BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Establishment of a Working	)
Case Regarding Membership of Missouri's	)
Investor-Owned Electric Utilities in Regional	) File No. EW-2021-0104
Transmission Organizations.	)

AMEREN MISSOURI'S RESPONSE TO ORDER DIRECTING COMMENTS

COMES NOW Union Electric Company d/b/a Ameren Missouri (the "Company" or "Ameren Missouri"), and for its response to the Commission's December 21, 2020 *Order Directing Comments* ("Order"), states as follows:

1. The Commission opened this working docket to "gather information about the benefits and costs of continued . . ." Regional Transmission Organization ("RTO") membership. To that end, the Order directed electric utilities to respond to a series of questions that its Staff posed in Staff's Motion for Commission Order, attaching Staff's questions to the Order as Appendix A.

2. Attached hereto as Exhibit A are Ameren Missouri's responses to those questions. Ameren Missouri appreciates this opportunity to provide the Commission with this information regarding its continued RTO membership.

WHEREFORE, as required by the Order, Ameren Missouri hereby submits its responses.

Respectfully submitted,

UNION ELECTRIC COMPANY
D/B/A AMEREN MISSOURI

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<u>CERTIFICATE OF SERVICE</u>

The undersigned hereby certifies that a true and correct copy of the foregoing document was served on all parties of record via electronic mail (e-mail) on this 16th day of February, 2021.

/s/James B. Lowery
James B. Lowery

EXHIBIT A

AMEREN MISSOURI'S RESPONSES TO THE QUESTIONS POSED IN APPENDIX A OF THE COMMISSION'S ORDER DIRECTING COMMENTS[1]

QUESTIONS FOR UTILITIES

RTO Benefits

(1) For your utility, please identify and describe all direct and indirect benefits that your utility receives from RTO participation.

The main benefits of MISO[2] participation are:

- Liquid, transparent capacity market;
- Market efficiencies arising from a co-optimized energy and ancillary services market;
- Decreased operating reserve requirements;
- Decreased planning reserve requirements;
- Reduced manpower requirements as MISO performs balancing authority and reliability coordinator functions;
- Reduced internal systems and operating costs;
- Avoidance of pancaked transmission rates; and
- Ability to utilize non-Missouri sited generation resource to satisfy resource adequacy requirements without incurring additional transmission expense.

(2) For each benefit, please identify the time period over which the utility expects to accrue those benefits. Additionally, please give the utility's best approximation of when each benefit will be experienced. If that benefit is expected to increase or decrease annually over time, please explain what changes would cause the benefit to change.

Benefits are expected to exist for the life of Ameren Missouri's participation in MISO. It is not known if such benefits will increase or decrease over time.

(3) For each benefit, please identify whether or not this benefit can be quantified.

a. Can the quantifiable benefits be measured or valued over a certain timeframe?
b. Please identify any discount rates used for measuring future benefits or likelihoods if scenario planning is involved.

The economic consequences of participation in MISO can be modeled, using a variety of assumptions over different time periods.

Because future prices, generation mix, transmission configuration, market design – including new products and services – cannot be known with certainty, and since

[1] The questions are reproduced in *italics*, with the response to each question following.
[2] Midcontinent Independent System Operator, Inc.

ascertaining the value of participation based upon assumed variables for the items just mentioned can only be done by comparing the economic benefit of participation to an alternative, hypothetical scenario (e.g., operating as an Independent Coordinator of Transmission ("ICT"), the economic consequences of MISO participation can only be estimated.

(4) For each quantifiable benefit, has the utility quantified those benefits since the utility began participation in the RTO? Why or why not? Additionally, please explain how the utility has quantified those benefits, provide any/all workpapers that calculated these benefits, and provide the cost of gathering, analyzing, and interpreting such information.

a. Have any measurable benefits factored into the utility's business plan or performance metrics?

Ameren Missouri commissioned a study filed in File No. EO-2008-0134, to examine the benefit of continued participation in MISO. In summary, the study concluded that over the ensuing 3-years, MISO participation would generate between $153 and $203 million of incremental benefits as compared to the alternatives (and over 10-years, MISO participation would generate between $346 and $563 million of incremental benefits as compared to the alternatives). All workpapers, reports, etc. were provided to Staff in that docket.

In File No. EO-2011-0128, Ameren Missouri, using the 2008 study as a base, performed a less detailed analysis projecting benefits of MISO participation through 2014. That analysis concluded that the three-year benefit case (2012-2014 as compared to 2008-2011) had improved by $105 million. All workpapers, reports, etc. were provided to Staff in that docket.

In both 2014 and 2017, Ameren Missouri, the Staff and other parties agreed that MISO participation should continue without commissioning the kind of hypothetical study first done in 2008 (which Ameren Missouri estimates would today cost approximately $1 million for outside consulting services and would require more than 100 hours of internal information gathering, oversight, and analysis of the study results). In both 2014 and 2017, Ameren Missouri provided the stakeholders, including Staff, significant information regarding MISO participation benefits. The information provided was similar in both years, with the latest information appearing in the *Joint Motion to Make Additional Modifications to April 19, 2012 Report and Order* submitted by the Company, Staff and others in File No. EO-2011-0128 on January 23, 2017.

Attached hereto as Exhibit 1 are additional materials showing benefits of MISO participation, including MISO's most recent Value Proposition, where MISO estimates that it brings approximately $3.6 billion in annual net benefits to its members. See Attachment 1 hereto. Based upon Ameren Missouri's load ratio share in MISO, a rough estimation of Ameren Missouri's share of those benefits would be approximately $250 million annually.

As outlined in response to RTO Benefit question (1), the benefits of MISO participation manifest themselves in cost savings and incremental revenues that are accounted for as

Ameren Missouri plans its business, operations, investment needs, and measures performance (e.g., generation, income, rates, etc.).

(5) Please identify how the utility would ideally quantify future benefits of RTO participation. Please provide the cost of gathering, analyzing, and interpreting such information under the ideal scenario. If such information is not reasonably and economically available, what kind of information would the utility propose as a proxy? Please provide the cost of gathering, analyzing, and interpreting such proxy information.

i. What will drive these future benefits?

- The theoretical "ideal" way to quantify the benefit of continued participation would be to conduct a very detailed, in-depth study involving multiple scenarios and heavily researched assumptions.
- As noted above, Ameren Missouri believes the cost of a study to compare participation in MISO vs SPP or an ICT to be approximately $1 million in outside consultant costs plus the significant internal labor stated above. The 2007 study referenced above cost $480,695.78 in outside consulting costs. If the scope of the study were expanded to consider more possible alternatives, the cost would be expected to increase significantly.

ii. Are there any existing benefits that will be eliminated based on upcoming or expected changes at the RTO?

Ameren Missouri expects that any upcoming or expected changes at MISO or RTOs generally will be overwhelmingly driven by overall changes in the marketplace and/or Federal rules and regulations promulgated by FERC[3] and/or the EPA.[4] As such, it would reasonably be expected that any negative consequences of these actions would also be experienced if Ameren Missouri were not to be in MISO. If the Company were not to be in MISO, the full cost of compliance, including any needed changes in systems and staffing would fall on Ameren Missouri.

(6) For each benefit of RTO participation that is not quantifiable, please explain why it is not quantifiable.

As noted above, the economic consequences of membership can be estimated through detailed scenario modeling, however, the vast number of uncertainties, prevent determining these values with a high degree of certainty.

(7) For each non-quantifiable benefit, has your utility placed a monetary value on the benefit? If so, please explain how the monetary value was derived, and provide the cost of gathering, analyzing, and interpreting such information.

Beyond those values noted in RTO Benefit question (3) above, no.

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[3] Federal Energy Regulatory Commission.

[4] United States Environmental Protection Agency.

(*8) Does your utility receive an adder from FERC for any of its RTO participation? What is the monetary value of those adders?*

Ameren Missouri's FERC regulated transmission service revenue requirement reflects a FERC authorized RTO adder of 50 basis points, which increases that revenue requirement by 1.9% as compared to what the revenue requirement would be without the adder (without the adder, the Attachment O revenue requirement would be lower by approximately $2.6 million).

However, Ameren Missouri does not collect its full FERC transmission revenue requirement since it does not charge itself for network transmission service. Therefore, the amount of realized value for the RTO adder is only that amount associated with revenues received from non-Ameren Missouri entities (point to point and other network customers (e.g., municipalities and cooperatives)). Based on 2020 transmission service revenues for schedules 7, 8 and 9, the realized value of these RTO adders is approximately $300,000.

As with all transmission revenues, those amounts are included in the determination of Ameren Missouri's retail revenue requirement and as such, credited back to its retail customers.

(9) How many FTE are there in your utility whose positions solely or mostly involve working with or monitoring or reporting data to the RTO? What is the cost of those positions or the parts that deal only with the RTO? What is the overall ancillary support? Do you expect the number of employees and the budget in this area to increase over time? Why?

a. Please estimate how the employment needs would change absent RTO membership budget to maintain these positions?

Ameren Missouri has interpreted Staff's questions to pertain to those Ameren Missouri and Ameren Services employees who dedicate at least 50% of their time performing those functions listed by Staff, on behalf of Ameren Missouri. The Company has further interpreted the portion of the request referencing monitoring MISO data to exclude those Ameren Services employees whose function it is to monitor the AMMO LBA itself (Ameren Missouri's own transmission system and the equivalent of the legacy control area.)

Those Ameren Services employees who perform functions which work with, monitor or report data to MISO, do so on behalf of not only Ameren Missouri, but also Ameren Illinois and Ameren Transmission Company of Illinois. Subject to the interpretations noted above, the Company has not identified any Ameren Services employees who dedicate more than 50% of their time to these functions solely on behalf of Ameren Missouri.

The Company has identified one Ameren Missouri employee who dedicates more than 50% of their time to functions which work with, monitor or report data to MISO, representing a fully loaded labor cost of approximately $150,000. That amount would be expected to increase over time, commensurate with annual wage increases.

The Company believes that it is important to note that, in the context of evaluating the costs and benefits of MISO membership, it is the change in costs for these functions which would occur if the Company were to no longer participate in MISO which is most meaningful. The Company has not identified any positions which would be eliminated if Ameren Missouri were to leave the MISO.

It must be recognized that the Company would still own significant generation assets which would remain in MISO – namely those connected to the Ameren Illinois transmission system – and that the MISO market would remain a valuable tool for both purchases and sales of energy. Those facts would require on-going interaction with the MISO for settlements and trading. The Company would also continue to perform the functions required to operate and monitor its own Control area.

Ameren Missouri has previously estimated that at least an additional 14 FTE's would be required if it were to not participate in MISO. As the complexity of the market increases, (DER aggregation, increased penetration of intermittent resources, etc.), it would be reasonable to expect this value to increase. While this increase in headcount is most likely to occur at Ameren Services, the associated cost would be expected to be allocated to Ameren Missouri.

RTO Costs

(1) For your utility, please identify and describe all costs that your utility incurs from RTO participation.

Ameren Missouri has interpreted this request to refer to costs that the Company incurs solely due its participation in MISO. As such, market and transmission costs (including those associated with regional expansion) that would be incurred regardless of participation are not included.

The costs directly attributable to MISO are administration costs, including:

- Market Administration Amounts, including FTR market administration.
- MISO Schedule 24 Allocations
- ISO Cost Recovery Adder
- FERC - Annual Charges Recovery

(2) For each cost, please identify the time period over which the utility expects to incur those costs. Additionally, please give the utility's best approximation of when each cost will be experienced. If that cost is expected to increase or decrease annually over time, please explain what changes would cause the cost to change.

Costs are expected to exist for the life of Ameren Missouri's participation in MISO. It is not known if such costs will increase or decrease over time. However, it should be noted that over the past three years, they have decreased by approximately $1 million annually, or by about 5%.

(3) For each cost, please identify whether or not this cost can be quantified.

Administrative costs arising from participation from MISO are quantified through the MISO settlement process.

