

Western Markets Exploratory Group

Transmission Rate Sub-Group (TRSG)

White Paper

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1 Executive Summary

The Western Markets Exploratory Group (WMEG) is a group of utilities located in the Western Electricity Coordinating Council (WECC) who are interested in reviewing the impacts that regional organizations, organized markets, Regional Transmission Organizations (RTO), regional planning, and regional tariff administration may have on neighboring markets and transmission systems.

The WMEG formed a Transmission Rates Sub-Group (TRSG) originally to discuss what analysis would be performed to examine the impact of developing and implementing a regional tariff, and in particular to evaluate de-pancaked transmission rates not only to facilitate the markets but also to meet the FERC Order 2000 requirements. As such, the TRSG gathered current transmission rates and the basis for those rates from members interested in this analysis. This data could be used to examine the impact of how transmission service rates will be affected by consolidating under a regional tariff with a de-pancaking of individual utility transmission rates. The TRSG would also evaluate revenue distribution from transmission service to mitigate any significant impacts that could support the potential evolution of the current organized market(s). This information could help guide future organized market development discussions regarding what type of transmission service rates would best support the desired market configuration.

The objectives for the TRSG also included a discussion of how issues may arise from a future de-pancaked transmission service tariff, discuss how transmission service revenue distribution can mitigate issues, and review how other regions have addressed these issues. The TRSG reviewed various operational issues and transitional steps taken by others as their markets evolved. The TRSG reviewed California Independent System Operator (CAISO), SPP and MISO and their evolution of Tariff transmission rates.

The TRSG then created this whitepaper to help start addressing the cost shifts and detail the operational challenges and benefits related that could come about as a result of a regional rate method. The whitepaper provides an overview of these challenges, highlighting key points and notable differences between them. The whitepaper also discusses possible approaches for transitioning from multiple utility transmission service rates to a single regional transmission rate system. Future analysis of scenarios with the collected data and transmission service processes could be used to help inform the WMEG, for the benefit of all WMEG participants.

The TRSG did provide some continued work recommendations that would be productive to continue this work.

1.1 Current State of WECC

There are a number of utilities operating in the WECC region who manage their own transmission service tariffs. The CASIO operates under a Federal Energy Regulatory Commission (FERC) approved regional transmission tariff and executes the transmission service provider (TSP) function. Besides CAISO, the West has many TSPs who coordinate with their RC to maintain reliable operations of the WECC transmission system.

