UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North Dakota Public Service Commission	)	
Montana Public Service Commission	)	
Arkansas Public Service Commission	)	
Mississippi Public Service Commission	)	
Louisiana Public Service Commission	)	
	)	
Complainants,	)	
	)	
v.	)	**Docket No. EL25-109-000**
	)	
Midcontinent Independent System Operator, Inc.	)	
	)	
Respondent.	)	

PREPARED DIRECT TESTIMONY OF JEREMIAH DONER ON BEHALF OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

September 9, 2025

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I. QUALIFICATIONS AND PURPOSE

A. Qualifications

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND RELATIONSHIP TO THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

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

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Illinois State University with a Bachelor of Science degree in economics and minors in Business Administration and Mathematics. Also, I received a Master of Science in economics from Illinois State University with a concentration in electricity, natural gas, and telecommunications. Prior to my current position, since joining MISO in 2007, I have performed various roles across the organization. I started as a Transmission Strategy Analyst in Transmission Planning, working on such items as MISO's Multi-Value Project (also referred to herein as "MVP") planning and cost allocation process development and FERC Order No. 1000 compliance. I subsequently undertook roles in corporate strategy, legal business operations, seams administration in system operations, membership services, and seams coordination in external affairs. More recently, I performed various economic and policy tasks as part of MISO's transmission planning functions.

As part of my role as Director of Economic and Policy Planning, starting in January 2021, I was a member of the leadership team overseeing multiple aspects of the Long Range Transmission Planning ("LRTP") Tranche 1, which included the development of forecasting assumptions (*i.e.* "Futures") and model development, economic planning, and development of the business case supporting the LRTP Tranche 1.

I have held my current position since April 2022. I am responsible for directing the teams focused on multiple areas of transmission planning: (1) LRTP business case development, including for LRTP Tranche 1 and 2.1; (2) all parts of MISO's competitive transmission process and the "variance analysis" process for after-the-fact review of regionally cost shared transmission projects; (3) MISO's regional and interregional transmission cost

allocation; (4) annual MTEP report development; and (5) MISO's seams coordination strategy. I also serve as the MISO staff liaison to the MISO stakeholder committee charged with improving and developing MISO's set of regional and interregional cost allocation methods, which is the Regional Expansion Criteria and Benefits Working Group.

Q. HAVE YOU SPONSORED ANY OTHER TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION OR ANY OTHER REGULATORY COMMISSION?

A. Yes. I provided sworn affidavits and pre-filed testimony in proceedings before the Commission, the Illinois Commerce Commission ("ICC"), the Missouri Public Service Commission, and the Public Service Commission of Wisconsin ("WPSC"). Specifically, I submitted sworn affidavits and pre-filed testimony in FERC Docket Nos. EL22-83-000, ER22-995-000, and ER22-1955-000 relating to MISO's LRTP initiative and various associated transmission planning, competitive process, and cost allocation issues. I submitted pre-filed testimony and testified in ICC Docket No. P2024-0088 and WPSC Docket Nos. 5-CE-158 and 5-CE-157 on the subject of the LRTP Tranche 1 projects located in Illinois and Wisconsin, respectively. I also submitted pre-filed testimony in MPSC File No. EA-2025-0087 regarding LRTP Tranche 1 projects located in Missouri.

B. <u>Purpose</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this proceeding, five state regulatory commissions[1] (collectively, the "Complainants") filed

[1] The five state regulatory commissions are the: (1) North Dakota Public Service Commission ("NDPSC"); (2) Montana Public Service Commission; (3) Arkansas Public Service Commission; (4) Mississippi Public Service Commission; and (5) Louisiana Public Service Commission.

a complaint against MISO, alleging MISO violated its Tariff[2] by developing and relying upon unreasonable benefit metrics that substantially overstate the benefits of LRTP Tranche 2.1 and, consequently LRTP Tranche 2.1 does not meet the cost benefit criteria (i.e., a benefit to cost ratio of 1.0 or greater, also referred to herein as the "B/C ratio") to qualify as MVP.[3]

My testimony:

- Addresses certain factual claims made in the Complaint and rebuts the Complainants' criticisms of the assumptions, metrics, and modeling that resulted in the establishment of LRTP Tranche 2.1, as well as the calculation of the B/C ratio. My testimony confirms that both efforts were thoroughly undertaken consistent with industry best practices, as authorized by MISO's Tariff, and through a robust stakeholder process.
- Explains the Complaint's request for MISO to file all future business cases used to support MVPs with the Commission would be duplicative to the FERC-approved, proactive transmission planning process that already includes a robust stakeholder process and will significantly delay the already lengthy construction timelines of critically needed transmission infrastructure within MISO.
- Discusses the consequences if the Complaint is upheld and the LRTP Tranche 2.1 Portfolio is cancelled, including detrimental impacts to: (i) maintaining reliability that will be further complicated with the overall load growth

[2] When capitalized, the term "Tariff" or "MISO Tariff" means MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff. All capitalized terms not otherwise defined herein have the meaning as set forth in the Tariff.

[3] Complaint at *e.g.,* 2, 23, 43, and 46.

occurring in the MISO footprint; and (ii) significant delays in bringing on-line new generation resources due to interconnection restudies, including MISO's recently implemented Expedited Resource Addition Study ("ERAS") process.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony is structured as follows:

- Part I states my qualifications and explains the purpose of my testimony.
- Part II provides: (1) background on the MTEP, LRTP, and MVP processes; and (2) an overview of the seven-step iterative process MISO followed to develop the LRTP Tranche 2.1 Portfolio, including development of futures, economic and reliability modeling, issue identification, solution evaluation, benefit metrics, and the calculation of the B/C ratio.
- Part III rebuts the Complainants' criticism of the LRTP Tranche 2.1 Portfolio. Specifically, I explain that:
    - The three benefit metrics the Complaint criticizes -- Mitigation of Reliability Issues, Avoided Capacity Costs, and Decarbonization – all reasonably reflect quantifiable benefits that were vetted with stakeholders and are consistent with industry best practices.
    - Tranche 2.1 is not being built to deliver remote wind generation from the western part of MISO to load centers in the eastern part of MISO, but instead enhances grid reliability and market efficiency across the MISO Midwest Subregion by building a 3,631-mile, 345 kV and 765 kV transmission backbone in the Midwest that proactively addresses reliability and economic challenges from factors like load growth from a range of drivers including new industries, weather variability, new resource interconnections, and supporting regional power transfer within MISO.

- Comments from the NDPSC during the robust stakeholder process were not ignored, but instead MISO incorporated numerous requests from the NDPSC into Tranche 2.1, including siting significant additional wind resources into the state based on the NDPSC's requests and including additional transmission projects identified by local Transmission Owners, which in addition to multiple local economic and reliability benefits will provide North Dakota the opportunity to further increase their role as an energy exporter.
- The additional regulatory oversight the Complaint seeks would be a further hinderance to already lengthy transmission planning studies, be redundant to the existing, Tariff-based processes, and could significantly delay construction of critical transmission infrastructure within MISO.

- Part IV explains how the timing of this Complaint, which was filed more than 8 months after the LRTP Tranche 2.1 Portfolio was approved, is: (1) disruptive to transmission planning as those entities who were directed to construct the projects included in the Tranche 2.1 Portfolio must now pause such efforts or undertake additional risk while this Complaint is pending; and (2) could, if upheld by the Commission, have drastic negative impacts by delaying load from receiving the significant economic and reliability benefits identified, result in a multi-year delay in bringing on-line much needed new resources and supporting new load integrations.

II. MISO'S TRANSMISSION PLANNING PROCESS, LRTP, AND MVPs

A. Transmission Planning

Q. WHAT ARE THE REQUIREMENTS AND OBJECTIVES OF THE MISO REGIONAL PLANNING PROCESS?

A. Regional planning at MISO is performed in accordance with several guiding documents. The Agreement of Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation ("Transmission Owners Agreement" or "TOA"), includes the planning framework that describes the planning responsibilities of MISO and its transmission owning members.[4] MISO's responsibilities include the development of the MTEP in collaboration with transmission owners and other stakeholders.

MISO also adheres to the nine planning principles outlined in FERC Order No. 890.[5] In so doing, MISO provides an open and transparent regional planning process that results in recommendations for expansion that are reported in the MTEP. MISO's processes are also in compliance with FERC Order No. 1000, which furthered the planning principles outlined in FERC Order No. 890 and included the requirements to plan for public policy and for coordinated inter-regional planning and cost allocation.[6]

Consistent with these planning principles, the objectives of the MTEP process are to: (i) identify transmission system expansions that will ensure the reliability of the transmission system that is under the operational and planning control of MISO; (ii) identify expansion that

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[4] *See* MISO Transmission Owners Agreement (TOA), 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.

[5] *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.

[6] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 66,051 (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).

is critically needed to support the reliable and competitive supply of electric power by this system; and (iii) identify expansion that is necessary to support energy policy mandates in effect within the MISO footprint. MISO's MTEP24 Report provides assessments of resource adequacy, analyses of various energy policy scenarios, and discusses the development of long-term resource forecasts based on those scenarios.

Q. WHAT IS THE PLANNING PROCESS USED TO DEVELOP THE MTEP?

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

Q. DOES THE MTEP ALSO INCLUDE REGIONAL PLANNING?

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

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

state and federal energy policy decisions. These possible future scenarios and energy polices ("Futures") form the basis for forecasts of generation resources and load under a variety of assumptions and consistent with member plans and policy. Transmission needs are then assessed, and plans developed to identify "least regrets"[7] transmission that reliably and economically deliver the necessary energy from generation resources to load under multiple scenarios.

