BILLIONS IN BENEFITS:

A PATH FOR EXPANDING TRANSMISSION BETWEEN MISO AND PJM

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EXECUTIVE SUMMARY

America's two largest Regional Transmission Organizations (RTOs), the Midcontinent Independent System Operator (MISO) and the PJM Interconnection (PJM), share a long and tangled border across Illinois, Indiana, Michigan, and Kentucky, as shown in the map on the next page. Transmission constraints between MISO and PJM annually cost consumers in both regions billions of dollars, and those costs will only increase as decarbonization of electricity supply and electrification of electricity demand increase the value of moving power across regions. Because the regions' combined footprint stretches from the Dakotas to the East Coast, expanded transmission ties between MISO and PJM offer considerable opportunity to balance the different timing of their peak needs, as well as access a diverse mix of low-cost renewable energy resources.

This paper outlines the following steps the regions can take to plan and pay for transmission that would realize those benefits, and equitably share them among consumers in both regions:

- MISO, PJM, the Federal Energy Regulatory Commission (FERC), states, and other stakeholders should work together to create workable mechanisms to plan and pay for interregional transmission. The solution should be modeled on the success of MISO and other regions in building regional transmission through proactive multi-value transmission planning with broad cost allocation. The ideal solution is co-optimized generation and transmission planning with broad negotiated cost allocation between MISO and PJM.
- As an essential step towards building interregional transmission, PJM should adopt proactive multi-value planning with broad cost allocation for regional transmission within its footprint. PJM could conduct a proactive multi-value transmission planning study to identify a portfolio of lines that provide large net benefits across its footprint, based on the successful model of MISO studies

building support for regional transmission. Federal funding available under the Inflation Reduction Act (IRA) of 2022 and Infrastructure Investment and Jobs Act (IIJA) of 2021 could help pay for this study, or even some share of the planned transmission.

- While proactive multi-value planning with broad cost allocation is the optimal solution for interregional transmission, MISO and PJM can use more coordinated planning as an interim step towards that ideal. Improved coordination of top-down regional transmission planning in MISO and PJM would allow the regions to identify more efficient interregional solutions to their regional needs. This could also include bottom-up planning, modeled on the Joint Targeted Interconnection Queue effort between MISO and the Southwest Power Pool, to more efficiently plan and pay for upgrades identified through generator interconnection studies.

- Under any solution, MISO and PJM should
    - Allow merchant transmission developers to propose interregional solutions and be fully compensated for the value their projects provide.
    - Improve the efficiency of energy market transactions across regional seams, saving consumers money and improving reliability during times of peak need.

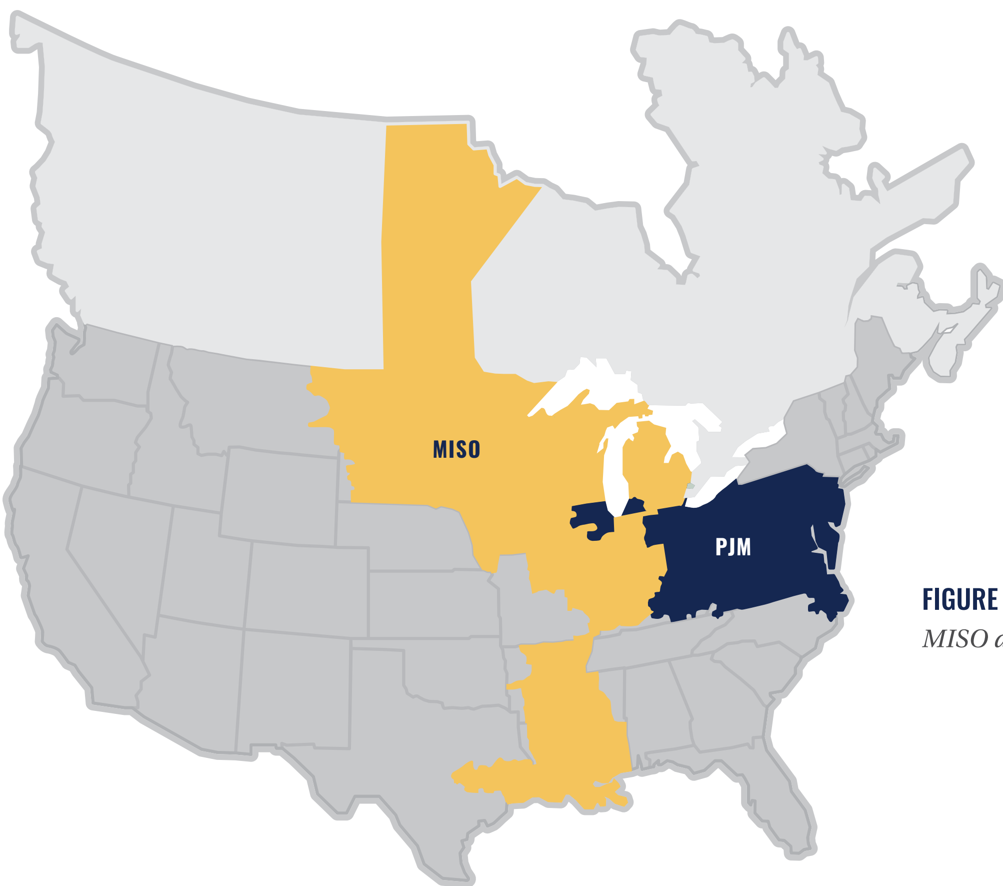

FIGURE 1.
MISO and PJM Map[1]

1 https://www.miso-pjm.com/.

I. BENEFITS OF EXPANDING TRANSMISSION BETWEEN MISO AND PJM

A. Energy cost savings

Expanded interregional transmission between MISO and PJM could provide over $1 billion in energy market savings per year by reducing transmission congestion, allowing lower-cost and lower-emitting generation to displace higher-cost resources. MISO and PJM report $1.7 billion in congestion between the two RTOs from 2021-2022,[2] with significant costs accruing to both regions. As explained below, the energy cost savings figure does not capture many additional benefits of transmission, including the value of reducing the amount of generating capacity that is required to maintain reliability in each region.

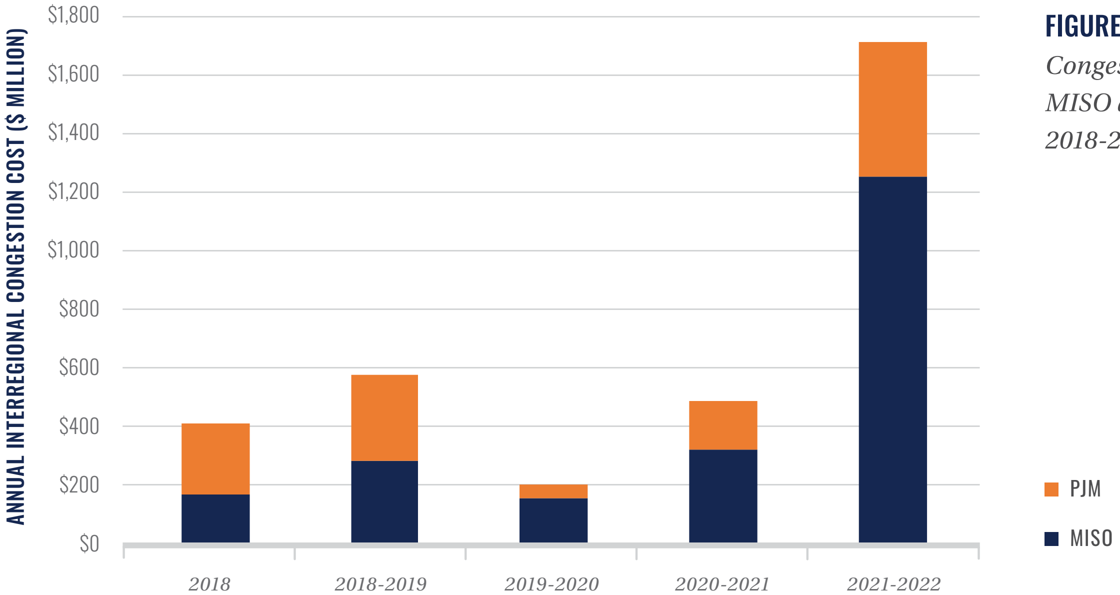

FIGURE 2.
Congestion Between MISO and PJM, 2018-2022

2 Meeting Materials, Inter-Regional Planning Stakeholder Advisory Committee (IPSAC) – MISO, February 2023, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2023/20230217/market-to-market-historical-congestion.ashx.

TABLE 1. *Congestion Between MISO and PJM ($ Millions), 2018-2022*

Year	MISO	PJM	Total
2018[3]	$172	$242	$414
2018-2019[4]	$285	$295	$589
2019-2020[5]	$159	$44	$203
2020-2021[6]	$325	$166	$498
2021-2022[7]	$1,255	$462	$1,717
Sum	**$2,196**	**$1,209**	**$3,421**

The historical congestion data reported by MISO and PJM and shown in the table and chart above indicate there is considerable interannual variability in congestion costs, including significant swings in which the regions experience higher congestion costs. This variability confirms that interregional transmission acts like an insurance policy, in that someone buying an insurance policy cannot precisely predict when or why they will need the coverage, but over the long term it provides valuable protection against extreme events. Transmission's value from protecting cost-sensitive consumers from price swings is additional to the actual cost savings. The interannual variability in benefits and beneficiaries also supports a broad allocation of transmission costs between the regions that is "roughly commensurate" with benefits. While beneficiaries cannot be predicted with exacting precision due to inherent uncertainty about fuel prices, the generation mix, load growth and patterns, and extreme events, experience clearly demonstrates that interregional transmission will deliver benefits to customers in both PJM and MISO at different points (particularly during extreme events).

Interregional transmission is an important mechanism to protect consumers against unpredictable volatility in the price of fuels used to produce electricity, particularly natural gas. This can be seen in the data above, given the swing in congestion costs between the high gas price year of 2022 and the low gas price year of 2020.[8] Interregional transmission alleviates the negative impact of fuel price fluctuations on consumers by expanding access to lower-cost power from other regions. As discussed in the section on severe weather, many fossil-fired power plants in MISO obtain coal and gas from different sources and delivery mechanisms (such as different gas fields and pipelines) than power plants in PJM, which is particularly valuable during localized fuel price spikes resulting from constrained supplies during severe weather events. This increased flexibility helps to mitigate the impact of fuel price spikes on electricity prices, and can even reduce fuel price spikes by shifting generation to resources that

3 Meeting Materials, IPSAC-MISO, March 2019, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190329/20190329-2018-m2m-congestion-summary.ashx.

4 Meeting Materials, IPSAC-MISO, January 2020, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2020/20200124/20200124-m2m-historical-congestion.ashx.

5 Meeting Materials, IPSAC-MISO, February 2021, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2021/20210226/20210226-market-to-market-historical-congestion.ashx.

6 Meeting Materials, IPSAC-MISO, February 2022, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20210217/20220217-m2m-historical-congestion.ashx.

7 Meeting Materials, IPSAC-MISO, February 2023, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2023/20230217/market-to-market-historical-congestion.ashx.

8 U.S. Energy Information Administration, Natural Gas Prices, https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm.

use other fuel sources, cutting demand for the constrained fuel. As the utilities Xcel and ITC noted in an approved application to build a transmission line in Minnesota, "a robust regional transmission system is also key to enabling access to a diverse mix of generation resources, which in turn allows customers to access the least expensive power available at any given time."[9]

The hedging benefit of transmission is even larger for transmission that allows deployment of new renewable generation, as renewables provide significant insurance against fuel price fluctuations and potential environmental regulations because they have no fuel cost and do not emit pollution. For example, MISO's Long-Range Transmission Planning (LRTP) analysis found that the fuel cost savings from the approved Tranche 1 transmission expansion would increase from $19.9 billion in net present value over 40 years to $45.1 billion if natural gas prices are only 20% higher,[10] while the economic value of carbon savings also greatly vary with the assumed price of carbon. Effective transmission planning and benefit-cost analysis should use fuel and carbon price sensitivities to explore how transmission protect against those risks and account for the hedging value of transmission.

Confirming the MISO and PJM congestion data shown above, Lawrence Berkeley National Laboratory (LBNL) compared hourly locational energy market prices between the two regions and found that expanded interregional transmission between MISO and PJM would have offered significant value in 2022.[11] Specifically, a hypothetical 1,000 MW tie between MISO Indiana and PJM's Commonwealth Edison zone in northern Illinois would have provided $193 million in energy arbitrage value for all of 2022. LBNL's analysis notes that 12% of that value, or $23 million, would have accrued during Winter Storm Elliott in late December 2022.[12] This value is high enough to defray a significant share of the cost of new transmission between MISO and PJM, if workable policies were in place to plan and pay for transmission between the regions.

B. Capacity benefit

One of the largest benefits of interregional transmission is capturing diversity in when different regions experience peak demand, lulls in renewable output, and correlated generator outages. That diversity allows both regions to maintain the same level of electric reliability with less generating capacity, if there is sufficient interregional transmission for each region to import from the other during its time of peak need. This reduced need for generating capacity results in reduced costs for consumers, a benefit that provides billions of dollars in savings in addition to the energy cost savings discussed above. However, this capacity benefit is not typically accounted for in interregional planning cost-benefit analyses and cost allocation, which typically only focus on energy cost savings.

The benefits of aggregating diverse sources of supply and demand have been a foundation of power system engineering since the larger geographic footprint of George Westinghouse's and

9 Northern States Power Company and ITC Midwest LLC, *Application to the Minnesota Public Utilities Commission for a Certificate of Need for the Huntley-Wilmarth 345 kV Transmission Line Project*, at 8, MPUC Docket No. E-002, (January 2018), *available at:* https://www.huntleywilmarth.com/staticfiles/microsites/hw/HW-Certificate-of-Need-Application.pdf.

10 MISO, LRTP Tranche 1 Portfolio Detailed Business Case (June 2022) https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf, at 54.

11 Berkeley Lab, The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade (2023) https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf.

12 *Id.*, at 4.

Nikola Tesla's Alternating Current grid won out over Thomas Edison's local Direct Current power system. As another example, the Pacific Intertie was completed in 1970 to link California, where load is summer-peaking, with the Pacific Northwest, where load is typically winter-peaking. The line also taps into the diversity of the output profiles for those regions' generating resources, which more recently has included the benefit of aggregating complementary output profiles between California solar and Pacific Northwest wind and hydroelectric resources.

MISO and PJM have each reported that aggregating diverse sources of electricity supply and demand within each of their footprints accounts for the majority of the benefits those RTOs provide. MISO calculates about $2.4 billion in annual benefits due to the following:

> MISO's large geographic footprint allows members to lower planning reserve margins (PRM), ultimately reducing the amount of required installed capacity. Much of the value MISO creates comes from the value of sharing capacity across MISO's large geographic footprint—by setting requirements for a system peak instead of each balancing authority keeping reserves for their own region. Savings are generated because MISO members do not need as much capacity for the same level of reliability.[13]

Similarly, PJM finds $1.2-1.8 billion in annual savings because:

> There is considerable diversity in electrical use patterns in the large PJM footprint; not all areas peak at the same time of the year. As a result, resources in one area of the system are available to help serve other areas at peak times, and a smaller reserve is required. In addition, the large and varied resource fleet across the entire PJM region spreads the generator outage risk across a larger collection of generators, improving reliability.[14]

The same reasoning and benefits described above for regional aggregation apply to expanding transmission ties between the two regions so they can balance localized fluctuations in electricity supply and demand with less generating capacity.

