

Enhancing MISO-SPP Interregional Transmission Planning

RECOMMENDATIONS FOR COORDINATED SYSTEM PLAN

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NOTICE

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Executive Summary

The 2024–2025 Coordinated System Plan (CSP) represents an important step forward in MISO and SPP’s efforts to coordinate interregional transmission planning across their two regions. Earlier CSP studies resulted in limited analysis of interregional upgrades as the initial review of issues resulted in no identified needs. The current CSP study has identified significant economic and reliability needs along the MISO South–SPP South seam and evaluated potential interregional solutions to address those needs. The August 2026 results represent further progress compared to previous CSP cycles, with two candidate solutions moving forward for additional evaluation as MISO and SPP work toward final project selection in the 2024-2025 CSP and prepare for the upcoming 2026 CSP cycle to begin.

While significant progress has been made, several aspects of the current CSP study understate the value of interregional transmission and result in the premature elimination of several promising solutions. Addressing these issues would strengthen the basis for the final results in the 2024-2025 CSP study and improve the process for future CSP cycles.

We identify four key issues with the current CSP analysis:

1. **The CSP evaluates a limited range of transmission benefits.** The current analysis is narrower than both the MISO-SPP Joint Operating Agreement and the frameworks MISO and SPP use in their regional planning processes. Screening projects primarily on adjusted production cost (APC) savings risks eliminating projects that provide value through avoided reliability investments, capacity-related benefits, or performance during stressed system conditions.
2. **The production cost modeling understates economic benefits.** CSP modeling does not fully capture conditions that increase the value of additional transfer capability, including extreme weather, transmission outages, fuel-price volatility, and real-time uncertainty. Historical market prices show that a disproportionate share of transmission value occurs during a relatively small number of high-value hours that are not reflected in normalized production cost simulations like those completed in this study.
3. **The proposed cost allocation does not reflect the full distribution of benefits.** MISO and SPP currently propose to allocate project costs between the RTOs based solely on APC savings, resulting in most of the costs allocated to SPP. If the supplemental analysis identifies

significant reliability or extreme-weather benefits in MISO, an APC-only allocation could assign SPP a disproportionate share of project costs relative to the benefits received by each region.

4. [The proposed solutions may be undersized for future system needs.](#) SPP approved significant 765 kV development in the region, while MISO is also advancing 765 kV facilities in other parts of its system. Developing new facilities at 345 kV or 500 kV could leave lower-voltage interregional ties between higher-voltage regional networks and make future expansion more costly.

Importantly, several of these concerns can be addressed before MISO and SPP complete the 2024–2025 CSP. We specifically recommend that the RTOs implement the following changes to identify the most cost-effective solutions in the current CSP study:

- Extend the supplemental benefits analysis to all five of the remaining solutions.
- Evaluate each solution based on its total quantified benefits.
- Incorporate supplemental benefits into the RTO-to-RTO cost allocation.
- Assess whether cost-effective solutions should be designed to be 765 kV-ready.

Looking ahead, the 2026 CSP provides an opportunity to make broader improvements to the planning framework. We recommend that future CSPs: (1) expand the benefits framework to reflect the metrics MISO and SPP already use in their regional planning processes and (2) validate production cost modeling against observed market outcomes to determine whether the simulations reasonably reproduce historical congestion, price separation, and transmission value during stressed conditions.

MISO and SPP have already done much of the difficult work required to move interregional planning from identifying needs toward evaluating actionable investments. Addressing these remaining issues would provide a stronger basis for selecting projects, allocating their costs, and ensuring that the investments approved through the CSP reflect the full value of interregional transmission between MISO and SPP.

I. 2024-2025 Coordinated System Plan

The Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP) have implemented successful proactive regional transmission planning processes that have resulted in significant long-term, multi-value transmission portfolios that reduce costs and increase the reliability of their markets. MISO and SPP together also engage in interregional transmission planning between their two markets through the Coordinated System Planning (CSP) process. Past CSP studies have been limited in scope, as initial reviews of interregional issues identified no needs requiring further study.¹ In contrast, the current 2024-2025 CSP cycle has identified significant needs along the MISO South-SPP Southeast seam that require a detailed study of interregional transmission drivers, solutions, and benefits. The 2024-2025 CSP is now nearing completion while SPP and MISO are concurrently developing plans for the next CSP cycle to start in late 2026.²

The 2024-2025 CSP process represents important progress in MISO and SPP's efforts to jointly plan their interconnected transmission systems. The Regional Transmission Organizations (RTOs) have undertaken a proactive assessment of needs over the next 15 years, solicited transmission solutions, and advanced several candidate projects for detailed evaluation. MISO and SPP are currently on track to approve their first economically-driven interregional transmission upgrade but also have prematurely eliminated promising solutions.³ The 2024-2025 CSP identified several improvements that the RTOs are planning to address in the 2026 CSP study. Further work is needed to address limitations in the CSP framework and ensure that the process fully captures the value of interregional transmission investments.

In this section, we summarize the key findings and results from the 2024-2025 study to date. We then turn to identifying concerns with the 2024-2025 CSP study and recommending improvements to the process for identifying cost-effective interregional upgrades between SPP and MISO.⁴

¹ MISO and SPP, Petition for Waiver of Tariff Provisions, Docket No. ER25-943-000 (January 15, 2025), p. 5.

² MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), p. 28.

³ MISO and SPP, Petition for Waiver of Tariff Provisions, Docket No. ER25-943-000 (January 15, 2025), p. 5.

⁴ This report builds on comments submitted by The Brattle Group on behalf of the Southern Renewable Energy Association on September 4, 2026 regarding the 2024–2025 CSP Study Presentation presented at the August 14, 2026 MISO-SPP Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting.

A. Transmission Needs Across the MISO-SPP Seam

The 2024-2025 CSP needs assessment identified significant economic and reliability issues along the seam between MISO and SPP. Based on jointly-developed reliability and economic planning models, preliminary results identified approximately 350 reliability-driven issues and 280 economic-driven issues that could be addressed by interregional upgrades.⁵ Importantly, SPP South exhibits relatively high levels of economic congestion, creating opportunities for transmission to reduce production costs by allowing lower-cost resources to serve load more efficiently. MISO South, by comparison, exhibits more significant reliability needs, creating opportunities for interregional transmission to avoid or defer reliability-driven upgrades in MISO.