(4) For each quantifiable cost, has the utility quantified those costs since the utility began participation in the RTO? Why or why not? Additionally, please explain how the utility has quantified those costs, provide any/all workpapers that calculated these costs, and provide the cost of gathering, analyzing, and interpreting such information.

Administrative costs arising from participation from MISO are quantified through the MISO settlement process (i.e., appear on MISO settlement statements). The below table compiles the annual sum of the applicable MISO settlement statement amounts since 2013. On an overall basis, these administrative costs have declined (in nominal dollars) by approximately 7% since 2013.

	Schedule 10 Demand and Energy	Schedule 10 FERC	DA/RT Admin, DA/RT Sch 24, FTR Admin	Total Admin Fees
2013	$ 6,209,105.84	$ 2,623,526.64	$ 9,784,858.62	$ 18,617,491
2014	$ 6,358,821.64	$ 2,771,927.62	$ 7,011,126.02	$ 16,141,875
2015	$ 6,598,145.79	$ 2,587,007.11	$ 7,542,366.26	$ 16,727,519
2016	$ 6,740,155.97	$ 2,630,257.13	$ 7,039,909.28	$ 16,410,322
2017	$ 6,759,635.36	$ 2,970,702.60	$ 7,451,857.04	$ 17,182,195
2018	$ 6,806,388.54	$ 3,011,201.09	$ 8,413,933.78	$ 18,231,523
2019	$ 7,055,136.96	$ 2,900,705.50	$ 7,251,245.52	$ 17,207,088
2020	$ 6,766,982.85	$ 2,688,353.47	$ 7,827,000.94	$ 17,282,337
	$ 53,294,373	$ 22,183,681	$ 62,322,297	$ 137,800,352

Settlement data prior to 2013 has been purged in accordance with Ameren Missouri's record retention policy. Compiling this additional data back to the date of Ameren Missouri's entry into MISO would require significant effort, which cannot easily be quantified.

(5) Please identify how the utility would ideally quantify future costs of RTO participation. Please provide the cost of gathering, analyzing, and interpreting such information under the ideal scenario. If such information is not reasonably and economically available, what kind of information would the utility propose as a proxy? Please provide the cost of gathering, analyzing, and interpreting such proxy information.

i. What will drive these future costs?

ii. Are there any existing costs that will be eliminated based on upcoming or expected changes at the RTO?

Please reference Ameren Missouri's response to question (5) in the benefits portion of this request. With respect to part ii of this question, Ameren Missouri is not aware of whether any costs will be eliminated.

(6) For each cost of RTO participation that is not quantifiable, please explain why it is not quantifiable.

Please reference the response to RTO Benefit question (4) above.

(7) For each non-quantifiable cost, has your utility placed a monetary value on the cost? If so, please explain how the monetary value was derived, and provide the cost of gathering, analyzing, and interpreting such information. - What have been the total cost of the RTO overheads allocated to the utility the past 3 years on an annual basis? What specific benefits are provided for those costs?

Please reference the response to RTO Benefit question (4) above.

Ameren Missouri's total MISO administrative charges (as identified in question (1) of the benefits section) for the period of January 1, 2018-December 31, 2020 were $17.3 million.

As these costs are non-discretionary, all of the benefits obtained from MISO participation are provided for these costs.

(8) What would be the cost of exiting an RTO? Are offsets to these costs possible? Please provide in graph form if possible from the date your company entered the RTO and the date at which the RTO mandated an exit fee (if these dates are not the same please explain) on a yearly basis the cost of what an exit fee would have been if your company had exited the RTO versus what the estimated benefits received were for those same years.

Estimated exit fee, as of:

- 2018 - $24-28 Million
- 2016 - $22 Million.
- 2011 - $40-45 Million (by reference to the amount we understood to have been paid by First Energy)
- 2010 - $26.5 Million (by scaling the exit fee paid by LGE.)
- 2007 - $35 Million (CRA study).

However, such an exit fee is not the only cost of not participating in MISO. These additional costs would include;

- loss of all of the benefits of MISO participation, including loss of a co-optimized energy and ancillary services market.

- increased operating and planning reserve requirements.
- loss of a liquid, transparent capacity market.
- increased staffing requirements.
- increased internal systems, training and operations costs.
- increased transmission service expense to export excess energy (off-system sales) or import energy to meet load obligations (purchased power).
- increased cost and complexity of operating Ameren Missouri's Illinois based generation resources, including potential transmission service costs related to importing capacity and energy.

RTO Benefit-Cost Study Period

As of now, when would your utility anticipate conditions being favorable to performing a benefit cost study? What would the time period be for that analysis? Please explain what changes to current conditions result in that period being selected. Additionally, are there identifiable events or categories of events that would result in that period being moved forward or back? Please identify and explain.

Is there value in the Commission maintaining the conditions in prior orders for utilities to provide benefit-cost studies? What if anything do other states in which a utility or its affiliates operate require for a comparable review?

Ameren Missouri continues to maintain that any benefit obtained from performing such a study is vastly overwhelmed by the cost of performing the study and by the fact that the study results will not establish the hypothetical future scenarios with a high level of certainty.

Ameren Missouri is not aware of any proposals before MISO which would make it disadvantageous to continue its participation or substantially change the historical benefits it and its customers have experienced from MISO participation. Furthermore, the Company struggles to develop a scenario where it would envision MISO participation not providing a net benefit.

Accordingly, Ameren Missouri does not believe that the continuation of the practice of having to proactively seek approval to maintain its MISO membership is of value. The Commission through its Staff, interested Stakeholders and the Company itself, are all active participants in MISO's stakeholder process, and thus aware of proposals which impact market design and transmission expansion. If a proposal were to move forward at MISO that was of such significance that it could reasonably be expected to wipe out the benefits of MISO participation, it would be well known by all, and an inquiry could be initiated at that time. Such proposals do not exist today.

Regarding other States, while the Company does not have comprehensive information on practices or requirements in all states, Ameren Missouri is not aware of any other MISO state that conditions continuation of RTO participation on specific, periodic cost/benefit study submissions on set timelines. Ameren Missouri is aware that in general, MISO states have required formal cost/benefit studies upon initial membership in MISO and that some utilities (e.g., in Arkansas) do periodically provide information on MISO participation benefits to their state commissions, not unlike the information Ameren Missouri has provided on at least two occasions over the past roughly seven years.

QUESTION FOR ALL STAKEHOLDERS

RTO Withdraw Events

Are there any identifiable "deal breaker" events or categories of events that would make it unreasonable for a Missouri investor-owned utility to remain in their current RTO? If so, please identify the event or category of events. Please provide a recommendation for how to analyze the costs and benefits for each event or category of events.

Please reference the response immediately above.

ATTACHMENT 1

2020 MISO Value Proposition

EXECUTIVE SUMMARY

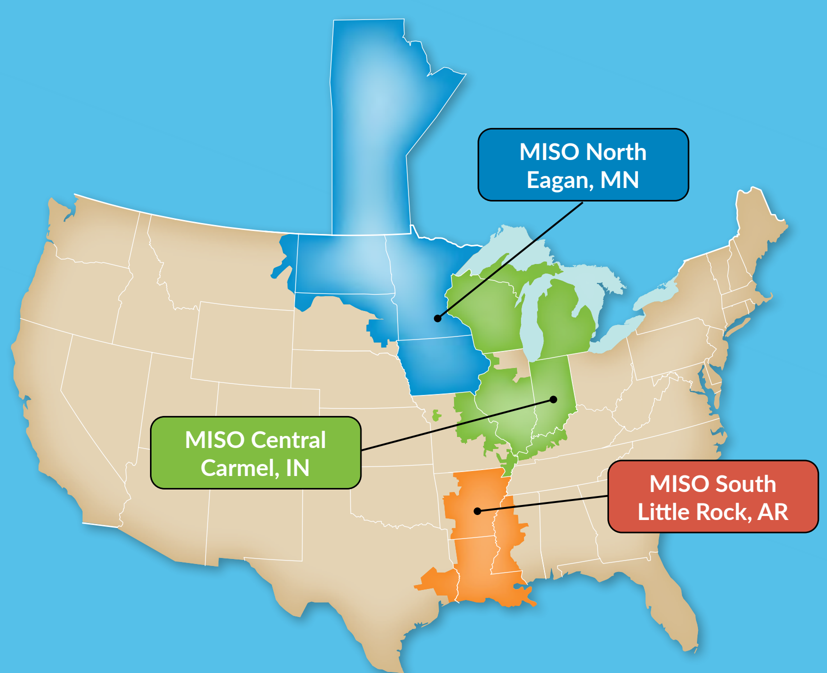
Highlights

- The 2020 Value Proposition study shows that MISO provides between $3.1 and $3.9 billion in annual net economic benefits to its region with over $30b to date.
- This value is provided through improved reliability, compliance, more efficient use of existing assets and reduced need for additional assets.
- MISO also provides qualitative benefits to the region that include price and information transparency, planning coordination and seams management.

misoenergy.org

The 2020 Value Proposition study shows that MISO **provided between $3.1 and $3.9 billion** in annual net economic benefits to its region.

This document details the annual value, background and calculation for each component of MISO's Value Proposition.



MISO's reliability footprint and locations of regional control centers.

What is the MISO Value Proposition?

The Value Proposition study is a quantification of value provided by MISO to the region, including the entire set of MISO market participants and their customers.

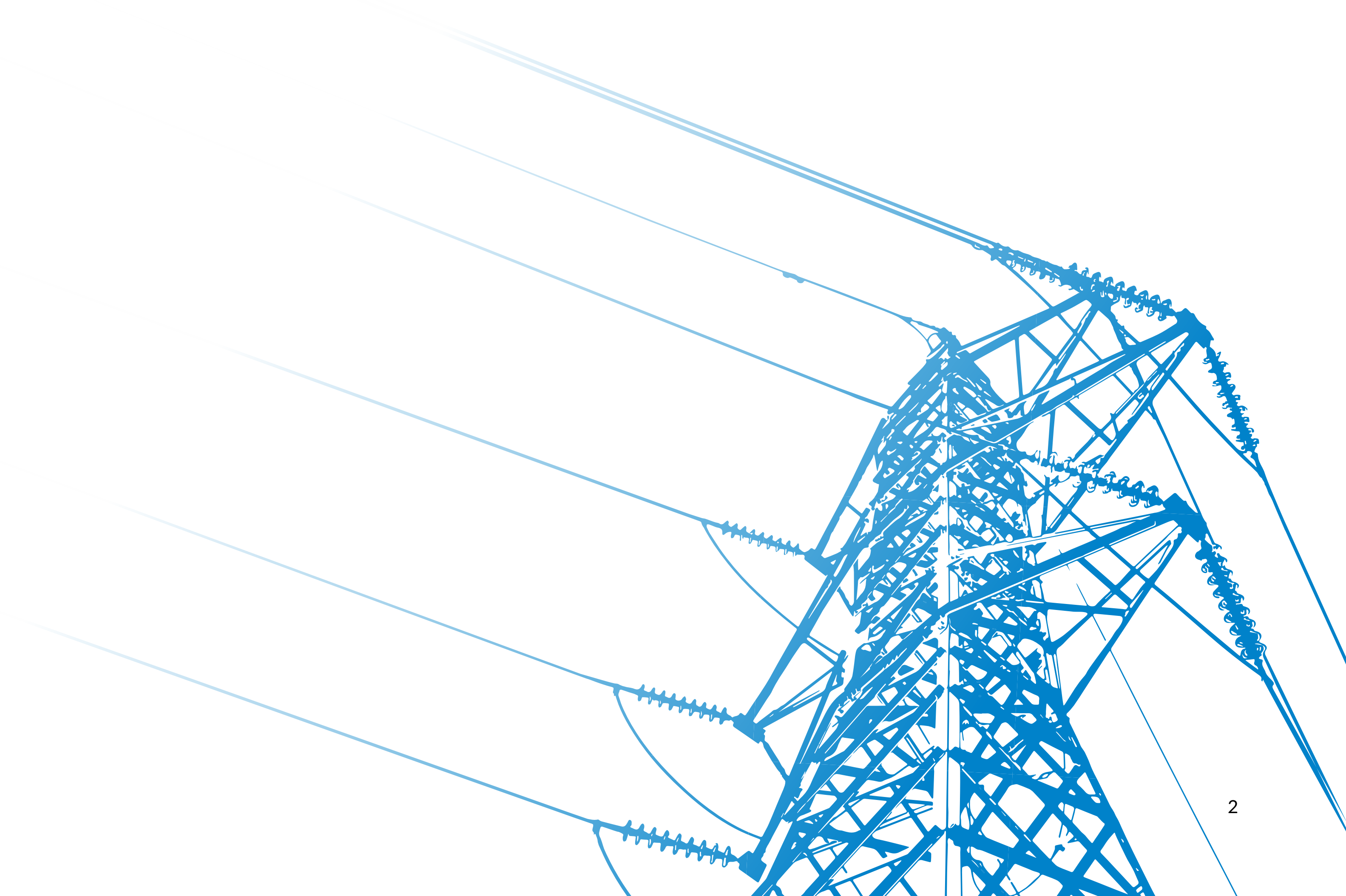
This value is provided through improved grid reliability and increased efficiencies in the use of generation resources enabled by MISO market operations.