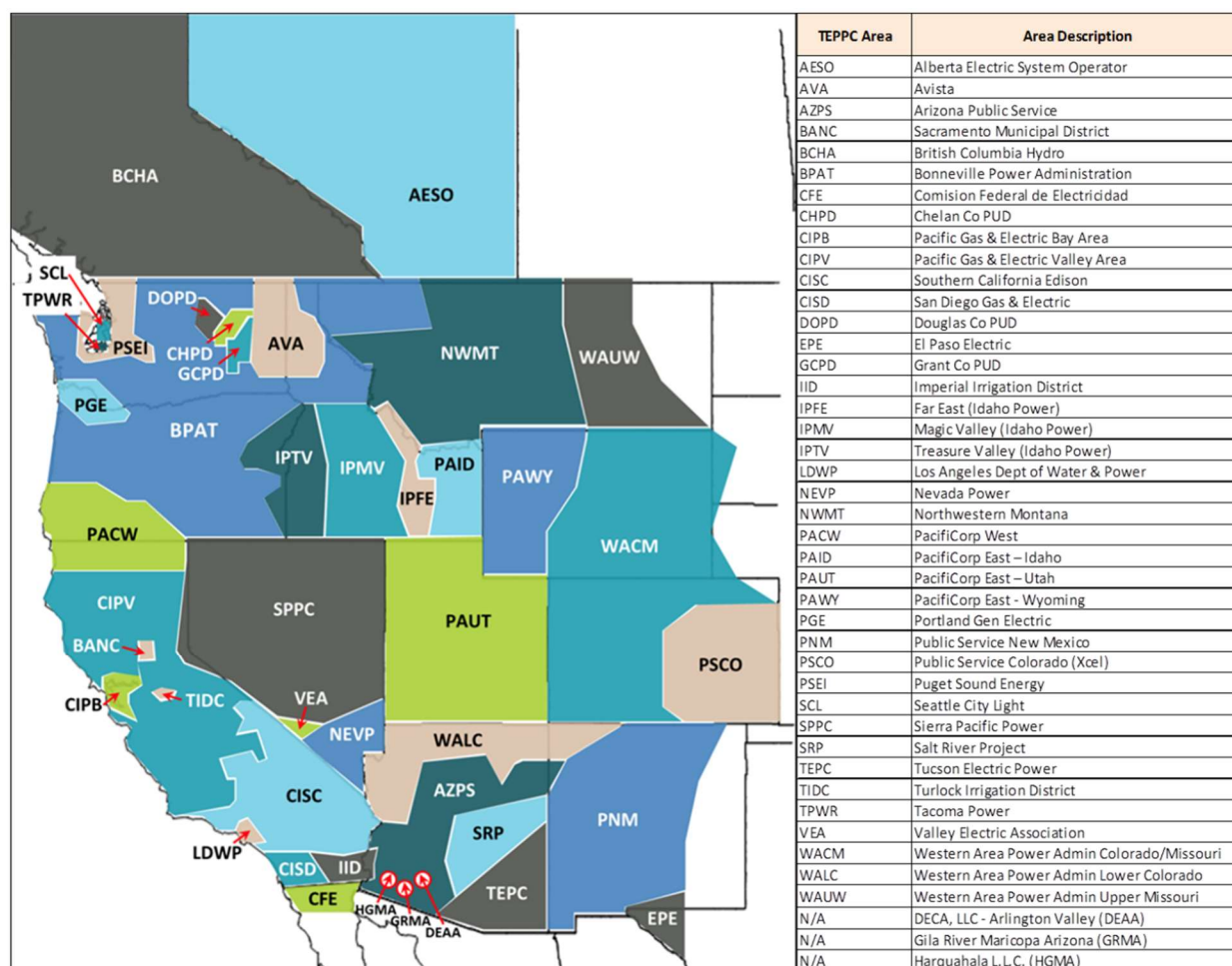


Figure 1. Load Areas in WECC¹

The WECC has multiple energy markets currently in operation; a bilateral market, the CAISO RTO market which integrates with CAISO managed Western Energy Imbalance Market (WEIM); and the SPP managed Western Energy Imbalance Service (WEIS) Market. Over the last several years, most WECC entities have transitioned to real-time organized markets with their participation in the WEIM and WEIS. The SPP has also announced the expansion of their RTO to the West with several WECC entities evaluating the benefits of joining the SPP RTO West. It is anticipated that individual organizations and regional collaborations will change the footprints of the existing RCs, BAs, TSPs, as well as WEIM and WEIS, as organizations transition from their current state to their desired final configuration. The CAISO RTO and SPP RTO West will use a Consolidated Balancing Authority (CBA) configuration, while the other developing market designs (i.e., EDAM and Markets+) will continue to retain the individual BA configurations.

¹ WECC ADS Data Development and Validation Manual.

https://www.wecc.org/Reliability/ADS_Data_Development_and_Validation_Manual_9-13-2021_V3.1.pdf

2 Legislative and Regulatory Changes

The US Congress passed the Federal Power Act of 1992 (FPA) which changed the authority of FERC. In response, FERC issued a “Mega-NOPR” on March 29, 1995, that questioned the role of transmission in reducing competition in wholesale electricity markets.

2.1 FERC Order 888

On April 24, 1996, the FERC issued Order No. 888², which required public utilities to provide open access transmission service on a comparable basis to the transmission service they provide themselves. Accordingly, in the proceeding and in the accompanying proceeding on OASIS, FERC, pursuant to its authorities under sections 205 and 206 of the FPA:

1. requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce
 - a. to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service;
 - b. to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs; and
 - c. to develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that the public utility enjoys, and further requires public utilities to separate transmission from generation marketing functions and communications;
2. clarifies Federal/state jurisdiction over transmission in interstate commerce and local distribution and provides for deference to certain state recommendations; and
3. permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and FPA section 211 transmission services.

FERC’s goal in issuing the Order was to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower-cost power to the nation’s electricity consumers. Order 888 put in place several key conventions that still drive the way the electricity industry operates today.

In subsequent orders, FERC added:

1. Order 2003, Large & Small Generation Interconnection Process – In order to standardize the processes and requirements for interconnecting new generation to the transmission system.
2. Order 890, Planning – FERC sought to make improvements to its pro forma open access transmission tariff, and better achieve the goal of eliminating undue discrimination/preference by mandating coordinated, open and transparent transmission planning on a local and regional level.

² FERC Order 888. <https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888>

3. Order 1000, Regional and Interregional Planning: Requires each public utility transmission provider to:
 - a. Participate in a regional transmission planning process that produces a regional transmission plan.
 - b. In addition to identifying reliability and economic transmission needs, such processes must provide an opportunity, with stakeholder input, to identify transmission needs that are driven by public policy requirements established by local, state, or federal statutes or regulations, and then to evaluate potential solutions to those needs.
 - c. Coordinate between neighboring transmission planning regions with respect to interregional transmission facilities.
 - d. Remove from FERC-jurisdictional tariffs and agreements any federal “right of first refusal” (essentially, an incumbency preference) to build new transmission facilities selected in a regional transmission planning process. FERC is not seeking to preempt state authority over siting, permitting, or construction. And, in compliance orders, FERC has clarified that state/local “rights of first refusal” can be recognized in the planning process, and early in that process.

Wholesale trading expanded quickly after Order 888 was issued, growing from approximately 100 GWh in 1996 to close to 4.5 thousand GWh in 2002³. However, until states began restructuring, the only buyers were still the utilities. Restructuring in some key states including California, New York, and Pennsylvania began in the late 1990s, opening the door for marketers and generators to sell directly to end-use customers.

2.2 NERC’s Response to Order 888

NERC formed several groups to debate the issues raised in the NOPR and to provide comments to FERC on various proposals and their potential impact on reliability. NERC also provided recommendations on how to maintain reliability. The following are some of the areas addressed:

1. Wide Area Coordination of Reliability
2. Ancillary Services
3. Open Access Same-Time Information System (OASIS) provisions
4. Interchange Scheduling

NERC took on changes in their Standards to respond to the suggested changes and what was finally adopted in FERC Order 888. Some of these changes were:

1. Define the Functional Entities necessary to maintain reliability and establish the requirements for each function, including the new RC and TSP functions.
2. Develop a tool for those RCs to both share information and communicate with the BA, TSP, and transmission customers who submit their schedules in Tagging for the use of the transmission

³ Energy Knowledge Base – FERC Order 888. <https://energyknowledgebase.com/topics/ferc-order-888.asp>

system irrespective of which TSP sold the service. This tool, known as the Interchange Distribution Calculator (IDC), would also assist in identifying the needed curtailment of flow on the transmission system based on curtailing transmission service aligned with FERC Order 888 priority of service.

3. Adjust Standards to reflect the requirements for Ancillary Services
4. Develop the function and operations of the OASIS
5. Develop and implement Tagging by fax for Interchange Scheduling

3 Major Functions of Order 888 Tariffs

FERC Order 888 standardized the provision of transmission service over the facilities that were under the specific entity's tariff. There were two services that were defined in Order 888 with another added in Order 2003:

1. Point-to-Point Transmission Service (PTP)
2. Network Integrated Transmission Service (NITS)
3. Order 2003 – Generator Interconnection Service (GI)

Later sections will cover any aspects that will be applicable to regional tariff changes.