Capturing diversity in renewable output across large geographic areas is essential for cost-effectively achieving high renewable penetrations. Geographically diverse renewables, as well as a more diverse portfolio of solar, land-based wind, and offshore wind resources, provide more dependable capacity and less variable generation because their output profiles are weakly or even negatively correlated. Multiple studies have confirmed that expanding transmission ties within and among grid operators to access that diversity is essential for cost-effective decarbonization.[15]

The following chart from MISO's Multi-Value Project (MVP) transmission planning report illustrates how transmission accesses valuable geographic diversity in renewable output.[16]

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13 MISO, *MISO Value Proposition Annual View, 2022 Overview*, March 2023, at 6, *available at* https://cdn.misoenergy.org/2022%20Value%20Proposition%20Annual%20View%20-%20Detailed%20Report628393.pdf.

14 PJM, *PJM Value Proposition*, at 2, *available at* https://www.pjm.com/about-pjm/-/media/about-pjm/pjm-value-proposition.ashx.

15 For example, see Patrick Brown and Audun Botterud, "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System," Joule, (January 2021), *available at* https://www.sciencedirect.com/science/article/pii/S2542435120305572; NREL, "The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study" (September 2021), *available at:* https://www.nrel.gov/docs/fy21osti/76850.pdf; Alexander E. MacDonald, Christopher T.M. Clack, Anneliese Alexander, Adam Dunbar, James Wilczak & Yuanfu Xie, *Future Cost-Competitive Electricity Systems and Their Impact on US CO2 Emissions*, Nature Climate Change 6, *available at* https://repository.library.noaa.gov/view/noaa/14578.

16 MISO, Multi Value Project Portfolio, Results and Analysis (2012) https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf, at 76.

Because wind speeds and other weather events are localized and move over time, the correlation between the output at any two wind plants significantly decreases as the distance between them increases. To a lesser degree, geographic distance also reduces the correlation in the output of any two solar plants by canceling out the localized impact of clouds and other weather phenomenon affecting solar output.[17] Moreover, the large distance between eastern PJM and western MISO increases the number of hours solar output is available to the combined footprint by about two hours and helps smooth out morning and evening ramps in solar output. That east-west distance also offers time zone diversity in electricity demand patterns.

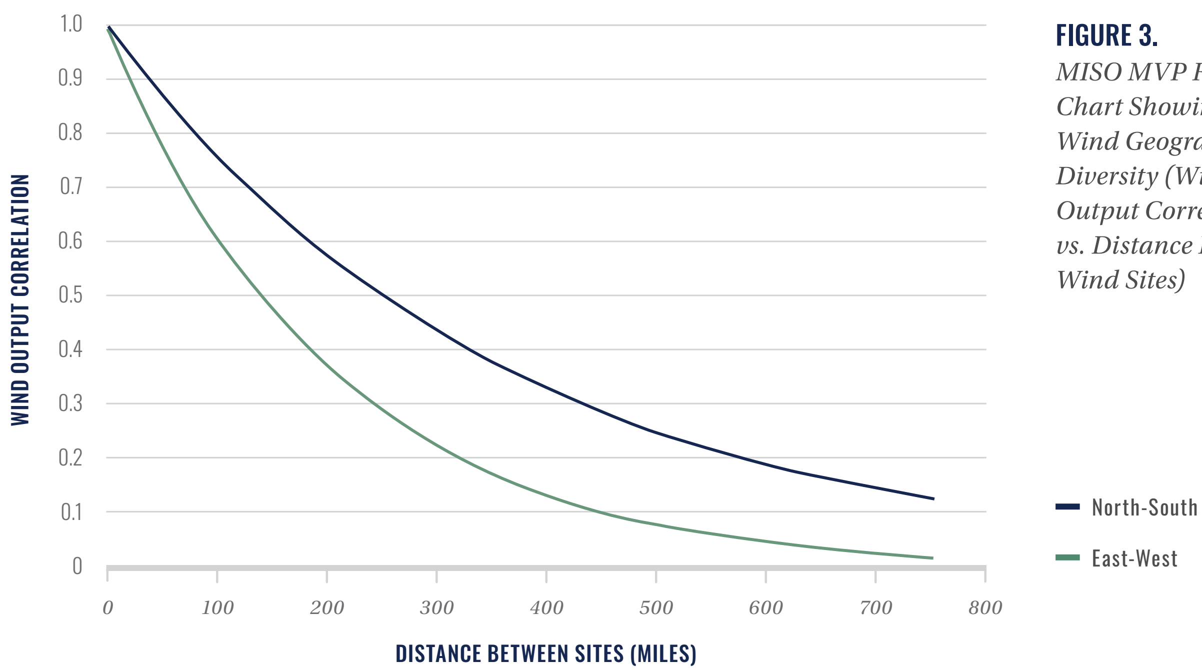

FIGURE 3.
MISO MVP Report Chart Showing Wind Geographic Diversity (Wind Output Correlation vs. Distance Between Wind Sites)

Geographic diversity in demand, renewable output, and conventional generator outages can save consumers billions of dollars by reducing the need to build and maintain generating capacity. For example, an analysis completed in May 2023 found that building enough transmission for all of the Eastern Interconnect and Texas to share generation could reduce the need for generating capacity by over 137 GW, saving $113 billion.[18]

Additional analysis of those results shows large diversity benefits between PJM and the Midwest subregion of MISO[19] that directly borders PJM, and that expanding interregional transmission between those regions would provide significant value by reducing the need for

17 Ernest Orlando Lawrence, Berkeley National Laboratory, Implications of Wide-Area Geographic Diversity for ShortTerm Variability of Solar Power (2010) https://eta-publications.lbl.gov/sites/default/files/report-lbnl-3884e.pdf.

18 Grid Strategies and Americans for a Clean Energy Grid, Quantifying a Minimum Interregional Transfer Capability Requirement (2023) https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf.

19 "Midwest subregion" is the terminology MISO has used in the LRTP process to refer to the North and Central subregions. Our analysis only focuses on the Midwest subregion because firm transmission between MISO Midwest and the other MISO subregion, MISO South, is limited to about 1,000 MW, and non-firm transmission between the subregions is 2,500-3,000 MW, much of which utilizes transmission paths through neighboring grid operators. LRTP Tranche 3 is slated to plan transmission within MISO South, and Tranche 4 will plan transmission ties between MISO South and the Midwest subregion. Given the load and resource diversity between MISO South and the rest of MISO and the lack of transmission ties currently, that transmission expansion should provide large net benefits. For background, see https://cdn.misoenergy.org/20220124%20RECBWG%20Item%2002c%20Brattle%20Analysis619915.pdf.

generating capacity in both regions, particularly as renewable penetrations increase. In 2022, the coincident peak need of MISO's Midwest subregion and PJM was 6,900 MW lower than the sum of their individual peak needs, resulting from diversity in electricity demand, renewable output, and conventional generator forced outages patterns. Said another way, MISO and PJM could reduce their need for generating capacity by 6,900 MW with sufficient interregional transmission for one region to share power with the other during times of peak need. This analysis compares the total generating capacity needed across both regions to meet electricity demand minus renewable output plus conventional generator outages under two scenarios: a case without interregional transmission in which each region must meet its peak needs entirely with its own generating capacity, versus a case in which interregional transmission allows the regions to share generating capacity because their peak needs do not occur at the same time. More details on how this diversity benefit is calculated can be found in the methodology section of the May 2023 analysis.[20]

This 6,900 MW of diversity benefit between MISO and PJM is about 3 times more credit than MISO and PJM each currently assign to all of their interregional ties, as noted below. If monetized at the capital cost of building a new gas combustion turbine, this 6,900 MW of diversity benefit equates to $6.3 billion in economic value from reducing the amount of generating capacity needed in both MISO and PJM to maintain the same level of electric reliability.[21]

As renewable resource penetrations increase in both MISO and PJM, the diversity benefit between the two regions will expand. Demand and renewable diversity accounted for over 1,300 MW of the total 6,900 MW diversity benefit between PJM and MISO's Midwest subregion in 2022, with conventional generator outage diversity during Winter Storm Elliott accounting for the remaining 5,600 MW. The chart on the next page shows how scaling up wind and solar output profiles to account for potential renewable additions MISO and PJM have studied for 2027 and 2035 causes this diversity benefit to significantly increase going forward. Specifically, the demand and renewable diversity between MISO's Midwest subregion and PJM more than doubles from over 1,300 MW to around 3,000 MW by 2027, and then nearly doubles again to 5,700 MW by 2035, based on renewables expansion scenarios studied by MISO and PJM. The benefit nearly doubles again to 11,000 MW in the high cases for 2035 renewable deployment that have been studied by MISO and PJM. The chart shows how the aggregated peak net load (demand minus renewable output) across MISO and PJM is smaller than their stand-alone peak net loads because their peak needs do not occur at the same time. This shows the reduction in total generating capacity need from a case without interregional transmission in which each region must meet its peak needs entirely with its own generating capacity, versus a case in which interregional transmission allows the regions to share generating capacity.

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20 *See*, supra note 18.

21 Conservatively using the assumed $867/kW cost of a frame combustion turbine from U.S. Energy. Info. Admin., Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023 (March 2023), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf, and the conservative assumption that a new combustion turbine offers 95% of its nameplate capacity as dependable capacity value. To be conservative, ongoing fixed O&M costs for maintaining that gas capacity were also not accounted for.

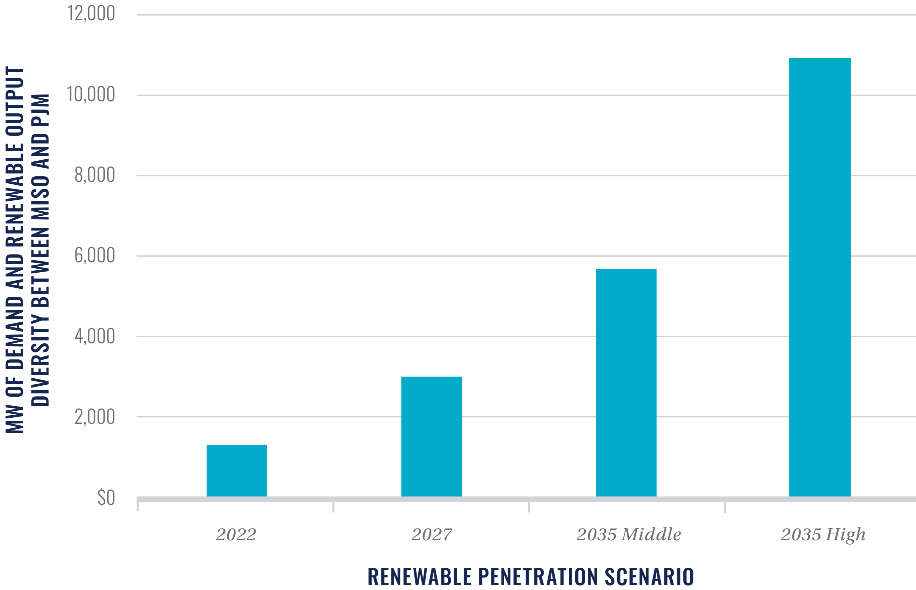


FIGURE 4. *MW of Demand and Renewable Diversity on Peak Between PJM and MISO's Midwest Subregion Under Various RTO Scenarios for Renewable Deployment*

This increase in the avoided capacity benefit of interregional transmission from 1,300 MW in 2022 to as much as 11,000 MW in 2035 as renewable penetration expands, produces an additional $8.8 billion in savings. When combined with the $6.3 billion in current benefits from diversity between the MISO Midwest subregion and PJM in demand, renewable output, and conventional generator forced outage patterns described above, this results in over $15 billion in savings.

The forward-looking analysis above only examines how net load diversity increases as renewable penetrations increase, and does not account for how changes in correlations in conventional generator outages affect the capacity need and diversity benefit. Any increase in weather-related conventional generator correlated outages, or greater reliance on resources subject to correlated outages, would add to the geographic diversity benefit between MISO and PJM, though it is more difficult to project how this benefit will change over time. However, because gas generators have accounted for the majority of correlated outages during recent extreme weather events, and because dependence on gas generation is increasing in both regions, this benefit is likely increasing. For example, gas generators accounted for 63% of unplanned outages and derates during Winter Storm Elliott,[22] and 55% during Winter Storm Uri[23] and the 2014 Polar Vortex.[24] As noted above and discussed in more detail below, gas generators in MISO and PJM are generally supplied from a different set of supply fields and pipelines, reducing the risk that extreme weather will disrupt a large share of the gas generating fleet in both regions at the same time. Electrification of heating should also increase the demand diversity benefit between MISO and PJM, because winter peak demand will become more sensitive to weather and these regions have considerable diversity in climate and weather.

22 FERC and NERC, December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations, (September 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

23 FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* 17 (2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

24 NERC, *Polar Vortex Review* iii (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

The need for interregional transmission and the benefit for renewable diversity will be even greater if the penetration of wind or solar increases in one RTO more than the other, as the regions will need interregional transmission to accommodate the different diurnal and seasonal profiles of those resources. For example, in the likely scenario that solar penetrations are higher in PJM and wind penetrations are higher in MISO, PJM will export power to MISO during the day and during the summer, while it will import wind power from MISO at night and during the fall, winter, and spring, when wind output tends to be highest.

Renewable geographic diversity not only reduces the need for generating capacity when renewable output is low in one region but not the other, but it also prevents renewable curtailment when renewable output is high in one region but not the other. By allowing excess power to be exported to the neighboring region, transmission helps ensure that the energy value of renewable generation remains high during periods of high renewable output and low net load in one region. Without interregional transmission, that energy would be curtailed or sold at low energy prices, denying consumers access to low-cost and zero-emission energy and impeding the continued development of renewable resources.

C. Benefits from renewable expansion enabled by transmission

As explained in the preceding section, a major benefit of interregional transmission is the access to greater diversity in wind and solar output patterns. Interregional transmission provides other benefits for renewable expansion by enabling the interconnection of new renewable resources, allowing renewable capacity to be sited in more productive and lower-cost areas, and reducing costly congestion and curtailment.

MISO's MVP and LRTP planning analyses accounted for the cost savings from accessing more productive and lower-cost renewable resources. As shown in the MISO chart below,[25] the goal of MVP planning was to minimize the total cost of generation plus transmission. All generation and transmission costs ultimately flow to ratepayers, so minimizing both costs results in the optimal outcome for consumers.

