Seams Coordination in the Western Interconnection

Staff Whitepaper

November 6, 2025

This report does not necessarily reflect the views of the Commission.

Contents

I. Introduction/Overview

This white paper is a product of the independent analysis of staff of the Federal Energy Regulatory Commission (FERC). FERC staff understand that the issues discussed in this white paper have been the subject of analysis by private entities, some of which have been published recently. The purpose of this white paper is to support the ongoing discussions among stakeholders and highlight the importance of collaboration by relevant parties to address these complex issues.

Over the past decade, the energy landscape of the West has been transformed by the creation and expansion of regional organizations, including centralized energy markets. The California Independent System Operator Corporation (CAISO) Extended Day-Ahead Market (EDAM), the Southwest Power Pool, Inc. (SPP) Markets+, the expansion of the SPP Regional Transmission Organization (RTO) footprint, and continued bilateral trading across more than 30 balancing authority areas (BAAs) together create a multi-market environment that will lead to the creation of seams – boundaries between markets and BAAs that create reliability, operation, and market efficiency hurdles. Moreover, RC West and SPP RC, as the two reliability coordinators[1] (RCs) in the Western Interconnection, will continue to be responsible for overseeing reliable operation in their respective regions, alongside the many Western Balancing Authorities (BAs). As numerous stakeholders have pointed out,[2] this new, complex environment will require formal seams coordination, and Commission staff believes it will be worthwhile for the relevant parties to work toward crafting new coordination agreements to address seams issues. This paper identifies seams issues that could arise as centralized markets expand in the Western Interconnection, highlights actions to address seams that are already under way in the West, and discusses potential approaches to managing seams going forward.

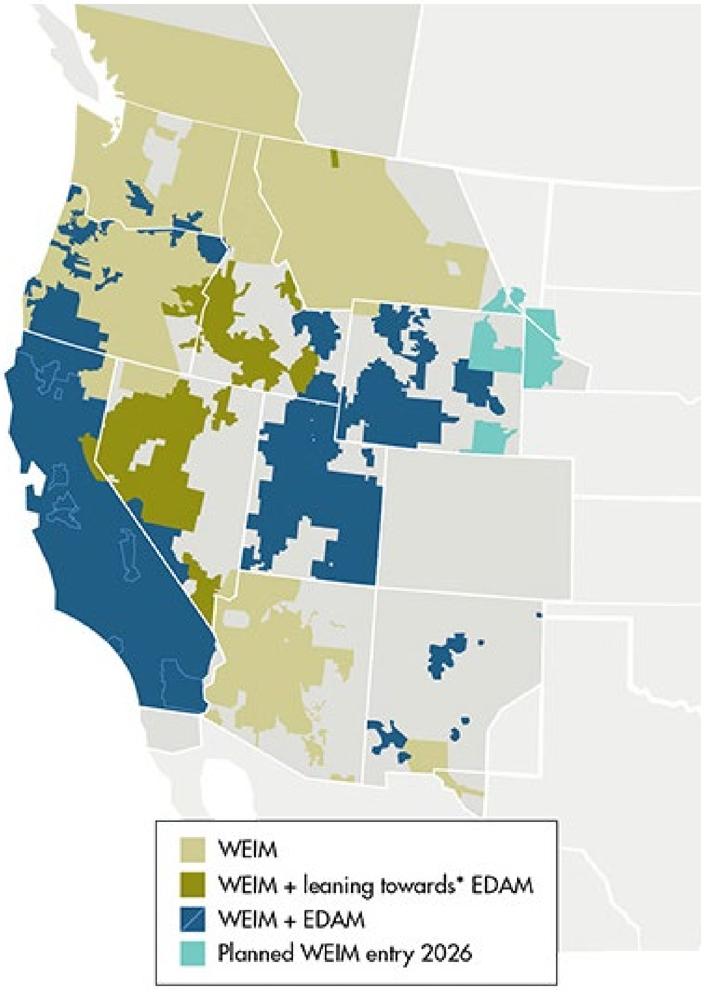
Figure 1 and Figure 2, show the complex and disconnected seam between Markets+ and EDAM. Figure 1 shows CAISO's existing WEIM footprint and expected EDAM footprint, based on public statements or signed participation agreements; Figure 2 shows participation in the next step of Markets+ development and SPP's RTO expansion into the West that will comprise sections of Arizona, Colorado, Montana, Utah, and Wyoming.

---

[1] A Reliability Coordinator is a NERC-approved entity with the highest level of authority responsible for the reliable operation of the bulk electric system and has oversight of operating parameters beyond that of an individual transmission operator, including the calculation of Interconnection Reliability Operating Limits.

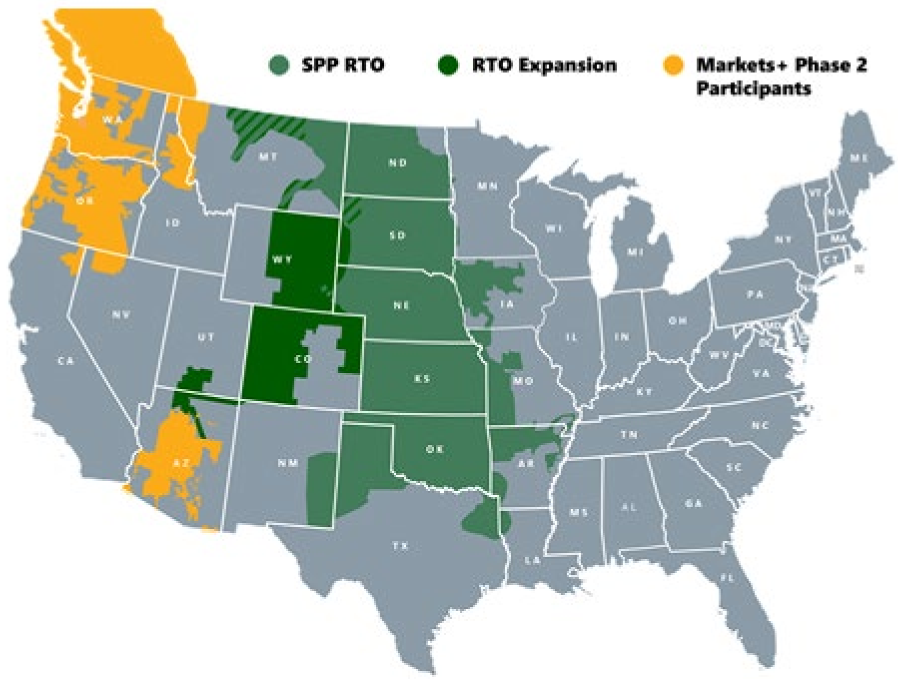
[2] *See* Grid Strategies and Western Resource Advocates, *Managing Seams: Market Coordination in Western Wholesale Energy Markets* (August 2025), https://gridstrategiesllc.com/wp-content/uploads/WRA-GS-Seams-Report.pdf (GS/WRA Seams Paper). *See also* Salt River Project Comments, Docket No. ER24-1658-000, at 8 (filed April 25, 2024); Interwest/NIPPC Comments, Docket No. ER24-1658-000, at 8-9 (filed April 29, 2024); Tucson Electric Power Company Comments, Docket No. ER24-1658-000, at 9 (filed April 29, 2025); Renewable Northwest Comments, Docket No. ER24-1658-000, at 4-8 (filed April 29, 2025); Western Power Trading Forum (WPTF), Docket No. ER24-1658-000, at 11 (filed April 29, 2025).

Figure 1: WEIM and EDAM Expected Footprints



Source: https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx

Figure 2: SPP RTO West Expansion and Markets+ Phase 2 Participants



Source: https://spp.org/western-services/marketsplus/

These seams can create operational and reliability hurdles that arise from several related issues: overlapping transmission ownership and rights, differences in transmission modeling, and congestion caused by loop flow.[3] The same issues could diminish the economic benefits of EDAM, WEIM, and Markets+ by limiting the ability to trade across markets. Although, on its own, the economically optimized commitment and dispatch of the new, expanded centralized markets are likely to bring economic benefits to the region, reducing barriers to trading across market and balancing authority (BA) borders could create further efficiencies.