Also, FERC Order 888 standardized the ancillary services that were necessary for providing those transmission services:

1. Schedule 1 - Scheduling, System Control and Dispatch Service
2. Schedule 2 - Reactive Supply and Voltage Control from Generation Sources Service
3. Schedule 3 - Regulation and Frequency Response Service
4. Schedule 4 - Energy Imbalance Service
5. Schedule 5 - Operating Reserve - Spinning Reserve Service
6. Schedule 6 - Operating Reserve - Supplemental Reserve Service

Generally, these ancillary services were to be provided by the TSP or the BA but the tariff allowed the transmission customer to self-provide.

4 Regional Tariff Evolution

4.1 Evolution for CAISO

The California legislature passed AB 1890 in 1996 that placed in motion the creation of the California Independent System Operator (CAISO) and the California Power Exchange (CPX), with both organizations starting operations in 1998. AB 1890 also ushered in retail competition for the state of California, which directly impacted the three investor-owned utilities (IOU) who served roughly 70% of California's retail load and required these IOUs to divest of 50% of their fossil fueled generating facilities.

The CAISO took over the management of the transmission services for the three IOUs, with the three IOUs retaining ownership of their transmission and distribution facilities. The CAISO managed services included managing the CBA for the three IOUs jurisdictional areas, operating the real-time and ancillary services markets, and management of transmission usage and congestion. The CPX was an independent market clearing exchange that originally cleared only day-ahead energy market submissions before adding a forward energy market in 1999 which cleared bids for up to six months out before ceasing operations in early 2001. The WECC, during this period, was the RC for the entire West.

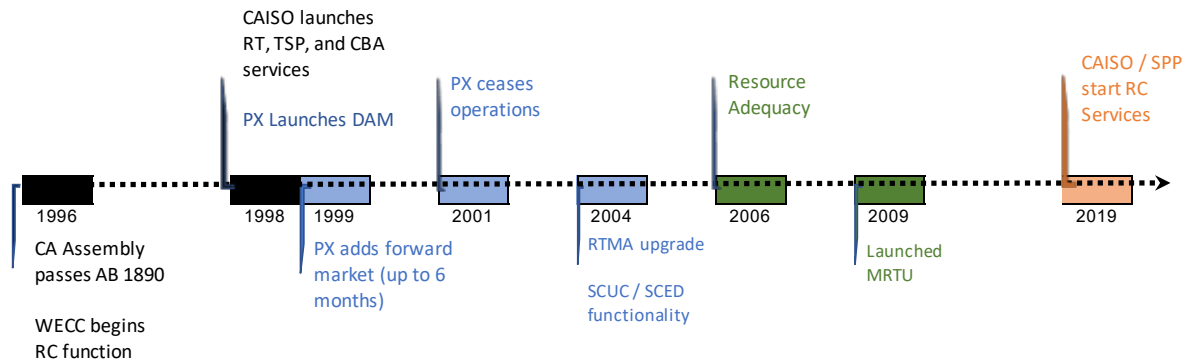


Figure 2. CAISO Development Timeline

WECC elected to spin off the RC function and responsibility to an independent organization called Peak in 2014. Peak performed the RC functions until ceasing operations in 2019 when RC West, Western RC Services, and BC Hydro RC began fulfilling the RC functions for select entities in WECC.

4.2 Evolution for MISO

The Midcontinent Independent System Operator, Inc., formerly named Midwest Independent Transmission System Operator, Inc. (MISO) is an Independent System Operator (ISO) and Regional Transmission Organization (RTO) providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States, Manitoba, Canada, and a southern United States region. The 15 states covered in whole or in part by MISO are Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin.

MISO was established as an ISO in 1998 after voluntary discussions by several transmission owners (TOs) led to its formation. One year later, the first board of directors was elected. By the end of 2000, the organization had more than 70 employees. In 2001, FERC approved MISO as the nation's first RTO.

MISO began Reliability Coordination Services for its members in December of 2001. Day-ahead reliability studies and outage coordination processes were established to provide situational awareness to the operators in real-time. Real-time monitoring of topology, power flow, reactive power, and voltages were done by the RC to ensure the reliability of the power grid. MISO built on these services in January of 2002 when it implemented real-time scheduling, tagging, and tariff administration services.

MISO launched its new energy markets in April 2005. These new energy markets provided a day-ahead market (DAM), real-time market (RTM) and Forward Reliability Assessment and Commitments that were completed prior to the operating day. To complement the DAM and RTM, MISO added an ancillary services market (ASM) on January 6, 2009. The combined markets provide energy and operating reserves and regulation and response services supporting reliable transmission services. MISO became the BA Operator and took on the responsibility for most of the NERC BA Standards. A few requirements remained with the local BA and were identified in a compliance matrix document. MISO was also the administrator for the reserve sharing group.