Scope of the MISO Value Proposition

The Value Proposition study does not calculate savings received by individual market participants as a result of MISO membership.

The Value Proposition study does not calculate the value for any individual market sector or state.

The study does not capture the complete value of MISO. For simplicity, all benefits with minimal value are excluded. Qualitative benefits, such as price and data transparency, planning coordination and seams management also are excluded as these are difficult to quantify.



IMPROVED RELIABILITY

ANNUAL VALUE (in millions): $288 - $313

MISO exceeds industry standards to improve reliability through:

- System Monitoring and Visualization
- Congestion Management
- Backup Capabilities
- Operator Training
- Performance Monitoring
- Procedure Updates

COMPLIANCE

ANNUAL VALUE (in millions): $96 - $134

MISO Compliance benefit covers:

- Standards Development
- NERC Compliance
- Tariff Compliance
- System Planning Compliance
- Operations Compliance

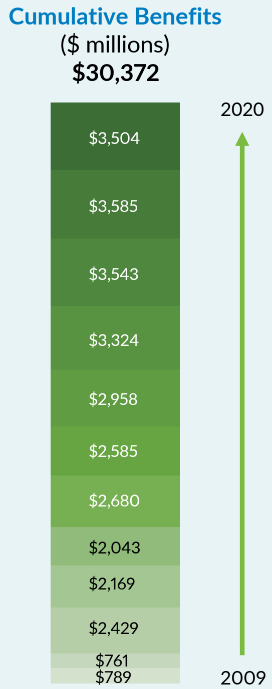
Operations ensures compliance per MISO's multiple roles:

- Reliability Coordinator
- Balancing Authority
- Transmission Service Provider

To ensure compliance with these requirements, Operations manages the following activities:

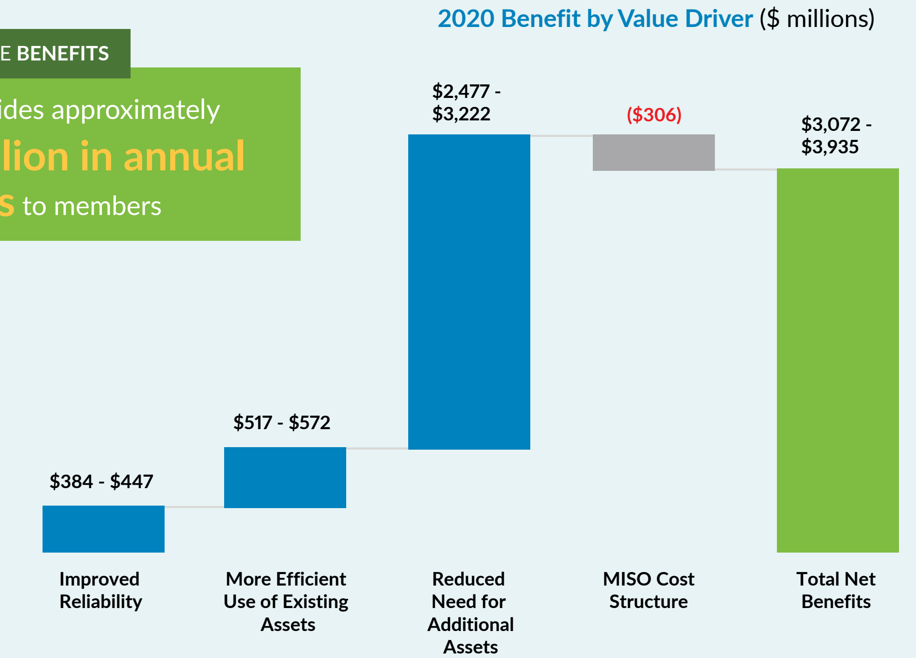
- Internal and external audits, including self-certifications
- New and revised standard readiness
- Issues Assessments

Operations also fulfills attestation requests to support member needs to demonstrate compliance.



QUANTITATIVE **BENEFITS**

MISO provides approximately **$3.5 billion in annual benefits** to members



More Efficient Use of Existing Assets

DISPATCH OF ENERGY

ANNUAL VALUE (in millions): **$329 - $363**

MISO commits and dispatches generation more efficiently than a decentralized market.

HISTORICAL PERSPECTIVE

Before MISO, the region operated as a decentralized, bilateral market. Transmission operations and bilateral power transactions were characterized by physical transmission constraints managed with mechanisms that limited transmission utilization, had high transaction costs, low market transparency, pancaked transmission rates, decentralized unit commitment and dispatch.

WHAT CHANGED WITH MISO?

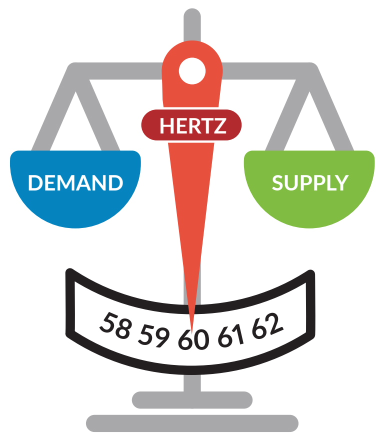
MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers provided by market participants.

The day-ahead market is a forward financial market for energy. Its clearing process produces a set of financially binding schedules according to which sellers are financially responsible to deliver, and purchasers are financially responsible to buy, energy at defined locations. The day-ahead market process is based upon a unit commitment model that minimizes total production costs over 24 hours. The primary purpose of the day-ahead market is to clear and schedule sufficient supply to satisfy cleared day-ahead demand, using the most economical generation resources. The real-time market dispatches generation resources to meet actual demand rather than bid demand. Real-time dispatch also is based on economics and dynamic congestion management.

REGULATION

ANNUAL VALUE (in millions): **$128 - $142**

The Ancillary Service Market reduces regulation requirements and improves commitment/dispatch efficiency.



HISTORICAL PERSPECTIVE

Prior to the launch of MISO's Regulation Market, each Balancing Authority (BA) maintained regulation within its area. This often resulted in the BAs within MISO's footprint working "against" each other – some regulating up while others were regulating down.

WHAT CHANGED WITH MISO?

With MISO's Regulation Market, significantly less regulation is required within the MISO footprint. This is due to one centralized footprint regulation target rather than multiple non-coordinated targets across the footprint.

The Regulation Market also changed the pricing mechanism for regulation by moving from Tariff pricing to market pricing. This pricing change is not included in the Value Proposition as it is not a true economic benefit. The impact of market pricing, however, is reported in MISO's monthly Market Operations report.

SPINNING RESERVES

ANNUAL VALUE (in millions): **$60 - $67**

The Ancillary Service Market also reduces spinning reserve requirements and improves efficiency.

HISTORICAL PERSPECTIVE

Pre-Contingency Reserve Sharing Group (CRSG)
Each Balancing Authority (BA) determined its spinning reserve requirement based on its individual (or Reserve Sharing Group) standards.

Post-CRSG/Pre-Ancillary Services Market (ASM)
Each BA determined its spinning reserve requirement based on the CRSG standards.

Post-ASM
MISO determines its spinning reserve requirement based on CRSG requirements.

WHAT CHANGED WITH MISO?

Starting with the formation of the CRSG and continuing with the Spinning Reserve Market, the total spinning reserve requirement has been significantly reduced. Reduced requirement frees up low-cost capacity to meet energy market needs.

The Spinning Reserve Market also changed the pricing mechanism for spinning reserves by moving from Tariff pricing to market pricing. This pricing change is not included in the Value Proposition as it is not a true economic benefit. The impact of market pricing, however, is reported in MISO's monthly Market Operations report.

Reduced Need for Additional Assets

WIND INTEGRATION

ANNUAL VALUE (in millions): **$450 - $517**

MISO's regional planning allows more economical placement of wind resources in the North/Central region.[1]

Local design of wind generation build-out

Combination design of wind generation build-out

LOCAL DESIGN - Renewable energy requirements and goals met with resources within the same state as the load

COMBINATION DESIGN - Renewable energy requirements and goals met with local resources combined with regional resources in high ranking renewable energy zones

[1] The wind integration benefit is based on work done for the Regional Generation Outlet Study II and includes the MISO North/Central footprint only.

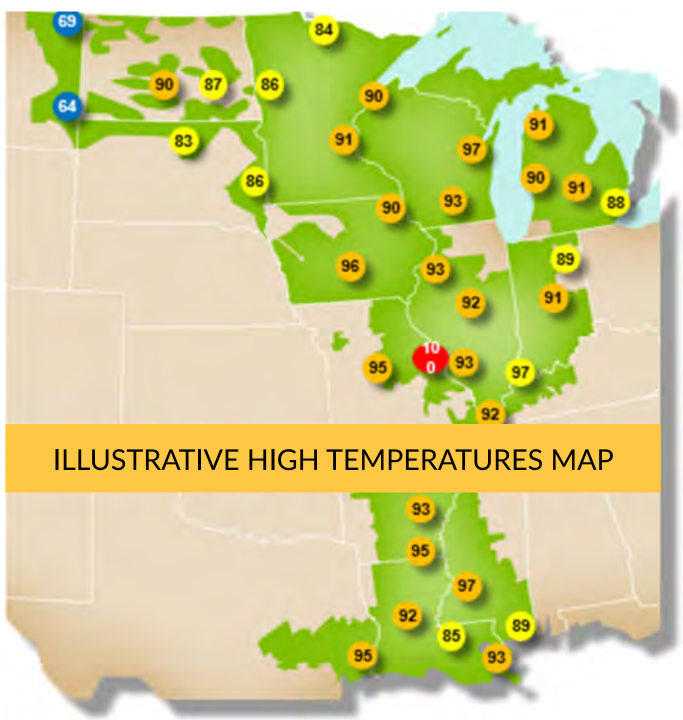
FOOTPRINT DIVERSITY

ANNUAL VALUE (in millions): **$1,911 – $2,494**

MISO members are able to have lower planning reserve margins as the planning reserves are shared across the footprint.

LOAD DIVERSITY EXPLAINED

The high temperature map illustrates that the peak for each Load Serving Entity (LSE) does not occur at the same time.



ILLUSTRATIVE HIGH TEMPERATURES MAP

Prior to MISO, individual LSEs maintained reserves based on their monthly peak-load forecasts. Due to MISO's broad and diverse footprint, LSEs now maintain reserves based on their load at the time of the MISO system-wide peak. This creates significant savings.

DEFERRED CAPACITY

Due to the diversity of MISO's large footprint, on a peak load of approximately 124,865 MW, about 15,212 MW of required capacity is deferred. This is 560 MW lower than last year.

