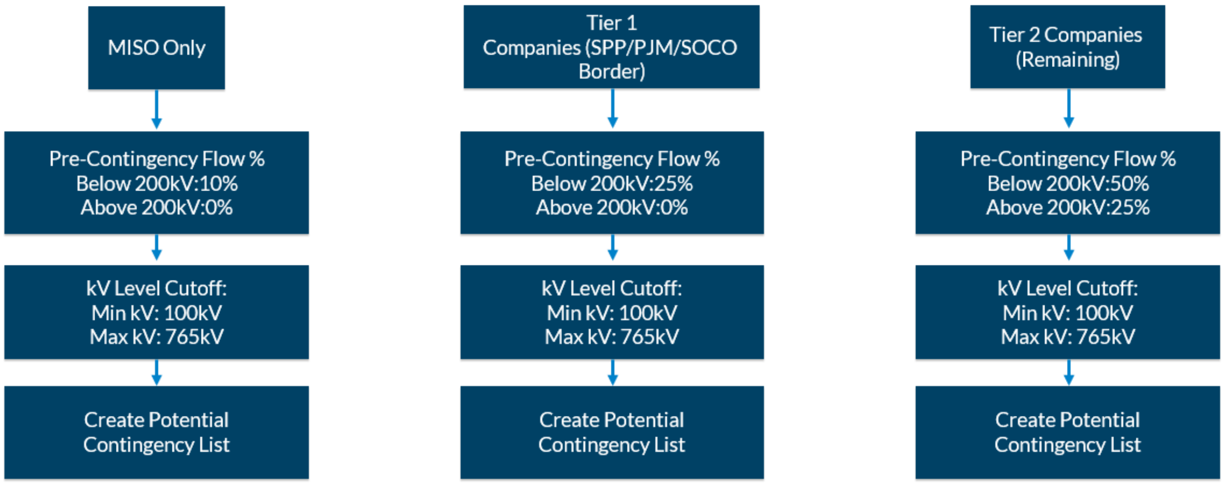


Figure 2.17: Flowgate Identification Constraint Selection Criteria Process IV

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	• 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	• 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	• 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.
- Lowers 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 LRTP workshop in August 31, 2023 and needs or issues presented at the LRTP 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 ($/MW)	An indication of the production cost savings opportunity from relieving transmission congestion	• Identifying most constrained transmission elements • A reduction in Congestion Measure for a constraint or group of constraints indicates a more optimal regional dispatch
Curtailment (MWh)	A measure of the total amount of energy from renewable sources which cannot be delivered economically	• Reduction of curtailment at a single generator improves that unit's financial viability • Reduction of total curtailment in a region indicates that transmission investments enable additional renewable generation
Load LMP ($/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	• 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) ($)	A measure, by company, of the costs to serve demand, considering the effect of purchase and sales	• Evaluating the combined measure of the operating cost of companies within MISO
Adjusted Production Cost Savings ($)	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	• 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	• Future Series Model Built resources with ≥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.

Curtailment

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

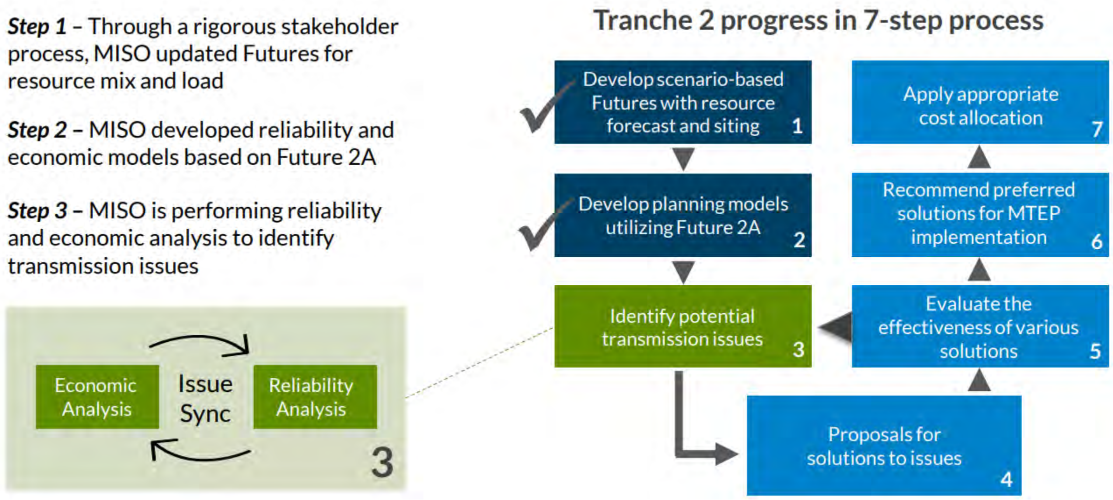


Figure 2.18: Economic and Reliability Transmission Issue Identification

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

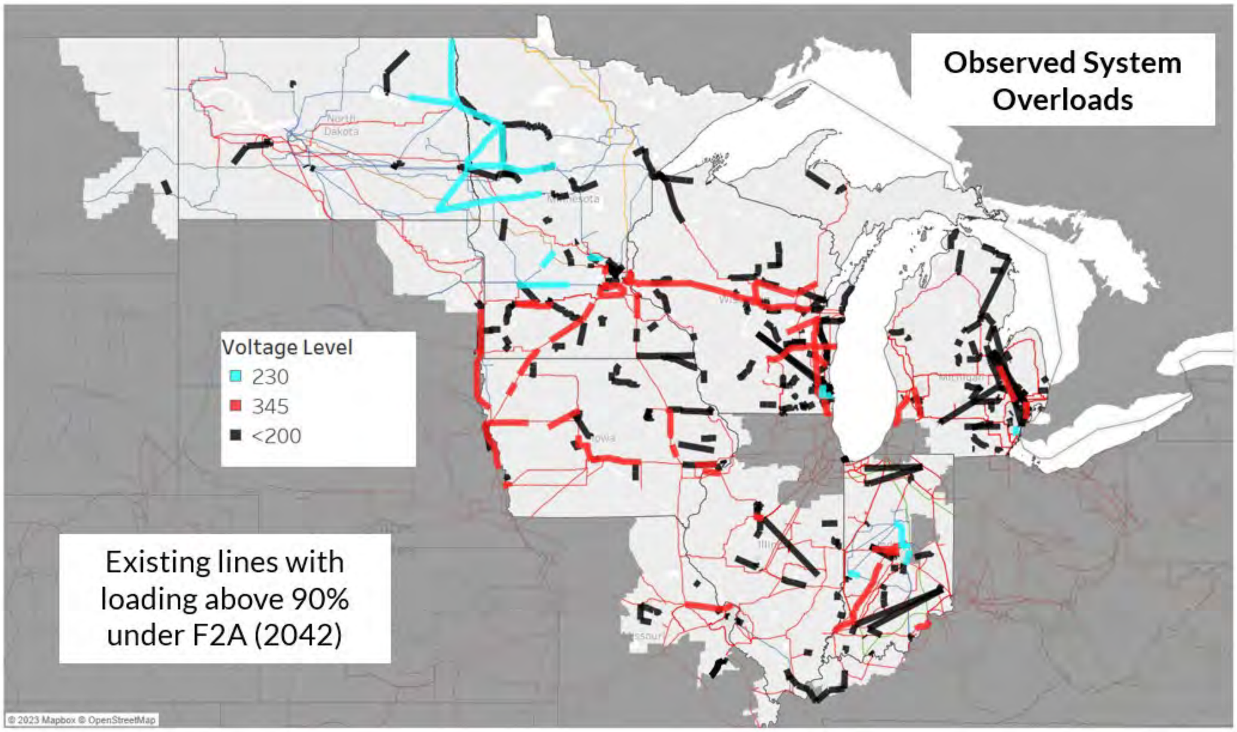


Figure 2.20: MISO Midwest subregion map showing thermal constraints observed by voltage level

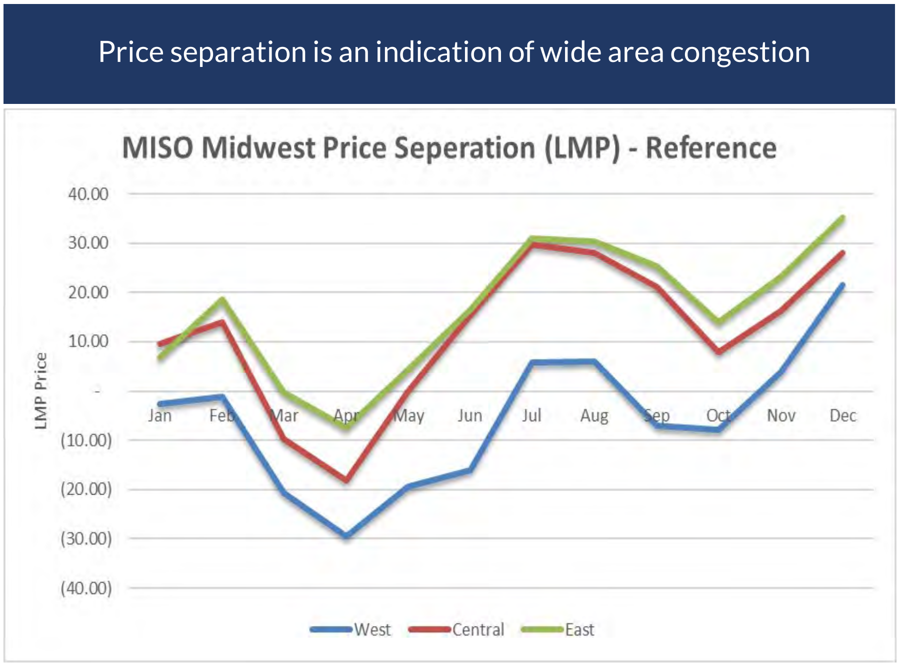


Figure 2.21: Figure 2.23: MISO Midwest Price Separation

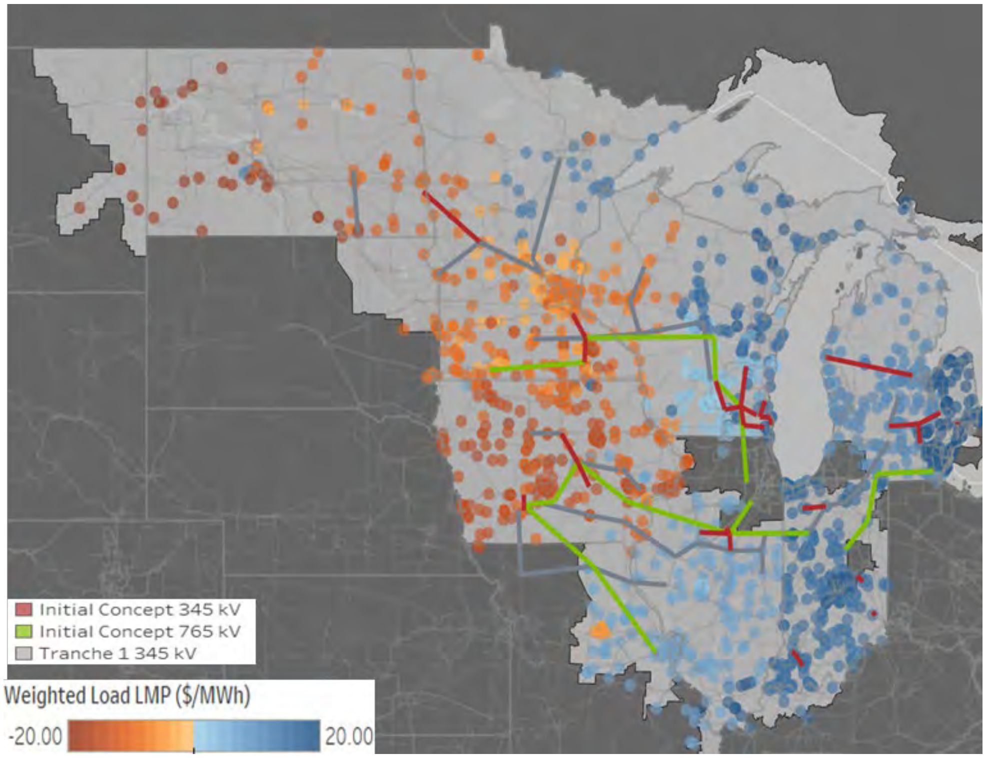


Figure 2.22: Pre-Portfolio LMP Map

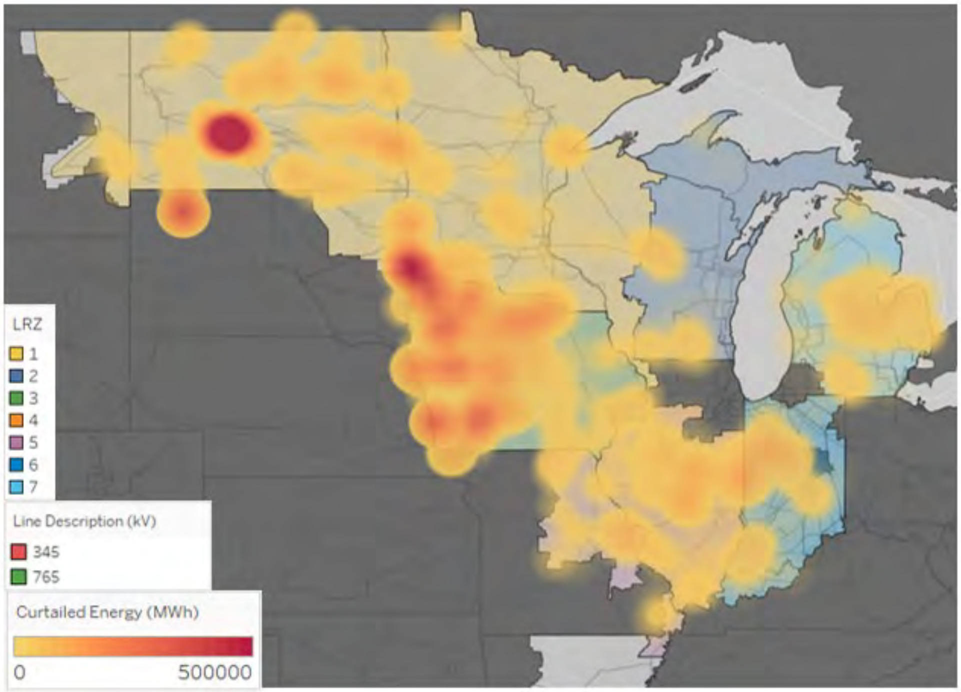


Figure 2.23: MISO Midwest Generation Curtailments Pre-Portfolio

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.

	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

Table 2.5: West Region – Reliability and Economic Issues

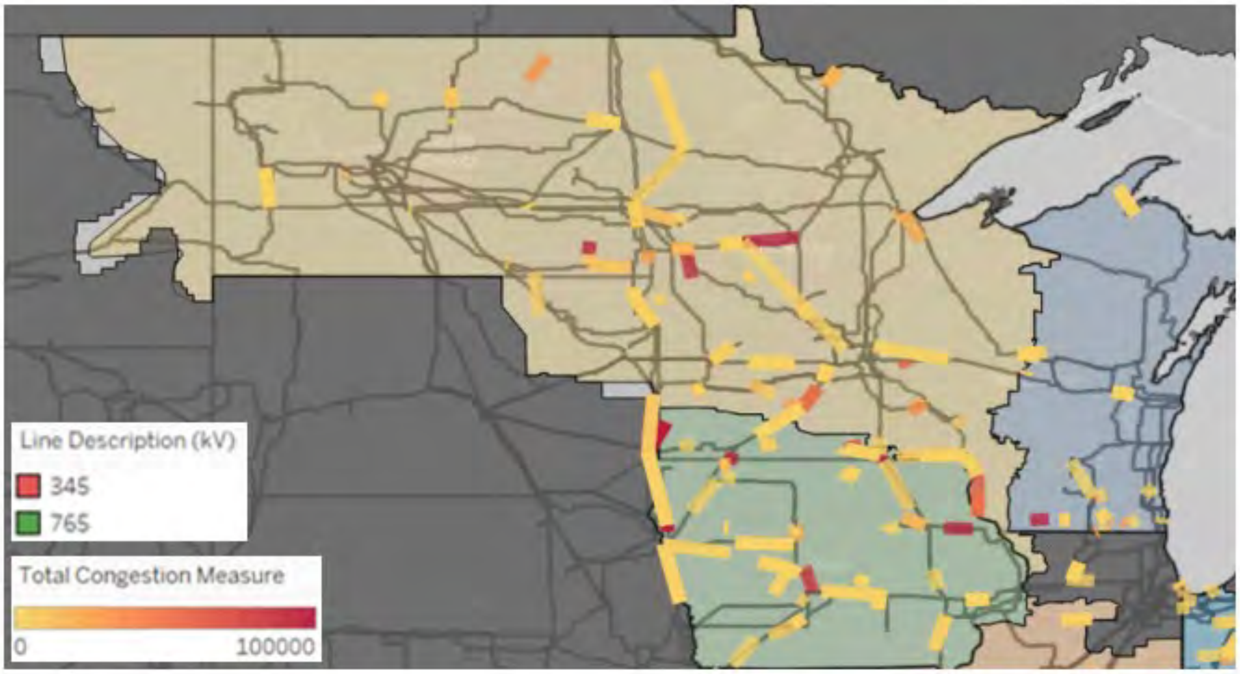


Figure 2.24: Reference Case: Economic Congestion (West)

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.

	RELIABILITY ISSUES		ECONOMIC ISSUES	
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

Table 2.6: Central Region – Reliability and Economic Issues

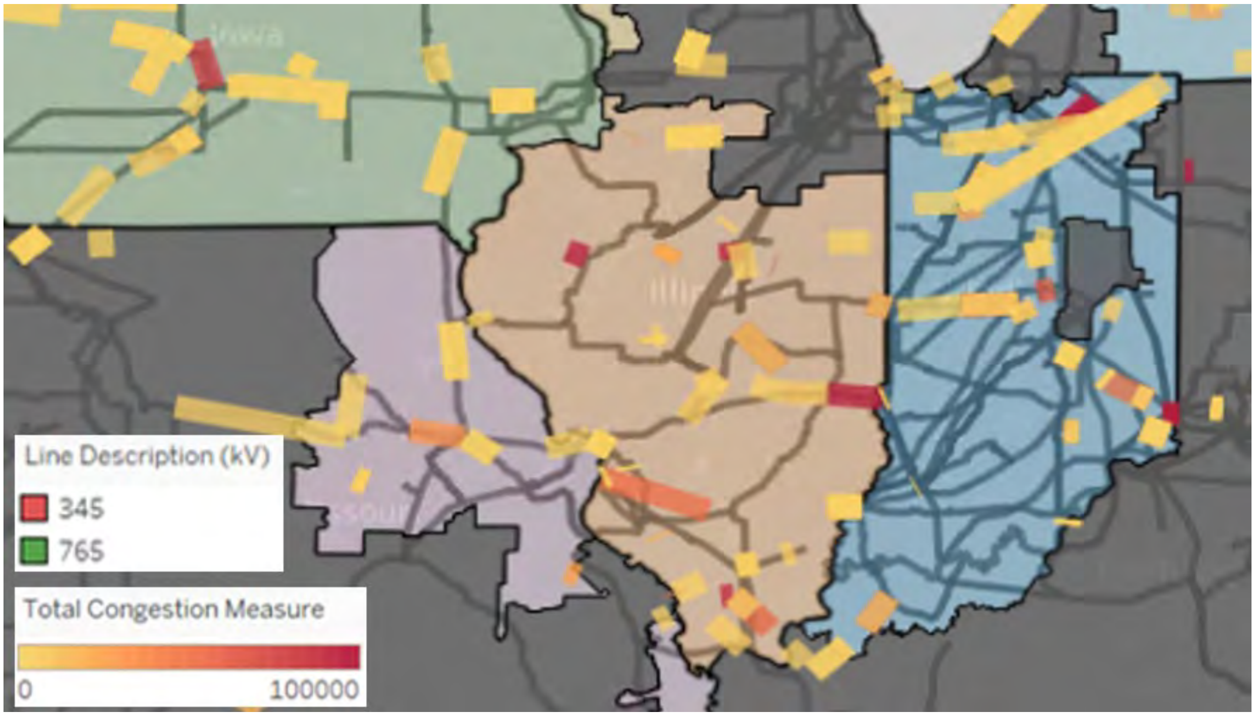


Figure 2.25: Reference Case: Economic Congestion (Central)

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.

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	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

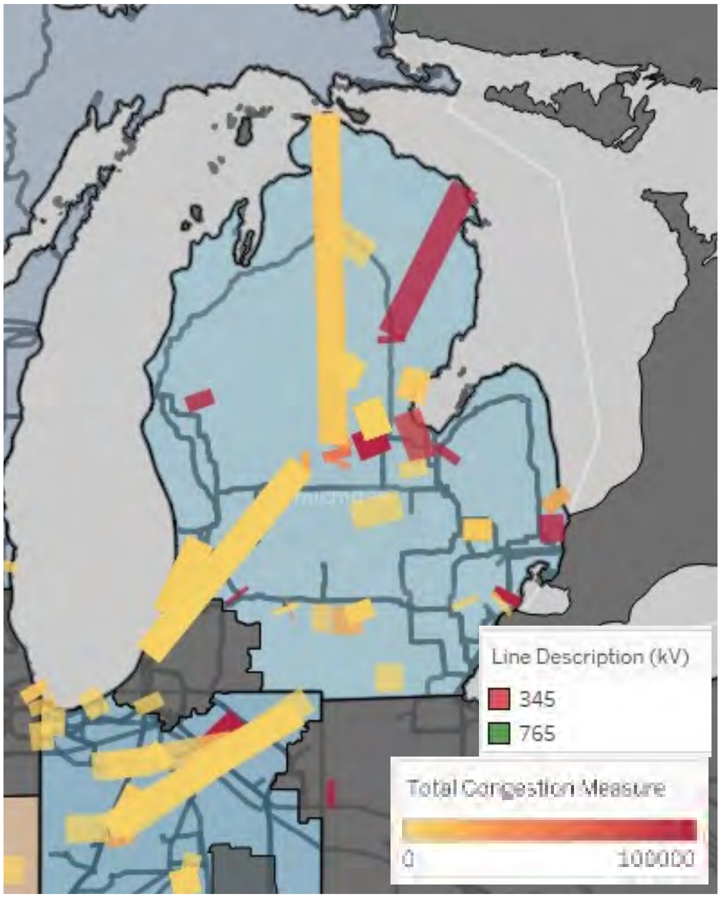


Figure 2.26: Reference Case: Economic Congestion (East)

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.

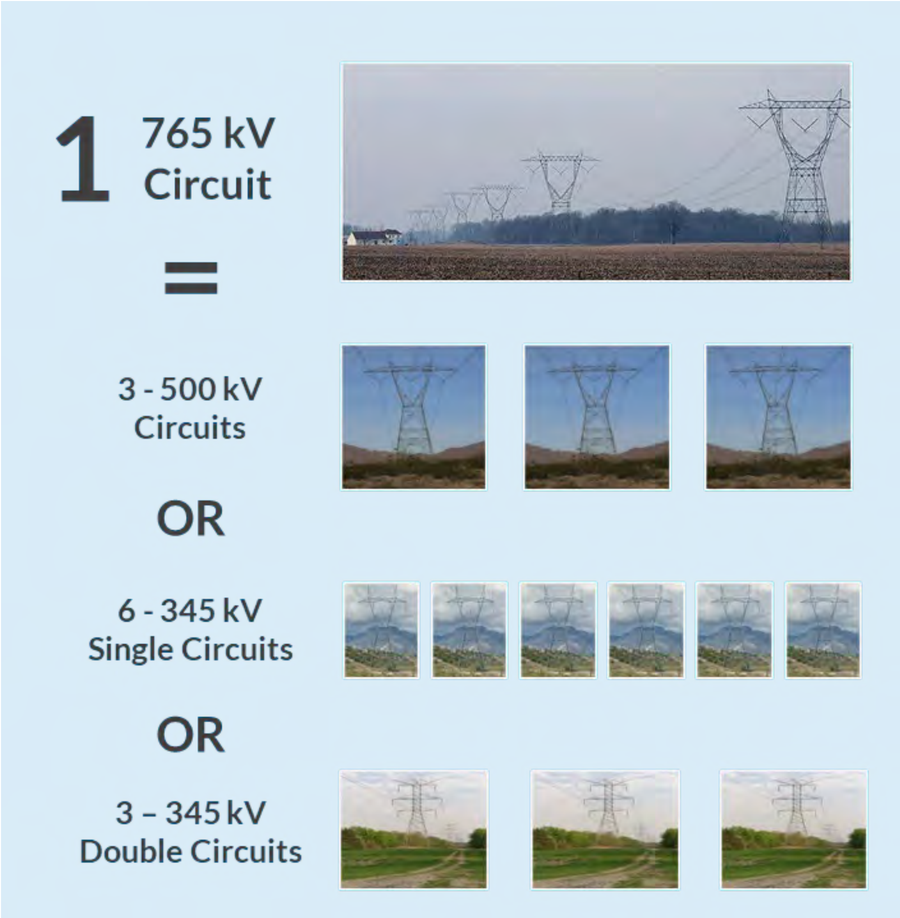


Figure 2.27: Land-Use Evaluation per Transmission Voltage

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:

<table>
<tr><th>Key projects eligible for robustness testing</th><th>Category</th><th>PSSE Area Number[2]</th></tr>
<tr><td>P23026 – New South-Central Illinois Transmission Expansion</td><td>MTEP23</td><td>357, 361</td></tr>
<tr><td>P50106 – Big Cedar Interconnection</td><td>MTEP24</td><td>627, 635</td></tr>
<tr><td>Bison – Hankinson – Big Stone South 345</td><td rowspan="4">JTIQ</td><td rowspan="4">600, 608, 613, 615, 620, 627, 633, 635, 661</td></tr>
<tr><td>Lyon Co. – Lakefield 345</td></tr>
<tr><td>Raun – S3452 345 kV</td></tr>
<tr><td>Auburn – Hoyt 345 kV</td></tr>
<tr><td>Grain Belt Express with projects
as identified in Transmission Construction Agreement</td><td>MHVDC</td><td>356, 357,
330, 333</td></tr>
</table>

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.

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

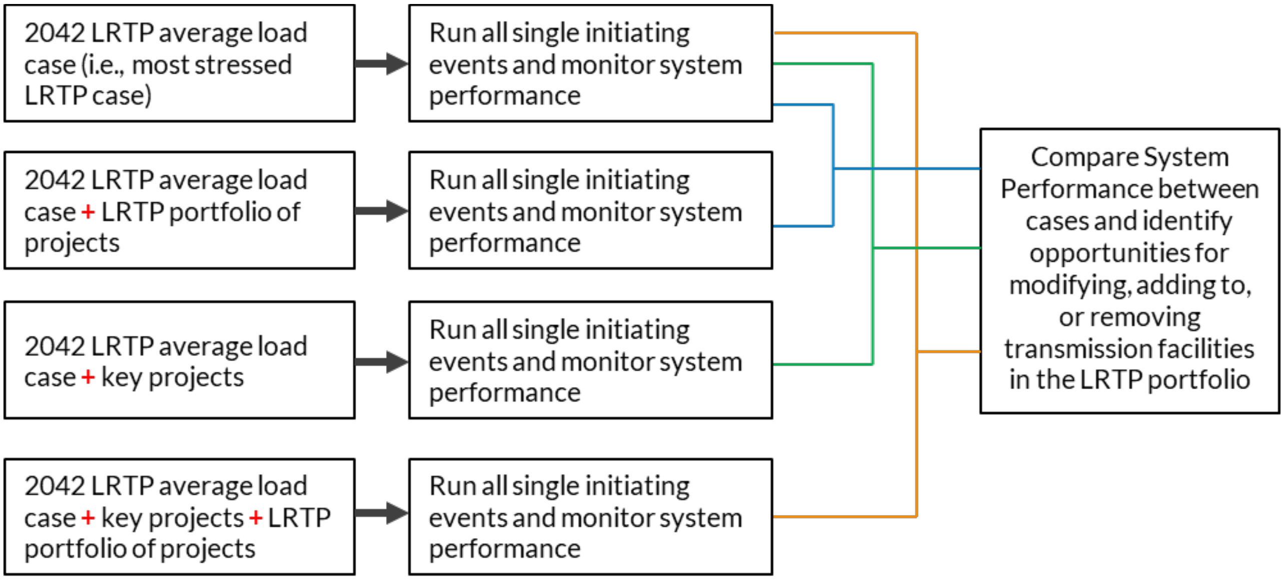


Figure 2.29: Models used in robustness testing

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:

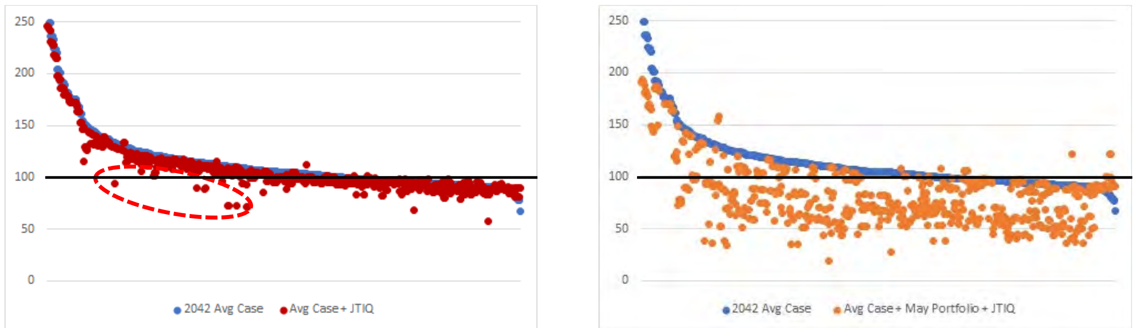
Robustness testing assessment reinforces the projects' alignment with local needs, consistent with their MTEP justification. No Tranche 2.1 project areas have been pinpointed for addition, removal, or modification. More information about the projects, local needs and robustness evaluation can be found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

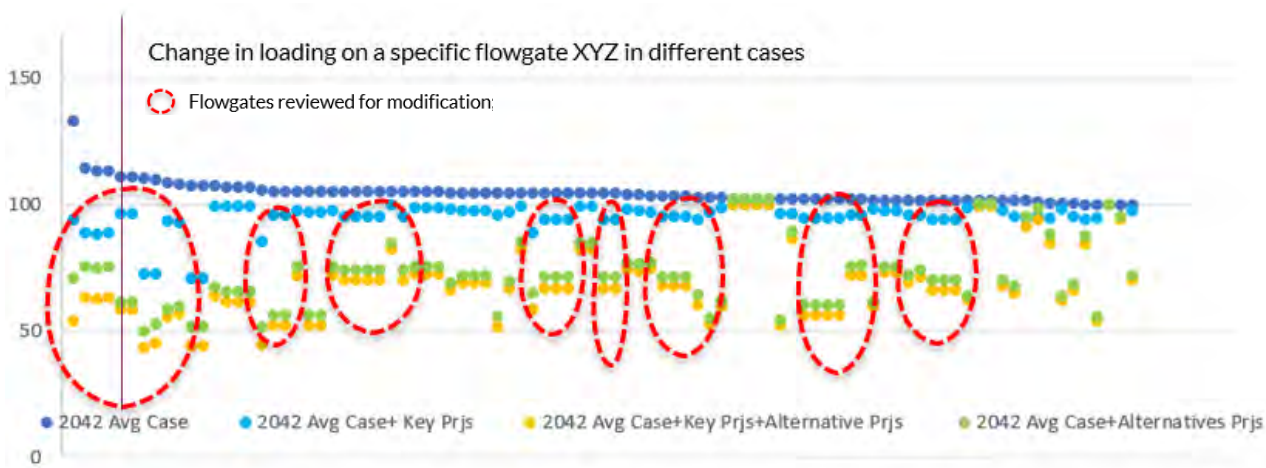


Figure 2.31: Flowgates considered for modification

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.

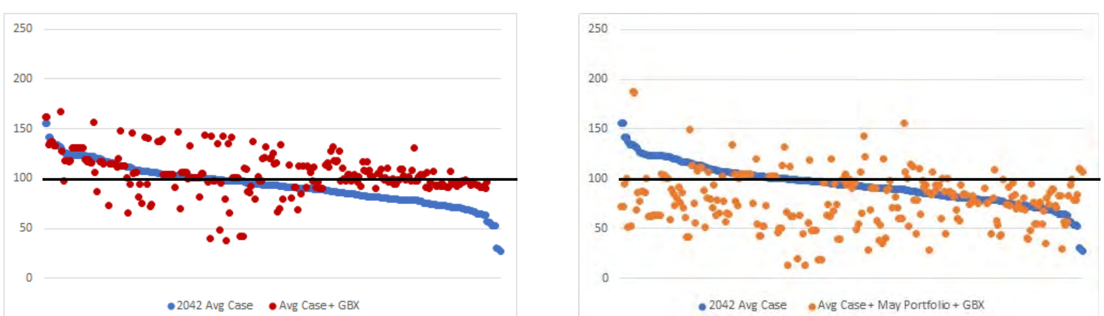
- Dispatch:
  - Injection of 1.5 GW (GBX) into the MISO system was balanced with renewables across MISO Midwest system scaled down to balance load/losses with generation.
  - Injection of 1.0 GW (GBX) into the AECI system was balanced with output reduced by 1.0 GW from the oldest coal units.

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.

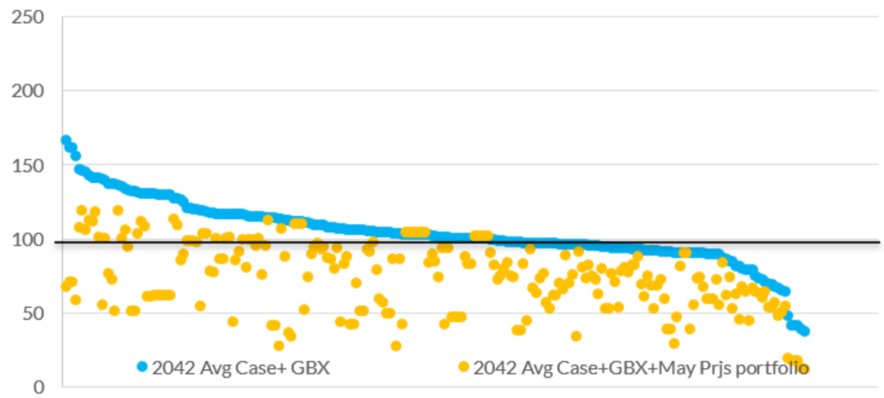


Figure 2.33: Flowgate loading in the Average Case with GBX vs. Flowgate loading in the Average Case with GBX + near-final proposed portfolio

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.**

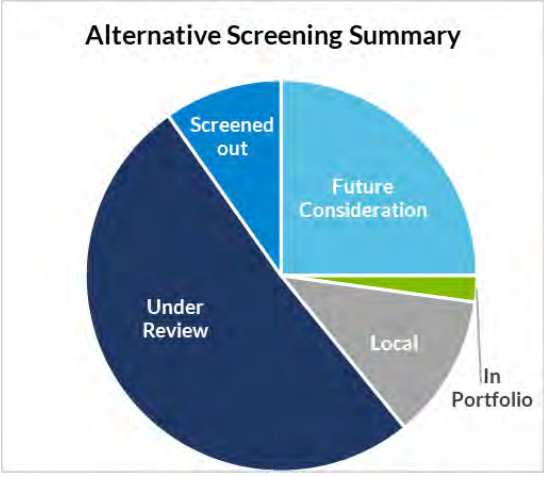


Figure 2.34: Alternative Screening Summary

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

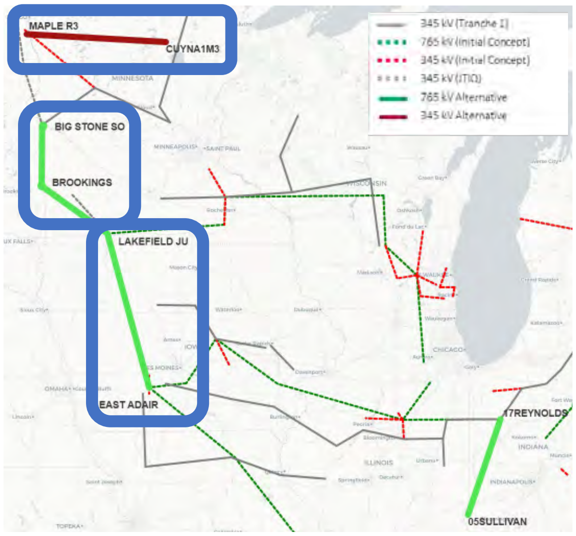


Figure 2.35: Map shows selected Alternative 1 projects in blue boxes

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.

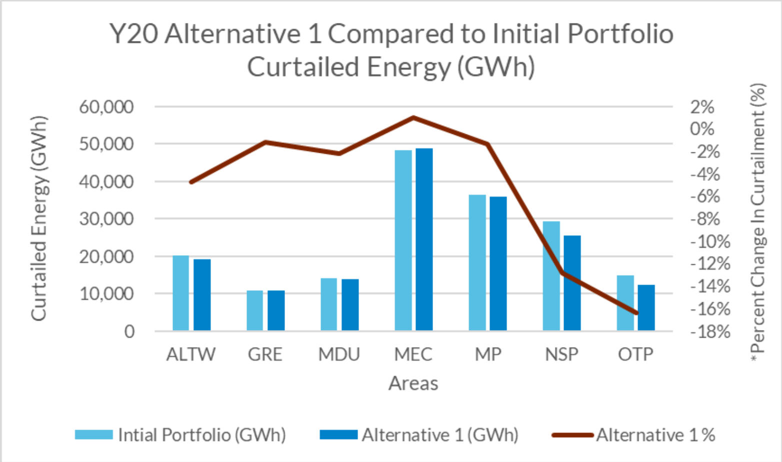


Figure 2.36: Year 20 Curtailed Energy for Initial Portfolio vs. Alternative 1

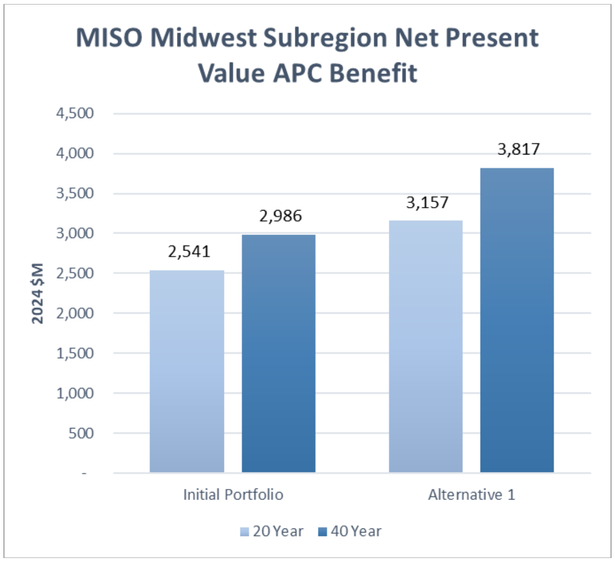


Figure 2.37: Midwest Subregion Net Present Value APC Benefit

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.

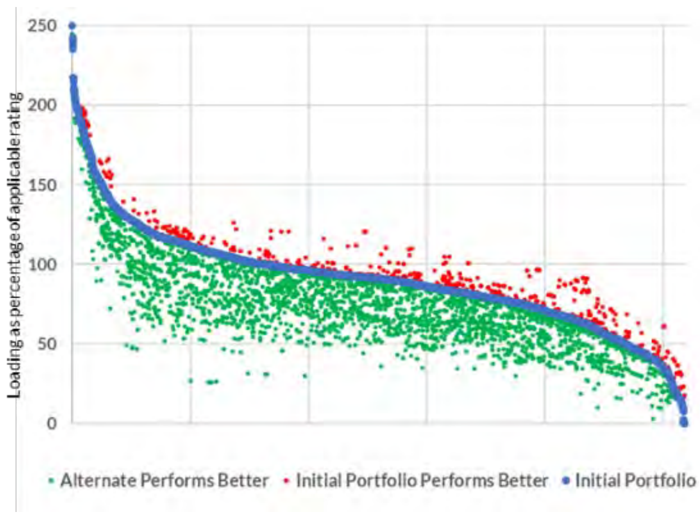


Figure 2.38: Scatter plot showing Alternative 1 performance as compared to Initial Portfolio

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.

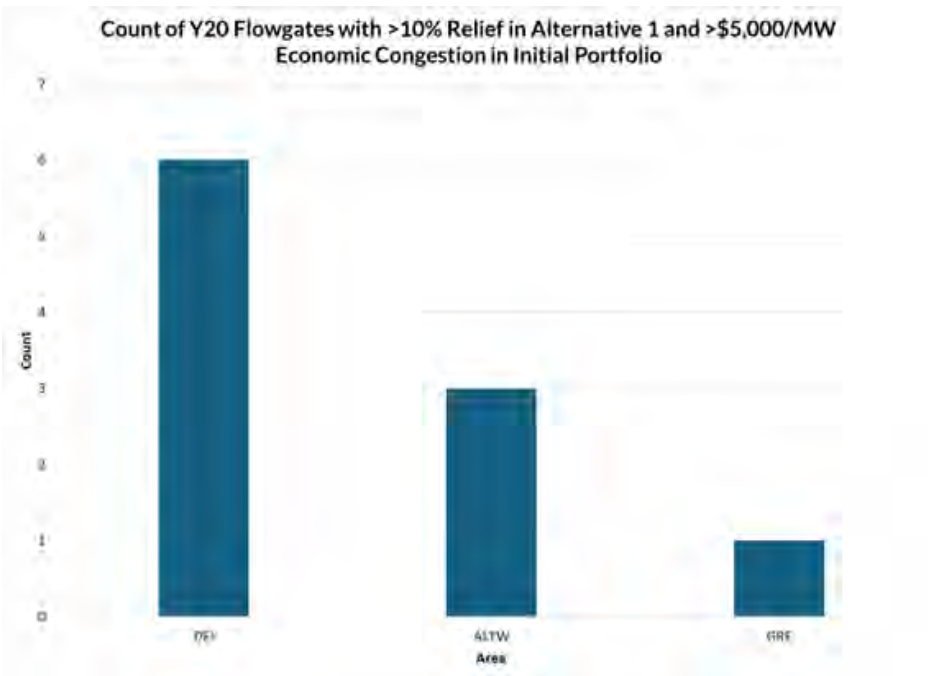


Figure 2.39: Count of Year 20 Flowgates with Congestion Relief for Alternative 1

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.

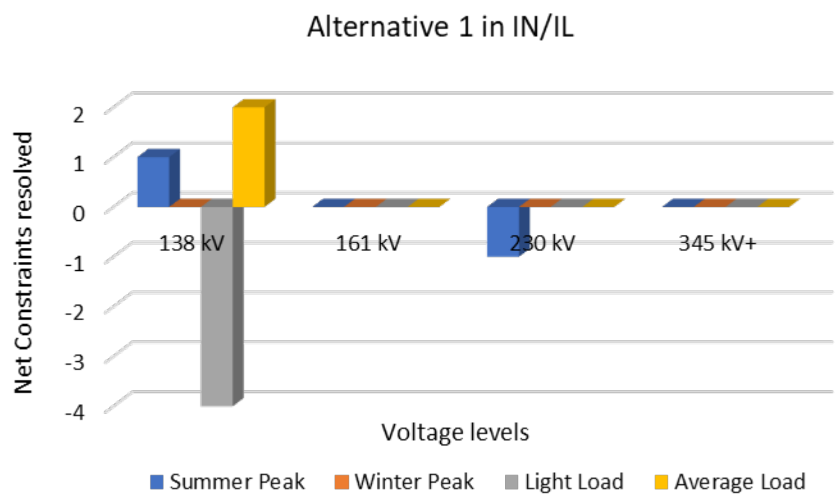


Figure 2.40: Figure: Indiana and Illinois Constraints resolved by Voltage level by Alternative 1 Indiana project

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

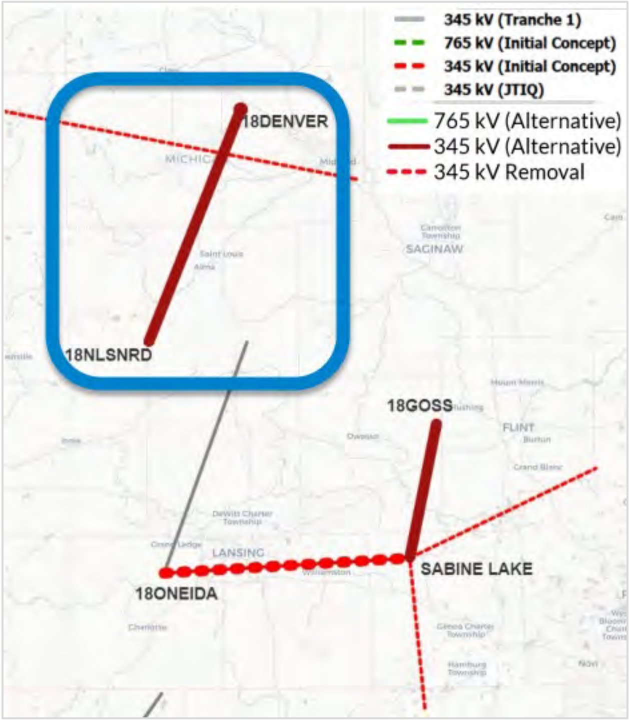


Figure 2.41: Map shows selected Alternative 2 projects in blue boxes

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 tab to the proposed 345 kV line at Denver and adds a 345 kV line from Denver to the Tranche 1 Nelson Road substation.

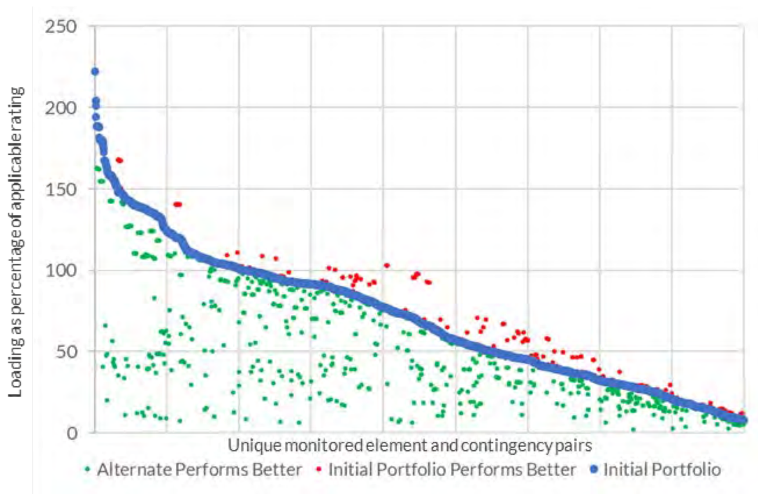


Figure 2.42: Scatter plot showing Denver-Nelson Road 345 kV performance as compared to Initial Portfolio

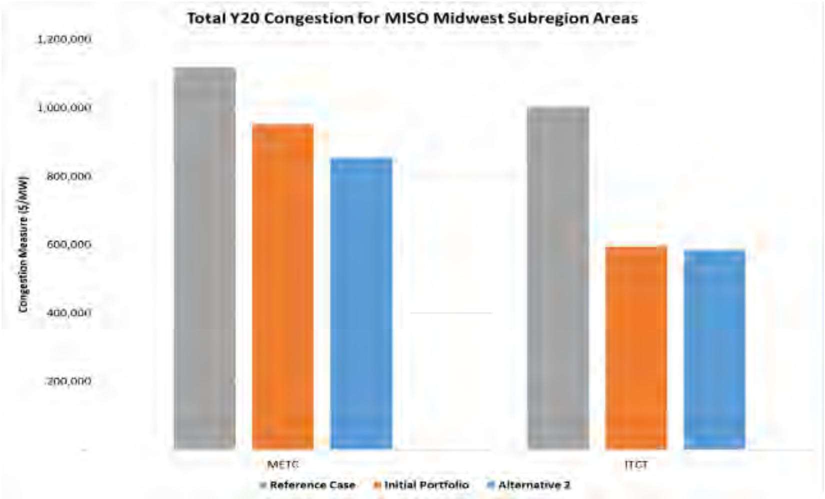


Figure 2.43: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 2

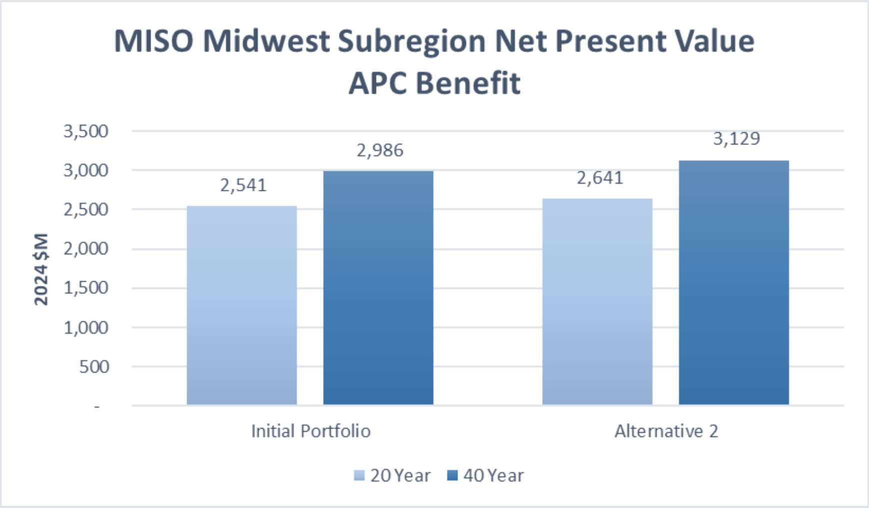


Figure 2.44: Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

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

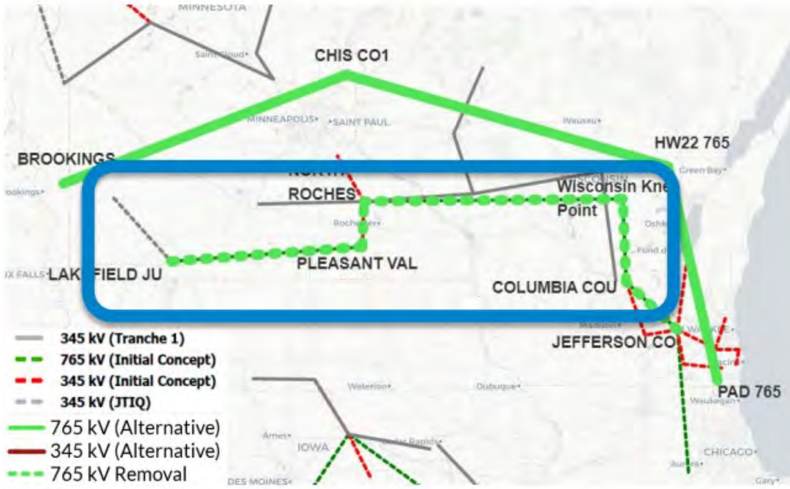


Figure 2.45: Map shows selected initial portfolio projects in blue boxes, Alternative 3 projects were not selected

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 Alternate 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.

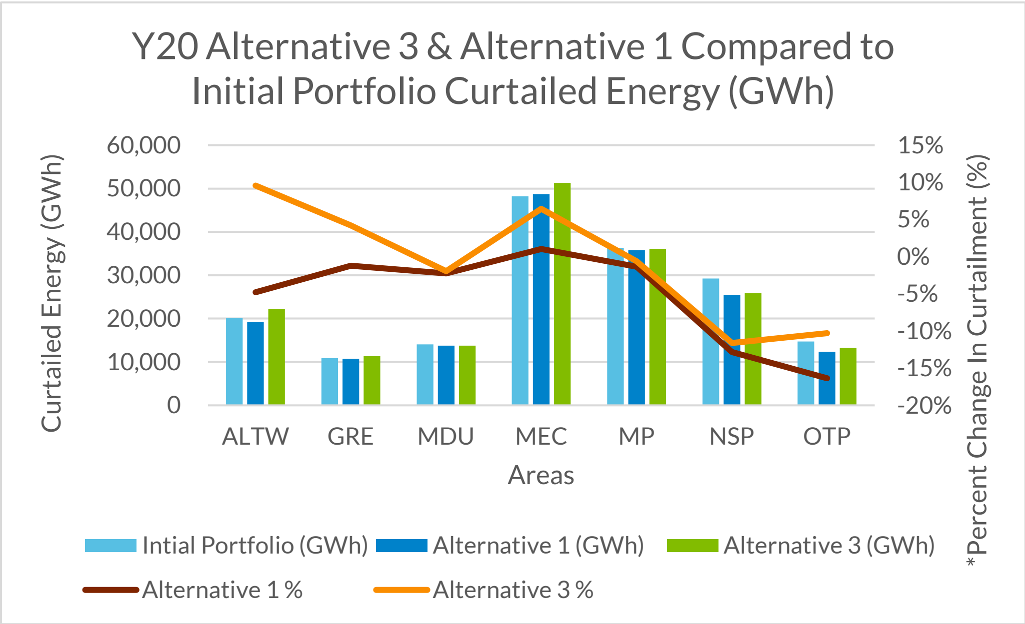


Figure 2.46: Year 20 Curtailed Energy for Initial Portfolio vs. Alternative 1 vs. Alternative 3

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

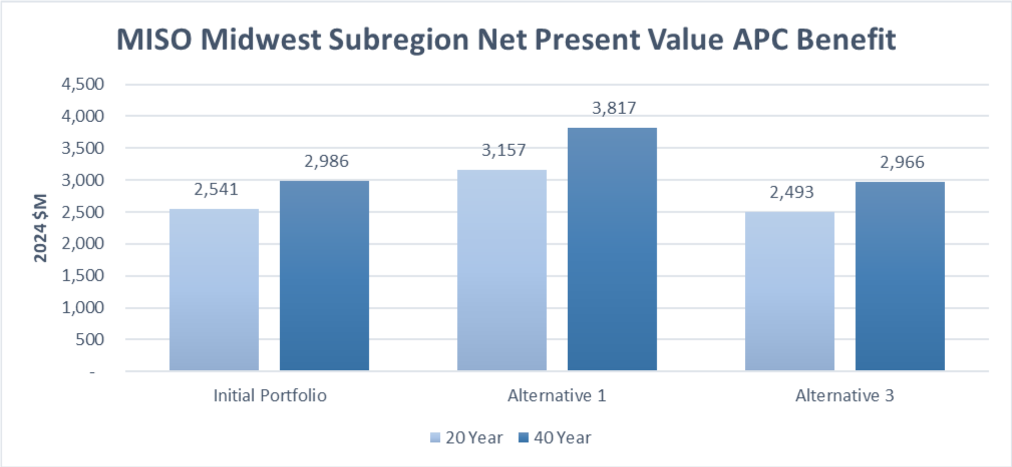


Figure 2.47: Initial Portfolio vs. Alternative 1 vs. Alternative 3 Adjusted Production Cost Savings

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.

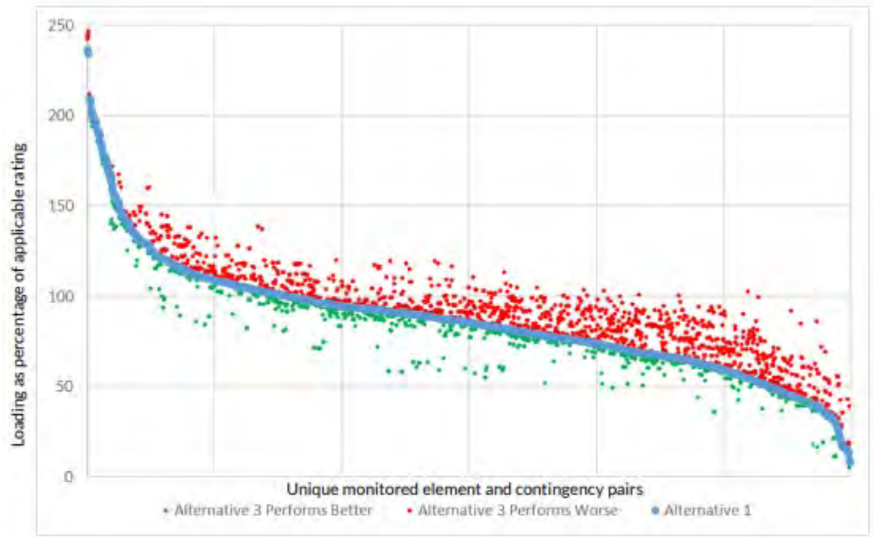


Figure 2.48: Scatter plot showing Alternative 3 performance as compared to Initial Portfolio with Alternative 1 in MN

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.

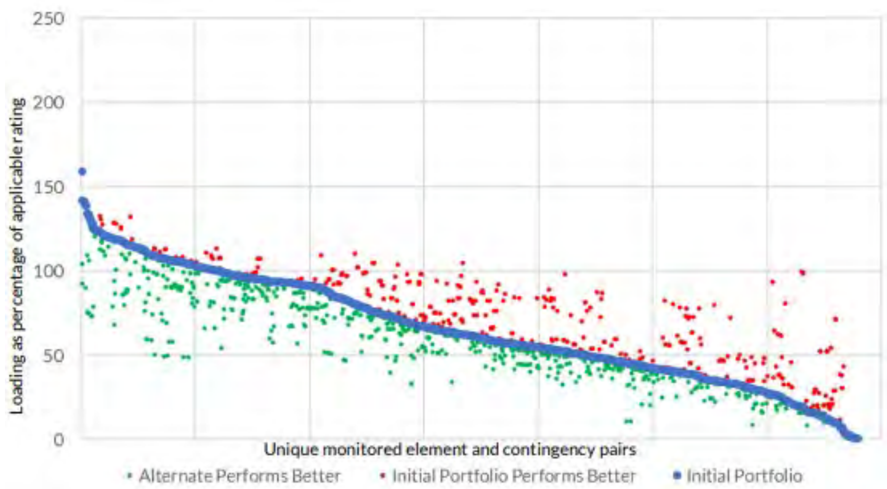


Figure 2.49: Scatter plot showing Alternative 3 performance as compared to Initial Portfolio in WI

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

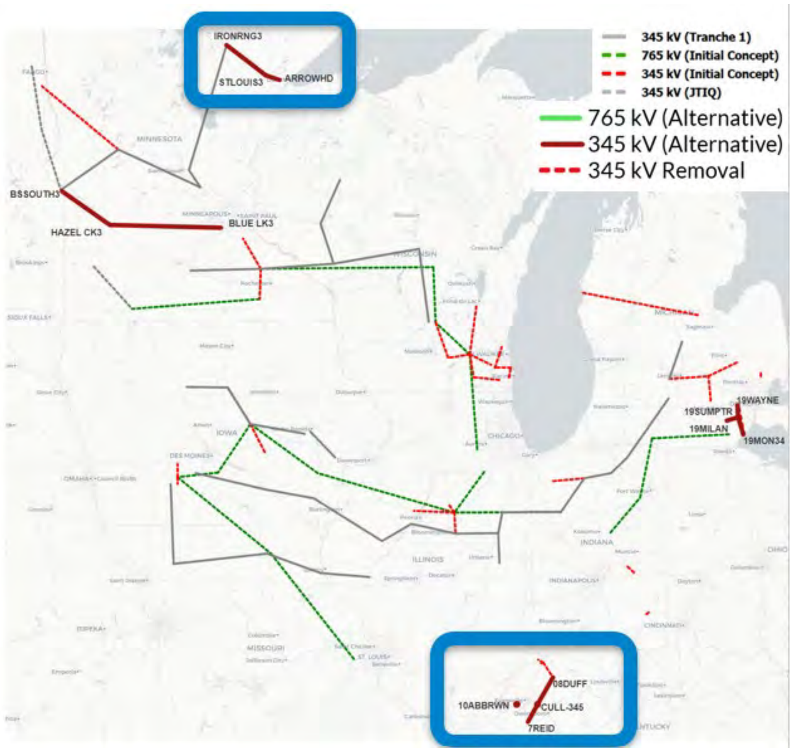


Figure 2.50: Map shows selected Alternative 4 projects in blue boxes

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.

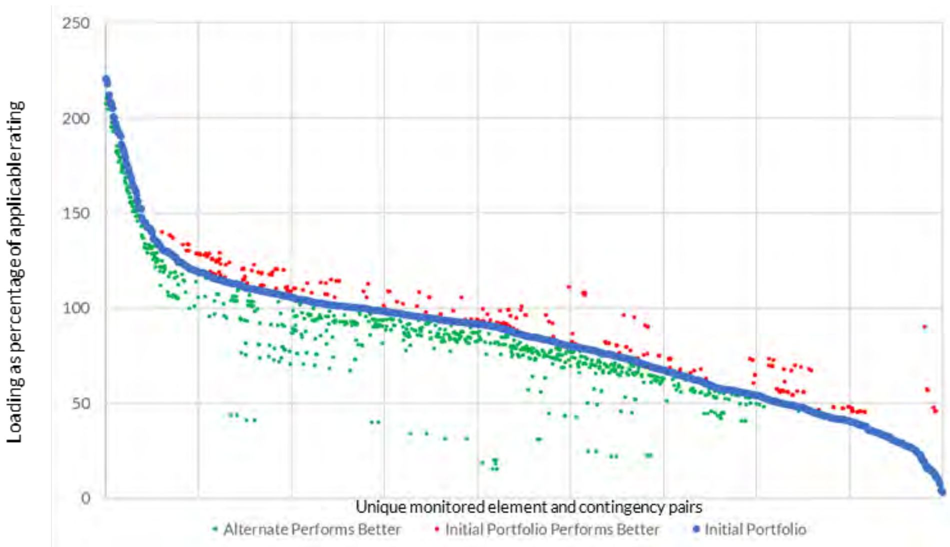


Figure 2.51: Scatter plot showing Iron Range- Arrowhead 345 kV performance as compared to Initial Portfolio

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.

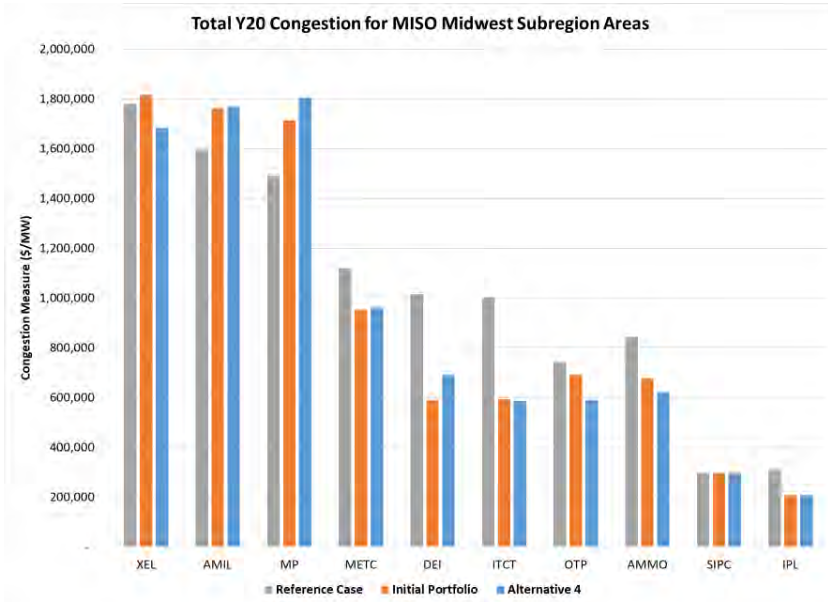


Figure 2.52: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 4 (MN)

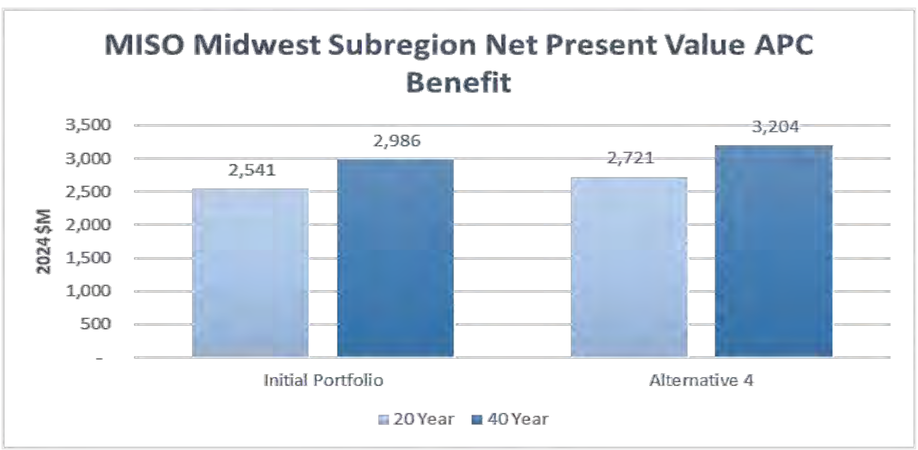


Figure 2.53: Initial Portfolio vs. Alternative 4 Adjusted Production Cost Savings

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.

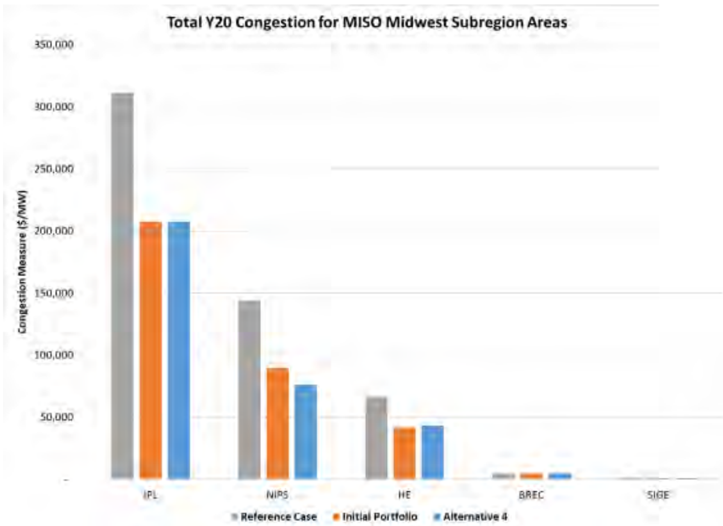


Figure 2.54: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 4 (IN)

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

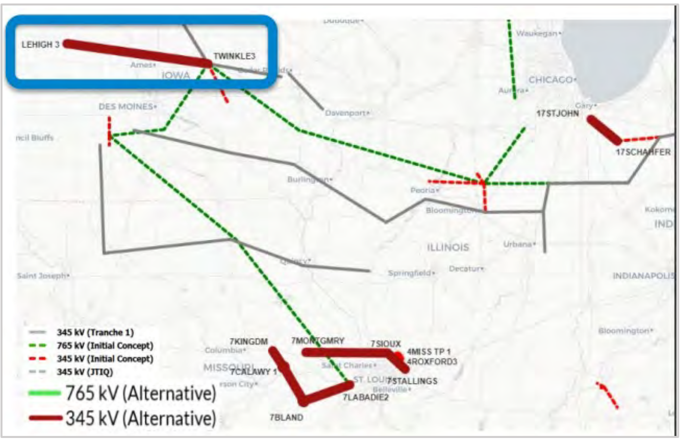


Figure 2.55: Map shows selected Alternative 5 projects in blue boxes

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.

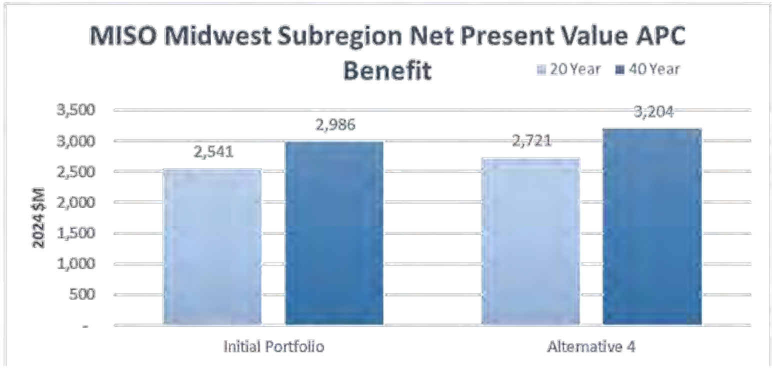


Figure 2.56: Initial Portfolio vs. Alternative 5 Adjusted Production Cost Savings

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, LRTP 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.

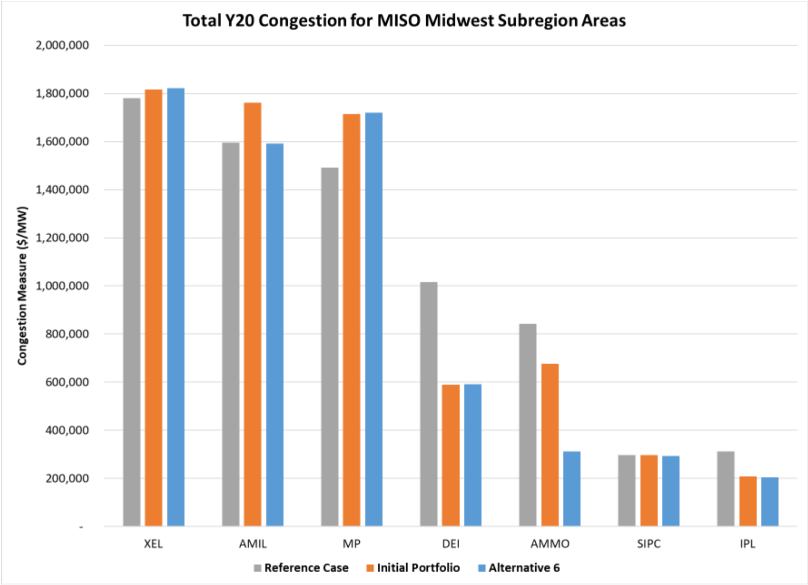


Figure 2.58: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 6

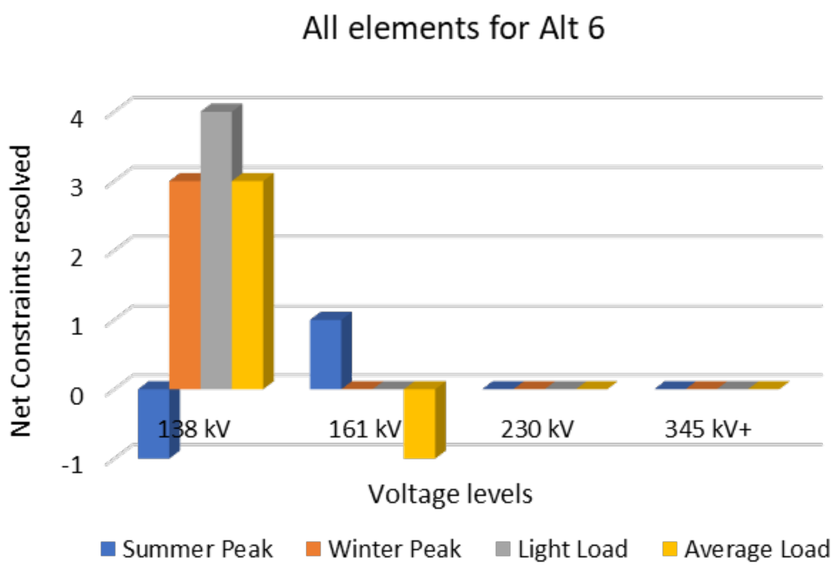


Figure 2.59: Constraints resolved by Voltage level by Alternative 6 project

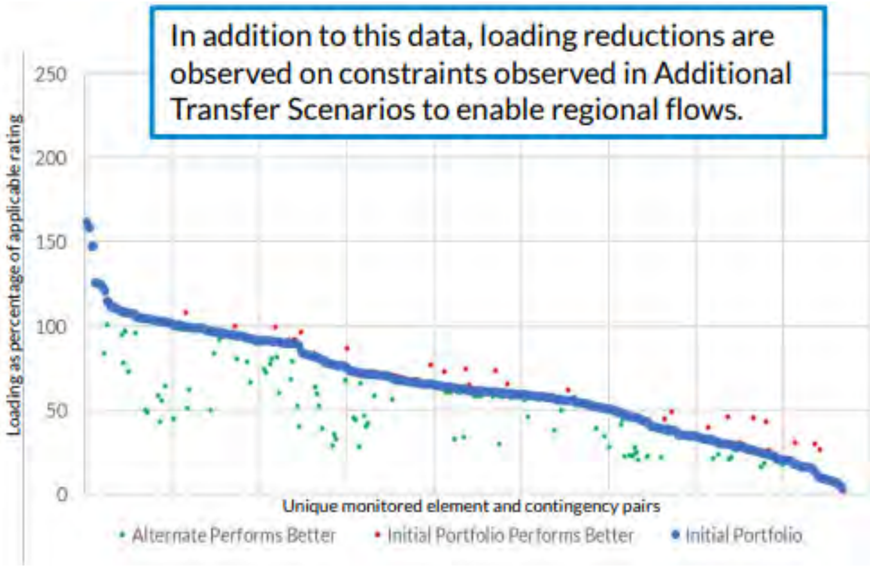


Figure 2.60: Scatter plot showing Alternative 6 performance as compared to Initial Portfolio

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](#).

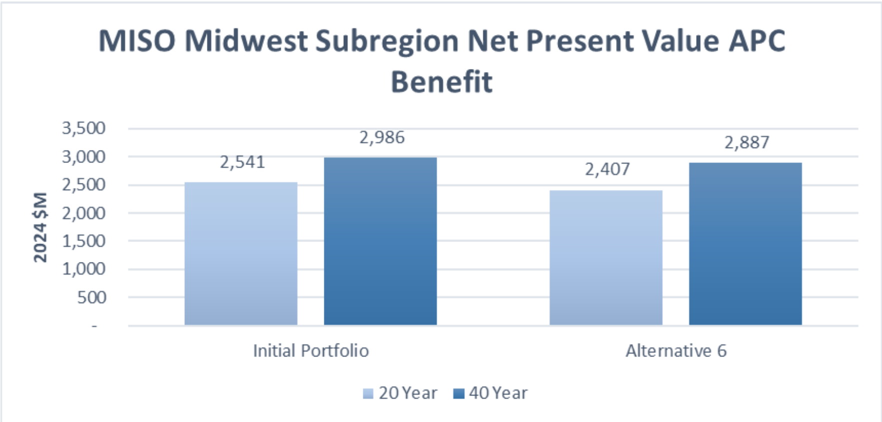


Figure 2.61: Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

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.

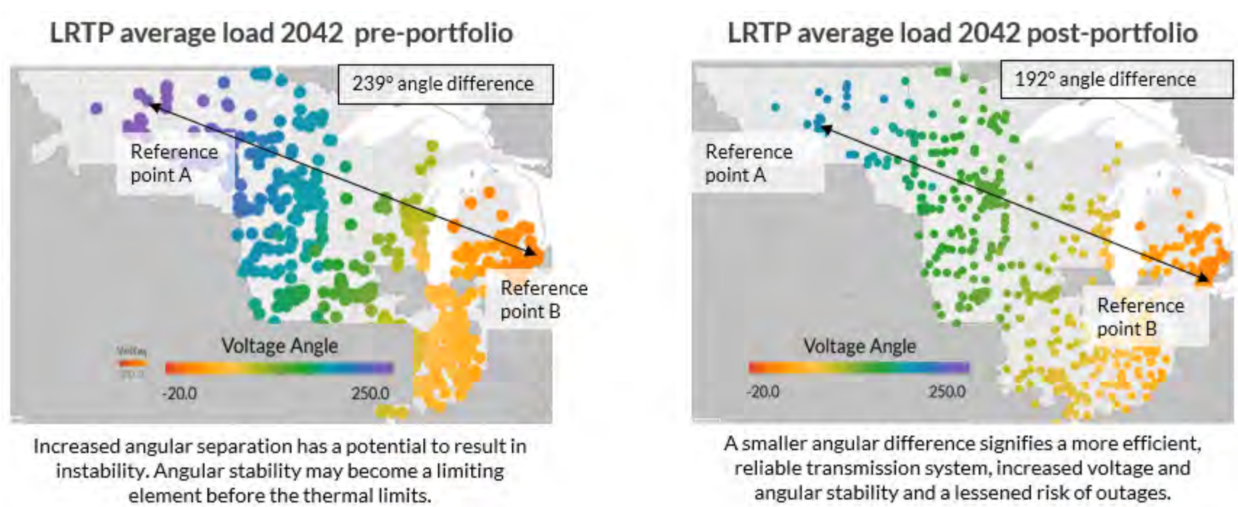


Figure 2.63: Angular separation with and without the Tranche 2.1 portfolio

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.

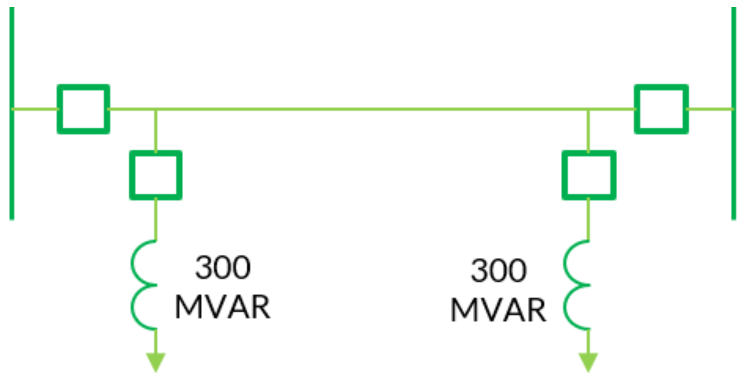


Figure 2.64: Default 765 kV line configuration includes line-side switchable shunt reactors to manage high voltages and mitigate Ferranti Effect during switching

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.

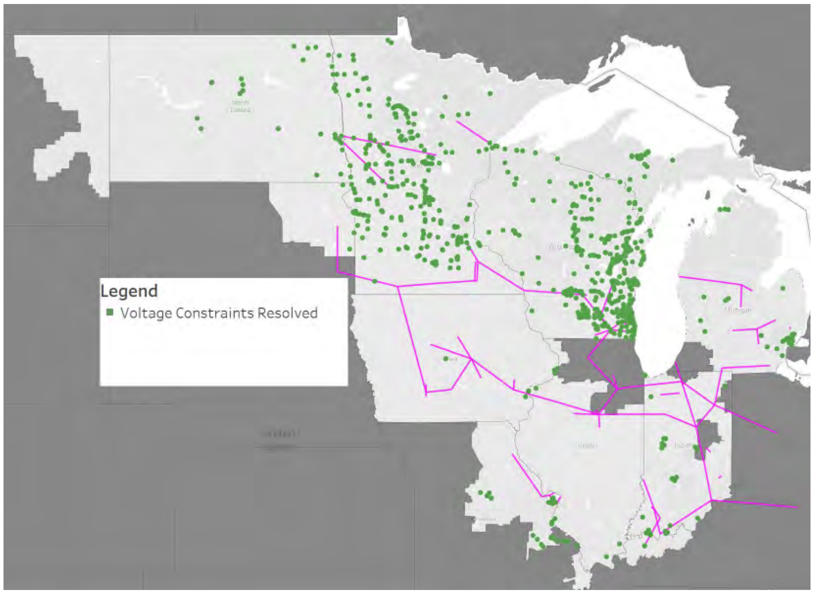


Figure 2.65: Green dots represent a voltage constraint observed in core models and is mitigated by the final portfolio

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.

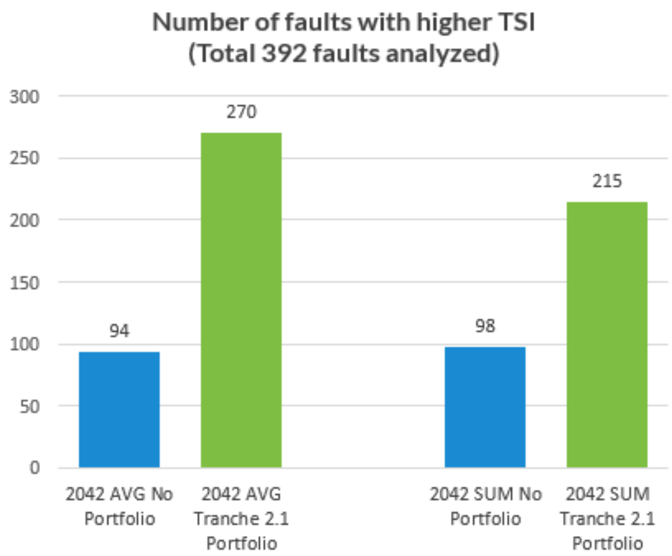


Figure 2.66: Transient Stability Index with and without the Tranche 2.1 portfolio

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.

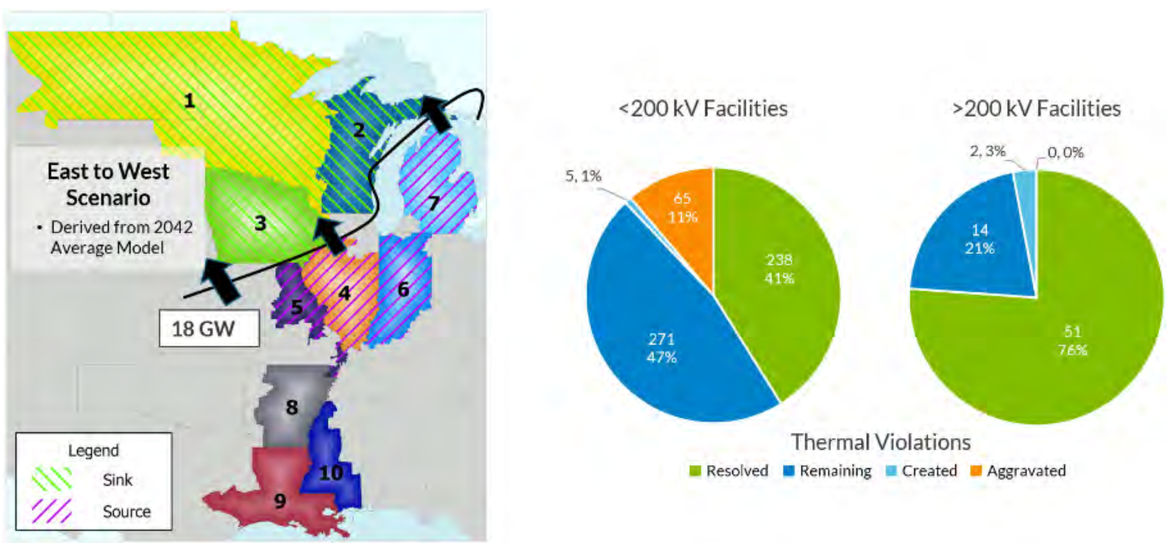


Figure 2.67: East to West Transfer results summary with the Tranche 2.1 portfolio

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.

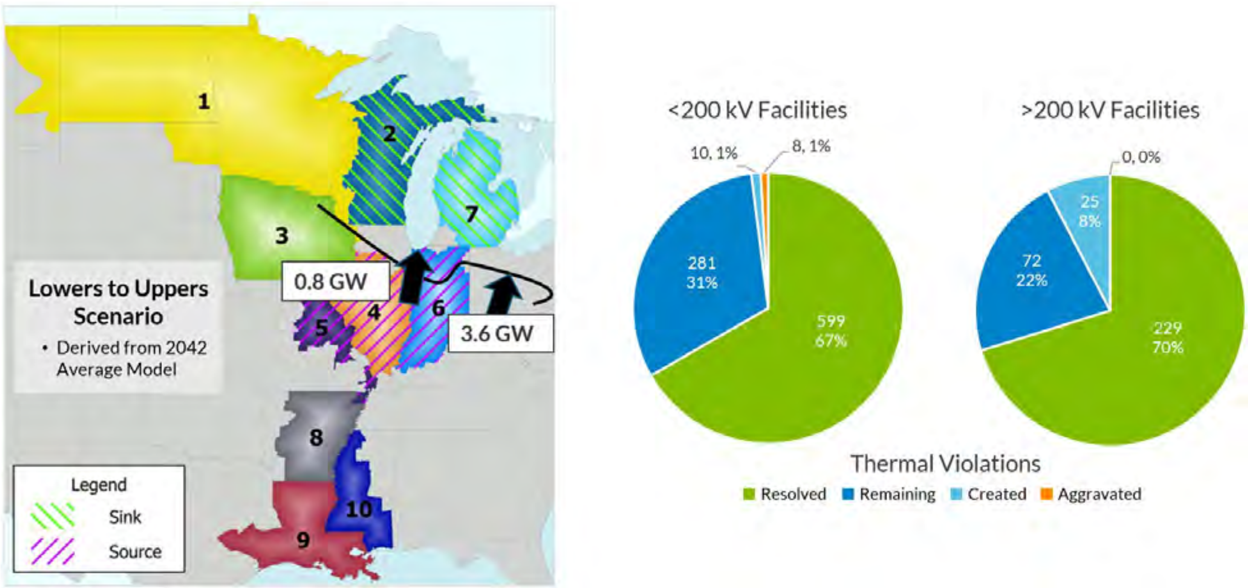


Figure 2.68: Lowers to Uppers Scenario results summary with the Tranche 2.1 portfolio

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.

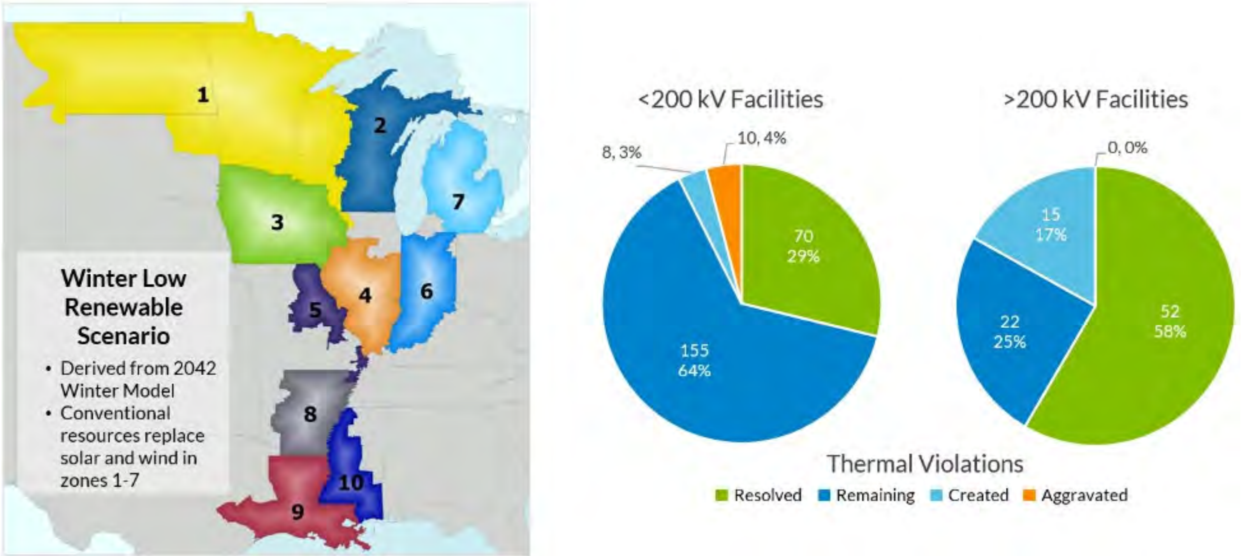


Figure 2.69: Winter Peak Low Renewable Scenario results summary with the Tranche 2.1 portfolio

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.

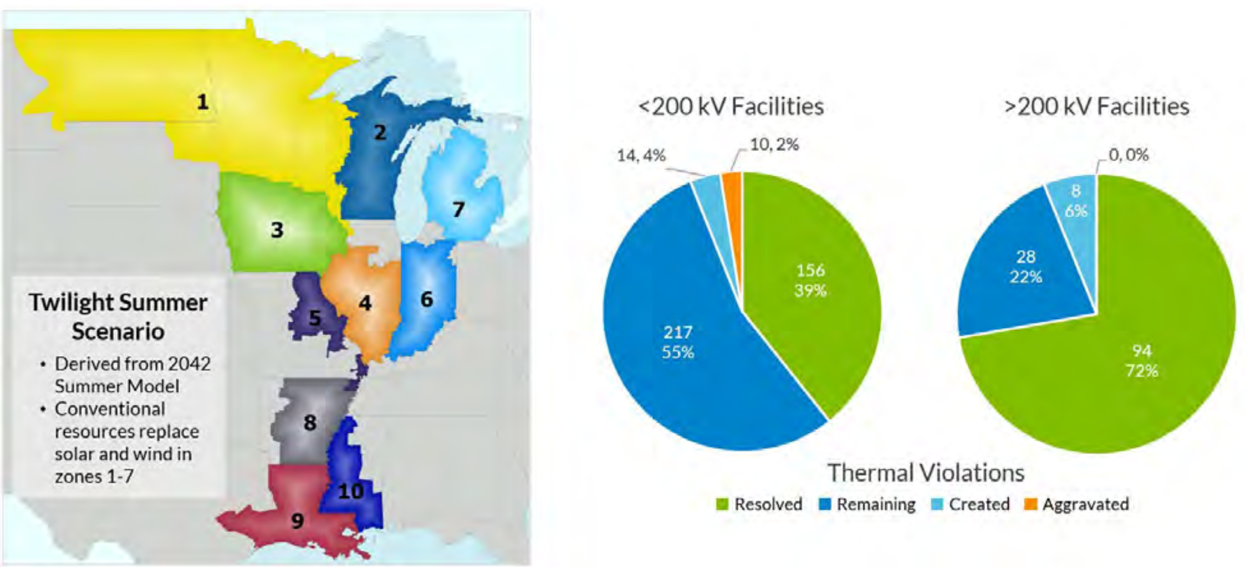


Figure 2.70: Twilight Summer Scenario results summary with the Tranche 2.1 portfolio

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

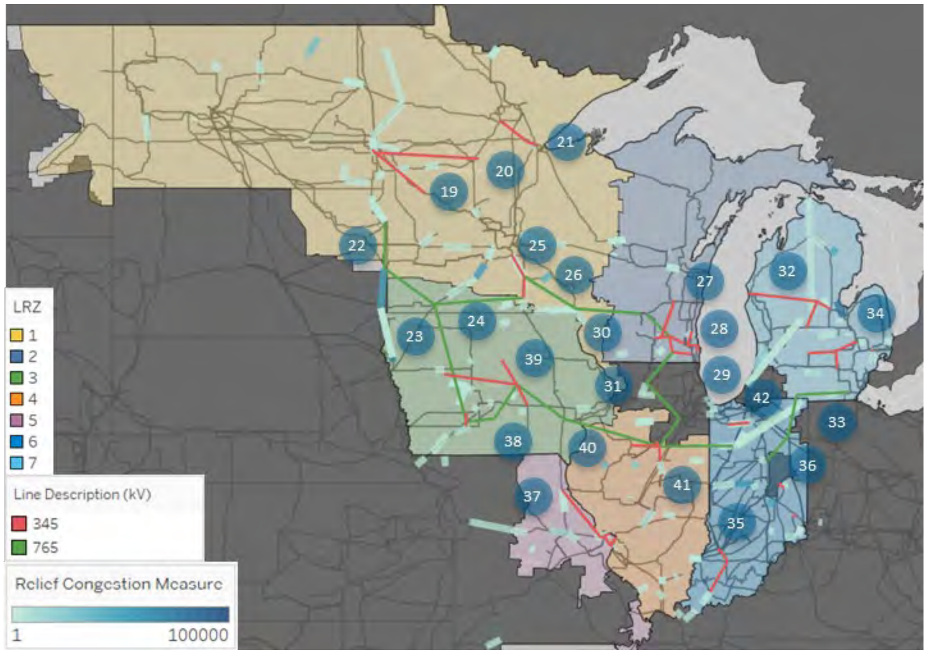


Figure 2.71: Change Case: Year 20 Economic Congestion Relief

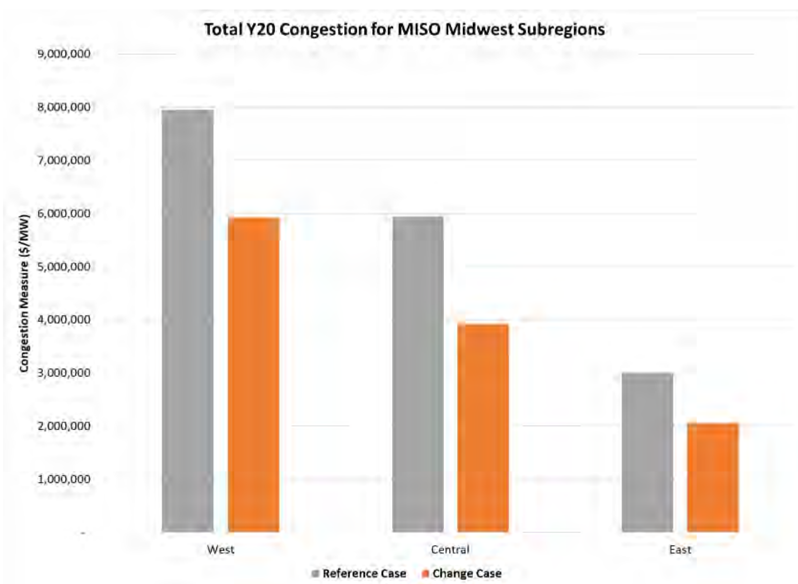


Figure 2.72: Reference and Change Case Year 20 Economic Congestion

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%

MISO Subregion Y20 Congestion Measure by LRZ					
Region	LRZ	Reference Case ($/MW)	Change Case ($/MW)	Reduction ($/MW)	Reduction (%)
	West	7,952,361	5,926,772	2,025,589	25.5%
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

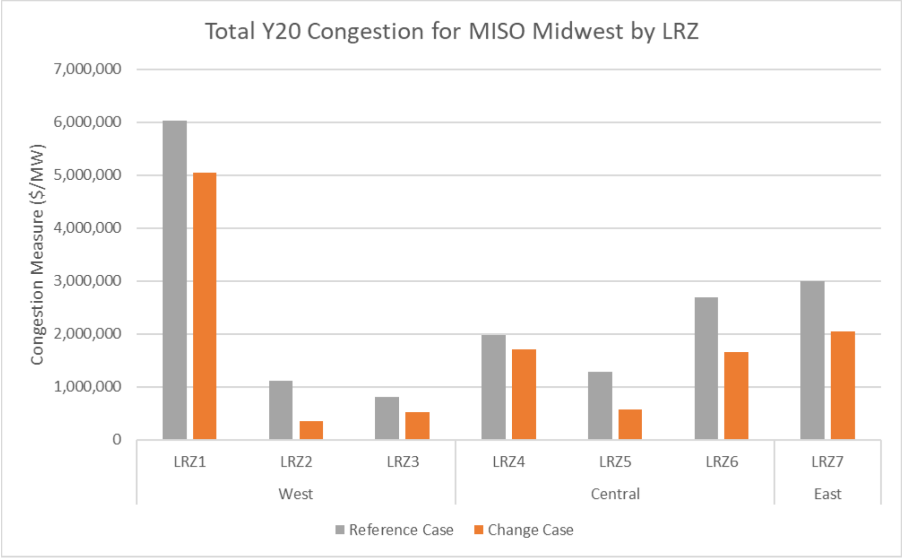


Figure 2.73: Year 20 Congestion with and without LRTP Tranche 2.1 by Local Resource Zone

Curtailment

Curtailment is due to many factors, including congestion and deliverability within MISO Midwest, which are substantially addressed with Tranche 2.1 transmission. Other curtailment 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 curtailment and improves access to more economic generation.

Curtailment in PROMOD is a measure of the available energy from renewable resources which are unable to deliver due to transmission constraints. Curtailment 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 curtailment 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.

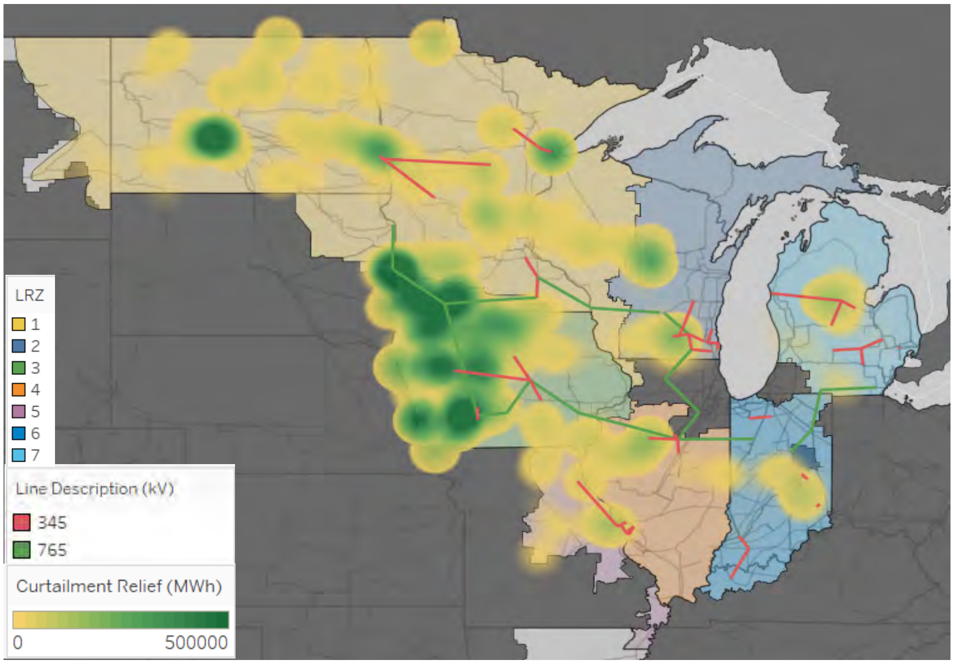


Figure 2.74: Change Case: Curtailment Energy Relief

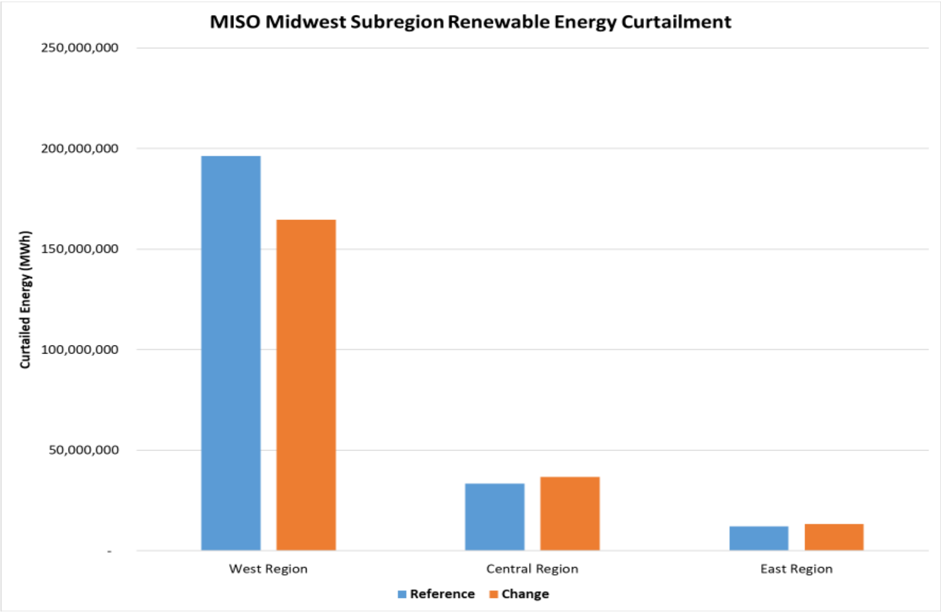


Figure 2.75: Reference and Change Case: Year 20 Curtailment Energy

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.

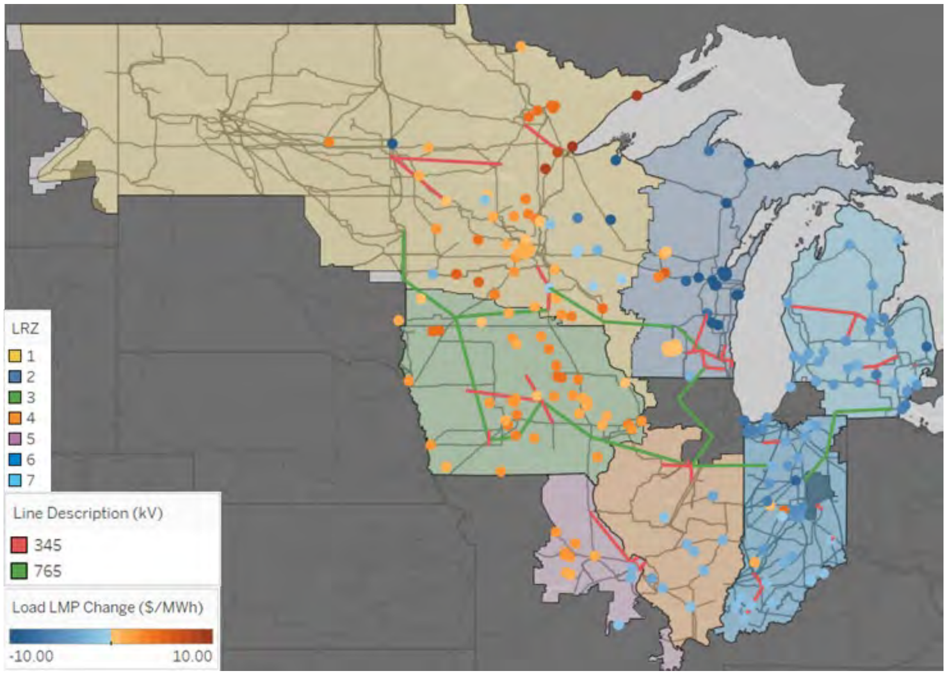


Figure 2.76: Change Case: Load LMP Price Reduction

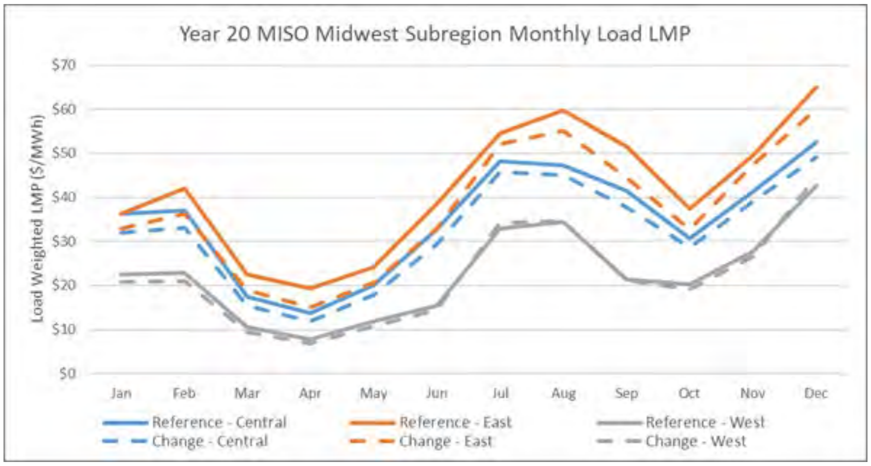
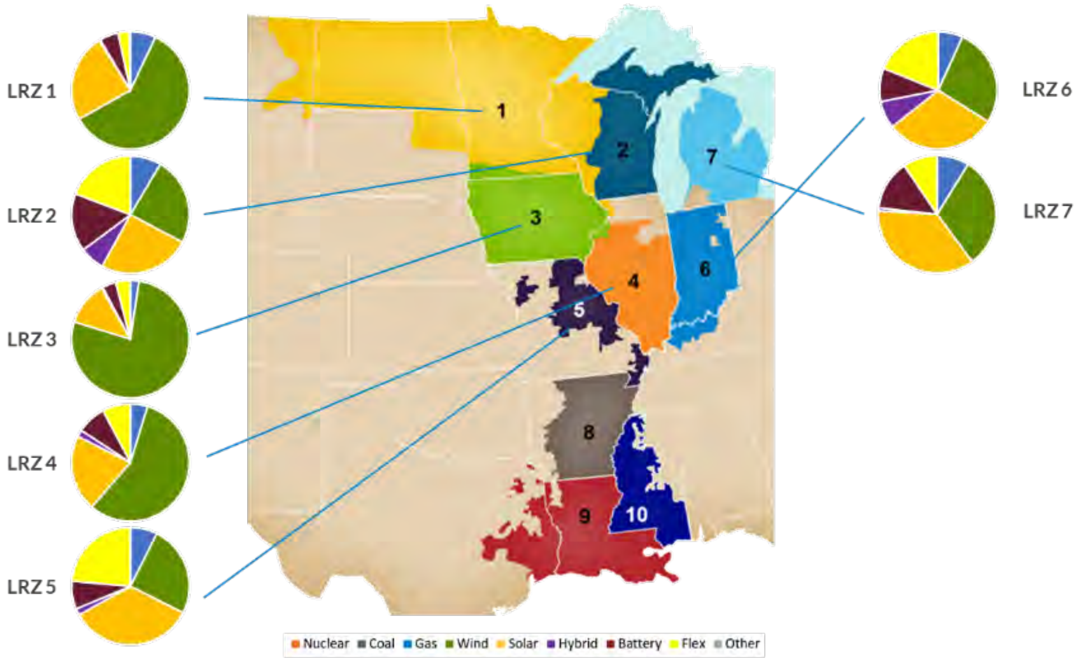


Figure 2.77: Reference & Change Case: Year 20 Load LMP Price

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.

Future 2A siting of planned and model-built resources by Local Resource Zone (LRZ)



Generation Enabled by Resource Type (GW)	
Storage	15.4
Gas & Flex	16.9
Solar	14.1
Hybrid	1.2
Wind	68.1
Total	**115.7**

Generation Enabled by Local Resource Zone (GW)	
LRZ 1	32.1
LRZ 2	9.5
LRZ 3	27.4
LRZ 4	16.1
LRZ 5	2.8
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

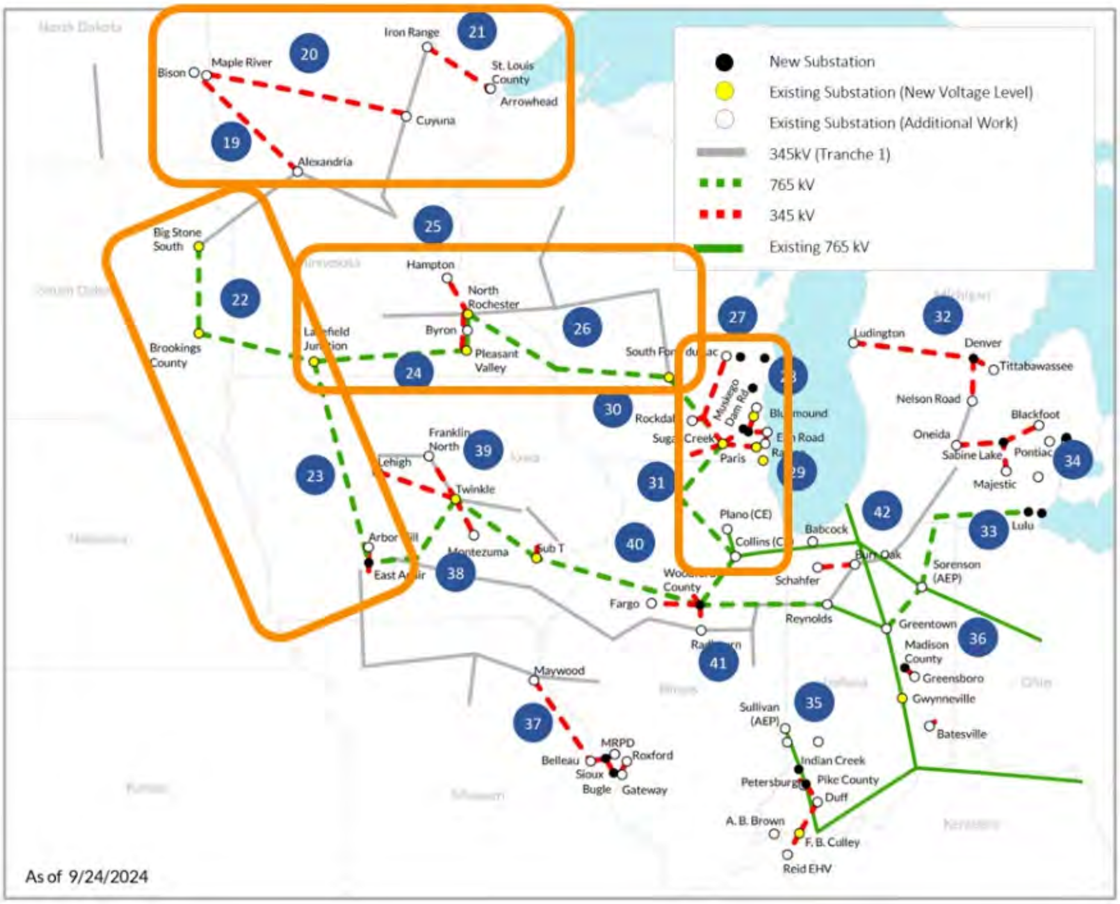


Figure 2.79: West Region Project Groups

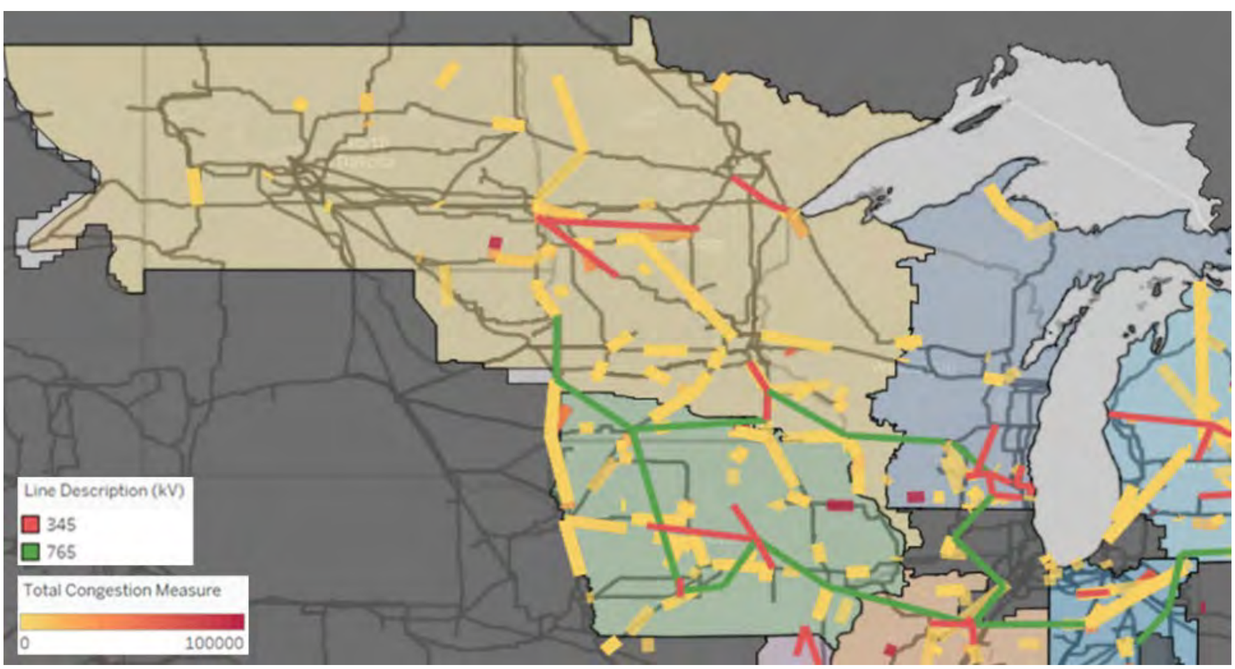


Figure 2.80: Change Case Economic Congestion - West

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.

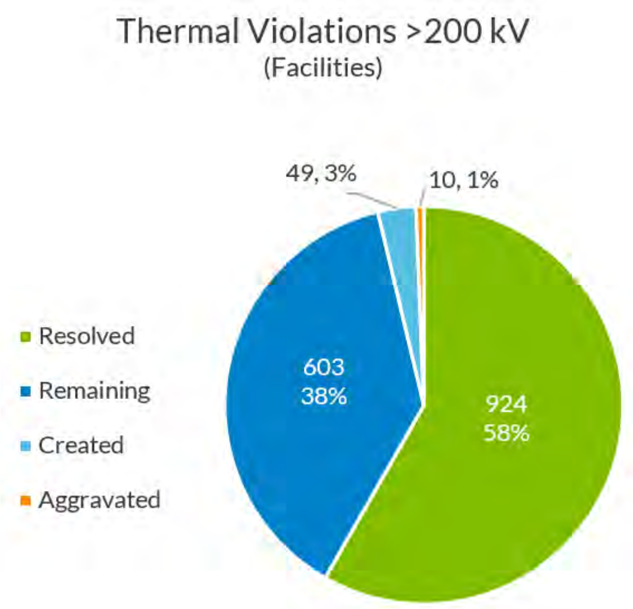


Figure 2.81: Thermal constraint resolution for LRZ1

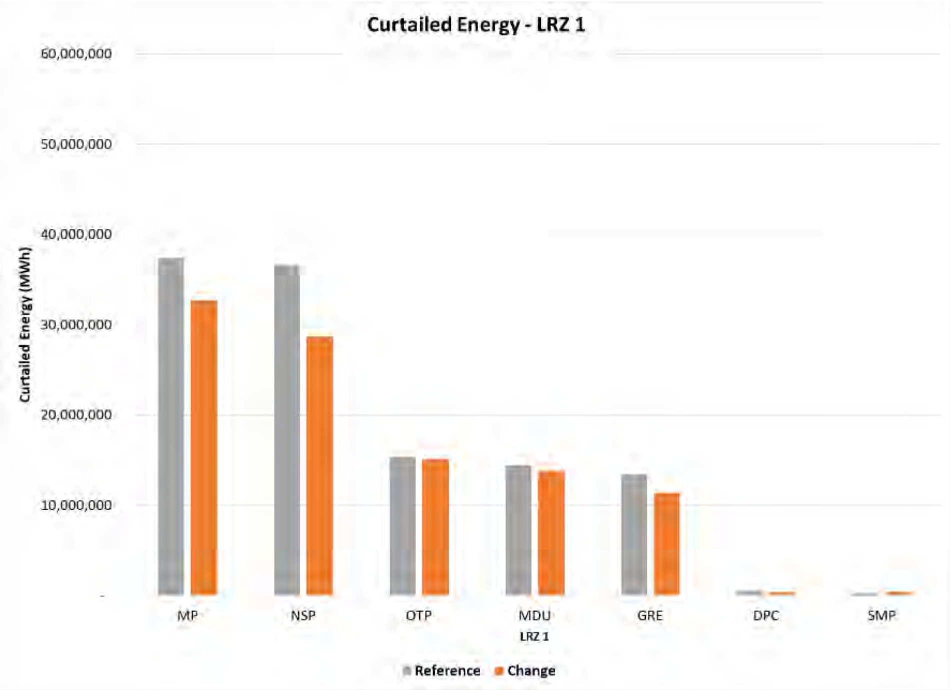


Figure 2.82: Curtailed Energy - LRZ 1

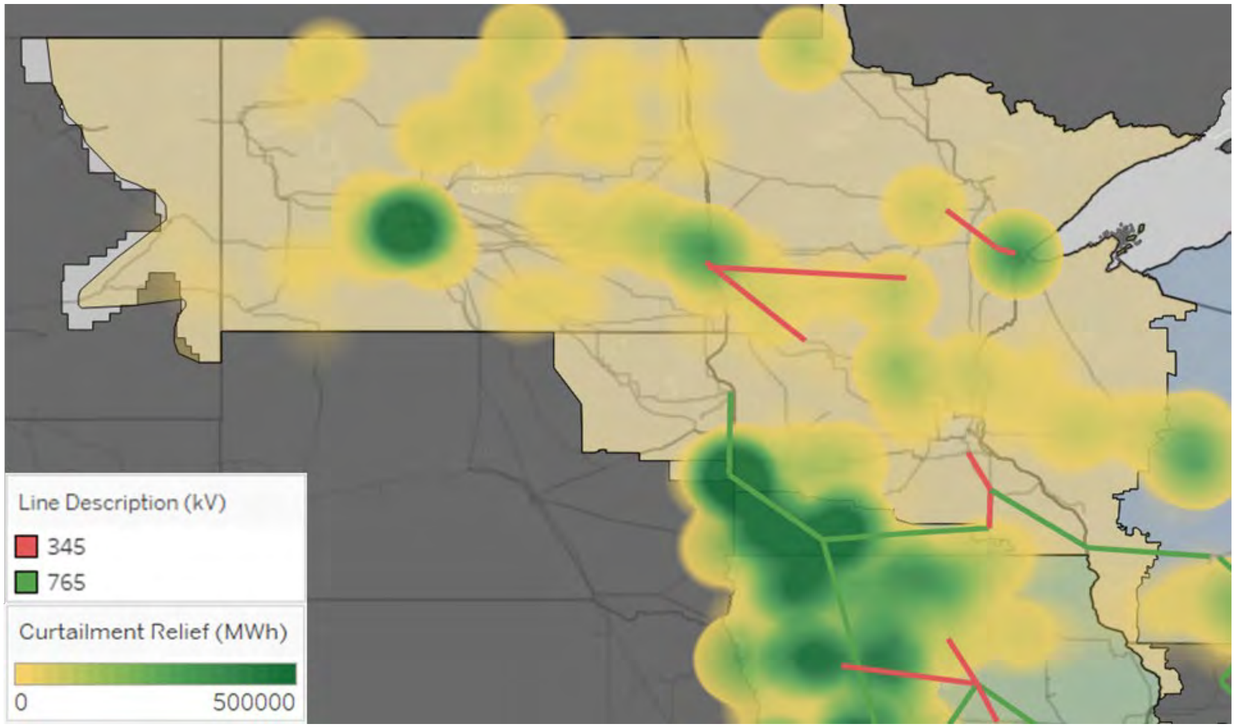


Figure 2.83: Change Case Curtailment Relief – LRZ 1

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

#	Element	Initial Worst Loading %	Final Worst Loading %
9	[GRE] Silver Lake-[GRE] Henning 230 kV	104	68
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

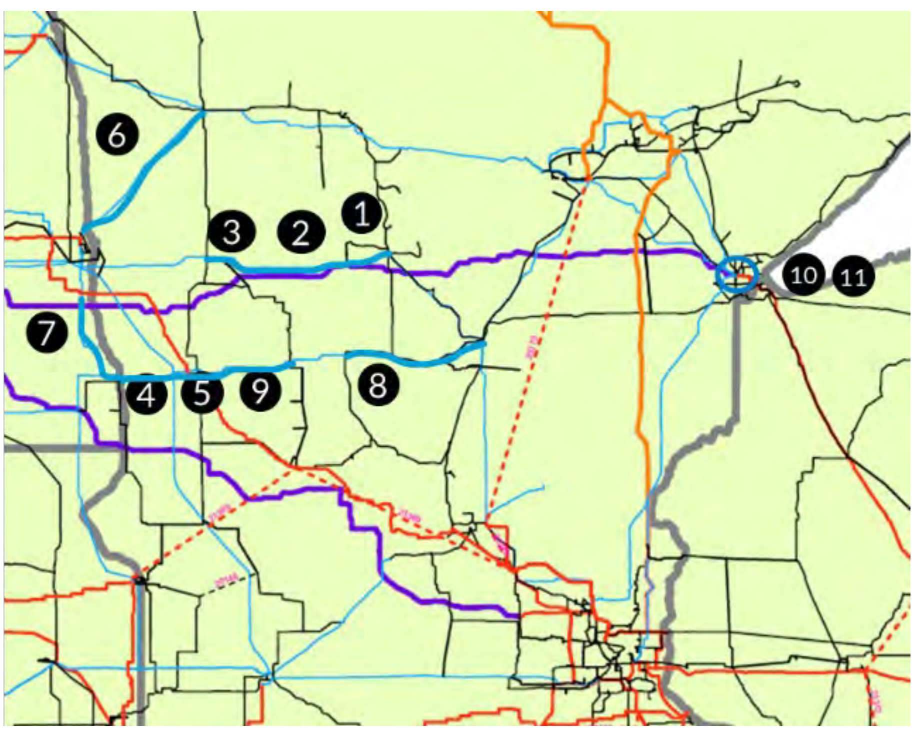


Figure 2.85: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Northern Minnesota

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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	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-LTLSKTP7 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] MDWLNDS7 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

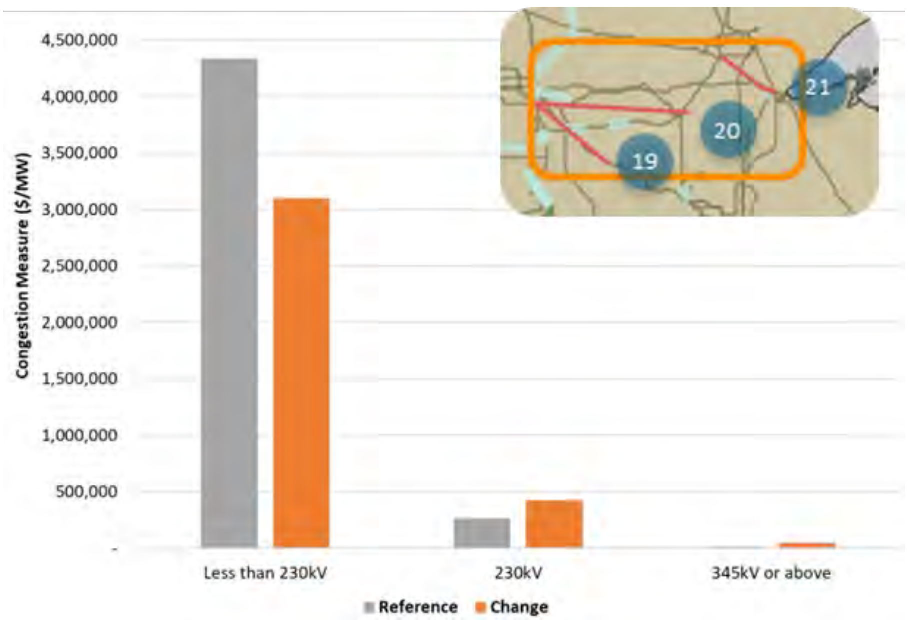


Figure 2.86: Congestion Measure for Projects 19, 20, and 21

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.

