

**BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION**

**In the Matter of the Application of Xcel Energy and
Otter Tail Power Company for an Energy Facility
Permit to Construct the PowerOn Midwest Project
Consisting of a 765-kV Transmission Line, a 345-
kV, and Associated Facilities**

Docket No. EL26-026

**TESTIMONY OF JOSEPH REDDOCH
SUBMITTED IN SUPPORT OF
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.'S
PETITION TO INTERVENE**

1 **I. INTRODUCTION AND WITNESS QUALIFICATIONS**

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

3 A. My name is Joseph Reddoch. I am employed by the Midcontinent Independent
4 System Operator, Inc. ("MISO") as a Principal Advisor for System Planning
5 Strategy in MISO's Transmission Planning Department. My business address is
6 720 City Center Drive, Carmel, IN, 46032.

7 **Q. What is the purpose of your testimony?**

8 A. In support of MISO's petition to intervene, my testimony helps explain why MISO
9 has unique and direct interests in this proceeding. Specifically, my testimony
10 explains MISO's unique role as a regional transmission planner and responsibility
11 for regional grid reliability. My testimony further demonstrates that MISO has a
12 direct interest in the PowerOn Midwest Project because its need was identified
13 through MISO's comprehensive, stakeholder-driven transmission planning
14 process.

1 **Q. What is MISO?**

2 A. MISO is a not-for-profit, member-based, regional transmission organization
3 (“RTO”) providing reliability and market services over more than 75,000 miles of
4 transmission lines in fifteen states and one Canadian province. MISO’s regional
5 area of operations stretches from the Ohio-Indiana line in the east to eastern
6 Montana in the west, and south to New Orleans. MISO is governed by an
7 independent ten-member Board of Directors.¹

8 **Q. What are MISO’s responsibilities?**

9 A. As an RTO, MISO is responsible for operational oversight and control, market
10 operations, and planning of the transmission systems of its member Transmission
11 Owners (“TOs”). Among many other responsibilities, MISO monitors and
12 calculates Available Flowgate Capability and provides tariff administration for its
13 Open Access Transmission, Energy and Operating Reserve Markets Tariff
14 (“Tariff”),² which has been accepted by the Federal Energy Regulatory
15 Commission (“FERC”).³ MISO is the Reliability Coordinator for its regional area
16 of operations, providing real-time operational monitoring and control of the

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.

1 transmission system. MISO operates real-time and day-ahead energy markets
2 based on Locational Marginal Prices (“LMPs”) in which each market participant’s
3 offer to supply energy is matched to demand and is cleared based on a security
4 constrained economic dispatch process. In addition, MISO operates a market for
5 Financial Transmission Rights, which are used by market participants to hedge
6 against congestion costs, and an ancillary services market, which provides for the
7 services necessary to support transmission of capacity and energy from generation
8 resources to load.

9 MISO is responsible for approving transmission service, new generation
10 interconnections, and new transmission interconnections within MISO’s regional
11 area of operations, and for ensuring that the system is planned to reliably and
12 economically provide for existing and forecasted usage of the transmission system.
13 MISO is the Planning Coordinator for its regional area of operations, which
14 includes the State of South Dakota, and performs planning functions
15 collaboratively with input from its TOs and other interested stakeholders, while also
16 providing an independent assessment and perspective of the needs of the overall
17 transmission system.

18 **Q. What is your educational background?**

19 A. I graduated from Virginia Polytechnic Institute & State University with a Bachelor
20 of Science degree in Electrical Engineering.

21 **Q. What is your professional experience?**

22 A. I spent the first 10 years of my career working for electric utilities, first in
23 distribution engineering and transmission operations at American Electric Power

1 Company and then in transmission planning engineering at Kansas City Power &
2 Light Company. For the past 25 years, I have been employed by MISO holding
3 roles in operations engineering, operations engineering management, market
4 engineering, and system planning. Over the last six years, I have been involved in
5 the development of the annual MISO Transmission Expansion Plan (“MTEP”),
6 including coordinating cost-benefit analysis for certain Long Range Transmission
7 Planning (“LRTP”) projects.

8 **Q. What are your duties and responsibilities as a Principal Advisor for System**
9 **Planning Strategy?**

10 A. My current responsibilities include supporting the LRTP activities. Specifically, I
11 have been working with MISO planning staff to refine our analytical methods for
12 project benefit calculations. The purpose of this work is to better align MISO’s
13 calculations with FERC Order No. 1920 requirements and ensure that our benefit
14 calculations remain well-supported for future LRTP efforts. In addition, my
15 responsibilities include providing technical support for intermediate planning
16 activities to enable enhanced coordination between planning and operations
17 business areas. This entails the development of Tariff provisions and business
18 practices necessary for conducting planning studies that address emerging issues in
19 the near-term planning horizon.

20 **II. PURPOSE AND SCOPE**

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

22 A. Yes. The parties that filed an Application in this docket, Northern States Power
23 Company, doing business as Xcel Energy, and Otter Tail Power Company

(collectively, the “Applicants”), seek a Facility Permit to construct the PowerOn Midwest Project (or, the “Project”). The Project includes 90 miles of new 765 kilovolt (“kV”) facilities in Grant, Deuel, and Brookings counties from the Big Stone South Substation to the Brookings County Substation to the South Dakota/Minnesota state line. The Project also includes expansions of the Big Stone South and Brookings County Substations and a new five-mile-long, single-circuit 345 kV transmission line in Brookings County connecting the expanded substations. The transmission lines and related facilities were included in the 2024 MTEP analysis and are identified by MISO as the South Dakota portion of LRTP project number 22. 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. Please describe the topics covered in your testimony.

A. As mentioned above, the purpose of my testimony is to help establish MISO’s direct interests in this proceeding by expounding upon the development of the Project as part of the LRTP Tranche 2.1 portfolio and its benefits to the MISO Midwest Subregion. To that end, 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.

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

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

8 Also, I will refer to the “MISO Midwest MVP Cost Allocation Subregion”
9 (or “Midwest Subregion”) in this testimony. The Midwest Subregion begins in
10 Missouri and extends northward to the Canadian border and is bounded by
11 Michigan and eastern Montana. This identification of a subregion within the MISO
12 footprint is relevant to responsibility for costs associated with the LRTP Tranche
13 2.1 portfolio of which the Project is a part.