DEMAND RESPONSE

ANNUAL VALUE (in millions): **$116 - $211**

Demand Response (DR) defers additional generation investment.

BACKGROUND

MISO's transparent price information aids market participants in making investment decisions related to existing and new load-reducing resources.

MISO recognizes and compensates four types of demand response:

- Demand Response Resource Type I (Energy / Capacity)
- Demand Response Resource Type II (Energy / Capacity)
- Demand Response as a Load Modifying Resource (Capacity)
- Emergency Demand Response (Energy during Emergencies)

Cost Structure

MISO costs are a small fraction of total benefits.

COST RECOVERY CATEGORY	2020 (in millions)
Schedule 10	$152.28
Schedule 16	$13.44
Schedule 17	$140.37
Schedule 31	$0.12
Total Operating Cost	**$306.21**

Qualitative Benefits

In addition to the quantitative benefits, MISO also demonstrates significant qualitative benefits that wholesale market participants receive from the operation of MISO, including:

- Price/Informational Transparency
- Planning Coordination
- Seams Management

For More Information

Please see the Value Proposition Presentation and also the Value Proposition Detailed Calculation Description posted to MISO's website

MISO

misoenergy.org

ATTACHMENT 1

DETAILED CALCULATION DESCRIPTION

MISO VALUE 2020 PROPOSITION

MISO

misoenergy.org

Contents

Executive Summary

The 2020 Value Proposition study shows that MISO provides between $3.1 and $3.9 billion in annual economic benefits to its region. This document details the annual value, background and calculation for each component of MISO's Value Proposition.

What is the MISO Value Proposition?

The Value Proposition study is a quantification of value provided by MISO to the region, including the entire set of MISO market participants and their customers.

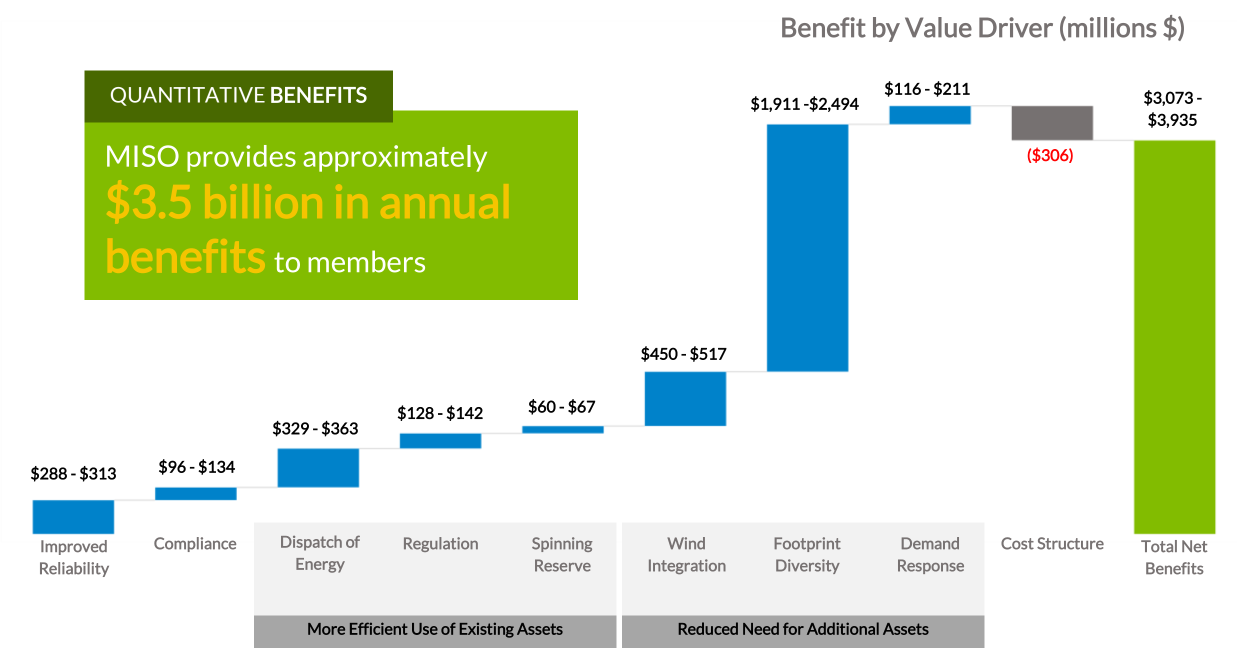
This value is provided through improved grid reliability and increased efficiencies in the use of generation resources enabled by MISO market operations.

Scope of the MISO Value Proposition

The Value Proposition study does not calculate savings received by individual market participants as a result of MISO membership.

The Value Proposition study does not calculate the value for any individual market sector or state.

The study does not capture the complete value of MISO. For simplicity, all benefits with minimal value are excluded. Qualitative benefits, such as price and data transparency, planning coordination and seams management also are excluded as these are difficult to quantify.



Improved Reliability

MISO exceeds industry standards to improve reliability.

ANNUAL VALUE

Low Estimate ($ in Millions)	**$288**
High Estimate ($ in Millions)	**$313**

Background

SYSTEM MONITORING AND VISUALIZATION

Industry Standard Practice	MISO Practice
Real-time monitoring using SCADA on a local area basis Use of standard vendor-supplied displays Operator interface of standard monitor display screen augmented with static map board Ad-hoc and off-line voltage security analysis review	Regional view/monitoring of the power system including: A state estimator that runs every 60 seconds Contingency analysis of over 12,000 contingencies every two minutes 24-hour shift engineer coverage responsible for maintaining security application performance Custom tools/displays for increased situational awareness Control centers with large video wallboards displaying real-time data reflecting the state of the electric grid and real-time market results Real-time Voltage Stability Analysis Tool (VSAT) and Transmission Security Assessment Tool (TSAT) allow comprehensive analyses of system operating conditions for predicting and preventing voltage insecurity

CONGESTION MANAGEMENT

Industry Standard Practice	MISO Practice
Performed using NERC Transmission Loading Relief (TLR) process or internally developed operating procedure based on congestion management system 30 – 60 minute response time	Transmission congestion management via five-minute security constrained economic dispatch based on least-cost analysis results in faster and more efficient solutions Look Ahead Commitment Tool models near-real-time conditions to better utilize resource capabilities and provide unit commitments, de-commitments and online extension recommendations for congestion management

BACKUP CAPABILITIES

Industry Standard Practice	MISO Practice
Offline and/or scaled down backup facility Significant time to bring backup facility after a failover or failback Testing of failover process performed annually	24 x 7 staffed back-up control center On-line back-up facility with full coverage of power system and market applications Critical applications require less than 10 minutes for failover or failback Monthly testing of failover process for critical applications

OPERATOR TRAINING

Industry Standard Practice	MISO Practice
Classroom training only Train to meet minimum NERC requirements Five-person rotation (no training rotation) Offline power system restoration procedure review	Training methods include extensive use of full-dispatch training simulator Training exceeds NERC requirements Six-person rotation at key operator positions allows for a training week during each cycle Annual regional “live” power system restoration drill involving dozens of members

PERFORMANCE MONITORING

Industry Standard Practice	MISO Practice
Post-event performance review Post-event operator call review	Daily review of operational performance including: Extensive review of established operational metrics Monthly tracking of improvements Frequent near-term performance feedback to operators and support personnel Routine review of upcoming operational events Standardized operator call review process incorporating established metrics that score calls for each operator on a routine basis Feedback provided to each operator

PROCEDURE UPDATES

Industry Standard Practice	MISO Practice
Procedures updated ad-hoc as needed	All control room procedures reviewed annually Conduct routine drills with member participation for capacity emergency and abnormal procedures Annual Emergency Operating Procedures workshop with members and adjacent reliability coordinators Summer and winter readiness workshops

Calculation

Improved Reliability = Transmission System Availability Index (TSAI) x MISO Load x Cost of Outage

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- Transmission System Availability Index (TSAI) = RTO TSAI less Non-RTO TSAI where TSAI is measured as a percent
- MISO Load is measured in MWh
- Cost of outage is measured in cost per MWh

TSAI FORMULAS

$$\text{TSAI} = \quad 1 - \left(\frac{\text{Sum of MWh Load Interrupted}}{\left(\begin{array}{c} \text{Sum of MWh Load Interrupted} \\ + \\ \text{Sum of MWh Load Served} \end{array} \right)} \right)$$

$$\sum_{\begin{array}{l}\text{\# of} \\ \text{Disturbances}\end{array}} \left(\begin{array}{l} \text{Duration (hrs) X} \\ \text{Disturbance Size (MW) X} \\ \text{Load Loss Recovery Factor} \end{array} \right)$$

Compliance

ANNUAL VALUE

Low Estimate ($ in Millions)	**$96**
High Estimate ($ in Millions)	**$134**

Background

STANDARDS DEVELOPMENT

Before MISO	With MISO
Utilities were varied in their approach to standards engagement. Many were "standards takers", relying on the good judgment of others to develop standards. This worked well in a voluntary compliance environment.	By collaborating and participating in standards creation, MISO and members can better manage ultimate compliance responsibilities. MISO engages in drafting teams at NERC, NAESB and other organizations to actively manage the scope of standards development and limit the number of changes required of MISO and stakeholders. MISO's collaborative efforts lighten the workload on all members for input and control of the process.

NERC COMPLIANCE

Before MISO	With MISO
Many parties in the MISO region were responsible for managing NERC compliance: • 3 Reliability Coordinators • 20+ Interchange Authorities • 20+ Transmission Service Providers • 20+ Balancing Authorities (BA) • Several Planning Authorities Individual Reserve Sharing Administration	With MISO as central balancing authority, many compliance responsibilities have consolidated and member responsibilities have decreased: • 1 Reliability Coordinator (MISO) • 1 Interchange Authority (MISO) • 1 Transmission Service Provider (MISO) • Significantly fewer BA Compliance Requirements (LBAs) • Fewer Planning Authorities • Single Reserve Sharing Administrator (MISO) • Centralization of some Transmission Operator Requirements (MISO) Allows members to avoid or reduce compliance-dedicated staff.

TARIFF COMPLIANCE

Before MISO	With MISO
Each utility managed the compliance of their individual tariffs and their separate OASIS functions.	Under MISO, Tariff compliance is consolidated, saving time and money for our members.

SYSTEM PLANNING COMPLIANCE

Tariff, Order 890, and Order 1000

MISO supports member long-term planning and compliance per our FERC-approved Tariff. Tariff compliance efforts focus on the following:

- Long-Term Expansion Planning
- Generator Interconnection
- Transmission Service Requests
- System Support Resource Studies
- Resource Adequacy
- Loss of Load Expectation
- FERC 715 Market Rates Filing

MISO's planning process ensures that the regional planning process is open, transparent and coordinated, and includes both reliability and economic considerations as well as equitable cost sharing of expansion costs.

After consolidating subsidiary companies, 42 of 43 MISO members have signed MISO's Order 890, as listed in Attachment FF-4.

NERC

MISO, as NERC Planning Authority, reduces compliance staff needs of members by performing required compliance activities such as the following:

- Long-Term Expansion Planning
- Seasonal Assessments of transmission and resource adequacy

OPERATIONS COMPLIANCE

Operations ensures compliance with approximately 850 Tariff and 270 NERC requirements per MISO's multiple roles:

- Reliability Coordinator
- Balancing Authority
- Transmission Service Provider

To ensure compliance with these requirements, Operations manages the following activities:

- Internal and external audits, including self-certifications
- New and revised standard readiness
- Issues Assessments

Operations helps members coordinate and communicate efficiently via the following efforts:

- Emergency Operating Procedures (EOP) Coordination and Workshops
- Balancing Authority Task Team
- Balancing Area Reliability-Based Control Field Trials
- Transmission Owners Compliance Task Team

Operations also fulfills attestation requests to support member needs to demonstrate compliance.

Calculation

Full-time equivalent (FTE) savings are based on internal MISO analysis.

The compliance benefit was calculated by multiplying the estimated FTEs needed to perform each compliance activity, the affected members and the labor rate per hour.