Q. WHAT DOES IT MEAN FOR A PROJECT TO BE APPROVED BY THE MISO BOARD OF DIRECTORS AS A PART OF THE MTEP?

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

Q. IN PREPARING THE MTEP REGIONAL PLANS, WHAT CONSIDERATIONS DOES MISO TAKE INTO ACCOUNT?

A. There are numerous considerations in planning for a regional transmission system; however, two considerations are crucial. First, the reliability of the transmission system must be maintained. That is, the transmission system must be able to withstand disturbances (generator and/or transmission facility outages) without interruption of service to load. This is achieved,

[7] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 66,051 (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).

in part, by assuring that disturbances do not lead to cascading loss of other generator or transmission facilities.

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

In a near term horizon, these factors are defined by commitments to specific load and generation, per NERC criteria. In a longer term horizon, multiple scenarios must capture a range of system conditions to "bookend"[8] potential scenarios (as discussed in the MISO Futures explanation further below in my testimony), with studies based on those scenarios identifying transmission that is useful across a number of system conditions, contingencies, and weather patterns. That transmission is the target of LRTP.

B. <u>LRTP and MVP</u>

Q. WHAT IS THE OVERALL PURPOSE OF MISO'S LRTP PROCESS?

A. LRTP, through its stakeholder process, focuses on the development of robust solutions that pro-actively address future reliability challenges posed on the system, including those driven by load growth, resource plans, and member policy objectives. Long range planning provides a comprehensive, forward-looking assessment of future needs based on a range of anticipated future conditions that identify the "least regrets" regional transmission expansion providing a

[8] 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.

range of benefits to maintain reliable performance under a range of operating conditions, cost efficient energy delivery, accessibility to resources, and flexibility in resource mix. MISO's LRTP process is a partnership with the MISO members and states to identify a transmission system that can reliably and efficiently serve load with the resources identified in the MISO Futures.

Q. WHAT IS AN MVP?

A. An MVP is a type of transmission project developed by MISO and stakeholders that was accepted by FERC in 2010,[9] whose costs are sub-regionally or regionally shared. An MVP is a project that must be: (i) evaluated as part of a portfolio of MVPs whose benefits are spread broadly across the MISO footprint or subregion and: (ii) must meet at least one of the following criteria, as stated in Attachment FF of the MISO Tariff: [10]

a. *Criterion 1*. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or

[9] A "least regrets" transmission plan is an approach to building new transmission infrastructure that performs well across a wide range of future scenarios, minimizing the risk of transmission projects becoming unnecessary.

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

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 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.[11]

Q. WHY WAS THE MVP COST ALLOCATION AND PLANNING PROCESS DEVELOPED?

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

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

Q. HAS THE MVP COST ALLOCATION BEEN REFINED SINCE ITS INITIAL APPROVAL?

A. Yes. Subsequent to the approval of the 2011 MVP portfolio, the MISO footprint had a major change with the addition of MISO South in 2013 (*i.e.*, south of Missouri). At the start of the LRTP initiative in 2021, MISO recognized this change and provided an additional option for subregional cost allocation for MVP portfolios. Changes to the MVP cost allocation process were filed with, and accepted by, the Commission in 2022.[12] This included subdividing the MISO footprint into two subregions – the Midwest Subregion and the MISO South MVP Cost Allocation Subregion ("South Subregion"). The Tariff provisions that provide for these subregions recognize that benefits from an MVP portfolio may be widespread and yet mostly contained within geographic subregions in the midwestern and southern portions of the MISO footprint. The Subregional option has been applied to two MVP Portfolios benefiting the

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

Midwest Subregion: (1) Tranche 1 approved in July 2022; and (2) Tranche 2.1 approved in December 2024.

C. LRTP Tranche 2.1

Q. WHAT IS THE LRTP TRANCHE 2.1 PORTFOLIO?

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

Q. WHAT IS THE RELATIONSHIP BETWEEN THE MVP PROJECT TYPE AND LRTP TRANCHE 2.1?

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

Q. DESCRIBE TRANCHE 2.1 FURTHER, INCLUDING THE BENEFITS AND COSTS.

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

- Pro-actively provides reliability and efficiently enabling future generation in support of load growth and member plans;
- Adding a 765 kV backbone to the MISO Midwest to support required energy transfers across the MISO system under multiple future system conditions to support system reliability. With a 765 kV backbone, more electricity can be delivered, while minimizing land use and reducing energy losses; and
- Primarily a reliability-driven portfolio, that also provides a broad range of value with a benefit-cost ratio ranging from 1.8 to 3.5.

Q. WHAT WAS THE OVERALL PROCESS FOR THE LRTP TRANCHE 2.1 PORTFOLIO OF PROJECTS?

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

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

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

(2) developing planning models utilizing the Futures;

(3) identifying potential transmission issues;

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

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

(6) recommending preferred solutions; and

(7) applying the appropriate cost allocation mechanism.

I discuss the steps further below.

i. Step 1 – Development of Futures

Q.WHAT ARE FUTURES?

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

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

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

Q. HOW DOES MISO DEVELOP FUTURE SYSTEM SCENARIOS?

A. To create the Futures, MISO considers member data, stakeholder input, state and federal policy, and technical and economic data. Using this data, and building from member planned resources, MISO builds multiple generation expansions to bookend potential future conditions, with each expansion developed with sufficient generation to meet projected demand, energy,

and resource adequacy requirements. Once these expansions are created, MISO works with stakeholders to site the forecasted generation to maximize resource availability and accommodate member goals.

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

Future 1A represents the conservative low bookend, assuming that: (1) 100% of utility Integrated Resource Plans and 85% of utility or state goals and policies are not supported by legislation; (2) carbon emissions decline solely as an outcome of utility and state plans; and (3) load growth is consistent with pre-2019 trends. For the Future 1A resource expansion 93% of the resources needed were based directly on member submitted resources and 7% being identified by MISO's resource expansion model.[13] For the Future 2A resource expansion 54% of the resources needed were based directly on member submitted resources and 46% being identified by MISO's resource expansion model.

Q. DID MISO REFRESH THE FUTURES AFTER THE APPROVAL OF THE LRTP TRANCHE 1 PORTFOLIO?

[13] https://cdn.misoenergy.org/20240126%20LRTP%20Workshop%20Item%2005%20Tranche%202%20Robustness%20Testing%20Low-End%20Bookend631474.pdf

A. Yes. Series 1 (Futures 1, 2 and 3) were developed in 2019 to 2021. Following Board approval of the Tranche 1 Portfolio, MISO refreshed the Futures. This resulted in the development of Series 1A (Futures 1A, 2A, and 3A).

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

Q. HOW WAS THE RESOURCE EXPANSION CONSIDERED IN DEVELOPING THE FUTURES?

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

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

Q. HOW WAS RESOURCE SITING CONSIDERED IN DEVELOPING THE FUTURES?

A. The Future scenarios development culminates in a siting process that maximizes resource availability and accommodates member goals. After the number and composition of resources are identified, siting analysis defines where these resources are located within the MISO footprint. MISO followed a stakeholder-approved siting process which was addressed in the Series 1A Futures Report[14] and Futures Refresh Assumptions Book.[15] As part of this process, MISO sited model-built resources considering:

- Member identified locations;
- Resource adequacy requirements: Each Local Resource Zone ("LRZ") must meet its Local Clearing Requirement ("LCR") and the footprint-wide Planning Reserve Margin Requirement ("PRMR");
- Policy goals: local, state, and regional Renewable Portfolio Standards and decarbonization goals;
- Additional resource type siting considerations:
  - Split of 80% Generator Interconnection ("GI") queue and 20% Vibrant Clean Energy ("VCE")/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;

[14] https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

[15] https://cdn.misoenergy.org/20230428%20LRTP%20Workshop%20Item%2003b%20Futures%20Refresh%20Assumptions%20Book628727.pdf

- 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.

ii. Step 2 – Develop Planning Models Utilizing Futures

Q. WHAT DID STEP 2 INVOLVE?

A. MISO developed reliability and economic models to assess system performance expected under future conditions. For the reliability models MISO built 10-year, and 20-year initialized from MTEP22 models and incorporated changes to reflect expected transmission topology and Future 2A load forecast and resource changes. The resulting series of reliability study models reflect seasonal load and generation dispatch conditions and include additional transfer scenarios to cover a range of likely and possible dispatch with a focus on the worst credible conditions from the system point of view, while recognizing that local conditions may vary.

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

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

Q. DID STAKEHOLDER INPUT PLAY A ROLE IN DEVELOPING THE RELIABILITY MODELS?

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

Q. DID STAKEHOLDER INPUT PLAY A ROLE IN DEVELOPING THE ECONOMIC MODELS?

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

[16] *Id*., pgs. 32-35.

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

iii. *Step 3 – Identify Potential Transmission Issues*

Q. WHAT DOES STEP 3 INVOLVE?

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

Tranche 2.1 work focused on resource changes and load growth contemplated by Future 2A. Key reliability and economic issues provided the foundation to develop Tranche 2.1 as a no-regrets and stand-alone first step towards the transmission required to reliably and efficiently serve load with the resources identified in Future 2A.

Q. WHAT WERE THE RELIABILITY ANALYSES THAT MISO PERFORMED FOR TRANCHE 2.1?

A. The reliability analysis included ensuring transmission system performance is reliable and adequate with both an intact system and one where contingencies have occurred, and high regional power transfer scenarios that result when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty. A detailed reliability analysis using powerflow simulations was conducted to identify transmission system equipment loadings and voltages with respect to safe equipment design tolerances. The MISO reliability analyses included several different types of simulations, each targeting different information about performance, as described below:

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

Q. WHAT WAS CONSIDERED DURING THE ECONOMIC ANALYSIS?

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

The economic analysis used several economic indicators to assess the transmission system performance, as described below:

- Congestion measure ($/MW) - an indication of the production cost savings opportunity from relieving transmission congestion;
- Curtailment (MWh) - a measure of the total amount of energy from renewable sources which cannot be delivered economically; and
- Load LMP ($/MWh) - the Locational Marginal Price (LMP) is the market price to purchase energy from a market. Load Weighted LMPs are expressed as an average price weighted by energy each hour and at each delivery point and are indicative of the price of energy in a region.