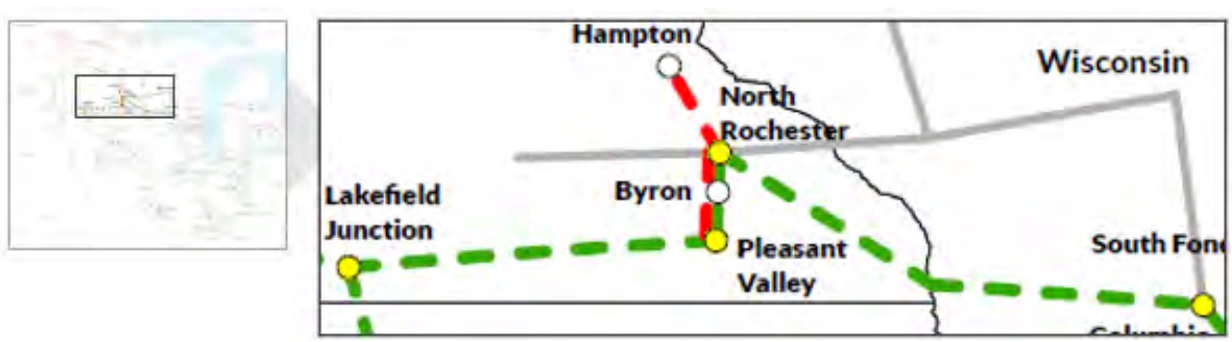


Figure 2.87: Southern Minnesota and Western Wisconsin LRTP Tranche 2.1 projects

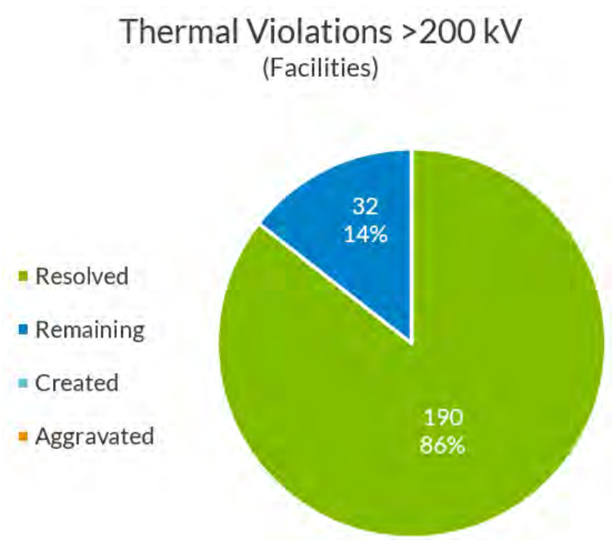


Figure 2.88: Thermal constraint resolution for Southern Minnesota and Western Wisconsin

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

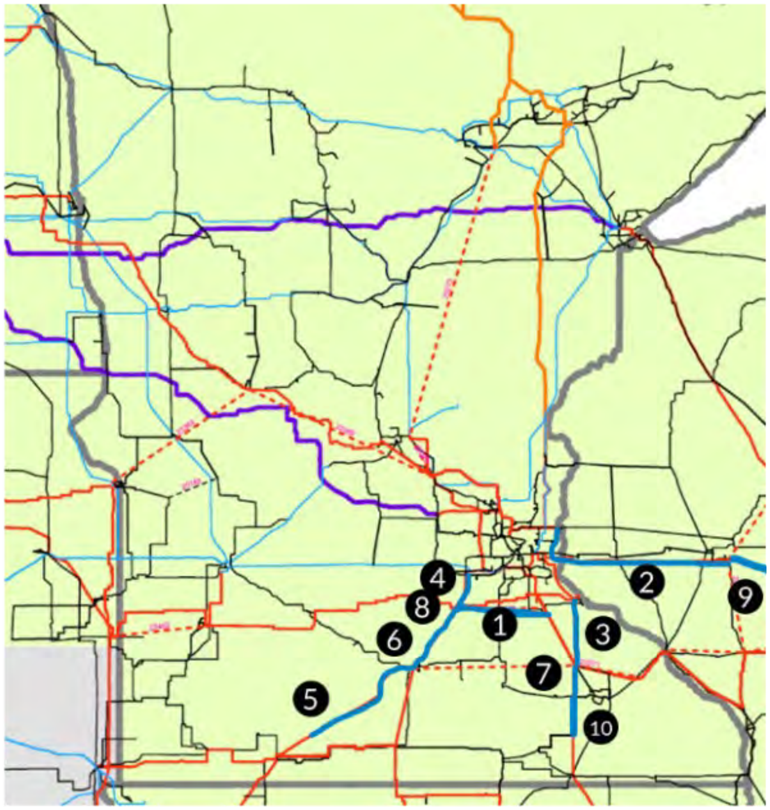


Figure 2.89: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Minnesota and Western Wisconsin

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

Y20 Top Relieved Flowgates Ranked by Cong, and 26estion Measure Relief - Projects 24, 25, & 26			
Event 1443: [NSP] WILMART3 - [ALTW] HUNTLEY3 345 kV 1	10,423	50	10,372
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

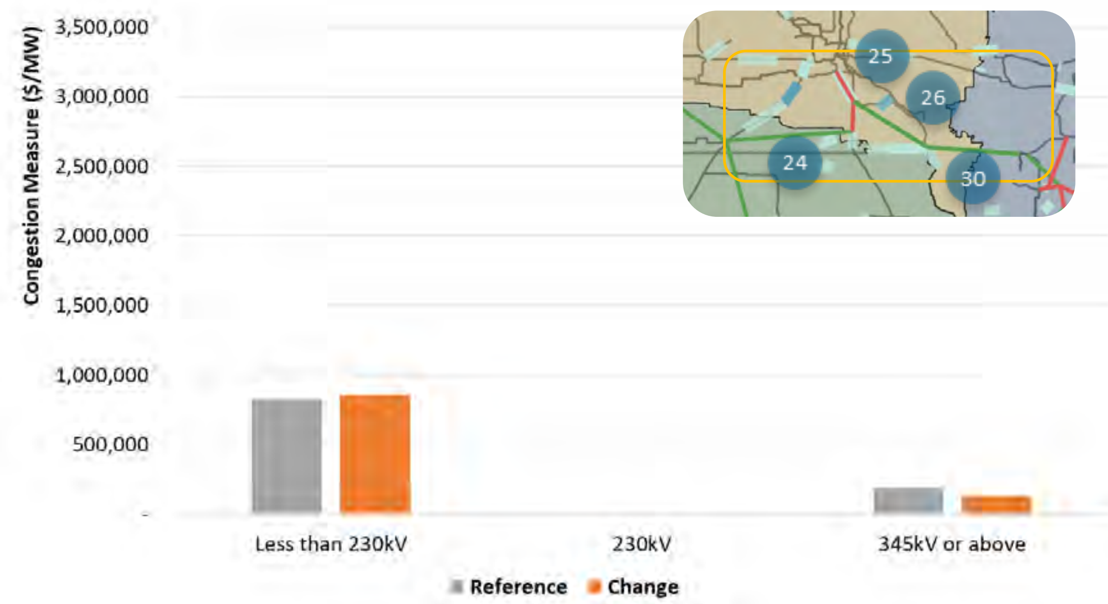


Figure 2.90: Congestion Measure for Projects 24, 25, and 26

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.

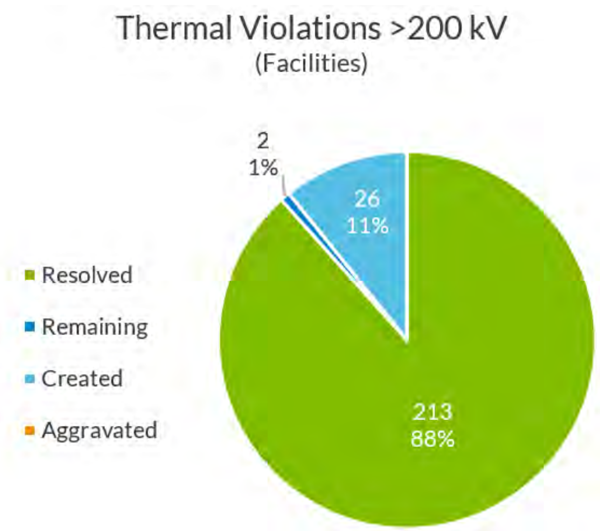


Figure 2.91: Thermal constraint resolution for LRZ2

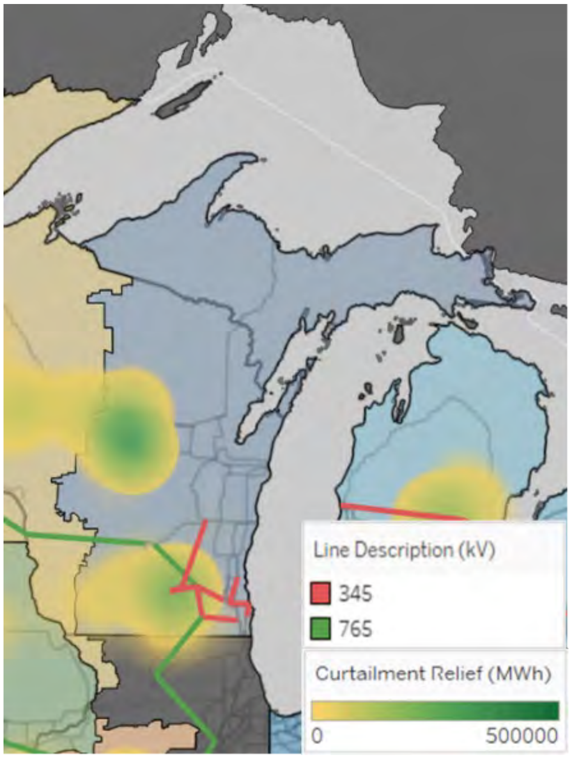


Figure 2.92: Change Case: Curtailment Relief for LRZ 2

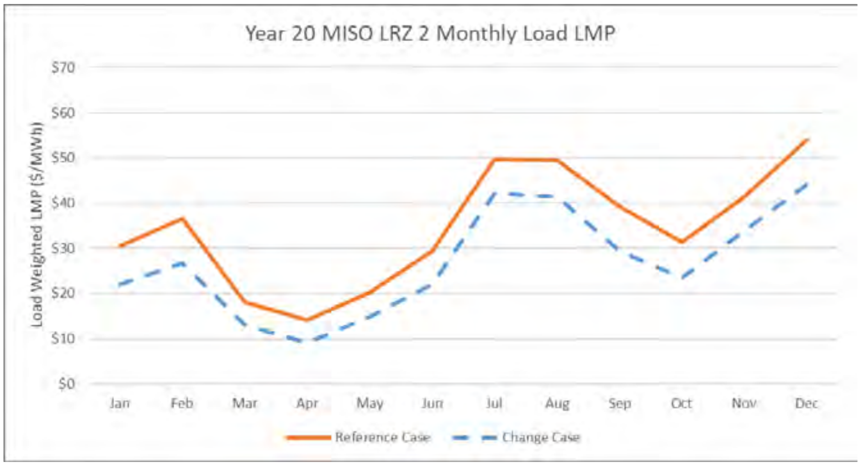


Figure 2.93: Comparison: Monthly Load LMP for LRZ 2

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), Bluemond - 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.

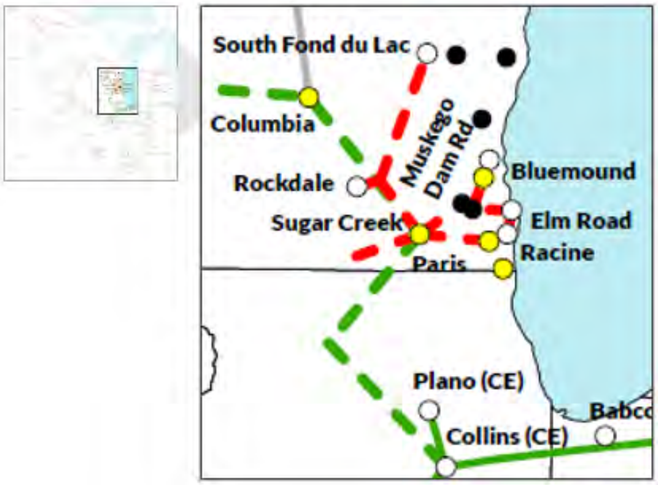


Figure 2.94: Southeastern Wisconsin LRTP Tranche 2.1 projects

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] Saukville 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

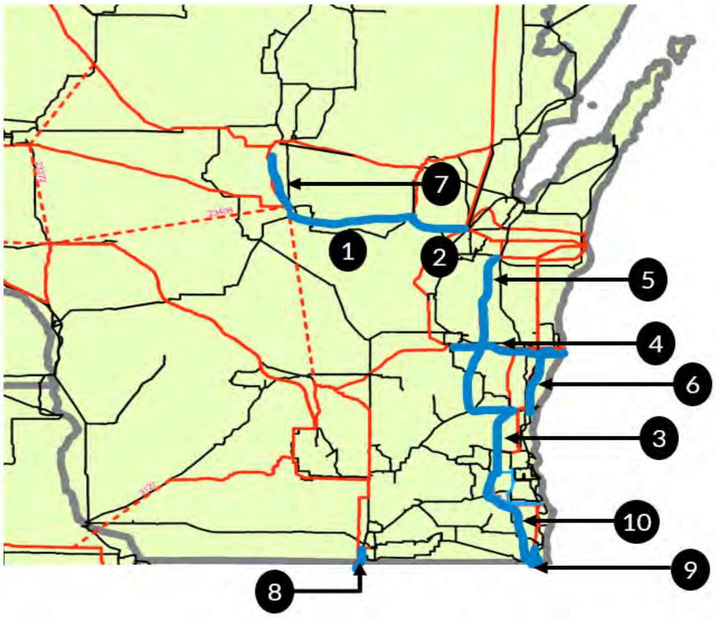


Figure 2.95: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southeastern Wisconsin

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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**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

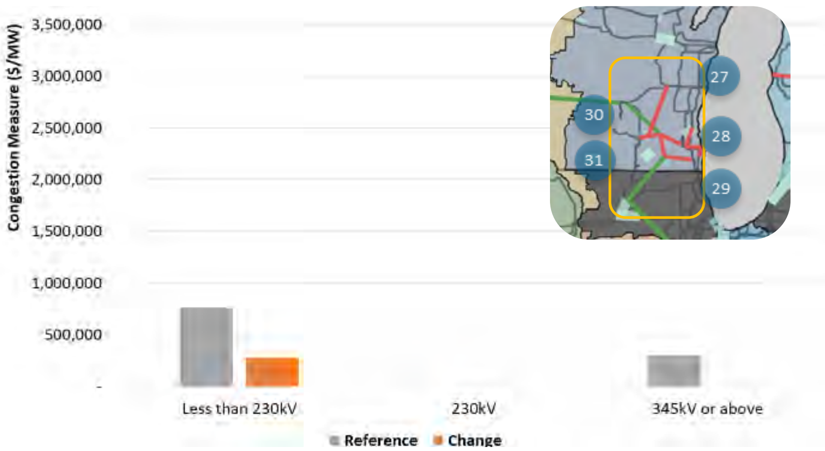


Figure 2.96: Congestion Measure for Projects 27, 28, 29, 30, & 31

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$/MW). 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.

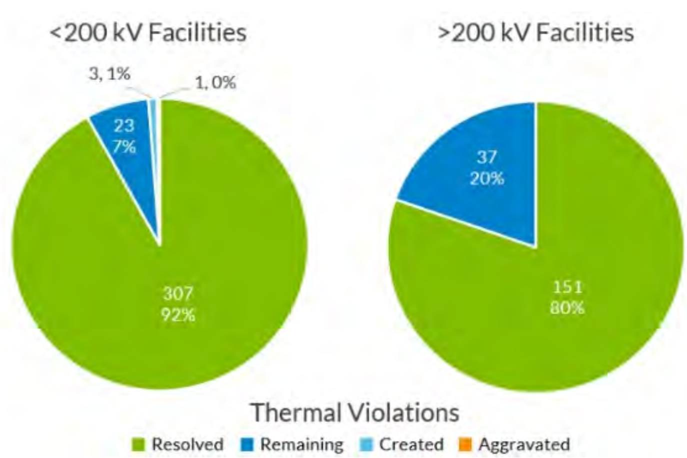


Figure 2.97: Pie- charts showing LRTP Tranche 2.1 resolving a vast majority of thermal violations in LRZ 3

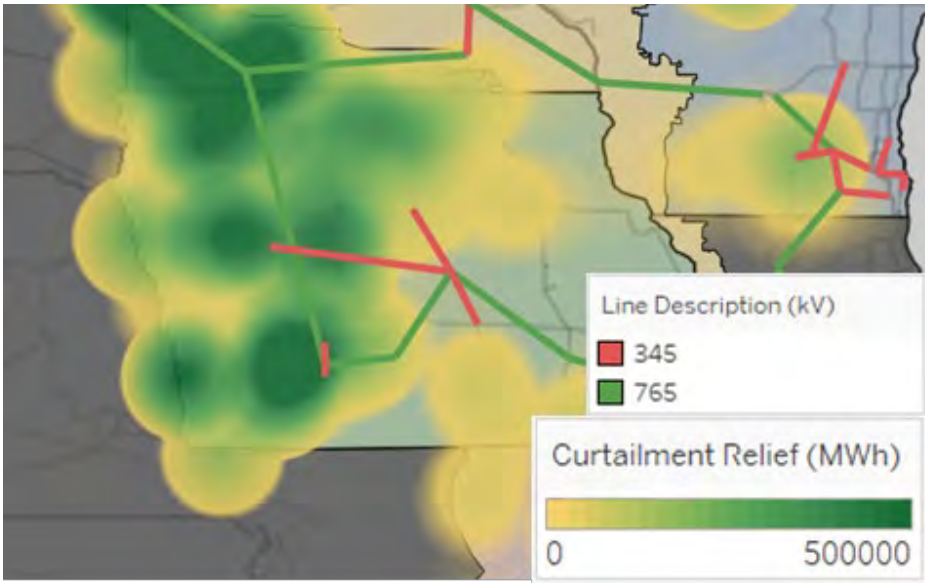


Figure 2.98: Change Case Curtailment Relief – LRZ 3

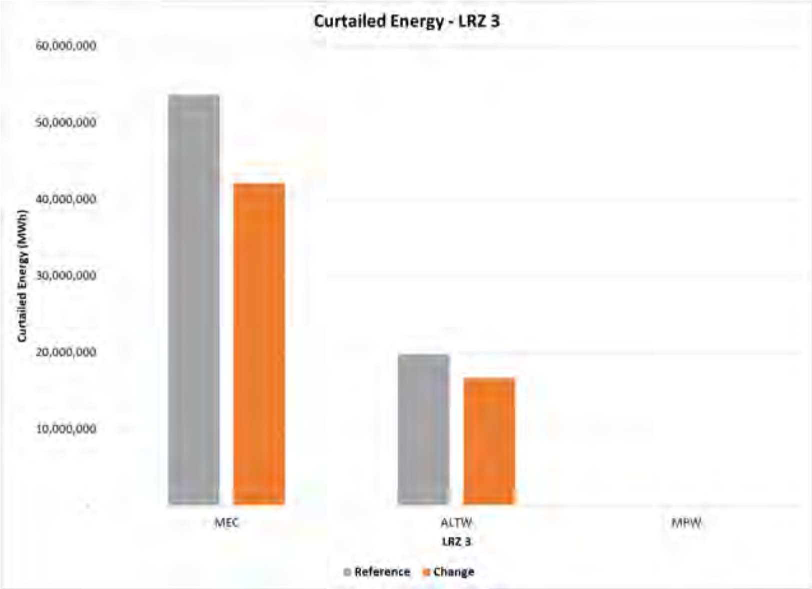


Figure 2.99: Curtailed Energy - LRZ 3

Big Stone South - Brookings County - Lakefield Junction765 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.

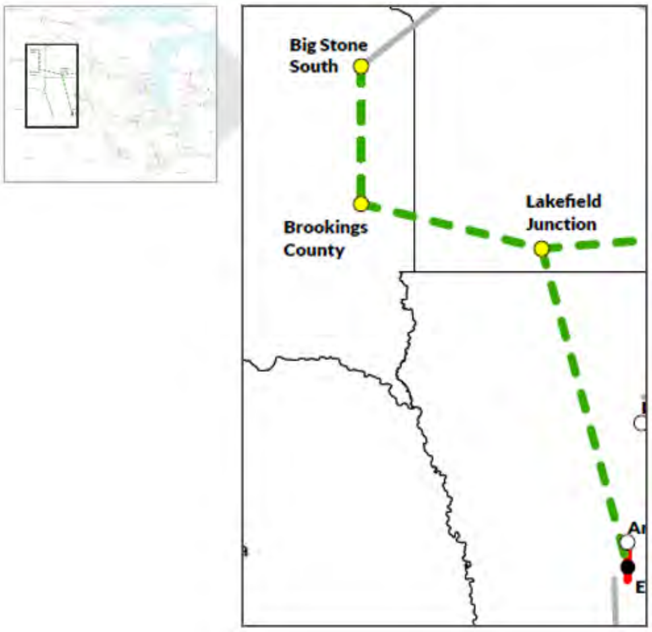


Figure 2.100: South Dakota, Southwestern Minnesota, and Western Iowa LRTP Tranche 2.1 projects

The LRTP 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.

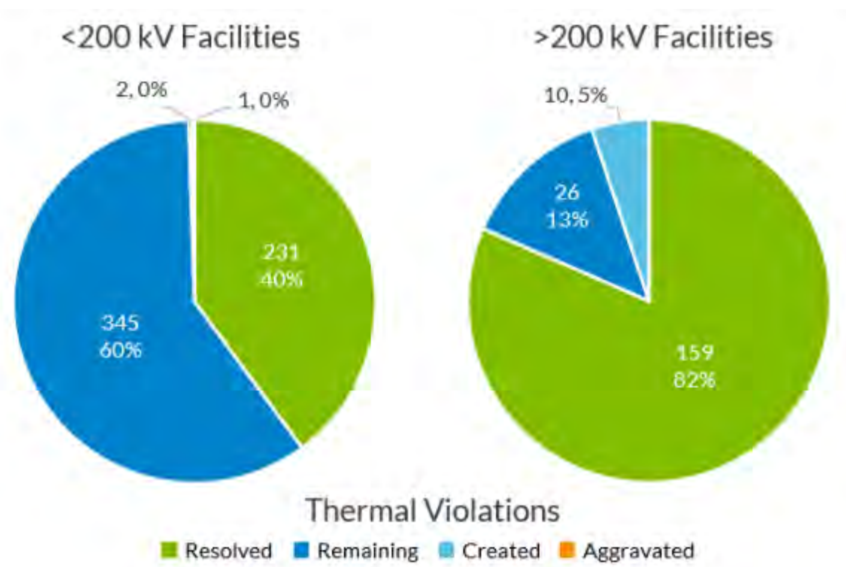


Figure 2.101: Pie-charts showing majority of thermal violations on the 200 kV and above facilities in South Dakota, Southwestern Minnesota, and Western Iowa being resolved by the LRTP Tranche 2.1 portfolio

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

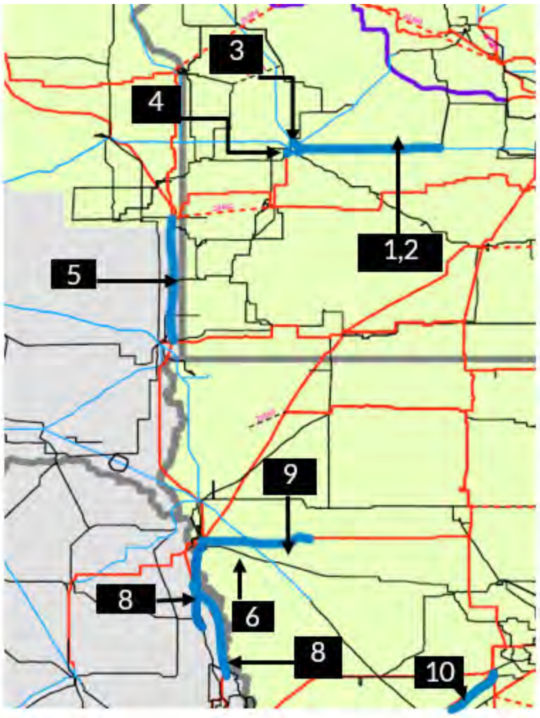


Figure 2.103: Top reliability constraints resolved by LRTP Tranche 2.1 projects in South Dakota, Southwestern Minnesota, and Western Iowa

The LRTP 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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	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

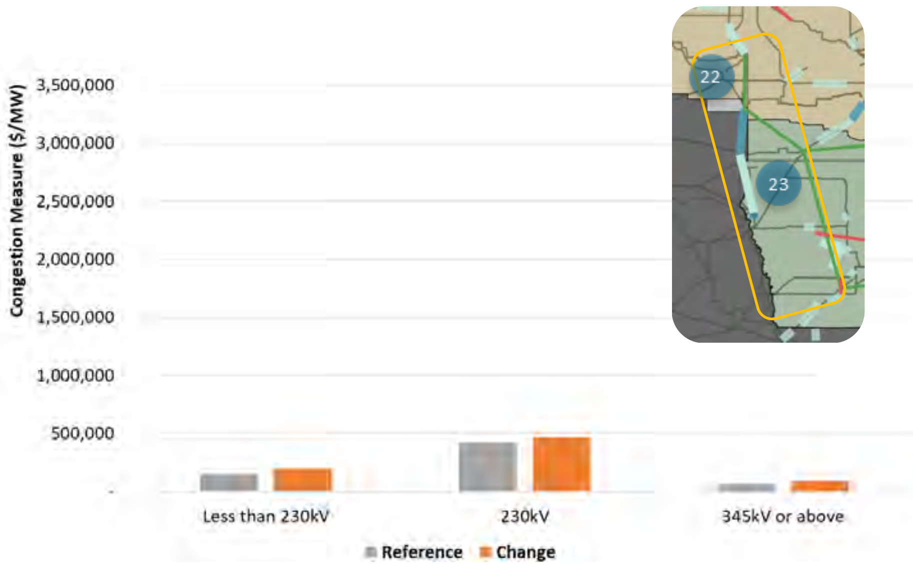


Figure 2.104: Congestion Measure for Projects 22, 23

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

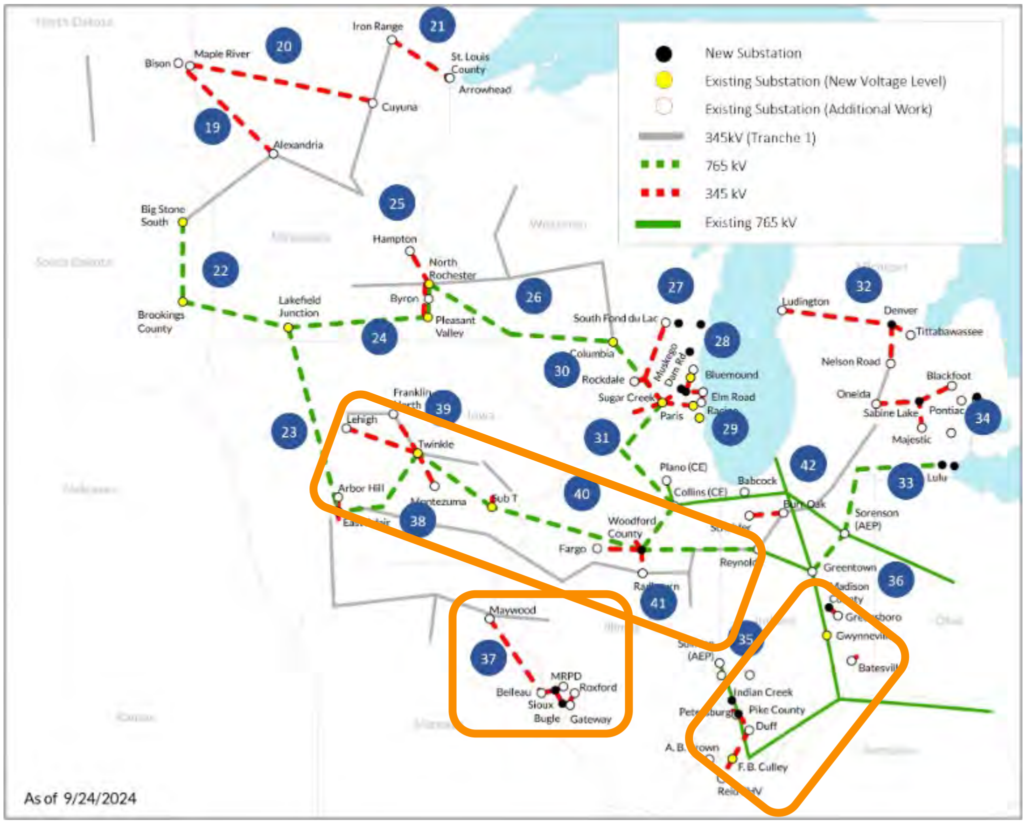


Figure 2.105: Central Region Project Groups

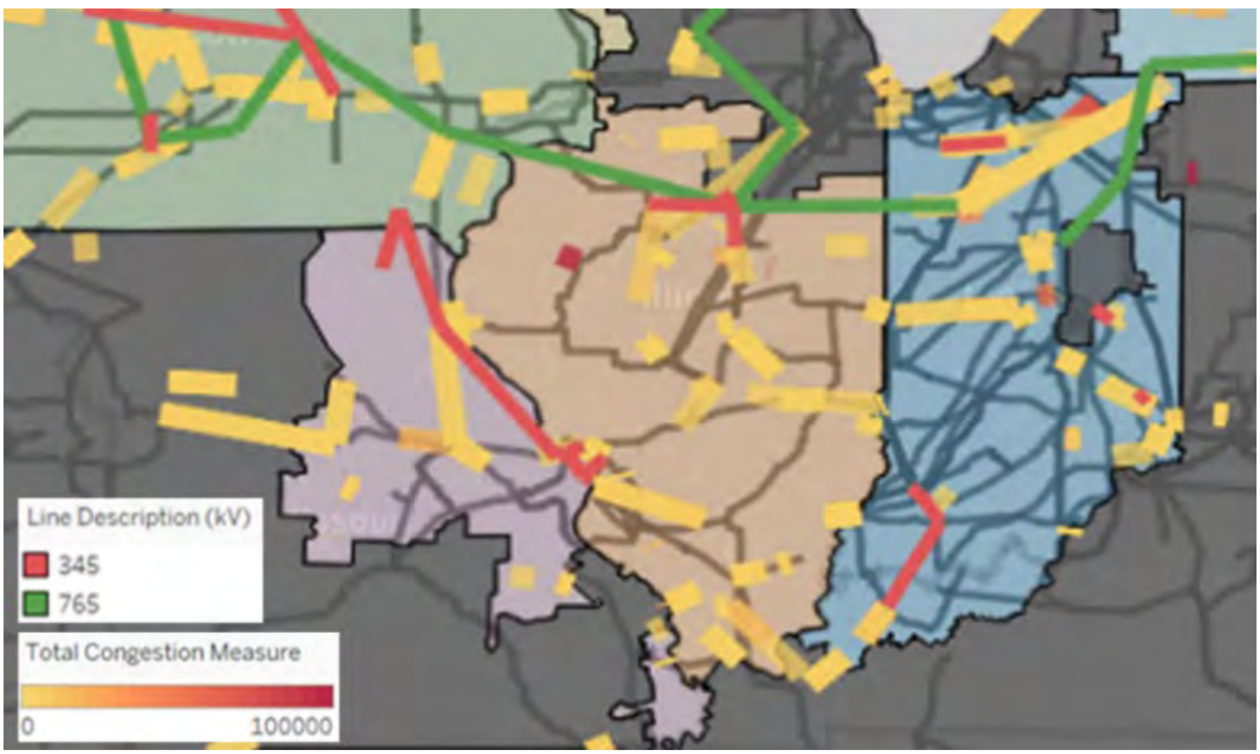


Figure 2.106: Change Case Economic Congestion - Central

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.

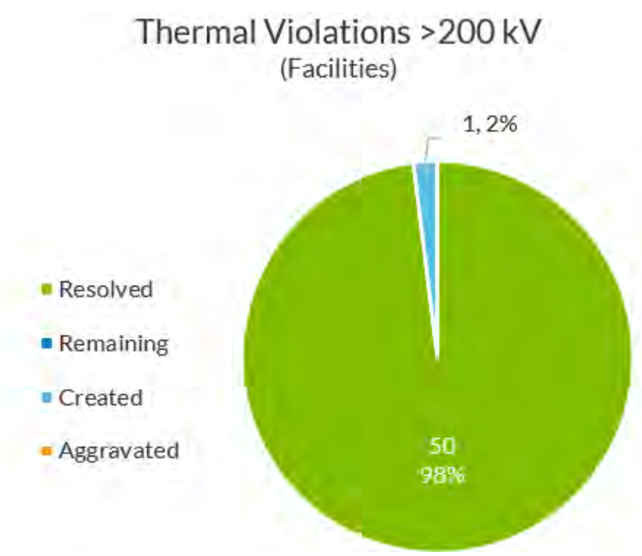


Figure 2.107: Thermal constraint resolution for LRZ4

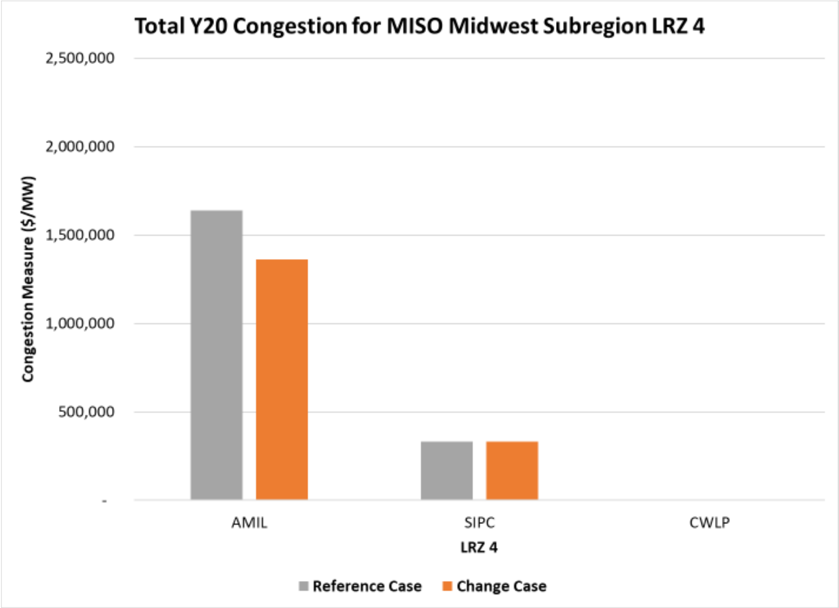


Figure 2.108: Congestion Measure – LRZ 4

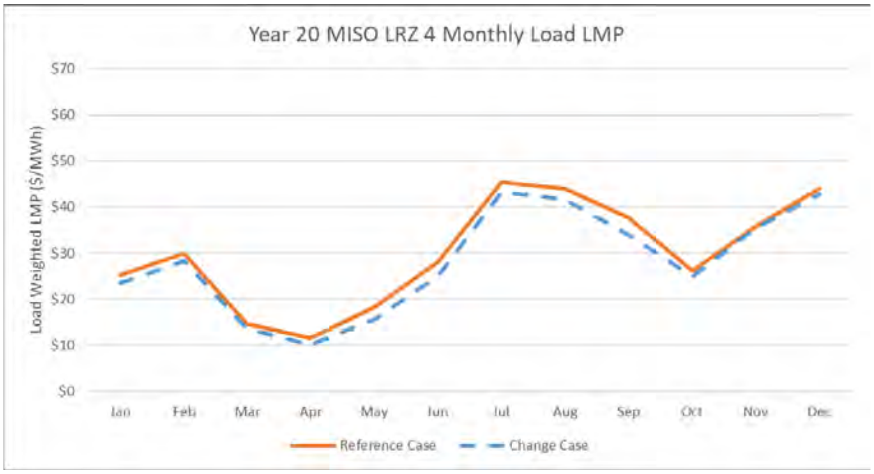


Figure 2.109: Comparison: Monthly Load LMP – LRZ 4

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)

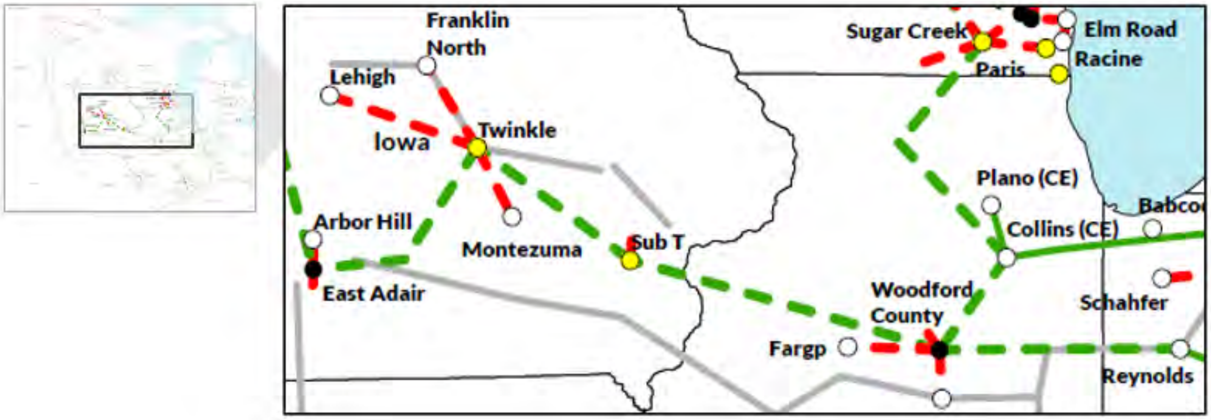


Figure 2.110: Central Iowa and, Illinois and Northern Indiana LRTP Tranche 2.1 projects

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

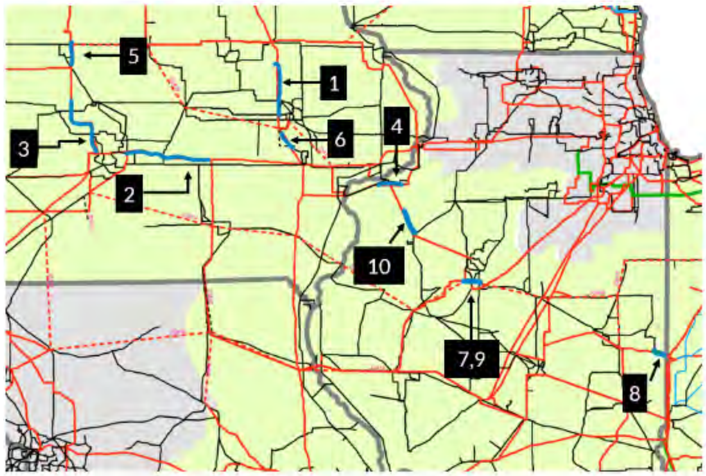


Figure 2.112: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Iowa and Illinois

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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	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.

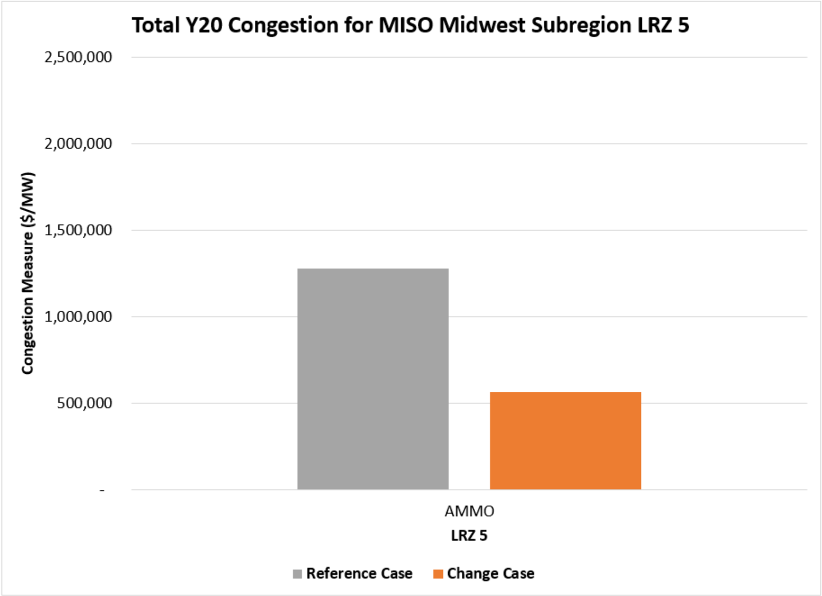


Figure 2.114: Congestion Measure – LRZ 5

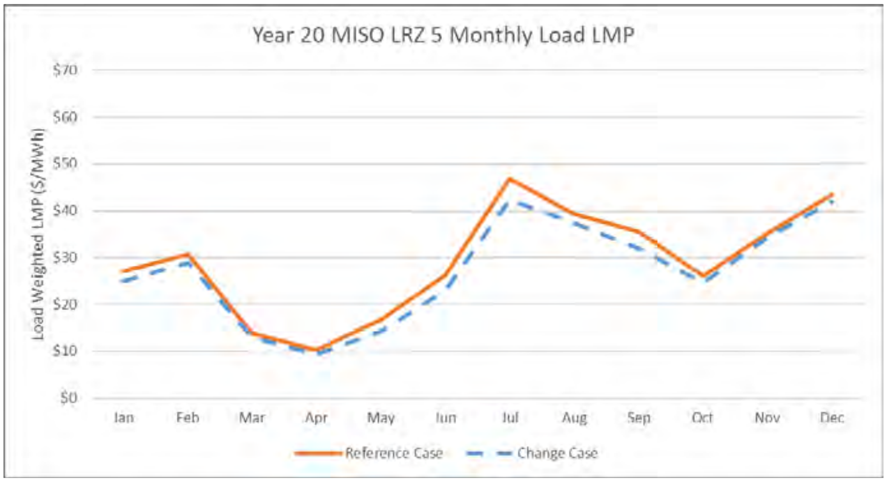


Figure 2.115: Comparison: Monthly Load LMP – LRZ 5

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

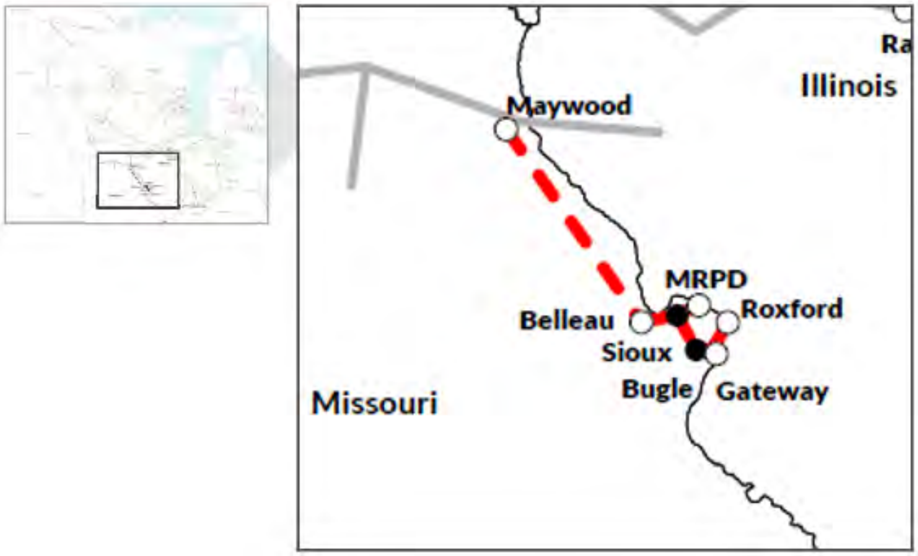


Figure 2.116: Missouri LRTP Tranche 2.1 projects

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

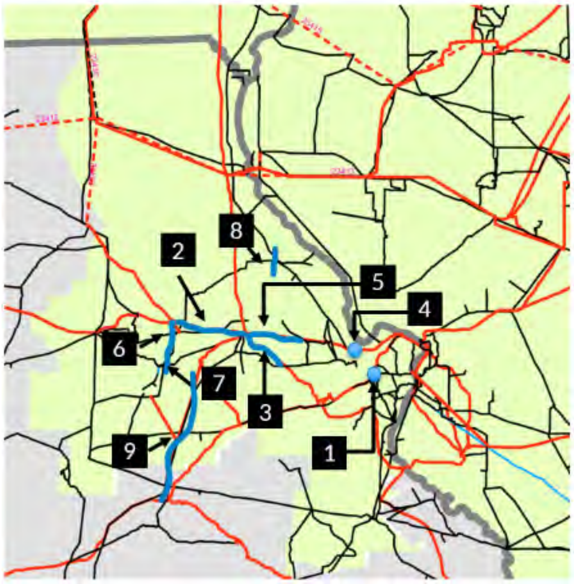


Figure 2.118: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Missouri

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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**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] 4WITTNBRG - [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

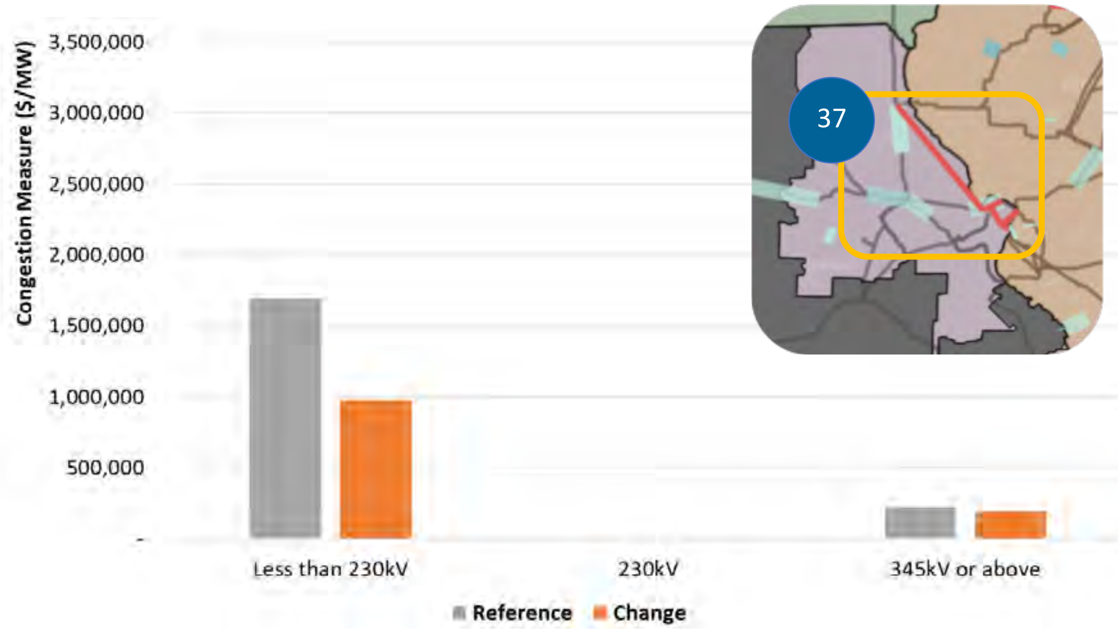


Figure 2.119: Congestion Measure – Project 37

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.

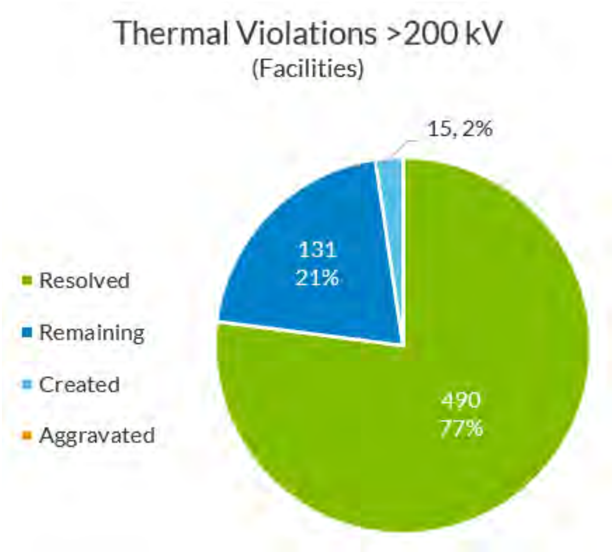


Figure 2.120: Thermal constraint resolution for LRZ6

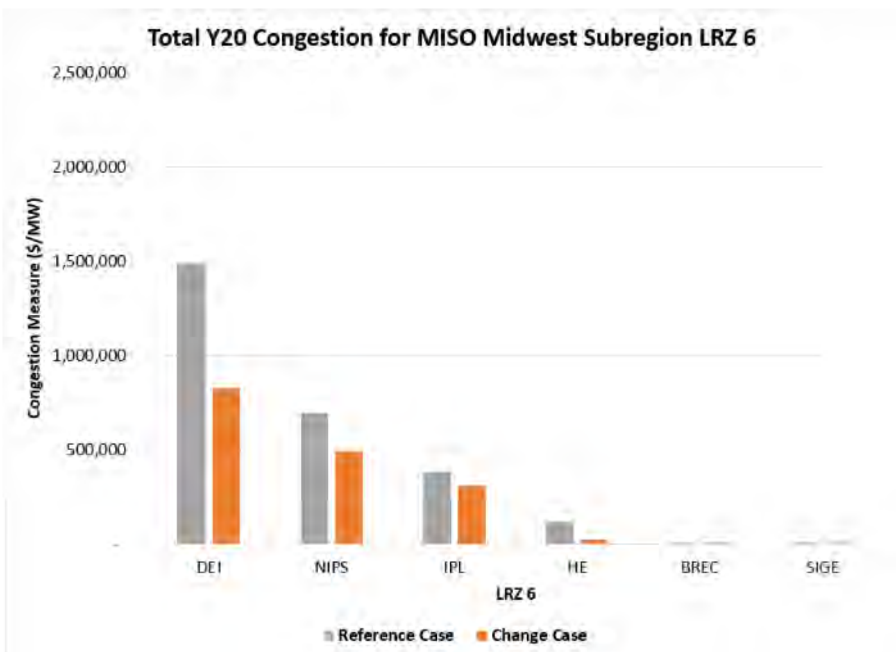


Figure 2.121: Congestion Measure – LRZ 6

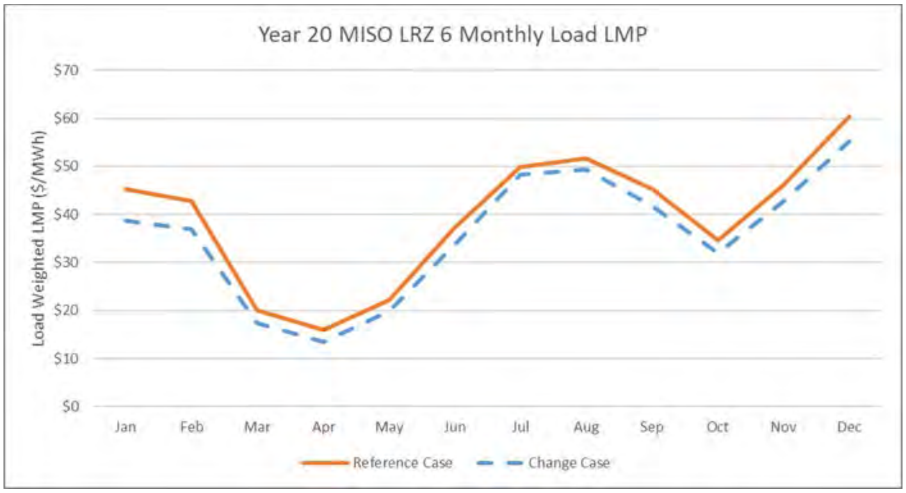


Figure 2.122: Comparison: Monthly Load LMP – LRZ 6

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.

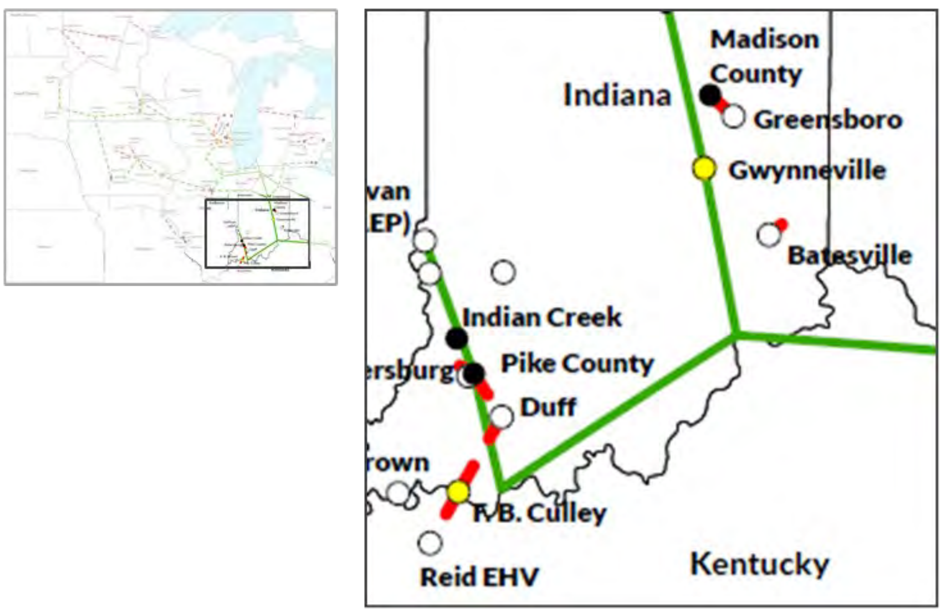


Figure 2.123: Southwest Indiana – Kentucky and Southeast Indiana LRTP Tranche 2.1 projects

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] Vincennces – [DEI] Lawrenceville 138 kV	105	68

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

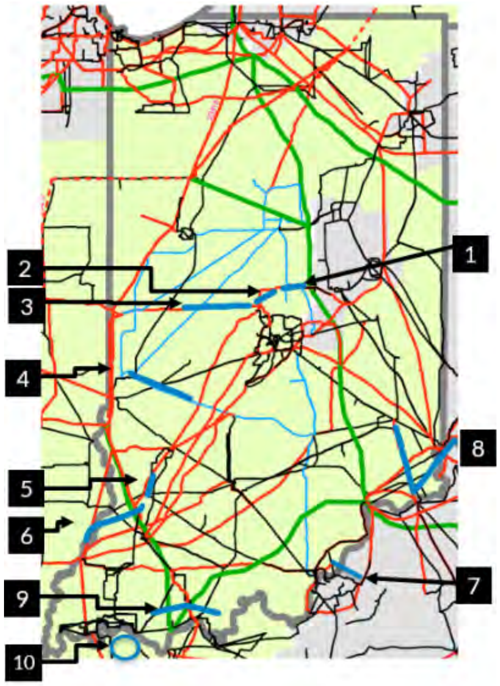


Figure 2.124: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central and Southern Indiana

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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**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

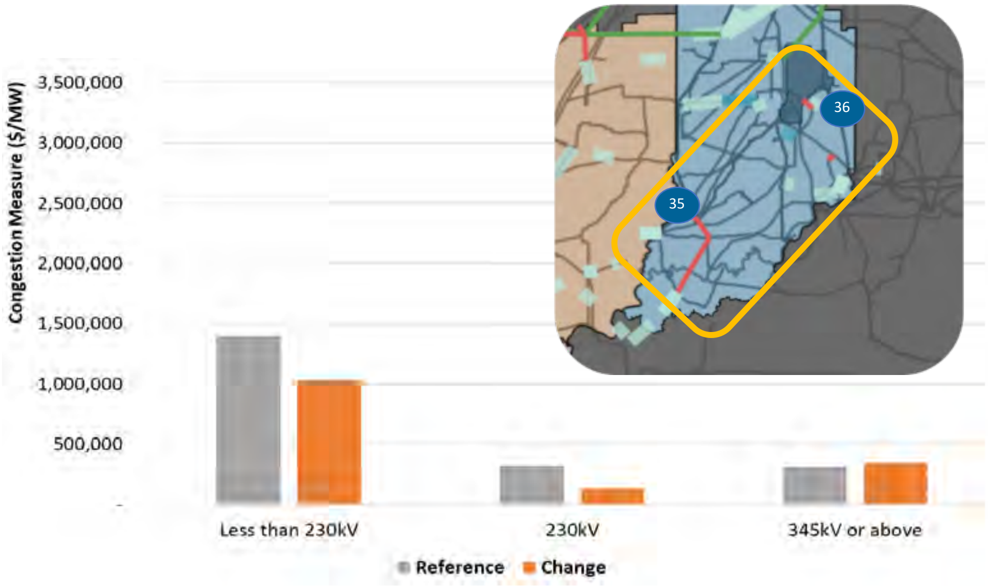


Figure 2.125: Congestion Measure – Project 35 & 36

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

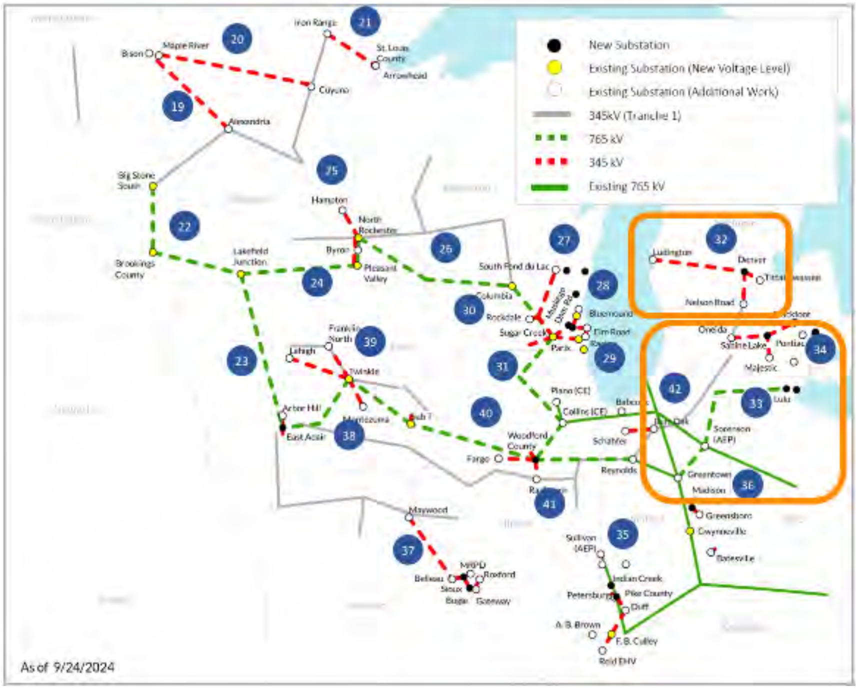


Figure 2.126: East Region Project Groups

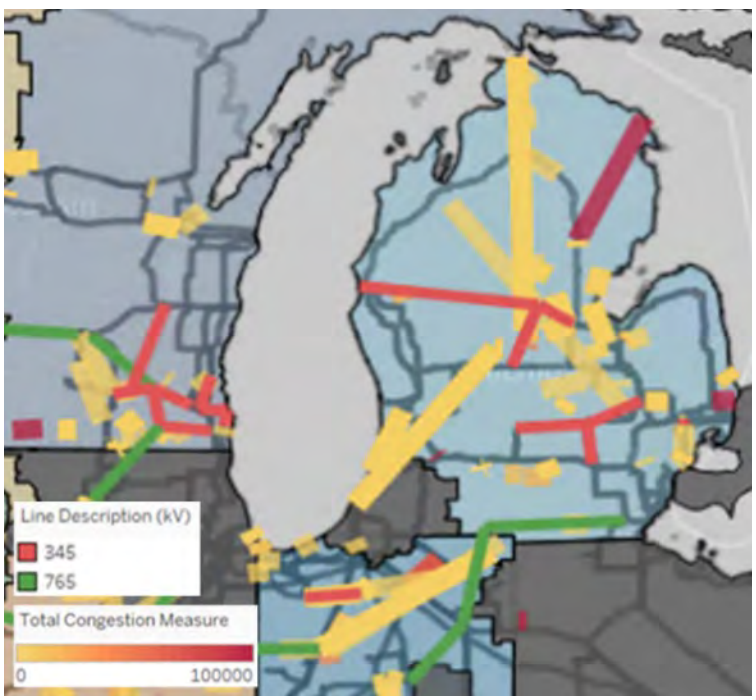


Figure 2.127: Change Case Economic Congestion - East

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.

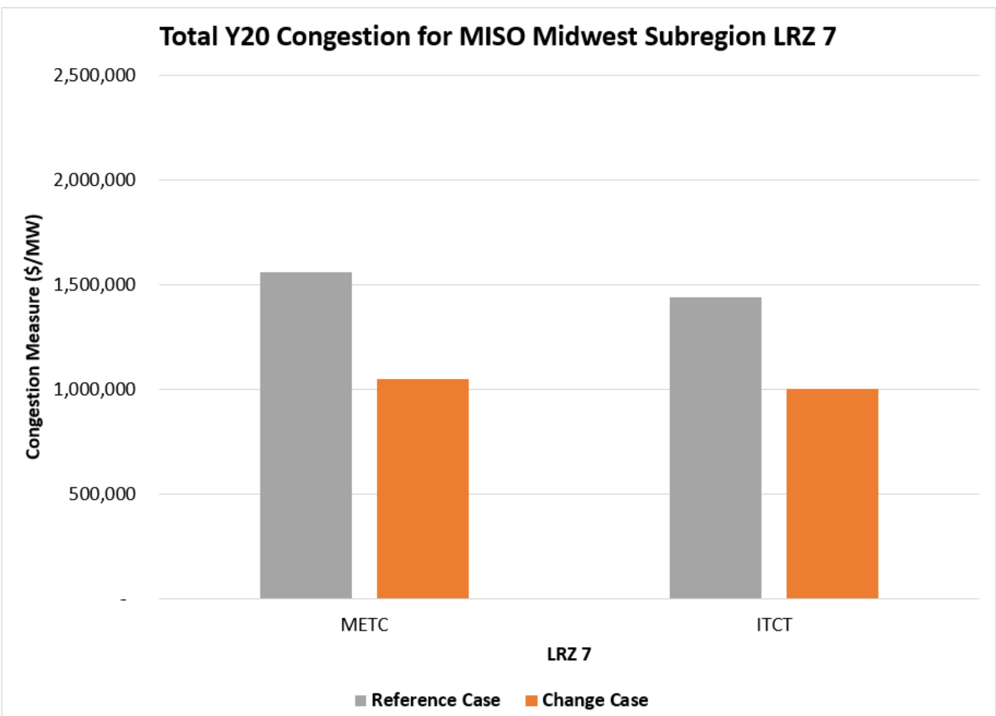


Figure 2.128: Congestion Measure – Project 37

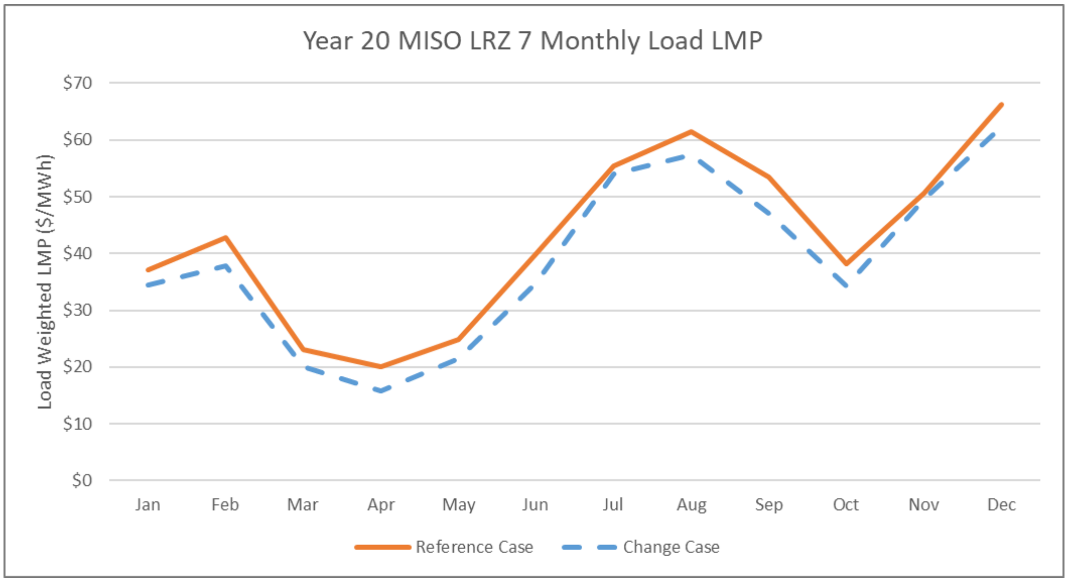


Figure 2.129: Comparison: Load LMP – Project 37

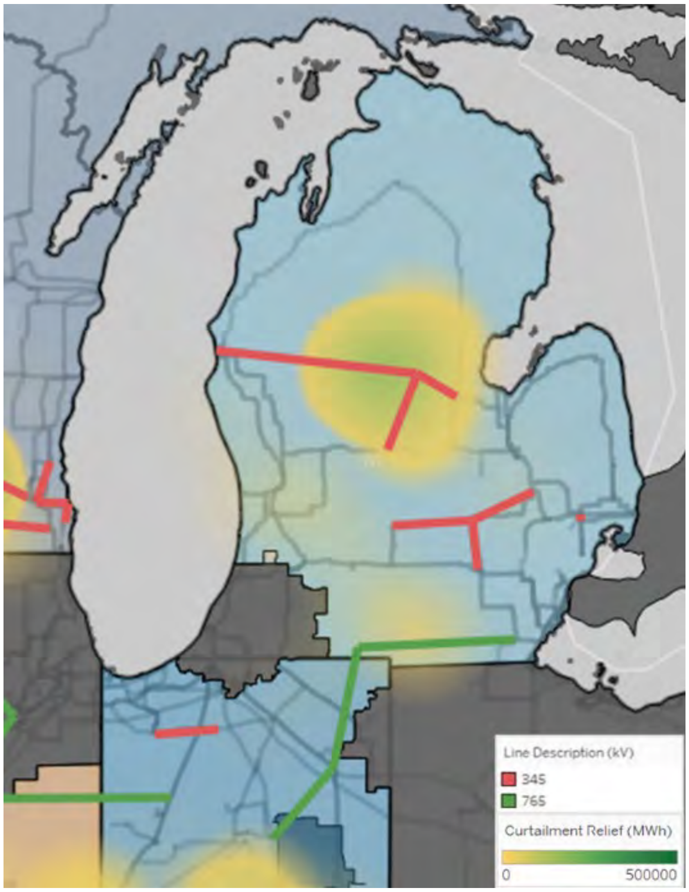


Figure 2.130: Change Case Curtailment Relief – LRZ 7

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

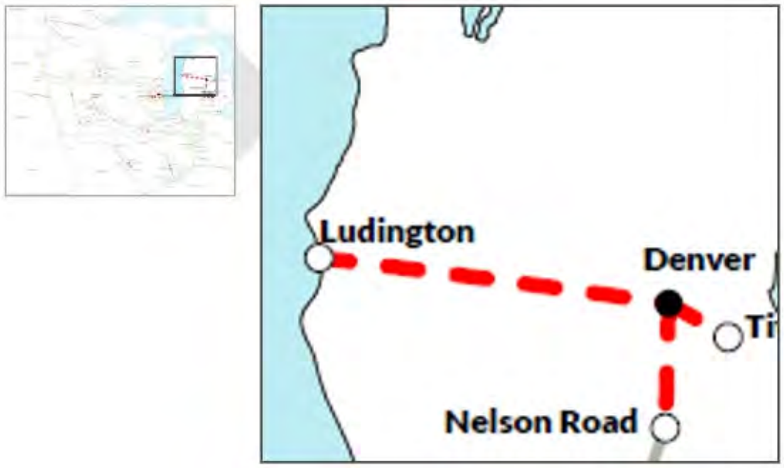


Figure 2.131: Central Michigan LRTP Tranche 2.1 projects

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

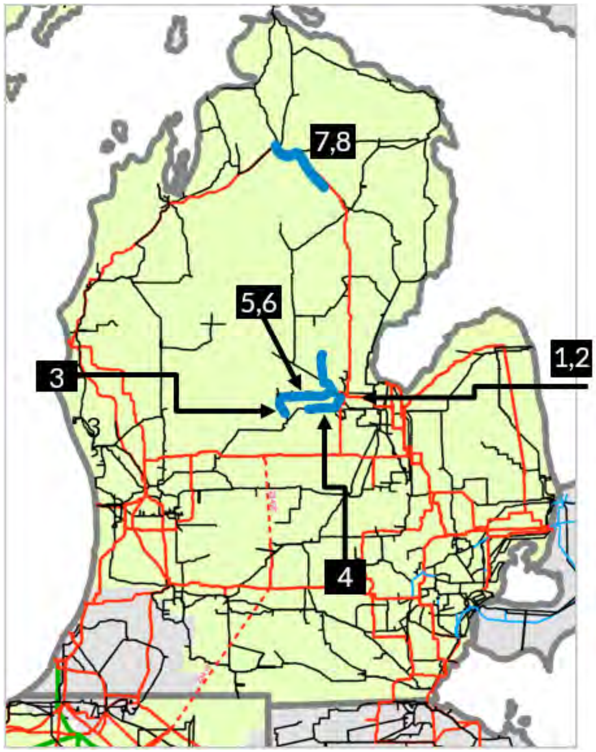


Figure 2.132: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Michigan

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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**Reference**	**Change Case**	**Total Relief**
Event 627: [CONS] 18BULLOCKW - [CONS] 18SALTRIV 138 kV 1	107,294	-	107,294
Figure	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] 18EDNVLJ 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] 18CAMLTJ - [CONS] 18SALTRIV 138 kV 1	13,502	-	13,502
Event 150: [CONS] 18CAMLTJ - [CONS] 18SALTRIV 138 kV 1	11,583	0	11,583

Table 2.25: Top Relieved Economic Flowgates – Projects 32

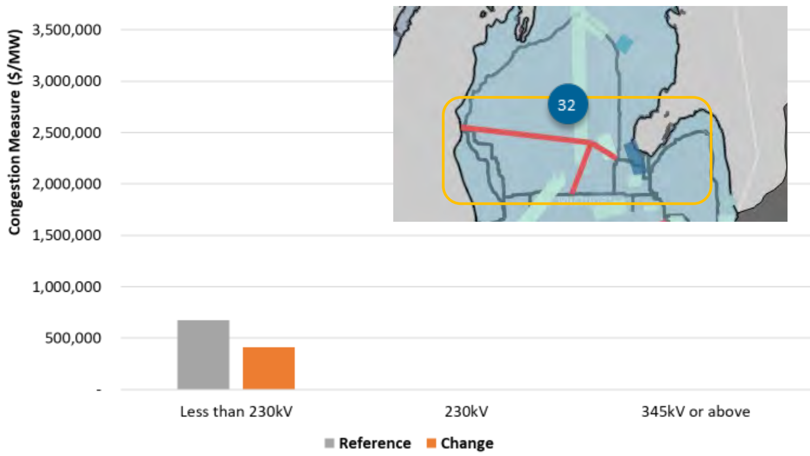


Figure 2.133: Congestion Measure – Project 32

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

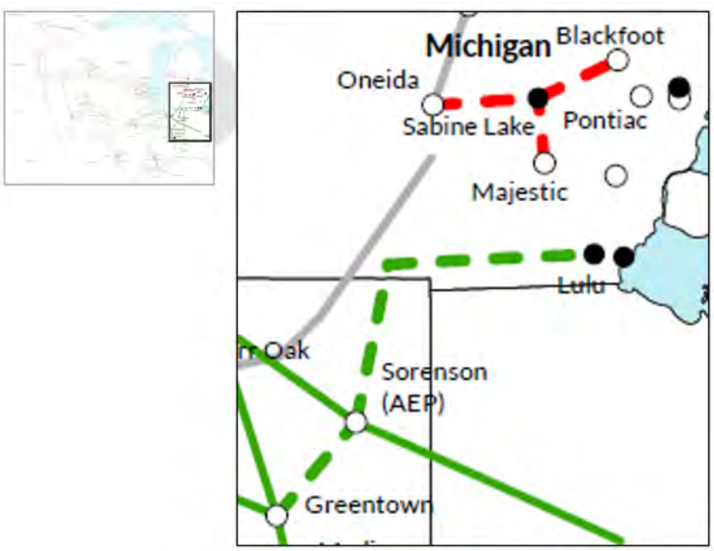


Figure 2.134: Southern Michigan and Northeastern Indiana LRTP Tranche 2.1 projects

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

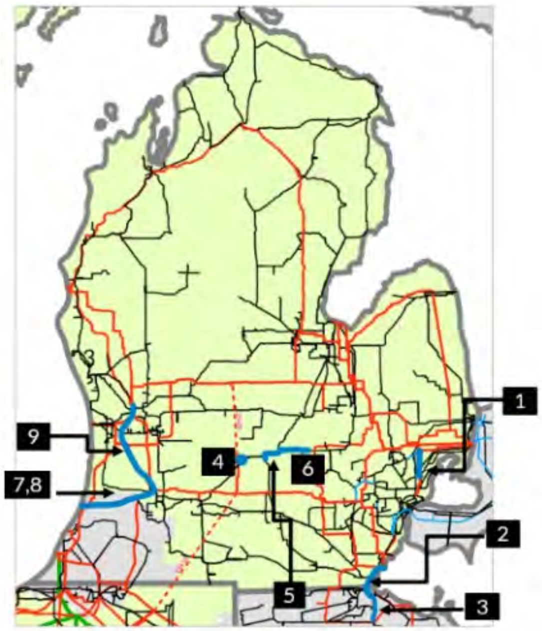


Figure 2.135: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Michigan

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			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**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

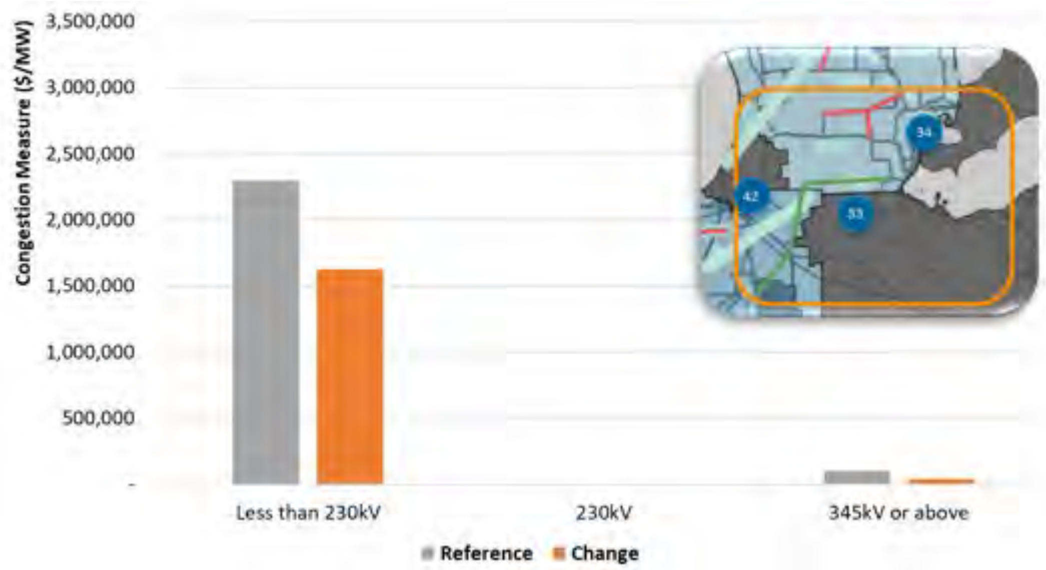


Figure 2.136: Congestion Measure – Project 33, 34 & 36

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.

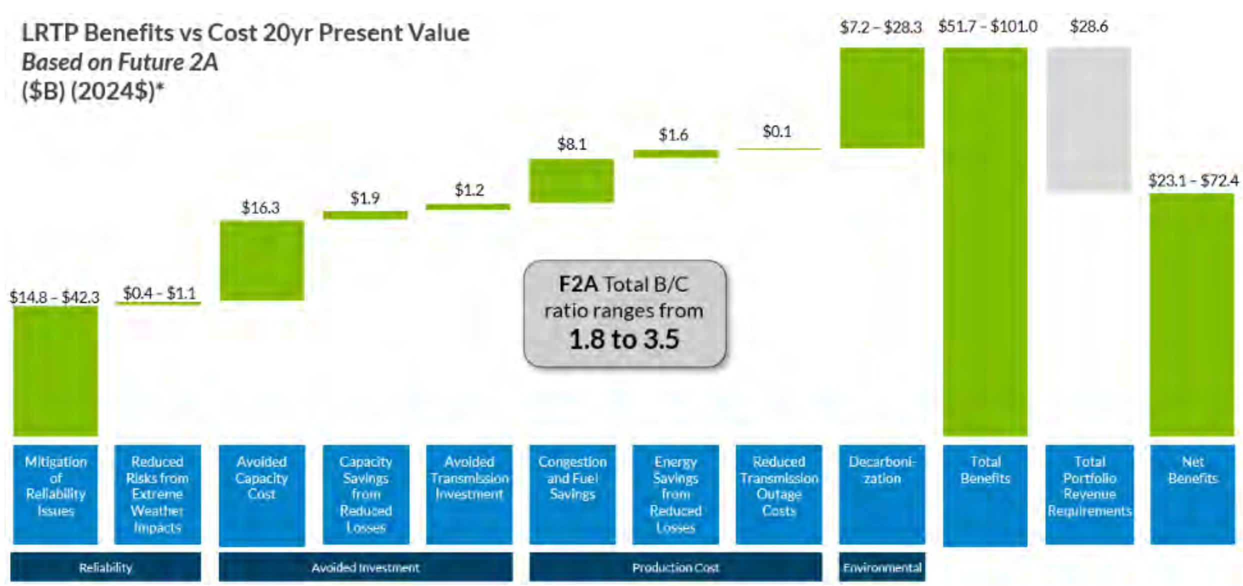


Figure 2.137: Financially Quantifiable Benefits of Tranche 2.1 Portfolio (values as of 11/1/2024).

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 past 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.

$$\text{Benefit} = \sum_{1}^{n} LoadShedMW * VOLL$$

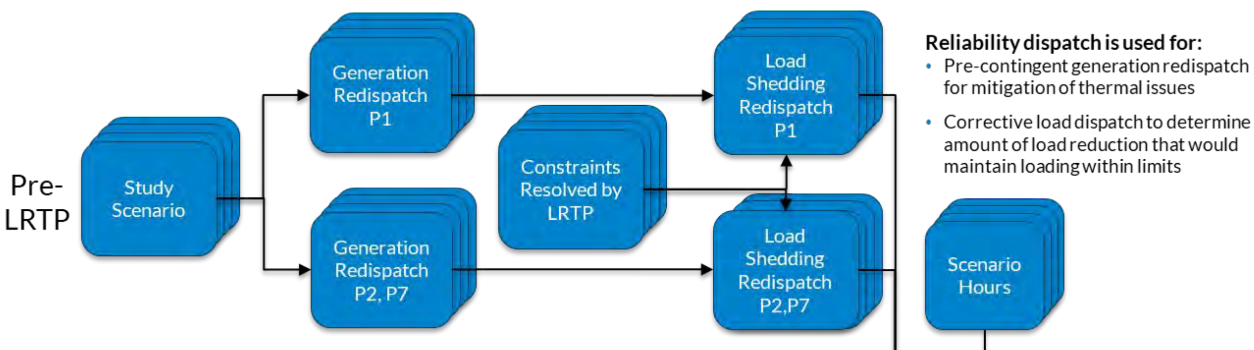
Where

n = dispatch scenario/season

LoadShedMW = amount of load redispatch for each study scenario

VOLL = Value of Lost Load ($3,500/MWh - $10,000/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.



Example Calculation (illustrative)

Model	Redispatch Scenario	Monitored	Contingency	Pre-overload %	Pre-MW Relief Required	Buses	Sum of Max Load Shed MW	Scenario Hours	MWh Benefit
2032sum	up/down	St A- St B	P1_Ctg1	115%	16MW	bus-a bus-b	124	48	5,952
2032avg	up/down	St C - St D	P1_Ctg2	124%	32MW	bus-c bus-d bus-e	46	420	19,320
2032avg	down-only	St E - St F	P1_Ctg3	107%	20MW	bus-f bus-g bus-h bus-i	295	1362	401,790
2032avg	down-only	St G - St H	P2_Ctg4	109%	18MW				
							Load Shedding MWh		427,062

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

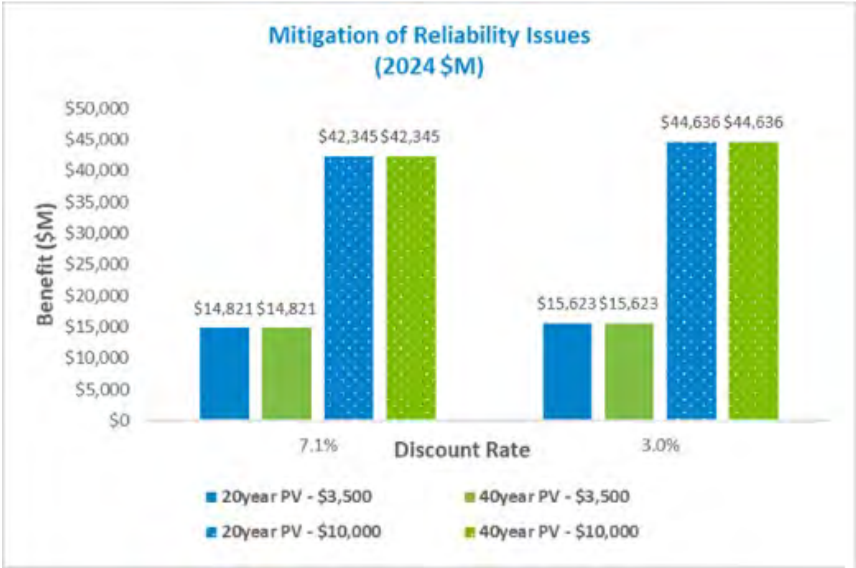


Figure 2.139: Mitigation of Reliability Issues Benefit Value

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,[3] is calculated by the following equation:

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 - $10,000MW/hr)

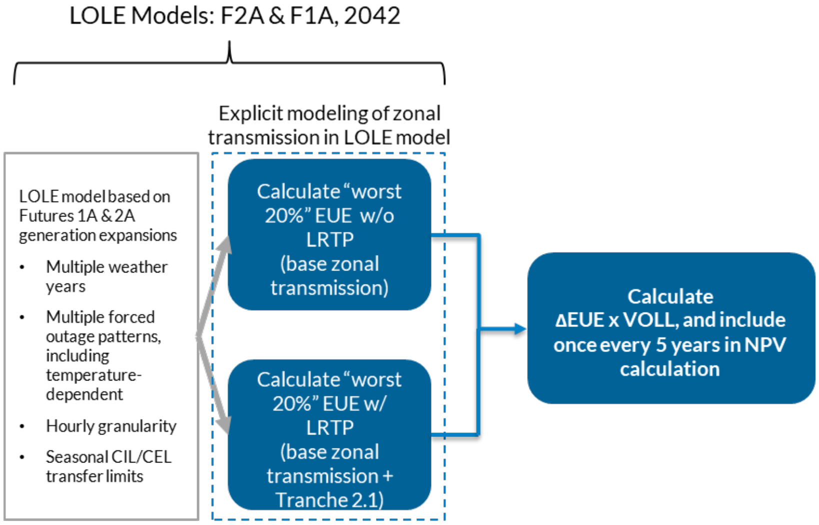


Figure 2.140: Reduced risk from extreme weather Calculation Process

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.

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

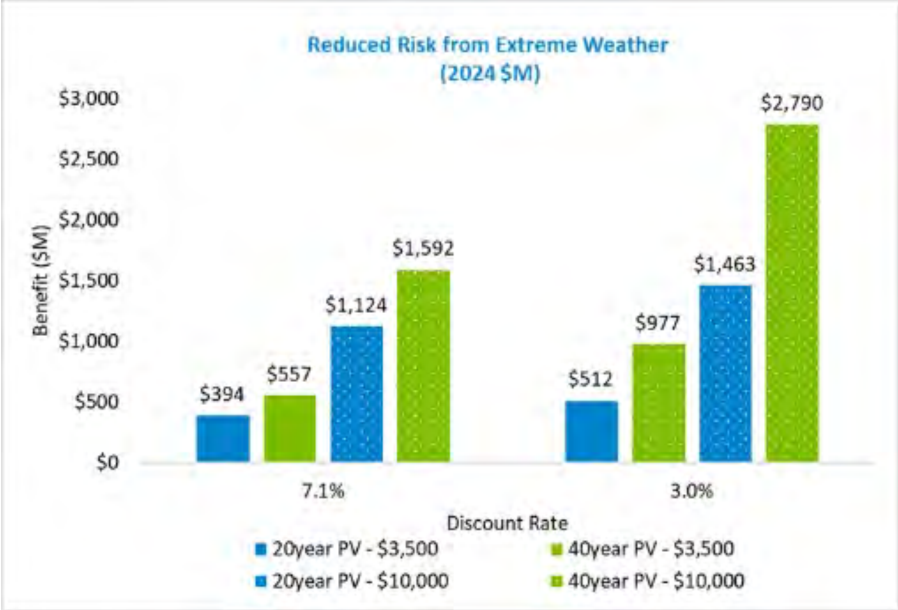


Figure 2.141: Reduced Risk from Extreme Weather Benefit Value

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.

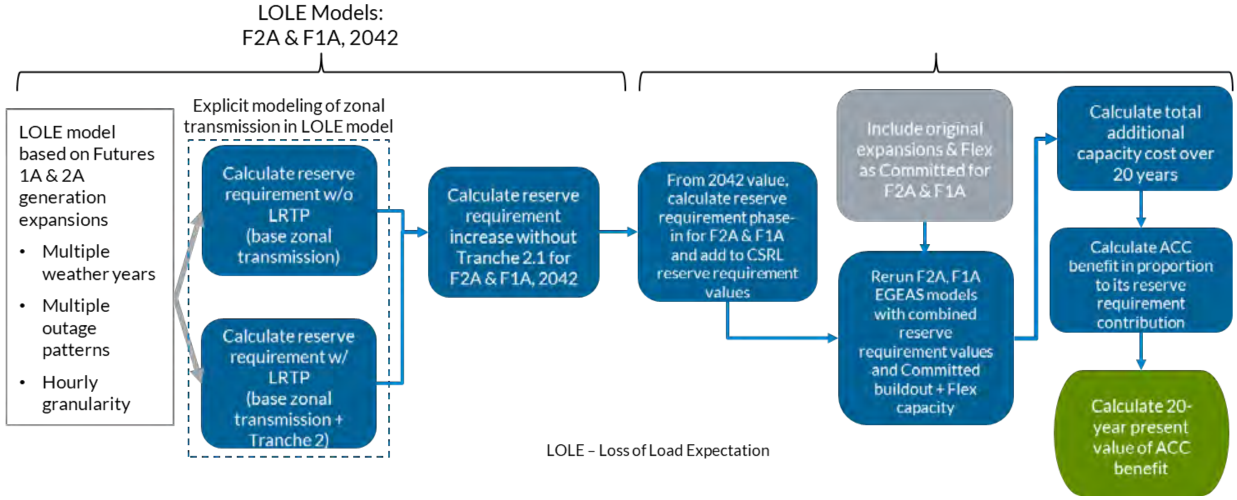


Figure 2.142: Avoided Capacity Costs Calculation Process

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.

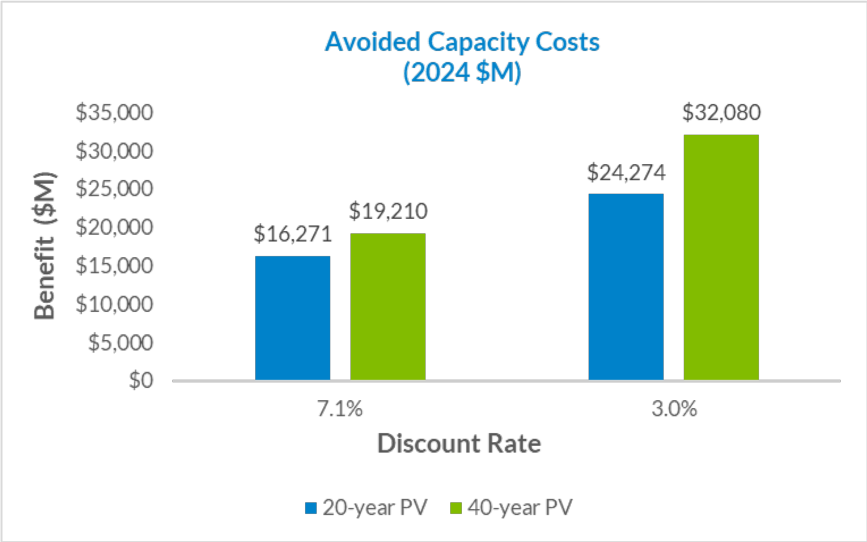


Figure 2.143: Avoided Capacity Costs Benefit Value

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.

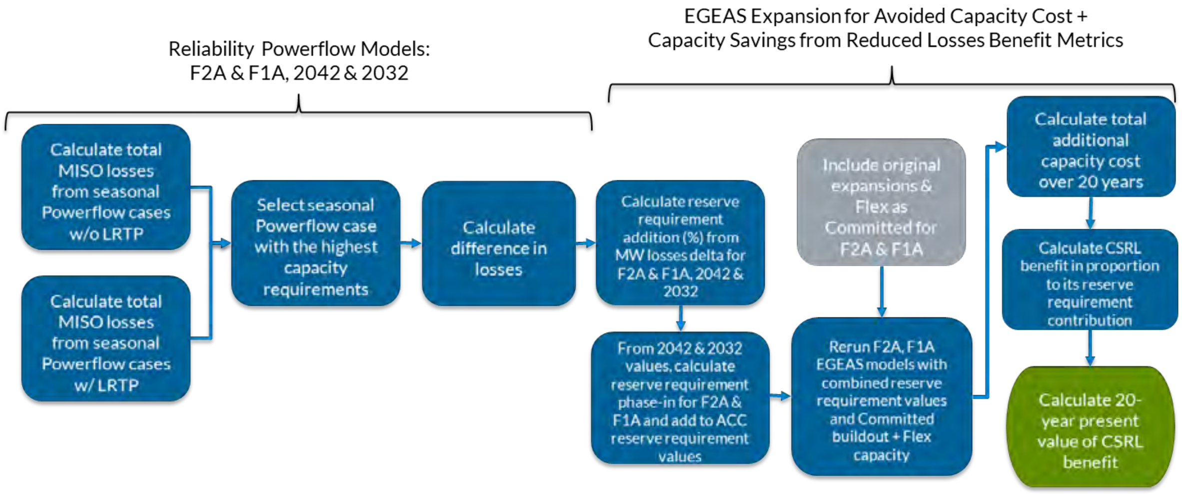


Figure 2.144: Capacity Savings from Reduced Losses Calculation Process.

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.

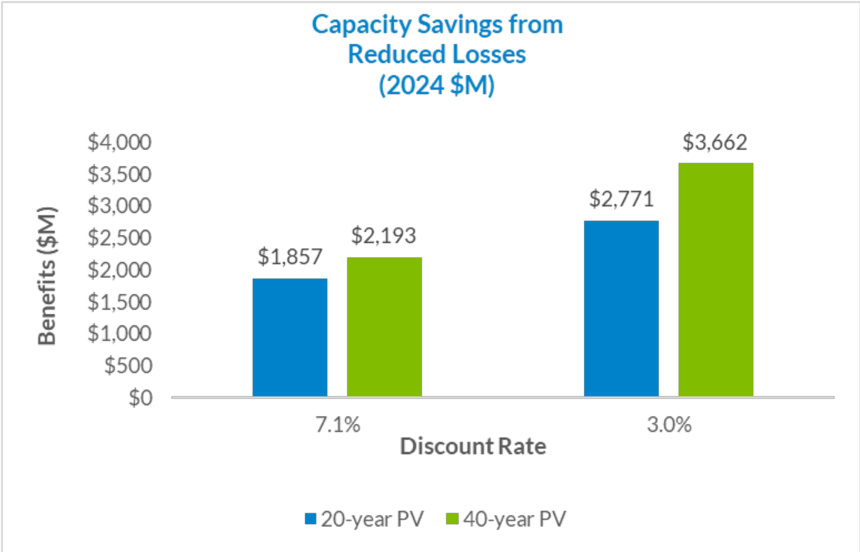


Figure 2.145: Capacity Savings from Reduced Losses Benefit Value.

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.

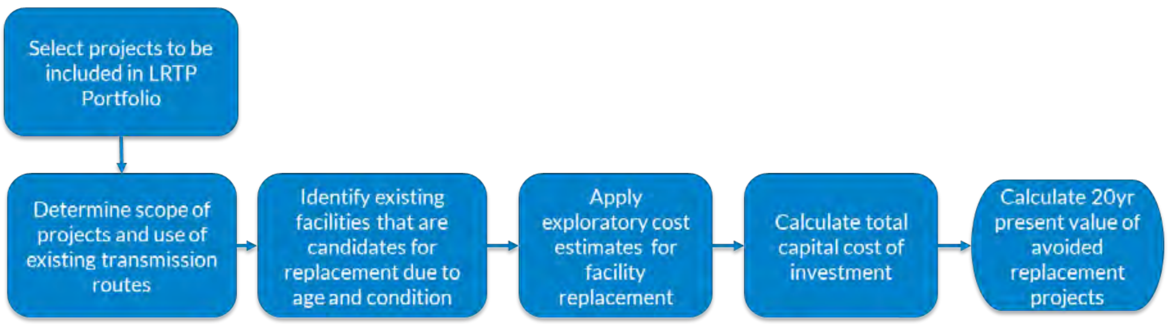


Figure 2.146: Avoided Transmission Investment Calculation Process.

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

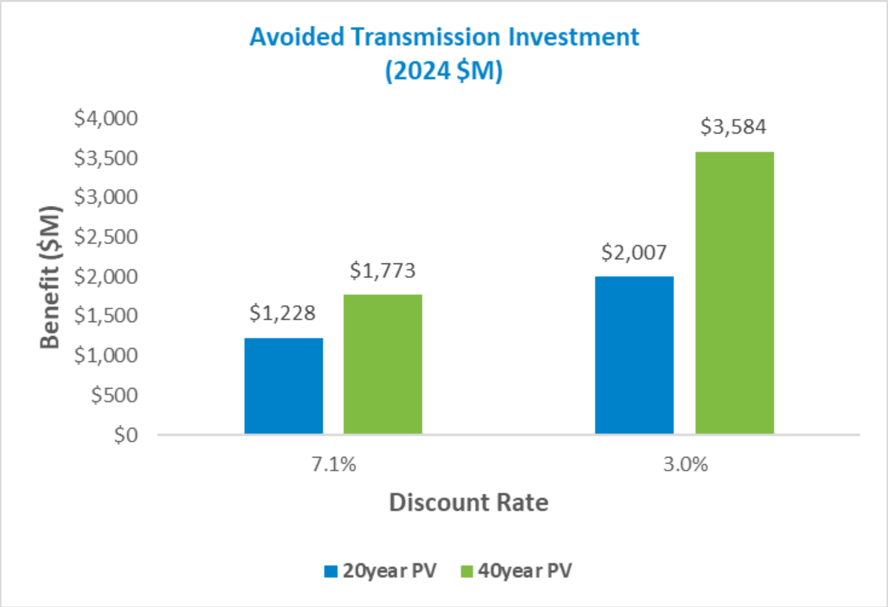


Figure 2.147: Avoided Transmission Investment Benefit Value.

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.

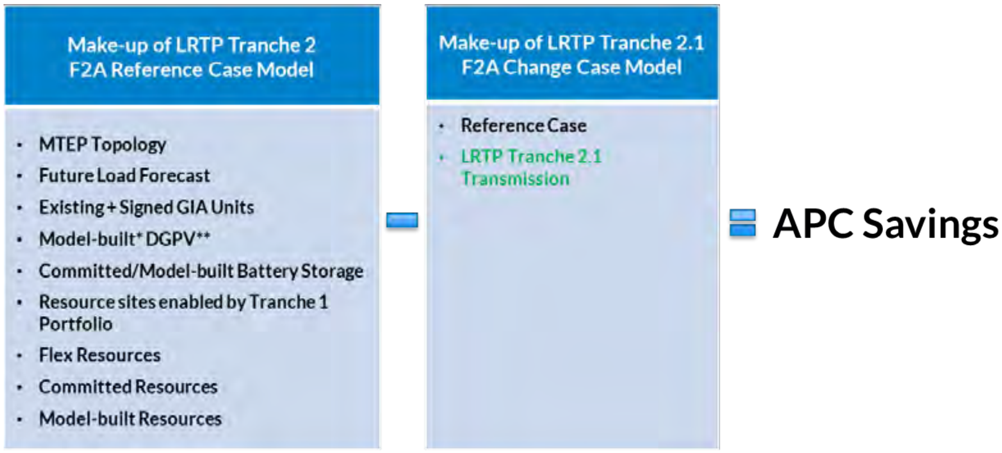


Figure 2.148: APC Savings

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.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	**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

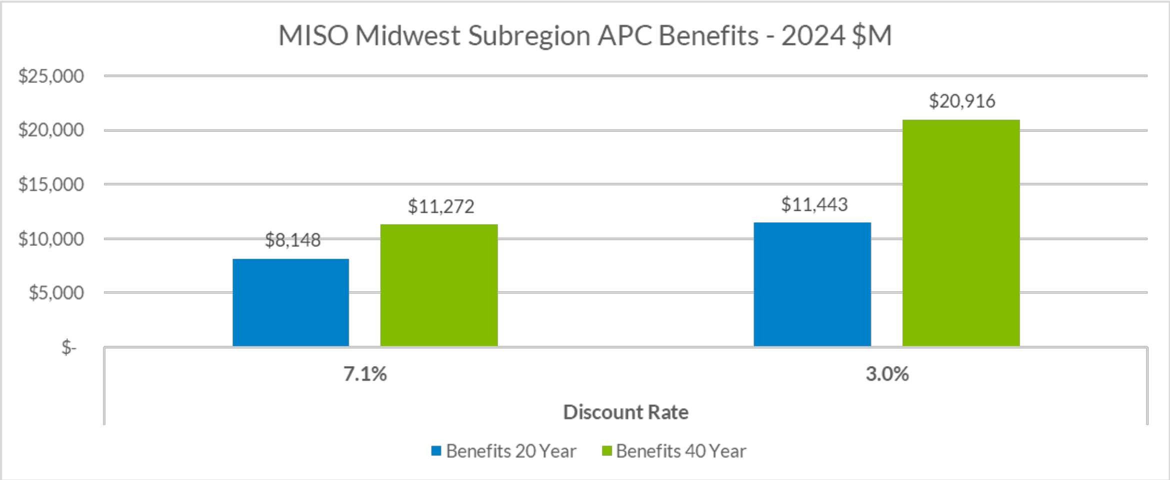


Figure 2.149: Congestion and Fuel Savings Benefit Value

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.

$$\begin{aligned} &APC\ Savings\ from\ Reduced\ Loss\ Energy \\ &\quad = (Baseline\ Reference\ Case\ APC - Reduced\ Loss\ Energy\ Change\ Case\ APC) \\ &\quad - (Baseline\ Reference\ Case\ APC - Baseline\ Change\ Case\ APC) \end{aligned}$$

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.

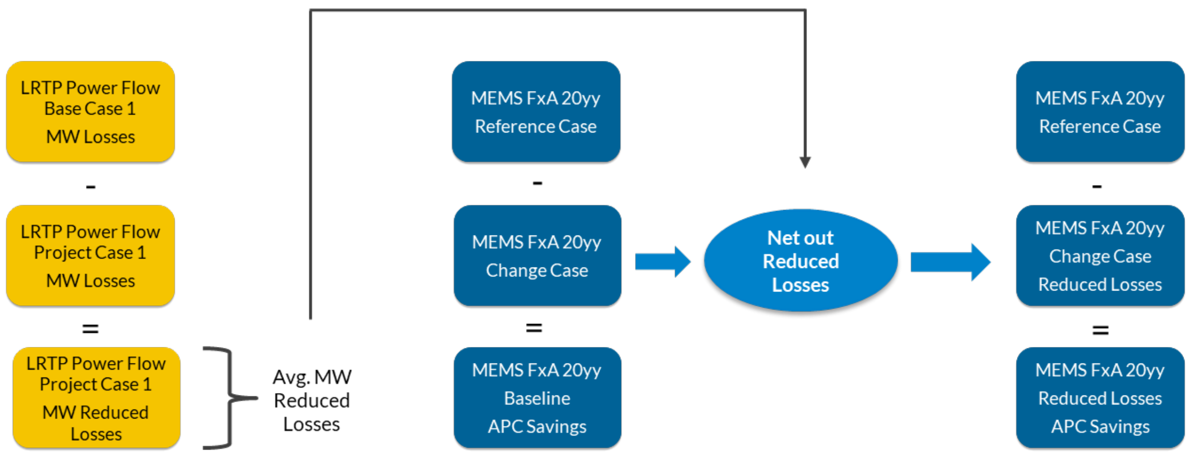


Figure 2.150: Energy Savings from Reduced Losses Calculation Process.

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.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	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

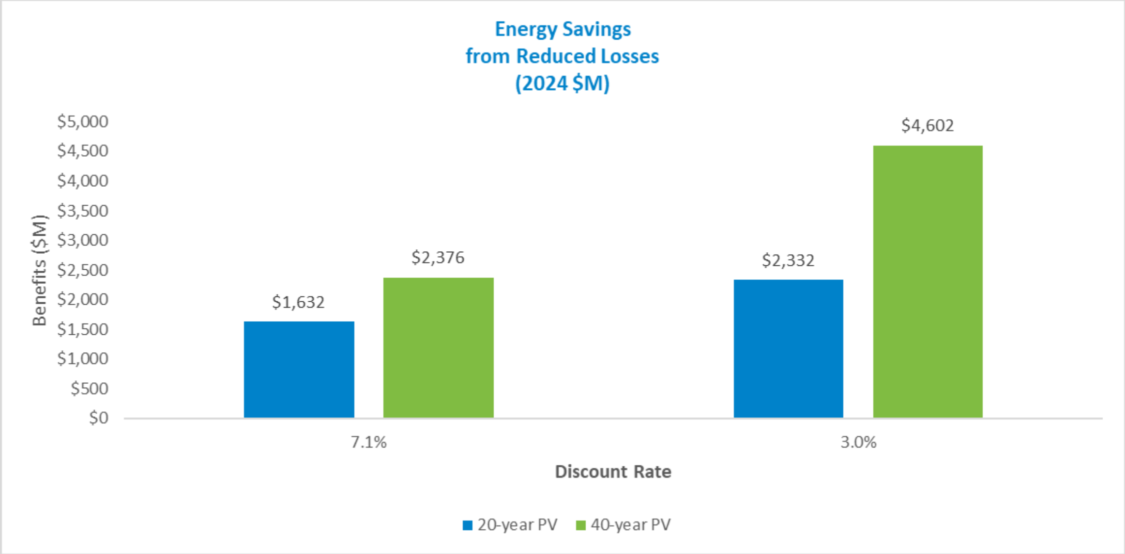


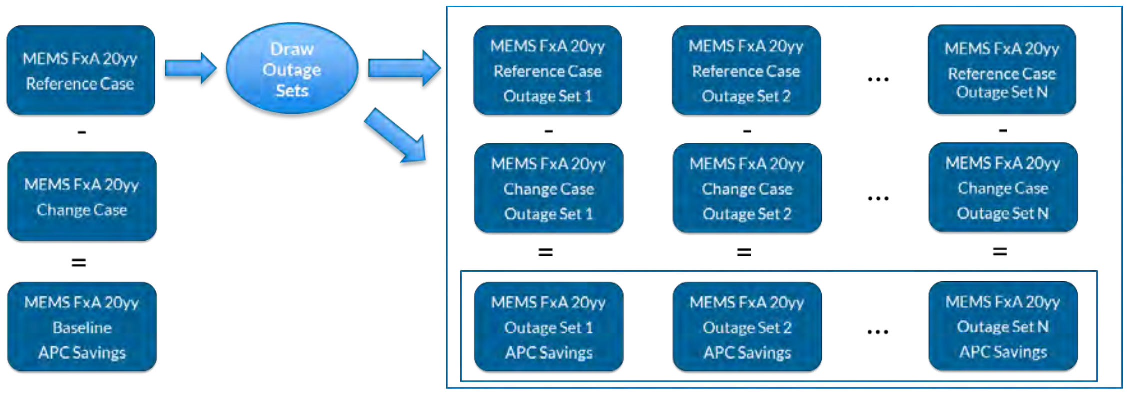
Figure 2.151: Energy Savings from Reduced Losses Benefit Value.

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.



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

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.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	**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

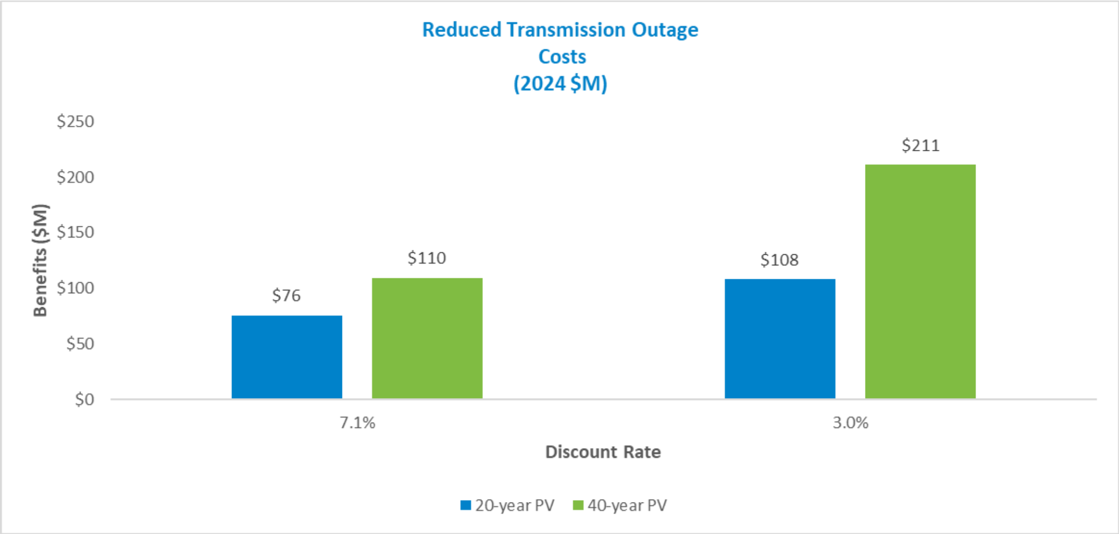


Figure 2.153: Reduced Transmission Outage Costs Benefit Value

Decarbonization

High-Level Methodology Overview

Decarbonization benefits are associated with avoided CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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.

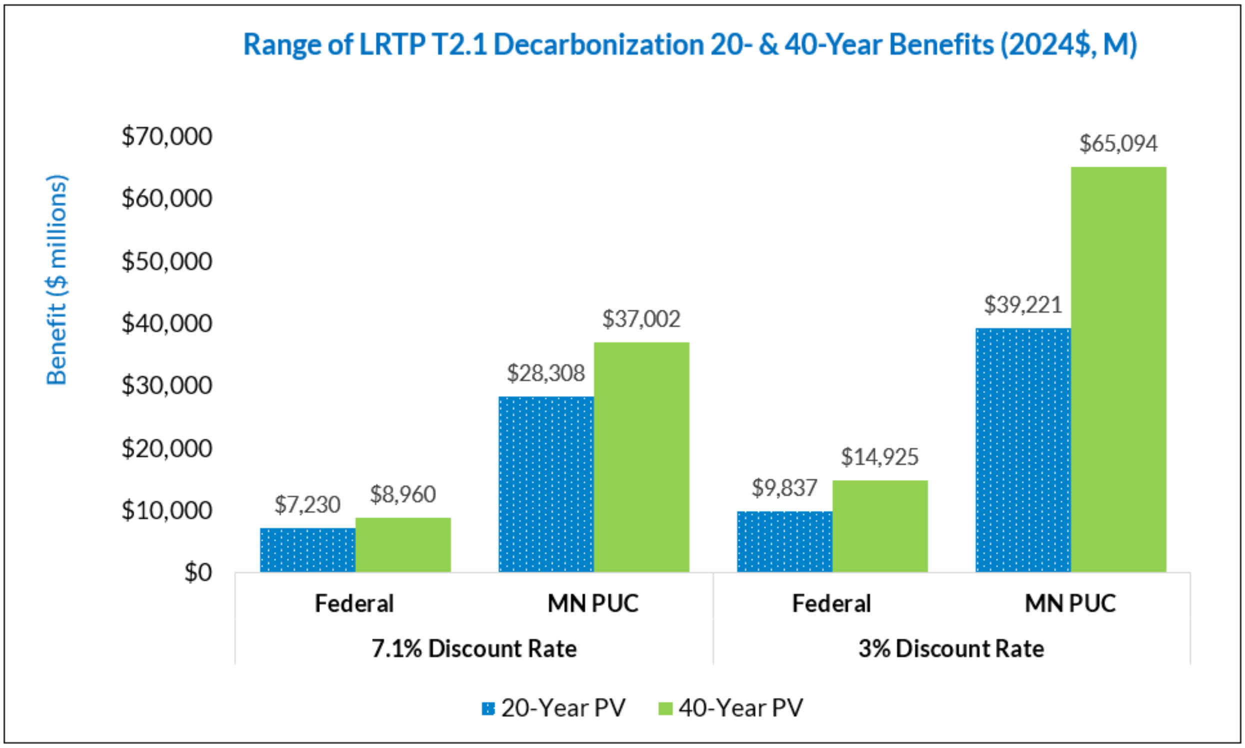


Figure 2.154: Decarbonization Benefit Value.

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.

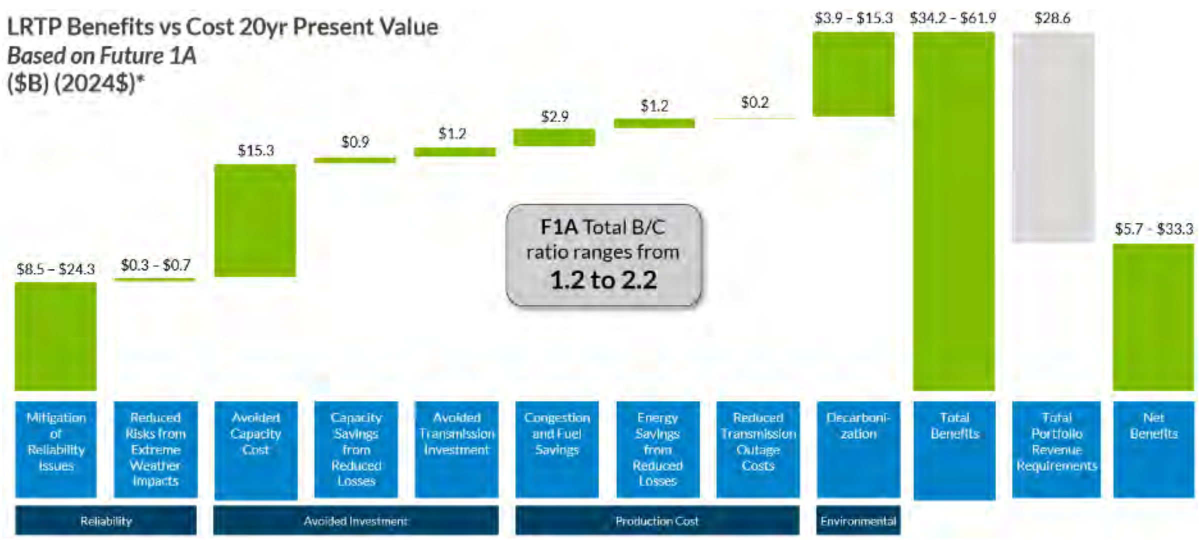


Figure 2.155: Tranche 2.1 Benefits based on Future 1A.

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.

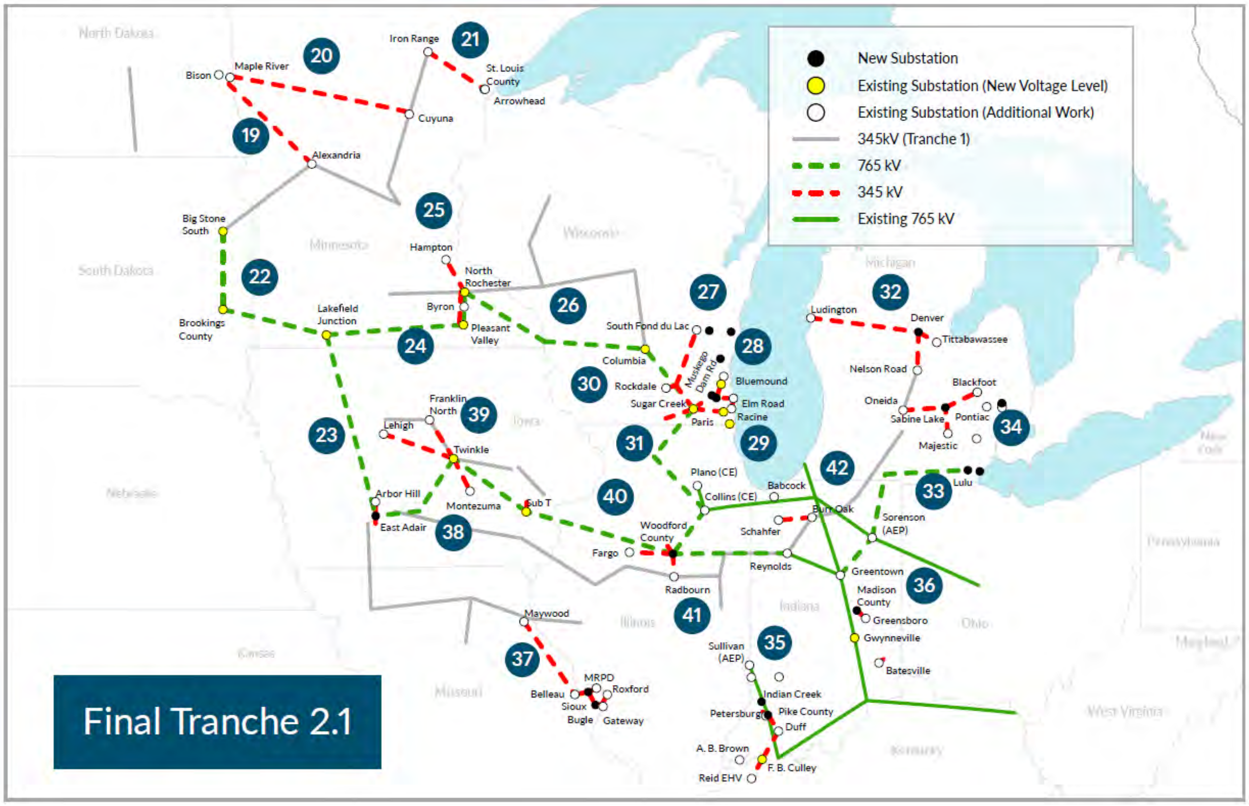


Figure 2.156: Tranche 2.1 Portfolio Map

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

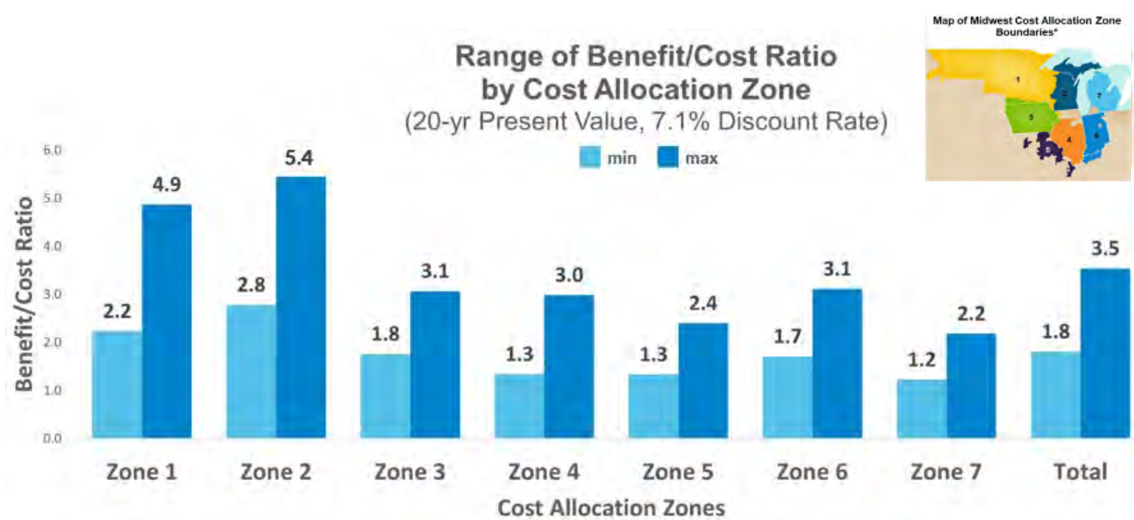


Figure 2.157: Tranche 2.1 Distribution of Benefits – Future 2A

Future 1A

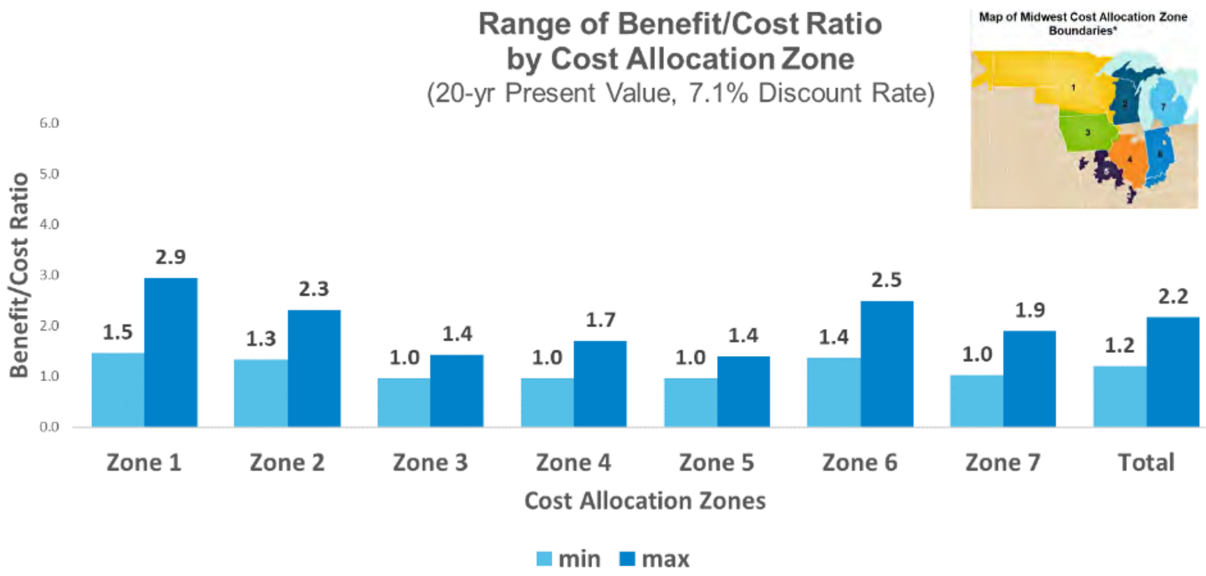


Figure 2.158: Tranche 2.1 Distribution of Benefits - Future 1A[4]

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.

