Attachment 1

UNITED STATES OF AMERICA
BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Docket No. EL25-109-000

September 9, 2025

AFFIDAVIT OF CHRISTOPHER J. RUSSO ON BEHALF OF XCEL ENERGY SERVICES INC. AND INTERNATIONAL TRANSMISSION COMPANY D/B/A ITC*TRANSMISSION*, MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC, ITC MIDWEST LLC, AND ITC GREAT PLAINS, LLC

I. QUALIFICATIONS AND PURPOSE

Q. Please state your name and business address.

A. My name is Christopher Russo. My business address is 200 Clarendon Street, Boston, Massachusetts 02116.

Q. By whom are you presently employed and in what capacity?

A. I am employed by Charles River Associates ("CRA"), a/k/a CRA International Inc. as a Vice President. CRA is an applied economics consulting firm.

Q. Please describe your duties and responsibilities in your current position.

A. The primary focus of my consulting is in the areas of wholesale electricity market analysis, business strategy for the electricity industry, and strategic planning for energy market participants. I have advised clients on strategic issues in the energy industry, including quantitative analysis of wholesale energy markets, the impact of regulatory restructuring, planning under uncertain conditions, market power issues, and energy procurement. I also testify in both regulatory proceedings and commercial disputes and litigation.

Q. Please describe your professional background and experience.

A. I received my BS in Mechanical Engineering from Tufts University, and my MS in Technology & Policy with a focus in Energy from the Massachusetts Institute of Technology ("MIT"). Prior to joining CRA in 2007, I worked as an independent energy market consultant, supporting clients in the analysis and modeling of electricity markets in the United States and Europe. My work has focused on quantitative analysis of energy markets, advising clients on investments and planning in these markets, and advising clients on overall market strategy. I built and led CRA's Energy Practice from 2012 through 2025 before returning to client work full-time. My curriculum vitae is set forth as Exhibit 1.

Q. Please describe your qualifications related to transmission planning.

A. I conducted my academic studies at the MIT Energy Laboratory under the tutelage of the team which developed the theory of locational pricing of electricity, and wrote my thesis using analysis from production cost models very similar to those employed by MISO in their planning processes. In my professional capacity, I was the lead author of the first New York City Master Transmission Plan, helped lead the EIPC nationwide transmission planning effort beginning in 2012 , was an author of the cost-benefit analysis for the ERCOT electricity market, and have conducted hundreds of engagements using models and processes similar to those used here. I have personal experience using models such as GE MAPS, Aurora, GE MARS, PROMOD, PROSYM, EGEAS, GridView, PSLF, and Plexos.

Q. Have you previously offered testimony before the Federal Energy Regulatory Commission, in this proceeding or any other proceeding?

A. Yes. I have offered testimony before the Federal Energy Regulatory Commission (FERC) in Dockets Nos. AD12-12-000, EL02-71-057, EL16-49-000, ER18-1314-000, ER18-1314-001, and EL18-178-000, but I have not previously offered testimony in this docket. My testimonial history is included in my attached curriculum vitae.

Q. On whose behalf are you offering testimony in this proceeding?

A. My testimony is being offered on behalf of Xcel Energy Services Inc. and International Transmission Company d/b/a ITC*Transmission*, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC.

Q. What is the purpose of your direct testimony in this proceeding?

A. I am responding to the testimony offered by Dr. William Hogan on behalf of the North Dakota Public Service Commission; Montana Public Service Commission; Arkansas Public Service Commission; Mississippi Public Service Commission; and Louisiana Public Service Commission (together, the "Complainants").

Q. How is your testimony organized?

A. My testimony is organized into the following sections:

- Section II provides a summary of my testimony
- Section III summarizes MISO's regional transmission planning process
- Section IV discusses MISO's planning assumptions and responds to Dr. Hogan's affidavit and critiques by explaining that MISO's planning assumptions for the Tranche 2.1 planning process were reasonable and consistent with the MISO tariff.
- Section V discusses MISO's benefit calculations and responds to Dr. Hogan's affidavit and critiques by explaining that MISO's benefit calculations were reasonable and consistent with the MISO tariff.
- Section VI explains how the Tranche 2.1 projects will support data centers and generative AI in MISO.

- Section VII identifies some of the downsides of granting the complaint, such as undermining regional transmission planning and impacting other transmission planning regions that have a planning methodology similar to MISO.

- Section VIII explains that the states the Complainants represent will be allocated either a small portion of Tranche 2.1 project costs or no costs at all.

II. SUMMARY

Q. Can you briefly summarize your testimony and your key conclusions.

A. First, I conclude that Dr. Hogan's critiques of the MISO planning process rely on his theoretical ideal of how joint transmission and generation planning might be performed, but ignores the reality of MISO's long-standing, stakeholder-driven, and FERC-approved approach. His theoretically ideal approach is incompatible with MISO's mandate and role, as well as the practical realities of RTO system planning.

Second, I conclude that MISO followed its approved processes and tariff, fulfilled its mandate, and made reasonable assumptions in the Tranche 2.1 planning process. MISO is charged with ensuring the reliability of the bulk power system, but it is *not* a central planner and has neither the authority to plan generation on its network, nor to override the long-term generation plans of its states and members, even in the interests of greater market efficiency. MISO is charged with developing transmission plans using good utility practices which are generally accepted, not a specific methodology. MISO's extensive and transparent process is a reasonable approach.

Third, granting the Complainants' requested relief would fundamentally alter the way that transmission must be planned, profoundly increase the complexity of the planning process, and make transmission infrastructure development markedly more difficult.

Fourth, the transmission projects included in Tranche 2.1 are likely to support further development of large-scale loads and generation, including those associated with generative AI data centers.

Fifth and finally, the Complainants' states have little, if any, stake in Tranche 2.1 given postage-stamp cost allocation.

Q. Can you briefly describe your understanding of the Complainants' and Dr. Hogan's overall argument?

A. Yes. The Complainants assert, based on Dr. Hogan's testimony, that MISO's cost-benefit analyses under their MTEP and MVP were deficient, and therefore MISO is in violation of its FERC-approved tariff.

Q. Can you briefly summarize your key points of disagreement with these arguments?

A. Yes. I disagree with the idea that MISO was or is required to perform long range system planning and perform a cost-benefit analysis as a "central planner"[1] holding responsibility both for optimal of planning transmission *and* generation for all member utilities, and who should correct the "distortion in participant decisions"[2] of its members. I disagree that MISO does or should have the authority to act as a central planner in the marketplace, including the ability to disregard the extant generation plans of its members and states. In fact, MISO has no such authority or mandate, and such a role would be incongruent with its mission, which is the planning of transmission using good utility practice.

My second main point of disagreement with Dr. Hogan follows directly from the first; I believe that MISO followed a FERC-approved, well-documented, years-long and transparent planning process with extensive stakeholder involvement to plan its Tranche 2.1 transmission portfolio, and that the Tranche 2.1 transmission plan is therefore reasonable, and that MISO is in compliance with its tariff. Dr. Hogan may have a difference of opinion with MISO, but his approach is (as he admits), not practically implementable. MISO's approach is empirically implementable. MISO's approach was consistent with the MISO tariff approved by FERC, and agreed to by its stakeholders and its Board, which in my opinion makes it a reasonable one.

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[1] Hogan Affidavit, at 4.
[2] *Id*., at 31.

Dr. Hogan's testimony argues that MISO's planning process contains deficiencies when compared to what Hogan believes is the proper approach and that MISO's plan is therefore invalid. Dr. Hogan also makes specific criticisms of the mechanics of MISO's planning process, which I will address later in my testimony.

Dr. Hogan's proposed approach would have implications on the planning processes in all RTOs, and would make planning of transmission materially more difficult. His proposed approach would create significant burdens related to planning, and, if adopted, would have profound implications on the roles and processes MISO would have to follow.

Dr. Hogan made a range of arguments in his affidavit, and I focus my affidavit on responding to Dr. Hogan's core arguments. My affidavit is not a point-by-point refutation of Dr. Hogan's affidavit, and the absence of a response to particular argument should not be construed as agreement with that argument.

Q. What other points do you make in your testimony?

A. I found that the planning assumptions MISO used in the Tranche 2.1 planning process, which included generation projections based on MISO member plans and generation added by MISO to ensure resource and energy adequacy, were reasonable, appropriate, and consistent with the MISO tariff.

Based on my review, I also found that the financial benefits MISO calculated were reasonable, and that Dr. Hogan's critiques were either unwarranted, or reflected a different approach that in and of itself did not render MISO's benefit calculations incorrect or unreasonable.

The Tranche 2.1 projects will support the development of data centers and artificial intelligence (AI) in MISO.

Customers in the states represented by the Complainants that filed the complaint will be allocated either a small portion – at most 3% – of Tranche 2.1 project costs, or no costs at all.

III. MISO'S ESTABLISHED TRANSMISSION PLANNING PROCESS REFLECTS ITS ROLE IN THE MISO TARIFF AND AUTHORITY AS AN RTO

Q. What is MISO's regulatory mandate?

A. MISO's mandate pursuant to the MISO tariff includes ensuring the reliability of the bulk power system and operating wholesale electricity markets. MISO also serves as the regional transmission planner for its system. Like all RTOs, MISO's transmission planning process must comply with FERC Order No. 890 and Order No. 1000.[3]

Q. What does MISO's tariff say when it comes to regional transmission planning?

A. MISO's regional transmission planning process is described in Attachment FF to the MISO tariff. MISO is required to develop a MISO Transmission Expansion Plan ("MTEP") for the MISO transmission system, which Attachment FF summarizes as follows: "The MTEP is developed to facilitate the timely and orderly expansion of and/or modification to the Transmission System to maintain reliability, promote efficiency in bulk power markets and facilitate compliance with applicable Federal and state laws, regulatory mandates and regulatory obligations."[4] Per MISO's tariff and FERC Order No. 1000, MISO must also engage with and take input from stakeholders during the transmission planning process.[5]

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[3] MISO's current tariff does not comply with Order No. 1920/1920-A because the FERC granted MISO's request to extended its compliance filing with this rule, with the exception of requirements related to interregional transmission, until June 12, 2026. See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Docket No. RM21-17-000, December 10, 2024.

[4] MISO Tariff, Attachment FF, Section I.A.

[5] MISO Tariff, Attachment FF, Section I.C.2 ("The Transmission Provider shall facilitate discussions with its Transmission Customers, Transmission Owners, the [Organization of MISO States] Committee, and other stakeholders about the Transmission Issues and solutions involving both transferred and non-transferred facilities").

In doing so, MISO, like all other FERC-jurisdictional transmission planners, must consider the objectives and interests of their members, states, and other stakeholders, which include regulated utilities, non-regulated electric cooperatives and municipalities, independent generators, large loads, states and cities, retail regulators, and other parties. The MISO tariff defines members as signatory members of the MISO Agreement.[6] MISO members include transmission owners, independent transmission companies, and eligible customers that do not own transmission.

Q. Is MISO a "central planner," as Dr. Hogan contends?

A. No. As is the case with every independent system operator (ISO) and regional transmission organization (RTO), MISO has no role or authority to decide what type of generation to build, nor where it should be built. As MISO system's regional transmission planner, MISO only has the authority to plan the transmission system. Independence requirements prohibit MISO from owning a financial stake in either transmission or electric generation assets.

Q. Who has responsibility for generation planning in MISO?

A. MISO's states and member utilities bear primary responsibility for generation planning, and they generally do so through integrated resource planning processes. Independent power producers in MISO also develop generation in MISO, but their investment decisions are made independently based on market signals, the cost of entry, their capital costs, and risk tolerance.

Q. What do you understand to be Dr. Hogan's core disagreement with MISO's LRTP Tranche 2.1 planning process?

A. Dr. Hogan believes that MISO's state and member generation plans are not optimized and that MISO's role is one of a central planner to correct "distortions" in market participant decisions and achieve optimal outcomes in its transmission planning exercises.

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[6] See MISO Tariff, Module A, Common Tariff Provisions.

> "*…it is precisely because the case of large-scale transmission with economies of scope and scale can create **distortion in participant decisions** that there is a need for the **central planner** and the oversight regulator to look to the fundamentals of generation, load and transmission investments. Were this not the case, there **would be no need for central planning and mandated cost allocation**.*"[7]

Q. Do you have any overall reaction about Dr. Hogan's objections and critiques?

A. What strikes me overall is Dr. Hogan's lack of discussion of the process which led to the methodology that Dr. Hogan now critiques. Dr. Hogan may have criticisms of MISO's approach, but the process he criticizes is the one that has been selected and implemented by the MISO and its stakeholders and members over a period of numerous years and has been approved by FERC.

Q. Is this dispute about transmission planning, generation planning, or something else?

A. This dispute is about the relationship between transmission and generation planning. As I describe further below, MISO initiated a long-range transmission planning (LRTP) process, and the Tranche 2.1 products were part of that exercise to determine which new transmission infrastructure should be constructed over the next 20 years. But planning new transmission must necessarily be considered with planning generation on the transmission system. At the most basic level, this is because the demand for electricity is growing on the MISO system, and therefore, new generation must be built to ensure resource adequacy and system reliability, and new transmission investments must be made to deliver that electricity to loads.

Dr. Hogan's core critique appears to stem from MISO's use of existing generation plans and other assumptions made by MISO about the future generation portfolio as inputs to its models for developing and assessing the costs and benefits of new transmission portfolios. In other words, Dr. Hogan disagrees with MISO's decision to take member

[7] Hogan Affidavit, at 31, emphasis added.

and state generation plans as a given rather than reconsidering them as part of a broader *system planning* process. He also disagrees with the methodology MISO used to add generation necessary to ensure system reliability, which I address later in my testimony.

Q. Do you agree with Dr. Hogan's position that MISO can or should act as a central planner, responsible for both transmission and generation?

A. No. MISO has no ability to direct the construction of generation, and no RTO/ISO in the United States has the authority make or direct decisions about new generation investment. RTOs/ISOs are independent entities that operate wholesale electricity markets, maintain the reliability of the bulk electric system, and ensure access to the transmission system on a non-preferential and not unduly discriminatory basis. States and other market participants decide whether to invest in generation and make decisions regarding the type, timing, and location of that generation. In fact, the most appropriate and reasonable course of action MISO can take is to add generation consistent with a reasonable expectation of what its members might add, even if those members make non-optimal and "distorted" decisions.