[3] *See* GS/WRA Seams Paper at 2, 13, 14-15 (discussing flow-based modeling). WPTF and Public Generating Pool, *Exploring Potential Seams Issues Between Proposed Western Day-Ahead Electricity Markets* at 42-43 (January 2024), https://www.wptf.org/files/Western_Day-Ahead_Seams_Exploration_FINAL_240116.pdf (discussing flowgate modeling) (WPTF/PGP Seams Presentation). *See also* Bonneville Power Administration (Bonneville) Comments, Docket No. ER23-2686-000, at 10-11 (filed Sept. 21, 2023); Public Interest Organizations Comments, Docket No. ER23-2686-000, at 7-9 (filed Sept. 21, 2023); Bonneville Comments, Docket No. ER24-1658-000, at 6 (filed April 29, 2024); Public Interest Organizations Comments, Docket No. ER24-1658-000, at 22-24 (filed April 29, 2024); PacifiCorp Comments, Docket No. ER24-1658-000, at 3-4 (filed April 29, 2024) (discussing flowgate-modeling); Tucson Electric Power Company Comments, Docket No. ER24-1658-000, at 9 (filed April 29, 2025); Renewable Northwest Comments, Docket No. ER24-1658-000, at 10-11 (filed April 29, 2025); Western Power Trading Forum (WPTF), Docket No. ER24-1658-000, at 11-12 (filed April 29, 2025); Powerex Comments, Docket No. ER24-1658-000, at 8, 21-22 (April 29, 2024) (discussing contract path modeling).

In the East, various seams agreements address interchange along three categories: congestion management, reliability, and economic market transactions. The history of their development is described in **Section II**. While seams coordination among eastern RTOs/Independent System Operators (ISOs) provides precedent for how to address seams issues, key structural differences between the eastern RTOs/ISOs and Western centralized markets limit direct applicability of those solutions to the developing markets in the West. For example, in the East, RTOs/ISOs operate as single BAs and as transmission providers/operators; in the West, participants in EDAM and Markets+ will not transfer functional control of their transmission systems to the market operator, and BAAs remain distinct rather than consolidated; some BAs will not join a centralized market at all. Therefore, seams agreements in the West could entail more parties, including market operators, BAs, federal power marketing administrations, public power entities, and governmental entities, and alignment across multiple OATTs and market protocols.

Two efforts to advance seams coordination in the West are already underway. First, RC West and SPP RC have advanced a North American Energy Standards Board (NAESB) proposal to expand procedures and tools for managing unscheduled flows, with explicit treatment of System Operating Limits and Interconnection Reliability Operating Limits.[4] Second, SPP's Markets+ Seams Working Group is developing Markets+ seams concepts with adjacent markets and non-participating BAs, including cross-market scheduling, outage and model coordination, interchange and dynamic transfer treatment, and minimum data-exchange transparency. The current status of cooperation and coordination on seams issues in the West is described in **Section III**.

This paper concludes in **Section IV** with a survey of Commission staff's view of key issues for coordination by market operators and others in the West, organized into three overlapping categories based on the EDAM and Markets+ market designs and implementation approaches. These categories are: (1) modeling of transmission availability and use in the West; (2) coordination to maintain reliability and manage congestion; and (3) coordination to enhance economic benefits of transactions across regions.

With respect to transmission modeling, Commission staff observes that transmission availability in the West is still primarily modeled based on contract paths rather than the flow-based modeling used in the East.[5] The continued use of contract-path based modeling and the use of different modeling methodologies may complicate efforts to maintain reliability, mitigate congestion, and enhance economic benefits in the Western Interconnection. Western entities could therefore investigate whether adopting flow-based modeling across the entire West could aid West-wide coordination.

[4] NERC defines a System Operating Limit as "All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post Contingency operating states." In effect, a System Operating Limit is the most restrictive value—such as voltage, current, or megawatt flow—that ensures the Bulk Electric System remains within acceptable reliability criteria under specified operating conditions. An Interconnection Reliability Operating Limit, by contrast, is a System Operating Limit that "if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System." *See* Glossary of Terms Used in NERC Reliability Standards, NERC, Updated July 10, 2025.

[5] The contract path, sometimes also referred to as rated path, methodology is generally used in transmission systems characterized by sparser density and greater distances between source and sinks—including most of the Western Interconnection.

Second, coordination to maintain reliability and manage congestion are inherently tied. Because EDAM and Markets+ participants will not transfer functional control of their transmission systems or consolidate BAAs, schedules cleared in one market can produce parallel-path (loop) flows[6] over facilities outside that market's footprint, creating congestion. Such congestion could have reliability impacts in the form of reduced transfer capability and, under stressed conditions, potential impacts on System Operating Limits and Interconnection Reliability Operating Limits, which could in turn result in curtailments or redispatch, creating economic impacts as well.

Third, coordination to enhance economic benefits may take different forms in the West than in the East. Material efficiencies can be realized by reducing the costs to participate in the centrally cleared markets. Transaction costs could be mitigated by establishing clear and consistent participation and scheduling rules at market interfaces and standardizing data interfaces and definitions for transmission availability, scheduling rights, and transactions across borders.

II. History of Seams Coordination in the Eastern Interconnection

Interchange between two BAs is composed of multiple, distinct wholesale interchange transactions. The framework for scheduling and tracking these transactions originates from efforts in the 1990s to promote open access and competition in wholesale generation markets, including the Energy Policy Act of 1992 and Order Nos. 888 and 889. As these markets developed, generation owners, load-serving entities, and marketers arranged for bilateral commercial agreements to transfer electricity across increasingly long distances, requiring arrangement of transmission service from multiple transmission providers. To facilitate these arrangements and minimize unintended third-party consequences, industry representatives developed standards to coordinate interchange transactions across BAAs. Today, these standards are maintained by NAESB and incorporated by reference in the Commission's regulations.[7]

As described in the NAESB standards, the implementation of an interchange transaction starts with a system operator or market participant submitting to the sink BA a request for interchange that includes the financial and physical contract path of the interchange transaction. The sink BA confirms the transaction will not create a reliability issue, and an e-Tag is created to record information on the transaction.

An e-Tag is also used to manage changes to the interchange schedule. Parties to the transaction may request changes to the interchange schedule for economic or reliability reasons. RCs and BAs may also request changes to the interchange schedule. For RCs, the need stems from a fundamental feature of any integrated transmission system: electricity does not travel exactly along the physical path defined in a commercial contract and, as a result, may inadvertently create reliability risks on a transmission facility not at issue in the contract. This feature means that interchange transactions could have a detrimental effect on a transmission facility not directly along the transaction path

---

[6] Loop flow is an unintended or unscheduled flow of electricity through a line or system.

[7] 18 CFR § 38.1 (2025). *See* NAESB, WEQ-004 Standards and Models Relating to Coordinate Interchange Version 004 (July 31, 2023); *see also* Reliability Standard IRO-006-EAST-2 (TLR Procedure for the Eastern Interconnection); *see also* NERC, *Transmission Load Relief (TLR) Procedure*, https://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx.

when the transactions cause electricity to approach or exceed the facility's limit (producing transmission congestion). Although a system operator can mitigate some of this transmission congestion by taking actions within its BAA, sometimes the system operator must request interchange schedule adjustments to maintain reliable operations.

Historically, in the Eastern Interconnection, RCs addressed transmission congestion due to interchange through the Transmission Loading Relief process by using the Interchange Distribution Calculator.[8] Overall, the Transmission Loading Relief process determines the appropriate remedial actions to address the reliability risk. Specifically, the Interchange Distribution Calculator identifies transactions contributing to the congestion and prescribes schedule changes, such as curtailments, which will affect the desired flow change.[9] The cost of redispatch and curtailment is not considered in the Interchange Distribution Calucator.

A. Centralized Markets with Economic Dispatch

The expansion of centralized markets with economic dispatch in the 2000s marked a departure from the traditional point-to-point bilateral transaction model both financially and physically.[10] The financial aspect of transmission service changed when buyers and sellers were allowed to participate in a centralized RTO/ISO market rather than enter individual bilateral transactions. Participants in a centralized market do not need to transact with specific counterparties. Instead, they make bids and offers for electricity and rely on the system operator to calculate the market price they receive or pay based on the least-cost solution to reliably serve load. This least-cost approach creates opportunities for cost savings because, when technically feasible, the system operator can replace expensive resources with lower-cost ones from across the market footprint.