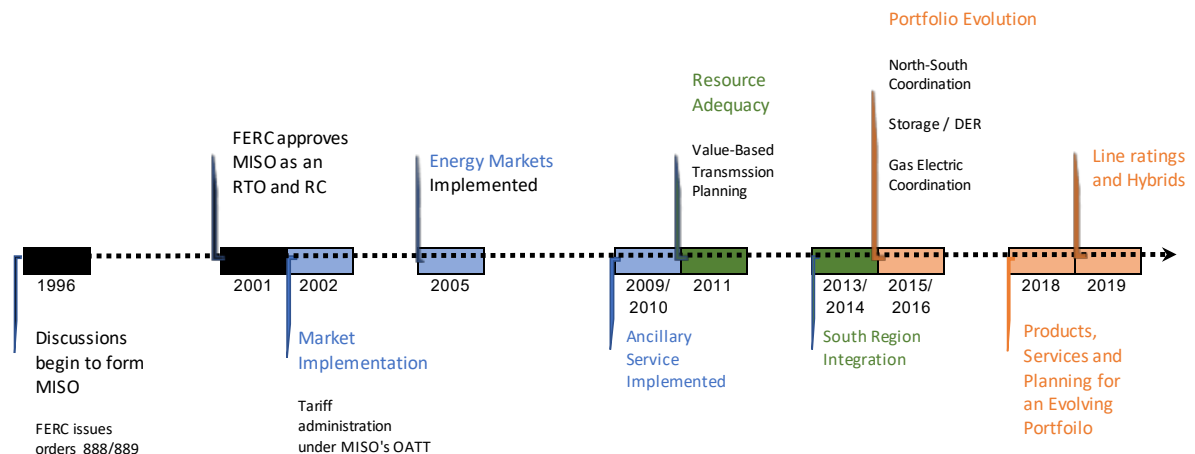


Figure 3. MISO Development Timeline

4.3 Evolution for SPP

SPP was formed in 1941 to “pool” utility resources, including transmission and generation, to meet the war time need for Aluminum. The utilities agreed to share their resources and coordinate plans to serve that war need. During and after the war, SPP continued to exist as a loose coordinated effort of those utilities even though SPP had no staff and only a one-page paper agreement of cooperation. SPP continued its focus on improving reliability which led to the implementation of a telecommunication network for the member utilities to share data in 1980 and an automated operating reserve sharing system in 1981. SPP incorporated as a not-for-profit corporation in 1994.

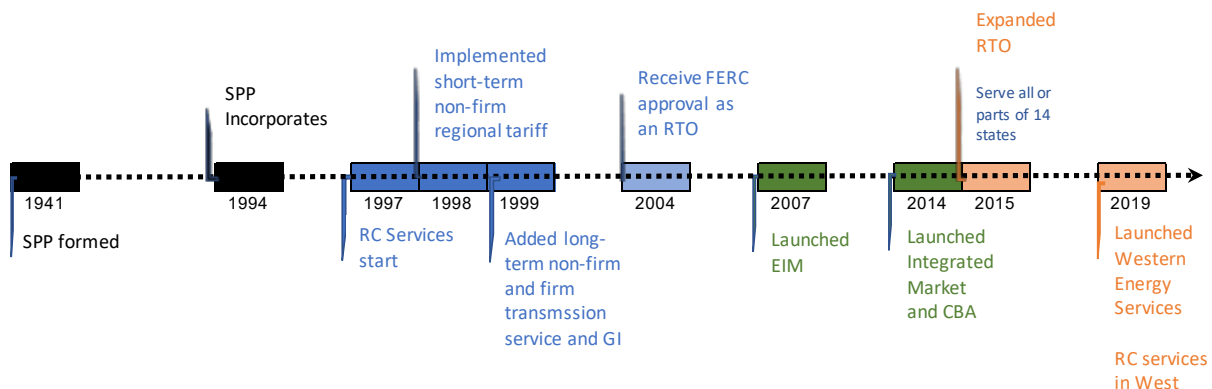


Figure 4. SPP Development Timeline

4.3.1 SPP Response to NERC and Order 888

SPP members began discussing how a regional tariff could meet the FERC NOPR expectations, provide efficiencies for managing the transmission system, and increase the efficiency of the wholesale markets by reducing the burden of “pancaked” transmission service. SPP members realized that SPP would be the best organization to take on the function of reliability coordination (<https://www.youtube.com/watch?v=fUCWbQpZGUw>). In order to provide the RC function, SPP invested in personnel and an EMS in order to assess the reliability of the transmission system as well as forecast any issues that would be faced in the near term. With this effort, SPP implemented the RC function in 1997 and took on those responsibilities.

SPP members also realized that if, as proposed by NERC, transmission service would be curtailed based on the flow of that service, they would push forward with a regional transmission tariff development to sell the use of the transmission service using flow-based analyses (also termed MOD 30 in NERC vernacular). SPP implemented the associated tariff changes in stages:

- 1998, implemented a regional tariff with Short Term, Non-Firm, Point-to-Point Transmission Service
- 1999, added Long Term, Firm and Non-Firm, Point-to-Point Transmission Service
- six months later added the remaining Order 888 Transmission Services and Generator Interconnections
- Additionally there was a transition period that required that each TO that had facilities under the SPP Tariff would have to take network service within ten years of the start of the regional tariff. This was accelerated by the introduction of the markets in SPP as network service provided the means to make the markets more effective.

4.3.2 SPP Regional Tariff Implications for BAs

FERC required that the TSP provide the defined Ancillary Services but also allow the Transmission Customer to self-provide those services. SPP specified in their tariff that the transmission customer could self-provide by paying the Ancillary Services rate in each of the affected BAs, and if they did not self-provide, SPP would arrange with those BAs for the Ancillary Services.

1. For regulation, operating/supplemental reserves, and imbalance, the rates would then be based on the BA existing published rates.
2. Physical losses for each schedule were determined by calculating the energy loss associated with moving energy from the Source to the Sink, with such losses then distributed to the impacted BA.
3. Note that the Source and Sink BA within the SPP footprint would be the only ones approving the Tag now that a single transmission service request facilitated the desired transmission service flowing across several TOs’ systems.
4. Voltage control would be provided by the existing provisions of the host TOP.

4.3.3 SPP Wholesale Market Development

In 2007, SPP implemented the Energy Imbalance Services Market (EIS), a 5-minute real-time market. In that market, SPP would dispatch all offered resources (generation or load control) to meet the full obligation (load – self schedule resources) of the market footprint, irrespective of the BA. The BAs were still responsible for providing the required Ancillary Services, but the market replaced the provision of energy imbalance for both load and generation.

In 2014, SPP implemented the Integrated Marketplace and CBA that added the Day-Ahead and Ancillary Service Markets as well as financial Transmission Congestion Rights. The members recognized that for SPP to be a BA, it would need dispatch authority of the resources to meet the NERC BA requirements. The members also recognized that by obtaining those resources using markets, there would be savings from both the amount of Ancillary Services required and the cost to provide those services. SPP added an agreement to its tariff that requires the TOs to provide and maintain the metering required for the SPP CBA. There have been no significant changes in the SPP BA functions post 2014.

5 Development of Regional Tariffs

In discussing consolidating of transmission tariffs for either the benefits that it provides or in pursuit of RTO status, in this whitepaper the combination is called a Regional Tariff. These Regional Tariffs, mostly, have taken the FERC Order 888 form of Tariff and modified the portions that would need to be changed to meet the requirements of the region.

