BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application for a Certificate of Need for the PowerOn Midwest 765 kV and 345 kV High Voltage Transmission Line Project	**Docket No. E002, ET2, ET6675/CN-25-117**

DIRECT TESTIMONY OF JEANNA FURNISH
SUBMITTED ON BEHALF OF
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name, employer, job title, and business address.

A. My name is Jeanna Furnish. I am employed by the Midcontinent Independent System Operator, Inc. ("MISO") as the Senior Director of Expansion Planning in MISO's Transmission Planning Department. MISO is the Planning Coordinator for the MISO region and prepares the MISO Transmission Expansion Plan ("MTEP") annually. My business address is 720 City Center Drive, Carmel, IN, 46032.

Q. What is MISO?

A. MISO is a not-for-profit, member-based, regional transmission organization ("RTO") providing reliability and market services over more than 75,000 miles of transmission lines in fifteen states and one Canadian province. MISO's regional area of operations stretches from the Ohio-Indiana line in the east to eastern

Montana in the west, and south to New Orleans. MISO is governed by an independent ten-member Board of Directors.[1]

Q. What are MISO's responsibilities?

A. As an RTO, MISO is responsible for operational oversight and control, market operations, and planning of the transmission systems of its member Transmission Owners ("TOs"). Among many other responsibilities, MISO monitors and calculates Available Flowgate Capability and provides tariff administration for its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"),[2] which has been accepted by the Federal Energy Regulatory Commission ("FERC").[3] MISO is the Reliability Coordinator for its regional area of operations, providing real-time operational monitoring and control of the transmission system. MISO operates real-time and day-ahead energy markets based on Locational Marginal Prices ("LMPs") in which each market participant's offer to supply energy is matched to demand and is cleared based on a security constrained economic dispatch process. In addition, MISO operates a market for Financial Transmission Rights, which are used by market participants to hedge

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1 MISO has nine independent directors, and its Chief Executive Officer fills a tenth seat on the Board.

2 The MISO Tariff is publicly available at: https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

3 MISO's Tariff was initially accepted by FERC in 1998, but suspended until subsequently adopted in 2001. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,326 (2001); *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,033 (2001), *order on reh'g*, 98 FERC ¶ 61,141 (2002). MISO began providing transmission service under its Tariff in 2002.

against congestion costs, and an ancillary services market, which provides for the services necessary to support transmission of capacity and energy from generation resources to load.

MISO is responsible for approving transmission service, new generation interconnections, and new transmission interconnections within MISO's regional area of operations, and for ensuring that the system is planned to reliably and economically provide for existing and forecasted usage of the transmission system. MISO is the Planning Coordinator for its regional area of operations, which includes the state of Minnesota, and performs planning functions collaboratively with input from its TOs and other interested stakeholders, while also providing an independent assessment and perspective of the needs of the overall transmission system.

Q. What is your educational background?

A. I graduated from Ohio Northern University with a Bachelor of Science degree in Electrical Engineering.

Q. What is your professional experience?

A. I began my professional career working for Northeast Utilities in 2004 as a program administer for transmission constrained areas. Since February 2006, I have been employed in various positions at MISO including roles in transmission planning, resource adequacy, collaborating with our seams members, and operations planning. In my almost 20 years at MISO, I have been involved with directing the development of the MTEP, studying interconnection of new generation resources, reviewing transmission impacts for resource adequacy, coordinating firm flow entitlements on the transmission system, outage planning coordination, and developing MISO's Long-Range Transmission Planning ("LRTP") initiative.

In addition, I have served on national and regional groups dedicated to ensuring transmission reliability (the ISO/RTO Council, Eastern Interconnect Planning Collaborative, and SERC). Starting in 2020 in my role as a Director of Expansion Planning, I was a member of the leadership team supporting multiple aspects of the LRTP Tranche 2.1 studies, which included model development, economic planning, and development of the business case supporting the LRTP Tranches 2.1 studies ("Tranche 2.1" or "LRTP Tranches 2.1").

Q. What are your duties and responsibilities in your position as the Senior Director of Expansion Planning?

A. As Senior Director of Expansion Planning,[4] my current responsibilities include coordinating the development of the local and regional transmission plans ("MTEP"), in particular ensuring that plans comply with Applicable Reliability Standards.

For LRTP planning, I supported the teams that reviewed technical information and made recommendations regarding transmission needs and transmission solutions. I oversee teams that work with the local or near-term planning involving the collaboration of the local and regional plans.

[4] In October 2025, my title changed from Director of Expansion Planning to Senior Director of Expansion Planning.

I also served as the MISO staff liaison to the MISO stakeholder committee charged with setting the scope and review of the MTEP, the Planning Advisory Committee, during the development of LRTP Tranche 2.1.

Q. Have you ever submitted a sworn affidavit or pre-filed testimony before a regulatory agency?

A. Yes. I have sponsored testimony in various proceedings before FERC on matters relating to MISO, including a matter dealing with the calculation of transmission capability. Most recently, I provided a sworn affidavit regarding local transmission planning in FERC Docket No. EL25-44-000.

II. PURPOSE AND SCOPE

Q. Are you familiar with the transmission project proposed in the Application?

A. Yes. The parties that filed a Joint Application in this docket, Great River Energy, ITC Midwest LLC, and Northern States Power Company, doing business as Xcel Energy (collectively, the "Applicants"), seek a Certificate of Need ("CON"). The Applicants seek authorization to construct the PowerOn Midwest Project (or, the "Project"). The Project includes new 765 kilovolt ("kV") facilities in four segments: (1) the South Dakota/Minnesota state line to the Lakefield Junction Substation, (2) the Lakefield Junction Substation to the Iowa/Minnesota state line, (3) the Lakefield Junction Substation to the Pleasant Valley Substation, and (4) the Pleasant Valley Substation to the North Rochester Substation. The Project also contains a new 345 kV second circuit between the Pleasant Valley Substation, North Rochester Substation, and the Hampton Substation. The transmission lines and related facilities were included in the 2024 MTEP analysis and are identified by MISO as the Minnesota portions of LRTP project numbers 22, 23, 24 and 25. These facilities are an integral part of the LRTP Tranche 2.1 portfolio of transmission projects that were approved as part of MISO's 2024 MTEP process.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to generally expound upon the development of the Project as part of the LRTP Tranche 2.1 portfolio and its benefits to the MISO Midwest Subregion. Specifically, I describe the planning functions performed by MISO, including the development of the MTEP. I also provide a summary of findings regarding the Project based on MISO's analyses and discuss the integration of the Project into MISO's regional plan. I explain how the LRTP Tranche 2.1 portfolio, including the Project, was developed using MISO's seven-step iterative process -- development of possible future scenarios and energy policies ("Futures"), economic and reliability modeling, issue identification, solution evaluation, benefit metrics, the calculation of the benefit-to-cost ratio, and cost allocation.

Q. Please elaborate on the terminology you will use in this testimony.

A. Throughout the testimony, I will refer to the benefits of the Project and the benefits of the 2024 Multi-Value Project ("MVP") portfolio. MVP is a transmission project type within the MISO Tariff. The 2024 MVP portfolio is commonly referred to as the LRTP Tranche 2.1 portfolio. The benefits of the Project are those that accrue to the Project directly. The benefits of the LRTP Tranche 2.1 portfolio are the aggregate benefits of all projects approved as part of the 2024 MVP portfolio, including the Project.

Also, I will refer to the "MISO Midwest MVP Cost Allocation Subregion" (or "Midwest Subregion") in this testimony. The Midwest Subregion begins in Missouri and extends northward to the Canadian border and is bounded by Michigan and eastern Montana. This identification of a subregion within the MISO footprint is relevant to responsibility for costs associated with the LRTP Tranche 2.1 portfolio of which the Project is a part.

Q. What analyses form the basis of your testimony?

A. The Project is part of the LRTP Tranche 2.1 portfolio. A more detailed report on the LRTP Tranche 2.1 projects is included in Appendix E.1 to the Application ("MTEP24 Report").[5] The portfolio was approved by the MISO Board of Directors on December 12, 2024 as part of the MTEP24 process. This approval was based on a set of reliability, economic, and public policy analyses conducted between 2022 and 2024 that documented the reliability and economic issues addressed by

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[5] MTEP24 Report Chapter 2: Regional/Long Range Transmission Planning is Appendix E.1 to the Application. Chapter 2 of the MTEP24 Report discusses the LRTP Tranche 2.1 portfolio, and is publicly available at: https://cdn.misoenergy.org/MTEP24%20Full%20Report658025.pdf. The Project contains the Minnesota portions of LRTP Project Nos. 22-25, which are referred to in the MTEP24 Report as "Big Stone South – Brookings County- Lakefield Junction," "Lakefield Junction – East Adair," "Lakefield Junction – Pleasant Valley – North Rochester," and "Pleasant Valley – North Rochester – Hampton Corner."

the Project and the combined reliability, avoided investment, production cost, and environmental benefits of the full LRTP Tranche 2.1 portfolio.