[4] 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 CO_2 emissions values (Decarbonization).

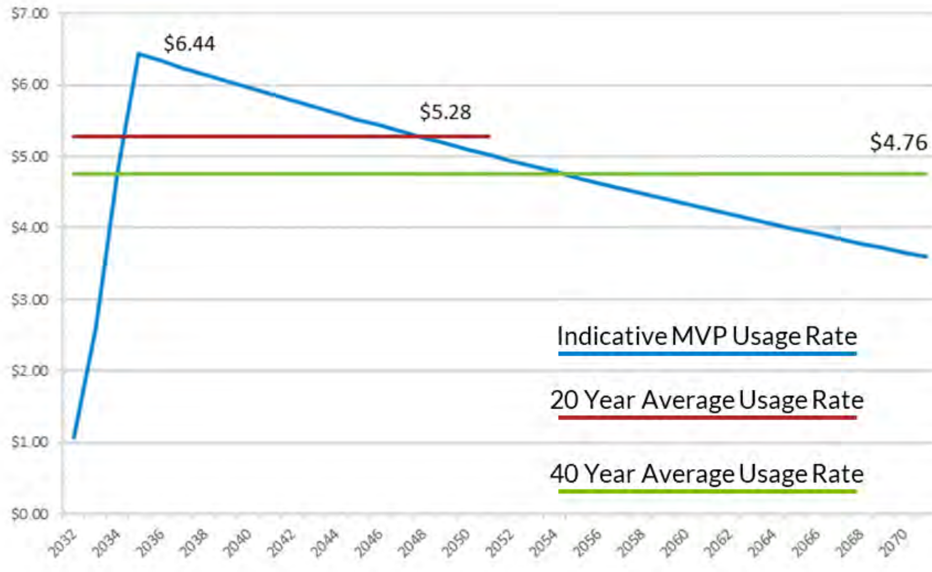


Figure 2.159: Tranche 2.1 Estimated MVP Usage Rate ($/MWh)[5]

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.

[5] 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.

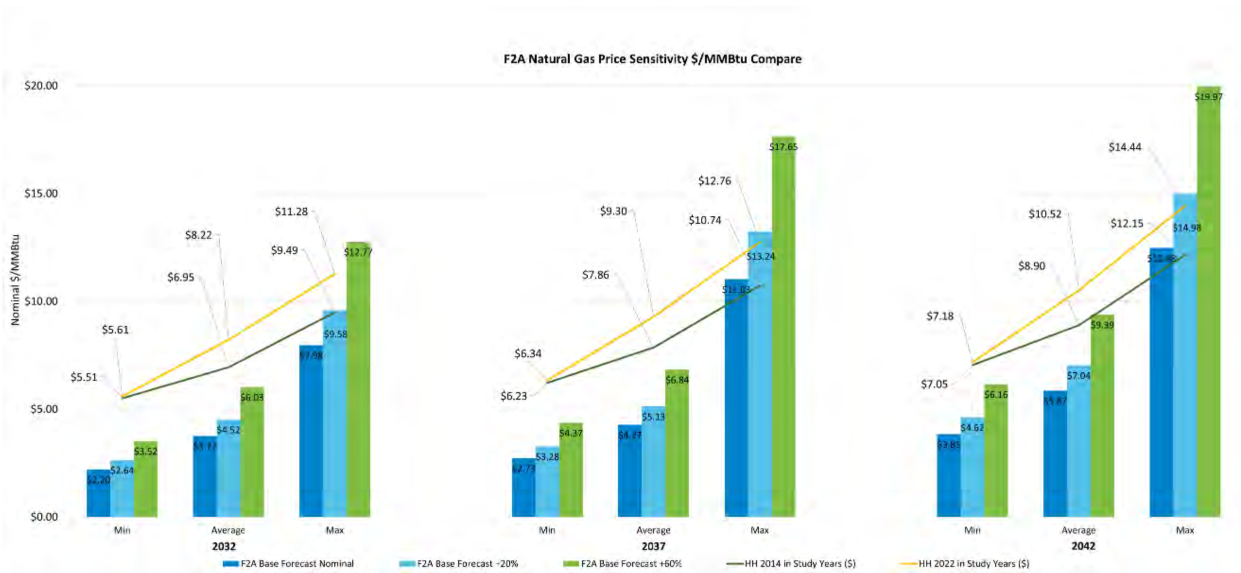


Figure 2.160: Future 2A Natural Gas Price Sensitivity Results

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.

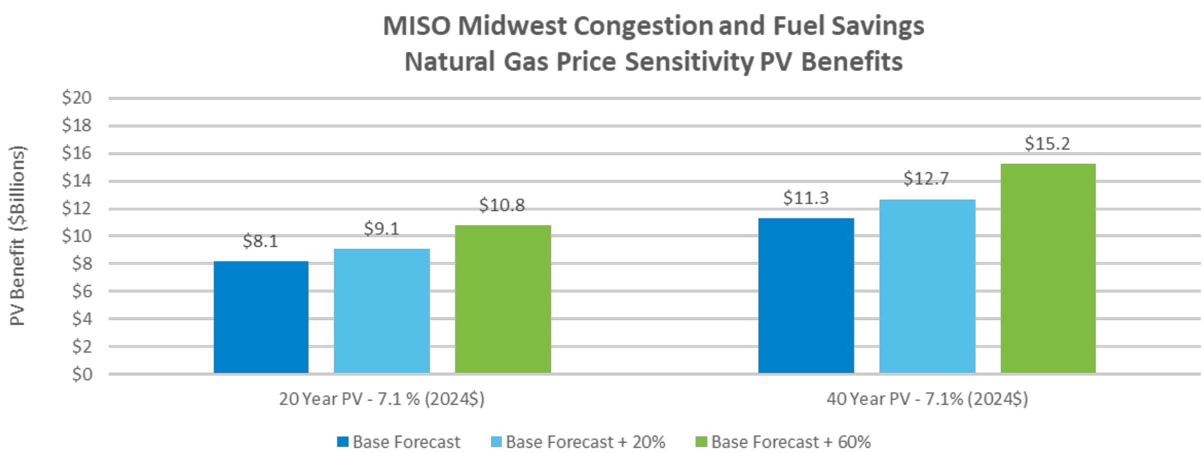


Figure 2.161: Natural Gas Price Sensitivity Congestion and Fuel Savings

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. MISOs 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)	
Central		*Low Estimate*	*High Estimate*	*Low Estimate*	*High Estimate*	*Low Estimate*	*High Estimate*
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.

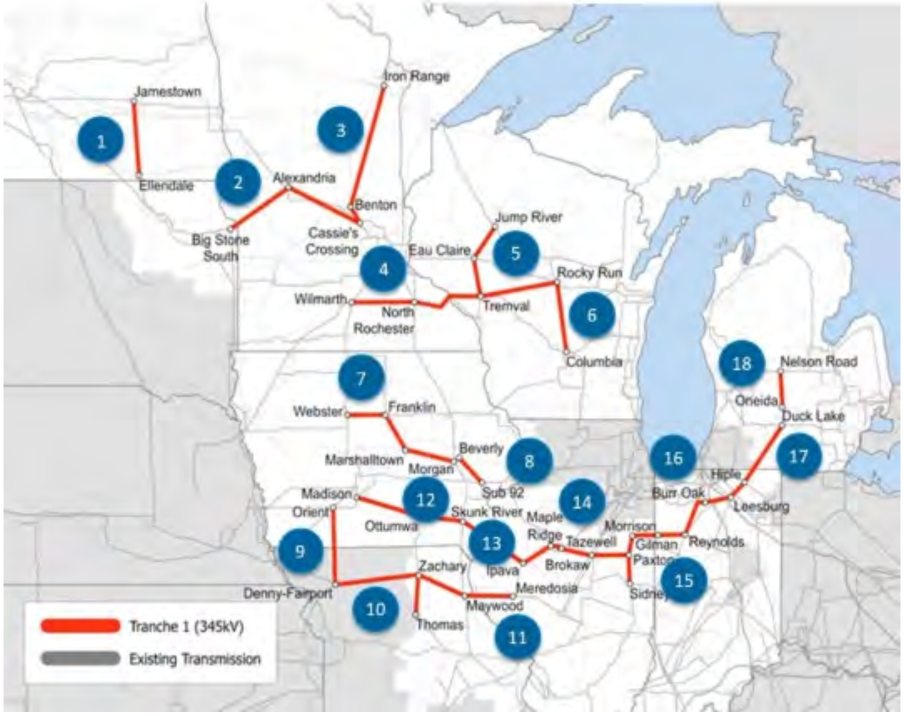


Figure 2.162: LRTP Tranche 1 Portfolio

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 PROMOD[6] 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.

[6] 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.

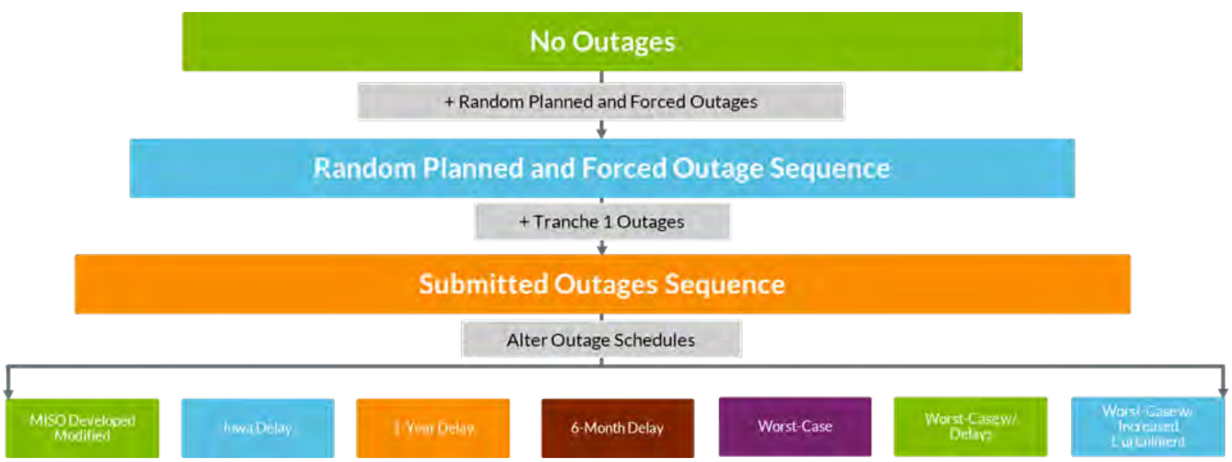


Figure 2.163: Process for Adding Outages and Building Scenarios

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:

<u>Submitted Outages (Base Outages)</u>

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.

<u>6-Month Delay</u>

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.

<u>1-Year Delay</u>

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.

<u>MISO Developed Modified</u>

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.

Gopher to Badger Link

Appendix E.2

MTEP24 Series 1A Futures Report

MISO Futures Report

SERIES 1A

- Published November 1, 2023 -

Highlights

- Electric utilities in the MISO region are responding to the energy industry's ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO's footprint.

- The three Series 1A MISO Futures encompass scenarios that refresh input data used in the Series 1 MISO Futures developed in 2019-20.

- Analysis of three scenarios allows for insights to the MISO system with transformation in peak seasons, as renewable energy penetration and projected demand increase.

Executive Summary

The energy industry is evolving in profound ways, with MISO members and states announcing increasingly advanced decarbonization and clean energy goals due to changing economics, environmental regulations, technological advancements, state and federal policies, and consumer preferences for cleaner energy. Over 75% of MISO's load is served by member utilities with such ambitious plans, creating new challenges and complexities in the realm of resource planning. Although MISO is not a resource planner and does not have authority over generation planning decisions or resource procurement, member and state plans often do not provide resource information for the full 20-year study period. This creates a resource "gap" which MISO fills through resource expansion analysis. To hedge uncertainty and "bookend" a range of economic, political, and technological possibilities over the 20-year study period, MISO's regional resource expansion analysis is performed on multiple planning scenarios called the MISO Futures. The MISO Futures resource expansion analysis seeks to find the optimal resource buildout that minimizes the overall system cost while meeting reliability and policy requirements.

As a key element of the Long-Range Transmission Planning (LRTP) initiative and the Reliability Imperative, the MISO Futures and their respective resource expansion plans set the foundation for MISO's long-term transmission planning analysis in identifying valuable transmission solutions that help enable members' and states' plans in a reliable and cost-effective manner. As part of Tranche 1 of the LRTP initiative, MISO collaborated with stakeholders to develop a cohort of three future planning scenarios, which are now referred to as the Series 1 Futures. This cohort of Futures was developed over an 18-month period beginning in mid-2019 through the end of 2020 and was the foundation of the LRTP Tranche 1 analysis, used to justify a $10.3 billion portfolio of new transmission investments unanimously approved by the MISO Board of Directors on July 25, 2022.

Since the completion of the Series 1 Futures, members' and states' plans were refined, new legislation and policies took effect, and prices, along with incentives for various resources, saw significant changes. These developments required MISO to update the Series 1 Futures with the latest input data while maintaining their original number and defining characteristics. To help distinguish the updated Futures from the original Series 1 Futures, the "refreshed" cohort is referred to as the Series 1A Futures. The effort to refresh the Futures began during the summer of 2022 and concluded during the fall of 2023. Results from the Series 1A refresh continue to reflect a significant fleet transition over the next 20 years. However, compared to the Series 1 Futures, the pace of the transition is accelerating. This report documents the process and results of the refreshed Series 1A Futures, which continue to enable the diverse plans and goals of MISO's members and states.

Future 2A, within the Series 1A Futures cohort, is the focus of the LRTP Tranche 2 analysis. While developing Future 2A, MISO observed an opportunity to add value by performing an energy validation of the Future 2A resource expansion results. PROMOD, a production cost modeling tool, provided hourly (annual) chronological security-constrained unit commitment and economic dispatch, to identify any energy adequacy shortfall needs that may not have been captured in the MISO Series 1A Future 2A expansion results produced by EGEAS, an unconstrained (transmission-less) non-chronological resource expansion modeling tool. Generation shortfalls were identified for 3-4 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, the Futures team added 29 GW of Flexible Attribute Unit capacity to the Future 2A expansion and siting. These "Flex" units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: RICE[1] units, long-duration battery (>4 hours), traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear SMRs,[2] green hydrogen, enhanced geothermal systems, and other emerging technologies.

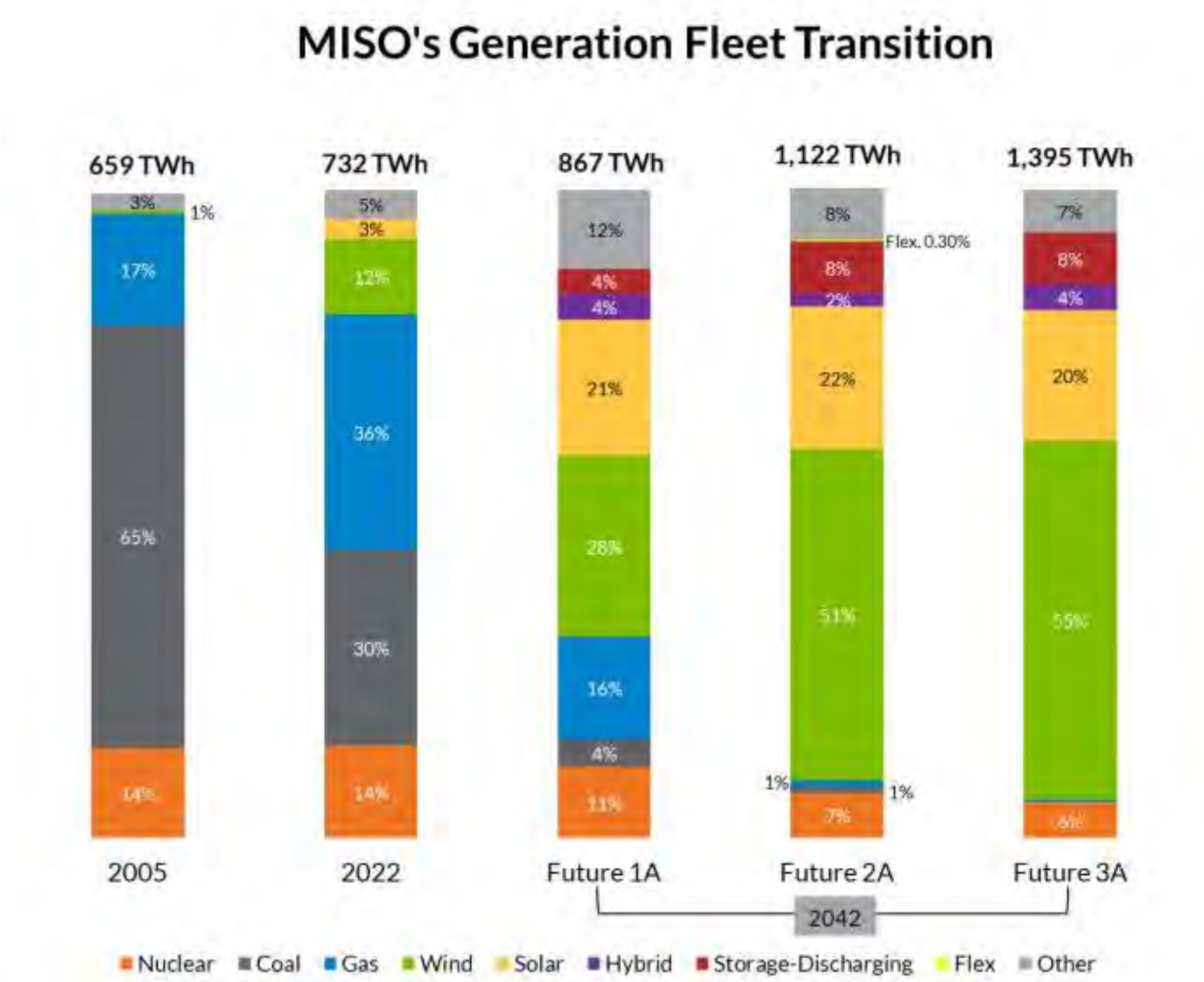


Figure 1: Overview of MISO's Generation Fleet Mix Transition[3]

[1] RICE: Stationary Reciprocating Internal Combustion Engines (gas-powered)

[2] SMR: Small Modular Reactor

[3] Storage energy percentages reflect discharge energy output. Overall energy production chart includes energy required for storage charging. Total energy production, net storage-charging, can be found for each Future in the expansion results section of this report.

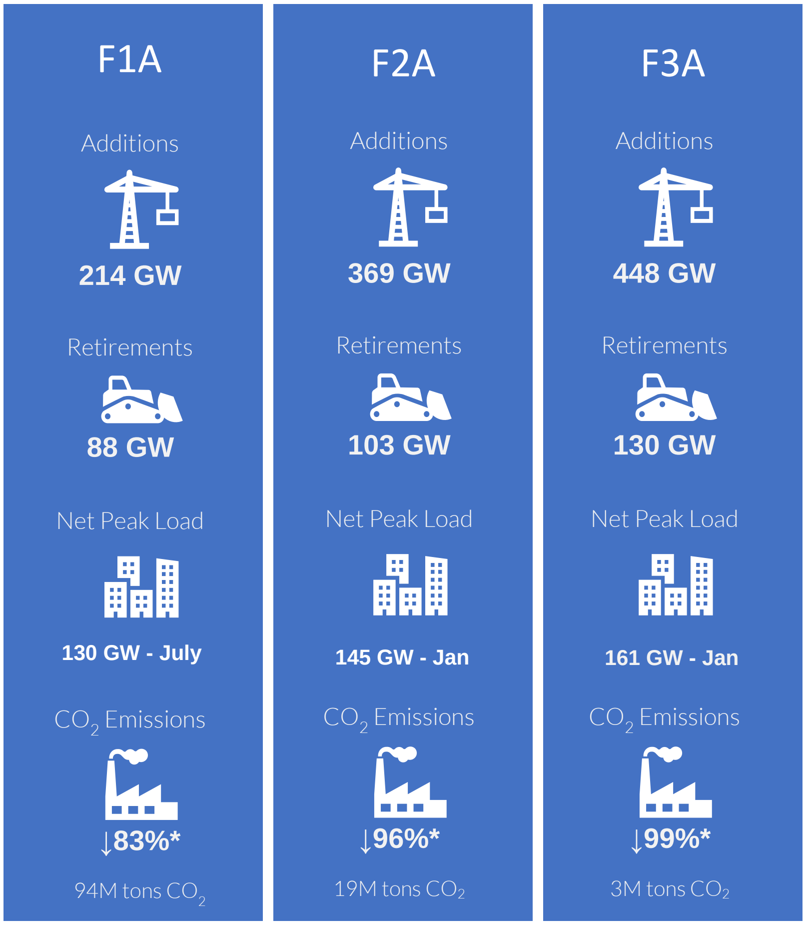


Figure 2: Summary of Future Scenario Impacts (Dec 31, 2042)

Future 1A Assumptions – Future 1 reflected substantial achievement of state and utility announcements, with a 40% decarbonization assumption.[4] Future 1A continues to incorporate 100% of updated utility integrated resource plan (IRP) announcements and state legislation. Updated non-IRP utility goals and non-legislated state goals are applied at 85% of their respective levels to hedge the uncertainty of meeting them. Accordingly, Future 1A incorporates 71% decarbonization for the MISO system. Future 1A assumes that demand and energy growth are driven by existing economic factors, with small increases in EV adoption, resulting in an annual energy growth rate[5] of 0.22%.

Future 2A Assumptions – Future 2 incorporated 100% of utility IRPs and announced state and utility goals within their respective timelines, and a 60% decarbonization assumption. To align with 100% achievement of updated member utility goals, F2A therefore incorporates 76% decarbonization for the MISO system. Future 2A introduces an increase in electrification, driving an approximate 0.8% annual energy growth rate.

Future 3A Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including an 80% carbon dioxide reduction since the updated member utility goals in aggregate did not exceed this level of MISO-wide decarbonization. Future 3A requires a minimum penetration of 50% wind and solar and introduces a larger electrification scenario, driving an approximate 1.08% annual energy growth rate.[105]

The Futures utilized announced goals and other input assumptions through October 2022 to represent a snapshot in time. Since the modeling of the Series 1A Future scenarios, new announcements and updates to utility and state goals have been publicized. While the Futures assumptions above summarize each scenario's inputs, Figure 2 details several key results of the modeling. For example, while Future 1A included a 71% carbon reduction trajectory, the model resulted in 83% carbon reduction. Additionally, "net peak load" results refer to peak load values, net of load-modifying resources.

[4] Carbon emission reduction in Future scenarios refer to power sector emissions across the MISO footprint from a 2005 baseline.
[5] Futures energy growth rates are compound annual growth rates (CAGR).

A Note on Data Reporting within this Report —

The Futures resource expansion modeling tool assumes that all new units are installed on January 1 and retiring units are retired on December 31, regardless of the actual unit addition/retirement date. Timing of unit additions and retirements determines the resulting annual fleet installed and estimated accredited capacity snapshots, depending on selection of beginning- or end-of-year reporting (BOY, EOY respectively).

Materials presented during the development of the Futures Refresh, prior to the publication of this report, utilized a BOY outlook.[6] To standardize data reporting across vintages of Futures cohorts and to capture all additions and retirements taking place between 2023 and 2042, the data and charts following this section of the report will use an EOY annual snapshot, reflecting retirement of units within the illustrated year.[7]

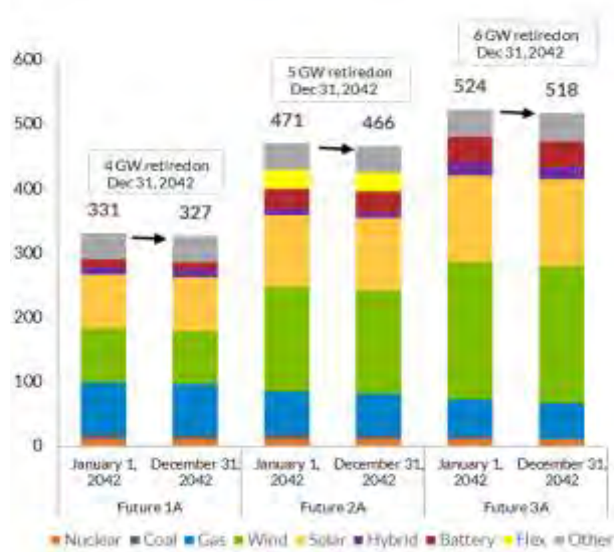


Figure 3: 2042 annual fleet installed capacity snapshot utilizing both beginning- and end-of-year reporting.

Figure 3 shows the difference in BOY and EOY 2042 installed capacity across all three Futures, due to unit retirements in the Futures resource expansion modeling tool taking place at 24:00, December 31, 2042. Figure 4 provides the BOY (left) and EOY (right) view of Future 2A, the focus of the LRTP Tranche 2 analysis.

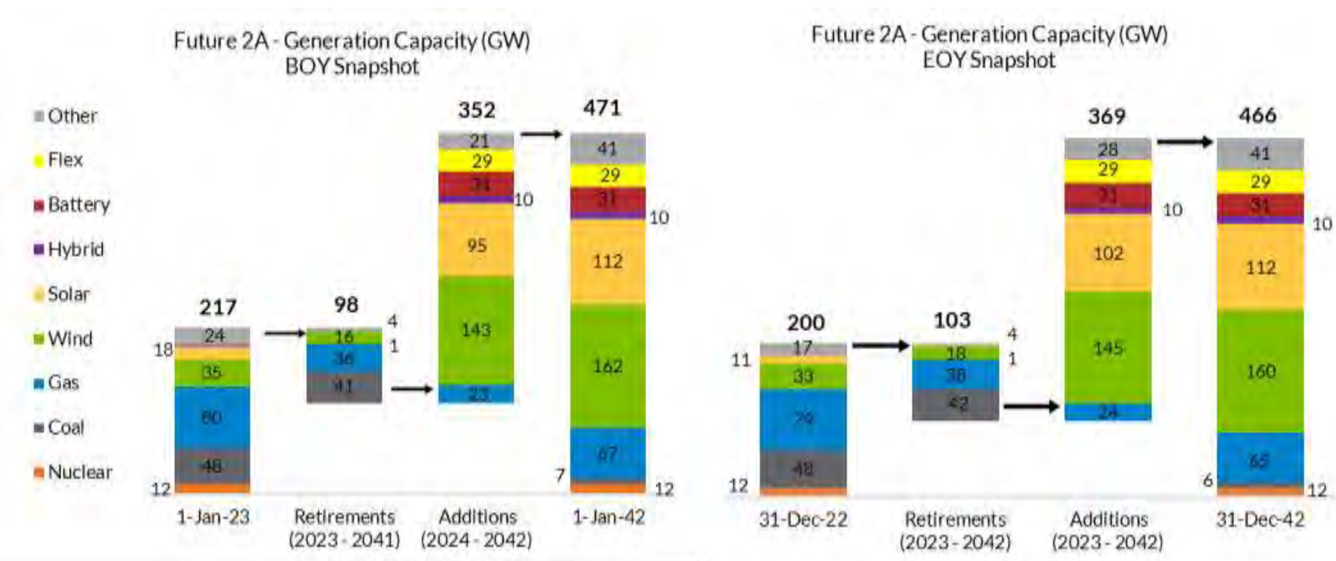


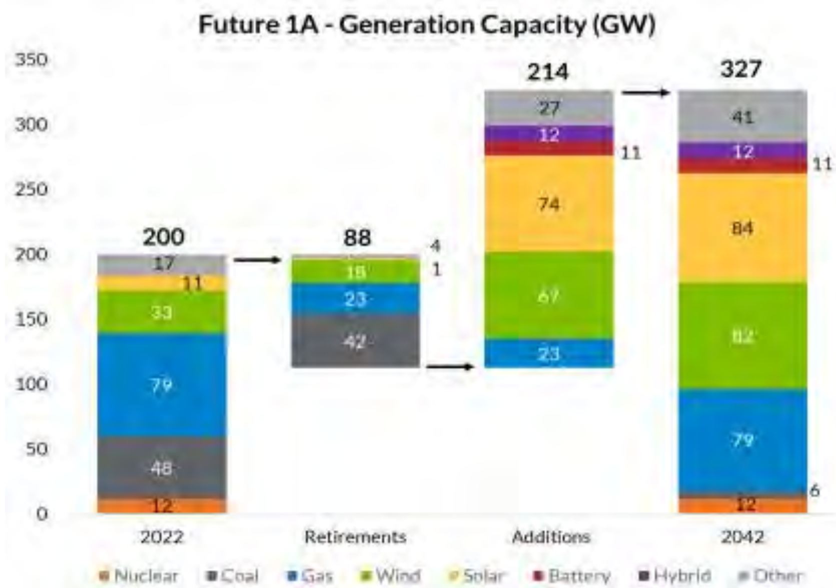
Figure 4: BOY and EOY Outlook for Future 2A Generation Capacity (GW)

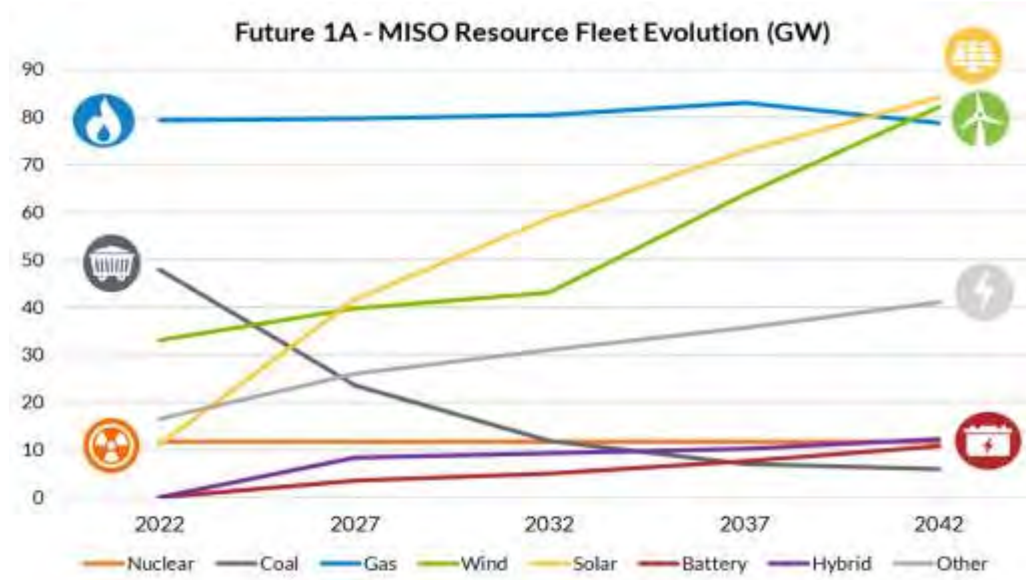
[6] Presentation Materials for development of Series 1A Futures

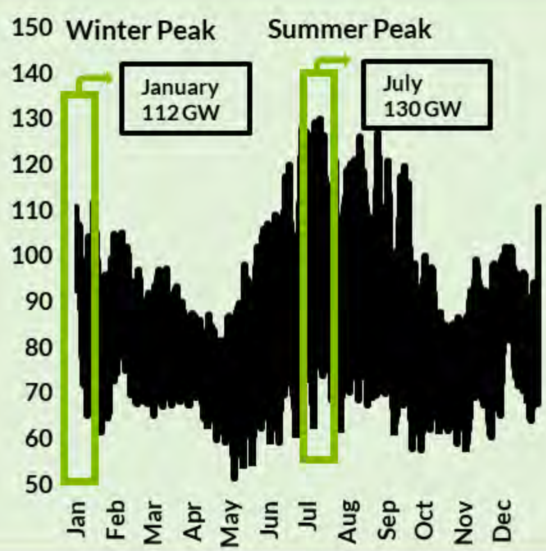
[7] Estimated Accredited Capacity with net load, in each respective Futures' expansion results, are reported utilizing a BOY snapshot for consistency with net load output reporting from the resource expansion modeling tool, EGEAS.

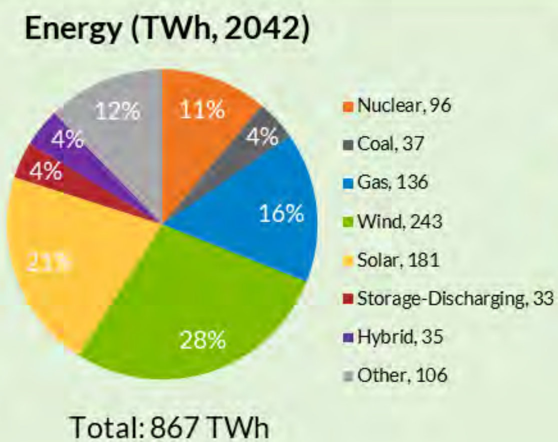
Future 1A Results

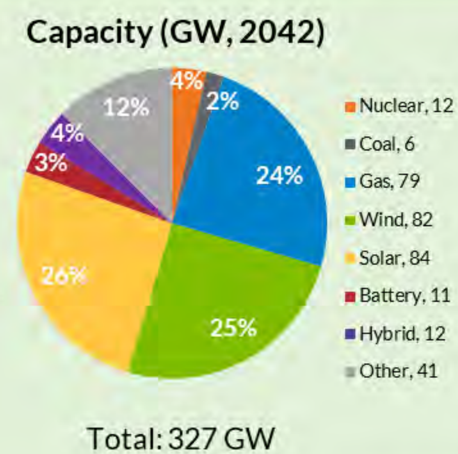
This Future assumes demand and energy growth are driven by existing economic factors, with small increases in EV adoption. Modeling for Future 1A results in the retirement of 88 GW and the addition of 214 GW of resources to the MISO footprint.









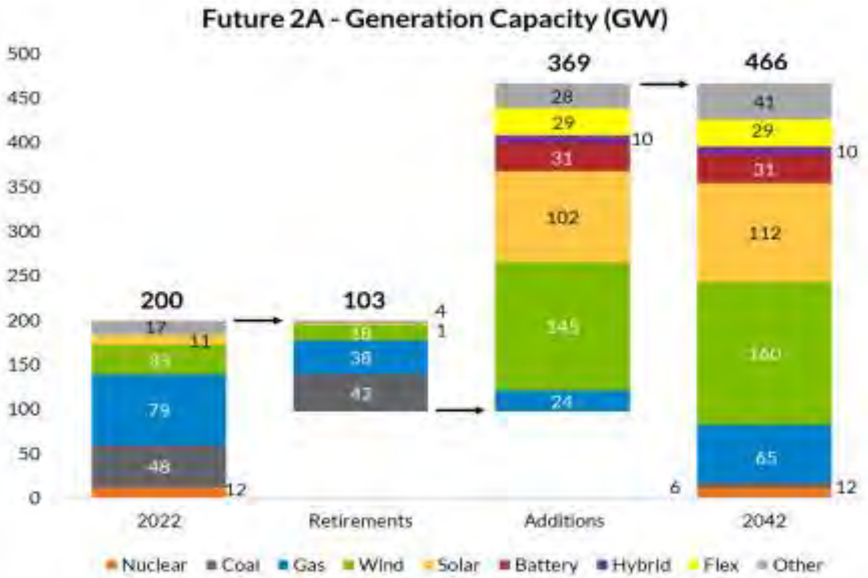


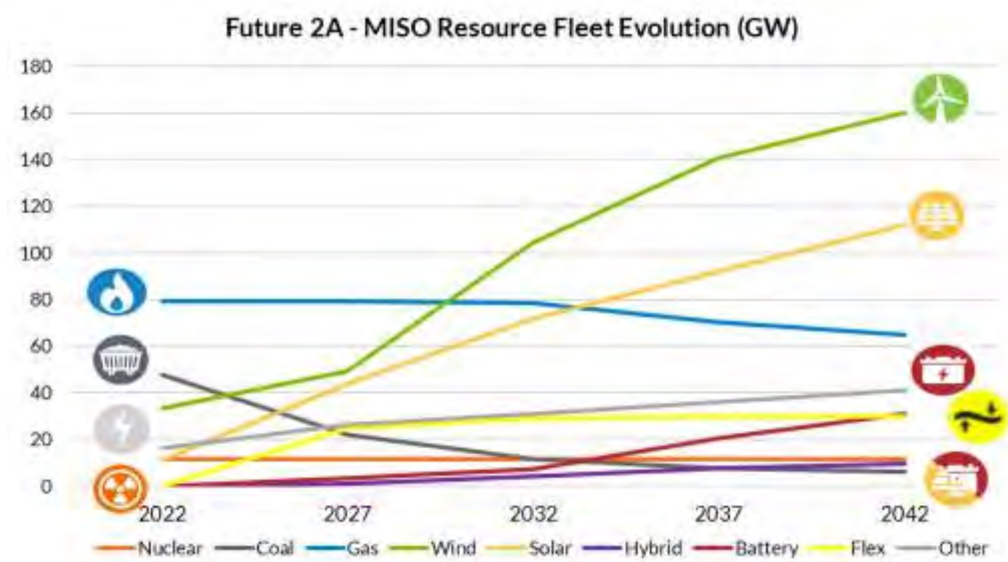
Decarbonization
Input: 71%
Results: 83%
Announced Plans
Goals Met: 85%
IRPs: 100%
Forecast % Increase
Energy: 4.4%
Demand: 7.5%
Compound Annual Growth Rates
Energy: 0.22%
Demand: 0.36%

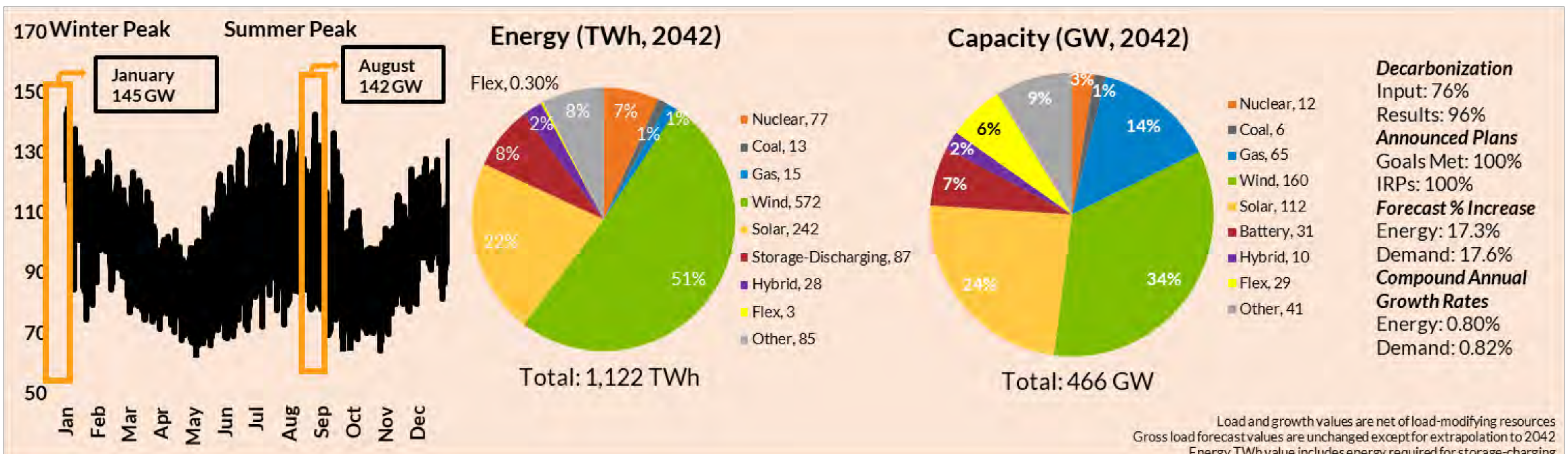
Load and growth values are net of load-modifying resources
Gross load forecast values are unchanged except for extrapolation to 2042
Energy TWh value includes energy required for storage-charging

Future 2A Results

Due to retirements and increased electrification, moderate increases in demand and energy cause Future 2A's load shape to have a slightly larger peak in the winter but remain relatively dual-peaking. Modeling of Future 2A results in the retirement of 103 GW and the addition of 369 GW of resources to the MISO footprint.

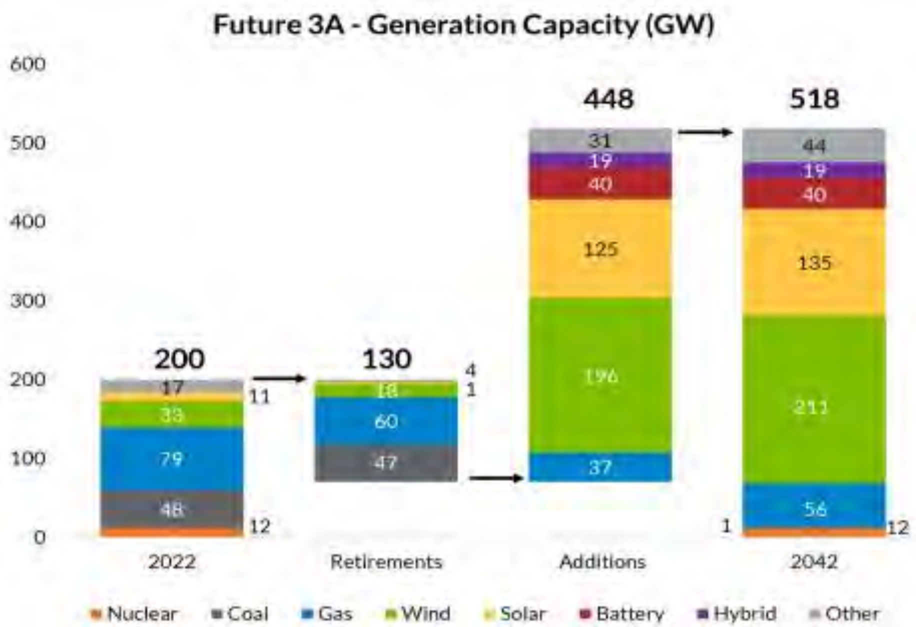


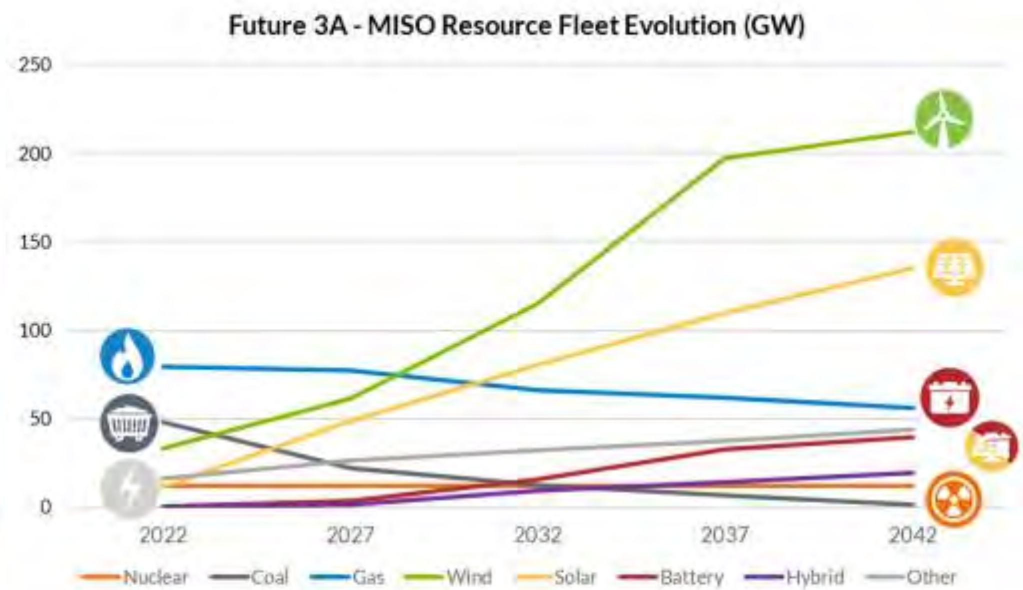


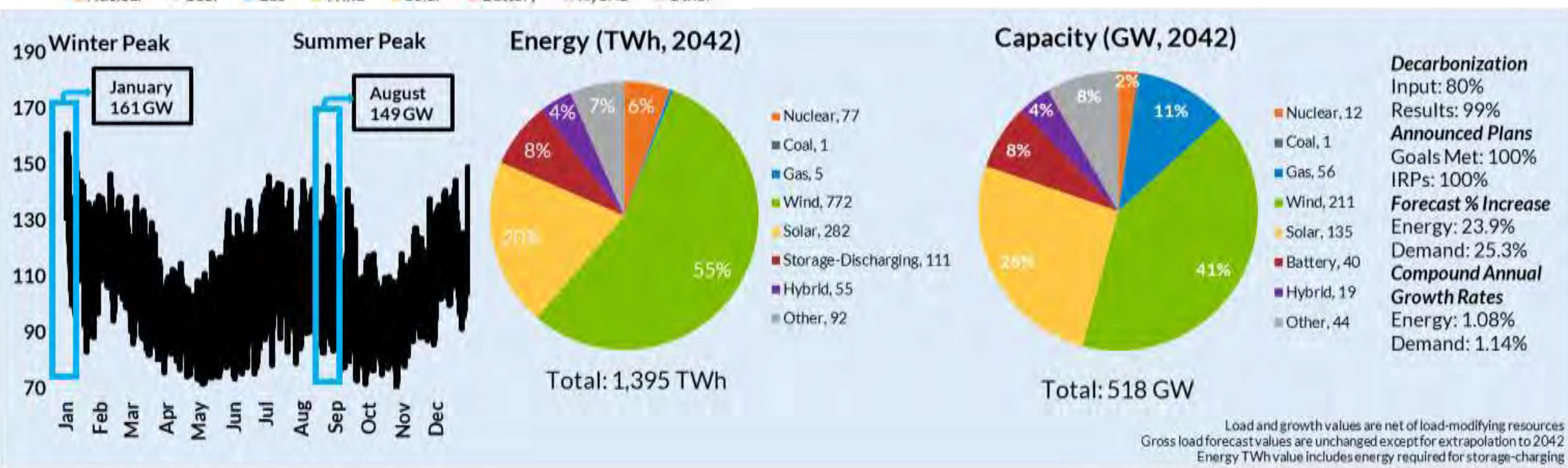


Future 3A Results

Due to retirements, decarbonization, and electrification, large increases in demand and energy cause Future 3A's load shape to peak in the winter. Modeling of Future 3A results in the retirement of 130 GW and the addition of 448 GW of resources to the MISO footprint.







MISO Futures Purpose and Assumptions

The energy industry is evolving in profound ways, with MISO members and states announcing increasingly advanced decarbonization and clean energy goals due to changing economics, environmental regulations, technological advancements, state and federal policies, and consumer preferences for cleaner energy. Over 75% of MISO's load is served by member utilities with such ambitious plans, creating new challenges and complexities in the realm of resource planning. Although MISO is not a resource planner and does not have authority over generation planning decisions or resource procurement, member and state plans often do not provide resource information for the full 20-year study period. This creates a resource "gap" which MISO fills through resource expansion analysis. To hedge uncertainty and "bookend" a range of economic, political, and technological possibilities over the 20-year study period, MISO's regional resource expansion analysis is performed on multiple planning scenarios called the MISO Futures. The MISO Futures resource expansion analysis seeks to find the optimal resource buildout that minimizes the overall system cost while meeting reliability and policy requirements.

As a key element of the Long-Range Transmission Planning (LRTP) initiative and the Reliability Imperative, the MISO Futures and their respective resource expansion plans set the foundation for MISO's long-term transmission planning analysis in identifying valuable transmission solutions that help enable members' and states' plans in a reliable and cost-effective manner. As part of Tranche 1 of the LRTP initiative, MISO collaborated with stakeholders to develop a cohort of three future planning scenarios, which are now referred to as the Series 1 Futures. This cohort of Futures was developed over an 18-month period beginning in mid-2019 through the end of 2020 and was the foundation of the LRTP Tranche 1 analysis, used to justify a $10.3 billion portfolio of new transmission investments unanimously approved by the MISO Board of Directors on July 25, 2022.

The Future scenarios in this document represent a "refresh" of the Series 1 Futures, in which the original number and defining characteristics of that cohort of Futures is preserved while providing an opportunity to update the input data. To help distinguish the *updated* Series 1 Futures from the *original* Series 1 Futures, the "refreshed" Series 1 Futures are now referred to as the Series 1A Futures. Series 1A was necessary because members' and states' plans were refined, new legislation and policies took effect, and prices, along with incentives, for various resources saw significant changes since the development of the Series 1 Futures three years ago. The collaborative effort to refresh Series 1 to create the Series 1A Futures began during the summer of 2022 and concluded during the fall of 2023. Results from the Series 1A Futures refresh continues to reflect that a significant fleet transition is underway over the next 20 years. However, when compared to the Series 1 Futures results, the pace of the transition is accelerating.

This report documents the process and results of Series 1A, which continues to enable the diverse plans and goals of MISO's members and states. Assumptions within the three Future scenarios vary to encompass reasonable bookends of the MISO footprint over the next two decades. Future 1 represents a scenario driven by state and members' plans, with demand and energy growth driven by existing economic factors. Future 2 builds upon Future 1 by fully incorporating state and members' plans and includes a significant increase in load driven by electrification (discussed in the Electrification section of this report). In the final scenario analyzed, Future 3 advances from Future 2, evaluating the effects of large load increases due to electrification, increased penetration of wind and solar, and decarbonization.

Series 1A and subsequent Futures series will continue to capture transformation within the MISO footprint, reflecting updates and serving as the foundation for forthcoming MISO initiatives. The "A" suffix signifies the first round of studies with refreshed input data, albeit without changing the assumptions of the parent study. F1A, F2A, and F3A thus update the original Series 1 MISO Futures with refreshed input data, while maintaining their definitions. As illustrated in the diagram below, if MISO elected to perform another refresh on Series 1, those Futures would be called F1B, F2B, and F3B. These iterations are a product of continued collaboration between MISO and its stakeholders.

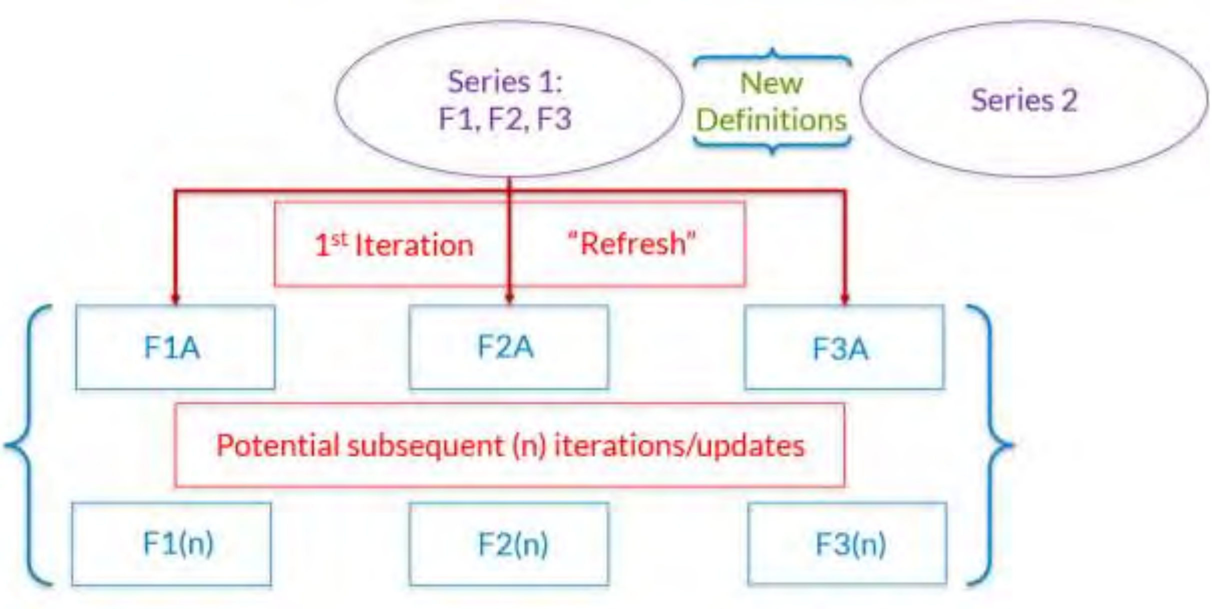


Figure 5: Potential Futures Series

Changing Energy Across MISO

Cities, states, large commercial and industrial corporations, and utilities are exploring and setting decarbonization goals that often include reaching 100% clean energy supply or net-zero carbon emissions by 2050. Although not all states and utilities share these clean energy goals, a fleet transition of this magnitude will have implications on what transmission will be needed across the MISO footprint to ensure reliability of the grid. The role of MISO is to remain resource-agnostic and to ensure a reliable and economic Bulk Electric System in an ever-changing environment.

Throughout the analysis of each Future scenario, MISO incorporated specific state and utility goals relative to carbon and renewable energy percentages into the models. Decarbonization was modeled in three aspects per Future. First, models converted utility goals into relative percentages of MISO and aggregated them into system-wide reduction trajectories. Second, state-specific reductions were applied, depending on generating resource locations. Third, to capture impacts of the Climate and Equitable Jobs Act (CEJA), unit-specific emissions were modeled for eligible units in Illinois.

Similarly, renewable goals were modeled by converting utility/state goals into relative percentages of MISO and taking the summation of these values to create footprint trajectories. Resources were assigned to their respective areas in the siting process.

Internal analysis indicates the MISO footprint has decarbonized by 35% since 2005. Early thermal retirements, public announcements, and evolving IRPs support MISO's preparation for a broad range of Future scenarios, enabling continual adaptation to the changing energy landscape while ensuring better grid reliability.

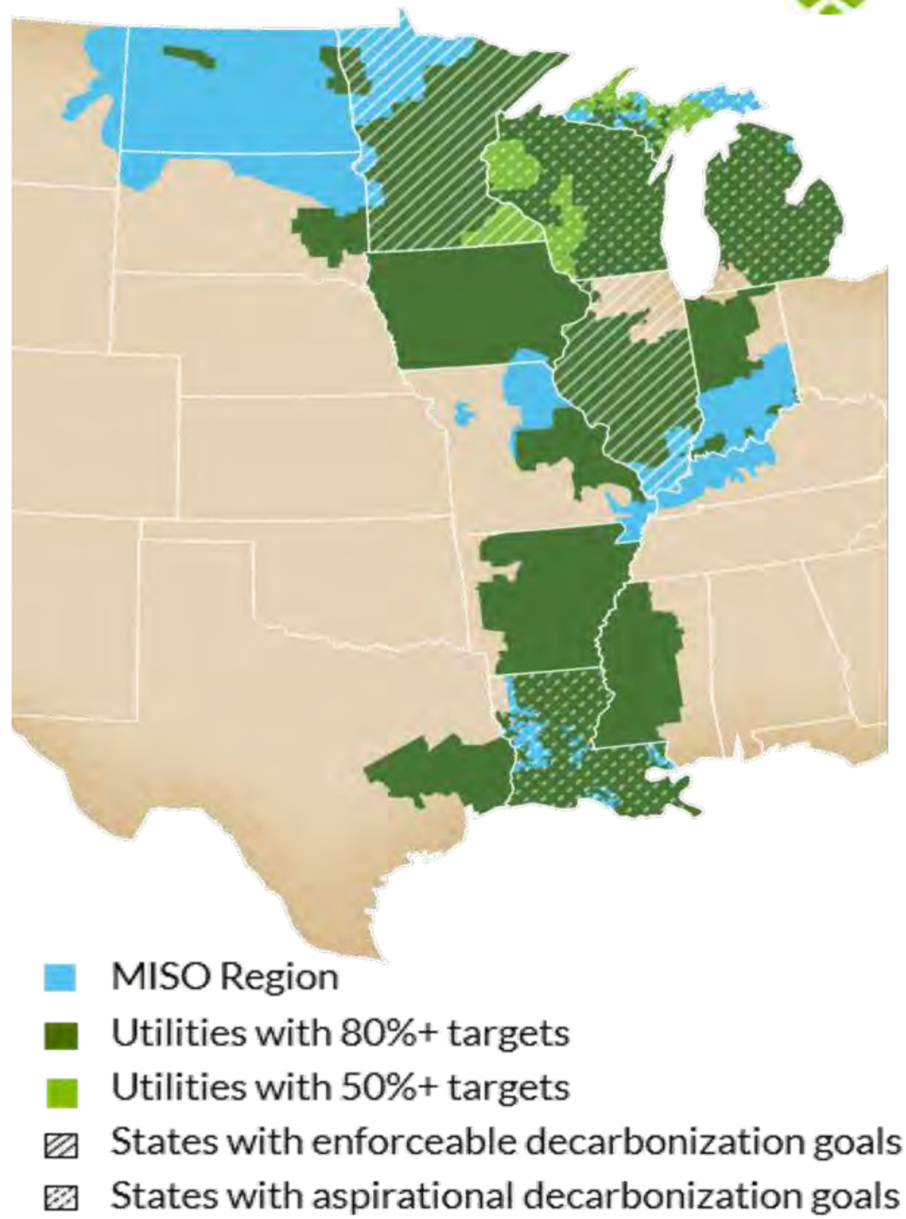


Figure 6: Clean Energy Goals above 50% Across Footprint

State and Utility Clean Energy Goals

Today, state and utility policies and goals are changing rapidly and continued to do so during the Series 1A process, regarding decarbonization, renewable energy, and unit retirements. To best account for these changes, MISO continuously updated these announced goals until the Series 1A stakeholder feedback window closed in April 2023.

When collecting goal announcements, MISO staff examined companies' IRPs, state publications, and results from the MISO/OMS State Data Survey. (OMS refers to the Organization of MISO States). Survey data from MISO's 2022 Regional Resource Assessment (RRA) was incorporated. Once this information was compiled, MISO compared unit addition announcements with signed generation interconnection agreements (GIA) in its queue to ensure that these units would not be double counted. MISO then added planned units into the base model to account for MISO members' and states' plans. These units had a variety of fuel types and contained announced additions throughout the study period (2023-2042). Throughout the model-building process, from July to October 2022, MISO also adjusted goals and incorporated unit-level revisions to planned and existing resources received through direct stakeholder engagement and feedback. Further base model updates were made considering stakeholder feedback during the siting process, starting in Spring 2023.

From Figure 6, it is apparent that much of the footprint has a clean energy goal greater than 50% (whether from decarbonization, renewable energy or both).[8]

Table 1 displays state and utility goals within the model, overlapping by service area. When considered together, over 75% of MISO's load is being served in states or by members with such ambitious plans. In this analysis, MISO considered current trends but also had the opportunity to look beyond and plan for a range of Future scenarios to bookend plausible possibilities over the next 20 years.

Climate and Equitable Jobs Act (CEJA)

The previous section noted that the Futures process endeavors to account for rapidly changing policies and goals among MISO's member states and utilities. One particular policy incorporated by the Series 1A Futures is Illinois' Climate and Equitable Jobs Act (CEJA), enacted in September 2021. Among other provisions of the law, the ones that significantly impact our Futures models are the following:

• ***Slash climate-changing carbon pollution by phasing out fossil fuels in the energy sector***. This provision requires Illinois to achieve a 100% zero-emissions energy sector by 2045, with significant emission reductions before then. Although the legislation does not spell out any annual statewide carbon emissions cap trajectory to attain the 100% zero-emission mark by 2045, it does mention certain guidelines on how to phase out the carbon emissions, with interim milestones applicable to certain units. These guidelines prioritize the ownership of the units, fuel category, and environmental justice in charting out a trajectory for Illinois to join the ranks of states with carbon-free power by 2050. All natural gas facilities must eliminate greenhouse gas (GHG) emissions by 2045 and all coal facilities must eliminate emissions by 2035. Additionally, there are intermediate deadlines based on characteristics of the facilities that stipulate accelerated phaseout dates for some plants.

- Private oil and coal generating facilities must phase out by 2030.

[8] Utility goals are represented with green shading while enforceable state goals of 100% are given white stripe and aspirational state goals of 100% are given white dots.

- Public oil and coal facilities are allowed to continue operation until 2045. Any source or plant with such units must also reduce their carbon dioxide equivalent (CO2e) emissions by 45% from existing emissions by no later than January 1, 2035.
- Public natural gas facilities must phase out by 2045.
- The phaseout of private natural gas facilities is somewhat more involved to expedite the reduction in emissions output and the retirement of resources that produce higher levels of air quality emissions and that are nearer to environmental justice communities.[9] In addition to the phaseout depicted below, private natural gas facilities may not emit, in any 12-month period, CO_2 or co-pollutants more than that unit's existing emissions for those pollutants. The specifications for fossil phaseout required by CEJA are illustrated below.

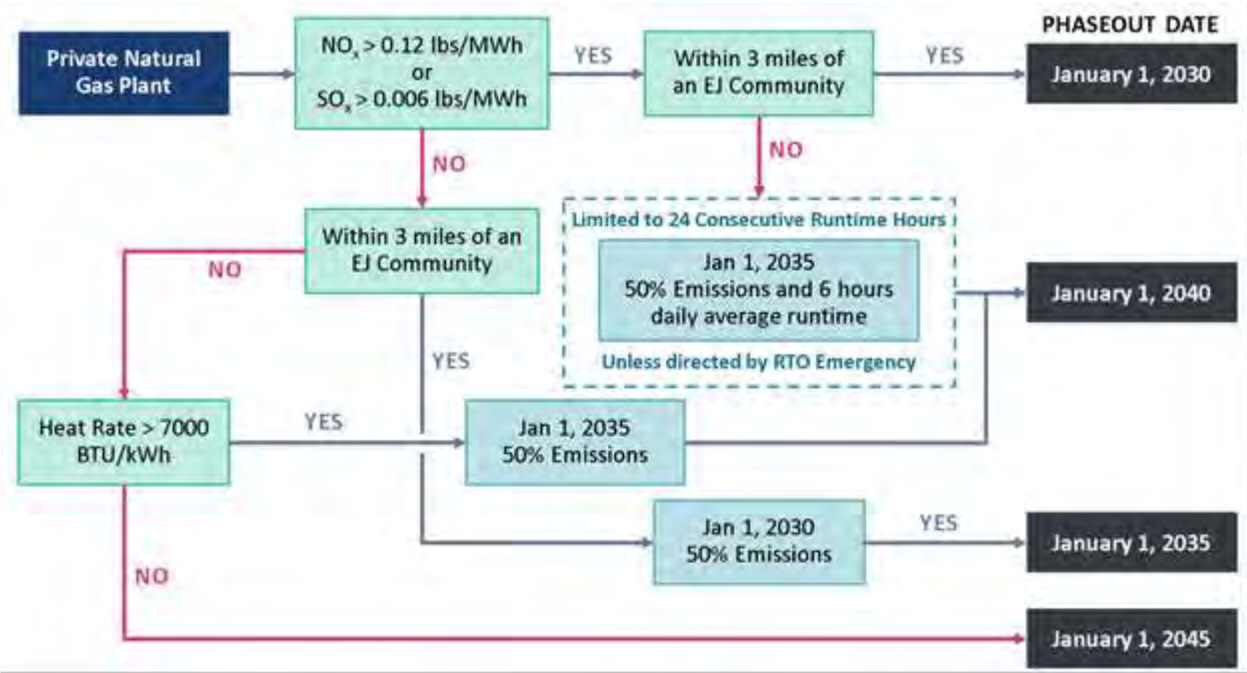


Figure 7: CEJA decarbonization guidelines for private natural gas facilities

• ***Grow renewable energy generation.*** The CEJA expands investments in clean energy and targets a transition to 40% of electricity provided by renewable energy by 2030, 50% by 2040 and 100% from carbon-free sources by 2050.

These provisions under CEJA were applied to the Series 1A Futures. In the study, all Illinois generation facilities fired by coal, oil, and natural gas were set to reduce their emissions (both 100% and any applicable interim targets) based on their fuel type, ownership, heat rates, NO_x and SO_x emissions,[10] and proximity to environmental justice communities per the CEJA guidelines mentioned above. The emission caps for all the Illinois GHG units were implemented in MISO and PJM models by enabling unit emission constraints in EGEAS. The CEJA-mandated RPS goals for Illinois were also used in the study to satisfy the state's targeted transition to 40% of electricity being provided by renewable energy by 2030, and 50% by 2040.

[9] Environmental Justice communities are communities that are most impacted by environmental harms and risks.
[10] Oxides of nitrogen and sulfur

State Clean Energy Goals & RPS5F[11] (source linked)	State	Utility	Utility Decarbonization Goals (2005 Baseline)6	Utility Renewable Energy Goals
RPS: 15% RE by 2021 (IOUs)	Missouri	**Ameren Missouri**	60% by 2030, 85% by 2040, Net Zero by 2045	15% by 2021
		Columbia Missouri Water and Light Department	-	30% by 2029
		Missouri River Energy Services	-	22% by 2027
100% Clean Energy by 2050 RPS: 25% by 2025, 50% by 2042, 100% by 2050	Illinois	**Ameren Illinois**	Carbon Free by 2050[12]	100% by 2050[12]
		Springfield Illinois – City Water Light & Power	Carbon Free by 2050[12]	100% by 2050[12]
		Southern Illinois Power Co-operative	Carbon Free by 2050[12]	100% by 2050[12]
		MidAmerican Energy	7% of MEC's load subject to Illinois state bill SB 2408 which requires 100% clean energy by 2050.[12]	97% by 2025
RPS: 105 MW (completed 2007)	Iowa	**Cedar Falls Utilities**	45% by 2030 (2010 Baseline) .Net Zero by 2050	-
		Alliant Energy	50% by 2030. Carbon Free by 2050	30% by 2030
		Dairyland Power	50% by 2030	12% by 2026
Carbon Free by 2050 (Governor) RPS: 10% by 2020	Wisconsin	**WEC Energy Group**	Carbon Neutral by 2050	10% by 2020
		Madison Gas & Electric	80% by 2030. Net Zero by 2050	30% by 2030. 40% by 2050
Carbon Neutral by 2050 (Executive Goal) RPS: 15% by 2021 (standard), 35% by 2025 (goal, including EE & DR), 50% by 2030 (MI Healthy Climate Plan)	Michigan	**Consumers Energy**	Net Zero by 2040	15% by 2021
		DTE Energy	80% by 2040	15% by 2021
		Michigan Upper Peninsula	Carbon Neutral by 2050	15% by 2021. 35% by 2025
		Upper Peninsula Power	Net Zero by 2050	50% by 2025
Voluntary clean energy RPS, 10% RE by 2025	Indiana	**Duke Energy**	50% by 2030. Net Zero by 2050	-
		Hoosier Energy	-	10% by 2025
		Southern Indiana Gas & Electric	Net Zero by 2035	-
		Wabash Valley Power Association	50% by 2031. 70% by 2040. Net Zero by 2050	-
		NIPSCO	90% by 2030	-
Carbon Free by 2040[13] RPS: 25% by 2025, 55% by 2035	Minnesota	**Xcel Energy**	80% Reduction by 2030. Carbon Free by 2050	60% by 2030
		SMMPA	90% by 2030	75% by 2030
		Minnesota Power	Carbon Free by 2050	70% by 2030
		Otter Tail Power Company	80% by 2042	35% by 2023
		Great River Energy	80% by 2050	50% by 2030
	Montana	**Montana Dakota Utilities Co.**	45% by 2030	-
Net Zero GHG by 2050 (Governor) RPS: 80% by 2050 (Executive Order)	Louisiana	**CLECO**	37.8% by 2030. Net Zero by 2050. (2011 Baseline)	-
City Clean Energy Goals & RPS5F (source linked)	**City**	**Entergy**	50% by 2030. Net Zero by 2050. (2000 baseline)	-
RPS: 70% by 2025, 100% by 2040	New Orleans			

Table 1: Modeled State & Utility Goals - Service Area Overlay

[11] DR: demand response; EE: energy efficiency; GHG: greenhouse gas; IOU: investor-owned utility; PS: portfolio standard; RE: renewable energy; RPS: renewable portfolio standard

[12] State of Illinois, state bill SB 2408

[13] MN Clean Energy Legislation passed February 2023. Utility goals developed before MN legislation were honored, in addition to the statewide legislation.

Inflation Reduction Act

In August 2022, President Joe Biden signed into law the Inflation Reduction Act of 2022 (IRA). Its chief areas of focus pertaining to the energy sector include expediting the shift from fossil fuels to clean energy, decarbonizing the American economy, and accelerating domestic production of renewable energy infrastructure. The IRA will achieve these ends primarily via economic incentives, such as tax credits for clean energy, electric vehicles, and upgrades related to energy efficiency and building electrification; totaling over $370 billion in all. These provisions are accompanied by a series of bonus credits that reward developers who use domestically sourced input materials, conform to fair labor practices, and promote energy justice via infrastructure growth and economic development in historically underserved communities and those negatively impacted by decarbonization.

The most direct effects of the IRA on MISO's Futures occur due to the Act's expansion of the Production Tax Credit (PTC) and Investment Tax Credit (ITC). Both of these tax credits provide enhanced economic incentives for qualifying wind, solar PV, and other renewable energy facilities. While the PTC and ITC were already in effect prior to the IRA's passage, they were scheduled to gradually phase out by the end of 2022. The IRA restores them to their full amount and extends them both for a minimum of 10 years, with the possibility of phaseout contingent upon attaining economy-wide decarbonization goals. Furthermore, the resources that qualify for the tax credits have been expanded: while the PTC was originally only applicable to wind projects, it can now also be applied to solar and solar hybrid projects; and the ITC is now also available for standalone storage facilities.

Both the PTC and ITC are subject to numerous credit-modifying provisions, which can either reduce or enhance their value. By default, both credits are reduced by 80% from their original value. However, the credits are restored to their full amount for all projects whose development meets prevailing wage and apprenticeship requirements; as these requirements are well-established standards in their respective industries, Series 1A models use the full value of each tax credit as its baseline assumption. PTC- and ITC-eligible projects that are constructed with a minimum threshold of domestically sourced content and/or that are sited in an IRA-defined "energy community" can also receive a 10% bonus credit for meeting each requirement.

The IRA contains numerous other provisions unrelated to the PTC and ITC that may still have an impact on the MISO footprint, though not as directly on the Futures. A host of low-carbon, no-carbon, and clean energy resources are also eligible for tax credits; new resources may appear with greater frequency in the Generator Interconnection Queue as they become more economical. Several economic incentives are directed at individual ratepayers rather than developers. Many consumers who make a qualifying purchase of an electric vehicle (EV) will be eligible for a tax rebate, potentially leading to an increase in EV sales, and thus load. Additional investment is also provided for building electrification, weatherization, and energy efficiency upgrades.

Ultimately, the economic components of the IRA will accelerate the energy transition. As the PTC and ITC return to their full, pre-phaseout values, developers will be able to take advantage of decreased capital costs, increasing growth in renewable capacity in the MISO footprint, especially of wind and solar resources. However, the availability of bonus credits for domestic content may delay the full impact of the IRA, as domestic supply chains for wind, solar, and battery infrastructure are still comparatively nascent; as such, supply chains may need to mature further in order for developers to take full advantage of the IRA's economic benefits. Series 1A assumes an incremental expansion of eligibility for bonus credits; a table depicting the implementation of these bonus credits can be found in the Futures Refresh Assumptions Book.

Other provisions of the IRA will also impact load. Tax credits for EVs and for building electrification will likely increase the total load on the MISO footprint.

System-Wide CO_2 Modeling

In addition to state and utility renewable goals, each Future scenario applied decarbonization goals. Each of the three Futures contained a minimum decarbonization floor; Future 1A was 40%, Future 2A was 60%, and Future 3A was 80%. Although there was a predefined decarbonization floor, each Future could exceed that floor based upon members' and states' goals as well as the economically selected resources within each Futures' expansion.

Unless otherwise noted in

Table 1, all MISO utility and state carbon calculations used a 2005 CO2 emissions baseline. Consistent with Futures assumptions, decarbonization included 100% of IRPs and 85% of other announced goals for Future 1A, while Futures 2A and 3A reflected 100% of members' and states' goals.

From analysis of the current fleet in 2005, MISO emitted 533 million (M) tons of CO2. Figure 8 below illustrates decarbonization for each Future scenario, displaying the tons of carbon emitted (bars) and the percentage of carbon reduction from the 2005 baseline (lines). The dotted line projects the historical trend of carbon emissions that MISO is assumed to have for comparison. The Future scenarios in this document allow for insights on how quickly carbon reduction across the footprint may occur. By the end of the study period, emissions reduced by 83% in Future 1A, 96% in Future 2A, and 99% in Future 3A.

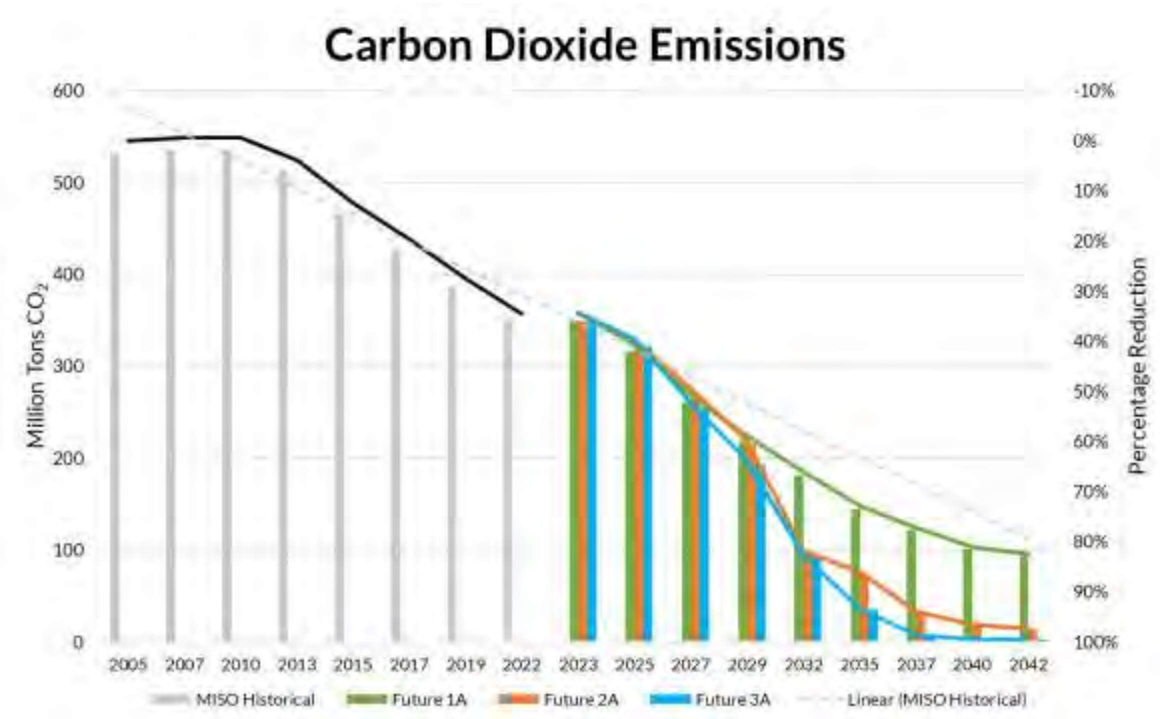


Figure 8: CO_2 Reduction Results (from 2005 Baseline)

Resulting Wind and Solar Penetration Levels

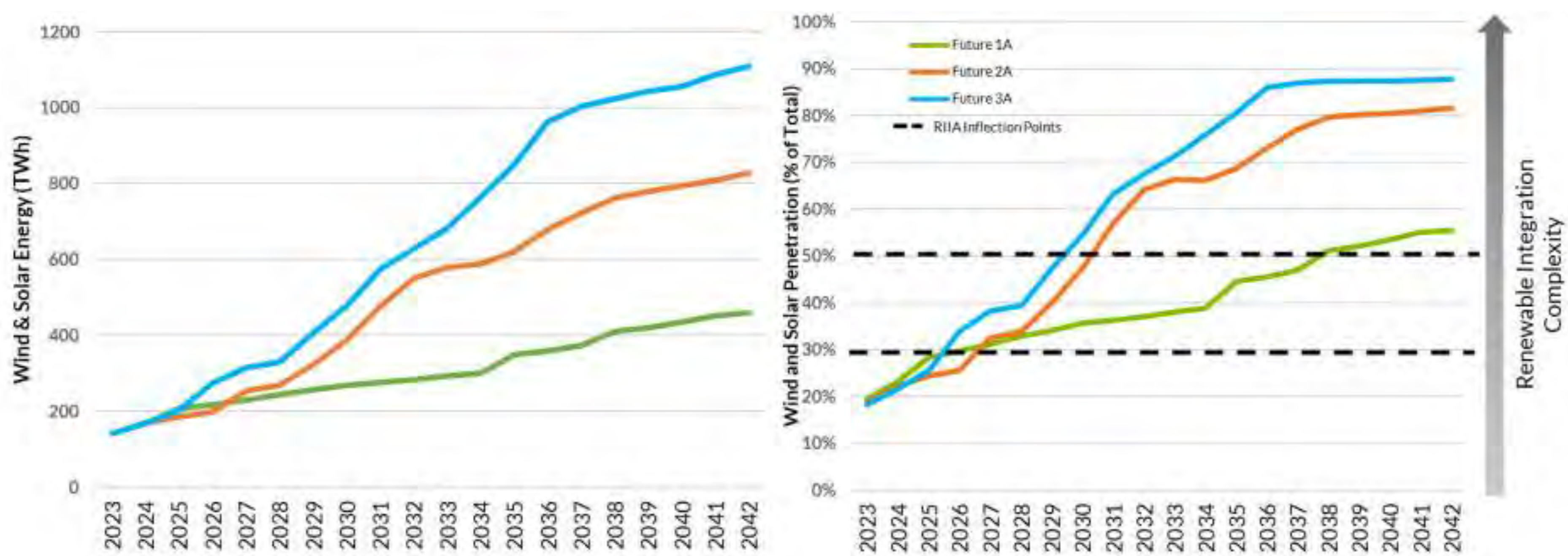


Figure 9: Wind and Solar Energy Generation Throughout Study[14]

[14] Wind and Solar Penetration (% of Total) reflected is based on total energy production, net storage-charging.

Future Capacity Factor Trends

As renewable penetration rises across the MISO footprint, renewable resources are called upon with higher frequency to meet load while ensuring compliance with member RPS and carbon reduction goals. Increased deployment of batteries and other storage resources allows those renewables to be utilized with greater efficacy, serving customer load even during periods of low generation. Consequently, thermal resources are dispatched progressively less across each Future, resulting in a gradual decrease in capacity factor for these resources.

Figure 10 illustrates the average capacity factor of coal and natural gas resources across the study period. In Future 1A, remaining coal and natural gas resources maintain a de-facto role as baseload generation throughout much of the planning period; coal resources regularly operate at a capacity factor in excess of 60%, while natural gas resources, varying by plant type, behave more similarly to "peaker" plants, operating when wind and solar generation is sparse. In both Future 2A and Future 3A, there is an initial increase in capacity factor for coal to accommodate a changing energy mix before utilization of thermal resources steeply declines from 2030 onwards. As outlined in

Table 1, many emission goals do not take effect until 2030; thermal resources are utilized to meet increased load assumptions before more renewable capacity is added to the system and emission reduction targets take effect.

By the middle of the study period in F2A and F3A, significantly expanded renewable capacity and heightened levels of thermal retirements, discussed subsequently, lead to dramatically reduced capacity factor across all thermal resource types. In Future 3A specifically, remaining thermal resources are only dispatched during a handful of hours throughout the year. As determined by the chronological energy validation, and subsequent addition of flexible attribute units conducted during Future 2A, clean firm generation may be required to address shortfalls during select hours, specifically twilight periods before sunrise or sunset. The Series 1A results provide insight into the value of having flexible resources available to support reliability when needed, even if these units run infrequently in increasingly renewable Futures.

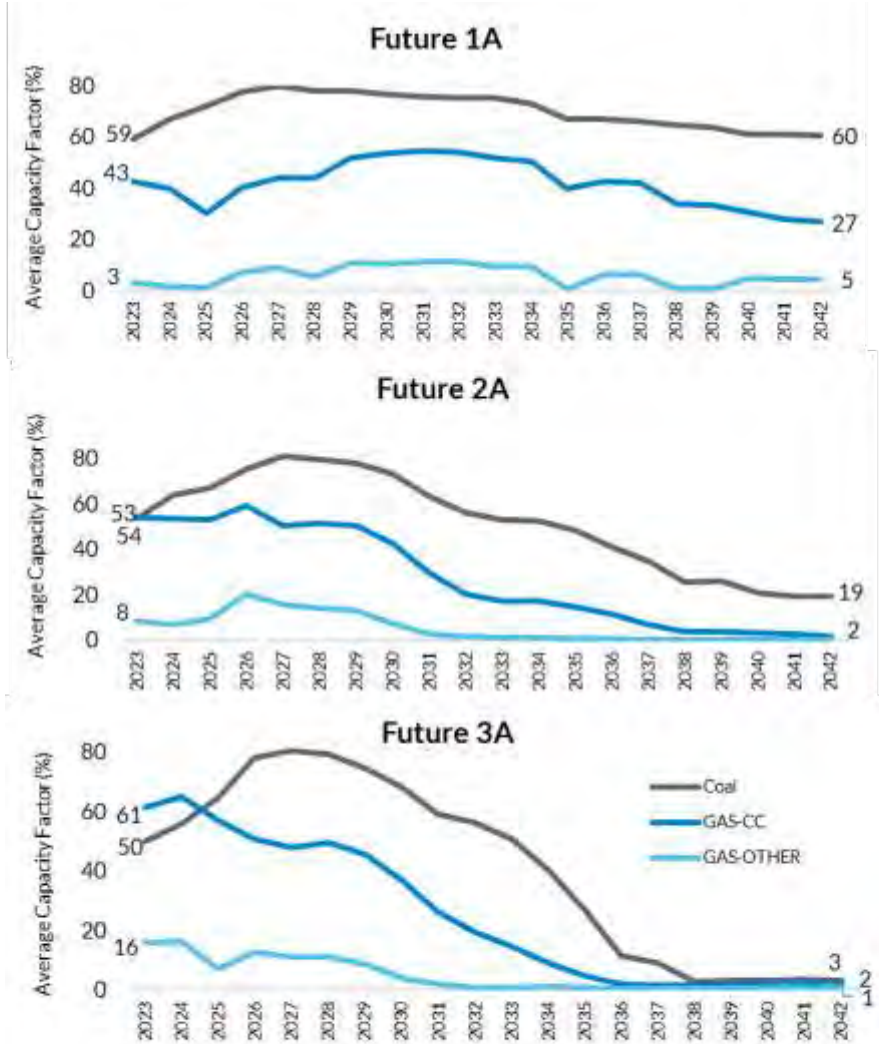


Figure 10: Average capacity factor of coal and natural gas resources across study period.

Divergence of Installed Capacity and Accredited Capacity

Figure 11 provides the projected capacity change (2022 baseline) for all three Futures based on existing and member-planned resources only. Differences in the net change of installed and estimated accredited capacity are driven by the varying age-based retirement assumptions applied to existing resources across Futures.

MISO members include a significant quantity of new resources – primarily wind and solar – increasing total installed nameplate capacity. Having the most conservative age-based retirement assumptions, Future 1A sees nearly a 70 GW increase of installed capacity by 2042 with member-planned resources alone. Future 3A, despite having the most aggressive age-based retirement assumptions, sees an approximate 25 GW increase in installed capacity.

Heightened levels of renewable penetration, when considered with the permanent retirement of thermal resources, result in a substantially higher percentage of renewables amongst MISO members' resources. While this transition may allow members to achieve RPS and decarbonization goals, it also carries implications for accredited capacity. Estimated accredited capacity reflects how much energy resources are expected to produce to meet tight conditions after accounting for historic performance, such as forced outage rates and availability due to weather.

In the model, retiring thermal resources enjoy an accreditation of 95% or greater of their nameplate capacity; in contrast, wind is accredited at 16.6%, while solar accreditation declines to 20% and battery storage receives as low as 75% accreditation by 2042. As the total resource mix shifts towards renewables and away from thermal resources, the average accreditation of resources on MISO's footprint reduces significantly, leading to a net decrease in total estimated accredited capacity despite the significant increase in nameplate capacity. With each Future increasing the total retirement of highly accredited thermal resources, this negative net change in estimated accredited capacity is more pronounced across Futures; Future 1A projects an 18 GW negative change in estimated accredited capacity across the study period, F2A projects a 32 GW negative net change, and F3A projects a 53 GW negative net change.

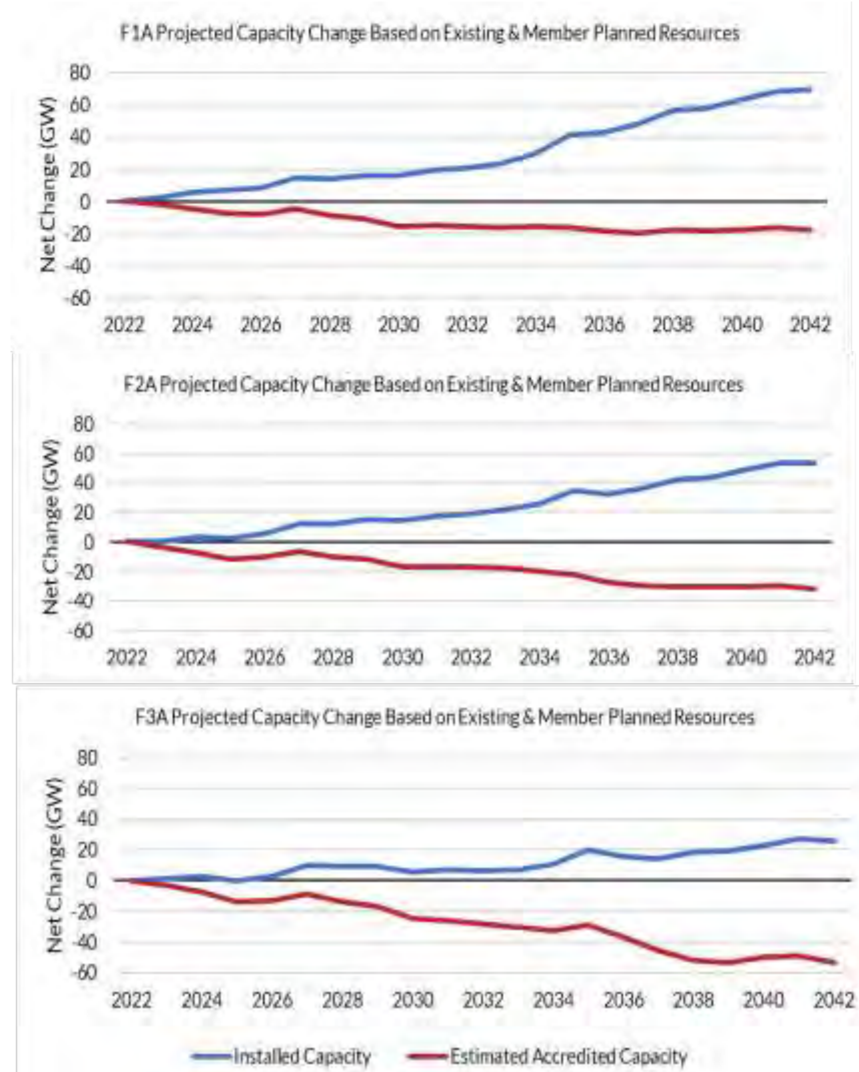
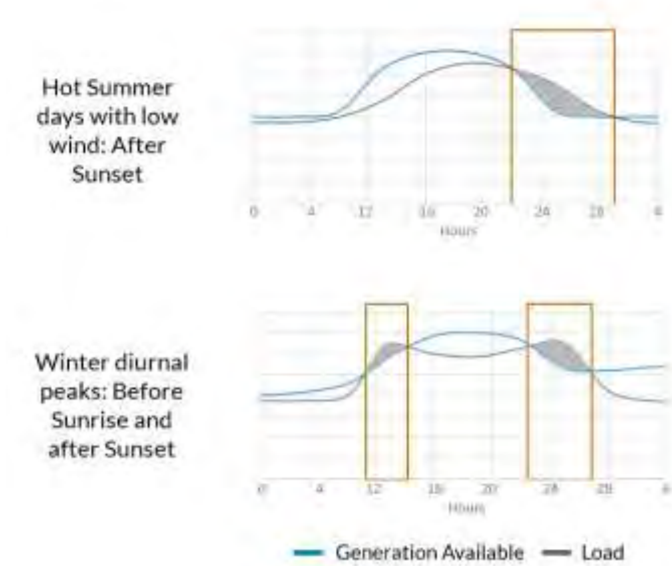


Figure 11: Projected capacity change based on existing resources and member plans (2022 Baseline).

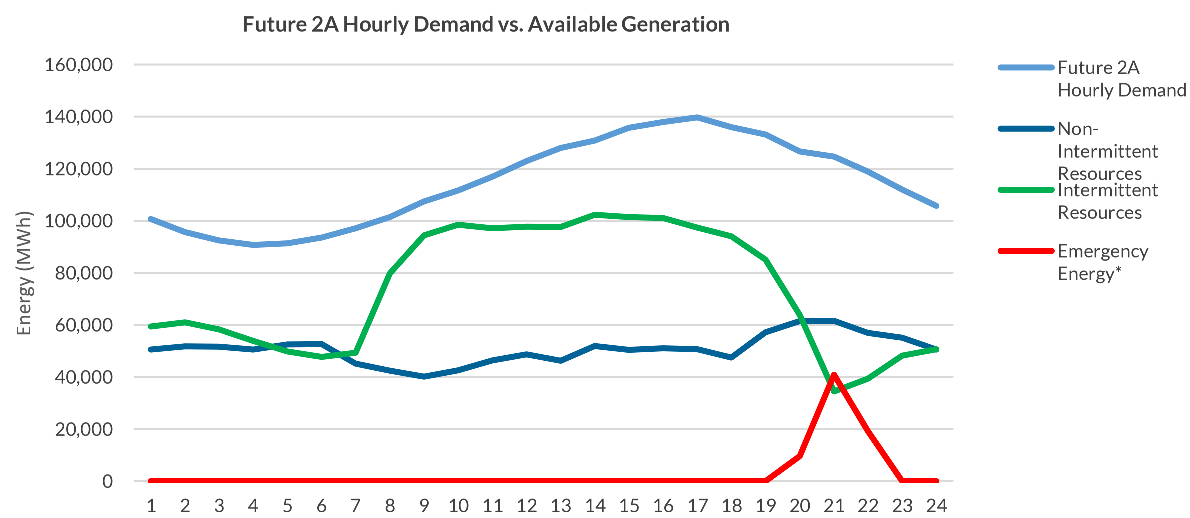
Chronological Energy Validation & Flex Units

In developing Future 2A, MISO observed an opportunity to add value in performing an energy validation of the Future 2A resource expansion results. PROMOD, a production cost modeling tool provided hourly (annual) chronological security constrained unit-commitment and economic dispatch, to identify any energy adequacy shortfall needs that may not have been captured in the MISO Series 1A Future 2A expansion results produced by EGEAS, an unconstrained (transmission-less) non-chronological resource modeling tool. Generation shortfalls were identified for 3-4 hours per day during twilight hours (before sun rise 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, the Futures team added 29 GW of Flexible Attribute Unit capacity to the Future 2A expansion and siting. These "Flex" units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but is not limited to: RICE[15] units, long-duration battery (>4 hours), traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear SMRs,[16] green hydrogen, enhanced geothermal systems, and other emerging technologies.

Flexible attribute units do not displace the need for previously identified resources and, instead, supplement them in periods of energy inadequacy.



[15] RICE: Stationary Reciprocating Internal Combustion Engines (gas-powered)
[16] SMR: Small Modular Reactor

Retirement and Repowering Assumptions

Base Retirement Assumptions

Nuclear and Hydroelectric –
Retirement of nuclear and hydroelectric units will occur when a unit has a publicly announced retirement plan or is listed to retire in an IRP. Otherwise, these units will remain active throughout the study across all Futures.

Age-Based Retirement Assumptions

Age-based assumptions were applied to all the units that fall into any of the categories listed below. However, in cases where these assumptions cause older units in the MISO system to retire before the start of the study period (2023), units will be retired by 2025.

Coal –
Retirement ages of coal units progressively decrease with each Future. It is assumed that with changing policies and emission standards, coal usage will decline further. The coal retirement ages modeled in the three Futures respectively are: 46, 36, and 30 years. The Future 1A retirement age of 46 years is based on the average age of coal units noted by the Energy Information Administration (EIA).

- Coal retirements in each Future are approximately a 80/20, 77/23, and 70/30 split respectively (Future 1A, Future 2A, and Future 3A) between base and age-based retirement assumptions.

Gas –
Retirements for gas units were split into two categories, Combined Cycle (CC) and Other-Gas (e.g., Combustion Turbine [CT], IC [Internal Combustion] Renewable, and Integrated Gasification Combined Cycle [IGCC]). Both unit types were given retirement ages that decreased across the Futures scenarios; retirement ages for CC gas units are: 50, 45, and 35 years and retirements for Other-Gas units are: 46, 36, and 30 years respectively.

- Gas retirements in Future 2A are approximately a 33/67 split between base and age-based retirement assumptions.

Oil –
Retirement ages of oil units decrease across each Future scenario and are 45, 40, and 35 years respectively.

- Oil retirements in Future 2A are approximately a 17/83 split between base and age-based retirement assumptions.

Wind and Solar –
Retirements for utility-scale wind and solar will occur once a unit reaches 25 years of age. However, wind units will be repowered the year following retirement. These will be replaced by a new 100-meter hub height wind turbine with the same capacity as the previous unit but will receive new wind profiles, dependent on location. New profiles have updated capacity factors that are higher than existing wind turbines.

	Future 1A	*Future 2A*	*Future 3A*
Coal	46	36	30
Natural Gas – CC	50	45	35
Natural Gas – Other	46	36	30
Oil	45	40	35
Nuclear & Hydro	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
Solar – Utility-Scale	25	25	25
Wind – Utility-Scale	25	25	25

Table 2: Age-Based Retirement Assumptions

Figure 12 through Figure 14 display the results of differing retirement assumptions across each of the three Future scenarios. Retirement totals were calculated by applying age-based assumptions, announced retirements, and adjusting generation units per stakeholder feedback provided to MISO. Age-based assumptions are the product of Future-specific retirement assumptions, while base retirements are announced by the generator owner, stated in an IRP, or filed with MISO's Attachment Y.[17]

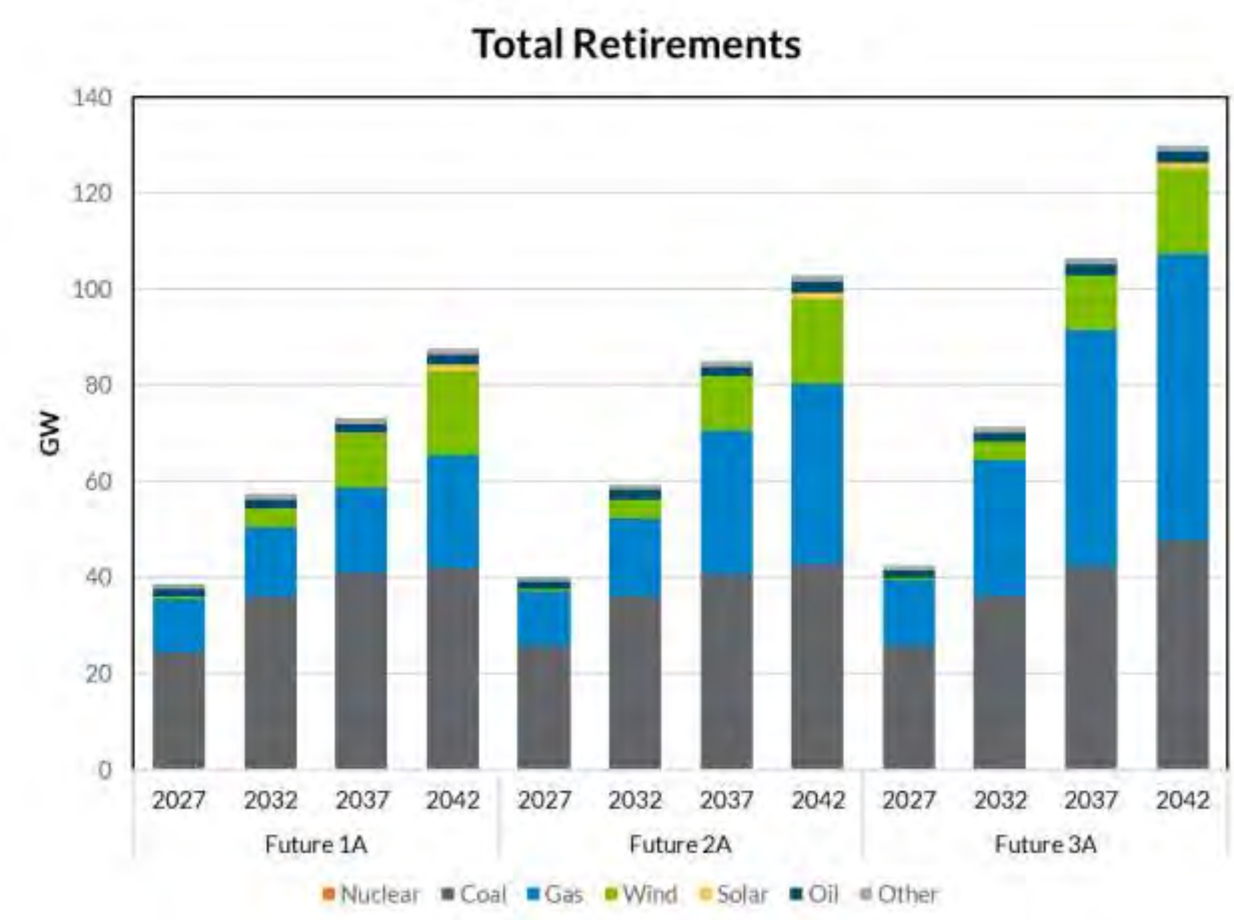


Figure 12: Total Retirements per Future (Cumulative by Year), Equal to Age-Based + Base

[17] MISO's retirement notification process

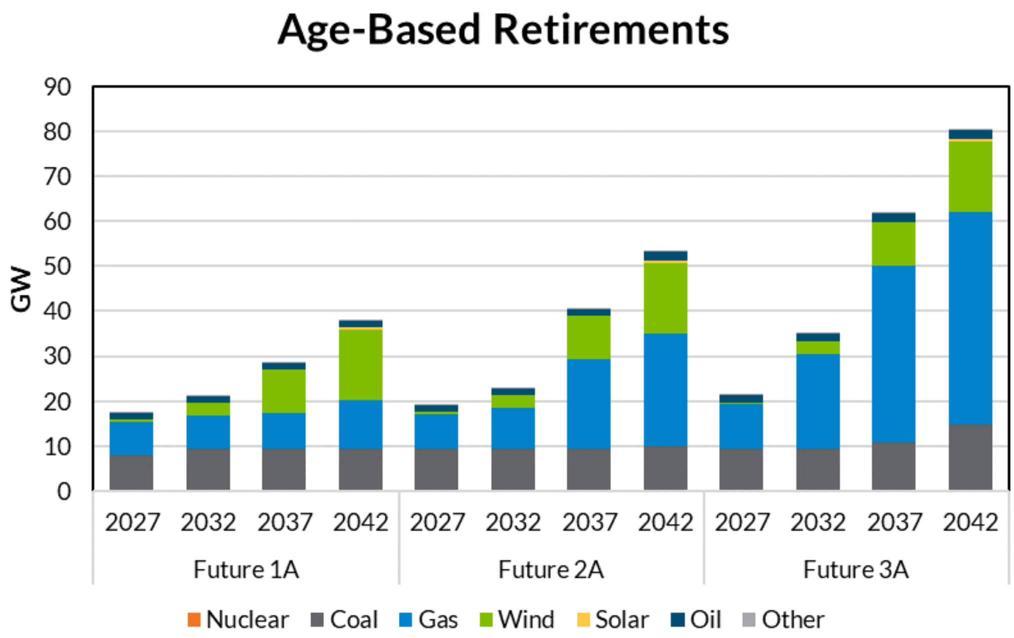


Figure 13: Age-Based Retirements per Future (Cumulative per Year)

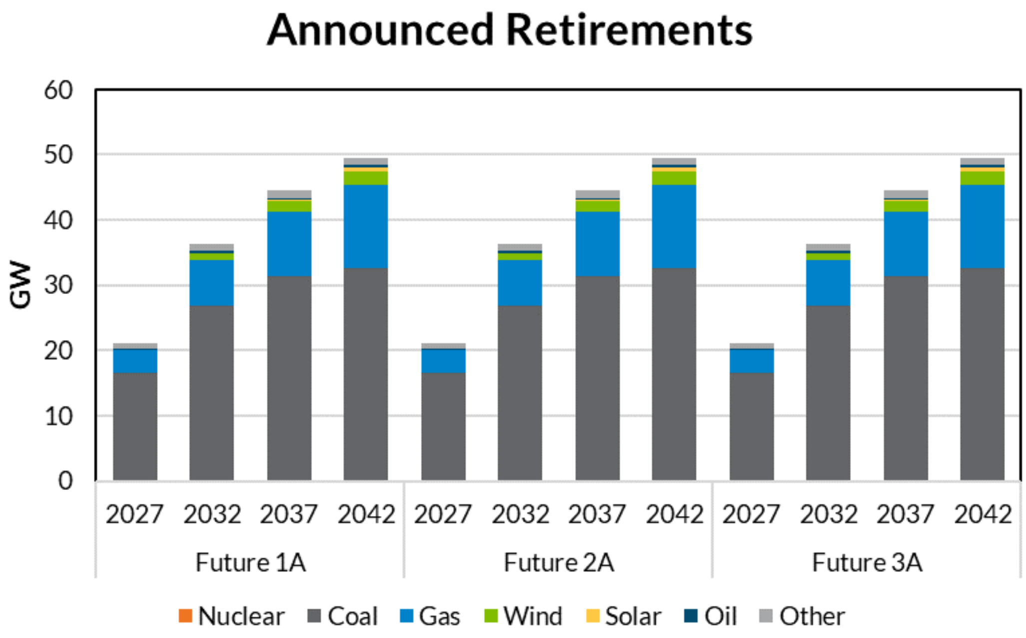


Figure 14: Base Retirements per Future (Cumulative per Year)

Figure 15 through Figure 17 display the results of the Future scenarios' retirement assumptions geographically throughout the MISO footprint. It is important to note that the wind units seen in these figures are assumed to be repowered with the same capacity.

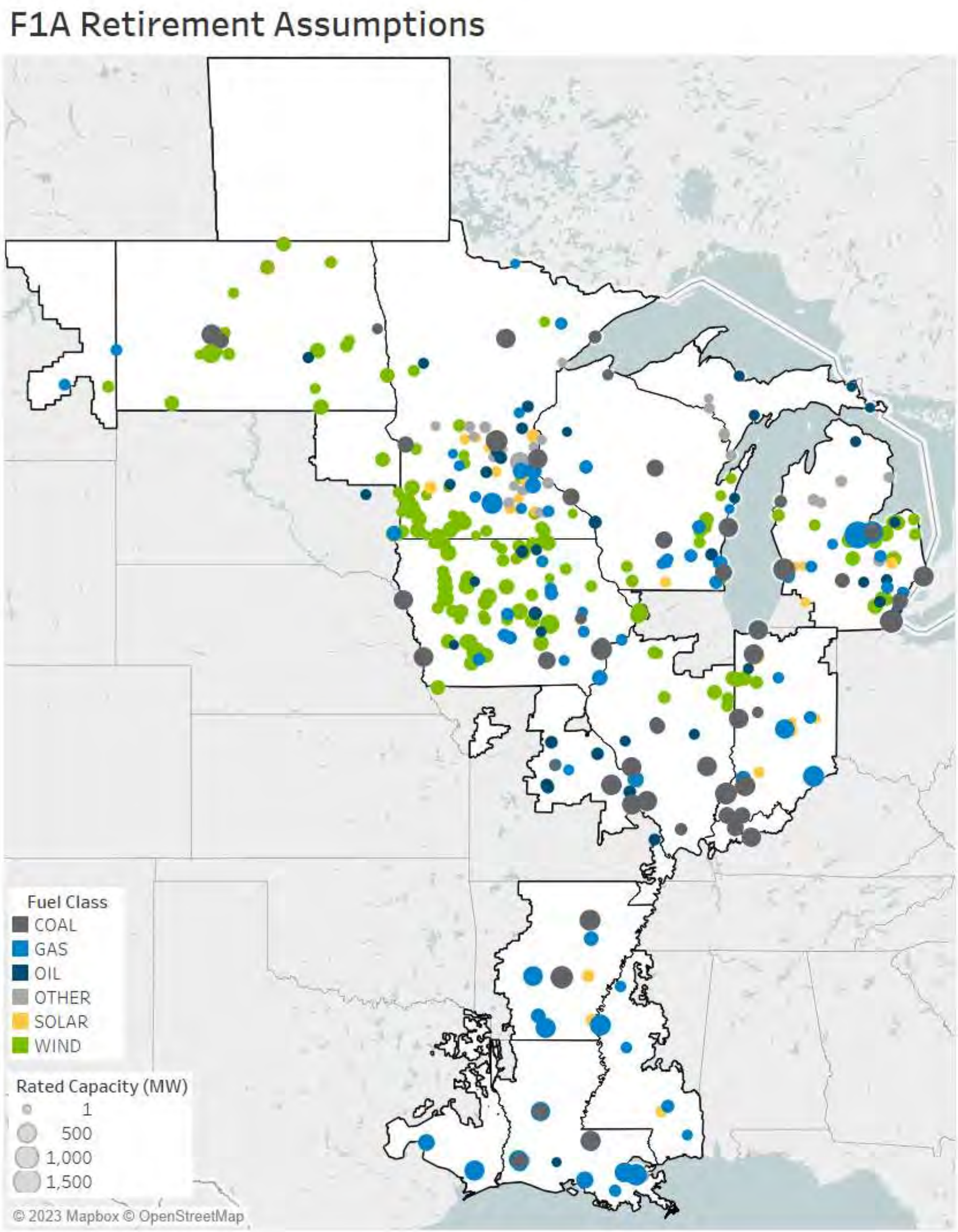


Figure 15: Future 1A Retirements by Fuel Type

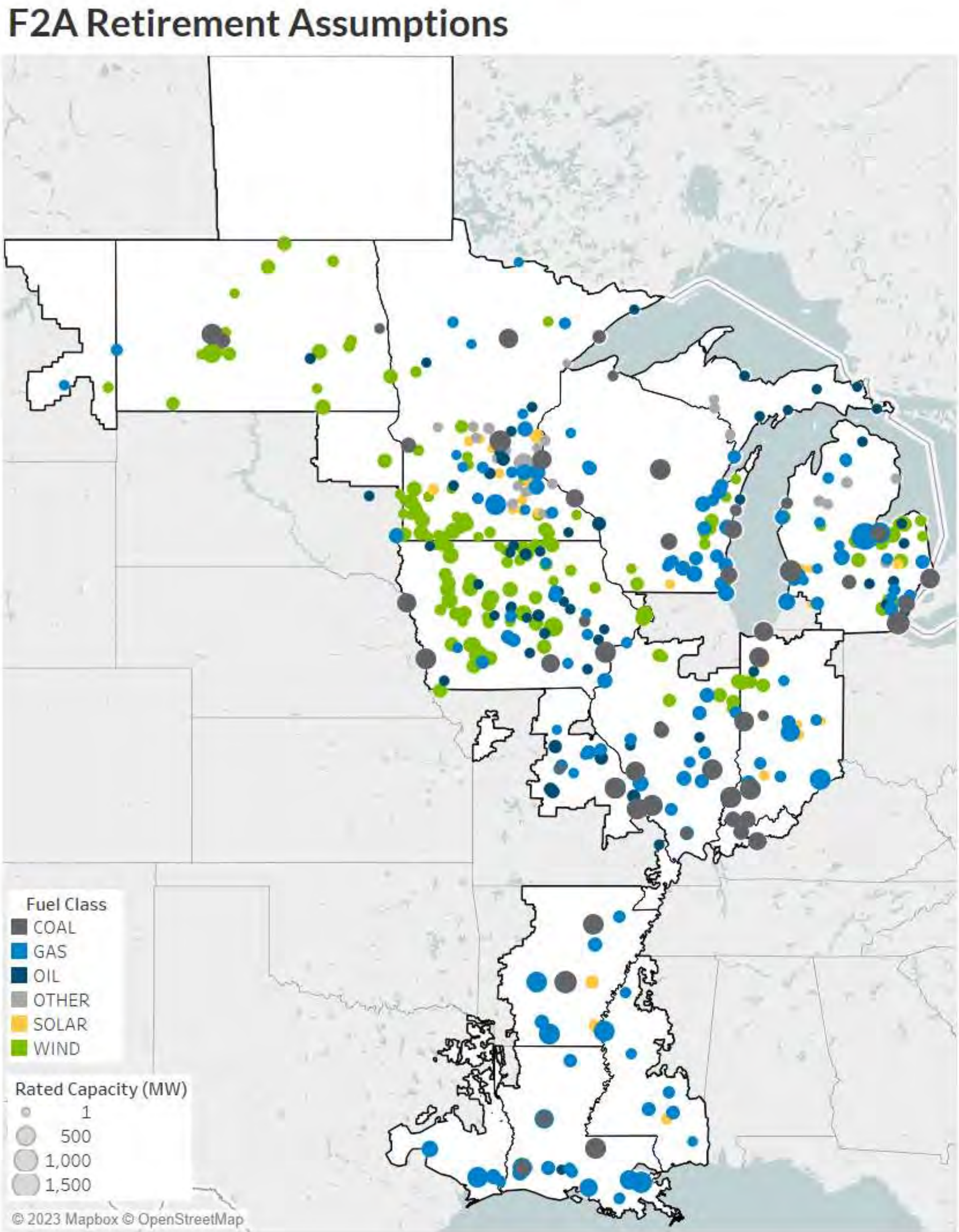


Figure 16: Future 2A Retirements by Fuel Type

F3A Retirement Assumptions

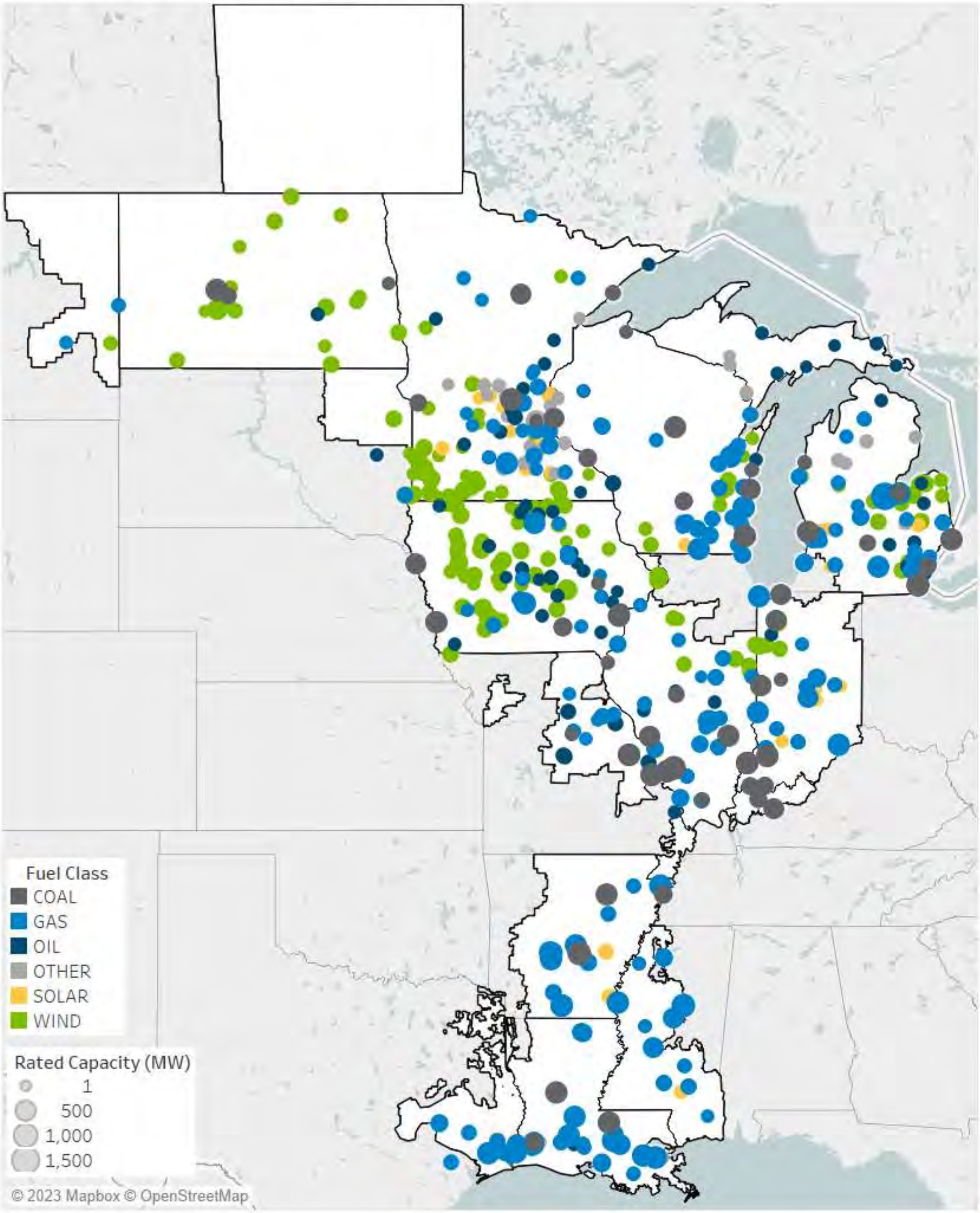


Figure 17: Future 3A Retirements by Fuel Type

Load Assumptions

The gross load assumptions developed as part of the Series 1 Futures were used in the Series 1A Futures Refresh. Since the Series 1 forecast only went to 2039, it was modified by extrapolating the forecast to 2042. Therefore, the gross annual energy and coincident peak load for the Series 1 and Series 1A Futures are the same except for the portion extrapolated, causing a slight difference when calculating the growth rates for Series 1A.

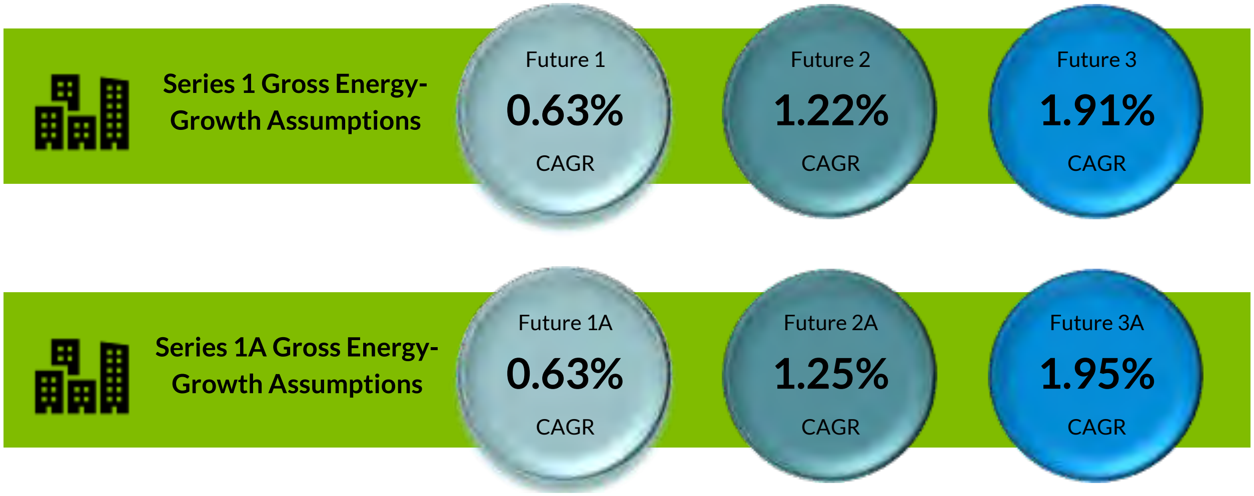


Figure 18: Gross Annual Energy Growth Comparison

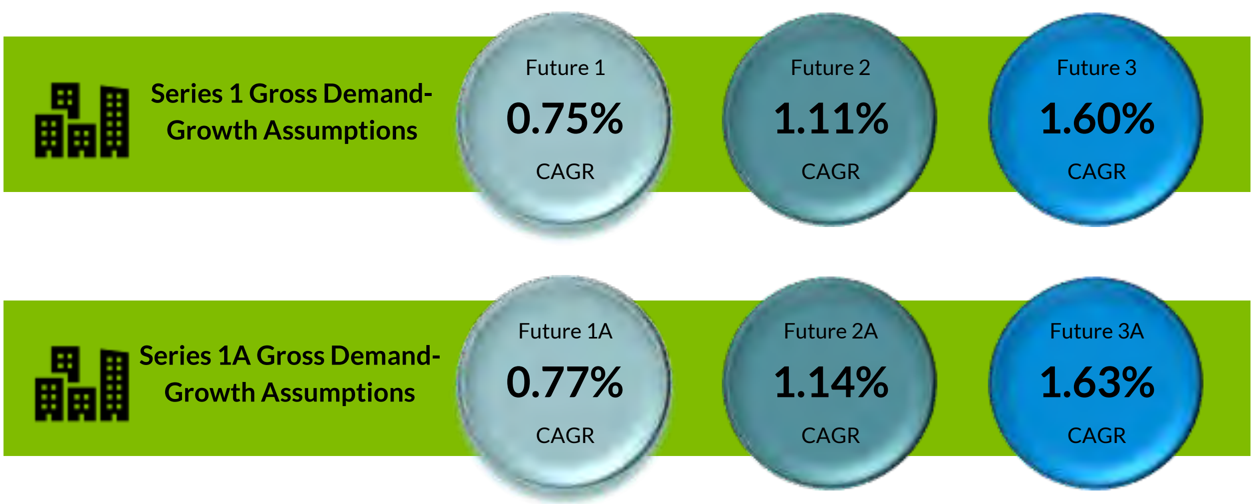


Figure 19: Gross Coincident Peak Demand Growth Comparison

The final net load results differ between Series 1 and Series 1A, as they incorporate the Distributed Energy Resources (DERs) that were included in the final resource expansion of each respective series and Future, as described in the Distributed Energy Resources (DERs) section of this report.