In RTOs/ISOs, the physical aspect of transmission service also changed, because transmission customers could receive network transmission service across a much larger footprint made up of several transmission owners' lines with a single operator. Transmission customers with network service do not need to submit a request for interchange or receive an e-Tag, unless they elect to do so. Instead, they rely on the system operator to deliver electricity where needed via economic dispatch and manage transmission congestion through generator redispatch. In centralizing the decision-making for system operations, this approach provides the system operator with improved situational awareness and additional remedial actions to manage any reliability concerns.

These changes have had profound, albeit unintended, implications for interchange transactions. For example, when multiple, previously distinct control areas join a centralized RTO/ISO market, they are aggregated into a single control area, which reduces the granularity of the Interchange Distribution Calculator and, thus, its efficacy. The reduced granularity occurs because, while the

---

[8] The Interchange Distribution Calculator was created in 1998 to allow RCs in the Eastern Interconnection to calculate the transmission distribution factor of interchange transactions over flowgates. The Interchange Distribution Calculator includes information on all interchange transactions and a matrix of transmission distribution factors. As discussed below, RCs in the Western Interconnection use the Enhanced Curtailment Calculator instead of the Interchange Distribution Calculator.

[9] *See* NAESB, WEQ-008 Transmission Loading Relief (TLR) – Eastern Interconnection, version 004, (July 31, 2023).

[10] Bilateral point-to-point transactions are still possible in centralized markets. For this white paper, centralized markets are wholesale electricity markets that clear through a security-constraint economic dispatch algorithm (historically RTOs/ISOs, currently RTOs/ISOs and the developing western markets described above).

Interchange Distribution Calculator can identify all source and sink transactions that contribute to a system constraint and specify schedule changes to be made that will affect the change in flows, it cannot specify source and sink locations in providing relief. Instead, it relies on a consolidated representation of generators and load within a control area. Thus, the RTO/ISO market control area aggregation limits the number of control areas the Interchange Distribution Calculator can use as proxies for generation and load impacts on constraints. This loss of granularity leads to a failure to effectively predict energy flow.[11] The modeling challenge is further complicated because network transactions no longer require an e-Tag and are not automatically reported to the Interchange Distribution Calculator. Fewer transactions with e-Tags degrade the quality of input data and further reduce the ability of the Interchange Distribution Calculator to estimate real power flows and identify schedule changes for constraint relief.

Another result of RTO/ISO formation was that market participants could export or import electricity between RTO/ISO markets based on market prices. Exports and imports could be scheduled in various ways including using self-scheduled point-to-point transmission service or using network (or related) service for exports/imports cleared in the market.[12] Regardless of how these transactions were scheduled, the ability to trade electricity between two regions that used locational marginal prices (LMPs) created opportunities and risks for market participants. In RTOs/ISOs, market participants have the opportunity to profit if the interchange transaction arbitraged price differences between regions, but face risks of loss through market price exposure, even for self-scheduled transactions.

B. History of Coordination Among Centralized Markets

The Commission discussed the importance of inter-market coordination in its foundational orders such as Orders Nos. 888 and 2000.

In Order No. 888, the Commission noted that technological advancement has allowed the utility industry to evolve beyond isolated grids within vertically integrated utilities' service territories to the possibility of "economic transmission of electric power over long distances at higher voltages,"[13] with increased coordinated transactions driving coordinated operations between utilities across greater distances.[14] The Commission included interregional coordination standards in Order No. 888's ISO Principle #10, which states that ISOs should "coordinate power scheduling with other entities['] operating transmission systems" as this coordination "is necessary to ensure provision of transmission services that cross system boundaries and to ensure reliability and stability of the

---

11 *See Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC P 61,202, at P 4 n.5 (2007).

12 Interchange transactions may also require the market participant to self-schedule as a bilateral transaction, or to secure network transmission service for the import or export of electricity. When scheduling a dispatchable, or market-based, interchange transaction between two market regions, the market participant must clear both markets (as an export in one market and an import in the other). Each market region has a different approach for approving these schedules and offers different types of schedules, some of which are discussed below.

13 *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,641 (1996).

14 *See id.*

system."[15] At the time, the Commission allowed ISOs and transmission operators to determine the appropriate mechanism for that coordination.

In Order No. 2000, the Commission strengthened the role of the RTOs/ISOs in interregional coordination by affirming that RTOs have exclusive authority to maintain the short-term reliability of the grid they operate, including receiving, confirming, and implementing all interchange schedules.[16] The Commission also mandated interregional coordination.[17] The Commission argued that "coordination of activities among regions is a significant element in maintaining a reliable bulk transmission system and for the development of competitive markets."[18] As a part of this mandate, RTOs must coordinate activities with other adjacent regions regardless of whether they are an RTO. The Commission also noted that while RTOs do not need to have uniform practices, they must coordinate practices to ensure "market activity is not limited because of different regional practices."[19]

As RTO/ISO development continued in the Midwest following Order No. 2000, the Commission maintained an active role in addressing seams issues through technical conferences and a series of orders.

The Commission convened the first technical conference on these issues in mid-2001[20] and the Commission noted that seams issues arose as different RTO practices and rules created friction for scheduling interchange transactions between regions. The Commission acted when a particularly complex seam was proposed in the late 1990s. Several utilities in Illinois, Ohio, and Virginia (known as the Alliance Companies) filed for their own RTO, separate from Midwest Independent Transmission System Operator, Inc. (Midwest ISO), now known as Midcontinent Independent System Operator, Inc. (MISO). Shown as highlighted in **Figure 3** below, the proposed Alliance RTO was located between PJM Interconnection, LLC (PJM) to the northeast and MISO to the northwest (neither highlighted). The Commission denied this RTO application when accepting the RTO application for MISO, specifically citing seams issues, and instructed the Alliance Companies to explore membership in either MISO or PJM.[21]

---

[15] *See id.* at 31,732.

[16] *See Reg'l Transmission Orgs.*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 31,104 (1999).

[17] *See id.* at 31,167 ("Interregional Coordination: The Regional Transmission Organization must ensure the integration of reliability practices within an interconnection and market interface practices among regions.").

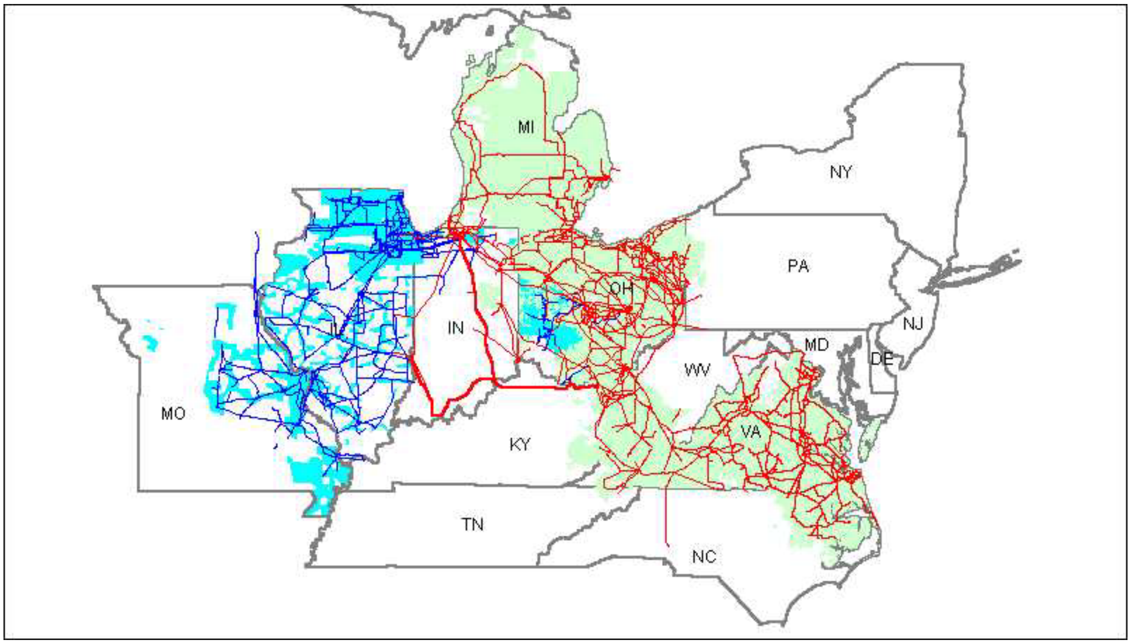
[18] *See id.*

[19] *See id.*

[20] Conference on RTO Interregional Coordination, Docket No. PL01-5-000, June 19, 2001.

