Recommendation Regarding Membership in the Southwest Power Pool Regional Transmission Organization

Colorado River Storage Project Management Center, Rocky Mountain Region, and Upper Great Plains Region

Western Area
Power Administration

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1. EXECUTIVE SUMMARY AND RECOMMENDATION

The Western Area Power Administration (WAPA) recommends the Rocky Mountain (RM) region with its Loveland Area Projects (LAP) transmission system, the Colorado River Storage Project - Management Center (CRSP-MC) with its Colorado River Storage Project (CRSP) transmission system, and the Upper Great Plains (UGP) region with its Pick-Sloan Missouri Basin Project - Eastern Division (PS-ED) generation and load in the Western Interconnection, proceed to final negotiations with the Southwest Power Pool (SPP) Regional Transmission Organization (RTO). The intent is for RM and CRSP-MC to join the SPP RTO as transmission-owning members and for UGP to expand its participation in the Western Interconnection.[1]

In October 2020, RM and UGP along with Tri-State Generation and Transmission Association (Tri-State), Basin Electric Power Cooperative (Basin), Municipal Energy Agency of Nebraska (MEAN), and Deseret Electric Power Cooperative (Deseret) each executed non-binding Letters of Interest (LOIs) to investigate membership or expansion of participation in the SPP RTO in the Western Interconnection (RTO-West). In April 2021, CRSP executed a non-binding LOI. Colorado Springs Utilities (CSU) joined the group in May 2021 and Platte River Power Authority (PRPA) joined in August 2022.

Since then, WAPA has worked with SPP and the above-named RTO-West participants to evaluate and assess the benefits of continuing to pursue expanded and new membership, including the high-level terms and conditions needed. WAPA has hosted multiple in-person and virtual customer meetings to educate all interested customers on key differences in the market structures as well as key evolutions in the RTO-West discussion. Additionally, in June 2022, all three of WAPA's RTO-West participating regions conducted outreach to Tribes, with invitations to participate in virtual information sessions concerning the exploration of the benefits and opportunities in joining and/or expanding participation in the SPP RTO-West. WAPA has also conducted webinars, held question and answer sessions, summarized activities through *WAPA and Markets* newsletters and shared such information on its external website.

On Jan. 31, 2023, the Southwest Power Pool (SPP) Board of Directors approved additional Western Area Power Administration (WAPA) Terms and Conditions and also extended the acceptance period for all the Terms and Conditions through July 1, 2023. SPP approval was contingent on WAPA notifying SPP it would initiate its process to publish the *Federal Register* notice (FRN) by Feb. 28, 2023, and notifying SPP staff of its intent to do so. WAPA subsequently made the decision to proceed with the FRN and provided notification to SPP on Feb. 27, 2023.

This recommendation to proceed to final negotiations for SPP RTO membership is based on five primary strategic considerations:

- **Provide Risk Mitigation**: Mitigate risks including but not limited to reduced depth of trading opportunities, unsustainable Balancing Authority (BA) integration of renewables, exposure to

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[1] UGP is already a transmission owning member in the SPP RTO.

inefficient bilateral market prices, potential for future unfavorable RTO or other market arrangements, missed opportunities to increase regional efficiencies, insufficient Resource Adequacy (RA), inadequate regional transmission development, and risks to reliability and supply availability associated with drought, wildfire, and extreme weather events.

- **Optimize Transmission**: Maximize the use of the existing transmission system and support ongoing reliability along with enabling more holistic regional transmission planning, development, and cost allocation across the footprint. Additionally, the SPP RTO would optimize the value and potential benefits of WAPA's AC-DC-AC converter stations (DC-ties) and the DC-tie rights owned by other SPP RTO participants across the seam between the Eastern and Western interconnections.[2]

- **Support Reliability**: Enable a broader, sustainable, expandable BA structure that can accommodate rapidly increasing levels of renewable resources and ensure reliability into the future.

- **Optimize Resource Dispatch**: Enable significant resource dispatch efficiencies for the footprint that only an RTO market can achieve. Support integration of renewable resources in alignment with the Administration's priorities.

- **Support Core Mission Success**: Support WAPA in reliably and cost-effectively adapting to a changing electricity industry where the status quo is no longer an option. Ensure WAPA can continue to meet its mission and project commitments.

Proceeding to final negotiations for SPP RTO membership is timely for several reasons. Although WAPA is evaluating the economic benefits of RTO membership, risk mitigation represents a more critical factor in protecting our ability to meet our core mission amid unprecedented industry change where status quo is no longer an option. Specifically, SPP RTO membership is expected to mitigate reliability risks associated with thermal unit retirements, increases in variable energy resources, persistent drought, more frequent extreme weather events, and long-standing institutional impediments to regional transmission development.

RTOs support system reliability and resilience with a broad array of advanced operational tools, consolidated BA footprints, increased operational flexibility, greater access to diverse generation resources, and coordinated RA. Additionally, an RTO provides advanced mechanisms for regional transmission planning, development, and cost allocation along with consolidated transmission tariffs that reduce transmission rate pancaking.[3]

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[2] There are seven DC-ties in the U.S. that connect the asynchronous Eastern and Western Interconnections. The RTO-West participants directly own or have contract rights on three of the DC-ties: Miles City, Stegall, and Sidney/Virginia Smith. WAPA owns and operates Miles City and Sidney/Virginia Smith.

[3] Rate pancaking occurs when energy is wheeled across multiple utility systems and separate transmission charges are levied for each system the energy crosses.

Outside of the California Independent System Operator (CAISO), which has not proposed expansion across more of the Western Interconnection, WAPA and other interested utilities currently have no other RTO option in the West.[4] Development of an RTO from the "ground up" in the West, regardless of the potential market operator and even if ultimately successful, would be time intensive and costly. WAPA's experience along with that of our customers has shown that attempting substantive RTO tariff modifications can result in extensive negotiations and delays, as was most recently the case with the Mountain West Transmission Group (MWTG). Due to the complexity of the MWTG negotiations along with conflicting stakeholder priorities, the initiative ultimately failed after five years of negotiations. Developing a new RTO in the West, or substantively modifying an existing one, would likely take an exceptional amount of time and may similarly fail to launch.

SPP has an established and successful RTO that WAPA and other participants could join with minimal tariff modifications. WAPA has previously been able to negotiate tariff modifications including numerous provisions that are essential for a federal entity to participate in an RTO. Although tariff modifications would be minimal, ensuring they capture WAPA's business needs is critical to the success of WAPA and its ability to proceed with final negotiations.

This precedent would reduce the risks of delays, negotiation failures, and new market design deficiencies. WAPA and the other SPP RTO participants, all of whom are WAPA customers, have devoted extensive resources to negotiating membership terms and conditions for more than two years. SPP's stance is that those terms and conditions will be suspended by SPP if the initiative does not move forward to the Commitment Agreement stage by June 2023.

WAPA and the other prospective SPP RTO participants in the Western Interconnection strongly agree that the status quo will not remain a viable option moving forward. Near-term action is necessary to protect the reliability and economic performance of our respective systems. WAPA's assessment finds that the SPP RTO would support our ability to achieve our mission to safely provide reliable, cost-based hydropower and transmission services to our customers and the communities we serve in an industry with rapidly changing generation resources, worsening drought conditions, and increases in extreme weather events. SPP RTO would enable WAPA to continue to provide value to our customers as they face industry changes that may have disproportionate impacts on smaller electricity providers including rural electric cooperatives, municipal electricity providers, and Indian Tribes.

WAPA is seeking stakeholder feedback on its recommendation to pursue final negotiations for CRSP and RM to join the SPP RTO, and for UGP to expand its participation. WAPA will hold at least one virtual customer and stakeholder meeting to provide an overview of the recommendation. WAPA's Administrator will carefully consider all stakeholder comments prior to making a decision. Concurrent with this comment process, WAPA also will conduct a separate Tribal consultation. If after this public process concludes WAPA decides to proceed, final negotiations with SPP will involve

[4] At various points throughout this document, the Western Interconnection is referred to as "West" and the Eastern Interconnection is referred to as "East."

finalizing agreed upon revisions to the SPP Governing Documents and Membership Agreement based on the Terms and Conditions and will also include the implementation details. If the final negotiations result in terms acceptable to WAPA, its participating regions will then execute Membership Agreements.

2. IMPLICATIONS OF INDUSTRY CHANGE AND OBSOLESCENCE OF STATUS QUO

The electricity industry in the U.S. is undergoing fundamental shifts that will increasingly affect bulk electric system operations, markets, and transmission planning. The combined impacts of thermal unit retirements, increases in variable energy resources, persistent drought, and more frequent extreme weather events along with changes in consumer demand patterns are creating a significantly more dynamic system than what electricity providers have managed in the past. Additionally, widespread vehicle electrification is expected to have significant implications for the electricity system.

The majority of the Western Interconnection is characterized by small BAs, hourly schedules, bilateral energy transactions, and contract path transmission arrangements. As a result of the shifts in the electricity industry, the manner in which the system has historically been operated is changing and there is an increasing need for wide-area situational awareness and control, access to geographically and operationally diverse generation resources, coordinated RA programs, increased transmission development, flow-based transmission operations, and sub-hourly operations along with centralized and co-optimized day-ahead, real-time, and ancillary service markets. These are fundamental features in the RTOs that encompass large geographical areas in the Eastern Interconnection.

WAPA and the other prospective SPP RTO members, all of whom are our customers, are in alignment that the status quo is not a sustainable option going forward. WAPA will be significantly affected by infrastructure and institutional changes in many ways including:

- The Western Area Colorado Missouri (WACM) BA, Western Area Upper Great Plains West (WAUW) BA, and BAs across the West will increasingly be required to accommodate the changes in power flows and ancillary service needs that will result from changes in the generation mix. Although the SPP Western Energy Imbalance Service market (WEIS) has served as a near-term mitigating strategy, WACM and BAs across the West are working with a diminishing pool of capacity resources to provide the ancillary services that are necessary to ensure reliability in those footprints.

- In supplying firm electric service under varying hydrological conditions, WAPA's regions are significant purchasers of wholesale electricity, and increases in both the price of energy and price volatility are a reality and a growing concern. As drought conditions and other hydropower supply constraints persist, federal resources produce less hydropower, and WAPA must purchase more of the firm energy it needs to deliver to its customers from the market.

Continuing to rely on purchases from the bilateral markets would likely further expose CRSP, RM, and UGP customers to higher prices and increased volatility.

- RA challenges are becoming an increasing issue in the Western Interconnection due to generator retirements, increased consumer demand during peak time periods, drought, extreme weather events, and climate change. This makes it imperative for WAPA and our customers to be able to access more geographically and resource-diverse generation as soon as possible, without excessive transmission rate pancaking.

WAPA has taken numerous proactive steps to evaluate and implement strategies to enable the organization to be resilient and flexible in a dynamic future while maintaining its statutory obligations and the reliability of its system. However, WAPA's actions to date have been incremental and will not be sufficient to maintain the reliability and economic performance of its system going forward.

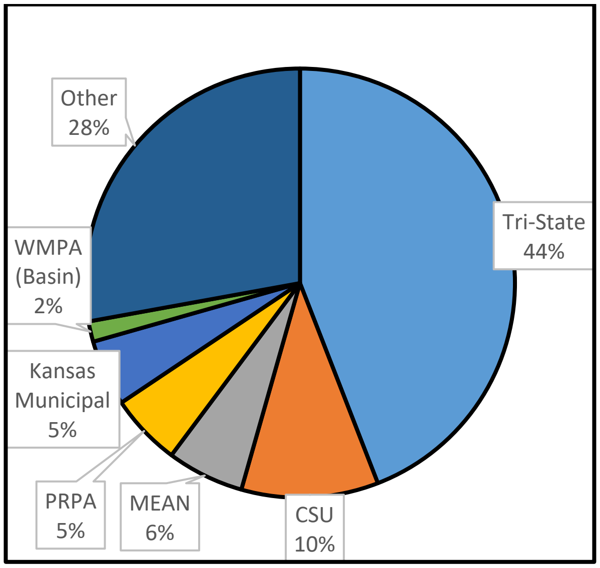
Membership in the SPP RTO is expected to support WAPA and our customers in mitigating current and future risks as the industry continues to evolve. Not joining the SPP RTO, continuing to implement incremental steps toward a full RTO, and relying on the status quo to persist into a highly uncertain future is a high risk option.

3. SPP RTO PARTICIPANTS AS A PERCENTAGE OF WAPA ENERGY SALES

The direct participants in the SPP RTO expansion initiative represent 67 percent of the 2021 long-term energy sales in LAP and 47 percent of the long-term energy sales administered by the CRSP-MC.[5]

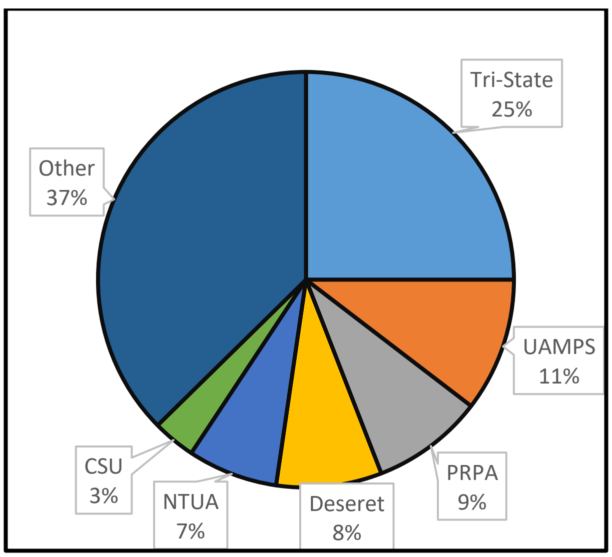
[5] The CRSP-MC is administratively responsible for the Salt Lake City Area/Integrated Projects (SLCA/IP) which include the Colorado River, Collbran, and Rio Grande Projects. The SLCA/IP projects are combined for purposes of WAPA power marketing statistics.

Figure 1: Loveland Area Projects 2021 Long-Term Energy Sales in megawatt-hours (MWhs)



Source: [WAPA 2021 Statistical Appendix]

Figure 2: CRSP-MC 2021 Long-Term Energy Sales (MWhs)



Source: [WAPA 2021 Statistical Appendix]

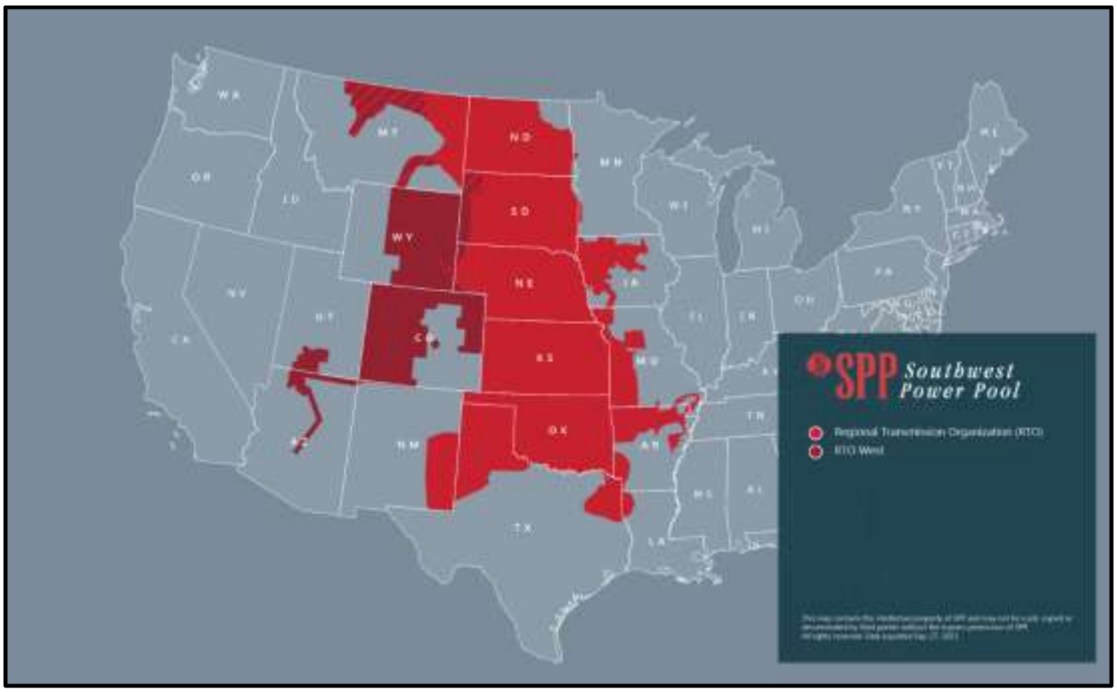
Combined, the direct participants in the SPP RTO expansion initiative comprise 51 percent of the long-term energy sales for LAP and CRSP. Additionally, approximately 90 percent of LAP's firm power revenue comes from entities in the SPP RTO expansion initiative or already in SPP's current RTO footprint.

4. SPP RTO FOOTPRINT

The proposed SPP RTO-West footprint is shown in dark red in the following graphic. Details about the SPP RTO are available at https://www.spp.org/western-services/rto-west/.

Five of the nine SPP RTO expansion participants have operations in both the Western and Eastern Interconnections.[6] The expanded SPP RTO would be optimized across the East-West interconnections seam via the rights owned by the participants on the DC-ties. There is significant diversity in generation resources between and within the Eastern and Western Interconnections that if leveraged could support system reliability, facilitate the economic integration of clean energy resources, help manage wholesale electricity market price volatility, and serve as a hedge against risks associated with extreme weather and drought. Additionally, the DC-ties would allow participants to leverage diversity of both load and generation resources across time zones.

