

Western Markets Exploratory Group

Seams White Paper

June 2023

Table of Contents

1	Executive Summary.....	3
1.1	Current State of WECC.....	3
1.2	Impacts from Regional Operations	4
2	Market Operations.....	8
2.1	Current Trading Activity between Markets	8
2.2	Recommendations for Efficient Transactions between Markets	12
3	Reliability.....	12
3.1	Current Reliability on the Transmission Grid.....	13
3.2	Reliability Seams Issues for WMEG.....	17
3.3	Reliability Seams Issue Recommendations.....	18
4	Transmission Planning	18
4.1	Planning Regions.....	18
4.2	Recommendations for Planning Regions	24
5	Transmission Service and Cost Allocation.....	25
5.1	Regional Tariffs	26
5.2	Transmission Service Seams Issues for WMEG.....	31
5.3	Transmission Service Seams Recommendations	31
6	Western Resource Adequacy Program (WRAP).....	31
6.1	WRAP Seams Issues	32
6.2	<i>WRAP Seams Recommendations</i>	33
7	Green House Gas.....	33
8	Summary of White Paper Findings.....	34
9	Abbreviations	35
	Attachment A.....	37

1 Executive Summary

The Western Markets Exploratory Group (WMEG) is a diverse group of electric services providers comprised of Investor Owned Utilities, Public Power Utilities, Municipal Utilities, Cooperatives and Federal Power Marketing Administrations, etc. located in the Western Electricity Coordinating Council (WECC) who are interested in reviewing the impacts that regional organizations, organized markets, Regional Transmission Organizations (RTOs), regional planning, regional tariff administration, and consolidating balancing authorities can have on neighboring markets and transmission systems. It appears likely that there will be several different markets, and market-related requirements, in the WECC over the next several years. Also, WMEG, or others, could form regional organizations to collaborate as above. The WMEG formed a Seams Task Force to review various Seams issues, learn how other regions are addressing these issues, and consider approaches for how these issues may be addressed as the WECC evaluates the potential transition to multiple regional organizations, market operators, and potentially RTOs.

This White Paper summarizes some of the key issues regional organizations encounter managing the Seams between market operators, transmission operators, and transmission providers. Each section discusses some of the benefits and challenges of these approaches. The Task Force members were not always in complete agreement on the best approach and those differences of opinion are captured in the associated sections.

This White Paper discusses possible approaches WMEG members could pursue during future regional organizational development efforts. It does not attempt to provide the exact approach nor language for Seams management. The White Paper does provide suggestions for criteria to use when developing efficient energy transactions between market regions, addressing reliability challenges, the need for coordination of market flows on the overall transmission systems, potential changes for regional and interregional transmission planning efforts, and the need to develop cost allocation for transmission projects. The Task Force also discussed many of the technical criteria that are part of a Joint Operating Agreement (JOA) between market operators, neighboring markets, and Balancing Authorities (BAs). The intermarket transactions and reliability coordination suggestions, along with the JOA discussions, may need to be brought forward into the two regional market development efforts underway, namely the California Independent System Operator (CAISO) managed Enhanced Day-Ahead Market (EDAM) and the Southwest Power Pool (SPP) managed Markets Plus (Markets+). The transmission planning and cost allocation discussions will likely involve a broader group of stakeholders and may be best handled in a different forum.

1.1 Current State of WECC

Most utilities operating in the WECC region manage their own balancing area. Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs), and Transmission Service Providers (TSPs) coordinate with each other to maintain reliable operations of the WECC transmission system. Many of the California entities are members of the California Independent System Operator (CAISO) tariff which manages regional markets and transmission activities. There are three regional transmission planning organizations in WECC: (1) CAISO; (2) NorthernGrid; and (3) WestConnect. The Western Resource Adequacy Program (WRAP) recently received Federal Energy Regulatory Commission (FERC)

approval of their tariff to begin operations, which could create further implications for entities operating in WECC.

The WECC has multiple energy markets currently in operation, a bilateral market, the CAISO, the CAISO managed Western Energy Imbalance Market (WEIM), and the SPP managed Western Energy Imbalance Service (WEIS) Market. Over the last several years, many WECC entities have started the transition to organized markets with their participation in the WEIM and WEIS. The SPP has also announced the expansion of their RTO to the West in April of 2026, with several WECC entities evaluating their commitment to join the SPP RTO West. The SPP RTO West is in addition to the two day-ahead regional market development efforts underway for EDAM and Markets+. It is anticipated that individual organizations and regional collaborations will change the footprints of the existing RCs, BAs, TSPs, WEIM, WEIS, and transmission planning regions as organizations transition from their current state to their desired final state.

1.2 Impacts from Regional Operations

The generation dispatch solution under an organized market structure will differ from the dispatch solutions individual utilities use today. The operator for an organized market, typically called a Market Operator (MOP), follows an extensive set of market rules to determine a least cost dispatch solution, which honors transmission limits, for the Market Participants (MPs). The market dispatch solutions will result in changes to flows on the transmission system for both members and non-members of the organized market. Some of the change in flows related to the market dispatch solutions may positively or negatively impact neighboring systems, which highlights the need for coordinating operations between neighboring systems.

The Federal Energy Regulatory Commission (FERC) has recognized that regional organizations may impact neighboring systems and has required entities to develop mechanisms to address interregional coordination. These issues can include such items as protocols for efficient market operations, reliable operations, transmission service and planning, and cost allocation. MOPs develop JOAs with neighboring systems that outline how best to work together and minimize potential negative impacts on each other's systems, how to facilitate the movement of energy between the entities, and how best to optimize the transmission systems for the benefit of all customers. The development of the JOA can take considerable time and effort to negotiate and may have a material impact on market operations and financial settlements between markets. It may be beneficial for the WMEG members to challenge SPP and CAISO with defining the JOA terms and conditions during the current market development efforts to ensure the final market structures and JOAs meet the intent of the market participants.

1.2.1 Market Operations

The MOP, working closely with their MPs, will create extensive market rules that will be memorialized through the development of market protocols. The MOP will follow these protocols to determine the market dispatch and resulting clearing prices. Organized markets generally have a price differential between adjacent markets. From time-to-time, this price differential may be substantial enough to support transactions between markets that can benefit both markets. The difficulty with moving energy between adjacent markets efficiently is that each market operates independently and non-synchronously and any transaction between them will be subject to market price volatility, various market charges, and potentially dissimilar market rules.

The Task Force reviewed two specific tools for transacting energy between organized markets. The first tool, which is the most widely used today, is the Coordinated Transaction Scheduling (CTS). The CTS tool is only used for transactions during the real-time market (RTM). The CTS tool is administered by adjacent MOPs who each provide **projected** RTM clearing prices for their market to aid MPs moving power between the two markets. The CTS transaction financially settles based on the **actual** RTM clearing price for each market. The MP takes the risk on the price movement and reaps the rewards when the price differential remains favorable. The second concept is Tie Optimization¹. This approach requires two adjacent MOPs to share incremental and decremental resource stacks directly with each other. Tie Optimization was studied for implementation between ISO-NE and the NYISO but was never implemented based on the recommendation of Potomac Economics, Ltd.²

The WMEG entities may want to adopt some guiding principles for the various MOPs to consider when developing market protocols to enable efficient transactions between markets. Some of these principles could include (1) create tools that help with price discovery, (2) provide an efficient process for submitting transactions simultaneously to both markets, (3) create transmission products and processes that maintain transmission revenues and enables efficient energy scheduling requirements, (4) ensure the process does not impact the timing of other market activities, and (5) clear all transactions at the applicable market clearing price.

Those WMEG members who are participating in the Markets+ protocol discussions may want to consider having SPP optimize the dispatch needs of WEIS, Markets+, and the SPP RTO West members. This would be similar to how CAISO is handling the dispatch solution for EDAM and WEIM.

1.2.2 Reliable Operations

Reliable operation of the transmission system is primarily the responsibility of the RC, who works closely with the various BAs, TOPs, Generator Operators (GOPs), and other NERC functional areas. The responsibilities for each functional area are laid out in the NERC Standards.

Most BAs in the WECC are responsible for the dispatch of their generation fleet to meet the demand of their balancing area. Many of the WECC TSPs use the MOD-029 contract path methodology for rating their transmission systems and granting transmission service between balancing areas. The WECC reliability entities use the Western Interconnection Unscheduled Flow Mitigation Path (WIUFMP) approach that uses certain controllable devices for managing congestion on the transmission system.

Organized markets economically dispatch geographically dispersed generating units to meet the demand across their market footprint while honoring the transmission limits set by each transmission owner. The organized markets operating in the eastern interconnect use the limits for individual transmission elements instead of a contract path rating. This flow-based approach enables the MOP to continue ramping up generation, which could result in flows between BAs that are potentially above a

¹ New York ISO White Paper on Inter-Regional Interchange Scheduling (IRIS) Analysis and Options dated January 5, 2011. https://www.iso-ne.com/static-assets/documents/pubs/whpprs/iris_white_paper.pdf

² First Year Evaluation of CTS between New England and New York Presented to the Joint ISO-NE/NYISO Stakeholder Meeting April 20, 2017. https://www.iso-ne.com/static-assets/documents/2017/04/a2_first_year_evaluation_of_cts_4132017.pdf

contract path limit, so long as the various transmission elements are not exceeding their individual limit. The MOD-030 flow-based methodology (see Attachment A) is used by most transmission planners of organized markets for modeling the use of the transmission system and for granting transmission service to more accurately study the flows related to the flow-based market operations.

The WECC reliability entities could benefit from the development of a tool that would enable them to manage congestion more effectively under the final market dispatch approach, which may be more of a flow-based approach. The Enhanced Curtailment Calculator (ECC), which is currently under review for additional functionality in the WECC, is evaluating the use of a flow-based approach to identify transmission issues and which transmission service or market transactions should be curtailed. The WMEG members may want to ensure the timely and proper development of these enhancements for the ECC tool. Note that moving to a flow-based approach for market dispatch where real-time flows on the transmission system are managed to honor the physical limitations of individual transmission elements may require an OATT change for the TSP to enable the MOP to dispatch the system based on this flow-based approach and for those responsible for reliability to curtail transmission service based on flows instead of contract path.

The second issue for the WMEG is to influence the current market developments in EDAM/WEIM and Markets+/WEIS, to reflect the above flow-based market methodology change as well and reduce the seams between those markets to better optimize the market operations to meet their intended goals, including modifications that would be required as part of the JOA.

1.2.3 Transmission Planning

Transmission planning in the West is primarily driven by the planning efforts of each transmission provider as the TSP. Planning efforts are focused on improvements to the transmission system to ensure reliable and resilient service for customers. These planning efforts have expanded over the last 10 years with the development of regional planning efforts through CAISO, WestConnect, and NorthernGrid. The CAISO has been successful in identifying and funding numerous projects to improve their transmission system. The NorthernGrid and WestConnect planning regions have a diverse slate of transmission owners, TSPs, multiple market configurations, and various regulatory jurisdictions, resulting in a complex structure for identifying and funding large regional projects.

FERC Order 1000 provided guidance for how jurisdictional entities should work together for both their own planning region and between planning regions. This order outlined the need to share respective regional and interregional transmission plans, principles regarding cost allocation, and the need to support public policy. FERC issued a Notice of Proposed Rule Making (NOPR) on April 21, 2022, titled 'Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection'.³ This NOPR is evaluating changes to regional and interregional planning processes that could have a significant impact on future transmission planning efforts.

Most of the planning regions in the eastern interconnect have footprints that are roughly the same as their organized markets and RTOs / ISOs. An organized market, operating across multiple entities, needs

³ Federal Energy Regulatory Commission Notice of Proposed Rule Making, Docket No. RM21-17-000. <https://www.ferc.gov/media/rm21-17-000>

a robust transmission system that is designed to support the desired market operations. The regional market dispatch solution for the organized market will differ from the legacy dispatch used by individual BAs. Western planning regions may want to adopt or enhance their processes for projecting future load and resource scenarios, incorporating public policy initiatives, and developing dispatch rules to simulate a regional market dispatch. The resulting projected regional market dispatch can then be used by the planning regions to identify the future needs for the transmission system. This may require the members of the WestConnect and NorthernGrid planning regions to adopt the principles of the MOD-030 flow-based methodology for their planning activity to better simulate the organized market dispatch and flow-based transmission usage (see Attachment A). The planning region can use this same regional market dispatch to help select which transmission solution(s) will provide the most benefit to the region and potentially use the breakdown of benefits from this model to help determine cost allocation for the transmission solution.