In order to discuss the development of such a Regional Tariff, the following sections and additions need to be considered to further reflect the region needs:

1. Transmission Rates
 - a. How transmission service would be charged to reflect multiple TOs
 - b. How the revenue from transmission service would be distributed back to the individual utilities
2. Tariff Services
 - a. PTP (Firm and Non-Firm)
 - b. NITS (Firm and NN-6)
 - c. GI (NRIS and ERIS)
3. Transmission Upgrades - Cost-Allocation for new transmission
4. Discounts for Inter-Market Transactions
5. Ancillary Services
6. Non-jurisdictional limitations in participation and regulation
7. Force-Majeure/Limitations of Liability
8. Transition Period
9. FERC Assessment Fee
10. Grandfathered Agreements
11. Recovery of Administrative Costs

In the following subsections, the basic revisions needed to transition the Order 888 pro-forma tariff into a Regional Tariff are discussed. In addition, issues that have arisen from these efforts and some thoughts on resolution will be provided.

5.1 Transmission Rates

In Order 888, FERC required that rates within jurisdictional entities would be the same for the incumbent as well as the third-party customer. FERC also implied (see their ISO requirements) they were looking to reduce hurdles including pancaked rates for transmission service.

Most regions, looking at Regional Tariffs, understood that they would need to sell transmission service across multiple TOs (one POR/POD pair and not multiple pairs to span those TOs). In fact, based on the basic premise that they would be trying to maximize the use of the transmission system in the Regional Tariff, each intended to provide transmission service on a flow basis (how the energy would flow over the transmission facilities) and not on a contract basis (where the flow would exit a TO facilities). One rule used in most of the Regional Tariff is that you had to request from source to sink and not have the capability to piece together transmission service, at least internal to the footprint of the Regional Tariff.

The transmission rates were intended to both:

1. Develop a rate that would be tied to the Annual Transmission Revenue Requirement of the TO(s)
2. Develop a revenue distribution that would provide compensation to the multiple TOs for the benefit of their systems “use”.

5.1.1 Issue #1 – To De-pancake or Not

In the age of the development of most Regional Tariffs, there was a push to de-pancake the rates of the transmission service provided, to reduce barriers to the commerce of energy, as well as to simplify the collection and distribution of the revenue from transmission service. This had been implied by FERC’s merger policies in place at the time as well as the expectation of those regionals to meet the FERC indicated expectation for ISOs.

There are methods to continue to have pancaked rates within the Regional Tariff, and they can be complicated and administratively burdensome. Some analysis is necessary to see what rates would result from these methods, as there is some that would be helpful to de-pancake rates.

All the current Regional Tariffs have de-pancaked rates through one of two methods:

5.1.1.1 License Plate Rates

License plate rates are the most common rate methodology used in existing Regional Tariffs. License plate rates are where the transmission customer pays a rate, normally derived from the rate where they sink the energy. As such, the rates can be different based on the sinks involved for the transmission customer(s). Generally, these rates were established as the existing rate of the TO where the sink of the energy was located. This keeps, at least, most of the transmission customers that would be transitioned to the new rate paying the same or about the same rate as they were paying prior to the inclusion of the TO’s facilities into the Regional Tariff. The transmission customers would have full access to all the

transmission facilities in the Regional Tariff through that one rate they would pay based on their sink. This rate would be set to fully recover the costs of the TO within that sink area.

This is one of the major issues with Regional Tariffs, that if a transmission customers wanted to, or already used neighboring TO's facilities, that previously, they would have to buy service over and pay that rate to the intervening TOs, they would not have to pay that rate and the intervening TOs would lose that revenue, which would result in higher rates for the customers paying their rate.

Most Regional Tariffs were created with some method to help compensate those intervening TOs for that loss of revenue. Note, this is about the distribution of revenue that will be covered below. This would be an issue to resolve in any Regional Tariff.

5.1.1.2 Postage Stamp Rates

Another method to de-pancake was just to set one rate for all service in the Regional Tariff as in CAISO, ERCOT, and NYISO. These were usually Regional Tariff within one specific state, which was driven within the legislative or regulatory authorities within the state. In this rate all the TOs are still fully recovered. The real issue is that each customer's rate would be different than what they would have paid before for the same service. This has been encountered in merger contexts also, particularly within a specific state and both methods have been used.

5.1.2 Issue #2 – Through and Out Rates

For the most part, traditional through and out rates were the same as those that were sinking in the footprint of the TO. For Regional Tariffs, the same method could be used to determine the rate to be used, by using the rate of the TO where the energy would exit the Regional Tariff. This replicates what was available to the transmission customer previously. But this could exasperate the loss of intervening TOs. Note, below we can cover revenue distribution as an issue and some solutions to help mitigate this loss.

Even in using this as a through and out rate, another consideration was important to resolve. Since several external areas were connected to multiple TOs within the Regional Tariff, with multiple rates that could be used, there needed to be a single rate for that exit point. Some used the cheapest TO rate that was connected to the exit area. This recognized that previous to the Regional Tariff, the transmission customer could choose and would probably choose that cheaper rate. Another method would be to use the average of those TO rates to set the rate.

For example, SPP calculates the rate using three factors, the first is the lowest rate of the internal area connected to the POD external area, the average of the zonal regional rate, and the full regional rate. MISO through and out rate is the average of all the zonal rates within MISO. CAISO through and out rates are based on the scheduling point voltage. It is a regional rate for higher voltage scheduling points and a zonal rate for lower voltage scheduling points.

Other Regional Tariffs have used other rate structures for their through and out rate. One popular one is the average of all the TO rates or the rate based on the total revenue requirements from all the TOs divided by the total service in the Regional Tariff. One last rate, that was considered but not used, was to use the highest rate of any TO in the Regional Tariff. This seems to really affect the exports from the

Regional Tariff and could be considered discriminatory with internal customers. Revenue distribution will be covered below.