The CSP’s screening analysis illustrates this distinction, as shown in Table 1 below. Across the regions’ most congested flowgates, the aggregate congestion measure provided to stakeholders was approximately 2.3 times as high in SPP as in MISO in the 2034 and 2039 study years.⁶ At the same time, the reliability analysis identified substantially more reliability violations in MISO than SPP across the modeled scenarios (3x in summer, 24x in winter, and 6x in light load in CSP’s 15-year forecast scenarios).⁷

TABLE 1. CSP RELIABILITY AND CONGESTION TRANSMISSION NEEDS METRICS

Metric		MISO	SPP
Average congestion measure at top 5 flowgates	<i>\$/MW</i>	\$384,745	\$871,458
Reliability issues (Total)	<i>Number issues</i>	659	155
Reliability issues (Summer)	<i>Number issues</i>	302	68
Reliability issues (Winter)	<i>Number issues</i>	55	50
Reliability issues (Light Load)	<i>Number issues</i>	302	37

Source: MISO and SPP, SPP-MISO Interregional Planning Stakeholder Advisory Committee 2024-25 CSP Study Results (March 6, 2026), p. 14.

These differences demonstrate that the value of an interregional project will provide differentiated and significant market-specific benefits on both sides of the seam. Interregional projects could, for example, provide significant production cost savings to SPP while allowing MISO to avoid or defer otherwise necessary reliability investments. A benefits framework capable of recognizing these different sources of value is critical to effectively evaluate potential solutions along the MISO-SPP seam.

⁵ MISO and SPP, [SPP-MISO Interregional Planning Stakeholder Advisory Committee](#) (August 6, 2025), p. 10.
⁶ MISO and SPP, SPP-MISO Interregional Planning Stakeholder Advisory Committee 2024-25 CSP Study Results (March 6, 2026), p. 14.
⁷ MISO and SPP, SPP-MISO 2024-25 Coordinated System Plan Study Report Draft (March 2026), p. 11

B. Benefits Evaluation Framework

The Joint Operating Agreement (JOA) between MISO and SPP provides the framework needed for evaluating the benefits of potential interregional economic projects between the two RTOs. Specifically, the JOA specifies that the economic benefits considered in the CSP include adjusted production cost savings, reliability benefits, and public policy benefits.⁸ In addition, the JOA states that “[o]ther benefit metrics may be added to the evaluation of the overall benefits of interregional projects in the CSP ... if those benefits metrics are agreed upon by both regions.”⁹

The RTOs confirmed this approach would be utilized in the current CSP study. During the May 2025 stakeholder meeting, SPP and MISO explained that benefits would be measured using the JOA criteria, including adjusted production cost (APC) savings, avoided or deferred reliability projects, and public policy benefits.¹⁰ Similarly, cost allocation of interregional economic projects (or the “RTO Split”) will be “proportional to APC savings + avoided reliability cost + avoided public policy projects + other mutually agreed upon benefit metrics.”¹¹ The JOA-specified approach to benefits analysis and cost allocation aligns well with the differing needs identified in the earlier screening analysis, allowing MISO and SPP to (1) account for market-specific needs; (2) identify cost-effective interregional solutions to support future load growth in each of their systems; and (3) fairly allocate the costs between ratepayers in both markets.

FIGURE 1: 2024-2025 CSP BENEFITS QUANTIFIED



Source: MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), p. 18.

⁸ MISO and SPP, Joint Operating Agreement Between the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc., § 9.6.3.1.1 “Determination of Benefits to each RTO from Interregional Project”, effective Nov. 14, 2024 (“MISO-SPP JOA”), p. 126.

⁹ Ibid.

¹⁰ MISO and SPP, SPP-MISO IPSAC CSP Studies Update, (May 14, 2026), p. 7.

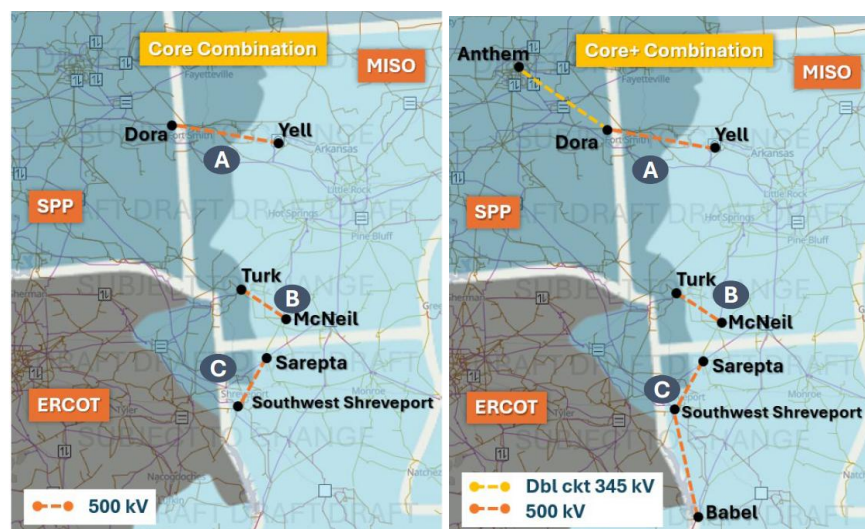
¹¹ MISO and SPP, SPP-MISO IPSAC CSP Studies Update, (May 14, 2026), p. 8.

As the CSP study progressed this summer, however, the RTOs separated the benefits analysis into two stages. First, the APC savings became the sole benefit metric used in the portfolio evaluation for justifying the approval of economic interregional projects and also for determining the RTO-to-RTO allocation of costs, as shown in the green box in the figure above.¹² Second, further benefits evaluation would include the analysis of “supplemental benefits” just for projects with sufficient APC savings to exceed their costs, shown by the two blue boxes. The supplemental benefits include avoided reliability investment and mitigating extreme weather impacts. This distinction has become an important feature of the current CSP process and is discussed further in later sections of this whitepaper.

C. Identification of Interregional Solutions

Following the identification of system needs, MISO and SPP solicited interregional solutions from stakeholders and received 70 proposed solutions. They then screened the solutions for their ability to address the identified interregional needs.¹³ Through that process, the RTOs focused their evaluation on five solutions across three corridors along the MISO-SPP seam.¹⁴

FIGURE 2. 2024-2025 MISO-SPP CSP PORTFOLIOS EVALUATED



Source: MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), pp. 10-11.