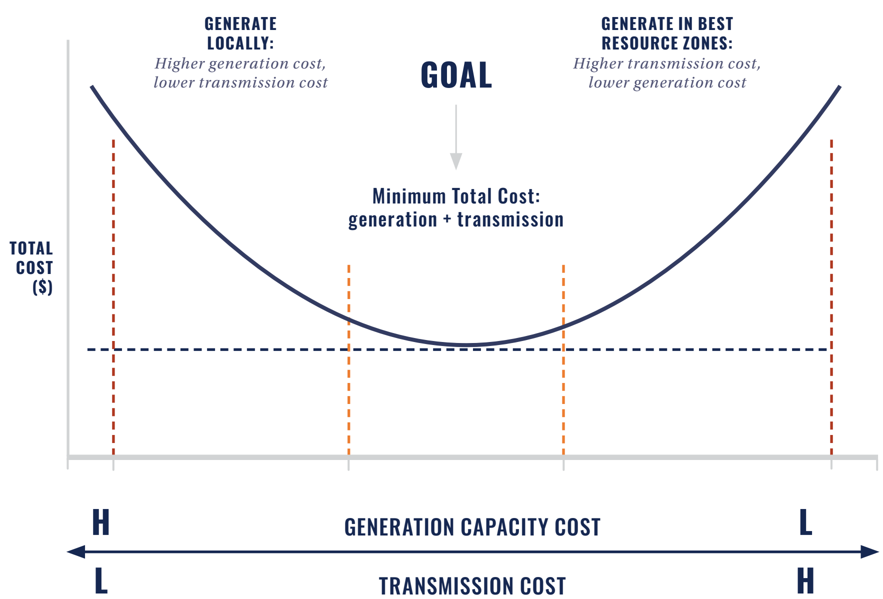


FIGURE 5. *MISO Chart Showing That Proactively Planned Transmission Can Reduce Total Consumer Costs by Accessing Lower Cost Generation*

Multiple studies have confirmed that expanding interregional transmission is essential for cost-effective decarbonization. A recent Department of Energy (DOE) draft study evaluated the transmission needed for various scenarios of the future generation mix, as identified by other modeling studies. DOE confirms that "The value in sharing electricity interregionally continues to increase in futures with high demand and clean energy growth. Median study results anticipate new transfer capacities of 157 GW in 2030 (154 percent growth compared to today's system) and 655 GW in 2040 (644 percent growth) nationwide."[26]

Across all regions, DOE's study found that the MISO-PJM seam has the greatest need for expanded interregional transmission ties under a range of scenarios for load growth and

25 MISO, MISO and Long Range, Transmission Planning: Minnesota House of Representatives Climate and Energy Finance and Policy Committee (2022) https://www.house.mn.gov/comm/docs/BdLQVikOwEOm_1_BkKc4Rw.pdf, at 9.

26 U.S. Department of Energy, Draft Transmission Needs Study (2023) https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf, at 107.

decarbonization, with the need between MISO and SPP for between 15.4 and 25.8 GW of new transfer capacity (median of 21.1 GW) coming in a distant second.[27] Specifically, DOE anticipates that for PJM "between 27.9 and 51.7 GW of new transfer capacity (median of 33.8 GW, a 156 percent increase relative to the 2020 system) needed with the Midwest region in 2035 to meet moderate load and high clean energy futures."[28] The study found that the increased transmission need with all of PJM's other neighbors sums to between 7.4 and 13.3 GW, meaning that the tie with MISO accounts for around 80% of PJM's total interregional transmission need.[29]

Confirming that finding, additional analysis of the results from 2021 modeling of high renewable penetrations in the Eastern U.S.[30] shows that flows across the seam between MISO and PJM increase to an annual maximum of around 25,000 MW in a high renewable future.[31] These flows were highly bidirectional because they allowed MISO to export wind to PJM during windy periods, and then import PJM solar during the day and during the summer.

Transmission planning and cost allocation should account not just for cost savings, but also for the public health and environmental benefits from enabled renewable generation displacing polluting fossil generation. For example, an analysis by LBNL estimates that wind generation provides $135/MWh of public health and environmental benefits on average nationally, five times greater than the average cost of wind energy.[32] As noted above, MISO's LRTP analysis accounts for the carbon benefits of renewables displacing fossil generation and finds them to be significant.

D. Transmission's value during severe weather and other extreme events

The energy, capacity, and hedging benefits of interregional transmission are particularly pronounced during periods of extreme weather, but extreme weather events are often excluded from transmission planning analyses,[33] understating the value of transmission. Extreme weather events can have a large impact on electricity demand and supply, both by affecting renewable output and causing forced outages and derates at conventional power plants. Because severe weather affects a limited geographic area, interregional transmission counteracts their impact by linking to neighboring regions that are less affected and therefore have surplus electricity supply. Expanded interregional transmission would have been extremely valuable during recent heat waves and cold snaps.[34] An analysis by LBNL confirms that extreme events, including severe weather, account for about half of the total value of interregional transmission between 2012 and 2022.[35]

27 *Id.*, at xiv.

28 *Ibid.*

29 *Ibid.*

30 Vibrant Clean Energy, Grid Strategies, and Americans for a Clean Energy Grid, Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S. (2020) https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf.

31 Calculated by summing interstate flows between MISO and PJM states.

32 "U.S. Department of Energy, Land-Based Wind Market Report (2023) https://emp.lbl.gov/sites/default/files/2023_lbwmr_final.pdf, at 62-64.

33 American Council on Renewable Energy, Natural Resources Defense Council, the Brattle Group, and Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (2021) https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

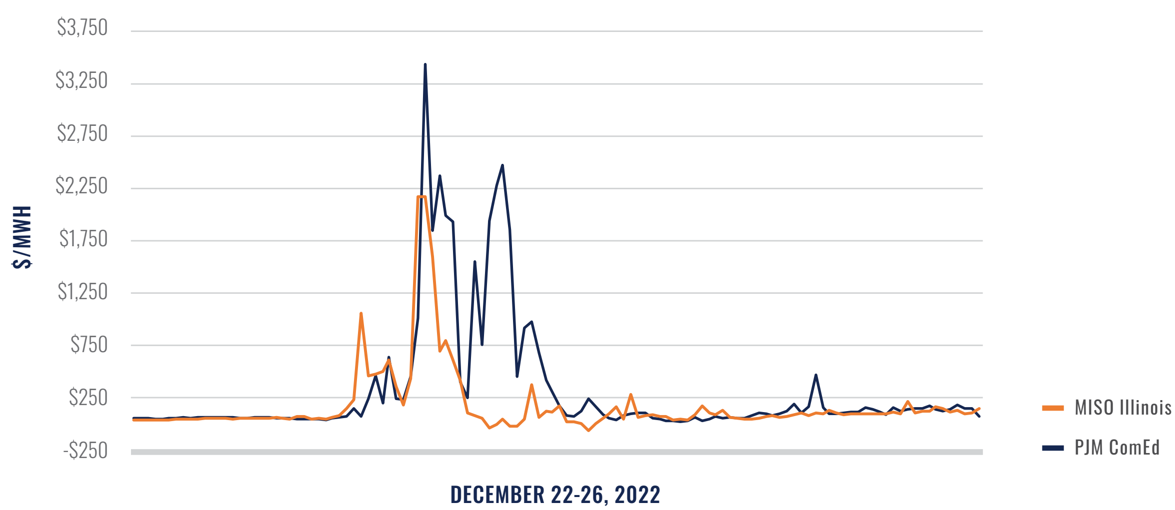
34 American Council on Renewable Energy and Grid Strategies, Transmission Makes the Power System More Resilient to Extreme Weather (2021) https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

35 Lawrence Berkley National Laboratory, "The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade (2023) https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf.

The hedging value of transmission discussed above is particularly pronounced during severe weather events because the price of natural gas can spike regionally; interregional transmission hedges against the risk of regional gas demand spikes or supply shortfalls. MISO and PJM have access to different gas production and storage areas sourced via different pipelines. MISO obtains a large share of its gas supplies from North Dakota, Oklahoma, and Texas, whereas PJM has much greater dependence on Marcellus and Utica gas supplies in the Northeast. MISO and PJM also access somewhat different sources and delivery mechanisms for coal, reducing the impact if supplies or deliveries are disrupted in one region.

Expanded transmission would have allowed larger power exchanges among MISO and PJM during Winter Storm Elliott in December 2022. Those regions experienced their peak need at different times as the cold air moved from west to east and north to south across the country.[36] As shown below, at the main MISO and PJM pricing hubs in the state of Illinois,[37] prices peaked in MISO many hours before they peaked in PJM. Commonwealth Edison (ComEd) is the PJM portion of Illinois, located in the northern part of the state. By the time PJM experienced its greatest need, MISO power prices were low or even negative. Transmission would have allowed more power to flow east to west as MISO dealt with the most extreme cold, and then west to east once the extreme cold had moved into PJM, benefiting consumers in both regions.

FIGURE 6. *$/MWh Power Prices at MISO and PJM trading hubs in Illinois during Winter Storm Elliott*



As shown below, a similar dynamic occurred during the 2014 Polar Vortex event, as the extreme cold weather migrated eastward from MISO into PJM.[38]

36 American Council on Renewable Energy, Transmission Makes the Power System More Resilient to Extreme Weather (2021) https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf.

37 Data from https://dataminer2.pjm.com/feed/rt_da_monthly_lmps, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Real-Time%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc.

38 *See*, supra note 34.

FIGURE 7. *$/MWh Power Prices at MISO and PJM trading hubs in Illinois during 2014 Polar Vortex*

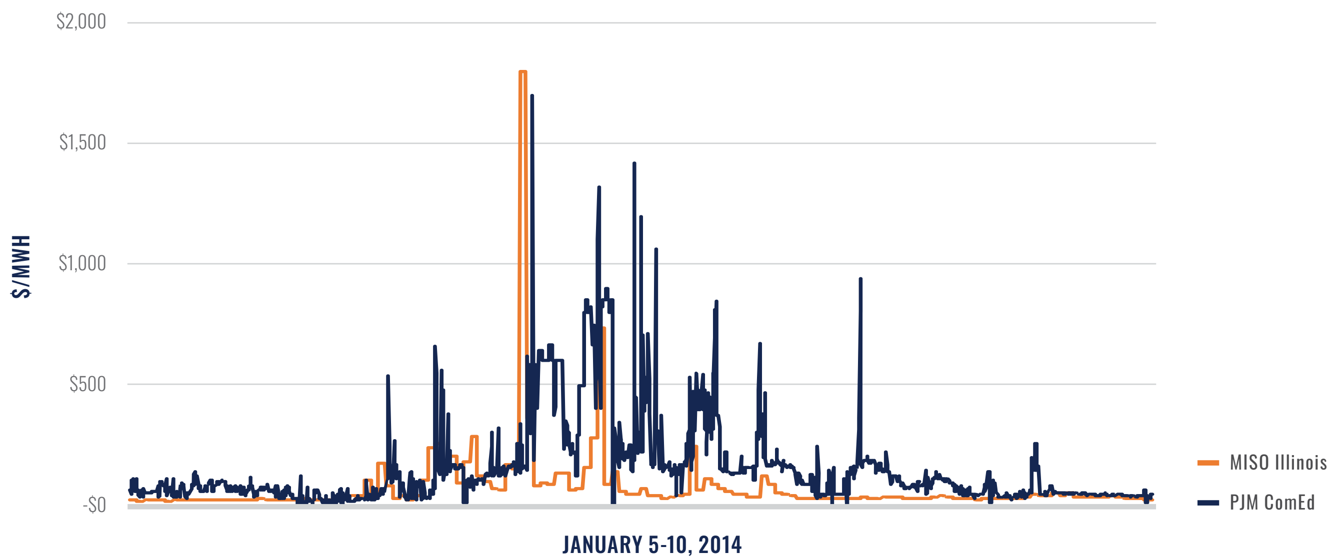
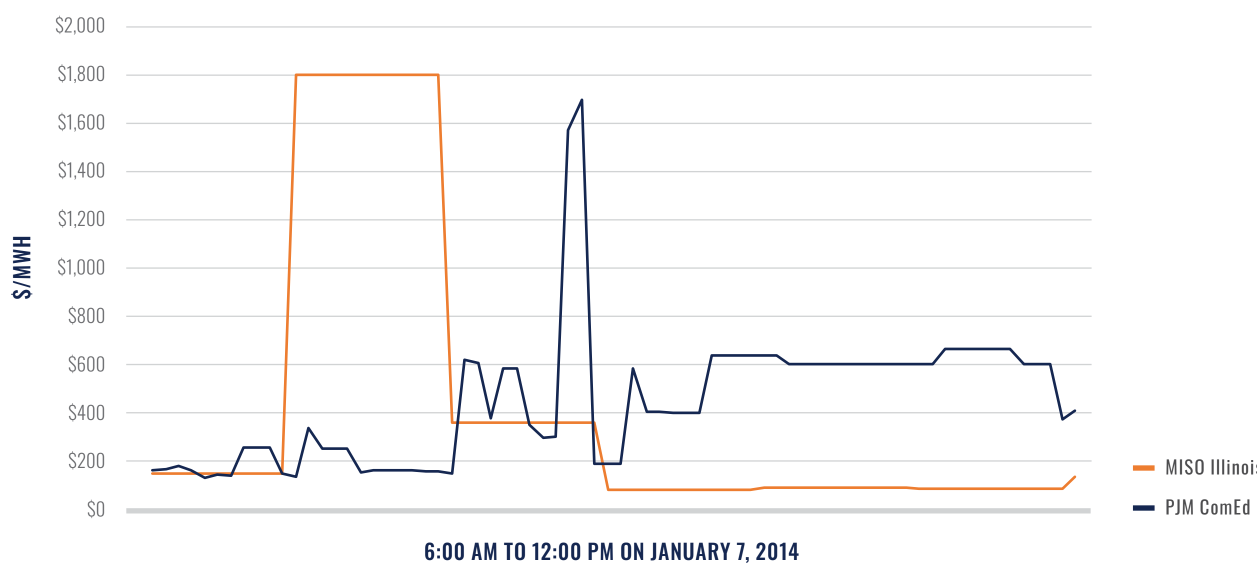
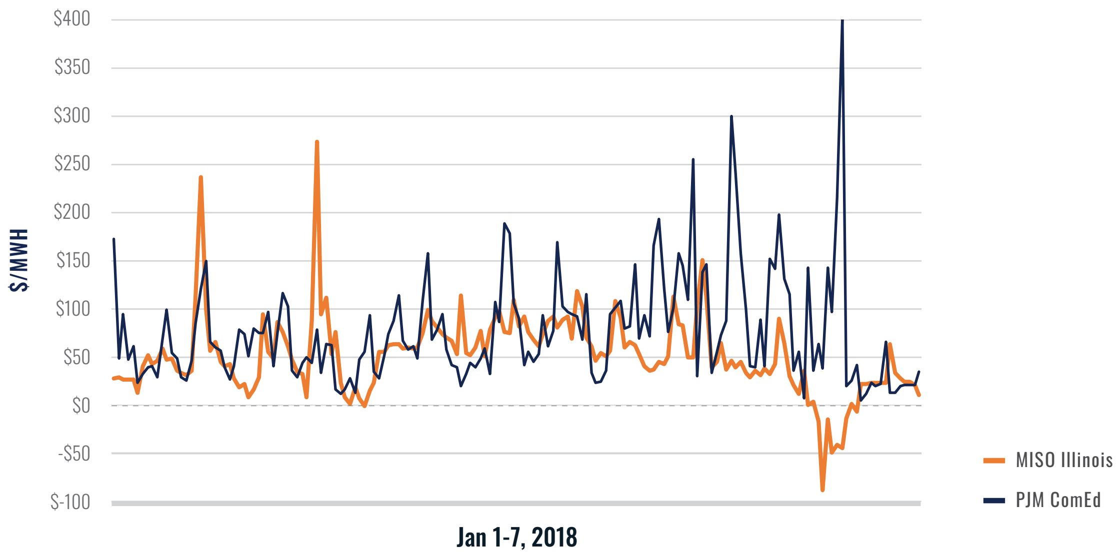