[21] *See Alliance Cos.*, 97 FERC ¶ 61,327, at 13-15 (2001) (Alliance Order).

Figure 3: Proposed Alliance RTO Footprint[22]



After the Alliance Companies joined either MISO or PJM, the Commission continued to address the seam between PJM and MISO. Specifically, the Commission directed MISO and PJM to develop a Common Market by late 2004.[23] This effort eventually evolved into the Joint and Common Market agreement.[24] This associated Commission order included an investigation under section 206 of the Federal Power Act[25] and a requirement that MISO and PJM find a solution to rate pancaking along their seam (known as "through and out" rates).[26] The solution ultimately accepted by the

---

[22] The Alliance RTO was an RTO proposed in mid-1999 by Ameren, American Electric Power, ComEd, Consumers Energy, Dayton Power & Light, Detroit Edison, Dominion Virginia Power, FirstEnergy Corporation, and Illinois Power. Its original footprint comprised of the service territories of the filing parties (the Alliance Companies), and this map was provided by the filing parties. Notably, the Alliance RTO was proposed to sit between the then Midwest ISO and PJM.

[23] *See Alliance Cos.*, 100 FERC ¶ 61,137, at 61,527 (2002) (Joint and Common Market Order), *order on reh'g and clarification*, 103 FERC ¶ 61,274 (2003) (Joint and Common Market Rehearing Order).

[24] The Joint and Common Market (JCM) dates back to 2002, as highlighted in a PJM-MISO White paper from 2005. *See* PJM & MISO, *PJM-MISO Joint and Common Market White Paper* (July 2025), https://www.pjm.com/-/media/DotCom/pjm-jointcommon/cross-border/postings/20050715-pjm-miso-jointandcommon-white-paper.ashx. The Commission determined that the JCM had satisfied the requirement in the Alliance Orders in 2007, after which the meetings occurred less frequently with no meetings in 2010-11. Regular meetings restarted in 2012. In January 2015, the Commission hosted a meeting to help the then restarted JCM effort, which continues today with biannual meetings on various topics such as firm-flow entitlements, settlements, etc. *See Coordination Across the Midcontinent Independent System Operator, Inc. PJM Interconnection, L.L.C. Seam*, 150 FERC ¶ 61,132 (2015).

[25] 16 U.S.C. § 824e.

[26] *See* Alliance Order, 97 FERC ¶ 61,327 at 61,529.

Commission was the PJM-MISO Joint Operating Agreement[27] and the elimination of through and out rates between PJM and MISO.[28]

C. The Development of Seams Coordination Agreements in the Eastern Interconnection

In the subsequent years, RTOs/ISOs, BAs, transmission providers, and RCs developed similar and additional agreements to govern, and sometimes facilitate, coordination of interchange in the Eastern Interconnection. The nature and specifics of these agreements vary. Generally, they address interchange for the purpose of congestion management, reliable operations, and market transactions.

Joint Operating Agreements (JOAs) between centralized markets are the most expansive agreements, typically covering all aspects of interchange and the necessary information sharing. Examples of information specified in JOAs include limits on flowgates,[29] forecasted interchange schedules and prices, actual flows on coordinated flowgates, telemetry points, interconnection facility ratings, information on each transmission system, Energy Management System models, and scheduled or actual outages of transmission and generation. Most JOAs include general principles or specific procedures on how to effectuate the three interchange purposes, but they can vary.

First, on congestion management, JOAs typically include congestion management agreements such as the Congestion Management Process and the market-to-market process seen in the MISO-PJM and MISO-SPP JOAs. The Congestion Management Process (CMP) generally describes the market-to-non-market coordination process system operators use when congestion arises along the seam between their systems. A CMP agreement can include descriptions of how to calculate and monitor flows, when actions such as calling a Transmission Load Relief are necessary, coordination agreements around available transfer capability (ATC) and Firm Flow Entitlements, and other congestion-related operational details. The market-to-market agreements build off the CMP and describe the data needs, market-to-market specific flowgate capabilities, and settlement process for managing redispatch to relieve congestion between two LMP-based systems.

Second, to ensure reliable operations, JOAs often have provisions on emergency energy flows. These sections typically contain generic language requiring the signatories to follow 'good utility practice' when market operators request emergency energy from an adjacent BA, and the terms of reimbursement for flowed power.

Third, on market transactions, JOAs can outline interregional market transaction processes such as Coordinated Transaction Scheduling. Coordinated Transaction Scheduling is used between PJM and MISO, PJM and the New York Independent System Operator (NYISO), and NYISO and ISO New England (ISO-NE) to economically coordinate transactions across borders by evaluating

---

[27] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,251, *order on reh'g and clarification*, 108 FERC ¶ 61,143, *order on clarification and denying reh'g*, 109 FERC ¶ 61,166 (2004).

[28] *Midwest Indep. Transmission Sys. Operator, Inc.*, 104 FERC ¶ 61,105, *order on reh'g*, 105 FERC ¶ 61,212 (2003); *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,262, at PP 6, 19, 23 (2004).

[29] NAESB defines a flowgate as a mathematical construct, comprised of one or more monitored transmission facilities or contingency facilities, used to analyze the impact of power flows on the Bulk Electric System. *See* NAESB, WEQ-000-2 Definition of Terms (defining flowgate).

interface bids using market data from both regions and scheduling interchange transactions on 15-minute intervals shortly before real-time. The scheduling system was adopted between PJM and NYISO in 2014, NYISO and ISO-NE in 2015, and PJM and MISO in 2017. Coordinated Transaction Scheduling is the only method of scheduling real-time market interchange transactions between NYISO and ISO-NE for the primary AC interface, while it is optional for the PJM/MISO and PJM/NYISO interfaces.

Other seams coordination agreement types can be narrower in scope than JOAs, such as specifying procedures for just one aspect of interregional flow management (e.g., congestion management or reliable operations). Reserve sharing agreements blend both congestion management and reliable operations. They typically identify seam flowgates or contract paths that may experience congestion during tight conditions and administratively cap their transfer capability to preserve capacity to transfer their pooled reserves during stressed conditions. Examples include the Tennessee Valley Authority (TVA) and Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) Reserve Sharing Group, Northeast Power Coordinating Council, Inc. Reserve Sharing Agreement, and VACAR Reserve Sharing Group. Emergency energy agreements, similar to the emergency energy provisions in JOAs, are primarily about reliable operations. Examples include the MISO/TVA and MISO/Southern Company (SOCO) emergency energy agreements.[30] Table 1 shows the variety of seams coordination agreements in the East.

[30] Other interregional coordination agreements describe higher level coordination activities such as regional transmission planning instead of operational procedures like JOAs. One example is the ISONE-PJM-NYISO Interregional Coordination Agreement. On the other hand, cost sharing agreements may cover specific infrastructure at or near a seam where two entities have a joint interest (typically through joint investment). These identify the entity responsible for management or outlines joint management procedures. Examples include the SPP-AECI Morgan Transformer Project and Wolf Creek-Blackberry 345kV Project agreements.

Table 1: Examples of Seams Coordination Agreements in the Eastern Interconnection

RTO/ISO/BA	Agreement	Agreement Components					
		TLR[31]	M2M[32]	CMP	CTS	Emergency Energy[33]	Reserve Sharing
PJM-NYISO	JOA	Yes	Yes	Yes	Yes	Yes	No
PJM-MISO	JOA	Yes	Yes	Yes	Yes	Yes	No
MISO-SPP	JOA	Yes	Yes	Yes	No	Yes	No
PJM-Duke Energy Progress	JOA	Yes	No	No	No	Yes	No
SPP-AECI	JOA	Yes	No	No	No	Yes	No
NYISO-ISONE	Coordination Agreement	No	No	No	Yes	Yes	Yes
PJM-TVA-LG&E/KU	Joint Reliability Coordination Agreement	Yes	No	Yes	No	Yes	No
MISO-SOCO	Emergency Energy Agreement	No	No	No	No	Yes	No
MISO-TVA	Emergency Energy Agreement	No	No	No	No	Yes	No
LG&E/KU-TVA	Reserve Sharing Group	No	No	No	No	No	Yes
VACAR South[34]	Reserve Sharing Group	No	No	No	No	No	Yes

[31] Transmission Loading Relief (TLR). The procedure for TLR issuance in the East is described in the NAESB standards. *See* NAESB, WEQ-008-3 Eastern Interconnection Procedure for Physical Curtailment of Interchange Transactions and Tagged PTP Intra-BA Transactions and Assignment of GTL Relief Obligations. In this table, we note when an agreement explicitly references the TLR process either through description of the TLR process, how the agreement informs operators when determining when to call a TLR, or uses TLR data. In the Western Interconnection, congestion is managed through the Qualified Transfer Path Unscheduled Flow Relief procedures instead of the TLR-based process. *See* NAESB WEQ000-2 (Definition of Terms).