The WestConnect and NorthernGrid planning regions conduct periodic evaluations of member proposed transmission projects. These evaluations identify synergistic projects and ensure that member proposed projects will not negatively impact other members. Future regional planning efforts may benefit from the development of consistent and transparent processes for determining how the preferred regional projects will be selected, how benefits will be calculated, and how costs will be allocated. The Task Force anticipates this will be an evolutionary process over the next several years as WECC entities transition from energy imbalance markets to multiple day-ahead markets before settling on the preferred future organized market structure(s). The Task Force also anticipate that the current members in the WestConnect and NorthernGrid transmission planning regions will shift their membership between planning regions to match their participation in the various energy markets.

One option for a regional planning configuration would be for a single “super” planning region to develop the West wide regional transmission solution. The Task Force acknowledges that such a configuration would be the first of its kind in the nation. By having such a super planning region, the West may be able to remove the seams issues related to interregional planning that exist today between separate planning regions. This super planning region could also limit its focus to the larger, higher voltage solutions, such as 300kV and above and then rely on other groups, possibly the current planning regions, to focus on lower voltage projects that are driven by more localized needs. The single planning region would need to create a regional tariff to handle planning requirements, benefit calculations, and cost allocation. The Task Force was uncertain how to develop such an organization and anticipates the West will have planning regions that closely resemble the final market footprints like those for other RTOs and ISOs.

1.2.4 Transmission Service and Cost Allocation

The WMEG, through the Transmission Rate Sub-Group, is reviewing implications associated with consolidating individual tariff rates into a regional tariff with a regional rate structure. This review is focused on the impact to rates, efficiency, revenue, and mitigations for any revenue shifts. This Transmission Rate Sub-Group is developing a white paper that will study the various issues raised by their review and how to coordinate the changes required for each WMEG member’s tariff to resolve the seams issues.

1.2.5 Western Resource Adequacy Program (WRAP)

The Western Power Pool (WPP) received FERC approval of their Western Resource Adequacy Program (WRAP) which will implement the first region-wide reliability planning and compliance program in the history of the West. WMEG may want to discuss concerns regarding WRAP participation, especially for those WMEG members who have not committed to join WRAP, to identify potential gaps or conflicts with other resource adequacy programs, potential seams issues with the two day-ahead market design efforts, and develop potential improvements for the WRAP.

2 Market Operations

The MOP is tasked with providing the lowest possible energy cost to reliably meet their customers' needs. Each MOP determines their best economic dispatch based on their market protocols, the generating units available to serve their energy demand, and the available transmission system capacity. The MOP may be able to achieve additional benefits, beyond those realized through optimizing their internal assets, by facilitating transactions with neighboring organizations.

A key concept for understanding the clearing price of an organized market is that the market clearing price represents the last incremental MW of energy available to economically supply the last MW of demand. In the day-ahead market (DAM), suppliers submit the minimum price they are willing to accept to produce a specified quantity of energy. Conversely, load serving entities (LSEs) and MPs submit the maximum price they are willing to pay for their energy demand. These prices and quantities are then run through the market clearing process to determine what supply and demand are cleared in the day-ahead market. Not all supply and demand will clear in the DAM, which occurs when the price entities are willing to pay for energy is less than the price that suppliers are willing to produce. After the DAM process is complete, any unserved demand can then be transferred to the RTM. The RTM will serve the actual energy needs for LSEs and the economic energy request from MPs using the least cost supply available to the market.

The CAISO-managed WEIM currently integrates offers from WEIM with those of the CAISO market to jointly dispatch both markets. The same approach is planned with EDAM for both the DAM and the real-time market (RTM). The SPP WEIS does not combine the needs of those members with the current SPP region. The Markets+ protocol development efforts are just getting started, so it is unknown if they will integrate Markets+ with their SPP RTO West activity. There has been no discussion regarding coordinating transactions between EDAM and Markets+ in either developing market offering.

2.1 Current Trading Activity between Markets

Transactions between organized markets create an import schedule for one organized market and a corresponding export schedule for the other market. Import schedules are treated as offers to supply energy to the market. Conversely, export schedules are treated as bids for additional demand for the market. The prices for the import and export schedules will be independently determined by each MOP through their market clearing process. Therefore, when the low-cost market adds the export schedule, that additional energy demand may result in the low-cost market using a more expensive unit to serve the new increment of demand. This more expensive unit would cause that market's clearing price to rise. The opposite can be said for the other market processing the import schedule. These price

movements can erode any arbitrage opportunity that may have existed prior to the execution of the transaction.

Organized markets support various types of bilateral transactions, which are generally done to support contractual obligations between parties who are in different markets. Figure 1 below provides an example of the various bilateral transactions used in the MISO market. A MP who owns all or a portion of a resource located in a different BA or market footprint, for example, can pseudo tie that resource out of one market and into their BA or market footprint. The MP will be obligated to pay the transmission related charges for moving this resource out of the existing region, which could include market related charges from the resource's host MOP, and into their BA or market footprint. The MP could also be assessed charges by the receiving MOP for the energy moved into the market footprint. These charges by adjoining MOPs are typical for energy moved between organized market footprints.

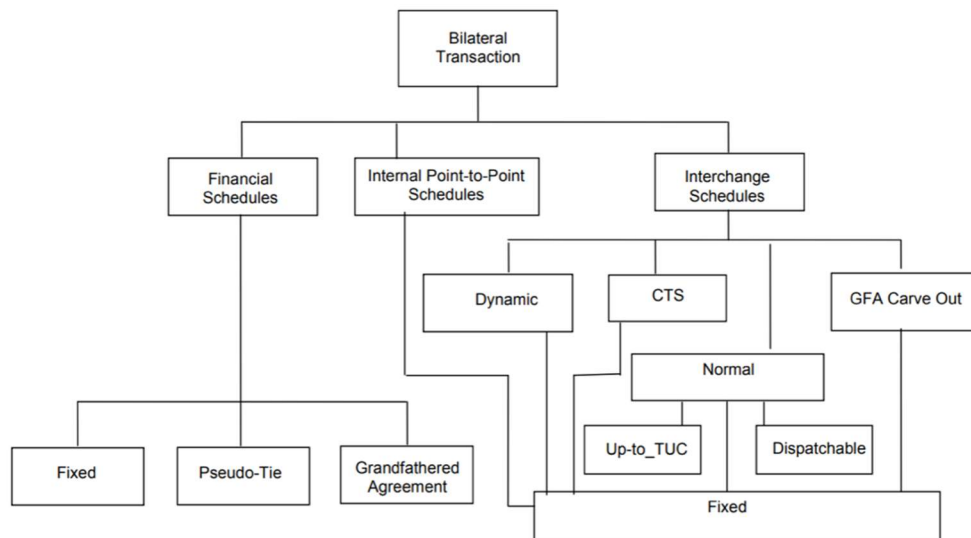


Figure 1. Examples of Bilateral Transactions⁴

There are some MPs who are willing to accept market price risk and will execute a bilateral transaction between two adjacent markets. There are many occasions when transacting energy between markets can provide mutual benefits to adjacent MOPs. However, these types of transactions can also cause the adjacent markets to settle at suboptimal price levels. Two tools that have been either used or evaluated by various MOPs to help MPs execute transactions between markets are discussed below. The CTS tool is used by several organized markets in the East. Tie Optimization was discussed as a possible alternative but has never been placed in service.

2.1.1 Coordinated Transaction Scheduling (CTS)

CTS is an interface bidding tool that MPs can use in the RTM for transacting and scheduling energy between organized markets. The objective of CTS is to improve interchange scheduling efficiency. This is accomplished by better aligning the scheduling of energy with the market price differential and

⁴ MISO Business Practices Manual, BPM 007 - Physical Scheduling, Page 19.
<https://www.misoenergy.org/legal/business-practice-manuals/>

increasing the volume of transactions to fully utilize the available transfer capability between the markets.

The CTS receives price estimates for upcoming RTM intervals from adjacent MOPs. The CTS uses these estimates to determine the price spread between the markets. The CTS will automatically clear MP's bids that are favorable to the projected price spread. The theory behind this process is simple, but there are challenges when implementing the CTS tool.

The first step in the process for using the CTS tool is for a MP to submit price/MW bid pairs and the to/from markets for each desired real-time price interval. These price intervals, for example, can range from a single pricing interval to all intervals for a multi-hour period. Figure 2 below provides a simple diagram of the CTS process timeline between PJM and MISO. Submissions need to be made prior to the delivery interval, which for some MOPs can be a minimum of 75 minutes in advance. The MP must purchase transmission service to facilitate the potential physical movement of energy between markets prior to knowing if their CTS bids clear. It is worth noting that a MP can submit multiple price/MW bid pairs for each interval and will then need to purchase transmission service for the maximum sum of MWs submitted for any interval. Next, the MP creates an electronic tag (E-Tag), noting the CTS Bid ID on the E-Tag. The MP's CTS bids will automatically expire if it is not linked to an E-Tag prior to the expiration time for the CTS tool to evaluate and process all bids received. The CTS tool receives the projected market prices from the adjacent MOPs between 40 and 60 minutes prior to the delivery interval. CTS bids that clear are posted between 15 and 30 minutes prior to the delivery interval and the associated E-Tag is automatically updated with the MWs cleared for that interval.

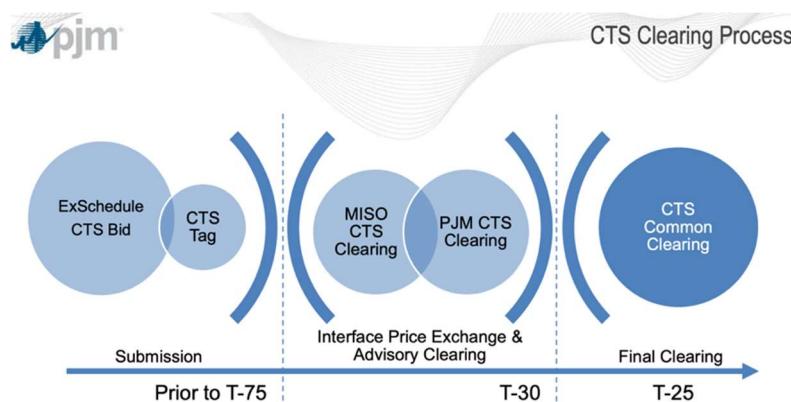


Figure 2. CTS Clearing Process for PJM and MISO⁵

There are significant risks and uncertainties for a MP related to the CTS process. The MP is taking a financial risk by purchasing transmission to support their CTS Bids with no assurance that any of their price/MW bids will clear. The MP is also taking on price risk between the projected prices and the actual clearing price for each delivery interval. Numerous things, such as loss of a generating unit, deviations from forecast for load and variable energy resources, and the loss of a transmission facility are some

⁵ PJM-MISO Coordinated Transaction Scheduling & Manual 11 Revision Review, July 27, 2017, Slide 4.
<https://www2.pjm.com/-/media/committees-groups/committees/mrc/20170727/20170727-item-07b-draft-manual-11-revisions-presentation.ashx>

factors that can cause the actual price to deviate from the projected price. There is also a risk associated with securing Ramp for CTS transactions. Some MOPs require Ramp to be reserved external to the CTS tool for CTS related transactions. Ramp is commonly required for scheduling power into or out of an organized market and is made available to MPs on a first come first served basis.

2.1.2 Tie Optimization

The concept for the Tie Optimization is to optimize the use of the transmission interties between organized markets. This would be similar to how the MOP optimizes transmission facilities under their control. The lower cost market would send power to the higher cost market until such time that the interties were loaded, or the price differential erodes. This concept is simple but does have challenges. One of the first problems to solve is determining the incremental price and volumes for the transactions.

As stated earlier, each MOP optimizes their market footprint for the benefit of their MPs. The market software is constantly solving each dispatch interval with all known parameters. Any change in a parameter can affect the market's clearing price. When the transactions are added to the associated organized market dispatches, the market clearing prices can change for each market.

The Tie Optimization concept requires one MOP to send an incremental / decremental stack, based on their forecasting tool, to the neighboring MOP. The neighboring MOP runs this incremental / decremental stack through their forecasting tool to determine which transactions would be beneficial for the parties to execute. The two MOPs would then schedule these transactions between their systems and clear the results in an upcoming market clearing interval. The actual benefit of these transactions will depend on the accuracy of the two forecasting tools. The length of time it takes for each MOP to process the needed information, referred to as latency, will increase the potential error in forecasted prices as the time to execute is extended. The Tie Optimization approach places the market price risk on all MPs within each organized market based on the actions taken by their respective MOP.