FIGURE 8. *$/MWh Power Prices at MISO and PJM trading hubs in Illinois during Polar Vortex, zoomed in on morning of January 7, 2014*



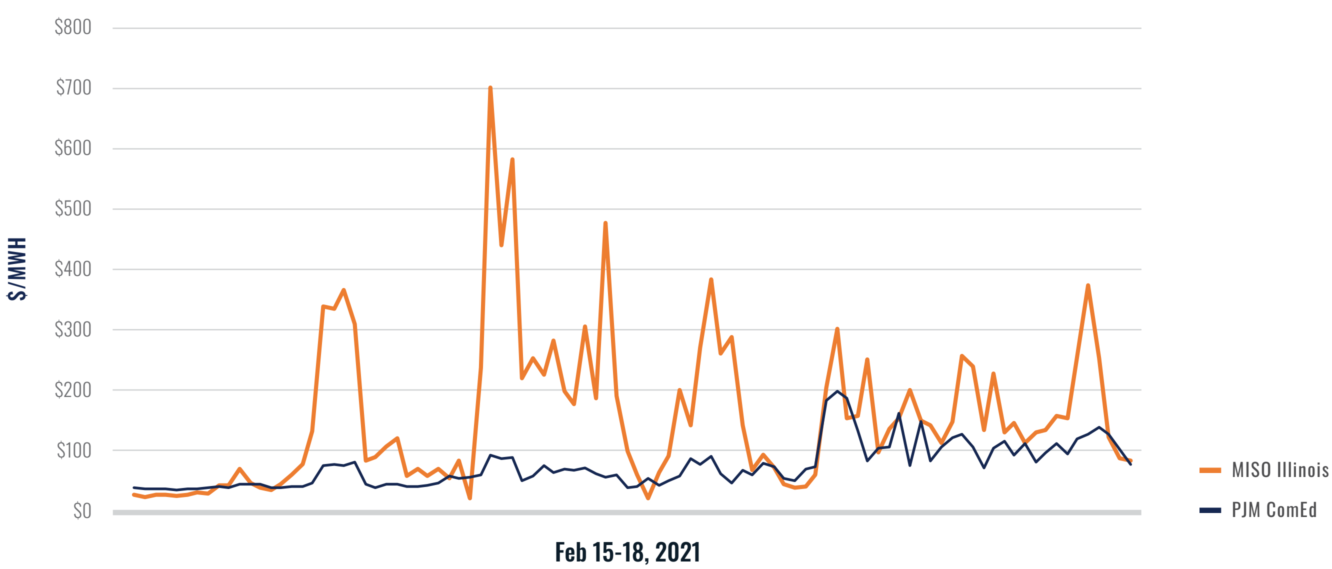
This also occurred in the 2018 Bomb Cyclone as cold air slowly moved eastward from MISO to PJM.

FIGURE 9. *$/MWh Power Prices at MISO and PJM trading hubs in Illinois during 2018 Bomb Cyclone*



During Winter Storm Uri, the extreme cold primarily affected MISO and other grid operators in the middle of the country while PJM was largely spared, so imports from PJM were extremely valuable.[39]

FIGURE 10. *$/MWh Power Prices at MISO and PJM trading hubs in Illinois during Winter Storm Uri*



39 *Ibid.*

Power prices were significantly higher in MISO than PJM during Winter Storm Uri, reflecting that there was insufficient transmission to deliver low-cost power to consumers in MISO. The resulting congestion as well as the market seam inefficiencies discussed below caused price anomalies along the MISO-PJM seam, reflected in the very low and high prices seen at various points along the seam in the snapshot below from the morning of February 15, 2021.

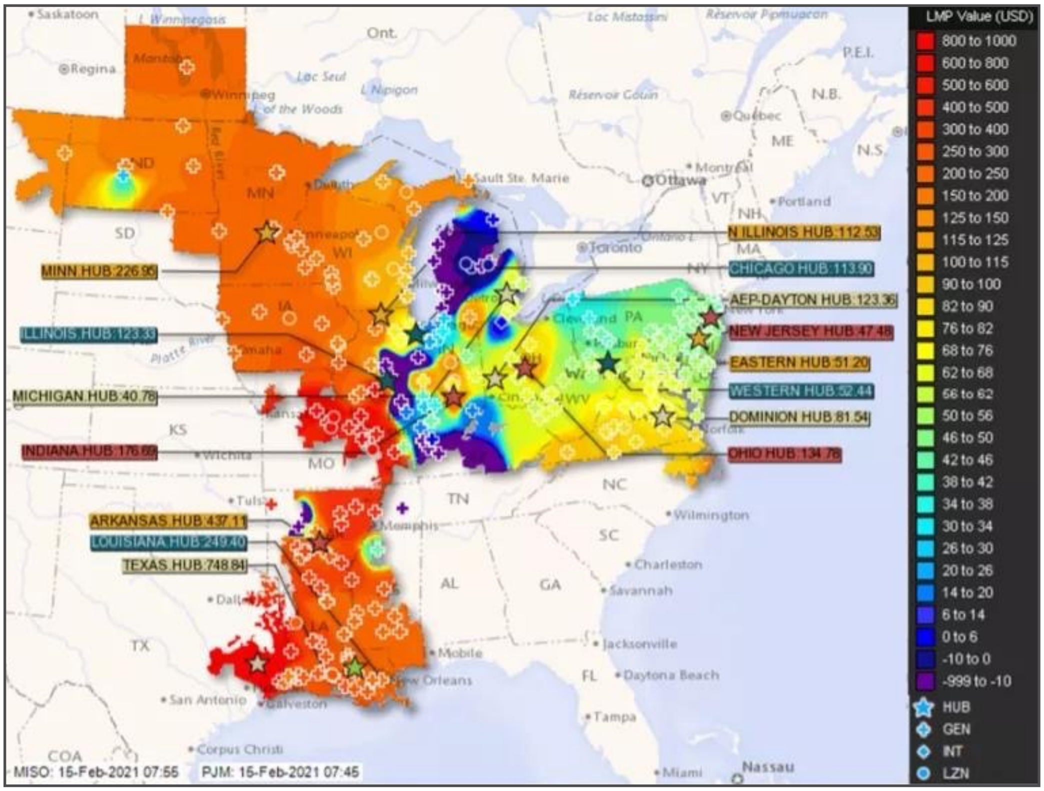


FIGURE 11. *Power prices on the morning of February 15, 2021, During Winter Storm Uri*

During these events, MISO and PJM also experienced peak wind output and correlated failures of conventional generators at different times, further increasing the value of interregional transmission.

Using interregional transmission to make the power system resilient to all types of extreme weather will be critical for reliability, particularly as climate change causes more extreme weather patterns. As DOE noted in its recent study of transmission needs, "The MISO region was unable to import additional capacity during the February 2021 cold weather event, negatively impacting resource adequacy. Increased bi-directional transfer capacities can improve system reliability during extreme weather events."[40]

In a Federal Energy Regulatory Commission (FERC) 2018 technical conference on grid resilience,[41] PJM, MISO, and other RTOs agreed that transmission should be a primary focus

40 *See*, supra note 26.

41 Grid Resilience in Regional Transmission Organizations and Independent System Operators, Docket No. AD18-7-000 Operators, March 2018.

of any efforts to increase resilience. PJM argued that "resilience efforts will require changes to transmission and infrastructure planning," explaining that "the Commission could provide assistance to RTOs by requiring them to plan for and address resilience, and confirm that resilience is a component of regional transmission system planning" and that "Robust long-term planning, including developing and incorporating resilience criteria into the RTEP, can also help to protect the transmission system from threats to resilience."[42] MISO focused on "Transmission Planning" and "Inter-regional Operations" as two of the three areas the Commission should focus on for improving resilience. As MISO explained, "Continued industry dialogue on more effectively identifying, valuing, and incorporating resilience attributes in transmission planning processes will help the Commission identify further opportunities to support and advance grid resilience."[43]

Similarly, NYISO's statement at the FERC proceeding explained that the Commission "must also recognize the critical importance of maintaining and enhancing grid interconnections. These interconnections support and bolster reliability and resilience by creating a larger and more diverse resource pool available to meet needs and address unexpected and/or disruptive events throughout an interconnected region."[44] The ISO's comments provided a detailed explanation of how "The resiliency value of an interconnected grid has been clearly demonstrated during recent periods of system stress," and explained that "Maintaining and protecting existing interconnections between neighboring regions and continually assessing opportunities to improve interregional transaction coordination can bolster the resiliency of the grid throughout an interconnected region. These interconnections foster the opportunity for the Northeast and Mid-Atlantic markets to rely on a broader, more diverse set of resources to meet the overall needs of the region."[45]

42 FERC https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=14838232, pages 11, 69, 50.
43 FERC https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=14837872, page 2.
44 FERC https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=14838205, pages 10-12.
45 *Id.*

FERC Order No. 896[46] will require regions to plan for extreme weather's impact on electricity supply and demand and address any reliability concerns. Solutions could include expanding transmission between regions or adding capacity resources in both regions. Because transmission is bidirectional, is not affected by correlated outages that affect new gas generators, and provides other benefits, it is likely to be a superior solution to adding generation. However, regions need to begin planning interregional transmission now if it will be in place in time to meet that need.

Transmission planning and cost allocation processes should also account for the resilience value of transmission. Severe weather and other extreme events should be included in those studies, ideally using probabilistic methods or at least scenario-based "stress tests." Assessments of the value of transmission should also include potential transmission and generation outages, including correlated generator outages, as a stronger transmission network is particularly valuable during times of system stress. MISO's LRTP analysis accounts for some of this benefit by quantifying the value of regional transmission for reducing the risk of loss of load from localized correlated generation failures during periods of extreme weather,[47] though the value is likely far greater for interregional transmission because of the larger weather and climate diversity between MISO and PJM.

46 FERC, Transmission System Planning Performance Requirements for Extreme Weather (2023) https://www.federalregister.gov/documents/2023/06/23/2023-13286/transmission-system-planning-performance-requirements-for-extreme-weather.

47 *See*, supra note 10.

II. POLICY PROBLEMS AND SOLUTIONS

A. Problems

1. PJM lacks an effective mechanism for planning and paying for regional transmission

PJM currently lacks a proactive multi-value transmission planning process with broad cost allocation.[48] Largely due to conflicts over cost allocation, PJM uses a siloed approach to transmission planning in which reliability, economic, public policy, and generator interconnection transmission projects are planned and paid for separately. As a result, PJM is not building high-capacity regionally-planned transmission. Rather, the vast majority of recent transmission build has been smaller "Supplemental Projects" proposed by local transmission owners to meet reliability needs, which tend to be less cost-effective and are not optimized to maximize multiple benefits.[49] PJM scored below average on DOE's metrics of recent transmission construction,[50] and received a D+ on a transmission planning report card compiled for Americans for a Clean Energy Grid.[51]

A proactive, multi-value planning approach with broad cost allocation has proven to be the most workable method of planning and paying for transmission. As noted above, MISO pioneered that approach with its MVPs. All but one of those lines have since been completed, and analyses have confirmed that those projects are providing large net benefits.[52] MISO's process was informed by Texas's success in using proactive transmission planning to build the Competitive Renewable Energy Zone projects, a portfolio of upgrades that allowed the state to more than double its use of renewable energy.[53] The Southwest Power Pool (SPP) also adopted a regional proactive multi-value transmission planning approach, and two subsequent SPP studies have confirmed that those upgrades are providing large net benefits by meeting a range of economic and reliability needs.[54]

In the Regional Generator Outlet Study (RGOS)[55] and subsequent MVP report, MISO identified renewable resource zones and proactively planned transmission to minimize total transmission and generation cost by accessing lower-cost wind resources. MISO accounted for and planned a portfolio to maximize the multiple benefits of transmission for meeting economic, reliability, and public policy needs (including renewable interconnection to meet state Renewable Portfolio

48 PJM/MISO IPSAC (2023) https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2023/20230217/third-party-issues.ashx.

49 For example, see https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/, and https://gridprogress.files.wordpress.com/2021/01/disconnected-the-need-for-a-new-generator-interconnection-policy-1.14.21-1.pdf.

50 *See*, supra note 26.

51 Americans for a Clean Energy Grid and Grid Strategies, Transmission Planning and Development Report Card (2023) https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf.

52 MISO, MTEP17 MVP Triennial Review–A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio (Sept. 2017), https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf.

53 *See, e.g.*, Lasher, *The Competitive Renewable Energy Zones Process*, ERCOT (Aug. 11, 2014), https://www.energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

54 See SPP Transmission Planning, *The Value of Transmission – A 2021 Study and Report by Southwest Power Pool*, SPP (Mar. 31, 2022), https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf; *see also* SPP, *The Value of Transmission*, SPP (Jan. 26, 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf.

55 MISO, Regional Generation Outlet Study https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf, at 2.

Standard requirements). In the MVP and LRTP planning, MISO also spread the portfolio of planned transmission projects across MISO's Midwest subregion to ensure that all zones received projects and had a high benefit-to-cost ratio, ensuring broad support for the overall portfolio.

As noted in the benefits discussion in the preceding section, MISO's MVP analysis and recent and ongoing LRTP analysis account for many types of benefits that are not assessed in PJM's Regional Transmission Expansion Plan (RTEP). PJM's RTEP process only accounts for savings in the PJM energy and capacity market when evaluating economic "market efficiency" projects.[56] In addition to those benefits, MISO's LRTP analysis also accounts for reduced generator capacity investment from accessing more productive renewable resources, savings from deferring transmission system investment needed to meet reliability criteria, reduced risk of load shedding from extreme events and other threats to resilience, and the value of reduced carbon emissions.

PJM currently has siloed planning and cost allocation mechanisms for different categories of transmission projects. Transmission projects are planned and paid for differently if they are categorized as reliability, market efficiency, public policy, or generator interconnection projects. Such categorization misses the fact that most large-scale transmission projects provide most if not all of those benefits. PJM's approach also misses opportunities to find more optimal transmission plans that maximize net benefits across all of those categories. Moving to multi-value transmission planning should be accompanied by moving to broad transmission cost allocation, reflecting that large-scale transmission investment provides multiple benefits across large geographic areas.

Analyses by the Brattle Group and others have confirmed the benefits of proactive multi-value transmission planning, rather than the current reactive approach to upgrading transmission through the generator interconnection process, including in MISO and PJM.[57] It is also essential for transmission planning to account for the multiple types of transmission benefits, as only accounting for a few categories of benefits understates the benefit-cost ratio and therefore results in an underinvestment in transmission.[58] MISO's MVP and LRTP processes are a successful model for what PJM's transmission planning process could be, given their proactive assessment of solutions to maximize multiple types of benefits.

