The Need for Intertie Optimization

Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission

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Executive Summary

Inefficient use of interregional transmission facilities unnecessarily raises system costs and reduces reliability. For nearly two decades, regional market monitors have recommended reforms to reduce these inefficiencies. Such inefficiencies exist because during many hours, energy flows do not fully utilize interregional transmission capabilities despite high price differences, or even flow in the opposite direction as price differences—hindering optimal economic use of interregional transmission and reducing its reliability value. The impacts of these inefficient flows will continue to increase with the accelerating deployment of large-scale variable resources with increasing net load variability and uncertainty that must be balanced in real-time.

Since the mid-2000s, market monitors have recommended that Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) optimize interties as part of day-ahead and real-time market clearing to resolve these inefficiencies. Despite these recommendations, the regions have elected to pursue only Coordinated Transaction Scheduling (CTS), hoping that CTS would address these inefficiencies. Contrary to these hopes, available experience now shows that CTS has not resulted in significant improvements to economic or operational efficiencies of interregional transmission. The continued inefficiencies are clearly documented by the market monitors for seams between ISO New England (ISO-NE), New York ISO (NYISO), the Midcontinent Independent System Operator (MISO), Southwestern Power Pool (SPP), and PJM Interconnection (PJM).

In contrast to these continued inefficiencies in intertie transactions between the eastern RTOs/ISOs, experience with energy imbalance markets used to managing interties between multiple Balancing Authorities (BAs) in the Western U.S. and "market coupling" in Europe has highlighted both the feasibility and the significant benefits that intertie optimization can offer. By optimizing available transmission and interties between participating system operators and their Balancing Authority Areas (BAAs) in real-time, Western energy imbalance markets have achieved between $170 million and $530 million in savings during each quarter of 2022 and 2023, with a cumulative savings of more than $4.0 billion since its inception. In response to the imbalance markets' success, a subset of participants have recently filed for Federal Energy Regulatory Commission (FERC or Commission) approval of the Extended Day Ahead Market (EDAM) and "Markets+" to expand this approach, adding day-ahead optimization to the real-time imbalance markets. In Europe, "market coupling" to optimize available transmission capacity between 23 national day-ahead and intra-day power markets has similarly been able to realize substantial efficiencies, saving over €115 million per year.

Market Monitors have noted that the inefficient use of interregional transmission substantially increases customer costs. We estimate that optimizing the use of existing or new interregional transmission capability between SPP, MISO, or PJM would provide approximately $50-60 million/year in additional value for every 1,000 MW of intertie capability beyond what bilateral trades can be expected to capture.

Based on the large seam-related inefficiencies and the potential benefits of addressing them, regions should expeditiously implement the recommendations of their market monitors and pursue the market-based optimization of available interregional transmission capacity. Such an effort would be consistent with recent FERC actions aimed at maximizing the capability of the existing grid. The implementation of intertie optimization will also be critical for maximizing the value of new interregional transmission capabilities, and should be designed to take advantage of available capacity on merchant transmission lines—similar to what is already proposed for the California Independent Transmission System Operator (CAISO) and the Western Energy Imbalance Market (WEIM).

The Commission has authority to implement intertie optimization options and has effectively used such authority by approving the WEIM. In fact, FERC has previously indicated that intertie optimization may be necessary if other means do not lead to a more efficient utilization of interregional transmission. The RTOs/ISOs should thus take advantage of this authority and expeditiously pursue reforms that optimize available intertie capacity, including on merchant transmission lines, between regions in both real-time and day-ahead markets.

In the absence of action by the regional grid operators, it would be well within the Commission's purview to remedy the well-documented inefficient uses of interregional transmission capabilities between energy markets.

I. The Case for Intertie Optimization

For nearly two decades, market monitors have recommended intertie optimization. In 2004, Potomac Economics, in its NYISO State of the Market Report, highlighted the ongoing prevalence of inefficient trading behavior along external New York interfaces.[1] Potomac expanded this analysis to MISO in 2005.[2] PJM's market monitor, then internal to PJM, also identified the issue in 2005,[3] and the ISO-NE Market Monitoring Unit (MMU) identified similar issues as early as 2006.[4]

The causes of the observed inefficient energy flows over interties between the regional power markets have similarly been explained in detail by market monitors and the RTOs/ISOs themselves. Put simply, efficient trade across interregional interties would maximize the energy flow that is cost effective and feasible. Efficient transactions would flow in the "direction" of prices, from the lower-priced region to the higher-priced region, thereby allowing larger amounts of lower-cost generation to serve load. In contrast, inefficient flows take two forms: (1) when interties are under-utilized, energy may flow in the right direction but at insufficient amounts that do not fully utilize the tie and maximize delivery of lower-cost generation; or (2) when energy flows in the wrong direction, from the higher-priced region to the lower-priced region, these flows displace more-efficient region-internal generation with less-efficient external generation.[5]

Three root causes underlying these inefficient flows have been identified:[6]

- **Latency Delay:** The time delay between when an intertie is scheduled and when power flows, during which time system conditions and market prices may have changed. Even if trader or RTO/ISO forecasts for the next few hours of real-time market conditions were accurate on average, the increasing volatility and uncertainty of real-time market conditions

1 D. Patton, 2003 State of the Market Report – New York Electricity Markets, Potomac Economics (April 2004) at 98-104.

2 D. Patton, 2005 State of the Market Report – MISO, Potomac Economics (July 2006) at 98.

3 PJM Market Monitoring Unit, 2005 State of the Market Report for PJM, (March 8, 2006) at 196–198.

4 ISO New England, 2006 Annual Markets Report, (June 11, 2007) at 34–35

5 See NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) at II-3–II-9.

6 See NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) at § II.C.

means that any time lag between when intertie bids or schedules have to be submitted and real-time operations will lead to uneconomic transactions and inefficient intertie utilization;

- **Non-Economic Clearing:** The RTOs/ISOs make decisions about which tie schedule requests to accept without economic coordination, producing inefficient schedules.
- **Transaction Costs:** The fees and charges levied by each RTO/ISO on external transactions are not reflective of the actual incremental costs of utilizing the transmission capacity, which means they disincentivize efficient transactions across seams, act as a barrier to efficient utilization of the available intertie capacity, impede price convergence, and raise total system costs.[7]

Inefficient flows over the interties between regional power markets are not an isolated problem. Analyses by PJM's Independent Market Monitor (IMM) show that 2022 power flows were inconsistent with price differences during 4,176 hours (or 48%) of the year.[8] These price differences across the MISO-PJM seam exceeded $10/MWh during 3,182 hours; yet during 1,570 (49%) of these hours, market flows were inconsistent with those price differences, exporting power from the higher-priced market to the lower-priced market. Similarly, on interties between PJM and NYISO, 2022 market flows were inconsistent with price differences during 3,463 hours (or 40%) of the year.[9] Price differences exceeded $10/MWh during 4,178 hours; yet flows were inconsistent with those price differences during 1,667 (40%) of these hours. This pattern was also confirmed by Potomac Economics, which noted in the MISO 2021 State of the Market Report that, going across the RTO seams, "**more than 40 percent of the current…transactions are ultimately unprofitable**".[10]

The inefficient utilization of available interregional transmission capacity is particularly pronounced during real-time market operations, when regional differences in wholesale power prices are often large and change frequently. For example, as shown by the PJM IMM in Table 1 below, the average (absolute) value of PJM-NYISO price differences in 2022 was $12.94/MWh in the day-ahead markets with price differences changing signs 3.1 times per day on average. In stark contrast, the average price difference in the real-time market was $115.36/MWh with

[7] Avoiding charges that do not reflect the true marginal cost of transmission is particularly important for scheduling economic transactions on interregional transmission capacity that would otherwise remain unused (such as in real-time, after all bilateral trades have been scheduled). This concept of "hurdle free" transactions (reflecting only congestion and marginal losses) is also central to the design of the RTO/ISO energy markets, the interregional energy imbalance markets in the Western U.S., and European "market coupling" frameworks.

[8] Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at Table 9-27.

[9] Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at Table 9-29.

[10] Potomac Economics, 2021 State of the Market Report for the MISO Electricity Markets (June 2022) at 90, emphasis added.

real-time price differences changing sign 47.9 times each day. Similarly, as also shown in the table, the average 2022 real-time price difference between PJM and MISO was $97.68/MWh with price differences changing sign 62.9 times each day—significantly larger and more volatile than day-ahead price differences.

TABLE 1: PJM, NYISO, AND MISO BORDER PRICE AVERAGES (2022)[11]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$69.51	$63.62	$66.59	$63.36
	ISO Price at PJM Border	$67.96	$63.62	$67.80	$63.97
	Difference at Border (PJM-ISO)	$1.55	$0.00	($1.21)	($0.62)
	Average Absolute Value of Interval Difference at Border	$115.36	$97.64	$12.94	$9.09
	Sign Changes per Day	47.9	62.9	3.1	4.1
Standard Deviation	PJM Price at ISO Border	$114.49	$97.68	$34.26	$32.54
	ISO Price at PJM Border	$86.15	$82.73	$34.44	$29.53
	Difference at Border (PJM-ISO)	$118.90	$99.86	$16.11	$11.31

Note: Effective April 1, 2018, PJM implemented 5-minute Locational Marginal Price (LMP) settlements in the real-time energy market. The sign changes per day represented in this table reflect the number times the sign of the price difference changed each day. For the real-time energy market, there are 288 five-minute intervals. For the day-ahead market there are 24 hourly intervals.

This well-documented pattern of inefficient utilization of available interregional transmission capacity is not limited to the mostly free-flowing interregional interfaces of regulated transmission owners. It also applies to power flows on interregional merchant lines, including transmission lines that could be (but are not) controlled in real-time to avoid such inefficient flows. For example, during 2022, on the Neptune line between New Jersey (PJM) and Long Island (NYISO) power flowed inefficiently from the higher-priced market to the lower-priced market during 1,385 hours of the year.[12] Similarly, on the Hudson Transmission Project and the Linden Variable Frequency Transformer facility (both providing controllable merchant transmission between New Jersey and New York City), 2022 power flows were inconsistent with market price differentials during 2,217 hours and 1,895 hours of the year, respectively.[13]

Multiple analyses have demonstrated the substantial cost associated with these inefficiencies, which are the foregone benefits of more optimal utilization of interregional ties. In 2010, for example, Potomac Economics estimated that optimizing existing interties between MISO, PJM, NYISO, ISO-NE, and Canadian system operators would conservatively yield between $160–

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11 Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at Table 9-30.

12 Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at Table 9-33.

13 Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at Tables 9-35 and 9-33.

300 million in annual cost savings.[14] In 2011, NYISO and ISO New England estimated that customer benefits from intertie optimization would be $789 million over five years.[15]

In response to this 2011 analysis, NYISO and ISO-NE proposed intertie optimization as the preferred and "more efficient" approach to address seams-related inefficiencies.[16] As an alternative option, however, the ISOs also designed an approach, called Coordinated Transaction Scheduling (CTS),[17] which was implemented instead.

CTS is used today to coordinate power flows between ISO-NE, NYISO, PJM, and MISO. The CTS approach relies on forecasted prices to allow bilateral market participants to project whether a submitted intertie transaction would be profitable in the real-time market.[18] The RTOs/ISOs then clear transactions that are projected to be profitable on the basis of the RTOs' price forecasts.[19] CTS was chosen over the intertie optimization recommendations of the ISOs and their IMM, because it was easier to implement and was hoped to offer similar levels of benefits.[20] However, the RTOs/ISOs' inability to correctly forecast prices and (in some cases) transaction costs imposed by some of the RTOs/ISOs have greatly limited the effectiveness of CTS—as reflected in the 2022 data on inconsistent power flows discussed earlier. As real-time markets are growing more uncertain and volatile with increasing shares of intermittent resources, interregional trading frameworks that rely on forecasts and require real-time trades

[14] Potomac Economics, Analysis of the Broader Regional Market Initiatives, (September 27, 2020) at 10–13.

[15] NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) at v.