Q. Does MISO's Long-Range Transmission Planning process require perfectly optimized system planning?

A. No. A perfectly optimized transmission and generation plan would require control over both generation and transmission decision-making and perfect foresight about the location and timing of load growth, the future cost of generation capacity and the fuel used for generation, weather, and a host of other highly uncertain variables. MISO's 2024 MTEP report directly acknowledges that the transmission projects selected through the LRTP, "*are not intended to resolve every issue associated with precise siting of future generation or load*."[8] MISO added that "*LRTP portfolios are 'least-regrets' to plan for an uncertain future based on the needs reflected in policy and member plans that are current at the time of modeling and analysis*."[9]

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[8] MISO, MTEP24 Transmission Portfolio, at 21 (MTEP24 Report).
[9] *Id*.

Q. Is it even practical for transmission and generation to be planned together in RTO/ISO areas?

A. I do not believe it is practical for transmission and generation to be planned together in RTOs/ISOs, and Dr. Hogan doesn't seem to, either. To grossly oversimplify, this is a "chicken-and-egg" problem. A brief primer may be helpful when it comes to understanding the "moving parts" in the process.

Two principal types of analysis[10] (and models) are commonly used in the process. The first is what is often called dispatch analysis, and concerns the operation of generation subject within the limits of the transmission system (e.g., security-constrained economic dispatch model). The second principal type of analysis is known as "capacity expansion" analysis, and concerns the addition (i.e. construction) and retirement of generation resources. There are ways to combine these two analytical components, but a common approach, and the one employed by MISO was to use two different (but related) analyses and accompanying models for these processes.

Capacity expansion models forecast an economically optimal[11] generation mix, but generally assume that the transmission system is fixed. But if the central planner then changes the transmission system to implement the generation buildout, they must then calculate a new optimal generation case. This necessitates going back and figuring out the optimal transmission build for the new generation build. To use a simple metaphor, you can't plan the roads in a town without knowing where people are going to build homes, but you can't optimally build the homes until you know where the roads are being built.

Dr. Hogan concedes that his theoretical ideal is unworkable in practice when he concludes that his "*conceptual framework that follows from cost-benefit principles and welfare maximization is too difficult to implement as a single computationally tractable*

[10] There are of course many other analyses that go into such analyses, and this is a simplified list.

[11] The optimality of any such analysis is, of course, a function of the optimization criteria employed by the analyst.

tool."[12] I agree. Dr. Hogan is correct that MISO must use "*more limited models that approximate the key features of the choices at hand*."[13]

Q. Does MISO's tariff specify a standard to which MISO must plan?

A. Attachment FF of the MISO states that MISO "shall develop the MTEP, consistent with Good Utility Practice and taking into consideration long-range planning horizons, as appropriate."[14] The MISO tariff definition of Good Utility Practice generally requires, among others things, MISO to exercise reasonable judgment in light of the facts known at the time of decision making, and expressly states that, "Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather, intended to include acceptable practices, methods, or acts generally accepted in the region." [15] As I have stated, the most appropriate planning approach is one which best predicts the actions of market participants, even if those actions do not fit a theoretically ideal model. The simple fact that MISO's process is the product of their stakeholder process would seem to make it acceptable in the region.

Q. Wouldn't you agree though, that there's only one way to plan optimally, and many ways to plan suboptimally? How do you suggest that the MISO go about its planning if not in an optimal manner?

A. I am neither suggesting nor recommending that MISO adopt any different planning methodology than it has today. I am stating that a practical and feasible planning process (and indeed the one the MISO has adopted) must accommodate the practical

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[12] Hogan Affidavit, at 11.

[13] *Id.*, at 12.

[14] MISO Tariff, Attachment FF, Section I.C.

[15] MISO Tariff, Module A General Provisions, defines Good Utility Practice as follows "Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather, intended to include acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4)."

realities of transmission planning for a large region covering multiple states and on behalf of multiple stakeholders with a heterogenous set of goals.

Q. Do you agree with Dr. Hogan that MISO, states, and members should jointly plan transmission and generation incrementally, adjusting each step of the way?

A. I do not believe that Dr. Hogan's proposal is practical to implement, regardless of whether it is theoretically optimal. The reality is that building large scale transmission and generation consists of making investments in projects that span many decades, and sometimes longer. It is not feasible for all of these entities, each with their own goals and priorities, to iterate and continually update generation and transmission plans until they achieve perfect optimization.

I note, moreover, that this approach posits that MISO (on the one hand) and states and member utilities (on the other) have a co-equal role in deciding what generation should be built and where. While that is an approach that our country could theoretically adopt, Dr. Hogan does not suggest that our country has in fact adopted such an approach.

Q. Was the approach that MISO took during the Tranche 2.1 planning process – to assume future generation portfolios – consistent with the MISO tariff and MISO's historical approach to regional transmission planning?

A. Yes. Section I.C.8 of MISO Attachment FF requires that, "[e]ach MTEP report shall list in detail the planning assumptions *upon which the analyses are based*."[16] The MISO tariff specifies that Planning Assumptions must include, among other things, projected load, generation, demand response resources, and the current transmission topology with approved projects.[17] The MISO tariff does not specify a particular methodology for planning exercises. As MISO explained in the MTEP24 report, the first step in the planning process was to develop Planning Assumptions, which MISO did when it developed Futures 1A and 2A.[18] MISO's approach of developing Futures as the first step in the regional transmission planning process is also consistent with how MISO has

[16] MISO Tariff, Attachment FF, Section II.C.8.
[17] MISO Tariff, Attachment FF, Section I.C.8.a-e.
[18] MTEP24 Report, at 27-28.

conducted transmission planning in the past. For example, MISO's MTEP19 report states that, "The first two steps in MISO's 7-Step value-based transmission planning process are associated with the development of multiple futures, resource forecasting, and siting of new forecasted resources."[19]

As such, Dr. Hogan's recent critiques would require a significant change to how MISO has conducted long-range transmission planning. Further, given that the MISO Tariff requires that MISO establish planning assumptions and base its analysis upon those assumptions, Dr. Hogan's proposal that MISO plan transmission and generation iteratively, rather than assuming future generation and load and as a first step, is arguably inconsistent with the MISO tariff.

IV. OVERVIEW OF MISO'S TRANCHE 2.1 PLANNING ASSUMPTIONS

Q. What was the goal of MISO's Tranche 2.1 planning exercise and how does it fit in with other planning efforts?

A. MISO developed Tranche 2.1 as part of its Transmission Expansion Plan (MTEP), specifically the Long-Range Transmission Planning (LRTP) process. LRTP cycles are launched periodically when needed to "address significant changes to future conditions that the grid must be prepared to address" and are used to project MISO's transmission needs over a 20-year planning horizon.[20] MISO launched a conceptual LRTP roadmap in 2021 to "determine how transmission can help ensure a reliable future system as the resource portfolio shifts, extreme weather events become more frequent and demand for power increases."[21] MISO divided this LRTP into four tranches; Tranches 1 and 2 are focused on the Midwest Subregion (Tranche 2 includes 2.1 and 2.2). Tranche 3 will focus on the South Subregion and Tranche 4 will address the Midwest/South interface limit.[22]

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[19] MISO, MTEP19 Report, at 33.
[20] MTEP24 Report, at 11.
[21] MISO, Long Range Transmission Planning (LRTP), Tranche 2 – Frequently Asked Questions, at 2.
[22] MTEP24 Report, at 22.

Q. What projects were included in LRTP Tranche 1?

A. MISO developed the Tranche 1 portfolio with stakeholders as part of the MTEP21. Tranche 1 ultimately consisted of 18 projects in MISO's Midwest subregion, with a projected cost of $10.3 billion.[23] The Tranche 1 projects were approved by the MISO Board in July 2022. According to MISO, the Tranche 1 projects resolved only about 30% of the issues MISO identified in the Tranche 1 planning process.[24]

Q. Did MISO engage stakeholders during the planning of the Tranche 2.1 projects?

A. Yes. After completing LRTP Tranche 1, MISO launched a stakeholder process to consider Tranche 2 solutions in the fourth quarter of 2022.[25] According to MISO, the Tranche 2.1 planning effort took 18 months, involved more than 40,000 hours of labor from MISO staff, and included more than 300 stakeholder meetings and discussions.[26]

Q. Were the Complainants part of that stakeholder process?

A. They had the opportunity to participate. The MISO tariff requires MISO to include the Organization of MISO States (OMS) Committee in the transmission planning process.[27] The MISO tariff generally provides that the OMS Committee may provide input to MISO staff and the System Planning Committee of the MISO Board about the planning principles and planning objectives and the planning scope at the start of a planning cycle, modeling inputs or assumptions and related cost/benefits that are not proposed strictly for reliability, and concerns or specific issues that arise during the MTEP process.

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[23] *Id.*, at 23.
[24] *Id.*
[25] MISO, MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1, Executive Summary, at 6.
[26] MISO, Michelle Wilson, Transforming the Grid: MISO's $21.8 Billion LRTP Tranche 2.1 Portfolio, September 25, 2024.
[27] MISO Tariff, Attachment FF, Section I.B, "OMS Committee Input to the MTEP Process."

Q. What approach did MISO take in developing the Tranche 2.1 transmission projects?

The approach MISO used in the Tranche 2.1 planning process was consistent with its tariff and with the approach used in prior MISO regional transmission planning processes (e.g. Tranche 1). MISO's regional transmission planning process is based on a forecast of the likely generation and load in the future, referred to in MISO as a "Future," that is developed at the beginning of the process. The remaining methodological steps in MISO's regional transmission planning process depend on the planning assumptions about the future state of the MISO system contained in the Future(s). So too do the benefit metrics MISO develops and uses to evaluate the benefits of a given portfolio of transmission projects.[28]

Figure 1 presents MISO's high-level summary of MISO's Long Range Transmission Planning Process (LRTP), which is periodically undertaken as part of MISO's Transmission Expansion Plan (MTEP). LRTP planning processes are designed to identify Multi-Value Projects (MVPs).

As shown in

[28] MISO, LRTP Tranche 2 Business Case Metrics, Methodology Whitepaper, October 1, 2024, at 4. For example, MISO states that "The development of benefit metrics and hence the quantification of value is largely dependent on the assumptions of the future state of the system which occurs in the Futures development at the beginning of the planning process". *Id*.

Figure 1, developing Futures is the first step in MISO's regional transmission planning process and fundamental to how MISO conducts the planning process, evaluates the benefits of potential transmission projects, and ultimately selects and recommends projects for MISO board approval.

Figure 1: MISO's Seven-Step Regional Transmission Planning Process used in LRTP

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

Source: MTEP24 Report, at 11.

- The first step of MISO's Tranche 2.1 planning process focused on developing a set of load and generation investment projections referred to as "Future 2A". As discussed further below, Future 2A was developed with stakeholder input and incorporated several factors such as state and LSE clean energy goals and mandates, planned resource additions, retirements, and other assumptions.[29]

- In step 2, MISO used a capacity expansion model (EGEAS) to determine type, magnitude, and timing of the new generation investments assumed in Future 2A. MISO also selected siting locations for the Future 2A resources and added capacity to ensure the system was resource- and energy-adequate. This included adding 140 GW of capacity and 29 GW of "Flexible Attribute Units" that MISO determined were necessary to meet the system's resource adequacy and reliability requirements.

- In step 3, MISO identified transmission issues based on the performance of the transmission system with the Future 2A and 1A planning assumptions.

- In step 4, MISO evaluated and selected transmission projects, or "solutions" to address the issues identified in step 3.

- In step 5, MISO evaluated the expected costs and benefits of the transmission projects selected in step 4 with a variety of benefit metrics. As discussed below, Dr. Hogan criticized several of MISO's benefit calculations for the Tranche 2.1 projects.

- In Step 6, MISO staff selected its preferred projects – referred to as the Tranche 2.1 projects – which were ultimately recommended to and approved by the MISO Board.

- Step 7 selects a cost-allocation method for the project. The Tranche 2.1 projects are Multi-Value Projects (MPVs). Per the MISO tariff, MVPs are projects that have broadly shared benefits that either help MISO reliably and economically deliver energy to meet energy policy mandates or laws; provide "multiple types

[29] MISO, LRTP Workshop Tranche 2.1 Journey, September 24, 2024, at 4-6.

of economic value" with a benefit-to-cost ratio of at least 1.0; or address at least one projected reliability violation and provide at least one economic value with total benefits exceeding costs.[30]

Q. Is MISO's overall approach to regional transmission planning similar to those in other regions?

A. Yes. For example, the Southwest Power Pool (SPP) also uses a Futures approach and follows the same high level methodological steps MISO does when it conducts regional transmission planning. Like MISO, SPP assumes Futures, which SPP characterize as drivers of future transmission needs. Like MISO, SPP has a "base" model based on the current transmission topology, planned transmission upgrades, and projected generation and load (i.e., the "Future" assumptions). Then, like MISO, SPP makes siting decisions about where the new generation will be located on the base transmission model. Then, like MISO, SPP evaluates how the base case transmission model with the assumed Future performs to identify what MISO calls "transmission issues" and what SPP calls a transmission "needs assessment".[31] SPP's process, like MISO's has been approved by FERC and is the result of an extensive, stakeholder-driven process.

Q. How did MISO develop the Future 2A generation portfolio?

A. MISO developed its Future 2A generation portfolio by gathering information from its states and member utilities about their resource plans, state legislative and executive decarbonization requirements and goals (e.g., Renewable Portfolio Standard (RPS)), LSE decarbonization and clean energy targets, and planned additions and retirements. The Future 2A portfolio assumed 100% achievement of updated member goals at the time of the estimate (2023).[32] The Future 2A generation portfolio ultimately included 199 GW of member-planned resources, or 54% of the overall total.

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

[31] SPP, 2024 Integrated Transmission Planning Assessment Report, January 24, 2025, at 29 (Table 3.1: Future Drivers), 34-35, and 69.

[32] MISO, LRTP Tranche 2 – Futures Refresh, Assumptions Book, updated: April 27, 2023, at 5.

MISO then performed additional analysis to ensure the system would be resource- and energy-adequate, which resulted in adding 169 GW of incremental generation beyond the 199 GW of generation included in MISO member plans. In total, the Future 2A generation portfolio contained 369 MW of resources. Table 1 shows the resource additions MISO included in Future 2A, as well as Future 1A, which served as a "low-end bookend" during the Tranche 2.1 planning process to evaluate the robustness of MISO's results in a range of possible future outcomes.[33]

[33] MISO MTEP24 Report, at 28.