ASSUMPTIONS / INPUTS

Full-time Equivalents (FTEs) Savings [1]

Category	FTE Savings
System Planning – Tariff Compliance	7 – 10
System Planning – Order 890 Compliance	4 – 7
System Planning – NERC Compliance	5
Operations Compliance	20 – 22

Affected Members [2]

Category	Count
Large-sized Members	3 – 4
Medium-sized Members	9 – 10
Small-sized Members	29

Hourly Rates

Category	Rate
Internal Rate	$66/hr (80% – 100% of hours)
External Rate	$120 – $225/hr (0% – 20% of hours)

[1] Full-time equivalents (FTEs) for large-size members based on internal MISO analysis. Medium-size members estimated to save 1/3 of a large-size member's FTEs. Small-size members estimated to save 1/6 of a large-size member's FTEs.
[2] Members were divided into large, medium and small based on their electric sales (in MWh). Members with sales above 50 million MWh are classified as large. Medium-size members have electric sales between 10 million and 50 million MWh. Small-size members have electric sales below 10 million MWh. MISO members with multiple operating utilities were counted as one member because it was assumed their service company operated a majority of their compliance functions.

More Efficient Use of Existing Assets

Dispatch of Energy

MISO commits and dispatches generation more efficiently than a decentralized market.

ANNUAL VALUE

Low Estimate ($ in Millions)	$329
High Estimate ($ in Millions)	$363

Background

HISTORICAL PERSPECTIVE

Before MISO, the region operated as a decentralized, bilateral market. Transmission operations and bilateral power transactions were characterized by physical transmission constraints managed with mechanisms that limited transmission utilization, high transaction costs, low market transparency, pancaked transmission rates, decentralized unit commitment and dispatch.

WHAT CHANGED WITH MISO?

MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers provided by market participants.

The day-ahead market is a forward financial market for energy. Its clearing process produces a set of financially-binding schedules according to which sellers are financially responsible to deliver and purchasers are financially responsible to buy energy at defined locations. The day-ahead market process is based upon a unit commitment model that minimizes total production costs over 24 hours. The primary purpose of the day-ahead market is to clear and schedule sufficient supply to satisfy cleared day-ahead demand, using the most economical generation resources. The real-time market dispatches generation resources to meet actual demand rather than bid demand. Real-time dispatch also is based on economics and dynamic congestion management.

Calculation

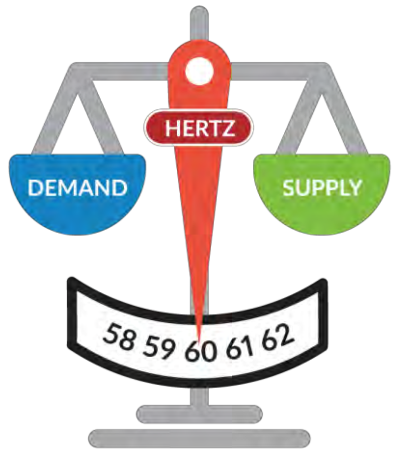
This benefit is modeled using the industry standard technique called production cost modeling. Independent firms consistently find that a market, such as MISO's, with central commitment and dispatch of generation for a large region, is more cost-efficient versus the same generation portfolio divided into sub-regions for commitment and dispatch.

ASSUMPTIONS / INPUTS

- Modeled based on MISO Commercial and Network Model
- Analysis performed in PROMOD®
- Pre-MISO market analysis
  - Transmission system utilization was de-rated by 10%
  - Hurdle rates between control areas: $3 for dispatch hurdle rate and $10 for commitment hurdle rate
- Post-MISO market analysis
  - Improved transmission system utilization by 10%
  - Hurdle rates between control areas were eliminated
  - 3,000 MW contract path transfer limit from MISO N/C to MISO South and 2,500 MW transfer limit from MISO South to MISO N/C

Regulation

The Ancillary Service Market reduces regulation requirements and improves commitment/dispatch efficiency.



ANNUAL VALUE

Low Estimate ($ in Millions)	$128
High Estimate ($ in Millions)	$142

Background

HISTORICAL PERSPECTIVE

Prior to the launch of MISO's Regulation Market, each Balancing Authority (BA) maintained regulation within its area. This often resulted in the BAs within MISO's footprint working "against" each other – some regulating up while others were regulating down.

WHAT CHANGED WITH MISO?

With MISO's Regulation Market, significantly less regulation is required within the MISO footprint. This is due to one centralized footprint regulation target rather than multiple non-coordinated targets across the footprint.

The Regulation Market also changed the pricing mechanism for regulation by moving from Tariff pricing to market pricing. This pricing change is not included in the Value Proposition as it is not a true economic benefit. The impact of market pricing, however, is reported in MISO's monthly Market Operations report.

Calculation

Capacity from low- cost generation units previously held to meet regulation requirements is available for energy dispatch. This component is valued using production-cost analysis.

This calculation is based on the difference between pre-ASM and post-ASM regulation multiplied by the production cost savings per MW.

ASSUMPTIONS / INPUTS

Category	Value
Pre-ASM Average Regulation [3]	1,559 MW
Post-ASM Average Regulation [4]	396 MW
Regulation Reduction	1,163 MW
Production Cost Savings Per MW [5]	\$110,404 – Low case \$122,026 – High case

[3] Pre-ASM MISO average regulation (MW) from 4/1/2005 to 12/31/2008 and adjusted for membership changes.
[4] Post-ASM average regulation (MW) from November 2019 to October 2020.
[5] Based on MISO production cost modeling using PROMOD® software.

Spinning Reserves

The Ancillary Service Market also reduces spinning reserves requirements and improves efficiency.

ANNUAL VALUE

Low Estimate ($ in Millions)	**$60**
High Estimate ($ in Millions)	**$67**

Background

HISTORICAL PERSPECTIVE

Pre-Contingency Reserve Sharing Group (CRSG)

Each Balancing Authority (BA) determined its spinning reserve requirement based on its individual (or Reserve Sharing Group) standards.

Post-CRSG/Pre-Ancillary Services Market (ASM)

Each BA determined its spinning reserves requirement based on the CRSG standards.

Post-ASM

MISO determines its spinning reserves requirement based on CRSG requirements.

WHAT CHANGED WITH MISO?

Starting with the formation of the CRSG and continuing with the Spinning Reserves Market, the total spinning reserves requirement has been significantly reduced. Reduced requirement frees up low-cost capacity to meet energy market needs.

The Spinning Reserves Market also changed the pricing mechanism for spinning reserves by moving from Tariff pricing to market pricing. This pricing change is not included in the Value Proposition as it is not a true economic benefit. The impact of market pricing, however, is reported in MISO's monthly Market Operations report.

Calculation

The reduced requirements for spinning reserves allows low-cost generation units (where spinning reserves were previously held) to serve the energy needs of the region. This component is valued using production cost analysis.

This calculation is based on the difference between pre-ASM and post-ASM spinning reserves multiplied by the production cost savings per MW.

ASSUMPTIONS / INPUTS

Category	Value
Pre-ASM average spinning reserves requirement [6]	1,482 MW
Post-ASM average spinning reserves requirement [7]	934 MW
Spinning reserves requirement reduction	548 MW
Production cost savings per MW [8]	\$110,404 – Low case \$122,026 – High case

[6] 2006 Spinning Reserves (based on reserve requirement of 2,635 MW multiplied by 45%) adjusted for membership changes.
[7] Monthly weighted average spinning reserve requirement (MW) from November 2019 to October 2020.
[8] Based on MISO production cost modeling using PROMOD® software.

Reduced Need for Additional Assets

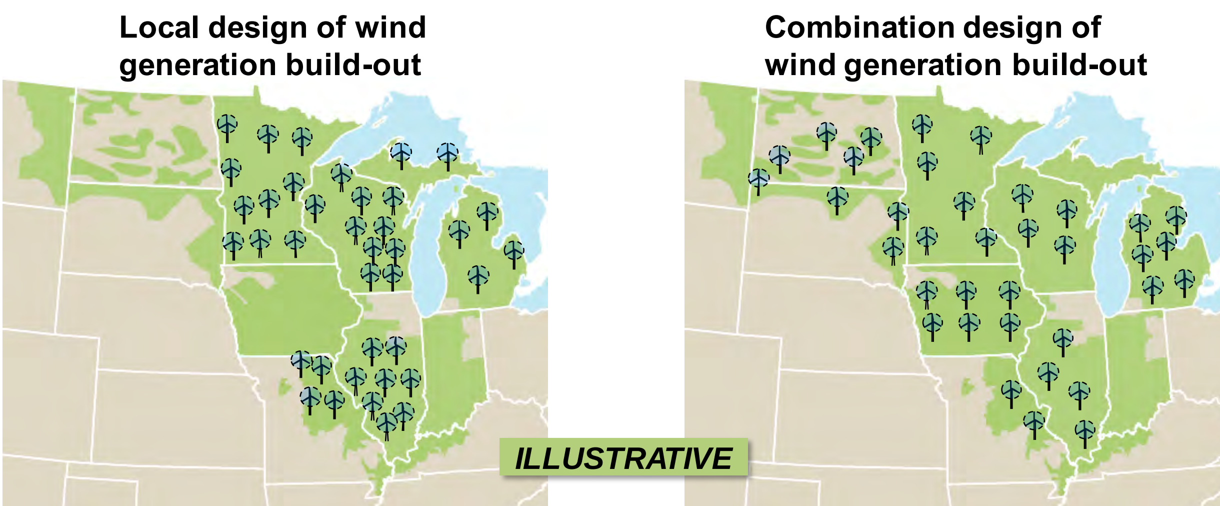
Wind Integration

ANNUAL VALUE

Low Estimate ($ in Millions)	$450
High Estimate ($ in Millions)	$517

Background

MISO's regional planning allows greater economic placement of wind resources in the North/Central region.[9]



Local Design = Renewable energy requirements and goals met with resources within the same state as the load

Combination Design = Renewable energy requirements and goals met with local resources combined with regional resources in high ranking renewable energy zones

[9] The wind integration benefit is based on work done for the Regional Generation Outlet Study II and includes the MISO North/Central footprint only.

Calculation

An annual revenue requirement is used to calculate an annualized avoided cost benefit. The annual revenue requirement is estimated based on an annual charge rate that includes rate of return, property tax rate, insurance cost rate, fixed O&M and depreciation. EGEAS software calculates the annual charge rate.

The calculation does not include production cost savings related to wind generation or congestion relief from transmission upgrades.

ASSUMPTIONS / INPUTS

Wind Turbine Build (2010 to 2020)	
Local – without MISO [10]	20,128 MW
Combination – with MISO [11]	18,170 MW
Cumulative wind savings	1,958 MW
Wind Turbine Cost Midpoint [12] ($ Millions)	
Local – without MISO	$71,287
Combination – with MISO	$64,053
Difference	$7,234
Cost/MW [13] ($ Millions)	$1,572–Low estimate $1,738–High estimate
Transmission Cost Offset [14] ($ Millions)	$16.1

[10] Wind build-out without MISO for 2010 to 2020 was calculated based on the results of the Regional Generation Outlet Study II (RGOS II). RGOS II was modified to include the MISO North/Central footprint only. RGOS II results (modified for the MISO footprint) show that wind turbines required to meet renewable energy mandates may be reduced by approximately 11% through the combination design siting methodology. The 11% additional wind under the local design was applied to the actual wind added in MISO's footprint to calculate the wind build-out in the region without MISO.

[11] Registered wind added to MISO footprint from 1/1/2010 to 8/31/2020.

[12] Wind turbine costs shown reflect the midpoint of low and high fixed charges for entire book life (25 years) of turbines.

[13] High and low estimate of the initial book value of a 1 MW onshore wind turbine generator. Estimates calculated using EGEAS software. Book/tax life = 25/15 years.