[16] NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) at III-1. Note that under either approach, (1) competitive, market-based offers are used to determine the real-time schedule of energy interchange between the interconnected transmission networks; (2) all scheduled energy flows between regions are priced at the LMP and settled through existing processes; and (3) the ISOs do not directly participate in the markets and do not buy or sell power; rather, they continue to act as independent settlement administrators for payments to and from market participants. (*Id.* at v)

[17] See NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) at § IV.

[18] See, e.g., Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at 526–528.

[19] See, e.g., Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at 526–528 ("The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the IT SCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP").

[20] CTS was simpler to implement as it only facilitated more efficient bilateral trades but did not require the ISOs to schedule energy-market transaction. See NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) at III-1; see also 146 FERC ¶ 61,096 at P 15 (2014) (approving CTS between PJM and NYISO) ("CTS will enhance market efficiency of interregional transactions and provide substantial benefits…should improve scheduling efficiencies…[and] significantly reduce latency risk"), 155 FERC ¶ 61,038 (2016) (approving CTS between MISO and PJM subject to conditions).

to be submitted up to 75 minutes before each trading period, will simply not be able to achieve optimal utilization of the available intertie capacity.

As PJM's Market Monitor has explained, "the large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling."[21] Moreover, ISO New England's Market Monitoring Unit has shown in its 2022 State of the Market Report that the performance of CTS is deteriorating, with the number of optimal CTS trades declining from 23% in 2018 to just 11% in 2022.[22] Even in hours with over $100/MWh of interregional price differences, CTS has on average left over 250 MW of intertie capability unused, failing to "effectively utiliz[e] the available capacity to improve price convergence."[23] This deterioration of CTS performance is particularly notable considering that ISO-NE and NYISO have depancaked transmission charges on all transactions between their regions. The increasing ineffectiveness of CTS on even such depancaked interregional seams points likely reflects the fact that real-time prices in regional energy markets are increasingly difficult to anticipate—even only 1 or 2 hours prior to each 5-minute operating period.

The application of transmission charges to CTS transaction has been identified by market monitors as one of the barriers to efficient utilization of interregional transmission. As part of a recent study of CTS and potential intertie optimization for SPP and MISO, Potomac and the SPP market monitor explained that "prices rarely diverge enough to cover both fees and historical risk premiums," discouraging market participants from participating in CTS and reducing available benefits.[24] Further, when transmission charges are applied, and these charges are applied even to CTS schedules that eventually do not clear and do now flow any power, this creates additional risk for market participants and reduces the effectiveness of the CTS product.[25] This recent finding echoes Potomac's long-held criticism of imposing transaction fees on CTS transactions along the MISO-PJM interface. In MISO's 2018 State of the Market report for example, Potomac repeated prior conclusions that "high transmission and energy charges have likely deterred traders from using CTS in lieu of traditional transaction scheduling."[26]

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[21] Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at 526.

[22] ISO New England Internal Market Monitor, 2022 Annual Markets Report (June 5, 2023) at 160, Figure 5-6. We refer to "optimal" trades as those where the total transmission capability is used in the appropriate (i.e., low-to-high priced) direction.

[23] ISO New England Internal Market Monitor, 2022 Annual Markets Report (June 5, 2023) at 162, Figure 5-7.

[24] Coordinated Transaction Scheduling Study, SPP Market Monitoring Unit (May 8, 2020) at 9, 11.

[25] Coordinated Transaction Scheduling Study, SPP Market Monitoring Unit (May 8, 2020) at n.4.

[26] Potomac Economics, 2018 State of the Market Report for the MISO Electricity Markets (June, 2019) at 82.

Because these charges do not represent incremental transmission costs incurred due to the transactions, the transmission charges imposed by PJM on interregional CTS trades create similar barriers to efficient use of interregional transmission. However, the experience with increasingly inefficient CTS transactions between ISO-NE and NYISO (discussed above) shows that eliminating transmission charges for CTS transactions—as is the case between ISO-NE and NYISO—is not sufficient to achieve efficient utilization of interregional transmission.

Despite repeated calls for CTS improvements or implementation of intertie optimization,[27] little has been done to address these inefficiencies. They thus persist and have changed little over the last decade. Consistent with the NYISO and ISO New England initial 2011 recommendation, Potomac Economics continues to recommend that the market operators address these seam-related inefficiencies by clearing "transactions every five minutes through [the Unit Dispatch System] based on the most recent five-minute prices in the neighboring RTO area."[28] Similarly, in 2023, the PJM IMM has repeated yet again the recommendation it has made since 2014—to replace CTS with intertie optimization:

> 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.[29]

These observations and recommendations by the market monitors of PJM, NYISO, ISO-NE, and MISO clearly highlight the importance of intertie optimization, since bilateral trades and CTS have been demonstrated to be insufficient to capture increasingly volatile interregional price differences and increasingly large amounts of intertie value. Intertie optimization can be particularly valuable for interregional transmission links on which power flows can be controlled through use of technologies such as Phase-Angle Regulators (PARs) or high-voltage

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[27] Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at 481 (interchange optimization recommendation first reported 2014); NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) at vii, viii; ISO New England Internal Market Monitor, 2022 Annual Markets Report (June 5, 2023) at 160, figure 5-6; Potomac Economics, 2021 State of the Market Report for the MISO Electricity Markets (June, 2022) at 89, Table 14.

[28] Potomac Economics, 2021 State of the Market Report for the MISO Electricity Markets (June, 2022) at 89, 120.

[29] Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at 105.

direct-current (HVDC). In fact, the value and feasibility of intertie optimization has been demonstrated impressively by the success of the energy imbalance markets that also manage interties between BAs in the Western U.S. as well as the European "market coupling" efforts to improve interregional efficiencies.[30]

We recognize, of course, that implementing full intertie optimization will require a careful assessment on how the optimization would need to be designed to enable an efficient integration with the unique existing market designs and generation dispatch processes of each neighboring region.[31] While ISO-NE and NYISO had already proposed for implementation a detailed intertie optimization design in their 2011 whitepaper,[32] more efficient interregional intertie optimization frameworks have been developed since[33]—and, in the case of the Western energy imbalance markets and European market coupling, implemented.

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30 In addition to inefficient energy transactions across regional seams that are the focus of this report, we note that similar inefficiencies exist in interregional capacity and ancillary service market transactions. These inefficiencies include barriers to capacity and ancillary services trades across interties and the failure to recognize and accurately quantify the resource adequacy and resilience value (or attribute zero such value) of uncommitted and non-firm transmission capabilities between regions.

31 The design of an intertie optimization framework will necessarily have to be detailed enough to work efficiently and reliably with the existing market design of the neighboring regions and address considerations such as differences in scheduling timelines, approaches to generation dispatch and market optimization, and each region's ramping capabilities.

Also note that an efficient intertie optimization design will avoid transaction charges on scheduled intertie flows. In place of transmission charges (which do not reflect incremental costs nor market fundamentals), the value of optimized incremental transactions (settled at the intertie's LMP difference) flows to the neighboring regions and the entities who make transmission capacity available for intertie optimization.

32 See Section III of NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011).

33 For example, ISO-NE staff developed and successfully tested through large-scale simulations a "marginal equivalence" approach to intertie optimization under which neighboring system operators exchange every 5 minutes information on marginal generation costs and relevant transmission constraints so that the information can be incorporated into the other RTO/ISO's real-time dispatch. This approach could be applied between two RTO/ISO regions or between RTOs/ISOs and non-market regions.

See Zhao, Litvinov, and Zheng, "A Marginal Equivalent Decomposition Method and Its Application to Multi-Area Optimal Power Flow Problems," IEEE Transactions on Power Systems, Volume 29, Issue 1 (2014).

The article also includes a bibliography of the extensive research that had already been done in this area.

II. Experience with Interregional Intertie Optimization

A. Energy Imbalance Markets in the Western U.S.

While much of the Western U.S. is not currently covered by any RTOs/ISOs (beyond CAISO), two energy imbalance markets have been established to more efficiently manage real-time transactions across multiple Balancing Authority Areas (BAAs):

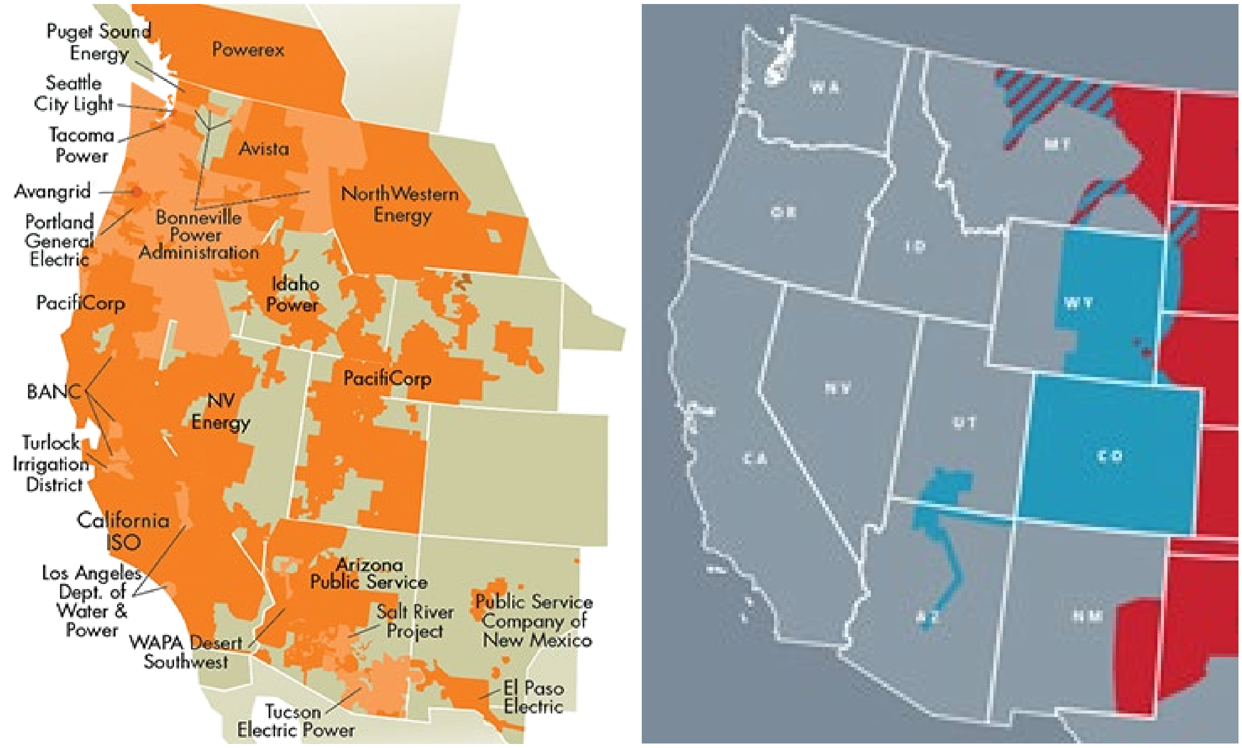
- the Western Energy Imbalance Market (WEIM), which includes the CAISO and 22 BAAs in the western portion of the Western Electricity Coordination Council (WECC) as shown in orange in Figure 1 below;[34] and
- the Western Energy Imbalance Service (WEIS) market, which is operated by the Southwest Power Pool (SPP) and covers 12 participants in multiple BAAs in the eastern portion of the WECC as shown in blue in the figure below.[35]

The WEIM and WEIS were created to optimize in real-time (after all bilateral trades have been scheduled) the use of available remaining transmission within and across the seams between multiple Balancing Authority Areas in the WECC. This is done by economically adjusting the dispatch of generating resources that have been made available for dispatch to the imbalance market. By co-optimizing in real-time available transmission capability with the dispatch of generation resources across neighboring BAAs, the real-time interchange schedules across the interties between BAAs are optimized as well. While the imbalance markets also optimize transmission with some of the generation within each BAAs, the main purpose of the imbalance markets was to help individual BAAs balance their generation and load more effective in the larger geographic footprint. As the experience shows, this multi-BAA optimization across regional interties is associated with significant cost savings.