Table 1: Generation Additions (MW) Assumed in Futures Evaluated During the Tranche 2.1 Planning Process

Resource type	Future 2A	Future 1A
CT	9,058	7,858
CC	10,000	10,000
ST Gas	2,964	2,964
IC Gas	1,839	1,839
ST Coal	163	163
Wind	144,634	66,634
Solar	84,702	57,102
Hybrid	9,825	12,225
Battery	31,099	10,799
Dist. Solar	17,137	17,138
DR	7,770	7,327
EE	17,589	17,589
UDG	2,688	2,688
Flex	29,800	0
Total	**369,269**	**214,326**

Source: MISO Futures Report Series 1A, November 2023, p 55. DR: demand response; EE: energy efficiency, UDG: utility-driven generation.

The Future 1A generation portfolio assumed 60% achievement of decarbonization goals and did not include any Flex units. Future 1A had only 46% of the wind capacity of Future 2A and only 67% of the solar capacity, and did not include any Flex capacity.

A. "MODEL-BUILT" GENERATION IN TRANCHE 2.1 FUTURES

Q. Can you please briefly summarize the different sources of capacity additions and their source?

A. The initial portfolio of Future 2A generation was based on the generator interconnection queue, planned and assumed retirements, and did not involve any reliability or resource adequacy analysis. MISO is responsible for ensuring the reliable operation of the MISO system, part of which consists of ensuring that it can meet the applicable resource adequacy and reliability requirements. As the entity responsible for planning transmission for MISO system, MISO must also comply with applicable transmission planning criteria.[34] As such, MISO started with the Future 2A generation portfolio discussed above, which was based on state and MISO LSE goals, policies, and announcements, and planned generation to ensure it met resource adequacy criteria.

MISO then performed two discrete studies – a resource adequacy study and an energy adequacy study – and determined it was necessary to add incremental capacity to ensure system reliability. MISO ended up adding approximately 140 MW of "model-built" capacity (from EGEAS) to ensure *resource* adequacy and 29 GW of Flex capacity to ensure *energy* adequacy.[35] I explain these studies and the incremental capacity MISO added below.

Q. Do other RTOs/ISOs add model-built capacity to their planning models when conducting regional transmission planning?

A. Yes. SPP, which as noted above follows the same high level methodological steps that MISO does in its transmission planning process, added model-built capacity into its recent transmission expansion plan. Similar to MISO, SPP added this model-built capacity developed during SPP's resource expansion plan to ensure resource adequacy during the ten-year study period. SPP's 2024 Integrated Transmission Plan explained that "SPP developed resource expansion plans to meet renewable portfolio standards, resource reserve margin requirements, and future specific renewable and emerging technology projections."[36] Like MISO, SPP assumed certain renewable resource additions and added model-bult capacity to ensure appropriate resource."[37]

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[34] See e.g., MISO Attachment FF, Section I.C.1.b.i(c).

[35] MISO, MISO LRTP Futures Review, September 24, 2024, at 15.

[36] SPP 2024 Integrated Transmission Planning Assessment Report, January 24, 2025, at 34.

[37] *Id*., at 35 ("SPP used the renewable resource expansion plan for each future as an input to the corresponding conventional resource expansion plan to ensure appropriate resource adequacy within the SPP footprint.")

Q. What was MISO's rationale for adding model-built capacity to ensure resource adequacy?

A. As noted above, MISO started with member-based plans and clean energy mandates and goals to develop the Future 2A generation portfolio. MISO then performed assessments to ensure the future resource fleet would meet the system's resource adequacy requirements in the planning studies. MISO performed a study with the Base case transmission topology to ensure each Local Resource Zone ("LRZ" or "zone") would maintain a reserve requirement of 18.05% throughout the study period. MISO calculated zonal Local Clearing Requirements for each zone associated with maintaining the 18.05% planning reserve requirement and made adjustments to address any significant surplus or capacity deficits in each zone.[38] As noted above, MISO added approximately 140 MW of "model-built" capacity to ensure resource adequacy.[39]

Q. Can you explain what "Flex units" are?

A. Flex units are additional capacity that MISO has added to "fill the gap" in intervals where the Future 2A generation was projected to fall below electric loads. They can best be described as a modeling convenience to facilitate long term system expansion modeling. MISO assumed these Flex units would have zero emissions, are proxy units and not intended to represent actual units, but rather ensure the system is energy-adequate in all hours. MISO assumed the Flex units would be low- or no-emissions and highly available and would include generation technologies such as reciprocating internal combustion engines, long-duration battery storage, traditional peaking resources, combined-cycle with carbon capture and sequestration, small modular resources, green hydrogen, enhanced, geothermal systems, and other emerging technologies.[40]

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[38] MISO, MISO Futures Report Series 1A, November 1, 2023, at 54. *See also*, MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 9.

[39] MISO, MISO LRTP Futures Review, September 24, 2024, at 15.

[40] MISO, Futures Report Series 1A, November 1, 2023, at 2-3, https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

Q. What was MISO's rationale for adding 29 GW of model-built Flex units?

A. MISO performed an analysis to ensure that the assumed future generation fleet could reliably meet projected loads in all hours of the year (i.e., ensure energy adequacy). This analysis was performed after MISO added capacity to meet the system's resource adequacy needs. MISO conducted an hourly analysis with PROMOD[41] and determined energy shortfalls for three to four hours per day during "twilight hours" before sunrise or after sunset, as shown in Figure 2.

Figure 2: MISO's Energy Adequacy Analysis and Rationale for Flex Units

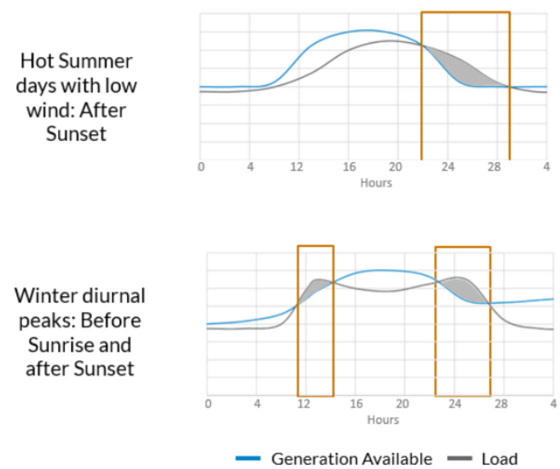

Figure 2.6: Energy Adequacy Analysis for Flexible Attribute Units

Source: MISO, MTEP24 Report, at 30.

MISO based the 29 GW addition of Flex units on the maximum hourly shortfall projected in the PROMOD modeling. MISO explained that the Flex units did not displace the need for resources that were already included in the assumed generation portfolio but rather supplemented them in periods of *energy* inadequacy.[42] MISO sited

[41] PROMOD is a chronological production-cost simulation tool which is used by MISO to model the MISO marketplace.
https://cdn.misoenergy.org/MISO%20Economic%20Planning%20Whitepaper651689.pdf

[42] MTEP24 Report, at 31. See also MISO, Series 1A Futures Report, November 1, 2023, at 20.

the Flex units at brownfield sites of retired units.[43] MISO documented and supported its choice to add of the Flex units. As the regional transmission planner and entity responsible for ensuring reliability in MISO, I believe it was reasonable appropriate for MISO to add this capacity.

Q. In your view, should MISO have removed renewable resources from the Future 2A generation portfolio after it added the model-built units?

A. No. Dr. Hogan argues that the renewable generation MISO included in the Future 2A generation portfolio should have fallen sharply because the Flex units, "would naturally satisfy many, if not all, of MISO's reliability needs."[42] Dr. Hogan here fails to appreciate that MISO is required by the tariff to incorporate the generation plans of its members, and state and federal policies. As such, removing generation from the Future 2A plan after adding the Flex units, as Dr. Hogan suggests, could result in displacing generation included in member's plan, which would be inconsistent with the regional transmission planning process outlined in MISO's tariff.

Q. Does Dr. Hogan challenge the idea that MISO's Future 2A generation portfolio is consistent with members' plans?

A. He does not. Instead, Dr. Hogan appears to be objecting that MISO's approach is not congruent with his preferred theoretical approach, stating that "consistency with member plans is not a stipulation of the cost-benefit analysis theory."[44] MISOs regional transmission planning process is not required to adhere to Dr. Hogan's theory of cost-benefit analysis.

Q. Isn't it true that only 54% of the resources in Future 2A are directly from members?

A. Yes. MISO started with the members' plans, and then added generation in the Future 2A which assumed 100% achievement of clean energy goals, policies, and announcements. As noted above, MISO added approximately 140 GW of model-built

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[43] MISO, Series 1A Futures Report, November 1, 2023, at 52.
[44] Hogan Affidavit, p. 31, ln. 9-10.

capacity to ensure *resource* adequacy and 29 GW of model-built Flex capacity to ensure *energy* adequacy.[45] I believe this was a reasonable approach and consistent with MISO's role as the region's reliability coordinator and MISO tariff.

For example, MISO is required to develop planning assumptions in the MTEP that meet expected future loads and ensure electric reliability.[46] The Tariff also requires MISO to consider state public policy goals in the MTEP,[47] a requirement of Order No. 1000, and MISO determined that additional generation (i.e., "model built" capacity) was necessary to ensure resource and energy adequacy given the renewable targets and goals of MISO members.

Q. Dr. Hogan claims that in the absence of MISO's assumed Tranche 2.1 transmission expansion projects, much of the Future 2A generation would likely not be built. Do you agree?

A. No. Dr. Hogan's argument appears to be that MISO members will only comply with state clean energy mandates and targets, many of which are mandatory, if the new generation investments are optimal given MISO's regional transmission topology.[48] Dr. Hogan's logic does not apply to member utilities that construct renewable generation to comply with mandatory state clean energy standards because such utilities have an obvious interest in following the laws of their respective states and thus generally will make such investments regardless of the regional transmission topology in MISO.

B. OTHER PLANNING ASSUMPTIONS

Q. MISO assumed the availability of wind, solar, and battery storage tax incentives from the Inflation Reduction Act when developing the Future 2A generation

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[45] MISO, MISO LRTP Futures Review, September 24, 2024, at 15.

[46] MISO Tariff, Attachment FF, Section 1.C, "The Transmission Provider shall develop the MTEP for expected use patterns and analyze the performance of the Transmission System in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions."

[47] MISO Tariff, Attachment FF, Section I.C.1.b.ii.

[48] Hogan Affidavit at 15 ("In the absence of the transmission expansion, much of the generation would likely not be built, so the generation profile is inconsistent with the definition of the Base Case.").

portfolio. Recent legislation significantly reduced these incentives. Do you view this as problematic?

A. No, for three reasons. First, MISO's planning assumptions were based on the federal law and policy in effect at the time they were developed, and the fact that the IRA changed later only underscores the level of inherent uncertainty under which MISO operates as it engages in long-term future planning. If MISO had to restart its planning process every time policies changed, it could never plan at all; it would become stuck in an endless loop of reconsidering its assumptions. The lifespan of transmission and generation investments normally far exceeds the lifespan of political administrations and their policies.

Second, MISO's assumptions were reasonable at the time and they remain reasonable over the 20-year planning horizon. According to MISO, over 75% of the load in its footprint is served by LSEs subject to ambitious decarbonization goals.[49] State RPS targets are mandatory and remain unchanged by recent changes in federal policy. The reduced federal subsidies will increase the cost and likely slow the pace of wind, solar, and battery storage deployment, at least while those subsidies remain at current levels.

Third and finally, MISO performed a sensitivity to ensure the Tranche 2.1 projects were robust to a range of likely futures. The Future 1A generation portfolio shown in Table 1**Error! Reference source not found.**, which assumes MISO members only achieve 71% of their decarbonization goals and targets[50] and has 46% (or 105.6 GW) less wind and solar capacity than the Future 1A, still forecasts that the Tranche 2.1 will have a cost-benefit ratio above one.[51] As such, the Tranche 2.1 projects still meet the requirements of an MVP project under more conservative assumptions about renewable generation development.

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[49] MISO, Futures Report Series 1A, November 1, 2023, at 9.
[50] MISO, Futures Report Series 1A, November 1, 2023, at 4.
[51] MTEP24 Report, at 160.

Q. MISO recently projected that the One Big Beautiful Bill Act will reduce renewable deployment in the near term. Does that call into question the Tranche 2.1 reliance on the Future 2A generation portfolio?

A. No. Again, MISO based its assumptions on the Federal PTC, state policies, and member targets in effect at the time it developed the Future 2A and 1A scenarios. And those scenarios on which MISO relied during the Tranche 2.1 transmission planning process, in turn, were developed in 2022 and 2023 in accordance with MISO's 7-step regional transmission planning methodology. In developing its assumptions and futures scenarios, MISO exercised good utility practice, which as noted above, includes using the best information available at the time the decision-making took place. System conditions, load and cost projections, and federal and state polices change constantly, and planners must exercise some judgment regarding the long-term arc of policy. MISO is currently working to revise the Series 2 Futures it will use in the next MTEP cycle with current information, including updated hyperscaler load forecasts and current Federal tax incentives for wind, solar, and storage facilities.[52]

Q. What load growth projections are reflected in Future 2A and 1A?

A. The load growth projections assumed in the Future 2A and Future 1A scenarios MISO used during the Tranche 2.1 planning process are summarized below.

Table 2: Projected load growth in Future 2A and 1A

	Peak Demand Growth from beginning of period		**Annual Energy Growth from beginning of period**	
	Future 2A	Future 1A	Future 2A	Future 1A
2030	14%	7%	16%	8%
2035	21%	11%	24%	12%
2040	27%	15%	32%	15%

Source: MISO LRTP Futures Review, September 24, 2024, at 29.

The Future 2A load forecast was initially developed in 2019 and as discussed further in Section VI below, MISO has since updated its load forecast.

[52] MISO, Futures Redesign Project Status & Schedule, Aug. 29, 2025.

V. MISO'S TRANCHE 2.1 BENEFIT CALCULATIONS WERE REASONABLE AND CONSISTENT WWITH THE MISO TARIFF AND MISO'S ROLE AS THE REGIONAL TRANSMISSION PLANNER

Q. What are the MISO tariff requirements for analyzing the costs and benefits of MVP projects?

A. The MISO Tariff requires that the "Total MVP Benefit-to-Cost Ratio," which is the ratio of financial benefits to Project Costs, exceed one.[53] The Tariff goes on to explain that, "For the purpose of this calculation, Financial Benefits will be set equal to the present value of all financially quantifiable benefits provided by the project projected for the first 20 years of the project's life and Project Costs will be set equal to the present value of the annual revenue requirements projected for the first 20 years of the project's life."[54]

Q. What types of benefits did MISO estimate for the Tranche 2.1 projects?

A. The MISO tariff does not require MISO to apply a "standard set of metrics and methodologies" in each LRTP process.[55] Rather, MISO is required under the tariff to assess the financially quantifiable benefits of MVP projects and compare them to the projects' costs. MISO calculated the Tranche 2.1 benefits and costs on a 20-year present value basis for the nine categories shown in Table 3 below. MISO calculates the net present value of benefits in two ways, the low estimate assumes a 7.1% discount rate and the high estimate assumes a 3% discount rate.[56]

[53] MISO Tariff, Attachment FF Section II.C.1.
[54] MISO Tariff, Attachment FF Section II.C.7.
[55] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 4.
[56] MISO assumed a 7.1% discount rate based on the gross-plant weighted average of the transmission owner's cost of capital, representing the minimum return required to make the transmission investment. The 3% discount rate is based on a "social discount rate" reflecting the return a ratepayer would typically earn on a risk-adjusted investment. MTEP24 Report, Figure 2.137, at 143.