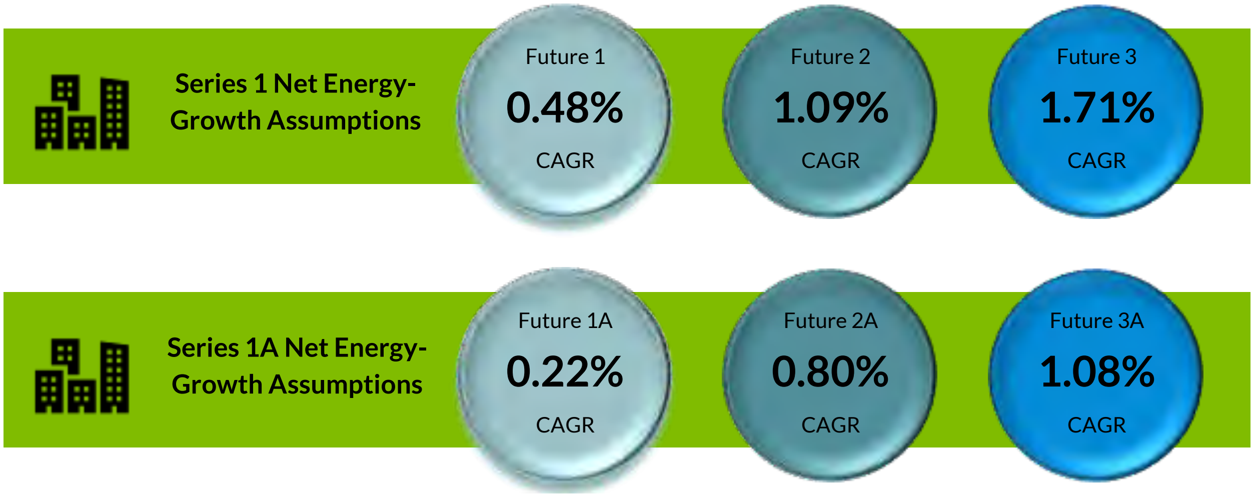


Figure 20: Net Annual Energy Growth Comparison

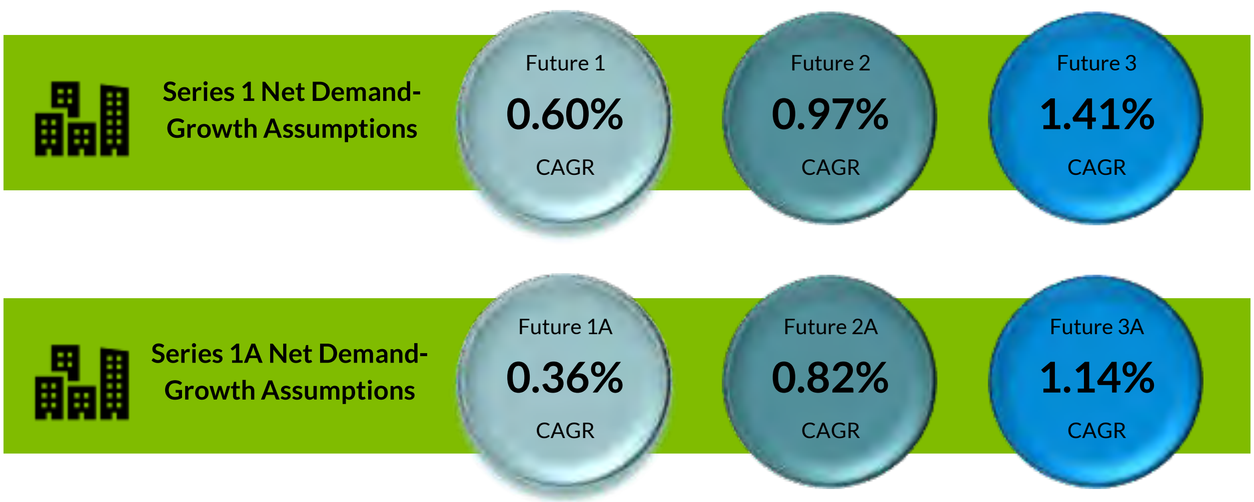


Figure 21: Net Coincident Peak Demand Growth Comparison

MISO Forecast Development

The development of the EGEAS-Ready Coincident Peak (CP) Demand and Energy Forecasts for each Future began with MISO's load-serving entities' 20-year demand and energy forecasts[18] and ended with the application of the various Future-driven assumptions, creating Future- and year-specific forecasts.

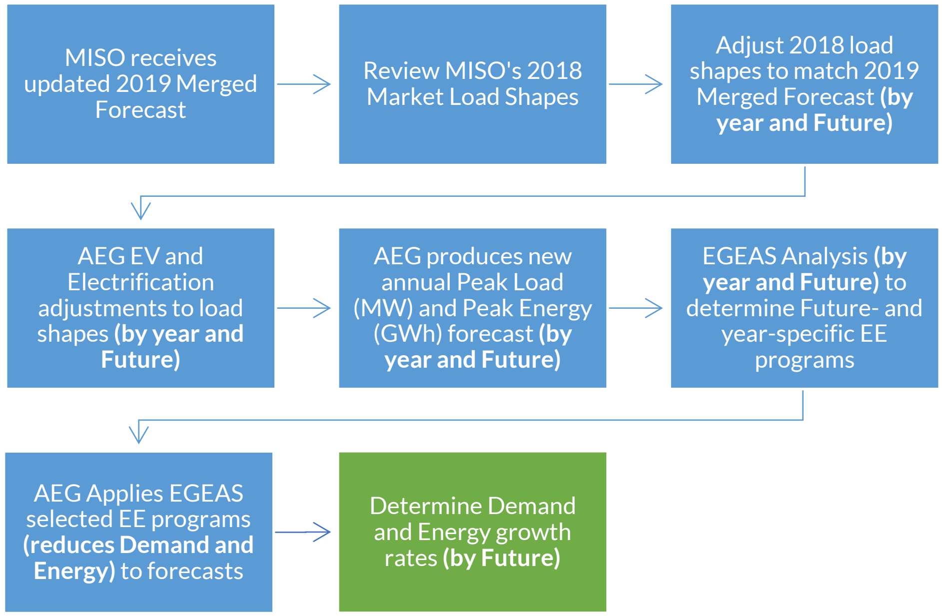


Figure 22: MISO's Forecast Development High-Level Process Flow Chart[19]

Base Forecast and Load Shapes

The 2019 Merged Load Forecast for Energy Planning forecast was reviewed for updates by stakeholders December 17, 2019 through January 10, 2020, and the updates received were incorporated. To accompany the forecast, MISO evaluated its 2018 load shapes for the impact of abnormal outages in operational load shape data due to weather anomalies. MISO evaluated the impact of Atlantic Tropical Cyclones which entered the MISO footprint according to the National Oceanic and Atmospheric Administration and determined that the 2018 shapes are suitable for MISO Futures.[20] MISO's 2018 load shapes also align with wind and solar shapes based on the most current data.

As a Futures process improvement, MISO used PROMOD to adjust each Load Balancing Authority's (LBA) 2018 load shape to meet Peak Load (MW) and Annual Energy (GWh) requirements set by the updated 2019 Merged Load Forecast for Energy Planning forecast. The benefit of this improvement was to create 20 years' worth of unique load shapes for the EGEAS analysis, as well to establish a common load shape for the EGEAS and Market Congestion Planning Studies (MCPS) analyses.

[18] If a particular MISO Load-Serving Entity (LSE) did not provide a 20-year demand and energy forecast, data from the State Utility Forecasting Group's Independent Load Forecast was used for it, creating the 2019 Merged Load Forecast for Energy Planning CP.

[19] Demand and Energy forecast process currently at box highlighted green.

[20] https://www.nhc.noaa.gov/data/tcr/index.php?season=2018&basin=atl

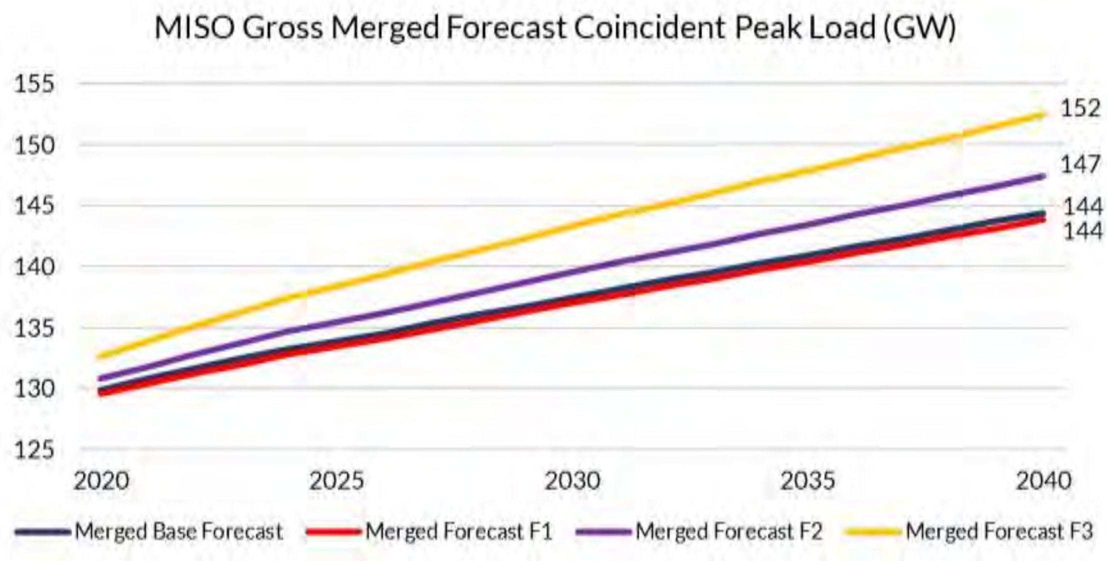


Figure 23: 2019 Merged Load Forecast Peak Load (GW)

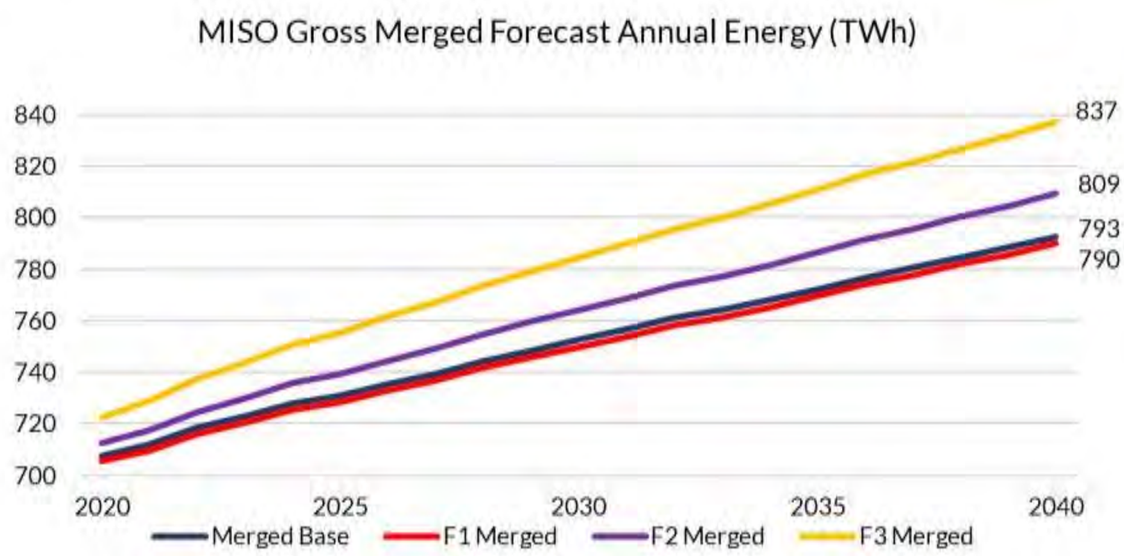


Figure 24: 2019 Merged Load Forecast Annual Energy (TWh)

Future-Specific Forecasts and Load Shapes

Applied Energy Group (AEG) used PROMOD-adjusted load shapes for their base input assumptions and then further modified these load shapes to achieve Future-specific electrification assumptions (EV growth and charging assumptions, residential electrification, and commercial and industrial electrification), ultimately creating 20 years of load shapes for each Future. A representation of the load shape modification from the original Futures cohort is shown in Figure 31.

These Future-specific load shapes were used to calculate the associated Peak Load (MW) and Annual Energy (GWh) forecast for each year to be used in the EGEAS analysis. Refer to the following figures for MISO Footprint and Local Resource Zone (LRZ) representation of this forecast.

Figure 25: Final AEG Modified MISO Gross Coincident Peak Load (GW) Forecast by Future[21, 22]

Figure 26: Final AEG Modified MISO Gross Annual Energy (TWh) Forecast by Future[23]

[21] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[22] Dips in Future 3 are due to different peak times of reference, EV charging, and electrification load forecasts.

[23] Differences in annual energy forecast and energy generation by Future are attributed to energy utilized for storage-charging and dumped energy. Total energy generation, net storage-charging, can be found for each Future in the expansion results section of this report.

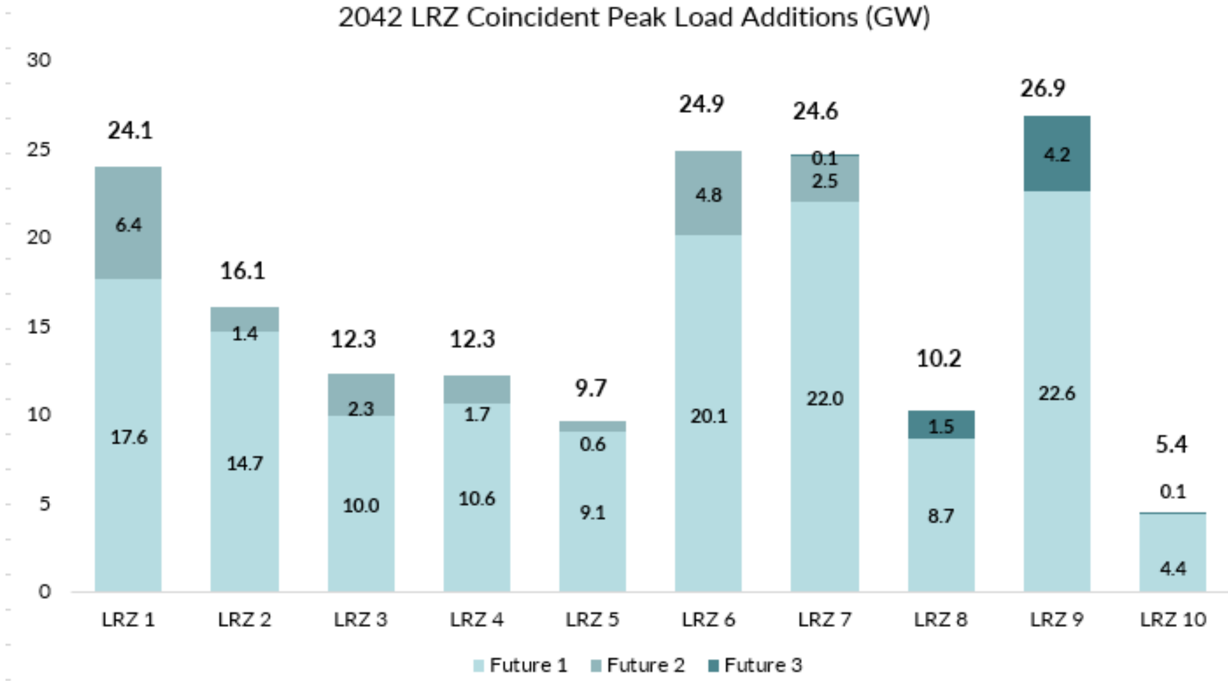


Figure 27: Final AEG Modified LRZ Coincident Peak Load (GW) Forecast[24,25]

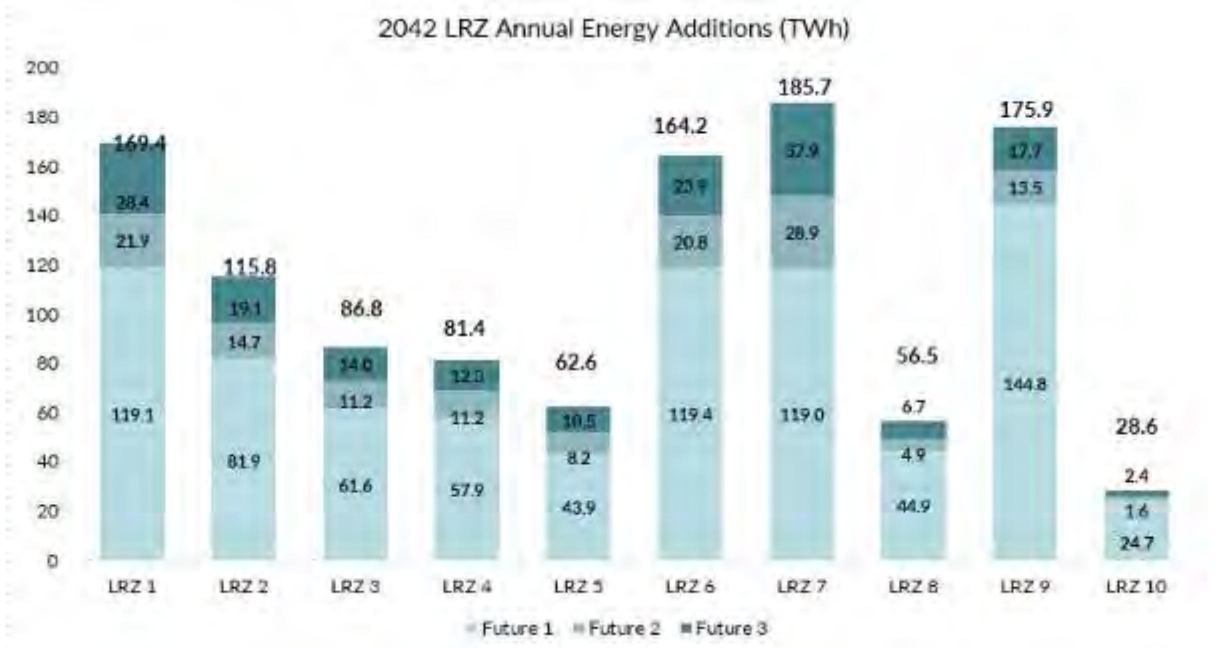


Figure 28: Final AEG Modified LRZ Annual Energy (TWh) Forecast[25]

[24] In LRZs 8 and 9, CP values decrease in Future 3, making the total shown less than the sum of values for Futures 1 and 2.

[25] Values shown do not include load and energy modifiers determined by EGEAS analysis.

Forecast Growth Assumptions

Demand and energy growth values are based on Futures assumptions and were determined once the analysis was finalized EGEAS having selected hourly load (MW) and energy (GWh) modifiers and programs applied to each Future scenario's Coincident Peak forecast. The following figures represent compound annual growth rates (CAGR) and forecast increases pre- and post-analysis.

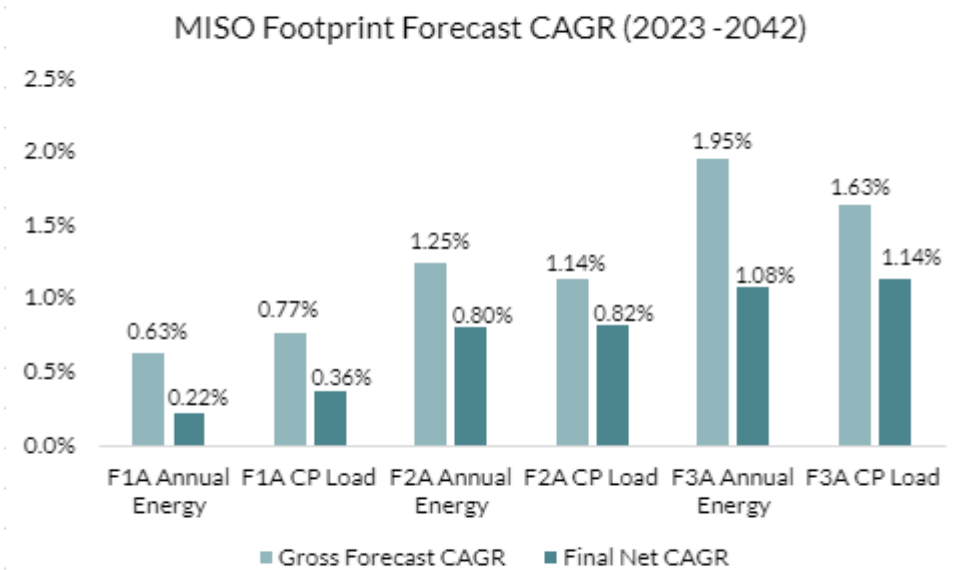


Figure 29: Final AEG Modified MISO Footprint Forecast Compound Annual Growth Rates (CAGR)

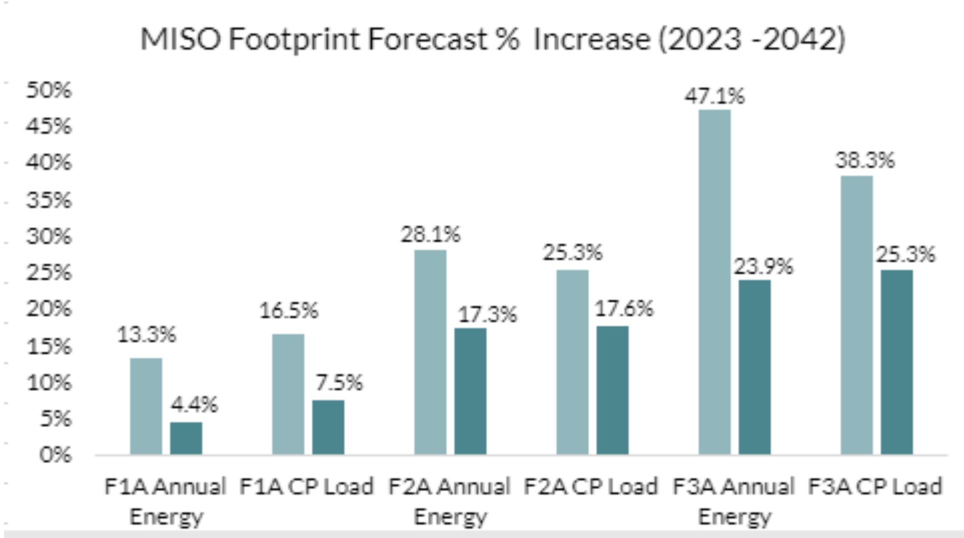


Figure 30: Final AEG Modified MISO Footprint Forecast % Increase[26]

[26] Gross values do not include load and energy modifiers determined by EGEAS analysis, while Net values include EE programs that were selected during modeling.

Forecast Evolution

To ensure the Futures update has effectively created broad and realistic bookends, especially with demand and energy assumptions as key drivers, the original Futures cohort compared the 2019 Merged Forecast (pre-application of EV and Electrification assumptions), MTEP21 Coincident Peak (CP) Future-specific forecasts (post-application of EV and Electrification assumptions), and MTEP19 Future forecasts.

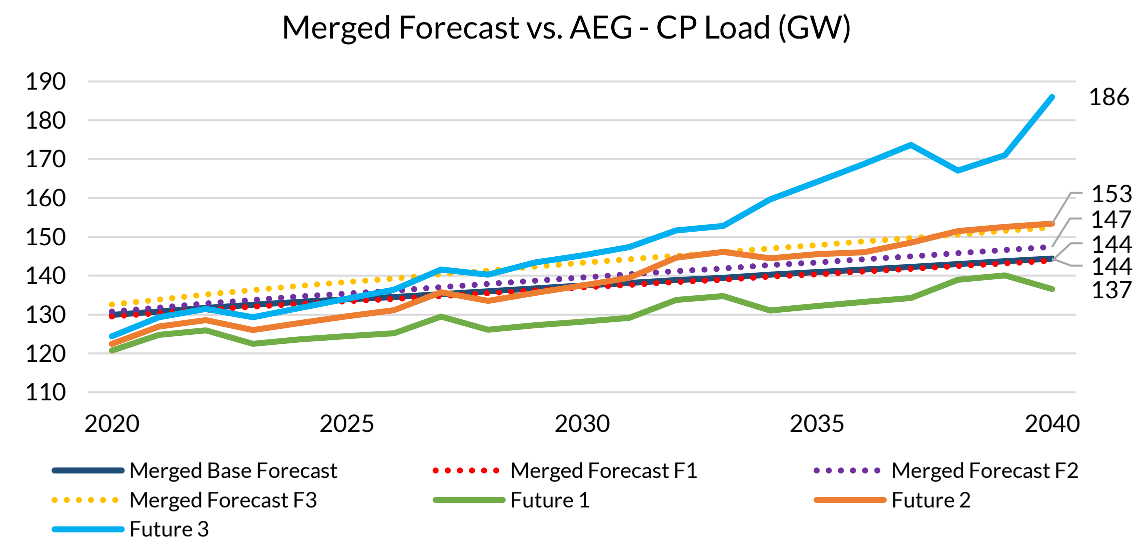


Figure 31: Merged Forecast vs. Future-Specific Adjustments – CP Load (GW)[27, 28]

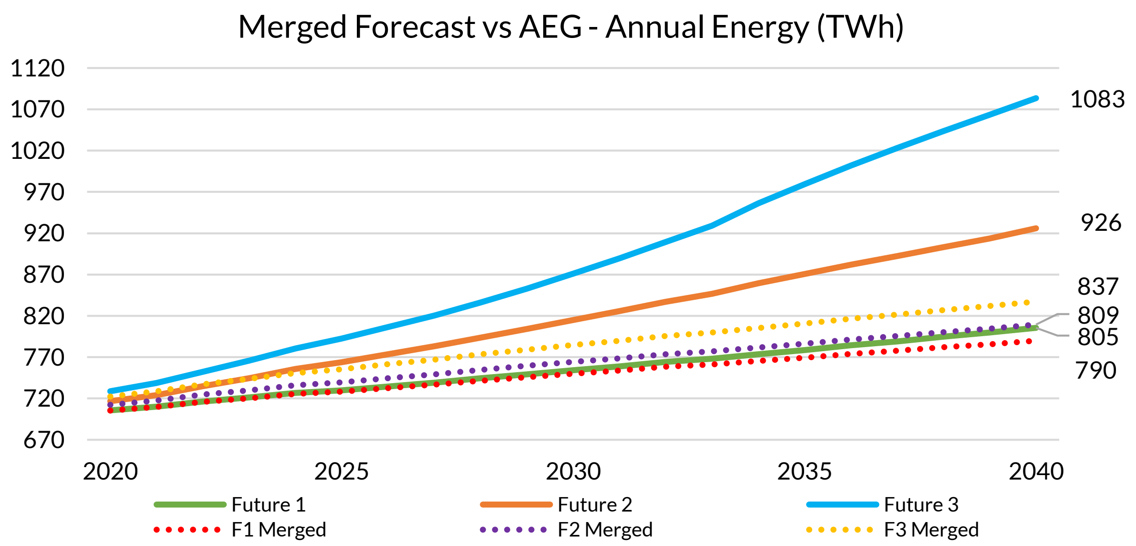


Figure 32: Merged Forecast vs. Future-Specific Adjustments – Annual Energy (TWh)

[27] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[28] Merged Forecast CP Load (GW) values are calculated from monthly peak data while the AEG Peak Load (GW) values are calculated from hourly data. This has the illusory effect of the Merged Forecast CP Load (GW) being reduced.

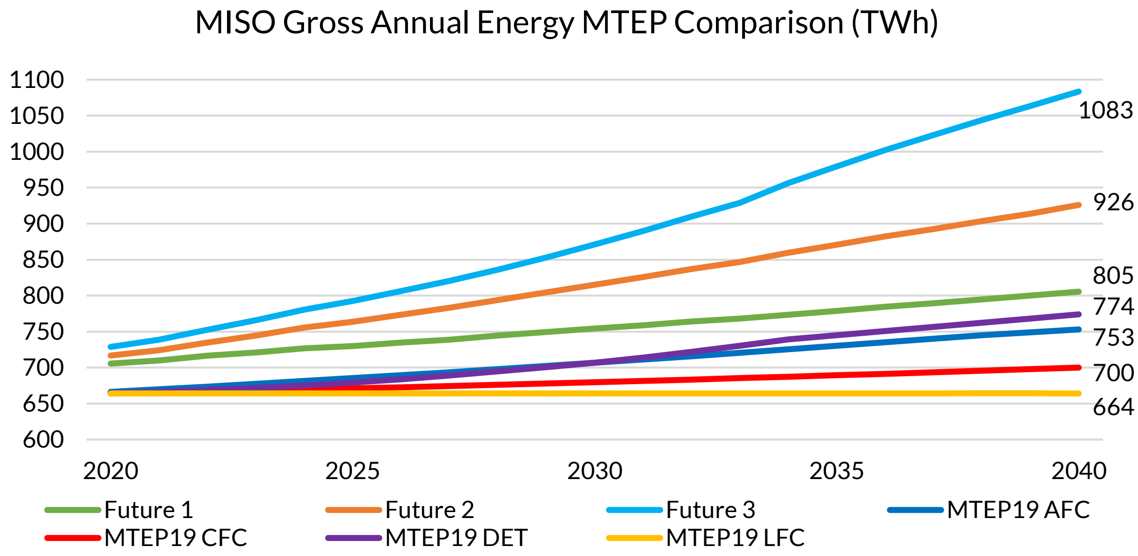


Figure 33: MTEP19 & MTEP21 MISO Annual Energy (TWh) Compare.[29]

Final Load Shapes

Upon conclusion of the EGEAS analysis, MISO removed energy proportionate with selected energy efficiency (EE) programs in each Future scenario's load shape to produce final net load shapes. In Figure 35 through Figure 37 , the evolution of each Future load shape is shown, comparing the final input load shape for year 2042 from AEG that includes electrification assumptions against the 2042 load shape post modeling of each scenario that nets out EE programs selected. Figure 34 displays each Future scenario's post-modeling load shape in the final year of the study, for comparison.

[29] Values shown do not include load and energy modifiers determined by EGEAS analysis.

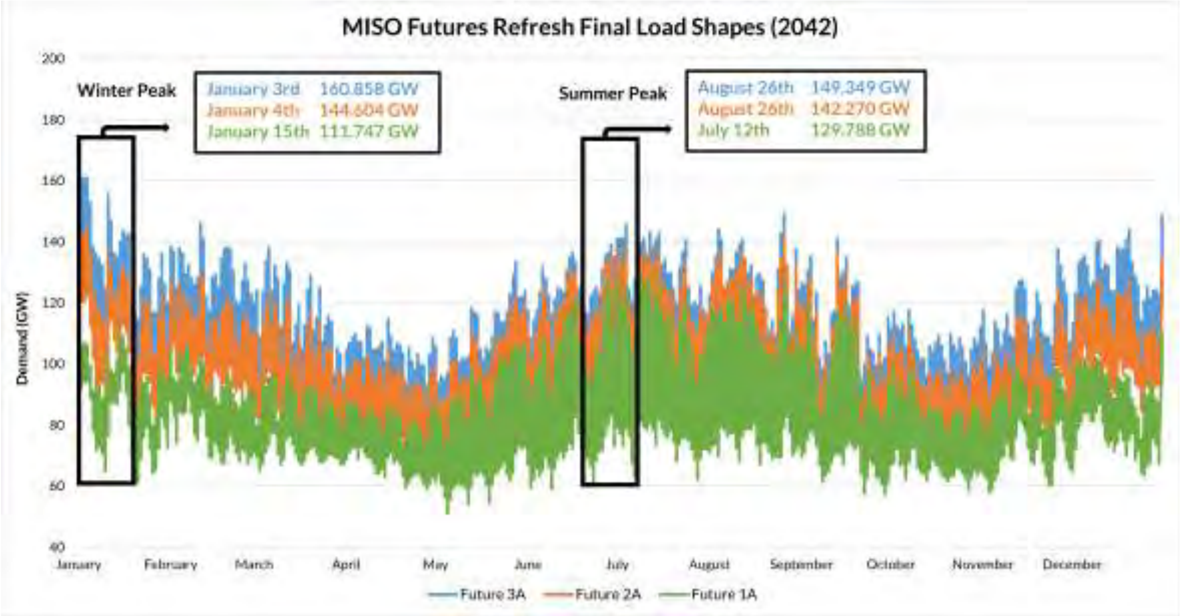


Figure 34: All Futures Final Load Shapes

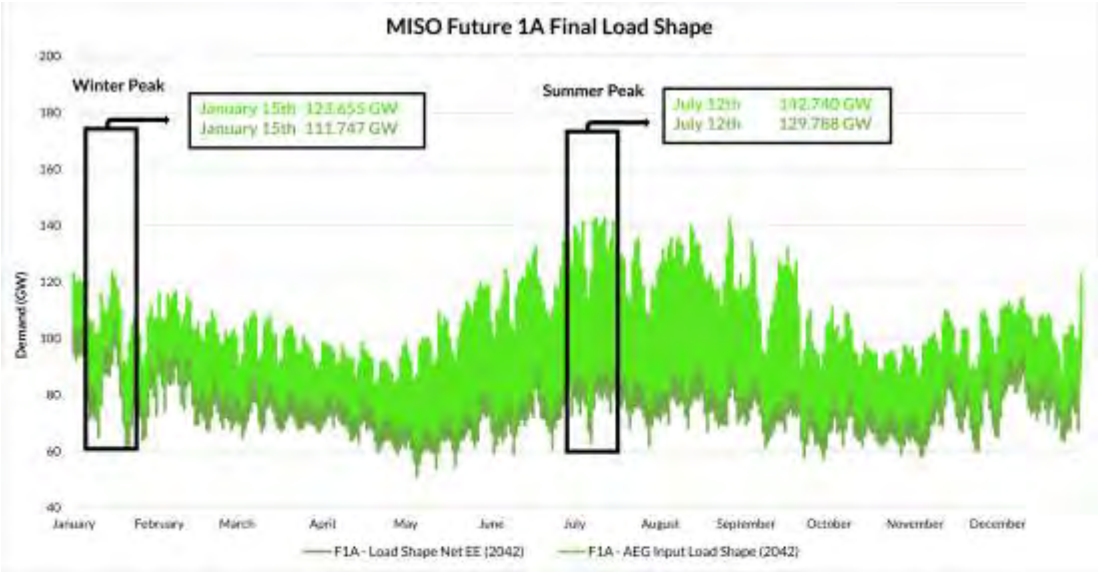


Figure 35: Future 1A Load Shape Evolution

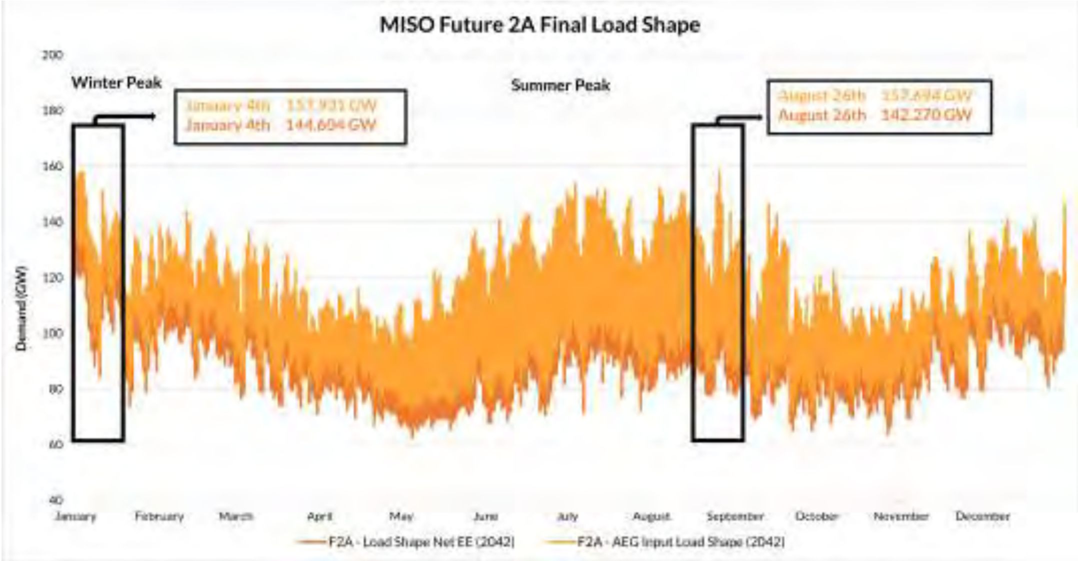


Figure 36: Future 2A Load Shape Evolution

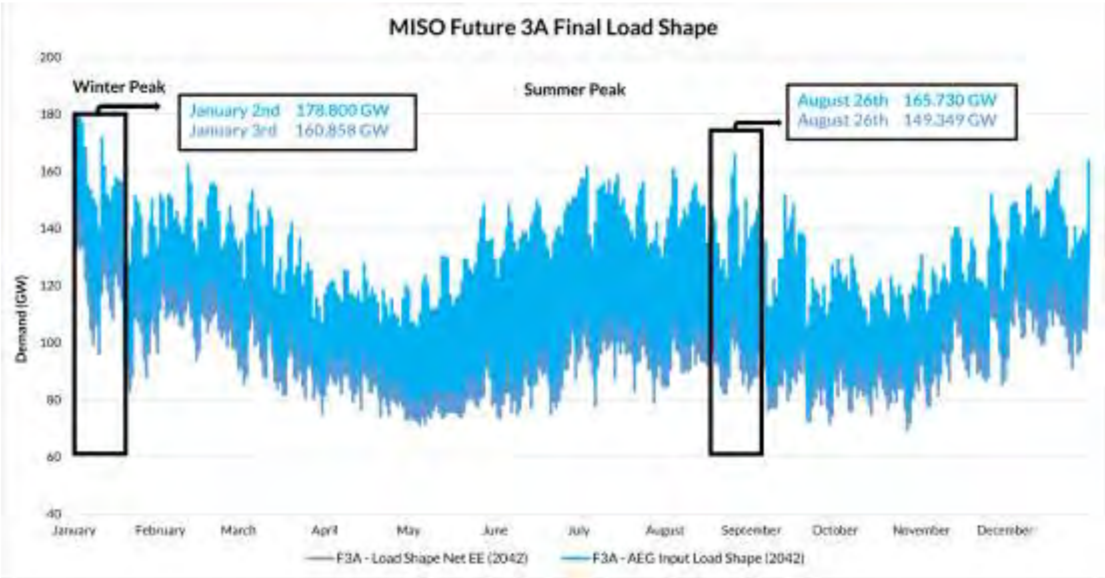


Figure 37: Future 3A Load Shape Evolution

Electrification

A primary driver of load growth in Futures 2 and 3 is electrification. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). The increased energy assumptions of 30% (F2 & F2A) and 50% (F3 & F3A) were selected by MISO to create a wide but plausible range of growth scenarios. Although electrification drives the load increase in two of the Futures, it is not the sole source of each scenario's load growth. A more detailed discussion of each Future's load growth and electrification assumptions is provided below and in the Electrification Section of this report.

MISO contracted Applied Energy Group (AEG) to evaluate the MISO footprint on its potential to electrify. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). In this study, electrification is calculated as a percentage of technical potential that a given LRZ could achieve. The figure to the right shows the categories of electrification and what percentages of the technical potential they comprise. More details on the assumptions for the categories are included below.

To estimate the available market for electrification, AEG started with the end-use load forecasting models developed for MTEP20 (previous set of MISO Futures), which include market data for each state in the MISO footprint. These market data included estimates of the penetration of many types of electric equipment. To estimate the total technical electrifiable load, AEG assumed that 90% of a particular end-use customer load was capable of being electrified, and then subtracted the electric equipment saturations (the load that is already electrified) from that value.

Figure 38: Electrification Categories

Electrification Categories

AEG identified each electrifiable technology and considered how likely or feasible it would be to be adopted before assigning it to one of four categories: mature technologies, emerging, high, and very high.[30] AEG considered how widespread the technology currently is, whether there are utility EE programs, and whether or not there are known market barriers. Since both mature and emerging versions of known technologies (e.g., traditional air-source heat pumps vs. cold-climate heat pumps) can coexist, AEG distributed the electrification potential for different technologies over more than one category. These are represented by the percentages below.

Additionally, AEG considered the certainty around each assumption. For example, industrial process loads are very customizable and would require a "bottom-up" approach to implementation, considering each industry and state individually. To capture this uncertainty, electrification of industrial process loads was assigned to higher electrification levels.

Each category is described below however, additional insights into the details of these categories may be found in MISO's Electrification Insights Report.

Mature Technologies

The "Mature Technologies" electrification category includes technologies that are widely available on the market today and are the most likely to electrify in the future. One example is an air-source heat pump,

[30] AEG's 2019 Presentation on Electrification

which is already found in many homes throughout the United States. Electric cooking equipment, such as induction ovens, is another example of an existing technology that is popular and relatively straightforward to install. Technologies in this category include:

- Air-Source Heat Pumps (50% of single-family [SF], 50% of multi-family [MF], 50% of Commercial and Industrial [C&I])
- Geothermal Heat Pumps (50% of SF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF)
- Clothes Dryers
- Dishwashers
- Stoves

To better understand how much of these technologies are being electrified in each category, it is best to give an example. For air-source heat pumps, this section is saying that 50% of single-family, multi-family, and commercial and industrial heat pumps that can electrify will be electrified in this category.

Emerging Technologies

The “Emerging Technologies” category represents electrification load that is beginning to become available or is more mature but limited by known market barriers. For example, while air-source heat pumps are a mature technology, they may not be easily installable without reconfiguring the ductwork. Gas forced-air furnaces provide hotter air and require smaller ducts, requiring an invasive modification to expand the ductwork to keep a home warm in the winter. Process loads also begin to appear in this category. Technologies in this category include:

- Air-Source Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Geothermal Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF, 50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

High Electrification Scenario Technologies

This category represents the point where substantial market barriers exist or where technologies are new or still in development. An example is a large-scale air-source heat pump that would be necessary to replace a large gas boiler heating a hospital. These are not readily available—gas is the most common fuel source in large-scale applications. However, if high levels of electrification are to be achieved, electrification using these new and in-development technologies would need to take place. Technologies in this category include:

- Air-Source Heat Pump (50% of C&I)
- Geothermal Heat Pump (50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

Very High Electrification Scenario Technologies

This category represents the highest levels of uncertainty in the analysis and is only applied in the highest-growth cases. As noted above, much of the industrial process electrification is present in this category. The only technology in this category is noted below:

- Industrial Process (50% of C&I)

Technologies Electrified

HVAC Heat Pumps - Air-source and geothermal heat pumps

- Lower-growth scenarios electrify many residential homes and some businesses, where this technology is already available (rooftop units and residential systems)
- Higher-growth scenarios assume large-scale replacements are available for technologies like gas boilers

Heat Pump Water Heaters - Efficient water heaters with a vapor-compression refrigeration cycle

- Lower-growth scenarios electrify tanks in both the residential and commercial sectors
- Higher-growth scenarios include the electrification of large-scale gas water heaters

Residential Appliances - Clothes dryers, dishwashers, and stoves

- Dishwasher electrification occurs when no existing dishwasher is present

Industrial Process - High growth potential, but only certain processes can be electrified

- Due to the complexity involved in electrifying industrial processes, AEG assumed that most of this occurs in the higher-growth scenarios
- Examples of technologies that may be electrified within industrial processes include ultraviolet (UV) curing and drying, machine drives, and process-specific heating and cooling
- Electric boiler, industrial heat pump, resistance heating industrial heat pump, induction furnace, etc.

LBNL PEV Forecasts[31] - All four forecasts were used in development of these scenarios

- These include combinations of uncontrolled and V2G versions of the: Low, Base, High, and Very High scenarios
- Merged PEV forecasts were selected for each growth scenario – adoption curves and load shapes specific to the selected forecast were used

Figure 40 through Figure 45 display the results of these electrification assumptions across each Future scenario in the MISO footprint. The charts present a detailed view of the results showing yearly cumulative increases in energy from electrification for the footprint, electrification totals for each Local Resource Zone for the entire study, and the proportion of electrification from each technology.

[31] Lawrence Berkeley National Lab EV Forecast Report

Electrification Potential Across MISO Footprint

This analysis was conducted at the state level in the MISO footprint then aggregated by LRZ. AEG's end-use forecasting and Demand-Side Management (DSM) potential model was used to conduct this analysis, providing estimates of electric equipment penetrations as well as consumption for MISO's fraction of each state. Since local weather and equipment penetration data were used in this analysis, each state will have different end-use consumption patterns and a different electrifiable load. These are high-level findings based on the end-use models and a result of the differences noted above. The three main drivers of technical potential for electrification are:

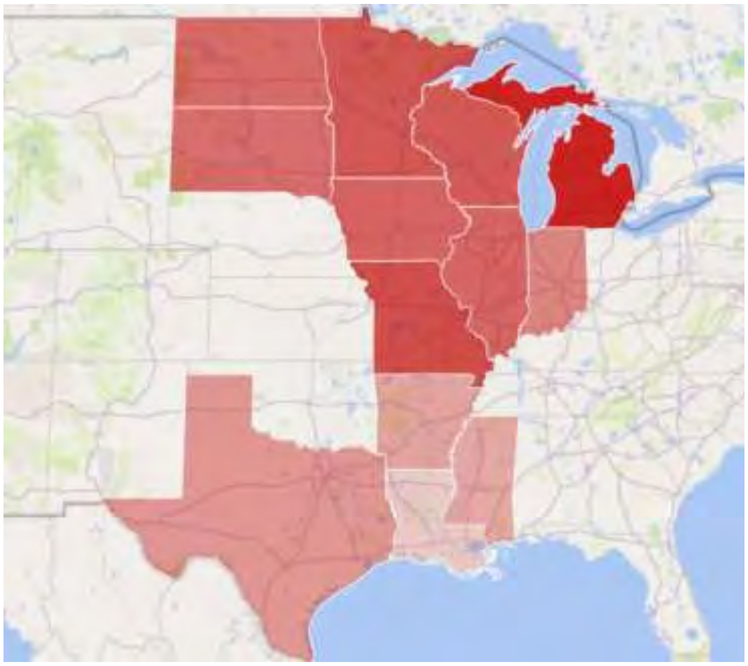


Figure 39: Electrification Potential by State

- **Latitude:** The northern states in the MISO footprint are generally colder than the southern states, resulting in larger space-heating loads. Since the heating end-uses represent some of the largest electrification potential, additional new loads are expected in the northern MISO states.
- **Gas Infrastructure:** Along with latitude, existing gas infrastructure heavily influences the electrifiable load. AEG utilized the state-level market data listed above to estimate gas equipment penetrations by state. If the load in a state is already mostly electric, there would be fewer non-electric units to convert, lowering potential.
- **Cooling Presence:** The final notable factor is the presence of existing cooling equipment. Similar to the gas infrastructure note above, high penetrations of existing cooling equipment limit electrification potential since the remaining non-electric market is smaller. In the warmer southern states, many homes already have cooling equipment installed, so their potential is lower.

Future 1 Electrification

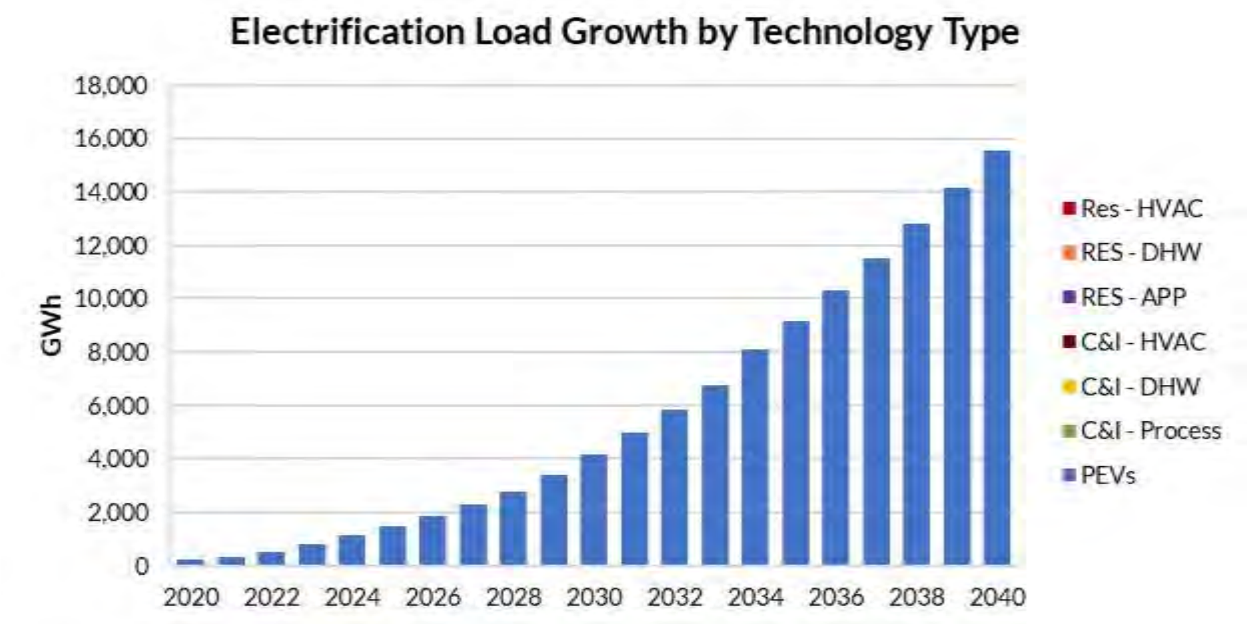


Figure 40: Future 1 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

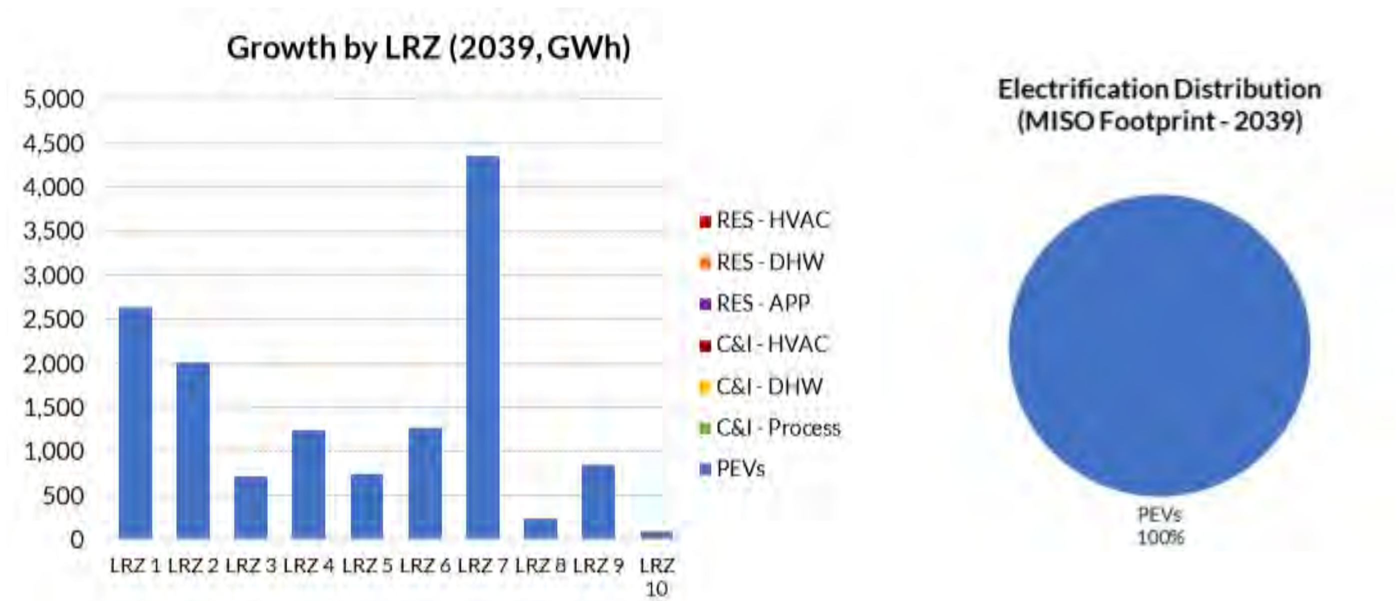


Figure 41: Future 1 Electrification Broken Down by End-Use

Future 2 Electrification

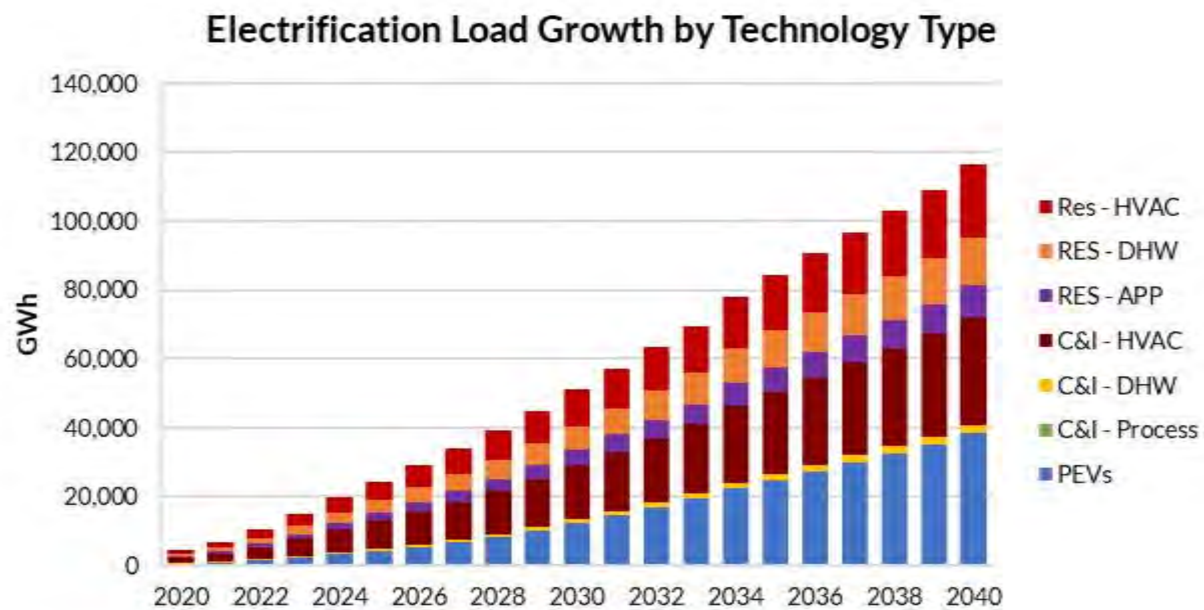


Figure 42: Future 2 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

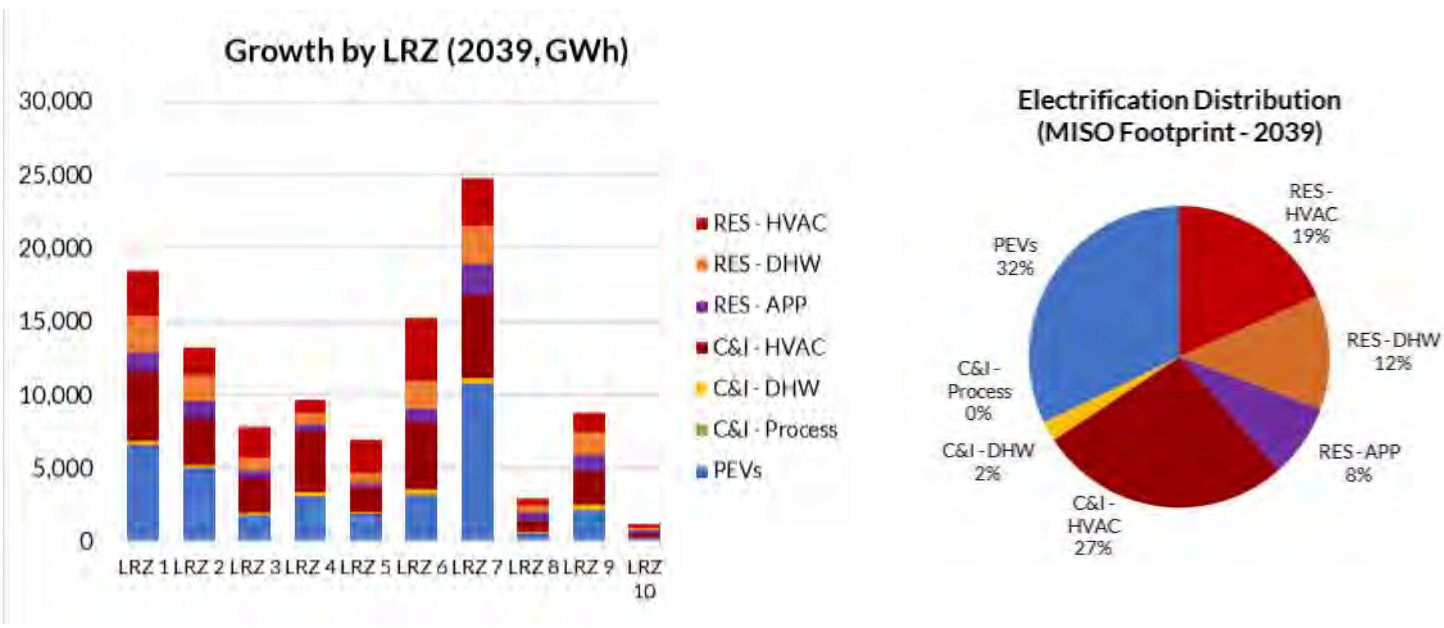


Figure 43: Future 2 Electrification Broken Down by End-Use

Future 3 Electrification

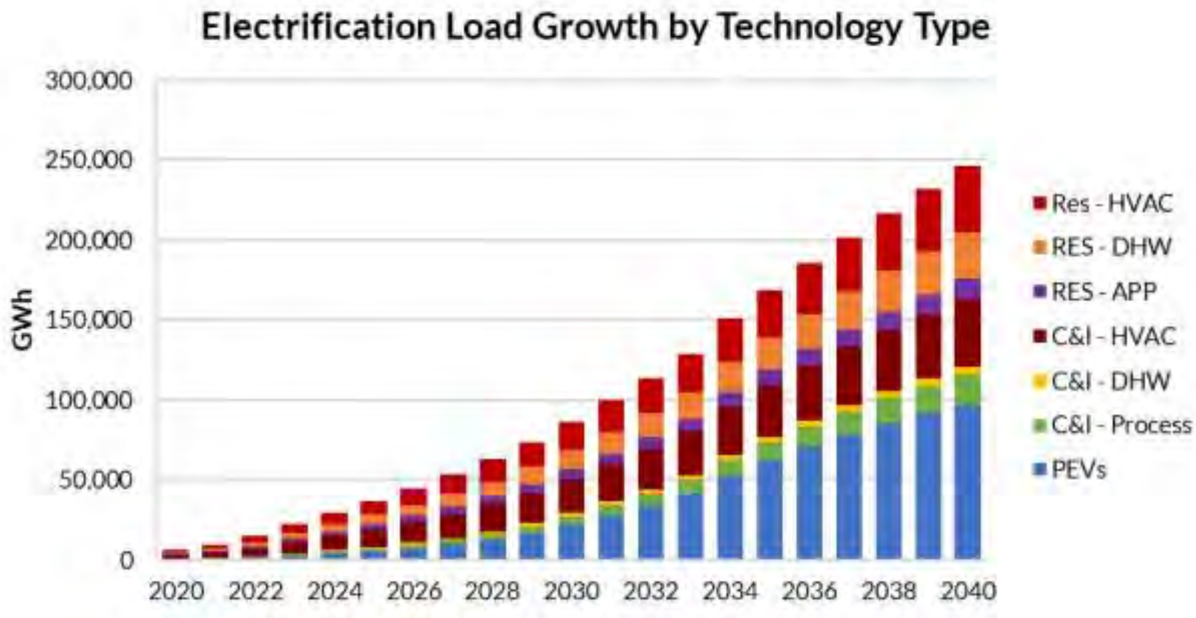
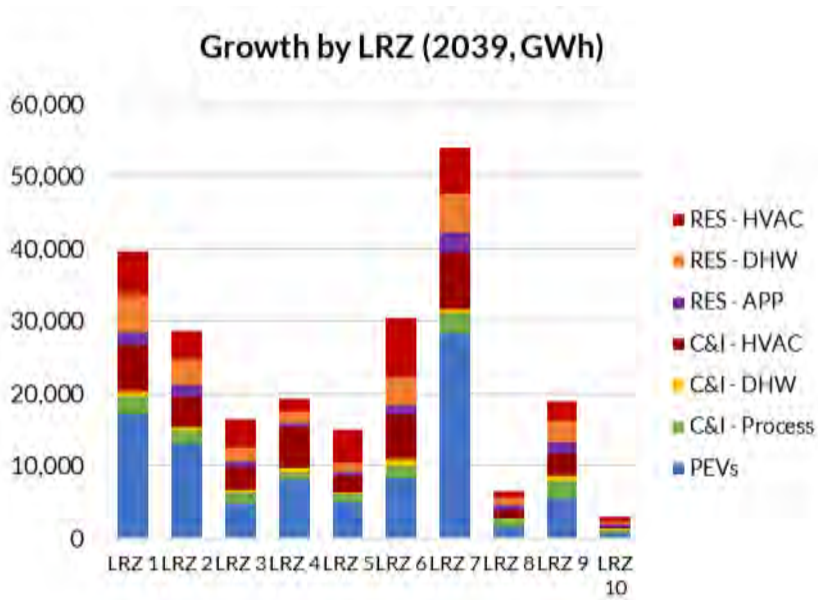


Figure 44: Future 3 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint



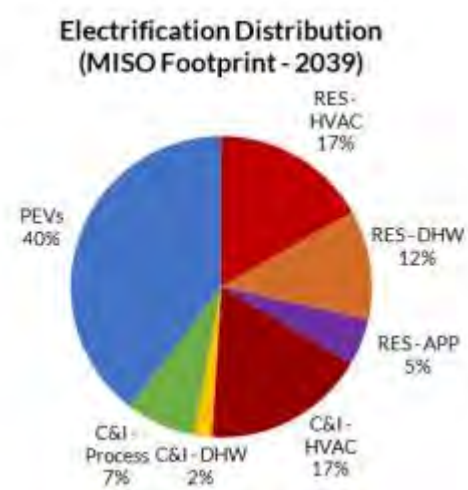
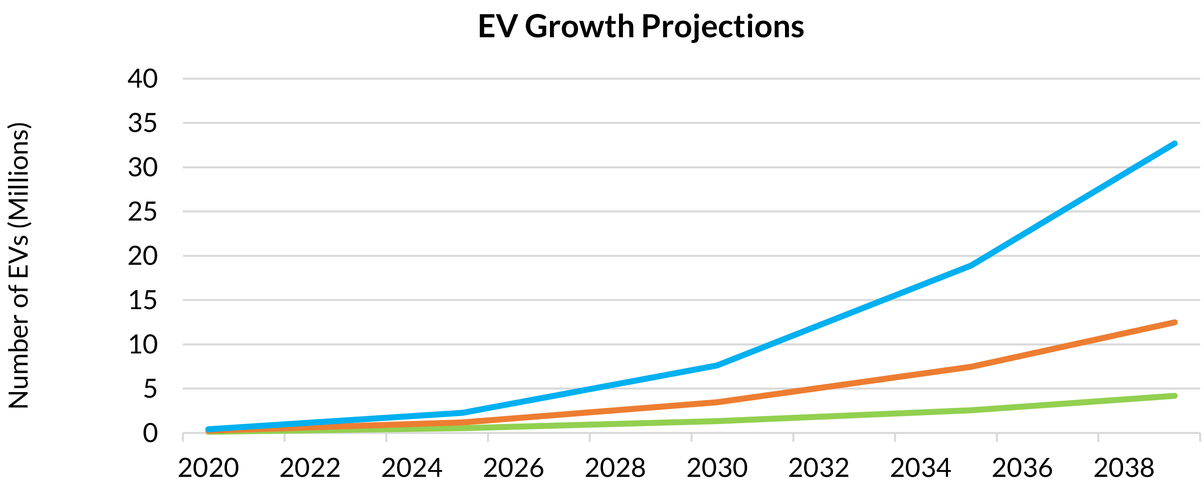


Figure 45: Future 3 Electrification Broken Down by End-Use

Electric Vehicle Forecasts

MISO collaborated with [Lawrence Berkeley National Laboratory (LBNL)]() on a study to determine the potential for EVs within the MISO footprint. This study categorized the projected growth of EVs in into four scenarios: low, base, high, and very high. Each of the three Futures used merged forecasted EV growth scenarios to include different amounts of light-duty EVs. All Futures explored a variety of EV growth and charging scenarios within every LRZ across the 20-year study period.

Future 1 evaluated only uncontrolled charging methods, Future 2 included vehicle-to-grid (V2G) charging after 2035, and Future 3 incorporated V2G charging after 2030. Figure 47 through Figure **49** detail the number of EVs in each scenario, MISO footprint and LRZ.



	2020	2025	2030	2035	2039
Future 1	0.135	0.53	1.33	2.57	4.19
Future 2	0.26	1.205	3.47	7.455	12.49
Future 3	0.416	2.272	7.598	18.91	32.686

Figure 46: EV Growth per Future (MISO footprint)

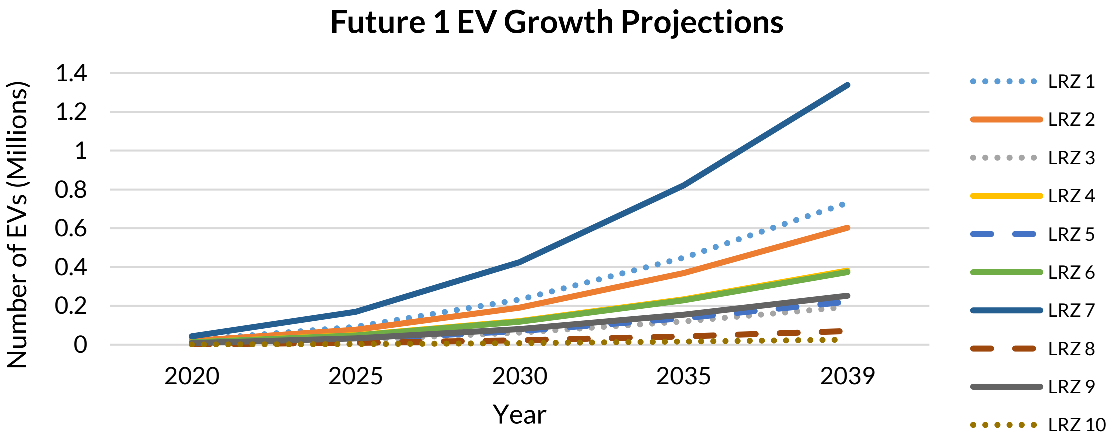


Figure 47: Future 1 EV Growth per LRZ

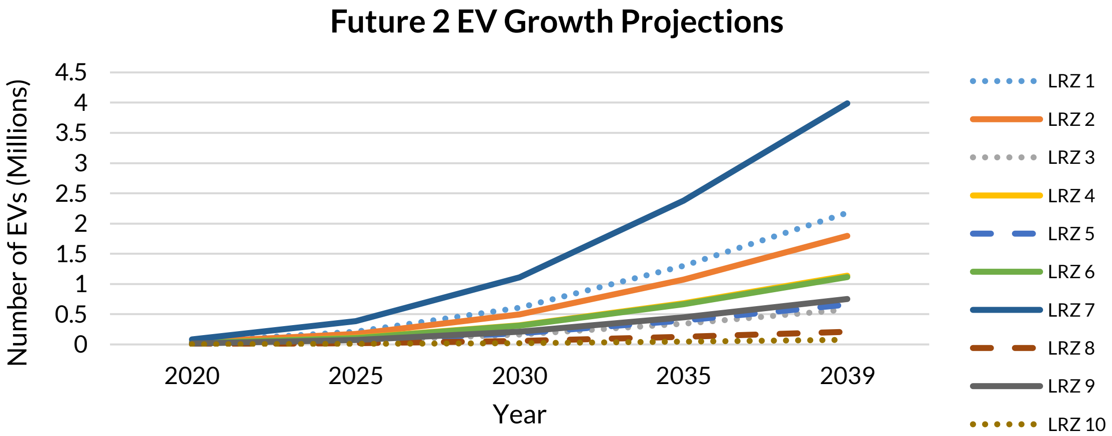


Figure 48: Future 2 EV Growth per LRZ

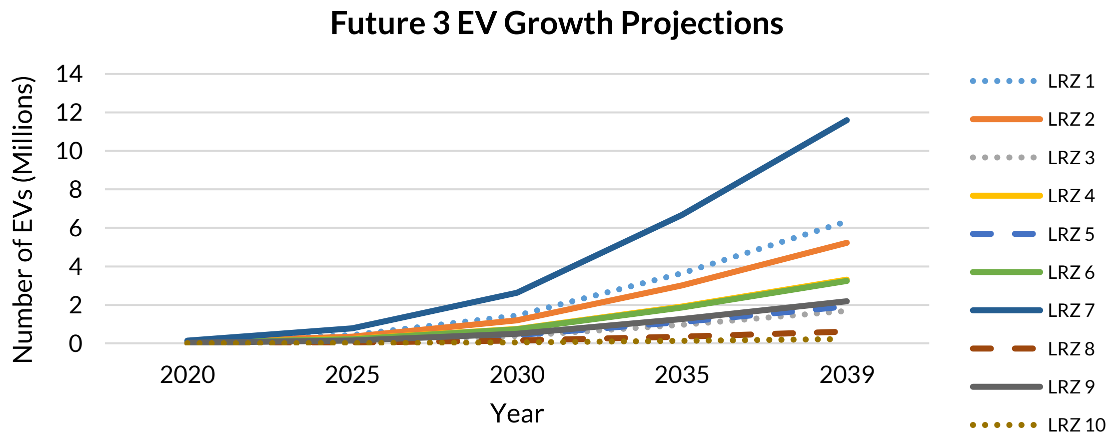


Figure 49: Future 3 EV Growth per LRZ

New Resource Additions

Regional Resource Forecast Units (RRF Units) are various resource types that are defined in and selected by MISO's capacity expansion tool, EGEAS, to achieve each of the Futures scenarios. The RRF units used in MISO Futures are discussed in further detail below.

Wind

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. New RRF units were built at 100m hub height throughout the study period. Existing units used representative wind profiles developed from 2018 historical data. All wind units assumed 16.6% capacity credit.

Solar

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. Existing units used representative solar profiles developed from 2018 historical data. All solar units assumed 50% capacity credit at the beginning of the study period and decreased by 3% starting in year 2028, until the capacity credit reached a minimum of 20%.

Hybrid: Utility-Scale Solar PV + Storage

Hybrid solar profiles were created by modifying VCE 2018 hourly profiles for solar units. Hybrid units were modeled as a 1200 MW inverter attached to 1500 MW of solar panels, resulting in an over-panel of 25%. When solar output exceeded the inverter capacity, the battery charged. Once solar output reached 20% or lower of the max capacity (max capacity is 1500 MW making 20%, 300 MW), the battery discharged until empty. Hybrid units assumed a 60% capacity credit at the beginning of the study period and decreased by 3% starting in 2028, until the capacity credit reached a minimum of 30%.

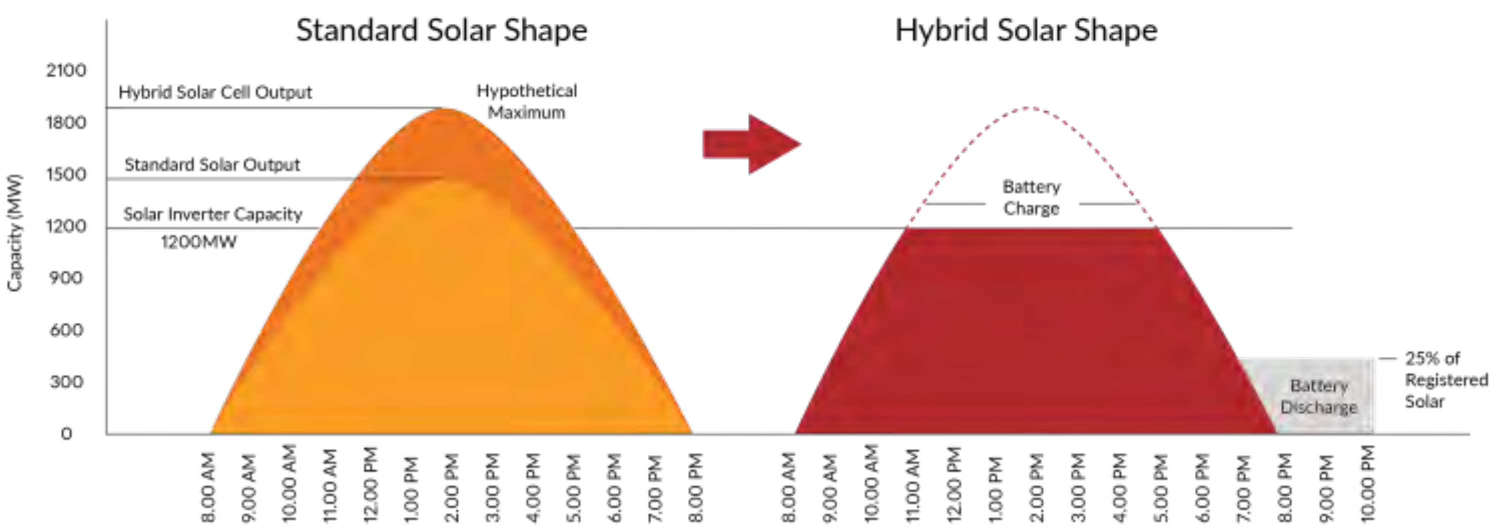


Figure 50: Solar + Storage Hybrid Profile

Storage: Lithium-Ion Battery (4-hour)

Batteries modeled in the capacity expansion were 4-hour duration lithium-ion batteries. Units were sited with a minimum capacity of 50 MW and a maximum capacity of 400MW across all Future scenarios.

Distributed Energy Resources (DERs)

For Series 1, MISO commissioned Applied Energy Group (AEG) to develop new DER technical potential. AEG developed estimates of DER impacts through survey of load-serving entities (LSE) and secondary research. To support Series 1A modeling, AEG compiled DER programs by type and cost into program blocks for EGEAS through study period ending in 2042. According to AEG data, Future 1 DER program levels represent minimum expected resource levels. Therefore, Future 1A programs are included as minima within the base model of all Series 1A scenarios. Futures 2A and 3A employ all F1A program amounts and allow incremental program blocks (the difference of total F2A or F3A programs and F1A levels) for selection.

Previously referred to as demand-side additions or management (DSM), these resources were modeled as program blocks in three main categories: Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). Programs also fall into two sectors: Residential and Commercial and Industrial (C&I).

During the program selection phase for the F2A and F3A models, incremental program blocks were offered against supply-side alternatives to determine economic viability. For both F2A and F3A, EGEAS selected the following program blocks: C&I Price Response, Residential Direct Load Control, and Residential Price Response. F2A also selected C&I Demand Response. Additionally, F3A selected C&I Utility Incentive PV; C&I High-, Mid-, and Low-Cost Energy Efficiency; and Residential High- and Low-Cost Energy Efficiency. Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential. A complete list of detailed AEG programs mapped to EGEAS program blocks is below in Table 5.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals below. F1A minima, F2A- and F3A-selected incremental programs, and stakeholder additions were implemented in the Futures models. Table 3 and Table 4 show total DER technical potential and additions modeled in MISO by the end of the study period.

Series 1A DERs Capacity (GW) Technical Potential & Added	Future 1A	Future 2A		Future 3A	
	Added	Potential	Added	Potential	Added
Demand Response (DR)	10.8	11.2	11.2	11.2	11
Energy Efficiency (EE)	17.7	19.4	17.7	20.5	20.5
Distributed Generation (DG)	19.9	19.9	19.9	28.6	20.5

Table 3: DER Capacity (GW): 20-Year Technical Potential & Additions in MISO

Series 1A DERs Energy (GWh) Technical Potential & Added	Future 1A	Future 2A		Future 3A	
	Added	Potential	Added	Potential	Added
Demand Response (DR)	1,051	1,147	1,147	1,154	1,142
Energy Efficiency (EE)	75,620	80,247	75,620	78,763	78,763
Distributed Generation (DG)	34,977	34,977	34,977	48,173	35,993

Table 4: DER Energy (GWh): 20-Year Technical Potential & Additions in MISO

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response*	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response*	C&I Price Response
DR	Residential Direct Load Control*	Res. Direct Load Control
DR	Residential Price Response*	Res. Price Response
EE	C&I High-Cost EE*	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retro commissioning Low
EE	C&I Mid-Cost EE*	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retro commissioning Mid
EE	Residential High-Cost EE*	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

Table 5: EGEAS Program Block/Specific DER Program Mapping

* Program increment was selected as economically viable and utilized by EGEAS in the resource expansion.

Natural Gas Resources

Combined Cycle (CC) and Combustion Turbine (CT) were the two gas resource types modeled. Site priority levels for these units remained the same when selecting a site. However, CC units were given a higher priority over CT units.

Resource Siting Process

RRF unit siting processes were developed to help identify where future generation would likely be located. While different RRF unit types need their own siting processes, there are universal criteria that apply to each resource type's unique siting process. These universal siting criteria and resource-specific processes are discussed below.[32]

[32] All capacities referenced in this section are (MW).

Universal Siting Criteria

To help improve siting measures, the following criteria underlie all resource-specific siting processes.

1. The same sites were used for each Future and site differences only occurred due to Future-specific renewable capacity needs and expansion timing. This included only using sites that were found in both the Year 5 and Year 10 MTEP Powerflow models.
2. Radial lines and associated buses were identified in the MTEP Powerflow models and excluded from potential resource sites.
3. Sited capacity could not exceed a site's N-1 capacity amount. This means the summation of all the transmission elements, excluding the highest rated capacity element, could not have a lower capacity than the resource capacity. Exception applies to units sited at buses selected by direct stakeholder feedback or site-specific planned resources.
4. Units were sited at MISO-owned transmission elements with the exception of several planned wind resources in MISO South due to stakeholder feedback.
5. Stakeholders had the opportunity to review and provide feedback on Future 2A resource siting. Usability of bus and alternatives provided by stakeholders were considered and referenced for subsequent Future 1A and 3A siting.
6. Resources were sited to ensure each Local Resource Zone (LRZ) met its Local Clearing Requirement (LCR) on an estimated accredited capacity basis in each milestone year.
    - The Planning Reserve Margin Requirement (PRMR) for each LRZ was evaluated and some manual adjustments to resource siting was made to address any significant surplus or deficits on an LRZ-level basis.
7. The 80/20 distribution between Generation Interconnection (GI) and VCE/Greenfield Sites for renewable resources developed during Series 1, was maintained to the extent feasible given GI site capacity availability as well as stakeholder feedback solicited in Future 2A and implemented in Future 1A, 2A, and 3A.
    - High renewable capacity expansions identified in Series 1A exhausted GI site availability for some resources. This resulted in a higher distribution of capacity to lower priority sites than the foundational 80/20 methodology.
    - Alternative buses provided by stakeholder feedback on queue sites were considered and counted towards the 80% GI queue split.

Wind and Solar PV

Resources of this type were modeled as a collector system, representing an aggregated capacity potential that can be installed within 10-30 miles of each site. Renewable capacity was first allocated to address LBA-scale RPS goals for each 5-year milestone (2027,2032,2027, 2042), with the remaining model-built capacity sited according to the following site priorities:

1. 80% of model-built capacity was distributed to Active DPP Phase 1,2, or 3 GI sites and Tranche 1 enabled sites.
    - If 80% of model-built capacity exceeded GI queue site availability, GI sites were utilized to their maximum site capacity with the remaining capacity distributed to lower priority sites.
    - GI projects were ranked based on GI queue status (projects further along in the GI study process were ranked higher)
2. The remaining 20% of model-built capacity was distributed among LBAs in proportion to the LBA's percentage of total GI queue capacity for each resource type, with the following site priorities:

- Vibrant Clean Energy[33] (VCE) results. Collector buses represent a 20- to 30- mile aggregated capacity potential.
- Greenfield siting criteria at available, high-capacity buses.
- Alternative buses provided by stakeholder feedback on either VCE, or greenfield sites were considered and counted towards the 20% distribution of renewable capacity.

Utility-Scale Solar PV + Storage (Hybrid)

Hybrid units were sited the same as Solar PV units. Only 80% of Hybrid generation allocated for RPS goal fulfillment was counted towards total sited RPS-eligible generation to account for solar vs. battery eligibility on an RPS-by-RPS basis.

Distributed Solar PV Generation (DGPV)

Distributed solar PV resources (DGPV) siting methodology utilized the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand Model (dGen) and consisted of the following:

- Used dGen to identify top 25 counties by DGPV potential within each LRZ.
- Identified (up to) top 30 load buses for each county.
- Distributed county capacity using dGen results weighting.
- DGPV sites were capped at a maximum capacity of 25 MW for MISO and 50 MW for external pools based on stakeholder feedback received during Future 2A siting.

Lithium-Ion Battery (4-hour)

Batteries were restricted to a minimum 2042 cumulative capacity of 50 MW and capped at a maximum capacity of 400 MW (PROMOD performance reasons).

1. 80% of model-built capacity was distributed to Active DPP Phase 1,2, or 3 GI sites.
   - If 80% of model-built capacity exceeded GI queue site availability, GI sites were utilized to their maximum site capacity with the remaining capacity distributed to lower priority sites.
   - GI projects were ranked based on GI queue status (projects further along in the GI study process were ranked higher)
2. The remaining 20% of model-built capacity was distributed among LRZs in proportion to the LRZ's percentage of total GI queue capacity for battery resources, with the following split:
   - 80% of battery capacity was sited at identified top load buses greater than 100 kV.
   - 20% of battery capacity was sited at the highest N-1 capacity buses near generation.
   - If an LRZ needed more than one battery site, the next bus selected would be from a different county to maintain geographical distribution.

Demand Response

Demand Response was sited at top load buses per LBA. Stakeholders had the opportunity to review and provide feedback on the buses identified. Alternative buses provided by stakeholder feedback were utilized in lieu of top load bus previously selected.

[33] VCE Report - https://cdn.misoenergy.org/2018%20VCE%20Study_Results536959.pdf

Combined Cycle and Combustion Turbine

Combined Cycle and Combustion Turbine siting largely remained the same as in past MTEP cycles with site rankings as follows:

- Combined Cycle units got higher priority sites over Combustion Turbine
- Priority 1: Active Definitive Planning Phase (DPP) Phase 1, 2, 3 Generator Interconnection Queue
- Priority 2: Brownfield – Existing and Retired Sites
  - Retired sites ranked by earliest commission date.
  - Retired sites had to be 50 MW and greater.
- Priority 3.1: SPA or Canceled/Postponed GI Queue
- Priority 3.2: Greenfield Siting Criteria

Flex Units

Flexible Attribute Units were sited at brownfield retirement sites not utilized for thermal model-built capacity siting, with the following site priorities:

- Priority 1: Retirement sites were selected to address LRZ-level deficits in the Planning Reserve Margin Requirement (PRMR) after all other resource types had been sited. Within deficit LRZ site selection, sites were ranked by earliest commission date.
- Priority 2: After PRMR site selection, retirement sites were ranked and utilized by earliest commission date.
- For Future 2A, the timing of Flex unit siting was driven by the above priorities, resulting in most Flex capacity being sited within Year 5 of the study period (2027). A small portion of Flex units were sited in later milestone years due to either a lack of available retirement sites with earlier commission dates or site selection based on PRMR.
- As a proxy resource representing a non-exhaustive range of existing and nascent technologies, Flexible Attribute Units were not restricted to thermal brownfield sites in state and local balancing authorities without clean energy goals.

JuiceBox: Generation Resource Portal

MISO partnered with the software company JuiceBox on the development of a public, interactive, online portal to host the Futures Series 1A expansion and siting results.

The portal is populated with existing, planned, and model-built generation for each Future, allowing users to explore Series 1A expansion and siting results using maps and charts (Figure 51). Generation units are displayed according to user-defined filters, including region, zone, fuel class, unit name, and status (existing, planned, model-built, retiring, and non-retiring). Following filter selection, results over the study period are available for generation (TWh), installed capacity (MW), and production cost (Mil$) by fuel type. Users can switch between charts using a dropdown menu located in the chart area. Annual generation, capacity, and utilization data is available for individual units by selecting the unit within the map display.

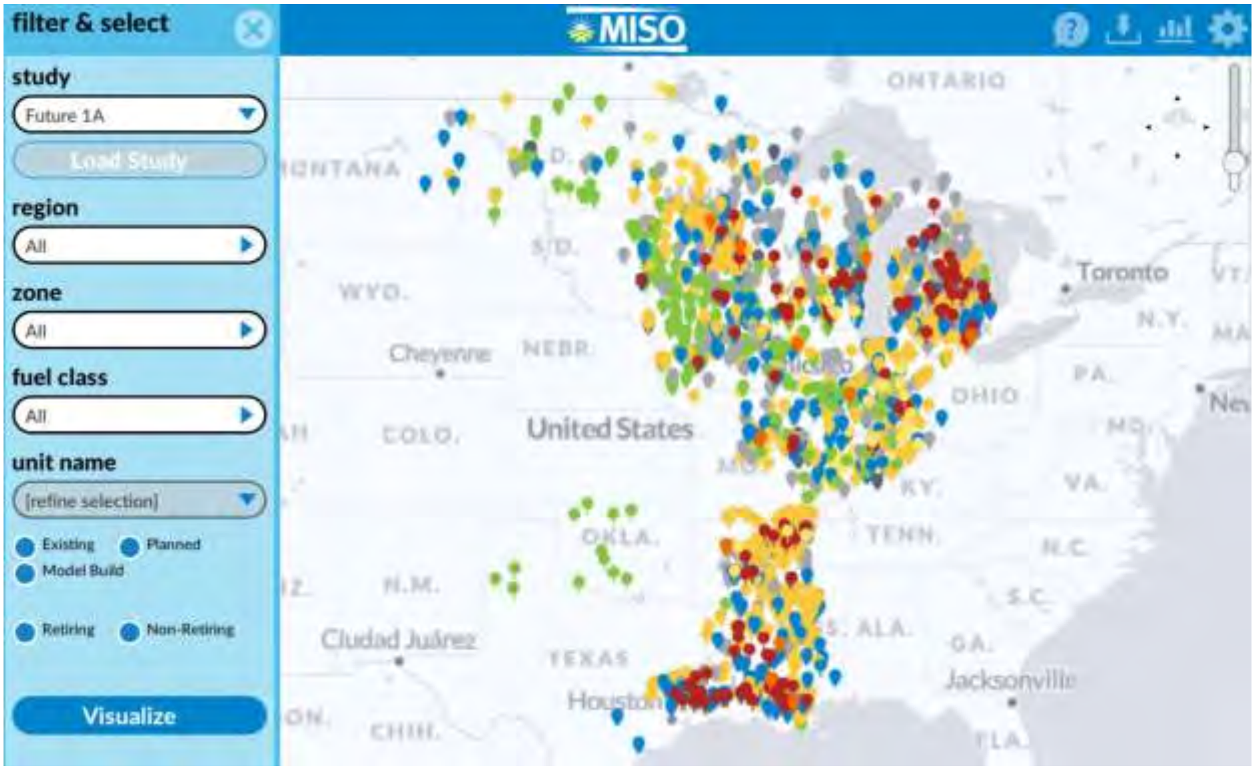


Figure 51: Screenshot of Future 1A expansion and siting as visualized in the Generation Resource Portal (JuiceBox).

MISO Expansion Results

While comparing the expansion results of the MISO footprint across each Future scenario, there are several key findings of note:

- All scenarios have relatively large amounts of renewable additions. Generally, this reflects industry-wide fleet evolution. More specifically, it owes to clean energy trajectories that incorporate decarbonization and renewable energy goals from member utilities and states, bolstered by policy innovation from the IRA and CEJA.
- Given lower accreditation of renewable resources compared to thermal generation, Future 1A and 3A result in a lower planning reserve margin (PRM) at the end of the study period than the start. Future 2A's PRM grows given addition of 29 GW of Flexible Attribute Units following the chronological energy validation in PROMOD. All Futures maintain a minimum 18.05% PRM for each year of the study period.
- All scenarios include 199 GW of member-planned resources. These planned resources account for 93% of the total expansion for Future 1A, 54% for Future 2A, and 44% for Future 3A. Within each Future's expansion results, total installed capacity is provided for each study year, broken out by existing, planned, and model-built resources.
- As the scenarios progress from F1A to F2A and F3A, more capacity is built due to increases in load and decarbonization.
- Futures 2A and 3A add significantly more wind than in F1A; this is primarily due to the increase in load, wind energy production and resulting PTC advantage, and respective shifts to dual- and winter-peaking systems.
- In Future 2A, Hybrid selection is somewhat offset by Battery selection. Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across all scenarios. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- Distributed generation, energy efficiency (EE), and demand response (DR) resources are composed of both DER programs and specific member feedback.

Future Resource Additions (MW)															
	CT	CC	ST Gas	IC Gas	ST Coal	Wind	Solar	Hybrid	Battery	Distributed Solar	DR	EE	UDG	Flex	Totals
Future 1A	7,858	10,000	2,964	1,839	163	66,634	57,102	12,225	10,799	17,138	7,327	17,589	2,688	0	214,326
Future 2A	9,058	10,000	2,964	1,839	163	144,634	84,702	9,825	31,099	17,137	7,770	17,589	2,688	29,800	369,269
Future 3A	18,658	13,600	2,964	1,839	163	196,234	107,502	19,425	39,599	17,794	7,511	20,448	2,688	0	448,425

Future Resource Retirements (MW)								
	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Totals
Future 1A	42,048	23,348	0	1,971	17,638	1,262	1,243	87,510
Future 2A	42,639	37,608	0	2,351	17,638	1,262	1,243	102,741
Future 3A	47,510	59,813	0	2,436	17,638	1,262	1,243	129,903

Table 6: MISO Resource Additions and Retirement Totals

Figure 52Figure 50 details the results from each Future scenario's resource additions as displayed in the table above. Solar resources are comprised of utility-scale solar PVand distributed solar resources. Wind totals include expansion wind units and repowered wind assumptions. The other resource category includes energy efficiency and demand side management programs selected within each Future. Gas resources include CC, CT, IC Gas, and ST Gas units.

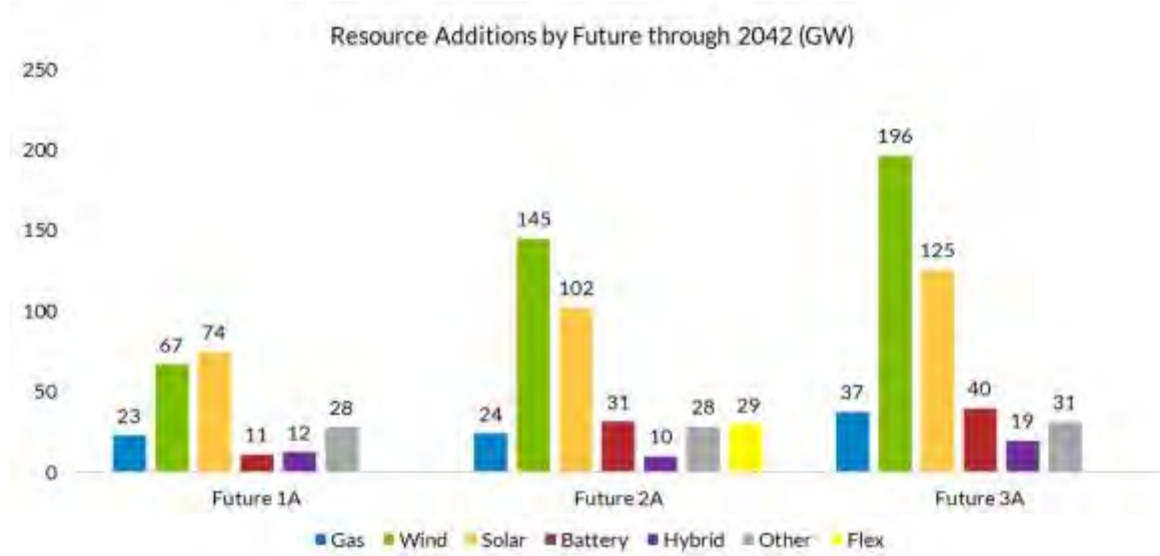


Figure 52: MISO Resource Addition Summary by Future

MISO – Future 1A

Future 1A – Retirements and Additions

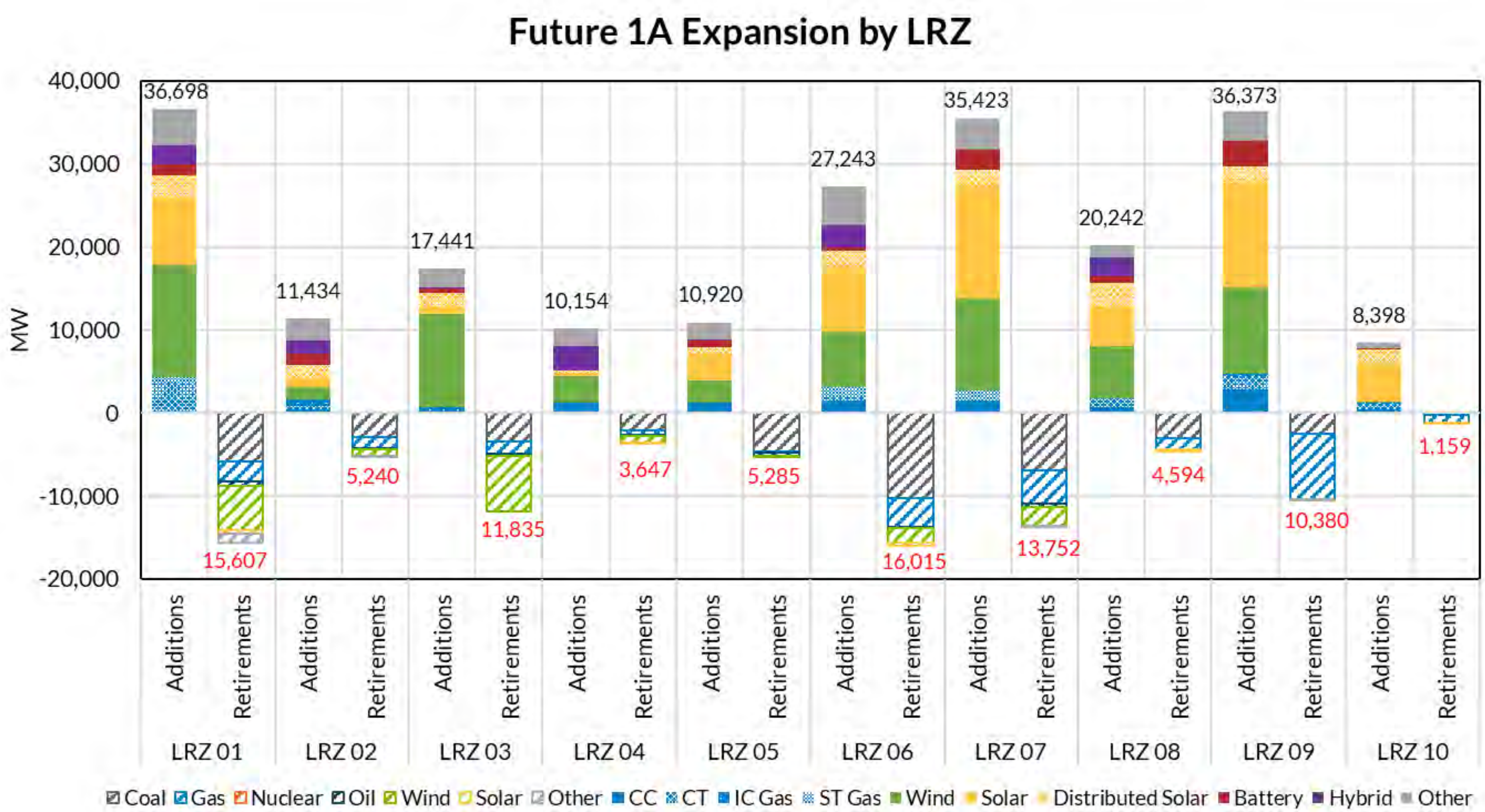


Figure 54: MISO Future 1A Resource Retirement and Addition Summary

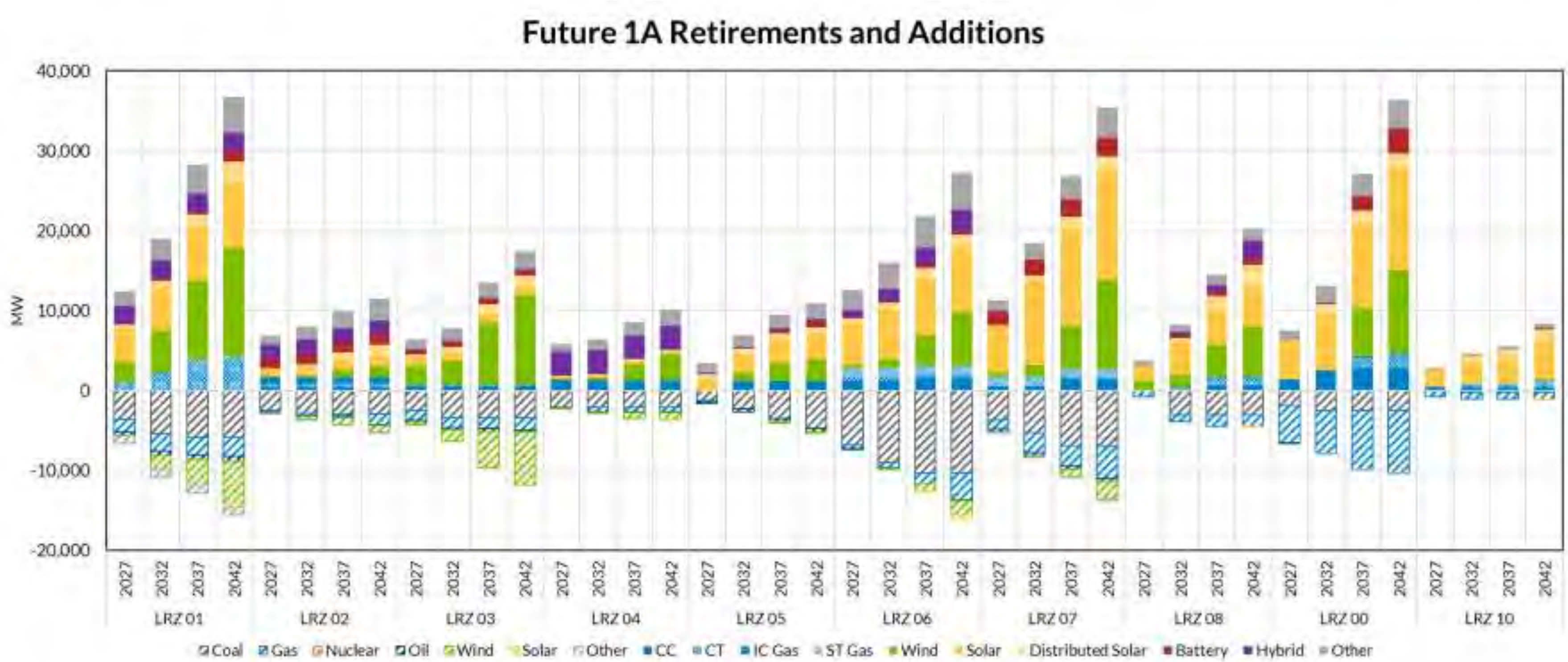


Figure 55: Future 1A Resource Retirement and Addition Summary by Milestone Year

Future 1A – Installed Capacity

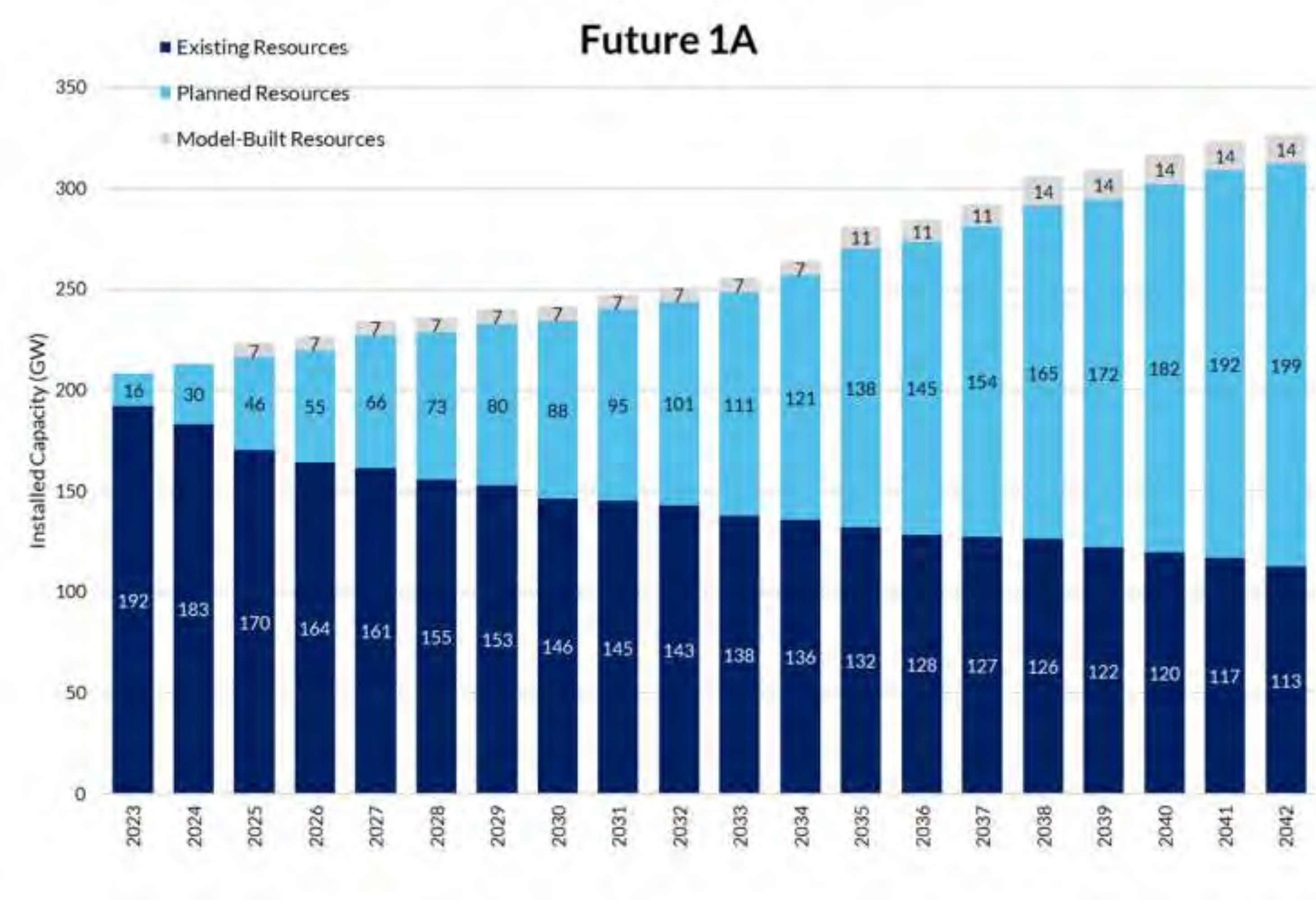


Figure 56: MISO F1A installed capacity of existing, planned, and model-built resources (GW).

Future 1A – Estimated Accredited Capacity

Figure 57 provides the end-of-year (EOY) installed and estimated accredited capacity (EAC)[34] for Future 1A. Figure 58 provides a beginning-of-year (BOY) outlook, overlaid with the load plus reserve. This alternative outlook aligns with the capacity expansion tool's output reporting for net load and attainment of a minimum 18.05% planning reserve margin (PRM) throughout the study period.

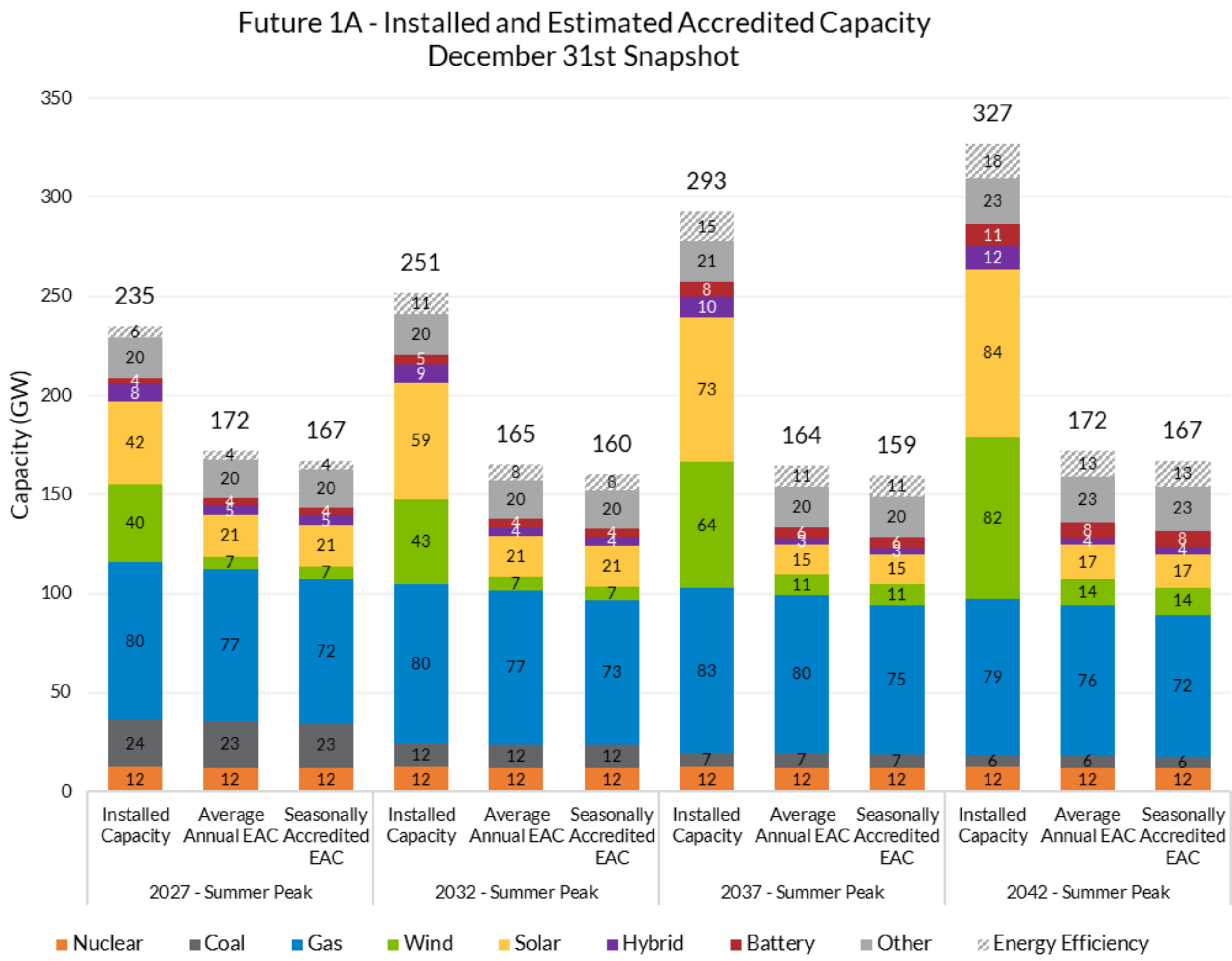


Figure 57: Installed, Seasonally Accredited[34] and Average Annual Estimated Accredited Capacity for Future 1A. Values reflect an end-of-year (December 31st) snapshot.

[34] Accreditation of thermal resources includes seasonal multipliers to align thermal capacity with seasonal peak; Future 1A is summer-peaking for the duration of the study period. Accordingly, thermal resources are seasonally de-rated from their average annual reserve capacity, resulting in a lower total estimated accredited capacity than the average annual EAC for all milestone years.

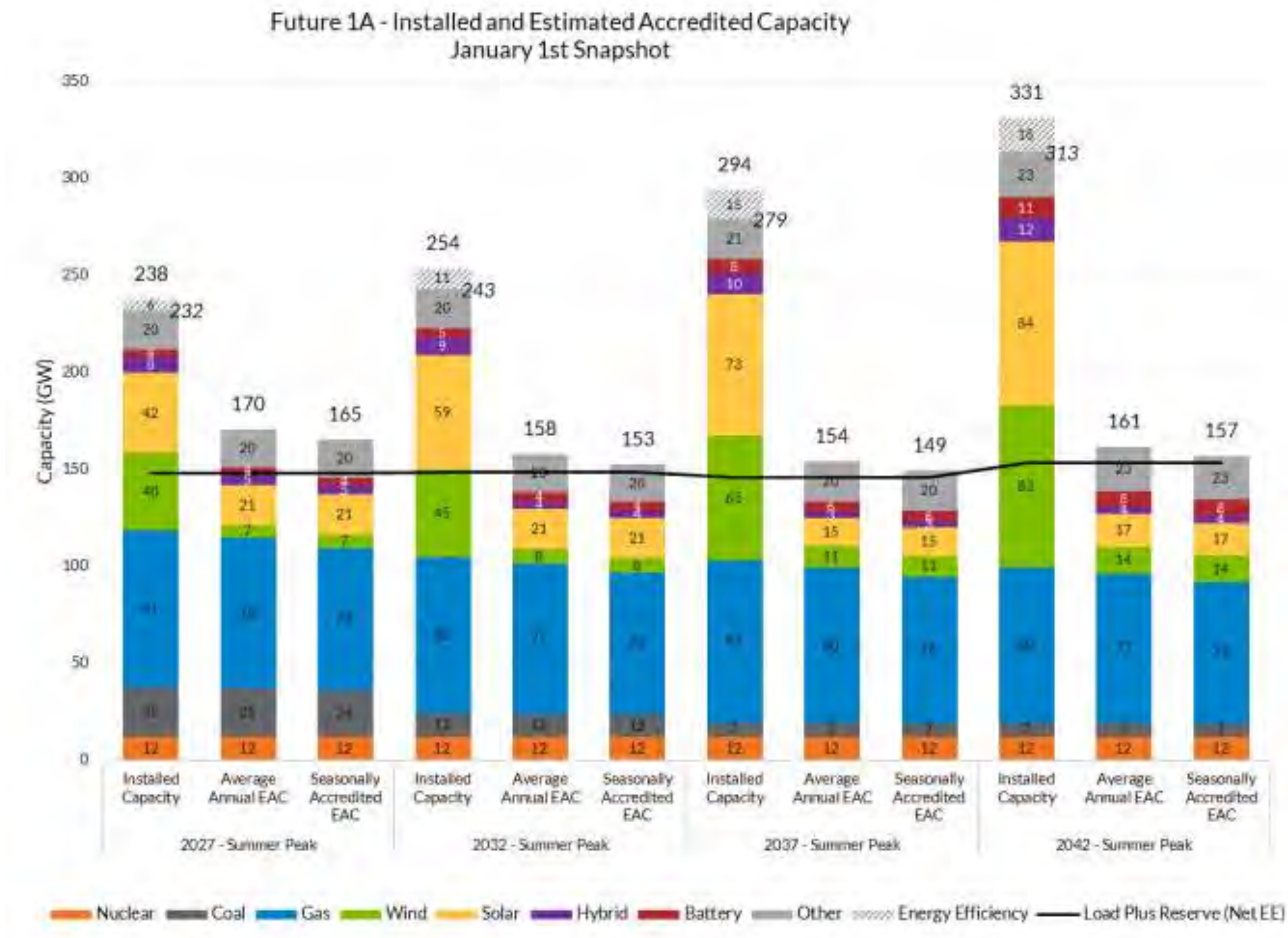


Figure 58: Installed, Seasonally Accredited[34] and Average Annual Estimated Accredited Capacity, with load plus reserve (net EE) for Future 1A. Installed capacity (net EE) totals are provided in *italics* for direct comparison with EAC.[35,36]

[35] The capacity expansion tool, EGEAS, utilizes the seasonal estimated accredited capacity in the calculation and attainment of a minimum 18.05% planning reserve margin (PRM) for all study years. Load plus reserve reflects netting of EE for calculation of PRM.

[36] Values reflect a beginning-of-year (Jan 1st) snapshot to align with the capacity expansion tool's output reporting for net load. Resources retiring in the reflected year are assumed to be in commission during system's summer peak given EGEAS' assumptions around retirement timing on December 31st.

Future 1A – Energy Production

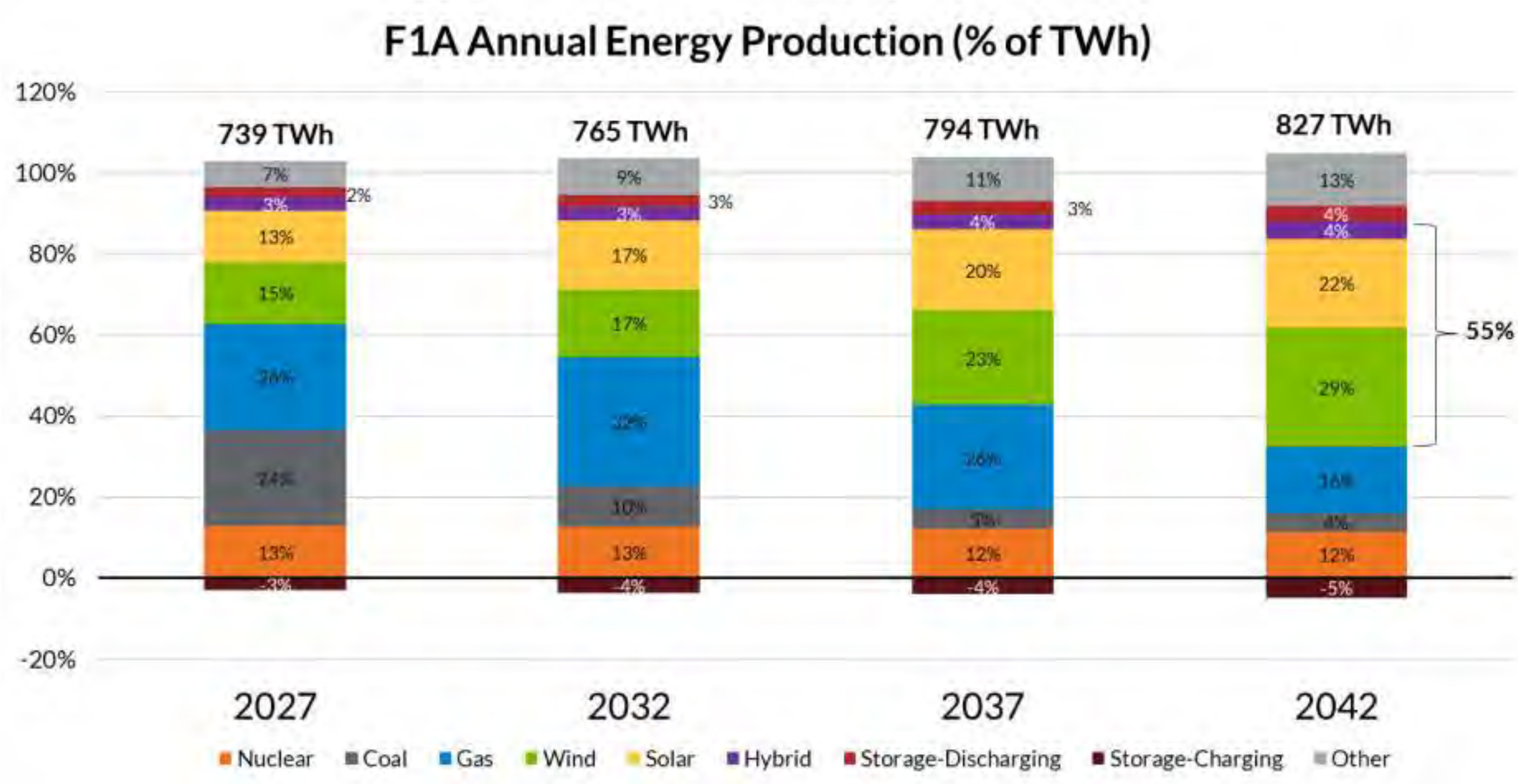


Figure 59: Future 1A Total Annual Energy Production by Milestone Year. Total energy production values are reported net storage-charging.