Figure 3: SPP RTO Expansion Footprint



Source: Southwest Power Pool

A graphic of the DC-ties is included below and additional discussion about the expected resource diversity benefits of the expanded SPP RTO footprint is included in Section 10.d.

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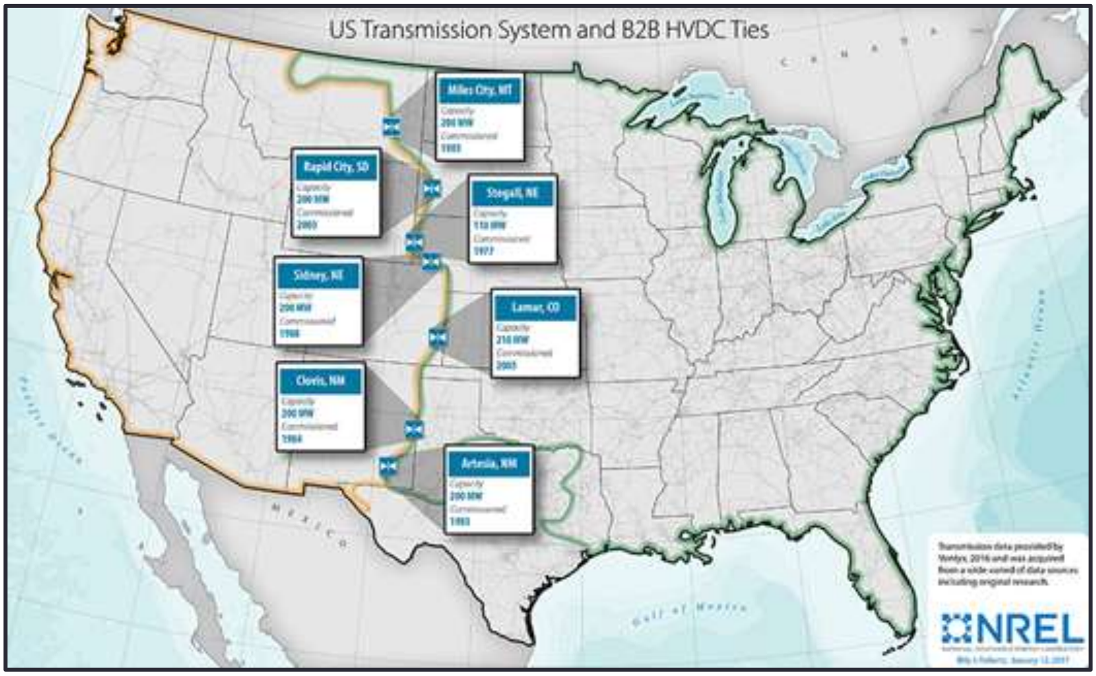
[6] Participants with operations in both interconnections include Basin, MEAN, Tri-State, UGP, and RM. CSU, Deseret, PRPA, and CRSP have operations only in the Western Interconnection.

Figure 4: East-West Interconnections Seam and DC-Ties



Source: National Renewable Energy Laboratory (NREL) Interconnections Seams Study

5. RTO COMPARED TO OTHER EXISTING AND PROPOSED MARKET OPTIONS

As noted previously, the benefits of SPP RTO membership include but extend beyond market efficiencies. Other critically important capabilities of RTOs serve to support system reliability and resilience. These include a broad array of advanced operational tools, consolidated BA footprints, coordinated RA, increased operational flexibility, and greater access to diverse generation resources. Additionally, an RTO provides advanced mechanisms for regional transmission planning, transmission development, and cost allocation along with consolidated transmission tariffs that reduce transmission rate pancaking.

The graphic below highlights the key differences between energy imbalance markets (EIM), potential day-ahead markets, and RTOs.

Table 1: RTO Compared to Other Existing and Proposed Market Constructs

EIM/Real-Time Market	Day-Ahead Market	RTO
✓ Centrally optimized real-time dispatch – *Day-ahead unit commitment not optimized across market participants* ✓ Individual transmission tariffs ✓ Limited transmission dedicated to market ✓ Balancing Authority Area (BAA) boundaries and associated reliability obligations retained ✓ Transmission providers retain operational control of transmission	✓ Centrally optimized real-time and day-ahead energy market ✓ Individual transmission tariffs ✓ Limited transmission dedicated to market (other transactions must explicitly pay for transmission) ✓ BAA boundaries and associated reliability obligations retained ✓ Transmission providers retain operational control of transmission	✓ Centrally optimized real-time and day-ahead energy market ✓ Joint transmission tariff for participants in a given footprint ✓ Transmission used up to reliability limit ✓ BAA boundaries and reliability obligations consolidated ✓ Joint transmission planning and cost allocation ✓ Transmission providers transfer of operational control of transmission

Source: DOE-Funded State-Led Market Study

a. Energy Imbalance

When comparing an energy imbalance/real-time market (EIM) to an RTO, an RTO is a superior market option because it offers not only imbalance market benefits but full resource optimization, operational/reliability benefits, and coordinated transmission development across the entire footprint. It is important to note the proposed SPP expansion does not set up an isolated RTO in the West, but rather expands the existing SPP RTO across the seam between the Eastern and Western Interconnections to co-optimize market solutions across the entire footprint.

b. Proposed Day-Ahead Markets

While both SPP and CAISO are working with interested parties on proposed day-ahead market options that would offer more than an EIM but less than an RTO, the proposed day-ahead options lack the full market integration and future-looking transmission optimization offered by the SPP RTO. Additionally, and very importantly, the proposed day-ahead market construct is unproven and could face regulatory, operational, and economic hurdles. Significant obstacles exist around governance, transmission utilization, and transmission compensation. It is not certain that either attempt would ultimately receive stakeholder and Federal Energy Regulatory Commission (FERC) approval.

c. RTO

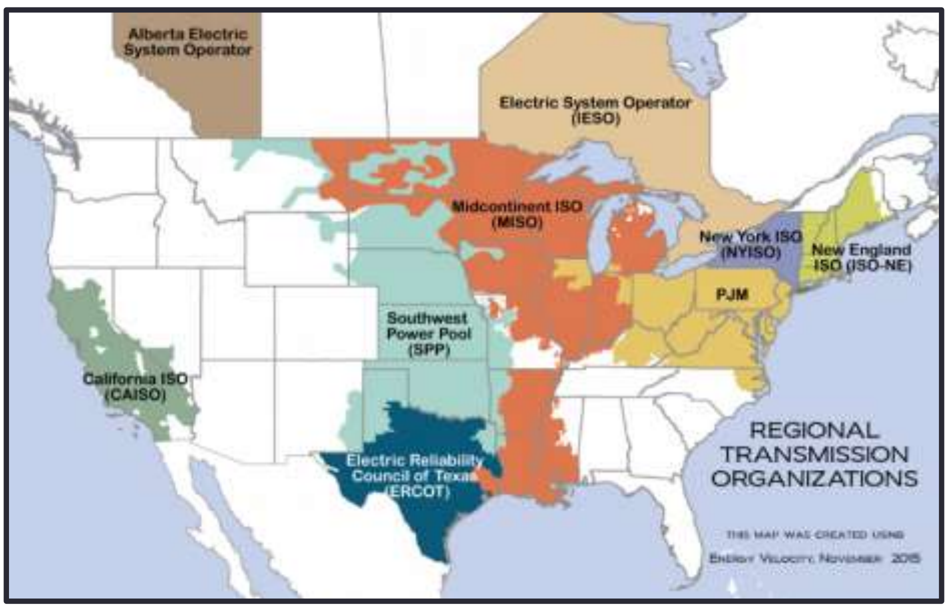
RTOs provide all the features of the imbalance/real-time and proposed day-ahead markets. Additionally, they provide consolidated transmission tariffs, optimized use of the transmission system, consolidated Balancing Authority Areas (BAAs), regional transmission planning, and regional cost allocation. RTOs are perceived by many as the "ultimate destination" for system operations, markets, and transmission planning in the West.

An expanded discussion of the key features of RTOs is provided in the next section.

6. KEY FEATURES OF RTOS

RTOs encompass the majority of the Eastern Interconnection. The large operating footprints, coordinated transmission planning, and centralized markets are widely acknowledged to provide reliability and economic benefits. Although entities across much of the West have historically been averse to RTO development, changing industry conditions are driving utilities and states to consider the need for centralization of electricity system operations, markets, and transmission planning.

Figure 5: Existing RTOs in North America



Source: Federal Energy Regulatory Commission (FERC)

Traditionally in the West, electric utilities built transmission systems that went from large generating sources to their load. Going forward in a system that is moving away from large central generators to a greater number of smaller generators, utilities will increasingly need to access generation that may be distant from their service areas. This is largely a function of increasing state-level clean energy requirements and the fact that renewable resource availability and quality vary by geography. For WAPA's customers, actual or potential decreases in the availability of capacity from hydro generators due to persistent drought conditions is also a significant consideration.

When accessing generation that is distant from their service areas in a non-RTO region, utilities are subject to the pancaking of transmission costs that occurs when wheeling energy across multiple utility systems. Transmission rate pancaking can be prohibitively expensive for utilities as they seek to integrate geographically diverse renewable energy resources. Additionally, utilities may not be able to reserve sufficient transmission on neighboring utility systems due to lack of available transmission capacity. If this occurs, they must either upgrade that system or build their own, which can also be prohibitively expensive and is economically inefficient from a system-wide perspective. This ultimately affects all electricity customers.

a. Single Transmission Tariff

A primary feature of an RTO is that it offers a single Open Access Transmission Tariff (OATT). OATTs set the terms and rates for providing transmission service to all transmission customers within a given footprint. This includes selling transmission service, performing transmission studies, interconnecting new generation, providing ancillary services, and many other wholesale electricity functions.

Non-RTO transmission service providers typically have their own individual transmission tariffs. In any given non-RTO area, multiple transmission service providers exist, and coordination between the transmission tariffs is complicated and can be expensive for transmission customers. While the individual tariffs are generally pro-forma and approved by FERC, they lack a cohesive and coordinated mechanism to manage terms, processes, and rates across multiple utilities.

An RTO's transmission tariff covers all included transmission system zones. Under a zonal design, the customers pay the transmission rate for the zone in which their loads are located and do not incur additional transmission charges for transporting energy across other zones within the RTO.

By combining multiple tariffs into a single RTO tariff, the RTO participants collectively:

- Enable an integrated market with co-optimized energy dispatch.
- Leverage resource and time zone diversity.
- Eliminate transmission rate pancaking in the RTO footprint.
- Attract greater generation development in the footprint due to the simplification of transmission management.

- Make more efficient use of the transmission systems by transitioning away from contract-path to flow-based transmission sales. This allows optimal utilization of transmission capacity by aligning with actual system flows.

- Support improved transmission planning and interconnection processes by increasing coordination between and across the systems. This helps avoid inefficient investment through duplication of facilities and creates additional siting opportunities for new resources.

b. Centralized Dispatch

An RTO performs a security constrained economic dispatch (SCED) of both the generation and transmission assets in the footprint in day-ahead and real-time. This allows the system to use the least-cost generation first and to use the integrated transmission system to its physical capability. This is in contrast to the current practices in the non-RTO West where each utility dispatches its own limited set of generation resources using contract-path transmission arrangements that do not align with how the transmission system physically operates (i.e., electrons follow the path of least resistance, not contract path). In addition to leveraging the least-cost generation resources, centralized dispatch also allows the market operator to manage congestion on the transmission system using market price signals versus the manual redispatch currently used to alleviate transmission congestion and related reliability issues in the non-RTO West.

c. Centralized Transmission Planning

Looking forward, coordinated transmission planning across broad geographic areas will become increasingly critical for both economic and reliability reasons. FERC Order 1000, which requires utilities to participate in regional and inter-regional transmission planning, is a testament to the importance of holistic transmission planning. However, the objectives of Order 1000 have been difficult to achieve in the West.

The current EIM and proposed day-ahead markets lack the ability to optimize transmission planning and development. RTOs have integrated, centralized, FERC-approved transmission planning and cost allocation processes for their entire footprint. RTOs have both the obligation and authority to perform transmission planning that considers both reliability and economic factors. This results in an optimized solution for the entire footprint that is inherently more efficient. Transmission-owning RTO members are required to participate in the planning and, as appropriate, the cost allocation. FERC-approved cost allocation mechanisms for the entire RTO footprint enable the successful construction of transmission.

d. Balancing Authority Consolidation

A particularly important feature of RTOs for WAPA is BA consolidation and management. In an RTO, the system operator performs the BA functions for the entire footprint. The RTO uses a suite of advanced operational tools to maintain real-time electricity balance across the footprint using all generation and transmission assets. In a system with declining dispatchable generation including coal, gas, and hydropower, having access to a range of diverse resources is critical. Additionally, the integration of market dispatch and BA operations allows the RTO to use price signals versus manual redispatch to manage the system. This is more equitable than the current paradigm in the West where BAs use a limited set of generation resources, typically their own, and where compensation for use of those assets may not be equitable. As noted in Section 2, WACM and other BAs across the West are working with a diminishing pool of capacity resources to provide the ancillary services that are necessary to ensure reliability in those footprints. Larger BAs, and particularly RTOs, have significantly greater access to resources necessary for reliable operations.

e. Resource Adequacy (RA)

As emphasized in a July 2021 FERC Technical Conference on Resource Adequacy Developments in the Western Interconnection, RA is an acute issue in the West. RA challenges are a function of insufficient generating capacity, changes in demand patterns, increases in distributed and variable generation, transmission congestion, and lack of coordination between operating footprints. WECC's 2021 Western Assessment of Resource Adequacy highlighted similar concerns. Utilities across the West rely heavily on short-term bilateral market purchases to supplement generation they own or have under long-term contract to meet peak electricity demand. Although this has historically been a successful model, in an era of decreased availability of dispatchable generation combined with widespread extreme weather events such as the August 2020 and summer 2021 heat events, this model is no longer functional and is resulting in reliability challenges along with increased wholesale electricity prices and price volatility.

In an RTO, an RA evaluation is performed by the RTO for each participating utility and for the entire footprint utilizing a consistent methodology. Mechanisms are in place to require utilities to be resource adequate, and penalties are imposed in the event a utility is not. This prevents "leaning" on the market and serves as an independent control mechanism to help prevent resource shortages across the full RTO footprint. While RA programs can and do exist outside of RTO footprints, having an RTO in place to enable coordination of capacity resources and optimization of transmission in both planning and operational time horizons is a more holistic approach.

WAPA is committed to continuing to work with our customers both in and out of the proposed RTO-West footprint to ensure their needs are addressed, and we continue to preserve the value of hydropower to our customers as much as possible. WAPA continues to monitor the evolution of RA strategies as well as how these might interplay in the developing market constructs and will work with customers on how best to integrate RA requirements within its established programs.

7. STATE CLEAN ENERGY POLICIES AND RTO LEGISLATION AFFECTING WAPA'S CUSTOMERS

Although WAPA is not regulated by the states, many of our customers are required to comply to varying degrees with state requirements including renewable and clean energy polices. Both WAPA and our customers are affected by the generation resources chosen by neighboring entities, many of which are regulated by the states in which they operate.

As state clean energy policies continue to become more stringent, WAPA's customers are likely to increasingly need to access renewable generation outside their service territories. As noted previously, in the current bilateral markets this could result in excessive transmission wheeling charges referred to as transmission rate pancaking. An RTO eliminates rate pancaking within its footprint via a single common transmission tariff. This greatly facilitates access to geographically diverse renewable resources.

Table 2: State Renewable and Clean Energy Policies in the West

State	Renewable and clean energy policies
AZ	Standard: Electric utility CO_2 reductions of 50 percent by 2032; 65 percent by 2040; 80 percent by 2050; 90 percent by 2060; and 100 percent by 2070
CA	Standard: Electric utilities must have 100 percent retail electricity produced from renewable and zero-carbon resources by 2045 (SB 18-100)
CO	Standard: All utilities with more than 50,000 customers must achieve at least 80 percent greenhouse gas (GHG) reduction below 2005 levels by 2030 (HB21-1266)
ID	None
MT	Standard: 15 percent renewable resources by 2020
NM	Standard: Investor Owned Utilities - Zero carbon by 2045. Cooperative Electric Utilities - Zero carbon by 2050 contingent upon technical feasibility, reliability, and affordability (SB 489,2019)
NV	Standard: 50 percent by 2030. Goal: 100 percent carbon-free by 2050
OR	Standard: 25 percent by 2025; 50 percent by 2040. PacifiCorp and Portland General Electric must reduce GHG emissions by 80 percent by 2030; 90 percent by 2035; 100 percent by 2040+
UT	Goal: 20 percent by 2025
WA	Standard: Electric utilities are required to (1) Eliminate coal from their state portfolio by 2025; (2) Be carbon neutral by 2030; (3) Provide 100 percent clean energy (renewable or non-emitting) by 2045 (SB 5160, 2019)
WY	None

Source: Western Interstate Energy Board. August 2022 State Survey of Clean Energy Policies.

In addition to the clean energy policies, several states are implementing legislation related to centralized markets and RTO membership. The following summarizes recent RTO legislation:

- Colorado Senate Bill 21-072 passed June 24, 2021, requires regulated utilities to join an RTO or Independent System Operator, collectively referred to as an Organized Wholesale Market, by Jan. 1, 2030. The legislation includes conditions and offramps if an RTO is not available or does not meet certain criteria.