[32] Market-to-market.

[33] Emergency energy refers to energy transfers and purchases from the neighboring BA when the home BA is in an emergency condition. This energy is typically supplied from the excess generating capability of the neighbor (sometimes this explicitly includes reserve sharing. For the purpose of the reserve sharing column, if reserves are mentioned in the emergency energy language, then they will be considered 'reserve sharing' as well). The process for request and/or payment is usually described in Emergency Energy Agreements and JOAs.

[34] VACAR South members include Cube Hydro Carolinas, Duke Energy Carolinas, LLC., Duke Energy Progress, LLC., Dominion Energy South Carolina, Inc., South Carolina Public Service Authority (Santee Cooper).

III. Status of Seams Coordination in the Western Interconnection

As discussed in detail below, Western entities are taking important steps to coordinate transmission usage across markets. Many issues remain unresolved in these nascent coordination efforts, however. As one example, discussed below, enhanced congestion management has been proposed in NAESB and stakeholders are discussing seams, but the West currently lacks any cohesive, binding framework for transmission coordination.

A. NAESB Western Interconnection Unscheduled Flow Mitigation Plan

The Western Interconnection Unscheduled Flow Mitigation Plan was developed in the 1990s to address ongoing concerns associated with unscheduled, or off-path, flows for Qualified Transfer Paths within the WECC region.[35] The mitigation plan defines processes and procedures for the use of phase-shifting transformers and other qualified devices to address reliability-threatening circumstances on certain transmission lines in the Western Interconnection. Under the mitigation plan, WECC members who own facilities that can mitigate the effects of unscheduled flow can have those facilities qualified as Controllable Devices[36] and recover a portion of facility costs through annual dues paid by other WECC members. Since 2020, it has been administered by SPP.[37] It is administered using the Enhanced Curtailment Calculator (ECC) tool, which identifies the sources of unscheduled flow.

In an effort to improve coordination between RCs, BAs, and transmission operators, RC West and SPP RC have proposed improvements to the Western Interconnection Unscheduled Flow Mitigation Plan to NAESB.[38] NAESB's ECC Task Force,[39] which includes members from CAISO and SPP, issued a white paper in April 2024 outlining the shortcomings of the current state of unscheduled flow mitigation standards.[40] It concluded that BAs and transmission operators largely resolve unscheduled flow issues using their own individual methods. As a result, transmission customers in one region of the West may experience curtailments for different reasons than similarly situated customers in another region of the West because different curtailment methodologies are applied by individual BAs and transmission operators. The white paper argued that this lack of

[35] The Commission first approved the plan in 1995. *See S. Cal. Edison Co.*, 73 FERC ¶ 61,219. The current version of the mitigation plan was accepted by the Commission in 2016. *PacifiCorp* 154 FERC ¶ 61,189 (2016).

[36] A Controllable Device is an element (phase shifter, series capacitors, back-to-back DC, etc.) that can be used to mitigate the effects of unscheduled flow.

[37] SPP, *Western Interconnection Unscheduled Flow Mitigation Plan*, https://www.spp.org/western-services/western-interconnection-unscheduled-flow-mitigation-plan-wiufmp/.

[38] NAESB, *Request for Initiation of a NAESB Standard for Electronic Business Transactions or Request for Enhancement of a NAESB Standard for Electronic Business Transactions*, R24005 (September 13, 2024), https://www.naesb.org/pdf4/R24005.docx.

[39] The ECC Task Force consists of representatives nominated by the ECC Working Group, which is comprised of Western Interconnection stakeholders including the western reliability coordinators and qualified owners and operators.

[40] ECC Task Force, *White Paper: ECC Future State* (April 30, 2024), https://www.naesb.org/pdf4/R24005_attachment.pdf.

coordination creates uncertainty and limits transparency for customers on curtailment processes for transactions moving across the West.

In their request to NAESB, RC West and SPP RC incorporated the findings from the white paper into a proposal in September 2024 that the use of the ECC be expanded.[41] They explained that the main drawback of the existing process is that it is currently limited to only five qualified paths and it cannot be used to address unscheduled flows that impact various System Operating Limits in the Western Interconnection. They proposed that the ECC be enhanced and used for System Operating Limits and Interconnection Reliability Operating Limits across the West. The Wholesale Electric Quadrant (WEQ) Business Practices Subcommittee recommended this proposal to the NAESB Executive Committee, stating that it will provide the framework for establishing a standardized, flow-based methodology that uses real-time data to assign curtailment and relief obligation priorities to relieve constraints on transmission facilities.[42] The proposal includes issuing relief obligations on a pro rata basis while respecting transaction priorities for both tagged and non-tagged transactions. The recommendation was approved by the WEQ Executive Committee and next moves to the NAESB Executive Committee.[43] If approved by the NAESB Executive Committee, it will be filed at the Commission for incorporation by reference into the Commission's regulation, and thus, required for FERC-jurisdictional electric utilities.

B. Markets+ Seams Working Group

1. Overview

The Markets+ Seams Working Group (MSWG) was established in early 2023 under the Western Markets Executive Committee[44] to develop seams coordination principles and policies associated with SPP's proposed Markets+ day-ahead market. It was formed alongside other foundational bodies such as the Markets+ Tariff Task Force, Governance Design Team, and the Markets+ Operations Working Group, to address seams issues critical to the success of a regionally integrated market across the Western Interconnection, and like those other working groups, is composed of members representing various stakeholder interests.[45]

From its inception, the MSWG was charged with supporting the development of seams coordination frameworks and identifying potential seams-related tariff content. Early goals focused on harmonizing market interaction with external entities, transmission service coordination, and

---

[41] *See supra* note 38.

[42] NAESB, *WEQ Business Practice Subcommittee Recommendation to NAESB Executive Committee* (September 2, 2025), https://www.naesb.org/pdf4/weq_bps_WICM090225a1.docx.

[43] *See* NAESB, *WEQ Business Practice Subcommittee Recommendation to NAESB Executive Committee* (October 22, 2025), https://www.naesb.org/pdf4/weq_ec102225a2.docx.

[44] The Western Markets Executive Committee is the WEIS Participants' governing body under SPP's Western Joint Dispatch Agreement. Through designated working groups and task forces, it develops and recommends to the SPP Board policies, procedures, and system enhancements for SPP's administration of the WEIS; approves proposed WEIS Tariff amendments prior to filing; collaborates on protocols, business practices, and interregional agreements; advises on the WEIS administration budget; conducts dispute resolution; and may establish additional working groups/committees. Each WEIS Participant appoints one senior-level representative to the committee.

[45] MSWG/MRATF Minutes – May 16, 2023, at 1, https://www.spp.org/documents/69382/mswg%20mratf%20minutes%2020230516.pdf.

outlining resource sufficiency evaluation triggers and reliability requirements across seams. The group was also tasked with ensuring consistency and compatibility with external BAs and market operators such as CAISO, Bonneville, and WAPA.[46]

2. Scope, Evolution, and Current Activities

While the MSWG's responsibilities grew to encompass deep-dive scenario planning, the development of a "Seams Coordination Framework," and recommendations for prioritizing seams elements to be included in the initial Markets+ Tariff filing,[47] by mid-2024, the MSWG had adopted a more targeted and phased approach, categorizing seams issues into short-term items for immediate implementation and long-term seams enhancements.[48] This shift came as stakeholders called for clarified priorities, with stakeholders requesting that the group focus first on tangible seams barriers for the first day of operations rather than attempting to solve for every long-term regional coordination challenge at once.[49]

As part of this focus on initial operations, the MSWG evaluated how Markets+ might interoperate with CAISO's EDAM despite the separate design tracks. These activities included detailed discussions on redispatch coordination, transmission priority alignment, and interface bidding practices used in CAISO's EDAM proposal.[50] For example, in July 2024, the MSWG developed a "Seams Straw Proposal," outlining proposals to address pseudo-tie management, interchange coordination, redispatch across seams, and parallel flow mitigation.[51]

As of mid-2025, the MSWG remains an active body that continues to refine the seams coordination principles and policies it developed, often working in tandem with the Markets+ Tariff Task Force and Markets+ Resource Adequacy Task Force to incorporate finalized seams solutions into the Markets+ Tariff.[52] The MSWG continues to host regular meetings.