34 https://www.westerneim.com/Pages/About/default.aspx

35 https://spp.org/western-services/weis/

FIGURE 1: ENERGY IMBALANCE MARKETS IN THE WECC
WEIM = Orange, WEIS = Blue, (SPP-East = Red)



As shown for WEIM in Figure 2 below, the co-optimization of generation and transmission within the WEIM footprint—which includes both alternating current (AC) and HVDC interties—has achieved substantial savings since its introduction in 2014. As shown in Figure 2, quarterly savings increased exponentially as the footprint is expanded and more market seams are optimized over a broader and more diverse geographic area.[36] By the end of 2022, cumulative benefits reached $3.4 billion (as shown in the chart); by the middle of 2023, these cumulative benefits have increased to $4.2 billion.[37]

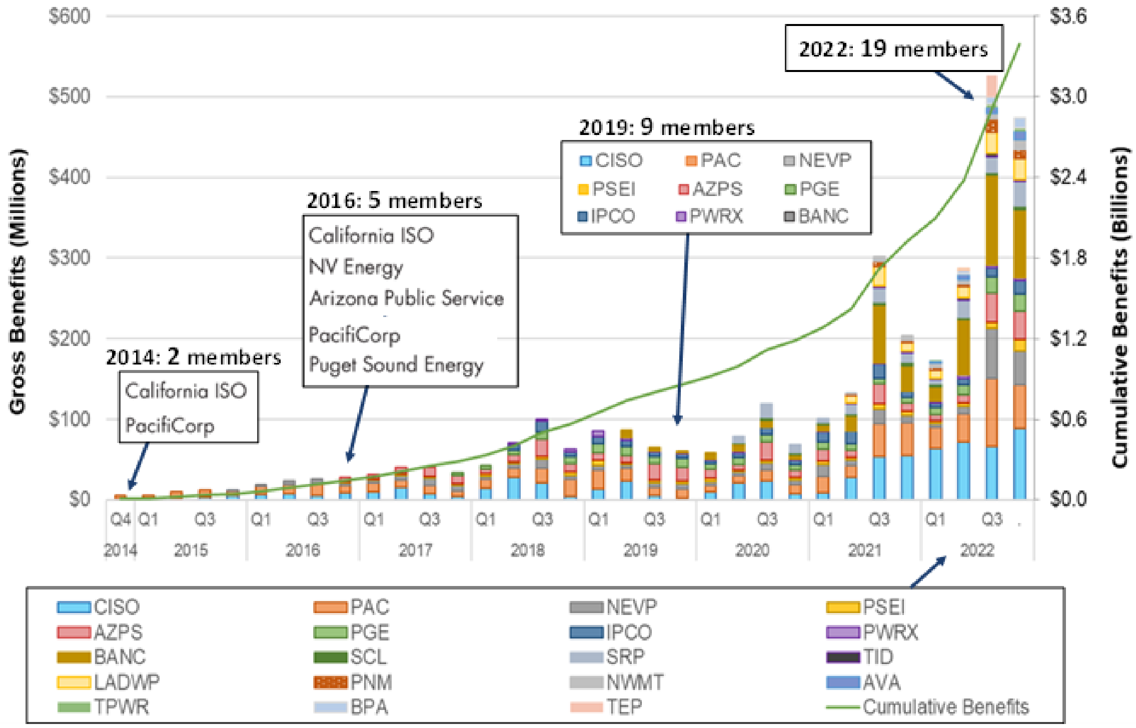
Significant benefits have also been documented for the smaller and more recently-established WEIS market. From its establishment in 2021 through the end of 2022, the WEIS market has produced an estimated $61 million in net benefits for its participants.[38]

[36] For how the number of BAA to BAA interties considered in the WEIM optimization has evolved since 2014, see https://www.caiso.com/Documents/EDAMForum-WEIMtransfers.pdf

[37] See https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

[38] SPP Western Energy Services, Benefit of the Market: Western Energy Imbalance Service (WEIS), March 27, 2023.

FIGURE 2: QUARTERLY AND CUMULATIVE WEIM BENEFITS 2014–2022



Source: based on [https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx. By the end of the second quarter of 2023, cumulative WEIM benefits have reached $4.196 billion for 22 members.](https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx)

As noted earlier, the optimized WEIM and WEIS transactions are incremental to a baseline of bilateral day-ahead and intra-day trades. After bilateral trading closes (approximately 20 minutes before each real-time operating period), the imbalance markets optimally schedule incremental transactions over any remaining available transmission capacity on a 15-minute and/or 5-minute basis. After incorporating the optimized 5-minute intertie schedules, each BAA remains responsible for reliably balancing its system. As the available experience shows, these optimized energy transactions across multiple BAAs offer significant value beyond what is achieved through bilateral trades.

In addition, the success of the optimization of regional and interregional transmission capability through WEIM and WEIS has led to the planned introduction of the Extended Day Ahead Market (EDAM, offered by CAISO) and Markets+ (offered by SPP), which expands the real-time co-optimization of interregional transmission and generation dispatch through energy imbalance markets to include day-ahead market transactions on available transmission between BAAs in the Western Interconnection.[39] While these efforts fall short of establishing larger RTOs in the Western U.S., their optimization of transmission across the seams between multiple BAAs point to the value, effectiveness, and feasibility of using intertie optimization to improve transmission utilization across the seams between the RTOs/ISOs (and possibly non-RTO regions) in the Eastern U.S.

B. Intertie Optimization for Merchant Transmission Lines: The CAISO Subscriber PTO Proposal

While few interregional transmission projects have been added in recent years, the U.S. Department of Energy has identified a significant need for additional interregional transmission capacity for 2030, 2040, and 2050 in each of several scenarios,[40] ranging from status-quo scenarios (with moderate load and renewable generation growth) to accelerated decarbonization scenarios (with high electrification-related load and associated high renewable generation growth).[41] As summarized in a recent study by ACEG and Grid Strategies, 36 large-scale regional and interregional transmission projects are currently "ready" to address the transmission needs identified by DOE. [42] Intertie optimization will be an important market function if the full value of the proposed interregional transmission lines should be realized.

Importantly, many of these "ready-to-go" and other proposed interregional transmission projects are being developed as *merchant* transmission lines—which highlights the importance of including merchant lines in any intertie optimization frameworks between neighboring markets and balancing areas. Any intertie optimization framework should thus be able to optimize the many interregional transmission lines that have already been built, are fully permitted or under construction, or are being planned by merchant transmission developers. [43]

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[39] CAISO, EDAM Fact Sheet and CAISO, Initiative: Extended day-ahead market, CAISO Stakeholder Center. See Day-Ahead Market Enhancements and Extended Day-Ahead Market, Transmittal Letter, CAISO, FERC Docket No. 23-2686, (August 22, 2023).

SPP, Markets+ and A Proposal for SPP's Western Day-ahead Market and Related Services. November 30, 2022.

[40] DOE, National Transmission Needs Study, Draft for Public Comment, February 2023.

[41] *Ibid.*, Table 4-IV, page 96.

[42] Americans for a Clean Energy Grid (ACEG) and Grid Strategies, Ready-to-go Transmission Projects 2023: Progress and Status since 2021, September 2023.

[43] Existing interregional merchant transmission lines include several transmission links between PJM and NYISO. Interregional merchant lines under fully permitted or under construction include SunZia (between New Mexico and western Arizona), Trans West Express (TWE, between Wyoming, Utah, and southern Nevada), and the Lake Erie Connector (between Ontario and PJM). Interregional merchant projects under active development include SOO Green (between Iowa and Illinois), Grain Belt Express (between western Kansas, Missouri, and eastern

In response to interregional merchant transmission lines now under development, CAISO has developed the regulatory and market frameworks to include available capacity on merchant transmission lines into both the CAISO and WEIM-wide market optimizations. To do so, CAISO has developed its "Subscriber Participating Transmission Owner" (Subscriber PTO or SPTO) framework. The new SPTO framework is specifically designed to achieve the integration and market optimization of available capacity on interregional merchant transmission lines that can deliver energy into CAISO from areas throughout the WECC.[44] The SPTO framework recognizes that expanding interregional market optimization to merchant transmission lines (in both day-ahead and real-time markets) and compensating the holders of transmission rights on the merchant lines for market-based use offers substantial benefits to CAISO, California customers, the larger western power market, as well as the parties that make merchant transmission rights available for market use. As explained by the CAISO:

> The ISO is developing [the SPTO option as] an opportunity for developers to deliver generation to California without increasing the Transmission Access Charge (TAC) and without picking the winner by selecting a project in the Transmission Planning Process (TPP). The ISO intends to implement the Subscriber Participating Transmission Owner model as a win-win arrangement versus trying to extract value from those paying for the line for the benefit of the ISO's existing ratepayers. This model allows the potential off takers/California load serving entities to make their own economic decisions with respect to which out-of-state generation projects to contract with, while the ISO would continue to exercise its existing tariff authority and utilize its supporting software systems to implement a new protocol.[45]
>
> Beyond California's internal resource planning needs, markets like the Extended Day-Ahead Market will also benefit from improved integration of

Illinois), and Southern Sprit (between ERCOT and Mississippi). In addition, a number of other interregional transmission projects have been proposed by merchant developers to connect market areas throughout the U.S.

44 See CAISO, Subscriber Participating TO Model, Final Proposal (June 22, 2023) at 3–4 and 28 (filed with FERC on September 22, 2023 in Docket ER23-2917).

45 https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Subscriber-participating-transmission-owner-model

> the ISO system with other utility systems in the Western interconnection through implementation of the Subscriber PTO Model.[46]

Subject to certain conditions, FERC regulations allow the developer of a merchant transmission project to provide priority access to selected customers ("subscribers") for up to the full amount of transmission capacity on the line.[47] This differs from the "open access" requirement to provide non-discriminatory access to all transmission facilities with regulated (not merchant) cost recovery. While FERC also requires that any unused capacity on merchant transmission lines be made available to third parties at a negotiated rate that is just and reasonable,[48] there is no requirement that any available merchant transmission capacity be offered to the regional market operators so that they can integrate the available transmission capacity with the surrounding grid and co-optimize it with generation in the regional wholesale power market. The SPTO framework aims to do just that: integrate merchant transmission lines into the regional power markets and co-optimize the capacity made available with all other regional and interregional transmission and generation resources.

The SPTO framework will be applied first to TransWest Express (TWE), an interregional merchant line from Wyoming to Utah and Southern California, whose costs are recovered primarily from "subscribers" rather than from CAISO transmission customers under the CAISO's regulated transmission rates. The proposed SPTO design includes the following elements:

- Unscheduled merchant transmission capacity (held by subscribers or the project owner) for delivery to or from California can be made available for market use in both the day-ahead and real-time energy markets.
- CAISO will co-optimize with generation dispatch the SPTO capacity made available, including interregionally within the WEIM and proposed EDAM (e.g., to optimize day-ahead and real-time market transactions on TWE between PacifiCorp's BAA in Wyoming and Utah and the CASIO).
- CAISO will pay a "Non-Subscriber Usage Rate" to compensate the owner or subscriber of the merchant facility for market use of the released transmission capacity. The Usage Rate will be paid from the CAISO transmission access charges to load and exports in

[46] CAISO, Subscriber Participating TO Model, Final Proposal (June 22, 2023) at 4.

[47] See *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects: Priority Rights to New Participant-Funded Transmission*, 142 FERC ¶ 61,038 at P 16 (2013).

[48] Id. at P 15, nn.37 & 27.

order to avoid rate pancaking and the market inefficiencies that would be associated with it.

- Under the CAISO's EDAM implementation tariff filed in FERC Docket ER23-2686), the Subscriber PTO (i.e., owner of the merchant line) will also receive the "EDAM transfer revenues" that are associated with market price differences between the participating EDAM BAAs.[49]

While not yet approved by FERC, the SPTO framework is a clear example of how available capacity on merchant transmission lines can be integrated into broader efforts to more efficiently utilize the interties between market regions.