- Nevada Senate Bill 448 passed June 10, 2021, requires regulated utilities to join an RTO by Jan. 1, 2030. The legislation includes conditions and offramps if an RTO is not available or does not meet certain criteria.

- New Mexico House Bill 233 passed March 4, 2020, established the Grid Modernization Advisory Group to develop analyses of various pathways to grid modernization. The fifth white paper recommends the state establish a New Mexico RTO Task Force.

- Oregon Senate Bill 589 passed May 21, 2021, required the Oregon Department of Energy to prepare a report identifying benefits, opportunities, and challenges for the State posed by development or expansion of an RTO. The report was published December 2021.

In addition to the legislative activities listed above, in July 2021, the Arizona Corporation Commission established a docket to investigate regional planning, markets, and collaboration in the Western Interconnection and explore the possibility of mandatory or voluntary participation in an RTO for its regulated utilities.

8. REGIONAL MARKET STUDIES

As industry and the states have increasingly recognized the benefits of centralized markets and the likely inability to reliably and cost effectively achieve state-level clean energy priorities in the West without one or more multi-state RTOs, DOE and multiple states have performed differing levels of analyses on the potential benefits of RTOs in the Western Interconnection. Three key studies discussed in the following sections are the:

- 2021 "*The State-Led Market Study*" funded by DOE and performed by Energy Strategies.[7]

- 2021 "*Colorado Transmission Coordination Act: Investigation of Wholesale Market Alternatives for the State of Colorado.*"[8]

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[7] DOE-Funded State-Led Market Study, July 2021.

[8] Colorado Transmission Coordination Act: Investigation of Wholesale Market Alternatives for the State of Colorado. December 2021.

- 2023 National Renewable Energy Laboratory *(NREL) "The Impacts on California of Expanded Regional Cooperation to Operate the Western Grid (Final Report)."*[9]

All three conclude that centralized markets provide substantive benefits, and a full RTO would provide the highest level of benefits relative to energy imbalance (EI) and potential day-ahead market options.

a. DOE-Funded State-Led Market Study

In 2021, Energy Strategies LLC, completed the DOE-funded *State-Led Market Study,* which evaluated the relative benefits of EI, day-ahead, and full regional markets in the West using three hypothetical footprints. The goal of the project was to provide western states with a neutral forum and neutral analysis to evaluate generic market expansion options while enhancing regional dialogue. Informed by broad policy and technical subject matter expertise, the study demonstrated the advantages of RTOs over EI and proposed day-ahead markets. The study estimated market and capacity benefits of up to $2 billion a year for a single RTO across the West and benefits of $1.4 billion to $1.8 billion per year with two RTOs in the West, dependent upon the footprints. The study also identified significant reliability benefits and increased ability to meet public policy requirements as key capabilities of RTOs.

Below is the summary of the projected 2030 day-ahead and full RTO benefits across the potential RTO footprint in terms of savings, range of administrative costs, and range of net benefits.

Table 3: DOE-Funded State-Led Market Study Results

	Day-Ahead (millions per year)	Full RTO (millions per year)
Adjusted Production Cost Savings	$ 95	$ 694
Capacity Savings	$ 652	$ 1,305
Combined APC and Capacity Savings	$ 747	$ 1,999
Range of Administrative Costs	$ 85 to $ 254	$ 187 to $ 513
Range of Net Benefits Per Year	**$ 493 to $ 662**	**$ 1,486 to $ 1,812**

Source: DOE-Funded State-Led Market Study – Technical Report.

In addition to the technical quantitative analyses, the study performed a qualitative analysis of the performance of bilateral, EI, proposed day-ahead, and RTOs in two primary categories:

- Ability to provide reliable and affordable energy to consumers.
- Ability to support increased use of clean energy technologies.

[9] Impacts on California of Expanded Regional Cooperation to Operate the Western Grid. NREL. February 2023.

Graphics of the relative performance of the different market constructs for these two categories are shown below.

Table 4: Comparison of Existing and Proposed Options for Reliability and Affordability

Scorecard for Reliable, Affordable Provision of Energy to Consumers

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	Bilateral	Real-Time	Day-Ahead	RTO
Efficient grid operation which reduces costs and increases flexibility of transactions	Fair	Good	Very Good	Excellent
Ability to unlock full potential of existing generation (lowering costs) and to decrease generation capital costs/investments	Poor	Fair	Good	Very Good
Ability to unlock full potential of existing transmission system (lowering costs) and to decrease transmission capital costs/investments	Fair	Good	Very Good	Excellent
General ability to support reliable operations	Good	Very Good	Very Good	Excellent
Visibility into electric system conditions to improve reliability	Fair	Good	Very Good	Excellent
Transparent and timely information available to state PUCs, consumer advocates and other stakeholders	Fair	Good	Very Good	Excellent
Long-term mechanisms to support a system with adequate electric resources	Fair	Good	Good	Very Good
Increased opportunities for cost-effective demand-side resource participation	Fair	Good	Very Good	Excellent

Source: DOE-Funded State-Led Market Study – Market and Regulatory Report. Page 40.

Table 5: Comparison of Existing and Proposed Options for Integrating Clean Technologies

Scorecard for Increased use of Clean Energy Technologies

Increased Use of Clean Energy Technologies	Bilateral	Real-Time	Day-Ahead	RTO
Efficient grid operation which allows low (and zero) marginal cost resources to be dispatched and reduces overall costs of integrating clean energy technologies	Fair	Good	Very Good	Excellent
Lower barriers to access new generation in high-quality renewable resource locations	Poor	Poor	Good	Excellent
Opportunities for clean electricity resources to be added to the grid (e.g. direct customer access to renewable/clean resource power purchase agreements)	Good	Good	Very Good	Excellent
Provides financing opportunities and a variety revenue stream opportunities for clean electricity technologies	Fair	Good	Very Good	Excellent
Economically facilitates emissions reduction goals/requirements via market signals	Fair	Good	Very Good	Excellent
Transparent and timely information on pricing, resource operations, and emissions	Fair	Good	Very Good	Excellent

Source: DOE-Funded State-Led Market Study – Market and Regulatory Report. Page 24.

b. Colorado Investigation of Wholesale Market Alternatives

Colorado Senate Bill 21-072, referred to as the Colorado Transmission Coordination Act, required the Colorado Public Utilities Commission (PUC) to perform an evaluation of the relative benefits of various market constructs for the State of Colorado. The resulting *Colorado Transmission Coordination Act: Investigation of Wholesale Market Alternatives for the State of Colorado*[10] study was released in December 2021 and concluded:

> *The quantitative analysis for this investigation concludes that markets have the potential to deliver substantial economic benefits through reduced operation and investment costs. Participation of Colorado electric utilities in an Energy Imbalance Market (EIM) could deliver on the order of $50 million in annual savings to Colorado (approximately 1 percent of a total annual Colorado electric revenue requirement of $6 billion). Full participation by the electric utilities in a Regional Transmission Organization (RTO) could deliver approximately $230 million annually or 4 to 5 percent of the total annual revenue requirement. A Day Ahead (DA) market construct, similar to a regional power pool, could deliver savings somewhere between these two options, depending on the exact market services included."* [Emphasis added.]

> *These kinds of savings were generally found to exist independent of whether Colorado looked west to the CAISO, east to SPP, or created something new in the middle working with neighboring utilities. As such, the quantitative study concludes that the key to obtaining these benefits was effectively participating in a broader market footprint, but it didn't matter so much which one.*

c. NREL Impacts of Expanded Regional Cooperation

A February 2023 NREL report on *The Impacts on California of Expanded Regional Cooperation to Operate the Western Grid (Final Report)* is a meta-analysis of market initiatives, studies, and papers.[11] The report was developed pursuant to California Assembly Concurrent Resolution 188. Although performed on behalf of California, the study scope focuses largely on previously identified qualitative and quantitative benefits of regional cooperation, including RTOs, as reported in 38 separate studies. A key finding from the analysis includes:

> *An RTO, because it is a more comprehensive structure for cooperation that optimizes a wider array of grid functions, tends to yield greater cost savings and grid flexibility than more limited forms of cooperation*.

[10] Colorado Transmission Coordination Act: Investigation of Wholesale Market Alternatives for the State of Colorado. Colorado Public Utilities Commission. December 2021.

[11] Impacts on California of Expanded Regional Cooperation to Operate the Western Grid. NREL. February 2023.

9. BRATTLE 2022 ADJUSTED PRODUCTION COST STUDY

Recognizing there are both quantitative and qualitative benefits to RTO membership, in 2022 the SPP RTO expansion entities contracted with The Brattle Group to perform a production cost analysis of the potential benefits of expanding the SPP RTO into the West. The purpose of the study, *Benefits of the SPP RTO Expansion into the WEIS Footprint*, was to measure the incremental market benefits of moving from the WEIS to the SPP RTO. The study builds on previous evaluations of the benefits of SPP RTO expansion into the Western Interconnection, including a 2020 study commissioned by SPP. The new 2022 study uses updated modeling assumptions about the participant footprint, generation portfolios, natural gas prices, and projected hydrology conditions.

The 2022 study found that expanding the SPP RTO into the Western Interconnection could produce a net total of $55 million to $73 million per year in savings depending on hydrological conditions. Additionally, Brattle noted there are additional benefits not calculated that include increased reliability and resiliency, system flexibility, and reduced administrative fees.

A key finding of the study is the magnitude of the increase in savings under severe drought conditions. Adjusted Production Cost (APC) savings in the West increase from $68 million per year given baseline hydrology forecasts to $81 million per year under severe drought conditions, including the potential loss of generation from Glen Canyon.

Table 6: SPP RTO Benefits Summary by Scenario (millions per year)

Benefit Metric	Westside		Eastside		Combined	
	Base WEIS vs. Base RTO	Low Hydro WEIS vs. Low Hydro RTO	Base WEIS vs. Base RTO	Low Hydro WEIS vs. Low Hydro RTO	Base WEIS vs. Base RTO	Low Hydro WEIS vs. Low Hydro RTO
APC Benefit	$68	$81	$3	$8	$71	$89
Wheeling Benefit	-$15	-$16	$0	$0	-$15	-$16
Net APC & Wheeling	$53	$65	$3	$8	$56	$73

Source: SPP RTO Brattle study. September 2022.

Prospective SPP RTO participants included in the study were Basin, CSU, Deseret, Tri-State, MEAN, and WAPA's CRSP, RM, and UGP. PRPA joined the group after the study was substantively underway and was not a direct participant.

Each of these entities is currently participating in the SPP WEIS and receives Reliability Coordinator (RC) services from SPP. Tri-State, WAPA's UGP region, Basin, and MEAN are already members of the SPP RTO in the Eastern Interconnection.

Outside of the study scope but significant to note is that in addition to the APC benefits, the SPP RTO expansion could increase the portfolio of tools available to support reliability in the Western Interconnection. This includes consolidated BA operations, a fully integrated wholesale market, coordinated RA, and the established SPP RTO transmission planning and development processes needed to support growing electricity demand and addition of more generation resources, including renewables. Additionally, deferral of capacity investments and avoided curtailment of renewable generation for both the East and West were out of scope for the Brattle APC study but have the potential to be significant.[12]

10. WHY SPP RTO?

The existing EI and proposed day-ahead markets in the West cannot provide the benefits of the range of multi-state RTO capabilities including advanced operational tools, consolidated BA footprints, consolidated transmission tariffs, coordinated RA, increased operational flexibility, and greater access to diverse generation resources. Additionally, an RTO provides advanced mechanisms for regional transmission planning, transmission development, and cost allocation, along with consolidated transmission tariffs that reduce transmission rate pancaking.

The only RTO currently operating in the West is the CAISO. It is confined to California largely for reasons related to governance. Significant stakeholder pressure and multiple attempts to modify the California governor-appointed board structure and transition to a sufficiently independent board to address gating concerns of entities outside of California have been unsuccessful to date.[13] Additionally, entities outside California have concerns that California greenhouse gas and other clean energy legislation along with California PUC regulations could adversely affect a multi-state market unless modified.

Developing an RTO from the ground up in the West is perceived as being an onerous task due to divergent stakeholder interests and the complexity of the required tariff development. There have been multiple attempts over decades to develop an RTO in the West from the ground up. These include “DesertSTAR”, proposed in the late 1990s but which did not become operational, and a “WestConnect RTO”, proposed in 2001 but which did not achieve FERC-approval. More recently, from approximately 2013 to 2018, eight electricity providers in the West attempted to expand SPP into the Western Interconnection with extensive modification of the SPP tariff for the West. This effort, the MWTG, failed due to inability to reach agreement on new tariff elements amid conflicting stakeholder priorities.

SPP has a stakeholder driven governance structure and tariff provisions that are in alignment with WAPA priorities and the priorities of our customers. The geographic scope encompasses the DC-ties between the Eastern and Western Interconnections, three of which are owned by SPP RTO expansion initiative participants. The diversity in generation resources across the expanded SPP RTO footprint is exceptional and will likely not only be critical in protecting system RA and reliability, but also clean energy integration.

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[12] Please see the Section 8.a of the DOE-funded State-Led Market study.

[13] As of this writing, there has been an initial step in the legislature *“to work with states across the West and create a regional electric system that expands the footprint for clean energy resources and enables better collaboration, transparency, and integration across the western electrical transmission grid system*.”. California Assembly Bill 538 introduced February 2023.

a. Pros and Cons of SPP RTO for WAPA

After careful evaluation of the pros and cons of SPP RTO membership, WAPA believes SPP is the appropriate RTO for CRSP, RM, and UGP. Considerations and benefits of SPP RTO membership include:

- Existing FERC-approved tariff that can be adopted by the participants with minimal modifications.
- Large adjacent market connected by DC-ties.
- WAPA's UGP region, Tri-State, Basin, and MEAN are already SPP RTO members with varying combinations of transmission, load, and generation in SPP's footprint.
- The SPP tariff has provisions for WAPA's UGP participation, including the Federal Service Exemption (FSE), which can readily be expanded to CRSP and RM. The FSE provides exemptions from the marginal congestion and marginal loss cost components for federal energy deliveries and exemption from regional transmission cost allocation charges. Although UGP was able to negotiate an FSE in SPP, the exemption may not be included or be as significant in other RTO or market constructs that might develop in the West in the future.
- SPP has a robust stakeholder-driven governance model that enables WAPA and our customers to have a meaningful voice.
- SPP has a proven ability to onboard new participants, successfully expand, and offer numerous services across the West.
- SPP has successfully incorporated non-jurisdictional entities in SPP.
- SPP is currently the only RTO option in the West outside of California. Any other option that could be proposed would be five to ten years from being functional if such option ever comes to fruition.
- Proceeding to join the SPP RTO would enable entities in the West to better optimize resources across the Western Interconnection. If WAPA decides not to join, it is not certain whether RTO market constructs will form in the near future. Significant regional resource optimization benefits would be delayed or prevented from becoming a reality.
- A decision to join SPP would transfer functional control of the WAPA transmission facilities to SPP allowing SPP to become the transmission service provider for the WAPA transmission facilities. SPP would become the BA for the entire SPP RTO footprint. At that time WAPA would no longer need to provide BA services for the current WAUW and WACM BA

footprints. This would enable WAPA to focus more fully on its core mission of marketing and delivering firm electric service to preference customers.

- Negotiations with SPP have been and continue to be an opportunity for WAPA to direct its own destiny, influence terms, and shape the kind of structure desired to support WAPA in continuing to deliver on its core mission.

- Joining SPP would hedge against the greater financial uncertainty of not joining. The costs of losing bilateral trading partners introduces risk of significantly increased costs as well as negative qualitative considerations.

- RM and UGP's Eastern Interconnection customers, along with other SPP members, would benefit from the SPP expansion, reduction of SPP administrative fees, and a larger, more efficient market.

- RM and UGP's membership in the same RTO is rational due to their financial integration with a common Pick-Sloan Missouri Basin Project. UGP has only a small part of its footprint outside the SPP RTO Integrated Marketplace (IM)[14] and, when measured by allocation size, two-thirds of LAP customers are already SPP members. Some of CRSP's largest customers are either members of SPP, participating in the SPP expansion effort, or both.

- The SPP RTO would enable the identification and optimization of transmission expansion on a broader scale due to the integrated transmission planning and cost allocation processes already in place.

- The SPP RTO would help facilitate the achievement of the federal government's clean energy goals as well as ensure WAPA's customers who need to meet state clean energy requirements have more cost-effective resources available to do so.

- Being part of the SPP RTO would allow WAPA to participate in SPP's Integrated Transmission Planning Process (ITP), which evaluates transmission needs for the entire RTO footprint. This should not only streamline the interconnection processes but also enable more inclusive consideration of clean energy resources for the entirety of the interconnected transmission system, including for WAPA's customers.

Proceeding with final negotiations regarding SPP RTO membership has the following risks and negative factors:

- Joining SPP results in the transfer of operational control to another entity, thus giving up certain discretion and control. For example, in addition to the existing protocols of SPP's RC.

[14] The SPP RTO IM is one of a portfolio of services included in the SPP RTO.

WAPA would need to receive authorization from the RTO as the market operator to return a generating unit or transmission element to service after routine maintenance.

- CRSP and RM transmission service would fall under a FERC jurisdictional tariff, whereas WAPA is non-jurisdictional and offers transmission service under a "safe harbor" tariff.[15]

- Joining SPP results in less control over transmission rates and the zonal revenue requirements.