3. Participation by EDAM-Affiliated Entities

---

[46] Joint MDWG-MORWG-MTWG-MSWG Minutes – June 13-14, 2023, at 3, https://www.spp.org/documents/69575/mdwg%20morwg%20mtwg%20mswg%20joint%20minutes%2020230613-14.pdf.

[47] MSWG Minutes – September 12, 2023, at 2-3, https://www.spp.org/documents/70159/mswg%20meeting%20minutes%2020230912.pdf.

[48] MSWG Minutes – November 16, 2023, at 2, https://www.spp.org/documents/70619/mswg%20meeting%20minutes%2020231116.pdf.

[49] MSWG/MRATF Minutes – March 14, 2024, at 3, https://www.spp.org/documents/71328/mswg-mratf%20meeting%20minutes%2020240314.pdf.

[50] MSWG/MRATF Minutes – April 11, 2024, at 2, https://www.spp.org/documents/71492/mswg-mratf%20meeting%20minutes%20%2020240411.pdf.

[51] MSWG Meeting Materials (Seams Straw Proposal PowerPoint) – July 11, 2024. NERC defines a pseudo-tie as an energy transfer that is included in the sinking BA's net-interchange calculation, therefore contributing to the sinking BA's area control error. *See* NERC, *Glossary of Terms Used in NERC Reliability Standards* (July 10, 2025), https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf.

[52] MSWG Minutes – June 13, 2024, at 2, https://www.spp.org/documents/71829/mswg%20minutes%2020240613.pdf.

EDAM-affiliated entities, including CAISO and neighboring BAs have participated in MSWG discussions. Bonneville has engaged in seams-specific issues involving priority of service and redispatch, often bringing forward concerns drawn from its EDAM coordination experience.[53] CAISO has attended select MSWG sessions as an observer or contributor during discussions on transmission priority and market interoperability, especially during the design alignment workshops held in late 2024.[54] Several market participants who are active in both Markets+ and EDAM stakeholder processes (e.g., Avangrid, NV Energy, WAPA) have consistently advocated for cross-framework compatibility, and they have routinely raised issues such as curtailment coordination, interface bidding, and congestion management in MSWG settings.[55]

While CAISO does not have a formal membership role in the MSWG, its engagement, either directly or through active EDAM participants, has helped shape MSWG outcomes and supported coordination that reduces the risk of conflicting market operations.[56]

IV. Considerations for Western Market Seams Coordination and Development

Based on staff's analysis of the history of seams coordination in the East, the EDAM and Markets+ market designs, and issues raised by stakeholders and observers, Commission staff has identified three primary categories of issues that Western entities should consider addressing through seams coordination agreements. These categories are: (1) flow-based modeling versus contract path modeling; (2) coordination to maintain reliability and mitigate congestion; and (3) coordination to enhance economic benefits. These are not mutually exclusive, and some coordinated actions could address multiple goals.

A. Modeling of the Transmission System

Transmission availability in the West is still primarily modeled based on contract paths rather than the flow-based modeling used in the East.[57] Contract path modeling assumes power flows on contracted paths between sinks and sources. On the other hand, the flow-based, or flowgate, methodology uses actual power flows to calculate Available Transfer Capability (ATC), by defining and identifying key transmission facilities (i.e., the flowgates) and their physical parameters and limits. Because flow-based modeling uses actual power flows to model the transmission system, it is

---

53 MSWG/MRATF Minutes – May 9, 2024, at 3, https://www.spp.org/documents/71636/mwsg-mratf%20minutes%2020240509.pdf.

54 MSWG Meeting Minutes – November 7, 2024, at 3, https://www.spp.org/documents/72715/mswg%20meeting%2020241107.pdf.

55 MSWG Minutes – February 13, 2025, at 2, https://www.spp.org/documents/73325/mswg%20meeting%20minutes%2020250213.pdf.

56 MSWG Minutes – April 10, 2025, at 3, https://www.spp.org/documents/73676/mswg%20meeting%20minutes%2020250410.pdf.

57 The contract path, sometimes also referred to as rated path, methodology is generally used in transmission systems characterized by sparser density and greater distances between source and sinks—including most of the Western Interconnection.

generally considered to be more efficient and robust than the contract-path based methodology.[58] Moreover, the use of contract path and flow-based methodologies is inconsistent across the West.[59]

The continued use of contract path-based modeling and the use of different modeling methodologies may complicate efforts to maintain reliability, mitigate congestion, and enhance economic benefits in the Western Interconnection. Thus, before discussing more specific approaches to coordinating operations in the West, it is important to ensure that the transmission availability and usage metrics these markets rely on be modeled as consistently and accurately as possible. Adopting flow-based modeling across the entire West could aid West-wide coordination, as discussed below.

Moving from contract path-based modeling to flow-based modeling has been raised in several Commission proceedings. For instance, panelists at the Commission's Western Resource Adequacy technical conference, and commenters filing in response, encouraged the Commission to direct NERC to consider mandating the use of flowgate modeling to calculate ATC.[60] Western entities could consider whether the expansion of centralized markets has sufficiently changed transmission usage patterns and modeling needs such that it is appropriate to move to flow-based modeling across the region. While contract path-based modeling might have been appropriate in an ecosystem dominated by bilateral contracts and delivery, if the West moves towards more centrally cleared market commitments and dispatch, staff believes conditions may have sufficiently changed such that it may be time to change modeling methodologies.

Moving to flowgate modeling across the West could have two sets of potential benefits: (1) more accurate modeling of transmission availability; and (2) better coordination across seams during day-ahead and real-time operations by market operators and BAs.

First, the tools that load-serving entities use to ensure reliability, whether long-term power purchase agreements, short-term bilateral trading, or day-ahead and real-time optimized markets, are more economically efficient when based on more accurate modeling. EDAM and Markets+ will both rely on transmission made available by market participants rather than by transmission owners ceding functional control of their systems. Flow-based modeling of ATC could provide a more accurate view of how much transmission is actually available to allocate between the markets compared to the results of contract path-based modeling prior to the actual day-ahead and real-time market runs.

---

[58] *See* Hung-po Chao, Stephen Peck, Shmuel Oren, & Robert Wilson, *Flow-Based Transmission Rights and Congestion Management*, 13 Elec. J. 8 (2000).

[59] For example, BPA uses the flowgate methodology in certain operational circumstances. *See* WECC, *Path Concept Whitepaper*, at 19-21 (2013), https://www.wecc.org/Administrative/Path%20Concept%20Whitepaper_PCC.pdf. APS and Salt River Project have recently converted their ATC methodologies to the flowgate methodology. *See Ariz. Pub. Serv. Co.*, 181 FERC ¶ 61,215 (2022); Salt River Project, OASIS Posting (October 1, 2024), https://www.oasis.oati.com/SRP/index.html. Tucson Electric Power Company also intends to convert to the flowgate methodology. *See* Tucson Electric Power Company, OASIS Posting (July 17, 2025), https://www.oasis.oati.com/tepc/.

[60] *See Technical Conference to Discuss Resource Adequacy in the Western Interconnection*, Docket No. AD21-14-000, June 23 Tr. at 40-41 (Alice Jackson). *See* APS/PSCo Comments, Docket No. AD21-14-000, at 5-7 (filed Jan. 31, 2022). We note that in 2021, the Commission approved the transfer of responsibility of ATC-related standards from NERC to NAESB in Order No. 676-J. *Standards for Business Practices and Communication Protocols for Pub. Utils.*, Order No. 676-J, 175 FERC ¶ 61,139 (2021).