¹² MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), p. 17.

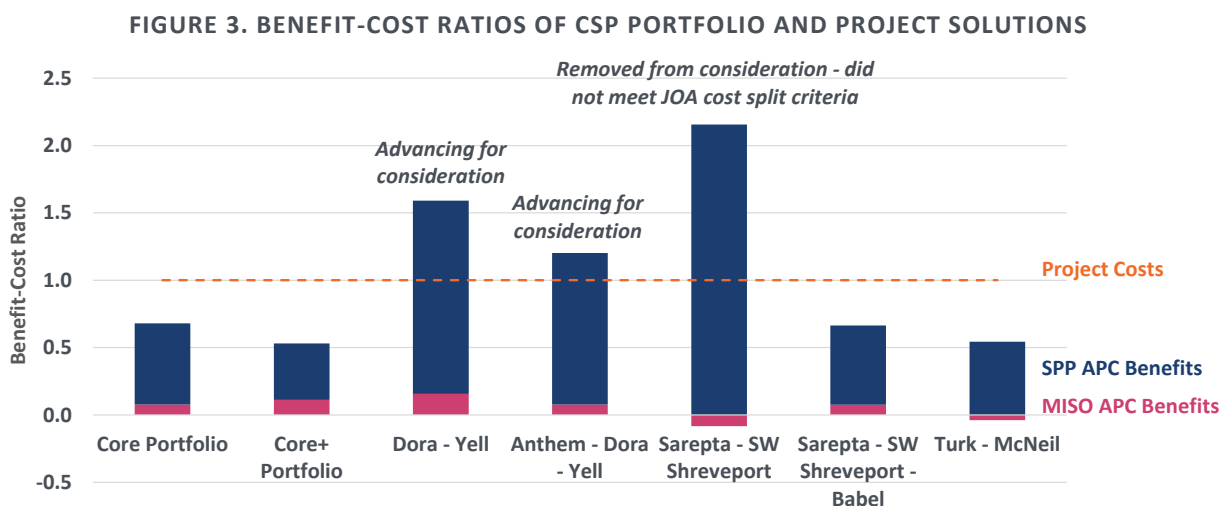
¹³ MISO and SPP, SPP-MISO 2024-25 Coordinated System Plan Study Report Draft (March 2026) (“2024-2025 CSP Study Report Draft”), p. 2

¹⁴ MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), p. 9.

The candidate solutions include transmission upgrades connecting portions of Oklahoma, Arkansas, Louisiana and Texas and were grouped into the “Core” and “Core+” portfolios shown in Figure 2 above.¹⁵ The Core portfolio includes lower-cost upgrades within each corridor, while the Core+ portfolio incorporates additional or higher-capacity facilities to address broader needs.

D. Quantification of Project Benefits

At the August 2026 stakeholder meeting, MISO and SPP presented the first quantified benefit results for the candidate 2024-2025 CSP solutions and portfolios.¹⁶ These benefits results reflected only the APC analysis, which estimates how transmission expansion changes the costs to operate and serve load on each system under the modeled conditions. The results, summarized in Figure 3 below, show that the two solutions in the northern corridor between Oklahoma and Arkansas (Dora-Yell and Anthem-Dora-Yell) produced sufficient APC savings to advance to further consideration. The benefits of these projects were concentrated heavily in SPP, with over 90% of the APC savings in both cases.¹⁷



Source: MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), pp. 10-11.

However, two other solutions (Sarepta-SW Shreveport-Babel and Turk-McNeil) and the two combined portfolios did not produce sufficient APC savings to cover their costs. The Sarepta-SW Shreveport upgrade had sufficient APC savings in SPP to justify the project, but a negative cost impact on MISO, such that it did not qualify as an interregional project. Those solutions were thus

¹⁵ MISO and SPP, SPP-MISO 2024-25 Coordinated System Plan Study Report Draft (March 2026), pp. 17-18.

¹⁶ MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), pp. 9-11.

¹⁷ MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), pp. 10-11.

removed from further consideration before the remaining analyses of supplemental benefits have been completed.¹⁸ The additional analyses of extreme-weather and avoided-reliability benefits would instead be conducted just for the two solutions that remain under consideration in the northern corridor.¹⁹

E. Completing the 2024-2025 CSP Study

MISO and SPP are currently continuing their evaluation of the two remaining candidate solutions. They will be completing additional benefit analyses that include reliability benefits from avoided or deferred reliability upgrades as well as production cost savings and avoided load shed during extreme market conditions, both of which could produce sizeable benefits for the solutions analyzed based on the initial 2024-2025 CSP needs analysis. These final steps of the 2024-2025 CSP study will inform which solutions ultimately advance to approval, but will not impact the cost allocation between SPP and MISO for the solution that is ultimately selected.

II. Concerns with the CSP Analysis

Taken as a whole, the 2024-2025 CSP represents meaningful progress for interregional planning between the RTOs. MISO and SPP have identified substantial and complementary needs along their seam, solicited and evaluated potential solutions, and advanced interregional projects farther through the planning process than in prior CSP cycles. The continued advancement of the two Oklahoma-Arkansas solutions represents an opportunity to approve economic interregional projects in the 2024-2025 CSP study. However, the decision to eliminate promising solutions on the other two corridors at this stage of the CSP study reflects limitations in the completeness of the RTOs' benefits analysis to-date.

Across several aspects of the RTOs' analysis, the current approach recognizes a narrower set of benefits than the solutions provide, places greater weight on normalized operating conditions, and gives less consideration to value of the solutions under a multi-value framework specified by the JOA that includes reliability, system stress, and longer-term system needs. Together, these choices can systematically understate the value of interregional transmission and skew the

¹⁸ MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), p. 9.

¹⁹ MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), p. 9, 13.

comparison among alternatives. The result is a risk of prematurely eliminating cost-effective projects, allocating costs in a way that does not fully reflect the distribution of benefits, and favoring smaller investments that may be less efficient to expand as future needs grow.

The sections below examine these concerns in greater detail and assess how they affect the valuation, selection, cost allocation, and sizing of potential interregional solutions. Where relevant, we compare the CSP approach with evidence from MISO and SPP's regional planning processes, historical market outcomes, and other transmission-planning studies in the region to illustrate the magnitude and implications of the value not captured by the RTOs' approach.