In addition, grid-enhancing technologies, reconductoring with high-performance conductors, rebuilding lines with modern tower designs, or adding circuits should also be evaluated as potential solutions to regional and interregional transmission constraints. These technologies can be deployed quickly and at low cost on existing transmission rights-of-way, making them an important complement to longer-term solutions. Finally, transmission planning should cover a long time horizon, reflecting that many transmission projects will be in operation for a half-century or more. MISO's LRTP includes 20-year and 40-year assessments of costs and benefits. Transmission planning should account for expected changes in the generation mix due

56 PJM Manual 14B https://www.pjm.com/-/media/documents/manuals/m14b.ashx, at 55.

57 American Council on Renewable Energy, Natural Resources Defense Council, Brattle, and Grid Strategies https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

58 *Id.*

to economics, utility and consumer plans, and state policies, as well as changes in electricity demand due to electrification and other factors.[59]

For public policy transmission projects, which are typically those built to interconnect renewables to meet state renewable requirements, PJM's current rules include a "State Agreement Approach" transmission planning process as part of its RTEP. The State Agreement Approach is outlined in Schedule 6, Section 1.5.9 of PJM's FERC-approved Operating Agreement.[60] Under this approach, for public policy-driven transmission to be included in the regional plan, one or more states must voluntarily agree to a FERC-accepted "allocation of all costs of a proposed transmission expansion or enhancement that addresses state Public Policy Requirements[.]" Costs of this transmission are not recovered from customers in states that do not agree to the cost allocation, so in practice the state sponsoring the project pays its full cost — without any consideration of any benefits that might accrue to other states. PJM's State Agreement Approach supplements, but does not replace, PJM's obligation to consider transmission for public policy, as required in FERC Order No. 1000. However, the requirement to "consider" public policy has proven insufficient for PJM to incorporate state policy into regional transmission plans, and as a result, public policy projects are only incorporated into PJM transmission plans if states volunteer to pay for them. The State Agreement Approach has only been used once in the dozen years since Order No. 1000 was issued, and in that instance, New Jersey alone is paying for the transmission.[61]

The State Agreement Approach does not solve the fundamental free rider problem that plagues transmission cost allocation because paying for public policy transmission is voluntary for states. Large-scale transmission investment provides benefits that are broadly spread across multiple states in the region, regardless of whether they pay for the transmission, removing the incentive for those other states to pay under the voluntary State Agreement Approach. Because transmission planning in the State Agreement Approach is typically focused solely on meeting public policy needs, it also misses opportunities for more optimal transmission plans that can also address reliability and economic needs.

Because the State Agreement Approach is part of Order No. 1000, it removes the incumbent transmission owner's right of first refusal to build a line, instead requiring competitive solicitations. While competition is beneficial, transmission owners have been hesitant to support transmission development through Order 1000 processes because they will not have a right of first refusal to build the line. A state is free to pay for transmission outside of the Order 1000 process, which transmission owners are more likely to support. Given this concern and the failure of the State Agreement Approach to solve the fundamental barriers to transmission by adopting multi-value planning and broad cost allocation, it is not surprising that it has not been more widely used.

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59 Macro Grid Initiative, Planning for the Future: FERC's Opportunity to Spur More Interregional Transmission https://gridprogress.files.wordpress.com/2021/02/planning-for-the-future.pdf.

60 PJM Interconnection, L.L.C. Rate Schedule FERC No. 24 (2011) https://www.pjm.com/directory/merged-tariffs/oa.pdf.

61 PJM Inside Lines, New Jersey Marks Milestone for Offshore Wind Using PJM's State Agreement Approach https://insidelines.pjm.com/new-jersey-marks-milestone-for-offshore-wind-using-pjms-state-agreement-approach/.

2. Regional transmission planning has yielded suboptimal solutions relative to interregional planning

As discussed above, MISO's regional planning of the MVP and LRTP projects serves as a model for PJM, and the completed MVP projects are providing large net benefits. However, the success of the MVP projects likely could have been further improved upon with optimized, or at least coordinated, interregional planning with PJM. Interregional planning likely could have realized economies of scale with larger and higher-capacity transmission investment, such as by extending PJM's 765-kilovolt (kV) network westward across Illinois or even into MISO. Relative to regional planning, interregional planning could more efficiently address congestion by connecting areas in one RTO that have low Locational Marginal Prices (LMPs) with areas in the other RTO that have high prices, and increase interregional transfer capacity to provide the resource adequacy and resilience benefits discussed in the preceding section.

The missed opportunity for more efficient interregional solutions can be seen by comparing MISO's MVP solution with that identified in the predecessor RGOS. Unlike the MVP study, RGOS included ComEd and Ohio,[62] and as a result it built large transmission upgrades across the MISO-PJM seam as shown in the maps below. RGOS planned 765-kV lines across the seam into Chicago and Ohio, in contrast to what was ultimately designed and built with the MVP lines. This is not to say that MVP or other MISO transmission plans are inefficient or should not have been built, because multiple studies have confirmed that they are providing large net benefits. MVP was optimized for MISO, which was the planning and cost allocation structure MISO had to work under at the time, and which is still in place. However, an even more efficient and effective solution is achievable if PJM were to join MISO in planning and paying for transmission that will benefit both regions.

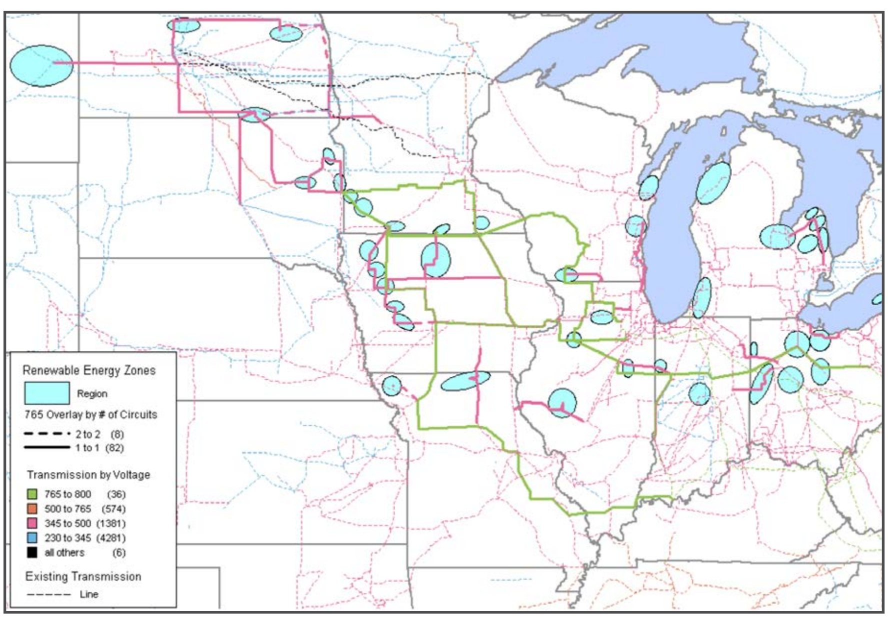


FIGURE 12.
MISO RGOS Plan[63]

62 *See*, supra note 55. https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf, at 2.
63 *Ibid.*, at 10.

In contrast, as shown below, the MVP lines[64] include a donut hole in the ComEd portion of PJM in northern Illinois and did not extend eastward into PJM. This difference from the RGOS plan presumably resulted from the shift in planning criteria to only evaluate benefits within MISO, consistent with MISO's planning and cost allocation rules.

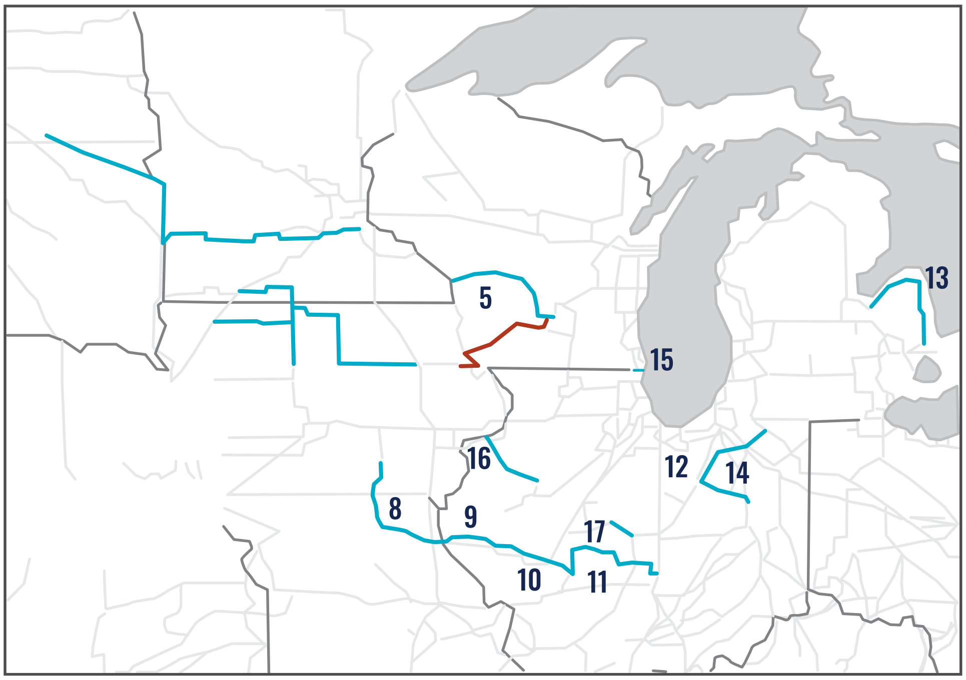


FIGURE 13.
MISO MVP Lines

Similar challenges caused by the inability to plan and pay for transmission between MISO and PJM continue to persist in the LRTP. A map of the approved LRTP 1 projects and draft proposal for LRTP 2 projects is shown below. While the planned LRTP expansion provides large net benefits for MISO, MISO and PJM could realize even greater benefits with combined or at least coordinated planning and cost allocation for interregional lines. The LRTP expansion is designed to be the optimal solution for MISO, consistent with current planning and cost allocation rules that entirely allocate costs to MISO customers.

64 See, supra note 25. https://www.house.mn.gov/comm/docs/BdLQVikOwEOm_1_BkKc4Rw.pdf, at 4.

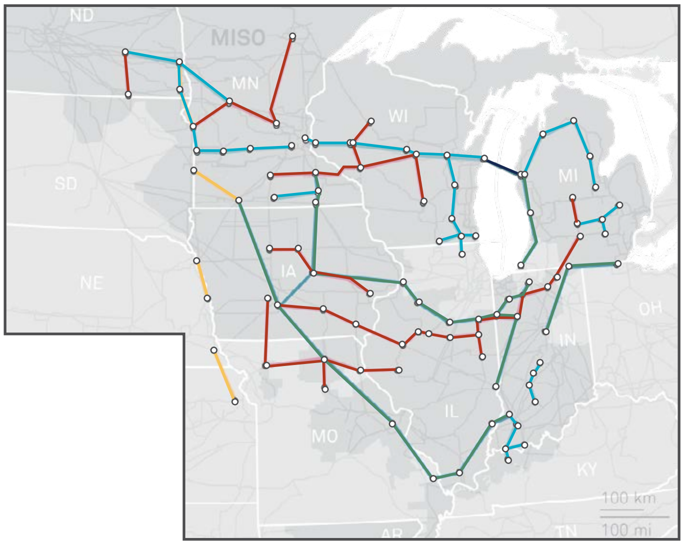


FIGURE 14.
MISO LRTP plans

LRTP TRANCHE 2
HVDC kV
765 kV
345 kV
JTIQ
345 kV
LRTP TRANCHE 1
345 kV

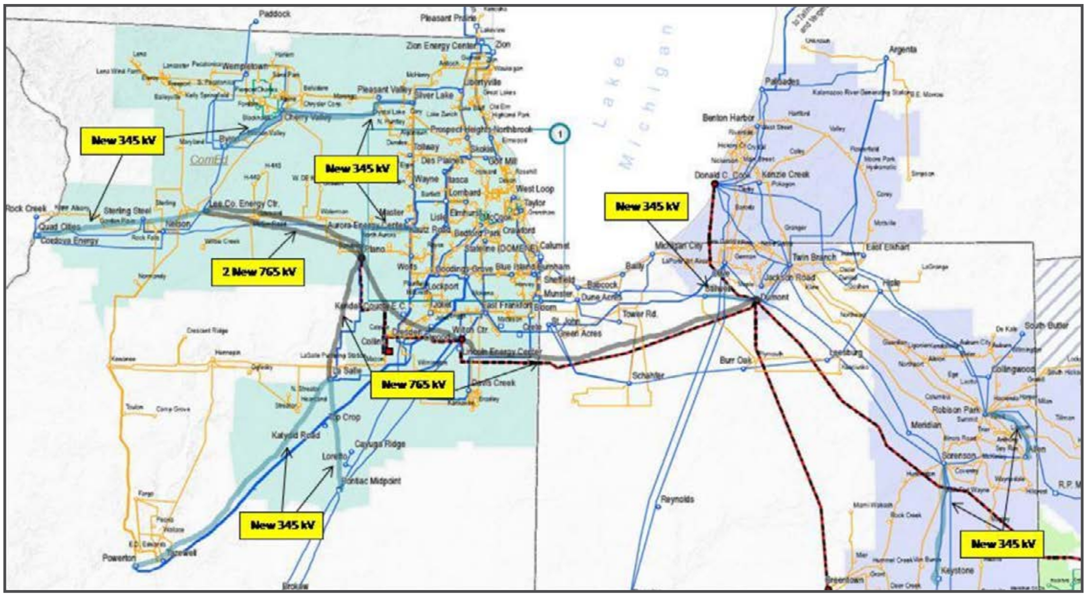
The RGOS analysis quantifies the savings that can be achieved from interregional planning relative to regional solutions. For example, the study found that transmission costs per MWh of enabled renewable generation would average around $50/MWh if planning for MISO alone, but $30/MWh if PJM were included,[65] showing the benefit from economies of scale and a more optimal network design. The analysis also found that about 10% of the production cost savings of the RGOS expansion would flow to PJM, but value realized outside of the RTO is currently ignored in regional transmission planning. Given that the RGOS analysis was conducted 13 years ago, those precise results for cost and savings would likely differ today given significant changes in fuel costs, the resource mix, and renewable costs. However, the directional indicator of large savings from coordinated planning is based on fundamental factors that have not changed, and if anything have grown larger due to cost reductions for renewable energy, extensive retirement of fossil generation in many regions, the need to move power from the renewables enabled by the MVP and LRTP lines eastward into PJM, and increased need for east-to-west transmission due to the growth of solar energy and low-cost shale gas generation in the eastern U.S.

Multiple studies have found that optimal network solutions build very large amounts of transmission across the MISO-PJM seam. Most notably, PJM's 2014 Renewable Integration Study evaluated a range of renewable penetration scenarios within PJM, and the transmission upgrades that would be needed to interconnect those new resources. That analysis identified a need for multiple new high-voltage lines across northern Illinois and the PJM portion of Indiana, including lines that lead up to the MISO seam,[66] resulting in an expansion in those states that is quite similar to what RGOS identified. For example, the map below shows some of the transmission upgrades required in a scenario in which all PJM state Renewable Portfolio Standard requirements at the time were met, which would require enough renewable energy to

65 *See*, supra note 55 at 8.
66 GE Energy Consulting, PJM Renewable Integration Study (2014) https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pjm-pris-task-3a-part-c-transmission-analysis.ashx.

serve 14% of PJM energy. This includes a new 765-kV line crossing northern Illinois and Indiana, two new 765-kV lines running west from the Chicago area, and the addition of a 345-kV line to the Iowa border where MISO begins.