C. European Market Coupling

Another example of a successful intertie optimization framework that efficiently utilizes interregional transmission capacity available after bilateral trading windows have closed is the "markets coupling" framework used in Europe. In Central and Western Europe (CWE), cross border trading among different markets was initially facilitated through separate cross-border auctions based on traders' expected market prices. This resulted in inefficient flows similar to those currently seen in the eastern U.S. power markets.[50] To mitigate these inefficiencies and more effectively utilize the available interregional transfer capability between national power markets, the European "market coupling" process was implemented in 2006 and improved over time:

- In 2006, Belgium, France, and the Netherlands "coupled" their day-ahead markets to better utilize the cross-border transmission capacity.[51]
- In 2010, the available transfer capacity (ATC) approach was added to market coupling and implemented in the entire CWE region. Under the ATC-based approach, the neighboring transmission system operators (TSOs) coordinate with each other to determine a Net

[49] The CAISO's SPTO proposal does not similarly address allocation of real-time and day-ahead congestion revenues on constrained SPTO transmission facilities, even though in WEIM/EDAM these market-based congestion revenues are distributed to the contributors of the transmission capacity made available for WEIM/EDAM use.

[50] T. Kristiansen, The Flow Based Market Coupling Arrangement in Europe: Implications for Traders, *Energy Strategy Reviews* (January 27, 2020).

[51] Belplex, Trilateral Market Coupling, Energy Exchanges and Transmission System Operators working together towards European Market Integration, (January 12, 2006).

Transfer Capacity (NTC) value for each direction on the border based on historical data that represent the maximum available commercial exchange capacity.

- In May 2015, the CWE region transitioned to a flow-based market coupling (FBMC) mechanism, which has been expanded to more countries over time.[52] The FBMC method is based on detailed representations of the European grid using Power Transfer Distribution Factors (PTDFs) to determine the linear relationship between the net energy exchange and flows on critical grid elements.[53]
- To further optimize the trading over cross-border interties (including HVDC links) in intra-day markets, a cross-border intraday trading platform, known as the Single Intraday Coupling (SIDC), was launched in 2018 across 15 countries and then expanded to 23 countries in 2021 to facilitate the optimal use of interties and 15-minute to hourly trading across the borders of participating markets. [54] SIDC is based on "order matching"[55] and has employed a flow-based approach since 2022.[56] From 2018 through the first quarter of 2022, SIDC has matched 151 million intra-day trades.[57]

Today, flow-based market coupling is used by the national European system operators to optimize cross-border energy exchanges and market-to-market transactions in both day-ahead trading and intra-day trading. For market-based scheduling of available capacity on directly-controllable cross-border links (i.e., the many HVDC links that have been added between countries), the same flow-based market coupling algorithm is used to maximize cost savings by optimizing the set points for controllable links that connect two binding zones—which could be two regions within a synchronous AC network or two regions with asynchronous AC networks. In particular, there are two ways to manage controllable HVDC links in the FBMC-based market coupling approach:

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52 See Launch of Flow-Based Market Coupling in the Core Region Enhances Energy Transition, Press Release (June 8, 2022).

53 C. Müller, A. Hoffrichter, et al., Integration of HVDC-Links into Flow-Based Market Coupling: Standard Hybrid Market Coupling versus Advanced Hybrid Market Coupling, *CIGRE Science and Engineering* (2007).

54 See ENTSO-E, Single Intraday Coupling (SIDC).

55 *Ibid.* SDIC creates a single "order book" for all buy and sell bids from all the participating markets; it then continuously matches the orders from sellers and buyers until one hour before delivery time. TSOs make any intraday cross-border capacities available to allow the bids submitted by a market participant in one market to be matched with bids in other markets. The trade is done on a first-come-first-served basis with the highest buy and lowest sell bids matched first until the available transmission is fully utilized.

56 See European Union Agency for the Cooperation of Energy Regulators (ACER), ACER to Consult on the Methodology for Electricity Intraday Flow-Based Capacity Calculation in the Core Region (April 26, 2023); see also ENTSO-E, Market Report 2022, at 83.

57 See ENTSO-E, Single Intraday Coupling (SIDC), at Market Information.

- In the "standard hybrid" coupling of AC and DC systems, HVDC links are modeled with their Net Transfer Capacities (NTC) with HVDC transactions receiving priority access to the AC grid.
- In the "advanced hybrid" market coupling approach, PTDF factors at the end nodes of HVDC lines are calculated and the two nodes act as virtual bidding zones that are linked to the flow-based constraints. In this case, flows from HVDC lines compete for capacity with all other trades and no AC grid capacity is reserved for HVDC. [58]

Several studies have documented the benefits of the FBMC approach and its ability to better optimize the operation of interties compared to the earlier ATC-based approach. The European TSOs tested the FBMC approach in parallel off-line runs from 2013 to 2015 and compared its performance to the actual cross-border exchange volumes and prices using the ATC-based approach, as documented in a 2015 report.[59] The report shows that the FBMC approach increased cross-border exchange volumes and improved price convergence, enabling an increase of €95 million in economic savings in 2013. A 2023 study empirically estimated the effect of introducing the advanced FBMC approach for cross-border arrangements, finding that the FBMC approach has increased the cross-border exchange volumes by 1,000 MWh per hour and decreased the average market price difference between different countries by 2 €/MWh. It estimated that the welfare gain associated with optimizing cross-border exchanges by the FBMC in the CWE region is currently around €116 million per year.[60]

The FBMC methodology is now being expanded to the Nordic power markets and is scheduled to launch in Q1 2024.[61] Nordic power markets have already started external parallel runs to evaluate the market results of the FBMC methodology in comparison to their current method.[62]

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58 See ENTSO-E, HVDC Links in System Operations (December 2, 2019) at 75–76.

59 Amprion, et al., CWE Flow Based Market- coupling project: Parallel Run performance report (May 2015).

60 M. Ovaere, M. Kenis, et al., The Effect of Flow-Based Market Coupling on Cross-Border Exchange Volumes and Price Convergence in Central Western European Electricity Markets, *Energy Economics* (February 1, 2023).

61 Statnett, Go-live of Nordic flow-based CCM delayed to Q1 2024 (November 18, 2022).

62 Nordic TSOs, External parallel run evaluation report—For assessment by the NRAs of the Nordic CCR, as required by the Nordic DA/ID CCM (June 12, 2023).

III. The Value of Interregional Transmission in the U.S.

Enabling energy market optimization of interties between wholesale power market areas has the potential to significantly increase the real-time value of interregional transmission. Aside from ensuring the full use of existing interties, unlocking the available energy market values through intertie optimization will maximize market efficiency, increase customer savings, and facilitate the necessary additional investment in new interregional transmission capacity. In contrast, unused or inefficiently-used interregional interties will not only mean higher prices for customers, but also reduce the benefit-to-cost ratios that regional grid operators might quantify in their planning processes in the rare cases when they might be evaluating new interregional transmission.[63] Inefficient interregional energy transactions will also reduce the value of merchant lines and increase the barriers faced by merchant transmission developers who are attempting to develop, construct, and operate interregional facilities.

Through intertie optimization, two separate streams of benefits converge to increase the energy market value of interregional transmission facilities: (1) intertie optimization increases the value to transmission rights from a fully and efficiently utilized intertie; and (2) the additional imports of lower-cost energy from the neighboring region will reduce system-wide costs. The first stream of benefits accrues to the rights holders on the interregional transmission interface, yielding additional revenues from the optimized incremental energy market transactions over the interface. For regulated transmission facilities, these additional transactions-related revenues will generally offset transmission rates and reduce customer costs. For merchant transmission lines, the additional energy market value will reduce the average subscription cost of the line. The second stream of market benefits accrues to

[63] As we have noted elsewhere, interregional transmission planning processes are large ineffective and essentially no major interregional transmission projects have been planned and built by system operators in the last decade. See Pfeifenberger, *The Benefits of Interregional Transmission: Grid Planning for the 21st Century*, Presented at the US Department of Energy's (DOE's) National Transmission Planning Study Webinar (March 15, 2022).

We note again that the total value of interregional transmission expands beyond the increased energy market value that could be achieved through intertie optimization, which is the focus of this report. The total value of interregional transmission facilities currently is further reduced through seams-related barriers to capacity exports and imports, and some system operator’s planning and resource adequacy frameworks that understate or ignore the resource adequacy and resilience value of interregional transmission.

customers in regional wholesale markets in the form of lower prices resulting from increased utilization of lower-cost generation. RTOs have found that these cost savings from intertie optimization are significant.[64]

As a readily quantifiable metric for transmission value, we focus on production cost savings estimated as the marginal value of additional transmission in relieving congestion, which accrues to rights-holders on the transmission facilities. This metric does not paint a picture of the full value of transmission, but instead focuses on just the transaction value of improved utilization of existing or new interregional transmission. For example, the metric does not consider customer benefits from a reduction in market prices or the mitigation of reliability challenges from increasingly frequent extreme weather events.[65]

Similar to prior studies performed by market monitors and RTOs/ISOs, the Lawrence Berkley National Laboratory (LBNL) recently estimated the value of improved utilization or an expansion of interregional transmission.[66] By analyzing real-time price differences for numerous locations over a 10-year period from 2012 through 2021, LBNL estimated the value of making available an additional 1,000 MW of regional and interregional transmission capacity between the locations analyzed as shown in Figure 3 below. Despite the relatively low natural gas prices and the still modest shares of renewable generation experienced over the 2012–2021 period, the LBNL analysis demonstrates substantial value for expanding interregional transmission. As shown, over the 2012–2021 period, the annual value of an additional 1,000 MW of transmission between southern SPP and MISO averaged $149 million per year while the value of an additional 1,000 MW between MISO and PJM averaged $107 million. Other interregional paths were even more valuable, with estimated average annual value of 1,000 MW of transmission capability between southeastern SPP and western Texas as high as $670 million per year over the same 10-year period. As we discuss further below, we estimate that bilateral trades are not able to capture roughly 20% to 30% of these real-time energy market values—which is lost value that intertie optimization would be able to restore.

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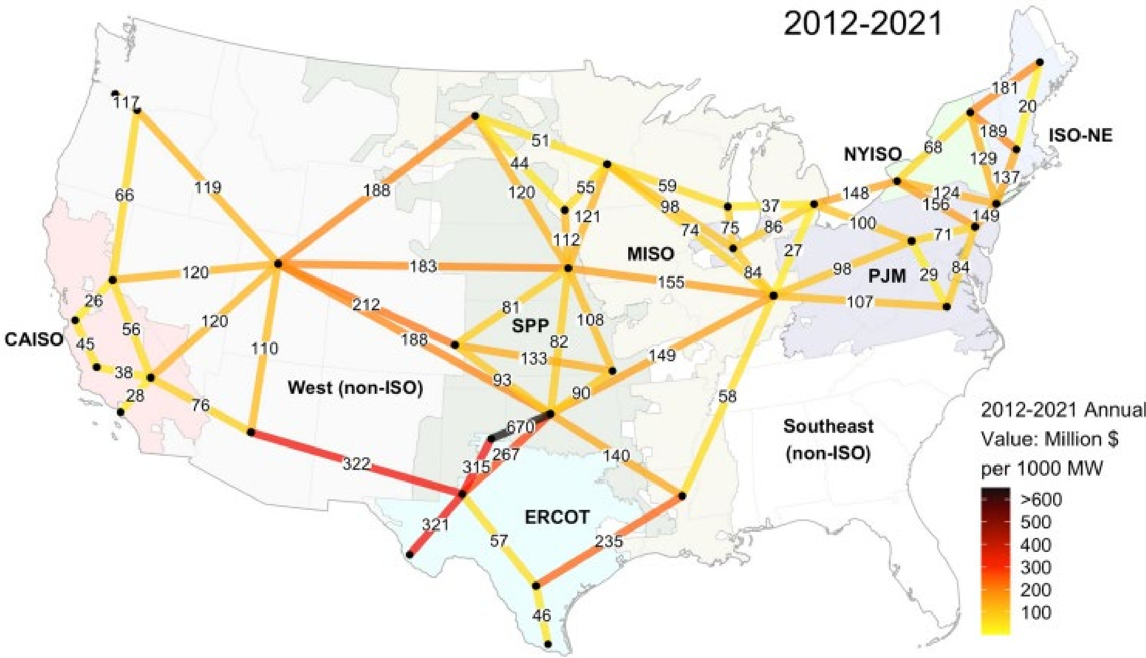
[64] RTOs have also estimated that the reduction in load expenditures from intertie optimization may be ten times larger than the identified reduction in production costs. See NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) at v, II-13 (identifying $77 million in production cost savings and $784 million in reduced load expenditures from intertie optimization between New York and New England for the five year study period from 2006 through 2010).