- Although expansion is likely over time, current interest by additional entities in joining SPP is limited, and the footprint has fewer participants than optimal.

- Although the DC-tie capacity connecting the West's footprint to the large existing SPP footprint is substantial, it is limited to a maximum of 510 megawatts (MW) available to the current participants.

- Decisions in SPP are made via large-group stakeholder processes, and changes may result with WAPA having limited control.

- Although the FSE[16] helps hedge against financial risk, there is always some inherent risk in any market. There is degree of uncertainty around the energy, congestion, and ancillary service market sub-components, and some WAPA energy deliveries may be exposed to more regional transmission costs.

- Due to WAPA's RM and Desert Southwest (DSW) regions having consolidated operations, there would be certain challenges associated with maintaining appropriate backup functionality while in two distinct market constructs.

While there are some negative factors involved with SPP RTO membership, WAPA believes the positive factors outweigh the negative. Based on both negative and positive factors, WAPA recommends that CRSP and RM proceed to final negotiations with SPP for full RTO membership, and that UGP expand its participation.

Relatively near-term action is critical for WAPA to retain its ability to define its own future, protect its negotiating power, and avoid having its options constrained by the actions of other entities.

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[15] In Order 888, FERC established safe harbor procedures which allow non-jurisdictional entities such as WAPA to voluntarily submit open access transmission tariffs. WAPA's safe harbor tariff is available for public viewing on FERC's ETariff site at https://etariff.ferc.gov/TariffBrowser.aspx?tid=2597.

[16] Due to the fact that WAPA's system was built to deliver finite federal generation, and generally does not serve load growth, the FSE in the current SPP tariff exempts UGP under certain circumstances from regional transmission expansion costs, congestion charges, and marginal loss charges.

b. SPP 2021 Member Value Statement

Like other RTOs that report extensive benefit estimates each year that far outweigh costs, SPP conducts an analysis and publishes an annual Member Value Statement (MVS). SPP's 2021 MVS reports an estimated $2.7 billion in annual savings and benefits[17]. This equates to an 18:1 benefit to cost ratio. The annual savings and benefits are broken into the following categories:

- $1.423 billion: Markets
- $879 million: Operations and Reliability
- $377 million: Transmission
- $38 million: Tariff, Scheduling, and Services

c. Multi-State Governance

WAPA has learned over the years, and across the numerous attempts to set up RTOs in the West, that governance is always a critically important topic. Along with others, WAPA agrees that representative governance is absolutely necessary. To turn over certain roles and responsibilities from WAPA to another entity, it is essential that trust exists with such an entity, and good governance generates trust. It is important to WAPA that we not only have a voice in RTO decisions, but that our customers do as well. It is also important for the RTO to not be overly aligned with any particular interest, and for the RTO to have a balanced governance structure to ensure decisions that represent the interests of entities across the full RTO footprint.

WAPA has experienced through UGP's existing membership that SPP's governance is a particularly good structure that meets our needs. In particular:

- SPP's stakeholder-driven governance gives WAPA a reasonable voice across the numerous committees that drive decisions in the RTO.

- SPP's stakeholder driven governance is inclusive to both transmission-owning members and transmission-using members and therefore gives adequate voice to our diverse customer base.

- SPP's independent board and stakeholder-driven governance is not overly aligned with any particular interest, political entity, or class of customer. This supports development of equitable decisions.

- SPP's practice of open meetings and member-driven governance supports stakeholder participation.

[17] 2021 Member Value Statement and summary slides.

- WAPA is structured around separately legislated federal projects, and each WAPA region or division would join SPP individually. SPP's governance allows this and for each WAPA division to be represented in various committees making decisions. This is particularly helpful for WAPA's participation across multiple regions with our varied customer interests.

- Over the years of negotiating with SPP on various issues, WAPA has experienced that SPP consistently supports their members' interests. As a primary structural element, SPP decision processes start with committees staffed by member organizations. Then, in quarterly Board of Director and Members Committee meetings, the SPP Board votes immediately after the Members Committee so the Board members are aware of member positions before they cast their votes. Examples like this demonstrate that SPP keeps its commitment to be a member-driven organization.

- UGP has been a member for over seven years now. The SPP governance has proven to be a very good fit for WAPA's culture and values, enabling the region to participate on numerous committees and have an active role in SPP's governance.

In summary, SPP has a governance structure that is well-aligned with WAPA's culture of collaboration with our stakeholders. With UGP's current membership in the SPP RTO and WAPA's experience with the SPP RC and the WEIS, SPP has earned the trust that is required to consider expanding our participation to include additional WAPA divisions.

d. DC-Ties and Resource Diversity

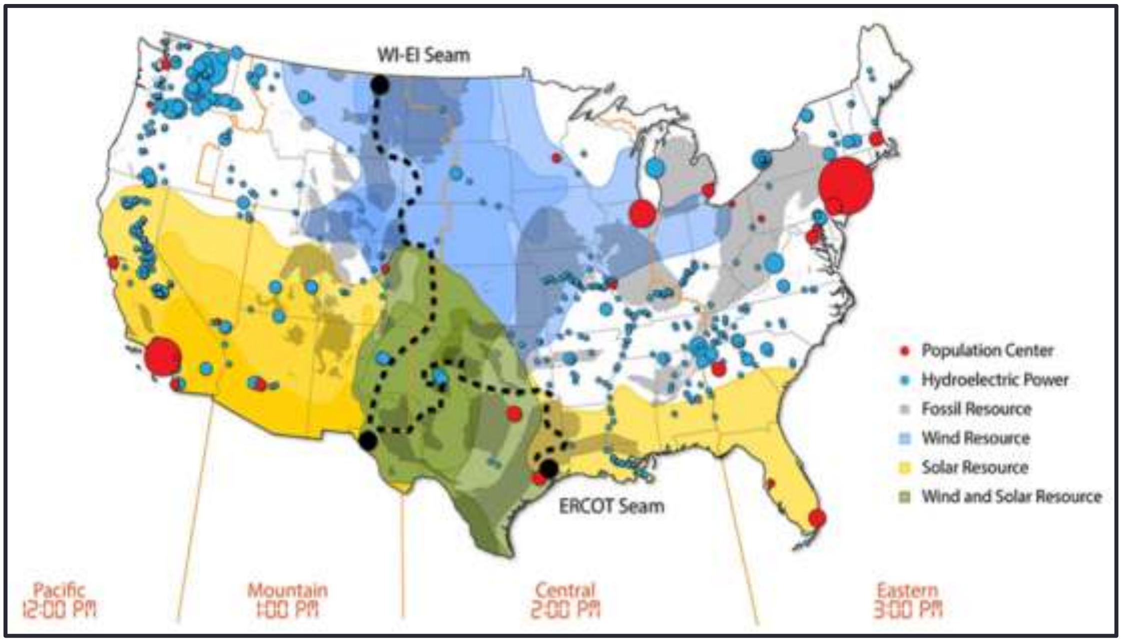
Large operating footprints inherently support increased integration of renewable resources by netting diversity in both supply and demand. SPP is performing at an exceptional level for renewable integration while maintaining system reliability.

- In 2020, SPP became the first RTO to have wind generation as its primary fuel source. [18]
- On March 29, 2022, SPP set a new renewable energy penetration record of 90.2 percent, beating the previous record of 87.5 percent set May 8, 2021. This means SPP served 90.2 percent of the demand for electricity across its 14-state service territory with renewable energy sources. This marks the first time an RTO served more than 90 percent of its load with renewables. Of total demand, 88.5 percent was served by wind, beating the previous wind penetration record of 84 percent, also set May 8, 2021.[19]
- SPP attributes its ability to reliably integrate renewable resources to its "diverse geographic region, fuel mix, and robust transmission grid."[20] SPP's current energy production is 37.5 percent[21] from wind alone.

[18] SPP news release: SPP becomes first regional grid operator with wind as No. 1 annual fuel source. Jan. 26, 2021.
[19] SPP news release: SPP sets regional records for renewable energy production. March 29, 2022.
[20] SPP news release: SPP sets regional records for renewable energy production. March 29, 2022.
[21] Southwest Power Pool. "Fast Facts." Accessed March 8, 2023.

As an example of the potential opportunities for renewable integration, the following graphic shows renewable energy diversity by geography and time zone. The dashed line in the center of the graphic is the seam between the Eastern and Western Interconnections. The SPP RTO footprint covers the entire eastern side of the interconnections seam. The combined footprint of the prospective RTO-West participants extends from the Canadian border to the Colorado-New Mexico border. As can be seen, SPP is exceptionally positioned to leverage benefits from both renewable energy and time zone diversity between the East and West.

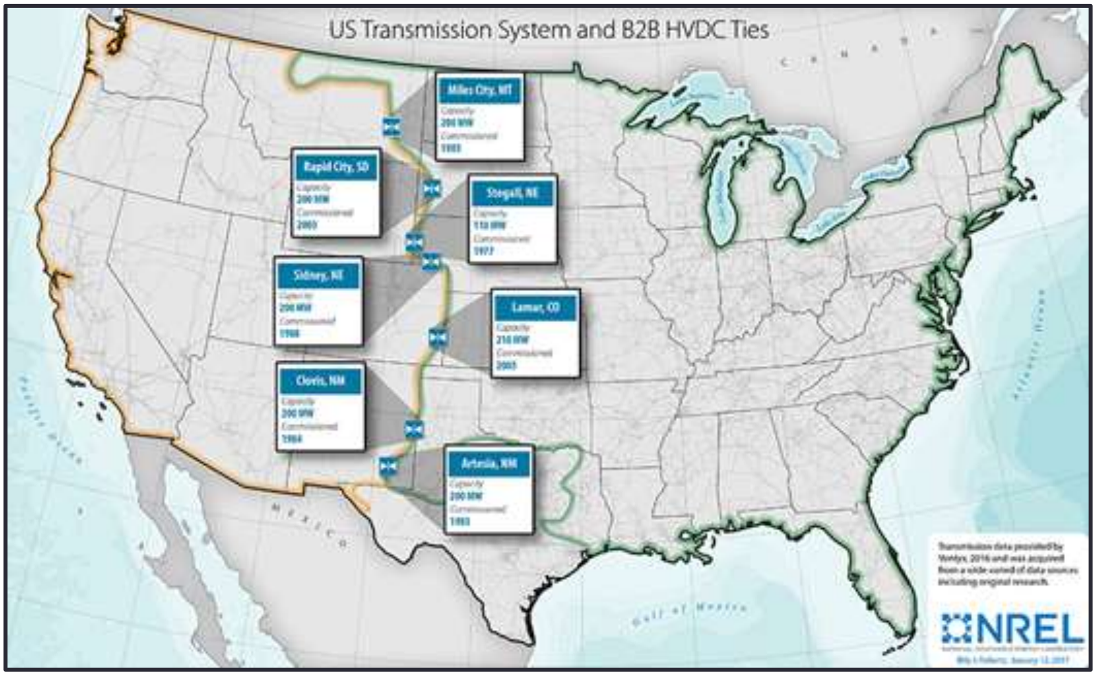
Figure 6: Renewable Energy by Geography and Time Zone



Graphic source: NREL Interconnections Seam Study

The prospective RTO-West participants own three of the seven U.S. DC-ties between the Eastern Interconnection and the Western Interconnection. The current combined transfer capability of these three DC-ties is 510 MW (East-to-West) and 460 MW (West-to-East).

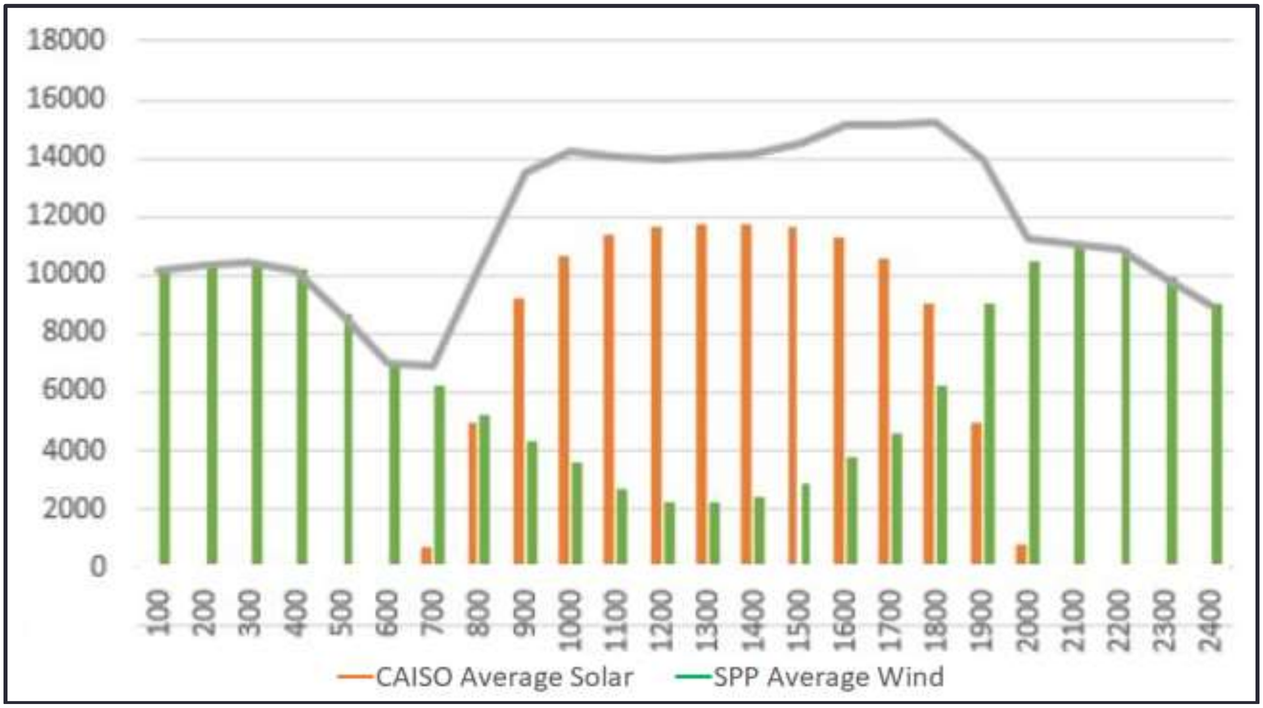
Figure 7: East-West Interconnection Seam and DC-Ties



Source: NREL Interconnections Seam Study

Overlaying wind and solar generation in the central and southwestern U.S. on a sample day in 2021 demonstrates the complementary correlation between wind generation in the central U.S. and solar generation in California. The net generation profile is much more aligned with consumer demand than either wind or solar alone. Although the current RTO-West initiative does not contemplate inclusion of California, it is known that renewable diversity is the key to renewable integration. The following graphics demonstrate the complementary correlation between wind in the East and solar in the West. Having the SPP IM reach into the West has the potential to provide exceptional support for integration of renewable resources.

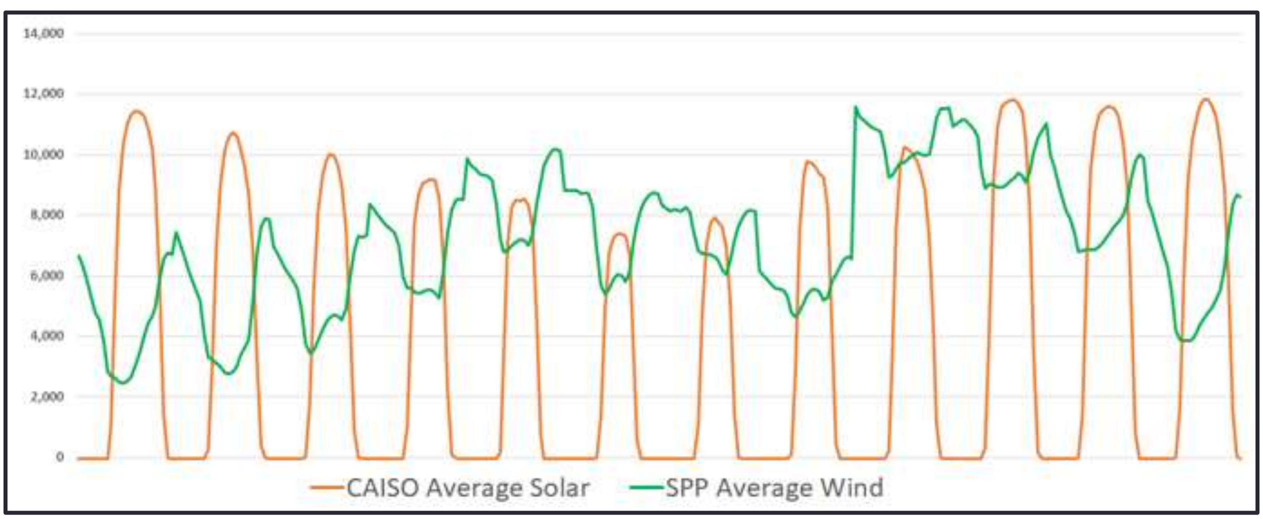
Figure 8: SPP Wind Generation and CAISO Solar Generation – Aug. 5, 2021



Source: SPP

The following graphic shows the average daily generation of SPP wind and CAISO solar from July 2020 through June 2021. It shows the complementary nature of wind and solar generation is persistent across the months of the year. This further emphasizes the potential benefit of integrating the wind-rich SPP RTO with the solar-rich West.