Q. What are your key findings?

A. Tranche 2.1 develops a 3,631-mile, 345 kV and 765 kV backbone that ensures future reliability while providing benefits to the MISO Midwest Subregion that exceed costs. It includes a $21.8 billion (in 2024 dollars) investment in 24 projects and 323 facilities across the MISO Midwest subregion. The Project, as part of the Tranche 2.1 portfolio, provides an extra-high voltage transmission path that increases the reliability of the regional transmission system while enhancing the ability of the transmission system in Minnesota to meet local load serving needs. The Project is part of the LRTP Tranche 2.1 portfolio that, as part of the MISO regional plan, will enable the reliable and efficient delivery of resources in support of member plans and provide for multiple types of benefits in excess of the portfolio costs when assessed under a future system scenario, known as "Future 2A,"[6] that is guided by consideration of future conditions that include such items as load growth, member plans, and federal and state policies. Additionally, benefits analysis performed under a more conservative scenario, known as "Future 1A," shows that Tranche 2.1 provides a robust transmission network that supports a broad range of generation and policy futures. Support for the Project, as a planned part of LRTP Tranche 2.1 portfolio, is described further in this testimony.

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[6] Future 2A is discussed in the MTEP24 Report, pgs. 10-14.

III. MISO Regional Transmission Planning

Q. What are the requirements and objectives of the MISO regional planning process?

A. Regional planning at MISO is performed in accordance with several guiding documents. The Agreement of Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation ("Transmission Owners Agreement" or "TOA"), includes the planning framework that describes the planning responsibilities of MISO and its transmission owning members.[7] MISO's responsibilities include the development of the MTEP in collaboration with transmission owners and other stakeholders.

MISO also adheres to the nine planning principles outlined in FERC Order No. 890.[8] In so doing, MISO provides an open and transparent regional planning process that results in recommendations for expansion that are reported in the

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[7] *See* MISO Transmission Owners Agreement (TOA), MISO Tariff Rate Schedule 01, Version: 36.0.0 Effective: 7/29/2020, Appendix B, Section VI, publicly available at: https://misodocs.azureedge.net/miso12-legalcontent/Rate_Schedule_01_-_Transmission_Owners_Agreement.pdf.

[8] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009). "The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects." Order 890-B, Attachment K.

MTEP. FERC Order No. 1000 furthered the planning principles outlined in FERC Order No. 890 and included the requirements to plan for public policy and for coordinated inter-regional planning and cost allocation.[9]

Consistent with these planning principles, the objectives of the MTEP process are to (i) identify transmission system expansions that will ensure the reliability of the transmission system that is under the operational and planning control of MISO, (ii) identify expansion that is critically needed to support the reliable and competitive supply of electric power by this system, and (iii) identify expansion that is necessary to support energy policy mandates in effect within the MISO footprint.

MISO implements these practices through its governing and informational documents, including Attachment FF to MISO's Tariff, the TOA, and MISO's Business Practices Manuals ("BPM").[10] MISO's MTEP24 report provides assessments of resource adequacy, analyses of various energy policy scenarios, and discussions of the development of long-term resource forecasts based on those scenarios.

Q. How did FERC Order 1920 impact the development of Tranche 2.1?

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9 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

10 *See* MISO's Business Practices Manual, Transmission Planning, BPM-020-r30, publicly available at: https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/.

A. On May 13, 2024, FERC issued Order No. 1920[11] to revise its policies and requirements regarding Long-Term Regional Transmission Planning and Cost Allocation. Order No. 1920 seeks to enhance forward-looking planning to address changing demand and the change in generation resource mix, improve transparency to allow better coordination between regional and local planning processes, and promote engagement with relevant state entities for purposes of cost allocation. MISO was in the midst of developing Tranche 2.1 at the time of Order No. 1920's issuance and the compliance deadline set by FERC was not until June 12, 2026, with a proposed implementation date for MISO's compliance revisions of June 12, 2028,[12] so Order No. 1920 did not directly influence the development of Tranche 2.1. However, Order No. 1920 expressly recognized that MISO's planning process

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[11] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, *order on reh'g*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024), *order on reh'g and clarification*, Order No. 1920-B, 191 FERC ¶ 61,026 (2025) ("Order No. 1920").

[12] MISO requested and received an extension from FERC until June 12, 2026 for submission of MISO's Order No. 1920 regional compliance filing. Notice of Extension of Time, RM21-17-000 (Dec. 10, 2024). MISO subsequently sought and received an extension to December 12, 2026 for its compliance filing addressing the interregional transmission coordination requirements in Order No. 1920. Motion for Extension of Time to Submit Interregional Compliance Filings of the Midcontinent Independent System Operator, Inc., Docket No. RM21-17-000 (Apr. 15, 2025), *granted by* Notice of Extension of Time (May 23, 2025). MISO requested and received an additional extension of time to submit its interregional filing. Motion for Extension of Time to Submit Interregional Compliance Filings of the Midcontinent Independent System Operator, Inc., Docket No. RM21-17-000 (June 22, 2026) *granted by* Notice of Extension of Time (July 17, 2026).

already incorporates many of the comprehensive regional planning aspects required by the final rule.[13]

Q. What is the planning process used to develop the MTEP?

A. MISO collaborates with its Transmission Owners to ensure the MTEP meets local needs and that the projects contained within it work together in a coordinated fashion. This coordination starts with the ongoing responsibilities of the individual TOs to continuously review and plan to reliably and economically meet the needs of their local systems. MISO then reviews these local planning activities with stakeholders and performs a review of the adequacy, and appropriateness, of the local plans in a coordinated fashion to most efficiently ensure that all of the needs are cost-effectively met.

Q. How does MISO determine if a transmission system has sufficient capacity to meet projected power flows while maintaining required voltage levels and stability?

A. Determining whether a transmission system has capacity sufficient to meet projected power flows while maintaining required voltage levels and stability requires an engineering evaluation of the system as a whole, as well as an evaluation of critical individual system components (transformers, lines, switchgear), under both normal

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[13] Order 1920 at paragraph 102 ("Indeed, in the limited instances in which transmission providers have followed processes that share many of the elements of the long-term, forward-looking, and more comprehensive regional transmission planning this rule requires, customers have seen clear and quantifiable benefits…This process resulted in MISO identifying, evaluating, and selecting transmission facilities that are estimated to generate $2.20 to $3.40 of benefit per dollar invested.").

and contingency conditions (conditions where one or more system components are out of service). Power system simulation models are developed for use in these analyses. Projected power flows for each major component during peak loading conditions are checked to ensure that rated capacities are not exceeded. Voltage levels are also checked to ensure that they are maintained at, or above, the minimum levels required for safe and reliable operation of the system for end-use customers. The model system is tested for both generator and voltage stability following severe disturbances.

Q. Does the MTEP include regional planning?

A. Yes. In addition to considering local needs and the most efficient way to enable the transmission of electricity, MISO, together with stakeholders, considers opportunities for improvements and expansions that would reduce consumer costs by providing access to new low-cost resources that are consistent with and required by evolving legislative energy policies. The planning horizon is longer-term and considers multiple drivers that support changes, such as economics, reliability, and policy directives.

As part of this process, stakeholders from each MISO member sector, including state regulatory authorities, public consumer advocates, transmission owners, end-use customers, and independent power producers, among others, are engaged to help develop a wide range of future system scenarios that are guided by a range of load growth forecasts, resource plans, as well as state and federal energy policy decisions. These possible future scenarios and energy policies (the

"Futures") form the basis for forecasts of generation resources and load that would be economical and consistent with member plans and policy. Transmission needs are then assessed, and plans developed to identify least-regrets transmission development that reliably and economically delivers the necessary energy from generation resources to load under multiple scenarios.

Q. In preparing the MTEP regional plans, what considerations does MISO take into account?

A. There are numerous considerations in planning for a regional transmission system; however, two considerations are crucial. First, the reliability of the transmission system must be maintained. That is, the transmission system must be able to withstand disturbances (generator and/or transmission facility outages) without interruption of service to load. This is achieved, in part, by assuring that disturbances do not lead to cascading loss of other generator or transmission facilities.

Second, the transmission system must be adequately planned to be able to accommodate changes in load and load growth patterns, as well as changes in generation and generation dispatch patterns without causing equipment to perform outside of its design capability. Additional considerations include planning the transmission system to address constraints that limit market efficiency and provide for expansions that enable energy policy mandates to be achieved.

In the near-term horizon, these factors are defined by commitments to specific generation and load assumptions, according to NERC criteria. In a longer-term horizon, multiple scenarios must capture a range of system conditions to "bookend"[14] potential scenarios (as discussed in the MISO Futures explanation further below in my testimony), with studies based on those scenarios identifying transmission that is useful across a number of system conditions, contingencies, and weather patterns. That transmission is the target of LRTP planning.

Q. What does it mean for a project to be approved by the MISO Board of Directors as a part of the MTEP?

A. The MTEP consists of the many individual projects or portfolios of projects that are recommended by the MISO staff to the MISO Board of Directors. In accordance with the TOA, approval of a MTEP by the Board of Directors certifies the MTEP as MISO's plan for meeting the transmission needs of all stakeholders, subject to any required approvals by federal or state regulatory authorities. The Board approval puts an obligation on identified TOs or developers selected as part of a competitive bidding process to make a good faith effort to design, certify, and build the applicable facilities.