Future 1A – Generation Siting

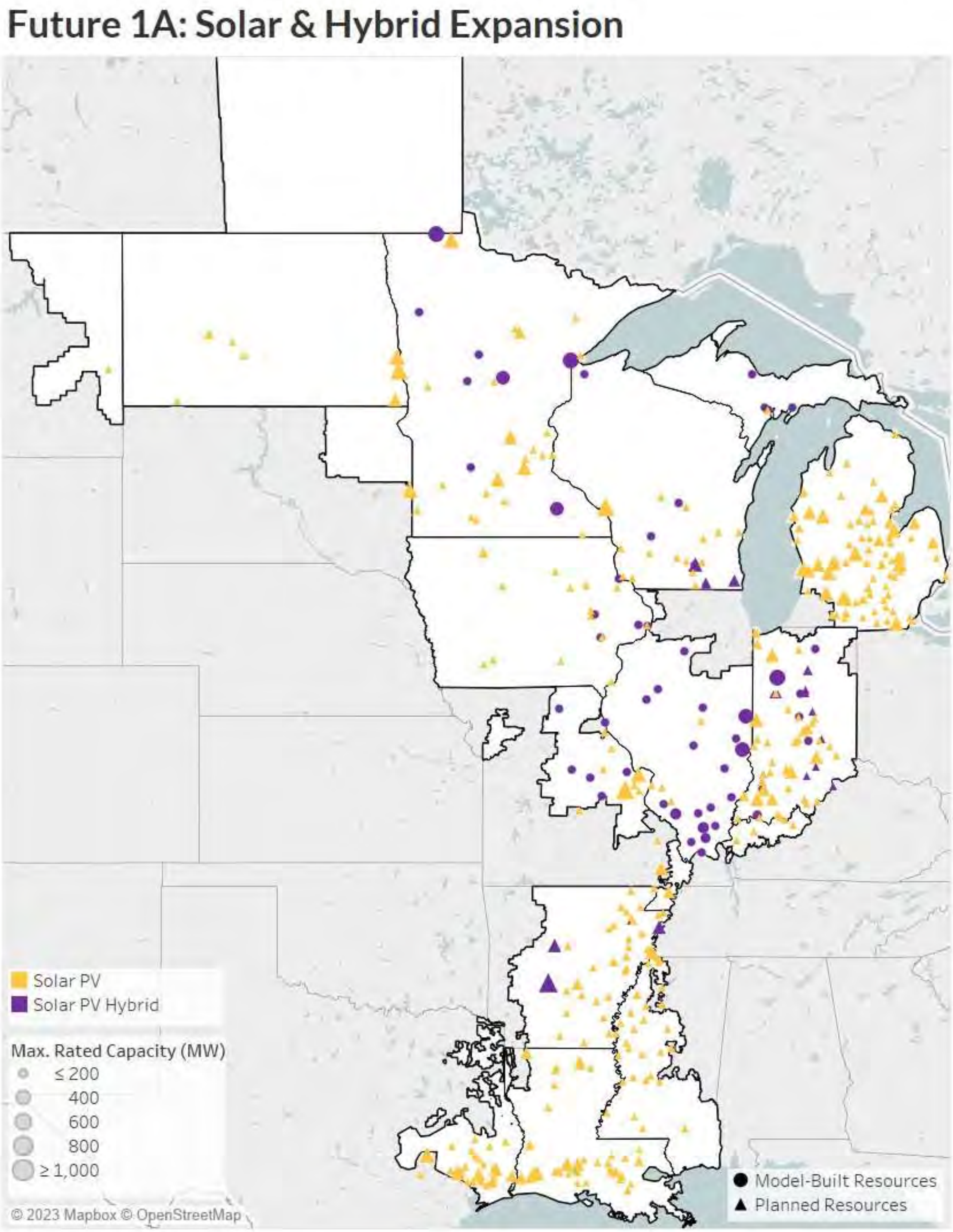


Figure 60**: MISO Future 1A Solar and Hybrid Siting**

Future 1A: Distributed Solar Expansion

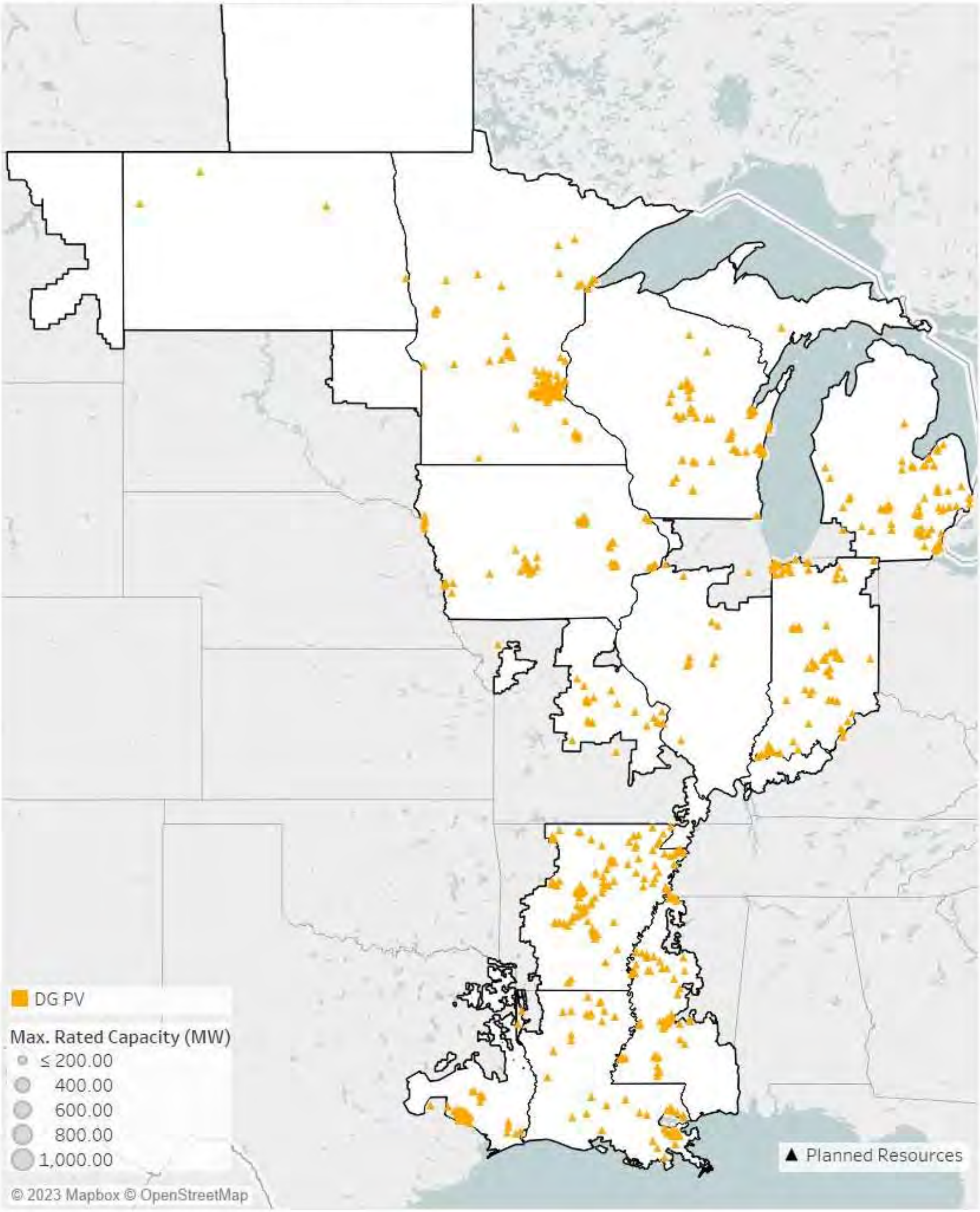


Figure 61: MISO Future 1A Distributed Solar Siting

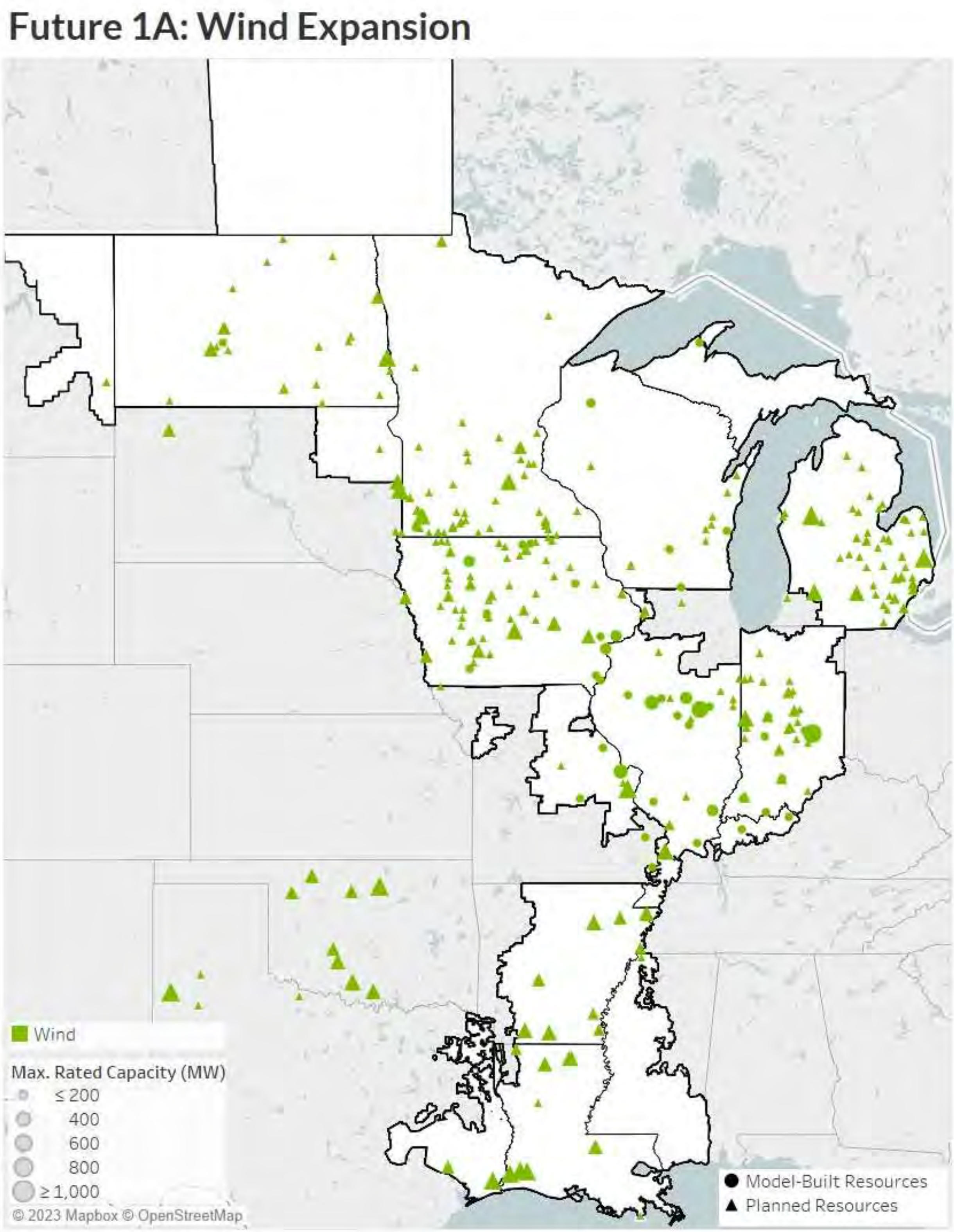


Figure 62: MISO Future 1A Wind Siting

Figure 63: MISO Future 1A Battery Siting

Future 1A: Thermal Expansion

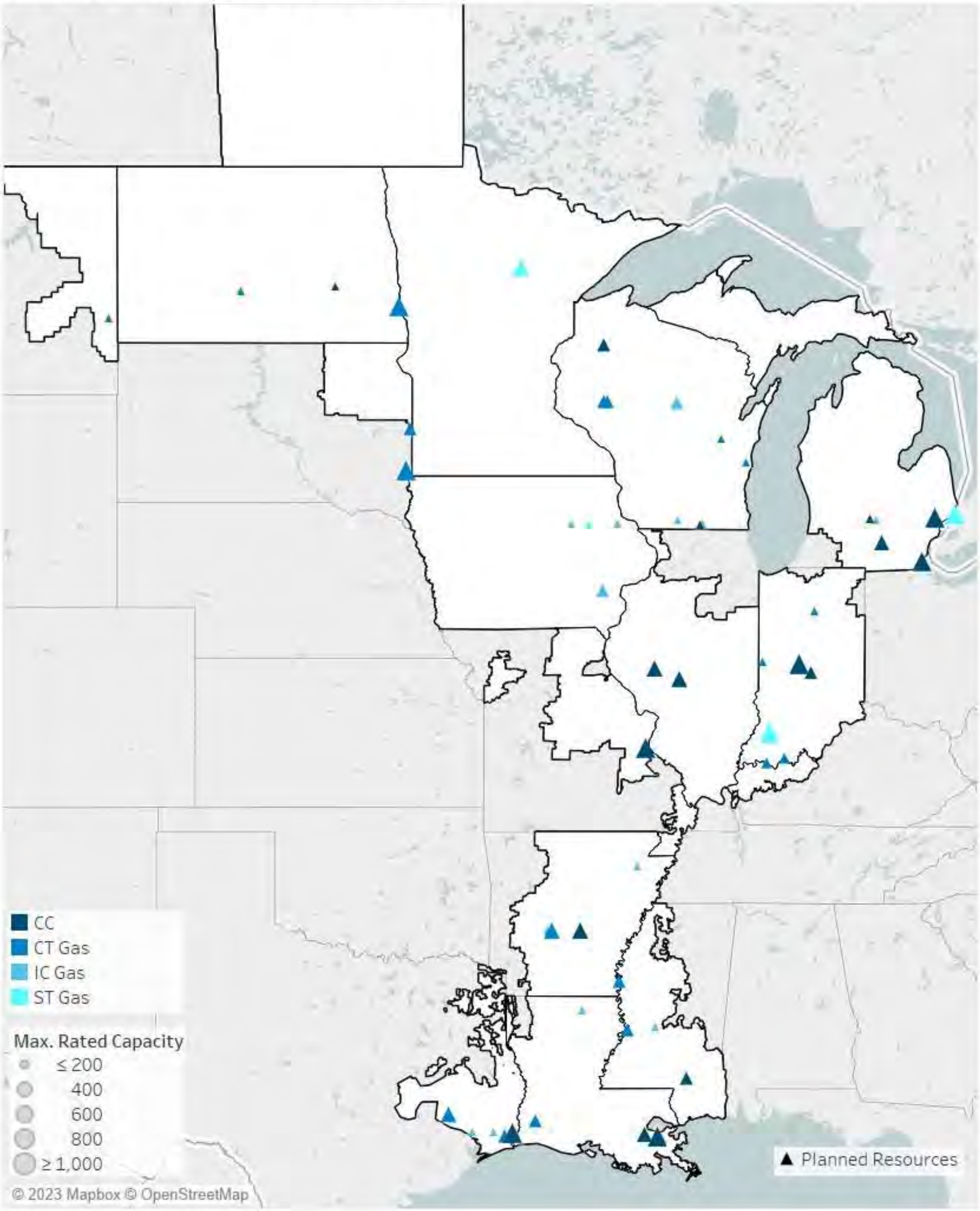


Figure 64: MISO Future 1A Thermal Siting

Future 1A: Model-Built Expansion

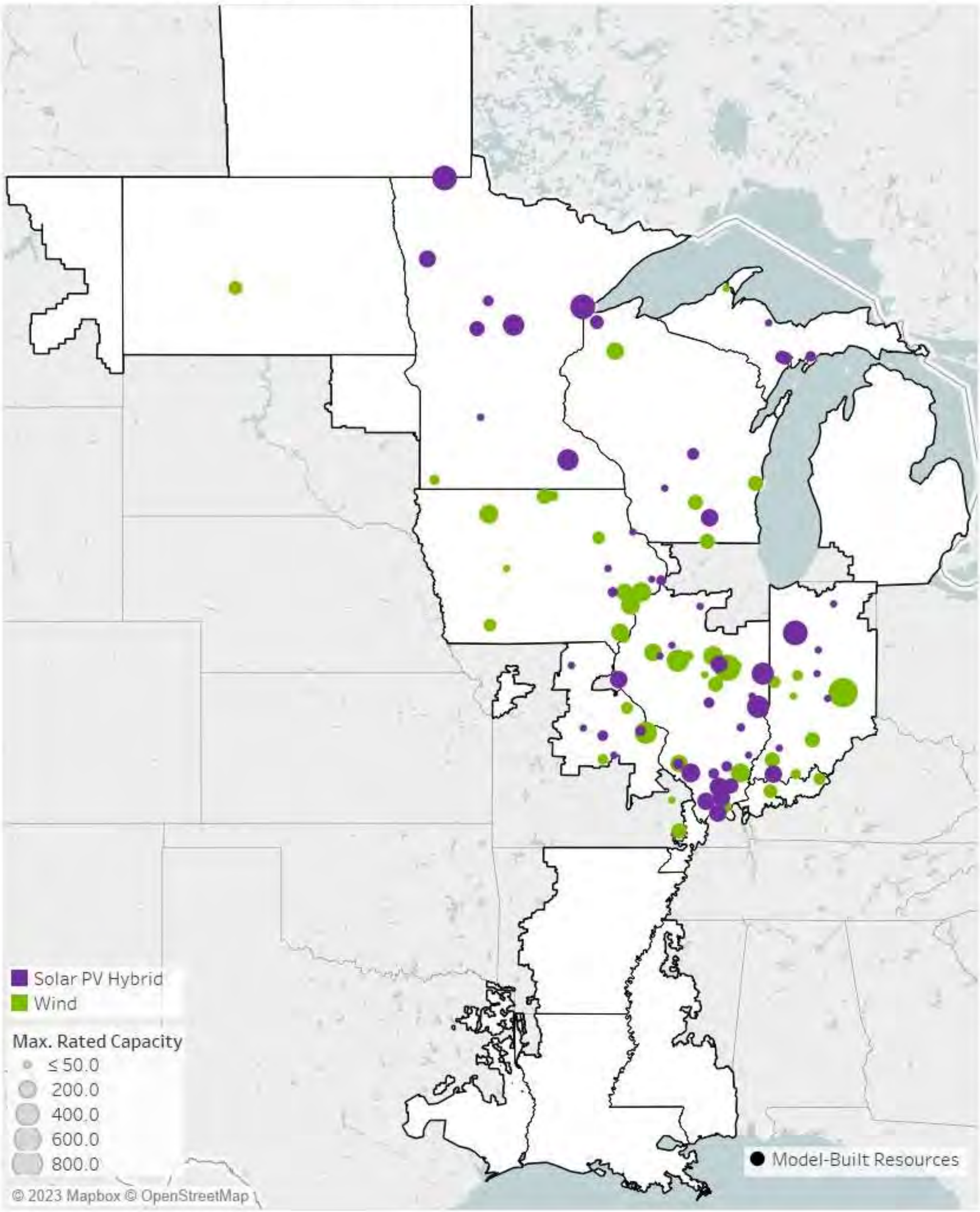


Figure 65: MISO Future 1A Complete EGEAS Expansion Siting

Future 1A: Planned Expansion

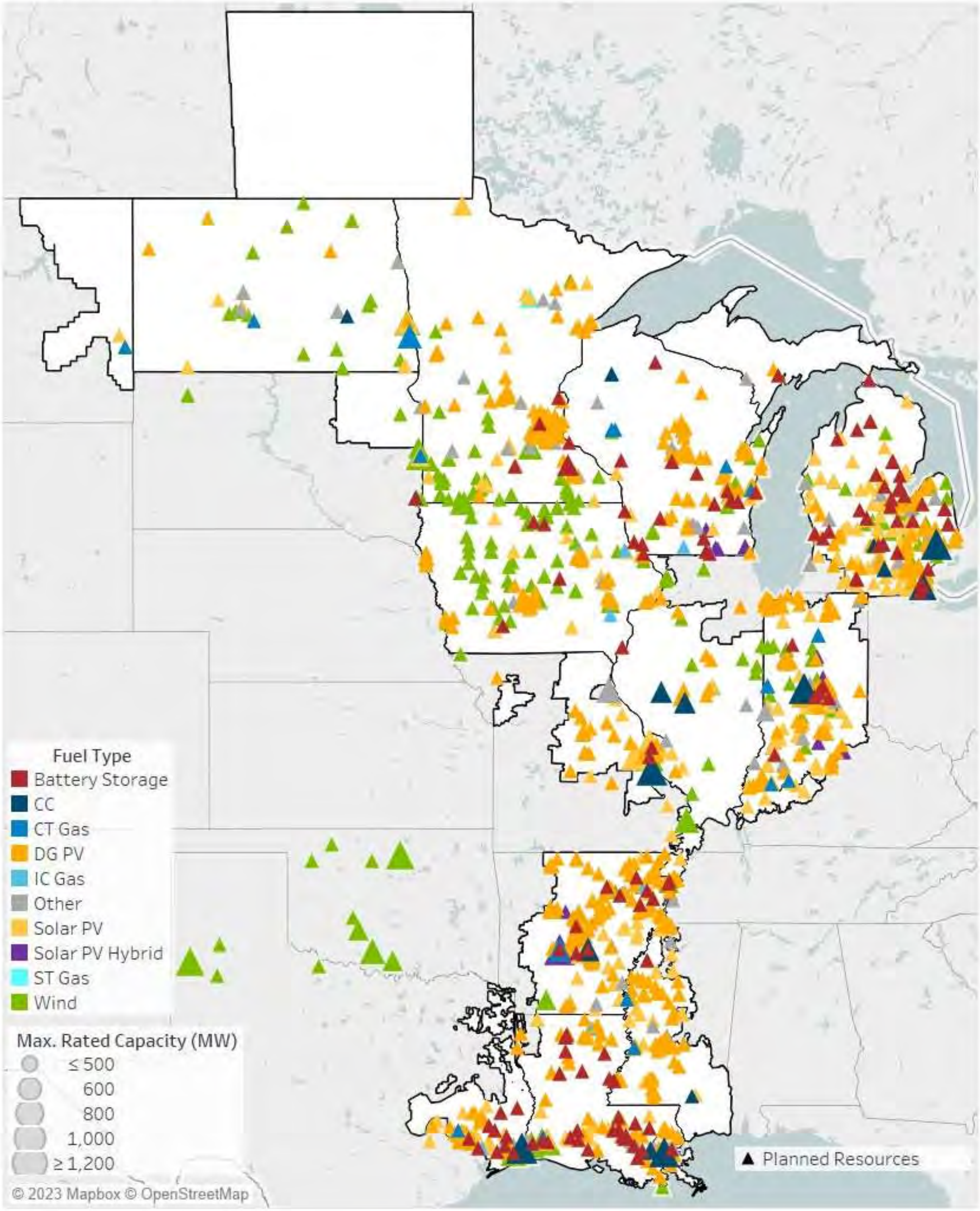


Figure 66: MISO Future 1A Non-EGEAS Expansion Siting

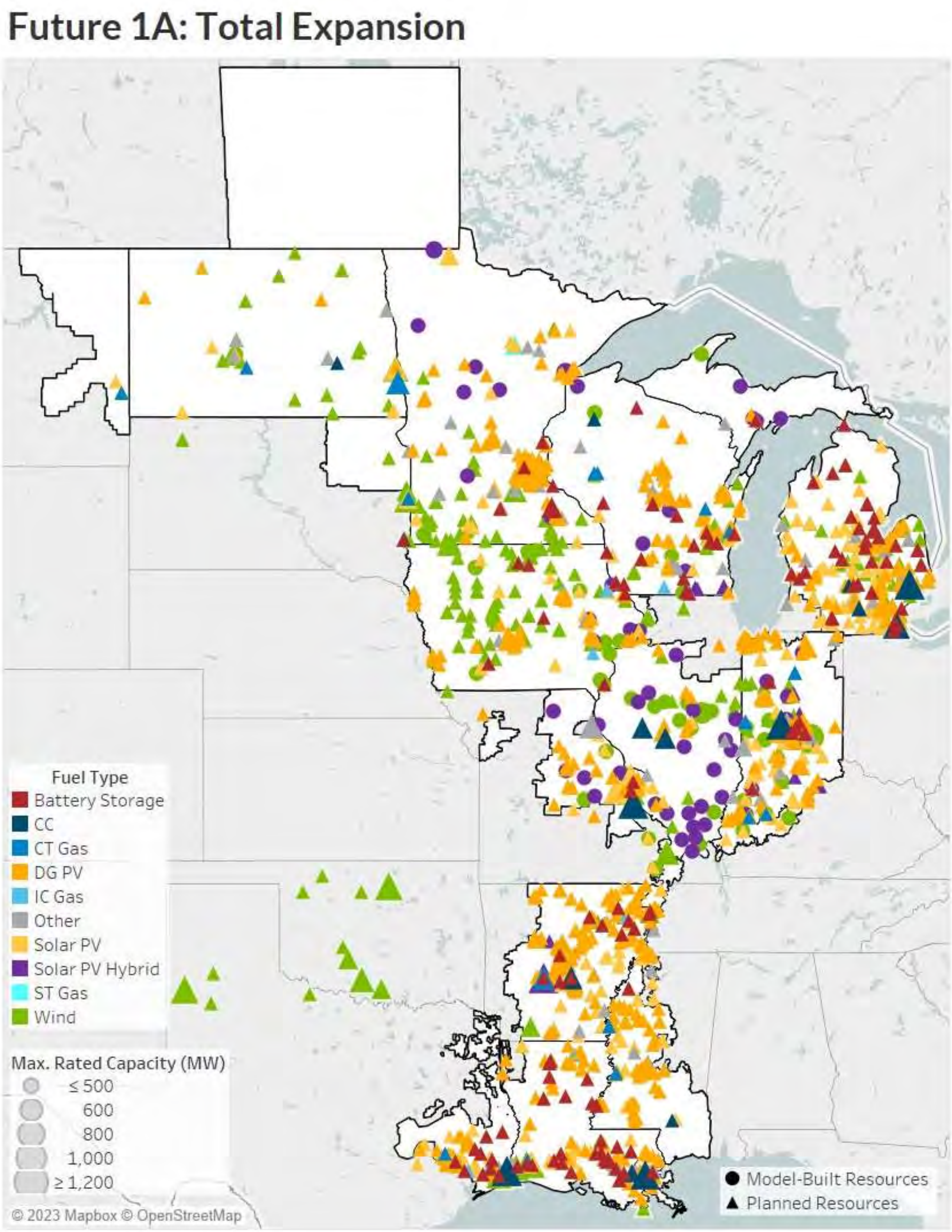


Figure 67: MISO Future 1A Non-EGEAS and EGEAS Expansion Siting

Future 1A Resource Additions (MW) - *Cumulative*															
Zone	**Milestone**	**Battery**	**CC**	**CT Gas**	**Demand Response**	**DGPV**	**IC Gas**	**Solar**	**Hybrid**	**ST Coal**	**ST Gas**	**Wind**	**EE**	**UDG**	**Totals**
LRZ 1	**2027**	20	100	981	845	375	0	4,375	2,285	163	0	2,445	804	18	12,411
	2032	270	100	2,103	940	925	0	5,225	2,285	163	0	5,343	1,579	42	18,975
	2037	270	100	3,225	1,255	1,675	0	6,625	2,285	163	595	9,795	2,128	115	28,231
	2042	1,270	100	3,599	1,411	2,675	0	8,175	2,285	163	595	13,490	2,559	376	36,698
LRZ 2	**2027**	1,179	487	300	550	30	843	1,039	1,734	0	0	122	572	13	6,869
	2032	1,312	487	300	563	405	843	1,139	1,734	0	0	122	1,048	30	7,983
	2037	1,312	487	300	568	967	843	1,139	1,734	0	0	1,023	1,440	82	9,896
	2042	1,312	487	300	634	1,555	843	1,139	1,734	0	0	1,413	1,748	269	11,434
LRZ 3	**2027**	475	0	0	800	418	670	1,000	153	0	50	2,403	400	9	6,378
	2032	575	0	0	824	675	670	1,000	153	0	50	3,060	733	21	7,761
	2037	575	0	0	854	1,375	670	1,000	153	0	50	7,744	1,008	58	13,486
	2042	575	0	0	898	1,500	670	1,000	153	0	50	11,184	1,223	188	17,441
LRZ 4	**2027**	0	1,277	0	561	0	0	375	2,983	0	0	250	400	9	5,855
	2032	0	1,277	0	586	150	0	375	2,983	0	0	258	733	21	6,384
	2037	0	1,277	0	621	250	0	375	2,983	0	0	2,013	1,008	58	8,584
	2042	0	1,277	0	651	275	0	375	2,983	0	0	3,182	1,223	188	10,154
LRZ 5	**2027**	0	0	0	800	725	0	1,270	242	0	0	35	343	8	3,423
	2032	0	1,200	0	800	725	0	2,270	242	0	0	1,035	629	18	6,919
	2037	400	1,200	0	800	725	0	2,970	242	0	0	2,237	864	49	9,487
	2042	800	1,200	0	800	725	0	3,170	242	0	0	2,773	1,049	161	10,920
LRZ 6	**2027**	80	1,221	513	1,655	680	0	5,158	978	0	1,052	404	858	20	12,617
	2032	300	1,221	513	1,655	881	0	6,208	1,428	0	1,052	1,134	1,571	45	16,007
	2037	480	1,546	513	1,655	1,317	0	7,058	2,103	0	1,052	3,827	2,159	123	21,833
	2042	460	1,546	513	1,655	1,795	0	7,858	2,628	0	1,052	6,712	2,622	403	27,243
LRZ 7	**2027**	1,842	509	0	351	0	0	5,965	0	0	1,267	426	915	21	11,295
	2032	1,974	509	0	402	650	0	10,524	0	0	1,267	1,426	1,676	48	18,476
	2037	2,215	1,455	0	462	1,650	0	12,016	0	0	1,267	5,321	2,303	132	26,821
	2042	2,376	1,455	0	527	1,975	0	13,516	0	0	1,267	11,081	2,796	430	35,423
LRZ 8	**2027**	0	0	0	300	0	95	1,935	0	0	0	1,100	343	8	3,781
	2032	400	0	380	305	550	95	4,035	400	0	0	1,500	629	18	8,312
	2037	550	667	1,047	320	1,775	95	4,335	800	0	0	3,944	864	49	14,446
	2042	760	667	1,047	340	2,900	95	4,835	2,200	0	0	6,188	1,049	161	20,242
LRZ 9	**2027**	10	1,215	0	339	0	173	4,885	0	0	0	0	915	21	7,558
	2032	195	2,317	0	349	1,300	173	7,035	0	0	0	0	1,676	48	13,093
	2037	1,730	2,866	1,260	374	1,750	173	10,535	0	0	0	5,956	2,303	132	27,079
	2042	3,060	2,866	1,640	411	2,050	173	12,535	0	0	0	10,412	2,796	430	36,373
LRZ 10	**2027**	0	402	0	0	0	58	2,150	0	0	0	0	172	4	2,786
	2032	0	402	380	0	700	58	2,750	0	0	0	0	314	9	4,613
	2037	0	402	380	0	1,150	58	3,050	0	0	0	0	432	25	5,497
	2042	185	402	760	0	1,688	58	4,500	0	0	0	200	524	81	8,398
MISO Total	**2027**	3,606	5,211	1,793	6,200	2,228	1,839	28,151	8,375	163	2,369	7,184	5,721	131	72,972
	2032	5,026	7,513	3,675	6,425	6,961	1,839	40,560	9,225	163	2,369	13,878	10,589	300	108,522
	2037	7,533	10,000	6,724	6,909	12,634	1,839	49,102	10,300	163	2,964	41,861	14,508	823	165,359
	2042	10,799	10,000	7,858	7,327	17,138	1,839	57,102	12,225	163	2,964	66,634	17,589	2,688	214,326

Table 7:MISO Future 1A Resource Additions by LRZ and Footprint

Future 1A Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2027**	3,639	1,604	0	325	123	0	962	6,653
	2032	5,396	2,136	0	570	1,772	0	996	10,870
	2037	5,885	2,136	0	570	3,178	24	1,014	12,807
	2042	5,885	2,381	0	584	5,274	470	1,014	15,607
LRZ 2	**2027**	2,515	166	0	76	102	0	20	2,879
	2032	2,844	299	0	76	385	0	20	3,623
	2037	2,960	299	0	139	823	0	20	4,241
	2042	2,960	1,263	0	139	823	11	44	5,240
LRZ 3	**2027**	2,462	1,269	0	240	311	0	0	4,283
	2032	3,407	1,269	0	240	1,468	0	0	6,385
	2037	3,407	1,363	0	319	4,582	0	0	9,672
	2042	3,407	1,481	0	319	6,628	0	0	11,835
LRZ 4	**2027**	2,123	0	0	117	20	0	0	2,260
	2032	2,123	564	0	117	28	0	0	2,832
	2037	2,123	564	0	117	698	0	0	3,502
	2042	2,123	564	0	117	823	20	0	3,647
LRZ 5	**2027**	1,251	67	0	345	0	0	0	1,663
	2032	2,257	67	0	345	0	0	0	2,669
	2037	3,471	67	0	345	169	0	0	4,052
	2042	4,704	67	0	345	169	0	0	5,285
LRZ 6	**2027**	6,838	475	0	50	0	0	0	7,363
	2032	8,986	693	0	50	131	0	0	9,860
	2037	10,256	1,331	0	50	942	2	0	12,581
	2042	10,256	3,468	0	71	1,742	475	0	16,015
LRZ 7	**2027**	3,692	1,163	0	390	0	0	38	5,283
	2032	5,297	2,446	0	390	113	0	147	8,392
	2037	6,922	2,524	0	390	929	0	147	10,911
	2042	6,922	4,061	0	390	2,180	54	147	13,752
LRZ 8	**2027**	0	788	0	0	0	0	0	788
	2032	3,089	788	0	0	0	0	0	3,877
	2037	3,089	1,324	0	0	0	0	0	4,413
	2042	3,089	1,324	0	0	0	181	0	4,594
LRZ 9	**2027**	1,880	4,627	0	7	0	0	0	6,515
	2032	2,496	5,352	0	7	0	0	28	7,883
	2037	2,496	7,358	0	7	0	0	39	9,900
	2042	2,496	7,838	0	7	0	0	39	10,380
LRZ 10	**2027**	0	816	0	0	0	0	0	816
	2032	206	816	0	0	0	0	0	1,022
	2037	206	816	0	0	0	0	0	1,022
	2042	206	901	0	0	0	52	0	1,159
MISO Total	**2027**	24,401	10,975	0	1,549	556	0	1,020	38,502
	2032	36,101	14,430	0	1,795	3,896	0	1,190	57,413
	2037	40,815	17,782	0	1,937	11,321	26	1,219	73,100
	2042	42,048	23,348	0	1,971	17,638	1,262	1,243	87,514

Table 8: MISO Future 1A Resource Retirements by LRZ and Footprint

MISO – Future 2A

Future 2A – Retirements and Additions

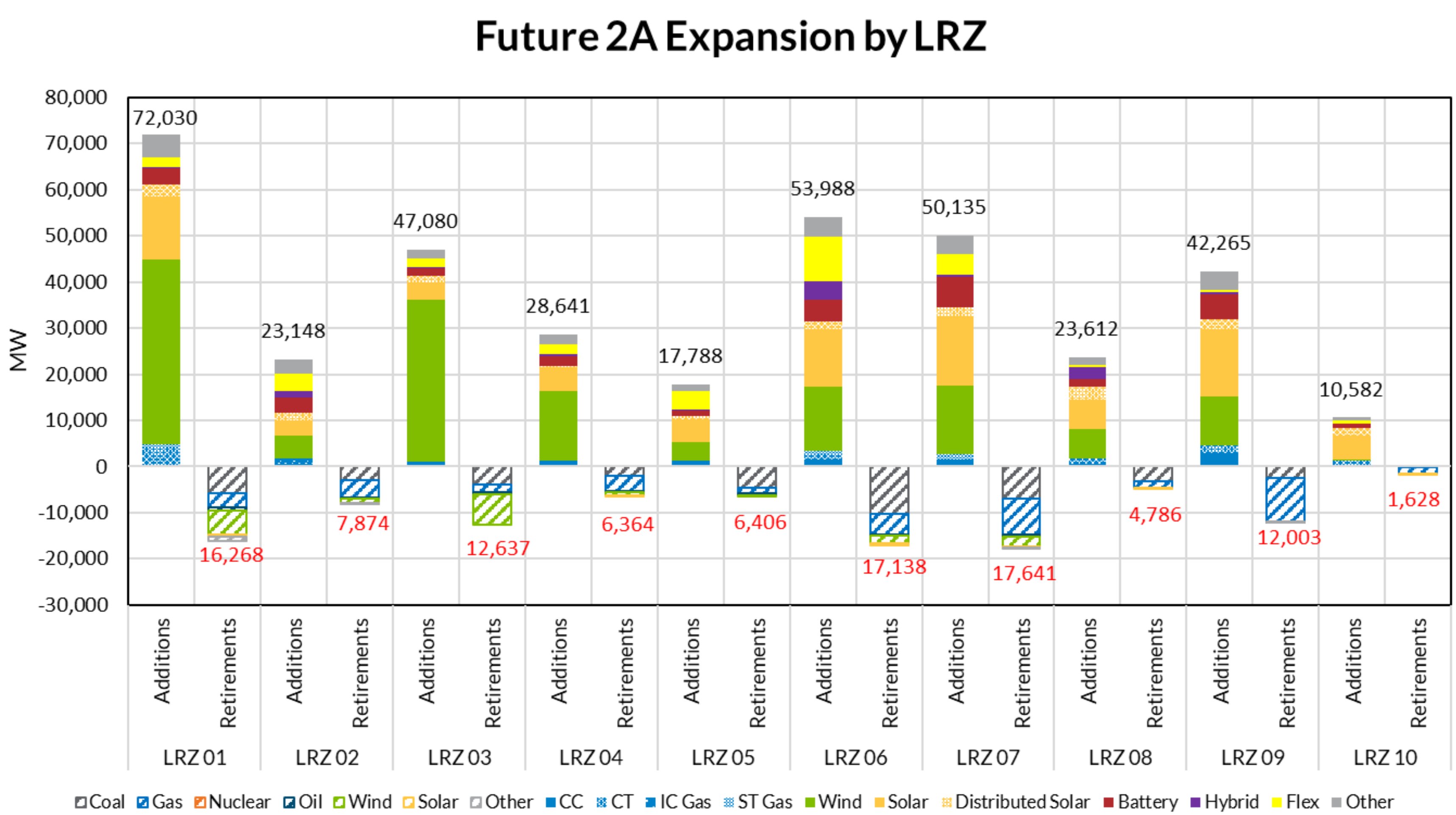


Figure 68: MISO Future 2A Resource Retirement and Addition Summary

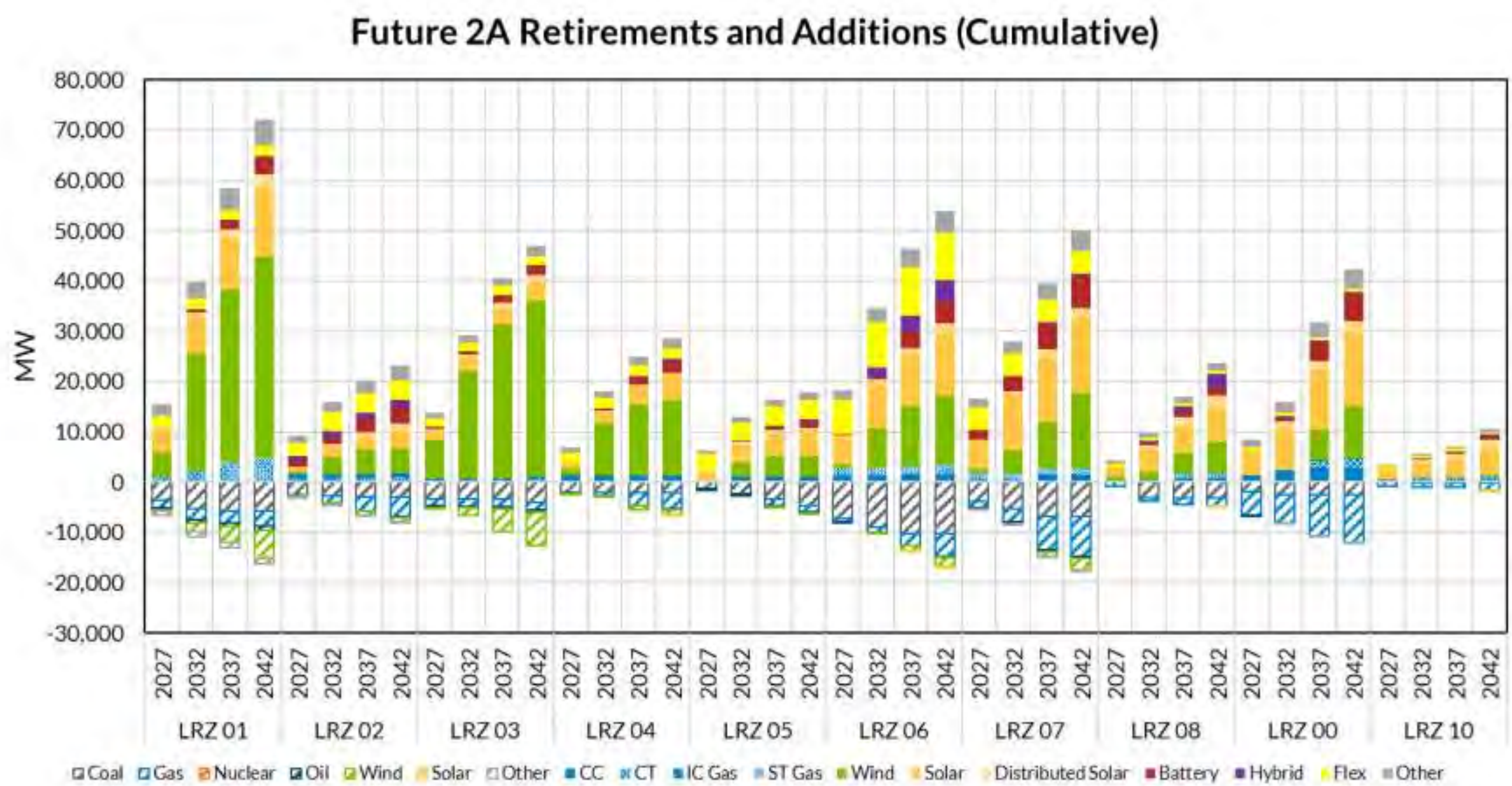


Figure 69: MISO Future 2A Resource Retirement and Addition Summary by Milestone Year

Future 2A – Installed Capacity

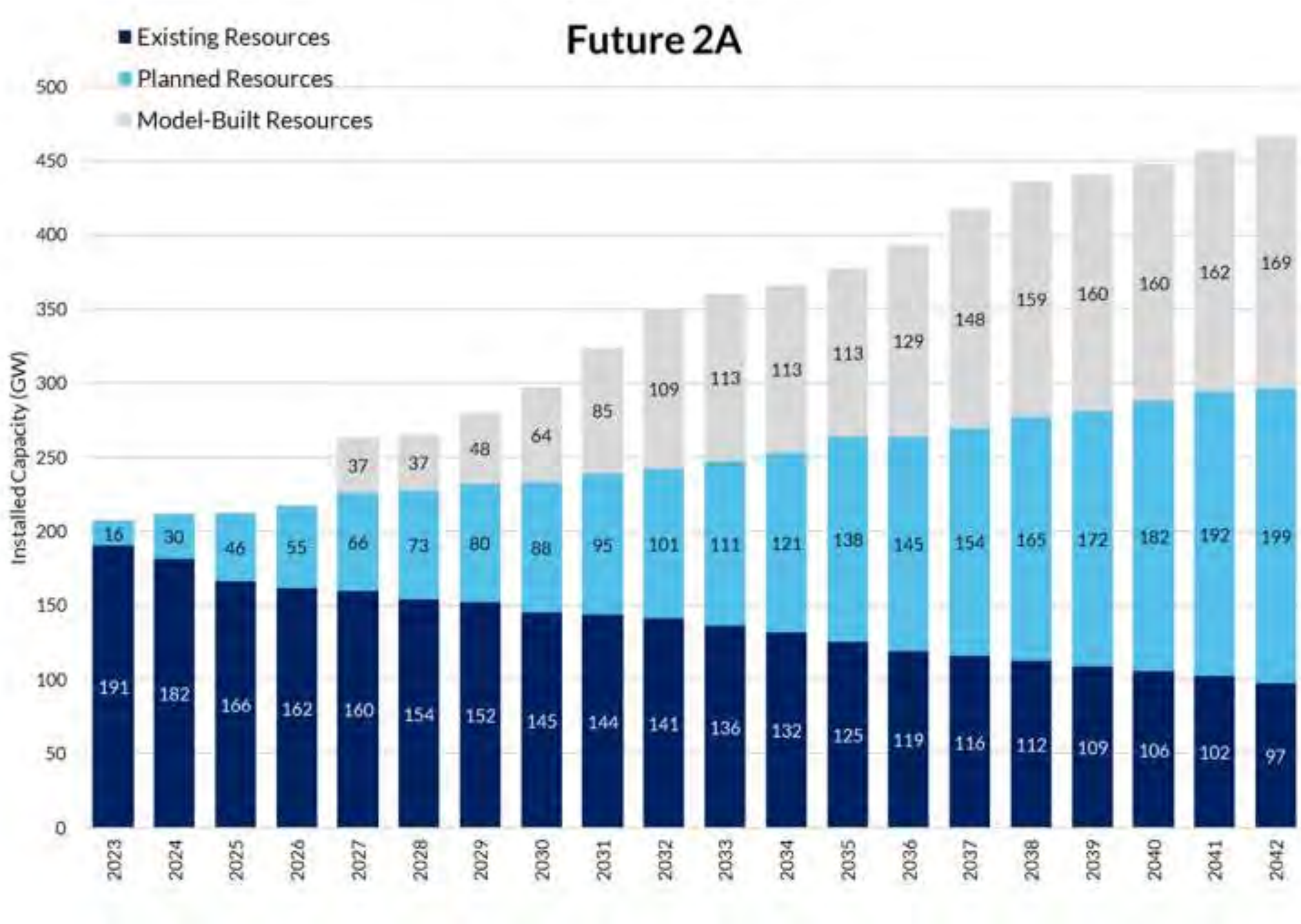


Figure 70: MISO F2A installed capacity of existing, planned, and model-built resources (GW)

Future 2A – Estimated Accredited Capacity

Figure 71 provides the end-of-year (EOY) installed and estimated accredited capacity (EAC)[38] for Future 2A. Figure 72 provides a beginning-of-year (BOY) outlook, overlaid with the load plus reserve. This alternative outlook aligns with the capacity expansion tool's output reporting for net load and attainment of a minimum 18.05% planning reserve margin (PRM) throughout the study period.

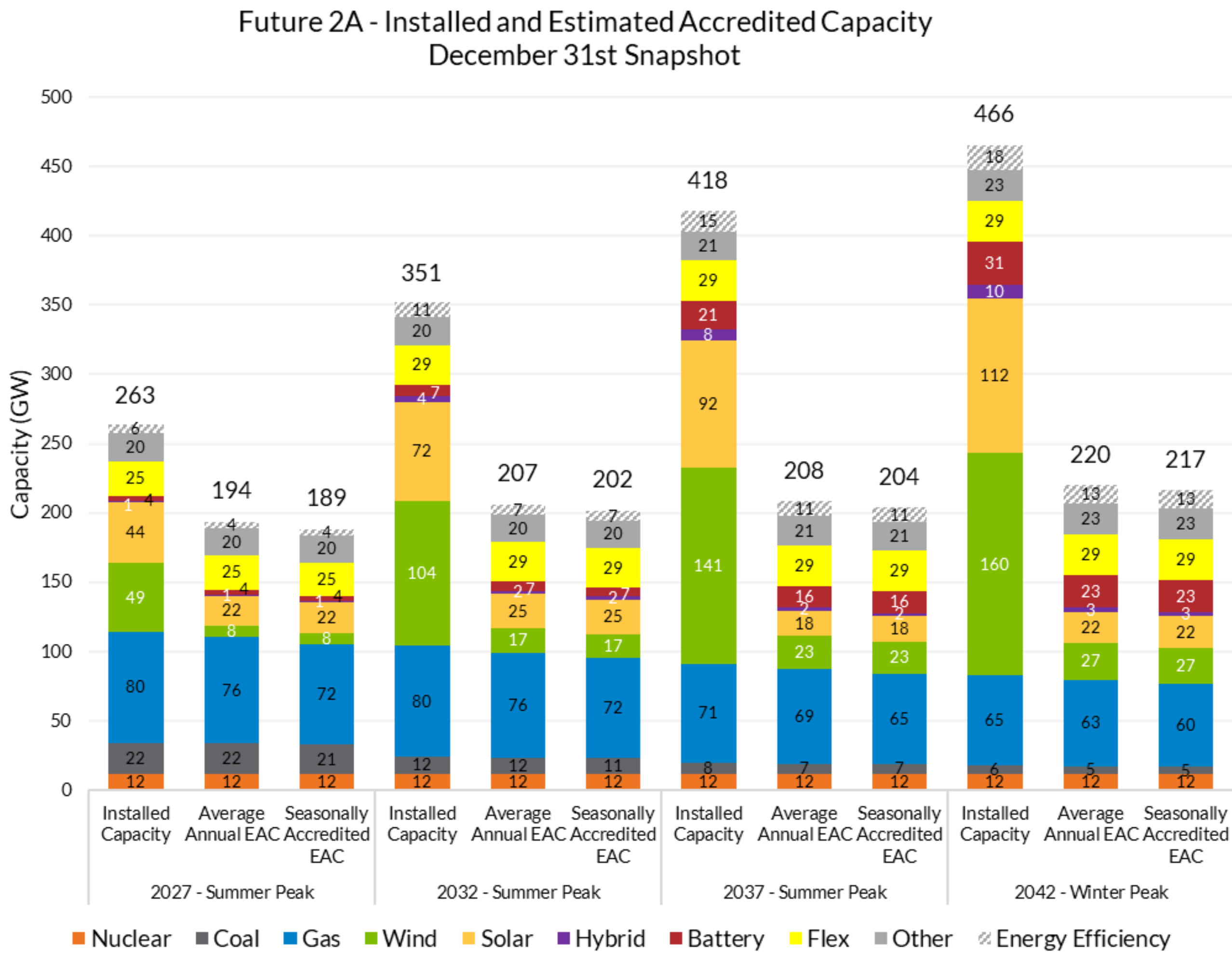


Figure 71: Installed, Seasonally Accredited[37] and Average Annual Estimated Accredited Capacity for Future 2A. Values reflect an end-of-year (December 31st) snapshot.

[37] Accreditation of thermal resources includes seasonal multipliers to align thermal capacity with seasonal peak; Future 2A is summer-peaking for 2027,2032, and 2037 and winter-peaking for 2042. Annual reserve capacity is based on the season in which reserve capacity is the lowest; as a result, F2A exhibits a lower seasonal EAC than the average annual EAC for all milestone years.

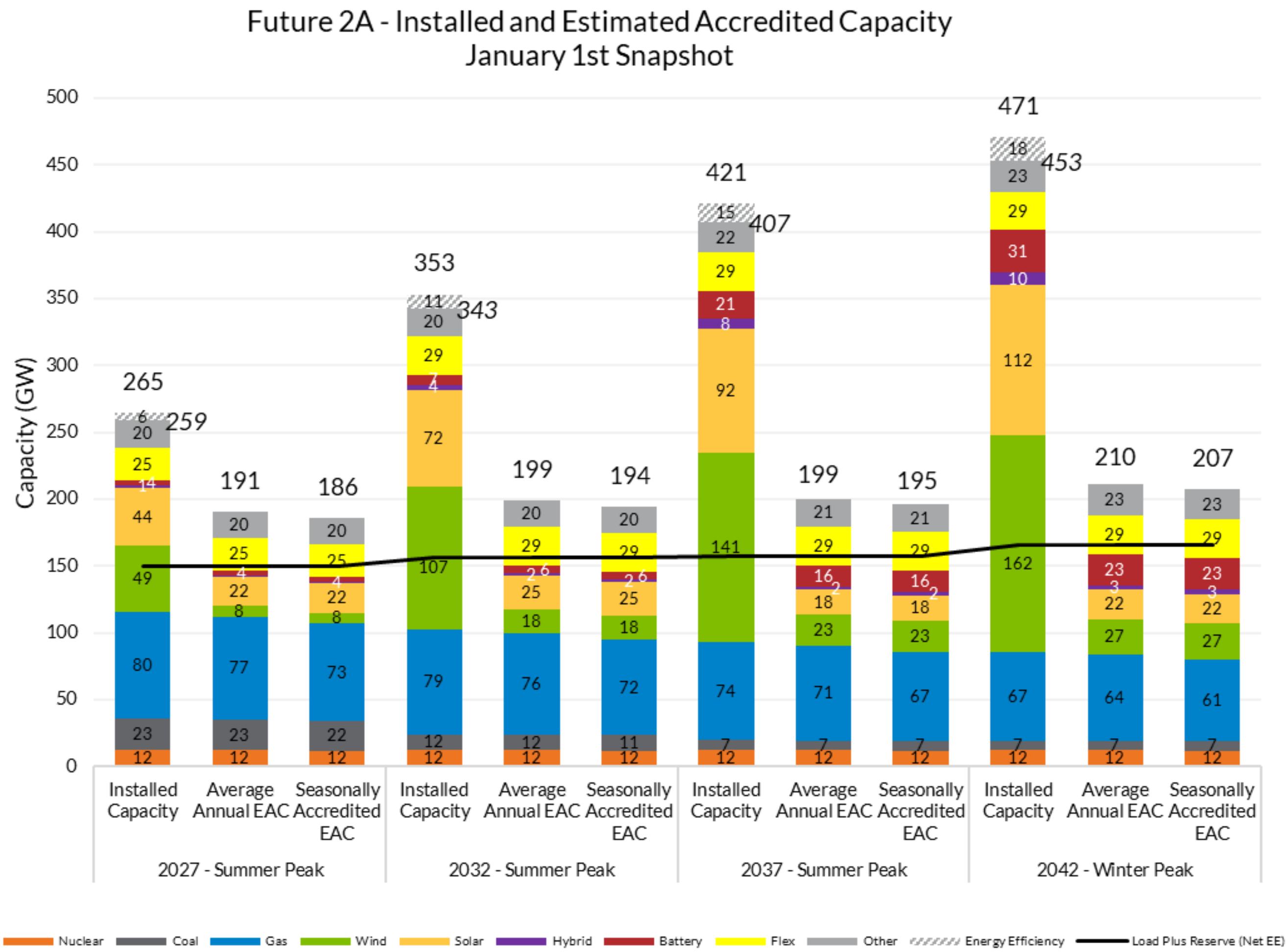


Figure 72: Installed, Seasonally Accredited[37] and Average Annual Estimated Accredited Capacity, with load plus reserve (net EE) for Future 2A. Installed capacity (net EE) totals provided in *italics* for direct comparison with EAC.[38,39]

[38] The capacity expansion tool, EGEAS, utilizes the seasonal estimated accredited capacity in the calculation and attainment of a minimum 18.05% planning reserve margin (PRM) for all study years. Load plus reserve reflects netting of EE for calculation of PRM.

[39] Values reflect a beginning-of-year (Jan 1st) snapshot to align with the capacity expansion tool's output reporting for net load. Resources retiring in the reflected year are assumed to be in commission during system's summer peak and January 2042 winter peak, given EGEAS' assumptions around retirement timing on December 31st.

Future 2A – Energy Production

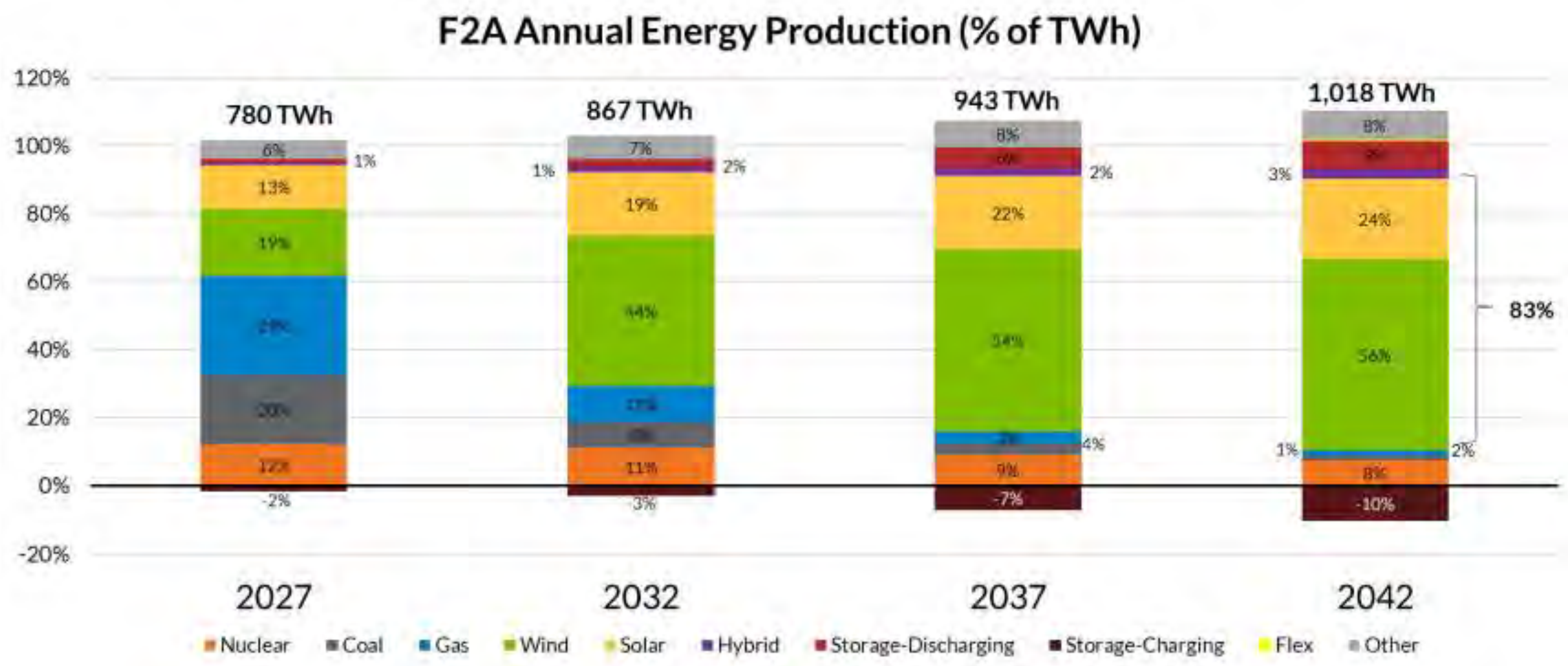


Figure 73: Future 2A Total Annual Energy Production by Milestone Year. Total energy production values are reported net storage-charging.

Future 2A – Generation Siting

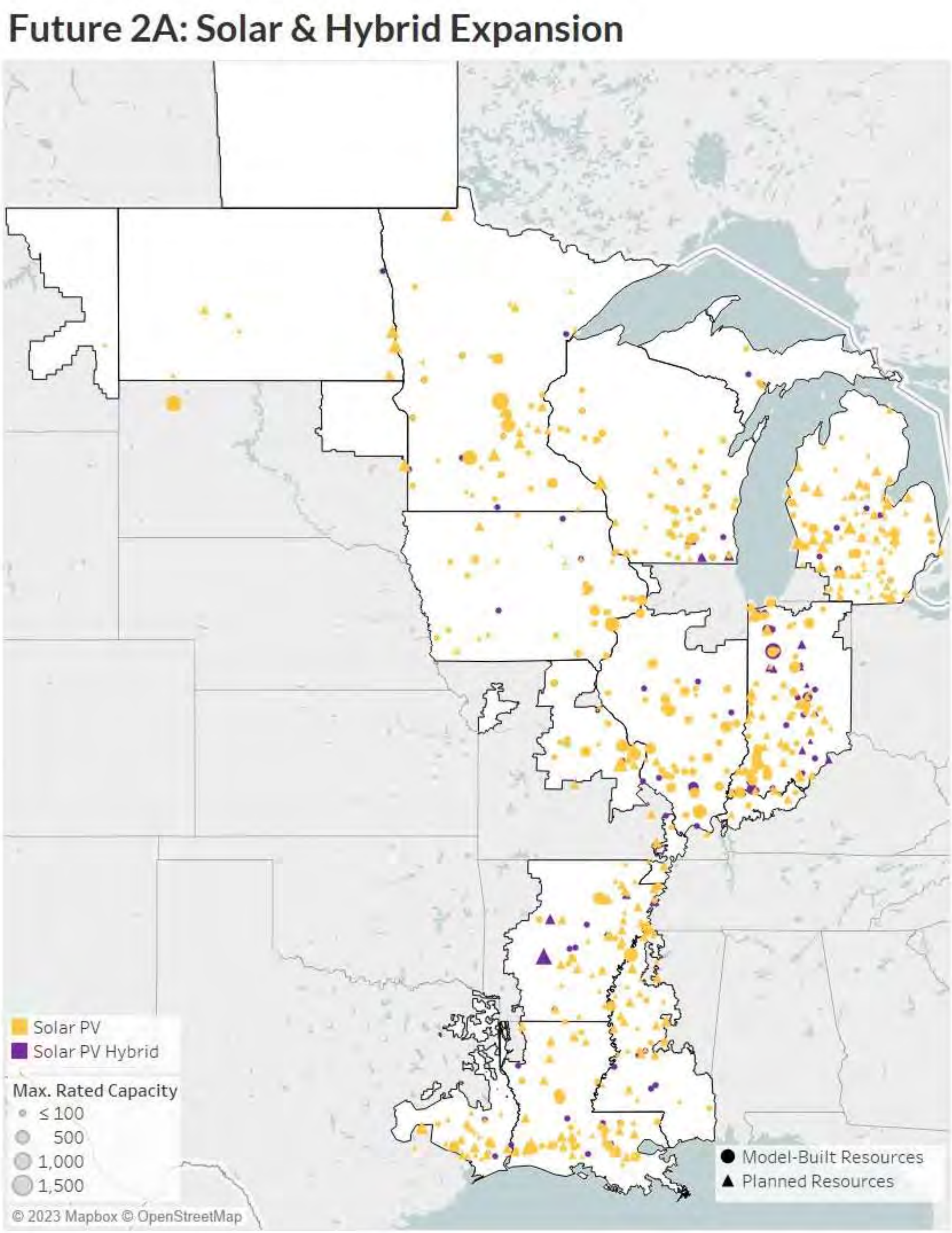


Figure 75: MISO F2A Solar PV and Hybrid Siting

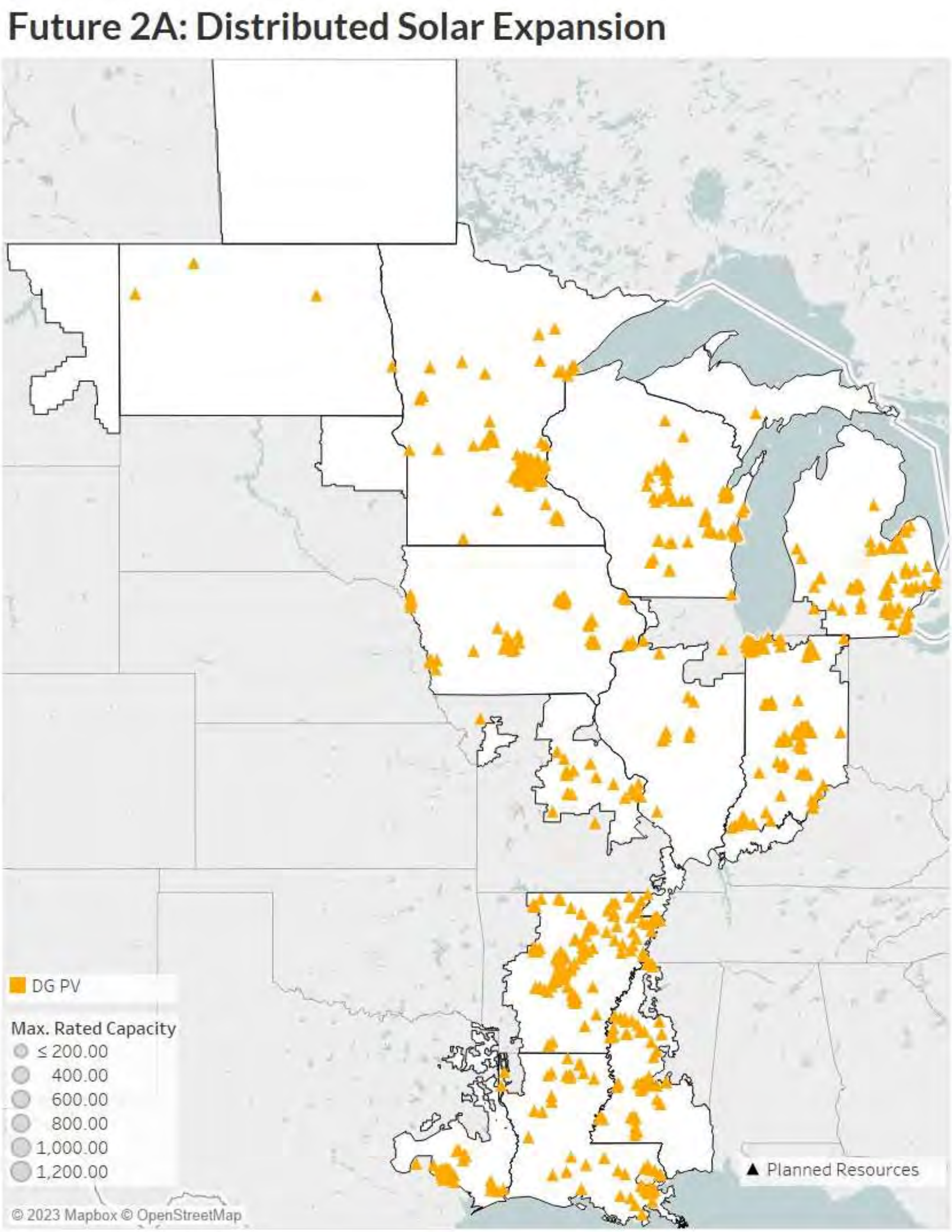


Figure 76: MISO Future 2A Distributed Solar Siting

Future 2A: Wind Expansion

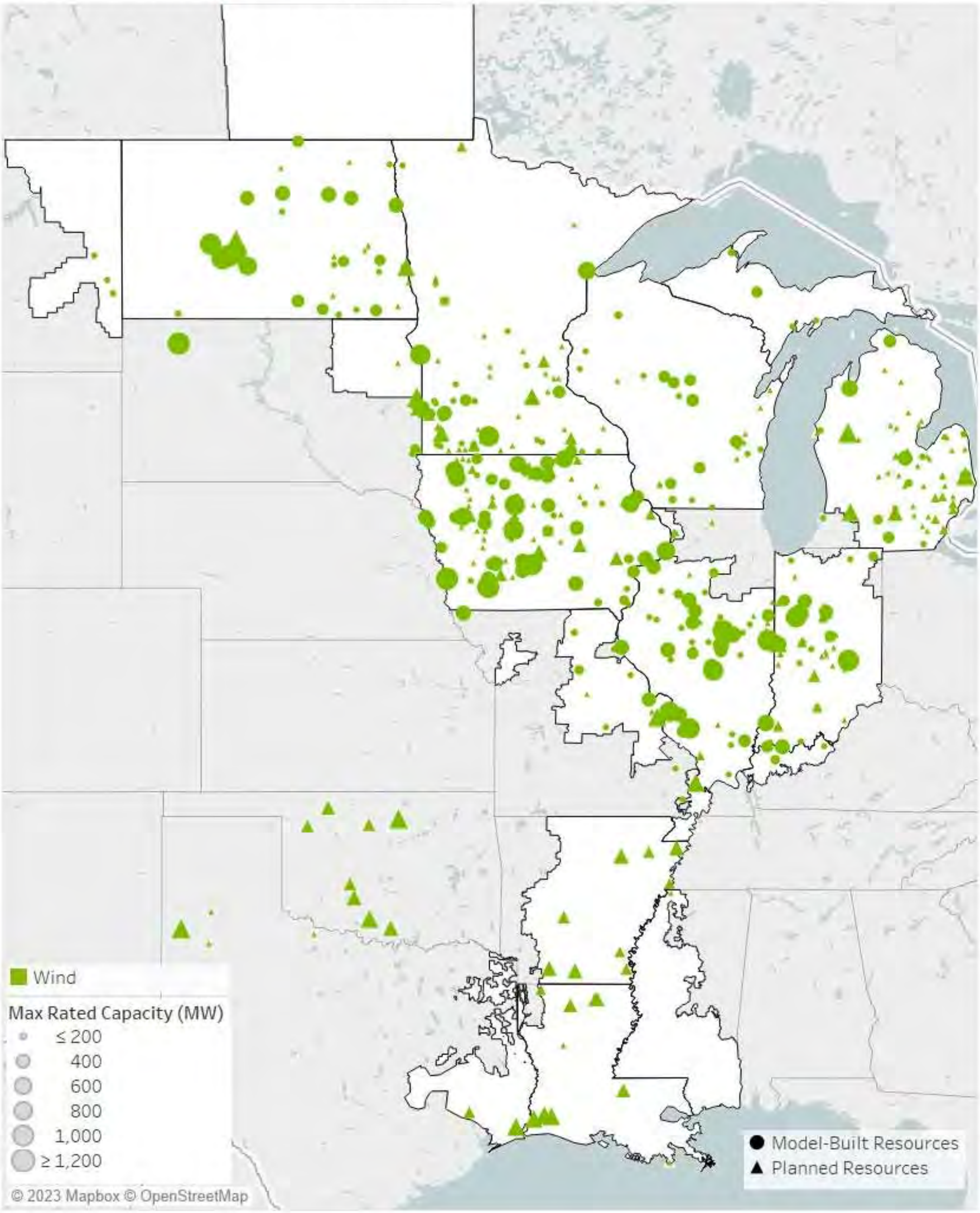


Figure 77: MISO Future 2A Wind Siting

Future 2A: Battery Expansion

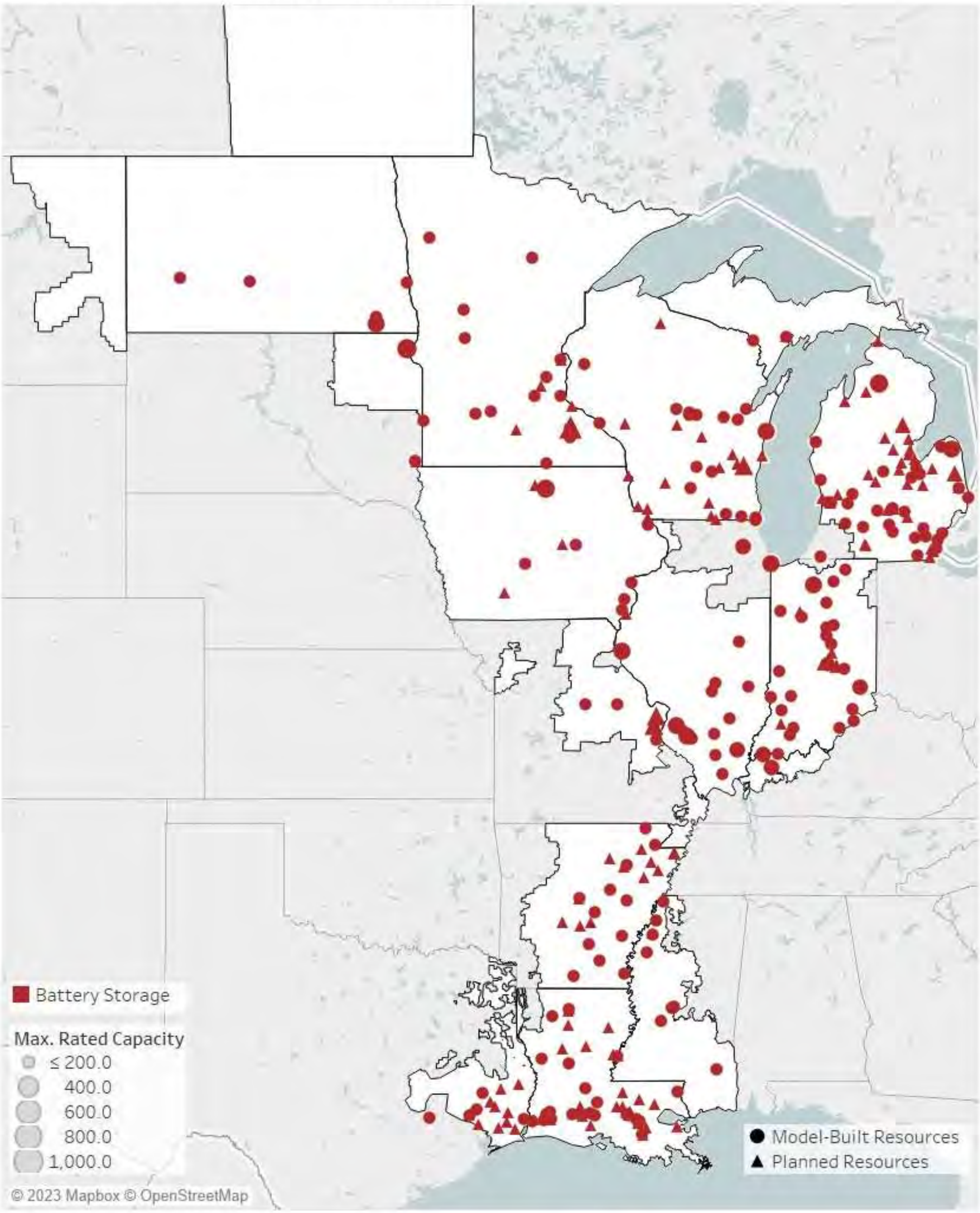


Figure 78: MISO Future 2A Battery Siting

Future 2A: Thermal Expansion

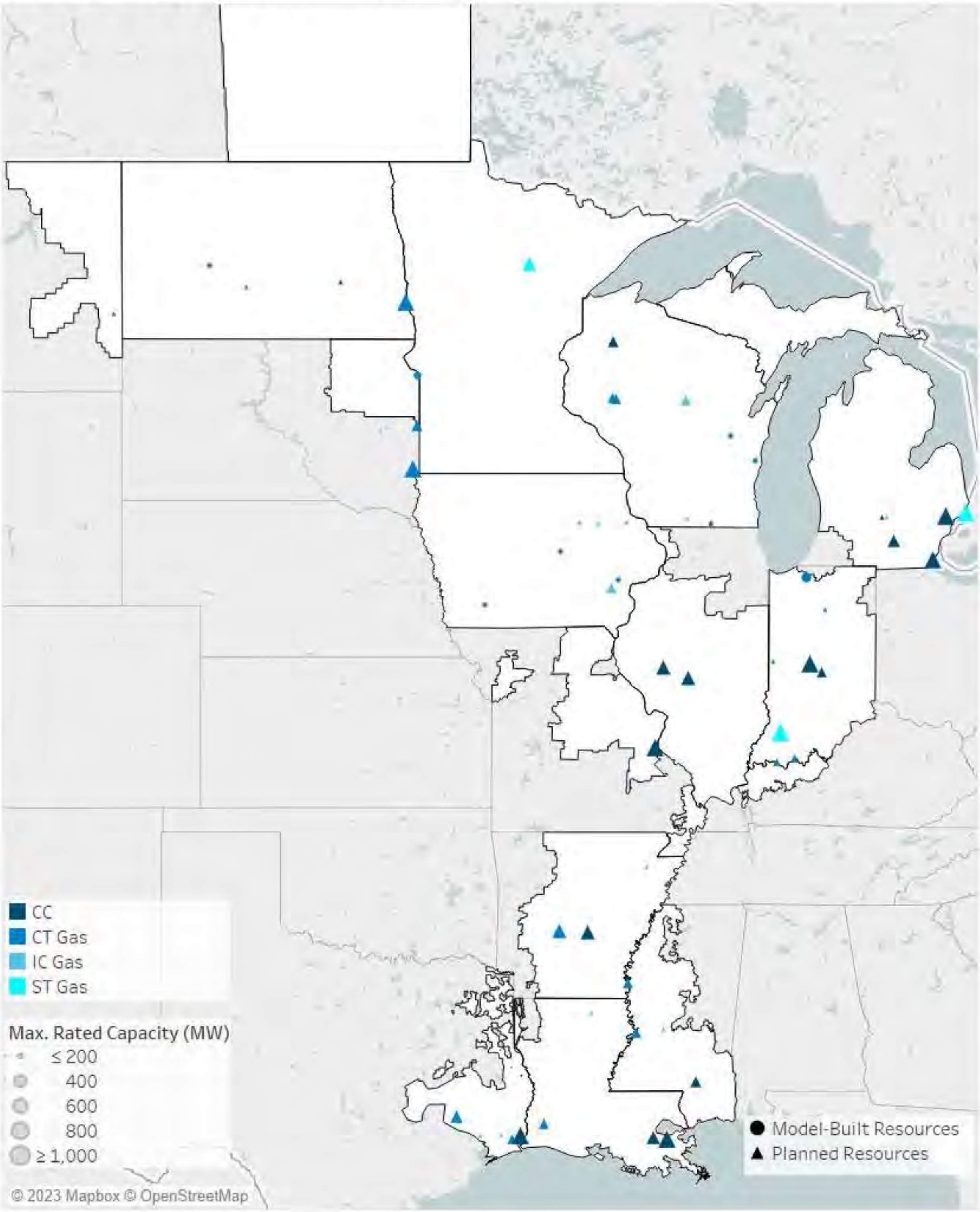


Figure 79: MISO Future 2A Thermal Siting

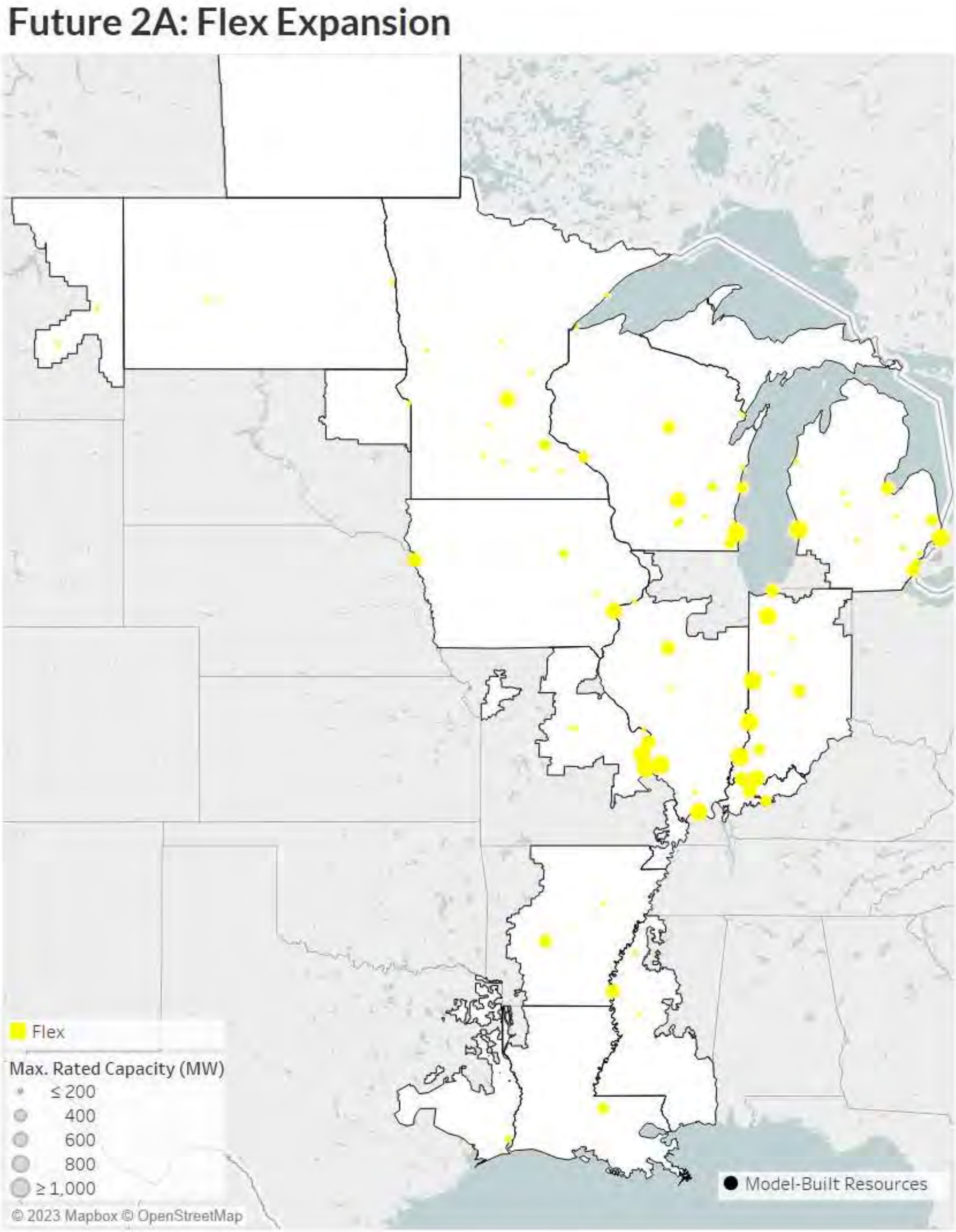


Figure 80: MISO F2A Flex Siting

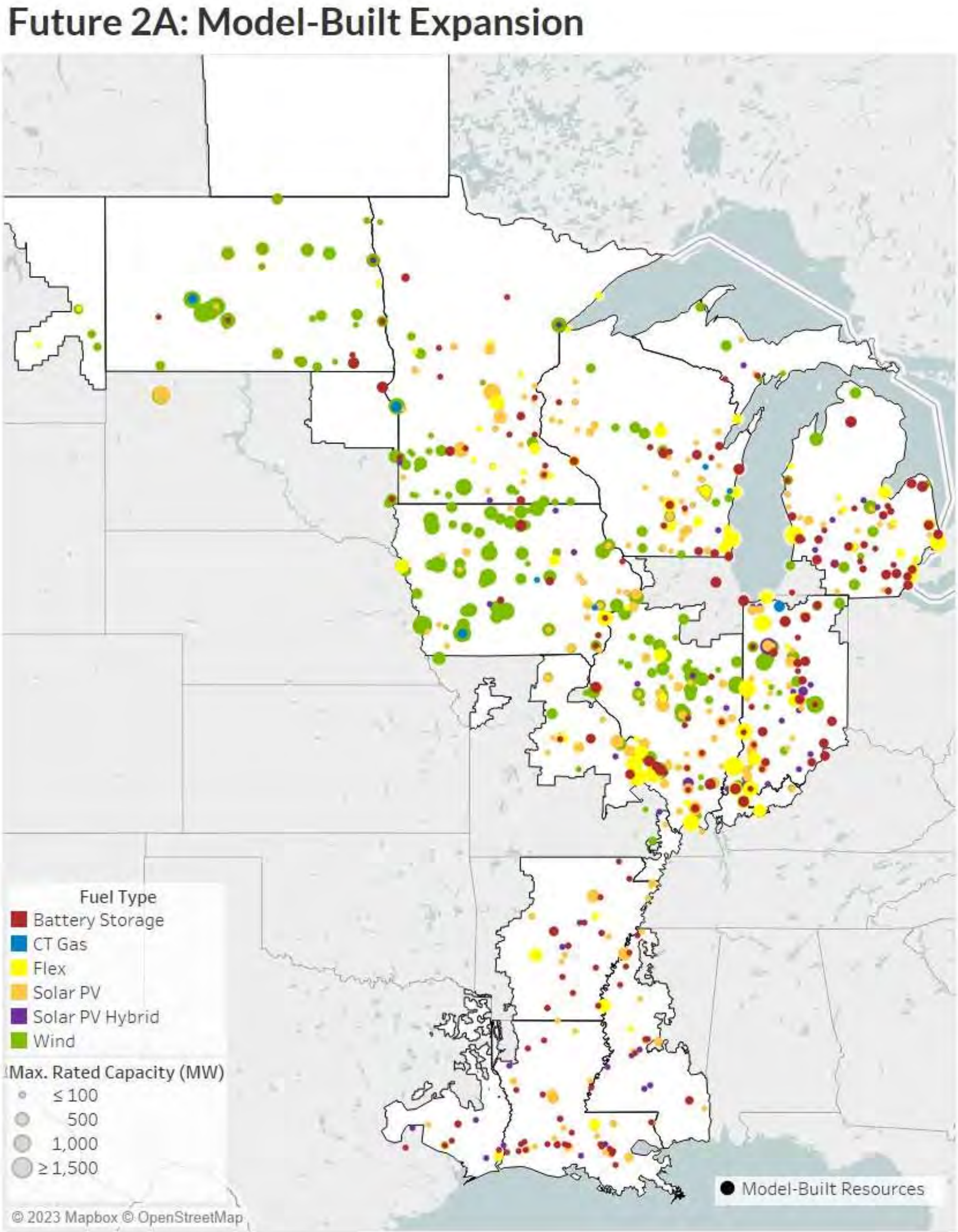


Figure 81: MISO Future 2A Complete EGEAS Expansion Siting

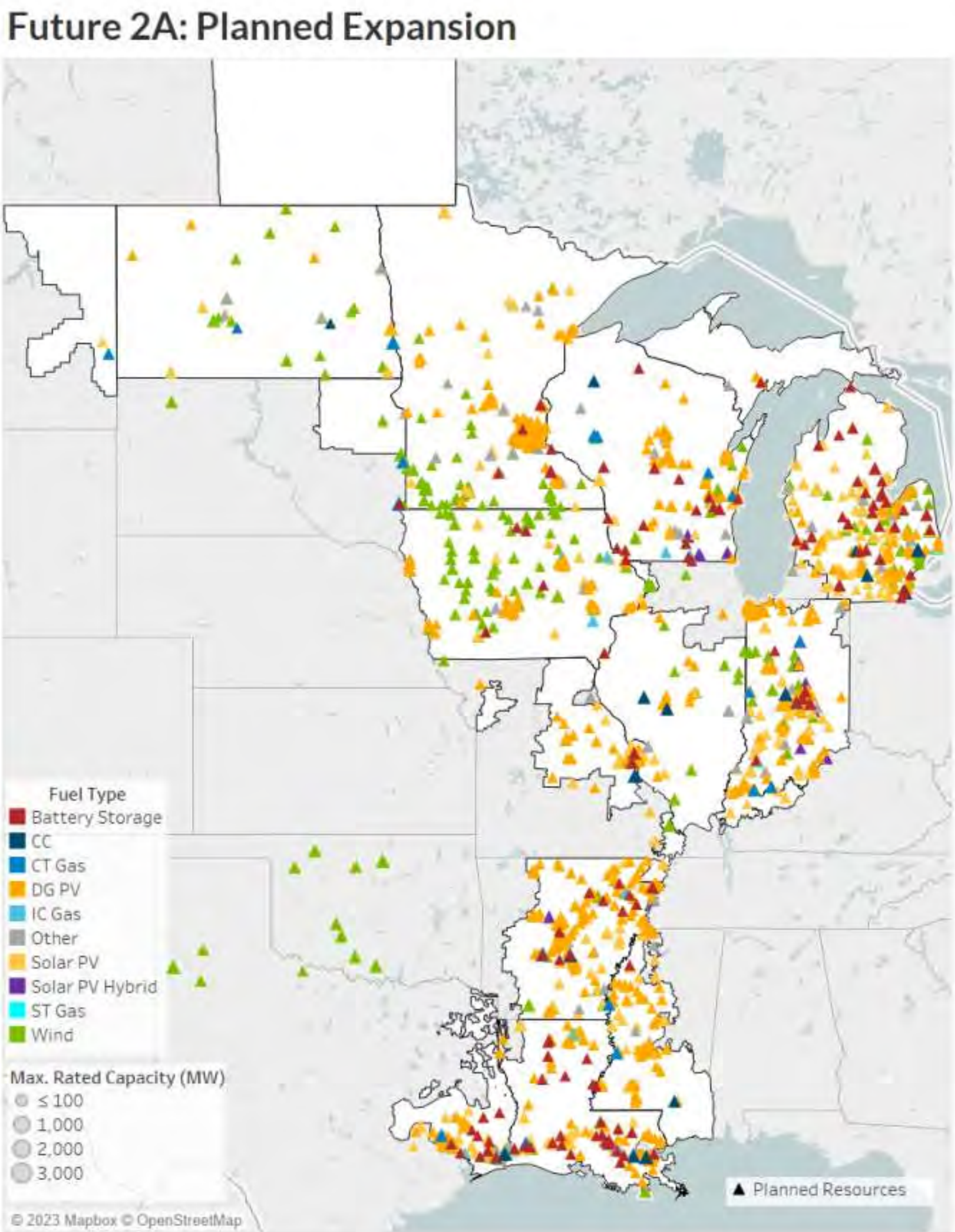


Figure 82: MISO Future 2A Non-EGEAS Expansion Siting

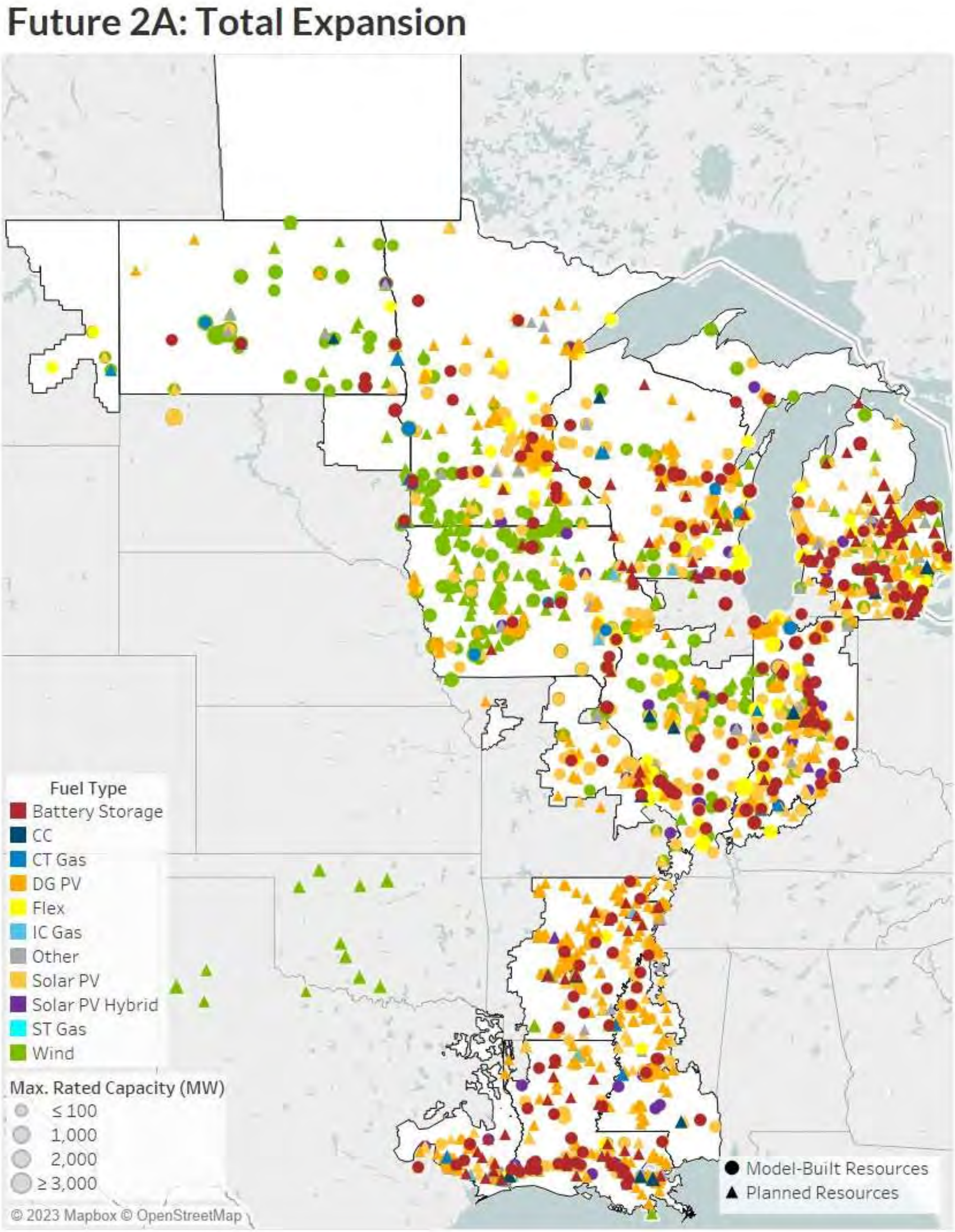


Figure 83: MISO Future 2A Non-EGEAS and EGEAS Expansion Siting

Future 2A Resource Additions (MW) - *Cumulative*																
Zone	Milestone	Battery	CC	CT Gas	Demand Response	DGPV	IC Gas	Solar	Hybrid	ST Coal	ST Gas	Wind	Flex	EE	UDG	Totals
LRZ 1	2027	20	100	981	1,446	375	0	4,867	0	163	0	4,651	2,123	804	18	15,548
	2032	540	100	2,103	1,533	925	0	7,200	70	163	0	23,444	2,123	1,579	42	39,822
	2037	1,616	100	3,225	1,807	1,675	0	10,264	219	163	595	34,388	2,123	2,128	115	58,418
	2042	3,493	100	4,029	1,919	2,675	0	13,654	219	163	595	40,125	2,123	2,559	376	72,030
LRZ 2	2027	1,179	487	300	826	30	843	1,065	1,100	0	0	269	2,570	572	13	9,254
	2032	1,349	487	300	862	405	843	2,166	1,177	0	0	3,376	3,897	1,048	30	15,940
	2037	2,541	487	300	920	967	843	2,534	1,383	0	0	4,779	3,897	1,440	82	20,174
	2042	3,253	487	400	989	1,555	843	3,395	1,383	0	0	4,929	3,897	1,748	269	23,148
LRZ 3	2027	375	0	0	552	418	670	1,720	0	0	50	7,675	1,872	400	9	13,741
	2032	611	0	0	576	675	670	2,505	14	0	50	21,388	1,872	733	21	29,115
	2037	1,222	0	0	614	1,375	670	3,034	181	0	50	30,604	1,872	1,008	58	40,687
	2042	1,634	0	370	685	1,500	670	3,704	181	0	50	35,003	1,872	1,223	188	47,080
LRZ 4	2027	0	1,277	0	552	0	0	1,155	0	0	0	1,414	2,087	400	9	6,894
	2032	285	1,277	0	577	150	0	2,481	184	0	0	10,325	2,087	733	21	18,121
	2037	1,249	1,277	0	616	250	0	3,654	516	0	0	14,141	2,087	1,008	58	24,855
	2042	2,155	1,277	0	663	275	0	5,237	516	0	0	15,020	2,087	1,223	188	28,641
LRZ 5	2027	0	0	0	276	725	0	1,417	0	0	0	313	3,225	343	8	6,307
	2032	11	1,200	0	289	725	0	3,456	14	0	0	2,686	3,839	629	18	12,867
	2037	759	1,200	0	309	725	0	4,425	290	0	0	3,885	3,839	864	49	16,345
	2042	1,256	1,200	0	332	725	0	4,851	290	0	0	4,085	3,839	1,049	161	17,788
LRZ 6	2027	80	1,221	513	1,163	680	0	5,263	75	0	1,052	620	6,798	858	20	18,342
	2032	494	1,221	513	1,188	880	0	8,746	1,976	0	1,052	7,920	8,947	1,571	45	34,553
	2037	3,125	1,546	513	1,228	1,317	0	10,369	3,342	0	1,052	11,899	9,632	2,159	123	46,305
	2042	4,687	1,546	813	1,274	1,794	0	12,449	3,867	0	1,052	13,849	9,632	2,622	403	53,988
LRZ 7	2027	1,842	509	0	679	0	0	5,975	0	0	1,267	743	4,527	915	21	16,477
	2032	2,764	509	0	752	650	0	11,229	179	0	1,267	4,439	4,527	1,676	48	28,040
	2037	4,997	1,455	0	812	1,650	0	12,931	386	0	1,267	9,064	4,527	2,303	132	39,524
	2042	6,553	1,455	0	906	1,975	0	15,016	386	0	1,267	14,824	4,527	2,796	430	50,135
LRZ 8	2027	0	0	0	275	0	95	1,950	0	0	0	1,100	622	343	8	4,393
	2032	437	0	380	287	550	95	4,730	491	0	0	1,500	622	629	18	9,739
	2037	1,151	667	1,047	306	1,775	95	5,378	1,022	0	0	3,944	622	864	49	16,920
	2042	1,760	667	1,047	329	2,900	95	6,372	2,422	0	0	6,188	622	1,049	161	23,612
LRZ 9	2027	10	1,215	0	551	0	173	4,965	0	0	0	0	601	915	21	8,451
	2032	825	2,317	0	575	1,300	173	8,165	290	0	0	0	601	1,676	48	15,970
	2037	3,528	2,866	1,260	626	1,750	173	12,145	431	0	0	5,956	601	2,303	132	31,771
	2042	5,389	2,866	1,640	673	2,050	173	14,804	431	0	0	10,412	601	2,796	430	42,265
LRZ 10	2027	0	402	0	0	0	58	2,175	0	0	0	0	600	172	4	3,411
	2032	10	402	380	0	700	58	3,083	30	0	0	0	600	314	9	5,586
	2037	444	402	380	0	1,150	58	3,569	130	0	0	0	600	432	25	7,190
	2042	918	402	760	0	1,688	58	5,221	130	0	0	200	600	524	81	10,582
MISO Total	2027	3,506	5,211	1,793	6,320	2,228	1,839	30,551	1,175	163	2,369	16,784	25,025	5,721	131	102,816
	2032	7,326	7,513	3,675	6,640	6,960	1,839	53,760	4,425	163	2,369	75,078	29,115	10,589	300	209,753
	2037	20,633	10,000	6,724	7,238	12,634	1,839	68,302	7,900	163	2,964	118,66	29,800	14,508	823	302,188
	2042	31,099	10,000	9,058	7,770	17,137	1,839	84,702	9,825	163	2,964	144,63	29,800	17,589	2,688	369,269

Table 9: MISO Future 2A Resource Additions by LRZ and Footprint

Future 2A Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2027**	3,612	1,604	0	325	123	0	962	6,625
	2032	5,355	2,141	0	570	1,772	0	996	10,834
	2037	5,844	2,362	0	584	3,178	24	1,014	13,005
	2042	5,844	2,988	0	678	5,274	470	1,014	16,268
LRZ 2	**2027**	2,515	171	0	76	102	0	20	2,884
	2032	2,844	1,170	0	76	385	0	20	4,495
	2037	2,960	2,744	0	139	823	0	20	6,686
	2042	3,019	3,778	0	200	823	11	44	7,874
LRZ 3	**2027**	3,407	1,363	0	240	311	0	0	5,322
	2032	3,407	1,481	0	319	1,468	0	0	6,676
	2037	3,407	1,513	0	319	4,582	0	0	9,822
	2042	3,980	1,573	0	455	6,628	0	0	12,637
LRZ 4	**2027**	2,123	0	0	117	20	0	0	2,260
	2032	2,123	564	0	117	28	0	0	2,832
	2037	2,123	2,534	0	117	698	0	0	5,472
	2042	2,123	3,222	0	176	823	20	0	6,364
LRZ 5	**2027**	1,251	67	0	345	0	0	0	1,663
	2032	2,257	67	0	345	0	0	0	2,669
	2037	3,471	1,177	0	345	169	0	0	5,162
	2042	4,704	1,188	0	345	169	0	0	6,406
LRZ 6	**2027**	7,255	543	0	50	0	0	0	7,848
	2032	8,986	963	0	50	131	0	0	10,130
	2037	10,256	2,356	0	71	942	2	0	13,627
	2042	10,256	4,591	0	71	1,742	475	0	17,135
LRZ 7	**2027**	3,787	1,248	0	390	0	0	38	5,463
	2032	5,357	2,532	0	390	113	0	147	8,538
	2037	6,922	6,535	0	390	929	0	147	14,922
	2042	6,922	7,920	0	419	2,180	54	147	17,641
LRZ 8	**2027**	0	788	0	0	0	0	0	788
	2032	3,089	788	0	0	0	0	0	3,877
	2037	3,089	1,418	0	0	0	0	0	4,507
	2042	3,089	1,516	0	0	0	181	0	4,786
LRZ 9	**2027**	1,880	4,627	0	7	0	0	0	6,515
	2032	2,496	5,582	0	7	0	0	28	8,113
	2037	2,496	8,171	0	7	0	0	39	10,712
	2042	2,496	9,461	0	7	0	0	39	12,003
LRZ 10	**2027**	0	816	0	0	0	0	0	816
	2032	206	901	0	0	0	0	0	1,107
	2037	206	901	0	0	0	0	0	1,107
	2042	206	1,370	0	0	0	52	0	1,628
MISO Total	**2027**	25,831	11,227	0	1,549	556	0	1,020	40,183
	2032	36,120	16,190	0	1,874	3,896	0	1,190	59,270
	2037	40,774	29,711	0	1,971	11,321	26	1,219	85,022
	2042	42,639	37,608	0	2,351	17,638	1,262	1,243	102,741

Table 10: MISO Future 2A Resource Retirements by LRZ and Footprint

MISO – Future 3A

Future 3A – Retirements and Additions

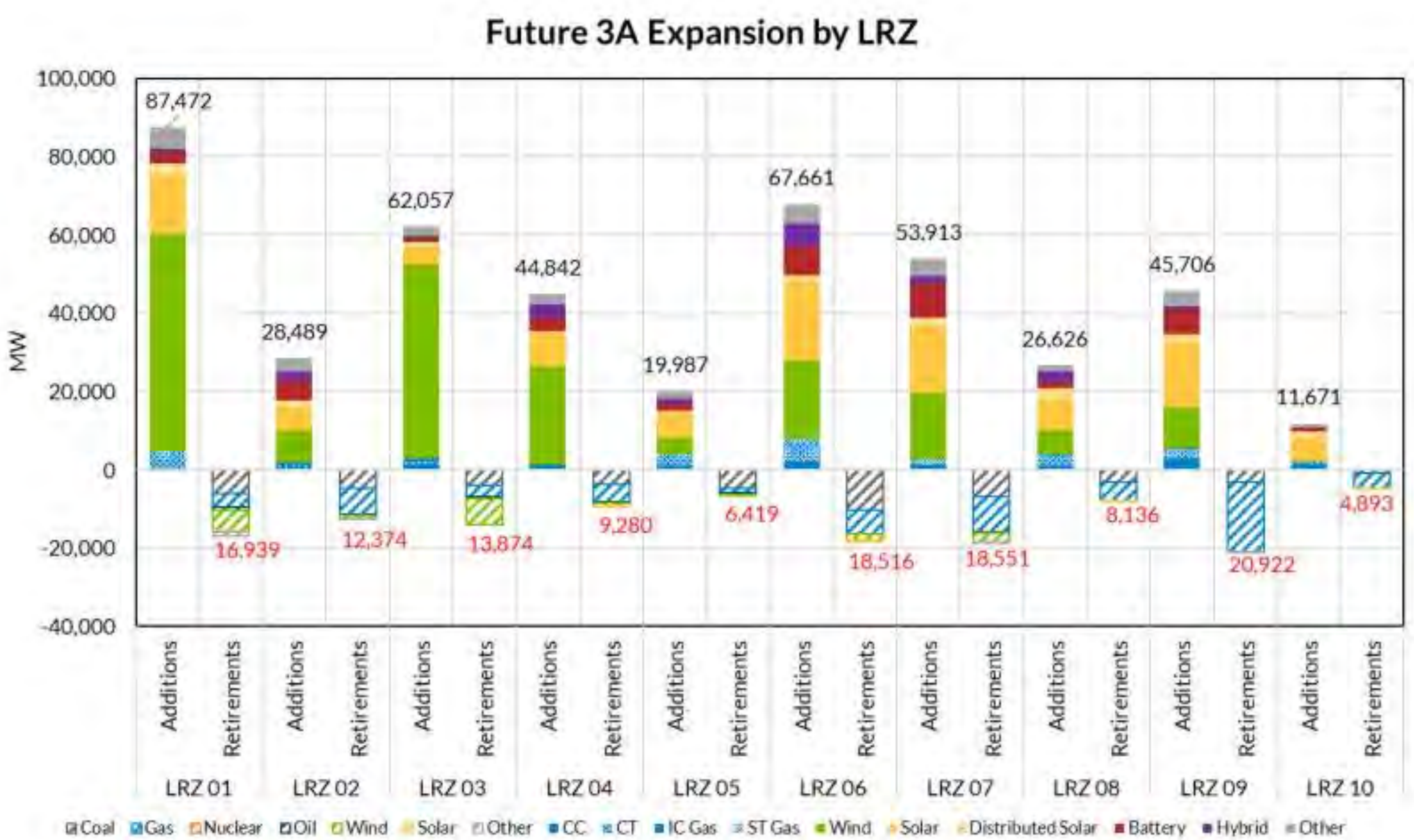


Figure 84: MISO Future 3A Resource Retirement and Addition Summary

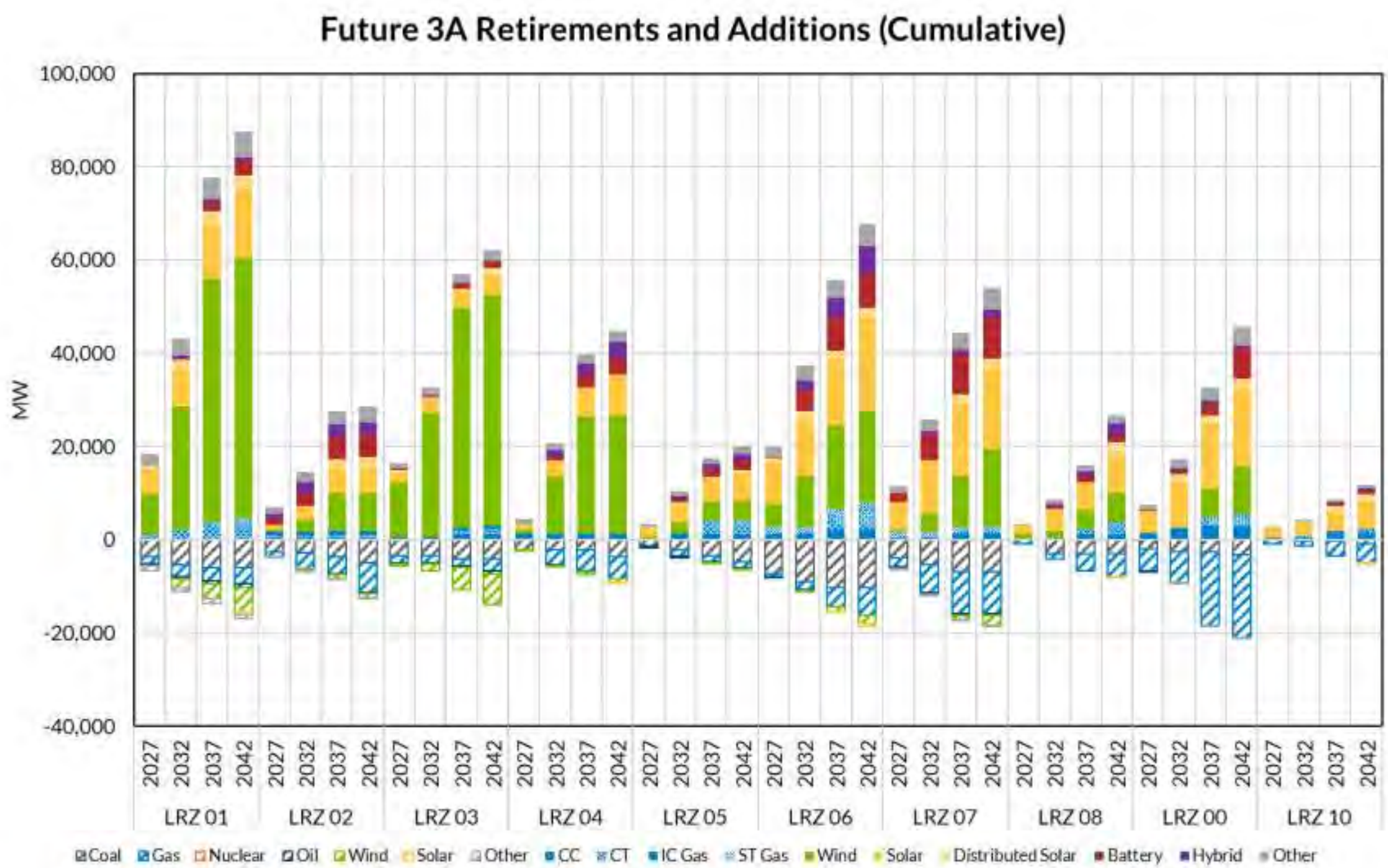


Figure 85: MISO Future 3A Resource Retirement and Addition Summary

Future 3A – Installed Capacity

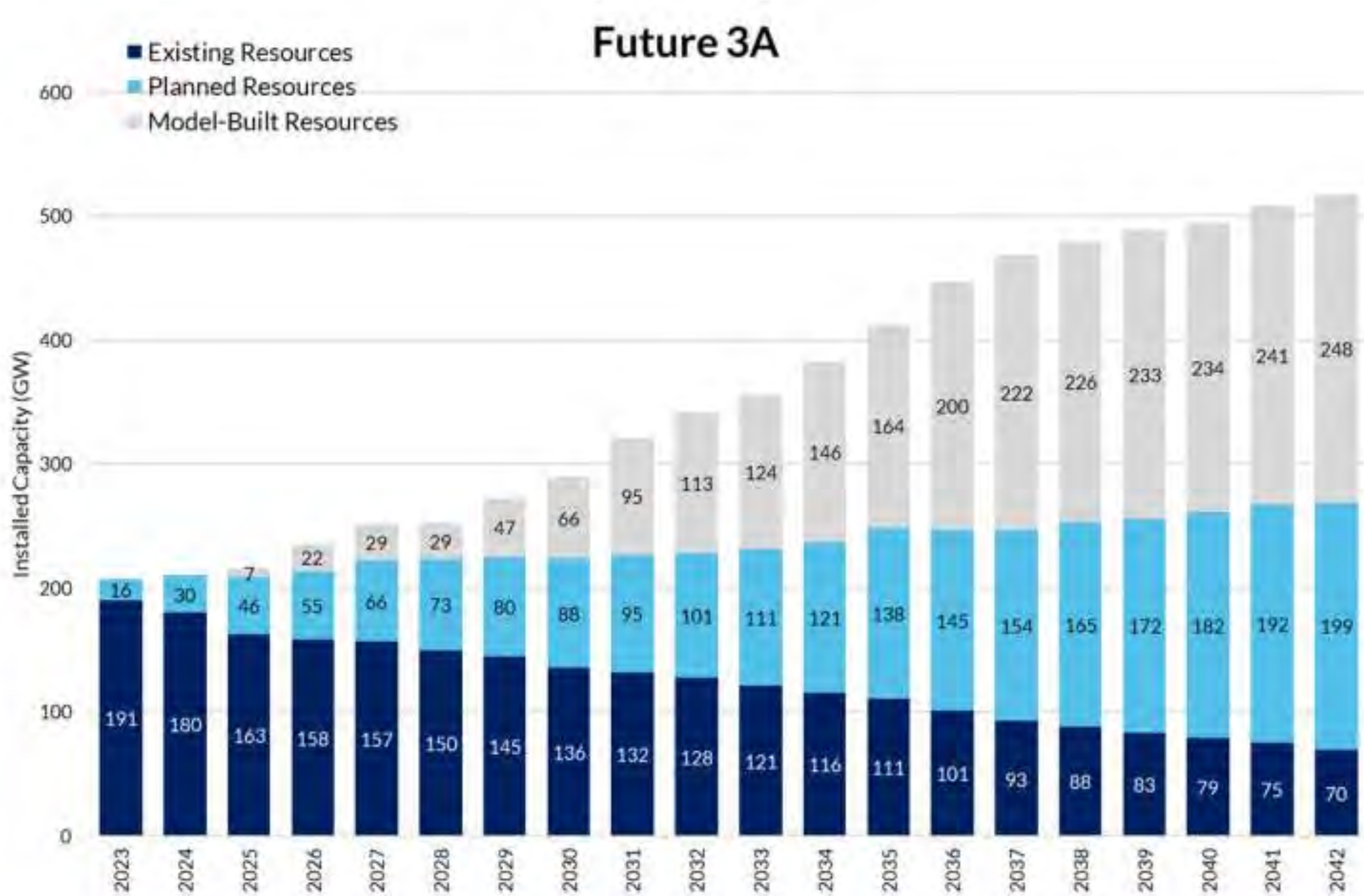


Figure 86: MISO F3A installed capacity of existing, planned, and model-built resources (GW).

Future 3A – Estimated Accredited Capacity

Figure 87 provides the end-of-year (EOY) installed and estimated accredited capacity (EAC)[40] for Future 3A. Figure 88 provides a beginning-of-year (BOY) outlook, overlaid with the load plus reserve. This alternative outlook aligns with the capacity expansion tool's output reporting for net load and attainment of a minimum 18.05% planning reserve margin (PRM) throughout the study period.

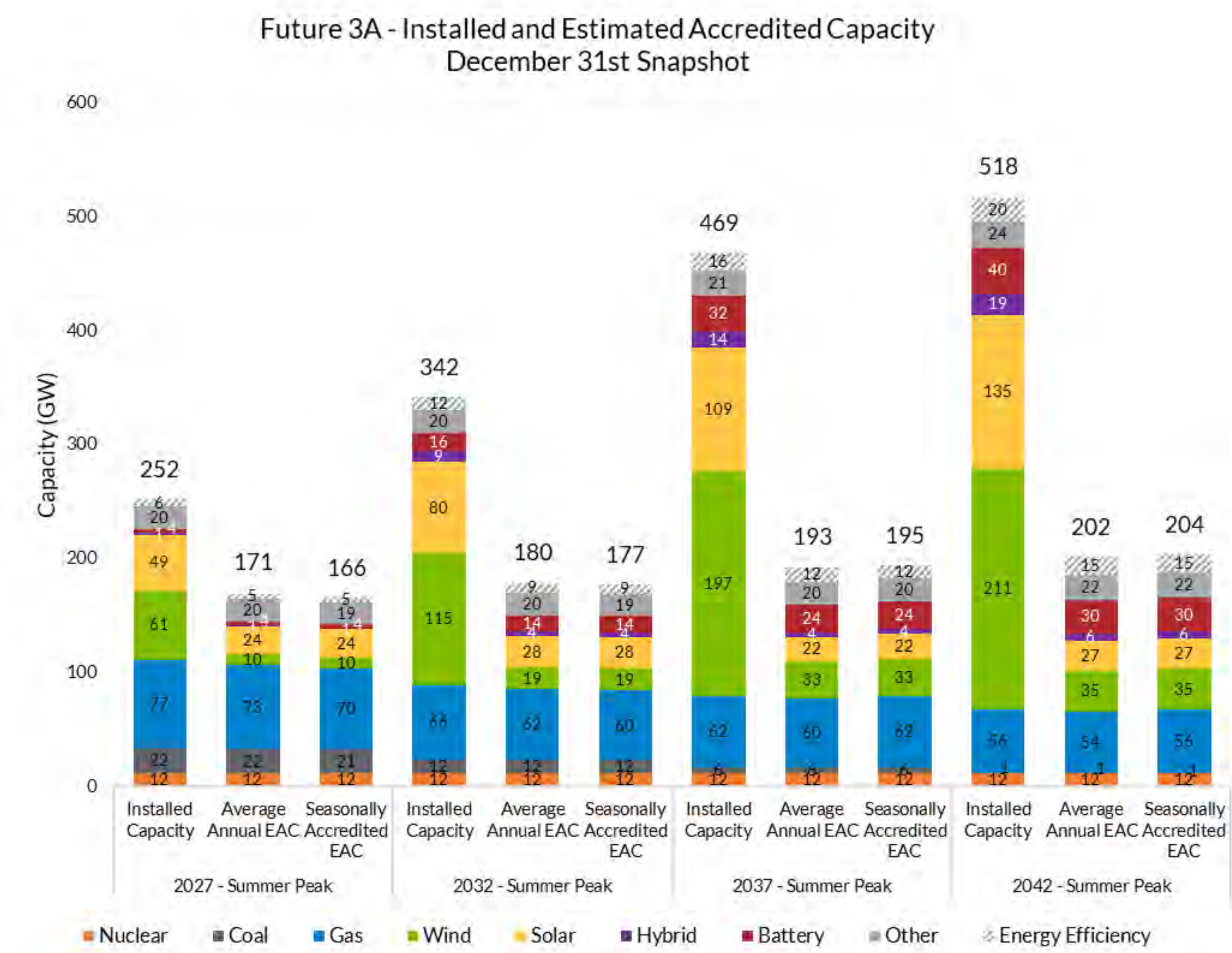


Figure 87: Installed, Seasonally Accredited[40] and Average Annual Estimated Accredited Capacity for Future 3A. Values reflect an end-of-year (December 31st) snapshot.

[40] Accreditation of thermal resources includes seasonal multipliers to align thermal capacity with seasonal peak; Future 3A is summer-peaking for 2027/2032 and winter-peaking for 2037/2042. Seasonal accreditation of thermal resources results in a lower total EAC during summer-peaking years and a higher total EAC during winter-peaking years than the average annual EAC.

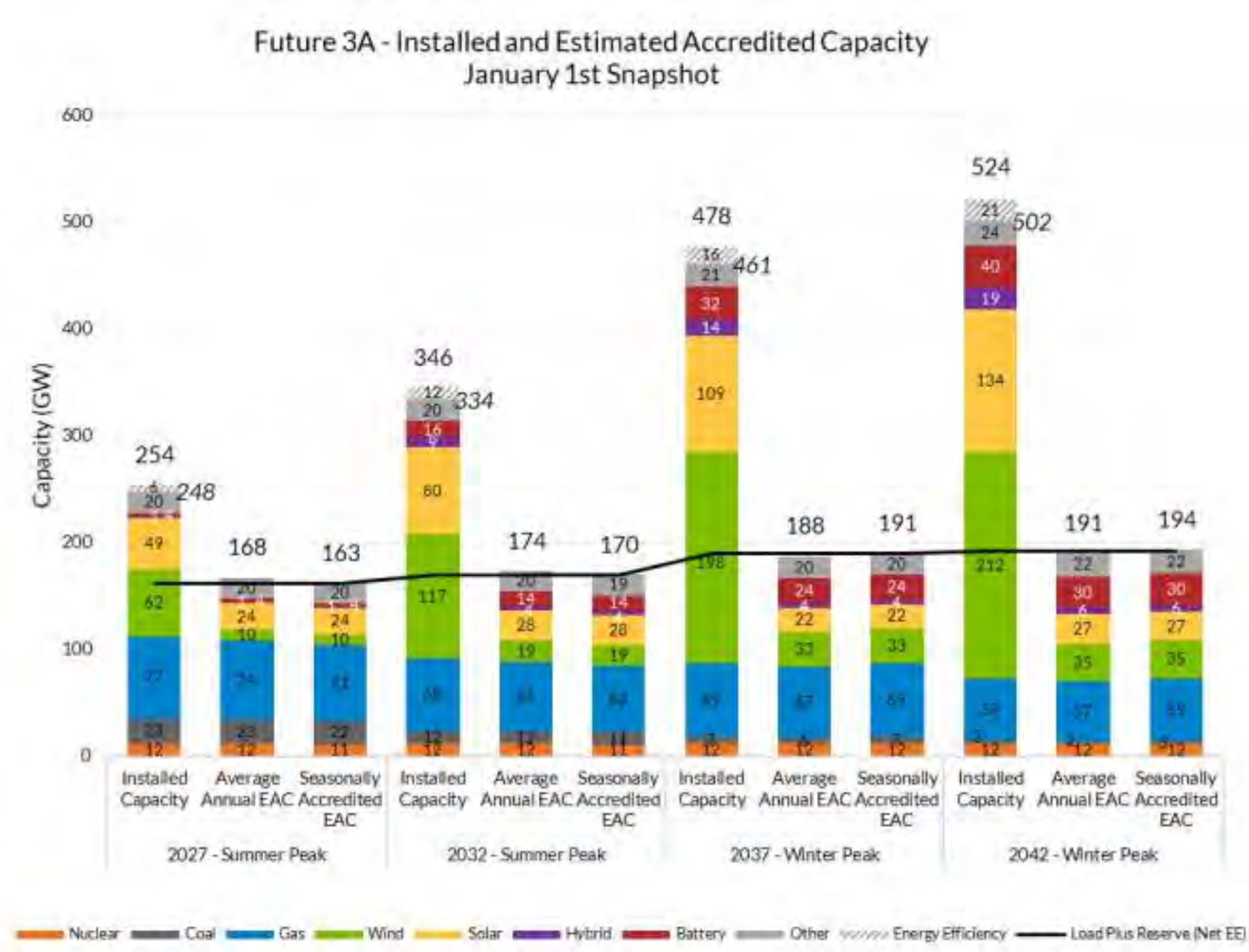


Figure 88: Installed, Seasonally Accredited[40] and Average Annual Estimated Accredited Capacity, with load plus reserve (net EE) for Future 3A. Installed capacity (net EE) totals are provided in *italics* for direct comparison with EAC.[41,42]

[41] The capacity expansion tool, EGEAS, utilizes the seasonal estimated accredited capacity in the calculation and attainment of a minimum 18.05% planning reserve margin (PRM) for all study years. Load plus reserve reflects netting of EE for calculation of PRM.

[42] Values reflect a beginning-of-year (Jan 1st) snapshot to align with the capacity expansion tool's output reporting for net load. Resources retiring in the reflected year are assumed to be in commission during system's summer peak and January 2037/2042 winter peak given EGEAS' assumptions around retirement timing on December 31st.

Future 3A – Energy Production

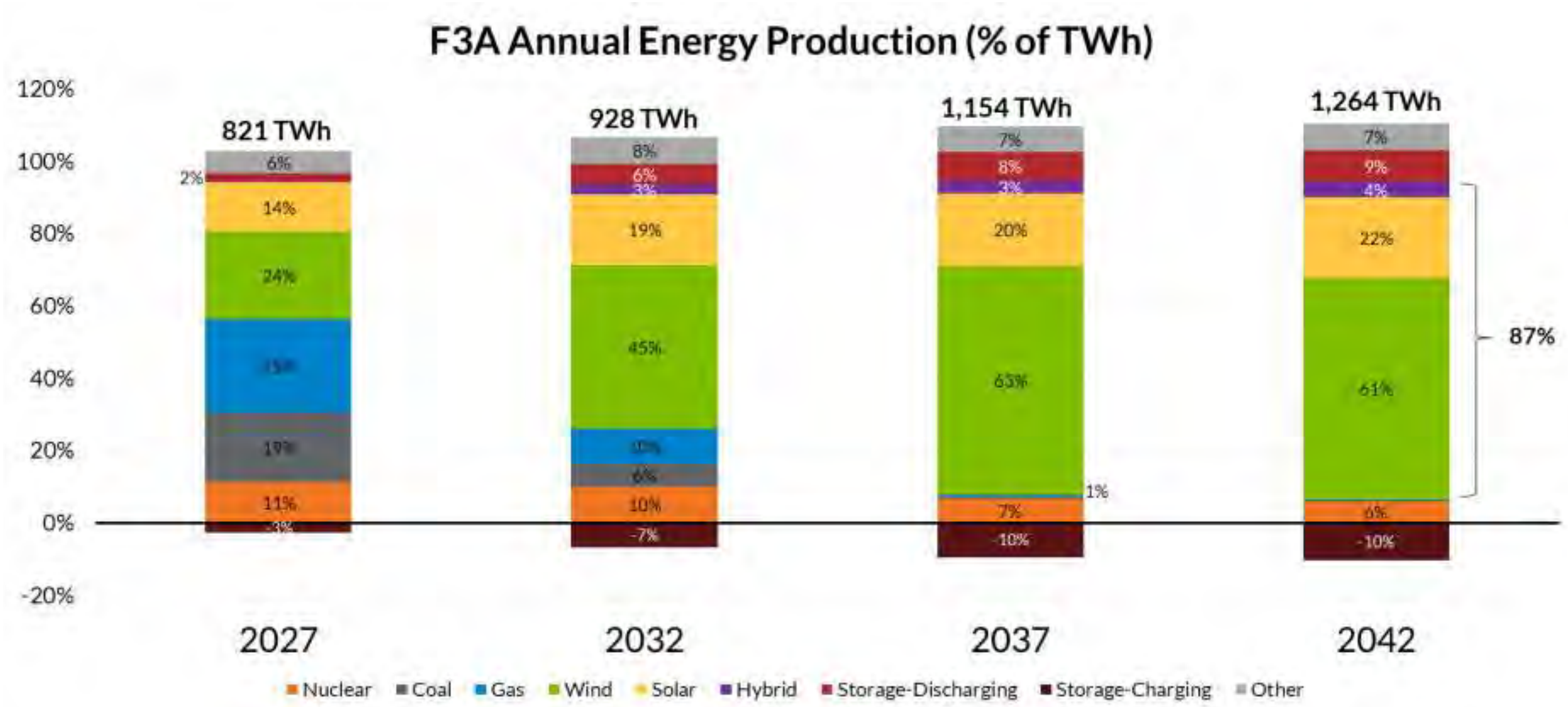


Figure 89: Future 3A Total Annual Energy Production by Milestone Year. Total energy production values are reported net storage-charging.