Figure 9: Average SPP Wind and CAISO Solar – July 2020 through June 2021



Source: SPP

Due to their diverse geography, multi-state RTOs are uniquely capable of facilitating integration of renewable energy resources. As a result, stakeholders and states in the West are looking at what RTOs may be able to do to address their accelerating challenges in resource planning and operations due to variable energy integration. As discussed previously, Colorado and Nevada have passed legislation to require RTO membership or similar structures by 2030 to cost-effectively and reliably reach their energy policy goals.

11. HISTORY OF WAPA AND SPP

WAPA has over many years consistently engaged with our customers, neighboring entities, and other stakeholders to evaluate and, where appropriate, implement wholesale market solutions that meet the needs of our individual regions. As key examples, WAPA's WACM and WAUW BAs joined the SPP WEIS in February 2021, the Western Area Sierra Nevada sub-BA (WASN) joined the CAISO EIM in March 2021, and WAPA's Desert Southwest region/Western Area Lower Colorado BA (WALC) went live with the CAISO EIM in April 2023.

The WACM and WAUW footprints' participation in the SPP WEIS has provided the opportunity to incrementally move toward full SPP RTO membership. Now that CRSP, RM, and UGP have evaluated RTO participation in collaboration with customers, these regions are recommending full SPP RTO membership. By the projected go-live date, estimated to be in 2026, UGP will have ten years of operating in the SPP RTO, including the SPP IM, in the Eastern Interconnection, with its transmission facilities under the SPP transmission tariff in both the Eastern and Western Interconnections. Entities within both WAUW and WACM will have accrued five years of experience with SPP WEIS, six years with SPP as their RC in the Western Interconnection, and six years with SPP as the administrator of the Western Interconnection Unscheduled Flow Mitigation (WIUFMP) program. This experience would facilitate the transition to full-RTO participation.

CRSP, RM, and UGP continue to believe that the full SPP RTO with the consolidated umbrella of markets, reliability coordination, operations, and transmission planning is a significantly better option where available. WACM and WAUW are in a position where their adjacency to the SPP RTO and sufficient transmission to connect the footprints allows them to join the SPP RTO. This is not currently the case for WAPA's DSW region.

CRSP, RM, and UGP have conducted collaborative analyses and extensive negotiations with neighboring electricity providers since approximately 1998 regarding the potential benefits of membership in an RTO. In the West, there has long been both support and resistance to centralized market development in the West. The resistance is due in part to the California energy crisis of the late 1990s and early 2000s, which caused electricity outages in California along with economic harm to entities both within California and across the West. Additionally, the transmission topography of the Western U.S. makes it particularly challenging to negotiate agreements on transmission cost shifts that arise under the common transmission tariff, which is foundational to RTO operations.

The electricity industry shifts noted previously highlight the driving factors that are overcoming the historical resistance to RTOs in the West. The current bilateral electricity markets, small control areas, contract path transmission, insufficient RA programs, and acute limitations in developing regional transmission are causing reliability issues and economic harm that are expected to become increasingly significant over time.

CRSP, RM, and UGP do not believe that the current paradigm of a bilateral market with an EI service is adequate for their footprints. It is noted that most of the West has been taking an incremental approach toward eventual RTO membership including imbalance market participation, consolidation of transmission planning regions, consolidation of reserve sharing groups (RSGs), development of regional RA programs, and potentially starting up a day-ahead market. WAPA is of the perspective that linking its WACM and WAUW BAs to the large SPP market via the DC-ties is the most rational approach, and that doing so in the near term is appropriate.

a. UGP Membership in the SPP RTO

In October 2015, WAPA's UGP joined the SPP RTO along with Basin Electric Power Cooperative and Heartland Energy and transferred federal transmission facilities in both the Eastern Interconnection and Western Interconnection to the functional control of SPP. Therefore, UGP is already in the SPP RTO in both the East and West, with limited participation in the West where the SPO RTO hasn't yet extended its IM. UGP's decision was driven in large part by a rapid reduction in bilateral trading partners, which created significant risk both in terms of power marketing and system operations, and an interest in further leveraging SPP's coordinated transmission planning. The economic and operational benefits of UGP's participation in the SPP IM have consistently exceeded expectations.

b. Mountain West Transmission Group

From 2013 to 2018, WAPA's CRSP and RM engaged in discussions with seven other neighboring electricity providers in the Western Interconnection about potential solutions to address emerging challenges to the reliable and economic operation of the Bulk Electric System (BES).[22] These challenges are largely a function of bilateral electricity markets, contract-path transmission arrangements, and fractionalized system planning ubiquitous across the West. The effort was eventually named the MWTG, and after evaluating numerous RTO offerings, SPP was chosen as the potential RTO operator. MWTG negotiations evolved over time to include significant revisions to the existing SPP RTO OATT and terminated in 2018 after Public Service of Colorado (PSCO) and Black Hills withdrew from the initiative. Concerns over the quantity and the extensive complexities of the proposed SPP tariff revisions in MWTG were substantial among the existing SPP membership and is partly why the current SPP expansion effort has a much simpler approach with very minimal tariff modifications.

[22] The MWTG participants were Basin, Black Hills Colorado Electric, Cheyenne Light Fuel and Power, CSU, PRPA, Public Service Company of Colorado, Tri-State, CRSP, and RM.

The current SPP RTO expansion effort is largely a continuation of the MWTG effort, with the same participants, lacking only PSCO and Black Hills participation. The need for centralized markets, operations, and planning persists and is becoming more critical as states in the Western Interconnection are facing generation RA challenges, lack of ability to develop regional transmission, and a rapidly evolving generation mix as states adopt increasingly rigorous clean energy policies.

c. SPP's Western Interconnection Services

In recent years, SPP's Western Services has expanded to include SPP services in the majority of states in the Western Interconnection. In 2015, when UGP region joined SPP, WAPA put UGP's West facilities into the SPP tariff, although the SPP IM does currently extend into the Western Interconnection. SPP's Western RC service began Dec. 3, 2019, and now includes 13 transmission operators and nine BAA.[23] SPP began as the WIUFMP coordinator in December 2019. Also in 2020, SPP began developing the Western Power Pool (WPP) Western Resource Adequacy Program (WRAP) that has 26 participants across ten states and one Canadian province,[24] with others also considering participation. In February 2021, SPP launched the WEIS. Given these extensive services and expansion in the West, SPP is well positioned to expand its full RTO operations into the Western Interconnection.

SPP's successful deployment of services in the Western Interconnection provides WAPA and other RTO participants confidence in SPP's ability to expand their established and fully functioning RTO into the West.

12. SPP RTO WEST MARKET DESIGN, TERMS AND CONDITIONS

Throughout the first half of 2021, SPP and RTO-West interested parties went through a comprehensive review of SPP's governing documents and carefully considered what changes might be required to expand the RTO into the West. The approach taken was to leave the existing RTO framework with only limited modifications the parties would need to join the RTO.

a. General Market Design

At a high level, SPP's RTO:

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[23] SPP news release: SPP's role in western reliability continues to grow with addition of new customers in four states. Sept. 1, 2020.

[24] SPP news release: Northwest Power Pool to Hire Southwest Power Pool to Provide Program Operator Services for Resource Adequacy Program under Development. Aug. 3, 2021.

- Utilizes a common tariff to manage the operation of the transmission systems and generation resources of multiple electricity providers to optimize the utilization of their assets for the benefit of the entire RTO footprint.

- Maintains a wide-area view and real-time situational awareness of the entire footprint to monitor and manage the reliability of the system.

- Serves as the centralized operator for a day-two market for auction-based electricity products.[25]

- Is the Transmission Service Provider for all member transmission systems under the SPP OATT.

- Provides market monitoring oversight.

- Facilitates transmission development, including cost allocation, across multiple transmission systems and states.

- Performs ongoing assessments to ensure that generation and transmission RA are in alignment with reliability, economic and public policy requirements.

b. West-Side Participant Terms and Conditions

By summer of 2021, the RTO-West entities and SPP finalized an initial terms and conditions document entitled "Integrating Western Parties into SPP's RTO: Terms and Conditions".[26] This document was submitted to and approved by the SPP Board of Directors in July 2021 and valid through April 15, 2022. Due to delays in initial timeline assumptions, the SPP Board approved of an extension of the initial terms and conditions during the April 2022 SPP Board meeting to March 1, 2023.[27] DC-tie terms and conditions to address the unique issues and market treatment associated with the East-West DC-ties were subsequently finalized by the RTO-West entities and SPP. In July 2022, the SPP Board approved these further provisions through March 1, 2023.[28] In January 2023, CRSP and SPP finalized additional terms and conditions specific to CRSP. SPP's board approved these on Jan. 31, 2023, along with an extension of all the terms and

[25] These products include varying combinations of energy, capacity, and ancillary services, such as day-ahead unit commitment, reliability unit commitment and real-time dispatch.
[26] The July 27, 2021, SPP Board meeting minutes and materials are posted publicly here. The terms and conditions as approved are on pages 20 through 47 and a summary PowerPoint is on pages 48 through 59.
[27] The April 26, 2022, SPP Board meeting minutes and materials are posted publicly here. The recommendation to extend the terms and conditions to March 1, 2023, is on pages 34 through 35 and was approved as part of the consent agenda.
[28] The July 26, 2022, SPP Board meeting minutes and materials are posted publicly here. The recommendation to approve the negotiated DC-tie terms and conditions are on pages 56 through 60 and was approved as part of the consent agenda. The DC-tie Proposal whitepaper referenced in the recommendations is posted publicly here.

conditions through July 1, 2023, contingent on WAPA initiating the process to publish its intent to pursue final negotiations for SPP RTO membership in the *Federal Register* by Feb. 28, 2023.[29]

Highlights of the terms and conditions are included below. More background and detailed descriptions of the terms and conditions are included in the materials posted for the SPP Board meetings noted above, with links provided in the associated footnotes:

i. Initial Terms and Conditions

- WAPA UGP federal provisions (including the FSE) extended to CRSP and RM.
- Single Order 1000 planning process coordinated with local planning.
- FERC waiver request for West-side interconnection queue processing without delay if East-side queue backlog still exists upon go-live.
- Zonal rate design under which each transmission owner (TO) would generally have a zone. Some zones (RM's and UGP's) would span East-West.
- Point-to-Point drive-out revenue assigned to interconnection-exit side (East or West).
- Point-to-Point drive-out rate would be West zone average instead of exit zone rate.
- There would be separate East and West Schedule 11 regional transmission rates (costs stay on each side).
- Transmission facilities defined at 100 or more kilovolts (kV) rather than 60kV+.
- Single IM across East-West, optimized across the DC-ties, with single market solution footprint wide.
- New SPP West BAA (with WACM and WAUW BAAs merged into SPP West BAA).
- SPP West BA would join the WPP RSG.
- Minor governance changes.
- SPP committee selections to consider East-West diversity.

[29] The Jan. 31, 2023, SPP Board meeting minutes and materials are posted publicly here. The additional CRSP-MC specific terms and conditions and extension of all the terms and conditions to July 1, 2023, as approved, are on pages 258 through 262, and a summary PowerPoint is on pages 247 through 257.

- Strategic Planning Committee expands by two seats, one for Transmission Owners, one for Transmission Users.

ii. <u>DC-tie Terms and Conditions</u>

The DC-tie terms and conditions noted above apply to the Miles City, Stegall, and Sidney DC-ties, and these three DC-ties would be incorporated into the SPP Transmission System and utilized by SPP to dispatch the SPP IM as a single market across the combined East and West RTO footprint.

- An incremental Market Efficiency Use (MEU) charge that provides revenue via a market uplift to the DC-tie owners to offset incremental DC-tie operational costs due to market dispatch of the DC-ties.

- DC-tie access charge for transmission reservations that utilize a DC-tie and sink beyond the DC-tie-owning zone.

- DC-tie congestion settlement provisions.

iii. <u>Additional CRSP-MC Specific Terms and Conditions</u>

- Point-to-Point transmission service revenue from CRSP reservations using CRSP facilities within the CRSP transmission pricing zone associated with the fulfillment of the CRSP contractual or Statutory Load Obligations would be distributed solely to CRSP.

- “Federal-Power-CRSP” would be defined to also include replacement energy acquired by CRSP, solely for the purpose of satisfying CRSP’s Statutory Load Obligations, as necessitated by CRSP’s inability to deliver sufficient energy from federal hydropower resources for reasons such as persistent drought or environmental constraints.

c. Federal Service Exemption

An important aspect of WAPA membership in the SPP RTO includes negotiated exemptions that recognize the unique circumstance of the federal power programs that WAPA administers. The SPP tariff currently provides a FSE for UGP. CRSP, RM, and UGP are proposing to extend the SPP FSE to CRSP, RM, and UGP’s West-side operations. The FSE[30] includes:

- Exemption from regional capital construction cost allocation: This part of the FSE would not have immediate value to CRSP, RM, and UGP’s West-side because no regional cost-allocated projects would have been approved and built. For this reason, benefit was not estimated for

[30] Section 39.3(e), SPP Tariff.

the initial years. Over time, however, regional projects would be approved and built, and this exemption from cost recovery charges would grow in value.

- Exemption from marginal congestion and marginal loss charges: The locational marginal price (LMP) methodology in SPP and other RTOs has three components: marginal energy component, marginal congestion component, and marginal loss component. The marginal energy component is system wide. The marginal congestion and loss components are at the nodal level. The FSE provides an exemption from charges for the marginal congestion and marginal loss components.[31] This exemption would only apply to CRSP, RM, and UGP's West-side hydroelectric power that is bilaterally scheduled to statutory load and cleared in the day-ahead market. Firming purchases or real-time transactions are not exempt from these components, with the exception of certain CRSP replacement energy acquisitions per the CRSP-MC specific terms and conditions noted above. It also should be noted that the congestion and marginal loss components are not necessarily positive value costs but could be negative, and therefore a potential missed revenue opportunity for WAPA. As a net, the hedge against these potential costs is expected to have significant value.

WAPA's recommendation includes CRSP, RM, and UGP. Each is individually discussed on the following pages.

13. SPP RTO CONSIDERATIONS AND IMPLICATIONS FOR CRSP

The CRSP-MC markets the output of Bureau of Reclamation-owned hydroelectric facilities of the Collbran Project, Rio Grande Project, Dolores Project, Seedskadee Project, and the Colorado River Storage Project collectively known as the Salt Lake City Area Integrated Projects (SLCA/IP). The projects serve customers in Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming with 1,816 MW of installed hydroelectric generation capacity and more than 2,323 miles of transmission line.

a. CRSP Considerations

The first and most important consideration for CRSP is maintaining power and energy deliveries to its Firm Electric Service (FES) and Project Use customers. CRSP is a unique and complex federal power project with most of its generation capacity delivered to customers at its transmission system boundaries. The CRSP transmission system was built differently than that of typical utility transmission system. It was designed to move federal hydropower to a customer's system rather than to directly serve load.

Under SPP's market design it is generally load that is assessed the transmission charge rather than a generator. Energy and capacity are delivered across one or more transmission systems,

[31] Physical loses are provided by WAPA.

and the transmission charge assessed is the transmission rate of the zone where the power sinks to load. The zone where the energy sinks to load also retains that transmission revenue.

Unique among potential RTO-West participants, most of the load CRSP serves would fall outside its prospective SPP zone. In fact, only about 12 percent of CRSP resource would be delivered inside CRSP's prospective SPP zone.

CRSP has highlighted challenges of integrating its system into this market design while ensuring recovery of its transmission costs. Without some market accommodation, CRSP would lose transmission revenues associated with delivering federal resources, over its own transmission lines, sinking in other SPP zones. Were CRSP to join SPP under the existing OATT, its current transmission rate would be projected to increase approximately 60 percent from today's rate of $1.75/kilowatt-month (kW-month) on day-one of RTO membership.

Ironically, the RTO's best-case scenario is CRSP's worst-case scenario. The worst-case scenario for CRSP is where all its customers join SPP. The CRSP transmission rate would soar to $18/kW-month, as the limited amount of load in the CRSP zone is responsible for recovering CRSP's $89 million annual transmission revenue requirement (ATRR). Compared to CRSP's current transmission rate or $1.75/kW-month, this represents a projected transmission rate increase of over 900 percent at full market expansion.

CRSP negotiated terms and conditions with SPP to address its ability to recover costs in the market. The Point-to-Point Transmission Service provision set out below is intended to allow CRSP to recover its transmission costs by buying Point-to-Point Transmission Service across its system to serve its obligations to deliver to federal transfer points.

In addition, CRSP negotiated provision~~s~~ to treat certain purchased power as comparable to federal hydropower for the purpose of applying the FSE. CRSP believes this provision would help address drought and resource limitation concerns. The Glen Canyon powerplant represents a significant portion of total SLCA/IP capacity available to meet load and firm power sales. The continued drought in the western United States in general, and the Colorado River Basin specifically, has put the availability of the Glen Canyon powerplant in question.

If Lake Powell were to fall below the level of the Glen Canyon water intake structures, the Glen Canyon powerplant would go offline. Since this condition could continue for months, if not years, CRSP would need to either reduce its obligations to deliver CRSP hydropower or arrange for long-term purchase power agreements in response. CRSP power is primarily marketed to customers serving rural and agricultural areas, small towns, irrigation districts, and Tribal reservations. These entities would be adversely affected by cost increases or diminished availability of CRSP power. Participating in the RTO market would allow CRSP to access additional resources to replace hydroelectric generation.

CRSP's existing contracts and marketing plan offer capacity products, initially developed to implement the Grand Canyon Protection Act of 1992, which allow customers to use capacity on the CRSP transmission system to deliver replacement power. Accordingly, CRSP negotiated a provision to allow certain CRSP purchases of firming power to qualify as federal power for purposes of applying the FSE.