IV. <u>LONG RANGE TRANSMISSION PLANNING PROCESS</u>

Q. What is the overall purpose of MISO's LRTP process?

A. LRTP, through its stakeholder process, focuses on the development of robust solutions that pro-actively address future reliability challenges posed on the system,

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[14] A bookend analysis is a strategic planning method that uses a range of future scenarios to understand the potential uncertainty of the future energy landscape. The analysis creates a bracket, or "bookend," by defining both conservative and aggressive scenarios for the region's future resource mix and energy needs.

including those driven by load growth, resource plans, and member policy objectives. Long-range planning provides a comprehensive, forward-looking assessment of future needs based on a range of anticipated future conditions that identify the "least regrets" regional transmission expansion that provides a number of benefits to maintain reliable performance under a range of operating conditions, cost efficient energy delivery, accessibility to resources, and flexibility in resource mix. MISO's LRTP process is coordinated with MISO members and states to identify a transmission system plan that can reliably and efficiently serve load with the resources identified in the MISO Futures.

Q. What is an MVP under the MISO Tariff?

A. An MVP is a type of transmission project developed by MISO and stakeholders that was accepted by FERC in 2010,[15] whose costs are sub-regionally or regionally shared. An MVP must be (i) evaluated as part of a portfolio of MVPs whose benefits are spread broadly across the MISO footprint or subregion and (ii) must meet at least one of the following criteria, as stated in Attachment FF of the MISO Tariff: [16]

> a. Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or

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[15] *Midwest Independent Transmission System Operator, Inc*., 133 FERC ¶ 61,221, at PP 1, 3 (2010), *order on reh'g,* 137 FERC ¶ 61,074, at P 1 (2011) ("MVP Rehearing Order").

[16] MISO Tariff, Attachment FF, Section II.C.

adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

b. Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit-to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.

c. Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.

The Tariff also requires that (1) MVPs must include transmission facilities at a voltage of 100 kV or above and (2) the total capital cost of the transmission project must be at least $20 million.[17]

Q. Why was the MVP cost allocation and planning process developed?

A. As early as 2002, in a process that would lead to approval of the first MVP portfolio in 2011, MISO began to conduct studies to investigate the regional transmission required to provide value to MISO stakeholders while responding to a growing

[17] MISO Tariff, Attachment FF, Section II.C.3(d) & (e).

desire for renewable energy in the MISO footprint. As time and analyses continued, renewable mandates were passed by an increasing number of states in the MISO footprint. At the same time, the MISO Interconnection Queue for generators saw a substantial increase in queued requests, and the study results for those generators continued to show the need for more large-scale transmission projects. These factors led to the definition of an MVP project type, and also led to the ultimate analysis and approval of the 2011 MVP portfolio to meet the policy goals of the states in the MISO Midwest Subregion.

Q. Has the MVP cost allocation been refined since its initial approval?

A. Yes. Subsequent to the approval of the 2011 MVP portfolio, the MISO footprint had a major change with the addition of MISO South in 2013 (*i.e.*, south of Missouri). At the start of the LRTP initiative in 2021, MISO recognized this change and provided an additional option for subregional cost allocation for MVP portfolios. Changes to the MVP cost allocation process were filed with, and accepted by, the Commission in 2022.[18] This included subdividing the MISO footprint into two subregions – the Midwest Subregion and the MISO South MVP Cost Allocation Subregion ("South Subregion"). The Tariff provisions that provide for these subregions recognize that benefits from an MVP portfolio may be widespread and yet mostly contained within geographic subregions in the midwestern and southern portions of the MISO footprint. The Subregional option

[18] *Midcontinent Independent System Operator, Inc.*, 179 FERC ¶ 61,124, at P 1 (2022).

has been applied to two MVP portfolios benefiting the Midwest Subregion: (1) Tranche 1 approved in July 2022; and (2) Tranche 2.1 approved in December 2024.

Q. What is the LRTP Tranche 2.1 portfolio?

A. The LRTP Tranche 2.1 portfolio is a group of transmission projects distributed across the Midwest Subregion that will enable the reliable and efficient delivery of resources in support of member plans and provide for multiple types of benefits in excess of the portfolio costs to the Midwest Subregion, primarily by supporting system reliability, reducing generator production costs and enabling more economically efficient resource and transmission investment. The Tranche 2.1 portfolio was approved as part of MTEP24 by MISO's Board of Directors on December 12, 2024.

Q. What is the relationship between the MVP project type and the LRTP Tranche 2.1?

A. Each project within the LRTP Tranche 2.1 portfolio was determined to be a necessary component of the portfolio, and the entire portfolio was shown to provide benefits that broadly span the MISO Midwest Subregion and meet at least one of the criteria to be classified as an MVP. Consequently, MVP cost allocation was assigned based on a combination of this analysis and a further review of the benefits against costs through the LRTP business case.

Q. Has the MISO Board of Directors approved prior LRTP Tranches?

A. Yes. In July 2022, the MISO Board of Directors approved LRTP Tranche 1 as part of MTEP21. Tranche 1 consisted of 18 projects spread across the MISO Midwest

Subregion. The analysis for Tranche 1 was based on MISO's Future 1 system scenario and had a benefit-to-cost ratio between 2.6 and 3.8. To date, most Tranche 1 projects have gained the necessary state regulatory certificates/franchises. The remaining few are progressing towards any applicable state regulatory determinations.

Q. What factors were considered by MISO and stakeholders in identifying and justifying the LRTP Tranche 2.1 portfolio?

A. MISO worked with stakeholders, including the Applicants, to identify potential transmission solutions that provided future benefits for the MISO Midwest Subregion. These potential transmission solutions were then intensively studied through MISO's open and transparent stakeholder process.

This intensive process began with analyses of the challenges expected from the future resource transition and the need for long-term transmission planning solutions in a number of MISO stakeholder forums. In July 2022, MISO initiated updating of future assumptions used in developing LRTP Tranche 2.1. The Tranche 2.1 projects reached final MISO Board approval in December 2024. MISO conducted over 300 internal and stakeholder meetings, the latter averaging 275 attendees at each meeting, to develop the Tranche 2.1 portfolio.

The overall goal for the LRTP Tranche 2.1 portfolio analyses was to design a transmission portfolio that takes advantage of the linkages between local and regional reliability and economic benefits to ensure a reliable and economic electric market. The portfolio was designed using reliability and economic analyses, applying a Future developed through the stakeholder process to determine a robust portfolio.

Tranche 2.1 work focused on resource changes and load growth contemplated by Future 2A. Key reliability and economic issues provided the foundation to develop Tranche 2.1 as a least-regrets and stand-alone first step towards the transmission required to reliably and efficiently serve load with the resources identified in Future 2A.

Q. Describe Tranche 2.1 further, including the benefits and costs.

A. Tranche 2.1 develops a 3,631-mile 345 kV and 765 kV backbone that ensures future reliability while providing benefits that exceed costs. It includes a $21.8 billion (in 2024 dollars) investment for 24 projects and 323 facilities across the MISO Midwest subregion. Projects are targeted to go in service from 2032 to 2034. Tranche 2.1 highlights are as follows:

- Tranche 2.1 pro-actively provides reliability and efficiency, enabling future generation in support of load growth across the MISO footprint and member plans;
- The portfolio adds a 765 kV backbone to the MISO Midwest to support required energy transfers across the MISO system under multiple future system conditions to support system reliability. With a 765 kV backbone, more electricity can be delivered, while minimizing land use and reducing energy losses; and

- As a portfolio primarily driven to address reliability, Tranche 2.1 provides a broad range of value with a benefit-to-cost ratio ranging from 1.8 to 3.5.

Q. What was the overall process by which the Project became part of the LRTP Tranche 2.1 portfolio of projects?

A. MISO undertook a multi-year planning process with stakeholders to define a range of potential snapshots, or future scenarios, of what the transmission system may look like 20 years in the future, to identify issues in the reliable and efficient transmission of energy from generation to load in these scenarios, and to propose solutions that maintain reliability while lowering total delivered wholesale energy costs.

Specifically, to develop the Tranche 2.1 portfolio, MISO engaged in its iterative seven-step process that includes:

(1) developing scenario-based Future resource forecasting and siting;

(2) developing planning models utilizing the Futures;

(3) identifying potential transmission issues;

(4) proposing solutions to address identified issues with sufficient value;

(5) evaluating and justifying the effectiveness of various solutions, including assessing alternatives;

(6) recommending preferred solutions; and

(7) applying the appropriate cost allocation mechanism.

I discuss the steps below.

Step 1 – Development of Futures

Q. What are Futures?

A. Futures are forward-looking planning scenarios used to understand what generation fleet and load landscapes could look like twenty years into the future. They allow MISO to bookend the uncertainty of the future generation and load needs by defining a range of potential plausible outcomes based on resource plans announced by member utilities and states.

The Futures development process considers economic, policy and technological changes over time to model generation capacity expansion. They allow for multiple rates of change for load growth, generator retirements, fuel prices, decarbonization, renewable energy levels and other factors.

The input from MISO's members and states is critical to the Futures process given that resource planning responsibilities fall to them and not to MISO. Because all transmission planning at MISO is dependent upon the type, location and quantity of future generation, Futures are an essential component in MISO planning processes, including LRTP. MISO's planning process through LRTP optimizes the transmission system to reliably and efficiently serve load with the resources identified in the MISO Futures.