Q. WHAT DID THE ECONOMIC AND RELIABILITY ANALYSES SHOW?

A. The economic and reliability analysis showed significant levels of overload on lower and higher voltage equipment across the footprint and severe voltage violations due to decreased reactive performance across the system. With the addition of long transmission lines required to strengthen the transfer capability across the multi-state Midwest Subregion power will travel a longer distance increasing the voltage angle, and reducing stability limits that increase stress on the system. Similarly, the economic analysis showed severe widespread congestion, price separation and significant generation curtailment due to congestion on the transmission. Results also revealed opportunities to provide additional benefits by resolving energy losses from power transfers on existing transmission and by mitigating economic congestion. MISO reviewed the economic and reliability study findings with stakeholders, and posted results for feedback to incorporate for further analysis and solution testing.

iv. *Step 4 – Propose Solutions*

Q. WHAT DOES STEP FOUR INVOLVE?

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

- Higher Transmission Rating Limits;
- Cost per MW-Mile; and
- Land-Use per MW-Mile.[17]

Q. DESCRIBE FURTHER WHY A 765 KV REGIONAL SOLUTION WAS CONSIDERED.

A. There were three primary reasons – loading capability, cost efficiency, and less land use. When considering the per MW-mile capability of 765 kV and 345 kV lines, 765 kV has much higher loading capability than 345 kV, particularly for longer distances. For Tranche 2.1, 50% of the proposed 765 kV facilities are more than 120 miles long. At 120 miles, the Safe Loading Limit

[17] 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

of a 345 kV line is less than 1,000 MVA and 765 kV is 4,500 MVA. The loadings observed on the Tranche 2.1 765 kV facilities range between 2,000 and 4,000 MVA.[18]

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

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

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

Q. WHEN DID MISO ISSUE ITS ANTICIPATED LRTP TRANCHE 2.1 PORTFOLIO?

A. It was shared with stakeholders at the March 15, 2024 LRTP Workshop. As a part of issuing the anticipated LRTP Tranche 2.1 Portfolio, MISO continued to analyze the anticipated portfolio, including the evaluation of stakeholder submitted alternatives and notified

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

stakeholders as new analysis was performed and updates made to the Tranche 2.1 Portfolio.[19] A near final Tranche 2.1 Portfolio was shared with stakeholders at the June 10, 2024 LRTP Workshop.[20]

Q. DID MISO CONDUCT ROBUSTNESS TESTING OF SOLUTIONS AND, IF SO, WHY?

A. Yes. A key objective of robustness testing is to identify key projects that were either approved or in the process of approval after the finalization of LRTP power flow models in October 2023, which may have a material impact on the anticipated Tranche 2 portfolio. The second main objective is to perform an assessment with and without key projects and identify areas that may result in MISO modifying, adding to, or removing transmission facilities in the LRTP portfolio. No modifications were required to the LRTP Tranche 2.1 Portfolio as a result of robustness testing.

Q. WERE ALTERNATIVES CONSIDERED?

A. Yes. MISO undertook an analysis of alternatives. 97 projects representing 47 solutions were received from stakeholders. Not all these solutions were evaluated as MISO focused on alternatives that are more closely aligned with the same issues and needs that drove the solutions for this portfolio, various alternatives were similar in location and ones that are likely to be constructed in a timely manner. Additionally, some solutions were evaluated along with variations of alternatives developed by MISO staff, and some projects addressed more local versus regional needs and are more suited for the annual MTEP reliability planning and the

[19] https://cdn.misoenergy.org/20240315%20LRTP%20Workshop%20Item%2002%20Tranche%202%20Anticipated%20Portfolio632013.pdf

[20] https://cdn.misoenergy.org/20240610%20LRTP%20Workshop%20Item%2002%20Near-Final%20Portfolio633836.pdf

generator interconnection processes. Based on alternative analysis, MISO made additions to the portfolio in Minnesota, Iowa, Indiana, North Dakota, South Dakota, Michigan and a replacement in Missouri.

v. *Step 5 – Evaluate and Justify Solutions*

Q. WHAT DOES STEP 5 INVOLVE?

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

- *Reliability and Economic - Modeling with solutions:* MISO develops new reliability and economic models that incorporate the proposed transmission solutions;
- *Effectiveness testing* - MISO evaluates how well the solutions address the reliability and economic transmission issues identified in Step 3, such as thermal overloads, voltage problems, and increased congestion and curtailment;
- *Additional Alternative analysis* - Submitted alternative solutions are reviewed and tested for their effectiveness; and
- *Business Case Analysis* - Projects and portfolios are tested against a range of future scenarios (or "bookends") using multiple types of benefits to ensure they provide long-term value, even if the future evolves differently than expected. For example, for LRTP Tranche 2.1, the portfolio was tested against a lower-end "Future 1A" scenario.

Q. WHAT BENEFITS DID THE RELIABILITY ASSESSMENT FOR THE LRTP TRANCHE 2.1 PORTFOLIO SHOW?

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

To better assess the impact and severity of overloads and voltage violations across multiple lines and substations, MISO utilized industry-standard ranking criteria known as Severity Indices. The Thermal Severity Index provides an overview of the performance of the Tranche 2.1 Portfolio taking into consideration the magnitude of thermal and voltage violations, respectively, from the contingency analysis. The Thermal and Voltage Severity Index values calculated for the Tranche 2.1 Portfolio indicated significant improvement in the overall system performance.

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

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

Q. DOES THE LRTP TRANCHE 2.1 PORTFOLIO PROVIDE VOLTAGE AND REACTIVE SUPPORT?

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

Q. DOES TRANCHE 2.1 ENHANCE OVERALL STABILITY OF THE TRANSMISSION SYSTEM?

A. Yes. The portfolio enhances the overall stability of the system as demonstrated by a significant reduction in the number of transient voltage violations, low damping violations and relay trip violations. The Transient Stability Index ("TSI") is an industry acceptable metric used in TSAT (Transient Security Assessment Tool) which assesses the severity of each disturbance. A higher TSI for a disturbance represents a more stable system response. The LRTP Tranche 2.1 Portfolio resolved 90% of the transient voltage violations in the 2042 AVG model and 30% of the transient voltage violations in the 2042 SUM model. In addition, the LRTP Tranche 2.1 Portfolio resolved all low damping violations and reduced the number of violations in both 2042 AVG and 2042 SUM models.

Q. WHAT BENEFITS DID THE ECONOMIC ANALYSES FOR TRANCHE 2.1 SHOW?

A. Analysis with annual economic models represent various system conditions and dispatch patterns that helped MISO better understand system performance with and without the LRTP Tranche 2.1 Portfolio. The Tranche 2.1 Portfolio enhances the economic value for the MISO Midwest subregion and enables member plans for fleet transition and load growth. The

economic analysis demonstrated the following results on the performance of the LRTP Tranche 2.1 Portfolio using Future 2A:

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

Q. DOES THE LRTP TRANCHE 2.1 PORTFOLIO PROVIDE RELIABILITY AND ECONOMIC BENEFITS TO THE WEST REGION OF MISO?

A. Yes, results of the transmission solutions in the West Region include the following:

- the Northern Minnesota project group provides outlets to North Dakota generation, resolves constraints in this area and connects to LRTP Tranche 1 lines;
- West Region sees a 25.5% ($2.0M/MW) reduction in economic congestion;
- increased generation outlets in North Dakota, South Dakota and Minnesota shift congestion to new flowgates, which are addressed through underbuild;
- the 765 kV project in northeastern South Dakota, Southwestern Minnesota and Western Iowa provides an outlet for generation in South Dakota and also

connects both west-to-east 765 kV paths developed in the initial portfolio to provide contingency support;

- the Minnesota-Wisconsin West – Wisconsin East project adds power transfer capability into load centers in Minnesota and Wisconsin;
- congestion in Eastern Wisconsin is reduced by moving regional flows onto the backbone network; and
- the Wisconsin-Illinois 765 kV project assists serving load centers in the region and provides contingency support by connecting to the West – East 765 kV path through Iowa and Illinois.

Q. DOES THE TRANCHE 2.1 PORTFOLIO PROVIDE BENEFITS TO THE CENTRAL REGION OF MISO?

A. Yes, results of the transmission solutions in the Central Region include the following:

- both 765 & 345 kV level projects going West – East from Iowa through Illinois into Indiana provide a regional transfer path that enables generation in LRZ 1, 3, and 4 and supports strong East – West transfers to and from LRZ 6 and 7;
- transmission relieves congestion across Central and Eastern Iowa and throughout Illinois, Missouri, and Indiana. The 345 kV project in Missouri resolves numerous constraints in the St. Louis Metro region and enables increased intraregional transfers across the Central Region;
- the Southern Indiana/Western Kentucky 345 kV project resolves constraints in the region and enhances West – East transfer capacity across the Central Region;

- East Central Indiana upgrades more than double the 345 kV outlet and allows both 765 & 345 kV connections to adequately and reliably transfer remote generation to the Indiana load centers in Central and Southeastern Indiana; and
- Central Region sees a 33.9% ($2.0M/MW) reduction in economic congestion.

Q. DOES THE LRTP TRANCHE 2.1 PORTFOLIO PROVIDE BENEFITS TO THE EAST REGION OF MISO?

A. Yes, results of the transmission solutions in the East Region include the following:

- Central MI project assists in unlocking generation in Western and Central MI and connects to Tranche 1 project to allow greater transfer capability;
- Transmission connects resources from Western MI to load centers in the East, relieving congestion especially near the Eastern load centers;
- MI to Northeast IN project supplement the existing connections into Michigan and provide the transfer capability in and out of MI; and
- East Region sees a 31.7% ($0.9M/MW) reduction in economic congestion.