In January 2023, CRSP-MC and SPP finalized WAPA Federal Provisions specific to CRSP, which the SPP Board approved on Jan. 31, 2023.[32] These provisions state:

> ***WAPA-CRSP Point-to-Point Transmission Service***
> *Point-to-Point (PtP) Transmission Service revenue from WAPA-CRSP reservations using CRSP facilities within the CRSP transmission pricing zone associated with the fulfillment of the WAPA-CRSP contractual or Statutory Load Obligations will be distributed solely to WAPA-CRSP. This will include revenue from any PtP Transmission Service reservation that delivers from within the CRSP zone to the border of the CRSP zone and is then paired with another transmission reservation, the revenue from which will not be distributed solely to WAPA-CRSP, across non-CRSP facilities for delivery to the ultimate contractual or Statutory Load Obligations either inside or outside the SPP RTO region.*
>
> ***Federal Service Exemption WAPA-CRSP Replacement Energy Provision***
> *The FSE, as found in Section 39.3 of the SPP Tariff, will apply to WAPA-CRSP as described below. Federal Power-WAPA-CRSP will be defined to also include replacement energy acquired by WAPA-CRSP, solely for the purpose of satisfying WAPA-CRSP's Statutory Load Obligations. Replacement energy is defined as energy purchased bilaterally by WAPA-CRSP for a minimum of 28 days in duration for purposes of meeting WAPA-CRSP Statutory Load Obligations when Federal generating resources are not sufficient. This is necessitated by WAPA-CRSP's inability to deliver sufficient energy from Federal resources for reasons such as persistent drought or environmental constraints.*
>
> *In order for replacement energy acquired on a bilateral basis or otherwise furnished to be eligible for the WAPA-CRSP FSE, WAPA-CRSP must first deliver the replacement energy to the WAPA-CRSP transmission zone, and that delivery is subject to SPP Tariff provisions and charges. The replacement energy used to meet Statutory Load Obligations then delivered from the location of the WAPA-CRSP transmission zone is eligible for the WAPA-CRSP FSE.*
>
> *For any and all transmission WAPA-CRSP purchases to meet its obligations that do not qualify for FSE treatment under Section 39.3 of the SPP Tariff, WAPA-CRSP shall be entitled to receive Auction Revenue Rights and any and all rights appurtenant thereto, including the right to*

[32] The Jan. 31, 2023 SPP Board meeting minutes and materials are posted publicly here. The additional CRSP-MC specific terms and conditions and extension of all the terms and conditions to July 1, 2023, as approved, are on pages 258 through 262, and a summary PowerPoint is on pages 247 through 257.

transfer ARRs to TCRs and receive any associated revenues, to be administered consistent with the SPP Tariff. [33]

b. CRSP Obligations in the Market

i. Sustainable Hydro Power (SHP)

SHP is a long-term level of hydroelectric capacity with energy, supplemented by WAPA power purchases due to hydrological conditions, delivered to specific customers each month under firm electric service contracts. This is a bundled product and can be considered somewhat analogous to native load. The FSE would apply to qualifying deliveries, which would be exempted from marginal congestion and marginal loss charges in the market, as well as to regional costs for directed facility improvements. Customers should notice no changes to delivery conditions for SHP energy and capacity allocations.

ii. Western Replacement Power (WRP)

Under WRP, a customer can call on WAPA to purchase energy to fulfill the shortfall of capacity between SHP or Available Hydropower (AHP) (whichever is greater) and the customer's Contract Rate of Delivery (CROD), representing the customer's full CRSP allocation. Expenses WAPA incurs in providing WRP are passed through to the customer requesting WRP. Purchased power in terms greater than 28 days would be eligible for the FSE under the negotiated provision above. WRP is currently offered on seasonal, monthly, day-ahead, and real-time bases, but scheduling requirements may need to be adjusted to efficiently operate within SPP. Below are examples of how CRSP anticipates serving WRP transactions in the market:

- Internal to RTO Market WRP (deliveries source and sink inside of market): WAPA would buy WRP bilaterally and offer it in the market. SPP's Bilateral Settlement Schedule can be used to transfer the settlement responsibilities. This would shift the settlement from the customer's statement to WAPA's statement. Accordingly, energy settlement and other charges would be included on WAPA's statement. WAPA would then add this energy settlement amount, along with associated charges (such as administrative fees, congestion, and losses) for the WRP deliveries, to the FES bill for that customer.

- External WRP (deliveries with source and sink outside of market): No change from existing practices. If the market expands, then this external WRP may become internal to RTO WRP as those deliveries fall within the expanded market.

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[33] Auction Revenue Rights (ARRs) and Transmission Congestion Rights (TCRs) are both financial rights used in the SPP IM to hedge against costs for transmission congestion between settlement locations.

- External to Market WRP (deliveries with resource in market but sink outside of market): WRP energy purchases internal to the RTO would be treated as a drive-out of energy from the RTO.

iii. Customer Displacement Power (CDP)

CDP is similar to WRP in that it is designed to allow the customer to use the CRSP transmission system to meet the difference between SHP/AHP and CROD. The major difference is that instead of WAPA procuring the energy and passing those costs through to the customer, the customer provides the energy either by making their own purchases or by supplying power they generated.

- Internal to Market CDP deliveries (source and sink inside of market): It is possible some type of CDP product can be provided to other market participants if it were advantageous. It appears that the market itself would be more efficient/cost effective for procuring energy rather than customers using CDP. CRSP would work with its customers to address questions and strategies surrounding the treatment of CDP inside the market.

- External CDP (deliveries with source and sink outside of market): No change from existing practices.

c. CRSP Financial Implications

The total estimate of new costs and benefits for CRSP range from negative to slightly positive. The financial impact to CRSP is estimated to be primarily due to drive-out revenues, market benefits, transmission cost changes, and RTO costs. Each of these categories and the summary of the Brattle study results are shown on the following pages.

Annual benefits, after subtracting for market expenses, range from negative $700,000 to positive $2.1 million per year depending on water conditions. The overall estimated benefit for CRSP during normal hydrology is $500,000. During extended drought, the value of an RTO market could approach $2.1 million for CRSP. This total does not include any congestion-related costs or benefits, nor does it reflect the costs and benefits associated with CRSP's negotiated provisions. The Brattle study also did not model transmission cost impacts. However, CRSP anticipates limited changes initially in joining the RTO compared to not joining. CRSP has determined this is a null cost/benefit and determined the transmission cost to the FES rate would not meaningfully change.

Table 7: CRSP Cost Benefit Summary

Cost or Benefit Categories	Cost or Benefit to CRSP	Quality of Estimate
Transmission Cost Shift	See Narrative	See Narrative
Wheeling Revenue	$ 1,497,000	Fair
Market Benefits (Normal hydro = $507K) (Low Hydro = $3.3M)	$ 507,000 to $3,300,000	Fair
Additional Admin Fee for RTO	$ 1,825,000	Good
Loss of Scheduling, System Control, and Dispatch (SSCD) Revenue	$ 499,809	Very good
Loss of EI Fee Revenue	$ 508,400	Very good
Loss of Western Power Pool (WPP) RSG Administrative Fee	$ 72,655	Very good
CRSP - New Software Annual Maintenance (Initial purchase price is ~$1M for CRSP)	$ 7,000	Very good
Retirement of Existing Software Annual Maintenance Costs for the Energy Management and Marketing Office	$ 191,178	Very good
COST/BENEFIT RANGE	**-$718,000 to $2,075,000**	

The market benefits are the APC savings as estimated in the 2022 Brattle study. Those results are further explained below. The sum includes a range from $3,300,000 during low hydro conditions to $507,000 under normal hydro conditions.

Although not immediate, CRSP projected benefits from staff reductions over time are expected to create a situation where both the high and low benefit estimates would be positive.

i. Transmission Cost Shift

Transmission cost changes include the loss of CRSP transmission revenues due to the elimination of pancaked rates in the expanded SPP footprint. The Point-to-Point Transmission Service revenues would be reduced and shared among participants in the SPP RTO-West. There is no reduction to transmission expenses in the FES rate.

ii. Wheeling Revenues

The SPP RTO expansion entities contracted with The Brattle Group to estimate drive-out transmission revenues for the RTO-West footprint. A breakdown of the 2022 results gave an estimate of the benefits to CRSP of an additional $1.5 million in transmission revenue compared to existing WEIS bilateral market conditions. The CRSP Point-to-Point provision could impact the wheeling revenues available to the RTO-West footprint.

iii. Changes to Ancillary Services – Scheduling, System Control, and Dispatch (SSCD), Energy Imbalance (EI), and WPP RSG Administrative Fee

According to a report by Argonne National Laboratory, completed during the MWTG evaluation, the elimination of requirements to provide regulation, load following, and contingency reserves makes capacity available for CRSP and would result in financial benefits. Argonne National Laboratory used the production cost model done during the MWTG effort to estimate this value in the market to be ~$1 million. Thus, CRSP is losing ancillary service revenue but is getting relief from its current ancillary obligations to WACM. In total, this category is estimated to have a negligible net financial impact compared to current conditions.

iv. Administrative Fees for the RTO

RTO costs of significance include SPP administrative fees, miscellaneous market fees, and SPP software licensing costs. SPP recovers its operating and capital costs from customers who are taking service under the SPP OATT. CRSP would pay SPP a Schedule 1-A fee and would have some exposure to the other rates. It is expected that the SPP overhead costs would increase over time, although SPP has estimated a net downward pressure in rates during the fifth year from go-live, when the startup costs are projected to be fully repaid. At a minimum, CRSP's likely administrative costs to SPP would be $1.25 – $1.5 million/year under Schedule 1-A. Additionally, CRSP would pay SPP about $500,000/year in Schedule 12 costs (to recover SPP's obligation to FERC for its annual charges). The combined total is $1.825 million. CRSP's negotiated Point-to-Point provision may increase the annual administrative fee totals, as those transactions incur greater administrative costs in the market.

v. Software Costs

Necessary subscription-based software system costs were also estimated. In total, this category is about $700,000 of new costs. Annual maintenance costs are expected to be about $7,000/year for vendor services. Approximately $191,000 in annual savings are achieved by removing redundant software systems and avoiding those costs.

vi. Brattle Adjusted Production Cost Summary Results

The Brattle study concludes that energy exchange prices would be, on average, lower than in a bilateral market. For illustration, below is a summary based on normal and dry hydrology that shows whether joining the SPP RTO benefits CRSP. It uses day-ahead to real-time forecasts for renewables in the WEIS footprint and SPP, along with historical data provided by the study participants, hurdle rates for the DC-ties, and predicted gas prices.

Table 8: Adjusted Production Cost Comparison for CRSP

Adjusted Production Cost Comparison for CRSP

	GWh			$/MWh			Total ($1000s/Year)		
Cost Components	WEIS Case	RTO Case	Difference	WEIS Case	RTO Case	Difference	WEIS Case	RTO Case	Difference
Production	5,015	5,015	0	$2.01	$2.01	$0.00	10,081	10,081	$0
Purchases									
Bilateral Market/Day-Ahead Market	947	947	0	$40.65	$39.79	-$0.85	38,484	37,679	-$805
Real-Time Market	0	0	0	$0.00	$0.00	$0.00	0	0	$0
Sales									
Bilateral Market/Day-Ahead Market	319	319	0	$34.07	$33.14	-$0.93	10,885	10,587	-$298
Real-Time Market	0	0	0	$0.00	$0.00	$0.00	0	0	$0
Total	5,643	5,643	0	$6.68	$6.59	-$0.09	37,680	37,173	-$507
% Change in APC									*-1.3%*

Source: [SPP RTO Brattle study](). September 2022

Table 9: Adjusted Production Cost Comparison for CRSP – Low Hydro Conditions

Adjusted Production Cost Comparison for CRSP Low Hydro

	GWh			$/MWh			Total ($1000s/Year)		
Cost Components	WEIS Case	RTO Case	Difference	WEIS Case	RTO Case	Difference	WEIS Case	RTO Case	Difference
Production	1,064	1,065	1	$2.01	$2.01	$0.00	2,138	2,140	$2
Purchases									
Bilateral Market/Day-Ahead Market	4,579	4,578	-1	$37.44	$36.73	-$0.71	171,461	168,159	-$3,302
Real-Time Market	0	0	0	$0.00	$0.00	$0.00	0	0	$0
Sales									
Bilateral Market/Day-Ahead Market	0	0	0	$0.00	$0.00	$0.00	0	0	$0
Real-Time Market	0	0	0	$0.00	$0.00	$0.00	0	0	$0
Total	5,643	5,643	0	$30.76	$30.18	-$0.58	173,599	170,299	-$3,300
% Change in APC									*-1.9%*

Source: [SPP RTO Brattle study](). September 2022

Table 10: Brattle Results for CRSP Transmission Wheeling for Base Case and Low Hydro

Base Case

CRSP	Total ($1000s)
Total Wheeling Revenue WEIS Case	$267
Total Wheeling Revenue Share RTO Case	$1,764
Change in Wheeling Revenue	$1,497

Low Hydro Sensitivity

CRSP	Total ($1000s)
Total Wheeling Revenue WEIS Case	$231
Total Wheeling Revenue Share RTO Case	$1,613
Change in Wheeling Revenue	$1,382

Source: [SPP RTO Brattle study](). September 2022

vii. Congestion Hedging: An Uncertain but Potential Source of New Revenue

Congesting hedging associated with CRSP's Point-to-Point reservations in the SPP RTO market has a potential for an offsetting revenue component where congestion revenue can be used to lower CRSP rates. This financial tool can be used to recover value associated with transactions that are not covered by the FSE. Because this area is new to CRSP, the total risks and opportunities associated with participating in SPP's congestion hedging market are unknown.

14. SPP RTO CONSIDERATIONS AND IMPLICATIONS FOR RM

The RM region markets and transmits federal power generated from certain Bureau of Reclamation hydroelectric facilities collectively known as LAP. RM also operates the WACM and WALC BAs, and provides transmission services, including, but not limited to, transmission service across WAPA-owned transmission facilities within the two BAAs.

LAP comprises the hydroelectric facilities of the Pick-Sloan Missouri Basin Program—Western Division and the Fryingpan-Arkansas Project. These two projects were integrated and are now collectively called LAP. LAP serves a marketing territory including portions of Colorado, Kansas, Nebraska, and Wyoming with 830 MW of installed hydroelectric generation capacity and 3,360 miles of transmission line. Approximately 100 miles of these lines are in the Eastern Interconnection. Approximately 125 entities have LAP power allocations across the marketing territory.

RM's transmission owning membership in SPP would include LAP's transmission facilities being included in SPP transmission service. SPP would take over as the BA, and RM would cease WACM BA services. With the expansion of the SPP IM into the West, LAP would transition its current financial-only market participation to that of an Asset Owner Market Participant, and transition LAP transmission service to equivalent SPP transmission service.

a. RM Considerations

RM's primary considerations have been reflected throughout this report and can be summarized with the five strategic considerations referenced in section 1. Restating those, they are:

- Provide Risk Mitigation
- Optimize Transmission
- Support Reliability
- Optimize Resource Dispatch
- Support Core Mission Success

As a BA operator, reliability while enabling continued renewable resource integration is a top priority, not only for WAPA but for all our BAA customers. This is tightly interconnected with the need to optimize transmission regionally. The Administration's goals of continuing to transform the energy industry will increasingly require broadly optimized transmission planning across the region. Repeated production cost modelling has consistently revealed significant footprint savings that RTO markets provide. RM has forgone such optimized resource dispatch savings for too long already and transitioning into an RTO is past due. The RM region has also watched as the pace of change has increased dramatically, and since we are committed to ensuring continued core mission success, we must address risks that are presenting themselves, like the inevitable loss of bilateral trading partners necessary to firm FES deliveries when hydropower generation is deficient.

The SPP RTO addresses all five of these considerations, and is viewed as the best course forward, not only for the RM region, but for the broader footprint as well.

b. RM Financial Implications

RM sells cost-based excess LAP transmission service and cost-based WACM BA services. Both of these services are financially part of LAP and RM strives to keep LAP transmission and WACM BA services as a net-zero impact to LAP. For this reason, RM's primary financial concern regards LAP. The impact of LAP transmission service and ancillary services migrating to SPP are components of the overall impact to LAP. Other market participants, including RM's customers, would also be impacted by these changes. This section discusses the impact that joining SPP would have on LAP.

i. LAP Financial Cost Benefit Summary

The total financial impact to LAP is estimated to be positive but depends heavily on assumptions. The financial impact to LAP is estimated to be primarily due to drive-out revenue changes, market benefits, transmission cost changes, staffing reductions, and RTO charges. Each of these categories is discussed below. The total impact, depending upon assumptions, results in a total benefit of around $2 million to $3 million per year. RM acknowledges that fewer staff would be needed to perform certain functions after transitioning to the SPP RTO. Staffing reductions would be expected to occur with reallocation of staff to vacant positions (leveraging existing skillsets) along with normal staff attrition. Since staffing reductions through attrition would take some time, it is expected that initial net benefits would be lower.

As FSE benefits are realized, the benefits of RTO participation would increase. It is important to note that while RM attempted to be realistic in its analysis and was conservative throughout, many of these estimates require assumptions and could deviate in either direction.

The scale of this impact is relatively small compared to total overall LAP revenue, which totals approximately $153 million per year. Also significant is the fact that the Pick-Sloan power repayment study, which drives the LAP rate, requires approximately $10 million of change to the annual revenue requirement to move the rate by $0.001/kWh and therefore the sole impact of joining SPP is not expected to result in a rate adjustment.