Q. How does MISO develop a Future system scenario?

A. To create the Futures, MISO considers member data, stakeholder input, state and federal policy, and technical and economic data. Using this data, and building from member planned resources, MISO develops multiple generation expansions to bookend potential future conditions, with each expansion developed with sufficient generation to meet projected demand, energy, and resource adequacy requirements. Once these expansions are created, MISO works with stakeholders to site the forecasted generation to maximize resource availability and accommodate member goals.

The LRTP Tranche 2.1 portfolio was developed with a focus on the Future 2A scenario that falls in the middle of the three Future scenarios, including such factors as a mid-level load growth forecast. Future 2A assumes that: (1) utilities and states meet their goals, policies, and announcements; (2) those goals, policies, and announcements result in a 60% reduction in carbon emissions across the MISO footprint from 2005 levels; (3) energy demand increases by 30% due to electrification; and (4) there are accelerated age-based retirements of resources. Future 1A and 2A were used for the benefit metrics analysis to further validate that the portfolio provides benefits in excess of costs.

Future 1A represents the conservative low bookend, assuming that: (1) 100% of utility integrated resource plans and 85% of utility or state goals and policies not supported by legislation are met; (2) carbon emissions decline solely as an outcome of utility and state plans; and (3) load growth is consistent with pre-2019 trends. For the Future 1A resource expansion, 93% of the resources needed were based directly on member submitted resources and 7% were identified by MISO's resource expansion model.[19] For the Future 2A resource expansion, 54% of the resources needed were based directly on member submitted resources and 46% were identified by MISO's resource expansion model.

Q. Did MISO refresh the Futures after the approval of the LRTP Tranche 1 portfolio?

A. Yes. Series 1 (Futures 1, 2 and 3) was developed between 2019 and 2021. Following Board approval of the Tranche 1 portfolio in 2022, MISO refreshed the Futures which resulted in the development of Series 1A (Futures 1A, 2A, and 3A).

MISO posted the Series 1A Futures Report in Fall 2023 and then continued to conduct various screening analyses of the resource mix identified in the Futures scenarios through January 2024. For Tranche 2.1, MISO determined Future 2A represented a mid-level load growth scenario that aligned with an optimized, least-cost expansion to meet member goals and Future 1A was an appropriate low-end bookend for the business case analysis.

Q. How was the load forecast developed for the Futures?

A. The demand and energy forecasts used to support the regional transmission development were derived from the 20-year forecasts of the MISO members with adjustments to reflect market load shape and incorporate projected electrification

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[19] *See* LRTP Workshop (January 26, 2024), "LRTP Tranche 2 Robustness Testing: Low-End Bookend," publicly available at: https://cdn.misoenergy.org/20240126%20LRTP%20Workshop%20Item%2005%20Tranche%202%20Robustness%20Testing%20Low-End%20Bookend631474.pdf.

impacts. Three forecast scenarios were created to represent gross load growth and included varying degrees of electric vehicle adoption and electrification. These scenarios did not include data center specific load growth.[20] EGEAS production cost modeling was then used to analyze energy efficiency programs and determine the adjustments in the load shapes to obtain the net load used in the planning analysis.

Q. How was resource expansion considered in developing the Futures?

A. Since MISO is not the resource planner for the region (*i.e.*, the states are responsible for resource planning), the MISO Futures reflect resource plans informed by member utilities and states, including resources already identified in their integrated resource plans. The model begins with resources identified by members as part of MISO member plans, and then is supplemented as needed using a resource expansion tool to identify a least-cost set of potential generation resources needed to meet projected load, policy objectives, and reserve margins.

MISO is obligated to reflect and define a resource expansion that aligns with the MISO member plans. As such, transmission planning works to ensure the energy planned by members, or required due to their plans or load growth, can be delivered to where it is needed. Additional future resources beyond member plans are required to meet projected load, policy objectives, and reserve margins. To

[20] MISO published its Series 2 Futures Report in June 2026. This report updates MISO's demand and generation forecasts, including data center specific load growth estimations.

bridge this gap, MISO performs an economic resource expansion analysis, which forecasts the additional resources to meet system needs at lowest cost.

Q. How was resource siting considered in developing the Futures?

A. The Future scenarios development culminates in a siting process that maximizes resource availability and accommodates member goals. After the number and composition of resources are identified, siting analysis defines where these resources are located within the MISO footprint. MISO followed a stakeholder-approved siting process that was addressed in the Series 1A Futures Report[21] and Futures Refresh Assumptions Book.[22] As part of this process, MISO sited model-built resources considering:

- Member identified locations;
- Resource adequacy requirements: Each Local Resource Zone ("LRZ") must meet its Local Clearing Requirement ("LCR") and the footprint-wide Planning Reserve Margin Requirement ("PRMR");[23]

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[21] *See* MISO Futures Report Series 1A (2023), publicly available at: https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

[22] *See* MISO LRTP Tranche 2 – Futures Refresh (April 27, 2023), publicly available at: https://cdn.misoenergy.org/20230428%20LRTP%20Workshop%20Item%2003b%20Futures%20Refresh%20Assumptions%20Book628727.pdf.

[23] In MISO's resource adequacy construct, resource adequacy is assessed on a MISO footprint and zonal basis. These zones are referred to as LRZs. Each LRZ must obtain a minimum amount of capacity each season, known as the Local Clearing Requirement. On a footprint basis, MISO establishes the Planning Reserve Margin ("PRM"), which is the percentage above forecasted demand to meet the 0.1 day/year Loss of Load Expectation. The PRM sets the amount of capacity that load serving entities in MISO must collectively obtain to meet the resource adequacy needs of the

- o Policy goals: local, state, and regional renewable portfolio standards and decarbonization goals;
- o Additional resource type siting considerations:
  - ▪ Split of 80% Generator Interconnection ("GI") queue and 20% Vibrant Clean Energy[24]/Greenfield Sites with renewable potential used for renewable resources;
  - ▪ Batteries were sited with a bias towards high load centers (80%), with the remaining 20% sited close to other generation;
  - ▪ Thermal resources were sited at active GI queue sites and brownfield retirement sites as needed;
  - ▪ Radial lines and associated buses were excluded from potential resource sites, and sited capacity could not exceed a site's single element outage (N-1) capability; and
  - ▪ Flexible attribute units sited at brownfield thermal locations.

Once the expansion was determined, MISO worked with stakeholders to finalize resource sites, resulting in over 500 revisions based on stakeholder feedback.

Step 2 – Develop Planning Models Utilizing Futures

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region. The PRMR refers to the amount of capacity that each LSE must obtain to meet its resource adequacy requirements.

[24] MISO commissioned Vibrant Clean Energy ("VCE") in 2016 to perform a MISO high penetration renewable energy study to assess carbon emissions reductions in future scenarios. In 2018 Vibrant Clean Energy conducted additional analysis to supply enhanced data sets of detailed renewable siting information for use in MISO future resource assessments.

Q. What did Step 2 involve?

A. MISO developed reliability and economic models to assess system performance expected under future conditions. For the reliability analysis, MISO built 10-year and 20-year models initialized from MTEP22 models and incorporated changes to reflect expected transmission topology and Future 2A load forecast and resource changes. The resulting series of reliability study models reflect seasonal load and generation dispatch conditions and include additional transfer scenarios to cover a range of 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.

For the economic analysis, MISO built 10-year, 15-year and 20-year economic models that reflect updated network topology and Future 2A load forecast and resource changes. As part of this analysis, economic modeling utilizes PROMOD, a chronological security-constrained unit commitment and economic dispatch tool which applies to 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.

These broad base economic and reliability models encompassed multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus allowing the platform to perform a wide range of economic and reliability analyses. A full list of models with assumptions is found in the MTEP24 Report.[25]

Q. Did stakeholder input play a role in developing the reliability models?

A. Yes. MISO conducted a series of workshop discussions with stakeholders to review the proposed approach to reliability studies and developed a reliability analysis methodology whitepaper to describe the process used to build models and conduct reliability analysis. The initial development established the need for a set of core models that represent various seasonal conditions in the 10-year and 20-year timeframe and a set of potential credible transfer scenarios that cover a range of dispatch variability. Further discussions included more details on the proposed methodology used to determine renewable generation dispatch levels and the proposed transfer scenario conditions for which MISO requested stakeholder feedback. MISO subsequently revised the transfer scenario definitions and adopted additional scenarios to cover a wider range of conditions to address stakeholder comments.

Q. Did stakeholder input play a role in developing the economic models?

A. Yes. MISO engaged stakeholders in a series of workshops that included discussions of the economic modeling process and updates to be applied to produce the economic models for the LRTP economic study. Once the economic models were developed, stakeholders with the appropriate access rights were allowed to review

[25] MTEP24 Report at pgs. 15-22.

and provide feedback on model details related to transmission ratings, generator attributes, and any other discrepancies. MISO worked with stakeholders to address modeling concerns and updated the model as needed. Further stakeholder discussions included a review of the natural gas price forecasting process used to more accurately align natural gas prices with the level of demand in the production cost simulations. MISO subsequently reviewed the flowgate identification process used to identify transmission constraints for inclusion in PROMOD event processing and posted results for stakeholder feedback that resulted in updates to the event files used for the LRTP Tranche 2.1 economic analysis.