Q. HOW DOES MISO USE BUSINESS CASE ANALYSIS TO ASSESS THE MONETARY BENEFITS PROVIDED BY THE LRTP TRANCHE 2.1 PORTFOLIO?

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

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

Q. WHAT BENEFIT METRICS WERE USED FOR THE LRTP TRANCHE 2.1 PORTFOLIO EVALUATION?

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

1. Mitigation of reliability issues - value of alleviating issues which, if unresolved, introduce a risk of unserved load;
2. Reduced risks of extreme weather impacts - increases grid resilience and decreases the probability of major service disruptions;
3. Avoided capacity cost - avoids capital costs for local resource builds versus regional expansions defined in Futures;
4. Capacity savings from reduction in losses - value of reducing transmission losses during peak capacity periods;
5. Avoided transmission investment - avoids the need for facility replacement due to age and condition;
6. Congestion and fuel savings - enhances market efficiency and provides access to low-cost generation;
7. Energy savings from losses - lower production costs to serve load with transmission facilities that reduce system losses;
8. Reduced transmission outage costs - reduced transmission congestion during forced and planned outages; and

9. Decarbonization - enables the economic dispatch of renewable resources to help reduce the carbon footprint.

Q. WERE THERE FURTHER ENHANCEMENTS TO THE BENEFIT METRICS LISTED ABOVE IN COMPARISON TO THE SIX BENEFIT METRICS USED FOR THE LRTP TRANCHE 1 PORTFOLIO?

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

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

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

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

Q. HOW DID MISO DETERMINE WHETHER TRANCHE 2.1 MET THE TARIFF CRITERIA TO QUALIFY AS A MVP?

A. In accordance with the guiding principles of the MISO transmission planning process, the allocation of costs for the transmission investment must be roughly commensurate with the expected benefits. As Multi-Value Projects, the eligibility criteria are established by Tariff requirements that define the need to demonstrate financially quantifiable benefits in excess of costs. Guided by the financially quantifiable benefits defined in the tariff for MVP projects, the nine benefit metrics listed above were evaluated to determine the amount of value delivered by the LRTP Tranche 2.1 Portfolio.

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 the portfolio is expected to be in-service. All benefit values are expressed in 2024 dollars. A discount rate of 7.1 percent is used to calculate the minimum value used to assess the benefit-to-cost ratio and is based on the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments. Benefits are also assessed using a discount rate of three percent to show how assets perform with a social discount rate that reflects the return a ratepayer would typically receive on a risk-adjusted investment.

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

Q. WHAT WERE THE OVERALL BENEFITS OF TRANCHE 2.1?

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

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

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 increases 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 avoids the	$1.8B	$1.9B

	need for 1.8GW under Future 1A and 2.3GW under Future 2A.		
Avoided transmission investment	Projects avoids the need for replacement of over 700 miles of existing transmission.	$1.2B	$1.2B
Congestion and fuel savings	Projects alleviates transmission constraint violations and reduces congestion to allow more efficient dispatch of lower cost resources.	$2.9B	$8.2B
Energy savings from losses	Projects provide additional transmission capacity and redistributes 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	$3.9B - $15.3B	$7.2B - $28.3B

	congestion, allowing for more efficient dispatch of non-emitting resources to reduce CO2 emissions.		
Total		$34.3B - $61.9B	$51.7B - $101.0B

Q. DID STAKEHOLDERS HAVE THE OPPORTUNITY TO PROVIDE INPUT ON THE METRICS THAT MISO USED AND THE RESULTS OF THE ANALYSES UNDERTAKEN?

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

- More robust methods were developed to isolate benefits from risk of unserved energy under extreme conditions from benefits related to capacity cost savings.
- Avoided transmission investment was simplified to remove avoided reliability upgrade costs that potentially overlapped with the mitigation of reliability issues benefit.
- Resource adequacy savings was eliminated to avoid double counting the reduction in planning reserves used in the avoided capacity cost benefit.
- Ramping flexibility was discontinued due to difficulty in implementation.

- Mitigation of reliability issues was further revised to avoid overlap with production cost savings and to eliminate potential for double counting of issues in the later study year.
- Other adjustments were made to update carbon costs, transmission cost estimates, and remove 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.

vi. *Step 6 - Recommend Preferred Solutions*

Q. WHAT OCCURS IN STEP 6?

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

Q. DISCUSS THE BOARD OF DIRECTORS REVIEW FURTHER.

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

Q. CAN YOU EXPAND ON THE FUNCTION OF THE SYSTEM PLANNING COMMITTEE?

A. The System Planning Committee is tasked with: (1) overseeing system planning matters affecting transmission expansion; (2) monitoring the development and implementation of the MTEP; (3) making recommendations to the Board of Directors; and (4) reporting to the Board of Directors regarding the progress of achieving expansion plans. Following the final stakeholder review, MISO Staff provides a final list of recommended projects to the System Planning Committee.[21] The System Planning Committee reviews stakeholder and MISO Staff comments before making recommendations to the Board of Directors for approval. Thereafter, the MISO Board of Directors considers approval of the MTEP portfolio of projects.

Q. WHAT PORTFOLIO RESULTED FROM STEP 6?

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

vii. *Step 7 - Apply Appropriate Cost Allocation*

Q. WHAT HAPPENS IN STEP 7?

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

[21] *Id.* § IV.A.

Q. DID MISO CONSIDER THE RATE RECOVERY OF THE TRANCHE 2.1 COSTS AND THE VALUE TO THE CAZ?

A. Yes. As Multi-Value-Projects, the costs of the LRTP Tranche 2.1 Portfolio will be recovered from MISO load and exports associated with the MISO Midwest Subregion through the energy-based MVP Usage Rate ($/MWh). No costs of Tranche 2.1 are allocated to the South Subregion (i.e., AR, LA, MS, and TX). Additionally, indicative annual MVP usage rates for the LRTP Tranche 2.1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. The MVP Usage Rate for LRTP Tranche 2.1 Portfolio is estimated to peak at $6.44 per MWh of energy usage and average $4.76 per MWh over a 40-year period. While the LRTP Tranche 2.1 Portfolio is estimated to cost MISO members about $5 per 1 MWh or 1,000 kWh of energy used, that investment will provide $10 to $18 of value over that same amount of usage, based on the Future 2A analysis.

Q. ARE THERE OTHER BENEFITS TO EACH STATE FROM LRTP TRANCHE 2.1 PORTFOLIO?

A. Yes. In addition to the direct benefits calculated in the business case analysis, the Tranche 2.1 transmission investments will also deliver significant economic development benefits to local economies in the MISO Midwest subregion. Such local economic development benefits include:

- Local investment and job creation (Tranche 2.1 investments are estimated to power roughly 22,000 to 65,000 direct jobs in the MISO region); and
- Attraction of new businesses and supporting the burgeoning high-growth industries, such as data centers.

The MTEP24 Report concluded that "Adding in the effects of supply chains and further induced demand and Tranche 2.1 investments are estimated to power between 44,000 and 131,000 total jobs in the MISO Midwest Subregion and between $4 and $24 billion in total economic output."[22]

III. RESPONSE TO THE COMPLAINTS ASSERTIONS

A. Metrics, Assumptions, and B/C Ratio

Q. EARLIER YOU IDENTIFIED THE NINE METRICS THAT MISO USED TO CALCULATE THE B/C RATIO OF TRANCHE 2.1, WHAT METRICS DOES THE COMPLAINT FOCUS ON?

A. The Complaint focuses on three benefit metrics: (1) Avoided Capacity Costs; (2) Mitigation of Reliability Issues; and (3) Decarbonization. I discuss each in turn below.

i. Avoided Capacity Costs

Q. PLEASE DESCRIBE THE AVOIDED CAPACITY COSTS METRIC FURTHER.

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

Q. HOW DID MISO UNDERTAKE THE ANALYSIS OF THE AVOIDED CAPACITY COSTS BENEFIT.

[22] See page 150 of the MTEP24 Report at https://cdn.misoenergy.org/MTEP24%20Chapter%202%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf

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

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

This additional reserve value is then applied as an adjustment to the planning reserve margin ("PRM") requirement in an incremental EGEAS resource expansion analysis that determines the amount and types of resources that are built to meet the added requirements. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the base model as committed capacity. The PRM adjustment is phased in, starting with the assumed portfolio in-service year and increased to the full value in the 2042 study year.

The EGEAS expansion for this metric is performed in combination with the Capacity Savings from Reduced Losses ("CSRL") metric to reflect the total impact of the LRTP Tranche 2.1 Portfolio. The ACC and CSRL components are split out after modeling completes, in proportion to their contribution to the total reserve requirement adjustment in 2042.

Q. THE COMPLAINT ALLEGES THAT MISO'S CALCULATION OF THIS BENEFIT IS FLAWED BECAUSE IT INCORRECTLY ASSUMES STATES AND UTILITIES WILL BUILD THE SAME FUTURE 2A GENERATION RESOURCES REGARDLESS OF WHETHER TRANCHE 2.1 IS BUILT.[23] WHAT IS YOUR RESPONSE?

A. The primary objective of the transmission identified (e.g., Tranche 2.1) through MISO's LRTP effort is to reliably and efficiently enable the resource plans of MISO members, by creating a "least-regrets" regional transmission backbone. When it comes to resource planning, MISO respects the rights of MISO utilities and states as the resource planner(s) for their respective areas, which means that MISO's role as the regional transmission planner is to plan the transmission given the resource fleet defined by MISO utilities and states.

MISO disagrees with actions that would require modifying member resource plans or the resource expansion which was developed in the MISO stakeholder process through the opportunity input from resource planners, members, and states. This position extends to the original Future 1A and Future 2A resource plans, the siting of resources within those Futures, and the base and change cases of business case metrics.

Q. THE COMPLAINT FURTHER ALLEGES THAT: (1) MISO'S BASE CASE IS FURTHER FLAWED BECAUSE, AFTER USING THE EGEAS MODEL TO CREATE FUTURE 2A, MISO DETERMINED THE FLEX UNITS (29.8 GW) WERE NEEDED

[23] Complaint at 34.