Future 3A – Generation Siting

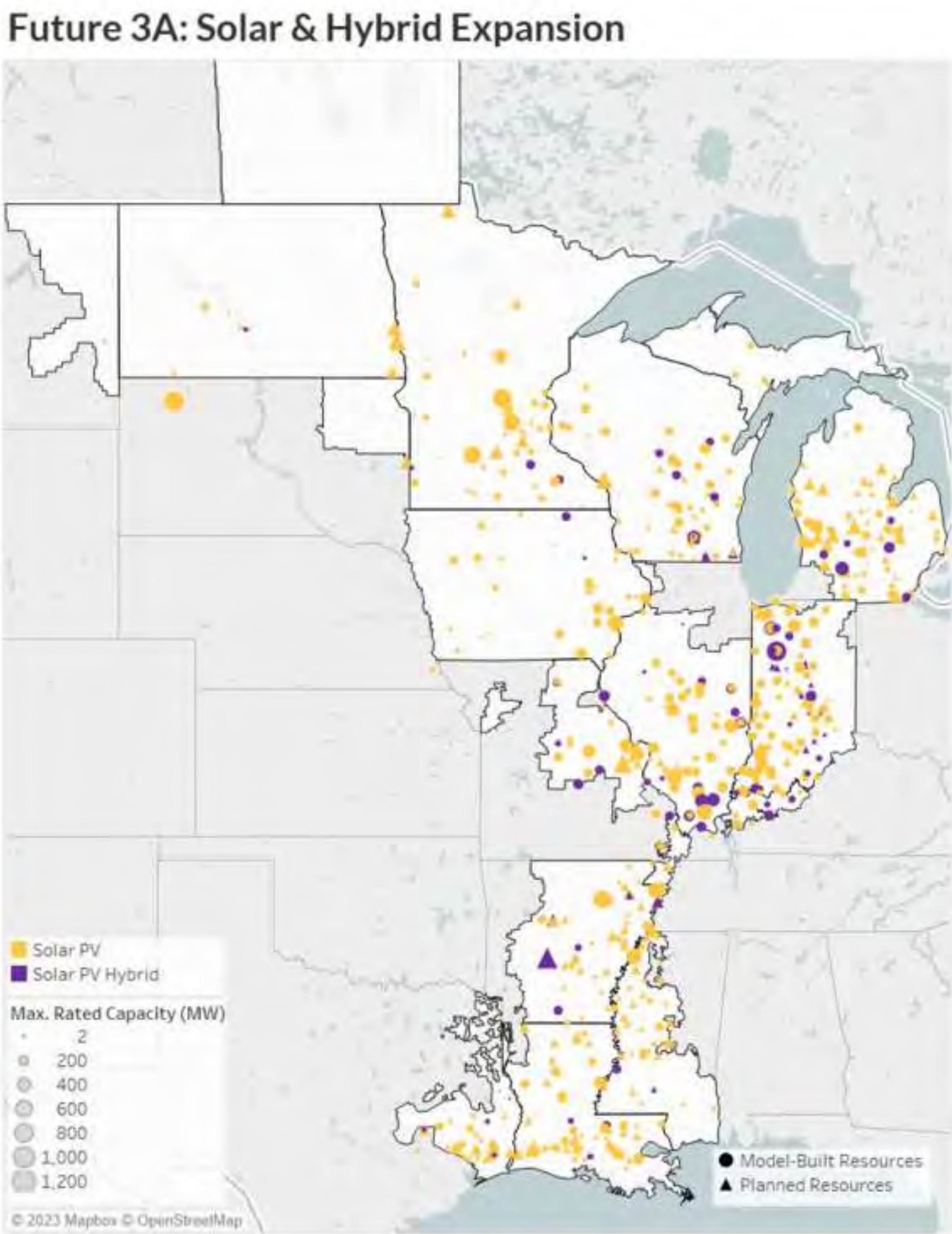


Figure 90: MISO Future 3A Solar and Hybrid Siting

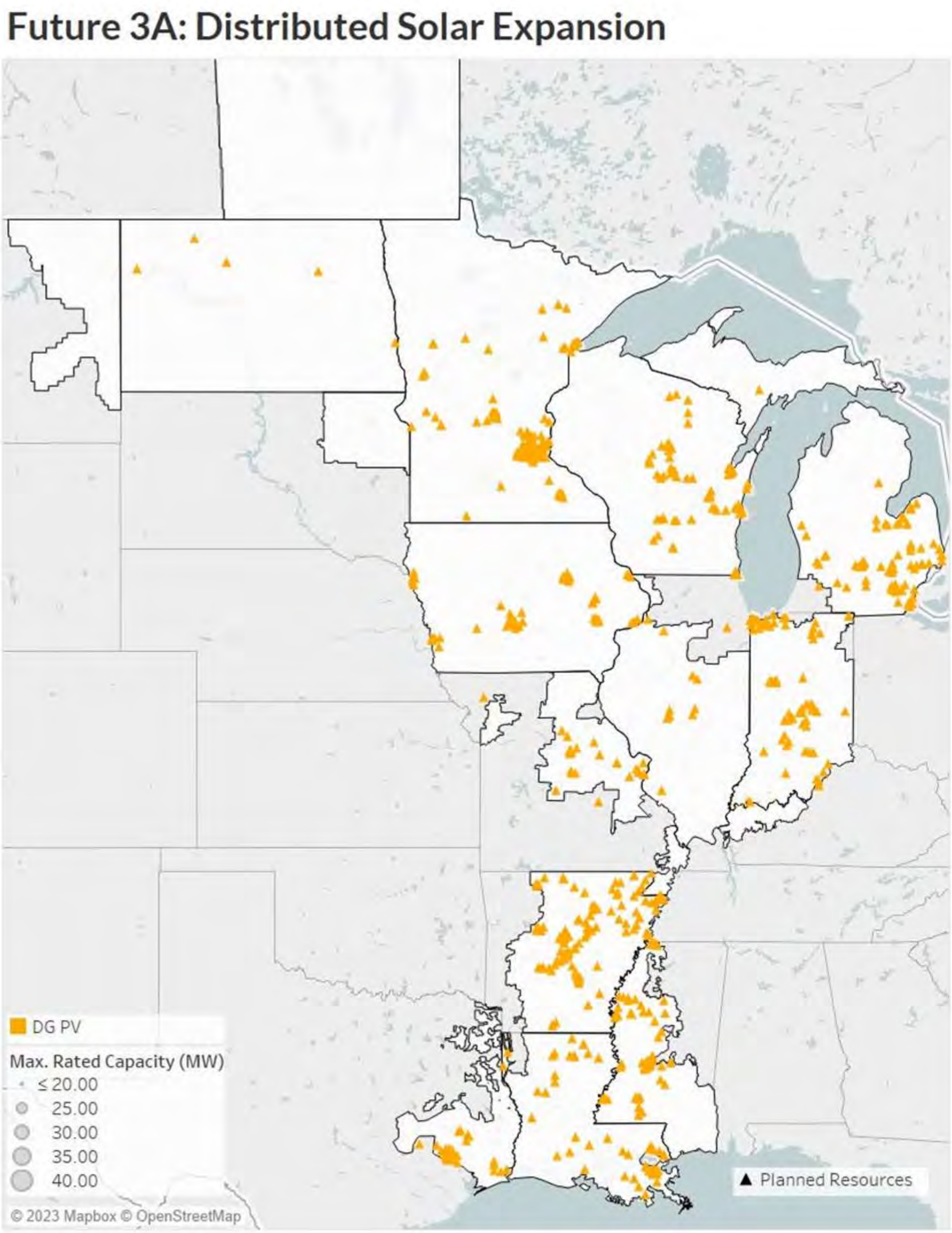


Figure 91: MISO Future 3A Distributed Solar Siting

Future 3A: Wind Expansion

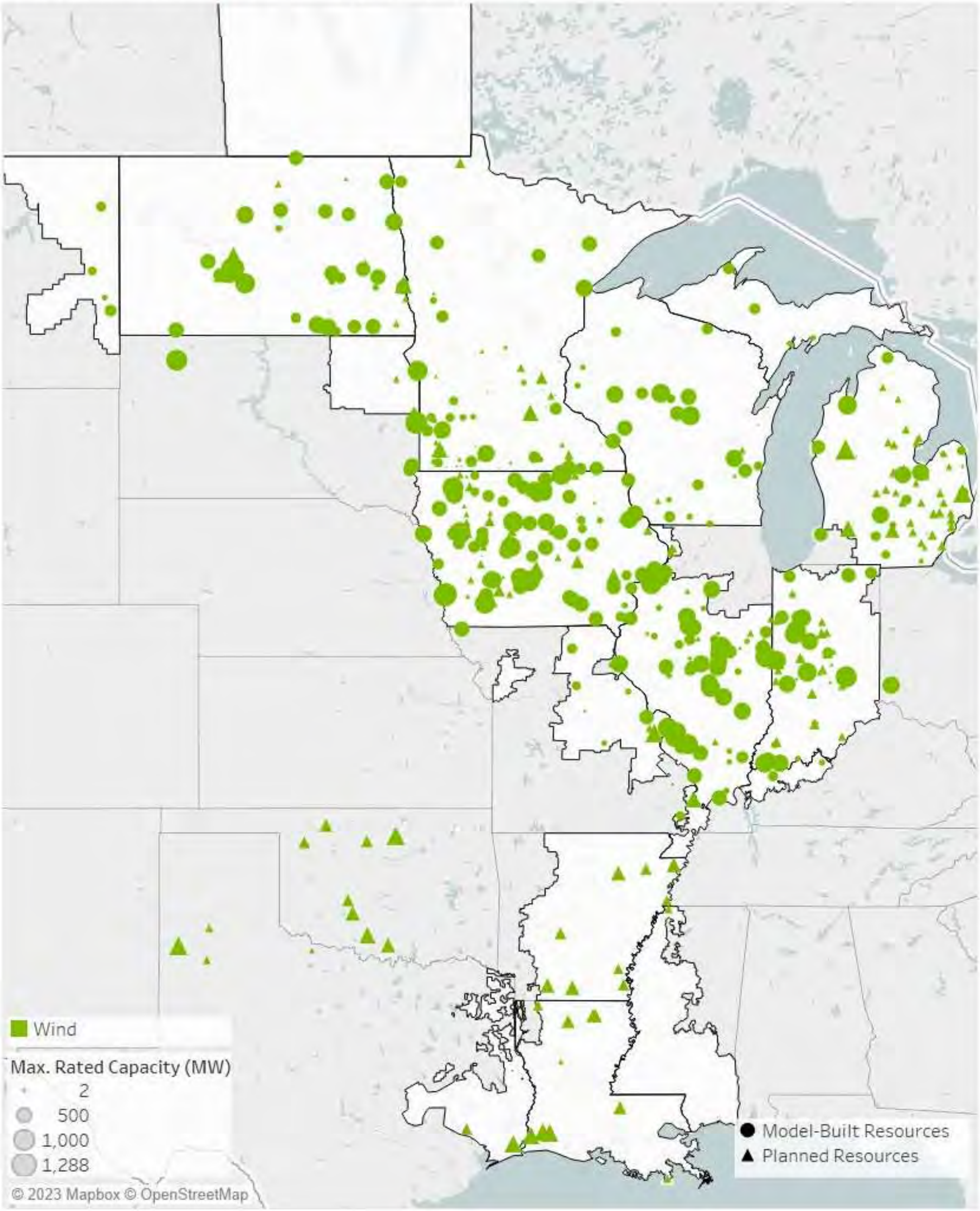


Figure 92: MISO Future 3A Wind Siting

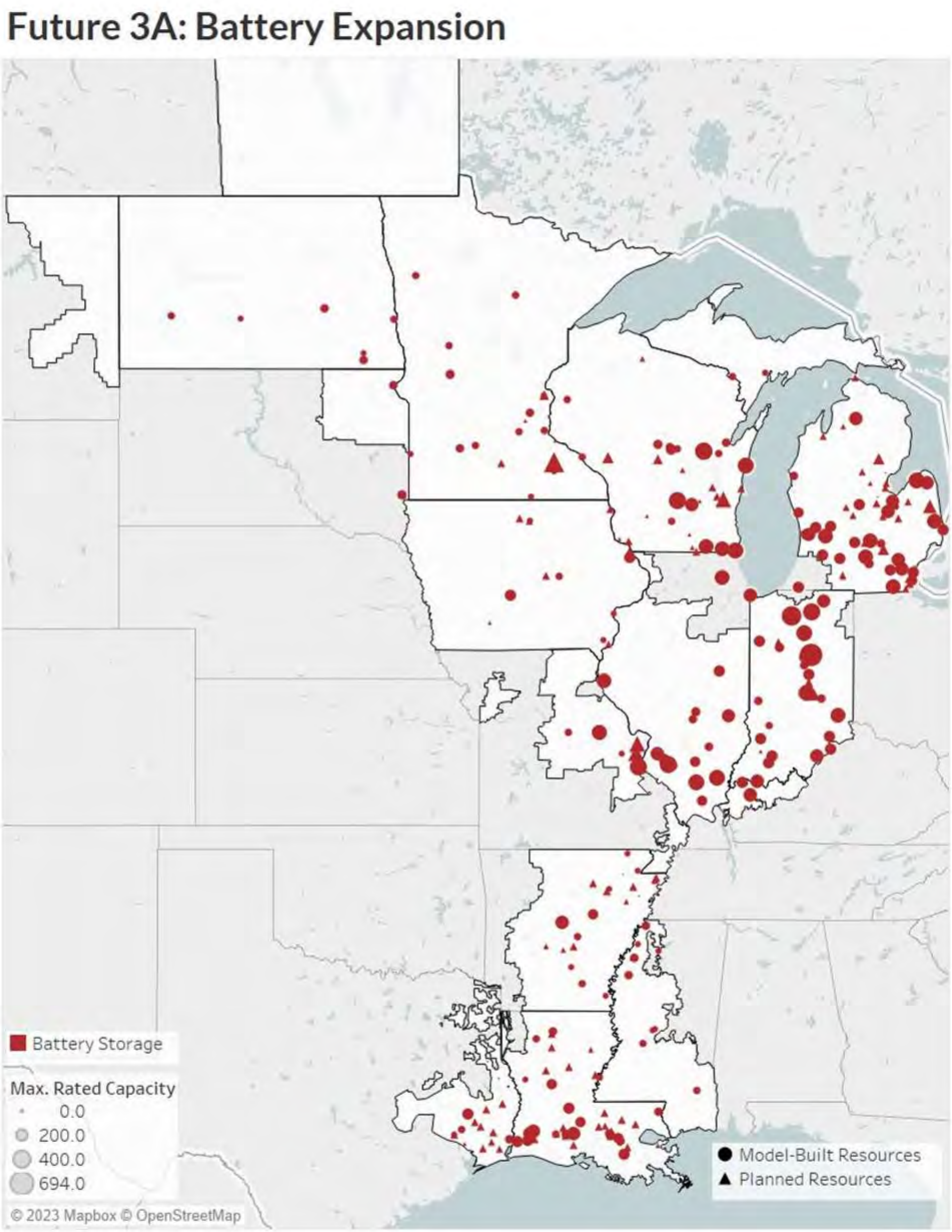


Figure 93: MISO Future 3A Battery Siting

Future 3A: Thermal Expansion

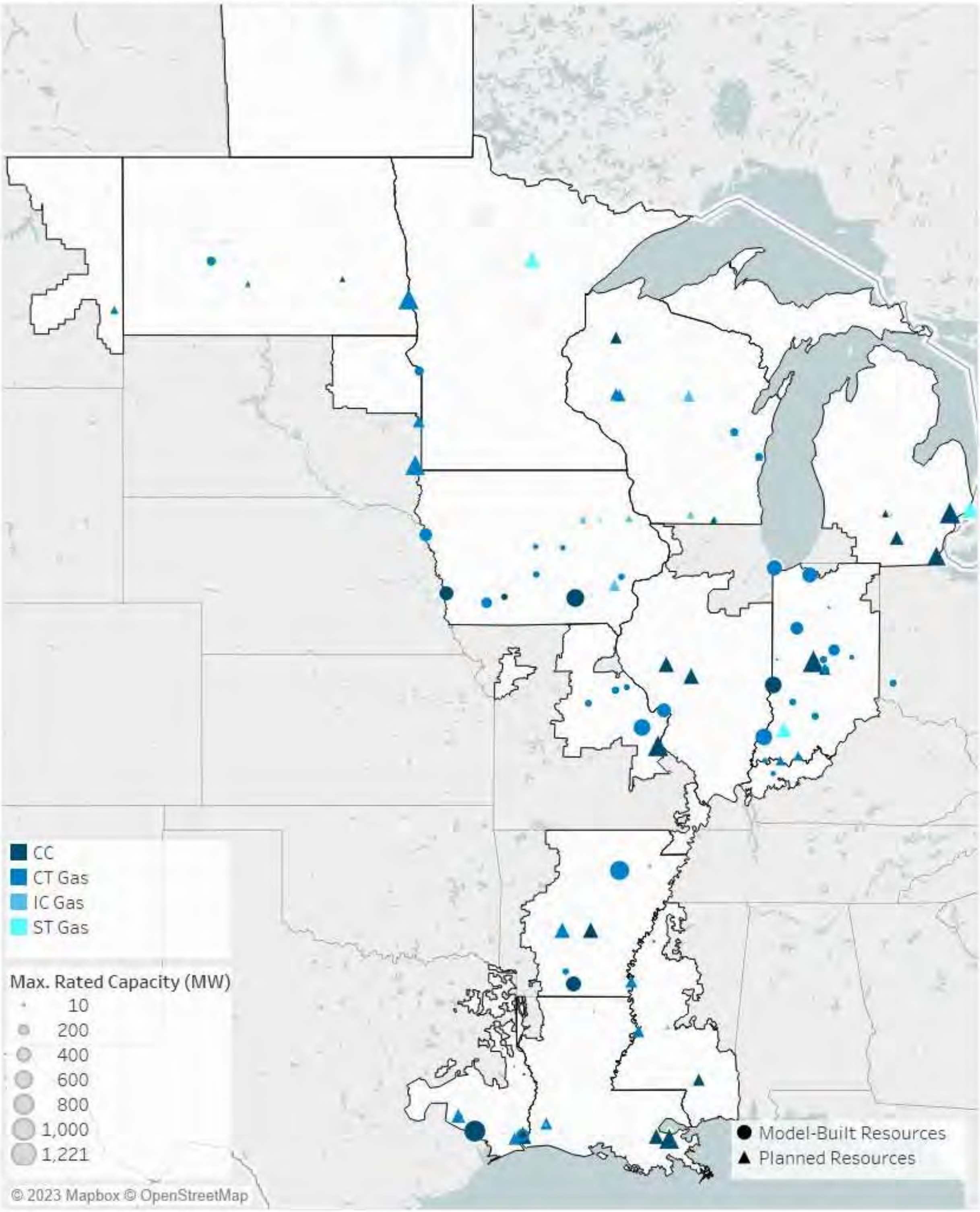


Figure 94: MISO Future 3A Thermal Siting

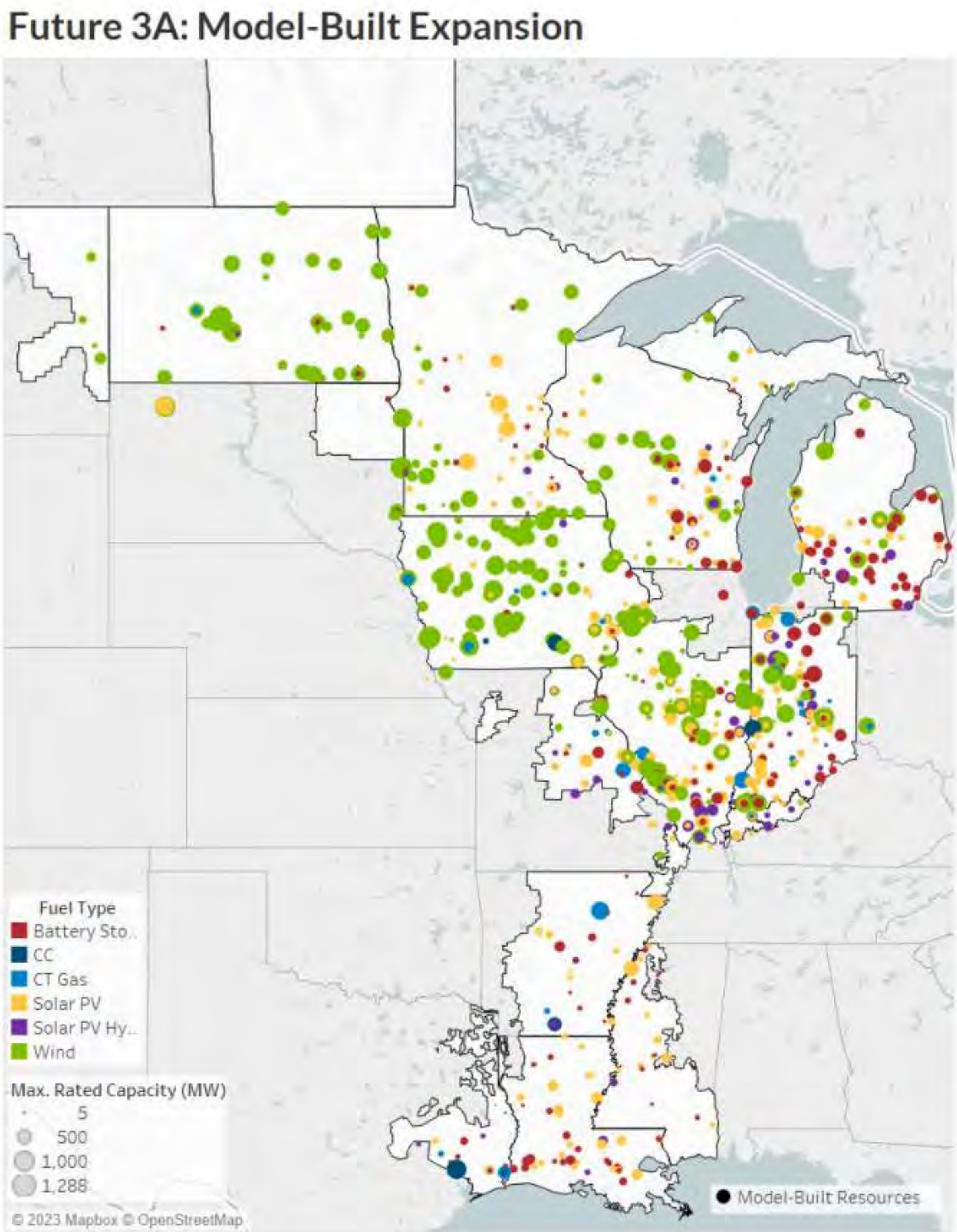


Figure 95: MISO Future 3A Complete EGEAS Expansion Siting

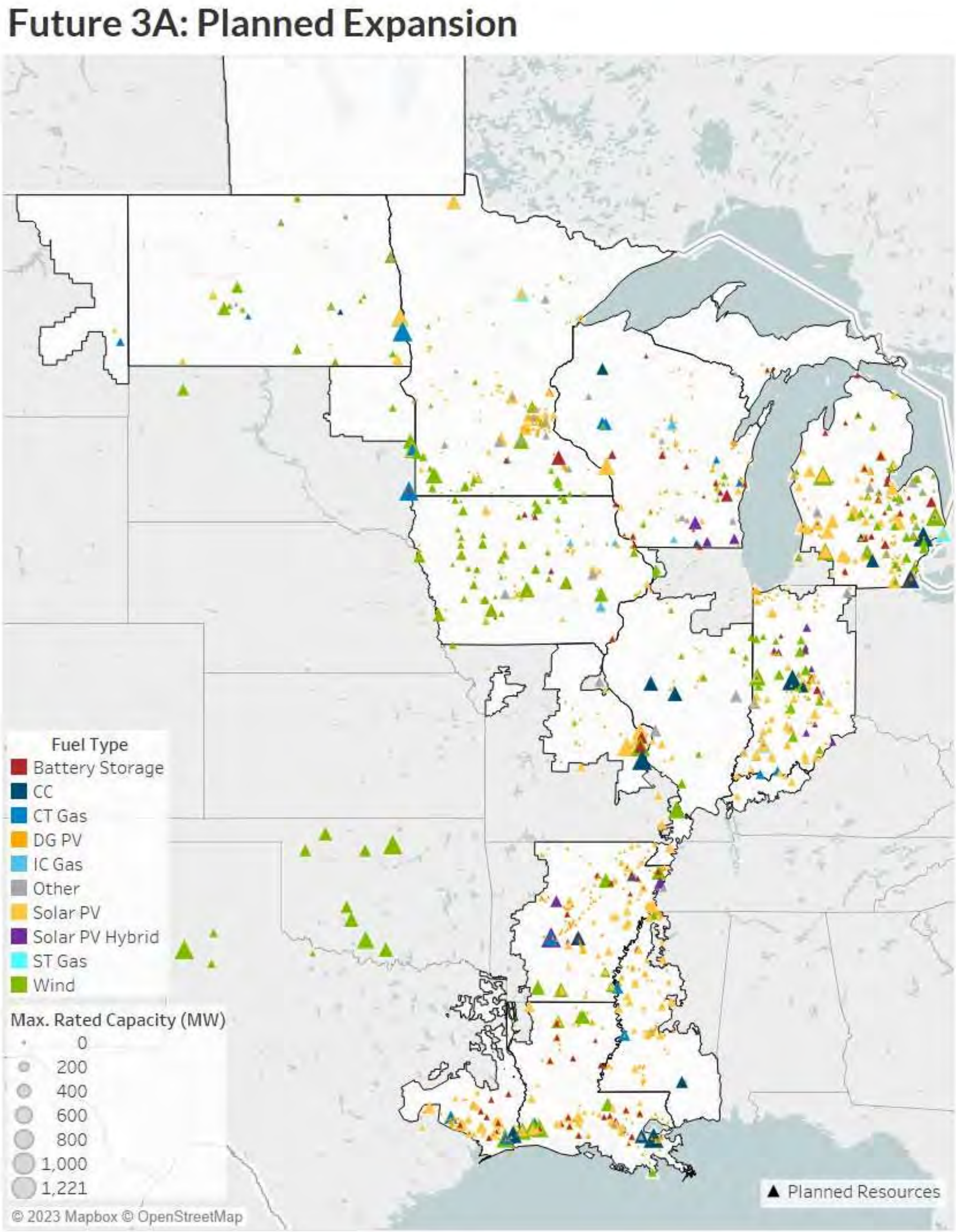


Figure 96: MISO Future 3A Non-EGEAS Expansion Siting

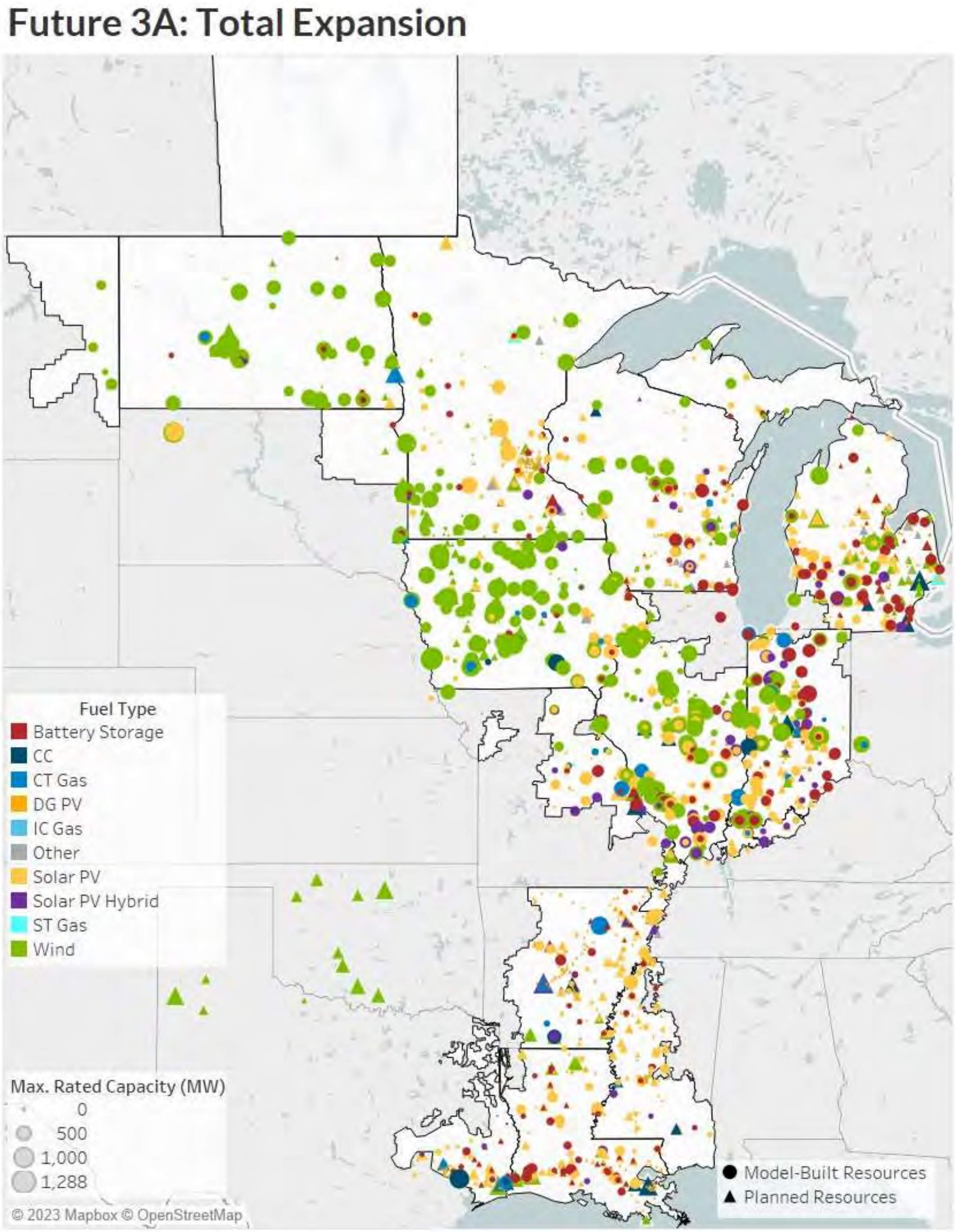


Figure 97: MISO Future 3A Non-EGEAS and EGEAS Expansion Siting

Future 3A Resource Additions (MW) - *Cumulative*

Zone	Milestone	Battery	CC	CT Gas	Demand Response	DGPV	IC Gas	Solar	Hybrid	ST Coal	ST Gas	Wind	EE	UDG	Totals
LRZ 1	2027	20	100	981	1,603	393	0	5,440	0	163	0	8,783	851	18	18,352
	2032	270	100	2,103	1,642	2,102	0	7,991	655	163	0	26,295	1,718	42	43,081
	2037	1,896	100	3,225	1,853	2,930	0	11,587	826	163	595	51,919	2,389	115	77,598
	2042	3,013	100	4,029	1,919	2,931	0	14,895	878	163	595	55,614	2,960	376	87,472
LRZ 2	2027	1,179	487	300	989	30	843	1,039	1,100	0	0	522	606	13	7,108
	2032	2,745	487	300	989	405	843	2,582	2,296	0	0	2,681	1,147	30	14,505
	2037	5,009	487	600	989	1,780	843	5,544	2,483	0	0	7,994	1,626	82	27,438
	2042	5,052	487	600	989	1,780	843	5,922	2,491	0	0	8,022	2,034	269	28,489
LRZ 3	2027	475	0	0	685	425	670	2,126	0	0	50	11,596	424	9	16,460
	2032	575	0	0	685	425	670	2,957	14	0	50	26,352	803	21	32,552
	2037	1,216	1,269	614	685	456	670	3,620	181	0	50	47,047	1,138	58	57,004
	2042	1,302	1,269	984	685	1,488	670	4,240	194	0	50	49,564	1,424	188	62,057
LRZ 4	2027	0	1,277	0	663	0	0	1,192	0	0	0	827	424	9	4,392
	2032	529	1,277	0	663	0	0	3,755	1,602	0	0	12,070	803	21	20,720
	2037	2,904	1,277	0	663	275	0	5,871	2,288	0	0	25,166	1,138	58	39,639
	2042	3,304	1,277	0	863	275	0	8,672	3,549	0	0	25,291	1,424	188	44,842
LRZ 5	2027	0	0	0	332	525	0	1,680	0	0	0	571	363	8	3,479
	2032	578	1,200	0	332	725	0	3,684	663	0	0	2,476	688	18	10,364
	2037	1,560	1,200	2,827	332	725	0	4,667	1,105	0	0	4,120	976	49	17,561
	2042	1,972	1,200	2,827	332	725	0	5,925	1,305	0	0	4,320	1,220	161	19,987
LRZ 6	2027	80	1,221	513	1,286	880	0	8,940	75	0	1,052	4,960	908	20	19,934
	2032	4,553	1,221	513	1,286	1,786	0	12,053	2,222	0	1,052	10,796	1,720	45	37,245
	2037	7,209	2,188	3,442	1,286	1,892	0	14,064	4,160	0	1,052	17,917	2,439	123	55,772
	2042	7,426	2,188	4,604	1,286	1,895	0	20,081	5,810	0	1,052	19,867	3,050	403	67,661
LRZ 7	2027	1,842	509	0	538	0	0	5,965	0	0	1,267	426	969	21	11,536
	2032	5,441	509	0	574	0	0	11,639	701	0	1,267	3,708	1,835	48	25,721
	2037	8,499	1,455	0	901	2,050	0	15,444	1,065	0	1,267	10,997	2,602	132	44,412
	2042	8,736	1,455	0	901	2,050	0	17,378	1,685	0	1,267	16,757	3,254	430	53,913
LRZ 8	2027	0	0	0	0	0	95	1,935	0	0	0	1,100	363	8	3,501
	2032	400	0	380	184	0	95	4,672	525	0	0	1,500	688	18	8,462
	2037	1,295	1,203	1,047	184	0	95	6,159	1,044	0	0	3,944	976	49	15,996
	2042	1,590	1,203	2,570	184	2,900	95	7,952	2,563	0	0	6,188	1,220	161	26,626
LRZ 9	2027	10	1,215	0	136	0	173	4,885	0	0	0	0	969	21	7,409
	2032	735	2,317	0	136	1,700	173	9,864	462	0	0	0	1,835	48	17,269
	2037	2,527	3,014	1,790	136	1,700	173	14,029	583	0	0	5,956	2,602	132	32,642
	2042	6,377	3,014	2,285	352	2,050	173	16,655	704	0	0	10,412	3,254	430	45,706
LRZ 10	2027	0	402	0	0	0	58	2,150	0	0	0	0	182	4	2,796
	2032	0	402	380	0	0	58	2,964	85	0	0	0	344	9	4,242
	2037	617	1,407	380	0	1,325	58	4,118	165	0	0	0	488	25	8,583
	2042	826	1,407	760	0	1,700	58	5,783	246	0	0	200	610	81	11,671
MISO Total	2027	3,606	5,211	1,793	6,231	2,253	1,839	35,351	1,175	163	2,369	28,784	6,060	131	94,967
	2032	15,826	7,513	3,675	6,492	7,143	1,839	62,160	9,225	163	2,369	85,878	11,578	300	214,161
	2037	32,733	13,600	13,924	7,029	13,133	1,839	85,102	13,900	163	2,964	175,061	16,375	823	376,645
	2042	39,599	13,600	18,658	7,511	17,794	1,839	107,502	19,425	163	2,964	196,234	20,448	2,688	448,425

Table 11: MISO Future 3A Resource Additions by LRZ and Footprint

Future 3A Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2027**	3,612	1,609	0	325	123	0	962	6,630
	2032	5,355	2,498	0	584	1,772	0	996	11,204
	2037	6,011	2,748	0	678	3,178	24	1,014	13,654
	2042	6,020	3,466	0	695	5,274	470	1,014	16,939
LRZ 2	**2027**	2,515	1,042	0	76	102	0	20	3,756
	2032	2,844	3,280	0	76	385	0	20	6,605
	2037	3,573	3,737	0	200	823	0	20	8,353
	2042	4,822	6,474	0	200	823	11	44	12,374
LRZ 3	**2027**	3,407	1,481	0	319	311	0	0	5,519
	2032	3,407	1,513	0	319	1,468	0	0	6,708
	2037	3,980	1,573	0	455	4,582	0	0	10,591
	2042	4,012	2,710	0	524	6,628	0	0	13,874
LRZ 4	**2027**	2,123	0	0	117	20	0	0	2,260
	2032	2,123	3,222	0	117	28	0	0	5,490
	2037	2,123	4,505	0	176	698	0	0	7,502
	2042	3,752	4,508	0	176	823	20	0	9,280
LRZ 5	**2027**	1,251	67	0	345	0	0	0	1,663
	2032	2,257	1,188	0	345	0	0	0	3,790
	2037	3,471	1,201	0	345	169	0	0	5,186
	2042	4,704	1,201	0	345	169	0	0	6,419
LRZ 6	**2027**	7,255	745	0	50	0	0	0	8,050
	2032	8,986	1,786	0	71	131	0	0	10,974
	2037	10,256	4,037	0	71	942	2	0	15,308
	2042	10,256	5,972	0	71	1,742	475	0	18,516
LRZ 7	**2027**	3,787	2,000	0	390	0	0	38	6,214
	2032	5,357	5,959	0	390	113	0	147	11,965
	2037	6,922	8,830	0	419	929	0	147	17,246
	2042	6,922	8,830	0	419	2,180	54	147	18,551
LRZ 8	**2027**	0	788	0	0	0	0	0	788
	2032	3,089	931	0	0	0	0	0	4,020
	2037	3,089	3,485	0	0	0	0	0	6,574
	2042	3,089	4,865	0	0	0	181	0	8,136
LRZ 9	**2027**	1,880	4,857	0	7	0	0	0	6,745
	2032	2,496	6,656	0	7	0	0	28	9,187
	2037	2,496	15,897	0	7	0	0	39	18,438
	2042	3,157	17,719	0	7	0	0	39	20,922
LRZ 10	**2027**	0	901	0	0	0	0	0	901
	2032	206	1,119	0	0	0	0	0	1,325
	2037	206	3,218	0	0	0	0	0	3,424
	2042	775	4,066	0	0	0	52	0	4,893
MISO Total	**2027**	25,831	13,491	0	1,628	556	0	1,020	42,526
	2032	36,120	28,153	0	1,908	3,896	0	1,190	71,268
	2037	42,127	49,232	0	2,351	11,321	26	1,219	106,277
	2042	47,510	59,813	0	2,436	17,638	1,262	1,243	129,903

Table 12: MISO Future 3A Resource Retirements by LRZ and Footprint

Appendix

EGEAS Modeling

Description

The Electric Generation Expansion Analysis System (EGEAS) is a program developed by EPRI which MISO uses to conduct its expansion analysis studies. The primary function of EGEAS is the creation of the lowest cost generation expansion plan that meets system requirements specified by inputs, assumptions, and constraints.

Modeling Procedure

The modeling process can be broken down into three main stages: definition of the model through inputs, computational analysis and solution processing, and consolidation of the results in the output file.

Inputs

Listed below are some of the key input parameters that EGEAS uses when selecting the optimal expansion solution. EGEAS allows users to input a variety of variables however, the inputs below include some of the more important parameters when setting up an economic expansion model.

- Hourly load shape files for the system and NDTs
- Projected peak yearly values of demand and energy
- Planning Reserve Margin (PRM) percentage requirement
- Renewable Portfolio Standard (RPS) percentage trajectories
- Decarbonization trajectories, may be input in short tons or $/short ton
- Existing unit data including planned additions and retirements
- Cost of unserved energy
- Available expansion resources and respective cost and emission data

Computational Analysis

To find the optimal resource expansion plan, EGEAS solves two objective functions:

1. Present value of the revenue requirements
2. The levelized average system rates ($/MWh)

The bulk of the work done by EGEAS is in solving these functions. It is an iterative process that progresses through the study year by year. Retaining only the feasible solutions each year, a single expansion plan that satisfies all input constraints and limitations over the study period is selected after the final year of study.

Output

The final report file is a text output file containing a report on the generic units EGEAS built to meet the system constraints in every year of the study. Metrics such as PRM, RPS, systemwide CO_2 emissions, resource generation, and cost data are also included in the report file.

From this information, MISO staff acquires its resource expansion and sites these resources throughout the footprint based on generator availability and other criteria discussed in the New Resource Addition Siting Process section of this report.

An important metric used in the Futures process is the RPS which EGEAS calculates as the ratio of Renewable Energy Generation (from wind, solar, and solar hybrid resources) to Net System Energy. In this calculation, net system energy is the sum of forecasted and storage charging energy minus energy from demand side management programs. While this may be how EGEAS calculated required contribution from renewable resources when defining an economic expansion, MISO displays these results differently so that energy generation from all resources may be seen. The calculation used by MISO is (Renewable Energy GWh / Total Generation GWh).

Shown below is an example of the EGEAS and MISO calculation to meet the RPS in Future 3, year 2039. MISO values appear less than EGEAS calculated values because total generation includes energy from DSM programs and curtailed renewable energy from low demand periods.

EGEAS Calculation

Forecasted System Energy (GWh)	Storage Charging (GWh)	DSM Energy (GWh)	Net System Energy (GWh)	Renewable Energy Generation (GWh)	RPS %
1,063,465	176,423	56,665	1,183,223	622,241	53%

$$\left(\frac{Renewable}{Forecasted + Storage - DSM}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}063{,}465 + 176{,}423 - 56{,}665}\right) \times 100 = 52.59$$

MISO Calculation

Total Energy Generation (GWh)	Renewable Energy Generation (GWh)	RPS %
1,352,519	622,241	46%

$$\left(\frac{Renewable}{Total\ Generation}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}352{,}519}\right) \times 100 = 46.01$$

Additional MISO Assumptions

Futures Assumptions Summary

Table 13 and Table 14 detail Future-specific input assumptions. Many of these variables were direct inputs to the model; however, selected DERs, retirements, and addition totals are results of the analysis.

Variables	Future 1A	Future 2A	Future 3A
Gross Load[43] Total Growth	Low-Base EV Growth 94,275 GWh	30% Total Energy Growth by 2040 196,996 GWh	50% Total Energy Growth by 2040 334,692 GWh
Energy (CAGR) Input/*Result*	0.63% / *0.22%*	1.25% / *0.80%*	1.95% / *1.08%*
Demand (CAGR) Input/*Result*	0.77% / *0.36%*	1.14% / *0.82%*	1.63% / *1.14%*
Electrification Growth & Technologies Growth from Electrification	2% of Total Growth 14,147 GWh	15.2% of Total Growth 109,101 GWh	31.8% of Total Growth 231,513 GWh
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process
Selected DERs DR	10.8 GW	11.2 GW	11 GW
EE	17.7 GW	17.7 GW	20.5 GW
DG	19.9 GW	19.9 GW	20.5 GW
Carbon Reduction *(2005 baseline)* MISO Footprint currently at 29%	71% *83% realized in results*	76% *96% realized in results*	80% *99% realized in results*
Wind & Solar Generation Percentage[14]	Resulted in 55% with No Minimum Enforced	Resulted in 83% with No Minimum Enforced	87%
Utility Announced Plans	85% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met

Table 13: MISO Futures Assumptions

[43] Total Growth is based on 2039 values due to the original study period ending on 12/31/2039.

Variables		Future 1A	Future 2A	Future 3A
Retirement Age-Based Criteria	Coal	46 years[44]	36 years	30 years
	Natural Gas-CC	50 years	45 years	35 years
	Natural Gas-Other	46 years	36 years	30 years
	Oil	45 years	40 years	35 years
	Nuclear	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
	Wind & Solar - Utility Scale	25 years	25 years	25 years
Retirements	Coal	42 GW	42.6 GW	47.5 GW
	Gas	23.3 GW	37.6 GW	59.8 GW
	Oil	2 GW	2.4 GW	2.4 GW
	Nuclear	0 GW	0 GW	0 GW
	Wind	17.6 GW	17.6 GW	17.6 GW
	Solar	1.3 GW	1.3 GW	1.3 GW
	Other	1.2 GW	1.2 GW	1.2 GW
	Total	87.5 GW	102.7 GW	130 GW
Additions	CC	10 GW	10 GW	13.6 GW
	CT	7.9 GW	9.1 GW	18.7 GW
	Gas Other[45]	4.8 GW	4.8 GW	4.8 GW
	Wind[46]	66.6 GW	144.6 GW	196.2 GW
	Solar	74.2 GW	101.8 GW	125.3 GW
	Hybrid	12.2 GW	9.8 GW	19.4 GW
	Battery	10.8 GW	31.1 GW	39.6 GW
	Flex	0 GW	29.8 GW	0 GW
	Total (Including DERs)	214.3 GW	369.3 GW	448.4 GW

Table 14: MISO Futures Assumptions and Expansion Results

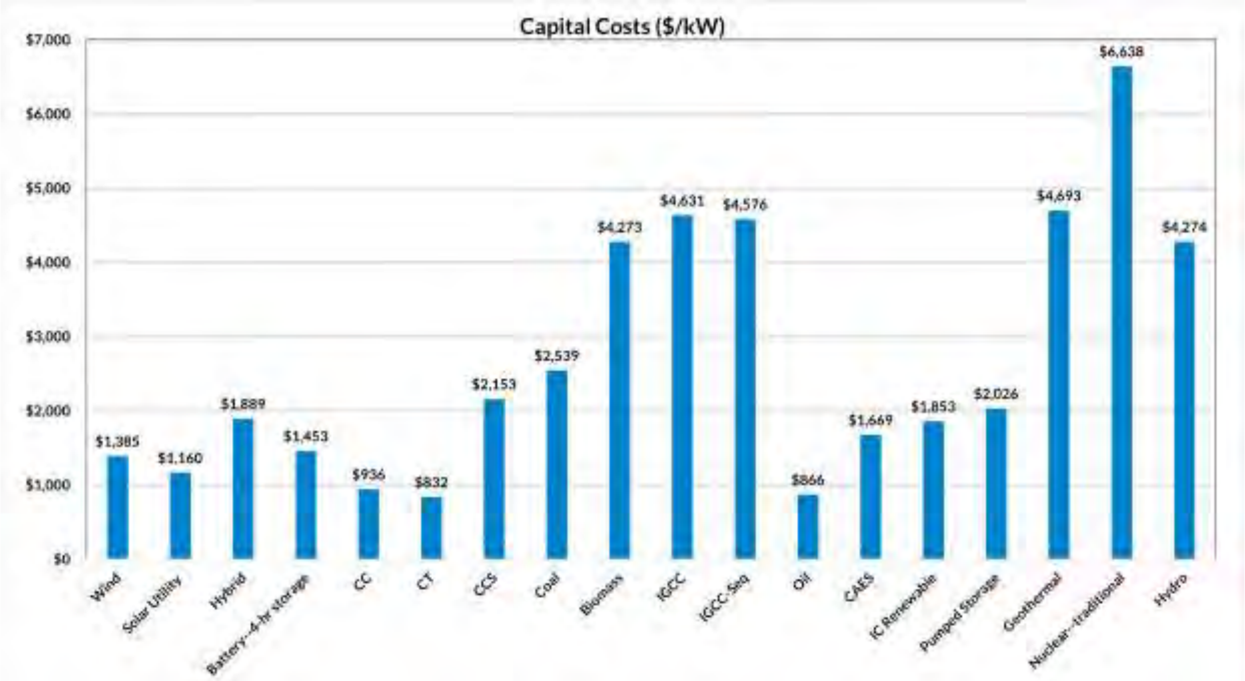
[44] EIA Source for Coal Retirement Age, Future 1A: https://www.eia.gov/todayinenergy/detail.php?id=40212

[45] Gas Other includes ST Gas (3.0 GW) and IC Gas (1.8 GW) across all Futures.

[46] All Futures include 17.1 GW of repowered wind and 44.4 GW of wind from planned additions.

Capital Costs

MISO used the 2022 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).[47] to calculate the capital costs for all resources except for oil,[48] compressed air energy storage (CAES),[49] and internal combustion (IC) renewable[50] costs. MISO utilized moderate cost values within the 2022 ATB, which are in 2020 dollars. These values were converted to 2022 dollars and projected into the 20-year study period to create cost trajectories. For Hybrid unit costs, 2022 ATB Solar PV + Battery costs are included.



All relevant resource types are presented prior to factoring in the effects of the PTC and ITC.

Figure 98: Annual Capital Cost Assumptions by Fuel Type

[47] NREL 2022 ATB: https://atb.nrel.gov/electricity/2022/data

[48] EIA costs were used and adjusted for 2022 dollars: https://www.eia.gov/electricity/generatorcosts/

[49] Costs from the Pacific Northwest National Laboratory 2020 Grid Energy Storage Technology Cost and Performance Assessment: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

[50] Capital expenses from the EPA Landfill Gas Energy Project Development Handbook, https://www.epa.gov/lmop/landfill-gas-energy-project-development-handbook . O&M costs from EIA Annual Energy Outlook, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

Production Tax Credits (PTC) and Investment Tax Credits (ITC)

Production Tax Credit (PTC) and Investment Tax Credit (ITC) effects on wind, utility-scale solar PV, and hybrid units are displayed below. Since the battery in the hybrid unit modeled is charged from solar resources 100% of the time, it may qualify for 100% of ITC benefits.[51,52]

Consolidated Appropriations Act of 2016 PTC with 2022 Extensions	2016	2017	2018	2019	2020	2021	2022	2023	2024 & onward
PTC	Full	80%	60%	40%	60%	60%	Full	Full	Full
ITC	30%	30%	30%	30%	26%	26%	30%	30%	30%

Table 15: PTC and ITC Schedule

Accreditations of PTC and ITC benefits are seen for wind, solar, hybrid, and battery units since the extensions of the tax credits facilitated by the Inflation Reduction Act. The model representation differs due to the assumed construction time of each of these units, in order to ensure their safe harbor provisions. MISO used the values in the model representation section to build cost trajectories for these resources in EGEAS.

In the original Futures cohort, both the PTC and ITC gradually phased out over the course of the planning period. Due to the passage of the Inflation Reduction Act in August 2022, both tax credits are assumed to be extended indefinitely. For more information on the effects of the IRA on the Futures, see the Inflation Reduction Act section of this report. Additional information on the implementation of the PTC and ITC in EGEAS models can be found in the Futures Refresh Assumptions Book.

Natural Gas Price Forecasting

MISO used the Gas Pipeline Competition Model (GPCM) base price forecast across the three Futures, instead of the Henry Hub price (HH) as in past cycles. GPCM outputs the gas price at a level of monthly granularity and produces unit-specific gas prices. The gas forecast per unit remained the same for all Futures modeled in EGEAS. As part of the Futures Refresh, the natural gas price was updated utilizing GPCM 2022 Q2 data.

[51] Source for PTC and ITC for Wind & Solar PV: https://fas.org/sgp/crs/misc/R43453.pdf

[52] NREL - ITC accreditation for Hybrids: https://www.nrel.gov/docs/fy18osti/70384.pdf

External Assumptions and Modeling

General Assumptions

Study Areas

For purposes of resource expansion, the areas being analyzed with the Futures assumptions are:

- Midcontinent Independent System Operator (MISO)
- PJM Interconnection (PJM)
- Southwest Power Pool (SPP)
- Southeast (which includes the following)
    - Duke Energy Carolinas (Duke)
    - Progress Energy Carolinas East (CPLE)
    - Progress Energy Carolinas West (CPLW)
    - South Carolina Electric & Gas Company (SCEG)
    - Santee Cooper (SC)
    - Alabama Power Company [SOCO]
    - Georgia Power [SOCO]
    - Gulf Power Company
    - Mississippi Power Company [SOCO]
    - PowerSouth Energy Coop
- TVA-Other (which includes the following)
    - Associated Electric Cooperative Inc. (AECI)
    - Louisville Gas & Electric/Kentucky Utilities (LG&E/KU)
    - Tennessee Valley Authority (TVA)

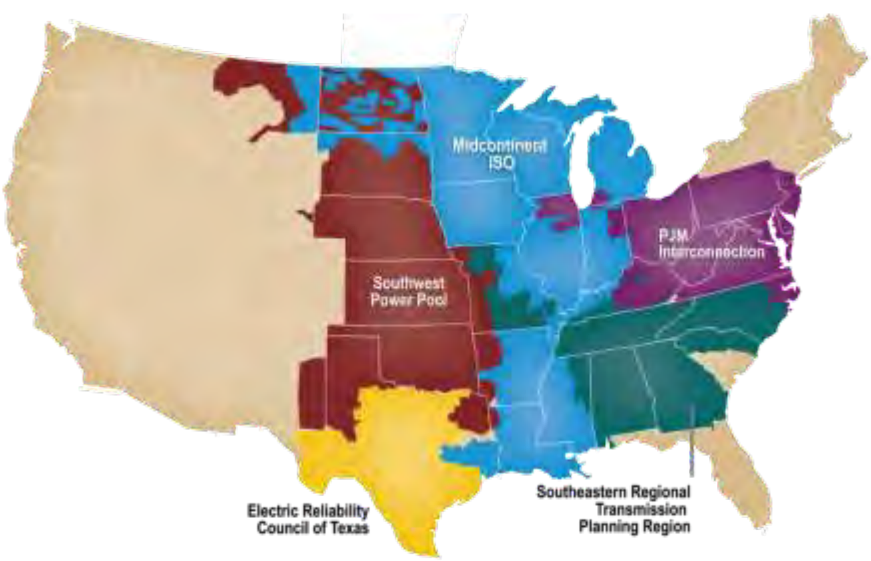


Figure 99: MISO Footprint & Neighboring Systems

External Areas Forecasts Development

The 2019 Merged Load Forecast for Energy Planning forecast did not include External (non-MISO) companies' forecasts, so when available, External areas utilized respective regional model forecasts, and when no regional forecast was available, the latest Multiregional Modeling Working Group (MMWG) model was used to create associated forecasts. Additionally, External areas utilized ABB's Velocity Suite 2018 load shapes.

External Expansion Results

While comparing the expansion results of the External regions across each Future scenario, there are several key findings of note:

- All scenarios have very different expansions; this is due to large contrasts among the regions with respect to geography, resource retirements, and current resource mixes.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. For the External areas, Future 3A sees more buildout of all resource types, with notably larger increases in wind and PV; this is primarily due to an increase in projected load, as well as heightened carbon reduction goals. For the External areas, Future 3A sees more buildout of all resource types, with notably larger increases in wind and PV; this is primarily due to an increase in projected load, as well as increased decarbonization goals.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across areas. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- As with the MISO footprint, DER programs included in each of the External areas in Future 1A are considered the minimum and were included across all three Futures, while incremental additions of each program were offered in F2A and F3A. PJM and SPP each incorporated ten DER programs in their base assumptions, while TVA-Other incorporated six. PJM selected incremental additions in five out of six DERs offered in F2A and eight out of ten in F3A. SPP selected five out of six incremental DER additions in F2A and six out of ten in F3A. TVA-Other selected four out of four incremental DER additions in F2A and six out of six in F3A. A list of EGEAS-offered and selected programs for the External regions is found below in Table 17.

Over the course of the following pages (Table 16 through Table 19) the detailed expansion results of each External Future scenario are displayed. Following the figures in each section are resource-specific retirement and addition (R&A) tables, each table details R&A capacities applicable for each region and milestone year.

Future Resource Additions (MW)														
Area	Future	CC	CT	ST Gas	Wind	Solar	Distributed Solar	Hybrid	Nuclear	Demand Response	EE	UDG	Flex	Total
PJM	Future 1A	6,591	3,600	1,926	81,828	16,416	16,616	18,000	0	12,796	40,361	604	0	198,737
	Future 2A	6,591	18,000	1,926	164,628	23,616	16,616	32,400	0	16,668	50,342	604	37,671	369,061
	Future 3A	28,191	54,000	1,926	222,228	102,816	17,048	50,400	0	16,841	52,597	604	0	546,650
SPP	Future 1A	198	0	287	182,473	39,600	6,616	0	0	2,346	3,457	2,402	0	237,378
	Future 2A	198	8,400	287	109,273	37,200	6,616	0	0	3,154	4,126	2,401	3,648	175,302
	Future 3A	3,798	21,600	287	175,273	43,200	7,047	10,800	0	2,434	4,275	2,402	0	271,116
TVA-Other	Future 1A	0	720	0	123,582	40,360	1,340	18,000	1,100	1,680	588	9,061	0	196,430
	Future 2A	0	43,920	0	123,582	36,760	1,340	28,800	1,100	1,860	645	9,061	3,225	250,293
	Future 3A	3,600	83,520	0	285,582	43,960	2,769	32,400	1,100	1,978	674	9,061	0	464,645

Future Resource Retirements (MW)									
Area	Future	Coal	Gas	Nuclear	Oil	Biomass	Solar	Wind	Total
PJM	Future 1A	49,432	13,697	18,092	6,708	91	1,266	10,413	99,699
	Future 2A	50,401	37,347	18,092	7,064	91	1,266	10,413	124,674
	Future 3A	51,983	57,451	18,092	7,079	91	1,266	10,413	146,375
SPP	Future 1A	19,528	2,812	766	1,026	0	314	18,564	43,010
	Future 2A	19,743	8,990	766	1,227	0	314	18,564	49,604
	Future 3A	22,691	20,153	766	1,327	0	314	18,564	63,816
TVA-Other	Future 1A	41,283	9,276	16,257	1,910	0	2,439	1,182	72,346
	Future 2A	42,593	34,526	16,257	1,990	0	2,439	1,182	98,987
	Future 3A	44,598	61,558	16,257	1,990	0	2,439	1,182	128,023

Table 16: External Resource Additions and Retirements Summary

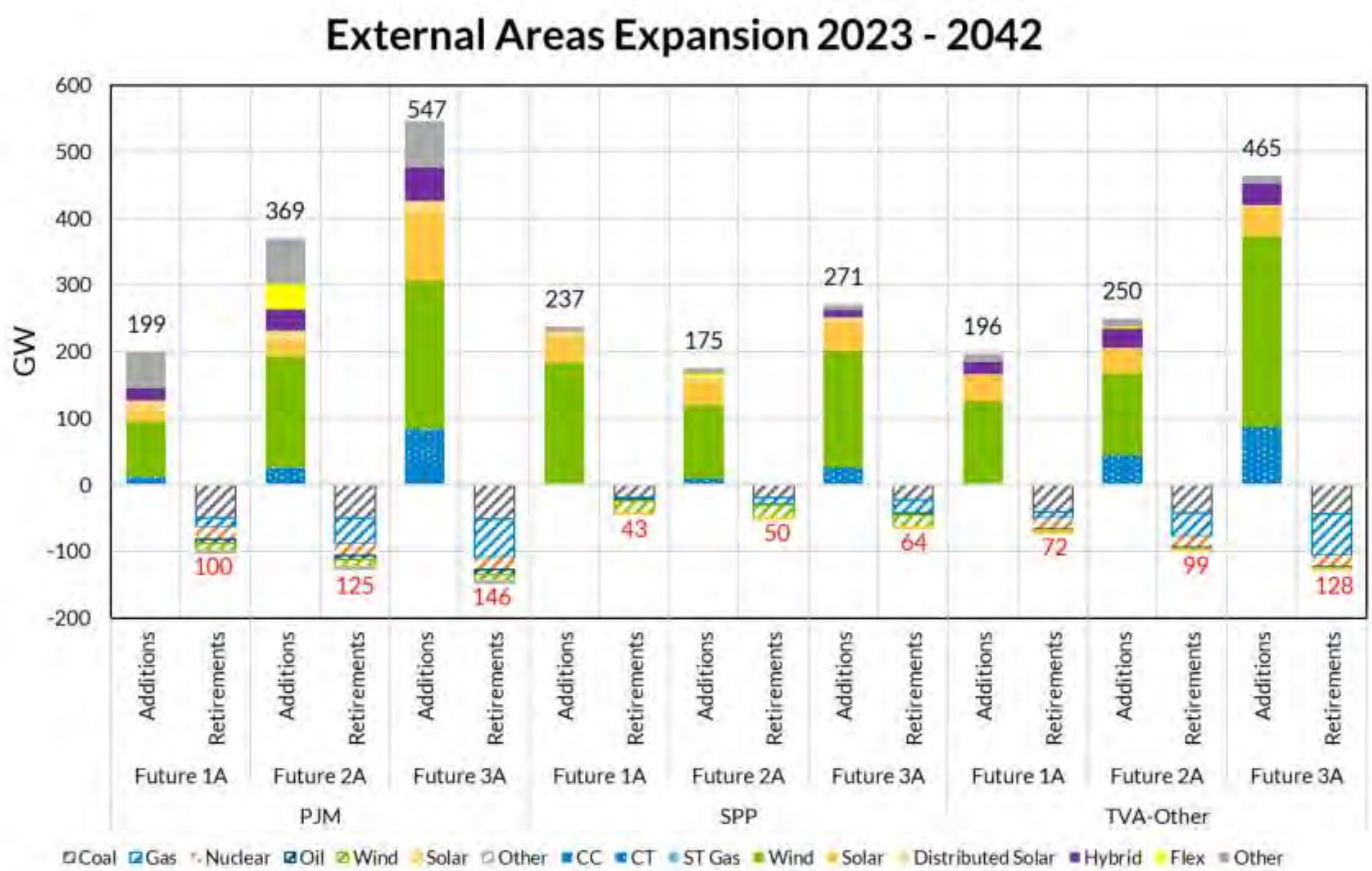


Figure 100: External Region Expansion Summary

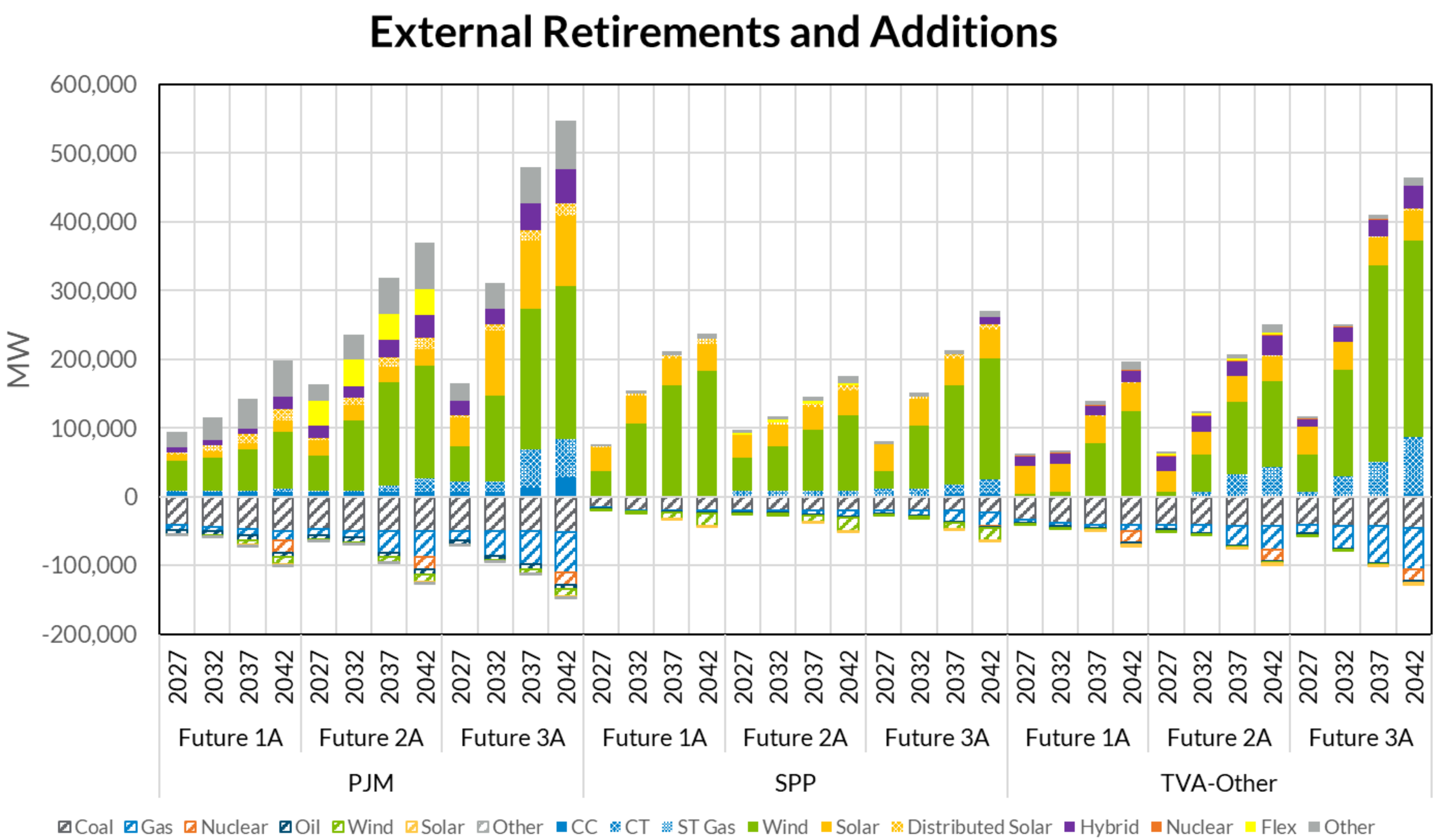


Figure 101: External Resource Additions and Retirements per Milestone Year (Cumulative)

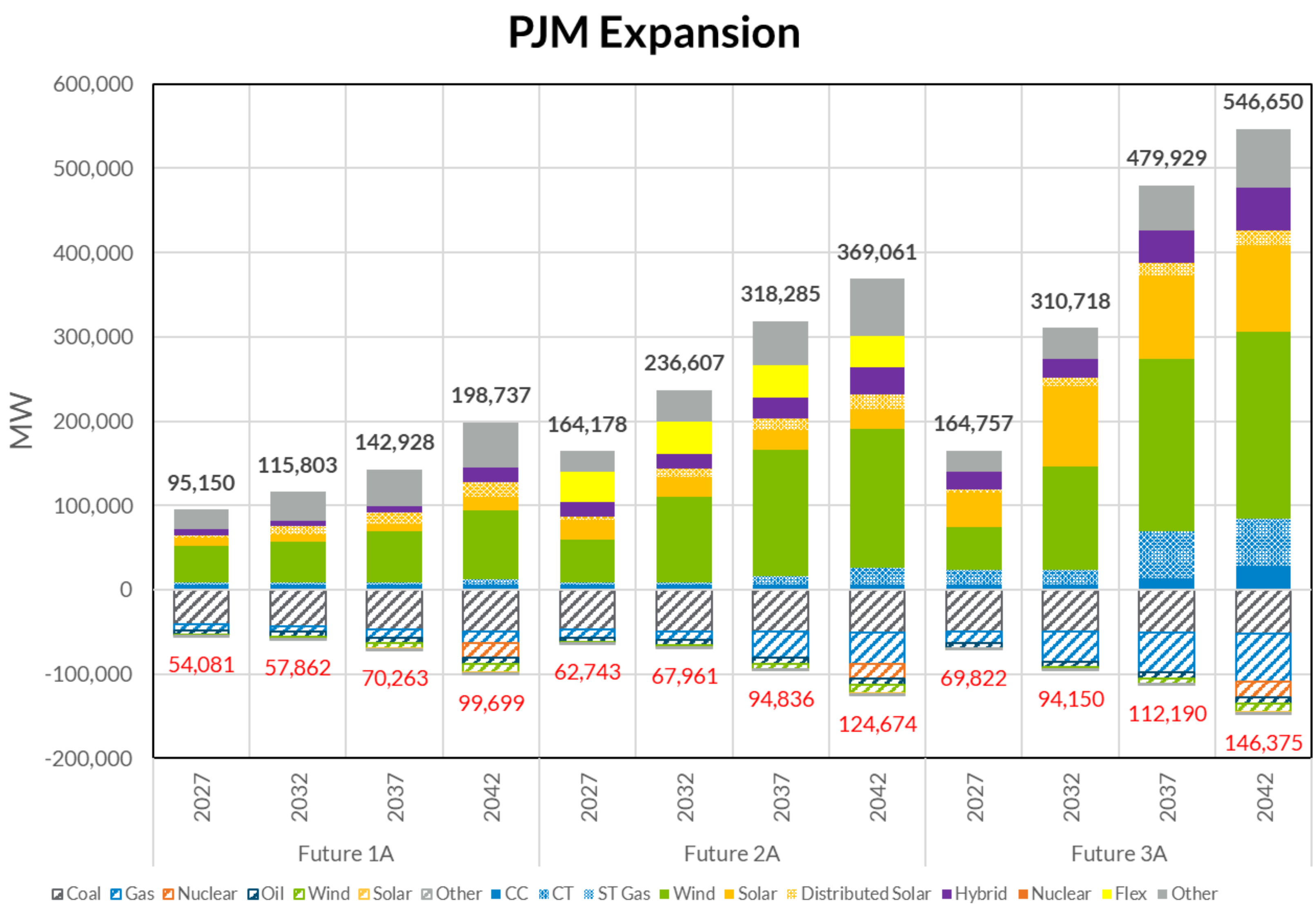


Figure 102: PJM Resource Additions and Retirements per Milestone Year (Cumulative)

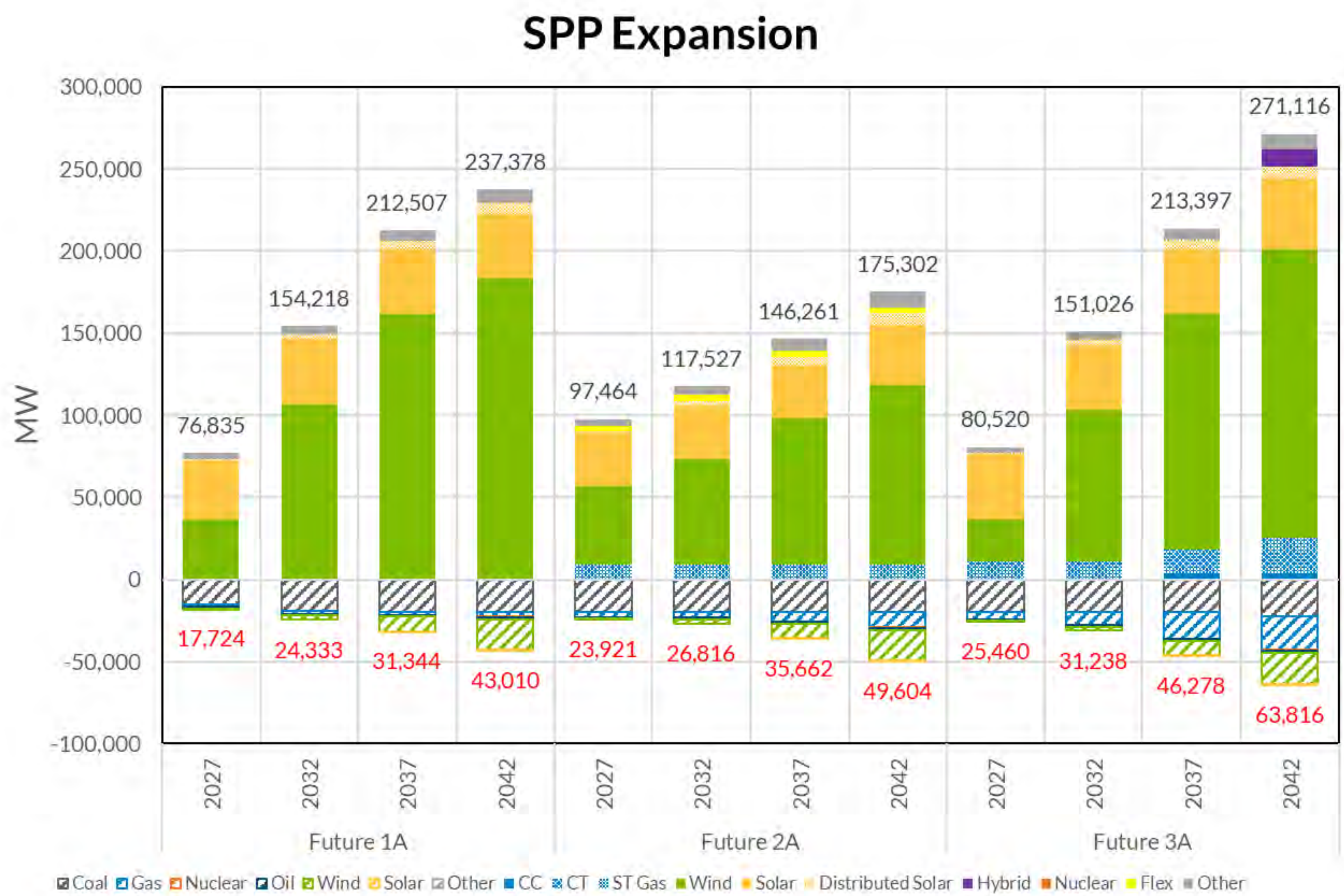


Figure 103: SPP Resource Additions and Retirements per Milestone Year (Cumulative)

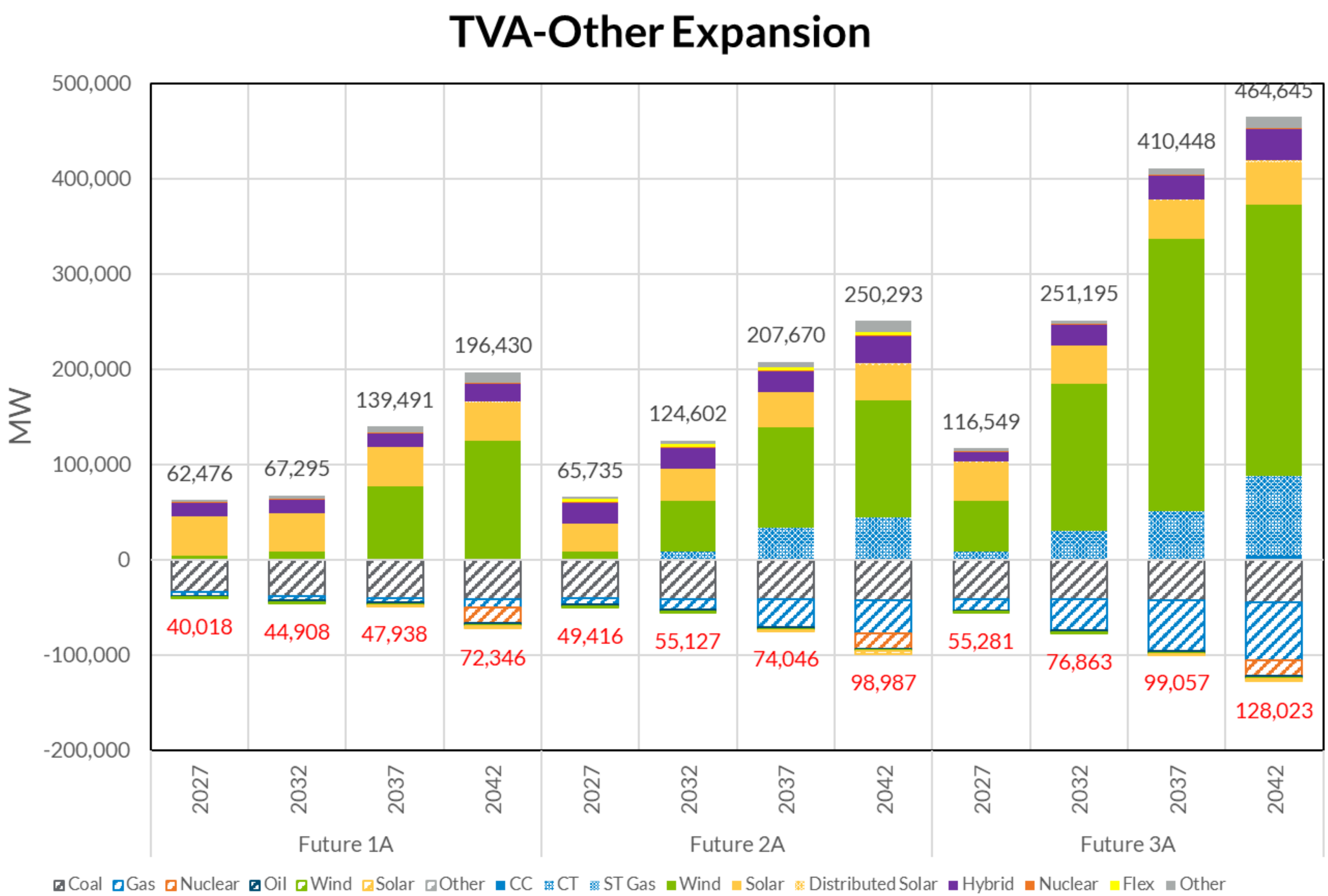


Figure 104: TVA-Other Resource Additions and Retirements per Milestone Year (Cumulative)

External DER Programs: Respective Offerings and Selections

DER Type	EGEAS Program Block	DER Program(s) Included	PJM			SPP			TVA-Other		
			Base	*Incremental Addition*		*Base*	*Incremental Addition*		*Base*	*Incremental Addition*	
			F1A	*F2A*	*F3A*	*F1A*	*F2A*	*F3A*	*F1A*	*F2A*	*F3A*
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
DR	C&I Price Response	C&I Price Response	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
DR	Res. Direct Load Control	Res. Direct Load Control	Yes	N/A	Yes	Yes	Yes	No	N/A	N/A	N/A
DR	Res. Price Response	Res. Price Response	Yes	Yes	Yes	Yes	Yes	Yes	N/A	N/A	N/A
EE	C&I EE	Custom Incentive, Lighting, New Construction, Prescriptive Rebate, Retro commissioning	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
EE	Res. EE	Appliance Incentives, Appliance Recycling, Behavioral Programs, Lighting, Low Income, Multifamily, New Construction, School Kits, Whole Home Audit	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
DG	C&I Customer Solar PV	C&I Customer Solar PV	Yes	N/A	No	Yes	N/A	No	Yes	N/A	Yes
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Util Incentive Batt Storage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG	C&I Utility Incentive Solar PV	C&I Utility Incentive Solar PV	Yes	No	Yes	Yes	N/A	Yes	N/A	N/A	N/A
DG	Res. Customer Solar PV	Res. Customer Solar PV	Yes	N/A	No	Yes	N/A	No	Yes	N/A	Yes
DG	Res. Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Util Incentive Batt Storage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG	Res. Utility Incentive Solar PV	Res. Utility Incentive Solar PV	Yes	N/A	Yes	Yes	N/A	Yes	N/A	N/A	N/A

Yes = selected. No = offered, not selected. N/A = not offered.
F1A Base DER programs are included across all three models (F1A, F2A, F3A); Incremental additions are only included in the specified Future.

Table 17: External DER Program Mapping, with Respective Offerings and Selection by Future in EGEAS

External Area Resource Additions per Future (MW) - *Cumulative*

Future/Area	Milestone	CC	CT	ST Gas	Wind	Solar	Distributed Solar	Hybrid	Nuclear	Demand Response	EE	UDG	Flex	Totals
PJM Future 1A	2027	6,591	0	1,926	43,656	9,216	3,171	7,200	0	12,796	10,482	112	0	95,150
	2032	6,591	0	1,926	47,984	9,216	9,328	7,200	0	12,796	20,530	232	0	115,803
	2037	6,591	0	1,926	60,386	9,216	13,547	7,200	0	12,796	30,882	384	0	142,928
	2042	6,591	3,600	1,926	81,828	16,416	16,616	18,000	0	12,796	40,361	604	0	198,737
PJM Future 2A	2027	6,591	0	1,926	50,856	23,616	3,171	18,000	0	13,498	11,183	112	35,225	164,178
	2032	6,591	0	1,926	101,984	23,616	9,328	18,000	0	14,302	22,957	232	37,671	236,607
	2037	6,591	7,200	1,926	150,386	23,616	13,547	25,200	0	15,438	36,326	384	37,671	318,285
	2042	6,591	18,000	1,926	164,628	23,616	16,616	32,400	0	16,668	50,342	604	37,671	369,061
PJM Future 3A	2027	6,591	14,400	1,926	50,856	41,616	3,200	21,600	0	13,191	11,264	112	0	164,757
	2032	6,591	14,400	1,926	123,584	95,616	9,431	21,600	0	14,012	23,325	232	0	310,718
	2037	13,791	54,000	1,926	204,386	99,216	13,816	39,600	0	15,445	37,365	384	0	479,929
	2042	28,191	54,000	1,926	222,228	102,816	17,048	50,400	0	16,841	52,597	604	0	546,650
SPP Future 1A	2027	198	0	287	36,192	36,000	650	0	0	2,307	921	281	0	76,835
	2032	198	0	287	106,414	39,600	2,978	0	0	2,318	1,798	625	0	154,218
	2037	198	0	287	161,137	39,600	5,084	0	0	2,330	2,656	1,215	0	212,507
	2042	198	0	287	182,473	39,600	6,616	0	0	2,346	3,457	2,402	0	237,378
SPP Future 2A	2027	198	8,400	287	48,192	32,400	649	0	0	2,444	966	281	3,648	97,464
	2032	198	8,400	287	64,414	32,400	2,977	0	0	2,620	1,958	626	3,648	117,527
	2037	198	8,400	287	89,137	32,400	5,083	0	0	2,873	3,019	1,216	3,648	146,261
	2042	198	8,400	287	109,273	37,200	6,616	0	0	3,154	4,126	2,401	3,648	175,302
SPP Future 3A	2027	198	10,800	287	25,392	39,600	676	0	0	2,315	971	281	0	80,520
	2032	198	10,800	287	92,014	39,600	3,176	0	0	2,344	1,982	625	0	151,026
	2037	3,798	14,400	287	143,137	39,600	5,481	0	0	2,387	3,091	1,215	0	213,397
	2042	3,798	21,600	287	175,273	43,200	7,047	10,800	0	2,434	4,275	2,402	0	271,116
TVA-Other Future 1A	2027	0	720	0	3,629	40,360	20	14,400	1,100	1,680	151	417	0	62,476
	2032	0	720	0	7,262	40,360	114	14,400	1,100	1,680	299	1,361	0	67,295
	2037	0	720	0	76,582	40,360	508	14,400	1,100	1,680	446	3,695	0	139,491
	2042	0	720	0	123,582	40,360	1,340	18,000	1,100	1,680	588	9,061	0	196,430
TVA-Other Future 2A	2027	0	720	0	7,229	29,560	20	21,600	1,100	1,710	155	417	3,225	65,735
	2032	0	7,920	0	54,062	33,160	114	21,600	1,100	1,747	313	1,361	3,225	124,602
	2037	0	33,120	0	105,382	36,760	508	21,600	1,100	1,802	478	3,695	3,225	207,670
	2042	0	43,920	0	123,582	36,760	1,340	28,800	1,100	1,860	645	9,061	3,225	250,293
TVA-Other Future 3A	2027	0	7,920	0	54,029	40,360	55	10,800	1,100	1,712	156	417	0	116,549
	2032	0	29,520	0	154,862	40,360	298	21,600	1,100	1,776	318	1,361	0	251,195
	2037	0	51,120	0	285,382	40,360	1,214	25,200	1,100	1,885	492	3,695	0	410,448
	2042	3,600	83,520	0	285,582	43,960	2,769	32,400	1,100	1,978	674	9,061	0	464,645

Table 18: External Resource Additions by Milestone Year

External Area Resource Retirements per Future (MW) - *Cumulative*									
Future/Area	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Biomass**	**Total**
PJM Future 1A	**2027**	41,256	6,674	0	6,011	90	0	50	54,081
	2032	43,238	6,698	0	6,025	1,835	0	67	57,862
	2037	47,446	9,151	0	6,553	6,813	210	91	70,263
	2042	49,432	13,697	18,092	6,708	10,413	1,266	91	99,699
PJM Future 2A	**2027**	47,446	9,133	0	6,025	90	0	50	62,743
	2032	49,432	10,074	0	6,553	1,835	0	67	67,961
	2037	49,612	31,402	0	6,708	6,813	210	91	94,836
	2042	50,401	37,347	18,092	7,064	10,413	1,266	91	124,674
PJM Future 3A	**2027**	49,432	13,697	0	6,553	90	0	50	69,822
	2032	49,612	35,928	0	6,708	1,835	0	67	94,150
	2037	50,401	47,611	0	7,064	6,813	210	91	112,190
	2042	51,983	57,451	18,092	7,079	10,413	1,266	91	146,375
SPP Future 1A	**2027**	15,344	1,388	0	782	210	0	0	17,724
	2032	19,208	1,817	0	782	2,526	0	0	24,333
	2037	19,528	2,264	0	923	8,579	50	0	31,344
	2042	19,528	2,812	766	1,026	18,564	314	0	43,010
SPP Future 2A	**2027**	19,528	3,401	0	782	210	0	0	23,921
	2032	19,528	3,839	0	923	2,526	0	0	26,816
	2037	19,528	6,480	0	1,026	8,579	50	0	35,662
	2042	19,743	8,990	766	1,227	18,564	314	0	49,604
SPP Future 3A	**2027**	19,528	4,799	0	923	210	0	0	25,460
	2032	19,528	8,158	0	1,026	2,526	0	0	31,238
	2037	19,743	16,679	0	1,227	8,579	50	0	46,278
	2042	22,691	20,153	766	1,327	18,564	314	0	63,816
TVA-Other Future 1A	**2027**	33,873	4,206	0	1,910	29	0	0	40,018
	2032	38,544	4,290	0	1,910	163	0	0	44,908
	2037	40,268	4,499	0	1,910	1,182	78	0	47,938
	2042	41,283	9,276	16,257	1,910	1,182	2,439	0	72,346
TVA-Other Future 2A	**2027**	40,448	7,029	0	1,910	29	0	0	49,416
	2032	41,463	11,591	0	1,910	163	0	0	55,127
	2037	41,993	28,883	0	1,910	1,182	78	0	74,046
	2042	42,593	34,526	16,257	1,990	1,182	2,439	0	98,987
TVA-Other Future 3A	**2027**	41,283	12,059	0	1,910	29	0	0	55,281
	2032	41,813	32,977	0	1,910	163	0	0	76,863
	2037	43,013	52,794	0	1,990	1,182	78	0	99,057
	2042	44,598	61,558	16,257	1,990	1,182	2,439	0	128,023

Table 19: External Resource Retirements by Milestone Year

Presentation Materials

Series 1A Futures Workshops & MISO Stakeholder Presentations:

June 22, 2022: PAC Presentation – Futures Data Refresh

October 19, 2022: PAC Presentation – Futures Data Refresh Update

November 29, 2022: PAC Presentation – Preliminary Future F2A Expansion Results

March 8: 2023: PAC Presentation – Futures Refresh Update

March 10, 2023: LRTP Workshop – Future 2A Expansion and Preliminary Siting

April 28, 2023: LRTP Workshop – Future 2A Siting Presentation

October 2, 2023: LRTP Workshop – LRTP Workshop Presentation - Sensitivities

Full Futures Material, including Series 1 results and development, available at: MISOEnergy.org misoenergy.org

Appendix E.3

Gopher to Badger Link Stability Analysis

December 12, 2025

GREAT RIVER ENERGY/ITC MIDWEST/XCEL ENERGY

MISO LRTP Tranche 2.1

Transfer Capability and Stability Analysis

Revision 1

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0258151_0000

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POWER ENGINEERS

TRANSFER CAPABILITY AND STABILITY ANALYSIS

PREPARED FOR:
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REVISION HISTORY						
REV.	ISSUE DATE	ISSUED FOR	PREP BY	CHKD BY	APPD BY	NOTES
A	2025-07-02	Appvl	MLP	CRG	KMJ	Issued for review and approval
B	2025-08-27	Appvl	MLP	CRG	KJM	Issued for review and approval
0	2025-09-19	Impl	MLP	CRG	KMJ	Phase I - Issued for implementation
1	2025-12-12	Impl	MLP	CRG	KMJ	Phase II – Issued for implementation

"Issued For" Definitions:

- "Prelim" means this document is issued for preliminary review, not for implementation
- "Appvl" means this document is issued for review and approval, not for implementation
- "Impl" means this document is issued for implementation
- "Record" means this document is issued after project completion for project file

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EXECUTIVE SUMMARY

Great River Energy (GRE), ITC Midwest, and Xcel Energy, herein referred to as the "Partners," are developing 765 kV lines throughout the upper Midwest, which MISO approved in the Long-Range Transmission Plan Tranche 2.1 (T2.1). The Partners have retained POWER Engineers, Inc. (POWER) to evaluate the impact of the planned 765 kV and 345 kV transmission projects as part of MISO's Long Range Transmission Planning (LRTP) Tranche 2.1 on the Minnesota Electric Grid from the bulk electric system (BES) reliability perspectives. The reliability assessment includes the impact on the regional transmission interfaces' available transfer capabilities, as well as the long-term voltage and short-term transient stability of the Minnesota electrical grid system.

As part of their LRTP Tranche 2.1 work, MISO approved 765 kV transmission corridors across Minnesota with the following electrical components – the combination of which is herein defined as the "Project":

- **Project 22:** Big Stone South - Brookings County - Lakefield Junction 765 kV
- **Project 23:** Lakefield Junction - East Adair 765 kV
- **Project 24:** Lakefield Junction - Pleasant Valley - North Rochester 765 kV
- **Project 25:** Pleasant Valley - North Rochester - Hampton Corner 345 kV
- **Project 26:** North Rochester – Columbia 765 kV

The analysis in this study focuses on the project's impact on the Minnesota electrical grid. Therefore, the following MISO's local regional zones (LRZ) were considered from the generation portfolio, transmission interface transfer capability, thermal congestion, and stability perspectives:

- **LRZ 1:** North Dakota, Minnesota, and a portion of South Dakota
- **LRZ 2:** Wisconsin and the upper peninsula of Michigan
- **LRZ 3**: Iowa

The study analyzed four different planning scenarios for the planning year 2042. These planning scenarios considered different system load conditions, generation portfolio mix and transmission interface levels:

1) The Light Load scenario represents off-peak system conditions, characterized by a high proportion of renewable energy serving the MISO load.
2) The Peak Summer Load scenario represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.
3) The Peak Winter Load scenario represents a scenario with the highest load and highly stressed conditions expected to occur during winter months.
4) The Average Load scenario 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 highest renewable penetration, meaning that renewables are serving most of MISO load and is the most severe case due to the required transfers of generation across long distances to serve load.

The study considered a comparative analysis of the above cases with and without the Project. In addition, a sensitivity scenario has been created for each of the planning scenarios above, with the generation portfolio shifted from wind resources to conventional synchronous generation-based resources. These sensitivity scenarios were analyzed with and without the Project.

To study the benefits of integrating the 765kV transmission, the study included a comparative analysis with the 345kV double circuit replacement/alternative of the 765kV components of the Project.
The analysis included in this report evaluated the impact of the 765kV components on:

a) The regional transfer capability limits of the different transmission interfaces with the State of Minnesota.
b) The operational considerations with planned system outages.

The voltage stability and dynamic stability analysis included in this report aim to evaluate the impact of the Project on the State of Minnesota's electric grid, highlighting the benefits and discussing the performance of the bulk electric system.

Voltage Stability Analysis

The voltage stability analysis concluded the following:

a) There are reported base case thermal overloads that aren't related to the Project (these base power flow scenarios overloads exist with and without the Project). These overloads are detailed in Table 4. The developed generation portfolio for the power flow scenarios was the main driver for these thermal overloads. It is expected that these overloads will be mitigated, in general, throughout the generation interconnection process.
b) The Project enables a significant increase in the transfer capability of the state of Minnesota's bulk transmission system, with a higher penetration of remote wind generation resources. In light load ("LL") high wind scenarios, the Project enabled the increment of 4 GW of wind generation in LRZ 1-3 to be transferred to load centers.
c) While the Project enables the transfer of an additional 1.2 GW and 0.8 GW of remote wind generation resources for the summer peak ("SUM") and winter peak ("WIN") in the high wind scenarios, respectively, it is concluded that the peak load conditions for both seasons have contributed to the analysis outcomes, considering the base cases had relatively depressed voltage conditions.
d) The average load ("AVG") scenarios showed a relatively significant gain with the Project (1.0 GW) of remote wind generation resources increment in the high wind scenario.
e) The voltage stability analysis highlighted sporadic needs for some discrete switched shunts to be strategically allocated in some substations. These discrete shunts aren't significant and don't pose any risks to the Project's implementation.
f) The Project outperformed the 345kV double circuit alternative with regards to LRZ 1-3 wind transfer to the Minnesota area in every base case contingency, with an average additional transfer of 425 MW across all scenarios.
g) In nearly every prior outage scenario, the Project also outperformed the 345kV alternative. The largest difference in transfer capability came during the North Rochester to Tremval 345kV prior outage, when the Project enabled an additional transfer of 656 MW on average across all scenarios. The Lakefield Junction to Pleasant Valley 765kV prior outage scenarios showed a significant decrease of 900 MW in transfer capability compared to the base 765kV Project case, showing that line's importance to the total suite.

Dynamic Stability Analysis

The dynamic stability analysis comparing the Project and non-Project cases concluded the following:

a) The Project enables higher renewable generation in LRZ1-3. Without the Project, the loss of some 765 kV and 345 kV lines in high-wind cases results in voltage stability issues.

b) The loss of the 765 kV line from Sub T in Iowa and Woodford County in Illinois triggered major voltage oscillations without the Project in the Average Load scenario with high wind generation conditions. Similarly, without the Project, the loss of the 765 kV transmission between Twinkle and Sub T in Iowa triggered significant angle instability conditions in the Light Load scenario with high wind generation conditions.
c) The loss of the 345kV line between Alexandria and Big Oaks in Minnesota (Tranche 1) or the loss of the 345kV line between Iron Range and St. Louis in Minnesota triggered voltage oscillations and generator angle instability conditions without the Project for the Average Load scenarios.
d) The fault and tripping of the Project lines (765kV and 345 kV) didn't report any dynamic instability risks for all the studied scenarios. Moreover, the analysis concluded that the Project is needed to maintain bulk electric system stability when the rest of Tranche 2.1 is implemented, enabling higher renewable generation from LRZs 1-3.
e) The transient stability indices considered for this study concluded, in the vast majority of the studied events, that significantly improved system stability performance was achieved with the Project for all the studied planning scenarios.

To assess the benefits of the 765kV integration of the Project, the comparative analysis with the 345kV double circuit alternative concluded the following:

a) Replacement of the 765kV components of the Project with a double circuit 345kV resulted in significant reliability risks with the loss of either the Twinkle to Sub T or Sub T to Woodford County 765kV lines. The analysis results depicted voltage instability conditions with the 345kV alternative in the Light Load high wind scenario.
b) Fault and tripping of the King to Eau Claire 345kV line resulted in the tripping of all 500 kV lines between Forbes and Riel, which include the 500kV lines in the Manitoba Hydro interface. This has been reported with the 345 kV alternative in the Summer high wind scenario.
c) The loss of one of the 345 kV lines between Bison and Alexandria reported angle/voltage instability risks with the 345 kV alternative in the Winter high wind scenario.

The analysis results concluded the superiority of the 765kV components of the Project, enabling extended transfer levels and securing system reliability in comparison with the 345 kV Alternative.

The benefits of the 765 kV components of the Project have been assessed from the regional transfer levels perspectives, in comparison with the 345kV alternative. The analysis results concluded the following:

a) For the East-West case: The extended North Dakota Import levels up to 2,750 MW did not conclude any reliability risks when either the 765 kV Project lines or the 345 kV alternative are considered.
b) When Manitoba Hydro is exporting 3,100 MW and the North Dakota Export (NDEX) is 1,800 MW, there are reported significant instability risks with fault and tripping of the King to Eau Claire 345kV line for the 345 kV alternative. The Project with the 765kV components reported no major reliability risks at these regional transfer levels.

c) With the NDEX extended for the Winter High Wind case by relatively higher flow on the Big Stone South to Brookings County 765kV corridor, the 345 kV alternative reported a significantly lower average transient stability index and a greater number of contingencies with voltage violations compared to the 765kV Project case. The 345kV alternative reported significant instability risks associated with the loss of the Big Stone South to Brookings County 345 kV double circuit, Lakefield Junction to Pleasant Valley 345kV double circuit, and Big Stone South to Alexandria 345kV single line. This indicates that the 765kV system provides higher transfer capacity without jeopardizing BES performance compared to the 345kV alternative.

The analysis concluded that the benefit of extending the 765kV system is to increase the regional transfer capability limits with no risks to the State of Minnesota BES.

Last but not least, the assessment of the criticality of each of the 765kV components of the project and the operational considerations in comparison with the 345kV alternative have been analyzed in the prior outage analysis results as below:

a) When key 765kV lines from the LRTP Tranche 2.1 Portfolio are removed from the model (especially the North Rochester to Columbia 765kV line) there are elevated risks for system instability.
b) When the flow levels are significantly increased with prior outages on key 765kV and 345kV lines, the 765kV Project has a higher transient stability index compared to the 345kV double circuit alternative. The 765kV Project also has significantly lower instability risks and fewer voltage violations.
c) When the Brookings to Lakefield Junction double circuit alternative, Lyon County to Cedar Mountain double circuit, or Crandall/Huntley to Wilmarth double circuit are applied as prior outages and the North Rochester to Columbia contingency is applied, the 345kV alternative cases show significant voltage instability and the Monticello nuclear generator is tripped. The 765kV Project analysis results for the same events have shown no reliability risks to the State of Minnesota BES.

The analysis of the prior outages' conditions confirmed the criticality of the 765kV components of the Project, supporting improved operation resilience of the BES of the State of Minnesota with the additional significant benefit of extending the regional transfer capability levels.

INTRODUCTION

GRE, ITC Midwest, and Xcel Energy, herein referred to as the "Partners," are developing 765 kV lines throughout the upper Midwest, which MISO approved in the Long-Range Transmission Plan Tranche 2.1 (T2.1). Through this utility partnership, 765 kV voltage assets will be designed, constructed, and operated within the region for the first time. These assets are necessary to maintain the reliability of the electrical system as Minnesota transitions from its historical reliance on fossil fuels to renewable energy. The Partners have retained POWER Engineers, Inc. (POWER) to evaluate the impact of the planned 765 kV and 345 kV transmission projects as part of MISO's Long Range Transmission Planning (LRTP) Tranche 2.1 on the Minnesota Electric Grid from the bulk electric system (BES) reliability perspectives. The reliability assessment includes the impact on the regional transmission interfaces' available transfer capabilities, as well as the long-term voltage and short-term transient stability of the Minnesota electrical grid system.

LRTP TRANCHE 2.1 PROJECT SUMMARY

As part of their LRTP Tranche 2.1 work, MISO approved 765 kV transmission corridors across Minnesota with the following electrical components – the combination of which is herein defined as the "Project":

- **Project 22:** Big Stone South - Brookings County - Lakefield Junction 765 kV
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- **Project 25:** Pleasant Valley - North Rochester - Hampton Corner 345 kV
- **Project 26:** North Rochester – Columbia 765 kV

The remaining T2.1 facilities will be included in the models, assuming that the MISO projects are needed for regional reliability and delivery of resources internal and external to the State of Minnesota's borders.

OBJECTIVES

The scope of this project is to conduct analysis and document findings to support GRE's and its utility Partners' Minnesota Certificate of Need application for the Project to the State of Minnesota. The analysis evaluates the Project's voltage and transient stability impacts and documents the results clearly.

CRITERIA

MISO's criteria files from their transient stability analysis were used as the basis for the criteria for POWER's transient stability analysis. Minor updates were made, see the transient stability analysis methodology section for more details.

For voltage stability analysis, POWER followed GRE's transmission planning criteria voltage limits to determine acceptable voltage levels in the study area.

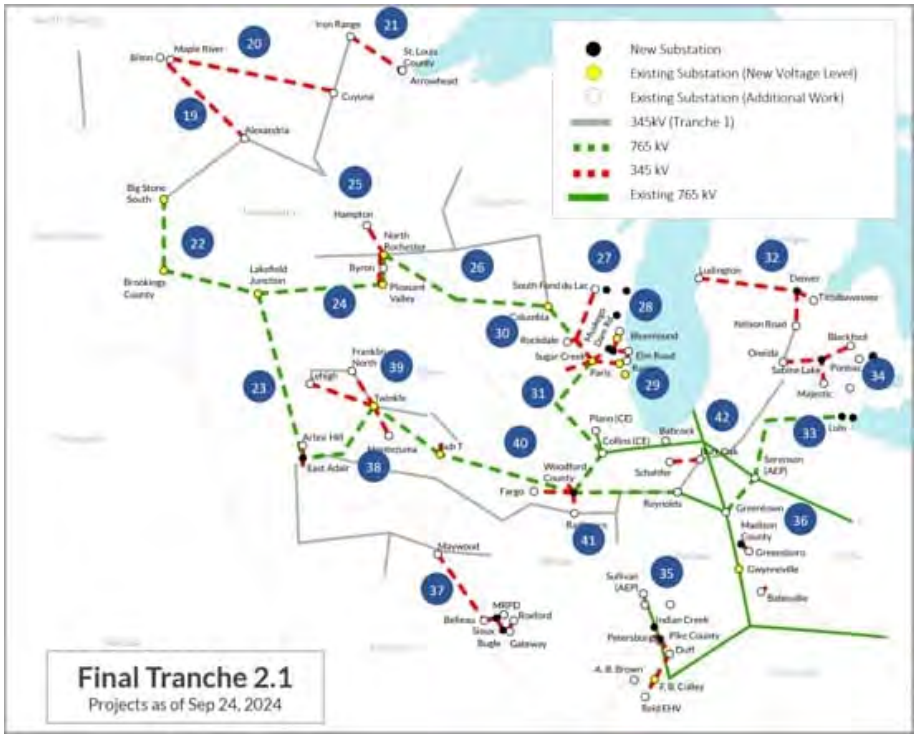

Figure 1: Map of Tranche 2.1 project lines approved by MISO

MODEL ADJUSTMENTS AND TUNING – BASE CASE DEVELOPMENT

The starting point for the base cases used in this analysis was the four 2042 cases that MISO created for LRTP Tranche 2.1 analysis. These four cases were Average, Light Load, Summer, and Winter:

- LRTP_TR2_2042_Avg_v5.1_Final Portfolio_08062024.sav
- LRTP_TR2_2042_LL_v5.1_Final Portfolio_08062024.sav
- LRTP_TR2_2042_Summer_v5.1_Final Portfolio_08062024.sav
- LRTP_TR2_2042_Winter_v5.1_Final Portfolio_08062024.sav

The following steps were followed to develop adequate modeling for the post-transient voltage stability and transient stability analysis:

- The first step of the case development process was to run the script provided by GRE for adding the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) transmission lines into the model.
- Then the nuclear dispatch from the Prairie Island and Monticello nuclear plants were maximized, per Table 2 of the RFP.
- Next, the Coal Creek generating units were put back in-service in the model (MISO had assumed they were retired in 2042) and increase their dispatch until the Coal Creek HVDC line was near its maximum flow of 1,000 MW. The original models only had one of the DC poles enabled for the Coal Creek line, so the other pole had to be put in service to allow for 500MW of flow on each pole.

- Originally, the models had the Square Butte HVDC line maximized at 900 MW. When the cases were imported into PSAT from PSS/E, the high flow on this line caused errors in the power flow solution. Lowering the line flow to 800 MW resolved these errors, so that is the scheduled HVDC flow on that line in all of the cases created.
- The HVDC modelling was also updated slightly to match how MISO modelled the HVDC buses in their Transient Security Assessment Tool (TSAT) analysis. Additional buses were added to align with MISO dynamics data for the lines.
- In the provided cases, the 765kV line reactors were modelled as bus reactors, which presents challenges when running contingency analysis. When a contingency for a 765kV line occurs in reality, its line reactors will be tripped with it. However, if the model represents the reactors as bus reactors, the reactors will remain in service when the line is tripped, resulting in bus voltage performance criteria violations. To correct this modelling deficiency, line reactors replaced the 765kV bus reactors on each end of the 765kV lines, with a susceptance value of 30% of the line's susceptance. The maximum size for a line reactor was assumed to be 300 Mvar; any additional reactive power support needed beyond that to reach 30% of the line susceptance was added as a bus reactor.
- Many of the future generators that were added to the 2042 cases had their voltage control set to monitor the same bus. As this created numerical conditions with initializing the dynamic models, as necessary, the generators were changed to control voltage at their local bus to avoid conflicts between multiple generators trying to control the same bus voltage.

Initial testing indicated severe voltage stability issues in the model. Most of these issues were the result of very tight reactive power limits and the power factor control mode used for the future renewable generation resources built into the model. The reactive power limits were set based on a 0.95 leading to 0.95 lagging power factor at the exact active power output of the generator in each case. This limited the ability of these generators to increase reactive power output as active power was increased for the transfer cases. It also limited the generators' ability to produce reactive power during faults and recover from disturbances. POWER’s solution was to expand the reactive power limits to 0.95, leading to 0.95 lagging power factor based on the plant’s maximum active power output, and change the control mode from a power factor limit to limits based on the Q_{max} and Q_{min} for the generator. This assumption that the renewable generators can provide a reactive power output of 0.95 lagging to leading, based on their maximum active power, across their entire active power output range, aligns with the requirements in the IEEE 2800-2022 standard. The vast majority of renewable generation plants in this 2042 model are planned/future units and will likely adhere to this standard.

Once all of these modelling updates were completed, a flat run of the models in TSAT was performed to ensure that the MISO-provided cases had a sufficient flat start to produce meaningful transient results. None of the cases had acceptable flat starts. Problem generators were identified and added to the GNET list where reasonable.

For the summer, winter, and average cases, removing the problem generators was not enough. The Bison area in North Dakota had a very high amount of renewable generation and appeared to be contributing greatly to the instability of the cases. This area consists of the 230kV buses 608603 TRICNTY4, 608600 BISONMP4, and 608602 SQBEAST4 and their surrounding generation. Therefore, generation from renewable resources (mainly wind, but also some solar) in this area were reduced first to get the TSAT flat runs to be more stable. As Bison generation was reduced, conventional generation in MISO LRZs 4-7 was increased to offset the changes. Table 1 summarizes the changes made to the cases.

TABLE 1: ADJUSTMENTS TO GENERATION TO ACHIEVE FLAT START			
MODEL	ORIGINAL BISON GENERATION (MW)	BISON GENERATION REDUCTION (MW)	RESULTING BISON GENERATION (MW)
AVERAGE	1,422	953	469
SUMMER	1,846	461	1,384
WINTER	1,248	832	416

For the winter case, in addition to reducing the generation in the Bison area, 977 MW of wind from the rest of LRZs 1-3 had to be reduced in order to achieve an acceptable flat start.

An example of the results of these adjustments is shown below for the average high wind case with the portfolio. Figure 2 and Figure 4 are the flat run voltage results for the original average case provided by MISO and used for MISO's transient analysis. Figure 3 and Figure 5 show the improvements to the flat run results after POWER's adjustments to the case.

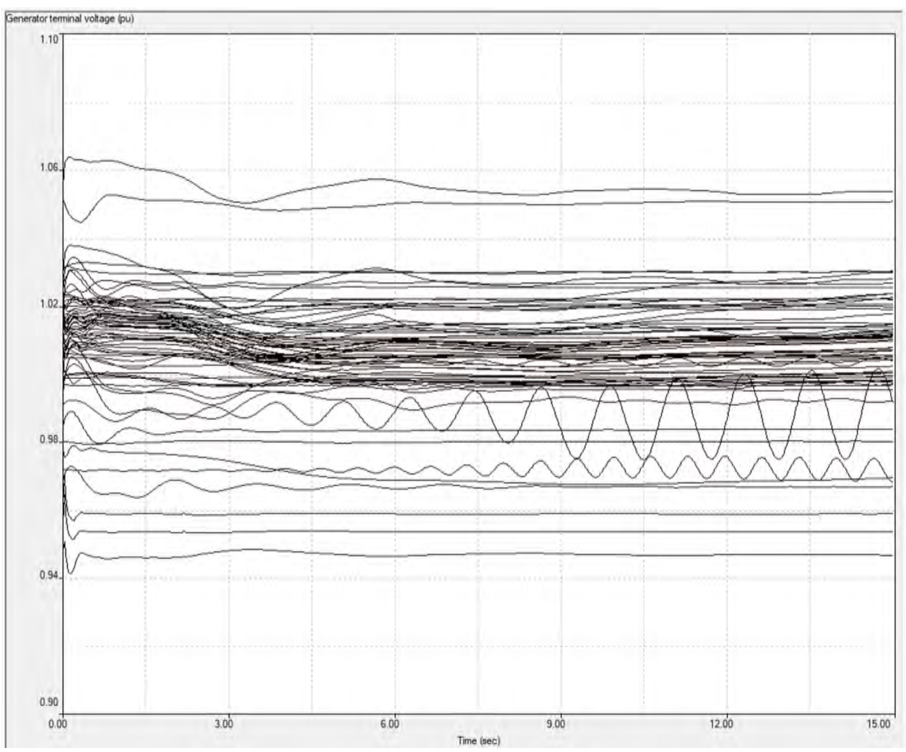

Figure 2: Generator terminal voltages, original MISO Average high wind case with Project

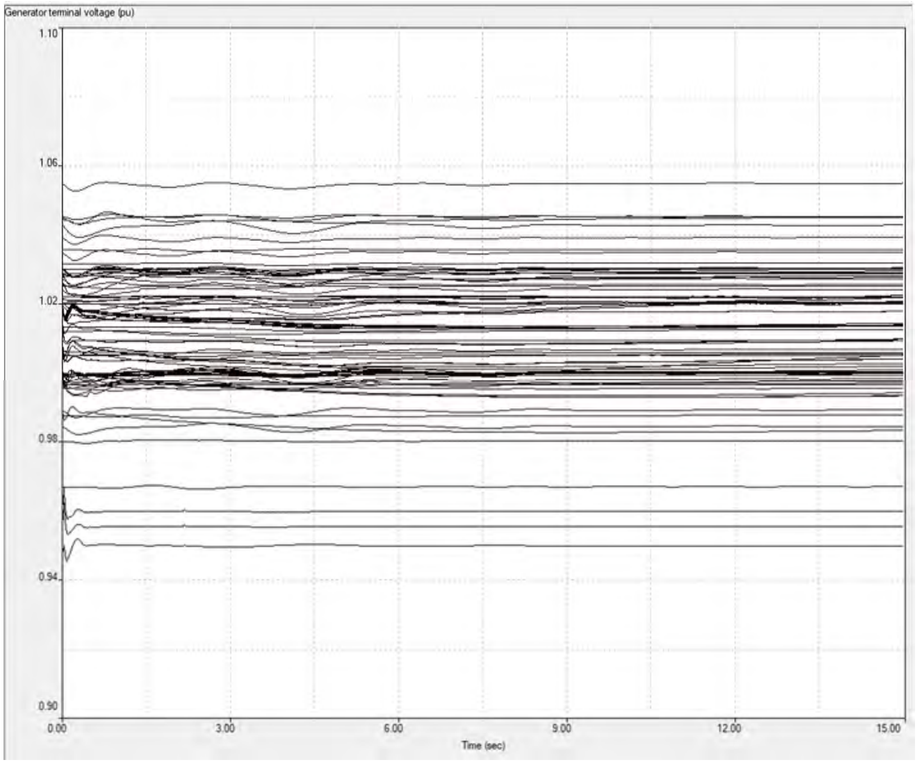

Figure 3: Generator terminal voltages, final Average high wind case with Project adjusted by POWER

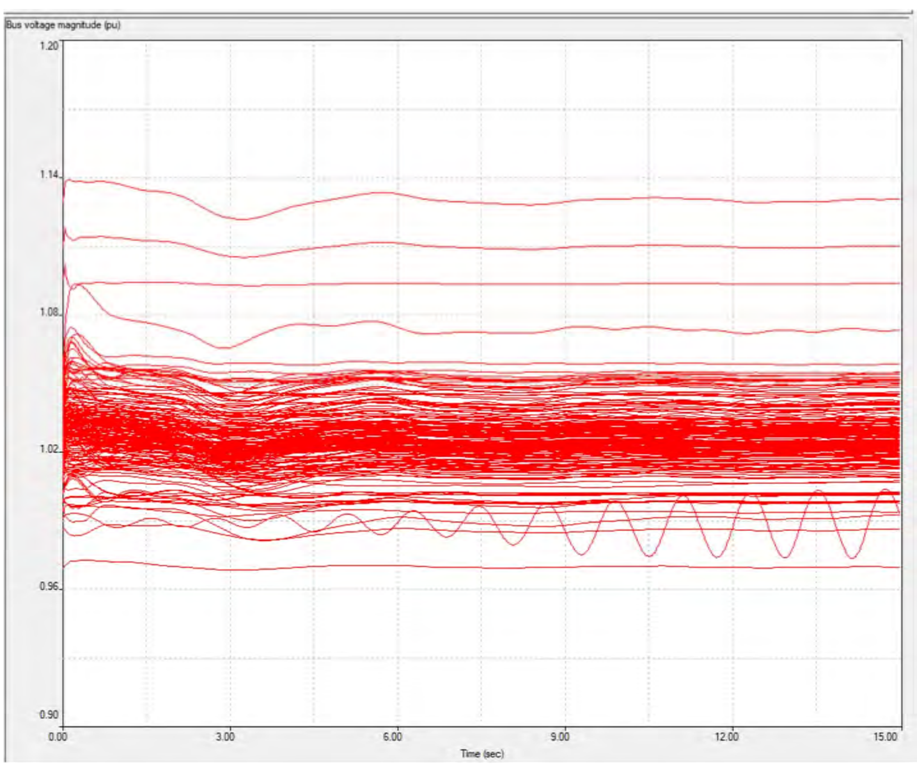

Figure 4: Bus voltages, original MISO Average high wind case with Project

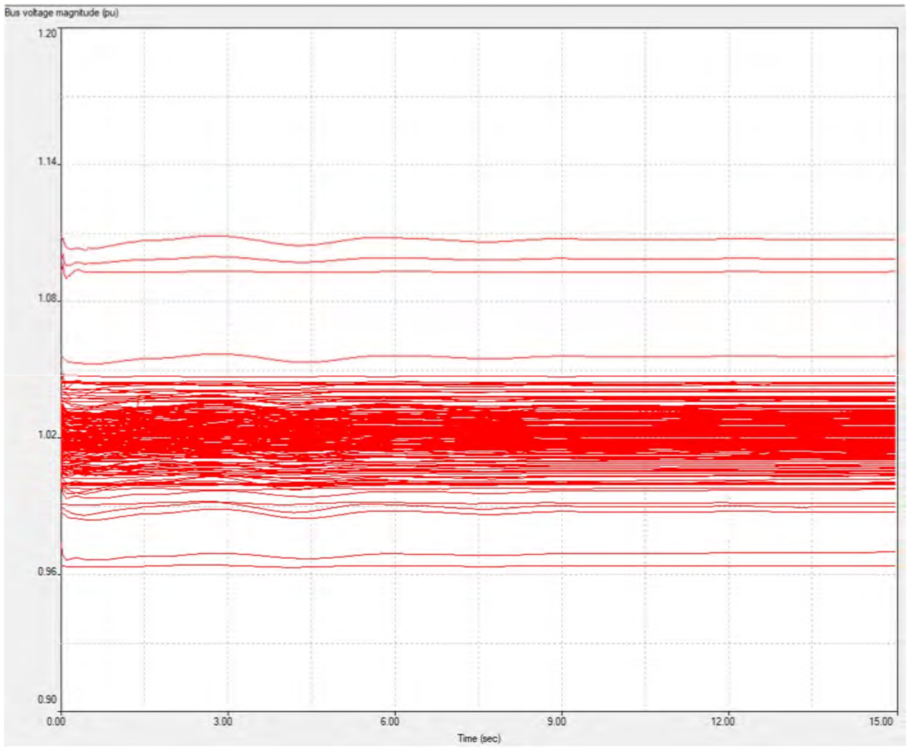

Figure 5: Bus voltages, final Average high wind case with Project adjusted by POWER

After the adjustments above were complete, the four final cases were considered the "high wind" cases. The dispatch of renewables in LRZs 1-3 only is summarized in Table 2 below. Wind dispatch, HVDC schedules, and nuclear plant outputs were the only items that were changed from the MISO original cases. Load was not changed, nor was solar or battery dispatch.

The four "No Portfolio" cases were created by removing the Project, as listed in the project summary section of this report. These eight cases were considered the high wind cases.

To create the eight low wind cases, approximately 3 GW of wind output in LRZs 1-3 was removed from the high wind cases. To offset this reduction in generation, conventional generation in LRZs 4-7 were increased by the same amount.

Final list of cases:

- LRTP_TR2_2042_Avg_HIGH_WIND_v5.1_Final Portfolio_wJTIQ
- LRTP_TR2_2042_Avg_HIGH_WIND_v5.1_No Portfolio_wJTIQ
- LRTP_TR2_2042_Avg_LOW_WIND_v5.1_Final Portfolio_wJTIQ
- LRTP_TR2_2042_Avg_LOW_WIND_v5.1_No Portfolio_wJTIQ
- LRTP_TR2_2042_SUM_HIGH_WIND_v5.1_Final Portfolio_wJTIQ
- LRTP_TR2_2042_SUM_HIGH_WIND_v5.1_No Portfolio_wJTIQ
- LRTP_TR2_2042_SUM_LOW_WIND_v5.1_Final Portfolio_wJTIQ
- LRTP_TR2_2042_SUM_LOW_WIND_v5.1_No Portfolio_wJTIQ
- LRTP_TR2_2042_LL_HIGH_WIND_v5.1_Final Portfolio_wJTIQ
- LRTP_TR2_2042_LL_HIGH_WIND_v5.1_No Portfolio_wJTIQ

- LRTP_TR2_2042_LL_LOW_WIND_v5.1_Final Portfolio_wJTIQ
- LRTP_TR2_2042_LL_LOW_WIND_v5.1_No Portfolio_wJTIQ
- LRTP_TR2_2042_Winter_HIGH_WIND_v5.1_Final Portfolio_wJTIQ
- LRTP_TR2_2042_Winter_HIGH_WIND_v5.1_No Portfolio_wJTIQ
- LRTP_TR2_2042_Winter_LOW_WIND_v5.1_Final Portfolio_wJTIQ
- LRTP_TR2_2042_Winter_LOW_WIND_v5.1_No Portfolio_wJTIQ

TABLE 2: SUMMARY OF HIGH WIND CASE DISPATCH IN LRZS 1-3

DISPATCH (MW)	SUMMER	WINTER	SHOULDER (AVG)	SPRING LIGHT LOAD
Wind dispatch %	20.98%	35.60%	29.66%	32.72%
Wind dispatch	18,834	31,955	26,620	29,366
Solar dispatch %	81.19%	13.89%	35.80%	2.63%
Solar dispatch	19,267	3,297	8,495	623
Battery dispatch %	-2.49%	47.37%	-62.36%	-61.21%
Battery dispatch	-211	3,918	-5,286	-5,188
Square Butte HVDC Sch.	800	800	800	800
Coal Creek HVDC Sch.	1000	1000	1000	1000
GRE LBA Load	3,255	2,618	1,868	1,351
ITC Midwest LBA Load - ALTW area	3,737	3,774	2,205	1,760
Xcel LBA Load	9,963	8,155	5,221	4,155
MP LBA Load	1,217	1,163	976	996
OTP LBA Load	1,756	1,443	1,084	923
Prairie Island Nuclear	1105	1105	1105	1105
Monticello Nuclear	637	637	637	637
Big Stone Coal	0 (retired)	0 (retired)	0 (retired)	0 (retired)
MN Coal	0 (all retired)	0 (all retired)	0 (all retired)	0 (all retired)

VOLTAGE STABILITY ANALYSIS RESULTS

The voltage stability analysis utilized Voltage Security Assessment Tool (VSAT) 24.0 to analyze the voltage stability of the MISO grid, in particular Minnesota. Various scenarios with and without the Project and contingencies were simulated.