2.1.3 Risk for Transactions between Markets

Transactions between organized markets have several different risk parameters associated with them. Transactions have market price risk, transmission availability, ramp availability, and transmission service costs. Transactions between markets, executed as either bilateral or using the CTS tool, places the risks on the MP who elects to execute such transaction. The Tie Optimization contemplated putting the risks on the adjoining MOPs who would then pass along the benefits and costs to their MPs through the settlement processes.

2.1.4 Transmission for Transactions between Markets

The use of the transmission system requires the transmission customer to secure transmission service from a TSP prior to using the transmission system. Energy transactions between organized markets typically requires transmission service from multiple TSPs. There have been some market monitoring units that have recommended discontinuing the requirement for transmission service and possibly other market-related charges for transactions between markets.⁶ The discontinuance of requiring

⁶ Coordinated Transaction Scheduling (CTS) Study, May 08, 2020 by SPP MMU.
<https://www.spp.org/documents/62154/coordinated%20transaction%20scheduling%20study%2020200508.pdf>

transmission service could be a comparability issue under the various open access transmission tariffs (OATT) by letting some use the transmission system for free while charging others for similar service. The Task Force discussed the possibility of annulling confirmed transmission service for CTS transactions if the CTS bids did not clear. This would shift the financial burden from the MP to the TSP. The TSP would need to decrease their available transmission capacity if sold for CTS, potentially inhibiting them from selling additional transmission service. If the transmission reservation was annulled for CTS bids that did not clear, the TSP would lose out on both potential sources of revenues. The Task Force preferred that transmission service be required for transactions between markets.

2.2 Recommendations for Efficient Transactions between Markets

The WMEG members may be able to encourage EDAM and Markets+ to develop tools for moving power between these two developing markets. It may be good to request features to move energy between markets early in the market development phase. The WMEG members will want to outline some key principles for the MOPs to use when developing these features. These principles could include such items as (1) create tools that help with price discovery, (2) provide an efficient process for simultaneously submitting transactions to both MOPs, (3) create transmission products and process that maintain transmission revenues and create efficient energy scheduling requirements, (4) ensure the process does not impact the timing for other market activities, and (5) clear all transactions at the applicable market clearing price.

Another consideration for those WMEG members who are participating in the Markets+ discussions is that they may want to consider optimizing the dispatch of Markets+ with the WEIS and SPP RTO West dispatch. This would provide additional demand and resources for both markets, which may create more synergies. The optimized dispatch may also remove a potential seam between SPP RTO West and Markets+. CAISO is already planning to optimize the EDAM dispatch with their CAISO market. This approach would leave only the market seam between the SPP and CAISO dispatch processes to be resolved. The market seam between SPP and CAISO would need interfaces created with inter-tie bidding for MPs and MOPs to optimize transactions between the markets.

3 Reliability

FERC authorized the North American Electric Reliability Corporation (NERC) the right to set standards for, and monitor, the reliability of the United States electric transmission system (as well as Canadian Provinces included voluntarily). NERC divided the responsibilities between multiple functional areas such as RC, BA, TOP, TSP, GOP, LSE, and MOP. The standards define what must be done, but the who must do it can vary depending on multiple factors.

When NERC defined these functional areas and their responsibilities and reporting obligations, they assigned to or shared between each a set of standards that are required to be followed. Each entity must be able to demonstrate how they meet the applicable standards. Within these standards, including during power system emergencies, are requirements for legal agreements describing how they will meet the standards for each of their seams. NERC worked to ensure that the seams reliability issues were highlighted and that the needed coordination was considered in those responsibilities. In discussing seams arrangements, a TSP (as well as any regional TSP) would need to agree how to coordinate their

provision of service to meet the standards. Parties have used interconnection agreements, coordination agreements, or JOAs to memorialize how they will work together to meet these standards.

3.1 Current Reliability on the Transmission Grid

In the operations of the transmission grid, the major elements that are monitored and controlled to maintain reliability are based on the following sections:

a. Frequency

Frequency on the transmission grid is now the responsibility of the BA; they must balance their load and generation and assist other BAs that might have issues with that balance. Particularly, the BA must be prepared to respond to small and large changes in their balancing area using generation control to restore or maintain the balance and frequency. This includes holding reserved generation to meet both the smaller changes (Regulation) and larger changes (Operating Reserves).

b. Voltage

As part of the transmission reliability, nominal voltage needs to be maintained to avoid damage to transmission, generation, or customer equipment, as well as voltage collapse. Most regional organizations recognize that the provision of voltage control and support is a local issue and depends on the local transmission owner and their controls to maintain voltage. If there is a transmission component that can be defined as a constraint on economic dispatch (such as a voltage collapse limit of the output of a set of generators), it would be used as a transmission limit. There are very few of these in use presently.

c. Thermal / Stability

The majority of limitations used in the organized markets are thermal limits on facilities. The vast number of these are first contingency (N-1) limits, where the limit is post-contingency flow on a “monitored facility” when the “contingency facility” trips out. Both in real-time flow monitoring and contingency analysis, the TOP is responsible for operating the transmission system to maintain flow below these N-1 limits.

There are also limits for individual transmission facilities that need to be respected in operations and future analysis. These are straight forward transmission elements using the simplest limits. Finally, there are limits established based on transient stability issues, either for voltage stability (as noted above) or for prevention of situations that would lose stability of the power system based on a disturbance such as the loss of a large generator. These can be complex to both identify and observe. To monitor for the identified limits, the TOP might use the flow on a set of transmission facilities and the limit for that sum of the flow. It can either be a simple limit or what is called a nomogram (a limit that depends on transmission system conditions).

The TOP monitors the system limits and takes action to keep conditions within the established limits. The most common actions are to move generation output to reduce the flow on the system. Note that movement of generation also requires maintaining the generator and load balance, (and so coordination with the BA) as well as all other conditions that need to be limited. In recent years, for real-time

dispatch of generation, operators have used new analytical tools such as a Security Constrained Economic Dispatch (SCED). This tool sets the dispatch of each generator to meet all stated limits on the transmission system. A Security Constrained Unit Commitment (SCUC) can also determine the generators that need to be committed to run to maintain the capability to meet the limits through a range of conditions anticipated. Another approach is the reconfiguration of the transmission system to isolate the limiting element(s), when operating conditions make such possible.

3.1.1 Reliability Seams Coordination in Eastern Interconnection

FERC Order 888 ushered in a major change for transmission owners who were required to allow the purchase and use of the transmission system on a non-discriminatory basis. This triggered debates among TSPs and TOPs on a variety of issues that might be faced in the planning and operation of the transmission system. For reliability, TOPs were concerned about the ability to observe and maintain the conditions of the transmission system, when the selling of the transmission system could be the result of actions of other TSPs who may or may not understand the impact on the whole transmission system. These were seams issues that would need to be addressed.

TSPs and TOPs were faced with the question of who would be responsible for changing flows on the transmission system if the current schedules, and resulting flows, were causing reliability issues. TCs were required to buy transmission service to create a contract path for delivery. This contract path was not required to represent the actual flow of energy for the desired use. The TC could secure the lowest cost contract path, which may involve several lower cost TSPs instead of one higher cost TSP. If there was not sufficient coordination between TSPs, then a transmission customer could obtain service from another TSP, thereby avoiding the limitations that prevented them from obtaining service by “buying” around the limitation.

The Eastern interconnect decided on two changes to address these seams issues that would allow the TOPs and TSPs to share information that could be used to coordinate both the operations and curtailment of the use of the transmission system based on the priority (from FERC 888 priority) of the individual uses, or service sold, of the transmission system. First, all TSPs, GOPs, and TOPs would supply the RCs with the necessary information to analyze the current conditions of a wider area of the transmission system, as well as future period, allowing the TOPs to both take action or prepare to take action to maintain the reliability of the transmission system. Second, all TSPs, GOPs, and TOPs would supply to NERC information needed to align each transmission system usage (transmission service) with the impacts it would have on the transmission system. Note this information was supplied to a new tool, called the Interchange Distribution Calculator (IDC), that was used for all point-to-point transmission service between systems, a simplified representation of network transmission service, and to coordinate and approve interchange schedules electronically. This information could then be used to analyze the impact on the transmission system, along with its priority of transmission service, for each schedule.

The RC uses the IDC to help manage flows on the transmission system. The RC issues curtailments on specific schedules or network usage based on the transmission system limitations. This IDC also made it possible to curtail the lowest priority schedules, or transmission service, first and work up the priority stack until the desired relief was attained. This encouraged and eventually led to all the TSPs deciding to sell their service on a flow basis rather than by contract path. Thus, NERC, in setting standards for

defining and calculating impacts on the transmission system, defined the flow-based definitions in their MOD-030 Flowgate Methodology.

Most regional tariffs and organized markets built on many of the lessons learned associated with the adoption of the flow-based approach. The market designs considered the BA, TOP, and TSP processes that would need to be observed in their solutions. The results were market tools and processes that allowed the RC and MOP to manage transmission flows in nearly real-time through changes to the market dispatch, when possible, to manage congested elements. There is still the option for the RC to use the IDC to curtail schedules external to the market if a market solution cannot provide the desired relief on the transmission system.

3.1.2 Reliability Seams Coordination in the Western Interconnection

Currently, the West uses mostly local controls for maintaining these limitations. There is also the WIUFMP that uses certain controllable devices in the mitigation of congestion along the transmission system in the West. This is limited to about four qualified paths. As such, the BAs are responsible for either resolving issues outside WIUFMP paths or coordinating with their neighbors to obtain relief.

3.1.3 Reliability Coordination in Market Operations

Regional market designers understood the need to assist NERC entities in both their responsibility as well as on the seams between entities. That would mean markets would need to consider RC, BA, and TOP standards and the data or processes each would need in order to maintain their compliance with NERC standards.

The majority of coordination for the TOP is with the RC and some with the BA. The markets simplified the interactions with the BA by requiring that any BA, and all their generators and load, in their footprint would be either wholly within their market or facilitate the movement of an LSE or GOP (even a part ownership of a generator) by Pseudo-Tie to another BA if that LSE or GOP would not participate in the market. Any considerations on the operation of the BA would be transferred to another BA and the TOP's responsibilities would be handled by their respective RC. For the TSP, this will be covered in the section below.

The market designers expected to assist the RC in several ways. First, the RC could meet their reliability requirements with the markets using the same tools of SCED and SCUC to commit and dispatch resources (generation, load, and other facilities offered to the market to control). Their solutions then would respect all the limitations defined by the owners and operators of the transmission system. Part of the benefit of these regional markets is to optimize the resources across a range of owners, marketers, and others to reduce the cost of production of electricity in the area. Therefore, they intended to maintain the balance of generation and load, constraining conditions within the system limitations, and meet all the reliability and process requirements of reliability on the transmission system.

Second, the dispatch of resources in an organized market would significantly change the conditions on the transmission system based on a wider range of resources and the ability to quickly and efficiently move those resources to reduce production cost. In order to implement the speed of dispatch and the limitations of the scheduling paradigm for implementing those changes, the organized markets

recognized that the RC and IDC would need additional information in order to observe and curtail the changed conditions on the transmission system. Therefore, the organized markets now provide to the RC the market plans for use in the RC's assessment of operations. The MOP also works closely with the RC to adjust market operations to enhance regional reliability. Note that the organized markets are normally the RC in their area and have processes that are integrated with the organized markets.

The organized markets identified those flowgates that their markets had an impact on, known as Coordinated Flowgates (CFs). Flowgates are defined mostly as the N-1 limitations but can also represent other transmission system limitations. The identification of these flowgates provided others the knowledge of which facilities they could see regional market impacts. Next, the markets would supply the IDC with their "market flow", or flow that represents how the market changes all of the scheduled impacts in the IDC. This market flow would also be divided into the priority of transmission service that supported those flows. Next, the markets determined the Firm Flow Limit for each CF, for use in the IDC to understand which transmission service priority that part of the market flow was to be considered in the IDC. This was calculated as the amount of historical "loop/parallel" flow that was observed with the historical dispatch and commitment before the regional market. Thereby, any new flows on a neighboring system would be non-firm service priority. With this information, the IDC could determine the impact of the market flow on each limitation, as well as when an RC called for curtailment, what instructions to give to each MOP to reduce their use of the transmission system.

One last issue that organized markets had to anticipate was that if the market solution could not resolve a transmission system issue, either fast enough or outside market controls, they could use an Out of Merit Energy Instruction (OOME) to address the situation. This could be either an internal issue or a seam issue.