[14] Transmission capital costs of $115M added each year, beginning in 2015 through 2027, to recognize the transmission costs required to incorporate new wind resources. Transmission cost offset incorporates annual revenue requirement as provided in Tariff Attachment O. Requirement assumes 40-year straight-line depreciation.

Footprint Diversity

MISO's large footprint allows lower planning reserve margins for Local Resource Zones.

Category	Planning Reserve Margin
Without MISO	25.2%
With MISO	18.0%

ANNUAL VALUE

Low Estimate ($ in Millions)	**$1,911**
High Estimate ($ in Millions)	**$2,494**

Background

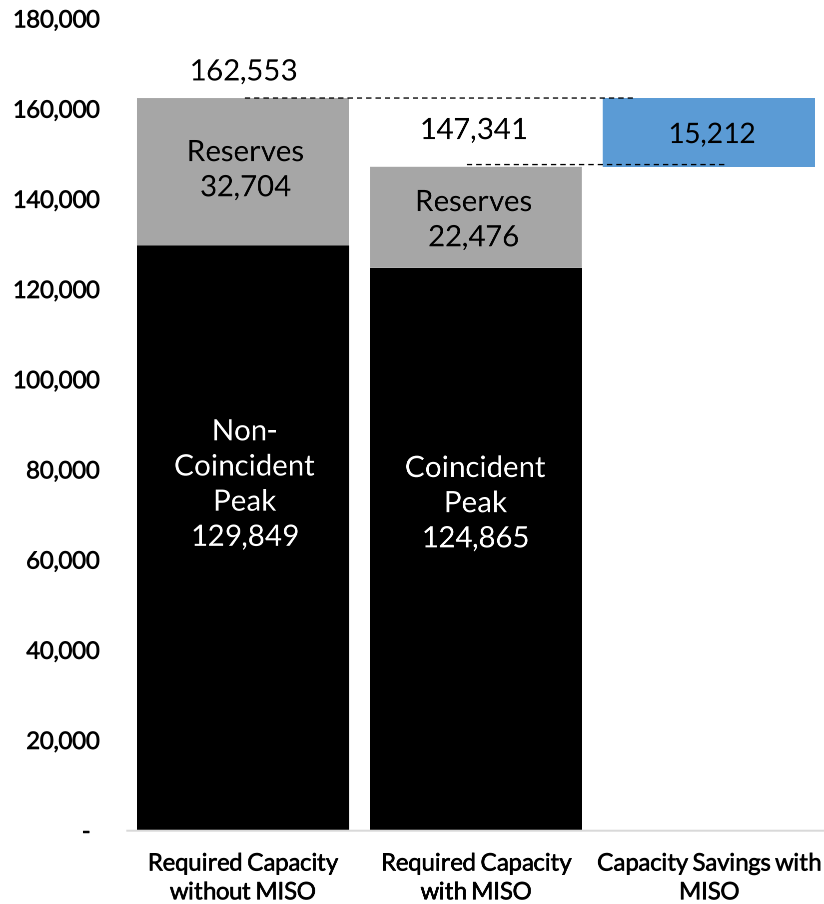
LOAD DIVERSITY EXPLAINED

The high temperature map illustrates that the peak for each Load Serving Entity (LSE) does not occur at the same time.

Prior to MISO, individual LSEs maintained reserves based on their monthly peak load forecasts. Due to MISO's broad and diverse footprint, LSEs now maintain reserves based on their load at the time of the MISO system-wide peak. This creates significant savings.

DEFERRED CAPACITY

MISO's footprint diversity defers need for 15,212 MW of additional capacity.



Due to the diversity of MISO's large footprint, on a peak load of approximately 124,865 MW, about 15,212 MW of required capacity is deferred. This is 560 MW lower than last year.

Calculation

Regional rather than localized use of the electrical system allows more efficient and effective operation of generation assets while reducing the planning reserve margin needed for reliability.

An annual revenue requirement is used to calculate an annualized avoided cost benefit. The annual revenue requirement is estimated based on an annual charge rate that includes rate of return, property tax rate, insurance cost rate, fixed O&M and depreciation. EGEAS software calculates the annual charge rate.

ASSUMPTIONS / INPUTS

Input	Value
2020 Planning Reserve Margin	18.0%
2020 Planning Reserve Margin without MISO	23.39% - 25.19%
2020 Required Capacity without MISO	160,222 MW – 162,553 MW
2020 Required Capacity with MISO	147,341 MW
Capital Investment Avoided, 2020	12,881 MW – 15,212 MW
Cost/MW	$1,062,447 - $1,116,932

Demand Response

Demand Response (DR) defers additional generation investment.

ANNUAL VALUE

Low Estimate ($ in Millions)	**$116**
High Estimate ($ in Millions)	**$211**

Background

MISO's transparent price information aids market participants in making investment decisions related to existing and new load-reducing resources.

MISO recognizes and compensates four types of demand response:

- Demand Response Resource Type I (Energy / Capacity)
- Demand Response Resource Type II (Energy / Capacity)
- Demand Response as a Load Modifying Resource (Capacity)
- Emergency Demand Response (Energy during Emergencies)

The following table illustrates the increase in Demand Response resources in MISO:

Category	MW of Demand Response
Without MISO	3,468 [15]
2020 Total Committed DR in MISO	7,557 [16]

- In 2009, ~2,900 MW of DR existed before DR could participate in MISO's Planning Resource Auction.
- In Dec. 2013, ~600 MW of DR existed in the MISO South region before the MISO South integration.
- In 2020, there are just over 7,500 MW of demand response resources in MISO's footprint, or about 4,100 MW more relative to the Without MISO scenario. The entire 4,100 MW is

[15] 2009 Fixed Resource Adequacy Plan Demand Response in Zones 1-7 (2,858 MW) plus the 2013/14 Transitional Planning Resource Auction (TPRA) results for Zones 8-10 (610 MW).
[16] From the 2020/2021 Planning Resource Auction: Fixed Resource Adequacy Plan Demand Response plus cleared Demand Response [7,557 MW].

not attributable to MISO, but we do believe some of that increase (25%-40%) in DR has been facilitated by MISO.

Calculation

An annual revenue requirement is used to calculate an annualized avoided cost benefit for the capacity deferred due to MISO-facilitated incremental Demand Response. The annual revenue requirement is estimated based on an annual charge rate that includes rate of return, property tax rate, insurance cost rate, fixed O&M and depreciation. EGEAS software calculates the annual charge rate.

ASSUMPTIONS / INPUTS

Category	Value
Incremental Demand Response 2009-2020 [17]	4,089 MW
% of incremental Demand Response assumed facilitated by MISO [18]	25% - 40%
Capacity deferred due to incremental Demand Response facilitated by MISO	1,022 MW – 1,636 MW
Cost/MW [19]	$1,062,447 – Low estimate $1,116,932 – High estimate

[17] 2020 Demand Response committed in MISO [7,557 MW] less total Demand Response without MISO [3,468 MW]. The 2020 Demand Response committed in MISO is from the 2020/2021 Planning Resource Auction: Fixed Resource Adequacy Plan Demand Response plus cleared Demand Response. The Without MISO Demand Response is the sum of the historical 2009 Fixed Resource Adequacy Plan Demand Response in Zones 1-7 (2,858 MW) and the 2013/14 Transitional Planning Resource Auction (TPRA) Results for Zones 8-10 (610 MW).

[18] Based on internal MISO analysis, percentages reflect incremental Demand Response that would not exist unless enabled by MISO's market.

[19] High and low estimate of the initial book value of a 1 MW combustion turbine generator. Estimates calculated using EGEAS software. Book/tax life = 30/15 years.

Cost Structure

MISO costs are a small fraction of total benefits.

Cost Recovery Category	2020 ($ in Mils.)
Schedule 10	$152.28
Schedule 16	$13.44
Schedule 17	$140.37
Schedule 31	$0.12
Total Operating Cost	$306.21

Qualitative Benefits

Price/Informational Transparency

Price and data transparency in the MISO market provides a host of benefits.

EFFICIENCY

Before MISO	With MISO
Bilateral markets lacked price and data transparency, leaving participants searching for which plants are operating at what cost.	Every market participant can see pricing and information, increasing market efficiencies.

INVESTMENT

Before MISO	With MISO
Bilateral markets provided insufficient price signals that resulted in inefficient investment and placement of generation resources and transmission infrastructure.	MISO's energy market price signals provide investors in generation assets the underlying data required to develop forecasts for future wholesale prices. Price forecasts, in turn, provide the necessary basis for market-driven investments.

RELIABILITY

Before MISO	With MISO
Bilateral markets achieved reliability based on contractual rights and industry standards with little thought to economic impacts.	MISO enhances reliability by informing all market participants of grid conditions and market operations through the public posting of electricity prices and other key system information. Prices in the MISO energy market reflect real-time system conditions, high market prices indicating where more generation is needed and lower market prices signifying the reverse.

Planning Coordination

MISO's transmission planning process focuses on minimizing total cost of delivered power to consumers.

TRANSMISSION EXPANSION PLANNING MODEL

Before MISO	With MISO
Reliability-based model Focuses primarily on grid reliability Typically considers a short time horizon Seeks to minimize transmission build	Value-based model Focuses on value while maintaining reliability Reflects appropriate time scales Seeks to identify transmission infrastructure that maximizes value Identifies the comprehensive value (reliability, economic and policy) of projects

PLANNING SCALE AND EFFICIENCY

Before MISO	With MISO
Local view Objective of expansion is to address local needs 26 individual entities optimizing the system within their area	Regional view Objective of expansion is to address aggregate regional needs consistent with value-based plans in addition to meeting local needs Offers opportunities to find efficiencies across multiple Transmission Owners

COST ALLOCATION

Before MISO	With MISO
Free-rider issues caused by a lack of alignment between transmission cost and the causers and beneficiaries	MISO helps facilitate the cost allocation of transmission to minimize free-rider issues MISO regional cost allocation matches costs roughly commensurate with beneficiaries

Seams Management

MISO adds value by managing the seams around its footprint.

INTERCHANGE TRANSACTIONS

Before MISO	With MISO
To avoid congestion, a utility or balancing authority (BA) had seams agreements with each neighbor to monitor flowgates when selling transmission service. Lacking such agreements, service was sold ignoring neighbors' flowgates with Transmission Loading Relief (TLR)—the only effective congestion management process. If firm service was sold, curtailment had implications to the owner of the firm service and made the service unavailable when needed.	Seams agreements between MISO and its neighbors eliminate the need for individual agreements between utilities or BAs. These agreements reduce the likelihood of parallel flows, causing overload on flowgates and the need for TLRs to manage congestion, except when unexpected events occur.

MARKET FLOWS AND ALLOCATIONS

Before MISO	With MISO
A utility or BA served its own interests by classifying all of its generation to load flows as firm so the flows would not be curtailed. This would cause parallel flow issues for neighboring BAs, in that, firm flow curtailment using TLR had wide-ranging implications. This required the utility or BA experiencing congestion to re-dispatch without compensation in order to manage parallel flow impacts from others.	The seams agreements between MISO, PJM and SPP provide flowgate allocations between the seams parties that limit the amount of firm market flows. This requires the parties to the seams agreement to classify some of their respective market flows as non-firm so they can be curtailed using TLR. Having each market classify some of its market flows as non-firm means these flows are then subject to curtailment using TLR along with other non-firm usages.

MARKET-TO-MARKET PROCESS

Before MISO	With MISO
When congestion occurred within the MISO region or PJM's footprint, the IDC assigned tag curtailments and/or market flow relief obligations to the flows. Prior to having a market-to-market process, utilities in the MISO and PJM regions would bind their own flowgates based on the relief obligation from the IDC without regard to the cost of re-dispatch in order to meet the relief obligation.	Under the market-to-market process, MISO and neighboring markets both bind a coordinated flowgate in order to dispatch the most cost-effective generation to manage congestion. After-the-fact settlement is used to compensate for assistance provided by the other market. With both markets binding on a constraint located in one market, the proper price signal is sent to both markets, helping achieve price convergence at the border.