Step 3 – Identify Potential Transmission Issues

Q. What does Step 3 involve?

A. 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 assess transmission needs and determine the most cost-effective and reliable solutions.

Tranche 2.1 work focused on resource changes and load growth contemplated by Future 2A. Key reliability and economic issues provided the foundation to develop Tranche 2.1 as a least-regrets and stand-alone first step towards the transmission required to reliably and efficiently serve load with the resources identified in Future 2A.

Q. What were the reliability analyses that MISO performed for Tranche 2.1?

A. The reliability analysis included 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. A detailed reliability analysis using power flow simulations was conducted to identify transmission system equipment loadings and voltages with respect to safe equipment design tolerances. The MISO reliability analyses included several different types of simulations, each targeting different information about performance, as described below:

- Steady-State - determines if transmission facilities remain within safe design limits (line loading and voltage) following disturbances;
- Transient stability - determines if the system experiences uncontrolled loss of load or generation following disturbances, focusing on voltage and frequency performance; and
- Transfer analysis assesses the impact of various system conditions, dispatch patterns, and intra-regional power transfer limit, focusing on line loading and voltages.

Q. What was considered during the reliability analysis?

A. MISO's steady state analysis included 10-year and 20-year models, described in the MTEP24 Report, and monitored all system elements operated at 100 kV and above within the MISO Midwest Subregion, as well as tie lines to the South Subregion and neighboring transmission systems. Category P1-P7 contingency events from the NERC Transmission Planning Reliability ("TPL") Standard were analyzed for the transmission system impacts within the MISO Midwest Subregion. All system elements where the worst loading was 100 percent or higher of the applicable rating were flagged as potential issues. A project is effective in resolving facility overloading if the worst loading is below 100 percent of the emergency rating after the addition of the transmission project.

Q. What was considered during the economic analysis?

A. Economic analysis required a market-type dispatch reflective of MISO Futures modeling and planned topology set by the MTEP power flow model 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. The economic analysis used several economic indicators to assess the performance of the system, as described below:

- Congestion measure ($/MW) - the production cost savings opportunity from relieving transmission congestion (*i.e.* reducing electric flow from exceeding transmission capacity);

- Curtailment (MWh) - a measure of the total amount of energy from renewable sources that cannot be delivered economically; and
- 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.

Q. What did the economic and reliability analyses show?

A. The economic and reliability analysis showed significant levels of overload on lower and higher voltage equipment across the footprint and severe voltage violations due to decreased reactive performance across the system. Without additional transmission to strengthen the transfer capability across the multi-state Midwest Subregion, the longer distance for power to travel between future resources and load causes increased voltage angle and reduced stability limits and results in greater stress on the system. Similarly, the economic analysis showed severe widespread congestion, price separation and significant generation curtailment due to congestion on the transmission system. Results also revealed opportunities to provide additional benefits by resolving energy losses from power transfers on existing transmission and by mitigating economic congestion. MISO reviewed the economic and reliability study findings with stakeholders, and posted results for feedback to incorporate for further analysis and solution testing.

Step 4 – Propose Solutions

Q. What does step four involve?

A. As MISO understood the impacts of member plans throughout the planning process, conceptual ideas were developed and then refined to create potential transmission solutions. In December 2022, MISO shared a hypothetical roadmap taking concepts from its initial long-term roadmap shared in 2021. This conceptual map was not based on new analysis; instead, it served to jumpstart conversation to determine the optimal voltage and transmission type (*e.g.*, 765 kV vs 345 kV; AC vs DC) for the overlay and was informed from prior transmission studies (*e.g.*, Tranche 1, MTEP annual studies, Generator Interconnection). This conceptual map was then updated in March 2024 based on the reliability and economic results and amended further based on stakeholder feedback in June 2024, focusing on a 765 kV regional solution to accommodate the higher regional transfers identified in the reliability and economic analysis. Some considerations regarding the performance of 765 kV included:

- Higher Transmission Rating Limits;
- Cost per MW-Mile; and
- Land-Use per MW-Mile. [26]

Q. Describe further why a 765 kV regional solution was considered.

A. There were three primary reasons – loading capability, cost efficiency, and less land use. When considering the per MW-mile capability of 765 kV and 345 kV lines,

[26] For additional discussion, *see* March PAC material (March 8, 2023) - https://cdn.misoenergy.org/20230308%20PAC%20Item%2007%20Discussion%20of%20765%20kV%20and%20HVDC628088.pdf

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.[27]

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 more costly to develop the system slowly and incrementally using sub-extra high voltage transmission only.

Given 345 kV is a legacy voltage in MISO Midwest, a hybrid regional solution making significant use of both 765 kV and 345 kV facilities was 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

[27] Safe Loading Limit is defined as the maximum amount of power it can conduct without causing damage, compromising system stability, and voltage limits.

765 kV is 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.

Q. When did MISO issue its anticipated LRTP Tranche 2.1 portfolio?

A. It was shared with stakeholders at the March 15, 2024 LRTP Workshop. As a part of issuing the anticipated LRTP Tranche 2.1 portfolio, MISO continued to analyze the anticipated portfolio, including the evaluation of stakeholder submitted alternatives and notified stakeholders as new analyses were performed and updates made to the Tranche 2.1 portfolio. A near final Tranche 2.1 portfolio was shared with stakeholders at the June 10, 2024 LRTP Workshop.

Q. Did MISO conduct robustness testing of solutions?

A. Yes. Robustness testing refers to a process for reviewing the impact of system changes. This testing was conducted during portfolio evaluation. A key objective of robustness testing is to identify key projects that were either approved or in the process of approval after the finalization of LRTP power flow models in October 2023, which may have a material impact on the anticipated Tranche 2.1 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. No modifications were required to the LRTP Tranche 2.1 portfolio as a result of robustness testing.

Q. Were alternatives considered?

A. Yes. MISO undertook an analysis of alternatives. 97 projects representing 47 solutions were received from stakeholders. Not all these solutions needed to be evaluated. MISO focused on alternatives that were more closely aligned with the same issues and needs that drove the solutions for this portfolio; various alternatives were similar in location; and some alternatives were likely to be otherwise constructed to address other transmission issues. Additionally, some solutions were evaluated along with various alternatives received from stakeholders and developed by MISO staff while other projects addressed more local versus regional needs and were more suited for the annual MTEP reliability planning and the generator interconnection processes.[28]

Q. Did MISO consider Grid Enhancing Technologies ("GETs") in developing the Tranche 2.1 portfolio?

A. Yes. MISO considered GETs and reviewed their impacts with stakeholders during the planning process. Stakeholders also had the ability to propose GETs as potential solutions during the development of Tranche 2.1.

GETs include hardware and software intended to increase the capacity and efficiency of the transmission system without major overhauls to transmission infrastructure (*e.g.* dynamic line ratings, power flow control, and topology optimization). GETs can provide incremental upgrades to the transmission system

[28] The assessment of alternatives in Step 5 resulted in adjustments and additions to the portfolio in Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, and South Dakota.

to address specific local issues. GETs were selected for certain underbuilt projects in Tranche 2.1. Transmission developers may also optimize the final design of assigned transmission projects, including by incorporating GETs, after approval of a project by the MISO Board.[29]

Step 5 – Evaluate and Justify Solutions, Including Assessing Alternatives

Q. What does Step 5 involve?

A. In this step, MISO assessed the proposed solutions (developed in Step 4) and any alternative options submitted by stakeholders. This evaluation is highly data-driven and includes the following elements:

- *Reliability and Economic Modeling with Solutions* - MISO develops new reliability and economic models that incorporate the proposed transmission solutions;
- *Effectiveness Testing* - MISO evaluates how well the solutions address the reliability and economic transmission issues identified in Step 3, such as thermal overloads, voltage problems, and increased congestion and curtailment;
- *Additional Alternative Analysis* - Submitted alternative solutions are reviewed and tested for their effectiveness; and

[29] These after-the-fact optimizations must also "comport with the approved MTEP" and be accepted by MISO. MISO Tariff, Attachment FF, Section VI.C.

- *Business Case Analysis* - Projects and portfolios are tested against a range of future scenarios (or "bookends") using multiple types of benefits to ensure they provide long-term value, even if the future evolves differently than expected. For example, for LRTP Tranche 2.1, the portfolio was tested against a lower-end "Future 1A" scenario.

Q. What benefits did the reliability assessment for the LRTP Tranche 2.1 portfolio show?

A. Analysis with twelve reliability models representing various system conditions and dispatch patterns helped MISO better understand system performance from a reliability perspective with and without the LRTP Tranche 2.1 portfolio. MISO monitored flow on lines and voltage at substations with and without the LRTP Tranche 2.1 portfolio.

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 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 indicated significant improvement in the overall system performance.

The reliability analysis demonstrated the following results on the performance of the LRTP Tranche 2.1 portfolio using Future 2A:

- resolves more than 60% of >200 kV constraints for single initiating and multiple element contingency events;
- resolves more than 70% of thermal violations, on average, for all voltage levels based on paired contingency;
- reduces majority of the loadings below Safe Loading Limits; and
- enables regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty.