[65] See *ibid.*

[66] D. Millstein, R. Wiser, et al., *Empirical Estimates of Transmission Value using Locational Marginal Prices*, LBNL (August, 2022) (LBNL Study Slides).

FIGURE 3: MARGINAL VALUE OF REGIONAL AND INTERREGIONAL TRANSMISSION (2012–2022)



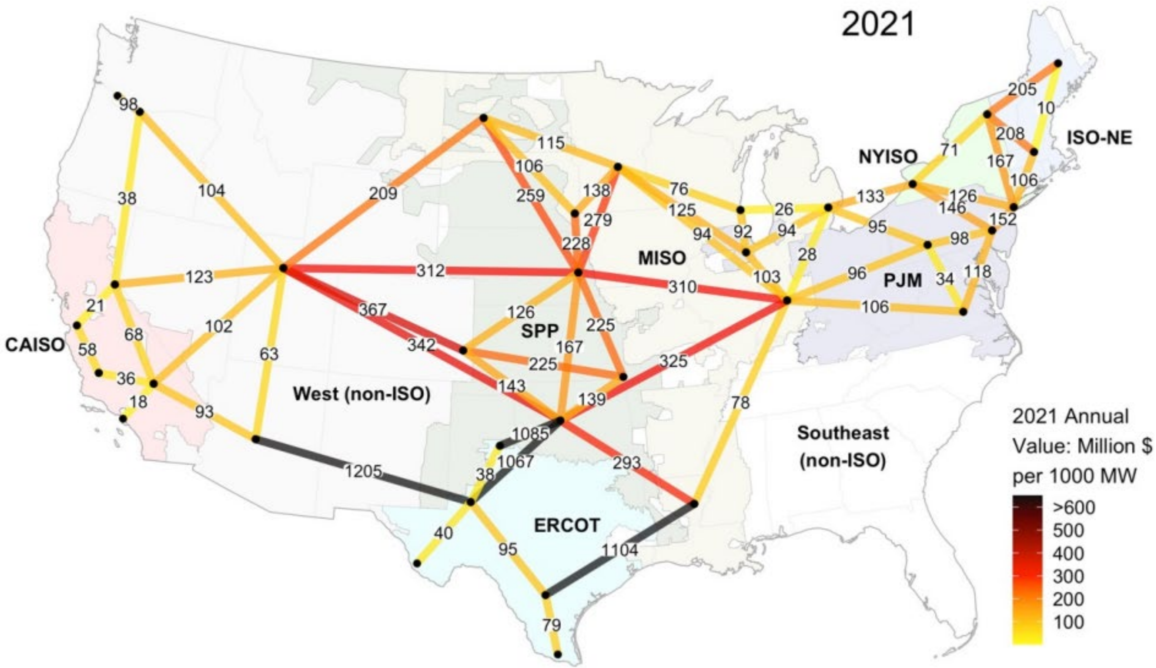
Source: LBNL, *[Empirical Estimates of Transmission Value](#)*, Slide 16.

As the share of renewable generation and the incidence of severe weather events continues to increase, the value of interties is expected to increase—particularly if these market fundamentals coincide with higher natural gas prices. Continued renewable growth will to increase the volatility of price differences between regions and the value that can be captured in part by more efficient use of existing transmission facilities through intertie optimization.

This is illustrated by the LBNL results for the most recent two years, 2021 and 2022, as shown in Figure 4 and Figure 5. These last two years included significant weather events, higher shares of renewable generation, and higher gas prices, all of which increased the value of regional and interregional transmission. In fact, LNBL found that transmission value in 2022 was higher than at any point in the last decade, with a median value across 64 hypothetical 1,000 MW transmission links of $220 million annually.[67]

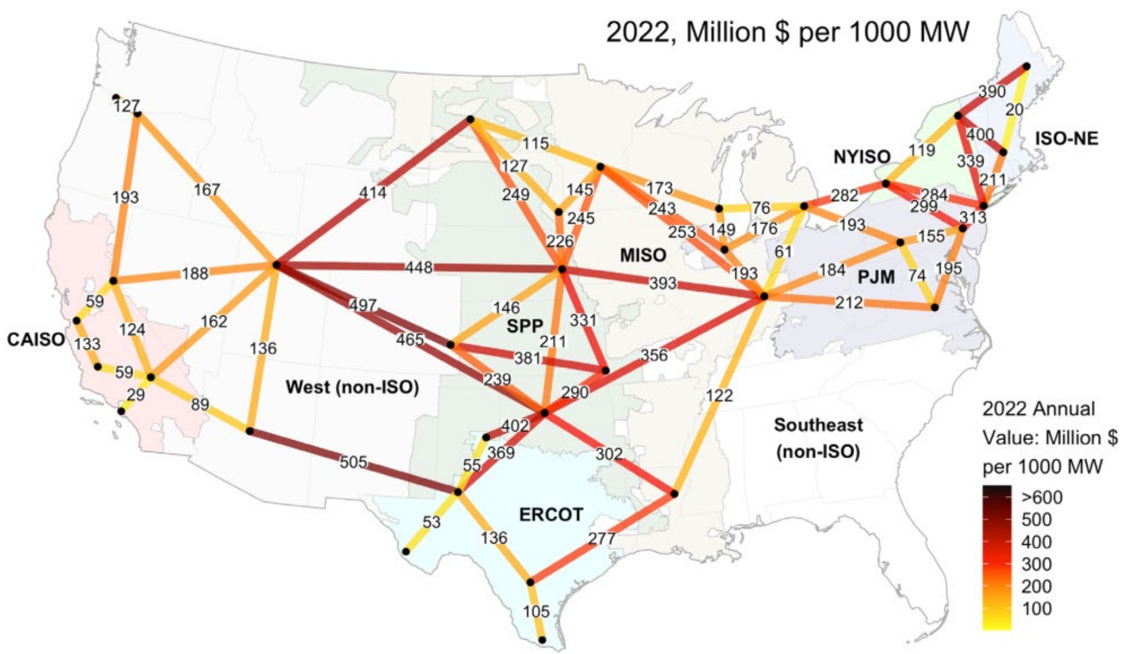
[67] D. Millstein, R. Wiser, et al., The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade, Fact Sheet, LBNL (February, 2023) at 3.

FIGURE 4: MARGINAL VALUE OF REGIONAL AND INTERREGIONAL TRANSMISSION (2021)



Source: LBNL, *Empirical Estimates of Transmission Value*, Slide 18.

FIGURE 5: MARGINAL VALUE OF REGIONAL AND INTERREGIONAL TRANSMISSION (2022)



Source: D. Millstein, R. Wiser, et al., 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, Fact Sheet, LBNL (February, 2023) at 2.

For example, as shown in the results for 2021 and 2022 below, the annual value 1,000 MW of transmission between southern SPP and MISO—which averaged $149 million for the decade from 2012 through 2021—was $325 million in 2021 and $356 million in 2022 (an increase of over 100%, reflecting in part the effects of SPP and MISO being exposed to severe weather events in both 2021 and 2022). Similarly, the annual value of 1,000 MW of transmission between MISO and PJM—which averaged $107 million over the decade from 2012 through 2021—was still $106 million 2021 but increased to $212 million in 2022 (reflecting in part the fact that PJM was exposed to severe weather events in 2022, but not in 2021).

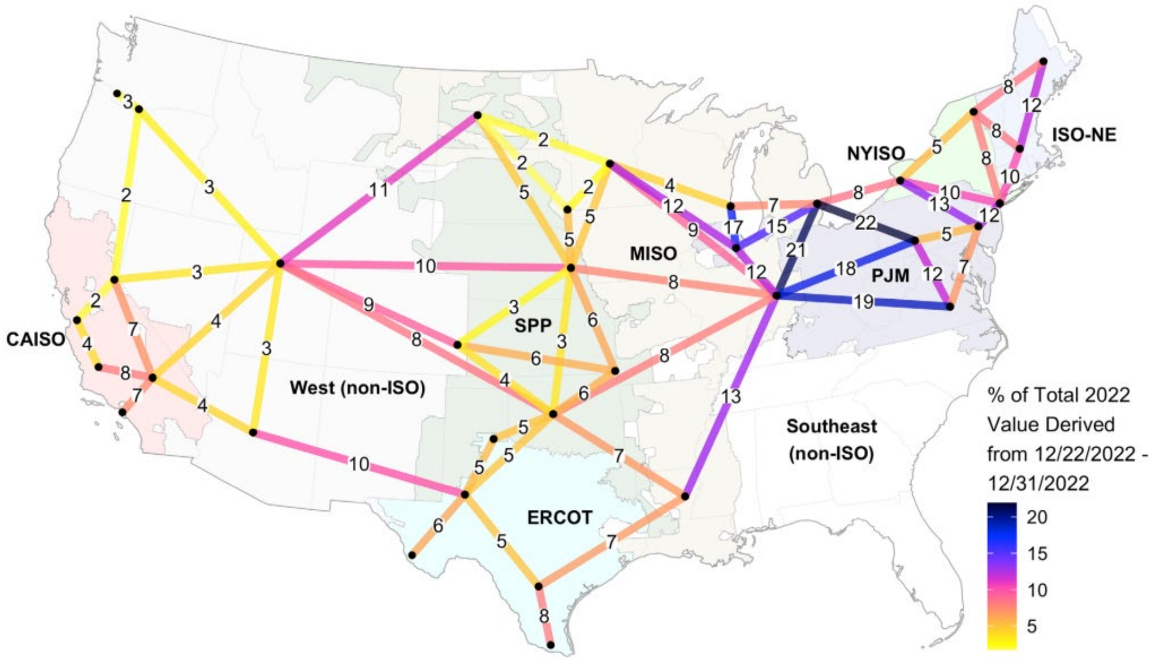
To demonstrate the substantial impact of severe weather events on the real-time energy market value of transmission, LBNL further analyzed the portion of its 2022 transmission value that was attributable to Winter Storm Elliott. From December 22 to December 31, 2022, Winter Storm Elliot caused significant disruptions to natural gas and power supply systems throughout the Eastern U.S., causing high prices and reliability challenges—particularly in the Southeastern and Mid-Atlantic regions of U.S.[68] As shown in Figure 6 below, the single severe weather event accounted for up to 22% of PJM's total annual interregional transmission value for 2022.

These observations during Winter Storm Elliott further support LBNL's earlier findings that a significant portion of the value of new transmission links comes from a relatively small share of high-impact time periods. In fact, between 2012 and 2021, between 40% and 80% of the total annual transmission value accrued within the top 5% of value-creating real-time operating periods of the year.[69] The fact that a small number of real-time trading periods represent such a disproportionate share of total annual value points to the need for intertie optimization that can schedule interregional transaction more quickly in response to changing and increasingly more variable real-time market conditions. This is illustrated by the WEIM benefits shown in Figure 2 above: the benefits of interregional optimization through WEIM within 2021 and 2022 were the highest during the third quarters of those years—both quarters that were affected by severe weather events involving the combination of heat waves and wild-fire-related transmission outages.

68 See PJM, Winter Storm Elliott, Event Analysis and Recommendation Report (July 17, 2023) at 20; R. Walton, *Duke Energy apologizes for winter storm outages as FERC, NERC open investigation into grid failures*, *Utility Dive* (January 4, 2023).

69 LBNL, *Empirical Estimates of Transmission Value*, Slide 28.

FIGURE 6: PORTION OF TOTAL 2022 TRANSMISSION VALUE ACCRUED DURING WINTER STORM ELLIOTT



Source: D. Millstein, R. Wiser, et al., [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](), Fact Sheet, LBNL (February, 2023) at 2.

IV. The Value of Intertie Optimization (Case Study)

While the LBNL study demonstrates the high value of making more interregional transmission available, the analyses by market monitors discussed above have demonstrated that bilateral trading frameworks that require scheduling of real-time interchange transactions well ahead of each real-time period will not be able to capture this value. Importantly, the efficiency losses in the real-time market from such prescheduling increases as more intermittent resources are added to the system. Additional benefits in the day-ahead timeframe—as WEIM participants are planning to capture through the EDAM—are available but not assessed in this analysis.