14 **Q. What analyses form the basis of your testimony?**

15 A. The Project is part of the LRTP Tranche 2.1 portfolio. A more detailed report on
16 the LRTP Tranche 2.1 projects is included in Appendix E.1 to the Application
17 (“MTEP24 Report”).⁴ The portfolio was approved by the MISO Board of Directors
18 on December 12, 2024 as part of the MTEP24 process. This approval was based

⁴ 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 South Dakota portion of LRTP Project No. 22, which is referred to in the MTEP24 Report as “Big Stone South – Brookings County- Lakefield Junction.”

1 on a set of reliability, economic, and public policy analyses conducted between
2 2022 and 2024 that documented the reliability and economic issues addressed by
3 the Project and the combined reliability, avoided investment, production cost, and
4 environmental benefits of the full LRTP Tranche 2.1 portfolio.

5 **Q. What are your key findings?**

6 A. Tranche 2.1 includes a 3,631-mile, 345 kV and 765 kV backbone that ensures future
7 reliability while providing benefits to the MISO Midwest Subregion that exceed
8 costs. It includes a \$21.8 billion (in 2024 dollars) investment in 24 projects and
9 323 facilities across the MISO Midwest subregion. The Project, as part of the
10 Tranche 2.1 portfolio, provides an extra-high voltage transmission path that
11 increases the reliability of the regional transmission system while enhancing the
12 ability of the transmission system in South Dakota to enable delivery to serve the
13 needs of the region. The Project is part of the LRTP Tranche 2.1 portfolio that, as
14 part of the MISO regional plan, will enable the reliable and efficient delivery of
15 resources in support of member plans and provide for multiple types of benefits in
16 excess of the portfolio costs when assessed under a future system scenario, known
17 as “Future 2A,”⁵ that is guided by consideration of future conditions that include
18 items such as load growth, member plans, and federal and state policies.
19 Additionally, benefits analysis performed under a more conservative scenario,
20 known as “Future 1A,” shows that Tranche 2.1 provides a robust transmission
21 network that supports a broad range of generation and policy futures. Support for

⁵ Future 2A is discussed in the MTEP24 Report, pgs. 10-14.

1 the Project, as a planned part of LRTP Tranche 2.1 portfolio, is described further in
2 this testimony.

3 **III. MISO Regional Transmission Planning**

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

6 A. Regional planning at MISO is performed in accordance with several guiding
7 documents. The Agreement of Transmission Facilities Owners to Organize the
8 Midcontinent Independent System Operator, Inc., a Delaware Non-Stock
9 Corporation (“Transmission Owners Agreement” or “TOA”), includes the planning
10 framework that describes the planning responsibilities of MISO and its
11 transmission owning members.⁶ MISO’s responsibilities include the development
12 of the MTEP in collaboration with transmission owners and other stakeholders.

13 MISO also adheres to the nine planning principles outlined in FERC Order
14 No. 890.⁷ In so doing, MISO provides an open and transparent regional planning

⁶ 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.

⁷ *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.

1 process that results in recommendations for expansion that are reported in the
2 MTEP. FERC Order No. 1000 furthered the planning principles outlined in FERC
3 Order No. 890 and included the requirements to plan for public policy and for
4 coordinated inter-regional planning and cost allocation.⁸

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

12 MISO implements these practices through its governing and informational
13 documents, including Attachment FF to MISO's Tariff, the TOA, and MISO's
14 Business Practices Manuals ("BPM").⁹ MISO's MTEP24 report provides
15 assessments of resource adequacy, analyses of various energy policy scenarios, and
16 discussions of the development of long-term resource forecasts based on those
17 scenarios.

⁸ *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).

⁹ 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/>.

1 **Q. How did FERC Order No. 1920 impact the development of Tranche 2.1?**

2 A. On May 13, 2024, FERC issued Order No. 1920¹⁰ to revise its policies and
3 requirements regarding Long-Term Regional Transmission Planning and Cost
4 Allocation. Order No. 1920 seeks to enhance forward-looking planning to address
5 changing demand and the change in generation resource mix, improve transparency
6 to allow better coordination between regional and local planning processes, and
7 promote engagement with relevant state entities for purposes of cost allocation.
8 MISO was in the midst of developing Tranche 2.1 at the time of Order No. 1920's
9 issuance and the compliance deadline set by FERC was not until June 12, 2026,
10 with a proposed implementation date for MISO's compliance revisions of June 12,
11 2028,¹¹ so Order No. 1920 did not directly influence the development of Tranche
12 2.1. However, Order No. 1920 expressly recognized that MISO's planning process

¹⁰ *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").

¹¹ 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 to February 12, 2027 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).

1 already incorporates many of the comprehensive regional planning aspects required
2 by the final rule.¹²

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

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

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

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

¹² Order No. 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.”).

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

9 **Q. Does the MTEP include regional planning?**

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

17 As part of this process, stakeholders from each MISO member sector,
18 including state regulatory authorities, public consumer advocates, transmission
19 owners, end-use customers, and independent power producers, among others, are
20 engaged to help develop a wide range of future system scenarios that are guided by
21 a range of load growth forecasts, resource plans, as well as state and federal energy
22 policy decisions. These possible future scenarios and energy policies (the
23 “Futures”) form the basis for forecasts of generation resources and load that would

1 be economical and consistent with member plans and policy. Transmission needs
2 are then assessed, and plans developed to identify least-regrets transmission
3 development that reliably and economically delivers the necessary energy from
4 generation resources to load under multiple scenarios.

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

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

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

20 In the near-term horizon, these factors are defined by commitments to
21 specific generation and load assumptions, according to NERC criteria. In a longer-
22 term horizon, multiple scenarios must capture a range of system conditions to

1 “bookend”¹³ potential scenarios (as discussed in the MISO Futures explanation
2 further below in my testimony), with studies based on those scenarios identifying
3 transmission that is useful across a number of system conditions, contingencies,
4 and weather patterns. That transmission is the target of LRTP planning.

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

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

15 **IV. LONG RANGE TRANSMISSION PLANNING PROCESS**

16 **Q. What is the overall purpose of MISO’s LRTP process?**

17 A. LRTP, through its stakeholder process, focuses on the development of robust
18 solutions that proactively address future reliability challenges posed on the system,
19 including those driven by load growth, resource plans, and member policy

¹³ 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.

1 objectives. Long-range planning provides a comprehensive, forward-looking
2 assessment of future needs based on a range of anticipated future conditions that
3 identify the “least-regrets” regional transmission expansion that provides a number
4 of benefits to maintain reliable performance under a range of operating conditions,
5 cost efficient energy delivery, accessibility to resources, and flexibility in resource
6 mix. MISO’s LRTP process is coordinated with MISO members and states to
7 identify a transmission system plan that can reliably and efficiently serve load with
8 the resources identified in the MISO Futures.