5.1.3 Issue #3 – Transmission Service Revenue Distribution

Without de-pancaked rates there is usually the same amount of revenue and the distribution could be distributed to not affect the transmission customers significantly. However, with de-pancaked rates the revenue collected will be less in total than in the current situation.

With using Postage Stamp rates, every customer is affected for the most part and since the revenue is set based on the total revenue requirement, all the revenue would be distributed to the TOs to meet their revenue requirements. So, unless there is some other need, revenue distribution is straight forward.

For License Plate rates, the revenue could be used to try to mitigate the loss of revenue in total. Since the largest portion of revenue is from the NITS customers, and it represents the use of the transmission owner rate in the sink area, the revenue from NITS is usually distributed to the TO of the sink. Note, this could provide a way to “spread the pain” within the Regional Tariff. One method is to use transition payments between TOs to recognize the benefits provided to the load in the sink zones of the Regional Tariff to those with loss of revenue.

Most Regional Tariffs use the PTP and/or the Through and Out revenue to mitigate the loss. Some use that revenue and distribute it to all TOs on an allocated basis to mitigate some of the loss in revenue.

For example, SPP distributes all the zonal regional rate revenue to the TOs that represent the projects that make up the zonal regional rate calculation, all the overall regional rate revenue to the TOs that represent the projects that make up the overall regional rate calculation, and lastly the revenue collected from the zonal legacy rate, 50% to all TOs based on their ratio of the overall ATRR, and 50% on the MW-Mile for all the TOs that are impacted by the transactions.

Another way to mitigate the loss is to have revenue transfers between TOs that can help to equalize the impact of the loss. For example, as a condition to its potential membership in SPP RTO West, the Colorado River Storage Project (CRSP) area expects to retain all their Point-to-Point revenue in order to mitigate the impact on their customers.⁴ Markets+ is discussing a market uplift charge to compensate for market uses of the transmission system that would be distributed to the TOs to also help with the expected revenue loss.

5.2 Tariff Services

As shown in the discussion above about Order 888, the order did outline the transmission service that was to be provided from each jurisdictional utility. These were PTP and NITS service. In Order 2003, FERC added the Generation Interconnection (GI) service to define the process needed to allow a new generator to attach to the transmission system under the tariff. All these services were to be provided thru a generalized process:

⁴ WAPA was unable to discuss SPP RTO West via WMEG. This example is based only on public information.

1. Customer submits request to OASIS
2. Provider studies the service request
3. Provider required to provide service if Customer commits to pay for necessary upgrades
4. Service granted after upgrades are complete

Regional Tariffs followed this same method to meet the Order 888 and 2003 requirements in their tariffs. Each of these were intended to be a queued process where the first request had to be satisfied (either granted or withdrawn). Most found that the required tools and processes would work on a regional basis, even with multiple transmission owners. Note that the Customers were responsible for the cost of the upgrades in the Regional Tariff also, although there are some Regional Tariffs that have change aspects of this based on their member requirements (which will be covered in the cost allocation for upgrades below).

One agreement made in the East that assisted both the processes as well as the seams was that all service analyses were/or were changed to use NERC MOD-030 Flowgate Methodology and only reflected contract path limitations when they were the most limiting issue.

At first, the queued process worked, but there arose Regional Tariff implications based on the number of transmission service requests and cost of upgrades assignment. The first issue was the number of requests to be handled started to lengthen the queue. Even with a short period of time to resolve the first customer in the queue, the queue lengthened. The second issue was when a service request required upgrades that were extensive and needed, it “hit the straw that broke the camel’s back”, those upgrades would be provide relief for subsequent service requests that would be granted without compensation for the upgrades. The third issue was as the service requests declined to pay for upgrades, the growing need for upgrades would increase the total cost of needed upgrades.

Regional Tariffs added a process to assess the requests based on clustering the requests over a period of time and to assess the upgrades needed for all those requests and allocate the cost of those upgrades over that set of requests, that might encourage the needed upgrades. This would reduce the cost for individual requests, and also those that required the upgrades would be allocated some of the costs of those upgrades.

This “clustering” helped for a short while but soon, when customers saw their allocated costs for upgrades growing, they would withdraw from the cluster. A Regional Tariff would then have to restudy the remaining requests that might reduce the costs, but not get the commitment of all the remaining customer. This would cause a cycle of restudies and withdraws that extended the times for each cluster and all the subsequent clusters. The customers for those requests had to wait longer and longer to resolve their requests, maybe even years for an answer.

As markets developed, it reduced the use of PTP service. For those regions, the queues for transmission service were greatly reduced and no changes were required to reduce the queue back up. Most have few problems resolving the transmission service clusters in reasonable times.

For GI requests, there was a similar queueing and clustering issue as was with the transmission service requests. especially in those areas with larger resource development. The development of wind and

other renewables has heightened these issues and have caused even more delay in completing the GI requests. Regional Tariffs recently implemented changes that call for more and earlier commitments of funding from the GI customers, even putting portions of that funding at risk, to improve the cycle time of the GI clustered queues.

Currently, for instance, MISO and SPP are working on finalizing clusters that were submitted in 2018 and 2017 respectfully, although they both expect to catch up in the next year. FERC has also issued a request for information about these issues and how to resolve the backlog in the GI request processes.

Note, the traditional transmission planning activity was recognized as the method to maintain firm transmission service, so that any additional load or even additions of some generation resources into the planning activity would upgrade the transmission system to sustain that firm service. Some Regional Tariffs added processes in case there were load additions that were requested before the planning activity could take them into effect.

5.3 Transmission Upgrades - Cost-Allocation/Beneficiary Pays

Originally in most Regional Tariffs, the costs for upgrades that were identified in the planning process would be borne by the constructor, added to their Annual Transmission Revenue Requirement (ATRR), which was mostly borne by its customers in their license plate rates. This naturally, drove the upgrades from transmission planning to be for only reliability issues for those customers and required minimal investment. The upgrades from service requests were paid by the requester.