3.1.3.1 Additional Market Seams Coordination

As regional markets grew and were more involved with neighboring markets, (seams between MOPs), they found more opportunities to share the use of their common CFs. These markets, as well as any non-market areas that agreed to be involved, would be a Reciprocal Entity (RE) and would share the full capacity of those CFs that qualified, not just the historical usage. These are known as Reciprocally Coordinated Flowgates (RCFs). Therefore, on these RCFs, any capacity above the sum of the Firm Flow Limits for every RE could be shared between all the REs. The markets determined to share such capacity based on the ratio of each of their Firm Flow Limits to the total Firm Flow Limits. Their flow would then have more transmission service capacity considered firm priority. They also agreed that they could request any unused capacity allocated to another RE. The capacity created by the RCFs could also be used for the selling of transmission service in their area.

3.1.3.2 Market-to-Market Coordination

Market-to-Market (M2M) coordination represents another seams enhancement that allows neighboring markets to assist each other in controlling the transmission system conditions to meet the limitations more cost-effectively. There are situations and times where a neighboring market can resolve a constraint with a less costly dispatch than the market that has a limitation. The markets agreed that they would exchange the cost of resolving the limitation (shadow price) so that if the neighboring

market had a less costly redispatch for that limitation, the benefiting market would pay the market providing the relief. The shadow price is the cost to reduce the constraint value by one megawatt. Note that the markets would continue to adjust their dispatch until their shadow prices matched.

3.1.3.3 Emergency Operation for Markets

One last adjustment for markets came from their responsibilities as a BA. The markets had to adjust their seams agreements to establish emergency energy transfer and compensation for it.

3.2 Reliability Seams Issues for WMEG

With the current state of reliability coordination in the West as well as the development of markets, WMEG has seams issues in the current state of operations as well as the opportunity to influence market development to resolve expected seams issues. Recognizing these changes, and the use and ability to maintain transmission reliability, the following sections explain some areas that WMEG can work together to mitigate or enhance the coordination and collaboration of the system.

3.2.1 Market Seams Issues

With the continued work on design and development of current and future markets, there will be seams issues that will need to be dealt with and any changes will have impacts on the members of the WMEG. There will be opportunities to influence the resolution of seams issues between those markets as well as with non-market entities. This will include impacts on the responsibilities of BAs, RCs, and TOPs. Specific expertise will need to be educated in those issues and the possible resolutions and enhancements. WMEG could establish a task force to follow the progress in markets and market footprints, as well as make proposals that would advantage the members. This might include some of the resolutions used in other markets, such as sharing capacity of transmission facilities.

3.2.2 West Transmission Flow Coordination

The West is already in discussions to increase the capability of the Enhanced Curtailment Calculator (ECC). WECC established the ECC Task Force to work on enhancements to the ECC that could include elements like the East IDC. Not much has been accomplished on this but there is a renewed interest in that work presently. SPP established an ECC Working Group (ECCWG) that has an ECC Task Force (ECCTF) that worked on the transition of the ECC tool to another platform so that the coordination of the WIUFCM would continue with SPP and CAISO RCs sharing the responsibility of RC in the West. ECCTF is working on proposed enhancements to the ECC tool that could include non-tagged transfers, use for more than qualified paths, and looking to future markets. With the depth of WMEG membership, this effort could be a focus for WMEG. WMEG could assign members to report on this discussion and see if it might require more coordination between WMEG members to help move the project forward in these areas as well as transparency of the effort and the changes.

3.3 Reliability Seams Issue Recommendations

Two recommendations for WMEG to consider:

1. WMEG could establish a Task Force to follow the progress in markets and market footprints, as well as make proposals that would advantage the members. This could include seams issues with BAs, RCs, and TOPs, as well as changes in their data or processes. This might include some of the resolutions in other markets, such as sharing capacity of transmission facilities.
2. WMEG could assign members to report on the ECC enhancement discussion and see if it might require more coordination between WMEG members to help move the project forward in these areas as well as transparency of the effort and the changes.

4 Transmission Planning

Transmission planning identifies enhancements for the transmission system to ensure reliable and resilient service for customers. Transmission planners study the impacts that their solution may have on adjacent transmission systems and transmission regions to ensure there are no unintended negative impacts. The FERC recognized a need for transmission planning to reach across historic planning boundaries and issued Order 1000 to usher in regional and interregional planning efforts. This FERC Order required that jurisdictional entities participate in a regional planning process that produces a regional transmission plan, that entities improve the coordination between planning regions, and that such regional planning must evaluate needs driven by public policy. The FERC Order also required regional and interregional planning processes to have cost allocation methods for new transmission facilities selected in a regional or interregional planning process. Cost allocation will be covered in Section 5 below. FERC issued a NOPR on April 21, 2022, titled Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection. This NOPR seeks to address perceived deficiencies in five key areas of current transmission planning requirements.

4.1 Planning Regions

Transmission planning regions are generally formed by adjacent entities with similar interest. Some of these transmission planning regions resemble the market footprint associated with their RTO or independent system operators (ISO). Figure 3 below shows a rough configuration of the current transmission planning regions. Note that many of these planning regions have areas that are not always contiguous, but generally have some type of transmission facilities interconnecting the regions.

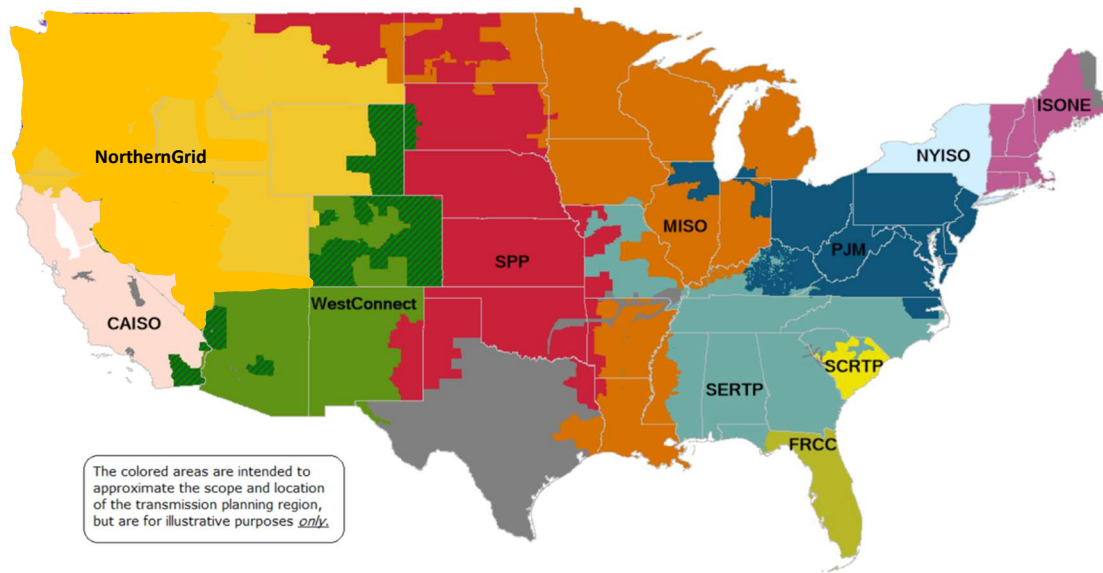


Figure 3. Transmission Planning Regions⁷

Each planning region has filed with and received approval from the FERC to perform the regional planning functions. There are similar approaches and differences for how each of these planning regions executes their regional planning activity. In addition to the individual planning regions shown in Figure 3 above, the Eastern Interconnection transmission planners have formed a collaboration called the Eastern Interconnection Planning Collaborative (EIPC)⁸. This EIPC includes all the regions shown above except the CAISO, WestConnect, and NorthernGrid planning regions. The EIPC provides a forum for the Eastern Interconnection transmission planners to work together on an interconnection-wide basis to ensure a reliable electric transmission grid for a region covering over two-thirds of the United States and Canada. This model may be something the three West planning entities would want to duplicate or could further enhance such an effort by working with the EIPC to expand their focus to include the West system and could also include methods to ensure the preferred regional transmission solutions are built and the cost properly allocated.

4.1.1 Reliability Driven Transmission Projects

Planning regions work closely with the transmission planners from the transmission owning members who identify reliability needs for the transmission system. The planning region will incorporate any company planned projects into the regional planning models to validate the company project(s) does not cause issues for other members of the planning region or in other planning regions. The regional planning process will also evaluate company proposed projects against other regional solutions to see if

⁷ FERC Order No. 1000 Transmission Planning Regions, modified to reflect current Northern Grid and West Connect Members. <https://www.ferc.gov/sites/default/files/industries/electric/indus-act/trans-plan/trans-plan-map.pdf>

⁸ EIPC was initiated in 2009 by a coalition of regional Planning Authorities. <https://eipconline.com/>

there is a better regional solution to address the identified reliability needs and provide greater benefits to the region.

4.1.2 Economic Transmission Projects

Planning regions that have both a regional tariff and an organized market use similar approaches to determine the future needs for their region. In addition to the reliability needs as noted above, planning regions that support an organized market can readily identify transmission projects to support improved market operations. The planning region works with their stakeholders to define potential future scenarios that also incorporate various public policy initiatives. These futures scenarios will be impacted by such things as changes in load, unit retirements (carbon reduction), the technology type and locations for new generating units (renewable penetration), deviations to member provided load growth driven by uncertainty of public policy (EV penetration, building electrification), fuel price sensitivities, and other factors impacting load and generation within their region. The stakeholder approved futures are then used to determine the dispatch models that will be used for the planning models. The regional planners use this information to identify areas on the transmission system where new transmission infrastructure may be necessary to maintain reliable operations and support the desired market operations for the identified futures.

MISO recently issued their Long-Range Transmission Plan that identified 18 transmission projects with a projected cost of \$10 billion for their Midwest subregion.⁹ This slate of projects addresses economic, public policy, and reliability needs for the study region as shown below in Figure 5. This portfolio has a benefit to cost ratio of roughly 2.6, when accounting for economics, avoided costs of local resources, and public policy. The MISO process develops a detailed breakdown of these benefits by cost allocation zones, which are shown below in Figure 4. This approach helps MISO allocate the costs for these projects commensurate with the benefits each zone is projected to receive, which is consistent with the cost allocation procedure in their OATT.

4.1.3 Transmission Project Selection

Transmission planning regions will each have their own method for determining which project will be selected for construction. Economic transmission projects that support improved market operations should have sufficient benefits to support their costs. Reliability projects generally cannot show sufficient benefits to justify their cost and are instead driven by the need to meet NERC compliance requirements. Reliability projects can be evaluated against other projects in case there is a regionally identified project that can meet the region's reliability needs at a lower cost for customers.

A challenge for each planning region is determining which project is the best solution for the region when evaluating competing projects. There is generally more than one solution to solve an identified need. Furthermore, the members of a planning region will have diverse perspectives on what the future needs will be for the transmission system, resulting in disagreement regarding which solution is best for

⁹ MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary.
<https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf>

the region. These different perspectives will create different needs and different benefits for each solution.