9 **Q. What is an MVP under the MISO Tariff?**

10 **A.** An MVP is a type of transmission project developed by MISO and stakeholders
11 that was accepted by FERC in 2010,¹⁴ whose costs are sub-regionally or regionally
12 shared. An MVP must be (i) evaluated as part of a portfolio of MVPs whose
13 benefits are spread broadly across the MISO footprint or subregion and (ii) must
14 meet at least one of the following criteria, as stated in Attachment FF of the MISO
15 Tariff:¹⁵

16 a. Criterion 1. A Multi-Value Project must be developed
17 through the transmission expansion planning process for the
18 purpose of enabling the Transmission System to reliably and
19 economically deliver energy in support of documented
20 energy policy mandates or laws that have been enacted or
21 adopted through state or federal legislation or regulatory
22 requirement that directly or indirectly govern the minimum
23 or maximum amount of energy that can be generated by

¹⁴ *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”).

¹⁵ MISO Tariff, Attachment FF, Section II.C.

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.¹⁶

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 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

¹⁶ MISO Tariff, Attachment FF, Section II.C.3(d), (e).

1 footprint. At the same time, the MISO Interconnection Queue for generators saw a
2 substantial increase in queued requests, and the study results for those generators
3 continued to show the need for more large-scale transmission projects. These
4 factors led to the definition of an MVP project type, and also led to the ultimate
5 analysis and approval of the 2011 MVP portfolio to meet the policy goals of the
6 states in the MISO Midwest Subregion.

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

8 A. Yes. After the approval of the 2011 MVP portfolio, the MISO footprint had a major
9 change with the addition of MISO South in 2013 (*i.e.*, south of Missouri). At the
10 start of the LRTP initiative in 2021, MISO recognized this change and provided an
11 additional option for subregional cost allocation for MVP portfolios. Changes to
12 the MVP cost allocation process were filed with, and accepted by, the Commission
13 in 2022.¹⁷ This included subdividing the MISO footprint into two subregions – the
14 Midwest Subregion and the MISO South MVP Cost Allocation Subregion (“South
15 Subregion”). The Tariff provisions that provide for these subregions recognize that
16 benefits from an MVP portfolio may be widespread and yet mostly contained
17 within geographic subregions in the midwestern and southern portions of the MISO
18 footprint. The Subregional option has been applied to two MVP portfolios
19 benefiting the Midwest Subregion: (1) Tranche 1 approved in July 2022; and (2)
20 Tranche 2.1 approved in December 2024.

¹⁷ *Midcontinent Independent System Operator, Inc.*, 179 FERC ¶ 61,124, at P 1 (2022).

1 **Q. What is the LRTP Tranche 2.1 portfolio?**

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

10 **Q. What is the relationship between the MVP project type and the LRTP Tranche**
11 **2.1 portfolio?**

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

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

19 A. Yes. In July 2022, the MISO Board of Directors approved LRTP Tranche 1 as part
20 of MTEP21. Tranche 1 consisted of 18 projects spread across the MISO Midwest
21 Subregion. The analysis for Tranche 1 was based on MISO's Future 1 system
22 scenario and had a benefit-to-cost ratio between 2.6 and 3.8. To date, most Tranche
23 1 projects have gained the necessary state regulatory certificates/franchises. The

1 remaining few are progressing towards any applicable state regulatory
2 determinations.

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

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

9 This intensive process began with analyses of the challenges expected from
10 the future resource transition and the need for long-term transmission planning
11 solutions in a number of MISO stakeholder forums. In July 2022, MISO initiated
12 the process to update future assumptions used in developing LRTP Tranche 2.1.
13 The Tranche 2.1 projects reached final MISO Board approval in December 2024.
14 MISO conducted over 300 internal and stakeholder meetings, the latter averaging
15 275 attendees at each meeting, to develop the Tranche 2.1 portfolio.

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

22 Tranche 2.1 work focused on resource changes and load growth
23 contemplated by Future 2A. Key reliability and economic issues provided the

1 foundation to develop Tranche 2.1 as a least-regrets and stand-alone first step
2 towards the transmission required to reliably and efficiently serve load with the
3 resources identified in Future 2A.

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

5 A. Tranche 2.1 develops a 3,631-mile 345 kV and 765 kV backbone that ensures future
6 reliability while providing benefits that exceed costs. It includes a \$21.8 billion (in
7 2024 dollars) investment for 24 projects and 323 facilities across the MISO
8 Midwest subregion. Projects are targeted to go in service from 2032 to 2034.
9 Tranche 2.1 highlights are as follows:

- 10 • Tranche 2.1 proactively provides reliability and efficiency,
11 enabling future generation in support of load growth across the
12 MISO footprint and member plans;
- 13 • The portfolio adds a 765 kV backbone to the MISO Midwest to
14 support required energy transfers across the MISO system under
15 multiple future system conditions to support system reliability.
16 With a 765 kV backbone, more electricity can be delivered,
17 while minimizing land use and reducing energy losses; and
- 18 • As a portfolio primarily driven to address reliability, Tranche 2.1
19 provides a broad range of value with a benefit-to-cost ratio
20 ranging from 1.8 to 3.5.

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

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

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

- 11 (1) developing scenario-based Future resource forecasting and
- 12 siting;
- 13 (2) developing planning models utilizing the Futures;
- 14 (3) identifying potential transmission issues;
- 15 (4) proposing solutions to address identified issues with sufficient
- 16 value;
- 17 (5) evaluating and justifying the effectiveness of various solutions,
- 18 including assessing alternatives;
- 19 (6) recommending preferred solutions; and
- 20 (7) applying the appropriate cost allocation mechanism.

21 I discuss the steps below.

1 Step 1 – Development of Futures

2 **Q. What are Futures?**

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

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

12 The input from MISO's members and states is critical to the Futures process
13 given that resource planning responsibilities fall to them and not to MISO. All
14 MISO transmission planning is dependent upon the type, location, and quantity of
15 future generation. As a result, Futures are an essential component in MISO planning
16 processes, including LRTP. MISO's planning process through LRTP optimizes the
17 transmission system to reliably and efficiently serve load with the resources
18 identified in the MISO Futures.

19 **Q. How did MISO develop a Future system scenario?**

20 A. To create the Futures, MISO considered member data, stakeholder input, state and
21 federal policy, and technical and economic data. Using this data, and building from
22 member planned resources, MISO developed multiple generation expansions to
23 bookend potential future conditions, with each expansion developed with sufficient

1 generation to meet projected demand, energy, and resource adequacy requirements.