A. Limited Evaluation of Transmission Benefits

The 2024-2025 CSP captures only a subset of the benefits that interregional transmission projects can provide to each of their systems. As mentioned, under the JOA, MISO and SPP may consider APC savings, reliability benefits, and public policy benefits when assessing project value. In addition, they can further analyze additional benefits mutually agreed upon.²⁰ This framework provides MISO and SPP with the ability to implement a comprehensive approach to evaluating the benefits of interregional projects.

However, the 2024-2025 CSP analysis completed to date is significantly narrower than what the JOA allows. As noted above, the benefits evaluation has focused just on conventional production cost savings, while reliability and extreme-weather benefits are being evaluated separately and only for the solutions that advanced beyond the initial screen.²¹

The CSP approach is also narrower than the frameworks MISO and SPP use to evaluate long-term, multi-value transmission investments within their respective regions. As shown in Table 2, MISO's Long Range Transmission Planning (LRTP) process and SPP's Integrated Transmission Planning (ITP) process each quantify a broader range of benefits, including avoided reliability investments, transmission losses, resource adequacy and capacity-related benefits, and benefits arising under

²⁰ MISO and SPP, Joint Operating Agreement Between the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc., § 9.6.3.1.1 "Determination of Benefits to each RTO from Interregional Project", effective Nov. 14, 2024 ("MISO-SPP JOA"), p. 126.

²¹ MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), p. 9.

stressed system conditions. In its LRTP Tranche 2.1 analysis, MISO quantified nine categories of benefits, while SPP’s 2025 ITP included seven.²²

TABLE 2. TRANSMISSION BENEFITS INCLUDED IN MISO AND SPP TRANSMISSION STUDIES

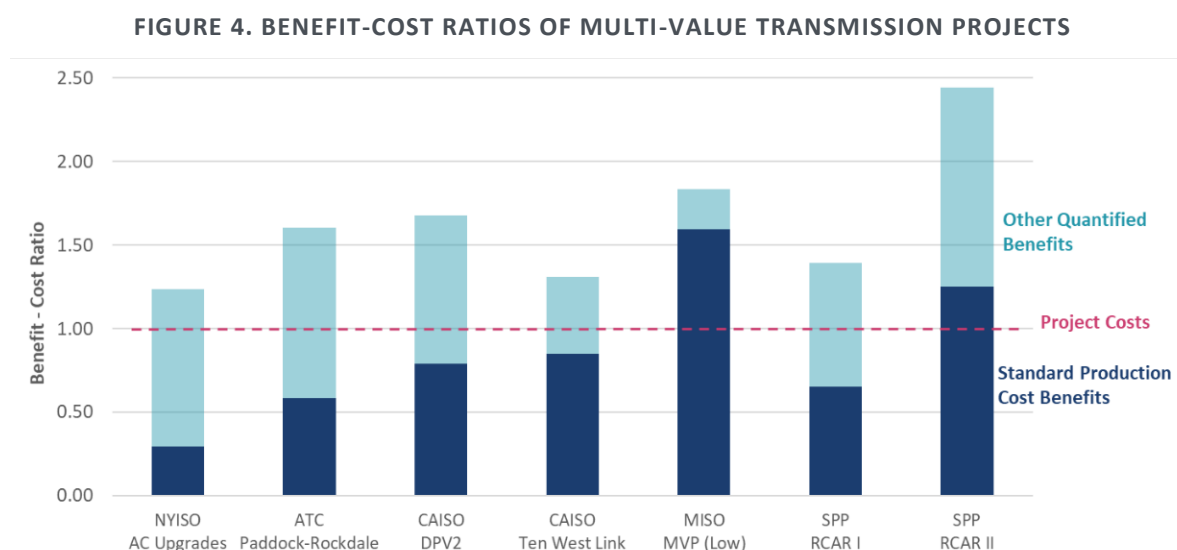
Transmission Benefit	MISO-SPP 2024-25 CSP	MISO LRTP T2.1	SPP 2025 ITP
1. Traditional Production Cost Savings	Yes	Yes	Yes
2. Additional Production Cost Savings			
-- Reduced impact of forced generation outages			
a. Reduced transmission energy losses		Yes	Yes
b. Reduced congestion due to transmission outages		Yes	Yes
c. Mitigation of extreme events and system contingencies	Supp. Only	Yes	
d. Mitigation of weather and load uncertainty			
e. Reduced costs due to imperfect foresight of real-time conditions			
f. Reduced cost of cycling power plants			
g. Reduced amounts and costs of ancillary services			Yes
h. Mitigation RMR conditions			
i. Realistic representation of system utilization in “Day-1” markets			
3. Reliability and Resource Adequacy Benefits			
a. Avoided or deferred reliability projects	Supp. Only	Yes	Yes
b. Reduced loss of load probability; or:			
c. Reduced planning reserve margin		Yes	
4. Generation Capacity Cost Savings			
a. Capacity cost benefits from reduced peak energy losses		Yes	Yes
b. Deferred generation capacity investments			
c. Access to lower-cost generation			
5. Market Benefits			
a. Increased competition			
b. Increased market liquidity			
6. Environmental Benefits			
a. Reduced emissions of air pollutants		Yes	Yes
b. Improved utilization of transmission corridors			
7. Public Policy Benefits			

MISO’s regional planning experience illustrates why the CSP’s limited evaluation of benefits can be consequential. MISO’s market efficiency process evaluates economically driven transmission projects largely based on whether they reduce production costs and congestion, while its multi-value planning framework evaluates broader portfolios of transmission by considering a wider range of system benefits, including reliability, economic, and other regional benefits. Since 2009, MISO has approved approximately \$247 million of transmission upgrades through its market

²² MISO, [LRTP Tranche 2.1 Benefits Analysis Results Review](#), (September 13, 2024), p. 6; and SPP, [2025 Integrated Transmission Planning Assessment Report](#) (November 25, 2025), p. 242. The MISO LRTP T2.1 Review outlines nine benefits; we have condensed two of its reliability benefits under ‘Avoided or deferred reliability projects.’

efficiency process.²³ By contrast, MISO has approved more than \$30 billion of transmission investment over the past four years through its multi-value planning framework, which recognizes a broader set of benefits.²⁴ Given this track record in MISO, it is not surprising that solely quantifying the production cost benefits of MISO-SPP interregional projects has not justified the need for more upgrades.