The 16 cases described above in the Base Case Development section were used for the VSAT analysis.

Voltage Stability (VSAT) Set Up

- Parameters: disregarded branch flows/thermal violations
- Voltage limits:
  - High and low voltage limits of 1.05 and 0.95 p.u. were applied in the pre-contingency scenarios, following the Partners' transmission planning criteria voltage limits
  - High and low voltage limits of 1.05 and 0.90 p.u. were applied in the post-contingency scenarios, following the Partners' transmission planning criteria voltage limits
- Monitored buses: Buses from the provided MISO LRTP T2 Transient Stability Package monitor file were monitored. In addition, high voltage buses (100 kV+) in LRZs 1-3, especially around Tranche 2.1 projects 22-26 like Big Stone South, Brooking County Substation, Lakefield Junction Substation, Pleasant Valley Substation, North Rochester, Columbia, and East Adair were included.
- Contingencies: All provided Tranche 1 and 2 contingencies were simulated from the provided MISO LRTP T2 Transient Stability Package fault list after they were converted into VSAT format. There were a total of 203 contingencies simulated, including Tranche-1 P1, Tranche-2 138 kV and 345 kV, and Tranche-2 765 kV contingencies.

Generation Source:

Wind generators in LRZ 1-3 were identified from the 2042 MISO Tranche 2.1 base cases and used as the generation source for the transfer.

Load Sink:

Loads in areas 600 (Xcel), 608 (MP), 613 (SMMPA), 615 (GRE), 620 (OTP), and 627 (ALTW/ITC Midwest) were used to sink the new wind generation.

Study case edits to support voltage stability:

The following reactive power support devices were considered for the analysis to mitigate the bus voltage violations enabling the extension of the transfer capability through the Project. The specific shunt sizing necessary varied in each case, the maximum required is noted below:

- Some of the new LRTP generation was edited to have local control of their bus voltage, this was done to help with case instability
- Move AC setpoint at voltage source converters to 1.01 at buses 608475 and 608473 (each end of the Square Butte HVDC line) to prevent high voltage
- Increase voltage at bus 690029 LR_TREMVAL with 100 MVAR capacitor bank, also change the initial value of bus 601044 BRIGGS RD 3 shunt reactor to 0
- Lower voltage at bus 860013 TWINKLE with -200 MVAR shunt reactor
- Lower voltage at bus 860000 EAST ADAIR with -150 MVAR shunt reactor
- Lower voltage at bus 860019 SUB T with -200 MVAR shunt reactor
- Lower voltage at bus 860061 BROOKINGS with -100 MVAR shunt reactor
- Lower voltage at bus 860062 BIG STONE SO with -100 MVAR shunt reactor
- Lower voltage at bus 860058 LAKEFIELD JU with -200 MVAR shunt reactor
- Lower voltage at bus 601028 EAU CL 3 with -100 MVAR shunt reactor
- Lower voltage at bus 694000 ARPIN B3 with -50 MVAR shunt reactor
- Lower voltage at bus 694003 ARPIN B1 with -50 MVAR shunt reactor
- Lower voltage at bus 608457 CUYNA1S3 with -150 MVAR shunt reactor

- Lower voltage at bus 608458 CUYNA2S3 with -100 MVAR shunt reactor
- Increase voltage at bus 667071 NEEPAWA4 with 100 MVAR capacitor bank
- Lower voltage at bus 690010 LR_JUMPRIVR3 with -100 MVAR shunt reactor
- Increase voltage at bus 601050 HELENA 3 with 50 MVAR capacitor bank
- Lower voltage at bus 657753 LTLFRK 4 with -100 MVAR shunt reactor

Post-Transient Voltage Stability Transfer Capability Results

The voltage stability transfer limits for each case are shown below in Table 3. In summary, the cases with the Project ("IN") were able to transfer more wind generation to serve load in Minnesota in every scenario compared to the cases without the Project ("NO"). The most significant improvement in transfer capability was in the light load ("LL") high wind ("HIGH") scenario, where 6200 MW additional LRZ 1-3 wind was able to be transferred with the Project, compared to 1800 MW without the Project, for a difference of 4400 MW.

Conclusions from VSAT analysis:

a) There are reported base case thermal overloads that aren't related to the Project (these base power flow scenarios overloads exist with and without the Project). These overloads are detailed in Table 4. The developed generation portfolio for the power flow scenarios was the main driver for these thermal overloads. It is expected that these overloads will be mitigated, in general, throughout the generation interconnection process.
    a. The Woad Hill – Crandall 345 kV line overload only shows up in the summer peak cases and is the same with and without the Project. There is a lot of wind generation feeding into the Woad Hill substation in these scenarios, up to 262 MVA in the high wind base cases, and the rating of the Woad Hill – Crandall line is only 221.7 MVA which seems unexpectedly low for a 345 kV line. Implementing ambient adjusted ratings (AAR) would likely eliminate this concern due to the radial nature of the line.

b) The Project enables a significant increase in the transfer capability of the state of Minnesota's bulk transmission system, with a higher penetration of remote wind generation resources. In light load ("LL") high wind scenarios, the Project enabled the increment of 4 GW of wind generation in LRZ 1-3 to be transferred to load centers.

c) While the Project enables the transfer of an additional 1.2 GW and 0.8 GW of remote wind generation resources for the summer peak ("SUM") and winter peak ("WIN") in the high wind scenarios, respectively, it is concluded that the peak load conditions for both seasons have contributed to the analysis outcomes, considering the base cases had relatively depressed voltage conditions.

d) The average load ("AVG") scenarios showed a relatively significant gain with the Project (1.0 GW) of remote wind generation resources increment in the high wind scenario.

e) The voltage stability analysis highlighted sporadic needs for some discrete switched shunts to be strategically allocated in some substations. These discrete shunts aren't significant and don't pose any risks to the Project's implementation.

TABLE 3: LIST OF VSAT RESULTS FOR TRANSFER OF LRZ 1-3 WIND TO MINNESOTA						
CASE	Base LRZ 1-3 Wind [MW]	Limit [MW]	EXTRA LRZ 1-3 WIND TRANSFER TO MINN [MW]	MINN LOAD [MW]	VIOLATION	BUS
LL_HIGH_IN	29366	35566	6200	13665	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
LL_HIGH_NO	29366	31166	1800	9265	Pre-cont low voltage	860019 SUB T [765kV]
LL_LOW_IN	26429	33530	7101	14565	Pre-cont low voltage	615353 GRE-DICKNSN3 [345kV]
LL_LOW_NO	26429	31730	5301	12765	Pre-cont low voltage	615353 GRE-DICKNSN3 [345kV]
SUM_HIGH_IN	18837	24338	5501	24802	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
SUM_HIGH_NO	18837	23138	4301	23602	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
SUM_LOW_IN	15823	21424	5601	24802	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
SUM_LOW_NO	15823	20724	4901	24202	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
WIN_HIGH_IN	31955	35856	3901	19845	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
WIN_HIGH_NO	31955	35056	3101	19045	Pre-cont low voltage	601050 HELENA 3 [345kV]
WIN_LOW_IN	28760	32860	4100	20045	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
WIN_LOW_NO	28760	32360	3600	19545	Pre-cont low voltage	601050 HELENA 3 [345kV]
AVG_HIGH_IN	26620	35221	8901	19420	Cont 8056	615590 GRE-CROWRIV7 [115kV]
AVG_HIGH_NO	26620	34521	7901	18420	Pre-cont low voltage	615590 GRE-CROWRIV7 [115kV]
AVG_LOW_IN	23426	32926	9500	20020	Pre-cont low voltage	615590 GRE-CROWRIV7 [115kV]
AVG_LOW_NO	23426	31526	8100	18620	Pre-cont low voltage	615590 GRE-CROWRIV7 [115kV]

Common Base Study Case Thermal Overloads

These 100+ kV thermal overloads might require mitigation or redispatch, depending on the study case. For the VSAT analysis, thermal overloads were disregarded to focus on the voltage stability results. Table 4 lists the worst base case overloads. These overloads were in many of the base cases and showed up in both Project and no Project cases.

TABLE 4: LIST OF BASE CASE THERMAL OVERLOADS IN STUDY AREA

VOLTAGE [KV]	FROM BUS	TO BUS	TERTIARY	CKT	BASE CASE	THERMAL OVERLOAD (%)
115	603192 BRKNGCO7	603240 OAK LAKEW 7		1	WIN_HIGH_IN	222
230	608600 BISONMP4	608607 NELSNLK4		1	SUM_HIGH_IN	155
345	601073 WOAD HILL 3	601074 CRANDAL 3		1	SUM_HIGH_IN	115
230	602006 SHEYNNE4	620337 LAKE PARK T4		1	SUM_HIGH_NO	101
230	620336 AUDUBON4	620337 LAKE PARK T4		1	SUM_HIGH_NO	100
230	657752 DRAYTON4	657798 LKARDCH4		1	WIN_HIGH_NO	112
230	657752 DRAYTON4	667048 LETELER4		1	WIN_HIGH_NO	129
230	657755 PRAIRIE4	657798 LKARDCH4		1	WIN_HIGH_NO	110
230/115/41.6	620363 FORMAN 4	620263 FORMN 7	620163 FORMN 9	1	AVG_HIGH_NO	110

DYNAMIC STABILITY ANALYSIS APPROACH

The basis of the transient stability analysis was the TSAT setup developed by MISO, which included dynamic, contingency, monitoring, and criteria files. Some of these items were altered or improved upon for this analysis.

The Tranche 2.1 765kV TSAT contingencies consist of a three-phase bus fault with a duration of three cycles, applied 5 seconds into the simulation. The fault is then followed by the loss of a transmission line or transformer upon fault clearing. All of MISO’s thirty-four 765kV contingencies were used in this analysis. All contingencies considered for the dynamic stability analysis are listed in Appendix A.

Only a subset of the remaining contingencies used by MISO was run to focus on the most severe 345kV contingencies in the area of interest. The Tranche 2.1 selected contingencies consist of a three-phase bus fault with a duration of four cycles, applied 5 seconds into the simulation. The fault is then followed by the loss of a bus, transmission line(s), or transformer upon fault clearing (as illustrated in Table 28 in Appendix A).

Updates were also made to the criteria files used in the TSAT analysis to facilitate the study of actual violations in the results. The XEL relay margin and generic relay margin criteria were updated so that the monitoring of the relay margin value wouldn't start until three cycles after fault clearing (beginning at a simulation time of 5.1 seconds). Also, the Milton R Young bus voltage drop criteria was removed because that coal plant is out of service in all of the cases. Lastly, a criterion for a peak-to-peak angle change threshold of 120 degrees was added to the model to check for angle stability in all cases.

A minor update was made to the MISO23_Year5_Dynamics.dyr file. Once the Coal Creek units were brought back in service in the model (MISO assumed they would be retired in 2042), it was discovered that the generator ID did not match the dynamic modelling in the dyr file. The dyr file was updated to correct this and ensure the Coal Creek dynamics were being used by TSAT.

Other minor updates were also made, such as adding more buses, generators, and HVDC lines to the monitor file and adding eight problematic generators to the GNET .idv file.

Lastly, the security criteria parameter was updated to be stricter. MISO's TSAT runs had used the "MW Tripped Due to Out of Step Condition" criteria, and had the threshold set to 2,000 MW. When this "MW Tripped" analysis option is selected, generators in critical clusters that lose synchronism are tripped. If the defined MW threshold is exceeded, then the contingency is deemed "insecure"; otherwise, the contingency is listed as "secure" (as long as no other criteria are violated). POWER lowered this criteria threshold to 1 MW, so that any tripping due to loss of synchronism could be identified and analyzed further.

DYNAMIC STABILITY ANALYSIS RESULTS

The transient stability index reported by TSAT for this analysis is the power swing-base stability index. According to the TSAT documentation, determining the power swing-base stability index consists of three steps:

1. Identify a critical cluster of generators. This is the group of generators that become unstable or will likely become unstable under more stressed system conditions.
2. Form a parametric one-machine-infinite-bus (OMIB) equivalent. The parameters of this equivalent are constantly updated using simulation results of the full system.
3. Determine the stability of the system and compute the stability margin (index).

An average value of the transient stability indices across the different contingencies for each case was used to make broad comparisons between cases.

In addition to the transient stability index, TSAT reports out violations of damping, voltage, frequency, relay margin, and peak-to-peak angle criteria for each contingency. If any one of the criteria is violated, TSAT labels the contingency as "insecure". POWER examined each violated criterion to determine if it was a concern to the area of interest for this study (Minnesota and the surrounding areas). Any violations that were not of concern were filtered out in post-processing, such as short transient violations, violations in areas far from the project lines, and localized issues (e.g., single buses at low voltages). Any localized transient frequency violations were also filtered out as they were considered to be false spikes created by the way frequency is calculated by the program.

765kV Contingency Events

Table 5 shows the results of the transient stability analysis for contingencies on the 765 kV project lines. There were only five contingencies across the eight cases which showed notable voltage violations, and all were minor. There were no relay margin or peak-to-peak angle violations for any of these cases.

Both the Average and Light Load cases with high wind see low voltage (just below the Minnesota Power criteria of 0.95 pu or Xcel criteria of 0.90 pu) at a few 345 kV and 161 kV buses in the Minnesota Power region when the North Rochester to Columbia 765 kV line is lost. For the average case, there is a reactor at bus 601044 (Briggs Rd, 345 kV, XEL), which is likely the cause of the low voltage violation below 0.90 pu. The other violations are at load buses in the Minnesota Power territory and one 345 kV generator tie line that leads to generators not in service, as connected to the Superior 345 kV bus. For the light load case, the voltage violations are at bus 608473 (STL_P1DC 290 kV) at the end of the Square Butte HVDC line, load buses in the Minnesota Power territory, and one 345 kV gen-tie line that leads to generators that are not in service by the Superior 345 kV bus. Note that the low voltage criteria of 0.95 pu is relatively strict.

For the Winter low wind case, there are low voltage violations at bus 603240 (Oak Lake W 7 115 kV, XEL) when the Lakefield Junction to Pleasant Valley 765 kV line is lost, when the Lakefield Junction 345 kV to 765 kV transformer is lost, and when the Lakefield Junction to East Adair 765 kV line is lost. There is a capacitor bank at the bus that is frozen at 0 MVAR in the model. If this control is changed to discrete, there is an injection of 48 MVAR at the bus in the base case model. This change eliminates the low-voltage violations for all contingencies.

Lowering the wind generation by 3GW increased the average transient stability index of the Average case by 20%, the Light Load case by 9%, and the Winter case by 69%. The high and low wind cases for Summer had essentially the same transient stability index.

TABLE 5: STABILITY ANALYSIS RESULTS FOR 765KV CONTINGENCIES ON PROJECT LINES					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONTINGENCIES WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	66.15	1	Low voltage violations in MP and XEL for the loss of the North Rochester to the Columbia line
Avg	Low	In	79.20	0	
LL	High	In	80.13	1	Low voltage violations in MP for loss of North Rochester to Columbia line
LL	Low	In	87.12	0	
SUM	High	In	69.96	0	
SUM	Low	In	69.67	0	
Winter	High	In	50.95	0	
Winter	Low	In	85.87	3	Minor low voltage violation at one bus in XEL, for: • Loss of Lakefield Junction to Pleasant Valley 765 kV line • Loss of Lakefield Junction 345kV to 765 kV transformer • Loss of Lakefield Junction to East Adair 765 kV line

Table 6 shows the results of the transient stability analysis for the remaining contingencies on the non-project 765 kV lines. There are fewer severe voltage violations for the cases with the Project, and none of the cases with the Project had any generator relative angle swings greater than 120 degrees.

The four Average cases show the highest amount of instability in the transient analysis. For the Average high wind case with the Project, there is one contingency that resulted in minor high voltage violations above 1.05 pu for a few 765 kV and 345 kV buses in Iowa. When examining the same case without the Project, there are significantly more stability issues. Major voltage violations are observed for three contingencies. For the loss of the Sub T to Woodford County 765 kV line, major voltage oscillations are seen.

The Average low wind cases with and without the Project both show one voltage violation each, high voltage at the East Adair 765 kV bus in Iowa. The difference between these results and the Average high wind case results indicate that the project lines are necessary to enable high renewable penetration in the future, while maintaining system stability in the event of worst-case contingencies.

The results are similar for the Light Load cases. There are no voltage violations for the two low wind cases. However, for the high wind case without the Project, there are major voltage issues for two of the contingencies and minor voltage issues for one other contingency. These issues are not seen for the high wind case with the Project, meaning that the Project allows for higher wind output in LRZs 1-3 while maintaining system stability.

There are very few stability issues in the summer and winter cases. The only voltage violations seen are in the Summer low wind case with the Project and the Winter low wind case with the Project. For both, high-voltage conditions are seen at just the East Adair 765 kV bus in Iowa for the contingency where one of the East Adair 345 kV to 765 kV transformers is lost.

The reason that these same high voltage violations aren't seen in the cases without the Project is that without the Project, the 765 kV line from Lakefield Junction to East Adair is not in service. With this line out of service, when one of the East Adair 345 kV to 765 kV transformers is lost, there are no more lines from the west connected at the bus. Therefore, no voltage issues occur post-contingency.

Increasing the size of the bus reactor at the East Adair 765 kV bus by just 100 MVAR in the pre-contingency base case resolved these high voltage violations for both the Summer low wind case and the Winter low wind case with the Project. The remaining contingencies were not tested to determine if increasing this reactor size would lead to low-voltage conditions in other events.

TABLE 6: STABILITY ANALYSIS RESULTS FOR 765KV CONTINGENCIES ON NON-PROJECT LINES					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	88.3	1	• Minor high voltage violations in MEC territory for loss of Sub T to Woodford County 765 kV line
Avg	High	Out	93.99	3	• Widespread low voltage violations in Minnesota for loss of East Adair to Twinkle 765 kV line • Major voltage oscillations for loss of Twinkle to Sub T 765 kV line • Major voltage oscillations for loss of Sub T to Woodford County 765 kV line
Avg	Low	In	90.92	1	• Minor high voltage violation at East Adair 765kV bus in MEC territory for loss of Sub T to Woodford County 765 kV line
Avg	Low	Out	94.33	1	• Minor high voltage violation at East Adair 765kV bus in MEC territory for loss of Sub T to Woodford County 765 kV line
LL	High	In	95.56	0	
LL	High	Out	90.89	3	• Major voltage oscillations for loss of Twinkle to Sub T 765 kV line • Major voltage oscillations for loss of Sub T to Woodford County • Minor low voltage violations for loss of East Adair to Twinkle 765 kV line
LL	Low	In	94.74	0	
LL	Low	Out	94.61	0	
SUM	High	In	78.16	0	
SUM	High	Out	84.31	0	
SUM	Low	In	84.11	1	• Minor high voltage violation at East Adair for loss of East Adair 345 kV to 765 kV transformer
SUM	Low	Out	84.12	0	
Winter	High	In	89.9	0	
Winter	High	Out	84.97	0	
Winter	Low	In	82.85	1	• Minor high voltage violation at East Adair for loss of East Adair 345 kV to 765 kV transformer
Winter	Low	Out	83.73	0	

The four bolded contingencies in Table 6 indicate extremely unstable system conditions post-contingency. This kind of instability is only observed in cases without the Project; the same contingencies for cases with the Project showed either minor or no issues.

This comparison is highlighted in the figures below. Figure 6 shows the bus voltages for the average high wind case with the Project when the 765 kV line between Sub T and Woodford County is lost. While it doesn't show a completely flat recovery, the voltages do return to normal ranges fairly quickly after the contingency. Compare that to Figure 7, which shows the bus voltages for the same case and contingency without the Project. Bus voltages post-fault are extremely unstable – with large oscillations through the end of the simulation.

Figure 8 and Figure 9 Compare generator relative angle values for the same contingency. It is clear that for the case without the Project, there are oscillations causing generator angle instability.

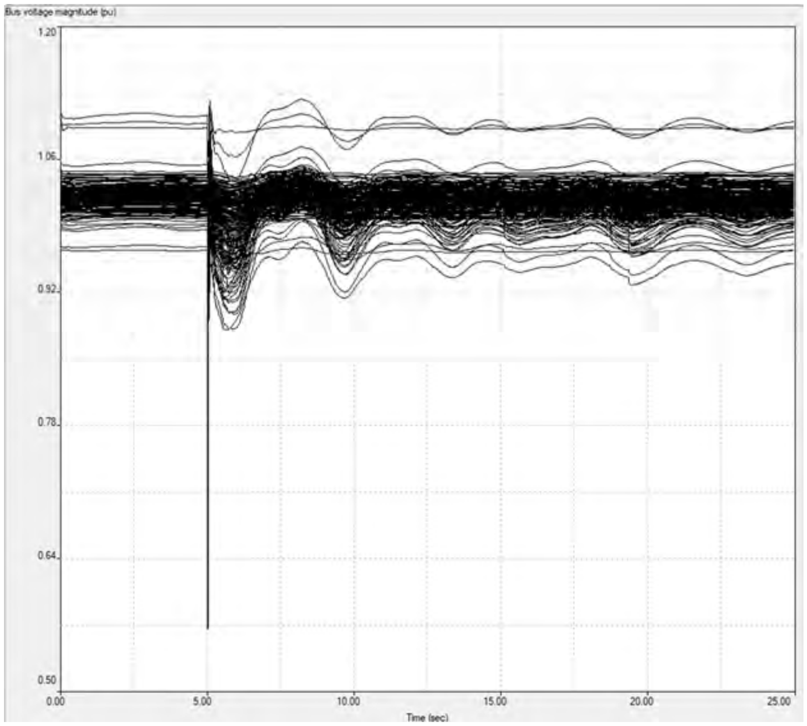

Figure 6: Bus voltages for Avg High Wind **Final Project** case, 765kV contingency 21 (loss of 765kV line between Sub T in Iowa and Woodford County in Illinois)

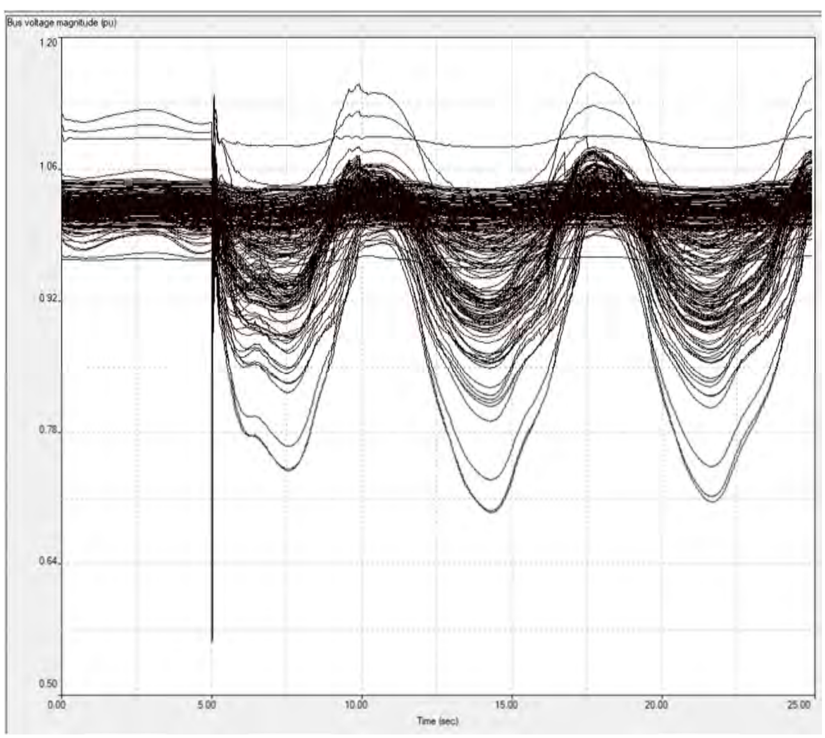

Figure 7: Bus voltages for Avg High Wind **No Project** case, 765kV contingency 21 (loss of 765kV line between Sub T in Iowa and Woodford County in Illinois)

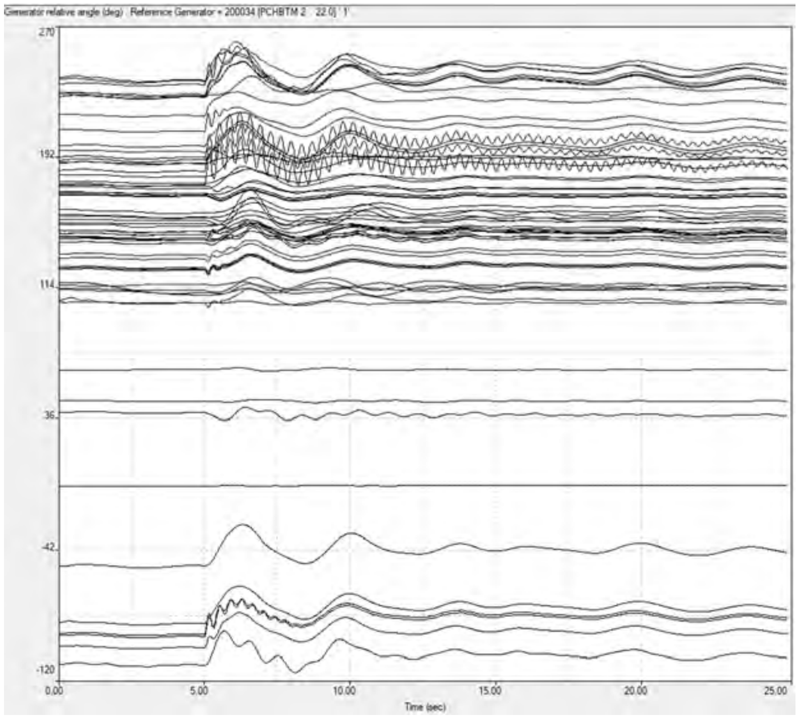

Figure 8: Generator relative angles for Avg High Wind **Final Project** case, 765kV contingency 21 (loss of 765kV line between Sub T in Iowa and Woodford County in Illinois)

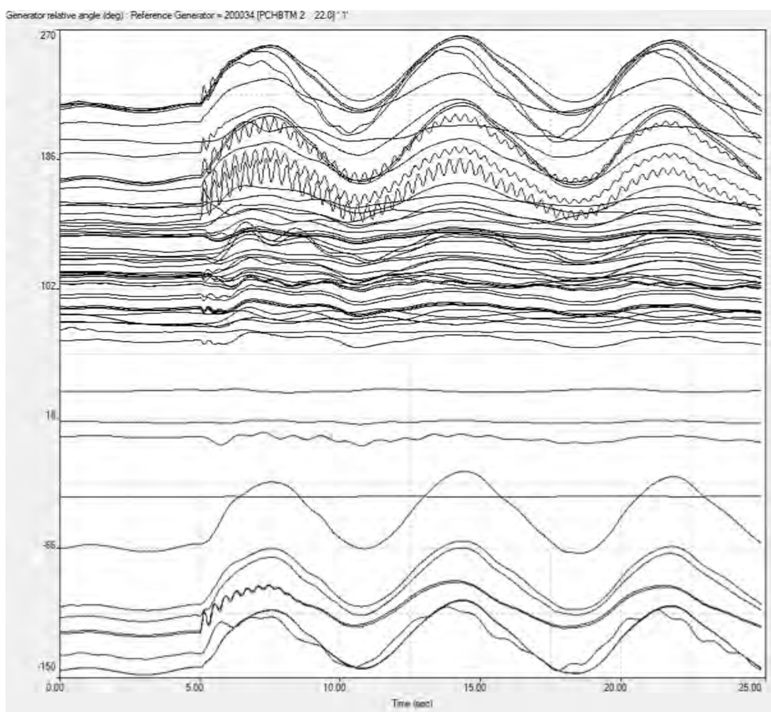

Figure 9: Generator relative angles for Avg High Wind **No Project** case, 765kV contingency 21 (loss of 765kV line between Sub T in Iowa and Woodford County in Illinois)

Results were similar for the light load high wind cases when the line between Twinkle and Sub T is lost. Figure 10 shows the bus voltages for the light load high wind case, which recover fairly quickly after the contingency. Compare that to Figure 11, which shows the bus voltages for the same case and contingency without the Project. Bus voltages post-fault are extremely unstable and appear to oscillate. At the same time, there is no voltage collapse. This could be due to angle instability conditions triggered by the event. The bus voltages do not stabilize or return to typical ranges within 20 seconds post-fault clearing.

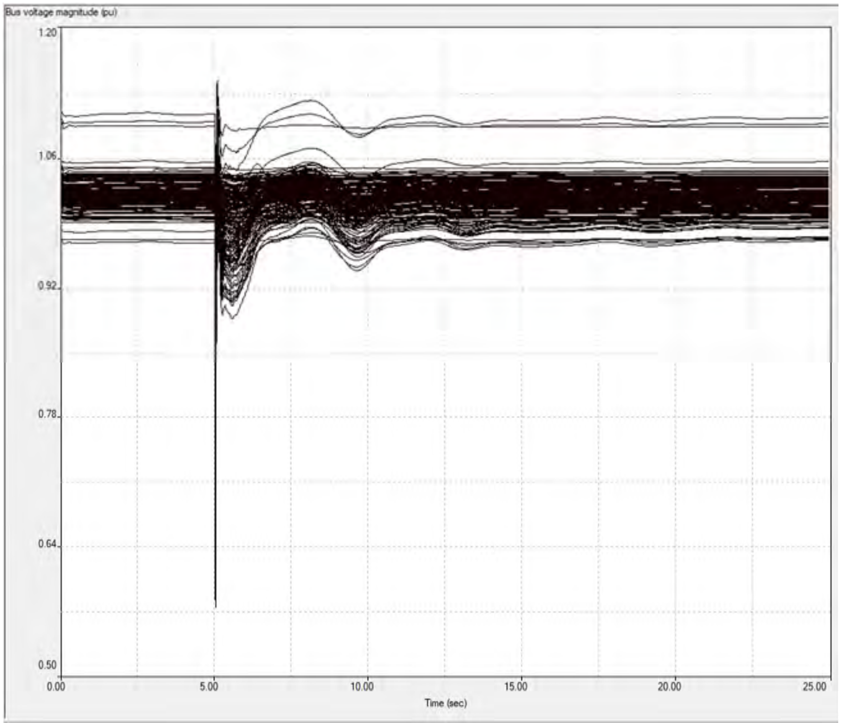

Figure 10: Bus voltages for LL High Wind **Final Project** case, 765kV contingency 18 (loss of 765kV line between Twinkle and Sub T in Iowa)

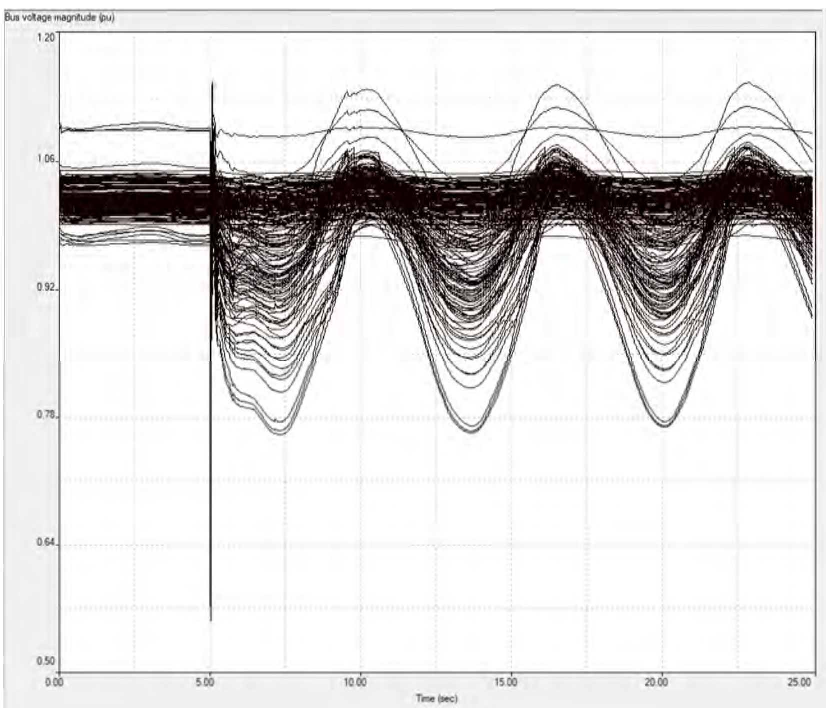

Figure 11: Bus voltages for LL High Wind **No Project** case, 765kV contingency 18 (loss of 765kV line between Twinkle and Sub T in Iowa)

Table 7 summarizes the maximum load shed identified by TSAT for the Project 765kV contingencies. The load shed values are reasonable given the severity of the contingencies analyzed. Table 8 summarizes the maximum load shed identified by TSAT across the sixteen cases for the non-Project 765kV contingencies. The difference in load shed between the Project and non-Project cases for the non-Project 765kV contingencies is negligible.

Note that the maximum load shed values for each individual area may not occur during the same contingency. Therefore, the maximum load shed per area will not necessarily add up to the maximum load shed across all five areas for a single contingency.

TABLE 7: MAXIMUM LOAD SHED RESULTS FOR PROJECT 765KV CONTINGENCIES

CASE	WIND DISPATCH	PROJECT STATUS	MAXIMUM LOAD SHED (MW) BY AREA					
			OTP	ALTW	GRE	XEL	MP	ALL 5 AREAS
Avg	High	In	16	12	8	15	1	50
Avg	Low	In	14	12	1	12	0	36
LL	High	In	17	9	7	14	1	47
LL	Low	In	16	9	6	13	1	44
SUM	High	In	19	20	4	19	2	61
SUM	Low	In	15	19	2	15	1	49
Winter	High	In	22	24	19	27	2	92
Winter	Low	In	18	22	8	23	1	72

TABLE 8: MAXIMUM LOAD SHED RESULTS FOR NON-PROJECT 765KV CONTINGENCIES								
CASE	WIND DISPATCH	PROJECT STATUS	MAXIMUM LOAD SHED (MW) BY AREA					
			OTP	ALTW	GRE	XEL	MP	ALL 5 AREAS
Avg	High	In	5	34	0	0	0	37
Avg	High	Out	1	38	0	1	5	38
Avg	Low	In	4	30	0	0	0	31
Avg	Low	Out	0	31	0	0	0	31
LL	High	In	6	39	0	0	0	42
LL	High	Out	0	44	0	0	1	45
LL	Low	In	5	34	0	0	0	37
LL	Low	Out	0	30	0	0	0	30
SUM	High	In	4	48	0	0	0	50
SUM	High	Out	0	47	0	0	0	47
SUM	Low	In	3	44	0	0	0	46
SUM	Low	Out	0	44	0	0	0	44
Winter	High	In	8	83	0	0	0	89
Winter	High	Out	1	81	0	0	0	82
Winter	Low	In	6	62	0	0	0	66
Winter	Low	Out	0	63	0	0	0	63

345kV Contingency Events

Table 9 shows the results of the transient stability analysis for contingencies on the 345 kV Project lines. None of the contingencies across the eight cases with the Project lines showed notable voltage, relay margin, or peak-to-peak angle violations.

TABLE 9: STABILITY ANALYSIS RESULTS FOR 345KV CONTINGENCIES ON PROJECT LINES

CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONTINGENCIES WITH VOLTAGE VIOLATIONS
Avg	High	In	41.29	0
Avg	Low	In	53.62	0
LL	High	In	50.11	0
LL	Low	In	48.05	0
SUM	High	In	52.17	0
SUM	Low	In	79.68	0
Winter	High	In	33.37	0
Winter	Low	In	69.12	0

Table 10 shows the results of the transient stability analysis for the remaining contingencies on the non-project 345 kV lines. The transient stability index is higher for the cases with the Project compared to without it. There are also fewer and/or less severe voltage violations in most cases involving the Project. None of the cases with the Project had any generator relative angle swings exceeding 120 degrees. Most notable are the results for the Average high wind cases. Without the Project there were 7 contingencies with notable voltage violations. With the Project this number decreased to only 1 – due to very minor high voltage violations for contingency 20 (loss of the Denmark 161kV to 345kV transformer) .

For all of the high wind cases, the cases with the Project always had fewer voltage violations than the cases without the Project. This ranged from three fewer contingencies with voltage violations for the Summer high wind case to six fewer contingencies with voltage violations for the Average high wind case.

TABLE 10: STABILITY ANALYSIS RESULTS FOR 345KV CONTINGENCIES ON NON-PROJECT LINES					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	69.24	1	
Avg	High	Out	60.71	7	Three contingencies led to very unstable system conditions: • Con 3 (Loss of 345 kV line from Alexandria to Big Oaks) • Con 33 (Loss of 345 kV line from Iron Range to St. Louis) • Con 37 (Loss of 345 kV line from King to Eau Claire)
Avg	Low	In	74.93	1	
Avg	Low	Out	74.72	2	
LL	High	In	72.68	0	
LL	High	Out	65.46	3	One contingency led to very unstable system conditions: • Con 3 (Loss of 345 kV line from Alexandria to Big Oaks)
LL	Low	In	77.86	0	
LL	Low	Out	71.09	0	
SUM	High	In	72.24	2	
SUM	High	Out	63.25	5	Simulation failed shortly after fault for Con 37 (Loss of 345 kV line from King to Eau Claire) due to tripping of lines near Manitoba hydro interface and creation of a small island of buses
SUM	Low	In	75.02	6	
SUM	Low	Out	71.95	4	Simulation failed shortly after fault for Con 37 (Loss of 345 kV line from King to Eau Claire) due to tripping of lines near Manitoba hydro interface and creation of a small island of buses
Winter	High	In	70.23	5	
Winter	High	Out	67.99	11	
Winter	Low	In	79.60	5	
Winter	Low	Out	73.24	5	

As noted in Table 10, some of the cases without the Project had unstable conditions post-fault clearing. This kind of instability is only observed in cases without the Project; the same contingencies for cases with the Project showed either minor or no issues.

This comparison is highlighted in Figure 12 showing the bus voltages for the Average high wind case with the Project when the Tranche 1 345 kV line between Alexandria and Big Oaks is lost. The bus voltages return to normal ranges fairly quickly after the contingency. This isn’t the same outcome when compared to Figure 13, which shows the bus voltages for the same case and contingency without the Project. Bus voltages post-fault are extremely unstable, and the oscillations actually worsen as the simulation goes on.

Figure 14 and Figure 15 compare generator relative angle values for the same contingency. It is clear that for the case without the Project, the angle instability oscillations do not dampen post-fault as the simulation goes on.

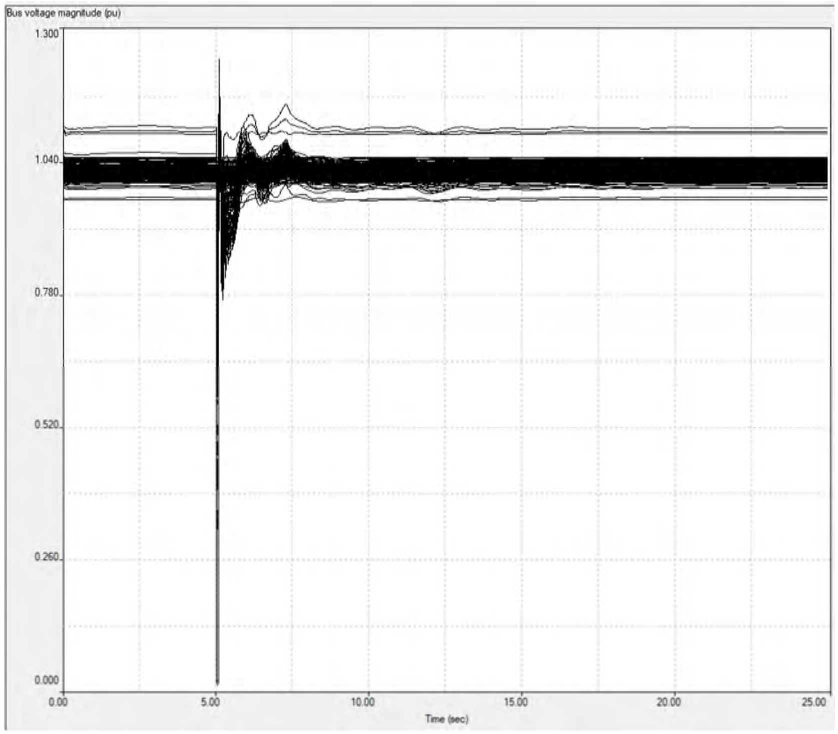

Figure 12: Bus voltages for Avg High Wind **Final Project** case, 345kV contingency 3 (loss of 345kV line between Alexandria and Big Oaks in Minnesota)

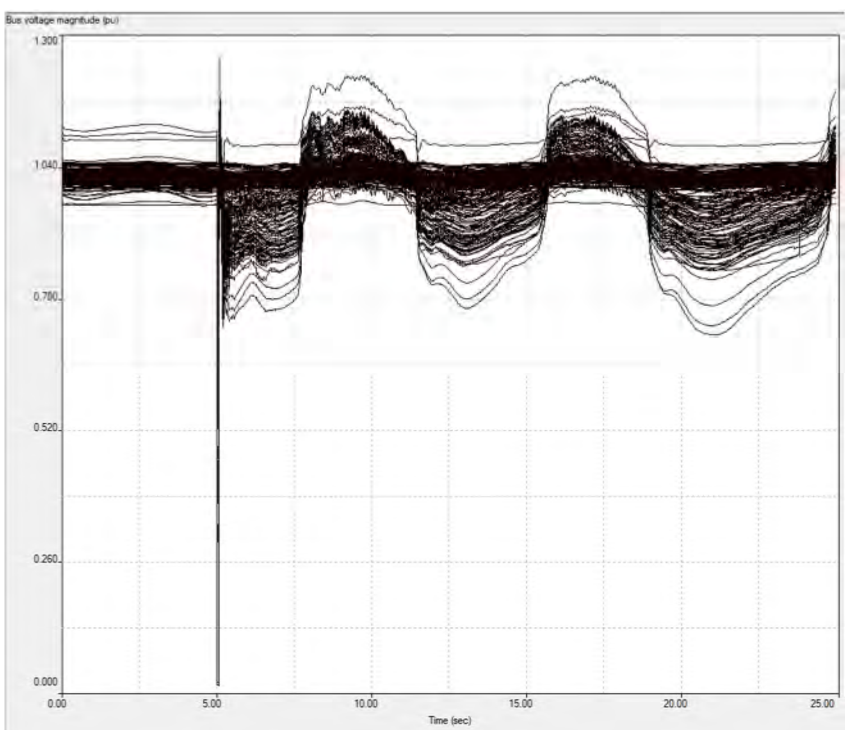

Figure 13: Bus voltages for Avg High Wind **No Project** case, 345kV contingency 3 (loss of 345kV line between Alexandria and Big Oaks in Minnesota)

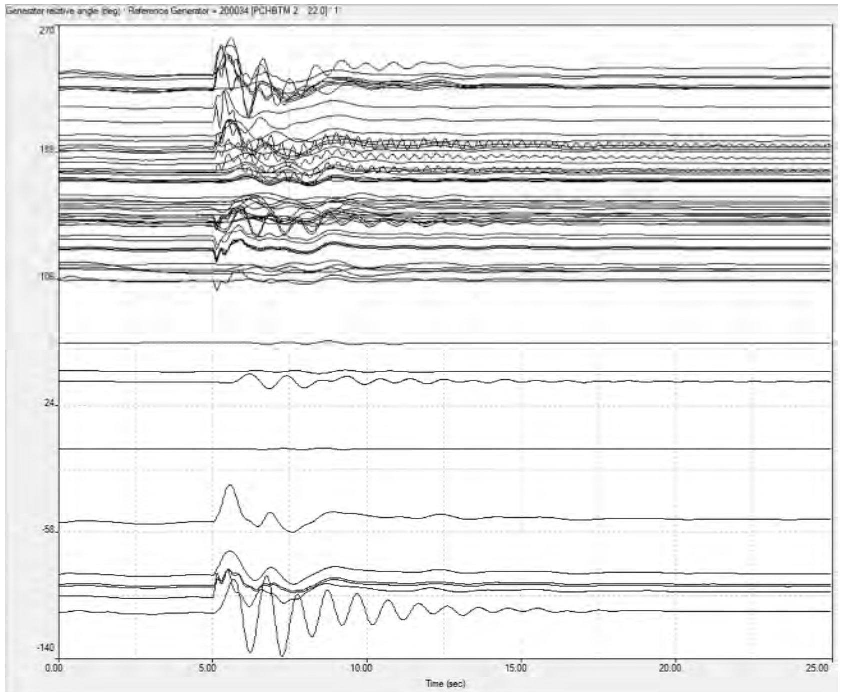

Figure 14: Generator relative angles for Avg High Wind **Final Project** case, 345kV contingency 3 (loss of 345kV line between Alexandria and Big Oaks in Minnesota)

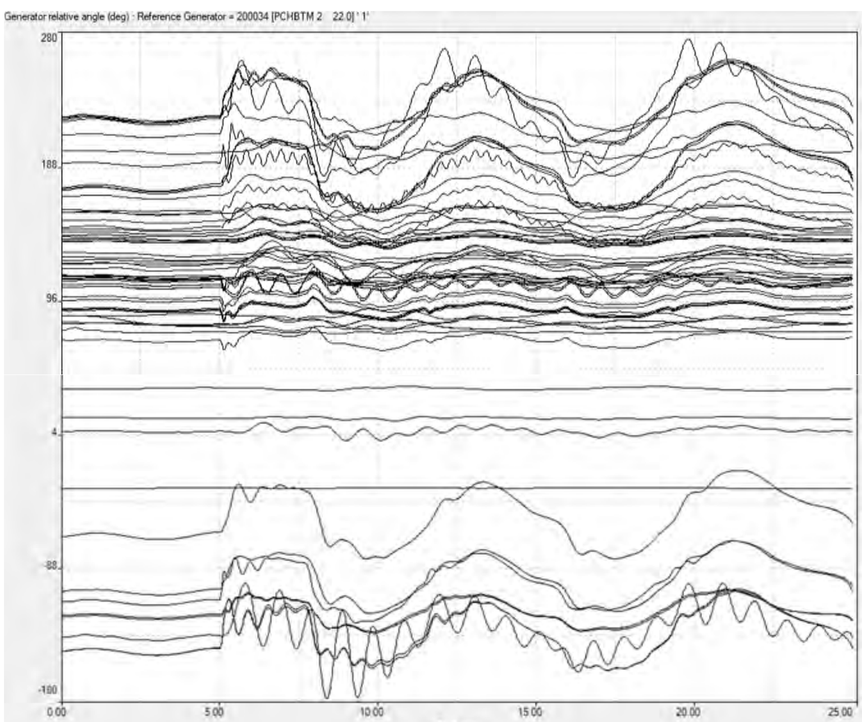

Figure 15: Generator relative angles for Avg High Wind **No Project** case, 345kV contingency 3 (loss of 345kV line between Alexandria and Big Oaks in Minnesota)

Results were similar for the Average high wind cases when the Tranche 2.1 345 kV line between Iron Range and St. Louis is faulted and tripped. Figure 16 shows the bus voltages for the case, which recover fairly quickly after the contingency. Compare that to Figure 17, which shows the bus voltages for the same case and contingency, but without the Project. The bus voltage post-fault is unstable and appears to oscillate. While there are no voltage collapse conditions, the bus voltage oscillations are due to generator angle instability conditions triggered by the event.

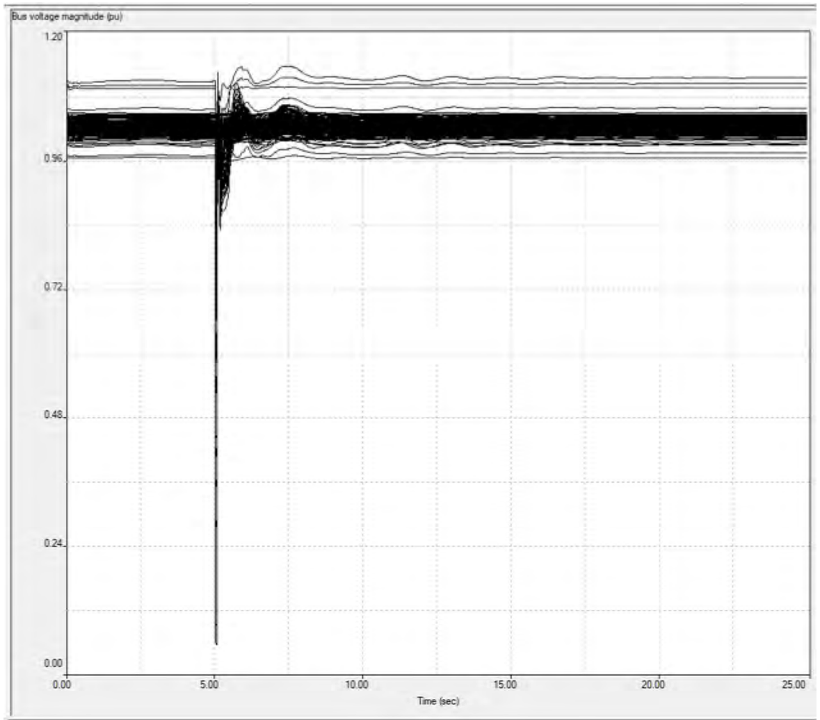

Figure 16: Bus voltages for Avg High Wind **Final Project** case, 345kV contingency 33 (loss of 345kV line between Iron Range and St. Louis in Minnesota)

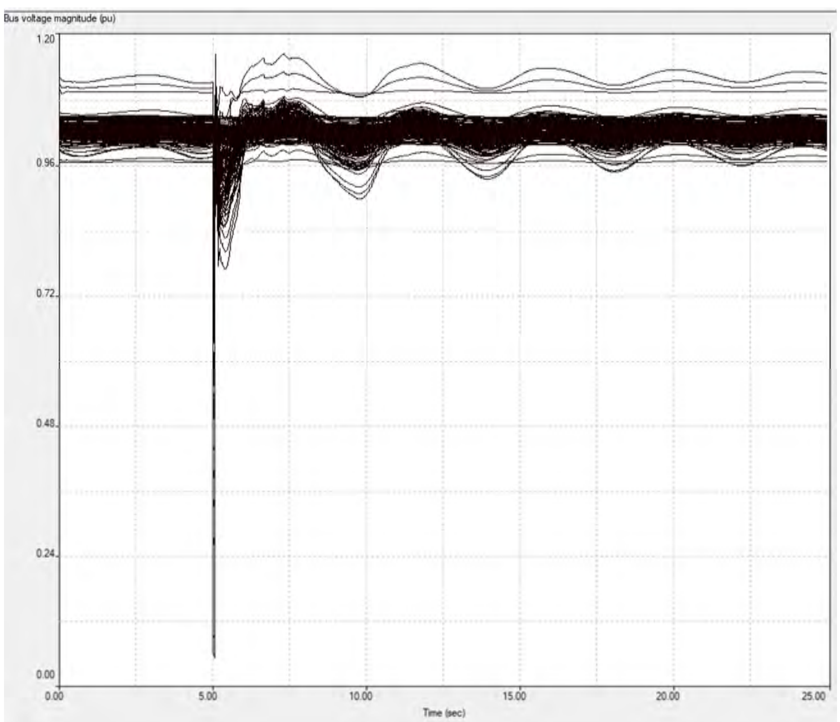

Figure 17: Bus voltages for Avg High Wind **No Project** case, 345kV contingency 33 (loss of 345kV line between Iron Range and St. Louis in Minnesota)

Lastly, Table 11 summarizes the maximum load shed identified by TSAT across the sixteen cases. Some of the contingencies resulted in notable load shed for load in the ALTW and MP areas in the cases.

Note that the maximum load shed values for each individual area may not occur during the same contingency. Therefore, the maximum load shed per area will not necessarily add up to the maximum load shed across all five areas for a single contingency.

TABLE 11: MAXIMUM LOAD SHED RESULTS FOR ANY 345KV CONTINGENCY

CASE	WIND DISPATCH	PROJECT STATUS	MAXIMUM LOAD SHED (MW) BY AREA					
			OTP	ALTW	GRE	XEL	MP	ALL 5 AREAS
Avg	High	In	39	200	19	8	166	210
Avg	High	Out	42	226	1	6	170	226
Avg	Low	In	38	185	11	7	163	187
Avg	Low	Out	40	194	20	8	167	211
LL	High	In	34	187	14	6	158	195
LL	High	Out	37	194	15	6	162	208
LL	Low	In	34	169	13	5	158	191
LL	Low	Out	35	172	14	5	158	199
SUM	High	In	55	339	36	14	200	339
SUM	High	Out	59	344	1	12	209	344
SUM	Low	In	51	335	22	14	197	335
SUM	Low	Out	55	339	34	14	205	339
Winter	High	In	55	420	30	10	184	427
Winter	High	Out	62	432	33	12	197	437
Winter	Low	In	53	365	18	10	179	371
Winter	Low	Out	61	386	30	11	187	390

345KV ALTERNATIVE ANALYSIS

345kV Alternative Case Development

For the next portion of the study, an alternative to the 765kV portions of the Project was analyzed. This alternative replaced all 765kV Project lines with double circuit 345kV lines. The client provided the following parameters for the 345kV double circuit alternative lines, which were assumed to use 2-954 ACSS [392F] conductors:

- R: 0.000045 pu/mi
- X: 0.000499 pu/mi
- B: 0.008582 pu/mi
- Rating: 1792.7 MVA

For the 345kV alternative cases, the 345kV Project lines were kept in the case to keep the underlying topology the same.

See Table 29 Appendix A for the list of additional contingencies that were performed on the 345kV alternative lines. Both single and double circuit contingencies were evaluated.

345kV Alternative Voltage Stability Analysis

The 345kV double circuit alternative cases were tested for voltage stability during the transfer of LRZ 1-3 wind generation to the Minnesota area using the same VSAT setup as was used to analyze the 765kV Project. The 345kV alternative contingencies were added to the previous list of all Tranche-1 P1, Tranche-2 138 kV and 345 kV, and Tranche-2 765 kV contingencies. No additional case updates were necessary to mitigate pre-existing voltage issues.

In every scenario, the 765kV Project had a higher extra transfer capability compared to the 345kV alternative before encountering low voltage limits. The average extra transfer capability of the 765kV Project was 425 MW.

The full VSAT result comparison can be seen in Table 12.

TABLE 12: 345KV ALTERNATIVE AND 765KV PROJECT VSAT RESULTS FOR TRANSFER OF LRZ 1-3 WIND TO MINNESOTA

CASE	Base LRZ 1-3 Wind [MW]	Limit [MW]	EXTRA LRZ 1-3 WIND TRANSFER TO MINN [MW]	MINN LOAD [MW]	VIOLATION	BUS
LL_HIGH_765	29366	35566	6200	13665	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
LL_HIGH_345ALT	29366	35266	5900	13365	Pre-cont low voltage	860019 SUB T [765kV]
LL_LOW_765	26429	33530	7101	14565	Pre-cont low voltage	615353 GRE-DICKNSN3 [345kV]
LL_LOW_345ALT	26429	32830	6401	13865	Pre-cont low voltage	615353 GRE-DICKNSN3 [345kV]
SUM_HIGH_765	18837	24338	5501	24802	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
SUM_HIGH_345ALT	18837	23938	5101	24402	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
SUM_LOW_765	15823	21424	5601	24802	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
SUM_LOW_345ALT	15823	21224	5401	24702	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
WIN_HIGH_765	31955	35856	3901	19845	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
WIN_HIGH_345ALT	31955	35356	3401	19345	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
WIN_LOW_765	28760	32860	4100	20045	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
WIN_LOW_345ALT	28760	32560	3800	19745	Pre-cont low voltage	601017 CHIS-N 2 [500kV]
AVG_HIGH_765	26620	35521	8901	19420	Cont 8056	615590 GRE-CROWRIV7 [115kV]
AVG_HIGH_345ALT	26620	35021	8401	18920	Pre-cont low voltage	615590 GRE-CROWRIV7 [115kV]
AVG_LOW_765	23426	32926	9500	20020	Pre-cont low voltage	615590 GRE-CROWRIV7 [115kV]
AVG_LOW_345ALT	23426	32426	9000	19520	Pre-cont low voltage	615590 GRE-CROWRIV7 [115kV]

345kV Alternative Dynamic Stability Analysis

The results of the dynamic stability analysis for contingencies on the 345kV alternative Project lines are shown in Table 13. No major issues with voltage or other instability are seen for these contingencies across the eight cases.

TABLE 13: STABILITY ANALYSIS RESULTS FOR 345KV CONTINGENCIES ON THE 345KV ALTERNATIVE PROJECT LINES

CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONTINGENCIES WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	345 Alt	54.92	3	Minor low voltages in MP area for loss of North Rochester to Columbia single and double circuit 345kV lines.
Avg	Low	345 Alt	72.61	0	
LL	High	345 Alt	53.31	3	Minor low voltages in MP area for loss of North Rochester to Columbia double circuit 345kV lines. Buffalo Ridge low voltage and relay margin issues: • Con 1 – Big Stone South to Brookings County 345kV alternative single circuit • Con 2 – Big Stone South to Brookings County 345kV alternative double circuit
LL	Low	345 Alt	72.19	2	Buffalo Ridge rapid voltage jumps and relay margin issues: • Con 4 – Lakefield Junction to East Adair 345kV alternative double circuit • Con 12 – Brookings County to Lakefield Junction 345kV alternative double circuit
SUM	High	345 Alt	67.75	0	
SUM	Low	345 Alt	78.95	0	
Winter	High	345 Alt	40.37	0	
Winter	Low	345 Alt	68.88	3	Buffalo Ridge rapid voltage jumps and relay margin issues: • Con 4 – Lakefield Junction to East Adair 345kV alternative double circuit • Con 9 – Lakefield Junction to Pleasant Valley 345kV alternative single circuit • Con 12 – Brookings County to Lakefield Junction 345kV alternative double circuit

For some cases and contingencies, issues are seen with the Buffalo Ridge wind farm. This is a wind farm in the Xcel area (South Dakota zone) at bus numbers 606035 and 606038, and it is two buses away from the Brookings County 115kV bus. In the 2042 model, the Buffalo Ridge wind farm has 1.3 GW of total generation capacity. For the 345kV alternative cases, there appears to be greater instability with this wind generation compared to the 765kV Project cases.

An example of this is shown in Figure 18. The Buffalo Ridge wind farm generators have high voltage at their generator terminals after the fault and loss of the double circuit 345kV alternative line between Brookings County and Lakefield Junction. Eventually, the generators lose stability and alternate between offline and online rapidly, causing rapid swings in voltage. This also causes relay margin issues as reported out by TSAT. However, this issue seems to be localized to the Buffalo Ridge generators only in the model – and does not appear to be an indicator of wider system stability issues.

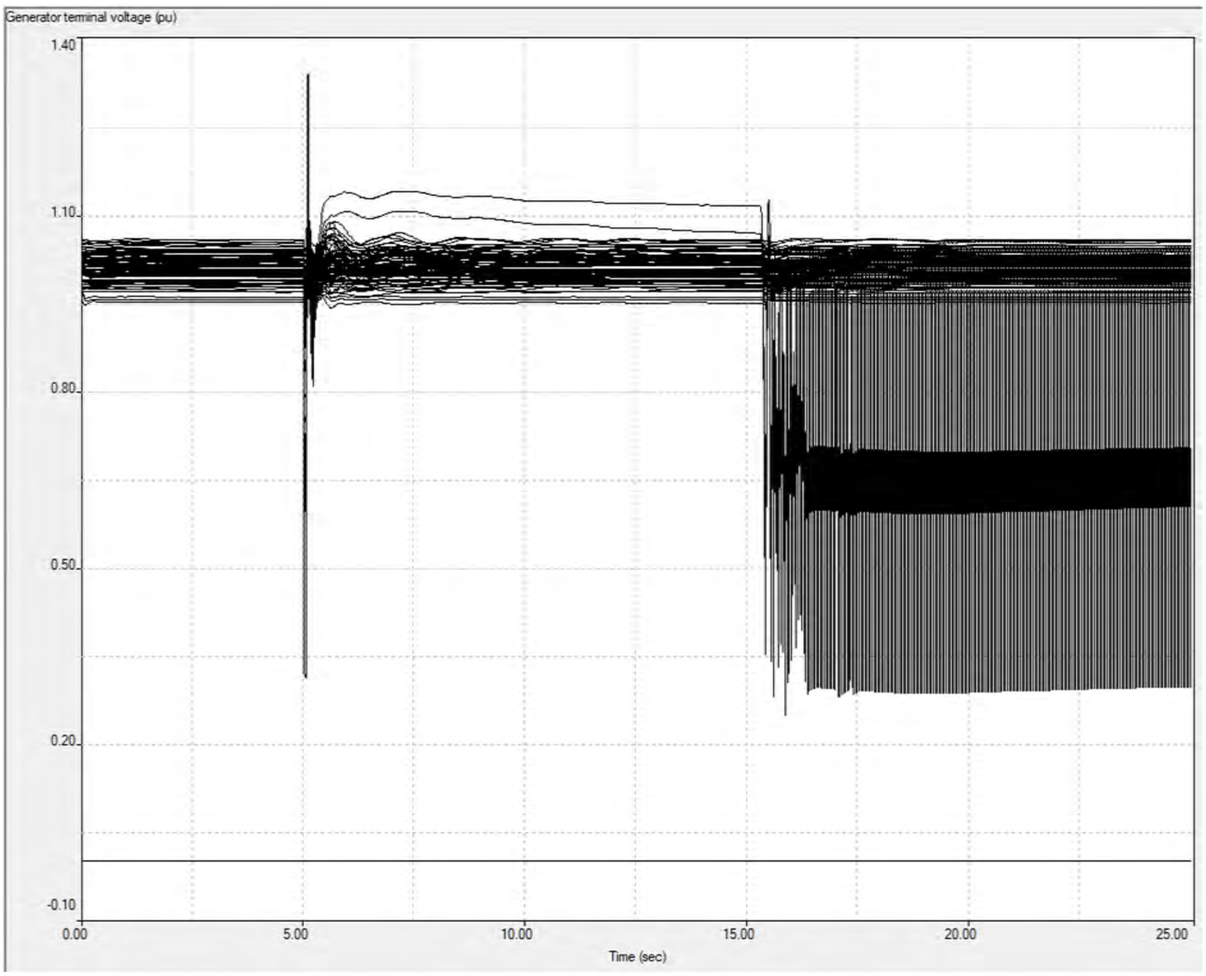

Figure 18: Generator terminal voltages for LL High Wind **345kV Alternative** case, 345kV alternative contingency 12 (loss of double circuit 345kV line between Brookings County and Lakefield Junction)

Table 14 compares results for the 765kV contingencies on the non-Project lines between the cases with the 765kV Project lines and the cases with the 345kV alternative. In 6 out of the 8 cases, the transient stability index was actually higher for the 345kV alternative than for the 765kV lines. This is likely due to lower flow on the non-Project 765kV lines when the 345kV alternative is used, resulting in less severe contingencies.

The light load high wind case is the only case with a notable difference in voltage violations between the two topologies. With the 345kV alternative there are two notable voltage violations, with the 765kV Project lines there are no voltage violations.

TABLE 14: 345KV ALTERNATIVE STABILITY ANALYSIS RESULTS FOR 765KV CONTINGENCIES ON NON-PROJECT LINES					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	88.3	1	• Minor high voltage violations in MEC territory for loss of Sub T to Woodford County 765 kV line
Avg	High	345 Alt	93.47	1	• Minor high voltage violation at East Adair 765kV bus in MEC territory and minor low voltage violations in MP territory for loss of Sub T to Woodford County 765 kV line
Avg	Low	In	90.92	1	• Minor high voltage violation at East Adair 765kV bus in MEC territory for loss of Sub T to Woodford County 765 kV line
Avg	Low	345 Alt	95.91	1	• Minor high voltage violation at East Adair 765kV bus in MEC territory for loss of Sub T to Woodford County 765 kV line
LL	High	In	95.56	0	
LL	High	345 Alt	95.47	2	• Low voltage in the MP area for loss of Twinkle to SubT 765kV line. Low voltage in MP and XEL for loss of SubT to Woodford County 765kV line.
LL	Low	In	94.74	0	
LL	Low	345 Alt	96.54	0	
SUM	High	In	78.16	0	
SUM	High	345 Alt	81.14	0	
SUM	Low	In	84.11	1	• Minor high voltage violation at East Adair for loss of East Adair 345 kV to 765 kV transformer
SUM	Low	345 Alt	82.82	0	
Winter	High	In	89.9	0	
Winter	High	345 Alt	92.67	0	
Winter	Low	In	82.85	1	• Minor high voltage violation at East Adair for loss of East Adair 345 kV to 765 kV transformer
Winter	Low	345 Alt	87.96	0	

The 345kV alternative has low voltage violations for the light load high wind case when some of the 765kV lines are lost in Iowa. Voltage results for the loss of Twinkle to SubT are shown in Figure 19 and Figure 20 below. The 345kV alternative case has some voltage oscillations that dampen out over time, while the 765kV Project case shows a more stable response that recovers more quickly.

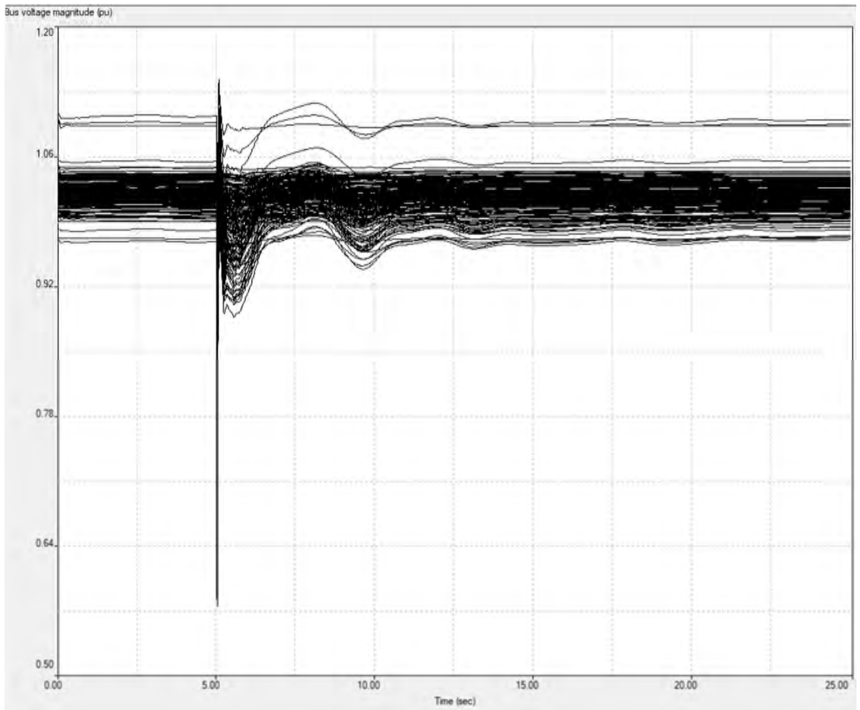

Figure 19: Bus voltages for LL High Wind **Final Project** case, 765kV contingency 18 (loss of 765kV line between Twinkle and Sub T in Iowa)

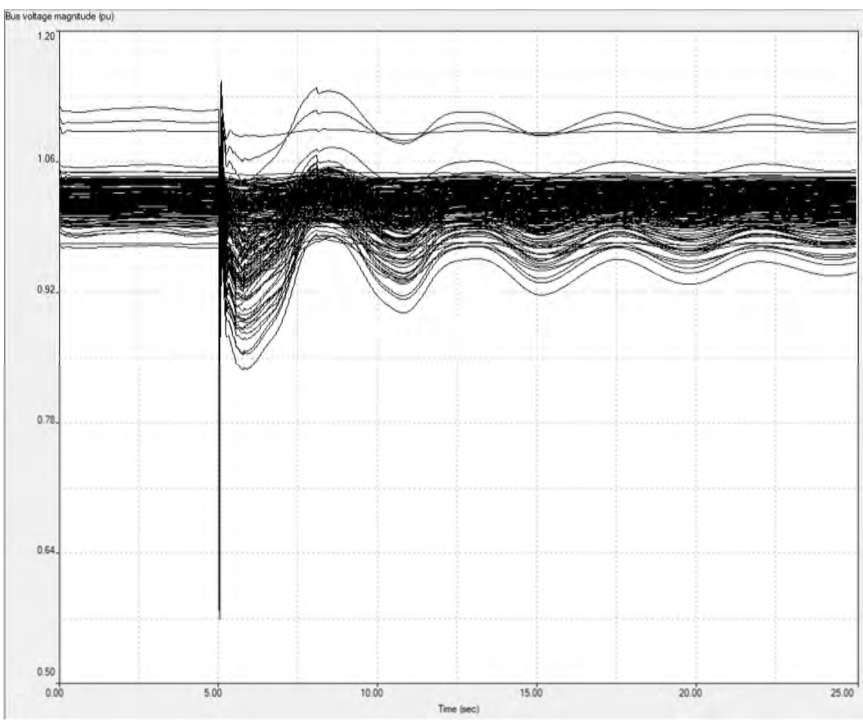

Figure 20: Bus voltages for LL High Wind **345kV Alternative** case, 765kV contingency 18 (loss of 765kV line between Twinkle and Sub T in Iowa)

For the 345kV Project contingencies, none of the cases showed any voltage violations as shown in Table 15. In 6 out of the 8 cases, the transient stability index was higher for the cases with the 765kV Project lines compared to the cases with the 345kV alternative.

TABLE 15: 345KV ALTERNATIVE STABILITY ANALYSIS RESULTS FOR 345KV CONTINGENCIES ON PROJECT LINES				
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS
Avg	High	In	41.29	0
Avg	High	345 Alt	48.84	0
Avg	Low	In	53.62	0
Avg	Low	345 Alt	39.78	0
LL	High	In	50.11	0
LL	High	345 Alt	46.74	0
LL	Low	In	48.05	0
LL	Low	345 Alt	47.58	0
SUM	High	In	52.17	0
SUM	High	345 Alt	54.43	0
SUM	Low	In	79.68	0
SUM	Low	345 Alt	68.99	0
Winter	High	In	33.37	0
Winter	High	345 Alt	31.05	0
Winter	Low	In	69.12	0
Winter	Low	345 Alt	48.34	0

Table 16 shows the results of the dynamic stability analysis with the 345kV non-Project contingencies. For 5 out of the 8 cases, the transient stability index was higher for the cases with the 765kV lines compared to the cases with the 345kV alternative. For all of the high wind cases, the cases with the 765kV lines had fewer voltage violations than the cases with the 345kV alternative.

For the Summer High Wind 345kV Alternative case, the loss of the King to Eau Claire 345kV line led to tripping of the 500kV lines between Forbes (bus 601001) and Riel (bus 667501). This includes the Riel to Roseau line, which is part of the Manitoba Hydro interface. Though the system stabilized after this loss of 500kV line segments, this is still a major event that could negatively impact the system if the flow on the lines was higher.

Note that the Summer Low Wind and Winter Low Wind 765kV Project cases have more contingencies with voltage violations compared to the 345kV alternative. This is due to voltages just over 1.05 pu for several seconds post-fault at the East Adair 765kV bus for a few contingencies in Iowa. This could be easily addressed with additional reactive power support post-fault. Additionally, it should be noted that pre-contingency voltage was relatively high at East Adair for both of these cases, over 1.04 pu. These high voltages are seen in the low wind cases but not the high wind cases due to lower flow on the 765kV lines.

TABLE 16: 345KV ALTERNATIVE STABILITY ANALYSIS RESULTS FOR 345KV CONTINGENCIES ON NON-PROJECT LINES					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	69.24	1	
Avg	High	345 Alt	70.05	3	
Avg	Low	In	74.93	1	
Avg	Low	345 Alt	74.58	1	
LL	High	In	72.68	0	
LL	High	345 Alt	66.47	3	Buffalo Ridge low voltage and relay margin issues for Con 2 (loss of Big Stone South to Alexandria 345kV line)
LL	Low	In	77.86	0	
LL	Low	345 Alt	75.84	0	
SUM	High	In	72.24	2	
SUM	High	345 Alt	72.65	3	The loss of the King to Eau Claire 345kV line led to tripping of all lines between Forbes (601001) and Riel (667501)
SUM	Low	In	75.02	6	High voltages post-fault at East Adair for some contingencies in Iowa
SUM	Low	345 Alt	78.45	2	
Winter	High	In	70.23	5	
Winter	High	345 Alt	64.36	6	The loss of one of the Bison to Alexandria 345kV lines leads to some voltage instability in northern MN and North Dakota
Winter	Low	In	79.60	5	High voltages post-fault at East Adair for some contingencies in Iowa
Winter	Low	345 Alt	74.59	1	

In the winter high wind case, the loss of one of the 345kV lines between Bison and Alexandria led to voltage instability when the 345kV alternative is implemented (Figure 22) but not when the 765kV Project lines are used (Figure 21).

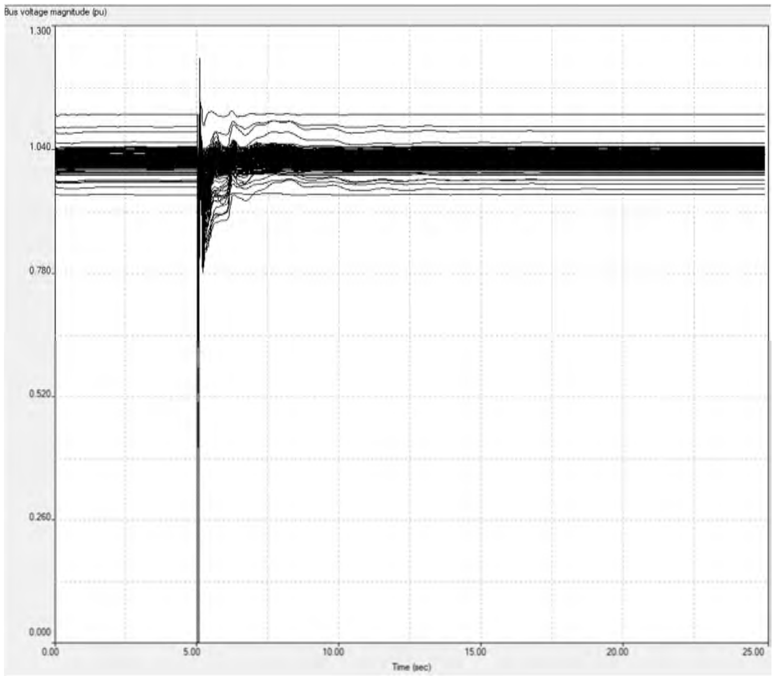

Figure 21: Bus voltages for Winter High Wind **Final Project** case, 345kV contingency 24 (loss of one 345kV line between Bison and Alexandria)

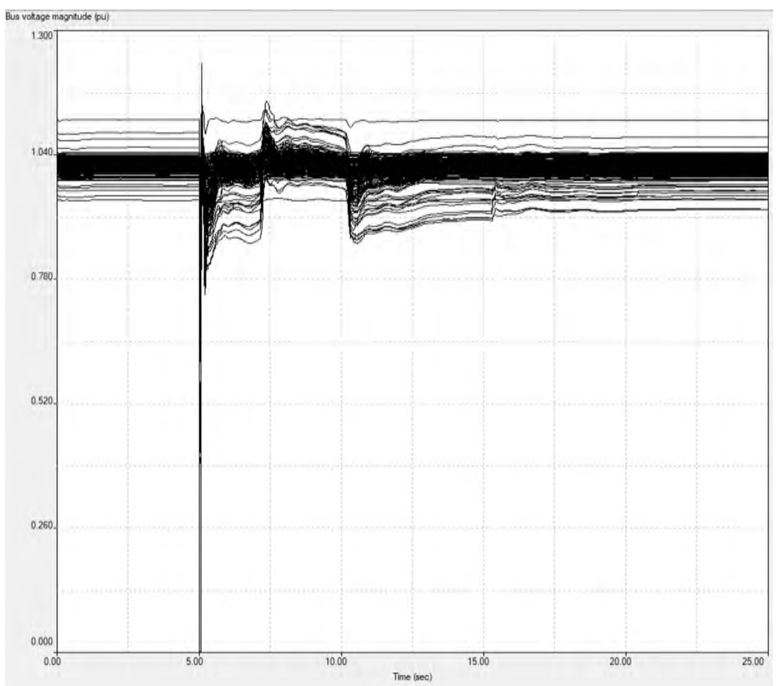

Figure 22: Bus voltages for Winter High Wind **345kV Alternative** case, 345kV contingency 24 (loss of one 345kV line between Bison and Alexandria)

SENSITIVITY ANALYSIS

Sensitivity Case Development

The original powerflow cases addressed several of the sensitivities requested to be included in this study. All eight of the cases showed a strong west to east flow across MISO, addressing the need for a west to east sensitivity. Table 17 shows the interface flows for all of the original powerflow cases. For all of the cases, the North Dakota export (NDEX) across the North Dakota interface lines is greater than the sensitivity target of 2,400 MW. The winter high and low wind cases cover the sensitivity for a Manitoba Hydro import of at least 1,400 MW.

TABLE 17: INTERFACE FLOWS FOR ORIGINAL POWERFLOW CASES

CASE	WIND DISPATCH	NDEX (MW)	MHEX (MW)
Avg	High	3,617	456
Avg	Low	2,917	464
LL	High	3,833	481
LL	Low	3,161	480
SUM	High	3,530	465
SUM	Low	2,763	465
Winter	High	3,984	-1,653
Winter	Low	3,305	-1,654

The MISO east to west powerflow case was altered to address the request for a sensitivity with a North Dakota import of 2,600 MW of higher. First, the MISO east to west powerflow case was converted from PSSE to PSAT format. Then the case was improved upon following the same steps outlined in the Base Case Development section of this report.

The east to west case provided by MISO had an east to west bias from LRZs 4-7 to LRZs 1-3, but still had around 430 MW of export across the North Dakota interface. To generate the necessary amount of import into North Dakota, generation in North Dakota was decreased by almost 3,500 MW. Generation was decreased by setting active power output to the minimum allowable for wind, solar, battery, and coal plants in North Dakota. This included generation in the XEL, OTP, MP, BEPC, and WAPA areas. To offset this decrease, generation (mostly wind, solar, and battery generation) was increased across Minnesota and some parts of South Dakota. The resulting case has an import of 2,750MW across the North Dakota interface and an export of 360 MW across the Manitoba Hydro interface.

Note that the east to west sensitivity has very low flow across the Project lines, as shown in Table 18.

Despite the high generation in Indiana and Illinois exporting to Wisconsin and Iowa in the MISO east to west case, there was still a west to east bias across the state of Minnesota to serve load centers around Minneapolis and Milwaukee. As generation was increased in Minnesota to increase the North Dakota import, this west to east flow across Minnesota remained. If Wisconsin generation was increased to reverse this flow direction across Minnesota to North Dakota, the transfer of power would be facilitated by the low impedance 765 kV lines.

TABLE 18: NORTH DAKOTA IMPORT SENSITIVITY LINE FLOWS (MW) FOR 765KV CASE

CASE	BSS to Brookings	Brookings to Lakefield Jnct	Lakefield Jnct to East Adair	Lakefield Jnct to Pleasant Valley	Pleasant Valley to NROC	NROC to Columbia
Average High Wind	675	1,824	1,158	1,743	1,840	2,408
East to West ND Import	-569	-98	-648	800	605	261

The Summer High Wind case was altered to address the request for a sensitivity with a Manitoba Hydro export of at least 3,050 MW and a North Dakota export of at least 1,800 MW. First, generation in the Manitoba Hydro area was increased by 2,900 MW, using mostly hydro units. This was offset by decreasing generation across MISO LRZs 1-5. The powerflow case solved successfully at this point, but dynamic stability runs in TSAT showed major instability in the flat start. This was likely due to the high North Dakota export of 2,900 MW that remained in the case.

To achieve an acceptable flat start and maintain stability for the critical contingencies for the 765kV case, additional generation changes were made to the model. The NDEX flow was decreased by decreasing generation in the OTP area and offsetting that with generation in Minnesota and Northern Iowa. Remaining instability for some critical contingencies in Minnesota was addressed by decreasing generation in the XEL areas in Minnesota and South Dakota and increasing generation in Wisconsin. The final MHEX max sensitivity case has a MHEX Flow of 3,110 MW and a NDEX flow of 1,840 MW.

Lastly, an additional sensitivity was created to increase flow along the Big Stone South to Brookings County corridor, to see if stressing this area would show differences between the 765kV Projects and the 345kV alternative. This sensitivity was developed from the Winter High Wind case. Wind generation was increased by 740MW near the Big Stone South substation, and solar generation was decreased by 720MW in Minnesota and Iowa to create higher flow from Big Stone South (BSS) to Brookings. Table 19 shows the flows on some of the Project lines for this sensitivity.

TABLE 19: BIG STONE SOUTH TO BROOKINGS SENSITIVITY LINE FLOWS (MW)

CASE	Project Status	BSS to Brookings	Brookings to Lakefield Jnct	Lakefield Jnct to East Adair	Lakefield Jnct to Pleasant Valley
Winter High Wind	In	290	1,293	550	1,877
Winter BSS-Brookings Max	In	631	1,674	733	2,005
Winter High Wind	345kV Alt	88	732	420	956
Winter BSS-Brookings Max	345kV Alt	172	972	510	1,020

Voltage stability analysis was not performed on these three sensitivity cases because their transfer capabilities have been maximized for the specific scenario.

Sensitivity Dynamic Stability Analysis

For the east to west North Dakota import sensitivity, no notable issues were seen across all of the contingencies for the case with the Project or the case with the 345kV double circuit alternative. The summary of the results is shown in Table 20. Differences in the average transient stability index are negligible, and there is no difference in voltage violations between the two cases.

TABLE 20: EAST TO WEST ND IMPORT SENSITIVITY STABILITY ANALYSIS RESULTS

PROJECT STATUS	CONTINGENCY SET	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS
In	765kV Project Cons	100	0
345kV Alt	345kV Alternative Cons	99.92	0
In	765kV non-Project Cons	86.6	0
345kV Alt	765kV non-Project Cons	87.6	0
In	345kV Project Cons	100	0
345kV Alt	345kV Project Cons	100	0
In	345kV non-Project Cons	90.56	1
345kV Alt	345kV non-Project Cons	89.73	1

Stability analysis results for the Summer MHEX maximum sensitivity are shown in Table 21. The transient stability index is higher for the case with the 765kV Project lines for the 345kV contingencies. However, for the 765kV contingencies, the 345kV alternative case has a higher average transient stability index.

TABLE 21: SUMMER MHEX MAX SENSITIVITY STABILITY ANALYSIS RESULTS				
PROJECT STATUS	CONTINGENCY SET	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
In	765kV Project Cons	75.98	0	
345kV Alt	345kV Alternative Cons	77.65	0	
In	765kV non-Project Cons	85.5	0	
345kV Alt	765kV non-Project Cons	89.88	0	
In	345kV Project Cons	71.25	0	
345kV Alt	345kV Project Cons	71.06	0	
In	345kV non-Project Cons	75.55	2	Some voltage instability for Con 3 (loss of Alexandria to Big Oaks 345kV) that dampens out.
345kV Alt	345kV non-Project Cons	69.81	3	Some voltage instability for Con 3 (loss of Alexandria to Big Oaks 345kV) that dampens out. Con 37 (loss of King to Eau Claire 345kV) has major voltage issues that get worse as simulation goes on.

The loss of the Alexandria to Big Oaks 345kV line leads to unstable voltages for both the case with the 765kV Project lines and the case with the 345kV double circuit alternative. Voltages recover for both cases by the end of the simulation (see Figure 23 and Figure 24).

The loss of the King to Eau Claire 345kV line led to major voltage instability for the 345kV double circuit alternative case only (Figure 26). This indicates that when the Manitoba Hydro interface is exporting near its maximum capability, the 345kV system in central Minnesota and western Wisconsin is at risk of being overloaded. The 345kV double circuit alternative becomes very unstable under these conditions when the 345kV line from King to Eau Claire is lost, but the 765kV Project lines maintain stability in this same scenario.

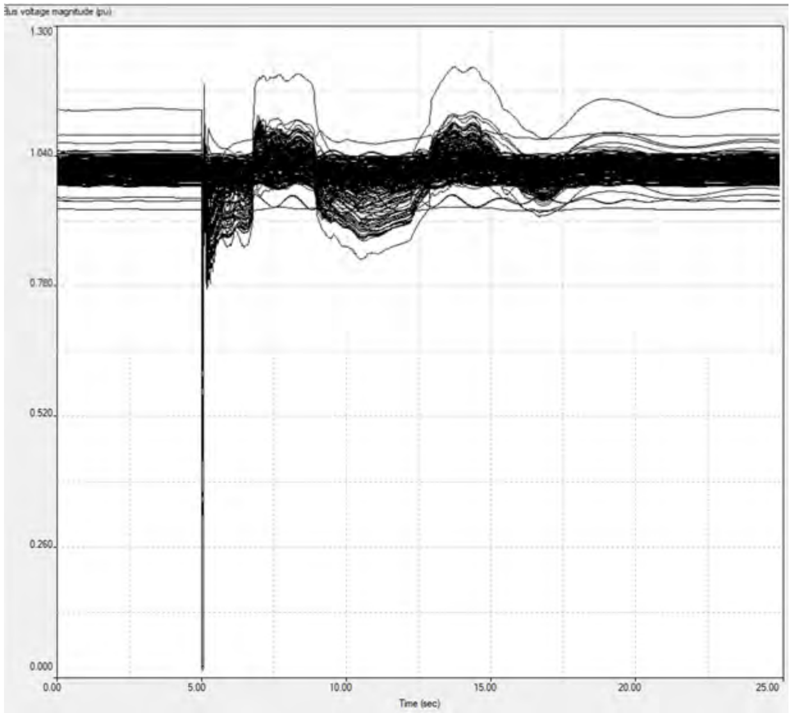

Figure 23: Bus voltages for the Summer MHEX Max sensitivity **Final Project** case, 345kV contingency 3 (loss of 345kV line between Alexandria and Big Oaks)

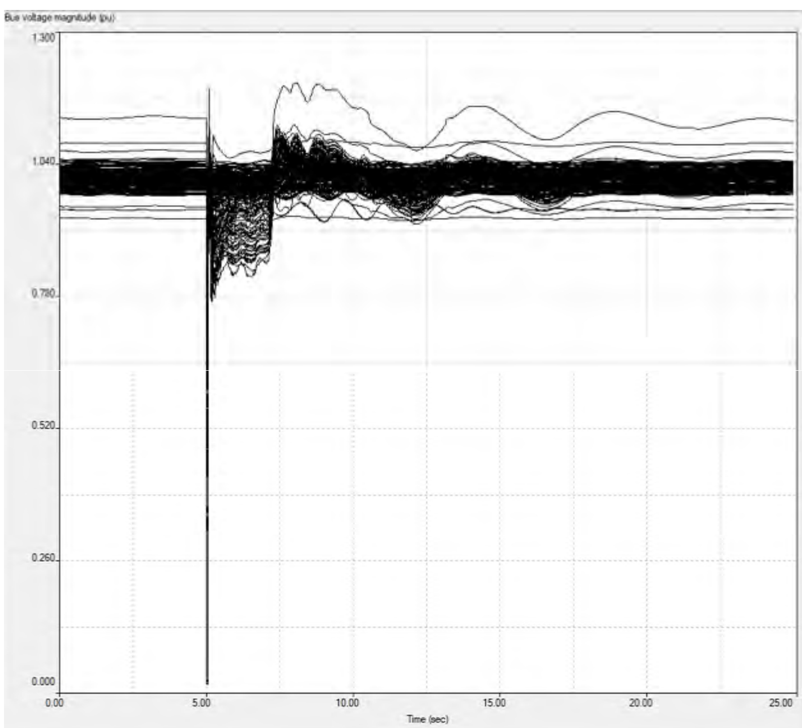

Figure 24: Bus voltages for the Summer MHEX Max sensitivity **345kV Alternative** case, 345kV contingency 3 (loss of 345kV line between Alexandria and Big Oaks)

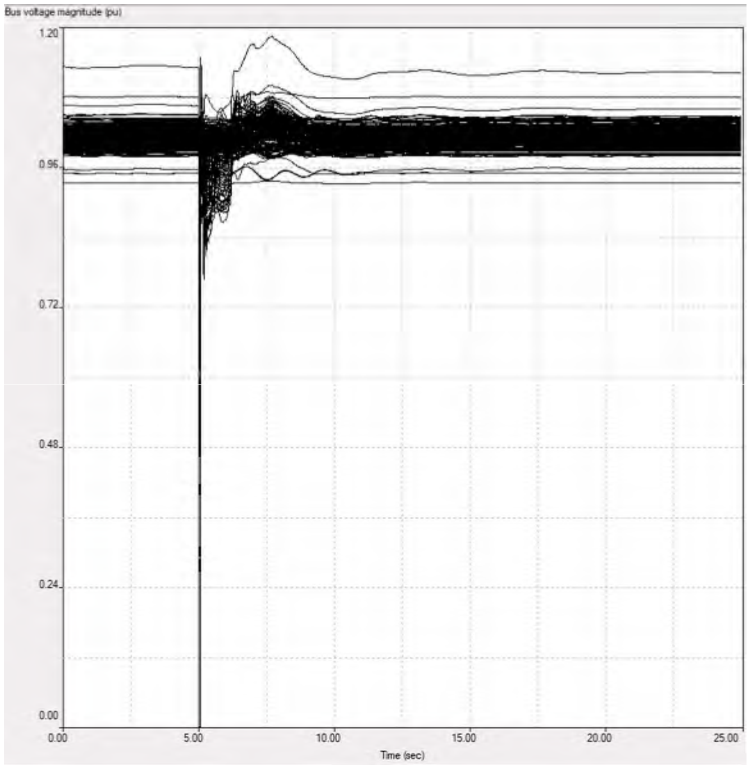

Figure 25: Bus voltages for the Summer MHEX Max sensitivity **Final Project** case, 345kV contingency 37 (loss of 345kV line between King and Eau Claire)

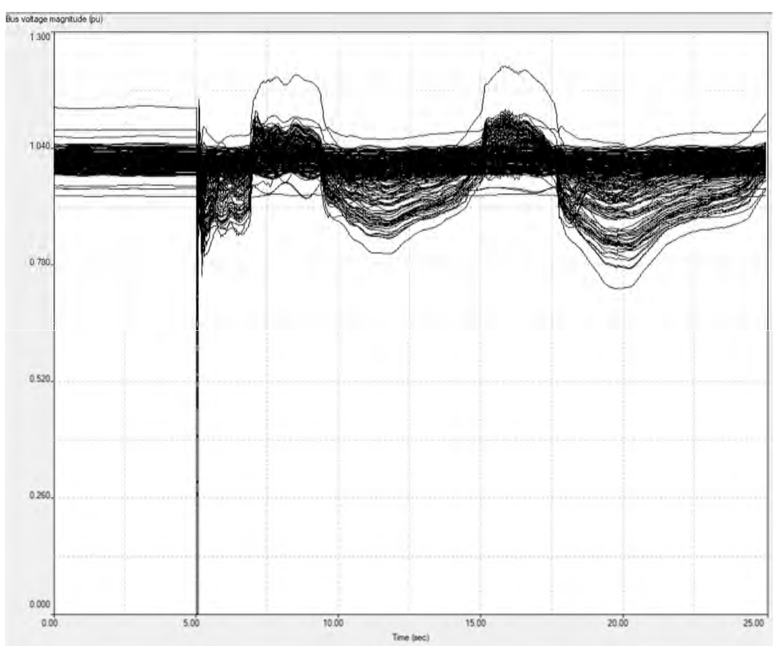

Figure 26: Bus voltages for the Summer MHEX Max sensitivity **345kV Alternative** case, 345kV contingency 37 (loss of 345kV line between King and Eau Claire)

Table 22 shows the stability analysis results for the Winter Big Stone South to Brookings County maximum flow sensitivity. For every set of contingencies, the case with the 765kV Project lines had a higher transient stability index than the case with the 345kV alternative.

Every one of the 345kV alternative contingencies resulted in some sort of voltage violation. Four of these were notable (all double circuit contingencies).

TABLE 22: WINTER BSS-BROOKINGS MAX SENSITIVITY STABILITY ANALYSIS RESULTS				
PROJECT STATUS	CONTINGENCY SET	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
In	765kV Project Cons	60.26	3	Low voltage post-fault that does recover: • Con 7 - Lakefield Junction to Pleasant Valley 765kV • Con 15 – Lakefield Junction to East Adair 765kV Con 6 (Brookings County to Lakefield Junction 765kV) has low voltage throughout but is mainly stable (no oscillations)
345kV Alt	345kV Alternative Cons	42.45	12	Low voltage post-fault that does recover: • Con 2 – Big Stone South to Brookings County double circuit 345kV • Con 4 – Lakefield Junction to East Adair double circuit 345kV • Con 12 – Brookings County to Lakefield Junction double circuit 345kV Con 10 (Lakefield Junction to Pleasant Valley double circuit 345kV) has low voltage and instability throughout the simulation
In	765kV non-Project Cons	88.55	0	
345kV Alt	765kV non-Project Cons	83.63	0	
In	345kV Project Cons	46.42	3	Minor voltage violations in the MP area
345kV Alt	345kV Project Cons	34.41	4	Minor voltage violations in the MP area
In	345kV non-Project Cons	63.35	11	Con 3 (Alexandria to Big Oaks 345kV) has low voltage post-fault that does recover
345kV Alt	345kV non-Project Cons	62.40	15	Low voltage post-fault that does recover: • Con 2 – Big Stone South to Alexandria 345kV • Con 3 – Alexandria to Big Oaks 345kV • Con 7 – Wilmarth to North Rochester 345kV

One instance where the 765kV Project line case shows significant low voltage violations is for the loss of Brookings County to Lakefield Junction. This is due to the fact that in the 765kV Project case the flow on this line is high at 1,674 MW. In comparison, when the 345kV alternative is used the flow along the corridor is only 972 MW - so the contingency itself is more significant for the 765kV Project case. Voltages are low but there is not much instability seen for many seconds. This indicates that dynamic reactive support could be used to enable high flow on this line while maintaining stability post-contingency.

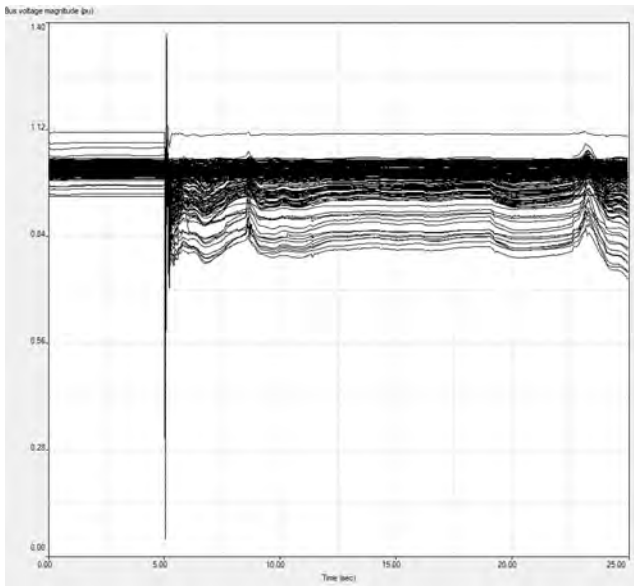

Figure 27: Bus voltages for the Winter BSS-Brookings maximum sensitivity **Final Project** case, 765kV contingency 6 (loss of 765kV line between Brookings County and Lakefield Junction)

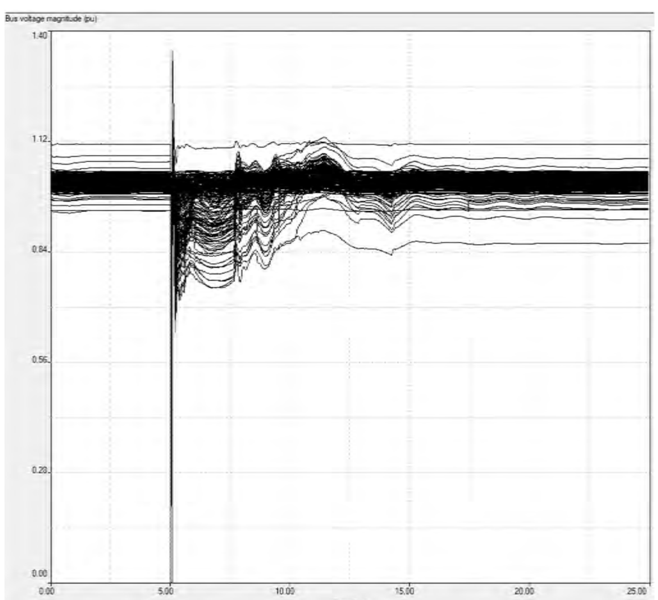

Figure 28: Bus voltages for the Winter BSS-Brookings maximum sensitivity **345kV Alternative** case, 345kV alternative contingency 12 (loss of 345kV double circuit between Brookings County and Lakefield Junction)

There are many other examples, however, of the 765kV Projects out-performing the 345kV alternative for this sensitivity case. For the loss of the Lakefield Junction to Pleasant Valley corridor, the 765kV Project case (Figure 29) recovers more quickly than the 345kV alternative case (Figure 30).

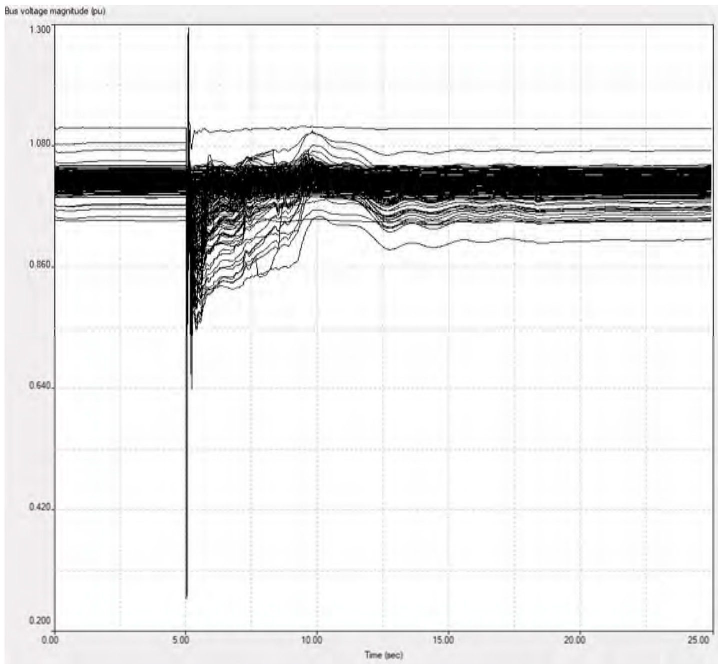

Figure 29: Bus voltages for the Winter BSS-Brookings maximum sensitivity **Final Project** case, 765kV contingency 7 (loss of 765kV between Lakefield Junction and Pleasant Valley)

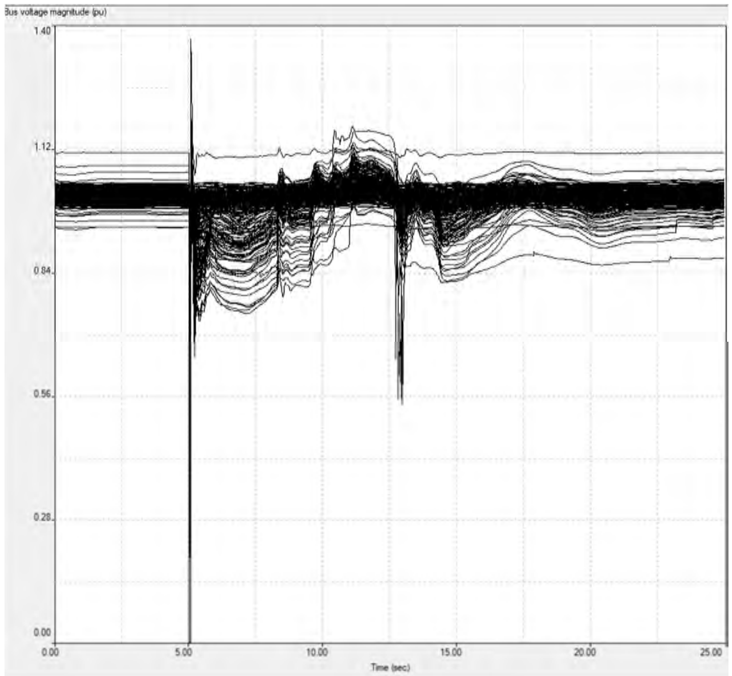

Figure 30: Bus voltages for the Winter BSS-Brookings maximum sensitivity **345kV Alternative** case, 345kV alternative contingency 10 (loss of 345kV double circuit between Lakefield Junction and Pleasant Valley)

For the loss of the Big Stone South to Brookings County corridor, the 765kV Project case (Figure 31) voltage also recovers much quicker compared to the 345kV alternative case (Figure 32).

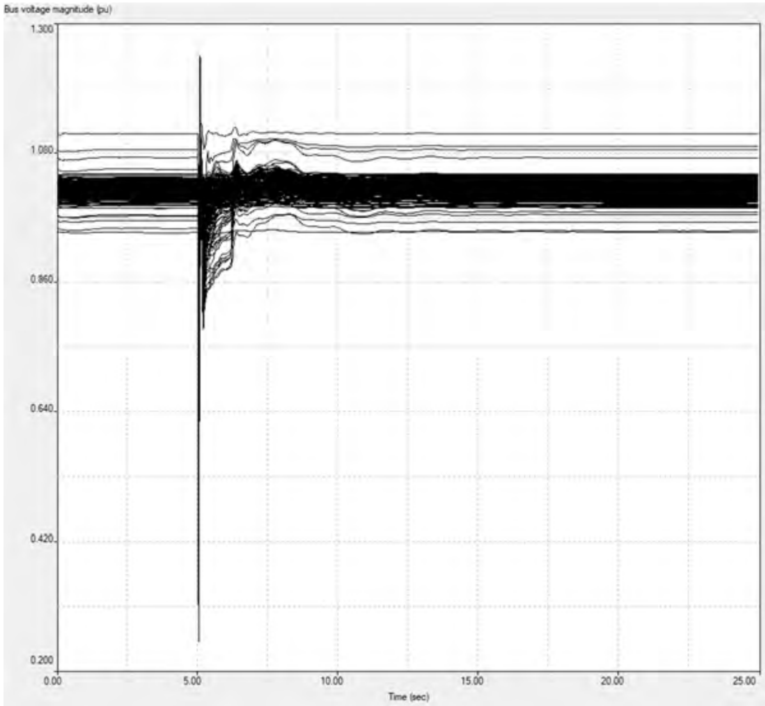

Figure 31: Bus voltages for the Winter BSS-Brookings maximum sensitivity **Final Project** case, 765kV contingency 1 (loss of 765kV between Big Stone South and Brookings County)

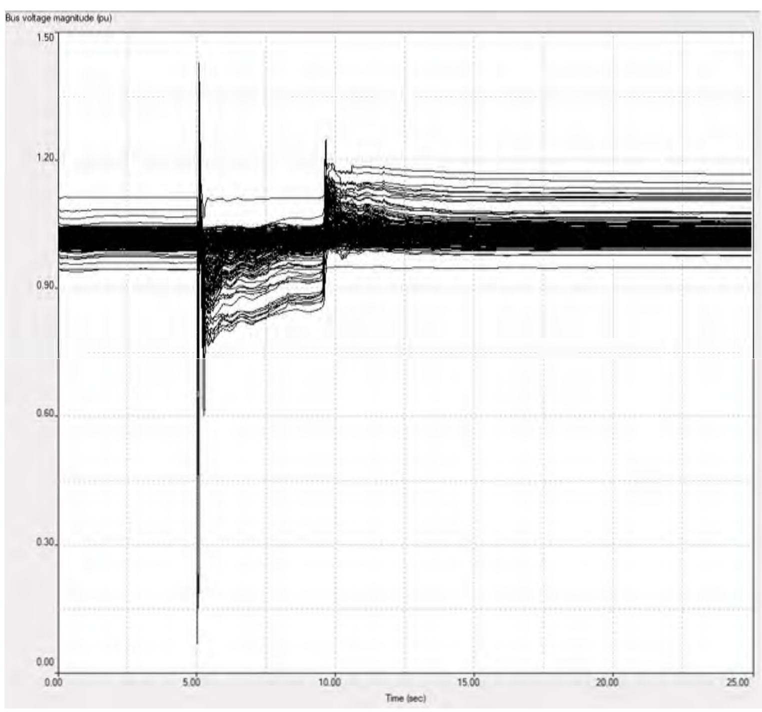

Figure 32: Bus voltages for the Winter BSS-Brookings maximum sensitivity **345kV Alternative** case, 345kV alternative contingency 2 (loss of 345kV double circuit between Big Stone South and Brookings County)

Similarly, for the loss of the Big Stone South to Alexandria 345kV line, the 765kV Project case (Figure 33) voltage also recovers much quicker compared to the 345kV alternative case (Figure 34). The 345kV alternative case also results in issues with the Buffalo Ridge wind generation plant, as can be seen toward the end of the simulation time.

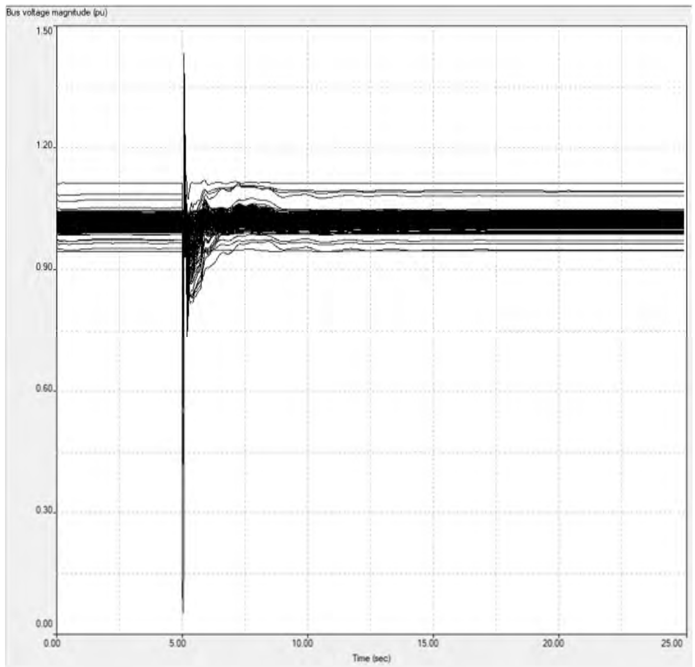

Figure 33: Bus voltages for the Winter BSS-Brookings maximum sensitivity **Final Project** case, 345kV contingency 2 (loss of Big Stone South to Alexandria 345kV)

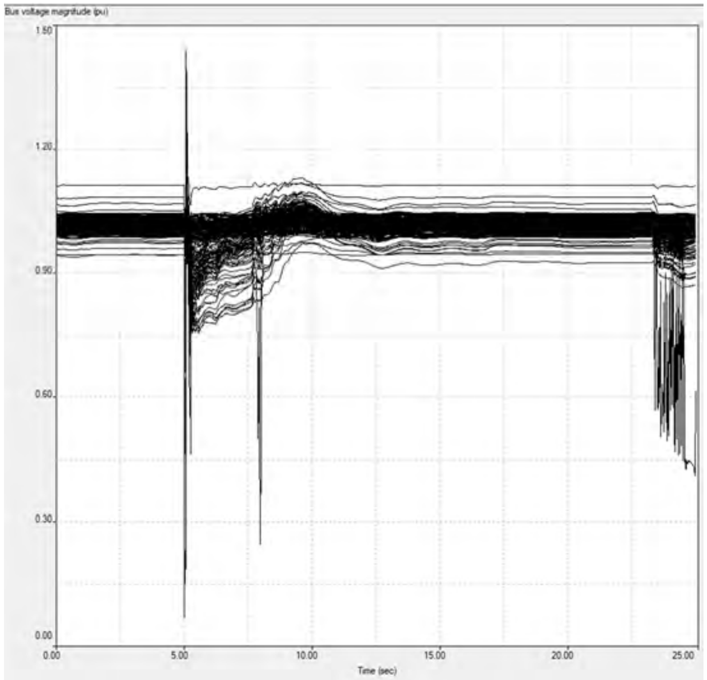

Figure 34: Bus voltages for the Winter BSS-Brookings maximum sensitivity **345kV Alternative** case, 345kV contingency 2 (loss of Big Stone South to Alexandria 345kV)

PRIOR OUTAGE ANALYSIS

Prior Outage Case Development

A list of prior outage cases to analyze was provided to POWER by the Partners. The same prior outages were applied to the cases with the 765kV lines (Table 23) and the cases with the 345kV double circuit alternative lines (Table 24). Note that for prior outages 1, 2, and 7 the outage for the path was either the loss of the 765kV line or the 345kV alternative double circuit lines depending on the case.

All eight cases (average, light load, summer, and winter - high and low wind for each) were created for each prior outage. Each case was modeled with the 765kV Project lines and the 345kV alternative, for a total of 160 cases.

TABLE 23: PRIOR OUTAGE LINES FOR 765KV CASES				
PRIOR OUTAGE	VOLTAGE LEVEL (KV)	FROM BUS	TO BUS	CIRCUIT ID
1. North Rochester to Columbia	765	860060	860048	T2
2. Brookings to Lakefield Junction	765	860061	860058	T2
3. East Adair to Twinkle	765	860000	860013	T2
4. Twinkle to SubT	765	860013	860019	T2
5. Lyon County to Cedar Mountain Double Circuit	345	601048	615643	1
		601048	615648	2
6. Crandall-Wilmarth/Huntley-Wilmarth Double Circuit	345	601004	631193	1
		601004	601074	1
7. Lakefield Junction to Pleasant Valley	765	860058	860057	T2
8. North Rochester to Tremval	345	601039	690029	C1
9. Adams to Mitchell Co	345	601002	631144	1
10. Helena to Scott Cty	345	601050	601055	1

TABLE 24: PRIOR OUTAGE LINES FOR 345KV ALTERNATIVE CASES				
PRIOR OUTAGE	VOLTAGE LEVEL (KV)	FROM BUS	TO BUS	CIRCUIT ID
1. North Rochester to Columbia Double Circuit	345	601039	699157	A1, A2
2. Brookings to Lakefield Junction Double Circuit	345	601031	631138	A1, A2
3. East Adair to Twinkle	765	860000	860013	T2
4. Twinkle to SubT	765	860013	860019	T2
5. Lyon County to Cedar Mountain Double Circuit	345	601048	615643	1
		601048	615648	2
6. Crandall-Wilmarth/Huntley-Wilmarth Double Circuit	345	601004	631193	1
		601004	601074	1
7. Lakefield Junction to Pleasant Valley Double Circuit	345	631138	615306	A1, A2
8. North Rochester to Tremval	345	601039	690029	C1
9. Adams to Mitchell Co	345	601002	631144	1
10. Helena to Scott Cty	345	601050	601055	1

Prior Outage Voltage Stability Analysis

The prior outage cases were tested for voltage stability during the transfer of LRZ 1-3 wind generation to the Minnesota area using the same VSAT setup as was used to analyze the 765kV Project and 345kV alternative. The 345kV alternative contingencies were added to the previous list of all Tranche-1 P1, Tranche-2 138 kV and 345 kV, and Tranche-2 765 kV contingencies. Some minor case adjustments to the prior outage cases were necessary to achieve transfer results similar to the previous analysis, mostly turning on reactors and adding some capacitors.

In the vast majority of scenarios, the 765kV Project had a higher extra transfer capability compared to the 345kV alternative before encountering voltage limits. Overall, when all eight scenarios were averaged together for each prior outage case, the 765kV Project could transfer more LRZ 1-3 wind than the 345kV alternative in every prior outage. The transfer difference was the largest for the North Rochester to Tremval prior outage, and the transfer difference was the smallest for the Lakefield Junction to Pleasant Valley prior outage. The Lakefield Junction to Pleasant Valley prior outage limited the 765kV Project transfer by 900 MW compared to the base 765kV Project, showing its importance in the overall Project suite.

A summary of the prior outage VSAT results can be found in Table 25- the results shown are averaged across all eight scenarios. The full VSAT result comparison can be seen in Appendix B, with results for each individual scenario.

TABLE 25: VOLTAGE STABILITY PRIOR OUTAGE RESULTS SUMMARY - AVERAGES

Prior Outage	765kV Final Project Transfer (MW)	345kV Alternative Transfer (MW)	Difference (MW)
Base	6351	5926	425
1. North Rochester to Columbia	6194	5901	294
2. Brookings to Lakefield Junction	5894	5776	119
3. East Adair to Twinkle	6219	5926	294
4. Twinkle to SubT	6144	5788	356
5. Lyon County to Cedar Mountain Double Circuit	6101	5644	456
6. Crandall-Wilmarth/Huntley-Wilmarth Double Circuit	5757	5294	463
7. Lakefield Junction to Pleasant Valley	5451	5401	50
8. North Rochester to Tremval	6332	5676	656
9. Adams to Mitchell Co	6376	6001	375
10. Helena to Scott Cty	5907	5538	369

Prior Outage Dynamic Stability Analysis

Dynamic stability analysis was performed on the prior outage cases using the list of contingencies in Appendix A Table 30 for the cases with the 765kV Project lines and Appendix A Table 31 for the cases with the 345kV alternative lines. The contingency list is made up of the 10 prior outage lines themselves, plus two additional contingencies: Sub T to Woodford County 765kV line and the King to Eau Claire 345kV line. The only difference in the contingency list applied to the 765kV Project lines versus the 345kV alternative lines is whether 765kV or 345kV double circuit lines are outaged for contingencies 1, 2, and 7. At 11 contingencies each for the 160 prior outage cases, this was a total of 1,760 separate runs.

Table 26 summarizes the findings of the prior outage dynamic stability analysis. The table shows the transient stability index for each prior outage averaged across all eight cases (average, light load, summer, and winter high and low wind) for the 765kV Project lines compared to the 345kV alternative. For all 10 prior outages, the cases with the 765kV Project had a higher average transient stability index than the cases with the 345kV alternative. When averaged across all prior outages, the 765kV Project cases had a 7% higher average transient stability index.

The table also shows the sum of the number of contingencies with voltage violations across all eight cases for each prior outage. For all 10 prior outages, the cases with the 765kV Project had fewer voltage violations compared to the cases with the 345kV alternative. When totaled across all prior outage cases, the 765kV Project cases had 84 fewer voltage violations (or 56% fewer voltage violations).

Every Summer High Wind case for the 345kV alternative prior outages resulted in tripping of the 500kV lines between Forbes (bus 601001) and Riel (bus 667501) for the King to Eau Claire 345kV contingency. This includes the Riel to Roseau line, which is part of the Manitoba Hydro interface. Though the system stabilized after this loss of 500kV line segments, this is still a major event that could negatively impact the system if the flow on the lines was higher. This 500kV line tripping was only seen for the Summer High Wind case in one prior outage (10 – Helena to Scott Cty) for the 765kV Project case. This 500kV line tripping is shown in more detail in Appendix C.

Additionally, some of the contingencies across the prior outages caused issues with the Buffalo Ridge wind generation – as discussed previously in the 345kV alternative dynamic stability analysis section. Due to the increased system instability with the prior outages, these Buffalo Ridge issues appeared in both the 765kV Project cases and the 345kV alternative cases. More details on which cases these issues appeared in can be found in Appendix C.

TABLE 26: DYNAMIC STABILITY ANALYSIS RESULTS FOR PRIOR OUTAGES								
PRIOR OUTAGE	AVERAGE TRANSIENT STABILITY INDEX			CONTINGENCIES WITH VOLTAGE VIOLATIONS			NOTABLE CONDITIONS	
	765 KV	345 KV ALT	DIFF	765 KV	345 KV ALT	DIFF	765 KV	345 KV ALT
1	78.38	71.84	-6.54	11	15	4	Major voltage oscillations for loss of Twinkle to Sub T 765kV line and Sub T to Woodford County 765kV line for Avg HW and LL HW	Major voltage oscillations for loss of Twinkle to Sub T 765kV line and Sub T to Woodford County 765kV line for Avg HW and LL HW
2	74.95	70.28	-4.66	7	15	8		Major voltage stability issues and an angular stability issue for loss of North Rochester to Columbia for Avg HW 345Alt, Monticello nuclear plant trips. Voltage oscillations for loss of SubT to Woodford County 765kV line for Avg HW 345Alt and LL HW 345Alt
3	72.04	65.87	-6.17	5	14	9	Voltage oscillations for loss of North Rochester to Columbia for Avg HW and LL HW	Major voltage stability issues and an angular stability issue for loss of North Rochester to Columbia for Avg HW.
4	72.15	68.11	-4.04	4	16	12	Low voltage issues for loss of North Rochester to Columbia for Avg HW. Major voltage oscillations for loss of North Rochester to Columbia for LL HW.	Low voltage issues for loss of North Rochester to Columbia for Avg HW. Small voltage oscillations for loss of North Rochester to Columbia for LL HW. Voltage oscillations for loss of SubT to Woodford County 765kV line for Avg HW and LL HW
5	74.07	67.67	-6.40	8	16	8		Major voltage stability issues and an angular stability issue for loss of North Rochester to Columbia for Avg HW 345Alt, Monticello nuclear plant trips.
6	70.59	67.61	-2.99	4	17	13		Major voltage stability issues and an angular stability issue for loss of North Rochester to Columbia for Avg HW 345Alt, Monticello nuclear plant trips.
7	77.15	71.31	-5.84	5	12	7		
8	79.87	73.46	-6.41	7	14	7	Voltage oscillations for loss of North Rochester to Columbia for Avg HW. Low voltage for loss of North Rochester to Columbia for LL HW.	Major voltage stability issues for loss of North Rochester to Columbia for Avg HW. Major voltage oscillations for loss of SubT to Woodford County for Avg HW and LL HW.
9	72.82	68.81	-4.02	7	15	8		Major voltage stability issues for loss of North Rochester to Columbia for Avg HW.
10	72.53	71.82	-0.71	7	15	8		
All	74.45	69.68	-4.78	65	149	84		

One key takeaway from the prior outage results is that without essential sections of the LRTP Tranche 2.1 portfolio, such as North Rochester to Columbia, East Adair to Twinkle, and Twinkle to SubT, some contingencies can lead to major instability issues even if the remaining 765kV Tranche 2.1 Portfolio is built.

The prior outage that shows some of the most critical results was North Rochester to Columbia. In both the Average and Light Load High Wind 765kV Project cases the system experiences significant voltage oscillations for the additional loss of two sections of the southern 765kV corridor through contingency application: Twinkle to SubT or SubT to Woodford County.

For the Average High Wind case, the loss of SubT to Woodford County (Figure 36) is more severe – leading to lower voltages during the oscillations compared to the loss of Twinkle to SubT (Figure 35). For both contingencies, the voltage oscillations are damped and improve by the end of the simulation time.

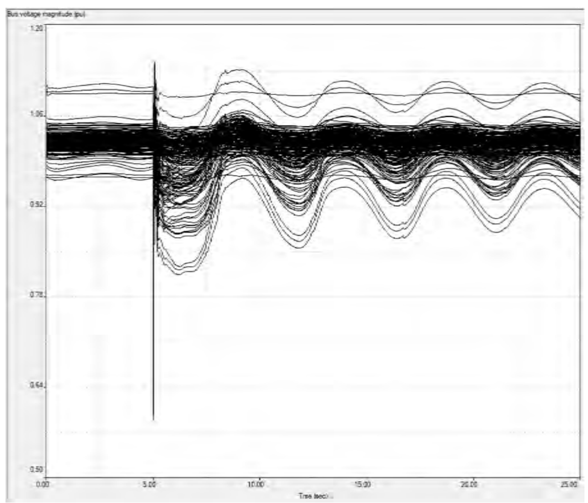

Figure 35: Bus voltages for the North Rochester to Columbia prior outage Average High Wind **Final Project** case, contingency 4 (loss of Twinkle to SubT 765kV)

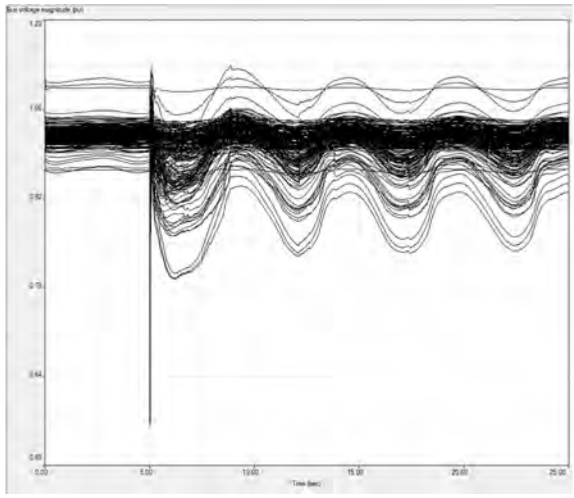

Figure 36: Bus voltages for the North Rochester to Columbia prior outage Average High Wind **Final Project** case, contingency 11 (loss of SubT to Woodford County 765kV)

For the Light Load High Wind case, the loss of Twinkle to SubT (Figure 37) results in lower voltages during the oscillations, but the loss of SubT to Woodford County (Figure 38) results in faster oscillations that do not appear to dampen well by the end of the simulation time.