Q. Does the LRTP Tranche 2.1 portfolio provide voltage and reactive support?

A. Yes. To enhance system reactive support and reduce reliance on other voltage support devices, MISO intentionally planned the system for higher Surge Impedance Loading ("SIL") capability 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.

Q. Does Tranche 2.1 enhance overall stability of the transmission system?

A. Yes. 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 Transient Stability Index ("TSI") is an industry accepted metric used in TSAT (Transient Security Assessment Tool) that assesses the severity of each disturbance. A higher TSI for a disturbance represents a more stable system response. The Tranche 2.1 portfolio resolved 90% of the transient voltage violations in the 2042 Average load model and 30% of the transient voltage violations in the 2042 Summer Peak load model. In addition, the Tranche 2.1 portfolio resolved all low damping violations and reduced the number of transient voltage violations in both 2042 Average load and 2042 Summer Peak load models.

Q. What benefits did the economic analyses for Tranche 2.1 show?

A. Analyses with annual economic models evaluated various system conditions and dispatch patterns that helped MISO better understand system performance with and without the LRTP Tranche 2.1 portfolio. 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 demonstrated the following results on the performance of the LRTP Tranche 2.1 portfolio using Future 2A:

- reduces economic congestion on existing transmission across the MISO Midwest Subregion by 29.5%;
- facilitates a more economical dispatch for the MISO Midwest Subregion resulting in $8.1B in Adjusted Production Cost ("APC") savings;
- 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 subregion and decreasing system cost to serve load; and

- provides a robust regional backbone supporting 115.7 gigawatts ("GW") of Future 2A resource enablement.

Q. How does MISO use business case analysis to assess the monetary benefits provided by the LRTP Tranche 2.1 portfolio?

A. MISO assesses proposed transmission solutions using multiple benefit metrics and scenarios to ensure the projects are least-regrets and cost-effective. Key evaluation criteria include:

- **Scenario testing:** MISO evaluates the benefits of solutions under different future resource mix and load scenarios to ensure they are durable and effective across a range of potential conditions.
- **Benefits evaluation:** Solutions must demonstrate multiple types of value to customers such that the analysis shows benefits in excess of costs.

Q. What benefit metrics were used for the LRTP Tranche 2.1 portfolio evaluation?

A. MISO leveraged previous benefit metric work on the LRTP Tranche 1 portfolio and developed in collaboration with stakeholders additional metrics to capture the full monetary value of the LRTP Tranche 2.1 portfolio. That work with stakeholders resulted in the nine benefit metrics listed below with definitions, which were used to demonstrate the value of the LRTP Tranche 2.1 portfolio under Futures 1A and 2A:

1. Mitigation of reliability issues - value of alleviating reliability issues which, if unresolved, introduce a risk of unserved load;
2. Reduced risks of extreme weather impacts - increases grid resilience and decreases the probability of major service disruptions;
3. Avoided capacity cost – value of savings in resource investment that results from the increased transfer capability enabling access to a more geographically diverse pool of resources;
4. Capacity savings from reduction in losses - value of reducing transmission losses during peak capacity periods;
5. Avoided transmission investment - avoids the need for facility replacement due to age and condition;
6. Congestion and fuel savings - enhances market efficiency and provides access to low-cost generation;
7. Energy savings from 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 outages; and
9. Decarbonization - enables the economic dispatch of renewable resources to help reduce the carbon footprint.

Q. Were there further enhancements to the benefit metrics listed above in comparison to the six benefit metrics used for the LRTP Tranche 1 portfolio?

A. Yes, MISO engaged stakeholders on the development of Tranche 2.1 benefit metrics at the start of the Tranche 2.1 study in January 2023 through the LRTP workshops. Over the next 18 months, MISO continued to engage stakeholders on the methodology development for each benefit metric.

MISO started the discussion with the Tranche 1 benefit metrics and proposed changes to certain metrics and identified new benefit metrics for consideration. Stakeholders were provided numerous opportunities for input throughout the process. Ultimately adjustments were made to the methodologies to reflect: (a) the updated Futures; (b) more rigorous calculation to ensure distinct benefits without overlap; and (c) further development of metrics that had been deferred in the earlier Tranche 1 effort, including benefits associated with losses, transmission outages, and reliability. Further details on changes made to benefit metrics from Tranche 1 to Tranche 2.1 included:

- Inclusion of a benefit metric analysis using Future 1A to ensure robust, least-regrets transmission solution;
- Decision to not use resource adequacy metric to ensure no overlapping value with avoided resource cost benefit metrics;
- Focused congestion and fuel savings on transmission value by including a consistent resource set across reference and change cases;

- Enhanced reduced risks from extreme weather impacts to include a probabilistic approach versus deterministic for identifying weather events; and
- Incorporated additional benefit metrics to capture unaddressed types of transmission benefits in Tranche 1 (*i.e.*, energy and capacity savings from reduced losses, transmission outage production costs, and mitigation of reliability issues).

Q. Describe further the methodology MISO undertook to quantify the benefits using the metrics.

A. Each benefit metric represents a distinct piece of the overall value resulting from the LRTP Tranche 2.1 portfolio. 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 the LRTP Tranche 2.1 portfolio on specific financially quantifiable measures that reflect the value of the investment.

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 also over a 40-year period to demonstrate the additional value provided by the portfolio over the many decades beyond 20-years that 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 discount 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 focused on Future 2A, the benefits analysis was also performed using Future 1A to provide a lower-bookend representation of the value the portfolio provides.

Q. What were the overall benefits of Tranche 2.1?

A. The $21.8 billion LRTP Tranche 2.1 portfolio has a benefit-to-cost ratio of 1.8 - 3.5 under Future 2A, which reflects net benefits potentially exceeding $72 billion. This means for every dollar invested, the projects are projected to have a return of $1.80 to $3.50 in benefits. Even under the more conservative Future 1A the LRTP Tranche 2.1 Portfolio has a benefit-to-cost ratio of 1.2 to 2.2.

Table 1 below provides a summary of each benefit metric, including an explanation of the value provided, and each metric's quantified monetary value using Future 1A and 2A over the initial 20-years of in-service life for the LRTP Tranche 2.1 portfolio.

Benefit Metric	Analysis Results	Future 1A – 20-year Value (2024$)	Future 2A – 20-year Value (2024$)
Mitigation of Reliability Issues	Projects provide value by proactively addressing numerous thermal overloads that reduces risk of unserved load.	\$8.5B - \$24.3B	\$14.8B - \$42.4B
Reduced risks of extreme weather impacts	Projects provide increased transfer capability that improves system performance during extreme weather events.	\$0.3B - \$0.7B	\$0.4B - \$1.1B
Avoided capacity cost	Projects increase transfer capability, which enhances resource diversity by allowing access to resources across the region and avoids the need for 15 GW under Future 1A and 20.5 GW under Future 2A.	\$14.3B	\$16.3B
Capacity savings from reduction in losses	Projects decrease transmission system losses and avoid the need for 1.8 GW under Future 1A and 2.3 GW under Future 2A.	\$1.8B	\$1.9B
Avoided transmission investment	Projects avoid the need for replacement of over 700 miles of existing transmission.	\$1.2B	\$1.2B
Congestion and fuel savings	Projects alleviate transmission constraint violations and reduce congestion to allow more efficient dispatch of lower cost resources.	\$2.9B	\$8.2B
Energy savings from losses	Projects provide additional transmission capacity and redistribute flows to reduce system energy losses.	\$1.2B	\$1.6B
Reduced transmission outage costs	Projects provide additional transmission capacity that helps to enhance operational flexibility and reduce congestion during transmission outages.	\$0.2B	\$0.08B
Decarbonization	Projects alleviate congestion, allowing for more efficient dispatch of non-emitting resources to reduce CO_2 emissions.	\$3.9B - \$15.3B	\$7.2B - \$28.3B
Total		\$34.3B - \$61.9B	\$51.7B - \$101.0B

Table 1

Q. Did stakeholders have the opportunity to provide input on the metrics that MISO used and the results of the analyses that were undertaken?

A. Yes. MISO conducted several in-depth discussions with stakeholders to present the details of the calculation methodologies for the benefit metrics and request feedback. As the effort progressed, MISO refined the details and made additional presentations to stakeholders in a series of ongoing discussions to seek more feedback on the approaches used to quantify benefits and further adjustments were made to address concerns of overlapping benefits. As a result of this collaboration with stakeholders:

- More robust methods were developed to isolate benefits from risk of unserved energy under extreme conditions from benefits related to capacity cost savings.
- Avoided transmission investment was simplified to remove avoided reliability upgrade costs that potentially overlapped with the mitigation of reliability issues benefit.
- Resource adequacy savings were eliminated to avoid double counting the reduction in planning reserves used in the avoided capacity cost benefit.
- Ramping flexibility was discontinued due to difficulty in implementation.
- Mitigation of reliability issues was further revised to avoid overlap with production cost savings and to eliminate potential for double counting of issues in the later study years.
- Other adjustments were made to update carbon costs, transmission cost estimates, and remove the resource enablement component from the congestion and fuel savings benefit.

The resulting nine benefit metrics represent distinct benefit components that capture the value of the LRTP Tranche 2.1 portfolio.