Looking more broadly across RTO transmission planning processes, experience from other regions illustrates why evaluating a broader set of benefits can have a large effect on which transmission projects are found to be cost-effective. As shown in Figure 4, production cost benefits would have fallen short of project costs for five of the seven projects examined. Once additional quantified benefits-such as reliability, capacity, and other system benefits-were included, however, each project produced total benefits exceeding its costs.²⁵



Source: Johannes Pfeifenberger, *et al.* (The Brattle Group and Grid Strategies), [Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs](#), October 2021.

The limited set of benefits considered in the CSP creates a risk that valuable interregional projects will not advance because important sources of system value are excluded from the initial evaluation. A more comprehensive benefits framework would allow the CSP to evaluate interregional projects on a basis consistent with the RTOs’ regional planning practices and more accurately identify projects that provide value across the seam.

²³ MISO, “MTEP Appendix A In Service Projects,” accessed September 3, 2026.

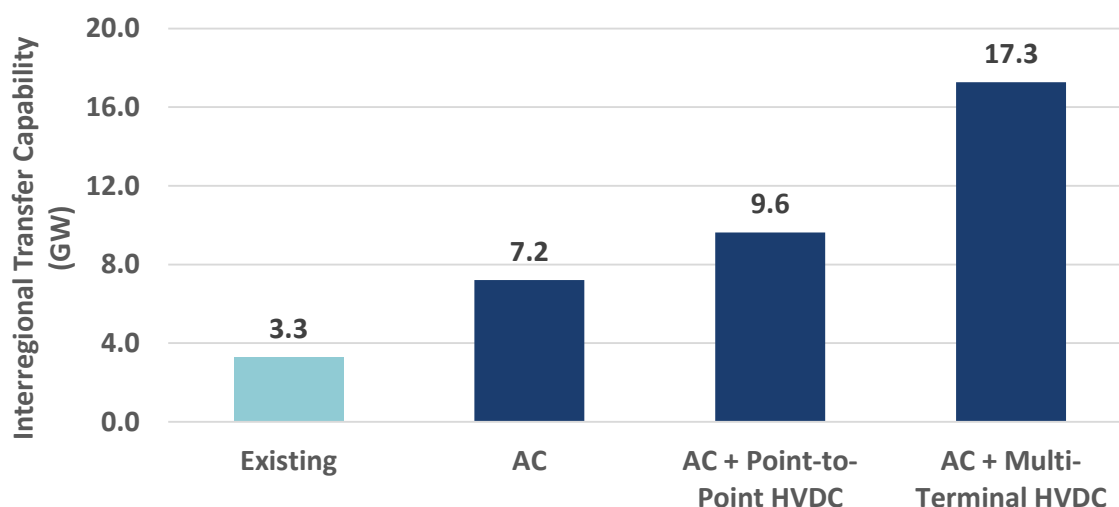
²⁴ MISO, “Long Range Transmission Planning,” <https://extranet.misoenergy.org/planning/long-range-transmission-planning>, accessed September 3, 2026.

²⁵ Johannes Pfeifenberger, *et al.* (The Brattle Group and Grid Strategies), [Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs](#), October 2021, p. 31-33.

The U.S. Department of Energy’s National Transmission Planning Study (NTPS) provides insights into the level of economically optimal transmission at the MISO South-SPP South seam. To do so, the study evaluates transmission needs under a wide range of future demand, generation, and policy scenarios. We specifically focus on the High Demand + Current Policies scenarios as they study the value of transmission driven by higher load growth, while assuming state and federal policies enacted at the time of the study are achieved. Under these scenarios, DOE’s model optimized the total amount of transmission expansion at the MISO South-SPP South seam to minimize total system costs with a combination of transmission technologies.

When expansion was limited to alternating current (AC) transmission, DOE found 7.2 GW of cost-effective transfer capability at this seam by 2035, compared with the existing baseline of 3.3 GW. The cost-effective level increased to 9.6 GW when point-to-point HVDC was available and to 17.3 GW when multiterminal HVDC was also available.²⁶ While the NTPS study was completed at the national level and did not identify specific projects, the magnitude of economic transmission expansion identified across MISO South-SPP South indicates that the CSP’s limited production cost benefits approach may be undervaluing the need at this seam.

FIGURE 5. DOE NATIONAL TRANSMISSION PLANNING STUDY’S MODELED EXPANSION OF TRANSFER CAPABILITY BETWEEN MISO SOUTH AND SPP SOUTH



Source: National Renewable Energy Laboratory (NREL), *National Transmission Planning Study – Long-Term Modeling Results*, “Transmission Map.csv,” dataset last updated October 9, 2024.

Evaluating a limited scope of transmission benefits can bias the CSP toward both underinvestment overall and the selection of undersized projects. When benefits are

²⁶ National Renewable Energy Laboratory (NREL), *National Transmission Planning Study – Long-Term Modeling Results*, “Transmission Map.csv,” dataset last updated October 9, 2024

understated, lower-cost solutions can appear more attractive even where a larger investment would provide greater long-term value. This creates a risk of inefficiently under-sizing interregional facilities and requiring more costly upgrades in the future. Together, these limitations could leave customers with higher costs and greater exposure to congestion-related price spikes and reliability challenges, particularly during extreme weather when neighboring regions can provide valuable support to one another.

B. Understated Production Cost Savings

Because APC savings are the primary quantified benefit used in the current CSP evaluation, accurately estimating those savings is important to identifying which interregional solutions provide value and will ultimately be approved by the RTOs. The current production cost modeling, however, does not fully capture several conditions that can increase the value of additional transfer capability, including extreme weather, generation and transmission outages, and fuel-price volatility. It also does not include the value of transmission in the real-time market, which tends to be more volatile than day-ahead market conditions and when transmission provides significant value to ratepayers. These limitations result in the CSP understating the production cost savings of the proposed solutions particularly during challenging market conditions.

The importance of modeling challenging market conditions when evaluating the production cost savings of transmission is captured in an analysis by Lawrence Berkeley National Laboratories (LBNL). LBNL analysis of a decade of historical market prices demonstrates that approximately 50% of total regional and interregional transmission value is concentrated in just 5% of all hours, with 20–30% concentrated in only 1% of hours.²⁷ Importantly, a substantial portion of this value is not reflected in day-ahead markets and instead materializes during real-time operations. LBNL finds that “unforeseen intraday variance, high net load, cold weather, or high renewable generation conditions are present in over 90% of the hours with peak transmission value.”²⁸ Given that the MISO and SPP production cost model accounts for normalized market conditions and does not yet account for more challenging conditions proposed to be modeled in the “supplemental benefits” analysis, it is unlikely that SPP or MISO are capturing the benefits of the proposed solutions during the most challenging hours in the results presented so far.