FIGURE 15. *Transmission Expansion in Northern Illinois and Indiana in PJM's 14% Renewable Scenario*



The map below shows the incremental transmission, beyond the upgrades identified in the 14% scenario above, that would be required in a scenario in which PJM obtained 30% of its energy from renewables, with a focus on building out land-based wind resources in optimal locations. This adds two incremental 765-kV lines across northern Illinois and Indiana and a 765-kV line to the Iowa border.

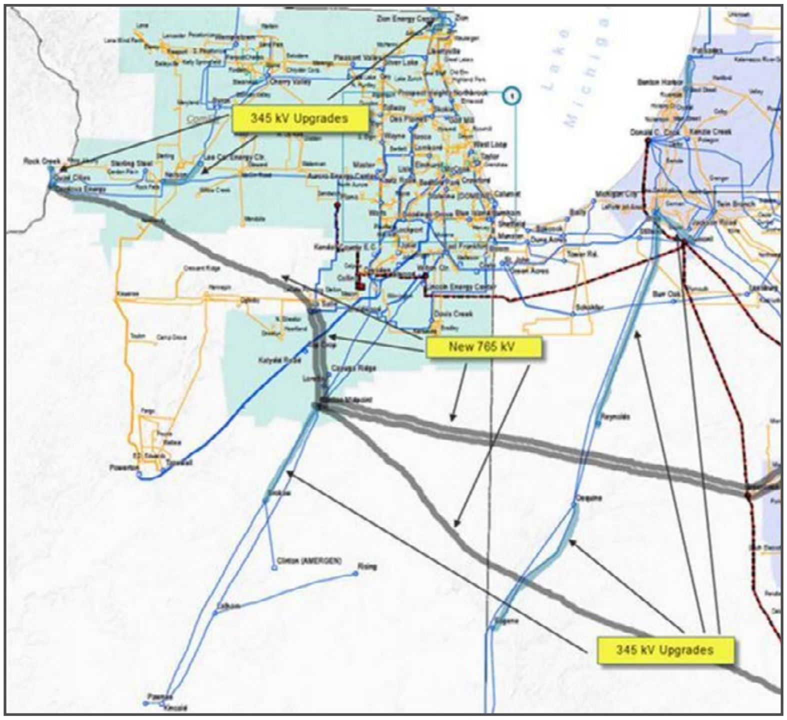


FIGURE 16. *Additional Transmission Expansion in northern Illinois and Indiana in PJM 30% Best Onshore Renewable Scenario, Relative to 14% Renewable Scenario Shown Above*

Other studies of optimal transmission networks for the Eastern Interconnection or entire country have called for at least four or five High-Voltage Direct Current (HVDC) lines to be built across the MISO-PJM seam, often accompanied by a significant expansion of the underlying Alternating Current (AC) network. These studies include a national optimization study using the WIS:dom-P model, [67] NREL's Eastern Wind Integration and Transmission Study,[68] the Joint Coordinated System Plan study, and NREL's seam study.[69]

3. Interregional transmission between MISO and PJM is not being built

The current process for planning and paying for transmission between MISO and PJM[70] is failing to develop needed interregional lines. MISO and PJM have an interregional planning process detailed in their Joint Operating Agreement (JOA). However, this study process has been limited and resulted in only a few small interregional upgrades. Most of these upgrades have fallen under the category of Targeted Market Efficiency Projects (TMEP), which to date have been small, low-cost projects with limited impact. Part of the problem is that TMEP relies on a narrow definition of flow-gates when identifying constraints between PJM and MISO, and thus is failing to identify solutions to persistent constraints. However, the fundamental problem undermining effective interregional planning is the underlying cost allocation fight over who will pay for interregional transmission.

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67 MacDonald and Clack, et al., Future cost-competitive electricity systems and their impact on US CO2 emissions, Nature Climate Change (2016) *available at* https://repository.library.noaa.gov/view/noaa/14578.

68 The National Renewable Energy Laboratory (NREL), Eastern Wind Integration and Transmission Study (2011) https://www.nrel.gov/docs/fy11osti/47078.pdf, at 37-38.

69 NREL, Interconnection Seam Study (2020) https://www.nrel.gov/docs/fy21osti/78161.pdf, at 20 (Scenario 2a).

70 PJM, Interregional Planning https://www.pjm.com/planning/interregional-planning, https://www.pjm.com/committees-and-groups/stakeholder-meetings/ipsac-midwest.aspx.

As a prominent example of the failure of the current interregional planning and cost allocation processes, in March 2023 PJM and MISO "determined that a long-term Interregional Market Efficiency Project (IMEP) study will not be conducted in 2023 because no interregional constraints were identified by the RTOs' coordinated modeling updates. Additionally, both RTOs agreed that a TMEP study will not be conducted in 2023 as parties believe an additional year of market data would be prudent to evaluate whether congestion was expected to persist after planned network upgrades go into service and M2M designations are re-established."[71] The claim that interregional constraints and congestion are not significant is at odds with MISO's and PJM's own data, discussed at the beginning of this paper, showing $1.7 billion in interregional congestion costs between them in 2021-2022.

The policy problems plaguing interregional transmission planning and cost allocation are not unique to MISO and PJM. Nationally, the interregional transmission planning processes under FERC Order No. 1000 are not properly identifying large projects between regions that would yield large economic, reliability, operational, and public policy benefits for consumers. These processes have failed to drive any large transmission projects between any regions to date.[72] This is largely because although Order No. 1000 requires neighboring transmission planning regions to coordinate planning it does not require a joint process or evaluation of interregional solutions and their benefits. FERC has significant authority to set interregional transmission planning and cost allocation policies under its authority to ensure rates are just and reasonable, enabling the Commission to play an important role in driving MISO and PJM to develop a workable mechanism for planning and paying for interregional transmission.

A significant hurdle for many interregional transmission planning processes is that regions employ different planning assumptions, benefit categories, and methods. For instance, different regions typically employ different assumptions including the timeframe for the analysis, the discount rate, and projections of fuel costs, load growth and patterns, new generator costs, and other key modeling inputs, as well as different modeling methods including different tools. MISO and PJM use very different assumptions and methods for these inputs,[73] and PJM's siloed approach in which lines are planned for a single type of benefit does not mesh with the multi-value approach MISO uses for the LRTP. Transmission planning regions even differ in assumptions about what contingencies should be studied when assessing compliance with NERC reliability standards like TPL-001 that govern transmission planning.

Consistency and standardization between neighboring regions for interregional planning would help avoid the "triple hurdle" — the situation in which proposed interregional transmission projects must first meet the requisite inter-regional criteria, then again qualify under each transmission planning region's planning criteria — subjecting interregional projects to three or more distinct approval processes. Instead, one interregional process with a common model and assumptions should replace the "triple hurdle." Interregional planning could also be improved

71 March 24, 2023, email to transmission planning stakeholders from MISO and PJM; also noted in https://cdn.misoenergy.org/20231027%20MISO-PJM%20IPSAC%20Presentation630649.pdf, at 5.

72 FERC, 2023 Summer Energy Market and Electric Reliability Assessment (2023) https://www.ferc.gov/media/report-2023-summer-energy-market-and-electric-reliability-assessment, at 28.

73 American Council on Renewable Energy and Concentric Energy Advisors, How Transmission Planning & Cost Allocation Processes are Inhibiting Wind & Solar Development in SPP, MISO, & PJM (2021) https://acore.org/wp-content/uploads/2021/03/ACORE-Transmission-Planning-Flaws-in-SPP-MISO-and-PJM.pdf, at 19-32.

by enabling projects to address different needs in different regions, such as reliability benefits in one region, but economic or public policy in another. Once benefits are considered and findings of benefits are agreed upon in an interregional study, these determinations should not be subject to reassessment by subsequent regional evaluations. Further, there should not be exclusions of projects of certain voltage levels or cost.

A 2013 study[74] found that traditional planning approaches are not adequate to achieve least-cost solutions given widespread fossil plant retirements and renewable additions. The study compared interregional transmission needs in the Eastern Interconnection using both the traditional approach that is largely reactive to applications to interconnect by generators, versus a proactive multi-value approach that co-optimizes transmission and generation investment and maximizes net benefits. The study found that proactive transmission planning would, as compared to the outcome of traditional reactive processes, reduce total generation costs by $150 billion, increase interregional transmission investments by $60 billion, resulting in net overall system-wide savings of $90 billion. Although a purely co-optimized process may be difficult to achieve in markets where utilities and planners do not have the full responsibility of integrated planning for generation and transmission, proactive planning based on capacity expansion modeling that considers scenarios that cover the likely range of future trends and uncertainties would achieve similarly co-optimized results. The analysis could use probabilistic or at least scenario-based methods to explicitly account for uncertainties about future growth in energy use; fuel costs; technological changes; technology cost; shifts in supply and demand patterns; environmental regulations; and other state, regional, and federal policies.

The politics of interregional cost allocation is the primary impediment to effective mechanisms to plan and pay for interregional transmission. Like many forms of infrastructure, the benefits of high-capacity transmission lines are widely dispersed across all electricity consumers across large regions. Moreover, transmission is a "natural monopoly" due to the inefficiency of building redundant competing systems and the inability to exclude those who do not pay from use of the AC network, characteristics that make transmission and similar types of infrastructure "public goods." Transmission is afflicted by the fundamental "free rider" problem that characterizes all public goods. Any transmission upgrade paid for by an individual generator can be used by competing generators, and for most grid upgrades, benefits largely flow to customers and other users of the grid. Similarly, a transmission line paid for by one state will benefit other states in the region, and large transmission in one region also benefits consumers in neighboring regions. As a result, generators, states, and regions have an incentive not to pay for transmission, in the hope that others will. Without policies to broadly allocate the cost of transmission as would be consistent with FERC's policy of allocating transmission costs in a manner that is reasonably commensurate with its benefits, there will be a significant underinvestment in transmission. As a result, there is an essential role for states, RTOs, FERC, and Congress to ensure that adequate transmission is built to realize these societal benefits, similar to the role governments play in the planning and cost recovery of highways, sewer systems, and rail networks.

74 Eastern Interconnection States' Planning Council, Co-optimization of Transmission and Other Supply Resources (September 2013), https://pubs.naruc.org/pub.cfm?id=536D834A-2354-D714-51D6-AE55F431E2AA.

While the potential benefits of interregional transmission are typically larger than those within a region, the cost allocation free rider problem is even more intractable between regions than within a region. The cost allocation of interregional projects should fully reflect the economic and public policy benefits, as well as other quantifiable benefits that will accrue. FERC has significant authority to require regions to develop interregional transmission planning and cost allocation methodologies, though FERC has hesitated to do so without coordinated political will from state and regional actors. As a guide for how to plan and pay for a portfolio of interregional transmission projects, regions should also look to the success of MISO and SPP in developing regional portfolios of projects that provide sufficiently large net benefits within their regions to overcome opposition from any one state.

B. Ideal solution: Proactive multi-value planning of interregional transmission

As discussed above, proactive multi-value planning is the gold standard for regional transmission planning, and should serve as the model for interregional transmission planning as well. Grid Strategies has previously outlined five key principles of proactive transmission planning:[75]

1. Proactively plan for future generation and load by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. Account for the full range of transmission projects' benefits and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.
4. Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. Jointly plan across neighboring interregional systems to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

Proactive planning yields major savings by realizing economies of scale in transmission investment. PJM recently found that proactive transmission planning could integrate 12.4 GW of offshore wind resources along with 14.5 GW of onshore wind, 45.6 GW of solar, and 7.2 GW of storage, for a total of just $2.2 billion.[76] This equates to a cost of $27/kilowatt for interconnecting new generation capacity, a fraction of the cost found through interconnection queue studies. For example, a Brattle Group analysis of PJM queue study results show $1.3 billion in total identified transmission upgrades for integrating 5.6 GW of PJM offshore wind

75 *See*, supra note 33.

76 PJM Interconnection, *Offshore Wind Transmission Study: Phase 1 Results*, 16, Scenario 6 (Oct. 19, 2021), https://pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

resources alone,[77] which equates to a cost of $415/kilowatt, 15 times greater than costs under PJM's proactive plan. Other analysis found that integrating 15.5 GW of offshore wind under today's rules would lead to $6.4 billion in upgrades,[78] at a cost of $236/kilowatt.

Similarly, a proactive planning effort in New Jersey for offshore wind resulted in the selection of onshore transmission upgrades that save ratepayers in the state approximately $1 billion for 6,400 MW of additional offshore wind, a two-thirds reduction relative to the costs identified though PJM queue studies of individual projects.[79]

The full range of benefits provided by large-scale transmission should be included in interregional planning, cost-benefit analysis, and cost allocation. In its pending rulemaking on transmission planning and cost allocation, FERC enumerated a dozen types of benefits provided by transmission:[80]

1. avoided or deferred reliability projects and aging infrastructure replacement,
2. either reduced loss of load probability or reduced planning reserve margin,
3. production cost savings,
4. reduced transmission energy losses,
5. reduced congestion due to transmission outages,
6. mitigation of extreme events and system contingencies,
7. mitigation of weather and load uncertainty,
8. capacity cost benefits from reduced peak energy losses,
9. deferred generation capacity investments,
10. access to lower-cost generation,
11. increased competition, and
12. increased market liquidity.

PJM has recognized many of these benefits in a 2019 report[81] and in its annual value proposition studies discussed above.

Ideally proactive planning would be conducted through synchronized or iterative co-optimized generation and transmission planning with the goal of minimizing total costs. Co-optimized generation capacity expansion modeling and transmission planning accounts for renewable development enabled by transmission expansion, and factors in production cost savings from that capacity expansion to find the optimal solution that minimizes the total cost of generation plus transmission. This was the method and principle underlying MISO's RGOS, MVP, and

77 Pfeifenberger, et al., New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, N.J. Bd. of Pub. Utils., 180, Table A-2 (Oct. 26, 2022), https://www.brattle.com/wp-content/uploads/2022/10/New-Jersey-State-Agreement-Approach-for-Offshore-Wind-Transmission-Evaluation-Report.pdf.

78 Burke, et al., Offshore Wind Transmission White Paper, Bus. Network for Offshore Wind, 40 (Oct. 2020), https://gridprogress.files.wordpress.com/2020/11/business-network-osw-transmission-white-paper-final.pdf.

79 Pfeifenberger, supra note 36 at 92, Figure 4.

80 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028, 18 CFR Part 35, Dkt. No. RM21-17-000 (Apr. 21, 2022), https://www.ferc.gov/media/rm21-17-000).

81 PJM, "The Benefits of the PJM Transmission System," April 2019, *available at* https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf.

LRTP studies, as illustrated in the MISO chart earlier in this report.[82] Because generation and transmission costs ultimately flow to ratepayers, minimizing total costs results in the optimal outcome for consumers. This planning process typically begins with capacity expansion modeling for generation, as was done in the studies DOE used to arrive at its transmission needs estimates.[83] An alternative that captures some of this benefit is to include the economic benefit of accessing more cost-effective renewable resources, as was done in MISO's transmission planning by quantifying the cost savings from reducing the amount of renewable capacity that must be built to produce a given amount of energy, as discussed previously.