It was soon apparent in some regions that the upgrades needed would provide benefits beyond the assigned customers to pay for the upgrades. Also, FERC insisted in order 888 that service customers would be refunded the amount that they had paid for network upgrades, or upgrades that provided benefits to the network customers outside the service customer. Regional Tariffs have dealt with this in various methods, like including them in their postage stamp rates, including them in one/multiple license plate rates, even providing the opportunity to recover from congestion costs within the wholesale markets. PJM structure requires those generators that want to interconnect to the PJM transmission system to be allocated all the cost of interconnection including network upgrades to make that generator effective in their wholesale markets, including as a capacity resource.

Also, there was a recognition that the construction of larger projects provided benefits even beyond the zonal license plate rate customers. First, postage stamp rates recognized this as their costs were borne by all customers beyond the constructor's direct customers. Second, Regional Tariffs were modified to allow (mostly new upgrades) the cost of upgrades to be shared in a license plate rate structure. MISO has Multi-Value projects that are shared across the northern areas of MISO, "MISO Classic". SPP has a highway/byway structure to a regional rate that allocates the costs of higher voltage upgrades to every customer and the lower to the local license plate area. SPP also allowed some of the costs of including new resources in NITS to have some of their costs allocated to all customers in SPP.

5.4 Discounts for Inter-Market Transactions

One of the hurdles that has been discussed in various forums, especially within the seam between markets, is a recognition that the FERC Order 888 requirement that the rates for transmission service must be non-discriminatory, including exports out of one market/transmission footprint to another.

FERC Order 888 recognized that imports under NITS would not require additional transmission service, as the payment covered the use of all the transmission facilities, even if the source was different than the customer's network resource.

Most regional markets within a tariff that grant a network customer the use of the full transmission system of the region for its purchase of NITS, would allow imports into the market without additional charge, 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. At present, there have been no addition proposals to help resolve the pancaking of this rate between organized markets.

5.5 Ancillary Services

Specifically for BA and their ancillary services (Schedules 3, 4, 5 & 6), FERC required that the TSP provide those but also allow the Transmission Customer to self-provide. Until markets started to provide ancillary services, the legacy Balancing Authorities would be providing those services, Regional Tariffs specified that the TC could self-provide by paying the ancillary services rate in each of the affected BAs, and if they did not self-provide, the Regional Tariff TSP would arrange with those BAs for the ancillary services and for Schedules 3, 4, 5 & 6, the rates would then be based on the BAs existing published rates. For losses, the Regional Tariff would "charge" based on a calculated MW provision from the Source that was not received at the Sink, but distributed to the BAs in the path, thru a distribution method.

As the markets evolved, most Regional Tariffs provided Schedule 4, Energy Imbalance, through their tariff as a product of the market mechanisms. Also, most regional markets, including in their tariffs, have included both a BA consolidation and the provision of Schedules 3, 5, & 6 thru ancillary service markets.

Most Regional Tariffs have the reactive ancillary service (Schedule 2) provided by the existing provisions of the TOP, unless extraordinary circumstances that may include an additional charge. These were mostly mitigated for any situations as GI requires the ability for reactive control and also the long-term planning process included assessment and upgrades to maintain voltage reliability.

5.6 Non-Jurisdictional Limitations in Participation and Regulation

As FERC is only jurisdictional over the terms and conditions of wholesale energy arrangements and transmission for wholesale energy with public utilities, other utilities, "Public power" utilities are not under their direct jurisdiction. In moving to a Regional Tariff, those non-jurisdictional utilities were concerned that by participation in a jurisdictional Regional Tariff, they would be fully under FERC jurisdiction. Therefore, the Regional Tariffs have provided in their tariffs, limitations on the non-rate

terms and conditions of the Regional Tariff and thus FERC on those non-jurisdictional entities. Specifically, that their governance jurisdiction rules in those areas and in areas that they are still in conflict can leave the Regional Tariff. Also, Federal, State, Municipal, and Cooperative participants sometimes have additional considerations that would need to be considered.

A more recent issue was raised and resulted in some rate considerations, particularly, if FERC approves the inclusion of non-jurisdictional rates in the Regional Tariff but later has to order a refund to transmission customers, there is not a way that FERC can issue that refund. So, FERC has directed that the non-jurisdictional would need to agree to refund if so directed or to not implement the rates until the time is past for refunds.

5.7 Force-Majeure/Limitations of Liability

Most Regional Tariffs, since they represent the interests of and the services required of multiple transmission owners, have included in their tariff limitations of liability including only those for gross negligence or intentional wrongdoing. Note that in most cases, any liability would be recovered from those transmission owners as, usually, the Regional Tariff operators have very limited assets to be used to compensate those injured.

5.8 Transition Period

There are multiple aspects of service and procedures that need to be considered in creating a Regional Tariff. Below each of these will be explained and highlight some of the issues with each of those areas.

5.8.1 Issue #1 – Existing Transmission Service Agreements

Since there will most likely be existing transmission service agreements for the transmission owners in transition to a Regional Tariff, most of the Regional Tariffs have allowed a transition to regional service by respecting the terms and conditions of the existing transmission service agreements. Note, this will be covered later in the grandfathered agreement section.

5.8.2 Issue #2 – Network Service

Another special consideration is when the NITS would convert from grandfathered under the individual TO tariff to Regional Tariff service. Note there is a benefit so that the NITS customer could use the full transmission system of the Regional Tariff. First, it is beneficial for the reach of more resources for serving NITS load. Second, to use in the market it is beneficial that the NITS is under a Regional Tariff for the load to use non-firm service (NN-6) for delivery of the market power. Also, it then allows the TO to be able to meet the Order 888 requirements without its own tariff. Some have mandated a time to convert when the facilities are put under the Regional Tariff, others have allowed a transition period for the TO to work through with their regulators the interactions with their retail rates.

5.8.3 Issue #3 – Transmission Service Queues

As the facilities are put under the Regional Tariff that have existing GI or other tariff services in their queues. Transition of these queues requires that the TO and their TC work through how they would best cover the integration of the queues with all the other queues, either to put under the Regional

Tariff, or already under that Regional Tariff. Most have used the original submission date to integrate all the requests together.