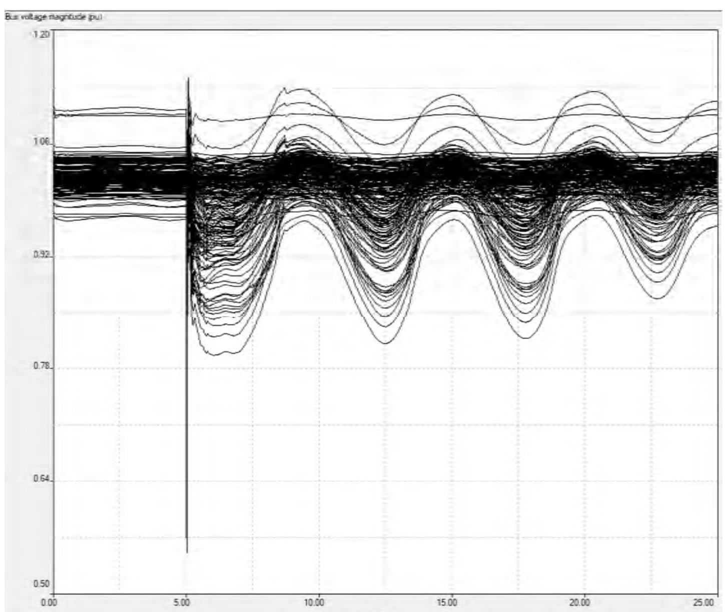

Figure 37: Bus voltages for the North Rochester to Columbia prior outage Light Load High Wind **Final Project** case, contingency 4 (loss of Twinkle to SubT 765kV)

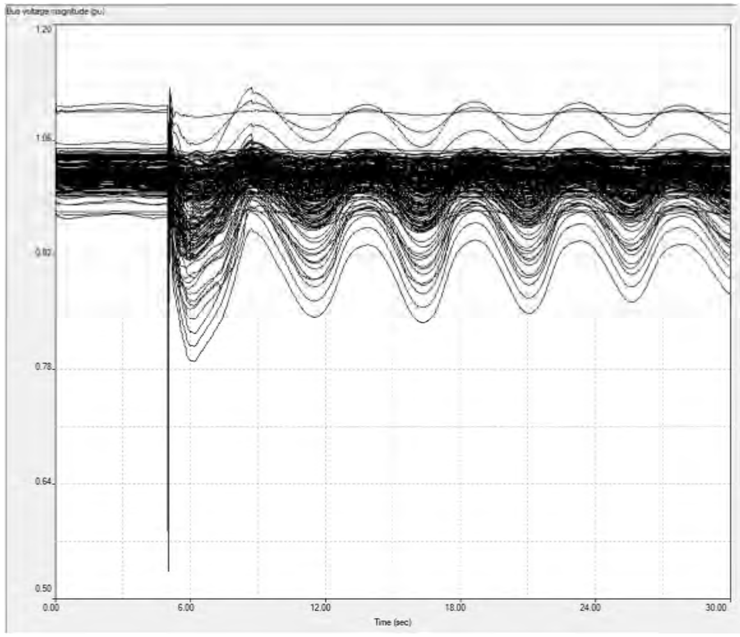

Figure 38: Bus voltages for the North Rochester to Columbia prior outage Light Load High Wind **Final Project** case, contingency 11 (loss of SubT to Woodford County 765kV)

Similarly, issues were seen in the 765kV Project cases when some of the southern 765kV portions of the LRTP Tranche 2.1 were used as the prior outage: East Adair to Twinkle and Twinkle to SubT. For both of these prior outage cases, the loss of North Rochester to Columbia led to voltage oscillations in the Average and Light Load High Wind 765kV Project cases. An example of this is shown in Figure 39 below.

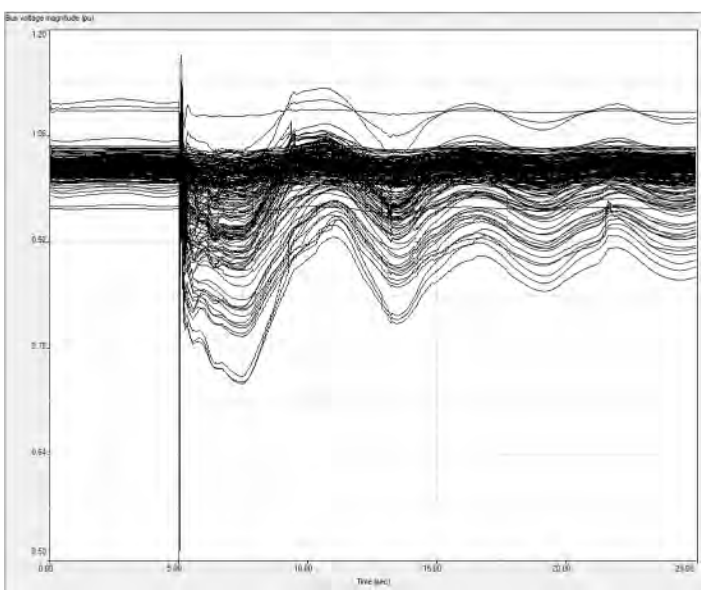

Figure 39: Bus voltages for the Twinkle to SubT prior outage Average High Wind **Final Project** case, contingency 1 (loss of North Rochester to Columbia 765kV)

Lastly, some instability is seen in the 765kV Project cases when a key 345kV corridor in Minnesota is used as a prior outage – North Rochester to Tremval. However, the voltage instability seen after contingencies for this prior outage is not as severe and appears to dampen as the simulation goes on. An example of this is shown in Figure 40.

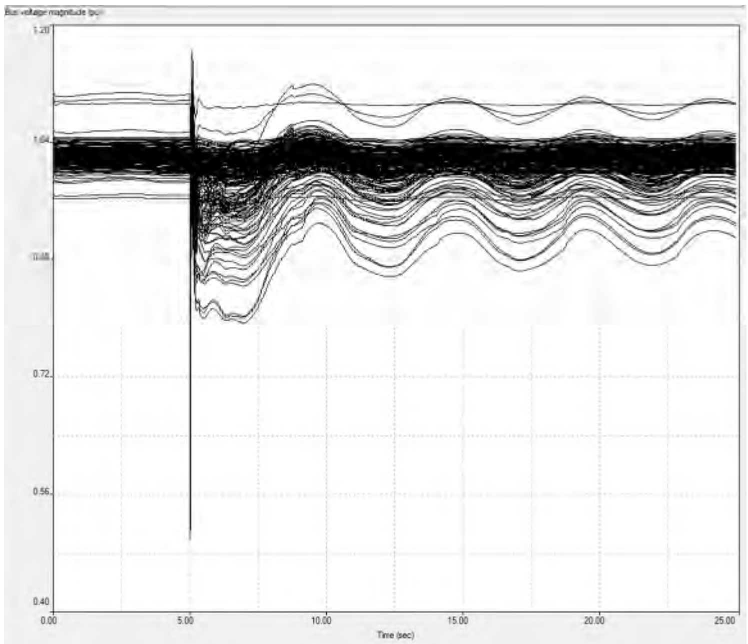

Figure 40: Bus voltages for the North Rochester to Tremval prior outage Average High Wind **Final Project** case, contingency 1 (loss of North Rochester to Columbia 765kV)

Another key takeaway from the prior outage results is that, for almost all cases and contingencies, the 765kV Project lines performed similar to or better than the 345kV alternative.

For the Brookings to Lakefield Junction prior outage, when the North Rochester to Columbia corridor contingency is applied to the Average High Wind 765kV Project case it quickly stabilizes (Figure 41). The 345kV Alternative case, on the other hand, has major voltage instability and the Monticello nuclear plant (with an output of 637 MW) trips around 10 seconds post-contingency (Figure 42). Figure 43 shows the generator angle stability that leads to Monticello tripping.

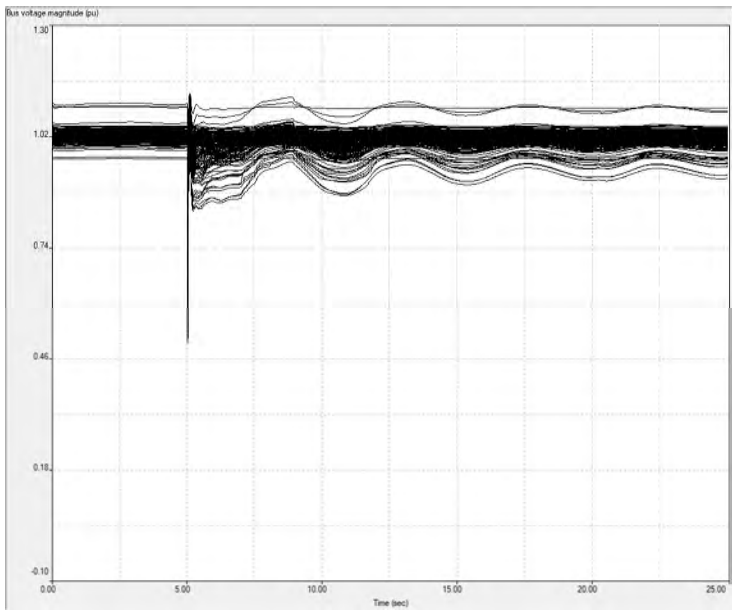

Figure 41: Bus voltages for the Brookings to Lakefield Junction prior outage Average High Wind **Final Project** case, contingency 1 (loss of North Rochester to Columbia 765kV)

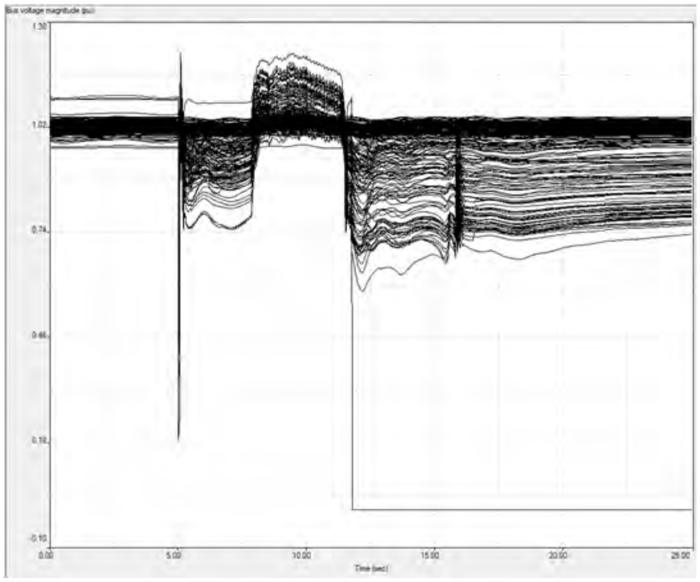

Figure 42: Bus voltages for the Brookings to Lakefield Junction prior outage Average High Wind **345kV Alternative** case, contingency 1 (loss of North Rochester to Columbia 345kV double circuit alternative)

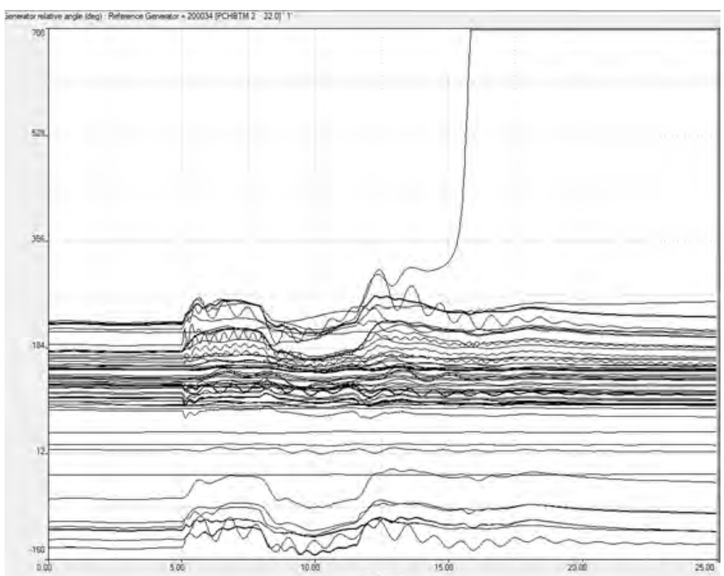

Figure 43: Generator relative angle for the Brookings to Lakefield Junction prior outage Average High Wind **345kV Alternative** case, contingency 1 (loss of North Rochester to Columbia 345kV double circuit alternative)

Similarly, when the Lyon County to Cedar Mountain 345kV double circuit is used as a prior outage, the Average High Wind 765kV Project case remains very stable when the North Rochester to Columbia corridor contingency is applied (Figure 44). Whereas the 345kV alternative case shows major voltage instability and again leads to the tripping of the Monticello nuclear plant (Figure 45).

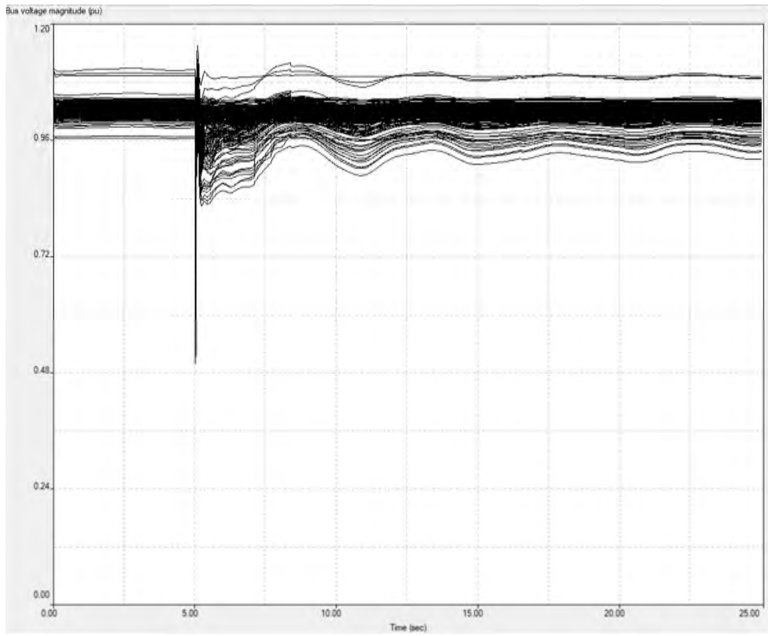

Figure 44: Bus voltages for the Lyon County to Cedar Mountain prior outage Average High Wind **Final Project** case, contingency 1 (loss of North Rochester to Columbia 765kV)

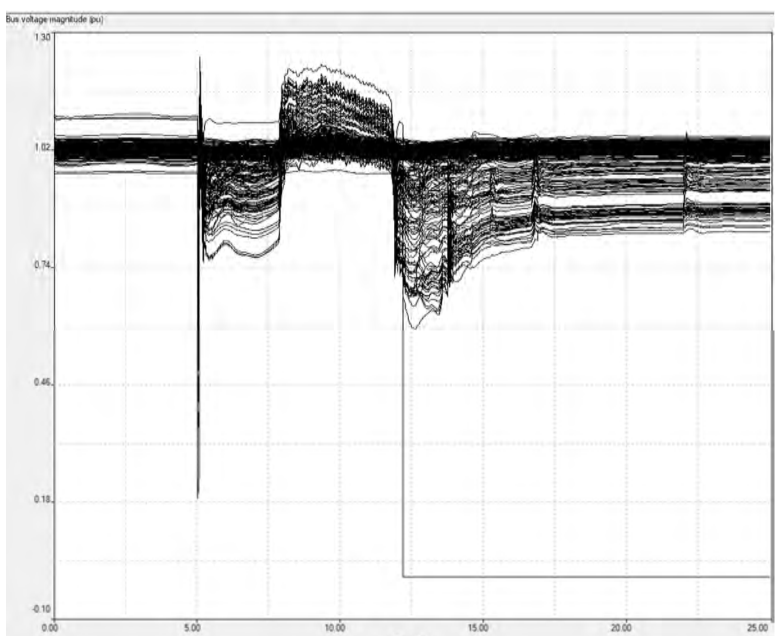

Figure 45: Bus voltages for the Lyon County to Cedar Mountain prior outage Average High Wind **345kV Alternative** case, contingency 1 (loss of North Rochester to Columbia 345kV double circuit alternative)

The 765kV Project case also outperforms the 345kV alternative for the North Rochester to Tremval prior outage with the Sub T to Woodford County 765kV contingency applied. For the Light Load High Wind case, the 765kV Project shows very little instability in this scenario (Figure 46), while the 345kV alternative shows notable voltage oscillations (Figure 47). This indicates that additional stress to the 345kV system with prior outages is more detrimental to system stability if the 345kV alternative was used instead of the 765kV Project lines in most cases.

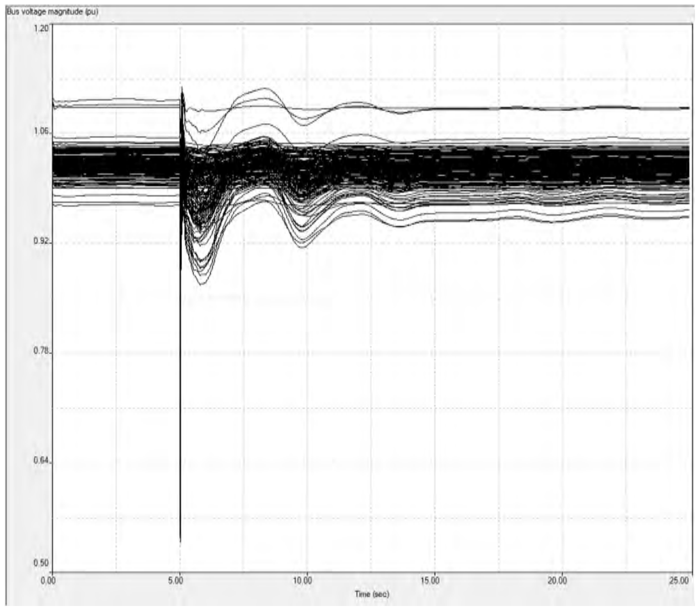

Figure 46: Bus voltages for the North Rochester to Tremval prior outage Light Load High Wind **Final Project** case, contingency 11 (loss of SubT to Woodford County 765kV)

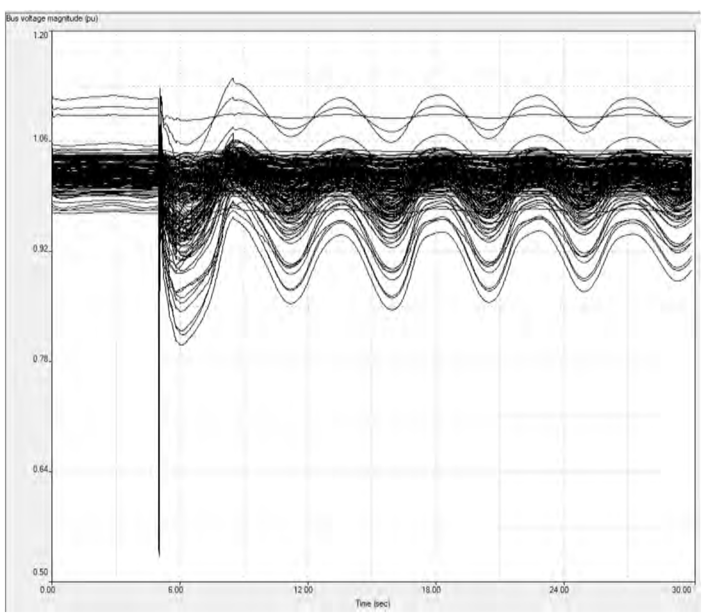

Figure 47: Bus voltages for the North Rochester to Tremval prior outage Light Load High Wind **345kV Alternative** case, contingency 11 (loss of SubT to Woodford County 765kV)

As a final example, the 765kV Project case also outperforms the 345kV alternative for the Adams to Mitchell Co prior outage with the North Rochester to Columbia corridor contingency applied. For the Average High Wind case, the 765kV Project shows some voltage oscillations and low voltage in this scenario (Figure 48), while the 345kV alternative shows an extremely unstable voltage response that worsens as the simulation continues (Figure 49).

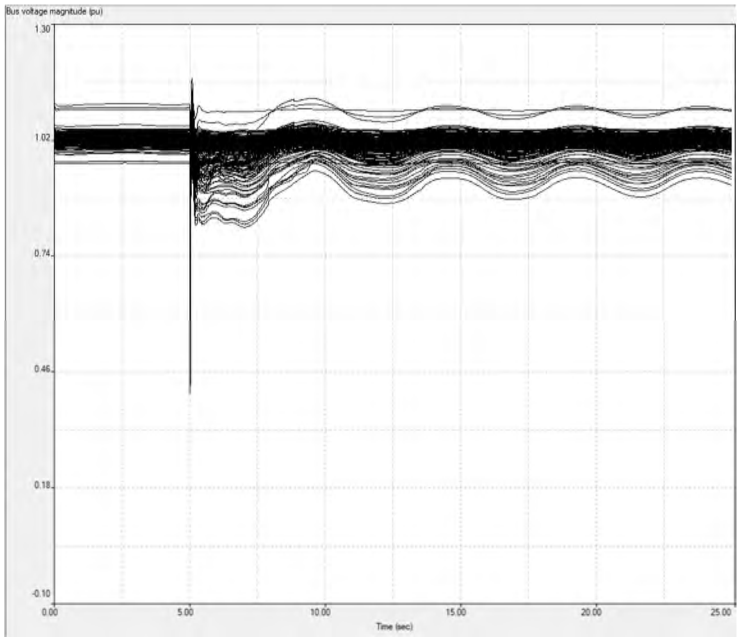

Figure 48: Bus voltages for the Adams to Mitchell Co prior outage Average High Wind **Final Project** case, contingency 1 (loss of North Rochester to Columbia 765kV)

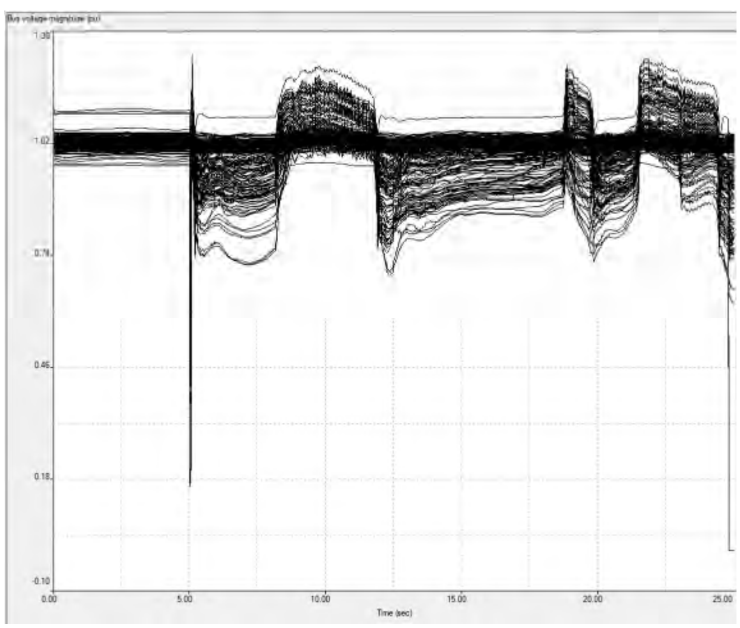

Figure 49: Bus voltages for the Adams to Mitchell Co prior outage Average High Wind **345kV Alternative** case, contingency 1 (loss of North Rochester to Columbia 345kV double circuit alternative)

There were only three cases where the 765kV cases showed noticeably worse instability than the 345kV alternative cases, detailed in the bullet points below. All three of these occurred for the North Rochester to Columbia corridor contingency, when the flow on the 765kV line from North Rochester to Columbia was at least 1,200 MW greater than the flow on the same corridor in the 345kV alternative case. Despite how severe the contingency is for the 765kV Project cases, for all three scenarios any voltage oscillations appear to be damped. Lingering low voltage issues in these cases could be addressed (as previously mentioned) with reactive support devices.

- East Adair to Twinkle prior outage, Light Load High Wind case, North Rochester to Columbia contingency
- Twinkle to SubT prior outage, Light Load High Wind case, North Rochester to Columbia contingency
    - 765kV Project response shown in Figure 50
    - 345kV Alternative response shown in Figure 51
- North Rochester to Tremval prior outage, Light Load High Wind case, North Rochester to Columbia contingency

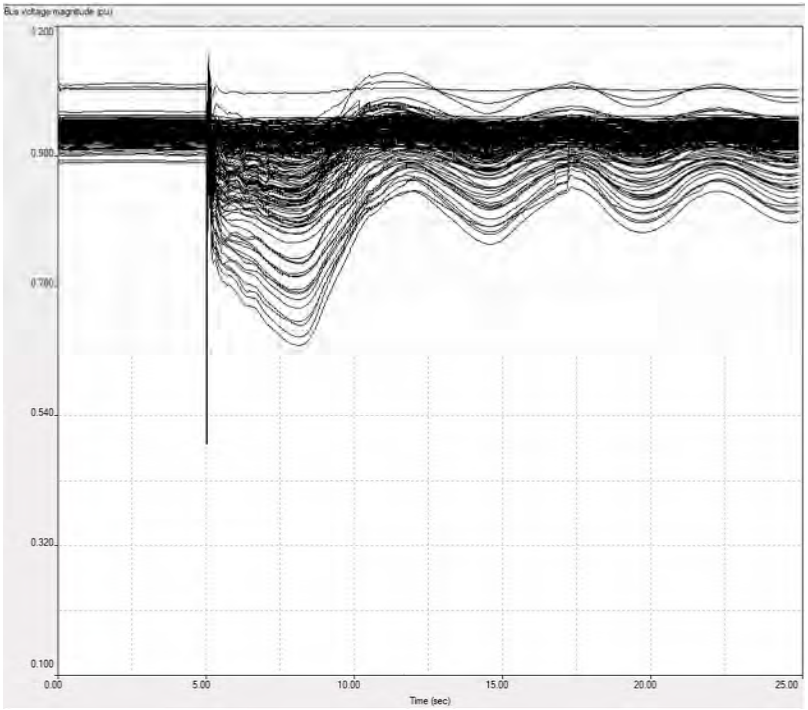

Figure 50: Bus voltages for the Twinkle to SubT prior outage Light Load High Wind **Final Project** case, contingency 1 (loss of North Rochester to Columbia 765kV)

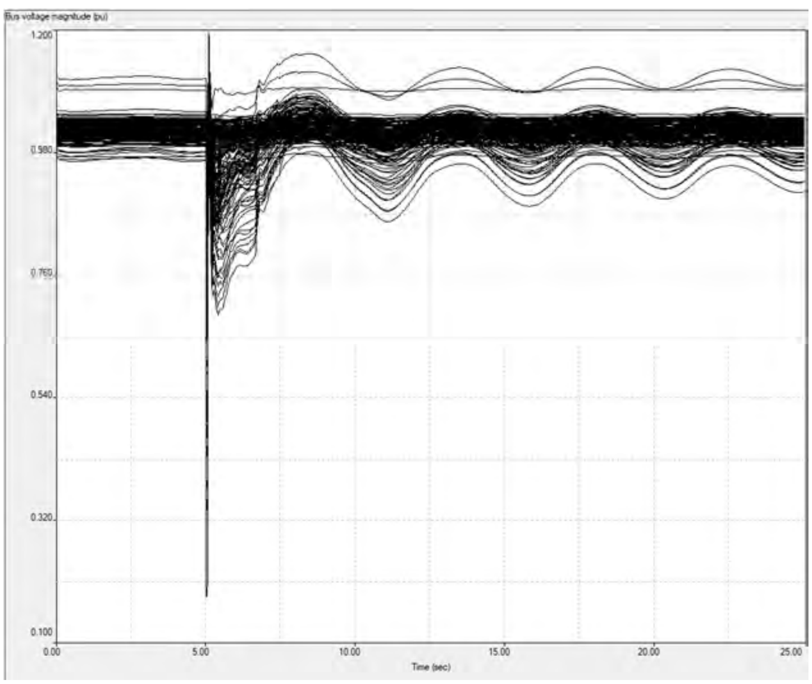

Figure 51: Bus voltages for the Twinkle to SubT prior outage Light Load High Wind **345kV Alternative** case, contingency 1 (loss of North Rochester to Columbia 345kV double circuit alternative)

CONCLUSION

Great River Energy (GRE), ITC Midwest, and Xcel Energy, herein referred to as the "Partners," are developing 765 kV lines throughout the upper Midwest, which MISO approved in the Long-Range Transmission Plan Tranche 2.1 (T2.1). The Partners have retained POWER Engineers, Inc. (POWER) to evaluate the impact of the planned 765 kV and 345 kV transmission projects as part of MISO's Long Range Transmission Planning (LRTP) Tranche 2.1 on the Minnesota Electric Grid from the bulk electric system (BES) reliability perspectives. The reliability assessment includes the impact on the regional transmission interfaces' available transfer capabilities, as well as the long-term voltage and short-term transient stability of the Minnesota electrical grid system.

As part of their LRTP Tranche 2.1 work, MISO approved 765 kV transmission corridors across Minnesota with the following electrical components – the combination of which is herein defined as the "Project":

- **Project 22:** Big Stone South - Brookings County - Lakefield Junction 765 kV
- **Project 23:** Lakefield Junction - East Adair 765 kV
- **Project 24:** Lakefield Junction - Pleasant Valley - North Rochester 765 kV
- **Project 25:** Pleasant Valley - North Rochester - Hampton Corner 345 kV
- **Project 26:** North Rochester – Columbia 765 kV

The analysis in this study focuses on the project's impact on the Minnesota electrical grid. Therefore, the following MISO's local regional zones (LRZ) were considered from the generation portfolio, transmission interface transfer capability, thermal congestion, and stability perspectives:

- **LRZ 1:** North Dakota, Minnesota, and a portion of South Dakota
- **LRZ 2:** Wisconsin and the upper peninsula of Michigan
- **LRZ 3**: Iowa

The study analyzed four different planning scenarios for the planning year 2042. These planning scenarios considered different system load conditions, generation portfolio mix and transmission interface levels:

1) The Light Load scenario represents off-peak system conditions, characterized by a high proportion of renewable energy serving the MISO load.
2) The Peak Summer Load scenario represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.
3) The Peak Winter Load scenario represents a scenario with the highest load and highly stressed conditions expected to occur during winter months.
4) The Average Load scenario 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 highest renewable penetration, meaning that renewables are serving most of MISO load and is the most severe case due to the required transfers of generation across long distances to serve load.

The study considered a comparative analysis of the above cases with and without the Project. In addition, a sensitivity scenario has been created for each of the planning scenarios above, with the generation portfolio shifted from wind resources to conventional synchronous generation-based resources. These sensitivity scenarios were analyzed with and without the Project.

To study the benefits of integrating the 765kV transmission, the study included a comparative analysis with the 345kV double circuit replacement/alternative of the 765kV components of the Project.
The analysis included in this report evaluated the impact of the 765kV components on:

a) The regional transfer capability limits of the different transmission interfaces with the State of Minnesota.
b) The operational considerations with planned system outages.

The voltage stability and dynamic stability analysis included in this report aim to evaluate the impact of the Project on the State of Minnesota's electric grid, highlighting the benefits and discussing the performance of the bulk electric system.

Voltage Stability Analysis

The voltage stability analysis concluded the following:

a) There are reported base case thermal overloads that aren't related to the Project (these base power flow scenarios overloads exist with and without the Project). These overloads are detailed in Table 4. The developed generation portfolio for the power flow scenarios was the main driver for these thermal overloads. It is expected that these overloads will be mitigated, in general, throughout the generation interconnection process.
b) The Project enables a significant increase in the transfer capability of the state of Minnesota's bulk transmission system, with a higher penetration of remote wind generation resources. In light load ("LL") high wind scenarios, the Project enabled the increment of 4 GW of wind generation in LRZ 1-3 to be transferred to load centers.
c) While the Project enables the transfer of an additional 1.2 GW and 0.8 GW of remote wind generation resources for the summer peak ("SUM") and winter peak ("WIN") in the high wind scenarios, respectively, it is concluded that the peak load conditions for both seasons have contributed to the analysis outcomes, considering the base cases had relatively depressed voltage conditions.
d) The average load ("AVG") scenarios showed a relatively significant gain with the Project (1.0 GW) of remote wind generation resources increment in the high wind scenario.
e) The voltage stability analysis highlighted sporadic needs for some discrete switched shunts to be strategically allocated in some substations. These discrete shunts aren't significant and don't pose any risks to the Project's implementation.
f) The Project outperformed the 345kV double circuit alternative with regards to LRZ 1-3 wind transfer to the Minnesota area in every base case contingency, with an average additional transfer of 425 MW across all scenarios.
g) In nearly every prior outage scenario, the Project also outperformed the 345kV alternative. The largest difference in transfer capability came during the North Rochester to Tremval 345kV prior outage, when the Project enabled an additional transfer of 656 MW on average across all scenarios. The Lakefield Junction to Pleasant Valley 765kV prior outage scenarios showed a significant decrease of 900 MW in transfer capability compared to the base 765kV Project case, showing that line's importance to the total suite.

Dynamic Stability Analysis

The dynamic stability analysis comparing the Project and non-Project cases concluded the following:

a) The Project enables higher renewable generation in LRZ1-3. Without the Project, the loss of some 765 kV and 345 kV lines in high-wind cases results in voltage stability issues.
b) The loss of the 765 kV line from Sub T in Iowa and Woodford County in Illinois triggered major voltage oscillations without the Project in the Average Load scenario with high wind generation conditions. Similarly, without the Project, the loss of the 765 kV transmission between Twinkle and Sub T in Iowa triggered significant angle instability conditions in the Light Load scenario with high wind generation conditions.
c) The loss of the 345kV line between Alexandria and Big Oaks in Minnesota (Tranche 1) or the loss of the 345kV line between Iron Range and St. Louis in Minnesota triggered voltage oscillations and generator angle instability conditions without the Project for the Average Load scenarios.
d) The fault and tripping of the Project lines (765kV and 345 kV) didn’t report any dynamic instability risks for all the studied scenarios. Moreover, the analysis concluded that the Project is needed to maintain bulk electric system stability when the rest of Tranche 2.1 is implemented, enabling higher renewable generation from LRZs 1-3.
e) The transient stability indices considered for this study concluded, in the vast majority of the studied events, that significantly improved system stability performance was achieved with the Project for all the studied planning scenarios.

To assess the benefits of the 765kV integration of the Project, the comparative analysis with the 345kV double circuit alternative concluded the following:

a) Replacement of the 765kV components of the Project with a double circuit 345kV resulted in significant reliability risks with the loss of either the Twinkle to Sub T or Sub T to Woodford County 765kV lines. The analysis results depicted voltage instability conditions with the 345kV alternative in the Light Load high wind scenario.
b) Fault and tripping of the King to Eau Claire 345kV line resulted in the tripping of all 500 kV lines between Forbes and Riel, which include the 500kV lines in the Manitoba Hydro interface. This has been reported with the 345 kV alternative in the Summer high wind scenario.
c) The loss of one of the 345 kV lines between Bison and Alexandria reported angle/voltage instability risks with the 345 kV alternative in the Winter high wind scenario.

The analysis results concluded the superiority of the 765kV components of the Project, enabling extended transfer levels and securing system reliability in comparison with the 345 kV Alternative.

The benefits of the 765 kV components of the Project have been assessed from the regional transfer levels perspectives, in comparison with the 345kV alternative. The analysis results concluded the following:

a) For the East-West case: The extended North Dakota Import levels up to 2,750 MW did not conclude any reliability risks when either the 765 kV Project lines or the 345 kV alternative are considered.
b) When Manitoba Hydro is exporting 3,100 MW and the North Dakota Export (NDEX) is 1,800 MW, there are reported significant instability risks with fault and tripping of the King to Eau Claire 345kV line for the 345 kV alternative. The Project with the 765kV components reported no major reliability risks at these regional transfer levels.

c) With the NDEX extended for the Winter High Wind case by relatively higher flow on the Big Stone South to Brookings County 765kV corridor, the 345 kV alternative reported a significantly lower average transient stability index and a greater number of contingencies with voltage violations compared to the 765kV Project case. The 345kV alternative reported significant instability risks associated with the loss of the Big Stone South to Brookings County 345 kV double circuit, Lakefield Junction to Pleasant Valley 345kV double circuit, and Big Stone South to Alexandria 345kV single line. This indicates that the 765kV system provides higher transfer capacity without jeopardizing BES performance compared to the 345kV alternative.

The analysis concluded that the benefit of extending the 765kV system is to increase the regional transfer capability limits with no risks to the State of Minnesota BES.

Last but not least, the assessment of the criticality of each of the 765kV components of the project and the operational considerations in comparison with the 345kV alternative have been analyzed in the prior outage analysis results as below:

a) When key 765kV lines from the LRTP Tranche 2.1 Portfolio are removed from the model (especially the North Rochester to Columbia 765kV line) there are elevated risks for system instability.
b) When the flow levels are significantly increased with prior outages on key 765kV and 345kV lines, the 765kV Project has a higher transient stability index compared to the 345kV double circuit alternative. The 765kV Project also has significantly lower instability risks and fewer voltage violations.
c) When the Brookings to Lakefield Junction double circuit alternative, Lyon County to Cedar Mountain double circuit, or Crandall/Huntley to Wilmarth double circuit are applied as prior outages and the North Rochester to Columbia contingency is applied, the 345kV alternative cases show significant voltage instability and the Monticello nuclear generator is tripped. The 765kV Project analysis results for the same events have shown no reliability risks to the State of Minnesota BES.

The analysis of the prior outages' conditions confirmed the criticality of the 765kV components of the Project, supporting improved operation resilience of the BES of the State of Minnesota with the additional significant benefit of extending the regional transfer capability levels.

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APPENDIX A: LIST OF TSAT CONTINGENCIES

TABLE 27: LIST OF TSAT 765KV CONTINGENCIES					
CONTINGENCY NUMBER	CONTINGENCY NAME	FAULTED BUS	REMOVED LINE FROM BUS	REMOVED LINE TO BUS	REMOVED LINE ID
1	8050_OTP_XEL_P12	860062	860062	860061	T2
2	8051_XEL_XEL_P13	860061	860061	601031	T2
3	8052_OTP_OTP_P13	860062	860062	620417	T2
4	8053_GRE_XEL_P12	860057	860057	860060	T2
5	8054_GRE_XEL_P13	860057	860057	615306	T2
6	8055_XEL_ALTW_P12	860061	860061	860058	T2
7	8056_ALTW_GRE_P12	860058	860058	860057	T2
8	8057_ALTW_ALTW_P13	860058	860058	631138	T2
9	8058_MGE_XEL_P12	860060	860048	860060	T2
10	8059_XEL_XEL_P13	860060	860060	601039	T3
11	8060_MGE_MGE_P13	860048	860048	699157	T2
12	8061_MGE_MGE_P12	860048	860048	860046	T2
13	8062_MGE_CE_P12	860046	860046	270607	T2
14	8063_MGE_WEC_P13	860046	860046	860038	T2
15	8064_MEC_ALTW_P12	860058	860000	860058	T2
16	8065_MEC_MEC_P13	860000	860000	860001	T2
17	8066_MEC_ALTW_P12	860000	860000	860013	T2
18	8067_MEC_ALTW_P12	860013	860019	860013	T2
19	8068_MEC_MEC_P13	860019	860019	636645	T2
20	8069_ALTW_ALTW_P13	860013	860013	631282	T2
21	8070_AMIL_MEC_P12	860019	860022	860019	T2
22	8071_AMIL_AMIL_P13	860022	860022	860023	T2
23	8072_CE_AMIL_P12	860022	270607	860022	T2
24	8073_AMIL_NIPS_P12	860022	860022	255204	T2
25	8074_NIPS_NIPS_P13	255204	255204	255205	T2
26	8075_IPL_AEP_P12	860016	860016	243210	T2
27	8076_IPL_AEP_P12	243209	860016	243209	T2
28	8077_IPL_IPL_P13	860016	860016	860017	T2
29	8078_AEP_ITCT_P12	246999	246999	860010	T2
30	8079_ITCT_ITCT_P13	860010	860010	264594	T2

31	8080_AEP_AEP_P12	243207	243207	246999	T2
32	8081_AEP_DEI_P12	243207	243207	860007	T2
33	8082_DEI_AEP_P12	860007	860007	243208	T2
34	8083_DEI_DEI_P13	860007	860007	249512	T2

TABLE 28: LIST OF TSAT 345KV CONTINGENCIES					
CONTINGENCY NUMBER	CONTINGENCY NAME	FAULTED BUS	REMOVED LINE FROM BUS	REMOVED LINE TO BUS	REMOVED LINE ID
1	8001_OTP_MDU_P12	661952	661952*		
2	8002_OTP_XEL_P12	620417	620417	658047	C1
3	8003_OTP_XEL_P12	604999	604999	658047	C2
4	8004_OTP_GRE_P12	658047	615664	658047	1
5	8005_OTP_P13	658047	658047	658050/658048**	9
6	8006_MP_P12	608452	608452	608454	1
7	8007_XEL_P12	601004	601004	601039	C1
8	8008_XEL_P12	601039	601039	690029	C1
9	8009_XEL_P12	690029	601028	690029	C1
10	8010_XEL_WPS_P12	601028	601028	690010	C1
11	8011_XEL_WPS_P12	694065	690029	694065	C1
12	8013_ATC_P12	694065	694065	699676	1
13	8014_ATC_P12	694065	694002***	694065	1
14	8015_ATC_P12	694065	694082***	694065	1
15	8016_ATC_P13	694065	694061	694065	1
			694061	699786	1
16	8017_ALTW_MEC_P12	636630	631221	636630	1
17	8018_MEC_P12	635570	635570	690002	1
18	8019_MEC_AECI_P12	300039	300039	690002	1
19	8025_ALTW_MEC_P12	631143	631143	635635	1
20	8028_ALTW_P13	690019	631108	690019	1
21	8155_XEL_XEL_P12	601039	601039	601051	T2
22	8156_XEL_XEL_P12	601039	601039	613060	T2
23	8157_XEL_XEL_P12	601039	601039	615306	T2
24	8158_XEL_OTP_P12	601067	601067	658047	T2
25	8159_XEL_XEL_P12	613060	613060	615306	T2
26	8160_ALTW_MEC_P12	631282	631282	635730	T2
27	8161_ALTW_MEC_P12	631282	631282	690004	T2
28	8162_MEC_MEC_P12	635568	635568	860001	T2
29	8163_MEC_MEC_P12	635570	635570	860001	T2

30	8164_MEC_MEC_P12	635580	635580	860001	T2
31	8165_MEC_MEC_P12	635630	635630	860001	T2
32	8166_MEC_MEC_P12	635635	635635	860001	T2
33	8223_MP_MP_P12	608450	608450	608470	1
34	8224_MP_WPS_P12	608470	608470	699449	1
35	8225_ALTW_MEC_P12	631282	631282	636010	1
36	8226_MP_OTP_P12	608455	608455	620361	1
37	0890_W_XEL_P12_Update	601014	601014	601028	1

*Bus outage
**Three-winding transformer
***Two other zero impedance lines also removed at this bus

TABLE 29: LIST OF TSAT 345KV ALTERNATIVE CONTINGENCIES

CONTINGENCY NUMBER	CONTINGENCY NAME	FAULTED BUS	REMOVED LINE FROM BUS	REMOVED LINE TO BUS	REMOVED LINE ID
1	9000	620417	620417	601031	A1
2	9001	620417	620417	601031	A1 and A2
3	9002	631138	631138	860001	A1
4	9003	631138	631138	860001	A1 and A2
5	9004	615306	615306	601039	A1
6	9005	615306	615306	601039	A1 and A2
7	9006	601039	601039	699157	A1
8	9007	601039	601039	699157	A1 and A2
9	9008	631138	631138	615306	A1
10	9009	631138	631138	615306	A1 and A2
11	9010	631138	631138	601031	A1
12	9011	631138	631138	601031	A1 and A2

TABLE 30: LIST OF TSAT CONTINGENCIES FOR PRIOR OUTAGE ANALYSIS 765KV CASES					
CONTINGENCY NUMBER	CONTINGENCY NAME	FAULTED BUS	REMOVED LINE FROM BUS	REMOVED LINE TO BUS	REMOVED LINE ID
1	8058_MGE_XEL_P12	860060	860048	860060	T2
2	8055_XEL_ALTW_P12	860061	860061	860058	T2
3	8066_MEC_ALTW_P12	860000	860000	860013	T2
4	8067_MEC_ALTW_P12	860013	860019	860013	T2
5	9101	601048	601048	615643	1
			601048	615648	2
6	9102	601004	631193	601004	1
			601074	601004	1
7	8056_ALTW_GRE_P12	860058	860058	860057	T2
8	8008_XEL_P12	601039	601039	690029	C1
9	2259_W_XEL_P12	601002	601002	631144	1
10	9100	601050	601050	601055	1
11	8070_AMIL_MEC_P12	860019	860022	860019	T2
12	0890_W_XEL_P12_MPEdits	601014	601014	601028	1

TABLE 31: LIST OF TSAT CONTINGENCIES FOR PRIOR OUTAGE ANALYSIS 345KV ALTERNATIVE CASES

CONTINGENCY NUMBER	CONTINGENCY NAME	FAULTED BUS	REMOVED LINE FROM BUS	REMOVED LINE TO BUS	REMOVED LINE ID
1	9007	601039	601039	699157	A1 and A2
2	9011	631138	631138	601031	A1 and A2
3	8066_MEC_ALTW_P12	860000	860000	860013	T2
4	8067_MEC_ALTW_P12	860013	860019	860013	T2
5	9101	601048	601048	615643	1
			601048	615648	2
6	9102	601004	631193	601004	1
			601074	601004	1
7	9009	631138	631138	615306	A1 and A2
8	8008_XEL_P12	601039	601039	690029	C1
9	2259_W_XEL_P12	601002	601002	631144	1
10	9100	601050	601050	601055	1
11	8070_AMIL_MEC_P12	860019	860022	860019	T2
12	0890_W_XEL_P12_MPEdits	601014	601014	601028	1

APPENDIX B: PRIOR OUTAGE VOLTAGE STABILITY ANALYSIS DETAILED RESULTS

TABLE 32: NORTH ROCHESTER TO COLUMBIA - PRIOR OUTAGE 1 VOLTAGE STABILITY ANALYSIS RESULTS

Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	35071	8451
AVG_HIGH_765	26620	35221	8601
AVG_LOW_345ALT	23426	32426	9000
AVG_LOW_765	23426	32776	9350
LL_HIGH_345ALT	29366	35216	5850
LL_HIGH_765	29366	35366	6000
LL_LOW_345ALT	26429	32680	6251
LL_LOW_765	26429	33430	7001
SUM_HIGH_345ALT	18837	23938	5101
SUM_HIGH_765	18837	24288	5451
SUM_LOW_345ALT	15823	21274	5451
SUM_LOW_765	15823	21424	5601
WIN_HIGH_345ALT	31955	35306	3351
WIN_HIGH_765	31955	35556	3601
WIN_LOW_345ALT	28760	32510	3750
WIN_LOW_765	28760	32710	3950
345ALT Average			5901
765 Average			6194
765 Greater Transfer Compared to 345ALT			294

TABLE 33: BROOKINGS TO LAKEFIELD JUNCTION - PRIOR OUTAGE 2 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34471	7851
AVG_High_765	26620	34871	8251
AVG_LOW_345ALT	23426	32276	8850
AVG_LOW_765	23426	32426	9000
LL_HIGH_345ALT	29366	34966	5600
LL_High_765	29366	34716	5350
LL_LOW_345ALT	26429	32680	6251
LL_LOW_765	26429	32930	6501
SUM_HIGH_345ALT	18837	23838	5001
SUM_High_765	18837	23838	5001
SUM_LOW_345ALT	15823	21274	5451
SUM_LOW_765	15823	21174	5351
WIN_HIGH_345ALT	31955	35306	3351
WIN_High_765	31955	35656	3701
WIN_LOW_345ALT	28760	32610	3850
WIN_LOW_765	28760	32760	4000
345ALT Average			5776
765 Average			5894
765 Greater Transfer Compared to 345ALT			119

TABLE 34: EAST ADAIR TO TWINKLE - PRIOR OUTAGE 3 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34871	8251
AVG_High_765	26620	35071	8451
AVG_LOW_345ALT	23426	32426	9000
AVG_LOW_765	23426	32676	9250
LL_HIGH_345ALT	29366	35216	5850
LL_High_765	29366	35216	5850
LL_LOW_345ALT	26429	32680	6251
LL_LOW_765	26429	33430	7001
SUM_HIGH_345ALT	18837	24088	5251
SUM_High_765	18837	24338	5501
SUM_LOW_345ALT	15823	21324	5501
SUM_LOW_765	15823	21574	5751
WIN_HIGH_345ALT	31955	35406	3451
WIN_High_765	31955	35806	3851
WIN_LOW_345ALT	28760	32610	3850
WIN_LOW_765	28760	32860	4100
345ALT Average			5926
765 Average			6219
765 Greater Transfer Compared to 345ALT			294

TABLE 35: TWINKLE TO SUBT - PRIOR OUTAGE 4 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34621	8001
AVG_High_765	26620	34871	8251
AVG_LOW_345ALT	23426	32276	8850
AVG_LOW_765	23426	32626	9200
LL_HIGH_345ALT	29366	34866	5500
LL_High_765	29366	35116	5750
LL_LOW_345ALT	26429	32630	6201
LL_LOW_765	26429	33280	6851
SUM_HIGH_345ALT	18837	24088	5251
SUM_High_765	18837	24338	5501
SUM_LOW_345ALT	15823	21324	5501
SUM_LOW_765	15823	21574	5751
WIN_HIGH_345ALT	31955	35206	3251
WIN_High_765	31955	35706	3751
WIN_LOW_345ALT	28760	32510	3750
WIN_LOW_765	28760	32860	4100
345ALT Average			5788
765 Average			6144
765 Greater Transfer Compared to 345ALT			356

TABLE 36: LYON COUNTY TO CEDAR MOUNTAIN - PRIOR OUTAGE 5 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34471	7851
AVG_High_765	26620	35121	8501
AVG_LOW_345ALT	23426	32276	8850
AVG_LOW_765	23426	32676	9250
LL_HIGH_345ALT	29366	34566	5200
LL_High_765	29366	35116	5750
LL_LOW_345ALT	26429	32530	6101
LL_LOW_765	26429	32780	6351
SUM_HIGH_345ALT	18837	24038	5201
SUM_High_765	18837	24338	5501
SUM_LOW_345ALT	15823	21324	5501
SUM_LOW_765	15823	21574	5751
WIN_HIGH_345ALT	31955	34706	2751
WIN_High_765	31955	35556	3601
WIN_LOW_345ALT	28760	32460	3700
WIN_LOW_765	28760	32860	4100
345ALT Average			5644
765 Average			6101
765 Greater Transfer Compared to 345ALT			456

TABLE 37: CRANDALL-WILMARTH/HUNTLEY-WILMARTH - PRIOR OUTAGE 6 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34321	7701
AVG_High_765	26620	34471	7851
AVG_LOW_345ALT	23426	32126	8700
AVG_LOW_765	23426	32176	8750
LL_HIGH_345ALT	29366	32616	3250
LL_High_765	29366	34816	5450
LL_LOW_345ALT	26429	32430	6001
LL_LOW_765	26429	33030	6601
SUM_HIGH_345ALT	18837	23688	4851
SUM_High_765	18837	23788	4951
SUM_LOW_345ALT	15823	21074	5251
SUM_LOW_765	15823	21174	5351
WIN_HIGH_345ALT	31955	34956	3001
WIN_High_765	31955	35206	3251
WIN_LOW_345ALT	28760	32360	3600
WIN_LOW_765	28760	32610	3850
345ALT Average			5294
765 Average			5757
765 Greater Transfer Compared to 345ALT			463

TABLE 38: LAKEFIELD JUNCTION TO PLEASANT VALLEY - PRIOR OUTAGE 7 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34321	7701
AVG_High_765	26620	34621	8001
AVG_LOW_345ALT	23426	32026	8600
AVG_LOW_765	23426	32026	8600
LL_HIGH_345ALT	29366	33366	4000
LL_High_765	29366	33116	3750
LL_LOW_345ALT	26429	32280	5851
LL_LOW_765	26429	32380	5951
SUM_HIGH_345ALT	18837	23838	5001
SUM_High_765	18837	23838	5001
SUM_LOW_345ALT	15823	21174	5351
SUM_LOW_765	15823	21174	5351
WIN_HIGH_345ALT	31955	35056	3101
WIN_High_765	31955	35206	3251
WIN_LOW_345ALT	28760	32360	3600
WIN_LOW_765	28760	32460	3700
345ALT Average			5401
765 Average			5451
765 Greater Transfer Compared to 345ALT			50

TABLE 39: NORTH ROCHESTER TO TREMVAL - PRIOR OUTAGE 8 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34571	7951
AVG_High_765	26620	35471	8851
AVG_LOW_345ALT	23426	32426	9000
AVG_LOW_765	23426	32926	9500
LL_HIGH_345ALT	29366	33616	4250
LL_High_765	29366	35466	6100
LL_LOW_345ALT	26429	32780	6351
LL_LOW_765	26429	33530	7101
SUM_HIGH_345ALT	18837	24088	5251
SUM_High_765	18837	24338	5501
SUM_LOW_345ALT	15823	21324	5501
SUM_LOW_765	15823	21574	5751
WIN_HIGH_345ALT	31955	35306	3351
WIN_High_765	31955	35706	3751
WIN_LOW_345ALT	28760	32510	3750
WIN_LOW_765	28760	32860	4100
345ALT Average			5676
765 Average			6332
765 Greater Transfer Compared to 345ALT			656

TABLE 40: ADAMS TO MITCHELL CO - PRIOR OUTAGE 9 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34971	8351
AVG_High_765	26620	35371	8751
AVG_LOW_345ALT	23426	32526	9100
AVG_LOW_765	23426	32776	9350
LL_HIGH_345ALT	29366	35366	6000
LL_High_765	29366	35566	6200
LL_LOW_345ALT	26429	32880	6451
LL_LOW_765	26429	33530	7101
SUM_HIGH_345ALT	18837	24088	5251
SUM_High_765	18837	24438	5601
SUM_LOW_345ALT	15823	21324	5501
SUM_LOW_765	15823	21574	5751
WIN_HIGH_345ALT	31955	35456	3501
WIN_High_765	31955	35956	4001
WIN_LOW_345ALT	28760	32610	3850
WIN_LOW_765	28760	33010	4250
345ALT Average			6001
765 Average			6376
765 Greater Transfer Compared to 345ALT			375

TABLE 41: HELENA TO SCOTT CITY - PRIOR OUTAGE 10 VOLTAGE STABILITY ANALYSIS RESULTS			
Case	Base LRZ 1-3 Wind [MW]	Limit [MW]	Extra LRZ 1-3 Wind Transfer to Minn [Mw]
AVG_HIGH_345ALT	26620	34721	8101
AVG_High_765	26620	35121	8501
AVG_LOW_345ALT	23426	32026	8600
AVG_LOW_765	23426	32526	9100
LL_HIGH_345ALT	29366	34966	5600
LL_High_765	29366	35216	5850
LL_LOW_345ALT	26429	32380	5951
LL_LOW_765	26429	33030	6601
SUM_HIGH_345ALT	18837	23588	4751
SUM_High_765	18837	23838	5001
SUM_LOW_345ALT	15823	20824	5001
SUM_LOW_765	15823	21074	5251
WIN_HIGH_345ALT	31955	34906	2951
WIN_High_765	31955	35306	3351
WIN_LOW_345ALT	28760	32110	3350
WIN_LOW_765	28760	32360	3600
345ALT Average			5538
765 Average			5907
765 Greater Transfer Compared to 345ALT			369

APPENDIX C: PRIOR OUTAGE DYNAMIC STABILITY ANALYSIS DETAILED RESULTS

TABLE 42: NORTH ROCHESTER TO COLUMBIA - PRIOR OUTAGE 1 DYNAMIC STABILITY ANALYSIS RESULTS

CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	70.05	3	Con 4 (Twinkle to SubT 765) has some oscillations, not as severe as the 345kV alt case. Con 11 (SubT to Woodford County 765) has major voltage oscillations
Avg	High	345 kV Alternative	75.70	5	Con 4 (Twinkle to SubT 765) and con 11 (SubT to Woodford County 765) have major voltage oscillations
Avg	Low	In	88.16	1	Con 5 (Lyon County to Cedar Mountain Double Circuit 345kV) has Buffalo Ridge issues
Avg	Low	345 kV Alternative	76.08	1	
LL	High	In	69.26	4	Con 4 (Twinkle to SubT 765) and con 11 (SubT to Woodford County 765) have major voltage oscillations
LL	High	345 kV Alternative	60.82	5	Con 4 (Twinkle to SubT 765) and con 11 (SubT to Woodford County 765) have major voltage oscillations
LL	Low	In	90.72	1	
LL	Low	345 kV Alternative	78.15	3	Two cons have issues with Buffalo Ridge
SUM	High	In	73.71	0	
SUM	High	345 kV Alternative	75.04	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	85.07	0	
SUM	Low	345 kV Alternative	75.03	0	
Winter	High	In	63.82	1	
Winter	High	345 kV Alternative	61.81	1	
Winter	Low	In	86.23	1	One con has issue with Buffalo Ridge
Winter	Low	345 kV Alternative	72.05	0	

TABLE 43: BROOKINGS TO LAKEFIELD JCT - PRIOR OUTAGE 2 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	76.19	2	
Avg	High	345 kV Alternative	54.41	5	Con 1 (North Rochester to Columbia double circuit 345) has major voltage issues. Leads to tripping of the Monticello nuclear plant (637 MW).
Avg	Low	In	80.19	1	
Avg	Low	345 kV Alternative	79.82	1	
LL	High	In	79.62	1	
LL	High	345 kV Alternative	67.65	4	Con 11 (SubT to Woodford County 765) has some voltage oscillations
LL	Low	In	80.07	1	
LL	Low	345 kV Alternative	73.35	1	
SUM	High	In	68.58	0	
SUM	High	345 kV Alternative	73.28	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	76.19	0	
SUM	Low	345 kV Alternative	79.22	0	
Winter	High	In	62.93	2	
Winter	High	345 kV Alternative	65.49	4	
Winter	Low	In	75.81	0	
Winter	Low	345 kV Alternative	69.04	0	

TABLE 44: EAST ADAIR TO TWINKLE - PRIOR OUTAGE 3 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	71.58	2	Con 1 (North Rochester to Columbia 765) has major voltage issues.
Avg	High	345 kV Alternative	55.00	4	Con 1 (North Rochester to Columbia double circuit 345) has major voltage issues.
Avg	Low	In	81.38	1	One con has issue with Buffalo Ridge
Avg	Low	345 kV Alternative	78.61	0	
LL	High	In	75.64	1	Con 1 (North Rochester to Columbia 765) has major voltage issues.
LL	High	345 kV Alternative	59.28	5	
LL	Low	In	90.33	1	
LL	Low	345 kV Alternative	70.95	3	Two cons have issues with Buffalo Ridge
SUM	High	In	61.58	0	
SUM	High	345 kV Alternative	63.60	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	70.79	0	
SUM	Low	345 kV Alternative	71.03	0	
Winter	High	In	51.66	0	
Winter	High	345 kV Alternative	62.69	1	
Winter	Low	In	73.34	0	
Winter	Low	345 kV Alternative	65.80	1	

TABLE 45: TWINKLE TO SUB T - PRIOR OUTAGE 4 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	63.65	1	Con 1 (North Rochester to Columbia 765) has major low voltage issues (probably worse than the 345kV case)
Avg	High	345 kV Alternative	68.55	4	Con 1 (North Rochester to Columbia double circuit 345) has major low voltage issues. Oscillations seen for Con 11 (SubT to Woodford County 765)
Avg	Low	In	85.57	0	
Avg	Low	345 kV Alternative	82.85	0	
LL	High	In	72.49	2	Con 1 (North Rochester to Columbia 765) has major voltage oscillations
LL	High	345 kV Alternative	68.09	5	Con 1 (North Rochester to Columbia double circuit 345) has some small voltage oscillations. Oscillations also seen for Con 11 (SubT to Woodford County 765)
LL	Low	In	87.20	1	
LL	Low	345 kV Alternative	77.16	4	3 cons with Buffalo Ridge issues
SUM	High	In	67.77	0	
SUM	High	345 kV Alternative	60.81	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	64.24	0	
SUM	Low	345 kV Alternative	73.45	0	
Winter	High	In	57.52	0	
Winter	High	345 kV Alternative	56.68	3	
Winter	Low	In	78.76	0	
Winter	Low	345 kV Alternative	57.31	0	

TABLE 46: LYON COUNTY TO CEDAR MOUNTAIN - PRIOR OUTAGE 5 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	74.51	0	
Avg	High	345 kV Alternative	57.01	4	Con 1 (North Rochester to Columbia double circuit 345) has major voltage issues. Leads to tripping of the Monticello nuclear plant (637 MW).
Avg	Low	In	80.88	2	One con with Buffalo Ridge issues. Other con with East Adair high voltage
Avg	Low	345 kV Alternative	70.72	1	
LL	High	In	67.23	1	
LL	High	345 kV Alternative	64.76	3	
LL	Low	In	78.08	1	
LL	Low	345 kV Alternative	75.86	3	Two cons with Buffalo Ridge issues.
SUM	High	In	65.43	0	
SUM	High	345 kV Alternative	68.49	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	82.00	0	
SUM	Low	345 kV Alternative	74.05	0	
Winter	High	In	64.42	2	One con with Buffalo Ridge issues
Winter	High	345 kV Alternative	59.14	4	
Winter	Low	In	80.02	2	One con with Buffalo Ridge issues
Winter	Low	345 kV Alternative	71.36	1	

TABLE 47: CRANDALL-WILMARTH/HUNTLEY-WILMARTH - PRIOR OUTAGE 6 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	58.94	0	
Avg	High	345 kV Alternative	49.46	5	Con 1 (North Rochester to Columbia double circuit 345) has major voltage issues. Leads to tripping of the Monticello nuclear plant (637 MW).
Avg	Low	In	75.04	1	High voltage at East Adair
Avg	Low	345 kV Alternative	74.55	2	High voltage at East Adair, and Con 7 has issues with Buffalo Ridge
LL	High	In	68.02	1	
LL	High	345 kV Alternative	63.63	4	
LL	Low	In	86.79	1	
LL	Low	345 kV Alternative	66.22	2	
SUM	High	In	66.97	0	
SUM	High	345 kV Alternative	67.11	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	78.73	0	
SUM	Low	345 kV Alternative	79.92	0	
Winter	High	In	57.45	1	
Winter	High	345 kV Alternative	63.94	4	
Winter	Low	In	72.79	0	
Winter	Low	345 kV Alternative	76.02	0	

TABLE 48: LAKEFIELD JCT TO PLEASANT VALLEY - PRIOR OUTAGE 7 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	84.77	1	One con with Buffalo Ridge issues
Avg	High	345 kV Alternative	68.77	3	
Avg	Low	In	82.59	1	One con with Buffalo Ridge issues
Avg	Low	345 kV Alternative	77.33	1	
LL	High	In	67.66	0	
LL	High	345 kV Alternative	67.75	3	
LL	Low	In	78.30	1	
LL	Low	345 kV Alternative	73.40	2	Two cons with Buffalo Ridge issues
SUM	High	In	70.17	0	
SUM	High	345 kV Alternative	73.69	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	84.94	0	
SUM	Low	345 kV Alternative	76.25	0	
Winter	High	In	69.50	1	
Winter	High	345 kV Alternative	66.90	3	
Winter	Low	In	79.24	1	One con with Buffalo Ridge issues
Winter	Low	345 kV Alternative	66.36	0	

TABLE 49: NORTH ROCHESTER TO TREMVAL - PRIOR OUTAGE 8 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	77.26	2	Con 1 (North Rochester to Columbia 765) has some voltage issues that linger, but improves over time
Avg	High	345 kV Alternative	69.07	4	Con 1 (North Rochester to Columbia double circuit 345) and con 11 (SubT to Woodford County 765) have major voltage issues. One con with Buffalo Ridge issues
Avg	Low	In	86.61	2	One con with high voltage at East Adair. Another con with Buffalo ridge issues
Avg	Low	345 kV Alternative	84.36	1	
LL	High	In	81.60	1	Con 1 (North Rochester to Columbia 765) has low voltage issues
LL	High	345 kV Alternative	64.04	4	Con 11 (SubT to Woodford County 765) has voltage oscillations.
LL	Low	In	94.89	1	
LL	Low	345 kV Alternative	77.60	3	Two cons with Buffalo Ridge issues
SUM	High	In	75.96	0	
SUM	High	345 kV Alternative	70.50	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	72.48	0	
SUM	Low	345 kV Alternative	75.91	0	
Winter	High	In	67.40	0	
Winter	High	345 kV Alternative	68.35	1	
Winter	Low	In	82.75	1	One con with Buffalo Ridge issues
Winter	Low	345 kV Alternative	77.85	1	One con with Buffalo Ridge issues

TABLE 50: ADAMS TO MITCHELL CO - PRIOR OUTAGE 9 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	64.58	3	One con has issues with Buffalo Ridge
Avg	High	345 kV Alternative	63.08	4	Con 1 (North Rochester to Columbia double circuit 345) has major voltage issues
Avg	Low	In	73.28	2	One con with high voltage at East Adair. Another con with Buffalo ridge issues
Avg	Low	345 kV Alternative	73.90	1	
LL	High	In	74.45	1	
LL	High	345 kV Alternative	55.13	5	
LL	Low	In	84.26	1	One con with Buffalo Ridge issues
LL	Low	345 kV Alternative	68.93	3	Three cons with Buffalo Ridge issues
SUM	High	In	68.11	0	
SUM	High	345 kV Alternative	76.06	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	73.81	0	
SUM	Low	345 kV Alternative	75.42	0	
Winter	High	In	64.13	0	
Winter	High	345 kV Alternative	70.21	2	One con with Buffalo Ridge issues
Winter	Low	In	79.95	0	
Winter	Low	345 kV Alternative	67.71	0	

TABLE 51: HELENA TO SCOTT CTY - PRIOR OUTAGE 10 DYNAMIC STABILITY ANALYSIS RESULTS					
CASE	WIND DISPATCH	PROJECT STATUS	AVERAGE TRANSIENT STABILITY INDEX	CONS WITH VOLTAGE VIOLATIONS	NOTABLE CONDITIONS
Avg	High	In	60.29	1	
Avg	High	345 kV Alternative	64.35	5	One con has issues with Buffalo Ridge
Avg	Low	In	75.46	1	
Avg	Low	345 kV Alternative	81.18	1	
LL	High	In	68.91	1	
LL	High	345 kV Alternative	63.23	5	
LL	Low	In	86.88	2	One con has issues with Buffalo Ridge
LL	Low	345 kV Alternative	75.72	2	One con has issues with Buffalo Ridge
SUM	High	In	66.98	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	High	345 kV Alternative	69.12	0	Con 12 (King to Eau Claire) led to tripping of several 500kV buses, but no voltage violations
SUM	Low	In	78.62	0	
SUM	Low	345 kV Alternative	80.47	0	
Winter	High	In	58.62	1	One con has issues with Buffalo Ridge
Winter	High	345 kV Alternative	65.25	2	
Winter	Low	In	84.46	1	One con has issues with Buffalo Ridge
Winter	Low	345 kV Alternative	75.22	0	

APPENDIX D: PSAT CASES

See: 25-0151-11400_Appendix_D_LRTP_T2-1_765kV_PSAT_Cases.zip

APPENDIX E: VSAT CASES

See: 25-0151-11400_Appendix_E_LRTP_T2-1_765kV_VSAT_Cases.zip

APPENDIX F: TSAT CASES

See: 25-0151-11400_Appendix_F_LRTP_T2-1_765kV_TSAT_Cases.zip

Appendix E.4

MTEP24 Studied Projects Detailed Reliability Results

PUBLIC

PUBLIC DOCUMENT--NONPUBLIC INFORMATION HAS BEEN EXCISED

MISO LRTP Tranche 2.1 Detailed Reliability Results

Summary	Group B LRTP #22, 23 (count)	Group C LRTP #24, 25, 26 (count)	*Studied Projects (Group B + Group C)*
Total Violations Resolved	390	923	*1313*
Total Violations Resolved >200kV	159	190	349
Unique Facilities Resolved (violations resolved for each contingency in all models)	26	76	*102*
Unique Facilities >200kV	11	16	27

[PROTECTED DATA BEGINS

Group	Limiting Element	Element ID	Cont ID	Cont Name	kV	Area	LRZ	Avg 2032 Core	Avg 2032 Portfolio	LL 2032 Core	LL 2032 Portfolio	Summer 2032 Core	Summer 2032 Portfolio	Winter 2032 Core	Winter 2032 Portfolio	Avg 2042 Core	Avg 2042 Portfolio	LL 2042 Core	LL 2042 Portfolio	Summer 2042 Core	Summer 2042 Portfolio	Winter 2042 Core	Winter 2042 Portfolio	East to West Core	East to West Portfolio	Lowers to Uppers Core	Lowers to Uppers Portfolio	Twilight Core	Twilight Portfolio	Winter Low Renewable Core	Winter Low Renewable Portfolio	Constraints Resolved	Starting Constraints	Total Constraints Resolved for one element	Total Starting Constraints	Percent Resolved	Constraints Created	Total Constraints Created	3% Increase (Already Overloaded)	Total 3% Increases (Already Overloaded)	Max Loading for Row	Max Loading For Element	MaxPostLdg	Const Remaining	Resolved	kVclass
B	603267 KERKHOVENTP7 115 616005 GRE-KERKHO7 115 1	1004	28288	P55:230[redacted]	115	600/620	1/1	96.39	66.69	60.19	39.98	107.27	75.76	89.97	63.08	105.83	67.06	89.22	56.22	102.45	70.61	116.36	75.64	29.35	22.54	105.85	67.91	57.8	38.29	18.89	11.98	5	5	5	5	1	0	0	0	0	116.36	116.36	75.76	0	Yes	115
B	603267 KERKHOVENTP7 115 616005 GRE-KERKHO7 115 1	1004	44870	P24:230[redacted]	115	600/620	1/1	79.26	54.61	48.46	31.66	90.45	65.44	71.39	49.57	89.5	56.06	74.51	46.61	86.73	60.49	93.43	60.74									0	0	5	5	1	0	0	0	0	93.43	116.36	65.44	0	Yes	115
B	602008 MINVALT4 230 652550 GRANITF4 230 1	1010	14386	P21:230[redacted]	230	600/652	1/External	101.56	70.94	62.47	45.4	112.44	79.56	88.38	62.45	113.86	79.58	100.56	71.44	95.46	63.13	115.99	75.07	29.14	20.24	115.06	80.88	37.09	19.46	11.82	16	6	6	18	18	1	0	0	0	0	115.99	115.99	80.88	0	Yes	230
B	602008 MINVALT4 230 652550 GRANITF4 230 1	1010	24638	P23:345[redacted]	230	600/652	1/External									80.87	56.25	75.68	54.51	66.55	43.35	91.47	60.52									0	0	18	18	1	0	0	0	0	91.47	115.99	60.52	0	Yes	230
B	602008 MINVALT4 230 652550 GRANITF4 230 1	1010	32235	P12:230[redacted]	230	600/652	1/External	101.56	70.94	62.47	45.4	112.44	79.56	88.38	62.45	113.86	79.58	100.56	71.44	95.46	63.13	115.99	75.07	29.14	20.24	115.06	80.88	37.09	19.46	11.82	16	6	6	18	18	1	0	0	0	0	115.99	115.99	80.88	0	Yes	230
B	602008 MINVALT4 230 652550 GRANITF4 230 1	1010	39088	P21:230[redacted]	230	600/652	1/External	101.56	70.94	62.47	45.4	112.44	79.56	88.38	62.45	113.86	79.58	100.56	71.44	95.46	63.13	115.99	75.07	29.14	20.24	115.06	80.88	37.09	19.46	11.82	16	6	6	18	18	1	0	0	0	0	115.99	115.99	80.88	0	Yes	230
B	620269 JAMSTWN7 115 620270 SPIRITWD7 115 1	1089	0	Base Case	115	620	1	15.92	15.98	25.12	25.7	94.31	93.64	68.01	68.18																	0	0	0	30	0	0	0	0	0	94.31	183.57	93.64	30	No	115
B	620269 JAMSTWN7 115 620270 SPIRITWD7 115 1	1089	18767	P23:115[redacted]	115	620	1	41.44	41.33	50.44	50.89	183.57	182.19	131.86	131.82	64.54	64.53	147.38	147.64	115.82	115.7	65.39	65.65	20.68	21.68	64.54	64.5	151.28	151.29	112.05	112.05	0	6	0	30	0	0	0	0	0	183.57	183.57	182.19	30	No	115
B	620269 JAMSTWN7 115 620270 SPIRITWD7 115 1	1089	2642	P12:115[redacted]	115	620	1	39.17	39.04	48.97	49.42	180.64	178.92	129.4	129.37	62.7	62.7	146.15	146.41	112.49	112.34	63.15	63.4	18.96	20.16	62.7	62.69	147.93	147.93	109.82	109.82	0	6	0	30	0	0	0	0	0	180.64	183.57	178.92	30	No	115
B	620269 JAMSTWN7 115 620270 SPIRITWD7 115 1	1089	2650	P12:115[redacted]	115	620	1	33.62	33.43	43.38	43.93	175.11	173.46	124.6	124.58	56.91	56.91	140.49	140.74	106.81	106.6	58.31	58.55	13.76	18.08	56.91	56.9	142.74	142.6	105.36	105.36	0	6	0	30	0	0	0	0	0	175.11	183.57	173.46	30	No	115
B	620269 JAMSTWN7 115 620270 SPIRITWD7 115 1	1089	2721	P12:115[redacted]	115	620	1	39.27	39.12	48.59	49.03	180.37	179.01	129.32	129.28	62.56	62.5	146.03	146.27	112.29	112.21	63.15	63.33	18.38	20.19	62.56	62.45	147.93	147.93	109.83	109.84	0	6	0	30	0	0	0	0	0	180.37	183.57	179.01	30	No	115
B	620269 JAMSTWN7 115 620270 SPIRITWD7 115 1	1089	27795	P55:115[redacted]	115	620	1	39.14	39.02	49.08	49.54	180.37	178.96	129.43	129.35	62.69	62.69	146.1	146.38	112.48	112.35	63.15	63.43	19	20.16	62.69	62.69	147.93	147.93	109.82	109.83	0	6	0	30	0	0	0	0	0	180.37	183.57	178.96	30	No	115
B	608479 NELSNLK3 345 3WXFMR NELSNLK4 _1 230 1	1172	0	Base Case	345/230	608	1																	10	100.31	10.14	101.76	9.96	100.03	2.1	20.86	0	0	0	0	No Constraints	3	3	0	0	101.76	101.76	101.76	0	No	230
B	620269 JAMSTWN7 115 620275 NJAMES7 115 1	1185	18732	P23:115[redacted]	115	620	1	14.98	15.22	32.5	33.45	135.35	134.95	92.69	92.96	40.58	40.44	122.22	123.08	74.39	74.43	36.92	37.92	8.51	13.05	40.46	40.36	106.28	106.33	74.69	74.8	0	3	0	15	0	0	0	0	0	135.35	137.73	134.95	15	No	115
B	620269 JAMSTWN7 115 620275 NJAMES7 115 1	1185	18734	P23:115[redacted]	115	620	1	14.36	14.84	33.19	33.81	133.99	134.14	93	93.14	41.34	41.77	120.92	121.69	74.97	75.13	36.73	37.95	8.09	11.93	41.34	41.7	105.22	105.3	74.16	74.28	0	3	0	15	0	0	0	0	0	134.14	137.73	134.14	15	No	115
B	620269 JAMSTWN7 115 620275 NJAMES7 115 1	1185	18735	P23:115[redacted]	115	620	1	14.48	14.82	32.95	33.68	134.8	134.8	93.66	93.85	41.07	41.38	122.34	122.82	75.19	75.67	36.75	37.93	8.03	12.41	41.08	41.25	106.08	106.14	74.69	74.8	0	3	0	15	0	0	0	0	0	134.8	137.73	134.8	15	No	115
B	620269 JAMSTWN7 115 620275 NJAMES7 115 1	1185	18763	P23:115[redacted]	115	620	1	16.61	16.99	34.3	35	137.73	137.68	95.78	95.96	42.77	43.06	123.47	123.95	78.33	78.74	38.73	39.9	7.69	12.43	42.78	42.93	109.08	109.15	76.59	76.7	0	3	0	15	0	0	0	0	0	137.73	137.73	137.68	15	No	115
B	620269 JAMSTWN7 115 620275 NJAMES7 115 1	1185	2698	P12:115[redacted]	115	620	1	14.48	14.82	32.95	33.68	134.8	134.8	93.66	93.85	41.07	41.38	122.34	122.82	75.19	75.67	36.75	37.93	8.03	12.41	41.08	41.25	106.08	106.14	74.69	74.8	0	3	0	15	0	0	0	0	0	134.8	137.73	134.8	15	No	115
B	602039 ROCKCO5 161 631038 MAGNLIA5 161 1	1198	24532	P23:345[redacted]	161	600/627	1/3																	7.13	5.52	64.38	36.49	90.28	59.37	56.11	38.94	0	0	0	0	No Constraints	0	0	0	0	90.28	90.28	59.37	0	No	161
B	602039 ROCKCO5 161 631038 MAGNLIA5 161 1	1198	43568	P23:345[redacted]	161	600/627	1/3																	7.13	5.52	64.38	36.49	90.28	59.37	56.11	38.94	0	0	0	0	No Constraints	0	0	0	0	90.28	90.28	59.37	0	No	161
B	601031 BRKNGCO3 345 3WXFMR BRKNGCO3 115 9	1257	0	Base Case	345/115	600	1	90.98		60.28		87.97		75.83		114.22	90.79	98.03	76.88	117.75	92.11	120.36	95.39									3	3	20	42	0.476190476	0	0	0	0	120.36	189	95.39	22	No	115
B	601031 BRKNGCO3 345 3WXFMR BRKNGCO3 115 9	1257	27847	P55:115[redacted]	345/115	600	1									117.08	104.44	100.04	88.64	114.89	102.14	NConv	NConv									1	4	20	42	0.476190476	0	0			117.08	189	104.44	22	No	115
B	601031 BRKNGCO3 345 3WXFMR BRKNGCO3 115 9	1257	27888	P55:115[redacted]	345/115	600	1	102.63		72.64		92.85		91.69		119.83	106.86	107.93	94.31	118.83	104.7	NConv	117.4									2	5	20	42	0.476190476	0	0			119.83	189	117.4	22	No	115
B	601031 BRKNGCO3 345 3WXFMR BRKNGCO3 115 9	1257	28405	P55:345[redacted]	345/115	600	1	NConv		NConv		NConv		NConv		NConv	NConv	NConv	NConv	118.13	105.07	NConv	NConv									4	8	20	42	0.476190476	0	0			118.13	189	105.07	22	No	115
B	601031 BRKNGCO3 345 3WXFMR BRKNGCO3 115 9	1257	28406	P55:345[redacted]	345/115	600	1	NConv		NConv		NConv		NConv		NConv	NConv	NConv	NConv	118.13	105.07	NConv	NConv									4	8	20	42	0.476190476	0	0			118.13	189	105.07	22	No	115

VLTAP4 230 615529 GRE-PANTHER4 230 1	837	24635	P23:345[redacted]	230	600	1
VLTAP4 230 615529 GRE-PANTHER4 230 1	837	28325	P55:345[redacted]	230	600	1
VLTAP4 230 615529 GRE-PANTHER4 230 1	837	30089	P71:345-345[redacted]	230	600	1
VLTAP4 230 615529 GRE-PANTHER4 230 1	837	30225	P71:345[redacted]	230	600	1
UN 3 345 635252 IDA CO W 3 345 1	843	24215	P23:345[redacted]	345	635	3
UN 3 345 635252 IDA CO W 3 345 1	843	29089	P611:345-345[redacted]	345	635	3
UN 3 345 635398 REMSEN 3 345 1	851	24211	P23:345[redacted]	345	635	3
UN 3 345 635398 REMSEN 3 345 1	851	24213	P23:345[redacted]	345	635	3
UN 3 345 635398 REMSEN 3 345 1	851	28349	P55:345[redacted]	345	635	3
UN 3 345 635398 REMSEN 3 345 1	851	29086	P611:345-345[redacted]	345	635	3
UN 3 345 635398 REMSEN 3 345 1	851	29087	P611:345-345[redacted]	345	635	3
UN 5 161 640377 TEKAMAH5 161 1	855	24243	P23:345[redacted]	161	635/645	3/External
UN 5 161 640377 TEKAMAH5 161 1	855	29089	P611:345-345[redacted]	161	635/645	3/External
UN 5 161 640377 TEKAMAH5 161 1	855	53091	P55:161-345[redacted]	161	635/645	3/External
UN 5 161 640377 TEKAMAH5 161 1	855	53209	P55:345[redacted]	161	635/645	3/External
UN 5 161 640377 TEKAMAH5 161 1	855	6858	P12:345[redacted]	161	635/645	3/External
T RK4 230 652523 SIOUXFL4 230 1	866	24532	P23:345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	24533	P23:345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	30442	P7:161-345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	32453	P12:345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	39102	P21:345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	43552	P23:345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	43553	P23:345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	43554	P23:345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	43568	P23:345[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	53530	P71:230[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	53531	P71:230[redacted]	230	600/652	1/External
T RK4 230 652523 SIOUXFL4 230 1	866	7037	P12:345[redacted]	230	600/652	1/External
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	14390	P21:230[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	18396	P23:115[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	19011	P23:115[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	23294	P23:230[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	28293	P55:230[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	28699	P55F:P55[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	29275	P71:115[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	3014	P12:115[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	32240	P12:230[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	43127	P23:230[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	53658	P71:345[redacted]	115	600	1
E-SWAN LK7 115 618501 GRE-STOCKTP7 115 1	877	6426	P12:230[redacted]	115	600	1
CO 3 345 635252 IDA CO W 3 345 1	893	29089	P611:345-345[redacted]	345	635	3
ANRMB7 115 618905 GRE-ELLSBOR7 115 1	905	27847	P55:115[redacted]	115	600	1
ANRMB7 115 618905 GRE-ELLSBOR7 115 1	905	27920	P55:115[redacted]	115	600	1
ANRMB7 115 618905 GRE-ELLSBOR7 115 1	905	28405	P55:345[redacted]	115	600	1
ANRMB7 115 618905 GRE-ELLSBOR7 115 1	905	28406	P55:345[redacted]	115	600	1
EROKEE 3 345 635400 HIGHLAND 3 345 1	911	29086	P611:345-345[redacted]	345	635	3
EROKEE 3 345 635400 HIGHLAND 3 345 1	911	29087	P611:345-345[redacted]	345	635	3
MOUTH 5 161 652566 SIOUXCY5 161 1	924	28217	P55:161[redacted]	161	635/652	3/External
MOUTH 5 161 652566 SIOUXCY5 161 1	924	28360	P55:345[redacted]	161	635/652	3/External
MSEN 3 345 635399 CHEROKEE 3 345 1	1670	29087	P611:345-345[redacted]	345	635	3
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VLTAP4 230 652550 GRANITF4 230 1	1739	6429	P12:230[redacted]	230	600/652	1/External
VLTAP4 230 652550 GRANITF4 230 1	1739	15621	P22:115[redacted]	230	600/652	1/External
VLTAP4 230 652550 GRANITF4 230 1	1739	40115	P22:115[redacted]	230	600/652	1/External
VLTAP4 230 652550 GRANITF4 230 1	1739	40116	P22:115[redacted]	230	600/652	1/External
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VLTAP4 230 652550 GRANITF4 230 1	1739	43276	P23:230[redacted]	230	600/652	1/External
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VLTAP4 230 652550 GRANITF4 230 1	1739	6431	P12:230[redacted]	230	600/652	1/External
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VLTAP4 230 652550 GRANITF4 230 1	1739	23546	P23:230[redacted]	230	600/652	1/External
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KHOVENTP7 115 658258 WMU-PRIAM 7 115 1	1771	6273	P12:230[redacted]	115	600/615	1/1
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BLES7 115 603307 J512 ZEPHYR7 115 1	1030	11700	P21:115[redacted]	115	600	1
BLES7 115 603307 J512 ZEPHYR7 115 1	1030	18402	P23:115[redacted]	115	600	1
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NTON 7 115 618906 GRE-LISMORE7 115 1	1061	19114	P23:115[redacted]	115	600	1
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NTON 7 115 618906 GRE-LISMORE7 115 1	1061	19283	P23:115[redacted]	115	600	1
NTON 7 115 618906 GRE-LISMORE7 115 1	1061	2944	P12:115[redacted]	115	600	1
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LAKE5 161 608631 MINONG 5 161 1	1063	23755	P23:345[redacted]	161	600/608	1/1
LAKE5 161 608631 MINONG 5 161 1	1063	23756	P23:345[redacted]	161	600/608	1/1
LAKE5 161 608631 MINONG 5 161 1	1063	23757	P23:345[redacted]	161	600/608	1/1
LAKE5 161 608631 MINONG 5 161 1	1063	23855	P23:345[redacted]	161	600/608	1/1
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T RK3 345 652864 SIOUXCY-LNX3 345 1	1074	53908	P12:345[redacted]	345	600/652	1/External
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U 138 138 699939 SAL 138 138 1	1108	0	Base Case	138	694	2
U 138 138 699939 SAL 138 138 1	1108	23846	P23:345[redacted]	138	694	2
U 138 138 699939 SAL 138 138 1	1108	23859	P23:345[redacted]	138	694	2
U 138 138 699939 SAL 138 138 1	1108	23860	P23:345[redacted]	138	694	2
U 138 138 699939 SAL 138 138 1	1108	27603	P51:ATC[redacted]	138	694	2
U 138 138 699939 SAL 138 138 1	1108	679	P71:345-345[redacted]	138	694	2
U 138 138 699939 SAL 138 138 1	1108	680	P71:138-345[redacted]	138	694	2
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KING3 345 601028 EAU CL 3 345 1	1111	488	P23:345[redacted]	345	600	1
KING3 345 601028 EAU CL 3 345 1	1111	53650	P71:345-161[redacted]	345	600	1

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681536 RCK ELM5 161 681543 ALMA 5 161 1	1452	22842	P23:161[redacted]	161	680	1
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603143 SHELDNP7 115 603144 OSPREY 7 115 1	1640	22894	P23:161[redacted]	115	600	1
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631046 ADAMS 5 161 3WXFMR ADAMS 3 161 9	166	22376	P23:161[redacted]	161	627	3
631046 ADAMS 5 161 3WXFMR ADAMS 3 161 9	166	27755	P55:115[redacted]	161	627	3
631046 ADAMS 5 161 3WXFMR ADAMS 3 161 9	166	28421	P55:345[redacted]	161	627	3
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631046 ADAMS 5 161 3WXFMR ADAMS 3 161 9	166	7024	P12:345[redacted]	161	627	3
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602002 SOUTHBE5 161 602003 BLUEETA5 161 1	183	24665	P23:345[redacted]	161	600	1
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615354 GRE-DICKNSN7 115 3WXFMR 615:AEM21001 115 1	376	30118	P71:345[redacted]	115	600	1

PUBLIC DOCUMENT - NONPUBLIC DATA HAS BEEN EXCISED

C	603192 BRKNGCO7 115 3WXFMR BRKNGCO3_1 115 9	387	0	Base Case	115	600
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C	603192 BRKNGCO7 115 3WXFMR BRKNGCO3_1 115 9	387	28405	P55:345[redacted]	115	600
C	603192 BRKNGCO7 115 3WXFMR BRKNGCO3_1 115 9	387	28406	P55:345[redacted]	115	600
C	603192 BRKNGCO7 115 3WXFMR BRKNGCO3_1 115 9	387	43565	P23:345[redacted]	115	600
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C	615644 GRE-CEDARMT7 115 3WXFMR 615:WT01121 115 1	406	30225	P71:345[redacted]	115	600
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C	693668 HLV138 138 699034 EEN 138 138 1	411	23766	P23:345[redacted]	138	694
C	693668 HLV138 138 699034 EEN 138 138 1	411	23807	P23:345[redacted]	138	694
C	693668 HLV138 138 699034 EEN 138 138 1	411	6651	P12:345[redacted]	138	694
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C	681532 WABACO 5 161 681556 KELLOGG 5 161 1	430	488	P23:345[redacted]	161	680
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C	658068 MARSHAL7 115 658078 SOUTHE7 115 1	432	27898	P55:115[redacted]	115	600
C	658068 MARSHAL7 115 658078 SOUTHE7 115 1	432	28379	P55:345[redacted]	115	600
C	658068 MARSHAL7 115 658078 SOUTHE7 115 1	432	28380	P55:345[redacted]	115	600
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C	681543 ALMA 5 161 681556 KELLOGG 5 161 1	441	28407	P55:345[redacted]	161	680
C	681543 ALMA 5 161 681556 KELLOGG 5 161 1	441	488	P23:345[redacted]	161	680
C	681543 ALMA 5 161 681556 KELLOGG 5 161 1	441	53651	P71:345[redacted]	161	680
C	681543 ALMA 5 161 681556 KELLOGG 5 161 1	441	654	P12:345[redacted]	161	680
C	681543 ALMA 5 161 681556 KELLOGG 5 161 1	441	655	P71:345[redacted]	161	680
C	681543 ALMA 5 161 681556 KELLOGG 5 161 1	441	7084	P12:345[redacted]	161	680
C	693849 7MILE CREEK 138 699241 POE 138 138 1	444	0	Base Case	138	694
C	693849 7MILE CREEK 138 699241 POE 138 138 1	444	1140	P11:138[redacted]	138	694
C	693849 7MILE CREEK 138 699241 POE 138 138 1	444	23	P12:765[redacted]	138	694
C	693849 7MILE CREEK 138 699241 POE 138 138 1	444	23846	P23:345[redacted]	138	694
C	693849 7MILE CREEK 138 699241 POE 138 138 1	444	23859	P23:345[redacted]	138	694
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C	693849 7MILE CREEK 138 699241 POE 138 138 1	444	679	P71:345-345[redacted]	138	694
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C	699242 SGL 138 138 699245 ARP 138 138 1	450	23846	P23:345[redacted]	138	694
C	699242 SGL 138 138 699245 ARP 138 138 1	450	25794	P24:115[redacted]	138	694
C	699242 SGL 138 138 699245 ARP 138 138 1	450	6665	P12:345[redacted]	138	694
C	699242 SGL 138 138 699245 ARP 138 138 1	450	667	P12:345[redacted]	138	694
C	699242 SGL 138 138 699245 ARP 138 138 1	450	679	P71:345-345[redacted]	138	694
C	698800 MAINE115 115 699733 PINE 115 1	451	28424	P55:ATC[redacted]	115	696
C	698800 MAINE115 115 699733 PINE 115 1	451	29215	P71:115-115[redacted]	115	696
C	698800 MAINE115 115 699733 PINE 115 1	451	29242	P71:115-345[redacted]	115	696
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C	601028 EAU CL 3 345 3WXFMR EAU CL3 161 10	470	30217	P71:345[redacted]	345/161	600
C	698800 MAINE115 115 699703 HILLTP 115 1	472	28424	P55:ATC[redacted]	115	696
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C	693757 ACKLEY 115 699667 ANTIGO 115 1	474	25793	P24:115[redacted]	115	696
C	693757 ACKLEY 115 699667 ANTIGO 115 1	474	28430	P55:ATC[redacted]	115	696
C	693757 ACKLEY 115 699667 ANTIGO 115 1	474	28436	P55:ATC[redacted]	115	696
C	693757 ACKLEY 115 699667 ANTIGO 115 1	474	28437	P55:ATC[redacted]	115	696
C	693757 ACKLEY 115 699667 ANTIGO 115 1	474	29217	P71:115-115[redacted]	115	696
C	698948 HOLYWOOD 138 699240 SAR 138 138 1	482	16175	P22:138[redacted]	138	694
C	698948 HOLYWOOD 138 699240 SAR 138 138 1	482	16455	P22:138[redacted]	138	694
C	698948 HOLYWOOD 138 699240 SAR 138 138 1	482	20380	P23:138[redacted]	138	694
C	698948 HOLYWOOD 138 699240 SAR 138 138 1	482	20381	P23:138[redacted]	138	694
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C	698948 HOLYWOOD 138 699240 SAR 138 138 1	482	23846	P23:345[redacted]	138	694
C	698948 HOLYWOOD 138 699240 SAR 138 138 1	482	4407	P12:138[redacted]	138	694

C	699637 BDGR 115 115 699572 BDGR 138 138 1	550	23805	P23:345[redacted]	115/138
C	699637 BDGR 115 115 699572 BDGR 138 138 1	550	23806	P23:345[redacted]	115/138
C	699637 BDGR 115 115 699572 BDGR 138 138 1	550	23860	P23:345[redacted]	115/138
C	699637 BDGR 115 115 699572 BDGR 138 138 1	550	680	P71:138-345[redacted]	115/138
C	603194 NOBLES 7 115 3WXFMR NOBLES 3 115 9	551	9774	P13:345-115[redacted]	115
C	601034 NOBLES 3 345 3WXFMR NOBLES 3 115 9	552	9774	P13:345-115[redacted]	345/115
C	603151 PINE LK7 115 3WXFMR PINE LK5 115 3	556	22144	P23:161[redacted]	115
C	603151 PINE LK7 115 3WXFMR PINE LK5 115 3	556	28252	P55:161[redacted]	115
C	603151 PINE LK7 115 3WXFMR PINE LK5 115 3	556	53916	P12:161[redacted]	115
C	603151 PINE LK7 115 3WXFMR PINE LK5 115 3	556	5627	P12:161[redacted]	115
C	602027 PINE LK5 161 3WXFMR PINE LK5 115 3	557	22144	P23:161[redacted]	161/115
C	602027 PINE LK5 161 3WXFMR PINE LK5 115 3	557	28252	P55:161[redacted]	161/115
C	602027 PINE LK5 161 3WXFMR PINE LK5 115 3	557	53916	P12:161[redacted]	161/115
C	602027 PINE LK5 161 3WXFMR PINE LK5 115 3	557	5627	P12:161[redacted]	161/115
C	690029 LR_TREMVAL 345 694098 NMAB5345 345 C1	585	23846	P23:345[redacted]	345
C	690029 LR_TREMVAL 345 694098 NMAB5345 345 C1	585	665	P12:345[redacted]	345
C	690029 LR_TREMVAL 345 694098 NMAB5345 345 C1	585	677	NB71:69-345[redacted]	345
C	690029 LR_TREMVAL 345 694098 NMAB5345 345 C1	585	678	NB71:69-345[redacted]	345
C	690029 LR_TREMVAL 345 694098 NMAB5345 345 C1	585	679	P71:345-345[redacted]	345
C	681532 WABACO 5 161 681537 ROCHSTR5 161 1	586	28407	P55:345[redacted]	161
C	681532 WABACO 5 161 681537 ROCHSTR5 161 1	586	488	P23:345[redacted]	161
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C	681532 WABACO 5 161 681537 ROCHSTR5 161 1	586	654	P12:345[redacted]	161
C	681532 WABACO 5 161 681537 ROCHSTR5 161 1	586	655	P71:345[redacted]	161
C	603010 LKYNKTN7 115 603134 BUFFRID7 115 1	681	28379	P55:345[redacted]	115
C	603010 LKYNKTN7 115 603134 BUFFRID7 115 1	681	28380	P55:345[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	0	Base Case	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	18	P12:765[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	19199	P23:115[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	24530	P23:345[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	24669	P23:345[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	27847	P55:115[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	27920	P55:115[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	32454	P12:345[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	43549	P23:345[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	43562	P23:345[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	43564	P23:345[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	43565	P23:345[redacted]	115
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C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	861	P11:0[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	9203	P13:115[redacted]	115
C	603192 BRKNGCO7 115 603240 OAK LAKEW 7 115 1	689	9204	P13:115[redacted]	115
C	601050 HELENA3 345 601051 HMPT CNR3 345 2	735	0	Base Case	345
C	601050 HELENA3 345 601051 HMPT CNR3 345 2	735	24555	P23:345[redacted]	345
C	601050 HELENA3 345 601051 HMPT CNR3 345 2	735	24653	P23:345[redacted]	345
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
C	601006 SPLT RK3 345 3WXFMR SPLT 11 115 11	957	43568	P23:345[redacted]	345/115
C	601006 SPLT RK3 345 3WXFMR SPLT 11 115 11	957	43569	P23:345[redacted]	345/115
C	601006 SPLT RK3 345 3WXFMR SPLT 11 115 11	957	9763	P13:345-115-13[redacted]	345/115
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C	631046 ADAMS 5 161 681527 BVR CRK5 161 1	959	23992	P23:345[redacted]	161
C	631046 ADAMS 5 161 681527 BVR CRK5 161 1	959	24012	P23:345[redacted]	161
C	631046 ADAMS 5 161 681527 BVR CRK5 161 1	959	28407	P55:345[redacted]	161
C	631046 ADAMS 5 161 681527 BVR CRK5 161 1	959	53651	P71:345[redacted]	161
C	631046 ADAMS 5 161 681527 BVR CRK5 161 1	959	655	P71:345[redacted]	161
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C	681523 GENOA 5 161 681528 HARMONY5 161 1	984	17181	P22:161[redacted]	161
C	681523 GENOA 5 161 681528 HARMONY5 161 1	984	26872	P24:161[redacted]	161
C	681523 GENOA 5 161 681528 HARMONY5 161 1	984	53651	P71:345[redacted]	161
C	681523 GENOA 5 161 681528 HARMONY5 161 1	984	5456	P12:161[redacted]	161
C	681523 GENOA 5 161 681528 HARMONY5 161 1	984	655	P71:345[redacted]	161
C	860060 NORTH ROCHES 765 601039 NROC 3 345 T3	1256	7	P12:765[redacted]	765/345
C	601050 HELENA 3 345 601072 SHEAS LK3 345 1	1669	30089	P71:345-345[redacted]	345
C	601050 HELENA 3 345 601072 SHEAS LK3 345 1	1669	28325	P55:345[redacted]	345
C	601050 HELENA 3 345 601072 SHEAS LK3 345 1	1669	53652	P71:345-115[redacted]	345
C	601039 NROC 3 345 613060 BYRON 3 345 1	1676	28421	P55:345[redacted]	345
C	635368 OBRIEN 3 345 635400 HIGHLAND 3 345 1	1678	29087	P611:345-345[redacted]	345
C	635368 OBRIEN 3 345 635400 HIGHLAND 3 345 1	1678	29086	P611:345-345[redacted]	345
C	601050 HELENA 3 345 601072 SHEAS LK3 345 1	1669	24635	P23:345[redacted]	345
C	601050 HELENA 3 345 601072 SHEAS LK3 345 1	1669	53653	P71:345-115[redacted]	345
C	601050 HELENA 3 345 601072 SHEAS LK3 345 1	1669	653	P12:345[redacted]	345
C	603182 SOUTH BEND 7 115 617200 GRE-NORTHPT7 115 1	1684	28421	P55:345[redacted]	115
C	603002 WILMART7 115 3WXFMR 345/115 115 10	1695	24668	P23:345[redacted]	115
C	602002 SOUTH BE5 161 3WXFMR SOUTH BE5 115 6	1698	28421	P55:345[redacted]	161/115
C	603002 WILMART7 115 3WXFMR 345/115 115 10	1695	24589	P23:345[redacted]	115

C	613060 BYRON 3 345 615306 GRE-PLVLLY3 345 1	1729	28421	P55:345[redacted]	345	600	1	93.13		86.08		89.13		NConv		1	1	5	5	1	0	0	0	0	93.13	113.59		0	Yes	345
C	601039 NROC 3 345 613060 BYRON 3 345 1	1676	23992	P23:345[redacted]	345	600	1	92.97		82.04		66.17		100.34		1	1	8	8	1	0	0	0	0	100.34	110.34		0	Yes	345
C	631052 LANSING L25 161 681528 HARMONY5 161 1	1720	17155	P22:161[redacted]	161	627/680	3/1	92.95	71.24	89.74	69.15	37.89	32.95	52.95	42.74	0	0	0	0	No Constraints	0	0	0	0	92.95	95.01	71.24	0	No	161
C	625445 CHESTER 161 681537 ROCHSTR5 161 16	1730	17129	P22:161[redacted]	161	613/680	1/1	92.69	71.11	80.38	59.6	64.49	59.19	64.75	54.93	0	0	0	0	No Constraints	0	0	0	0	92.69	92.69	71.11	0	No	161
C	613070 BYRON 5 161 625430 CASCADE 161 1	1718	7084	P12:345[redacted]	161	600/613	1/1	92.69	Contingency Disabled	75.65	Contingency Disabled	91.12	Contingency Di	82.71	Contingency Disabled	0	0	0	0	No Constraints	0	0	0	0	92.69	95.48	0	0	No	161
C	631052 LANSING L25 161 681528 HARMONY5 161 1	1720	17156	P22:161[redacted]	161	627/680	3/1	92.59	70.89	89.56	68.94	37.32	32.4	52.57	42.36	0	0	0	0	No Constraints	0	0	0	0	92.59	95.01	70.89	0	No	161
C	631052 LANSING L25 161 681528 HARMONY5 161 1	1720	17127	P22:161[redacted]	161	627/680	3/1	92.56	70.86	89.54	68.92	37.27	32.35	52.54	42.31	0	0	0	0	No Constraints	0	0	0	0	92.56	95.01	70.86	0	No	161
C	681527 BVR CRK5 161 681528 HARMONY5 161 1	1746	53651	P71:345[redacted]	161	680	1	90.15	62.33	83.21	57.31	47.98	37.89	57.04	43.25	0	0	0	0	No Constraints	0	0	0	0	90.15	90.15	62.33	0	No	161
C	681527 BVR CRK5 161 681528 HARMONY5 161 1	1746	655	P71:345[redacted]	161	680	1	90.15	62.33	83.21	57.31	47.98	37.89	57.04	43.25	0	0	0	0	No Constraints	0	0	0	0	90.15	90.15	62.33	0	No	161
C	603188 EASTWD18 115 617235 GRE-POHL 7 115 1	1764	27965	P55:115[redacted]	115	600	1	86.12	71.44	69.53	57.78	90.09	77.72	81.53	67.72	0	0	0	0	No Constraints	0	0	0	0	90.09	90.32	77.72	0	No	115
C	603188 EASTWD18 115 617235 GRE-POHL 7 115 1	1764	30465	P7:345-115[redacted]	115	600	1	85.78	58.29	82.47	59.49	67.86	42.64	90.32	61.16	0	0	0	0	No Constraints	0	0	0	0	90.32	90.32	61.16	0	No	115
C	631035 OSCEOLA_WF5 161 631124 DKSN_CO5 161 1	1772	0	Base Case	161	627	3	84.33	84.15	88.22	87.94	47.41	47.36	95.06	95.02	0	0	0	0	No Constraints	0	0	0	0	95.06	95.06	95.02	0	No	161
C	601004 WILMART3 345 631193 HUNTLEY3 345 1	1778	24588	P23:345[redacted]	345	600/627	1/3	81.71	54.34	73.85	49.91	71.49	48.23	107.75	72.93	1	1	5	5	1	0	0	0	0	107.75	107.75	72.93	0	Yes	345
C	601004 WILMART3 345 631193 HUNTLEY3 345 1	1778	7102	P12:345[redacted]	345	600/627	1/3	81.71	54.34	73.85	49.91	71.49	48.23	107.75	72.93	1	1	5	5	1	0	0	0	0	107.75	107.75	72.93	0	Yes	345
C	601004 WILMART3 345 631193 HUNTLEY3 345 1	1778	24666	P23:345[redacted]	345	600/627	1/3	81.71	54.33	73.85	49.91	71.49	48.23	107.75	72.93	1	1	5	5	1	0	0	0	0	107.75	107.75	72.93	0	Yes	345
C	613070 BYRON 5 161 615307 GRE-PLVLLY5 161 1	1779	28381	P55:345[redacted]	161	600/615	1/1	81.41	40.97	66.54	34.47	94.37	47.6	113.32	51.68	1	1	3	3	1	0	0	0	0	113.32	116.16	51.68	0	Yes	161
C	601004 WILMART3 345 631193 HUNTLEY3 345 1	1778	24664	P23:345[redacted]	345	600/627	1/3	81.38	53.94	73.7	49.69	70.87	47.56	107.26	72.37	1	1	5	5	1	0	0	0	0	107.26	107.75	72.37	0	Yes	345
C	603131 AIRLAKE7 115 615650 GRE-CHUBLAK7 115 1	1782	19188	P23:115[redacted]	115	600	1	80.86	71.56	63.07	56.05	92.85	87.66	92.61	86.49	0	0	0	0	No Constraints	0	0	0	0	92.85	92.85	87.66	0	No	115
C	601004 WILMART3 345 631193 HUNTLEY3 345 1	1778	7105	P12:345[redacted]	345	600/627	1/3	80.06	53.7	72.23	49.31	70.54	47.88	106.19	72.34	1	1	5	5	1	0	0	0	0	106.19	107.75	72.34	0	Yes	345
C	603131 AIRLAKE7 115 615650 GRE-CHUBLAK7 115 1	1782	18361	P23:115[redacted]	115	600	1	79.84	70.5	62.42	55.37	91.29	86.14	91.37	85.26	0	0	0	0	No Constraints	0	0	0	0	91.37	92.85	86.14	0	No	115
C	601039 NROC 3 345 613060 BYRON 3 345 1	1676	28249	P55:161[redacted]	345	600	1	76.14		61		87.37		109.08		1	1	8	8	1	0	0	0	0	109.08	110.34		0	Yes	345
C	613070 BYRON 5 161 615307 GRE-PLVLLY5 161 1	1779	24604	P23:345[redacted]	161	600/615	1/1	76.06	44.44	66.57	37.77	85.52	51.15	111.71	57.54	1	1	3	3	1	0	0	0	0	111.71	116.16	57.54	0	Yes	161
C	613070 BYRON 5 161 615307 GRE-PLVLLY5 161 1	1779	7050	P12:345[redacted]	161	600/615	1/1	75.76	Contingency Disabled	69.12	Contingency Disabled	83.17	Contingency Di	116.16	Contingency Disabled	0	0	3	3	1	0	0	0	0	116.16	116.16	0	0	Yes	161
C	601039 NROC 3 345 613060 BYRON 3 345 1	1676	28248	P55:161[redacted]	345	600	1	75.19		59.92		87.98		108.78		1	1	8	8	1	0	0	0	0	108.78	110.34		0	Yes	345
C	601039 NROC 3 345 613060 BYRON 3 345 1	1676	24669	P23:345[redacted]	345	600	1	74.54		60.68		81.66		110.34		1	1	8	8	1	0	0	0	0	110.34	110.34		0	Yes	345
C	613070 BYRON 5 161 615307 GRE-PLVLLY5 161 1	1779	28382	P55:345[redacted]	161	600/615	1/1	74.2	40.97	66.59	34.47	82.42	47.6	110.98	51.68	1	1	3	3	1	0	0	0	0	110.98	116.16	51.68	0	Yes	161
C	601039 NROC 3 345 613060 BYRON 3 345 1	1676	30476	P7:345-161[redacted]	345	600	1	72.82		59.66		80.48		107.88		1	1	8	8	1	0	0	0	0	107.88	110.34		0	Yes	345
C	601003 PRISLD3 345 601023 REDROCK3 345 1	1807	24527	P23:345[redacted]	345	600	1	72.6	58.93	64.98	53.73	73.18	67.9	91.97	83.83	0	0	0	0	No Constraints	0	0	0	0	91.97	96.2	83.83	0	No	345
C	601003 PRISLD3 345 601023 REDROCK3 345 2	1819	24651	P23:345[redacted]	345	600	1	68.97	57.74	60.5	51.37	72.67	69.86	99.87	93.23	0	0	0	0	No Constraints	0	0	0	0	99.87	99.87	93.23	0	No	345
C	615650 GRE-CHUBLAK7 115 616929 GRE-KENRICK7 115 1	1820	28414	P55:345[redacted]	115	600	1	68.94	61.1	52.87	47.31	84.26	80.4	92.26	86.2	0	0	0	0	No Constraints	0	0	0	0	92.26	93.32	86.2	0	No	115
C	616929 GRE-KENRICK7 115 616931 GRE-RITTRPK7 115 1	1822	28414	P55:345[redacted]	115	600	1	68.65	60.71	52.85	47.2	83.59	79.72	90.31	84.3	0	0	0	0	No Constraints	0	0	0	0	90.31	91.25	84.3	0	No	115
C	615650 GRE-CHUBLAK7 115 616929 GRE-KENRICK7 115 1	1820	28418	P55:345[redacted]	115	600	1	68.34	64.27	51.95	49.53	82.96	81.38	92.77	90.12	0	0	0	0	No Constraints	0	0	0	0	92.77	93.32	90.12	0	No	115
C	616929 GRE-KENRICK7 115 616931 GRE-RITTRPK7 115 1	1822	28418	P55:345[redacted]	115	600	1	68.08	63.95	51.93	49.47	82.32	80.77	90.84	88.24	0	0	0	0	No Constraints	0	0	0	0	90.84	91.25	88.24	0	No	115
C	613060 BYRON 3 345 615306 GRE-PLVLLY3 345 1	1729	24669	P23:345[redacted]	345	600	1	67.45		64.21		70.24		113.59		1	1	5	5	1	0	0	0	0	113.59	113.59		0	Yes	345
C	615650 GRE-CHUBLAK7 115 616929 GRE-KENRICK7 115 1	1820	27703	P53:345[redacted]	115	600	1	66.89	57.43	51.77	44.77	80.34	74.64	92.93	84.24	0	0	0	0	No Constraints	0	0	0	0	92.93	93.32	84.24	0	No	115
C	616929 GRE-KENRICK7 115 616931 GRE-RITTRPK7 115 1	1822	27703	P53:345[redacted]	115	600	1	66.6	56.98	51.74	44.61	79.65	73.91	90.99	82.36	0	0	0	0	No Constraints	0	0	0	0	90.99	91.25	82.36	0	No	115
C	613060 BYRON 3 345 615306 GRE-PLVLLY3 345 1	1729	30476	P7:345-161[redacted]	345	600	1	66.08		63.39		69.33		111.44		1	1	5	5	1	0	0	0	0	111.44	113.59		0	Yes	345
C	615650 GRE-CHUBLAK7 115 616929 GRE-KENRICK7 115 1	1820	30233	P71:345[redacted]	115	600	1	65.95	58.42	51.07	45.65	80.24	75.94	90.41	83.66	0	0	0	0	No Constraints	0	0	0	0	90.41	93.32	83.66	0	No	115
C	613060 BYRON 3 345 615306 GRE-PLVLLY3 345 1	1729	24594	P23:345[redacted]	345	600	1	65.9		61.61		68.47		109.53		1	1	5	5	1	0	0	0	0	109.53	113.59		0	Yes	345
C	613060 BYRON 3 345 615306 GRE-PLVLLY3 345 1	1729	22338	P23:161[redacted]	345	600	1	65.61		62.42		71.77		109.55		1	1	5	5	1	0	0	0	0	109.55	113.59		0	Yes	345
C	631124 DKSN_CO5 161 631271 LKEFLD CRNRS 161 1	1827	31946	P12:161[redacted]	161	627	3	65.11	79.37	77.23	91.35	27.41	28.45	66.93	75.67	0	0	0	0	No Constraints	0	0	0	0	91.35	93.19	91.35	0	No	161
C	601003 PRISLD3 345 601023 REDROCK3 345 1	1807	28415	P55:345[redacted]	345	600	1	64.99	54.12	57.5	48.56	67.67	64.74	93.83	87.2	0	0	0	0	No Constraints	0	0	0	0	93.83	96.2	87.2	0	No	345
C	615650 GRE-CHUBLAK7 115 616929 GRE-KENRICK7 115 1	1820	27709	P53:345[redacted]	115	600	1	64.89	56.35	48.87	43.39	76.04	74.51	93.32	81.81	0	0	0	0	No Constraints	0	0	0	0	93.32	93.32	81.81	0	No	115
C	616929 GRE-KENRICK7 115 616931 GRE-RITTRPK7 115 1	1822	27709	P53:345[redacted]	115	600	1	64.52	55.87	48.79	43.21	75.3	73.73	91.25	79.9	0	0	0	0	No Constraints	0	0	0	0	91.25	91.25	79.9	0	No	115
C	601002 ADAMS 3 345 615306 GRE-PLVLLY3 345 1	1828	28421	P55:345[redacted]	345	600	1	63.59	58.46	54.78	56.76	76.08	53.61	NConv	85.68	1	1	1	1	1	0	0	0	0	85.68	96.63	85.68	0	Yes	345
C	601003 PRISLD3 345 601023 REDROCK3 345 2	1819	24577	P23:345[redacted]	345	600	1	63.31	55.09	55.31	48.75	73.31	71.75	96.34	91.27	0	0	0	0	No Constraints	0	0	0	0	96.34	99.87	91.27	0	No	345
C	601003 PRISLD3 345 601023 REDROCK3 345 2	1819	24536	P23:345[redacted]	345	600	1	63.31	55.09	55.31	48.75	73.31	71.75	96.34	91.27	0	0	0	0	No Constraints	0	0	0	0	96.34	99.87	91.27	0	No	345
C	601003 PRISLD3 345 601023 REDROCK3 345 2	1819	7089	P12:345[redacted]	345	600	1	63.31	55.09	55.31	48.75	73.31	71.75	96.34	91.27	0	0	0	0	No Constraints	0	0	0	0	96.34	99.87	91.27	0	No	345
C	601003 PRISLD3 345 601023 REDROCK3 345 1	1807	7090	P12:345[redacted]	345	600	1	63.22	55.01	55.23	48.68	73.2	71.64	96.2	91.14	0	0	0	0	No Constraints	0	0	0	0	96.2	96.2	91.14	0	No	345
C	601003 PRISLD3 345 601023 REDROCK3 345 1	1807	24578	P23:345[redacted]	345	600	1	63.22	55.01	55.23	48.68	73.2	71.64	96.2	91.14	0	0	0	0	No Constraints	0	0	0	0	96.2	96.2	91.14	0	No	345
C	601039 NROC 3 345 613060 BYRON 3 345 1	1676	0	Base Case	345	600	1	63.18		50.71		72.52		93.69		0	0	8	8	1	0	0	0	0	93.69	110.34		0	Yes	345
C	601003 PRISLD3 345 601023 REDROCK3 345 1	1807	24652	P23:345[redacted]	345	600	1	61.06	53.05	53.59	47.24	70.63	69.12	93.94	88.96	0	0	0	0	No Constraints	0	0	0	0	93.94	96.2	88.96	0	No	345
C	603097 REDROCK7 115 603098 ROGRSLK7 115 1	1834	19258	P23:115[redacted]	115	600	1	56.08	57.07	36.72	38.52	90.28	89.98	36.61	34.47	0	0	0	0	No Constraints	0	0	0	0	90.28	90.28	89.98	0	No	115
C	603097 REDROCK7 115 603098 ROGRSLK7 115 1	1834	19312	P23:115[redacted]	115	600	1	56.08	57.07	36.72	38.52	90.28	89.98	36.61	34.47	0	0	0	0	No Constraints	0	0	0	0	90.28	90.28	89.98	0	No	115
C	613060 BYRON 3 345 615306 GRE-PLVLLY3 345 1	1729	0	Base Case	345	600	1	55.7		54.83		60.81		98.15		0	0	5	5	1	0	0	0	0	98.15	113.59		0	Yes	345
C	601003 PRISLD3 345 601023 REDROCK3 345 2	1819	30232	P71:345[redacted]	345	600	1	52.96	57.15	48.33	52.1	72.63	76.53	91.36	93.3	0	0	0	0	No Constraints	0	0	0	0	93.3	99.87	93.3	0	No	345
C	631124 DKSN_CO5 161 631271 LKEFLD CRNRS 161 1	1827	29000	P611:161-161[redacted]	161	627	3	51.66	82.96	60.45	91.83	30.29	33.29	59.84	78.46	0	0	0	0	No Constraints	0	0	0	0	91.83	93.19	91.83	0	No	161
C	631124 DKSN_CO5 161 631271 LKEFLD CRNRS 161 1	1827	28999	P611:161-161[redacted]	161	627	3	50.04	81.94	60.02	92.02	28.19	31.12	59.28	78.17	0	0	0	0	No Constraints	0	0	0	0	92.02	93.19	92.02	0	No	161
C	631124 DKSN_CO5 161 631271 LKEFLD CRNRS 161 1	1827	29086	P611:345-345[redacted]	161	627	3	47.55	81.76	59.66	93.19	33.51	29.75	68.41	83	0	0	0	0	No Constraints	0	0	0	0	93.19	93.19	93.19	0	No	161
C	631124 DKSN_CO5 161 631271 LKEFLD CRNRS 161 1	1827	29087	P611:345-345[redacted]	161	627	3	47.55	81.77	59.66	93.19	33.54	29.76	68.45	83	0	0	0	0	No Constraints	0	0	0	0	93.19	93.19	93.19	0	No	161
C	601002 ADAMS 3 345 615306 GRE-PLVLLY3 345 1	1828	19	P12:765[redacted]	345	600	1	Contingency Disabled	74.78	Contingency Disabled	71.15	Contingency Disabled	62.59	Contingency Di	96.63	0	0	1	1	1	0	0	0	0	96.63	96.63	96.63	0	Yes	345

PROTECTED DATA ENDS]

Appendix E.5

MISO September 2025 Fact Sheet

MISO

Fact Sheet

SEPTEMBER 2025

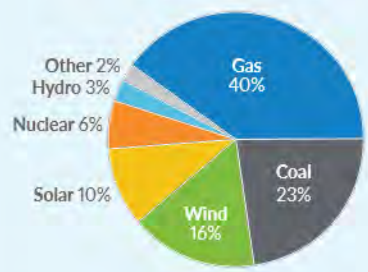
MISO is an independent, not-for-profit, member-based organization responsible for keeping the power flowing across its region reliably and cost effectively. MISO focuses on three critical tasks:

1. Managing the flow of high-voltage electricity across 15 U.S. states and the Canadian province of Manitoba
2. Facilitating one of the world's largest energy markets with more than $33 billion in annual transactions
3. Planning the grid of the future

MISO's reliability footprint and regional control center locations.

INSTALLED CAPACITY

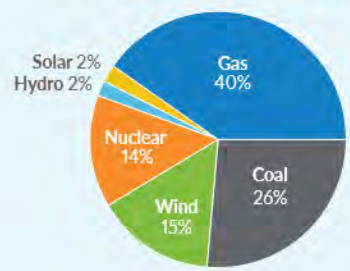
September 2025



207 GW

ENERGY PRODUCTION

January-December 2024



638 Million MWh

*Other: Diesel, Biomass, Storage, Demand Response Resources

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KEY FACTS

Area Served	15 U.S. States and Manitoba, Canada
Population Served	45 Million
Transmission Line	79,000 Miles
Generating Units (Commercial Model)	1,949
Record Demand	127.1 GW 7/20/2011
Wind Peak	25.6 GW 1/12/2024
Solar Peak	14.5 GW 9/7/2025
Members	56 Transmission Owners
	174 Non-transmission Owners
Market Participants	>550
Carbon Reduction	Approximately 32% since 2014

MISO TRANSMISSION EXPANSION PLAN (MTEP24)

	Local MTEP	Regional LRTP	Interregional JTIQ
Approved New Projects	459	24	5
Miles of Transmission Line	932	3,631	490