<u>Step 6 – Recommend Preferred Solutions</u>

Q. What occurs in Step 6?

A. During the sixth step of the LRTP process, MISO and stakeholders review analysis of proposed transmission portfolios and alternatives to recommend final, preferred solutions. The analysis examines reliability, economic benefits, and other performance metrics to determine the optimal portfolio. This step is built on a transparent, stakeholder-driven process, which concludes with a recommendation to stakeholders and the MISO Board of Directors after identifying the applicable cost allocation in Step 7.

Q. Discuss the Board of Directors review further.

A. Following stakeholder review and feedback, the portfolio is presented for approval. It is first reviewed and voted on by the Planning Advisory Committee ("PAC") to recommend to the Board of Directors for approval. It then moves to the System Planning Committee of the MISO Board of Directors. Finally, the portfolio is presented to the full MISO Board of Directors for approval, which typically occurs in December. For Tranche 2.1, the PAC review and motion occurred on November 8, 2024 and the System Planning Committee review and motion occurred on November 19, 2024.

Q. What portfolio resulted from Step 6?

A. The Board of Directors approved Tranche 2.1 on December 12, 2024. As I noted earlier, the portfolio includes 24 projects and 323 facilities across the MISO Midwest Subregion with an estimated cost of $21.8 billion and is targeted to go in service from 2032 to 2034.

Step 7 - Apply Appropriate Cost Allocation

Q. What happens in Step 7?

A. Cost allocation of the LRTP Tranche 2.1 portfolio was determined in Step 7. Analysis of the nine benefit metrics included identifying the distribution of each benefit across the Cost Allocation Zones ("CAZ") in the Midwest Subregion. The distribution of benefits of the LRTP Tranche 2.1 portfolio demonstrated that a subregional cost allocation approach (*e.g.* MVP cost allocation) is appropriate given the benefits are in excess of costs for each CAZ in the Midwest Subregion under Futures 1A and 2A.

Q. Did MISO consider the rate recovery of the Tranche 2.1 costs and the value to the CAZ?

A. Yes. As MVPs, 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). This recovery methodology is implemented in Attachment MM of the MISO Tariff.[30] Additionally, indicative annual MVP usage rates for the LRTP Tranche 2.1

[30] *See* MISO Tariff, Attachment MM, Multi-Value Project Charge ("MVP Charge").

portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. The MVP Usage Rate for LRTP Tranche 2.1 portfolio 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 LRTP 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 the Future 2A analysis.

V. PROJECT RELIABILITY AND ECONOMIC ASSESSMENT

Q. Did MISO perform analyses to determine the effectiveness of the Project to provide a reliable supply of electric energy to customers and promote the development of a competitive and efficient electric market?

A. Yes. The LRTP Tranche 2.1 portfolio analyses evaluated the expected future conditions on the MISO regional transmission system. MISO's analyses found that the Project will be needed in order to ensure the continued reliable operation of the regional transmission system, including the Applicants' transmission systems in Minnesota.

In addition, MISO's analyses show that the LRTP Tranche 2.1 portfolio, which includes the Project, provides additional connectivity across the transmission system, reducing congestion and enabling access to a broader array of resources by customers in Minnesota. These improvements will increase market efficiency and the competitive supply of energy, and will provide economic benefits to retail electric consumers well in excess of the LRTP Tranche 2.1 portfolio costs. The

LRTP Tranche 2.1 portfolio represents a holistic solution for delivering these benefits when considering generation, transmission, and other factors under expected future conditions.

Q. What are the areas of concern in Minnesota, as determined in the steady state analysis?

A. The Project is part of the transmission facilities across southern Minnesota that provide connectivity from generation resources in North and South Dakota and southwestern Minnesota to the load centers in Minnesota and Wisconsin. The project addresses over 250 overloads across southern Minnesota, including a number of severe post contingent overloads in excess of 125%. The Project adds transmission capacity that shifts regional power transfers from the underlying network to the 765 kV backbone which significantly reduces curtailment of generation to improve energy delivery in Minnesota and the neighboring states.

Q. What are some key thermal constraints mitigated by the Project?

A. The Project, along with the connecting facilities,[31] resolves thermal violations on 33 overloaded transmission facilities for N-1 contingency events and 47 overloaded facilities for N-1-1 contingency events in the Minnesota area.[32] The highest loaded

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[31] "The Project" and "the connecting facilities" refer to LRTP Tranche 2.1 Projects 22-26 as defined in Chapter 2 of the MTEP24 Report. The Minnesota portion of LRTP Tranche 2.1 Project 26 is the subject of MPUC Docket No. CN-25-121 and is called the Gopher to Badger Link Transmission Line Project in the application.

[32] An "N-1" event includes NERC TPL Category P1, P2, P4, P5 and P7 contingencies and means that the grid experiences the outage of a single transmission circuit, transformer, generator, shunt device, or common transmission structure. An "N-1-1"

Bulk Electric System ("BES") elements in Minnesota that experienced excessive loading under N-1 and N-1-1 contingency conditions are listed below.

The highest N-1 violations are as follows:

- Panther – Mcleod 230 kV #1;
- Minn Valley – Granite Falls 230 kV #1;
- Minn Valley Tap – Panther 230 kV #1;
- Hazel Creek 345/230 kV Transformer #9;
- Kerkhoven Tap – Kerkhoven 115 kV #1;
- Helena – Hampton Corner 345 kV #2;
- AS King – Eau Claire 345 kV #1;
- Helena – Scott County 345 kV #1;
- Wilmarth – Crandall 345 kV #1;
- Prairie Island – North Rochester 345 kV #1;
- Byron – Pleasant Valley 345 kV #1;
- Wilmarth – Sheas Lake 345 kV #1;
- North Rochester – Byron 345 kV #1;
- Wabaco – Kellogg 161 kV #1;
- Alma – Kellog 161 kV #1;
- Blue Earth – Huntley 161 kV #1;
- Wabaco – Rochester 161 kV #1;
- Adams – Beaver Creek 161 kV #1;
- Byron – Pleasant Valley 161 kV #1;
- Rutland – Fox Lake 161 kV #1;
- Genoa – Harmony 161kV #1;
- Adams 345/161 kV Transformer #9;
- Wilmarth – Swan Lake 115 kV #1;
- Minn Valley – Redwood Falls 115 kV #1;
- Cedarmont Transformer 115 kV #1;
- Franklin – Cedarmont 115 kV #1;

event includes NERC TPL Category P3 and P6 contingencies and means that a sequence takes place consisting of an initial loss followed by another loss of a single transmission circuit, transformer, generator, shunt device, or common transmission structure.

- Wilmarth 345/115 kV Transformer #9;

The highest N-1-1 violations are as follows:

- Panther – Mcleod 230 kV #1;
- Minn Valley Tap – Panther 230 kV #1;
- Minn Valley – Granite Falls 230 kV #1;
- Hazel Creek 345/230 kV Transformer #1;
- Swan Lake – Stockton Tap 115 kV #1;
- Lake Mina – Brandon 115 kV #1;
- Bigstone – Highway 12 115 kV #1;
- Helena – Hampton Corner 345 kV #2;
- Prairie Island – North Rochester 345 kV #1;
- Byron – Pleasant Valley 345 kV #1;
- North Rochester – Byron 345 kV #1
- AS King – Eau Claire 345 kV #1;
- Wilmarth – Crandall 345 kV #1;
- Wilmarth – Huntley 345 kV #1;
- Wilmarth – Sheas Lake 345 kV #1;
- Prairie Island – Hampton Corners 345 kV #1;
- North Rochester – Tremval 345 kV #1;
- Rutland – Fox Lake 161 kV #1;
- Rutland – Huntley 161 kV #1;
- Alma – Kellogg 161 kV #1;
- Huntley 345/161 kV Transformer #1;
- Wabaco – Rochester 161 kV #1;
- Adams – Beaver Creek 161 kV #1;
- Austin – Murphy Creek 161 kV #1;
- Fort Ridley – Franklin 115 kV #1;
- Minn Valley 230/115 kV Transformer #5;
- South Bend – Northport 115 kV #1;
- Minn Valley – Redwood Falls 115 kV #1;
- Wilmarth – Northport 115 kV #1;
- Wilmarth – Swan Lake 115 kV #1;
- Wilmarth 345/115 kV Transformer #9.

Q. What contingencies resulted in the steady state issues relieved by the Project and the connecting facilities?

A. Approximately 135 unique N-1 contingencies resulted in overloading of facilities in Minnesota that are relieved by the incorporation of the Project, along with the connecting facilities, into the transmission system. The most excessive overloads result from the outage of 230 kV and 345 kV transmission facilities in southwestern Minnesota. The Project also alleviates facility overloading associated with 3700 unique N-1-1 contingency combinations.