2 Once these expansions were created, MISO worked with stakeholders to site the
3 forecasted generation to maximize resource availability and accommodate member
4 goals.

5 The LRTP Tranche 2.1 portfolio was developed with a focus on the Future
6 2A scenario that falls in the middle of the three Future scenarios, including such
7 factors as a mid-level load growth forecast. Future 2A assumes that: (1) utilities
8 and states meet their goals, policies, and announcements; (2) those goals, policies,
9 and announcements result in a 60% reduction in carbon emissions across the MISO
10 footprint from 2005 levels; (3) energy demand increases by 30% due to
11 electrification; and (4) there are accelerated age-based retirements of resources.
12 Future 1A and 2A were used for the benefit metrics analysis to further validate that
13 the portfolio provides benefits in excess of costs.

14 Future 1A represents the conservative low bookend, assuming that: (1)
15 100% of utility integrated resource plans and 85% of utility or state goals and
16 policies not supported by legislation are met; (2) carbon emissions decline solely
17 as an outcome of utility and state plans; and (3) load growth is consistent with pre-
18 2019 trends. For the Future 1A resource expansion, 93% of the resources needed
19 were based directly on member submitted resources and 7% were identified by
20 MISO's resource expansion model.¹⁸ For the Future 2A resource expansion, 54%

¹⁸ See LRTP Workshop (January 26, 2024), "LRTP Tranche 2 Robustness Testing: Low-End Bookend," publicly available at:

1 of the resources needed were based directly on member submitted resources and
2 46% were identified by MISO's resource expansion model.

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

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

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

14 **Q. How were the load forecasts developed for the Futures?**

15 A. The demand and energy forecasts used to support the regional transmission
16 development were derived from the 20-year forecasts of the MISO members with
17 adjustments to reflect market load shape and incorporate projected electrification
18 impacts. Three forecast scenarios were created to represent gross load growth and
19 included varying degrees of electric vehicle adoption and electrification. These

1 scenarios did not include data center specific load growth.¹⁹ Production cost
2 modeling was then used to analyze energy efficiency programs and determine the
3 adjustments in the load shapes to obtain the net load used in the planning analysis.

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

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

12 MISO is obligated to reflect and define a resource expansion that aligns with
13 the MISO member plans. As such, transmission planning works to ensure the
14 energy planned by members, or required due to their plans or load growth, can be
15 delivered to where it is needed. Additional future resources beyond member plans
16 were required to meet projected load, policy objectives, and reserve margins. To
17 bridge this gap, MISO performed an economic resource expansion analysis, which
18 forecasted the additional resources to meet system needs at lowest cost.

¹⁹ 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.

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

2 A. The Future scenarios development culminated in a siting process that maximized
3 resource availability and accommodated member goals. After the number and
4 composition of resources were identified, siting analysis defined where these
5 resources were located within the MISO footprint. MISO followed a stakeholder-
6 approved siting process that was addressed in the Series 1A Futures Report²⁰ and
7 Futures Refresh Assumptions Book.²¹ As part of this process, MISO sited model-
8 built resources considering:

- 9 ○ Member identified locations;
- 10 ○ Resource adequacy requirements: Each Local Resource Zone (“LRZ”) must
11 meet its Local Clearing Requirement (“LCR”) and the footprint-wide
12 Planning Reserve Margin Requirement (“PRMR”);²²
- 13 ○ Policy goals: local, state, and regional renewable portfolio standards and
14 decarbonization goals;

²⁰ See MISO Futures Report Series 1A (2023), publicly available at:
https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

²¹ 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>.

²² 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 region. The PRMR refers to the amount of capacity that each LSE must obtain to meet its resource adequacy requirements.

○ Additional resource-type siting considerations:

- Split of 80% Generator Interconnection (“GI”) queue and 20% Vibrant Clean Energy²³/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

Q. What did Step 2 involve?

A. MISO developed reliability and economic models to assess expected system performance under future conditions. For the reliability analysis, MISO built 10-year and 20-year models initialized from MTEP22 models and incorporated changes to

²³ 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.

1 reflect expected transmission topology and Future 2A load forecast and resource
2 changes. The resulting series of reliability study models reflected seasonal load and
3 generation dispatch conditions and included additional transfer scenarios to cover a
4 range of likely and possible dispatch with a focus on the worst credible conditions
5 from the system point of view, while recognizing that local conditions may vary.

6 For the economic analysis, MISO built 10-year, 15-year and 20-year
7 economic models that reflected updated network topology and Future 2A load
8 forecast and resource changes. As part of this analysis, economic modeling utilized
9 PROMOD, a chronological security-constrained unit commitment and economic
10 dispatch tool which applied to a wide variety of operating constraints. Within the
11 PROMOD model, Futures assumptions around load, generation, and fuel costs were
12 incorporated up to a 20-year time horizon along with transmission grid topology and
13 constraints to assess future transmission needs.

14 These broad base economic and reliability models encompassed multiple
15 uncertainties around variable renewable energy output, load profiles, and seasons,
16 thus allowing the platform to perform a wide range of economic and reliability
17 analyses. A full list of models with assumptions is found in the MTEP24 Report.²⁴

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

19 A. Yes. MISO conducted a series of workshop discussions with stakeholders to review
20 the proposed approach to reliability studies and developed a reliability analysis
21 methodology whitepaper to describe the process used to build models and conduct

²⁴ MTEP24 Report at pgs. 15-22.

1 reliability analysis. The initial development established the need for a set of core
2 models that represented various seasonal conditions in the 10-year and 20-year
3 timeframe and a set of potential credible transfer scenarios that covered a range of
4 dispatch variability. Further discussions included more details on the proposed
5 methodology used to determine renewable generation dispatch levels and the
6 proposed transfer scenario conditions for which MISO requested stakeholder
7 feedback. MISO subsequently revised the transfer scenario definitions and adopted
8 additional scenarios to cover a wider range of conditions to address stakeholder
9 comments.

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

11 A. Yes. MISO engaged stakeholders in a series of workshops that included discussions
12 of the economic modeling process and updates to be applied to produce the economic
13 models for the LRTP economic study. Once the economic models were developed,
14 stakeholders with the appropriate access rights were allowed to review and provide
15 feedback on model details related to transmission ratings, generator attributes, and
16 any other discrepancies. MISO worked with stakeholders to address modeling
17 concerns and updated the model as needed. Further stakeholder discussions included
18 a review of the natural gas price forecasting process used to more accurately align
19 natural gas prices with the level of demand in the production cost simulations. MISO
20 subsequently reviewed the flowgate identification process used to identify
21 transmission constraints for inclusion in PROMOD event processing and posted
22 results for stakeholder feedback that resulted in updates to the event files used for the
23 LRTP Tranche 2.1 economic analysis.