Table 3: MISO's Estimated benefits of Tranche 2.1 projects by category

Benefit category	**MISO estimated benefits $B in 2024$ on a 20-yr present value basis**
1. Mitigation of reliability issues	$14.8 - $42.3
2. Reduced risks from extreme weather events	$0.4 - $1.1
3. Avoided capacity costs	$16.3
4. Capacity savings from reduced losses	$1.9
5. Avoided transmission investments	$1.2
6. Congestion and fuel savings	$8.1
7. Reduced transmission outage costs	$0.1
8. Energy savings from reduced losses	$1.6
9. Decarbonization	$7.2 - $28.3
Total Benefits	**$51.7 - $101.0**

Source: MTEP24 Report, Figure 2.137.

MISO projected the Tranche 2.1 projects would have a revenue requirement of $28.6 billion on a net present value basis, yielding benefit/cost ratios ranging from 1.8 to 3.5.[57]

Q. Dr. Hogan estimated alternative benefits for the Tranche 2.1 benefits. Please summarize Dr. Hogan's estimates of the benefits and the methods he used.

A. Dr. Hogan concludes that MISO miscalculated the estimated benefits of Tranche 2.1 in various ways. Dr. Hogan contends that MISO's calculation of the avoided capacity costs and the mitigation of reliability issues were methodologically flawed and should instead be zero, though he did not conduct his own resource adequacy or reliability analysis to reach these conclusions. Dr. Hogan also estimated lower decarbonization benefits based on a lower cost of carbon metric. Finally, Dr. Hogan estimated that MISO overestimated the energy loss reduction benefits of Tranche 2.1 projects. The table below shows MISO's Tranche 2.1 benefit calculations and the benefits Dr. Hogan claims the projects will produce.

[57] MISO 2024 MTEP Report, Figure 2.137, at 142.

Table 4: MISO and Dr. Hogan's Estimated Benefits for Tranche 2.1 Projects

Benefit category	MISO estimated benefits $B in 2024$ on a 20-yr present value basis	Dr. Hogan's Analysis of Benefits in $B of 2024$ (Hogan Figure 2)
1. Mitigation of reliability issues	$14.8 - $42.3	$0
2. Reduced risks from extreme weather events	$0.4 - $1.1	$0.4 - $1.1
3. Avoided capacity costs	$16.3	$0
4. Capacity savings from reduced losses	$1.9	$0
5. Avoided transmission investments	$1.2	$1.2
6. Congestion and fuel savings	$8.1	$8.1
7. Reduced transmission outage costs	$0.1	$0.1
8. Energy savings from reduced losses	$1.6	<$1.6
9. Decarbonization	$7.2 - $28.3	<$4.3 - <$7.2
Total	**$51.7 - $101.0**	**<$15.7 - < $19.4**

Source: MTEP24 Report, Figure 2.137 and Hogan Affidavit, Hogan Figure 2.

Dr. Hogan did not substantively address or provide alternative benefit calculations for reduced risks from extreme weather risks, avoided transmission investments, congestion and fuel savings, or reduced transmission outages. As such, I do not address these benefit calculations in my affidavit. Instead, I focus on Dr. Hogan's critiques and his alternative benefit calculations for avoided capacity costs and capacity savings from reduced losses (which are linked); mitigated reliability issues; and decarbonization. I address each in turn below.

1. MISO Reasonably Calculated Avoided Capacity Cost Benefits

Q. How did MISO calculate avoided capacity cost benefits for the Tranche 2.1 projects?

A. To estimate the capacity benefits of the Tranche 2.1 projects, MISO developed an analysis to measure the extent to which relieving transmission constraints between MISO's capacity zones would reduce the need for loads to build capacity within their zones. Instead, transmission expansion would permit such loads to import capacity from other areas, which would generally reduce the system's required planning reserve margin. MISO captured this benefit by developing two transmission planning cases –

one with the Tranche 2.1 projects (Tranche 2.1 case) and one without (ACC case).[58] MISO used these cases to estimate the extent to which the Tranche 2.1 projects lowered the system's planning reserve margin and avoided the need for incremental capacity. MISO employed a probabilistic LOLE model to perform the planning cases over the 20-year planning period (i.e., the ACC and Tranche 2.1 cases) and calculated the incremental capacity needed to achieve a loss of load expectation of 1 day in 10 years.[59]

The ACC case required more incremental capacity additions to achieve this target than the Tranche 2.1 case did – and thus a higher planning reserve margin. This occurred because the transmission system in the Tranche 2.1 case had more transfer capability. This is intuitive; greater ability to move capacity between zones should lead to less overall capacity needed. MISO then calculated the difference in the planning reserve margins (reserve margin delta) between the ACC and Tranche 2.1 cases.

Next, MISO created a new planning case (ACC2 case) by performing a new capacity expansion with EGEAS but with a higher planning reserve margin in the latter half of the forecast period.[60] The ACC2 case included MISO Future 2A generation portfolio with the model-built units. MISO then expanded the generation in the ACC2 case to achieve the same planning reserve margin as the Tranche 2.1 case by 2042, the end of the forecast period. MISO compared the capacity additions of the ACC2 case with the Tranche 2.1 case and found a 22.8 GW difference in incremental capacity.

From this, MISO estimated that the Tranche 2.1 portfolio avoided the need for 22.8 GW of capacity (or equivalently, had a financial benefit equal to 22.8 GW of incremental capacity).[61] MISO estimated the financial benefits of the higher reserve margin the

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[58] MISO did not use these names for the planning cases. I am using them for ease of exposition.

[59] MISO, LRTP Tranche 2 Benefit Metrics Methodology Whitepaper, at 5-11.

[60] MISO does not use the term ACC2 case, I add this term for ease of exposition. MISO increased the previously assumed 18.05% planning reserve margin by the reserve margin delta and performed a new capacity expansion to meet the higher reserve requirement.

[61] MTEP24 Report, at 148-149. The planning reserve margin (PRM) is assumed to be constant at 18.05% until the Tranche 2.1 projects were assumed to be in service in 2032. The

system would achieve with the Tranche 2.1 projects based on the cost of the additional capacity ranged, which between \$16.3 and \$19.2 billion over a 20- to 40-year period. MISO then allocated these benefits between avoided capacity costs and avoided losses.[62]

Q. Is it reasonable to assume the Tranche 2.1 projects do not have any avoided capacity cost related benefits at all?

A. No. I find Dr. Hogan's claim that the Tranche 2.1 projects will not obviate the need to construct any capacity or result in any capacity savings from reduced losses - and thus have no financially quantifiable benefits - to be unreasonable. Expanding the transmission system increases the ability to purchase capacity from other regions and can avoid the need to build capacity in a given area. The avoided capacity cost benefits of transmission expansion are a well recognized benefit in regional transmission planning.[63]

Given the scale of Tranche 2.1 and the nature of the transmission backbone it supports, it is simply implausible that it would convey zero benefits in avoided capacity costs, and Hogan's claim that it carries zero benefits casts doubt on his methodology. Furthermore, the avoided capacity cost calculation benefit MISO performed, which estimated the financial benefits of having an increased reserve margin with the Tranche 2.1 projects, is generally consistent with one of the benefits FERC required in Order No. 1920. Specifically benefit number 2, "a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin."[64]

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expansions proceeded through 2042. See MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 14-15. Note that the 22.8 GW figure is taken from the Tranche 2.1 Detailed Business Case Analysis, posted on May 16, 2025.

[62] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 13-16.

[63] See SPP, 2021 Value of Transmission Report, at 14. See also *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost, Allocation*, Order No. 1920, 89 FR 49280 (2024), 187 FERC ¶ 61,068 (2024) at P 720.

[64] See e.g., *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost, Allocation*, Order No. 1920, 89 FR 49280 (2024), 187 FERC ¶ 61,068 (2024) at P 720. SPP, 2021 Value of Transmission Report, at 14.

Q. Dr. Hogan claims that the "most fundamental mistake" in Tranche 2.1 avoided capacity cost benefit calculation is that MISO assumes the costs of Future 2A generation portfolio are sunk when calculating the benefits of the projects. Do you agree?

A. No. The Future 2A generation represents the accumulated planning of the states and member utilities, each of whom may have employed their own criteria, along with assumptions made by MISO to ensure resource adequacy. Characterizing these resources as "sunk" implies that MISO has some authority to override the plans of its members or is otherwise directing parties to construct the generation assumed in the Future 2A generation portfolio. Among other things, Dr. Hogan also took issue with the methodological steps took when estimating avoided capacity costs, suggesting that the 22.8 GW of generation added should have eliminated some of the generation in Future 2A.[65] Here, Dr. Hogan fails to appreciate that, as explained above, MISO added the 22.8 GW to estimate the financial benefit of the increased reserve margin associated with the Tranche 2.1 portfolio. Given the methodology MISO used to calculate avoided capacity costs, removing generation from the Future 2A generation portfolio as Dr. Hogan suggests would not be appropriate because it would *lower* the reserve margin in a benefit calculation methodology designed to capture the benefits of a *higher* reserve margin. Dr. Hogan may object to MISO's approach, but it followed a well-established stakeholder process to add that capacity and MISO's approach was consistent with its tariff.

2. MISO Reasonably Calculated the Benefits of Mitigated Reliability Issues

Q. At a high level, how did MISO estimate the benefits the Tranche 2.1 projects would provide related to the mitigation of reliability issues?

A. MISO performed simulations with reliability models and methods to estimate whether the Tranche 2.1 transmission projects would reduce instances of load shed. MISO accomplished this by simulating various load conditions in two models: a model without the Tranche 2.1 projects (Base case); and a model with the Tranche 2.1 projects

[65] Hogan Affidavit, at 16-19.

(Tranche 2.1 case). MISO then performed simulations on the Base and Tranche 2.1 cases and tabulated instances of load shed in each. The simulations projected that load shed events would to be lower with the Tranche 2.1 projects than without them. That is, load shedding was higher in the Base case than in the case with Tranche 2.1 transmission. MISO termed this benefit, "mitigating reliability issues." As required by the tariff, MISO then quantified the financial value of the avoided load shed by multiplying the hours of avoided load shed by an administratively determined value of lost load (VOLL). MISO estimated a range of possible benefits based on a low-end VOLL of $3,500/MWh and a high-end VOLL of $10,000/MWh.[66]

Q. What specific steps did MISO take to identify instances where the Tranche 2.1 projects might avoid the need for load shedding?

A. MISO developed reliability models for 2032 and 2042 (ten and 20 years into the forecast period, respectively) to identify reliability issues associated with thermal, voltage, and stability that could require the operator to shed load. Specifically, MISO performed simulations in a Base case model with the Future 2A portfolio and without the Tranche 2.1 projects in 2032 and 2042. MISO analyzed reliability issues in the Base case under a range of possible future load conditions in 2032 and 2042: summer peak, winter peak, average load, and light load. MISO analyzed NERC Category P1, P2, P7 contingency events.[67] MISO then performed a two-pass simulation to attempt address any reliability issues (e.g., thermal overload) identified in the model that could lead to load shed.[68]

[66] MISO MTEP24 Report, at 144-146.

[67] MISO is required to consider NERC Transmission Planning standards (TPL) when it conducts transmission planning which requires evaluating several types of contingencies. P1 is a single contingency event resulting from the loss of a generator, transmission circuit, transformer, shunt device, or single pole of a DC line. P2 is a single contingency event resulting from the opening of a line section without a fault, a bus section fault, or an internal breaker fault (either non-bus tie breaker or bus tie breaker). P7 is a multiple contingency event involving the loss of any two adjacent (vertically or horizontally) circuits on a common structure and the loss of a bipolar DC line. *See* North American Electric Reliability Corporation, TPL-001-5 — Transmission System Planning Performance Requirements, Table 1 - Steady State & Stability Performance Planning Events, https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

[68] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 37.

In the first pass, MISO used TARA software to perform a security constrained reliability dispatch model to redispatch resources in an attempt to resolve the reliability issue and avoid load shed.[69] If the first pass was unsuccessful - meaning the reliability issue could not be addressed with redispatch - the simulation would proceed to a second pass that largely focused on redispatching renewable resources based on their assumed ability to resolve the reliability issue. This ability hinged on the assumed upward dispatch capability, or headroom, of renewable resources.[70]

Q. Why did MISO use a two-pass model to estimate the benefits of mitigating reliability issues?

A. MISO explained that it used this two-pass approach to ensure the benefits calculated under this category did not overlap with the benefits calculated for other categories; specifically minimizing production costs, minimizing congestion, and fuel savings.[71] In other words, MISO specifically designed the analysis of this benefit to avoid overlap with other Tranche 2.1 benefits and to capture the fact that the TARA model simulations can reflect a range of conditions for renewable resources.[72] The second pass was designed to model whether wind and solar generation capacity that was not redispatched in the first pass could have additional dispatch capability. MISO included this second pass given the uncertainty of variable wind and solar output. The second pass was only reached if the redispatch in the first pass was unable to resolve the reliability issue.

In the second pass MISO created two deterministic dispatch scenarios: scenario 1, in which renewable resources could be dispatched up or down; and scenario 2, in which renewable resources could not be dispatched up and could only be dispatched down. In

[69] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024. October 1, 2024, at 41.

[70] MISO LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024. October 1, 2024, at 34-39. In the second pass, other resource types were somewhat limited in in their ability to be redispatched because they too were redispatched, if possible, during the first pass.

[71] MISO LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024. at 37.