5.9 FERC Assessment Fee

FERC requires that if there is a Regional Tariff, all service will be offered under the tariff, even if the NITS serves the TOs retail load. This requires each of the loads to actually pay more for FERC's assessment fees. So, some method for the collection of this fee is required.

5.10 Grandfathered Agreements

Existing transmission or GI agreements that were under a tariff before the Regional Tariff are under the original tariff terms and conditions, including the rates. Most Regional Tariffs have allowed these agreements to stand, but allow the conversion to Regional Tariff service if all parties agree. Some TOs can force the conversion based on the terms and conditions of that agreement. Others can require a conversion at the expiration or even the term of the agreement for roll-over. Some are still grandfathered in the Regional Tariff.

5.11 Recovery of Administrative Costs

Because the function of the Regional Tariff is usually an independent organization to administer and operate the Regional Tariff. For this expense, the organization needs to recover this under an administration charge in the Regional Tariff.

6 Benefits of a Regional Tariff

Regional Tariffs were created to provide multiple benefits to both the loads under the Regional Tariff and also the use of generation resources. These benefits as described below may have off-setting increase in costs, reduced revenue (as discussed above, or other drawbacks from their participation in a regional tariff. One such risk is that their rates may increase. Another could be a loss of control of elements in or that could be included in their own tariffs.

First, more service was available for use of the transmission system including using a more widespread flow-based assessment of the transmission system.

Second, there was a relief of TOs from tariff administration, that reduced their costs. It also actually reduced the total cost of administration of the service in the Regional Tariff footprint.

Third, the integration of the use of generation resources to make service to load more cost-effective, but also allows the markets to use the transmission system more effectively. Note that to use the more expensive portion of electric service more effectively was viewed as more valuable than the

loss of transmission revenue, which was a less expensive portion of the electric service to load and customers. Some RTOs have documented their benefits in a variety of ways that can be informative⁵.

Fourth, it allowed other benefits in the operation of BAs, RCs, planning, or other activities that could be integrated on a regional basis.

Fifth, it can be a step to RTO services that is evolution instead of step-changes.

Sixth, the governance of an independent organization provides the TOs with another party that can help in their governance and regulatory relationships, as an advocate for the load and the transmission system.

Seventh, markets thrive in their integration with the use of the transmission system, as well as transmission planning thrives in the expected benefits that are provided through markets. For instance, SPP does a value of transmission study periodically that is based on the expansion of transmission value to wholesale markets that is premised on planning transmission to make a more efficient market⁶. Also, MISO promoted large transmission projects for the same purposes in the Multi-Value Projects⁷.

Some RTO/ISOs have documented the benefits of their operations that can be used to look at these benefits, although the TRSG has not documented any qualitative benefits.

7 Conclusions

A. The purpose of this report is to examine the possibilities of creating a consolidated OATT (regional tariff) outside of an RTO or ISO footprint.

B. A regional tariff in a non-RTO footprint can provide de-pancaking benefits for its participants

C. Both license plate and postage stamp rate structures in a regional tariff are options for pricing network service and point to point transmission service. Both structures provide the benefit of allowing for transactions across the regional tariff footprint pancake-free. Both structures also provide cost shift challenges and opportunities.

D. The WMEG TRSG developed a workbook that can be used to determine cost shifts that may result from the combination of the transmission service cost of service between two or more WMEG transmission providers. The workbook may be used as a tool to determine the benefits and challenges of a regional tariff.

E. While some of the WMEG transmission providers participated in populating the cost shift spreadsheet, they did not perform significant additional work on what a joint regional tariff would

⁵ MISO Value Proposition. <https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/>, SPP Member Value.

<https://www.spp.org/documents/66991/2021%20spp%20mvs%20methodology.pdf>

⁶ SPP Value of Transmission. <https://www.spp.org/value-of-transmission>

⁷ MISO MVPs. <https://www.misoenergy.org/planning/planning/multi-value-projects-mvps/#t=10&p=0&s=&sd=>

look like based on a certain number of parties/zones. This activity could be accomplished by two or more parties undertaking this task, whether this activity results in future work toward tariff consolidation or not.

8 Recommendations

WMEG members, either as a whole or a subset of members, could continue to 1) use the workbook to explore the impact that the group would see under de-pancaking scenarios and how revenue distribution might mitigate some of the impacts to member transmission service revenue, and 2) start discussions on the other elements of a regional tariff, to both understand how those elements affect the members and transmission customers, but also to see if whether consensus could be reached on how to promote an acceptable method for use in a regional tariff. Note, both of these would assist even in the case where the efforts evolve in the SPP or CAISO market development or RTO offerings in the West.

9 Abbreviations

ASM	Ancillary Service Market
BA	Balancing Authority
CAISO	California Independent System Operator
CBA	Consolidated Balancing Area
CPX	California Power Exchange
DAM	Day-Ahead Market
EDAM	CAISO Extended Day-Ahead Market
EIM	Energy Imbalance Market for SPP East entities
EMS	Energy Management System(s)
E-Tag	NERC Electronic Tag
FERC	Federal Energy Regulatory Commission
GOP	Generator Operator(s)
IOU	Investor-Owned Utilities
LMP	Locational Marginal Price
LSE	Load Serving Entity
Markets+	SPP Markets Plus
MISO	Midwest Independent System Operator
MOP	Market Operator(s)
MP	Market Participant(s)
MW	Megawatt
NERC	North American Electric Reliability Cooperation
NIS	Net Schedule Interchange
OATT	Open Access Transmission Tariff
OASIS	Open Access Same-time Information System
RC	Reliability Coordinator(s)
RTM	Real-Time Market
RTMA	Real-Time Market Application
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SPP	Southwest Power Pool
TOP	Transmission Operator(s)
TSP	Transmission Service Provider(s)
WECC	Western Electricity Coordinating Council
WEIM	CAISO Western Energy Imbalance Market
WEIS	SPP Western Energy Imbalance Service
WMEG	Western Markets Exploratory Group