The window for submitting CTS transactions closes 75 minutes ahead of delivery, with transmission service reserved between 75 and 30 minutes before delivery, and CTS schedules typically cleared 30 minutes prior to delivery.[70] This CTS timeline essentially means that interregional transactions have to be “decided on” (based on forecasts of price differences) 1–2 hours before each real-time trading interval—particularly when accounting for administrative processes associated with market assessment, bid development, and bid submission. Bilateral trades, even if facilitated through CTS, consequently will not be able to respond sufficiently quickly to the real-time changes in market conditions that have made the intra-hour balancing of load and generation increasingly more challenging for the regional system operators.

As shown in Table 1 earlier, the 2022 absolute value of 5-minute real-time price differences between PJM and its neighboring RTOs/ISOs averaged approximately $100/MWh and the value of that price difference changed signs between 50 and 60 times a day, or more than twice each hour. To achieve efficient interregional trading outcomes with this level of price variability and uncertainty requires that intertie optimization can respond promptly to the frequent changes in real-time market conditions, even after the scheduling windows for bilateral trades and CTS transactions have closed. The success of WEIM implicitly shows how important it is to avoid scheduling delays in intertie optimization.

Assume, for example, wind generation ramps up unexpectedly within an RTO/ISO relative to the most recent 1–2 hour forecast. The RTO/ISO’s real-time prices will drop and the price difference with neighboring markets will increase (and may even change sign). Even with CTS, bilateral trades will not be able to respond and capture the available additional value. In contrast, if real-time intertie schedules could be optimized by the neighboring regions (using transmission that remains available after all bilateral trades have been scheduled) such that they could dynamically respond to the observed change in interregional price differences, the outcome would be more efficient in both regions—and the interties’ dynamic (e.g., 5 minute) response would partly mitigate the RTO/ISO’s forecasting errors and mitigate intra-hour flexibility challenges and costs associated with such unexpected variances.

For each bilateral interchange transaction that underutilizes available interregional transmission or results in energy flows counter to price differences during actual real-time operations, potential energy market value is lost for transmission rights holders and available

[70] See Frequently Asked Questions regarding CTS MISO, PJM (October 9, 2017) at 3 (PJM-MISO CTS); Joint Energy Scheduling System Enhancements and 15-Minute Scheduling Changes and Coordinated Transaction Scheduling with PJM, NYISO (August-September, 2014) at 33 (NYISO-PJM CTS); Coordinated Transactions Scheduling (CTS) Training, ISO-NE (September 21, 2015) at 27 (ISO-NE-NYISO CTS).

Although the CTS bids must be submitted 75 minutes before delivery interval, the economic clearing processes that determine which CTS bids are economic occur closer to the delivery interval, typically 30 minutes prior. See Coordinated Transaction Scheduling Study, SPP Market Monitoring Unit (May 8, 2020) at 6.

cost savings are not realized for regional power market customers. As market monitors have pointed out, these inefficiencies are considerable.[71] This outcome is not surprising because even CTS requires RTO/ISO forecasts of price differences and bids for bilateral trades designed to capture real-time price differences to be prepared 1–2 hours prior to each real-time operating period. In fact, as market monitors point out, the RTOs' short-term forecasts of real-time prices tend to be quite inaccurate.[72]

To supplement the analyses conducted by LBNL and market monitors, we reviewed (consistent with LBNL's analyses) the 2020–2022 hourly values of real-time price differences between nodes in SPP, MISO, and PJM and the extent to which a 1–2 hours "delay" of scheduling bilateral transaction fails to capture the available real-time value for 1,000 MW of transmission between the selected nodes. This SPP-MISO-PJM case study is meant to provide a "bookend" estimate of the benefits that can be achieved by adding intertie optimization to more optimally use existing or new interregional transmission capacity than prescheduled bilateral trades.

As shown in Table 2 below and Appendix A, we find that the value that cannot be captured through bilateral trades is approximately **20–30% of the total real-time value** of interregional transmission, assuming a 1–2 hour delay of bilateral trades in response to observed prices. This represents the value that only system operators can capture through operational means, such as intertie optimization (e.g., as proposed by PJM's market monitor) or through a more complete interregional Energy Imbalance Market that covers several of the regional markets and balancing areas (similar to the WEIM).

We estimate this bookend of potential efficiency gains made possible by intertie optimization by analyzing the value of 1,000 MW transfer capability based on historical 2020–2022 real-time price differences between SPP, MISO, and PJM. This bookend analysis assumes that 1,000 MW of power flows would be scheduled on the transmission links between the three regions whenever price differences exceed $3/MWh and (consistent with the LBNL analysis) that the assumed power flows will not change the observed average hourly real-time price differences between regions.

As shown in Table 2, three scenarios were modeled:

- Flows are scheduled in real time based on the observed real-time price differences without delay, as would be the case with intertie optimization;

[71] See Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at 525, 530.

[72] Monitoring Analytics, 2022 State of the Market Report for PJM (March 9, 2023) at Tables 9-43, 9-44, 9-47, 9-48.

- Flows are scheduled using the previous hours' prices, reflecting a one-hour pre-scheduling delay with imperfect foresight of real-time price; and
- Flows are scheduled using observed prices two hours before each trading period, reflecting a two-hour pre-scheduling delay, reflecting even less foresight of real-time prices.

The difference between the "no-delay" and "1 to 2 hour delay" scenarios provide an upper-bound (bookend) estimate of the energy market value lost when interregional power flows are not optimized in real-time after bilateral trading windows close 1–2 hours before real-time operations. As shown in Table 2, relative to hourly trades based on actual real-time market conditions (without delay), the 1–2 hours of prescheduling delays reduce the annual value that 1,000 MW transactions over these interties could capture by between 14% (for a potential future SPP-PJM link and 1-hour latency) to 52% (for the MISO-PJM intertie with 2-hour latency), or roughly 20% to 30% on average. Based on these three sets of interties and the three-year period from 2020 to 2022, we estimate that implementing intertie optimization for 1,000 MW of transmission between one pair of neighboring RTOs would capture approximately $50–$60 million per year in additional energy market value.[73]

TABLE 2: ANNUAL ENERGY MARKET VALUE OF A 1000 MW OF INTERREGIONAL TRANSMISSION BETWEEN SPP, MISO, AND PJM (2020–2022 AVERAGE)

Bidirectional Intertie		SPP-MISO	MISO-PJM	SPP-PJM
Annual Average Value with No Trading Delay ($ million)	[1]	$278	$122	$311
Annual Average Value with 1 Hour Delay ($ million)	[3]	$230	$72	$267
% Value Lost Due to Delay	1 - ([3]/[1])	17%	41%	14%
Annual Average Value with 2 Hour Delay ($ million)	[4]	$206	$58	$250
% Value Lost Due to Delay	1 - ([4]/[1])	26%	52%	20%
Annual Average Value of Intertie Optimization ($ million)				
One hour	[1] - [3]	$48	$50	$43
Two hour	[1] - [4]	$71	$63	$61

Sources and Notes: Real-time LMP data from Hitachi ABB Energy Velocity Suite; assumes no LMP price convergence from trades; Assumes no ramping limits or other constraints; assumes 1,000 MW of available transmission in all trading intervals for all shown pairs of RTOs/ISOs, including a direct contract path between SPP and PJM (to reflect proposed merchant transmission between SPP and PJM).

The individual annual results of this analysis are shown for each of the years 2020, 2021, and 2022 in Appendix A. As also shown in Figure A-1 in Appendix A, 50% of the energy market value

[73] $423/3/3=$47; $587/3/3 = $65.

of the evaluated transmission links between the three RTOs is concentrated in the top 10–20% of hours in each year.

V. FERC Has the Authority to Implement Intertie Optimization

The Commission has long recognized that seams-related inefficiencies across regional markets can give rise to unjust and unreasonable rates, as well as serious reliability and resilience issues.[74] It is well settled that the ability to address seams issues falls squarely within the Commission's statutory authority under the Federal Power Act (FPA) to ensure just and reasonable rates. Indeed, not only does the Commission have authority to implement intertie optimization, but there is additional precedent for doing so with the Commission's approval of the WEIM.

Pursuant to section 205 of the FPA,[75] the Commission has the authority to accept RTO/ISO changes to existing market rules to address seams issues, as long as they are just and reasonable. Regions should take advantage of this authority to pursue reforms that implement the repeated recommendations of market monitors and that optimize intertie capacity across regions in both real-time and day-ahead markets. Any intertie optimization should also be designed to enable the unique capabilities of merchant transmission lines, as is already occurring in the CAISO and WEIM.[76]

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74 See, e.g., *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,147, at P 74 (2003) ("We are actively addressing Midwest seams issues and consider this issue a priority that must be addressed to ensure future reliability is enhanced in the region."); *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design Notice of Proposed Rulemaking*, RM01-12-000, 100 FERC ¶ 61,138, at PP 80–85 & Appx. C (2002) (Resolution of persistent seams problems are "critical for making the inter-RTO transmission systems and power markets work."); *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. 31,036, at 31,730–32 (1996) (cross referenced at 75 FERC ¶ 61,080 (1996)).

75 16 U.S.C. § 824d.

76 The CAISO market systems already optimize the controllable transmission devices as part of its security constrained economic dispatch and security constrained unit commitment. See CAISO, Business Practice Manual for Market Operations, Version 89, at § 3.1.12 (April 6, 2023); see also CAISO, Subscriber Participating TO Model, Final Proposal (June 22, 2023).

In the absence of action by the regional system operators, pursuant to section 206 of the FPA,[77] the Commission has the authority to require reforms in response to complaints or to propose, on its own motion, broad generic rulemakings to correct unjust and unreasonable rates. It is well within the Commission's purview to remedy the amply documented seams issues across RTO/ISO markets, as well as the inefficient uses of interregional transmission capabilities between markets, including merchant lines under development. These inefficiencies impede interregional power transfers, cost consumers hundreds of millions of dollars each year, and undermine reliability and resilience.

A. FERC Has Long Recognized Seams Issues and Sought Solutions

Concerns about cross-market inefficiencies were among the drivers behind the creation of competitive wholesale markets in the first instance. In Order No. 888, the Commission required single control area ISOs to "develop mechanisms to coordinate with neighboring control areas"[78] in recognition that "[s]uch coordination is necessary to ensure provision of transmission services that cross system boundaries and to ensure reliability and ability of the systems."[79] Shortly thereafter, in Order No. 2000, the Commission imposed additional requirements on RTOs/ISOs, including "develop[ing] mechanisms to coordinate…activities with other regions whether or not an RTO yet exists in these other regions."[80] The Commission reasoned that "RTO reliability and market interface practices must be compatible with each other, especially at the 'seams'[.]" Interregional coordination requirements were established in Order No. 2000 to "ensure the integration of reliability practices within an interconnection and market interface practices among regions."[81]

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77 16 U.S.C. § 824e.

78 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730–32.

79 *Ibid.*

80 *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) (cross-referenced at 89 FERC ¶ 61,285), 1999 WL 33505505, at *203 (Dec. 20, 1999), *order on reh'g,* Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201).

81 *Id.* *204. More specifically, in Order No. 2000, the Commission required RTOs to develop "some level of standardization of inter-regional market standards and practices, including the coordination and sharing of data necessary for calculation of TTC [Total Transfer Capability] and ATC, transmission reservation practices, scheduling practices, and congestion management procedures, as well as other market coordination requirements covered elsewhere in [Order No. 2000]."