[72] MISO LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024. at 39.

the second pass, MISO constrained the dispatch of resources other than wind and solar. MISO performed simulations for the two study years, four load conditions, and the two dispatch scenarios (if the second pass was reached) for the Base case and the Tranche 2.1 case. MISO then identified instances where load shed was avoided in the Tranche 2.1 case but not in the Base case. That is, MISO identified instances where the increased transfer capability from the Tranche 2.1 projects enabled MISO to avoid load shed events by redispatching renewables that would have otherwise occurred without the projects. MISO then quantified the financial value of the load shedding the Tranche 2.1 projects were able to avoid by multiplying the MWh of avoided load shed by the value of lost load (VOLL).[73]

Q. Dr. Hogan claimed that MISO's reliability analysis restricted the ability of Flex units to address post-contingency overloads. Is that correct?

A. No. As noted above, MISO's reliability study had two passes, and all generators were redispatched within their operating limits in the first pass. Dr. Hogan appears to have misunderstood MISO's two-pass reliability analysis. Contrary to Dr. Hogan's claim, MISO used the dispatch capabilities of Flex resources and other resource types during the first pass of this reliability study. The dispatch capability of Flex dispatch was only constrained in the second pass for addressing NERC P2 and P7 contingencies and was not limited in NERC category P1 contingencies.[74]

In the first pass, all generation is redispatched in an attempt to address the overload while respecting generator thermal limits and, as Dr. Hogan notes, a $50/MW cost is imposed on generator redispatch.[75] However, this is a financial constraint and not a

[73] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 42-44. MISO also assumed that reliability issues MISO identified in the 2032 study year are resolved by 2042 and such issues are not considered again in the 2042 study year.

[74] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 38.

[75] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 38-39. Note the table on page 38 in this report applies to the second pass and the two dispatch scenarios MISO models for the availability of renewable generation to be dispatched in the second pass.

physical one. It is only in the second pass that MISO physically limits the dispatch capability of Flex and other units.

In the second pass, MISO assumes two scenarios where renewable resources could be redispatched to address the overload depending on whether or not the resources could be dispatched up. MISO explained that it made this methodological choice to ensure that the financial benefits associated with the mitigation of reliability issues did not overlap with the financial benefits MISO calculated for economic dispatch for congestion and fuel savings. Thus, MISO designed this approach to avoid double counting with other Tranche 2.1 benefit streams, which is entirely appropriate.

Q. Dr. Hogan argued that MISO's analysis of mitigated reliability benefits should have included capacity assumed in the avoided capacity cost analysis. Do you agree?

A. No. Dr. Hogan is conflating multiple and distinct benefit streams MISO calculated for each benefit. Dr. Hogan argues that the analysis of mitigated reliability benefits should have included 22.8 GW of incremental capacity MISO included in the avoided capacity case. He claims that "If the Tranche 2.1 transmission investments were not made, and the alternative generation built, the alternative generation would of course be sited to meet these reliability needs. Hence there would be no reliability benefits to the Tranche 2.1 transmission because the reliability issues would be addressed by the generation that would be built if the Tranche 2.1 transmission was not built."[76]

In other words, Dr. Hogan claims that MISO's reliability risk mitigation analysis should have included the 22.8 GW of capacity MISO identified in the avoided capacity cost benefits analysis. But Dr. Hogan fails to recognize that MISO is actually analyzing a *different* benefit in MISO's analysis – avoiding the risk of load shed from thermal overloads (e.g., thermal or voltage). MISO's avoided capacity cost metric was an estimate to capture the benefit of the enhanced reliability MISO loads would experience from carrying a higher reserve margin. This benefits analysis focused on avoiding

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[76] Hogan Affidavit, at 33.

specific, and different, types of overloads. MISO also designed this benefits study to avoid overlapping with other benefit streams and Dr. Hogan's suggestion could conflict with that goal. Dr. Hogan also assumes, without evidence, that the capacity MISO included in its avoided capacity cost benefits analysis would address these needs. Dr. Hogan did not indicate that either he or MISO performed a security constrained reliability dispatch with the TARA model to analyze whether the capacity associated with the ACC case described above could have avoided the specific reliability issues (i.e., overloads) that MISO analyzed in this mitigated reliability issues benefits analysis.

Q. Dr. Hogan also argues that MISO's assessment of the financial benefits of mitigated reliability issues is incomplete. Do you agree?

A. No. Dr. Hogan also critiques MISO for projecting any load shed at all, and argues that the instances of load shedding MISO projected in its reliability analysis would be identified and addressed in other near-term planning processes such as MTEP, or investment.[77] Here, Dr. Hogan appears to claim that MISO should have simply ignored the risk of load shedding during the 20-year forecast period, and instead assumed that other future and unknown solutions would mitigate those risks. I disagree that MISO should have simply assumed away the risk of load shed, and making such assumptions would be contrary to the requirement that MISO operate and plan a reliable transmission system.

Most importantly, MISO followed its tariff in its analysis of mitigated reliability – it identified likely instances based on the MISO Future 2A conditions that the Tranche 2.1 projects would avoid load shed. MISO is required by the MISO tariff to quantify the financial benefits of MVP projects and MISO's choice to use VOLL was entirely reasonable and appropriate as VOLL is designed to assign a financial value to load shed events. The VOLL values MISO used – \$3,500/MWh and \$10,000/MWh were also appropriate and consistent with the MISO tariff. In April 2025, FERC approved MISO's proposal to increase the VOLL parameter used for pricing purposes from \$3,500/MWh to \$10,000/MWh based on a MISO analysis. As such, the \$3,500/MWh

[77] Hogan Affidavit, at 35-36.

VOLL value lower bound value MISO uses to quantify the financial benefits of mitigating reliability issues (i.e., $14.8 B) is quite conservative.[78] The upper bound value of $42.3 B, which is based on the $10,000/MWh the recently approved for MISO, is arguably more appropriate. The MISO tariff also requires MISO to test its planning models against applicable planning criteria, which MISO did in this benefits analysis with the TARA model.[79]

Q. Does Dr. Hogan's criticism of MISO's assessment of reliability benefits resemble criticisms of the Department of Energy's recent *Report on Evaluating U.S. Grid Reliability and Security*?

A. Yes. Certain parties claimed that the Department of Energy's study, which found significant risks to reliability in many regions of the country, had "outlined an implausible reliability crisis" by allegedly ignoring "future planning by utilities, states and communities" that could and would address issues created by retirements of dispatchable generation.[80] Like Dr. Hogan, these parties claim that the Department of Energy should have assumed that other processes would address the reliability issues it identified, and that if it had done so, the Loss of Load Hours it calculated would have been much lower. I do not think it is reasonable to assume that MISO would decline to address reasonably foreseeable reliability issues.

3. MISO Reasonably Calculated Environmental Benefits

Q. Please describe the environmental benefits MISO estimated for the Tranche 2.1 projects.

A. MISO used the dispatch cases developed for the congestion and fuel savings benefits analysis to measure the change in CO_2 emissions between the Base case and the Tranche

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[78] *Midcontinent Independent System Operator, Inc.*, 191 FERC ¶ 61,019 (2025) at PP 5-7. The $10,000/MWh VOLL was referred to as a "pricing VOLL" that would be used to administratively price electricity during EEA3 load shed events. FERC also approved a system VOLL of $35,000/MWh VOLL to scale the Operating Reserve Demand Curve, which was capped at $6,000/MWh.

[79] See e.g., MISO Tariff, Attachment FF, Sectio I.C1.b.i(c).

[80] Request for Rehearing of Clean Energy Associations at 46-47, *Resource Adequacy Protocol, Evaluating the Reliability and Security of the United States Electric Grid*.

2.1 case.[81] MISO performed annual production cost simulations for 2032, 2037, and 2042, and interpolated the years in between to estimate the change in CO_2 emissions that would occur if the Tranche 2.1 projects were placed in service. MISO estimated that the Tranche 2.1 projects would reduce carbon emissions by 127 metric tons over 20 years and 199 metric tons over 40 years. MISO applied two carbon costs to estimate a range of financial benefits; a federal value of $85/metric ton based on the Q45 tax credit for carbon sequestration and a $248.67/metric ton value based on the Minnesota's public utility commission's social cost of greenhouse gasses.[82] MISO applied these carbon costs to the CO2 emissions avoided by the Tranche 2.1 projects and estimated decarbonization financial benefits ranging from $7.2 billion to 28.3 billion over a 20-year period, depending on which carbon cost is used.[83]

Q. Dr. Hogan argues that MISO "materially overstated" the environmental benefits of the Tranche 2.1. Do you agree?

A. No. Dr. Hogan argues, among other things, that a consistent comparison of the Base and the Tranche 2.1 cases that considers regional rather than global changes in carbon emissions would find that the Tranche 2.1 benefits would have no incremental decarbonization benefits.[84] Dr. Hogan's critique fails to recognize that the Tranche 2.1 projects will result in a different dispatch than the Base case, so carbon emissions would change. As MISO explained in its decarbonization benefits analysis, the Tranche 2.1 projects will alleviate congestion and enable the increased dispatch of lower-cost wind and solar resources compared to the Base case.[85] MISO's benefits analysis is designed to capture this impact of the Tranche 2.1 projects. Dr Hogan also argues that the $85/metric ton figure is a "global damage calculation."[86] Dr Hogan argues that the IMM's $50/metric ton value, based on the federal production tax credit is a more

[81] MISO used the adjusted production cost analysis to calculate the congestion and fuel savings benefits. MTEP24 Report, at 159.
[82] MISO, Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, at 32.
[83] MTEP24 Report, at 159-160.
[84] Hogan Affidavit at 39.
[85] MTEP24 Report, at 159.
[86] Hogan Affidavit, at 37.

appropriate value than the $85/ton value MISO used.[87] The $85/ton value MISO used was also based on a federal tax policy in effect at the time.[88] Parties can disagree about the appropriate carbon price to use because a range of values exist, but I found MISO's $85/metric ton estimate, based on Federal tax credits for carbon sequestration, to be reasonable given that it was based on Federal tax policy and involved a $/MWh credit associated with avoided carbon emissions.

Q. Based on your assessment of the evidence you reviewed, is the Future 2A generation portfolio MISO assumed reasonable to use for long range transmission planning?

A. Yes. Based on my view, MISO's assumptions to develop Future 2A were sound and vetted by stakeholders as part of its FERC approved regional transmission planning process. MISO also incorporated extensive feedback from stakeholders during the Tranche 2.1 planning cycle. For example, MISO made 500 changes to siting decisions of the Future 2A portfolio in response to stakeholder comments.[89]

VI. MISO'S TRANCHE 2.1 PROJECTS SUPPORT LARGE LOAD INTERCONNECTIONS, SUCH AS THOSE NECESSARY TO SUPPORT GENERATIVE AI AND OTHER ECONOMIC DEVELOPMENT IN THE REGION

Q. Does new transmission investment help promote new economic activity?

A. In general, yes, when as in the case of MISO Tranche 2.1, the RTOs make reasonable transmission planning decisions. MISO expects significant load growth in the coming years and decades, including in Local Resource Zone 1 (the Zone where Montana and North Dakota are located, the states of two of the Complainants). New transmission investment helps support that load growth. Much of this new load growth is being driven by generative AI data centers in the MISO.

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[87] *Id.*, at 38.

[88] Congressional Research Service, The Section 45Q Tax Credit for Carbon Sequestration, Updated August 25, 2023, Table 1, https://sgp.fas.org/crs/misc/IF11455.pdf.

[89] MISO, MISO LRTP, Futures Review, September 24, 2024, at 5.

Ceteris paribus, new transmission investment enhances the reliability of the grid, reducing the probability of outage by reducing congestion and increasing the ability of generation to reach load. Similarly, new transmission investment reduces generation costs, by reducing transmission congestion, allowing lower cost-generation to reach load in otherwise congested areas, and promoting competition between resources.

Both factors – lower generation costs and increased reliability – encourage increased economic activity, particularly from larger loads that can choose their location. In addition, the construction of large-scale infrastructure projects such as transmission may have indirect and induced economic benefits on local areas.

Q. How does new transmission investment benefit AI loads specifically?

A. Generative AI-related loads can be very large, tens or hundreds of MW, even above one GW and require sufficient transmission (and generation) to be constructed without compromising reliability. Without sufficient transmission, new large loads may be canceled or delayed. Large loads, and especially generative AI loads with lower latency requirements, have greater flexibility when it comes to location. A major factor in their location decision is the availability and reliability of power supply in the marketplace. Finaly, increased ability to deliver lower-marginal-cost generation to loads due to new transmission investment may lower prices for large AI loads, thus incentivizing their development.

Q. What does MISO say about the importance of Tranche 2.1 investments for data centers?

A. In its Fact Sheet on Tranche 2.1, MISO notes that "With growth of new data centers, U.S. manufacturing and electrification, 765 kV lines can also accommodate the increasing electricity demand expected. … Transmission also has the potential to attract new businesses and support connections to promising high-growth industries, such as data centers."[90]

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[90] MISO, Long Range Transmission Planning (LRTP) Tranche 2.1, at 1-2.

MISO also commented on data centers and artificial intelligence specifically in its MTEP24 Report (the relevant MISO transmission expansion plant report for Tranche 2.1), noting that: "Large spot power demand is growing rapidly because of **significant growth in data centers and other energy-intensive facilities to support today's economy and the future of technologies like artificial intelligence**, electrification and the resurgence of manufacturing in the United States. MISO has been calling these 'large load additions' in contrast to 'incremental load growth'. The uncertainty about where and how many large load additions will be developed complicates MISO's ability to project long-term growth in planning."[91] MISO added that "transmission has the potential to attract new businesses and support connections to burgeoning high-growth industries, such as data centers."[92]

Q. Do you agree with MISO's comments on data centers as they relate to new transmission?

A. I do. Significant new load from data centers for AI will require commensurately significant transmission investment. Said differently, new transmission investment will likely help attract new data center loads to MISO's territory.

As to MISO's comment regarding the uncertainty of new large loads, while I agree that uncertainty about new large loads complicates transmission planning, it is important to note that MISO has increased its load forecast substantially since it set the load forecast that underpinned Tranche 2.1 analysis. Increased expectations for new data center load were a large part of that increase in the load forecast (I discuss this point in Q&As below). Thus, if anything, Tranche 2.1 investment may be on the lower side in terms of increased transmission capacity, considering the connection between transmission and accommodation of new large data center and AI load.

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[91] MTEP24 Report, at 4, emphasis added.
[92] *Id*., at 167.