1 Step 3 – Identify Potential Transmission Issues

2 **Q. What did Step 3 involve?**

3 A. Step three involved performing reliability and economic analysis to identify
4 transmission issues. The purpose of reliability analysis was to ensure the MISO
5 Transmission System can reliably deliver energy from future resources to future
6 loads under a range of projected load and dispatch patterns associated with the
7 Future 2A scenario in the 10-year and 20-year time horizons. Economic analysis
8 identified issues like congestion, generation curtailment, widespread price
9 separation, and price to serve load. The reliability and economic analyses were
10 iterative processes that were coordinated with each other to assess transmission
11 needs and determine the most cost-effective and reliable solutions.

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

17 **Q. What was the reliability analysis that MISO performed for Tranche 2.1?**

18 A. The reliability analysis included ensuring transmission system performance was
19 reliable and adequate with both an intact system and one where contingencies had
20 occurred, and high regional power transfer scenarios that resulted when geographic
21 diversity must be relied upon to help manage dispatch volatility and uncertainty. A
22 detailed reliability analysis using power flow simulations was conducted to identify
23 transmission system equipment loadings and voltages with respect to safe

1 equipment design tolerances. The MISO reliability analysis included several
2 different types of simulations, each targeting different information about
3 performance, as described below:

- 4 ○ Steady-State - determined if transmission facilities remained within safe
5 design limits (line loading and voltage) following disturbances;
- 6 ○ Transient stability - determined if the system experienced uncontrolled loss
7 of load or generation following disturbances, focusing on voltage and
8 frequency performance; and
- 9 ○ Transfer analysis assessed the impact of various system conditions, dispatch
10 patterns, and intra-regional power transfer limit, focusing on line loading
11 and voltages.

12 **Q. What was considered during the reliability analysis?**

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

1 **Q. What was considered during the economic analysis?**

2 A. Economic analysis required a market-type dispatch reflective of MISO Futures
3 modeling and planned topology set by the MTEP power flow model to evaluate
4 potential future transmission inefficiencies. MISO's economic analysis process
5 relied on the production cost modeling software PROMOD to identify and address
6 economic issues caused by these inefficiencies. The economic analysis used
7 several economic indicators to assess the performance of the system, as described
8 below:

- 9 ○ Congestion measure (\$/MW) - the production cost savings opportunity from
10 relieving transmission congestion (*i.e.* reducing electric flow from exceeding
11 transmission capacity);
- 12 ○ Curtailment (MWh) - a measure of the total amount of energy from renewable
13 sources that cannot be delivered economically; and
- 14 ○ Load LMP (\$/MWh) - the LMP is the price to purchase energy from a market.
15 Load Weighted LMPs are expressed as an average price weighted by energy
16 each hour and at each delivery point and are indicative of the price of energy
17 in a region.

18 **Q. What did the economic and reliability analyses show?**

19 A. The economic and reliability analyses showed significant levels of overload on
20 lower and higher voltage equipment across the footprint and severe voltage
21 violations due to decreased reactive performance across the system. Without
22 additional transmission to strengthen the transfer capability across the multi-state
23 Midwest Subregion, the longer distance for power to travel between future

1 resources and load causes increased voltage angle and reduced stability limits and
2 resulted in greater stress on the system. Similarly, the economic analysis showed
3 severe widespread congestion, price separation and significant generation
4 curtailment due to congestion on the transmission system. Results also revealed
5 opportunities to provide additional benefits by resolving energy losses from power
6 transfers on existing transmission and by mitigating economic congestion. MISO
7 reviewed the economic and reliability study findings with stakeholders, and posted
8 results for feedback to incorporate for further analysis and solution testing.

9 Step 4 – Propose Solutions

10 **Q. What did step four involve?**

11 A. As MISO began to understand the impacts of member plans, conceptual ideas were
12 developed and then refined to create potential transmission solutions. In December
13 2022, MISO shared a hypothetical roadmap taking concepts from its initial long-
14 term roadmap shared in 2021. This conceptual map was not based on new analysis;
15 instead, it served to jumpstart conversation to determine the optimal voltage and
16 transmission type (e.g., 765 kV vs 345 kV; AC vs DC) for the overlay and was
17 informed from prior transmission studies (e.g., Tranche 1, MTEP annual studies,
18 generator interconnection studies). This conceptual map was then updated in
19 March 2024 based on the reliability and economic results and amended further
20 based on stakeholder feedback in June 2024, focusing on a 765 kV regional solution
21 to accommodate the higher regional transfers identified in the reliability and
22 economic analysis. Some considerations regarding the performance of 765 kV
23 included:

- 1 • Higher transmission rating limits;
- 2 • Cost per MW-Mile; and
- 3 • Land-Use per MW-Mile.²⁵

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

5 A. There were three primary reasons – loading capability, cost efficiency, and less land
6 use. When considering the per MW-mile capability of 765 kV and 345 kV lines,
7 765 kV has much higher loading capability than 345 kV, particularly for longer
8 distances. For Tranche 2.1, 50% of the proposed 765 kV facilities are more than
9 120 miles long. At 120 miles, the Safe Loading Limit of a 345 kV line is less than
10 1,000 MVA and 765 kV is 4,500 MVA. The loadings observed on the Tranche 2.1
11 765 kV facilities range between 2,000 and 4,000 MVA.²⁶

12 The cost per MW-mile of a 765 kV line is generally 33% to 50% of the cost
13 per MW-mile of 345 kV or 500 kV lines. This implies a long distance, well utilized
14 regional transmission system will cost much less if it incorporated a substantial
15 amount of 765 kV transmission. Conversely, it would be much more costly to
16 develop the required regional transmission system using only 345 kV transmission,
17 and substantially more costly to develop the system slowly and incrementally using
18 sub-extra high voltage transmission only.

²⁵ 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>.

²⁶ Safe Loading Limit is defined as the maximum amount of power it can conduct without causing damage, compromising system stability, and voltage limits.

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

7 In addition to lower cost, a 765 kV line requires less land-use on a per MW-
8 mile basis than 500 kV or 345 kV. The land use in acres per MW-mile required for
9 765 kV is 25% to 67% of the land use required in acres per MW-mile for the
10 equivalent 345 kV alternative, and about 33% of the land use required in acres per
11 mile for 500 kV.