²⁷ D. Millstein, et al. (Lawrence Berkeley National Laboratory), Empirical Estimates of Transmission Value using Locational Marginal Prices, August 2022, p. 27

²⁸ J. Kemp, et al. (Lawrence Berkeley National Laboratory), Electric Transmission Value and Its Drivers in United States Power Markets, August 2025, p. 9.

Several studies have demonstrated the significant historical value of interregional transmission across the MISO South-SPP South seam during periods of extreme weather and system stress. For example, Grid Strategies estimated in its 2025 assessment of transmission resilience benefits that each additional 1 GW of transfer capability between SPP South and MISO South could have provided approximately \$110 million in savings during Winter Storm Uri in 2021.²⁹

To assess whether transmission value is similarly concentrated at the MISO South-SPP South seam, we analyzed historical energy arbitrage value from 2021 through 2025. Using hourly locational marginal prices (LMPs) at the SPP South Hub and MISO Arkansas Hub, we estimated the potential energy arbitrage value associated with additional transfer capability between the two regions.

The historical data confirm that transmission value between MISO South and SPP South is concentrated in a relatively small number of high-value hours. As shown in Table 3, the top 1% of hours accounted for more than 10% of annual energy arbitrage value on average from 2021 through 2025. This concentration was particularly pronounced in 2021 with Winter Storm Uri, when the top 1% of hours accounted for 25% of annual value. The top 5% of hours across the past five years account for about 22% of the value. These results reinforce LBNL’s finding that production cost simulations based on normalized assumptions miss a significant source of transmission value when they do not capture the frequency or severity of market conditions.

TABLE 3. HISTORICAL ENERGY VALUE OF TRANSMISSION BETWEEN MISO SOUTH AND SPP SOUTH

	Energy Arbitrage Value	Percent Contribution of Top n% Hours			
	<i>thousands of nominal \$/year</i>	1%	2%	5%	10%
2021	\$297	25%	31%	36%	42%
2022	\$314	9%	11%	16%	23%
2023	\$149	6%	9%	14%	21%
2024	\$194	7%	10%	18%	25%
2025	\$214	10%	13%	19%	25%
2021-2025 Average	\$234	13%	16%	22%	29%

A more direct assessment of the CSP’s production cost savings would compare the energy arbitrage value using the hourly prices produced by the CSP model and compare those results with historical LMPs. This comparison could help determine whether the CSP modeling captures the economic value observed under real-world market conditions, particularly during periods of system stress. However, MISO and SPP do not publicly provide the hourly modeled price outputs

²⁹ Michael Goggin (Grid Strategies LLC), Transmission Makes the Power System Resilient to Extreme Weather, prepared for ACORE, July 2021, p. 11.

underlying the CSP results, preventing stakeholders from independently evaluating this aspect of the analysis.

Simulating production cost savings during extreme weather events will address one of the limitations of the CSP's production cost modeling, but others exist as well. Real-world power systems are much more volatile throughout the year than the simulated system due to challenging conditions such as planned and forced transmission outages and fluctuations in natural gas prices that will increase the production cost savings of the solutions. Since the simulations have perfect foresight of market conditions, even simulations that model challenging conditions (such as heat waves and cold snaps) most closely replicate day-ahead market conditions. They do not account for uncertainty and the much higher level of volatility experienced during the real-time market conditions when there are fewer options to respond to the challenges. As noted above, LBNL estimated that the majority of the most challenging conditions are not visible on a day-ahead basis and are realized only in real-time markets.³⁰ Modeling the added congestion and production costs due to outages on the existing transmission (e.g., based on historical experience near the evaluated projects) and other factors that drive tight market conditions would additionally be necessary to achieve realistic estimates of production cost savings.

C. Cost Allocation Based on Production Cost Savings

Due to the limited scope of its benefits analysis, MISO and SPP changed their proposed approach to cost allocation for economic interregional projects.³¹ Instead of utilizing all quantified benefits to allocate costs between the two markets, the updated approach solely relies on the APC savings to do so. This approach could result in the RTOs paying a disproportionate share of total project costs for approved lines.

For the two solutions with sufficient APC savings to justify their costs, the APC benefits are much higher for SPP than MISO. This approach to cost allocation is likely to result in approximately 90%

³⁰ Lawrence Berkeley National Laboratory, Electric Transmission Value and its Drivers in United States Power Markets, August 2025, p. 9

³¹ The May 2026 stakeholder materials included a broader set of benefits for splitting costs between the markets including all of the benefits proposed to be evaluated in the 2024-2025 CSP study. However, the same table in the August presentation showed a different approach and only included production cost savings. See: MISO and SPP, MISO-SPP IPSAC CSP Studies Update (May 14, 2026), p. 8; and MISO and SPP, MISO-SPP IPSAC CSP Studies Update (August 14, 2026), p. 17.

of the costs of the approved projects being allocated to SPP and 10% to MISO.³² However, the 2024-2025 CSP reliability analysis demonstrated that MISO has disproportionately higher reliability needs along the seam that would be resolved by the proposed solutions.

The supplemental benefits analysis will provide more information on which of the solutions in the northern corridor provides the most benefits to the markets by quantifying the incremental production cost savings during extreme market conditions and the additional cost savings of avoided reliability upgrades. If that supplemental analysis finds a more even split of benefits between the two markets, the proposed cost allocation approach would not reflect those additional benefits to MISO and could therefore over-allocate the share of project costs to SPP.

For example, the Anthem (345) – Dora – Yell 500 kV project resolves 52 reliability violations in MISO and creates 20 new violations in SPP.³³ A hypothetical example helps explain how considering reliability benefits in the cost allocation would change each RTO's cost responsibility. If the avoided reliability upgrades analysis were to demonstrate \$250 million of avoided reliability costs in MISO and no reliability value in SPP under this example, the total quantified benefits would shift from approximately 94% in SPP to 83%. Applied to the capital cost of the solution, an 11% difference in the split of benefits from SPP to MISO would result in MISO paying for an additional \$172 million for the interregional upgrade based on the broader set of benefits.³⁴

While these specific figures are illustrative, they show a structural concern that cost allocation based solely on APC risks allocating costs in a way that is disproportionate to the benefits received in each market. If the avoided reliability costs are significantly higher for MISO than SPP, shifting costs from SPP to MISO would be supported by the analysis. However, the current proposal for how to allocate costs only reflects the use of APC, such that SPP would pay for more than its fair share of costs for the interregional project.