TO MAINTAIN SYSTEM RELIABILITY AND THAT: (2) HAD MISO INCLUDED THE FLEX UNITS IN ITS EGEAS MODELING, IT LIKELY WOULD NOT HAVE NEEDED THE BASE CASE RELIABILITY GENERATION THAT MISO USED TO CALCULATE ITS AVOIDED CAPACITY COST BENEFIT.[24] WHAT IS YOUR RESPONSE?

A. That is not an accurate description of how the Flex Units were reflected in the models used for the Avoided Capacity Cost benefit metric. Flex Units were included in all steps of the analysis, including the LOLE analysis and EGEAS modeling that identified the additional resources needed to meet the higher planning reserve margin.

Q. THE COMPLAINT ASSERTS THAT MISO WOULD HAVE THE STATES PAY FOR TRANSMISSION FACILITIES THAT ARE NOT NECESSARY NOR CONSISTENT WITH STATE RESOURCE PLANS.[25] DO YOU AGREE?

A. No. As explained earlier in my testimony Step 1 in the LRTP Tranche 2.1 study was to work closely with stakeholders, including MISO members and states to develop the Future scenarios used as the foundation for the planning study. The results of the Futures resource expansions show they are closely aligned with the resources plans of our members and states: 1) for the Future 1A resource expansion 93% of the resources needed were based directly on member submitted resources and 7% being identified by MISO's resource expansion model; and 2) for the Future 2A resource expansion 54% of the resources needed were based directly on member submitted resources and 46% being identified by MISO's resource expansion model. Further the business case analysis demonstrated that each CAZ under Futures 1A and 2A have a B/C

[24] Complaint at 34.

[25] Complaint at 35.

ratio of at least 1.0 supporting that the LRTP Tranche 2.1 Portfolio is providing benefits in excess of costs for customers in all MISO Midwest states.

ii. *Mitigation of Reliability Issues*

Q. PLEASE DESCRIBE THE MITIGATION OF RELIABILITY ISSUES METRIC FURTHER.

A. Traditionally, the NERC TPL standard has been used to ensure the transmission system is planned to be reliable. The NERC TPL standards articulate a minimum level of reliability with which the transmission system must support. With regard to long-range transmission planning, the objective is to ensure the regional system is reliable and cost effective in the long-term given the many changes that are expected to the resource fleet and load characteristics. In that respect, long-range transmission planning is not TPL compliance-focused, but instead value-focused. LRTP seeks to determine the benefits of reliability improvements associated with long-term projects.

The Mitigation of Reliability Issues benefit metric captured the monetary value the LRTP Tranche 2.1 Portfolio provides by pro-actively resolving thousands of reliability issues projected to occur over the long-run. Specifically the metric examines the post contingent thermal overloading issues resolved by LRTP and quantifies the load shedding that would be needed after re-dispatch to return the facility within applicable limits. The amount of avoided load shedding risk is monetized as the benefit provided by the LRTP transmission. This load shedding is used as a measure of the reliability risk that would need to be addressed rather than an operating action that would occur to resolve issues.

Q. HOW DID MISO UNDERTAKE THE ANALYSIS OF THE BENEFITS RESULTING FROM THE MITIGATION OF RELIABILITY ISSUES?

A. Analysis of benefits is performed in a two-step process which initially applies preventive generation re-dispatch in the first step to reflect the dispatch variability of resources and to mitigate initial overloads followed by a corrective load re-dispatch process to calculate the minimum load shedding that would address the contingency violations. This analysis uses the TARA software application to perform an optimal security constrained reliability dispatch for NERC Category P1, P2, and P7 contingencies associated with the LRTP resolved issues. Thermal overloads identified in each of the core (seasonal) study scenarios for the 2032 and 2042 study years that are relieved by the addition of the LRTP Tranche 2 Portfolio, and their associated contingencies are compiled and monitored in the first step where generation is adjusted to reflect a wide range of load and generation dispatch conditions in the seasonal models. Two generation re-dispatch scenarios are created for each of the seasonal core study scenarios. The first scenario represents hours with excess renewable availability where renewables are allowed to dispatch in the upward direction. The second scenario represents hours with less renewable availability than modeled where renewables are limited in dispatch to the downward direction.

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

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

Q. THE COMPLAINT ALSO ALLEGES THAT MISO ACCELERATED THE RETIREMENT TIMELINE FOR GAS-FIRED GENERATION UNITS IN FUTURE 2A AND IF MISO DID NOT ACCELERATE THESE TIMELINES, EXISTING GAS-FIRED GENERATION MAY HAVE MET THE RELIABILITY NEEDS IDENTIFIED BY MISO IN FUTURE 2A ABSENT TRANCHE 2.1.[26] WHAT IS YOUR RESPONSE?

A. The retirement assumptions used in development of MISO Futures for LRTP Tranche 2.1 were based on member input and age-based retirements by resource type. All retirement assumptions whether unit specific or resource-type based were reviewed with stakeholders and modified as appropriate based on stakeholder feedback.

Q. HOW DO YOU RESPOND TO THE ALLEGATION THAT MISO ARTIFICIALLY RESTRICTED FLEX UNIT DISPATCH IN ITS MODELING THAT COULD HAVE RESOLVED RELIABILITY ISSUES?

A. Dispatchable resources, including Flex Units, were allowed to adjust to maintain power balance and for the mitigation of constraints in single element contingency scenarios to avoid capturing overlapping benefits with the congestion and fuel savings benefit metric. For higher order contingency scenarios, dispatchable resources, including Flex Units, are only adjusted to maintain power balance.

[26] Complaint at 36.

Q. THE COMPLAINT ALSO ALLEGES THAT MISO ASSUMES THAT ABSENT BUILDING TRANCHE 2.1, UTILITIES AND STATE COMMISSIONS WOULD TAKE NO OTHER ACTIONS OVER TWENTY YEARS TO PREVENT FUTURE LOAD SHED.[27] WHAT IS YOUR RESPONSE?

A. This is a mischaracterization of the mitigation of reliability Issues metric. MISO is not assuming utilities would do nothing over the next 20 years to prevent load shedding. As explained earlier in my testimony the LRTP Tranche 2.1 Portfolio is resolving thousands of future reliability issues that put the system at risk of load shed and would need to be addressed in the future. The mitigation of reliability issues benefit metric monetizes the avoided risk as the value the LRTP Tranche 2.1 Portfolio provides by pro-actively resolving reliability issues.

iii. *Decarbonization*

Q. PLEASE DESCRIBE THE DECARBONIZATION BENEFIT METRIC FURTHER.

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

[27] Complaint at 37.

Q. HOW DID MISO UNDERTAKE THE ANALYSIS OF THE BENEFITS RESULTING FROM DECARBONIZATION?

A. Analysis of decarbonization benefits uses the emissions data from the APC analysis used for the base Congestion and Fuel Savings benefit metric and compares the change in CO2 emissions between the reference case without the LRTP Tranche 2.1 Portfolio and the change case with the LRTP Tranche 2.1 Portfolio. Values are computed for years 2032, 2037 and 2042; and are interpolated for years in between and extrapolated for years beyond 2042. The reductions in annual CO2 emissions are converted to metric tons and monetized by applying a range of carbon prices that reflect the value of decarbonization.

Q. THE COMPLAINT ALLEGES THAT MISO SIGNIFICANTLY INCREASED THE COST OF CARBON USED TO QUANTIFY THIS BENEFIT BY USING THE FEDERAL 45Q TAX CREDIT FOR CARBON SEQUESTRATION IN ITS LOW END BENEFIT ANALYSIS, WHICH IS $85 PER METRIC TON, AND THE MINNESOTA-BASED CREDIT OF $249 PER METRIC TON. WHY DID MISO CHOOSE THESE VALUES?

A. Initial stakeholder feedback did not provide a consensus on the cost of carbon value, so MISO chose a range of values. In determining the values to use in the range MISO prioritized using values codified in federal and/or state legislation. The low-end value of $85 per metric ton is sourced from the federal 45Q tax credit for carbon sequestration, while the high-end value of $249 per metric ton is based on Minnesota state legislation that requires the Minnesota Public Utility Commission to consider the values from the final 2023 EPA Report on the Social Cost of Greenhouse Gases.[28]

[28] https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf.

Q. WERE THE VALUES USED FOR THE COST OF CARBON REVIEWED BY STAKEHOLDERS?

A. Yes, MISO reviewed the costs with stakeholders at multiple different LRTP workshops (March 10, 2023; August 31, 2023; June 10, 2024) throughout the LRTP Tranche 2.1 study process, which included the proposed decarbonization benefit metric methodology and assumed cost of carbon values.

Q. IF MISO WERE TO USE THE LOW-END FEDERAL SOCIAL COST OF CARBON VALUE PROPOSED BY THE COMPLAINANTS OF $50 PER METRIC TON OF CARBON EMISSIONS, HOW WOULD THAT IMPACT THE BENEFITS OF TRANCHE 2.1?

A. The Complainants suggested value of $50 per metric ton of carbon emissions would reduce the decarbonization benefit value on the low end by 42%, but even with this adjustment the LRTP Tranche 2.1 Portfolio provides a greater than 1.0 b/c ratio under Futures 1A and 2A.

iv. PJM upgrade costs

Q. THE COMPLAINT ALLEGES THAT MISO HAS UNDERSTATED THE COSTS OF THE TRANCHE 2.1 BECAUSE IT DID NOT INCLUDE COSTS OF NETWORK UPGRADES TRIGGERED ON THE PJM SYSTEM.[29] WHAT IS YOUR RESPONSE?

A. This is not an accurate representation of what was identified on the PJM system prior to Board approval of the LRTP Tranche 2.1 Portfolio. MISO first shared with stakeholders at the March 15, 2024 LRTP workshop that the proposed LRTP Tranche 2.1 Portfolio could include transmission facilities interconnecting with the PJM system, and therefore require PJM Transmission Owners to own and operate facilities required as part of the LRTP Tranche 2.1

[29] Complaint at 41 and 42.