Q. What are the forecasts for data center load growth in MISO?

A. MISO recently forecast 19 GW to 30 GW of new data center load by 2040,[93] a significant amount considering that MISO's 2024 peak was 122 GW.[94]

Q. What parts of MISO expect to experience the most growth from data centers?

A. The northern states, per MISO's December 2024 load forecast, in particular LRZs 1, 3, and 6. Zone 1 includes, among other things, the states of North Dakota and Montana, the Commissions of which are two of the Complainants in this proceeding. MISO states "LRZ 1 is expected to see an additional 4 GW of demand throughout the forecast period, mainly from a burgeoning data center market in Minnesota and North Dakota." [95] Generally, Zone 1 is expected to have quite significant load growth on an energy basis ranging from 53 TWh to 100 TWh over the 2024-2044 timeframe, with datacenter load a significant part of that.[96]

Q. Please provide further assessment of AI and data center growth in North Dakota and Montana.

A. Certainly. Considering North Dakota, I note that Applied Digital plans to build a $3 billion data center near Fargo, North Dakota.[97] This Polaris Forge 2 data center is scheduled to enter service in 2026, ramp up to an initial load 280 MW in 2027, and could expand further. Polaris Forge 2 follows Polaris Forge 1, also in North Dakota.[98]

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[93] MISO, Long-Term Load Forecast, December 2024, at 16.
[94] *Id.*, at 3.
[95] *Id.*, p. 13.
[96] *Id.*, p. 12 (Figure 9).
[97] Beach, Jeff, Energy & Environment Company announces plan for $3 billion data center north of Fargo, North Dakota Monitor, August 18, 2025.
[98] Applied Digital Press Release, Applied Digital to Break Ground on $3 Billion Polaris Forge 2 Campus in September 2025, Expanding North Dakota's Role as a National AI Infrastructure Leader, August 18, 2025.

The trade press reported on a planned development of two data centers in North Dakota that claim to have scalability up to 5-10 GW and have a cost of $125B each were announced in August 2024.[99]

Many of the same reasons supporting potential data center development in North Dakota (expansive land, relatively low electricity prices, and colder weather) also apply to Montana. The press has also reported on the future of data centers in Montana.[100]

Q. What about other new large loads?

A. North Dakota has significant and increasing fracking-related load – 2024 set a record for number of sites producing oil and natural gas.[101] Transmission investment should support growth in large energy infrastructure loads as well.

Q. Was Tranche 2.1 developed with load growth in mind?

A. Yes. Tranche 2.1 was developed using Future 2A, which reflected annual demand growth of 0.82% on a net basis.[102]

Q. Have load growth forecasts increased since Tranche 2.1 was planned?

A. Yes. MISO's December 2024 Long-Term Load Forecast has net demand increasing between 1.1% and 2.0% per year until 2044 (compared with the 0.82% assumed for Tranche 2.1). The updated forecast mentions 1.6% annual growth (twice the amount of Future 2A used to develop Tranche 2.1) as the "Current Trajectory," which specifically accounts for "an increase in data centers." The "High Trajectory" of 2.0% per year accounts for "additional buildouts of data centers."[103]

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[99] See e.g., Butler, Georgia, Datacenter Dynamics, Two companies seek to develop $125bn AI data centers in North Dakota – report, September 4, 2024.

[100] For example, see Hansen, Jordan, Lawmakers consider state energy capacity with AI, data centers looming, Daily Montanan, July 28, 2025.

[101] Spotlight on North Dakota Energy, 2024 Annual Report, at 21-22, https://energynd.com/uploads/1/spotlight2025web.pdf

[102] MISO, Series 1A Futures Report, November 1, 2024, at 28.

[103] MISO, Long-Term Load Forecast, December 2024, at 3.

Q. Are there other benefits of the Tranche 2.1 projects that are worth considering?

A. Yes, in addition to the resource adequacy, reliability, and economic benefits MISO described in the MTEP24 report for the Tranche 2.1 benefits and that I discussed above, MISO recently explained that the Tranche 2.1 projects are an important part of MISO's strategy to meet the system's growing loads, "Collectively, the [Expedited Resource Addition Study] ERAS projects, MISO's Long Range Transmission Plan (LRTP) and our approach to expedited transmission projects are critical for meeting load growth, spurring economic development and ensuring reliability for the 45 million people in our footprint."[104] The press release went on to say, "MISO's comprehensive approach of advancing LRTP Tranches 1 and 2.1 as well as ERAS allows us to meet our customer needs faster."[105]

These statements indicate that other MISO efforts to increase reliability and improve resource adequacy, such as the ERAS reforms which FERC approved in 2025, will also benefit from the Tranche 2.1 projects. The benefits of enhancing the ERAS reform were not considered in the MTEP report.[106]

In addition, North Dakota's former Governor and current Secretary of the Interior, Doug Burgum, in an August 6, 2024 press release about the North Plains Connector project, said that North Dakota, "needs to add transmission capacity and build upon our existing baseload generation – not try to shut it down."[107] The same press release quoted Montana Governor Gov. Greg Gianforte support for the project, "Access to a steady supply of affordable and reliable energy is critical for communities across Montana and the United States."[108]

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[104] MISO Press Release, MISO announces first 10 ERAS projects - Projects span MISO's full territory, supporting reliability and economic growth, September 4, 2025.
[105] *Id.*
[106] See Table 1 above for a summary of the benefits MISO considered in the 2024 MTEP Report that evaluated the benefits of the Tranche 2.1 projects.
[107] North Dakota Office of Governor Doug Burgum, August 6, 2025.
[108] North Dakota Office of Governor Doug Burgum, August 6, 2025.

VII. GRANTING THE COMPLAINT WOULD UNDERMINE REGIONAL TRANSMISSION PLANNING AND INCREASE THE DIFFICULTY OF DEVELOPING TRANSMISSION IN OTHER TRANSMISSION PLANNING REGIONS

Q. What are some implications of FERC granting the Complainants' requests?

A. If FERC were to adopt the approach of transmission planning proposed by Dr. Hogan, it will have profound implications on how transmission is planned.

First, it would place additional and different burdens on MISO when it comes to long-term regional transmission planning. Specifically, it would require MISO to iteratively develop transmission and generation, potentially developing its own generation plan, which could differ from the plans put forth by its members, and which might not be consistent with member state policies and mandates. It would also create more uncertainty in the process.

Second, granting the complaint would mean that stakeholders that participated in the Tranche 2.1 stakeholder process have less of a voice in this planning process going forward, and would move MISO into the role of a central planner, which is explicitly not its mandate. As noted above, the MISO tariff requires MISO to incorporate member plans into its planning models and incorporate state policy goals into MISO's regional transmission planning process.

Third, it would place an unreasonable burden on MISO when it comes to transmission planning. Long-range regional transmission planning is a highly complex process, affected by the plans of member utilities, the policy goals of its members, likely load growth and generation development, and the economic objectives of investors. If the standard to which MISO would be held is one which is theoretically optimal, it may prompt a world in which no regional transmission gets built because of endless debate of whether or not each investment is optimal. Furthermore, MISO, like all RTOs, must necessarily apply some reasonable judgment from time to time when it comes to planning its system, and such judgment may include making reasonable estimates regarding the future growth of the system.

Q. What are other disadvantages of granting the relief sought in this complaint?

A. MISO's tariff specifies a *process*, and that MISO adhere to good utility practice, not a specific methodology or set of assumptions. MISO was transparent about its assumptions and engaged in extensive outreach and sought comment to develop Tranche 2.1 projects. Regional transmission planning, and MISO's MVPs in particular, confer different quantities and types of benefits across the MISO region, with some parties possibly benefiting more than others.

The objective of regional transmission planning is selecting projects that benefit the region (or a sub-region, like MISO Midwest) as a whole. Allowing a party or parties to interject, very late in the process, to a multi-year process with significant stakeholder and change the transmission projects selected projects would fundamentally undermine regional transmission planning processes in MISO and other RTOs/ISOs. Granting the relief sought in this complaint would thus make it more difficult to develop much needed regional transmission backbone infrastructure in the United States.

VIII. THE COMPLAINANTS ARE NOT MATERIALLY AFFECTED BY COSTS FROM THE TRANSMISSION PLANNING PROCESS TO WHICH THEY OBJECT

Q. What are the MISO tariff requirements for analyzing the costs of benefits of MVP projects?

A. The MISO Tariff requires that the "Total MVP Benefit-to-Cost Ratio," which is the ratio of financial benefits to Project Costs, exceed one.[109] The Tariff goes on to explain that, "For the purpose of this calculation, Financial Benefits will be set equal to the present value of all financially quantifiable benefits provided by the project projected for the first 20 years of the project's life and Project Costs will be set equal to the present value of the annual revenue requirements projected for the first 20 years of the project's life."[110]

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[109] MISO Tariff, Attachment FF Section II.C.7.
[110] *Id.*

Q. How will the Tranche 2.1 cost be allocated to MISO members?

A. The Tranche 2.1 project costs will be allocated to MISO's Midwest subregion, which includes Zones 1 through 7, based on energy consumption, on a load ratio share. MISO's 2024 MTEP Report estimates that the average charge of the costs will be $4.76/MWh over a 40-year period and provide benefits that range between $10-18/MWh of benefits.[111] MISO South, which includes Zones 8, 9, and 10, will not be allocated any Tranche 2.1 costs.

MISO provided stakeholders with an estimate of how the cost of the Tranche 2.1 projects would be allocated to each zone in the Midwestern subregion on a net present value basis. As shown in **Table 5**, the cost estimates ranged depending on the assumed discount rate.

Table 5: Zonal Cost Allocation of Tranche 2.1 Portfolio

				20 year Present Value (Millions of 2024$)	
Zone	**States in Zone**	**LSEs**	**Load Ratio Share**	**7.1% Discount Rate**	**3.0% Discount Rate**
Zone 1	Minnesota, North Dakota, Montana, and Wisconsin	DPC, GRE, MDU, MP, NSP, OTP, SMP	21.0%	$5,977	$8,060
Zone 2	Wisconsin and Michigan	ALTE, MGE, UPPC, WEC, WPS, MIUP	13.4%	$3,821	$5,153
Zone 3	Iowa and Minnesota	ALTW, MEC, MPW	11.1%	$3,159	$4,260
Zone 4	Illinois	AMIL, CWLP, SIPC, GLH	9.5%	$2,709	$3,654
Zone 5	Missouri	AMMO, CWLD	7.6%	$2,179	$2,938
Zone 6	Indiana	BREC, CIN, HE, IPL, NIPS, SIGE	17.8%	$5,073	$6,841
Zone 7	Michigan	CONS, DECO	19.7%	$5,608	$7,563
Total			**100.0%**	**$28,525**	**$38,470**

Source: MISO, LRTP_Tranche2.1_Detailed_Business_Case_Analysis_F2A_final portfolio_DRAFT.xlsx "0_PortfolioCost_CAZAllocation" tab.

Q. What portion of the costs of Tranche 2.1 would the customers of the state Commissions bear?

A. A small portion: approximately 3% for North Dakota customers and about 0.2% for customers in Montana. Arkansas, Louisiana, and Mississippi customers will not be

[111] MTEP24 Report, at 164.

allocated any of the costs of the Tranche 2.1 projects, as those states are not part of the Midwest subregion of MISO.[112]

Q. How did you determine that approximately 3% and 0.2% were the portions of the costs of Tranche 2.1 that would be borne by customers in North Dakota and Montana, respectively?

A. I started with MISO's estimate that 21.0% of the costs would be borne by the loads in Zone 1 (see **Table 5** above). Next, I determined that, collectively, North Dakota and Montana represent about 14% of Zone 1 on a load-ratio share in terms of energy consumption in MWh.[113] When multiplied by the 21.0% of the costs of Tranche 2.1 that Zone 1 would be allocated, the result is a collective share of Tranche 2.1 costs for North Dakota and Montana of about 3% (14% times 21%). As to the collective share (North Dakota plus Montana), I estimated that North Dakota would bear about 94% of the collective amount of Zone 1 load, with the remaining about 6% in Montana.[114] Based on this information, I found that North Dakota customers will be allocated

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[112] The tariff requires MISO to allocate the cost of MVP projects to a subregion if benefits are primarily provided to that subregion.

[113] First, I estimated the annual retail load specific to Zone 1, by state, for each state in Zone 1 (using 2023 data of total retail load by state from EIA (EIA's 2023 Electric Power Annual, Table 2.8 Sales of Electricity to Ultimate Customers by End-Use Sector) and using estimates of the percentages of total load, by state, that are in MISO Zone 1, as stated in a 2023 MISO load forecast report—that report aggregated North Dakota and Montana, which is why I also start with those states aggregated). Then, I determined the collective portion of total Zone 1 load contained within North Dakota and Montana by taking the ratio of the North Dakota plus Montana Zone 1 retail load estimate to the total Zone 1 retail load estimate. The result is 14%. Finally, I note that the 2023 MISO load forecast report I referenced above is "2023 MISO Independent Energy and Peak Demand Forecast", November 2023, Prepared for MISO by Perdue University State Utility Forecasting Group—see Table 60, Allocation Factors to Convert State Sales to LRZ Energy Sales.

[114] I estimated these percentages using data from EIA, Electric Sales, Revenue, and Average Price Report, Table 10 2023 Utility Bundled Retail Sales—Total. That table has energy sales (MWh) by each retail utility in each state. I considered the subset of those utilities that seemingly have load in MISO rather than in SPP or the Western Interconnection and compared the totals for each state, resulting in the estimate of a 94% - 6% split between North Dakota and Montana, considering MISO load.

approximately 3% of the Tranche 2.1 project and Montana customers will be allocated approximately 0.2% of the Tranche 2.1 project costs.[115]

Q. Based on your review, will customers in North Dakota and Montana benefit from the Tranche 2.1 projects?

A. Yes. MISO's MTEP24 report breaks down the estimated cost-benefit ratio of the Tranche 2.1 projects will be above one for all zones under both the Future 2A and Future 1A scenarios. MISO projects that Zone 1 will be among the zones that benefit most from the Tranche 2.1 projects.[116] For example, the Tranche 2.1 projects will have reliability and economic benefits for MISO's Western region, which includes Zone 1. MISO found that the Tranche 2.1 projects will provide increased generation outlets in North Dakota, South Dakota, and Minnesota, and that projects in Northern Minnesota will provide outlets to North Dakota generation, resolve constraints in the area, and will interconnect with the projects selected in MISO's recent Tranche 1 planning process.[117]

Q: Does this conclude your testimony?

A: Yes.

9/9/25

9/9/25

SUZANNE M. WALSH
Notary Public
Massachusetts
My Commission Expires
Dec 11, 2031

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[115] For North Dakota: 94% of 3% is still about 3%. For Montana: 6% of 3% is about 0.2%.

[116] MISO MTEP24 Report, Figures 2.157 and 2.158.

[117] MTEP24 Report, at 94.