D. Undersizing Solutions for Future Needs

Finally, a fourth concern is that the proposed CSP solutions may not be appropriately sized for the transmission system that MISO and SPP are already planning to develop. As mentioned previously, evaluating a limited scope of transmission benefits can bias the CSP toward the selection of undersized projects. In their regional plans, SPP has approved a significant expansion

³² MISO and SPP, MISO-SPP IPSAC CSP Studies Update (August 14, 2026), pp. 10-11.

³³ MISO and SPP, MISO-SPP IPSAC CSP Studies Update, (August 14, 2026), p. 11.

³⁴ Based on the \$1,614 million capital costs of the project noted on slide 11.

of its 765 kV network, including at the Anthem and Southwest Shreveport substations included in the CSP study, while MISO is also pursuing 765 kV solutions in its Midwest subregion.³⁵ In this context, developing new interregional facilities at only 345 kV or 500 kV could leave the seam dependent on lower-voltage facilities between higher-voltage networks on either side. American Electric Power (AEP) raised a similar concern in its comments on the March 2026 draft CSP Report, arguing that interregional tie lines should be sized so that they do not become the limiting element for transfers between the regions and recommending that MISO and SPP evaluate 765 kV alternatives.³⁶

Undersizing the transmission investments risks locking the system and customers into infrastructure that is more costly to expand in the future. AEP points to SPP's recent planning experience as an example of this risk: SPP approved a double-circuit 345 kV project in its 2021 ITP, followed by another nearby 345 kV project and ultimately a 765 kV project in subsequent planning cycles. AEP argues that this sequence illustrates how incremental planning can lead to unnecessary costs and development challenges rather than providing a more efficient long-term solution upfront.³⁷ Transmission lines are long-lived assets, and a substantial share of the cost and difficulty of developing new corridors is associated with siting, permitting, acquiring rights-of-way, and constructing the underlying infrastructure. Designing the proposed facilities to be 765 kV-ready, even if they initially operate at 345 kV or 500 kV, could preserve the option to increase transfer capability as load and transmission needs grow in the future without incurring the full cost and delay of developing a new corridor.

The optionality is increasingly valuable given uncertainty around future system needs. Continued load growth, greater reliance on interregional transfers, and the expansion of higher-voltage networks within both RTOs could increase the value of transfer capability over the life of these assets. Selecting a design based primarily on needs identified within the current planning horizon without considering the broader development context may therefore reduce flexibility and increase the cost of meeting future transmission needs.

³⁵ MISO, [Long Range Transmission Planning: Tranche 2.1 Approved](#), accessed September 11, 2026; and SPP, 2025 Integrated Transmission Planning Assessment Report (11/25/2025), p. 176-178; and SPP, "[SPP board advances regional transmission plan to keep pace with accelerating growth and ensure grid reliability](#)," (November 5, 2025), accessed September 11, 2026.

³⁶ American Electric Power (AEP), Comments on the SPP-MISO 2024-2025 Coordinated System Plan Study Report, April 3, 2026 ("AEP Comments"), p. 3-4.

³⁷ AEP Comments, p. 3-4.

III. Recommendations for the MISO-SPP CSP

The 2024-2025 CSP has advanced to a point where MISO and SPP have identified a focused set of candidate projects, completed their initial production cost savings analysis, and are now undertaking additional benefits analyses to complete the planning study. Several of the methodological concerns discussed above can still be addressed within the remaining planned scope of the 2024-2025 CSP study prior to the RTOs completing the final project selection and cost allocation. These near-term improvements to the 2024-2025 CSP include (1) extending the supplemental benefits analysis to the three solutions in the central and southern corridors, (2) reconsidering project selection based on total quantified benefits, (3) aligning cost allocation with the total quantified benefits, and (4) assessing whether the identified cost-effective solutions should be designed as 765 kV-ready. Other improvements, particularly broadening the benefits framework and strengthening the production cost modeling assumptions, should be incorporated into the 2026 CSP.

These recommendations are intended to build on the RTOs' progress to date while improving both the current CSP outcomes and the framework used in future cycles. A more robust approach would ultimately give customers and stakeholders greater confidence that MISO and SPP's project selection and cost allocation reflect the full value that these interregional transmission investments provide.

A. 2024-25 CSP Recommendations

1. Evaluate the Supplemental Benefits for All Solutions

MISO and SPP should extend the analyses currently characterized as “supplemental benefits” to the Core and Core+ solutions across all three corridors before making final project-selection decisions. As discussed, the CSP needs assessment identified different types of needs across the seam: greater economic congestion in SPP South and more substantial reliability needs in MISO South. Relying solely on APC savings for justifying the selection of interregional solutions prematurely eliminates projects from consideration that also provide significant avoided reliability cost savings and/or production cost savings during stressed system conditions. The central and southern corridor solutions are particularly important to reassess on this basis because they extend farther into areas where the CSP identified significant reliability needs.

These benefits should not be treated as secondary to the CSP evaluation. Avoided or deferred reliability projects and production cost savings are expressly included in the JOA, both of which will be quantified in the supplemental benefits analysis. Because MISO and SPP are already performing the supplemental analysis for the remaining northern corridor solutions, extending the same methods to the central and southern corridors should require relatively limited additional effort and would allow the RTOs to compare all candidate solutions on a more consistent and complete basis before determining which projects provide the greatest value across the seam.

2. Evaluate Each Solution Based on Total Quantified Benefits

Once the full set of benefits has been quantified for all five solutions, MISO and SPP should use those total benefits—not APC savings alone—to determine which solutions are justified and approved. The Turk–McNeil and Sarepta–Southwest Shreveport–Babel solutions, for example, produced insufficient APC benefits to advance, but the analysis had not yet quantified the avoided reliability investments or stressed-system benefits those projects could provide. Evaluating those benefits without allowing them to affect the ultimate project-selection decision would not resolve the underlying concern with the current approach.