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

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

19 **Q. Did MISO conduct robustness testing of solutions?**

20 A. Yes. Robustness testing refers to a process for reviewing the impact of system
21 changes. This testing was conducted during portfolio evaluation. A key objective
22 of robustness testing was to identify key projects that were either approved or in
23 the process of approval after the finalization of LRTP power flow models in

1 October 2023, which may have materially impacted the anticipated Tranche 2.1
2 portfolio. The second main objective was to perform an assessment with and
3 without key projects to identify areas that may have resulted in MISO modifying,
4 adding to, or removing transmission facilities in the LRTP portfolio. No
5 modifications were required for the LRTP Tranche 2.1 portfolio as a result of
6 robustness testing.

7 **Q. Were alternatives considered?**

8 A. Yes. MISO undertook an analysis of alternatives. 97 projects representing 47
9 solutions were received from stakeholders. Not all these solutions needed to be
10 evaluated. MISO focused on alternatives that were more closely aligned with the
11 same issues and needs that drove the solutions for this portfolio; various alternatives
12 were similar in location; and some alternatives were likely to be otherwise
13 constructed to address other transmission issues. Additionally, some solutions were
14 evaluated along with various alternatives received from stakeholders and developed
15 by MISO staff while other projects addressed more local versus regional needs and
16 were more suited for the annual MTEP reliability planning and the generator
17 interconnection processes.²⁷

²⁷ 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.

1 **Q. Did MISO consider Grid Enhancing Technologies (“GETs”) in developing the**
2 **Tranche 2.1 portfolio?**

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

6 GETs include hardware and software intended to increase the capacity and
7 efficiency of the transmission system without major overhauls to transmission
8 infrastructure (e.g. dynamic line ratings, power flow control, and topology
9 optimization). GETs can provide incremental upgrades to the transmission system
10 to address specific local issues. GETs were selected for certain underbuilt projects
11 in Tranche 2.1. Transmission developers may also optimize the final design of
12 assigned transmission projects, including by incorporating GETs, after approval of
13 a project by the MISO Board.²⁸

14 Step 5 – Evaluate and Justify Solutions, Including Assessing Alternatives

15 **Q. What did Step 5 involve?**

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

²⁸ These after-the-fact optimizations must also “comport with the approved MTEP” and be accepted by MISO. MISO Tariff, Attachment FF, Section VI.C.

- 1 • *Reliability and Economic Modeling with Solutions* - MISO developed
- 2 new reliability and economic models that incorporated the proposed
- 3 transmission solutions;
- 4 • *Effectiveness Testing* - MISO evaluated how well the solutions addressed
- 5 the reliability and economic transmission issues identified in Step 3, such
- 6 as thermal overloads, voltage problems, and increased congestion and
- 7 curtailment;
- 8 • *Additional Alternative Analysis* - Submitted alternative solutions were
- 9 reviewed and tested for their effectiveness; and
- 10 • *Business Case Analysis* - Projects and portfolios were tested against a
- 11 range of future scenarios (or "bookends") using multiple types of benefits
- 12 to ensure they provide long-term value, even if the future evolves
- 13 differently than expected. For example, for LRTP Tranche 2.1, the
- 14 portfolio was tested against a lower-end "Future 1A" scenario.

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

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

22 To better assess the impact and severity of overloads and voltage violations
23 across multiple lines and substations, MISO utilized industry-standard ranking

1 criteria known as Severity Indices. The Thermal Severity Index provides an
2 overview of the performance of the Tranche 2.1 portfolio taking into consideration
3 the magnitude of thermal and voltage violations, respectively, from the contingency
4 analysis. The Thermal and Voltage Severity Index values calculated for the
5 Tranche 2.1 portfolio indicated significant improvement in the overall system
6 performance.

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

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

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

17 A. Yes. To enhance system reactive support and reduce reliance on other voltage
18 support devices, MISO intentionally planned the system for higher Surge
19 Impedance Loading (“SIL”) capability of regional lines when practical (*e.g.*, use of
20 765 kV options and high-SIL 345 kV options for very long 345 kV lines), thus
21 providing substantial reactive power capability from the regional transmission
22 system under most conditions.

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

2 A. Yes. The portfolio enhances the overall stability of the system as demonstrated by
3 a significant reduction in the number of transient voltage violations, low damping
4 violations and relay trip violations. The Transient Stability Index (“TSI”) is an
5 industry accepted metric used in TSAT (Transient Security Assessment Tool) that
6 assesses the severity of each disturbance. A higher TSI for a disturbance represents
7 a more stable system response. The Tranche 2.1 portfolio resolved 90% of the
8 transient voltage violations in the 2042 Average load model and 30% of the
9 transient voltage violations in the 2042 Summer Peak load model. In addition, the
10 Tranche 2.1 portfolio resolved all low damping violations and reduced the number
11 of transient voltage violations in both 2042 Average load and 2042 Summer Peak
12 load models.

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

14 A. Analyses with annual economic models evaluated various system conditions and
15 dispatch patterns that helped MISO better understand system performance with and
16 without the LRTP Tranche 2.1 portfolio. The Tranche 2.1 portfolio enhances the
17 economic value for the MISO Midwest subregion and enables member plans for
18 fleet transition and load growth. The economic analysis demonstrated the
19 following results on the performance of the LRTP Tranche 2.1 portfolio using
20 Future 2A:

- 21 • reduces economic congestion on existing transmission across the MISO
- 22 Midwest Subregion by 29.5%;

- 1 • facilitates a more economical dispatch for the MISO Midwest
- 2 Subregion resulting in \$8.1B in Adjusted Production Cost (“APC”)
- 3 savings;
- 4 • reduces curtailment in the MISO Midwest Subregion by 27.1M MWh
- 5 (11.2%), improving access to more economic generation;
- 6 • supports the MISO Midwest Subregion by reducing price separation
- 7 across the subregion and decreasing system cost to serve load; and
- 8 • provides a robust regional backbone supporting 115.7 gigawatts
- 9 (“GW”) of Future 2A resource enablement.

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

12 A. MISO assessed proposed transmission solutions using multiple benefit metrics and
13 scenarios to ensure the projects were least-regrets and cost-effective. Key
14 evaluation criteria included:

- 15 • **Scenario testing:** MISO evaluated the benefits of solutions under
- 16 different future resource mix and load scenarios to ensure they were
- 17 durable and effective across a range of potential conditions.
- 18 • **Benefits evaluation:** Solutions demonstrated multiple types of value to
- 19 customers such that the analysis showed benefits in excess of costs.