With multiple entities making market-based decisions about generation additions and retirements, the ideal of co-optimized generation and transmission planning may be difficult to achieve in the near term, but at a minimum transmission planning should account for utility plans and goals and state requirements. Because utilities in most MISO states own generation, MISO utilities generally develop Integrated Resource Plans that aim to minimize generation costs, whereas most PJM states do not require IRPs.[84] However, many PJM utilities do have long-term plans or goals for decarbonization or renewable procurement, and many PJM states have renewable energy requirements, which at minimum these should be incorporated into PJM's planning.

Another potential starting point for synchronized generation and transmission planning is to identify high-quality renewable energy resource zones and then plan transmission to access them, building on the success of the MISO MVP and ERCOT CREZ studies, and more recently the renewable energy zones being developed as part of the Illinois Renewable Energy Access Plan (REAP) process. Renewable energy zones can be drawn in part by using the interconnection queue to identify areas with large and persistent development interest. That analysis should then be supplemented with capacity expansion modeling or other analysis of locations that are suitable for renewable resources development but do not receive large numbers of queue applications because they are remote from the current transmission system or are plagued by high transmission congestion or upgrade costs. Another starting point for such an analysis can be an open solicitation process, like the Open Season process pioneered by the Bonneville Power Administration in the Pacific Northwest, in which generation developers use financial bids and commitments to indicate their interest in developing in certain locations.

As discussed above, cost allocation is the thornier problem that often derails effective regional or interregional transmission planning. The ideal cost allocation for interregional transmission is to share costs broadly across both footprints, reflecting that both regions will benefit over time. In addition, inherent uncertainty regarding fuel prices, load growth, generation costs, extreme weather, and other factors makes precise quantification of benefits and beneficiaries impossible, and often leads to analysis paralysis when parties opposed to paying for transmission use that inherent uncertainty to argue for unreasonable assumptions. While pro rata assignment of costs across both the MISO and PJM footprints using a single $/MWh rate would be the simplest approach, broad regional cost allocation starting with a rough negotiated share between MISO

82 *See*, supra note 26. https://www.house.mn.gov/comm/docs/BdLQVikOwEOm_1_BkKc4Rw.pdf.

83 *See*, supra note 25.

84 U.S. DOE, Integrated Resource Planning in the U.S. Overview (2021) https://eta-publications.lbl.gov/sites/default/files/sc_commission_day_1_irps_in_us_review_of_requirements_final.pdf.

and PJM may be more politically feasible. A negotiated allocation of costs between MISO and PJM also helps address the "triple hurdle" concern discussed above, as it makes it feasible to build lines that provide a greater share of benefits to one region. MISO and PJM and their states and stakeholders should begin discussions to develop a workable cost allocation mechanism to pay for interregional transmission, likely informed by the distribution of benefits identified in the planning studies proposed later in this paper, and which should reflect the full range of transmission benefits discussed previously.

Steps toward the ideal approach

States and other stakeholders may be able to leverage PJM's ongoing Master Plan discussion of potential reforms to its regional transmission planning process[85] and changes to the Long-Term Regional Transmission Planning (LTRTP)[86] to develop stronger planning and cost allocation measures for both regional and interregional transmission. PJM's Master Plan proposes scenario-based planning that accounts for generation plans and customer needs, looking out 15 years, and correctly discusses the importance of planning for interregional needs and extreme conditions.

However, stakeholders also need to advocate to strengthen PJM's Master Plan proposal and the LTRTP in the following areas:

- Because the proposal references FERC's pending transmission planning rule, if FERC does not take strong action in that final rulemaking, the prospects for PJM significantly reforming its transmission planning processes are at best unclear.
- PJM argues for continuation of existing cost allocation processes, which are the primary impediment to building proactive and multi-value transmission.[87]
- The proposed plan also only calls for public policy to be "considered," which is the status quo under Order 1000 and has not resulted in PJM incorporating state policies into its transmission planning.

PJM states and stakeholders should work towards adopting the MISO MVP and LRTP model of proactive multi-value transmission planning coupled with broad cost allocation. As in PJM, MISO states are also politically diverse, yet MISO has twice succeeded in identifying a portfolio of transmission projects that provide net benefits that are sufficiently large and evenly spread across the footprint to earn widespread support. A key factor in MISO's success was the recognition that determining transmission upgrades through the generator interconnection queue was failing to efficiently meet the need for new transmission, and in turn leading to lengthy interconnection backlogs. With around 250,000 MW of generation in the PJM interconnection queue as of the end of 2021,[88] a more proactive and multi-value approach is clearly needed there as well.[89]

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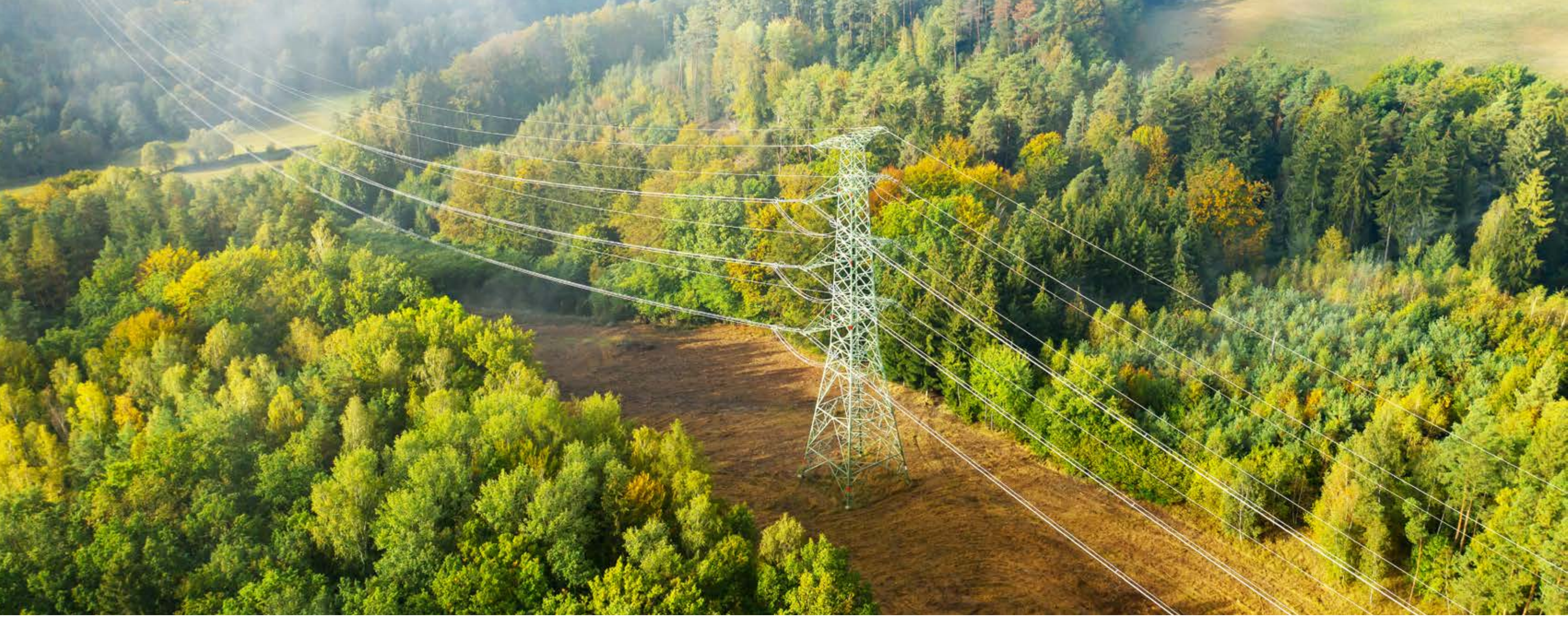
85 PJM, Enhanced 15-Year LongTerm Planning (Master Plan) White Paper (2022) https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220525-long-term/enhanced-long-term-planning-discussion-document.ashx.

86 PJM, Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection (2022) https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220809-special/item-03---ltrtp-workshop-nopr-response.ashx.

87 *Id.*, at 5.

88 Berkley Lab, Generation, Storage, and Hybrid Capacity in Interconnection Queues https://emp.lbl.gov/generation-storage-and-hybrid-capacity.

89 Americans for a Clean Energy Grid, Macro Grid Initiative, and Grid Strategies, Disconnected (2021) https://gridprogress.files.wordpress.com/2021/01/disconnected-the-need-for-a-new-generator-interconnection-policy-1.14.21-1.pdf.



A valuable first step would be for PJM to conduct a PJM-wide proactive multi-value transmission planning study to identify a portfolio of lines that provide large net benefits across the footprint. Demonstrating the large net benefits of transmission to consumers in every part of PJM should help build support for broad cost allocation. In addition, such a study would likely identify transmission solutions that offer larger net benefits and are more workable than upgrades identified through interconnection queue studies, alleviating pressure on what is widely recognized by PJM stakeholders to be a broken interconnection queue process.[90] This follows the model of RGOS, the 2010 study led by MISO described previously.

States play an essential role in mobilizing support for RTOs to enact planning and cost allocation policies that will result in efficient regional transmission solutions. MISO states are politically diverse, yet in both the MVP and LRTP processes they have been able to unite and support broad regional cost allocation for a portfolio of multi-value projects that offer benefits to all states in the footprint. States with high penetrations of current and planned renewable resources gain jobs and economic development from tapping those resources, other states receive low-cost power from those incremental renewable investments, and all states can use a stronger transmission network to access more affordable and reliable power. Given its location in both PJM and MISO, Illinois can possibly use its REAP process as a starting point for working with other states to drive support for a PJM-wide proactive multi-value transmission planning study to identify a portfolio of lines that provide large net benefits across the footprint. Other states that also straddle the MISO-PJM seam, like Indiana, Michigan, and Kentucky, can help mobilize support in PJM for workable regional transmission planning and cost allocation based on MISO's successful models, and advocate in both RTOs for workable planning and cost allocation measures for interregional transmission.

It may be possible to leverage federal funding available under the Inflation Reduction Act (IRA) of 2022 and Infrastructure Investment and Jobs Act (IIJA) of 2021 to conduct that planning, and even help pay for identified transmission solutions. The Inflation Reduction Act includes

90 Berkley Lab, PJM Data Show Substantial Increases in Interconnection Costs https://emp.lbl.gov/news/pjm-data-show-substantial-increases.

funding for Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis (Sec. 50153), which can be used for transmission planning, modeling, analysis, and the convening of stakeholders for interregional transmission projects. If that planning is successful and leads to the development of transmission lines, the Inflation Reduction Act also established Grants to Facilitate the Siting of Interstate Electricity Lines (Sec. 50152), expanded the DOE Loan Program Office funding (Title 17) (Sec. 50141), and Transmission Facility Financing (Sec. 50151). The wholesale market grants and technical assistance program established by the IIJA includes funds for analyses of market seams issues and integrated resource and transmission planning.[91]

The IIJA also contains several funding mechanisms that could be used. The State Energy Program (Sec. 40109) provides assistance in implementing energy efficiency programs, energy security planning, and energy waste management, among other state-led energy initiatives. Transmission and distribution planning is included as part of state energy conservation plans. The Grid Resilience and Innovation Partnerships (Sec. 40101(c), 40103(b), 40107) also could be used, as it includes funding "(A) to demonstrate innovative approaches to transmission, storage, and distribution infrastructure to harden and enhance resilience and reliability; and (B) to demonstrate new approaches to enhance regional grid resilience, implemented through States by public and rural electric cooperative entities on a cost-shared basis." DOE in its October 2023 announcement of its first round of GRIP funding awarded over $450 million to MISO and SPP for their JTIQ projects, which are discussed further below. MISO and PJM could work towards a plan that could receive similar funding.[92]

Moreover, some of the incremental reforms outlined in the following section can help build trust and confidence among MISO and PJM stakeholders, which is essential for achieving the ideal interregional planning and cost allocation solutions discussed above.

C. Second-best solution: Improved coordination between MISO and PJM

While the optimized interregional process discussed above is the best solution, there are other options that could also serve as an interim step towards that optimum.

1. Coordinated top-down planning

If PJM adopted proactive multi-value regional planning, its regional planning could be coordinated with MISO's LRTP planning. Interregional planning should be synchronized with regional planning, which would allow planners to identify an optimal portfolio of regional and interregional solutions and identify interregional solutions that are more efficient than regional solutions. As discussed above this would require consistency and standardization between neighboring regions in the regional planning process, such as the assumptions and methods used in the regions' planning analyses, including using the full range of benefit metrics.

91 Wholesale Electricity Market Studies and Engagements Funding Opportunity Announcement (FOA), Grid Deployment Office, Department of Energy, September 29, 2023, https://www.grants.gov/web/grants/view-opportunity.html?oppId=350396.

92 DOE, Grid Deployment Office, Grid Resilience and Innovation Partnerships Program https://www.energy.gov/sites/default/files/2023-10/DOE-GRIP-Minnesota-Department-of-Commerce.pdf.

As discussed previously, it is essential for PJM to move to proactive multi-value planning with broad regional cost allocation. This reform is needed under any future scenario to provide PJM consumers with more reliable and affordable power, and efficiently address challenges related to the energy transition. PJM's own Energy Transition analysis notes that historically only around 5% of renewable projects in the interconnection queue successfully come online, which PJM claims poses a reliability risk as that success rate is inadequate to replace potential generation retirements.[93] PJM will also need regional transmission to tie into interregional transmission solutions and maximize the benefits they provide.

PJM's proactive transmission planning should account for utility plans and goals and state policy requirements. Regional capacity expansion planning can take the role of IRPs for states and utilities that do not conduct routine generation planning. If there is opposition to regional capacity expansion modeling, information from the interconnection queue or utility goals can be used instead. MISO uses generator capacity expansion modeling as the primary input into its LRTP, but also uses the IRP and interconnection queue data to inform its planning. For example, MISO notes that it needed to update its capacity expansion modeling because "renewable goals in Integrated Resource Plans (IRP) and the scale of renewable applications in the Generator Interconnection Queue (GIQ) all indicate a more rapid transition to renewables than what the Series 1 Futures anticipated."[94]

MISO should also take steps to better coordinate its LRTP plans with PJM. Regarding its current interregional coordination of its LRTP plans, MISO has stated that it "anticipates addressing larger interregional issues in later LRTP Tranches. Interregional coordination in Tranche 2 will focus on ensuring awareness and coordination for the potential Tranche 2 solutions on neighboring regions. As with the LRTP Tranche 1 process, MISO will coordinate with our neighboring RTOs and TOs to address underbuild or other needs that impact the feasibility of regional Tranche 2 projects."[95] This level of coordination, while better than none, falls short of the ideal. For example, MISO could realize economies of scale in transmission investment by planning 765-kV lines to interconnect with the 765-kV lines that currently exist in western PJM. MISO's LRTP seems to hint at this benefit when it notes that "There is minimal 765 kV and HVDC infrastructure in the MISO footprint, and strategies for spare equipment, redundancy during line outages, and the impacts on operations must be considered before the technology is implemented."[96]

MISO states that its LRTP is qualitatively assessing the value of increases to external transfer capability,[97] but this could be expanded to a more comprehensive quantitative analysis that would likely yield a more optimized solution with greater interregional transfer capacity. As noted above, expanded ties between MISO and PJM are extremely valuable for capturing geographic diversity that reduces the need for generating capacity, particularly as renewable penetrations increase.