Portfolio. All of the directly interconnecting PJM facilities of Tranche 2.1: (a) were included in the benefit-cost analysis presented to stakeholders and MISO's Board of Directors for approval, and (b) represent the vast majority of the costs associated with the PJM system. As part of these conversations with stakeholders, MISO also communicated that PJM is performing a reliability "no-harm" study to determine if any additional upgrades are required on the PJM system due to the interconnecting Tranche 2.1 projects. Historically the "no-harm" study and upgrades identified have been a small share of the overall project costs.

v. B/C Ratio

Q. THE COMPLAINT ALLEGES THAT AFTER CORRECTING FOR MISO'S ASSUMPTIONS AND ANALYSIS, THE BENEFITS OF THE TRANCHE 2.1 PROJECTS ARE SIGNIFICANTLY LESS THAN THE COSTS AND THE COMPLAINANTS CALCULATE THE TOTAL BENEFITS OF THESE METRICS AT APPROXIMATELY $4.3 BILLION AT THE LOW END AND APPROXIMATELY $7.2 BILLION AT THE HIGH END.[30] WHAT IS YOUR RESPONSE?

A. Even under MISO's "low end" estimates these two benefits—$16.3 billion of "avoided capacity costs" and $14.8 billion of "mitigation of reliability issues" benefits—on their own exceed the $28.6 billion costs of the projects.

The benefits metrics for the LRTP Tranche 2.1 Portfolio were evaluated with Future 1A assumptions to assess value in a lower-bookend scenario applying the same methodologies used for Future 2A. The analysis demonstrates that under the Future 1A scenario representing 93% of member utilities resource plans, the LRTP Tranche 2.1 Portfolio delivers benefits in

[30] Complaint at 42 and 43.

excess of costs, totaling $34.2B - $61.9B over a 20-year period with an overall benefit-to-cost ratio ranging from 1.2 to 2.2.

Q. IF MISO WERE TO RELOOK AT THE BENEFIT METRICS USING UPDATED LOAD GROWTH ASSUMPTIONS CURRENTLY ASSUMED IN THE UPDATED FUTURES UNDER DEVELOPMENT, WOULD THE VALUE OF TRANCHE 2.1 BE MORE THAN WHAT WAS QUANTIFIED PREVIOUSLY BY MISO?

A. Yes, there is a positive correlation in the future value of the LRTP Tranche 2.1 Portfolio and increasing load growth. MISO is currently in the process of updating the MISO Futures and one of the key input assumptions is forecasted load. For reference, the Futures 1A and 2A scenarios assumed energy compound annual growth rates ("CAGR") of 0.35% and 0.80%, respectively. For the Futures currently in development, the assumed energy CAGR has increased significantly due to such drivers as data centers, manufacturing, and electrification. For example, the comparable updated Series 2 Futures 1 and 2 assumes energy CAGR of 1.1% and 1.6%.[31]

B. <u>Tranche 2.1 is a 3,631-mile, 765 kV transmission backbone in the Midwest.</u>

Q. THE COMPLAINT ALLEGES THAT TRANCHE 2.1 IS DESIGNED TO EFFECTUATE THE RENEWABLE ENERGY GOALS OF CERTAIN STATES AND UTILITIES AT THE EXPENSE OF OTHERS.[32] DO YOU AGREE?

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[31] https://cdn.misoenergy.org/20250228%20Futures%20Redesign%20Workshop%20Item%2001%20Series%202%20Futures%20Introduction681092.pdf

Note that the higher load growth rates assumed in the updates Futures also incorporate an updated baseline that reflects less load growth in the 2019 - 2024 timeframe than was assumed in the Futures 2A used for the Tranche 2.1 portfolio. This resetting of the baseline still results in a material increase in expected energy needs over the next 20 years of 57% for Future 2 compared to the 19% expected in Future 2A over 20 years.

[32] Complaint at 43.

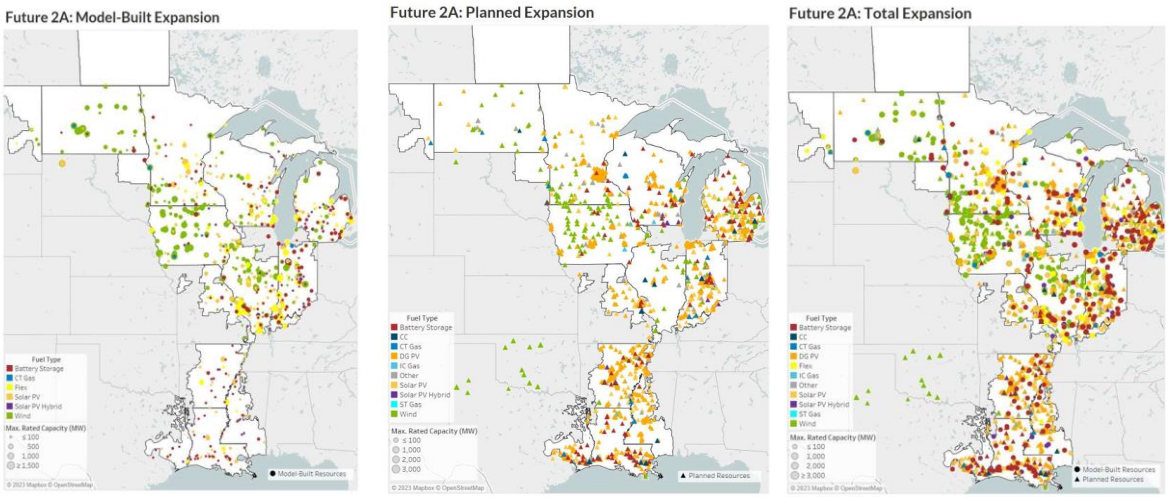
A. No. Tranche 2.1 is a 3,631-mile, 765 kV transmission backbone in the Midwest, which will resolve issues like voltage violations and address reliability challenges from factors like extreme weather, resource retirements, and increased electricity demand from new industries. By establishing a high-voltage backbone, Tranche 2.1 addresses the complex challenges posed by the energy transition and increasing load, ensuring a reliable and efficient power supply for the future while providing tangible economic benefits.

Q. THE COMPLAINT ALLEGES THAT MISO: (A) IS SITING RENEWABLE GENERATION REMOTELY TO MEET CERTAIN STATE AND UTILITY GOALS AND; (B) CREATES AN ARTIFICIAL NEED FOR ENORMOUS TRANSMISSION INVESTMENT.[33] IS MISO SITING BIASED TOWARDS LOCATING RENEWABLE GENERATION REMOTELY?

A. No. A key step in the Futures creation process is stakeholder review of the resource expansions and the location of these resources. These resource locations are initially sited by MISO planning staff, considering the physical characteristics of the transmission system, ensuring sufficient resources are sited locally using MISO resource adequacy requirements as guidance (e.g. Local Clearing Requirements, Planning Resource Margin Requirements), and optimal physical location by resource type, and Generation Interconnection Queue information. Stakeholders then had the opportunity to review and provide feedback on the resource sites, submitting over 500 recommended changes. MISO reviewed this feedback and created a final siting for the Futures. The resulting generation sites spanned the entire footprint. This can best be illustrated by the resource expansion maps developed for each Future scenario, which

[33] Complaint at 44.

shows resources broadly distributed across the entire MISO footprint and consisting of multiple resource types.



As the Futures resource expansion maps demonstrate, the LRTP Tranche 2.1 Portfolio is providing increased transfer capability to bi-directionally move energy in and out of all states in the Midwest to reliably and more efficiently service load over varying hour-to-hour operating conditions, and not as the Complaint alleges to deliver wind from the western part of MISO to eastern load centers.

C. <u>Comments from the NDPSC did not fall on deaf ears.</u>

Q. ON MULTIPLE OCCASIONS, THE COMPLAINT ASSERTS THAT ITS COMMENTS (NOW A PART OF THE COMPLAINT) FELL ON "DEAF EARS." DID THE NDPSC SUBMIT COMMENTS AS A PART OF THE DEVELOPMENT OF THE TRANCHE 2.1?

A. Yes. Table 2 below provides a summary of the comments submitted by the NDPSC and shows, contrary to the Complaint's allegations, MISO was responsive and made modifications to assumptions used for LRTP Tranche 2.1 in response to the NDPSC.

Table 2

	Stakeholder Comments	MISO Response
NDPSC	Overall, the assumptions for future generation being siting and developed in North Dakota are extremely light and fail to recognize a couple important realities:	MISO has sited an additional 17.3 of GW in North Dakota for a total of 27.8 GW of new resources sited within the state.
NDPSC	1) North Dakota is the only natural gas producing state in the MISO region making it an extremely valuable and logical place to assume development of additional natural gas peaking units. These will be essential for reliable operations into the indefinite future, and North Dakota's in-state production offers fuel security that all other locations lack. What's more, one such facility that is already planned by Xcel in North Dakota is not even reflected in this refresh.	MISO has sited an additional 1.5 GW of gas in North Dakota for a total of 1.5 GW of new gas resources sited within the state, including two CTs planned by Xcel Energy.
NDPSC	2) North Dakota has one of the best wind resources in the MISO region, which enhances the reliability, reduces intermittency, and increases the efficiency of wind generators in North Dakota. MISO needs to increase the assumption for wind development in North Dakota.	MISO has sited an additional 14.8 GW of wind in North Dakota for a total of 21.8 GW of new wind resources sited within the state.
NDPSC	North Dakota is also concerned with the lack of dispatchable power MISO assumes will be developed in this model. Dispatchable resources, even if they aren't being planned by MISO utilities, need to be modeled in order to reflect a system that is reliable long-term and has the transmission infrastructure needed to support this essential generation.	In addition to 4.2 GW of additional planned dispatchable resources provided in the siting feedback, MISO has also added 29 GW of Flexible Attribute Units to the MISO model based on the PROMOD energy adequacy check. MISO has sited an additional 1.5 GW of dispatchable resources in North Dakota.
NDPSC	Additionally, we echo the concerns raised by Otter Tail Power, MDU and Xcel, specifically:	Thank you for the feedback.
NDPSC	The demand response in the OTP LBA is unrealistically high.	Demand Response for OTP has been reduced from 660 MW to 300 MW