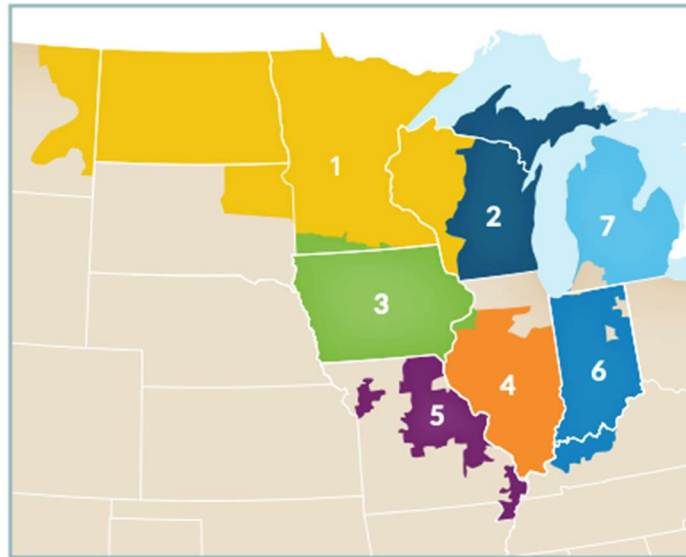


Figure 4. MISO Cost Allocation Zone Boundaries

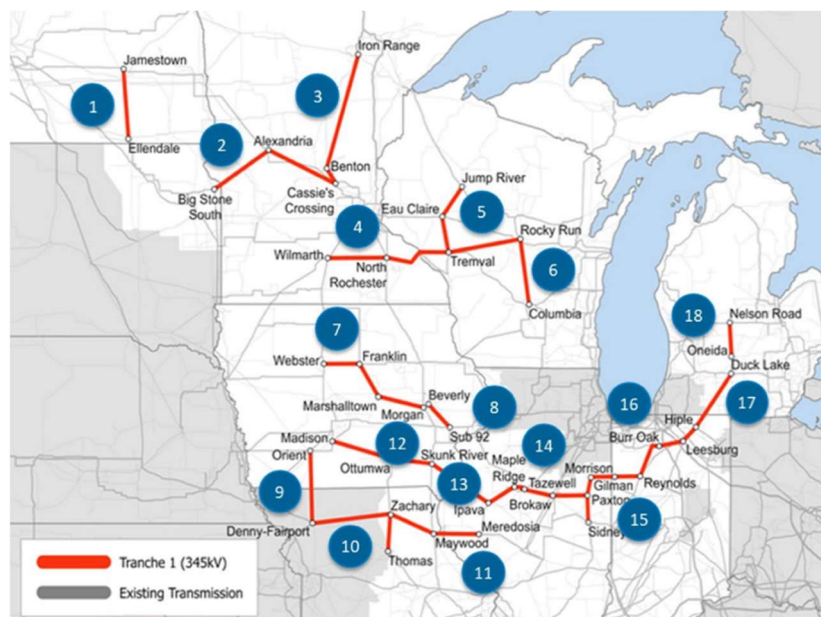


Figure 5. Transmission Projects for MISO MTEP21

Transmission issues along a seam, which can be between two transmission owners or between two planning regions, can create a debate about what is causing the issue, who needs to construct what facilities, and who will pay for the new facilities. If the preferred project spans across multiple

transmission owners or across multiple planning regions, the planning region will need to coordinate their study efforts with others to determine the best solution. There have been numerous jointly owned transmission facilities built by parties with similar interest who agree to construct and fund those specific projects. PJM and MISO approved an Interregional Market Efficiency Project¹⁰ that resulted in each planning region funding a portion of a 138kV line rebuild in Indiana. This line was along the PJM-MISO market seam. Other regional planning efforts have identified facilities on a neighboring planning region's system that needed to be upgraded or built and interested parties have either agreed to fund those needs or required the transmission customer to work with the third-party to ensure such needs are addressed.

Figure 6 below shows some of the current constraints between the MISO and the SPP regions. These entities continue to struggle with defining interregional criteria for future scenarios, model dispatch differences, and cost allocation principles. The MISO and SPP have a JOA in place and have been coordinating planning efforts for a considerable period. They also have a joint task force that is looking into how the two regions can resolve their differences to get projects approved, especially those along their seam. This example is not intended to provide an opinion of these two planning regions, rather to demonstrate how difficult it can be to approve interregional projects between planning regions.

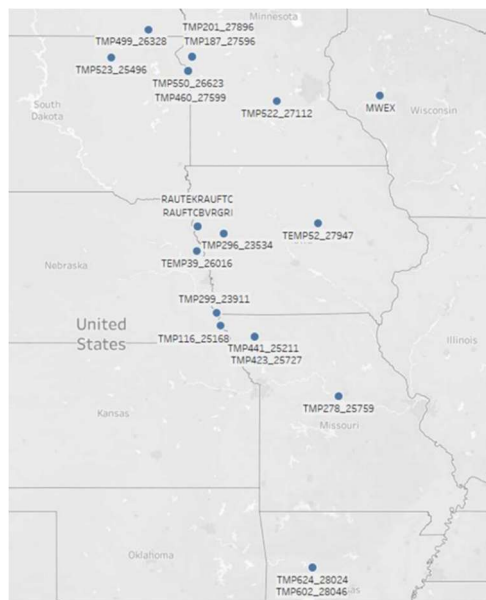


Figure 6. Constraints between SPP and MISO¹¹

¹⁰ MISO MTEP19 Executive Summary and Report, Chapter 3: Regional and Interregional Economic Studies, pg 46. <https://www.misoenergy.org/planning/planning/previous-mtep-reports/#t=10&p=0&s=FileName&sd=desc>

¹¹ MISO M2M Constraints in SPP DAMKT Update November 2022, slide 11. <https://cdn.misoenergy.org/20221109%20MISO%20SPP%20CSI%20Item%2005%20M2M%20Constraints%20in%20the%20SPP%20DAMKT626901.pdf>

4.1.4 West Planning Regions

The three main planning regions in the West, as shown in Figure 3 above, are WestConnect, NorthernGrid, and CAISO. NorthernGrid is a newer entity formed through the combination of the Northern Tier Transmission Group and Columbia Grid planning regions and a shift in participation by NV Energy from WestConnect to NorthernGrid. Both NorthernGrid and WestConnect use a 10-year forecast period to identify future regional needs. They use a biennial study cycle to evaluate member identified projects, identify efficient regional reliability solutions and projects necessary to support public policies, and use a production cost modeling tool to estimate economic benefits. The three planning regions hold an annual interregional planning coordination meeting.

The recently completed biennial study cycle for NorthernGrid and WestConnect identified limited regional transmission projects. There were no economic projects identified during this planning cycle for either region. WestConnect did not identify any regional transmission solutions for the 2020-21 planning cycle. NorthernGrid approved a slate of projects, shown in Figure 7 below, during their recent planning cycle. These projects were reliability driven, with cost allocation following each individual jurisdictional member's OATT. The slate of projects solved the reliability concerns for members more efficiently than each member could do separately.

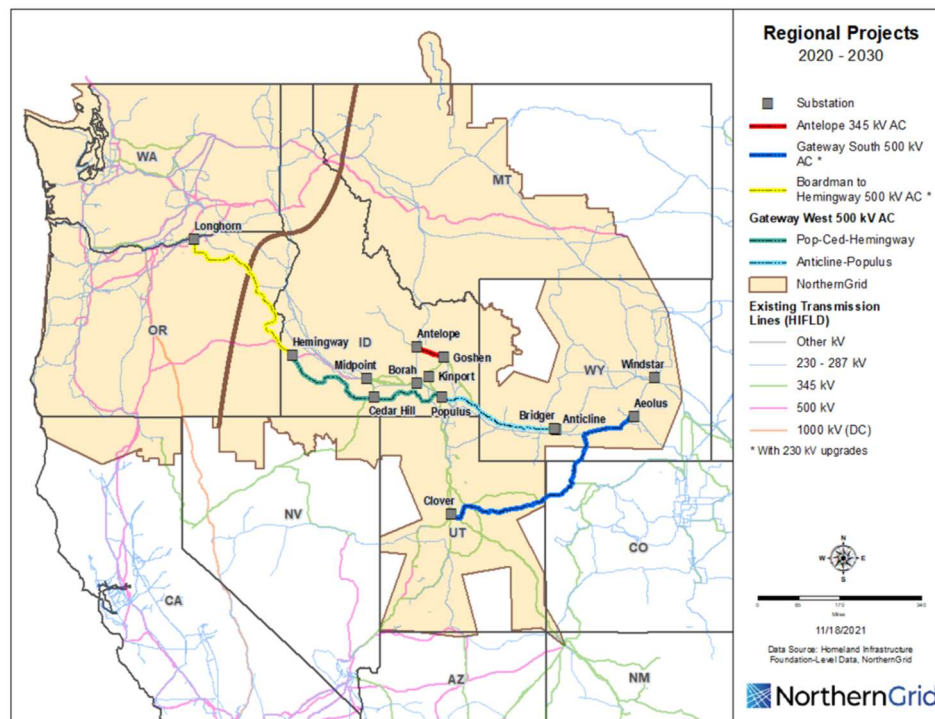


Figure 7. Regional Transmission Plan for the 2020-2021 NorthernGrid¹²

CAISO conducts an annual transmission planning process that looks at the needs for their region over a 10-year planning horizon. CAISO works extensively with the California Public Utilities Commission and

¹² NorthernGrid Regional Transmission Plan for the 2020-2021 NorthernGrid Planning Cycle, December 8, 2021, p. 31. https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf

the California Energy Commission regarding key inputs, assumptions, and policy-driven initiatives. The single state regulatory and legislative oversight provides a distinct advantage for CAISO regarding finalizing modeling assumptions and cost recovery compared to the other two regional planning regions that cover multiple states and impact multiple regulatory and legislative bodies. The CAISO 2021-2022 Transmission Plan identified 23 projects with a projected costs of \$2.96 billion, which was a large increase over the average for the last five years of \$217 million. Reliability needs drove 16 of the projects and roughly half of the \$2.96 billion cost estimate, six policy-driven transmission projects accounted for most of the remaining cost estimate, with one economic project accounting for \$40 million.

4.2 Recommendations for Planning Regions

Planning regions with the ability to identify, fund, and construct substantial transmission facilities have well defined processes. These planning regions tend to align along organized market boundaries, which enables the market dispatch rules to drive the benefit calculations. These regions also have some type of regional tariff that defines the planning process and associated cost allocation.

An organized market, operating across multiple entities, needs a robust transmission system that is designed to support the desired market operations. As the West transitions from their current real-time market to the day-ahead markets, there will be benefits to refining the regional planning study processes. West planning regions may want to enhance their processes for projecting future load and resource scenarios, incorporating public policy initiatives, and developing dispatch rules to simulate a regional market dispatch. The market dispatch can be used by the planning regions to identify future needs for the transmission system to support such market dispatch. The planning regions could then use the principles of the MOD-030 methodology to have the study more closely resemble the flow-based use of the transmission system by the market dispatch. The planning region could use the dispatch model to help select which transmission solution will provide the most benefit to the region and then use the resulting benefits to help determine potential cost allocation for the transmission solution.

The West entities may want to evaluate developing a single planning region for planning, evaluating, and funding transmission solutions for the entire West system. This would be similar to the configuration that would occur if there was only one market or RTO in the West. This configuration could address the Seams issues that have plagued other interregional planning activity. The development of a single planning region would require significant effort and extensive negotiations to get all stakeholders to agree on the key principles, which the Task Force acknowledges would be a very complicated undertaking. To simplify this concept some, the West entities could have this single planning region focus on larger, higher voltage solutions, such as 300kV and above, and then have other groups, possibly the existing planning regions, focus on lower voltage projects that are driven by more localized needs. Absent such a development, the anticipation is that there will be more than one planning region in the West, with each planning region working closely with the organized market that is serving most of their membership. The Task Force anticipates the existing planning region membership will be an evolutionary process over the next several years as entities transition from energy imbalance markets to multiple day-ahead markets. The current members in the WestConnect and NorthernGrid transmission planning regions are expected to shift their membership between planning regions to match their participation in the various organized markets. The West planning regions may also want to

consider either forming a Western interconnection planning collaborative, similar to the EIPC, and possibly include the SPP in this collaboration or work with the EIPC to expand their focus to include the Western Interconnection.

5 Transmission Service and Cost Allocation

Transmission service is provided by a TSP in accordance with their OATT. Each TSP's OATT is based on the FERC Order 888 and subsequent orders that details the requirements for their OATT, including seams issues between TSPs. The seams issues between TSPs in the West will become more dynamic as market development in the West continues.

The TSP projects how the transmission system will be used and determines what transmission facilities are necessary to meet the future demand on the transmission system. The TSP also determines available transmission capacity (ATC) to serve tariff service requests made by transmission customers. Now that many West entities are considering joining an organized market, the actual use of the transmission system will change as the MOP takes on more of the regional dispatch authority. This change will impact both TSPs, who are members of the regional market, and those who manage neighboring transmission systems. This change in use of the transmission system creates a need to enhance the current approach for studying and granting transmission service.

The process for requesting tariff service, for both Generation Interconnects (GI) or Transmission Service Request (TSR), under a regional tariff is similar to the process used by an individual TSP. The transmission customer submits a request to the TSP through their OASIS. The TSP studies the request to determine what transmission facility enhancements would be necessary to their system and to adjacent transmission systems to provide the requested service. The TSP then provides these results to the transmission customer, who may need to commit to pay for specific enhancements before their request can become effective. The cost for any identified upgrades on the host and adjacent transmission systems associated with an individual request is assigned to the transmission customer. The cost allocation becomes more complex when a TSP groups multiple TSRs from multiple transmission customers into one study and that study identifies various upgrades necessary by potentially multiple transmission owners. The TSP now must determine how to allocate the upgrade costs across the various transmission customers.