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93 PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks (2023) https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx, at 2.

94 MISO,. Long-Range Transmission Planning Tranche 2, Frequently Asked Questions https://cdn.misoenergy.org/MISO%20Long-Range%20Transmission%20Planning%20LRTP%20Tranche%202%20FAQs.pdf627648.pdf, at 7.

95 MISO, Long-Range Transmission Planning Overview https://help.misoenergy.org/knowledgebase/article/KA-01391/en-us.

96 *Id.*

97 *Id.*: Qualitative factors that are assessed in LRTP include "External transfer capability for mutual support during extreme weather and events."

2. Coordinated bottom-up planning

Coordinated bottom-up planning between MISO and PJM could be modeled on what MISO and SPP have recently adopted through their Joint Targeted Interconnection Queue (JTIQ) process.[98] In that process, the regions partner to plan and pay for upgrades that are regularly identified as being necessary in the "affected system" component of generation interconnection studies. Affected system studies evaluate whether interconnecting a new generator will create a need for transmission upgrades in a neighboring region, and the costs of those upgrades are typically assigned to that generator.

The status quo of assigning affected system upgrade costs to generators is particularly inefficient because these costs are often not identified until late in the interconnection process, after considerable resources have been devoted to developing the projects and studying their interconnection impacts. When affected system upgrade costs are greater than expected, generators assigned those costs often drop out of the queue, triggering restudies of both regional network upgrades and affected system costs for all other generators remaining in the queue. This cascading uncertainty is a significant cause of queue withdrawals and delays.

MISO and PJM could develop an interregional study focused specifically on resolving constraints that are regularly identified in interconnection studies for generators interconnecting near the seam, modeled on the JTIQ process. MISO and PJM should consider a large amount of new generation resources near the seam that could be addressed in a single interconnection study cycle, that would ideally also identify solutions that would bring additional reliability and economic benefits to load. Stakeholder discussions regarding the cost allocation between MISO and SPP for JTIQ projects are ongoing, and PJM and MISO can adopt lessons and solutions from that process.

MISO and SPP are currently working to develop a process to integrate JTIQ-like studies on an ongoing basis into their affected system study process, so that interconnecting generators have more cost and timing certainty related to any upgrades required for their interconnection. MISO and PJM could consider how to integrate such an interregional interconnection study into their affected system studies of their generator interconnection processes.

Another bottom-up solution would be for MISO and PJM to amend their JOA to require an annual assessment of whether interregional transmission upgrades are more cost-effective than incurring persistent congestion costs. The JOA could be amended to include specific quantified metrics that will trigger a study of potential transmission solutions, such as a measure of total congestion cost or an average absolute value difference in locational marginal prices between nodes in the different RTOs.

98 SPP and MISO, SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes (2022) https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf.

D. Necessary reforms under any solution

1. Allow merchant transmission developers to propose interregional solutions and be fully compensated for the value their projects provide

Merchant developers are currently working on multiple interregional transmission projects between MISO and PJM, reflecting the clear economic value of those projects and the fact that there is currently no workable RTO mechanism for planning and paying for large-scale interregional transmission. MISO and PJM processes for interconnection, transmission planning and cost allocation, and capacity value accreditation should recognize the value of these projects, and not serve as an impediment to merchant developers trying to meet the need for interregional transmission.

One part of the solution would be for MISO and PJM to evaluate transmission solutions proposed by merchant developers that offer net benefits to one or both regions in the interregional planning and cost allocation process. Proposed solutions should be evaluated under the multi-value planning process outlined above, so that the multiple benefits of large interregional transmission are fully captured. Projects that offer significant net benefits should then be able to receive cost recovery under the broad cost allocation policies proposed above.

Merchant transmission developers have filed complaints to FERC about the treatment of interregional transmission lines in MISO and PJM. Invenergy[99] filed a complaint regarding MISO's exclusion of its proposed Grain Belt Express transmission line from the LRTP process. SOO Green's complaint[100] alleges that PJM's interconnection study process, which studies their transmission projects as if they were interconnections for new generators, causes unacceptable delays and costs for their projects. SOO Green is developing a proposed underground 2,100 MW HVDC line between Iowa in MISO and Illinois in PJM, while Invenergy's Grain Belt Express is a proposed overhead 5,000 MW HVDC line connecting SPP wind and solar resources to the MISO and PJM markets, with the potential for bidirectional transfer capacity among the three RTOs.

Another issue is that interregional transmission lines should receive credit for the capacity value their transmission lines provide by reducing generating capacity needs in one or both connected regions. SOO Green has filed a separate complaint alleging PJM's current capacity value accreditation practices are a barrier to entry for interregional transmission. Under SOO Green's proposed solution, specific MISO resources serving as capacity resources in PJM via SOO Green would receive capacity credit. Those resources would have to be specifically identified and attest that they cannot be recalled to serve needs in MISO, and PJM would send a dispatch signal to the HVDC line itself.[101]

An even bolder concept would be for the capacity accreditation of the transmission line to be based on statistical diversity between MISO and PJM and not specific generators that are committed to only one RTO, which would allow both MISO and PJM to count on some capacity

99 FERC https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220808-5195&optimized=false.
100 EL21-85-000.
101 FERC https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=el21-103&sub_docket=000&dt_from=1960-01-01&dt_to=2021-10-26&chklegadata=false&pagenm=dsearch&date_range=custom&search_type=docket&date_type=filed_date&sub_docket_q=allsub.

value from the line. As explained, interregional transmission provides dependable capacity value by tapping into geographic diversity in the timing of peak demand, renewable output, and generator outages between regions. Under current MISO and PJM rules, transmission developers are not accredited for this capacity value, even though reliability planning analysis conducted by the RTOs recognizes that diversity with neighbors provides some capacity value. Interregional transmission lines can currently only access some of that value through energy market arbitrage, but the transmission should also receive credit in the capacity market.

MISO and PJM account for some of the capacity value provided by existing interregional transfers, but do not account for how increases in interregional transfer capacity increase that value or assign that credit to the owner of the transmission line. Part of the problem is that MISO and PJM use a low estimate for the capacity contribution of external imports, and this assumption is not updated to account for increases in interregional transfer capacity.

PJM's reserve margin analysis assumes only 3,500 MW of import transmission capacity is available during peak periods, and provides only 2,127 MW of reduced installed capacity need.[102] PJM's assumed capacity benefit margin from transmission ties with neighboring Balancing Authorities has been fixed at 3,500 MW[103] since 2010 per the terms of the Reliability Assurance Agreement among PJM Load-Serving Entities. No effort has been made to evaluate or update that assumption despite significant changes in the generation mix, load patterns, and transmission capacity and flows with neighbors since 2010, even though the 2010 agreement assigned PJM responsibility for "periodic reviews of the capacity benefit margin."[104]

PJM's calculation of the 2,127 MW reduction in installed capacity needs due to the assumed 3,500 MW of transmission ties only accounts for demand diversity with neighboring Balancing Authorities,[105] which misses the benefits of both conventional and renewable resource output geographic diversity. These benefits are becoming increasingly important as renewable and gas resources make up a much larger share of the generation mix, as discussed above. Over 2020 and 2021, PJM hourly wind output only had a 0.59 correlation with MISO hourly wind output.[106] For comparison, MISO's load was 98.9% of its annual maximum at the time of PJM's peak load. While wind energy accounts for only a fraction of PJM's load, wind offers much more diversity with PJM's neighbors than load. The wind output diversity between PJM and MISO is likely partially driven by the timing differential and the evolution of weather systems as they move across the country, but also the different wind resource regimes that have been developed in MISO (more plains) and PJM (more ridgetop wind). As notable examples, during the Bomb Cyclone and Polar Vortex events their wind output patterns were non-coincident, as were their peak load patterns.[107] Moreover, as explained above, correlated outages and derates of conventional generators are often driven by cold and hot-weather related events that coincide with peak electric demand, particularly for gas generators, so geographic diversity also reduces

102 PJM, 2021 PJM Reserve Requirement Study (2021) https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20211005/20211005-item-05b-2021-pjm-reserve-requirement-study.ashx, at 34.

103 PJM, PJM Reserve Requirement Study (2022) https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220510/item-08c---rrs-assumptions-letter-2022---redline---20220411.ashx, at 17.

104 PJM, Letter to Honorable Kimberly D. Bose (2010) https://www.pjm.com/directory/etariff/FercDockets/63/20101129-er10-2710-006.pdf, at 89, 126.

105 *See*, supra note 102.

106 https://docs.misoenergy.org/marketreports/202012_hwd_HIST_csv.zip; https://docs.misoenergy.org/marketreports/20211231_hwd_HIST.csv; https://dataminer2.pjm.com/feed/wind_gen.

107 *See*, supra note 34.

the vulnerability of conventional generators during peak demand periods because power can be imported from neighboring regions that are less affected by extreme weather.[108]

EIA data for the last seven years show that during periods of high demand and high prices in PJM, the time periods when imports are most needed, imports are much higher than PJM's reserve margin analysis assumes. Imports from all of PJM's neighbors during PJM's highest load hours are often around 5,000 MW, and in the range of 6,000-7,000 MW when PJM electricity prices are also higher than $180/MWh.[109] PJM electricity prices were still relatively moderate during all of those hours, indicating that additional imports could likely be obtained if they were in higher demand. Imports during some high demand hours have been as high as 10,000 MW, and exports as high as 13,000 MW. Outside of high demand hours, PJM imports with all neighbors have been greater than 15,000 MW and exports as high as 29,000 MW, indicating there are large transmission ties with neighbors that could be more heavily utilized if needed. PJM appears to have never offered any justification for the assumption that only 3,500 MW of transmission capacity is available for imports during peak periods.

MISO similarly assumes that imports provide only 2,331 MW of capacity in the reliability analysis used as the basis for its capacity auction. However, MISO actually imported more than 13 GW during Winter Storm Uri,[110] and routinely imports more than that. MISO explains its assumption that imports only provide 2,331 MW of capacity value as follows: "Historically, MISO modeled the external system, including non-firm imports, in the LOLE study which resulted in year-over-year volatility in the PRM. In order to provide a more stable result and remove the false sense of precision, the external non-firm support was set at an ICAP of 2,987 MW and a UCAP of 2,331 MW in the 2015 LOLE study and has since remained constant."[111] MISO and PJM should both account for how increases in interregional transfer capacity reduce their need for generating capacity, and assign that capacity credit to the transmission line causing the increase in transfer capacity.

2. Optimize seams transactions

While MISO and PJM have a forum to discuss operational seams issues, so far solutions have not been adequately implemented.[112] Recent analysis confirms there are major impediments to efficient market transactions across the MISO-PJM seam and other RTO seams, resulting in large unnecessary costs for consumers and even undermining reliability during times of peak need.[113] Reforms are needed to optimize the use of existing interregional transmission regardless of future transmission expansion, and such reforms can be implemented in parallel with interregional planning and cost allocation policy improvements.

108 https://www.astrape.com/wp-content/uploads/2022/10/Accrediting-Resource-Adequacy-Value-to-Thermal-Generation-1.pdf

109 PJM, Data Miner 2 https://www.eia.gov/electricity/gridmonitor/knownissues/xls/PJM.xlsx; https://dataminer2.pjm.com/feed/rt_hrl_lmps

110 *See*, supra note 34.

111 MISO, Planning Year 2022-2023 Loss of Load Expectation Study Report https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf, at 22.

112 PJM/MISO Joint & Common Market Initiative https://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common

113 American Council on Renewable Energy, et al., The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission (2023) https://acore.org/wp-content/uploads/2023/10/The-Need-for-Intertie-Optimization.pdf.

PJM's Market Monitoring Unit (MMU) proposes an ambitious solution for optimizing transactions across PJM's seams with neighboring grid operators:

> The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.[114]

Such an optimization between market and non-market entities would be a highly efficient way to increase seams coordination and might serve as a model for seams management in other regions. Another option is the use of a market to optimize transactions among RTOs and other Balancing Authorities, modeled on the success of the energy imbalance market in the Western U.S.[115]Another option is the use of a market to optimize transactions among RTOs and other Balancing Authorities, modeled on the success of the energy imbalance market to across Balancing Authorities in the Western U.S.[116]

The PJM market monitor also offers recommendations for more incremental reforms, including "that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market."[117] It also recommends that for import transactions, "the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner."[118]

MISO's Independent Market Monitor (IMM) has similarly recommended several solutions to inefficient pricing at MISO's seams with neighboring grid operators. These incremental reforms are less ambitious than the PJM market monitor's recommendation for fully optimizing commitment and dispatch with neighbors through a joint dispatch solution,[119] though MISO should evaluate both types of solutions in concert with its neighbors. For incremental reforms, the MISO IMM recommends "that MISO eliminate all transmission and other charges applied to CTS [Coordinated Transaction Scheduling] transactions, while encouraging PJM to do the same..."[120] This change would increase the liquidity of CTS transactions and provide more efficient price formation by removing barriers to efficient market transactions. The MISO IMM also notes that inefficiencies in the calculation of interface prices incorrectly double congestion at the MISO-SPP seam.[121] MISO's IMM also notes the current use of a 30-minute ahead forecast for scheduling seams transactions costs tens of millions of dollars relative to more efficiently

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114 PJM MMU (2021) available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol2.pdf at 99

115 American Council on Renewable Energy, et al., The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission (2023) https://acore.org/wp-content/uploads/2023/10/The-Need-for-Intertie-Optimization.pdf, at 2

116 *Id.*

117 PJM MMU (2021) available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol2.pdf at 99

118 *Id.*

119 *Id.*

120 MISO IMM (2022) at 121, *available at* https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf

121 MISO IMM, "OMS-RSC: Seams Study: Market-To-Market Coordination" (May 2020) at 91, *available at* https://www.potomaceconomics.com/wp-content/uploads/2020/06/Seams-Study_MISO-IMM_M2M-Evaluation_Final.pdf.

using prices from the latest 5-minute market interval.[122] The MISO IMM further notes that a redispatch agreement with TVA and Ontario could greatly reduce congestion relative to the current practice of issuing transmission loading relief requests.[123]

Finally, the MISO IMM recommends that MISO:

> Remove external congestion from interface prices. When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it is generally not accurate and duplicates the congestion pricing by the external system operator. In addition, external operators provide MISO no credit for making these payments, neither through the TLR process nor through the M2M process. Hence, they are both inefficient and costly to MISO's customers. To fully address these concerns, we continue to recommend that MISO eliminate the portions of the congestion components of each of MISO's interface prices associated with the external constraints.[124]

In short, MISO has a range of tools to improve pricing efficiency at its market seams.

122 MISO IMM (2021) at 89, *available at* https://cdn.misoenergy.org/20220622%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20IMM%20State%20of%20the%20Market%20Report625261.pdf

123 *Id.* at 113.

124 *Id.* at 114.

III. CONCLUSION

Transmission constraints between MISO and PJM annually cost consumers in both regions billions of dollars today, and those costs will only increase as decarbonization of electricity supply and electrification of electricity demand increase the value of moving power across regions. MISO, PJM, FERC, and the states and other stakeholders can work together to create workable mechanisms to plan and pay for interregional transmission. The solution should be modeled on the success of MISO and other regions in building regional transmission through proactive multi-value transmission planning with broad cost allocation.

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