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

22 A. MISO leveraged previous benefit metric work on the LRTP Tranche 1 portfolio
23 and developed, in collaboration with stakeholders, additional metrics to capture the

1 full monetary value of the LRTP Tranche 2.1 portfolio. That work with
2 stakeholders resulted in the nine benefit metrics listed below, which were used to
3 demonstrate the value of the LRTP Tranche 2.1 portfolio under Futures 1A and 2A:

- 4 1. Mitigation of reliability issues - value of alleviating reliability issues which,
5 if unresolved, introduce a risk of unserved load;
- 6 2. Reduced risks of extreme weather impacts - increases grid resilience and
7 decreases the probability of major service disruptions;
- 8 3. Avoided capacity cost – value of savings in resource investment that results
9 from the increased transfer capability enabling access to a more
10 geographically diverse pool of resources;
- 11 4. Capacity savings from reduction in losses - value of reducing transmission
12 losses during peak capacity periods;
- 13 5. Avoided transmission investment - avoids the need for facility replacement
14 due to age and condition;
- 15 6. Congestion and fuel savings - enhances market efficiency and provides
16 access to low-cost generation;
- 17 7. Energy savings from losses - lower production costs to serve load with
18 transmission facilities that reduce system losses;
- 19 8. Reduced transmission outage costs - reduced transmission congestion
20 during forced and planned outages; and
- 21 9. Decarbonization - enables the economic dispatch of renewable resources to
22 help reduce the carbon footprint.

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

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

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

- 16 • Inclusion of a benefit metric analysis using Future 1A to ensure
17 robust, least-regrets transmission solution;
- 18 • Decision to not use resource adequacy metric to ensure no
19 overlapping value with avoided resource cost benefit metrics;
- 20 • Focused congestion and fuel savings on transmission value by
21 including a consistent resource set across reference and change
22 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 was used to calculate

1 the minimum value used to assess the benefit-to-cost ratio and was based on the
2 gross-plant weighted average of the Transmission Owners' cost of capital and
3 represents the minimum return required on their transmission investments.
4 Benefits were also assessed using a discount rate of three percent to show how
5 assets perform with a social discount rate that reflects the return a ratepayer would
6 typically receive on a risk-adjusted investment.

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

10 **Q. What were the overall benefits of Tranche 2.1?**

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

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

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Table 1

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 CO2 emissions.	\$3.9B - \$15.3B	\$7.2B - \$28.3B
Total		\$34.3B - \$61.9B	\$51.7B - \$101.0B

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

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

- 10 • More robust methods were developed to isolate benefits from risk of
11 unserved energy under extreme conditions from benefits related to
12 capacity cost savings.
- 13 • Avoided transmission investment was simplified to remove avoided
14 reliability upgrade costs that potentially overlapped with the mitigation
15 of reliability issues benefit.
- 16 • Resource adequacy savings were eliminated to avoid double counting
17 the reduction in planning reserves used in the avoided capacity cost
18 benefit.
- 19 • Ramping flexibility was discontinued due to difficulty in
20 implementation.
- 21 • Mitigation of reliability issues was further revised to avoid overlap with
22 production cost savings and to eliminate potential for double counting
23 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.

Step 6 – Recommend Preferred Solutions

Q. What occurred in Step 6?

A. During the sixth step of the LRTP process, MISO and stakeholders reviewed analyses of proposed transmission portfolios and alternatives to recommend final, preferred solutions. The analysis examined reliability, economic benefits, and other performance metrics to determine the optimal portfolio. This step was built on a transparent, stakeholder-driven process, which concluded 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 was presented for approval. It was first reviewed and voted on by the Planning Advisory Committee (“PAC”) to recommend to the Board of Directors for approval. It then moved to the System Planning Committee of the MISO Board of Directors. Finally, the portfolio was presented to the full MISO Board of Directors for approval. 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.

1 **Q. What portfolio resulted from Step 6?**

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

6 *Step 7 - Apply Appropriate Cost Allocation*

7 **Q. What happened in Step 7?**

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

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

17 A. Yes. As MVPs, the costs of the LRTP Tranche 2.1 portfolio will be recovered from
18 MISO load and exports associated with the MISO Midwest Subregion through the
19 energy-based MVP Usage Rate (\$/MWh). This recovery methodology is
20 implemented in Attachment MM of the MISO Tariff.²⁹ Additionally, indicative
21 annual MVP usage rates for the LRTP Tranche 2.1 portfolio were calculated over

²⁹ See MISO Tariff, Attachment MM, Multi-Value Project Charge (“MVP Charge”).

1 a 40-year period using the current project cost estimates and estimated in-service
2 dates. The MVP Usage Rate for LRTP Tranche 2.1 portfolio is estimated to peak
3 at \$6.44 per MWh of energy usage and average \$4.76 per MWh over a 40-year
4 period. While the LRTP Tranche 2.1 portfolio is estimated to cost MISO members
5 about \$5 per 1 MWh or 1,000 kWh of energy used, that investment will provide
6 \$10 to \$18 of value over that same amount of usage, based on the Future 2A
7 analysis.

8 **V. PROJECT RELIABILITY AND ECONOMIC ASSESSMENT**

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

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

17 In addition, MISO's analyses show that the LRTP Tranche 2.1 portfolio,
18 which includes the Project, provides additional connectivity across the transmission
19 system, reducing congestion and enabling access to a broader array of resources by
20 customers in South Dakota. These improvements will increase market efficiency
21 and the competitive supply of energy, and will provide economic benefits to retail
22 electric consumers well in excess of the LRTP Tranche 2.1 portfolio costs. The
23 LRTP Tranche 2.1 portfolio represents a holistic solution for delivering these

1 benefits when considering generation, transmission, and other factors under
2 expected future conditions.

3 **Q. What are the areas of concern in South Dakota, as determined in the steady**
4 **state analysis?**

5 A. The Project is part of the transmission facilities that provide connectivity across the
6 northern MISO region from South Dakota to Wisconsin. The Project mitigates
7 thermal overloading in eastern South Dakota, including severe post contingent
8 overloads in excess of 125%. The Project adds transmission capacity that shifts
9 regional power transfers from the underlying network to the 765 kV backbone
10 which significantly reduces curtailment of generation to improve energy delivery
11 in South Dakota and the neighboring states.

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

13 A. The Project, along with the connecting facilities,³⁰ relieves thermal overloading on
14 five facilities in eastern South Dakota and resolves overloading on ten facilities in
15 Minnesota for N-1 contingency events. Additionally, the Project, along with the
16 connecting facilities, provides relief for thermal overloading on six facilities in
17 eastern South Dakota under most system conditions and resolves overloading for
18 many Minnesota facilities during N-1-1 contingency events.³¹ The Bulk Electric

³⁰ “The Project” and “the connecting facilities” refer to LRTP Tranche 2.1 Projects 22-26 as defined in Chapter 2 of the MTEP24 Report.