Western entities could investigate whether this would ease longer-term transmission expansion needs and make more transmission available for day-ahead and real-time market optimization.

Second, in terms of coordination benefits when the markets run optimizations, flow-based modeling in the East has made seams coordination more effective. For example, market-to-market coordination between PJM and MISO using flow-based modeling jointly manages flowgates affected by both markets. By sharing real-time grid topology, outage, and dispatch data to co-optimize congestion management at the seam, market operators ensure that resources on both sides of the seam are efficiently dispatched to relieve congestion. The commitment and dispatch optimizations used in EDAM/WEIM and Markets+ will use flow-based modeling and a real-time view of network flows informed by a state estimator showing real-time flows. BAs that do not participate in one of the day-ahead markets could be scheduling their day-ahead use of transmission based on contract paths. Thus, there could be an inherent conflict between the centralized market operators and BAs in the West if they inconsistently model the network and estimate flows using different methodologies resulting in, at a minimum, inefficient coordination across seams.

B. Coordinating Interchange for Reliability and Congestion Management

Coordinating interchange is a key tool in maintaining reliability and managing congestion. While these issues are deeply intertwined, in this section we separately highlight considerations for crafting agreements on reliability separately from considerations for crafting agreements on congestion management.

1. Reliability

Transferring electricity between BAs can be essential to maintaining system stability during critical conditions as seen during Winter Storms Uri and Elliott.[61] Agreements that formalize interchange procedures during critical system conditions between markets, as well as those between markets and non-markets, have generally provided greater certainty to system operators and improved cooperation between BAs. These include agreements such as emergency energy agreements, reserve sharing arrangements, and JOAs discussed in **Section II-C**. Coordination to maintain reliability will involve not just individual BAs, but also structured protocols among RCs, market operators, and transmission providers. Western entities should consider the degree to which these types of reliability agreements address:

(1) data and model coordination;
(2) protocols during emergency events; and
(3) loop flow management.

---

[61] *See* FERC, NERC and Regional Entity Staff, The February 2021 Cold Weather Outages in Texas and the South Central United States 182 (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and; *see also* FERC, NERC and Regional Entity Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott 125 (Oct. 2023), https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.

Data and model coordination may involve things such as aligning network models and outage coordination (topology, facility ratings, flowgates/nomograms, and contingency definitions) to support accurate studies and coordinated corrected actions. It could also include making e-Tag practices visible to all market operators involved in the scheduled transaction path, and joint drills and post-event reviews to validate data quality and continually improve procedures.

Protocols during emergency events for RCs, BAs, and market operators can help to ensure common situational awareness, consistent management of operating limits, and interoperable emergency procedures. For RCs, these protocols can include establishment of RC-to-RC communication triggers and authority for redispatch, curtailments, and temporary operating instructions when System Operating Limits or Interconnection Reliability Operating Limits are approached or exceeded. For BAs and market operators, reliability protocols could harmonize emergency assistance constructs[62] so that needed electricity can flow across market seams without delay and clarify curtailment priorities and schedule treatment where firm OATT rights (including WRAP scheduling requirements) intersect with market flows and unscheduled flow mitigation tools. They may also include coordinated ramp management at interties.

Specifically for loop flows, because EDAM and Markets+ participants will not transfer functional control of their transmission systems or consolidate BAAs, schedules cleared in one market can produce loop flows over facilities outside that market's footprint, creating congestion. This congestion can introduce reliability concerns such as reduced transfer capability and, under stressed conditions, potentially impact System Operating Limits and Interconnection Reliability Operating Limits.

2. Congestion Management

Congestion management is not a new problem, and while the need to manage congestion exists even without centrally cleared RTO/ISO markets, the expansion of centralized markets in the West introduces new challenges and opportunities for managing congestion between markets areas as well as between markets and non-markets. Particularly in the West, loop flows caused by schedules in an adjacent market could also cause congestion that could extend beyond EDAM and Markets+, including across Bonneville and WAPA systems.

For general congestion management, data consistency and accuracy are paramount. RCs, BAs, and market operators must effectively communicate and share data that all parties can use. This could be achieved through agreements and tools that define and provide data specifications and exchange frequency.[63] As an example of a successful data tool from the East, updating the Interchange

---

[62] *E.g.*, Energy Emergency Alert declarations, reserve definitions, scarcity pricing triggers, and emergency energy transactions.

[63] Relevant data include real-time telemetry, state-estimator outputs, net scheduled interchange (including dynamic schedules), resource status/commitment, forecasted variable energy resources output and net load, Remedial Action Scheme status, and planned/unplanned outages.

Distribution Calculator to include the Parallel Flow Visualization tool[64] has been seen as greatly beneficial by providing real-time flow data across RCs, including non-market areas.[65]

As discussed above, a similar tool to enhance the ECC is under consideration in the West. This NAESB initiative, advanced by RC West and SPP RC, is intended to expand common procedures and tools for unscheduled-flow mitigation and congestion coordination. In its recommendation to the NAESB Executive Committee, the WEQ Business Practices Subcommittee states that this proposal will establish a standardized, flow-based methodology that uses real-time data to assign curtailment and relief obligation priorities to relieve constraints on transmission facilities.[66]

Market-to-Market Coordination

While congestion management procedures exist for both markets and non-markets, congestion management processes can use the granularity of pricing data unique to market areas. In the East, this process is known as market-to-market coordination. Market-to-market coordination facilitates more efficient redispatch to mitigate congestion at the lowest possible cost by using market pricing data between two RTOs/ISOs. This process between RTO/ISO market regions in the East has provided significant economic benefits and supplanted the need to use less precise tools like Transmission Loading Relief. As a result, incorporating market pricing data into the ECC tool, or otherwise accounting for price differences across seams in curtailment decisions, could provide greater benefits in the West.

There are two important considerations when implementing market-to-market agreements, as experienced in the East. The first is that, while market-to-market agreements have improved the efficient management of congestion between markets, this system does not cover flows where LMPs are not calculated (i.e., for flows to/from non-market regions). The West will have a mix of BAs participating in both day-ahead and real-time markets, only real-time markets, and no centrally cleared market. For transactions between market and non-market regions, tools such as Parallel Flow Visualization have provided better awareness for operators in the East by providing near real-time generation and load data to calculate flows on flowgates, as the ECC does for certain flowgates in the West. Additionally, since the majority of Western BAs already participate in either WEIM or WEIS and real-time LMPs are calculated across the majority of the West, market operators and BAs could evaluate how this pricing information could be put to use in market-to-market coordination.

Second, establishing a fixed date for calculating firm flow entitlements continues to impact the total economic benefits of the market-to-market process. Firm flow entitlements are defined by historical

---

[64] The Parallel Flow Visualization tool is an enhancement to the Interchange Distribution Calculator that provides real-time data (including topology, outages, load, generation output, and load forecasts) to calculate Generation-to-Load impacts for generators in the Eastern Interconnection. Generation-to-Load impacts are the contributions to congested flowgates from flows from generators to serve load.

[65] *See, e.g.*, *PJM Interconnection L.L.C.*, Transmittal, Docket No. ER22-1163-000, at 4 (filed Mar. 2, 2022) ("the [parallel flow visualization] approach that has long underlay the "Market Flow" calculations will now… be more uniformly adopted for parallel flow calculations."); *see also* PJM Interconnection, L.L.C., *Parallel Flow Visualization*, 4 (2022), https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/pjm-miso-joint-common/2022/20220829/item-02-idc-update-presentation.pdf; *see also* MISO, *Freeze Date Project Update*, 3 (2024), https://cdn.misoenergy.org/20241115%20MISO%20SPP%20CSI%20Item%2003b%20Freeze%20Date%20Update%20(SPP)661161.pdf.

[66] *See supra* note 42.

flows. In some Eastern seams coordination agreements, that historic date is fixed and, thus, firm flow entitlements are fixed.[67] In contrast, some agreements include an established methodology for updating firm flow entitlements by continually updating the model to a more recent year.[68] By establishing firm flow entitlements as fixed values based on transmission system usage for a specific date, entitlements could eventually become outdated as the transmission system changes in terms of supply resource interconnection, load growth and interconnection, transmission expansion, or changes to BAAs and market footprints.