Another challenge for effectively processing tariff service requests is cost allocation. The OATT process requires the transmission customer to pay for upgrades necessary to support their request. The study identifies the minimum facility rating that is necessary. The TSP works with the transmission owner(s) to determine the cost to meet these identified facility upgrades. Transmission owners typically have standards for equipment installed on their system, which results in the transmission owner specifying equipment that meets or exceeds the minimum rating required. This approach could create excess capacity on the transmission system that subsequent requests can use without paying for the upgrades. This dynamic started a sort of chicken and egg process with customers withdrawing their request and re-entering a new request in hopes that a different transmission customer would agree to fund the transmission upgrades that would then enable their subsequent request to get approved without them

needing to pay for the upgrades. This dropping out and re-entering also required the TSP to study the same basic requests multiple times before all those transmission customers made their final decision.

There are opportunities to change how the TSP's processes work in the West. These opportunities could include discussion on how best to determine ATC under a regional markets dispatch, how to manage the seams between TSPs, and how transmission service can facilitate improved market efficiencies. These opportunities can also include discussions regarding pancaked rates and the barriers they create for market efficiencies, how the current TSP's Seams create barriers to transmission development, and changes to the way transmission service is granted and curtailments are managed across the market footprint. Some of these issues are currently being discussed in a variety of forums including market development, WECC, and of course between TSPs.

5.1 Regional Tariffs

A regional tariff incorporates multiple transmission owners into a single tariff that meets the requirements of the various entities of the region it serves. The larger geographic footprint of a regional TSP does address some seams issues between individual TSPs who are part of the regional TSP's service area. The regional TSP can streamline the study process across multiple transmission owners. It also simplifies the process for determining the total cost of upgrades now that the TSP's area includes many of the former third party impacted systems as part of the regional TSP. The regional TSP still faces many of the same issues an individual TSP does regarding coordination with adjacent TSPs. Each TSP is working through their own queue of requests and studying third party impacts for adjacent TSPs, with each TSP following their OATT defined timing requirements and queue management, resulting in adjacent TSPs having nonsynchronous timelines. Other areas that the regional tariffs address are:

- 1) Tariff Service
 - a) Generation Interconnection
 - b) Transmission Service
- 2) Transmission Rates
 - a) Reflect the charges for transmission service to reflect multiple Transmission Owners
 - b) Reflect how revenue from Transmission Service would be distributed
- 3) Transmission Upgrades - Cost-Allocation/Beneficiary Pays
- 4) Discounts for Inter-Market Transactions
- 5) Ancillary Services
- 6) Non-jurisdictional limitations in participation and regulation
- 7) Force-Majeure/Limitations of Liability
- 8) Dispute Resolution
- 9) Transition Period
- 10) FERC Assessment Fee
- 11) Grandfathered Agreements

We cover some of these sections below in more detail. Those not covered are important but are not related to our seams' discussion.

5.1.1 *Generation Interconnections*

FERC Order 888 required a queueing process for GI request to allow the GI customer time to determine their next steps. This queueing process was good for generation developers who were juggling the timing for various aspects of their development efforts, such as site control, permits, equipment, etc. As competition and rising interconnect costs crept into the mix, the queue time began to lengthen. This was caused by the queueing related options that needed to be resolved before the GI customer had to either commit or withdraw their request. This original transmission customer had to exhaust all their queueing options before the TSP could begin work on the next GI request in the queue. Also, with the tremendous growth of renewable projects, the number of new GI requests in the queue grew substantially which further lengthened the time it took before the TSP could act on a transmission customer's request.

The GI process, under the FERC Order 888 context, does not provide any transmission service use of the network, it only provides the ability for the generator to connect and operate. A separate TSR is needed to facilitate moving the output from this interconnect point to the desired delivery point.

5.1.2 *Transmission Service*

There is a benefit for transmission customers to use a regional tariff when their desired service involves multiple transmission owners. The customer can make a single TSR request to the regional TSP who then works with the various transmission owners to determine if service can be granted and under what terms. Without a regional tariff, the transmission customer is faced with submitting TSRs on multiple TSPs' OASIS and navigating the different timing requirements for submitting and receiving approval for each request.

5.1.3 *Regional Tariff Implications*

Many of the regional TSPs have adopted the NERC MOD-030 Flowgate Methodology for studying tariff service requests. The transmission service analyses only reflect contract path limitations when they are the most limiting issue. The flow-based approach provides a more consistent analysis of the use for the transmission system under a regional market dispatch and as discussed above in the Reliability section, a stronger correlation between how transmission service is granted, and the curtailment of that service.

The regional TSP receives all the tariff service request that were originally spread out among the various TSPs. This creates a challenge for the regional TSP to process the larger volume of request timely and to get customers to commit to funding the necessary upgrades. The regional TSP can experience a notable decline in TSRs when their region starts to serve an organized market. The number of GI requests will either remain unchanged or increase if the organized market provides opportunities for generation developers to monetize their investment.

The sequential processing of requests can cause significant delays for customers waiting for those ahead of them in the queue to finalize their decisions. Some regional tariffs elected to create a cluster of requests for tariff services. This enables the TSP to study multiple requests at a time, reducing the delay for customers. The cluster approach also provides an opportunity to spread the cost of upgrades across the various requests. This socialization of costs sought to encourage customers to commit to the needed upgrades. These improvements were helpful for a short period but then customers, who received a significant cost allocation, would drop out of the current queue and resubmit their request in the next

study queue hoping for a less expensive solution. This approach left customers who were wanting service uncertain of their actual cost for as each request withdrew from the cluster, the required upgrades could change along with the cost allocated to each transmission customer who remained in this cluster. The regional TSP would restudy the remaining requests and reassess the upgrades and their costs until all requests remaining in the cluster committed to paying for their share of the upgrade cost.

This cycle of withdraw and restudy extended the processing times for the cluster, which also delayed the start of studying the next cluster of requests. These delays frustrated customers who needed the requested service to connect their generation resources or to serve their loads but were being forced to wait years for an answer. Two examples of how long these delays can be are the current SPP and MISO GI queues. SPP is working on finalizing clusters that were submitted in 2017 and MISO is working on finalizing clusters submitted in 2018. Based on these timing concerns, some regional TSPs have recently implemented changes that would require an earlier commitment of funding the upgrades from the customers, even funding that may be put at risk, to improve the cycle time of the clustered queues.

5.1.4 *Seams Issues*

FERC requires each TSP to identify and coordinate with other transmission systems (outside the TSP's facilities) that are affected by a tariff service request. This requires the TSP to inform the transmission customer and the affected system(s) who then need to resolve those impacts before the TSP can grant the service request. For a single owner TSP, this required significant coordination with adjacent transmission systems for studying the impacts to their transmission system for both requests made through their own OASIS and those made with neighboring TSPs. A Regional TSP is able to bridge some of these seams issues between individual TSPs by studying the impacts for those who are part of their regional tariff but will still need to reach out to adjacent TSPs for impacts on their systems.

Regional TSPs continue to work with their neighbors to improve interregional coordination. A recent example of this is the joint study conducted by the MISO and SPP to identify facilities needed by both regions to facilitate the various GI requests in their respective queues. The next step in this process is for the MISO and SPP impacted parties to agree on how to allocate the costs of those upgrades to each regional TSP and then allocating those costs to either their load or GI customers in their respective queues.

Each regional TSP continually works with their neighbors to improve the coordination between TSPs. The FERC Order 1000 placed more emphasis on this coordination and collaboration of the transmission planning processes that would make the TSR process less complex. The MOD-030 flow-based methodology can more accurately identify the impacts and transmission flows for both transmission service requests and granted service even on transmission facilities owned by others. This needs to be coordinated with the neighboring transmission owners as required by FERC. This coordination and projection of impacts would need to be handled and is enhanced and simplified if the neighboring transmission owner also uses MOD-030.

5.1.5 *Transmission Rates*

FERC Order 888 required that rates, within jurisdictional entities, be the same for the incumbent and any third-party customer. For a regional tariff, the incumbent could be a single or multiple transmission owners. FERC also implied that they were looking to reduce hurdles, including pancaked rates, for

providing service across multiple transmission owners. As the regions debated how to implement their tariff, they generally agreed that if the transmission service could be requested once, no matter what POR/POD pair, simplifying the rates for that service, it would de-pancake rates for service using multiple transmission owner facilities. This change would need to both develop a rate that would be tied to recovery of the Annual Transmission Revenue Requirement (ATRR) of the transmission owner(s) and develop a revenue distribution that would be roughly commensurate to the beneficial use of the multiple transmission owners' systems. WMEG is currently discussing these rates and service issues in their Transmission Rate Subgroup.

Another evolution for transmission rates is the increased use of formula rates by transmission owners to determine their ATRR. Formula rates have streamlined the process for adjustments to ATRR based on wholesale usage and changes in facilities determined necessary to provide regional service.

5.1.6 Transmission Upgrades – Cost Allocation

The cost for new facilities that are associated with a request for new tariff service are paid for by the requesting transmission customer. Upgrades identified in the planning process that are necessary to continue providing transmission service previously sold is borne by the transmission owner, who adds these costs to their transmission tariff, which is then recovered from its customers. The planning process identified upgrades that are mainly to address reliability and resiliency issues for existing customers.

As members recognized the need for larger upgrades and had some experiences with sharing of the costs of larger upgrades for wider benefits, some regional organizations looked to enhance their tariffs to allow for costs of upgrades to be shared with a wider set of customers. FERC has consistently held and even been taken to Federal Court over making sure that cost allocation is roughly commensurate with the benefits received from transmission upgrades. The FERC continues to have this as its policy in Order 1000.

For instance:

1. SPP filed and FERC approved a “Highway/Byway” Rate change that would assign costs of upgrades locally or over the full region based on the general concept of how those benefits were realized from a project, up to assigning costs across all SPP tariff customers for larger projects (≥ 345 kV – full regional sharing, < 345 kV and > 100 kV – 1/3 regional sharing, 2/3 local zone(s), ≤ 100 kV – 100% local zone(s)). SPP also included a Regional Cost Allocation Review process to demonstrate that this cost allocation was roughly commensurate with the benefits achieved from those costs.
2. MISO filed and FERC approved “Multi-Value” project that the costs would be shared over the full MISO (classic) footprint. (As part of their compliance with Order 1000, they eliminated zonal sharing for economic projects.)

FERC Order 1000 required each regional planning entity to determine a cost allocation method that would be used for any regionally identified and funded transmission facilities. These cost allocation methods must satisfy six cost allocation principles. In general, these principles require costs to be allocated roughly commensurate with benefits, that there be a transparent way to calculate benefits, and that cost cannot be involuntarily put on non-beneficiary entities. FERC did not define how benefits

should be determined nor how cost allocation must be done. FERC did state that different cost allocations methods can be used for different types of projects. Each planning region has filed their plans with FERC, with each having a different approach for how they comply with this order.

Transmission owners who elect to upgrade their system have an internal process they follow for determining their preferred solution. The costs for any new facilities will be included in their OATT, which is then paid for by their transmission customers. Transmission facilities that are identified and approved through the regional planning process to be regionally funded will need to be part of a regional funding process. The construction of these regionally identified facilities may need to be competitively bid, depending on the structure approved by FERC in the regional tariff. In Order 1000, the FERC required that any transmission project that received regional funding had to allow competition for the right to build the project and that the regional planning process had to remove the right of first refusal for incumbent transmission owners.

5.1.7 Interregional Transmission Rate Discount

One of the hurdles that have been discussed in various forums, especially within the seam between markets, is a recognition that the FERC Order 888 required rates for transmission service must be non-discriminatory. However, all exports from a tariff require point-to-point transmission service, whereas FERC allowed network customers in a tariff to import to serve their load as an undesignated resource, which is not additional transmission service and does not require any additional charge. FERC Order 888 recognized that imports under network transmission service would not require additional transmission service, as the payment for network service covered the use of all the transmission facilities, even if the source was different than the network customer resource.

As allowed above, most organized markets within a tariff that grants network customer the use of the full transmission system of the region for its purchase of network service, would allow imports into the market without additional transmission charges, but still requires payment for exports from the footprint. FERC, in one instance, eliminated that charge between MISO and PJM. There are efforts to try to determine how this hurdle could be reduced across market seams.

5.1.8 Non-Jurisdictional Participants

One of the “seams” issues that regional tariffs needed to resolve was the relationship and inclusion of non-jurisdictional participants as full Transmission Owners within that regional tariff framework. FERC has been considerate of those relationships and their jurisdiction and has not used those tariffs to extend its jurisdiction.