Exhibit 1

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Christopher Russo is a Vice President in CRA's Energy Practice. He advises domestic and international clients in the electricity and gas industries in the areas of investment strategy and economic analysis, asset valuation, energy technology, and generation and transmission development. His expertise covers electricity and gas markets in North America, Europe, the Middle East, and worldwide.

Mr. Russo started the Energy practice from a team of six people, growing it to over sixty as the Practice Leader from 2012 through 2025 before returning to focus full-time on client work.

He has testified in litigation and regulatory matters on issues regarding the economics, planning, operation, and manipulation of energy markets and has testified numerous times at trial in numerous countries. Mr. Russo also served on the Board of Directors of Neuco, a Boston-based company which provides software to enable AI and neural network control of thermal power plants.

Prior to joining CRA, Mr. Russo was a senior consultant with Cambridge Energy Research Associates in Paris, and prior to that, owned his own energy consulting firm as well as working for ABB Corporate Research in the US and Switzerland. He started his career at MIT as the Plant Engineer for the campus cogeneration power plant, and later held an academic appointment as a Visiting Scientist at the MIT Energy Laboratory where he investigated electricity technology and energy policy.

Areas of Expertise

Mr. Russo is an energy economist and consultant with expertise in the following areas:

- The dynamics of electricity and gas markets in North America, Europe and worldwide, including market operations, regulatory economics, system planning, physical and economic grid characteristics, generation/dispatch system operations, power systems, and power plant operations. His experience covers nuclear, coal-fired, gas, hydroelectric and renewable (including solar, wind and hydro) generation resources and transmission projects.
- Expert witness testimony and reports related to energy disputes in multiple venues
- Strategic planning and advice for companies engaged in energy markets
- Financial valuations and assessments of generation and transmission assets
- Master planning for energy systems, including assessments of upstream supply sources, energy conversion, transmission, and demand sectors, and sustainability measurement and analysis.

Professional History

2007–Present *Vice President & Practice Leader*, Charles River Associates, Boston

(*Previously held positions as Associate Principal, Principal and Vice President)*

2006 *Senior Consultant*, Cambridge Energy Research Associates (CERA), Paris

1999–2006 *Principal*, Russo & Associates LLC, Boston

- Worked with numerous market participants and regulators in markets in the US and abroad on the operations and software for restructured energy markets.
- Provided economic analysis for market participants and regulators on generation and transmission assets.

1998–2002 *Consultant*, Department of Energy & Global Change, ABB Corporate Research Center, Baden-Dättwil, Switzerland

- Investigated CO_2 reduction strategies, climate change, new generation, and end-use technologies for decarbonization and helped to initiate the China Energy Technology Program. Acted as liaison between ABB and MIT. Worked closely with researchers from ETHZ and PSI. Held a Visiting Scientist appointment at the MIT Energy Laboratory.

1995–1998 *Plant Engineer*, MIT Cogeneration Project, Massachusetts Institute of Technology, Cambridge, MA

- Managed gas turbine and cogeneration plant operations, negotiated environmental permits, managed gas market purchases and contracts, and performed regular performance analyses for a cogeneration and district energy plant. Was a guest lecturer in the Department of Aeronautics teaching students about gas turbine technology.

Honors and Awards

- *Who's Who Legal*
    - *Thought Leader (Energy Experts)*
    - *Global Elite Thought Leader (Client Choice Energy)*
    - Thought Leader (USA Energy Experts)

Testimonial History, Litigation Consulting & Major Public Reports (Prior Ten Years)

- *Confidential AAA arbitration.* Testimony on behalf of a US utility in a contract dispute regarding the economics of powerplant retirements, coal-supply contracts and electricity market dynamics. Expert report submitted January 2025, direct and cross-examination testimony at hearing, March 2025.
- *Grain Belt Express Holding, LLC v. Invenergy Transmission LLC and Grain Belt Express LLC,, Index No. 651445/2023, Supreme Court of the State of New York.* Testimony on behalf of Grain Belt Express Holding on issues related to wind power, HVDC projects, and the SPP power market. Expert report submitted November 2024, deposition December 2024.
- *Beth Israel Deaconess Medical Center, Inc. v. MATEP LLC, et al, Suffolk Superior Court, 2384CV01373-BLS2.* Testimony as a 30(b)(6) representative on behalf of Charles River Associates. Deposition August 2024.
- *Power Distribution Services Ghana Ltd v. Electricity Company of Ghana (ECG) Ltd.*, *UNCITRAL international arbitration.* Expert report prepared on behalf of ECG in international arbitration on the quantum related to the cancellation of a transmission and distribution concession in Ghana. Prepared jointly with Ms. Laura Sochat, expert report submitted September 2022, answering reports submitted October 2023 and January 2024. Direct and cross-examination at hearing July 2024.
- *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program Large-Scale Renewable Program and a Clean Energy Standard, New York Public Service Commission Proceeding 15-E-0302.* Testimony on behalf of Champlain Hudson Power Express and Hydro Quebec on tariff adjustments for transmission construction based macroeconomic conditions. Expert report submitted August 2023.
- *Confidential JAMS Arbitration.* Testimony on behalf of a defendant in a damages case related to financial/virtual power purchase agreements and swaps for a wind power project. My testimony related to custom and practice for power trading in US electricity markets, dynamics of power pricing, and mechanics of the swap agreement. Expert report submitted May 2023, direct and cross examination at hearing, June 2023
- *NECEC Transmission LLC et al. v. Maine PUC and NextEra Energy Resources, State of Maine Civil Action BCD-CIV-2021-00058.* Testimony on behalf of NextEra on issues of HVDC and AC transmission line construction and economic decisions. Deposition March 2023
- *NRG South Texas LP v. Matagorda County, District Court of Matagorda County, Case No. 21-F-0473.* Testimony on behalf of NRG and the South Texas Project nuclear powerplant on topics of electricity market modeling, and the ERCOT market. Expert report submitted November 2022, deposition December 2022.

- *Sjunde AP-Fonden and the Cleveland Bakers and Teamsters Pension Fund v. General Electric Company and Jeffrey Bornstein, United States District Court for the Southern District of New York, Case No. 17 Civ. 08457 (JMF) (GWG).* Expert report prepared on behalf of General Electric in securities class action litigation on topics of global energy markets, the market for gas turbines, customer service agreements, and factoring of receivables. Expert report submitted May 2022, deposition June 2022. Case was ultimately settled.
- *Rainbow Energy Marketing Corporation v. DC Transco, LLC, United States District Court for the Western District of Texas, Austin Division, Civil Action 1:21-cv-313.* Expert report prepared on behalf of Rainbow Energy Marketing on the topics of energy management agreements, ISDA agreements, controllable transmission lines, and the ERCOT market. Expert report submitted April 2022, rebuttal report submitted May 2022.
- *Superior Court of Nassau County, Long Island Power Authority v. Nassau County, 403754/2016, 403760/2016, 403222/2017, 403227/2017, 402338/2018, 402348/2018, 403044/2019, 403046/2019, 401265/2020, 401267/2020 403757/2016, 403225/2017, 402347/2018, 403045/2019, 403739/2016, 403226/2017, 402354/2018, 403047/2019, 401264/2020*, Expert Report on behalf of the Long Island Power Authority in tax litigation projecting revenues and costs for the E.F. Barrett and Glenwood powerplants on Long Island. Expert Report filed October 2021.
- *Buckthorn Wind Project, LLC v. JPMorgan Chase Bank, N.A, United States District Court for the Northern District of Texas, Fort Worth Division, Civil Action No. 4:21-cv-562.* Expert report prepared on behalf of JP Morgan on the topic of wind power purchase agreements, ISDA hedges, and the ERCOT market. Expert report submitted August 2021, deposition October 2021.
- *Confidential AAA Arbitration.* Lead expert on electricity markets in a case involving costs associated with coal plant shutdowns and coal fuel supply contracts. Expert report submitted January 2021. Case settled during hearing.
- *Confidential JAMS Arbitration.* Lead expert on damages and electricity markets in a case involving wake effects on wind turbines and PPA and merchant market revenues in California. Expert report submitted December 2020. Direct and cross examination at trial, February 2021.
- *Confidential AAA Arbitration.* Lead economic expert in a dispute related to miscalculation of payments under a power purchase agreement (PPA) between a US powerplant and an offtaker. Expert report submitted August 2019. Direct and cross-examination at trial November 2019.
- *Market Design Issues in the Alberta Capacity and Energy Markets*, Proceeding 23757, Application 23757-A001*, Alberta Utilities Commission*. Expert testimony filed on behalf of the Alberta Market Surveillance Administrator (MSA), February 2019, filed jointly with Dr. David Patton and Mr. Jordan Kwok. Cross-examination at hearing May 2019.

- *In the matter of Trina Solar Limited, Cause No. FSD 92 of 2017 (NSJ), Grand Court of the Cayman Islands.* Expert testimony related to the solar energy industry, solar manufacturing, and project development, submitted on behalf of Maso Capital Investments Limited and Blackwell Partners LLC in dissenting-shareholder litigation related to valuation of Trina Solar. Expert report submitted October 2018, rebuttal report January 2019. Cross-examination at trial May 2019.
- *Offer Behaviour Guidelines Prior to the Implementation of a Capacity Market.* Report prepared on behalf of the Alberta Market Surveillance Administrator (MSA), December 2018. Filed jointly with Dr. Adonis Yatchew, Dr. David Hunger, and Mr. Jordan Kwok. Presentation and oral appearance at Stakeholder Meeting January 2019.
- *Petition of Eversource & National Grid et al., for approval of long-term contracts for renewable energy, pursuant to Section 83D of An Act Relative to Green Communities, dockets DPU 18-64, 18-65 and 18-66, Massachusetts DPU*. Testimony related to the proposed Quebec- Maine New England Clean Energy Connect transmission line and power purchase agreement on behalf of NextEra Energy. Testimony filed jointly with Robert Stoddard and Stephen Whitley, December 2018. Cross-examination at hearing February 2019.
- *Affidavit on behalf of Vistra Energy Corp. & Dynegy Marketing & Trade, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000, Federal Energy Regulatory Commission*. Testimony related to proposed PJM capacity market reforms. Affidavit filed October 2018, answering affidavit filed November 2018
- *Hydro One Networks Inc. Lake Superior Link Project Leave to Construct Application, Ontario Energy Board,* Docket EB-2017-0364 and EB-2017-0182, Expert testimony submitted on behalf of NextBridge Infrastructure. Expert report filed April 2018. Testimony at hearing May 2018 and February 2021.
- *Request for Approval of CPCN for the New England Clean Energy Connect Consisting of a 1,200 MW HVDC Transmission Line from Québec-Maine Border to Lewiston (NECEC) and Related Network Upgrades, State of Maine Public Utilities Commission,* Docket 2017-00232. Direct testimony on behalf of NextEra Energy Resources filed April 2018. Testimony and cross-examination at technical conference and hearings, June 2018, August 2018, and January 2018.
- *Massachusetts Superior Court,* Expert report submitted on behalf of a plant owner calculating damages from operational limitations on a district energy plant in the ISO-New England Market. Expert report submitted March 2018.
- *State of New Hampshire, e*xpert report submitted on behalf of a plant owner and operator in a tax certiorari proceeding in February 2018. Case was settled before hearing.
- *In re: Request for Advanced Ratemaking Principles by Interstate Power & Light Company*, *Docket RPU-2017-0002, Iowa Utilities Board*. Direct Testimony on behalf NextEra Energy Resources commenting on IPL's resource plan and the Duane Arnold Energy Center nuclear power plant. Direct, rebuttal and sur-rebuttal written testimony, and cross-examination at hearing, November 2017.

- *ABB AB v. Alstom Grid AB, Alstom Grid SAS and Alstom Grid UK Ltd., Stockholms Tingsrätt (Stockholm District Court), Cases 7403-15 and 11527-15*. Expert testimony submitted on behalf of Alstom related to economic damages resulting from the alleged IP infringement of HVDC technology. Expert report filed August 2017. Direct and cross-examination (in English with translation) at trial, October 2017.
- *State of California v. Coral Power LLC et al., Docket EL02-71-057, Federal Energy Regulatory Commission*. Testimony on behalf of Shell Energy North America (f/k/a Coral Power) related to the causes of the 2000-2001 California Power Crisis and alleged energy market manipulation. Written testimony filed February 2017, deposition March 2017, direct and cross-examination at trial April 2017.
- *Confidential AAA Arbitration,* Lead economic expert in a dispute related to the economics of environmental regulations, coal-fired power plants, and coal supply contracts in the US. Expert report filed September 2016, deposition November 2016, direct and cross-examination at trial December 2016.
- *In re: Direct Application of MidAmerican Energy Company For The Determination Of Ratemaking Principles, Docket RPU-2016-001, Iowa Utilities Board*. Direct Testimony on behalf of Google Inc., Facebook Inc., and Microsoft Corporation related to the economics of MidAmerican's Wind XI proposal, filed June 2016. Case was settled before hearing.
- *MAG Energy Solutions Inc. v. TEC Energy Inc. et al., Province de Québec, Cour Supérieure, Case No. 500-17-087823-152*. Expert report submitted on behalf of TEC Energy on issues related to energy trading and transmission scheduling in Canada and the United States, filed May 2016. Joint report with opposing expert filed June 2019
- *Northern States Power Company, Southern Minnesota Municipal Power Agency, Aegis Insurance Services et al., v. General Electric Company, State of Minnesota, Tenth Judicial District, Case 71-CV-13-1472*, Expert report submitted on behalf of GE calculating damages related to the outage of the Sherburne county coal-fired power plant, filed March 2016. Deposition June 2016.
- *Entergy Nuclear FitzPatrick, LLC v. Town of Scriba, et al.*, *Supreme Court of the State of New York,* Expert report of behalf of Entergy in a tax certiorari case projecting electricity revenue and nuclear fuel cycle costs for the James A. FitzPatrick Nuclear power plant, expert report filed January 2016. Case was settled before trial.
- *NRG v. State of Maryland, Case 09-RP-CH-261-265; 09-RP-CH-280-284; and 09-RP-CH-294-298.* Expert report on behalf of NRG projecting energy and capacity revenues for the coal-fired Mirant Mid-Atlantic Dickerson facility, 2014. Deposition March 2014, direct and cross-examination at trial, May 2014
- *In the Matter of Entergy Nuclear Indian Point 2, LLC & Entergy Nuclear Indian Point 3, LLC, DEC: 3-5522-00011/00004, SPDES: NY-0004472, DEC: 3-5522-00011/00030, DEC: 3-5522-00011/00031,* Direct and rebuttal pre-filed testimony on behalf of the City of New York related to the operations and economic impact of the Indian Point nuclear power plant, filed March 2014. Direct and cross-examination at hearing April 2014