In the decades following the issuance of Order Nos. 888 and 2000, the Commission has continued to exercise its broad authority to address seams issues. The Commission, for example, has convened technical conferences,[82] set seams disputes for hearing, investigation, and settlement procedures,[83] found specific pancaked rates resulting from seams issues to be unjust and unreasonable,[84] and considered seams issues in subsequent rulemakings.[85] Between 2012 and 2016, the Commission accepted a number of RTO/ISO proposals to establish CTS between regions, reasoning that CTS was "a just and reasonable mechanism for enhancing the market efficiency of external transactions between RTOs."[86]

CTS facilitates bilateral trading in real time through a simplified bid format (called an "interface bid") and coordinated acceptance of interface bids by the RTOs/ISOs using an improved clearing rule. The Commission hoped that "CTS will provide substantial benefits to consumers…by addressing inefficiencies present in the current external transaction scheduling process."[87] For example, "for the combined ISO-NE and NYISO region, Potomac Economics estimates that CTS will result in $129 million to $139 million in annual consumer savings, and $9 million to $11

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82 *See, e.g., RTO Border Utility Issues, Notice of Technical Conference on Seams Issues for RTOs and ISOs in the Eastern Interconnection*, Docket No. AD06-9-000 (Jan. 25, 2007); *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design Notice of Proposed Rulemaking*, 100 FERC ¶ 61,138 at P 83 n.63 (2002) (citing Conference on RTO Interregional Coordination, Docket No. PL01-5-000 (June 19, 2001), and noting, "[c]alled by many the 'FERC Seams Conference,' this technical conference on the RTO interregional coordination requirements of Order No. 2000 helped the Commission learn about seams issues and about how uniform standards for some rules could benefit power markets.").

83 *See, e.g.*, *SPP, Inc.*, 149 FERC ¶ 61,113 at P 112 (2014); *Midwest Indep. Transmission Sys. Operator, Inc.* 117 FERC ¶ 61,230 (2006).

84 *Am. Elec. Power Serv. Corp.*, 122 FERC ¶ 61,083 at P 7 (2008) ("In response to concerns about seams issues related to the RTO configurations that would result from the Alliance Companies' choices, the Commission also instituted, under section 206 of the FPA, an investigation and hearing of the through-and-out rates that Midwest ISO and PJM charged for inter-RTO transmission service…, which resulted in rate pancaking for transactions crossing the seam between the two RTOs.… [A]fter the hearing was held and an Initial Decision was issued, the Commission issued an order finding that the rate pancaking that resulted…was unjust and unreasonable. Accordingly, the Commission directed the RTOs to eliminate the rate pancaking for such transactions.").

85 *See, e.g.*, *Offer Caps in Markets Operated by RTOs and ISOs*, 154 FERC ¶ 61,038, at P 4 (2016) ("The Commission proposes to make a generic change to the offer cap applicable to all RTOs/ISOs through a rulemaking to avoid exacerbating seams issues. Seams issues could arise if one RTO/ISO has an offer cap that materially differed from a neighboring RTO/ISO's offer cap. Different offer caps in neighboring RTOs/ISOs could result in flows that depend on the level of the two offer caps as opposed to economics or reliability needs.").

86 *Midcontinent Indep. Sys. Operator, Inc. and PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,038, at P 2 (2016) (citing *PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,096 (2014)); *N.Y. Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,097, at P 33 (2014); *ISO-NE Inc. and New England Power Pool Participants Committee*, 153 FERC ¶ 61,159 (2015); *ISO-NE Inc. and New England Power Pool*, 139 FERC ¶ 61,047 (2012).

87 *N.Y. Indep. Sys. Operator, Inc.*, 139 FERC ¶ 61,048, at P 29 (2012).

million in annual production cost savings."[88] Given the promise of CTS to increase interregional market efficiency, the Commission used its section 205 authority to implement CTS between ISO-NE and NYISO,[89] NYISO and PJM,[90] and PJM and MISO.[91]

B. The Commission Has Authority to Approve Intertie Optimization Under FPA Section 205

Just as the Commission had the authority to adopt CTS under section 205 of the FPA, it has the authority to consider and approve proposals to address seams issues through intertie optimization. In fact, the Commission already considered intertie optimization in 2012 when NYISO and ISO-NE proposed "Tie Optimization," along with CTS, to address seams-related inefficiencies.[92] Although the Commission elected to adopt only CTS at the time, it left the door open for re-evaluation of this decision.

A future re-evaluation, the Commission reasoned, "may lead to ISO-NE and NYISO improving the design or operation of CTS, or adopting a different methodology for scheduling external transactions (i.e., Tie Optimization or a superior alternative), if it is determined that such changes could result in greater cost savings."[93] The Commission added, "because Tie Optimization has already been vetted as a possible solution it is valid to incorporate it as a possible alternative for the NYISO Board to consider.… Focusing the Board's options on a solution that has previously been considered narrows the time necessary to implement a fix if CTS is not fulfilling its goals as envisioned."[94] Notably, NYISO and ISO-NE had proposed specific implementation details, including a process for transitioning to Tie Optimization.

More than a decade after implementation of CTS, it is clear that CTS has not fulfilled its goals as envisioned. As noted earlier in this report, the market monitors for PJM, MISO, and NYISO have long critiqued its deficiencies and proposed intertie optimization in its place. For example, Potomac Economics has noted that CTS "has produced very little of the sizable savings it could generate" and that more than 40 percent of the current CTS transactions are ultimately

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88 *Ibid.*
89 *Id.* P 27.
90 *PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,096, at P 15 (2014).
91 *MISO and PJM, L.L.C.*, 155 FERC ¶ 61,038 at P 16.
92 *NYISO*, 139 FERC ¶ 61,048 at P 8.
93 *Id.* P 30.
94 *Id.* P 31.

unprofitable." Similarly, the PJM Market Monitor has recommended reconsideration of intertie optimization since 2014. In almost half of all trading periods between PJM and MISO and PJM and NYISO, intertie schedules are inconsistent with seams-related price differences.

There is precedent for the Commission using its section 205 authority to implement intertie optimization and for intertie optimization to deliver huge benefits to consumers. In 2014, the Commission accepted CAISO's proposed EIM, which effectively allows for intertie optimization across BAA seams in real time, without combining the individual BAAs into a single RTO/ISO.[95] The Commission noted that "Parties generally concur that expansion of CAISO's energy imbalance market beyond its BAA will provide customers with a range of benefits, including reduced costs, more efficient dispatch, improved integration of renewable resources, and enhanced reliability."[96] In marked contrast to CTS, the WEIM has lived up to its promise. Since its inception in November 2014, it has delivered more than $4 billion in benefits to consumers across the West, while increasing the integration of renewable energy and reducing the need for flexible real-time reserves.[97]

Thus, RTOs/ISOs should act on the long-standing recommendations of market monitors, re-examine the value of intertie optimization in light of their disappointing experience with CTS, and accept the Commission's invitation to change methodologies "if it is determined that such changes could result in greater cost savings."[98] We now know that there will be significantly greater cost savings from intertie optimization than from CTS. Were the RTOs/ISOs to file a proposal with the Commission to optimize intertie capacity between regions in both the real-time and day-ahead markets, the Commission would clearly be able to accept it as just and reasonable under its section 205 authority and CTS precedent.

C. The Commission Has Authority to Require Intertie Optimization under FPA Section 206

If RTOs/ISOs fail to act, the Commission has the purview to use its section 206 authority to require the use of intertie optimization. This could happen in response to a complaint filed by stakeholders or through a generic Commission rulemaking. Under section 206, the complainant bears the burden of establishing that the challenged rate is unjust and unreasonable and that the replacement rate is just and reasonable.

95 *Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,231, at PP 153–154 (2014).

96 *Id.* P 76.

97 CAISO, *Western Energy Imbalance Market Benefits Report*, at 6 (July 31, 2023).

98 *NYISO, Inc.*, 139 FERC ¶ 61,048, at P 30.

Here, the argument in support of the Commission's section 206 authority to require intertie optimization is a straightforward one. Were the Commission to open a rulemaking, the record would establish the following:

- The Western U.S. energy imbalance markets have proven the benefits of intertie optimization, with more than $4 billion in benefits to consumers in the West since inception less than a decade ago;
- In contrast, significant seams issues persist in the Eastern U.S. power markets;
- Attempts to address seams issues through CTS have been deficient for a number of reasons while CTS-related inefficiencies have increased;
- Inefficient power flows across the seams cost consumers hundreds of millions of dollars a year and reduce competition for wholesale electricity because lower-cost electricity cannot reach higher-priced markets;
- Seams inefficiencies impair reliability and resilience because they impede the timely flow of power during scarcity conditions, including extreme weather events;
- Extreme weather events are increasing in frequency and severity and, in recent years, have placed significant constraints on the grid; and
- The failure to optimize interties means that the benefits of interregional transmission are not fully realized or compensated by the markets, which reduces the incentive to build interregional transmission and results in a planning process that undervalues its benefits.

On this record, the Commission could fairly conclude that rates are not just and reasonable and that allowing intertie optimization would be just and reasonable. Given the scope of the problem and the importance of harmonizing market rules across RTOs/ISOs, there is also value in a generic rulemaking in lieu of a series of ad hoc regional measures that may inadvertently create new seams issues while solving existing ones. The Commission has not hesitated to use its section 206 authority to promote market efficiency, competition, or innovation, whether with respect to interconnection reform,[99] price formation in the RTO/ISO markets,[100] gas-

[99] *See Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054 (2023).

[100] *See Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, FERC Stats. & Regs. ¶ 31,384 (2016) (cross-referenced at 155 FERC ¶ 61,276) (aligning settlement and dispatch intervals and setting shortage pricing across RTO/ISO markets); *Offer Caps in Markets Operated by RTOs and ISOs*, Order No. 831, FERC Stats. & Regs. ¶ 31,387 (2016) (cross-referenced at 155 FERC ¶ 61,038), *order on re'h and clarification,* Order No. 831-A, FERC Stats. & Regs. ¶ 31,394 (2017) (cross-referenced at 161 FERC ¶ 61,156) (setting offer caps across RTO/ISO markets).

electric coordination,[101] transmission line ratings,[102] demand response,[103] energy storage,[104] or distributed energy resources.[105] Similarly, on an issue as important, vexing, and costly as regional market seams, the Commission should not hesitate to act.

D. Intertie Optimization Should Enable Merchant Transmission

Any intertie optimization solution should be designed to include available capacity on merchant transmission lines (as already proposed by CAISO for the WEIM footprint). Merchant HVDC transmission lines are particularly well suited for long-distance interregional transmission and for addressing seams issues because HVDC technology offers cost-effective, large-scale, controllable power transfer over long distances with low line losses, no loop flows, and other benefits.[106]

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[101] *See Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Order No. 809, FERC Stats. & Regs. ¶ 31,368 (2015) (cross-referenced at 151 FERC ¶ 61,049).

[102] *See Managing Transmission Line Ratings*, Order No. 881, FERC Stats. & Regs. ¶ 31,449 (2021) (cross-referenced at 177 FERC ¶ 61,179, at PP 1–4) (adopting Commission-proposed reforms to improve accuracy and transparency of transmission line ratings used by transmission providers including RTOs and ISOs upon finding inaccurate transmission line ratings result in unjust and unreasonable rates; requiring transmission providers, including RTOs and ISOs, to making compliance filing within 120 days and to fully implement all requirements within three years).

[103] *See Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. 31,322 (2011) (cross-referenced at 134 FERC ¶ 61,187); *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 at P 66 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *vacated sub nom. Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded sub nom. EPSA*, 577 U.S. 260 (2016).

[104] *See Electric Storage Participation in Markets Operated by Regional Transmission Organizations & Independent System Operators*, Order No. 841, FERC Stats. & Regs. ¶ 31,398 (2018) (cross-referenced at 162 FERC ¶ 61,127, at P 76), *order on reh'g and clarification*, Order No. 841-A, FERC Stats. & Regs. ¶ 31,417 (2019) (cross-referenced at 167 FERC ¶ 61,154), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 964 F.3d 1177 (D.C. Cir. 2020).

[105] *See Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247, at PP 1, 1766–1767 (2020), *order addressing arguments raised on reh'g, setting aside prior order in part, and clarifying prior order in part on reh'g,* Order No. 2222-A, FERC Stats. & Regs. ¶ 31,441 (2021) (cross-referenced at 174 FERC ¶ 61,179), *order addressing arguments raised on reh'g setting aside in part and clarifying in part prior order*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021) (adopting reforms to remove barriers to the participation of distributed energy resource aggregations in RTO/ISO markets upon finding "that existing RTO/ISO market rules are unjust and unreasonable in light of barriers that they present to the participation of distributed energy resource aggregations in the RTO/ISO markets, which reduce competition and fail to ensure just and reasonable rates").