C. Coordinating Electricity Transfers for Cost Savings

Coordination to enhance the benefits of more economically efficient transfer of electricity across regions could take different forms in the West compared to the East because eastern constructs for economic interchange might not be directly transferrable to the West. While the Eastern RTOs/ISOs have implemented tools to coordinate electricity transfers across their borders more economically, EDAM and WEIM rules may impact the benefits that coordination could achieve in the West. Specifically, current EDAM and WEIM market rules allow participating BAs to decide whether they will allow non-resource specific economic bidding at their interties with non-participating BAs. In the Markets+ day-ahead market design, intertie economic trading will be implemented along its seam with neighboring transmission systems. In this framework, market participants are able to submit buy bids and sell offers for imports and exports as part of the day-ahead scheduling process, provided they secure the required transmission rights.[69] The day-ahead market clearing engine in Markets+ centralizes the clearing of these day-ahead seams transactions using price signals and system conditions to dispatch imports or exports alongside internal generation and load. This Markets+ intertie trading platform could facilitate more economically efficient trading across its seams.

Implementing coordinated economic trading or interchange optimization[70] on the border of Markets+ and CAISO's EDAM and WEIM could further enhance economic benefits from interchange. There are different ways interchange could be implemented, each with its own challenges and potential benefits. Again, the Eastern seams coordination agreements provide insight into how other centralized markets have addressed these challenges. In general, each coordination agreement has certain data requirements, forecasting challenges, and latency in the optimization process.

The most basic way the market operators could coordinate transactions is via standard intertie import and export bidding rules already used at RTO/ISO seams. This would require non-CAISO EDAM BAs to allow non-source specific economic import bids at their borders. Under this

---

[67] *See* PJM, Interregional Agreements, MISO-JOA, attach. 2, § 6.4 Calculating Historic Firm Flows (0.1.0); *see also* MISO, MISO Rate Schedules, Joint Operating Agreement MISO and SPP, attach. 1 Congestion Management Process (CMP) Master, § 6.4 Calculating Historic Firm Flows (31.0.0).

[68] *See* NYISO, NYISO Tariffs, NYISO OATT, § 35.23 attach. CC sched. D – M2M Coordination (9.0.0), § 6.1 (M2M Entitlement Topology Model and Impact Calculation).

[69] SPP, Markets+ Tariff, attach. A, § 4.3.1 (0.0.0).

[70] For clarity, 'interchange optimization' in this context means system operators using generation and transmission data, not traders' interchange-specific bids, to schedule economic interchange on the available remaining intertie capacity after traditional bilateral and self-scheduled transfers were accounted for. Some public reports use different terms (tie or intertie optimization, intermarket optimization, interchange optimization) for this general idea.

approach, a resource wishing to export from one market and import into the other would need to submit the relevant bids and offers and clear both markets. As such, the burden for arranging transactions is primarily on the market participant, who must submit bids and offers in both markets and take the risk of only one clearing.

Another way the market operators could coordinate interchange transactions is to allow market participants to submit price spread bids through a single portal, which is done between some markets in the East using Coordinated Transaction Scheduling. In this paradigm, market participants submit a bid that specifies a spread between neighboring markets' LMPs at which they would be willing to import/export. However, with the exception of the NYISO/ISO-NE interface, Coordinated Transaction Scheduling may be providing limited benefits where it has been implemented.[71]

It might also be possible for market operators to use a hybrid of the first two methods in the form of intertie bid optimization. In this model, market participants could submit separate export bids and import offers at external interfaces. Each region would then be able to incorporate the external biding information into their security-constrained unit commitment and economic dispatch optimizations, along with internal bids and offers. Market operators would then jointly dispatch these bids and offers accordingly based on least-cost principles until prices converge at interface pricing points or the limit of the flowgate is reached.

Finally, the market operators could also coordinate interchange transactions by implementing some form of interchange optimization.[72] Adopting an interchange optimization system between centralized markets has the potential of improving cost savings across the interconnection by reducing latency delay, non-economic clearing, and transaction costs.[73] Under such coordination, market participants would not submit separate import/export bids to transfer electricity between EDAM/WEIM and Markets+ interfaces. Rather, market participants would submit standard supply offers and demand bids to buy and sell electricity within their respective markets. Market operators would then use information on their own market and shadow prices, bids and offers, and/or

[71] *See* Potomac Economics, *2024 State of the Market Report for the MISO Electricity Markets,* 86 (2025), https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-MISO-SOM_Report_Body_Final.pdf (IMM 2024 SOM Report for MISO) ("CTS transactions remain a *de minimis* fraction of transactions at the PJM interface"); *see also* Potomac Economics, *2024 State of the Market Report for the New York ISO Markets,* 112 (2025), https://www.potomaceconomics.com/wp-content/uploads/2025/05/NYISO-2024-SOM-Full-Report_5-14-2025-final.pdf (IMM 2024 SOM Report for NYISO) ("The estimated production cost savings from the NY/NE CTS process totaled $43 million over the past five years, compared to just $3 million at the primary PJM interface.").

[72] *See* The Brattle Group, Intertie Optimization: Achieving Efficient Use of Interregional Transmission (Apr. 2025), https://www.brattle.com/wp-content/uploads/2025/04/Intertie-Optimization-Achieving-Efficient-Use-of-Interregional-Transmission.pdf (Brattle Intertie Presentation); *see also* The Brattle Group, The Need for Intertie Optimization (Oct. 2023), https://www.brattle.com/wp-content/uploads/2023/10/The-Need-for-Intertie-Optimization-Reducing-Customer-Costs-Improving-Grid-Resilience-and-Encouraging-Interregional-Transmission-Report.pdf (Brattle Intertie Optimization); *see also* SPP Staff Strategic Planning Committee Presentation, *Inter-Market Optimization Framework* (Oct. 8, 2024), https://www.spp.org/Documents/72497/SPC%20Meeting%20Materials_20241016_C.zip (SPP Inter-Market Optimization); *see also* Feng Zhao, Eugene Litvinov, and Tongxin Zheng, *A Marginal Equivalent Decomposition Method and Its Application to Multi-Area Optimal Power Flow Problems*, 29 IEEE Transactions on Power Systems 1 (Jan. 2014); *see also* ISO-NE and NYISO Staff, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (Jan. 2011), https://www.iso-ne.com/static-assets/documents/pubs/whtpprs/iris_white_paper.pdf.

[73] *See* Brattle Intertie Optimization at 3-4.

transmission constraint information in the neighboring market, depending on the specific implementation of interchange optimization.[74] With this information, each market operator would be able to optimize the bids and offers from its own resources but also use the available intertie capability as an additional resource.

Therefore, when developing cooperative economic interchange systems in the West, stakeholders should carefully consider several important implementation details.[75] In general, seams arrangements can enhance net economic benefits of interchange transactions by: (1) establishing clear and consistent participation and scheduling rules at market interfaces; (2) aligning bid windows, e-Tag visibility, ramp management, and settlement timelines; (3) harmonizing credit, collateral, and dispute-resolution provisions; and (4) standardizing data interfaces and definitions for transmission availability, scheduling rights, and loss treatment. The data required to effectuate economic interchange for market operators (in both interchange optimization and bid-based interchange) and market participants (in bid-based interchange) can vary widely depending on how the program is implemented. However, regardless of the method of interchange, ensuring the accuracy of the data is paramount to the effectiveness of the economic interchange.

V. Conclusion

The complex seams arising in the West from the expansion of Western markets presents challenges to operations, reliability, and the efficiency of the markets. To address these challenges, FERC staff believe it is important that Western entities continue their work coordinating operations to ensure the reliability and efficiency of their markets and BAs as Western markets proceed toward implementation and in advance of live operations. As highlighted above, key issues we recommend the parties address in seams coordination include: (1) modeling of transmission availability and use in the West; (2) coordination to maintain reliability and manage congestion; and (3) coordination to enhance the economic benefits of transactions across regions. We understand that these are difficult issues that will require time to address.

[74] *See, e.g.*, Brattle Intertie Presentation at 7 ("There is a range of implementation methods that could achieve a version of interchange optimization of varying complexity, some of which are summarized in this presentation.").

[75] An additional concern for consideration with interchange optimization is ensuring that the market clearing engine can produce a timely dispatch solution after incorporating the additional constraints and data needed to optimize flow over flowgates at the seam.