5.1.9 Grandfather Agreements

Most of the regional tariffs had to recognize that the Transmission Owners who put their facilities in the regional tariff had to maintain the Transmission Service that was already being provided thru pre-888 Tariff service as well as FERC Order 888 Tariff service. The regional tariff continued providing this service under the existing agreements to the customer until such time that service was converted to the new regional tariff or other arrangements were made with the customer. Various methods are used.

5.2 Transmission Service Seams Issues for WMEG

WMEG members will be facing these issues in market development, resource adequacy, curtailment changes, and others that will create exploring changes in TSP operations and tariff changes. As such, a regional tariff is one method to work together on these issues, although this could also be explored as a coordination task for the WMEG members.

5.3 Transmission Service Seams Recommendations

WMEG members, through the Transmission Rate Sub-Group, are exploring the rate implications of consolidating rates to a regional rate consideration. WMEG can task this or a more policy Task Force to explore a regional tariff and the plan to study the various issues raised by that path or to coordinate the changes required in WMEG member tariff to resolve the seams issues.

6 Western Resource Adequacy Program (WRAP)

Resource adequacy has traditionally been the responsibility of the LSE working with their regulators and with the BA on use in real-time. Western entities are concerned with resource adequacy and are actively discussing resource adequacy requirements and how to share those responsibilities. The WPP complied many of these resource adequacy requirements and responsibilities in a WRAP Tariff, which was approved by FERC on February 10, 2023. The WRAP will be “the first region-wide reliability planning and compliance program in the history of the West.”

The following utilities have formally committed to moving forward with the WRAP:

- Arizona Public Service
- Avista
- Bonneville Power Administration
- Calpine
- Chelan County PUD
- Clatskanie PUD
- Eugene Water & Electric Board
- Grant PUD
- Idaho Power
- Northwestern Energy
- NV Energy
- PacifiCorp
- Portland General Electric
- Powerex
- Public Service Company of New Mexico
- Puget Sound Energy
- Salt River Project
- Seattle City Light
- Shell Energy

- Snohomish County PUD
- Tacoma Power

WRAP leverages the existing bilateral market structure in the West to develop a resource adequacy construct with two distinct aspects:

- 1) Forward Showing Program through which the WPP forecasts Participants' peak load and establishes a Planning Reserve Margin ("PRM") based on a probabilistic analysis to satisfy a loss of load expectation ("LOLE") of not more than one event-day in ten years, and Participants demonstrate in advance that they have sufficient qualified capacity resources (and supporting transmission) to serve their peak load and share of the PRM; and
- 2) Real-time Operations Program through which Participants with excess capacity, based on near-term conditions, are requested to "holdback" capacity during critical periods for potential use by Participants who lack sufficient resources to serve their load in real-time.

Importantly, and as noted above, the WRAP is voluntary but any Participant that executes the WRAP Agreement becomes obligated to comply with the binding aspects of the Forward Showing Program and Operations Program with potential financial "deficiency" and "delivery failure" charges for failing to meet program requirements.

6.1 WRAP Seams Issues

Seams are created for both the Forward Showing and Operations Programs in WRAP.

6.1.1 Forward Showing Seams

Within the participants of the WRAP for Forward Showing, their seams issues are handled by the rules under the WRAP. Outside of those participants there could be different seams created for entities who are governed by different resource adequacy programs other than WRAP such as those administered by state regulatory agencies or those without an independently administered formal program.

Particularly the issues with Seams for the Forward Showing will be based on:

1. Capacity committed to one resource adequacy program should not be committed to another similar program.
2. Requirements to use capacity from resources external to the WRAP footprint, including documentation and transmission service.
3. Conflicts between the WRAP program and other state regulatory or formal resource adequacy programs.

6.1.2 Operational Program Seams

The Operations Program of WRAP will have seams with non-WRAP entities. Additionally, the CAISO has a resource adequacy program for their market participants. There may be new seams created with the ongoing market developments for EDAM and Markets+, which may include:

1. How WRAP requirements align with the commitment and change of commitments in the WRAP program (timing issues).
2. Specific requirements in WRAP on resources that conflict or need to be recognized in the markets.
3. Misalignment in the requirements or penalties between markets and WRAP.

WPP has been in discussion with the market operators and their development to assist with ways to effectively manage the seams created.

The same concerns as above will be in place for the Operational Program as with the Forward Showing about the commitments of capacity from resources outside the WRAP footprint as well as capacity commitments made to others outside the WRAP footprint.

6.2 WRAP Seams Recommendations

WMEG may want to discuss concerns regarding WRAP participation, especially for those WMEG members who have not committed to join WRAP, to identify potential gaps between or conflicts with other resource adequacy programs, potential seams issues with the two day-ahead market design efforts, and the development of potential improvements to the WRAP.

The WMEG Market Design TF could help develop policies to influence the EDAM and Markets+ markets development to resolve seams issues with the WRAP Operations Program. The WRAP has a governance structure that includes a Board, a Resource Adequacy Participants Committee (RAPC), and a Program Review Committee (PRC). Modifications to the WRAP Tariff required to address seams would need to be supported through this governance framework.

7 Green House Gas

During the WMEG Straw Proposal Phase, a Green House Gas (GHG) Task Force was formed to discuss how to model GHG attribution within the Cost Benefit Study (CBS). Through this forum, the Members discussed several different state GHG policies – especially those of California, Washington, and Colorado, but also other state and corporate goals – and how they might be modeled in a CBS or in the EDAM or Markets+ efforts. The intent of the GHG modeling in the CBS framework was not to capture all the nuances of various state policies or market designs but to assign some preference for non-emitting resources under those policies, either through a pricing mechanism or via direct emissions measurement. There were many mismatches between policy, market design, and what could be accomplished within the CBS framework and the Members made the best assumptions available for the overall modeling objectives. The key assumptions and approaches used for the CBS are documented in the CBS report.

Following the conclusion of the CBS modeling effort, the GHG Task Force considered whether WMEG would be a useful forum to further discuss regional coordination of GHG policies and how the Market Designs could accommodate them. While the group acknowledged that there is a lot of work to do to design market structures that support the achievement of state clean energy goals, do not create barriers to regional market cooperation, and observe the realities of operating a regional electric grid, at

this time, the group concluded that the best forums for that work were with Regulators and through the Market Operator-facilitated design efforts, rather than through WMEG.

8 Summary of White Paper Findings

Utilities operating in the Western Interconnect are experiencing an unprecedented number of changes to their industry. There are two new organized market development efforts underway, a new RTO starting operations in a few years, and regulatory efforts placing increased focus on new low or zero emitting generating units and enhanced regional operations. These changes will significantly change the historic operations for the impacted utilities, ushering in an entirely new set of operational challenges for those utilities. Utilities will face the need for greater coordination between entities to install the necessary infrastructure to support these changes while controlling costs and maintaining reliable and resilient service for their customers.

The WMEG members will continue to spend considerable time developing new market rules and enhancing transmission processes to meet the challenges brought on by the changes to their industry. They will also need to work closely with the various governing bodies to develop cost effective solutions to meet the desired public policy initiatives. This will require sophisticated market rules, additional transmission infrastructure, cost allocation principles, and new operational approaches.

9 Abbreviations

AFC	Available Flowgate Capacity
ASTFC	Available Share of Total Flowgate Capacity
ATC	Available Transfer Capability
BA	Balancing Authority
B/C	Benefit to cost ratio
CAISO	California Independent System Operator
CBS	Cost – Benefit Study
CF	Coordinated Flowgates
CTS	Coordinated Transaction Scheduling
DAM	Day-Ahead Market
ECC	Enhanced Curtailment Calculator
EDAM	CAISO Extended Day-Ahead Market
EIPC	Eastern Interconnection Planning Collaborative
ETC	Existing Transmission Commitments
E-Tag	NERC Electronic Tag
GHG	Green House Gas
GI	Generation Interconnect
GOP	Generator Operator
IDC	Interchange Distribution Calculator
ISO-NE	ISO New England, Inc.
JOA	Joint Operating Agreement
Markets+	SPP Markets Plus
M2M	Market-to-Market
MISO	Midwest Independent System Operator
MOP	Market Operator
MP	Market Participant
MW	Megawatt
NERC	North American Electric Reliability Cooperation
NOPR	Notice of Proposed Rule Making
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
PJM	PJM Interconnection, LLC
PTP	Point-to-Point
RC	Reliability Coordinator(s)
RCF	Reciprocal Coordinated Flowgates
RE	Reciprocal Entity
RTM	Real-Time Market
RTO	Regional Transmission Organization
SOL	System Operating Limit
SPP	Southwest Power Pool
STFC	Share of Total Flowgate Capacity
TDF	Transmission Distribution Factor
TFC	Total Flowgate Capacity
TOP	Transmission Operator
TSP	Transmission Service Provider

TSR	Transmission Service Request
TTC	Total Transfer Capability
WECC	Western Electricity Coordinating Council
WEIM	CAISO Western Energy Imbalance Market
WEIS	SPP Western Energy Imbalance Service
WMEG	Western Markets Exploratory Group
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program

Attachment A

MOD-030 Calculations for Transmission Service

Basic Principles

MOD-030 is one of three NERC Standards defining the allowable methodologies for Transmission Service Providers (TSPs) to calculate Available Transfer Capability (ATC) for use in the coordination and provision of transmission service. MOD-030 is the Flowgate Methodology. The other two are MOD-029 Rated System Path Methodology and MOD-028 Area Interchange Methodology.

The basic principles of MOD-030 are to define the potential constraining elements of the Transmission Provider's System, called flowgates, and then assess them all simultaneously for any Transmission Service Request (TSR) based on the calculated MW impact of a transfer from the source to sink (or POR to POD if source and sink are optional) of the request. Note that most flowgates are based on an N-1 operation of the transmission system, so that they would represent the limit on post-contingency flow on the monitored element. Each flowgate has a Total Flowgate Capacity (TFC) generally determined by the monitored facility's System Operating Limit (SOL). Other flowgates can represent voltage or transient stability limits, usually represented by the flow over a group of facilities and the limit based on limiting the flow to protect transmission system stability. Impacts of Existing Transmission Commitments (ETC) are subtracted from each flowgate's TFC to determine its Available Flowgate Capacity (AFC). Most MOD-030 entities also use external flowgates to help determine if there are affected parties that might need to be notified about the transmission service impacts.

For each transfer path, the transfer distribution factors (TDFs) against each flowgate are calculated. The MW amount of the requested transfer is multiplied by the respective TDF of each flowgate to determine the MW impact of the requested transfer. If the remaining AFC of any flowgate cannot accommodate the impact of the requested transfer without exceeding its limit, the request will be denied. If all flowgates can accommodate the transfer, each flowgate will have its AFC reduced by its calculated impact. Each flowgate will be impacted by multiple transmission service paths and each path will have a different TDF to the flowgate. Effective ATC is reflected as the remaining AFC of the most limiting flowgate divided by the TDF of the path on the flowgate. This also means that the limiting flowgate can be different for the same path at different times representing different conditions.

This process utilizes multiple updated power flow models for the multiple time horizons ATC is calculated. The intent is to use the best available input data for load forecasts, VER forecasts, expected generation, outages, transmission service reservations, and e-Tagged schedules when known to produce a realistic forecast for each time horizon of the physical flow impacts component of the ETC. Data sources for each of these pieces of input data may vary, however, use of centralized data sources such as SPP West RC or CAISO RC West is preferred, as the RC data systems have transmission and BA-level information for multiple areas. This power flow model building process is fully automated to take in all of the input data and produce solved power flow models for each time horizon. Impacts of approved TSRs which are not considered a part of the model for that time horizon will then be subtracted from each flowgate to determine the AFC. Scheduling and operating horizon models can be updated as frequently as hourly.

Comparison to MOD-029

MOD-029, or the Rated System Path methodology, is widely used within the Western Interconnection. There are some examples of flow-based calculations for transmission service in the West, such as within the Bonneville Power Administration (BPA) system. While BPA carries out flow-based calculations for its internal network, it still uses the Rated System Path Methodology at its boundaries. Recently, Arizona Public Service (APS) company went live with its MOD-030 implementation, which is the only current TSP to officially declare the use of a MOD-030 methodology in the West.