ATTACHMENT 1

MISO

MISO 2020
VALUE PROPOSITION

INTRODUCTION

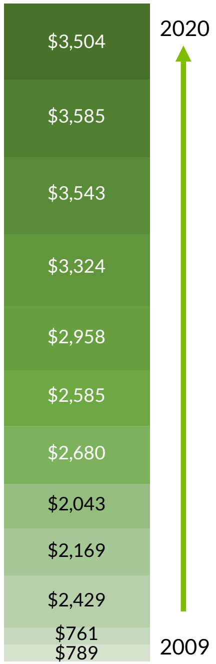
The 2020 Value Proposition study shows that MISO provided between $3.1 billion and $3.9 billion in regional benefits driven by enhanced reliability, more efficient use of the region's existing assets and a reduced need for new assets.

The Value Proposition quantifies the value MISO provides to the region, including the entire set of MISO market participants and their customers.

This study breaks MISO's business model into recognized categories of benefits and calculates a range of value for each category.

Since 2009, MISO has documented over $30 billion in benefits

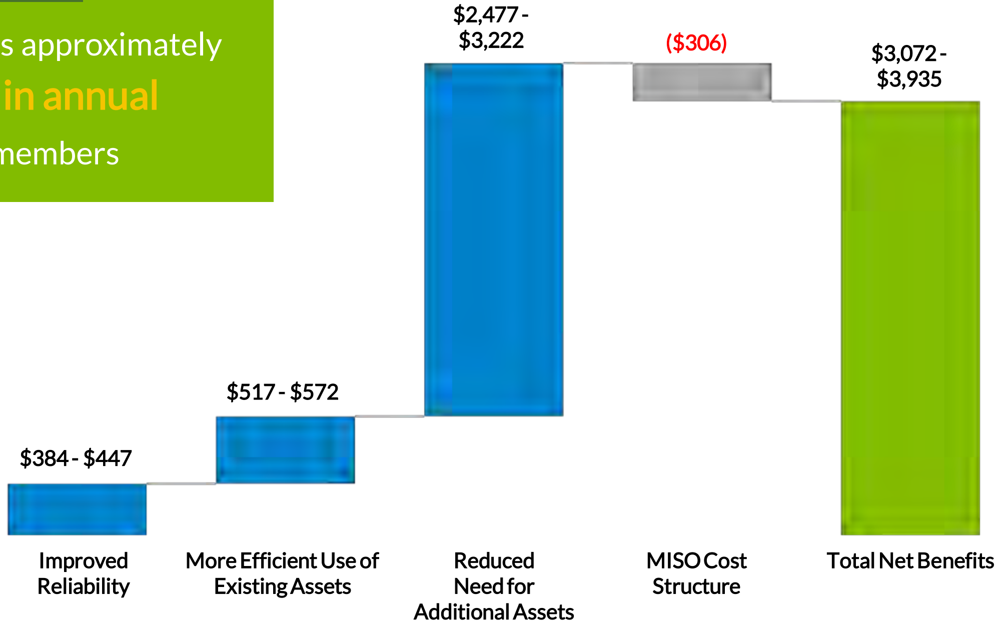
Cumulative Benefits
($ millions)
$30,372



QUANTITATIVE **BENEFITS**

MISO provides approximately **$3.5 billion in annual benefits** to members

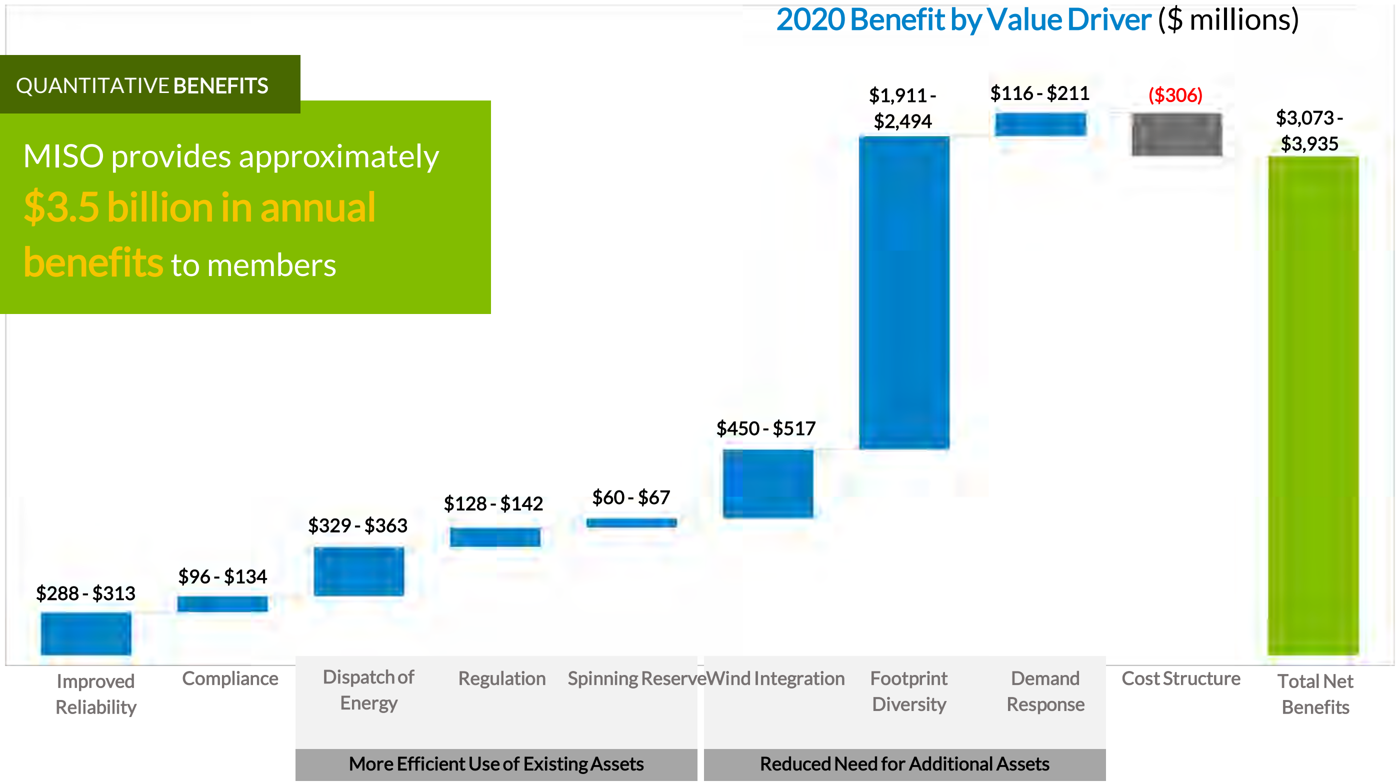
2020 Benefit by Value Driver ($ millions)



MISO 2020 Value Proposition

QUANTITATIVE **BENEFITS**

MISO provides approximately **$3.5 billion in annual benefits** to members



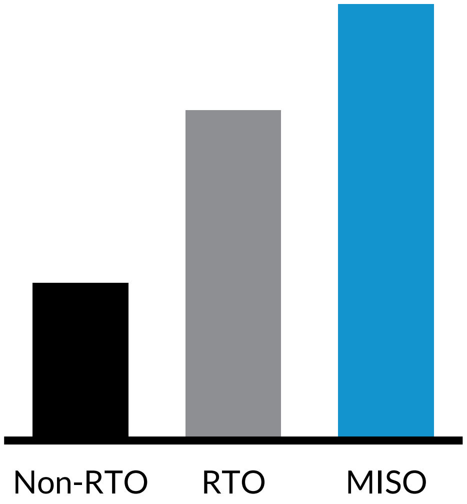
IMPROVED RELIABILITY $288 – $313 Million

MISO's broad regional view and state-of-the art reliability tools enable improved reliability as measured by transmission system availability.

MISO exceeds industry standards in the following categories, improving reliability:

- System monitoring and visualization
- Congestion management
- Backup capabilities
- Operator training
- Performance monitoring
- Procedure updates

Transmission System Availability Index is used to evaluate the value of improved reliability



Transmission System Availability Index

COMPLIANCE $96 – $134 Million

With MISO, FERC and NERC compliance responsibilities have been consolidated and member responsibilities have decreased.

MISO adds quantitative and qualitative value by performing the following compliance activities on behalf of its members:

- Standards development
- NERC compliance
- Tariff compliance
- System planning compliance
- Operations compliance

Internal MISO analyses of full-time equivalent (FTE) personnel savings are used to calculate the value of compliance.

DISPATCH OF ENERGY $329 – $363 Million

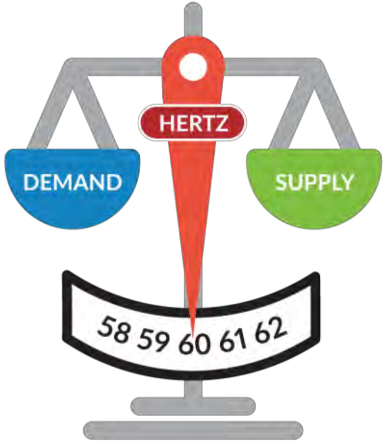
MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.

- Before MISO, the region operated as a decentralized, bilateral market.
- Now, the day-ahead / real-time market processes are used to minimize total production costs.
- Primary purpose of day-ahead market is to clear and schedule sufficient supply to satisfy cleared demand, using the most economic generation resources.
- Real-time market dispatches generation resources to meet actual demand rather than bid demand.
- Real-time dispatch is also based on economics and dynamic congestion management.

REGULATION $128 – $142 Million

With the regulation market, the MISO region moved to a centralized regulation target rather than several non-coordinated regulation targets, which significantly reduced the amount of regulation required.

- Prior to the launch of MISO's regulation market, each balancing authority (BA) maintained regulation within its area. This often resulted in the BAs within MISO's footprint working "against" each other – some regulating up while others were regulating down.
- In addition to creating one centralized regulation target, MISO's regulation market also changed the pricing mechanism for regulation (moving from Tariff pricing to market pricing).
- Capacity from low-cost generation units previously held to meet regulation requirements is now available for energy dispatch.



SPINNING RESERVES $60 – $67 Million

Starting with the formation of the Contingency Reserve Sharing Group (CRSG) and continuing with the implementation of the spinning reserves market, the total spinning reserves requirement declined, freeing low-cost capacity to meet energy market needs.

- Prior to the CRSG, each balancing authority (BA) determined its spinning reserve requirement based on its individual (or Reserve Sharing Group) standards.
- The CRSG improved this by creating standards from which BAs determined their requirements.
- With the spinning reserves market, MISO determines the spinning reserve requirement based on CRSG requirements.
- The spinning reserves market also changed the pricing mechanism for spinning reserves by moving from Tariff pricing to market pricing.

ATTACHMENT 1

WIND INTEGRATION $450 – $517 Million

MISO's regional planning enables more economic placement of wind resources, reducing the overall capacity needed to meet required wind energy output.

Local Design

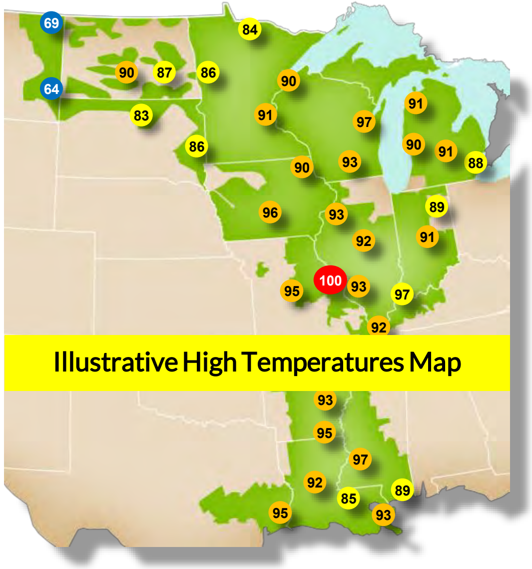
Combination Design

ILLUSTRATIVE

FOOTPRINT DIVERSITY $1,911 – $2,494 Million

Prior to MISO, load-serving entities (LSE) maintained reserves based on their monthly peak-load forecasts. Due to MISO's broad footprint, LSEs now maintain reserves based on their load at the time of the MISO system-wide peak, creating significant savings.