It is also noteworthy that our estimates are by default a comparison to today's costs. If we do not join the SPP RTO, our costs are unlikely to remain at today's levels, but will adjust to accommodate the ever-increasing pace of changes that occur each year. While the RTO is estimated to save LAP $2 million to $3 million per year compared to today, it is likely that not joining the RTO would end up costing LAP more than today's costs.

Each of the four major categories of impacts are discussed below:

(1) Market Benefits and Drive-Out Revenues:

Prior to the study completed in 2022, SPP contracted with The Brattle Group to do production cost modeling analyses to estimate market benefits and drive-out revenues for the WEIS footprint. According to this study completed in 2020, LAP benefits would be in the range of $2.5 million, mostly from drive-out revenues. [34] Drive-out revenues would be distributed 50 percent based on transmission system revenue requirements, and 50 percent based on a MW-mile impact study. Since the MW-mile impact study is difficult to predict and estimate, 100 percent revenue requirement distribution was used to come up with this rough estimate.

In December 2021, the West-side participants decided to update this Brattle study (also discussed in previous sections of this report) to include CSU in the RTO footprint, update gas prices and other assumptions, as well as model certain sensitivities to increase our understanding of potential benefits. In this updated study, finalized during the summer of 2022, the benefits to LAP are shown to be in the range of $2.4 million to $3.4 million, plus a minor increase in drive-out revenues not included in these numbers. [35] Both modeling efforts were relatively conservative and did not assume optimized use of the hydro generation, but rather historical schedules, and did not maximize the benefit of LAP's Mt. Elbert pumped hydro storage plant in the market, and thus may be low estimates.

(2) Transmission Cost Changes:

Transmission cost changes to LAP include: upward pressure on the transmission rate due to the loss of revenue from pancaked transmission service; downward rate pressure due to DC-tie revenues for DC-tie use beyond the LAP zone; and LAP cost savings due to

[34] https://spp.org/documents/63517/weis%20and%20spp%20west%20rto%20benefits%20study.pdf
[35] https://www.wapa.gov/About/keytopics/Documents/2022-spp-rto-brattle-study.pdf

eliminating pancaked transmission service the project currently pays. The total impact to LAP for these areas is estimated to be roughly even with savings offsetting increases but is heavily dependent on assumptions and could vary substantially in either direction.

(3) WACM and Ancillary Service Changes:

A transition to SPP's market environment across the WEIS footprint would include having SPP combine and take over responsibilities for the WACM and WAUW BAAs. With this transition, WACM would cease selling ancillary services and any financial impact of that change impacts LAP. The most significant cost impacts include: the freeing up of regulation reserve capacity; the loss of regulation revenue; the loss of reactive supply revenue; the loss of EI and generator imbalance (GI) administrative revenue from parties that take that service from WACM rather than directly from SPP WEIS; the reduction of WAPA staff due to all these changes; and elimination of software costs for these services.

Regarding freeing up regulation reserve capacity, it is expected that this freed up capacity would reduce LAP purchase power as well as provide revenue for both energy and ancillary services sold into the integrated market. However, LAP would lose the revenue that it currently receives by offering regulation service to WACM customers. Since this specific impact is difficult to predict, and may not result in savings, LAP is not assuming a net benefit in this area. The sale of reactive supply is similar. LAP's revenue would decrease if reactive supply is converted to the current practice within SPP. However, LAP may be able to obtain revenue and thus offset this impact. Regardless, to any extent that these changes could potentially result in a negative impact to LAP, it should be noted that these lost revenues to LAP would occur by eliminating customer payments to WACM. For this reason, from our customer's perspective, even a negative impact to LAP may be viewed as positive.

RM currently passes through costs associated with EI/GI, as well as SSCD service, and WPP RSG administration, and would lose the revenue from those charges. Although the costs are small, certain software would no longer be needed upon joining SPP, and would result in some savings. The overall costs equate to roughly $1 million per year harm but would be offset by reduction of staffing levels once these services are no longer supported.

In total, taking everything into account, the total LAP impact related to the WACM BA category is estimated to be a cost of about $0.6 million. However, this cost would be more than offset by decreased staffing levels once that adjustment is made.

(4) RTO Costs:

RTO costs include the SPP administrative fees beyond what we currently pay SPP for RC services and the WEIS, miscellaneous market fees, and software system cost changes.

Necessary subscription-based software system costs were roughly estimated along with the elimination of the WEIS systems which would no longer be necessary. In total, the costs and savings in this area are expected to roughly cancel out, primarily due to full-time equivalent (FTE) savings canceling the RTO administrative fee cost.

In summary, from a financial perspective, RM's conservative estimate is significant savings for LAP, and thus supports our recommendation to finalize negotiations to join the SPP RTO.

15. SPP RTO CONSIDERATIONS AND IMPLICATIONS FOR UGP

The UGP region markets and transmits federal power from reservoir projects under the control of the U.S. Army Corps of Engineers (USACE) and the U.S. Bureau of Reclamation. UGP operates the WAUW BAA in the Western Interconnection, where a portion of its transmission and generating facilities are located. UGP transferred federal transmission facilities in both the Eastern Interconnection and Western Interconnection to the functional control of SPP when it joined the SPP RTO in 2015. Therefore, UGP is already in the SPP RTO in both the East and West, with limited participation in the West where the SPO RTO hasn't yet extended its Integrated Marketplace.

UGP markets the output of USACE and Bureau of Reclamation-owned hydroelectric facilities of the Pick-Sloan Missouri Basin Program—Eastern Division (PS-ED). PS-ED has a marketing territory that includes parts or all of Montana, North Dakota, South Dakota, Nebraska, Minnesota and Iowa with 2,698 MW of installed hydroelectric generation capacity and 7,829 miles of transmission lines. Approximately 265 MW of this installed hydroelectric generation capacity and 680 miles of these lines are in the Western Interconnection. Approximately 349 customers have PS-ED power allocations across the marketing territory.

The expansion of UGP's participation in the SPP RTO proposed in this report would include SPP taking over as the BA in the Western Interconnection for UGP, and UGP would cease WAUW BA services. In addition, with the expansion of SPP's IM into the West, UGP would expand its existing East-side participation in the SPP IM to include its Western Interconnection loads and applicable resources.

a. UGP Considerations

UGP's primary considerations related to the proposed expansion of UGP's participation in the SPP RTO in the Western Interconnection are consistent with CRSP and RM considerations that have been reflected throughout this report. They can be summarized with the five WAPA strategic considerations referenced in Section 1, which include:

- Risk mitigation for UGP in the Western Interconnection.
- Transmission and market optimization, including UGP's Miles City DC-tie.

- Improve reliability for UGP in the Western Interconnection, including UGP being part of a larger SPP West BAA.

- Optimized resource dispatch for UGP in the Western Interconnection.

- Support core mission success for UGP in the Western Interconnection.

Expansion of UGP's participation in the SPP RTO in the Western Interconnection addresses all five of these considerations, and is viewed as the best course forward, not only for the UGP region, but for the broader footprint as well.

b. UGP Background

UGP is situated differently than CRSP or RM. UGP is already a Transmission Owner Member of the SPP RTO, with limited participation in the Western Interconnection. UGP completed a public process and an extensive UGP Alternative Operations Study/Recommendation to evaluate the impacts and risks for UGP and support its decision to join the SPP RTO in 2015. Additional information related to UGP's overall process to join SPP are available at: UGP SPP RTO Membership. UGP's customers overwhelmingly supported UGP's recommendation to join the SPP RTO in 2015.

Specific details regarding UGP's SPP RTO membership and current participation in the Western Interconnection are:

- UGP joined the SPP RTO in 2015 as a Transmission Owning Member and Market Participant and transferred "functional control" of its transmission facilities (both East and West and including the Miles City DC-tie) to SPP at that time.

- UGP's transferred transmission facilities (both East and West) are in a single existing SPP pricing zone: Zone 19 Upper Missouri Zone (UMZ).

- UGP's applicable East generation and load are already in the SPP IM, which is SPP's full Day-Two Market with Real-Time Energy Balancing and Day-Ahead Unit Commitment.

- UGP considered in 2015 extending the SPP IM to include UGP's generation and load on the West. However, at that time SPP was not prepared to do that.

- UGP previously negotiated with SPP in 2015 and obtained FERC approval of necessary terms and conditions to allow it to join the SPP RTO and participate in the SPP IM (e.g., SPP Tariff Section 39.3 – "Federal Provisions"). One of the critical terms and conditions was the FSE to address Energy Policy Act of 2005 requirements. The FSE included exemptions for UGP from:

- Congestion market charges (and market losses) for UGP's deliveries from federal generation to federal load; and,

- Regionally allocated SPP transmission network upgrade costs given UGP's fixed service (no load growth) requirements.

- UGP retained its West WAUW BAA.

- UGP moves part of the West load and generation to the East and into the SPP IM during certain outages and maintenance activities.

- UGP entered into the "Westside Agreement" with SPP that includes provisions in the SPP "*Attachment AS: Western Area Power Administration Contract,*" which applies to UGP's West facilities and generation and load.

- UGP subsequently placed its generation and load in the WAUW BAA into the WEIS in 2021.

UGP would incur limited incremental changes to expand its participation in the SPP RTO, as follows:

- UGP would place its relatively small West generation and load directly into the SPP IM. No major market impacts for UGP are expected because it is already a market participant in the SPP IM in the East. Expanding the SPP IM into the West would greatly simplify UGP's East-West load switching, since all UGP applicable generation and load would be in the same market.

- UGP's West generation at Fort Peck and Yellowtail would be dispatched by the expanded SPP IM on a five-minute basis and incorporated into the day-ahead market. Those units are already registered, metered, and dispatched real-time by the SPP WEIS, and ready to be incorporated into the SPP IM.

- UGP would not require any new market software, tools, additions, or additional staff support, as UGP is already fully in the SPP IM in the East and developed those tools and market support staff in 2015 (and in 2021 for the WEIS). No major RTO workload changes are expected. Expected workload reductions in the WAUW BAA desk would create opportunities to provide additional support to other UGP functional areas, if needed.

- UGP would merge its WAUW BAA into the SPP BAA on the West and withdraw its applicable West generation and load from the SPP WEIS.

    - UGP's WAUW BA would stop providing ancillary services, which would be available under the SPP IM. UGP, as a Market Participant, would decide whether to offer such ancillary service products into the SPP IM, and as a load serving entity would still be responsible to either self-supply its needs or purchase them from the SPP IM, whichever is most efficient for the given time period.

- UGP's WAUW BA, would end its participation in the WPP RSG for operating reserves. SPP intends to join WPP as the SPP BAA operator to obtain and provide that service.

▪ UGP's Miles City DC-tie would be placed under the SPP IM five-minute dispatch and committed in the day-ahead market instead of the current hourly schedules and manual non-market ramps.

c. UGP Region Financial Implications

i. Cost/Benefit Summary

UGP anticipates that expanding its participation in the SPP RTO markets in the West would result in financial benefit to UGP's customers. The benefits are expected to grow over time due to increased market efficiencies, expanded FSE benefits on the West, and additional transmission owners and market participants joining the RTO-West.

Given the fact that UGP is already in the SPP RTO, the incremental changes for UGP are significantly less compared to CRSP and RM, and much of the cost/benefit analysis that drove UGP's decision to join the SPP RTO was completed in 2014 prior to UGP joining the RTO. UGP completed a public process and an extensive UGP Alternative Operations Study/Recommendation to evaluate the impacts and risks for UGP and support its decision to join the SPP RTO in 2015. UGP previously sought to also place its West generation and load into the SPP IM in 2015, but SPP was not prepared to implement that level of change in 2015.

The largest financial cost/benefit impacts and other issues that would be created for UGP occur if the SPP RTO (and associated SPP IM) is not expanded into the West, and UGP is forced to join a non-SPP RTO with part of its existing system that is already in the SPP RTO. UGP believes that RTOs in the West are inevitable, and it is a significant risk to UGP if its West facilities cannot remain in the SPP RTO.

UGP's financial and other impacts associated with the RTO-West expansion are detailed below.

(1) Market Benefits:

Market benefits of a fully integrated market come about by introducing optimized generation dispatch across the entire UGP footprint (East and West), thus reducing UGP's overall cost to provide its FES customers' allocation requirements through the added efficiencies of scale and process in day-ahead and real-time market constructs. In general, markets generally lower the purchase costs through the more effective and efficient dispatch of generation resources over a larger regional market area. UGP is dependent upon the seasonal hydrological cycle for its generation output curve, and during an average water year, is generally a purchaser through the winter months and a seller through the summer months. This normal water cycle aligns well with SPP IM being a summer-peaking market footprint, thus allowing UGP to maximize its net operating revenue while most efficiently supplying its customers' needs. The addition of the smaller West system into the SP IM would increase UGP efficiency in merchant operations in the West, thus contributing to more effectively meeting customers' needs well into the future.

The SPP IM has been estimated to bring benefits to the RTO-West region, and UGP has a projected share of those benefits. The market benefits are based upon the Brattle study completed for the RTO-West participants in 2022. UGP expected that the results would show a small net positive gain due to net purchases for UGP's zone for the APC analysis. This is because UGP's generation is purposely modeled in the Brattle study as essentially self-scheduled due to the process application of our FSE. This results in UGP generation being *non-price sensitive* and therefore the APC results do not show potential savings from offsets from other potentially lower priced generation from the market dispatch. Therefore, the APC results for UGP are intentionally conservative. UGP's WAUW BAA APC impacts in the Brattle study results are related to other potential purchases and sales, including to third parties.

Brattle's final 2022 estimated APC results show UGP's WAUW BAA benefiting by $124,000 per year in the RTO base case and $316,000 per year in the RTO low hydro case, compared to the existing case (i.e., WAUW BAA only in the WEIS in the West). The low hydro case is the assumed likely condition given UGP and WAPA's forecasted hydrology in the West. [36] Given the results are driven by purchases and UGP is forecast to be in potential drought conditions and would need to schedule much of its available West resources to the East, UGP is expected to drive these purchases in the WAUW BAA and therefore for purposes of this analysis is assumed to receive all the purchase benefits shown.

(2) UGP West-side Transmission Revenue Impacts:

Expanding UGP's participation in the RTO, by the extension of the SPP IM into the WAUW BAA footprint with RTO-West, would result in limited impacts related to UGP's West transmission system facilities. All of UGP's eligible transmission facilities were already included in the SPP RTO when UGP joined SPP on Oct. 1, 2015. SPP has overseen more efficient transmission planning for UGP's entire transmission system (both East and West) since 2015. The UGP transmission facilities (both East and West) are included in a

[36] https://www.wapa.gov/About/keytopics/Documents/2022-spp-rto-brattle-study.pdf

single SPP UMZ pricing zone. Currently, the UMZ is the only SPP pricing zone located in the West, and any network upgrades required under the SPP Integrated Planning Process (ITP) are allocated solely to the UMZ (with a portion allocated to UGP). The following summarizes the expected cost impacts:

- Wheeling revenues change from keeping the existing UMZ Point-to-Point revenues (for drive-out transactions) to keeping a shared portion of the entire West footprint Point-to-Point revenues. UGP, as a TO, currently only gets a share of the UMZ revenues for drive-out transactions given the size of the UMZ and multiple TOs in the UMZ. Based upon the 2022 Brattle study results, the impact to the wheeling revenues to the WAUW BAA footprint is a minor gain of $38,000 per year for the average hydro RTO case and $16,000 per year for the low hydro RTO case.[37] Given the UMZ is a single pricing zone, the impact of the wheeling revenue changes is borne by the UMZ transmission customers, regardless of which TO incorporates the reduction in revenues in its ATRR for the UMZ. UGP's customer load in the UMZ is around 24 percent based upon load-ratio share, therefore the UGP impact (benefit/cost) to UGP's customers is roughly 24 percent of the wheeling revenue gain/loss in the UMZ estimated in the Brattle study. Overall, given the Brattle study results, the wheeling revenue impacts for UGP are small enough to be within the margin of error for the study results.

- Potential DC-tie revenues would be received from outside the UMZ and from market use to address incremental operations and maintenance cost increases at the Miles City DC-tie. The Miles City DC-tie is already included in the UMZ as a "legacy" transmission facility, and the costs of the DC-tie are currently recovered primarily from UMZ customers. The SPP Board of Directors approved an Incremental Market Efficiency Use (MEU) in July 2022[38] that would assess the SPP IM (via an uplift charge) for the incremental cost incurred by UGP due to the increased wear-and-tear and earlier replacements of certain DC-tie equipment such as reactive switching devices, converter transformers, solid-state AC/DC conversion valve equipment, etc., removing that direct cost risk to UGP or the customers in the UMZ.

- No or insignificant pancaked transmission service revenue losses are expected due to UGP (or other UMZ transmission owners participating in RTO-West) not having load external to the UMZ (served from the UMZ) on the West and therefore having pancaked payments to the TO being eliminated. The de-pancaking cost shifts associated with transmission service revenues occurred for UGP when it joined the RTO in 2015 and were accounted for in the initial cost/benefit analysis UGP completed at that time.

[37] ibid

[38] The July 27, 2022 SPP Board meeting minutes and materials are posted publicly here. The recommendation to approve the negotiated DC-tie terms and conditions are on pages 56 through 60, and was approved as part of the consent agenda. The DC-tie Proposal Whitepaper referenced in the recommendations is posted publicly here.