[106] Merchant HVDC lines can also connect asynchronous systems, allow for precise control of real and reactive power flows, and can be used to reduce AC grid congestion and the impacts of loop flows on neighboring

Importantly, the integration of merchant transmission into intertie optimization frameworks will offer additional benefits to consumers because merchant transmission developers, not ratepayers, bear the project risk and provide the capital. The process to develop a merchant project is inherently competitive in nature, so developers have every incentive to identify the most valuable transmission paths, to contain costs, and to deliver the greatest value at lowest cost. Merchant projects avoid the difficult, litigious cost allocation issues raised by traditionally regulated, rate-based transmission projects. In addition, interregional merchant projects do not need to survive the many hurdles under the Order No. 1000 interregional planning processes.[107] Although the Commission is in the midst of transmission planning reform, the current reform effort focuses mostly on improving regional, not interregional, transmission planning.[108] Given the many hurdles to interregional planning, merchant transmission developers will continue to play an important role in developing, constructing, and operating necessary additional transmission capacity between regions.

For all these reasons, any effort to promote intertie optimization should enable the participation of merchant transmission.

VI. Conclusions

Inefficient use of interregional transmission facilities unnecessarily raises system costs and reduces reliability. These inefficiencies have been pointed out by market monitors for over a decade. The impacts of these inefficient flows will continue to increase with the accelerating deployment of large-scale variable resources that must be balanced in real-time.

Since the mid-2000s, market monitors have recommended that RTOs/ISOs optimize interties as part of day-ahead and real-time market clearing to resolve these inefficiencies. Despite these recommendations, eastern RTOs/ISOs have elected to pursue only CTS, hoping that CTS would address these inefficiencies. Contrary to these hopes, available experience now shows that CTS

systems, thereby enhancing the value of the free-flowing AC interties between regions. *See* Pfeifenberger, Plet et al., The Operational and Market Benefits of HVDC to System Operators, September 2023.

[107] *See, e.g.*, *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,008, at P 37 (2016) (e.g., describing a "triple hurdle" having to "meet separate, inconsistent regional transmission project criteria, using different models with identification of system constraints on each side of the RTOs' seam, before considering interregional transmission issues"); see also Pfeifenberger et al., *A Roadmap to Improved Interregional Transmission Planning*, at Appendix A (November 30, 2021).

[108] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028, at P 10 (2022).

has not resulted in significant improvements to economic or operational efficiencies of interregional transmission.

In contrast to these continued inefficiencies in intertie transactions between the eastern RTOs, experience with the Western Energy Imbalance Market and "market coupling" in Europe has highlighted both the feasibility and the significant potential benefits that intertie optimization can offer.

FERC has the authority to require the implementation of intertie optimization measures and, in fact, has effectively already done so by approving the Western energy imbalance markets. The RTOs/ISOs should thus take advantage of this authority and urgently pursue reforms that optimize available intertie capacity between regions in both real-time and day-ahead markets. Intertie optimization frameworks should also allow for the integration of interregional merchant transmission lines, as already proposed by CAISO for optimization in WEIM and EDAM.

Appendix A: The Value of Interregional Transmission Between SPP, MISO, and PJM With and Without Intertie Optimization

Table A-1 below summarizes the bookend estimates of the 2020–2023 real-time energy market values between grid points in Western SPP, central MISO, and Western PJM for 1,000 MW of transfer capability, using hourly real-time prices for the three trading points, assuming transaction costs of $3/MWh.

The first group of rows (for 2020, 2021, and 2022) calculates the annual energy market value for fully-optimized hourly real-time trades (without trading-related prescheduling delays), similar to what could be achieved by the neighboring RTOs/ISOs through intertie optimization.

TABLE A-1: REAL-TIME ENERGY MARKET VALUE OF 1000 MW BETWEEN SPP, MISO, AND PJM

		SPP > MISO	MISO > SPP	MISO > PJM	PJM > MISO	SPP > PJM	PJM > SPP
Value with No Trading Delay ($ million)	[1]						
2020		$91	$27	$26	$23	$93	$26
2021		$189	$136	$69	$44	$222	$143
2022		$338	$53	$144	$58	$410	$39
Value with 1 Hour Delay ($ million)	[3]						
2020		$76	$10	$13	$11	$79	$10
2021		$165	$108	$46	$22	$198	$117
2022		$307	$23	$104	$20	$384	$14
Value with 2 Hour Delay ($ million)	[4]						
2020		$71	$7	$11	$9	$75	$7
2021		$150	$95	$39	$17	$185	$107
2022		$290	$8	$91	$7	$372	$3
Value of Intertie Optimization ($ million)	[1] - [3]						
1 Hour Delay: 2020		$15	$17	$13	$12	$14	$16
2021		$24	$28	$24	$21	$24	$26
2022		$31	$30	$40	$39	$26	$25
	[1] - [4]						
2 Hour Delay: 2020		$20	$20	$16	$13	$18	$19
2021		$39	$41	$30	$26	$37	$37
2022		$48	$46	$53	$51	$38	$35

Sources and Notes: Real-time LMP data from Hitachi ABB Energy Velocity Suite; assumes no LMP price convergence from trades; assumes no ramping limits or other constraints; assumes 1,000 MW of available transmission in all trading intervals for all shown pairs of RTOs/ISOs, including a direct contract path between SPP and PJM (reflecting proposed merchant transmission links).

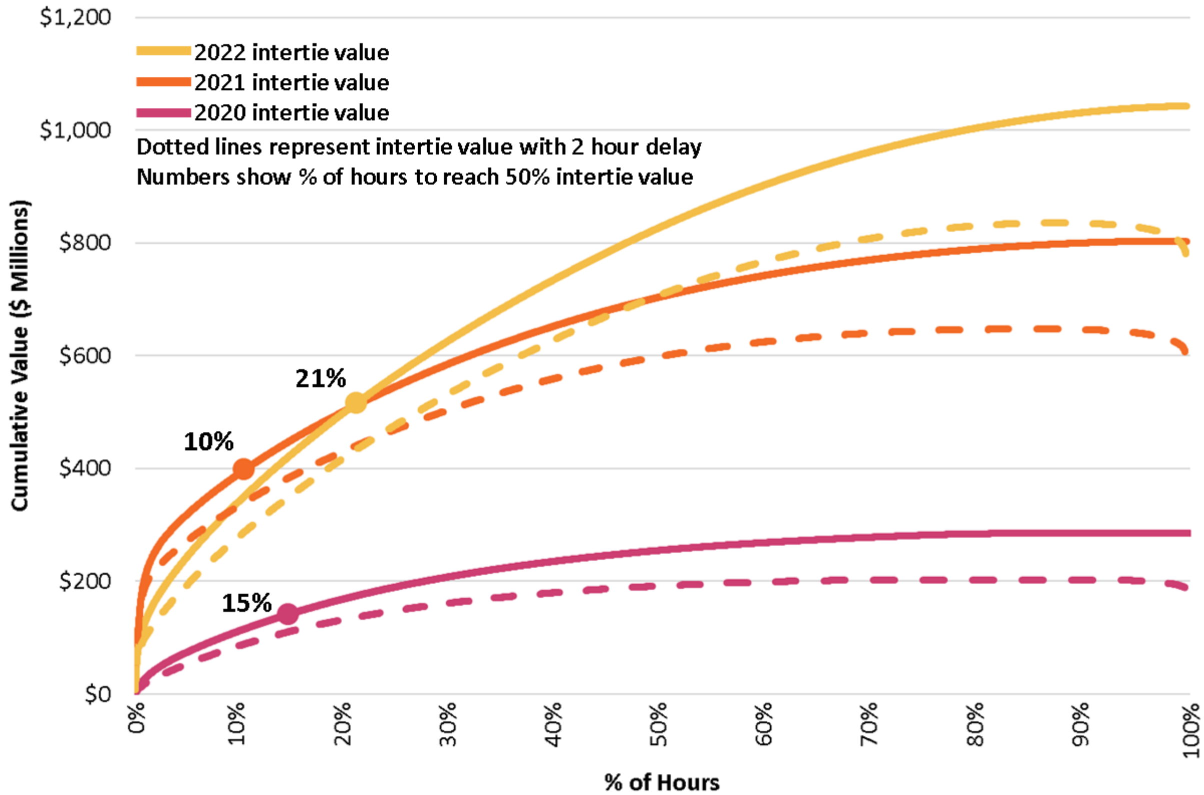
The second group of rows show the lower energy market value for the same 1,000 MW of transfer capability if trades have to be prescheduled with imperfect foresight, consistent with a 1-hour delay. In other words, the results shown are the energy market values in which bilateral trades for the next hour are determined based on the current hour of observed real-time prices (i.e., trades are executed with a 1-hour delay to observed prices).

The third group of rows shows the 2020–2022 energy market value for trades that are prescheduled with a 2-hour delay to observed real-time market prices. And finally, the last group of rows estimates the energy market value of intertie optimization for 1,000 MW of transfer capability between SPP, MISO, and PJM as the difference in energy market value between the first set of rows (reflecting intertie optimization based on real-time price differences) and the second and third set of rows (reflecting bilateral trades that can be executed with a 1- or 2-hour delay to observed real-time market prices).

As shown earlier in Table 2 (Section IV of the report), bilateral trades that have to be decided on and prescheduled well ahead of each real-time operating period (and with imperfect foresight of real-time market condition) are unable to capture roughly 20–30% of the total real-time energy market values that could be captured through intertie optimization. As shown in Table A-1 above, applying intertie optimization to any unidirectional 1,000 MW of transfer capability between SPP, MISO, and PJM would have increased the energy market value of transactions (relative to bilateral trades with a 2-hour delay) by between $13 million and 20 million in 2020 and by between $35 million and $53 million in 2022. As also shown by the results in Table A-1 (above), the value of intertie optimization for a bidirectional 1,000 MW of transfer capability is approximately double that of the unidirectional value.

Figure A-1 below graphs the total hourly energy market value of the analyzed 1,000 MW of (bi-directional) interregional transmission capacity between the three pairs of RTOs/ISOs, sorted from highest hourly energy values to lowest, calculating the cumulative total of the course of the year, such that the right end of each line reflects the total for the year (100% of all hours of a year). The solid line reflects the total real-time value of the 1,000 MW of interregional transfer capability, while the dashed lines show the (lower) value achievable through bilateral trades with a 2-hour prescheduling delay. The difference between the solid and dashed lines represents the bookend estimate of the incremental value achievable by intertie optimization during real-time market operations after all bilateral trades have been scheduled. The figure also shows that for these pairs of interties, half of the total annual real-time energy value is associated with the top 10–20% of all hours of the year.

FIGURE A-1: ANNUAL REAL-TIME ENERGY MARKET VALUE "DURATION CURVE"
(Total Across SPP-MISO, MISO-PJM, and SPP-PJM)



Sources and Notes: Results shown are for the no delay case (solid lines) and the two-hour delay cases (dashed lines)

List of Acronyms

AC	Alternating Current
ATC	Available Transfer Capacity
BAA	Balancing Authority Area
CAISO	California Independent System Operator
CTS	Coordinated Transaction Scheduling
CWE	Central and Western Europe
DC	Direct Current
EDAM	Extended Day Ahead Market
ERCOT	Electric Reliability Council of Texas
FBMC	Flow-Based Market Coupling
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
HVDC	High-Voltage Direct Current
IMM	Independent Market Monitor
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
LBNL	Lawrence Berkley National Laboratory
LMP	Locational Marginal Pricing
MISO	Midcontinent Independent System Operator
MMU	Market Monitoring Unit
MW	Megawatt
MWh	Megawatt Hour
NTC	Net Transfer Capacity
NYISO	New York Independent System Operator
PJM	PJM Interconnection
PTDF	Power Transfer Distribution Factor
PTO	Participating Transmission Owner
RTO	Regional Transmission Organization
SIDC	Single Intraday Coupling
SPP	Southwest Power Pool
SPTO	Subscriber Participating Transmission Owner
TSO	Transmission System Operator
TTC	Total Transfer Capability
TWE	TransWest Express
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market