NDPSC	Retiring generators are likely to replace their capacity at the same location where they have existing transmission rights. There are several examples where MISO assumes OTP-owned resources will retire but MISO shows no replacement generation at those locations.	MISO does not automatically add replacement resources when existing generators retire, with the exception of wind repowerments; however, MISO does agree that it is highly likely that utilities will replace their retired capacity, which is why we favor brownfield sites where possible. MISO has updated the siting in ND and OTP now has model-built CT gas and Flexible Attribute units sited at OTP brownfield thermal sites.
NDPSC	The futures do not reflect enough resources sited in the MDU territory to support their future load projections.	Total capacity sited in MDU has been increased to 5.26 GW from the 1.66 GW in the preliminary siting. MISO's process is to ensure that Local Resource Zones (LRZ) meet their Local Clearing Requirement (LCR) and Planning Reserve Margine Requirement (PRMR). All MISO LRZs have met their LCRs and PRMR. MISO does not evaluate each specific LSE to ensure that they have enough resources to meet their load.
NDPSC	MISO should not be planning to add so much wind in northern Minnesota where the wind resource is poor, and should be shifted to North Dakota.	In general, model-built wind has been moved out of Northern Minnesota to other locations, primarily North and South Dakota. The remaining 1.6 GW of wind north of 46 degrees latitude includes repowerments, queue priority buses, Tranche 1 enabled sites, and other resources specifically indicated for use by stakeholder feedback.
NDPSC	The amount of solar additions MISO is assuming for eastern North Dakota seems high. The Red River Valley is prime farmland, making it a less attractive location for solar. Wind would be a better assumption there.	Remaining model-built utility scale solar sited in North Dakota at busses indicated by LBA feedback as available for use.
NDPSC	The lack of siting MISO is reflecting in the MDU territory is a real concern. MDU is on the western edge of the MISO region and serves load all the way into Montana. MDU is in the heart of the Bakken oil and gas field, making	Based upon stakeholder feedback, MISO has sited an additional 1.5 GW of dispatchable resources in North Dakota and an additional 267 MW in Montana. Specific to MDU, sited dispatchable resources have increased

	it a natural and valuable location for siting future natural gas generation.	from 1.66 GW to 5.26 GW (3.6 GW increase).
NDPSC	Additionally, the wind resources in central and western North Dakota are strong and MISO must not strand the potential of these resources by failing to enhance the transmission infrastructure there.	Thank you for your feedback; wind sited in ND increased from 7 GW to 21.8 GW, an increase of 14.8 GW.

* 20230428 LRTP Workshop Item 03b Feedback Responses628728.xlsx

As Table 2 illustrates, the NDPSC requested several additions to assumptions used for the development of Tranche 2.1, which MISO made: (1) the addition of natural gas peaking units; (2) increase in wind generation development in North Dakota; (3) the addition of dispatchable resources in North Dakota; (4) reduction of demand response; (5) the addition of replacement generation resources as combustion turbine gas and flexible attribute units; and (6) enhancements of transmission development to deliver the wind generation resources in central and western North Dakota.

Q. IN ADDITION TO THE REQUESTS FROM THE NDPSC AND THE ADJUSTMENTS MADE BY MISO REFLECTED IN TABLE 2, DID NORTH DAKOTA SUBMIT ANY LETTERS TO MISO REGARDING TRANCHE 2.1?

A. Yes. On May 28, 2024, the then Governor of North Dakota, Doug Burgum, sent a letter to MISO President and Chief Executive Officer John Bear, highlighting North Dakota as a high exporter of wind generation to other MISO states. The governor asked that Tranche 2.1 be revisited to include critical transmission infrastructure to bridge North Dakota to the market. The letter is attached to my testimony as Attachment 1.

Q. HOW DID MISO RESPOND TO THE MAY 28, 2024 LETTER?

A. John Bear provided a letter in response on May 31, 2024, which stated that MISO would be adding additional transmission projects in western MISO that will benefit North Dakota and

the MISO region. Mr. Bear noted that the added projects would enable 7,500 MW (energy to power 6 million homes) of congestion relief for the Dakotas and Minnesota. The letter is attached to my testimony as Attachment 2.[34]

Q. DOES NORTH DAKOTA BENEFIT FROM TRANCHE 2.1?

A. Yes. As the May 28, 2024, letter discussed above indicates, North Dakota exports substantial amount of wind generation to the rest of MISO. Tranche 2.1 allows North Dakota to export additional wind generation to other MISO states. As I noted above, Tranche 2.1 provides both reliability and economic benefits to the West Region of MISO, where North Dakota is located, including:

- The Northern Minnesota project group provides outlets to North Dakota generation, resolves constraints in this area and connects to Tranche 1 lines;
- Increased generation outlets in North Dakota, South Dakota and Minnesota shift congestion to new flowgates, which are addressed through underbuild; and
- The 765 kV project in northeastern South Dakota, Southwestern Minnesota and Western Iowa provides an outlet for generation in South Dakota and also connects both west-to-east 765 kV paths developed in the initial portfolio to provide contingency support; and
- West Region sees a 25.5% ($2.0M/MW) reduction in economic congestion.

Q. APPROXIMATELY HOW MUCH OF THE TRANCHE 2.1 COSTS ARE ALLOCATED TO NORTH DAKOTA, MONTANA, LOUISIANA, ARKANSAS AND MISSISSIPPI?

[34] The final Tranche 2.1 Portfolio included an additional major transmission line connecting Maple River, North Dakota to Cuyana, Minnesota.

A. Based on the three MISO-member utilities that operate in Montana and/or North Dakota their customers share of the LRTP Tranche 2.1 Portfolio costs is estimated to approximately equal 2% of the total costs, subject to future actual monthly energy withdrawals. None of the costs for Tranche 2.1 will now or in the future be allocated to MISO South, which includes three of the states (Louisiana, Arkansas and Mississippi) that are part of the Complainants. The application of the MVP cost allocation for the LRTP Tranche 2.1 Portfolio reflects a FERC-approved cost allocation method that was the outcome after a full year of stakeholder evaluation of many options.

D. Additional regulatory oversight of MISO's MVP or LRTP process would be redundant, would stagnate transmission development.

Q. THE COMPLAINT ASSERTS MISO MVP PROCESS LACKS REGULATORY OVERSIGHT AND COST CONTROL AND REQUESTS THAT MISO BE DIRECTED TO FILE AT THE COMMISSION ALL FUTURE BUSINESS CASES USED TO SUPPORT MVPS.[35] WHAT IS YOUR RESPONSE?

A. Additional Commission regulatory oversight is not needed. The LRTP is a stakeholder-driven process that uses extensive public engagement to identify and approve large-scale transmission projects. Stakeholders, including utilities, state regulators, end-use customers, and environmental groups, influence the LRTP through feedback, model review, solution submissions, and active participation in workshops. In the case of LRTP Tranche 2.1:

- Stakeholders were substantially engaged, with more than 300 meetings in various formats and forums, numerous one-on-one discussions, email exchanges and more.

[35] Complaint at 47, 48, and 50.

- Workshops averaged 275 participants, and MISO combined the oral feedback from these workshops with 10 instances of formal or informal written comments to refine the LRTP processes and results.
- Examples of input and revisions to the LRTP process includes:
    - The Futures and Siting process was informed by 500+ stakeholder revisions impacting the inputs of the process;
    - MISO received significant stakeholder feedback and used the feedback to implement changes to the reliability and economic models throughout multiple months; and
    - Stakeholder feedback informed the transfer scenarios selected as part of the LRTP scope.
- More than 100 alternative solutions were submitted to MISO's initial LRTP Tranche 2.1 Portfolio, representing 47 projects. These alternatives shaped the final LRTP portfolio, with some being directly implemented, others found to be less valuable than the initial portfolio, and others captured for future regional or local studies.

Q. ARE THE MTEP AND LRTP ALREADY INDEPENDENTLY UNDERTAKEN?

A. Yes. As a Commission-approved RTO, MISO independently undertakes the transmission planning of the MISO Transmission System. At the end of the process, MISO staff independently determines the preferred solutions. Projects proposed to move forward are reviewed with stakeholders through multiple forums (e.g., PAC, Sub-regional Planning Meetings, and Workshops). At the PAC stakeholders have a final opportunity to submit

comments on the MTEP process and the recommended projects to the MISO Board of Directors.

The MISO Board of Directors' role in the transmission planning process is a key component of the independent planning process. First, pursuant to MISO's Principles of Corporate Governance, as well as MISO's TOA and Bylaws, all Directors (who are not an officer or employee of MISO) are required to comply with independence requirements, including: (1) not being a director, officer, or employee of a MISO member, user, or affiliate of a member or user for one year prior to election; and (2) not having a direct financial interest in or a conflict of interest with any member, user, or affiliate of a member or user.[36] Second, Directors are required to possess the highest personal and professional ethics, integrity, and values.[37] In addition, specific qualifications are required for Directors: (1) six of the Directors are required to have expertise in, among other things, corporate leadership, engineering, or utility laws and regulation; and (2) three of the Directors are required to have expertise in the operation of electric transmission systems, the planning of electric transmission systems, and in commercial markets and trading, and associated risk management.[38] Third, the System Planning Committee of the MISO Board of Directors is tasked with: (1) overseeing system planning matters affecting transmission expansion; (2) monitoring the development and implementation of the MTEP; (3) making recommendations to the Board of Directors; and (4) reporting to the Board of Directors regarding the progress of achieving expansion plans.

Following the final stakeholder review, MISO Staff provides a final list of

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[36] MISO's Principles of Corporate Governances § I.A.1, *available at* https://cdn.misoenergy.org/MISO%20Principles%20of%20Corporate%20Governance110859.pdf (last visited May 6, 2025).