- Regional rather than localized use of the electrical system allows more efficient and effective operation of generation assets while reducing the planning reserve margin needed for reliability.
- An annual revenue requirement is used to calculate an annualized avoided-cost benefit. The annual revenue requirement is estimated based on an annual charge rate that includes rate of return, property tax rate, insurance cost rate, fixed O&M and depreciation. EGEAS software calculates the annual charge rate.



DEMAND RESPONSE $116 – $211 Million

**Demand response defers additional generation investment.
MISO's transparent price information helps market participants make informed market investment decisions related to existing and new load-reducing resources.**

MISO recognizes and compensates four types of demand response:

- Demand Response Resource Type I (energy / capacity)
- Demand Response Resource Type II (energy / capacity)
- Demand Response as a Load Modifying Resource (capacity)
- Emergency Demand Response (energy during emergencies)

An annual revenue requirement is used to calculate an annualized avoided-cost benefit for the capacity deferred due to MISO-facilitated incremental Demand Response.

COST STRUCTURE $306 Million

MISO's administrative costs have remained relatively flat, representing a small percentage of overall benefits.

QUALITATIVE BENEFITS

1 Price/Informational Transparency

Price and data transparency in the MISO market provides a host of benefits that improve market efficiencies, investment decisions and system reliability.

2 Planning Coordination

MISO's transmission planning process is focused on minimizing total cost of delivered power to consumers.

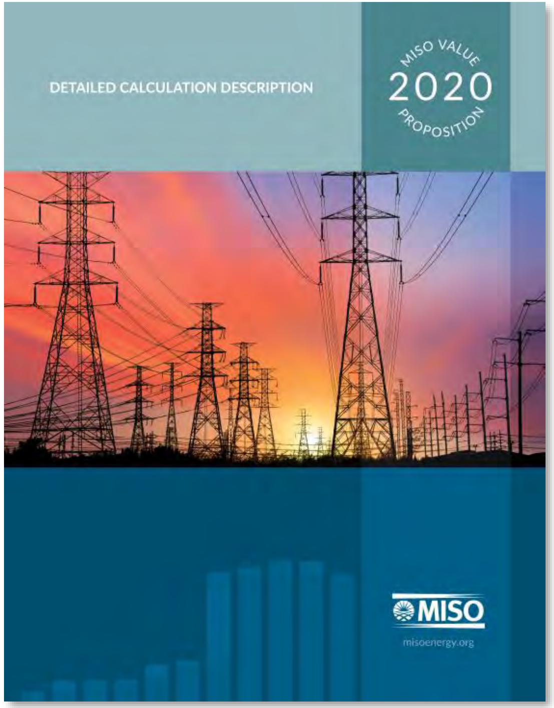
3 Seams Management

MISO adds value by managing the seams around its footprint. Seams management includes interchange transactions, market flows and allocations and the market-to-market process.

ADDITIONAL INFORMATION

- The Value Proposition is posted on misoenergy.org
  > About MISO > MISO Strategy and Value Proposition.

- Please see the Detailed Calculation Description whitepaper for more details.



Questions?

ATTACHMENT 1

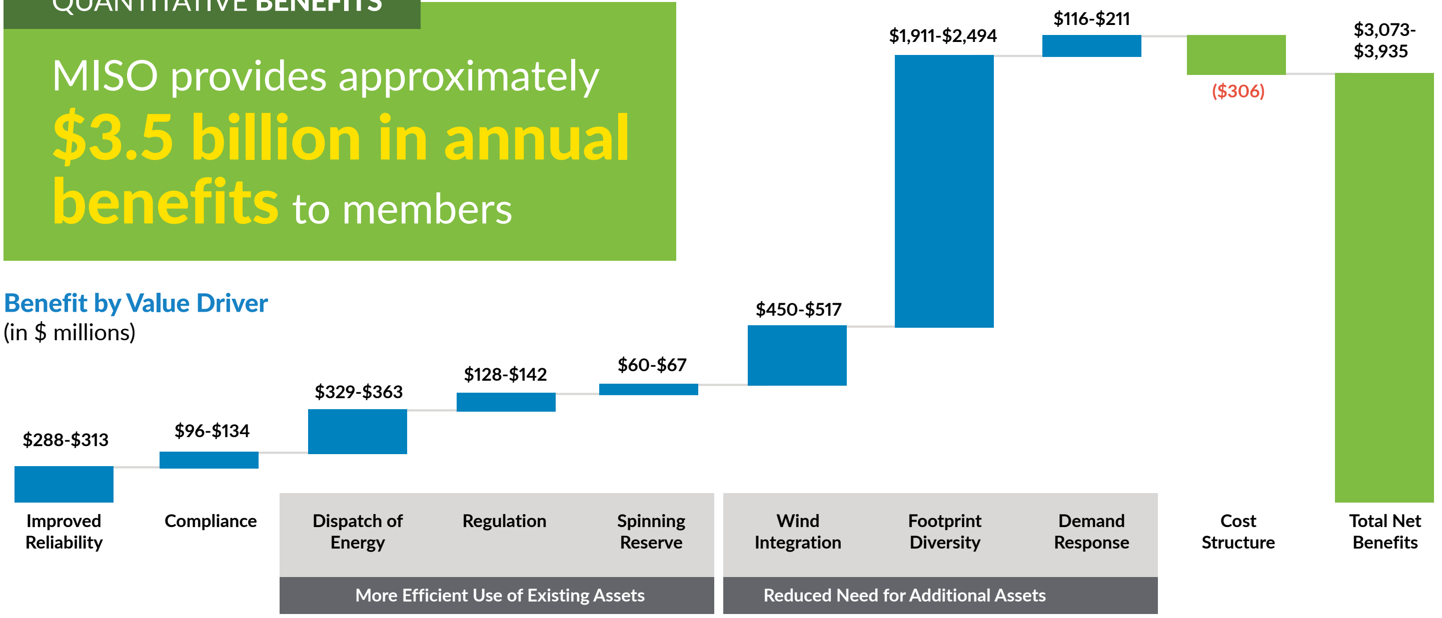
VALUE DELIVERED

MISO VALUE PROPOSITION 2020

QUANTITATIVE **BENEFITS**

MISO provides approximately **$3.5 billion in annual benefits** to members

Benefit by Value Driver
(in $ millions)



IMPROVED RELIABILITY

MISO's broad regional view and state-of-the-art reliability tool set enable improved reliability for the region as measured by transmission system availability.

DISPATCH OF ENERGY

MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.

REGULATION

With MISO's regulation market, the amount of regulation required within the MISO footprint dropped significantly. This is the outcome of the region moving to a centralized common footprint regulation target rather than several non-coordinated regulation targets.

SPINNING RESERVES

Starting with the formation of the Contingency Reserve Sharing Group and continuing with the implementation of the Spinning Reserves Market, the total spinning reserves requirement declined, freeing low-cost capacity to meet energy requirements.

WIND INTEGRATION

MISO's regional planning enables more economic placement of wind resources in the region. Economic placement of wind resources reduces the overall capacity needed to meet required wind energy output.

COMPLIANCE

Before MISO, utilities in the MISO footprint managed FERC and NERC compliance. With MISO, many of these compliance responsibilities have been consolidated. As a result, member responsibilities decreased, saving them time and money.

FOOTPRINT DIVERSITY

MISO's large footprint increases the load diversity, allowing for a decrease in regional planning reserve margins. This decrease delays the need to construct new capacity.

DEMAND RESPONSE

MISO enables demand response through transparent market prices and market platforms. MISO-enabled demand response delays the need to construct additional capacity.

MISO COST STRUCTURE

MISO expects administrative costs to remain relatively flat and to represent a small percentage of the benefits.

QUALITATIVE **BENEFITS**

In addition to the quantitative benefits, MISO also demonstrates significant qualitative benefits that wholesale market participants receive from the operation of MISO, including:

- **Price/Informational Transparency**
- **Planning Coordination**
- **Seams Management**

VALUE PROPOSITION HISTORY

After launching the energy-only market in 2005, the value MISO adds to the region became apparent. To quantify this value, MISO – in collaboration with its stakeholders – created the MISO Value Proposition. The annual Value Proposition study began in 2009 and quantifies the value MISO provides to the region, including MISO market participants and their customers.

The Value Proposition breaks MISO's business model into recognized categories of benefits and calculates a range of dollar values for each defined category.

From 2009 through 2020, the Value Proposition studies revealed that the MISO region realized an estimated $30 billion in cumulative benefits.

The Value Proposition and its calculations, assumptions and supporting information are publicly available at www.misoenergy.org.

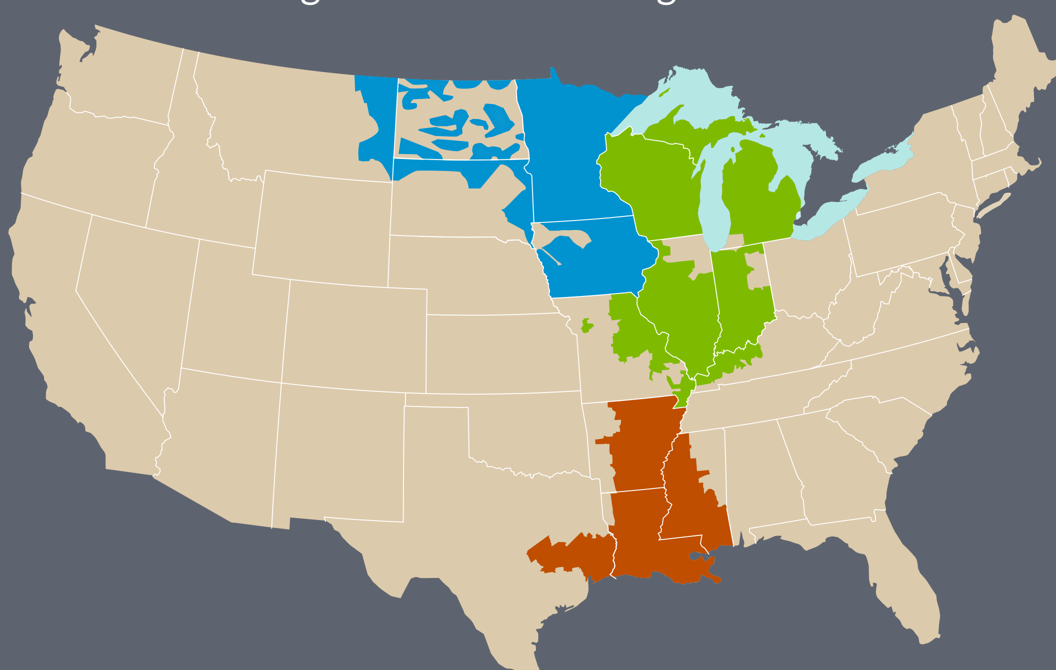
VALUE DELIVERED

MISO ensures reliable operation of and equal access to high-voltage power lines in 15 U.S. states and the Canadian province of Manitoba.

MISO manages one of the world's largest energy markets, covering 965,000 square miles and delivering over 700 terawatt-hours of energy annually to millions of homes. The not-for-profit 501(c)(4) organization is governed by an independent Board of Directors, and is headquartered in Carmel, Indiana.

MISO's Value Proposition continues to document the billions in annual savings its collective efforts unlock for the region. In 2020, those efforts provided between $3.1 billion to $3.9 billion in regional benefits, driven by enhanced reliability, more efficient use of the region's existing transmission and generation assets and a reduced need for the addition of additional assets.

MISO's Value Proposition affirms its core belief that a collective, region-wide approach to grid planning and management delivers the greatest benefit.



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