- *NRG v. State of Maryland, Case 09-RP-CH-261-265; 09-RP-CH-280-284; and 09-RP-CH-294-298*. Expert report on behalf of NRG, jointly filed with Robert B. Stoddard, projecting energy and capacity revenues for the coal-fired Mirant Mid-Atlantic Morgantown facility, January 2014
- *ThyssenKrupp Companhia Siderúrgica do Atlântico v. CITIC Group, ICC Arbitration*, expert report for international arbitration submitted on behalf of CITIC group related to damages from improper operation of a coal-fired power plant in Brazil, filed July 2012. Case was settled before hearing.
- *Indian Point Energy Center Retirement Analysis*, Prepared for the City of New York, August 2011
- *Summary of economic effects for proposed Spectra NJ-NY gas pipeline*, Memo prepared for Spectra Energy, and submitted to the New Jersey Bureau of Public Utilities, March 2011
- *Confidential Arbitration,* Expert report provided on behalf of a power plant investor regarding the appraised value of a coal-fired power plant in the PJM market, August 2011. Case was settled before hearing.
- *Proceedings before the New York State Assembly on the economic and reliability impact of the potential closure of the Indian Point Nuclear Energy Center.* Direct testimony at hearing January 2012
- *Confidential Arbitration*, Expert report related to the valuation of a hydroelectric plant in California, which was settled before hearing, June 2013.
- *Coordination between Natural Gas and Electricity Markets, Docket AD12-12-000, Federal Energy Regulatory Commission*, Comments filed jointly with Dr. Richard Tabors and Scott Englander, 2012
- *In the Matter of Hudson Transmission Partners, LLC Case 08-T-0034*, direct and rebuttal pre-filed testimony on behalf of the City of New York before the New York State Public Service Commission in the Article VII proceeding for the proposed Hudson Transmission Partners HVDC cable. Direct and cross-examination at hearing April 2010
- *A Master Electrical Transmission Plan for New York City*, Prepared for the City of New York, May 2009
- *Public Utility Commission of Texas proceedings Cost-Benefit Analysis of the Texas Nodal Market.* Expert report on behalf of the Public Utilities Commission of Texas filed jointly with Alex Rudkevich and Ellen Wolfe December 2008. Direct testimony at hearing January 2009
- Mr. Russo was retained as an expert in civil litigation related the 2021 Texas Winter Storm on issues of market rules and dynamics. He was not disclosed before the case ended for legal reasons.
- Mr. Russo prepared an expert report calculating damages from the delayed construction of a gas-fired combined cycle power plant in the United States for a civil litigation matter. The case settled before his report was submitted and he was disclosed and thus remains confidential.

- Mr. Russo prepared testimony and analysis on behalf of a client accused of electricity market manipulation before the FERC. The case relates to alleged cross-product manipulation involving renewable and thermal assets and financial instruments. The case was settled before his testimony was submitted.
- Mr. Russo acted as an expert in a case concerning coal mines and fuel contracts with coal-fired power plants. The case was settled before his report was submitted and he was disclosed and thus remains confidential.
- Mr. Russo assisted in the damages analysis for a case litigated in federal court related to damages associated with renewable power plant revenue as a result of market rule changes in the MISO market.
- Mr. Russo assisted in analyzing how transmission upgrade costs were allocated in Quebec for new development in support of testimony before the Régie d l'Ēnergie.
- Mr. Russo performed analysis on behalf of a party in FERC litigation resulting from the California energy crisis, including simulation of the CAISO market clearing process and trading strategies employed by different parties.
- Mr. Russo is currently engaged as an as-yet-undisclosed expert witness in US Federal litigation related to cross-product manipulation of electricity markets.

Selected Commercial Consulting Experience

- Mr. Russo has directed the analysis of over one hundred generation, transmission, and district energy assets for utilities, equity and debt investors, infrastructure funds, regulators and market operators. He has analyzed assets in all major power markets, including ISO-NE, PJM, ERCOT, SPP, SERC, NYISO, CAISO, IESO, AESO, MISO and the Pacific Northwest. These include thermal (gas, coal, nuclear, oil), renewable (solar, wind, biomass), hydro, and storage (pumped, CAES, and battery) assets.
- Mr. Russo directed the analysis of the value of a proposed entity which utilized HALEU fuel to fabricate and supply fuel for the advanced nuclear reactor market
    - Mr. Russo led a team supporting hyperscalers entering organized North American power markets
    - Led the regulatory analysis of proposed market rule changes for the ERCOT electricity market in Texas for a client.
    - Mr. Russo led an engagement for an investor developing a market entry strategy for investments in the US hydrogen market.
    - Mr. Russo led a team investigating the difference in financing approaches that exist between different-sized nuclear reactors and construction approaches.
- Mr. Russo led the team to help an advanced Gen IV nuclear reactor technology company develop a commercial strategy for market entry and commercialization.

- Mr. Russo directed the team assisting a client in its efforts to bid battery storage into utility-sponsored RFPs in the Northeast US.
- Mr. Russo directed the diligence efforts for the purchase of two large district energy facilities in the Northeast US.
- Mr. Russo led the analysis for a major foreign investor entering the North American gas pipeline, processing and midstream market, consisting of strategic guidance and the analysis and due diligence of numerous North American and Mexican midstream assets.
- Mr. Russo supervised the analysis for the Alberta Electric System Operator on the development of new capacity market mechanisms in the provincial electricity market.
- Mr. Russo directed and led due diligence efforts related to nuclear technology and power markets for a major private equity investor acquiring a nuclear fuel and services vendor in bankruptcy.
- Mr. Russo led the financial and transactional analysis for a group of investors on a combined heat and power gas-fired cogeneration plant.
- For a major renewable energy and transmission developer, Mr. Russo led the analysis of market impacts of proposed projects and assisted in developing commercial and regulatory strategy in New England and New York.
- Mr. Russo led the analysis for a major transmission project in PJM, including analysis of costs and benefits, production cost modeling, regulatory implications of FERC Order 1000 and other rules, and strategic advice on project development.
- For a transmission developer, Mr. Russo designed and directed the economic and technical analysis of a 2,000 MW HVDC project in the northeast US with detailed analysis of ISO-NE and NYISO markets.
- Mr. Russo directed the economic and technical analysis for a major offshore wind developer connecting into the NYISO and PJM markets for several proposed projects.
- For a worldwide operator of data centers, Mr. Russo directed a risk exposure analysis of multiple markets, commodities and assets to assess the company’s exposure to global trends.
- For a private equity investor, Mr. Russo led the diligence on a potential acquisition of the services business of a gas turbine manufacturer. The work involved the analysis of the market for services, the market for service agreements, and an analysis of competitors.
- Mr. Russo directed the analysis of new regulatory approaches and energy technologies for a large African electric utility.
- Mr. Russo assessed the economic and technical suitability of large-scale photovoltaic technologies for a large Middle Eastern utility.
- Mr. Russo directed the analysis of renewable energy (solar and wind) procurement options for one of the largest renewable energy purchasers in the world. This evaluated technical, financial, and economic factors affecting the renewable technologies.

- Mr. Russo directed the analysis of capacity need and market conditions related to the siting of new capacity on Long Island for a client.
- Mr. Russo led a major review of new nuclear development strategy, including technical reviews, risk analyses, economic forecasts and prudence reviews for a US-based electric utility.
- Working for the mayor and city council of a major US city, Mr. Russo managed a due diligence effort to determine the feasibility of supporting new nuclear licensing applications for a municipally owned utility. This included a review of nuclear technology, market conditions, Nuclear Regulatory Commission (NRC) resource constraints, and federal regulatory policy related to nuclear loan guarantee programs.
- Mr. Russo led the analysis for a large industrial client of how electricity market rules related to reliability affected prices in installed capacity markets, including analyses of resource-adequacy and short-term grid contingency events.
- For a major municipal utility, Mr. Russo provided an independent review of the utility's investment analysis to retrofit emissions control equipment to a coal-fired power plant to comply with pending environmental regulations.
- For a transmission developer, Mr. Russo advised on the open-season transmission requirements and FERC process for a new merchant transmission line.
- Mr. Russo directed the analysis of the socioeconomic benefits of advanced coal technology in European, Chinese and South Asian markets, focusing on market effects, induced and indirect benefits and social impacts.
- Mr. Russo led the effort to develop an electrical market model for Europe for a Paris-based client. Working with the production-cost modeling software and his team, he assembled databases of resources, demand, fuel prices, and transmission network characteristics to build a comprehensive model of the EU grid.
- Mr. Russo designed and conducted a series of workshops to assist a major foreign investor with a market-entry strategy for offshore wind into the Northeast US.
- Mr. Russo directed and led a project to synthesize and summarize the nuclear technology risk and seismic hazard data for a two-unit nuclear reactor in North America.
- Mr. Russo directed an engagement for a client to assist in the purchase and contracting of large amounts of electricity to support aluminum smelting operations. This consisted of financial analysis of North American power markets including the MISO and PJM and financial evaluation of proposed contract structures.
- Mr. Russo managed a major effort for the City of New York to develop a Master Electrical Transmission Plan to address economic and reliability needs in the context of a multi-stakeholder process, incorporating the Mayor's Office, Economic Development Corporation, NYISO, ConEd, and the NYS Public Service Commission. The program addressed the economic and technical factors associated with AC and HVDC transmission, as well as the policy and financial impacts of public-private partnerships and equity investment strategies.

- For a major power development company, Mr. Russo led several projects to determine the optimal strategy for entering the gas-fired development market under pending environmental constraints and regulations. In a related project, he led efforts to investigate the feasibility of new and waste coal development in the PJM energy market.
- For the City of New York, Mr. Russo led a major effort to investigate the reliability and economic and environmental impact of the closure of the Indian Point Nuclear Energy Center on consumers and the economy. This comprised a report as well as testimony before various commissions.
- For a private equity firm, Mr. Russo directed the due diligence assessment of an energy storage technology manufacturer, focusing on the analysis of market opportunities for energy storage.
- For a major global semiconductor manufacturer, Mr. Russo led an effort to develop a global energy procurement strategy, analyze potential power contracts, and benchmark procurement activities against other similar firms
- Mr. Russo directed the review of the internal technical and financial modeling processes for an investor in the liberalized UK energy market.
- For a gas pipeline developer, Mr. Russo directed the analysis of a new pipeline project's impact on gas basis differentials.
- For a major European utility, Mr. Russo designed and managed a process to develop internally consistent analysis scenarios to enhance corporate planning. The effort involved soliciting input from different groups throughout the enterprise, designing scenarios, analyzing the results, and presenting the results to internal and external stakeholders.
- For a major Internet search provider, Mr. Russo directed the evaluation of potential sites for data centers in Europe and the US.
- For a major Asian utility, Mr. Russo managed an engagement to develop a growth strategy for a subsidiary of the parent firm, including a review of current operations, market positioning, potential risks, and strategic alliances, culminating in a concrete division growth plan.
- Working for the Executive Office of Sheikh Mohammed of Dubai, Mr. Russo was a principal in a major study examining the effectiveness of Dubai's current electric utility, petrochemical resources, and water resources. Working closely with local personnel, he spent significant time interviewing Dubai Electricity and Water Authority (DEWA) and Dubai Supply Authority (DUSUP) personnel, Emirati leaders, and stakeholders; evaluating petrochemical and water resources; and developing a comprehensive multi-attribute, multi-scenario energy system model of the emirate for evaluation of future energy strategies.
- Mr. Russo was a principal in a project to restructure a major utility in the United Arab Emirates, including long-term planning functions, regulatory efforts, customer service systems, IT architecture, and financial systems.

- Mr. Russo led a project for a major Hong Kong-based utility to help them adapt their management processes, planning infrastructure, and IT systems to pending emissions and energy trading regulations through performing needs assessments, sourcing strategies, and drafting RFPs.
- While with ABB, Mr. Russo helped design and organize the China Energy Technology Program, a joint ABB/AGS program to investigate sustainable energy systems in China, which included Electric Generation Expansion Analysis (EGEAS) modeling of the eastern China power network to identify long-term, cost-effective strategies for environmental improvement. The project was conducted in conjunction with the Swiss Federal Institute of Technology (ETHZ) and the Paul Scherrer Insitut (PSI).
- Working with the MIT Cogeneration Plant, Mr. Russo provided continuing guidance and expertise on cogeneration plant and gas turbine operations, as well as conducting several economic cost-benefit analyses to plan future plant expansion.
- For a major software firm and federal clients, Mr. Russo helped prepare and develop a wide-area synchronized phasor measurement system to measure phase angle and frequency perturbations across the Eastern Interconnection to enhance grid stability.
- For PJM, Mr. Russo developed software and systems to visualize market participant bidding behavior to assist market monitors and dispatchers.
- For New York ISO, Mr. Russo designed and implemented a PI data historian system for tracking all operational data. He also trained system operators on its use, played an integral part in the standard market design to implementation and EMS development and developed various software applications to analyze system operations.
- For the California ISO, Mr. Russo worked as a consultant during the startup, developing systems to track generator dispatch operations and identify anomalous generator behavior to assist market surveillance personnel. During the power crises and rolling blackouts, he managed and maintained a critical system in use by all ISO personnel and developed a system to analyze results of Stage 2 and 3 events.
- Mr. Russo began his career in power as an intern for the Trigen Energy Corporation analyzing the operations and economics of Trigen's fleet of cogeneration plants.

Additional Professional Training

- New York ISO Market Operations Course
- New York ISO DSS Market Participants Course
- California ISO Market Participants Course

Publications & Media Appearances

"*An Incomplete Compendium of Energy Disputes", July 2025*

"*Climate policies and investment: implications for disputes*", co-authored with Rebecca Rowden and Laura Sochat. Arbitration Review of the Americas 2023.

"*Economic Evidence of Market Manipulation,*" chapter in the *Guide to Energy Market Manipulation* with Robin Cohen, David Hunger and Brian Rivard. Published by Global Competition Review, March 2018

"*Data Collection*," chapter in *Integrated Assessment of Sustainable Energy Systems in China: The China Energy Technology Program*. Baldur Eliasson. Kluwer Academic Publishers, 2003.

Quoted in *"Ideas to Bolster Power Grid Run Up Against the System's Many Owners"*, New York Times, July 12, 2013.

Citizenship and Languages

Mr. Russo is a dual citizen of the United States and Italy.

- English (native)
- Italian (proficient)
- German and French (basic)