MISO and SPP should therefore reassess all candidate solutions once the additional benefits have been quantified and determine whether each project’s total benefits justify its costs. Where the combined production cost, reliability, and extreme-weather benefits demonstrate that a previously screened-out solution is cost-effective, that project should be returned to consideration alongside the remaining alternatives. The objective should be to select the solution or combination of solutions in each corridor that provides the greatest net value across the two systems, rather than limiting approval to projects that can be justified by traditional APC savings alone.

3. Incorporate Supplemental Benefits into Cost Allocation

Given the differing needs identified across the seam, the current proposal to allocate project costs based only on APC savings may not reflect the full distribution of benefits between MISO and SPP once the supplemental analyses are completed. MISO and SPP should base the RTO cost split on the full set of quantified benefits used to support project approval. If reliability, extreme weather, and other benefits contribute to demonstrating a project is cost effective, those same benefits should also inform how its costs are assigned between the two regions.

4. Assess the Benefits of 765 kV-Ready Solutions

Given the 765 kV networks now being developed within both RTOs, MISO and SPP should evaluate whether the cost-effective CSP solutions should be designed to accommodate future 765 kV operation. The analysis should compare the incremental cost of making the facilities 765 kV-ready today, while initially operating them at 345 kV or 500 kV, with the cost of upgrading or replacing them later to provide additional transfer capability. This would allow the RTOs to assess whether the additional upfront investment could preserve valuable flexibility as load and transfer needs grow, while avoiding the greater cost and delay associated with reconstructing facilities or developing a new corridor in the future.

B. 2026 CSP Recommendations

Some of the concerns identified above will require broader changes to the CSP framework than what can reasonably be incorporated into the remaining 2024–2025 process. With the 2026 CSP approaching, MISO and SPP have an opportunity to incorporate the below improvements at the outset of the next cycle and establish them as standard practice for future studies.

1. Expand Benefits Framework to Reflect Metrics Used in Regional Planning

MISO and SPP should broaden the benefits framework used in future CSPs to reflect the range of value they already recognize in regional transmission planning. MISO's LRTP and SPP's ITP processes quantify multiple categories of benefits, including reliability, resource adequacy and capacity, transmission losses, and performance under stressed system conditions. As shown in Table 2 above, this broader approach can materially affect project selection.

Future CSPs should adopt the multi-benefit framework from the outset. For each candidate project, MISO and SPP could identify the benefit categories relevant to that project and quantify them using established methods—for example, avoided or deferred reliability project costs, reduced transmission losses, changes in resource adequacy or capacity requirements, reductions in expected unserved energy valued using VOLL, and incremental production cost savings under stressed system conditions. Embedding this structure into the CSP from the outset would allow MISO and SPP to compare projects based on their total system value while maintaining a transparent and internally consistent benefit-cost analysis.

2. Validate Production Cost Modeling Against Historical Congestion

MISO and SPP should validate the production cost modeling used in future CSPs against observed market outcomes to determine whether the simulated results reasonably reproduce the congestion, price separation, and production cost savings that interregional transmission can provide. As discussed, historical outcomes along the MISO South–SPP South seam show that a disproportionate share of transmission value can arise during a relatively small number of high-value hours, including periods of extreme weather, outages, and other system stress.

To do so, SPP and MISO should run their market simulations using assumptions based on recent historical market conditions including recent load conditions, generation resources, and natural gas prices. Efforts should be made to ensure that the historical simulations account for similar normalized conditions used in forward-looking simulations. Comparing modeled LMPs and congestion patterns with historical outcomes for a similar timeframe would help identify whether the CSP systematically understates the frequency or magnitude of these conditions.

Where differences emerge, the RTOs should use the findings to improve the analysis. This could include revising assumptions related to outages, fuel prices, weather, and real-time uncertainty; adding targeted stress scenarios; or calibrating modeled benefits to account for value that the simulations consistently underrepresent. Where fully incorporating these conditions into the production cost model is not possible, MISO and SPP can analyze the extent to which their simulations understate historical congestion levels and price differences and use the difference as a multiplier that can then be applied to their simulation results as a proxy for the understated benefit amounts. NYISO and the NYISO Independent Market Monitor have utilized this approach, adding 40-56% to the simulated (but understated) production cost results based on their analysis of underrepresented benefits.³⁸ Such a multiplier can be calculated based on MISO and SPP specific conditions and simulation results to develop a well-supported but simplified approach to improving the quantification of production cost savings.

Making this validation a standard part of the CSP would provide a stronger empirical basis for the APC benefits used in project screening, selection, and cost allocation, and reduce the risk that projects are evaluated using production cost savings that are systematically below the value observed under actual system conditions.

³⁸ See: Newell, Samuel, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015, pp. 86 and 89. Patton, David, et al., NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects (June 2018), p. 15.

IV. Conclusion

The 2024–2025 CSP has brought MISO and SPP closer than prior planning cycles to identifying and approving interregional transmission investments that address needs on both systems. The RTOs have identified complementary economic and reliability needs along the seam, developed concrete project alternatives, and advanced solutions through detailed evaluation. That work provides a foundation for selecting projects that deliver value to customers across both regions.

The analysis presented in this whitepaper also shows why the methodological choices are important. The current CSP evaluates a narrower set of benefits than MISO and SPP consider in their regional planning, relies on production cost modeling that understate value observed under real-world market conditions, and proposes to allocate costs based on APC savings despite differing benefits across the seam. The proposed projects also warrant consideration in the context of the higher-voltage regional systems that both RTOs are now developing. These choices can affect not only whether projects appear cost-effective and are ultimately approved, but also how their costs are shared and whether the facilities remain well suited to future system needs.

There is still an opportunity in the current 2024-2025 CSP to address several of these concerns by extending the supplemental benefits analysis to all candidate solutions, using total quantified benefits in project-selection and cost-allocation decisions, and evaluating whether selected projects should be designed for future 765 kV operation.

Looking ahead, the 2026 CSP provides an opportunity to establish a broader multi-benefit framework from the outset and more systematically validate production cost modeling against actual market outcomes. MISO and SPP have already done much of the difficult work required to move interregional planning from identifying needs toward evaluating actionable investments. Following through with a more complete assessment of transmission benefits would help ensure that the projects approved reflect the most cost-effective investments for upgrading the MISO-SPP interregional transmission system and ultimately providing value to ratepayers in each of their markets.