³¹ 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” event includes NERC TPL Category P3 and P6 contingencies and means that a

1 System (“BES”) elements in South Dakota relieved by the Project under N-1 and

2 N-1-1 contingency conditions are listed below.

3 The facilities with N-1 violations are as follows:

- 4 • Bigstone – Highway 12 115 kV #1;
- 5 • Canby – Burr 115 kV #1;
- 6 • Brookings County 345/115 kV Transformer #9;
- 7 • Split Rock 230/115 kV Transformer #9;
- 8 • Split Rock – Sioux Falls 230 kV #1.

9 The facilities with N-1-1 violations are as follows:

- 10 • Bigstone – Highway 12 115 kV #1;
- 11 • Canby – Burr 115 kV #1;
- 12 • Brookings County 345/115 kV Transformer #9;
- 13 • Split Rock 230/115 kV Transformer #9;
- 14 • Split Rock – Sioux Falls 230 kV #1;
- 15 • Bigstone – Brownsville 230 kV #1.

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

18 A. The Project and the connecting facilities relieve approximately 34 unique N-1
19 contingencies that could otherwise cause facility overloading in eastern South
20 Dakota. The most excessive overloads that the Project and connecting facilities
21 would relieve result from the outage of 230 kV and 345 kV transmission facilities
22 in eastern South Dakota. The Project and the connecting facilities also alleviate
23 facility overloading associated with 1473 unique N-1-1 contingency combinations.

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.

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

3 A. The full Tranche 2.1 portfolio, including the Project, reduced the total congestion
4 measure in eastern South Dakota by \$237,173/MW. The flowgates with the
5 greatest reduction in congestion in South Dakota and the surrounding areas are
6 listed in the table shown below:

7 **Table 2: Congestion Measure by Flowgate Constraint**

Flowgate Constraint	Congestion Measure
Base Case: BIGSTON4 230kV - YBUS770100 kV (OTP)	\$15,099
Event 54: BIGSTON4 230kV - BROWNSV4230 kV (OTP)	\$3,570
Base Case: BRKNGCO3 345kV - BRKNGCO7115 kV (NSP)	\$1,739
Event 46: BIGSTON4 230kV - BROWNSV4230 kV (OTP)	\$1,363
Event 71: SPLT RK4 230kV - SIOUXFL4230 kV (NSP-WAUE)	\$1,253

8

9 **Q. Did MISO consider alternatives to the Project?**

10 A. Yes. MISO considered numerous alternatives for each potential LRTP project.
11 Most relevant to the PowerOn project, MISO considered a 345 kV transmission
12 line from Big Stone South to Blue Lake. The purpose of this line would been to
13 provide an outlet for generation in North and South Dakota and western Minnesota.
14 Ultimately, MISO concluded that this alternative was inferior to the proposed
15 Project. The alternative offered marginal improvement over the initial design in
16 constraint mitigation and was less effective in addressing similar constraints. The

1 proposed 345 kV alternative improved economic congestion in Minnesota but the
2 production cost value was not as significant as the 765 kV alternative. Given the
3 lack of benefits, MISO concluded that the PowerOn project was a better fit for
4 regional needs and therefore included it in the Tranche 2.1 portfolio.

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

7 A. Studies for interconnection requests for new generation in MISO's 2023 and 2025
8 Interconnection Queue cycles, as well as the Expedited Resource Addition Study
9 ("ERAS") process, assume that the LRTP Tranche 2.1 portfolio will be constructed
10 and made part of the existing transmission network. Active generation
11 interconnection requests include 1.8 GW of new generation resources in South
12 Dakota³² that are needed to help meet future resource adequacy needs. These
13 requests could be negatively impacted if the LRTP Tranche 2.1 projects, such as
14 the Project, are delayed or denied. The resulting disruption of the Interconnection
15 Queue studies and the ERAS process would cause withdrawals of interconnection
16 requests and increased risks to resource adequacy. In the absence of the LRTP
17 Tranche 2.1 portfolio, the generating capacity that achieves commercial operation
18 from the 2023 and 2025 Interconnection Queue cycles may encounter substantial
19 curtailment of output due to unresolved transmission constraints that could also

³² See https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/.

1 result in higher energy costs or create risks of unserved energy if a significant
2 amount of generating capacity is trapped behind these constraints. These situations
3 would be mitigated by completion of the Project and other LRTP Tranche 2.1
4 projects.

5 Generation interconnection studies prior to the 2023 Interconnection Queue
6 cycle were conducted before the LRTP Tranche 2.1 portfolio was included in
7 MISO's transmission system base case, but the studies may still identify new
8 transmission projects from the LRTP Tranche 2.1 portfolio as mitigation for issues
9 caused by the proposed generation interconnection requests. Operation of the added
10 generating capacity could be contingent on construction of LRTP projects if the
11 proposed mitigation in a queue study is the same end-to-end project as an approved
12 LRTP Tranche 2.1 project. Prior queue cycles that comprise 55.8 GW of generating
13 resources are currently under study in the MISO Midwest Subregion.³³ Some of
14 this generating capacity may be dependent on LRTP Tranche 2.1 transmission
15 development in order to secure generator interconnection agreements.

16 **VI. OTHER REGIONAL IMPACTS IF PROJECT IS NOT CONSTRUCTED**

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

19 A. The purpose of the very extensive planning functions of MISO is to involve all
20 stakeholders in a process that will derive the most cost-effective expansion plan
21 that will meet local and regional needs for reliability, optimize access to economic

³³ *Id.*

1 generation resources, and deliver other important values that benefit the ultimate
2 consumer and society. The MTEP process designs a very complex system that will
3 serve both short- and long-term needs of the BES in a coordinated manner. The
4 inability to construct a key element of the regional expansion plan, especially a high
5 voltage element such as the one proposed in the Application that is designed for
6 both reliability and its economic attributes, could result in the loss of the economic
7 benefits provided by the Project and the need to develop less optimal solutions to
8 reliability concerns. The revised plan would likely have a negative economic
9 impact on customers located in the Midwest Subregion.

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

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

1 **VII. CONCLUSION**

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

5 **A.** The facilities proposed by the Applicants would provide substantial reliability and
6 economic benefits to South Dakota. These facilities also fit well as a component of
7 the MISO regional plan for the continued development of a reliable and economic
8 regional transmission system.

9 **Q. Does this conclude your testimony?**

A. Yes, it does.

Signed this 16th day of October, 2026

By: Joseph Reddoch