The Rated System Path Methodology determines dedicated transmission path segments between a defined POR and POD. Each segment also has a Total Transfer Capability (TTC) determined through a study which is generally less than or equal to the facility rating between the two points. The path segment could represent one line or transformer or multiple elements. For jointly owned facilities, each owner is allocated a share of the TTC for its use in ATC calculations. Posted paths for transmission service utilize one or more specific transmission path segments which are designated for each reservable path. ETC for each segment is determined from the base study cases and subtracted from the TTC to determine the starting ATC for each horizon covered by the base case, typically seasonal. Each transmission request on a path decrements the ATC 1:1 for the MW amount of the request on each segment that makes up the posted path. Therefore, the impacts on the path segment facilities themselves are overstated while impacts to parallel facilities are not accounted for at all. Also, if segments of transmission service are used together, the impact on the paths might be dramatically different than assessed.

Outage cases are developed during the study process and certain outages will result in a reduced TTC for the duration of the outage. These may be validated in the nearer term, but in general are fairly static reductions for the specific outage scenario. For those path segments truly represented by a single element, an outage on that path segment would result in the inability to schedule using any TSR that reserved that path segment, even if the transmission system were able to support the transactions through the remaining network.

The rated path method is much simpler than the Flowgate Methodology and does not require an automated model building system to cover multiple time horizons offered. The base models generally utilize conservative assumptions for transmission system status, generation dispatch, load, and interchange (although the current situation could be worse than the studied base model) when determining the baseline and outage scenario TTCs.

Another factor of MOD-029 is that neighboring facilities and transactions are not accounted for except to the extent they are part of the ETC in the base models used to calculate TTC. External party TSRs and e-Tagged schedules are not included in the ATC calculations and external flowgates are not considered as potential limitations.

Potential Benefits of MOD-030

There are several potential benefits of utilizing MOD-030. Although seasonal or monthly models utilized in MOD-030 can also use more conservative assumptions than the near term to account for uncertainties, the fact that TSRs are assessed against the entire network based on impacts and using the

full SOL of the constraint still generally leads to more availability on most, if not all transmission service paths of a TSP. Using a consistent flow-based approach can also result in greater generation deliverability in those longer-term Network Integration Transmission Service studies and where generation assets may require some sort of Point-to-Point (PTP) reservations for delivery.

The dynamic nature of the short-term modeling process using the best-known data can yield much greater availability in the Scheduling and Operating horizons while still capturing conditions where capability is reduced for short durations due to specific system conditions such as Peak days and planned outages.

Since MOD-030 ATC evaluations look at constraint impact, specific transmission system upgrades can be pinpointed to maintain existing and grant new transmission service where a constraint is consistently a bottleneck. Conversely, the conservative studies under MOD-029 and assessing 100% of transfers on a path segment may also indicate a need for capital projects to increase TTC on a segment that are not identified as necessary yet using a flow-based evaluation.

Impacts on neighboring TSPs can also be coordinated more efficiently. External parties' flowgates can be represented and automated model development can account for neighboring systems as well. You can also coordinate external party TSRs and e-Tagged schedules that may affect your transmission system due to loop flows.

For those in Markets with logical constraints representing the calculated transfer capability, the fact that short-term ATC may be dramatically increased can also be a benefit.

Finally, while it is not a primary benefit for converting to MOD-030, the implementation of MOD-030 can bring auxiliary benefits for TSPs in the implementation of FERC 881. Specifically, the automated powerflow model component of the MOD-030 is well suited to receive flowgate ambient adjusted ratings in a streamlined process, compared to MOD-029, and may mitigate some challenges of FERC 881 incorporation into MOD-029.

So, there are several potential benefits of moving toward a MOD-030 approach. However, each TSP should perform its own benefits studies with its specific business objectives in mind to get a better assessment of the potential benefits.

Regional Coordination

Moving to MOD-030 in the West is not without its challenges. The largest hurdle being the fact that most neighboring TSPs are using the MOD-029 Rated Path methodology. The two methods do not mesh well and without overhauling the established scheduling practices in the West, it generally means that many of the POR/PODs between MOD-030 and MOD-029 entities need to remain in place and the MOD-030 methodology be molded to fit. If more TSPs move to MOD-030, POR/PODs could be consolidated over time, however, this may result in a longer, stepwise process towards a streamlined MOD-030 model similar to many Eastern MOD-030 TSPs.

MOD-030 can be implemented unilaterally as APS has done, however, it could be much more effective and efficient if multiple regional or subregional TSPs were to transition together. Even if this was not under a Regional-type Transmission Service Tariff and single TSP, developing the common methodology,

data exchange processes, rules and software systems potentially would provide continuity and allow for those regional entities to consolidate and streamline their scheduling paths compared to MOD-029. A single calculation system could even be developed to determine ATC for multiple TSPs, reducing costs and maintenance overhead. This could be a function that would make sense for the RCs to take on as they already have significant systems, data, and processes that would be more cost effective to modify. Additional coordination may be required for a TSP to transition to MOD-030, such as a TSP with facilities solely within the footprint of one or multiple other unaffiliated balancing authorities and transmission operators. In this case, the TSP may need to work with the BA(s) and Transmission Operators to agree on specific areas of design and operation before an implementation could occur.

Even if not performed on a regional basis, coordination with other neighboring TSPs to that group and all Transmission Customers will be important.

With neighboring TSPs, developing guidelines for the calculations, how impacts on other parties' facilities are accounted for, and what data is necessary from your neighbors to be effective are all a part of transitioning to MOD-030. This is especially important in the event there are jointly owned facilities within a TSP's network. Mixing MOD-029 and MOD-030 Transmission Service methodologies for the same facilities can be a challenge. This mixture necessitates specific definition of what each parties' rights represent in their methodology, how to ensure that those using MOD-029 will not be infringed upon, and how the MOD-030 entity will ensure they are not oversubscribing their rights. This can often be a slippery discussion since physical flows have some impact on everyone's facilities, even where a TSP has no ownership. This is true under a mix of MOD-030 and MOD-029. Using an approach called Share of Total Flowgate Capacity (STFC) and Available Share of Total Flowgate Capacity (ASTFC) is one option pursued by some MOD-030 TSPs. STFC involves a flow-based assessment on the whole facility plus an assessment of just the impacts using its provided service alone. This is performed using the TDFs mentioned above for reservations, schedules, and Generation to Load impacts. All impacts of other TSPs are ignored in this process. All of this requires good communication, education, and coordination with neighboring TSPs.

TSPs should evaluate their customers and their specific needs to determine the appropriate level of customer outreach to ensure their transmission customers have an opportunity to understand project timeline, design elements, operational details, and any anticipated changes in their service of transitioning from MOD-029 to MOD-030. It may also be appropriate to plan for customer-specific meetings, where customer details can be covered on a one-on-one basis with each customer, such as specific TSR conversion from MOD-029 to MOD-030 and contract changes.

Energy Markets Impact

The markets in the West function with most TSPs using the MOD-029 methodology today, but with different representations of the use of the committed transmission service and any unused capacity. So, moving to MOD-030 is not a requirement of the Markets, and certainly not the Imbalance markets as they are defined today for WEIM (CAISO) and WEIS (SPP). The MOD-030 approach does however align more closely with how the market engines for the security constrained economic dispatch work. They also are assessing the transmission system using flow-based generator to load shift factors. For those in the energy imbalance markets that utilize logical constraints based on transfer capability between

parties, moving to MOD-030 may provide increases in that capability. These logical constraints are still often binding within the WEIM reducing potential benefits, even with the high number of participants and overall interconnections/paths that could be used to represent the most efficient and physically reliable dispatch. Although the models of the market operators could be quite different than those of the individual TSPs, in theory, the same constraints showing up in the security constrained dispatch would be the same ones showing up as limiting to the TSPs ATC for some of its paths. Having consistent flow-based methodologies and also opting to have the market system assess physical constraints within a TSP's network could help both parties improve their models by reviewing these constraints. This also provides their transmission customers with a more accurate picture on the available use of their service.

The need for improved transfer capability in these markets may be even more important as they evolve to EDAM and Markets+ respectively. These market rules are still being developed but proposals for compensation for the market transfers are a part of these market designs and making the most transmission service available that is still reliable could be even more important to maximize benefits of regional commitment and dispatch, not just imbalance related redispatch and very short-term commitment. Also, the market's use of uncommitted transmission would be also better represented in the continued assessment of transmission service after the day-ahead market closing.

MOD-030 is not a prerequisite for joining a full RTO market such as CAISO's MRTU or SPPs RTO West, but under both of those market designs, the TSP function is turned over to the RTO. In both cases, those are flow-based designs. So, moving to MOD-030 prior to joining might provide better insight into expected constraints under that paradigm. CAISO continues to hold to rated-path limitations for its interconnections to other providers, but internally, the market is all flow-based.

In terms of Market-to-Market Coordination, the calculation of Available Transfer Capability between the markets for bilateral sales is a separate function from Market-to-Market dispatch coordination. Calculating available transfer capability would become a function of the RTO but bilateral transmission sales would still be performed primarily outside the DA and RT Market horizons. For Market-to-Market coordination, separate seams agreements are made outlining how both markets will coordinate data and even dispatches. The Markets are respecting constraints in the other RTO(s) on a flow basis and in some cases re-dispatching to manage a constraint in the other RTO with compensation mechanisms in place.

Transition Process

Transitioning from MOD-029 to MOD-030 is a major initiative, involving extensive changes to people, process, and technology. Generally, we recommend that the project be broken down into three phases, and the outcomes of one phase resulting in the principles and strategy for executing the subsequent one.

1. Planning phase:
 - Align organization on drivers and goals and conduct a benefits assessment.
 - Perform a gap assessment to evaluate the impacts to people, process, and technology resulting from the transition to MOD-030.

- Develop a comprehensive implementation plan covering charter, organization, work breakdown structure for the solution delivery, and a project management plan.
- Develop the Budget and Schedule for the Design and Implementation phases.
- Develop Business Case and obtain approval.

2. Design phase:

- Vendor Selection, statement of work development, and contract negotiations.
- Business design, assumptions, and key decisions for power flow modeling, commercial transmission, and joint ownership (if needed).
- System architecture and integration design involving multiple vendor and internal applications.
- Stand up an environment (consisting of all relevant applications) to validate design assumptions
- Finalize all functional and system design elements.

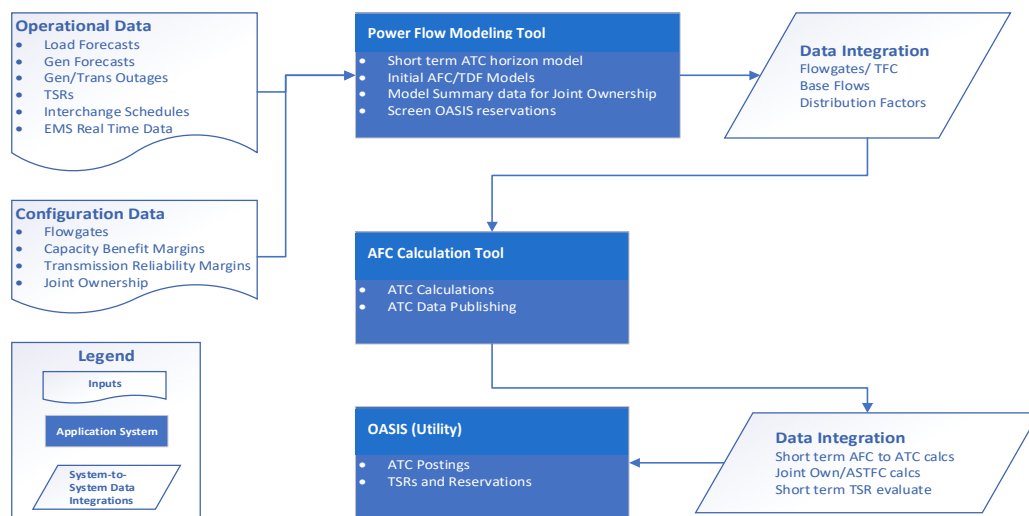


Figure 1: Sample high-level system integration and data flow

3. Implementation phase:

- Develop, configure, and customize applications to align with the final functional/system design.
- Create a Test Management plan, design test scenarios, and test cases aligned with the final design and requirements.
- Deploy the applications and data integrations in a production-like environment for functional, system, integration, and user acceptance testing.
- Conduct Parallel Operations in the pre-production system simulating the future production processes.
- Create a Cutover plan and switch over to the new MOD-030 capable systems.
- In parallel to the system efforts, undertake:

- Tariff and Business Practice Updates
- External coordination and outreach
- Internal Change Management
- Transmission Rights conversion

Start to finish, if resourced appropriately, the transition can be executed in about 2.5 years. However, the schedule could be longer if a multi-TSP implementation is undertaken, especially the first two phases and reaching agreement among multiple parties on the design and implementation approach.