Q. What impact did the Project and the Tranche 2.1 portfolio have on congestion in the surrounding area?

The full Tranche 2.1 portfolio, including the Project, reduced the total congestion measure in Minnesota by $1,030,742/MW. The flowgates with the greatest reduction in congestion in Minnesota and the surrounding areas are listed in the table shown below:

TABLE 2: Congestion Measure by Flowgate Constraint

Flowgate Constraint	Congestion Measure
Event 43: HUC-MCLEOD 4 230kV - HUC-MCLEOD 7115 kV (NSP-OTP) [1]	$124,771
Event 131: RUTLAND5 161kV - FOX LK 5161 kV (SMP-ALTW) [1]	$84,343
Event 147: BLUE LK3 345kV - SCOTTCO3345 kV (NSP) [1]	$35,672
Event 33: BLUE LK3 345kV - HMPT CNR3345 kV (NSP) [1]	$28,922
Event 588: BARTON5 161kV - LIME CK L2 5161 kV (ALTW) [1]	$19,367
Event 144: ADAMS 3 345kV - ADAMS 5161 kV (NSP-ALTW) [9]	$18,194

Base Case: ALMA 5 161kV - KELLOGG 5161 kV (DPC) [1]	$17,093
Base Case: BIGSTON4 230kV - YBUS770100 kV (OTP) [2]	$15,099
Event 1444: WILMART3 345kV - HUNTLEY3345 kV (NSP-ALTW) [1]	$10,372
Event 44: HUC-MCLEOD 4 230kV - HUC-MCLEOD 7115 kV (NSP-OTP) [1]	$8,200
Event 393: HANKSON4 230kV - FORMAN 4230 kV (OTP) [1]	$5,781
Event 256: BRIGGS RD 5 161kV - TREMVAL5161 kV (NSP) [1]	$5,038
Event 251: WEBSTER5 161kV - SUB T FD 5161 kV (MEC) [1]	$4,729
Event 79: WILMART3 345kV - SHEAS LK3345 kV (NSP) [1]	$4,619
Event 147: HELENA 3 345kV - SCOTTCO3345 kV (NSP) [1]	$4,446
Event 54: BIGSTON4 230kV - BROWNSV4230 kV (OTP) [1]	$3,570
Event 395: HAYWARD L2 5 161kV - GLENWRTH5161 kV (ALTW) [1]	$3,456
Event 376: RAUN 3 345kV - S3451 3345 kV (MEC-OPPD) [1]	$3,289
Event 874: SPLT RK3 345kV - SIOUXCY-LNX3345 kV (NSP-WAUE) [1]	$2,851
Event 172: RAUN 3 345kV - S3451 3345 kV (MEC-OPPD) [1]	$1,940
Base Case: WABACO 5 161kV - KELLOGG 5161 kV (DPC) [1]	$1,924
Base Case: BRKNGCO3 345kV - BRKNGCO7115 kV (NSP) [9]	$1,739
Event 46: BIGSTON4 230kV - BROWNSV4230 kV (OTP) [1]	$1,363
Event 71: SPLT RK4 230kV - SIOUXFL4230 kV (NSP-WAUE) [1]	$1,253
Event 222: PINE LK5 161kV - PINE LK7115 kV (NSP) [3]	$1,037

Q. Did MISO consider alternatives to the Project?

A. MISO examined a northern 765 kV path from Brookings – Chisago County – Highway 22 – Paddock as an alternative project to strengthen the connectivity into the load centers in Wisconsin and Illinois. This configuration extends north of the

Minneapolis-St. Paul metro along a route that is 200 miles longer than the initial design and contributes to higher costs. The alternative project resulted in improved reliability performance over the original design; however, many of the constraints are the same as those addressed by the Brookings – Lakefield – East Adair 765 kV alternative which also provided better reliability performance and offered lower energy curtailments. The Brookings – Chisago County – Highway 22 – Paddock alternative project did not show sufficient reliability and economic performance improvements considering the increased cost to warrant inclusion in the portfolio.

Another alternative was proposed for a Big Stone South – Hazel Creek – Blue Lake 345 kV line to provide an outlet for generation in North and South Dakota and western Minnesota. The alternative offered marginal improvement over the initial design in constraint mitigation and was less effective than the Big Stone – Brookings – Lakefield – East Adair 765 kV alternative in addressing similar constraints. The proposed 345 kV alternative improved economic congestion in Minnesota but the production cost value was not as significant as the 765 kV alternative, and the 765 kV alternative project was selected for inclusion in the Tranche 2.1 portfolio.

Q. Both the Project and the Gopher to Badger Link Transmission Line Project include 765 kV connections at the North Rochester Substation. Why are both connections necessary?

A. The purpose of the connections to the North Rochester area is to establish a hub that serves the south side of the Twin Cities, southeastern Minnesota, and

Wisconsin. The hub is designed to transfer power from the west to the Twin Cities and points east during high wind generation scenarios (*e.g.* nighttime conditions, along a line from Lakefield Junction to Pleasant Valley) and from the east to the Twin Cities and points west during low wind generation scenarios (*e.g.* summer peak load conditions, along a line from the Wisconsin state line). A robust and resilient design requires both Pleasant Valley and North Rochester to be within the 765 kV network, which requires having two 765 kV line sources to both areas such that loss of either 765 kV line resulting from a single contingency does not disable the 765 kV buses at either Pleasant Valley or North Rochester. Eliminating the connection to North Rochester or only building a portion of the 765 kV connections would defeat the purpose that is served by the Project.

Q. Please elaborate on how the Project is connected to the results from recent Generator Interconnection Queues.

A. Interconnection requests for new generation in MISO's 2023 and 2025 Interconnection Queue cycles that are currently under study, as well as the Expedited Resource Addition Study ("ERAS") process, assume that the LRTP Tranche 2.1 portfolio will be constructed and made part of the existing transmission network. Active generation interconnection requests include 5.9 GW of new generation resources in Minnesota[33] that are needed to help meet future

[33] *See* https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/.

decarbonization goals and 1.2 GW of additional ERAS resources to support the resource adequacy needs of Minnesota. Those requests could be negatively impacted if the LRTP Tranche 2.1 projects, such as the Project, are delayed or denied. The resulting disruption of the Interconnection Queue studies and the ERAS process would cause withdrawals of interconnection requests and increased risks to resource adequacy. In the absence of the LRTP Tranche 2.1 portfolio, the generating capacity that achieves commercial operation from the 2023 and 2025 Interconnection Queue cycles may encounter substantial curtailment of output due to unresolved transmission constraints that could also result in higher energy costs and carbon emissions or create risks of unserved energy if a significant amount of generating capacity is trapped behind these constraints. These situations would be mitigated by completion of the Project and other LRTP Tranche 2.1 projects.

Generation interconnection studies prior to the 2023 Interconnection Queue cycle were conducted before the LRTP Tranche 2.1 portfolio was included in MISO's transmission system base case, but the studies may still identify new transmission projects from the LRTP Tranche 2.1 portfolio as mitigation for issues caused by the proposed generation interconnection requests. Operation of the added generating capacity could be contingent on construction of LRTP projects if the proposed mitigation in a queue study was the same end-to-end project as an approved LRTP Tranche 2.1 project. Prior queue cycles that comprise 55.8 GW of generating resources are currently under study in the MISO Midwest Subregion.[34] Some of this generating capacity may be dependent on LRTP Tranche 2.1 transmission development in order to secure generator interconnection agreements.

VI. <u>OTHER REGIONAL IMPACTS IF PROJECT IS NOT CONSTRUCTED</u>

Q. What is the impact on the MISO regional plan if one of the projects that has received MISO approval is not constructed as planned?

A. The purpose of the very extensive planning functions of MISO is to involve all stakeholders in a process that will derive the most cost-effective expansion plan that will meet local and regional needs for reliability, optimize access to economic generation resources, and deliver other important values that benefit the ultimate consumer and society. The MTEP process designs a very complex system that will serve both short- and long-term needs of the BES in a coordinated manner. The inability to construct a key element of the regional expansion plan, especially a high voltage element such as the one proposed in the Application that is designed for both reliability and its economic attributes, could result in the loss of the economic benefits provided by the Project and the need to develop less optimal solutions to reliability concerns. The revised plan would likely have a negative economic impact on customers located in the Midwest Subregion.

Q. More specifically, what would be the system impacts if the Project was not constructed as planned?

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[34] *Id.*

A. The result of not constructing the Project would be the inability of the existing transmission system to reliably and economically deliver power in support of the long-term resource and loads needs of Minnesota and the other states in the MISO Midwest Subregion, and puts at risk fully realizing the benefits offered by the LRTP Tranche 2.1 portfolio. The MISO analyses of the LRTP projects identified numerous transmission facilities that will be loaded above safe operating levels or below adequate voltage levels without the Project. The overall result would be a transmission system that would also be less secure, with additional voltage and transient stability limitations. In addition, without the Project, Minnesota and the other states in the MISO footprint would not receive the full set of economic benefits that is provided by the LRTP Tranche 2.1 portfolio.

VII. CONCLUSION

Q. Based upon the results of MISO planning studies, as well as your review and analyses, how would you summarize your recommendations for the facilities contained in the Application submitted by the Applicants?

A. The facilities proposed by the Applicants would provide substantial reliability, economic, and public policy benefits to Minnesota. These facilities also fit well as a component of the MISO regional plan for the continued development of a reliable and economic regional transmission system.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

This certifies that on the 13th day of August, 2026, a true and correct copy of the Direct Testimony of Jeanna Furnish has been efiled by posting the same on eDockets in the above-referenced docket. The Testimony has also been served on the Service Lists on file with the Minnesota Public Utilities Commission.

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