- No additional transmission owners on the West are expected to include additional costs in the UMZ compared to that existing potential risk with UGP's current SPP RTO participation in the West.

The net effect of these transmission-related cost impacts is not expected to appreciably raise the UMZ rate or create any appreciable cost exposures to UGP that do not already exist independent of the RTO-West. UGP's detailed analysis and recommendations in 2014 addressed these transmission related cost impacts.

(3) SPP RTO Administrative Costs:

In transitioning to an RTO, certain functions would be performed by SPP rather than WAPA. However, for UGP the impacts of this transition have already occurred. UGP already pays the SPP administrative fees (Schedule 1A fees) as part of its RTO membership costs. UGP may have a minor increase in the SPP Schedule 1A fees with the expanded RTO footprint (i.e., due to increased 1A market related charges in the West). However, this would depend upon the final reduced SPP 1A charges accounting for the larger load and market billing factors with the RTO expansion. UGP anticipated this potential 1A charge on the West when it first joined SPP in 2015 and sought to have SPP extend the SPP IM across its WAUW BAA.

(4) Human Resource Costs:

UGP has already added any additional human resources needed when it joined the RTO in 2015 and hasn't identified the need for any additional resources to expand its participation in the SPP IM on the West. It is undetermined at the present if UGP would have any reduction in the number of FTE's due to merging its WAUW BAA into the SPP BAA, and if it did, UGP would be able to phase out using attrition. In summary, UGP doesn't expect additional human resource related costs or significant savings.

(5) Termination of WAUW BAA Services:

Transitioning WAUW BAA operations to SPP involves several impacts including:

- Elimination of WPP participation costs (approximately $42,000 per year) to the WAUW BA. The UGP Merchant would still need to acquire such "reserves" products within the SPP IM construct.

- Possible reduction in workload of the Watertown Operations Office Generating Desk due to elimination of WAUW BAA; however, given the overlap of duties where the Generating Desk performs transmission related dispatch tasks, which would continue after the elimination of WAUW BAA, and other pricing zone reconciliations, no reduction in FTE is expected. Any reduction in workload due to the RTO-West, would allow for increased support for workload in other functional groups within UGP.

- Seams coordination with impacted neighbors.

The financial impact of these changes is expected to be a small net benefit to UGP. Given the expectation that future UGP staffing requirements under the RTO-West may be marginally reduced, the small financial impact was not quantified. UGP has had preliminary discussions regarding the RTO-West evaluation with NorthWestern Energy and hasn't identified any significant seams issues.

(6) SPP IM West Implementation and Software Costs:

Transitioning to the SPP IM in the West would be a relatively minor change for UGP's Merchant, Settlements, Operations, and Transmission Services divisions compared to the other WAPA regions because UGP is already in the SPP RTO and most of its generation and load is already in the SPP IM on the East. The limited impact would be absorbed by existing staff without added cost expenditures. No additional software or software changes are required for UGP to transition from the WEIS to the SPP IM in the Western Interconnection.

(7) Capacity Benefits:

The WAUW BAA utilizes generation capacity from Fort Peck West generation to provide regulation, following and frequency response, and operating reserves for the WAUW BAA (8.9 MW for regulation and frequency response, and 7.5 MW for operating reserves, currently). Upon joining SPP and turning over BA responsibilities, UGP, as the WAUW BA, would no longer have this responsibility. Instead, the SPP IM would offer such ancillary services in the future from market participants' generation offers into the SPP IM ancillary service market. This released hydro capacity would be able to be utilized to fulfill other possible obligations within UGP's long-term power contracts. The change produces a financial impact. However, the net financial impact of this transition is complicated to estimate. UGP currently recovers these generation costs within the WAUW BA's Schedule 3 regulation rate and Schedule 5 and 6 operating reserves rates, and meanwhile incurs extra purchases to firm up power contract obligations, and so the net impact of having limited additional capacity available, and thus less purchase power incurred should be a benefit to UGP. Given the expected limited change, this impact is likely within the margin of error in being conservative with market benefits, and therefore a conservative approach of estimating no impact has been taken.

(8) Federal Service Exemption Benefits:

When UGP negotiated its 2015 membership in the SPP RTO, the terms included a FSE that under certain conditions exempted WAPA from congestion charges and marginal losses (two of the three components of the LMPs used in RTOs). This is a significant market benefit, but difficult to estimate into a dollar figure. This FSE would apply to UGP's system in the West with the SPP IM expansion over the existing SPP RTO footprint in the Western Interconnection. UGP recognizes the significance of this benefit, and although not estimated with a dollar figure, has this unknown level of benefit in mind with this recommendation to pursue the RTO-West.

In addition to the exemption from congestion and marginal loss charges, possibly more significant is the FSE exemption from regional transmission charges under certain conditions. As new transmission is built in the RTO-West, that portion categorized as regional in nature would be charged to load across the RTO-West footprint in a Schedule 11 transmission charge. UGP has received significant exemption from Schedule 11 charges for new SPP network upgrades in the East that are classified as regional costs, and if the SPP RTO footprint expands on the West to include multiple pricing zones as proposed for RTO-West, UGP would reduce its existing potential exposure to pay for network upgrades in the UMZ on the West. For much of its operations, WAPA would be exempt from this charge. This benefit is very substantial, and although likely starts out as zero in the West, it would grow substantially over time.

Considering all the costs and benefits together, where the other quantified non-market costs/benefits basically net to zero, or are insignificant, leaves UGP with an estimated net benefit in the range of about $100,000 to $300,000 thousand per year for the small portion of its system located in the Western Interconnection that isn't already fully in the SPP RTO and IM. UGP financial impact is one consideration in weighing the decision of whether to expand its SPP RTO participation in the West. However, the overall UGP concern of more importance, and a key concern of our customers, is to not impact UGP's current membership in the SPP RTO or bifurcate UGP's system. A decision to expand UGP's participation in the SPP RTO in the Western Interconnection would eliminate that risk.

16. TRIBAL GOVERNMENT OUTREACH

In June 2022, all three of WAPA's RTO-West participating regions reached out to Tribes with invitations to participate in virtual information sessions concerning the exploration of the benefits and opportunities in joining and/or expanding participation in the SPP RTO-West. CRSP and RM held a joint virtual session on July 12, 2022. Tribal customers have also been invited to participate in customer outreach meetings. UGP held a virtual session for Tribal customers on July 14 and has since met one-on-one with these affected Tribal customers. To date, none of the regional Tribes have voiced concerns. As part of the public process, WAPA will also hold a Tribal consultation to provide an overview of the recommendation to pursue final negotiations with SPP concerning membership and expansion of membership in SPP.

17. CONCLUSION AND RECOMMENDATION

WAPA recommends the RM region with its LAP transmission system, the CRSP-MC with its CRSP transmission system, and the UGP region with its PS-ED transmission system in the Western Interconnection enter final negotiations with SPP to join its RTO. If WAPA decides to proceed with final negotiations and if those negotiations are successful, CRSP and RM would join the RTO as transmission-owning members, and UGP would expand its participation. The WACM and WAUW BAAs would merge and be operated by SPP. This recommendation successfully addresses WAPA's five primary strategic considerations:

- Provide Risk Mitigation
- Optimize Transmission
- Support Reliability
- Optimize Resource Dispatch
- Support Core Mission Success

Proceeding to final negotiations for SPP RTO membership is urgent for several reasons. As discussed previously, although the SPP WEIS market has served as a near-term mitigating strategy, WACM and BAs across the West are working with a diminishing pool of capacity resources to provide the ancillary services that are necessary to ensure reliability in those footprints.
Also, with the current RA challenges facing the Western Interconnection due to conventional generator retirements, increased consumer demand during peak time periods, drought, extreme weather events, and climate change it is imperative that the ability to utilize more geographically and resource-diverse generation is increased as soon as possible. The SPP RTO would facilitate this and help mitigate the RA impacts facing the Western Interconnection for those in the RTO footprint.

Another reason this is urgent is due to the projected drought conditions facing much of the Western Interconnection and their impact on WAPA's customers. As drought conditions persist, WAPA produces less hydropower and must purchase more of the firm energy it needs to deliver to its customers from the market. RTO fully integrated markets have been shown to lower adjusted production costs. CRSP, RM, and UGP joining the SPP RTO as soon as possible is intended to ensure our customers are impacted as little as possible by the continued pressure on wholesale electricity prices. Results from the production cost analysis performed by The Brattle Group indicate savings of $81 million per year for the RTO-West footprint in low hydropower conditions when compared to the status quo.

WAPA needs to move quickly with this decision to support our customers in achieving federal, state, and local clean energy goals and regulations. Without an RTO, and the geographical and resource diversity associated with it, it will be very difficult to integrate sufficient renewables into the system to meet these goals and requirements. The SPP RTO is currently the best viable option, and it appears unlikely another option could be negotiated, developed, and implemented in time to provide support to meet the Administration's and various states' renewable energy goals.

A decision to not join the SPP RTO could be costly for both WAPA and the other participants, all of whom are WAPA customers. From an APC benefit perspective alone, which is usually a small portion of RTO benefits, the most recent Brattle study has estimated the SPP market expansion would generate adjusted production cost savings of $68 million under "average" hydrological conditions to over $81 million per year in low hydropower conditions for the West side portion of the SPP RTO. Any significant delay in the decision would prevent those savings from being realized. Additionally, there are potentially even greater benefits that would be generated from joint transmission development and planning.

There is currently no other RTO option in the Western Interconnection, and development of a different one, even if successful, would be time intensive and costly. SPP has an established and successful RTO that WAPA and other participants could expand participation or join with minimal tariff modifications, thereby reducing risk of delays, negotiation failures, and new market design deficiencies. Although tariff modifications would be minimal, ensuring they capture WAPA's business needs is critical to the success of WAPA and its ability to proceed with final negotiations. WAPA and the other SPP RTO participants, all of whom are our customers, have devoted extensive resources to negotiating membership terms and conditions for more than two years.

WAPA has previously been able to negotiate tariff modifications including numerous provisions that are essential for a federal entity to participate in an RTO. Although tariff modifications would be minimal, ensuring they capture WAPA's business needs is critical to the success of WAPA and its ability to proceed with final negotiations.

WAPA and the other participants, all of whom are our customers, have devoted extensive resources to developing terms and conditions for membership over more than two years. The ability to negotiate the same or similar provisions in a different market paradigm is uncertain.

SPP has been working with WAPA and our customers on deployment of RTO services in the Western Interconnection for over eight years, and the dedication of SPP and participant staff resources has been significant.

For these reasons, WAPA recommends moving forward with the decision to finalize negotiations regarding membership in the SPP RTO.

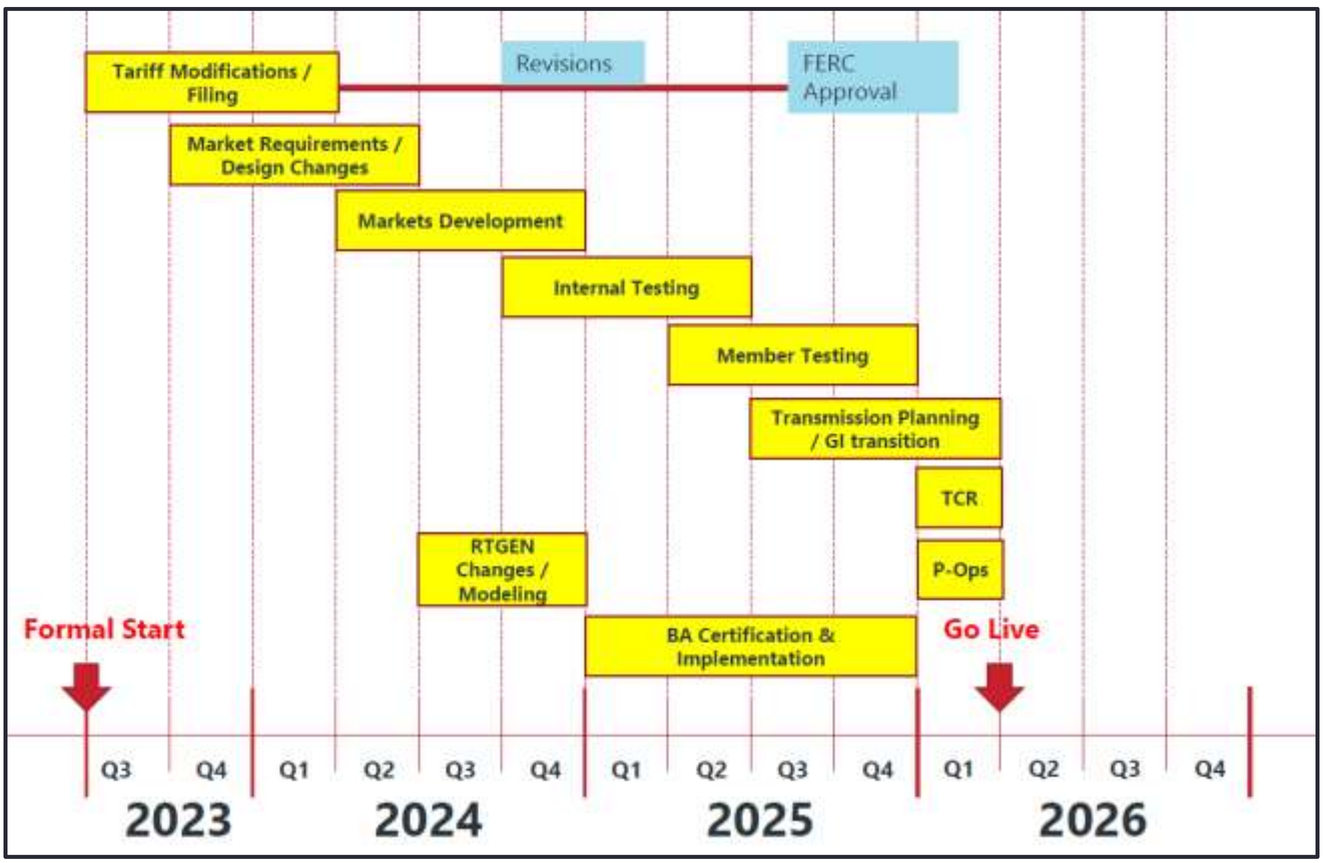
WAPA will review and consider all comments received through this public process and will strive to reach a final decision by summer 2023. WAPA will notify customers of our decision and post it to our website at https://www.wapa.gov/About/keytopics/Pages/southWest-power-pool-membership.aspx.

18. COMMITMENT AGREEMENT AND IMPLEMENTATION TIMELINE

Based on the internal analyses and input from the FRN public process, WAPA's Administrator may decide to suspend activity on pursuing negotiations for an RTO, or may make the decision to proceed to final negotiations, which would include the WAPA regions executing SPP Commitment Agreements. This is required by SPP in large integrations that are costly for SPP to implement. Signing the Commitment Agreements would obligate the participating entities to reimburse SPP for implementation costs in the event the West-side expansion does not go live. This is a mechanism to protect existing SPP members from being exposed to stranded implementation costs. If the West-side expansion becomes operational and the participants proceed and join SPP, the implementation costs would be recovered through SPP's administration charge paid by all SPP members.

Assuming the decisions are made to (1) move to final negotiations, (2) those negotiations are successful, and (3) the parties receive necessary approvals to proceed to implementation, the SPP timeline as of the date of this report is projected to be:

Figure 10: Draft Implementation Timeline



Source: SPP

APPENDIX 1: ACRONYMS

APC: Adjusted Production Cost
ATC: Available Transfer Capability
ATRR: Annual Transmission Revenue Requirement
BA: Balancing Authority
BAA: Balancing Authority Area
CAISO: California Independent System Operator
CROD: Contract Rate of Delivery
CRCM: Colorado River Colorado Missouri
CRSP: Colorado River Storage Project
CRSP-MC: WAPA's Colorado River Storage Project – Management Center
CSU: Colorado Springs Utilities
DSW: WAPA's Desert Southwest region
EI: Energy Imbalance
EMMO: Energy Management and Marketing Office
FERC: Federal Energy Regulatory Commission
FES: Firm Electric Service
FRN: Federal Register notice
FSE: Federal Service Exemption
FTE: Full-Time Equivalent
GFA: Grandfathered Agreement
GI: Generator Imbalance
IM: Integrated Marketplace
ISO: Independent System Operator
LAP: Loveland Area Projects
LMP: Locational Marginal Price
MISO: Mid-Continent Independent System Operator
MW: Megawatt(s)
NERC: North American Electric Reliability Corporation
NREL: National Renewable Energy Laboratory
OATT: Open Access Transmission Tariff
PRPA: Platte River Power Authority
PSCO: Public Service Company of Colorado
PtP: Point-to-Point Transmission Service
RA: Resource Adequacy
RC: Reliability Coordinator
RE: Reliability Entity
RM: WAPA's Rocky Mountain region
RSG: Reserve Sharing Group
RTO: Regional Transmission Organization
RTOR: Regional Through and Out Rate
SPP: Southwest Power Pool

SRP: Salt River Project
SSCD: Scheduling, System Control, and Dispatch
TO: Transmission Owner
UGP: WAPA's Upper Great Plains region
UMZ: Upper Missouri Zone
WACM: Western Area Colorado Missouri BA
WALC: Western Area Lower Colorado BA
WAPA: Western Area Power Administration
WAUW: Western Area Upper Great Plains West BA
WECC: Western Electricity Coordinating Council
WEIS: Western Energy Imbalance Service
WIUFMP: Western Interconnection Unscheduled Flow Mitigation Plan
WPP: Western Power Pool