[37] *Id*. § I.

[38] *Id*. § I.B.

recommended projects to the System Planning Committee.[39] The System Planning Committee reviews stakeholder and MISO Staff comments before making recommendations to the full Board of Directors for approval. Thereafter, the MISO Board of Directors considers approval of the portfolio of projects.[40]

Q. WOULD THE FILING OF BUSINESS CASES WITH THE COMMISSION BE REDUNDANT TO THE COMMISSION-APPROVED TRANSMISSION PLANNING STAKEHOLDER PROCESS YOU DESCRIBED ABOVE?

A. Yes. I expect that if such filings were required, interested parties would have the opportunity to intervene and offer comments or protests on the business cases, which MISO would then have to respond, and finally require a Commission ruling. As I described above, MISO's planning process, including all components of LRTP, are well vetted with stakeholders and adheres to MISO's FERC-approved Order Nos. 890 and 1000 processes.

Q. WOULD THE FILING OF BUSINESS CASES WITH THE COMMISSION CREATE DELAYS FOR DEVELOPING AND CONSTRUCTING NEW TRANSMISSION FACILITIES?

A. Yes. As I explained earlier, development of Future 2A began in June of 2022, with final Board approval occurring in December of 2024. The portfolio of projects is expected to be in service between 2032 and 2034. The additional time associated with making Commission filings and potentially going through administrative litigation would assuredly delay the implementation of critical transmission projects.

IV. CONSEQUENCES IF TRANCHE 2.1 IS VACATED.

[39] *Id*. § IV.A.

[40] TOA, Appendix B.

Q. DOES THE TIMING OF THIS COMPLAINT CREATE UNCERTAINTY FOR THE TRANSMISSION PLANNING PROCESS?

A. Yes. LRTP Tranche 2.1 was approved by the Board of Directors approximately eight months before this Complaint was filed. Specifically, approval by the MISO Board certifies an MTEP as the transmission plan for meeting the transmission needs of all stakeholders subject to any required approvals. It also requires the affected Transmission Owners or Selected Developers to make a good faith effort to design, certify, and build the designated facilities. At this point, those entities that were directed to construct the portfolio of transmission projects have already undertaken actions towards construction, including local and state permitting processes. Thus, the filing of the Complaint will put at risk the LRTP Tranche 2.1 Portfolio meeting the critically needed 2032 to 2034 in-service dates.

Q. IF THE LRTP TRANCHE 2.1 PORTFOLIO IS VACATED DUE TO THE COMPLAINT, WHAT ARE THE CONSEQUENCES THAT WILL RESULT FOR RESOURCE INTERCONNECTION PURPOSES?

A. MISO just finished the Definitive Planning Phase ("DPP") 2022 Phase 1 and MISO relied heavily on the LRTP Tranche 2.1 Portfolio as mitigation for that cycle, which includes a total of 49.8 GW in the Midwest Subregion. Additionally, MISO is about to use LRTP Tranche 2.1 Portfolio in the base case for DPP 2023 that will kick off soon, and includes an additional 67.7 GW in the Midwest Subregion. MISO would use Tranche 2.1 in base case of DPP 2025 that closes in October 2025 and will kick off in January of 2026. Consequently, there would be a huge upheaval and multi-year restudy timelines to the DPP queue cycles if Tranche 2.1 was vacated due to this Complaint, as many pending interconnection requests would drop out of the queue and MISO would have to restudy several cycles.

Q. IF LRTP TRANCHE 2.1 PORTFOLIO IS VACATED DUE TO THE COMPLAINT, WHAT ARE THE CONSEQUENCES THAT WILL RESULT FOR ERAS?

A. Similar to the DPP, the LRTP Tranche 2.1 Portfolio is a part of the base case for ERAS analysis. So, if LRTP Tranche 2.1 Portfolio would be cancelled, it would require MISO to evaluate the impacts of the changes in the base cases – introducing a delay in the ERAS process. All ERAS applications which were determined to be impacted in that evaluation would then require restudy, introducing additional delays for those study completions. As of August 25, 2025 MISO has received 47 ERAS submittals representing a total of 26.5 GW of resources across the MISO footprint.

Q. IF TRANCHE 2.1 IS VACATED DUE TO THE COMPLAINT, WHAT ARE THE CONSEQUENCES THAT WILL RESULT FOR OTHER TRANSMISSION PROJECTS PROCEEDING THROUGH MISO'S ANNUAL MTEP PROCESS?

A. Similar to the DPP and ERAS, the LRTP Tranche 2.1 Portfolio is a part of the base case for the MTEP 25 analysis. This could result in restudies for some of the 434 projects recommended for MTEP25 approval in December, including those which support 11.6 GW of large load additions.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

Affidavit of Jeremiah Doner

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

Jeremiah Doner, being duly sworn, deposes and states that he prepared the Direct Testimony of Jeremiah Doner, and the statements contained therein are true and accurate to the best of his knowledge and belief.

Jeremiah Doner

SUBSCRIBED AND SWORN BEFORE ME, this 9th day of September, 2025.

Kandi Hahn

KANDI HAHN
Notary Public, State of Indiana
Marion County
Commission Number NP0740038
My Commission Expires
March 23, 2030

NORTH Dakota | Office of the Governor

Be Legendary.™

May 28th, 2024

John Bear
Chief Executive Officer
Midcontinent Independent System Operator, Inc.
Corporate Headquarters
720 City Center Drive
Carmel, IN 46032-3826

Dear Mr. Bear,

This letter is to voice our significant concerns regarding MISO's March 4, 2024, proposed Tranche 2 draft portfolio of transmission projects, particularly in the context of the broader challenges imposed by recent federal regulations.

North Dakota is a leader in the energy sector, not only in energy production but also in maintaining exemplary environmental and air quality standards. Our state boasts a robust energy generation portfolio, including coal, oil, natural gas, hydroelectric power, wind and biofuels, making us one of the few states with such a diverse energy mix. Remarkably, we export approximately 4,000 GWh of electricity each month, which represents about 30% of North Dakota's total generation, thereby supporting the energy needs of numerous other states.

Given the extensive energy generation in North Dakota and the projected increase in regional energy demands due to substantial governmental incentives and mandates forcing the adoption of electric vehicles, coupled with the exponential growth in artificial intelligence, it is crucial that our transmission infrastructure be scaled appropriately. The federal government's recent rules pose a substantial threat to the reliability and affordability of our electric grid by targeting fossil fuel-fired power plants. These regulations not only challenge our baseload power sources, but also potentially hinder the development of emerging technologies, such as carbon capture. MISO should consider carbon capture and hydrogen facilities as equally viable options for future infrastructure and not assume that everyone benefits from transmission the same when allocating cost. These technologies will provide other states with much-needed reliability benefits, and North Dakota is well-positioned in developing them and supporting the grid with baseload attributes.

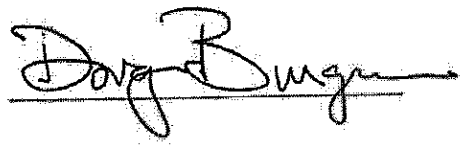
In light of these developments, MISO's Tranche 2 draft portfolio must be revisited and expanded to include additional, critical transmission projects that bridge North Dakota to market. These projects are essential to managing the immediate voltage and thermal limits and the anticipated

increase in energy demands. Furthermore, it is imperative that the costs of these upgrades are allocated to those causing the cost within the MISO region, reflecting a fair cost allocation that does not unduly burden North Dakota consumers.

Our state's ability to produce and export significant amounts of energy is a testament to our commitment to both economic growth and environmental stewardship. Revisiting the Tranche 2 draft portfolio is essential so MISO can cost-effectively maintain the stability and reliability of the grid. This will enable the continued transfer of low-cost electric generation from west to east, benefiting consumers across the MISO footprint, while ensuring that our energy resources are delivering the most value and reliably meeting future demands.

Thank you for considering these critical issues. We look forward to MISO's collaborative approach to revising the Tranche 2 proposals, ensuring they align with the reliability imperatives and economic interests of all stakeholders involved.

Sincerely,



Doug Burgum
Governor



John R. Bear
Chief Executive Officer
317-249-5176
jbear@misoenergy.org

May 31, 2024

The Honorable Doug Burgum
Governor, North Dakota
600 E. Boulevard Ave.
Bismarck, ND 58505-0001

Governor Burgum,

I received and appreciated your May 28th letter. MISO has a long history of collaborating with the great state of North Dakota to enhance reliability in the MISO Region. In particular, the North Dakota Transmission Authority and ND PSC Commissioner (and current NARUC President) Julie Fedorchak have advocated for responsible energy development in the state which has contributed to the reliability of MISO.

In support of MISO's Reliability Imperative, our team has focused on ensuring there is sufficient transmission to support states' resource adequacy requirements, economic development and policy goals.

MISO's draft Long-Range Transmission Plan (LRTP) Tranche 2 portfolio in March represented our initial assessment of transmission needs. Since then, we've continued to work with our members and states to refine the portfolio. Specifically, for LRTP Tranche 2, MISO recently received 100+ alternative projects and suggested solutions from stakeholders throughout our North and Central region (11 states).

MISO ran additional Tranche 2 portfolio analyses and will be proposing additional transmission projects in western MISO that will benefit North Dakota and the broader MISO region. For example, we expect these added projects would enable an additional 7,500 MWs (energy to power 6 million homes) of congestion relief for the Dakotas and Minnesota.

These additional project alternatives will be shared with our Stakeholders during the upcoming workshop scheduled for June 10th.

MISO will continue to evaluate the transmission needs of the region and values North Dakota's interest and "all of the above" approach to energy sufficiency. We appreciate North Dakota's past support for necessary transmission in Tranche 1. We hope to earn your support for the next tranche of transmission buildout, for which we expect to seek approval by the MISO Board of Directors before the end of this year.

Sincerely,



John R. Bear
Chief Executive Officer